500 Consumers Road
North York, Ontario M2J 1P8
PO Box 650
Scarborough ON M1K 5E3

Lorraine Chiasson
Regulatory Coordinator
Regulatory Affairs
phone: (416) 495-5499
fax: (416) 495-6072
Email: egdregulatoryproceedings@enbridge.com

March 7, 2014

VIA RESS, EMAIL and COURIER

Ms. Kirsten Walli
Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario
M4P 1E4

**Re: EB-2012-0459 - Enbridge Gas Distribution Inc. ("Enbridge")
2014 – 2018 Rate Application
Undertaking Responses**

Further to Enbridge Gas Distribution's earlier of March 6, 2014, enclosed please find the following undertaking responses:

Exhibit J3.1;
Exhibits J5.3, and J5.11 and ;
Exhibits J6.3 and J6.5

This submission was filed through the Board's RESS and is available on the Company's website at www.enbridgegas.com/ratecase.

Yours truly,

(original signed)

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis
EB-2012-0459 Intervenors

UNDERTAKING J3.1

UNDERTAKING

TR 8

To provide EGDI's productivity analysis, if available.

RESPONSE

EGD provided a working draft productivity analysis to Concentric for its evaluation and review at the outset of the engagement in February 2011. That working draft was referenced in Mr. Coyne's comments in response to Mr. Shepherd, and is attached. Several points must be understood to put the document in context:

1. This was a working draft, and not of sufficient rigor to be shared publicly
2. The data required rigorous review, assessment, and updating
3. A significant number of assumptions were required that required validation
4. The model and approach were derived from a combination of PEG and Brattle analysis submitted in the Ist Generation IR process in 2007, and could not be independently verified by EGD

Concentric examined the model, data and underlying assumptions, and after independent development of its productivity analyses, made the determination that the EGD approach did not accurately reflect EGD's productivity profile over this 2000-2009 period. Among the differences between EGD's and Concentric's approaches included:

1. Concentric relied upon updated data through 2011
2. The output index derived by EGD was based on a weighted average of both volume and customer growth rates; whereas the output index derived by Concentric was based entirely on customer growth rates. Concentric's approach avoided problems associated with more volatile volumes and delinked the output analysis from programs designed to reduce consumption, which could signal lower productivity than that measured by customers alone.
3. The capital quantity input developed by Concentric included a more complex analysis of the various vintages of EGD's capital; whereas EGD extrapolated based on a 2000 net plant starting point
4. Concentric developed a more robust estimate of capital price, including the effects of taxes, and capital gains & losses.

Witnesses: J. Coyne – Concentric
M. Lister

As a result of these material differences, and Concentric's greater expertise with the measurement of productivity, EGD relied entirely on the Concentric analysis for estimation of the company's TFP productivity over the historic period, and placed no weight on this draft analysis.

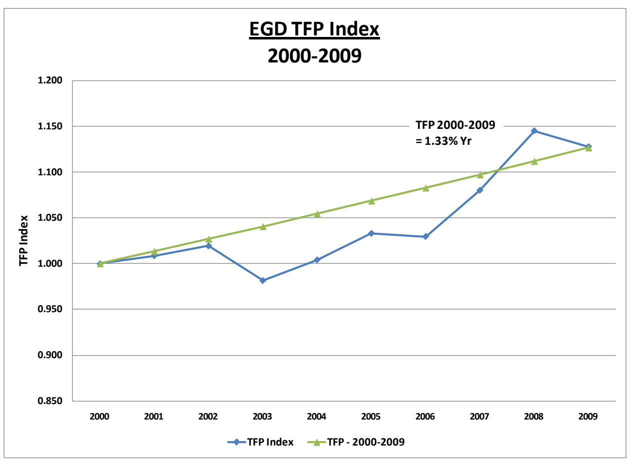
Witnesses: J. Coyne – Concentric
M. Lister

Productivity Performance

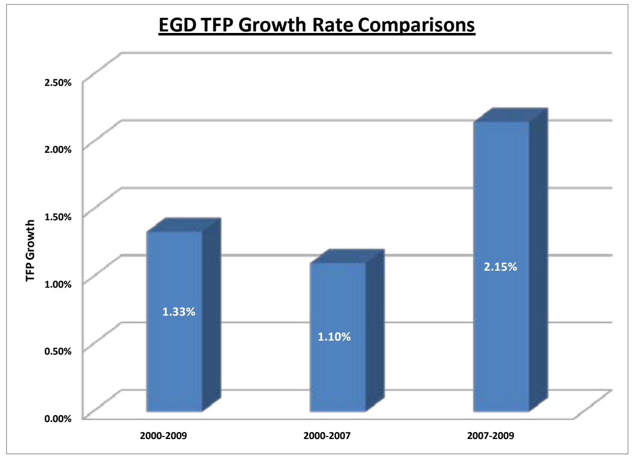
Productivity measures how well a firm converts its inputs into outputs. In the IR model, there is a direct productivity offset to the escalation of distribution revenue requirement per customer. If the utility can surpass the level of productivity offset, then it can retain a share of the incremental earnings it generates as a result. Growth in productivity can be accomplished by either reducing the quantity of inputs, increasing the quantity of outputs, or by simultaneously both increasing the outputs and reducing the inputs. Inputs are measured as the quantity of each of materials, labour (excluding capitalized labour), and capital. Outputs are measured as the number of customers and the quantity of volumes delivered.

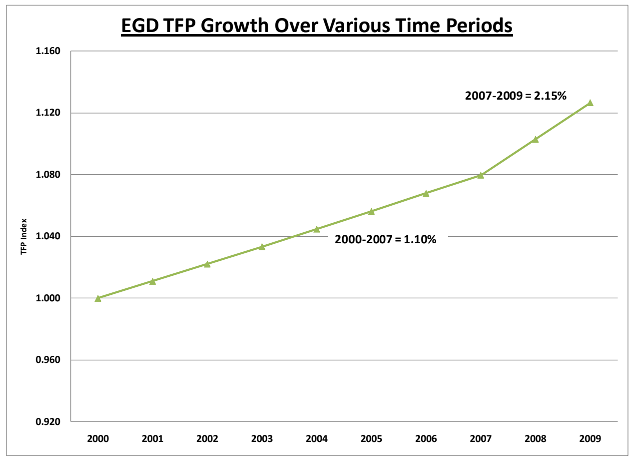
EGD Productivity Review

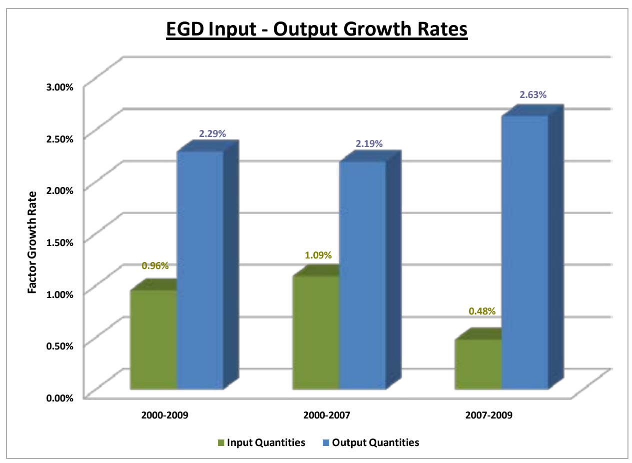
EGD's productivity growth over the 2000-2009 period was 1.33% per year, as show below.



In some years the increased productivity was due to outputs increasing faster than inputs, and in other years it was the result of inputs declining faster than outputs. The charts below depict how the growth rate in productivity has changed over various periods of measurement. Over the pre-IR period, productivity improved by 1.10% per year. Since the start of IR, however, productivity has improved significantly to 2.15% on average per year.







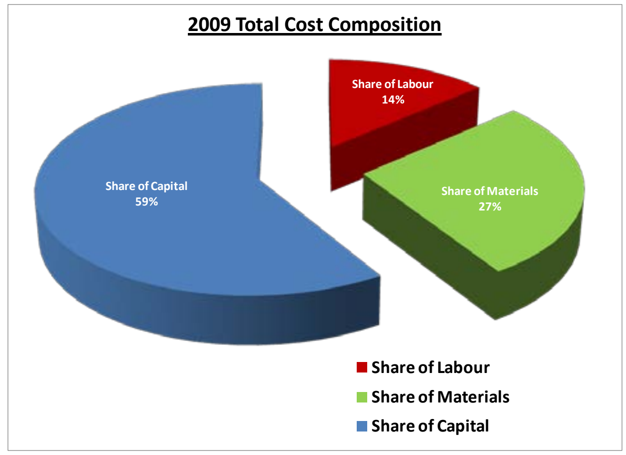
In order to understand the drivers of change, we examine the movements of inputs and outputs over time. The graph above shows the relative size of changes in both inputs and outputs over the entire horizon. The difference between the growth rate of outputs and the growth rate of inputs is equal to the growth rate in productivity.

The 1.10% per year productivity growth performance over the 2000-2007 period was due to outputs growing 2.19% per year, relative to inputs growing by 1.09% per year. During the IR term, the pace of productivity has increased due to both an increase in the pace of output growth and a reduction in the pace of input growth. Output growth increased to 2.63% per year, while input growth slowed to just 0.48% per year. Over the entire 2000-2009 period, output growth outpaced input growth by 1.33% per year, with outputs growing on an average annual basis by 2.29%, and inputs growing on an average annual basis by 0.96%.

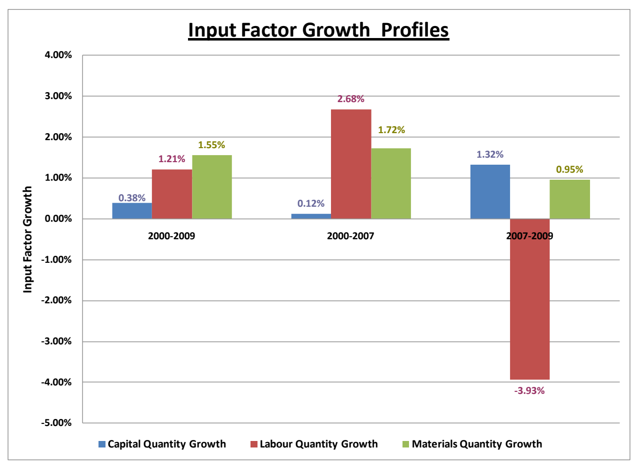
Input Growth Drivers

The composite input growth rate is derived by calculating the growth rates of each of the input quantities and combining them at each inputs' relative cost contribution for the given year. The graph below displays the relative cost shares for each of the materials, labour, and capital input components for 2009. The dominant share of EGD's cost structure relates to capital. Therefore, changes in capital quantities will generally dominate input growth and have the greatest impact on productivity. The materials and labour components are still important, representing approximately 41% of the total cost structure, however.

Looking at the relative changes for each of the input quantity components below reveals that over the 2000-2009 period total capital increased 0.38% per year, labour increased 1.21% per year, and materials increased by 1.55% per year. To derive the total input growth, the factor input growth rates are weighted by their relative cost shares, resulting in 0.96% total input growth over the whole period.



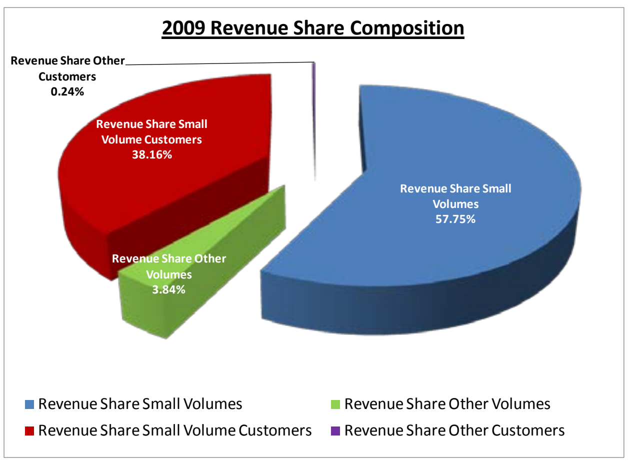
Over the 2000-2007 period, capital quantity grew by just 0.12% per year, non-capitalized labour quantity grew by 2.68% per year, and materials quantity grew by 1.72% per year, all combined for total input growth of 1.09% per year. Since the beginning of IR, the pace of growth in capital quantity increased to 1.32% per year, while the labour quantity declined by -3.93% per year, and materials quantity increased by just 0.95% per year.

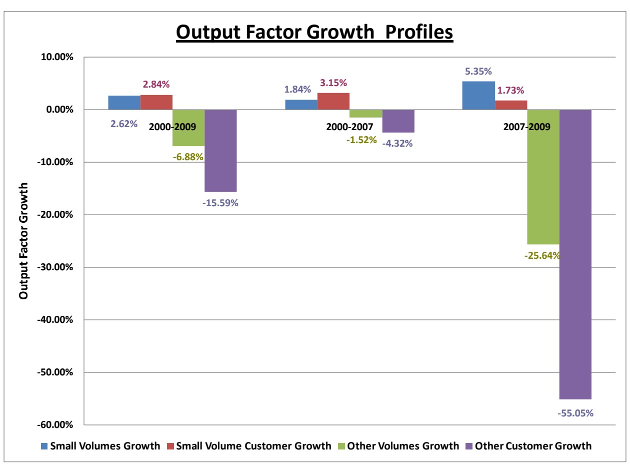


The net result is a change in the total input growth from 1.09% over the 2000-2007 period to just 0.48% over the 2007-2009 period. The change in relative input growth therefore contributed 0.61% of the total increased productivity growth in the post-IR period, or roughly 58% of the change.

Output Growth Drivers

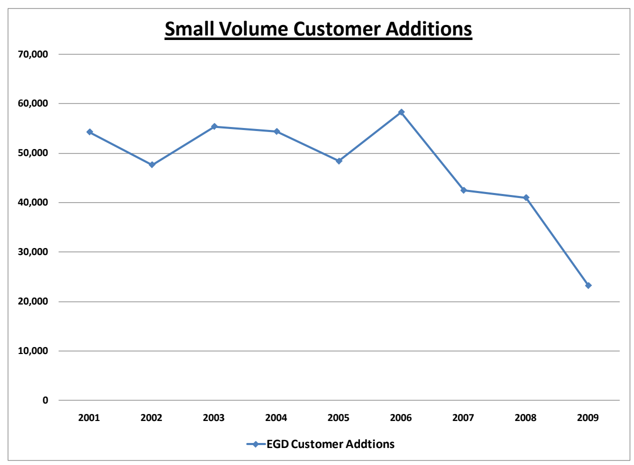
Similar to the construction of the composite input index, the composite output growth rate is derived by calculating the growth rates of each of the output quantities involved and combining them by their relative revenue contribution. The graph below displays the relative revenue shares for each of the residential volumes, residential customer charges, other volumes, and other customer charges for 2009. EGD's total revenue is predominately provided by small volume customers, with roughly 58% coming from volumetric charges and 38% coming from customer charges. The other 4% of revenues comes from the combination of other volumetric revenues and other customer related charges. Therefore, changes in small volume customers and volumes will dominate the changes in total output growth and have a greater impact on productivity, all else equal.





Over the entire 2000-2009 horizon the small volume volumes growth and the small volume customer growth positively contributed to output growth, growing 2.62% and 2.84%, respectively. The declines in other volumes were large, but did not significantly affect output growth because their combined revenue share contribution is very small. Other volumes decreased by 6.88% per year, while other customer growth declined by 15.59% per year. The large decline in other volumes and other customers can be largely attributed to the removal of rate 100 for commercial customers in 2009, where many of these customers migrated to the small volume rate 6 category.

General Service volumes increased by 1.84% per year over the 2000-2007 period, and then increased substantially to 5.35% per year through the IR period. Conversely, the pace of small volume customer growth declined to 1.73% per year during the IR period, down from 3.15% per year over the 2000-2007 period. This has mainly been due to slower economic and housing starts activity.



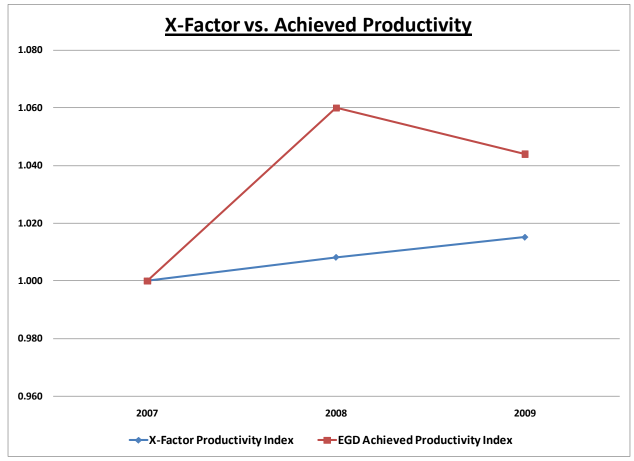
Going forward the sustainable pace of customer additions may have turned a corner. That is, prior to IR, customer growth averaged around 50,000 customers per year. However, since the beginning of IR the number of customer additions has slowed to an average of just over 30,000 customers per year. While this is attributable to slowing economic activity, it is questionable whether a return to 50,000 plus customers per year is attainable and/or sustainable. Further, as the customer base continues to grow, the percentage growth from customers has to decline by definition. That is, growing the customer base by 50,000 on 1.5 million customers, which was the reality for many of the pre-IR years, is a very different scenario growing the customer base by 30,000 on 2.0 million customers. Slowing the pace of customer additions, and accounting for a much larger customer base necessarily means that the overall growth rate from customer additions will slow over the next IR term.

While small volume customer growth slowed during the IR period, the number of customers and the volumes from the other customer categories actually turned negative. Other volumes declined by -1.52% per year prior to IR, and this pace increased to a 25.64% per year decline since the beginning of IR. Similarly, other customer growth declined by 4.32% per year prior to IR and then 55.05% per year since IR began. This was in due to customer migration away from Rate 100 and into Rate 6. In addition, the slower economic conditions since the beginning of IR have had a greater impact on large volume customers than on small volume customers in terms of volume and customer growth. The net result of all of the changes in output factors was a change in the total output growth from 2.19% over the 2000-2007 period to 2.63% during the IR period.

The change in relative output growth therefore contributed 0.44% of the total increased productivity growth in the post-IR period, or roughly 42% of the change.

Achieved Productivity vs. X-Factor Challenge

During the IR period, the annual growth in distribution revenue requirement per customer is directly tempered by a productivity offset, or X-Factor. In 2008, the X-Factor was calculated as 0.4 times the rate of inflation, and in 2009 as 0.45 times the rate of inflation, translating into X-Factor rates of 0.82% and 0.69%, respectively. On a compound growth rate basis, the X-Factor in the first year of the plan represented a 0.82% challenge, and by the second year a total 1.51% challenge. EGD's productivity achievement was 5.83% in the first year of the plan, and a compound total of 4.30% through the second year of the plan. This corresponds to an annual average of 2.15% improvement in productivity in each year.



UNDERTAKING J5.3

UNDERTAKING

TR 29

To show specifically which projects are qualified under what the Company describes as a fundamental technical regulatory shift, and relate that to line items on Exhibit B2, Tab 5, Schedule 1, Table 2.

RESPONSE

As described in Exhibit J5.11, the Company has been required to fundamentally shift its approach to integrity management to become more proactive for pipelines operating below 30% SMYS. The current 2012 TSSA CAD Amendment now requires Enbridge to implement a comprehensive program for proactively identifying risks and evaluating the corresponding risk reduction approaches and implementing corrective actions. Historically, the Company would have reacted to known failures and focussed on only mitigating these failures (for instance, Cast Iron mains). The results of Enbridge's efforts to comply with the language of CSA Z662-11 clause 3.2 and the expectations of the TSSA are seen in the Asset Plan (as explained in Exhibit B2-10-1, pp. 56 to 84), and are explained within the System Integrity and Reliability capital budget evidence at Exhibit B2 Tab 5.

This Undertaking requests that the Company evaluate the line items from Exhibit B2, Tab 5, Schedule 1, Table 2, in order to identify which of the programs described are a result of the "fundamental technical regulatory shift" and to compare this to Exhibit B2, Tab 5, Schedule 1, Table 13, Updated page 45. Enbridge has undertaken the requested exercise, but has looked at the details behind Exhibit B2, Tab 5, Schedule 1, Table 2. In the result, the table that Enbridge has prepared addresses the line items within the programs set out within each of the Mains, Services, Station Replacements, Other and Direct Resource Cost categories of System Integrity and Reliability Costs.

In Enbridge's view, the existence or the proposed scope of many of these programs are the result of/required by the change in regulation that mandates a proactive risk assessment model. However, it is difficult to determine what the budget requirements would have been over the forecast period if the 2012 TSSA CAD Amendment had not been enacted. In other words, some incremental amount undoubtedly would have been required simply based on industry best practices, industry incidents and prudent professional judgment.

Witness: J. Sanders

In the table below, Enbridge sets out its view of which programs have been impacted or required by the change in regulation. In some cases, the scope of the program has been impacted, while in other cases the entire program is a result of the regulation change. The dollar amounts indicated within the table below represent the incremental costs associated with the change in regulation.

Enbridge believes that it is important to note that some of the items/dollar amounts identified on the chart would have been pursued even without the change in regulation, so it would not be appropriate to conclude that this alternate view is what the Company would have filed should the legislation not have changed.

In any event, as can be seen in the table below, based on the Company's assessment, the incremental budget amounts required as a result of the 2012 TSSA CAD Amendment are material.

Description ($Million)	2014F	2015F	2016F	Total	Comments
Mains – Replacement (B2 T5 S2 p5)					
- Compression Couplings	1.62	2.04	2.06	5.72	
- Load Shed Planning Program	1.15	1.17	1.19	3.51	
- MOP Verification Program	3.30	3.40	3.20	9.90	
- ILI Inspection & Assessment (in part)	6.60	6.60	6.50	19.7	20% to 30% SMYS portion
- ROW Easement Monitoring Program	0.58	0.94	1.77	3.29	
Services (B2 T5 S3 p4)					
- AMP Fitting Replacement Program	8.54	13.10	30.05	51.71	
- COST Replacement Program	2.87	2.92	2.98	8.77	
- Service Replacement <$2M	2.12	1.03	1.22	4.37	
Station Replacements (B2 T5 S4 p5)					
- Gate Stations	4.94	3.70	3.27	11.90	
- District Stations	4.78	8.43	9.36	22.57	
- CLR Stations	1.76	1.79	1.83	5.38	
- Station Replacements <$2M	0.57	0.60	0.68	1.85	
Other (B2 T5 S5 p2)					
- DRM Program	8.37	8.74	7.70	24.81	Excludes Gate & District in 2014
Direct Resource Costs (B2 T5 S6 p2)					
- Incremental SI&R Resources	15.19	11.19	11.59	37.97	
- Contractor Fixed Costs	5.63	5.74	5.86	17.23	
Total	68.0	71.4	89.3	228.7	
B2 T5 S1 Table 13 Updated p45	132.3	135.1	141.1	408.5	

Witness: J. Sanders

UNDERTAKING J5.11

UNDERTAKING

TR 5/98 and TR 6/47-55

To provide FS-087-06 and Appendix with detailed requirements. This undertaking was expanded at TR6/47-55.

RESPONSE

Regulation Overview

There are three Director's Orders/Code Adoption Document Amendments (Regulatory Documents) of relevance. Each amends the original Code Adoption Document ("CAD") published by the Technical Standards Safety Authority ("TSSA") dated June 1, 2001. Each also adopts as the standard for oil and gas pipeline operators the standards set by the Canadian Standards Association ("CSA"). As noted below, the requirements and standards applicable to gas distribution systems changed with each of the three relevant documents identified in the Table below.

Regulation Chronology

	Reference No. of Order/Amendment	Date	CSA Standard Adopted
1.	FS-087-06	August 15, 2006	Z662-03
2.	FS-121-08	January 14, 2008	Z662-07
3.	FS-196-12	November 1, 2012	Z662-11

A copy of the requested 2006 TSSA Director's Order (FS-087-06), along with Appendix 1 (Guideline for gas distribution system integrity management programs) is attached (Attachment 1). Also attached are the 2008 TSSA CAD Amendment (FS-121-08) which superseded FS-087-06 (Attachment 2), and the current 2012 TSSA CAD Amendment (FS-196-12) (Attachment 3).

Witnesses: L. Lawler
J. Sanders

Overview of Changes

While the response below goes into greater detail about the changes between the various Regulatory Documents, the significant change of relevance which came into effect in 2012 is the fact that pipelines operating at or above 30% of Specified Minimum Yield Strength ("SMYS") and the integrity management program for pipeline systems operating less than 30% of SMYS were both required to comply with a new clause, Clause 3.2 of CSA Z662-11. Formerly, the provisions which applied to pipeline systems with a Maximum Operating Pressure ("MOP") of less than 30% of SMYS were not subject to the same mandatory language and prescriptive requirements which were required in respect of pipelines operating with a MOP at or above 30% of SMYS.

When one compares the language of the currently applicable Clause 3.2 of CSA Z662-11 to the language of Appendix 1 to Director's Order FS-087-06 or Annex M of CSA Z662-07 which was adopted by the 2008 TSSA CAD Amendment FS-121-08 (which applied at relevant times to pipeline systems with a MOP less than 30% of SMYS), it is clear that there has been a shift from non-mandatory language to the current mandatory "shall" requirements of Clause 3.2.

Detailed Response

As explained within Enbridge's testimony (see, for example 5Tr.11 to 15), and within the Asset Plan filed in this case (Exhibit B2-10-1, pages 58 to 62 and Appendix), the recent changes in the current 2012 TSSA CAD (FS-196-12) have increased the scope of what must be included within the distribution system integrity management programs ("DSIMP") for Ontario gas distributors. At a high level, the requirements for what must be included within the DSIMP for pipelines with a MOP less than 30% of SMYS are now mandatory, rather than optional. Most importantly, FS-196-12 mandated that pipeline operators assess the operating assets for potential risks, identify risk reduction requirements and implement corrective action plans, and monitor results. These are new mandatory requirements, which have led to a number of new or increased activities for the Company.

2006

The August 15, 2006 TSSA Director's Order FS-1087-06 revoked and substituted language under Chapter 12, Gas Distribution Systems, including language related to the DSIMP concept. Within clause 12.10.11.1 of the 2006 TSSA Director's Order (FS-087-06), operating companies were required to establish effective procedures for managing the integrity of pipeline systems with a MOP less than 30% of SMYS. In developing the DSIMP, it was noted that the operating company "shall consider

Appendix 1, Guidelines for Gas Distribution System Integrity Management Programs". Appendix 1 sets out items that "should" be included or considered within the DSIMP. This non-mandatory language signalled that the operating company had latitude in terms of what it decided to include within the DSIMP for pipeline systems with a MOP under 30% of SMYS. At the time of this Director's Order, the Company had all elements required for pipelines operating below 30% SMYS to meet this regulatory change (a management system, a working records management system, a condition monitoring program, and a mitigation program). Therefore there were no significant changes required to manage these assets. What did result from this requirement was the start of a new way to assess the assets more comprehensively, as can be seen in the 2008 Distribution System Integrity Management Program Annual Report at Exhibit J5.1.

2008

The subsequent January 14, 2008 TSSA CAD Amendment FS-121-08 (which superseded FS-087-06) also revoked and substituted language under Chapter 12, Gas Distribution Systems, including language related to the DSIMP concept. This 2008 TSSA CAD Amendment maintained the requirement for operating companies to establish effective procedures for managing the integrity of pipeline systems with a MOP less than 30% of SMYS. What changed was that the operating company was then directed to consider "Annex M" from CSA Z662-07 in developing the DSIMP, rather than Appendix 1 to FS-087-06. The language in Annex M is almost identical to FS-087-06, Appendix 1, with only minor wording adjustments in some line items. Therefore there was no significant change resulting from this 2008 TSSA CAD Amendment for pipelines operating below 30% SMYS.

Between 2008 and 2012, the Company continued to consider incidents and industry trends that informed the approach to Asset Management and DSIMP to continuously improve its processes. As part of the Company's direct involvement in the CSA standards development and the TSSA Risk Reduction Groups and Gas Advisory Council, EGD was involved in the shift in thinking from a failure based to a risk based approach to integrity management. In anticipation of the coming regulatory change (which is described below), the Company undertook activities to systematically and comprehensively understand asset risk which culminated in the production of the first iteration of the Asset Plan (completed May 2012).

2012

In November 2012, the TSSA issued CAD Amendment FS-196-12. That document changed the requirements from the 2008 TSSA CAD Amendment FS-121-08 for the

DSIMP for pipelines with an MOP of less than 30% SMYS. The current 2012 TSSA CAD Amendment FS-196-12, adopts the CSA Z662-11, and now amends a clause in Chapter 12 by adding the following clause:

> 12.10.16
> Operating companies shall establish effective procedures for managing the integrity of pipeline systems with an MOP less than 30% of SMYS (Distribution Systems) so that they are suitable for continuous service, in accordance with the applicable requirements of clause 3.2 of CSA Z662-11.

It is noteworthy that Clause 10.3.10 of FS-196-12 also requires pipelines with an MOP of 30% or more of SMYS to comply with the applicable requirements of Clause 3.2 of CSA Z662-11. A note following Clause 3.2 points to Annex N of the CSA Z662-11 for all pipelines. The CSA Z662-07 Annex M is not part of the new standard. This is the first time that the integrity management program required in respect of pipelines and systems operating at a MOP above and below 30% of SMYS were directed to the same code, clause and Annex. Prior to this, each was referred to separate codes or appendices which were not identical.

Therefore, with FS-196-12 Clauses 10.3.10 and 12.10.16 coming into force, the TSSA has deliberately directed Ontario's natural gas utilities to the same CSA clause which governs the development of the required system integrity programs. These requirements now cover all pipelines, regardless of whether they operate with a MOP of above or below 30% of SMYS.

A further change of note with the adoption by FS-196-12 and Z661-11 versus the previous version (CSA Z662-07) was the addition of the new Chapter 3, Safety and loss management systems, integrity management programs, and engineering assessments for oil and gas industry pipeline systems. Enbridge Gas Distribution's interpretation is that this new chapter applies to all pipelines, independent of % SMYS value.

Clause 3.2 is reproduced below. As can be seen from the bolded phrases there is now new mandatory language for pipelines operating under 30% SMYS. This is a change from the non-mandatory optional language included in earlier guidelines referenced in the 2006 TSSA Director's Order and 2008 CAD Amendment.

> 3.2 Pipeline system integrity management program
> Operating companies shall develop and implement an integrity management program that includes effective procedures (see Clauses 10.3 and 10.5) for managing the integrity of the pipeline system so that it is suitable for continued service, including procedures to monitor for conditions that can lead to failures, to eliminate or mitigate such condition and to manage integrity data. **Such integrity management programs <u>shall</u> include a**

description of operating company commitment and responsibilities, quantifiable objectives, and methods for

- **(a) assessing current potential risks;**
- **(b) identifying risk reduction approaches and corrective actions;**
- **(c)** implementing the integrity management program; **and**
- **(d) monitoring results**.

Bullet (c) in the above clause represents all of the mandatory requirements from the previous versions of the TSSA 2006 and 2008 Regulatory Documents. The bolded items had not previously been mandatory.

This change represents a fundamental shift in assessing and mitigating the Company's operating assets. This requires a comprehensive program for proactively identifying risks and evaluating the corresponding risk reduction approaches and implementing corrective actions. Historically, the Company would have reacted to known failures and focussed on only mitigating these failures (for instance, Cast Iron mains).

The Company continues to address known failures within the framework of the required DSIMP in addition to assessing potential risks associated with all operating assets (above and below 30% SMYS) for potential risks.

This requires significantly more effort than the historic approach and the result has led to new proactive and prudent programs for risk reduction. Assessing the current potential risk of all operating distribution assets requires first a determination of what the potential risks could be. For each type of asset there are a number of potential failures that could occur, with corresponding probabilities.

Using mains as an example, the Company must assess the approximate 36,000 km of pipelines for risk. Risk manifests as the product of probability of failure and consequence of failure. The probability of failure can be influenced by type of material including material specification, by operating pressure, by age, by ground conditions, history of leaks, corrosion, etc. The consequence of failure can be influenced by proximity to the public, other assets, other infrastructure, by operating pressure, customer demand, system configuration, number of supply points, etc. The complexity compounds when other asset classes are included, such as services, measurement, regulation and control facilities, fittings, etc.

The outcome of this new approach to integrity management will result in a prudent reduction in operating risk which will have a positive impact both on the Company's ratepayers and workers.

Witnesses: L. Lawler
J. Sanders

Conclusion

Before the current 2012 TSSA CAD Amendment came into effect, the above concepts were written (within Appendix 1 of FS-187-06 and Annex M of CSA Z662-07 associated with FS-121-08) in non-mandatory language, i.e., should and should consider, not shall. In other words, while the 2006 and 2008 TSSA requirements indicated that an operating company had to have a DSIMP that included a management system, records management system, condition monitoring program and mitigation program, it was not until the 2012 TSSA CAD Amendment that it became mandatory to include and implement systematic proactive asset management approaches of the type set out within Enbridge's current Asset Plan.

The results of Enbridge's efforts to comply with the language of CSA Z662-11 Clause 3.2 and the expectations of the TSSA are seen in the Asset Plan (as explained in Exhibit B2-10-1, pp. 56 to 84), and are explained within the System Integrity and Reliability capital budget evidence at Exhibit B2 Tab 5. At Exhibit J5.3, Enbridge sets out examples of capital budget projects in the coming years that are responsive to the updated requirements of the current TSSA CAD Amendment.

Witnesses: L. Lawler
J. Sanders

Fuels Safety Program	Ref. No.: FS- 087- 06	Rev. No.:
DIRECTOR'S ORDER	Date: August 15, 2006	Date:

IN THE MATTER OF:
THE TECHNICAL STANDARDS AND SAFETY ACT, 2000, S.O. 2000, c. 16

- and -

ONTARIO REGULATION 223/01 (Codes and Standards Adopted by Reference)
- and –
-
ONTARIO REGULATION 210/01 (Oil and Gas Pipeline Systems)

Subject: Amendment to the Oil and Gas Pipeline Systems Code Adoption Document
Sent to: Gaseous Fuels Advisory Council, Pipeline RRG, Posted on TSSA's Web-Site

The Director of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems) pursuant to section 8 of Ontario Regulation 223/01 (Codes and Standards Adopted by Reference) hereby provides notice that the Oil and Gas Pipeline Systems Code Adoption Document published by the Technical Standards & Safety Authority and dated June 1, 2001, as amended, is amended as follows:

All sections of the Oil and Gas Pipeline Systems Code Adoption Document (Sections 1 to 5) are revoked and replaced with the following:

Section 1

REFERENCE PUBLICATIONS

1.(1) The reference publications as set forth herein are approved by the Director and adopted as part of this Document and the standards, procedures and requirements therein, as applicable to this Document, shall be complied with by operating companies as well as anyone engaged in the design, construction, erection, alteration, installation, testing, operation or removal of a pipeline, for the transmission of oil or gas or the distribution of gas.

Government of Ontario

Technical Standards & Safety Act, 2000, Ontario Regulation 220/01 (Boilers and Pressure Vessels)

Canadian Standards Association

Service Regulators for Natural Gas, CSA 6.18-02

Section 2

GENERAL REQUIREMENTS

2. (1) The Standards issued by the Canadian Standards Association entitled Oil and Gas Pipeline Systems Z662-03, as amended by this Director's Order, and CSA Z276-01 Liquefied Natural Gas (LNG) – Production, Storage and Handling and the standards, specifications, codes and publications set out therein as reference publications insofar as they apply to the said Standards are adopted as part of this Document, with the following changes for the CSA-Z662-03 Standard:

(2) Clause 1.2 is amended by adding the following item:

(g) pipelines that carry gas to and from a well head assembly of a designated storage reservoir.

(3) Clause 1.3 is amended by adding the following items:

(p) digester gas or gas from landfill sites
(q) multiphase fluids
(r) gathering lines
(s) offshore pipeline systems
(t) oil field steam distribution pipeline systems oil field water services
(u) carbon dioxide pipeline systems.

(4) Clause 4.1.6 is revoked and the following substituted:

4.1.6 Subject to prior review by the Director, it shall be permissible for steel oil and gas pipelines to be designed in accordance with the requirements of Annex C, provided that the designer is satisfied that such designs are suitable for the conditions to which such pipelines are to be subjected.

(5) Clause 7.10.2.2 is revoked and the following substituted:

7.10.2.2 For HVP and for sour service pipeline systems, all butt welds shall be inspected by radiographic or ultrasonic methods, or a combination of such methods, for 100% of their circumferences, in accordance with the requirements of clause 7.10.4.

(6) Clause 10.4.10 is amended by adding the following clauses:

10.4.10.7 Operating companies shall inform agencies to be contacted during an emergency, including the police and fire departments about the hazards associated with its pipelines.

10.4.10.8 Operating companies shall prepare an emergency response plan and make it available to local authorities.

(7) Clause 10.5 is amended by adding the following clause:

10.5.5 Right-of-Way Encroachment

10.5.5.1 It shall be prohibited to install patios or concrete slabs on the pipeline right-of-way or fences across the pipeline right-of-way unless written permission is first obtained from the operating company.

10.5.5.2 It shall be prohibited to erect buildings including garden sheds or to install swimming pools on the pipeline right-of-way. Storage of flammable material and dumping of solid or liquid spoil, refuse, waste or effluent, shall be also forbidden.

10.5.5.3 Operating companies shall be allowed to erect structures required for pipeline system operation purposes on the pipeline right-of-way.

10.5.5.4 No person shall operate a vehicle or mobile equipment except for farm machinery and personal recreation vehicles across or along a pipeline right-of-way unless written permission is first obtained from the operating company or the vehicle or mobile equipment is operated within the traveled portion of a highway or public road.

10.5.5.5 Operating companies shall develop written procedures for periodically determining the depth of cover for pipelines operated over 30% of SMYS. Such written procedures shall include a rationale for the frequency selected for such depth determinations. Where the depth of cover is found to be less than 60 cm in lands being used for agriculture, an engineering assessment shall be done in accordance with clause 10.11.2 and a suitable mitigation plan shall be developed and implemented to ensure the pipeline is adequately protected from hazards.

(8) Clause 10.11.2 is amended by adding the following items:

10.11.2.6 The Director may require operating companies or a person to submit a design, specification, program, manual, procedure, measure, plan or document to the Director if:

a) the operating company or person makes an application to the Director under subsections 18.(1) 1, 18(1) 3 and 16 (6) of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems).

b) the Director has reasons to believe that the design, construction, operation or abandonment of a pipeline, or any part of a pipeline is or may cause

i. a hazard to the safety of the public or to the employees of the operating company

ii. an adverse effect to the environment or to property, or

c) the Director wishes to assess the operating company's pipeline integrity management program.

10.11.2.7 For the protection of the public, the pipeline, and the environment, an operating company shall develop a pipeline integrity management program for steel pipelines with a MOP of 30% or more of the SMYS. The pipeline integrity management program shall contain:

a) a management system,
b) a working records management system,
c) a condition monitoring program, and
d) a mitigation program.

10.11.2.8 When developing the pipeline integrity management program, an operating company shall consider Z662S1-05 Supplement No. 1 to CAN/CSA-Z662-03, Oil and Gas Pipeline Systems, Annex N, Guidelines for Pipeline Integrity Management Programs. The implementation of this program based on Annex N must be completed no later than June 30, 2007. In the interim, the requirements outlined in Appendix 2 shall apply.

(9) Clause 10.11.3.1 is revoked and the following substituted:

10.11.3.1 Prior to a change in service fluid, including sweet to sour, the operating company shall conduct an engineering assessment to determine whether it would be suitable for the new service fluid. The assessment shall include consideration of the design, material, construction, operating, and maintenance history of the pipeline system and be submitted to the Director for approval.

(10) Clause 10.13.1.2 is amended by adding the following items:

(e) maintain warning signs and markers along the pipeline right-of-way,
(f) maintain existing fences around above ground pipeline facilities, and
(g) empty tanks and purge them of hazardous vapours.

(11) Clause 12.4.8.1 is renumbered as clause 12.4.8.1.1. Clause 12.4.8 is amended by adding the following clauses:

12.4.8.1.2 All new and replacement natural gas service regulators shall comply with the requirements of CSA 6.18-02 standard, Service Regulators For Natural Gas, including the Drip and Splash Test contained in Appendix A of the said Standard. Where a regulator – meter set installation or supplemental protective devices that is providing equivalent protection against regulator vent freeze up, passes a successful test in accordance to Appendix C of the said Standard, the requirements of Appendix A (Drip and Splash Test) and those contained in Clause 14.15 (Freezing Rain Test) of the Standard are waived. Evidence of test made in accordance with Appendix C, shall be kept by the operating Company as permanent records.

12.4.8.1.3 Regulator-meter set configurations shall be included in the operating company's operating and maintenance procedures.

(12) Clause 12.4.10.6 is amended by replacing the second sentence with the following:

…Clearances from building openings shall be commensurate with local conditions and the volume of gas that might be released, but shall not be less than those required by CSA B149.1 clause 5.5.9 as amended by Item 1.12 of the Gaseous Fuels Code Adoption Document…

Note: The amendment to clause 5.5.9 of CSA B149.1 by the Gaseous Fuels Code Adoption Document adds a new column to the "Table 5.2 – Pipe Threshold Stress Values", found in the CSA B149.1, that states: "The discharge clearances from relief device openings with capacities under 50 cf/h (1.5 m^3 /h) will be 1 ft. (.3 m) to a building opening, appliance vent outlet, appliance air intake or source of ignition, and 3 ft. (1 m) to a mechanical air intake".

(13) Clause 12.10.9 is amended by adding the following:

12.10.9(e For polyethylene piping installed in Class 1 and Class 2 location, the upgraded maximum operating pressure shall not exceed the design pressure calculated in accordance with the requirements of Clause 12.4.2.1; and

12.10.9(f) For polyethylene piping installed in Class 3 and Class 4 location, the upgraded maximum operating pressure shall not exceed the design pressure calculated in accordance with the requirements of clause 12.4.2.1.1 with a combined design factor and temperature derating factor (F x T) of 0.32.

(14) Clause 12.10.11.1 is revoked and the following substituted:

12.10.11.1.1 Operating companies shall establish effective procedures for managing the integrity of pipeline systems with a MOP less than 30% of SMYS (Distribution Systems) so that they are suitable for continued service. The integrity management program shall contain:

a) a management system;
b) a working records management system;
c) a condition monitoring program, and
d) a mitigation program.

12.10.11.1.2 When developing the distribution system integrity management program (DSIMP), an operating company shall consider Appendix 1, Guidelines for Gas Distribution System Integrity Management Programs (DSIMP).

12.10.11.1.3 The Director may require operating companies or a person to submit a design, specification, program, manual, procedure, measure, plan or document to the Director if:

a) the operating company or person makes an application to the Director under Section 18.(1) 1 and 18(1) 3 of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems).

b) the Director has reasons to believe that the design, construction, operation or abandonment of a pipeline, or any part of a pipeline is or may cause
i. a hazard to the safety of the public or to the employees of the operating company
ii. an adverse effect to the environment or to property, or

c) the Director wishes to assess the operating company's DSIMP.

12.10.11.1.4 The implementation of DSIMP shall be completed no later than April 30, 2008.

Section 3

POLYETHYLENE PIPE CERTIFICATION

3. (1) Polyethylene piping and fittings that are used in a polyethylene gas pipeline shall be certified by a designated testing organization accredited by the Standards Council of Canada as conforming to the CAN/CSA-B137.4-99 - Polyethylene Piping Systems for Gas Services.

Section 4

WELDER QUALIFICATION
4. (1) Welds shall not be made in any steel pipe that forms or is intended to form a part of a steel oil or gas pipeline or a component of a steel oil or gas pipeline unless the welder is qualified to make the weld in accordance with the requirements of the CSA Z662 Standard as adopted under section 2 of this document and is the holder of the appropriate authorization issued under Ontario Regulation 220/01 (Boilers and Pressure Vessels), made under the *Technical Standards & Safety Act, 2000*.

Section 5

In the event of a conflict between any provision of a standard, specification, code or publication adopted in this document, this document shall prevail.

Any person involved in an activity process or procedure to which this document applies shall comply with this document.

The said amendments are effective immediately.

Dated at Toronto this 15th_day of August, 2006.

____
Roland Hadaller
Statutory Director
Ontario Regulation 210/01 (Oil and Gas Pipeline Systems)
made under the *Technical Standards & Safety Act, 2000*

Appendix 1

Guideline for gas distribution system integrity management programs (DSIMP)

1.0 Introduction

1.1 This Appendix provides guidelines for developing, documenting, and implementing an integrity management program (DSIMP) for gas distribution systems. The purpose of a DSIMP is to prevent or mitigate conditions leading to failure incidents with significant consequences, so that distribution systems are capable of providing safe and reliable service.

1.2 The major components in a DSIMP are detailed in this Appendix.

2.0 Definitions

"Failure incident" – means an unplanned release of gas due to failure of a pipe or component.

"Damage incident" – means an event that results in a pipe, component or coating defect, without release of service fluid.

"Hazard" – includes any condition that might cause a failure or damage incident.

3.0 Integrity management program scope

3.1 A gas DSIMP should include methods to collect, integrate, and analyze information related to:

(a) design and construction;
(b) maintenance and repair;
(c) operating conditions;
(d) failure incidents with significant consequences;
(e) damage incidents, and
(f) damage and deterioration.

3.2 Gas distribution companies should document the facilities included in the DSIMP. When parts of the distribution system are not included in the DSIMP, reasons for such exclusions should be stated.

4.0 Corporate policies, objectives, and organization

4.1 Gas distribution companies should have statements of integrity-related corporate policies, values, and objectives, and performance indicators.

4.2 Gas distribution companies should document the types of consequences they consider to be significant and the rationale for determining their significance.

4.3 Gas distribution companies should document those positions responsible for key integrity-related activities.

5.0 Integrity management program records

5.1 Gas distribution companies should prepare and manage records related to gas distribution system design, construction, operation, and maintenance that are needed to perform the activities included in a DSIMP.

5.2 The methods and results for the activities described in this Appendix should be documented.

5.3 Gas distribution companies should document the methods used for managing DSIMP records. Items that should be considered include:

(a) responsibilities and procedures for the creation, updating, retention, and deletion of records;
(b) evidence of past activities, events, changes, analyses, and decisions; and
(c) an index describing the types, forms, and locations of records.

6.0 Competency and training

6.1 Gas distribution companies shall utilize personnel that have appropriate knowledge and skills to perform tasks associated with the development and implementation of the DSIMP.

6.2 Gas distribution companies should consider documenting the methods used to evaluate the integrity management knowledge and skills of their personnel.

6.3 Where evaluation of the knowledge and skills indicates that development is required, training should be arranged. Such training should include:

(a) formal training courses provided by educational institutions or industry organizations;
(b) workshops and conferences related to gas distribution system integrity;
(c) technical committees of industry and standards development organizations;
(d) research and development projects related to gas distribution system integrity; and
(e) supervised work experience.

7.0 Change Management

7.1 Gas distribution companies should have a documented change management process to manage changes that may affect the integrity of the gas distribution system.

7.2 The change management process should have procedures in place to address and document, where applicable, items such as:

(a) monitoring to identify anticipated and actual changes that may affect gas distribution system integrity;
(b) responsibilities for approving and implementing changes;
(c) analysis of implications and effects of the changes;
(d) communication of changes to affected parties;
(e) timing of changes; and
(f) reasons for the changes.

8.0 Hazard identification and control

8.1 Gas distribution companies should identify and document hazards that can lead to a failure or damage incident with significant consequences.

8.2 The methods and data used for hazard identification should be documented, taking into consideration the primary causes and any additional failure or damage incident causes that are relevant.

8.3 Where hazards that may lead to a failure or damage incident with significant consequences are identified, the gas distribution company should:

(a) assess and document the risks associated with such hazards in accordance with the provisions of sections 9.0 to 9.4 of this Appendix.

(b) implement and document actions to monitor for conditions that can lead to failures or damage incidents; and

(c) implement and document actions to eliminate or mitigate conditions that can lead to failure or damage incidents.

9.0 Risk assessment

Gas distribution companies should consider incorporating risk assessment in a DSIMP. This section provides guidance to distribution companies for conducting risk assessments. For further guidance see Annex B of CSA Z662-03.

9.1 Risk analysis approach

When selecting an appropriate approach for performing risk analysis, gas distribution companies should consider:

(a) the features that are unique to the design, construction and operation of the gas distribution system;

(b) existing screening and analysis approaches;

(c) the availability of procedures, models, and information needed to perform the analysis; and

(d) how the results of the risk assessment will be used.

9.2 Risk analysis refinement

Gas distribution companies should consider methods to refine its risk analysis including the following options:

(a) a review of its risk analysis approach; and

(b) additional observations and analysis of the operating conditions.

9.3 Risk Evaluation

Gas distribution companies should have methods to evaluate gas distribution system risk. This may include:

(a) establishment of various risk levels; and

(b) methods or approaches to screen and, where appropriate, further refine risk analysis.

9.4 Risk reduction validation

The risk analysis and risk evaluation should be repeated to establish that the options selected reduce the estimated risk to a level that is considered to be not significant.

10.0 Options for hazard control and risk reduction

10.1 Operator errors

Options that can be used to reduce the frequency of failure incidents associated with operator error should include items such as:

(a) personnel training;
(b) improved system monitoring methods;
(c) modified operating and maintenance practices; and
(d) improvements or modifications to piping and equipment.

10.2 External interference

Options that can be used to reduce the frequency of failure incidents associated with external interference include items such as:

(a) participation in one-call utility location organizations;
(b) improved public awareness and education of the presence of the gas distribution system;
(c) additional vegetation control, markers and signs to identify the presence of gas distribution facilities;
(d) improved procedures for gas distribution system location and excavation; and
(e) installation of structures or materials to protect the gas distribution system from damage.

10.3 Gas distribution system defect~~s~~ or malfunction~~s~~

Options that can be used to reduce the frequency of failure or damage incidents associated with gas distribution system defects or malfunctions include, where applicable, items such as:

(a) improved quality measures for manufacturing, design, construction and operations;
(b) improved failure detection measures;
(c) temporary or permanent reductions in the established operating pressure; and
(d) assessment, repair rehabilitation and replacement measures.

10.4 Natural hazards

Options that can be used to reduce the frequency of failure or damage incidents associated with natural hazards include where applicable, items such as:

(a) the design and location of facilities and materials that eliminate or mitigate the potential for failure incidents;
(b) the design and installation of structures or materials to protect the gas distribution system from external loads;
(c) programs to monitor pipe or soil movement;
(d) increased monitoring and inspection measures;
(e) excavation and reburial to relieve loads on the facilities; and
(f) relocation of facilities.

10.5 Consequence reduction

Options that can be used to reduce the consequences associated with failure or damage incidents include, where applicable, items such as:

(a) improved system and facility design;
(b) improved measures for early detection of a failure or damage incident;
(c) improved public awareness and education; and
(d) improved emergency response procedures.

11.0 Gas DSIMP planning

11.1 Gas distribution companies should develop and document plans for completion of activities related to their gas distribution integrity management.

11.2 DSIMP planning should include, in addition to other clauses in this Appendix, consideration of the following:

(a) failure and damage incident history of the gas distribution company;
(b) recommendations from previous integrity reviews and activities;
(c) the presence or potential growth of known conditions that may lead to failure incidents; and
(d) industry experience.

11.3 DSIMP plans should include steps to review completed integrity activities in order to:

(a) verify that the relevant methods and procedures for such activities were properly performed;
(b) determine if the intended objectives were achieved;
(c) identify incomplete work and unresolved issues;
(d) develop recommendations and plans for future work; and
(e) verify that the relevant records were created or revised.

12 DSIMP implementation

12.1 Gas distribution companies should document and implement methods and procedures to inspect, test, patrol, and monitor in accordance with the requirements of Clauses 9, 10, and 12 of CSA Z662-03.

12.2 The rationale used to determine the timing or frequency should be documented. Consideration to both indirect and direct assessment methods should be made.

12.3 Gas distribution companies should consider the need for supplemental inspections using more direct methods, where an inspection is performed using indirect methods.

12.4 Records of inspections, testing, patrols, and monitoring activities should include:

(a) dates when performed;
(b) equipment used;
(c) results and observations; and
(d) evaluation of the acceptability of the results and observations.

13.0 Evaluation of results

13.1 Where apprised of conditions that may lead to a failure incident with significant consequences, gas distribution companies should:

(a) perform an engineering assessment as specified in Clause 12.10.11.2 of CSA Z662-03; and
(b) perform corrective action as specified in Clause 10.11.2.3 of CSA Z662-03.

13.2 Portions of the gas distribution system with indications of imperfections shall be subject to detailed visual inspection, mechanical measurement, non-destructive inspection as deemed appropriate by the gas distribution company. Evaluation shall be as specified in Clause 10.8 limited by Clauses 12.10.6 and 13 of CSA Z662-03.

14.0 Mitigation

14.1 Gas distribution companies should document the types of corrective actions that will be considered for anticipated conditions that may cause a failure incident with significant consequences.

15.0 Failure and damage incident investigations

15.1 Gas distribution companies should develop procedures for investigating and reporting failure and damage incidents. Failure incidents shall be addressed in accordance with the requirements specified in Clause 12.10.2.2.3 of CSA Z662-03.

15.2 Such procedures should include, where applicable an analysis to determine the need for changes to improve the effectiveness of the DSIMP.

16.0 Program review and evaluation

16.1 Gas distribution companies shall periodically review and evaluate their DSIMPs to determine if it is in accordance with the provisions of this Guideline and be revised, as necessary. Such review shall give consideration to the root causes of failure incidents. The methods and responsibilities for review and evaluation and the results of such reviews shall be documented. Gas distribution companies shall also consider having audits performed on their DSIMPs.

Appendix 2

Pipeline Integrity Management for Pipelines with a Maximum Operating Pressure (MOP) over 30% SMYS

(Interim requirements until June 30, 2007)

1.0 The Director may require operating companies or a person to submit a design, specification, program, manual, procedure, measure, plan or document to the Director if the Director wishes to assess the operating company's pipeline integrity management program (IMP).

1.1 For the protection of the public, the pipeline and the environment, an operating company shall develop a IMP for steel pipelines operating at 30% or more of the SMYS. The IMP shall contain:

a) a management system;

b) a working records management system;

c) a condition monitoring program, and

d) a mitigation program.

1.3 When developing the pipeline IMP, an operating company shall consider the following:

a) **In the management system:**

(i) the program scope, including a description of facilities, goals and objectives;
(ii) the organizational lines of responsibility for the IMP, including the reporting requirements to senior management;
(iii) the training of management and staff required to develop and execute the IMP;
(iv) the qualifications of consultants and contractors required to develop and execute the IMP;
(v) the methods of keeping abreast of industry practice and current research activities;
(vi) the methods to be used to manage change in respect of the design, construction and operation of the pipeline; and
(vii) the methods to be used to measure the effectiveness of the program.

b) **In the working records management system (RMS):**

The maintenance of an RMS that would allow timely access by sections to records regarding the pipeline system. Where practicable, the RMS should include information on the original pipe and all repairs such as:

(i) pipe material, manufacturer and date of manufacture, category, seam and girth weld type, grade, welder identification, non-destructive examination records, heat number, weld maps (e.g. weld number, non-destructive examination type and number);
(ii) coating type for line pipe, joints and tie-ins, manufacturer, application method and weather condition at the time of application;

(iii) repair history (e.g. location and type of repair, type and specification of sleeves, hot taps, grinding, cut-outs and replacements, type of defects, cut out or repaired, major coating repairs, and re-coating specifications);
(iv) mapping (e.g. location of pipelines including class location, depth of cover, location of buried valves and flanges, and geotechnical data);
(v) all pressure test data and records, maximum operating pressure, construction drawings, in-line inspection (ILI) tool data and reports, corrosion control and cathodic protection records including design and survey results;
(vi) inspection records of pressure relieving and emergency shutdown devices;
(vii) valve inspection records;
(viii) documentation of condition monitoring and mitigation programs and past condition monitoring and mitigation decision analyses; and
(ix) review of IMP effectiveness as outlined in 10.11.2.8 a).

c) **In the condition monitoring program:**

An internal inspection with ILI tools (e.g. caliper, metal loss), where such tools are commercially available, an engineering assessment (EA) of pipeline segments to address pipeline integrity. Both time dependent (e.g. corrosion, stress corrosion cracking, hydrogen induced cracking and fatigue) and non-time dependent (e.g. manufacturing defects, third party damage and geotechnical (slope stability, and stream washout) hazards that are to be considered and investigated in the EA. The EA should consider the results of such methods as pressure testing, use of ILI tools and investigative digs. The risk assessment (RA) method to be used when assigning priorities for integrity evaluations of facilities or line segments. Factors to be included in the RA are items such as: pipeline age and condition, coating age and condition, cathodic protection data and ILI data. Consideration should be given to determining the area affected (consequence) by a product release, where appropriate, monitoring and surveillance programs for slope movement, river crossing, depth of cover, frost heave and thaw settlement; a program to minimize third party damage, including line patrols; the methods used to evaluate and maintain pipeline integrity and the criteria for their application, which may include:

(i) the use of the appropriate ILI tool technology and the methods used to verify ILI findings;
(ii) the hydrostatic retesting procedure;
(iii)the corrosion control monitoring methods and cathodic protection survey documentation;
(iv) the method used to evaluate remaining life where defects exist;
(v) the methods used to verify the coating type and condition; and
(vi) any other method utilized for defect detection.
(vii) the procedures used to track, analyze and trend the condition of the pipeline and its coating; and
(viii) the steps to be taken to evaluate the cause of the line or facility failure including the minimum investigation and requirements (e.g. cut-out, metallurgical analysis).

d) **In the mitigation program:**

(i) the criteria and procedures for evaluation of imperfections and repairs of piping containing defects;
(ii) the procedures for performing consequence analysis to establish repair priorities;

(iii) the criteria and procedures for consideration of such measures as pipe replacement (e.g. cut-out), repair (e.g. grinding, sleeving (steel or fiberglass), hot taps, hot work, excavation procedures, maintenance welding, recoating, hydrostatic retesting and reduction in operating pressure (temporary or permanent); and
(iv) an outline of the short term (e.g. 1 to 3 year(s)) and long term (e.g. 4 to 10 years) IMP plans and priorities.

Fuels Safety Program	Ref. No.: FS-121-08	Rev. No.:
Oil and Gas Pipeline Systems Code Adoption Document - Amendment	Date: January 14, 2008	Date:

IN THE MATTER OF:
***THE TECHNICAL STANDARDS AND SAFETY ACT, 2000, S.O. 2000, c. 16* (the "Act")**

- and -

ONTARIO REGULATION 210/01 (Oil and Gas Pipeline Systems) made under the Act

and

ONTARIO REGULATION 223/01 (Codes and Standards Adopted by Reference) made under the Act

Subject: Amendments to the Oil and Gas Pipeline Systems Code Adoption Document adopted by reference as part of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems)

Sent to: Gaseous Fuels Advisory Council, Pipeline RRG, Posted on TSSA's Web-Site

The Director of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems) pursuant to section 8 of Ontario Regulation 223/01 (Codes and Standards Adopted by Reference) hereby provides notice that the Oil and Gas Pipeline Systems Code Adoption Document published by the Technical Standards & Safety Authority and dated June 1, 2001, as amended, is amended as follows:

All sections of the Code Adoption Document (Sections 1 to 5) are revoked and replaced with the following:

Section 1

REFERENCE PUBLICATIONS

(1) The reference publications as set forth herein are approved by the Director and adopted as part of this Document and the standards, procedures and requirements therein, as applicable to this Document, shall be complied with by operating companies as well as anyone engaged in the design, construction, erection, alteration, installation, testing, operation or removal of a pipeline, for the transmission of oil or gas or the distribution of gas.

Government of Ontario

Technical Standards & Safety Act, 2000, Ontario Regulation 220/01 (Boilers and Pressure Vessels)

Canadian Standards Association

Service Regulators for Natural Gas, CSA 6.18-02

Section 2

GENERAL REQUIREMENTS

2. (1) The Standards issued by the Canadian Standards Association entitled Oil and Gas Pipeline Systems Z662-07 and CSA Z276-07 Liquefied Natural Gas (LNG) – Production, Storage and Handling and the standards, specifications, codes and publications set out therein as reference publications insofar as they apply to the said Standards are adopted as part of this Document, with the following changes to the CSA-Z662-07 Standard:

(2) Clause **1.2** is amended by adding the following item:
(h) pipelines that carry gas to and from a well head assembly of a designated storage reservoir.

(3) Clause **1.3** is amended by adding the following items:
(p) digester gas or gas from landfill sites
(q) multiphase fluids
(r) gathering lines
(s) offshore pipeline systems
(t) oil field steam distribution pipeline systems oil field water services
(u) carbon dioxide pipeline systems.

(4) Clause **4.1.7** is revoked and the following substituted:
4.1.7 Subject to prior review by the Director, it shall be permissible for steel oil and gas pipelines to be designed in accordance with the requirements of Annex C, provided that the designer is satisfied that such designs are suitable for the conditions to which such pipelines are to be subjected.

(5) Clause **7.10.3.2** is revoked and the following substituted:
7.10.3.2 For HVP and for sour service pipeline systems, all butt welds shall be inspected by radiographic or ultrasonic methods, or a combination of such methods, for 100% of their circumferences, in accordance with the requirements of clause 7.10.4.

(6) Clause **10.5.10** is amended by adding the following clauses:
10.5.10.7 Operating companies shall inform agencies to be contacted during an emergency, including the police and fire departments about the hazards associated with its pipelines.

10.5.10.8 Operating companies shall prepare an emergency response plan and make it available to local authorities.

(7) Clause **10.6** is amended by adding the following clause:
10.6.5 Right-of-Way Encroachment

10.6.5.1 It shall be prohibited to install patios or concrete slabs on the pipeline right-of-way or fences across the pipeline right-of-way unless written permission is first obtained from the operating company.

10.6.5.2 It shall be prohibited to erect buildings including garden sheds or to install swimming pools on the pipeline right-of-way. Storage of flammable material and dumping of solid or liquid spoil, refuse, waste or effluent, shall be also forbidden.

10.6.5.3 Operating companies shall be allowed to erect structures required for pipeline system operation purposes on the pipeline right-of-way.

10.6.5.4 No person shall operate a vehicle or mobile equipment except for farm machinery and personal recreation vehicles across or along a pipeline right-of-way unless written permission is first obtained from the operating company or the vehicle or mobile equipment is operated within the travelled portion of a highway or public road.

10.6.5.5 Operating companies shall develop written procedures for periodically determining the depth of cover for pipelines operated over 30% of SMYS. Such written procedures shall include a rationale for the frequency selected for such depth determinations. Where the depth of cover is found to be less than 60 cm in lands being used for agriculture, an engineering assessment shall be done in accordance with clauses 10.14.2 and 10.14.6 and a suitable mitigation plan shall be developed and implemented to ensure the pipeline is adequately protected from hazards.

(8) Clause **10.14.2** is amended by adding the following clauses:

10.14.2.6 The Director may require operating companies or a person to submit a design, specification, program, manual, procedure, measure, plan or document to the Director if:

a) the operating company or person makes an application to the Director under Section 18.(1) 1, 18.(1) 3 and 16.(6) of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems), or

b) the Director has reasons to believe that the design, construction, operation or abandonment of a pipeline, or any part of a pipeline is or may cause,

i. a hazard to the safety of the public or to the employees of the operating company,
ii. an adverse effect to the environment or to property, or
iii. the Director wishes to assess the operating company's pipeline integrity management program.

10.14.2.7 For the protection of the public, the pipeline and the environment, an operating company shall develop a pipeline integrity management program for steel pipelines with a MOP of 30% or more of the SMYS. The pipeline integrity management program shall contain:

a) a management system;
b) a working records management system;
c) a condition monitoring program, and
d) a mitigation program.

10.14.2.8 When developing the pipeline integrity management program, an operating company shall consider CAN/CSA-Z662-07, Oil and Gas Pipeline Systems, Annex N, Guidelines for Pipeline Integrity Management Programs.

(9) Clause **10.14.3.1** is revoked and the following substituted:

10.14.3.1 Prior to a change in service fluid, including sweet to sour, the operating company shall conduct an engineering assessment to determine whether it would be suitable for the new service fluid. The assessment shall include consideration of the design, material, construction, operating, and maintenance history of the pipeline system and be submitted to the Director for approval.

(10) Clause **10.16.1.2** is amended by adding the following items:
(e) maintain warning signs and markers along the pipeline right-of-way;
(f) maintain existing fences around above ground pipeline facilities; and
(g) empty tanks and purge them of hazardous vapours.

(11) Clause **12.4.11.1** is renumbered as clause **12.4.11.1.1**. Clause **12.4.11** is amended by adding the following clauses:
12.4.11.1.2 All new and replacement natural gas service regulators shall comply with the requirements of CSA 6.18-02 standard, Service Regulators For Natural Gas, including the Drip and Splash Test contained in Appendix A of the said Standard. Where a regulator – meter set installation or supplemental protective devices as providing equivalent protection against regulator vent freeze up passes a successful test in accordance to Appendix C of the said Standard, the requirements of Appendix A (Drip and Splash Test) and those contained in Clause 14.15 (Freezing Rain Test) of the Standard are waived. Evidence of test made in accordance with Appendix C, shall be kept by the operating Company as permanent records.

12.4.11.1.3 Regulator-meter set configurations shall be included in the operating company's operating and maintenance procedures.

(12) Clause **12.4.15.6** is amended by replacing the reference to CAN/CSA-B149.1 to "Table 5.2 of B149.1S1-07 Supplement No. 1 to CAN/CSA-B149.1-05, Natural Gas and Propane Installation Code".

(13) Clause **12.10.11** is amended by adding the following clauses:
12.10.11(e) For polyethylene piping installed in Class 1 and Class 2 location, the upgraded maximum operating pressure shall not exceed the design pressure calculated in accordance with the requirements of Clause 12.4.2.1; and

12.10.11(f) For polyethylene piping installed in Class 3 and Class 4 location, the upgraded maximum operating pressure shall not exceed the design pressure calculated in accordance with the requirements of clause 12.4.2.1 with a combined design factor and temperature derating factor (F x T) of 0.32.

(14) Clause **12.10.13.1** is revoked and the following substituted:
12.10.13.1.1 The Director may require operating companies or a person to submit a design, specification, program, manual, procedure, measure, plan or document to the Director if:
a) the operating company or person makes an application to the Director under subsection 18.(1) 2 of Ontario Regulation 210/01 (Oil and Gas Pipeline System),
b) the Director has reasons to believe that the design, construction, operation or abandonment of a pipeline, or any part of a pipeline is or may cause,
i. a hazard to the safety of the public or to the employees of the operating company,
ii. an adverse effect to the environment or to property, or
iii. the Director wishes to assess the operating company's integrity management program.

12.10.13.1.2 Operating companies shall establish effective procedures for managing the integrity of pipeline systems with a MOP less than 30% of SMYS (Distribution Systems) so that they are suitable for continued service. The integrity management program shall contain:

a) a management system;
b) a working records management system;
c) a condition monitoring program, and
d) a mitigation program.

When developing the integrity management program, an operating company shall consider Annex M, Guidelines for Gas Distribution System Integrity Management Programs.

This program and implementation plan shall be completed no later than April 30, 2008.

Section 3

POLYETHYLENE PIPE CERTIFICATION

3. (1) Polyethylene piping and fittings that are used in a polyethylene gas pipeline shall be certified by a designated testing organization accredited by the Standards Council of Canada as conforming to the CAN/CSA-B137.4-05. Polyethylene Piping Systems for Gas Services.

Section 4

WELDER QUALIFICATION

4.(1) Welds shall not be made in any steel pipe that forms or is intended to form a part of a steel oil or gas pipeline or a component of a steel pipeline unless the welder is qualified to make the weld in accordance with the requirements of the CSA Z662-07 Standard adopted under section 2 of this document and is the holder of the appropriate authorization issued under Ontario Regulation 220/01 (Boilers and Pressure Vessels), made under the *Technical Standards & Safety Act, 2000*.

Section 5

5.(1) Where there is a conflict between a standard, specification, code or publication adopted in this document, this document shall prevail.

(2) Any person involved in an activity process or procedure to which this document applies, shall comply with this document.

(3) The above amendments to the Oil and Gas Pipeline Code Adoption Document are effective on March 31, 2008.

Dated at Toronto this 26th. day of March, 2008.

____

John Marshall
Statutory Director
Ontario Regulation 210/01 (Oil and Gas Pipeline Systems)
made under the *Technical Standards & Safety Act, 2000*

Fuels Safety Program	Ref. No.: FS-196-12	Rev. No.:
OIL AND GAS PIPELINE SYSTEMS CODE ADOPTION DOCUMENT AMENDMENT	Date: **November 1, 2012**	Date:

IN THE MATTER OF AN AMENDMENT TO THE

Oil and Gas Pipeline Systems Code Adoption Document

adopted as part of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems)
by section 8(1) of Ontario Regulation 223/01 (Codes and Standards Adopted by Reference)
made under the *Technical Standards and Safety Act, 2000,* S.O. 2000, c. 16

The Director for the purposes of O. Reg. 210/01 (Oil and Gas Pipeline Systems), under authority of section 36(3)(a) of the *Technical Standards and Safety Act, 2000,* S.O. 2000, c. 16 (the "Act"), hereby amends the Oil and Gas Pipeline Systems Code Adoption Document published by the Technical Standards and Safety Authority and dated June 1, 2001, as amended, as follows:

1. **All sections of the Oil and Gas Pipeline Systems Code Adoption Document (Sections 1 to 5) are revoked and replaced with Sections 1 to 5 of this document.**

Section 1

CODES ADOPTED BY REFERENCE

1. The Director hereby adopts and requires all persons to whom O. Reg. 210/01 (Oil and Gas Pipeline Systems) applies to comply with the standards, procedures and other requirements of the following codes and regulations:

(a) **CSA Z662-11 (Oil and Gas Pipeline Systems)**, published by the Canadian Standards Association, as amended by Section 2 of this document;

(b) **CSA Z246.1-09 (Security Management for Petroleum and Natural Gas Industry Systems)**, published by the Canadian Standards Association; and

(c) **CSA Z276-11 (Liquefied Natural Gas (LNG) - Production, Storage and Handling)**, published by the Canadian Standards Association.

Section 2

AMENDMENTS TO CSA Z662-11 (OIL AND GAS PIPELINE SYSTEMS)

2. For the purposes of compliance with this Code Adoption Document, CSA-Z662-11 (Oil and Gas Pipeline Systems) shall be deemed to be amended as follows:

(1) Clause **1.2** is amended by adding the following item:

(h) pipelines that carry gas to and from a well head assembly of a designated storage reservoir.

(2) Clause **1.3** is amended by adding the following items:

(p) digester gas or gas from landfill sites
(q) multiphase fluids
(r) gathering lines
(s) offshore pipeline systems
(t) oil field steam distribution pipeline systems oil field water services
(u) carbon dioxide pipeline systems.

(3) Clause **3.2** is amended by renumbering the existing clause as 3.2.1 and adding the following clause:

3.2.2

Natural gas distributors shall incorporate into the procedures for managing the integrity of pipeline systems required in clause 3.2.1 an action plan that includes:

(a) a description of the steps taken or that will be taken to mitigate the potential of penetration of sewer lines by a natural gas pipeline during trenchless installation;
(b) a program that raises stakeholder awareness of the potential safety issues that could arise when attempting to clear a blocked sewer service line beyond the outside walls of a building; and
(c) an assessment of potential risks and a plan to mitigate these risks.

(4) Clause **4.1.8** is deleted and substituted with the following:

4.1.8

Steel oil and gas pipelines may be designed in accordance with the requirements of Annex C, provided that such designs are suitable for the conditions to which such pipelines are to be subjected, and provided that the design has been reviewed and approved by the Director prior to installation or use.

(5) Clause **4.3.4** is amended by adding the following clauses:

4.3.4.9 High consequence areas

4.3.4.9.1 Definitions

The following definitions apply to the remainder of clause 4.3.4:

Assessment means the use of testing techniques set out in this section to ascertain the condition of a covered pipeline segment.

Covered segment or ***Covered pipeline segment*** means a segment of oil or gas transmission pipeline located in a high consequence area. The terms "oil", "gas" and "transmission" are defined in O. Reg. 210/01. For the purpose of this document, transmission lines include only lines with an MOP of 30% or more of the SMYS.

High consequence area means

(a) for a gas transmission pipeline, an area defined as:
  (i) a Class 3 location under CSA Z662-11, Clause 4.3.3;
  (ii) a Class 4 location under Clause 4.3.3;
  (iii) any area in a Class 1 or Class 2 location where the potential impact radius is greater than 200 metres and the area within the potential impact circle contains 20 or more buildings intended for human occupancy; or
  (iv) any area in a Class 1 or Class 2 location where the potential impact circle contains an *identified site*; and

(b) for an oil pipeline, an area containing:
  (i) a *commercially navigable waterway,* which means a waterway where a substantial likelihood of commercial navigation exists;
  (ii) a *high population area,* which means an urbanized area, as defined and delineated by the latest Statistics Canada Census, that contains 50,000 or more people or has a population density of at least 385 people per square km;
  (iii) an *other populated area,* which means a place, as defined and delineated by the latest Statistics Canada Census, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area; or

(iv) an *unusually sensitive area,* as defined in company's pipeline integrity management program.

Identified site means, for Class 1 and Class 2 locations, any of the following areas:

(a) an outside area or open structure that is occupied by 20 or more persons on at least 50 (not necessarily consecutive) days in any 12 month period. Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, and areas outside a rural building such as a religious facility;

(b) a building that is occupied by 20 or more persons at least five (not necessarily consecutive) days a week for at least 10 (not necessarily consecutive) weeks in any 12 month period. Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, sporting and entertainment facilities; or

(c) a facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities and assisted-living facilities.

Potential impact circle, for natural gas or *HVP pipelines systems*, is a circle of radius equal to the potential impact radius (PIR).

Potential impact radius **(PIR)** means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property, determined by the following formula:

$$r = 0.00313 \text{ times square root of } (pd^2)$$

where:

r is the radius of the circular area surrounding the point of failure in metres (m)

p is the MOP of the pipeline in kPa

d is the nominal diameter of the pipeline in mm

NOTE: 0.00313 is the factor for natural gas based on conversion from a formula used in GRI-00/0189. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas shall refer to ASME/ANSI B31.8 S for the formula to calculate the potential impact radius.

4.3.9.2 Identification of high consequence areas

(a) *General*. Operating companies shall identify which segments of its oil and gas transmission pipeline system are in high consequence areas. The operator must describe in its integrity management program the method used to establish high consequence areas, including the determination of the potential impact radius.

(b) *Identified sites.* The operator shall identify identified sites by

(i) using information the operator has obtained from routine operation and maintenance activities; and

(ii) obtaining information about locations that are likely to meet the criteria for identified sites from public officials with safety or emergency response or planning responsibilities (such as officials from local emergency planning response agencies or from municipal planning departments).

(c) *Identified sites – where public officials cannot assist*. If the public officials mentioned above indicate that they do not have the necessary information or are otherwise unable to identify potential identified sites, the operator shall use the following methods, as appropriate, to identify potential identified sites:

(i) the presence of signs, public notices, flags or other markings that suggest that the area may become an identified site in the future; and

(ii) the existence of publicly available information, including online and at local land registry offices, that suggests the area may become an identified site in the future.

(d) *Newly identified high consequence areas*. When an operator obtains information suggesting that the area around a pipeline segment not previously identified as a high consequence area could constitute a high consequence area, the operator shall evaluate whether the area indeed constitutes a high consequence area. If the segment is determined to constitute a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

4.3.4.10 Operator's responsibility to implement this clause

4.3.4.10.1

An operator of a covered pipeline segment shall develop and follow a written program (part of the pipeline system integrity management program (IMP)) that contains all the elements described in the IMP and that addresses the risks on each covered transmission pipeline segment.

4.3.4.10.2 *Implementation standards*

An operator may use an equivalent standard or practice to a standard or practice required by clause 4.3.4 only when the operator demonstrates in its Integrity Management Program that the alternative standard or practice provides an equivalent level of safety to the public and property.

4.3.4.11 Risk assessment

The operator shall conduct a risk assessment that follows Annex B Guidelines for risk assessment of pipelines falling within the scope of CSA Z662-11 for each covered segment. The risk assessment shall include the high consequence areas and determine if additional preventive or mitigation measures are needed.

The operator shall prioritize the covered pipeline segments according to the risk.

4.3.4.12 Remediation

For each covered segment, the operator shall develop and establish measures to prevent or reduce the probability of an incident and to limit the potential consequences thereof.

These measures shall include conducting a risk analysis of the pipeline segment to identify additional measures to enhance public safety or environmental protection. Such measures may include, but are not limited to:

(a) establishing shorter inspection intervals;

(b) installing emergency flow restricting devices (remote operated valves, check valves and automatic shut off valves, as applicable);

(c) modifying the systems that monitor pressure or detect leaks, as applicable;

(d) providing additional training to personnel on response procedures;

(e) conducting drills with local emergency responders; and

(f) adopting other management controls.

Evacuation procedures shall take into consideration the PIR.

For oil pipeline segments located in high consequence areas, the operating company shall provide the Ontario Ministry of Natural Resources (MNR) and the Ontario Ministry of Environment (MOE) an opportunity to comment on the company's contingency plan for leaks or spills and shall address any comments provided by MOE or MNR.

(6) Clause **7.10.3.2** is deleted and substituted with the following:

7.10.3.2

For HVP and for sour service pipeline systems, all butt welds shall be inspected by radiographic or ultrasonic methods, or a combination of such methods, for 100% of their circumferences, in accordance with the requirements of clause 7.10.4.

(7) Clause **10.3.7.1** is deleted and substituted with the following:

10.3.7.1

Prior to a change in service fluid, including from non-sour service to sour service, the operating company shall conduct an engineering assessment to determine whether the pipeline systems would be suitable for the new service fluid. The assessment shall include consideration of the design, material, construction, operating, and maintenance history of the pipeline system and shall be submitted to the Director for approval.

(8) Clause **10.3** is amended by adding the following clause:

10.3.10

For the protection of the pipeline, the public and the environment, the operating company shall develop a pipeline integrity management program for steel pipelines with an MOP of 30% or more of the SMYS that complies with the applicable requirements of clause 3.2 of CSA Z662-11. The integrity management program shall include the following items:

(a) a management system;

(b) a working records management system;

(c) a condition monitoring program, and

(d) a mitigation program.

(9) Clause **10.5.2** is amended by adding the following clauses:

10.5.2.6 Emergency communication meetings

The operator of a transmission pipeline shall conduct meetings with local authorities, inviting police, firefighting authorities, Ontario Ministry of Transportation (MTO), Ministry of Natural Resources (MNR), Ministry of the Environment (MOE), local conservation authorities and TSSA, to explain to the authorities the characteristics of the pipeline system the operator operates, the type of fuels being transported and the typical behaviour of these fuels in case of uncontrolled escapes or spills and the capabilities and the coordination required to respond to pipeline emergencies.

These meetings shall be conducted at intervals not exceeding five years at locations that ensure the key stakeholders can attend. The meetings shall be prioritized so as to correspond to the operating company's prioritization of the covered pipeline segments according to the risk.

10.5.2.7

Operating companies shall prepare an emergency response plan and make it available on request to the authorities referred to in clause 10.5.2.6.

(10) Clause **10.6** is amended by adding the following clause:

10.6.5 Right-of-way encroachment

10.6.5.1

No person shall install patios or concrete slabs on the pipeline right-of-way or fences across the pipeline right-of-way unless written permission is first obtained from the operating company.

10.6.5.2

No person shall erect any building (including garden sheds) or install swimming pools on the pipeline right-of-way, and no person shall deposit or store any flammable material, solid or liquid spoil, refuse, waste or effluent on the pipeline right-of-way.

10.6.5.3

Notwithstanding the above, operating companies may erect structures required for purpose of pipeline system operation on the pipeline right-of-way.

10.6.5.4

No person shall operate a vehicle or mobile equipment except for farm machinery or personal recreation vehicles across or along a pipeline right-of-way unless written permission is first obtained from the operating company or the vehicle or mobile equipment is operated within the travelled portion of a highway or public road in the pipeline right-of-way.

10.6.5.5

Operating companies shall develop written procedures for periodically determining the depth of cover for pipelines operated over 30% of SMYS. Such written procedures shall include a rationale for the frequency selected for such depth determinations. Where the depth of cover is found to be less than 60 cm in lands being used for agriculture, an engineering assessment shall be done in accordance with clause 3.3 and a suitable mitigation plan shall be developed and implemented to ensure the pipeline is adequately protected from hazards.

(11) Clause **10.15.1.2** is amended by adding the following items:

(e) maintain warning signs and markers along the pipeline right-of-way;
(f) maintain existing fences around above ground pipeline facilities; and
(g) empty tanks and purge them of hazardous vapours within 60 days of deactivation.

(12) Clause **12.4.11.1** is renumbered as clause **12.4.11.1.1**. Clause **12.4.11** is amended by adding the following clauses:

12.4.11.1.2

All new and replacement natural gas service regulators shall comply with the requirements of CSA 6.18-02 (R2008) (Service Regulators for Natural Gas), published by the Canadian Standards Association, including the Drip and Splash Test contained in Appendix A of the said standard. Where a regulator-meter set installation or supplemental protective devices provides equivalent protection against regulator vent freeze up passes a successful test in accordance with Appendix C of the said standard, the requirements of Appendix A (Drip and Splash Test) and those contained in clause

14.15 (Freezing Rain Test) of the standard are waived. Evidence of tests completed in accordance with Appendix C of the standard shall be retained by the operating company as permanent records.

12.4.11.1.3

Regulator-meter set configurations shall be included in the operating company's operating and maintenance procedures.

(13) Clause **12.4.15.6** is revoked and substituted with the following:

12.4.15.6

Where regulator failure would result in the release of gas, open ends of the vents shall be located where the gas can escape freely into the atmosphere and away from any openings in the buildings. Clearances from building openings shall be commensurate with local conditions and the volume of gas that might be released, but shall not be less than those set out in the following table:

Clearance from service regulator vents discharge (m)

Column:	I	II	III	IV
Building opening	0.3	1	3	1
Appliance vent outlet	0.3	1	1	1
Moisture exhaust duct (dryers)	1	1	1	1
Mechanical air intake	1	3	3	3
Appliance air intake	0.3	1	3	3
Source of ignition	0.3	1	1	3

Column I applies to natural gas regulators certified under CSA 6.18 standard, incorporating an OPCO system and with a limited relief of 1.5 m^3/h.

Column II applies to natural gas regulators certified under CSA 6.18 standard (if within the scope of the standard) with a relief capacity up to 55 m^3/h.

Column III applies to natural gas regulators with a relief capacity over 55 m^3/h.

Column IV applies to propane regulators.

Where regulators might be submerged during floods, either a special anti-flood-type breather vent fitting shall be installed or the vent line shall be extended above the height of the expected flood waters.

(14) Clause **12.10.11** is amended by adding the following items:

(e) For polyethylene piping installed in Class 1 and Class 2 locations, the upgraded maximum operating pressure shall not exceed the design pressure calculated in accordance with the requirements of Clause 12.4.2; and

(f) For polyethylene piping installed in Class 3 and Class 4 locations, the upgraded maximum operating pressure shall not exceed the design pressure calculated in accordance with the requirements of clause 12.4.2 with a combined design factor and temperature derating factor (F x T) of 0.32, unless the operating company conducts an engineering assessment to determine whether it would be suitable for the existing polyethylene piping to be operated at the new pressure. The assessment shall include consideration of the design, material, construction, operating, and maintenance history of the pipeline system and be submitted to the Director for approval.

(15) Clause **12.10** is amended by adding the following clause:

12.10.16

Operating companies shall establish effective procedures for managing the integrity of pipeline systems with an MOP less than 30% of SMYS (Distribution Systems) so that they are suitable for continued service, in accordance with the applicable requirements of clause 3.2 of CSA Z662-11.

Section 3

POLYETHYLENE PIPE CERTIFICATION

3. Polyethylene piping and fittings that are used in a polyethylene gas pipeline shall be certified by a designated testing organization accredited by the Standards Council of Canada as conforming to CAN/CSA-B137.4-09 (Polyethylene Piping Systems for Gas Services).

Section 4

WELDER QUALIFICATION

4. Welds shall not be made in any steel pipe that forms or is intended to form a part of a steel oil or gas pipeline or a component of a steel pipeline unless the welding procedures have been approved and the welder is qualified to make the weld in accordance with the requirements of CSA-Z662-11 (Oil and Gas Pipeline Systems) and is the holder of the appropriate authorization issued under O. Reg. 220/01 (Boilers and Pressure Vessels) made under the Act.

Section 5

MISCELLANEOUS

5.

(1) Where there is a conflict between a standard, specification, code or publication adopted in sections 1, 2, 3 or 4 of this document, this document prevails.

(2) Any reference to "Director" in a code amended by this document means the Director for O. Reg. 210/01 (Oil and Gas Pipeline Systems).

(3) Any person involved in an activity, process or procedure to which this document applies shall comply with this document.

(4) Except as provided below, this Code Adoption Document amendment is effective **November 1, 2012**.

(5) Notwithstanding Section 5(4), the following parts of the Code Adoption Document are effective **March 1, 2013**:

(a) Section 1(b), which adopts CSA Z246.1-09 (Security Management for Petroleum and Natural Gas Industry Systems); and

(b) Section 2(5), which adds clause 4.3.4.9 (re high consequence areas) to clause 4.3.4. of CSA Z662-11 (Oil and Gas Pipeline Systems).

SIGNED this 31st day of August, 2012

____

John Marshall
Director for O. Reg. 210/01, appointed under authority of section 4(1) of the Act

Technical Standards and Safety Authority
14th Floor - Centre Tower
3300 Bloor St. West
Toronto, Ontario M8X 2X4

This document was developed in consultation with the
Gaseous Fuels Advisory Council and the Pipeline Risk Reduction Group

UNDERTAKING J6.3

UNDERTAKING

TR 18

To provide an updated forecast for total cost of Ottawa reinforcement project, the drivers of the variances, and the lessons learned in the Ottawa reinforcement project that will be applied to the GTA project to reduce the risk of a similar result.

RESPONSE

The project was estimated to cost $51,235,000 at the time of the Leave to Construct application (Please see EB-2012-0099, Exhibit C, Tab 2, Schedule 1 and also EB-2012-0459, Exhibit B2, Tab 3, Schedule 2, Attachment 1). The current project cost estimate is $66,987,000, resulting in an unfavourable variance of $15,751,000. A comparison of the variance in project costs is shown in Table 1.

Table 1 – Total Project Costs Estimate ($'000)

Breakdown	June 2012 estimate	February 2014 estimate	Variance
Material Cost	$8,678	$11,200	$2,522
Labour Cost	$30,775	$49,200	$18,425
External Cost	$3,364	$5,500	$2,136
Land Cost	$677	$322	($355)
Overhead Cost	$2,175	$765	($1,410)
Contingency	$5,567	$0	($5,567)
Total Project Costs	$51,236	$66,987	$15,751

Witness: F. Smith

The main contributing factor to the total project cost variance is the increase in labour costs. Approximately 81% of the variance in construction labour, or $14.9 million, is due to factors relating to: 1) reduced productivity from loss of working space, and 2) unplanned rock excavations.

The inability to secure planned working easements, primarily along the National Capital Commission (“NCC”) lands, about 7km of the 19km project route, has changed the methods of construction to accommodate the restricted work areas. Specifically, the loss of working easements has resulted in slower production, expensive traffic control management and additional haulage of materials. It is estimated that $11.7 million of the labour cost increase is due to these factors arising from loss of working space.

The construction labour estimate was based on established allowances for rock blasting, rock breaking, rock haulage and sand haulage in line with the geotechnical investigation. However, unknown rock conditions were discovered along certain sections of the project. Rock removal is estimated to be 20% greater than estimated amounts resulting in 40% of the selected route to require rock removal. It is estimated that factors related to rock removal have contributed $3.2 million of the labour cost variance.

With regards to learnings for the GTA Project, discussions were initiated early on with Infrastructure Ontario and Hydro One concerning the project’s temporary work space requirements. To date these discussions have progressed well with no major concerns identified by the parties.

With regards to rock, a geotechnical program was initiated in 2013 and is continuing. The results to date from the geotechnical program do not indicate that rock will be a major concern at typical pipeline depths. In addition, approximately 70% of the pipeline route parallels existing pipelines installed and maintained by the Company, and experience from prior work activity in the same corridor does not indicate the presence of large quantities of rock. At 5 Horizontal Directional Drill (HDD) locations on Segment A deep rock has been identified. This may result in some additional drilling time but the risks have been taken into account to the extent possible with the currently available data.

Witness: F. Smith

UNDERTAKING J6.5

UNDERTAKING

TR 41

To provide an explanation of contingencies prior to the Ottawa project, and pre-engineering methodology used to develop it.

RESPONSE

Contingency was determined using a parametric model based on the Rand and Industrial Project Analysis ("IPA") studies of industrial projects over the past 40 years in combination with actual data from Enbridge projects.

Risk assessment sessions were held to review systemic and project specific risks. Session participants, selected based on the project scope, provided input on any risks relating to their areas of responsibilities. Using the parametric model, this information is captured in a risk register, which assesses risks that would impact the capital cost or schedule. Applying several criteria and using a Monte Carlo simulation, the costs associated with the different risks are captured in the base estimate or in contingency.

The accuracy of the contingency calculation is based on input data available at the time of estimation. In some circumstances such as rock evaluation, the sufficiency of the input data is influenced by the extent of sampling along the route. In the case of working easement availability, the input is based on then current status of negotiations.

The contingency of the Ottawa project was calculated at the time of project cost development to be 13 %.

Witness: F. Smith