HISTORY AND OPERATING EXPERIENCE OF DESIGN FACTORS ABOVE 0.72 IN CANADIAN GAS TRANSMISSION PIPELINES[1]

Brian Rothwell
Staff Engineer, TransCanada PipeLines

INTRODUCTION

This paper is largely based on TransCanada's experience over some 50 years in constructing and operating a gas transmission system that now comprises some 41 000 km of pipelines, and, within Canada, extends from British Columbia in the West to Québec in the East. The system makes up about 40% of the total length of transportation pipelines in Canada, and currently ships about 11.5 bcf/day. Relative to operation above 72% SMYS, TransCanada's experience is fully representative of Canadian practice and experience.

The paper briefly presents the historical background to the use of higher design factors in Canada, including the evolution of the Canadian standards for oil and gas pipelines. The specific experience of TransCanada will then be discussed, including a brief summary of integrity performance and its evolution over time, as compared with other jurisdictions for which roughly comparable statistics are available. Other presentations at this meeting will deal with several specific expected effects of higher design factors; this paper deals only with the issues of critical flaw size, resistance to puncture by excavating equipment and SCC.

EARLY HISTORY OF THE EVOLUTION OF HIGHER DESIGN FACTORS

In the late Sixties, Battelle carried out a major investigation of the feasibility of basing gas pipeline operating pressure directly on hydrostatic testing, and of using the hydrostatic test to establish, in place, the strength of the pipeline [1]. They concluded that the integrity of the pipeline was primarily a function of the ratio between hydrostatic test pressure and operating pressure, that it was feasible to carry out testing up to a minimum pressure corresponding to the nominal yield of the pipe (SMYS), and that a factor of 1.25 provided a suitable margin of safety. For reasons connected with the timing of the initial promulgation of the US federal pipeline regulations, the resulting maximum design factor of 0.80 was not incorporated in US pipeline industry standards at that time. These circumstances are discussed more fully elsewhere [2].

In the early Seventies, primarily on the basis of this work,TransCanada and Alberta Gas Trunk Line [2] and their regulators (respectively federal and provincial) agreed to a regime that allowed pipelines to be operated at up to 80% of the minimum hydrostatic strength test pressure, which could be up to 100% SMYS. Existing pipelines were upgraded by pressure testing; testing of new and existing lines to a minimum of 100% SMYS allowed operation at pressures corresponding to 80% SMYS.

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[1] Presented to PHMSA Public Meeting on Reconsideration of Natural Gas Pipeline Maximum Allowable Operating Pressure for Class Locations, Reston, VA, March 21, 2006.
[2] The precursor companies of the present TransCanada PipeLines, which was formed by merger in 1998.

Canadian pipeline standards began to reflect this situation in the 1973 edition of Z184, the gas pipeline standard. This allowed adoption of an MAOP corresponding to 80% SMYS, based on hydrostatic testing at a minimum of 1.25 times the intended MAOP. Testing above 100% SMYS was facilitated by the introduction of a more liberal volume strain criterion. Initially, the design factors themselves were not changed, but parallel “hydrostatic test factors” could be used to determine MAOP. This led to the somewhat anomalous situation that the MAOP could, and often did, exceed the design pressure. This anomaly was removed in the 1990 edition of Z183 (oil) and the 1992 edition of Z184 (gas), when a single design factor of 0.80 was adopted, in conjunction with maximum “location factors” that varied from 1.000 for Class 1 to 0.550 for Class 4.[3] Since 1994, this approach has been maintained in CSA Z662, which replaced Z183 and Z184 and is the current standard for oil and gas pipeline systems.

TRANSCANADA’S OPERATING EXPERIENCE AT DESIGN FACTORS EXCEEDING 0.72

As indicated above, TransCanada began to upgrade some existing pipelines and design new ones at up to 80% SMYS in the early Seventies. On the Alberta system, there are currently about 9600 km (6000 miles) of pipelines with MAOP corresponding to 78-80% of the pipe’s SMYS. The outside diameters range between 150 and 1219 mm (6 in to 48 in), SMYS is from 359 to 690 MPa (X52-X100), and they were installed (or upgraded) between the early Seventies and this year. On the federally-regulated Canadian Mainline system, there are about 7200 km (4500 miles) of pipelines with MAOP corresponding to 77-80% SMYS; outside diameters range from 508 to 1219 mm (20 in to 48 in) and strength levels from 359 to 550 MPa (X52-X80), and they were installed (or upgraded) over the same period. The federally-regulated Foothills Pipelines system consists of over 1000 km (600 miles) of 914 and 1067 mm (36 and 42 in) OD, Grade 448 and 483 (X65 and X70) pipelines, with MAOP corresponding to 80% SMYS, and installed between 1979 and 1998. The operating history of these pipelines represents some 30% of the system total of over 1 million km yr (625 000 mile yr), and, naturally, a significantly larger percentage of the large diameter pipeline history.

Integrity performance statistics

It can be surprisingly difficult to generate overall incident frequency statistics, broken down by pipeline attributes and incident severity, from existing databases. This situation is widely recognised; in fact, the IGU has recently set up a study group to propose a way to resolve the problem, which will present its first report later this year. Even within TransCanada, such analysis is not easy, since our main database was set up to aid detailed risk analysis on a metre by metre basis, and synthesis currently involves the attribute-specific aggregation of literally millions of individual records. However, some conclusions can

[3] The class location definitions in CSA Z662 are based on population and other land-use issues, and are similar to those in ASME B31.8. The design formula in Canadian standards is based on nominal wall and outside diameter.

certainly be drawn, based on the historical evolution of incident statistics and of pipeline technical characteristics.

TransCanada's overall incident frequency (leaks and ruptures) since the start of operation in 1954 is approximately 0.20 per 1000 km yr; this reflects a total exposure of over 1 million km yr. By comparison, the overall frequency reported by EGIG[4] in its sixth report is 0.41 per 1000 km yr on a total exposure of 2.8 million km yr [3]. The EGIG incident frequency has been continuously declining, and the figure for the period 2000-2004 is 0.17 per km yr on a total exposure of 0.57 million km yr. Statistics derived from the US DOT 30-day incident reports indicate an overall frequency of 0.14 per 1000 km yr, for onshore transmission pipelines, on a total exposure of ~7.3 million km yr between 1985 and 2000. The TransCanada and EGIG data included all pipeline gas release incidents, regardless of size. However, in comparing these figures, it should be considered that small leaks were probably under-recorded in the early period of TransCanada's operation (it is not implied that statutory reporting requirements were not met, simply that not all instances may have been captured in a central database). Small leaks are definitely much less fully represented in the DOT statistics, because of the US$50 000 reporting threshold. Annual records of leaks repaired on US federally-regulated transmission pipelines indicate thousands of repairs per year, though the number declined dramatically between 1985 and 2000.

The above comparisons, although they represent different pipeline populations operating in different environments over different time periods and with different reporting criteria, are certainly not indicative of any intrinsic negative correlation between design factor and reliability, since about 40% of the TransCanada system has a design factor close to 0.80, while a very small proportion of the European or US pipeline population can operate above 72% SMYS. In fact, many of the standards used in Europe use a design formula based on minimum wall (though sometimes with mean diameter), making the effective design factor even lower, when expressed in North American terms.

It is probably more relevant to the present discussion to review comparisons involving rupture frequency alone, since for typical gas transmission conditions ruptures have the potential for much the most severe consequences and usually dominate overall risk. The overall lifetime rupture frequency on the TransCanada system is 0.07 per 1000 km yr. This is a little higher than the corresponding frequency from the EGIG database (~0.06 per 1000 km yr); however, this is counterbalanced by the fact that large leaks (e.g. stable punctures by excavating equipment) have been extremely rare on the TransCanada system, while they account for about a third of all EGIG incidents.

The variation of rupture frequency over time on the TransCanada system is of some interest (see Figure 1). The cumulative frequency has declined over the system lifetime to its current value; because of the great size of the accumulated exposure, it now changes only slowly. The rolling 5-year average

[4] EGIG maintains a pipeline incident database representing the onshore gas transmission operations of twelve European companies, covering the period from 1970 on.

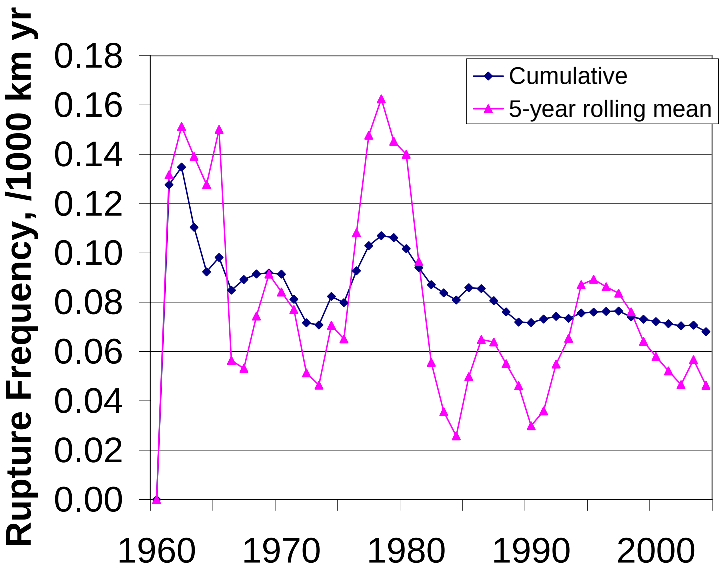

Figure 1 Historical rupture frequency

is more volatile, and gives a better picture of the emergence of specific issues and the effect of the response to them. Initially, rupture frequencies were significantly higher than the current overall mean, probably to some extent because of a relative lack of experience both within the company and in the community at large, as well as the relatively limited accumulated exposure. There is a distinct spike in rupture frequency centred on the late Seventies. However, detailed review of the incident causes indicates that there was no plausible connection between this increase and increased design factor; it was primarily associated with material and construction quality deficiencies in this first period of rapid expansion. The introduction of modern specifications and quality management systems brought this situation under control. There was an additional, less pronounced peak in the Nineties; this was associated with time-dependent failure causes (corrosion and SCC) on older-generation pipelines with coating systems that were found to have inadequate long-term performance in some Canadian environments. These have been brought under control (without any long-term reduction in MAOP) by more aggressive integrity management programs using detailed risk assessment methods to optimize the necessary monitoring, mitigation and maintenance decisions.

Further analysis of incident causes, particularly for ruptures, is also interesting. Prior to the early Eighties, TransCanada's rupture causes were dominated (more than 50%) by material and construction deficiencies, followed by external interference (see Figure 2). More recently, the dominant causes have been time dependent (external corrosion and SCC), which together account for 64% of all ruptures. External interference has declined, even as the system has continued to expand and considerable levels of urban encroachment have occurred in some regions; this is accounted for by such improvements as one-call systems, comprehensive community awareness initiatives and a higher level of surveillance. Material and construction deficiencies have entirely disappeared as a cause of rupture, as a result of the improvements previously noted.

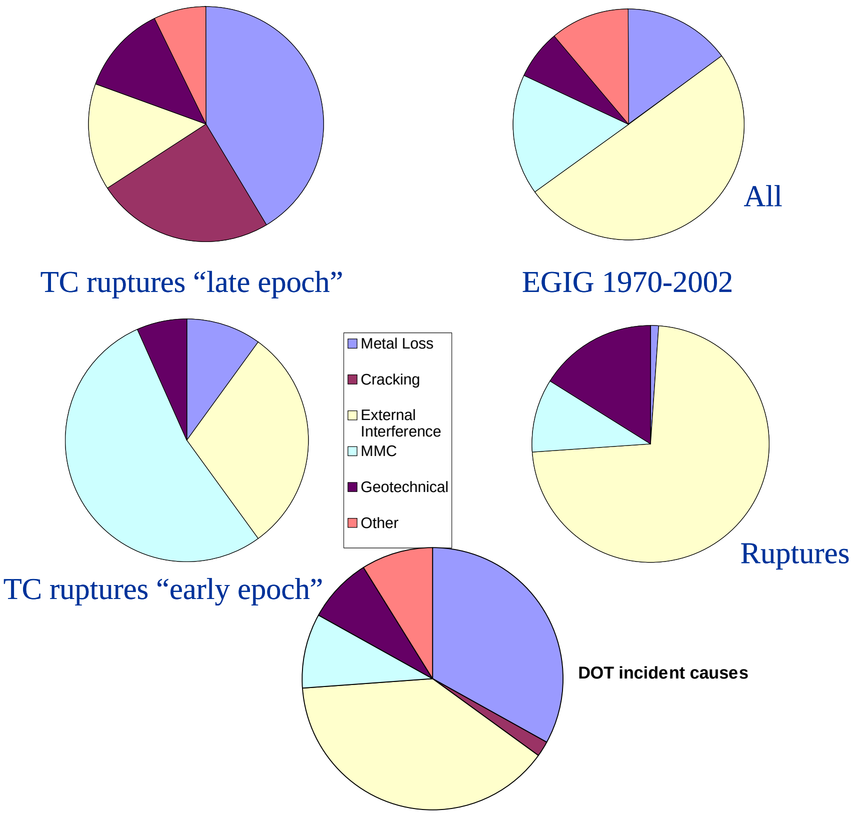

Figure 2 Failure causes – TransCanada, EGIG and DOT

Interestingly, the break-down of failure causes in the EGIG database is quite different, reflecting the generally different distribution of population and dominant land usage in Europe. External interference dominates even the “all-incident” statistics at about 50%, and accounts for nearly three quarters of the ruptures. Corrosion is a completely insignificant cause of rupture (it is believed that there is one corrosion rupture in the entire database), possibly reflecting historically different coating systems and ILI philosophies.

It is difficult to separate out the relevant ruptures from the DOT database (covering 1985-2000), and again, some ruptures on small lines may not have been captured. It is still of some interest to compare the overall incident failure causes, however. Overall, the distribution is rather similar to the EGIG data, though metal loss is more significant and external interference somewhat less.

SPECIFIC INTEGRITY ISSUES

In assessing the physical effects of higher design factors, it is clear that they can have some influence on actual failure conditions. Only three of these will be mentioned here, as other participants in this meeting will deal with this topic.

Critical flaw size

All else being equal, a higher design factor (thinner wall) will lead to a reduction in the critical dimensions of both surface and through-wall defects. Figure 3 shows an example, for a 1067 mm (42 in) OD, Gr.483 (X70) pipeline operating at 8.69 MPa (1260 psig).

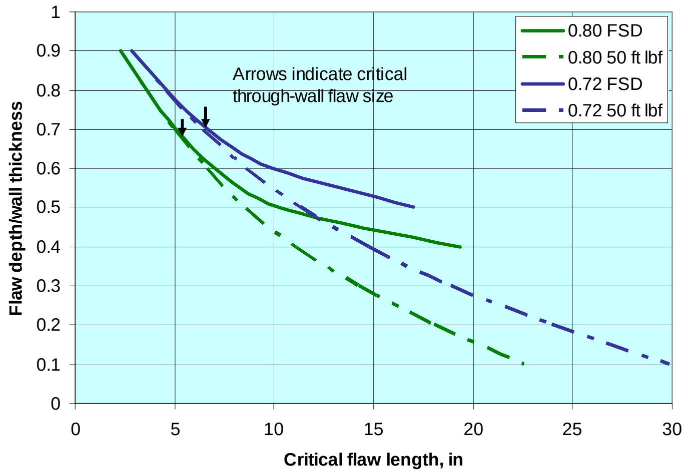

Figure 3 Critical surface flaw sizes at design factors of 0.80 and 0.72, flow stress dependent and 50 ft lbf Charpy energy

The figure shows the effect on surface flaw size of a change from 0.72 to 0.80 design factor. Critical through-wall flaw lengths are also indicated. While there is a modest reduction in critical flaw length, it still indicates very acceptable flaw tolerance for any practical depth, and the reduction will have negligible influence in the context of integrity management. Note that flaws deeper than about 70% of wall thickness will fail as stable leaks in both cases.

Puncture resistance

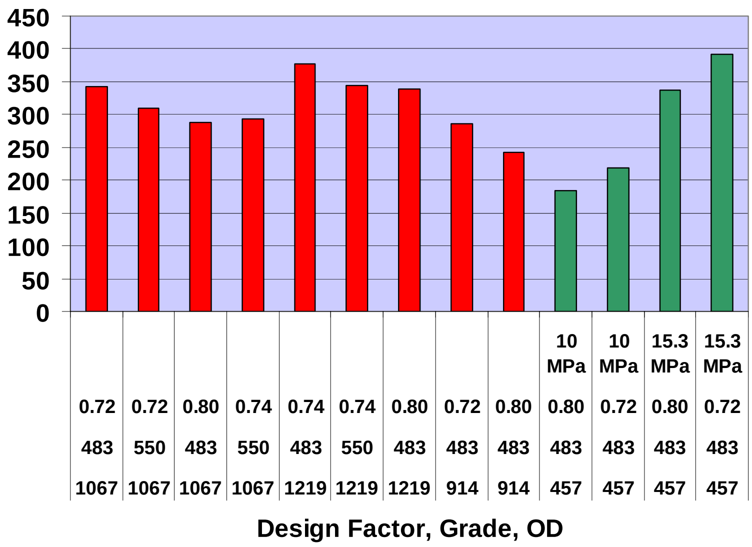

Figure 4 Lower bound deterministic puncture resistance, kN

A good deal of practical and theoretical work has been carried out over the last ten years on the resistance of pipe to mechanical damage; in this paper, only direct puncture by excavating equipment will be considered.

Figure 4 shows deterministic puncture resistance for a number of design cases involving design factors from 0.72 up to 0.80; MAOP is 6.90 MPa (1000 psig) except as noted. The values shown are the lower bound calculated according to the model developed by Driver and Zimmerman [4]. It can be seen that there is a modest reduction in puncture resistance with both increasing SMYS and increasing design factor. Note that the maximum design factor is, in some instances, constrained by practical limits on D/t. In any event, it should be noted that only a small proportion of large excavators are capable of generating a puncture force exceeding 300 kN, and that the reductions in resistance noted will have little impact in the context of modern, integrated approaches to the management of mechanical damage threats, (see, for example, reference [5]).

Stress corrosion cracking (SCC)

Since the Eighties, stress corrosion cracking (predominantly of the near-neutral variety), has been an integrity issue in Canada. While it may have been considered that operating at higher design factors had been a factor in these failures, no clear link has been established with respect to either crack initiation or crack growth. The inquiry conducted by the National Energy Board in 1996 [6] found that the available information relating to the effect of stress and pressure fluctuations was limited and conflicting; the situation is not greatly different today, though the effect of pressure fluctuations is much better documented. No useful threshold stress below which SCC would not grow to failure was identified. It was also pointed out that local stress intensifiers, such as corrosion, gouges and weld seams, were involved in almost all SCC failures. Overall, SCC has been managed without any permanent change in MAOP by focussed integrity management efforts, involving investigative digs, hydrostatic testing, and ILI (though there is still a need for further development of a discriminating tool that will function without a liquid couplant). Where environments that promote SCC are present, high-integrity coatings are critical to the achievement of long-term integrity. To date, TransCanada has experienced no SCC failures in pipelines that were constructed in the “modern” technology epoch (post-1981), during which FBE and extruded PE coatings have been used exclusively.

GENERAL CONCLUSIONS

Since the early Seventies, Canadian gas pipeline operators have accumulated a large amount of operating experience with design factors close to 0.80. Operating experience and comparison with pipeline performance in other jurisdictions that have not permitted design factors over 0.72 support the view that there is no intrinsic relationship between design factor and integrity performance; materials, construction, quality management, operating and maintenance and integrity management practices are the dominant factors. The advances that have been made in all these areas over the last thirty years have led to important improvements in integrity performance, despite an aging pipeline infrastructure and increasing urbanization. For the future, the most complete embodiment of an integrated approach to integrity management is reliability-based design and assessment, which relies on the explicit consideration of all credible failure causes and limit states to meet specific reliability targets throughout the system lifetime. Even in the absence of such a systematic approach, on the basis of the recent technical advances, there is no reason to believe that design factors up to 0.80 will have a detrimental effect on the integrity of pipelines designed and operated to existing best practices.

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