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RE: Enbridge Line 9

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Letter of Comment Pertaining to the Enbridge Application to Reverse Flow in Line 9

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Concerns Regarding Enbridge's Line 9 Proposal and Beyond

by

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Introductory Remarks

Engineers who design and maintain infrastructure in our society have an obligation to the public whom they serve, that the requirements of need and safety are considered paramount, and, indeed, that their broader mandate of protecting, or at least minimizing harm to the natural environment and to life support systems in general are considered vital in this regard. The focus here, however, is to confine our discussion to issues of safety and prevention of releases that pertain to Enbridge's Line 9 project involving flow reversal of diluted bitumen in the existing 38 year old Sarnia to Montreal pipeline. We leave it to others to make the case for need and the long term consequences pertaining to climate change.

Up to the period of the 1950s, civil engineering infrastructure was essentially based on historical information and observation. Allowable stress design and their associated factors had been formulated that provided designers with a degree of safety that had a minimal connection to actual data or to the severity of consequences should a structure fail. Indeed, probability theory virtually played no role in the standards of the day meant to guide engineers to avoid failures from loads generated from conceivable sources. However, by the early '60s, probability and statistics began to make inroads into such designs, and researchers such as Ellingwood and Cornell helped to develop such codes of practice. The standard known as A58 in the U.S. titled

"Probability Based Limit States Design – Methods for Establishing Safety Levels" provided great impetus to consider variability in material strength, ductility and types and intensities of loadings that could be anticipated. Although such design standards are based on frequency of failure analyses and have become commonplace in areas of structural design that involve buildings, bridges, water and transmission towers etc., the philosophy seemingly has *not* been applied to pipeline design. It is our opinion that such an omission is an important reason why this type of conveyance infrastructure has had an unacceptably poor record of performance in recent decades involving breakages, ruptures and leaks.

The Issue of Safety Factor and Allowable Stresses

The basic equation employed in Enbridge's Facilities Integrity Engineering Assessment document (Attachment 8) and based on CSA standard Z662-11 for the Calculated Design Pressure is:

$$P = 2St/D \ (F \times L \times J \times T) \qquad (1)$$

This is a standard equation that can be found in strength of materials textbooks in an undergraduate engineering curriculum. In this case, the nominal yield stress, S, is used, together with the original prescribed pipe thickness, t. The parameter D employed is defined as the outside diameter of the pipe.

All factors within the curly brackets that could affect *P* are given the value of unity except for the allowable stress factor F which is prescribed as 0.6 (p.9 of the document noted above). The inverse of 0.60 can also be described as the safety factor, i.e. 1.67.

Then on top of that, there is another apparent factor of safety based upon the MOP (maximum operating pressure) which is less than *P*. In the case of the North Westover station (near Hamilton) the MOP is actually 69% of value *P*, and so it appears that the safety factor might be of the order of 1.67/0.69 = 2.4. The question which we wish to address is: Can we assume that with all of the uncertainties involved in a 38 year old system (for the most-part) that such infrastructure is safe for the type of crude oil equivalent that is proposed? We will examine some of the uncertainties below.

Uncertainties of Material Properties and Loadings

To account for the possibility that actual yield strength is less than the nominal value, codes of practice pertinent to structural engineering employ a ϕ factor < 1.0. In the case of steel, it is 0.90. It needs to be emphasized that such a factor is relevant to new construction - *NOT* to steel that is aged, corroded and full of undefined cracks and pits. Leaving aside the possibilities of overburden loadings, damage from equipment external to the pipeline, such as earthmovers and diggers etc. safety factors are needed to account for such uncertainties. In buildings, for example, we employ typical live and load factors of 1.5 and 1.25 respectively (CSA S16.1) in design to denote a larger degree of uncertainty with respect to live loadings than is the case for dead loading (primarily construction materials and known furnishings).

In the case of a pipeline, internal pressures can increase from valve shut downs, start-up pumping, operator errors, equipment failure and a host of pipeline degrading consequences that ordinary above-ground structures do not experience. The summation of all of these influences and the uncertainties associated therewith should justify a factor of safety much higher than the 1.5/0.9 value, which is the same as prescribed pipeline safety noted as the reciprocal of the allowable stress factor (1/0.60). We recognize that Enbridge has denoted maximum operating pressures (MOP) as being less than the design pressure *P*, and as such the company may believe that the risks of pipeline failures are minimal. However, like any complex technological equipment, the unexpected can occur despite best practices being employed. As noted in the EI Statement draft report for the Keystone XL project "A pressure sensor may stop working and allow abnormal pressures to develop without triggering alarms" – an alarming prospect indeed!

Our purpose, however, is to raise issues with which we have some degree of expertise, and enumerate where possible to establish whether or not the computed safety factor, applicable to the Westover pipeline segment should be considered acceptable or not. We will attempt to be more specific regarding some of these threats to pipeline integrity below, and make recommendations accordingly.

__Loss of Metal Corrosion__

As noted in section 3.5 of the attachment 8 document (cited earlier), previous inspection at Line 9 locations indicate "internal corrosion depth...0% to 30% of WT" (pipeline thickness), while external corrosion depth was between 0% and 15% of WT. Since it is unlikely that metal loss amounts would be maximal top and bottom at identical locations, it is, in our opinion, reasonable to assume either worst case – in this instance 30% internal corrosion controls. According to the citation of CSA Z662-11, this value in itself does not necessitate repair. However, for more than half the length of the pipeline distance from SA to ML, $t = 0.25''$ for 30" diameter pipe which makes for greater susceptibility to damage from external activities independent of pipeline management. By accounting for a 30% reduction to thickness, the safety factor is reduced to 0.7 times 2.4 = 1.68, virtually equivalent to the value 1.67 suggested as being a reasonable basis for design of above-ground steel structures.

__Corrosion of Welded Joints and Consequences of Pitting Mechanisms__

In equation (1), the factor J has been assumed to be unity, i.e. no weakening of material accounted for in the welds and the heat affected zone due to welding. In the case of hollow structural sections formerly manufactured by Stelco from plate in a rolling mill plant such as was employed for the pipe segments of Line 9. The process used to convert flat sheet into rolled shapes resulted in cold formed bending which would have caused plastic strains and residual stresses in both the longitudinal and hoop directions. These built-in stresses, when added to those generated during pipeline operation will likely result in localized yielding. Of even greater concern for pipeline applications, is the consequence of longitudinal welding needed to "close the loop". This process results in hoop direction weaknesses (our focus here) due to metallurgical changes in the heat affected zone and inner and outer surface defects from the weldments themselves.

One of the grades used for the 30" diameter pipeline was higher strength steel than what is usually employed in structural applications, i.e. 52 ksi (359 MPa) yield (CSA Z245.2). A recent study co-authored by Mexican researchers, Vargas-Arista et al, entitled "Deterioration of the Corrosion Resistance of Welded Joints in API5L X52 Steel Isothermally Aged" is quite revealing in its findings (see References). While not an identical steel to that used 38 years ago, their general comments are worth citing:

> "It is well known that the pipeline steel surface is strongly affected by aggressive chemical components such as hydrogen sulfide, carbon dioxide and chloride ions that are mixed with hydrocarbons when the pipeline transports crude oils".

The 2011 publication in the peer-reviewed International Journal of Electrochemical Science, describes experiments on welded pipes subjected to exposure to a brine and hydrogen sulfide. Examination of the microstructure using a scanning electron microscope, together with transmission electron microscopy followed after short term aging. Their research led them to conclude that:

> "The deterioration of the corrosion resistance was confirmed by the formation of brittle porous corrosion products of iron sulfide and iron oxide with considerable differences in the morphology for the three different microstructural zones. The corrosion resistance of the aged weld bead was more affected by the accelerated aging than the complete HAZ (heat affected zones) and the base metal because of a higher corrosion rate, shallow corrosion products, higher increase in carbide precipitation at the peak-aging, and their lower coarsening after 500 hours".

Others have described such changes in ductile materials as locally being in a "brittle state" (Boresi and Sidebottom – sect. 12.6) which is indeed worrisome from the standpoint of longitudinal crack propagation, much akin to the 22' rupture and release of diluted bitumen of the ExxonMobil pipeline into the Arkansas River earlier this year.

Further to the argument that localized corrosion is indeed a very serious issue is a quote from American Standard for Metals organization in a document entitled "Corrosion in the Petrochemical Industry" that is noteworthy. On p.115 in the section on "Localized Corrosion" are the statements "Although general corrosion is relatively easy to evaluate and monitor, localized corrosion in such forms as pitting, crevice corrosion and weld metal attack is at the opposite end of the scale and materials selection is difficult. (Such) corrosion is insidious and often results in failure or even total destruction of equipment without warning. .....carbon and alloy steel pipelines will pit in aggressive soils because of localized concentrations of corrosive compounds, different aeration cells, corrosive bacteria, stray dc currents (from cathodic protection) or other conditions."

We are not in a position to postulate the extent to which the existing 38 year old pipeline will have been weakened because of the points made above. However, to obtain a sense of the extent to which pits can cause high levels of localized stresses, we resort to the textbook by Boresi and Sidebottom titled as "Advanced Mechanics of Materials" and will employ three idealized pit shapes and depths to illustrate a method developed by a German researcher, H. Neuber (German text, 1958).

Neuber developed a diagram for which knowledge of bar thickness, pit depth and radius at its base allows one to determine stress concentration factors (elasticity theory). Employing a thickness of 6.35 mm for example, with pit depths of 1.35 and and 3.35 mm, with an associated radius of 0.25 mm in each case results in a SCC (stress concentration factor) of 2.5 and 2.6 respectively. A smaller radius at the base of the 3.35 mm notch of 0.07 mm gives an SCC of 4.5. Multiplying the nominal stress obtained from Eq.1 with MOP value by such SCC factors will indeed predict local yielding around areas of adjacent to such pits, and would be serious threats under conditions of further losses of material. If, over a period of years, enough load cycling is employed from pressure and flow velocity changes that are routine in pipeline operations, metal fatigue and crack propagation become extremely worrying threats. Such analytical refinements further add to the increased potential for pipeline failure.

Pin-Hole Lleaks – Are They a Worry or not?

Even in the realm of minor spills (< 50 bbl) such as can occur through leaky valves or a pin-hole sized openings emanating from pits that advance through the pipe's thickness, there is reason for worry. As noted in the EIS Keystone draft report, "oil exiting a pinhole may create a medium to large spill due to difficulties for SCADA (supervisory control and data acquisition) or aerial surveillance to detect such a leak". And, of course, pin holes will expand in size very quickly, for reasons of high velocity flows generating accelerated erosion/corrosion and a stress concentration effect that will increase the magnitude of localized stresses by a factor of 3 (theory of elasticity).

Since the majority of the pipeline will be buried, "these small continuous-type releases may go unnoticed for an extended period until the spill volume is expressed on the surface" (EIS report). Such a situation is not very comforting for those citizens who have adjoining property to the pipeline right-of-way - to say nothing about the consequences to ground water and those surface waters that drain into areas on which large populations depend.

Inspection Tool Reported Features

Enbridge submitted a report to the NEB entitled Line 9B Reversal and Line 9 Capacity Expansion Project – Pipeline Integrity Engineering Assessment that provides a great deal of useful information about the pipeline itself and planned measures to mitigate the potential occurrences of leaks and spills. Over a period of several years, GE was sub-contracted to identify feature anomalies utilizing their patented UltraScan Crack Detection tool to indicate potential threats in portions of Line 9B deemed to pose integrity risks. Of the three tool runs involved (distances not stated), there were a total of 4738 crack related features and 8223 metal loss features. Despite these frightening results, the report cited above states (p.54) that the GE "field findings associated with such features indicate that they are not a threat to the integrity of the pipeline." The report goes on to say that "approximately 72% of the reported features for which depth was provided had a reported depth of <12% of the pipe WT (nominal thickness), while only one of the reported features had a depth >40% of WT " (44% in later examination).

The question that should be answered is – how many such features exist along the entire 639 km. length of the pipeline? And, above all – how can GE possibly conclude that the remaining life associated with the category of Stress Crack Corrosion (SCC) where such features have ONLY penetrated down to a depth of 29% WT (1.85 mm) is greater than 250 years? And then for another category of crack related features and with a maximum depth of 1.8 mm, the remaining life is 125 years!! (p.54). Clearly, the methodology and assumptions giving rise to these predictions are essential.

Concluding Remarks

In its report on frequency of leaks, The Enbridge report indicates that over a period of its 38 year life, there have been 12 leaks and 1 rupture (Table 3.2, Attachment 7), while on p.22 of Attachment 8, the state that "in the last 10 years there have been no corrosion related releases at the Facilities from assets within the scope of the Project". It's important to point out that a release from any cause is problematic and hence when employing a data set to establish a safety record, in this case all 13 large or small spills need to be taken into account.

As noted earlier, there are several types of threats any one of which, or in combination could cause a spill, and hence the issue of what safety factor is present in any particular segment of this very long pipeline is debatable. But, for example, if SCC along a longitudinal seam reduces the hoop strength to ½ of the nominal yield stress value (a circumstance that is very plausible), the safety factor <1 and a pipe failure is the result. And, when metal loss is combined with such a weakness, an even worse case scenario presents itself!

Unfortunately, Enbridge provides little in the way of insights into how the analysts arrived at the remaining life periods stated in their report. Even ignoring the corrosion processes that inevitably will cause this pipeline to turn to dust – whether they employ cathodic protection or not, there are simply too many abnormal features to be reckoned with, for which we can be confident that pipeline integrity will be preserved over the long haul of time.

In our view, the best solution is the "null solution". It's compatible with the Precautionary Principle that engineers are adopting, in recognition that some projects are simply too risky, with medium and long term consequences outweighing short term benefits . At times, the "do nothing" approach is the best solution. This project is deemed by us to be one such case.

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