Final Report:
Manitoba Hydro

PRS Ice Formation Study

Consulting Services Agreement #036927

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Initiative of
Manitoba Hydro

Manitoba
HYDRO INTERNATIONAL

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Winnipeg, MB – R3E 3G2

ATTENTION: Alan Aftanas

Subject: **Final Report – PRS Ice Formation Study**
Consulting Services Agreement 036927

Dear Mr. Aftanas,

The following Final Report details the activities, findings and recommendations of MHI regarding the study of ice formation at selected pressure reducing stations operated by Manitoba Hydro, the "PRS Ice Formation Study".

The conclusions and recommendations detailed in the following report have been based on MHI's understanding of certain key project inputs, site visits that were performed by MHI project staff during the course of the assignment, the industry experience of key project team members, and technical information provided by Manitoba Hydro.

We look forward to your comments on the report.

Best regards,

Scott Russell
Project Manager
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Content

FIGURES

TABLES

APPENDICES

1.0 EXECUTIVE SUMMARY

1.1. Background

As a vertically integrated electricity and natural gas utility, Manitoba Hydro (MH) owns and operates the transmission and distribution network for approximately 260,000 natural gas consumers. The network consists of over 7,000 kilometres of pipe and over 170 pressure reduction facilities. Natural gas is supplied to Manitoba via the TransCanada Pipelines (TCPL) mainline.

MH is experiencing a changing situation with regards to the inlet pressure and quality of natural gas supplied by TCPL. Reduced gas transportation needs have in turn reduced the compression required in TCPL's pipeline. The results of this reduction in pressure are decreased downstream gas temperatures and increased potential for ice and hydrate formation on internal components of pressure reduction facilities. MH has also experienced instances of increased moisture content in the gas supplied by TCPL, which has necessitated manual intervention to prevent internal freeze-off at its facilities.

MH has also faced ice formation on the outside of its station piping, pressure regulators and downstream isolation valves. The formation of ice has the potential to compromise the operation and maintenance of the pressure reducing stations as well as increases the risk of a major event and emergency situation.

1.2. Project Overview

It is MH's objective to quantify the risks associated with ice/hydrate formation, and formulate a strategy to not only mitigate the current risks, but also address a long-term solution. To do this MH has engaged Manitoba Hydro International (MHI).

The following provides an overview of the scope of work that was undertaken by MHI:

1. Information Gathering – MHI undertook a review of previous reports, design standards and specifications, O&M standards and procedures, and other relevant documents provided by MH. MHI and technical experts from MHI's project team visited the five selected facilities to gather first-hand data.

2. Risk Assessment – For the purpose of establishing the magnitude of the potential issue, MHI undertook a risk assessment which included a review of past reports and operational issues, an estimate of the ongoing operational costs, an evaluation of the historical quality and future quality trends of TCPL's gas supply, a probability-based risk assessment, and an evaluation of MH's current supplemental heating systems.

3. Evaluation of Internal Ice/Hydrate Formation – MHI then completed an analysis of the internal ice/hydrate formation on the five selected facilities which included a review of the pressure reducing station (PRS) design and components, identification of conditions under which ice/hydrate formation is more likely to occur, a recommendation of possible mitigation measures, and a pipeline heater

option including capital costs, operating costs, and energy consumption.

4. Evaluation of External Ice Formation – Similarly to point 3 above, MHI completed an analysis of the external ice formation on the five selected facilities which included a review of the PRS design and components, identification of conditions under which ice/hydrate formation is more likely to occur, a recommendation of possible mitigation measures, and a pipeline heater option including capital costs, operating costs, and energy consumption.

1.3. Analysis & Conclusions

Based on an analysis of the information provided by MH, TCPL, and other sources, first-hand site visits to a number of MH's pressure reducing stations, and completion of the risk assessment, internal ice/hydrate formation and external ice formation analysis, MHI has come to the following conclusions regarding the ice/hydrate issue faced by MH:

- MH is operating many of its pressure reducing stations at significant risk of internal ice/hydrate and/or external ice formation. The occurrence of either, particularly in severe weather conditions, may cause a disruption in the gas supply to a large number of consumers including to those that may be considered critical such as hospitals and extended care facilities.
- Based on previous internal studies regarding internal ice/hydrate and/or external ice formation in its facilities, MH is aware of the situation and many of the risks it faces. Although some mitigative measures have been taken, knowing this, in the consultant's opinion, MH must take the necessary steps to further mitigate the risks before an emergency situation/failure occurs as the inherent liability that MH faces could be substantial.
- Variability in the gas supply quality supplied by TCPL to MH, although within Tariff limits, is increasing the level of uncertainty as natural gas with water content higher than historically provided to MH increases the risk of internal ice/hydrate formation that may result in a significant emergency situation/failure. Accordingly MH's design basis and standards for pressure reducing stations should be updated to ensure designs are robust and able to operate its pressure reducing stations with high reliability in consideration of the variability in the gas supply quality.

1.4. Recommendations

MHI's recommendation for addressing internal ice/hydrate and external ice formation in MH's pressure reducing facilities is made in context of the conclusions above. As documented in the previous sections of the report, the climate and conditions under which the MH gas system operates, and current design basis of the pressure reducing stations, are conducive to internal ice/hydrate and external ice formation. Further, the risk may increase for internal ice/hydrate formation due to the potential for future variability of TCPL gas quality. Therefore, consistent with common gas industry practices the use of heat is recommended.

In more detail MHI recommends:

i. For the purpose of mitigating the dual risks of internal ice/hydrate and external ice formation, MH should significantly expand the use of heat in its pressure reducing stations. Proposed parameters/criteria for the application of heat are as follows:

- Primary flow heat should be installed in all pressure reducing stations with inlet pressure in excess of 2068 kPa (300 psig) and pressure reduction in excess of 2068 kPa (300 psig) and any one of the following:
    - Pilot controlled pressure regulators
    - Flow Measurement
    - Flow rates in excess of 1000 Sm3/hr (35.3 mcfh)
- Pilot gas heat should be installed for all pilot controlled pressure regulators with inlet pressure in excess of 2068 kPa (300 psig) and pressure reduction in excess of 2068 kPa (300 psig).

The above parameters/criteria have been incorporated into a “PRS Heat Requirement Matrix”, which is described in more detail in section 3.12.

MHI stresses that the application of the “PRS Heat Requirement Matrix” should be assessed with professional judgment and that additional parameters/criteria that may be applied at the discretion of MH, such as site-specific considerations, including:

- History of operating issues including regulator failures
- Indications of stress and strain on pressure reducing station piping or on the outlet pipeline
- The number of customers
- Service of critical customers
- The availability of an alternate or back feed supply
- Expected variability/consistency in the gas supply quality

It should be noted that this recommendation is made in the context that heat is the typical measure that is widely used by North American utilities, most of which have less extreme climates than Manitoba to address internal ice/hydrate and/or external ice formation.

ii. A second recommendation is that, whereas the “PRS Heat Requirement Matrix” was issued to determine which installation require heat, that Manitoba Hydro utilize the provided Risk Assessment as a tool to prioritize the retrofitting of pressure reducing stations with heat and developing an action plan for all pressure reduction locations by considering those sites indicating the highest scores being accorded the highest priority for implementation of mitigation measures.

iii. The third recommendation (preventative) is that MH review its pressure reducing station engineering and design standards and practices. Notably, as a basis of design, MH should be prepared for variability of TCPL gas quality such that its pressure reducing stations designs are robust and able to operate with high reliability for the full range of Tariff parameters (ie Water Content, H2S content, Pressure, Temperature). The standards and practices should incorporation of the use of heat, as described above should be included as a design requirement to address both internal ice/hydrate formation and external ice formation.

NB: A number of observations, suggestions and recommendations for possible inclusion in MH existing standards are provided in Appendix M.

1.5. Next Steps

MHI encourages MH to take prompt action to implement the above recommendations. Next steps may include:

Preliminary Tasks

- Use PRS Heat Requirement Matrix to identify PRS requiring heat.
- Apply Risk Assessment to prioritize and hence sequence the PRS upgrades.
- Develop a comprehensive PRS design document set.
- Develop an implementation/execution strategy (e.g. 3, 5 or 10 year implementation, contractor versus company execution, full upgrade versus retrofit).
- Prepare contract documents (e.g. for Engineering, Procurement and Construction (EPC) and Project Management Consultant (PMC)).

Annually

- Tender Contracts for Phased (Annual) PRS upgrades.
- Capture and document lessons learned and improve design document set.

2.0 INFORMATION GATHERING

2.1. Site Visit/Data Gathering

The following notes and observations resulted from site visits to MH facilities and meetings / discussions with MH personnel during the week of January 28 to February 1, 2013.

Table 1 – Meetings and Discussions

Date	Manitoba Hydro Attendees	Purpose/Discussion
January 28, 2013	Alan Aftanas, Doug Miller, John Kenny, Axel Thiem, Scott Russell, Tanis Guyot, Jim Desjardins, David Coleman, Jim Keil	Kick-Off Meeting
	John Kenny, Axel Thiem, Alan Aftanas	System Introduction and Background
January 31, 2013	Tanis Guyot	Engineering
	Jim Keil, Tim Starodub, Doug Miller, Tanis Guyot, Dave Petursson, Alan Aftanas	Engineering and Standards
February 1, 2013	Dan Prydun, Alan Aftanas	Standards
	Tanis Guyot, Alan Aftanas	Debrief/Status Meeting
	Jim Desjardins, Alan Aftanas	Operations

Site visits occurred January 29 and 30, 2013 and included 5 pressure reducing facilities selected by MH for study as well as 3 other pressure reducing stations with line heaters and one facility with a vortex pilot gas heater. Facilities visited include:

- Starbuck (GS-165)
- Russell (GS-103)
- Binscarth (GS-102)
- Niverville (GS-150)
- Ile des Chenes (GS-017)
- Transcona (GS-003)
- Fort Whyte (GS-020)
- City Gate (GS-001)

During site visits familiarization with station configuration and operation was done. External pipe temperatures were observed from inlet to outlet at the 5 pressure reducing stations identified for the study.

2.2. Natural Gas Supply from TCPL

2.2.1. TCPL Tariff

See Appendix B for information on the TCPL tariff.

2.2.2. Water Content of Natural Gas

- MH tariff maximum water content is 4 lb/MMscf (65 mg/m3). This tariff specification is consistent with other pipeline companies in Canada.
- Historical MH gas supply has originated from Empress gas processing plant where gas processing has ensured that the downstream gas supply has had very low water content (< 0.5 lb/MMscf).
- Recently a portion of the MH gas supply has come from Emerson and has had higher water content but still well below tariff (i.e. up to 3.5 lb/MMscf). However, this change has resulted in a number of operating issues.
- Future gas supply, while still compliant with the tariff limit of 4 lb/MMscf, may be more variable in quality, particularly with respect to water content. This variability is beyond the control of MH.

  NB: This higher water content gas may be introduced into the TCPL pipeline from various sources and including entering the TCPL system downstream of the Empress gas processing plant. Potentially, TCPL may use slip streaming when introducing gas into the system to ensure the total pipeline flow meets tariff values.
- Historically during slip streaming after pipeline construction or hydro-static re-testing, MH understands, TCPL has endeavoured to maintain 2 to 3 lb/MMscf water content as the objective.

2.2.3. H2S Content

The MH Tariff is that the H2S is a maximum of 23 mg/m3 or 16 ppm volume. Although TCPL Tariff allows delivery of natural gas at the maximum levels no information has been provided to MHI as to the actual H2S content historically provided to MH thus, as with the water content, H2S levels may have been considerably lower.

The significance of high H2S levels for the MH Ice Study is that elevated H2S may influence the development of hydrates. Specifically, if flow conditions result in free water being present, hydrocarbon gases [methane] (C 1), ethane (C 2), propane (C 3), and butane (n-C 4 and i- C 4) and /or impurities [nitrogen (N 2), carbon dioxide (CO 2) and hydrogen sulphide (H 2 S)], crystals may form and the mixture become solid.

NB: CSA Z662 states in Clause 12.3 “Distribution systems shall not be used to convey gas containing more than an average of 7 mg of hydrogen sulphide per cubic metre of gas at an absolute presssure of 101.325 kPa at 15 Celsius”. MH’s design standards and practices should fully address and consider the Tariff maximum allowable H_2S content.

2.2.4. Custody Transfer Metering from TCPL

- TCPL does not meter at each MH tap point/primary station. In locations where TCPL does not meter, MH meters the gas and provides information to TCPL.
- TCPL sales to MH are based on energy, which is measured by TCPL’s gas chromatographs. Thus MH does not require nor have its own gas chromatographs.

NB: During discussions with MHI it was suggested by some MH personnel that having gas chromatographs or getting real time data from TCPL as to gas quality would be to MH. However, the discussions did not identify conclusive benefits as MH operating personnel are already using all available tools to prevent operating problems. Thus additional responsive actions available to MH personnel if notified of low quality gas entering the system are presently limited to:

- Increasing frequency of station checks
- Increasing number of standby personnel
- Ensuring pilot heaters were in operation
- Removing external ice to ease operating PRS valves

The benefit of these response actions and thus the value of real time data may not justify the expense of acquiring it.

2.3. Pressure Reducing Station Configurations

NB: The following notes and observations relate only to the pressure reducing stations observed by MHI during the course of the study.

Notes/Observations based on site visits by MHI to 5 pressure reducing stations:

- MH has, in some circumstances where high stress and strain are anticipated, selected and installed weld body regulators and ball valves (e.g. Angle Road Station). This is MH's current design standard for all new stations.
- Stations are designed to be rigid but MH personnel confirmed that residential customer meter sets are designed with single and often double swing arms to accommodate soil movement. Residential meter sets have swings to accommodate soil movement, however larger customer meter sets are typically supported by piles or pipe supports and do not have swing joints.
- Below ground headers have been utilized in some stations as noise mitigation. The adverse effect of this is rigidity of the piping as well as greater chilling of the ground.
- With the exception of Starbuck and St Malo, MHI observed no “for purpose” swing joints or expansion loops on station inlets and outlets intended to mitigate stress.
- Weld end regulators and valves, both Mooney and Fisher EZR, due to stress and strain in stations. Similarly a decision has been made to use weld end valves in stations.
- Adopting ball valves instead of plug valves in stations.

2.4. Pressure Regulators and Pilots

Notes/Observations:

- Using lead/lag runs with different manufacturers regulators was suggested as one way of avoiding similar failures of each lead/lag runs.
- MH has a variety of configurations (e.g. worker/monitor, monitor/worker, full relief) in its stations. Although MH Engineering has a selection table in its draft station design manual it is not clear that

Operations is aware or implementing this. Discussions with MH personnel did not establish clear benefit of any configuration although it was generally observed that worker monitor would expose the monitor to colder J-T temperature post pressure reduction

- S-20 Mooney Pilot has been adapted for use with axial flow, Fisher as it has greater pressure range, easier maintenance (i.e. cartridge containing needle and orifice) can be removed and exchanged (Spring exchange is also easy). Singer and Fisher have been left in place where it is performing.
- Fisher 627M & HM performance is moderately good, however failures still occur.
- Configuration Monitor/Worker versus Worker/Monitor versus Working Monitor:
    - Worker/monitor for environmental considerations.
    - No apparent preferred configuration with respect to reducing the effects of hydrates were observed by MH personnel
    - Axial flow regulators - due to issues of servicing stations that are subject to heaving EZR and Mooney regulators are often used to replace axial flow regulators. Operationally axial flow, EZR or Mooney are acceptable. However MH has pursued elimination of axial flows as reliefs due the need for improved accuracy of relief pressure (e.g. stiffness of boot as locked up for long duration and in cold. Influences accuracy of relief). Typically MH is replacing Axial Flow reliefs with EZR reliefs
- Design velocities:
    - Pipelines 10-20 ft/s
    - Stations 75-125 ft/s

2.5. Pressure Reducing Station Inlet Temperature

Notes/Observations:

- Observations during site visits of pipe external surface temperature as well as MH SCADA temperature readings, primarily on meter runs, validated the assumption by MH of 0 Celsius as a design inlet temperature.
- Although Environment Canada Data suggests the ground temperature at the typical depth pipelines are buried may be much lower (e.g. at 1 m depth for 3300 degree days F ground temperature may be as -5 to -10 Celsius)[1], this higher temperature may be attributed to the insulating effect of snow cover and/or the rate of thermal conductivity of the soil to the pipe.

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[1] (See reference documents in Appendix O)

2.6. Pressure Reducing Station Sites

2.6.1. Selection

- Geography in Manitoba dictates that pressure reducing stations sites are often low lying with high water tables.
- The presence of organics, silts and clays is also common.
- Site selection is often restricted in that dryer sites are often significantly more expensive or already occupied for other purposes.

2.6.2. Site Preparation

Notes/Observations:

- Recognition of the impact of site conditions, particularly high water tables, MH has done more site preparation on recent station installations.
- Site preparation currently included the use of select fill at stations and/or insulation on station outlet piping in an effort to reduce the likelihood of underground external ice formation below the buried pipe which could cause heaving.
- It is not clear that drainage has been included to actually remove water and no sumps or pumping was identified.

2.6.3. Foundation Design

Notes/Observations:

- Geotechnical site investigation is not typically done.
- Foundation design for foundations is generally a standard empirical design rather than site specific.

2.7. Odorization

Notes/Observations:

- MH uses a blend of 80/20 by weight TBM & MES Gas Odorant from Chevron
- There have been no issues of hydrates interfering with injection or bypass odorizer operation.
- Most of MH’s odorant injection occurs upstream of the PRS using injection systems by YZ Systems.
- Some odorant systems are pulse bottle type systems. These are controlled based on metered gas volumes through the station.

2.8. Pressure Reducing Stations

2.8.1. Ile des Chenes (GS-017)

Notes/Observations:

- In spring, summer and fall outlet pressure is reduced to provide a high flow rate. This is done to aid mixing and prevent dropout of odorant in downstream piping.
- Ile des Chenes gets worse J-T but reduce J-T at downstream stations. (NB: Some downstream stations such as St Norbert and Oak Bluff have been shut down during summer.)
- On a regular basis, 2 or 3 times annually, the 12" turbine meters fail. This is attributed to ice buildup and stripping of the turbine gear assembly (ice is external to the pipe but internal to the gear drive mechanism in the meter). The cost of replacing the module each time is approximately $8000 plus labour.
- Welker pressure regulators are used in Ile De Chene station and were selected for their high capacity and low noise. These have proven to be robust and dependable pressure regulators.

2.8.2. Transcona (GS-003)

Notes/Observations:

- Some heaving is occurring in the vicinity of the pressure reducing run.
- It is not clear if this is due to thermal transmission in concrete pile or simply a result of the type of soil surrounding it.

2.8.3. Selkirk (GS-004)

Notes/Observations:

- Upgraded to new station design standard due to ice induced movement and concern about excessive strain.
- Line heater provision in piping
- Survey monitoring of underground ice induced pipe movement was initiated and records are available.

2.8.4. St Malo (GS-167)

Notes/Observations:

- Identical to Starbuck configuration
- Currently fed from Emerson (wet gas) and has many operating problems.

NB: On Feb 5, 2013 MH removed slightly over 4 liters of liquid. The substance had a smell similar to kerosene, and was flammable when a flame had direct contact with the liquid, very similar to how kerosene may possibly ignite. The substance is being sent to the lab for analysis. The regulation run that the substance was removed from had a heater on the regulator body, the regulator that did not have a heater had ice of which was the source of the initial problem. MH suspects that the liquids could be coming from a compressor out of the Great Lakes system, as they are using oil based lubrication and, although unsubstantiated, they have had some problems. MH has been informed that TCPL is investigating this as well.

2.8.5. Angle Road Gate Station (GS-182)

Notes/Observations:

- Evaluation of stress on piping.

2.9. Operating Issues at PRS

MH provided a list of operating issues at PRS. The list has been screened to eliminate issues that were clearly not ice related. Additional screening may eliminate additional issues however, as is, the list indicates the maximum number of issues 2002 to present is 413 averaging over a ten year period about 41 per year. Although MH operating personnel have indicated that the number of issues has increased due to wet gas the number of recently reported issues does not indicate a marked increase. This may be attributable to any number of issues with the reporting including it not capturing the significance of current issues.

2.10. PRS Equipment Selection

Notes/Observations:

- In general most of MH equipment selection is industry standard.
- MH is eliminating Singer Axial Flow Regulators in favor of Fisher 399 EZR regulators. It is understood this is partly due to performance (i.e. responsiveness particularly in monitor and relief configurations) but primarily due to pipe stress and strain making the removal and replacement in line difficult and even dangerous.

NB: MH has, in some circumstances where high stress and strain are anticipated, selected and installed weld end regulators and ball valves (e.g. Angle Road Station).

- MH favors Mooney S20 pilots and is using them with some other manufacturers’ regulators in part due to great performance but mostly due to the ease of maintenance (i.e. modular).
- MH has Welker pressure regulators in its Ile des Chenes Primary Station. Although this is the only location MH have had excellent service from these regulators, which are available from 1" up to 8"x12". Potentially these regulators are a better choice for pipeline conditions where potential for hydrate formation exists.[2]
- MH operations personnel suggested that using electric rather than pneumatic pilots may resolve many problems.

2.11. System Pressure

Notes/Observations:

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[2] http://www.welkereng.com/engineering/products/WelkerJet.html

- TCPL – Contract minimum delivery pressure is 580 psig. Normal has historically been 700 to 720 psig. Maximum historical has been 880 psig.
- Transmission (greater than 275 psig) – varied seasonally with reduced pressure in spring/summer/fall for safety (i.e. Ile de Chene outlet pressure is varied between 500 psig in winter and 350 psig in summer (to reduce the risk in the event of activity on the right of way) to maintain a high velocity for odorant mixing and to reduce the pressure cut at downstream stations.
- High Pressure (80 to 275 psig) – The majority of the Winnipeg High Pressure system has an MOP of 150 psig. However, a number of supply laterals have a higher MOP of 225 psig. Rather than introducing an additional level of pressure reduction the stations supplying these laterals are controlled by remote sensing (Kixcells). In this way the laterals are operated at up to their MOP to ensure that sufficient supply pressure is delivered to the 150 psig system.
- Distribution (Medium Pressure at 60 psig and less, with some rural elevated MP systems at 61 to 100 psig) – Typical distribution systems have an MOP of 60 psig, however, many are operated at lower pressures as the higher pressure is not required to deliver adequate gas. Additionally, operating personnel believe the higher pressure will cause issues for them stopping off damaged gas lines.

  NB: For systems currently operated at 30 psig changing the MOP to 60 psig would reduce J-T effect by as much as 2° Fahrenheit.

2.12. Data Monitoring

All manual pressure recorders for Pressure, Volume and Temperature have been eliminated. Some stations have SCADA systems, but for others the sole available indication of performance is pressure gauges and reliefs. During station check for these facilities personnel get only single point in time feedback from pressure gauges as they cannot see the historical performance (i.e. fluctuations in control pressure that may be indicative of past loss of control that may be predictive of pending failures).

2.13. Configuration of Equipment and Piping

Notes/Observations:

- Pilot regulator tubing is standardized at 3/8" for lengths less than 10'. For lengths of 10' to 20' tubing of 1/2" is specified. For lengths above 20 feet increase one pipe size.
- Using lead/lag runs with different manufacturers' regulators was suggested as one way of avoiding similar failures of each lead/lag runs.
- MH has a variety of configurations (e.g. worker/monitor, monitor/worker, full relief) in its stations. Although MH Engineering has a selection table in its draft station design manual, it is not clear that operations personnel are aware or implementing this. Discussions with MH personnel did not establish clear benefit of any configuration although it was generally observed that worker/monitor would expose the monitor to colder J-T temperature post pressure reduction
- Design velocities:
  - Pipelines 10-20ft/s

  - Stations 75-125 ft/s
- Filters are not used on MH stations. Some stations, and the draft station design manual, have single strainers (100 mesh or 149 micron). These strainers require station bypass to be serviced. It was noted that at one station basket strainers were installed on the flanges of the inlet valves on regulator runs.
- No hydrate issues have been identified in strainers.

NB: After one strainer at Stonewall was fully blocked with debris resulting in the loss of approximately 1200 customers in 2004, a program of annual venting with 5 year removal/inspection of strainers was implemented.

2.14. Corrosion

Notes/Observations:

- Visual observations of corrosion during site visits were limited to surface corrosion where paint had been damaged through routine operating and maintenance activity including ice removal efforts.
- MH advised that at the Transcona station corrosion pitting was discovered under the insulation resulting in the removal of insulation. Inspections of pipe under insulation at other stations is now being completed by MH.
- There has been no indication of significant increased corrosion under external ice except for surface corrosion due to paint damage.

2.15. External Ice

A number of MH's stations are subject to external ice formation year around. Two distinct variations of external above ground ice are encountered.

- In winter a snowy hoar frost build-up is most common. However in spring, summer and fall dense, solid ice tends to form.
- This later form of ice is heavier and much harder to remove. MH does not routinely as part of station checks remove above ground external ice. MH only removes ice if it is necessary to do so for immediate operating functions.

MH's options for external ice removal include:

- Physical Removal - may cause damage to pipe coating
- Moving pipe
- Hot water - however any pooled water, such as may develop on concrete surfaces or frozen ground below piping, may be a hazard
- Methanol – while not encouraged practice, operating personnel may be removing some ice using methanol, particularly dense hard ice. This may have led on one occasion to triggering of a gas detection alarm.

- Glycol
- Heat
- Propane heater
- Infrared
- Electric
- Catalytic

2.16. Industry Best Practices

MH has made efforts to inform its personnel and adopt industry best practices. It is a member of the Canadian Gas Association (CGA) and has availed itself of this membership to submit an SOS request to CGA for Tabulation on Line Heater Use as well as Pipeline Dust.

MH is also aware of current technology as follows:

- SaskEnergy's use of CWT (Cold Weather Technologies) Line Heater.
- MH personnel are familiar with CWT Line Heaters.
- Although widely used in Saskatchewan and in other jurisdictions, MH believes these heaters are not approved for use in Manitoba.

MH has the most current technologies for heating pilot gas:

- Catalytic heaters
- Electric heaters
- Vortex heaters

2.17. Line Heaters

Notes/Observations:

- MH's use of line heaters at three stations, Ile des Chenes, Fort Whyte and Transcona, has largely resolved the ice induced pipe stress and operating issues.
- Transcona is an example where operational problems can arise from building a station with non site specific design without geotechnical investigation at a non-optimal site with high water table and poor soil conditions.

2.18. Pilot Gas Heaters

2.18.1. Catalytic Heaters

Notes/Observations:

- MH is not currently using catalytic line heaters or catalytic infrared heaters to heat pipe, however they are used to heat regulators and for pilot gas heat in some cases.
- Generally the use of catalytic heaters is initiated and done as an operating response measure without Engineering consultation or support.
- Installations are considered temporary and are done by mounting the heater on a shop fabricated angle iron frame.
- MH has used both Bruest & Catadyne but current purchases are of Catadyne.
- Estimated cost:
    - $1800 for 1800 Btu
    - $2500 for 5000 Btu

- There is a limited life expectancy of catalyst heating pads. Based on MH experience, even allowing for drying (baking) of wet pads, the real life expectancy of pads is limited to 2 years. Heating pads can be replaced at cost of between 25% and 50% of the cost of a replacement heater.

NB: MH is buying 5000 Btu units in part on the premise that the unit cost per Btu is lower and that even a partially depleted heated pad will still yield enough heat for heating pilots.

2.18.2. Electric Radiant Pilot Gas Heater

Notes/Observations:

- Caloric Electric Heaters (350 watt) have recently received approval for Class 1 Div1 installations by CSA.
- MH has purchased 2 of these units and optimistic about their use as they are thermostatically controlled and the opportunity exists for remote control.
- MH intends to test these two units for possible wider utilization.

2.18.3. Vortex Pilot Gas Heater

Notes/Observations:

- MH has one of these heaters in service but has had little success with it to date.
- Based on observations made during the site visits, the lack of success may be attributable to incorrect setup. MH intends to change the setup or try the heater in an alternative location to assess the viability of this equipment.
- As the vortex pilot gas heater provides a non-energy consuming, no emissions and low even no maintenance source of heat that can be left in operation year around it is strongly suggested that MH resolve the issues with the equipment on hand.

2.19. Station Design Standards

Notes/Observations:

- In addition to corporate approved standards MH Engineering station designs are done with reference to the draft station design manual.
- No standard drawings were provided, however drawings showing a recently used design compliant with the draft station design manual were provided. The drawings provided to MHI from recently installed stations were in fact indicative of the station design that is currently used at all locations. MH staff reported that they are actively working on the completion of standardized designs.
- Select stations have been upgraded or remedial work has been done. This station work has generally included excavation and/or replacement of the station outlet piping with the new configuration being to have select fill surrounding the pipe and insulation below the pipe. The objective has been to eliminate pipe contact with fine soils that would contribute to underground ice formation via capillary action of water being drawn out of the soil by the cold emanating from the pipe. More specifically the objective has been to prevent or minimize frozen soil below the pipe and thus limit heaving that would induce stress on the pipe.

3.0 RISK ASSESSMENT

As the second major component of the project, MHI undertook a comprehensive risk assessment focusing on various aspects and variables associated with the formation of internal and external ice/hydrates. The outcome of this component of the overall study is to determine what is currently known about the problem, the costs and risks associated with continuing to address the issue as it is currently addressed and a quantifiable method for assessing the likelihood of a pressure reducing station failure based on relevant criteria.

Activities included:

- A review and comment on previous reports provided to MHI relating to this issue.
- A discussion and quantification of the historical operational issues that have occurred at the selected pressure regulation facilities.
- An estimation of the ongoing operating costs of the necessary repairs to pressure reducing stations related to external ice formation.
- An evaluation of TCPL's historical gas quality as well as a forecast of future trends in gas quality.
- The completion of a probability based risk assessment of potential outages associated with ice formation as well as the creation of a PRS Heat Requirement Matrix.
- An assessment of MH's three current supplementary heating systems.

3.1. Review Previous Reports

As mentioned in Section 1.0 - Info Gathering, MHI was provided with the following reports:

- Study On Regulation Station Freeze-Up – Oct 28, 1996
- Report on Natural Gas Line Heater Installation - DDW-G2011-O1 – Oct 21, 2011
- Notes from a discussion among the leadership team at GAM&C, regarding operating concerns at station pressure reduction facilities – 2012

Generally, the reports established that MH is aware of ice/hydrate formation issues at its regulating stations and uses a number of reactive techniques to address the issue in the short term. The reports did not appear to consider the full scope of the issue and risk faced by MH, nor did they detail the path to implement a comprehensive solution. Based on MHI's review there appears to be reluctance within MH to adopt the use of line heaters, which is a generally accepted industry practice (see CGA and AGA SOS reports in Appendix G).

3.1.1. Study On Regulation Station Freeze-Up – Oct 28, 1996

Notes/Comments:

This report focused solely on internal ice formation. The following recommendations were made based on the finding of the report:

> *To reduce the possibility of hydrate formation and the resulting station freeze-off and potential customer outage, the following recommendations are made:*
>
> 1. *Prior to energizing, transmission lines be dehydrated to a -40°C dew point to remove all residual water.*
> 2. *The inlet lines to pressure regulation stations be insulated to minimize heat loss. Following the first pressure cut, insulation is not required.*
> 3. *New town border stations be equipped with a source of supplemental heat and/or inhibitor (alcohol or methanol) injection to prevent hydrates.*
> 4. *Supplemental heat and/or inhibitor injection be re-evaluated after a year or two or after substantial customer attachments and the associated load has occurred.*
> 5. *Avoid oversizing of regulators. Consider installing regulators for current load replacing them with larger regulators when load increases.*
> 6. *Operate transmission systems at as low a pressure as is practical.*

Based on the reference to supplemental heat in the body of the report as being to catalytic heaters, this report recognizes the need for heat for pilot gas, but has not addressed line heaters. Further, while MH does use pilot gas heaters at some stations, pilot gas heater use is not universal in the system. MHI was provided with MH's draft station design manual however it does not incorporate this mitigation measure as standard nor has it been applied in practice. It should also be noted that recommendation no. 4 is for a follow-up re-evaluation. MHI was not provided a copy of this re-evaluation however has been informed that it was executed on a station by station basis not as a single re-evaluation and that this re-evaluation would typically consist of field trials of operating without supplemental heat and assessing the station operation.

3.1.2. Report on Natural Gas Line Heater Installation - DDW-G2011-O1 - Oct 21, 2011

Notes/Comments:

It is not apparent that the conclusions and recommendations of report are fully supported within the body of the document. The primary recommendation is:

> *Manitoba Hydro should not pursue the installation of line heaters at this time, as there is insufficient technical evidence that this action will decrease the probability of future system failures.*

However, other sections of the report explain the benefits of use of line heaters.

A secondary recommendation to install gas chromatographs is mentioned in the body of the report and in the recommendations.

> *Re-establishment of a regular online gas chromatography analysis of TCPL gas supply.*

It is not made clear how gas chromatographs benefited MH in the past, nor does it detail the rational that was applied to justify their removal. The document also does not address how re-installation of gas chromatographs would aid MH in responding to conditions that may result in ice formation. Presumably MH is at all times applying all available mitigation measures whereby any advance warning of advisers changes in the gas composition would have little value. It should also be noted that the second recommendation, re-establishment of regular online gas chromatography analysis of the TCPL gas supply, has not been implemented at the date of MHI's study.

3.1.3. Notes from a discussion among the leadership team at GAM&C, regarding operating concerns at station pressure reduction facilities - 2012

Notes/Comments:

This document is essentially comprised of two sections:

1. List of general concerns at stations.
2. Strategies Currently in use at MH.

While these sections provide valuable background information and observations for MHI's analysis and report, no actionable conclusions and recommendations are made.

3.2. Historical Operating Issues and the Impact of Potential Outages

3.2.1. Historical Operating Issues

During the assessment, MHI noted that historical operational costs due to ice formation have not been specifically tracked nor documented. Rather, MH has treated these costs as a normal operating expense and in some respects response to ice formation has become a normal operating activity. The result is that analysis of operating records is dependent on identification of operating activities that may have been the result of ice formation. As such this situation suggests that reporting does not distinguish operational costs associated with ice formation from other operating costs.

Regardless, a search of MH pressure reducing station operating records (see Appendix E - PRS Failure Reports (2002-2012) identified that as many as 412 failures that may have been related to ice formation have occurred in the period 2002 to 2012. The number failures by year are shown in the following Table 2:

Table 2 – Failures by Year

	Number of Failures					
Year	**All Stations**	**GS-102 Binscarth**	**GS-103 Russell**	**GS-017 Ile des Chenes**	**GS-150 Niverville**	**GS-165 Starbuck**
2002	8	0	0	0	0	0
2003	23	0	0	0	0	0

2004	98	2	0	2	2	3
2005	52	0	0	1	1	1
2006	33	0	0	0	3	1
2007	36	1	0	1	0	0
2008	56	0	0	1	2	0
2009	30	0	0	2	3	0
2010	24	0	0	0	2	0
2011	23	1	0	2	1	0
2012	29	0	0	0	0	3
Total	413	4	0	9	14	8

Notable is the disproportionate number of failures recorded in 2004 however MH has communicated to MHI that that abnormally low winter temperatures explains this increase in reported failures. Further, while the selected stations represent only 2.9% (5 of 170) of MH's pressure reduction facilities they account for 8.5% (35 of 413) of the reported failures with 2.2% (9 of 413) of the reported failures occurring in one of MH's most critical primary stations Ile des Chenes.

Also notable is that MH has indicated an increase in failures largely due to a change in the TCPL gas quality and pressure, which has caused them to initiate the current Ice study. However, the records of failures does not substantiate this perceived increase in the frequency of failures as the number of reported failures in 2010, 2011 and 2012 remains at or below historical levels. For this reason the value of evaluating the historical operating records based on reported failures must be carefully considered. It must be further stressed that MH failure reporting is not focused on identification of the cause of failures particularly with respect to ice as the causal effect. As such the perception of operating personnel that MH is experiencing an increase of ice related operating failures is not discounted.

3.2.2. Impact of Failures

Evaluating the operating costs of ice related failures, considering the reported failures documented above is done on the following basis:

Average number of failures per year – 41
Number of man-hours per failure (2 man team including travel time) – 8
Fully loaded labour rate inclusive of vehicle - $180

Total Annual Operating Cost (approximate) = $59,000

For the selected pressure regulation facilities Ile des Chenes has anecdotally been reported to have 2 or 3 turbine meter module failures each year that are attributed to ice formation. The cost per failure is estimated, inclusive of replacement modules, to exceed $10,000 per failure.

3.3. Potential On-going Operating Issues

The following diagram provides a graphical illustration of both the technical factors that affect and increase the risk of ice formation, as well as the associated costs.

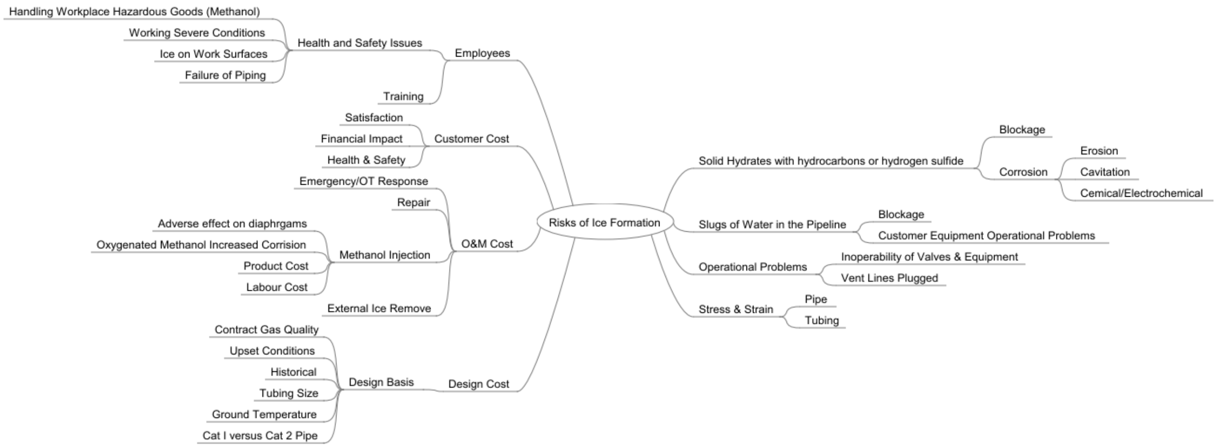


Figure 3.1 – Potential on-going operating issues

3.3.1. Operating Costs – All Stations

MHI understands that MH methodology and procedures to address stress and strain on piping due to external ice is undocumented. Each station is understood to be evaluated (criteria for action) and acted upon (corrective solutions). While the criteria is qualitative a number of corrective solution to mitigate the effect of external ice are used by MH include:

- Release pipe from rigid supports to allow movement due to ice build-up.
- Place temporary supports when pipe has lifted off permanent supports.
- Extend regulator vent lines.
- Painting surface damages by ice or that are damaged during ice removal.

NB: It is recommended that clear guidance be given to operating personnel regarding the acceptance by MH of the use of chemicals or liquids (e.g. methanol) to remove external ice. MHI was not provided with operating procedures that communicated if the use of such chemicals or liquids was either officially condoned or officially rejected.

The result is that routine operating costs due to external ice formation are low. Evaluating the operating costs of external ice related operating failures, considering the methods above, is done on the following basis:

Average number of stations requiring support adjustment and re-painting – 40
Number of man-hours per adjustment (2 man team including travel time) – 4
Number of man-hours per re-paint (2 man team including travel time) – 8
Fully loaded labour rate inclusive of vehicle - $180

Total Annual Operating Cost (approximate) = $43,000

3.3.2. Operating Costs – Selected Stations

Where external ice formation causes pipe heaving to occur, this heaving causes strain on station equipment (piping and structures). This is a concern during equipment maintenance and can have a negative effect on the pipe coating. MH current criteria for remedial action is not documented and given the long standing history of heaving largely tolerant of heaving.

Gate / Reg Stn #	Name	Location
GS-102	Binscarth	Binscarth, MB
GS-103	Russell	Russell, MB
GS-017	Ile des Chenes	Ile des Chenes, MB
GS-150	Niverville	Niverville, MB
GS-165	Starbuck	Starbuck, MB

As indicated in the individual assessments below, the most significant directly attributable operating cost impact occurs at Ile des Chenes, namely repeated failure of the turbine meter that is attributable to internal ice formation. Other directly attributable costs are relatively minor (e.g. external ice formation and associated damage to pipe coating). Although there is pipe movement due to underground ice formation the associated direct costs (i.e. jacking up/blocking pipe, cutting out building panels to accommodate movement) are minimal. Ultimately the potential costs associated with the risk of a significant interruption in gas supply or a pipe failure due to stress is more significant.

For the five selected stations, external ice formation issues have regularly occurred during prior years. To this point, the measures taken by MH can be described as routine remedial actions. MHI has assumed that the external ice was known, accepted and was not seen as a non-conformance. Therefore, MHI has considered ongoing operational costs to include only these remedial actions.

As indicated in the above, the only directly attributable cost MH is currently incurring due to external ice formation is for re-painting. For the five selected stations this is limited, totalling less than $2,150 annually based on these stations representing only 5% of the number of stations. It must be stressed that the valuation of the risk of a significant failure is not considered within this figure.

3.4. Binscarth (GS-102)

Location: Binscarth, MB

Few internal ice formation problems have been reported at this station. It is possible that this is attributable to the station being on the TCPL section of pipeline that has for many years and still to date receives its gas supply from Empress Processing Plant. Although the station develops significant above ground ice, other than being a potential issue in that it can delay emergency response, no related operational issues have been identified with the mitigation measures used by MH (i.e. extended vents). As risers and above ground pipe installed to the bypass is apparently acting as a swing joint accommodating any movement due to underground ice formation.

Estimated quantified impact of ice formation is limited to re-painting.

3.5. Russell (GS-103)

Location: Russell, MB

Few internal ice formation problems have been reported at this station. Although the station develops significant above ground ice, other than being a potential issue in that it can delay emergency response, no related operational issues have been identified with the mitigation measures used by MH (i.e. extended vents). As the risers enter the station directly there is no inherent swing joint to absorb the movement so the station goes through annual shifting due to underground ice that is accommodated via jacks and blocking. Particularly without exposing the underground pipe there is no practical method of accurately assessing the resulting the stress and strain on the piping.

Impact of ice formation is the need for adjusting jacks and/or blocking of piping as well as re-painting.

Additional photos of GS-103

3.6. Ile des Chenes (GS-017)

Location: Ile des Chenes, MB

In spring, summer and fall outlet pressure is reduced provide a high flow rate as this is believed to aid mixing and prevent dropout of odorant in downstream piping. The effect of this change is that Ile des Chenes experiences a somewhat greater J-T temperature effect during these months but that there is a reduced J-T temperature effect at downstream stations. There are signs of significant movement of the meter runs downstream of the pressure regulation including shifting in building siding and cut outs made to accommodate the movement.

Additional photos of GS-017

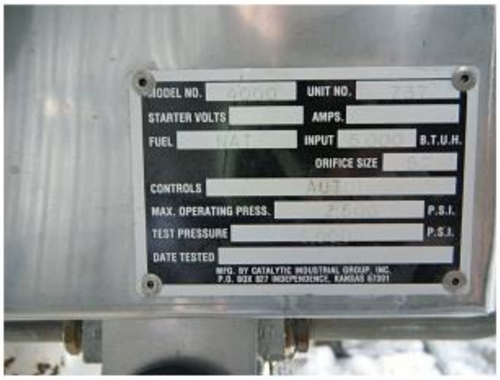
3.7. Niverville (GS-150)

Location: Niverville, MB

Internal ice problems at the Niverville station are being mitigated through the use of a catalytic heater that is temporarily positioned at the station. Although the station develops significant above ground ice, other than being a potential issue in that it can delay emergency response, the mitigation measures used by MH (i.e. extended vents) no related operational issues have been identified. As the risers enter the station directly there is inherently no swing joint to absorb the movement so the station goes through annual shifting due to underground ice that is accommodated via jacks and blocking. Particularly, without exposing the underground pipe there is no practical method of accurately assessing the resulting the stress and strain on the piping.

Impact of ice formation is the need for adjusting jacks and/or blocking of piping as well as re-painting.

Additional photos of GS-150



3.8. Starbuck (GS-165)

Location: Starbuck, MB

Few internal ice formation problems have been reported at this station. It is possible that this is attributable to the station being on the TCPL section of pipeline that has for many years and still to date receives its gas supply from Empress Processing Plant. Although the station develops significant above ground ice, other than being a potential issue in that it can delay emergency response, the mitigation measures used by MH (i.e. extended vents) no related operational issues have been identified. As risers and above ground pipe installed to the bypass is apparently acting as a swing joint accommodating any movement due to underground ice formation.

Impact of ice formation is the need for adjusting jacks and/or blocking of piping as well as re-painting.

3.9. Future Trends in TCPL Gas Conditions

TCPL is expected to comply, long term, with the terms of its gas supply contract with MH. Due to the large number of customers receiving TCPL gas, as well as the regulatory framework within which TCPL operates, it is unlikely TCPL will make changes to the gas supply contract. Changing the terms of gas supply is believed to be an issue that would be subject to National Energy Board approval and as such would be the subject of public hearing. Hence, if such a change were forthcoming MH would have significant notice with an opportunity to implement mitigation measures if required.

However, MH has been receiving very dry and consistent quality gas due to a substantially single source and direction of flow on TCPL pipelines, and although still compliant with contract the quality of gas supplied to MH, can be expected to be lower and more variable. This is expected to occur as shale gas supplies in regions that have not historically been producing now bring shale gas to the market and in doing so it is transported in TCPL's pipelines such that it is supplied to MH. Thus, MH needs to ensure that its facilities and operating practices can accommodate the supply of gas that is of lesser quality but still by contract to specifications.

3.10. Probability-Based Risk Assessment

3.10.1. Purpose of Risk Assessment

The purpose of the assessment is to identify the number of pressure regulation facilities that may be impacted by potential ice/hydrate formation, and provide a means for MH to prioritize the stations in greatest need of mitigation measures. To do this MHI has designed both a PRS Heat Requirement Matrix and Risk Assessment. It is intended that the outcomes of this assessment will determine if supplemental heat or other mitigation measures are required at the facilities identified as vulnerable to ice formation problems.

3.10.2. Methodology

A number of key factors have been identified for consideration in the development of the Risk Assessment. A weighting system for these factors and operating conditions that contribute to the possibility of ice formation has been incorporated into the PRS Risk Assessment worksheet, of which MH will be provided a copy, listing the MH facilities and the contributing factors.

MH utilized their operating knowledge to assess each category for each station a weighting between zero (no risk) and ten (highest risk) and has entered the ratings and operating conditions into the worksheet.

Each risk factor will contribute to an overall risk rating for each site that can be used to identify higher risk facilities, which will allow MH to target remedial action on a risk based prioritization basis.

3.10.3. Risk Assessment Weighting Factors

1. Response Time – Stations in remote locations with no SCADA are a greater risk due to lengthened response times.

For stations with SCADA and within 1 hour of nearest service center assign 0 points, for stations with no SCADA and within one hour of service center assign 5 points, for stations with no SCADA and more than one hour from service center assign 10 points.

2. Design Day Load – Stations with higher loads present a greater risk (i.e. higher load is indicative of more or high value customers) in the volumes of gas involved.

   For stations with loads less than 50 Mcfh; assign 0 points, 50 - 100 Mcfh 1 point, 100-250 Mcfh 2 points, 250 - 1000 Mcfh 5 points, over 1,000 Mcfh 10 points.

3. Number of Customers – The risk increases with the number of customers potentially affected due to public safety, cost of relight and loss of reputation.

   For stations with less than 20 customers; assign 0 points, 20 - 50 customers 1 point, 50 - 100 customers 2 points, 100 - 500 customers 3 points, 500 -1000 customers 5 points, 1000-5000 customers 7 points, over 10,000 customers 10 points.

4. Previous Frost Heave or Severe External Icing – Stations having exhibited a past history of external icing or frost heaving have a higher risk of future problems of this nature.

   For stations with no history of either; assign 0 points, for a history of minor icing 2 points, major icing 5 points, minor frost heaving 7 points, major frost heaving 10 points.

5. Previous Hydrate Formation - Stations having exhibited a past history of hydrate formation may have a higher risk of future problems of this nature.

   For stations with no history of hydrates; assign 0 points, previous hydrates 10 points.

6. Back Fed or Loner – A station that operates as part of a grid (back fed) poses less risk since should it fail it is possible another station can pick up the load with no resulting outage as opposed to a loner which is a standalone station

   For backfed stations; assign 0 points, for loners assign 10 points.

7. Lubricated plug valves upstream of regulators – Lubricated plug valves upstream of pressure control equipment present a risk to regulator pilots and regulator orifices when lubricant is carried downstream and can plug orifices.

   For stations with no lubricated plug valves upstream of pressure control equipment; assign 0 points, for stations with lubricated plug valves and self-operated regulators 5 points, plug valves and pilot operated regulators 10 points.

8. Single Cut or Double Cut – Stations that reduce pressure in stages with working monitors or double cut stations present less risk than those that take a single large pressure cut.

For stations taking a double cut; assign 5 points, single cut 10 points.

9. Filter or Strainer – Filtration on a station inlet can remove dry particulates plus all water and oil in slug, droplet and mist form that may otherwise contribute to hydrate formation during pressure reduction.

   For stations with a coalescing filter; assign 0 points, dry filter or strainer 5 points, no filter or strainer 10 points.

10. Make/ Model of Regulator – Control valves are least likely to be affected by external ice or hydrates and self- operated pressure regulators are more tolerant than pilot operated flexible element pressure regulators, which are at risk of pilot orifice icing.

    For stations utilizing control valves; assign 0 points, self-operated regulators 5 points, pilot operated regulators 10 points.

11. Regulator Configuration – The degree of risk is dependent on the amount of redundancy (back-up runs) and over pressure protection (monitors and reliefs)

    For stations configured with worker/monitor regulators with redundant run and full capacity relief; assign 0 pts., worker/monitor with redundant run and token relief 2 points, worker/monitor with redundant run and no relief 5 points, single regulator with back up run and full relief 8 points, single regulator with no back up run 10 points.

12. Joule Thompson Effect – The gas is chilled at pressure reduction in proportion to the pressure cut. Higher pressure cuts increase the risk of external icing, frost heaving and hydrate formation.

    For stations with Δ P less than 100 psig; assign 0 points, Δ P 100 psig to 300 psig, Δ P 300 psig to 500 psig 6 points, Δ P 500 psig to 800 psig 9 points, Δ P over 800 psig 10 points.

13. Line Heater – Station line heaters are proven to dramatically reduce the risks associated with pressure reduction in pressure reducing stations.

    For stations with line heaters; assign 0 points, for stations without line heaters assign 10 points.

14. Pilot Heater – Stations with pilot operated regulators are less likely to fail if the pilot gas is heated.

    For stations with no pilots or with pilots that are heated; assign 0 points, stations with pilots that are not heated assign 10 points.

15. Insulation – Piping insulation reduces the risks associated with freezing gas by retaining ground heat in above grade piping prior to pressure reduction and for retaining the heat in the gas after it is heated before pressure reduction

For stations with heaters that have insulation on all above grade pipe upstream of regulators; assign 0 points, partial 5 points, none 10 points.

16. Allowance for Flexibility in Pipe design – Designing station outlet pipe with flexibility to allow for expansion and contraction to minimize stress

    Station designed with flexibility allowance; assign 0 points, station not designed with flexibility allowance but with no history of icing 5 points, station not designed with flexibility allowance with history of icing 10 points.

17. Dew Point / Water Content – The probability of hydrate formation increases as the amount of water vapour in the gas increases.

    For stations with history of water vapour less than 8 g/m3 = 0 points, 8 g - 16 g = 5 points, over 16 g = 10 points.

    NB: If a station has experienced higher than typical water vapour content due to TCPL's line testing operations, then this represents a transient event that would not be indicative of future issues unless that testing is repeated.

18. Station By-pass – The ability to expediently by-pass a station without delay can minimize the extent of an outage.

    For stations with by-passes assign 0 points, for stations without by-passes assign 10 points.

19. Inhibitor Injection–Injection of methanol upstream of pressure reduction can assist in the prevention of hydrate formation.

    For stations with methanol injection; assign 0 points, no injection 10 points.

20. Ambient Temperature–Pressure regulating equipment housed in warmer areas is less likely to experience icing.

    For regulators in heated building; assign 0 points, regulators in unheated buildings assign 5 points, regulators outside 10 point.

3.10.4. Conclusions and Recommendations

MH personnel provided MHI with the estimated risk weighting for the five selected pressure reducing facilities based on the weighting factors developed by MHI and detailed in the previous section. From this data and based on equal valuation of each risk assessment weighting factor MHI has arrived at a numerical average risk rating factor for each station. The following Table 3 details the results:

Table 3 – Average Risk Rating of the Five Selected Stations

Station #	Station Name	Average Risk Rating (whereas 10 is maximum)
GS 102	Binscarth	4.6
GS 103	Russell	7.3
GS 017	Ile des Chenes	5.7
GS 150	Niverville	6.7
GS 165	Starbuck	4.7

3.11. Evaluation of Three Existing Stations with Line Heaters

Table 4 – Reported Failures at Existing Stations with Line Heaters

	Number of Reported Failures			
Year	**All Stations**	**GS-001 City Gate Station**	**GS-003 Transcona**	**GS-020 Fort Whyte**
2002	8	0	0	0
2003	23	0	1	1
2004	98	4	1	0
2005	52	0	0	0
2006	33	0	0	0
2007	36	0	0	1
2008	56	0	0	1
2009	30	0	2	0
2010	24	0	2	1
2011	23	0	1	0
2012	29	0	0	0
Total	413	4	7	4

MHI notes that there is a disproportionate number of failures recorded in 2004, MHI has communicated to MHI that abnormally low winter temperatures explains this increase in reported failures. While the selected stations represent only 1.8% (3 of 170) of MH’s pressure reduction facilities they account for 5.5% (15 of 413) of the reported failures with 1.7% (7 of 413) of the reported failures occurring in one of MH’s most critical primary stations City Gate. As these stations are equipped with line heaters and MH has not communicated to MHI that there are ice formation issues with these facilities, the value of the current failure reports in assessing the impact of ice formation is decreased.

NB: All three stations are equipped with modern and typically dependable regulators that are widely used in the natural gas industry, the Fisher 399 EZR. Considering all MH pressure reducing facilities involving this type of regulator account 21.2% (36 of 170) account for 32.7% (135 of 413) of failures. On this basis the rate of failure in stations with heaters has a higher rate of reported failure than in stations without heaters.

3.12. PRS Heat Requirement Matrix

As requested by MH in addition to the Probability-Based Risk Assessment**,** MHI has prepared a PRS Heat Requirement Matrix, which uses a number of editable parameters to separate stations into two groups, those in need of heat, and those not in need of heat.

It is envisioned that MH will use this tool prior to the Risk Assessment to eliminate stations not meeting the criteria. Stations meeting or exceeding the defined threshold should then be subjected to the Risk Assessment by MH to determine the priority order for the phasing and implementation of heat based on the risk weighting of each.

Parameters and Usage

The default parameters used in the PRS Heat Requirement Matrix have been derived from the MHI technical team's understanding of the current situation, knowledge of best industry practice, and extensive experience on this type of issue.

It is MHI's recommendation that flow heat be required in all pressure reducing stations with inlet pressure in excess of 2068 kPa (300 psig) and pressure reduction in excess of 2068 kPa (300 psig) and any one of the following:

- Pilot controlled pressure regulators
- Flow Measurement
- Flow rates in excess of 1000 Sm3/hr (35.3 mcfh)

To properly utilize the PRS Heat Requirement Matrix, MH must input Y/N data for pilot controlled pressure regulators, flow measurement, and numerical data for flow rate (Sm3/hr).

It is MHI's recommendation as well that pilot gas heat be required on all pilot controlled pressure regulators with inlet pressure in excess of 2068 kPa (300 psig) and pressure reduction in excess of 2068 kPa (300 psig).

MHI stresses that the application of the PRS Heat Requirement Matrix should be assessed with professional judgment and that additional parameters/criteria that may be applied at the discretion of MH, such as site-specific considerations, including:

- History of operating issues including regulator failures
- Indications of stress and strain on pressure reducing station piping or on the outlet pipeline
- The number customers
- Service of critical customers
- The availability of an alternate or back feed supply
- Expected variability/consistency in the gas supply quality

4.0 INTERNAL ICE FORMATION

4.1. *Review of Drawings and Cut Sheets*

As the first step in the evaluation of internal ice formation on MH's pressure reducing stations, MHI conducted a review of the various P&IDs provided by MH for the five selected facilities. Based on observations made during the site visits and the review of the P&IDs, none of the installations have any abnormal installations that would make them specifically vulnerable to ice formation other than the absence of line heaters.

4.2. *Conditions of Ice Formation*

Internal Ice formation is a phenomenon that can occur with pressure reduction of natural gas. This phenomenon is due to the absorption of heat as the pressure of the gas is reduced and the gas expands. This effect is known as the Joule - Thompson effect, named for James Joule and William Thompson, who in 1852 developed a number of formulae to predict this effect.

For practical purposes in the natural gas industry a 'Rule of Thumb' is that the temperature of natural gas will be reduced 8° F for every 100 psig of corresponding pressure reduction.

Free water in the pipeline will freeze at a temperature of 32° F. Water vapour molecules will also combine with different gas molecules to form a solid, ice like substance known as hydrates. The formation of hydrates can restrict or interrupt flow by plugging orifices, instruments and pipelines.

Figure 4.1 – Hydrates plugging a pressure regulator

Hydrate formation depends on water vapor, operating conditions and gas composition. Due to the varying composition of natural gas, velocity, turbulence, temperatures and pressures in a pipeline, the formation of hydrates can be difficult to predict. Hydrates are prone to formation in areas of high turbulence thus, in combination with freezing temperatures, regulator pilots and regulators are particularly vulnerable to freezing. Hydrates can form well above freezing temperature at high pressures in pipelines as Figure 4.2 illustrates.

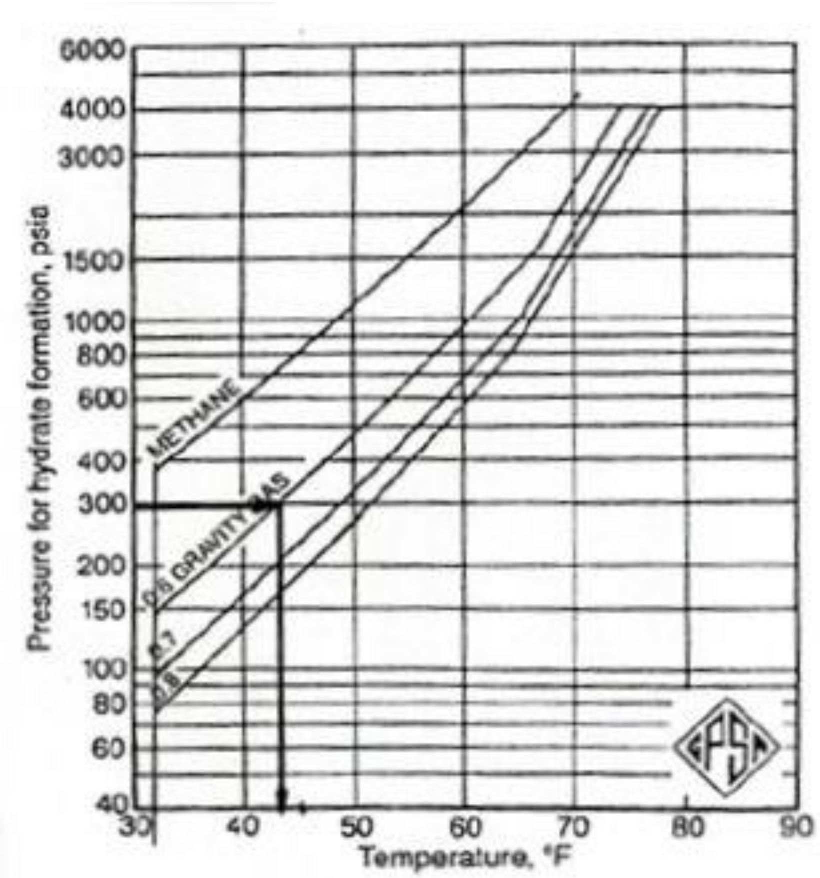


Figure 4.2 – Relationship between temperature and pressure for hydrate formation

Underground pipelines with relatively stable pressures and temperatures are less prone to hydrate formation than pressure reducing stations where high velocities, turbulence, and temperature drop will contribute to hydrate formation. Hence, gas transmission pipelines, which operate at relatively stable pressures and temperatures, may not have the same hydrate issues that gas distribution companies, which operate the pressure reducing stations, may face.

4.3. Potential Measures to Mitigate Internal Ice/Hydrate Formation

Since ice and hydrate formation may restrict flow of gas through the pipe, orifices, regulators, instruments, etc., measures to mitigate internal ice formation are often implemented. Figure 4.3 illustrates a variety of methods used to mitigate internal ice formation. A number of the most commonly utilized measures are described in this section.

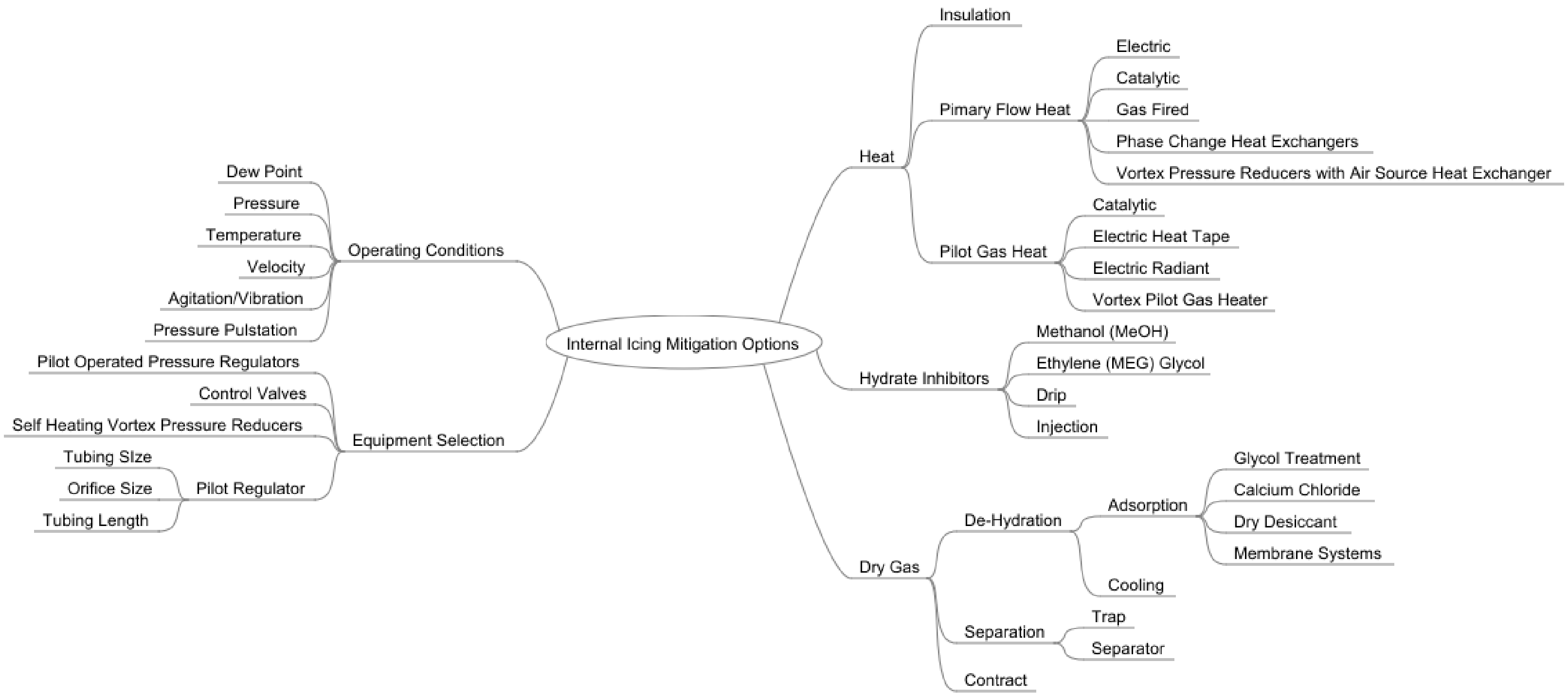


Figure 4.3 – Measures to mitigate internal ice formation

4.3.1. Dry Gas

Water must be present in the gas to form hydrates. Drying the gas reduces the possibility water will form and thus reduces the risk of internal ice and hydrate formation.

For a distribution company contracts are important tools for establishing the water content / dew point of the gas it receives. For MH the contract with TCPL limits the water content to 4 lb/MMscf.

Separation or trapping is viable but only aerosol or liquid water will be removed from the gas. Efficiencies of gas/liquid coalescers are typically very high (e.g. capture of 0.3 Micron liquid particles, with efficiencies to 99.98%) however manufacturers should be consulted regarding achievable capture for MH.

Dehydration via cooling or various absorption methods can be more effective than separation as water vapour; aerosol and liquid water can be removed. However dehydration is typically much more expensive.

4.3.2. Inhibitors

Inhibitors may be used to limit the formation of hydrates by lowering the formation temperature or acting to inhibiting the formation of hydrates. Inhibitors must be introduced into the gas stream in sufficient quantity and in a manner to achieve mixing with the gas flow to be effective. Drip and injection systems are often used. Methanol is a commonly used inhibitor.

4.3.3. Heaters

Heaters add heat to the gas stream prior to pressure reduction to replace the heat lost to the Joules Thompson effect. Using one of a variety of heaters is very effective in preventing internal ice/hydrates with the added benefit of also preventing external ice formation.

Following is a short description of a selection of heating systems available:

Pilot Gas Heaters

Pilot gas heaters, although they do not contribute significantly to the prevention of external ice formation, can play an important role in preventing internal ice/hydrate formation. When gas reaches its dew point, small openings line on pilots are typically the most prone to freezing. Pilot gas heaters may be installed to protect the pilot from freezing.

Indirect Line Heaters

Indirect water bath line heaters utilize either atmospheric burners on a heat exchanger or high-pressure nozzle burners directed through a fire tube to heat a bath (normally glycol/water solution). A high-pressure process coil containing the gas to be heated is routed through the warmed bath, where the gas in the coil is heated by the hot solution in the bath. Several manufacturers, such as BS&B and Fourstar build these indirect water bath line heaters, which are the original oilfield standard.

Figure 4.4 – Indirect line heater

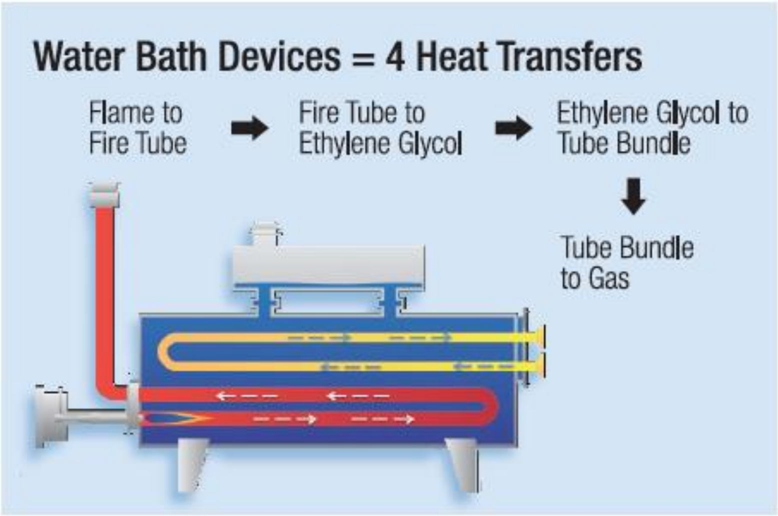


Figure 4.5 – Indirect line heater

Boiler/External Heat Exchange Systems

Boiler/external heat exchange systems can be custom designed and built utilizing a high efficiency boiler such as Viessmann to heat a water/glycol solution. The heated glycol is pumped through a high efficiency shell/tube heat exchanger to warm the process gas.

Catalytic Heaters

Catalytic heaters use infrared heat directed on the outside of the surface to be heated to transfer heat to the gas stream. The catalytic process is an oxidation reduction reaction that converts natural gas into three components: infrared energy, CO2 and water. It does not have an open flame or a chemical charge. To start the reaction, the catalyst bed is heated by an external heat source (usually an electrical element) to the minimum reaction temperature (typically 300º F). The ensuing chemical reaction produces heat, CO2 and water vapor. The infrared energy emitted by the catalytic heater is directed at the surface that has to be heated and absorbed by the metal and transferred to the process gas inside the coil. Catalytic infrared is a direct rather than indirect heating method, which may result in higher efficiencies and lower operating costs compared to indirect heaters. A catalytic pipeline heater generating infrared energy may have an average heat transfer efficiency of 70%, compared to the widely-published water bath transfer efficiency of 40-50%.

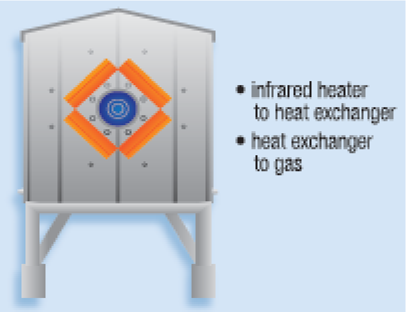


Figure 4.6 – Catalytic Infrared line heater

Several suppliers such as Catadyne and Bruest offer catalytic heaters in a wide range of sizes. Either single catalytic heater for localised heating or large units with multiple heaters or 'zones' can be used.

Figure 4.7 – Catalytic pipeline heater

Cold Weather Technology (CWT)

CWT heaters manufactured by Grit Industries of Lloydminster Saskatchewan utilise the energy release of steam created at a low temperature in a vacuum to heat gas in a process coil. An atmospheric burner heats a fin tube heat exchanger containing a glycol/water solution in a closed system under vacuum. Because the system is under 23" Hg of vacuum, the glycol solution begins to boil at a lower temperature (50º C or 122º F) producing steam. The steam migrates to the process coil containing the gas to be heated where it condenses on the coil, giving up its latent heat of vaporisation and heating the gas inside the coil. The steam condenses and flows by gravity back to the heat exchanger to repeat the cycle.

Figure 4.8 – CWT 630E line heater

4.4. Recommended Mitigation Measures at the Five Selected Pressure Reducing Stations

Although there are a number of methods for reducing the likelihood of ice and hydrate formation on the internal piping and components of natural gas pressure reducing stations, the use of heat also has the benefit of reducing external ice formation.

As evidenced in earlier sections of the report, the climate/conditions under which the MH gas system operates, and design basis of the pressure reducing stations is conducive to external ice and internal ice/hydrate formation. The risk has increased for internal ice/hydrate formation with the potential for changing gas quality from TCPL. Therefore, consistent with common gas industry practices the use of heat is recommended at the five selected stations.

NB: AGA & CGA provide support to their members who seek industry information on a variety of issues. The SOS Program is a resource for AGA members who have the need to query others on a particular subject. The SOS program is a simple and effective way for members to better understand how others are addressing a particular issue/challenge. An SOS survey of AGA and CGA member companies indicated that most gas companies use heat to mitigate internal ice formation. Results of the SOS survey on line heaters are included in Appendix G.

5.0 EXTERNAL ICE FORMATION

5.1. Conditions of Ice Formation

External icing is a phenomenon that can occur with pressure reduction of natural gas. This phenomenon is due to the absorption of heat as the pressure of a gas is reduced and the gas expands. It is known as the Joule - Thompson effect; named for James Joule and William Thompson who in 1852 developed a number of formulae to predict this effect.

For practical purposes in the natural gas industry a 'Rule of Thumb' is that the temperature of natural gas will be reduced 8° F for every 100 psig of corresponding pressure reduction.

External icing of downstream piping and valves will occur when the gas stream cools the pipe below the dew point causing condensation to freeze. This can limit access to and interfere with the operation of valves and other fittings.

5.2. Potential Risks of External Ice Formation

There are a multitude of risks to pressure reducing stations and their components due to external ice formation. The risks associated with external ice formation include:

- Frost heave can occur when buried pipe becomes cold enough to freeze the surrounding ground. This can set up stresses in the pipe and damage footings, foundations and roads.
- Steel can become brittle at low temperatures and susceptible to impact fracture necessitating the use of impact tested pipe, fittings and valves.
- Weight of above ground ice can place stress and strain on encased piping, tubing and equipment
- Ice can impair the operation of equipment (e.g. block regulator vents).
- Ice can prevent ready access to valves or equipment for routine or emergency operation.

5.3. Potential Mitigation Measures

Since ice formation may damage the pressure reducing station piping, pipelines and associated equipment measures to mitigate external ice formation are often implemented. The following diagram shows a variety of methods used to mitigate external ice formation:

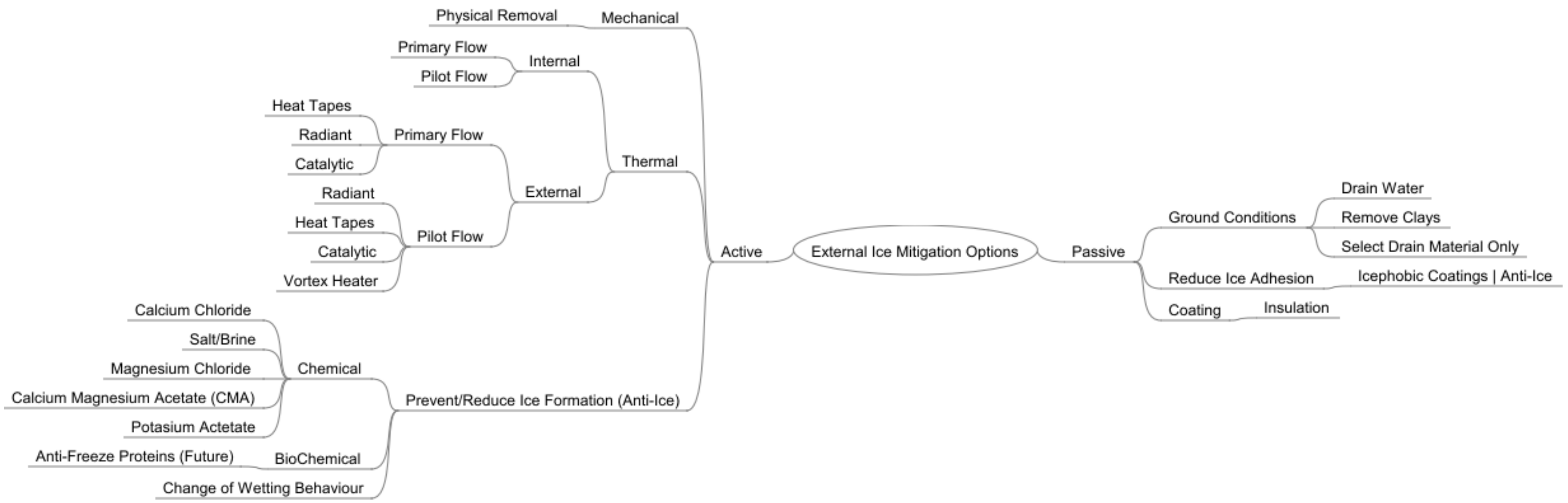


Figure 5.1 – Measures to mitigate external ice formation

5.3.1. Mechanical Removal of Ice

Applicable only to above ground piping and equipment the most basic and reactive method of dealing with ice is mechanical removal.

5.3.2. Thermal

Thermal solution can address either ice formation on pilot gas lines or on all above ground piping and equipment as well as underground piping. Further in addition to resolving issues of external ice formation, heat has the benefit of also resolving issues with internal ice/hydrate formation. A wide variety of heating devices and methods exist for providing heat as required for the individual circumstance. However the gas industry typically uses primary flow heaters to heat the gas itself and in this way extend the benefit of the heat not only to above ground pipe and equipment but also to downstream below ground piping.

5.3.3. Prevention/Reduction of Ice Formation

Applicable only to above ground piping and equipment various chemical, biochemical and innovative products can be used to prevent and reduce ice formation.

5.3.4. Ground Conditions

Underground external ice formation can, to some extent, be mitigated by ensuring pipe is installed in soils that can be kept free of water. Soils that are free of fine materials with high hydraulic conductivity (e.g. loams and silts that retain water due to pore sizes between particles and particle surface area that promote capillary flow). Drainage, or if natural drainage is not viable, pumping should be considered to ensure soils in the immediate vicinity of the pipe can be kept water free.

5.3.5. Reduction of Ice Adhesion

Reducing the adhesion of ice is only applicable to above ground piping and equipment however there are many commercial products, often developed for bridges and surfaces where ice accumulation puts people and property at risk, that can be applied to metal surfaces to reduce the adhesion of ice. In fact some products are hydrophobic preventing water from adhering and thus preventing ice from forming.

5.3.6. Insulation

Insulation of piping may provide some benefit both above and below ground with respect to preventing ice formation. However some design considerations are corrosion and, particularly below ground, the possibility of ice formation due to water migration under the insulation. For underground piping both insulation and ground conditions/drainage management would have to be extended downstream of the pressure reducing station to a point where the ground has warmed the gas to above the freezing point of water.

NB: It should be noted that MH has reported some success placing insulation below piping downstream of pressure reducing stations. It is understood by MHI that the intent is to prevent cold from pipe freezing water below the pipe from freezing and causing frost heaving. However the benefits have not been long lived nor fully documented. MHI has been informed that after some years frost heave has been apparent at some sites where insulation was placed below the piping leading to speculation of compression of the foam insulation used thus reducing its effectiveness. However it is also possible that the water table may be higher than the insulation so that it cannot provide any benefit.

5.4. Recommended Mitigation Measures at the Five Selected Pressure Reducing Stations

While the design and configuration of piping in the immediate vicinity of the PRS may address localized issues of external ice formation, the issues have the potential to extend beyond the PRS compound and have a detrimental effect on roads and other infrastructure downstream. For this reason the only truly effective mitigation measure for external ice formation is heat.

Unlike other external ice formation mitigation measures, heating the gas at pressure reduction stations has the added benefit of addressing internal ice/hydrate formation. Therefore, consistent with common gas industry practices the use of heat is recommended at the five selected stations.

NB: As mentioned above the AGA & CGA provide support to their members who seek industry information on a variety of issues. The SOS Program is a resource for AGA members who have the need to query others on a particular subject. The SOS program is a simple and effective way for members to better understand how others are addressing a particular issue/challenge. An SOS survey of AGA and CGA member companies indicated that most gas companies use heat to mitigate internal ice formation. Results of the SOS survey on line heaters are included in Appendix G.

5.4.1. Heater Selection Criteria

Each type of heater has a set of advantages and disadvantages. The following criteria will need to be considered when selecting a line heater:

- Heater load and future growth.
- Daily and seasonal variations in heater load.
- Noise generation and aesthetics (i.e. is there a requirement to house heater in a building?)
- Availability and requirement for power.
- Environmental requirements such as glycol containment.
- Heater efficiency and greenhouse gas emissions.
- Service life and total projected annual cost.
- Compliance with required codes and standards.

6.0 DESIGN CONCEPT AND COSTS OF MITIGATION

6.1. Design Concept

For the five selected sites identified by MH, installation of a line heater is recommended as per the above analysis. Line heaters are a proven, effective method of reducing risk associated with both internal and external ice formation in gas utility pressure reducing stations. As outlined above there are a number of factors for consideration when selecting the type of line heater to be used, which should be further refined by MH during the installation process.

For the purpose of this study it is assumed that CWT heaters will be used. The CWT heater has been very successful in recent years and is widely used by Fortis BC and SaskEnergy. The benefits of using the CWT heater include:

- Energy efficient.
- Does not require AC power to operate.
- CSA approved for Class 1 Div 2 locations.
- Painted and insulated which allows installation outside.

Key Considerations for Implementation:

- Installation of the respective line heaters should be within the station compound, upstream of the pressure regulating runs.
- Heaters should be located as close as practical to the regulating runs and above grade pipe insulated to conserve heat.
- Heaters should be installed on and anchored to solid concrete foundations that will resist frost heave. A fuel gas line (normally at distribution pressure) and a 5 psig meter are required.
- Each heater will be tied into the existing station inlet pipe and have an inlet valve, outlet valve and by-pass valve.
- Heaters should be located to facilitate disassembly for servicing and have flanged connections.
- An electrical control line (DC mA) to maintain a set outlet temperature runs from the heater burner controls to a thermowell located in the gas stream downstream of the pressure reduction and common to both regulator runs.
- A high temperature safety switch set at 150 F is recommended on the heater outlet to protect regulator elements from excessively hot gas in the event of a heater failure.
- SCADA should be considered at least in critical stations as a monitoring/alarm method and local temperature recorders as a minimum.

A schematic layout of a typical line heater is provided in Appendix J.

Sizing of MH Line Heaters is based on the gas pressure before and after pressure reduction (ΔP), the maximum flow rate, the minimum temperature of the incoming gas and the required temperature of the gas after pressure reduction. Table 5 below summarizes the heat input required at each of the selected locations. Detailed calculations for sizing the line heaters is shown in Appendix K.

Table 5 – Line Heater Size

Location	Inlet Temperature (°C)	Inlet Pressure (psi)	Required Heat Input (Btu/hr)	
			Peak Flow	Typical Flow
Binscarth	-5	880	23,363	23,363
Ile des Chenes	-5	880	7,224,035	7,224,035
Niverville	-5	880	154,632	154,632
Russell	-5	880	658,885	658,885
Starbuck	-5	880	28,823	23,059

Considerations:

- Typically a five-year load forecast is used for sizing heaters although this can be increased depending on the size of the heater installation.
- For the five selected facilities, load and pressure information provided by MH were used in the sizing calculations. The incoming gas temperature was assumed to be -5°C with a temperature of 0°C downstream of pressure reduction, ensuring that the heater will be more than adequately sized to replace the heat lost to the Joule Thompson effect.
- The heater sizing calculations were performed using the MHI's software and confirmed by the supplier.

Heater sizing can also be manually calculated using the following equation:

$Q = w \Delta H$

Where:
Q = heat required, BTU/hr
W = weight of gas to be heated, lb/hr
ΔH = change in enthalpy required (from Mollier diagrams for inlet and outlet temp and pressure)

The required rated input of the heater is then calculated by dividing the figure calculated above by the efficiency of the proposed heating system.

Input Rating of the Heater = Q / Heater Efficiency

6.2. *Mitigation Costs*

Capital cost estimates should be considered preliminary with an accuracy of +/- 50% and are based on installation of Cold Weather Technology (CWT) heaters. Estimates are total direct installed costs but do not include tax, overhead, land acquisition, permits, public hearings, travel time or out of town expenses.

Table 6 below summarizes the model number and the capital cost estimate of the line heaters for each of the selected stations.

Table 6 – Line Heater Capital Cost Estimates

Location	CWT Model	Capital Cost Estimate (CAD)
Binscarth	DLH-140-2D1L-001-AAC020R	$130,000
Russell	DLH-1155-1B3L-001-DCC150R	$330,000
Ile des Chenes	2 x DLH-4620-2E6R-001-JCC600R	$1,605,000
Niverville	DLH-385-1B1L-001-BCC050R	$180,000
Starbuck	DLH-140-2D1L-001-AAC020R	$130,000

Recommended periods of operation would be difficult to predict in advance without detailed operational knowledge. It is entirely possible that some of the heaters could be turned off in the summer when loads are lower and ambient temperatures are higher but this would need to be evaluated on a case-by-case basis after heater installation.

Estimated Annual Energy costs are determined for a gas cost of $4.00/MMBTU and assuming the heater is firing at a rate to sustain peak load conditions for 20% of the year. This rate of fuel gas consumption is based on the consultants experience and knowledge of consumption at FortisBC being 15% and includes a 33.33% allowance for the more sever climate within which MH operates its facilities. This represents the assumption that the average year round heater load is 20% of what the consumption would be to sustain peak load conditions year around (i.e. full fire consumption x 20% x 24 hours x 365 days. This is an indicative consumption however there are many variables (e.g. load profile, operator settings and the concurrent use of pilot gas heat) that can affect annual heater load. Table 7 below summarizes the estimated annual energy costs for the heaters for each of the selected stations. Appendix H provides more detailed energy cost calculations.

Table 7 – Line Heater Annual Energy Cost Estimates

Location	CWT Model	Energy Cost Estimate (CAD)
Binscarth	DLH-140-2D1L-001-AAC020R	$245
Russell	DLH-1155-1B3L-001-DCC150R	$6,908
Ile des Chenes	2 x DLH-4620-2E6R-001-JCC600R	$32,259
Niverville	DLH-385-1B1L-001-BCC050R	$1,620
Starbuck	DLH-140-2D1L-001-AAC020R	$368

Estimated Annual Greenhouse Gas Emissions CO2 and NOx are based on the estimated annual energy usage and calculated based on US EPA emissions for combustion of natural gas. Table 8 below summarizes the estimated GHG emissions for each of the selected stations. Detailed calculation of GHG emissions are provided in Appendix H.

Table 8 – Line Heater GHG Emissions

Location	CWT Model	GHG Emissions (Approximate tonnes per year)
Binscarth	DLH-140-2D1L-001-AAC020R	3
Russell	DLH-1155-1B3L-001-DCC150R	94
Ile des Chenes	2 x DLH-4620-2E6R-001-JCC600R	439
Niverville	DLH-385-1B1L-001-BCC050R	22
Starbuck	DLH-140-2D1L-001-AAC020R	5

6.3. Energy Saving Options

It is recognized that the use of heat is significant from an energy consumption and environmental impact perspective due to the resulting emissions. Therefore the following supplemental energy saving options are recommended for consideration by MH.

6.3.1. Pilot Gas Heaters

The use of a pilot gas heater can reduce the amount of heat that is required from a line heater. As the pilot line is a separate small diameter line it tends to cool readily in extreme temperatures. Often line heaters are set at high outlet temperatures than is required for the primary regulator or than to prevent external ice formation to prevent ice formation in the pilot regulator. By installation a heater for the pilot the line heater can often have a lower set point.

A number of options exist for pilot gas heaters:

1. Catalytic Pilot Gas Heater
2. Electric Heat Tape
3. Electric Flow through Heater
4. Vortex Pilot Gas Heater

Caution is recommended to ensure installed pilot gas heaters, particularly when installed concurrent with other heat sources, do not cause overheating that could, for example, damage components of pilot regulators.

6.3.2. Vortex (Self-Heating) Pressure Reduction

Vortex pressure reduction using a Vortex (self-heating) Pressure Reducer (VPR) with a single stream outlet is suitable for PRS with low throughput, self operated regulators and where external ice formation is not considered to be an issue. As these stations will typically not have line heaters installed this alternative method of pressure reduction reduces the risk of internal ice/hydrate formation by using a VPR. A VPR is does not need any external heat source as it provides heat to the inlet orifice by using the vortex induced mass and energy separation thus providing non-freeze pressure reduction. The VPR is a self contained unit with multiple internal flow paths to facilitate the internal heating but with a single inlet and single outlet. Each VPR does need to be installed with a regulator for pressure control; however the VPR does not have any moving parts, which results in low maintenance of the unit.

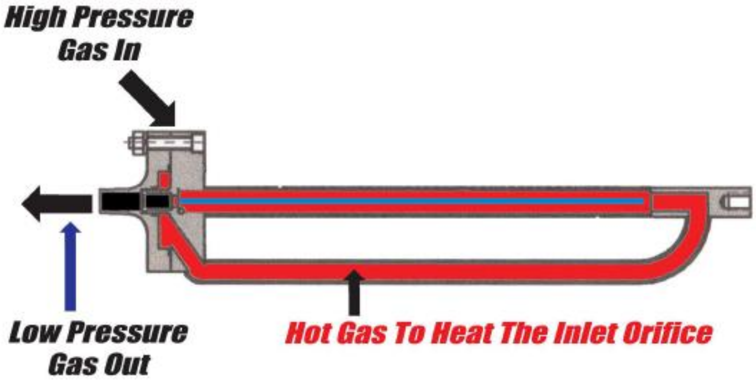


Figure 6.1 – Vortex self-heating pressure regulator

6.3.3. Vortex Pressure Reducing Station with Heat Exchangers

Vortex pressure reduction using Vortex (self-heating) Pressure Reducer (VPR) with a dual stream outlet and a heat exchangers is suitable for PRS with high throughput, pilot operated regulators and where external ice formation is considered to be an issue. As these stations may require an external source of heat be installed this alternative method of pressure reduction reduces the risk of internal ice/hydrate formation and provides heat to the primary gas stream without an external energy source. Depending on flow, climatic and/or the availability of a low grade heat or waste heat source, vortex pressure reduction can be used in pressure reducing stations to reduce or eliminate the need for a natural gas or electric fired heat exchangers. A Vortex Pressure Reducing Station (VPRS) uses self-heating vortex pressure reducers and optimizes the vortex induced mass and energy separation to provide hot and cold outlet flows such that the cold stream can be heated from the ambient air (or a low grade/waste heat source) instead of using natural gas or electricity. A technical proposal showing an initial conceptual design of such a vortex pressure reducing station is presented in Appendix L.

7.0 CONCLUSIONS

Based on an analysis of the information provided by MH, TCPL, and other sources, first-hand site visits to a number of MH's pressure reducing stations, and completion of the risk assessment, internal ice/hydrate formation and external ice formation analysis, MHI has come to the following conclusions regarding the ice/hydrate issue faced by MH:

- MH is operating many of its pressure reducing stations at significant risk of internal ice/hydrate and/or external ice formation. The occurrence of either, particularly in severe weather conditions, may cause a disruption in the gas supply to a large number of consumers including to those that may be considered critical such as hospitals and extended care facilities.
- Based on previous internal studies regarding internal ice/hydrate and/or external ice formation in its facilities, MH is aware of the situation and many of the risks it faces. Knowing this, in the consultant's opinion, MH must take the necessary steps to mitigate the risks before an emergency situation/failure occurs as the inherent liability that MH faces could be substantial.
- Variability in the gas supply quality supplied by TCPL to MH, although within Tariff limits, is increasing the level of uncertainty as natural gas with water content higher than historically provided to MH increases the risk of internal ice/hydrate formation that may result in a significant emergency situation/failure. Accordingly MH's design basis and standards for pressure reducing stations should be updated to ensure designs are robust and able to operate its pressure reducing stations with high reliability in consideration of the variability in the gas supply quality.

MH operates most of its pressure reducing stations without heating the natural gas to make up for the absorption of heat as the pressure of the gas is reduced and the gas expands (i.e. the Joule Thompson effect). This Joule Thompson cooling of natural gas results in MH pressure reducing stations being at risk of both internal ice/hydrate formation and external ice formation.

The risks from internal ice/hydrate formation include equipment failure leading to disruption of flow or over-pressure of the downstream system. The risks of external icing include ice accumulation on station piping and equipment creating operation and maintenance challenges and ice accumulation on downstream piping and valves that may lead to frost heave, pipe stressing caused by expansion, and impact failure of pipe and fittings due to low temperatures. Although there are a number of methods for reducing the likelihood of internal ice/hydrate formation only the use of heat also addresses both internal ice/hydrate formation and external ice formation.

Hydrate Formation

High water content in natural gas, dependent on the pressure and temperature, can result in liquid phase water being present in a pipeline or within a pressure reducing station. When liquid water is present the formation of hydrates is possible as follows: Water is actually a loosely formed group of molecules with spaces between. When the spaces are filled with other molecules such as hydrocarbon gases [methane] (C 1), ethane (C 2), propane (C 3), and butane (n-C 4 and i- C 4) and /or impurities [nitrogen (N 2), carbon dioxide

(CO 2) and hydrogen sulphide (H 2 S)], crystals will form and the mixture becomes solid. Gas molecules can occupy those spaces under the right conditions of temperature and pressure based on solubility of the gas in water. Hence the formation of hydrates first requires condensation of water into liquid, which, in the presence of hydrocarbon gases and/or impurities, under the certain pressure and temperature conditions will form hydrates. Controlling any of the factors that will trigger condensation of water thus manages the formation of hydrates. Reducing water content of natural gas, increasing the gas temperature or lowering the pressure reduces the possibility of water condensing. Therefore, drying the gas or supplying heat controls the condensation of water and the formation of hydrates. (Alternatively the use of methanol, which mixes with water, lowers the water freezing point as an anti-freeze agent.)

The primary factors are pressure, temperature and water content however and other "minor" factors, even a particle of dust and/or restriction in flow, may be critical factors so truly accurate prediction very difficult. At the pressures and temperatures MH operates its facilities and at the water content that TCPL may, according to Tariff, deliver natural gas, hydrates can form. MH has a great deal of evidence that this can and has happened in its facilities; not only pilot regulators but also primary regulators have failed to operate due to hydrates. MH needs to be able to operate its facilities with high reliability. Considering that:

- The TCPL Tariff allows higher water content than has already resulted in operating issues for MH.
- Anticipated changes in gas supply for TCPL may reasonably result in gas with higher water content being provided in future.

Ultimately MHI's recommendation for heat is driven by the fact that it is the only measure that addresses the risk of internal ice/hydrate formation and external ice formation. It is also a measure that is widely used in the gas industry.

8.0 RECOMMENDATIONS

MHI's recommendation for addressing internal ice/hydrate and external ice formation in MH's pressure reducing facilities is made in context of the conclusions above. AS documented in the previous sections of the report, the climate and conditions under which the MH gas system operates, and current design basis of the pressure reducing stations, are conducive to internal ice/hydrate and external ice formation. Further the risk has increased for internal ice/hydrate formation due to the potential for future variability of TCPL gas quality. Therefore, consistent with common gas industry practices the use of heat is recommended in more detail MHI recommends:

i. For the purpose of mitigating the dual risks of internal ice/hydrate and external ice formation, MH should implements the use of heat in pressure reducing stations whereby the parameters/criteria for heating is as follows:

  - Primary flow heat is required in all pressure reducing stations with inlet pressure in excess of 2068 kPa (300 psig) and pressure reduction in excess of 2068 kPa (300 psig) and any one of the following:
    - Pilot controlled pressure regulators
    - Flow Measurement
    - Flow rates in excess of 1000 Sm3/hr (35.3 mcfh)
  - Pilot gas heat is required on all pilot controlled pressure regulators with inlet pressure in excess of 2068 kPa (300 psig) and pressure reduction in excess of 2068 kPa (300 psig)

  The above has been incorporated into a "PRS Heat Requirement Matrix". Additional parameters/criteria may be applied at the discretion of MH, such as site-specific considerations, including:

  - History of operating issues including regulator failures
  - Indications of stress and strain on pressure reducing station piping or on the outlet pipeline
  - The number customers
  - Service of critical customers
  - The availability of an alternate or back feed supply
  - Expected variability/consistency in the gas supply quality

  It should be noted that this recommendation is made in the context that heat is the typical measure that is widely used by North American utilities, most of which have less extreme climates than Manitoba to address internal ice/hydrate and/or external ice formation.

ii. A second recommendation is that Manitoba Hydro utilize the provided Risk Assessment as a tool to prioritize the retrofitting of pressure reducing stations with heat and developing an action plan for all pressure reduction locations by considering those sites indicating the highest scores being accorded the highest priority for implementation of mitigation measures.

iii. The third recommendation (preventative) is that MH review its pressure reducing station engineering and design standards and practices. Notably, as a basis of design, MH should be prepared for variability of TCPL gas quality such that its pressure reducing stations designs are robust and able to operate with high reliability for the full range of Tariff parameters (ie Water Content, H2S content, Pressure, Temperature). The standards and practices should incorporation of the use of heat, as described above should be included as a design requirement to address both internal ice/hydrate formation and external ice formation.

NB A number of observations, suggestions and recommendations for possible inclusion in MH existing standards are provided in Appendix M.

Regarding the 5 selected stations all, per the criteria documented herein, require the use of primary flow heat and, as they have piloted regulators should also have pilot gas heaters. As further detailed in the risk assessment component that was conducted by MHI with input from MH personnel for the five selected pressure reducing stations, the following priority order should be applied to mitigation measures for these stations.

Table 9 – Mitigation Priority Listing of Selected Stations

Station #	Station Name	Average Risk Rating (whereas 10 is maximum)
GS 103	Russell	7.3
GS 150	Niverville	6.7
GS 017	Ile des Chenes	5.7
GS 165	Starbuck	4.7
GS 102	Binscarth	4.6

APPENDIX A

TCPL PIPELINE GAS SPECIFICATIONS (INDICATIVE)

Gas Quality Specifications

TransCanada and other pipelines

TransCanada Pipelines

Specs	Canadian Mainline System	Alberta System	Foothills System (BC) Zone 8	Foothills System (Sask.) Zone 9	GTN System	North Baja System	ANR
Hydrogen Sulphide	Max 23 mg/m^3	Max 23 mg/m^3	Max 23 mg/m^3	Max 23 mg/m^3	Max 0.25 grains/Ccf^3	Max 0.25 grains/Ccf^3	Max 1 grains/Ccf^3 SE & SW area 1/4 grains/Ccf^3 Mainline area
Total Sulphur	Max 115 mg/m^3	Max 115 mg/m^3	Max 230 mg/m^3	Max 230 mg/m^3	Max 10 grains/Ccf^3	Max 0.75 grains/Ccf^3 Total, 0.3 grains/Ccf^3 mercaptan	Max 20 grains/Ccf^3
Carbon Dioxide	Max 2% by volume	Max 2% by volume	Max 2% by volume	Max 2% by volume	Max 2% by volume	Max 2% by volume	Max 2% by volume
Oxygen	Max 0.4% by volume	Max 0.4% by volume	Max 0.4% by volume	Max 0.4% by volume	Max 0.4% by volume	Max 0.2% by volume	Max 1% by volume
Nitrogen	See TCPL Mainline Tariff	Not specified	Not specified	Not specified	Not specified	Max 3% incl. CO_2, N_2, He, O_2,	Max 3% by volume
Temperature	Max. 50°C	Max. 49°C	Max. 43.3°C	Max. 49°C	Max. 110°F	Max. 105°F or Min. 50°F	Min 40°F Max 120°F
Heating Value	Min. 36 MJ/m^3 Max, 41.34 MJ/m^3	Min. 36 MJ/m^3	Min. 36 MJ/m^3	Min. 36 MJ/m^3	Min. 995 BTU/ft^3	Min. 990 BTU/ft^3 or Max. 1150 BTU/ft^3	Min. 967BTU/ft^3 Max. 1200 BTU/ft^3
Water	Max. 65 mg/m^3	Max. 65 mg/m3 or Min. -10°C @>8275 kPa	Max. 65 mg/m^3 or Min. -10°C @>8275 kPa	Max. 65 mg/m3 or Min. -10°C @>8275 kPa	Max. 4 lbs/MMcf	Max. 7 lbs/MMcf	Max. 7 lbs/MMcf
Hydrocarbon Dewpoint	Min. -10°C at 5500kPa absolute	Min. -10°C at operating pressure	Min. -10°C at operating pressure	Min. -10°C at operating pressure	Min. 15°F up to 800 psig	Min. 20°F pressures up to 600 psig	Min. 15°F or less
Interchangeability	See TCPL Mainline Tariff	Not Specified	Not Specified	Not Specified	Not Specified	Wobbe Number: Min: 1279 Max: 1385	Not Specified

Canadian Pipelines

Specs	Alliance Canada	ATCO Pipe	TransGas	WEST COAST	TQM	GazMetro
Hydrogen Sulphide	Max. 23 mg/m^3	Commercial Integration with Alberta System (see specifications above)	Max. 6 mg/m^3	Max. 6 mg/m^3	Max. 23 mg/m^3	Max. 23 mg/m^3
Total Sulphur	Max. 115 mg/m^3		Max. 23 mg/m^3 total, 6 mg/m^3 mercaptan	Max. 23 mg/m^3	Max. 115 mg/m^3	Max. 115 mg/m^3
Carbon Dioxide	Max. 2% by volume		Max. 2% by volume	Max. 2% by volume	Max. 2% by volume	Max. 2% by volume
Oxygen	Max. 0.4% by volume		Max. 0.4% by volume	Max. 0.4% by volume	Max. 0.4% by volume	Max. 0.4% by volume
Nitrogen	Not specified		Max. 15 ml/m^3 each (nitric oxide & total oxides of nitrogen)	Not specified	Not specified	Not specified
Temperature	Max. 50°C		Max. 50°C	Max. 54°C	Max. 50°C	Max. 50°C
Heating Value	Min. 36 MJ/m^3, Max. 60 MJ/m^3		Min. 35 MJ/m^3	Min. 36 MJ/m^3	Min. 36 MJ/m^3	Min. 36 MJ/m^3
Water	Max. 65 mg/m^3		Max. 65mg/m^3 at 101.325 kPa and 15°C	Max. 65 mg/m^3	Max. 65 mg/m^3	Max. 65 mg/m^3
Hydrocarbon Dewpoint	Min. -10°C at opt. Pressure		Min. -10°C at 5500 kPa absolute	Min. -9°C at del. pres.	Not specified	Not specified
Interchangeability	Not Specified		Not Specified	Not Specified	Not Specified	Not Specified

The Gas Quality Specifications tables are intended to be used for planning purposes only and although TransCanada endeavours to maintain the information in such a way that is accurate and current, it may not provide accurate results. Use of this information is at user's sole risk and TransCanada shall not be liable for user's, or any party's, use of or reliance on any results obtained from it.

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Gas Quality Specifications

TransCanada and other pipelines

US Pipelines

Specs	Alliance USA	Empire	GLGT	Iroquois	Northern Border
Hydrogen Sulphide	Max. 1 grains/Ccf^3	Max. 1 grains/Ccf^3	Max. 1/4 grains/Ccf^3	Max. 1/4 grains/Ccf^3	Max. 0.3 grains/Ccf^3
Total Sulphur	Max. 5 grains/Ccf^3	Max. 20 grains/Ccf^3	Max. 20 grains/Ccf^3	Max. 1.25 grains/Ccf^3	Max. 2 grains/Ccf^3, (0.3 grains mercaptan/Ccf^3)
Carbon Dioxide	Max. 2% by volume	Max. 2% by volume	Max. 2% by volume	Max. 2% by volume	Max. 2% by volume
Oxygen	Max. 0.4% by volume	Max. 1% by volume	Max. 1% by volume	Max. 0.2% by volume	Max. 0.4% by volume
Nitrogen	Not specified	Not specified	Max. 3% by volume	Max. 2.75% N$_2$+O2 4% N$_2$+ CO$_2$	Not specified
Temperature	Max. 122°F	Max. 120°F, Min. 40°F	Max. 120°F, Min. 20°F	Max. 120°F	Min. 32°F Max. 120°F
Heating Value	Min. 962 BTU/ft^3	Min. 950 BTU/ft^3 Max. 1200 BTU/ft^3	Min. 967 BTU/ft^3 Max. 1069 BTU/ft^3	Min. 967 BTU/ft^3 Max. 1110 BTU/ft^3	Min. 967 BTU/ft^3
Water	Max. 4 lbs/MMcf	Max. 7 lbs/MMcf	Max. 4 lbs/MMcf	Max. 4 lbs/MMcf @ 14.73 psi & 60°F	Max. 4 lbs/MMcf
Hydrocarbon Dewpoint	Min. 14°F at opt. pres.	Not specified	Not specified	Min. 15°F or less	Min. -5°F (800psia) -10°F (1000 psia) -18°F@(1100 psia)
Interchangeability	Not specified	Not specified	Not specified	See Iroquois Tariff	Not specified
Specs	NWP	PNGTS	SOCAL	Tennessee GP	Viking
Hydrogen Sulphide	Max. 0.25 grains/Ccf^3	Max. 0.25 grains/Ccf^3	Max. 0.25 grains/Ccf^3	Max. 0.25 grains/Ccf^3	Max. 1/4 grains/Ccf^3
Total Sulphur	Max. Non Laplata Facilities 5 grains/Ccf^3, Laplata Facilities 0.75 grains/Ccf^3, 0.3 grains mercaptan/Ccf^3	Max. 20 grains/Ccf^3	Max. 0.75 grains/Ccf^3 (0.3 grains mercaptan/Ccf^3)	Max. 10 grains/Ccf^3	Max. 20 grains/Ccf^3
Carbon Dioxide	Non Laplata Facilities Max. 2% by volume, Laplata Facilities Max. 0.1% by volume	Max. 3% by volume	Max. 3% by volume	Max. 3% by volume	Max. 3% by volume
Oxygen	Non Laplata Facilities Max 0.2% by volume, Laplata Facilities Max 0.1% by volume	Max. 0.2% by volume	Max. 0.2% by volume	Max. 0.2% by volume	Max. 0.2% by volume
Nitrogen	Max. 3% incl. O$_2$, CO$_2$	Max. 4% incl. CO$_2$	Max. 4% incl. O$_2$, CO$_2$ and inerts	Max. 4% incl. CO$_2$, O$_2$	Max. 4% incl. CO$_2$
Temperature	Non Laplata Facilities Max. 120°F Laplata Min. 40°F, Max. 120°F	Max. 120°F	Min. 50°F, Max. 105°F	Max. 120°F	Max. 120°F
Heating Value	Min. 985 BTU/ft^3	Min. 967 BTU/ft^3 Max. 1100 BTU/ft^3	Min. 990 BTU/ft^3 Max. 1150 BTU/ft^3	Min. 967 BTU/ft^3 Max. 1100 BTU/ft^3	Min. 967 BTU/ft^3 Max. 1100 BTU/ft^3
Water	Max. 7 lbs/MMcf	Max. 7 lbs/MMcf	Max. 7 lbs/MMcf @<800psi or < 20°F @>800psi	Max. 7 lbs/MMcf @14.73psi @ 60°F	Max. 7 lbs/MMcf @14.73psi @ 60°F
Hydrocarbon Dewpoint	Min 15°F (100-1000psia)	Not specified	See SOCAL Tariff	Min.15°F	Not specified
Interchangeability	Not Specified	Not Specified	See SOCAL Tariff	Not Specified	Not Specified

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APPENDIX B

TCPL TRANSPORTATION TARIFF

GENERAL TERMS AND CONDITIONS

INDEX

I DEFINITIONS

Except where the context expressly states another meaning, the following terms, when used in these General Terms and Conditions, in any Contract and in any Toll Schedule into which these General Terms and Conditions are incorporated, shall be construed to have the following meanings:

- “Alternate Receipt” shall mean the receipt of quantities of gas at a receipt point not specified in Shipper’s FT, FT-SN or FT-NR Contract.

- "Banking Day" shall mean any day that the Royal Bank of Canada, Main Branch, Calgary, Canada or other financial institutions agreed to by TransCanada for payment pursuant to Section XI herein, conducts business.

- "Contract" shall mean a transportation service contract or a contract pursuant to the SNB Toll Schedule and shall also mean an Order of the NEB pursuant to Section 71(2) of the National Energy Board Act, as amended from time to time requiring TransCanada to provide transportation service.

- "Contract Demand" shall mean:

  (i) with respect to transportation service contracts entered into prior to November 1, 1998, the contract demand, maximum daily quantity, annual contract quantity or maximum quantity as stated in a transportation service contract, converted to GJ by multiplying such contract demand, maximum daily quantity, annual contract quantity or maximum quantity by GHV-97 for the relevant delivery point as more particularly set out in the HV-97 Schedule attached to these General Terms and Conditions subject to variance pursuant to a Shipper election to restate its contract demand within the range from 99% of GHV-97 to 101% of GHV-97, which was received by TransCanada on or before February 13, 1998; and,

  (ii) with respect to transportation service contracts entered into on or after November 1, 1998, that quantity of gas expressed in GJ specified in Shipper's transportation service contract as Shipper's daily or seasonal entitlement, as the case may be, to transportation capacity.

- "Contract Year" shall mean a period of 12 consecutive months beginning on a first day of November.

- "Cubic Metre" or "m^3" shall mean the volume of gas which occupies one cubic metre when such gas is at a temperature of fifteen degrees (15°) Celsius, and at a pressure of 101.325 kilopascals absolute.

- "Cumulative Storage Balance" for a Shipper's STS or STS-L Contract on any Day shall be equal to: **A + B + C + D – E**

  Where:

  "A" = the cumulative Daily Injection Quantity on such Day;

  "B" = the cumulative Daily STFT Quantity on such Day;

  "C" = the cumulative Daily IT Quantity on such Day;

  "D" = the cumulative Daily Diversion Quantity on such Day; and

  "E" = the cumulative Daily Withdrawal Quantity on such Day;

  all as defined in subsection 3.1(e) of the STS Toll Schedule for STS Contracts or 3.1(c) of the STS-L Toll Schedule for STS-L Contracts.

- "Daily Contract Injection Quantity" shall, for the purposes of the STS-L Contracts, mean the quantity of gas specified in the STS-L Contract for delivery from the Market Point to the Storage Injection Point(s).

- "Daily Contract Withdrawal Quantity" shall, for the purposes of the STS-L Contracts, mean 75% of the Daily Contract Injection Quantity, for delivery from the Storage Withdrawal Point to the Market Point.

- "Daily Diversion Quantity" shall have the meaning ascribed in subsection 3.1(e)(i) of the STS Toll Schedule.

- "Daily Excess Withdrawal Quantity" shall be as defined in subsection 3.1(e) of the STS Toll Schedule for STS Contracts and subsection 3.1(c) of the STS-L Toll Schedule for STS-L Contracts.

- "Daily Injection Quantity" shall be as defined in subsection 2.2(a) of the STS Toll Schedule for STS Contracts or STS-L Toll Schedule for STS-L Contracts.
- "Daily IT Quantity" shall be as defined in subsection 3.1(e) of the STS Toll Schedule for STS Contracts and in subsection 3.1(e) of the STS-L Toll Schedule for STS-L Contracts.
- "Daily Operational Injection Quantity" shall, for the purposes of STS-L Contracts, mean the least of the aggregate of the Contract Demand(s) of the Linked FT Contract(s) and the Daily Contract Injection Quantity from the Market Point to the Storage Injection Point(s).
- "Daily STFT Quantity" shall be as defined in subsection 3.1 (e) of the STS Toll Schedule for STS Contracts and in subsection 3.1(e) of the STS-L Toll Schedule for STS-L Contracts.
- "Daily Withdrawal Quantity" shall be as defined in subsection 2.2(b) of the STS Toll Schedule for STS Contracts and subsection 2.2(b) STS-L Toll Schedule for STS-L Contracts.
- "Daily Demand Toll" shall mean the toll determined by multiplying the Monthly Demand Toll for transportation service, as approved by the NEB (as set forth in the List of Tolls referred to in Section III hereof), by twelve (12) and dividing the result by the number of days in the Year.
- "Day" shall mean a period of 24 consecutive hours, beginning and ending at 09:00 hours Central Clock Time, or at such other time as may be mutually agreed upon by Shipper and TransCanada. The reference date for any day shall be the calendar date upon which the 24 hour period shall commence.
- "Delivery Pressure Daily Demand Toll" shall mean the toll determined by multiplying the Delivery Pressure Monthly Demand Toll, as approved by the NEB (as set forth in the List of Tolls referred to in Section III hereof), by twelve (12) and dividing the result by the number of days in the Year.
- "Diversion" shall mean the delivery of quantities of gas at a delivery point and/or delivery area not specified in Shipper's FT, FT-SN, FT-NR, FST or LT-WFS Contract.
- "EDI" means Electronic Data Interchange being the direct computer-to-computer transfer of information using ANSI ASC X12 protocol and a specific definition assigned by TransCanada under standards agreed to by a consensus of the natural gas industry (through standard-setting committees).

- “EDI format” shall mean a file format compliant with the ANSI ASC X12 protocol used for EDI and according to the specific definition assigned by TransCanada under standards agreed to by a consensus of the natural gas industry (through standard-setting committees).

- “Financial Assurance” shall have the meaning attributed to it in subsection XXIII(1) hereof.

- "Fuel Quantity" shall mean the quantity of gas expressed in gigajoules which is to be used by TransCanada as fuel for transporting Shipper's Authorized Quantity.

- "GJ" shall mean gigajoule being 1,000,000,000 joules and include the plural as the context requires.

- "GHV-97" shall mean the gross heating value for each delivery point as set out in the HV-97 Schedule attached to these general terms and conditions as adjusted in accordance with any Shipper election given to TransCanada prior to February 13, 1998.

- "GHV" shall mean gross heating value.

- "Gas" shall mean: (i) any hydrocarbons or mixture of hydrocarbons that, at a temperature of 15° C and a pressure of 101.325 kPa, is in a gaseous state, or (ii) any substance designated as a gas product by regulations made under section 130 of the National Energy Board Act.

- "Gross Heating Value" shall mean the total joules expressed in megajoules per cubic metre (MJ/m^3) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion to be at standard temperature and all water formed by combustion reaction to be condensed to the liquid state.

- "Joule" (J) shall mean the work done when the point of application of a force of one (1) newton is displaced a distance of one (1) metre in the direction of the force.

- “Linked FT Contract” shall mean the FT Contract(s) identified in Exhibit “B” of Shipper’s STS-L Contract and such FT Contract shall satisfy the following:

    i. the delivery point shall be the same as the Market Point specified in Exhibit “A” of Shippers STS-L Contract;

  - ii. is not identified in any other STS Contract or any Exhibit “B” of any other STS-L Contract;
  - iii. has a minimum Linked Term of 1 month, and shall commence on the first day of a month and shall end on the last day of a month;
  - iv. has a receipt point that is Empress or in the province of Saskatchewan.

- “Linked Term” shall have the meaning ascribed in Exhibit “B” of the STS-L Toll Schedule
- “Market Point” shall have the meaning ascribed in Exhibit “A” of the STS Contract or STS-L Contract as the case may be.
- "Month" shall mean the period beginning on the first day of the calendar month and ending at the beginning of the first day of the next succeeding calendar month.
- “Natural Gas Interchangeability Indices” shall have the meaning ascribed in section 5(iv).
- “CCT” shall mean Central Clock Time, representing the time in effect in the Central Time Zone of Canada at the time a transaction occurs, regardless of whether that time may be Standard Time or Daylight Savings Time as those terms are commonly known and understood.
- "NEB" shall mean the National Energy Board or any regulatory or government authority hereafter having a similar jurisdiction in substitution therefor.
- "Shipper" shall mean a customer of transportation service.
- "Shipper's Authorized Quantity" shall be as defined in subsection 1 of Section XXII.
- “Shipper’s Maximum Hourly Flow Rate” shall mean, on any Day, the maximum hourly rate of flow of Gas Shipper may receive at a delivery point or area and which shall be equal to the sum of:
  - a) 5% of the aggregate daily Contract Demand for all of Shipper’s service pursuant to FT, FT-NR, FST, LT-WFS, STFT, FBT, STS and STS-L Contracts which specify delivery of gas to such delivery point or area (excluding deliveries pursuant to STS and STS-L Contracts that are on a best efforts basis) minus all Diversions under such Contracts on such Day; and

b) 5% of the aggregate Shipper’s Authorized Quantity for deliveries to such delivery point or area under all of Shipper’s IT, IBT, and ECR Contracts, STS Overrun, FST Makeup, Diversions on such Day and deliveries which are on a best effort basis pursuant to STS and STS-L Contracts.

- “Short Notice Service” shall mean service pursuant to a FT-SN Toll Schedule, SNB Toll Schedule or ST-SN Toll Schedule.

- “Storage Injection Point” shall have the meaning ascribed in Exhibit “A” of the STS Contract or the STS-L Contract as the case may be.

- “Storage Withdrawal Point” shall have the meaning ascribed in Exhibit “A” of the STS Contract or the STS-L Contract as the case may be.

- "Subsidiary" shall mean a company in which 50% or more of the issued share capital (having full voting rights under all circumstances) is owned or controlled directly or indirectly by another company, by one or more subsidiaries of such other company, or by such other company and one or more of its subsidiaries.

- “Title Transfer” shall mean the transfer of title to gas between two (2) Shippers at a Title Transfer Point.

- “Title Transfer Point” shall be those points and areas where the quantity of gas allocated to each Shipper is established each day and is not subject to reallocation.

- "TransCanada" shall mean "TransCanada PipeLines Limited" and its successors.

- "Transportation Service Contract" shall mean "Firm Transportation Service Contract", "FT Contract", “Firm Transportation Short Notice Contract”, “FT-SN Contract”, “Non Renewable Firm Transportation Contract”, “FT-NR Contract”, "Interruptible Service Transportation Contract", "IT Contract", "Interruptible Backhaul Service Contract", "IT Backhaul Contract", "Storage Transportation Service Contract", "STS Contract", “STS-L Contract”, “Short Term Firm Transportation Service Contract", “STFT Contract”, “Short Term Short Notice Service Contract”, “ST-SN Contract”, “Firm Service Tendered Contract, "FST Contract", "Enhanced Capacity Release Service Contract", "ECR Contract", "Long-Term Firm Service Contract", "LT-WFS Contract", Firm Backhaul Transportation Service Contract" and "FBT Contract"."

- "Union Dawn Receipt Point Daily Demand Toll" shall mean the toll determined by multiplying the Union Dawn Receipt Point Monthly Demand Toll by twelve (12) and dividing the result by the number of days in the Year.

- “Union Dawn Receipt Point Surcharge” shall mean a charge payable by Shipper for service from the Union Dawn Receipt Point determined as follows:

  (a) for service under FT, FT-NR and FT-SN Transportation Service Contracts, by multiplying the Union Dawn Receipt Point Monthly Demand Toll by Shipper’s Contract Demand; provided however that if Shipper’s Contract Demand changes during a month, then a weighted average daily Contract Demand shall be determined for such month and shall be used to calculate the demand charge for such month; and

  (b) for service under all other Transportation Service Contracts, by multiplying the Union Dawn Receipt Point Daily Demand Toll by Shipper’s Authorized Quantity.

- “Wobbe Index” shall mean a measure of the thermal input through a fixed orifice, calculated by dividing the natural gas Gross Heating Value in mega joules per cubic meter by the square root of the natural gas specific gravity with respect to air, based on a gross or higher heating value (HHV) at standard conditions 14.73 psi/60^{o} F, 101.325Kpa/15^{o} C real, dry basis.

- "Year" shall mean a period of 365 consecutive days commencing January 1st of any year; PROVIDED HOWEVER, that any such year which contains a date of February 29 shall consist of 366 consecutive days.

II APPLICABILITY AND CHARACTER OF SERVICE

1. (a) Subject to the provisions of the applicable Toll Schedule and these General Terms and Conditions, on each day for which service is requested by Shipper, and authorized by TransCanada pursuant to Section XXII hereof, Shipper shall deliver and TransCanada shall receive, at the receipt point set out in Shipper's Contract (the "receipt point"), the Shipper's Authorized Quantity and TransCanada shall transport for Shipper and Shipper shall receive, at the delivery point set out in Shipper's Contract (the "delivery point"), a quantity of gas equal thereto; PROVIDED HOWEVER, that under no circumstances shall TransCanada be obligated to deliver to Shipper in any one day, at the delivery point, a quantity of gas in excess of the Contract Demand.

(b) If on any day Shipper fails to accept all or any portion of the gas delivered at the delivery point by TransCanada pursuant to the applicable Toll Schedule, TransCanada shall have the right to curtail further receipts of gas from Shipper at the receipt point in a quantity equal to that which Shipper failed to accept from TransCanada. If on any day Shipper requests service hereunder but fails, for whatever reason, to deliver gas to TransCanada at the receipt point, then TransCanada shall have the right to curtail further deliveries of gas to Shipper at the delivery point in a quantity equal to that which Shipper failed to deliver to TransCanada.

2. Shipper's Authorized Quantity shall, where applicable, be delivered on such day by Shipper to TransCanada at the receipt point or taken on such day by Shipper from TransCanada at the delivery point or area, as the case may be, at hourly rates of flow as nearly constant as possible; PROVIDED HOWEVER, that Shipper may not, without TransCanada's consent, take delivery of such gas at the delivery point or area at an hourly rate of flow in excess of the Shipper’s Maximum Hourly Flow Rate.

3. Departures from scheduled daily deliveries due to the inability of TransCanada or Shipper to maintain precise control shall be kept to the minimum permitted by operating conditions.

4. From the time gas is delivered into the possession of TransCanada at the receipt point TransCanada shall have the unqualified right to commingle such gas with other gas in TransCanada's pipeline system.

III TOLLS

1. The tolls applicable to service provided under any Contract into which these General Terms and Conditions are incorporated shall be determined:

(i) in the case of all transportation services, except Storage Transportation Service ("STS") and “Storage Transportation Service-Linked” (STS-L), where the receipt point is located at the Alberta/Saskatchewan border or where the receipt and delivery points are located in different provinces, on the basis of the Canadian Toll Zone in which the delivery point is located for gas which is delivered for consumption in Canada under a Contract in which the principal delivery point(s) specified therein do not include any export delivery points for gas destined for export to the United States; or

(ii) as fixed and approved by the NEB, on the basis of the receipt and delivery points for delivery of gas destined for export to the United States; or

(iii) in the case of STS and STS-L contracts and contracts providing receipt and delivery points within one province of Canada, as fixed and approved by the NEB, on the basis of the receipt point and delivery points set out therein.

If gas intended for consumption in Canada is delivered hereunder at more than one delivery point within a Canadian Toll Zone, the appropriate toll shall be applied as though such delivery points were one point and as if the gas delivered was measured by one meter; or

(iv) in the case of service pursuant to the SNB Toll Schedule using a methodology approved by the NEB.

2. The tolls applicable to services provided pursuant to the Toll Schedules of TransCanada's Transportation Tariff are set out in the List of Tolls of TransCanada's Transportation Tariff as same may be amended from time to time upon approval of the NEB.

IV SHIPPER PROVISION OF FUEL REQUIREMENTS

1. Daily Operations

(a) For each and every day in respect of which Shipper's Authorized Quantity is accepted by TransCanada for transportation, Shipper shall, in addition to Shipper's Authorized Quantity, nominate, pursuant to the provisions of Section 2 hereof, and make available to TransCanada at any receipt point specified in the contract and/or Alternate Receipt point for FT or FT-NR Contracts the Fuel Quantity ("Qf"), which quantity shall be determined as follows:

$$Qf = Qd \times FR\% / 100 + \Sigma (Qd_i \times fr_i\% / 100) + \Sigma (Qd_{Dawn} \times fr_{Dawn}\% / 100)$$

Where:

“FR%” is the applicable monthly fuel ratio respecting transportation service from the nominated receipt point to the nominated delivery point;

“fr_i%” is the applicable monthly fuel ratio for delivery pressure in excess of a gauge pressure of 4000 kilopascals at delivery point "i", both as set out in TransCanada's notice to Shipper delivered pursuant to Section 2 hereof;

“fr_{Dawn}%” is the applicable monthly fuel ratio respecting transportation service from the nominated Union Dawn Receipt Point to the nominated delivery point;

“Qd” is the Shipper's Authorized Quantity;

“Qd_i“is the quantity to be delivered at delivery point "i", for which point a toll for delivery pressure services has been approved by the NEB (as set forth in the List of Tolls referred to in Section III hereof);

“Qd_{Dawn} “ is the quantity to be transported by Shipper from the Union Dawn Receipt Point, for which a toll has been approved by the NEB (as set forth in the List of Tolls referred to in Section III hereof) ;

“Σ (Qd_i x fr_i% / 100)” represents the sum of the fuel quantities required for delivery pressure in excess of a gauge pressure of 4000 kilopascals at all points applicable to Shipper's Authorized Quantity; and

“Σ (Qd_{Dawn} x fr_{Dawn} % / 100)” is the sum of the fuel quantities required for the Union Dawn Receipt Point applicable to Shipper’s Authorized Quantity.

(b) TransCanada shall not be required to accept or deliver gas on any day if the appropriate Fuel Quantity has not been nominated by Shipper, or if TransCanada is unable to confirm that a quantity of gas equal to Shipper's Authorized Quantity plus the appropriate Fuel Quantity will, in fact, be made available on such day.

2. **Nominations and Authorizations**

Concurrent with nominating for transportation service for a given day, pursuant to Section XXII hereof, Shipper shall also nominate the Fuel Quantity to be made available to TransCanada on such day (the "fuel tender"). In the event TransCanada is not prepared to authorize Shipper's nomination or if TransCanada determines that Shipper's fuel tender is incorrect, TransCanada shall, by 14:00 hours CCT of the day immediately preceding the day for which service has been requested, advise Shipper to revise its fuel tender, and Shipper shall nominate such revised fuel tender by 15:00 hours CCT on such day. All fuel tenders shall be stated to the nearest one (1) GJ.

Shipper's fuel tender shall be determined by Shipper pursuant to the formula set out in subsection 1(a) hereof. On or before the twenty-fifth day of each month, TransCanada shall provide Shipper with written notice of the monthly fuel ratio to be applied during the next succeeding month. In the absence of any notice as aforesaid Shipper shall determine the fuel tender on the basis of the fuel ratio used in the immediately preceding month.

V QUALITY

1. The gas to be delivered hereunder shall be natural gas; provided however, that helium, natural gasoline, butane, propane and any other hydrocarbons except methane may be removed prior to delivery. TransCanada may subject, or permit the subjection of the natural gas to compression, cooling, cleaning and other processes.

2. **Heating Value:** The minimum gross heating value of the gas to be received and delivered by TransCanada shall be 36.00 MJ/m^3. The maximum Gross Heating Value of the gas to be received and delivered by TransCanada shall be 41.34 MJ/m^3. TransCanada shall have the right to refuse to accept Shipper's gas if the Gross Heating Value of such gas remains below 36.00 MJ/m^3 or above 41.34 MJ/m^3.

   In the event that the Gross Heating Value of the gas to be delivered by TransCanada is below 36.00 MJ/m^3 or above 41.34 MJ/m^3 the Shipper shall have the option to refuse to accept such gas so long as the Gross Heating Value remains below 36.00 MJ/m^3 or above 41.34 MJ/m^3.

3. **Freedom from Objectionable Matter:** The gas to be received by TransCanada from Shipper and to be delivered by TransCanada hereunder:

(a) Shall be commercially free (at prevailing pressure and temperature in TransCanada's pipeline) from sand, dust, gums, oils, hydrocarbons liquefiable at temperatures in excess of minus ten degrees (-10°) Celsius at five thousand five hundred (5500) kPa absolute, impurities, other objectionable substances which may become separated from the gas, and other solids or liquids which will render it unmerchantable or cause injury to or interference with proper operations of the lines, regulators, meters or other appliances through which it flows; and shall not contain any substance not contained in the gas at the time the same was produced other than traces of those materials and chemicals necessary for the transportation and delivery of the gas and which do not cause it to fail to meet any of the quality specifications herein set forth.

(b) Shall contain no more than twenty-three (23) milligrams of hydrogen sulphide per cubic metre nor more than one hundred and fifteen (115) milligrams of total sulphur per cubic metre of gas as determined by standard methods of testing.

(c) Shall not contain more than two per cent (2%) by volume of carbon dioxide.

(d) Shall have been dehydrated, if necessary, for removal of water present therein in a vapour state, and in no event contain more than sixty-five (65) milligrams of water vapour per cubic metre of gas.

(e) Shall not exceed a temperature of fifty degrees (50°) Celsius.

(f) Shall be as free of oxygen as practicable and shall not in any event contain more than four tenths of one percent (0.4%) by volume of oxygen.

(g) Shall not have a total inert gas content in excess of 4% when used as a diluent to meet Natural Gas Interchangeability Indices.

(h) Shall be free of any microbiological organisms, active bacteria or bacterial agents, including but not limited to sulphate reducing bacteria, iron oxidizing bacteria, and/or acid producing bacteria.

4. **Failure to Conform to Specifications Re Objectionable Matter:** If the gas being received by TransCanada from Shipper or transported by TransCanada to Shipper fails at any time to conform to any of the specifications set forth in subsection 3 of this Section, then the party receiving such gas (the “First Party”) shall notify the party delivering such gas (the “Second Party”) of such deficiency and thereupon the First Party may at the First Party's option refuse to accept delivery pending correction by the Second Party. Upon the Second Party's failure promptly to remedy any deficiency in quality as specified in subsection 3 of this Section, the First

Party may accept delivery of such gas and may make changes necessary to bring such gas into conformity with such specifications, and the Second Party shall reimburse the First Party for any reasonable expense incurred by the First Party in effecting such changes.

5. **Natural Gas Interchangeability Indices:** The natural gas received by TransCanada shall conform to the following specifications (the "Natural Gas Interchangeability Indices");

i) Weaver Incomplete Combustion Index less than or equal to 0.05;

ii) AGA Yellow Tipping Index greater than or equal to 0.86;

iii) The minimum Wobbe Index of the gas shall be 47.23 MJ/m^3;

iv) The maximum Wobbe Index of the gas shall be 51.16 MJ/m^3; and

v) Shall not contain greater than 1.5 mole percent (%) Butanes Plus.

The Natural Gas Interchangeability Indices are based on the following historical supply gas composition:

Compound	Mole %
Methane	95.6734
Ethane	1.6241
Propane	0.1410
I-Butane	0.0180
N-Butane	0.0173
I-Pentane	0.0034
N-Pentane	0.0034
N-Hexane	0.0014
N-Heptane	0.0007
N-Octane	0.0002
Nitrogen	1.8419
Carbon Dioxide	0.6411
Helium	0.0339

VI MEASUREMENTS

1. **Unit of Volume and Unit of Quantity:** The unit of volume for the purpose of reporting shall be one thousand (1000) cubic metres (10^3m^3) of gas and the unit of quantity shall be GJ.

2. **Determination of Volume and Gross Heating Value:** The volume and the gross heating value of the gas received by TransCanada from Shipper and delivered to Shipper shall be determined as follows:

   (a) The gas volumes shall be computed in accordance with the methodology prescribed in the Electricity and Gas Inspection Act (Canada) (R.S.C. 1985, c.E-4) as amended from time to time including all regulations and specifications promulgated pursuant to such Act (collectively, the "Electricity and Gas Inspection Act").

   (b) For the purpose of measurement of gas received into and delivered from the TransCanada system, the parties agree that the average absolute atmospheric (barometric) pressure at such points shall be assumed to be constant during the term thereof, regardless of variations in actual barometric pressure from time to time, and shall be calculated based on the elevation of the measurement point. The formula used to calculate the atmospheric pressure shall be in accordance with the methodology prescribed in the Electricity and Gas Inspection Act (Canada) (R.S.C. 1985, c.E-4) amended from time to time including all regulations and specifications promulgated pursuant to such Act.

   (c) The determination of the gross heating value of the gas received or delivered shall be performed in a manner approved under the Electricity and Gas Inspection Act or, if such specification is not set out in such Act, in accordance with industry accepted standards, and, in any event, in such manner as to ensure that the gross heating values so determined are representative of the gas received or delivered at the receipt or delivery point.

   (d) The determination of the relative density of the gas received or delivered shall be performed in a manner approved under the Electricity and Gas Inspection Act or, if such specification is not set out in such Act, in accordance with industry accepted standards, and, in any event, in such manner as to ensure that the relative densities so determined are representative of the gas received or delivered at the receipt or delivery point.

VII DELIVERY POINT

1. For the purpose of Section VIII hereunder, unless otherwise specified in the Contract, the delivery point or points for all gas to be delivered by TransCanada to Shipper pursuant to any Contract into which these General Terms and Conditions are incorporated shall be on the outlet side of TransCanada's measuring stations located at or near the point or points of connection with the facilities of Shipper or Shipper's agent in receiving the gas, as specified in the Contract.

2. If the total quantity of gas delivered at any delivery point is less than 3750 GJ during any contract year, then Shipper shall pay TransCanada at the end of such contract year, in addition to any amounts otherwise payable, an amount equal to:

$$\frac{(\text{ 3750 GJ minus "X"}) \text{ times "Y"}}{\text{3750 GJ}}$$

Where "X" is the total quantity (expressed in GJ) actually delivered by TransCanada to all Shippers at such delivery point during such contract year; and

Where "Y" is 18% of TransCanada's actual original costs of installation of the delivery facilities at such delivery point.

VIII POSSESSION OF GAS

TransCanada shall be deemed to be in control and possession of, and responsible for, all gas transported under the Contract from the time that such gas is received by it at the receipt point until such gas is delivered at the delivery point.

IX MEASURING EQUIPMENT

1. All meters and measuring equipment for the determination of gross heating value and/or relative density shall be approved pursuant to, and installed and maintained in accordance with, the Electricity and Gas Inspection Act.

   Notwithstanding the foregoing, all installation of equipment applying to or affecting deliveries of gas shall be made in such manner as to permit an accurate determination of the quantity of gas delivered and ready verification of the accuracy of measurement. Care shall be exercised by both parties in the installation, maintenance and operation of pressure regulating equipment so as to prevent any inaccuracy in the determination of the volume or quantity of gas delivered under the Contract.

(a) **Measuring Station:** In accordance with the above, TransCanada will install, maintain and operate, or will cause to be installed, maintained and operated, at or near each delivery point, a measuring station equipped with a meter or meters and other necessary equipment for accurate measurement of the gas delivered under the Contract.

2. **Calibration and Test of Measuring Equipment:** The accuracy of measuring equipment shall be verified by TransCanada at reasonable intervals, and if requested, in the presence of representatives of Shipper, but TransCanada shall not be required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party shall notify the other that it desires a special test of any measuring equipment the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment is found to be in error by not more than the limits set out as follows:

(a) 2% for measuring equipment utilized to determine volume,
(b) 1% for any instrument utilized to determine relative density,
(c) 0.5% for any instrument utilized to determine gross heating value.

If upon test, any measuring equipment is found to be in error by not more than the limits specified above, the previous readings of such equipment shall be considered accurate in computing deliveries or receipts of gas but such equipment shall be adjusted at once to register accurately.

If, for the period since the last preceding test, it is determined that:

(a) any measuring equipment, except for those instruments specified in (b) and (c) below, shall be found to be inaccurate by an amount exceeding 2% at a recording corresponding to the average hourly rate of flow for such period, and/or

(b) any instrument utilized to determine the relative density shall be found to be inaccurate by an amount exceeding 1%, and/or

(c) any instrument utilized to determine the gross heating value shall be found to be inaccurate by an amount exceeding 0.5%, then the previous readings of measurement equipment and/or instruments utilized to determine the relative density or gross heating value, as the case may be, shall be corrected to zero error for any period which is known definitely but in any case where the period is not known or agreed upon such correction shall be for a period extending over 50% of the time elapsed since the date of the last test.

Notwithstanding the foregoing, when TransCanada and Shipper mutually agree that a measurement instrument inaccuracy occurred at a definite point in time, a quantity correction shall be made even though said inaccuracy is less than the limits specified in (a), (b) and (c) above.

3. **Correction of Metering Errors:** Failure of Meters: In the event a meter is out of service, or registering inaccurately, the volume or quantity of gas delivered shall be determined by the most equitable method. Such methods shall include but not be limited to:

   (a) mathematical calculations and comparisons including prevailing ratio with a parallel meter,

   (b) the use of Shipper's check measuring equipment, and

   (c) comparison to deliveries under similar conditions when the meter was registering accurately.

4. **Preservation of Metering Records:** TransCanada and Shipper shall each preserve for a period of at least six (6) years all test data, charts and other similar records. Microfilms of the original documents shall be considered true records.

5. **Check Measuring Equipment:** Shipper may install, maintain and operate at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of TransCanada's measuring equipment. Any pressure or volume control regulators installed by Shipper shall be operated so as not to interfere with TransCanada's measuring facilities.

6. **Rights of Parties:** The measuring equipment so installed by either party together with any building erected by it for such equipment, shall be and remain its property. However, TransCanada and Shipper shall have the right to have representatives present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating or adjusting done in connection with the other's measuring equipment used in measuring or checking the measurement of the delivery of gas under the Contract. The records from such measuring

equipment shall remain the property of their owner, but upon request each will submit to the other its records and charts, together with calculations therefrom, for inspection and verification, subject to return within ten days after receipt thereof.

X BILLING

1. **Monthly Billing Date:** For all contracts in effect prior to the effective date of the NEB's Decision in the RH-2-95 proceeding, TransCanada shall render bills on or before the tenth (10th) day of each month for all transportation services provided by TransCanada to the Canadian Toll Zones ("Domestic Service") and on or before the fifteenth (15th) day of each month for all transportation services provided by TransCanada to any Export Delivery Point ("Export Service"). For gas taken by Shipper in excess of the total daily quantity authorized by TransCanada, TransCanada shall also render bills for charges made pursuant to Section XXII on or before the tenth (10th) day of each month, in respect of Domestic Service, and on or before the fifteenth (15th) day of each month, in respect of Export Service.

   For all Export Service Contracts coming into effect after the effective date of the NEB's Decision in the RH-2-95 proceeding, including the renewal of any Export Service Contracts which existed prior to such date, the billing date shall be the tenth (10th) day of each month.

2. **Information:** Shipper hereby undertakes to provide TransCanada with all the information and material required by TransCanada to calculate and verify the quantity of gas actually received by TransCanada from Shipper, and the quality specifications and components thereof.

   If such information is not received by TransCanada in sufficient time prior to TransCanada rendering bills to Shipper pursuant to this Section X, such bills shall be calculated based on TransCanada's best estimate of the quantity and quality of gas actually received by TransCanada from Shipper. Any overcharges or undercharges resulting from any differences between the above estimates and the actual amounts shall be adjusted in the subsequent bill without any interest thereon.

XI PAYMENTS

1. **Monthly Payment Date:** For all contracts in effect prior to the effective date of the NEB's Decision in the RH-2-95 proceeding, Shipper shall pay to TransCanada, at its address designated in the Contract, or shall pay to the Royal Bank of Canada, Main Branch, Calgary,

Alberta, or at other institutions if agreed to by TransCanada for deposit to the account of TransCanada so that TransCanada shall receive payment from Shipper on or before the twentieth (20th) day of each month for Domestic Service, and by the twenty-fifth (25th) day of each month for Export Service (the "Payment Date") provided by TransCanada to Shipper pursuant to the applicable toll schedules and for any charges made pursuant to Section XXII herein during the preceding month and billed by TransCanada in a statement for such month according to the nominated and/or measured deliveries, computations, prices and tolls provided in the Contract. If the Payment Date is not a Banking Day, then payment must be received by TransCanada on Shipper's account or before the first (1st) Banking Day immediately prior to the Payment Date.

For all Export Service Contracts coming into effect after the effective date of the NEB's Decision in the RH-2-95 proceeding, including the renewal of any Export Service Contracts which existed prior to such date, the payment date shall be the twentieth (20th) day of each month; provided however, if the Payment Date is not a Banking Day, then payment must be received by TransCanada on Shipper's account on or before the first (1st) Banking Day immediately prior to the Payment Date.

2. **Remedies for Non-Payment: Notwithstanding Section XVII,** if Shipper fails to pay the full amount of any bill when payment is due, TransCanada may upon four (4) Banking Days written notice immediately suspend any or all service being or to be provided to Shipper provided however that such suspension shall not relieve Shipper from any obligation to pay any rate, toll, charge or other amount payable to TransCanada. If at any time during such suspension Shipper pays the full amount payable to TransCanada, TransCanada shall within two (2) Banking Days recommence such suspended service.

Notwithstanding Section XVII following suspension, TransCanada may, in addition to any other remedy that may be available to it, upon four (4) Banking Days written notice to Shipper immediately:

(a) terminate any or all service being or to be provided to Shipper; and
(b) declare any and all amounts payable now or in the future by Shipper to TransCanada for any and all service to be immediately due and payable as liquidated damages and not as a penalty.

In the event Shipper disputes any part of a bill, Shipper shall nevertheless pay to TransCanada the full amount of the bill when payment is due.

If Shipper fails to pay all of the amount of any bill as herein provided when such amount is due, interest on the unpaid portion of the bill accrues daily at a rate of interest equal to the prime rate of interest of the Royal Bank of Canada as it may vary from time to time, plus one percent (1%) and the principle and accrued interest to date shall be payable and due immediately upon demand.

3. **Adjustment of Underpayment, Overpayment or Error in Billing:** If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions of the Contract and Shipper shall have actually paid the bills containing such overcharge or undercharge, then within thirty (30) days after the final determination thereof, TransCanada shall refund the amount of any such overcharge with interest which is equal to the prime rate of interest of the Royal Bank of Canada as it may vary from time to time from the time such overcharge was paid to the date of refund, plus one percent (1%) in addition thereto. If such refund is made by a credit on an invoice from TransCanada to Shipper, then the date of the refund shall be the date upon which the invoice reflecting such credit was rendered to Shipper by TransCanada. Shipper shall pay the amount of any such undercharge, but without interest. Adjustments to the amount billed in any statement rendered by TransCanada shall be made within the following time frames:

   (a) Measurement data corrections shall be processed within six (6) months of the production month with a three (3) month rebuttal period.

   (b) The time limitation for disputes of allocations shall be six (6) months from the date of the initial month-end allocation with a three (3) month rebuttal period.

   (c) Prior period adjustment time limits shall be six (6) months from the date of the initial transportation invoice with a three (3) month rebuttal period, excluding government-required rate changes.

   These time limits shall not apply in the case of deliberate omission or misrepresentation or mutual mistake of fact. Parties' other statutory or contract rights shall not be otherwise diminished by these time limits.

4. **Time of Payment Extended if Bill Delayed:** If presentation of a bill to Shipper is delayed after the tenth (10th) or the fifteenth (15th) day of the month, as applicable for domestic or export service respectively, then the time of payment shall be extended accordingly unless Shipper is responsible for such delay.

XII DELIVERY PRESSURE

Subject to the provisions set out in subsections a) and b) below, TransCanada shall deliver gas to Shipper at TransCanada's line pressure at the delivery point or points designated in the Contract, but the minimum pressure at each delivery point shall be not less than a gauge pressure of 4000 kilopascals or such lesser pressure that is agreed to by the parties; provided, however, that:

(a) the parties shall not be required in any Contract into which these General Terms and Conditions are incorporated, to agree to delivery pressures less than the minimum contractual pressure theretofore applicable at existing delivery point; and

(b) if the deliveries to Shipper at a delivery point or an agreed upon grouping of delivery points, exceeds the Shipper’s Maximum Hourly Flow Rate without the prior consent of TransCanada, and the delivery pressure to Shipper falls below the delivery pressure agreed to in the Contract, despite reasonable preventative measures undertaken by TransCanada, then TransCanada shall, for the period of such excess deliveries, be relieved of its contractual obligation to such Shipper to deliver gas at such delivery point or area affected by the excess deliveries at the delivery pressure stipulated in the Contract.

If the receipt point or points under Shipper's Contract include that point on TransCanada's system which is immediately east of the Alberta/Saskatchewan border ("Empress"), then Shipper agrees to cause NOVA Corporation of Alberta (hereinafter called "NOVA") to design and construct sufficient facilities to allow Shipper's Authorized Quantity to be delivered to TransCanada at Empress at a gauge pressure of 4137 kPa or any greater pressure which may from time to time be specified by TransCanada for all gas to be delivered into TransCanada's system at Empress and to cause NOVA to deliver Shipper's Authorized Quantity to TransCanada at NOVA's line pressure provided that said pressure shall not be less than a gauge pressure of 3792 kPa.

For any receipt point downstream of Empress, Shipper shall do or cause others to do all that is required to allow Shipper's Authorized Quantity to be delivered to TransCanada at a pressure no less than that prevailing in TransCanada's pipeline at such receipt point at the time of delivery and no greater than the maximum allowable operating pressure of TransCanada's pipeline at such point.

XIII WARRANTY OF TITLE TO GAS

Shipper warrants that it owns or controls, has the right to:

1. deliver or have delivered, the gas that is delivered to TransCanada under the Contract;
2. transfer the gas pursuant to Section XXIV of these General Terms and Conditions.

Shipper shall indemnify and hold harmless TransCanada against all claims, actions or damages arising from any adverse claims by third parties claiming an ownership or an interest in the gas delivered for transport to TransCanada under the Contract or transferred pursuant to Section XXIV of these General Terms and Conditions.

XIV FORCE MAJEURE

In the event of either Shipper or TransCanada being rendered unable, wholly or in part, by force majeure to perform or comply with any obligation or condition hereof or any obligation or condition in any Contract into which these General Terms and Conditions are incorporated, such party shall give notice and full particulars of such force majeure in writing or by telegraph to the other party as soon as possible thereafter, and the obligations of the party giving such notice, other than obligations to make payments of money then due, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused but for no longer period, and such cause shall as far as possible be remedied with all reasonable dispatch. The term "force majeure" as used herein shall mean acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, the necessity for making repairs to or alterations of machinery or lines of pipe, freezing of wells or lines of pipe, temporary failure of TransCanada's gas supply, inability to obtain materials, supplies, permits or labour, any laws, orders, rules, regulations, acts or restraints of any governmental body or authority, civil or military, any act or omission (including failure to deliver gas) of a supplier of gas to, or a transporter of gas to or for, TransCanada which is excused by any event or occurrence of the character herein defined as constituting force majeure, any act or omission by parties not controlled by the party having the difficulty and any other similar causes not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

The settlement of strikes, lockouts or other labour disputes shall be entirely within the discretion of the party having the difficulty. Under no circumstances will lack of finances be construed to constitute force majeure.

In the event of an occurrence of a force majeure, TransCanada shall curtail delivery of gas to Shipper in accordance with Section XV hereof, and with respect to FST Service Contracts:

(a) TransCanada's obligation to deliver gas to Shipper during the particular season shall be reduced by the amount of the curtailment under such Contract pursuant to subsection 2(c) of Section XV and,

(b) For purposes of subsection 2.5 of TransCanada's FST Toll Schedule no quantities curtailed under subsection 2 of Section XV shall be included in determining the accumulative deficiency in delivery.

XV IMPAIRED DELIVERIES

For the purposes of this Section XV, TransCanada's minimum obligation to deliver gas under a FST Contract in any season shall be deemed to be an obligation to deliver the Winter Capacity or the Summer Capacity as the case may be.

On each day TransCanada shall determine in respect of all Contracts:

(i) the total quantities which all Shippers have requested to be delivered on that day, and

(ii) its available system capacity, including the maximum transportation on TransCanada's behalf under agreements that it has with Great Lakes Gas Transmission Limited Partnership, Union Gas Limited and Trans Québec and Maritimes Pipeline Inc.

If due to any cause whatsoever TransCanada is unable on any day to deliver the quantities of gas Shippers would have received if such disability did not exist, then TransCanada shall order curtailment by all Shippers affected thereby in the following manner to the extent necessary to remove the effect of the disability:

1. If TransCanada estimates that, notwithstanding its then inability to deliver, it nevertheless will be able to meet its total minimum obligations to deliver under all Contracts during the then current season, TransCanada shall order daily curtailment in the following order of priority:

   (a) First under any Shipper's Make-up provided pursuant to the FST Toll Schedule

   (b) Second under interruptible service provided pursuant to the IT and IT Backhaul Toll Schedules.

   The toll for STS Overrun is the 100% Load Factor Toll. Therefore when STS Overrun is tolled at an equal or higher price than IT, then the priority of STS Overrun is higher; when the STS Overrun Toll is at a lower price than IT, then the priority of STS Overrun is lower.

   (c) Third under any gas storage program of TransCanada.

   (d) Fourth under:

   Diversions made

   A. under FST contracts which:

      (i) cause the flow of gas on a lateral or extension to exceed the capability of the lateral or extension, and/or:

      (ii) cause the actual flow of gas through a metering facility to exceed the capability of the metering facility, and/or

      (iii) cause the actual flow of gas on any segment of TransCanada's integrated pipeline system (including those notional segments comprised of TransCanada's maximum transportation entitlements under transportation agreements that it has with Great Lakes Gas Transmission, L.P., Union Gas Limited and Trans Québec and Maritimes Pipeline Inc.) to exceed the capability of the affected segment by an amount greater than that which would have occurred had the gas which is the subject of the Diversion been delivered at the delivery point(s) or delivery area specified in the FST Contract; and

B. to TransCanada's St. Clair export delivery point under FST Contracts.

(e) Fifth under:

Alternate Receipts made pursuant to FT, FT-SN or FT-NR Contracts or Diversions made pursuant to FT, FT-SN, FT-NR or LT-WFS Contracts which:

A. cause the actual flow of gas on a lateral or extension to exceed the capability of the lateral or extension, and/or

B. cause the actual flow of gas through a metering facility to exceed the capability of the metering facility, and/or

C. cause the actual flow of gas on any segment of TransCanada's integrated pipeline system (including those notional segments comprised of TransCanada's maximum transportation entitlements under transportation agreements that it has with Great Lakes Gas Transmission, L.P., Union Gas Limited and Trans Québec and Maritimes Pipeline Inc.) to exceed the capability of the affected segment by an amount greater than that which would have occurred had the gas which is the subject of an Alternate Receipt and/or a Diversion, been received at the receipt point and delivered at the delivery point(s) or delivery area specified in the FT, FT-SN, FT-NR or LT-WFS Contract. Solely for the purpose of making the aforesaid determination, TransCanada may, for certain quantities, treat the point of interconnection between TransCanada's system and the system of Union Gas Limited at Parkway as a delivery point specified in those FT, FT-SN, FT-NR or LT-WFS Contracts which have delivery points on the segment of TransCanada's integrated system from Kirkwall to Niagara Falls.

(f) Sixth quantities to be delivered on a best efforts basis under STS and STS-L Contracts.

(g) Seventh except for Shipper's Make-up quantities curtailed pursuant to 1 (a) above, under any FST Contracts up to the total amount that TransCanada is entitled to curtail under such contracts during such day under the provisions thereof other than under this Section XV; PROVIDED HOWEVER, that subject to TransCanada's seasonal obligations if TransCanada's inability to deliver is due to an occurrence of a force majeure during the period May 1 to September 30, then TransCanada shall be entitled to completely interrupt deliveries under such contracts on such day during such period.

(h) Eighth proportionately under:

(i) FT, FT-SN, FT-NR, FST, STFT, ST-SN, SNB, STS, STS-L and LT-WFS Contracts (other than quantities to be delivered on a best efforts basis under STS and STS-L Contracts) in amounts proportional to the Operating Demand Quantities minus the quantities to be delivered pursuant to an Alternate Receipt or a Diversion of such Contracts.

(ii) Alternate Receipts made pursuant to FT, FT-SN or FT-NR Contracts and/or Diversions made pursuant to FT, FT-SN, FT-NR, FST, and LT-WFS Contracts not already curtailed pursuant to subsections, (d) and (e) above, in amounts to be delivered pursuant to such Alternate Receipt and/or Diversion.

(For the purpose of this subsection, the Operating Demand Quantity shall be:

(A) under FT Contracts, the Contract Demand;

(B) under FT-SN Contracts, the Contract Demand;

(C) under FT-NR Contracts, the Contract Demand;

(D) under LT - WFS Contracts, the LT - WFS Maximum Daily Quantity;

(E) under STS Contracts, the Daily Injection Quantity or the Daily Withdrawal Quantity, as the case may be;

(F) under STS-L Contracts, the Daily Contract Injection Quantity and the Daily Contract Withdrawal Quantity;

(G) under FST Contracts, fifty (50%) percent of the winter period average daily winter capacity, or TransCanada's estimate of Shipper's requirement, as the case may be;

(H) under STFT Contracts, the Maximum Daily Quantity;

(I) under ST-SN Contracts, the Maximum Daily Quantity;

(J) under FBT Contracts, the Maximum Daily Quantity; and

(K) under SNB Contracts, the Contract Quantity.

(iii) Any forward haul component of an FBT Contract, that are affected by the disability in proportion Operating Demand Quantities of such Contract.

(iv) Back haul components of an FBT Contract as required due to any lack of forward haul quantities to support the back haul quantities.

2. If TransCanada estimates that it will be unable to meet its total minimum obligations to deliver under all of its contracts during the then current season, TransCanada shall order seasonal curtailment in the following order of priority:

(a) First under any Shipper's Make-up pursuant to the FST Toll Schedule

(b) Second under interruptible service provided pursuant to the IT and IT Backhaul Toll Schedules.

The toll for STS Overrun is the 100% Load Factor Toll. Therefore when STS Overrun is tolled at an equal or higher price than IT, then the priority of STS Overrun is higher; when the STS Overrun Toll is at a lower price than IT, then the priority of STS Overrun is lower.

(c) Third under any gas storage program of TransCanada.

(d) Fourth under:

Diversions made:

(A) under FST Contracts which:

(I) cause the actual flow of gas on a lateral or extension to exceed the capability of the lateral or extension, and/or

(II) cause the actual flow of gas through a metering facility to exceed the capability of the metering facility, and/or

(III) cause the actual flow of gas on any segment of TransCanada's integrated pipeline system (including those notional segments comprised of TransCanada's maximum transportation entitlements under transportation agreements that it has with Great Lakes Gas Transmission, L.P., Union Gas Limited and Trans Québec and Maritimes Pipeline Inc.) to exceed the capability of the affected segment by an amount greater than that which would have occurred had the gas which is the subject of the Diversion been delivered at the delivery point(s) or delivery area specified in the FST Contract; and

(B) to TransCanada's St. Clair export delivery point under FST Contracts.

(e) Fifth under:

Alternate Receipts made pursuant to FT, FT-SN or FT-NR Contracts or Diversions made pursuant to FT, FT-SN, FT-NR or LT-WFS Contracts which:

(A) cause the actual flow of gas on a lateral or extension to exceed the capability of the lateral or extension, and/or

(B) cause the actual flow of gas through a metering facility to exceed the capability of the metering facility, and/or

(C) cause the actual flow of gas on any segment of TransCanada's integrated pipeline system (including those notional segments comprised of TransCanada's maximum transportation entitlements under transportation agreements that it has with Great Lakes Gas Transmission, L.P., Union Gas Limited and Trans Québec and Maritimes Pipeline Inc.) to exceed the capability of the affected segment by an amount greater than that which would have occurred had the gas which is the subject of an Alternate Receipt and/or a Diversion, been received at the receipt point and delivered at the delivery point or delivery area specified in the FT, FT-SN, FT-NR or LT-WFS Contract.

Solely for the purpose of making the aforesaid determination, TransCanada may, for certain quantities, treat the point of interconnection between TransCanada's system and the system of Union Gas Limited at Parkway as a delivery point specified in those FT, FT-SN, FT-NR or LT-WFS Contracts which have delivery points on the segment of TransCanada's integrated system from Kirkwall to Niagara Falls.

(f) Sixth Quantities to be delivered on a best efforts basis under STS and STS-L Contracts.

(g) Seventh under FST Contracts up to the total amount that TransCanada is entitled to curtail under such contracts during such season under the provisions thereof other than under this Section XV.

(h) Eighth proportionately under:

(i) FT, FT-SN, FT-NR, FST, STFT, ST-SN, SNB, STS, STS-L and LT-WFS Contracts (other than quantities to be delivered on a best efforts basis under STS and STS-L Contracts) once the curtailments made in (e) above have taken place, in amounts proportional to the Operating Demand Quantities or Maximum Daily Quantities, as the case may be, minus the quantities to be delivered pursuant to an Alternate Receipt and/or a Diversion of such Contracts,

(ii) Alternate Receipts made pursuant to FT, FT-SN or FT-NR Contracts and /or Diversions made pursuant to FT, FT-SN, FT-NR, FST, or LT-WFS Contracts not already curtailed pursuant to subsections (d) and (e) above, in amounts to be delivered pursuant to such Alternate Receipt and/or Diversion.

(iii) Any forward haul components of a FBT Contract, that are affected by the disability in proportion Operating Demand Quantities of such Contract.

(iv) Back haul components of an FBT Contract as required due to any lack of forward haul quantities to support the back haul quantities.

For this purpose the seasonal requirement shall be:

(i) under FST Contracts, the seasonal quantity of the applicable season, less the quantity curtailed pursuant to subsections 2 (a), (d) and (e) above.

(ii) under FT Contract, FT-SN Contracts, SNB Contracts, FT-NR Contracts, STFT Contracts, ST-SN Contracts, STS Contracts, STS-L Contracts and FBT Contracts, TransCanada's estimate of Shipper's total seasonal requirements under each such Contract.

(iii) under LT-WFS, the LT-WFS Maximum Daily Quantity, as the case may be, multiplied by the number of days in Shipper's Service Entitlement.

In curtailing deliveries under this subsection 2, TransCanada will endeavor to minimize its daily curtailments under its FT Contracts, FT-SN Contracts, FT-NR Contracts, STFT Contracts, ST-SN Contracts, SNB Contracts, LT-WFS Contracts, STS Contracts, STS-L Contracts and FBT Contracts in an attempt to meet Shipper's daily requirements for deliveries.

XVI DETERMINATION OF DAILY DELIVERIES

1. A Shipper taking delivery of gas under contracts and/or toll schedules for more than one class of service in one delivery area or one Export Delivery Point shall be deemed on any day to have taken delivery of Shipper's Authorized Quantity under the applicable contract and/or toll schedule in accordance with such agreement as may exist between TransCanada and the downstream operator(s). Absent such agreement, shipper shall be deemed to have taken delivery of Shipper's Authorized Quantities sequentially as follows:

(a) IT Backhaul Contract Receipt Quantity

(b) FT Contract

(c) FT-SN Contract

(d) FT-NR Contract

(e) STFT and ST-SN Contracts

(f) STS and STS-L Contracts

(g) FBT Contract

(h) LT- WFS Contract

(i) firm portion of gas quantities under FST Contract

(j) interruptible portion of gas quantities under FST Contract, except for any Shippers Make-up

(k) IT and IT Backhaul Contracts, Delivery Quantity

(l) Shippers Make-up under FST Contract

XVII DEFAULT AND TERMINATION

Subject to the provisions of Section XI, Section XIV, Section XV and Section XXIII of these General Terms and Conditions, if either TransCanada or Shipper shall fail to perform any of the covenants or obligations imposed upon it under any Contract into which these General Terms and Conditions are incorporated, then in such event the other party may, at its option, terminate such Contract by proceeding as follows: the party not in default shall cause a written notice to be served on the party in default stating specifically the default under the Contract and declaring it to be the intention of the party giving the notice to terminate such Contract; thereupon the party in default shall have ten (10) days after the service of the aforesaid notice in which to remedy or remove the cause or causes stated in the default notice and if within the said ten (10) day period the party in default does so remove and remedy said cause or causes and fully indemnifies the party not in default for any and all consequences of such default, then such default notice shall be withdrawn and the Contract shall continue in full force and effect.

In the event that the party in default does not so remedy and remove the cause or causes or does not indemnify the party giving the default notice for any and all consequences of such default within the said period of ten (10) days, then, at the option of the party giving such default notice, the Contract shall terminate. Any termination of the Contract pursuant to the provisions of this Section shall be without prejudice to the right of TransCanada to collect any amounts then due to it for gas delivered or service provided prior to the date of termination, and shall be without prejudice to the right of Shipper to receive any gas which it has not received but the transportation of which has been paid prior to the date of termination, and without waiver of any other remedy to which the party not in default may be entitled for breaches of the Contract.

This Section shall not apply to any default and terminations pursuant to Section XI and Section XXIII.

XVIII NON-WAIVER AND FUTURE DEFAULT

No waiver by TransCanada or Shipper of any one or more defaults by the other in the performance of any provisions of the Contract shall operate or be construed as a waiver of any continuing or future default or defaults, whether of a like or different character.

XIX DELIVERY AREAS

Deliveries of gas within a delivery area shall be subject to sufficient capacity and facilities within such delivery area.

XX DELIVERY AREAS, TOLL ZONES AND EXPORT DELIVERY POINTS

1. Delivery Areas

TransCanada's delivery areas for purposes of determining the Contract Demand applicable to the points of delivery of TransCanada's pipeline system are as follows:

Saskatchewan Southern Delivery Area or SSDA
extends from a point on TransCanada's main pipeline at the Alberta- Saskatchewan border near Empress, Alberta to a point on TransCanada's main pipeline at the Saskatchewan-Manitoba border.

Manitoba Delivery Area or MDA
extends from a point on TransCanada's main pipeline at the Saskatchewan- Manitoba border to a point on TransCanada's pipeline at the Manitoba-Ontario border to a point on TransCanada's pipeline at the International Border near Emerson, Manitoba.

Western Delivery Area or WDA
extends from a point on TransCanada's pipeline at the Manitoba- Ontario border to a point on TransCanada's pipeline 24.99 kilometres east of TransCanada's Station 80 near Geraldton, Ontario.

Northern Delivery Area or NDA
extends from a point on TransCanada's pipeline 24.99 kilometres east of TransCanada's Station 80 near Geraldton, Ontario to a point on TransCanada's pipeline 23.09 kilometres south and east respectively of TransCanada's Station 116 near North Bay, Ontario.

Sault Ste. Marie Delivery Area or SSMDA
any point on TransCanada's Sault Ste. Marie pipeline.

North Central Delivery Area or NCDA
extends from a point on TransCanada’s pipeline 23.09 kilometres south of TransCanada’s Station 116 near North Bay Ontario, to a point on TransCanada’s pipeline 0.50 kilometres south of TransCanada’s Station 127 near Barrie Ontario, provided that points of delivery to the Enbridge Gas Distribution Inc. Gas within this area are deemed for the purposes of this Tariff to be in the Central Delivery Area.

Central Delivery Area or CDA
extends from a point on TransCanada's pipeline 0.50 kilometres south of TransCanada’s Station 127 near Barrie Ontario to a point on TransCanada's pipeline at the International Border near Niagara Falls, Ontario and to a point on TransCanada's pipeline 24.99 kilometres east of TransCanada's Station 134 near Bowmanville, Ontario.

Southwestern Delivery Area or SWDA
any point on TransCanada's St. Clair to Dawn pipeline.

Eastern Delivery Area or EDA
extends from a point on TransCanada's pipeline 24.99 kilometres east of TransCanada's Station 134 near Bowmanville, Ontario and from a point on TransCanada's North Bay Shortcut 23.09 kilometres east of TransCanada's Station 116 near North Bay, Ontario to a point on TransCanada's pipeline at the International Border near Philipsburg, Québec and to a point on the pipeline system of Trans Québec & Maritimes Pipeline Inc. near Québec City, Québec.

2. **Toll Zones**

TransCanada's toll zones for purposes of determining the toll applicable to any point of delivery on TransCanada's pipeline system are as follows:

Saskatchewan Zone or Zone S
includes all points in the Saskatchewan Southern Delivery Area.

Manitoba Zone or Zone M
includes all points in the Manitoba Delivery Area.

Western Zone or Zone W
includes all points in the Western Delivery Area.

Northern Zone or Zone N
includes all points in the Northern Delivery Area and the Sault Ste. Marie Delivery Area.

Eastern Zone or Zone E
includes all points in the North Central Delivery Area, the Central Delivery Area and the Eastern Delivery Area.

Southwest Zone or Zone SW
includes all points in the Southwestern Delivery Area.

XXI INCORPORATION IN TOLL SCHEDULES AND CONTRACTS

1. These General Terms and Conditions are incorporated in and are a part of all of TransCanada's Toll Schedules, Contracts and transportation service contracts.

2. These General Terms and Conditions are subject to the provisions of the National Energy Board Act or any other legislation passed in amendment thereto or substitution therefor.

XXII NOMINATIONS AND UNAUTHORIZED QUANTITIES

1. **Nominations**

For service required on any day under each of Shipper's transportation contracts (for the purposes of this Section XXII the "said Contract"), Shipper shall provide TransCanada with a nomination of the quantity of gas, expressed in GJ, it desires TransCanada to deliver at the delivery point ("Shipper's nomination") or Title Transfer pursuant to Section XXIV of these General Terms and Conditions. Unless otherwise provided under the applicable Toll Schedule or as outlined under this section in the Schedule of Nomination Times below, such nominations are to be provided in writing or EDI format, or by other electronic means, so as to be received by TransCanada's Gas Control Department in Calgary on or before 12:00 hours CCT on the day immediately preceding the day for which service is requested. Subject to the provisions of the applicable toll schedules and Sections XIV and XV of these General Terms and Conditions, TransCanada shall determine whether or not all or any portion of Shipper's nomination will be accepted.

In the event TransCanada determines that it will not accept such nomination, TransCanada shall advise Shipper, (on or before 14:00 hours CCT on the day immediately preceding the day for which service is requested), of the reduced quantity of gas, (if any) (the "quantity available") that TransCanada is prepared to deliver under the said Contract. Forthwith after receiving such advice from TransCanada but no later than 1 hour after receiving such notice on such day, Shipper shall provide a revised nomination to TransCanada which shall be no greater than the quantity available. If such revised nomination is not provided within the time allowed as required above or such revised nomination is greater than the quantity available, then the revised nomination shall be deemed to be the quantity available. If the revised nomination (delivered within the time allowed as required above) is less than the quantity available, then such lesser amount shall be the revised nomination. That portion of a Shipper's nomination or revised nomination, which TransCanada shall accept for delivery shall be known as "Shipper's Authorized Quantity" which authorized quantity shall be limited, for firm services, to Shipper's Contract Demand and, for other services, to such quantity permitted by the provisions of the Contract.

Schedule of Nomination Times (CCT)

Gas Day Time	Class of Service *	Effective 0900 Hours Next Gas Day
12:00	All Services	Faxed, EBB & EDI (EBB & EDI commencing on October 1, 1997)

Please refer to FST Toll Schedule for appropriate times.

** Effective October 1, 1997 nominations for service must be received by TransCanada through its electronic bulletin board or EDI at the time specified pursuant to Section XXII of the General Terms and Conditions. TransCanada shall not accept nominations by fax unless TransCanada's electronic bulletin board and EDI systems are inoperative, except in the case of FT-SN and SNB Service. Nominations for FT-SN and SNB Service shall be submitted to TransCanada via fax or by other electronic means as determined from time to time by TransCanada.

2. Definitions in Section XXII

In this Section XXII, the following terms shall be construed to have the following meanings:

(a) "Total Allocated Quantity":

(i) for any receipt point, means the total quantity of gas which TransCanada determines has been received during any time period under all transportation service contracts with a Shipper; and

(ii) for any delivery point or delivery area, means the total quantity of gas which TransCanada determines has been delivered during any time period under all transportation service contracts with a Shipper.

(b) "Total Authorized Quantity" or “TAQ” for any day:

(i) for any receipt point, means the sum of the Shipper's Authorized Quantities under all transportation service contracts at that receipt point.

(ii) for any delivery point or delivery area, means the sum of the Shipper's Authorized Quantities under all transportation service contracts at a delivery point or for that delivery area.

(c) "Daily Variance" for a Shipper at any receipt or delivery point or delivery area means the absolute difference between the Total Authorized Quantity and the Total Allocated Quantity.

(d) "FT Daily Demand Charge" or “FTD” means the result when the Demand Toll for Canadian Firm Service to the Eastern Zone Toll, as set out in the List of Tolls, is multiplied by 12 and divided by the number of days in the Year.

(e) "Average Authorized Quantity" or “AAQ” for a Shipper at any receipt or delivery point or delivery area means the average Total Authorized Quantity during the preceding 30 days.

(f) "Cumulative Variance" is the absolute value accumulation of the daily differences between the Total Authorized Quantity and the Total Allocated Quantity for a Shipper at any delivery point, delivery area or receipt point.

3. Emergency Operating Conditions

(a) EOC Definition

“Emergency Operating Conditions” (“EOC”) means that TransCanada determines, in the exercise of its reasonable judgement, that its ability to fulfill its obligations under firm contracts is at risk due, in whole or in part, to Shipper variances during periods of extreme weather changes, and/or supply, market, pipeline interruptions, and TransCanada issues an EOC notice pursuant to subsection 3(b).

(b) EOC Notices

If TransCanada determines an EOC exists, TransCanada shall issue notice to all Shippers via High Priority Bulletin on its electronic bulletin board setting out the following information related to the EOC:

i) EOC effective time, and

ii) anticipated duration of the EOC, and

iii) delivery points and delivery areas where EOC is in effect

In addition to such notice, TransCanada will use reasonable efforts to contact by phone those Shippers directly impacted by the EOC.

(c) EOC Effective Times

If TransCanada issues notice of EOC prior to 13:00 Central Clock Time (CCT), then the EOC takes effect on that day. If TransCanada issues notice of EOC after 13:00 CCT, then the EOC takes effect on the next day. The EOC will remain in effect until the operational condition has been remedied.

4. Daily Balancing Fee

On each day Shipper shall pay a "Daily Balancing Fee" equal to:

(Tier 1 Quantity times Tier 1 Fee); plus

(Tier 2 Quantity times Tier 2 Fee); plus

(Tier 3 Quantity times Tier 3 Fee); plus

(Tier 4 Quantity times Tier 4 Fee).

Where:

(a) Tier 1, 2, 3, 4 Fees and Quantities are set out in the following Table:

	Tier 1	**Tier 2**	**Tier 3**	**Tier 4**
Minimum Quantity	Greater of: 2% of TAQ, or 2% of AAQ or 75 GJ	Greater of: 4% if TAQ, or 4% of AAQ, or 150 GJ	Greater of: 8% of TAQ, or 8% of AAQ, or 302 GJ	Greater of: 10% of TAQ, or 10% of AAQ, or 377 GJ
Maximum Quantity	Greater of: 4% of TAQ, or 4% of AAQ, or 150 GJ	Greater of: 8% of TAQ, or 8% of AAQ, or 302 GJ	Greater of: 10% of TAQ, or 10% of AAQ, or 377 GJ	∞ (Infinity)
Standard Fee	0.2 times FTD	0.5 times FTD	0.75 times FTD	1.0 times FTD
EOC Draft Fee	1.0 times Index	1.25 times Index	1.50 times Index	2.0 times Index
EOC Pack Fee	0	0	0	0

(a) Quantity for each Tier equals that portion of the Daily Variance which is greater than the Minimum Quantity and less than the Maximum Quantity.

(b) The applicable Fee for each Tier equals:

(i) Standard Fee for days and locations where EOC are not in effect,

(ii) EOC Draft Fee for days and locations where EOC are in effect and where Shipper's Total Authorized Quantity is less than Shipper's Total Allocated Quantity, and

(iii) EOC Pack Fee for days and locations where EOC are in effect and where Shipper's Total Authorized Quantity is greater than Shipper's Total Allocated Quantity.

(c) No Daily Balancing Fee is payable on the portion of a Daily Variance which is less than 75 GJ.

(d) The Daily Balancing Fee is added to the bill for the month in which the day is included.

(e) "Index" means the highest price of gas on the day among all receipt and delivery points on the TransCanada pipeline system as published by Platts Gas Daily or such other recognized industry publication.

5. Cumulative Balancing Fee

On each day Shipper shall pay a "Cumulative Balancing Fee" equal to:

(Tier 1 Quantity times Tier 1 Fee); plus

(Tier 2 Quantity times Tier 2 Fee).

Where:

(a) Tier 1, 2 Fees and Quantities are set out in the following Table:

	Tier 1	**Tier 2**
Minimum Quantity	Greater of: 4% of TAQ, or 4% of AAG, or 150 GJ	Greater of: 6% of TAQ, or 6% of AAQ, or 225 GJ
Maximum Quantity	Greater of: 6% of TAQ, or 6% of AAQ, or 225 GJ	∞ (Infinity)
Standard Fee	0.15 times FTD	0.25 times FTD
EOC Draft Fee	0.15 times FTD	0.25 times FTD
EOC Pack Fee	0	0

(b) Quantity for each Tier equals that portion of the Cumulative Variance which is greater than the Minimum Quantity and less than the Maximum Quantity.

(c) The applicable Fee for each Tier equals:

(i) Standard Fee for days and locations where EOC are not in effect,

(ii) EOC Draft Fee for days and locations where EOC are in effect and where Shipper's accumulated Total Authorized Quantity is less than Shipper's accumulated Total Allocated Quantity, and

(iii) EOC Pack Fee for days and locations where EOC are in effect and where Shipper's accumulated Total Authorized Quantity is greater than Shipper's accumulated Total Allocated Quantity.

(d) No Cumulative Balancing Fee is payable on the portion of an Absolute Cumulative Variance which is less than 150 GJ.

(e) The Cumulative Balancing Fee is added to the bill for the month in which the day is included.

(f) A Cumulative Balancing Fee is in addition to Daily Balancing Fees payable under subsection 4 of Section XXII, and an additional Cumulative Balancing Fee is payable on each day where there is an Absolute Cumulative Variance.

6. Payback Provisions

(a) Shippers may reduce Cumulative Variances through nomination of "Payback Quantities" which shall be nominated and authorized in accordance with these General Terms and Conditions.

TransCanada is not obligated to provide additional transportation capacity to deliver Payback Quantities.

(b) If, on any day, a Shipper nominates a Payback Quantity under subsection (d), and TransCanada is unable to deliver or receive a quantity ("Minimum Payback Quantity") equal to the lesser of:

(i) Shipper's nominated Payback Quantities, or

(ii) the greater of:

(a) two percent of the Total Authorized Quantity,

(b) two percent of the Average Authorized Quantity, and

(c) 75 GJ

then Shipper is relieved from the Cumulative Balancing Fee by a quantity ("Payback Relief Quantity") equal to the difference between:

(iii) the Minimum Payback Quantity, and

(iv) The level of Payback Quantities which TransCanada was able to deliver or receive.

The relief from Cumulative Balancing Fees shall apply for each day until TransCanada delivers or receives the Payback Relief Quantity. No Payback Relief will be granted as a result of TransCanada not authorizing a transportation service.

(c) If TransCanada determines, in its sole discretion, that its ability to meet firm obligations is at risk due to Shipper variances, and after curtailment of all discretionary transportation services that are hindering TransCanada's ability to meet its firm obligations, TransCanada may, without further notice, adjust Shipper's nominations for any day in order to reduce Shipper's Cumulative Variance to zero.

7. Obligation to Balance Accounts

Payments of balancing fees under this Section XXII do not give Shipper the right to receive or deliver unauthorized quantities, or incur Cumulative or Daily Variances, nor shall payment of the balancing fees be a substitute for other remedies available to TransCanada.

8. Energy Imbalance Recovery

(a) Cumulative energy imbalances that result from energy in transit, accumulated fuel imbalances and imbalances held under other applicable accounts, shall be recovered in the following manner:

(i) on the 20th Day of each month, TransCanada shall advise Shipper in writing of all cumulative energy imbalances attributed to Shipper arising up to the end of the 19th Day of such month and carried forward or arising from previous months, provided however that such cumulative energy imbalances for export delivery points referred to in subsection 8(b) shall be the amount by which the cumulative energy imbalance at such points exceed 50 GJ;

(ii) the cumulative energy imbalance reported to Shipper shall be aggregated at each applicable location from all of Shipper's Contracts, nomination groups and other applicable accounts;

(iii) on or before the 3rd last Day of each month, Shipper may reduce the cumulative energy imbalances reported by TransCanada.

(iv) The cumulative energy imbalance after giving effect to applicable offsetting transactions (the “Net Imbalance”), shall be determined on:

(A) the end of the 3rd last Day of such month if the cumulative energy imbalance is less than the cumulative energy imbalance on the 19th Day of such month; or

(B) the 19th Day of such month if the cumulative energy imbalance on the 3rd last Day of such month is greater than the energy balance on the 19th Day of such month.

The Net Imbalance shall be scheduled and recovered in equal amounts on each Day over the first 15 Days, or a lesser number of Days as mutually agreed to by Shipper and TransCanada, of next month (the "Recovery Period"). The amount of the Net Imbalance to be recovered each Day of the Recovery Period (the "Daily Imbalance Recovery") will be determined by TransCanada and verbally communicated to Shipper on the 2nd last Day of each month. Shipper shall nominate the Daily Imbalance Recovery on each Day of the Recovery Period as an "Imbalance Payback" under the Shipper account (nomination group) with the largest energy imbalance as determined by TransCanada based on the most recent monthly statements available.

(vi) in nominating the Daily Imbalance Recovery, Shipper will ensure that all nominations remain in balance. Any nomination received from Shipper which does not include the required Daily Imbalance Recovery will, at TransCanada's sole discretion, be either rejected or forced to balance by TransCanada. TransCanada is authorized to curtail Shipper's gas supply and market, as necessary, to balance the nomination after accounting for the Daily Imbalance Recovery;

(vii) where applicable, deliveries of the Daily Imbalance Recovery shall be the first deliveries made under the nomination on each Day of the Recovery Period; and

(viii) any imbalance shall be deemed to have occurred and shall be held at the primary receipt point specified in the transportation service agreement.

(b) Cumulative energy imbalances at export delivery points that result from rounding when converting between energy units used for daily scheduling purposes shall be subject to the following:

(i) Each Day Shipper shall be entitled to an energy imbalance of up to 5 GJ provided however, Shipper's cumulative energy imbalance at any time shall not exceed 50 GJ;

(ii) Shipper may reduce its cumulative energy imbalance on any Day by up to 10 GJ provided however, such reduction shall not result in the cumulative energy imbalance moving from a positive imbalance to a negative imbalance, or from a negative imbalance to a positive imbalance.

XXIII FINANCIAL ASSURANCES

1. **Financial Assurance for Performance of Obligations:** TransCanada may request that Shipper (or any assignee) at any time from time to time prior to and during service, provide TransCanada with an irrevocable letter of credit or other assurance acceptable to TransCanada, in form and substance satisfactory to TransCanada and in an amount determined in accordance with subsection XXIII(3) hereof (the "Financial Assurance").

2. **Failure to Provide Financial Assurance:** TransCanada may withhold the provision of new service until TransCanada has received a requested Financial Assurance.

Notwithstanding Section XVII, if Shipper fails to provide a requested Financial Assurance to TransCanada within four (4) Banking Days of TransCanada's request, TransCanada may upon four (4) Banking Days written notice immediately suspend any or all service being or to be provided to Shipper provided however that any such suspension shall not relieve Shipper from any obligation to pay any rate, toll, charge or other amount payable to TransCanada. If at any time during such suspension Shipper provides such Financial Assurance to TransCanada, TransCanada shall within two (2) Banking Days recommence such suspended service.

Notwithstanding Section XVII, if Shipper fails to provide such Financial Assurance during such suspension, TransCanada may, in addition to any other remedy that may be available to it, upon four (4) Banking Days written notice to shipper immediately:

a) Terminate any or all service being or to be provided to Shipper; and

b) Declare any and all amounts payable now or in the future by Shipper to TransCanada for any and all service to be immediately due and payable as liquidated damages and not as a penalty.

Any notice provided by TransCanada to Shipper to withhold, suspend or terminate service pursuant to **sub-Section XXIII(2) hereof** shall be filed concurrently with the NEB.

3. **Amount of Financial Assurance:** The maximum amount of Financial Assurance TransCanada may request from a Shipper (or assignee) shall be as determined by TransCanada an amount equal to:

a) for the provision of all gas transportation and related services, other than such services referred to in **sub-Section XXIII(3)(b),** the aggregate of all rates, tolls, charges or other amounts payable to TransCanada for a period of seventy (70) days. Provided however, the amount of the Financial Assurance for all rates, tolls and charges other than demand charges shall be based on the daily average of the actual charges billed for service for the preceding twelve (12) month period with the initial forecast to be provided by Shipper; and

b) for the provision of any gas transportation and related services where TransCanada determines it must construct facilities and Shipper has executed the Financial Assurances Agreement defined in Section 4.4(c)(ii) of the Transportation Access Procedure, the aggregate of all rates, tolls, charges or other amounts payable to TransCanada for a period of seventy (70) days plus one (1) month for each remaining year of the term of such service, up to a maximum of twelve (12) months total.

Nothing in this Section XXIII shall limit Shipper's right to request the NEB to issue an order, under sub-section 71(2) of the National Energy Board Act, requiring TransCanada to receive, transport and deliver gas offered by Shipper for transmission, or to grant such other relief as Shipper may request under the circumstances, notwithstanding Shipper's default under this Section XXIII.

XXIV TITLE TRANSFERS

Shippers may request and TransCanada shall authorize Title Transfers subject to the following:

a. TransCanada receives a nomination satisfactory to TransCanada from each Shipper that is a party to a Title Transfer;

b. If TransCanada determines at any time that any title transfer account of a Shipper is out of balance, TransCanada may, without notice to the title transfer account holder, curtail transfers up to such amounts as TransCanada deems necessary to bring all affected title transfer accounts into balance. In so doing, TransCanada shall have no liability whatsoever to Shipper or any third party claiming through Shipper for any claims, actions or damages of any nature arising out of or in any way related to such curtailment

XXV LIABILITY AND LIMITATION OF LIABILITY

TransCanada’s and Shipper’s liability to each other is limited to direct damages only. In no event, other than in the case of gross negligence or wilful default, shall either TransCanada or Shipper be liable for loss of profits, consequential, incidental, punitive, or indirect damages, in tort, contract or otherwise.

HV-97 SCHEDULE

Area	**Heating Value**
	MJ/m3
CHIPPAWA	37.77
CORNWALL	37.69
EMERSON 1	37.68
EMERSON 2	37.68
EMPRESS	37.73
IROQUOIS-EXP.	37.68
NAPIERVILLE	37.68
NIAGARA FALLS	37.75
PARKWAY ENBRIDGE	37.69
PARKWAY UNION	37.68
PHILIPSBURG	37.68
ST-LAZARE	37.69
SABREVOIS	37.69
SPRUCE	37.68
ST. CLAIR	37.72
NCDA, UNION GAS LIMITED	37.69
CDA, ENBRIDGE GAS DISTRIBUTION INC.	37.69
CDA, UNION GAS LIMITED	37.68
EDA, UNION GAS LIMITED	37.68
EDA, GAZ METROPOLITAIN & CO. L.P.	37.69
EDA, KINGSTON PUBLIC UTILITIES COMM	37.68
EDA, ENBRIDGE GAS DISTRIBUTION INC.	37.69
MDA, CENTRA GAS MANITOBA INC	37.68
MDA, CENTRA TRANSMISSION HOLDINGS	37.68
MDA, GLADSTONE AUSTIN	37.68
NDA, UNION GAS LIMITED	37.68
NDA, GAZ METROPOLITAIN & CO. L.P.	37.68
NDA, TRANSCANADA POWER, L.P.	37.68
SSDA, CENTRA GAS MANITOBA INC	37.67
SSDA, TRANSGAS LTD.	37.66
SSMDA UNION GAS LIMITED.	37.71
SWDA, ENBRIDGE GAS DISTRIBUTION INC	37.68
SWDA, UNION GAS LIMITED	37.71
WDA, UNION GAS LIMITED	37.68
WDA, TRANSCANADA POWER, L.P.	37.67

APPENDIX C

PREVIOUS MH INTERNAL REPORTS AND STUDIES

FINAL DRAFT

CENTRA GAS MANITOBA INC.

REPORT

STUDY ON REGULATION STATION FREEZE-UP

OCTOBER 28, 1996

WRITTEN BY:

Greg Head
David Petursson

FREEZE-OFF STUDY TEAM:

David Petursson
Doug Miller
Don Oster
Guy Chateau
Bob Richards
Sandy Boyd

TABLE OF CONTENTS

INTRODUCTION

The phenomenon of freeze ups at pressure regulator stations during winter operations has been a chronic problem for Centra Gas Manitoba that has resulted in unplanned customer outages and significant operating costs.

This report will examine regulator Station freeze ups in order to identify the root cause and determine methods for prevention.

Data has been collected from Centra personal, trouble reports, town border station log books, and reports on hydrate prevention.

The scope of this report is limited to freeze-up at pressure regulation stations including existing stations and those built as part of the Rural Gas Expansion Project. Plant downstream of regulator stations, ie. distribution mains and services are not within the scope of this report.

BACKGROUND

Operations disruptions due to regulator station freeze-off have been occurring for a number of years for Centra and other gas distribution companies. "Freezing off" of gas stream is also a problem that has plagued the gas production industry since the 1930's. Millions of dollars are spent annually by the upstream and downstream energy industries to maintain the reliable flow of natural gas.

A synopsis of some recent problems Centra incurred are as follows:

RURAL EXPANSION TOWN BORDER STATIONS

During the period of November 1995 to April 1996, there was a total of 22 freeze up related problems at Rural Expansion town border stations. These stations included Elkhorn, Souris North, Souris South, St. Malo, and Starbuck. The stations were energized during the last two months of 1995.

The problems that occurred were fairly consistent with all town border stations and typical of problems at other stations in the past. The freeze ups would occur at the lead worker and monitor regulators. On one occasion the 2" transmission line running into the Elkhorn town border station was discovered plugged below ground, also on two occasions the y-strainer was found plugged.

Methanol was the first inhibitor used, although to combat persistent problems supplemental heat in the form of catalytic heaters was used. See appendix B for information and pictorials used for prevention.

ELIE AND ST.ADOLPHE

The Elie town border station was energized late in 1992. Since then, the station has had on going problems during the winter months with regulator freeze ups.

In order to combat freeze ups, heat and alcohol have been the main prevention techniques used. During the past winter, the station ran without freeze ups while the heaters were running. Once the heaters would go out the pilot regulators would freeze up resulting in station shut-down. The heaters are used to heat the pilot lines.

As water was used to test the line during construction, to confirm the presence of any residual water, a dew point reading was completed at both ends of the Elie transmission line last winter. The line had a dew point reading of -38 degrees Celsius consistent at both ends of the line from the Oakville Primary to the Elie station confirming that the line was dry. The town of Elie has maintained a relatively small gas consumption rate throughout its existence, hence having a low flow rate at its town border station.

The other station to have on going freeze up problems has been St. Adolphe. St. Adolphe was also energized late in 1992. To prevent the introduction of moisture into the St. Adolphe pipeline from Iles Des Chene, nitrogen rather than water was used as a test medium on the transmission line. Initially St. Adolphe experienced freeze-off problems which were combatted with alcohol and the installation of catalytic heaters on the inlet piping to heat the gas stream prior to the pressure regulation.

OBSERVATIONS

Observations made by Centra personal regarding the solid material found in the regulators at the town border stations were as follows:

- "ice-like material"
- "oily"

- "once the solid was introduced to atmosphere pressure it seemed to disappear"
- "very little moisture left behind once the solid condensed"
- "distinct odour - similar to odourant, yet different"

These observations are consistent with hydrate formation. As hydrates often appear to be similar to conventional water ice, hydrates may have been overlooked in the past as the cause for station freeze ups.

New transmission lines have been often hydro tested. Reportedly, although the lines have been de-watered by repeated pigging to remove the majority of the water, the lines have not been dehydrated to remove substantially all of the moisture. Following dewatering, some lines have been further dried either by running a slug of alcohol between two pigs or after energizing by flaring gas.

The freeze-off phenomenon tends to occur at new stations, smaller stations, or on small diameter lines. After a few years of operation, some stations reportedly experience fewer or no problems.

New stations generally have a lower flow rate during the first few years of operation because of the limited amount of customers. Customer load growth after a few years of operation increases the flowrate through the station.

Based on an analysis of the information available, on the recorded histories of freeze-off at several stations and the information gathered from operations personnel who deal directly with stations, the following specific observations are drawn:

1. Hydrates as opposed to water ice (plain frozen water) are encountered at regulation stations that have frozen-off.

2. Water has been present in some of the pipelines upstream of stations that have frozen off. (eg. Starbuck)

3. Freeze-off can occur when the line feeding a station is confirmed to be dry (eg. Elie)

4. Pilot operated regulators (such as Fisher 399 or axial flow) are more prone to freeze-off than direct acting regulators (such as a Fisher 627). Freeze-off tends to occur in the pilot regulators.

5. A greater problem in freeze-off is observed in axial flow regulators with restrictors, particularly the 90% restrictors.

6. Regulators operating at a low percentage of their flow capacity have more problems with freeze-off than a smaller regulator operating closer to flow capacity.

DISCUSSION OF HYDRATES

As the description of the substances found in regulators that have frozen off conforms to the characteristics of hydrates, hydrates need to be better understood to address the problem.

HYDRATE DESCRIPTION

A hydrate is a solid material which has an "ice like" appearance. Hydrates consist of a water lattice in which light hydrocarbon molecules are embedded. They are a form of chemical compound called cathrates, a term denoting compounds that may exist in stable form but do not result from true chemical combination of all the molecules involved.
Hence, hydrates have a characteristic of disappearing once they condense. The Methane in a hydrate will vaporize when heated or taken to atmospheric pressure leaving behind the water that had combined with the methane to form the hydrate.

HYDRATE FORMATION

Generally, hydrates potentially can form once a gas stream has been cooled below its hydrate formation temperature. The water that forms hydrates with a light hydrocarbon usually is in vapour form when the hydrate is formed. There are a number of factors, not all fully understood, that affect the formation of hydrates so prediction of hydrate formation is not an exact science.

Hydrate formation temperature is affected by pressure and water content in the gas stream where increased pressure or increased water content will elevate the hydrate formation temperature. Under appropriate pressure and water content conditions, the hydrate formation temperature can be much higher than the freezing point of water.

Temperature is a critical factor in hydrate formation. For a gas at a given water content and pressure, lowering the temperature to or below the hydrate formation temperature will enhance the risk of hydrate formation. Conversely, raising the temperature of the gas stream will reduce or eliminate the risk of hydrate formation.

Regulators are used in the distribution of natural gas to expand the gas from a high pressure transmission line to lower pressure distribution lines. As the pressure drop that occurs causes a decrease in temperature, hydrate formation is most likely to occur at regulators or other pressure reducing devices such as pilots.

Temperature loss can also occur with heat loss to ambient on above grade piping when the air temperature is less than the temperature of the gas in pipeline.

Under the right conditions hydrates can begin to form when as little as 17 molecules of "free" water come into contact with one molecule of gas. Hence, hydrate formation requires very little moisture. While the thermodynamic properties of hydrates are well known, the rates of hydrate formation and growth are imprecisely known, the way that the hydrate inhibitors act is unknown and the mechanism for hydrate dissolutions still unsolved. This precludes any rational design of new inhibitors from a basic chemical perspective.

METHODS OF HYDRATE PREVENTION

In cases where hydrate formation in a gas line is a possibility, consideration should be given to redesigning the system so that hydrates are inhibited from forming. Industry experience in the production and distribution of natural gas has identified four primary methods of hydrate prevention: addition of heat, changing the pressure, removal of water, use of chemical inhibitors.

Heat

Hydrate formation can be inhibited by maintaining the gas above the hydrate formation temperature by the addition of heat and/or by reducing the heat loss from the gas.

Heat is commonly added by a variety of heaters, such as indirect fired glycol bath heaters, radiant catalytic heaters which can be configured to heat the pipe, a regulator body or a tubing (sense) line, or use of electric heat tape.

Pressure regulation stations have been designed to minimize heat loss from inlet piping by the addition of insulation on piping before the regulators and by designing stations to have minimal pipe above grade upstream of the regulator. Pipe insulation will aid in keeping the gas as close as possible to ground temperature until it reaches a pressure reducing device. Relatively speaking, ground temperature at pipeline depth of approximately 0^0C is warm compared to ambient which regularly falls to -30^0C to -40^0C.

Hydrate formation is very prone to small tubing and orifices such as those located on pilot operated regulators. Electric heat tape can be applied to the tubing of the pilot operated regulators. Heat applied directly to prone areas is an effective method of hydrate prevention.

Pressure

As pressure increases the hydrate formation temperature also rises. Restating, at any given temperature, hydrates are more likely to form in gas lines at higher pressures. An option to reduce the likelihood of hydrate formation would thus be to operate pipeline systems at lower pressures. As this is an impractical alternative, other means of hydrate prevention should be sought.

Recognizing the effect pressure has on hydrate formation can help explain why new stations operating without heat or any other hydrate prevention provisions (eg. La Broquerie, 1995-1996 inlet pressure 175 psi) did not experience any hydrate problems.

Water

The hydrate formation temperature (at a given pressure) increases with water content in the gas. Consequently, temperature and pressure notwithstanding, minimizing the water content of the gas will reduce the formation of hydrates. Although there is moisture in the gas received from TransCanada Pipelines, the water content is relatively low (specification maximum of 4#/MMCF).

Infrequently, higher water content gas is observed when TransCanada PipeLines hydrotest a portion of their pipeline system upstream of our point of delivery. Reducing the water content below this would be beneficial from a hydrate formation perspective but it is impractical from an economic perspective.

Moisture can also be introduced into a gas stream from water left in pipes during the construction of the pipeline, eg. from hydrotesting. If water is present in the pipes, the water content of the gas will be elevated above that received from TransCanada thus increasing the susceptibility to hydrate formation.

Dehydrating the pipelines is an effective hydrate prevention method.

Inhibitors

Hydrate formation can be inhibited by the addition of chemical inhibitor such as methanol or glycol. Methanol dissolves in the water and lowers the hydrate formation temperature of the mixture. Injection of a sufficient amount of chemical to lower the hydrate formation temperature below the minimum system temperature will prevent hydrate formation.

Methanol is typically pumped into the gas line or added by a controlled drip from a drip pot operating at line pressure.

ROOT CAUSE ANALYSIS

Two hypotheses have been advanced as the root cause of station freeze-off:

1) The root cause of station freeze-off is residual water left in the pipeline from the construction of the pipeline.

2) The root cause of station freeze-off is chilling of the gas below the hydrate formation temperature due to heat loss to ambient.

Hypothesis #1 is well supported by historical data. Classic examples are St. Malo and Starbuck where the line installed by TransCanada Pipeline was not properly dried and major freeze-off problems occurred.

Hypothesis #1 is challenged as freeze-off conditions have been encountered at stations where the line to the stations have been tested and confirmed to be free of any residual moisture from the construction.

Hypothesis #2 is supported by freeze-off conditions occurring primarily at new stations or small towns in either case where customer load is relatively light and consequently velocities are less and heat loss to ambient is greater.

An interesting observation is that hydrate problems in new stations often diminish or disappear after a few years. This observation can support both of the above hypotheses. A few years of relatively dry gas transported through a pipeline will dehydrate any residual moisture left from construction thus supporting hypothesis #1. Hypothesis #2 is supported by this observation as typically a town load is light in the first year or two and increase as the number of customers attached and taking gas increases. With increasing load, velocities are greater, heat loss is reduced and regulator inlet pressures are reduced at peak flows.

CONCLUSIONS

1) A root cause of station freeze-up is water in the pipeline.
While it is concluded that the presence of water in a pipeline is a root cause of stations freeze-up, the converse (all freeze-ups are a result of water in the line) is not true. Freeze-up can and does occur when there is no additional water in the pipeline.

2) A root cause of station freeze-up is heat loss to ambient during relatively low flow conditions.
While we cannot quantify how much heat loss is required or how little flow is low flow, qualitatively speaking this root cause does account for some freeze-up observations.

3) Often situations are encountered where both hypotheses presented are incurred and both contribute to a station freeze-off, possibly in varying degrees.

4) Hydrate preventative measures on an operational front, reducing heat loss, addition of heat or the use of inhibitors will reduce station freeze-off due to hydrates regardless of the root cause of the hydrate formation.

5) Sizing of regulators to more closely match actual flow, particularly in the early years of a new station, will help to reduce freeze-off problems.

RECOMMENDATIONS

To reduce the possibility of hydrate formation and the resulting station freeze-off and potential customer outage, the following recommendations are made:

1) Prior to energizing, transmission lines be dehydrated to a -40°C dewpoint to remove all residual water.

2) The inlet lines to pressure regulation stations be insulated to minimize heat loss. Following the first pressure cut, insulation is not required.

3) New town border stations be equipped with a source of supplemental heat and/or inhibitor (alcohol or methanol) injection to prevent hydrates.

4) Supplemental heat and/or inhibitor injection be reevaluated after a year or two or after substantial customer attachments and the associated load has occurred.

5) Avoid oversizing of regulators. Consider installing regulators for current load replacing them with larger regulators when load increases.

6) Operate transmission systems at as low a pressure as is practical.

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APPENDICES

APPENDIX 1A
ELKHORN TOWN BORDER REGULATION STATION HISTORY

ELKHORN SUMMARY OF STATION HISTORY	
Date:	Activity, Event, or Occurrence:
November 15, 1995	The Elkhorn TBS (town border station) was energized.
December 13, 1995	Gerald Wallack reported that the cage on the lead worker was broken. The broken cage was replaced and the other pilots and cages were thawed.
December 27, 1995	During routine station check, Bob Richards found the relief blowing and the outlet pressure was at 49 psig (regulator set at 40 psig). Upon further investigation, Bob found that the lead worker pilot was full of a solid material which resembled ice. Bob manually slugged three litres of alcohol into the station inlet using the purge valve. In a effort of prevention, methanol was put into the line on a regular basis using a alcohol pot that was installed at the purge valve.
December 31, 1995	Alcohol pot was filled.
January 07, 1996	Alcohol pot was filled.
January 10, 1996:	During routine station check, Bob Richards found the relief blowing and the outlet pressure at 50 psig. The cause for the pressure increase was due to the lead worker regulator having a plugged cage. More methanol was slugged into the line to unplug the regulator.
January 13, 1996	The alcohol pot was refilled.
January 20, 1996	The alcohol pot was refilled.
January 21, 1996	The alcohol pot was refilled.
February 05, 1996	Bob Richards installed catalytic regulator heaters on the lead worker and monitor.

ELKHORN
SUMMARY OF STATION HISTORY

Date:	Activity, Event, or Occurrence:
February 28, 1996	On routine station check, Gerald Wallack discovered a fluctuating transmission pressure. Upon further investigation, Wayne noticed the that the y-strainer was plugged and there was also a partial blockage below grade in the 2" transmission line. Alcohol was injected at the block valve at the take off from the Virden transmission line. Since there was very little flow through the Elkhorn transmission line, methanol was put in through the purge valve on the inlet piping to the TBS. By alternately opening and closing the purge valve, they were able to get the methanol down to the blockage. The line was purged for 20 to 30 minutes. During this time solid pieces of ice or hydrates were forced out through the valve. The substance which came out of the line was milky and when it condensed it seem to disappear.
March 20, 1996	During routine station check, Bob Richards reported that the gauge inside the station read 330 psig and the gauge on the inlet purge valve read 410 psig. This discovery lead to the assumption that the y-strainer was beginning to plug up again. Methanol was slugged into the line through the purge valve and a four litre slugger was installed upstream from the y-strainer.
March 29, 1996:	Gerald Wallack discovered the relief venting at the TBS. The problem was traced to the lead worker being plugged at the screen. Gerald Wallack and Wayne Schmitz took the regulator apart and cleaned out the "ice-like" material and installed a new kit.
March 30, 1996	Bob Richards discovered the relief venting again and the distribution pressure was at 50 psig. Gerald Wallack was called for assistance and the lead worker was rebuilt. No cause of failure was recorded. This was the last recorded problem at the Elkhorn TBS.

APPENDIX 1B
KILLARNEY TOWN BORDER REGULATION STATION HISTORY

KILLARNEY
SUMMARY OF STATION HISTORY

Date:	Activity, Event, or Occurrence:
December 17, 1995	The Killarney TBS was energized.
February 08, 1996	Regulator body heaters were installed by Bob Richards. They were installed on the worker and monitor on the lead run.
April 10, 1996	During routine station check, Paul Olson discovered a pilot regulator blowing gas. He then proceeded to tighten the pilot screws to stop the leaks on the lead run.
April 12, 1996	During routine station check, Paul Olson found a regulator creeping to 55 psig. He rebuilt the lead regulator and set to 30 psig.
April 26, 1996	Steve Cann found the station at 50 psig and rebuilt the lead worker & monitor. The 112 restrictor on the worker was replaced.
April 29, 1996	Station was found to be venting by Steve Cann. The relief was rebuilt and reset. Dirt was removed from the regulators.

APPENDIX 1C
SOURIS NORTH TOWN BORDER REGULATION STATION HISTORY

SOURIS NORTH SUMMARY OF STATION HISTORY	
Date:	Activity, Event, or Occurrence:
December 16, 1995	The Souris North station was energized.
December 28, 1995	During routine station check, Bob Richards discovered the lead pilots froze up. The regulators were cleaned and rebuilt and the slugger was filled.
December 30, 1995	Paul Olson discovered the relief venting, the distribution pressure was at 50 psig. The lead regulators were cleaned and rebuilt. The pressure increase was due to a solid material which resembled dirty ice in the lead worker regulator.
January 05, 1996	Lead worker regulator boot was packed with "dirty ice". Bob Richards cleaned and rebuilt the regulator.
January 25, 1996	Wayne Schmitz installed a regulator heater on the lead worker and monitor. Heater was set at 115 degrees Fahrenheit.

APPENDIX 1D
SOURIS SOUTH TOWN BORDER REGULATION STATION HISTORY

SOURIS SOUTH SUMMARY OF STATION HISTORY	
Date:	Activity, Event, or Occurrence:
December 16, 1996	The Souris South TBS was energized.
January 05, 1996	During routine station check, Bob Richards discovered the relief venting blowing gas. He later found the lead worker full of a solid material which resembled dirty ice. Methanol was slugged through the purge valve.
January 23, 1996	Bob Richards installed regulator heaters in the lead worker and monitor. Heaters were also started.
March 11, 1996	During routine station check, Paul Olson found the relief vent blowing gas. Wayne Schmitz rebuilt the 1805 relief and reset the regulators accordingly.
April 10, 1996	Heaters were turned off.

APPENDIX 1E
ST. MALO TOWN BORDER REGULATION STATION HISTORY

ST. MALO
SUMMARY OF STATION HISTORY

Date:	Activity, Event, or Occurrence:
November 13, 1996	The St. Malo TBS was energized.
November 22, 1995	Regulators froze off, causing a low outlet pressure. Two gallons of methanol was introduced into the inlet line. and a line heater was installed.
November 23, 1995	A 2" line heater was installed.
November 30, 1995	Regulators were found frozen and then repaired.
December 01, 1995	Regulators were found frozen, TCPL and Centra personal blew out inlet line and then flushed with methanol.
December 6, 1995	The lead worker was found frozen.
January 18, 1996	The lead worker was found frozen. A Regulator heater was installed on the lead worker.

APPENDIX 1F
OAKVILLE TOWN BORDER REGULATION STATION HISTORY

OAKVILLE
SUMMARY OF STATION HISTORY

Date:	Activity, Event, or Occurrence:
August 8, 1995	The Oakville TBS was energized.
December 11, 1996	The station by-pass regulator was plugged with dirt.

APPENDIX 1G
STARBUCK TOWN BORDER REGULATION STATION HISTORY

STARBUCK
SUMMARY OF STATION HISTORY

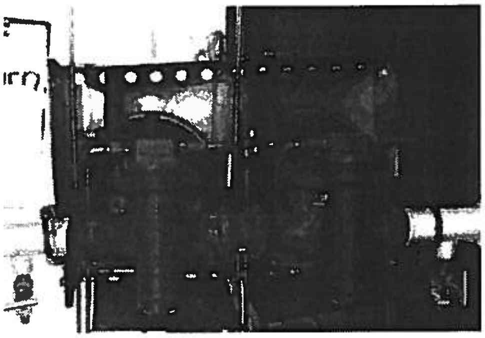
Date:	Activity, Event, or Occurrence:
November 13, 1995	The Starbuck TBS was energized.
December 6, 1995	Frozen regulator found. Heaters were installed over the 627 regulators.
December 13, 1995	Lag run, first cut regulator. was found frozen.

APPENDIX 2
REGULATOR STATION HYDRATE PREVENTION PROVISIONS

RURAL GAS EXPANSION PROJECT REGULATOR STATION HYDRATE PREVENTION PROVISIONS			
Town	Regulator Style	Heater	Other
Oakville	399	Reg. Body	-
LaBroquerie	399	-	-
St. Malo	627	Reg. Body	-
Starbuck	627	Reg. Body (630 heaters)	-
Elkhorn	399	Reg. Body (Standby)	Methanol injection pump
Souris North	399	Reg. Body	-
Souris South	627	Reg. Body	-
Killarney	399	Reg. Body	-
Boissevain	399	Reg. Body	-
Deloraine	399	Reg. Body	
Hartney	627	Reg. Body	-
Melita	399	Reg. Body	-

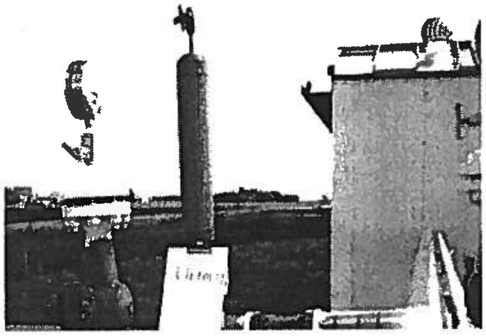
APPENDIX 3
CURRENT HYDRATE PREVENTION METHODS AND EQUIPMENT

Reg Body Catalytic Heaters:



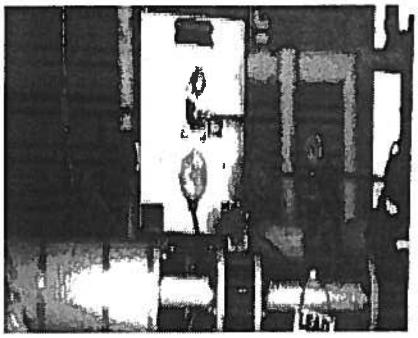
This picture was taken from the Elkhorn town border station. The reg heaters are located on the lead worker and monitor regulators.

Methanol Pot:



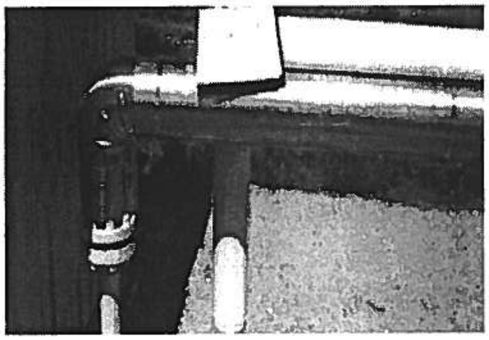
This picture was taken from the Elkhorn town border station. The methanol pot was installed on the inlet purge valve.

Pilot Line Catalytic Heater:



This picture was taken from the Elie town border station. The heater is used to heat the pilot gas.

Pipe Insulation:



This picture was taken from the Oakville town border station. The pipe insulation is installed on the inlet piping.

Catalytic Line Heater:

This picture was taken from the St. Malo town border station. The line heater is installed just before the inlet piping enters the building. The heater was covered by a tarp in order to prevent the heater from going out.

Manitoba Hydro

CUSTOMER SERVICE AND DISTRIBUTION
DISTRIBUTION ENGINEERING & CONSTRUCTION
DISTRIBUTION DESIGN DEPARTMENT - WINNIPEG

REPORT ON

Natural Gas Line Heater Installation

DDW-G2011-01

PROVINCE OF MANITOBA
Nov 25/2011
M. D.
PRYDUN
D. Prydun
REGISTERED PROFESSIONAL ENGINEER

PREPARED BY: MD Prydun

DATE PREPARED: October 21, 2011

REVIEWED BY:

FILE NUMBER:

RECOMMENDED FOR IMPLEMENTATION

DEPARTMENT:

DIVISION:

DATE:

DISTRIBUTION: *(see: https://wcms/dco/drl/objectId/0901c2a78066d925 to populate list, sample headings noted below – erase this bracketed info before finalizing document)*

Executive	**Station Design**	**Distribution Engineering & Construction**	**Commissioning**	**Customer Service & Operations**
GB Reed		JD Keil		
		JA Kreml		
		GR Paskaruk		
		D Petursson		
Transmission Planning & Design	**Apparatus Maintenance**			
	D Miller			

Executive Summary

RECOMMENDATION

Manitoba Hydro should not pursue the installation of line heaters at this time as there is insufficient technical evidence that this action will decrease the probability of future system failures.

Manitoba Hydro is encouraged to analyze data on natural gas operational issues that contribute to system failure and employ proactive methods of operation to mitigate this risk. This can be achieved through;

- Re-establishment of a regular online gas chromatography analysis of TCPL gas supply
- Identification of high risk locations that would benefit from the installation of pilot gas heater and make necessary upgrades
- Initiation of a high level analysis of operational data and industry trends to determine risk of future natural gas supply challenges

TECHNICAL EVALUATION

The fundamental purpose of a natural gas line heater is to heat the natural gas product to an elevated temperature and therefore avoid freezing during deliberate pressure reduction. Manitoba Hydro's natural gas is received from Transcanada Pipelines at an elevated or high pressure level. The design of the gas distribution system in the province of Manitoba is to use this elevated pressure as a means of economic transportation so that capital and operating costs of a compression system can be avoided.

The applicable scientific principle that pertains to natural gas line heaters is a direct temperature pressure relationship. i.e., as pressure is reduced temperature is also reduced. An assessment of the anticipated temperature reductions is one aspect of design considerations that are evaluated against the design requirements for a natural gas pressure reducing facility.

Natural Gas Quality

Natural gas quality is of primary consideration and the stable operation of a natural gas pressure regulator is impacted by the presence of liquids. Liquids such as water, larger molecule hydrocarbons and oils will condense or drop out of natural gas as the dew point is approached. It is important to note the presence of liquids and the consistency are both factors in product quality. The natural gas product received from TransCanada Pipelines (TCPL) is a highly processed product since the natural gas provided to TCPL from producers has higher end hydrocarbons, water and other undesirable components. These components are for the most part removed before transportation to Manitoba Hydro. Natural Gas quality is evaluated monthly from data received from TCPL and it has been found to be both consistent and dry. It would, however, be prudent to independently evaluate the natural gas quality apart from the data provided by TransCanada Pipelines.

Infrastructure

Natural gas line heaters are also used to mitigate impacts to infrastructure due to the expansion of ambient soil moisture (frost heave). Design considerations for pipe strength and ground preparations are used whenever possible but where impractical (i.e. swamps) line heaters are used. In instances where freezing conditions will impact the road or highway structure, line heaters are also used. This is the case in three locations in the Manitoba Hydro natural gas distribution system due to high water tables and where line heaters are in operation.

FINANCIALS

Two investment aspects exist for the consideration of the use of natural gas line heaters. Both capital and operating costs are influenced by the capacity requirements of the pressure regulating station and will be higher with larger facilities. Established natural gas pressure regulating sites will also command higher capital cost as compared with newly designed natural gas pressure regulating facilities.

Capital Costs

Capital costs are highly variable. In a new site installation, the costs are limited to equipment, installation and land and the installation of line heaters would be included in the design process. At existing facility sites the incorporation of line heaters present challenges to existing site layout, limited availability for property expansion and disruption of normal facility operation. The incremental capital cost for a small green field application, where land is readily available and a line heater forms part of the initial design is estimated at $ 100,000. In an existing large natural gas pressure reducing facility where a TCPL tap alteration would be required for the incorporation of a line heater, the projected capital cost is in the range of $2 million.

Operating Costs

More predictable and scalable than capital, operating costs can be extrapolated from the experience of Manitoba Hydro's three existing line heater installations. Operating costs are comprised of fuel costs required to operate the line heaters, maintenance to ensure reliability, inspection and overhaul costs for preventative maintenance. One must also anticipate future operational issues and costs as greenhouse gas emissions will become an operational cost in the future. The current annual operating budget for the three existing natural gas line heaters is $ 300,000 averaging $100,000 per heater installation The thermal efficiency of the Corporation's three natural gas line heaters is poor by today's standards and a reduction in operating costs could be realized with the replacement or upgrade to currently available technology.

OPERATIONAL ISSUES

Pilot Regulator Failures

Pilot regulators are similar to a tug boat that steers an ocean liner. They aid in the enhanced control and performance of an otherwise crude means of gas pressure control. The main body pressure regulator relies on a mechanical spring to balance a supply pressure and an outlet pressure set point. A pilot regulator utilizes pneumatic advantage to improve set point adherence of the main body regulator by trimming the mechanical spring load. Pilot regulators are susceptible to poor operation or failure from particulate or moisture in the natural gas stream due to the relatively small size of the orifice that is used to pneumatically control the main body loading pressure. Currently Manitoba

Hydro utilizes particulate filtration to mitigate failures from natural gas contamination but does not consistently utilize pilot gas heaters to raise the dew point of the natural gas source above the condensation point when moisture is present in the natural gas product. This process to maintain effective operation of pressure regulators could provide greater assurance if pilot gas heaters were installed, but the incremental benefit beyond is likely very location specific.

Frost Accumulation on Facility Piping and Appurtenances

As previously identified, as one reduces natural gas pressure a corresponding reduction in product temperature is realized. The combination of the natural gas pressure reduction and inlet product temperature can result in natural gas outlet temperatures well below zero Celsius. In the presence of moisture (i.e. humidity and low ambient temperature condensation), ice or frost will adhere to downstream pipe and appurtenances. This can cause operational challenges when valve operation is required. While line heaters will prevent this situation, the frequency of valve malfunction due to ice build-up has been very negligible.

Frost Heaving on Facility Piping

The temperature effect is not limited to the facility piping and appurtenances. The temperature effect extends beyond the facility piping and into below grade pipe causing freezing of the material in contact with the pipe. If there is high moisture content in the surrounding material or if the material is of a nature that is hydroscopic, the moisture compounds will freeze and expand. This expansion will cause the pipe to elevate to the area of least resistance i.e. heave out of the ground. Due to the nature of the soil conditions in Manitoba this effect has been problematic and is also is variable dependent on the fall ground moisture levels. Design methodologies have been employed to restructure soil conditions to control or constrain pipe movement. In most cases these design alternates have been successful. An extreme case of a moisture laden environment, in which current design methodologies have been utilized, is under assessment which may indicate a supplemental benefit to the use of line heaters.

TransCanada Pipe Lines Hydrostatic Pressure Testing

TransCanada Pipelines transports natural gas across the province of Manitoba in multiple interconnected pipelines. In order to ensure “fitness for use”, TransCanada Pipe Lines routinely pressure tests their pipelines. The method of testing is hydrostatic pressure testing or water pressure testing. Sections of pipeline are taken out of service and filled with water, pressure is increased and an evaluation is made. Upon successful testing, the section of the tested pipeline is drained of water and a process of drying is employed prior to returning the pipeline to service. By contract, TransCanada Pipe Lines is limited to 65 mg water per cubic meter of natural gas. It is TCPL’s practice to “slip stream” i.e. blend, flow from the tested portion of pipe into the other pipeline legs. TCPL practice is to inform potentially impacted receipt point customers and monitor the slip streamed natural gas moisture levels to ensure adherence to the contractual moisture levels. Once the moisture levels in the natural gas stream from the tested segment of pipeline reaches the upper water maximum level, the tested pipeline segment is returned to full service. Operational contingencies for hydrostatically tested pipelines are pilot gas heaters, alcohol injection and direct manual intervention.

RISKS

Gas Quality Deterioration

The natural gas quality that Manitoba Hydro currently receives is considered second to none. It is a highly processed product that exceeds the quality specification of the tariff agreements with local distribution companies. This however, does not preclude that there could be spot variations or even degradation of natural gas quality over time. Gas distribution operations in the past have utilized online gas chromatography analysis. It would be practical and prudent for Manitoba Hydro to independently evaluate the quality of the product that it receives from TCPL in order to identify degrading quality trends or anomalies. This data would also serve as a source of evidence to substantiate future capital investment.

Storage of Natural Gas

Storage of natural gas in caverns is currently not an issue. If Manitoba Hydro was to pursue purchase of natural gas from a supplier that utilized cavern storage or if Manitoba Hydro was to pursue cavern natural gas storage internally, the impact on natural gas quality would require investigation. It is likely that additional measures would be required to mitigate changes to quality and it is reasonable to expect that natural gas line heaters would be a consideration at that time

Solution gas

Manitoba Hydro has been approached several times by petroleum producers to consider the introduction of solution gas into the natural gas distribution network. Solution gas is a by-product of crude oil extraction and is normally burned off but it does not meet the quality margins established or technically required by Manitoba Hydro. Past responses from Manitoba Hydro to these producers have factored in high level cost estimates of natural gas line heaters for at-risk facilities.

Regulatory

Both capital and operating costs of line heater investment would form part of rate based applications. Manitoba Hydro's justification to support a change in design practice would need to be supported by substantial evidence of cause and effect as the incorporation of natural gas line heaters in the past 50 years has not been raised to be an urgent requirement.

Natural Gas Distribution Company Experience

A summary of other natural gas distribution companies' (LDC) experience regarding the application and use of natural gas line heaters is misleading if an understanding of the conditions that necessitate natural line heaters is not fully understood at each individual LDC. This assessment and evaluation is beyond the scope of this report.

Other Considerations

The presence of "wet gas" is recognized to be a technical concern of Manitoba Hydro's natural gas distribution system but this situation is rated as high consequence but a very low probability of occurrence. While the installation of line heaters will lower the probability of a significant operational event, it is difficult to quantify how it will further reduce the likelihood of a significant event. The technical perspective is that the integrity of Manitoba Hydro's natural gas system is based on many factors with line heater installations being only one example of how improvements can be made. Other factors include our operational capabilities, proactive response to supply conditions and ability to align gas capital investment to optimize gas system performance. The evaluation of line heaters in conjunction with other factors would provide a more comprehensive understanding of how to reduce risk of failure of our natural gas system.

CONCLUSIONS

Manitoba Hydro should not pursue the installation of natural gas line heaters at this time but should consider the installation of pilot gas heaters at high risk geographic locations. While Manitoba Hydro does not fully employ existing proven solutions to mitigate the presence of "wet gas", the risk believed to be very low needs to be substantiated with detailed planning studies. The risk of moisture in the gas supply should be studied in tandem with a variety of other factors that influence natural gas system integrity.

Notes from a discussion among the leadership team at GAM&C, regarding operating concerns at station pressure reduction facilities. (Specifically ice/frost formation at the stations)

Do we need Supplemental Heat at the Natural Gas Stations?

Are our natural gas pressure reduction station facilities, Gate Stations and Regulator Stations, designed to operate reliably in our ambient conditions, flowing contract tariff quality (dew point) natural gas?

Does Design only consider supplemental heat a requirement for gas quality of a wet nature? If so, what value has Design determined is the dew point where supplemental heat would be required, what value does Design identify as wet gas? (TCPL identifies the gas within or outside of tariff. Tariff = 4lbs. /million cubic feet)

Should supplemental heat be considered because of?

- Equipment Operation (winter and summer)
- Equipment Maintenance

Should pipe, structure heaving be considered?

Should a site specific Geotechnical Survey be performed on the site, prior to a station being installed?

List of general concerns at stations:

- Pipe heaving
- Piles heaving
- Building damage
- Regulator Ice/Frost Balls
- Emergency access to equipment may be impeded
- Pipe coating (paint)
- Humidity buildup in buildings causing mold, fungus and the rotting of the wooden building structures

Metering concerns:

- EVC freeze ups
- Mechanical gear box freezing up

Concerns regarding the Reliable Operation of pressure regulating equipment:

- Need to Extend the vents of regulators and pilots
- Moisture buildup in pilots (Atmospheric side and internal)
- Moisture buildup in Regulators (Atmospheric side and internal)
- Unknown tolerance for dew point
- Can we tolerate Tariff value gas quality dew points
- Reliability of Set points because of cold equipment (maintenance performed in summer and operation which may be required in winter.)

Valves:

- Can be encased in ice, inhibiting (immediate) emergency use
- Maintenance is a concern, surface rusting and difficulty of operation (very difficult to operate when cold) (may result in the use of cheaters, NOT CONDONED)

Strategies currently used by Manitoba Hydro

Existing Catalytic Heaters:

- Some manufactures require venting others do not, which is correct?
- No Standard install method (drawings or provisions identified at stations)
- Provisions for installation are identified or not available at all stations
- Physical congestion at the station
- Accessibility to existing equipment
- Pads require frequent replacement
- Pest control – rodents like to nest there because of the heat
- Reliability – how do we know when they go out and they have (Elie a number of times and we lost the supply to the town)
- Co Production. (The heaters do not burn 100% efficiently and degrade from there. CSO staff have identified CO concerns when they have probed the buildings prior to building entry)

Vortex:

- Under investigation (not proven at MB Hydro)(some utilities have had good success with Vortex pilot heaters under the right conditions)

Heat tape:

- Power not available at all sites

  - Equipment accessibility
  - Reliability?

Existing Line Heaters:

- Current equipment is old technology
- Requirement for secondary containment
- Costly to operate (inefficient to today's standards)
- Requirement for five year detailed inspection

APPENDIX D

MH PRESSURE REDUCING FACILITIES

Winnipeg System

Manitoba Hydro

Table D.1 - Natural Gas Reducing Station - Pressure Let-Down Summary

Based on: System Pressure Settings for 2011-12 Season

Reducting Station Information			Upstream Conditions		Downstream Conditions			Delta	
System Name	Station #	Station Name	Max Winter Pressure (psig)	Max Summer Pressure (psig)	System MOP (psig)	Winter Pressure (psig)	Summer Pressure (psig)	Δ P Winter (psi)	Δ P Summer (psi)
Winnipeg Primary Stations	**GS-002**	St Norbert Primary (off in summer)	880	880	250	150	150	730	730
	GS-015	La Salle Primary	880	880	900	550	350	330	530
	GS-017	Ile des Chenes Primary	880	880	700	550	350	330	530
	GS-030	Oakbluff Primary (off in summer)	880	880	700	460	460	420	420
Winnipeg Gate Stations	**GS-001**	City Gate (Wilkes)	550	350	150	150	145	400	205
	GS-003	Transcona Gate **(KIXCELL - Loop 2)**	550	350	250	250	145	300	205
	GS-003	Transcona Gate	550	350	700	145	145	405	205
	GS-003	Transcona Gate (Dugald/Oakbanrk)	550	350	250	250	145	300	205
	GS-004	Selkirk Gate	550	350	250	100	100	450	250
	GS-005	Clandeboye Gate	550	350	60	55	40	495	310
	GS-006	Matlock Gate	550	350	60	45	40	505	310
	GS-007	Winnipeg Beach	550	350	60	50	40	500	310
	GS-008	Gimli Gate	550	350	700	90	90	460	260
	GS-009	Stony Mountian gate	550	350	60	55	40	495	310
	GS-010	Stonewall Gate	550	350	60	55	45	495	305
	GS-011	East Selkirk Gate	550	350	60	55	45	495	305
	GS-011	HP to Selkirk GS (2")	550	350	250	250	250	300	100
	GS-012	Garson Gate	550	350	60	55	40	495	310
	GS-013	Tyndal gate	550	350	60	50	40	500	310
	GS-014	Beausejour Gate	550	350	60	55	45	495	305
	GS-019	Symington CNR St Boniface Rd	550	350	60	45	45	505	305
	GS-020	Fort Whyte **(KIXCELL - Loop 3)**	550	350	250	250	145	300	205
	GS-020	Fort Whyte	550	350	60	55	55	495	295
	GS-021	Petersfield TBS	550	350	60	45	40	505	310
	GS-023	Symington Rd.	550	350	250	155	155	395	195
	GS-024	Raleigh St Station **(KIXCELL - Loop 1)**	550	350	250	250	145	300	205
	GS-025	Lockport East	550	350	60	55	55	495	295
	GS-027	Lockport Rd	550	350	60	55	55	495	295
	GS-028	Concord Colony	550	350	60	55	55	495	295
	GS-031	Rosser Gate Station **(KIXCELL - Loop 4)**	700	460	250	250	250	450	210
	GS-031	Rosser Gate MP	700	460	60	40	40	660	420
	GS-034	Petersfield Gate	550	350	60	55	40	495	310
	GS-035	Brady Rd	550	350	250	150	150	400	200
	VS-002	Arborg Valve Station (Temp. Regulation)	550	350		125	90	425	260
	GS-036	Arborg Gate	550	350	100	50	50	500	300
	GS-036	Arborg Rural Feed	550	350	100	50	50	500	300
	GS-037	Riverton Gate	550	350	100	40	40	510	310
	GS-037	Riverton Rural Feed	550	350	100	60	60	490	290
	GS-010	Warren Valve Station (Temp. Regulation)	550	350		95	95	455	255
	GS-038	Warren Gate	550	350	100	40	40	510	310
	GS-038	Warren Rural Feed	550	350	100	60	60	490	290
	VS-001	Teulon Valve Station (Temp. Regulation)	550	350		125	90	425	260
	GS-039	Teulon Gate	550	350	100	40	40	510	310
	GS-039	Teulon Rural Feed	550	350	100	65	65	485	285
	GS-040	PTH # 101 & Hewitson	550	350	60	55	55	495	295
	GS-204	Birds Hill TBS	550	350	60	55	55	495	295
	GS-203	Saskatchewan & P.T.H. 101 (bypass in	700	460	250	150	150	550	310
Winnipeg Regulating Stations	**RS-001**	Watt st at William Newton	150	150	60	55	55	95	95
	RS-002	Harbison st at Brazier av	150	150	60	55	55	95	95
	RS-003	PTH # 101 at Henderson Hwy	150	150	60	55	55	95	95
	RS-004	Archibald at Doucete	150	150	60	55	55	95	95
	RS-005	Goulet st at Youville st	150	150	60	55	55	95	95
	RS-006	St Anne's Rd at Sherwood Pl.	150	150	60	55	55	95	95
	RS-007	Mission St Stn	150	150	60	55	55	95	95
	RS-008	Jubilee av at Daly st	150	150	60	55	55	95	95
	RS-009	Pembina Hwy at Parker Ave	150	150	60	55	55	95	95

Winnipeg System

Table D.1 - Natural Gas Reducing Station - Pressure Let-Down Summary

Based on: System Pressure Settings for 2011-12 Season

Reducting Station Information			Upstream Conditions		Downstream Conditions			Delta	
System Name	**Station #**	**Station Name**	**Max Winter Pressure (psig)**	**Max Summer Pressure (psig)**	**System MOP (psig)**	**Winter Pressure (psig)**	**Summer Pressure (psig)**	**Δ P Winter (psi)**	**Δ P Summer (psi)**
	RS-010	Lorette av at Harrow st	150	150	60	55	55	95	95
	RS-011	Hurst way at Waverley st	150	150	60	55	55	95	95
	RS-012	Kenaston at Grant	150	150	60	55	55	95	95
	RS-013	Kenaston at Willow	150	150	60	55	55	95	95
	RS-014	Roblin at Berkley (bypass in summer)	150	150	60	55	55	95	95
	RS-015	St Norbert Rue Trappiste	250	150	60	55	55	195	95
	RS-016	May st at McDonald Ave	150	150	60	55	55	95	95
	RS-017	Ross Ave Station	150	150	60	55	55	95	95
	RS-018	Furby st at Mcdermot av	150	150	60	55	55	95	95
	RS-019	Furby st at Ellice av	150	150	60	55	55	95	95
	RS-020	Furby st at Westminister av	150	150	60	55	55	95	95
	RS-021	Wilkes at Community ROW	150	150	60	55	55	95	95
	RS-022	St Mathews at Madison	150	150	60	55	55	95	95
	RS-023	Century at Wellington	150	150	60	55	55	95	95
	RS-024	Buchanan at Saskatchewan	150	150	60	55	55	95	95
	RS-025	Portage at Bedson	150	150	60	55	55	95	95
	RS-026	Inkster Blvd and Powers St	150	150	60	55	55	95	95
	RS-027	Inkster Blvd and Lansdowne	250	250	60	55	55	195	195
	RS-028	Main St. & Perimeter	250	145	60	55	55	195	90
	RS-030	Selkirk RS	550	350	60	45	45	505	305
	RS-031	Gimli - First St S.	550	350	60	45	40	505	310
	RS-032	Gimli - Solvin Rd	550	350	60	45	40	505	310
	RS-033	Gimli - Aspen Park Rd	550	350	60	55	55	495	295
	RS-035	Kotelko Dr at PTH #100 South	155	155	60	55	55	100	100
	RS-036	PTH 15 W of Dugald	250	145	60	20	20	230	125
	RS-038	South Glen Trail Park	155	155	60	55	40	100	115
	RS-040	Dugald Rd	250	145	60	55	40	195	105
	RS-042	Oakbank TBS	250	145	60	55	55	195	90
	RS-043	St Marys Rd at PTH #100	155	155	60	55	55	100	100
	RS-044	Creek Bend rd at St Annes (bypass in	155	155	60	55	55	100	100
	RS-045	St Norbert Father Labonte Ave	250	150	60	55	55	195	95
	RS-046	King edward & Inkster Blvd.	250	250	60	55	55	195	195
	RS-047	Pembina & Bishop Grandin Bv	150	150	150	150	150	0	0

Notes:

1) Pressures in this table are approximate. Confirm actual pressure with CSO prior to use for calculations.
2) Upstream pressure is approximate and assumes no friction/pressure losses in upstream piping. Typically the upstream pressure will be lower; in some cases much lower.

Brandon System

Manitoba Hydro

Table D.2 - Natural Gas Reducing Station - Pressure Let-Down Summary

Based on: System Pressure Settings for 2011-12 Season

Reducing Station Information			Upstream Conditions		Downstream Conditions			Delta	
System Name	Station #	Station Name	Max Winter Pressure (psig)	Max Summer Pressure (psig)	System MOP (psig)	Winter Pressure (psig)	Summer Pressure (psig)	Δ P Winter (psi)	Δ P Summer (psi)
Brandon Gate Stations	**GS-192**	Brandon CombustionTurbine	880	880	500	420	420	460	460
	GS-123	Brandon Primary	880	880	600	420	420	460	460
	GS-123	Husky_Mohawk Ethanol	880	880	600	125	125	755	755
	GS-124	Brandon City Gate #1 Bdn HP	420	420	100	90	90	330	330
	GS-124	Brandon City Gate #1 Bdn MP	420	420	60	40	40	380	380
	GS-125	Brandon City Gate #2 Bdn HP	420	420	100	90	90	330	330
	GS-125	Brandon City Gate #2 Bdn MP	420	420	60	50	50	370	370
	GS-126	Forrest TBS	420	420	60	25	25	395	395
	GS-190	Can Oxy	250	250	60	30	30	220	220
	GS-191	Brandon Maple Leaf	250	250	0	60	60	190	190
	GS-125/168	Southwest	880	880	720	250	250	630	630
	GS-169	Souris North	250	250	80	55	55	195	195
	GS-170	Souris South	250	250	80	40	40	210	210
	GS-171	Hartney	250	250	80	35	35	215	215
	GS-172	Melita	250	250	80	35	35	215	215
	GS-174	Boissevain Gate	250	250	80	35	35	215	215
	GS-173	Deloraine	250	250	80	35	35	215	215
	GS-175	Killarney	250	250	80	40	40	210	210
Brandon Regulating Stations	**RS-104**	Kirkcaldy Dr NW 26-10-19	90	90	60	45	45	45	45
	RS-106	Lane West of 20th St N., North of Louise Ave	90	90	60	45	45	45	45
	RS-107	Lane West of 10th St N., North of Victoria Ave.	90	90	60	45	45	45	45
	RS-109	Van Horne Ave at Park St.	90	90	60	45	45	45	45
	RS-111	34th St	90	90	60	45	45	45	45
	RS-114	Keystone Center	90	90	60	50	50	40	40

Notes:

1) Pressures in this table are approximate. Confirm actual pressure with CSO prior to use for calculations.
2) Upstream pressure is approximate and assumes no friction/pressure losses in upstream piping. Typically the upstream pressure will be lower; in some cases much lower.

Rural Systems

Table D.3 - Natural Gas Reducing Station - Pressure Let-Down Summary

Based on: System Pressure Settings for 2011-12 Season

Reducting Station Information			Upstream Conditions		Downstream Conditions			Delta	
System Name	Station #	Station Name	Max Winter Pressure (psig)	Max Summer Pressure (psig)	System MOP (psig)	Winter Pressure (psig)	Summer Pressure (psig)	Δ P Winter (psi)	Δ P Summer (psi)
Minell	**GS-100**	**Minell Primary**	880	880	1050	880	500	0	380
	GS-101	St Lazare TBS	880	500	60	45	40	835	460
	GS-102	Binscarth TBS	880	500	60	40	40	840	460
	GS-105	Harrowby CSP	880	500	500	450	350	430	150
	GS-103	**Russell Primary**	880	500	950	440	350	440	150
	GS-103	Russell TBS	440	350	60	45	40	395	310
	GS-106	Inglis TBS	440	350	60	35	35	405	315
	GS-107	Roblin TBS	440	350	60	40	40	400	310
	GS-108	Grandview TBS	440	350	60	40	40	400	310
	GS-109	Gilbert Plains TBS	440	350	60	40	40	400	310
	GS-110	Dauphin TBS	440	350	60	45	40	395	310
Miniota	**GS-111**	**Miniota Primary**	880	880	775	450	325	430	555
	GS-111	Miniota TBS	450	325	40	22	22	428	303
	GS-176	Elkhorn TBS - Town Feed	450	325	80	40	40	410	285
	GS-176	- Kola feed	450	325	100	75	75	375	250
	RS-128	Kola TBS	450	325	100	30	30	420	295
	GS-113	Virden	450	325	60	50	50	400	275
	VS-006	Cromer Valve Station	450	325	775	100	100	350	225
	GS-179	Cromer Enbridge	450	325	80	40	40	410	285
Hamiota	**GS-114**	**Hamiota Primary**	880	880	480	380	250	500	630
	GS-115	Shoal Lake HP Feed	380	250	145	110	110	270	140
	GS-202	Shoal Lake MP	380	250	100	40	40	340	210
	GS-115	Hamiota TBS	380	250	20	20	20	360	230
Rivers	**GS-117**	**Rivers Primary**	880	880	480	380	250	500	630
	GS-118	Rivers TBS	380	250	60	40	40	340	210
	GS-116	Oo-Za-We-Kwun TBS	380	250	60	45	40	335	210
Minnedosa	**GS-119**	**Moore Park Primary**	880	880	420	350	350	530	530
MP	**GS-120**	Minnedosa	350	350	60	35	35	315	315
	GS-129	CFB Shilo TBS	350	350	60	50	50	300	300
Neepawa	**GS-121**	**Neepawa Primary**	880	880	560	385	385	495	495
MP	**GS-122**	Neepawa	385	385	60	40	50	345	335
HP	**GS-122**	Neepawa	385	385	156	150	150	235	235
Carberry	**GS-127**	**Carberry Primary**	880	880	600	450	400	430	480
	GS-128	Carberry TBS	450	400	60	40	40	410	360
	GS-189	Carberry Mid West Foods	450	400	60	55	55	395	345
Gladstone-Austin	**GS-195**	**Gladstone Primary**	880	880	700	350	300	530	580
(GANG)		Rural Feed	350	300	80	70	40	280	260
North	**GS-197**	Cibula Station	350	300	80	70	40	280	260
	GS-198	Novak Station	350	300	80	70	40	280	260
	GS-200	Neauschwander Station	350	300	80	70	40	280	260
	GS-201	Jarvis Station	350	300	80	70	40	280	260
	GS-199	Gladstone Gate	350	300	80	50	45	300	255

Rural Systems

Table D.3 - Natural Gas Reducing Station - Pressure Let-Down Summary

Based on: System Pressure Settings for 2011-12 Season

Reducting Station Information			Upstream Conditions		Downstream Conditions			Delta	
System Name	Station #	Station Name	Max Winter Pressure (psig)	Max Summer Pressure (psig)	System MOP (psig)	Winter Pressure (psig)	Summer Pressure (psig)	Δ P Winter (psi)	Δ P Summer (psi)
	GS-195	**Gladstone Primary**	880	880	700	350	300	530	580
South	**GS-196**	Austin Urban	350	300	80	50	40	300	260
South	**GS-196**	Austin RURAL (Sidney)	350	300	80	70	50	280	250
Mac Gregor	**GS-130**	**Mac Gregor Primary**	880	880	1000	880	880	0	0
	GS-131	Mac Gregor TBS	880	880	60	35	35	845	845
Portage Simplot	**GS-193**	**Portage Simplot Primary**	880	880	1000	350	350	530	530
	GS-194	Simplot GS	350	350	250	70	70	280	280
Portage	**GS-132**	**Portage Primary - North**	880	880	500	450	450	430	430
	GS-134	Southport TBS	450	450	60	45	45	405	405
IP	**GS-182**	Angle Road Gate Station	450	450	100	90	90	360	360
IP	**GS-178**	Mc Cains Portage Gate Station	450	450	100	90	90	360	360
MP	**GS-135**	Portage North River Gate	450	450	60	55	55	395	395
MP	**GS-133**	Portage City Gate Cresent Rd	450	450	60	55	55	395	395
St. Claude	**GS-132**	**Portage Primary - South**	880	880	790	450	450	430	430
	GS-163	St Claude TBS	450	450	60	40	40	410	410
South Loop (Oakville-Dominion City)	**GS-136**	**Oakville Primary**	880	880	880	580	435	300	445
	GS-166	Oakville TBS	580	435	80	40	40	540	395
	GS-166	Oakville Rural	580	435	140	70	70	510	365
	GS-164	Elie TBS	580	435	80	70	50	510	385
	GS-164	Elie Rural	580	435	145	125	125	455	310
	GS-138	Elm Creek TBS	580	435	60	40	40	540	395
	GS-137	Carman TBS	580	435	60	40	40	540	395
	GS-139	Morden City Gate	580	435	60	55	55	525	380
	GS-140	Winkler City Gate	580	435	60	55	55	525	380
	GS-142	Plum Coulee TBS	580	435	60	40	40	540	395
	GS-143	Altona TBS	580	435	60	50	50	530	385
	GS-144	St Joseph TBS	580	435	60	45	45	535	390
	GS-148	St Jean Baptiste TBS	580	435	60	40	40	540	395
	GS-149	Morris TBS	580	435	60	55	55	525	380
		Feed to Rosenort same as GS-	580	435	80	50	50	530	385
	GS-145	Lettelier TBS	580	435	60	40	40	540	395
	GS-146	**Dominion City Primary**	880	880	880	580	450	300	430
	GS-147	Dominion City TBS	580	450	60	40	40	540	410
	GS-147	Dominion City HP (TO	580	450	880	200	100	380	350
	RS-115	Emerson TBS	580	450	60	55	40	525	410
Starbuck Primary	**GS-165**	Town feed	880	880	80	50	40	830	840
	GS-165	Rural Distribution	880	880	100	50	50	830	830
Sanford/Oakbluff	**GS-030**	**Oak Bluff Primary**	880	880		700	460	180	420
	GS-030	Sanford TP	880	880	720	100	100	780	780
	GS-032	OakbluffTBS	100	100	60	45	45	55	55
	GS-033	Sanford TBS	100	100	100	55	55	45	45
La Salle Gate South	**GS-029**	Town Feed	550	350	80	55	55	495	295
	GS-029	Rural Distribution	550	350	100	55	55	495	295

Rural Systems

Table D.3 - Natural Gas Reducing Station - Pressure Let-Down Summary

Based on: System Pressure Settings for 2011-12 Season

Reducting Station Information			Upstream Conditions		Downstream Conditions			Delta	
System Name	Station #	Station Name	Max Winter Pressure (psig)	Max Summer Pressure (psig)	System MOP (psig)	Winter Pressure (psig)	Summer Pressure (psig)	Δ P Winter (psi)	Δ P Summer (psi)
Ile Des Chenes	**GS-017**	Alfalfa Plant	880	880	100	55	55	825	825
Gate South	**GS-016**	St Adolphe TP	880	880	700	550	350	330	530
(St. Adolphe)	**GS-026**	St Adolphe	550	350	80	50	50	500	300
	GS-016	Ile des Chenes TBS - Town Feed	550	350	60	55	40	495	310
	RS-037	Ile Des Chenes Trailer Park	50	40	15	15	15	35	25
	GS-016	Oak Island	550	350	100	75	60	475	290
Ste Agathe	**GS-180**	**Ste Agathe Primary (West)**	880	880	100	80	80	800	800
		Rural Distribution	80	80	100	55	55	25	25
Hanover / LaBroqueri	**GS-180**	**Ste Agathe Primary (East)**	880	880	720	410	350	470	530
	GS-181	St. Agathe TBS - Town	410	350	100	40	40	370	310
	GS-181	- Associated Proteins Ltd	410	350	100	60	60	350	290
	GS-183	Kleefield TBS - Town	410	350	100	40	40	370	310
		- Rural	410	350	100	60	60	350	290
	GS-184	Harms RD Gate	410	350	100	60	60	350	290
	GS-185	PTH #12 Gate	410	350	100	60	60	350	290
	GS-186	North LaBroquerie Gate	410	350	100	60	55	350	295
	GS-187	Moosemeadow Gate	410	350	100	60	55	350	295
	RS-127	Marchand	410	350	100	40	40	370	310
Niverville	**GS-150**	**Niverville Primary -** Town	880	880	60	55	40	825	840
	GS-150	Niverville Primary - Rural	880	880	100	55	55	825	825
New Bothwell	**GS-150**	New Bothwell TP	880	880	804	340	310	540	570
	GS-158	New Bothwell TBS - Town	340	310	60	40	40	300	270
	GS-158	New Bothwell TBS - Rural	340	310	100	55	55	285	255
Otterbourne	**GS-153**	**St Pierre Primary (North)**	880	880	700	500	300	380	580
	GS-152	Otterbourne TBS - Rural	500	300	240	90	90	410	210
	GS-152	- Town	500	300	60	45	45	455	255
	RS-125	Crystal Springs Colony	500	300	60	40	40	460	260
St Pierre	**GS-153**	**St Pierre Primary (South)**	880	880	720	515	300	365	580
	GS-154	St Pierre TBS	515	300	60	40	40	475	260
	GS-155	Grunthal TBS -Town	515	300	60	40	40	475	260
Ste Anne	**GS-159**	**St Anne Primary**	880	880	700	500	400	380	480
	GS-160	St Anne TBS	500	400	60	40	40	460	360
	GS-157	Blumenort TBS	500	400	60	50	40	450	360
	GS-151	Twin Creeks - Rural	500	400	100	55	55	445	345
	GS-156	Steinbach TBS	500	400	60	55	55	445	345
	GS-156	Feed to LaBroquerie TBS	500	400	250	175	125	325	275
	RS-126	LaBroquerie TBS	500	400	80	70	55	430	345
St Malo	**GS-167**	St Malo/ Dufrost - Primary/ TBS	880	880	80	40	40	840	840
Selkirk Generating Station	**GS-018**	**Landmark Primary (North)**	880	880	1000	575	575	305	305
	GS-041	Selkirk Combustion Turbne R.S.	575	575	250	130	130	445	445
Landmark	**GS-018**	**Landmark Primary (South)-1st**	880	880	1000	500	500	380	380

Rural Systems

Table D.3 - Natural Gas Reducing Station - Pressure Let-Down Summary

Based on: System Pressure Settings for 2011-12 Season

Reducting Station Information			Upstream Conditions		Downstream Conditions			Delta	
System Name	**Station #**	**Station Name**	**Max Winter Pressure (psig)**	**Max Summer Pressure (psig)**	**System MOP (psig)**	**Winter Pressure (psig)**	**Summer Pressure (psig)**	**Δ P Winter (psi)**	**Δ P Summer (psi)**
	GS-018	**Landmark Primary (South)**	880	880	500	250	150	630	730
	RS-041	Lorette TBS	500	500	60	50	40	450	460
	GS-018	Landmark TBS	500	500	60	50	40	450	460
Pineland	**GS-177**	Primary off TCPL	880	880	60	45	45	835	835

Notes:

1) Pressures in this table are approximate. Confirm actual pressure with CSO prior to use for calculations.

2) Upstream pressure is approximate and assumes no friction/pressure losses in upstream piping. Typically the upstream pressure will be lower; in some cases much lowe

APPENDIX E

PRS FAILURE REPORTS (2002-2012)

location	summary	failinitevent	failtaskused	donedate	mh_desig	geo_locat	manufacturer	modtype	act_othrs	act_otcos	failuremode	failsubcomp
KLEEFELD GS	Rebuilt Lead Worker			26-06-2002	GS-183	IP WORK UP	MOONEY	FG-50 - 2"X1" - 600SWE			Fails to Control Set Pressure	Diaphram
STEINBACH GS	boot failurte	System Disturbance		25-07-2002	GS-156-PR01	1ST CUT UPPER	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Diaphram
STEINBACH GS	fail to lock-up	Foreign Interference	Functional	26-07-2002	GS-156-PR02	1ST CUT LOWER	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Lock Up
ST. CLAUDE GS	cracked diaphram casing	Animal Contact		04-11-2002	GS-163	1st Cut S.	FISHER	627H			Fails to Control Set Pressure	Diaphram
MACGREGOR GS	City Gate receiving pressure alarms			10-11-2002	GS-131	1st Cut Upper	AMERICAN METER	AXIAL 600#	4.5	405	Fails to Control Set Pressure	Seat / Disc
ILE DES CHENES GS	low outlet pressure	System Disturbance		14-11-2002	GS-016	2nd cut lower	MOONEY	FG-30 - 2" - 300# RF			Fails to Control Set Pressure	Pilot
SOUTHPORT GS	leak detected at 161 pilot			05-12-2002	GS-134	1st Cut Upper	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
RIVERTON GS	Sudden 5# pressure drop and slowly climbing back		SCADA ALA	31-12-2002	GS-037	1ST CUT WORK UP	MOONEY	FG-12 - 1" - 600SWE			Fails to Control Set Pressure	Pilot
STE. AGATHE PGS	reg not holding	System Disturbance		08-04-2003	GS-180	1st Cut Mon N.	MOONEY	FG-62 - 3" - 600# BUTT WE	3.5	315	Fails to Control Set Pressure	Diaphram
MORDEN GS	reg's not seating	System Disturbance		29-05-2003	GS-139	1st Cut North	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Diaphram
STE. ANNE GS	Failed to lock up	System Disturbance		13-06-2003	GS-160-PR04	2ND CUT LOWER	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Diaphram
ST. BONIFACE GS	stn found at 62 psig relief set point 60 psig 2nd cut reg not holding	System Disturbance	Integrity	16-06-2003	GS-019	Relief	FISHER	63EG			Fails to Control Set Pressure	Diaphram
HEWITSON GS	regulator diaphram failed			09-07-2003	GS-040	Worker E. Run	MOONEY	FG-62 - 3" - 600# BUTT WE			Fails to Control Set Pressure	Diaphram
SOUTHPORT GS	failure to lock up	System Disturbance		22-07-2003	GS-134	2nd Cut Upper	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
PETERSFIELD GS	Did not lock-up	System Disturbance		30-07-2003	GS-021	S. Run	FISHER	627			Fails to Control Set Pressure	Orfice
PORTAGE LINCOLON GS	Did not lock off.	System Disturbance		31-07-2003	GS-178	Worker E.	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
STONEWALL GS	failure to hold press.	System Disturbance		05-08-2003	GS-010	1st Cut S. Run	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Pilot
STONEWALL GS	Failed to lock-off	System Disturbance		05-08-2003	GS-010	2nd Cut N. Run	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Diaphram
FORT WHYTE GS	Fails to lock up	System Disturbance		11-09-2003	GS-020	Mon Ft Whyte	AMERICAN METER	AXIAL			Fails to Control Set Pressure	Diaphram
ILE DES CHENES GS	reg. did not lockup		Functional	24-09-2003	GS-016	2nd_cut upper	MOONEY	FG-30 - 2" - 300# RF			Fails to Control Set Pressure	Diaphram
SYMINGTON & PMTR GS	did not lockup	System Disturbance	Detld Insp	25-09-2003	GS-023	S. Run	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
SYMINGTON & PMTR GS	Failed to lock up		Functional	25-09-2003	GS-023	S. Run	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
TRANSCONA GS-003	north worker failed to lock up	System Disturbance	Functional	07-10-2003	GS-003	Worker S.	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
SYMINGTON & PMTR GS	reg not holding press.	System Disturbance		08-10-2003	GS-023	N Run	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
ST. ANNE'S RD. RS	Slag on cage	System Disturbance	Detld Insp	23-10-2003	RS-044	S Worker	FISHER	399 EZR			Fails to Control Set Pressure	Cage
ST. ANNE'S RD. RS	reg not holding		Detld Insp	23-10-2003	RS-044	N Worker	FISHER	399 EZR			Fails to Control Set Pressure	Debris
CARMAN GS	lag run first cut frosted	Overloading		18-11-2003	GS-137	1st Cut Upper	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Pilot
WILLIAM NEWTON RS	dismantled east run worker monitor and rebuilt as req.	System Disturbance	Functional	18-11-2003	RS-001	E Worker	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
MINIOTA PGS	Pressure out generating low alarms in the morning			12-12-2003	GS-111	1st Cut Lower	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	
HARBISON RS	leak at restictor manifold ,station placed on by-pass, repaired	System Disturbance	Detld Insp	17-12-2003	RS-002	Monitor	AMERICAN METER	AXIAL 300#	7	630	Fails to Control Set Pressure	Restricter Bloc
MAY RS	reg not holding	System Disturbance		22-12-2003	RS-016	Relief	FISHER	1805			Fails to Control Set Pressure	Seat / Disc
CARBERRY MIDWEST GS	Pressure in and out of high alarm			02-01-2004	GS-189	1st Cut Lower	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	
RIVERTON GS	Rebuilt Worker and Monitor regs on upper (lead) run	System Disturbance		05-01-2004	GS-037	2ND CUT LOWER	MOONEY	FG-12 - 1" - 600SWE			Fails to Control Set Pressure	Diaphram
DOMINION CITY GS	gas leak at pilot			05-01-2004	GS-147	1st Cut W Lo	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
BRANDON TURBINE GS	Pressure fluctuations downstream			06-01-2004	GS-192	N.Run Worker	BECKER	488F6WTO-SR-PD			Fails to Control Set Pressure	Pilot
PINELAND PGS	Reg venting	Human / Process Error		07-01-2004	GS-177	1ST CUT WORK LO	FISHER	627H			Fails to Control Set Pressure	Diaphram
MARCHAND RS	regulator venting,diaphragm problem			07-01-2004	RS-127	W.Run	FISHER	99			Fails to Control Set Pressure	Diaphram
BINSCARTH GS	regulator venting			13-01-2004	GS-102	2nd Cut Upper	FISHER	627M	1	90	Fails to Control Set Pressure	Diaphram
MOOSEMEADOW GS	top reg venting @ 35% LEL			23-01-2004	GS-187	UPPER	FISHER	627			Fails to Control Set Pressure	Pilot
STONEWALL GS	High pressure	System Disturbance		29-01-2004	GS-010	Warren Takeoff	MOONEY	FG-28 - 2" - 600SWE			Fails to Control Set Pressure	Debris
southwest odorant/regulatio	repaired leaks. purged gas out of 399 reg runs,YZ alarm cleared			05-02-2004	GS-168	N Worker	FISHER	399 EZR			Fails to Control Set Pressure	
STONEWALL GS	High Pressure	System Disturbance		10-02-2004	GS-010	1st Cut N. Run	AMERICAN METER	AXIAL 300#	37.66	3389.4	Fails to Control Set Pressure	Debris
STONEWALL GS	High Pressure	System Disturbance		10-02-2004	GS-010	1st Cut S. Run	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Debris
STONEWALL GS	Failed high pressure	System Disturbance		10-02-2004	GS-010	2nd Cut N. Run	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Debris
STONEWALL GS	Failed High Pressure	System Disturbance		10-02-2004	GS-010	2nd Cut S. Run	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Debris
STONY MOUNTAIN GS	Regulators dirty from pipeline debris	System Disturbance		12-02-2004	GS-009	1st Cut S. Run	AMERICAN METER	AXIAL 300#	8	720	Fails to Control Set Pressure	Debris
STONY MOUNTAIN GS	Pipeline debris in regs	System Disturbance		12-02-2004	GS-009	1st Cut N. Run	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Debris
STONY MOUNTAIN GS	Pipeline dbris in regs	System Disturbance		12-02-2004	GS-009	2nd Cut s. Run	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Debris
STONY MOUNTAIN GS	Pipeline debris in regs	System Disturbance		12-02-2004	GS-009	2nd Cut N.Run	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Debris
WARREN GS	Relief cap off check relief and regs	Weather (except lightning)		20-02-2004	GS-038	Relief	AMERICAN METER	AXIAL 300#	2.58	232.2	Fails to Control Set Pressure	Ice
WARREN GS	Regulator iced blocking orface and restricting diaphram	Weather (except lightning)		20-02-2004	GS-038	1st Cut W Upper	MOONEY	FG-12 - 1" - 600SWE			Fails to Control Set Pressure	Ice
WARREN GS	Regultors iced up	Weather (except lightning)		20-02-2004	GS-038	1st Cut M Upper	MOONEY	FG-12 - 1" - 600SWE	3	274.5	Fails to Control Set Pressure	Ice
WARREN GS	1st cut worker (upper) 60psig drops to 50psig then gos back to tag press 6	System Disturbance	Functional	27-02-2004	GS-038	1st Cut W Lower	MOONEY	FG-12 - 1" - 600SWE			Fails to Control Set Pressure	Ice
PLUM COULEE GS	Lag in operation	Human / Process Error		28-02-2004	GS-142	1st Cut Upper	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Pilot
WARREN GS	install catalytic heater on regulator to prevent frost build up	Weather (except lightning)		03-03-2004	GS-038	Relief	AMERICAN METER	AXIAL 300#	4.16	374.4	Fails to Control Set Pressure	Ice
MINIOTA PGS	Reg venting			05-03-2004	GS-111	2nd Cut Lower	FISHER	627H	1	90	Fails to Control Set Pressure	Diaphram
CITY GATE 1 GS	failed to lock-up		Functional	06-04-2004	GS-001	E Monitor	FISHER	399A			Fails to Control Set Pressure	Diaphram
CITY GATE 1 GS	did not lock-up		Functional	06-04-2004	GS-001	W Monitor	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
CITY GATE 1 GS	no lock-up		Functional	06-04-2004	GS-001	W Worker	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
WARREN GS	Low pressure alarm reported by SCADA			11-04-2004	GS-038	Relief	AMERICAN METER	AXIAL 300#	7	640.5	Fails to Control Set Pressure	
MELITA GS	venting after test/ rebuilt and reset			15-04-2004	GS-172	Relief	FISHER	1805			Fails to Control Set Pressure	Debris
PINELAND PGS	1st cut lead worker(bottom) weeping	System Disturbance	Functional	16-04-2004	GS-177	1ST CUT WORK LO	FISHER	627H			Fails to Control Set Pressure	Diaphram
PETERSFIELD GS	Failed to lock up		Functional	16-04-2004	GS-021	S. Run	FISHER	627			Fails to Control Set Pressure	Lock Up
PETERSFIELD GS	Failed to lock up		Functional	16-04-2004	GS-021	N Run	FISHER	627			Fails to Control Set Pressure	Lock Up
VICTORIA AVE RS	relief venting			19-04-2004	RS-107	Relief	FISHER	1805			Fails to Control Set Pressure	
PORTAGE SIMPLOT PGS	Hi Pressure Alarm			08-05-2004	GS-193	Upper Monitor	FISHER	399 EZR			Fails to Control Set Pressure	
GIMLI GS	lag in operation-tag 85#----ajusted lead & lag ---lead set point 90#		Integrity	10-05-2004	GS-008	South	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
MACGREGOR PGS	Failed to lock up		Functional	17-05-2004	GS-130	West Run	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Seat / Disc
Ile Des Chenes PGS	Fails to control			17-05-2004	GS-017	South Monitor	WELKER	JET	3.25	297.38	Fails to Control Set Pressure	

ILE DES CHENES PGS	Fails to control set pressure			17-05-2004	GS-017	South Worker	WELKER	JET			Fails to Control Set Pressure	
MORRIS CITY GS	Rebuilt regulator		Functional	18-05-2004	GS-149	1st Cut Lower	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Lock Up
MORRIS CITY GS	Rebuilt regulstor		Functional	18-05-2004	GS-149	2nd Cut Upper	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Lock Up
EMERSON RS	Changed seat and orfice	System Disturbance	Detld Insp	20-05-2004	RS-115	W Run Worker	FISHER	627M			Fails to Control Set Pressure	Seat / Disc
EMERSON RS	Changed seat and orfice	System Disturbance	Detld Insp	20-05-2004	RS-115	W Run Monitor	FISHER	627			Fails to Control Set Pressure	Seat / Disc
LETELLIER GS	Replaced seat and	System Disturbance	Functional	21-05-2004	GS-145	West Worker	FISHER	627H			Fails to Control Set Pressure	Orfice
ST. JEAN BAPTISTE GS	Replace seat and orfice	System Disturbance		21-05-2004	GS-148	Monitor W.	FISHER	627			Fails to Control Set Pressure	Orfice
ST. JEAN BAPTISTE GS	replaced seat and orfice		Functional	21-05-2004	GS-148	Worker W.	FISHER	627M			Fails to Control Set Pressure	Lock Up
HARMS ROAD GS	Check out hi hi outlet pressure	System Disturbance		23-05-2004	GS-184	LOWER MONITOR	FISHER	399 EZR			Fails to Control Set Pressure	Debris
DOMINION CITY GS	Rebuilt 399- boot and o rings. Need new cages ordered as these are showing	System Disturbance	Functional	25-05-2004	GS-147	1st cut M Up	FISHER	399 EZR			Fails to Control Set Pressure	Lock Up
DOMINION CITY GS	Rebuilt 399-boot and o rings Cages show wear	System Disturbance	Functional	25-05-2004	GS-147	1st Cut W Up	FISHER	399 EZR	4	368	Fails to Control Set Pressure	Diaphram
DOMINION CITY GS	Rebuilt 399	System Disturbance	Functional	25-05-2004	GS-147	1st Cut M Lo	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
DOMINION CITY GS	Rebuilt 399	System Disturbance	Functional	26-05-2004	GS-147	1st Cut W Lo	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
DOMINION CITY GS	Rebuilt 627 H	System Disturbance	Functional	26-05-2004	GS-147	2nd Cut W Lo	FISHER	627H			Fails to Control Set Pressure	Orfice
DOMINION CITY GS	Rebuilt 627 HM	System Disturbance	Functional	26-05-2004	GS-147	2nd Cut M Lo	FISHER	627HM			Fails to Control Set Pressure	Lock Up
PINELAND PGS	Service check found venting 627 regulator			26-05-2004	GS-177	1ST CUT WORK LO	FISHER	627H	7.58	697.36	Fails to Control Set Pressure	Diaphram
MISSION & PANET	failure to lock up during functional test	System Disturbance	Functional	01-06-2004	RS-007	MONITOR	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
MISSION & PANET	failure to lock during fuctional	System Disturbance	Functional	01-06-2004	RS-007	WORKER	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
STARBUCK PGS	check out hi hi outlet pressure.			05-06-2004	GS-165	Relief	MOONEY	FG-31 - 2" - 600# RF			Fails to Control Set Pressure	
MORDEN GS	exremely dirty diaphragm . removed from line and re-placed	System Disturbance	Functional	09-06-2004	GS-139	1st CutSouth	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Diaphram
ALTONA GS	intermediate pressure lo alarm	System Disturbance		29-06-2004	GS-143	1st Cut W Up	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
STONEWALL GS	Pressure going to relief setting (227#) then dropping down to aprox. 207#-c	System Disturbance		29-06-2004	GS-010	1st Cut N. Run	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Pilot
STONEWALL GS	Found 1rst cut relief venting and main body relieving. re-built reg. and pil	System Disturbance		29-06-2004	GS-010	1st Cut Relief	FISHER	63EG			Fails to Control Set Pressure	Diaphram
BRANDON RICHMOND GS	reg failed to seat off	Foreign Interference	UnSched	07-07-2004	GS-190	1st Cut Worker	MOONEY	FG-76 - 2" - 600SW			Fails to Control Set Pressure	
STONEWALL GS	low press. alarm	Human / Process Error		11-07-2004	GS-010	1st Cut N. Run	AMERICAN METER	AXIAL 300#	3	276	Fails to Control Set Pressure	Pilot
ARCHIBALD RS	Failed to lock up debrise on diaphame. REBUILT....	System Disturbance	Functional	14-07-2004	RS-004	E. Worker	FISHER	399 EZR			Fails to Control Set Pressure	Debris
BRANDON TURBINE GS	grove reg failed to respond to pressure fluctuations -rebuilt	No Initiating Event	UnSched	15-07-2004	GS-192	N.Upper	GROVE	900TE	3	276	Fails to Control Set Pressure	
NIVERVILLE PGS	Pilot failed to opperate. Fixed	System Disturbance	Detld Insp	15-07-2004	GS-150	3RD CUT LOWER	AMERICAN METER	AXIAL 300#	20	1840	Fails to Control Set Pressure	Pilot
CARMAN GS	Intermediate pressure into low alarm, adjusted first cut	Human / Process Error		19-07-2004	GS-137	1st Cut Upper	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Pilot
KINVER RS	found debris on diaphram	Foreign Interference	Functional	22-07-2004	RS-046	Relief	FISHER	1805			Fails to Control Set Pressure	Diaphram
INKSTER & MC RS	Failed Lockup	System Disturbance	Functional	22-07-2004	RS-027	East Worker	MOONEY	FG-65 - 6" - 300#			Fails to Control Set Pressure	Debris
INKSTER & MC RS	Failed Lockup	System Disturbance	Functional	22-07-2004	RS-027	West Worker	MOONEY	FG-65 - 6" - 300#			Fails to Control Set Pressure	Debris
KINVER RS	Failed Lockup	System Disturbance	Functional	22-07-2004	RS-046	S Monitor	MOONEY				Fails to Control Set Pressure	Debris
MCAULEY PGS	pressure dropped to 455psi-checked regulator and reset to 500psi	Foreign Interference	Call Out	27-07-2004	GS-100	SW 6-15-29W	MOONEY	600#	1.5	138	Fails to Control Set Pressure	
PORTAGE SIMPLOT GS	intermediate pressure same as inlet hihi alarm	System Disturbance		03-08-2004	GS-194	N. Run Worker	MOONEY	FG-18 - 3" - 600# RF	8	736	Fails to Control Set Pressure	Diaphram
BRANDON PGS	Regulator failed to seat off	Foreign Interference	Detld Insp	16-08-2004	GS-123	North	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Debris
PORTAGE SIMPLOT GS	Raise outlet pressure to aprox. to tagged setting (70#)	Human / Process Error		26-08-2004	GS-194	N. Run Worker	MOONEY	FG-18 - 3" - 600# RF			Fails to Control Set Pressure	Pilot
SYMINGTON & PMTR GS	Failed to lock up	System Disturbance	Functional	26-08-2004	GS-023	S. Run	FISHER	399 EZR			Fails to Control Set Pressure	Debris
INGLIS GS	Failed functional check prior to detailed inspection	Foreign Interference	Detld Insp	08-09-2004	GS-106	Lower Worker	FISHER	627M			Fails to Control Set Pressure	Debris
INGLIS GS	Fasiled functional check prior to detailed inspectrion	No Initiating Event	Functional	08-09-2004	GS-106	Lower Monitor	FISHER	627			Fails to Control Set Pressure	Lock Up
ROBLIN GS	Failed function test	No Initiating Event	Functional	08-09-2004	GS-107	2nd Cut Lower	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Lock Up
TRANSCONA GS-003	fails to control press	System Disturbance	Functional	16-09-2004	GS-003	Worker Center	FISHER	399 EZR			Fails to Control Set Pressure	Debris
CSP HARROWBY GS	leak on axialflow pilot	No Initiating Event	UnSched	22-09-2004	GS-105	Upper Run	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Pilot
NIVERVILLE PGS	Adj. outlet pressure to niverville-lo press alarm			30-09-2004	GS-150	2ND CUT LOWER	MOONEY	FG-4 - 2" - 300# RF			Fails to Control Set Pressure	Pilot
STONY MOUNTAIN GS	Fail to control	System Disturbance	Functional	14-10-2004	GS-009	1st Cut S. Run	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Diaphram
CITY GATE 1 GS	Lower Outlet Press Hi Caution Alarm	Human / Process Error		18-10-2004	GS-001	ByPass	FISHER	399A			Fails to Control Set Pressure	Pilot
OTTERBURNE GS	Failed to lock up	System Disturbance		21-10-2004	GS-152	2ND CUT LOWER	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Diaphram
MORRIS CITY GS	intermediate pressure in lo alarm	System Disturbance		25-11-2004	GS-149	1st Cut Upper	AMERICAN METER	AXIAL 600#	8.5	782	Fails to Control Set Pressure	Diaphram
EMERSON RS	outlet press in lo Caution on scada			25-11-2004	RS-115	W Run Worker	FISHER	627M			Fails to Control Set Pressure	
STARBUCK PGS	outlet pressure erratic, low then high			01-12-2004	GS-165	Relief	MOONEY	FG-31 - 2" - 600# RF			Fails to Control Set Pressure	Pilot
MARCHAND RS	99 Venting			01-12-2004	RS-127	W.Run	FISHER	99	12.5	1150	Fails to Control Set Pressure	Diaphram
RIVERTON GS	reg freezing	Weather (except lightning)		02-12-2004	GS-037	1ST CUT WORK UP	MOONEY	FG-12 - 1" - 600SWE	4.5	414	Fails to Control Set Pressure	Pilot
STARBUCK PGS	Lo Outlet Pressure			07-12-2004	GS-165	3rd Cut N Run	MOONEY	FG-28 - 2" - 600SWE			Fails to Control Set Pressure	
SOUTH WEST PGS	Leaking Pilot Diaphram	No Initiating Event	UnSched	13-12-2004	GS-168	N Worker	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
MINIOTA PGS	fisher 627 regulator venting	No Initiating Event	Call Out	17-12-2004	GS-111	2nd Cut Upper	FISHER	627H	3	276	Fails to Control Set Pressure	Diaphram
RIVERTON GS	intermediate pressure in hi hi alarm	Weather (except lightning)		19-12-2004	GS-037	1ST CUT WORK UP	MOONEY	FG-12 - 1" - 600SWE	7.5	690	Fails to Control Set Pressure	Ice
CITY GATE 1 GS	outlet press-HIHi-check and adj accordingly	Human / Process Error		20-12-2004	GS-001	ByPass	FISHER	399A			Fails to Control Set Pressure	Pilot
BINSCARTH GS	regulator venting gas/rebuilt and reset	Environmental Contamina	UnSched	21-12-2004	GS-102	1st Cut Lower	FISHER	627H	2	184	Fails to Control Set Pressure	
STONEWALL GS	regulator unable to function due to extreme cold, re-built and re-set	Weather (except lightnin	Functional	23-12-2004	GS-010	Warren Takeoff	MOONEY	FG-28 - 2" - 600SWE	2	184	Fails to Control Set Pressure	Diaphram
BRANDON TURBINE GS	north run overpressurizing, BCT plant not online	Foreign Interference	Call Out	26-12-2004	GS-192	Relief	FISHER	399 EZR	6	552	Fails to Control Set Pressure	
BRANDON MPL LEAF GS	Floating in and out of high alarm	Foreign Interference	UnSched	02-01-2005	GS-191	W.Worker	MOONEY	FG-63 - 4" - 150-300# BUT	3	276	Fails to Control Set Pressure	
STONEWALL GS	Warren take off pressure lo lo 78#			04-01-2005	GS-010	Warren Takeoff	MOONEY	FG-28 - 2" - 600SWE			Fails to Control Set Pressure	Pilot
RIVERTON GS	heater out ---lead reg frozen-- relight heater heater set at 130 degrees	System Disturbance	Detld Insp	05-01-2005	GS-037	1ST CUT WORK UP	MOONEY	FG-12 - 1" - 600SWE			Fails to Control Set Pressure	Ice
RIVERTON GS	inter press creeping up to hihi			05-01-2005	GS-037	1ST CUT WORK UP	MOONEY	FG-12 - 1" - 600SWE	6.5	598	Fails to Control Set Pressure	Pilot
BRANDON TURBINE GS	Overpressure ESD off High alarm	Foreign Interference	UnSched	12-01-2005	GS-192	N.Run Worker	BECKER	488F6WTO-SR-PD	8	736	Fails to Control Set Pressure	Lock Up
CROMER GS	Station in LO-LO outlet pressure alarm	Foreign Interference	UnSched	17-01-2005	GS-179	627	FISHER	627	0.5	46	Fails to Control Set Pressure	Ice
CROMER GS	Station outlet in LO_LO alarm	Weather (except lightnin	UnSched	17-01-2005	GS-179	Lower Worker	FISHER	399 EZR			Fails to Control Set Pressure	Ice
BRANDON TURBINE GS	north run outlet pressure hi caution	Foreign Interference	Call Out	18-01-2005	GS-192	N.Run Worker	BECKER	488F6WTO-SR-PD	3	276	Fails to Control Set Pressure	
BRANDON TURBINE GS	Outlet Hi caution reported by scada	Weather (except lightnin	UnSched	20-01-2005	GS-192	N.Run Worker	BECKER	488F6WTO-SR-PD			Fails to Control Set Pressure	
ALTONA GS	leak on monit. pilot 2nd cut bottom run		Detld Insp	08-02-2005	GS-143	2nd Cut M Lo	FISHER	399 EZR			Fails to Control Set Pressure	Pilot

BRANDON TURBINE GS	north run high outlet pressure	Foreign Interference	Call Out	26-03-2005	GS-192	N.Run Worker	BECKER	488F6WTO-SR-PD	3	285	Fails to Control Set Pressure	
ST. ANNE'S RS	lead reg no control	System Disturbance	Functional	26-03-2005	RS-006	Relief	FISHER	1805			Fails to Control Set Pressure	Diaphram
ST. JOSEPH GS	adjust outlet pressure	Foreign Interference		01-04-2005	GS-144	Worker Upper	FISHER	627H			Fails to Control Set Pressure	Seat / Disc
MORRIS CITY GS	adjust outlet pressure			01-04-2005	GS-149	2nd Cut Lower	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	
ST. ANNE'S RS	outlet pressure hi hi, regulator needs adjusting	Human / Process Error		13-04-2005	RS-006	Relief	FISHER	1805	15	1425	Fails to Control Set Pressure	Pilot
MINIOTA PGS	Failed Functional check	Foreign Interference	Functional	21-04-2005	GS-111	1st Cut Lower	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	
LANDMARK 2 PGS	Regulator would not lock off	System Disturbance		26-04-2005	GS-018	E.Worker E Selk	FISHER	399 EZR			Fails to Control Set Pressure	Debris
LANDMARK 2 PGS	Found regulator would not lock off	System Disturbance		26-04-2005	GS-018	E.Monitor E Selk	FISHER	399 EZR			Fails to Control Set Pressure	Debris
HARMS ROAD GS	Found lag run not holding during lock-up test	System Disturbance	Functional	11-05-2005	GS-184	LOWER WORKER	FISHER	399 EZR			Fails to Control Set Pressure	Debris
GRUNTHAL GS	Failed to control-- Repaired as required	System Disturbance		12-05-2005	GS-155	1st Cut Lower	MOONEY	FG-28 - 2" - 600SWE			Fails to Control Set Pressure	Pilot
SOUTHPORT GS	Fails to lockup.	System Disturbance	Functional	18-05-2005	GS-134	1st Cut Upper	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
BRANDON TURBINE GS	north and south run overpressuring after shut down	Weather (except lightnin	Call Out	19-05-2005	GS-192	Relief	FISHER	399 EZR	3	285	Fails to Control Set Pressure	
TWIN CREEKS (1) GS	Flange leak on inlet to releif	System Disturbance		25-05-2005	GS-151-RV0	1ST CUT RELIEF	AMERICAN METER	AXIAL 300#	2	190	Fails to Control Set Pressure	Diaphram
MACGREGOR PGS	outlet pressure lo alarm, reset to tag settings	Environmental Contamina	Call Out	02-06-2005	GS-130	West Run	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	
STARBUCK PGS	press jumped from 435 to 467 and climbing when polled	System Disturbance	Detld Insp	02-06-2005	GS-165	Relief	MOONEY	FG-31 - 2" - 600# RF	9.5	902.5	Fails to Control Set Pressure	Seat / Disc
CARMAN GS	Replaced boot from h-7 to h-5.	System Disturbance	Functional	08-06-2005	GS-137	2nd Cut Upper	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Diaphram
CARMAN GS	Replaced boot from h-7 to h-5.	System Disturbance	Functional	08-06-2005	GS-137	2nd Cut Lower	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Diaphram
CARMAN GS	Pilot fails to control	System Disturbance	Functional	08-06-2005	GS-137	2nd Cut Upper	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Pilot
GIMLI SEVENTH AVE RS	Failed to lock up, rebuilt 399	System Disturbance		09-06-2005	RS-031	SW 16-19-4 E	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
CLANDEBOYE GS	Failed to lock up, rebuilt 630	System Disturbance		15-06-2005	GS-005	1st Cut E.Run	FISHER	630			Fails to Control Set Pressure	Seat / Disc
MORDEN GS	Fails to lockup.	System Disturbance	Functional	20-06-2005	GS-139	2nd Cut South	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Debris
ST. JEAN BAPTISTE GS	Fails to lockup.	System Disturbance	Functional	21-06-2005	GS-148	Monitor W.	FISHER	627			Fails to Control Set Pressure	Seat / Disc
ST. JEAN BAPTISTE GS	Fails to lockup.	System Disturbance	Functional	21-06-2005	GS-148	Worker W.	FISHER	627M			Fails to Control Set Pressure	Seat / Disc
ST. JOSEPH GS	Failed to lockup.	System Disturbance	Functional	22-06-2005	GS-144	Worker Upper	FISHER	627H			Fails to Control Set Pressure	Seat / Disc
PARK ST. RS	failed lockup,	Environmental Contamina	Functional	27-06-2005	RS-109	W.Worker	MOONEY	FG-21 - 4" - 150# RF			Fails to Control Set Pressure	
PARK ST. RS	failed lockup	Environmental Contamina	Functional	27-06-2005	RS-109	E.Worker	MOONEY	FG-21 - 4" - 150# RF			Fails to Control Set Pressure	Pilot
WINKLER GS	Faile to lockup.	System Disturbance	Functional	28-06-2005	GS-140	1st Cut M Upper	FISHER	399 EZR	2	190	Fails to Control Set Pressure	Seat / Disc
MORRIS CITY GS	Failed to lockup.	Foreign Interference	Functional	06-07-2005	GS-149	1st Cut Lower	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Debris
PORTAGE LINCOLON GS	Leak reported by Serviceman onn 161 pilot	Weather (except lightnin	Stn Insp	12-07-2005	GS-178	Worker E.	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
EAST SELKIRK GEN GS	Failes to control locked in pressure	System Disturbance		21-07-2005	GS-041	Start-up-Monitor	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
PORTAGE PGS	Failed to lockup.	System Disturbance	Functional	21-07-2005	GS-132	North Run	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Debris
PORTAGE LINCOLON GS	leak on pilot	System Disturbance		18-08-2005	GS-178	Monitor E.	FISHER	399 EZR	15	1425	Fails to Control Set Pressure	Pilot
ILE DES CHENES PGS	gas deteck alarm, leak on indicator stem not a fails to control	Human / Process Error	Stn Insp	06-10-2005	GS-017	Center Monitor	FISHER	399A			Fails to Control Set Pressure	Pilot
LANDMARK 2 PGS	2 in startup 399 reg not controling	System Disturbance	Stn Insp	07-10-2005	GS-018	E.Worker E Selk	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
MACGREGOR PGS	Reg fails to lockup	Environmental Contamina	Functional	11-10-2005	GS-130	West Run	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Diaphram
	1ST CUT LOWWER LEAK AROUND SPRING CAGE..... FIXED		Functional	04-11-2005	GS-177	1ST CUT WORK LO	FISHER	627H			Fails to Control Set Pressure	Spring
ALTONA GS	appears to have failed-monitor taken over	System Disturbance		06-11-2005	GS-143	1st Cut W Up	FISHER	399 EZR	5	475	Fails to Control Set Pressure	Seat / Disc
NIVERVILLE PGS	Fails to control outlet pressure.	Overloading		16-11-2005	GS-150	3RD CUT LOWER	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	
PORTAGE PGS	Fails to control pressure	System Disturbance		28-11-2005	GS-132	North Run	AMERICAN METER	AXIAL 600#	16	1520	Fails to Control Set Pressure	Pilot
WINKLER GS	lo pressure on int press	Human / Process Error	Stn Insp	06-12-2005	GS-140	2nd Cut W Upper	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
PORTAGE LINCOLON GS	Bob Brick reported Lead Worker failing,whirly bird broken.	System Disturbance		06-12-2005	GS-178	Worker E.	FISHER	399 EZR			Fails to Control Set Pressure	Ice
WINKLER GS	Leak on filter		Stn Insp	01-02-2006	GS-140	1st Cut W Upper	FISHER	399 EZR			Fails to Control Set Pressure	
WINKLER GS	Found pilot on reg venting	System Disturbance	Stn Insp	02-02-2006	GS-140	1st Cut W Upper	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
STONEWALL GS	diaphram on pilot leaking		Stn Insp	17-02-2006	GS-010	1st Cut Relief	FISHER	63EG			Fails to Control Set Pressure	Seat / Disc
BRANDON TURBINE GS	high outlet press on north line	Human / Process Error	Call Out	19-02-2006	GS-192	S.Upper	GROVE	900TE	6	570	Fails to Control Set Pressure	
LANDMARK 2 PGS	reg not holding after shut down	Foreign Interference	Call Out	03-03-2006	GS-018	E.Worker E Selk	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
PORTAGE PGS	outlet pressure in lolo alarm	System Disturbance	Call Out	09-03-2006	GS-132	North Run	AMERICAN METER	AXIAL 600#	4.5	427.5	Fails to Control Set Pressure	Pilot
FURBY & MCDERMOT RS	25% LEL in Pit			09-03-2006	RS-018	Regulator	FISHER	399A			Fails to Control Set Pressure	Pilot
CARBERRY GS	Pressure spiking to 160 #	Foreign Interference	Call Out	19-04-2006	GS-128	2nd Cut W Lo	AMERICAN METER	AXIAL 300#	6	582	Fails to Control Set Pressure	Pilot
TEULON GS	inlet press in lolo alarm at 60 please raise			04-05-2006	GS-039	Worker Upper	MOONEY	FG-12 - 1" - 600SWE			Fails to Control Set Pressure	
ALTONA GS	intermediate pressure hihi alarm		Detld Insp	06-05-2006	GS-143	1st Cut W Up	FISHER	399 EZR	7	679	Fails to Control Set Pressure	Pilot
WILLIAM NEWTON RS	Found leak on filter	Through Fault		10-05-2006	RS-001	E Worker	FISHER	399 EZR			Fails to Control Set Pressure	
RIVERS GS	Reg surging	Foreign Interference	Stn Insp	24-05-2006	GS-118	1st Cut Lower	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Pilot
HARMS ROAD GS	pilot bonet thread stripped ,,, restriktor cracked	Through Fault	Detld Insp	24-05-2006	GS-184	UPPER WORKER	FISHER	399 EZR			Fails to Control Set Pressure	Restricter Bloc
STEINBACH GS	Not regulating set pressure-please check out operation	Through Fault	Call Out	26-05-2006	GS-156-PR02	1ST CUT LOWER	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Diaphram
HARMS ROAD GS	High Pressure			31-05-2006	GS-184	UPPER WORKER	FISHER	399 EZR	9	873	Fails to Control Set Pressure	Diaphram
HARMS ROAD GS	High Pressure			31-05-2006	GS-184	UPPER MONITOR	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
STARBUCK PGS	Reg not controlling-please check out operation & repair	Foreign Interference	Detld Insp	02-06-2006	GS-165	1st Cut W Lower	FISHER	627H	4	388	Fails to Control Set Pressure	Seat / Disc
BRANDON TURBINE GS	reg over pressurizing			04-06-2006	GS-192	Relief	FISHER	399 EZR			Fails to Control Set Pressure	
BRANDON TURBINE GS	outlet pressure in hi alarm	Foreign Interference		10-06-2006	GS-192	N.Run Worker	BECKER	488F6WTO-SR-PD	1.5	145.5	Fails to Control Set Pressure	
SOURIS SOUTH GS	numerous RBX'S outlet in/out of low alarm	System Disturbance	UnSched	10-06-2006	GS-170	Upper Worker	FISHER	627	1.5	145.5	Fails to Control Set Pressure	
BRANDON TURBINE GS	North and South runs in high caution. Overpressurizing	System Disturbance	Call Out	14-06-2006	GS-192	Relief	FISHER	399 EZR	3	291	Fails to Control Set Pressure	
PORTAGE SIMPLOT GS	high press	Overloading	Call Out	16-06-2006	GS-194	S. Run Worker	MOONEY	FG-18 - 3" - 600# RF			Fails to Control Set Pressure	Pilot
MACGREGOR PGS	Regulator found fluctuating		Stn Insp	28-09-2006	GS-130	West Run	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Restricter Bloc
NIVERVILLE PGS	overpressurizing please check operation			30-09-2006	GS-150	1ST CUT LOWER	AMERICAN METER	AXIAL 600#	16	1552	Fails to Control Set Pressure	Diaphram
NIVERVILLE PGS	Regulator not controlling properly	Foreign Interference	UnSched	10-10-2006	GS-150	2ND CUT LOWER	MOONEY	FG-4 - 2" - 300# RF			Fails to Control Set Pressure	Diaphram
NIVERVILLE PGS	Regulator not controlling	Foreign Interference		12-10-2006	GS-150	2ND CUT LOWER	MOONEY	FG-4 - 2" - 300# RF			Fails to Control Set Pressure	Pilot
LA SALLE PGS	Please reset lead reg to 450#		Call Out	17-10-2006	GS-015	CENTER	MOONEY	FG-66			Fails to Control Set Pressure	
ALTONA GS	Low outlet pressure	Overloading	Call Out	20-10-2006	GS-143	2nd Cut W Up	FISHER	399 EZR	4	388	Fails to Control Set Pressure	Pilot
LA SALLE PGS	Does not have very good control	System Disturbance	Stn Insp	25-10-2006	GS-015	NORTH	MOONEY	FG-66	6	582	Fails to Control Set Pressure	Cage

ST. ADOLPHE GS	Pilot Venting	System Disturbance	Call Out	01-11-2006	GS-026	UPPER-E.-MON	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Pilot
ST. NORBERT PGS	Pilot on reg leaking	Through Fault	Detld Insp	24-11-2006	GS-002	E. Worker	FISHER	399A	4	388	Fails to Control Set Pressure	Pilot
DOMINION CITY GS	Pilot Venting			04-12-2006	GS-147	1st cut M Up	FISHER	399 EZR	13	1261	Fails to Control Set Pressure	Diaphram
EMERSON RS	Leak at Pilot vent	Weather (except lightnin	Call Out	19-12-2006	RS-115	Relief	FISHER	63EG			Fails to Control Set Pressure	Diaphram
ST. NORBERT PGS	lid leaking & pilot blowing out side by diaphram	Weather (except lightnin	Call Out	10-01-2007	GS-002	E Monitor	FISHER	399A	6.5	630.5	Fails to Control Set Pressure	Pilot
MORDEN GS	Intermediate pressure in lo lo alarm on SCADA	Human / Process Error		12-01-2007	GS-139	1st Cut Relief	AMERICAN METER	AXIAL 300#	4	388	Fails to Control Set Pressure	Pilot
LA SALLE PGS	Lo inlet pressure to City Gate			12-01-2007	GS-015	NORTH	MOONEY	FG-66			Fails to Control Set Pressure	
MINIOTA PGS	Metering pressure erratic, spiking from app.360 to 425			16-01-2007	GS-111	1st Cut Lower	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	
BIRDS HILL GS	Fails to operate	Foreign Interference	Call Out	18-01-2007	1st Cut Upper		FISHER	399 EZR			Fails to Control Set Pressure	Cage
RIVERTON GS	Riverton Intermediate Pressure LOLO alarm, 53.3 and dropping	Weather (except lightnin	Call Out	05-02-2007	GS-037	1ST CUT WORK UP	MOONEY	FG-12 - 1" - 600SWE	6	582	Fails to Control Set Pressure	Pilot
PORTAGE PGS	outlet pressure in hi alarm			08-02-2007	GS-132	North Run	AMERICAN METER	AXIAL 600#	4	388	Fails to Control Set Pressure	Diaphram
MINIOTA PGS	Pressure performing erratically		Call Out	09-02-2007	GS-111	1st Cut Lower	AMERICAN METER	AXIAL 600#	2	194	Fails to Control Set Pressure	
LA SALLE PGS	lo inlet presssure @ Fort Whyte	Overloading	Call Out	14-02-2007	GS-015	NORTH	MOONEY	FG-66	16.5	1600.5	Fails to Control Set Pressure	Diaphram
PORTAGE SIMPLOT PGS	Pressure erratic from Hi to HiHi outlet-base pressure requires adjustment			27-02-2007	GS-193	Upper Worker	FISHER	399 EZR			Fails to Control Set Pressure	Spring
ALTONA GS	In HI alarm - running app 10 #'s above set pressure	Overloading	Call Out	01-03-2007	GS-143	1st Cut W Up	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
WINKLER GS	Intermediat pressure in Hi alarm, not clearing and pressure slowly rising	Overloading	Call Out	03-03-2007	GS-140	1st Cut W Upper	FISHER	399 EZR	4	388	Fails to Control Set Pressure	Pilot
LA SALLE PGS	Reg not operating correctly	Through Fault	Call Out	05-03-2007	GS-015	CENTER	MOONEY	FG-66			Fails to Control Set Pressure	Diaphram
BINSCARTH GS	Regulator fluctuating set point		Call Out	26-03-2007	GS-102	2nd Cut Lower	FISHER	627M	18	1998	Fails to Control Set Pressure	
LANDMARK PGS	Not regulating, please check out	System Disturbance	Call Out	21-04-2007	GS-018	1st	FISHER	399 EZR	17	1887	Fails to Control Set Pressure	Diaphram
ILE DES CHENES PGS	Becker pilot not not controling	Through Fault	Call Out	01-05-2007	GS-017	South Worker	WELKER	JET	17	1887	Fails to Control Set Pressure	Pilot
PORTAGE SIMPLOT PGS	Please check out HiHi press alarm	System Disturbance	Call Out	04-05-2007	GS-193	Lower Worker	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
DOMINION CITY PGS	Station in and out of Lo alarm app 15 # lower than set pressure		Call Out	05-05-2007	GS-146	Lower Run	AMERICAN METER	AXIAL 600#	4.83	536.13	Fails to Control Set Pressure	
INKSTER & POWERS	Pilot Filter leaking	System Disturbance	Stn Insp	31-05-2007	RS-026	WORKER N RUN	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
ST. ADOLPHE GS	Intermediate pressure LoLo	Through Fault	Call Out	25-06-2007	GS-026	UPPER-W.-MON	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	
ST. BONIFACE GS	relief weeping over press	System Disturbance	Call Out	11-07-2007	GS-019		FISHER	399 EZR			Fails to Control Set Pressure	
PORTAGE SIMPLOT PGS	Pressure adjustment	System Disturbance	Call Out	29-07-2007	GS-193	Lower Worker	FISHER	399 EZR	3	333	Fails to Control Set Pressure	
GILBERT PLAINS GS	monitor regulator failure	Foreign Interference	Stn Insp	01-08-2007	GS-109	Lower Monitor	FISHER	399A	4.5	499.5	Fails to Control Set Pressure	Pilot
HENDERSON RS	Reg leaking from lid.	System Disturbance	Stn Insp	20-09-2007	RS-003		FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
ALTONA GS	Going down to lag pressure	System Disturbance	Call Out	04-10-2007	GS-143	2nd Cut W Up	FISHER	399 EZR			Fails to Control Set Pressure	
HAMIOTA PGS	Reg Venting			02-11-2007	GS-114	Upper	FISHER	627H	1	111	Fails to Control Set Pressure	Diaphram
ALTONA GS	Outlet pressure drooped - 5#		Call Out	07-11-2007	GS-143	2nd Cut W Up	FISHER	399 EZR	18.5	2053.5	Fails to Control Set Pressure	Pilot
WINKLER GS	Outlet HIHI alarm above 60#		Call Out	08-11-2007	GS-140	2nd Cut W Lower	FISHER	399 EZR			Fails to Control Set Pressure	
MACGREGOR PGS	oulet pressure in and out of alarms		Call Out	15-11-2007	GS-130	West Run	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Restricter Block
FORT WHYTE GS	regs not locking off			20-11-2007	GS-020	Worker	FISHER	399 EZR	7.5	832.5	Fails to Control Set Pressure	Diaphram
PORTAGE LINCOLON GS	Lead run not controlling			20-11-2007	GS-178	Worker E.	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
HEWITSON GS	Lo caution alarm reported by SCADA			22-11-2007	GS-040	Monitor W. Run	MOONEY	FG-62 - 3" - 600# BUTT WE			Fails to Control Set Pressure	
ILE DES CHENES GS	froze off			27-11-2007	GS-016	2nd cut lower	MOONEY	FG-30 - 2" - 300# RF			Fails to Control Set Pressure	Pilot
DOMINION CITY GS	Pilot venting		Stn Insp	30-11-2007	GS-147	1st Cut M Lo	FISHER	399 EZR	10	1110	Fails to Control Set Pressure	Pilot
RALEIGH ST. GS	Erratic outlet operation			07-12-2007	GS-024	West Worker	FISHER	399A	5	555	Fails to Control Set Pressure	Diaphram
TEULON GS	OUTLET PRESSURE GOING DOWN	No Initiating Event	UnSched	12-12-2007	GS-039	Worker Lower	MOONEY	FG-12 - 1" - 600SWE			Fails to Control Set Pressure	
MOORE PARK PGS	Low outlet to Minnedosa		Call Out	09-01-2008	GS-119	1st Cut Lower	AMERICAN METER	AXIAL 600#	2	222	Fails to Control Set Pressure	
PORTAGE PGS	Outlet pressure in and out of alarm		Stn Insp	17-01-2008	GS-132	North Run	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	
ST. PIERRE PGS	LO outlet pressure		Call Out	21-01-2008	GS-153	Worker Upper	FISHER	399A			Fails to Control Set Pressure	
PORTAGE PGS	Lo lo outlet pressure			23-01-2008	GS-132	North Run	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	
LA SALLE PGS	Low outlet pressure		UnSched	29-01-2008	GS-015	NORTH	MOONEY	FG-66	1	111	Fails to Control Set Pressure	Diaphram
RIVERS PGS	overpressure and increase station flowrate		UnSched	04-02-2008	GS-117	East Run	FISHER	399 EZR	1	111	Fails to Control Set Pressure	Seat / Disc
ST. PIERRE PGS	Pressure not holding			05-02-2008	GS-153	Worker Upper	FISHER	399A			Fails to Control Set Pressure	Restricter Block
LA SALLE PGS	Fails to control pressure		UnSched	19-02-2008	GS-015	NORTH	MOONEY	FG-66			Fails to Control Set Pressure	Diaphram
LANDMARK PGS	Reg not controlling		UnSched	26-02-2008	GS-018	2nd	FISHER	630	4	444	Fails to Control Set Pressure	
LANDMARK PGS	Reg Not controlling			26-02-2008	GS-018	2nd	FISHER	630			Fails to Control Set Pressure	Seat / Disc
LANDMARK PGS	reg not controlling			26-02-2008	GS-018	2nd	FISHER	630			Fails to Control Set Pressure	Seat / Disc
ST. PIERRE PGS	High Pressure Alarm		UnSched	06-03-2008	GS-153	Worker Upper	FISHER	399A	12	1332	Fails to Control Set Pressure	Pilot
ST. PIERRE PGS	High Pressure Alarm		UnSched	06-03-2008	GS-153	Monitor Upper	FISHER	399A			Fails to Control Set Pressure	Cage
FORT WHYTE GS	tubing leaking on regs	No Initiating Event	Functional	20-03-2008	GS-020	Worker	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
ILE DES CHENES PGS	Welkers will not seal off as per Greg S and Grant Nicol			20-03-2008	GS-017	North Worker	WELKER	JET	11	1221	Fails to Control Set Pressure	
LANDMARK 2 PGS	Pressure not set correctly	Through Fault	Call Out	15-04-2008	GS-018	E.Worker E Selk	FISHER	399 EZR	3.5	392	Fails to Control Set Pressure	Pilot
ST. LAZARE GS	Outlet in low low alarm			21-04-2008	GS-101	2nd Cut Lower	FISHER	627M			Fails to Control Set Pressure	Seat / Disc
SOUTH WEST PGS	Southwest Lo and Deloraine and Killarney Lo Inlets			06-05-2008	GS-168	N Worker	FISHER	399 EZR	3	336	Fails to Control Set Pressure	
HUSKY GS	Monitor - Failed Functional Test		Stn Insp	06-05-2008	GS-205	upper-worker	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
HUSKY GS	Worker - Failed Functional Test			06-05-2008	GS-205	upper-monitor	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
STONEWALL GS	Overpressure		UnSched	24-06-2008	GS-010	Warren Takeoff	MOONEY	FG-28 - 2" - 600SWE			Fails to Control Set Pressure	
LANDMARK 2 PGS	Please check out reg operation as outlet has dropped to low alarm setting	Human / Process Error	UnSched	29-07-2008	GS-018	E.Worker E Selk	FISHER	399 EZR	2.5	280	Fails to Control Set Pressure	Pilot
MINIOTA PGS	Regulator erratic	Environmental Contamina	UnSched	01-08-2008	GS-111	1st Cut Upper	AMERICAN METER	AXIAL 600#	9	1008	Fails to Control Set Pressure	Spring
NIVERVILLE PGS	Possible failure please check operation	System Disturbance	Call Out	01-08-2008	GS-150	1ST CUT LOWER	AMERICAN METER	AXIAL 600#	8	896	Fails to Control Set Pressure	Diaphram
ST. ADOLPHE GS	LOW INTERMEDIATE PRESSURE	No Initiating Event	Call Out	30-08-2008	GS-026	UPPER-W.-MON	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Orfice
PORTAGE SIMPLOT PGS	pressure adjust	Human / Process Error	Call Out	10-09-2008	GS-193	Lower Worker	FISHER	399 EZR	3	336	Fails to Control Set Pressure	Pilot
RALEIGH ST. GS	No filter on regs.		Functional	11-09-2008	GS-024	East Worker	FISHER	399A			Fails to Control Set Pressure	Pilot
NEEPAWA PGS	FAILS TO CONTROL PRESSURE SETTING		UnSched	15-09-2008	GS-121	1st Cut W Lo	FISHER	399 EZR	2	224	Fails to Control Set Pressure	Pilot
NORTH NORFOLD PGS	set pressure drooped then reset		UnSched	16-09-2008	GS-195	1st Cut Worker Bottor	MOONEY	FG-5 - 2"			Fails to Control Set Pressure	Pilot
NEEPAWA PGS	Lo pressure Alarm	Environmental Contamina	UnSched	02-10-2008	GS-121	1st Cut W Lo	FISHER	399 EZR	4.5	504	Fails to Control Set Pressure	

NEEPAWA PGS	Lo pressure alarm	Environmental Contamina	UnSched	02-10-2008	GS-121	1st Cut M Lo	FISHER	399 EZR	7	784	Fails to Control Set Pressure	
MORRIS CITY GS	Fails to maintain setpoint		UnSched	14-10-2008	GS-149	2nd Cut Upper	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	
PORTAGE LINCOLON GS	high pressure	System Disturbance	UnSched	23-10-2008	GS-178	Worker E.	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
ALTONA GS	Intermediate pressure in alarm	System Disturbance		10-11-2008	GS-143	1st Cut W Up	FISHER	399 EZR			Fails to Control Set Pressure	
NIVERVILLE PGS	In Lo Lo alarm		UnSched	11-11-2008	GS-150	2ND CUT LOWER	MOONEY	FG-4 - 2" - 300# RF			Fails to Control Set Pressure	
MOORE PARK PGS	Lo outlet to Minnedosa		UnSched	28-11-2008	GS-119	1st Cut Lower	AMERICAN METER	AXIAL 600#	4	448	Fails to Control Set Pressure	Spring
LA SALLE PGS	Lead runs not controllong set pressure		UnSched	04-12-2008	GS-015	NORTH	FISHER	399 EZR			Fails to Control Set Pressure	
ST. NORBERT PGS	Lead run not controlling set pressure		UnSched	04-12-2008	GS-002	E. Worker	FISHER	399A			Fails to Control Set Pressure	
ALTONA GS	Not controllling set point	Foreign Interference	UnSched	12-12-2008	GS-143	1st Cut W Up	FISHER	399 EZR			Fails to Control Set Pressure	
LA SALLE PGS	!st lag run diaphram damaged	Foreign Interference	Call Out	15-12-2008	GS-015	CENTER	FISHER	399 EZR	30	3360	Fails to Control Set Pressure	Diaphram
LA SALLE PGS	Please check out low outlet pressure	System Disturbance	Call Out	15-12-2008	GS-015	SOUTH	FISHER	399 EZR	10	1120	Fails to Control Set Pressure	Diaphram
TEULON GS	LoLo outlet pressure	Overloading	UnSched	16-12-2008	GS-039	Worker Lower	MOONEY	FG-12 - 1" - 600SWE			Fails to Control Set Pressure	
MORDEN GS	Low outlet presssure		UnSched	18-12-2008	GS-139	2nd Cut North	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	
ST. NORBERT PGS	Not controlling set pressure	Foreign Interference	UnSched	19-12-2008	GS-002	E. Worker	FISHER	399A			Fails to Control Set Pressure	
ST. NORBERT PGS	ST. NORBERT OUTLET PRESSURE HIHI ice in pilot swap runs east lead west lag	Foreign Interference	Call Out	22-12-2008	GS-002	E. Worker	FISHER	399A	6	672	Fails to Control Set Pressure	Pilot
PORTAGE PGS	Outlet Pressure HiHi Alarm	System Disturbance	Call Out	27-12-2008	GS-132	North Run	AMERICAN METER	AXIAL 600#	6.5	728	Fails to Control Set Pressure	Pilot
WARREN GS	not contolling set pressure, intermediate in hihi alarm	Foreign Interference	Call Out	05-01-2009	GS-038	1st Cut W Upper	MOONEY	FG-12 - 1" - 600SWE	10	1120	Fails to Control Set Pressure	Pilot
LA SALLE PGS	TCPL lowering pressure/Station Bypass - Monitoring			25-01-2009	GS-015	NORTH	FISHER	399 EZR			Fails to Control Set Pressure	
OAK BLUFF PGS	Lo Pressure at Meter		UnSched	03-02-2009	GS-030	Relief	CROSBY	JPVM-45A			Fails to Control Set Pressure	Pilot
LANDMARK PGS	630 reg. venting at body			19-02-2009	GS-018	2nd	FISHER	630			Fails to Control Set Pressure	Diaphram
WINKLER GS	Low Pressure		UnSched	09-03-2009	GS-140	2nd Cut W Lower	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
TEULON GS	Pressure in LoLo Alarm			10-03-2009	GS-039	Monitor Upper	MOONEY	FG-12 - 1" - 600SWE			Fails to Control Set Pressure	
PORTAGE LINCOLON GS	lead run fails to control station outlet set pressure	Overloading	Call Out	10-04-2009	GS-178	Worker E.	FISHER	399 EZR	12	1428	Fails to Control Set Pressure	Seat / Disc
NIVERVILLE PGS	LO LO Alarm		Stn Insp	17-04-2009	GS-150	2ND CUT LOWER	MOONEY	FG-4 - 2" - 300# RF			Fails to Control Set Pressure	Pilot
NIVERVILLE PGS	Lo Lo Alarm		Call Out	18-04-2009	GS-150	2ND CUT LOWER	MOONEY	FG-4 - 2" - 300# RF	3	357	Fails to Control Set Pressure	Pilot
NIVERVILLE PGS	Reg not controlling		Call Out	21-04-2009	GS-150	2ND CUT LOWER	MOONEY	FG-4 - 2" - 300# RF			Fails to Control Set Pressure	Pilot
WINKLER GS	Low pressure		UnSched	24-04-2009	GS-140	2nd Cut W Lower	FISHER	399 EZR			Fails to Control Set Pressure	
EAST SELKIRK GEN GS	hihi outlet pressure alarm to Selkirk Generating Plant			27-04-2009	GS-041	Relief	FISHER	63EG	4	476	Fails to Control Set Pressure	Diaphram
WILKES RS	Lag worker failed	Foreign Interference	Stn Insp	06-05-2009	RS-011	N.Run Worker	MOONEY	FG-65 - 6" - 300#			Fails to Control Set Pressure	Diaphram
ILE DES CHENES PGS	Becker pilot not controlling.		Stn Insp	06-05-2009	GS-017	South Worker	WELKER	JET			Fails to Control Set Pressure	Pilot
TRANSCONA GS-003	Reg not controlling		UnSched	08-05-2009	GS-003	Worker Center	FISHER	399 EZR	4	476	Fails to Control Set Pressure	Pilot
TRANSCONA GS-003	No outlet pressure.		UnSched	11-05-2009	GS-003	MonitorN.	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
ALTONA GS	Outlet pressure high		UnSched	19-05-2009	GS-143	2nd Cut W Up	FISHER	399 EZR				
ALTONA GS	Outlet pressure high		UnSched	19-05-2009	GS-143	2nd Cut W Up	FISHER	399 EZR			Fails to Control Set Pressure	
MORRIS CITY GS	intermediate pressure lo alarm	Through Fault	UnSched	25-05-2009	GS-149	1st Cut Lower	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Diaphram
NEW BOTHWELL GS	Small leak on Axial flow bottom lead. Tagged at leak by Regan doing leak survey.			25-06-2009	GS-158	2ND CUT LOWER	AMERICAN METER	AXIAL			Fails to Control Set Pressure	
ST. BONIFACE GS	No filter on inlet to pilot	System Disturbance	Detld Insp	23-07-2009	GS-019		FISHER	399 EZR			Fails to Control Set Pressure	Pilot
ST. BONIFACE GS	No filter on inlet to pilot		Detld Insp	23-07-2009	GS-019		FISHER	399 EZR	8	888	Fails to Control Set Pressure	Pilot
STEINBACH GS	outlet regulator surging as per Steinbach serviceperson	Foreign Interference	UnSched	28-09-2009	GS-156-PR03	2ND CUT UPPER	AMERICAN METER	AXIAL 300#	2	238	Fails to Control Set Pressure	Restricter Bloc
STEINBACH GS	Check erractic pressure	Foreign Interference	UnSched	28-10-2009	GS-156-PR02	1ST CUT LOWER	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	
ALTONA GS	outlet in lolo ajust lag & lead set point		Call Out	31-10-2009	GS-143	2nd Cut W Up	FISHER	399 EZR	4	476	Fails to Control Set Pressure	Pilot
PORTAGE SIMPLOT PGS	OPutlet pressure in and out of lo alarm		UnSched	13-11-2009	GS-193	Lower Worker	FISHER	399 EZR			Fails to Control Set Pressure	
MORDEN GS	FIRST CUT REG. FAILED.		Call Out	03-12-2009	GS-139	1st Cut North	AMERICAN METER	AXIAL 600#	13	1547	Fails to Control Set Pressure	Pilot
BRANDON PGS	Adj feed to Huskey			04-12-2009	GS-123	South	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	
MORDEN GS	Inter pressure in low alarm. Please check out reg operation.		Call Out	07-12-2009	GS-139	1st Cut North	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Diaphram
ST. LAZARE GS	Low Low alarm.		Call Out	15-12-2009	GS-101	2nd Cut Lower	FISHER	627M	15.5	1844.5	Fails to Control Set Pressure	Diaphram
ILE DES CHENES PGS	Fails to control pressure		UnSched	16-12-2009	GS-017	South Monitor	WELKER	JET			Fails to Control Set Pressure	Pilot
MINNEDOSA GS	intermedialte pressure lo		UnSched	24-02-2010	GS-120	1st Cut Upper	FISHER	399			Fails to Control Set Pressure	Restricter Bloc
STE. AGATHE PGS	pilot on lead run leaking		UnSched	08-03-2010	GS-180	2nd Cut Mon Up	MOONEY	FG-12 - 1" - 600SWE			Fails to Control Set Pressure	Pilot
PORTAGE SIMPLOT PGS	Verify Monitor Lock Up	System Disturbance	UnSched	18-03-2010	GS-193	Upper Monitor	FISHER	399 EZR			Fails to Control Set Pressure	
NIVERVILLE PGS	Please check out reg operation & reset to tagged pressure setting.		UnSched	18-03-2010	GS-150	3RD CUT LOWER	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	
LANDMARK 2 PGS	Pressure not holding 10# to 15# swing		UnSched	18-03-2010	GS-018	W.Worker E Selk	FISHER	399 EZR			Fails to Control Set Pressure	
BRANDON PGS	Pressure spike and did return to set		UnSched	24-03-2010	GS-123	North	AMERICAN METER	AXIAL 600#	1	119	Fails to Control Set Pressure	
ROSSER GS	LOWER OUTLET PRESSURE BY 5 PSI	Weather (except lightnin	UnSched	29-03-2010	GS-031	N. Run Worker	FISHER	399 EZR			Fails to Control Set Pressure	
STONEWALL GS	Reg. no controll		Functional	30-03-2010	GS-010	Warren Takeoff	MOONEY	FG-28 - 2" - 600SWE			Fails to Control Set Pressure	Diaphram
FORT WHYTE GS	Please lower base pressure by 5#.		Call Out	01-04-2010	GS-020	Worker	FISHER	399 EZR	5	595	Fails to Control Set Pressure	
STE. ANNE GS	Pilot Frosted up		Functional	06-05-2010	GS-160-PR01	1ST CUT UPPER	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Pilot
TRANSCONA GS-003	Reg not controlling at set pressure		Functional	26-05-2010	GS-003	Monitort Center	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
PORTAGE PGS	lolo outlet pressure	Weather (except lightnin	Call Out	10-06-2010	GS-132	North Run	AMERICAN METER	AXIAL 600#	2	248	Fails to Control Set Pressure	
HUSKY GS	LATCHED UP NEAR HIHI PRESS ALARM. CHECKED OUT OK.	System Disturbance	Call Out	26-06-2010	GS-205	NW2-15-18W	FISHER	1805	3	372	Fails to Control Set Pressure	
ST. ADOLPHE GS	INTERMEDIATE PRESSURE LOW	System Disturbance	Functional	15-07-2010	GS-026	LOWER-W.-WORK	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Orfice
NIVERVILLE PGS	1st cut upper boot fail		Call Out	03-08-2010	GS-150	1ST CUT UPPER	AMERICAN METER	AXIAL 600#	8	992	Fails to Control Set Pressure	Seat / Disc
RIVERS PGS	meter pressure low caution alarm		UnSched	03-09-2010	GS-117	East Run	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
KINVER RS	1805 weapping		Stn Insp	29-10-2010	RS-046	Relief	FISHER	1805			Fails to Control Set Pressure	Seat / Disc
BRANDON #2	Regulator fails to lockup	No Initiating Event	UnSched	03-11-2010	GS-125	2nd Cut Lower	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	
TRANSCONA GS-003	adjust base pressures			15-11-2010	GS-003	Worker Center	FISHER	399 EZR			Fails to Control Set Pressure	
MOORE PARK PGS	MOORE PARK OUTLET PRESSURE UP TO 403 PSIG	Through Fault	UnSched	02-12-2010	GS-119	WorkerN	FISHER	399 EZR			Fails to Control Set Pressure	Seat / Disc
CARBERRY PGS	meter outlet presssure in hihi alarm	Environmental Contamina	Call Out	08-12-2010	GS-127	W.Run	AMERICAN METER	AXIAL 600#	5.5	682	Fails to Control Set Pressure	Pilot
BRANDON PGS	station outlet in lolo alarm	Environmental Contamina	Call Out	10-12-2010	GS-123	North	AMERICAN METER	AXIAL 600#	18.75	2325	Fails to Control Set Pressure	Pilot
OAK BLUFF PGS	Fails control	Environmental Contamina	UnSched	10-12-2010	GS-030	North Run	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram

STONEWALL GS	erractic pressure from Stonewall feed to Warren inlet	Weather (except lightnin	Call Out	12-12-2010	GS-010	Warren Takeoff	MOONEY	FG-28 - 2" - 600SWE	5.5	682	Fails to Control Set Pressure	Pilot
NEEPAWA PGS	station outlet in lolo alarm	Environmental Contamina	Call Out	14-12-2010	GS-121	1st Cut W Up	FISHER	399 EZR	6.75	837	Fails to Control Set Pressure	Pilot
IDC TR PK RS	Regulator may have had water enter body, check operatrion	Weather (except lightnin	Stn Insp	25-01-2011	RS-037	Regulator	FISHER	621			Fails to Control Set Pressure	Diaphram
OAK BLUFF PGS	Oakbluff	Environmental Contamina	Call Out	27-01-2011	GS-030	South Run	FISHER	399 EZR	1.5	186	Fails to Control Set Pressure	Seat / Disc
HEWITSON GS	GSO reports multiple pressure alarms	Environmental Contamina	UnSched	28-01-2011	GS-040	Worker E. Run	MOONEY	FG-62 - 3" - 600# BUTT WE			Fails to Control Set Pressure	Pilot
ST. ADOLPHE GS	Service staff reported lag pilot iced up		UnSched	28-01-2011	GS-026	LOWER-E.-WORK	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Pilot
BINSCARTH GS	outlet pressure in/out lolo alarm numerous times	Environmental Contamina	UnSched	01-02-2011	GS-102	2nd Cut Upper	FISHER	627M			Fails to Control Set Pressure	Orfice
ST. LAZARE GS	check operation outlet in lolo alarm	Environmental Contamina	UnSched	01-02-2011	GS-101	2nd Cut Lower	FISHER	627M			Fails to Control Set Pressure	Orfice
ILE DES CHENES PGS	leak	Through Fault	Stn Insp	25-02-2011	GS-017	South Monitor	WELKER	JET			Fails to Control Set Pressure	Pilot
WILKES & COMM RS	Pilot frozen	Environmental Contamina	Stn Insp	14-03-2011	RS-021	Monitor	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
MORDEN GS	Regulator run reported frosted up	Environmental Contamina	Stn Insp	13-04-2011	GS-139	2nd Cut South	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Pilot
LANDMARK 2 PGS	LOW OUTLET PRESSURE	Overloading	UnSched	26-04-2011	GS-018	E.Worker E Selk	FISHER	399 EZR	3.5	434	Fails to Control Set Pressure	
ILE DES CHENES PGS	Pilot - small leak in diaphagm	No Initiating Event	UnSched	28-04-2011	GS-017	South Worker	WELKER	JET			Fails to Control Set Pressure	Pilot
BLUMENORT GS	Pilot regulator is hunting, unable to maintain stable pressure	No Initiating Event	Functional	14-06-2011	GS-157-PR01	1ST CUT UPPER	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Pilot
CARBERRY MIDWEST GS	Would not seat after testing	Environmental Contamina	Functional	22-06-2011	GS-189	FT Relief	FISHER	1805			Fails to Control Set Pressure	Diaphram
HUSKY GS	Failed functional test	Foreign Interference	Functional	27-06-2011	GS-205	Upper	FISHER	399 EZR			Fails to Control Set Pressure	Seat / Disc
TRANSCONA GS-003	Reg failed.	Foreign Interference	UnSched	05-07-2011	GS-003	MonitorN.	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
NIVERVILLE PGS	outlet pressure in lolo alarm	No Initiating Event	Call Out	08-07-2011	GS-150	2ND CUT LOWER	MOONEY	FG-4 - 2" - 300# RF	4.5	612	Fails to Control Set Pressure	Pilot
HARMS ROAD GS	Fails to control pressure	No Initiating Event	Functional	26-07-2011	GS-184	UPPER MONITOR	FISHER	399 EZR			Fails to Control Set Pressure	Orfice
BRANDON TURBINE GS	Outlet pressure in High alarm	Overloading	Call Out	18-10-2011	GS-192	N.Upper	GROVE	900TE	3	408	Fails to Control Set Pressure	
MCAULEY PGS	LOW INLET PRESS	System Disturbance	Call Out	24-10-2011	GS-100	SW 6-15-29W	MOONEY	600#	4	536	Fails to Control Set Pressure	Seat / Disc
STE. ANNE PGS	Pressure in Lag run	No Initiating Event	Functional	30-10-2011	GS-159-PR01	Upper	MOONEY	FG-31 - 2" - 600# RF			Fails to Control Set Pressure	Seat / Disc
LA SALLE PGS	south run not contoling	System Disturbance	Functional	10-11-2011	GS-015	SOUTH	FISHER	399 EZR			Fails to Control Set Pressure	Seat / Disc
MORDEN GS	Goes to low alarm under morning load	System Disturbance	Functional	17-11-2011	GS-139	1st Cut North	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Seat / Disc
CRYSTAL SPRINGS RS	No isolation valve	Human / Process Error	Stn Insp	22-11-2011	RS-125	Relief	FISHER	1805			Fails to Control Set Pressure	
BRANDON TURBINE GS	Valve would not stroke.	Weather (except lightnin	Detld Insp	13-12-2011	GS-192	S.Run Worker	BECKER	488F6WTO-SR-PD	15	1860	Fails to Control Set Pressure	Seat / Disc
PINELAND PGS	inspect gas detech alarm	No Initiating Event	Call Out	13-01-2012	GS-177	1ST CUT WORK UP	FISHER	627H			Fails to Control Set Pressure	Diaphram
MACGREGOR GS	Over Pressure	System Disturbance	Detld Insp	19-01-2012	GS-131	2nd Cut Lower	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Pilot
PINELAND PGS	Leaking past diaphragm	Weather (except lightnin	Call Out	20-01-2012	GS-177	1ST CUT MON UP	FISHER	627HM	5	670	Fails to Control Set Pressure	Diaphram
MINIOTA PGS	Hi Pressure on first cut	Environmental Contamina	UnSched	26-01-2012	GS-111	1st Cut Upper	AMERICAN METER	AXIAL 600#	9.75	1306.5	Fails to Control Set Pressure	Seat / Disc
ALTONA GS	Pilot regulator is venting gas, can smell in building	No Initiating Event	Stn Insp	19-03-2012	GS-143	1st Cut W Up	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
MISSION & PANET	Pilot power gas supply needs ball valve installed	No Initiating Event	Stn Insp	26-03-2012	RS-007	WORKER	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
ST. ADOLPHE GS	Pressure High	No Initiating Event	Call Out	11-04-2012	GS-026	UPPER-E.-WORK	MOONEY		2	268	Fails to Control Set Pressure	Pilot
OAK BLUFF GS	not controlling outlet pressure	Through Fault	Call Out	18-04-2012	GS-032	2nd Cut Lower	AMERICAN METER	AXIAL 300#	20.5	2747	Fails to Control Set Pressure	Pilot
ST. MALO PGS	REG SPEWING GAS	System Disturbance	Call Out	12-06-2012	GS-167	1ST WORKER LO	FISHER	627H	7.5	855	Fails to Control Set Pressure	Diaphram
ALTONA GS	Pilot regulator is venting gas (small amount)	No Initiating Event	Stn Insp	02-07-2012	GS-143	1st Cut M Up	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
GRUNTHAL GS	leak on lag run distribution regulator	Through Fault	Call Out	11-07-2012	GS-155	1st Cut Upper	MOONEY	FG-28 - 2" - 600SWE			Fails to Control Set Pressure	Pilot
HUSKY GS	Reg did not maintain steady outlet pressure	System Disturbance	Call Out	20-07-2012	GS-205	Upper	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
PORTAGE N. RIVER GS	fails to control	Foreign Interference	Stn Insp	09-08-2012	GS-135	2nd-Cut-Upper-Monito	FISHER	399 EZR			Fails to Control Set Pressure	Seat / Disc
STARBUCK PGS	627 venting valved off.	No Initiating Event	Call Out	23-08-2012	GS-165	1st Cut M Upper	FISHER	627HM	2	228	Fails to Control Set Pressure	Diaphram
EAST SELKIRK GS	2nd cut lead reg will not lock-up	Through Fault	Stn Insp	12-09-2012	GS-011	S. Run 2nd Cut	FISHER	630	3	342	Fails to Control Set Pressure	Seat / Disc
STONY MOUNTAIN GS	Regulator Hunting	Through Fault	Functional	19-09-2012	GS-009	2nd Cut N.Run	AMERICAN METER	AXIAL 300#			Fails to Control Set Pressure	Seat / Disc
STARBUCK PGS	damaged bonnet	Foreign Interference	Stn Insp	24-09-2012	GS-165	2nd Cut W Upper	FISHER	627H			Fails to Control Set Pressure	Cage
STARBUCK PGS	inspect gas detect alarm	No Initiating Event	Call Out	02-10-2012	GS-165	Relief	MOONEY	FG-31 - 2" - 600# RF			Fails to Control Set Pressure	Diaphram
ELIE GS	outlet pressure in hihi alarm	Foreign Interference	Call Out	03-10-2012	GS-164	2nd Cut W Up	FISHER	399 EZR	7.25	826.5	Fails to Control Set Pressure	Seat / Disc
WINKLER GS	Reg Fails to Control	Environmental Contamina	UnSched	25-10-2012	GS-140	2nd Cut W Upper	FISHER	399 EZR	11.5	1311	Fails to Control Set Pressure	Pilot
LA SALLE PGS	Pressure Dropped and Pilot is unresponsive	Human / Process Error	UnSched	25-10-2012	GS-015	SOUTH	FISHER	399 EZR	2	228	Fails to Control Set Pressure	Pilot
LA SALLE PGS	Regs dipped 20lbs.	System Disturbance	UnSched	14-11-2012	GS-015	CENTER	FISHER	399 EZR				
LA SALLE PGS	Regs dipped 20lbs.	System Disturbance	UnSched	14-11-2012	GS-015	CENTER	FISHER	399 EZR			Fails to Control Set Pressure	Diaphram
PORTAGE PGS	Regs going into low alarm	Foreign Interference	UnSched	28-11-2012	GS-132	North Run	AMERICAN METER	AXIAL 600#			Fails to Control Set Pressure	Seat / Disc
STONEWALL GS	Reg pressure went high	Environmental Contamina	UnSched	30-11-2012	GS-010	Warren Takeoff	MOONEY	FG-28 - 2" - 600SWE			Fails to Control Set Pressure	Diaphram
BRANDON MPL LEAF GS	Mercury at meter set going in and out of hi alarm	Foreign Interference	UnSched	05-12-2012	GS-191	W.Worker	MOONEY	FG-63 - 4" - 150-300# BUT			Fails to Control Set Pressure	Diaphram
ROSSER GS	High Pressure	No Initiating Event	Call Out	05-12-2012	GS-031	S.Run Worker	FISHER	399 EZR	7.5	1005	Fails to Control Set Pressure	Pilot
ROSSER GS	worker not contoling	Overloading	Call Out	05-12-2012	GS-031	S.Run Worker	FISHER	399 EZR	3	402	Fails to Control Set Pressure	Pilot
STE. AGATHE PGS	Pressure is going low	Weather (except lightnin	UnSched	20-12-2012	GS-180	1st Cut Work S.	MOONEY	FG-62 - 3" - 600# BUTT WE			Fails to Control Set Pressure	
STONEWALL GS	Pressure dipped into low alarm.	Weather (except lightnin	UnSched	07-01-2013	GS-010	Warren Takeoff	MOONEY	FG-28 - 2" - 600SWE	4.5	483	Fails to Control Set Pressure	Seat / Disc
LA SALLE PGS	Pressure going in to Hi alarm	Foreign Interference	UnSched	08-01-2013	GS-015	SOUTH	FISHER	399 EZR			Fails to Control Set Pressure	
ST. PIERRE PGS	Pilot frozen and off set point	No Initiating Event	UnSched	11-01-2013	GS-153	Worker Lower	FISHER	399 EZR			Fails to Control Set Pressure	Pilot
HEWITSON GS	Pressure going into low low alarm	Weather (except lightnin	UnSched	22-01-2013	GS-040	Worker E. Run	MOONEY	FG-62 - 3" - 600# BUTT WE			Fails to Control Set Pressure	Pilot
ST. MALO PGS	inspect lolo outlet alarm			22-01-2013	GS-167	2ND WORK LO	FISHER	627H			Fails to Control Set Pressure	Seat / Disc
BEAUSEJOUR GS	INTERMEDIATE PRESS HIGH	Environmental Contamina	UnSched		GS-014	Lower_W. Run	MOONEY	FG-28 - 2" - 600SWE			Fails to Control Set Pressure	Pilot
ST. ADOLPHE GS	Hi Intermediate Pressure	Foreign Interference	UnSched		GS-026	UPPER-E.-WORK	MOONEY		7.75	883.5	Fails to Control Set Pressure	
ILE DES CHENES GS	Reg doesn't have vent extension		UnSched		GS-016	2nd_cut upper	MOONEY	FG-30 - 2" - 300# RF			Fails to Control Set Pressure	Pilot

APPENDIX F

RISK ASSESSMENT TABLE

Table X.1 - Natural Gas Reducing Station - Risk Assessment

Based on: System Pressure Settings for 2011-12 Season

Reducing Station Information		Upstream Conditions		Downstream Conditions			Delta		Flow	Customer Count	Risk Factors Weighted 0 - 10																				
Station #	Station Name	Max Winter Pressure (psig)	Max Summer Pressure (psig)	System MOP (psig)	Winter Pressure (psig)	Summer Pressure (psig)	Δ P Winter (psi)	Δ P Summer (psi)	Design Day Load (mcfh)	Approx. Number of Customers	Response Time	Design Day Load Risk	Number of customers risk	Previous Frost Heave or Severe External Icing	Previous Hydrate Formation	Backfed or loaner	Lubricated plug valves upstream of pilots	single cut or double cut	Filter or Strainer	Make/ Model of Regulator	Regulator Configuration	J-T Effect	Line Heater	Pilot Gas Heater	Insulation	Allowance for Flexibility in Piping Design	*Dew Point / Water Content	Station By-pass	Inhibitor Injection	Ambient Temperature	Average Risk Rating (whereas 10 is maximum)
GS-102	**Binscarth**	880	500	60	40	40	840	460	12	86	0	0	2	2	10	10	0	5	10	5	2	10	10	10	0	0	0	0	10	5	4.6
GS-103	**Russell**	880	500	950	440	350	440	150	525	4,233	0	5	7	10	10	10	10	5	10	10	8	6	10	10	10	10	0	0	10	5	7.3
GS-017	**Ile Des Chenes**	880	880	700	550	350	330	530	7659	87,104	0	10	10	5	0	10	0	10	10	0	5	9	10	10	5	5	0	0	10	5	5.7
GS-150	**Niverville Primary - Town**	880	880	60	55	40	825	840	62	705	0	1	5	10	10	10	10	5	0	10	8	10	10	0	10	10	10	0	10	5	6.7
GS-165	**Starbuck - Town**	880	880	80	50	40	830	840	9	85	0	0	2	5	10	10	0	5	0	5	2	10	10	10	10	0	0	0	10	5	4.7

NB: Each risk factor is considered equally weighted and rated on a scale of 1 to 10 with 10 being the highest risk.
*** These risk factors vary between 1 and 10 based on historical minimum and Tariff maximums.**

Risk Assessment Weighting Factors - Refer to Word Document for Explanations
Response Time - has SCADA and within 1 hour of service center 0 pts., no SCADA but within 1 hour of service center 5 pts.,no SCADA and more than 1 hour from service center 10 pts.
Design Day Load - less than 50 mcfh 0 pts, 50 - 100 mcfh 1 pts, 100-250 mcfh 2 pts, 250 - 1000 mcfh 5 pts, over 1000 mcfh 10 pts
Number of Customers - less than 20 zero pts, 20 - 50 customers 1 pt., 50 - 100 customers 2 pts., 100 - 500 customers 3 pts, 500 -1000 customers 5 pts, 1000-5000 customers 7 points, over 10,000 customers 10 points
Previous Frost Heave or Severe External Icing - neither 0 points, minor icing 2 points, major icing 5 points, minor frost heaving 7 points, major frost heaving 10 points
Previous Hydrate Formation - no hydrates 0 points, previous hydrates 10 points
Backfed or loaner - station part of a grid backfed by other stations 0 points, not backfed 10 points
Lubricated plug valves upstream of regulators - no lubricated plug valves 0 points, plug valves and self operated regulators 5 points, plug valves and pilot operated regulators 10 points
Single Cut or Double Cut - Double cut 5 points, single cut 10 points
Filter or Strainer - filter 0 points, strainer 5 points, no filter or strainer 10 points
Make/ Model of Regulator - control valves 0 points, self operated regulators 5 points, pilot operated regulators 10 points
Regulator Configuration - main/monitor with redundant run andfull relief 0 pts., main/monitor with redundant run and token relief 2 points, main/monitor with redundant run and no relief 5 points, single regulator with back up run and full relief 8 points, single regulator with no back up run 10 points
Joule Thompson Effect - ΔP less than 100 psig 0 points, ΔP 100 psig to 300 psig, ΔP 300 psig to 500 psig 6 points, ΔP 500 psig to 800 psig 9 points, ΔP over 800 psig 10 points
Line Heater - yes 0 points, no 10 points
Pilot Heater - yes 0 points, no10 points
Insullation - all above grade upstream of regs 0 points, partial 5 points, none 10 points
Allowance for Flexibility in Pipe design - yes = 0 pts, no with no history of icing 5 pts, no with history of icing 10 pts
Dew Point / Water Content - water vapour less than 16 g/m3 = 0 pts, 16 g - 32 g = 5 pts, over 32 g = 10 pts
Station By-pass - yes 0 pts, no 10 pts
Inhibitor Injection - methanol injected 0 points, no injection 10 points
Ambient Temperature Regulators in heated building 0 points, regulators in unheated building 5 points, regulators outside 10 points

APPENDIX G

SOS AGA AND CGA

AGA SOS Summary: Regulator Station - Equipment Reliability Concerns Due to Internal/External Ice Formation

February 2011

AGA Contact: Ali Quraishi, aquraishi@aga.org

Notice: Survey responses are based on an informal survey and are for general information only. They are not intended to bind any company or state a company's official position. The information represents an unaudited compilation of information and could contain coding or processing errors.

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Your company name:	Alagasco	Central Hudson Gas & Electric Corp.	Colorado Springs Utilities	Columbia Gas of Ohio	Consolidated Edison of New York	Consumers Energy	DTE Energy / MichCon Gas Company
Company contact:	Randy Wilson	Tara Stoner	Mark Connolly	Keith Smith	Len Toscano	Regis Klingler	Erick T. Doke, manager
Telephone:	205-326-2987	845-486-5464	(719) 668-3633	614-460-6308	718-579-1247	517-788-5898	989-365-5120
Email:	randy.wilson@energen.com	tstoner@cenhud.com	Mconnolly @csu.org	rksmith@nisource.com	toscanol@coned.com	rpklingler@cmsenergy.com	dokee@dteenergy.com
Question	*Response*	*Response*	*Response*	*Response*	*Response*	*Response*	*Response*
1. Has your utility experienced ice or frost formation on/in station equipment and/or piping caused by the pressure reduction process at gate stations?	Yes	Yes	no	Yes	Only when pipeline heaters are not operational	Yes we have ice and hydrate formation primarily in regulator pilots, regulators, filter-seps and piots for relief valves and control valves.	Yes
2. Does your company heat the pipeline gas at gate stations?	No. Suppliers heat the gas at some stations and own the heating equipment.	Yes, at three of our four gate stations	no	Yes at some of them	Yes. Target temperature entering our system is 50 deg F, at 300 psig.	Yes, we heat the gas at almost all city gates. We use line heaters and catalytic heaters on pilots for regulators and other ccrtical control equipment.	Yes
3. If the answer is yes to question 2. What are the benefits?		No frost heaving. Heated gas for large size equipment and some instrumentation.	n/a	Reducing chance of freeze off due to liquids falling out at pressure reduction points. Eliminate heaving of pipe below ground due to frost build up on outlet piping. Eliminate freeze off of supply lines to pilot type regultors to avoid over pressure situations.	Key focus is on pipeline protection and transitional temperature of pipeline steel. (Charpy factor) Also, mitigation of ice buildup supports emergency and full time access to pressure regulating equipment. Ice build up within manholes is minimized since direct contact to ground water infiltration and accumulation does occur. Warm pipeline gas helps mitigate ice blocks from forming.	Prevent hydrate formation in the equipment listed above which prevents loss of pressure control, overpressure protection, loss of gas flow and prevents ground heaving due to frost formation in the ground.	Reduce freeze offs on gas piping and on the pilots, monitors and regulators.
4. If your company does not use line heaters do you use pressure regulator body heaters, pilot supply tubing heaters, etc.?	Low temperature boots.	Yes, pilot heaters are used.	no	We use line heaters, Body heaters and Pilot supply heaters.	Both indirect contact and pumped water bath heat exchangers	We use line heaters and catalytic heaters on pilots for regulators and other ccrtical control equipment.	Yes
5. Does your company use other methods to mitigate the possibility of pressure regulator freeze-offs?		Filters are used.	We heat the high pressure regulators that go to the odorizers	Also waterbath heaters and Vortex type heaters on Large POD townborder stations.	Not our company. Some gate station sites, not managed by our company, but serving us does incorporate small catalytic style pilot heaters for select applications.	We use filter-seps and dehydrators at storage field withdrawal locations to try to prevent or limit the amount of water, salt, scale and HC liquids from entering the gas system. We monitor key supply locations with gas chromatographs and water monitors to enforce gas quality limits.	In line heaters
6. What is the maximum water content in the gas you receive from your suppliers?	7 lbs/1 MMcf	Currently not measuring water content.	n/a	The maximum we should receive is 5PPM. However we have had local production settings exceed the permissable limit and were shut off until a dyhydrator was installed.	Unknown	The water limit is 7 lbs/MMcf of water in the gas. Most suppliers are routinely less than 5 lbs/MMcf.	Seven pounds per mcf

AGA SOS Summary: Regulator Station - Equipment Reliability Concerns Due to Internal/External Ice Formation

February 2011

AGA Contact: Ali Quraishi, aquraishi@aga.org

Your company name:	Elizabethtown Gas, Elizabeth NJ	Equitable Gas Company	Gaz Metro	Memphis Light, Gas & Water	New Jersey Natural Gas	Nicor Gas	NMGC
Company contact:	Dan O'Donnell	Michael Gavin	Sylvain Coulombe	Brent Haywood	John Wyckoff	David Turk	Peter Ford
Telephone:	908-558-3507	412 670 0739	(514) 719-8145	901-320-1401	732-938-7864	(815)272-2583	5056973510
Email:	dodonnel@aglresources.com	gavinm@eqt.com	scoulombe@gazmetro.com	Bhaywood@mlgw.org	jbwyckoff@njng.com	dturk@nicor.com	Peter.Ford@nmgco.com
Question	*Response*	*Response*	*Response*	*Response*	*Response*	*Response*	*Response*
1. Has your utility experienced ice or frost formation on/in station equipment and/or piping caused by the pressure reduction process at gate stations?	On occasion	Yes - we have experienced ice build up on the exterior piping of our regulator stations.	yes	Yes	Yes	No.	Yes, typically on piping downstream of the pilot and main body regulator
2. Does your company heat the pipeline gas at gate stations?	Yes	Yes, but not all stations	yes	No	Yes, typically at stations w/ pressure drop >300#.	Yes. Depending on heat requirement calculations pipeline heaters are installed on gate stations, as necessary.	No
3. If the answer is yes to question 2. What are the benefits?	Protection of equipment, we also utilize Bruest pilot heaters.	Prevent freeze offs in the internal operations of the Regulator and moisture dropout.	Prevention of ice/frost formation which could cause malfunction of regulators		Eliminates ice buildup around outside of regulators and control piping, which can prohibit maintenance access or result in equipment failure. Can also result in freezing / thawing of ground downstream of the station, damaging roads and other utilities.	Minimize risk of freeze-up especially the risk of forming hydrates, or potentially picking up hydrates from source supply. For Stations that have piping going out and across a road the heat will mitigate frost heaving of the road.	N/A
4. If your company does not use line heaters do you use pressure regulator body heaters, pilot supply tubing heaters, etc.?		Yes - we have catalytic pilot heaters at all custody locations and regulator body heaters at a couple of locations.		No	No. Solely use line heaters (indirect water bath & catalytic), but tried catalytic pilot heaters at one time.	All stations are equipped with catalytic-type heaters on regulator instrumentation regardless of whether or not they have an upstream pipeline heater.	In some cases we use heaters on the pilot supply gas, we have also had great success with large filters on the supply gas that allow any liquids to brought out.
5. Does your company use other methods to mitigate the possibility of pressure regulator freeze-offs?	Not at ETG	Yes - We use coalescent filters on the inlet, and pilot filters at all locations	In a few regulator stations we have had good success with Vortex pilot gas heaters. See www.universal-vortex.com	No	No	No.	We wactch our gas quality spec and data very close to minimize the risk of recieveing gas that can lead to these types of issues.
6. What is the maximum water content in the gas you receive from your suppliers?	Unknow it fluctuates; depending on flow status.	7 PPM	According to contract: 4 lb/MMSCF, but usually less than 1 lb/MMSCF	7 pounds per MMCF is our acceptable limit	No max limit set. Last analysis range = 0.88 - 6.22 lbs H2O/MMCF	Typically 7 lbs per MMCF	7 ld/mmscf

AGA SOS Summary: Regulator Station - Equipment Reliability Concerns Due to Internal/External Ice Formation

February 2011

AGA Contact: Ali Quraishi, aquraishi@aga.org

Your company name:	Pacific Northern Gas Ltd.	Peoples Natural Gas Company	Piedmont Natural Gas	Public Service Electric & Gas Co.	Questar Gas Company	SEMCO Energy Gas Company	South Jersey Gas
Company contact:	Tony Harmel	Randy R. Ciotola	Benjamin Davis	Jack Zerega	Bryan Niebergall	Robert McPherson	Jeff Langley
Telephone:	250-638-5320	412-244-2535	704-731-4438	1-973-430-5134	801-324-3419	810-887-4746	609-561-9000
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Question	*Response*	*Response*	*Response*	*Response*	*Response*	*Response*	*Response*
1. Has your utility experienced ice or frost formation on/in station equipment and/or piping caused by the pressure reduction process at gate stations?	Yes	Yes it has	yes	Yes	Yes	Typical not at gate station. It is present at district reg stations, primarily those without catholitic or line heaters on location.	Yes
2. Does your company heat the pipeline gas at gate stations?	Yes	Yes we do in some cases where it is necessary	yes. But not at all stations. Only those that are iced due to the pressure cut	Yes	Yes, at some of them	Yes	Yes
3. If the answer is yes to question 2. What are the benefits?	Less frost and condensation. Regulators operate better	The benefits are more reliability in regards to the equipment, and less moisture issues. There is also a reduction in ground or roadway heaving from icing or frost.	better regulator performance. Less maintenance in the long run	Prevents equipment and pipe stress due to frost heave, eliminates control problems caused by liquid condensation in sensing lines and pilot vent blockages, eliminates freezing of water lines in close prximoty, reduces wear and tear on pipe coating,	more reliable pressure regulation	Prevention of regulator and pipeline components freeze offs.	Reduced ice formations.
4. If your company does not use line heaters do you use pressure regulator body heaters, pilot supply tubing heaters, etc.?	Cat heaters for some application	We use line heaters where applicable. We also use catalytic regulator body heaters and catalytic pilot supply tubing heaters.		Yes, these are used too.	If the station does not have a line heater, we often use pilot gas heaters	Yes. We use a variety of components.	Yes. Pilot supply tubing heaters
5. Does your company use other methods to mitigate the possibility of pressure regulator freeze-offs?	Cat heaters for some application	We also use insulation wraps where needed in conjunction with the heaters or in some cases without the heaters where wind chill causes problems. Buildings are also used to house regulation equipment. Some insulated buildings with catalytic wall heaters installed some unheated just for wind chill issues.	no	Currently no other method is used.	not currently, but have use methanol injection in the past	Yes. Installing upstream filters and or drips to prevent regulator problems.	No
6. What is the maximum water content in the gas you receive from your suppliers?	< 4 lbs per million cubic Ft.	7# per million	this information is unavailable	Tariff limit is 7 pounds per million cubic feet	Tariff is 5 lbs/MMCF	Our tariff states we are not to receive more than 7 lbs/MMCF gas delivered.	7lbs. Per million cubic feet

AGA SOS Summary: Regulator Station - Equipment Reliability Concerns Due to Internal/External Ice Formation

February 2011

AGA Contact: Ali Quraishi, aquraishi@aga.org

Your company name:	Southern California Gas Company	Southwest Gas Corporation	Valley Energy, Inc	Washington Gas	We Energies	Manitoba Hydro
Company contact:	Mike Bermel	Steve Frehse	Steve Hurd	Bonnie Deaton	Jim Gruennert	Axel Thiem
Telephone:	(213)244-5331	702-364-3142	570-888-9664 (234)	703-750-4556	414 389-4333	204-360-5917
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Question	*Response*	*Response*	*Response*	*Response*	*Response*	*Response*
1. Has your utility experienced ice or frost formation on/in station equipment and/or piping caused by the pressure reduction process at gate stations?	Yes, there have been incidents of freezing on/in regulator stations due to large pressure reductions.	Yes	yes	We have experienced ice or frost when there is a malfunction of our heating equipment and it may also occur depending on the amount versus pounds of pressure reduction.	Yes	Yes
2. Does your company heat the pipeline gas at gate stations?	Not a general practice to heat the pipeline gas. Have one regulator station where hot water boilers and heat exchangers are used to heat the pipeline gas.	No	yes	We use indirect line heaters to heat the gas at gate stations.	Yes	We have three line heaters.
3. If the answer is yes to question 2. What are the benefits?	In the one station where the pipeline gas is heated, icing within the regulators is avoided.		system reliability	We are able to keep our equipment from freezing and our station outlet gas temperature above freezing temperatures.	Assists with maintaining a reliable operation of regulation as well as the ability to work on the regulators if maintenance work needs to occur.	Prevent frost heave and reg freeze offs.
4. If your company does not use line heaters do you use pressure regulator body heaters, pilot supply tubing heaters, etc.?	Pilot supply is often heated with catalytic heaters to avoid freezing in the pilot regulator.	We have used these especially when moisture levels are elevated due to hydrotest upstream. Also where we have delived temporary CNG awaiting pipeline installation.	no	We use pilot supply tubing heaters for all supply gas that runs our equipment along with line heaters.	Yes	Yes, vortex heaters and catalytic heaters.
5. Does your company use other methods to mitigate the possibility of pressure regulator freeze-offs?	Staging the pressure reduction has helped to avoid freezing.	Move below ground stations above ground due to less moisture in the air than the ground at some locations, also where there is ground water.	no	We also use vortex heaters on some of our pilot regulator applications.	On limited basis we have taken two pressure cuts to reduce the temperature drop through the regualtion.	We have used methanol drip and minimize pressure reduction at stations where possible.
6. What is the maximum water content in the gas you receive from your suppliers?	Our Rules of operation - Moisture Content or Water Content: For gas delivered at or below a pressure of eight hundred (800) psig, the gas shall have a water content not in excess of seven (7) pounds per million standard cubic feet. For gas delivered at a pressure exceeding of eight hundred (800) psig, the gas shall have a water dew point not exceeding 20 degrees F at delivery pressure.	7 lbs per MCF	7# per MMcf	The water content varies based on supplier and where the gas is being produced.	We do not measure.	4lbs/mmcf or 65 mg/1000m^3

CGA Members

Your company name:	AltaGas Utilities Ltd	ATCO Gas	Enbridge Gas Distribution	Heritage Gas	SaskEnergy	Manitoba Hydro
Company contact:	Dennis Saby	Ron Moisey	Randy Wilton	Chris MacAulay	Rick Schafer	Axel Thiem
Telephone:	780-675-2652	403-357-5233	416 495 5409	(902) 466-1678	306 975-8550	204-360-5917
Email:	dsaby@agutl.com	ron.moisey@atcogas.com	randy.wilton@enbridge.com	cmacaulay@heritagegas.com	rschafer@saskenergy.com	athiem@hydro.mb.ca
1. Has your utility experienced ice or frost formation on/in station equipment and/or piping caused by the pressure reduction process at gate stations?	Yes	Yes	Yes	Yes	Yes we have experienced frost formation on/in station piping/regulator equipment and have lost flow through the station as the result.	Yes
2. Does your company heat the pipeline gas at gate stations?	Yes - not all Stations	Yes	Yes	Yes - using indirect line heaters (Type - GRIT - Coldweather Technologies)	Yes we preheat our gas prior to pressure reduction at most stations where we are reducing transmission pressure (275 - 1,250 psi) to distribution pressure (20 psi - 100 psi) .	We have three line heaters. (Th e three heaters are at stations in the City of Wpg where transmission pressure is reduced to High Pressure)
3. If the answer is yes to question 2. What are the benefits?	No freez-offs/icing	Prevents ice cristals from forming due to poor gas quality causing regulator orifices to freeze up and eventualy loss of gas pressure down stream.	Performance, Municipal (Frost Heaving roads and sidewalks) Reduced maintenance	keeping ice and frost buildup off station piping allows for easier operation and maintenance	1. Reduce the risk of losing flow through the station. 2. Reduce the amount of ice build up on the outside of pressure piping equipment which is a operation and safety hazard. 3. Helps to reduce the amount of stress on underground piping leaving the gate stations caused by frost heaving.	Prevent frost heave and reg freeze offs.
4. If your company does not use line heaters do you use pressure regulator body heaters, pilot supply tubing heaters, etc.?	Line heaters/heating of pilot supply tubing	Yes	Yes - All components	-	We do use line heaters and have nearly 400 in our system. For the smaller stations that don't require line heaters we don't use regulator body heaters if I understand what this is correctly, however we use catalytic heaters that radiate heat onto the outside portion of the body of the pressure regulators. We also preheat piping/heat exchangers with catalytic heaters just ahead of the pressure regulators. For heating pilot gas we use both freeze fighters (catalytic heaters that radiate heat onto pilot gas tubing) and at other stations we have installed Vortex heaters which do not require any fuel usage and can heat the pilot gas to 90F. Web site attached. http://www.universal-vortex.com/	Yes, vortex heaters and catalytic heaters.
5. Does your company use other methods to mitigate the possibility of pressure regulator freeze-offs?	Methonal injection	Line heaters (several types), catalytic heaters (regulator body heaters) and Frost Fighters (pilot Supply heater) are the primary methodes we use to prevent freeze offs.	Full Boiler, Heat exchanger Glycol / Water mixture systems	In new construction areas, pipelines are dried after testing using a desiccant pipeline drier.	We have in the past used methanol drips. We are also engaged in developing small heat exchangers to allow better heat transfer into the gas utilizing catalytic heaters as the pre heating source.	We have used methanol drip and minimize pressure reduction at stations where possible.
6. What is the maximum water content in the gas you receive from your suppliers?	4lbs water max per mmcf	The maximum water content in our area is 4 lbs water/million cubic feet of gas.	57mg / m3	Tariff regulations on Maritimes & Northeast Pipeline (our supplier) requires less than 80 mg water vapour per cubic metre of gas.	4 lbs water per million standard cubic feet of gas	4lbs/mmcf or 65 mg/1000m^3

AGA Members

Your company name:	Alagasco	Central Hudson Gas & Electric Corp.	Colorado Springs Utilities	Columbia Gas of Ohio	Consolidated Edison of New York	Consumers Energy	DTE Energy / MichCon Gas Company Division	Elizabethtown Gas, Elizabeth NJ
Company contact:	Randy Wilson	Tara Stoner	Mark Connolly	Keith Smith	Len Toscano	Regis Klingler	Erick T. Doke, manager	Dan O'Donnell
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Email:	randy.wilson@energen.com	tstoner@cenhud.com	Mconnolly @csu.org	rksmith@nisource.com	toscanol@coned.com	rpklingler@cmsenergy.com	dokee@dteenergy.com	dodonnel@aglresources.com
1. Has your utility experienced ice or frost formation on/in station equipment and/or piping caused by the pressure reduction process at gate stations?	Yes	Yes	no	Yes	Only when pipeline heaters are not operational	Yes we have ice and hydrate formation primarily in regulator pilots, regulators, filter-seps and piots for relief valves and control valves.	Yes	On occasion
2. Does your company heat the pipeline gas at gate stations?	No. Suppliers heat the gas at some stations and own the heating equipment.	Yes, at three of our four gate stations	no	Yes at some of them	Yes. Target temperature entering our system is 50 deg F, at 300 psig.	Yes, we heat the gas at almost all city gates. We use line heaters and catalytic heaters on pilots for regulators and other ccrtical control equipment.	Yes	Yes
3. If the answer is yes to question 2. What are the benefits?		No frost heaving. Heated gas for large size equipment and some instrumentation.	n/a	Reducing chance of freeze off due to liquids falling out at pressure reduction points. Eliminate heaving of pipe below ground due to frost build up on outlet piping. Eliminate freeze off of supply lines to pilot type regultors to avoid over pressure situations.	Key focus is on pipeline protection and transitional temperature of pipeline steel. (Charpy factor) Also, mitigation of ice buildup supports emergency and full time access to pressure regulating equipment. Ice build up within manholes is minimized since direct contact to ground water infiltration and accumulation does occur. Warm pipeline gas helps mitigate ice blocks from forming.	Prevent hydrate formation in the equipment listed above which prevents loss of pressure control, overpressure protection, loss of gas flow and prevents ground heaving due to frost formation in the ground.	Reduce freeze offs on gas piping and on the pilots, monitors and regulators.	Protection of equipment, we also utilize Bruest pilot heaters.
4. If your company does not use line heaters do you use pressure regulator body heaters, pilot supply tubing heaters, etc.?	Low temperature boots.	Yes, pilot heaters are used.	no	We use line heaters, Body heaters and Pilot supply heaters.	Both indirect contact and pumped water bath heat exchangers	We use line heaters and catalytic heaters on pilots for regulators and other ccrtical control equipment.	Yes	
5. Does your company use other methods to mitigate the possibility of pressure regulator freeze-offs?		Filters are used.	We heat the high pressure regulators that go to the odorizers	Also waterbath heaters and Vortex type heaters on Large POD townborder stations.	Not our company. Some gate station sites, not managed by our company, but serving us does incorporate small catalytic style pilot heaters for select applications.	We use filter-seps and dehydrators at storage field withdrawal locations to try to prevent or limit the amount of water, salt, scale and HC liquids from entering the gas system. We monitor key supply locations with gas chromatographs and water monitors to enforce gas quality limits.	In line heaters	Not at ETG
6. What is the maximum water content in the gas you receive from your suppliers?	7 lbs/1 MMcf	Currently not measuring water content.	n/a	The maximum we should receive is 5PPM. However we have had local production settings exceed the permissable limit and were shut off until a dyhydrator was installed.	Unknown	The water limit is 7 lbs/MMcf of water in the gas. Most suppliers are routinely less than 5 lbs/MMcf.	Seven pounds per mcf	Unknow it fluctuates; depending on flow status.

AGA Members

Your company name:	Equitable Gas Company	Gaz Metro	Memphis Light, Gas & Water	New Jersey Natural Gas	Nicor Gas	NMGC	Pacific Northern Gas Ltd.	Peoples Natural Gas Company
Company contact:	Michael Gavin	Sylvain Coulombe	Brent Haywood	John Wyckoff	David Turk	Peter Ford	Tony Harmel	Randy R. Ciotola
Telephone:	412 670 0739	(514) 719-8145	901-320-1401	732-938-7864	(815)272-2583	5056973510	250-638-5320	412-244-2535
Email:	gavinm@eqt.com	scoulombe@gazmetro.com	Bhaywood@mlgw.org	jbwyckoff@njng.com	dturk@nicor.com	Peter.Ford@nmgco.com	tharmel@png.ca	Randy.R.Ciotola@Peoples-Gas.com
1. Has your utility experienced ice or frost formation on/in station equipment and/or piping caused by the pressure reduction process at gate stations?	Yes - we have experienced ice build up on the exterior piping of our regulator stations.	yes	Yes	Yes	No.	Yes, typically on piping downstream of the pilot and main body regulator	Yes	Yes it has
2. Does your company heat the pipeline gas at gate stations?	Yes, but not all stations	yes	No	Yes, typically at stations w/ pressure drop >300#.	Yes. Depending on heat requirement calculations pipeline heaters are installed on gate stations, as necessary.	No	Yes	Yes we do in some cases where it is necessary
3. If the answer is yes to question 2. What are the benefits?	Prevent freeze offs in the internal operations of the Regulator and moisture dropout.	Prevention of ice/frost formation which could cause malfunction of regulators		Eliminates ice buildup around outside of regulators and control piping, which can prohibit maintenance access or result in equipment failure. Can also result in freezing / thawing of ground downstream of the station, damaging roads and other utilities.	Minimize risk of freeze-up especially the risk of forming hydrates, or potentially picking up hydrates from source supply. For Stations that have piping going out and across a road the heat will mitigate frost heaving of the road.	N/A	Less frost and condensation. Regulators operate better	The benefits are more reliability in regards to the equipment, and less moisture issues. There is also a reduction in ground or roadway heaving from icing or frost.
4. If your company does not use line heaters do you use pressure regulator body heaters, pilot supply tubing heaters, etc.?	Yes - we have catalytic pilot heaters at all custody locations and regulator body heaters at a couple of locations.		No	No. Solely use line heaters (indirect water bath & catalytic), but tried catalytic pilot heaters at one time.	All stations are equipped with catalytic-type heaters on regulator instrumentation regardless of whether or not they have an upstream pipeline heater.	In some cases we use heaters on the pilot supply gas, we have also had great success with large filters on the supply gas that allow any liquids to brought out.	Cat heaters for some application	We use line heaters where applicable. We also use catalytic regulator body heaters and catalytic pilot supply tubing heaters.
5. Does your company use other methods to mitigate the possibility of pressure regulator freeze-offs?	Yes - We use coalescent filters on the inlet, and pilot filters at all locations	In a few regulator stations we have had good success with Vortex pilot gas heaters. See www.universal-vortex.com	No	No	No.	We wactch our gas quality spec and data very close to minimize the risk of recieveing gas that can lead to these types of issues.	Cat heaters for some application	We also use insulation wraps where needed in conjunction with the heaters or in some cases without the heaters where wind chill causes problems. Buildings are also used to house regulation equipment. Some insulated buildings with catalytic wall heaters installed some unheated just for wind chill issues.
6. What is the maximum water content in the gas you receive from your suppliers?	7 PPM	According to contract: 4 lb/MMSCF, but usually less than 1 lb/MMSCF	7 pounds per MMCF is our acceptable limit	No max limit set. Last analysis range = 0.88 - 6.22 lbs H2O/MMCF	Typically 7 lbs per MMCF	7 ld/mmscf	< 4 lbs per million cubic Ft.	7# per million

AGA Members

Your company name:	Piedmont Natural Gas	Public Service Electric & Gas Co.	Questar Gas Company	SEMCO Energy Gas Company	South Jersey Gas	Southern California Gas Company	Southwest Gas Corporation	Valley Energy, Inc
Company contact:	Benjamin Davis	Jack Zerega	Bryan Niebergall	Robert McPherson	Jeff Langley	Mike Bermel	Steve Frehse	Steve Hurd
Telephone:	704-731-4438	1-973-430-5134	801-324-3419	810-887-4746	609-561-9000	(213)244-5331	702-364-3142	570-888-9664 (234)
Email:	benjamin.davis@piedmontng.com	jack.zerega@pseg.com	bryan.niebergall@questar.com	bob.mcpherson@semcoenergy.com	jlangley@sjindustries.com	MBermel@semprautilities.com	steve.frehse@swgas.com	steveh@ctenterprises.org
1. Has your utility experienced ice or frost formation on/in station equipment and/or piping caused by the pressure reduction process at gate stations?	yes	Yes	Yes	Typical not at gate station. It is present at district reg stations, primarily those without catholitic or line heaters on location.	Yes	Yes, there have been incidents of freezing on/in regulator stations due to large pressure reductions.	Yes	yes
2. Does your company heat the pipeline gas at gate stations?	yes. But not at all stations. Only those that are iced due to the pressure cut	Yes	Yes, at some of them	Yes	Yes	Not a general practice to heat the pipeline gas. Have one regulator station where hot water boilers and heat exchangers are used to heat the pipeline gas.	No	yes
3. If the answer is yes to question 2. What are the benefits?	better regulator performance. Less maintenance in the long run	Prevents equipment and pipe stress due to frost heave, eliminates control problems caused by liquid condensation in sensing lines and pilot vent blockages, eliminates freezing of water lines in close prximoty, reduces wear and tear on pipe coating,	more reliable pressure regulation	Prevention of regulator and pipeline components freeze offs.	Reduced ice formations.	In the one station where the pipeline gas is heated, icing within the regulators is avoided.		system reliability
4. If your company does not use line heaters do you use pressure regulator body heaters, pilot supply tubing heaters, etc.?		Yes, these are used too.	If the station does not have a line heater, we often use pilot gas heaters	Yes. We use a variety of components.	Yes. Pilot supply tubing heaters	Pilot supply is often heated with catalytic heaters to avoid freezing in the pilot regulator.	We have used these especially when moisture levels are elevated due to hydrotest upstream. Also where we have delived temporary CNG awaiting pipeline installation.	no
5. Does your company use other methods to mitigate the possibility of pressure regulator freeze-offs?	no	Currently no other method is used.	not currently, but have use methanol injection in the past	Yes. Installing upstream filters and or drips to prevent regulator problems.	No	Staging the pressure reduction has helped to avoid freezing.	Move below ground stations above ground due to less moisture in the air than the ground at some locations, also where there is ground water.	no
6. What is the maximum water content in the gas you receive from your suppliers?	this information is unavailable	Tarriff limit is 7 pounds per million cubic feet	Tariff is 5 lbs/MMCF	Our tariff states we are not to receive more than 7 lbs/MMCF gas delivered.	7lbs. Per million cubic feet	Our Rules of operation - Moisture Content or Water Content: For gas delivered at or below a pressure of eight hundred (800) psig, the gas shall have a water content not in excess of seven (7) pounds per million standard cubic feet. For gas delivered at a pressure exceeding of eight hundred (800) psig, the gas shall have a water dew point not exceeding 20 degrees F at delivery pressure.	7 lbs per MCF	7# per MMcf

AGA Members

Your company name:	Washington Gas	We Energies	
Company contact:	Bonnie Deaton	Jim Gruennert	
Telephone:	703-750-4556	414 389-4333	
Email:	bdeaton@washgas.com	jim.gruennert@we-energies.com	
1. Has your utility experienced ice or frost formation on/in station equipment and/or piping caused by the pressure reduction process at gate stations?	We have experienced ice or frost when there is a malfunction of our heating equipment and it may also occur depending on the amount versus pounds of pressure reduction.	Yes	
2. Does your company heat the pipeline gas at gate stations?	We use indirect line heaters to heat the gas at gate stations.	Yes	
3. If the answer is yes to question 2. What are the benefits?	We are able to keep our equipment from freezing and our station outlet gas temperature above freezing temperatures.	Assists with maintaining a reliable operation of regulation as well as the ability to work on the regulators if maintenance work needs to occur.	
4. If your company does not use line heaters do you use pressure regulator body heaters, pilot supply tubing heaters, etc.?	We use pilot supply tubing heaters for all supply gas that runs our equipment along with line heaters.	Yes	
5. Does your company use other methods to mitigate the possibility of pressure regulator freeze-offs?	We also use vortex heaters on some of our pilot regulator applications.	On limited basis we have taken two pressure cuts to reduce the temperature drop through the regualtion.	
6. What is the maximum water content in the gas you receive from your suppliers?	The water content varies based on supplier and where the gas is being produced.	We do not measure.	

Survery Summary: Pipeline Dust (Iron Oxide Particles)

Responses submitted by: December 13, 2011

AGA SOS Summary
Pipeline Dust
(Iron Oxide Particles)
December 19, 2011
AGA contact: Victoria Plotkin;
vplotkin@aga.org

Note: The survey responses are based on an informal survey and are for general information only. They are not intended to bind any company or state a company's official position. The information represents an unaudited compilation of information and could contain coding or processing errors. Anyone using this document should rely on his or her own independent judgment or, as appropriate, seek the advice of a competent professional. References to work practices, products or vendors do not imply an opinion or endorsement by AGA or a responding company. This publication is confidential and proprietary to AGA. AGA Full and Limited Members are granted a limited license to reproduce this publication for internal business purposes but not for regulatory or civil matters. The identity of individual respondents and their contact information is separately maintained by AGA and may be distributed to AGA Full and Limited members upon request.
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Company	Total/ Average	Company A	Company B	Company C	Company D	Company E	Company F	Company G	Company H	Company I	Company J	Company K	Company L	Company M	Company N	Company O	Company P
1. Are you finding pipeline dust (iron oxide particles) inside your distribution system (e.g. meter sets)?																	
Yes	19	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	
No	3			No							No						No
2. If you answered "Yes" to Question 1, please indicate where in your distribution system the pipeline dust (iron oxide) particles were found:		We discovered dust particles in one of our larger industrial customer meter stations. (Rotary meter)This appears to be the first incident we have had overall. This particular customer was located at the end of a long gas main near the outer borders of our system. we have not seen this issue showing up at other locations.	PRS and customer regulators.		We have had two instances at stations where pipeline dust was found. Both were isolated instances - one in 1999 and the other in 2005	Pilot filters on certain District Regulator Stations	meter sets, regulators, filters	Bottom of the pipleline	Large meter installations, generally new sites at start-up	Pipeline Dust was found in: -District Stations after inline inspection activities -Distribution Piping		In filters and on orifice plates	Isolated areas of the distribution system in mains, services and filters/meter sets	Generally in dumping station. District regulator station	Usually in regulator station strainers/filters	Walls of Regulators bodies, and piping	
3. Are you finding pipeline dust (iron oxide) particles collecting in city gate meter and regulator equipment?																	
Yes	14		Yes	Yes		Yes	Yes		Yes			Yes			Yes	Yes	Yes
No	8	No			No			No		No	No		No	No			
4. If you answered "Yes" to Question 3, please indicate if the amounts are consistent or if they have increased over the past year:																	
Amounts being found are comparable to what is historically found	12			X		X	X		X						X	X	X
Amounts have increased over the past year	2		X									X					
5. Are you finding pipeline dust (iron oxide) particles collecting in downstream regulator equipment?																	
Yes	16		Yes			Yes	Yes	Yes		Yes		Yes		Yes	Yes	Yes	Yes
No	6	No		No	No				No		No		No				
6. Is this having an impact on the proper operation of regulator equipment?																	
Yes	11		Yes			Yes			Yes			Yes		Yes	Yes		Yes
No	11	No		No	No		No	No		No	No		No			No	
7. What are you doing to prevent the buildup? (Check all that apply)																	
Installing additional filters	14		X	X	X	X	X			X	X	X	X		X		
Installing additional strainers	4		X	X										X			
Performing more frequent inspections	9	X	X	X					X				X			X	
Other (please specify)		More freq at the one meter station mentioned above			Nothing presently since the occurances were years ago and isolated			Have not found a need	There have been 5 random occurrences in the last 5 years. Generally, this occurs at new sites or just after pipeline cleaning work. The problem diminishes after a few days. At one site a dust filter was installed to due to reoccurrence								Using monitoring equipment via SCADA
8. If there are other issues that you have encountered with pipeline dust other than iron oxide, please explain the type of dust that was found, where is was found in your system and the challenges that it posed:		Other than this one customer location, we have not seen any issues with pipeline dust.	The dust is destroying our mooney regulator boots in PRS. Large volume customers require filters and changed weekly. Finding up to two cups of dust per visit.		In the isolated cases identified above, the iron oxide did have an impact on the proper operation of equipment.		N/A	N/A		N/A	N/A						

Survery Summary: Pipeline Dust (Iron Oxide Particles)

Responses submitted by: December 13, 2011

AGA SOS Summary
Pipeline Dust
(Iron Oxide Particles)
December 19, 2011
AGA contact: Victoria Plotkin;
vplotkin@aga.org

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Company	Total/ Average	Company Q	Company R	Company S	Company T	Company U	Company V
1. Are you finding pipeline dust (iron oxide particles) inside your distribution system (e.g. meter sets)?							
Yes	19	Yes	Yes	Yes	Yes	Yes	Yes
No	3						
2. If you answered "Yes" to Question 1, please indicate where in your distribution system the pipeline dust (iron oxide) particles were found:		In meter, filters and regulators	In mains and services in older towns.	Various, LS and XS stations in intermittent areas throughout the system	City Gate Stations	Areas that are fed off older Reulator Staions that have yet to be fitted with filters (specidfic issolated areas), dust has been found at Meter Set Assemblies.	Dust is showing up in city gates, regulator stations and meters.
3. Are you finding pipeline dust (iron oxide) particles collecting in city gate meter and regulator equipment?							
Yes	14	Yes		Yes	Yes	Yes	Yes
No	8		No				
4. If you answered "Yes" to Question 3, please indicate if the amounts are consistent or if they have increased over the past year:							
Amounts being found are comparable to what is historically found	12	X		X	X	X	X
Amounts have increased over the past year	2						
5. Are you finding pipeline dust (iron oxide) particles collecting in downstream regulator equipment?							
Yes	16	Yes	Yes	Yes	Yes	Yes	Yes
No	6						
6. Is this having an impact on the proper operation of regulator equipment?							
Yes	11	Yes		Yes	Yes		Yes
No	11		No			No	
7. What are you doing to prevent the buildup? (Check all that apply)							
Installing additional filters	14		X	X		X	X
Installing additional strainers	4					X	
Performing more frequent inspections	9	X	X- at gate station	X	X		
Other (please specify)						For the mojority of our system the dust (Iorn Oxide) is contained by filters located at Regulator stations. As stated in question 2, areas that have older Reulator Staions that have not yet been fitted with filters (specidfic issolated areas), is where dust issues have a potintial to occur. As the Regulator Staions are rebuilt/upgraded, filters are added to address this topic.	Installing equipment to indicate the differential across filters such as a tattle tail indicator or differential pressure transmitter connected to SCADA.
8. If there are other issues that you have encountered with pipeline dust other than iron oxide, please explain the type of dust that was found, where is was found in your system and the challenges that it posed:		Dust, small chips of rock, we are in a very dry environment and if care is not taken to prevent sand from entering the pipe during string and welding process sand can enter the pipeline. We have added several procedures to prevent outside particulate from being allowed to enter the pipeline during construction, such as bagging the pipe when strung. We also run cleaning pigs before smart pigs and again try to capture all of the particulate at that time.	On the Distribution System: We have installed filters ahead of the District Regulator Station, and service regulators. At gate Stations, we are finding sulfur deposits in a few of our gate station regulators causing the station to shut down.				We have seen an increase in dust since about 2001 with the increase in pipeline integrity survey work by both our upstream suppliers and our own internal inspection work. Cleaning solvents and water can also be part of the gas flow resulting from pipeline integrity activities. We recently began receiving service from a new transmission line that resulted in the receipt of pipeline dust.

APPENDIX H

COSTS OF MITIGATION MEASURES

Manitoba Hydro Line Heater Cost Estimate

Station ID and Name: **Binscarth (GS-102)**

Description	Total
Material	
CWT Line Heater DLH 140	$29,000
2" ANSI 600 ball valves for heater isolation	$3,600
2" Ansi 600 ball valve for heater bypass	$1,800
Flanges	$800
Pipe	$1,200
Fittings	$800
Temperature indicators (local)	$200
Fuel gas line and meter	$4,000
Heater Foundation	$4,000
Backfill	$2,000
Electrical	$3,000
Miscellaneous material	$7,560
Labour	
Inspection and testing	$4,000
Engineering	$10,000
Project Management	$8,000
Fabrication and Instalation	$12,000
Backhoe and dump truck	$6,000
Contingenecy (30%)	$29,388
Total	$127,348

Manitoba Hydro Line Heater Cost Estimate

Station ID and Name: **Russell (GS-103)**

Description	**Total**
Material	
CWT Line Heater DLH 1155	$140,000
4" ANSI 600 ball valves for heater isolation	$7,500
3" ANSI 600 ball valve for heater bypass	$2,750
Flanges	$1,600
Pipe	$2,000
Fittings	$2,000
Temperature indicators (local)	$200
Fuel gas line and meter	$4,000
Heater Foundation	$7,000
Backfill	$2,000
Electrical	$3,000
Miscellaneous material	$25,808
Labour	
Inspection and testing	$7,000
Engineering	$15,000
Project Management	$10,000
Fabrication and Instalation	$18,000
Backhoe and dump truck	$6,000
Contingenecy (30%)	$76,157
Total	$330,015

Manitoba Hydro Line Heater Cost Estimate

Station ID and Name: **Ile Des Chene (GS-017)**

Description	Total
Material	
2 x CWT DLH 4620 Line Heaters	$860,000
10" ANSI 600 ball valves for heater isolation	$18,000
8" ANSI 600 ball valves for heater bypass	$7,000
Flanges	$6,000
Pipe	$8,000
Fittings	$4,000
Temperature indicators (local)	$200
Fuel gas line and meter	$4,000
Heater Foundation	$15,000
Backfill	$5,000
Electrical	$3,000
Miscellaneous material	$139,530
Labour	
Inspection and testing	$10,000
Engineering	$80,000
Project Management	$30,000
Fabrication and Instalation	$30,000
Backhoe and dump truck	$15,000
Contingenecy (30%)	$370,419
Total	$1,605,149

Manitoba Hydro Line Heater Cost Estimate

Station ID and Name: **Niverville (GS-150)**

Description	**Total**
Material	
CWT Line Heater DLH 385	$57,000
2" ANSI 600 ball valves for heater isolation	$3,600
2" ANSI 600 ball valves for heater bypass	$1,800
Flanges	$800
Pipe	$1,200
Fittings	$800
Temperature indicators (local)	$200
Fuel gas line and meter	$4,000
Heater Foundation	$8,000
Backfill	$2,000
Electrical	$3,000
Miscellaneous material	$12,360
Labour	
Inspection and testing	$4,000
Engineering	$10,000
Project Management	$8,000
Fabrication and Instalation	$14,000
Backhoe and dump truck	$6,000
Contingenecy (30%)	$41,028
Total	$177,788

Manitoba Hydro Line Heater Cost Estimate

Station ID and Name: **Starbuck (GS-165)**

Description	**Total**
Material	
CWT Line Heater DLH 140	$29,000
2" ANSI 600 ball valves for heater isolation	$3,600
2" ANSI 600 ball valves for heater bypass	$1,800
Flanges	$800
Pipe	$1,200
Fittings	$800
Temperature indicators (local)	$200
Fuel gas line and meter	$4,000
Heater Foundation	$4,000
Backfill	$2,000
Electrical	$3,000
Miscellaneous material	$7,560
Labour	
Inspection and testing	$4,000
Engineering	$10,000
Project Management	$8,000
Fabrication and Instalation	$12,000
Backhoe and dump truck	$6,000
Contingenecy (30%)	$29,388
Total	$127,348

Binscarth

For 23 MBTUH Duty Cycle

Natural Gas Heating Value	1000	btu/scf

Fuel	Inputs						CO_2 Emission Annually		NOx Emission	
							lbs/year	kg/year	lbs/year	kg/year
Natural Gas	35	scf/hr =	35000	btu/hr =	0.31	mmscf/year	36,817	16,692	31	14
Cost of gas					$1,227	$/year				

Note: Emission factors are from US EPA

Fuel	CO_2	NOx	Units
Natural Gas	120,000	100	lbs/MMSCF

Cost of Gas calculated at $4.00 / MMBTU
Assumed heater efficiency 66 % for input

or 20 % Duty Cycle @ 23 MBTUH

Natural Gas Heating Value	1000	btu/scf

Fuel	Inputs						CO_2 Emission Annually		NOx Emission	
							lbs/year	kg/year	lbs/year	kg/year
Natural Gas	7	scf/hr =	7000	btu/hr =	0.06	mmscf/year	7,363	3,338	6	3
Cost of gas					$245	$/year				

Note: Emission factors are from US EPA

Fuel	CO_2	NOx	Units
Natural Gas	120,000	100	lbs/MMSCF

Ile de Chene

For 100% (4.6 MMBTUH) Duty Cycle

Natural Gas Heating Value	1000	btu/scf

Fuel	Inputs						CO_2 Emission Annually		NOx Emission Annually (assumes	
							lbs/year	kg/year	lbs/year	kg/year
Natural Gas	4600	scf/hr =	4600000	btu/hr =	40.32	mmscf/year	4,838,832	2,193,785	4,032	1,828
Cost of gas					$161,294	$/year				

Note: Emission factors are from US EPA and are as follows...				
Fuel	**CO_2**	**NOx**	**Units**	
Natural Gas	120,000	100	lbs/MMSCF	

Cost of Gas calculated at $4.00 / MMBTU
Assumed heater efficiency 66 % for input

For 20 % @ 4.6 MMBTUH Duty Cycle

Natural Gas Heating Value	1000	btu/scf

Fuel	Inputs						CO_2 Emission Annually		NOx Emission Annually (assumes	
							lbs/year	kg/year	lbs/year	kg/year
Natural Gas	920	scf/hr =	920000	btu/hr =	8.06	mmscf/year	967,766	438,757	806	366
Cost of gas					$32,259	$/year				

Note: Emission factors are from US EPA and are as follows...			
Fuel	**CO_2**	**NOx**	**Units**
Natural Gas	120,000	100	lbs/MMSCF

Niverville

For 100% (154 MBTUH) Duty Cycle

Natural Gas Heating Value	**1000**	btu/scf

Fuel	Inputs						CO_2 Emission Annually		NOx Emission Annually (assumes	
							lbs/year	kg/year	lbs/year	kg/year
Natural Gas	231	scf/hr =	231000	btu/hr =	2.02	mmscf/year	242,994	110,166	202	92
Cost of gas					$8,100	$/year				

Note: Emission factors are from US EPA and are as follows...

Fuel	CO_2	NOx	Units	
Natural Gas	120,000	100	lbs/MMSCF	

Cost of Gas calculated at $4.00 / MMBTU
Assumed heater efficiency 66 % for input

For 20 % @ 154 MBTUH Duty Cycle

Natural Gas Heating Value	**1000**	btu/scf

Fuel	Inputs						CO_2 Emission Annually		NOx Emission Annually (assumes	
							lbs/year	kg/year	lbs/year	kg/year
Natural Gas	46.2	scf/hr =	46200	btu/hr =	0.40	mmscf/year	48,599	22,033	40	18
Cost of gas					$1,620	$/year				

Note: Emission factors are from US EPA and are as follows...

Fuel	CO_2	NOx	Units
Natural Gas	120,000	100	lbs/MMSCF

Russell

For 100% (658 MBTUH) Duty Cycle

Natural Gas Heating Value	1000	btu/scf

Fuel	Inputs						CO_2 Emission Annually		NOx Emission Annually (assumes	
							lbs/year	kg/year	lbs/year	kg/year
Natural Gas	987	scf/hr =	987000	btu/hr =	8.65	mmscf/year	1,038,245	470,710	865	392
Cost of gas					$34,608	$/year				

Note: Emission factors are from US EPA				
Fuel	**CO_2**	**NOx**	**Units**	
Natural Gas	120,000	100	lbs/MMSCF	

Cost of Gas calculated at $4.00 / MMBTU
Assumed heater efficiency 66 % for input

For 20 % @ 658 MBTUH Duty Cycle

Natural Gas Heating Value	1000	btu/scf

Fuel	Inputs						CO_2 Emission Annually		NOx Emission Annually (assumes	
							lbs/year	kg/year	lbs/year	kg/year
Natural Gas	197	scf/hr =	197000	btu/hr =	1.73	mmscf/year	207,228	93,951	173	78
Cost of gas					$6,908	$/year				

Note: Emission factors are from US EPA and are as follows...			
Fuel	**CO_2**	**NOx**	**Units**
Natural Gas	120,000	100	lbs/MMSCF

For 100% (35 MBTUH) Duty Cycle

Natural Gas Heating Value	1000	btu/scf

Fuel	Inputs						CO_2 Emission Annually (assumes 100% on time)		NOx Emission Annually (assumes 100% on time)	
							lbs/year	kg/year	lbs/year	kg/year
Natural Gas	52.5	scf/hr =	52500	btu/hr =	0.46	mmscf/year	55,226	25,038	46	21
Cost of gas					1840.86	$/year				

Note: Emission factors are from US EPA and are as follows...

Fuel	CO_2	NOx	Units
Natural Gas	120,000	100	lbs/MMSCF

Cost of Gas calculated at $4.00 / MMBTU
Assumed heater efficiency 66 % for input

For 20 % @ 35 MBTUH Duty Cycle

Natural Gas Heating Value	1000	btu/scf

Fuel	Inputs						CO_2 Emission Annually		NOx Emission Annually	
							lbs/year	kg/year	lbs/year	kg/year
Natural Gas	10.5	scf/hr =	10500	btu/hr =	0.09	mmscf/year	11,045	5,008	9	4
Cost of gas					368.17	$/year				

Note: Emission factors are from US EPA and are as follows...

Fuel	CO_2	NOx	Units
Natural Gas	120,000	100	lbs/MMSCF

APPENDIX I

MH PRS DESIGN PRACTICES AND STANDARDS

– STANDARD 3 on 2 –

DRAWING NO.	DESCRIPTION
1-G0000-DB-91100-0003 C001 00	COVER SHEET
1-G0000-MB-91100-0004 0001 00	BILL OF MATERIALS
1-G0000-DB-91130-0007 0001 00	PIPING LAYOUT
1-G0000-DB-91132-0004 0001 00	DETAIL AND SECTIONS
1-G0000-DB-91133-0002 0001 00	DETAIL AND SECTIONS
1-G0000-DB-91120-0002 0001 00	EXCAVATION AND COMPACTION DETAILS
1-G0000-DB-22000-0003 0001 00	BUILDING FABRICATION DETAILS
1-G0000-DB-22000-0003 0002 00	BUILDING FABRICATION NOTES
1-G0000-DB-91142-0002 0001 00	RADIOGRAPHICAL IDENTIFICATION (X-RAY)
1-G0000-DB-91112-0002 0002 00	RADIOGRAPHICAL IDENTIFICATION (X-RAY)

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△0	2012/04/13	ISSUED FOR CONSTRUCTION	DPRY

REFERENCE DOCUMENTS:

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GIS GRID:

Manitoba Hydro GAS DISTRIBUTION

–STANDARD–

COVER SHEET FOR A TWO CUT TWO OUTLET 3 ON 2 REGULATION STATION SOUTH INLET

DRAWING NO.	SHT.	REV.
1-G0000-DB-91100-0004	C001	00

1-G0000-MB-91100-0004 0001 01

BILL OF MATERIALS

NO.	QUANTITY	SIZE	DESCRIPTION	CIIC
1	14	1/2	2000# THD VELAN HB-2000 BALL VALVE C/W LOCKING DEVICE	009803
2	1	3/4	THD FISHER RELIEF VALVE	
3	1	1	2000# THD VELAN HB-2000 BALL VALVE C/W LOCKING DEVICE	
4	2	1	600 ANSI THD VELAN TE-600 BALL VALVE C/W LOCKING DEVICE	009807
5	3	2	600 ANSI BW Nordstrom Fig. 2245 1/2 PLUG VALVE C/W LOCKING DEVICE	
6	8	3	600 ANSI BW FULL PORT BALL VALVE C/W LOCKING DEVICE	
7	2	3	600 ANSI BW Nordstrom Fig. 2245 1/2 PLUG VALVE C/W LOCKING DEVICE	
8	2	4	600 ANSI BW Nordstrom Fig. 2245 1/2 PLUG VALVE C/W LOCKING DEVICE	
9	1	1	THD MOONEY RELIEF VALVE FG-24	
10	4	2	600 ANSI BW REGULATOR	
11	4	3	600 ANSI BW REGULATOR	
△1 12	5'	3/4	SCH 80 SMLS. STL. ASTM A-106 GR. B PIPE	
13	5'	1	SCH 40 SMLS. STL. ASTM A-106 GR. B PIPE	009221
14	14'	2	SCH 40 SMLS. STL. ASTM A-106 GR. B PIPE	009225
15	68'	3	SCH 40 SMLS. STL. ASTM A-106 GR. B PIPE	009228
16	28'	4	SCH 40 SMLS. STL. ASTM A-106 GR. B PIPE	009229
17	28'	6	SCH 40 SMLS. STL. ASTM A-106 GR. B YJ PIPE	011436
18	64'	4	SCH 40 SMLS. STL. ASTM A-106 GR. B YJ PIPE	
19	12	1/2 X 2	SCH 80 SMLS. STL. ASTM A-106 GR. B TBE NIPPLE	010339
20	2	1/2 X 3	SCH 80 SMLS. STL. ASTM A-106 GR. B TBE NIPPLE	010340
21	3	3/4 X 3	SCH 80 SMLS. STL. ASTM A-106 GR. B TBE NIPPLE	010345
23	2	1 X 3	SCH 40 SMLS. STL. ASTM A-106 GR. B TBE NIPPLE	008235
26	3	2	SCH 40 BW SMLS. STL. ASTM A234-WPB 90 DEG LR ELBOW	807080
27	9	3	SCH 40 BW SMLS. STL. ASTM A234-WPB 90 DEG LR ELBOW	433303
28	4	4	SCH 40 BW SMLS. STL. ASTM A234-WPB 90 DEG LR ELBOW	009259
29	5	4 X 3	SCH 40 BW SMLS. STL. ASTM A234-WPB 90 DEG LR REDUCING ELBOW	012964
30	2	6 X 4	SCH 40 BW SMLS. STL. ASTM A234-WPB 90 DEG LR REDUCING ELBOW	012967

31	1	2	SCH 40 BW SMLS. STL. ASTM A234-WPB TEE	807657
32	3	3	SCH 40 BW SMLS. STL. ASTM A234-WPB TEE	620723
33	2	4	SCH 40 BW SMLS. STL. ASTM A234-WPB TEE	989034
34	2	3 X 2	SCH 40 BW SMLS. STL. ASTM A234-WPB REDUCING TEE	013002
35	2	4 X 2	SCH 40 BW SMLS. STL. ASTM A234-WPB REDUCING TEE	013005
36	4	3 X 2	SCH 40 BW SMLS. STL. ASTM A234-WPB CONC REDUCER	844288
37	2	4 X 3	SCH 40 BW SMLS. STL. ASTM A234-WPB CONC REDUCER	012445
38	3	3 X 1/2	3000# THD FORGED STEEL ASTM A-105 ELBOLET	010198
39	3	4 X 1/2	3000# THD FORGED STEEL ASTM A-105 ELBOLET	010198
40	1	3/4 X 3	THREADED THERMOWELL	030548
43	14	2 X 1/2	3000# FORGED STEEL ASTM A-105 THREADOLET	010193
44	6	3 X 1/2	3000# FORGED STEEL ASTM A-105 THREADOLET	010194
45	1	3 X 1	3000# FORGED STEEL ASTM A-105 THREADOLET	
46	2	4 X 3/4	3000# FORGED STEEL ASTM A-105 THREADOLET	017231
47	1	2	SCH 40 BW SMLS. STL. ASTM A234-WPB CAP	009240
48	2	3	SCH 40 BW SMLS. STL. ASTM A234-WPB CAP	009241
49	1	4	SCH 40 BW SMLS. STL. ASTM A234-WPB CAP	009243
50	18	1/2	3000# THD FORGED STEEL ASTM A-105 [hex head] PLUG	239811
51	1	1	3000# THD FORGED STEEL ASTM A-105 [hex head] PLUG	010469
52	2	3	600 ANSI FORGED STEEL ASTM A-105 RF WN FLANGE	017235
53	1	3 X 1	600 ANSI RF FL KECKLEY CS WYE STRAINER	
54	2	3	600 ANSI FLEXITALLIC GASKET	010844
55	16	3/4 X 5	STL. ASTM A-193 GR. B7 STUDS c/w 2H HEX NUTS	056003
55a	32	3/4	2H HEX NUT	127391
56	2	1/2	THD 0-100# GAUGE	010876
57	1	1/2	THD 0-1000# GAUGE	010880
58	2	1/2	THD 0-200# GAUGE	010878
59	1	3/4	RAINCAP	010812
60	1	1	RAINCAP	
61	6	4' x 8' x 8"	STYROFOAM INSULATION	008472
62	24	4	BOLLARD, SCH 40 STL. ASTM A-53 GR. B PIPE	011766
63	1	3/4	2000# THD VELAN HB-2000 BALL VALVE C/W LOCKING DEVICE	009805
△1 64	1	1 X 1 X 1/2	3000# THD FORGED STEEL ASTM A-105 REDUCING TEE	
△1 65	1	3/4 X 3/4 X 1/2	3000# THD FORGED STEEL ASTM A-105 REDUCING TEE	
66	1	1	3000# THD FORGED STEEL ASTM A-105 COUPLING	010152
67	1	3/4	3000# THD FORGED STEEL ASTM A-105 COUPLING	047845

NO.	DATE	REVISIONS	APP.
△1	2012/06/12	REVISION	DPRY
△0	2012/04/13	ISSUED FOR CONSTRUCTION	DPRY

IN MY OPINION, THE PLANS AND SPECIFICATIONS SUBMITTED ARE IN ACCORDANCE WITH CSA Z662-11 GAS PIPELINE SYSTEMS AND THE CONSTRUCTION OF THE FACILITIES PROPOSED HEREIN WILL NOT ENDANGER THE PUBLIC.

M. D. PRYDUN

June 13/2012

REFERENCE DOCUMENTS:

SCALE: NTS

DRAWN: EBEC

DATE: 2012/04/13

NETWORK:

CHECK: DPRY

CATH.: –

GIS GRID:

Manitoba Hydro

GAS DISTRIBUTION

-STANDARD-

BILL OF MATERIAL FOR A TWO CUT TWO OUTLET 3 ON 2 REGULATION STATION SOUTH INLET

DRAWING NO.	SHT.	REV.
1-G0000-MB-91100-0004	0001	01

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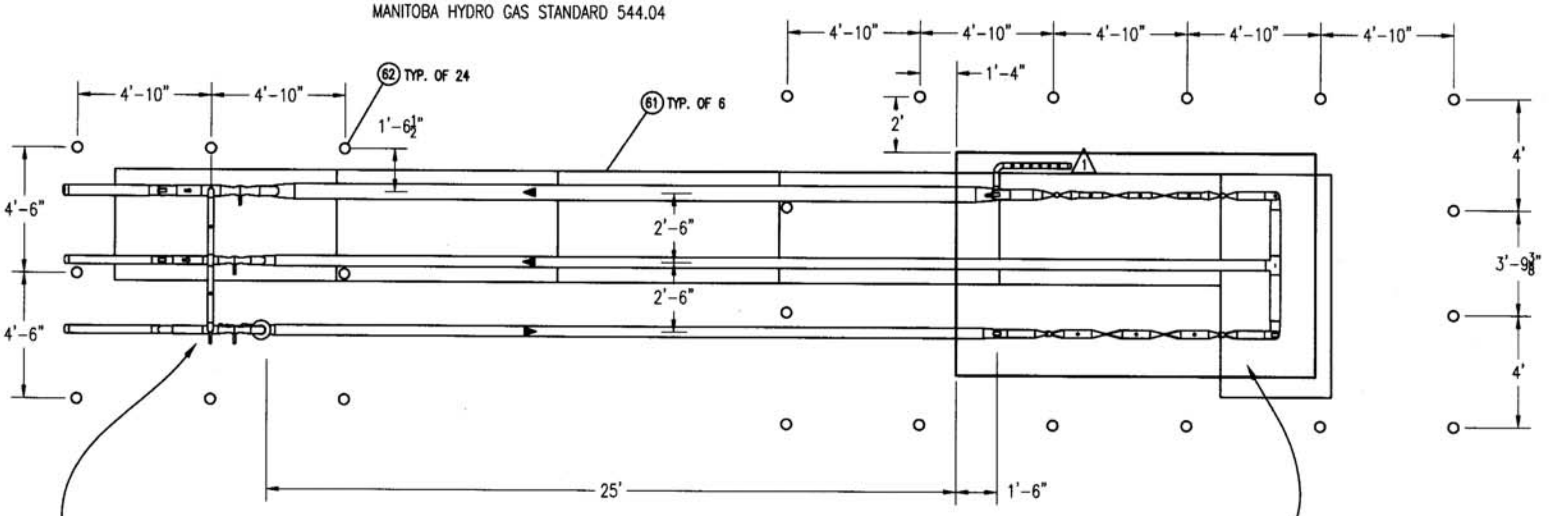
NOTE:
BOLLARDS SHALL BE INSTALLED AS PER
MANITOBA HYDRO GAS STANDARD 544.04



FOR DETAILS OF STATION BLOCK AND BY-PASS
SEE DRAWING 1-G0000-DB-91133-0002 0001 00

FOR DETAILS OF STATION REGULATION
SEE DRAWING 1-G0000-DB-91132-0004 0001 00

PLAN VIEW
NTS

FOR MICROFILM USE ONLY

IN MY OPINION, THE PLANS AND SPECIFICATIONS SUBMITTED ARE IN ACCORDANCE WITH CSA Z662-11 GAS PIPELINE SYSTEMS AND THE CONSTRUCTION OF THE FACILITIES PROPOSED HEREIN WILL NOT ENDANGER THE PUBLIC.

PROVINCE OF MANITOBA
June 13/2012
M. D.
PRYDUN
REGISTERED PROFESSIONAL ENGINEER

NO.	DATE	REVISIONS	APP.
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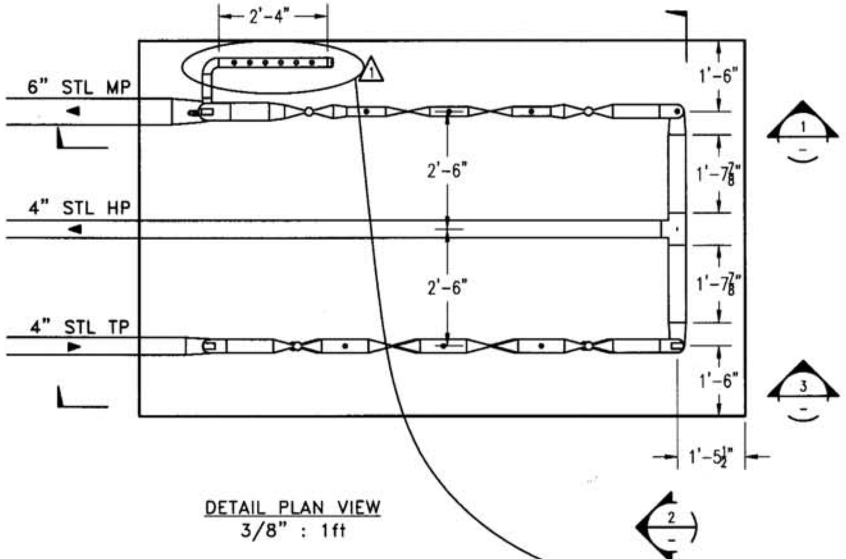
Manitoba Hydro GAS DISTRIBUTION

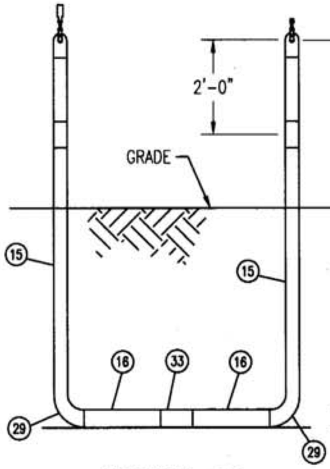
-STANDARD-

PIPING LAYOUT FOR A TWO CUT
TWO OUTLET 3 ON 2 REGULATION
STATION SOUTH INLET

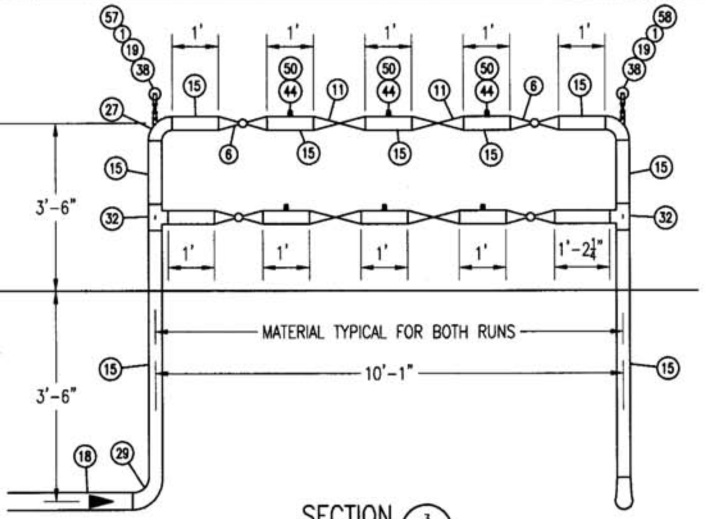
DRAWING NO.	SHT.	REV.
1-G0000-DB-91130-0007	0001	01



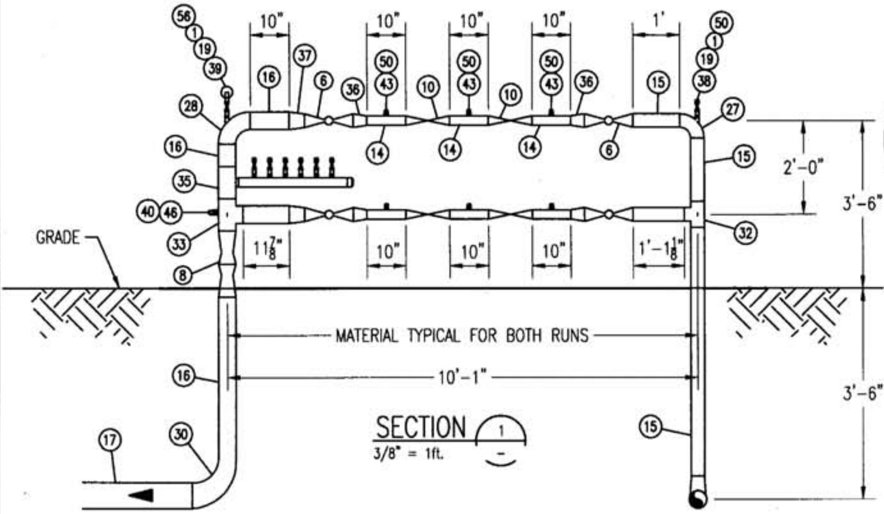
DETAIL PLAN VIEW
3/8" : 1ft



SECTION 2
3/8" = 1ft.



SECTION 3
3/8" = 1ft.



SECTION 1
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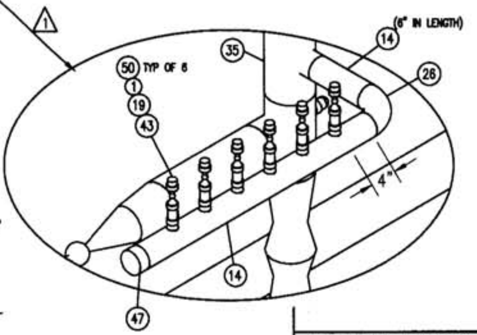

NOTE: TUBING INSTALLATION BY MH ACCORDING TO MH STD 650.20

IN MY OPINION, THE PLANS AND SPECIFICATIONS SUBMITTED ARE IN ACCORDANCE WITH CSA Z662-11 GAS PIPELINE SYSTEMS AND THE CONSTRUCTION OF THE FACILITIES PROPOSED HEREIN WILL NOT ENDANGER THE PUBLIC.

JUNE 13/2011
M. D. PRYDUN

NO.	DATE	REVISIONS	APP.
△1	2012/06/12	REVISION	DPRY
△0	2012/04/13	ISSUED FOR CONSTRUCTION	DPRY

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Manitoba Hydro GAS DISTRIBUTION

-STANDARD-

DETAIL AND SECTIONS OF REGULATION
EQUIPMENT FOR A TWO CUT TWO OUTLET
3 ON 2 REGULATION STATION SOUTH INLET

DRAWING NO.	SHT.	REV.
1-G0000-DB-91132-0004	0001	01

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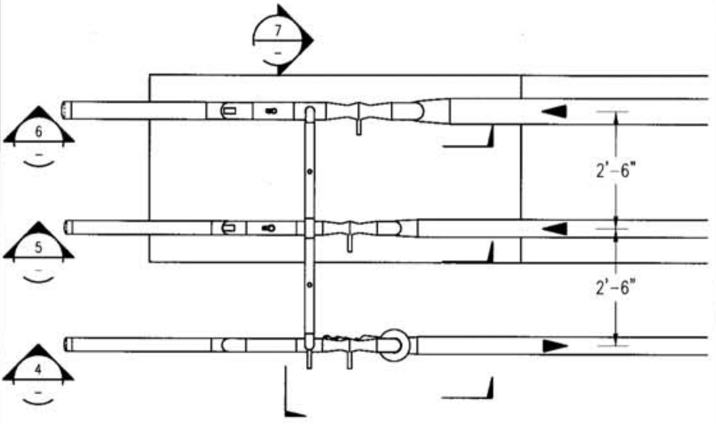
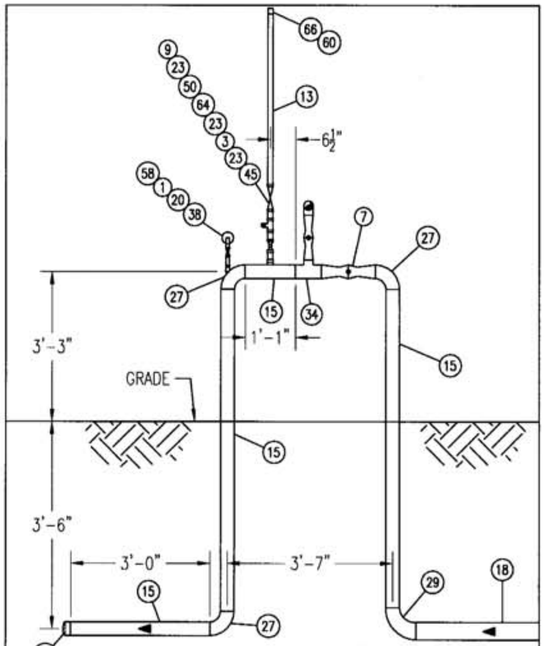
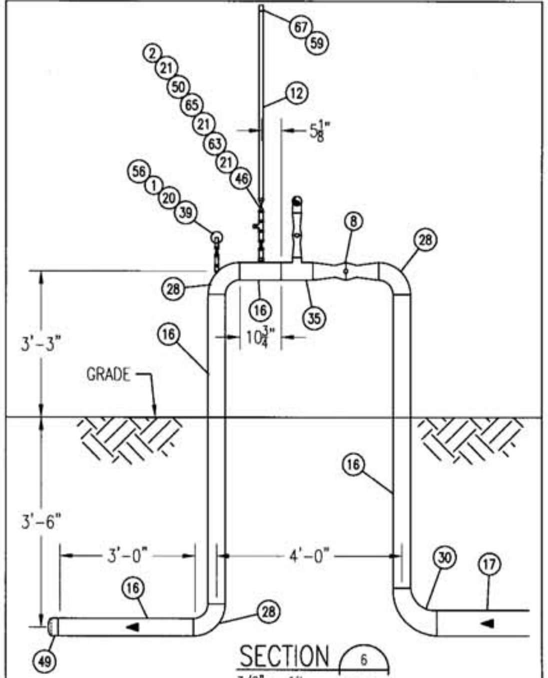


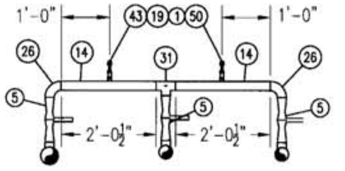
DETAIL PLAN VIEW
3/8" = 1ft.



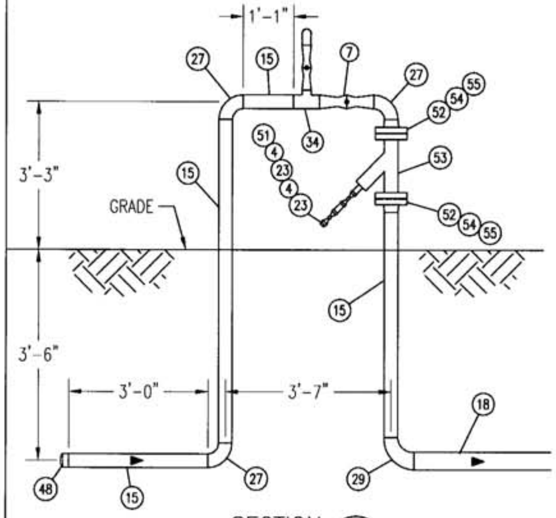
SECTION 5
3/8" = 1ft.



SECTION 6
3/8" = 1ft.



SECTION 7
3/8" = 1ft.



SECTION 4
3/8" = 1ft.

IN MY OPINION, THE PLANS AND SPECIFICATIONS SUBMITTED ARE IN ACCORDANCE WITH CSA Z662-11 GAS PIPELINE SYSTEMS AND THE CONSTRUCTION OF THE FACILITIES PROPOSED HEREIN WILL NOT ENDANGER THE PUBLIC.

D. Prydun

April 13/2012
M. D. PRYDUN

NO.	DATE	REVISIONS	APP.
0	2012/04/13	ISSUED FOR CONSTRUCTION	DPRY

REFERENCE DOCUMENTS:

SCALE: AS SHOWN
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DATE: 2012/04/13
NETWORK:
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CATH.: –
GIS GRID:

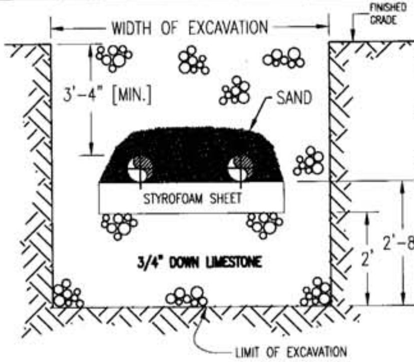
Manitoba Hydro GAS DISTRIBUTION

-STANDARD-

DETAIL AND SECTIONS OF BLOCK & BY-PASS FOR A TWO CUT TWO OUTLET 3 ON 2 REGULATION STATION SOUTH INLET

DRAWING NO.	SHT.	REV.
1-G0000-DB-91133-0002	0001	00

FOR MICROFILM USE ONLY



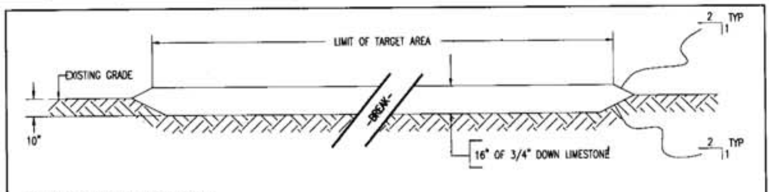
NOTES:

1. REMOVE ALL TOP SOIL AND ORGANIC IN EXCAVATION (ABOVE & BELOW PIPE)
2. WET & COMPACT 3/4" DOWN CRUSHED LIMESTONE TO 90% STANDARD PROCTOR IN LIFTS NOT EXCEEDING 6" EACH.
3. ALL NATIVE EXCESS MATERIAL TO BE HAULED AWAY AND DISPOSED OF.

DETAIL 'A' – COMPACTION BELOW STYROFOAM (N.T.S.)

KEY

▨	ZONE 1 – LIMIT OF AREA REQUIRING MATERIALS FOR SITE FOUNDATION CONSTRUCTION, SEE DETAIL 'B' FOR SPECIFICATION.
▩	ZONE 2 – LIMIT OF AREA REQUIRING MATERIALS FOR SITE FOUNDATION CONSTRUCTION, SEE DETAIL 'A' FOR SPECIFICATION.



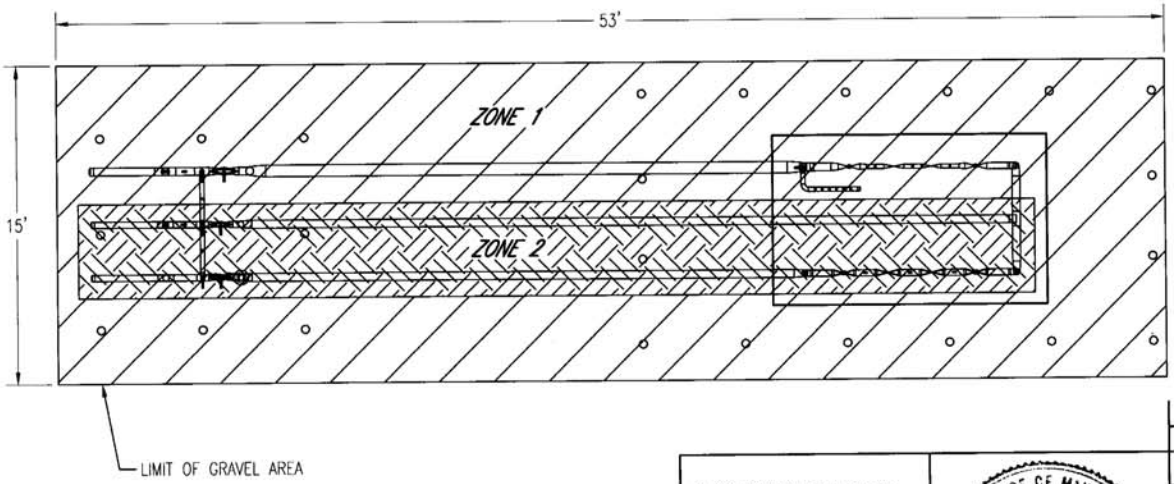
NOTES– SITE FOUNDATION

1. REMOVE THE TOP 10" OF TOP SOIL & ORGANIC MATERIAL AT THE STATION SITE.
2. COMPACTION OF THIS NEW MATERIAL TO CONFORM TO 90% STANDARD PROCTOR TESTS
3. PROVIDE GRAVEL THROUGHOUT AS INDICATED. COMPACT AREAS AS NOTED.
4. ALL COMPACTION TO BE DONE IN LIFTS NOT GREATER THAN 6" AT A TIME.

DETAIL 'B'

GENERAL SITE NOTES:

1. REMOVE 10" OF TOP SOIL AND ORGANIC MATERIAL WITHIN AREAS COMPRISED OF ZONES 1 AND 2.
2. ZONE 1– FOLLOW SITE FOUNDATION INSTALLATION AND COMPACTION INSTRUCTIONS FOUND IN DETAIL 'B'.
3. ZONE 2– FOLLOW SITE FOUNDATION INSTALLATION AND COMPACTION INSTRUCTIONS FOUND IN DETAIL 'A'.
4. ALL FINISHED COMPACTED AREAS TO CONFORM TO 90% STANDARD PROCTOR TESTS.
5. ALL NEW VERTICAL PIPE RISERS TO BE ROCK WRAPPED ALONG BELOW GRADE PORTIONS AS PER MB. HYDRO STANDARD 260.08 PRIOR TO BACKFILLING.
6. ALL EXPOSED AND NEW PIPE TO BE LINED WITH 6" OF SAND PRIOR TO BACKFILLING.
7. BACKFILL MATERIAL TO BE FREE OF ORGANIC MATERIAL, LARGE ROCKS AND STONES.
8. APPROXIMATELY 60 CUBIC YARDS OF 3/4" DOWN CRUSHED LIMESTONE MATERIAL IS REQUIRED FOR FOUNDATION
9. APPROXIMATELY 3 CUBIC YARDS OF SAND REQUIRED AT SITE.



IN MY OPINION, THE PLANS AND SPECIFICATIONS SUBMITTED ARE IN ACCORDANCE WITH CSA Z662-07 GAS PIPELINE SYSTEMS AND THE CONSTRUCTION OF THE FACILITIES PROPOSED HEREIN WILL NOT ENDANGER THE PUBLIC.

D. Prydun

PROVINCE OF MANITOBA
M. D. PRYDUN
REGISTERED PROFESSIONAL ENGINEER
April 13/2012

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Manitoba Hydro GAS DISTRIBUTION

–STANDARD–

EXCAVATION AND COMPACTION DETAILS
FOR A TWO CUT TWO OUTLET
3 ON 2 REGULATION STATION SOUTH INLET

DRAWING NO.	SHT.	REV.
1-G0000-DB-91120-0002	0001	00

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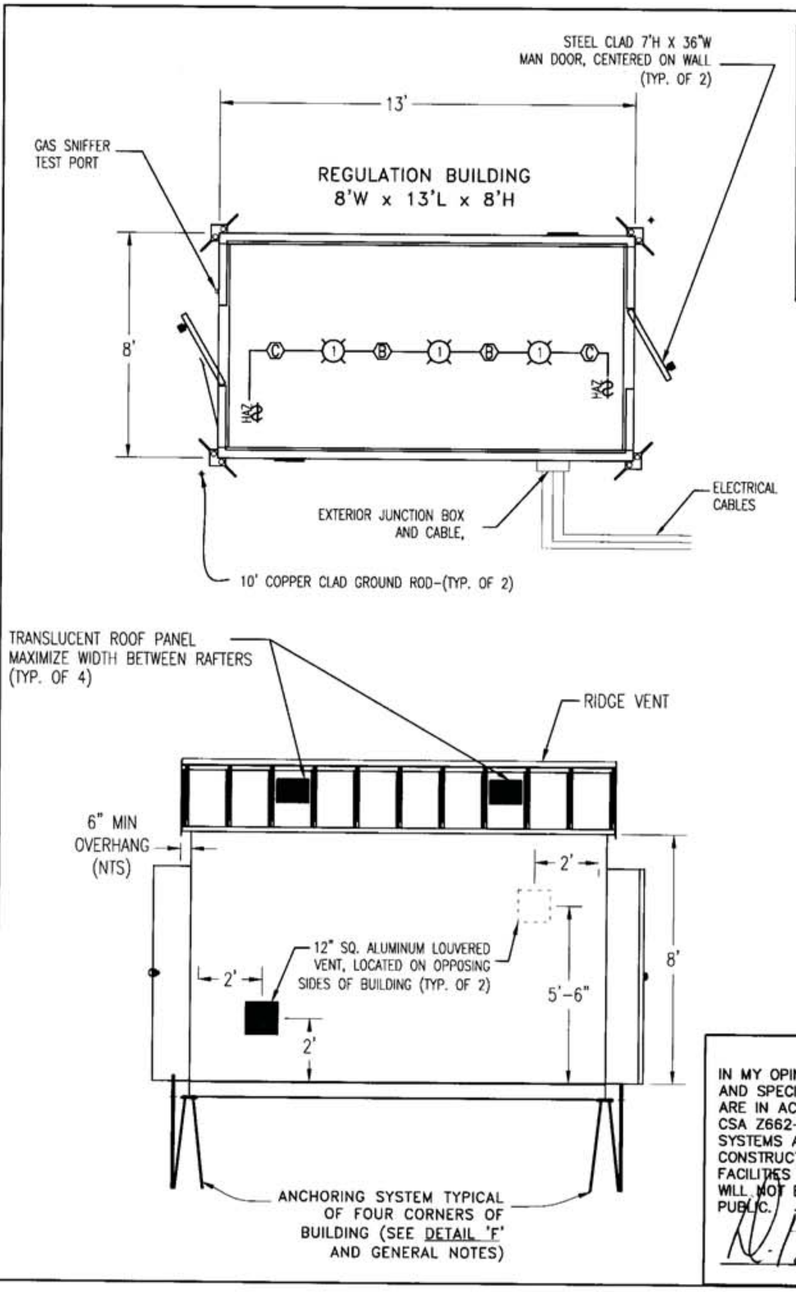


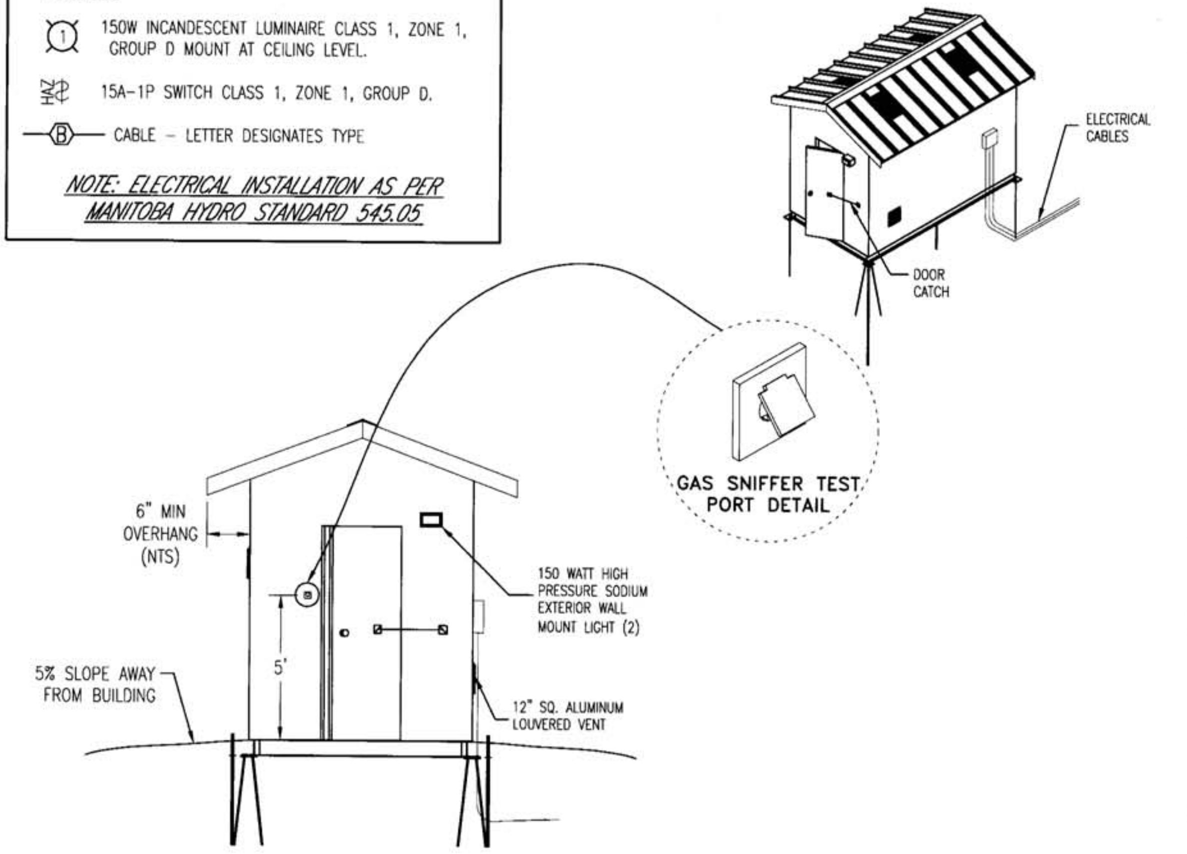
LEGEND

① 150W INCANDESCENT LUMINAIRE CLASS 1, ZONE 1, GROUP D MOUNT AT CEILING LEVEL.

HAZ 15A–1P SWITCH CLASS 1, ZONE 1, GROUP D.

—Ⓑ— CABLE – LETTER DESIGNATES TYPE

NOTE: ELECTRICAL INSTALLATION AS PER MANITOBA HYDRO STANDARD 545.05



IN MY OPINION, THE PLANS AND SPECIFICATIONS SUBMITTED ARE IN ACCORDANCE WITH CSA Z662-11 GAS PIPELINE SYSTEMS AND THE CONSTRUCTION OF THE FACILITIES PROPOSED HEREIN WILL NOT ENDANGER THE PUBLIC.

M. D. PRYDUN
Apr. 13/2012

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CATH.:	–
GIS GRID:	

Manitoba Hydro GAS DISTRIBUTION

–STANDARD–

BUILDING FABRICATION DETAILS FOR A TWO CUT TWO OUTLET 3 ON 2 REGULATION STATION SOUTH INLET

DRAWING NO.	SHT.	REV.
1–G0000–DB–22000–0003	0001	00

GENERAL BUILDING NOTES:

1. DO NOT SCALE DRAWINGS.

2. MAXIMUM DEFLECTION OF BUILDING COMPONENTS:
   A. ROOF CLADDING UNDER FULL DESIGN LOAD: 1/240 OF CLEAR SPAN.
   B. WALL CLADDING UNDER FULL WIND LOAD AND SUCTION: 1/240 OF CLEAR SPAN.

3. SUBMIT THE FOLLOWING DOCUMENTS IN ACCORDANCE WITH CSSBI 38.4-32, PARAGRAPH 14;
   A. CERTIFICATION STATING DESIGN CRITERIA USED AND LOADS ASSUMED IN DESIGN MEETING APPLICABLE CODES AND PLACING SOLE RESPONSIBILITY FOR DESIGN OF BUILDING COMPONENTS WITH STEEL BUILDING SYSTEMS MANUFACTURER.

4. BUILDING MATERIALS:

   A. WALL CONSTRUCTION: 24 GA. PREPAINTED STEEL INTERLOCKING STRUCTURAL RIB WALL PANELS (PROFILE W75-500). 5000 SERIES PAINT SYSTEM TO COLOR- WHITE-WHITE QC-8317. NO INSULATION OR VAPOR BARRIER REQUIRED.

   B. ROOF CONSTRUCTION: 22 GA. PREPAINTED STEEL INTERLOCKING STRUCTURAL RIB ROOF PANELS (PROFILE R75-500). 5000 SERIES PAINT SYSTEM TO COLOR- WHITE-WHITE QC-8317. NO INSULATION OR VAPOR BARRIER REQUIRED.

   C. TRIM CONSTRUCTION: GABLE FLASHING, ALL NOTED FLASHINGS, DOOR LEAF FRAME, DOOR FRAME FINISH AND RIDGE VENT TO BE PREPAINTED STEEL. 5000 SERIES PAINT SYSTEM TO COLOR- ROYAL BLUE QC-790.

   D. ROOF LITES: 4- 16" X 48" CLEAR, ALL-WEATHER SEALED 2BE SKY LITES.

   E. DOOR CONSTRUCTION AND HARDWARE:
   2- 36" X 7' STEEL INSULATED EXTERIOR MAN DOORS c/w HARDWARE AS FOLLOWS:
      - DOOR LEAF- 20 GA. STEEL 1.77" THICK HONEYCOMB CORE, FINISH: ROYAL BLUE QC-790.
      - DOOR FRAME- 16 GA. PRESSED STEEL, FINISH: ROYAL BLUE QC-790.
      - BUTT HINGES- INSTALL "TAYMOR" 4.5" X 4" BB X NRP X C26D #25-4173DC
      - PANIC HARDWARE- INSTALL "VON DUPRIN" #44TP (THUMB PIECE ACTION, LOCKABLE)
      - CHAIN CHECK (HEAVY DUTY CRASH CHAIN)- INSTALL "TAYMOR" #25-4858U25. A HYDRAULIC CLOSURE IS NOT AN ACCEPTABLE DEVICE.
      - LOCKCYLINDER- "BEST" BRAND RIM CYLINDER C/W CONSTRUCTION CORE CYLINDER
      - THRESHOLD- 18 GA. STEEL
      - WEATHERSTRIP- ALUMINUM/VINYL
      - SWEEP- ALUMINUM/VINYL

   F. GAS SNIFFER TEST PORT- SPRING ACTIVATED, SOFT SEATED PORT WITH 1"ø MIN. PROBE INSERTION OPENING. MOUNT 5'-0" ABOVE T.O.S.

   G. SCREWS: CADMIUM PLATED STEEL, PURPOSE MADE, HEAD COLOR SAME AS EXTERIOR SHEET.

   H. 2- 12" X 12" MANUALLY ADJUSTABLE ALUMINUM LOUVERS. TO BE MOUNTED TO EXTERIOR OF BUILDING AS SPECIFIED.

   I. FIXED OPEN RIDGE VENT

5. ELECTRICAL EQUIPMENT:

   A. ALL INTERIOR BUILDING ELECTRICAL COMPONENTS SHALL MEET THE ELECTRICAL HAZARDOUS CLASSIFICATION REQUIREMENTS OF CLASS 1, ZONE 1. ALL EXTERIOR MOUNTED ELECTRICAL COMPONENTS SHALL MEET THE ELECTRICAL HAZARDOUS CLASSIFICATION REQUIREMENTS OF CLASS 1, ZONE 2.

   B. HIGH TEMPERATURE WIRE AND A MINIMUM 9 INCH LENGTH CONDUIT SHALL BE CONNECTED TO THE INTERIOR LIGHT FIXTURE.

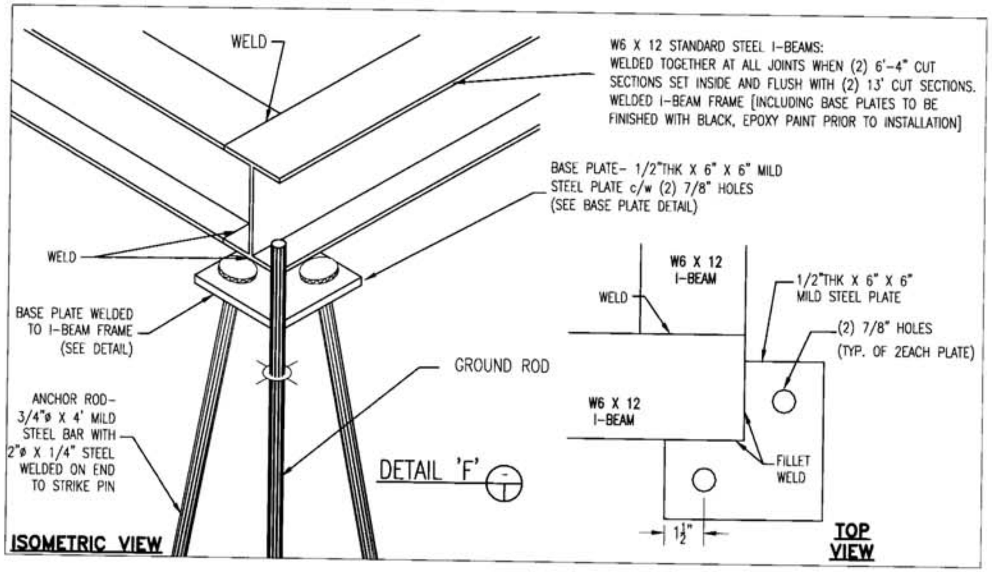
6. MISCELLANEOUS BUILDING FEATURES:

   A. SUPPLIER TO FABRICATE BUILDING ANCHORING SYSTEM (SEE DETAIL 'F' FOR ACCEPTABLE METHOD OF ANCHORING STATION STRUCTURE).

   B. BUILDING TO BE FASTENED TO WELDED W6 X 12 STEEL I-BEAM FRAME AND PLACED ON GRAVEL BASE. STEEL FRAME TO BE SITUATED PREFERABLY ON UNDISTURBED SOIL OR DESIGN SPECIFIED BASE.

   C. GROUNDING- GROUND ROD (TYP. OF 2) INSTALLATION PROCEDURE:
   GROUND RODS TO BE DRIVEN IN THE GROUND (CLOSE TO OPPOSING BUILDING CORNERS) LEAVING 4" EXPOSED ABOVE FINAL GRADE. GROUND ROD TO BE CONNECTED TO BUILDING WITH SHORT SECTION OF #6 BARE COPPER WIRE. FIX #6 BARE COPPER CONNECTOR TO END OF BARE COPPER WIRE AND ATTACH TO EXPOSED STEEL I-BEAM FRAME BY APPROVED FASTENER. A 2/0 ONE-SHOT SHALL BE USED TO CONNECT GROUND WIRE TO ABOVE GRADE END OF GROUND ROD
   ONLY MANITOBA HYDRO APPROVED METHOD AND MATERIAL TO BE USED.

7. REFERENCE STANDARDS: MANITOBA BUILDING CODE, LATEST EDITIONS.



IN MY OPINION, THE PLANS AND SPECIFICATIONS SUBMITTED ARE IN ACCORDANCE WITH CSA Z662-07 GAS PIPELINE SYSTEMS AND THE CONSTRUCTION OF THE FACILITIES PROPOSED HEREIN WILL NOT ENDANGER THE PUBLIC.

D. Prydun

M. D. PRYDUN

April 13/2012

NO.	DATE	REVISIONS	APP.
0	2012/04/13	ISSUED FOR CONSTRUCTION	DPRY

REFERENCE DOCUMENTS:
SCALE: NTS
DRAWN: EBEC
DATE: 2011/04/13
NETWORK:
CHECK: DPRY
CATH.: –
GIS GRID:

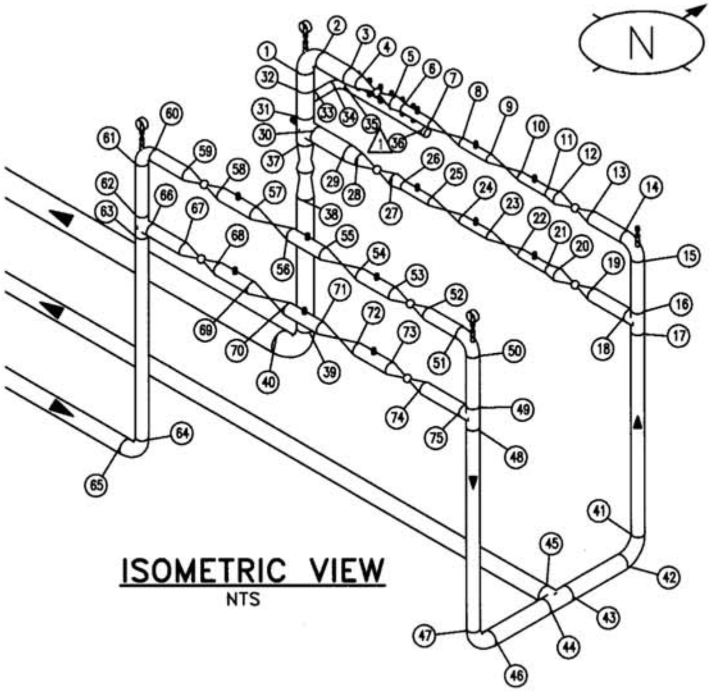
Manitoba Hydro GAS DISTRIBUTION

-STANDARD-

BUILDING FABRICATION NOTES FOR A TWO CUT TWO OUTLET 3 ON 2 REGULATION STATION SOUTH INLET

DRAWING NO.	SHT.	REV.
1-G0000-DB-22000-0003	0002	00

FOR MICROFILM USE ONLY



ISOMETRIC VIEW

NTS

NO.	WELD RESULT	NO.	WELD RESULT
1		26	
2		27	
3		28	
4		29	
5		30	
6		31	
7		32	
8		33	
9		34	
10		35	
11		36	
12		37	
13		38	
14		39	
15		40	
16		41	
17		42	
18		43	
19		44	
20		45	
21		46	
22		47	
23		48	
24		49	
25		50	

NO.	WELD RESULT
51	
52	
53	
54	
55	
56	
57	
58	
59	
60	
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66	
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NO.	WELD RESULT
68	
69	
70	
71	
72	
73	
74	
75	

FOR MICROFILM USE ONLY

NO.	DATE	REVISIONS	APP.
1	2012/06/12	REVISION	DPRY
0	2012/04/13	ISSUED FOR CONSTRUCTION	DPRY

REFERENCE DOCUMENTS:

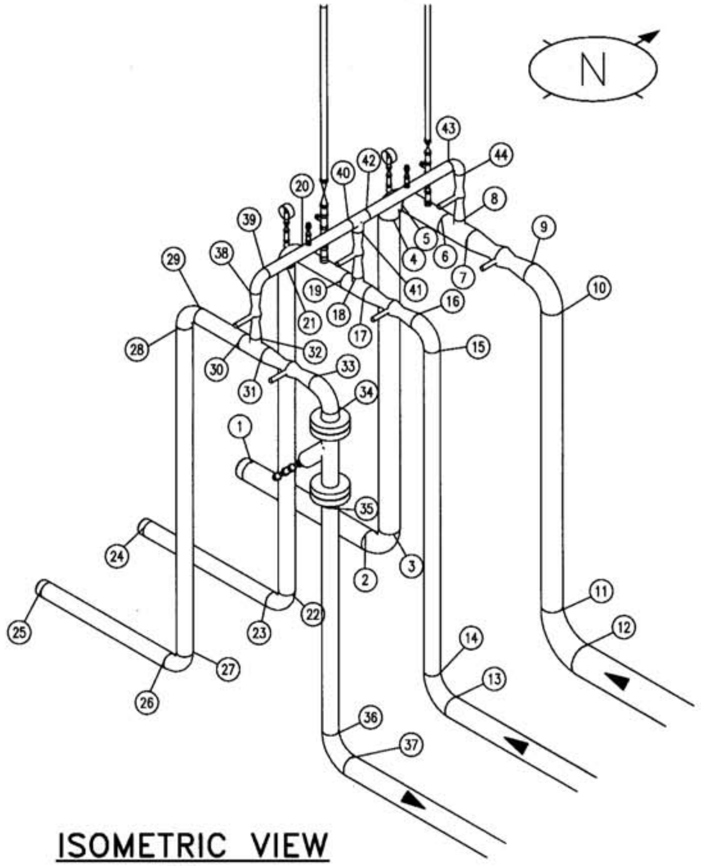
SCALE:	NTS
DRAWN:	EBEC
DATE:	2012/04/13
NETWORK:	
CHECK:	DPRY
CATH.:	–
GIS GRID:	

Manitoba Hydro GAS DISTRIBUTION

-STANDARD-

RADIOGRAPHICAL IDENTIFICATION (X-RAY) OF REGULATION EQUIPMENT 3 ON 2 SOUTH INLET

DRAWING NO.	SHT.	REV.
1-G0000-DB-91142-0002	0001	01



ISOMETRIC VIEW

NTS

NO.	WELD RESULT	NO.	WELD RESULT
1		26	
2		27	
3		28	
4		29	
5		30	
6		31	
7		32	
8		33	
9		34	
10		35	
11		36	
12		37	
13		38	
14		39	
15		40	
16		41	
17		42	
18		43	
19		44	
20		45	
21		46	
22		47	
23		48	
24		49	
25		50	

NO.	DATE	REVISIONS	APP.
0	2012/04/13	ISSUED FOR CONSTRUCTION	DPRY

REFERENCE DOCUMENTS:

SCALE: NTS
DRAWN: EBEC
DATE: 2012/04/13
NETWORK:
CHECK: DPRY
CATH.: –
GIS GRID:

Manitoba Hydro GAS DISTRIBUTION

-STANDARD-

RADIOGRAPHICAL IDENTIFICATION (X-RAY)
OF BLOCK AND BY-PASS
3 ON 2 SOUTH INLET

DRAWING NO.	SHT.	REV.
1-G0000-DB-91142-0002	0002	00

FOR MICROFILM USE ONLY

8.0 REGULATOR SELECTION

8.1 General

Pressure control regulators can be categorized into the following types:

1. self-operated
2. pilot-operated

Self operated regulators characteristically provide less accurate control, but are more dependable in terms of freeze off prevention, less expensive and easier to operate than pilot controlled types. Self-operated regulators sense the downstream pressure through either an internal pressure tap or external pressure control line. This downstream pressure opposes a spring, which moves a diaphragm and valve plug to restrict flow of the gas stream through the regulator orifice.

The pilot-operated regulator is essentially two regulators, with the main regulator controlling the gas flow and the pilot regulator providing an intermediate pressure to the loading side of the diaphragm of the main regulator. With the pilot regulator providing a reduced pressure differential across the main regulator, it is possible to use a lighter spring which in turn makes the regulator react more quickly to pressure changes and maintain a more constant downstream pressure.

Boot style regulators such as Fisher 399, Mooney, and Axial Flow regulator operates in the same manner as other pilot operated regulators except that the diaphragm, spring and valve plug are replaced with a rubber boot which is pushed away from a cage opening (orifice) when a decrease in downstream pressure is sensed.

8.2 Regulator Runs

Pressure control regulators can be further grouped into the following arrangements or better known as regulator runs:

1. single regulator
2. worker monitor
3. working monitor

If economics were the most important factor governing station design, almost all would be single regulator designs. However, safety and security of supply are the most common overriding factors.

This has lead to the development of designs using parallel and monitor backup regulators. The following guidelines shall be used to determine which type of regulator run will be used:

TYPE	APPLICATION
1. Single Run, Single regulator	Small Farm Tap – less than 115 m3/hr (4000 cfh). – full capacity relief valve is required. See appendix XXXX
2. Parallel Run, Single regulator	Large Farm Tap – less than 570 m3/hr (20,000 cfh) – full capacity relief valve is required. See appendix XXXX
3. Single Run, worker monitor (pilot-operated)	Regulator Station (RS) type application – urban setting – max. pressure differential 3450 kPa (500 psi). See appendix XXXX
4. Parallel Run, worker monitor (pilot-operated)	Less than 2,850 m3/hr (100,000 cfh) – max. pressure differential 3450 kPa (500 psi). See appendix XXXX
5. Parallel Run, worker monitor – two pressure cuts (pilot-operated)	Greater than 2,850 m3/hr (100,000 cfh) – pressure differential greater than 3450 kPa (500 psi). See appendix XXXX
6. Parallel Run, working monitor (pilot-operated)	Less than 2,850 m3/hr (100,000 cfh) and pressure differential is greater than 3450 kPa (500 psi). See appendix XXXX

For pressure drops of more than 3450 kPa (500 psig) the regulation should be done in two stages. When this is required the intermediate pressure is best approximated by a ratio of the pressure as follows:

(Note: This is only used if two single regulators are used, or a working monitor setup is conducted to perform the two stage pressure reduction)

$$\frac{P1}{P2} = \frac{P2}{P3}$$

Therefore: $P2 = (P1\ P3)^{\wedge}1/2$

where:
P1= maximum inlet pressure
P2= intermediate pressure
P3= design outlet pressure

Other considerations in the design of regulator runs are regulator isolation valves, pressure taps and the piping itself.

Each regulator run requires an upstream and a downstream isolation valve in order to isolate the regulator run and repair the regulator without affecting gas service. The valves should be sized to the regulator inlet and outlet piping without restriction and should be a full port configuration. Plug or ball valves are considered ideal for this type of application. In addition, the valves must be pressure rated to the maximum upstream pressure.

Piping should be sized and meet material standards as discussed in section 7 of this manual. In addition, piping should be sized to a maximum of 60 m/s (200 ft/s) or the regulator body size, whichever is larger. Since the velocity is dependent on pressure, it may be necessary to use different size pipe on the upstream and downstream side of the regulator.

An additional tap is to be located on the downstream side of the regulator (if the regulator uses an external pilot). The location of this tap is best suited at a point where flow is laminar and the pressure is more stable to improve accuracy of the sense point. A typical location of these sense points is on separate header or on the outlet run of the piping (a guideline is a minimum of 5-10 pipe diameters from the regulator or other flow restricting devices)

Additional pressure taps (1/2" needle valves) are required on both sides of each regulator for each regulation run, in order to blowdown pressure to the atmosphere. Each blowdown is tubed to a common header and tubed outside the building or structure. If no structure is required for the station, the blowdowns can be tubed so that the pressure is released away from the employee. A short spool of tubing on each needle valve to a location ending below the regulator run piping is typically used.

8.3 Sizing and Selection

The following parameters must be known before selecting any regulator:

- maximum inlet pressure
- minimum inlet pressure
- maximum outlet pressure
- minimum inlet pressure
- desired outlet pressure
- maximum hourly flowrate
- minimum hourly flowrate

The regulator must be designed to withstand the maximum pressure the upstream system is likely to deliver (MAOP). This information is documented in all manufacturers equipment literature and this pressure must always meet or exceed this maximum inlet pressure to the regulator. Some manufacturers, list the maximum allowable pressure differential across the regulator. This is the difference between the maximum allowable inlet pressure and the minimum outlet pressure (set pressure). Exceeding this differential may cause partial or full regulator failure.

In monitor or two stage regulators, where there is no relief valve between the upstream and downstream regulators, both regulators must be able to withstand the maximum operating pressure of the inlet supply line and the maximum pressure differential.

The maximum inlet pressure must also used to determine the wide-open capacity of the regulator, which is required for relief valve sizing.

Regulator capacity decreases in proportion to a decrease in differential pressure across it. Since it is necessary to size the regulator for the worst conditions, its capacity should be determined using the minimum inlet pressure, the proposed set pressure and the peak load. In parallel run installations, each regulator run must be sized to handle the full load. A typical rule of thumb is to size the regulator to handle 75-80% of the maximum capacity that the regulator can pass under the conditions being designed. Please refer to the manufacturers literature for capacity information or contact the manufacturer where questions arise.

In worker monitor arrangements, seldom is there manufacturer information readily available to complete "quick" sizing. Therefore, for a reference guide a capacity of 70% of the working capacity of the smaller regulator/orifice can be used. But in all cases, it is best to have verification of the capacity from the manufacturer, especially if the design load is close to this capacity.

Currently both Mooney and Fisher both provide Centra Gas Manitoba Inc. with regulator sizing software to handle both single and worker monitor type applications. Copies if necessary can be provided from Facilities Optimization Engineer.

When in doubt about the specification of any regulating equipment, the local supplier or the manufacturer should be consulted.

8.4 Material Specifications

A variety of materials are commonly used in the fabrication of the regulator body and the internal components. For this reason it is not possible to specify exactly what is or is not acceptable;

Some guidelines to follow are:

1. The regulator must be designed for natural gas use.
2. It must be from the approved list of manufacturers given in Section xxxx of this standard.
3. All materials must be corrosion resistant
4. All rubber parts must be made of materials which are resistant to the effects of hydrocarbons. (examples: Hydrin-200, Buna-N and neoprene)
5. Fisher 627 regulators should be ordered with the nitrile seat as opposed to nylon.
6. Temperature capabilities should withstand a minimum of -29 C to +82 C
7. If a new regulator is to be reviewed, inquire as to other utilities using the product and verify their comments on its performance within their system.

Complete material specifications can be found in Section XXXX of the standards manual.

Manitoba
Hydro

NATURAL GAS STANDARD MATERIAL SPECIFICATION 210.01

AMENDMENT ~~2~~ 3

COATED STEEL PIPE

IMPORTANT
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Review Date: ~~April 5, 2012~~ August 22, 2012
Issued: ~~April 5, 2012~~ August 22, 2012

MANITOBA HYDRO
NATURAL GAS STANDARD MATERIAL SPECIFICATION 210.01
AMENDMENT ~~2~~ 3

COATED STEEL PIPE

TABLE OF CONTENTS (1 page)

GENERAL REQUIREMENTS (5 pages)

NOTE New or amended text is identified by shading, while deleted text is

COATED STEEL PIPE

GENERAL REQUIREMENTS

1 SCOPE OF THE WORK

Specification 210.01 provides the requirements for the supply and delivery of coated steel pipe for use in natural gas distribution and transmission.

2 REFERENCE STANDARDS

CSA Z662	Oil and Gas Pipeline systems
CSA Z245.1	Steel Pipe
CSA Z245.20/ CSA Z245.21	External fusion bond epoxy coating for steel pipe/ External Polyethylene Coating for Pipe
API 5L	Line Pipe
ASTM A 333	Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service
ASTM A 106	Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service

The latest editions, amendments and supplements of these standards shall apply, unless specifically identified.

3 PIPE

Pipe size, wall thickness, minimum grade, nominal pipe length, coating type and quantity shall be as indicated in Table 1.

Table 1 Pipe Requirements

Pipe Size				Pipe Specifications			
Manitoba Hydro CHC	NPS	Outside Diameter (mm)	Wall Thickness (mm)	Grade (MPa)	Coating Type	Nominal Pipe Lengths (meters)	Required Quantity (meters)
01-41-00	3/4	26.7	2.87	241	PE	6	
01-40-98	1 1/4	42.2	3.56	241	PE	6	
01-40-97	2	60.3	3.18	317	PE	12	
01-40-96	2	60.3	3.91	317	PE	12	
02-22-05	2	60.3	5.54	317	PE	12	

NOTE New or amended text is identified by shading, while deleted text is identified by strikeout.

Table 1 Pipe Requirements

Pipe Size				Pipe Specifications			
Manitoba Hydro CIIC	NPS	Outside Diameter (mm)	Wall Thickness (mm)	Grade (MPa)	Coating Type	Nominal Pipe Lengths (meters)	Required Quantity (meters)
04-59-73	2	60.3	5.54	317	~~FBPE~~ DUAL LAYER	12	
03-35-49	4	114.3	3.18	317	PE	12	
03-35-50	4	114.3	6.02	317	PE	12	
04-59-74	4	114.3	6.02	317	~~FBPE~~ DUAL LAYER	12	
03-35-51	6	168.3	4.78	317	PE	12	
03-35-52	8	219.1	4.78	317	PE	12	
03-35-53	3	88.9	3.18	317	PE	12	
N/A	10	273.1	5.56	317	PE	12	
N/A	12	323.9	6.35	317	PE	12	
N/A	14	355.6	6.35	317	PE	12	
N/A	16	406.4	6.35	317	PE	12	

All pipe shall be manufactured to the requirement of CSA Z245.1. For quantities below 100 m per size and wall thickness, pipe meeting the requirements of CSA Z662 can be directly substituted as follows:

Pipe			Acceptable Alternate Standard
NPS	Outside Diameter (mm)	Wall Thickness (mm)	
NPS 3/4	26.7	2.87	ASTM A333 Gr. 6 seamless ASTM A106 Gr. B seamless
NPS 1 1/4	42.2	3.56	ASTM A333 Gr. 6 seamless ASTM A106 Gr. B seamless
NPS 2 and over	60.3 and over	all	API 5L Grade X46

Pipe shall be CSA Z245.1 Category I.
Pipe is to be suitable for natural gas sweet service.
Pipe shall be electric resistance welded.
Pipe shall have bevel ends.
Pipe grade shall not exceed Gr. 386.
Mill jointers are not acceptable.

NOTE New or amended text is identified by shading, while deleted text is identified by ~~strikeout~~.

4 PIPE COATING: POLYETHYLENE (PE)

The pipe coating shall be an extruded high density polyethylene applied over a mastic adhesive conforming to CSA Z245.21 system A2.

Colour to be yellow.

Cutback lengths on each end of the pipe to be 75 +/- 25 mm for the adhesive and 125 +/- 25 mm for the polyethylene jacket.

Flexibility test temperature of -30°C.

Pipe marking to be in accordance with CSA Z245.1. The phrase "Manitoba Hydro Gas Pipeline" is to be included on all pipe coated specifically for an order from Manitoba Hydro.

Pipe with coating dates more than six months old will not be accepted without prior approval.

5 PIPE COATING: FUSION BOND EPOXY (FBE)

The pipe coating shall be a fusion bond epoxy protective coating for steel pipe conforming to CSA Z245.20.

Thickness to be nominally between 300 and 350 µm or micrometre.
Cutback lengths on each end of the pipe to be 125 +12/-38 mm.

Flexibility test temperature of -30°C.
Pipe marking to be in accordance with CSA Z245.1. The phrase "Manitoba Hydro Gas Pipeline" is to be included on all pipe coated specifically for an order from Manitoba Hydro.

6 PIPE COATING: DUAL LAYER ~~FUSION BOND EPOXY~~ POLYETHYLENE (DUAL LAYER ~~FB~~PE)

The pipe coating shall be a dual layer~~, a fusion bond epoxy protective coating with an abrasion resistant overcoat for steel pipe~~ of extruded high density polyethylene applied over a mastic adhesive conforming to CSA Z245.~~20~~21 system A2.

~~Fusion Bond Epoxy layer thickness to be nominally between 300 – 350 µm.~~
~~Abrasion Resistance Overcoat thickness to be nominally between 450 – 500 µm.~~

NOTE New or amended text is identified by shading, while deleted text is identified by ~~strikeout~~.

~~Total thickness to be nominally between 750 – 850 µm.~~

Colour to be yellow.

Cutback lengths on each end of the pipe to be ~~125 +12/-38~~ 75 +/- 25mm for the adhesive and 125 +/- 25mm for the polyethylene jacket.
Flexibility test temperature of -30 C.
Pipe marking to be in accordance with CSA Z245.1. The phrase "Manitoba Hydro Gas Pipeline" is to be included on all pipe coated specifically for an order from Manitoba Hydro.

Pipe with coating dates more than six months old will not be accepted without prior approval.

7 TESTING AND CERTIFICATION

Certificates of compliance for the pipe and coatings are to be provided for all pipe. For pipe delivered to project sites, certificates are to be provided prior to shipping. Certificates are to be provided in either electronic (PDF) format or hard copy (one).

7.1 Pipe

The Manufacturer shall provide a certificate of compliance for each item. The certificate shall include chemical composition and tensile properties specific to each heat or lot supplied and to indicate compliance with all required quality control measures.

7.2 Pipe Coating

For all pipe coated specifically for an order from Manitoba Hydro, the applicator shall furnish a certificate of compliance stating that the coating has been manufactured, applied, inspected and tested in accordance with the requirements of CSA Z245.20 and any other requirements specified in the purchase order, and the results of the coating tests and other required tests have been found to conform to such requirements.

8 PIPE HANDLING AND DELIVERY

The pipe ends shall be capped or plugged for all pipe shipped to Manitoba Hydro Central Stores. Capping or plugging is not required for pipe delivered to project sites from April 1 to October 1.

NOTE New or amended text is identified by shading, while deleted text is identified by ~~strikeout~~.

The pipe is to be delivered by flatbed truck to the location(s) as indicated for offloading by Manitoba Hydro or their identified agents.

Pipe is to be supported and secured on the truck bed to avoid damage to the pipe coating during transport.

For project sites, offloading will include direct stringing of the pipe along the intended route of installation. Additional charges for costs associated with stringing of the pipe will be accepted.

Manitoba
Hydro

NATURAL GAS STANDARD MATERIAL
SPECIFICATION 210.11

AMENDMENT 0

BARE STEEL PIPE

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Review Date: September 30, 2009
Issued December, 2009

MANITOBA HYDRO
NATURAL GAS STANDARD MATERIAL SPECIFICATION 210.11
AMENDMENT 0

BARE STEEL PIPE

TABLE OF CONTENTS (1 page)

GENERAL REQUIREMENTS (3 pages)

NOTE New or amended text is identified by shading, while deleted text is identified by ~~strikeout~~.

Manitoba
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GENERAL REQUIREMENTS

NOTE New or amended text is identified by shading, while deleted text is identified by ~~strikeout~~.

BARE STEEL PIPE

GENERAL REQUIREMENTS

1 SCOPE OF THE WORK

Specification 210.11 provides the requirements for the supply and delivery of bare steel pipe for use in natural gas distribution and transmission.

2 REFERENCE STANDARDS

CSA Z662	Oil and Gas Pipeline Systems
ASTM A53	Standard Specification for Pipe, Steel, Black and Hot - Dipped, Zinc-Coated, Welded and Seamless
ASTM A106	Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service
ASTM A 333	Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service

The latest editions, amendments and supplements of these standards shall apply, unless specifically identified.

3 PIPE

Pipe size, Schedule, minimum grade, nominal pipe length, and quantity shall be as indicated in Table 1.

Table 1: Pipe Requirements

Manitoba Hydro CIIC	NPS	Pipe Schedule	Standard and Grade	Nominal Pipe Lengths (meters)	Required Quantity (meters)
00-92-06	1/8	40	ASTM A53 Type F, Gr. A	6.1 to 6.4	
00-92-07	1/4	40	ASTM A53 Type E, Gr. A	6.1 to 6.4	
00-92-08	3/8	40	ASTM A53 Type F, Gr. A	6.1 to 6.4	
00-92-09	1/2	40	ASTM A53 Type E, Gr. B	6.1 to 6.4	
00-92-10	1/2	80	ASTM A53 Type E, Gr. B	6.1 to 6.4	

NOTE New or amended text is identified by shading, while deleted text is identified by strikeout.

Table 1: Pipe Requirements

Manitoba Hydro CIIC	NPS	Pipe Schedule	Standard and Grade	Nominal Pipe Lengths (meters)	Required Quantity (meters)
00-92-11	3/4	40	ASTM A106 Gr. B	6.1 to 6.4	
00-92-21	1	40	ASTM A106 Gr. B	6.1 to 6.4	
00-92-22	1 1/4	40	ASTM A106 Gr. B	6.1 to 6.4	
00-92-24	1 1/2	40	ASTM A106 Gr. B	6.1 to 6.4	
00-92-25	2	40	ASTM A106 Gr. B	6.1 to 6.4	
00-92-26	2 1/2	40	ASTM A106 Gr. B	6.1 to 6.4	
00-92-28	3	40	ASTM A106 Gr. B	6.1 to 6.4	
00-92-29	4	40	ASTM A106 Gr. B	6.1 to 6.4	
01-14-36	6	40	ASTM A106 Gr. B	3 to 3.2	
01-16-71	2	80	ASTM A106 Gr. B	6.1 to 6.4	
N/A	8	40	ASTM A106 Gr. B	6.1 to 6.4	
N/A	10	40	ASTM A106 Gr. B	6.1 to 6.4	
N/A	12	STD	ASTM A106 Gr. B	6.1 to 6.4	
N/A	14	STD	ASTM A106 Gr. B	6.1 to 6.4	
N/A	16	STD	ASTM A106 Gr. B	6.1 to 6.4	

Pipe NPS 2 and larger shall have bevel ends. End preparation on smaller sizes to be at the manufacturer's choice.

Mill jointers are not acceptable.

Pipe marking to be in accordance with referenced standards.

4 TESTING AND CERTIFICATION

Certificates of compliance for the pipe are to be provided for all pipe immediately following delivery. Certificates are to be provided in either electronic (PDF) format or hard copy (one).

The Manufacturer shall provide a certificate of compliance for each item. The certificate shall include chemical composition and tensile properties specific to each heat or lot supplied and to indicate compliance with all required quality control measures.

5 PIPE HANDLING AND DELIVERY

The pipe ends shall be capped or plugged for all pipe shipped to Manitoba Hydro Central Stores.

The pipe is to be delivered by flatbed truck to the location(s) as indicated for offloading by Manitoba Hydro or their identified agents.

Pipe is to be supported and secured on the truck bed to avoid damage to the pipe during transport.

Manitoba Hydro

Natural Gas Standards

Table of Contents

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000 Administration

100 General

200 Material Specifications

For Access go to: **MPower - Service Areas - Purchasing - SMS & TLMS**
http://fa.hydro.mb.ca/cs/purchasing/Pages/SMS_Webparts.aspx

300 Equipment Specifications

500 Design

700 Operations & Maintenance

Term	Definition
Above Grade Installation	Installation of a pipeline above the surface of the ground on supports or in an embankment constructed from the earth or other materials.
Actuator Lever	Arm attached to rotary valve shaft to convert lineal actuator stem action to rotary force to position disc or ball of rotary-shaft valve.
Actuator Stem Force	The net force from an actuator that is available for actual positioning of the valve plug.
A-Frame	A piece of equipment used during an above grade coating survey. When used with a PCM (Pipeline Current Mapper) an operator can pinpoint a coating fault to within centimeters.
Anode	The electrode of a galvanic cell whereby the current (conventional, + to -) flows from the electrode to the solution or electrolyte. It is the point in the circuit of the galvanic cell at which oxidation and corrosion occurs.
Arc Burn	A localized condition or deposit that is caused by an electric arc and consists of remelted metal, heat-affected metal, a change in the surface profile, or a combination thereof.
Automated Meter Reading	Any one of several methods to read meters without physically examining the meter dial readings. This includes reading via communication lines and radio frequency transmission.
Automatic Control System	A control system which operates independent of human intervention.
Backfeed	To obtain supply from an alternate direction in a line with two-way feed.
Backfill	Earth or other material that is used to refill a ditch, trench, or hole. The act of refilling a ditch or trench.
Bar Hole	A small diameter hole made in the ground in the vicinity of the gas piping for the purpose of extracting a sample of the ground atmosphere for analysis when searching for leaks.
Bar Hole Survey	A leakage survey made by driving or boring holes at regular intervals along the route of buried piping and testing the atmosphere in the holes with a combustible gas detector or other suitable device.
Bell Hole	An excavation of sufficient size to allow personnel to work at pipeline depth to install, repair or maintain underground plant
Board	The Public Utilities Board of Manitoba.

Term	Definition
Bond	A metallic connection that provides electrical continuity.
Bond Interference	A metallic connection designed to control electrical current interchange between metallic systems.
Bonnet Assembly	The top cover or closure on a valve or control valve which may include an opening and sealing assembly for a valve stem
Branch	A tee or cross connection in a pipeline system. For welding, a fitting or pipe that is scarfed to fit on the run pipe and is welded using a groove and filet weld. An example is a service tee.
By-Pass	An auxiliary piping and valve arrangement, generally to carry gas around a component or a section of a piping system.
Cadweld	Commonly used term refers to thermite welding. See Thermite Welding.
Cage	1) A hollow cylindrical trim element to guide the movement of a valve plug. 2) A perforated or slotted metal guide or support for the rubber boot or membrane in rubber boot style regulators.
Capacity	Maximum rate of flow that a device will pass under stated conditions.
Casing	A piece of pipe through which a pipeline is inserted to provide additional protection, often used under railway or other crossings.
Casing Insulator	Insulating material attached to a steel pipeline within a casing to ensure electrical insulation between the pipeline and the pipeline casing.
Cast Iron	All forms and types of cast iron, including ductile cast iron.
Cast Iron, Ductile	A cast iron in which the graphite present is substantially spheroidal or nodular in shape and the iron is essentially free from other forms of graphite. (It is also known as spheroidal or nodular cast iron).
Cathode	The electrode of a galvanic cell whereby the current (conventional) flows from the solution to the electrode. A cathode is sufficiently negative in potential with respect to the surrounding electrolyte that corrosion does not occur on its surface and the chemical reaction is one of reduction.
Cathodic Area	A geographic area in which the steel pipe is electrically continuous and is electrically isolated from adjoining cathodic areas.

Term	Definition
Cathodic Disbondment	Separation of the coating from a cathodically protected surface because of the effects of excessive cathodic potential in that hydrogen and electrolytically derived precipitates accumulate at breaks in the coating and lift the coating off the surface.
Cathodic Protection	A technique to prevent the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.
Check Meter Station (CMS)	A primary gate station that measures the gas flow.
Checkpoint	A point at or above grade of electrical connection to a buried structure, such as a pipeline, anode or tracer wire. Frequently wires from several buried structures may be present at one checkpoint.
City Gate	An informal term for a larger gate station; usually applied to gate stations that serve cities or larger communities.
Class 1 - Zone 1	The electric classification for hazardous locations in which: 1. Explosive gas atmospheres are likely to occur in normal operation; or 2. Explosive gas atmospheres may exist frequently because of repair or maintenance operations or because of leakage; or 3. The location is adjacent to a Class 1 Zone 0 location from which explosive gas atmospheres could be communicated (Note: Excerpted from C22.1 Canadian Electrical Code)
Class 2 - Zone 2	The electric classification for hazardous locations in which: 1. Explosive gas atmospheres are not likely to occur in normal operation and, if they do occur, they will exist for a short time only; or 2. Flammable volatile liquids, flammable gases, or vapours are handled, processed, or used, but in which liquids, gases, or vapours are normally confined within closed containers or closed systems from which they can escape only as a result of accidental rupture or breakdown of the containers or systems or the abnormal operation of the equipment by which the liquids or gases are handled, processed or used; or 3. Explosive gas atmospheres are normally prevented by adequate ventilation but which may occur as a result of failure or abnormal operation of the ventilation system; or 4. The location is adjacent to a Class 1, Zone 1 location from which explosive gas atmospheres could be communicated unless such communication is prevented by adequate positive pressure ventilation from a source of clean air, and effective safeguards against ventilation failure are provided. (Note: Excerpted from C22.1 Canadian Electrical Code)

Term	Definition
Class Location	A geographical area defined in CSA Z662 that is classified according to its approximate population density and other characteristics that are to be considered when designing and pressure testing piping to be located in the area.
Close Interval Potential Survey (CIPS)	A technique aimed at assessing the Cathodic Protection effectiveness over the entire length of a pipeline.
Coincidence Factor	The ratio of the maximum average rate of use for a group of customers to the sum of the maximum rates of use for each customer.
Cold Patch	Gravel and asphalt mix which can be tamped into a paving repair without heating, to form temporary repair in blacktopping.
Collapse	Cross-sectional instability of pipe resulting from combinations of bending, axial loads, and external pressure.
Combustible Gas Indicator (CGI)	A portable instrument used to detect low concentrations of flammable gases or vapours in air.
Component	A pressure-containing member of the pipeline system other than pipe such as valves, fittings and flanges.
Compressor	Mechanical or hydraulic device for increasing the pressure of a gas.
Connected Load	The sum of the volumetric gas fuel requirements of all appliances connected to a service or gas piping system.
Construction	All activities required to fabricate, install, test, and commission pipeline systems.
Controller	A device that receives information from an input source component (measured value), compares it to an expected value (setpoint) and adjusts an output component (output) to bring the measured value within an acceptable range of the set point.
Conventional Current Flow	Assumed to be from a given point to a more negative point; this is the opposite to the actual movement of electrons.
Corrosion	The deterioration of a material, usually metal, because of a reaction with its environment.
Corrosion, Stray Current	Corrosion resulting from direct current flow through paths other than the intended circuit.

Term	Definition
Coupling	Sleeve-type fitting used to connect two pipes.
Coupon	The piece of pipe material removed from the pipeline after tapping with a hole saw or similar cutter.
Current Density	The current per unit area, usually [mA /sq. in.] or [mA /sq. cm].
Current, Impressed	Direct current supplied by a device employing a power source external to the electrode system.
Current, Stray Direct	Current flowing through paths other than the intended circuit.
Customer	A recipient of a product provided by the supplier.
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.
Dent	A depression caused by mechanical damage that produces a visible disturbance in the curvature of the wall of the pipe or the component without reducing the wall thickness.
Diameter, Outside	The specified outside diameter (OD) of the pipe, excluding the manufacturing tolerance provided in the applicable pipe specification or standard.
Diaphragm	A flexible pressure responsive element which transmits force to the diaphragm plate on an actuator stem.
Distribution Line	A pipeline in a distribution system that conveys gas to the individual service lines or other distribution lines
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 meter set.
District Regulator Station (DRS)	Another name for a regulator station. See Regulator Station.
Diversity Factor	The reciprocal of coincidence factor.
Downstream	a) The direction that a fluid will flow. b) A location further along the direction of flow.
Dresser	A mechanical compression fitting used to join two pipes and often provides electrical isolation. A brand name of Dresser Industries Inc. and Dresser Canada Inc.
Easement	A legal agreement giving the company the right to install and maintain a pipeline across land owned by others, but does not include surface rights.

Term	**Definition**
Electrical Isolation	The condition of being electrically isolated from other metallic structures and the environment.
Electrolyte	A chemical substance or mixture, usually liquid, containing ions that migrate in an electric field. For the purpose of these standards, electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged metallic structure, including the moisture and other chemicals contained therein.
Ell or Elbow	Pipe fitting that makes an angle in a pipe run. Unless stated otherwise, the angle is assumed to be 90 degrees.
Emergency	Any incident that occurs which requires immediate response and continuous action until the situation is brought under control (e.g. fire calls, explosions, outage/system failure, emergency shutdowns, carbon monoxide asphyxiation, odor and leakage response.
Engineer of Record	The Professional Engineer responsible for a design and whose seal appears on a construction drawing, specification or standard.
Erosion	The removal of material due to the abrasive action of flowing liquids, gasses or mixtures.
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.
Fail Open	A controller or actuator that will move to the full open position upon loss of signal or actuator pressure.
Fail Safe	A controller or actuator that upon loss of signal or actuator pressure will move to a position which is considered safe for the system involved. This could be full open position, full closed position or maintaining the last position.
Failed Closed	A controller or actuator that will move to the full closed position upon loss of signal or actuator pressure.
Farm Tap	A small “reg station” type set up that serves one or very few customers at distribution pressure. Typically located in a rural setting near a transmission pipeline.
Feeder Main	A larger major supply main that feeds gas to smaller distribution mains.
Fitting	An item in a pipe or tubing system that is used as a connector, such as an elbow, return bend, tee, union, bushing, coupling, cross, or nipple, but not including such functioning items as a valve or pressure regulator.

Term	Definition
Flange	Plate of material set at right angles to the surface at which it is attached, and ordinarily used to fasten two sections of material together.
Foreign Line	A pipe, conduit, cable, wire, duct or other buried structure that is not part of the pipeline under consideration.
Galvanic Anode	A metal which, because of its relative position in the galvanic series, corrodes and so provides sacrificial protection to metal or metals that are more noble in series, when coupled in an electrolyte. These anodes are the current source in one type of cathodic protection. A piece of metal (e.g. zinc, magnesium) complete with an electrical connection wire which is buried near below-grade gas lines and electrically connected to them to provide corrosion protection by electrochemical (galvanic) means.
Galvanic Cell	An electrolytic cell that is capable of producing electrical energy by electrochemical action.
Gas Fitting	The work involved in the installation, repair, alteration, or removal of any gas equipment, appliances or piping downstream of the meter.
Gas Pipeline Right of Way	The land on which a pipeline is located by virtue of land ownership, easement, lease, agreement, or permission.
Gate Station (G.S.)	A facility for pressure reduction of gas supplied from a transmission line and may include metering and/or odourization.
GMI	Gas Measurement Instruments Ltd. A specific brand of combustible gas indicators. Commonly used as a generic term for a combustible gas indicator.
Gouge	A surface imperfection caused by mechanical removal or displacement of metal that reduces the wall thickness of a pipe or component.
Grade Installation	Installation of a pipeline on the surface of the ground or in a shallow ditch and may be covered with earth or other materials in the form of a berm.)
Ground Temperature	The temperature of the earth, river bottom, or lake bottom at pipe depth.
Groundbed	A number of closely spaced, buried anodes that are connected together and through which direct current is discharged to provide cathodic protection to a steel piping system.
Hardness	Metallic material hardness is commonly expressed by either a Brinell number or a Rockwell number, the higher the number, the harder the material.
Header	A pipe with fittings that provides for interconnection of a number of branch pipes.

Term	Definition
Heat Fusion Joint	A joint made in thermoplastic piping by heating the parts sufficiently to permit fusion of the materials when parts are pressed together.
Heat-affected Zone	That portion of a weld consisting of base metal that has not been melted but whose microstructure or mechanical properties have been altered by the heat of welding.
Holiday	A discontinuity of the protective coating that exposes the metal surface.
Horizontal Directional Drilling (HDD)	A trenchless method of installing pipe in the ground at variable angles using a guidable drill head.
Hot Tap	A branch connection made to piping while it is under pressure.
Houseline	See Customer Piping.
Hunting	Instability in the operation of a control valve where the output oscillates with an unacceptable magnitude around the setpoint
Hydrate	A solid resulting from a physical combination of water and other small molecules such as methane which has a dirty ice-like appearance but has a different structure to ice.
Hydro-vac	The use of a high pressure, usually heated, water stream to cut and liquefy soil/fill to permit vacuum excavation of the material. Used near pipe and cable to reduce excavation damage.
Imperfection	A material discontinuity or irregularity that is detectable by inspection.
Impressed Current	Direct current supplied by a power source external to the electrode system, for the purpose of cathodic protection.
Incident	An event where natural gas is, or may be, involved and where damage to person or property and/or an interruption in service occurs or may occur.
Inspection	An activity such as measuring, examining, testing or gauging one or more characteristics of an entity and comparing the results with specified requirements in order to establish whether conformity is achieved.
Inspection Nondestructive	The inspection of piping to reveal imperfections, using radiographic, ultrasonic, or other methods that do not involve disturbance, stressing, or breaking of the materials.
Insulating Coating System	All components comprising the protective coating, the sum of which provides effective electrical insulation of the coated structure from its environment.

Term	Definition
Insulating Fitting	A pipe fitting which provides electrical insulation between the inlet and outlet of the fitting
Intermediate Line	A pipeline to supply gas to a distribution system or another intermediate line and operates at a pressure greater than the distribution system supplied but less than transmission. This is also called High Pressure.
Jeep	1. The popular name, “Jeeper”, given to the "holiday" detector, an electrical device used for checking the coating on the pipe to find any holidays or nicks in the coating. 2. To use a holiday detector to check a pipe coating.
Joint Mechanical Interference Fit	A nonthreaded joint for metallic pipe involving the controlled plastic deformation and subsequent mating of the pipe ends, or the mating of the pipe ends with a coupling, the resultant joint being the interference fit between the mated parts.
Knit Lines	The line along which two polyethylene surfaces have fused located on a polyethylene fitting on the opposite side to the plastic injection point.
Laminar Flow	Fluid flow that is free of macroscopic fluctuations or disturbances; usually associated with low velocities.
Lateral	A pipeline branch.
Leak Clamp	Clamp used to press and hold tight a gasket against a leaking section of pipe or pipe joint to seal the leak.
Leakage Survey	A systematic survey made for the purpose of locating leaks in a pipeline.
Line Current	The direct current flowing on a pipeline.
Liner	A tubular product that is inserted into buried piping to form a corrosion-resistant barrier or separate, free standing, pressure-containing piping.
Looping	Paralleling of existing pipeline by another line to increase capacity.
Lower Explosive Limit (LEL)	The smallest proportion of flammable gas mixed with air that would result in combustion when exposed to a source of ignition, 5% methane in air.
Main	A pipeline that transports gas to supply service lines and may be a transmission line, feeder line or a distribution line.
Main Extension	A lengthening, extension or capacity increase of a gas distribution mains to serve new customers or connect a new load
Main Pre-Installation	Installing a main before it is needed in the system because of outside constraints (e.g. ahead of paving or road construction.)

Term	Definition
Main Renewal	Renewing a main for any reason other than to increase the system's capacity e.g. due to leakage, change of location.
Main Replacement	Abandoning an existing main and replacing it with another main in order to increase the system's capacity.
Maintenance Welding	Welding performed during the replacement of portions of pipeline systems, the attachment of devices to operating pipeline systems, the repair of defects by direct deposition welding, and the installation of tie-ins to connect new facilities to existing pipeline systems.
Manifold	Pipe to which two or more outlet pipes are connected.
Maximum Operating Pressure (M.O.P)	See Pressure, Maximum Operating (M.O.P.)
Maximum Regulator Setting	These pressures are determined by considering line test pressures, valve, regulator, relief valve and fittings ratings. The maximum pressures are only to be used in an emergency situation.
Mechanical Air Intake	An air intake to a building or structure that uses a motorized fan or blower on the air intake to move air into the building or structure.
Mechanical Connector	A device or element, other than a threaded joint, used to join pipe ends by a mechanical process.
Meter, Customer's	A meter that measures the gas delivered to a customer
Meter, Inside	Meter located inside the building it serves.
Meter Installer	Company employee or authorized contractor engaged in installing, changing or altering meter sets.
Meter Guards	Device or devices to protect gas meters from vehicular damage.
Meter Recess	Recess into a building form an outside wall, into which a gas meter set can be placed in such a way that no part of the set protrudes outside the plane of the wall.
Meter – Remote Reader	Instrument designed to permit meter reading by telephone or other means.
Meter, Rotary Displacement	An instrument that measures volume by means of rotating impellers, matching gears, or sliding vanes.
Meter Set	Assembly of a meter and fittings. Where necessary, the meter set also includes pressure regulator(s) and over-pressure protection.

Term	Definition
Meter Stop	The shut off valve to the meter set on the riser at a customer's service location.
National Pipe Thread (NPT)	A tapered pipe thread conforming to the ANSI/ASME Standard B1.20.1. Within this standard, NPT refers to a thread denoted as National Pipe Tapered. It also is used informally for any compatible thread such as that used in a threaded coupling.
Nipple	A short piece of pipe, usually threaded at both ends and usually less than 300mm in length.
Nitrogen Slug	Nitrogen gas inserted into a natural gas pipeline to provide a buffer between air and natural gas for a purging operation
Notch Toughness	Notch toughness is the resistance of steel to fracture under suddenly applied loads at a notch. Notch toughness requirements for steel pipe and components shall include a test temperature at which the notch toughness tests shall be conducted.
Operating Limits	The range of operating conditions to which a device may be subjected without permanent impairment of operating characteristics.
Overpressure Protection	Devices or equipment used for the purpose of preventing the pressure in a pipeline system from exceeding a predetermined value.
Padding	Sand, soil free of rock or similar material spread on the bottom of a trench and around the pipe to prevent damage or abrasion by rock, frozen backfill or other backfill material that could damage the pipe or pipe coating.
Pete's Plug	A self closing pipeline tap that permits the reading of the internal pressure or temperature using a suitable, compatible probe and eliminates the need for a valve or thermowell. Pete's Plug is a registered trademark of the Peterson Equipment Company Inc.
Pig	A device used to clean the internal surface of a pipeline usually made of metal, plastic or foam and may contain wire brushes or carbide chips to aid in the removal of corrosion or scale on the pipe wall.
Pilot	1. A small regulator that senses pipeline pressure and controls a larger regulator to maintain the desired setpoint. 2. A small continuous flame in a gas appliance that provides a source of ignition to the main burner, often called pilot light 3. A small hole preceding a larger hole.
Pipe	A tubular product manufactured in accordance with a pipe specification or standard.

Term	Definition
Pipe Coating	Moisture resistant material used to protect metal pipelines from corrosion.
Pipe, Deactivated	Pipe that is taken out of service and is physically isolated from any in-service pipe.
Piping, Control	The piping used to interconnect air-, gas-, or hydraulic-operated control apparatus, or instruments transmitters and receivers.
Piping, Instrument	The piping used to connect instruments to main piping to other instruments and apparatus, or to measuring equipment.
Plastic	A material that contains one or more organic polymeric ingredient substance(s) of large molecular weight, is solid in its finished state and, at some stage in its manufacture or processing into finished articles, can be shaped by flow.
Plug	1. A pipe fitting that is inserted into the open end of a coupling to seal the end of a pipe 2. Sealing a hole in a vessel, such as pipe or tank, by inserting material into the hole and then securing it 3. Refers to the material used to plug the hole.
Point of Entry	The point at which the service piping enters a building.
Polarization	The deviation from the open circuit potential of an electrode which may also mean a structure or a part of it, resulting from the effects of the passage of current at the surface that is in contact with the electrolyte. In these standards polarization is considered to be change of the potential of metal surface resulting from the passage of current directly to or from an electrolyte.
Polyethylene	A polymer that is prepared by the polymerization of ethylene as the primary monomer, with comonomers such as butene and hexene.
Port	A fixed opening in a valve, control valve or regulator through which fluid passes.
Premises	Any unit occupied as an entity by a firm, organization or individual; may be the whole of a building or just part of it.
Pressure, Absolute	The pressure above a complete vacuum which is equal to the sum of gauge pressure and barometric pressure
Pressure, Barometric	The absolute pressure of the atmosphere.
Pressure, Base	See Pressure, Standard.

Term	Definition
Pressure Control Device	Equipment installed for the purpose of automatically reducing or regulating the pressure in the downstream pipeline system in order to prevent the fluid pressure from exceeding a predetermined value. Under normal operating conditions, the pressure-limiting device may exercise some degree of control of fluid flow or may remain in the wide-open position.)
Pressure, Delivery	Gas pressure delivered to a customer downstream of the regulator, usually 1.75 kPa or 35 kPa
Pressure, Distribution	A pressure range for a gas distribution pipeline or system that delivers gas directly to a regulator on a customer's meter set. Distribution pressure is greater than 14 kPa and does not exceed 700 kPa.
Pressure Factor Measurement	Metering of gas at a pressure greater than the basic delivery pressure of 1.75 kPa requiring the meter reading to be adjusted by a pressure determined factor to yield correct volumes.
Pressure Gauge	The pressure above barometric pressure and is the pressure generally shown by pressure measurement devices.
Pressure, High	Pipeline pressure greater than distribution but less than transmission. See Intermediate Line.
Pressure, Intermediate	Pipeline pressure greater than distribution but less than transmission. Also referred to as High Pressure. See Intermediate Line.
Pressure, Loading	The pressure employed to effect a position change on a controlling device.
Pressure, Low	A distribution system in which the gas pressure does not exceed 14 kPa.
Pressure, Maximum Allowable Operating (M.A.O.P.)	See Maximum Operating Pressure
Pressure, Maximum Operating (M.O.P)	The maximum working pressure at which a pipeline may be operated as qualified by pressure testing or limited by the weakest component in the system
Pressure, Medium	Generally the same as distribution pressure but in some contexts can refer to 14 to 420 kPa (MOP)
Pressure Regulating Station	A broad term that covers any facility providing pressure reduction or control.
Pressure Regulator	A device, either adjustable or nonadjustable, for controlling and maintaining within acceptable limits, a uniform outlet pressure.

Term	Definition
Pressure, Standard	An absolute pressure of 101.325 kPa. Also referred to as base pressure or pressure at standard conditions, it is the reference pressure for gas measurements of standard volumes.
Pressure, Supply	The pressure at the supply port of a device.
Pre-tested Pipe	Pipe that has been pressure tested in accordance with the requirements of the CSA Z662 standard prior to being placed in the pipeline system.
Primary Gate Station (PS)	Facilities located at a gas receipt point and may include any one or more of the following: pressure reduction, check metering, custody transfer or odourization.
Purge	To replace the existing fluid (gas or liquid) in piping or tubing with a desired fluid (gas or liquid).
Purge Point	Connection near a valve or other flow-stopping device that will allow a section of gas piping to be purged into or out of service.
Purge Stack	A vertical length of pipe connected to a purge point to carry the vented gas to a safe height.
Pusher Pipe	Length of pipe used in a pushing operation where pipe is pushed from one excavation to another for the purpose of pulling back a gas pipe to effect a crossing or service installation
Rated Travel	Movement from the full closed position to the full open position.
Recess	An indentation, small hollow or alcove in a building wall.
Rectifier	A device for converting alternating current to direct current, which can be used as a source of impressed current for cathodic protection.
Reference Cell	An electrode that allows consistent and accurate contact with moist soil or electrolyte. It is also referred to as a copper – copper sulfate electrode or half cell.
Reference Electrode	A device whose open-circuit potential is constant under a similar condition of measurement.
Regulator	Device for controlling and maintaining a desirable downstream gas pressure.
Regulator, Monitoring	A pressure regulator arranged in series with the working-pressure regulator, for taking over the control of the downstream pressure in case of malfunction of the working-pressure regulator.

Term	Definition
Regulator, Service	A regulator installed on a service line to control the pressure of the gas delivered to the customer.
Regulator Station	A facility for pressure reduction for gas supplied from a feeder line or a distribution line.
Remote Sensing Unit (RSU)	A device that can conduct a measurement at prescribed intervals, store the data obtained and download the data to a central computer at preset periods via telephone lines. These are often installed in customer homes to monitor cathodic protection or distribution pressure.
Remote Terminal Unit	Remote telemetry units or field computers used to collect, store and transmit data. In some applications RTU's can be used to control output devices.
Repair Sleeve, Pressure Containment	A full encirclement repair sleeve that has the ability to contain pipeline pressure within the sleeve.
Repair Sleeve, Reinforcement	A full encirclement repair sleeve that reinforces the run pipe to prevent failures by reducing bulging of the defective area and/or transferring load from the run pipe to the sleeve.
Resin	The term is used to designate any polymer that is a basic material for plastics and is used to produce our plastic pipe and fittings. The properties of the resin determine the performance of the pipe and fitting.
Retired and Removed	The main or service is physically disconnected from its source and entirely removed from the ground.
Retired In Place	A service or main is physically disconnected from its source (not just shut-off), purged out with air or an inert gas, and abandoned in place
Reverse Current Switch	A device that prevents the reversal of direct current through a metallic conductor.
Riser	A length of pipe connected to a buried line that brings gas above ground.
Root Bead	The weld bead that extends into, or includes part or the entire region where two or more parts to be welded are closest.
Safety and Loss Management System	A systematic, comprehensive, and proactive process for the management of safety and loss control associated with design, construction, operation, and maintenance activities.

Term	Definition
Sacrificial Protection	Control of corrosion of a metal in an electrolyte by coupling it to form a galvanic cell with a more anodic (less noble) metal which corrodes, or is sacrificed to prevent corrosion of the cathodic (more noble) metal.
Saddle - Steel	A weld fitting that is shaped to fit closely on the outside of the steel pipe and is welded to the pipe by a filet weld. It may be a partial or full encirclement fitting. An example is a reinforcing sleeve or a spherical hot tap fitting.
- Plastic	A fusion fitting that is shaped to fit closely on the outside of the PE pipe and is fused to the pipe by a conventional saddle fusion machine or by the electrofusion technique.
Seat	That portion of the seat ring or valve body that a valve plug contacts for closure.
Seat Load	The contact force between the seat and valve plug.
Service, Abandoned	1. A service which has been disconnected from a gasified main and has been plugged or capped at the service tee. 2. One that has been left connected to an abandoned main and has its downstream end disconnected and capped or plugged.
Service, Active	A service line that is in use delivering gas to one or more customers.
Service Alteration	Modification of an existing service that may involve the lengthening, shortening or rerouting of a service brought about by relocation of a main, a meter or service entry.
Service, Branch	Length of service piping tapped from an existing service to serve a building or premises.
Service, Capped	A service line that was constructed and activated to the meter stop – but which has never been used to deliver gas to a customer.
Service Charge	Fee charged to a customer by the company for the work done.
Service, Extra Length	That portion of service piping required to reach a termination point located beyond the specified allowance.
Service Header	Header installed on private property to serve two or more buildings or premises.

Term	Definition
Service, High Pressure	A service to a customer from a pipeline operating at a pressure greater than that used for distribution, e.g. Intermediate line. This service requires two stages of pressure reduction.
Service, Inactive	A service from which the meter has been removed and the service piping has been capped at the meter location.
Service Line	A pipeline that conveys gas from a gathering line, transmission line, distribution line or another service line to the customer.
Service, Long	A service to a customer on the opposite side of the street as the gas main, thus requiring a road crossing.
Service Reconnection	Reactivation of a service stub or inactive service.
Service, Replacement	Replacement of an existing service; also, the installation of a new service to serve the same customer which may be installed in the same or different location.
Service Riser	1. The attachment to a polyethylene service line to bring the gas above grade to the service shut-off 2. That portion of a steel service line extending above grade to the service shut-off
Service, Short	A service to a customer on the same side of the street as the gas main
Service Shut-off	A valve cock located in a service line between the gas distribution line and the meter. See also Meter Stop.
Service Stub	A piece of pipe that may or may not be connected to a main and usually extended from the main to the curb line for the future addition of a service.
Service, Stubbed	Service that has been capped or plugged between the main and meter; usually near the property line.
Service Tee	A fitting for making a hot tap tee or branch connection on a gas main to supply a service.
Setpoint	The required value of a controlled system.
Shrink Sleeve	Sleeve of polyethylene or similar material that is used to cover a welded joint and is shrunk tightly into place by application of heat. Sleeves can be cylindrical in shape and are slid over the pipe before welding or may be split allowing installation after welding.

Term	Definition
Sleeve	Piece of pipe or casing for covering another pipe or joint, or for coupling two lengths of piping.
Sniffer	Portable instrument used to detect low concentrations of flammable gases or vapours in the air. This term refers specifically to the Johnson-Williams Model “G” Sniffer.
Socket Fitting	A fitting with socket connections. A socket connection has a pipe inserted into a matching cavity on the fitting and is either fused in the case of plastic pipe or fillet welded for steel pipe.
Soft dig	*See Hydro-vac*
Source of Ignition	Any mechanical, electrical, or other device that would produce sufficient energy and temperature to start combustion of a flammable mixture.
Span	The difference between the maximum and minimum values.
Specification	A document stating requirements.
Squeeze	1. Method of stopping gas flow through a pipe 2. A special tool that squeezes the pipe flat to shut off the gas flow.
SRBX	“Spontaneous Report By Exception” A RTU function that will initiate an alarm when system parameters are exceeded.
Standard Volume	A volume of gas measured at Standard Pressure and Standard Temperature
Steel, Alloy	Steel which owes its distinctive properties primarily to elements other than carbon.
Steel, Carbon	Steel which owes its distinctive properties primarily to the carbon it contains.
Stop-off	Method of stopping gas flow through a pipe in which a solid rubber plug, or rubber sealed plug or disc, is inserted into the pipe through a special fitting so that the gas flow is shut off.
Stray Current Corrosion	Corrosion resulting from current flow through paths other than the intended circuit.
Strength Specified Minimum Yield (SMYS)	The minimum yield strength prescribed by the specification or standard to which a material is manufactured.

Term	Definition
Stress Hoop	The stress in the wall of pipe or component that is produced by the pressure of the fluid in the pipeline, any external hydrostatic pressure, or both, and acts in the circumferential direction.
Structure-To-Soil Potential	The potential difference between a buried metallic structure and the soil surface which is measured with a reference electrode in contact with the soil. This should be quoted stating the reference electrode but not the Cu / CuSO4 reference is commonly used.
Structure-To-Structure Potential	The difference in potential between metallic structures in a common electrolyte.
Survey, Bar Hole	A gas leakage survey made by driving or boring holes at regular intervals along the route of buried piping and testing the atmosphere in the holes with a combustible gas detector or other suitable device.
Survey, Gas Detector	A gas leakage survey made by testing with a combustible gas detector the atmosphere in water valve boxes, street vaults, cracks in pavements and other available locations where access to the soil under the pavement is provided.
Survey, Leakage	A systematic survey made for the purpose of locating leaks in a pipeline.
Survey, Vegetation	A leakage survey made by observing vegetation above buried piping.
Swivel or Meter Swivel	A fitting that connects to a diaphragm meter inlet or outlet.
System Betterment	See System Improvement
System Improvement	Work undertaken to maintain the integrity or increase the capacity of any gas main or system.
Temperature, Ambient	The temperature of the surrounding medium in which piping is situated or a device is operated.
Temperature, Base	See Temperature, Standard
Temperature, Standard	A temperature of 15^{o}C. Also referred to as base temperature or temperature at standard conditions, it is the reference temperature for gas measurements of standard volumes.
Test Head Assembly	An assembly of pipe and components that forms a temporary facility used for pressure testing of piping,

Term	Definition
Test Strength	A pressure test to confirm the pressure-retaining capability of piping and establish the maximum operating pressure.
Thermite Welding	A form of welding that involves an exothermic reaction of powdered metal. It is most commonly used to attach a wire to a steel pipe. It is often referred to by the patented name of “Cadwelding”
Tie-in	A connection between (a) two pressure-test sections; (b) pretested piping and other piping; (c) new facilities and existing piping; or (d) two lengths of piping that are fixed at their opposite ends or are long enough to act as though they are so fixed.
Token Relief	See Valve, Token Relief
Town Border Station (TBS)	An informal term for a gate station, often referring to a rural station that serves a town but can also apply to any gate station.
Transmission Line	A pipeline to transport gas at pressures above 1900kPa.
Transmission System	A network of gas transmission lines.
Travel Indicator	A pointer attached near the stem connector, to indicate the travel of the valve plug.
Trim	The internal parts of a valve which are in flowing contact with the controlled fluid.
Tubing (tube)	A tubular product manufactured in accordance with a tubing (tube) specification or standard.
Turbulence	Flow with relatively large fluctuations or disturbances, i.e. not laminar flow. Associated with flow rate, pipe wall surface roughness, directional changes and throttling.
Two-way Feed	A line which has a source of supply from both directions.
Upgrading	Qualifying an existing pipeline system, or portion thereof, for a higher maximum operating pressure or for a changed class location.
Upper Explosive Limit	The greatest proportion of flammable gas mixed with air that would result in combustion when exposed to a source of ignition, approximately 15% methane in air.

Term	Definition
Upstream	1. The direction from which a fluid will flow. 2. A location in the direction from which a fluid will flow
Valve, Angle	A valve construction having inlet and outlet line connections on different planes; usually perpendicular to each other.
Valve, Automatic Shut-off	An actuated valve that automatically closes when a sensing device detects a variable, usually pressure, that varies from set limits.
Valve, Ball	A valve utilizing a complete sphere with a hole allowing flow to be stopped or controlled by rotating the sphere.
Valve Box	Ground surface housing placed over a vertical tile or pipe giving access to a valve which is below grade.
Valve, Curb	A buried valve installed in a service line at or near the property line, accessible through a valve box and cover, and operable by removal key.
Valve, Emergency	A strategically located valve that is installed in a pipeline system to isolate the gas flow in emergency situations.
Valve Flow Coefficient (Cv)	The number of U.S. gallons per minute of 15.6^{o}C water that will flow through a valve with a 6.895 kPa pressure drop.
Valve, Full Relief	A pressure relief valve that is sized to vent at a sufficient rate to prevent the pressure in the system from rising beyond an acceptable level
Valve, Globe	A valve construction style with a linear motion flow controlling member with one or more ports, normally distinguished by a globular shaped cavity around the port region.
Valve, Isolating	A valve for isolating lateral, stations, pressure relieving installations, and other facilities
Valve, Line	A manually or automatically controlled shut-off valve in a pipeline.
Valve, Meter Stop	See Meter Stop
Valve, Pressure Relief	A device that operates to actively lower pressure by dumping, flaring, or blowing down the pressurized fluid
Valve, Remote Control	An actuated valve or controller whose setpoint or position can be adjusted by a signal from a remote location
Valve, Sectionalizing	A valve for isolating a segment of pipeline.

Term	Definition
Valve, Station Inlet	First valve in a branch line or lines serving a regulator station that will stop the supply of gas to the station when closed.
Valve, Token Relief	Small pressure-relief valve intended to discharge gas at a greatly reduced or token rate to serve as a warning that upset conditions exist. Note: A token relief valve is not large enough to prevent excess pressure build up under all circumstances.
Vault	A buried enclosure for equipment with a manhole opening for access and egress, usually in street areas or where control valves are required to be installed below grade.
Vena Contracta	Location where cross-sectional area of the flow stream is at its minimum size, where fluid velocity is at its highest level, and the fluid pressure is at its lowest level. Normal occurs just downstream of the actual physical restriction in a control valve.
Vent Stack	A vertical length of pipe connected to a relief valve or regulator vent with internal relief to carry vented gas to a safe height.
Voltage	An electromotive force or a difference in electrode potentials expressed in volts.
Wall Thickness	The difference between inside and outside diameter of a pipe.
Wall Thickness, Nominal	The specified wall thickness of the pipe purchased. Actual wall thickness can vary due to manufacturing variances.
Water Column	A unit of pressure representing the hydrostatic head of a specified height of water.
Weld	A localized coalescence of metals produced by heating the materials to the welding temperature, with or without filler metal.
Weld, Butt	A circumferential weld in pipe fusing the abutting pipe walls completely from inside wall to outside wall.
Welding Procedure Specification	A document providing, in detail, the required parameters for welding.
Yellow Jacket	Polyethylene coating applied over a tacky elastomer film of adhesive on steel pipe supplied by Shaw Pipe Coating Ltd.
Yield Strength	The stress at which a material exhibits a specified limiting permanent set.

Term	Definition
Yoke	A structure by which the diaphragm case or cylinder assembly is supported rigidly on the bonnet assembly.

Abbreviation	Meaning
ABS	Absolute Pressure.
AGA	American Gas Association
AMR	Automated Meter Reading
ANSI	American National Standards Institute
ASTM	American Society for Testing Materials
BMI	Black Malleable Iron
BTU	British Thermal Units
BW	Butt Weld
°C	Degrees Celsius
CGI	Combustible Gas Indicator
CTS	Copper Tube Size
Cv	Valve Flow Coefficient
DRS	District Regulator Station
FF	Flat Face
GS	Gate Station
GMI	Gas Measurement Instruments Ltd. (A brand of CGI's)
HDD	Horizontal Directional Drilling
HP	High Pressure
ID	Inside Diameter
IP	Intermediate Pressure
ISA	Instrument Society of America
°K	Degrees Kelvin
kPa	Kilopascal
kPaa	Kilopascal Absolute
LEL	Lower Explosive Limit
LP	Low Pressure
MAOP	Maximum Allowable Operating Pressure
MDPE	Medium Density Polyethylene
MI	Malleable Iron
MOP	Maximum Operating Pressure
MP	Medium Pressure

Abbreviation	Meaning
MPa	Mega Pascal
MSDS	Material Safety Data Sheet
MSS	Manufacturers Standards Society of valve and fittings industry.
NGV	Natural Gas for Vehicles; Natural gas stored in a gaseous state to be used as engine fuel for a vehicle.
NPS	Nominal Pipe Size; Acronym used in conjunction with a non-dimensional number to designate the nominal size of valves, fittings, and flanges.
NPT	National Pipe (Thread) Tapered
NTS	Nominal Tube Size
OD	Outside Diameter
OSHA	Occupational Safety and Health Administration
PFM	Pressure Factor Measurement
PQR	Procedure Qualification Record (Welding)
PS	Primary Station
PSI	Pounds per Square inch
PSIA	Pounds per Square inch Absolute
PSIG	Pounds per Square inch Gauge
PPE	Personal Protective Equipment
RCV	Remote Control Valve
RF	Raised Face
RS	Regulator Station
RSU	Remote Sensing Unit
RTU	Remote Terminal Unit
SCADA	An acronym for Supervisory Control And Data Acquisition, a monitoring and control system.
SCRD	Screwed
SMYS	Specified Minimum Yield Strength
SRBX	Spontaneous Response by Exception
SSPC	Structural Steel Painting Council
SW	Socket Weld
TBS	Town Border Station
THD	Threaded
TOE	Thread One End
UEL	Upper Explosive Limit
WC	Water Column
WN	Weld Neck
WOG	Water Oil Gas
WPS	Welding Procedure Specification

Abbreviation	**Meaning**
WT	Wall Thickness
WWP	Working Water Pressure

Station Designations

Stations shall be designated according to the definitions provided and as per table 1 following:

Table 1
Station Designations Based on Source and Output

		From			
		Supply (TCPL)	Transmission	Intermediate	Distribution
To	Supply (TCPL)	-o-	-o-	-o-	-o-
	Transmission	Primary Gate Station	Gate Station	-o-	-o-
	Intermediate	-o-	Gate Station	Regulator Station	-o-
	Distribution	-o-	Gate Station or Farm Tap	Regulator Station	Regulator Station
	Customer	-o-		High Pressure Service	Service

Scope

This standard defines terms that are in common usage to refer to ranges of pipeline maximum operating pressures in the Manitoba Hydro gas transmission and distribution systems.

Pressure Classifications

Pressure classifications for pipeline systems are listed in Table 1.

These terms are company specific and are not defined or referenced in any national standard. Similar references may or may not be used by other gas distribution companies and their definitions may be different.

These terms are for general reference use only. Wherever possible, documentation and records shall reference the actual pipeline system maximum operating pressure (M.O.P.) rather than these general pressure classifications.

Table 1
Pipeline System Pressure Classifications

Pressure Class		**Maximum pressure or range**		**Application**
		Psig	**kPa**	
Distribution				A generic term for the broad range of pressures used for gas distribution. Specifically, the pressure in gas distribution systems that deliver gas directly to customer's meter sets with only one stage of pressure regulation.
	Medium	60	420	Historically, medium pressure has typically been the standard in urban distribution systems.
	Elevated	61-100	421 – 700	A pressure term encompassing the upper end of distribution pressure that exceeds medium pressure. Elevated pressure is typically found in rural gas distribution systems.
High (also referred to as Intermediate Pressure)		80 - 275	550 – 1900	This pressure range is found in intermediate lines that deliver gas from a transmission line to a distribution system. This pressure range is higher than distribution pressure supplied and less than transmission pressure.
Transmission		>275	>1900	The pressure range normally used in transmission lines.

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Approved:

T.D.M. STARODUB

MANITOBA HYDRO NATURAL GAS STANDARD

Section: **Design**

Subject: **General**

Title: **System Pressure Classifications**

Supercedes: 2002 10 31

Effective Date: 2010 06 15

Standard Number: **510.01**

Undesignated Pressure Classes

Some pipeline systems have a maximum operating pressure that does not conform to the ranges in Table 1. Where a distribution system has a distribution pressure other than medium pressure or elevated pressure, the maximum operating pressure shall be specified. For example, a distribution system with a maximum operating pressure of 100 kPa shall have the “MOP 100kPa” noted in designs, drawings and records.

Systems using PE100 at pressures above 700 kPa shall be labeled as an undesignated pressure class.

Pipeline Component Pressure Class Nomenclature

The CSA standard CSA Z245.12 specifies the maximum cold working pressure for various classes of flanges. These classes may be defined by a “PN” number or by an ANSI Class. For more information on these pressure classes, refer to Standard 110.02 - Units of Measure.

Table 2 lists the maximum cold working pressure for the pipeline components normally used in gas transmission and distribution.

Table 2
Pipeline Component Pressure Classes

ANSI Class	(PN) number	Maximum working pressure rating (kPa)
150	20	1 900
300	50	4 960
600	100	9 930

Scope

This applies to the initial selection of sites for new pressure regulation stations.

This does not apply to the location of farm tap assemblies.

References

Policy and Procedures

P280-5	Preparing Request for Easement, Land Purchase or Lease
P280-6	Receiving Request for Easement, Land Purchase or Lease from Property Department Number:

General

The selection of land for pressure regulation facilities will be dependent on availability from current land owners for an acceptable cost and under suitable conditions. Available sites are to be evaluated based on the Station Requirements indicated. An Individual Assessment of a site(s) may be required to identify a preferred location or to accept an available site.

Station Location Requirements

- The station site shall be a minimum of 30 m by 30 m. Other lot sizes or shapes can be considered (see Individual Assessment).
- The station site shall be on, adjacent to, and accessible from, a paved or graveled all-season road i.e. a road that is maintained and cleared by the Municipality all year.
- The station site shall be suitable for the construction of its own approach approved by the appropriate governing body. e.g. highways, the R.M. etc. (Note: A shared approach with others shall not be permitted unless extraordinary circumstances are present.)
- The station site shall not be in a location subject to extraordinary snow accumulation such as adjacent to a windbreak.
- The station site shall be of such an elevation with respect to surrounding area and shall have sufficient drainage such that no more than 0.3m of site build-up will be required to keep station site well drained at all times.
- Stations considerations shall be given to:
  - a maximum of 250 m from a Hydro power supply
  - a maximum of 250 m from a telephone line
  - a maximum of 150 m from the pipeline or proposed pipeline supplying the station
- Stations to be supplied by a transmission line shall be:

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MANITOBA HYDRO NATURAL GAS STANDARD

Section: **Design**

Subject: **Stations**

Title: **Station Site Selection**

Supercedes: 1999 09 20

Effective Date: 2008 02 15

Standard Number: **541.06**

  - a minimum of 200 m from residential development i.e. multiple dwellings
  - a minimum of 50 m from an inhabited dwelling
  - a minimum of 200 m from public building property such as school yards or hospital property.
  - a minimum of 200 m from rail lines
  - a minimum of 50 m from any high voltage electric transmission lines
  - a minimum of 50 m from an electrical sub-station
- The station site shall not have any location factors that could abnormally impact the safety or security of a station.

Station Location Preferences

Where possible, the station should be located on the same side of road right of way as the high pressure or transmission pressure pipeline.

Environmental Acceptance

The location of a station on the selected site should not unduly impact land use, drainage patterns or wildlife.

Noise levels to be generated by a station should be taken into account when determining the station location.

The proposed site shall be free of contaminants or other environmental liabilities or concerns.

Note: Environmental review and screening is part of the land acquisition process.

Individual Assessment

Should a proposed station site not meet the mandatory criteria as set forth, a site-specific assessment by the Engineer responsible for the design of the station is required. The Engineer may waive one or more of the requirements on a site-specific basis.

Scope

This document specifies the pipe wall thickness and pipe grade for general pipeline and station applications for steel pipe up to NPS 16. This does not apply to steel pipe used for structural purposes. This does not apply to steel pipe used for casings.

References

210.01	Material Specifications - Coated Steel Pipe
210.11	Material Specifications - Bare Steel Pipe
720.07	Pre-tested Pipe
ASTM	B36.10M - Welded and Seamless Wrought Steel Pipe

Specifications

The wall and grade specifications for pipe to be primarily used in below and above grade applications shown in Table 1 and are subject to:

- Pipe from NPS 2 through NPS 6 shall have a minimum wall thickness of 3.18 mm
- Pipe larger than NPS 6 shall have a minimum wall thickness of 4.78 mm
- Pipe grade shall not exceed 386 MPa
- Above grade piping for applications other than customer service risers shall have a minimum wall thickness corresponding to standard weight (see Table 2).
- These parameters are in addition to Specification 210.01

Table 1 also lists options for below grade piping that may be used where the design engineer considers the alternative to be more appropriate to the particular installation.

These specifications are not intended to be fully comprehensive but are to be used as a guide for most applications. See Exceptions.

For above grade pipe runs over 50m, Category II pipe may be required. Review applicable requirements of CSA Z662.

Exceptions

Pipe that does not conform to these specifications may be used on a project specific basis where a detailed engineering design has been done. In this situation, the design shall consider whether:

- the pipe specified is supported by the current welding procedures,
- the pipe is compatible with maintenance equipment and procedures, and
- the pipe is supported by the pre-tested pipe inventory.

Where a non-standard pipe is specified and changes are required to welding procedures, maintenance equipment or procedures, or the pre-tested pipe inventory, such changes shall be in place or initiated prior to the installation of the pipe.

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MANITOBA HYDRO NATURAL GAS STANDARD

Section: **Design**

Subject: **Steel**

Title: **Steel Pipe Specifications**

Supercedes: 2002 01 31

Effective Date: 2010 06 15

Standard Number: 530.02

Pipe Weight Class or Schedule Specifications

Pipe specifications may denote the wall thickness dimension directly, as is usual for line pipe specifications.

Pipe may also be specified by weight class or schedule number as per ASTM B36.10M.

Table 2 contains an excerpt of Weight Classes and Schedule Numbers for pipe sizes most commonly used.

Table 2

Selected Steel Pipe Dimensions by Weight Class and Schedule Number

Nominal Pipe Size	Outside Diameter		Wall Thickness		Weight Class	Schedule Number
	(mm)	(inches)	(mm)	(inches)		
¾	26.7	1.050	2.87	0.113	STD	40
			3.91	0.154	XS	80
1	33.4	1.315	3.38	0.133	STD	40
			4.55	0.179	XS	80
1¼	42.2	1.660	3.56	0.140	STD	40
			4.85	0.191	XS	80
1½	48.3	1.900	3.68	0.145	STD	40
			5.08	0.200	XS	80
2	60.3	2.375	3.91	0.154	STD	40
			5.54	0.218	XS	80
3	88.9	3.500	5.49	0.216	STD	40
			7.62	0.300	XS	80
4	114.3	4.500	6.02	0.237	STD	40
			8.56	0.337	XS	80
6	168.3	6.625	7.11	0.280	STD	40
			11.0	0.432	XS	80
8	219.1	8.625	6.35	0.250		20
			7.04	0.277		30
			8.18	0.322	STD	40
			10.3	0.406		60
			12.7	0.500	XS	80
10	273.1	10.750	6.35	0.250		20
			7.80	0.307		30
			9.27	0.365	STD	40
			12.7	0.500	XS	60
			15.1	0.594		80
12	323.9	12.750	6.35	0.250		20
			8.38	0.330		30
			9.53	0.375	STD	
			10.3	0.406		40
			12.7	0.500	XS	
			14.3	0.562		60
			17.5	0.688		80
14	355.6	14.000	6.35	0.250		10
			7.92	0.312		20
			9.53	0.375	STD	30
			11.1	0.438		40
			12.7	0.500	XS	
			15.1	0.594		60
			19.1	0.750		80
16	406.4	16.000	6.35	0.250		10
			7.92	0.312		20
			9.53	0.375	STD	30
			12.7	0.500	XS	40
			16.7	0.656		60
			21.4	0.844		80

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MANITOBA HYDRO NATURAL GAS STANDARD

Section: **Design**

Subject: **Steel**

Title: **Steel Pipe Specifications**

Supersedes: 2002 01 31

Effective Date: 2010 06 15

Standard Number: 530.02

Scope

This standard specifies parameters for 1/8 inch to 1/2 inch tubing installation(s) at natural gas transmission and distribution facilities.

References

650.01 Pressure Testing
ASTM A269 Seamless and Welded Austenitic Stainless Steel Tubing for General Service

Acceptable Materials

Tubing: Stainless steel tubing, type 304 or 316, seamless or welded and drawn, maximum hardness of 80 HRB, ASTM A269. Length 20 feet (6.1 m) unless otherwise specified. The tubing wall thickness shall be as follows:

Tubing Size (O.D.) (in.)	Tubing Wall Thickness (in.)
1/8, 1/4, 3/8	0.035
1/2	0.049

Fittings: Parker CPI or Swagelok fittings in 316 stainless steel. The products from the two manufacturers are not interchangeable. The manufacturer shall be selected to match the existing used at a site. For new locations, the manufacturer shall be selected to match the systems used at most sites in the district.

Equipment or equipment packages supplied with pre-installed tubing may use Parker CPI or Swagelok fittings in 316 stainless steel.

Tubing Requirements

Typical Sense Line Tube Diameters

Length	Diameter	Notes
Less than 10 feet	3/8 inch	①
10 to 20 feet	1/2 inch	②
over 20 feet	Increase one tube size	③

① Use control lines of equal or greater size to the control tap on the regulator.
② If the control line is long (over 10 feet), the size should be increased.
③ Use the next nominal pipe size for every 20 feet of control line.

Undersized control lines cause a delayed response of the regulator, leading to increased chance of instability.
3/8 inch OD tubing is the minimum recommended control line size for new installation.
Do not place control lines immediately downstream of rotary & turbine meters.

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Supercedes: 2006 01 30

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MANITOBA HYDRO NATURAL GAS STANDARD

Section: **Construction**
Subject: **Facilities**
Title: **Tubing Installation**

Effective Date: 2009 10 28

Page 1 of 5

Standard Number: **650.20**

Bending

Bending shall be done as follows:

- All bending of tubing shall be done using tubing benders. Spring type tubing benders shall not be used.
- Kinks in the tubing are not permitted.
- Wrinkled bends are not permitted.
- The minimum bending diameter as measured to the center of the tubing shall be as shown on Table 1.
- A straight length minimum shall be provided between a fitting and the start of a bend. The minimum length of this straight length is shown in Table 2.
- The bending diameter is measured to the centerline of the tubing.

Table 1

Bending Diameter for Stainless Steel Tubing

Tubing Size O.D. (inches)	Minimum		Recommended	
	(Inches)	(mm)	(Inches)	(mm)
1/8	5/16 (0.31)	7.9	5/16 (0.31)	9.5
1/4	5/8 (0.63)	15.9	3/4 (0.75)	19.1
3/8	15/16 (0.94)	23.8	1 1/8 (1.13)	28.6
1/2	1 1/4 (1.25)	31.8	1 1/2 (1.5)	38.1

Table 2

Minimum Straight Length at End of Tube

Tubing Size O.D. (inches)	Straight length (Minimum)	
	(Inches)	(mm)
1/8	¾	19
1/4	1	25
3/8	1	25
1/2	1.25	32

Cutting

- Tubing cuts shall be made with tubing cutters made for stainless steel tubing.
- The cut tubing ends shall be reamed and deburred.

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Section: **Construction**

Subject: **Facilities**

Title: **Tubing Installation**

Supercedes: 2009 01 30

Effective Date: 2009 10 28

Standard Number: **650.20**

Table 3

Tubing Support – Horizontal ①

Tubing Size (in)	Maximum Horizontal Length of Tubing Between Supports (m)
1/8	0.3
1/4	0.6
3/8	1
1/2	1.5

① This is the total length of horizontal tubing, vertical tubing length not included.

Additional support for tubing shall be added when:

- ice forms on the tubing or the tubing will be subject to ice formation.
- tubing demonstrates noticeable vibration.

Electrical Isolation

The tubing or devices connected to the tubing shall not impair the operation of the pipeline cathodic protection. In some facilities, the station piping is isolated from the cathodic protection of the pipeline. In other facilities the cathodic protection is carried through above grade piping.

Where cathodic protection is carried through above grade piping to which tubing is attached:

- an insulating connection is required if tubing contacts anything that is grounded such as the building wall or a pipe support.
- an insulating fitting may be required where tubing connects to a terminal device such as a pressure transducer or pressure recorder.

Pressure Testing

Tubing 1 inch and smaller in outside diameter shall be tested as follows:

- Tubing shall be tested at operating pressure.
- Tubing shall be pressurized to operating pressure for a minimum of 10 minutes before leak testing.
- The tubing shall be visually inspected and 100 % of the joints and connections shall be inspected for leaks.
- Soap testing may be used to inspect for leaks.
- Leak testing shall be done by Manitoba Hydro personnel or the testing shall be witnessed by Manitoba Hydro personnel.

Alternatively, the tubing may be tested along with the testing of the piping.

1.0 OBJECTIVES

This manual is to provide guidance in designing stations and documentation of the design methodology. It is to be used as a tool in the standardization of designs, layouts, and specifications of all regulating and metering facilities produced by Centra Gas Manitoba Inc..

2.0 SCOPE

The manual contains general information on the operation of various components of a regulator and metering station. The manual is intended to apply to all 2" through to 8" piping at all gate and regulator stations.

It is not the intention of this standard to supercede, or contradict, any existing codes or regulations except where it provides for a higher degree of safety or more stringent specifications.

3.0 SUCCESS MEASURES

The assembly must reduce the pressure and maintain it at the desired set point. All components to the design must meet or exceed current code requirement and must be easily accessible for maintenance, operability, and safety purposes.

4.0 REFERENCE CODES

CSA Z-662-96	Oil and Gas Pipeline Systems
CSA B51-95	Boiler, Pressure Vessel, and Pressure Piping Code
CSA C22.1-1994	Canadian Electrical Code, Part 1
CAN/CSA- C22.2 No. 0-M91	General Requirements – Cdn Electrical Code, Part II
CSA C22.3 No. 4-1974 (R1995)	Control of Electrochemical Corrosion of Underground Metallic Structures
CAN/CSA-C22.3 No. 6-M91	Principles and Practices of Electrical Coordination between Pipelines and Electric Supply Lines.
CAN/CGA-B149.1-95	Natural Gas Installation Code
CGA-OCC-1-1985	Recommended Practice for the Control of External Corrosion on Buried or Submerged Metallic Structures and Piping Systems.

5.0 STATION TYPES

5.1 Gate Station (GS)

This type of station is sometimes referred as the Primary Station and usually signifies larger volumes and typically involves the custody transfer point or check metering for gas purchased by Centra Gas Manitoba Inc.. These installations can include pressure control equipment, process control and odourization systems.

5.2 Town Border Station (TBS)

This describes larger capacity installations where gas is received from a transmission system and regulated to a set-point to enter either a high pressure, or elevated pressure network or a medium pressure system, or a combination of both. In some cases these stations may also contain metering or odourization components. Typically these stations are located on the boundaries of towns or at the perimeter of densely populated areas.

5.3 Regulator Station (RS)

These stations are installed on the downstream side of either the GS or TBS. On urban gas systems they are primarily used to reduce the pressure from high pressure (HP) to medium pressure (MP). On rural systems they are often used to reduce the pressure from transmission pressure (TP) to elevated pressure (EP). These types of installations vary in volume capacity from 1420 m3/hr (50 mcfh) to 42,500 m3/hr (1500 cfh) depending on the location.

5.4 Farm Tap (FT)

These type of installations are small regulating (sometimes may contain odourization) facilities that serve a single customer or a small defined distribution system. Pressure reduction is typically from transmission pressure (TP) to medium pressure (MP). Metering is usually done at the customers meter set and is not required at this installation. The installation vary in volume but are usually less than 1420 m3/hr (50 mcfh).

6.0 SITE SELECTION

6.1 Site Requirements

The station site requirements are dictated by the amount equipment and the intended use of the site. A general outline is shown below in Table 6.1.1. When using this table, consideration must also be given to such things as land availability, population density (includes encroachment, noise, ascetics) in the proximity of the proposed station site.

Table 6.1.1

STATION SITE REQUIREMENTS
LAND

Station Type	Metres	Feet
Gate Station (GS)	30.5 x 30.5	100’ x 100’
Town Border Station (TBS)	30.5 x 30.5	100’ x 100’
Regulator Station (RS)	15.25 x 15.25	50’ x 50’
Farm Tap (FT)	To be installed on public property or R/W	To be installed on public property or R/W

The station site must be located along a maintained year round road. Power and telephone to be available. Additional information to consider before selecting a site must be:

- snow accumulation such as drifting (ie: not locating a station near farm wind row).
- Site and local land elevations – the proposed site should be level and flat and not adjacent to any hills or hollows. The local land elevations must be confirmed prior to purchase in the event of flooding concerns. If the proposed site must be located within a potential flood area, every effort must be made to either locate within a properly constructed dike area or steps are to be taken to ensure security of supply of the proposed facility.
- Refer to the Station selection standard for further details – ENG-STC-S-002

Other than farm taps, all stations that will require company vehicles to enter or exit the property must have compaction of a minimum of 10” below existing grade.

See compaction criteria in Section 17.

6.2 Site Layout

The station piping including all regulation equipment and valving should be located in such a manner on the property that a future upgrade could be completed on site without requiring further land procurement or numerous piping changes.

As per table 6.2.1, where practicable site layouts should conform to the following dimensions.

Table 6.2.1 Station Site Layout – Side Yard Dimensions

From	To	Minimum Distance
Public Roadway	Fence	3 m
Fence	Block and Bypass Valves	1m
Fence	Property Line	0.3 m
Structure Door	Fence	2 m
Structure Wall	Fence	0.3 m
Bollards	Any piping or structures	0.3 m (not to exceed 1 m)
Edge of Gravel (grade)	Fence	0.3 m
Equipment or Structure/Piping	Edge of Compacted Gravel	1 m
Power Pole	Fence	0.3 m

Other: Minimum width of Driveway – 5 metres
Minimum width of Gate for Driveway – 5 metres

7.0 STATION PIPING

7.1 Steel Pipe

Unless otherwise specified, station piping is specified as CSA Z245.1, Seamless* Grade 290 standard or higher. Stainless steel tubing is usually used for piping less than 21.3 mm (1/2”). For most applications Category I pipe is sufficient. However, for the following special applications section 5.2.2 of the CSA Z662-96 should be consulted:

- Piping lengths greater than 50m (160’);
- Where the design operating stress is 50 MPa (7250 psig) or more, steel pipe 60.3 mm (2”) OD or larger with a nominal wall thickness exceeding 5.0 mm (0.197”)
- Pipe operating at temperatures less than –30 C (-22 F)

The determination of required pipe diameter should be based upon peak gas velocity and pressure drop. The velocity in the station piping should not exceed 60 m/s (200 ft/sec).

The maximum velocity should be determined using peak hourly flow. Gas velocity can be approximated using the following formula:

$$V = 3.66 \times 10^7 \frac{Q}{P\ (Di^2)}$$

Where:
V= gas velocity (m/s)
Q= peak flow (10^3m^3/hr
P= absolute pressure of the gas (kPa)
Di= inside diameter of pipe (mm)

To convert the velocity calculation from m/s to ft/s simply change the constant in the formula to 1.20×10^8.

Pressure drop can be determined using various computer modeling software such as Gwcalc or Stoner. For determination of station pressure drop the following parameters should be used:

Base equation= IGT Improved Equation for pressure than 690 kPa (100 psig) or PanHandle A for pressures greater than 690 kPa (100 psig).

Pipe Efficiency= Steel – 92%, Plastic 95%
Flow= Hourly peak flow should be used

Length= Use length of spool that is to be calculated

Once the pipe has been sized, the minimum wall thickness can be calculated using the following formula from CSA Z662-96 clause 4.3.3.1.1 :

$$t= \frac{PD}{2 \quad S(F)(J)(T)(L)} \quad x \quad 10\text{^-}3$$

where t= pipe wall thickness (mm)
P= design pressure (kPa) – The design pressure must always be greater than the maximum operating pressure of the system.
S= specified minimum yield strength of the pipe (MPa)
D= outside diameter of the pipe (mm)
F= design factor (0.8)
J= joint factor in accordance with CSA Z662-96 (1.0 for seamless or electric weld)
L= location factor in accordance with CSA Z662-96 (see table below)
T= temperature de-rating factor in accordance with CSA Z662-96 (1.0 for T up to 120 C)

		Location Factor(L)		
Application	Class location 1	Class location 2	Class location 3	Class location 4
Gas (non-sour)				
General and cased crossings	1.00	0.90	0.70	0.55
Roads*	0.75	0.625	0.625	0.50
Railways	0.625	0.625	0.625	0.50
Stations	0.625	0.625	0.625	0.50
Other	0.75	0.75	0.625	0.50

- For gas pipelines, it shall be permissible to use a location factor higher than the given value, but not higher than the applicable value given for “general and cased crossings,” provided that the designer can demonstrate that the surface loading effects on the pipeline are within acceptable limits (see Clause 4.6).

For the majority of the cases the calculated wall thickness will be less than the standard wall thickness (schedule 40). However, standard wall pipe should be used as a minimum. If the pipe is to mechanically loaded, subjected to severe vibration or a corrosive environment extra precautions may be necessary. Each case should be handled on an individual basis and is out of scope for this standard.

In addition to the above, the following general requirements concerning station piping should be observed:

1. All underground piping and fittings are to be welded.
2. Threaded connections should be avoided where possible on all above grade piping intended to operated over 690 kPa (100 psig).
3. All above grade piping must be adequately supported to minimize stresses from external loading.
4. The centre line of the lowest pipe run or fittings should be 152 mm (6") above grade. (only pipe that contains only sense points can be placed this low, pipe runs containing valves or regulators must be a minimum of 610 mm (24")
5. Above grade piping is to be painted to company standards.
6. Below grade piping is to be yellow-jacket coated and cathodically protected. The coating should extend 300 mm (12") above grade level.
7. Piping systems of different operating pressures are to be electrically insulated from each other and all piping is to be insulated from electrically grounded structures.

When transitioning from station piping to line pipe there is often a difference in wall thickness. Where differences occur some form of a transition piece may be required. The following should be used as a guide on when to specify a transition:

1. A transition is required if the nominal internal or external offset exceeds one-half the thinner wall section.
2. A transition is required if the nominal wall thickness of adjoining ends vary by more than 2.4mm (0.944"). This may be increased to 3.2 mm (0.125") if the piping is to operate at hoop stresses less than 30% of the specified minimum yield strength
3. When transitioning between piping of different yield strengths (grades), the transition pipe must be made of the same material as the higher grade pipe and have the same wall thickness as the lower grade pipe.

For further information please refer to CSA Z662-96 Clause 7.2.2.

7.2 Fittings

All fittings and flanges must be designed to at least CSA Z245.1 Category I Standard, and must be suitable for service with the grade of pipe to which they are to be joined. Proven notch toughness properties shall not be required for the following steel components: valves smaller than NPS 4, valves with nominal pressure class of PN20 and fittings and flanges smaller than NPS 2.

Welded fittings are preferred, where available, on all applications where the maximum operating pressure is greater than 410 kPa (60 psig). Below grade fittings must all be welded. In order to reduce the possibility and risk of leaks at stations welded fittings instead of flanges have been adopted. Common sense should be used in determining whether assemblies should be welded or flanged. Where in doubt please refer to existing station practice and drawings as found in Appendix A.

8.0 REGULATOR SELECTION

8.1 General

Pressure control regulators can be categorized into the following types:

1. self-operated
2. pilot-operated

Self operated regulators characteristically provide less accurate control, but are more dependable in terms of freeze off prevention, less expensive and easier to operate than pilot controlled types. Self-operated regulators sense the downstream pressure through either an internal pressure tap or external pressure control line. This downstream pressure opposes a spring, which moves a diaphragm and valve plug to restrict flow of the gas stream through the regulator orifice.

The pilot-operated regulator is essentially two regulators, with the main regulator controlling the gas flow and the pilot regulator providing an intermediate pressure to the loading side of the diaphragm of the main regulator. With the pilot regulator providing a reduced pressure differential across the main regulator, it is possible to use a lighter spring which in turn makes the regulator react more quickly to pressure changes and maintain a more constant downstream pressure.

Boot style regulators such as Fisher 399, Mooney, and Axial Flow regulator operates in the same manner as other pilot operated regulators except that the diaphragm, spring and valve plug are replaced with a rubber boot which is pushed away from a cage opening (orifice) when a decrease in downstream pressure is sensed.

8.2 Regulator Runs

Pressure control regulators can be further grouped into the following arrangements or better known as regulator runs:

1. single regulator
2. worker monitor
3. working monitor

If economics were the most important factor governing station design, almost all would be single regulator designs. However, safety and security of supply are the most common overriding factors.

This has lead to the development of designs using parallel and monitor backup regulators. The following guidelines shall be used to determine which type of regulator run will be used:

TYPE	**APPLICATION**
1. Single Run, Single regulator	Small Farm Tap – less than 115 m3/hr (4000 cfh). – full capacity relief valve is required. See appendix XXXX
2. Parallel Run, Single regulator	Large Farm Tap – less than 570 m3/hr (20,000 cfh) – full capacity relief valve is required. See appendix XXXX
3. Single Run, worker monitor (pilot-operated)	Regulator Station (RS) type application – urban setting – max. pressure differential 3450 kPa (500 psi). See appendix XXXX
4. Parallel Run, worker monitor (pilot-operated)	Less than 2,850 m3/hr (100,000 cfh) – max. pressure differential 3450 kPa (500 psi). See appendix XXXX
5. Parallel Run, worker monitor – two pressure cuts (pilot-operated)	Greater than 2,850 m3/hr (100,000 cfh) – pressure differential greater than 3450 kPa (500 psi). See appendix XXXX
6. Parallel Run, working monitor (pilot-operated)	Less than 2,850 m3/hr (100,000 cfh) and pressure differential is greater than 3450 kPa (500 psi). See appendix XXXX

For pressure drops of more than 3450 kPa (500 psig) the regulation should be done in two stages. When this is required the intermediate pressure is best approximated by a ratio of the pressure as follows:

(Note: This is only used if two single regulators are used, or a working monitor setup is conducted to perform the two stage pressure reduction)

$$\frac{P1}{P2} = \frac{P2}{P3}$$

Therefore: $P2 = (P1\ P3)^{\wedge}1/2$

where:
P1= maximum inlet pressure
P2= intermediate pressure
P3= design outlet pressure

Other considerations in the design of regulator runs are regulator isolation valves, pressure taps and the piping itself.

Each regulator run requires an upstream and a downstream isolation valve in order to isolate the regulator run and repair the regulator without affecting gas service. The valves should be sized to the regulator inlet and outlet piping without restriction and should be a full port configuration. Plug or ball valves are considered ideal for this type of application. In addition, the valves must be pressure rated to the maximum upstream pressure.

Piping should be sized and meet material standards as discussed in section 7 of this manual. In addition, piping should be sized to a maximum of 60 m/s (200 ft/s) or the regulator body size, whichever is larger. Since the velocity is dependent on pressure, it may be necessary to use different size pipe on the upstream and downstream side of the regulator.

An additional tap is to be located on the downstream side of the regulator (if the regulator uses an external pilot). The location of this tap is best suited at a point where flow is laminar and the pressure is more stable to improve accuracy of the sense point. A typical location of these sense points is on separate header or on the outlet run of the piping (a guideline is a minimum of 5-10 pipe diameters from the regulator or other flow restricting devices)

Additional pressure taps (1/2” needle valves) are required on both sides of each regulator for each regulation run, in order to blowdown pressure to the atmosphere. Each blowdown is tubed to a common header and tubed outside the building or structure. If no structure is required for the station, the blowdowns can be tubed so that the pressure is released away from the employee. A short spool of tubing on each needle valve to a location ending below the regulator run piping is typically used.

8.3 Sizing and Selection

The following parameters must be known before selecting any regulator:

- maximum inlet pressure
- minimum inlet pressure
- maximum outlet pressure
- minimum inlet pressure
- desired outlet pressure
- maximum hourly flowrate
- minimum hourly flowrate

The regulator must be designed to withstand the maximum pressure the upstream system is likely to deliver (MAOP). This information is documented in all manufacturers equipment literature and this pressure must always meet or exceed this maximum inlet pressure to the regulator. Some manufacturers, list the maximum allowable pressure differential across the regulator. This is the difference between the maximum allowable inlet pressure and the minimum outlet pressure (set pressure). Exceeding this differential may cause partial or full regulator failure.

In monitor or two stage regulators, where there is no relief valve between the upstream and downstream regulators, both regulators must be able to withstand the maximum operating pressure of the inlet supply line and the maximum pressure differential.

The maximum inlet pressure must also used to determine the wide-open capacity of the regulator, which is required for relief valve sizing.

Regulator capacity decreases in proportion to a decrease in differential pressure across it. Since it is necessary to size the regulator for the worst conditions, its capacity should be determined using the minimum inlet pressure, the proposed set pressure and the peak load. In parallel run installations, each regulator run must be sized to handle the full load. A typical rule of thumb is to size the regulator to handle 75-80% of the maximum capacity that the regulator can pass under the conditions being designed. Please refer to the manufacturers literature for capacity information or contact the manufacturer where questions arise.

In worker monitor arrangements, seldom is there manufacturer information readily available to complete “quick” sizing. Therefore, for a reference guide a capacity of 70% of the working capacity of the smaller regulator/orifice can be used. But in all cases, it is best to have verification of the capacity from the manufacturer, especially if the design load is close to this capacity.

Currently both Mooney and Fisher both provide Centra Gas Manitoba Inc. with regulator sizing software to handle both single and worker monitor type applications. Copies if necessary can be provided from Facilities Optimization Engineer.

When in doubt about the specification of any regulating equipment, the local supplier or the manufacturer should be consulted.

8.4 Material Specifications

A variety of materials are commonly used in the fabrication of the regulator body and the internal components. For this reason it is not possible to specify exactly what is or is not acceptable;

Some guidelines to follow are:

1. The regulator must be designed for natural gas use.
2. It must be from the approved list of manufacturers given in Section xxxx of this standard.
3. All materials must be corrosion resistant
4. All rubber parts must be made of materials which are resistant to the effects of hydrocarbons. (examples: Hydrin-200, Buna-N and neoprene)
5. Fisher 627 regulators should be ordered with the nitrile seat as opposed to nylon.
6. Temperature capabilities should withstand a minimum of –29 C to +82 C
7. If a new regulator is to be reviewed, inquire as to other utilities using the product and verify their comments on its performance within their system.

Complete material specifications can be found in Section XXXX of the standards manual.

9.0 RELIEF VALVES

9.1 General

Relief valves can be categorized as either;

1. self –operated
2. pilot-operated

Similar to selecting regulators, some decisions must be considered before specifying which type of relief valve to install. Self-operated, or spring-loaded, relief valves are generally less complicated mechanically and require less maintenance. However, they allow more pressure buildup in the system than similar pilot-operated valves and they are not necessarily less expensive, especially in the larger sizes.

In self-operating relief valves the gas pressure acts directly against a plug, which seats against an orifice. The plug is held in place by a compressed spring. When the force of the gas against the plug becomes greater than that exerted by the spring (ie: the pressure becomes greater than the set pressure), the spring and plug deflect allowing gas to escape. If the upstream pressure continues to build the spring will continue to compress until a maximum area equal to the size of the orifice is exposed. Build-up of system pressure is mostly a function of the spring constant up to this point. Beyond this point, it becomes a function of the gas flow rate. Operation in this region is usually considered to be beyond the capacity of the relief valve.

Pilot-operated relief valves use upstream gas pressure (control gas pressure) to apply a force on the back of the plug. This force is applied through a loading chamber in conjunction with a lightweight spring. The plug is seated and prevents gas from escaping under normal operation. If the pressure increases above the set point, the pilot regulator opens allowing gas from the control chamber to escape to the atmosphere. It bleeds off at a greater rate than it can be replaced and creates a pressure imbalance which forces the plug off its seat. Once the plug is lifted, the overpressure gas is allowed to escape to the atmosphere.

9.2 Relief Valve Stacks

The essential elements in the design of the relief valve stack are:

1. Isolation valve, complete with locking device;
2. Short pipe section with pressure tap for testing the set pressure of the valve, typically a spool of 4” is adequate with the sense point centred.

3. A relief valve;
4. Outlet piping, usually directed straight upward, to a minimum height of 2.4 m (8’) or a minimum of 1.5 m (5 ft) above the roof of any building (if the relief valve is housed within a structure)
5. Rain cap (must be full port design with no restrictions, a mushroom cap is not allowed) – a brass chain is attached to the cap so that in the event of a pressure release the can is still attached to the relief stack piping.

The isolation valve must be pressure rated to the downstream pressure of the regulators plus buildup (10% maximum). It should be a type plug or ball valve and must be at least equal in size to the inlet connection provided on the relief valve. Further, it should be specified locked in the open position.

The pipe section between the isolation valve and the relief valve should be between 10 cm (4”) to 30 cm (12”) in length and have a ½” tap connection for testing of the relief valve.

The outlet piping and fittings are not required to be pressure rated under normal conditions. However, consideration must be given to the dynamic force produced by the escaping gas when the outlet piping contains bends, is longer than 1 m (3’) in length, or when the projected volumes become larger than approximately 15,000 m^3/hr (500 mscfh). For these conditions, a reaction force should be determined and proper bracing of the pipe provided where necessary. The reaction force can be calculated from the following formula:

$$Fe = 1.29\ Fa\ Ft$$

where Fe= Total reaction force for gas (lb)
Fa= Total reaction force for air (lb)
Ft= Temperature correction factor

9.3 Sizing and Selection

Before selecting a relief valve, the required capacity and set pressure must first be determined.

Capacity requirements are dependent upon the upstream regulating equipment and the differential pressure between the upstream and downstream systems. To ensure safety, the following criteria shall be followed:

1. Single Regulator – the relief valves capacity must be at least equal to the wide open capacity of the regulator, with pressure build-up limited to the greater of 10% or 35 kPa (5psi) above the maximum operating pressure of the downstream system.

2. Double or Multiple run regulators – sizing is similar to number 1 above, with the relief valve sized to the regulator with the greatest capacity.

3. Monitor regulators – where this type of regulation is used, the monitor regulator is intended to protect the system. The relief valve is typically installed only as a warning device to indicate that the main regulator has failed. Therefore, it can be sized to a capacity equal to the lesser of 100 m^3/hr (3,500 cfh) or 5% of the wide-open capacity of the monitor regulator, given at the downstream maximum operating pressure. If the station is deemed remote in terms of response times and does not contain any SCADA monitoring a full relief valve should be sized as per criteria #1. Protection of the downstream system is critical, therefore not only economics but also security of supply must be addressed.

NOTE: Regulator wide-open capacity for relief valves sizing is determined by the maximum operating pressure of the upstream system and the regulators set pressure.

Determination of a relief valve's capacity can be determined from the manufacturers sizing table, usually interpolation is required to reveal the desired set pressure.

NOTE: Conversion of relief valves capacity from air to natural gas can be made by multiplying the air capacity by 1.29.

Where more than one station supplies gas to a system, each station must have its own protection, designed to the above criteria.

The relief valve should be sized to have a maximum capacity of 10% greater than the required load (the wide-open capacity of the upstream regulator).

The relief valve set pressure is usually adjusted to a minimum of 35 kPa (5 psig) higher than the regulator set pressure. This ensures a tight seal under normal closed conditions and allows for mechanical resistance when the valve reseats after use. If the regulators are operating at a lower pressure than the MAOP of the downstream system, the relief valve can be adjusted for a set pressure based on the MAOP rather than the regulator set pressure (note: this is noted as note a common design set-point, care is advised for this type of situation).

In addition all relief valves must:

1. Have soft-seat closures
2. Have a minimum body rating equal to the maximum operating pressure of the system it is designed to protect.

3. If it is a pilot-operated valve, it must be designed to fail open in the event of sense line blockage or failure of the pilot.

When in doubt about the specifications of a relief valve, the local supplier or manufacturer should be consulted.

9.4 Material Specifications

As with regulators, it would be lengthy procedure to specify exactly the acceptable materials for construction of relief valves. The safest procedure is to specify only those relief valves approved for use in section XXXXX of this standard. However, when it is necessary to investigate the acceptability of a new relief valve, the following guideline must be used:

1. The relief valve must be designed for natural gas use;
2. It must be ANSI/ASME rated and approved;
3. All materials must be corrosion resistant;
4. It should have soft seat seals.
5. Inquire as to other utilities using the product and verify as to their comments on its performance within their system.

10.0 VALVES

10.1 General

A number of different valve types are common to natural gas regulating stations. Each type of valve is designed for different applications. Therefore, it is not uncommon to see a number of different valve types in a single station. The following is a list of common valve types and a brief description:

1) Plug valves

   These valves are a straight through flow design. They have a plug, usually tapered, with a cast or drilled opening which provides a flow passage. A 90 degree turn of the plug will fully open or close the passage. The opening in the plug is usually slot shaped to reduce the plug size and the amount of material required.

   Most plug valves used by Centra Gas Manitoba Inc. are lubricated so that the faces of the plug and seat are wiped with grease with each turn of the valve. This grease makes the valve easier to turn and helps ensure a bubble-tight seal, even with a worn plug or stem.

   These valves are to be used for their quick opening and closing design and should be specified for applications where a full open or closed valve is required. These valves can also be used in a throttling position such as use as the bypass valve.

2) Ball valves

   These valves are a modification of the plug valve. The obvious difference being that flow is regulated through a spherical element rather than a plug. The passage through sphere is usually the same shape and cross-sectional area as the valve end connections.

   These valves allow the gas to flow uninterrupted and, therefore, add minimum pressure drop to the system. They also simplify insertion of pigging devices into the system.

   They have the disadvantages of requiring more space to install in the system and, due to the large contact surface area, require more torque to turn (in some cases). In addition, some ball valves are designed with seats which are not fire-safe. Valves which are not fire-safe should not be used as the main isolation or by-pass for any station.

3) Gate valves

These valves are also a straight-through flow design. The barrier of flow is either a flat or wedge shaped disk which slides at right angles to the direction of flow and seats tightly in the valve body.

These valves are relatively thin and allow the gas to flow without interruption. They are usually lighter, require less material, and are less expensive than comparable valves.

Their major drawback is that they often fail to provide a tight shut-off because of particles caught in the groove in which the gate slides. In addition, they tend to leak through the valve stem because of there non-lubricated design.

As a result of these design traits, they are not usually specified in stations or within Centra Gas piping systems. However, they are sometimes found in older stations and should be changed out where possible.

4) Globe valve

Flow through these valves is directed up or down through a circular opening, which may be sealed either by forcing a disk down upon a flat seat or by inserting a tapered plug into a conical seat.

These valves are designed for throttling in the moderate to full flow range and are often used as regulators or control valves.

The gas changes flow direction several times within the body of the globe valve and, therefore, adds considerable pressure drop in the piping system. For this reason, they are found unacceptable for piping use within Centra Gas Manitoba Inc..

5) Needle valves

The needle valve is a special design of the globe valve in which the plug is a slender, tapered needle that seats in a small orifice of different taper.

These valves are especially well suited for fine control of flow in the low-flow range and are commonly used a connection for a pressure gauge within a station or as a sense point for a regulator or relief valve. Pressure drop is also very high across these valves.

Centra Gas Manitoba Inc. practice is not to use needle valves as sense points for regulator and relief valves, as it tends to cause to much of a restriction and does not allow adequate response to the regulator. Therefore all regulator sense points will use a ½” ball valve.

10.2 Sizing and Selection

Once the piping has been sized, it is common practice to install the same size valves. However, in applications where the piping is 219.1 mm (8.625”) and larger, the policy has been adopted to reduce the valve one pipe size in order to cut costs. When specifying valves, calculations must be performed to ensure that the gas velocity through the throat of the valve does not exceed 60 m/sec (200 ft/sec). This will prevent excessive pressure drops through the valves and restrict noise to acceptable levels.

For valving applications at maximum inlet pressures greater than 5000 kPa (720 psig) the block and bypass assembly shall have two bypass valves complete with a centre blow down. This is to provide redundancy in valving to protect the lower rated pipeline. In situations where the differential rating (maximum inlet pressure of station to maximum outlet pressure rating) of two piping systems separated by a regulator stations is less than 3,500 kPa (500 psig) then it is allowable to install one bypass valve rated to the higher of the two pressure systems.

The torque required to operate a valve is dependent upon a number of factors, including the pressure and temperature at which the valve is operated and the contact surface between the valve body and the plug. It has been adopted that all valves NPS 6 or larger be gear-operated to make operations of the valves manageable under all conditions. Centra Gas Manitoba Inc. presently uses worm gear operators on all above ground valves NPS 6 or larger, and spur gear for all below ground valves NPS 6 or larger. In addition, all ball valves which are NPS 3 or larger and are operating over 2000 kPa (300 psig) should be ordered trunnion mounted.

The selection of end connections for valves are to be consistent with the guidelines for pipe and fittings as described in section 7. The following table provides a quick reference summary of the proper valves for different applications.

LOCATION	**VALVE TYPE**	**END CONNECTION**
Station Shut-off	Plug Valve	buttweld (1)
Station By-pass	Plug Valve	buttweld (1)
Regulator Isolation	Ball Valve	buttweld (1)
Relief Valve Isolation	Plug Valve or Ball Valve	buttweld (1)
Process Equipment Isolation	Plug Valve or Ball Valve	buttweld (1)
Pressure sense points	Ball Valve	threaded
Blow downs – regulator runs	Needle valves/Ball valve	threaded
Blow downs – station (line access)	Ball valves	buttweld (1)

Note (1): In addition, buttweld end connections may be substituted with raised face flanged connections if the valve is not housed within a electrically connected building, and/or delivery or cost restrictions.

10.3 Material Specification

The standard material in the manufacture of the main body components for valves is carbon steel. However, cast iron and stainless steel are also common. However, cast iron valves should not be used where external or mechanical loading on the valve is anticipated.

In general, the following criteria must be satisfied by a valve before use:

- the valve must be selected form the approved list of manufacturers and conform to the material standard specification as listed in section XXXX of this standard.
- all materials must be corrosion resistant and the effects of hydrocarbons and odorants.
- all valves must meet the requirements of section 5.2.5 of the CSA Z662-96.

11.0 METERS

11.1 General

All meters used by Centra Gas Manitoba Inc. fall into two basic categories, either inferential or positive displacement.

Inferential meters determine the average velocity of the gas flowing past a point with fixed cross-sectional area. The instantaneous velocity, together with the gas density and known area, are used to determine the instantaneous flow rate. This instantaneous flow rate is then integrated over time to determine the total flow. Turbine and orifice meters are examples of this type of metering. Over time Centra Gas has eliminated all orifice plate meters within its system, and replaced them, were applicable, with turbine style meters.

Positive displacement meters segregate precisely know volumes of gas from the upstream piping, transport it across a barrier, and discharge it to the downstream piping. The meter then totalizes the cycles which, adjusted for the known density, is used to compute the total flow. Rotary and diaphragm meters are examples of this principal.

11.2 Meter Assemblies

The following is a list of elements that comprise a typical meter run:

1) meter;
2) isolation valves;
3) pressure and/or temperature correcting device;
4) pressure, volume, temperature (PVT) chart recorder or flow totalizer;
5) Blow downs and instrumentation taps;
6) meter by-pass
7) straightening vanes

In addition to these items a startup screen or filter might be required to protect the meter from erosion damage due to particles in the gas stream.

Most meters are designed to be installed in a particular orientation, which is specified by the manufacturer. The assembly must be orientated (horizontally or vertically) to ensure that liquids are not trapped in or around the meter. The buildup of liquids in the run will increase measurement error.

If the station is also regulating pressures a decision must be made as to whether the meter is installed on the high or low side of the regulators. Measuring on the downstream side of the regulators normally provides a more constant pressure which may eliminate the need for a pressure correcting device and, since most meters are designed and tested at low pressures, slightly greater accuracy. However, meters can be calibrated for high pressure conditions if specified, and a smaller meter can usually be used if installed on the high pressure side of the station. Therefore, the decision is usually based on the economics of size versus pressure. Centra Gas Manitoba Inc. typically installs all station meters downstream of the regulation.

Isolation valves and a by-pass run are required on all meter assemblies designed to measure loads in excess of 310 m^3/hr (11,000 cfh). This makes maintenance possible without disruption of service. The valves should be sized as shown below. No meter runs are to be designed or installed with the isolation valves connected directly to the inlet and outlet of the meter. The resulting turbulence and density variations makes this design impractical.

TYPICAL METER VALVE SIZES

METER SIZE (NPS) **	ISOLATION VALVE SIZE, NPS	BY-PASS VALVE SIZE, NPS
2	2	1
3	3	2
4	4	2
6	6	3
8	6	3
12	8	4

** Based on end connections provided

These sizes are based on a gas velocity of approximately 15 m/sec (50 ft/sec) through the isolation valves and 60 m/sec (200 ft/sec) through the by-pass. For additional information on the valves refer to Section 10.

Chart-recorders or other monitoring devices may also be added to give permanent record.

For each external pressure correcting device, an NPS ½ or NPS ¾ ball valve is required on the meter run. These are best placed downstream of the meter but upstream of any flow restricting devices such as the meter isolation valves. They should not be positioned in a way that could disrupt flow through the meter.

External temperature compensating devices will require a probe, to be inserted into the gas stream on the downstream side of the meter for minimal disruption of flow. The probe should be inserted perpendicular to the direction of flow, be extended into the meter run piping from 50% to 75% of the diameter and be at least two (2) pipe diameters downstream of the meter and upstream of the meter isolation valve. The probe should also be protected from the effects of external temperature conditions. In extreme cases this may mean insulating the piping of the meter assembly. The temperature probe is protected by installing it in a thermowell, which is threaded into the piping.

Blow-down taps should be provided on all meter assemblies larger than 60 mm (2") and/or operating over 410 kPa (60 psig). They should also be situated on the downstream side of the meter to avoid gas flowing backward through the meter, resulting in possible damage. Ball or Plug valves should be used on blow-down taps, sized from the following table:

BLOW-DOWN SIZING

METER SIZE, NPS	BLOW-DOWN, NPS
2	½
3	½
4	½
6	1
8	1
12	1

Straightening vanes are installed at the inlet of turbine meter runs to minimize turbulence
in the gas stream and to create a more uniform velocity profile. They are sized to the nominal pipe diameter of the meter run and are manufactured in predetermined lengths. Most turbine meters are now manufactured with integral straightening vanes. Therefore, when installing these meters in full length runs, it is unnecessary to specify a straightening vane. Refer to the manufacturers literature to confirm.

Figures xx.xx to xx.xx illustrate typical installation requirements for each type of metering device. (2 pages).

11.3 Sizing and Selection

A meter's absolute capacity increases proportionally with pressure. Since it must be sized for maximum flow conditions, its maximum capacity must exceed the design peak hourly load at the minimum measurement pressure. Similarly, its minimum capacity, or turn-down, must be less than the design minimum hourly load at the maximum measurement pressure of the facility. Figure xx.xx indicates the load ranges over which each of the 3 common meters types can be used. Individual meters will vary depending on size and the pressure at which they are operated. (see page 58?)

Other factors which affect the selection of a meter besides the load and pressure range, are the required accuracy, operating temperatures, gas quality, cost, space availability, and orientation of the meter. The following table provides a summary of the different meter characteristics by type.

Meter Type	Max. Pressure (psig)	Flowing Temp. Limits (F)	Accuracy percent over rated range	Turndown Ratio	Ambient Temp. Range (F)	Installation limitations of meter
Diaphragm	100	-30 to +140	+/- 1%	>100:1	-30 to +140	Level
Rotary	1440	-40 to +145	+/- 1%	25:1	-40 to +145	Not Critical
Turbine	1440	-40 to +145	+/- 1%	13.5:1 to 25:1	-40 to +145	Horizontal

The combined accuracy of the meter, plus any correcting equipment should be within +/- 1% for any installation to be used for billing purposes.

11.4 Material Specifications

There are a number of meters presently on the market designed specifically for natural gas use and the materials used in their construction, are compatible. Therefore, there is seldom any selection of materials involved. However the following may serve as a guideline of requirements:

- The meter must be selected from the approved list of manufacturers given in Section xx.xx of the Standard Practice Manual
- It must be CGA approved for custody transfer;
- It must be pressure rated to the system in which it is being used.

12.0 ODOURIZATION

12.1 General

Natural gas by itself is normally colourless and odourless. Odourant is therefore added to the gas stream to make its detection possible well before explosive levels are reached. The concentration of odourant required is dependent upon such factors as the type of odourant, its purity and its absorption rate into the gas and piping. Centra Gas Manitoba Inc. adds odourant into the gas stream at a rate that the odour in the gas is readily detectable at 1/10 th of the Lower Explosive Limit. (LEL). To provide maximum protection and safety to the public and customers, odourization is done prior to the delivery of natural gas into the distribution system. The exception to this rule occurs where a customer requires that the natural gas supply be unodourized for their process. The most common odourant used is Mercaptan. Some of the characteristics of an ideal odourant are:

- Penetrating odour
- Harmless and non-toxic
- Non-corrosive
- Insoluble in water
- Retention by the natural gas
- Burn completely without harmful products of combustion
- Inexpensive

The following table gives the suggested odourization rates and compositions of the type of odourant used in Centra Gas Manitoba Inc.

Manufacturer: NGO Chemical
Trade Name: Captan RP(V)

Nominal Composition *, % by weight

- TBM: 77%
- IPM: -
- NPM: -
- other Mercaptans: -
- DMS: -
- MES: 23%
- Th T: -

Sulphur Content % by weight: 37%
Suggested odourization rate (lb/mm c.f.): 0.3 – 1.0
Density (lbs/US Gal. @ 60 F): 6.76

- TBM – Tertiary Butyl Mercaptan
  IPM – Isoporpyl Mercaptan
  NPM – Normal Propyl Mercaptan
  DMS – Dimethyl Sulfide
  MES – Methyl Ethyl Sulfide
  Th T – Tetrahydro Thiophene (Thiophane)

12.2 Types of Odourizers

Centra Gas Manitoba Inc. mainly uses two types of odourizers. Those that inject odourant into the gas stream , and those which pass of portion of the gas stream over the liquid odourant which is absorbed as it evaporates.

Centra Gas Manitoba Inc. odourizers are almost always purchased as units. The final electrical and pipe/tube connections are made by the operations staff. The following is a list of checks which can be followed when specifying odourization installations:

- the odourization unit and all associated fittings must be pressure rated to the maximum operating pressure of the system in which it is to be installed;
- the odourizer can be isolated from the system without interrupting service;
- a minimum NPS ½ fill connection must be supplied with a shut-off valve;
- all units over 10 litres must be supplied with a NPS ½ minimum purge connection and valve;
- all odourizer piping connections and valves should have a minimum of 0.5 m (18") ground clearance;
- all odourizers which require electricity must have CSA approved explosion proof electrical fittings for Class I, Division I requirements.
- units and bulk tanks with individual or combined capacities in excess of:
    a) 200 litres in highly populated or high hazard areas
    b) 500 litres in rural or non hazardous areas;

  must have secondary containment to protect the surrounding soil and environment from a possible leak or odourant discharge.

12.3 Sizing and Selection

The type and size of odourization unit is determined using the peak daily gas load (metres cubed per day) and the peak hourly load. This value is multiplied by the desired odourization rate and then divided by the odourant density.

Once the consumption is determined, a decision is made on the odourizer type, injection or pulse, and size of volume bottle or pump.

Load (metres cubed/day*)	Type
< 0.1	Wick Type
0.1 – 5.0	Pulse type
> 5.0	Injection

* This assumed a normal load distribution with fluctuations between minimum and maximum flows less than 15:1 on a daily basis. If fluctuations are greater than this, sizing for peak hourly load may be required.

The next step in the sizing process is to determine the amount of odourant which will be required in a peak month and on an annual basis for the storage bottle or tank. The minimum capacity of the holding tank should be sufficient to hold the peak months supply of odourant. In addition, a bulk tank with capacity to hold one year's supply of odourant is required.

12.4 Secondary Containment

Centra Gas Manitoba Inc.'s odourant tanks all have secondary containment in case of leakage from the bulk tank. The secondary containment types varies from tubs, buildings with liners and buildings with a floor pan that acts as the secondary containment. The containment facility must be able to hold 125% of the bulk tank capacity. In addition, design considerations should be made towards protecting against spraying of the odourant on the side walls, therefore seams must be installed to connect the walls to the floor.

- One drawing of wick type odourizer and one of the injection type.

13.0 STRUCTURES

13.1 General

Where deemed necessary it is common to house gas piping within a building or structure in order to protect the equipment from the environment such as snow, rain, blowing soil and sleet. Other advantages to housing the piping within a structure include ascetics, security, and operator comfort during extended hours for maintenance during the winter months.

Due to the extreme temperatures within Manitoba it has been company practice to house the gas piping within a building. The following table can act as a guideline in determining when a structure is appropriate.

Station Type	Type of Structure	Approximate Size (metres)
Gate Station (GS)	Metal Building	4.6m x 4.6m
Town Border Station (TBS)	Metal Building	3m x 3m
Regulator Station (RS)	Metal Building (insulated)	3m x 3m
Large Farm Tap	optional metal enclosure	1.2m x 1.2m x 1.2m
Small Farm Tap	optional metal enclosure	n/a
True Rural Station	Metal building	1.83m x 2.4m

Where gas burning appliances are housed by a building, building ventilation shall be sized and provided in accordance with the Installation Code for Natural Gas Burning Appliances and Equipment B149.1 M95.

13.2 Building and Paint Specifications

Station buildings that house gas piping shall be constructed of non-combustible materials as defined by the National Building Code of Canada. Building ventilation shall be sufficient to provide a safe environment under normal operating conditions within normal work areas.

The following features must be included and or provided by the building manufacturer:

- Certification stating design criteria used and loads assumed in design meeting applicable codes and placing sole responsibility for design of building components with steel building systems manufacturer.
- Provide copy of building erection and shop drawings
- Door hardware: one pair 1 ½” steel butts, panic set with lockable thumb-latch. Provide all doors with threshold weather stripping and eye hook and door chain on both doors to secure in the open position.

- All doors to be keyed alike. (Centra Gas Standard Key to fit). Use “BEST” brand cylinder locks, “WG” series. Locks provided by Centra Gas for installation by contractor.
- Buildings are typically unheated, single skin buildings. If building is to be located in environment where noise is a greater concern, then standard is to order acoustically insulated throughout.
- Maximum deflection of building components: roof cladding under full design load – 1/240 of clear span, wall cladding under full wind load and suction – 1/240 of clear span.
- Rolled or welded steel structural sections and plates to be G40.21 44 W grade steel.
- Provision of spring-closed, soft seated test port with 1” diameter minimum probe insertion opening. Mounted 4’ 6” above top of skid.
- Provide a manually operated horizontal sliding, single piece damper at each louvered opening. Locate damper on outside of building.
- Contractor to provide engineered shop drawings for review by Centra Gas. Provide min. 2 sets.
- Provide 2 – 12” x 12” louvers, locate bottom of opening 5’ 0’’ above top of concrete, and another 2 – 12” x 12” louvers, located 24” above top of concrete. Each set of louvers to be on opposing walls (ie: west and east, or north and south) – location depends on door location. All louvers to come complete with manual control and bird screen.
- Provide a minimum of one 12” diameter turbine type roof ventilator. (Chain operated control to open/close vent on both inside and outside of building
- All bolts to meet ASTM A307-82A complete with nuts and washers.
- Welding materials to be meet CSA W59-1982
- All sheet metal exposed to exterior must meet ASTM A446-76 Grade “A” galvanized to ASTM A525-79 coating designation. Factory pre-coated stelco 5000 series finish or approved equal (colours to be approved, see below)
- Metal flashing to be installed around curb edge of concrete pad to base of building to eliminate rain water seepage into building.

Paint Specification – if manufacturer is unable to produce the same paint a suitable alternate can be allowed, subject to approval by the Engineer.

Exterior walls:
Door Trim:
Door:
Roof:

14.0 SECURITY

All stations and farm taps shall be adequately protected. Common sense should be used in all cases. In cases where heavy vehicle traffic is prevalent, pipe bollards shall be used with a minimum size NPS 3 schedule 40.

All pipe guards used are to be bare pipe and must be primed and painted to CGM meter grey.

To improve structural rigidity, steel cross pieces can be used to connect the posts into a corral arrangement. Refer to the Standard Guard Assembly for further details.

14.1 Locks

All station doors and fences are to be locked at all times when not in use by company personnel. All locks are to be keyed alike. Currently the brand “Best” is used.

All above grade valves and enclosures are to be locked to prevent public tampering and possible misuse of company equipment.

14.2 Fencing

Where necessary fences may be required to provide access control to company facilities and equipment. Minimum height of chainlink fence is to be 6 feet. Where zoning laws allow, provide 3 rows of bar wire is to be attached to the top run of fencing.

All fence posts are to be installed in sonotube holes complete with concrete to a minimum of 1 metre in depth.

Minimum installation of 2 man gates and 1 drive in gate (minimum width 16 feet) are to be provided.

The man gates to be installed 2 feet from finished grade to allow ease of opening during the winter months. Often this is referred as winter man gates. All gates are to be able to open out, as to allow entry in the winter months.

Adequate allowance for snow removal equipment must be maintained within the fencing area. A general rule of thumb is 13’ from any structure. Where necessary to minimize fencing and cleaning requirements a building should be installed in such a way to eliminate the need of cleaning on one or more sides.

Refer to the Station Fencing standard for further installation details on fencing.

14.3 Yard Lighting

In areas of additional concern, a yard light should be installed to provide additional lumination on the building and valve assemblies.

Thought should be given to the surrounding area such as proximity of residential homes or business's that could be bothered by the additional light.

The minimum height above finished grade for the light shall be no lower than 13 feet.

Minimum wattage should be ....

The yard light shall be installed to provide adequate lumination on the building entry and on the remote block and bypass assembly.

15.0 SCADA

15.1 Criteria

The decision to install a monitoring capability at a station can depend on various factors, such as:

- volume through station
- load type (hog barns, residential, process load, hospital, etc.)
- emergency response capability
- location along pipeline (last station on high or transmission pressure pipeline)
- type of regulating equipment selection (pilot operated?, worker-monitor with full relief or token relief?, etc.)
- alternate sources of supply (ie: redundancy – full or partial)
- does the station require "live data" or would an RSU at the next closest service be sufficient.
- access or cost to electric power and telephone

Based on the numerous factors as shown above it is often difficult to have a cut and dry criteria as where SCADA should be used. The following principles shall be used as an Engineering guideline as to its suitability but final approval shall be based upon the Design Engineer.

	Principles
SCADA required:	• Station flows are greater than 100 mcfh (2830 m^3/hr) or more than 500 customer which ever comes first. • First responder times is greater than 60 minutes. • Station is located on the end of high or TP pressure pipeline. • Where there is no current provision for full relief protection. • Load type dictates more stringent security of supply.
RSU acceptable:	• if no SCADA, then an RSU shall be used. • access or cost to electric power and telephone is not deemed feasible.

16.0 ELECTRICAL

16.1 Criteria

The decision to install electricity at a station can depend on various factors, such as:

- volume through station
- access or cost to existing electrical sources (Winnipeg Hydro, Manitoba Hydro)
- security of the site (is vandalism prevalent in the area)
- size and/or type of building design

Based on the factors indicated it is often difficult to have a clear cut criteria as where electrical should be used. The following principles shall be used as an Engineering guideline as to its suitability but final approval shall be based upon the Facilities Design and Operations Engineer.

	Principles
Electrical – required	• Station volumes require the use of regulators, meters or valves greater than NPS 4 are prevalent. • Security of site requires use of yard illumination and chain link fencing is necessary. • Building design does not allow the use translucent roof panels. • Building floor size is greater than 20 square meters.
Electrical – not required	• No building on site • If a building is on site, provision should be made for the use of translucent roof panels for additional natural light inside the structure.

If electrical is not required, the design should include provision for future electrical pole within the station property. This is accommodate possible future upgrades or growth in the area that makes electricity necessary.

Refer to the current station electrical standard for design details (543.01)

17.0 SITE PREPARATION

17.1 Legal Survey and Elevations

All stations that are to be constructed on purchased land or through an easement agreement must be legally surveyed by a registered land survey. The company land purchase agent can arrange this task.

All stations that are to be constructed must have all site elevations obtained. A site elevation grid of no more than 1 metre grid square should be used. All measurements must be correlated to a permanent landmark and reference elevations should include all road heights (such as the crown, shoulder of the roadway, and profile of the ditch – elevations at every 1 metre)

The legal survey and elevations must be incorporated into the drawing set for approvals, unless deemed unnecessary by the Design Engineer.

17.2 Compaction Criteria

All stations requiring vehicle access or concrete pads for a building must be compacted to conform to 100% Standard Proctor compaction tests.

Compaction criteria must include the following:

- removal of the top 12” of top soil and organic material at the station site.
- compact this new excavated layer to 100% Standard Proctor
- first 12” layer – 3” Down granular material or equivalent
- second layer – 6” of 1” Down granular material or equivalent
- third layer – 6” of A-Base or equivalent

All compaction is to be done in lifts not greater than 6” at a time. Gravel area is to include all areas where vehicles or company employees may enter, exit or maintain station.

Due to varying soil conditions and design conditions, a specific compaction design by the Design Engineer will take precedent over the general guidelines presented.

17.3 Piling

When site conditions or due to the size of the station piping used, piling may be required to support the building and/or station piping whether whole or in part.

A soil profile shall be obtained prior to using piles to verify stratification of the soil in the area.

Where access is possible, precast piles shall used. Poured in place piles are an acceptable alternative but are not preferred.

Minimum diameter of piles will not be less than 8” in diameter. The current company standard is to use 16” diameter piles.

All piles must be driven to a minimum depth of 7.7 metres (25 feet) or to refusal whichever comes first.

17.4 Gradebeams

A gradebeam can be used where general support is required for a small station assembly or for a building.

Gradebeams such as a skid should only be used on NPS 3 or smaller and when the building manufacturer requires a gradebeam for use of their structure.

Typically a 6” wide flange beam is used as a base to fasten a metal skin building. Gravel is typically filled in on the inside to level out the structure (gravel used to fill the inside of the beam eliminates employees stepping).

18.0 DESIGN FILE

The intent of this section is to ensure that individuals completing designs on stations record and file all necessary information needed to operate the station and enable personnel to fully understand the decisions made to arrive at a final design.

According to the CSA Z662-96 the following information must be maintained by the utility:

- maximum operating limits
- specifications and nameplate data of major equipment
- pipe data, including wall thickness', grades, standards or specifications, field test pressure.

Using this information as a minimum starting point, the following sections must be used in each station design file;

- Pre-work
- Design Conditions
- Tender
- Construction
- Post-Construction

All work related to the design file must be dated on each page with all changes indicated in red, all other work must be completed in black/blue pen.

Prior to placing records in permanent file, all work must be reviewed and signed off and dated by another Engineering member.

This file is to be complete and ready for permanent file upon commissioning of the station. If an individual is unable to complete entire file prior to energizing station, every effort must be made to have completed in an expedite manner.

Pre-work

- background (purpose, scope, objective)
- justification
- land information
- existing drawings or site layout
- project schedule
- asbuilts
- status reports on progress

Design

- pressure information (maximum inlet, outlet – minimum inlet, outlet – etc)
- network analysis results
- flowrates (maximum and minimum)
- velocity calculations, pressure drop
- configuration of station, schematic
- internal review – summary of comments, list of reviewers, replies on comments.
- external review information (Dept. of Highways, etc..)
- valve selection (type, size, max. operating pressure)

Tender

- land confirmation
- tender drawings
- minutes of tender meeting
- notes

Construction

- testing and tie-in procedures
- station schedule
- notes

Post-Construction

- test records
- station asbuilt
- photos of station
- project notes (comments from inspector, contractor, project manager, design engineer)

Please refer to the standard templates for further information. The following tabs shall be used in creating the station design file. All necessary information must be filled prior to completion.

Once all information is completed the following information must be retained for permanent record. Although important, the other information should be archived or in some cases destroyed. The discarded information is vital for the design but in terms of operating the station serve less importance. The discarded information should be kept intact for a period of no shorter than 12 months following the station completion. The precise time and which information is necessary for permanent file is at the Design Engineer's discretion.

Permanent Records

- stamped original drawing in drawing storage room, filed appropriately
- copy of station asbuilt in station design file
- all related design information – pressures, velocities, flow data.
- background on why the station was rebuilt and a complete summary on major decisions made to complete design. (Design Summary)
- test records
- copy of asbuilt showing related below grade mains
- copies of land certificates indicating ownership and dimensions of said land
- MAOP of each section of pipe in and out of station. This can be covered in the design summary
- network analysis summary (indicating file name of analysis, date, designer)

The design summary must include the following: (an example is shown in Appendix A)

- Project Description – indicating station number, town location, date of project and the capital account number used.
- Purpose – purpose of the summary (ie: to provide a record of the issues and the parameters that lead to decisions on the design of the project).
- Scope – entire scope of work (ie: construct new station X, abandon existing, reference drawings)
- Background – background for the need of the project, why was initiated, reference to capital justification worksheet – attach to summary
- Design Basis – discuss design features of the station, listing regulator, meter arrangement, quantity of cuts and runs, type of equipment (regulators, valves, etc..), describe features of site (fencing, gravel compaction, lighting, SCADA), detail testing data and MAOP of inlet and outlet lines (indicate wall thickness, grade of pipe, etc..), list of key design aspects that are appropriate.
- Safety – describe if legal surveys, field checks, site visits, company records, etc... were reviewed and detail confidence in data. Describe access to station, security.
- Network Analysis – reference studies completed, along with a brief description of the results, name of designer, etc...
- Construction – describe who reviewed drawings, who was the awarded contractor, did the design follow a standard, were the fittings used approved by the company, etc..
- Maintenance – describe if meetings were conducted with GDO and GDM, Cathodic – both during the drawing phase and during construction. Reference tie-in procedure.

- Drawing Distribution: a record of all internal parties that received a copy of the drawing for review as well as brief summary of their comments and whether or not they were adopted into the design. This can be accomplished with the actual copies of the drawings, but a spreadsheet would be preferred.

19.0 PRESSURE TESTING

19.1 Guidelines For Testing:

According to testing requirements in the CSA Z662-M96 (table 8.1), all station piping shall be tested to 1.4 times design pressure. The table below illustrates the yield strength and pressure of pipe typically used in station construction.

Pipe Size	O.D. (mm)	Wall Thickness (mm)	SMYS (MPa)	30% SMYS (MPa)	Pressure to Yield (kPa)	30% of Yield Pressure P* (kPa)
¾	26.7	2.9	290	87	62996	18899
1	33.4	3.4	290	87	59042	17713
2	60.3	3.9	290	87	37512	11254
3	88.9	5.5	290	87	35883	10764
4	114.3	6.0	290	87	30446	9133
6	169.3	7.1	290	87	24323	7297
8	219.1	8.2	290	87	21706	6512
12	323.9	9.5	290	87	17011	5103

Note: To determine the pressure at which a given size and grade of pipe will reach 30% of its yield pressure, the following equation should be used:

$$*P = \frac{2\ (\text{W.T.})\ (30\%\ \text{SYMS})}{\text{O.D.}}$$

Socket weld fittings are allowed on NPS 2 and under, otherwise buttweld fittings are to be used. Threaded connections are allowed on NPS ¾ only or where the maximum operating pressure is below 700 kPa. Compression couplings shall not be used to install test connections on any system.

Refer to the current Pressure testing standards for further requirements for regulator station testing.

20.0 COMMISSIONING

20.1 General:

All stations will have a documented commissioning plan for each design or installation.

Unless otherwise indicated, the standard rural station commissioning plan will be followed for all rural expansion type stations. Stations that were rebuilt or designed for upgrades reasons may require a specific plan, this plan must be specified with the design drawings.

Examples of previous procedures are attached. These are to be used as a general guideline only. Each design can be unique and therefore requires a thorough review by the Design Engineer.

20.2 Purging:

According to the current CSA Z662 code, section 8.12, new and reactivated pipeline systems shall be purged with gas after testing but before being put into operation.

Purge point shall be located as close as possible to the upstream side of the station outlet isolating valve. With the station outlet valve closed and purge point open, the station inlet valve is slowly opened. The station relief valves can also serve as purge points. The outlet gas at these vents shall be tested for natural gas content to determine when the purge is complete. Once the purge is complete, the station may be turned in and feeding.

Note: When purging care is to be taken to ensure the regulator diaphragm's and/or disk assemblies are not damaged. Vital operating equipment such as these items should be removed prior to commencement of the purging procedure.

21.0 CATHODIC PROTECTION

All systems shall be electrically isolated from each other. This shall be done at each regulator station by insertion of insulating flange set, a kerotest insulating fitting or insulation union immediately downstream of all inlet valves to the station or on the downstream end of the upstream regulator isolating valve(s).

Electrical isolation shall occur outside of any structure that contain electrical equipment and must be approved by the Cathodic Protection Engineer.

Where sense lines requires insulation, suitable insulated fittings shall be installed at all pressure connections on the inlet side of the pipe. Recorder gauges shall be insulated from the ground unless insulated from station piping.

22.0 INSULATION

22.1 Acoustic

Predicting station noise level at the design stage can be a difficult to predict. If, once the station is commissioned and feeding, the allowable noise levels are not met, acoustic insulation is added as a retrofit. If noise level is still unacceptable, it may be necessary to enclose the regulators in a building that has noise abatement techniques as well.

However, since station noise level is very design dependent, factors known to contribute to it are minimized. Flexible element regulators (boot style regulators) generally produce less noise than conventional regulators and, therefore, should be installed wherever possible when noise level is a consideration. Where a noise problem is anticipated, projected noise levels should be calculated and compared with allowable levels, with appropriate measures being taken.

Noise levels will be further reduced by using thicker walled pipe (ie: Schedule 80), keeping the number of pipe bends to a minimum, burying headers, and by choosing suitable valves. Plug valves with port restrictions will add to the overall station noise level.

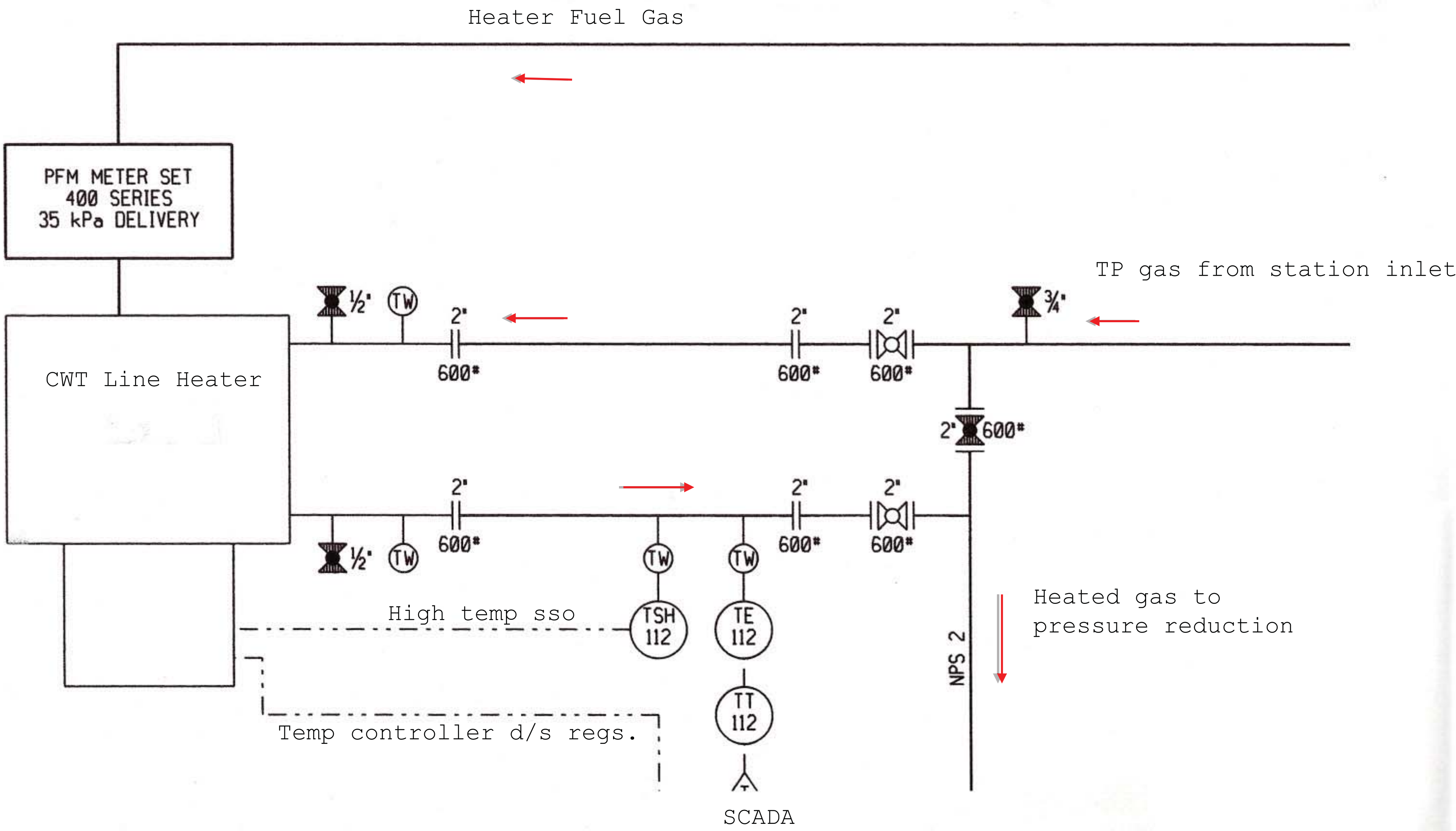
22.2 Thermal

Thermal insulation approved for installation shall be 38.1 mm (1 ½”) Foamglas insulation and is used on all stations on outlet piping from the regulator outlet to the outlet riser. Minimum depth of insulation shall be to the below grade elbow on the outlet riser.

Underground insulation shall be installed on stations where frost heave is a consideration but station size is too small to justify heater installations. Insulation shall be used and cut by the manufacturer to accommodate a double wrap of tapecoat.

APPENDIX J

SCHEMATIC LAYOUT OF TYPICAL LINE HEATER



Line Heater Schematic for Manitoba Hydro

APPENDIX K

LINE HEATER SIZING/HEAT REQUIREMENT CALCULATIONS

Station:	Manitoba Hydro	By:	D Record	Comments:	Inlet gas temp -5 C, outlet gas temp 0 C flow 12 MCFH Pin 880 psig, Pout 40 psig
Location:	Binscarth	Date:	2013-Mar-18		

UNIT PREFENCES

Pressure psi ⇕ Flow ft³ ⇕ Temperature °C ⇕

CURRENT LINE HEATER

Plate Rating: BTU

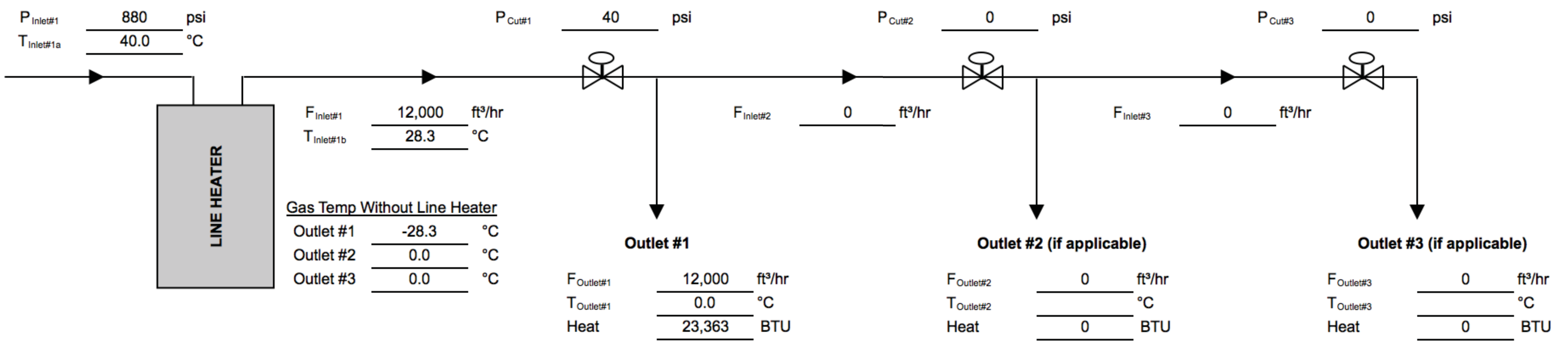
Typical Firing: BTU

Approx. Thermal Efficiency

USER DEFINED PARAMETERS

Station Inlet			**Outlet #1**			**Outlet #2 (if applicable)**			**Outlet #3 (if applicable)**		
Pressure - Typ.	880	psi	Pressure	40	psi	Pressure		psi	Pressure		psi
- Max.	880	psi	Flow - Peak	12,000	ft³/hr	Flow - Peak		ft³/hr	Flow - Peak		ft³/hr
- Min.	880	psi	- Typical	12,000	ft³/hr	- Typical		ft³/hr	- Typical		ft³/hr
Temperature	-5.0	°C ± °C	Outlet Temp	0.0	°C	Outlet Temp		°C	Outlet Temp		°C

SCHEMATIC REPRESENTATION OF VARIABLES



$P_{Inlet\#1}$ 880 psi

$T_{Inlet\#1a}$ 40.0 °C

$P_{Cut\#1}$ 40 psi

$P_{Cut\#2}$ 0 psi

$P_{Cut\#3}$ 0 psi

$F_{Inlet\#1}$ 12,000 ft³/hr

$T_{Inlet\#1b}$ 28.3 °C

$F_{Inlet\#2}$ 0 ft³/hr

$F_{Inlet\#3}$ 0 ft³/hr

Gas Temp Without Line Heater

Outlet #1	-28.3	°C
Outlet #2	0.0	°C
Outlet #3	0.0	°C

Outlet #1			**Outlet #2 (if applicable)**			**Outlet #3 (if applicable)**		
$F_{Outlet\#1}$	12,000	ft³/hr	$F_{Outlet\#2}$	0	ft³/hr	$F_{Outlet\#3}$	0	ft³/hr
$T_{Outlet\#1}$	0.0	°C	$T_{Outlet\#2}$		°C	$T_{Outlet\#3}$		°C
Heat	23,363	BTU	Heat	0	BTU	Heat	0	BTU

SUMMARY OF RESULTS

INLET	INLET	TOTAL HEAT INPUT REQUIRED (BTU/hr)									
Pressure	Temperature	% of Peak Flow									
psi	°C ±	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
880	-5.0	23,363	21,027	18,691	16,354	14,018	11,682	9,345	7,009	4,673	2,336
880	-5.0	23,363	21,027	18,691	16,354	14,018	11,682	9,345	7,009	4,673	2,336
880	-5.0	23,363	21,027	18,691	16,354	14,018	11,682	9,345	7,009	4,673	2,336
880	-5.0	23,363	21,027	18,691	16,354	14,018	11,682	9,345	7,009	4,673	2,336
880	-5.0	23,363	21,027	18,691	16,354	14,018	11,682	9,345	7,009	4,673	2,336
880	-5.0	23,363	21,027	18,691	16,354	14,018	11,682	9,345	7,009	4,673	2,336
880	-5.0	23,363	21,027	18,691	16,354	14,018	11,682	9,345	7,009	4,673	2,336
880	-5.0	23,363	21,027	18,691	16,354	14,018	11,682	9,345	7,009	4,673	2,336
880	-5.0	23,363	21,027	18,691	16,354	14,018	11,682	9,345	7,009	4,673	2,336

LEGEND

- 🟨 Typical Inlet Condition
- 🟩 Typical Flow Condition
- 🟧 Typical Heat Requirement

	PEAK FLOW (BTU/hr)	TYPICAL FLOW (BTU/hr)
HEAT INPUT REQUIRED **Based on Typical Inlet Pressure and Temperature**	**23,363**	**23,363**

RESET SHEET

Station: Manitoba Hydro
Location: Isle De Chen
By: D Record
Date: 2013-Mar-18
Comments: Isle De Chen Pin 880 psig, Pout 550 psig, flow 7659 MCFH Tin -5 C

UNIT PREFENCES

Pressure psi ⇕ Flow ft³ ⇕ Temperature °C ⇕

CURRENT LINE HEATER

Plate Rating: BTU
Typical Firing: BTU
Approx. Thermal Efficiency

USER DEFINED PARAMETERS

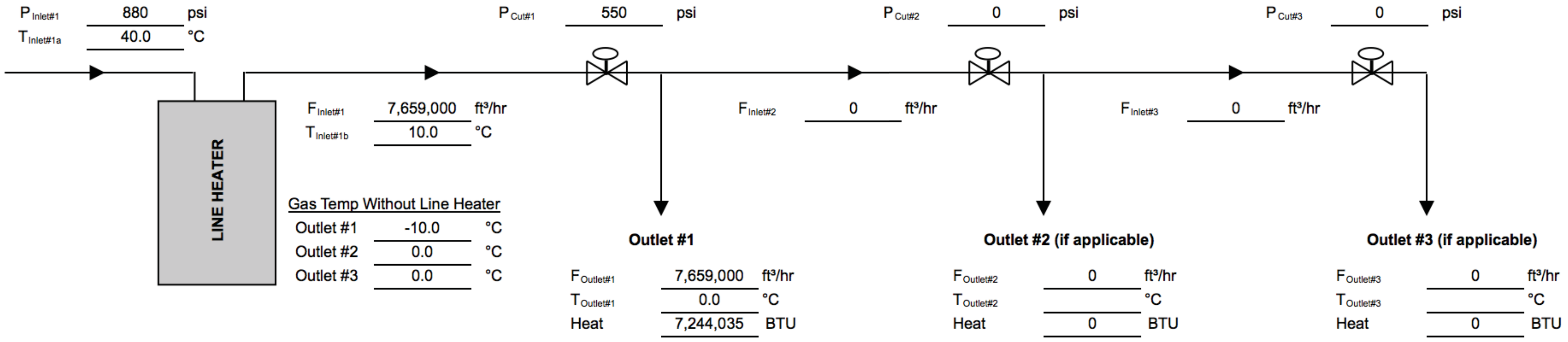
Station Inlet
Pressure - Typ. 880 psi
- Max. 880 psi
- Min. 600 psi
Temperature -5.0 °C ± 5.0 °C

Outlet #1
Pressure 550 psi
Flow - Peak 7,659,000 ft³/hr
- Typical 7,659,000 ft³/hr
Outlet Temp 0.0 °C

Outlet #2 (if applicable)
Pressure psi
Flow - Peak ft³/hr
- Typical ft³/hr
Outlet Temp °C

Outlet #3 (if applicable)
Pressure psi
Flow - Peak ft³/hr
- Typical ft³/hr
Outlet Temp °C

SCHEMATIC REPRESENTATION OF VARIABLES



$P_{Inlet\#1}$ 880 psi
$T_{Inlet\#1a}$ 40.0 °C
$P_{Cut\#1}$ 550 psi
$P_{Cut\#2}$ 0 psi
$P_{Cut\#3}$ 0 psi
$F_{Inlet\#1}$ 7,659,000 ft³/hr
$T_{Inlet\#1b}$ 10.0 °C
$F_{Inlet\#2}$ 0 ft³/hr
$F_{Inlet\#3}$ 0 ft³/hr

Gas Temp Without Line Heater
Outlet #1 -10.0 °C
Outlet #2 0.0 °C
Outlet #3 0.0 °C

Outlet #1
$F_{Outlet\#1}$ 7,659,000 ft³/hr
$T_{Outlet\#1}$ 0.0 °C
Heat 7,244,035 BTU

Outlet #2 (if applicable)
$F_{Outlet\#2}$ 0 ft³/hr
$T_{Outlet\#2}$ °C
Heat 0 BTU

Outlet #3 (if applicable)
$F_{Outlet\#3}$ 0 ft³/hr
$T_{Outlet\#3}$ °C
Heat 0 BTU

SUMMARY OF RESULTS

INLET Pressure psi	INLET Temperature °C ±	TOTAL HEAT INPUT REQUIRED (BTU/hr) % of Peak Flow									
		100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
600	-10.0	5,505,805	4,955,225	4,404,644	3,854,064	3,303,483	2,752,903	2,202,322	1,651,742	1,101,161	550,581
600	-5.0	3,097,716	2,787,945	2,478,173	2,168,401	1,858,630	1,548,858	1,239,086	929,315	619,543	309,772
600	0.0	689,627	620,664	551,702	482,739	413,776	344,814	275,851	206,888	137,925	68,963
880	-10.0	9,856,606	8,870,946	7,885,285	6,899,624	5,913,964	4,928,303	3,942,643	2,956,982	1,971,321	985,661
880	-5.0	7,244,035	6,519,632	5,795,228	5,070,825	4,346,421	3,622,018	2,897,614	2,173,211	1,448,807	724,404
880	0.0	4,631,465	4,168,318	3,705,172	3,242,025	2,778,879	2,315,732	1,852,586	1,389,439	926,293	463,146
880	-10.0	9,856,606	8,870,946	7,885,285	6,899,624	5,913,964	4,928,303	3,942,643	2,956,982	1,971,321	985,661
880	-5.0	7,244,035	6,519,632	5,795,228	5,070,825	4,346,421	3,622,018	2,897,614	2,173,211	1,448,807	724,404
880	0.0	4,631,465	4,168,318	3,705,172	3,242,025	2,778,879	2,315,732	1,852,586	1,389,439	926,293	463,146

LEGEND
🟨 Typical Inlet Condition
🟩 Typical Flow Condition
🟧 Typical Heat Requirement

	PEAK FLOW (BTU/hr)	TYPICAL FLOW (BTU/hr)
HEAT INPUT REQUIRED Based on Typical Inlet Pressure and Temperature	**7,244,035**	**7,244,035**

RESET SHEET

Station: Manitoba Hydro
Location: Niverville
By: D Record
Date: 2013 March 18
Comments: Niverville Pin 880, Pout 55 psig, Flow 81 MCFH, Tin -5 C

UNIT PREFENCES

Pressure psi ⬍ Flow ft³ ⬍ Temperature °C ⬍

CURRENT LINE HEATER

Plate Rating: BTU
Typical Firing: BTU
Approx. Thermal Efficiency

USER DEFINED PARAMETERS

Station Inlet

Pressure - Typ.	880	psi		
- Max.	880	psi		
- Min.	600	psi		
Temperature	-5.0	°C ±	5.0	°C

Outlet #1

Pressure	55	psi
Flow - Peak	81,000	ft³/hr
- Typical	81,000	ft³/hr
Outlet Temp	0.0	°C

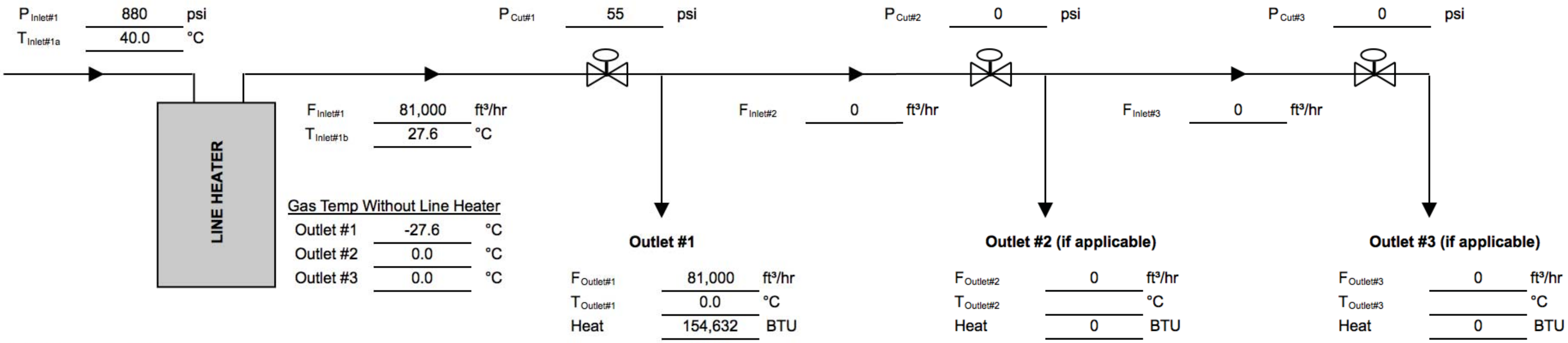
Outlet #2 (if applicable)

Pressure		psi
Flow - Peak		ft³/hr
- Typical		ft³/hr
Outlet Temp		°C

Outlet #3 (if applicable)

Pressure		psi
Flow - Peak		ft³/hr
- Typical		ft³/hr
Outlet Temp		°C

SCHEMATIC REPRESENTATION OF VARIABLES



$P_{Inlet\#1}$ 880 psi
$T_{Inlet\#1a}$ 40.0 °C
$P_{Cut\#1}$ 55 psi
$P_{Cut\#2}$ 0 psi
$P_{Cut\#3}$ 0 psi
$F_{Inlet\#1}$ 81,000 ft³/hr
$T_{Inlet\#1b}$ 27.6 °C
$F_{Inlet\#2}$ 0 ft³/hr
$F_{Inlet\#3}$ 0 ft³/hr

Gas Temp Without Line Heater

Outlet #1	-27.6	°C
Outlet #2	0.0	°C
Outlet #3	0.0	°C

Outlet #1

$F_{Outlet\#1}$ 81,000 ft³/hr
$T_{Outlet\#1}$ 0.0 °C
Heat 154,632 BTU

Outlet #2 (if applicable)

$F_{Outlet\#2}$ 0 ft³/hr
$T_{Outlet\#2}$ °C
Heat 0 BTU

Outlet #3 (if applicable)

$F_{Outlet\#3}$ 0 ft³/hr
$T_{Outlet\#3}$ °C
Heat 0 BTU

SUMMARY OF RESULTS

INLET Pressure psi	INLET Temperature °C ±	TOTAL HEAT INPUT REQUIRED (BTU/hr) % of Peak Flow 100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
600	-10.0	136,249	122,624	108,999	95,374	81,749	68,124	54,500	40,875	27,250	13,625
600	-5.0	110,781	99,703	88,625	77,547	66,469	55,391	44,313	33,234	22,156	11,078
600	0.0	85,314	76,783	68,251	59,720	51,188	42,657	34,126	25,594	17,063	8,531
880	-10.0	182,262	164,036	145,810	127,583	109,357	91,131	72,905	54,679	36,452	18,226
880	-5.0	154,632	139,169	123,706	108,242	92,779	77,316	61,853	46,390	30,926	15,463
880	0.0	127,002	114,302	101,602	88,901	76,201	63,501	50,801	38,101	25,400	12,700
880	-10.0	182,262	164,036	145,810	127,583	109,357	91,131	72,905	54,679	36,452	18,226
880	-5.0	154,632	139,169	123,706	108,242	92,779	77,316	61,853	46,390	30,926	15,463
880	0.0	127,002	114,302	101,602	88,901	76,201	63,501	50,801	38,101	25,400	12,700

LEGEND

- 🟨 Typical Inlet Condition
- 🟩 Typical Flow Condition
- 🟧 Typical Heat Requirement

	PEAK FLOW (BTU/hr)	TYPICAL FLOW (BTU/hr)
HEAT INPUT REQUIRED Based on Typical Inlet Pressure and Temperature	**154,632**	**154,632**

RESET SHEET

Station: Manitoba Hydro
Location: Russell

By: D Record
Date: 2013 March 18

Comments: Pin 880, Pout 440, Flow 576 MCFH, TIn -5 C

UNIT PREFENCES

Pressure psi
Flow ft³
Temperature °C

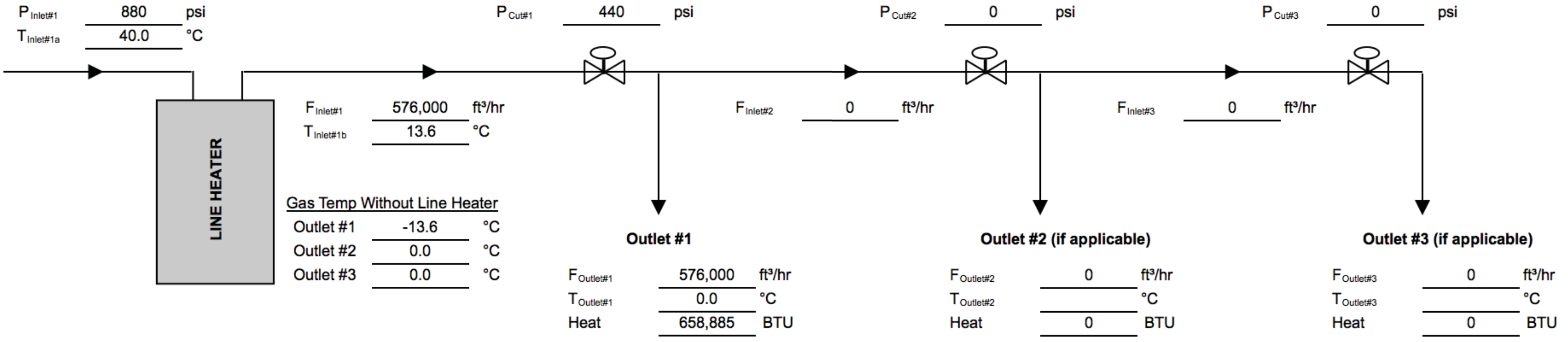
CURRENT LINE HEATER

Plate Rating: BTU
Typical Firing: BTU
Approx. Thermal Efficiency

USER DEFINED PARAMETERS

Station Inlet				**Outlet #1**			**Outlet #2 (if applicable)**			**Outlet #3 (if applicable)**		
Pressure - Typ.	880	psi		Pressure	440	psi	Pressure		psi	Pressure		psi
- Max.	880	psi		Flow - Peak	576,000	ft³/hr	Flow - Peak		ft³/hr	Flow - Peak		ft³/hr
- Min.	600	psi		- Typical	576,000	ft³/hr	- Typical		ft³/hr	- Typical		ft³/hr
Temperature	-5.0	°C ±	5.0 °C	Outlet Temp	0.0	°C	Outlet Temp		°C	Outlet Temp		°C

SCHEMATIC REPRESENTATION OF VARIABLES



$P_{Inlet\#1}$ 880 psi
$T_{Inlet\#1a}$ 40.0 °C

$P_{Cut\#1}$ 440 psi
$P_{Cut\#2}$ 0 psi
$P_{Cut\#3}$ 0 psi

$F_{Inlet\#1}$ 576,000 ft³/hr
$T_{Inlet\#1b}$ 13.6 °C
$F_{Inlet\#2}$ 0 ft³/hr
$F_{Inlet\#3}$ 0 ft³/hr

Gas Temp Without Line Heater
Outlet #1 -13.6 °C
Outlet #2 0.0 °C
Outlet #3 0.0 °C

Outlet #1
$F_{Outlet\#1}$ 576,000 ft³/hr
$T_{Outlet\#1}$ 0.0 °C
Heat 658,885 BTU

Outlet #2 (if applicable)
$F_{Outlet\#2}$ 0 ft³/hr
$T_{Outlet\#2}$ °C
Heat 0 BTU

Outlet #3 (if applicable)
$F_{Outlet\#3}$ 0 ft³/hr
$T_{Outlet\#3}$ °C
Heat 0 BTU

SUMMARY OF RESULTS

INLET	INLET	TOTAL HEAT INPUT REQUIRED (BTU/hr)									
Pressure	Temperature	% of Peak Flow									
psi	°C ±	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
600	-10.0	528,160	475,344	422,528	369,712	316,896	264,080	211,264	158,448	105,632	52,816
600	-5.0	347,059	312,353	277,647	242,941	208,235	173,529	138,823	104,118	69,412	34,706
600	0.0	165,957	149,361	132,765	116,170	99,574	82,978	66,383	49,787	33,191	16,596
880	-10.0	855,365	769,829	684,292	598,756	513,219	427,683	342,146	256,610	171,073	85,537
880	-5.0	658,885	592,997	527,108	461,220	395,331	329,443	263,554	197,666	131,777	65,889
880	0.0	462,405	416,165	369,924	323,684	277,443	231,203	184,962	138,722	92,481	46,241
880	-10.0	855,365	769,829	684,292	598,756	513,219	427,683	342,146	256,610	171,073	85,537
880	-5.0	658,885	592,997	527,108	461,220	395,331	329,443	263,554	197,666	131,777	65,889
880	0.0	462,405	416,165	369,924	323,684	277,443	231,203	184,962	138,722	92,481	46,241

LEGEND

🟨	Typical Inlet Condition
🟩	Typical Flow Condition
🟧	Typical Heat Requirement

	PEAK FLOW (BTU/hr)	TYPICAL FLOW (BTU/hr)
HEAT INPUT REQUIRED Based on Typical Inlet Pressure and Temperature	**658,885**	**658,885**

RESET SHEET

Station:	Manitoba Hydro	By:	DLR	Comments:	Starbuck Pin 880 psig, Pout 50 psig, Flow 15 MCFH, T in -5 C
Location:	Starbuck	Date:	2013 March		

UNIT PREFENCES

Pressure psi

Flow ft³

Temperature °C

CURRENT LINE HEATER

Plate Rating: BTU

Typical Firing: BTU

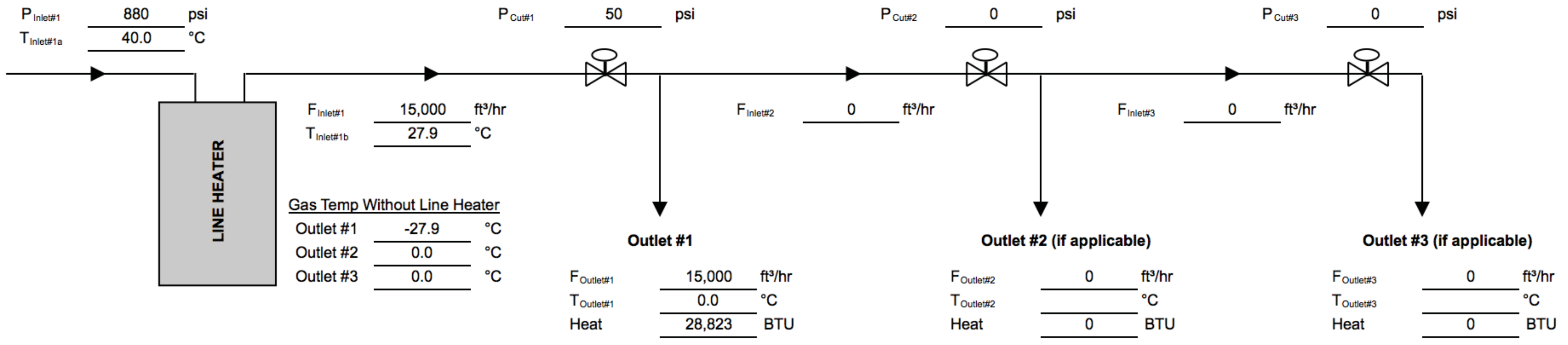
Approx. Thermal Efficiency

USER DEFINED PARAMETERS

Station Inlet			**Outlet #1**				
Pressure - Typ.	880	psi	Pressure	50	psi		
- Max.	880	psi	Flow - Peak	15,000	ft³/hr		
- Min.	600	psi	- Typical	12,000	ft³/hr		
Temperature	-5.0	°C ± 0.0 °C	Outlet Temp	0.0	°C		

Outlet #2 (if applicable)			**Outlet #3 (if applicable)**		
Pressure		psi	Pressure		psi
Flow - Peak		ft³/hr	Flow - Peak		ft³/hr
- Typical		ft³/hr	- Typical		ft³/hr
Outlet Temp		°C	Outlet Temp		°C

SCHEMATIC REPRESENTATION OF VARIABLES



$P_{Inlet\#1}$ 880 psi

$T_{Inlet\#1a}$ 40.0 °C

$P_{Cut\#1}$ 50 psi

$P_{Cut\#2}$ 0 psi

$P_{Cut\#3}$ 0 psi

$F_{Inlet\#1}$ 15,000 ft³/hr

$T_{Inlet\#1b}$ 27.9 °C

$F_{Inlet\#2}$ 0 ft³/hr

$F_{Inlet\#3}$ 0 ft³/hr

Gas Temp Without Line Heater

Outlet #1 -27.9 °C

Outlet #2 0.0 °C

Outlet #3 0.0 °C

Outlet #1

$F_{Outlet\#1}$ 15,000 ft³/hr

$T_{Outlet\#1}$ 0.0 °C

Heat 28,823 BTU

Outlet #2 (if applicable)

$F_{Outlet\#2}$ 0 ft³/hr

$T_{Outlet\#2}$ °C

Heat 0 BTU

Outlet #3 (if applicable)

$F_{Outlet\#3}$ 0 ft³/hr

$T_{Outlet\#3}$ °C

Heat 0 BTU

SUMMARY OF RESULTS

INLET Pressure psi	INLET Temperature °C ±	TOTAL HEAT INPUT REQUIRED (BTU/hr) % of Peak Flow									
		100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
600	-5.0	20,703	18,632	16,562	14,492	12,422	10,351	8,281	6,211	4,141	2,070
600	-5.0	20,703	18,632	16,562	14,492	12,422	10,351	8,281	6,211	4,141	2,070
600	-5.0	20,703	18,632	16,562	14,492	12,422	10,351	8,281	6,211	4,141	2,070
880	-5.0	28,823	25,941	23,059	20,176	17,294	14,412	11,529	8,647	5,765	2,882
880	-5.0	28,823	25,941	23,059	20,176	17,294	14,412	11,529	8,647	5,765	2,882
880	-5.0	28,823	25,941	23,059	20,176	17,294	14,412	11,529	8,647	5,765	2,882
880	-5.0	28,823	25,941	23,059	20,176	17,294	14,412	11,529	8,647	5,765	2,882
880	-5.0	28,823	25,941	23,059	20,176	17,294	14,412	11,529	8,647	5,765	2,882
880	-5.0	28,823	25,941	23,059	20,176	17,294	14,412	11,529	8,647	5,765	2,882

LEGEND

🟨 Typical Inlet Condition

🟩 Typical Flow Condition

🟧 Typical Heat Requirement

	PEAK FLOW (BTU/hr)	TYPICAL FLOW (BTU/hr)
HEAT INPUT REQUIRED Based on Typical Inlet Pressure and Temperature	**28,823**	**23,059**

RESET SHEET

APPENDIX L

VORTEX PRESSURE REDUCING STATION INITIAL CONCEPTUAL DESIGN

Technical Proposal

Initial Conceptual Design Vortex Pressure Reducing Station for Ile Des Chene

Prepared by:

Gasficient Products & Services
with
Universal Vortex, Inc

May 2013

TECHNICAL PROPOSAL
Vortex Pressure Reducing Station (VPRS) for Ile Des Chene

TECHNICAL PROPOSAL
Vortex Pressure Reducing Station (VPRS) for Ile Des Chene

1 Introduction

Gasficient Consulting Services with the support of Universal Vortex is pleased to submit this technical proposal presenting a conceptual design for a Vortex Pressure Reducing Station (VPRS) for Ile Des Chene. This conceptual design has been prepared on the basis of the basic data available at this time. The design concept will be updated once additional data is available.

The VPRS concept using vortex pressure reduction provides a thermal solution to overcome the Joule-Thomson effect that occurs during throttled pressure reduction. Using UVI's innovation and proprietary technology in this application eliminates the requirement for gas or electric fired heating of the natural gas stream prior to pressure reduction.

2 Design Objectives

The Vortex Pressure Regulation Station (VPRS) process design concept is applied to achieve the following objectives:

2.1 Primary Objective

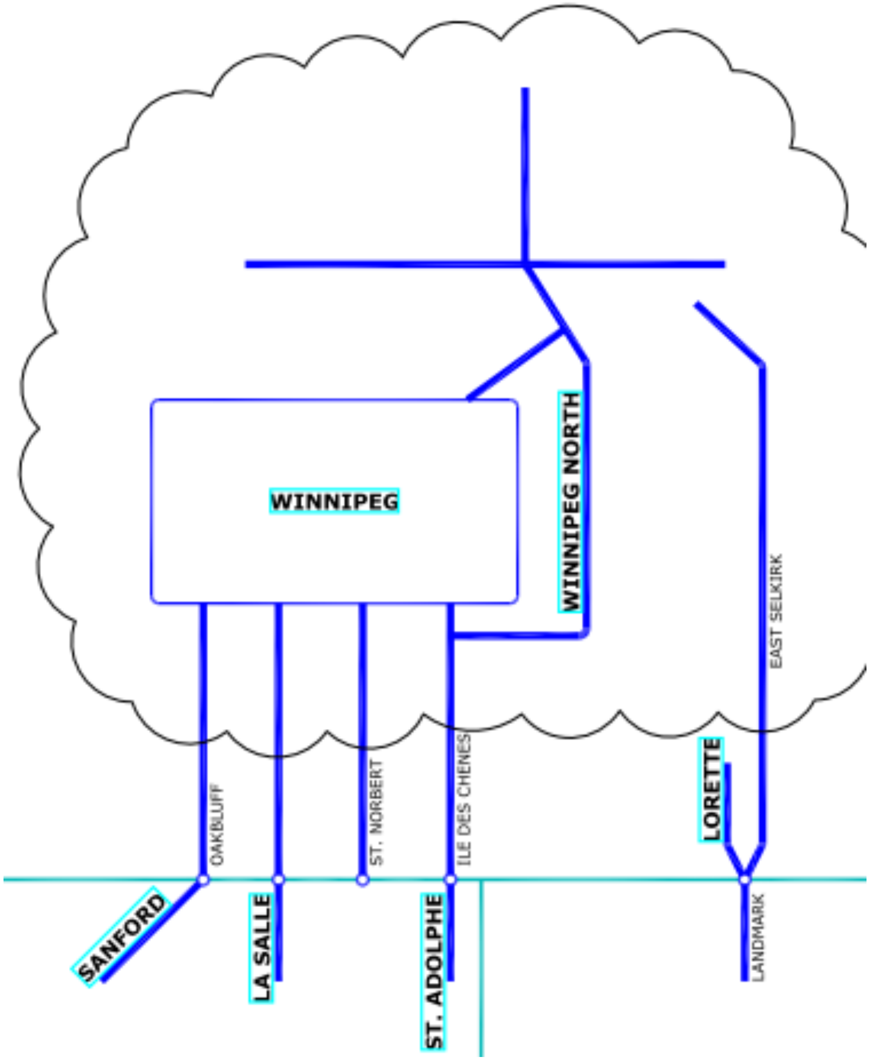
To serve natural gas demand an existing PRS with a pressure reduction of 880 psig to 550 psig is required. The estimated Joule-Thomson temperature drop for this pressure reduction is approximately 10 Celsius. This significant temperature drop may result in internal ice/hydrate and external ice formation that may jeopardize security of gas supply and/or the structural integrity of the PRS and downstream pipe. Therefore the primary objective is to prevent both of these adverse conditions.

2.2 Secondary Objective

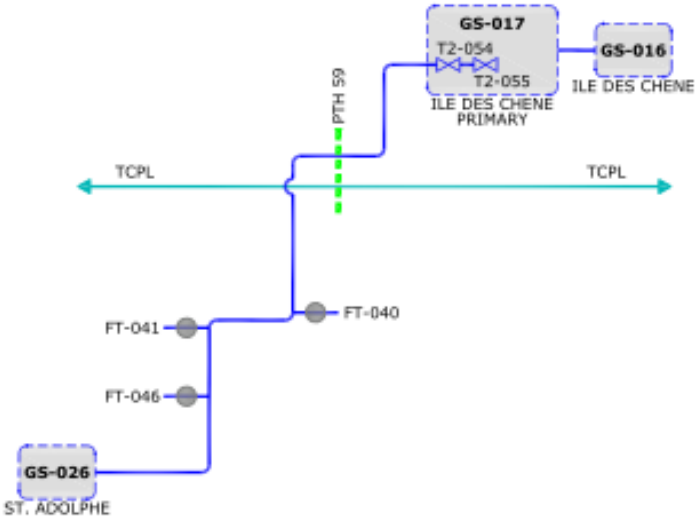
An important but secondary objective is to reduce energy consumption and reduce operating expenses.

3 Design Basis

An existing pressure reducing station provides a supply of gas to a high pressure system that in turn supplies 6 town border stations:



TECHNICAL PROPOSAL
Vortex Pressure Reducing Station (VPRS) for Ile Des Chene



The design capacity of the existing Ile Des Chene Station is 7659 Mcfh with the average flow to be 50% of the peak flow. The City Gate Station is connected via a pipeline that supplies gas from Transcanada transmission pipeline system.

Winnipeg's location in the Canadian Prairies, gives it a humid continental climate (Köppen Dfb, USDA Plant Hardiness Zone 2b) in that there are great differences between summer and winter temperatures. The openness of the prairies leaves Winnipeg exposed to numerous weather systems including blizzards and cold Arctic high pressure systems, known as the Polar high. Winnipeg has four distinct seasons, with short transitional periods between winter and summer. Summers are hot with plenty of thunderstorms, winters are cold and dry, and spring and autumn are pleasant. Snow sometimes lasts 6 months of the year; and some years (like 5 February 2007) reach −40 °C (−40 °F), without the windchill. There is 318 days per year with measurable sunshine, with summer being the sunniest.

APPENDIX M

MH DESIGN STANDARDS OBSERVATIONS, SUGGESTIONS AND RECOMMENDATIONS

Design Document Set

MHI suggests that MH consider developing a set or suite of design documents. This set/suite of design documents may include:

Design Basis including:

- Regulations and Codes
- Climate
- Gas Supply Composition and Availability
- Pressure Regimes
- Delivered Gas Specification
- Design Criteria
- Design Parameters
- Design Methodology
- Design Software and Calculations

Minimum Functional Specifications including component specific functional criteria and parameters such as:

- Over/Under Pressure Protection
- Flow variability
- Allowance/Accommodation for stress & strain
- Operability Requirements

Design Process

- Concept
- Front End Engineering Design
- Detailed Design

HSE Requirements

- Environmental Identification
- Hazards Identification
- Risk Assessment

Site Investigations

Material Specifications

Fire and Safety Philosophy

Isolation and Control Philosophy including:

- Routine Operations
- Emergency Operations
- Shutdown & Start-up

Typical Lists Formats including:

- Line List
- Equipment List
- Valve List

Typical Drawings including:

- PFDs
- P&ID's
- General Layout
- Footings/Foundations
- Architectural
- Electrical Single Line
- Fabrication Drawings

The document set should address all the multi-disciplinary and functional aspects of design including civil, mechanical, corrosion prevention system, SCADA, electrical and instrumentation.

Pressure Reducing Station Design - Observations, Suggestions and Recommendations:

Specific comments resulting from MHI's reference to MH existing standards, particularly the draft station design manual, are provided below:

i. It is recommended that selection criteria for pressure reducing station sites include soil stability and water table.

ii. Standard drawings do not indicate all required construction information such as welding procedures, NDE requirements and pressure testing criteria.

   NB: MH has advised that existing standard drawings are referenced from the site specific drawings for a pre-existing station. On the site specific drawings the NDE, pressure test, regulator set points are specified.

iii. Hazardous area classification drawings for stations were not forwarded to MHI. It is recommended that they be developed if they do not exist.

   NB: MH has advised that this is addressed in existing Standard 543.01

iv. Location and size of sensing lines is critical to the safe and effective operation of a pressure reducing station. It is recommended that such a standard be developed.

   NB: MHI has been subsequently advised that MH have a standard for size and length of sensing lines.

v. It is recommended that positive displacement (rotary) meters be avoided in multiple customer pressure reducing stations particularly if there is no filtration or heat since the meters can jam with debris or hydrates and cause outages. If rotary meters are selected, then filters or heat are recommended.

vi. Reference to maximum velocity of 200 ft/sec in regulator runs within MH draft station design guide appears to be high. MHI believes a guideline of 60 ft/sec to be more appropriate.

vii. It is recommended that a standard for minimum wall thickness of pipe in stations be considered (e.g. schedule 40 for NPS 8 and smaller, all threaded nipples minimum schedule 80).

NB MH Standard 530.02 specifies a minimum of schedule 40 for all station pipe. Standard weight nipples are permitted and used widely in low pressure customer piping. Schedule 80 for threaded nipples in higher pressure applications is more at MH common and this could be documented in the standard.

viii. It is recommended that needle valves only be used as instrument valves and not for the purpose of blowing down sections of pipe as referenced in MH draft station design guide. This is because they can easily clog with debris are of low Cv and are slow to open.

ix. It is recommended that material descriptions for regulators, relief valves and valves have more detail (e.g. operating temperature range, approval requirements, CSA, API) in order to source appropriate material. A valve specification recounting all policies, standards and approved products is recommended.

NB: MHI has been subsequently advised that MH has a specification sheet for valves that can be found on MPower in the SMS sheets for gas materials.

x. Gate valves are referenced in MH draft station design manual however MHI has been informed these are not used in MH system. MHI advises that, in general, gate valves are not appropriate for use in pressure reducing stations.

xi. MHI is not aware of a specific policy at MH for the use of SCADA and local recorders to monitor temperature at facilities.

xii. MH does not universally specify the use of filters on their station inlets. Removal of any water or hydrocarbon aerosols that may be present as well as any dust or debris that may exist in the gas stream and that may provide nuclei for water to form. Thus filtration, especially coalescing filters, can reduce the risk of internal ice/hydrate formation. Dust removal itself can be particularly beneficial in stations with pilot operated regulators.

xiii. At stations operated without filtration, MH does not appear to have a policy for primary and secondary over pressure protection (i.e. monitor regulators and full capacity reliefs in the event that debris or hydrates should impair the primary OPP device).

xiv. It is recommended that double block and bleed non-lubricated valves be specified in stations for lock out when working downstream and to prevent valve lubricant contamination of pressure regulator and pilot components.

xv. A policy for cleaning and drying of pipe prior to commissioning was not noted by MHI and is recommended to prevent hydrate formation. We have a construction procedure for drying pipe prior to commissioning.

NB: MH has advised that they have a construction procedure for drying pipe prior to commissioning.

xvi. MHI believes it is pertinent to take specific design steps to allow for frost heave and icing as recommended in CSA Z 662-11 section 4.6 – 4.8 Flexibility and stress analysis, section 11.6 Environmental Loads, and section 11.8 Design for mechanical strength.

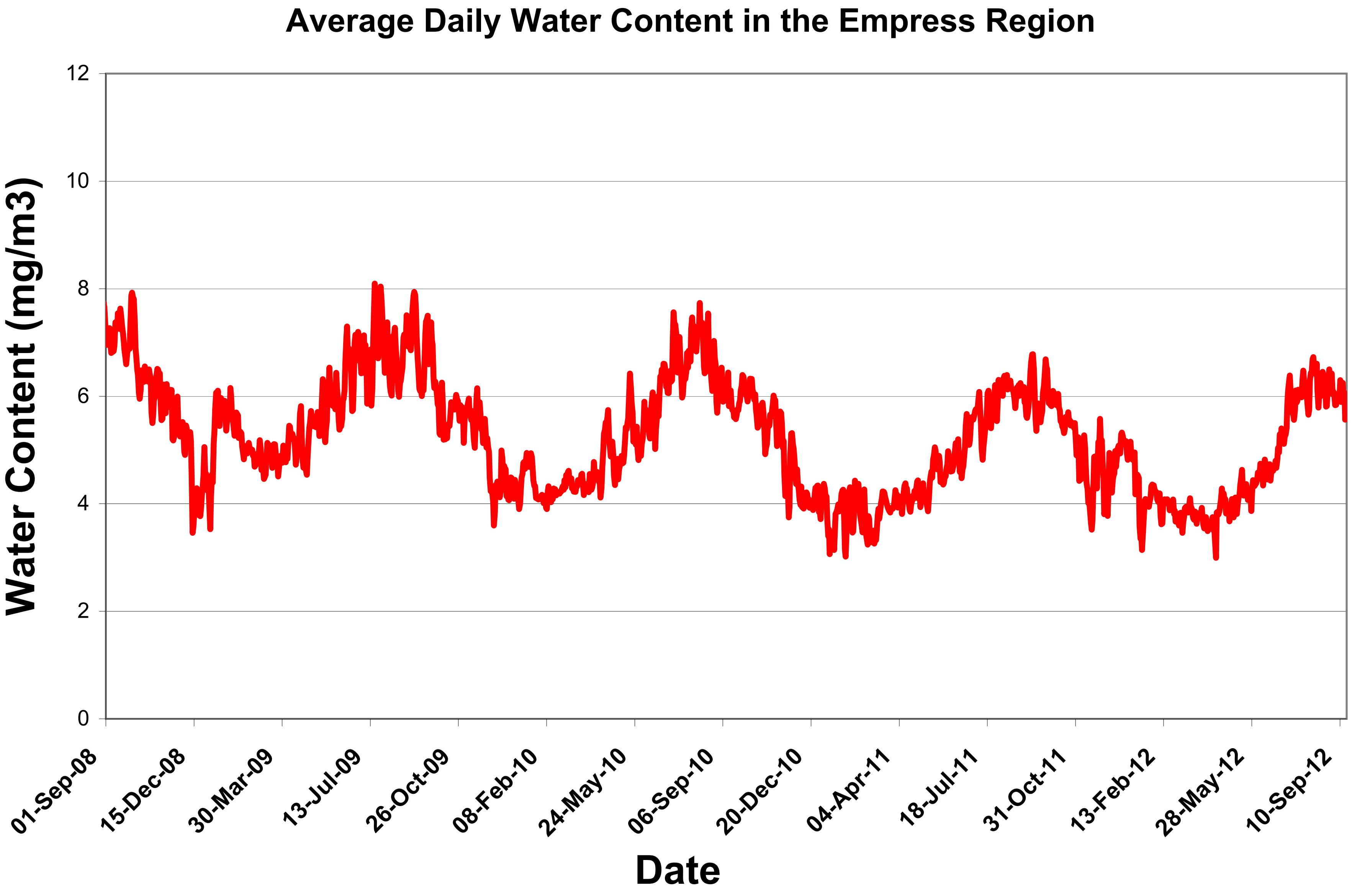
xvii. MHI has noted that in general MH does not specify the use of CSA Z245.1 notch toughness category 2 pipe nor proven notch toughness fittings and valves as recommended for temperatures below -30° C. However CSA Z662 does not require Category 2 in some situations based on pipe diameter, wall thickness and operating stress and it allows exceptions to this requirement based on length of run. Irrespective, it is suggested where CSA Z662 calls for category 2 materials based on size, wall thickness and stress level, but where the length of a piping run could allow category 1 materials, then MH give consideration to using category 2 materials to provide additional mitigation against the catastrophic nature of impact failure within a pressure reducing station.

xviii. MHI has not examined the joining philosophies of MH nor the ability of existing welds to withstand potential weld failures at low temperatures downstream of unheated pressure reducing facilities, but recommends that MH undertake such a study.

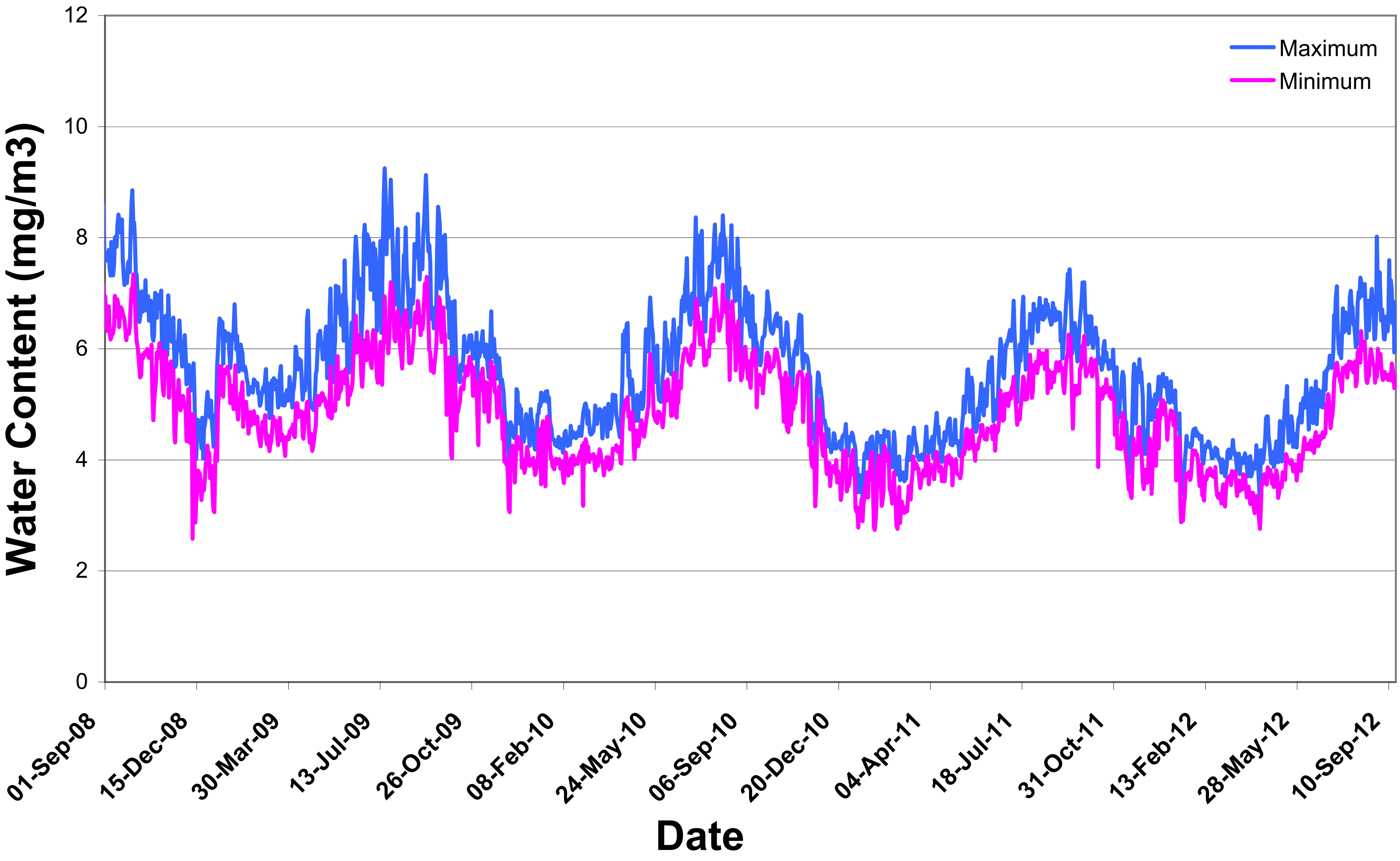
xix. Although line heaters are the most effective way of dealing with heat loss issues in pressure reducing stations other options to reduce risk can be considered. Pilot heaters, chemical (methyl hydrate) injection, no or low bleed pilots (Becker BPR), control valves (Becker T0), extra back up runs, dehydrators, pipe flexibility, filtration and self-actuated regulators are all possibilities.

APPENDIX N

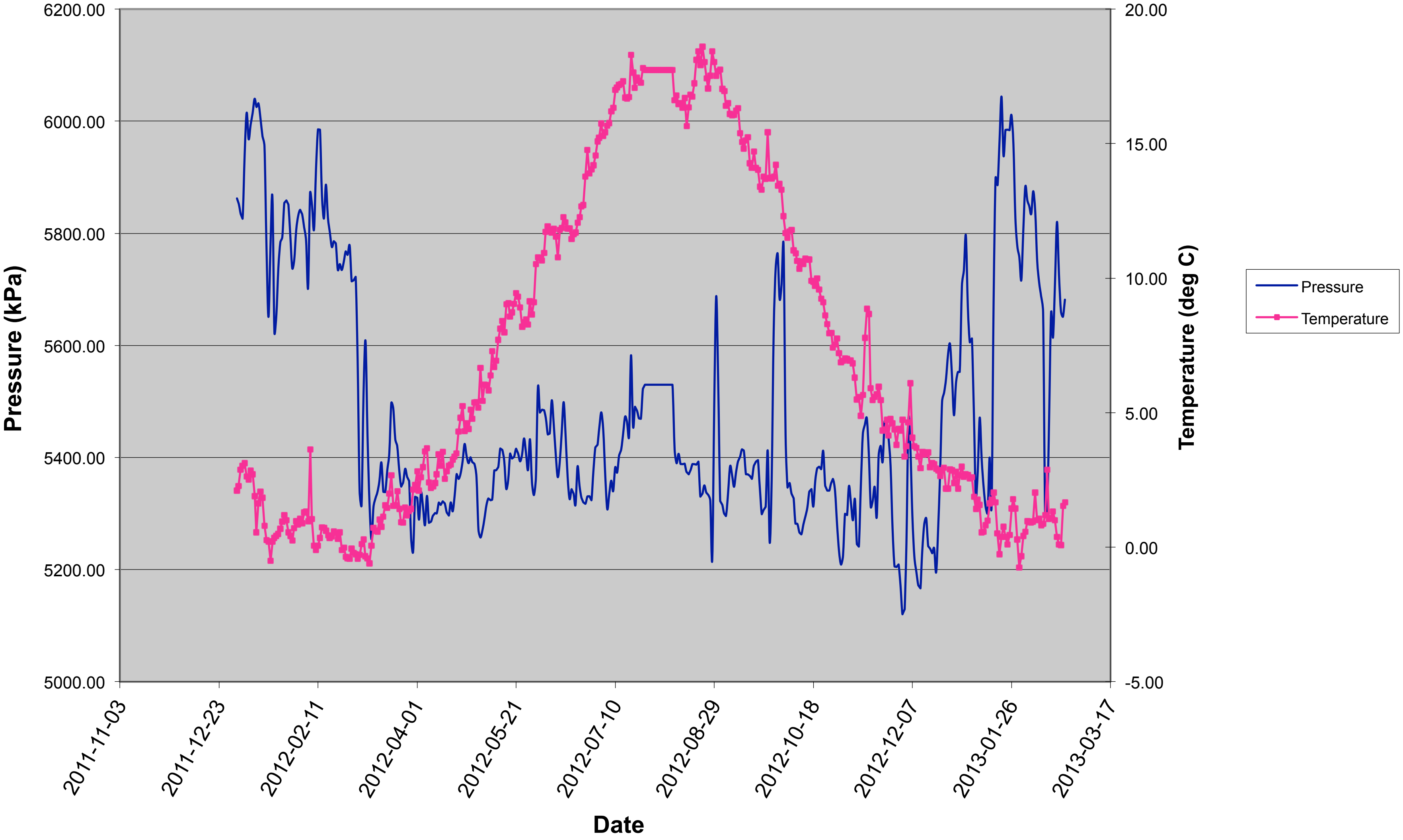
TCPL HISTORICAL PRESSURE AND MOISTURE DATA

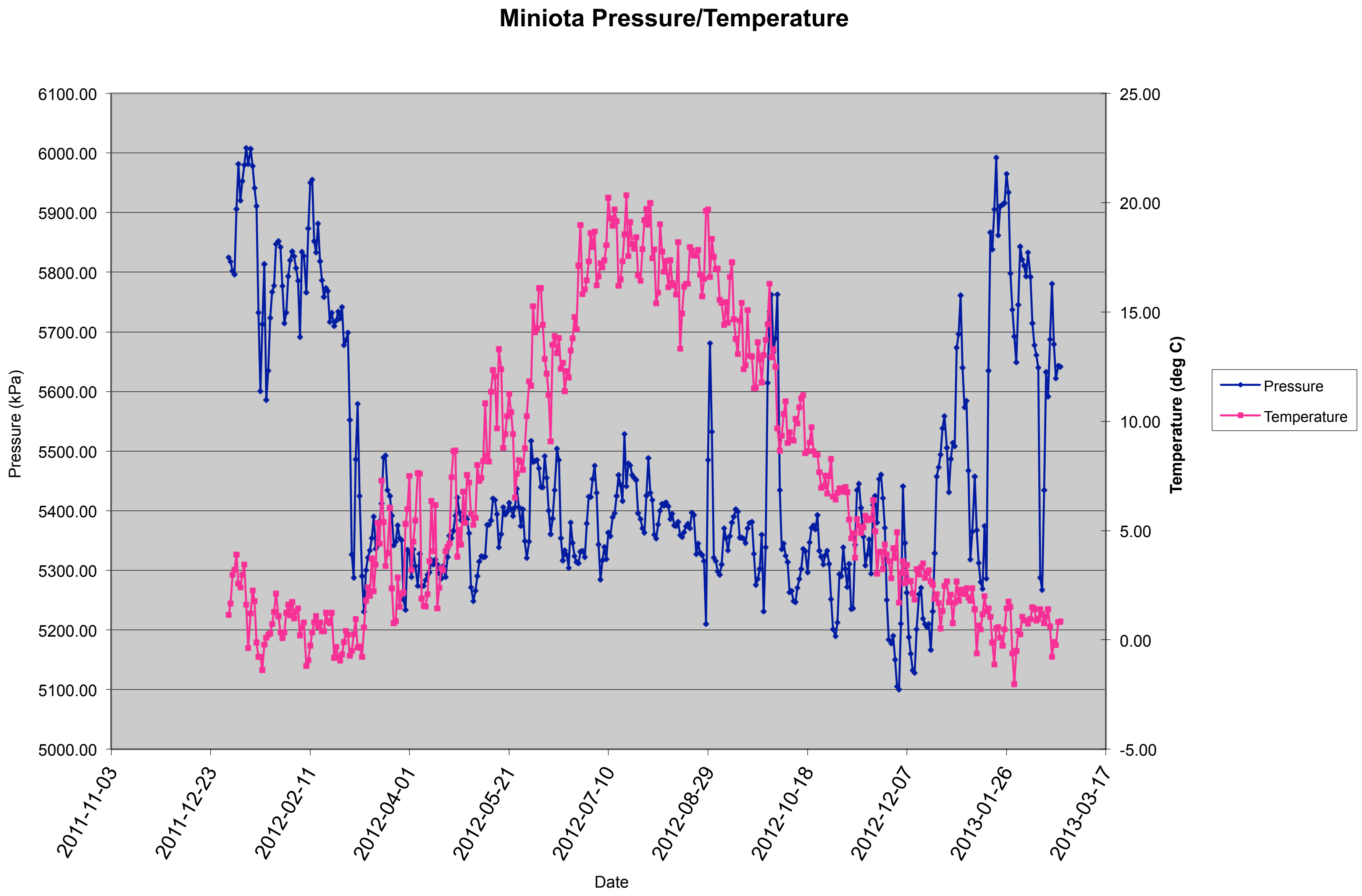

Average Daily Water Content in the Empress Region
Water Content (mg/m3)
12
10
8
6
4
2
0
01-Sep-08
15-Dec-08
30-Mar-09
13-Jul-09
26-Oct-09
08-Feb-10
24-May-10
06-Sep-10
20-Dec-10
04-Apr-11
18-Jul-11
31-Oct-11
13-Feb-12
28-May-12
10-Sep-12
Date

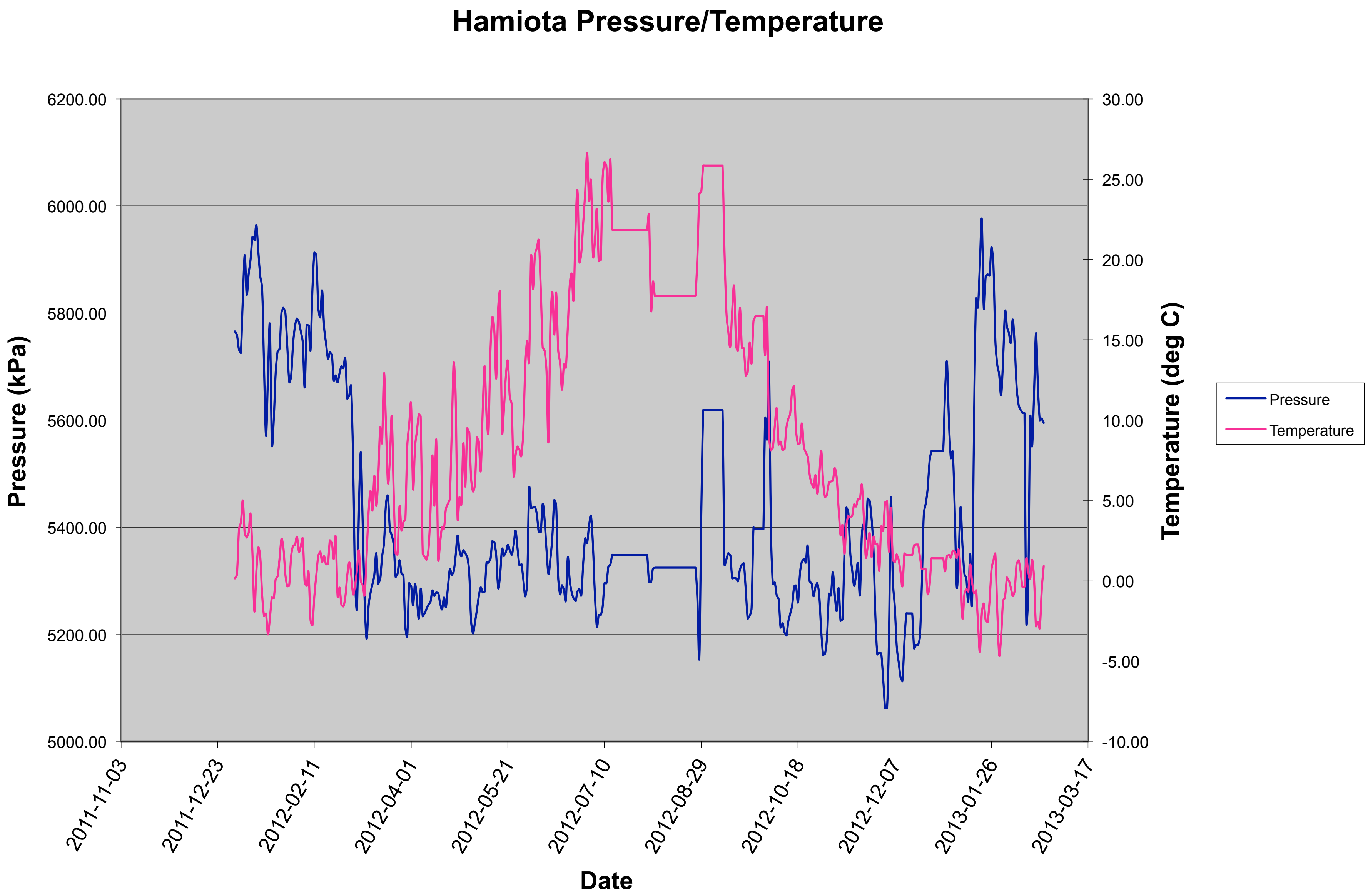
Maximum and Minimum Daily Water Content in the Empress Region



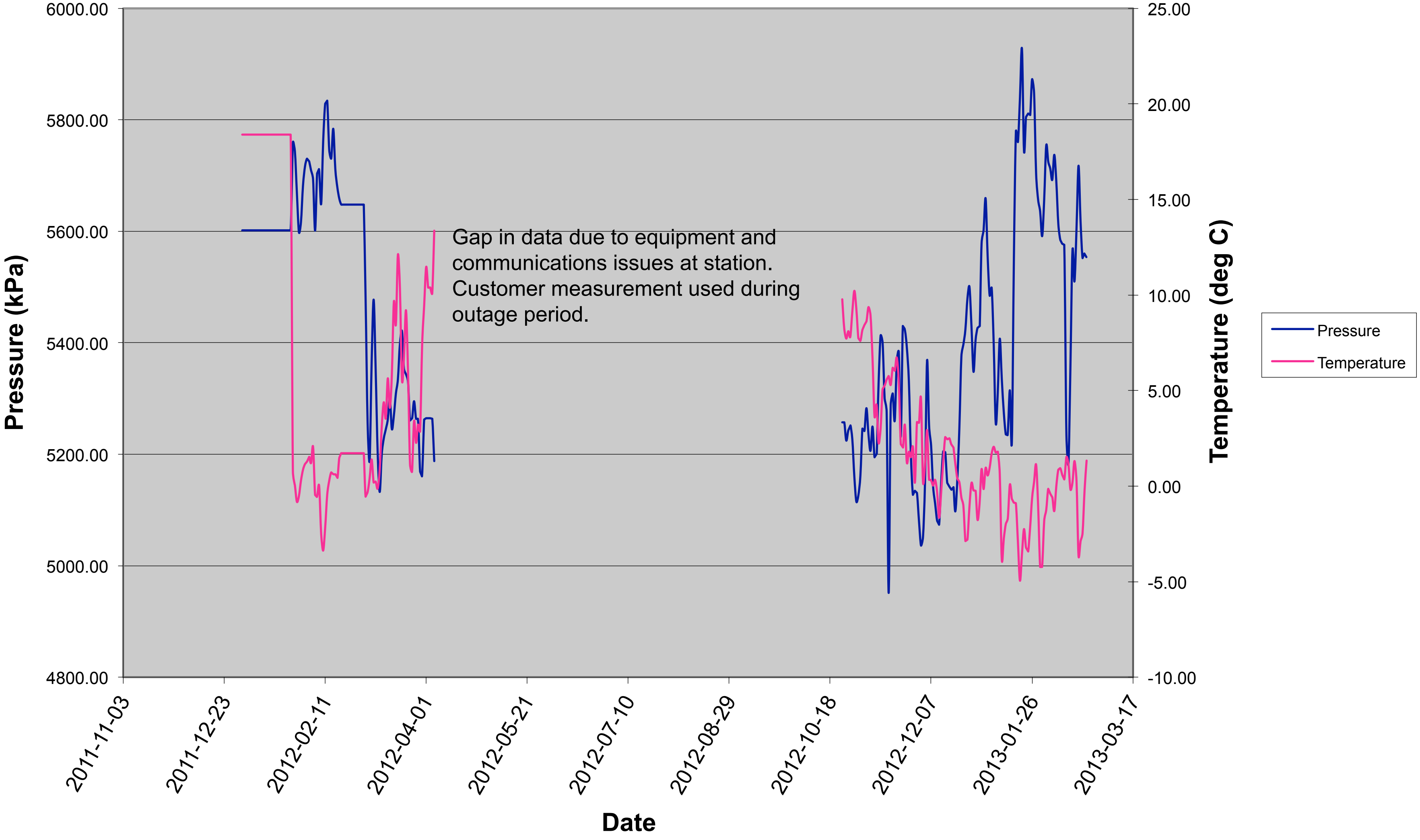
Dauphin Pressure/Temperature



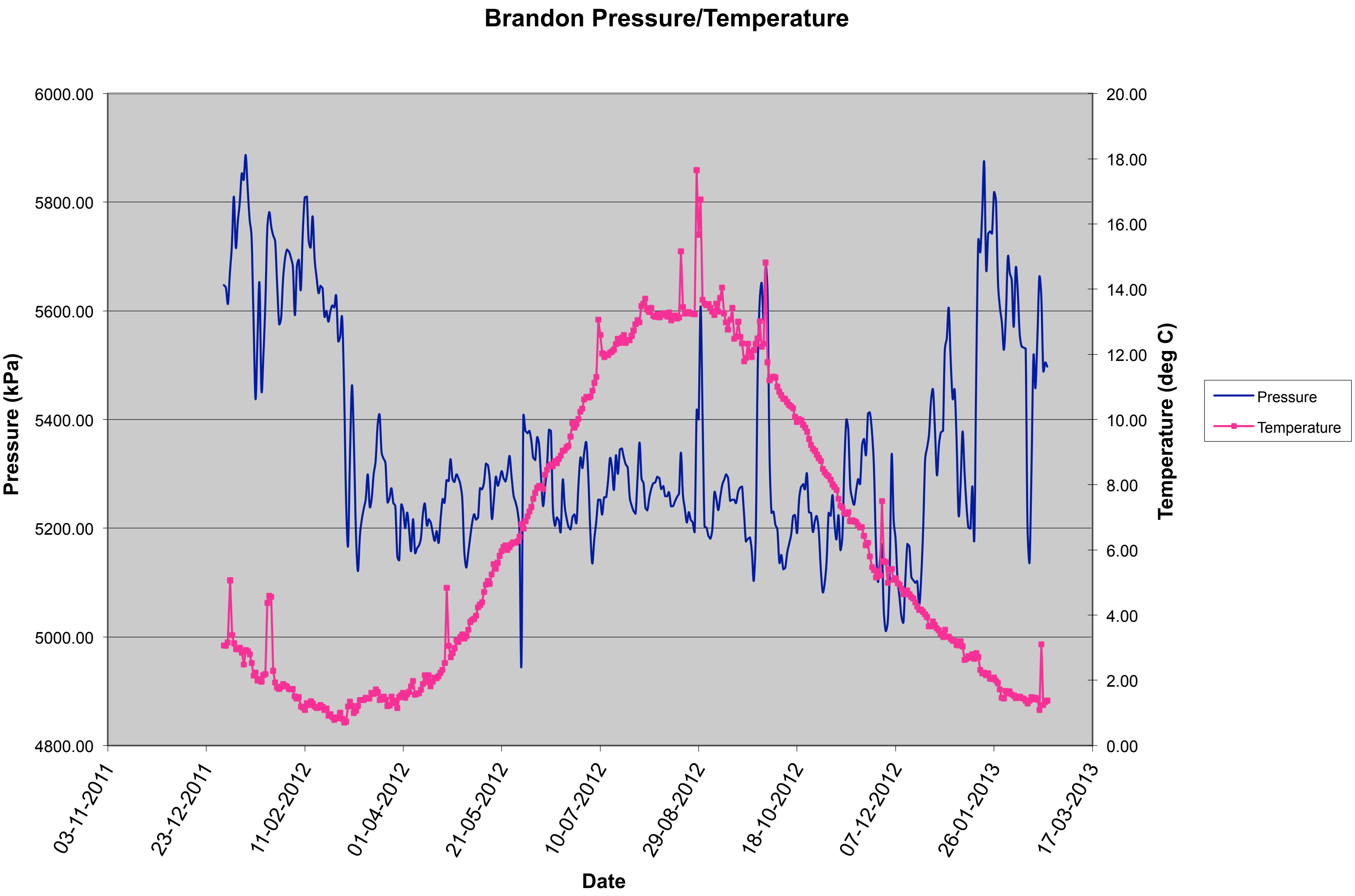

Miniota Pressure/Temperature
Pressure (kPa)
6100.00
6000.00
5900.00
5800.00
5700.00
5600.00
5500.00
5400.00
5300.00
5200.00
5100.00
5000.00
Temperature (deg C)
25.00
20.00
15.00
10.00
5.00
0.00
-5.00
2011-11-03
2011-12-23
2012-02-11
2012-04-01
2012-05-21
2012-07-10
2012-08-29
2012-10-18
2012-12-07
2013-01-26
2013-03-17
Date
Pressure
Temperature

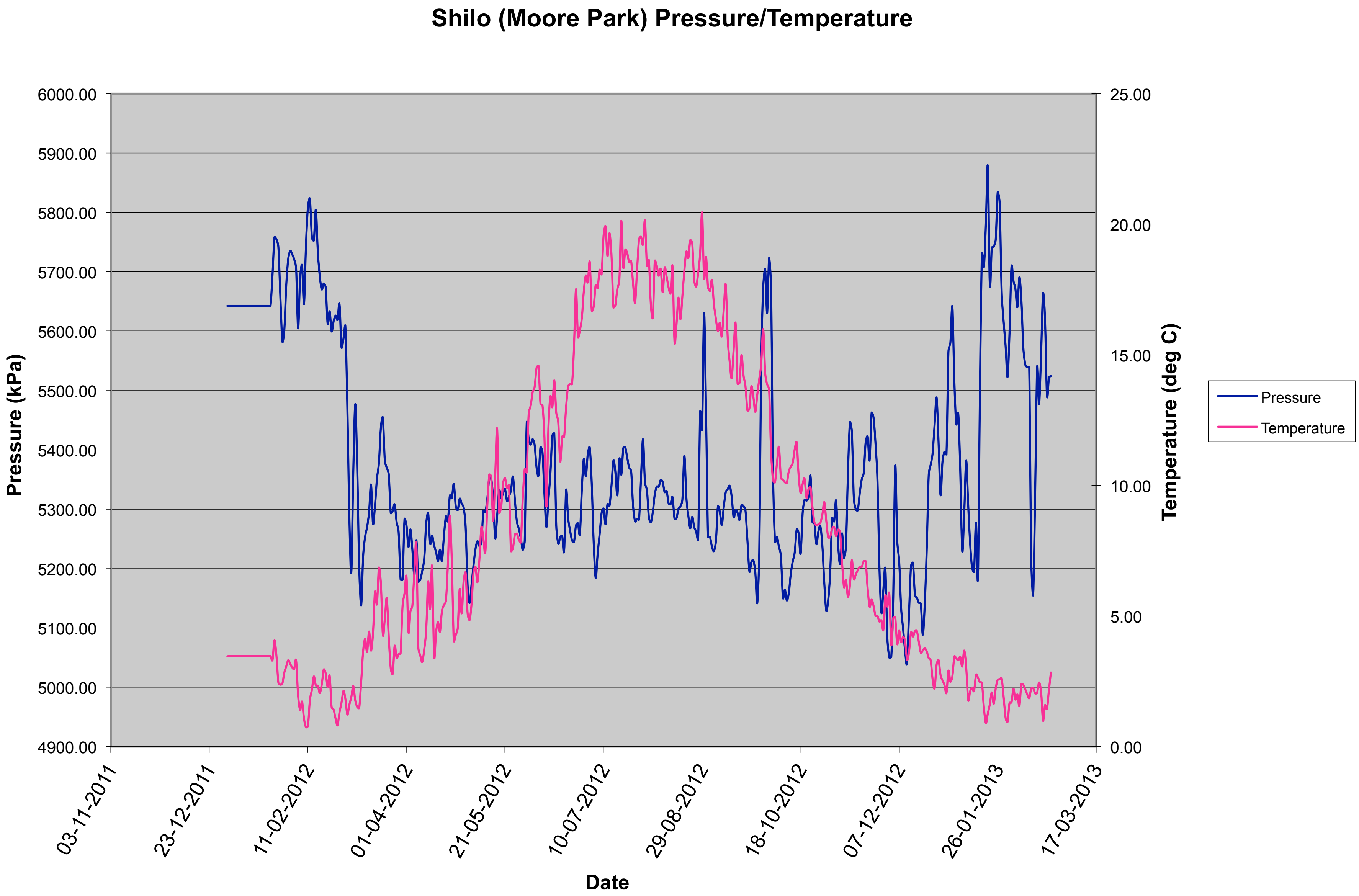

Hamiota Pressure/Temperature
Pressure (kPa)
6200.00
6000.00
5800.00
5600.00
5400.00
5200.00
5000.00
Temperature (deg C)
30.00
25.00
20.00
15.00
10.00
5.00
0.00
-5.00
-10.00
2011-11-03
2011-12-23
2012-02-11
2012-04-01
2012-05-21
2012-07-10
2012-08-29
2012-10-18
2012-12-07
2013-01-26
2013-03-17
Date
Pressure
Temperature

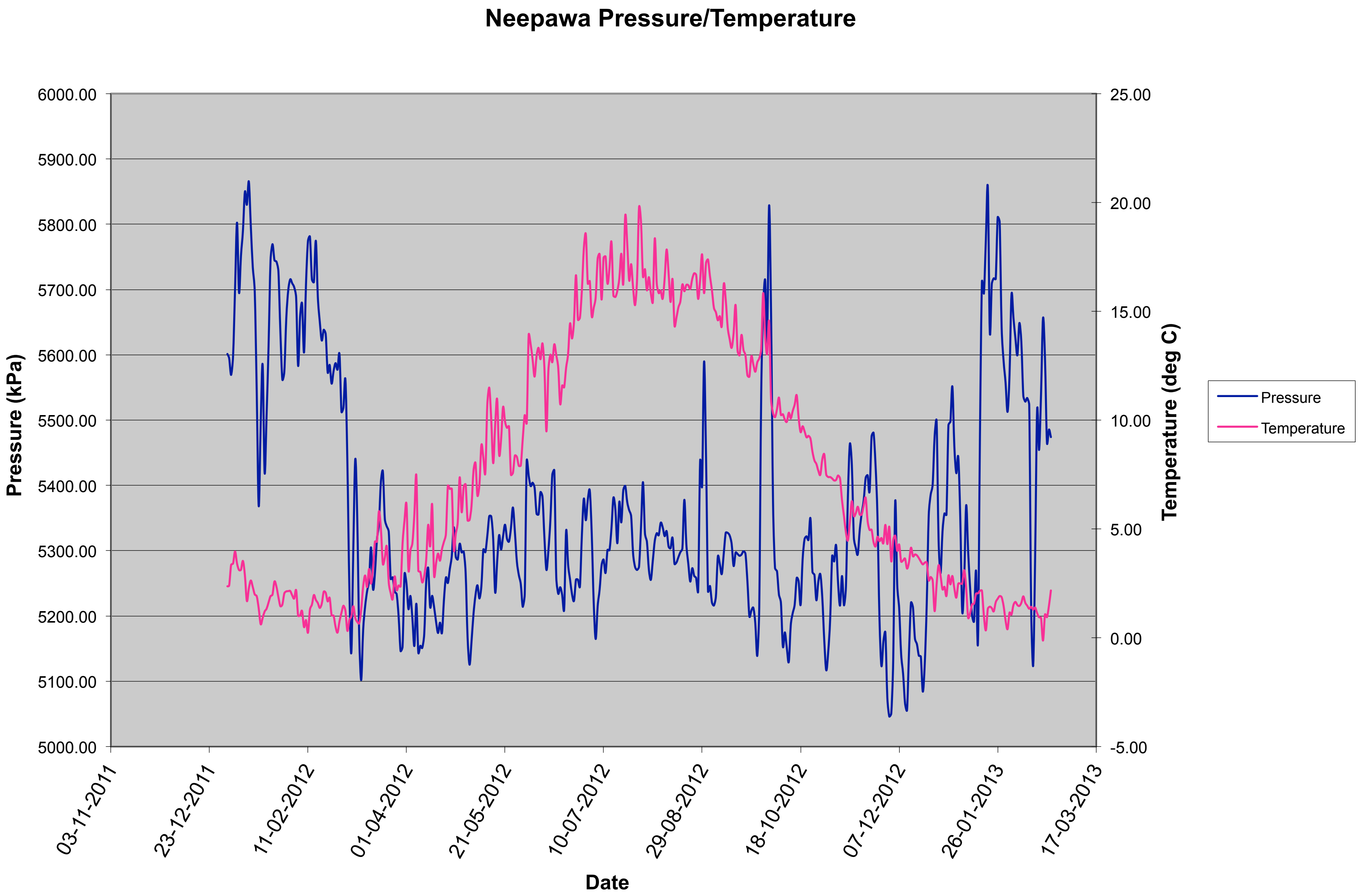
Rivers Wheatland Pressure/Temperature

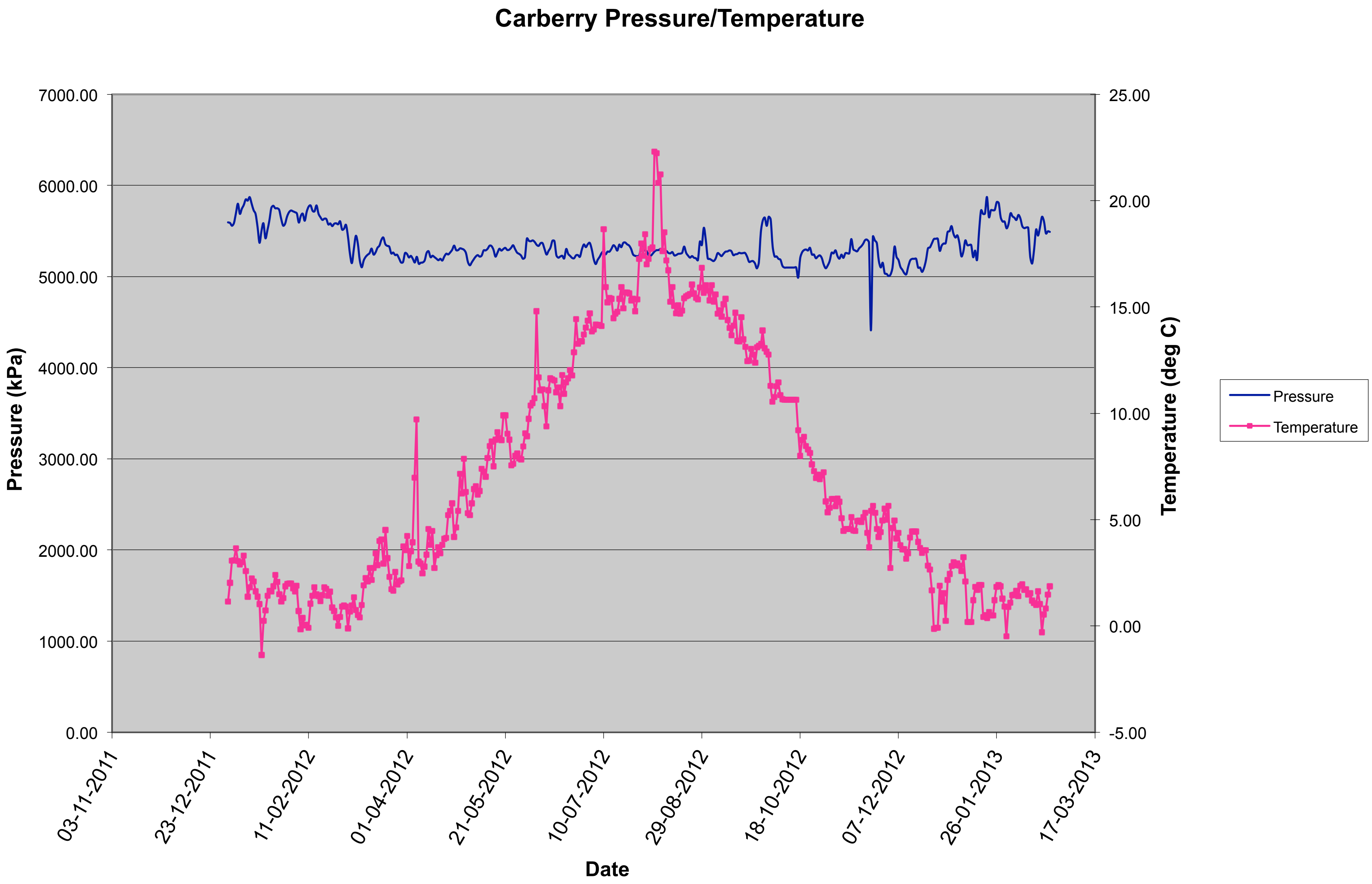


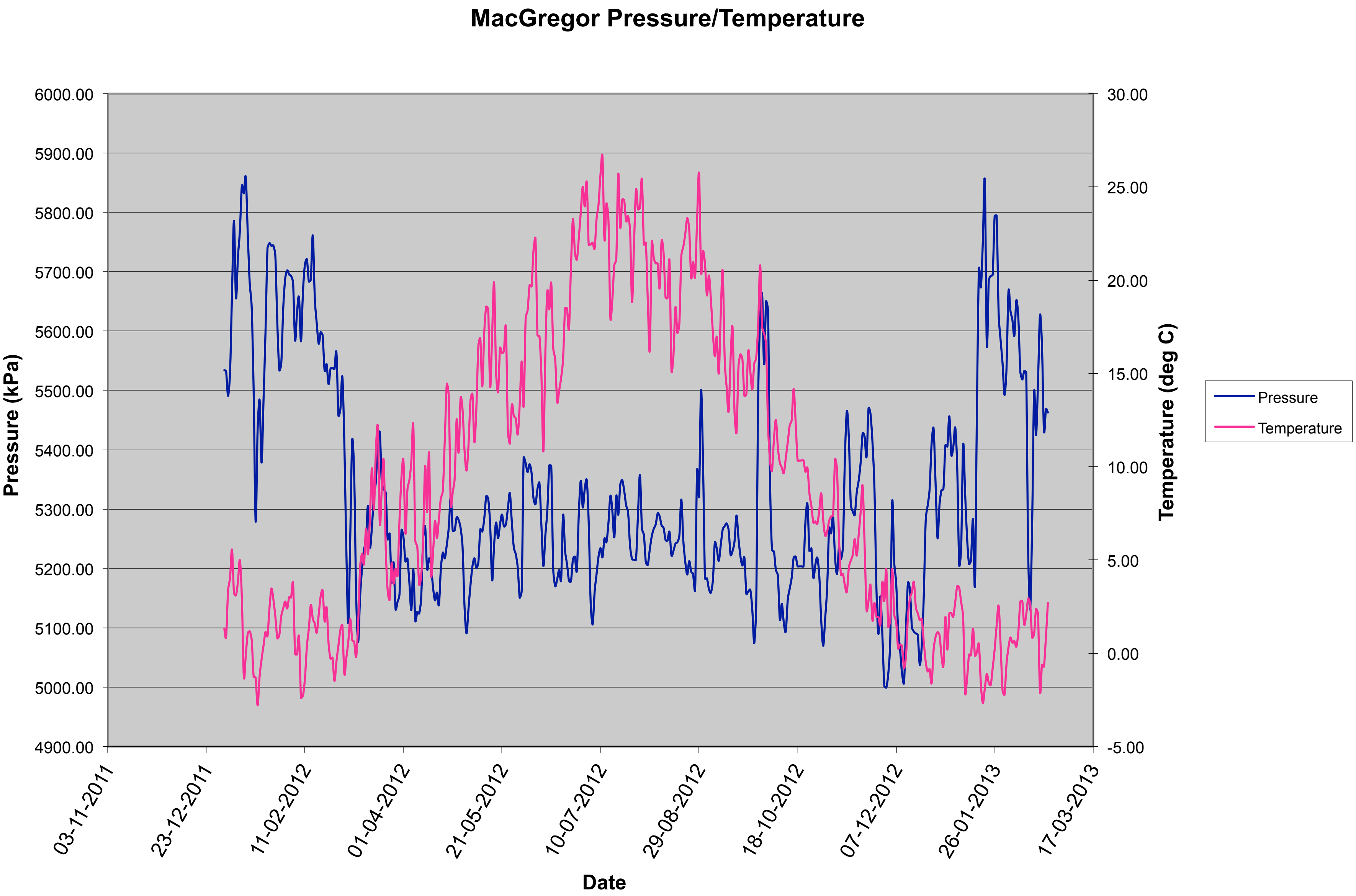
Gap in data due to equipment and communications issues at station. Customer measurement used during outage period.


Brandon Pressure/Temperature
Pressure (kPa)
6000.00
5800.00
5600.00
5400.00
5200.00
5000.00
4800.00
Temperature (deg C)
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
03-11-2011
23-12-2011
11-02-2012
01-04-2012
21-05-2012
10-07-2012
29-08-2012
18-10-2012
07-12-2012
26-01-2013
17-03-2013
Date
Pressure
Temperature


Shilo (Moore Park) Pressure/Temperature
Pressure (kPa)
6000.00
5900.00
5800.00
5700.00
5600.00
5500.00
5400.00
5300.00
5200.00
5100.00
5000.00
4900.00
Temperature (deg C)
25.00
20.00
15.00
10.00
5.00
0.00
03-11-2011
23-12-2011
11-02-2012
01-04-2012
21-05-2012
10-07-2012
29-08-2012
18-10-2012
07-12-2012
26-01-2013
17-03-2013
Date
Pressure
Temperature


Neepawa Pressure/Temperature
Pressure (kPa)
6000.00
5900.00
5800.00
5700.00
5600.00
5500.00
5400.00
5300.00
5200.00
5100.00
5000.00
Temperature (deg C)
25.00
20.00
15.00
10.00
5.00
0.00
-5.00
03-11-2011
23-12-2011
11-02-2012
01-04-2012
21-05-2012
10-07-2012
29-08-2012
18-10-2012
07-12-2012
26-01-2013
17-03-2013
Date
Pressure
Temperature


Carberry Pressure/Temperature
Pressure (kPa)
7000.00
6000.00
5000.00
4000.00
3000.00
2000.00
1000.00
0.00
Temperature (deg C)
25.00
20.00
15.00
10.00
5.00
0.00
-5.00
03-11-2011
23-12-2011
11-02-2012
01-04-2012
21-05-2012
10-07-2012
29-08-2012
18-10-2012
07-12-2012
26-01-2013
17-03-2013
Date
Pressure
Temperature


MacGregor Pressure/Temperature
Pressure (kPa)
6000.00
5900.00
5800.00
5700.00
5600.00
5500.00
5400.00
5300.00
5200.00
5100.00
5000.00
4900.00
Temperature (deg C)
30.00
25.00
20.00
15.00
10.00
5.00
0.00
-5.00
03-11-2011
23-12-2011
11-02-2012
01-04-2012
21-05-2012
10-07-2012
29-08-2012
18-10-2012
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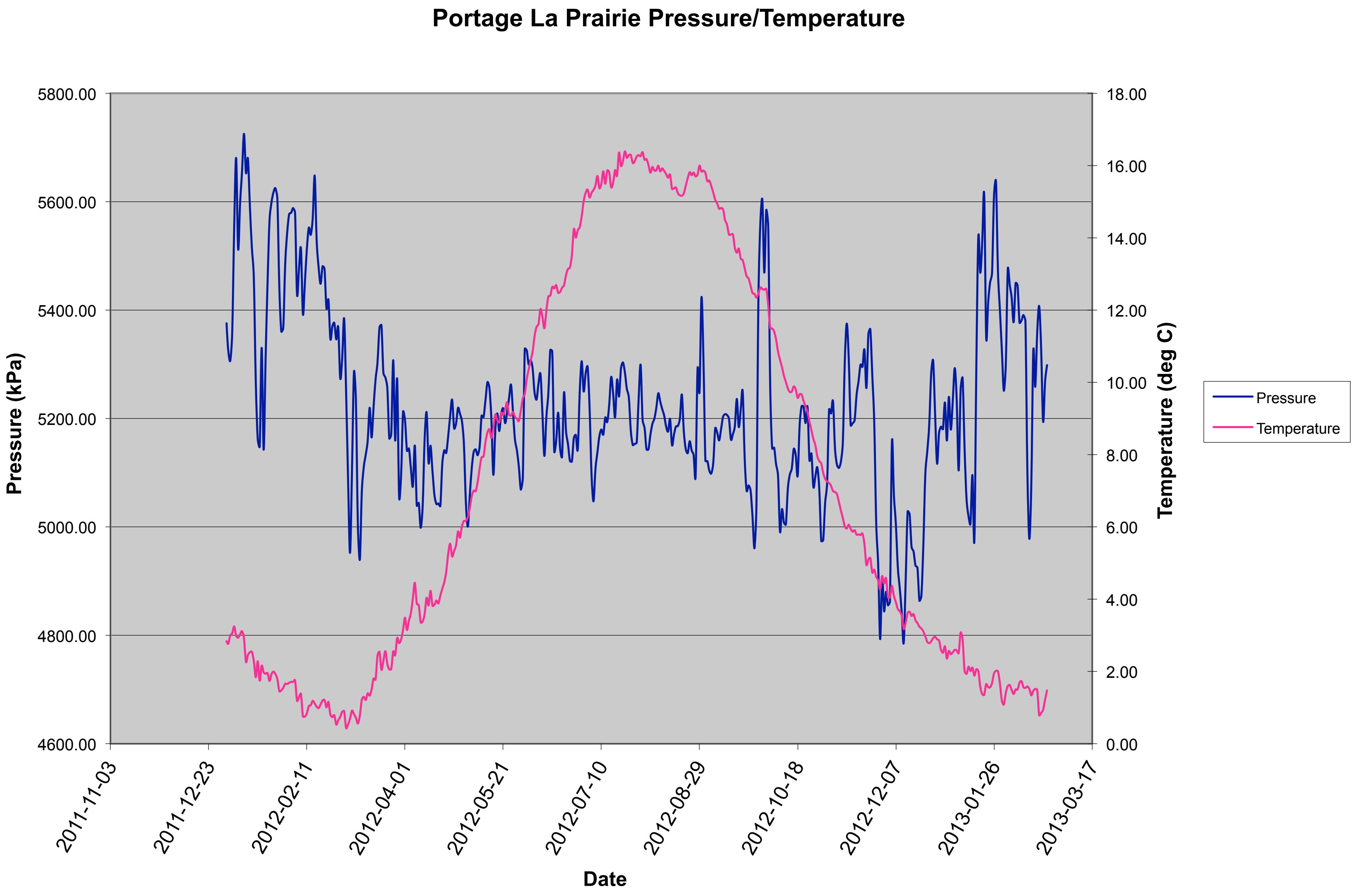
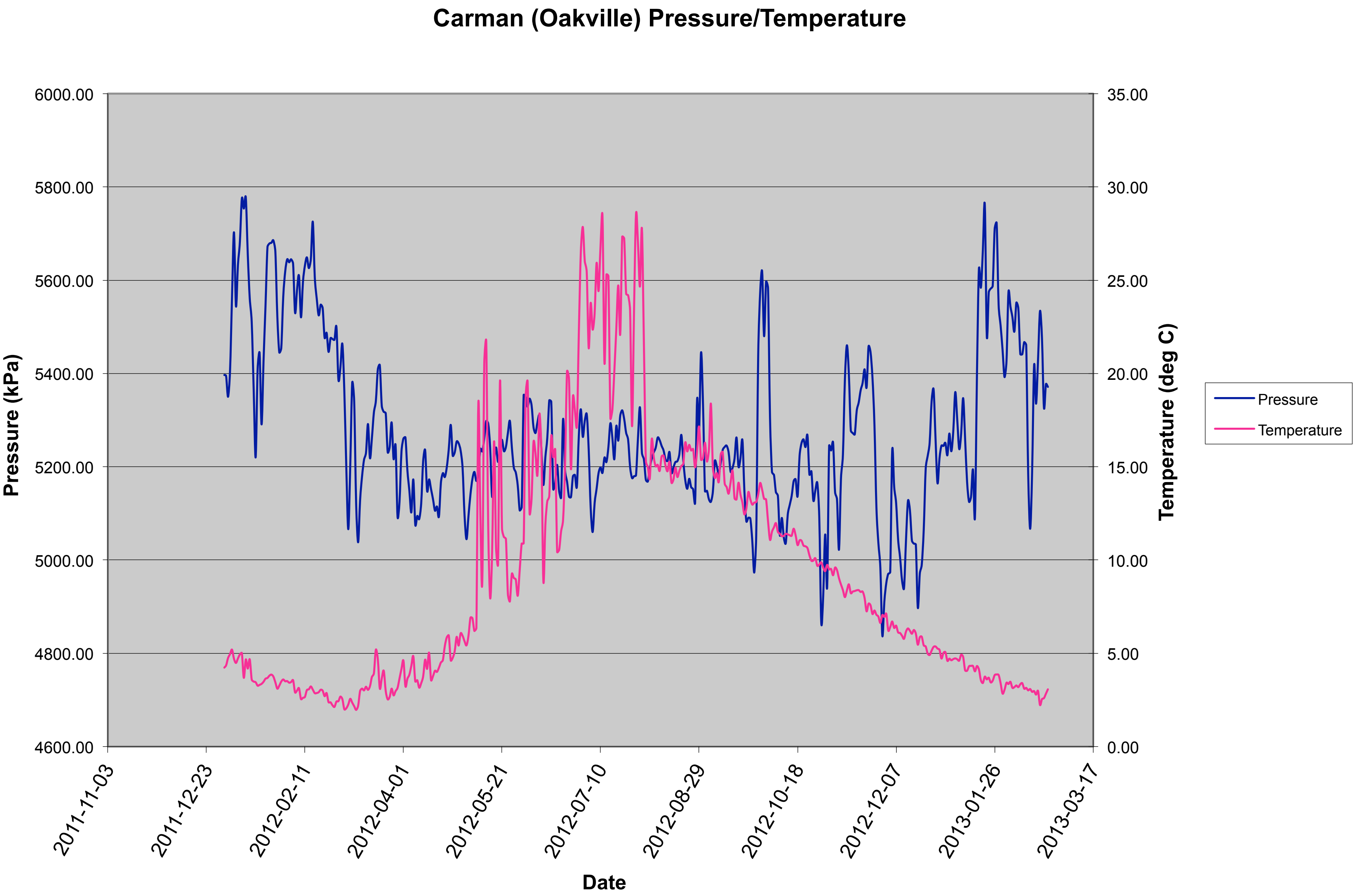
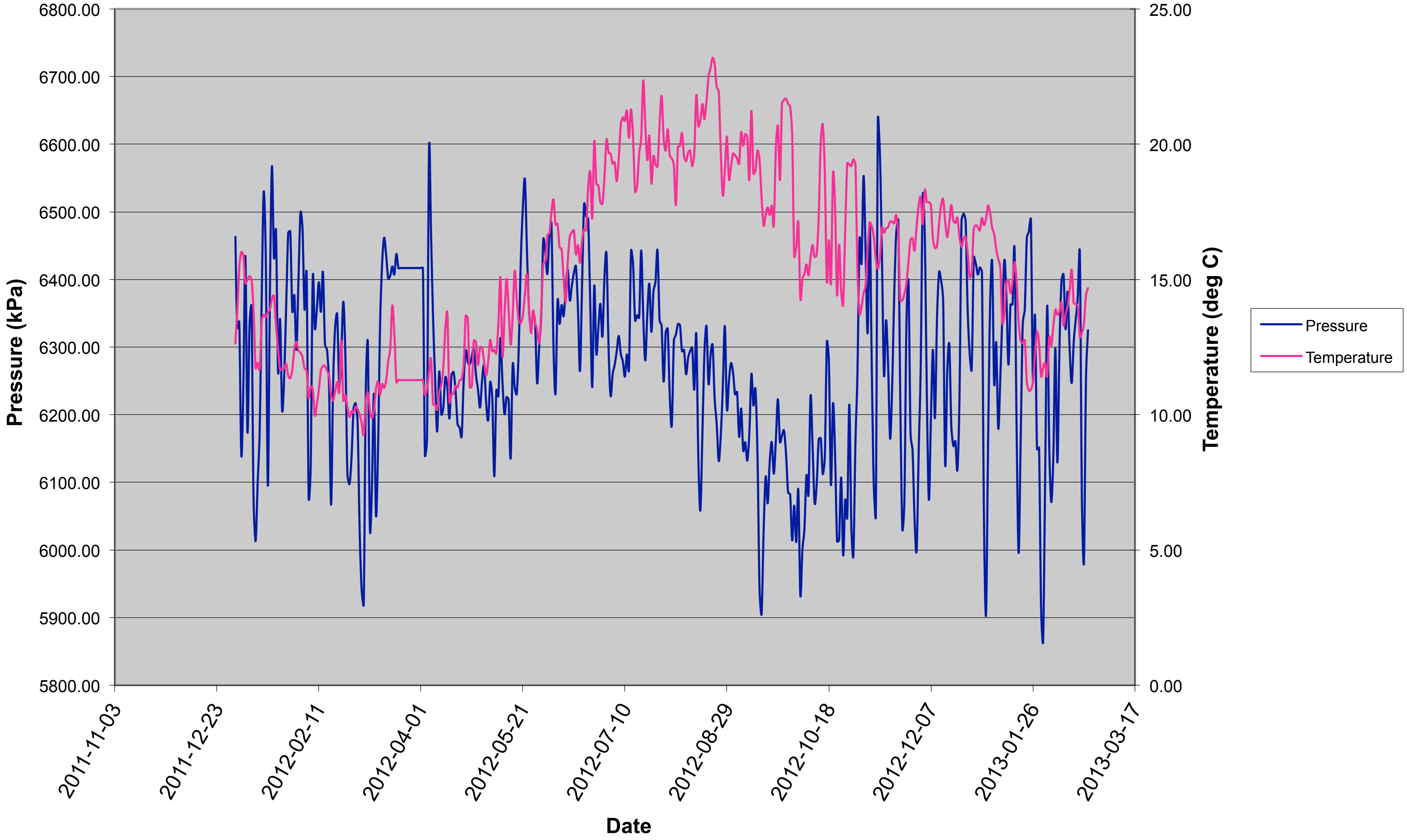
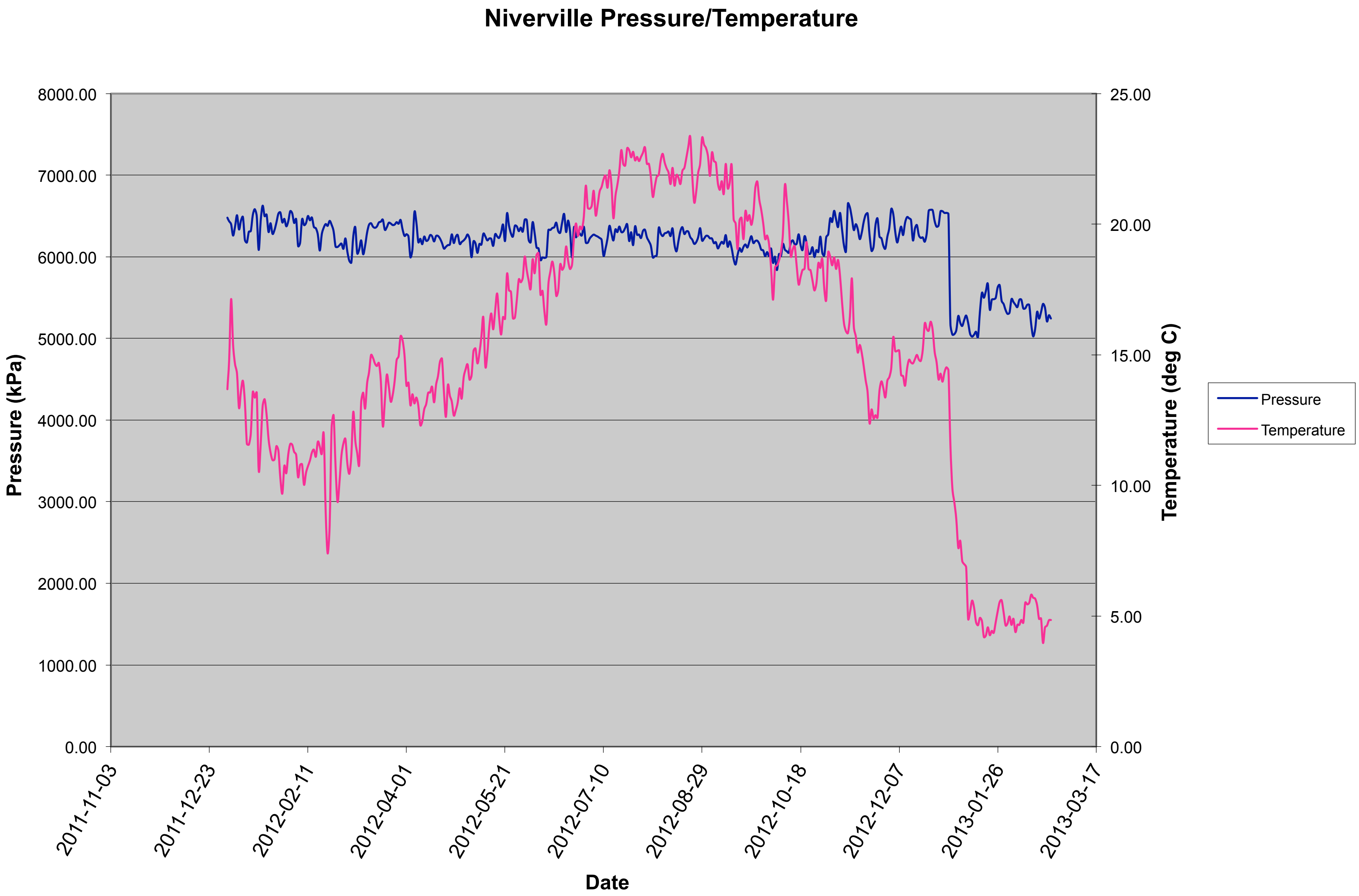
26-01-2013
17-03-2013
Date
Pressure
Temperature


Portage La Prairie Pressure/Temperature
Pressure (kPa)
5800.00
5600.00
5400.00
5200.00
5000.00
4800.00
4600.00
Temperature (deg C)
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2011-11-03
2011-12-23
2012-02-11
2012-04-01
2012-05-21
2012-07-10
2012-08-29
2012-10-18
2012-12-07
2013-01-26
2013-03-17
Date
Pressure
Temperature

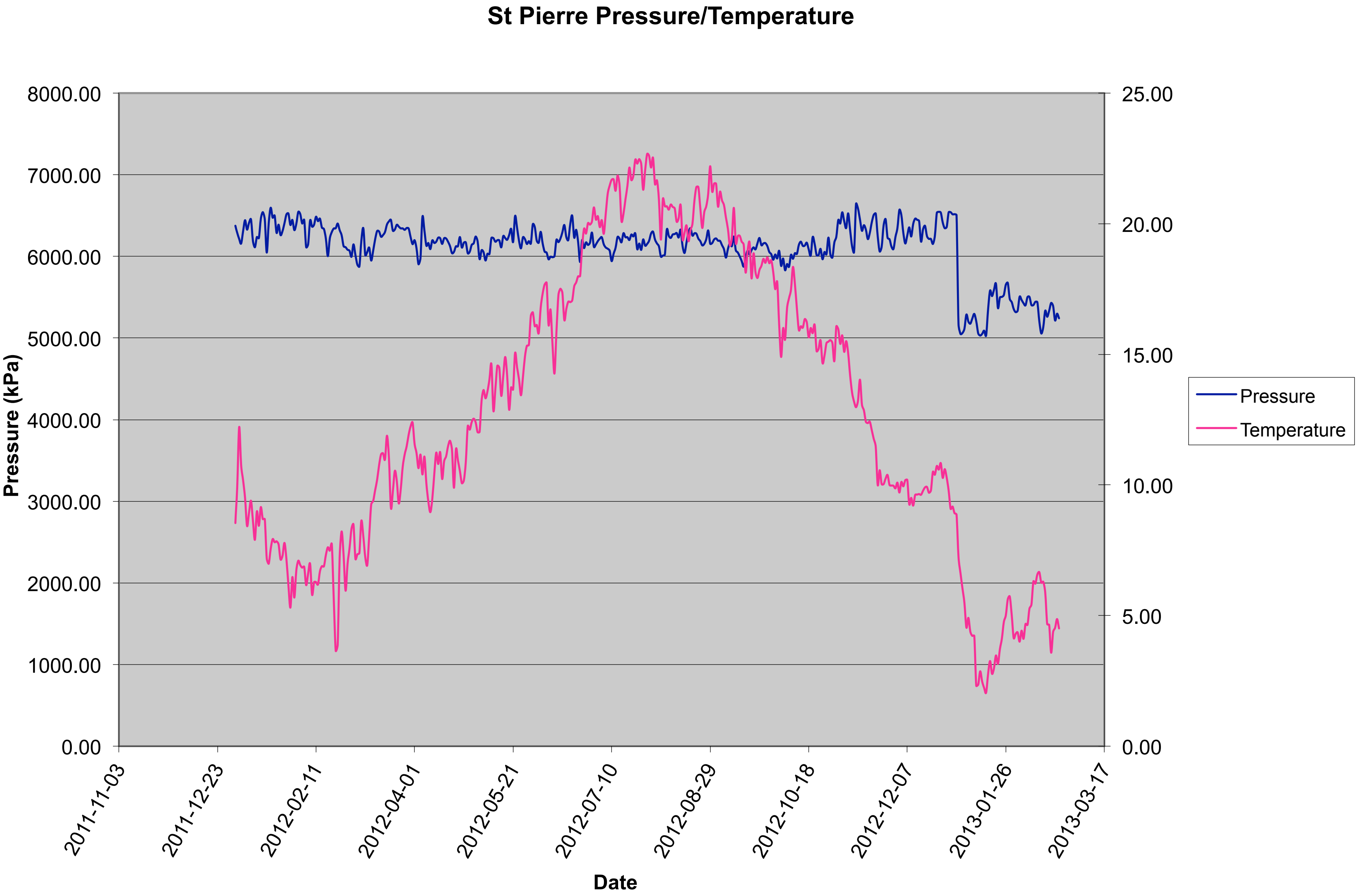

Carman (Oakville) Pressure/Temperature
Pressure (kPa)
6000.00
5800.00
5600.00
5400.00
5200.00
5000.00
4800.00
4600.00
Temperature (deg C)
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
2011-11-03
2011-12-23
2012-02-11
2012-04-01
2012-05-21
2012-07-10
2012-08-29
2012-10-18
2012-12-07
2013-01-26
2013-03-17
Date
Pressure
Temperature

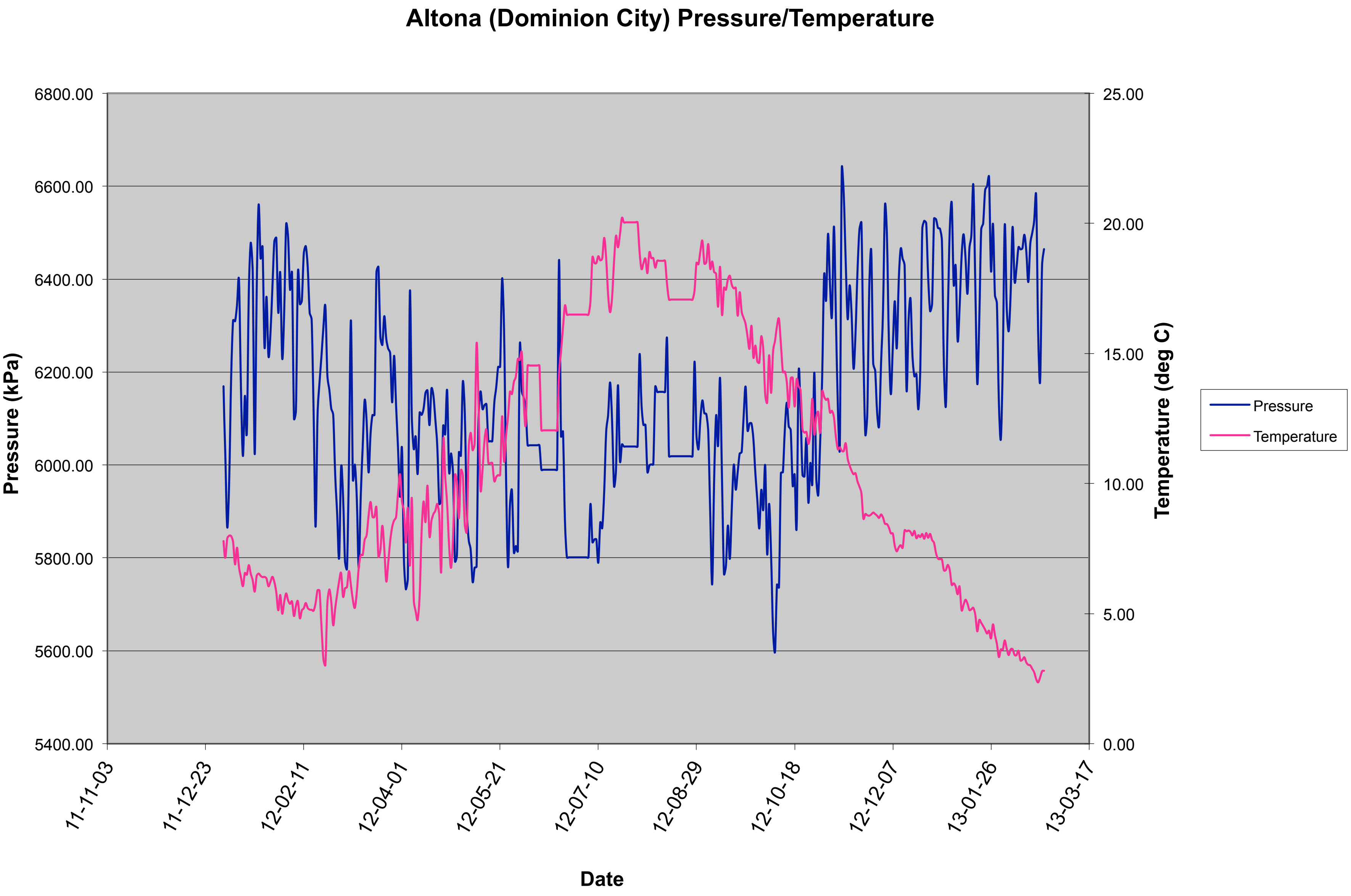
Steinbach (St. Anne) Pressure/Temperature



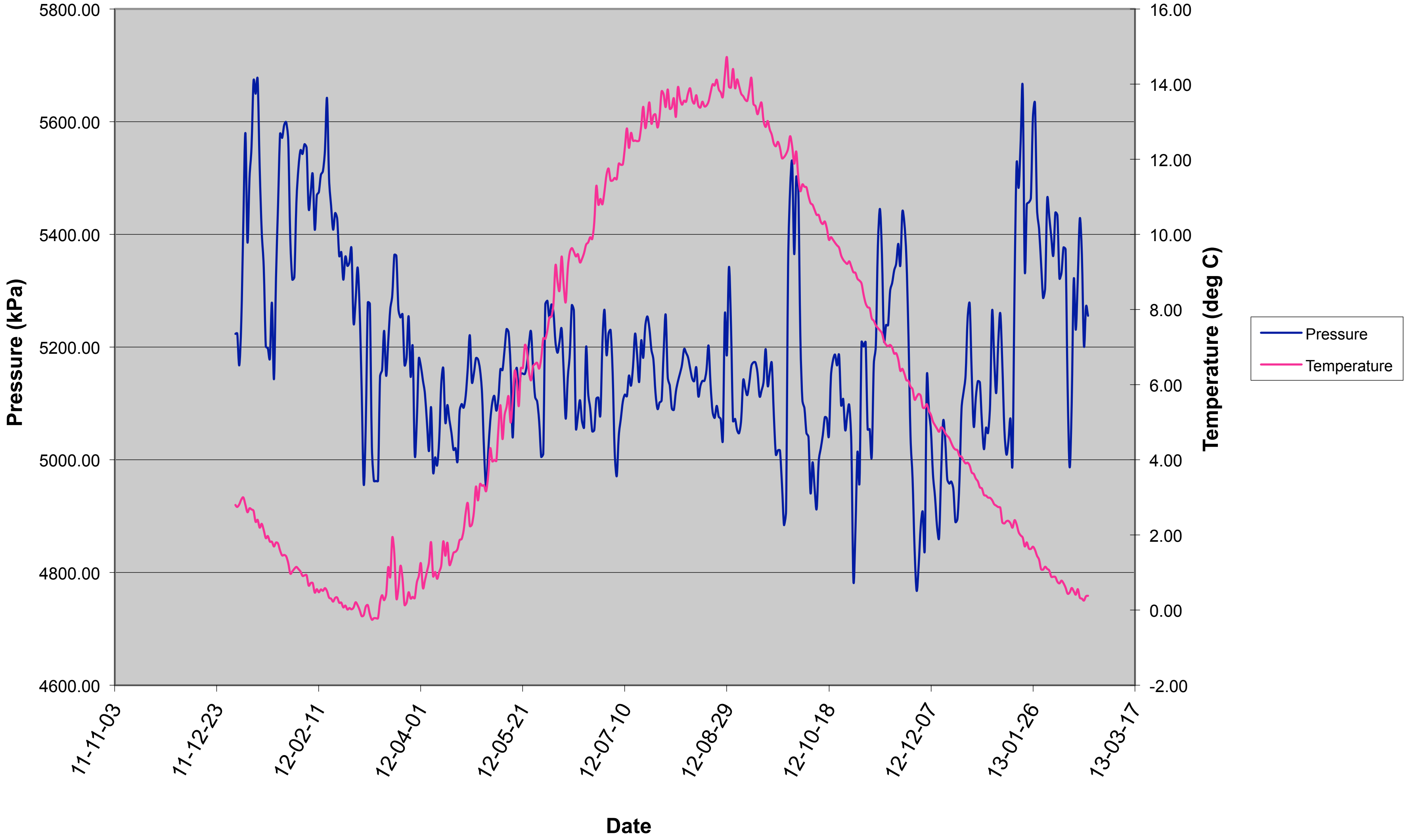


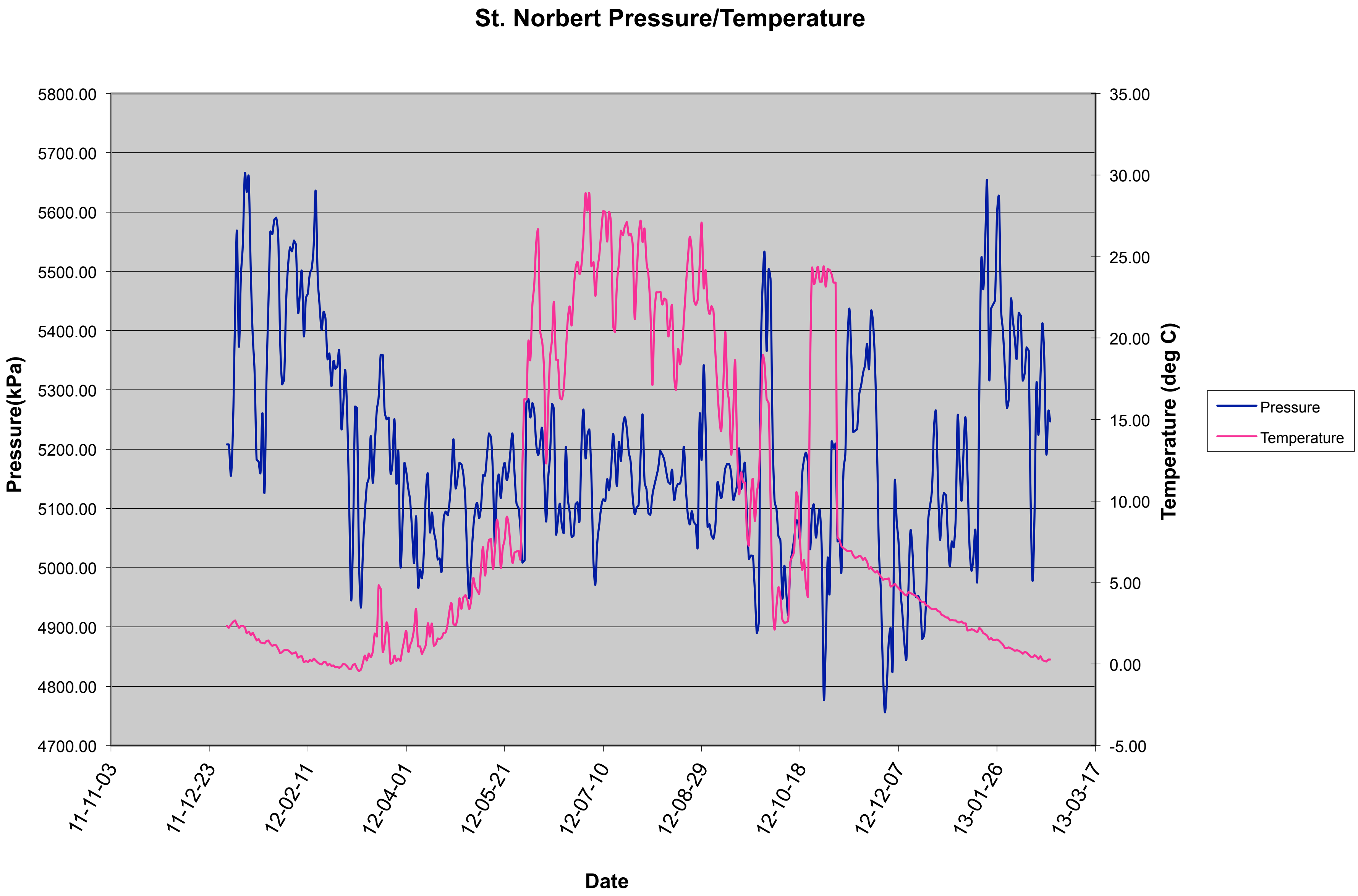
Niverville Pressure/Temperature
Pressure (kPa)
8000.00
7000.00
6000.00
5000.00
4000.00
3000.00
2000.00
1000.00
0.00
Temperature (deg C)
25.00
20.00
15.00
10.00
5.00
0.00
2011-11-03
2011-12-23
2012-02-11
2012-04-01
2012-05-21
2012-07-10
2012-08-29
2012-10-18
2012-12-07
2013-01-26
2013-03-17
Date
Pressure
Temperature


St Pierre Pressure/Temperature
Pressure (kPa)
8000.00
7000.00
6000.00
5000.00
4000.00
3000.00
2000.00
1000.00
0.00
25.00
20.00
15.00
10.00
5.00
0.00
2011-11-03
2011-12-23
2012-02-11
2012-04-01
2012-05-21
2012-07-10
2012-08-29
2012-10-18
2012-12-07
2013-01-26
2013-03-17
Date
Pressure
Temperature

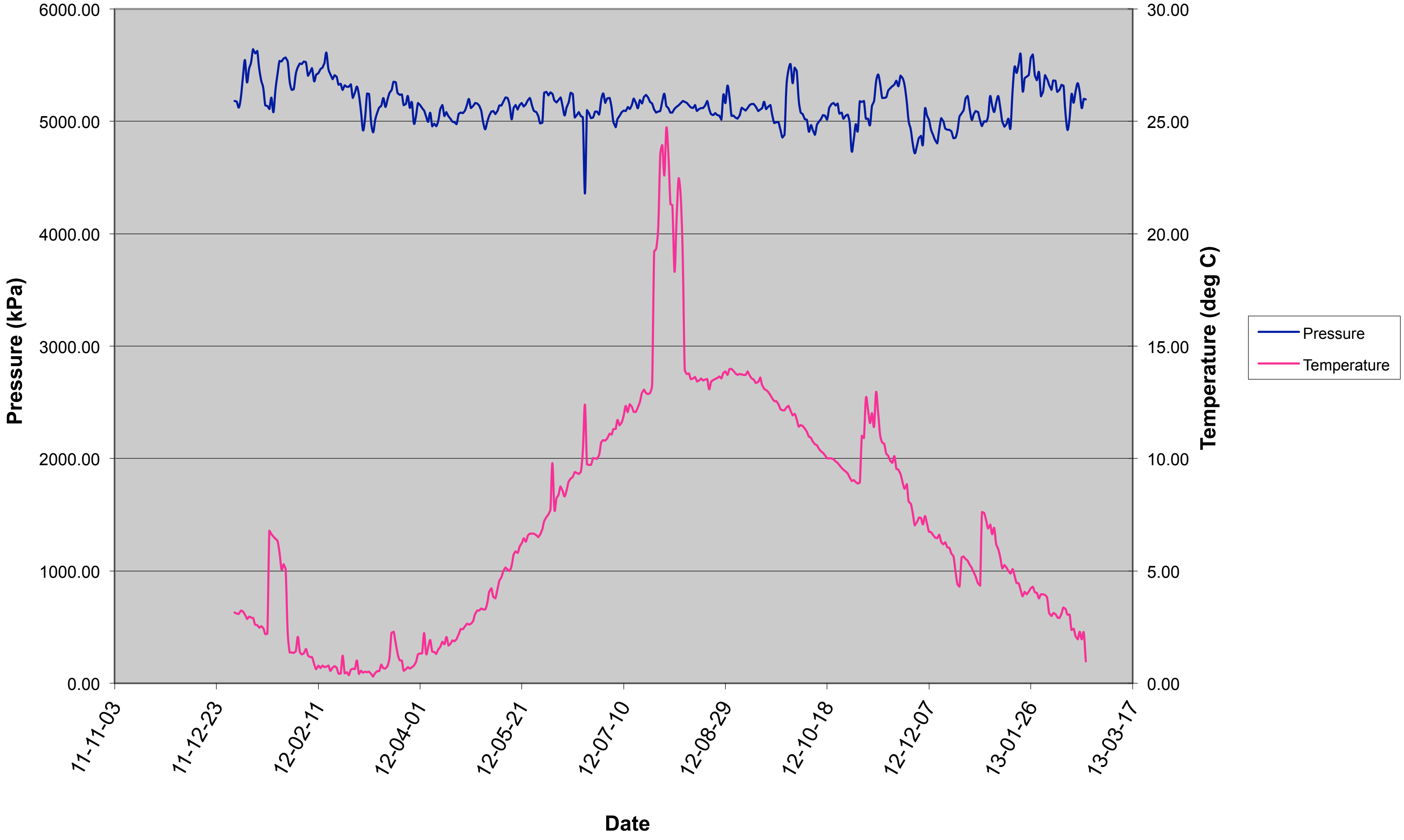

Altona (Dominion City) Pressure/Temperature
Pressure (kPa)
6800.00
6600.00
6400.00
6200.00
6000.00
5800.00
5600.00
5400.00
Temperature (deg C)
25.00
20.00
15.00
10.00
5.00
0.00
11-11-03
11-12-23
12-02-11
12-04-01
12-05-21
12-07-10
12-08-29
12-10-18
12-12-07
13-01-26
13-03-17
Date
Pressure
Temperature

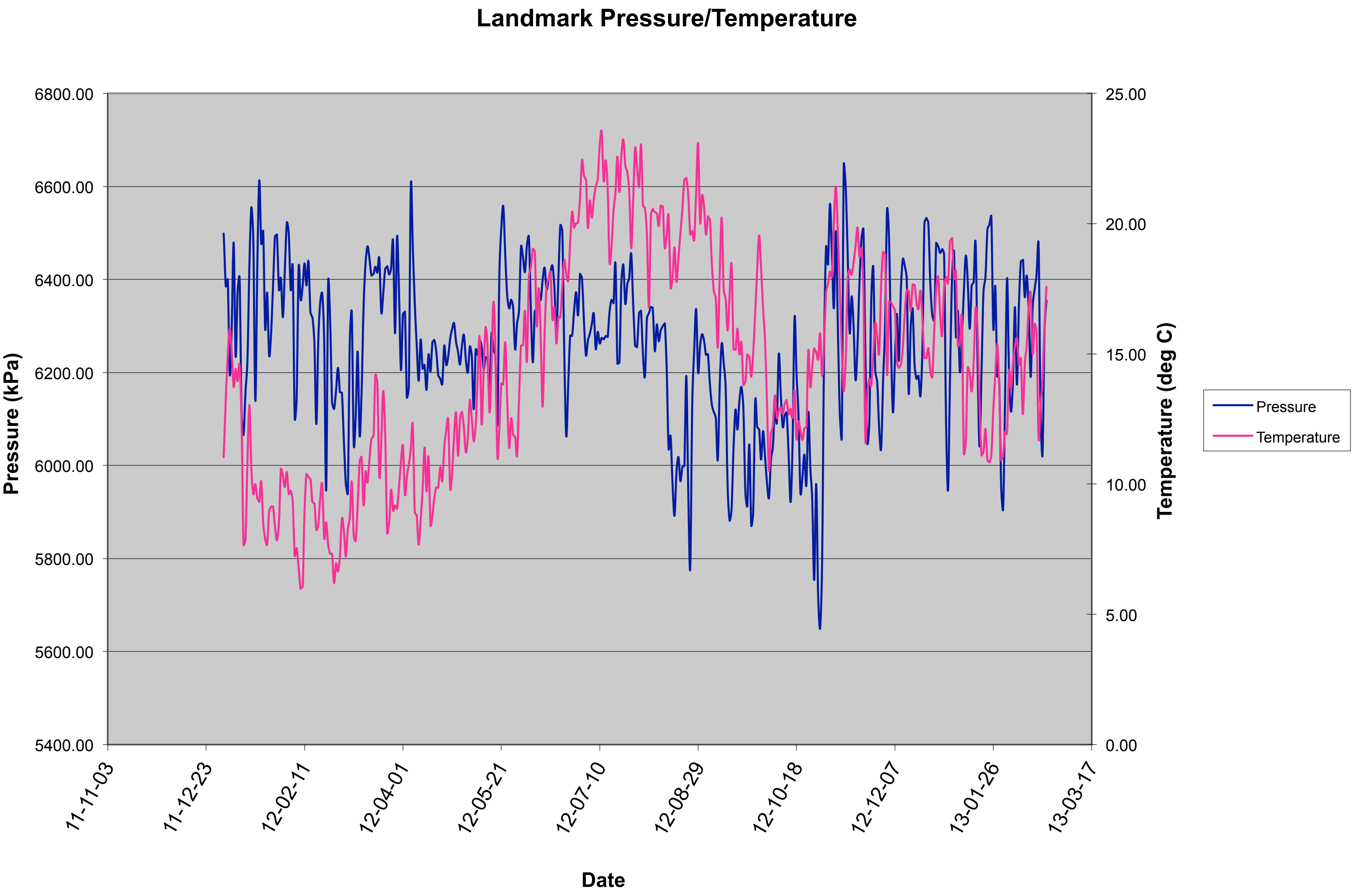
Winnipeg (La Salle) Pressure/Temperature



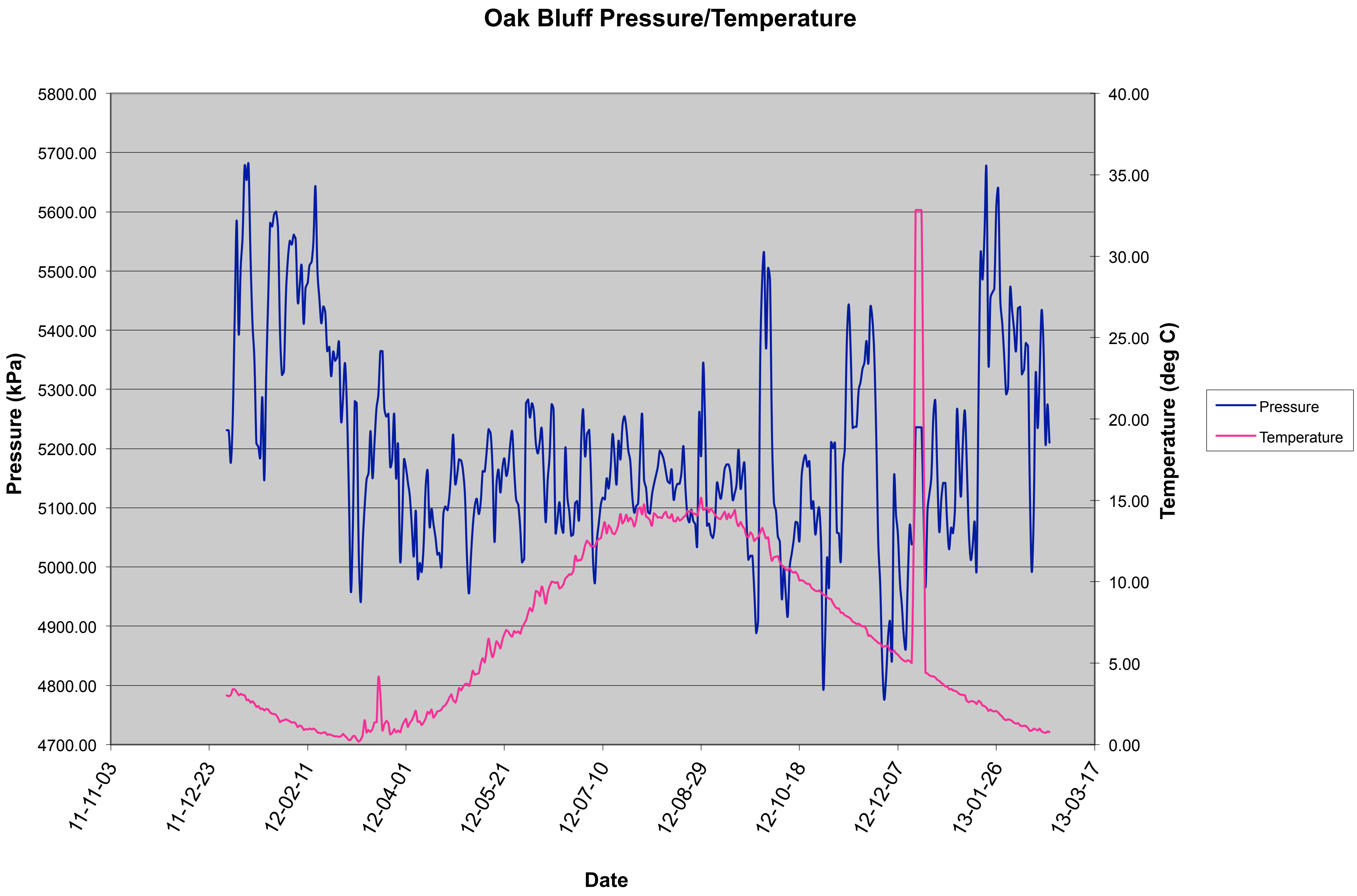

St. Norbert Pressure/Temperature
Pressure(kPa)
5800.00
5700.00
5600.00
5500.00
5400.00
5300.00
5200.00
5100.00
5000.00
4900.00
4800.00
4700.00
Temperature (deg C)
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
-5.00
11-11-03
11-12-23
12-02-11
12-04-01
12-05-21
12-07-10
12-08-29
12-10-18
12-12-07
13-01-26
13-03-17
Date
Pressure
Temperature

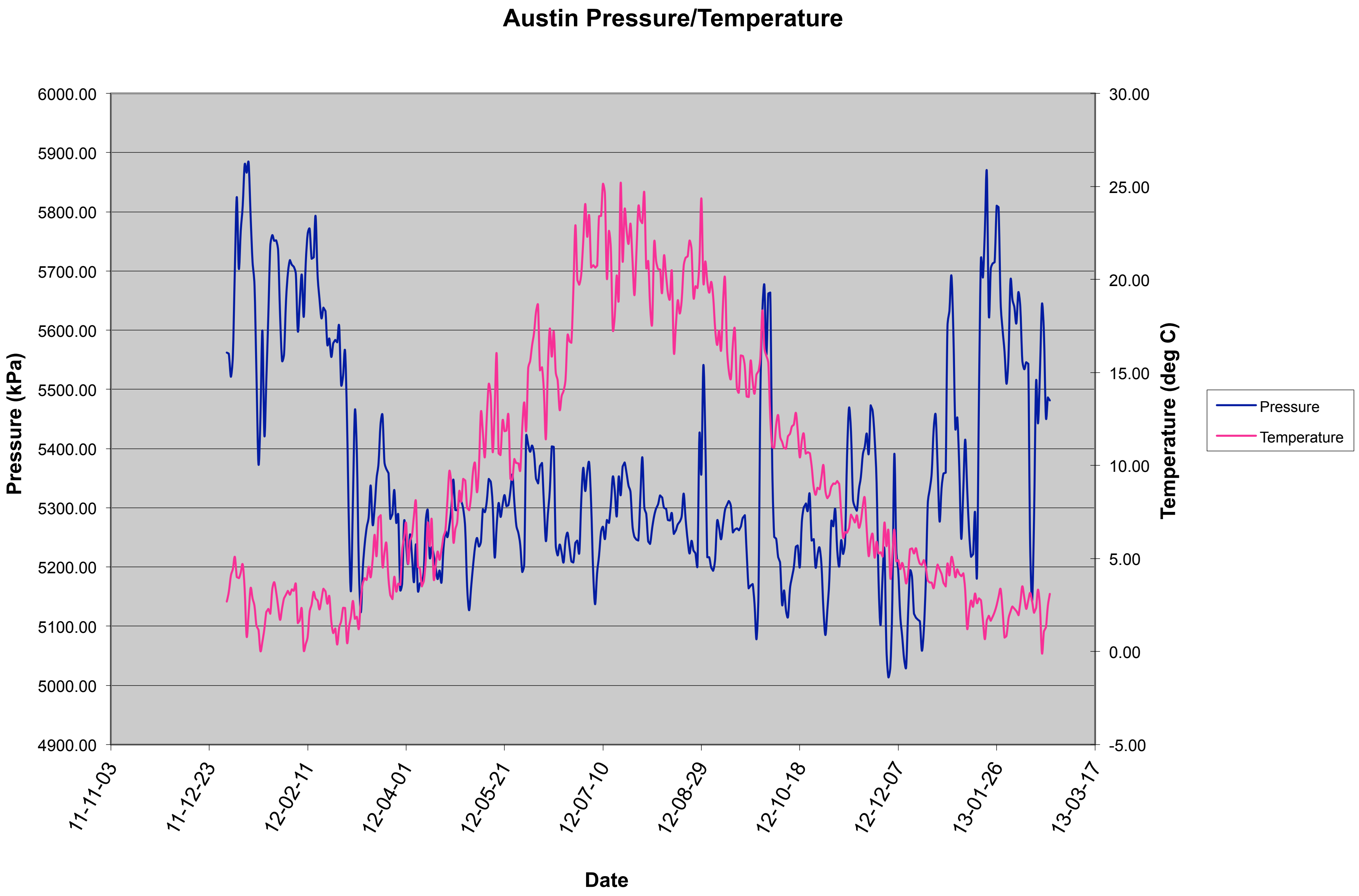
Transcona (IL DE CHENES) Pressure/Temperature



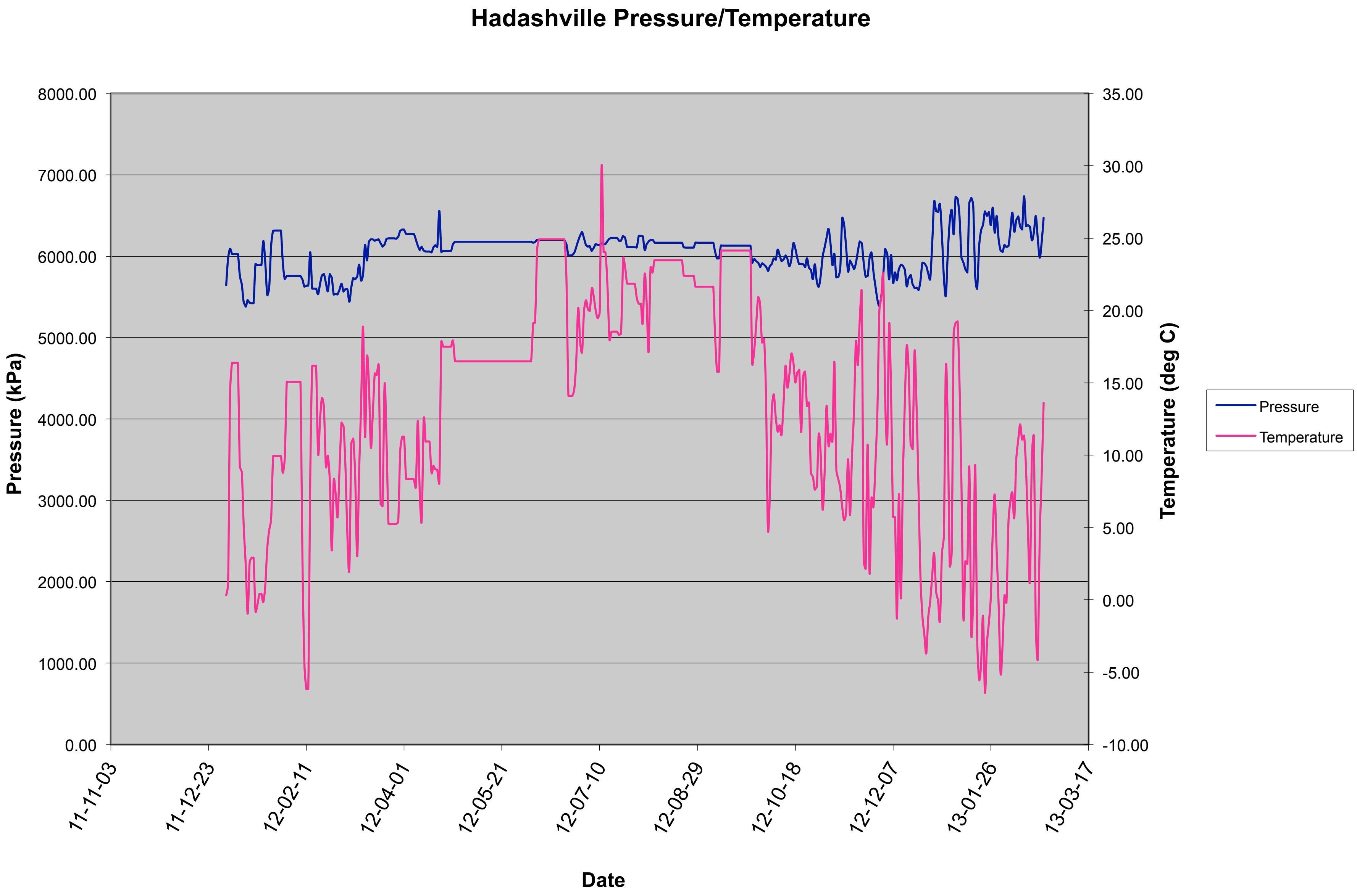


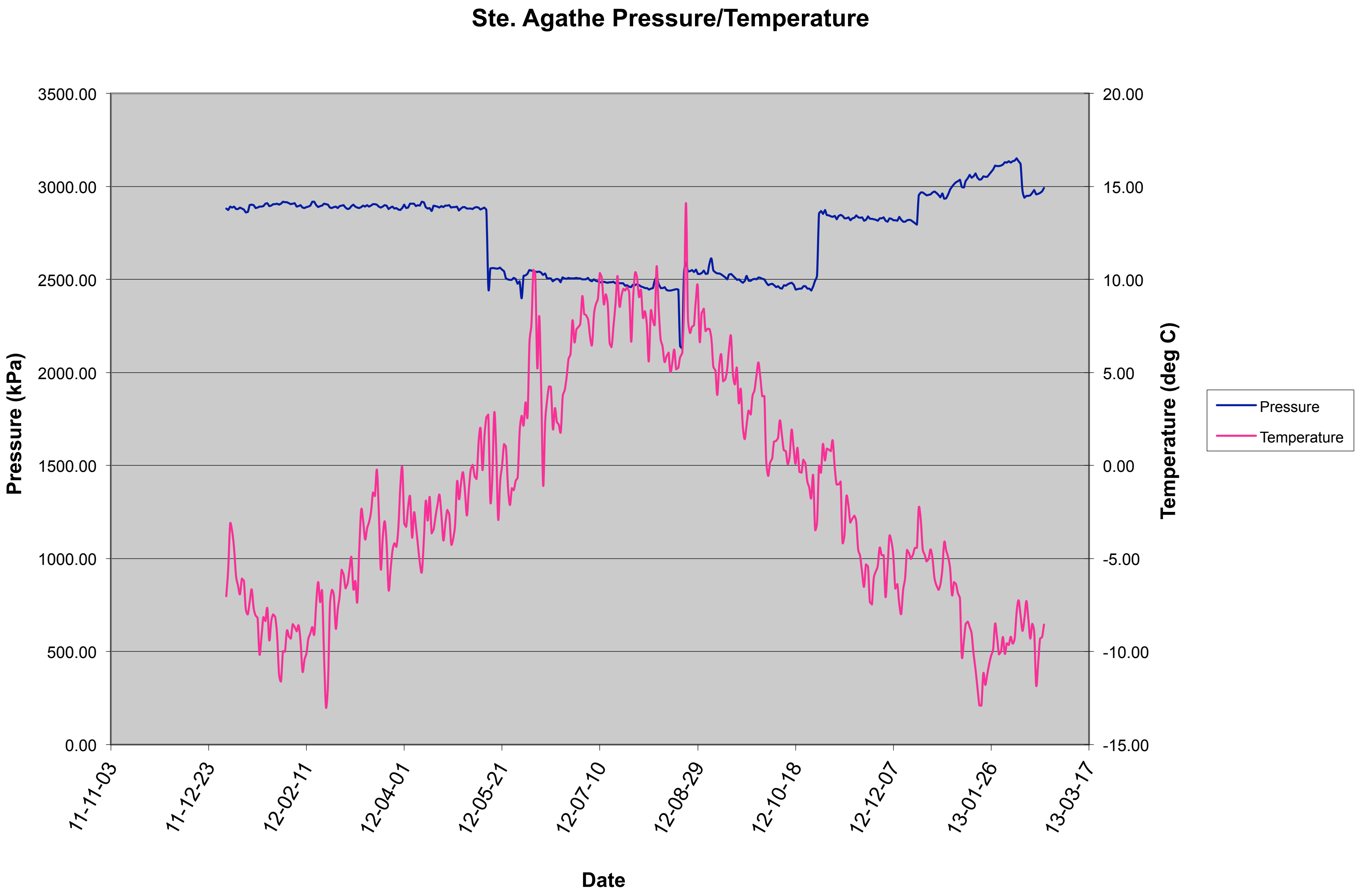
Landmark Pressure/Temperature
Pressure (kPa)
6800.00
6600.00
6400.00
6200.00
6000.00
5800.00
5600.00
5400.00
Temperature (deg C)
25.00
20.00
15.00
10.00
5.00
0.00
11-11-03
11-12-23
12-02-11
12-04-01
12-05-21
12-07-10
12-08-29
12-10-18
12-12-07
13-01-26
13-03-17
Date
Pressure
Temperature

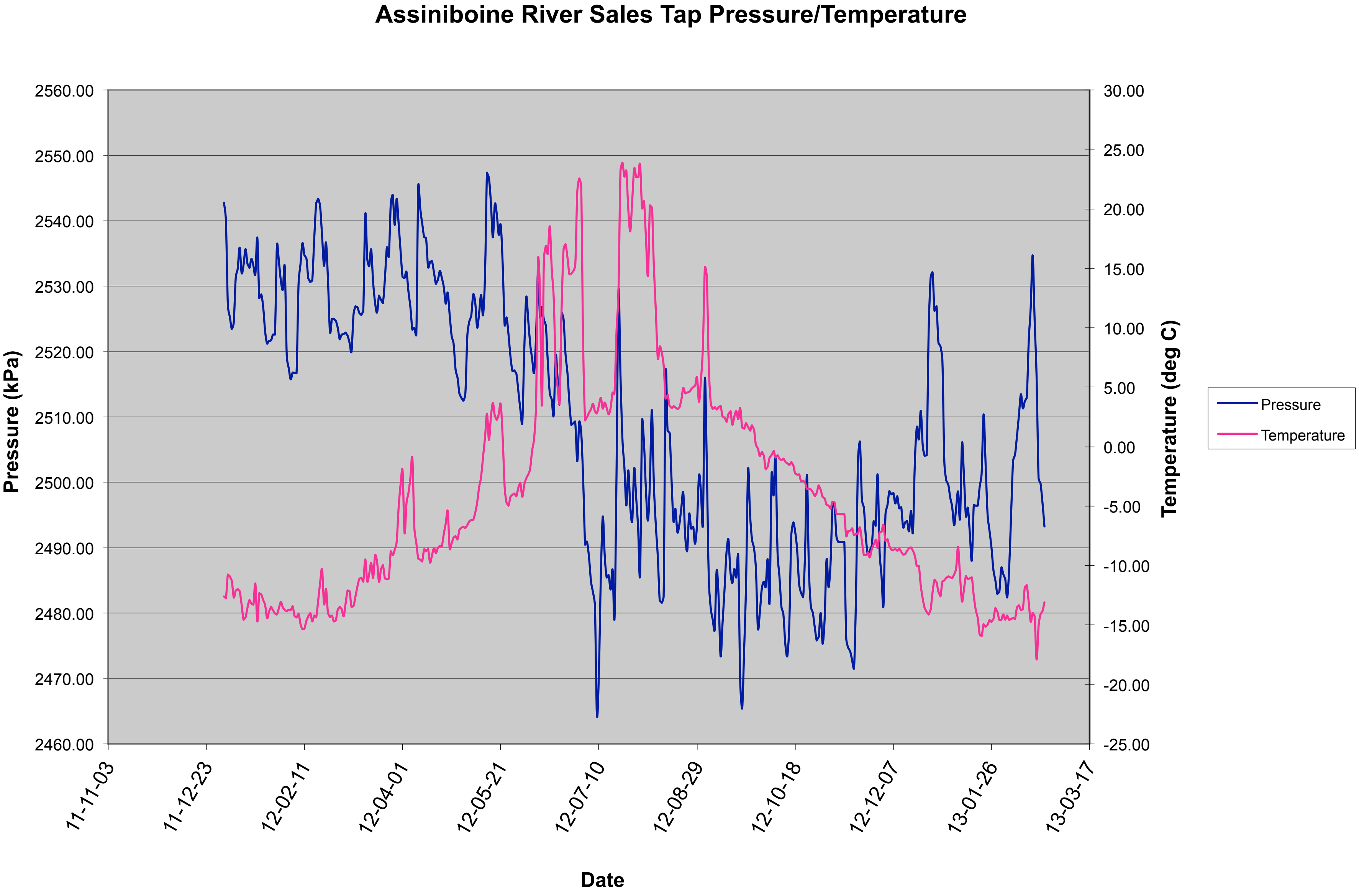

Oak Bluff Pressure/Temperature
Pressure (kPa)
5800.00
5700.00
5600.00
5500.00
5400.00
5300.00
5200.00
5100.00
5000.00
4900.00
4800.00
4700.00
Temperature (deg C)
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
11-11-03
11-12-23
12-02-11
12-04-01
12-05-21
12-07-10
12-08-29
12-10-18
12-12-07
13-01-26
13-03-17
Date
Pressure
Temperature

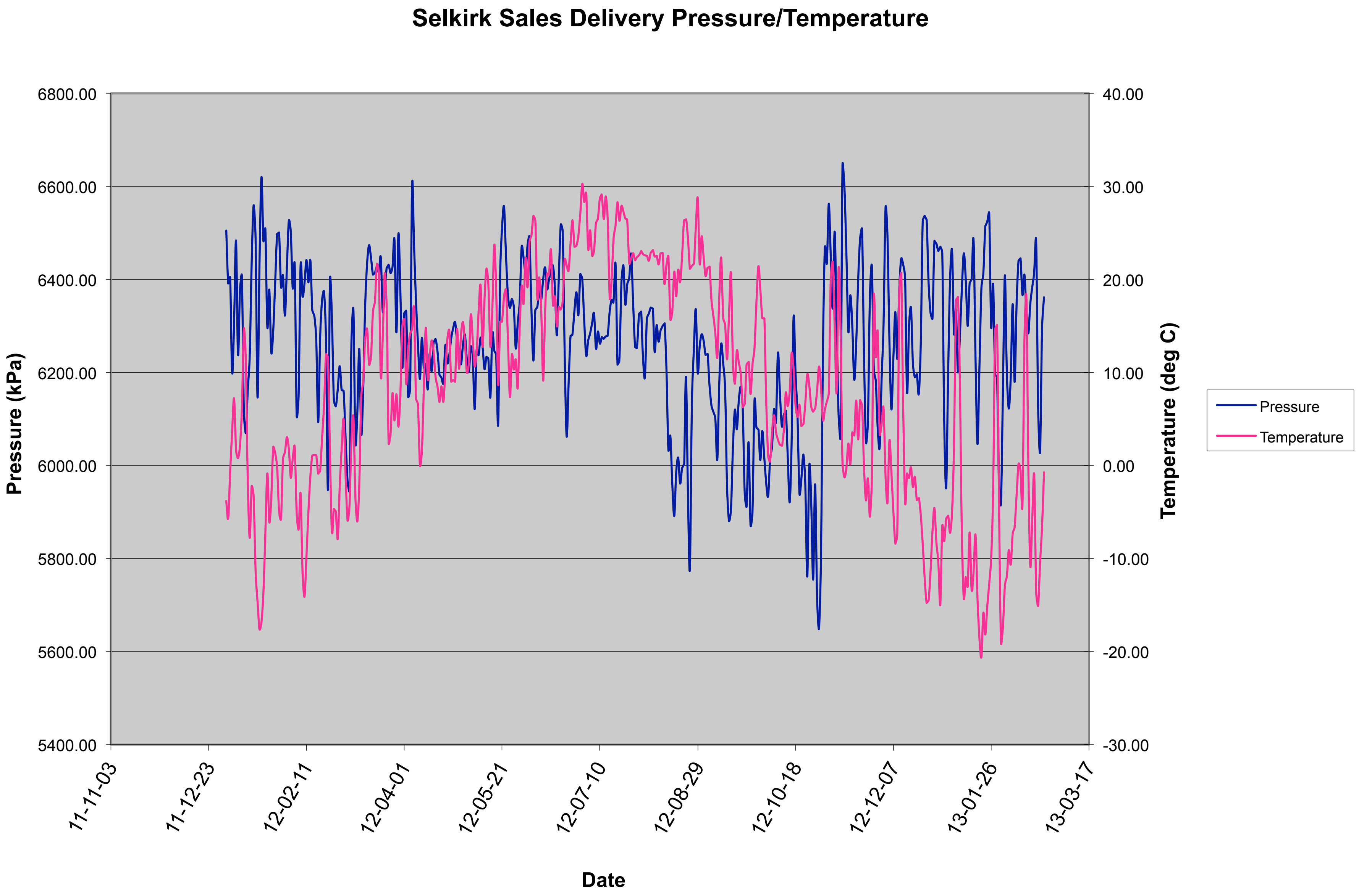


Austin Pressure/Temperature
Pressure (kPa)
6000.00
5900.00
5800.00
5700.00
5600.00
5500.00
5400.00
5300.00
5200.00
5100.00
5000.00
4900.00
Temperature (deg C)
30.00
25.00
20.00
15.00
10.00
5.00
0.00
-5.00
11-11-03
11-12-23
12-02-11
12-04-01
12-05-21
12-07-10
12-08-29
12-10-18
12-12-07
13-01-26
13-03-17
Date
Pressure
Temperature

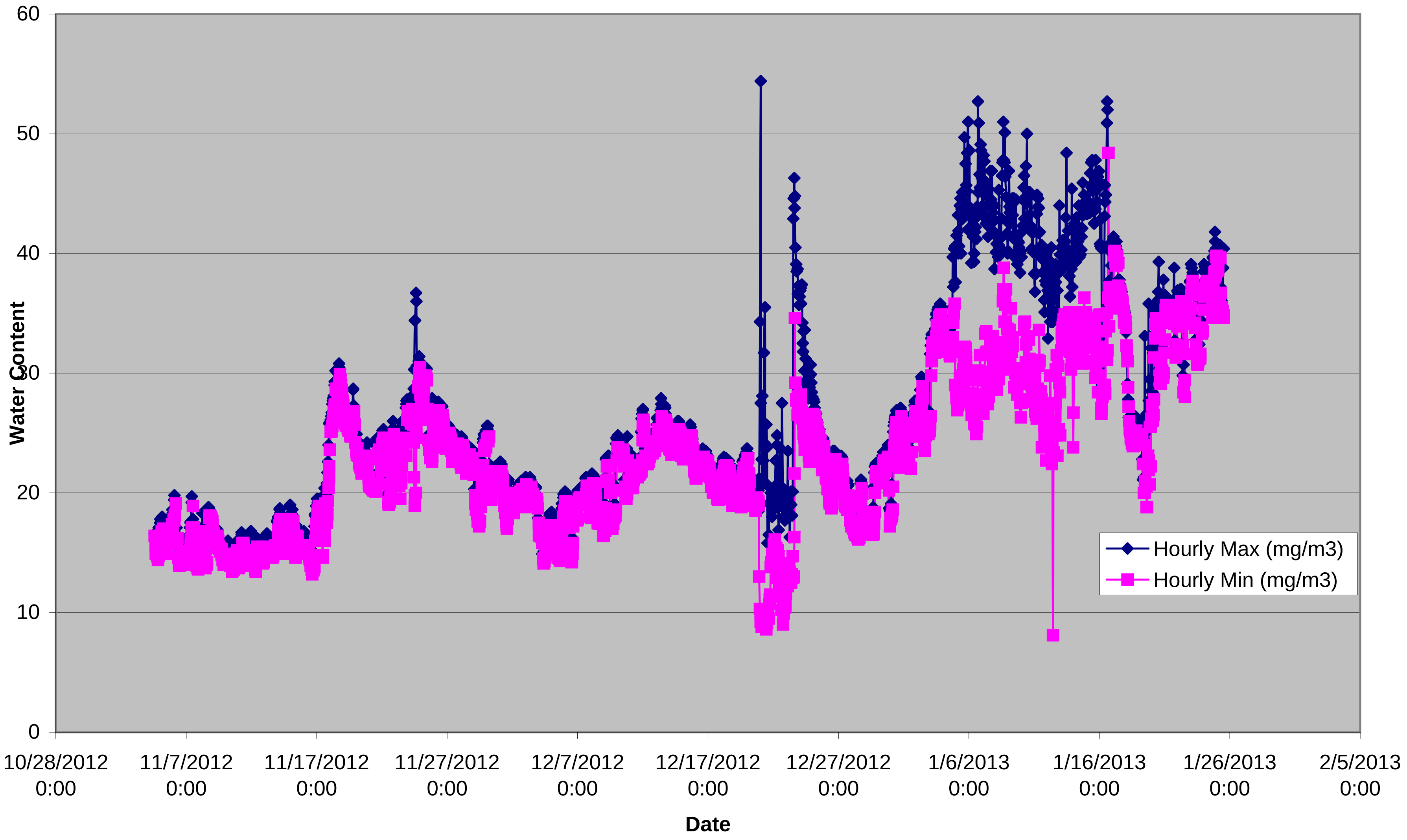

Hadashville Pressure/Temperature
8000.00
7000.00
6000.00
5000.00
4000.00
3000.00
2000.00
1000.00
0.00
Pressure (kPa)
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
-5.00
-10.00
Temperature (deg C)
11-11-03
11-12-23
12-02-11
12-04-01
12-05-21
12-07-10
12-08-29
12-10-18
12-12-07
13-01-26
13-03-17
Date
Pressure
Temperature


Ste. Agathe Pressure/Temperature
Pressure (kPa)
3500.00
3000.00
2500.00
2000.00
1500.00
1000.00
500.00
0.00
Temperature (deg C)
20.00
15.00
10.00
5.00
0.00
-5.00
-10.00
-15.00
11-11-03
11-12-23
12-02-11
12-04-01
12-05-21
12-07-10
12-08-29
12-10-18
12-12-07
13-01-26
13-03-17
Date
Pressure
Temperature


Assiniboine River Sales Tap Pressure/Temperature
Pressure (kPa)
2560.00
2550.00
2540.00
2530.00
2520.00
2510.00
2500.00
2490.00
2480.00
2470.00
2460.00
Temperature (deg C)
30.00
25.00
20.00
15.00
10.00
5.00
0.00
-5.00
-10.00
-15.00
-20.00
-25.00
11-11-03
11-12-23
12-02-11
12-04-01
12-05-21
12-07-10
12-08-29
12-10-18
12-12-07
13-01-26
13-03-17
Date
Pressure
Temperature


Selkirk Sales Delivery Pressure/Temperature
Pressure (kPa)
6800.00
6600.00
6400.00
6200.00
6000.00
5800.00
5600.00
5400.00
Temperature (deg C)
40.00
30.00
20.00
10.00
0.00
-10.00
-20.00
-30.00
11-11-03
11-12-23
12-02-11
12-04-01
12-05-21
12-07-10
12-08-29
12-10-18
12-12-07
13-01-26
13-03-17
Date
Pressure
Temperature

Emerson - Min/Max



APPENDIX O

FROST PENETRATION AND GROUND TEMPERATURE

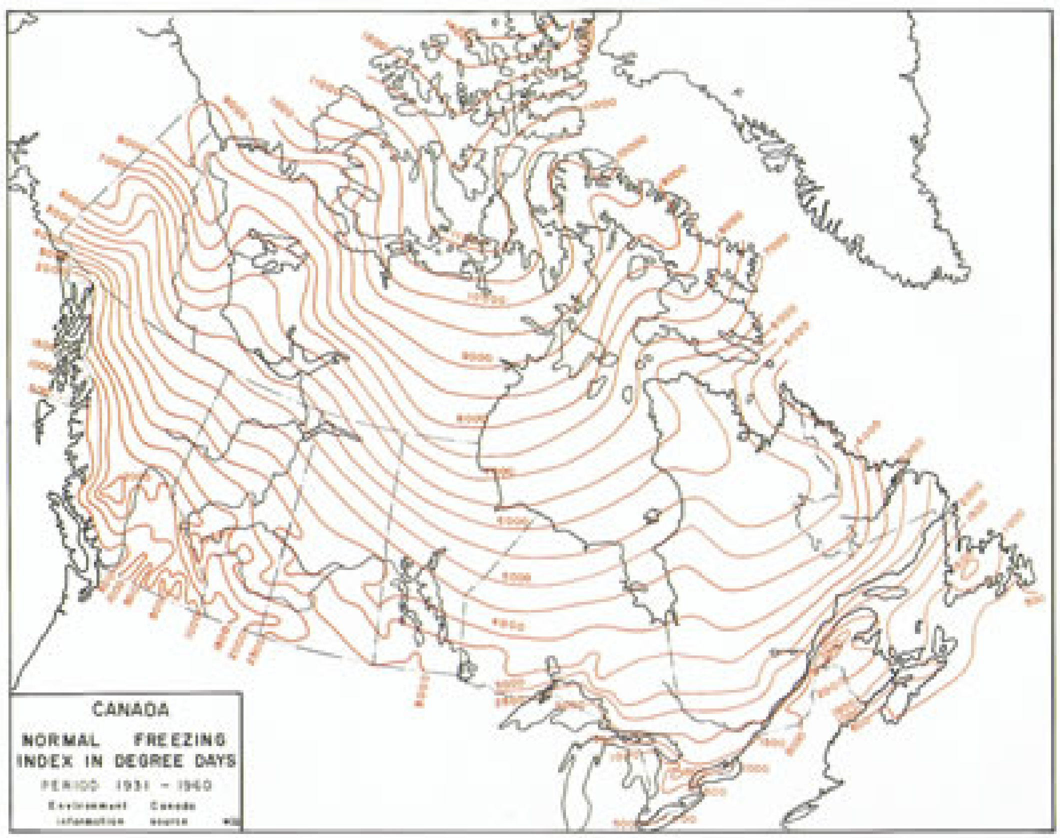
Ambient Temperatures - Below Ground

http://www.urecon.com/applications/municipal_ambient_below.html

Frost Depth

The **frost depth** can be fairly accurately calculated as it is usually directly related to the number of freezing degree days for a given geographic location. The exact frost depth will vary depending on the specific soil type and condition, elevation, as well as other variables. The following map indicates the number of freezing degree days for Canada by zone. It is provided courtesy of Environment Canada. The table below provides the average frost depth in meters for any given number of freezing degree days. By consulting the map and then the table, the average frost depth can be obtained.

Normal Freezing Index in Degree Days



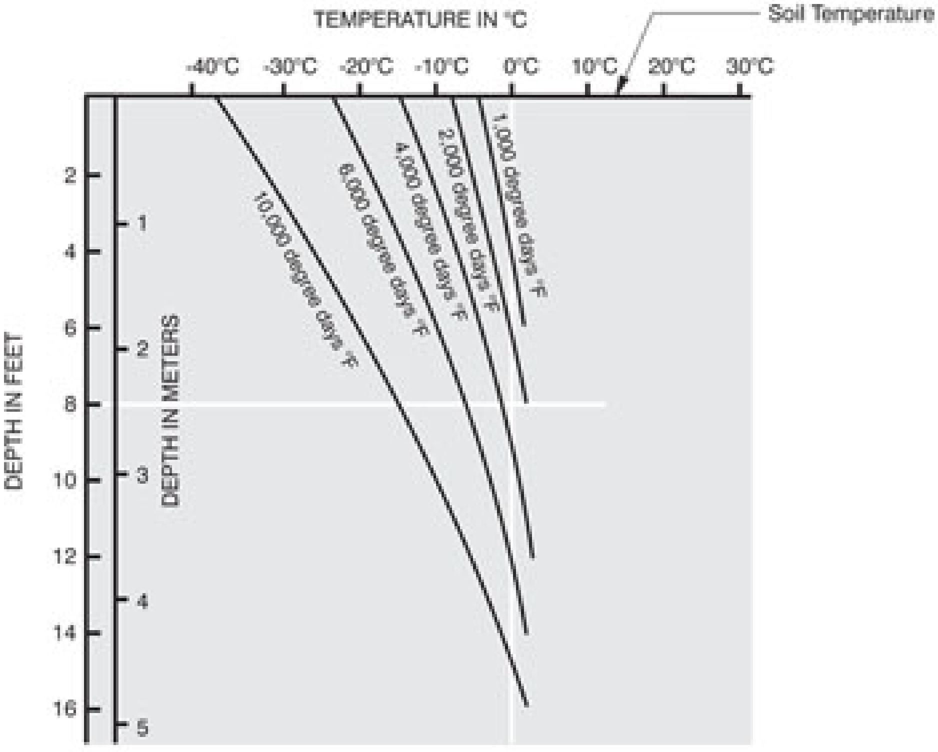
Freezing Index Degree days	Estimated Frost Depth in meters	Freezing Index Degree days	Estimated Frost Depth in meters	*Estimated Frost Depth in feet*

400	0.66	2000	1.98	*6.5*
450	0.71	2050	2.01	*6.6*
500	0.76	2100	2.04	*6.7*
550	0.81	2150	2.07	*6.8*
600	0.86	2200	2.10	*6.9*
650	0.91	2250	2.13	*7.0*
700	0.96	2300	2.16	*7.1*
750	1.00	2350	2.19	*7.2*
800	1.05	2400	2.22	*7.3*
850	1.09	2450	2.25	*7.4*
900	1.14	2500	2.28	*7.5*
950	1.18	2550	2.31	*7.6*
1000	1.21	2600	2.34	*7.7*
1050	1.25	2650	2.36	*7.7*
1100	1.29	2700	2.39	*7.8*
1150	1.32	2750	2.42	*7.9*
1200	1.36	2800	2.45	*8.0*
1250	1.39	2850	2.48	*8.1*
1300	1.43	2900	2.51	*8.2*
1350	1.47	2950	2.52	*8.3*
1400	1.50	3000	2.54	*8.3*
1450	1.54	3050	2.56	*8.4*
1500	1.57	3100	2.59	*8.5*
1550	1.62	3150	2.62	*8.6*

1600	1.66	3200	2.64	*8.7*
1650	1.70	3250	2.67	*8.8*
1700	1.74	3300	2.69	*8.9*
1750	1.78	3350	2.72	*8.9*
1800	1.82	3400	2.74	*9.0*
1850	1.86	3450	2.77	*9.0*
1900	1.90	3500	2.79	*9.1*
1950	1.94	and more	2.80	*9.2*

Soil Temperature

The **soil temperature** at a given depth will vary depending on the soil type, moisture content, etc. The following table which is provided, courtesy of the Ontario Ministry of the Environment, can be used as an approximate guide to determine soil temperature. Refer to the map below to obtain the freezing index degree days for the location being studied, then plot to obtain the approximate soil temperature at a given depth.



Theoretical Soil Temperature
Versus Depth

TECH SOLUTIONS 605.0

CALCULATING INSULATION NEEDS TO FIGHT FROST HEAVE BY COMPARING FREEZING INDEX AND FROST DEPTH

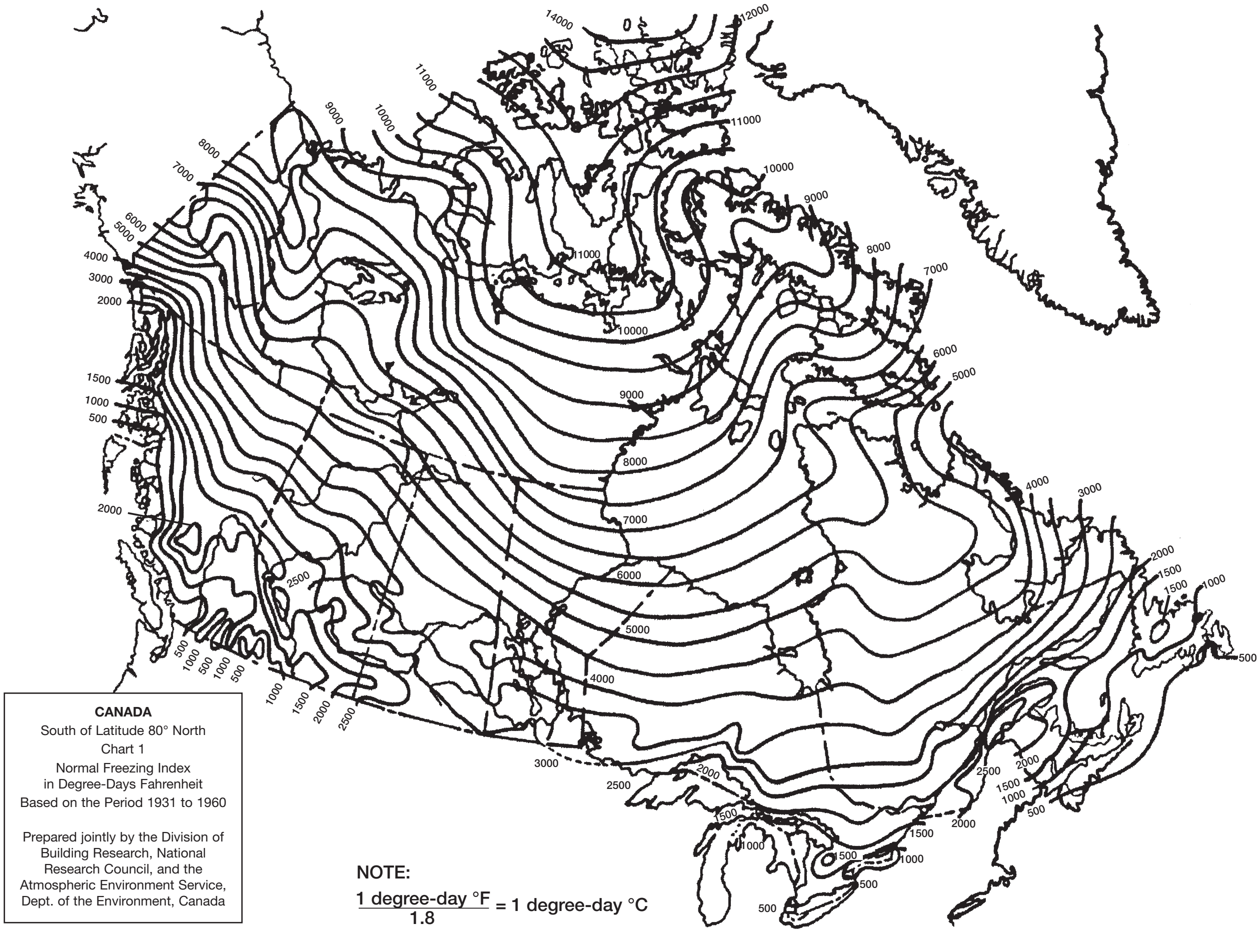
To calculate the amount of insulation needed to protect highways, railroads, airport runways, utility lines and building foundations against frost heave, it's important to know the amount of frost penetration. There are two ways to calculate frost penetration: theoretically or actual field monitoring. Dow uses both methods. A theoretical formula that predicts frost depth with freezing index information provides a quick estimate. Obtaining actual field data provides the most accurate information.

The freezing index is defined as the number of degree-days (above and below 32°F [0°C]) between the highest point in the autumn and the lowest point in the spring on the cumulative degree-day time curve for one winter season. Or, simply the total number of degree-days of freezing for a given winter.

To help with calculations, this information sheet includes:

- maps of Canada showing the normal (mean) value of freezing index
- listings of normal freezing index data for major areas across Canada
- charts showing the relationship between freezing index and frost penetration as prepared by the Ministry of Transportation of Ontario

Figure 1: Freezing Index Map for Canada



NOTE:

$\frac{1 \text{ degree-day °F}}{1.8} = 1 \text{ degree-day °C}$

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Figure 2: Freezing Index Map for Southern Ontario

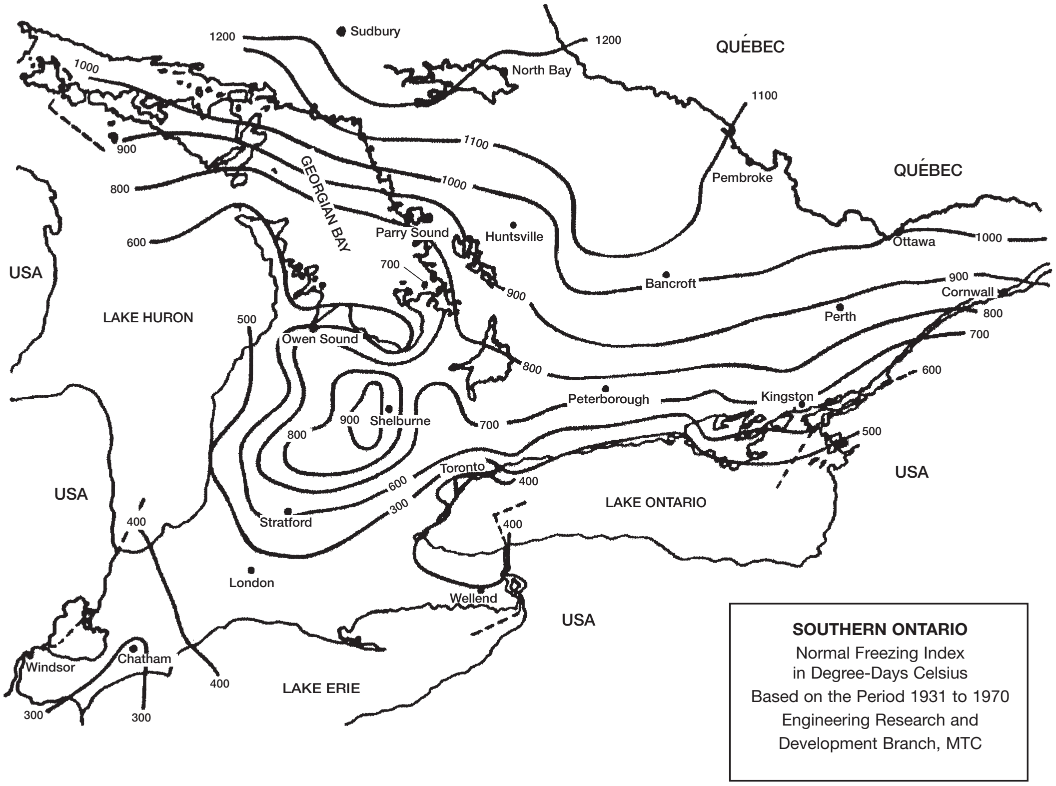
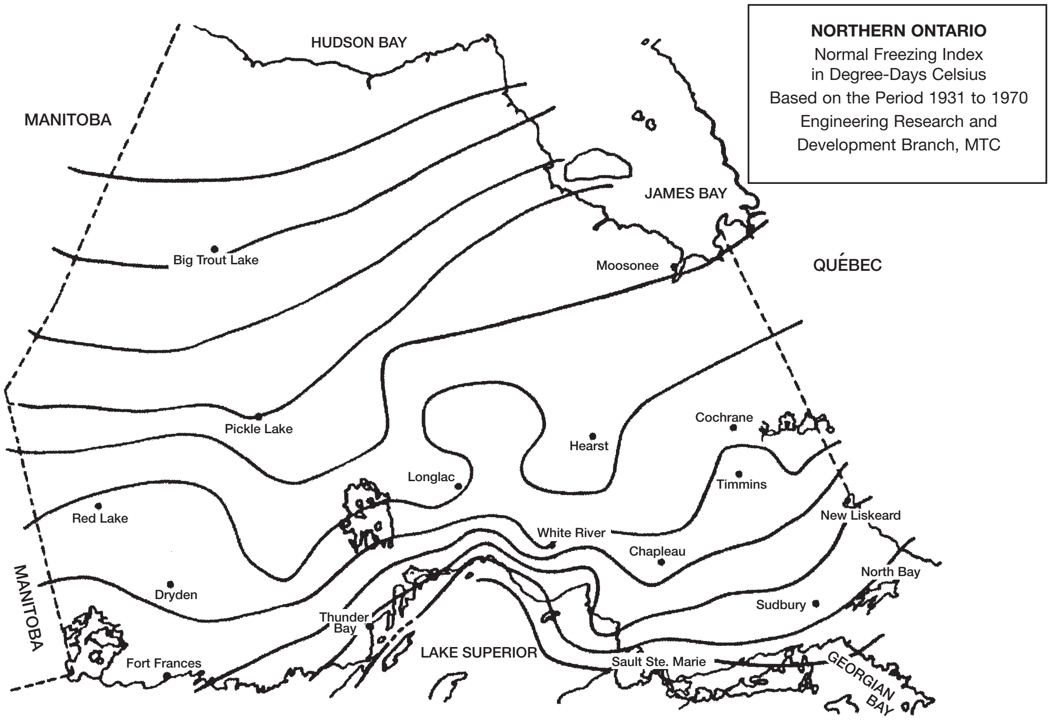


Figure 3: Freezing Index Map for Northern Ontario



CALCULATING INSULATION NEEDS TO FIGHT FROST HEAVE BY COMPARING FREEZING INDEX AND FROST DEPTH

Figure 4:

Relationship between air freezing index, surface cover and frost penetration into homogeneous soils

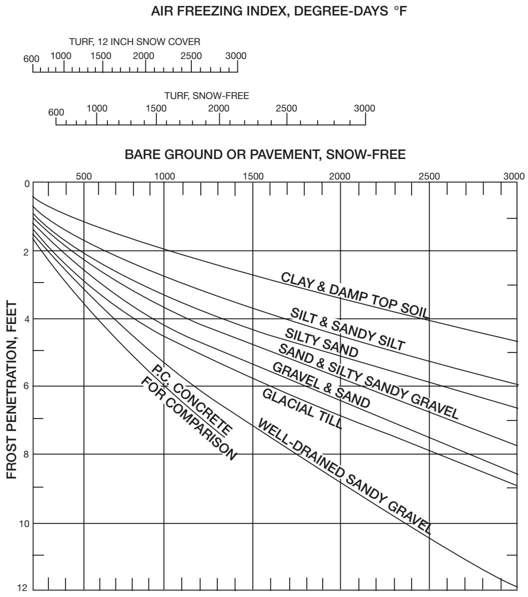


Figure 5:

Relationship between air freezing index, surface cover and frost penetration into a granular soil overlying a fine-grained soil

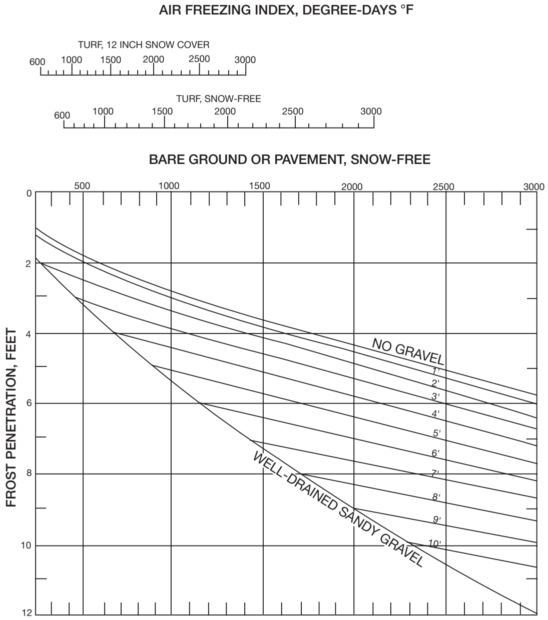
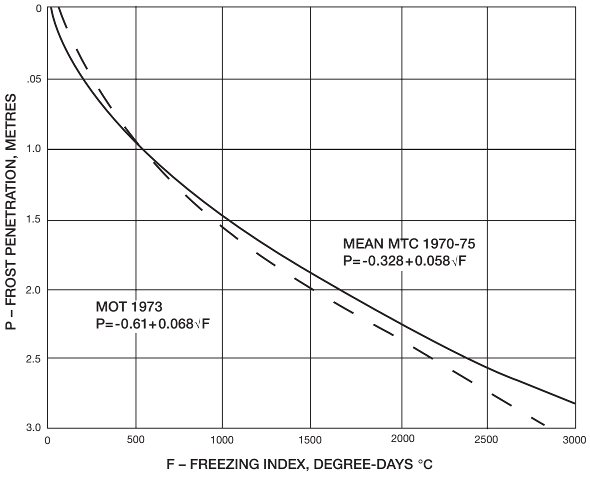


Figure 6:

Frost Penetration in Ontario 1970-1975



TECH SOLUTIONS 605.0

CALCULATING INSULATION NEEDS TO FIGHT FROST HEAVE BY COMPARING FREEZING INDEX AND FROST DEPTH

TABLE 1: FREEZING INDICES FOR CANADA

Station	Freezing Index	
	Degree-Days °F	Degree-Days °C
British Columbia		
Abbotsford A(1)	45	25
Beatton River A	3,893	2,164
Comox A	596	331
Cranbrook A	1,314	730
Dog Creek A	1,457	809
Fort Nelson A	4,523	2,513
Fort St. John A	2,848	1,582
Kamloops A	603	335
Kimberley A	1,434	797
New Westminister	35	19
Penticton A	313	174
Port Hardy A	33	18
Prince George A	1,670	928
Prince Rupert A	64	36
Princeton A	1,111	617
Quesnel A	1,457	809
Sandspit A	35	19
Smithers A	1,498	832
Smith River A	4,866	2,703
Terrace A	637	354
Tofino A	20	11
Vancouver A	31	17
Victoria A	28	16
Williams Lake A	881	489
Yukon Territory		
Aishihik A	5,038	2,799
Dawson	6,174	3,430
Haines Junction	4,498	2,499
Mayo	5,454	3,030
Snag A	6,477	3,598
Teslin A	3,754	2,086
Watson Lake A	3,281	1,823
Whitehorse	3,574	1,986
Northwest Territories		
Cape Dyer A	7,058	3,921
Coral Harbour A	8,552	4,751
Fort McPherson	7,747	4,304
Frobisher Bay A	7,026	3,903
Hay River A	5,512	3,062
Inuvik A	8,424	4,680
Norman Wells A	7,026	3,903
Resolute Bay A	11,166	6,203
Tuktoyaktuk	8,855	4,919
Yellowknife A	6,506	3,614
Alberta		
Banff	1,963	1,091
Calgary A	1,791	995
Cold Lake A	3,174	1,763
Cowley A	1,413	785
Edmonton A	2,593	1,441
Embarras A	4,439	2,466
Fort McMurray A	4,024	2,236
Grande Prairie A	2,967	1,648
Jasper	1,885	1,047
Lake Louise	2,810	1,561
Lethbridge A	1,326	737
Medicine Hat A	1,809	1,005
Peace River A	3,805	2,114
Alberta – continued		
Penhold A	2,586	1,437
Red Deer	2,382	1,323
Suffield A	2,259	1,255
Vermilion A	3,222	1,790
Saskatchewan		
Broadview A	3,244	1,802
Dafoe A	3,722	2,068
Estevan A	2,646	1,470
Moose Jaw A	2,555	1,419
North Battleford A	3,378	1,877
Prince Albert A	3,739	2,077
Regina A	3,175	1,764
Saskatoon A	3,284	1,824
Swift Current A	3,323	1,846
Uranium City A	5,551	3,084
Yorkton A	3,563	1,799
Manitoba		
Brandon A	3,388	1,882
Churchill A	6,698	3,721
Flin Flon	4,279	2,377
Gimli A	3,417	1,898
MacDonald A	3,038	1,688
Neepawa A	3,282	1,823
Portage La Prairie A	2,855	1,586
Rivers A	3,315	1,842
Winnipeg A	3,251	1,806
Ontario		
Algonquin Park	2,147	1,193
Belleville	1,143	635
Brampton	1,026	570
Brantford	790	439
Chalk River	2,096	1,164
Chatham	531	295
Cochrane	3,309	1,838
Collingwood	975	542
Dryden	3,395	1,886
Georgetown	1,084	602
Guelph	1,055	586
Hamilton	663	368
Huntsville	1,656	920
Iroquois Falls	3,388	1,882
Kapuskasing A	3,439	1,911
Kenora A	3,172	1,762
Kingston	1,220	678
Kirkland Lake	3,244	1,802
Kitchener	983	546
Lindsay	1,445	803
London A	863	479
Moosonee	4,081	2,267
Niagara Falls	684	380
North Bay	2,210	1,228
Orangeville	1,423	791
Orillia	1,495	831
Ottawa A	1,829	1,016
Owen Sound	995	553
Parry Sound	1,517	843
Peterborough	1,365	758
Port Arthur (Thunder Bay)	2,541	1,412

(1) A indicates an airport data station.

Continued on next page

CALCULATING INSULATION NEEDS TO FIGHT FROST HEAVE BY COMPARING FREEZING INDEX AND FROST DEPTH

TABLE 1: CONTINUED

Station	Freezing Index Degree-Days °F	Degree-Days °C
Ontario – continued		
St. Catharines	506	281
St. Thomas	710	394
Sarnia	670	372
Sault Ste. Marie A	1,663	924
Simcoe	751	417
Sioux Lookout A	3,450	1,917
Stratford	1,072	596
Sudbury A	2,401	1,334
Timmins A	3,160	1,756
Toronto	629	349
Toronto A	897	498
White River	3,344	1,858
Windsor A	565	314
Woodstock	929	516
Québec		
Bagotville A	2,867	1,593
Baie Comeau A	2,518	1,399
Chicoutimi	2,536	1,409
Drummondville	1,827	1,015
Gagnon A	4,216	2,342
Gaspé	2,012	1,118
La Malbaie	2,043	1,135
Mont Laurier	2,325	1,292
Montréal A	1,583	879
Québec	1,822	1,012
Québec A	2,059	1,144
Sept-Iles A	2,746	1,526
Sherbrooke	1,581	878
Sorel	1,997	1,109
Tadoussac	2,038	1,132
Three Rivers	2,139	1,188
New Brunswick		
Edmundston	2,219	1,233
Fredericton A	1,561	867
Moncton A	1,397	776
Pennfield Ridge A	1,178	654

TABLE 1: CONTINUED

Station	Freezing Index Degree-Days °F	Degree-Days °C
New Brunswick – continued		
Sackville	1,174	652
St. George	1,115	619
Saint John	1,002	557
Saint John A	1,137	632
Sussex	1,337	743
Woodstock	1,701	945
Nova Scotia		
Annapolis Royal	593	329
Cheticamp	955	531
Debert A	1,136	631
Greenwood A	815	453
Halifax	556	309
Halifax A	856	476
Ingonish Beach	828	460
Liverpool	453	252
Shearwater A	699	388
Springfield	933	518
Sydney A	811	451
Truro	1,025	569
Yarmouth A	415	231
Prince Edward Island		
Alliston	1,000	556
Charlottetown A	1,201	667
Summerside A	1,242	690
Newfoundland		
Argentia A	475	264
Bonavista	853	474
Buchans A	1,724	958
Churchill Falls A	4,818	2,677
Corner Brook	1,120	622
Gander International A	1,207	671
Goose A	3,268	1,816
Grand Falls	1,394	774
St. John's	648	360
Stephenville A	925	514
Wabush Lake A	4,688	2,604

For Technical Information: 1-866-583-BLUE (2583) (English) 1-800-363-6210 (French)
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Form No. 178-00754-1108P&M

APPENDIX P

TCPL GAS SUPPLY DATA

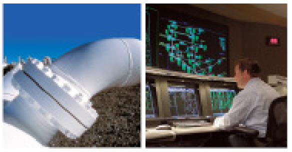
Manitoba Hydro

Information Request

March 2013

TransCanada
In business to deliver

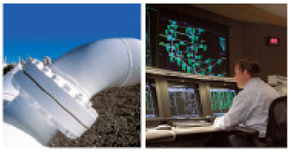
Background



In the fall of 2012 Manitoba Hydro submitted a request to TransCanada for measurement data and moisture content on the Mainline to evaluate the risk to their system of freeze offs.

Further requests were made to TransCanada in February 2013 for information on gas supplies from TransCanada for their distribution system. These requests are answered in the following slides.

Manitoba Hydro



Question 1:

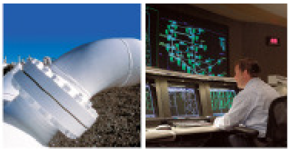
Does TCPL have gas supply temperature and supply pressure data for each of the primary supply stations to Manitoba Hydro? If so is it possible to get a 1 year graph of this data?

Answer:

Please refer to the attached spreadsheet showing the pressure data for all delivery points to Manitoba Hydro. This information can be accessed via the VEC report found in Customer Reporting at the following link. TransCanada's Call Centre can assist if you have any questions about this report.

https://services.tcpl.ca/cor/ext/IRMenuIndexML.htm

Manitoba Hydro



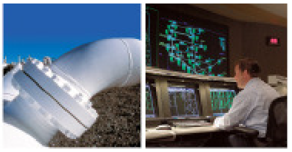
Question 2:

Does TCPL have projects/plans for any other flow-reversal projects? Say pipeline # 3 from Emerson to Ile des Chenes? Or on the mainline to Ontario?

Answer:

TransCanada has no plans for any flow reversal projects from Emerson to Ile des Chenes or on the Mainline to Ontario.

Manitoba Hydro



Question 3:

The primary gate station feeding the City of Winnipeg is at Ile des Chenes. Is this gas connection to the City upstream or downstream of the Compressor station?; more specifically is the “south” (Emerson) gas fed into the City of Winnipeg?

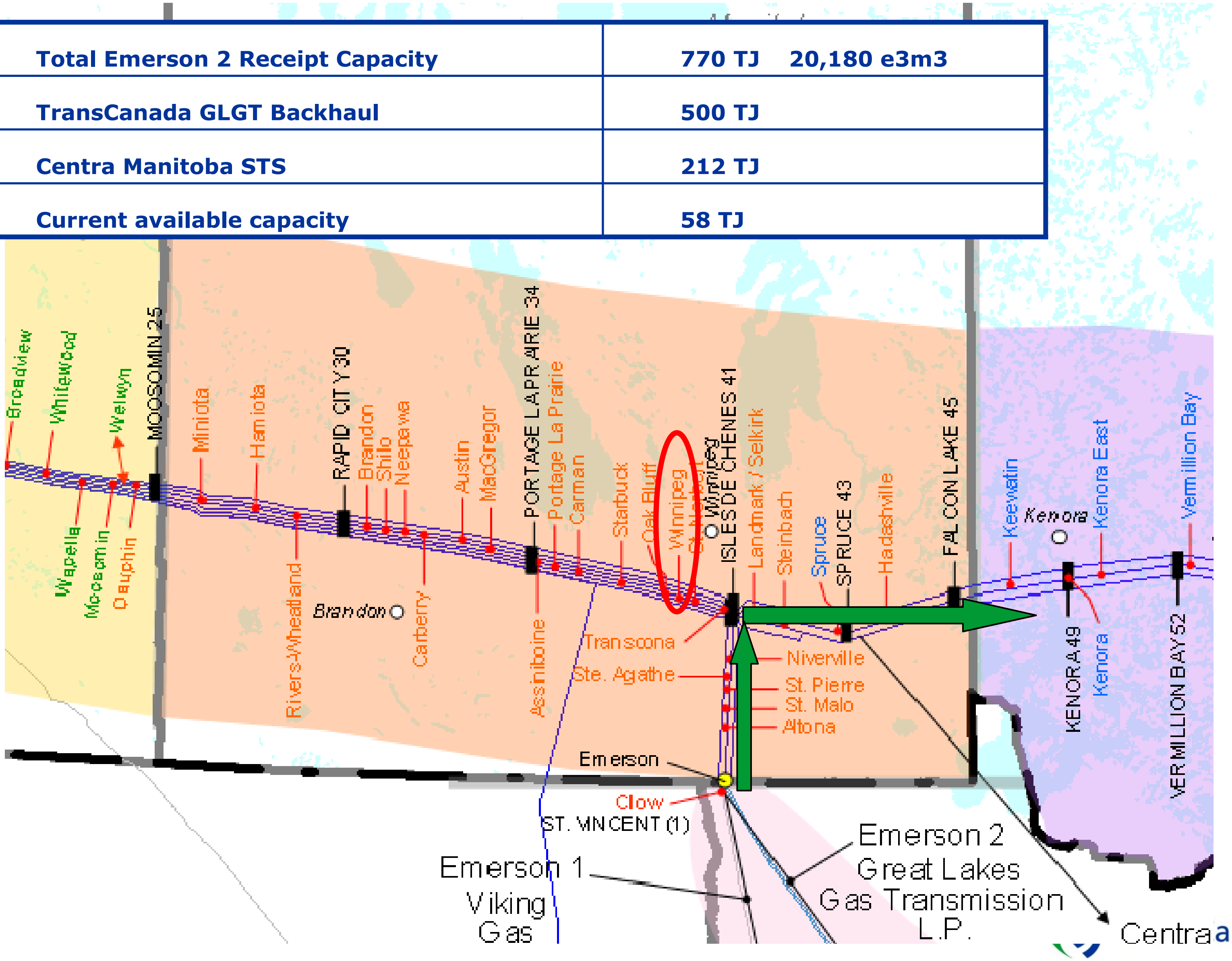
Answer:

The deliveries to the Winnipeg Meter occur west of Ile Des Chenes compressor station 41 and therefore supply comes from the WCSB. The gas received at Emerson 2 feeds into the suction of compressor station 41 and is comingled with Western flow and heads East along the Mainline.

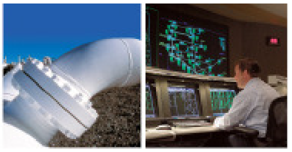
TransCanada

MDA

Total Emerson 2 Receipt Capacity	770 TJ 20,180 e3m3
TransCanada GLGT Backhaul	500 TJ
Centra Manitoba STS	212 TJ
Current available capacity	58 TJ



Manitoba Hydro



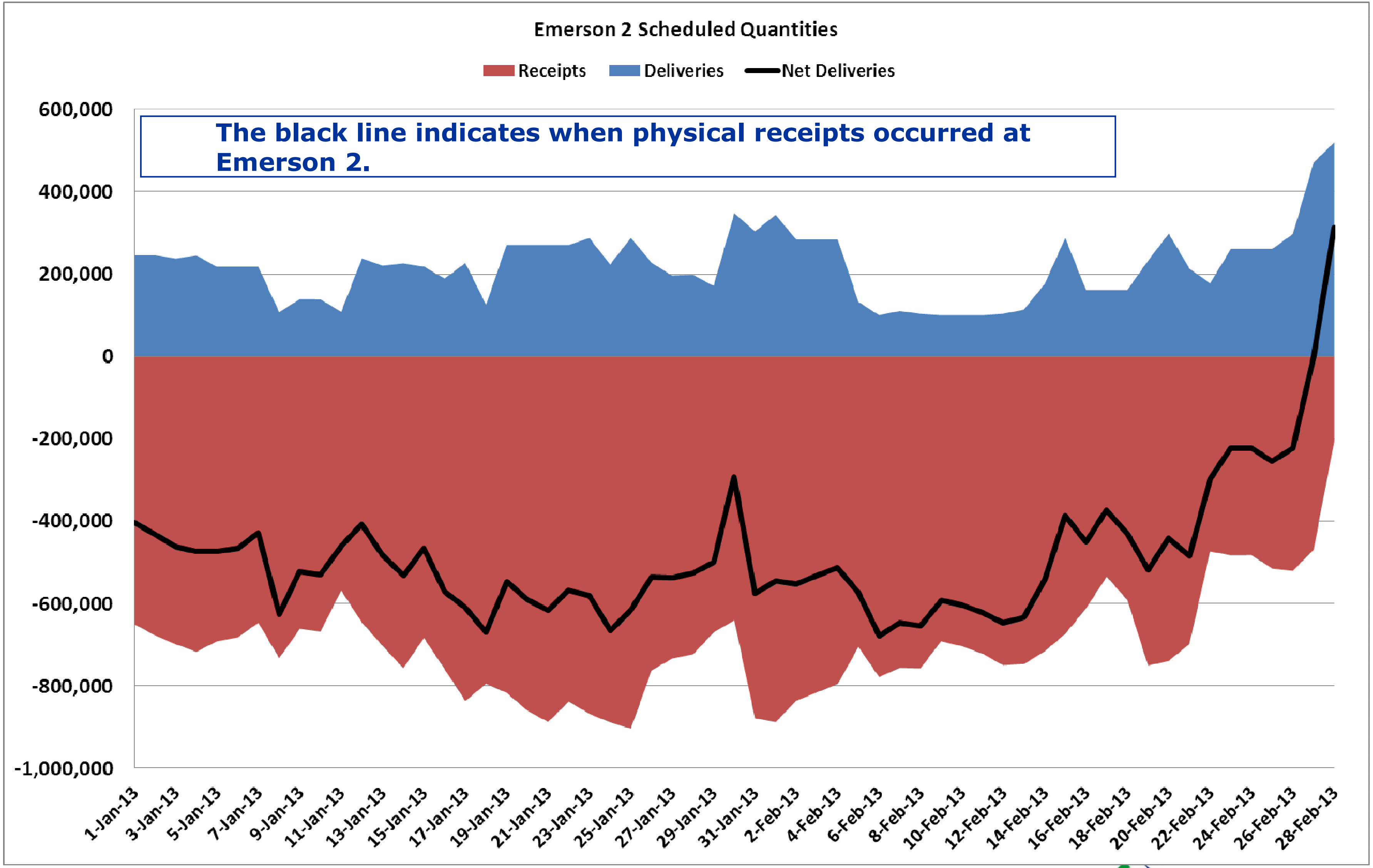
Question 4:

Based on the “gas day summary” pipeline #1 and #2 from Emerson are flowing about 880,000 GJ, while Empress is flowing about 3,050,000 GJ. Could we see a larger portion flow from Emerson in the future?; and how much?

Answer:

The scheduled receipt nominations in the gas day summary report at Emerson 2 are on average over 700,000 GJ since January 2013. The scheduled delivery nominations for Emerson 2 average approx 200,000 GJ. The physical flow is the net of these 2 numbers. The following graph will show the total scheduled deliveries, scheduled receipts and Net Deliveries at Emerson 2.

Manitoba Hydro

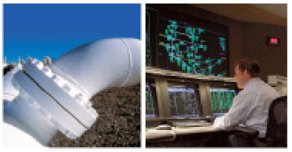


Emerson 2 Scheduled Quantities

The black line indicates when physical receipts occurred at Emerson 2.

TransCanada

Manitoba Hydro



Question 5:

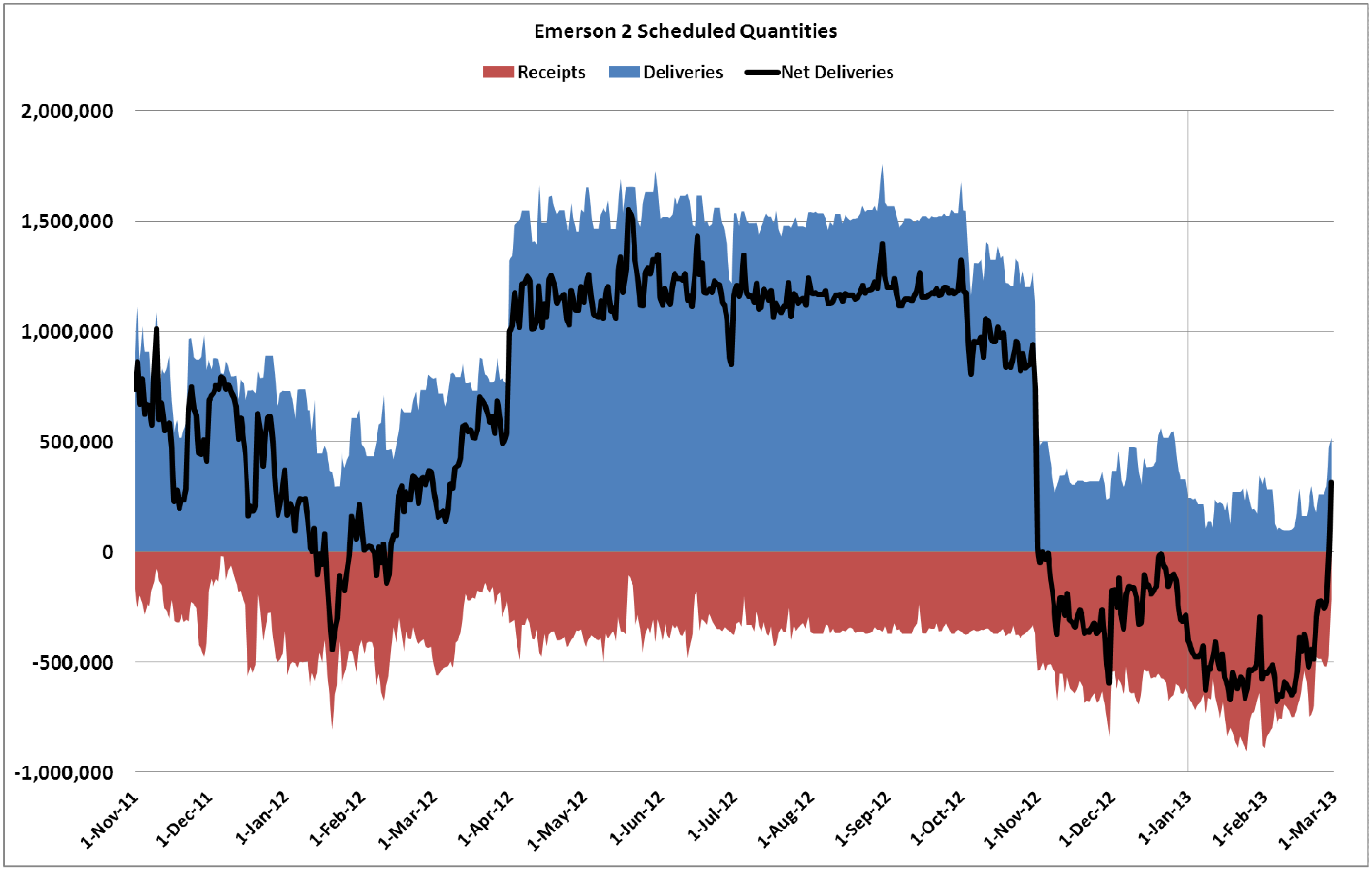
How frequently does TCPL hydrostatic testing of the pipelines feeding Manitoba? More specifically on an annual basis, how often can we expect spikes in moisture as “bleed-in” occurs? Can you provide the dates over the last 2 years when bleed in’s have occurred?

Answer:

Over the last 2 years there have been a total of 5 hydrotests and subsequent bleed-ins. The dates and pipe sections of these are listed below:

- November 2011 - MLV 25 to MLV 27 on line 2
- September 2011 – MLV 25 to MLV 27 on line 4
- September 2011 – MLV 30 to MLV 31 on line 4
- October 2011 – MLV 32 to MLV 33 on line 2
- September 2011 – MLV 42 to MLV 43 on line 3

Backup Slide



TransCanada