

*Comparison of US and Canadian
Transmission Pipeline Consensus Standards*

FINAL REPORT

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LIST OF ACRONYMS AND ABBREVIATIONS

AIV	Alternative Integrity Validation
AISC	American Institute of Steel Construction
AGA	American Gas Association
ANSI	American National Standards Institute
API	American Petroleum Institute
APL	Alliance Pipeline LP
ASA	American Standards Association
ASD	Allowable Stress Design
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
AUT	Automated Ultrasonic Testing
CAN	Canadian
CFR	Code of Federal Regulations
CSA	Canadian Standards Association
CTOD	Crack Tip Opening Displacement
DA	Direct Assessment
DOT	US Department of Transportation
D/t	Diameter-to-Wall-Thickness Ratio
ECA	Engineering Critical Assessment
EIA	Energy Information Administration
ERCB	Energy Resources and Conservation Board
EUB	Alberta Energy and Utilities Board
FAD	Failure Assessment Diagram
FAC	Failure Assessment Curve
FFS	Fitness-For-Service
FRA	Federal Railroad Administration
GMAW	Gas-Metal Arc Welding
GOR	Goal-Oriented Regulation
GPTC	Gas Piping Technology Committee
HCA	High Consequence Area
HDD	Horizontal Directional Drill
HLPSA	Hazardous Liquid Pipeline Safety Act

Comparison of US and Canadian Transmission Pipeline Consensus Standards

HVP	High Vapor Pressure
ILI	In-line Inspection
IM	Integrity Management
IMP	Integrity Management Program
INGAA	Interstate Natural Gas Association of America
ISO	International Organization for Standardization
JIP	Joint Industry Project
km	kilometer
kp	kilo pound
ksi	kips per square inch
LNG	Liquefied Natural Gas
LRFD	Load and Resistance Factor Design
LVP	Low Vapor Pressure
LPG	Liquefied Petroleum Gas
LSD	Limit State Design
MAOP	Maximum Allowable Operating Pressure
MAWP	Maximum Allowable Working Pressure
MMS	Minerals Management Service
MOP	Maximum Operating Pressure
MOU	Memorandum of Understanding
NACE	NACE International
NDE	Non-destructive Examination
NDT	Non-destructive Testing
NEB	National Energy Board
NFPA	National Fire Protection Association
NGL	Natural Gas Liquids
NGPSA	Natural Gas Pipeline Safety Act
NTSB	National Transportation Safety Board (US)
OHMS	Office of Hazardous Materials Safety
OPR	Onshore Pipeline Regulations
OPS	Office of Pipeline Safety
PHMSA	Pipeline and Hazardous Materials Safety Administration
psi	pounds per square inch
PRCI	Pipeline Research Council International

Comparison of US and Canadian Transmission Pipeline Consensus Standards

QA/QC	Quality Assurance/Quality Control
RBDA	Reliability-Based Design and Assessment
RP	Recommended Practice
SBD	Strain-Based Design
SCC	Standards Council of Canada
SDO	Standards Development Organization
SLS	Service Limit State
SMYS	Specified Minimum Yield Strength
TAPS	Trans-Alaska Pipeline System
tcf	trillion cubic feet
Texas Eastern	Texas Eastern Transmission Corporation
TG	Technical Group
TransCanada	TransCanada PipeLines Limited
TPSSC	Technical Pipeline Safety Standards Committee
TSB	Transportation Safety Board (Canada)
ULS	Ultimate Limit State
US	United States
UT	Ultrasonic Testing
Y/T	Yield-to-Ultimate-Strength Ratio

Note to Reader:

This comprehensive report is a living document and is the first step toward consistency with consensus standards between the US and Canada. The intent of this work is to categorically address the medium to high level similarities and differences between US and Canadian pipeline standards.

This report does not compare the secondary standards sometimes incorporated in the main standard (i.e., NACE standards incorporated by reference in ASME standards). This report makes some mention of the pipeline regulations of the US and Canada, but presents no comparison of the regulations. Only some of the consensus standards incorporated by reference in the code are compared. The number of compared standards in this report may grow with time and with the decision to address new ones done in collaboration.

This report utilized the latest edition made available at the time of the comparison. The next edition of the standards compared in this report may be revisited on a periodic basis in order to capture any changes. The next step must be made in collaboration between the US and Canada. The report findings may be used to build more consistent standards for cross border pipelines. The next step may also require Standards Developing Organizations (SDO) to focus deeper on some of the technical issues identified in this report in order to increase technical rigor.

Executive Summary

A coordinated effort between the pipeline regulatory entities in the United States and Canada is paramount for reducing energy congestion across the border. The interconnected nature of the pipeline infrastructure in North America and the growing demand for energy in the US are clear drivers for cross border coordination and collaboration. Regulatory agency cooperation by the Canadian National Energy Board (NEB) and the US Pipeline and Hazardous Materials Safety Administration (PHMSA) recognizes this dependency and the continued safe operation and expansion of the pipeline infrastructure. To achieve these goals, much is dependent on the adequacy and effectiveness of safety and specification consensus standards covering a wide range of pipeline transportation activities.

Pipeline regulations in the US and Canada rely largely on the partial or complete incorporation of industry standards by reference. These standards in many cases are generally compatible regarding material and equipment issues.

The US and Canadian national pipeline regulations are also closely related in most design and construction areas, although there are important differences. Many of the differences have been documented and in certain instances, special permits have been issued, often as a result of industry discussions.

In the US, regulations for pipeline integrity management (IM) are evolving to more prescriptive in timeline or milestone but flexible in the technology or process used to meet requirements. To some extent, this stands as a clear contrast to parallel federal Canadian goal-oriented regulations. The approach provides definitive timelines, although it leaves operators leeway in developing specific details of the means of compliance. It is likely that the “prescribed” US regulations will be in line with what would be implemented by most leading operators in the maintenance of a major new pipeline. However, performance or goal-based regulations can provide an improved regulatory-industry environment that facilitates innovation.

The following sections summarize each of the comparisons made and indicate in table format, the specific differences between the US and Canadian standards. The appendices to this report contain expanded individual comparisons of major consensus standards incorporated by reference in the US and Canadian codes. This report is dynamic in nature and will grow as the comparison appendices are added.

Summary of Natural Gas Transmission Pipeline Issues (Appendix A)

Appendix A focuses on the comparison of the American Society of Mechanical Engineers (ASME) B31.8, *Gas Transmission and Distribution Piping Systems* and the Canadian Standards Association (CSA) Standard Z662, *Oil and Gas Pipeline Systems*. Significant issues which are expected to be the basis of continued discussion include:

- Increasing the design factor in Class 1 locations in the US to the Canadian value of 0.80
- Allowing additional flexibility in valve spacing
- Normalizing requirements for pressure testing, especially hydrostatic testing
- IM requirements.

There are also differences in depth-of-cover requirements, although they do not appear to be a critical factor.

Both standards incorporate concepts of strain-based design and reliability approaches, although no consensus has been reached on a standard approach for pipeline design or operations. In this regard, a prescriptive approach would likely be counterproductive and an application methodology might be a better option. (The 2007 edition of CSA Z662 Annex O provides a reliability-based methodology that can be applied to both design and operating scenarios for gas pipelines. The methodology establishes definitive target levels of reliability. ASME B31.8 is expected to publish Reliability Based Design and Assessment methodology in December 2008 which is reportedly based on the same reference material as Annex O; however, detailed information was unavailable at the time of this report).

Table 1 provides a tabulated version of comparisons between US and Canadian gas transmission pipeline design.

Comparison of US and Canadian Transmission Pipeline Consensus Standards

Table 1 – Comparisons Between US and Canadian Gas Transmission Pipeline Design			
Code Issue	ASME B31.8	CSA Z662-03	Discussion
<u>Class Location</u>	840.3 (c) Class 3	Z662-03 4.3.2.2 Class 2	Difference in how groups of 20 or more persons which congregate in outside areas are covered.
<u>Design Factor</u>	Table 841.114A	Z662-03 4.3.3.2 (Non-sour)	Design factor difference necessitates at least a 10 percent increase in pipe wall thickness, with a concomitant increase in freight costs, handling and welding.
Class 1, Div 1	0.80	-	Special permits granted for increase to 0.80 in US on site-specific basis.
Class 1, Div 2	0.72	0.80	Consideration given to reliability-based and risk-based approaches in special permits.
Class 2	0.60	0.72	Note in the CSA document clause 4.3.5.4 limits pipe not manufactured to API5L, Z245.1, or several ASTM standards to a maximum of 72%SMYS.
Class 3	0.50	0.56	
Class 4	0.40	0.44	
<u>Valve Spacing</u>	846.11 <u>miles</u>	Z662-03 4.4.4 <u>Gas miles (km)</u>	This provision of prescribed valve spacing in Class 1 locations can be anticipated to be petitioned for review for any significant US project with significant mileage located in a remote area, with implications in operations and maintenance issues and initial capital costs driving factors.
Class 1	20	Not Required*	* However Clause 4.4.3 requires an engineering assessment to be performed
Class 2	15	15.5 (25)	
Class 3	8	8 (13)	
Class 4	5	5 (8)	
<u>Cover Depth (inches)</u>	841.142 (Larger than NPS 20)	Z662-03 4.7	Ratio of US cover requirement to Canadian:
	<u>Normal Rock</u>	<u>Normal Rock</u>	<u>Normal Rock</u> •The potential for cover reduction could be explored in remote areas
Class 1	24 18	24 24	1.00 0.75 • Exemptions for reduced cover granted to accommodate thaw settlement
Class 2	30 18	24 24	1.00 0.75 • There is a general requirement for greater depth of cover for uncased crossings, rivers etc.
Class 3 and 4	30 24	24 24	1.25 1.00

Table 1 – Comparisons Between US and Canadian Gas Transmission Pipeline Design (con't)			
Code Issue	ASME B31.8	CSA Z662-03	Discussion
<u>Limit State Design</u>	Not found as a design approach methodology in the major US pipeline codes and code references	Z662 Annex C presents a framework for a project to develop a Limit State Design approach	ASME B31.8 has provisions to allow a project to develop a strain-based design. Since the strains would be beyond the stress allowables of the code, a new approach to judge the acceptability of these strains would be compatible with the code intent. The logical framework for development of these allowables, and comparison with the applied loads, would be a Limit State design approach. Thus, a US project could use the triggering words of ASME B31.8 to develop a Limit State Design approach, especially for those conditions that are not explicitly already handled. Reportedly, the ASME B31.8 Life Cycle Management standard currently under development will include Limit State Design as the failure frequency component.
<u>Reliability-Based Design</u>	Not found as a design approach methodology in the major US pipeline codes and code references	Not found as a design approach methodology in CSA Z662-03 but is included in the June 2007 edition as Annex O.	Active groups in both countries are working to further reliability-based approaches. A draft CSA Z662 version circulated for comment contained provisions addressing reliability targets for pipeline evaluations. These have subsequently been included in the most recent release of the Canadian standard and represents a significant step forward. The role for reliability-based design approaches will be to support the development of Limit State Design methodologies as well as on-going maintenance philosophies.
<u>Materials</u>	<i>Chapter 1 Materials and Equipment</i> §812 generally references materials for use in cold climates	<i>Z662-03 Section 5 "Materials"</i> Extensive section covering fracture toughness	Pipe manufacturing is an international industry; most pipeline material can be expected to meet the same industry minimum requirements. Higher grades of steel will allow for reduction in wall thickness: <ul style="list-style-type: none">▪ Strain-based design and Limit State Design will require consideration of material properties beyond the traditional single consideration of SMYS; as D/t ratio increases, the axial compressive strain capacity decreases▪ An increase in grade may result in little to no increase (if not a decrease) in pipe resistance to longitudinal loadings. If longitudinal loadings are a controlling factor, the benefits of higher grade steels must be carefully weighed. Higher grade steels can be expected to be investigated by any new major project group and tested against regulatory acceptance. Spiral welded pipe has been used for almost 20 years in Canada and recently in some US projects (e.g. Cheyenne Plains) and will likely be under increased consideration for material selection in the US, as Canadian & US mills market this type of line pipe. Spiral pipe allows mills to use narrow plate to make large diameter pipe.

Table 1 – Comparisons Between US and Canadian Gas Transmission Pipeline Design (con't)

Code Issue	ASME B31.8	CSA Z662-03	Discussion
<u>Welding</u>	<p><i>Chapter 2 Welding</i></p> <p>Extensive section that covers welding</p>	<p><i>Z662-03 Section 7 "Joining"</i></p> <p>Extensive section that covers welding</p>	<p>The level of detail in ASME B31.8 is comparable in detail to CSA Z662; no differences appear critical. However, the NEB OPR requires 100% NDE, while CSA Z662 requires that only 15% of the production welds made daily be nondestructively inspected. Practically, however, most new transmission pipeline is 100 percent NDE as it federally regulated and is covered by the NEB OPR.</p> <p>Welding designed and matched to the strength requirements of high-strength steel will be an issue on new projects because of the effects in overall system reliability:</p> <ul style="list-style-type: none"> ▪ Strain capacities required may not be reached at industry workmanship levels. (Refer to page A.31) ▪ Additional and more stringent requirements for flaw detection may be imposed, causing higher than usual weld reject/repair rates and requiring careful consideration of repair procedure and documentation of acceptance, prompting the use of semi- and fully-automatic welding techniques. <p><i>CSA Annex J "Recommended Practice for Determining the Acceptability of Imperfections in Fusion Welds"</i> outlines the application of engineering critical assessment (ECA) to fusion welds. This is an informative, non-compulsory procedure to determine whether or not repairs are required for imperfections in those circumstances where the standards for acceptability for non destructive inspection in C17.11 have not been met. The recommended method for determining tolerable defect sizes is set out in <i>Appendix "K" Standards of Acceptability for circumferential butt welds based upon fracture mechanics principles. Appendix "J" is generally used to assess existing pipelines and Appendix "K" new construction.</i></p> <p>Through time, annex procedures could become generally acceptable and potentially evolve into a compulsory part of Z662.</p>
<p><u>Hydro Test Requirements</u></p> <p>Class 1</p> <p>Class 2</p> <p>Class 3</p> <p>Class 4</p>	<p>841.322</p> <p>110%</p> <p>125%</p> <p>140%</p> <p>140%</p>	<p><i>Reference to Table 8.1</i></p> <p>Intended minimum pressure</p> <p>125% of MOP</p> <p>125% of MOP</p> <p>140% of MOP</p> <p>140% of MOP</p>	<p>ASME B31.8 allows a hydrotest to 1.25 times design pressure for Class 1, Division 1 if the maximum operating pressure produces a hoop stress level greater than 72% of SMYS.</p> <p>In Class 1 locations, CSA Z662-03 requires a minimum strength test pressure of 125 percent of intended MOP, compared to 110 percent of intended MAOP required by ASME B31.8 and 49 CFR 192. There is also a difference of 10 percent (140 percent for CSA compared to 150 percent of intended MAOP for 49 CFR 192) for Class 3 and 4.</p> <p>CSA takes care to divide the pressure test into two parts – the strength test and the leak test, whereas CFR does not make this distinction. The four-hour hold time for each test part, together equals the total test time specified by CFR of 8 hours.</p>

Table 1 – Comparisons Between US and Canadian Gas Transmission Pipeline Design (con't)

Code Issue	ASME B31.8	CSA Z662-03	Discussion
<u>Pneumatic Testing</u>	<p><i>841.322</i></p> <p>Allows air/gas medium (1.1 x MOP) for Class 1, Division 2; for Class 2 allows air testing (1.25 x MOP)</p>	<p><i>Z662-03 5.2.2</i></p> <p>Limits the maximum test pressure when using a gaseous medium to 95%* of SMYS; the effect is a 0.76 design factor as opposed for the normal 0.8 design factor in Class 1 locations</p>	<p>Generally, pneumatic testing would only be considered for fulfilling pressure testing requirements, especially at isolated construction sites.</p> <p>There does not appear to be focused study or industry interest for a reconsideration of code regulations for pneumatic testing, and no compelling argument can be currently made for such a focus. Nevertheless, companies do seek to use pneumatic testing on a case-by-case basis.</p> <p>* Limit is to be increased to 100% of SMYS in the 2007 release.</p>
<u>Operations and Maintenance</u>	<p><i>ASME B31.8S Managing System Integrity of Gas Pipelines</i></p>	<p><i>Z662 Section 10 Operating, Maintenance and Upgrading with references to 2 Annexes</i></p>	<p>Both the US and the Canadian standards provide an operator with considerable latitude in the methodology to apply in undertaking and updating risk assessments, and in developing IM programs.</p> <p>Differences exist in the IM arena in the two following areas, as viewed from the Canadian standards vantage point:</p> <ul style="list-style-type: none"> ▪ The principle of a prescriptive re-inspection period, although the reality of a major arctic cross-border pipeline would likely accommodate the 7-year cycle ▪ The singular specificity in the calculation to establish HCA boundaries, although again the reality of a major arctic cross-border pipeline would likely accommodate this approach. <p>An apparently less important issue but one that may well require revisiting a section of ASME B31.8S is the Integrity Threat Classification structure. The current classification of earth movements in the time-independent category (clause 2.2, page 4) may be revisited on its own with consideration to moving it to the time-dependent category. The need to revisit and possibly redress this aspect of ASME B31.8S would likely become a higher priority ahead of considering a major arctic pipeline.</p>

Summary of Hazardous Liquid Transmission Pipeline Issues (Appendix B)

Appendix B focuses on the comparison of ASME B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids* and CSA Standard Z662, *Oil and Gas Pipeline Systems*. Significant issues which are expected to be the basis of continued discussion include:

- Increasing the design factor in the US to the Canadian value of 0.80
- Depth of cover requirements
- IM requirements.

The liquid pipeline standards in the US do not provide even the minimal level of guidance found in the gas pipeline standards for concepts of strain-based design except for offshore liquid pipelines.

Table 2 provides a tabulated version of comparisons between US and Canadian liquid pipeline design.

Comparison of US and Canadian Transmission Pipeline Consensus Standards

Table 2 - Comparisons Between US and Canadian Liquid Transmission Pipeline Design																		
Code Issue	ASME B31.4	CSA Z662-03	Discussion															
<u>Class Location</u>	NA	Z662-03 4.3.2.2	Does not contribute to noticeable differences, especially for LVP.															
<u>Design Factor</u>	Table 402.3.1(a) 0.72	Z662-03 4.3.3.2 0.8	Design factor difference necessitates at least a 10 percent increase in pipe wall thickness, with a concomitant increase in freight costs, handling and welding. Note: in the CSA document clause 4.3.5.4 limits pipe not manufactured to API5L, Z245.1, or several ASTM standards to a maximum of 72%SMYS. Special permits granted for increase to 0.80 in US on site-specific basis. Consideration given to reliability-based and risk-based approaches in special permits.															
<u>Valve Spacing</u>	434.15.2 Waterways, 7.5 miles for LPG and liquid anhydrous ammonia	Z662-03 4.4.4 Not required for LVP, nor Class 1 for HVP. 15km spacing for other than Class 1 for HVP.	No difference that would likely lead to special permit negotiations.															
<u>Cover Depth (inches)</u>	Table 434.6(a) <u>Normal</u> <u>Rock</u> 48 30 * 48 30 ** 48 18 ** 36 18 ***	Z662-03 4.7 <u>Normal</u> <u>Rock</u> 24 24 30 24 48* 24 24 24	* Industrial, commercial, residential area ** Drainage ditches at roadways and railroads ** River and stream crossings *** All other areas Canadian cover requirements for LVP or gas. Ratio of US cover requirement to Canadian: <table border="0"> <tr> <td><u>Normal</u></td> <td><u>Rock</u></td> <td></td> </tr> <tr> <td>2.0</td> <td>1.25</td> <td>•The potential for cover reduction could be explored in remote areas</td> </tr> <tr> <td>1.6</td> <td>1.25</td> <td>• Exemptions for reduced cover granted to accommodate thaw settlement (Norman Wells)</td> </tr> <tr> <td>1.0</td> <td>0.75</td> <td>* may be reduced if erosion effects are shown to be minimal</td> </tr> <tr> <td>1.5</td> <td>0.75</td> <td></td> </tr> </table>	<u>Normal</u>	<u>Rock</u>		2.0	1.25	•The potential for cover reduction could be explored in remote areas	1.6	1.25	• Exemptions for reduced cover granted to accommodate thaw settlement (Norman Wells)	1.0	0.75	* may be reduced if erosion effects are shown to be minimal	1.5	0.75	
<u>Normal</u>	<u>Rock</u>																	
2.0	1.25	•The potential for cover reduction could be explored in remote areas																
1.6	1.25	• Exemptions for reduced cover granted to accommodate thaw settlement (Norman Wells)																
1.0	0.75	* may be reduced if erosion effects are shown to be minimal																
1.5	0.75																	

Table 2 - Comparisons Between US and Canadian Liquid Transmission Pipeline Design (con't)			
Code Issue	ASME B31.4	CSA Z662-03	Discussion
<u>Limit State Design</u>	Not found as a design approach methodology in the major US pipeline codes and code references	Z662 Annex C presents a framework for a project to develop a Limit State Design approach	ASME B31.4 does not address provisions to allow a project to develop a strain-based design except for offshore design. The CSA clearly notes that Annex C is applicable for liquid pipelines.
<u>Reliability-Based Design</u>	Not found as a design approach methodology in the major US pipeline codes and code references	Not found as a design approach methodology in CSA Z662-03 but is included in the June 2007 edition as Annex O for natural gas pipelines.	Active groups in both countries are working to further reliability-based approaches. A draft CSA Z662 version circulated for comment contained provisions addressing reliability targets for pipeline evaluations, which would be a significant step forward. However, the target reliability levels set in the 2007 version of the Standard pertain to gas pipelines only. The role for reliability-based design approaches will be to support the development of Limit State Design methodologies as well as on-going maintenance philosophies.
<u>Materials</u>	<i>Chapter III Materials</i> (Discussion of D/t requirements in ASME B31.4, Paragraph 402.6)	<i>Z662-03 Section 5 "Materials"</i> Extensive section covering fracture toughness requirements	Pipe manufacturing is an international industry; most pipeline material can be expected to meet the same industry minimum requirements. Higher grades of steel will allow for reduction in wall thickness: <ul style="list-style-type: none"> ▪ Strain-based design and Limit State Design will require consideration of material properties beyond the traditional single consideration of SMYS; as D/t ratio increases, the axial compressive strain capacity decreases. ▪ An increase in grade may result in little to no increase (if not a decrease) in pipe resistance to longitudinal loadings. If longitudinal loadings are a controlling factor, the benefits of higher grade steels must be carefully weighed. <p>Higher grade steels can be expected to be investigated by any new major project group and tested against regulatory acceptance. Spiral welded pipe has been used in some US projects (e.g. Cheyenne Plains) and will likely be under increased consideration for material selection in the US, as Canadian mills market this type of line pipe.</p>

Table 2 - Comparisons Between US and Canadian Liquid Transmission Pipeline Design (con't)

Code Issue	ASME B31.4	CSA Z662-03	Discussion
<p><u>Welding</u></p>	<p><i>Chapter V Construction Welding, and Assembly</i></p> <p>Extensive section that covers welding</p>	<p><i>Z662-03 Section 7 "Joining"</i></p> <p>Extensive section that covers welding</p>	<p>The level of detail in ASME B31.4 is comparable in detail to CSA Z662; no differences appear critical.</p> <p>The NEB OPR requires 100% NDE, while CSA Z662 requires that only 15% of the production welds made daily be nondestructively inspected. CFR 195.234 requires 10% of girth welds made by each welder in each welding day be nondestructively inspected, except for special cases such as within railroad right-of-ways. Practically, however, standard practice on new transmission pipeline construction is 100% NDE even though this is not required by some codes.</p> <p>Welding designed and matched to the strength requirements of high-strength steel will be an issue on new projects because of the effects in overall system reliability:</p> <ul style="list-style-type: none"> ▪ Strain capacities required may not be reached at industry workmanship levels ▪ Additional and more stringent requirements for flaw detection may be imposed, causing higher than usual weld reject/repair rates and requiring careful consideration of repair procedure and documentation of acceptance, prompting the use of semi- and fully-automatic welding techniques. <p><i>CSA Annex J "Recommended Practice for Determining the Acceptability of Imperfections in Fusion Welds"</i> outlines the application of engineering critical assessment (ECA) to fusion welds. This is an informative, non-compulsory procedure to determine whether or not repairs are required for imperfections in those circumstances where the standards for acceptability for non destructive inspection in CI7.11 have not been met. The recommended method for determining tolerable defect sizes is set out in <i>Appendix "K" Standards of Acceptability for circumferential butt welds based upon fracture mechanics principles. Appendix "J" is generally used to assess existing pipelines and Appendix "K" new construction.</i></p> <p>Through time, annex procedures could become generally acceptable and potentially evolve into a compulsory part of Z662.</p>
<p><u>Hydro Test Requirements</u></p>	<p><i>Chapter VI Inspection and Testing</i></p> <p>125%</p>	<p><i>Reference to Table 8.1</i></p> <p>125% for LVP. 140% for HVP, Class 1, 150% for all other Classes.</p>	<p>ASME B31.4 allows a hydrotest to 1.25 times design pressure if the maximum operating pressure produces a hoop stress level greater than 20% of SMYS, followed by visual inspection or a hydrotest of 1.1 times design pressure for another 4 hours.</p> <p>For LVP, CSA Z662-03 requires a minimum strength test pressure of 125 percent of intended MOP. HVP test requirements are more stringent, requiring 140 percent for class 1 and 150 percent of intended MOP for Class 2, 3 and 4.</p> <p>CI 8.15.1.4 in CSA permits setting the qualification pressure on a point specific basis usually dictated by the elevation profile.</p>

Table 2 - Comparisons Between US and Canadian Liquid Pipeline Design (con't)			
Code Issue	ASME B31.4	CSA Z662-03	Discussion
<u>Pneumatic Testing</u>	<p><i>437.4.3 Leak testing</i></p> <p>Only allowed for piping systems operated at 20% or less of SMYS</p>	<p><i>Z662-03 5.2.2</i></p> <p>Limits the maximum test pressure when using a gaseous medium to 95%* of SMYS; the effect is a 0.76 design factor as opposed for the normal 0.8 design factor in Class 1 locations</p> <p>* Limit has been increased to 100% of SMYS in 2007 version of Z662</p>	<p>Generally, pneumatic testing would only be considered for fulfilling pressure testing requirement, especially at isolated construction sites.</p> <p>There does not appear to be focused study or industry interest for a reconsideration of code regulations for pneumatic testing, and no compelling argument can be currently made for such a focus.</p>
<u>Operations and Maintenance</u>	<p><i>Covered under API 1160</i></p>	<p><i>Z662 Section 10 Operating, Maintenance and Upgrading with references to 2 Annexes</i></p>	<p>Both the US and the Canadian standards provide an operator with considerable latitude in the methodology to apply in undertaking and updating risk assessments, and in developing IM programs.</p> <p>Differences exist in the IM arena in the two following areas as viewed from the Canadian standards vantage point:</p> <ul style="list-style-type: none"> ▪ The principle of a prescriptive re-inspection period. ▪ The singular specificity in the calculation to establish HCA boundaries, although again the reality of a major arctic cross-border pipeline would likely accommodate this approach. <p>API 1160 provides guidance on managing system integrity of liquid pipelines.</p>

Summary of Pipeline Welding Issues (Appendix C)

Appendix C focuses on the comparison of API 1104, *Welding of Pipeline and Related Facilities* and CSA Standard Z662, *Oil and Gas Pipeline Systems*. Differences which are expected to be the basis of continued discussion include:

- Defect Acceptance Criteria
- QA/QC requirements for verifying the acceptance criteria
- Regulatory acceptance requirements for new welding technology

Of these, the current standards show differences in the defect acceptance criteria. Table 3 provides a tabulated version of comparisons between US and Canadian welding standards for these criteria. These differences would not present significant difficulties for typical cross-border pipeline construction, although project-specific requirements for pipelines with limit state design approaches may have to be reconciled.

The differences in requirements for QA/QC procedures and the use of new welding technology and hardware would rely on reconciliation of the defect acceptance criteria. Especially for an arctic pipeline that crosses international borders, defect acceptance criteria would be carefully scrutinized by developing projects to ensure that the pipeline strain limits, which are directly dependent on the defect acceptance criteria, are high enough to resist loadings induced by geohazards such as thaw settlement or frost heave.

Table 3 – CSA Z662-03 and API 1104-19th - Butt Weld RT/Visual Workmanship Defect Acceptance Criteria

Indication	Acceptance Criteria - Length or Dimension Allowed		Discussion
	API 1104	CSA Z662	
Inadequate Penetration (IP)	Without high-low: individual or cumulative 25mm in 300mm weld or 8% < 300mm weld With high-low: individual 50 mm, cumulative 75 mm in any 300 mm of weld	Individual 12 mm, cumulative 25 mm in 300 mm or 8% in welds < 300 mm	SMAW - common (esp. with high-low or external line-up clamps), API 1104 recognizes common causes, allows 3 to 4x CSA limits CSA defines as incomplete penetration of root bead
Incomplete Fusion (IF)	Individual 50 mm, cumulative 150 mm in any 300 mm of weld or 8% < 300 mm welds	Individual 12 mm, cumulative 25 mm in 300 mm weld or 8% in welds < 300 mm	Due to cold lap: CSA - 50 mm or 16% cumulative welds < 300 mm; API - 2 in. or cumulative 8% of weld. API allows 2x more
Internal Concavity (IC)	Any, if density > thinnest adjacent WT. If <, burn-through criteria applies	Any, if density > thinnest adjacent WT. If <, 50 mm or 16% in welds < 300 mm	Defined by density of RT image. Common with SMAW. CSA allows 8x more individual indications
Burn-through (BT)	< 60.3 OD, 1 indication 6 mm and density > adjacent WT ≥ 60.3 OD, same with cumulative 12 mm in 300 mm of weld	< 60.3 OD, 1 indication lesser of ≤ 6 mm dimension or WT dimension ≥ 60.3 OD, lesser of > 5 mm or WT, cumulative 12 mm in 300 mm weld	Common with SMAW. CSA slightly more restrictive.
Internal Undercut (IUC)	Cumulative 1/6 weld or 50 mm in 300 mm weld	Individual 50 mm, cumulative 50 mm in < 300 welds or 16% if > 300 mm weld	For API: Depth ≤ 0.4 mm or 6% nom. WT acceptable; Depth > 0.4 mm or 6% to 12.5 % WT - 2 in. in 12 in. or 1/6 weld; > 0.8 mm or 12.5% WT – unacceptable For CSA: Depth < 0.5 mm or 6% nom. WT acceptable if UC shims or visual or mechanical means used to measure
Lack of Cross Penetration (LCP)	Not addressed	50 mm, or 16% if < 300 mm weld	Common in GMAW. API does not address this defect easily identified by RT
Hollow Bead Porosity (HB)	Individual 12 mm or 6 mm when separation < 50 mm, cumulative 50 mm or 8% weld	Individual 12 mm, cumulative 25 mm or 8% in welds < 300 mm	Common in SMAW. API allows 2x more cumulative length
Porosity (P)	Individual/scattered - 3.2 mm or 25% Thk.; Dist. per Figs 18, 19 on pp. 26, 27 Cluster - Individual > 1.6 mm or Dia. > 12 mm; cumulative > 12 mm in 300 mm weld	Spherical - Individual 3 mm or 25% Thk.; Cumulative in 150 mm 3% area in < 14 mm weld Thk., 4% in 14 to 18 mm weld Thk. and 5% in >18 mm weld Thk. Wormhole - Individual 2.5 mm or 0.33 Thk.; Cumulative ≤ 4 indications or 10 mm in 300 mm weld; Adjacent indications separated by 50 mm	Common with SMAW and GMAW. API better defines maximum diameter of cluster

Comparison of US and Canadian Transmission Pipeline Consensus Standards

Table 3 – CSA Z662-03 and API 1104-19th - Butt Weld RT/Visual Workmanship Defect Acceptance Criteria

Indication	Acceptance Criteria - Length or Dimension Allowed		Discussion
	API 1104	CSA Z662	
Elongated or Isolated Slag Inclusions (ESI or ISI)	<p>Elongated < 60.3 mm OD - 3x WT, width > 1.6 mm, cumulative 8% WT</p> <p>Elongated ≥ 60.3 mm OD - 2 in., width > 1.6 mm, cumulative 8% WT</p> <p>Isolated < 60.3 mm OD - cumulative 2x WT, width > 0.5x WT or > 8% weld</p> <p>Isolated ≥ 60.3 mm OD - > 3.2 mm width or > 4 at 3.2 mm width in 12 in. weld or cumulative 8% WT</p>	<p>Elongated < 60.3 mm OD - 2.5 mm or 0.33 WT</p> <p>Elongated ≥ 60.3 mm OD - 50 mm in 300 mm weld or 16% for welds < 300 mm</p> <p>Isolated < 60.3 mm OD - individual 3x WT, cumulative 2x WT</p> <p>Isolated ≥ 60.3 mm OD - individual 2.5 mm or 0.33 WT, cumulative in 300 mm weld < 10 mm or ≤ 4 indications, adjacent indications separated by 50 mm</p>	<p>API defines as entrapped non-metallic solids. Parallel slag lines shall be considered separate if width of either exceeds 0.8 mm</p> <p>Common with SMAW. CSA has min. separation restriction</p> <p>CSA defines as entrapped non-metallic solids < 1.5 mm width. Parallel slag lines shall be considered separate if width of either exceeds 0.8 mm</p>
Cracks (CR)	Zero	Zero	API allows shallow crater (star) solidification cracks ≤ 4 mm long
Arc Burns (AB)	API disposition by repair or removal at Company discretion	Unacceptable regardless of location	CSA also permits repair
Weld Crown (Reinforcement)	Min. outside surface of base metal; Max. 1.6 mm	Min. outside surface of base metal; Max. 2.5 mm ≤ 10 mm WT, 3.5 > 10 mm WT	
Accumulation of Imperfections	50 mm in 300 mm weld or > 8% of weld length	25 mm in 300 mm weld. For welds < 300 mm and IP, IF, HB and BT ≤ 8 %. If IC, UC, IF, LCP, ESI, ISI or Spherical or wormhole porosity ≤ 16%	API excludes IP due to high-low and UC
Definitions: RT = Radiographic Testing SMAW = Shield Metal Arc Welding GMAW = Gas Metal Arc Welding Thk. = thickness WT = wall thickness			

1. Introduction

Scope of Study

This paper summarizes the major elements of the current standards that govern design, construction, operations and maintenance of natural gas and hazardous liquid transmission pipelines at the federal level in both Canada and the United States.

Study Approach

There are a number of papers and studies that have dealt with the differences in the pipeline standards of both countries in an attempt to both explain and reconcile the approaches to some degree. The standards, as well as the background studies, are reviewed with this objective in mind.

The main body of this report discusses standards development in the US and Canada as well as regulatory oversight of natural gas and hazardous liquid pipeline safety. The importance of cross-border coordination with regard to the standards in use by the two countries is also discussed.

Appendices incorporated in the report address specific US and Canadian industry consensus standards which have significance to existing natural gas and hazardous liquid transmission pipelines which cross between the US-Canadian border and those projects contemplated for construction. The standards are discussed with regard to design, material and equipment issues, construction considerations and code formulations with regard to operations and maintenance, which is an increasingly important area for considerations in the early phases of project design.

2. Background of Standards and Regulatory Oversight

2.1. US Standards Development

It is federal policy in the US to encourage the use of industry consensus standards. Congress expressed a preference for technical standards developed by consensus bodies over agency-unique standards in the National Technology Transfer and Advancement Act of 1995. The Office of Management and Budget's Circular A-119 provides guidance to federal agencies on the use of voluntary consensus standards, including the attributes that define such standards. Voluntary consensus standards are standards developed or adopted by voluntary bodies that develop, establish, or coordinate technical standards using agreed upon procedures. The voluntary consensus standards process has been shown to be the best way to produce codes and standards that meet the needs of all stakeholders.

Historically, pipeline standards and guidelines in the US have been developed and revised by Standards Development Organizations (SDO), organizations such as the American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), NACE International (NACE) and the American Society for Testing and Materials (ASTM) in forums, workshops, meetings, and selective projects. While SDOs do not take the place of an effective regulatory program, regulatory agencies such as PHMSA are the beneficiaries of the work of SDOs. By incorporating portions of or whole standards into the pipeline safety regulations, regulatory agencies ensure that the regulations remain performance based, but are supported by technical depth and ongoing re-evaluation by the developing organization.

PHMSA participates in more than 25 national voluntary consensus standards committees. PHMSA's policy is to adopt voluntary consensus standards when they are applicable to pipeline design, construction, maintenance, inspection, and repair. In recent years, PHMSA has adopted dozens of new and revised voluntary consensus standards into its gas pipeline (49 Code of Federal Regulations [CFR] part 192), hazardous liquid pipeline (49 CFR part 195), and liquefied natural gas (LNG) (49 CFR part 193) regulations.

49 CFR Parts 192, 193, and 195 incorporate by reference all or parts of more than 60 standards and specifications developed and published by technical organizations, including API, ASME, ASTM, American Gas Association (AGA), Manufacturers Standardization Society of the Valve and Fittings Industry, National Fire Protection Association (NFPA), Plastics Pipe Institute, and Pipeline Research Council International (PRCI). These organizations update and revise their published standards every 3 to 5 years, to reflect modern technology and best technical practices. PHMSA then reviews the revised voluntary consensus standards and incorporates them in whole or in part in 49 CFR Parts 192, 193, and 195.

Several of the SDOs which issue significant pipeline safety standards incorporated by reference into federal code are discussed below.

2.1.1. ASME

ASME has a long history of developing standards for use in the oil and gas pipeline industry. The first draft of the ASME Code for Pressure Piping, issued in 1935, contained rules for the design, manufacture, installation and testing of oil and gas pipelines. As the needs of the industry evolved over the years, additional rules for operation and maintenance procedures were added.

ASME relies on a consensus process and committees having a balanced representation from all stakeholders in the oil and gas pipeline industry, including PHMSA, Minerals Management Service (MMS), API, Interstate Natural Gas Association of America (INGAA), industry leaders, legislators and the public, to reach a consensus on Code requirements. There are two ASME Codes in use for hydrocarbon pipelines:

- ASME B31.4 – *Pipeline Transportation Systems for Liquid Hydrocarbon and Other Liquids*
- ASME B31.8 – *Gas Transmission and Distribution Piping Systems*

These two standards have become widely recognized industry standards both in the US and around the world. In addition, ASME B31.8S, *Managing System Integrity of Gas Pipelines*, is used for pipeline IM.

PHMSA, within the US Department of Transportation (DOT), works to ensure the safe operation of pipelines and the protection of the environment through regulation, industry consensus standards, research, education (e.g., to prevent excavation-related damage), oversight of the industry through inspections, and enforcement, when safety problems are found. PHMSA currently recognizes ASME B31.4 and ASME B31.8 as a means of complying with performance oriented standards. PHMSA first referenced ASME B31.4 on April 1, 1970, referencing the 1966 edition. Several parts of ASME B31.4 are used as a basis to develop regulations, and CFR, Title 49, Part 195.3 incorporates it by reference. Title 49, Part 192 was developed at about the same time using the 1967 edition of the ASME B31.8 standard as its basis. CFR, Title 49, Part 192.7 incorporates ASME B31.8 by reference. However, as ASME B31.4 and ASME B31.8 are regularly revised and updated, 49 CFR 192 and 195 remain somewhat out-of-date compared with the latest industry practices.

2.1.2. API

The development of consensus standards is one of API's oldest and most successful programs. Beginning with its first standards in 1924, API now maintains some 500 standards covering all segments of the oil and gas industry. Today, the API standards program has obtained a global reach, through active involvement with the International Organization for Standardization (ISO) and other international bodies.

API is an American National Standards Institute- (ANSI) accredited standards developing organization, operating with approved standards development procedures and undergoing regular audits of its processes. API produces standards, recommended practices, specifications, codes and technical publications, reports and studies that cover each segment of the industry. API standards promote the use of safe, interchangeable

equipment and operations through the use of proven, sound engineering practices as well as help reduce regulatory compliance costs, and in conjunction with API's Quality Programs, many of these standards form the basis of API certification programs.

Among the significant API consensus standards are API 1104, *Welding of Pipelines and Related Facilities* and API 1160, *Managing System Integrity for Hazardous Liquid Pipelines*.

2.2. Canadian Standards Development

2.2.1. CSA Z662

The National Standards System is the system for developing, promoting and implementing standards in Canada. The Standards Council of Canada (SCC) coordinates the National Standards System. The SCC is a federal crown corporation comprised of representatives from the federal and provincial governments, as well as from a wide range of public and private interests. The council prescribes policies and procedures for developing the National Standards of Canada, coordinates Canada's participation in the international standards system, and accredits more than 250 organizations involved in standards development, product or service certification, and testing and management systems registration activities in Canada.

There are four accredited SDOs in Canada: the CSA, the Underwriters' Laboratories of Canada, the Canadian General Standards Board, and the Bureau de Normalisation du Québec. Each SDO develops standards according to the procedures stipulated by the SCC, including the use of a multi-stakeholder committee, consensus-based decision making, and public notice and comment requirements. An SDO may submit standards it has developed to the SCC to be incorporated into the National Standards of Canada. SDOs also develop other standards-related documents, such as codes and guidelines (non-mandatory guidance and information documents). CSA develops the Z662 *Oil and Gas Pipeline Systems* standards for pipelines.

CSA started developing pipeline standards in the early 1960s. The CSA Committee on Oil Pipe Line Code started work in early 1962, followed by the Gas Pipe Line Code Committee about a year later. In June 1967, the first edition of CSA Standard Z183, *Oil Pipe Line Transportation Systems*, was published. In March 1968, CSA Z184, *Gas Transmission and Distribution Piping Systems*, was also published. The CSA Z183 and CSA Z184 standards were based extensively on the provisions of American Standards Association (ASA) B31.4 and B31.8, respectively.

Revised editions of both the CSA Z183 and Z184 standards were published until the early 1990s, at which time the two standards were combined. In 1994, the combined standards were amalgamated with CAN/CSA Z187-M87 (R1992) to produce the first edition of CSA Standard Z662, *Oil and Gas Pipeline Systems*.

The CSA Standard Z662, *Oil and Gas Pipeline Systems*, identifies the technical requirements for the design, construction, operation, and maintenance of oil and gas

industry pipeline systems. The CSA Z662-03 is the fourth edition of the standard and supersedes the 1999 edition. CSA Z662-07 was released during the writing of this report.

The requirements incorporated in the CSA standard apply to more than 750,000 kilometers (km; 466,000 miles) of pipelines in Canada.

CSA standards are developed by committees whose members utilize a consensus approach. The composition of each committee must be “balanced,” i.e., there are specific requirements regarding size, representation, and voting arrangements to ensure a breadth of interest, including the active participation of federal and provincial regulators (for example, the current chairperson of the CSA Z662 technical committee has a regulatory background). In Canada, pipeline regulations, whether federal or provincial, do not incorporate but instead reference the standards, thus giving the standards the force of law. In view of this, the CSA Z662 committee also incorporates a formal group, comprised of seven to eight regulators, that evaluates the potential impacts on regulations from proposed changes to standards.

2.2.2. OPR-99

“In May 1994, the NEB began a consultation process regarding the *National Energy Board Onshore Pipeline Regulations*. The regulation of safety and environmental protection worldwide changed dramatically in the 1990s, in part because of recommendations resulting from inquiries into major accidents like the Piper Alpha disaster in the UK offshore. The NEB requested comments from approximately 1,800 individuals and organizations on revising its regulations. During this period, the Board also conducted an inquiry on stress corrosion cracking on Canadian oil and gas pipelines. Based on the trends in regulation worldwide and the perspectives provided by stakeholders, the NEB decided to modify its Onshore Pipeline Regulations (OPR) to a goal-oriented model.

A consultative process with industry and stakeholders was undertaken to amend the OPR. The draft regulation was sent to all companies under NEB jurisdiction. The NEB also provided further clarification at the request of the Canadian Energy Pipeline Association (CEPA) on September 9, 1997. On April 8, 1998 the Draft OPR was submitted to the Department of Justice and was pre-published on September 28, 1998. A mail-out of the proposed OPR was sent to companies and stakeholders on January 18, 1999. The new regulations, known as OPR-99, came into force in August 1999.” (Matrix, 2004)

2.3. Regulatory Oversight Responsibilities

2.3.1. United States

The Office of Pipeline Safety (OPS) was formed on August 12, 1968 within DOT under the Natural Gas Pipeline Safety Act (NGPSA). The role assigned to OPS was to administer the NGPSA, including investigating system failures, researching the causes of failures, defining safety problems, and seeking solutions to those problems on natural gas

pipeline facilities. In 1969, Congress transferred authority to regulate liquid pipeline safety from the Federal Railroad Administration (FRA), which held that authority since 1967, to OPS.

OPS was incorporated into the PHMSA, created under the Norman Y. Mineta Research and Special Programs Improvement Act (P.L. 108-426) of 2004. The purpose of the act was to create a more focused research organization and establish a separate operating administration for pipeline safety and hazardous materials transportation safety operations under DOT. In addition, the act presented an opportunity for the department to establish model practices in the area of government budget and information practices in support of the President's Management Agenda initiatives.

PHMSA is the federal agency charged with the safe and secure movement of almost 1 million daily shipments of hazardous materials by all modes of transportation. The agency also oversees the nation's pipeline infrastructure which accounts for 64 percent of the energy commodities consumed in the US. The approximate pipeline mileage encompassed by the network includes the following:

- 170,000 miles of onshore and offshore hazardous liquid pipelines;
- 295,220 miles of onshore and offshore gas transmission pipelines;
- 1,900,000 miles of natural gas distribution pipelines; and
- 70,000 miles of propane distribution pipelines.

There are two major program offices within PHMSA:

- Office of Hazardous Materials Safety (OHMS) is the federal safety authority for the transportation of hazardous materials by air, rail, highway, and water.
- OPS is the federal safety authority for the nation's 2.3 million miles of natural gas and hazardous liquid pipelines.

OPS is responsible for ensuring that pipelines are safe, reliable, and environmentally sound. From the federal level, PHMSA oversees the development and implementation of regulations concerning pipeline construction, operation, and maintenance, sharing these responsibilities with state regulatory partners. The pipeline safety regulations implement the laws found in the US code.

The National Transportation Safety Board (NTSB) is the independent federal agency that investigates significant aviation, railroad, highway, marine, and pipeline accidents. NTSB also issues safety recommendations to help prevent future accidents. The NTSB investigates three key areas relative to pipeline safety:

- Pipeline accidents involving a fatality or substantial property damage;
- Releases of hazardous materials via all forms of transportation; and
- Selected transportation accidents that involve problems of a recurring nature.

After an investigation is completed, a detailed report is prepared that analyzes the investigative record, identifies the probable cause(s) of the accident, and provides recommendations. The nature of the recommendations determines whether they are directed to OPS, other government agencies, industry associations, or pipeline operators.

Working closely with NTSB is an important part of the OPS Problem Identification strategic goal. OPS places a priority on resolving problems through implementation of NTSB recommendations.

2.3.2. Canada

The 1957 government of Prime Minister Diefenbaker established a Royal Commission on Energy to determine whether a National Energy Board (NEB) should be created and the nature of its authority. In 1959, the commission recommended that a NEB be established. The government acted promptly on the commission's recommendations, drafting a legislative proposal and introducing it to Parliament in May 1959. As a result, the National Energy Board Act was proclaimed in November of the same year. The act transferred to the new board responsibility for pipelines from the Board of Transport Commissioners and responsibility for oil, gas, and electricity exports from the Minister of Trade and Commerce. In addition, it granted the board responsibility for regulating tolls and tariffs and defined its jurisdiction and status as an independent court of record.

With regard to pipeline safety, the NEB is responsible for ensuring that pipeline companies comply with regulations concerning the safety of persons and protection of the environment, as these may be affected by the design, construction, operation, maintenance and abandonment of interprovincial and international pipelines.

Since its inception, the Board has expanded its expertise in energy matters and enjoys a respected national and international reputation. In 1991, the Board relocated from Ottawa, Ontario, to Calgary, Alberta. In 1994, legislative amendments expanded the board's jurisdiction to include decision-making authority for frontier lands not administered through provincial/federal management agreements.

Under the NEB Act, up to nine board members may be appointed by the governor in council. A member is appointed initially for a seven-year term. Reappointment may be for seven years or less until the age of 70. In addition, up to six temporary board members may also be appointed subject to terms and conditions established by the governor in council. Members typically possess a wide range of government and energy industry experience.

The Governor-in-council appoints the chairman, vice-chairman and board members for fixed terms. The chairman is the chief executive officer of the NEB.

Members are assisted by approximately 280 employees who possess the diverse skills required to support the work of the board. Employees may be financial analysts, computer specialists, economists, engineers, environmental specialists, geologists, geophysicists, communications specialists, lawyers, human resource and library specialists, or administrative staff.

The NEB's relationship with the Transportation Safety Board (TSB) is analogous to that of PHMSA and the NTSB in the US. The NEB runs a parallel investigation of pipeline incidents along with the TSB. The NEB investigates pipeline incidents to determine

whether its regulations have been followed and whether the regulations may need to be changed. The TSB investigates the accident cause(s) and contributing factors. They do not attribute blame and have no authority to enact changes; rather, their recommendations are sent to the NEB for consideration and, if required, for follow up action. The NEB also monitors excavations performed by third parties near pipelines to ensure compliance with existing Crossings and Damage Prevention regulations.

The NEB regulates over 45,000 km (approximately 28,000 miles) of natural gas, hazardous liquid, and product pipeline crossing interprovincial and/or international boundaries of all the provinces and territories west of the Atlantic region. Pipeline systems which are wholly contained within a province typically fall under that province's regulatory jurisdiction. Significant among the provincial authorities is the Alberta Energy and Utilities Board (EUB), recently renamed the Energy Resources and Conservation Board (ERCB), an independent, quasi-judicial agency of the Government of Alberta. The EUB's responsibilities include regulation of 330,000 km (205,000 miles) of pipeline.

3. Importance of Cross-Border Coordination

In 2006, Canada supplied more than 2.3 million barrels of petroleum per day to the US. This represents a six percent increase over 2005 levels. Canadian oil currently accounts for 17 percent of US imports and 11 percent of US consumption. According to the US Energy Information Administration (EIA), Canada remains the largest supplier of oil to the US. These liquid trends will increase as Canada produces more from its oil sands.

Natural gas exports from Canada declined slightly in 2006 from 3.7 trillion cubic feet (tcf) to 3.6 tcf, but increased slightly as a share of US imports (from 85 percent to 86 percent). Warmer than normal weather and near record storage saw the need for US natural gas imports to fall sharply in the second half of 2006. Canada remains the largest supplier of natural gas to the US, with Canadian natural gas representing 16 percent of US consumption, and is expected to remain the primary source of natural gas imported into the US until 2010.

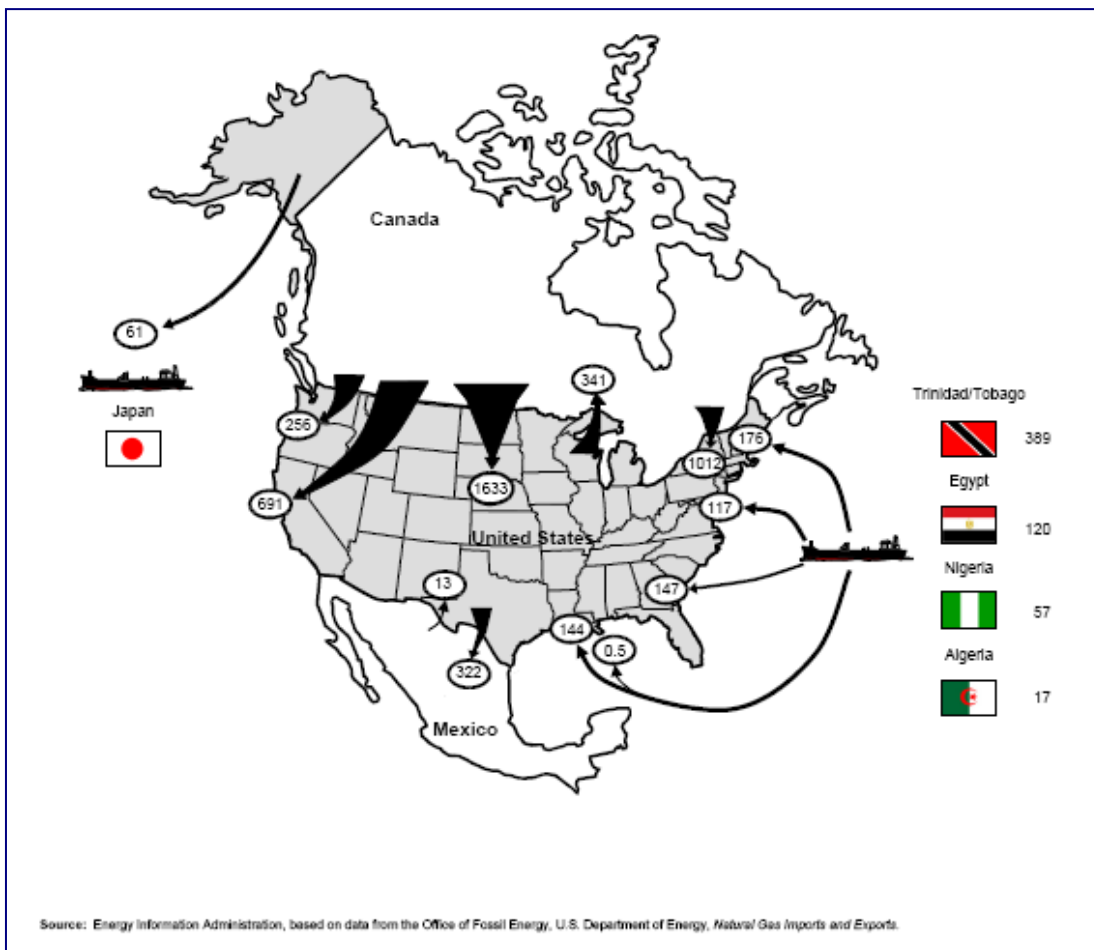


Figure 1 – US Natural Gas Imports and Exports, 2006 (Billion Cubic Feet)

http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2008/ngimpexp/ngimpexp.pdf

Oil and natural gas exchanges between Canada and the US are facilitated by a free trade agreement. The North American Free Trade Agreement (NAFTA) has allowed US investors to have equal access to Canadian resources and established a common oil and natural gas market. This common market has been win-win for both countries.

Canada's gas flows to the United States through several major pipelines feeding US markets in the Midwest, Northeast, the Pacific Northwest, and California. Some key examples are the Alliance Pipeline, the Northern Border Pipeline, the Maritimes & Northeast Pipeline, the TransCanada PipeLines Limited (TransCanada) Pipeline System and Westcoast Energy pipelines. It is more economic for customers in northern cities to purchase Canadian gas than to purchase gas transported from the Gulf coast. Today, there are 35 cross-border natural gas pipelines and 22 oil and petroleum product pipelines¹. As new pipelines are constructed from Canada to the US, the total amount of natural gas and oil imported from Canada is expected to continue growing.

In recent years, hurricane damage in the Gulf reduced North American energy supply at a critical time, further increasing US reliance on Canadian oil and natural gas production. According to US Energy Information Administration (EIA) estimates, Canadian oil exports to the US will reach 2.6 million barrels per day by 2030. Even more significant, the US has been pursuing a policy of reducing reliance on Middle East oil while increasing exports from Western Canada.

Among the cross-border pipelines under current planning is TransCanada's proposed Keystone Oil Pipeline, a 2,965-km (1,842-mile) pipeline with a nominal capacity to transport approximately 435,000 barrels per day of crude oil from Hardisty, Alberta, to US Midwest markets at Wood River and Patoka, Illinois. Of even more significance is the proposed multibillion dollar Alaska Natural Gas Pipeline, which would transport natural gas from the North Slope through Alaska to Alberta, discussed later in this section.

3.1 Standards Normalization

Capital requirements for investments in oil and natural gas pipelines are highly dependent on those projects for which the rate of return is the greatest. Infrastructure decisions are less likely to be based on geology and available infrastructure than they are on the regulatory processes in place that facilitate getting the product to market. Competition not only takes into account economic issues, but also the regulatory, environmental and safety climate of countries and geopolitical regions. Particularly in the case of trans-border pipelines crossing from Canada to the US, standards governing their design need to be consistent so that issues associated with design and construction differences do not stand as impediments to the timely approval of future projects.

¹ <http://www.energysavingtips.gov/news/1947.htm>. (Canadian Council of Chief Executives - Remarks Prepared for Energy Secretary Samuel Bodman, Sept. 12, 2005).

The term “standards normalization” is used to describe the adoption of consensus standards such that any variations from the commonality of these standards are eliminated until each country has the same standard by mutual consent. Normalization enhances safety, compliance, and free exchange of trade while minimizing the regulatory burden on the pipeline operator. To the extent that the differences in standards impacting cross-border pipelines can be vetted and a consensus reached for dealing with them, the more certain will be the regulatory approval process and the overall economics of new pipeline projects.

3.2 Arrangement between the NEB and PHMSA

In November 2005, PHMSA and the NEB executed an Arrangement to enhance cooperation and coordination between them for the purpose of improving pipeline safety both in the US and Canada. Signed by Stacey Gerard, Acting Associate Administrator/Chief Safety Officer for PHMSA and Jim Donihee, Chief Operating Officer for the NEB, the Arrangement recognizes that the pipeline infrastructure in Canada and the US is interconnected, and that the continued safe operation of this infrastructure is dependent on the adequacy and effectiveness of design, construction, operation, maintenance, and other aspects of pipeline transportation activities in both nations. Both entities recognize that the conduct of their responsibilities has required and will necessitate in the future that they examine, regulate, or otherwise oversee interconnecting pipeline facilities or activities. Furthermore, the NEB and PHMSA recognize that appropriate cooperation in the development and implementation of regulatory programs will provide greater regulatory uniformity to pipeline companies operating pipelines which cross the boundary between Canada and the United States. In addition to cooperation, which may take the form of staff exchanges, emergency management planning and exercises, joint training initiatives, sharing of data and reports, and possible co-funding of identified research projects, is the intent to act with regard to consultative regulatory development. Specifically mentioned is the requirement for coordination and collaboration on an Alaskan Natural Gas Pipeline that is authorized by law to be designed, constructed and operated. The Arrangement can be found at the following address: <http://ops.dot.gov/library/mous/PHMSA-NEB%20Arrangement.pdf>.

3.3 Alaska Natural Gas Pipeline

The current desire to examine US and Canadian pipeline standards is being driven, in part, by a proposed Alaska Natural Gas Pipeline, a major Arctic pipeline project traversing the border between the US and Canada.

The terminus of the Alaskan line would be a metering station at the Canadian border, and the pipeline would continue from there to a hub in Alberta, and then on to Chicago. It can be expected that the proponents would desire to maintain the same design basis for the entire system, such that design principles or operating characteristics would not be altered at the border. In the event of provision conflicts, the proponents would be expected to argue for the least onerous regulatory provisions.

In this regard, the project would benefit from a consistent oversight viewpoint, which would be discussed and coordinated in advance. The benefits might be realized in project component design (e.g., pipe wall thickness), but less regulatory uncertainty clearly promotes project confidence in an expeditious regulatory review. Moreover, it could be argued that a consistent design (and operational) regulatory framework would promote overall system reliability and operational response by eliminating, to the degree possible, disparities at the border.

4. Summary

The impetus for coordination between the US and Canada on transmission pipeline standards is driven by the interconnectedness of the pipeline infrastructure in North America. US demand for Canadian energy resources will continue to grow, as will the eventual need to build a natural gas pipeline from Alaska through Canada to bring North Slope production to the Lower 48. As outlined in the November 2005 arrangement between PHMSA and the NEB, both regulatory agencies recognize that appropriate cooperation in the development and implementation of regulatory programs will provide greater regulatory certainty to pipeline companies planning to construct new pipelines, as well as to those operating existing pipelines which cross the boundary between Canada and the United States.

The remainder of this report, in appendix format, contains detailed comparisons of major consensus standards incorporated by reference in the US and Canadian codes. This report is dynamic in nature and will grow in length as comparison appendices are added.

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Appendix A

Natural Gas Transmission Pipelines

A.1 Overview of Natural Gas Transmission Pipeline Safety Regulations

Before focusing on the consensus standards for natural gas pipelines which have been incorporated in the federal pipeline safety regulations in the US and Canada, an overview of the regulations governing natural gas pipelines in the US and Canada is presented.

A.1.1 United States Regulations

The federal regulations for natural gas pipelines are contained in Title 49 of the Code of Federal Regulations (CFR) Part 192, *Transportation of natural and other gas by pipeline: minimum Federal safety standards*. The American Society of Mechanical Engineers (ASME) Code for Pressure Piping ASME B31.8 - 2007, *Gas Transmission and Distribution Piping Systems* (ASME B31.8) is the current industry standard for design and operation of gas pipelines and is incorporated by reference in 49 CFR 192.

The development of federal regulations for natural gas pipelines in the US was spurred by a bill introduced in the 81st Congress (January 3, 1949 - January 3, 1952.) The bill provided an impetus to the industry to develop its own safety code in order to forestall the need for congressional action. The gas pipeline code was issued in 1952 as American Standards Association (ASA) B31.1.8: *American Standard Code for Pressure Piping, Section 8, Gas Transmission and Distribution Piping Systems*.

The Natural Gas Pipeline Safety Act (NGSA) enacted on August 12, 1968 established exclusive federal authority for safety regulation of interstate transmission lines. It also established non-exclusive federal authority for safety regulation of gathering lines in non-rural areas and intrastate transmission and distribution pipelines (Docket OPS-3, 1970). It did not include gas production or related processing facilities.

The Pipeline Safety Act gave the Secretary of Transportation broad power to develop and publish federal regulations applicable to the design, construction, operation, and maintenance of facilities used in the transportation of natural (and other) gas. It also required the Secretary of Transportation to establish minimum federal safety regulations for all phases of the design, construction, maintenance, and operation of gas pipeline facilities.

The evaluative criteria used in the regulatory development process include the following:

- **Relationship between cost and benefit** – The purpose of the regulations was to establish a standard of safety that would be acceptable to the general public. The cost/benefit aspect is not a mathematical formula, but instead is simply a general assessment of both costs and benefits of regulatory proposals, with the goal being to minimize the hazard to the public within the limits of economic feasibility.
- **Public participation** – The development of regulations is a political process, balancing the needs of Congress, the public, and industry. Regulatory agencies perform a public function, and the participation of the public contributes to the

validity of the regulatory process. Facts are best tested and conclusions best validated through the clash of opposing opinions. The pipeline safety regulatory process invited public input at all steps and on all subjects. The public was provided ample opportunity to participate in the identification and definition of safety problems, the development of alternative solutions, and the selection of regulatory solutions (where regulation is appropriate).

- **Performance language** – To the extent possible, the regulations were to be stated in terms of performance standards rather than design and construction specifications. That is, the regulations prescribe what industry must do to achieve adequate safety by stating the level of performance that must be met. Tests and analytical procedures are prescribed to measure performance.

49 CFR 192 essentially replaced the ASME B31.8 Code as the safety standard for US gas pipeline operators. Upon publication of 49 CFR 192, a document entitled *Guide for Gas Transmission Piping Systems* (the Guide), was created, containing information that gas pipeline operators could use to comply with the provisions of the Pipeline Safety Regulations. A recommended means of compliance with each of the requirements of 49 CFR 192 was developed by the Gas Piping Standards Committee (later renamed the Gas Piping Technology Committee [GPTC]), a group formed from the membership and leadership of the ASME B31.8 Committee. The *Guide* was initially sponsored by ASME and later approved as an American National Standard and given the designation of ANS/GPTC Z380. The *Guide* is revised each time there is a change to 49 CFR 192.

A.1.2 Canadian Regulations

Canadian regulations governing natural gas pipeline safety are contained in [*Onshore Pipeline Regulations, 1999*](#) (OPR-99) which became effective on August 1, 1999. OPR-99 contains many "goal-oriented" requirements and reflects the National Energy Board's (NEB) commitment to the development of less prescriptive regulations under the NEB Act. OPR-99 sets out minimum requirements for all stages of a pipeline's life cycle. The intention of this new direction in regulation was to reinforce the fact that the primary responsibility for pipeline safety and environmental protection rests with the companies, not the regulator. OPR-99 requires companies to develop appropriate approaches to ensure that required end results set out in the regulations would be met. The NEB did not abandon all prescriptive requirements, such as adherence to relevant Canadian Standards Association (CSA) standards. The CSA's pipeline standards provide a technical basis for OPR-99 by setting out the minimum technical requirements for the design, construction, operation and abandonment of pipelines. The NEB participates with industry and other government agencies in the development and maintenance of these standards. If the NEB finds that a CSA pipeline standard requirement is not sufficient for the pipelines under its jurisdiction, it may impose more stringent requirements within its own regulations.

CSA Standard Z662-07: *Oil and Gas Pipeline Systems* is the current standard incorporated in NEB and provincial regulations governing natural gas pipelines. This standard was very recently revised, so its predecessor, Z662-03, formed the basis for the comparison undertaken in this study. Recommended practice may be introduced in the CSA code in Annex format. While recommended practices do not have the weight of

regulations, pipeline operators may use, and possibly refine, voluntary practices which might then evolve into a code requirement. The draft standard is reviewed and re-issued on a four-year cycle with any addenda issued after two years. After written and oral comments are received and evaluated, the draft standard is issued for public comment, after which it is published. Questions of interpretation can be submitted at any time to the technical committee for its consideration. However, since responses from the committee are only issued in the form of a “Yes” or “No” answer, questions must be appropriately formulated. In similar fashion as the US, Canadian pipeline regulations are developed and issued for industry and public comment before being promulgated. Because regulations must also undergo lengthy legal review by the Department of Justice, they tend to require more time to revise than standards, hence their adoption by reference.

A.1.3 Code Issues for a United States – Canada Pipeline: General

Proponents of a US – Canada pipeline may request that a number of issues related to existing regulations be reviewed and resolved. Because of the lengthy process required for formal code revision, it is unlikely that code revisions would be requested. Rather, the request may be for special permits of project application provisions, based on pipeline or route-specific details and corresponding justification.

To illustrate, on December 9, 2006, the Alliance Pipeline LP (APL) system, which transports high-energy, rich natural gas from northeastern British Columbia and northwestern Alberta through Saskatchewan, North Dakota, Minnesota, and Iowa to its terminus in Illinois, requested a special permit:

PHMSA is granting Alliance Pipeline LP (APL) a waiver of compliance from certain PHMSA regulations for the United States portion of its pipeline system. This waiver increases the maximum allowable operating pressure (MAOP) for its pipeline. It also increases the design factor for its compressor station piping, grants relief for the hydrostatic testing requirements for its compressor station piping, and grants relief from equipment requirements for pressure relieving and limiting stations.

The waiver request is for approximately 874.7 miles of 36-inch diameter pipe located in the United States between the Canadian border at Milepost 0.0 and the inlet of the Aux Sable Deliver Meter Station near Chicago, Illinois at Milepost 874.7” [Docket No. PHMSA-205-23387, Grant of Waiver, July 06, 2006]

The MAOP increase granted by this waiver corresponded to an allowable hoop stress level up to 80 percent of the pipeline’s SMYS.

Requests for Special permits should be expected for an Alaska–Canada pipeline, with much of the justification associated with either the arctic environment or the remote location, or both. The terminus of the Alaskan line (as proposed by the producers in 2006) would be a metering station at the Canadian border; the pipeline would continue

from there to a hub in Alberta. It is expected that the proponents would desire to maintain the same design and operational criteria for the entire system, with no variations implemented at the border. In the event of conflicts in the provisions, the proponents would be expected to argue for the least onerous regulatory provisions.

The project would benefit from consistent oversight, which would be discussed and coordinated in advance. While benefits might be realized in the design of project components (e.g., pipe wall thickness), consistent oversight would also reduce regulatory uncertainty and, in turn, promote confidence in an expeditious regulatory review. It could also be argued that uniformity of regulations for design and operations would promote overall system reliability and enhance operational response by reducing the potential for project disparities at the border to the maximum extent possible.

In summary, a push to normalize standards for design and operational plans and practices for an arctic gas pipeline to traverse the US and Canada should be anticipated from proponents in both countries. It is difficult to imagine that the pipeline design and operations on one side of the border can be conducted completely independently of operations on the other side. Efforts should be coordinated all along the system to promote design and operational continuity and ensure efficient, safe pipeline operation and maintenance.

The remainder of this Appendix discusses specific differences in the ASME B31.8 and CSA Z662-03 standards as they relate to transborder natural gas pipelines.

A.2 Design

Critical differences in the pipeline codes can contribute to significant variations in the final design of a new pipeline project. Examples of code-related variations that can impact final pipeline design are identified below.

- Pipeline Design Factors
- Valve Spacing
- Pipeline Ditch Ground Cover Depth
- Stress- versus Strain-Based Design Approach
- Reliability-Based Design Approach

Class location also determines particular elements of pipeline design, including valve spacing. The impacts of code variations and class location are explored further in this section, along with their potential cost implications for a new project.

The codes are often based on historical standard practice, as opposed to the application of technical methodology. A brief review of code development history is included in this discussion. In general, the historically established standard practices have served the industry well. Recommended technical improvements are often evaluated against these historically proven, but rigidly prescriptive, practices.

A.2.1 Class Locations

A.2.1.1 US Reference

Class location requirements are contained in 49 CFR 192.5. A corridor width of ¼ mile (220 yards each side of the pipeline right of way) is used to define a “class location unit.” The number of buildings intended for human occupancy within the corridor is used as an index of population density. Class 1 locations have 10 or fewer buildings; the higher classes have increasingly higher densities.

An important difference between ASME B31.8 and CFR 192.5 is the ASME B31.8 subdivision of Class 1 into two divisions. Division 1 remains as a Location Class 1, but the pipe has been hydrostatically tested to 1.25 maximum operating pressure (MOP). For Class 1, Division 1 the design safety factor is greater than 0.72 but less than 0.8. Class 1 Division 2 remains as Location Class 1, but the pipe has been tested to 1.1 MOP. The design factor for Class 1, Division 2 is equal to or less than 0.72.

A.2.1.2 Canadian Reference

CSA Z662-03 4.3.2.2 **Class Location Designations** states:

“Class location designations shall be as given in Table 4.1.”

Table 4.1 – Class Location Designations (See Clauses 4.3.2.2 and 4.3.2.3.2.)	
Development within the class location assessment area	Class location designation
None	Class 1
10 or fewer dwelling units	Class 1
One or more of the following: Class 2 a) 11 to 45 dwelling units; b) a building occupied by 20 or more persons during normal use; c) a small, well-defined outside area occupied by 20 or more persons during normal use, such as a playground, recreation area, outdoor theatre, or other place of public assembly; or d) an industrial installation, such as a chemical plant or a hazardous substance storage area, where release of the service fluid from the pipeline could cause the industrial installation to produce a dangerous or environmentally hazardous condition.	Class 2
46 or more dwellings	Class 3
A prevalence of buildings intended for human occupancy with 4 or more stories above ground	Class 4
Notes: 1) Each dwelling unit in a multiple-dwelling-unit building shall be counted separately. 2) If it is likely that there will be future development in the class location assessment area sufficient to increase the class location designation, consideration shall be given to using the higher class location designation. 3) Consideration shall be given to designating class location assessment areas that contain buildings intended for human occupancy from which rapid evacuation may be difficult, such as hospitals or nursing homes, as Class 3 locations.	

A.2.1.3 Development History

An explanation of the origin and development of the rules for class locations is given below (Shires et al, 1998):

The 1952 edition of B31.1.8 allowed operation of a pipeline with a hoop stress of 72 percent of SMYS in all locations except those inside incorporated limits of cities and towns (Eiber, 1997). Within cities and towns, operators used heavier wall pipe to limit the maximum operating pressure to that which would produce a stress of 50 percent of SMYS. Unfortunately, the densely populated areas did not always align with the city limits. Many operators were specifying heavier wall pipe to reduce the stress level below 72 percent of SMYS in certain population areas and at road and railroad crossings, but the criteria were not uniform among operators (McGehee, 1998).

To address the complex problem of relating pipeline location to operating pressure and to re-examine the appropriateness of the 50 percent SMYS design limit for high population areas, the 1955 B31.1.8 Committee appointed a subgroup to study the problem...The subgroup recommended

that the width of the area for determining population density and defining pipeline construction and the right-of-way zone be one-half mile (i.e., a quarter mile on either side of the center line of the pipeline). This width was selected because a zone of this width was conveniently identified on typical aerial photographs used for locating pipelines. In addition, the Committee believed that this width provided a representative sample of the area traversed by a pipeline and especially the activity occurring around the pipeline.

The number of buildings intended for human occupancy within this half-mile zone was examined. A statistical compilation of the population densities within a quarter-mile of the pipelines determined that a house count of approximately 20 dwellings per one-mile length would have a negligible effect on the majority of the existing pipeline systems. In fact, less than 5 percent of the total transmission pipelines at the time were impacted by higher populations requiring stress levels below 72 percent of SMYS (McGehee, 1998). Due to heightened political pressure resulting from the Heselton Bill, the Committee agreed on a limit of 20 dwellings per mile as the maximum density for areas where 72 percent of SMYS is permitted. The Committee believed that this designation reflected the current practices of pipeline operators, was demonstrated safe based on current practices, and would be politically acceptable.

The Committee did not intend for this width to imply that the pipeline was unsafe in this area. Rather, as the number of houses around the pipeline increases, the expected activity near the pipe threatens pipeline integrity...As a result of the population density study, the Code Committee established four class location types in the 1955 edition of the B31.1.8 pipeline Code. The class locations were designated to address the concerns of increasing potential damage to the pipeline due to population and nearby activities, as well as issues with the availability of heavier wall plate. Increasing the wall thickness would provide additional safety if corrosion or increased third-party damage occurred in higher population areas. At a constant MAOP, the thicker pipe reduces the stress levels, and reduced stress levels increased the ability of the pipe to withstand limited pipeline damage without rupturing.

The reduction in corridor width from ½ mile in the ASME provisions to ¼ mile in the federal regulations is a significant change. The Notice of Proposed Rule Making concluded:

A recent study that included hundreds of miles of pipeline right-of-ways areas indicated that a zone of this width is not necessary to reflect the environment of the pipeline. A one-quarter-mile-wide zone extending one-eighth of a mile on either side of the pipeline appears to be equally appropriate for this purpose. It would be an unusual instance in which a population change more than one-eighth of a mile away would have an

impact on the pipeline. Conversely, an accident on the pipeline would rarely have an effect on people or buildings that were more than an eighth of a mile away. For these reasons it appears that the density zone can be reduced from one-half to one-quarter of a mile without any adverse effect on safety (Michalopoulos and Babka, 2000).

A.2.1.4 Comparison

There is no appreciable difference in the standards for the development of the Class Locations except for the designation of the following as a Class 3 location in §840.3(c), which CSA Z662-03 would designate as Class 2:

An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreational area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive).

A.2.1.5 Discussion

As can be seen from the background discussion, these standards were based on industry practice, after a careful review of existing practice and consideration of the effect of the regulation. On the other hand, there is no firm technical basis for the prescriptive code designations. As an alternative example based on methodology, the United Kingdom code TD/1 bases zone distinctions on building proximity, which incorporates the concept of potential damage distances from the radiation of jetting gas following a pipeline incident.

The concept of class location can be viewed as only an intermediate step in the design process, which has ingrained the element of risk to both personnel and buildings, as well as the risk to the pipeline from activity at the location, increasing with population density. Thus, class location is useful in prescribing a methodology to address the major risk to US pipelines – that of third party damage – as well as in establishing a reasonable safety zone for the protection of personnel and buildings from the consequences of pipeline failure. Note that basing the width of the class locations on the potential impact radius of flame in the event of a failure, as for example by using the formula in ASME B31.8S “Potential Impact Area” similar to the UK code, is a screening tool which addresses the problem – specifically, the aspect of potential risks to human life and property. The number of receptors inside the circle does address the concern of increased activity within the corridor and the correspondingly increased potential for pipeline damage associated with this activity.

Finally, the concept of class location is ingrained into the design and maintenance process, and there is little evidence of major recommended changes from available industry studies. While there may be suggested changes to the details of methodology, suggested special permit conditions should be expected to address the consequences of the class location (e.g., design factors) rather than changes in the general approach of class location. It is noted that the ASME RBDA and Life Cycle Maintenance standards

currently under development are reported to provide alternative methodologies to the class location approach.

A.2.2 Design Factors

Pipe wall thickness for virtually every gas transmission pipeline project is initially determined from the general formula:

$$P = F \times (2 \times SMYS \times t / D)$$

where:

<i>SMYS</i>	=	Specified Minimum Yield Strength of the pipe
<i>P</i>	=	Design Pressure
<i>D</i>	=	Pipe Outside Diameter
<i>t</i>	=	Pipe Wall Thickness
<i>F</i>	=	Modification Factor

If the Modification Factor is set equal to one, the formula is seen to be the classical Barlow's formula, derived from statics, which relates the pipe stress in the circumferential direction (hoop stress) to the internal pressure. With a Modification Factor of less than one to account for such conditions as high temperature service and extra wall thickness as the population density increases, the formula essentially limits the pipe hoop stress to a value less than the minimum tested material yield strength, thus supplying a margin of safety to counter any expected plastic yielding and, ultimately, pipe rupture.

There are further formulae in the codes which also limit the bending stress and/or the combined stress effects in the hoop and circumferential directions. However, pipe is typically designed so that its wall thickness meets – but does not exceed – the requirements for the restraint of internal pressure (as an exception, in cold climates, the limiting wall thickness may be designed to compensate for axial stresses caused by the differential between the installation temperature and the operating temperature of the pipeline pressure, and ground movements such as frost heave).

Mitigation designs also conform to the design standard. Therefore, for a given set of system parameters, a project's pipe wall thickness will linearly increase as a function of the Modification Factor. Since to a large degree the construction cost of a pipeline project is determined by the pipe wall thickness, close attention is required to ensure that the Modification Factor balances safety and economics.

A.2.2.1 US Reference

ASME B31.8, Table 841.114A gives the Basic Design Factors, F:

Location Class	Design factor (F)
Location Class 1, Division 1	0.80 - Hydrotested to 1.25 MOP
Location Class 1, Division 2	0.72 - Hydrotested to 1.1 MOP
Location Class 2	0.60
Location Class 3	0.50
Location Class 4	0.40

This can be contrasted with 49 CFR 192.111 (a) which states:

Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in 192.105 is determined in accordance with the following table:

Class location	Design factor (F)
1	0.72
2	0.60
3	0.50
4	0.40

Unlike ASME B31.8, 49 CFR 192 does not recognize Class 1, Division 1, which was introduced by ASME twenty years ago and essentially allows an increase in the design factor from 0.72 to 0.80 in remote locations. However, the Pipeline and Hazardous Materials Safety Administration (PHMSA) recently approved a design factor increase for two pipelines on a site-specific basis. These special permits were granted based on a review of construction methodology, original pipe properties, hydrostatic testing, third party damage resistance, and construction inspection criteria. It is reasonably anticipated that the owners of additional pipeline systems will be requesting special permits under similar circumstances.

A.2.2.2 Canadian Reference

The Design Factor (F) is used to control the wall thickness of the pipe and is defined in Z662, 4.3.3.2: “The design factor to be used in the design formula in Clause 4.3.3.1.1 shall be 0.8.”

To be compared to the US Codes, this Design Factor must be first combined with the Location Factor given in Table 4.2, which is reproduced here for convenience.

Table 4.2 – Location Factor for Steel Pipe (See Clauses 4.3.3.3 and 15.4.1.3.)				
Location factor (L)				
Application	Class 1 location	Class 2 location	Class 3 location	Class 4 location
Gas (Non-sour service)				
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
Gas (Sour Service)				
General and cased crossings	0.90	0.75	0.625	0.50
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
<p><i>* 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).</i></p> <p>Notes:</p> <ol style="list-style-type: none"> 1) <i>Roads: Pipe, in parallel alignment or in uncased crossings, under the traveled surface of the road or within 7 m of the edge of the traveled surface of the road, measured at right angles to the centerline of the traveled surface.</i> 2) <i>Railways: Pipe, in parallel alignment or in uncased crossings, under the railway tracks or within 7 m of the centerline of the outside track, measured at right angles to the centerline of the track.</i> 3) <i>Stations: Pipe in, or associated with, compressor stations, pump stations, regulating stations, or measuring stations, including the pipe that connects such stations to their isolating valves.</i> 4) <i>Other: Pipe that is</i> <ol style="list-style-type: none"> a) <i>supported by a vehicular, pedestrian, railway, or pipeline bridge;</i> b) <i>between any two components in a fabricated assembly; or</i> c) <i>in a fabricated assembly, within five pipe diameters of the first or last component, other than a transition piece or an elbow used in place of a pipe bend that is not associated with the fabricated assembly.</i> 				

A.2.2.3 Development History

Pipe for a particular line is generally purchased according to specified minimum yield strength (SMYS). No pipe which can test less than SMYS is accepted. Operating pressure is then set at a stress level lower than the SMYS, to establish a safety factor. A maximum design factor of 72 percent of SMYS was derived from the first all-welded pipeline,

installed by Natural Gas Pipeline Company of America in the 1930s. Because the use of an all-electric girth-welded line was new, no precedent existed for operating pressure. It was determined that the pipe could be used safely at a stress level of 80 percent of the manufacturer's mill test pressure (typically 90 percent of SMYS), where 80 percent of the 90-percent-of-SMYS figure results in a maximum allowable operating pressure (MAOP) of 72 percent of SMYS. A 72 percent stress level first appeared in the 1935 American Tentative Standard Code for Pressure Piping. The 1935 code committee agreed that mill test pressure would serve as the most accurate and reliable determiner of MAOP. This method of determining MAOP was proven in the field to be safe. Post construction gas pipeline testing to MAOP plus 10 psi before going into service was an industry practice at the time the 72-percent-of-SMYS criterion was selected, primarily as a gas leak test. The only strength test conducted was the 90 percent SMYS mill test.

In Canada and the US, attention was given to Battelle's work in the late 1960s using a construction hydrostatic test pressure to determine MOP. The findings indicated that it was the margin between the hydrostatic test pressure and MOP that was the best predictor of operational integrity. In the early 1970s, TransCanada Corporation (TransCanada) and Alberta Gas Trunk Line and their regulators agreed to a regime that allowed pipelines to be operated at up to 80 percent of hydrostatic test pressure. Pipelines were upgraded by pressure testing. Testing of new and existing pipelines to a minimum pressure corresponding to 100 percent of SMYS allowed operation up to 80 percent of SMYS. CSA Z184-M1973 (for gas pipelines) permitted operation at up to 80 percent of SMYS, based on hydrostatic testing at a minimum of 1.25 times the intended MOP. In 1990 (for oil) and 1992 (for gas), the CSA code adopted a single design factor of 0.80, and location factors that varied from 1.000 to 0.550 for class locations 1 to 4, respectively. Since 1994, this approach has been maintained in CSA Z662, the current standard for oil and gas pipeline systems (Rothwell, 2006).

A.2.2.4 Comparison

A comparison of the design factors for the class locations (class locations are discussed further in Section A.2.1) is given in the following table. The last column specifies the increase in minimum wall thickness that is indicated by the difference in factors.

Comparison of the Design Factors for the Class Locations				
Class	ASME B31.8	CFR	CSA (Non-sour gas)	Required Increase in Wall Thickness (%) for US Pipelines
Class 1 (ASME B31.8 Division 1)	0.8	NA	0.8	0
Class 1 (ASME B31.8 Division 2)	0.72	0.72	0.8	11
2	0.6	0.6	0.72	20
3	0.5	0.5	0.56	12
4	0.4	0.4	0.44	10

A.2.2.5 Discussion

Since CFR controls, the ASME B31.8 Class 1, Division 1 design factor is not currently allowed for transmission pipelines. Thus, the most noteworthy comparison for a gas pipeline is that the US design factor difference necessitates at least a 10 percent increase in pipe wall thickness, with a concomitant increase in steel, construction and freight costs, handling, and especially extra welding volume.

Numerous studies of pipeline design factors have been performed. The investigations recognize that the original factors used in the US codes were determined based on the industry practice of four decades ago. Since that time, there have been advances in nearly every area of pipe metallurgy fabrication and construction, including steels designed for welding, material uniformity, welding, inspection, and monitoring. In addition, modern steel codes for other industries (e.g., highway bridge fabrication and construction) have moved toward limited state- and reliability-based code concepts, rather than strictly “prescriptive” design.

On the other hand, the current US design factors have generally served the industry well, especially considering the wide variation in service characteristics and environments, and the many pipelines that remain in service long after their initially projected design life.

Instead of a step change to a different constant factor, the most frequently considered recommendations applicable to both the US and Canadian codes are the use of a reliability-based approach where the sources and probabilities of failure must be evaluated for each project, plus a risk-based approach in which the consequences are also explicitly evaluated to establish a safety factor that addresses a system target using the specific system characteristics and operating environment. Note that this type of approach is mentioned in the following APL Request for Waiver:

Pipeline System Analysis

APL conducted evaluations of the US portion of its pipeline to confirm whether the system could safely and reliably operate at increased stress levels. As part of its evaluation, APL established a feasibility criterion to assess the safety and reliability of the pipeline to operate at stress levels up to 80 percent of the pipeline’s SMYS. The feasibility criterion includes, but is not limited to:

- Developing operational commitments that would improve safety for any person residing, working, or recreating near the US portion of its pipeline, including approximately 15 miles of pipeline located in high consequence areas.
- Conducting in-depth assessments of its existing pipeline equipment to ensure the equipment is capable of sustaining operations at increased pressures. In addition, APL plans to modify its existing pipeline to enhance the safety and reliability of the pipeline to operate at stress levels up to 80 percent of the pipe’s SMYS.
- APL also performed technical reviews of its pipeline and compared the threats imposed on a pipeline operating at 72 percent SMYS to those

imposed on a pipeline operating at 80 percent SMYS. The following nine threats were analyzed: (1) Excavation damage; (2) external corrosion; (3) internal corrosion; (4) stress corrosion cracking; (5) pipe manufacturing; (6) construction; (7) equipment; (8) weather/outside factors; and (9) incorrect operation. [Docket No. PHMSA–2006–23387; March 22, 2006]

The reliability-based approach and the risk-based approach have been utilized in numerous previous industry studies that attempt to prove the applicability of a single design factor. However, a “methodology-based” performance approach offers a key advantage over the use of single prescribed value: it directs attention to the risks to pipeline integrity posed by project-specific elements and threats, rather than calculating risk based on industry averages.

The results of past studies have confirmed that an increased design factor is justified based on modern pipeline fabrication and construction practice – and imply that the grandfathering of a higher factor for older pipelines must be approached with care, including suitable engineering assessments which support safe performance. The general concern over “opening the door” to an increased design factor is reflected in comments made at the March 21, 2006 PHMSA Public Meeting to discuss raising the allowable operating pressure on certain natural gas transmission pipelines:

“One of my biggest concerns regarding this issue is what pipelines will end up qualifying for a waiver like this in the future? Will tape coated lines be allowed? What will be the toughness requirements to qualify? Is there a diameter limitation? etc.” (McGrath, 2006)

A.2.3 Valve Spacing

A.2.3.1 US Reference

The requirements identified in 49 CFR 192.179 regarding transmission line valve spacing are the same as those in ASME B31.8, Section 846.1, and are as follows:

(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:

The spacing information described in this paragraph is summarized in the following table:

Class location	Valve Spacing (miles)
1	20
2	15
3	8
4	5

A.2.3.2 Canadian Reference

The requirements of CSA Z662-03, Paragraph 4.4.4 for valve spacing on transmission lines are as follows:

It shall be permissible for the spacing of valves in the pipeline to be as given in Table 4.7 or adjusted based upon factors such as operational, maintenance, access, and system design considerations.

Table 4.7 – Valve Spacing, miles (km)				
Type of pipeline	Class 1 location	Class 2 location	Class 3 location	Class 4 location
Gas	NR	15.5 (25)	8 (13)	5 (8)
CO2	NR	9.3 (15)	9.3 (15)	9.3 (15)
Notes: NR = not required. Valve spacing adjustments should not normally exceed 25% of the applicable distances given in Table 4.7.				

A.2.3.3 Development History

Operating convenience, economics, and the need to limit adverse publicity during an incident were the primary motivations for establishing valve spacing recommendations. Although it is often perceived that valve spacing is based on minimizing the consequences of a pipeline incident, in actuality, the majority of damage from a pipeline rupture occurs in the first few minutes (Sparks, 1995; Sparks, 1998). If the gas is ignited, being able to close the valve quickly has no effect on safety but may minimize negative public perception. Timely valve closure may not significantly reduce the amount of gas released to the atmosphere (Sparks, 1995, 1998). Safety is best addressed in the Code by ensuring that the valve is accessible, and unexpected gas losses are minimized.

The Code Committee surveyed industry practice in 1955 and suggested a requirement for valve spacing as a function of class location. Specific intervals were designated to satisfy concerns of potential litigation associated with specifying valve spacing based on engineering judgment. The Code Committee intended the valve spacing recommendations to be used as guidelines, but for pipeline operators to also consider local conditions. For example, a valve located near a roadway is more readily accessible than one located in the middle of a pasture, cornfield, or swamp. These spacing intervals reflected the current practices of the majority of pipeline operators in 1955, while also responding to governmental and public pressure for more valves in higher population areas.

The valve spacing requirements in 49 CFR 192 were based on recommendations in the original ASME B31.8 Code, but were rewritten to more clearly express the intended result (Docket OPS-3). The Technical Pipeline Safety Standards Committee (TPSSC) believed that valve placement was primarily an economic matter rather than a safety consideration. The increased number of valves required for higher population areas was based on minimizing the volume of gas released during maintenance activities and was not a decision based on public safety.

A.2.3.4 Comparison

As can be seen, there is a major difference in the valve spacing requirements of the codes for gas pipelines for the Class 1 location. Spacing of valves in the US for a Class 1 location is specified to be 20 miles (32 kilometers [km]) while it is noted as “Not Required” in Canada. The nominal valve spacing for the other Class locations is the same, although the codes offer latitude in allowing adjustments to this spacing based on the specific considerations of the design.

A.2.3.5 Discussion

This provision of prescribed valve spacing in Class 1 locations can be anticipated to be petitioned for review for any significant US project with significant mileage located in a remote area. If the pipeline crosses the US-Canadian border in a Class 1 location, the difference in codes and implications to operations and maintenance, if not initial capital costs, would be difficult to ignore. Note that CI 4.4.4 in CSA Z662 stipulates maximum valve spacing, but that CI 4.4.3 also requires an engineering assessment with respect to a given set of relevant factors.

The argument would be expected that valves do not prevent the occurrence of pipeline failure incidents. Further, personnel risk is, if not negligible, greatly reduced in remote areas (especially Class 1, Div 1) and, in any case, valve spacing plays no significant role in reducing the risk of the initial release of gas and ignition. No significant negative environmental consequences are caused by the larger volume of gas that could be released with a greater spacing. In general, this is largely an operator decision that can be based on operational and maintenance requirements, such as the need for isolation for pipeline repairs. (Eiber, 2000)

A.2.4 Cover Depth

A.2.4.1 US Reference

The requirements contained in 49 CFR 192.327 regarding pipeline cover are as follows:

- (a) Except as provided in paragraphs (c), (e), (f) and (g) of this section each buried transmission line must be installed with a minimum cover as follows:

Location	Normal Soil	Consolidated Rock
Inches (m)		
Class 1 locations	30 (0.75)	18 (0.5)
Class 2, 3, and 4 locations	36 (0.9)	24 (0.6)
Drainage ditches of public roads and railroad crossings	36 (0.9)	24 (0.6)

ASME B31.8 Section 841.142 requirements are less stringent as shown in the following table (for pipe size larger than NPS 20):

Comparison of US and Canadian Transmission Pipeline Consensus Standards

Location	Normal Soil	Consolidated Rock
Inches (m)		
Class 1 locations	24 (0.6)	18 (0.5)
Class 2 locations	30 (0.75)	18 (0.5)
Class 3 and 4 locations	30 (0.75)	24 (0.6)
Drainage ditches of public roads and railroad crossings	36 (0.9)	24 (0.6)

A.2.4.2 Canadian Reference

The requirement in CSA Z662-03: C1 4.7 for cover and clearance is as follows:

The cover requirements for buried pipelines shall be as given in Table 4.9, except that where underground structures or adverse conditions prevent installation with such cover, it shall be permissible for such pipelines to be installed with less cover, provided that they are appropriately protected against anticipated external loads.

Table 4.9 – Cover and Clearance (See Clauses 4.7.1, 4.7.2, and 4.8.2.1.)				
Location	Type of Pipeline	Class Location	Normal Excavation Inches (m)	Rock excavation requiring blasting or removal by comparable means Inches (m)
General (other than as indicated below)	gas	Any	24 (0.6)	24 (0.6)
	CO2	1	36 (0.9)	24 (0.6)
	CO2	2,3 or 4	48 (1.2)	24 (0.6)
Right-of-way (road or railway)	Any	Any	30 (0.75)	30 (0.75)
Below traveled surface (road)*	Any	Any	48 (1.2)	48 (1.2)
Below base of rail (railway)†	— Cased	Any	48 (1.2)	48 (1.2)
	— Uncased	Any	78(2.0)	78 (2.0)
Water Crossing	Any	Any	48 (1.2)‡	24 (0.6)
Drainage or irrigation ditch invert	Any	Any	30 (0.75)	24 (0.6)

Clearance from	Type of Pipeline	Class Location	Clearance for buried pipelines, minimum Inches (m)
Underground structures and utilities (conduits, cables, and other pipelines)	Any	Any	12 (0.3)
Drainage Tile	Any	Any	2 (0.05)

Notes:

* See Clause 4.8.3.1.

† Within 7 m of centerline of the outside track, measured at right angles to the centerline of the track.

‡ Cover not less than 0.6 m shall be permissible where analysis indicates that the potential for erosion is minimal.

1) Cover shall be measured to the top of the carrier pipe or casing pipe, whichever is applicable.

2) See also Clause 1.6.*

A.2.4.3 Practical Considerations

The pipeline cover affords some protection against third-party damage by ensuring that the pipeline is at a sufficient depth to avoid damage from incidental, shallow excavations. Some protection against the potential extent of damage in the event of a pipeline failure can be argued as the burial depth increases.

However, the pipeline cover should also be considered part of the pipeline design in that it supplies the mechanical restraint to the buried pipeline. Buried pipelines are designed based on the assumption that the friction between the surrounding soil and the pipe restrains, at least to some extent, the thermal growth, while developing an axial compressive force. Especially for large diameter transmission pipelines, this consideration forms a practical limitation in minimum cover depth requirements based on this required pipe restraint. If the pipeline is not adequately restrained (through the placement of sufficient fill) its natural tendency is to undergo buoyancy and possibly Euler buckling (i.e., pipeline deflects laterally if the axial compressive force greatly exceeds the shrinkage caused by the internal pressure). A similar concept applies to buried pipelines, with the locations of insufficient fill (i.e., lack of soil density or lateral restraint) being the factor that could provide the failure path. One of the concerns with upheaval buckling is that the pipe will be sufficiently buoyant and breach the ground surface and be increasingly vulnerable to damage. Another concern is that the soil movements such as frost heave may cause excessive bending stresses in the pipe, possibly to the extent of exceeding code stress limits.

A.2.4.4 Comparison

A side-by-side comparison of cover for a gas pipeline in general conditions is given below, along with the ratio of increased cover relevant (US to Canada).

Class Location	US Cover requirements (inches)		Canadian Cover Requirements (inches)		Ratio (US cover to Canadian)	
	Normal	Rock	Normal	Rock	Normal	Rock
1	30	18	24	24	1.25	0.75
2, 3 or 4	36	24	24	24	1.5	1.0

Except in the instance of rock excavation in a Class 1 location, the US code would require additional cover.

A.2.4.5 Discussion

In remote areas, and especially where there is no discernible possibility for third-party operations, the potential for cover reduction could be explored and argued. This simply might be the reduction of ditching requirements, but also might be coupled with pipe integrity design situations. For example, proponents of the 540-mile (869-km) Norman Wells crude oil pipeline, running from Norman Wells in the Northwest Territory to Zama in northern Alberta, requested, and were granted, an exemption for a reduced cover depth to accommodate potential thaw settlement in some areas (the reduced cover lessens the downward load on the pipeline if it loses the ditch support due to settlement). For frost heave of a chilled line, a reduction in the cover depth could lessen resistance to uplift and may allow the pipeline to better accommodate high-heave situations. In such cases, a

corresponding design requirement would then be to ensure that the cover decrease does not increase the propensity for upheaval displacement (and consequent higher pipe strains).

The major effect of decreased cover is to lower the soil resistance to the developing flexural state of the pipeline as it responds to the imposed upward displacement of frost heave. Lowered soil uplift resistance allows the pipeline to conform over a longer distance to differential heave development along the route, allowing more gradual build of the pipe strain demand.

A mitigative practice for frost heave situations that may be found during operations is to reduce the cover. It is also noted that similar mechanical relief happens during surface thaw of the pipe cover, although the recoverable elastic strain may be quickly regained the following winter. Analogous effects are found for the effects of differential thaw settlement. For the Norman Wells pipeline, the designers successfully petitioned for cover reduction for largely this reason.

The danger that is being alerted in the report is that such a practice may have an unintended consequence – that of exacerbating the potential for upheaval buckling. It is noted that the potential for upheaval buckling is greatest soon after start-up of a chilled buried line – the cover may be entirely thawed during the preceding dormant period so the cover offers the lowest (thawed) resistance to potential upward movement. Reduced cover would then further lower soil resistance. Continued operations would tend to freeze the soil around the pipe so the soil uplift resistance to upheaval is substantially increased.

A.2.5 Limit State Design

Limit state design (LSD) is different from the traditional allowable stress design. In the allowable stress design method, the focus is on keeping the stresses resulting from the design loads under a certain working stress level that is usually based on successful similar past experience. Note that limited plastic deformation may be permitted. This methodology requires redundancy to ensure time for appropriate inspection and mitigation/prevention.

LSD is a set of design principles that guides the development of an appropriate design framework, as exemplified in CSA Z662 Annex C. LSD principles can be implemented in either a deterministic form or probabilistic form. Load and Resistance Factor Design (LRFD) is an example of a typical deterministic form. Reliability-Based Design and Assessment (RBDA) constitutes a typical probabilistic form. The LRFD approach is included in Annex C, although the load and resistance factors require calibration. While calibration can be done based upon various acceptance criteria (such as reliability, risk, etc.), reliability targets, such as those defined in Annex O, are often used as the basis for the calibration. The RBDA approach is also outlined in Annex O, which defines the acceptance criteria directly by reliability targets and represents variability more explicitly. When the LSD principle applies to only a subset of design conditions where strains are used to represent the design/acceptance criteria, the approach then becomes

Strain-Based Design (SBD). Similarly, SBD can either be deterministic or probabilistic and therefore becomes a special form of either LRFD or RBDA, respectively.

In contrast to the allowable stress design, the limit state design is based on the explicit consideration of the various conditions under which the structure, in this case a pipeline, may cease to fulfill its intended function. For these conditions, the applicable capacity or strength is estimated and used in design as a limit for such behavior. The load-carrying capacity of a structure is for this purpose normally evaluated using simplified design formulations or by using more refined computations such as nonlinear elastic-plastic large-deformation finite element analyses with appropriate modeling related to geometric/material properties, initial imperfections, boundary conditions, load application, and finite element mesh sizes, as appropriate.

During the last two decades, the emphasis in the structural design of buildings, aircraft and marine structures has been moving from the allowable stress design method to the use of limit state design since the latter approach makes possible a rigorously designed, yet economical, structure considering the various relevant modes of failure directly.

A limit state is formally defined by the description of a condition for which a particular structural member or an entire structure fails to perform the function that is expected of it. From the viewpoint of a structural designer, four types of limit states are considered for steel structures, namely:

- Serviceability limit state (SLS);
- Ultimate limit state (ULS);
- Fatigue limit state (FLS); and
- Accidental limit state (ALS).” Paik and Thayamballi (2003).

A.2.5.1 US Reference

With regard to structural stress evaluation of gas pipelines, 49 CFR 192 limits the governing hoop stress to be less than a fraction of a material minimum, the SMYS for the different class locations. For guidance on limits for other structural/stress conditions, ASME B31.8 is used (e.g., ASME B31.8 Paragraph 833 “Design for Longitudinal Stress”). ASME B31.8, both in Paragraph 833 and Chapter VIII, “Offshore Gas Transmission,” allows strain-based design (i.e., Section 833.5 “Design for Stress Greater than Yield” and Section A842.23 “Alternate Design for Strain”).

Limit State Design as a design approach methodology is not found in the major US pipeline codes and code references.

A.2.5.2 Canadian Reference

CSA Z662, Annex C “Limit States Design” presents a framework for a pipeline project to develop a Limit States Design approach:

For many design loadings, the only primary load acting is that due to internal pressure; all other loads are secondary. For these situations, an elastic design method may be excessively conservative, as it does not recognize the ability of the pipe to plastically deform and still maintain pressure integrity. A plastic design approach does recognize such behavior, and can therefore be used to advantage. In some instances the response of the pipeline structure will be displacement controlled (limited) rather than load controlled (as is the case with the allowable stress method).

Annex C provides a detailed outline for the investigation of a Limit States approach, but would require additional work and improved knowledge of the pipeline on the part of the proponent for application in any particular instance. For example, Load Factors which specify multiplicative factors greater than one to be applied to the operational, environmental, accidental and fatigue components of loading are tentatively given in Table C.1, but with the proviso: “*Note: The factors given in this table require verification through a process of code calibration; until then, they should be used for comparative design purposes only.*” These factors would affect the design demand longitudinal tensile and compressive strains.

The project loads, appropriately increased by the Load Factors, are combined into credible load groups. Their loading effect must be evaluated for the appropriate limit states, chiefly the longitudinal tensile or compressive strains, often using nonlinear techniques. Since the evaluation is beyond the elastic range, appropriate material stress-strain behavior is also needed beyond the elastic limit to predict the effect of the loads into the plastic range. In addition, increasingly sophisticated structural analyses are used which can appropriately follow the behavior into this plastic range.

The resultant values are then compared against the factored Resistance values. The Resistance values are found through examination of the various “Limit States” such as compressive buckling and wrinkle failure or tensile rupture. Then factors less than one are applied as described in Table C.3 “Resistance Factors” with the same caveat: “*Note: The factors given in this table require verification through a process of code calibration; until then, they should be used for comparative design purposes only.*” These factors would affect the design capacity longitudinal tensile and compressive strains.

If the strains found from the factored Load Groups (with their factors typically greater than one) are less than the strains determined as the factored Resistance values (with factors typically less than one), then the design is found acceptable.

A.2.5.3 Development History

In the pipeline industry as well as other industries, the US has been particularly slow to adopt Limit State design approaches, commonly known in the US and to the Canadian construction industry as the “Load and Resistance Factor Design” (LRFD) approach. The American Institute of Steel Construction (AISC) issues a combined manual of steel construction (the 2005 manual) that contains both the “traditional” stress-based approach (Allowable Stress Design [ASD], last updated in 1989), and LRFD. For bridge structural

design, the US has evolved over the last 10 to 20 years to LRFD, although ASD is still the accepted practice in some states.

In Canada, the pipeline code has included the informative Annex C which describes the required basis for a pipeline approach using LRFD. In general, the information has been referenced in several approaches for design, although no project could be found which completely adopted the approach. The design subcommittee of CSA Z 662 is currently actively pursuing calibrating the load and resistance factors in Annex C to enable the method to be more widely used.

A.2.5.4 Comparison

ASME B31.8 has provisions to allow a project to develop a strain-based design. Since the strains would be beyond the stress allowables of the regulation, a new approach to judge the acceptability of these strains must be considered. The logical framework for development of these allowables, and comparison with the applied loads, would be a Limit State design approach. Thus, although a framework for patterning this development is clearly better developed in the Canadian regulatory framework, a US project could use the triggering words of ASME B31.8 to develop a Limit State Design approach, especially for those conditions that are not explicitly already handled.

A.2.5.5 Discussion

A strain-based design for longitudinal loadings, such as slope movement or pipe settlement due to thaw of permafrost in arctic regions, is especially appropriate since these are “secondary loadings.” Secondary loadings, such as differential ground movement, are generated by structural deformations; the pipe displacement growth is generally limited by the deformation mechanism. Pipelines that are designed to address these secondary loadings by consideration of the resultant strains are considered “strain-based design pipelines.”

Note that secondary loadings from various geohazards (such as frost heave and thaw settlement) often develop relatively slowly over time with the displacement of the ditch profile, thereby permitting effective monitoring strategies to observe any developing deformation well before a critical strain state is reached. This consideration, and appropriate strategies during design, can form an important part of developing an approach to such hazards.

A strain-based design needs a recognizable framework to guide design acceptance. Stress-based design usually proceeds on the principle of avoidance of yield behavior, i.e., stresses are judged to be acceptable if they are some fraction of yield (i.e. 72 percent of SMYS). Since strain-based design, almost by definition, exceeds yield, new acceptance principles and tools used to forecast the resulting performance are required. The principles developed will almost invariably include the concept of a “limit state”; that is, a state of pipeline deformation or strain that limits some required behavior. A Service Limit State (SLS) refers to the state that limits a behavior required for some routine inspection activity, such as pigging, but still maintains basic functionality of pressure containment. A state that involves loss of containment, such as tensile fracture, is called an Ultimate Limit State (ULS). Thus, a strain-based design will almost invariably look to

the development of a Limit State Design philosophy for its project to have a logical, and recognizable, framework to judge the nominal resistance requirements for potential hazards.

Considerable effort is spent to define, test, and document the values and conditions corresponding to these resistance states since these become the limits against which design is judged.

Although the terms and much of the methodology has been refined, the use of a strain-based design, testing to define appropriate limits, and development of criteria using this approach has certainly been used in the US in the past. In addition to a number of stress-based criteria mostly sourced to code requirements, the TAPS project design criteria developed in the mid-1970s allows 0.8 percent effective strain, especially to address geohazards. (Compare this to 0.275 percent (=80 kips per square inch [ksi]/29000 ksi), which is the computed elastic strain at SMYS for X80). This allowable strain value is based on the ultimate compressive strains developed from full-scale buckling tests conducted on the project's relatively thin-walled (diameter-to-wall-thickness ratio $[D/t] > 100$) pipe at the University of California, at Berkeley. Such project-specific testing is typical for projects that need to extend criteria to approach circumstances not addressed by regulations or outside of code limitations.

Finally, the Load Factors and Resistance Factors noted in Annex C will be required to develop the required "safety factor" against the load resultant exceeding the resistance. As noted in Annex C, this can be viewed as an exercise to demonstrate that these factors to be used will result in meeting failure reliability targets. Thus, in some sense, the Load and Resistance factors act as surrogates for the reliability analysis – which leads to the examination of the direct use of reliability-based design methodology in the next section. The development and acceptance of reliability-based analyses is an improvement which allows a quantitative evaluation of risk, and a procedure to examine design factors and overall project safety factors for use of project-specific criteria.

A.2.6 Reliability-Based Design

An alternative to Limit State Design or LRFD design is an explicit reliability-based design approach. In this approach, the reliability/risk of the pipeline is estimated using statistical simulation techniques, with input for the various statistical distributions involved and input from a number of project sources (e.g., route soils data and variability, material properties variability, etc.). An overall reliability estimate (i.e., probability of criteria exceedence or probability of reaching a service or ULS during the design life) can be found and compared to historical pipeline failure rates, or acceptance criteria based on analogous sections of the installed project, to judge acceptability.

A.2.6.1 US Reference

Reliability-based design, as a design approach methodology, is not found in the major US pipeline codes and code references. On the other hand, risk and reliability concepts form an important part of the operational integrity maintenance approaches outlined by the codes.

ASME B31.8S-2001 noted that: “The B31.8 Code manages risk to pipeline integrity by adjusting design and safety factors and inspection and maintenance frequencies as the potential consequences of a failure increase. This has been done on an empirical basis without quantifying the consequences of a failure.”

A.2.6.2 Canadian Reference

Reliability-based design as a design approach methodology was likewise not found in the 2003 version of the CSA pipeline code. Annex B “Guidelines for Risk Assessment of Pipelines” contains some useful approach considerations, but is not structured in a criteria format, like Annex C, so as to allow design application.

A.2.6.3 Development History

Although risk and reliability analyses have been generally available for some time, it is only relatively recently that the concepts and considerations have been developed and accepted to a point of usefulness to the pipeline industry.

Such evaluations were first used in industry studies especially for consideration of installed pipeline conditions. The general consideration for such project-specific evaluations is often that a change from the original design conditions does not present an unacceptable risk to the pipeline. Such evaluations focus on the quantification of pipeline reliability, comparing this reliability to other portions of the same pipeline or to industry failure incidence values. Rarely will such evaluations also consider the potential consequences of failure, thus requiring a full risk analysis, although qualitative discussions of risk generally accompany a reliability analysis. Annex O of the CSA Z662-07 code, to be published in summer of 2007, should provide some clarification on this issue.

A.2.6.4 Comparison

There are active groups in both countries working to further develop reliability-based approaches. A draft CSA Z662-07 version circulated for comment contained provisions addressing reliability targets for pipeline evaluations, which would be a significant forward step.

A.2.6.5 Discussion

Although reliability and risk is currently part of any pipeline project’s standard lexicon, along with estimation tools and procedures, it is considered unlikely that a Limit State Design approach methodology such as CSA Z662 Annex C would be bypassed in favor of a direct reliability-based design, at least at this time. It is likely that at least for the near future, the chief role for reliability-based approaches will be to support the development of Limit State Design methodologies. However, industry organizations contend that RBDA may be the favored approach since a LSD (or LRFD) approach will require calibration using RBDA in any case, due to the lack of existing recognized calibration and the uniqueness of the proposed projects.

Even though the definition of the pipeline Limit States is fairly objective in concept, design for many operating loads would not want to push right to these limits since there is

always some associated uncertainty with the loads and load estimation procedures. Similarly, there is some uncertainty associated with the values of the limit states themselves (e.g., tensile strain at rupture). Thus, appropriate and acceptable factors of safety are required as in any code development. The *Load* factors are one or greater; that is, the demand on the pipeline due to the loading is increased to account for uncertainty in the loading and analysis. The *Resistance* factors on the capacity are one or less; that is, the capacity of the pipeline to resist a loading is decreased to account for uncertainty in failure predictions.

It is the selection of these applicable factors for strain as well as strain capacity that require further consideration. The first question to ask is: “What is the basis for selection?” Theory states that such factors can be selected to minimize to some acceptable level the combined risk of failure for the operational pipeline for the design life; however, this merely centralizes the problem to: “What is acceptable risk?” Thus, the problem involves not only a quantitative evaluation of the probability for the Load to exceed the limit state value, but also development of an acceptable target for this probability of exceedence. This is always a very difficult concept to rationalize since the discussion of what is an acceptable reliability target necessarily involves discussion of societal acceptance of risk from infrastructure projects. It is likely best resolved, as has been proposed in the work conducted in support of Annex “O,” by calibration of design non-exceedence frequencies against existing pipeline designs in each class location, incorporating both historical trends and targeted reductions.

Finally, and as a practical consideration, formal reliability approaches, although rapidly becoming developed and accepted, are the domain of specialty consultants. For final design and construction bid directions, field change design, and operational engineering, rule-based project criteria are unavoidable to ensure project uniformity by a large and diverse user group. Reliability-based design, at the current time, has neither broadly acceptable tools for pipeline and construction engineers, nor a broad-based understanding of requirements. Thus, for the foreseeable reliability-based approaches can be generally expected to be used to formulate and calibrate allowable stress and/or strain-based limit state design criteria and codes, rather than used as a direct project evaluation methodology for design. On the other hand, increased use of reliability-based approaches, involving specialty consultants, should be expected to be employed in operational considerations that involve judging acceptability of unique or evolving route conditions not originally anticipated by design.

A.3 Materials

Both the US and Canadian codes address pipe materials, with the aid of extensive references to industry guides (e.g., API 5LX, *API Specification for High-Test Line Pipe*). With the use of such standards, there are no significant expected differences within the codes. Rather, this topic explores the scope of both codes, as well as some new material requirements and specifications that could be expected for new gas transmission projects.

A.3.1 US Reference

49 CFR 192 Subpart B—Materials, 192.51 Scope states:

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

However, the specifics of the material requirements is contained in Appendix B, and relies almost entirely on reference to manufacturing standards, such as API 5L.

ASME B31.8 Chapter I, “Materials and Equipment” contains the material requirements, and is similar to CFR, Subpart B.

Both codes delineate minimum requirements for determining pipe properties of unknown or unlisted specification.

A.3.2 Canadian Reference

CSA Z662-03 Section 5 “Materials” is an extensive section that covers fracture toughness and low temperature service requirements. CSA Z245.1 “Steel Pipe” covers seamless pipe, electric-welded pipe (flash-welded pipe and low-frequency electric-welded pipe excluded) and submerged-arc-welded pipe primarily intended for use in oil or gas pipeline systems.

A.3.3 Background

Prior to 1949, the API Standard 5L covered steel Grades A, B, and C and other materials such as wrought iron. Grade C, the highest strength steel grade (SMYS = 45,000 pounds per square inch [psi]), was discontinued in the 1930s and Grade B (SMYS = 35,000 psi) became the highest grade mentioned. However, purchasers could, and often did, obtain line pipe materials with SMYS levels above 35,000 psi by negotiation. For example, the SMYS that could be produced by a manufacturer at the time of construction of the original Tennessee Gas system (October 31, 1943) was 50,000 psi. A special steel alloy and plate rolling procedure was required to reach this strength level. At the time, the average actual yield strength of most of the pipe produced was 47,000 psi.

In 1949, the first tentative X-grade specification, American Petroleum Institute (API) Standard 5LX, appeared. This specification provided requirements for Grade 5L X42 only (SMYS = 42,000 psi), but it stated that requirements for higher grades could be

negotiated. Over time, the strength improved with better alloying and rolling techniques. By 1954, specific requirements for cold-expanded and non-expanded pipe in Grades X42, X46, and X52 were included in API Standard 5LX.

A.3.4 Comparison

Pipeline materials generally follow the same industry standards largely established by North American groups. API assumed the secretariat in 1995 from the American National Standards Institute (ANSI) for the International Organization for Standardization (ISO) standard (ISO TC 67/SC 2, Pipeline transportation systems for “Standardization of pipeline transportation systems and equipment used in the petroleum and natural gas industries”) and works hard to harmonize ISO 3183 “Steel pipe for pipelines” with API 5LX. However, no North American pipeline project to date was found to have specified this ISO standard as the project standard.

The procedure for accepting new grades of pipe by API has been used for new, higher grades without noticeable problems. Additional and project-specific requirements for pipe do not need to be generally specified; project groups are expected to impose additional requirements for their project’s fabricator bid material specifications as required in development of their procurement specifications.

An industry challenge would be to develop the procedures and bid specifications for a pipe material for use in strain-based design, with consensus development and understanding of a number of potential suppliers so as to ensure consistency of the critical inelastic properties. Different suppliers may have different variations of these properties depending upon their exact manufacturing processes, which would not be expected to be shared.

Also, steel behavior, especially beyond the elastic range, may be modified by various project requirements after initial production (e.g., transportation could induce fatigue cracks, or coating application could cause strain aging effects), and these factors may have to be considered for contractual specifications and control or possibly even site spot-testing at later dates than would be normal.

A.3.5 Discussion

Pipeline manufacture is an international industry, with quotes for a gas transmission pipeline project mainly solicited from international vendors. Shipping distances could curtail competition and potential supply, so most pipelines can be expected to meet the same industry minimum requirements. For example, pipe mill owners in Russia are emerging to compete for international market share. One Russian mill owner notes: “TMK produces high quality products according to both Russian and international standards including API, ASTM, and EN/DIN. The quality-testing system has been certificated at all the group’s mills in compliance with the requirements of ISO 9001 and API Specification Q1 standards ([http://www.tmk-group.com/ Downloads/official/kit/0031.pdf](http://www.tmk-group.com/Downloads/official/kit/0031.pdf)). Pipe today is being made in Europe, Asia, South America as well as North America for use in US pipelines.

New and higher grades of steel are always a consideration for use in any new pipeline project. An increase of SMYS from 80ksi to 100ksi would result in a 20 percent reduction in wall thickness, assuming the wall thickness critical function is direct pressure containment through limiting hoop stress. Thus, for pipelines in which longitudinal stresses/strains are not controlling design, higher-strength steels will be more economical (assuming any premium price per pound for the higher grade remains at about present levels).

However, strain-based design and Limit State Design will require consideration of material properties beyond the traditional single consideration of SMYS. As the thickness decreases for the same diameter due to increased SMYS, the slenderness ratio also increases (i.e., the pipe is considered more “slender” as a function of an increasing D/t). As the D/t ratio increases, the compressive strain buckling resistance capacity decreases.

Similarly, the tensile strain capacity depends largely on material properties, especially strength overmatching in the weld zones. Plastic behaviors are more familiar to fracture mechanics (e.g., Charpy or crack tip opening displacement [CTOD] values), than to strength of materials. In addition, the shape and ductility characteristics of the inelastic range of the stress-strain curve affect the tensile strain (e.g., ratio of yield to ultimate strength [Y/T], a measure of ductility).

Concurrently with an increase in pipe strength, which reduces the need for pipe wall thickness, the structural resistance areal properties of the pipe (e.g., cross-sectional area, moments of inertia) decrease, which tends to escalate the estimated stress/strain from temperature and / or geo-loadings and induces longitudinal bending. This is somewhat compensated for up to yield by an increase in the strength (grade), though it is not clear that an increase in grade will result in an increase in strength once the pipe is in the plastic regime. An increase in grade may actually result in little to no increase in pipe resistance to longitudinal loadings.

For stress-based design, given the same unchanging strength parameters (i.e., Young’s modulus) to the strength limit (i.e., SMYS), a direct proportion exists for bending resistance. However, for designs that rely on strains beyond yield, a more thorough examination of the stress-strain curve – including the strain at ultimate, associated ductility and the nature of the curve itself – must be considered.

After consideration of their inelastic properties, it may be that high strength steels, such as X100 or X120, produce a negligible increase in, or even lower, allowable strains in cases of displacement-controlled longitudinal bending, when compared to low-strength steels, such as X65 or X80. This possibly could be remedied through collaboration with the pipe manufacturers and welding designers. In addition, where route conditions predict high strain demand, the use of lower grade steels with better ductility may improve performance reliability.

Thus, when longitudinal loadings may be a controlling loading consideration for a pipeline, the benefits of higher grade steels must be carefully weighed. It is possible that using a lower grade steel, which would necessitate a higher wall thickness for the same

pressure, would be more cost effective. Lower grade steel with familiar stress-strain curve properties and lower Y/T values may perform better than a higher grade steel, but with a higher Y/T. Pipe steel specifications (especially in displacement controlled, secondary, load situations) may require increased ductility (reflected largely in a low Y/T value) rather than high strength, especially if that strength comes with a corresponding high Y/T value as often seen in the higher strength steels (e.g., X100). Thus, for some loadings where strain based design is employed, it may be more practical to employ X65 rather than X80 to benefit from the steel characteristics beyond SMYS.

Nevertheless, higher grades of pipe such as X100 and X120 are being investigated by a new major project group (Shell, BP and TransCanada) and tested against Canadian regulatory acceptance, since this would have wide application at least in most of the pipeline alignment. In addition, high strength spiral welded pipe has been used in some US projects (e.g. Cheyenne Plains) and will likely be under increased consideration for material selection in the US, as Canadian US and foreign mills market this type of line pipe.

A.4 Construction

Detailed construction oversight by regulatory mandate is not generally evident in regulations. Generally, prescriptive requirements for pipeline construction would probably be seen to inhibit construction innovation and the introduction of new technology.

There are two areas where regulations require both focus and reporting in detail – welding and pressure testing.

A.4.1 Welding

A.4.1.1 US Reference

49 CFR 192, Subpart E—Welding of Steel in Pipelines

192.221 Scope.

(a) This subpart prescribes minimum requirements for welding steel materials in pipelines to historic workmanship standards.

(b) This subpart does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

The section is not lengthy, and clearly relies on referenced standards (e.g. API 1104, *Welding Pipelines and Related Facilities*) and standards incorporated by reference.

ASME B31.8, Chapter II, “Welding” is the analog to the CFR Subpart E. The scope was made the same in 1970, and generally followed ASME B31.8, relying as well on references, notably API 1104. There are some differences, such as more stringent requirements for non-destructive examination (NDE) in Class 3 and 4 (100 percent unless impracticable, but at least 90 percent) in CFR as opposed to 40 percent for Class 3 and 75 percent for Class 4.

A.4.1.2 Canadian Reference

CSA Z662-03 Section 7 “Joining” is an extensive section that covers welding.

Analogous to the CFR provisions, it does not cover welding during the manufacture of the pipe. CSA Z245.1 “Steel Pipe” covers seamless pipe, electric-welded pipe (flash-welded pipe and low-frequency electric-welded pipe excluded) and submerged-arc-welded pipe primarily intended for use in oil or gas pipeline systems.

One notable difference between the CSA codes and the NEB OPR is that the NEB OPR requires 100 percent NDE, while CSA Z662 requires that only 15 percent of the production welds made daily be nondestructively inspected. Practically, however, most new transmission pipeline is 100 percent NDE as it is federally regulated and is required by the NEB OPR.

A.4.1.3 Comparison

While 49 CFR 192 does not contain the detail of CSA with regard to welding, the ASME B31.8 code is comparable in detail. It is generally understood that the level of detail in CSA is consistent with ASME B31.8.

Welding methods and quality are the dominant issues of high-strength steel construction because of the effects on overall system reliability, as well as its cost impact to the project. New mechanized welding procedures are routinely investigated, including dual and quad tandem systems; however, the weld control must be carefully designed and matched to the strength requirements. Regarding the interaction of welding with a Limit State Design approach, it is noted that the strain capacities required may not be reached at industry workmanship levels in CFR, so additional and more stringent requirements for flaw detection are imposed. This workmanship standard may cause a higher than usual and unwarranted weld reject/repair rates; therefore, the repair procedure and documentation of alternative acceptance methodologies would be carefully considered. More generally, the use of high-strength steels, pipe, weld and HAZ toughness, mechanized welding, and UT inspection virtually necessitates performance of engineering critical assessments (ECA), as identified in Appendix K of CSA Z662, to determine an alternative defect acceptability.

A.4.1.4 Discussion

Although the codes utilize slightly different techniques to approaching this subject – CSA covers subjects in much greater detail, while CFR relies on references – the outcome is nearly the same, with no differences that appear critical. Possibly this is a reflection that labor and construction groups often cross borders to perform work in both countries, and that research is performed by common organizations (e.g., the Pipeline Research Council International [PRCI]).

CSA contains Annex J (informative), *Recommended Practice for Determining the Acceptability of Imperfections in Fusion Welds*, to outline the application of the concept of ECA to fusion welds. Annex J refers to Annex K for specific analytical details. Annex K provides a method to determine whether or not repairs are required for imperfections. Very interesting in itself, this also underscores the value of CSA annexes to provide informative, non-compulsory information and alternate safe procedures. With these annexes, it is implicit that the operator wishing to employ such information has to further study its applicability to his specific situation, and perhaps extend and/or adopt the informative annex procedure, as required. Through time, these procedures could become generally acceptable and potentially evolve into the alternative non prescriptive part of the code. In the US, the analog is similar to the alternative Nonmandatory Appendix of ASME B31.8 (e.g., *Nonmandatory Appendix R – Estimating Strain in Dents*).

Regarding the issue that strain capacities may not be reached at industry workmanship levels, there are a number of uncertainties in developing the tensile strain limit, all of which must be factored into developing an acceptable (allowable) value that satisfies such project targets as an acceptable reliability level. This became an issue of intense study on the Mackenzie Gas Project (MGP), which involved Imperial Oil Resources

Ventures Ltd, ConocoPhillips Canada North Ltd, Shell Canada Ltd, ExxonMobil Canada Properties and the Mackenzie Valley Aboriginal Pipeline Corp (Additionally, TransCanada Corp provides technical support and finance development costs for APG).

Criteria stricter than those comprising workmanship levels were discussed. Discussion included the expected increase in tensile strain resistance distribution as flaw size changes; the distribution of detectable flaw size; accuracy of detection techniques; orientation and location of flaws and relation to peak demand locations; and assembly of all variables and their corresponding distributions into a formal reliability assessment to study the relation of tensile strain resistance distribution to tensile strain demand distribution.

This effort was undertaken to calibrate the load and resistance factors required by Z662-07 Annex C “Limit States Design” (see for example the note of Table C.1 “Load Factors” and Table C.3 “Resistance Factors”). The quantitative reliability assessment estimated the corresponding route reliability levels, although, to the authors’ knowledge, acceptable target reliability levels were not established with the agreement of the NEB by the end of MGP conceptual studies. Annex O was not available before the end of MGP conceptual design studies, although even with its publication there is no assurance that the NEB would accept the indicated reliability target levels.

In the US, without even the CSA framework to guide preliminary discussion, the path to identify allowable project tensile strain values appears even more uncertain.

In summary, considering the lessons learned from MGP, a project group for arctic pipeline design would be remiss in failing to consider the effects of higher-than-workmanship level requirements in the development of strain capacities, especially for application on high demand route segments. Certainly, the expected increased cost would be compared to other avoidance and/or mitigative techniques. It may not be the optimal solution – but the consideration would be justified.

A.4.2 Hydrostatic Test Requirements

A.4.2.1 US Reference

49 CFR 192 Subpart J Test Requirements:

(c) Except as provided in paragraph (e) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.

49 CFR 192.619 Maximum allowable operating pressure: Steel or plastic pipelines states the following:

(ii) For steel pipe operated at 100 psi (689 kPa) gage or more, the minimum test pressure is divided by a factor determined in accordance with the following table:

Factors ¹ , segment			
Class location	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Constructed under 192.14
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5
Notes: 1 For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.			

ASME B31.8, Table 842.322(f) shows that the minimum pressure test prescribed is 1.4 MOP for Class 3 and 4. Also, Class 1, Division 1 requires a hydrostatic test with a minimum pressure test prescribed as 1.25 MOP – as noted earlier, this is the distinguishing characteristic between Class 1 Division 1, and Class 1 Division 2. Class 1 Division 2 factors are the same for Class 1 as shown in the CFR table, i.e., 1.1 MOP. ASME B31.8 recommends using API 1110 as an alternative to the prescriptive requirements in CFR. API 1110 discusses the expected methodology, sets out the maximum pressures and durations for a variety of threats and performance expectations.

A.4.2.2 Canadian Reference

**Table 8.1 – Test Requirements for Steel Piping Intended to Be Operated at Pressures Greater Than 700 kPa
(See Clauses 8.2.1.1.1, 8.2.3.1.1, 8.2.5.1, 8.5.1, 8.6.2.4, and 10.11.5.2.)**

Service fluid	Class location	Strength test pressure			Leak test pressure		Maximum operating pressure‡‡
		Intended minimum pressure*	Maximum pressure		Minimum pressure	Maximum pressure	
			Liquid medium	Gaseous medium			
Gas	1 or 2	125% of intended MOP	Lesser of 0.2% deviation on a P-V plot and 110%§ of the SMYS of the pipe	95%** of the SMYS of the pipe (100% in 2007 edition)	110% of the intended MOP	Lesser of the qualification pressure‡‡ and the pressure corresponding to 100% of the SMYS of the pipe	Lesser of qualification pressure‡‡ divided by 1.25 and design pressure of the pipe
Gas	3 or 4	140% of intended MOP					Lesser of qualification pressure‡‡ divided by 1.40 and design pressure of the pipe
Clause references		8.2.3.1.1	8.2.4.2	8.2.4.3	8.2.3.1.1	8.2.5.1	8.5.1

Notes:
 *See also the note to Clause 8.2.3.
 †See also Clause 8.2.4.1.
 ‡For gaseous-medium testing, see also Clause 8.5.1.2.
 §66% for continuous welded pipe.
 **57% for continuous welded pipe.
 ††Except as allowed by Clause 8.5.1.5, the qualification pressure shall be the lowest pressure achieved, over the duration of the strength test, at the high point of elevation in the test section, as measured directly or as derived by adjusting the corresponding pressure measured at another point in the test section to account for the elevation difference between the high point of elevation and the pressure-measurement point.
 1) For steel piping intended to be operated at pressures of 700 kPa or less, see Clauses 8.2.1.2, 8.2.3.2, and 8.5.2.
 2) For steel piping in compressor stations, gas pressure-regulating stations, and gas-measuring stations, the intended minimum strength test pressure shall be 140% of the intended MOP; the MOP shall be in accordance with the requirements of Clause 8.5.1.3.

CSA Z662-03 addresses the duration of tests in the following sections:

Z662: 8.2.6.1

Except as allowed by Clause 8.2.6.2, strength tests shall be maintained for continuous periods of not less than 4 h.

Z662:8.2.6.3

Except as allowed by Clause 8.2.6.4, leak tests shall be maintained for continuous periods of not less than 4 h for liquid-medium testing or 24 h for gaseous-medium testing.

Notes:

1) *For liquid-medium testing, leak test durations in excess of 4 h may be required where thermal variations or other factors affect the validity of the tests.*

2) *For gaseous-medium testing of large-volume test sections, leak test durations in excess of 24 h may be required in order to compensate for the compressibility of the pressure-test medium, as the pressure drop resulting from a small leak in a large test section may not be sufficient within a 24 h period to clearly indicate the presence of the leak.*

A.4.2.3 Background

A pre-service integrity validation by pressurizing the pipeline to a level above the MOP was a method of ensuring the reliability of pressure vessels. This safety practice was always an important part of the ASME Boiler and Pressure Vessel Code. However, prior to the 1955 B31.1.8 Code, the post-construction/pre-operation test requirements for gas transmission and distribution piping stated that the line must be capable of withstanding a gas test pressure of 10 to 50 psi higher than the maximum pressure at which the line is to be operated.

The practice of hydrostatically testing pipelines to yield was initiated by Texas Eastern Transmission Corporation (Texas Eastern). Texas Eastern had purchased two pipelines from the federal government, a 20-inch products line and a 24-inch crude line (also known as the Little- and Big-Inch pipelines), and converted them to natural gas. In the late 1940s, a number of pipeline incidents occurred on these lines, such that Texas Eastern's insurance carrier threatened to cancel coverage unless a program was developed to prevent further pipeline system failures. To verify integrity, Texas Eastern elected to test the 20-inch pipeline.

High-pressure hydrostatic testing was further examined by Battelle over the time period from 1953 through 1968 (Duffy, 1968). This program examined test results from hundreds of miles of large diameter pipe using water as the test medium and at test pressures that would produce a transverse stress in the pipe wall equal to the SMYS. The benefits of hydrostatic testing documented by the program included:

- The ability to establish the real minimum strength of the pipeline as opposed to the mill tensile tests which are based on testing only about 1 percent of the pipe (to make this determination, the test must include a pressure/volume plot);
- The increased safety inherent in basing operation on an established minimum strength;
- The ability to remove significant defects originating in the plate mill, pipe mill, or during fabrication and installation; and
- The excellent service performance of lines tested to actual yield.

Participants in the program recommended that the allowable operating pressure should be set based on a percentage of the hydrostatic test pressure. They specifically recommended that the allowable operating pressure be set at 80 percent of the minimum hydrostatic proof test pressure when the minimum test pressure is 90 percent of SMYS or higher.

A.4.2.4 Comparison

In Class 1 locations, CSA Z662-03 requires a minimum strength test pressure of 125 percent of intended MOP, compared to 110 percent of intended MAOP required by 49 CFR 192. There is also a difference of 10 percent (140 percent for CSA compared to 150 percent of intended MAOP for 49 CFR 192) for Class 3 and 4.

CSA takes care to divide the pressure test into two parts – the strength test and the leak test, whereas CFR does not make this distinction. The four-hour hold time for each test part together equals the total test time of 8 hours specified by CFR.

A.4.2.5 Discussion

The most critical difference in test pressure requirements for the design of test segments of major gas transmission lines is the difference for Class 1. For CSA, this requires the hoop stress to be at SMYS ($1.25 \times 0.8 \text{ SMYS} = 1.0 \text{ SMYS}$). Further, the test pressure can be no greater than to cause a stress of 110 percent of SMYS – and even going to this value may require consideration of the strength response of the pipe beyond SMYS. This has the effect of limiting the test segment lengths, especially in hilly terrain. CFR allows a lower test pressure, with the same practical considerations to limits on a maximum test pressure, though not explicitly stated. The difference can be viewed in some ways as a “price” for the difference in design factors in this class – i.e., the higher test pressure allows the additional confidence for an increase of the design factor in Class 1.

Separating the test into two parts – strength test and leak test – is highly beneficial because it focuses on pressure test objectives. Generally, if a significant defect is introduced during construction, the pipe would be expected to fail when, or shortly after, the maximum test pressure is reached. Typically, time-dependent processes, at least for the time durations of pressure testing, do not play a significant role in determining steel pipeline strength. API 1110 restricts the interval at the highest pressure to minimize damage to the pipe and sets out the leak test interval to ensure integrity.

Hydrostatic testing is the most common means of pressure testing. Note that various reports question whether hydrostatic testing, or indeed any type of pressure testing of modern pipe, is as much of a necessity today as when the test originated (Kirkwood, 2000). Also, it is noted that hydrostatic test special permits have been granted in offshore situations in the Gulf of Mexico, and the Minerals Management Service (MMS) and PHMSA have participated in a Joint Industry Project (JIP) for Hydrotest Alternatives (<http://www.mms.gov/tarprojects/525.htm>). No request for special permit, much less for special permit agreement, has been undertaken for a US onshore pipeline, although the NEB has granted a special permit to a company for a TransCanada pipeline and the Alberta Provincial regulator has granted two permits to that same company for separate projects.

In the web site announcement of its Alternative Integrity Validation (AIV) program (http://www.transcanada.com/Customer_Express/Update/april_2005/article_5.html), TransCanada notes that it collaborated with several groups, including the provincial regulatory group (Alberta Energy and Utilities Board (EUB) (now ERCB) “...to develop this sound approach to achieving safe and reliable pipeline operation without performing

a post-construction hydrostatic test on some new pipelines...The AIV process was approved in February 2005 and TransCanada was granted experimental approval to implement the process on the second phase of the Peerless Lake pipeline project in northern Alberta. This means we've been given approval for a one-time application and have recently shared our findings with the EUB." In October 2006, a similar type of approval was given to TransCanada for a 20-km NPS 42 looped section of line in Ontario. Note for these initial two projects, at least one portion of the pipeline construction underwent hydrotesting. In addition, the in-service operating stress for the exempted NEB-regulated pipeline does not exceed 64 percent of SMYS.

TransCanada has recently (April 2008) completed another AIV project under EUB/ERCB jurisdiction. This project included 114 km NPS 36 pipeline designed to 80 percent SMYS and the requirement for a hydrotest for the entire 114 km pipeline was waived.

The replacement of the code-specified pressure test requirements by such a program would necessarily emphasize quality assurance and quality control (QA/QC) so as to obviate the need for a pressure test after installation but before start-up. Possible considerations would include increased hold time for mill tests, formal third-party oversight and review, pipe examination after transport and lowering in, increased weld NDE, detailed startup procedures to "test" with the product with increased leak detection, and startup ILI baseline. NEB has stated more work has to be done to make this a generally accepted procedure.

A.4.3 Pneumatic Testing

Pneumatic testing of pipelines can be accomplished using a number of gaseous mediums. However, any pneumatic test must be approached cautiously due to the amount of energy that is stored in the compressed gas. The larger the diameter and/or length of the line being tested, the greater the amount of energy stored in the system.

Because of its straightforward approach and interpretation, hydrostatic testing is generally accepted to be a cost-effective technique that ensures the integrity of a pipeline at the time of testing. Pneumatic testing sometimes requires severe test restrictions, as well as potential restrictions on MAOP. Pipeline operating companies and construction contractors are generally familiar with hydrostatic testing techniques. Indeed, with the current industry trend for a contractor to provide a "warranty" for the pipeline, often for one year of service, contractors may resist a change from the "industry standard" of hydrostatic testing.

A.4.3.1 US Reference

49 CFR 192 Subpart J test requirements states in 192.503 (c):

Except as provided in §192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class Location	Natural gas (%)	Air or inert gas (%)
1	80	80
2	30	75
3	30	50
4	30	40

Generally, these limits are consistent with the provisions of ASME B31.8, 841.3 “testing after Construction.” The notable exception is a pipeline for Class 1, Division 1 which specifically requires a hydrostatic test to 125 percent of the hoop stress level.

A.4.3.2 Canadian Reference

Pneumatic testing requirements are contained in the table presented in Section A.4.2.2, although the maximum pressure will move to 100 percent of SMYS for a gaseous medium in the 2007 version of Z662.

A.4.3.3 Background

For early testing practices, natural gas was the common test medium. Proof testing with water is safer, since a rupture during a gas test can be very dangerous. Although proof testing with water was used in other industries, its use was very limited in the pipeline industry. The volume of water required to pressure test pipelines and the transportation of the water made hydrostatic testing prohibitively expensive and impractical, particularly in the climatically dry areas of the US where many of the first long-distance gas pipelines were constructed. Also, obtaining and treating before disposing of the water is expensive and time-consuming. In addition, operating problems may result if the water is not removed from the pipeline.

The use of natural gas as the test medium limited the test pressure that could be achieved because operators were reluctant to raise the pressure much higher than the expected operating pressure. Representatives of one gas company recalled thinking that they had done well if they could reach a pressure of five or ten psi over the operating pressure. This was a potentially dangerous practice for the operators. When a pipe failure was initiated during gas testing, the potential energy and slow decompression of the natural gas would drive long, brittle-type pipe fractures.

A.4.3.4 Comparison

Within the US code, the first comparison is made between the results of using a hydrostatic test to those of a pneumatic test. The minimum test pressure as a function of SMYS is determined by multiplying the design factor by the factor given in 49 CFR 192.619. The results of this calculation are presented in Table A.4-1.

Table A.4-1 – Minimum Test Pressure for MAOP at Design Factor			
Class Location	Test Pressure as Percentage of SMYS		
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under §192.14
1	79	79	90
2	75	75	75
3	70	75	75
4	56	60	60

However, when a pneumatic test is performed, limits on the maximum hoop stress allowed are imposed as given in 49 CFR 192.503 and given in Section A.4.3.1 above. A comparison shows that the use of a non-liquid test medium can result in a MAOP that may be significantly lower than what can be obtained using a liquid medium.

Until the proposed change in 2007, the Canadian code limited the maximum test pressure when using a gaseous medium to 95 percent of SMYS. Since the MOP is limited to the test pressure divided by 1.25, this has the effect of limiting MOP in Class 1 to an effective 0.76 design factor (0.95/1.25), as opposed to the nominal 0.8 design factor.

Generally, both codes have additional provisions for pneumatic testing, necessitating additional concerns and cautions than for hydrostatic testing.

A.4.3.5 Discussion

Pneumatic testing is often a consideration for fulfilling pressure testing requirements, especially at isolated construction sites (e.g., Horizontal Directional Drill [HDD] crossings, aerial pipeline crossings, etc.) where it would be difficult to coordinate hydrostatic testing with the rest of the pipeline in the construction spread. However, although pneumatic testing appears initially inviting, there are significant concerns, as well as practical cost considerations, that pose obstacles to its use.

Of prime importance, any pipe failure during such a test would likely result in significant damage to the pipeline and possible injury to personnel. In the event of a suspected leak, it may be difficult to detect the leak location, especially if air, nitrogen or a combination is used.

In terms of a cost comparison, the compressor system required to fill and test a pipeline segment using gas/air media would be more complicated than the equivalent system for conducting a hydrostatic test. The test pressure is achieved in a series of pressure steps. The time to pressurize may be very long compared to filling with a liquid medium. It may also be difficult to ensure stability of the test pressure and to determine whether any subsequent pressure loss is attributable to temperature change rather than leaking.

In general, pneumatic testing is a minor consideration for major transmission pipelines. Operating pressures can be expected to keep increasing for new design, further complicating pneumatic test requirements. On the other hand, there probably will always be site-specific considerations where pneumatic testing can be effective. Pneumatic testing is typically the choice when an alternative is proposed as a replacement for a hydrotest.

There appears no focused study or industry interest for a reconsideration of code regulations for pneumatic testing, and no compelling argument can be currently made for such a focus.

A.5 Operations and Maintenance

A.5.1 General

A review of how operations and maintenance considerations are addressed is a logical extension to the design and construction focus of this report insofar as regulatory permitting of new pipeline facilities calls for the filing of operational and integrity management (IM) planning documents.

The applicable codes and standards are:

- US: CFR 49 Part 192 Subparts L – Operations (192.601 to 192.629), M – Maintenance (192.701 to 192.755), N – Qualifications of Pipeline Personnel (192.801 to 192.809) and O – Gas Transmission Pipeline Integrity Management. There are numerous direct references in Subpart O to ASME B31.8S.
- Canada: CSA Z662 Section 10 – Operating, Maintenance and Upgrading with reference to 2 Annexes

Generally, similar subtopics are included in both the US and Canadian codes and standards insofar as addressing operations and maintenance. While IM currently might be a subtopic of somewhat higher profile in the codes and standards, other areas included – some interrelated with IM – are as follows:

- Procedures: emergencies, investigations and pipeline identification
- Records: the pipeline system and history of leaks and breaks
- Safety: training programs, supervisor responsibilities, special hazard considerations such as sour, carbon dioxide and high-vapor-pressure product
- ROW Inspection: patrolling, vegetation control exposed facilities and crossings
- Operation and Maintenance of Facilities and Equipment: compressor stations, pressure vessels, storage, valves, and the inter-relation between pressure-control, pressure-limiting and pressure relieving systems
- Change of Class Locations
- Evaluation of Imperfections and Repair of Defects: weld imperfections in both field circumferential welds and mill seam welds; temporary and permanent repair methods
- Maintenance Welding and Hot Tapping
- Odorization
- Deactivation, Reactivation and Abandonment

A.5.2 Integrity Management

A.5.2.1 Development in the US

In June 1999, a pipeline ruptured in Bellingham, Washington, spilling more than five thousand barrels of gasoline into two creeks in a popular city park. The release and its subsequent ignition resulted in the deaths of two ten-year-old boys and a teenager, and environmental damage along 1.5 miles of a salmon stream. In 2000, a natural gas transmission line, weakened by internal corrosion, ruptured killing twelve people near Carlsbad, New Mexico. PHMSA carefully studied the causes of these accidents. What was learned confirmed lessons from the risk management demonstration program: it is essential that operators integrate information from a variety of sources (such as ILIs, right-of-way activity records, corrosion control monitoring, and construction and repair data) to obtain an accurate picture of the integrity of their pipeline systems.

The implications of these lessons were that a new way of managing safety and a new approach to regulating pipeline operators was needed. The first major step in implementing this approach was the issuance in December 2000 of the first Integrity Management (IM) Rule applicable to large hazardous liquid operators, followed in January 2002 by a comparable rule for smaller liquid operators. The IM rule for natural gas operators was issued in December of 2003. Through these rules, PHMSA is attempting to answer the question of how to balance prescriptive and management-based regulations, and how management-based regulations can be added to the regulatory mix to produce efficient safety improvements. As in the earlier rule for IM of hazardous liquid pipelines, PHMSA had four fundamental objectives:

- To increase the level of integrity assessments (i.e., in-line inspection, pressure testing or direct assessment) for pipelines that can affect high consequence areas;
- To improve operator integrity management systems;
- To improve government oversight of operator integrity management programs; and
- To improve public assurance in pipeline safety.

The IM rules for gas transmission pipelines initially require operators to identify high consequence areas (HCAs): geographic areas that contain a high density of residences, areas in which people congregate, and facilities housing people with impaired mobility. To identify these areas, the operator first must evaluate the potential impact radius associated with its pipeline, using an approach developed by C-FER Technologies, and then it must identify HCAs by looking for threshold residence densities and identified sites within the areas circumscribed by a circle of that radius.

The gas IM rule then requires operators to establish and implement plans to physically assess the condition of any pipeline segment within an HCA and make any necessary repairs. The initial assessment is called a baseline assessment and must be completed within ten years. Assessments can be performed through ILI, pressure testing, direct assessment (DA) or other equivalent means, depending on the threats applicable to a covered segment. The rule also requires each operator to have a documented IM program that describes the processes by which the company collects and integrates integrity-

related information, assesses risks to its pipeline, identifies applicable threats, and determines the necessary preventive and mitigative activities to maintain pipeline system integrity.

A series of technical exchange meetings provided the technical basis for IM. However, the decision was made that a national consensus standard would be the best means to provide the structure of an effective program and to organize the details of technical approaches best able to ensure gas pipeline integrity. Thus, a team was organized to develop such a standard, to be called ASME B31.8S.

While this standard was effective in structuring integrity management programs (IMPs), several additional issues were recognized as critical to consistent application of IM by operators. For example, while ILI had been used to identify pipeline defects of various types and sizes for more than a decade, standardized practices to apply ILI and to evaluate the results were lacking. These gaps led to the initiation of three national consensus standards:

- In-Line Inspection (ILI) of Pipelines (NACE RP 0102)
- ILI System Qualification (API 1163)
- ILI Personnel Qualification (ASNT ILI PQ)

Another example is the development, demonstration and validation of DA processes. Because of changes in diameter, sharp bends and restrictions from certain valves, ILI is not a suitable inspection method for a significant fraction of gas transmission pipelines. Many other pipelines are closely coupled with distribution systems and cannot be pressure tested without disrupting gas supply. These physical realities made it necessary to explore alternative techniques for assessing the integrity of these pipelines. Thus, the concept of DA was born. While many of the techniques being considered for DA had been in use for many years, their inherent limitations necessitated that they be integrated into a more thorough process. Development of the DA processes (many processes are needed to address the various threats to pipeline integrity), demonstration of their effectiveness, and validation of their performance required significant effort.

The results of these efforts are being codified in a series of national consensus standards, including:

- External Corrosion Direct Assessment (NACE RP 0502)
- Internal Corrosion Direct Assessment – including development of national consensus standards for dry gas (by NACE SP0207) and wet gas (by NACE TG 305)
- Confirmatory Direct Assessment (being written by NACE TG377 and under consideration for ASME B31.8S)
- Stress Corrosion Cracking Direct Assessment (ANSI/NACE RP 0204)
- Third-Party Damage Direct Assessment (potential future standard development) effort, and now included in ASME B31.8-2007)

Assessments can be performed through ILI, pressure testing, DA or other equivalent means, depending on the threats applicable to a covered segment. These regulations continue to follow the prescriptive path, allowing alternatives through petition. The rule also requires each operator to have a documented IM program that describes the processes by which the company collects and integrates integrity-related information, assesses risks to its pipeline, identifies applicable threats, and determines the necessary preventive and mitigative activities to maintain pipeline system integrity. (Barrett, 2004)

A.5.2.2 Development in Canada

The NEB has developed and pursued a new regulatory approach termed “Goal-Oriented Regulation” (GOR), initially implementing this approach through the Onshore Pipeline Regulations in 1999 (OPR-99). This represents a move from a purely prescriptive regulation towards a more performance-based system. Under GOR, regulated companies are given more flexibility to achieve regulatory compliance goals aimed at improving pipeline safety and environmental protection.

In 2004, the NEB, through participatory workshops, identified prevention as the principal mechanism for achieving the common goal of reducing risks. GOR has been a positive initiative in meeting the goal of advancing pipeline safety, the protection of property and environmental protection. The GOR approach provides industry with the flexibility to apply its knowledge and experience to address specific operating conditions, and provides the NEB with reasonable assurance of compliance.

The GOR approach is a valid one, and its introduction through OPR-99 has been successful. There is room for improvement as there is not yet a shared understanding among, and sometimes within, the NEB, regulated companies and other stakeholders about the concept and reality of GOR. Although there is a need for consistent minimum standards (through prescriptive regulations), GOR provides a mechanism to encourage innovation and performance beyond the minimum. (Matrix, 2004)

The 2007 release of Z662 contains an informative Annex “N” outlining the requirements of an Integrity Management program. In addition, Annex A sets out requirements for a Safety and Loss Management program. Both annexes are intended to initiate a life cycle management system approach to pipeline design and operation.

A.5.2.3 Comparison of Regulations

The similarities and differences in IM code issues for a U.S-Canadian pipeline are the most interesting to review in some detail. On the whole, there is certainly a high degree of cross-border alignment in what would be expected from a pipeline operator’s IM practices – particularly for a new pipeline.

The overall IM business processes are aligned as described in the following:

- US: ASME B31.8 and B31.8S - Managing System Integrity of Gas Pipelines with
- US: 49CFR190 to 199 regulations
- Canada: CSA Z662 Annexes B - Guidelines for Risk Assessment of Pipelines, and N – Guidelines for Pipeline Integrity Management Programs. It should be

noted while these Annexes were introduced by the CSA as “informative” and “non mandatory”, they have been widely and promptly adopted as “mandatory” by several Provincial regulators. Additionally, the proponents of the NEB-regulated Mackenzie Gas Project committed to adopt Annexes B and N.

- Canada: OPR 99, Section 40 and Guidance Notes

The US and the Canadian regulations, codes and standards provide an operator with considerable latitude in the methodology to apply in undertaking and updating risk assessments, and in developing IM programs.

There are two areas of stark and potentially substantive differences pertaining to IM, as viewed from the Canadian regulations, codes and standards vantage point:

- The principle of a prescriptive re-inspection period
- The singular specificity in the calculation to establish HCA screening boundaries, although again the reality of a major arctic cross-border pipeline would likely accommodate this approach.

An apparently less important issue, but one whose analysis may well require revisiting a section of ASME B31.8S, is the Integrity Threat Classification structure. Arguably, earth movements are currently classified as time independent, (clause 2.2, page 4) since earth movement in temperate climates typically involves slope instability and faulting. However, earth movement threats, such as frost heave and thaw settlement, which are of central concern for the integrity of arctic pipelines, develop slowly over time. Data on the magnitude of earth movement can be gathered through the use of geopositioning pigs and analyzed to determine the degree of integrity threat to the pipeline. In addition, slope creep, possibly leading to geologic instability, is a right-of-way threat and a concern for arctic pipelines. Active operational slope monitoring right-of-way programs established for the major arctic/subarctic lines – including both TAPS and Norman Wells – incorporate condition reporting to regulatory oversight agencies at agreed-upon intervals. The need to revisit and possibly redress this aspect of ASME B31.8S would likely increase in priority in planning for a major arctic pipeline. At the very least, a continued discussion of these slowly developing, time-dependent threats would benefit both the industry and regulatory groups.

A.6 Conclusion

US and Canadian regulations generally can be considered as compatible regarding material and equipment, relying largely on industry standards to guide regulatory procedures.

Strain-based design would have to be considered by development groups in both or either country with a suggestion to merge requirements.

The two national codes are also closely related in most design and construction areas, although there are important differences. These have been largely documented and some special permits in particular instances issued, often based largely on industry discussions. Generally the focus has been on:

- Increasing the design factor in Class 1 locations in the US to the Canadian value of 0.8
- Allowing additional flexibility in valve spacing
- Normalizing requirements for pressure testing, especially hydrostatic testing
- Acceptance of spiral and high-strength pipe
- AIV as an acceptable alternative to pressure and/or strength testing

There are also differences in cover requirements, although this does not appear to be a critical factor.

There are developing concepts of strain-based design and reliability approaches emerging in different areas of both codes, although no consensus standard approach for pipeline design or operations has been accepted. In this regard, a prescriptive approach would probably be counterproductive and performance based approaches using an application methodology might be a better target.

In recent years, a prescriptive philosophy has been adopted in US regulations for pipeline IM which is in contrast to some parallel Canadian regulations. However, it is likely that the “prescribed” US regulations will be in line with what would be implemented by most leading operators in the maintenance of a major new pipeline.

A.7 References

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Appendix B

Hazardous Liquid Transmission Pipelines

B.1 Overview of Liquid Transmission Pipeline Safety Regulations

Before focusing on the consensus standards for hazardous liquid pipelines that have been incorporated in the federal pipeline safety regulations in the US and Canada, an overview of the regulations governing hazardous liquid pipelines in the US and Canada is presented.

B.1.1 United States Regulations

The development history for hazardous liquid pipeline safety regulations is similar to that for natural gas pipelines. The Hazardous Liquid Pipeline Safety Act of 1979 as amended (HLPSA) authorizes the regulation of pipeline transport of hazardous liquids (crude oil, petroleum products, anhydrous ammonia, and carbon dioxide.) The Act has been recodified as 49 U.S.C. Chapter 601. Authority for enforcement rests with the Pipeline and Hazardous Materials Safety Administration (PHMSA). Specific federal regulations concerning the safety of hazardous liquid pipelines are found in 49 Code of Federal Regulations (CFR) Part 195, *Transportation of hazardous liquids by pipeline: minimum Federal safety standards*. The American Society of Mechanical Engineers (ASME) Code for Pressure Piping ASME B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids* (ASME B31.4) is the current industry standard for design and operation of hazardous liquid pipelines and is incorporated by reference in 49 CFR 195. The current edition of the standard is ASME B31.4-2006, approved by the American National Standards Institute (ANSI) on January 25, 2006. The current version referenced in CFR, Part 195.3 is ASME B31.4-2002 (October 2002).

B.1.2 Canadian Regulations

Canadian regulations governing hazardous liquid pipelines, like those for natural gas pipelines, are contained in [*Onshore Pipeline Regulations, 1999*](#) (OPR-99). Canadian Standards Association (CSA) Standard Z662-XX: *Oil and Gas Pipeline Systems* likewise, is the current standard incorporated in National Energy Board (NEB) and provincial regulations governing hazardous liquid pipelines. XX indicates the year of publication, 2003 in the case of this review, 2007 as it pertains today.

B.1.3 Code Issues for a United States – Canada Pipeline: General

The issue of consistent standards governing design, construction, operations, maintenance and abandonment of both new construction and existing hazardous liquid pipelines crossing the US – Canadian border is driven both by pipeline operators' desire for regulatory consistency and the goal that design and construction differences do not impede timely approval of future projects.

Proponents of a new pipeline between the US and Canada may request that a number of issues related to existing regulations be reviewed and resolved. Because of the lengthy process required for formal code revision, it is unlikely that code revisions would be

requested. Rather, the request may be for special permits of project application provisions, based on pipeline or route-specific details and corresponding justification.

Recently, TransCanada PipeLines Limited (TransCanada) successfully obtained a special permit from the 0.72 design factor in Class 1 for its Keystone Oil Pipeline, a proposed 2,969-kilometer ([km]; 1,845-mile) pipeline with an initial nominal capacity to transport approximately 435,000 barrels per day of crude oil from Hardisty, Alberta, to US Midwest markets at Wood River and Patoka, Illinois. “In its analysis of TransCanada's application, PHMSA found that operating the pipelines at 80 percent specified minimum yield strength (SMYS) will provide a level of safety equal to or greater than that which would be provided if the pipelines were operated under existing regulations.” (INFOCUS, 2007) By this, it is understood that additional design and/or operational considerations can contribute to overall performance and safety.



The special permit process was accomplished over a 10-month period and involved technical meetings with PHMSA, as well as a public comment period. The special permit represented the first request by an operator to design and operate a liquid pipeline in the US at a higher operating stress level than the existing regulations.

The special permit is projected to result in a cost savings of approximately \$50 million for the project through the use of high-strength pipe with a decreased wall thickness, which will reduce the total weight of material required, while still enabling the safe transport of crude oil.

The permit does not cover certain portions of the pipeline where the use of thicker pipe for construction reasons or damage prevention is required (e.g., high-population areas, major river crossings, and highway, railroad and road crossings).

Comparison of US and Canadian Transmission Pipeline Consensus Standards

The remainder of this Appendix discusses specific differences in the ASME B31.4 and CSA Z662-03 standards as they relate to transborder hazardous liquid pipelines.

B.2 Design

Critical differences in the pipeline codes can contribute to significant variations in the final design of a new pipeline project. Examples of code-related variations that can impact final pipeline design are identified below.

- Pipeline Design Factors
- Valve Spacing
- Pipeline Ditch Ground Cover Depth
- Stress- versus Strain-Based Design Approach
- Reliability-Based Design Approach

Class location designations, applicable for some aspects of Canadian liquid pipelines but not US liquid pipelines, can also determine particular elements of pipeline design, including valve spacing.

The impacts of code variations are explored further in this section, along with their potential impacts for a new project.

The codes are often based on historical standard practice, as opposed to the application of technical methodology. A brief review of code development history is included in this discussion. In general, the historically established standard practices have served the industry well. Recommended technical improvements are often evaluated against these historically proven, but rigidly prescriptive, practices.

B.2.1 Class Locations

B.2.1.1 US Reference

There are no class location distinctions to be made for hazardous liquid pipelines in either ASME B31.4 or 49 CFR 195. This is a major difference between the hazardous liquid pipeline requirements and those for natural gas pipelines.

B.2.1.2 Canadian Reference

CSA Z662-03 4.3.2.2 Class Location Designations does not distinguish between gas and liquid pipelines. Nevertheless, for low-vapor-pressure (LVP) pipelines, the class distinctions do not materially influence design since the class distinctions do not lead to different design factors as they do for gas pipelines. The only distinction made is for Class 1 high-vapor-pressure (HVP) pipelines.

B.2.1.3 Development History

No historical reasons for the divergence of the hazardous liquid and gas pipeline requirements for the US and Canada are readily available.

B.2.1.4 Comparison

There are very few location restrictions or differentiations cited in ASME B31.4. The location of the right-of-way is noted in Paragraph 434.3.1 in a general manner:

Right-of-way should be selected so as to minimize the possibility of hazard from future industrial or urban development or encroachment on the right-of-way.

This general approach is repeated in 49 CFR 195, for the most part. In Paragraph 195.210, pipelines located within 50 feet of any private dwelling, or any industrial building or place of public assembly are specified to require an additional 12 inches of cover over the nominal cover depths specified in the table of Paragraph 195.248. So, for normal excavation in “industrial, commercial and residential areas,” the specified cover would be increased from 36 inches to 48 inches. Table 434.6(a) of ASME B31.4 specifies 48 inches of cover for “industrial, commercial and residential areas,” with 36 inches specified for the category of “All other areas,” i.e., areas not covered by this table. Although CFR is specific in its requirements, there is no difference in the approaches.

B.2.1.5 Discussion

While US gas pipeline design focuses on class distinctions and regulation levels dependent on those distinctions, liquid pipeline design regulations make no mention of this. Canadian regulations do not exempt any pipeline from the discussion involving Class locations, but these do not lead to noteworthy distinctions for LVP pipelines.

B.2.2 Design Factors

Pipe wall thickness for virtually every hazardous liquids transmission pipeline project is initially determined from the general formula:

$$P = F \times (2 \times SMYS \times t / D)$$

where:

<i>SMYS</i>	=	Specified Minimum Yield Strength of the pipe
<i>P</i>	=	Design Pressure
<i>D</i>	=	Pipe Outside Diameter
<i>t</i>	=	Pipe Wall Thickness
<i>F</i>	=	Modification Factor

If the Modification Factor is set equal to one, the formula is seen to be the classical Barlow’s formula, derived from statics, which relates the pipe stress in the circumferential direction (hoop stress) to the internal pressure. With a Modification Factor of less than one, the formula essentially limits the pipe hoop stress to a value less than the minimum tested material strength, thus supplying a margin of safety against yield and, ultimately, pipe rupture due to overpressure.

There are further formulae in the codes that also limit the bending stress and/or the combined stress effects in the hoop and circumferential directions. However, pipe is typically designed so that its wall thickness meets – but does not exceed – the requirements for the restraint of internal pressure (as an exception, in cold climates, the limiting wall thickness may be designed to compensate for axial stresses caused by the differential between the installation temperature and the operating condition of the pipeline). Mitigation designs also conform to this design standard. Therefore, for a given

set of system parameters, a project’s pipe wall thickness will linearly increase as a function of the Modification Factor. Since to a large degree the cost of a pipeline project is determined by the pipe wall thickness, close attention is required to ensure that the Modification Factor balances safety and economics.

B.2.2.1 US Reference

The design factor, analogous to the class location factor specified for natural gas pipelines, is generally 0.72 for hazardous liquid pipelines, as per Section 402.3.1. A value of 75 percent of this factor, or 0.54, is used for pipe that is cold-expanded to meet SMYS and then heated to 600° F or higher while 0.6 is used for pipe on an offshore platform (Table A402.3.5(a)).

This approach is the same as specified in 49 CFR 195.106 “Internal Design Pressure.” Unlike the natural gas pipeline design factor (that could reach 0.8 as per ASME B31.8, but which is limited to 0.72 by 49 CFR), there is no contradiction in this most important design factor.

B.2.2.2 Canadian Reference

The Design Factor (F) is defined in Z662, 4.3.3.2: “The design factor to be used in the design formula in Clause 4.3.3.1.1 shall be 0.8.”

To be compared to the US Codes, this Design Factor must be first combined with the Location Factor given in Table 4.2, which is reproduced here for convenience.

Table 4.2 – Location Factor for Steel Pipe (See Clauses 4.3.3.3 and 15.4.1.3)				
Location factor (L)				
Application	Class 1 location	Class 2 location	Class 3 location	Class 4 location
HVP and CO2				
General and cased crossings	1.00	0.80	0.80	0.80
Roads*	0.80	0.80	0.80	0.80
Railways	0.625	0.625	0.625	0.625
Stations and Terminals	0.80	0.80	0.80	0.80
Other	0.80	0.80	0.80	0.80
LVP				
All except uncased railway crossings	1.00	1.00	1.00	1.00
Uncased railway crossings	0.625	0.625	0.625	0.625
Notes:				
1) Roads: Pipe, in parallel alignment or in uncased crossings, under the traveled surface of the road or within 7 m of the edge of the traveled surface of the road, measured at right angles to the centerline of the traveled surface.				
2) Railways: Pipe, in parallel alignment or in uncased crossings, under the railway tracks or within 7 m of the centerline of the outside track, measured at right angles to the centerline of the track.				
3) Stations: Pipe in, or associated with, compressor stations, pump stations, regulating stations, or measuring stations, including the pipe that connects such stations to their isolating valves.				
4) Other: Pipe that is				
a) supported by a vehicular, pedestrian, railway, or pipeline bridge;				
b) between any two components in a fabricated assembly; or				
c) in a fabricated assembly, within five pipe diameters of the first or last component, other than a transition piece or an elbow used in place of a pipe bend that is not associated with the fabricated assembly.				

B.2.2.3 Development History

Pipe for a particular line is generally purchased according to a SMYS. Operating pressure is then set at a stress level lower than the SMYS, to establish a safety factor. A minimum design factor of 72 percent of SMYS was derived from the first all-welded pipeline, installed by Natural Gas Pipeline Company of America in the 1930s. Because the use of an all-electric girth-welded line was new, no precedent existed for operating pressure. It was determined that the pipe could be used safely at a stress level of 80 percent of the manufacturer's mill test pressure (typically 90 percent of SMYS), where 80 percent of the 90-percent-of-SMYS figure results in a maximum allowable operating pressure (MAOP) of 72 percent of SMYS. A 72 percent stress level first appeared in the 1935 American Tentative Standard Code for Pressure Piping. The 1935 code committee agreed that mill test pressure would serve as the most accurate and reliable determiner of MAOP. This method of determining MAOP was proven in the field to be safe. Post testing was not an industry practice at the time the 72-percent-of-SMYS criterion was selected.

B.2.2.4 Comparison

The class location differences evident for gas pipelines are not seen for liquid pipelines. For the majority of transmission pipelines, the main difference would be between that of a design factor of 0.72 for the US portion of the pipeline, and 0.8 for the Canadian portion. This could be seen to be analogous to the differences for a gas pipeline in Class 1 locations

B.2.2.5 Discussion

The most noteworthy comparison for a liquid pipeline is that the design factor difference necessitates at least a 10 percent increase in pipe wall thickness, with a concomitant increase in freight costs, handling, and welding.

Numerous studies of pipeline design factors have been performed, but they have generally focused on gas pipelines. The investigations recognize that the original factors used in the US codes were determined based on the industry practice of a number of decades ago. Since that time, there have been advances in nearly every area of pipe fabrication and construction, including pipe materials, material uniformity, welding, inspection, and monitoring.

On the other hand, the current US design factors have generally served the industry well, especially considering the wide variation in service characteristics and environments, and the many pipelines that remain in service long after their initially projected design life.

The reliability-based approach and the risk-based approach have been utilized in numerous previous industry studies that attempt to prove the applicability of a single design factor. However, a "methodology-based" approach offers a key advantage over the use of single prescribed value: it directs attention to the risks to pipeline integrity posed by project-specific elements, rather than calculating risk based on industry averages.

The results of past studies have confirmed that an increased design factor is justified based on modern pipeline fabrication and construction practice – and imply that the grandfathering of a higher factor for older pipelines must be approached with care.

B.2.3 Valve Spacing

B.2.3.1 US Reference

The requirements identified in 49 CFR 195.260 regarding valve spacing are generally similar to those in ASME B31.4, Section 434.15. Valves must be installed on both sides of major waterways and public water supply reservoirs. ASME specifies a block valve on the upstream side, and either a block or check valve on the downstream side, and this is not contradictory to the general requirements of CFR. Although the language differs, additional valve location siting statements reflect general agreement, but there is no specific cross-country spacing requirement similar to the gas valve spacing requirements (an exception is the 7.5-mile spacing requirement of ASME B31.4 for LPG and liquid anhydrous ammonia on industrial, commercial and residential areas.)

B.2.3.2 Canadian Reference

The requirements of CSA Z662-03, Paragraph 4.4.4 for valve spacing on transmission lines are as follows:

It shall be permissible for the spacing of valves in the pipeline to be as given in Table 4.7 or adjusted based upon factors such as operational, maintenance, access, and system design considerations.

Table 4.7 - Valve Spacing, miles (km)				
Type of pipeline	Class 1 location	Class 2 location	Class 3 location	Class 4 location
HVP	NR	9.3 (15)	9.3 (15)	9.3 (15)
LVP	NR	NR	NR	NR
Notes: NR = not required. Valve spacing adjustments should not normally exceed 25% of the applicable distances given in Table 4.7.				

B.2.3.3 Development History

The emphasis in liquid pipeline valve location is on protection of water bodies and sources of potable water. This may reflect the general liquid and gas pipeline regulatory differences – namely, that the emphasis for gas pipelines is on personnel safety and protection from third-party mechanical damage, while that for liquid pipelines is on watershed safety. Naturally, this does not mean that the focus is exclusive, yet this viewpoint does appear to guide some of the differences in approaches.

B.2.3.4 Comparison

There is little difference between the code approaches. The largest perceived difference is the maximum spacing for liquid anhydrous ammonia, which differs by only 3 kilometers (km) from (15 km to 12km), or approximately 1.9 miles.

B.2.3.5 Discussion

Valve locations designated during design would not be expected to appreciably differ.

B.2.4 Cover Depth

B.2.4.1 US Reference

The requirements contained in ASME B31.4, Table 434.6(a) regarding pipeline cover are as follows:

434.6 Ditching: Depth of ditch shall be appropriate for the route location, surface use of the land, terrain features, and loads imposed by roadways and railroads. All buried pipelines shall be installed below the normal level of cultivation and with a minimum cover not less than that shown in Table 434.6(a).

Location	Normal Excavation	Rock Excavation
Inches (meters)		
Cultivated, agricultural areas where plowing or subsurface ripping is common	48 (1.2)	N/A
Industrial, commercial, and residential areas	48 (1.2)	30 (0.75)
River and stream crossings	48 (1.2)	18 (0.45)
Drainage ditches at roadways and railroads	48 (1.2)	30 (0.75)
All other areas	36 (0.9)	18 (0.45)

B.2.4.2 Canadian Reference

The requirement in CAS Z662-03: 4.7 for cover and clearance is as follows:

The cover requirements for buried pipelines shall be as given in Table 4.9, except that where underground structures or adverse conditions prevent installation with such cover, it shall be permissible for such pipelines to be installed with less cover, provided that they are appropriately protected against anticipated external loads.

Table 4.9 – Cover and Clearance (See Clauses 4.7.1, 4.7.2, and 4.8.2.1.)				
Location	Type of Pipeline	Class Location	Normal Excavation Inches (m)	Rock excavation requiring blasting or removal by comparable means
General (other than as indicated below)	LVP or gas	Any	24 (0.6)	24 (0.6)
	HVP or CO2	1	36 (0.9)	24 (0.6)
	HVP or CO2	2, 3 or 4	48 (1.2)	24 (0.6)
Right-of-way (road or railway)	Any	Any	30 (0.75)	30 (0.75)
Below traveled surface (road)*	Any	Any	48 (1.2)	48 (1.2)
Below base of rail (railway)†	— Cased	Any	48 (1.2)	48 (1.2)
	— Uncased	Any	78 (2.0)	7830 (2.0)
Water Crossing	Any	Any	48 (1.2)‡	24 (0.6)
Drainage or irrigation ditch invert	Any	Any	30 (0.75)	24 (0.6)
Clearance from	Type of Pipeline	Class Location	Clearance for buried pipelines, minimum, mm	
Underground structures and utilities (conduits, cables, and other pipelines)	Any	Any	300	
Drainage Tile	Any	Any	50	
Notes: *See Clause 4.8.3.1. †Within 7 m of centerline of the outside track, measured at right angles to the centerline of the track. ‡Cover not less than 0.6 m shall be permissible where analysis indicates that the potential for erosion is minimal. 1) Cover shall be measured to the top of the carrier pipe or casing pipe, whichever is applicable. 2) See also Clause 1.6."				

B.2.4.3 Practical Considerations

The pipeline cover affords some protection against third-party damage by ensuring that the pipeline is at a sufficient depth to avoid damage from incidental, shallow excavations. Some protection against the potential extent of damage in the event of a pipeline failure can be argued as the burial depth increases.

Similar to considerations for a gas pipeline, the pipeline cover is also considered part of the pipeline design in that it supplies the mechanical buoyancy restraint to the buried pipeline. Liquid pipelines, on the other hand, have the additional load of the product to overcome before upheaval can occur.



Figure B.2-1 – Upheaval of buried pipe, Norman Wells oil pipeline (Sept. 1997). The exposed pipe has since been covered by a berm (http://gsc.nrcan.gc.ca/permafrost/pipeline_e.php)

B.2.4.4 Comparison

A side-by-side comparison of cover for an LVP pipeline in general conditions is given below, along with the ratio of increased cover (US to Canadian).

Class Location	US Cover requirements (inches)		Canadian Cover Requirements (inches)		Ratio (US cover to Canadian)	
	Normal	Rock	Normal	Rock	Normal	Rock
Any	36	18	24	24	1.5	0.8

Except in the instance of rock excavation, which is usually a relatively minor consideration in design, the US code would require 50 percent additional cover.

B.2.4.5 Discussion

In remote areas, and especially where there is no discernible possibility for third-party operations, the potential for cover reduction could be explored and argued. This simply might be the reduction of ditching requirements, but also might be coupled with pipe integrity design situations. For example, proponents of the 540-mile (869-km) Norman Wells crude oil pipeline requested, and were granted, an exemption for a reduced cover depth to accommodate potential thaw settlement in some areas (the reduced cover lessens the downward load on the pipeline if it loses the ditch support due to settlement). The Norman Wells pipeline runs from Norman Wells in the Northwest Territory to Zama in northern Alberta. The focus geohazard for a liquid pipeline in the arctic is thaw settlement, and cover reduction assists in lowering developed stresses/strains.

B.2.5 Limit State Design

The general approach for development and application of Limit State Design was discussed for gas pipelines.

B.2.5.1 US Reference

With regard to structural stress evaluation of liquid pipelines, 49 CFR 195 limits the governing hoop stress to be less than a fraction of a material minimum, the SMYS for the different class locations. For guidance on limits for other structural/stress conditions, ASME B31.4 is used (e.g., ASME B31.4 Paragraph 402.3.2 “Limits of Calculated Stresses Due to Sustained Loads and Thermal Expansion”). Unlike ASME B31.8, ASME B31.4 does not mention the possibility of considering a strain-based design except in Chapter IX “Offshore Liquid Pipeline Systems,” Paragraph A402.3.5 “Strength Criteria During Operations.”

Limit State Design as a design approach methodology is not found in the major US oil pipeline codes and code references.

B.2.5.2 Canadian Reference

CSA Z662, Annex C “Limit States Design” presents a framework for a pipeline project to develop a Limit States Design approach:

For many design loadings, the only primary load acting is that due to internal pressure; all other loads are secondary. For these situations, an elastic design method may be excessively conservative, as it does not recognize the ability of the pipe to plastically deform and still maintain pressure integrity. A plastic design approach does recognize such behavior, and can therefore be used to advantage.

Annex C begins by stating “This annex provides guidance for the design of oil and gas industry steel pipelines...,” indicating that the guiding principles in the annex can be applied to both gas and liquid pipeline design.

Annex C provisions were discussed for gas pipelines, and there is no difference in the application for liquid pipelines.

B.2.5.3 Development History

As noted for gas pipelines, in the pipeline industry as well as other industries, the US has been particularly slow to adopt Limit State design approaches. In Canada, the pipeline code has included the informative Annex C that describes the required basis for a pipeline approach. In general, the information has been referenced in several approaches for design, although no project could be found which completely adopted the approach.

B.2.5.4 Comparison

ASME B31.4 does not have clear provisions to allow a liquid pipeline project to develop a strain-based design. Since the strains would be beyond the stress allowables of the code, a new approach to judge the acceptability of these strains might require more effort than that needed for a gas line application. On the other hand, both TAPS in Alaska and

Norman Wells in Canada used elements of Limit State Design in their project criteria and both can be used as precedents for liquid pipeline application.

B.2.5.5 Discussion

There is no appreciable difference in the suggested approach, or the application, of this design, especially for protection from geohazards. A strain-based design for longitudinal loadings, such as slope movement or pipe settlement due to thaw of permafrost in arctic regions, is especially appropriate since these are “secondary loadings.” Secondary loadings, such as differential ground movement, are generated by structural deformations; the pipe displacement growth is generally limited by the deformation mechanism. Pipelines that are designed to address these secondary loadings by consideration of the resultant strains are considered “strain-based design pipelines.”

Secondary loadings from such geohazards that would be particularly apt for liquid pipelines, such as thaw settlement, often develop relatively slowly over time with the displacement of the ditch profile, thereby permitting effective monitoring strategies to observe any developing deformation well before a critical strain state is reached. This consideration, and appropriate designation of in-line inspection (ILI) strategies during design, can form an important part of developing an approach to such hazards.

A strain-based design approach for liquid pipelines would be similar to those for gas pipelines. Although the terms and much of the methodology has been refined, the use of a strain-based design, testing to define appropriate limits, and development of criteria using this approach has certainly been used in the US in the past for liquid pipelines. In addition to a number of stress-based criteria, mostly sourced to code requirements, the TAPS project design criteria developed in the mid-1970s allows 0.8 percent effective strain, especially to address geohazards. (Compare this to 0.275 percent (=80 kips per square inch [ksi]/29000 ksi), which is the computed elastic strain at SMYS for X80). This allowable strain value is based on the ultimate compressive strains developed from full-scale buckling tests conducted on the project’s relatively thin-walled (diameter-to-wall-thickness ratio $[D/t] > 100$) pipe at the University of California, at Berkeley. Such project-specific testing is typical for projects that need to extend criteria to approach circumstances not addressed by code or outside of code limitations.

Finally, the Load Factors and Resistance Factors noted in the Canadian Annex C will be required so as to develop the required “safety factor” against the load resultant exceeding the resistance. As noted in Annex C, this can be viewed as an exercise to demonstrate that these factors to be used will result in meeting reliability targets. Thus, in some sense, the Load and Resistance factors act as surrogates for the reliability analysis – which leads to the examination of the direct use of reliability-based design methodology in the next section. The development and acceptance of reliability based analyses is an improvement which allows a quantitative evaluation of risk, and a procedure to examine design factors and overall project safety factors for use of project-specific criteria.

B.2.6 Reliability-Based Design

The discussion of reliability-based design for liquid pipelines follows that for gas pipelines. Currently, the industry focus appears more on the development for gas pipelines, although the general principles would apply to both types of pipelines.

B.3 Materials

Both the US and Canadian codes address pipe materials, with the aid of extensive references to industry guides (e.g., American Petroleum Institute [API] 5LX, *API Specification for High-Test Line Pipe*). With the use of such standards, there are no significant expected differences within the codes. Rather, this topic explores the scope of both codes, as well as some new material requirements and specifications that could be expected for new gas transmission projects.

B.3.1 US Reference

49 CFR 195 has no counterpart to Subpart B of 49 CFR 192 “Materials.” Minimum requirements for the selection and qualification of pipe and components for use in pipelines are contained in Subpart C “Design Requirements,” generally by using references to API 5L. This leaves the development of material requirements almost entirely to ASME B31.4, Chapter III “Materials” which has the extensive table 423.1 “Material Standards” providing cross references to relevant ASTM and API designations.

B.3.2 Canadian Reference

CSA Z662-03 Section 5 “Materials” is an extensive section that covers low temperature use of materials and fracture toughness requirements. CSA Z245.1 “Steel Pipe” covers seamless pipe, electric-welded pipe (flash-welded pipe and low-frequency electric-welded pipe excluded) and submerged-arc-welded pipe primarily intended for use in oil or gas pipeline systems.

B.3.3 Background

There is no difference in the development of pipe material for gas as compared to liquid pipelines. Generally, gas pipeline operators have been more enthusiastic regarding pursuit of higher grades of steel, possibly due to the higher pipeline pressures utilized and forecast for construction of gas transmission lines.

B.3.4 Comparison

Again, no real difference is seen between pipeline specifications and regulations for gas or liquid pipelines.

Steel behavior, especially beyond the elastic range, is currently more the focus of higher pressure gas pipelines, rather than liquid pipelines, probably because of the increased mass flows from higher pressures in gas lines coupled with the forecast for construction of transmission lines. But the initial focus in the 1970s and 1980s in this area was led by challenges to liquid lines, including TAPS and Norman Wells.

B.3.5 Discussion

It is likely that material developments will be spurred more by requirements for new gas pipeline designs, rather than liquid lines, because of the push to operate in higher stress/strain ranges. Yet higher grades of steel are always a consideration for use in any

new pipeline project. An increase of SMYS from 80ksi to 100ksi results in a 20 percent reduction in wall thickness, assuming the wall thickness critical function is direct pressure containment through limiting hoop stress. For pipelines in which longitudinal stresses/strains are not controlling design, higher strength steels will be more economical (assuming any premium price per pound for the higher grade is at about present levels). Additional comments regarding the design of pipe steel beyond traditional stress-based approaches follow the same reasoning as for gas pipelines. “Leak before rupture” is the guiding philosophy underlying the design of both types of pipeline. Therefore, preventing the initiation of fractures by increasing toughness requirements for pipe materials seems a viable approach to the current prescriptive approaches. Life Cycle Management and Reliability Based Design Assessment both acknowledge that integrating design, construction, and maintenance assures a balanced and engineered management approach for safe and reliable operations.

B.4 Construction

Detailed construction oversight by regulatory mandate is not generally evident in codes and regulations. Generally, prescriptive requirements for pipeline construction would probably be seen to inhibit construction innovation and the introduction of new technology.

There are two areas where regulations require both focus and reporting in detail – welding and pressure testing.

B.4.1 Welding

B.4.1.1 US Reference

49 CFR 195, Subpart D – Construction contains some minimal requirements for welding, relying heavily on industry standards for acceptability. The references are not lengthy, and clearly rely on the referenced standards (e.g., API 1104, *Welding Pipelines and Related Facilities*) and standards incorporated by reference.

ASME B31.4, Paragraph 434.8 “Welding” provides appreciably more detail concerning welding, such as figures that detail transitions between ends of unequal thickness. However, API 1104 is still the referenced base document.

B.4.1.2 Canadian Reference

CSA Z662-03 Section 7 “Joining” is an extensive section that covers welding.

Analogous to the CFR provisions, it does not cover welding during the manufacture of the pipe. CSA Z245.1 “Steel Pipe” covers seamless pipe, electric-welded pipe (flash-welded pipe and low-frequency electric-welded pipe excluded) and submerged-arc-welded pipe primarily intended for use in oil or gas pipeline systems.

One important difference between the CSA codes and the NEB OPR is that the NEB OPR requires 100 percent non-destructive examination (NDE), while CSA Z663 requires that only 15 percent of the production welds made daily be nondestructively inspected. Practically, however, most new transmission pipeline is 100 percent NDE as it federally regulated and is covered by the NEB OPR.

B.4.1.3 Comparison

While 49 CFR 195 does not contain the detail of CSA with regard to welding, the ASME B31.4 code is comparable in detail. It is generally understood that the level of detail in CSA is consistent with ASME B31.4.

B.4.2 Hydrostatic Test Requirements

B.4.2.1 US Reference

49 CFR 195 Paragraph 195.304 Test Pressure

The test pressure for each pressure test conducted under this subpart must be maintained throughout the part of the system being tested for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the maximum operating pressure and, in the case of a pipeline that is not visually inspected for leakage during the test, for an additional 4 continuous hours at a pressure equal to 110 percent, or more, of the maximum operating pressure.

ASME B31.4, Paragraph 437.4.1 “Hydrostatic Testing of Internal Pressure Piping” gives the same requirements of CFR 195.

B.4.2.2 Canadian Reference

Table 8.1 – Test Requirements for Steel Piping Intended to Be Operated at Pressures Greater Than 700 kPa (See Clauses 8.2.1.1.1, 8.2.3.1.1, 8.2.5.1, 8.5.1, 8.6.2.4, and 10.11.5.2.)							
Service fluid	Class location	Strength test pressure			Leak test pressure		Maximum operating pressure††
		Intended minimum pressure*	Maximum pressure		Minimum pressure	Maximum pressure	
			Liquid medium	Gaseous medium			
LVP	All	125% of intended MOP	Lesser of 0.2% deviation on a P-V plot and 110%§ of the SMYS of the pipe	95%** of the SMYS of the pipe	110% of the intended MOP	Lesser of the qualification pressure‡‡ and the pressure corresponding to 100% of the SMYS of the pipe	Lesser of qualification pressure‡‡ divided by 1.25 and design pressure of the pipe
HVP or CO2	1	140% of intended MOP					
HVP or CO2	2, 3 or 4	150% of intended MOP					Lesser of qualification pressure‡‡ divided by 1.50 and design pressure of the pipe
Clause references		8.2.3.1.1	8.2.4.2	8.2.4.3	8.2.3.1.1	8.2.5.1	8.5.1
Notes: *See also the note to Clause 8.2.3. †See also Clause 8.2.4.1. ‡For gaseous-medium testing, see also Clause 8.5.1.2. §66% for continuous welded pipe. **57% for continuous welded pipe. ††Except as allowed by Clause 8.5.1.5, the qualification pressure shall be the lowest pressure achieved, over the duration of the strength test, at the high point of elevation in the test section, as measured directly or as derived by adjusting the corresponding pressure measured at another point in the test section to account for the elevation difference between the high point of elevation and the pressure-measurement point. 1) For steel piping intended to be operated at pressures of 700 kPa or less, see Clauses 8.2.1.2, 8.2.3.2, and 8.5.2. 2) For steel piping in compressor stations, gas pressure-regulating stations, and gas-measuring stations, the intended minimum strength test pressure shall be 140% of the intended MOP; the MOP shall be in accordance with the requirements of Clause 8.5.1.3.							

The duration of test requirements under CSA Z662-03 are contained in the following sections:

Z662: 8.2.6.1

Except as allowed by Clause 8.2.6.2, strength tests shall be maintained for continuous periods of not less than 4 h.

Z662:8.2.6.3

Except as allowed by Clause 8.2.6.4, leak tests shall be maintained for continuous periods of not less than 4 h for liquid-medium testing or 24 h for gaseous-medium testing.

Notes:

1) *For liquid-medium testing, leak test durations in excess of 4 h may be required where thermal variations or other factors affect the validity of the tests.*

2) *For gaseous-medium testing of large-volume test sections, leak test durations in excess of 24 h may be required in order to compensate for the compressibility of the pressure-test medium, as the pressure drop resulting from a small leak in a large test section may not be sufficient within a 24 h period to clearly indicate the presence of the leak.*

B.4.2.3 Background

Generally, the interest in hydrotest requirements has been led by gas pipeline design.

B.4.2.4 Comparison

For LVP pipelines, there is no real difference in the testing requirements. The initial 4-hour higher test pressure of 125 percent of maximum operating pressure (MOP) is followed by a lesser pressure of 110 percent, also to be held for 4 hours.

All approaches take care to divide the pressure test into two parts – the strength test and the leak test. The four-hour hold time for each test part together equals the total test time of 8 hours.

B.4.2.5 Discussion

Separating the test into two parts – strength test and leak test – is highly beneficial because it focuses on pressure test objectives. Generally, if a significant defect is introduced during construction, the pipe would be expected to fail when, or shortly after, the maximum test pressure is reached. Typically, time-dependent processes, at least for the time durations of pressure testing, do not play a significant role in determining steel pipeline strength.

Hydrostatic testing is the norm for pressure testing. Note that various reports question whether hydrostatic testing, or indeed any type of pressure testing of modern pipe, is as much of a necessity today as when the test originated (Kirkwood, 2000).

The replacement of the code-specified pressure test requirements by such a program would necessarily emphasize quality assurance and quality control (QA/QC) so as to obviate the need for a pressure test after installation but before start-up. Possible considerations would include increased hold time for mill tests, formal third-party oversight and review, pipe examination after transport and lowering in, increased weld

NDE, detailed startup procedures to “test” with the product with increased leak detection, and startup ILI baseline. NEB has stated more work has to be done to make this a generally accepted procedure, with a particular focus on leak detection.

B.4.3 Pneumatic Testing

Because of its straightforward approach and interpretation, hydrostatic testing is generally accepted to be a cost-effective technique that ensures the integrity of a pipeline at the time of testing. Pneumatic testing sometimes requires severe test restrictions, as well as potential restrictions on MAOP. Pipeline operating companies and construction contractors are generally familiar with hydrostatic testing techniques.

B.4.3.1 US Reference

ASME B31.4, Paragraph 437.4.3 “Leak Testing” allows pneumatic testing for piping systems to be operated at a hoop stress of 20 percent or less of the SMYS of the pipe. CFR 195.306 also allows air or inert gas as the test medium in “low-stress” pipelines.

B.4.3.2 Canadian Reference

Pneumatic testing requirements are contained in the table presented in Section A.4.2.2, although the maximum pressure will move to 100 percent of SMYS for a gaseous medium in 2007.

B.4.3.3 Background

Historically, on the average, pneumatic testing has been utilized less frequently for liquid pipelines than for gas pipelines, except in mountainous regions where water has been in short supply or the number of test sections would have been prohibitively high..

B.4.3.4 Comparison

Compared to gas pipelines, codes do not support pneumatic testing.

B.4.3.5 Discussion

Comments for gas pipeline pneumatic testing apply here. Generally, it is doubtful if this would be a concern for liquid pipeline operation except at isolated tie-ins or special pipeline segments. Liquid pipelines must be able to be operated above the temperature regime of the product, which might cause waxing. Thus, these pipelines already incorporate some type of provision, such as insulation, that allows their operation in cold weather, which alleviates to a certain extent concerns about testing in winter temperatures.

B.5 Operations and Maintenance

B.5.1 General

A review of how operations and maintenance are addressed is a logical extension to the design and construction focus of this report insofar as regulatory permitting of new pipeline facilities calls for the filing of operational and integrity management (IM) planning documents.

The applicable codes and standards are:

- US: CFR 49 Part 195 Appendix C – Guidance for Implementation of Integrity Management. Program.
- US: API 1160 - Managing System Integrity for Hazardous Liquid Pipelines
- Canada: CSA Z662 Section 10 – Operating, Maintenance and Upgrading with reference to 2 Annexes

Generally, similar sub-topics are included in both the US and Canadian codes and standards insofar as addressing operations and maintenance. While IM currently might be a sub-topic of somewhat higher profile in the codes and standards, other areas included – some interrelated with IM – are as follows:

- Procedures: emergencies, investigations and pipeline identification
- Records: the pipeline system and history of leaks and breaks
- ROW Inspection: patrolling, vegetation control and crossings
- Operation and Maintenance history
- Inspection and Inspection tools
- Maintenance History

B.5.2 Integrity Management

B.5.2.1 Recent Developments in the US

The first Integrity Management Rule applicable to large hazardous liquid operators was issued in December 2000, followed in January 2002 by a comparable rule for smaller liquid operators. The requirements established in December 2000 and supplemented in January 2002 lay out comprehensive IM program requirements for hazardous liquid pipeline operators. These rules have four primary objectives:

- Accelerate integrity assessments (e.g., in-line inspection or pressure testing) in locations where a release might have significant adverse consequences;
- Improve operator integrity management systems;
- Improve public confidence in pipeline safety; and
- Improve government’s role in the oversight of pipeline integrity.

The operator has the flexibility to develop an IM program that is best suited to its particular pipeline assets, organizational structure, and customary business and operating practices; IM therefore plays an integral rather than a peripheral role in the operator's pipeline system operation.

The IM rule is based on a set of management-based requirements (referred to as “Program Elements” in the rule) - fundamentally different from the previously existing, largely prescriptive pipeline safety requirements. The evaluation of operator compliance with these requirements requires the inspection of management and analytical processes – aspects of an operator’s business that are not reviewed in standard PHMSA compliance inspections.

Protocol-guided inspections included a comprehensive review of the processes, tools, and methods for the operator IM Program Elements. The inspections also examined the implementation of the program. Among the results and records reviewed:

- Confirmation of completed integrity assessments
- Review of ILI results, and the issues identified through analysis of these results and integration of other data sources;
- Review of the repair and remediation schedules;
- Confirmation that repairs were made in accordance with established time constraints, and that pressure was promptly reduced when required for certain “immediate repair” conditions;
- Review of pressure test records to assure tests complied with Subpart E of 49 CFR 195, and the operator’s evaluation of any test pressure failures; and
- Confirmation that additional preventive and mitigative measures had been implemented.

PHMSA started the second round of IM inspections for hazardous liquid pipeline operators in mid-2005. Since then, PHMSA has used the information gained from all of the hazardous liquid IM inspections to further the development of the hazardous liquid IM inspection process.

PHMSA has gained significant experience with the fundamentally different approach to oversight needed to ensure that operators are developing and implementing effective IMPs:

“...Since the initial pilot hazardous liquid integrity management (HL IM) inspections in 2002, PHMSA has found that operators generally understand what portions of their pipeline systems can affect high consequence areas, and have made significant progress in conducting integrity assessments on these areas ... However, the development of effective management and analytical processes, and quality data and information to support these processes still requires considerable attention from some operators. While most operators appear to be headed in the right direction, fundamental changes to management systems require time and management commitment. PHMSA recognizes this situation and continues to develop and implement an inspection and enforcement approach that seeks to

assure compliance with the rule requirements and continuous improvement in operator integrity management programs.”(Hansen, 2006)

B.5.2.2 Comparison of Gas and Liquid Regulations

There are important differences in the US rules for gas and liquid pipelines.

The first distinction is the basis for identifying high consequence areas (HCAs). In the hazardous liquid rule, PHMSA identified several types of areas where additional assurance of pipeline integrity was desired, and then developed data on where these areas were located. Operators were then required to determine whether their pipelines could affect these HCAs. In the gas IM rule, PHMSA has specified the screening approach that an operator must follow to identify the areas near its pipelines where high consequences are possible. This approach involves calculation of a potential impact radius, based on the diameter and MAOP of the pipe, and then identification of the particular pipeline segments that could lead to high consequences in the event of failure.

A second distinction of the gas IM rule is the strong reliance on one or more consensus standards developed by ASME and NACE to support identification of IM requirements. Perhaps the most significant distinction in these standards was the codification in ASME B31.8S of a threat-based approach to IM. This approach, which was adopted in the rule for gas IM, requires the operator to gather a prescribed set of integrity-related data and to use these data to identify which threats apply to each segment subject to the IM rule. The determination of applicable threats then serves as the basis for selection of integrity assessment methods.

Another distinction is the time allowed for the baseline assessment and the reassessment interval. For hazardous liquid pipelines, the baseline assessment period and the reassessment interval are seven and five years, respectively. For gas pipelines these periods are ten and seven years, respectively.

A prior significant difference was that the gas IM rule allowed the use of Direct Assessment (DA), in addition to pressure testing and ILI, to assess the integrity of pipeline segments subject to the rule. This was changed by the adoption of 49 CFR Part 195.588 “What standards apply to direct assessment?” in 2005 to permit ECDA for liquid pipelines.

B.5.2.3 Comparison of US and Canada Regulations

As per comments for the gas pipeline regulations, the US and Canadian codes and standards provide an operator with considerable latitude in the methodology to apply in undertaking and updating risk assessments and in developing IM programs.

B.6 Conclusion

US and Canadian regulations for hazardous liquid pipelines generally are compatible regarding material and equipment, relying largely on industry standards to guide regulatory procedures.

Strain-based design would have to be considered by development groups in either country with a suggestion to merge requirements.

The two national codes are also closely related in most design and construction areas, although there are important differences. These have been largely documented and some special permits in particular instances issued, often based largely on industry discussions. Generally the focus has been on:

- Reconciliation of the design factor in the US to the Canadian value of 0.8
- Normalization requirements for pressure testing, especially hydrostatic testing
- Acceptance of spiral and high-strength pipe

There are also differences in cover requirements, although this does not appear to be a critical factor.

US standards for liquid pipelines appear to lag those for gas pipelines in the emerging strain-based design and reliability approaches. This is in contrast to the actual history of use of these concepts on the major arctic pipelines of TAPS and Norman Wells.

The US regulations for pipeline IM have been developed, and audits have been concluded and stand in contrast with parallel Canadian regulations. However, as with gas pipelines, it is likely that the “prescribed” US regulations will be in line with what would be implemented by most leading operators in the maintenance of a major new pipeline.

B.7 References

American Society of Mechanical Engineers, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids (2006).

API 1160, *Managing System Integrity for Hazardous Liquid Pipelines*.

Canadian Standards Association, Oil and Gas Pipeline System Standards, CAN/CSA Z662 (2003).

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Transportation of Hazardous Liquids by Pipeline, 49 CFR 195

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Appendix C

Welding Standards

C.1 Overview of Welding Regulations

This appendix presents a comparison between the welding requirements in consensus standards for pipelines that have been incorporated into federal pipeline safety regulations in the US and Canada. An overview of the regulations governing welding of pipelines in the US and Canada is presented and notable differences between these are reviewed.

C.1.1 United States Regulations

The federal regulations for pipelines in the US contain a number of references to requirements for welding. In Subpart E of Code of Federal Regulations (CFR) Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, the minimum requirements for welding steel materials in pipelines are prescribed. Subpart D of CFR Part 195 – Transportation of Hazardous Liquids by Pipeline – also contains requirements for welding. Both of these subparts incorporate by reference three sections of American Petroleum Institute (API) 1104 – Welding of Pipeline and Related Facilities. These sections include the following:

- **Qualification of welding procedures** – CFR Parts 192 and 195 require that welding be performed by a qualified welder in accordance with welding procedures qualified under Section 5 of API 1104 or Section IX of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code – Welding and Brazing Qualifications.
- **Qualification of welders** – CFR Part 192 requires that for gas pipelines to be operated at a pressure that produces a hoop stress of 20 percent of specified minimum yield strength (SMYS) or greater, each welder must be qualified in accordance with Section 6 of API 1104 or ASME Section IX. CFR Part 195 requires the same welder qualification for all hazardous liquid pipelines regardless of operating pressure. Additionally, welders are required to demonstrate ongoing proficiency through utilizing the qualified processes and testing.
- **Acceptance limits for discontinuities discovered during non-destructive inspection** – Both CFR Part 192 and 195 require that the acceptability of welds that are nondestructively tested or visually inspected be determined according to the standards in Section 9 of API 1104. Except for cracks, CFR Parts 192 and 195 also allow the use of Appendix A in API 1104 as an alternative method to determine acceptability of discontinuities based on fitness-for-purpose principals.

While CFR Parts 192 and 195 allow welding procedures and welders to be qualified to either API 1104 or ASME Section IX, the majority of pipeline operators in the US choose to use API 1104. API 1104 covers the gas and arc welding of butt, fillet, and socket welds in carbon and low-alloy steel piping used in the compression, pumping, and transmission of crude petroleum, petroleum products, fuel gases, carbon dioxide, and nitrogen and, where applicable, covers welding on distribution systems.

Portions of ASME B31.8 and ASME B31.4 which are also incorporated by reference in CFR Parts 192 and 195, respectively, also make reference to API 1104. The requirements in Chapter II – Welding – of ASME B31.8 were originally duplicated from and are analogous to those in Subpart E of CFR Part 192. The requirements in Chapter V – Construction, Welding, and Assembly – of ASME B31.4 are analogous to those in Subpart D of CFR Part 195. There are some notable differences, however. One example is the more stringent requirements for non-destructive testing (NDT) of girth welds in Class 3 and 4 location in CFR 192 (100 percent unless impracticable, but at least 90 percent) compared to those in ASME B31.8 (40 percent for Class 3 locations and 75 percent for Class 4 locations). Many pipeline operators choose to employ 100 percent NDT for all class locations.

C.1.2 Canadian Regulations

The federal regulations for pipelines in Canada also reference requirements for welding. The National Energy Board Act, Onshore Pipeline Regulations Part 4 references Canadian Standards Association (CSA) Z662 – *Oil and Gas Pipeline Systems* – for the design and construction of pipelines transporting liquid or gaseous hydrocarbons. The regulation also specifies that the welding procedures be submitted to the Board for approval.

Part 3 of the Onshore Pipeline Regulations – Joining – requires that the owning company “*shall develop a joining program in respect of the joining of pipe and components to be used in the pipeline and shall submit it to the Board when required to do so.*” This part also requires non-destructive examination (NDE) of the entire circumference of each joint by radiographic or ultrasonic methods.

The requirements for welding steel pipelines in Canada are contained in CSA Z662. Clause 7 of CSA Z662 covers the requirements for joining pipes, components, and non-pressure-retaining attachments to piping by means of arc welding, gas welding, explosion welding, and mechanical methods. CSA Z662 also covers the requirements for joining pipes and components made of steel, polyethylene, cast iron, or copper (Clause 12.7) for gas distribution systems. Annex K of CSA Z662 contains an alternative method to determine acceptability of discontinuities based on fitness-for-purpose principals. While the US regulations are distributed throughout a variety of documents, the Canadian regulations are all contained in CSA Z662.

CSA Z662 permits welding procedure specifications and welders to be qualified in accordance with the requirements of ASME Section IX, provided that specific conditions defined by CSA Z662 are met.

CSA Z662 specifies that compressor and pump station piping that is designed in accordance with the requirements of ASME B31.3 shall be welded in accordance with the welding requirements of ASME B31.3, provided that additional requirements of CSA Z662 are met for any welds other than partial-penetration butt welds.

C.1.3 Comparison on US and Canadian Regulations

The first edition of API 1104 was published in 1953. The current edition of API 1104 is the Twentieth Edition, which was published in 2006. An errata/addenda document to the Twentieth Edition was issued in July 2007 which includes a significantly revised version of Appendix A for determining the acceptability of discontinuities based on fitness-for-purpose principles.

The current edition of CSA Z662 is the fifth edition, which was published in June 2007. CSA began developing pipeline standards in the early 1960s. The original CSA pipeline standards, CSA Z183, Oil Pipe Line Transportation Systems, and CSA Z184, Gas Transmission and Distribution Piping Systems, were combined in 1994 to produce the first edition of CSA Z662, Oil and Gas Pipeline Systems.

As with many national and international pipeline standards, many of the welding requirements in the original CSA standards are rooted in API 1104. Consequently, the sections pertaining to welding in CSA Z662 are very similar in format and content to those in API 1104. The following is a broad overview of the major topics:

Comparison on US and Canadian Regulations		
Topic	CSA Z662	API 1104
General	Clauses 7.1 through 7.5	Sections 1 through 4
Qualification of Welding Procedures	Clause 7.6 and 7.7	Section 5
Qualification of Welders	Clause 7.8	Section 6
Production Welding	Clause 7.9	Section 7
Inspection and Testing of Production Welds	Clause 7.10	Section 8
Standards of Acceptability for Nondestructive Inspection	Clause 7.11	Section 9
Repair of Welds Containing Repairable Defects	Clause 7.12	Section 10
Procedures for Nondestructive Testing	Clause 7.13 through 7.15	Section 11
Other Welding Methods/Processes	Clause 7.16 and 7.17	Section 12 and 13
Alternative Acceptance Standards	Annex K	Appendix A
In-Service/Maintenance Welding	Clause 10.9	Appendix B

While many revisions have been made to both of these standards over the years, the requirements remain similar, with few notable exceptions.

Standards of acceptability for discontinuities discovered during nondestructive inspection (Clause 7.11 in CSA Z662 and Section 9 in API 1104) is an example of the “different but similar” nature of the requirements in these two standards. Girth welds made in the field sometimes contain imperfections or discontinuities. A discontinuity is any interruption in the uniform nature of a structure or item. In contrast, a defect is a discontinuity that has been compared to acceptance criteria of some sort and found to be non-conforming. Both CSA Z662 and API 1104 contain acceptance criteria based on workmanship standards and alternative acceptance criteria based on fitness-for-purpose principles. Traditionally, tolerable defect sizes in pipeline girth welds and welds in other structures have been based on workmanship criteria. Workmanship criteria are predicated on a level of quality that can be expected of a skilled welder without consideration of mechanical properties. These criteria are empirically based (i.e., severity is not directly related to pipeline reliability) and rely only on defect length, but have been historically proven to be safe in practice. Because they are empirically based, they can be overly conservative. A comparison of the allowable length or dimension of various discontinuities in each standard is shown in Table 1. While there are several differences, these differences would not significantly affect the resulting reliability of a completed pipeline. Many pipeline construction projects of a significant size (e.g., greater than 30 miles) utilize mechanized welding over manual welding to reduce the weld volume, therefore the deposition time and corresponding joining costs. Because the typical defects found during mechanized welding (e.g., planar defects such as lack of fusion) are different than manual welding (e.g., volumetric defects such as slag inclusions), most all mechanized welding projects use automated ultrasonic testing (AUT) and acceptance criteria based on fitness-for-purpose principals. There can be significant differences between these two standards in this regard, which are discussed in detail in Section C.2.1.

Another example of the “different but similar” nature of the two standards is the qualification of welding procedures (Clause 7.6 and 7.7 in CSA Z662 and Section 5 in API 1104). The purpose of qualifying a welding procedure is to demonstrate that the procedure is capable of producing sound, crack-free welds with adequate mechanical properties under production conditions. Procedure qualification involves making a weld using the proposed welding parameters and then subjecting that weld to a variety of destructive tests. Limits are specified for some variables (i.e., essential variables), which if exceeded, require that the procedure be requalified. While some of the destructive testing and essential variable requirements are different, the similarity of CSA Z662 and API 1104 would allow for the development of a single weld qualification procedure and separate procedures qualified to each standard. Both require additional mechanical testing (e.g., fracture toughness testing) for procedures to be employed in conjunction with acceptance criteria based on fitness-for-purpose principles. Additional essential variable requirements also apply, which are discussed in detail in Section C.2.1.

In regard to record keeping for visual inspection and NDT results for girth welds, the requirements on both sides of the border are similar, although CSA Z662 is a bit more specific than the regulations in the US. CSA Z662 includes a specific time interval for the retention of the radiographs themselves (two years). Record keeping of this nature is

addressed in CFR Parts 192 and 195, although a time interval for the retention of radiographs is not specified.

C.1.4 Code Issues for a US-Canada Pipeline: General

Differences between API 1104 and the welding requirements in CSA Z662 have not presented difficulty for the cross-border pipelines that have been constructed to date. When an owner chooses to build a pipeline, the construction activities are typically divided into spreads that separate different geographic regions. Pipeline construction contractors are invited to bid on construction activities for these different spreads. For a cross-border pipeline, a logical termination point for the end of one spread and the beginning of another is the US-Canadian border. By dividing the spreads in this manner, pipeline construction contractors who are registered in Canada can bid on spreads north of the US-Canadian border and pipeline construction contractors who are registered in the US can bid on spreads south of the US-Canadian border. If a spread were to traverse the US-Canadian border, the pipeline construction contractor would be required to be registered in both the US and Canada. A cross-border pipeline spread would also present labor law issues, with Canadian workers requiring permits to work in the US and US workers requiring permits to work in Canada. However, many US contractors have aligned themselves with Canadian contractors. Most of the major large-diameter Canadian pipeline contracting companies are owned by US pipeline contractors.

Welding equipment and welding processes can be unique to a particular pipeline construction contractor, particularly in the case of mechanized gas-metal arc welding (GMAW) equipment. Each contractor typically qualifies his own welding procedures which will be specific to the contractor's welding construction practices. These procedures are reviewed and approved by the pipeline operator. The welders themselves also tend to work exclusively for a particular pipeline construction contractor and are typically qualified by that contractor. Pipeline construction contractors in Canada qualify their welding procedures and welders according to CSA Z662, and pipeline construction contractors in the US typically qualify their welding procedures and welders according to API 1104.

Because of the complexities described above, there had not been a driving force to reconcile pipeline welding standards prior to the efforts of the International Organization for Standardization (ISO) in developing ISO 13847 Petroleum and Natural Gas Industries - Pipeline Transportation Systems – Welding of Pipelines. ISO 13847 specifies the requirements for producing and inspecting girth, branch and fillet welds in carbon and low-alloy steel pipeline transportation systems for the petroleum and natural gas industries. The development of this standard, led by ISO Working Group 8, was intended to reconcile ISO 13847 with API 1104, EN (European Standards) 12732, BS (British Standards) 4515-1, CSA Z-662 and other national and international standards. However, to date, little use has been made of ISO 13847.

C.2 Notable Differences between API 1104 and CSA Z662

In the following section, notable differences between API 1104 and CSA Z662 are reviewed, including those that a contractor performing work in both the US and Canada would likely request to be reconciled. Alternate Acceptance Standards

C.2.1 Alternate Acceptance Standards

Because of the widespread conservatism of acceptance standards based on workmanship criteria, “alternative” defect acceptance criteria began to be implemented into various codes and standards beginning in the late 1970s and early 1980s. These criteria are based on fracture mechanics principles as opposed to workmanship standards and relate the tolerable defect size with the magnitude of loading and the material’s resistance to failure. Both API 1104 and CSA Z662 contain alternative defect acceptance criteria based on fracture mechanics principles. These criteria allow the suitability of discontinuities in pipeline girth welds to be assessed for the intended service conditions. This practice is referred to as assessment based on fitness-for-service (FFS) or engineering critical assessment (ECA).

C.2.1.1 US Reference

Appendix A in API 1104 includes three options for the determination of acceptance limits of planar imperfections. The options are increasingly complex in application but offer a wider range of applicability. Option 1 provides the simplest methodology. Option 2 allows for the full utilization of the toughness of the materials, thereby providing a more accurate criterion, but one which requires more calculation. The first two options were developed with a single set of underlying procedures but are limited to applications with a low to moderate fatigue loading. Option 3 is provided primarily for those cases where fatigue loading exceeds the limit established for the first two options and is not typically applicable to cross-country pipelines. Option 3 was written specifically for offshore pipelines.

In Option 1, two sets of acceptance criteria are given, depending on the crack tip opening displacement (CTOD) toughness value - CTOD toughness equal to or greater than 0.010 in. (0.25 mm) and CTOD toughness equal to or greater than 0.004 in. (0.10 mm) but less than 0.010 in. (0.25 mm). Charts are provided that relate maximum allowable defect height to defect length for various load levels.

Option 2 involves the use of a failure assessment diagram (FAD). The three key components of an assessment using a FAD approach are failure assessment curve (FAC), stress or load ratio, and toughness ratio. The FAC is a locus that defines the critical states in terms of the stress and toughness ratios. The stress ratio defines the likelihood of plastic collapse. The toughness ratio is the ratio of applied crack-driving force over the material’s fracture toughness, which defines the likelihood of brittle fracture.

C.2.1.2 Canadian Reference

As an alternative to the workmanship standards contained in Clauses 7.11 and 7.15.10 of CSA Z662, Annex K provides the analytical methods that are used to derive standards of acceptability for weld imperfections. The standards of acceptability that are derived are based on ECA and include consideration of the measured weld properties and the intended service conditions. Annex K sets defect tolerance using separate fracture and plastic collapse criteria. This annex also includes requirements for stress analysis, weld properties, welding procedure qualification and control, weld inspection, and documentation.

C.2.1.3 Development History

Both API 1104 Appendix A and CSA Z662 Annex K were developed in the early- to mid-1980s and thus represent the technology of that time. Significant progress has been made since then in understanding the structural behavior of girth welds containing welding defects. Although certain parts of API 1104 Appendix A and CSA Z662 Annex K are derived from PD6493:1980, the defect acceptance criteria can vary significantly.

While CSA Z662 Annex K sets defect tolerance using separate fracture and plastic collapse criteria, the original version of Appendix A in API 1104, which first appeared in the Seventeenth Edition in 1988, contained only a fracture criterion. While Annex K in CSA Z662 has remained relatively unchanged (excluding the designation, which was originally *Appendix K*), the new version of Appendix A in API 1104 issued in an errata/addenda document in July 2007 differs considerably from the original version. The worldwide trend in defect assessment is moving towards a FAD- based approach, through which both fracture and plastic collapse can be assessed in one consistent format. This trend formed the basis for the revision of Appendix A of API 1104 that was issued as an errata/addenda document to the Twentieth Edition in July 2007.

C.2.1.4 Comparison

The defect acceptance criteria that results from the use of API 1104 Appendix A compared to that which results from the use of CSA Z662 Annex K can be significantly different. However, for a reasonable given design load, provided that the toughness of the completed weld (as measured during procedure qualification) is also reasonable, both of these methods result in allowable defect lengths that are quite generous. As defect height increases, allowable defect length decreases. Calculations of maximum allowable defect sizes based on like inputs will result in different acceptable defect lengths. The generous nature of API 1104 Appendix A and CSA Z662 Annex K is the result of the highly tolerant nature of pipeline girth welds to planar discontinuities when the toughness is reasonable. Under high stress conditions, the use of the standards may, in rare circumstances, result in defect height and lengths less than those allowed under workmanship.

The pipeline owner who chooses to build a cross-border pipeline may elect to determine allowable defect lengths using both API 1104 Appendix A and CSA Z662 Annex K and then develop a project-specific criterion for application in both the US and Canada that allows defect lengths less than those specified by either nation's regulations. Because of the generous nature of both API 1104 Appendix A and CSA Z662 Annex K, this project

specific criterion may be a compromise between allowable defect length determined using fitness-for-purpose methods and workmanship criteria or it may become the more limiting standard as it was in the case of the Alliance pipeline. Even this compromise value would not cause difficulties for the pipeline construction contractor provided that the mechanized welding system is operating with reasonable efficiency. It is only when difficulties are encountered producing welds with reasonable toughness during procedure qualification that the absolute limits of allowable defect length, as determined using fitness-for-purpose methods, would come into play.

Another difference between API 1104 Appendix A and CSA Z662 Annex K is essential variable requirements. In both standards, the essential variable requirements for welding procedures that are to be used in conjunction with alternative defect acceptance criteria based on FFS methods are more restrictive than those for procedures to be used in conjunction with workmanship criteria. While these essential variable requirements differ, they are nonetheless in closer agreement now that the new version of Appendix A was issued. A remaining difference that is significant is the specification of specific ranges for these essential variables in CSA Z662 Annex K (e.g., a change in specified bevel angle exceeding +10 percent, -5 percent). Many of the essential variable ranges in API 1104 Appendix A are left for the user to define (e.g., a major change in joint design).

C.2.1.5 Discussion

Although the use of API 1104 Appendix A and CSA Z662 would probably result in different allowable maximum defect sizes, this is unlikely to have a significant effect on the construction of cross-border pipelines since the defect acceptance criteria specified by the owner would likely be a compromise between criteria determined using fitness-for-purpose methods and workmanship criteria or the more limiting standard.

Because of the significant cost associated with qualifying welding procedures to Appendix A in API 1104 or Annex K in CSA Z662, a contractor working on both sides of the border might prefer to use one or the other. Even this is not as significant as it once was, since the essential variable requirements in the new version of Appendix A are in closer agreement with those in Annex K.

Recent updates to API 1104 Appendix A include alternative defect acceptance criteria to address the immediate need of pipeline construction in the US, typically with pipeline longitudinal strains less than 0.5 percent. Guidance pertaining to pipeline design based on limit states design methods is provided in Annex C of CSA Z662. Future development possibilities include the development of alternative defect acceptance criteria for ultrahigh-strength pipelines (e.g., X100) in geotechnically challenging environments, such as arctic areas and deep water offshore. These updates will continue to reflect the increased use of mechanized welding and automated ultrasonic testing (AUT) in new pipeline construction.

Anticipated future revisions to CSA Z662 Annex K include the adoption of a FAD-based approach, which will bring these two documents even closer in alignment.

C.3 Conclusions

This appendix compares the welding requirements in consensus standards for pipelines that have been incorporated into federal pipeline safety regulations in the US and Canada. The federal regulations in the US and Canada incorporate by reference API 1104 and CSA Z662, respectively. As with many national and international pipeline standards, many of the welding requirements in CSA Z662 were originally derived from API 1104, which was first published in 1953. As a result, the sections pertaining to welding in CSA Z662 are very similar in format and content to those in API 1104. While many revisions have been made to both of these standards over the years, the requirements remain predominantly similar, with few notable exceptions. Several examples of the “different but similar” nature of the requirements in these two standards are given.

Any future major cross-border pipeline will certainly be constructed using mechanized welding equipment and the completed welds will be inspected using AUT equipment. The majority of pipeline construction projects on which this equipment is utilized take advantage of the option to use alternative defect acceptance criteria based on FFS methods. The most significant differences between API 1104 and CSA Z662 appear to be those associated with Appendix A and Annex K in API 1104 and CSA Z662, respectively. Even these differences would be unlikely to present significant difficulties for a pipeline construction contractor building a major cross-border pipeline, as the owner would likely specify a defect acceptance criteria that is a compromise between criteria determined using fitness-for-purpose methods and workmanship criteria or adopt the results from the more conservative standard. However, a contractor may choose to qualify welding procedures using one over the other because of differences in essential variable requirements.

Future development in pipeline technology that may impact the conclusions listed above include the use of even more productive welding processes that go beyond the optimization of the GMAW process (e.g., dual torch, tandem torch, dual tandem, etc.) and further development of the AUT process (e.g., phased array transducers). These developments may include the use of hybrid laser/GMAW for all or a portion of the weld or the use of “single shot” welding processes such as friction stir welding. Control of weld quality may be accomplished in the future by advanced process control methods instead of NDE of completed welds. It is difficult to say in which country new technology would first be considered by regulators – this has been done on a case-by-case basis in the past. In Canada, for example, explosion welding was proposed and used by TransCanada following approval by the National Energy Board (NEB). The requirements for this process were also incorporated into CSA Z662. In the US, flash-butt welding was thought to be on the horizon and the requirements for this process were incorporated into API 1104. However, this process has never been used for a transmission pipeline in the US. Code and regulatory requirements for future developments in welding and quality control processes have yet to be developed, so it is not possible to explore differences between these in the US and in Canada.

C.4 References

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