CAPERN – 028M
C.P. – Inversion du
flux de l'oléoduc
9B d'Enbridge

Mémoire déposé dans le cadre de la consultation publique du gouvernement du Québec

Inversion du flux de l'oléoduc 9B d'Enbridge

3 décembre 2013

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équiterre

1. La pertinence d'Equiterre

Équiterre s'est donné pour mission de contribuer à bâtir un mouvement de société en incitant citoyens, organisations et gouvernements à faire des choix écologiques, équitables et solidaires. Par son action, Équiterre veut porter l'attention sur les aspects fondamentaux de la vie. Manger, se transporter, habiter, jardiner et consommer : des besoins vitaux, mais aussi des moyens à la portée de chacun pour agir de façon responsable et changer le monde un geste à la fois.

Très préoccupé par le phénomène des changements climatiques, Équiterre a développé au cours des années une expertise enviable en matière de politiques de réduction des émissions de gaz à effet de serre (GES). Il a rapidement identifié les choix de modes de transport et les pratiques d'aménagement du territoire comme les causes principales d'émissions de GES au Québec et a fait de la réduction de la consommation de pétrole une des solutions privilégiées permettant leur diminution. Steven Guilbeault, Directeur principal d'Équiterre, a notamment assuré la présidence du comité sur les énergies renouvelables émergentes au ministère des Ressources naturelles (2009-10) et a été membre du comité consultatif sur l'élaboration du PACC 2 (2010-2012) ainsi que du comité aviseur sur le PACC 2 récemment lancé par le Ministre Yves-François Blanchet..

Depuis 2009, Équiterre a publié une série de rapports sur la dépendance aux énergies fossiles et sur les moyens de la réduire. Toujours avec la perspective de présenter des recommandations concrètes et innovantes sur les politiques publiques, *Libérer le Québec du pétrole d'ici 2030* a lancé la série, suivi de *Changer de direction* en 2010 portant sur l'aménagement et le transport des personnes. En 2013, un rapport sur la dépendance aux énergies fossiles en agriculture verra le jour. Le transport des marchandises et l'élimination du mazout sont les prochains chantiers.

Au cours des cinq dernières années, Équiterre a mis au jeu, seul ou en partenariat, plusieurs documents portant sur les politiques publiques à mettre en place afin de viser l'adoption de meilleures pratiques en matière d'énergie[1].

Équiterre est également membre actif de *TRANSIT, l'Alliance pour le financement des transports collectifs au Québec* [2], ainsi que de *SWITCH, l'Alliance pour une économie verte au Québec* [3]. Ces deux regroupements cherchent également à bonifier les politiques publiques québécoises en faveur d'un virage vers la réduction de la consommation d'énergie et de pétrole, le déploiement accéléré des transports collectifs et la transformation durable et efficiente de l'économie québécoise.

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[1] www.equiterre.org/choix-de-societe

[2] www.transitquebec.org

[3] www.allianceswitch.ca

Depuis 2008, Équiterre suit les projets de pipelines au Québec. Travaillant en coalition avec des groupes de partout en Amérique du Nord, Équiterre informe et mobilise les citoyens autour des enjeux de changements climatiques et de sécurité des pipelines au Québec.

Ce mémoire présentera la position d'Équiterre sur le projet d'inversion du flux de l'oléoduc 9B ainsi que des recommandations-clés afin d'agir en ce sens.

2. La lutte aux changements climatiques

Cette consultation sur l'inversion du flux de l'oléoduc 9B, a comme trame de fond les conclusions du récent rapport du GIEC publié en septembre 2013, attribuant avec 95 % de certitude, soit extrêmement probable, que le réchauffement climatique soit lié aux activités humaines.

Pour Équiterre, le Québec doit réduire sa consommation totale d'énergie en commençant par les énergies fossiles. Ceci doit se faire dans un contexte global où l'on doit encourager la production d'énergie verte ici et dans le monde. Offrir plusieurs sources d'énergie renouvelables aux entreprises qui s'installeront au Québec permettra de réduire le bilan énergétique mondial. C'est avec cette vision que nous avons préparé ce mémoire.

La cible du gouvernement est de réduire de 25 % les émissions de GES en dessous des niveaux de 1990 d'ici 2020 ce qui représente 21 Mteq CO_2. Ceci implique que nous devons réduire de 23 % notre consommation d'énergie fossile par rapport à l'énergie consommée aujourd'hui[4]. Le gouvernement s'est également engagé à réduire de 30 % d'ici 2020 et de 60 % la consommation de pétrole au Québec d'ici 2030 par rapport aux niveaux de 2009, soit des économies de 4,2 milliards de litres de pétrole et représentant 4,0 milliards de dollars et 9,8 millions de tonnes de gaz à effet de serre [5].

On observe une volatilité croissante des prix du pétrole [6]. Alors que l'économie mondiale actuelle s'éloigne difficilement de la récession, les prix du pétrole demeurent élevés. Selon plusieurs experts, la volatilité des prix du pétrole risque de perdurer dans les prochaines années, favorisant une évolution tout aussi volatile de l'économie mondiale. L'économie du Québec, fortement dépendante du pétrole, n'échappera pas à cette volatilité.

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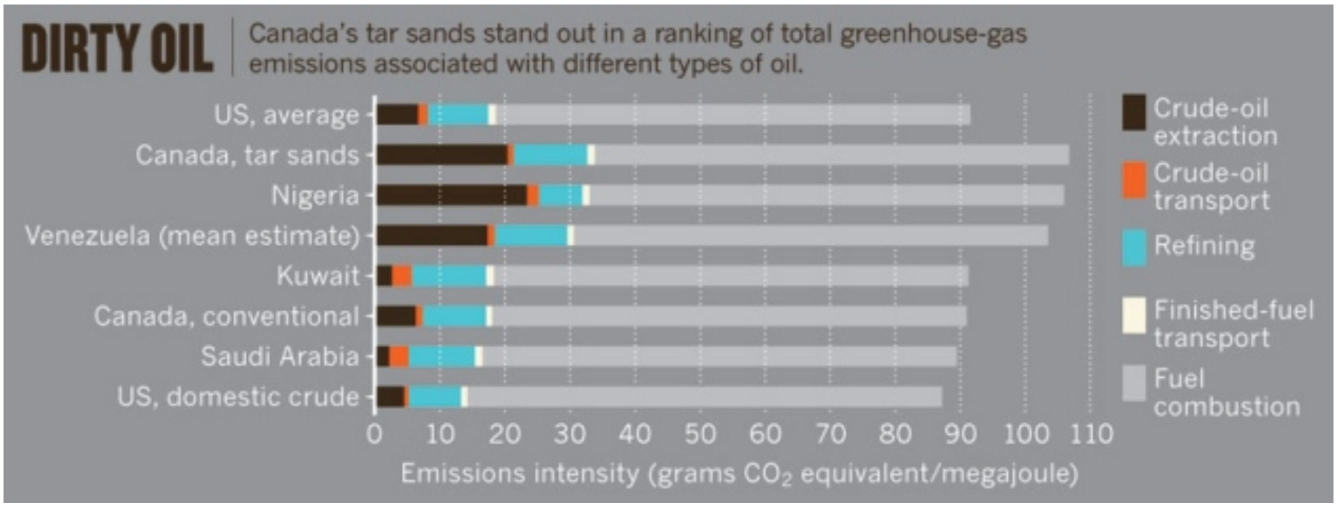
[4] Document de consultation. Commission enjeux énergétiques du Québec. 2013.

[5] Equiterre et Vivre en ville. 2011. Changer de direction. http://www.equiterre.org/publication/changer-de-direction-chantier-en-amenagement-du-territoire-et-transport-des-personnes

[6] *Équiterre et Vivre en ville, 2011. Changer de direction http://www.equiterre.org/publication/changer-de-direction-chantier-en-amenagement-du-territoire-et-transport-des-personnes*

L'exploitation des sables bitumineux en Alberta constitue actuellement un des plus graves problèmes environnementaux de la planète [7] (voir figure ci-dessous). La directive européenne sur la qualité des carburants, approuvée par les États membres en 2009, a accordé une « valeur d'intensité » en gaz à effet de serre au pétrole issu des sables bitumineux de 22 % supérieure à celle des bruts conventionnels [8]. Alors que le niveau de production actuel engendre déjà des impacts colossaux sur l'eau, la forêt et le climat, compagnies privées et gouvernements cherchent à tripler la production actuelle d'ici 2020.



Source:Nature, Jeff Tollefson, 07 August 2013, http://www.nature.com/news/climate-science-a-line-in-the-sands-1.13515.

Réduire la teneur en carbone des carburants

Dans le cadre de la consultation sur la Politique de mobilité durable, le gouvernement du Québec cite l'exemple d'états comme la Colombie-Britannique et la Californie qui ont adopté des normes visant à réduire la quantité de carbone présente dans les carburants utilisés sur leurs territoires. Or, selon les études effectuées par le Congrès américain, l'Union européenne ou encore celle présentée dans le graphique ci-haut, les sables bitumineux sont l'un, sinon le, pétrole le plus polluant d'un point de vue GES. Il serait irresponsable pour le Québec d'aller de l'avant avec le projet d'Enbridge alors que de plus en plus d'états cherchent à réduire, non augmenter, la quantité de GES que contiennent leurs carburants.

[7] IRIS, 2013. et Lattanzio, 2013. Canadian Oil Sands: Life-Cycle Assessments of Greenhouse Gas Emissions. Prepared for Members and Committees of American Congress.

8 http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:31998L0070:fr:NOT

équiterre

3. Les conclusions des rapports d'experts déposés à l'ONÉ

Équiterre, ainsi que d'autres groupes environnementaux ontariens et québécois, ont participé aux audiences de l'Office national de l'Énergie dans le cadre du « Projet d'inversion de la canalisation 9B et d'accroissement de la capacité de la canalisation 9 » d'Enbridge. Cette coalition représentée par Ecojustice, était constituée d'Équiterre, Environmental Defence, ENJEU, Association québécoise de lutte contre la pollution atmosphérique (AQLPA), le Sierra Club - chapitre de Montréal, Climate Justice Montreal (CJM) et Nature Québec. Deux rapports d'experts ont été déposés en tant que preuve dans le cadre de ces audiences et ont soulevé de sérieux doutes quant aux avantages de l'inversion de la ligne 9B en matière de sécurité et d'économie. Nous les avons joints en annexe de ce mémoire.

Un risque élevé de rupture du pipeline

Dans son rapport "Report on Pipeline Safety for Enbridge's Line 9B Application to NEB" en annexe, Richard Kuprewicz, expert international en sécurité des pipelines, a conclu à un « risque élevé de rupture sur la ligne 9 au cours des premières années de l'inversion ». Richard Kuprewicz a analysé plusieurs documents publics sur le cas du déversement de Marshall au Michigan. Selon cet expert, Enbridge refuse de faire preuve de prudence en donnant suite aux leçons tirées du déversement de Marshall, au Michigan, en 2010 : «Étant donné les nombreuses lacunes mises au jour dans la demande présentée par Enbridge, je dois en déduire qu'il y a un risque élevé de rupture dû à l'interaction de la fissuration par corrosion sous contrainte, de la fatigue-corrosion et de la corrosion générale. De plus, la démarche d'Enbridge en matière de sécurité des pipelines ne saurait prévenir les ruptures dans les conditions d'exploitation résultant de la mise en œuvre du projet.» [9]

Des coûts élevés, peu de bénéfices

Un risque élevé de rupture, tel qu'évalué par l'expert Kuprewicz, entraîne des conséquences élevées en matière de coûts selon Ian Goodman et Brigid Rowan, économistes spécialisés en énergie du Goodman Group, Ltd. (TGG). Dans leur rapport "The Relative Economic Costs and Benefits of the Line 9B Reversal and Line 9 Capacity Expansion",[10] ces experts ont affirmé qu'en raison de la proximité extraordinaire de ce projet aux populations, aux cours d'eau et aux activités économiques, les coûts de rupture pourraient varier entre des sommes importantes et des montants catastrophiques. TGG a estimé les coûts de rupture dans un mauvais scénario à 1 milliard de dollars et les coûts dans le pire scénario entre 5 à 10 milliards de dollars. Le projet

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[9] Kurapwicz, Report on Pipeline Safety for Enbridge's Line 9B Application to NEB, 2013. https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/92263/790736/890819/956564/956632/981386/A3J7T4_-_Attachment_B-_ACCUFACTS_PIPELINE_SAFETY_REPORT.2013.08.05?nodeid=981150&vernum=0

[10] Goodman et Rowan, The Relative Economic Costs and Benefits of the Line 9B Reversal and Line 9 Capacity Expansion, 2013. https://www.neb-one.gc.ca/ll fre/livelink.exe/fetch/2000/72399/72487/74088/660700/750773/794638/794847/813450/C13-6-11_-_Attachment_E-_TGG_Evidence_NEB_Line_9B_20130806_-_A3J7U2.pdf?nodeid=813481&vernum=0&redirect=3

d'Enbridge pose un risque considérable de dommages et de perturbations économiques majeurs, et pourrait même causer des pertes humaines. C'est particulièrement le cas à Toronto et à Montréal, où le pipeline, qui longe ou traverse des infrastructures urbaines essentielles, pourrait mettre en danger l'approvisionnement en eau potable. En effet, un accident majeur dans une zone densément peuplée, causant des dommages sur des infrastructures clés pourrait occasionner des coûts pire scénario, soit entre 5 et 10 milliards de dollars.

Le Goodman Group, Ltd. estime les bénéfices à moins d'un milliard par année et plus probablement de moins de 0.5 milliard de dollars par année pour l'ensemble du projet (durée de vie de 30 ans). TGG a démontré que ces bénéfices iront surtout aux raffineries du Québec et que le prix à la pompe ne baissera pas. En utilisant les chiffres provenant du rapport d'expert d'Enbridge nommé le « Rapport Demke » sur les impacts économiques du projet,[11] TGG a aussi démontré dans son rapport que les impacts du projet sur l'emploi canadien sont minimes et se chiffrent à environ 200 emplois par année pour la construction et l'exploitation sur la vie du projet (2013-2043).

Le rapport Demke ventile les impacts par province et démontre que les impacts du projet sur l'emploi au Québec sont encore plus minimes. Selon les calculs de l'expert d'Enbridge, le nombre d'emplois temporaires (directs, indirects et induits) créés au Québec associés à la construction du projet sera de 200 par année pendant la période de construction (estimée d'une durée d'environ deux ans), soit 400 années-personnes temporaires pendant cette période. L'impact de l'exploitation du projet sur l'économie québécoise se chiffre à 70 emplois par année (directs, indirects et induits) et à seulement 4 emplois directs permanents reliés à l'exploitation de l'oléoduc sur la durée de vie du projet, soit 30 ans. Par ailleurs, l'impact de ce projet sur le PIB ne sera pas significatif.

Ainsi, TGG a conclu que les coûts économiques potentiels du projet pourraient dépasser, et grandement dépasser dans des conditions de rupture diverses, les bénéfices. Par ailleurs, les coûts et les bénéfices du projet sont répartis de façon inéquitable parmi les parties prenantes et les régions touchées. La majeure partie des bénéfices ira à l'industrie alors que des risques importants devront être assumés par les citoyens et les gouvernements.

Couverture d'assurance nettement insuffisante

Les experts Goodman et Rowan ont aussi exprimé des préoccupations importantes au sujet du fait qu'Enbridge n'a pas su fournir de garanties suffisantes permettant de croire que l'entreprise serait entièrement responsable des dégâts dans l'avènement d'une rupture majeure. En ce moment, Enbridge possède une

[11] Annexe 1 à la réponse au DDR de Stratégies Énergétiques 1.4.a, intitulé "An Evaluation of the Economic Impacts on Canada of the Enbridge Line 9B Reversal Project," préparé pour Enbridge par Demke Management Ltd., le 30 août, 2013, Adobe pp.12, 17.

https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/965026/B18-41__-_Attachment_1_to_Strategies_Energetiques_IR_1.4.a_-_A3I6T6.pdf?func=doc.Fetch&nodeid=965026

assurance en responsabilité civile de 685 millions de dollars américains pour tous les projets d'Enbridge.[12] Ainsi TGG recommande un minimum de couverture pour ce type d'assurance de 3 milliards de dollars uniquement pour ce projet, de même que de rendre responsable Enbridge de la totalité des coûts sur le territoire en cas de rupture.[13]

Les sables bitumineux, un risque pour l'économie canadienne?

Depuis quelques années, plusieurs études et analyses de différentes organisations chercheurs, tels le Fonds monétaire international (FMI), la Banque du Canada, le Conseil international du Canada (CIC), le Centre canadien de politiques alternatives (CCPA), l'Organisation de coopération et de développement économiques (OCDE) et le Conference Board du Canada estiment que le rythme accéléré du développement de l'industrie des sables bitumineux engendre des risques économiques et des disparités régionales qui méritent qu'on leur prête attention.

C'est d'ailleurs ce qui a amené Équiterre et l'Institut Pembina à publier, le 12 novembre dernier, l'étude nommée « Risques bitumineux — Les conséquences économiques de l'exploitation des sables bitumineux au Canada[14]» et qui se penche sur les effets secondaires du boom des sables bitumineux et présente une analyse différente des retombées économiques souvent exagérées qu'on associe au développement de cette industrie.

Cette étude indique que la très grande majorité des retombées économiques directes et indirectes profitent uniquement à l'Alberta, soit environ 94 %[15]. Même les États-Unis pourraient compter sur plus de possibilités de création d'emplois que les autres provinces canadiennes si les projets de développement des sables bitumineux voyaient le jour comme prévu. Les répercussions du boom des sables bitumineux sur l'économie se font sentir partout au pays, comme la force du dollar qui donne du fil à retordre aux fabricants du secteur manufacturier d'ici pour soutenir la concurrence mondiale.

Étant donné la forte croissance anticipée de l'industrie des sables bitumineux, ces effets indésirables constatés à l'heure actuelle devraient servir d'avertissements. En favorisant le secteur pétrolier et gazier par rapport à

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[12] Goodman et Rowan, The Relative Economic Costs and Benefits of the Line 9B Reversal and Line 9 Capacity Expansion, 2013. https://www.neb-one.gc.ca/ll fre/livelink.exe/fetch/2000/72399/72487/74088/660700/750773/794638/794847/813450/C13-6-11_-_Attachment_E-_TGG_Evidence_NEB_Line_9B_20130806_-_A3J7U2.pdf?nodeid=813481&vernum=0&redirect=3

[13] Goodman et Rowan, Équiterre (Coalition) Response to National Energy Board (NEB or Board) Information Request No. 1, le 5 septembre, 2013.https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/1032317/C13-8-1__-_EQUITERRE_%28COALITION%29_Response_to_NEB_IR_1_Line_9B_2013.09.05__A3K8G3.pdf?func=doc.Fetch&nodeid=1032317

[14] http://www.equiterre.org/sites/fichiers/risques_bitumineux_final.pdf

[15] idem, p.7

d'autres secteurs qui possèdent un potentiel de croissance à plus long terme, le gouvernement fédéral place la prospérité de tous les Canadiens en position précaire.

D'ailleurs, un gouvernement fédéral responsable s'inquièterait du fait que les secteurs manufacturiers ontariens et québécois ont souffert de l'appréciation rapide du dollar et continuent d'en souffrir aujourd'hui. Hélas, cette situation ne semble pas préoccuper M. Harper et ses acolytes. Un vrai plan économique et énergétique à l'échelle nationale profiterait aux communautés et aux entreprises de l'ensemble du pays plutôt qu'à une seule région. En acceptant le pétrole des sables bitumineux, le Québec ne fera qu'exacerber ce phénomène... c'est un peu comme si on se tirait dans le pied!

4. Un processus qui manque de transparence

Le document de consultation fait surtout état des conditions gagnantes pour la venue d'un tel projet au Québec. Selon nous, ceci passe complètement à côté de l'un des enjeux de ce projetl soit : une véritable transparence sur la sécurité des pipelines,à laquelle, nous croyons,. Une étude indépendante doit avoir un mandat de faire la lumière sur les véritables risques reliés au projet, et non de déterminer quelles seraient les conditions optimales pour sa mise en œuvre. À titre d'exemple, le recours actuel au système de racleur pour la détection des fuites ne permet pas un contrôle à 100 %. Des experts peuvent entériner les recommandations de l'industrie, sans avoir analysé les enjeux. C'est précisément ce que nous voulons éviter, soit un processus bâclé et non transparent.

Comment la CAPERN peut-elle se prononcer sur ce projet avant même d'avoir les données sur l'état du pipeline d'Enbridge? Or, lors des audiences devant l'ONE, Enbridge a affirmé ne pas être en mesure de déposer ces données avant 2014.

Des groupes environnementaux ont d'ailleurs exigé, par le biais d'une lettre au ministre Blanchet le 9 avril dernier, que soit tenue une véritable évaluation environnementale stratégique sur le projet. Nous constatons que cette condition n'a toujours pas été remplie.

L'importance d'une évaluation par des experts indépendants a été amplement démontrée par les conclusions élaborées dans nos rapports d'experts et résumée ci-haut. Concernant la sécurité du projet, et particulièrement la conclusion de Richard Kuprewicz, d'un risque élevé de rupture sur la ligne 9 au cours des premières années de l'inversion est extrêmement pertinente à une évaluation éclairée et objective de ce projet.

Ainsi, nous demandons une étude d'impact transparente qui fera état des enjeux environnementaux réels pour le Québec.

Nous soulignons que plusieurs municipalités et MRC du Québec ont adopté des résolutions municipales interdisant la venue des sables bitumineux sur leur territoire. La Ville de Montréal a également dénoncé cet automne le fait qu'Enbridge n'avait toujours pas démontré comment leur plan d'urgence allait sécuriser l'approvisionnement en eau de la ville. Plusieurs organisations ontariennes ont d'ailleurs émis des craintes similaires lors des audiences de l'Office national de l'énergie (ONÉ).

Nous recommandons que le Québec rejette ce projet, pour 5 raisons:

1- ce projet va l'encontre des objectifs de réduction de GES du Québec, des objectifs de réduction de notre dépendance au pétrole ainsi que de l'adoption d'une norme sur la teneur en carbone des carburants
2.- il va à l'encontre d'une vision économique sobre en pétrole,
3- le risque de rupture du pipeline est trop élevé (chiffré par Kuprewicz à au-delà de 90 %),
4- les coûts surpassent les bénéfices et
5- l'allocation des coûts et des bénéfices est inéquitable parmi les parties prenantes et les régions touchées.

5. Le raffinage du pétrole lourd au Québec

A travers une demande d'accès à l'information, nous avons obtenu les permis autorisant la construction d'une usine de cokéfaction dans l'est de Montréal. Ils ont déjà été octroyés par le gouvernement du Québec ainsi que par la Ville de Montréal en 2007 à Pétro Canada, alors propriétaire du terrain maintenant détenu par Suncor. Donc, nous savons que l'industrie pétrolière souhaite raffiner une partie du pétrole lourd issu des sables de l'Alberta dans la raffinerie de Montréal Est.

Le raffinage du pétrole lourd au Québec nécessite plus d'énergie que le pétrole léger et donc augmente les GES[16]. Il est aussi probable que le raffinage du pétrole lourd émet plus de particules aériennes dommageables pour la santé que le raffinage de pétrole léger tel que des émissions de NOx, N_2O et SOx [17]. Avec la venue du raffinage de pétrole lourd dans l'est de Montréal, comment le gouvernement assurera un contrôle à l'échelle de la province de ces émissions?

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[16] http://www.eipa.alberta.ca/media/39640/life%20cycle%20analysis%20jacobs%20final%20report.pdf

[17] http://www.capp.ca/rce/wp-content/uploads/2013/10/RCE-2013-Full-Print-Report.pdf et http://www.ineris.fr/ippc/sites/default/files/files/ref_bref_0203_VF_1.pdf

6. Un processus non inclusif et tardif

Le gouvernement de Québec a annoncé la tenue d'une consultation le 13 novembre dernier, près d'un an après que le projet ait été soumis à l'ONE, en novembre 2012. En effet, les audiences ont débuté le 26 novembre 2012, moins de deux semaines après l'annonce de la tenue de la consultation. Le gouvernement du Québec aurait bien pu agir avant, alors qu'il en avait la capacité et les moyens. Les groupes environnementaux, lui ont d'ailleurs rappelé d'une seule voix, en exigeant que soit tenue une véritable évaluation environnementale stratégique sur le projet, par le biais d'une lettre envoyée le 9 avril dernier.

De plus, seulement quelques organisations, MRC et villes ont été invitées à se prononcer sur la question. Plusieurs groupes dont des groupes citoyens directement touchés par le pipeline ont été invités à participer, qu'une fois les auditions en cours et suite à leur sortie publique le 28 novembre dernier à Montréal. Nous avons critiqué l'ONE qui a dû, en vertu des changements de certaines lois fédérales, changer les règles, ce qui a réduit la participation citoyenne. Non seulement cette consultation québécoise n'est pas plus inclusive que celle de l'ONE, mais en plus, elle s'est orchestrée de manière précipitée.

Pour ces raisons, nous croyons que le gouvernement s'est croisé les bras sur ce projet en attendant à la toute dernière minute pour réagir, ce qui est selon nous, inacceptable. Un gouvernement doit démontrer qu'il a à coeur la sécurité de ses citoyens ainsi que leurs préoccupations en ce qui a trait à la qualité de leur eau potable et leur santé.

7. Annexe: rapports d'expert déposés devant l'ONÉ le 6 août 2013

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Accufacts Inc.

"Clear Knowledge in the Over Information Age"

Report on Pipeline Safety for Enbridge's Line 9B Application to NEB

August 5, 2013

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Appendix – Exhibits Referenced in Report

I. Executive Summary

Accufacts was asked to provide an independent analysis regarding pipeline safety concerning the Line 9B Reversal and Line 9 Capacity Expansion Project Application and related documents filed to the National Energy Board ("NEB" or "Board") by Enbridge, including their Pipeline Integrity Engineering Assessment, as well as related Information Requests and Enbridge Responses (collectively referenced in this report as the "Project").[1] The Project basically makes pump station modifications to reverse the flow of an existing 30-inch Line 9B pipeline segment routed through southeastern Canada from the North Westover Pump Station in Ontario to the Montreal Terminal in Quebec. The applicant, Enbridge, is asking to link up and increase the capacity of a previously NEB approved Line 9A proposal (an earlier similar 30-inch pipeline reversal from Sarnia, Ontario to North Westover, Ontario). The applicant is now asking to be permitted to move a wide range of crude oils, including heavy oil that includes various forms of diluted Canadian tar sands bitumen, or dilbit, as well as light crudes such as Bakken, eastward on the 9A and 9B segments. The Project directly concerns only pipeline assets within Canada, and is thus governed by Canadian approval processes and pipeline safety regulations, falling under the jurisdiction of the NEB. The Project, however, could also have an impact on several major pipelines operating in the U.S. connecting to the Sarnia, Ontario and Montreal, Quebec Terminals.[2] It is hoped this report will assist the NEB in making its decision.

Enbridge has claimed they are one of the largest users of inline inspection ("ILI"), or smart pig technology, so it is surprising that their crack assessment tool use, verification, and integration into their IM program is proving inadequate, even after Enbridge's Marshall, MI 30-inch Line 6B pipeline rupture. The many shortcomings in Enbridge's IM crack threat assessment program, discovered from investigation of various public records following the July 25, 2010 Marshall, MI rupture from Stress Corrosion Cracking ("SCC"), are discussed. Like Line 6B, both Line 9A and Line 9B are 30-inch pipelines exhibiting extensive SCC coincidental with general corrosion pipe wall loss from severely disbonded polyethylene external coating. Such cracking threats are prevalent along the system, appear to pose the greatest threat to pipeline integrity, and are proving very challenging to identify or assess via ILI and engineering assessments. Public records make it very clear that Enbridge is still not heeding pipeline investigators/regulators in IM, nor has Enbridge adequately incorporated the critical safety process management perspectives that serve as the basis of prudent pipeline IM regulation to assure safety. Given these still serious IM deficiencies, especially in the ILI crack management program, in order to substantially reduce the risk from crack rupture, Accufacts must now recommend that hydrotests

[1] "Line 9B Reversal and Line 9 Capacity Expansion Project Application by Enbridge Pipelines Inc.," Filed with the National Energy Board, major files NEB web site at https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=890819&objAction=browse.

[2] Canadian Energy Pipeline Association ("CEPA"), "Liquid Pipelines," at website http://hamiltonline9.files.wordpress.com/2012/08/na-pipeline-map.jpg.

be performed on both Line 9A and Line 9B to verify the pipeline's integrity and current fitness for its new service. Accufacts must conclude, given our extensive experience in pipeline risk management and the information provided in this report indicating continuing serious deficiencies still in Enbridge's IM approach, that without a proper hydrotest there is a high risk the pipeline will rupture in the early years following the Project's implementation.

Recommended hydrotesting should obviously be performed to Canadian standards that are superior in their prescriptive requirements compared to U.S. pipeline safety hydrotesting regulations. Canada has a long history and considerable experience in assuring performance of such proper hydrotesting of pipelines containing extensive cracking risks, such as SCC. Accufacts further concludes that Enbridge statements suggesting that such hydrotests can damage a transmission pipeline, or be dangerous to the pipeline, are without technical merit, and appear to be attempts to misinform decision makers and the public.

As also explained in this report, substantial improvements in Enbridge's leak detection approach are also warranted as Enbridge has not demonstrated they understand the weaknesses of the Mass Balance System ("MBS") approach that played a major role in the more than 17 hours it took to recognize that a rupture at Marshall, MI had occurred, and close proper remote operated isolation valves. Leak detection improvements should focus on rapid identification of rupture, even during transients. In the area of rupture detection, history has repeatedly demonstrated just meeting "industry standards" will not prove sufficient. Accufacts advises that simple operational changes should also be implemented to eliminate the potential of slack line during transient and normal operation on Line 9, and additional efforts focused to significantly reduce false MBS alarms to the Control Room. Based on Accufacts' extensive experience in pipeline leak detection, control room management regulatory development, and pipeline incident investigation, current estimated oil spill volumes indicated in the Project are most likely significantly understated. In addition, in the event of a release, claimed Enbridge response times in various IR responses of 1.5 to 4 hours for such a high consequence pipeline system as Line 9B are also not adequate or appropriate.[3]

Section VIII summarizes Accufacts' twelve main conclusions and three specific recommendations to the NEB concerning the Enbridge Project.

[3] For example, see Enbridge responses to Toronto or Ontario, IR No. 2.

II. Brief Review of Enbridge Line 9 Project Proposal

Exhibit 1 is a system map of the Line 9 Project taken from Enbridge's Pipeline Integrity Engineering Assessment ("EA").[4] The Project builds from a previously NEB approved reversal and expansion for the approximately 120 mile (~ 194 kilometer) Line 9A segment from Sarnia, Ontario (Milepost, or "MP", ~ 1742) to North Westover Station, Ontario (MP ~ 1862.6). The Project consists of an additional approximately 397 mile (~ 636 kilometer) Line 9B segment from North Westover station to the Montreal Terminal (~ MP 2259.6) in Quebec, also reversing previous flow operation in this segment to move eastward. This Project will also increase the design capacity on the entire Line 9 system (Sarnia to Montreal Terminal) to approximately 333,000 bbls/d utilizing DRA at each pump station).[5] The original Project application indicated an annual rate of 300,000 bbls/d, but subsequent filings indicate a higher stream day rate design capacity using existing pump station sites, as indicated in Table 1 below, with DRA injection at various pump stations.[6]

Table 1 – Main Station Facility MP Locations for Line 9

Main Station Facilities	MP	Delta Mileage to Nearest Downstream Line 9 Station
Sarnia Pump Station (SA)	1742	
North Westover Pump Station (NW)	~1862.6	120.6
Hilton Pump Station (HL)	~1997.3	134.7
Cardinal Pump Station (CD)	~2131.6	134.3
Terrebonne Station (No pumping)	~2247.8	116.2
Montreal Terminal (MT)	~2259.6	12
	Total (SA – MT)	517.8

4 Enbridge Pipelines Inc. Pipeline Integrity Department, "Line 9B Reversal and Line 9 Capacity Expansion Project Pipeline Integrity Engineering Assessment," Submitted to National Energy Board, November 2012, "Figure 2.1 – The Project System Map," p. 11.
5 Drag Reducing Agent, or DRA, is an additive injected in certain locations along a pipeline to reduce energy loss due to fluid turbulence. Sudden loss of DRA injection may seriously affect liquid velocity and possible surge pressures within a pipeline.
6 Enbridge Pipeline Inc., Line 9B Reversal and Line 9 Capacity Expansion Project, "Mainline Transient Analysis Summary Report," June 2013, p. 4.

With the exception of some possible "temporary" workspace sites, the Project will mainly involve construction activities modifying existing pump stations on current Enbridge properties and rights-of-way. While the project is designed to operate at higher pressures than current westward flow, the MOP of the pipeline will not change from that last established by a hydrotest in 1997. The Project is designed for higher throughput and is asking the NEB for approval to also move heavy Canadian (most likely containing blended tar sands oils, aka dilbit), as well as lighter crude oils from the Western Canadian and U.S. Bakken region eastward along the entire Line 9 system, both the Line 9A and 9B segments.[7] In approving the Line 9A project in 2012 the NEB had limited the Line 9A segment to shipping only light and medium crude oils, subject to a reapplication.[8] Once modified, Line 9 will be designed to flow in only one direction, eastward.[9]

The mainline pipe, outside of the pump stations, in segment 9B consists of 30-inch (762 mm) diameter, X-52 grade, Double Submerged Arc Weld (DSAW) pipe, ranging in thickness from 0.25 inch (6.35 mm) to 0.5 inch (12.7 mm) with approximately 97 % of the mainline pipe equal to or less than 7.92 mm thick (0.250, 0.281, and .312 inches thick).[10] The pipeline was installed in 1975 and is externally coated with polyethylene tape, a tape coating that can seriously disbond or separate from the pipe wall to introduce the threat of SCC in certain environments. This type of coating has a tendency to "tent" near the longitudinal manufacturing seam, generating areas where fields of SCC colonies or "crack-fields" in sites of extensive general corrosion that further reduce pipe thickness under the tenting (see Exhibit 2 –SCC colonies/clusters in areas of general corrosion wall loss on the pipe joint that ruptured in Marshall, MI). What can make Fitness for Service time to failure predictions associated with SCC unpredictable in such conditions is that the SCC colonies can interact or quickly link up in sufficient depth and length within the area of general corrosion in an unpredictable manner, causing the pipe to rupture well before Fitness for Service or engineering assessment time estimates. These extensive SCC sites can also be at risk from another form of environmentally associated cracking, corrosion fatigue cracking, which to the naked eye looks similar to SCC, but is also driven by similar growth mechanisms such as pressure cycling. SCC, corrosion-fatigue, and general corrosion can also interact to accelerate time to failure. Based on the information supplied in the Project's EA, it is fair to assume that

[7] "Line 9B Reversal and Line 9 Capacity Expansion Project Application by Enbridge Pipelines Inc.," filed with the NEB, p. 24.
[8] NEB Letter Decision, "Enbridge Pipelines Inc. (Enbridge) Line 9 Reversal Phase I Project (Project) Hearing Order OH-005-2011," 27 July 2012, p. 27.
[9] Enbridge Response to Stragetgies Energetiques Information Request No. 2 OH-002-2013 File OF-Fac-Oil-E101-2012-10 02, "IR 2.2.m," p. 10.
[10] Enbridge Pipelines Inc. Pipeline Integrity Department, "Line 9B Reversal and Line 9 Capacity Expansion Project Pipeline Integrity Engineering Assessment," submitted to National Energy Board, November 2012, p. 14.

both Line 9A and 9B segments have extensive crack threat sites, such as SCC, similar to those observed in Line 6B across that system.[11]

III. Critical Factors in Previous Accufacts Line 9A Phase I Reversal Report on Enbridge's Methods

Several observations from my earlier report on Line 9A are, in my opinion, very relevant to the current Project.[12] I do not mean to over work these points, but the Project's application clearly demonstrates these issues still apply very much to the Project. Briefly highlighted are these important considerations:

1) For Cracks threats, ILI unity plots showing what the ILI tool actually measures is critical

For cracks, unity plots (a plot of the field dig readings versus pig indication) for <u>both crack depth and crack length</u> are critical to allow a direct comparison by engineers and regulators of the results provided by the pig vendor. In addition, special consideration should be paid to crack location and multiple crack fields associated with disbonded coating, especially in proximity to the manufacturing seam weld where "tenting" can occur.

Given the misapplications of the IM processes uncovered by the NTSB investigation of the Enbridge Marshall, MI rupture, crack ILI unity plots should not be plotted as predicted failure pressure ratio ("PFPR"). This is even more important given the problems discovered with the crack predicted failure pressure ratio approach and ILI performance by the NTSB, but also the Fitness for Service (aka Fitness for Purpose) methods that Enbridge utilized. Enbridge's current approach appears to still contain many of the biases that could result in non-conservative prediction in identifying crack threats. The Board should require Enbridge to supplement Figures 4.38 though 4.43 with additional unity plots for crack length that would allow an independent audit that would uncover any serious shortcomings in Fitness for Service engineering assessment approaches that are not conservative (See Exhibit 3 - Table of remaining strength calculations for 51.6 inch long feature that ruptured in Marshall MI using various wall thicknesses and ILI tool tolerances).[13]

Enbridge was using, and still maintains to this day, that their Fitness for Service approach should not use actual wall thickness measurements in crack fields such as SCC (See Exhibit 2 SCC colonies/clusters in areas of general corrosion wall loss on the pipe joint that ruptured in Marshall, MI), despite repeated wall measurement ILIs indicating substantially less wall

[11] Enbridge Pipelines Inc. Pipeline Integrity Department, "Line 9B Reversal and Line 9 Capacity Expansion Project Pipeline Integrity Engineering Assessment," Submitted to National Energy Board, November 2012, pp. 57 – 59.
[12] Accufacts Inc., "Accufacts' Perspective on Enbridge Filing for Modification on Line 9 Reversal Phase I Project," April 23, 2012.
[13] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Materials Laboratory Study for Marshall, MI, Report No. 12-046," 4-20-12, p. 4.

thickness in areas with wall thinning in the SCC crack field. It is also worth mentioning that the depth figures for the ILI crack tool run indicate a non-conservative bias (underreporting the depth of SCC cracks in the 2004/2005/2006 USCD crack ILI tool evaluation) which is consistent with the findings of the NTSB in their Line 6B investigation of the 2005 USCD ILI tool run. Plots of Predicted Failure Pressure Ratios (PFPRs) can hide many shortcomings in a crack's actual ability to withstand operating pressure. A review of Exhibit 3 (Table of remaining strength calculations for 51.6 inch long feature that ruptured in Marshall MI using various wall thicknesses and ILI tool tolerances), produced at the request of the NTSB) clearly demonstrates why the Marshall rupture failed well below MOP and even below Enbridge's self imposed pressure reduction.

2) Low pressure operation should never be used as credit in an IM program

Accufacts previously warned that pressure reduction should not be relied upon as a "safety" in pipeline operation for various reasons. Regulations, for example, permit operators to periodically exceed the Maximum Operating Pressure ("MOP"), especially during surges, such as those associated with changing crude slates or emergency upsets. It should be noted that the Board wisely stated in their approval of the Line 9A proposal that "The Board is of the view that, if a pipeline is not able to operate safely at its approved MOP of existing pressure, a pressure reduction may be a temporary solution. Ultimately, repair of any features affecting the integrity of the pipeline is the only permanent solution."[14] From Accufacts' perspective the Board understands the importance of not taking integrity credit for lower pressure operation.

As a point of reference, the Marshall, MI pipe joint that ruptured, failed at a pressure of approximately 56% SMYS or less, while operating under an Enbridge self imposed pressure reduction of 60% SMYS for approximately one year. The pipeline had a MOP of 72 % SMYS.

3) Possible effects of changing crude slate

When crack threats pose a significant threat to a pipeline, pressure cycling is an important consideration requiring accurate and thorough evaluation. Pressure cycling has the ability to seriously affect, vary, and accelerate crack growth rates. Special care should be taken to assure that field measurements for cracks do not unduly understate pressure cycling spectrums and are representative of actual and future operation. Accufacts has observed many failures where the pressure cycle spectrum was classified at a lower spectrum when actual failures were caused by much more aggressive cycling. It is very easy to use the wrong spectrum on engineering assessments, resulting in serious underestimating of time to failures with premature failure, usually below MOP. Changing crude slates, especially running dilbit, can significantly increase pressure cycles that can accelerate crack growth. The various and changing compositions of dilbit, both the bitumen and/or the diluent, can significantly impact pressure cycles on a pipeline where crack risk is a bona fide threat. Accufacts believes that the movement of dilbit in pipelines at risk to cracking threats presents a higher potential to cause pipeline ruptures if not adequately managed.

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[14] NEB Letter Decision, "Enbridge Pipelines Inc. (Enbridge) Line 9 Reversal Phase I Project (Project) Hearing Order OH-005-2011," 27 July 2012, p. 25.

4) Valve analysis and surge analysis for over pressure protection

Given its significance in a liquid pipeline rupture as well as many IR requests related to valving, Accufacts believes it is worth commenting further on the issue of valves building off my observation on the earlier 9A filing.[15] It is my opinion that Enbridge, on the subject of valves in the Line 9 Project's application is showing itself to be an industry leader in this area. This opinion is subject to several caveats uncovered from the Marshall, MI incident investigations.

1. Automated valves in Enbridge's responses mean remote operated valves commanded via SCADA at the direction of the control center operator.
2. When Line 9 is shut down it can be safely segment isolated by closure of remote operated valves along the pipeline system.
3. Maximum Volume Out release estimates between valves are affected not only by drainage, but by Enbridge's assumed time to shut down pumps and close the valves within 13 minutes. Such volumes are driven by the adequacy of the leak detection as well as control center operator proficiency to recognize a release and react appropriately.[16]

Failure to have a procedure, or follow a procedure of mainline segment isolation, significantly contributed to the release of oil in the Marshall, MI event, and raises questions as to the current adequacy of control room procedures and pipeline design to allow the control center to isolate a segment of a pipeline where there is a rupture, especially segments affecting high consequence areas. While I do not expect to uncover any surprises in the area of valving on Line 9, the NEB should follow through to their satisfaction on this subject given proper valve operation can play an important role after a pipeline rupture.

IV. Key Relevant Differences Between Canadian and U.S. Integrity Management Regulatory Approaches

Table 2 (U.S. and Canadian IM Liquid Pipeline Regulatory Approaches) on the following page, provides a simple summary of several major relevant differences in pipeline IM regulatory approaches between the U.S. and Canada. Table 2 is by no means meant to be an exhaustive list.

This section is not meant to be a complete comparison between U.S. and Canadian pipeline safety regulations, but rather an assessment of several major integrity management ("IM") approach differences that are significant as to how they impact the Project. Accufacts has observed that no particular country has developed a best regulatory pipeline safety practice, especially as it relates to IM to avoid rupture failure. Each country has certain approaches in

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[15] Accufacts Inc., "Accufacts' Perspective on Enbridge Filing for Modification on Line 9 Reversal Phase I Project," April 23, 2012, p. 10.

[16] Enbridge Response to Ontario Attachment 1 to Ontario IR 2.9.c, OH-002-2013 File OF-Fac-Oil-E101-2012-10 02.

specific areas that may be better or worse and different from those of other countries. It is eventually up to the citizens of each country to determine if the pipeline safety regulatory approaches are sufficient, especially given various differences in their jurisprudence systems. Accufacts feels very strongly, however, that the major purpose of any IM regulation is to assure a safety culture approach that is geared toward prudent management processes to avoid pipeline failures. It should be mentioned that all regulation, no matter how well intended, can be ineffective if the regulations are too complex, are not clear, or there is no appropriate follow-up or effective enforcement by the regulatory agencies whose resources are often stretched very thin.

Table 2 –U.S. and Canadian IM Liquid Pipeline Regulatory Approaches

IM Issue	Canada	U.S
Pressure Reduction	Permitted at discretion of operator without notification to regulator	Generally not permitted without prior notification to regulator
Minimum Assessment Intervals	Indicates continual assessment. Defines no minimum interval, reassessments determined by operator	Indicates continual assessment. Defines at least every 5 years not to exceed 68 months, restrictive variance permitted <u>in limited</u> situations
Defines Permitted Assessment Methods	No, but listed as examples	Yes
Identifies Certain At-risk Anomalies and Defines Remediation Timing to Address Them	No	Yes
Highly Dependent on Risk Approach	Yes, risk assessment very critical	Yes, risk based with focus on High Consequence Areas ("HCAs")
Engineering Assessments (EA)	Heavily dependent on EA defined and incorporated in regulation. Requires "conservative" assumption if data missing.	EA not defined in regulation, except in limited analysis situations.
Liquid Pipeline Application and IM Transparency	NEB application process for liquid pipelines more public and transparent. IM information can be sheltered from public, however.	Highly non public, even secretive, depending on specific state. Information controlled at discretion of the operator.

A key issue to an IM approach and its effectiveness is how public and transparent the core IM pipeline safety information is in order to assure the pipeline operator has their pipeline under reasonable control. The IM effort in the U.S. was initiated after several tragic liquid and gas transmission pipeline ruptures clearly demonstrated to the public that pipeline management had lost control of their pipelines for various reasons.[17] From my perspective, the Canadian NEB currently leads U.S. efforts in making much important pipeline and IM information public, though improvements are still warranted in this area in both countries.

V. Pipeline Integrity Assessment Technologies – Strengths and Weaknesses

As a result of high profile and tragic liquid and gas transmission pipeline ruptures, the Office of Pipeline Safety, the predecessor to the U.S. Pipeline and Hazardous Materials and Safety Administration ("PHMSA") responsible for pipeline safety in the U.S., in the early 2000's initiated federal pipeline safety rulemaking processes focused on requiring companies to phase in development of integrity management programs starting with liquid transmission pipelines. Prior to these rulemaking efforts, pipeline operators, under minimal federal pipeline safety regulations, were under no requirement to periodically reassess the integrity of their transmission pipelines except during the hydrotest following initial construction, though not all liquid pipelines were required to be hydrotested under various "grandfathering" exclusions.

The development of IM regulation required liquid pipeline transmission operators to initially baseline assess and periodically reassess their pipeline systems, depending on the type of threat, using four methods permitted in the IM regulations.[18] Canadian regulations also identify some of these methods as examples of pipeline inspection and testing but do not restrict assessment methods to those limited in U.S regulations.[19] Neither country identifies the various strengths and weaknesses of the assessment methods, but direct assessment as a process in the U.S. is clearly restricted to certain limited corrosion threats. Those methods defined in the U.S. pipeline regulations are summarized in Table 3 (Assessment Methods Identified in U.S. Pipeline IM Safety Regulations) with some of the various strengths and weaknesses I have observed in 40 years of experience in this area.

[17] For example, NTSB/PAR-02/02 Pipeline Accident Report, " Pipeline Rupture and Subsequent Fire in Bellingham, Washington June 10, 1999," adopted October 8, 2002 and NTSB/PAR-03/01 Pipeline Accident Report, "Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico August 19, 2000," adopted February 11, 2003.
[18] U.S. 49CFR§195.452(c) & (e).
[19] CSA Standards, "Oil and Gas pipeline systems – Z662-11, reprinted January 2012," Section 3.3.3.3, Notes (1) & (2), p. 33.

Table 3 - Assessment Methods Identified in U.S. Pipeline IM Safety Regulations

Assessment Method	Description	Strength	Weakness
Strength Testing (Usually hydrotest)	Takes critical axial aligned (e.g. cracks) anomalies to failure for properly designed hydrotest by applying a pressure safety margin. Claims of possible damage to pipe overplayed.	Proof test of system integrity establishing safety margin at time of test. Excellent at validating longitudinally oriented cracks, such as SCC. Canadian hydrotest regulation superior and more definitive than U.S. strength test regs.	Doesn't test girth welds well. Doesn't eliminate possible future crack threats, especially if test performed at too low a test pressure. Can leave anomalies in pipe that can grow to failure at a later date. Requires shutdown of pipeline.
Inline Inspection (ILI)	General Corrosion and Caliper (deformation/dent) ILI tools well developed from many decades of improvement and field verification. Crack tools still in early development with very mixed results.	When technology proven, tells more about condition of pipe than hydrotest. Pipeline usually doesn't have to be shut down.	Pipeline must be designed to run ILI tool. Good ILI results can still be misapplied. Running the ILI tool is usually the cheaper part of a pipeline assessment. Verification digs can cost more than ILI run. ILI technology claims often overstated.
Direct Assessment	Inferred process that uses direct readings of selected pipe sections usually via field digs.	Field dig observations usually more reliable for specific pipe segments observed.	Inferred assessment can leave much pipe not actually inspected. Can only be applied to certain corrosion risks.
Other Technology	Not defined, but open ended to permit development of new technologies if they can be demonstrated to work reliably to be equivalent (e.g. self propelled "robot" pigs with cameras, etc.)	Must be proven to satisfaction and approval of regulator before use allowed.	New technology doesn't always work as claimed. Important to understand its limitations.

VI. Central Findings in NTSB/PHMSA Investigation of Marshall, MI July 25, 2010 Rupture Applicable to Line 9

1) Accufacts synopsis of NTSB/PHMSA investigation

The following synopsis is gathered by Accufacts from information readily available in the public domain.[20] It should be noted that while the NTSB is ultimately responsible for their investigation and Final Report, many of the documents will indicate that PHMSA was also a party to many of the interviews.

On the afternoon of July 25, 2010 at approximately 5:58 PM (EDT) while shutting down the line for a temporary scheduled shutdown, Line 6B ruptured approximately 0.6 mile downstream from a mainline pump station at Marshall, MI (See Exhibit 4 - View of Line 6B ruptured pipe in trench). The pipe that ruptured was a 30-inch diameter, 0.25 inch thick, grade X-52, double submerged arc welded ("DSAW") pipe joint that failed at or below the maximum recorded discharge pressure at the closest upstream pump station, the Marshall Pump Station, of 486 psig (≤ 56% SMYS), which is well below the pipeline's MOP rating of 624 psig (72% SMYS).[21] The rupture failure occurred from an axial aligned crack that grew to a point of failure, such that the pipe ruptured below an Enbridge imposed pressure reduction of 523 psig (60% SMYS) at the time, and well below MOP.[22]

At the time of the rupture the pipeline was moving a unique form of oil called dilbit, a blend of Canadian tar sands oil diluted with a solvent, or diluent, to allow flow of the mixture at normal pipeline operating conditions established by pipeline tariffs, usually viscosity and gravity (density) limits. Through a series of misunderstandings, control center misoperations, and confusion caused by a perceived phenomena called column separation (aka slack line), where the pipeline does not operate liquid full, oil continued to spill from the pipeline over the next 17 plus hours as the pipeline segment containing the rupture remained not properly isolated and two subsequent lengthy startups (totaling approximately 1 ½ hours) were attempted. Emergency spill

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[20] 378 public files (as of 7/14/13) encompassing over 14,000 pages and almost 100 interviews are listed on the NTSB website for the July 25, 2010 Marshall, MI accident (DCA10MP007) located at:
http://dms.ntsb.gov/pubdms/search/hitlist.cfm?docketID=49814&CFID=23241&CFTOKEN=60045174

[21] MOP stands for Maximum Operating Pressure which is the normal maximum operating pressure permitted during normal operations on a particular pipeline segment established by regulations. MOP for liquid pipelines is usually a test qualification pressure divided by 1.25 (i.e., usually 72% SMYS in the U.S and up to 80% SMYS in Canada, though not always).

[22] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Material Laboratory Factual Report, Report No. 11-055," dated May 21, 2012, p. 2.

response procedures calling for shutdown and mainline valve isolation spanning the rupture site were not initiated until after a call was made to the control center from a non Enbridge utility company employee finding signs of spilled oil late in the morning of July 26, 2010. Enbridge estimated the 30-inch pipeline released 20,082 barrels (843,444 gallons). As of April 30, 2012, the EPA figures for recovered oil to that date had amounted to 27,334 bbls (1,148,012 gallons) substantially above Enbridge's earlier release estimate.[23] Given the propensity of dilbit to sink in water, oil recovery is still proceeding. As such, it is my understanding that a final estimate of the oil actually recovered has yet to be released. Current spill recovery costs have been estimated to exceed $1,000,000,000 U.S.

From an integrity management perspective, Enbridge relied on <u>one</u> highly specialized and what I would call push development technology "cracking tool" ILI (USCD) tool run in Line 6B in 2005. The objective of this specialized tool was to help detect axially aligned "anomalies" or crack features that can be very difficult to accurately determine and estimate time to failure. Axially aligned threats, such as SCC, are especially difficult to evaluate as these threats can occur in crack fields or clusters which is typical of SCC, or in combination with other threats such as corrosion-fatigue, that can make corrosion rates vary considerably. The 2005 USCD tool run was analyzed in early 2006 and results reported as capturing six crack-like (single crack) features in the pipe joint that ruptured at a site of SCC rather than the more significant crack colonies (i.e., crack-field). The NTSB reported "The crack feature corresponding to the rupture origin location was listed in the 2005 USCD report as a 51.6-inch-long crack-like feature with a maximum depth of 0.71 inches. In a post-accident analysis of the 2005 USCD data, PII found that the 51.6-inch long feature was misclassified as a crack-like feature in 2005."[24] Crack-like was defined to mean single crack while another term, crack-field, was used to indicate crack colonies or SCC. The rupture site was in an area of crack-field or SCC.

Enbridge's engineering assessments based on historical pressure cycling measurements and the 2005 USCD ILI run data placed Fitness for Service remaining fatigue life of the deepest crack feature in the pipe joint that eventually ruptured, at 21 years. This estimate was well beyond the approximate 4½ years to the actual rupture failure that occurred at much lower pressures than the engineering assessment calculated pressure thresholds.[25] In addition, underreporting by the ILI tool and analysis team resulted in the failure to identify this pipe joint for field dig verification to confirm ILI crack analysis that eventually caused the Line 6B "premature" rupture failure.

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[23] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Enbridge Line 6B Addendum to Emergency and Environmental Response Group Chairman's Factual Report," dated June 13, 2012, p. 2.

[24] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Materials Laboratory Study Report No. 12-046," April 20, 2012, p. 2.

[25] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Material Laboratory Factual Report – Report No. 11-055," May 21, 2012, pp. 21 - 23 and Figure 27, p. 42.

Enbridge was in the process of running another crack detection tool in 2010 when the pipeline ruptured.

Surprisingly, exacerbating the IM crack analysis of Line 6B, was:

1. GE's misreporting / mischaracterization of the SCC crack field anomalies in the pipe joint,
2. Enbridge's failure to use the proper nominal wall thicknesses for the pipe joint reported by previous ILI tools designed for such wall thickness measurements (the USCD tool was not designed for such measurements as its focus was crack feature identification),
3. Enbridge's failure to utilize remaining wall thickness measurements at the crack colonies (e.g., failing to integrate integrity data from various ILI runs), and
4. Enbridge's failure to incorporate crack tool tolerances that should assist in accounting for ILI tool imprecision.

The SCC that failed was in an area of general corrosion wall loss that further reduced the remaining pipe thickness in the area of crack penetration (See Exhibit 5 - Line 6B rupture site actual pipe crack penetration/corrosion wall loss). Clearly, this developing crack feature technology ILI run was still in development and limited or biased, definitely understating at least the depth and the seriousness of crack anomalies, which was the very intent of the USCD ILI tool run. Compounding the problems with this ILI tool's use, was Enbridge's failure to incorporate additional data, such as information from various different ILI runs actually designed to measure wall thickness (the USCD tool was not designed to measure pipewall thickness). A core requirement of IM processes, and associated risk management applications and pipeline safety regulations is the integration of data to assure the integrity of the pipe.

Based on the short time to rupture failure, Enbridge's subsequent engineering assessment approaches on Line 6B based on this ILI technology were highly incomplete and far from "conservative." The NTSB estimated average annual crack growth rate determined from the December, 2005 crack ILI run to the July 25, 2010 rupture at the crack failure to be 0.574 millimeters per year compared to Enbridge's assumed maximum growth rate on Line 6B of 0.38 millimeters per year.[26] This NTSB observation differs considerably from the response by Enbridge to an Information Request in the NEB Application process regarding crack growth rates on Line 6B for the pipe that ruptured.[27] Enbridge's maximum crack growth rates were too low, by approximately 50% for the site that ruptured, as compared to the NTSB estimated average annual crack growth rate. SCC, especially for sites where corrosion fatigue and/or general corrosion may

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[26] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Materials Laboratory Study, Report No. 12-046," 4-20-12, p. 6.

[27] Enbridge Response to Equiterre Information Request No. 1.1.(s), p.4, "There was no yearly growth rate specified by the NTSB for Line 6B."

be present, can exhibit a wide range of growth rates that can vary, depending on the corrosion environment and the pressure cycle/fatigue stress spectrum that can cause the crack colonies to link as well as grow unpredictably. SCC crack growth rates can be off by an additional margin if such SCC is occurring in sites of general corrosion wall loss due to the interaction of the threats on each other to accelerate growths. SCC predicted time to failure based on crack ILI and engineering assessments still remain a significant challenge.

2) NTSB investigation of Line 6B July 25, 2010 Marshall, MI rupture

After a detailed investigation, the National Transportation Safety Board ("NTSB") determined that 28 Findings were relevant to the July 25, 2010 Line 6B incident. Given their related applications to the proposed Line 9 Project, the NTSB Findings are summarized below as taken directly from the NTSB Accident Report for the Marshall, MI rupture event. [28] While all the NTSB Findings are significant their Findings related to IM are specifically called to mind as Nos. 3, 4, 5, 6, 7, 8, 9, 10, 27, and 28 are directly associated with IM issues that may apply to the Line 9 Project. I have extracted the NTSB Findings and bolded those IM related findings for easy reference.

a) NTSB Findings

1. The following were not factors in this accident: cathodic protection, microbial corrosion, internal corrosion, transportation-induced metal fatigue, third-party damage, and pipe manufacturing defects.

2. Insufficient information was available from the postaccident alcohol testing; however, the postaccident drug testing showed that use of illegal drugs was not a factor in the accident.

3. **The Line 6B segment ruptured under normal operating pressure due to corrosion fatigue cracks that grew and coalesced from multiple stress corrosion cracks, which had initiated in areas of external corrosion beneath the disbonded polyethylene tape coating.**

4. **Title 49 *Code of Federal Regulations* (CFR) 195.452(h) does not provide clear requirements regarding when to repair and when to remediate pipeline defects and inadequately defines the requirements for assessing the effect on pipeline integrity when either crack defects or cracks and corrosion are simultaneously present in the pipeline.**

5. **The Pipeline and Hazardous Materials Safety Administration (PHMSA) failed**

[28] NTSB Accident Report "Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release Marshall, Michigan July 25, 2010," NTSB/PAR-12-01, adopted July 10, 2012, pp. 118 - 120.

to pursue findings from previous inspections and did not require Enbridge Incorporated (Enbridge) to excavate pipe segments with injurious crack defects.

6. **Enbridge's delayed reporting of the "discovery of condition" by more than 460 days indicates that Enbridge's interpretation of the current regulation delayed the repair of the pipeline.**

7. **Enbridge's integrity management program was inadequate because it did not consider the following: a sufficient margin of safety, appropriate wall thickness, tool tolerances, use of a continuous reassessment approach to incorporate lessons learned, the effects of corrosion on crack depth sizing, and accelerated crack growth rates due to corrosion fatigue on corroded pipe with a failed coating.**

8. **To improve pipeline safety, a uniform and systematic approach in evaluating data for various types of in-line inspection tools is necessary to determine the effect of the interaction of various threats to a pipeline.**

9. **Pipeline operators should not wait until PHMSA promulgates revisions to 49 CFR 195.452 before taking action to improve pipeline safety.**

10. **PII Pipeline Solutions' analysis of the 2005 in-line inspection data for the Line 6B segment that ruptured mischaracterized crack defects, which resulted in Enbridge not evaluating them as crack-field defects.**

11. The ineffective performance of control center staff led them to misinterpret the rupture as a column separation, which led them to attempt two subsequent startups of the line.

12. Enbridge failed to train control center staff in team performance, thereby inadequately preparing the control center staff to perform effectively as a team when effective team performance was most needed.

13. Enbridge failed to ensure that all control center staff had adequate knowledge, skills, and abilities to recognize and address pipeline leaks, and their limited exposure to meaningful leak recognition training diminished their ability to correctly identify the cause of the Material Balance System (MBS) alarms.

14. The Enbridge control center and MBS procedures for leak detection alarms and identification did not fully address the potential for leaks during shutdown and startup, and Enbridge management did not prohibit control center staff from using unapproved procedures.

15. Enbridge's control center staff placed a greater emphasis on the MBS analyst's flawed interpretation of the leak detection system's alarms than it did on reliable indications of a leak, such as zero pressure, despite known limitations of the leak detection system.

16. Enbridge control center staff misinterpreted the absence of external notifications as evidence that Line 6B had not ruptured.

17. Although Enbridge had procedures that required a pipeline shutdown after 10 minutes of uncertain operational status, Enbridge control center staff had developed a culture that accepted not adhering to the procedures.

18. Enbridge's review of its public awareness program was ineffective in identifying and correcting deficiencies.

19. Had Enbridge operated an effective public awareness program, local emergency response agencies would have been better prepared to respond to early indications of the rupture and may have been able to locate the crude oil and notify Enbridge before control center staff tried to start the line.

20. Had the firefighters discovered the ruptured segment of Line 6B and called Enbridge, the two startups of the pipeline might not have occurred and the additional volume might not have been pumped.

21. Although Enbridge quickly isolated the ruptured segment of Line 6B after receiving a telephone call about the release, Enbridge's emergency response actions during the initial hours following the release were not sufficiently focused on source control and demonstrated a lack of awareness and training in the use of effective containment methods.

22. Had Enbridge implemented effective oil containment measures for fast-flowing waters, the amount of oil that reached Talmadge Creek and the Kalamazoo River could have been reduced.

23. PHMSA's regulatory requirements for response capability planning do not ensure a high level of preparedness equivalent to the more stringent requirements of the U.S. Coast Guard and the U.S. Environmental Protection Agency.

24. Without specific Federal spill response preparedness standards, pipeline operators do not have response planning guidance for a worst-case discharge.

25. The Enbridge facility response plan did not identify and ensure sufficient resources were available for the response to the pipeline release in this accident.

26. If PHMSA had dedicated the resources necessary and conducted a thorough review of the Enbridge facility response plan, it would have disapproved the plan because it did not adequately provide for response to a worst-case discharge.

27. **Enbridge's failure to exercise effective oversight of pipeline integrity and control center operations, implement an effective public awareness program, and implement an adequate postaccident response were organizational failures that**

resulted in the accident and increased its severity.

28. **Pipeline safety would be enhanced if pipeline companies implemented safety management systems.**

b) NTSB Recommendations to Enbridge following the Marshall rupture

The NTSB made numerous recommendations following their investigation of the Marshall, MI incident. Of special concern are the recommendations made to Enbridge (aka Enbridge Incorporated):

> "Revise your integrity management program to ensure the integrity of your hazardous liquid pipelines as follows: (1) implement, as part of the excavation selection process, a safety margin that conservatively takes into account the uncertainties associated with the sizing of crack defects from in-line inspection; (2) implement procedures that apply a continuous reassessment approach to immediately incorporate any new relevant information as it becomes available and reevaluate the integrity of all pipelines within the program; (3) develop and implement a methodology that includes local corrosion wall loss in addition to the crack depth when performing engineering assessments of crack defects coincident with areas of corrosion; and (4) develop and implement a corrosion fatigue model for pipelines under cyclic loading that estimates growth rates for cracks that coincide with areas of corrosion when determining reinspection intervals. (P-12-11)
>
> Establish a program to train control center staff as teams, semiannually, in the recognition of and response to emergency and unexpected conditions that includes supervisory control and data acquisition system indications and Material Balance System software. (P-12-12)
>
> Incorporate changes to your leak detection processes to ensure that accurate leak detection coverage is maintained during transient operations, including pipeline shutdown, pipeline startup, and column separation. (P-12-13)
>
> Provide additional training to first responders to ensure that they (1) are aware of the best response practices and the potential consequences of oil releases and (2) receive practical training in the use of appropriate oil-containment and -recovery methods for all potential environmental conditions in the response zones. (P-12-14)
>
> Review and update your oil pipeline emergency response procedures and equipment resources to ensure that appropriate containment equipment and methods are available to respond to all environments and at all locations along the pipeline to minimize the spread of oil from a pipeline rupture. (P-12-15)

> Update your facility response plan to identify adequate resources to respond to and mitigate a worst-case discharge for all weather conditions and for all your pipeline locations before the required resubmittal in 2015. (P-12-16)"[29]

c) Enbridge's responses to NTSB IM concerns

Accufacts has reviewed Enbridge's responses to Ontario-specific requests related to their Application process for the Line 9B Project, and various Enbridge Responses to the NTSB/PHMSA during the NTSB Marshall, MI rupture investigation at MP 608 on Line 6B.[30, 31, 32] Concerning the NTSB IM recommendations, it should become fairly clear from comparing the referenced documents that Enbridge has failed to incorporate important NTSB recommendations into their integrity management program and this Project's EA, especially as they relate to the unique and highly challenging threats related to prevalent SCC and associated corrosion, and corrosion fatigue along Line 9. Line 9 contains numerous similar threats associated with polyethylene external coating disbondment and the Enbridge EA fails to adequately demonstrate a prudent evaluation of the SCC /corrosion threat risks on Line 9.

I further find that Enbridge's approach to cracking threat assessment via ILI as provided in the Section 4 of the Project's EA has not included many of the NTSB recommendations. I see no sufficient detail in the EA that the Enbridge approach has incorporated information to assure that still-developing crack detection ILI technology is being applied in such a manner so as to recognize that this ILI method is still "push technology" and is not reliable, especially when it comes to SCC in corrosion sites associated with this polyethylene tape coating. I use the term "push technology" to mean the application of a new still developing technological approach *that has yet to be sufficiently field demonstrated to be highly accurate or reliable, either by the use of the ILI tool or related engineering assessments using the tool's results.*

The EA also fails to mention that the 2004/2005/2006 crack runs may be of questionable value based on the Marshall, MI rupture. As a matter of reference, the crack in the Marshall, MI pipeline utilized the same ILI tool crack technology, the same biased software algorithm

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[29] *Ibid.,* pp. 123 -124.

[30] Line 9B Reversal and Line 9 Capacity Expansion Project OH-002-2013 File-OF-Fac-Oil-E101-2012-10 02, Enbridge Response to Ontario Ministry of Energy ("Ontario") Information Request No. 1., Section 1.44 Michigan and other Spills, pp. 70 – 77.

[31] Enbridge submission to NTSB, "Enbridge Energy, Limited Partnership Party Submission Investigation of July 2010 Line 6B Accident Near Marshall, Michigan; NTSB ID: DCA 10MP007," May 22, 2012.

[32] Enbridge response to NTSB email request of April 3, 2012 by Matt Nicholson during MP 608 – Marshall Michigan Incident NTSB/PHMSA Information Request Number 404, "Enbridge Responses to NTSB/PHMSA No. 404," pp. 1 – 15.

underreporting SCC depths, and that missed the rupture site on Line 6B that occurred well below MOP. The use of this ILI tool should thus be characterized as *still in development*, a research experiment. I see no specific indication in the crack section of the Project's EA that Enbridge has embraced or appropriately incorporated the IM recommendations of the NTSB for the 2004/2005/2006 crack ILI tool runs, and the EA was submitted to the NEB well after the NTSB report on Marshall was adopted.

VII. Summary of PHMSA Violations on Marshall, MI Failure

On September 7, 2012 following an investigation of the Marshall event and probable violation notice due process, PHMSA, the federal agency charged with pipeline safety in the U.S., issued to Enbridge Energy a Final Order. The Final Order rendered 24 items of violation of U.S federal minimum pipeline safety regulations involving the Marshall, MI incident, assessing a civil penalty of approximately $3.7 million. Four of the 24 violations I would also characterize as violations of the integrity management section of the minimum federal safety regulations. Two of the four IM violations (items 1 and 4 below) were assessed the maximum fine permitted under law of $1,000,000 underscoring the gravity of the IM violations.[33] While the Line 9 Project is governed by Canadian pipeline safety regulations, given the importance that the PHMSA findings of violations may play in any IM safety process, I have indicated the IM violations below. The reader should find that there are several critical IM violations that might relate to IM approaches in Canada as well, and a review of Section IV will suggest some findings that may not be considered a violation in Canada. Extracting directly from the PHMSA Final Order:[34]

1) §195.452 Pipeline integrity management in high consequence areas.

> **(h)** ***What actions must an operator take to address integrity issues?***
>
> (1) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity ....
>
> (2) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that

[33] Under the 2011 Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, the maximum civil fine that PHMSA can levy for a related series of violations has now been raised to $2,000,000.

[34] PHMSA, "Final Order, CPF 3-2012-5013," dated September 7, 2012.

determination, unless the operator can demonstrate that the 180-day period is impracticable.

Enbridge failed within 180 days after an integrity assessment of Line 6B to obtain sufficient information about anomalous conditions presenting a potential threat to the integrity of Line 6B. Enbridge conducted a high-resolution MFL integrity assessment of Line 6B on October 13, 2007. Enbridge received a vendor report on June 4, 2008 regarding this ILI run. The 180 day deadline was April 10, 2008. Enbridge did not demonstrate that the 180 day period was impracticable.

Enbridge implemented pressure restrictions as of July 17, 2009, a period of approximately 462 days after the deadline to have sufficient information to identify anomalous conditions. After another year, on July 15, 2010, the company submitted a Long Term Pressure Reduction Notification to PHMSA on July 15, 2010 in which the date of discovery was reported by Enbridge as July 17, 2009.

2) §195.452 Pipeline integrity management in high consequence areas.

(i) What actions must an operator take to address integrity issues?

(4) Special requirements for scheduling remediation

Beginning with the 2004 USWM ILI, Enbridge did not schedule remediation of corrosion anomalies involving the longitudinal weld seam of pipe joint #217720 within 180 days of discovery of the conditions as required by **§195.452(h)(4)(iii)(H).** Enbridge also did not remediate crack-like anomalies on the same pipe joint (longitudinal in orientation) that could impair the integrity of the pipeline reported by the 2005 USCD ILI as required by **§195.452(h)(4)(iv)** in accordance with **(Appendix C)(VIl)(D).** Enbridge could not demonstrate that the company attempted or scheduled any remediation of the corrosion or crack anomalies that were identified by the assessments.

The reported corrosion and crack like anomalies on pipe joint #217720, on Line 6B, were not selected for excavation, and the pipe joint ultimately ruptured in service on July 25, 2010, resulting in a crude oil release of over 20,000 bbls, and significant environmental damage, as the released product migrated to a creek, which in turn flowed into the Kalamazoo River.

3) §195.452 Pipeline integrity management in high consequence areas.

(i) What preventive and mitigative measures must an operator take to protect the high consequence area?

(1) General requirements. An operator must take measures to prevent

and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures included conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection .

(2) Risk analysis criteria. In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:

(i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;
(ii) Elevation profile;
(iii) Characteristics of the product transported;
(iv) Amount of product that could be released;

In preparing the risk analysis, Enbridge failed to consider all relevant risk factors associated with the determination of the amount of product that could be released from a rupture on Line 6B. Enbridge's risk analysis process assumed a pipeline rupture of this magnitude would be identified by instrumentation (SCADA and Leak Detection System) within 5 minutes, and that it would take an additional 3 minutes to close remotely operated valves on either side of the rupture. The amount of product that could be released is clearly impacted by different operating scenarios including transient conditions such as those associated with start-ups and shutdowns or personnel response to abnormal operating conditions.

Prior to the release, Enbridge estimated the worst case scenario release at the M.P. 608 location to be 1,670 bbls initial volume out, plus 1938 bbls stabilization loss (drain down) for a total of 3,608 bbls.

The actual failure scenario demonstrates the rupture was not recognized by Enbridge, and the isolation valves were not closed, until approximately 17 hours after it occurred. An additional 16,431 bbls of product was injected into the ruptured pipeline, causing the total spill volume to greatly exceed Enbridge's worst case discharge scenario for this location.

4) §195.452 Pipeline integrity management in high consequence areas.

(j) What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(2) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline,

including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

Enbridge did not properly consider the results of corrosion and cracking assessments nor did Enbridge integrate the information from these assessments to properly assure overall pipeline integrity. Witness interviews and prior ILI assessment results of Line 6B, including 2004 USWM, 2005 USCD, 2007 MFL, and 2009 USWM demonstrate that Enbridge has a long history of performing integrity assessments using ILI tools. These assessment results were evaluated independently and not integrated in a fashion that assures pipeline integrity.

Additional observations are very relevant as it relates to the Enbridge incomplete and deficient IM program, their recurring pattern of failing to prudently and effectively incorporate regulator IM audit findings related to these serious deficiencies, and how these serious process failings led to the Marshall, MI rupture failure. For example, SCC is obviously a cracking threat by its nature, but is also a corrosion threat though most conventional general corrosion inline inspection tools are incapable of reliably identifying this highly selective form of corrosion/cracking threat that tends to fail more as cracks. Thus, for potential ILI evaluation, SCC and other more selective forms of corrosion tend to fall into the specialized much more difficult form of “crack feature” detection ILI tools. As discussed later in this report, such ILI crack detection tools are fairly new in their technical development and field application. These tools have serious technical limitations as to their accuracy and reliability (what I call push technologies), and it is hoped technical improvements and advancements will eventually occur. Until then pipeline operators need to incorporate various safety margins commensurate with the field advancement or lack of advancement of a particular ILI inspection tool for its intended design. Such safety factors include incorporating the tool tolerance and clear presentation of unity plots (both depth and length) to uncover ILI tool bias, especially if a developing tool is indicating in the non-conservative range, such as understating crack depth and length, as well as characterization.

VIII. Accufacts Conclusions and Recommendations to NEB

The following are my conclusions and recommendations based on a review of the Project’s documents include IR responses.

A) Conclusions

1) SCC within corrosion wall loss is prevalent and a high risk along Line 9

The EA makes it fairly clear that a primary IM threat prevalent along Line 9 is cracking introduced by the polyethylene disbonded coating tenting in close proximity to the DSAW seam weld.[35] This disbonded coating has permitted significant SCC to occur within general wall loss corrosion in or near the DSAW seam. A CP system is ineffective in dealing with this type of coating disbondment and will not protect against this SCC/corrosion threat, as the protective CP current cannot get to the affected pipe steel that is shielded by this type of coating. SCC by itself in pipelines is somewhat difficult to access but when such SCC is coincident with corrosion wall loss, the engineering assessments can be very difficult to perform with a high degree of confidence and accuracy. It should be obvious that Fitness for Service or engineering assessments must actually consider the real remaining wall thickness as well as other factors. Phased array ultrasonic crack detection ILI tools attempt to measure crack depth, and this technical approach does not accurately measure pipe wall thickness. The phased array crack detection tools must be supplemented or ILI trains combined with other wall thickness measure ILI tools that are designed to actually measure wall thickness, but don't measure cracks.

While it is true that current industry standards have not been developed to address this serious interactive threat combination, the prevalence of such interactive threats on Line 9 does not excuse Enbridge from running the right tools or integrating various tools, or exceeding industry standards, or choosing other assessment methods such as hydrotesting, to assess pipeline integrity for service.[36] In the Marshall, MI rupture the NTSB made it very clear that Enbridge's IM approach failed to coordinate SCC within corrosion wall loss sites (See Exhibit 3 – Table of remaining strength calculations for 51.6 inch long feature that ruptured in Marshall MI using various wall thicknesses and ILI tool tolerances) among other engineering assessment failings. Enbridge has not incorporated such a serious NTSB recommendation into the Line 9B Project's IM approach. This observation is further supported by Enbridge's recent response to Ontario's IR that fails to identify such a critical detail as integrating interactive threats (cracking and corrosion) that seriously contributed to the Marshall rupture.[37]

In addition, the Line 9B Project's EA also fails to make a key point very clear, that the ILI tool during 2004/2005/2006 was non conservative (understated crack depths) for SCC so it is not clear if the EA submitted results have been correctly adjusted for this well-know tool bias, known both to the pig vendor GE and Enbridge, in those specific tool runs. This was the same problem in the 2005 Marshall, MI crack tool run that failed to properly classify and correct for that tool run's non-conservative bias. Such under indicating can seriously taint Fitness for Service or engineering assessment approaches. This is a recurring problem within Enbridge that

[35] Enbridge Pipelines Inc. Pipeline Integrity Department, "Line 9B Reversal and Line 9 Capacity Expansion Project Pipeline Integrity Engineering Assessment," Submitted to National Energy Board, November 2012, pp. 57 - 59.
[36] Enbridge submission to NTSB, "Enbridge Energy, Limited Partnership Party Submission Investigation of July 2010 Line 6B Accident Near Marshall, Michigan; NTSB ID: DCA 10MP007," May 22, 2012, pp. 11 -12.
[37] Enbridge Response to Ontario IR 1.44.a., p 71.

has been discovered by Canadian and U.S. investigators after other pipeline crack ruptures (See on the next page, Table 4 - Recent Enbridge Pipeline Ruptures After Crack ILI).[38]

2) The ILI cracking tool appears to still be a research experiment

Given various information uncovered by the NTSB Marshall investigation, it is evident that the pig vendor and Enbridge knew that there were non conservative biases introduced by the crack detection ILI tool. The ability of the crack detection tool to reliably identify SCC was overstated. Enbridge's engineering assessments' inability to apply proper tool tolerance for such developing technology as well as the failure to properly integrate such information with other threats, leads me to conclude that the ILI crack tool runs are more along the line of a research experiment with a high potential for error. Enbridge appears overfocused on running ILI technology when such special applications may not be reliable to assure a pipeline's integrity. These ILI runs are the cheaper part of an ILI assessment approach, and such developing tools need a increasing amount of verification digs to assure the newer technology is actually working in the field as claimed. In addition, even if the ILI tool is performing correctly the pipeline operator must incorporate engineering assessments that actually allow a rational time-to-failure estimate of cracks to assure they don't fail in service.

Table 4 – Recent Enbridge Pipeline Ruptures After Crack ILI

Date	Line #	Diameter (inch)	Estimated Release (BBls)	Location
7/4/02	3	34	~ 6,000	Cohasset, MN
4/15/07	3	34	~ 6,214	Glenavon, SK
11/13/07	3	34	Not available	Clearbrook, MN
1/8/10	2	26	3,784	Neche, ND
4/17/10	2	26	Not available	Deer River, MN
7/25/10	6B	30	+20,000	Marshall, MI
7/27/12	14	24	~1,200	Grand Marshall, WI

As demonstrated in Table 4, clearly there is still much work needed before ILI crack technology and engineering assessments can be considered reliable, especially on SCC. While I support the development of ILI technology and advancements, crack ILI and their application concerning engineering assessments are still a research experiment when it comes to the serious SCC evaluation challenges especially in sites within pervasive corrosion.

It is true that a properly developed, field demonstrated, and utilized ILI tool, usually designed for a specific purpose, can tell one more about a pipeline than a hydrotest, for example. Such more reliable and proven ILI approaches, however, have evolved and advanced over many decades. The level of ILI crack detection evolving in the last decade has not yet reached the reliability of

[38] NTSB, "Liquid Pipeline Accident – Marshall, Michigan Integrity Management Group Chair's Factual Report," pp. 21 – 26.

hydrotesting, especially for SCC and/or other crack features such as fatigue cracks. The obligation to choose, use, and apply the right assessment method(s) falls to the pipeline operator who eventually must demonstrate their use is appropriate. If an ILI tool cannot prove reliable and accurate, or its results used appropriately, hydrotesting is still a superior assessment method for many types of threats, especially axially aligned crack threats. As in all assessment methods, periodic reassessments are needed depending on the threat, even for hydrotesting.
Industry standards also require the pipeline operator to verify pig vendor assertions and claims for very good reasons.[39] The pipeline operator is responsible for the safe operation of their pipeline. In selecting IM assessment methods the operator must incorporate each assessment method's strengths, weaknesses, and capabilities to address certain threats. Since Enbridge has only recently incorporated changes in the ILI crack tools that were well known by the ILI vendor and Enbridge since 2008 to adjust for SCC misclassification and non-conservative depth bias, I cannot determine if the USCD ILI tool runs of 2012 will be accurate or reliable, or if field verification digs are appropriate for this still developing "push technology."[40]

3) Changing crude slates, especially dilbit, will substantially increase crack growth rates

There are numerous SCC crack threats along Line 9B and these threats are highly susceptible, given their axial orientation, to operating pressure cycling such as those associated with changes in a wide range of crudes that are being proposed for the reversal project. The movement of dilbit, given the substantial changes associated with small variation in composition either in the bitumen or the diluent solvent while meeting tariff requirements, merit exceptional attention on pipelines posing such cracking risks.

Enbridge needs to assure that their crack growth rates ("CrGRs") are truly conservative. Such CrGRs can vary substantially when they involve SCC / fatigue corrosion, especially with major changes in crude makeup. Once a pipeline operator has established the ability of an ILI tool to reliably identify a threat of concern, such as cracking, estimated crack growth rates need to be demonstrated to be truly conservative in determining the next crack tool reassessment. Exhibit 7 (Enbridge estimated corrosion growth rates) is an Enbridge response to a question concerning corrosion growth rates (CGRs).[41] These Enbridge reported numbers are substantially lower than the NTSB estimated average annual crack growth rate for the Marshall, MI rupture determined from the December, 2005 crack ILI run to the July 25, 2010 rupture at the SCC/corrosion failure of 0.574 millimeters per year.[42, 43] Granted, the estimated NTSB growth rates include both

[39] API, "API Recommended Practice 1163 In-line Inspection Systems Qualification Standard," first edition August 2005, updated April, 2013.
[40] NTSB, "12-9-11 Interview of Clint Garth, Global Analysis Manager for Ultrasonics of GE PII Pipeline Solutions and Geoff Foreman, Growth and Structure Leader for GE PII Pipeline Solutions," p. 14.
[41] Enbridge Response to Les Citoyens au Courant, Attachment 1 to Les Citoyens au Courant IR Question 5.11.b, OH-002-2013 File OF-Fac-Oil-E101-2012-10 02.
[42] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Materials Laboratory Study for the Marshall, MI Report No. 12-046," 4-20-12, p. 6.
[43] Enbridge Response to Equiterre IR No. 1.1.s & 1.1.t, OH-002-2013 File OF-Fac-Oil-E101-2012-10 02, p. 4.

corrosion and crack growth which is the more relevant crack growth rate approach for this type of crack threat.

4) Line 9B is situated in significant high consequence areas

A detailed review of the maps provided in the NEB process of Line 9B and Responses to Equiterre IRs will readily demonstrate that a great deal of Line 9 is located near large populations and/or sensitive waterways/wetland areas where a rupture will have serious consequences.[44, 45] This is not a pipeline routed in sparsely populated non sensitive areas of Canada, but a pipeline running in some of the more populated corridors of southeastern Canada. Such a route definitely merits special considerations in IM approaches that actually reflect true conservativeness.

5) SCC cracks are most likely to fail as rupture

There is a long history in both Canada and the U.S. demonstrating that SCC, when it goes to failure, will usually fail as rupture, which is one reason why SCC threats command much respect. The EA has not adequately demonstrated that the ILI tool and related engineering assessments have reached the level of confidence that such massive and pervasive SCC threats on Line 9 can be remediated before they reach rupture limits.

6) Enbridge has failed to heed some important IM recommendations of the NTSB following the Marshall rupture

Regarding Enbridge's IM program following the Marshall, MI incident, the NTSB identified Enbridge's IM program as inadequate because it did not consider the following:

I. a sufficient margin of safety,
II. appropriate wall thickness,
III. tool tolerances,
IV. use of a continuous reassessment approach to incorporate lessons learned,
V. the effects of corrosion on crack depth sizing, and
VI. accelerated crack growth rates due to corrosion fatigue on corroded pipe with a failed coating.[46]

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[44] NEB, "Line 9B Stantec Scale Maps Showing pump stations, existing valves MP, KP and other sensitive environments highlighted in color," Files:
A316Z3_-_03_Attachment_1_to_NEB_2.7_pages_1_to_60.pdf,
A316Z3_-_03_Attachment_1_to_NEB_2.7_pages_61_to_120.pdf,
A316Z3_-_03_Attachment_1_to_NEB_2.7_pages_121_to_175.pdf.

[45] Enbridge Response Attachment 1 to Equiterre IR 1.3a and b, "Segments of pipeline in Highly Populated Areas (HPA), Other Populated Areas (OPA), Environmentally Sensitive Areas (ESA), Drinking Water Sources (DW) and Commercially Navigable Waterways (CNW)."

[46] NTSB Accident Report "Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release Marshall, Michigan July 25, 2010," NTSB/PAR-12-01, adopted July 10, 2012, p.118.

7) Something appears very wrong with Enbridge's Line 9B risk assessment

A review of Exhibit 6 (Enbridge's Risk Profile for Line 9B (NW – ML) Pre and Post Flow Reversal) taken from their engineering assessment should be raising all sorts of questions and challenges.[47] I would advise the NEB to further explore the impression given by the EA that there is very little change in the risks from the reversal. Accufacts finds particularly disturbing the statement, "Based on this EA, there are presently no features reported by the 2004, 2005 and 2006 crack detection inspections that are predicted to reach critical dimensions until December 2013 based on current reduced operating pressures."[48] The impression that is being created is that engineering assessment predictions can be reliably estimated for cracks within one year. I must assume that this calculation has not included the NTSB findings and recommendations that clearly indicated that such Enbridge calls needed true "conservativeness." There is just too much uncertainty with cracks coinciding with corrosion to convey such time-to-failure accuracy, especially if an accurate remaining wall thickness is not utilized. Enbridge has also still failed to incorporate the interactive threats associated with corrosion and cracking with real conservatism, such as using a safety factor as recommended by the NTSB.[49]

8) Enbridge's culture of implied hydrotesting safety margins appears to be an illusion – the most dangerous of safeties

Enbridge's continued use of the hydrotesting pressure value (usually 1.25 of MOP) as a threshold safety margin is conveying a margin of safety that in all probability does not exist, creating the worst of all safeties, an illusion of safety.

Line 9B was last hydrotested in 1997 to a pressure level that established MOP. Enbridge did not answer Equiterre's request about hydrotest pressure as a percent of SMYS, an important IM assessment parameter.[50] As noted by the NTSB, the thresholds utilized by Enbridge to determine verification field digs for corrosion and cracking ILI calls, did not apply the same level of safety margin between corrosion (RPR=1 is 100% SMYS) and cracking (hydrotesting threshold is usually, but not always, 90% SMYS).[51, 52, 53] The safety factors for general corrosion have stood

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[47] Enbridge, "Line 9B Reversal and Line 9 Capacity Expansion Project Pipeline Integrity Engineering Assessment, Figure 4.47 Risk Profile for Line 9B (NW-ML) Pre and Post Flow Reversal," November 2012, p. 82.
[48] *Ibid.,* p. 82.
[49] Enbridge submission to NTSB, "Enbridge Energy, Limited Partnership Party Submission Investigation of July 2010 Line 6B Accident Near Marshall, Michigan; NTSB ID: DCA 10MP007," May 22, 2012.
[50] Line 9B Reversal and Line 9 Capacity Expansion Project OH-002-2013 File-OF-Fac-Oil-E101-2012-10 02, Equiterre Information Request No 1.1d, p. 3, and Enbridge Response to Ontario Information Request No. 1.14.a, Hydrostatic Test, p. 22 - 23.
[51] American Society of Mechanical Engineers ("ASME"), "Manual for Determining the Remaining Strength of Corroded Pipes: Supplement to B31 Code for Pressure Piping – B31G-2012," 2012 edition.
[52] CSA Standards, "Oil and Gas pipeline systems – Z662-11, reprinted January 2012," Section 3.3.3.3, Notes (1) & (2), p. 177.

the test of many decades of verification while crack failure predictions are a more recent development, especially for SCC/corrosion-fatigue/corrosion. Ironically, the most difficult to determine category of threats, with the least likely predictability for time-to-failure, cracking features have the lower threshold safety margin in Enbridge's IM program.

9) Given the many deficiencies uncovered in this application Accufacts places Line 9 at a high risk of rupture failure post reversal

Given the following:

I. the preponderance of new information surprisingly uncovered in the NTSB investigation and the associated Enbridge interviews;
II. Enbridge's failure to incorporate the NTSB IM recommendations,
III. the apparent disconnect in the Risk Assessment in the EA,
IV. the continual apparent refusal of Enbridge to prudently integrate SCC cracking threats with corrosion wall loss,
V. the difficulty in evaluating extensive SCC across the system,
VI. the still-in-development (research project) nature of the ILI crack tool, and
VII. Accufacts' extensive pipeline experience, including IM regulatory development and investigative experience,

I must conclude there is a high risk that Line 9 will rupture from the SCC/corrosion-fatigue/general corrosion interaction attack in the early years following Project implementation: and that Enbridge's IM approach, which relies on ILI and related engineering assessments, will not prevent rupture <u>under the operating conditions</u> resulting from the implementation of the Project.

10) Enbridge's leak detection will not timely detect rupture

The NTSB recommended that leak detection "Incorporate changes to your leak detection processes to ensure that accurate leak detection coverage is maintained during transient operations, including pipeline shutdown, pipeline startup, and column separation. (P-12-13)"[54] Additional NTSB factual reports during the Marshall investigation indicate that Enbridge has a culture of column separation which significantly complicates the reliability of leak detection in the control room to avoid false alarms. Enbridge has reported that the MBS systems across their pipeline network were requiring the MBS analysts in the control room to receive an average of 1.7 to 4.5 MBS alarms during a normal 12-hour shift in the first seven months of 2010.[55] This is a very high number of false leak alarms in a shift. While it is not illegal to operate in column

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[53] U.S. pipeline regulation 49CFR§195.304 **Test Pressure**.
[54] NTSB Accident Report "Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release Marshall, Michigan July 25, 2010," NTSB/PAR-12-01, adopted July 10, 2012, p. 123.
[55] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Liquid Pipeline Accident – Marshall, Michigan, Group Chairman's Factual Report Human Factors," dated March 28, 2012, p. 25.

separation (aka slack line), where the pipeline is not liquid full, industry standards warn about the complication in reliability of such leak detection systems. Column separation can seriously hinder and delay control center recognition of possible rupture indications as was clearly the case in the Marshall, MI rupture involving a release of over 17 hours.

11) Rupture release volumes are in all probability understated

In response to an information request, Enbridge has estimated a "Maximum Volume Out" in barrels between valves.[56] From another response to an IR it appears these volumes assume a 10-minute time estimate to detect/affirm a rupture and another 3 minutes to close the valves to avoid surge, plus drainage affected by the elevation profile between the remote control valves.[57] Ten minutes can pass very quickly in a control room emergency situation especially if mixed signals and procedures are complicated by lack of clear rupture alarms. While I am certain that Enbridge has made many changes in their control center in an attempt to improve rupture response, and apply their "ten minute rule," the lack of a clear rupture detection system that will not generate false alarms places a very high probability that false alarms will delay response in the control room to greater than 10 minutes, no matter Enbridge's best intentions.

The ten-minute rule "requires operators to shut down a line if a column separation cannot be resolved with[in] 10 minutes."[58] The ten-minute rule was supposed to have been imposed by Enbridge management following a similar pipeline crack rupture and major oil release from a pipeline rupture in 1991 on another Enbridge pipeline that confused control room operators by the issue of column separation that went on for several hours before isolation valves were closed.[59] While I can also appreciate Enbridge's attempts to improve their leak detection approach after the Marshall rupture, applying industry best practices and the five leak detection methods indicated by Enbridge's IR responses, will not be effective.[60] Based on my extensive experience in the area of pipeline leak detection, control center operators need SCADA computer tools that assist in rapid rupture detection and indication. Since Enbridge has not demonstrated that have properly or adequately improved in this area, there is a greater likelihood that volume release will thus be much greater than indicated upon rupture on a 30-inch pipeline, unless changes are made to the pipeline operation, such as eliminating column separation as a complication.

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[56] Enbridge Response to Ontario IR, Attachment 1 to Ontario IR 2.9.c.
[57] Enbridge Response to National Farmers Union IR No 2.1.e, p. 2.
[58] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Liquid Pipeline Accident – Marshall, Michigan, Group Chairman's Factual Report Human Factors," dated March 28, 2012, p. 23.
[59] NTSB, "Liquid Pipeline Accident – Marshall, Michigan Control Room and Supervisory Control and Data Acquisition (SCADA) Group Chairman Factual Report – SCADA Attachment 32 10-minute rules," dated April 10, 2012, p. 22 of 90.
[60] Enbridge Responses to Ontario IR No 1.44.b.iv, pp. 75 – 76, and NEB IR No. 3.10.c, pp. 27 - 29.

12) The emergency response plan and response times are not adequate for a high consequence area

Enbridge has indicated in several IR responses that travel times for response will be on the order of 1.5 to 4 hours.[61] These response times are completely unworkable for a pipeline located in so many high consequence areas. Enbridge needs to improve equipment staging sites and coordinate/commit appropriate personnel such that response times are significantly reduced for such high consequence areas along Line 9.

Sufficient detail has also not been provided as to the response if dilbit is released. The ERP/Oil Spill Response should distinguish between an ERP which focuses on saving lives and then property, versus oil spill response which focuses on reducing potential oil spill volume, then containment, then recovery. Oil spill response plans also need to address the situations where dilbit can sink such as was clearly shown in the Marshall, MI rupture, and now apparently in the Pegasus Pipeline rupture this past March at Mayflower, AR. Of course oil spill plans still need to address crudes where oil releases will float in water, such as with the lighter Bakken crudes.

B) Recommendations to NEB

Given the above general observations pertaining to the Line 9B Project, Accufacts recommends:

1) Hydrotesting should be required before Line 9 is reversed

Proper hydrotests should be performed on Line 9A and 9B before commencing the Reversal Project's operation to prove the integrity of the system to handle the demands of the Reversal Project. Based on the preponderance of information from the NTSB investigation, Accufacts finds that Enbridge has a culture of denial when it comes to the strengths of hydrotesting and a highly distorted over-reliance on ILI inspection on crack detection that has yet to be sufficiently proven to assure pipeline integrity from certain extensive SCC and/or corrosion fatigue cracking threats on Line 9.

Accufacts finds Enbridge's statements concerning the possible damage from hydrotesting are without technical merit, and appear to be attempts to misinform decision makers and the public. Recommended hydrotesting should obviously be performed to Canadian standards that are superior in their clearer prescriptive requirements compared to U.S. pipeline safety hydrotesting regulations. Canada has a multi-decade history and considerable experience in assuring performance of such proper hydrotesting of pipelines containing extensive cracking risks, such as SCC. As in any assessment method, depending on the threat, the pipeline should periodically be reassessed, even though such periodic maximum periods between such assessments are not specifically defined in Canadian pipeline safety regulations.

[61] Enbridge Responses to Equiterre IR No. 2.

2) The leak detection approach should be modified to focus on rupture detection in all modes of operation

Enbridge should design Line 9 to not operate in slack line operation. This will greatly improve the reliability of the MBS to avoid false alarms during normal operation. The leak detection approach should also be modified to focus on rupture detection during major transients that can be from line packing/inventory impacts associated with compressible hydrocarbons, during startup and shutdown, as well as normal operation. Procedures should be added that assure that such a rupture alarm <u>is never treated as a false alarm</u>. In other words, every rupture alarm should require shutdown, remote valve closure and pipeline field review to confirm no release occurred. Such modifications should not be expensive to implement.

3) Emergency response plan volume and timing should be extensively modified to reflect the high consequence areas

In reviewing the various IR responses Enbridge has not given sufficient attention to, or provided enough detail, that the response plans are appropriate for a pipeline rupture in such sensitive high consequence areas. It is possible that the company is waiting to see if the Project gets NEB approval. Regardless, prior to startup of the reversed pipeline, Enbridge should provide to the NEB an oil spill response plan in sufficient detail to demonstrate that the plan can be effective in the Eastern Canada environment for all the crudes that will be moved on Line 9.

IX. Summary

Integrating the Project's many documents supplied in the NEB process with the results of the Marshall, MI pipeline rupture investigation clearly indicates, in my opinion, that Enbridge has a culture where safety management seems not to be a critical component of their operation. In Canada the integrity management approach is seriously influenced/controlled by the Risk Assessment process that permits several methods to reduce risk, depending on the imperfection, such as ILI or pressure testing as applicable.[62] Surprisingly, Enbridge, in my opinion has not supplied sufficient information or incorporated the relevant NTSB recommendations that are intended to prevent failure from prevalent SCC coincident with general corrosion threats on Line 9.

Richard B. Kuprewicz
President
Accufacts Inc.

[62] "CSA Standards Z662-11, Oil and gas pipeline standards - N.10.3 Imperfections," Reprinted January 2012, p. 456.

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flux de l'oléoduc
9B d'Enbridge

The Relative Economic Costs and Benefits of the Line 9B Reversal and Line 9 Capacity Expansion

Written Expert Evidence Prepared

by

Ian Goodman
Brigid Rowan

on behalf of
Équiterre (Coalition)

Presented in the case of
Enbridge Pipelines Inc.
Line 9B Reversal and Line 9 Capacity Expansion Project Application
under section 58 of the National Energy Board Act
OH-002-2013

the goodman group, ltd.

August 6, 2013

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1. Mandate

Following the filing by Enbridge Pipelines Inc. (Enbridge) of the Line 9B Reversal and Line 9 Capacity Expansion Project (Project) Application under section 58 (Application) of the National Energy Board Act OH-002-2013, the Équiterre Coalition (Coalition)[1] retained the services of The Goodman Group, Ltd. (TGG). Ian Goodman and Brigid Rowan of TGG were retained as experts in order to assist the Coalition with its intervention before the National Energy Board (NEB), and to produce written evidence (TGG Report) within the context of the case. In accordance with the NEB's List of Issues[2] in this case, TGG specified the hearing subjects on which it intended to present evidence (in TGG's "Proposal for Expert Assistance on Enbridge Line 9B Reversal and Line 9 Capacity Expansion Project (NEB OH-002-2013)," filed on April 11, 2013).

As stated in TGG's Proposal for Expert Assistance, TGG focusses on economic issues, but has also considered relevant interactions between the economic issues and other important issues in this hearing.

In particular, the TGG Report reviews various claims made in the Enbridge Application (Filing A3D7I1) regarding the economic costs and benefits of the project:

1. "The Project was initiated in response to requests from eastern Canadian refineries to have access to the growing and less expensive supplies of crude oil production from western Canada and the U.S. Bakken region."[3]
2. The Project "will provide western Canadian and U.S. Bakken producers access to the Quebec refining market while reducing the reliance of Quebec refiners on crude oil from areas of declining, or potentially unreliable, supply."[4]
3. The Project has substantial benefits in terms of allowing refineries in Québec to access lower cost crudes supplies, resulting in increased competitiveness and sizable cost savings for these refineries.[5]

[1] The Équiterre Coalition is made up of: Équiterre, Ecojustice, Environmental Defence, ENJEU, Association québécoise de lutte contre la pollution atmosphérique (AQLPA), The Sierra Club, Climate Justice Montreal (CJM) and Nature Québec.
[2] Filing A3G6J4, Procedural Update No. 1 Appendix I, Adobe p. 11.
[3] Filing A3D7I1, Enbridge Application, p. 24, lines 2-4.
[4] Enbridge Application, p. 24, lines 15-19.
[5] Enbridge Application, p. 25, lines 3-6:

> The Project allows refineries in Quebec to access lower cost crude oil supplies from western Canada and the U.S. Bakken region, increasing the competitiveness of these refineries. Over the next 30 years, refinery cost savings of approximately $23 B are expected as a result of the Project.

4. The Project has substantial socio-economic benefits, such as increased GDP, increased labour income, and increased employment.[6]
5. The Enbridge Application further claims that incremental environmental and stakeholder effects will be minimized[7] and that the Project is unlikely to result in a significant negative residual environmental effect.[8]

In evaluating the economic benefits of the Project, TGG has also reviewed Enbridge's evidence regarding the specifics of supply and crude types (notably heavy versus light) expected to be transported on Line 9, as well as Enbridge's request to move all allowable crude types, including heavy crude, on Line 9.[9]

In light of our review of Enbridge's claims in its Application and its answers to Information Requests from various participants, the TGG Report provides its own evaluation of the costs and benefits of the Project.

Following the List of NEB Issues[10] discussed in TGG's Proposal for Expert Assistance, the TGG Report covers the following Issues:

1. The need for the proposed Project.
2. The potential commercial impacts of the proposed Project.
3. The appropriateness of the proposed Rules and Regulation Tariff and tolling methodology.

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[6] Enbridge Application, p. 25, lines 7-14:

> Over a 30 year period (2013 – 2043), the Project is expected to result in socio-economic benefits, such as:
> - an impact on Canadian Gross Domestic Product ("GDP") of approximately $25 B, taking into account the Project's total multiplied impact;
> - labour income increase of nearly $350 MM, mostly in the provinces of Ontario and Quebec; and
> - employment increases of approximately 5,500 person years, mostly in the provinces of Ontario and Quebec.

[7] Enbridge Application, p. 26, lines 1-2:

> By taking advantage of existing facilities and ROW, incremental environmental and stakeholder impacts will be minimized.

[8] Enbridge Application, p. 49, lines 22-25:

> Enbridge has developed general, and will develop Project-specific, programs to ensure that the recommended mitigation measures and commitments made in the ESEIA [Environmental and Socio-Economic Impact Assessment] are implemented throughout the construction and operations phases of the Project. Taking into account the implementation of these programs and mitigation measures, the ESEIA concludes that the Project is not anticipated to result in a significant negative residual environmental effect.

[9] Enbridge Application, p. 50, lines 2-15.
[10] See footnote 2.

4. The potential environmental and socio-economic effects of the proposed Project, including the potential effects of malfunctions or accidents that may occur, and any cumulative environmental effects that are likely to result from the proposed Project.
9. The terms and conditions, related to the above issues, to be included in any approval the Board may issue for the proposed Project.

The focus of the work to be undertaken is on economics, as opposed to engineering, environmental effects, and safety. Nonetheless, consideration of the issues identified above (i.e. Issues 1, 2, 3, 4, and 9) is taken into account, and have implications for, the following issues specified in the NEB List of Issues:

5. The engineering design and integrity of the proposed Project.
6. The safety, security, and contingency planning associated with the construction and operation of the proposed Project, including emergency response planning and third-party damage prevention.

The TGG Report's evaluation of the costs and benefits of the Project covers all of these Issues, either implicitly or explicitly.

2. Executive Summary

TGG has undertaken a relative cost-benefit analysis to compare to relative economic costs and benefits of the Project in order to assist the NEB in carrying out its mandate. We have limited our cost analysis to costs that directly affect economic activity and can be approximately quantified using market economics. In the economic benefits, we have considered both the commercial impact of the Project, as well as the economic-development benefits that can be approximated through macro-economic analysis.

To make a decision whether to approve or reject the Project, the NEB must consider the following questions:

1. Do the potential benefits justify the potential costs?
2. How are the costs and benefits distributed among the various stakeholders?

Because of the risk factors involved in this case (and especially the unusual proximity of Line 9 to people, water and economic activity), it is particularly important and challenging for the NEB to weigh the costs and benefits in this Project.

TGG provided an approximation of the benefits as less than \$1 billion/per year and likely less than \$0.5 billion/year, especially in the near-term. We also concluded that these benefits are insignificant in the relevant context of the overall Quebec, Ontario, and Canadian economies, and even more insignificant when weighed against the cost of a major accident/spill. Enbridge has downplayed any potential cost, but the Project has a range of rupture costs that vary from significant to catastrophic. However there is a high degree of uncertainly associated with a broad range of costs that make a precise determination of costs very challenging. Nonetheless, TGG has provided the NEB with a range of relative magnitudes for potential costs under a variety of accident/spill possibilities.

The conclusion of pipeline safety expert, Richard Kuprewicz, that there is a high risk of rupture in early years of the reversal under the operation conditions resulting from the Project,[11] greatly influenced our evaluation of the expected costs associated with rupture. Due to Line 9B's extraordinary proximity to people, water and economic activities, the rupture costs of the Project, under a range of pipeline malfunction/accident possibilities, vary from significant to catastrophic. With rupture

[11] Kuprewicz, Richard, "Report on Pipeline Safety for Enbridge's Line 9B Application to NEB," August 5, 2013, Conclusion 4, p. 26

costs that vary from significant to catastrophic and an assessment of a high risk of rupture, the expected Project costs therefore range from significant to catastrophic.

Under bad to worst-case scenarios, TGG concludes that the potential economic costs for a major rupture in an HCA[12] but not an urban setting (similar to Marshall) could start at $1 billion (bad scenario). If a major accident occurred in a densely populated area, damaging and disrupting key infrastructure, these costs could escalate to multi-billion dollar damages (potentially as high as $5-$10 billion) (worst-case scenario). Given the flammability of the proposed new crude slate to be carried on Line 9B, which includes both Bakken and dilbit, an accident involving this pipeline could also involve loss of human life.

Based on our evaluation of economic costs and benefits, TGG concludes that the potential economic costs could exceed (and, under a range of malfunction/accident conditions, greatly exceed) the potential economic benefits.

In light of the following:

1. the results of our relative economic cost benefit analysis, which demonstrates that the potential economic costs could exceed (and, under a range of malfunction/accident conditions, greatly exceed) the potential economic benefits;
2. the highly uneven allocation of costs and benefits among the stakeholders; and across regions;
3. the Kuprewicz Report's conclusion that there is a high risk that Line 9 will rupture in the early years following project implementation due to a combination of cracking and corrosion,

TGG strongly recommends that the NEB reject Enbridge's Project.

Section 1 contains a description of TGG's mandate in this proceeding. Section 2 is the Executive Summary. Section 3 sets out the Analytical Framework used to evaluate to relative economic costs and benefits. Section 4 analyzes the Benefits and provides an approximate range for these. Section 5 analyzes the Costs and explains how we determined a range of relative magnitudes for potential costs under a variety of accident/spill possibilities. Section 6 compares the Costs and Benefits, and Section 7 provides TGG's Recommendations.

[12] High Consequence Area. See Section 3.3 for more details.

3. Analytical Framework

3.1. Economic Cost-Benefit Analysis

The analytical framework for this report is an economic cost-benefit analysis (CBA), which has been applied to assist the National Energy Board in carrying out its mandate, as set out on its website.

> The NEB carries out its mandate in the *public interest*. The public interest is inclusive of all Canadians and refers to a balance of economic, environmental and social considerations that changes as society's values and preferences evolve over time.[13]
>
> […]
>
> The Board must ask itself: to what extent is Canada better off, or worse off, overall, by choosing a course of action? By considering all the evidence in context of the circumstances, the Board is able to make recommendations in the public interest.[14]

The NEB regulates pipelines, including the construction and operation of interprovincial oil pipelines, in the Canadian public interest. Thus, the NEB must consider the public interest, as defined above in its decision regarding Enbridge's Project for Line 9B Reversal and Line 9 Capacity Expansion.

In its decision, the NEB must weigh both the costs and benefits of the Project. TGG has focussed our review on the comparison of the <u>economic</u> costs and benefits of the Project because (i) these are the elements that can be most readily be estimated and compared; (ii) TGG has a well-developed expertise in the evaluation of economic development benefits from various energy options; (iii) the evaluation of the environmental and social costs and benefits is subject to major controversy and will be considered by other parties.

The NEB must balance environmental and social considerations with economic considerations. The NEB is an economic regulator (with a very strong focus/expertise in

[13] See NEB website, under The National Energy Board Mandate.
http://www.neb-one.gc.ca/clf-nsi/rsftyndthnvrnmnt/prtctngcndnnvrnmnt/vrvw-eng.html
[14] See NEB website, A, Our purpose – Public Interest
http://www.neb-one.gc.ca/clf-nsi/rsftyndthnvrnmnt/prtctngcndnnvrnmnt/ntnlnrgbrd-eng.html

regard to economics) and is therefore greatly concerned with the economic costs and benefits of its decisions. Based on our evaluation of economic costs and benefits, TGG concludes that the potential economic costs could exceed (and, under a range of malfunction/accident conditions, greatly exceed) the potential economic benefits.

As indicated in Section 0, Enbridge claims that the Project has substantial "socio-economic benefits," such as increased GDP, increased labour income, and increased employment.[15] Furthermore, Issue #4 in the NEB List of Issues[16] includes consideration of:

> The potential environmental and socio-economic effects of the proposed Project, including the potential effects of malfunctions or accidents that may occur, and any cumulative environmental effects that are likely to result from the proposed Project (Issue #4).

As part of our evaluation of the economic costs and benefits of the Project, TGG has taken into account:

1. The potential commercial impacts of the Project.
2. The potential economic-development-related socio-economic effects[17] of the Proposed Project insofar as these effects can be readily measured with macroeconomic analysis.[18]
3. The potential environmental[19] and other socio-economic effects[20] of the proposed Project, including the potential effects of malfunctions or accidents that may occur insofar as these impacts can be readily and broadly quantified using market economics.

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[15] See footnote 6

[16] See footnote 2.

[17] These potential economic-development-related socio-economic effects fall within the "Employment and Economy" category of the Socio-Economic Elements of the NEB's Filing Manual. See NEB Filing Manual, Guide A.2 – Environmental and Socio-Economic Assessment, Section A.2.8, Table A-3: Filing Requirements for Socio-Economic Elements, Employment and Economy.

[18] Beyond the commercial impacts of the Project, TGG has taken into account the macroeconomic impacts of the project with respect to employment, labour income, GDP, and economic development spinoffs. These are the same impacts that Enbridge identifies as the Project's "socio-economic benefits" (see footnote 6).

[19] These potential environmental effects fall within the relevant Biophysical Elements listed in the NEB Filing Manual. See NEB Filing Manual, Guide A.2 – Environmental and Socio-Economic Assessment, Section A.2.8, Table A-2: Filing Requirements for Biophysical Elements.

[20] "Other" socio-economic effects fall within the relevant Socio-Economic Elements listed in the NEB Filing Manual, excluding those that fall into the "Employment and Economy" category. See NEB Filing Manual, Guide A.2 – Environmental and Socio-Economic Assessment, Section A.2.8, Table A-3: Filing Requirements for Socio-Economic Elements.

Items 1 and 2 comprise the benefits of the Project, which will be analyzed in Section 4, Item 3 comprises the costs of the Project, which will be analyzed in Section 5.

Regarding the potential environmental and other socio-economic effects of the Project (i.e., item 3), TGG did not undertake a complete evaluation of the potential environmental costs, nor did we attempt to quantify impacts on human health and safety and the cumulative environmental effects that are likely to result from the Project. A complete analysis of all of the potential environmental effects of the Project would be subject to major controversy, very difficult to measure, and exceeds the scope of TGG's mandate in this case.

Similarly, Socio-Economic Elements, as defined in the NEB filing manual include some effects that are more difficult and subjective to measure, such as social and cultural well-being. Although these elements are important, TGG has not included them in our evaluation of socio-economic impacts. The economic-development-related socio-economic impacts considered by TGG in item 2 are those included in traditional economic development studies (and are the same as those included in Enbridge's own economic evaluation).

In item 3, TGG considered a range of potential environmental and other socio-economic costs related to "the potential effects of malfunctions or accidents that may occur." We have limited our cost analysis to environmental and socio-economic impacts that directly affect economic activity and can be somewhat readily (albeit approximately) quantified using market economics.. These impacts are less subjective than impacts on human health and safety, and broader and cumulative environmental and other socio-economic effects of a spill.[21] Furthermore we have limited our consideration of the potential environmental and other socio-economic costs to those associated with pipeline malfunctions or accidents.

This is not to say that there should not be consideration of impacts on human health and safety and the broader and cumulative environmental and other socio-economic effects. Especially in light of the extensive participation in this case by numerous parties, TGG trusts that other participants in this case will attempt to address and measure these effects. For instance, a spill that harms plant and animal life will have important environmental (and potential human health and safety) impacts that should be quantified. The consideration of human health and safety and the broader and

[21] As will be discussed in Section 5.2, TGG has not attempted to assign a cost to potential effects on human health and safety, including loss of life. But to illustrate potential effects, especially for worst case scenarios for what could occur in a densely populated urban area, loss of life data are provided for the relevant examples of pipeline accidents and other disasters described in Section 5.5.

cumulative environmental and other socio-economic costs will further increase the overall costs of the Project. However, TGG has concluded that our relative comparison of more narrowly defined economic costs and benefits (including a more limited consideration of socio-economic and environmental impacts) will provide the NEB with sufficient evidence to assist it in making a decision.

TGG's evaluation of the economic-development-related socio-economic benefits will be discussed in detail in Section 4. Our evaluation of the environmental and other socio-economic costs will be further discussed in Section 5.

3.2. Definition of the Reference Case

In order to measure the costs and benefits of the Project, it is necessary to define a base case. Enbridge has confirmed that the base case for the Project as follows:

> The economic effects of the Line 9B Reversal and Line 9 Capacity Expansion Project (the "Project") are measured relative to a reference case without the Project (but including the Line 9 Phase I Reversal Project).[22]
>
> […]
>
> Throughput on Line 9 over the last three years (2009-2011) has averaged only 10,175 m3/day (64,000 d) and ultimately, Line 9B, unless it is reversed, would be idled when Line 9A is reversed.[23]

In other words, the reference case for the Project includes the following:

1. Line 9A is reversed (as per the NEB approval in the Line 9 Phase 1 Reversal Project);
2. Line 9B remains idle;
3. There is no capacity expansion for Line 9.[24]

We note that an economic impact study prepared for Enbridge of the Project also assumes that Line 9B will be idled absent NEB approval of the Project.[25]

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[22] Enbridge Response 2.1 a) to NEB IR No. 2.
[23] Enbridge Application, p. 26, lines 7-9.
[24] See also Enbridge Response 2.3 to Équiterre IR No. 1.
[25] Attachment 1 to Stratégies Énergétiques IR 1.4.a, entitled "An Evaluation of the Economic Impacts on Canada of the Enbridge Line 9B Reversal Project," prepared for Enbridge by Demke Management Ltd. and dated August 30, 2012 ("the Demke Evaluation"), Adobe pp.12, 17.

Under this reference case, Line 9B would be idled, so TGG estimates that the economic benefits and costs of the reference case (i.e. Line 9B idled and no capacity expansion for Line 9) to Canada would therefore be negligible and round off to zero.

So the economic benefits and costs are measured relative to a reference case that has essentially zero economics benefits and costs.

3.3. Line 9B: A Unique Pipeline with Extraordinary Proximity to People, Water, and Economic Activity

In making its public interest determination for Enbridge's Project, the NEB is faced with a particularly important and challenging task. Line 9B is a unique pipeline in the Canadian and North American context.

Quite simply, no other crude oil pipeline in Canada has the same proximity to human activity, water and economic activity.

Enbridge's IR response to Équiterre's IR 1.3 a) and b)[26] indicates that this pipeline has extraordinary proximity to High Consequence Areas (HCAs) (including Highly Populated Areas, Other Populated Areas, Drinking Water Resources, Environmentally Sensitive Areas, and Commercially Navigable Waterways).

The Expert Report of Richard Kuprewicz ("the Kuprewicz Report") further confirms the uniqueness of the pipeline as well as its extraordinary proximity to HCAs:[27]

> **4) Line 9B is situated in significant high consequence areas**
>
> A detailed review of the maps provided in the NEB process of Line 9B and Responses to Equiterre IRs will readily demonstrate that a great deal of Line 9 is located near large populations and/or sensitive waterways/wetland areas where a rupture will have serious consequences. [Footnotes 44 and 45 in original omitted.] This is not a pipeline routed in sparsely populated non sensitive areas of Canada, but running in some of the more populated corridors of southeastern Canada. Such a route definitely merits special considerations in IM approaches that actually reflect true conservativeness.

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[26] Attachment 1 to Équiterre IR 1.3.a) and b), "Segments of pipeline in Highly Populated Areas (HPA), Other Populated Areas (OPA), Environmentally Sensitive Areas (ESA), Drinking Water Sources (DW) and Commercially Navigable Waterways (CNW)."

[27] Kuprewicz, Richard, "Report on Pipeline Safety for Enbridge's Line 9B Application to NEB," August 5, 2013, Conclusion 4, p. 26.

In addition to the extraordinary proximity to HCAs, Line 9B is routed through Canada's economic heartland, coinciding with the region of Canada with the largest concentrations of population and highest density, including Canada's two major metropolitan areas (Montreal and Toronto).

Line 9B's route through Toronto runs parallel to or crosses much of the region's key infrastructure, including major highways (400, 401, 403, 404, 407, and 427).[28] In fact, the pipeline crosses under a key junction in the highway network (401 and 427), just east of Canada's busiest airport (Pearson International).[29] Moreover, Line 9B runs just north of Finch Avenue, crossing Yonge Street directly adjacent to the Finch subway terminal.[30] Thus, a pipeline rupture could potentially affect large numbers of people, and damage and disrupt key infrastructure.

Furthermore, a pipeline rupture could threaten the drinking water supplies in both Toronto and Montreal. The July 4, 2013 Letter of Comment from the City of Montreal filed in the current proceeding confirms that the City is highly concerned with the effect of a Line 9B spill on the security of Montreal's drinking water. The City points out that a major spill into the Ottawa River or one of its tributaries could jeopardize the drinking water supply of Greater Montreal, and thus have a major impact on Montreal's public health, environment and economic prosperity:[31]

> *La ligne 9B traverse la rivière des Outaouais entre les municipalités Pointe-Fortune en Montérégie et Saint-André-d'Argenteuil, dans les Laurentides. La rivière des Outaouais s'écoule dans le lac des Deux Montagnes pour ensuite alimenter la Rivière-des-Prairies, le Lac-Saint-Louis et le fleuve Saint-Laurent.*
>
> *Le réseau de production et de distribution d'eau potable montréalais s'alimente à partir des sources d'eau citées. Il assure une distribution d'eau surpassant les normes de qualité aux citoyens, commerces, industries et institutions de*

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[28] Attachment 1 to NEB IR 2.7, entitled "Detailed Project Map,"Adobe pp. 11-28.
[29] Attachment 1 to NEB IR 2.7, entitled "Detailed Project Map,"Adobe p. 18.
[30] Attachment 1 to NEB IR 2.7, entitled "Detailed Project Map,"Adobe p. 24. See also street view, showing Enbridge pipeline marker for Line 9B (with warning) next to Finch Station subway entrance: https://maps.google.com/maps?q=bishop+yonge+toronto&hl=en&ll=43.781738,-79.415954&spn=0.000001,0.001265&sll=37.269174,-119.306607&sspn=11.253772,20.720215&t=h&hq=bishop+yonge&hnear=Toronto,+Toronto+Division,+Ontario,+Canada&z=20&layer=c&cbll=43.781844,-79.415978&panoid=HOKclyDIoEZgd6I_XQfMSg&cbp=12,69.55,,1,3.76
[31] Lettre de commentaires de la Ville de Montréal présentée à l'Office national de l'énergie dans le cadre de l'audience OH-002-2013, Projet d'inversion de la canalisation 9B et accroissement de la capacité de la canalisation 9 de la compagnie Pipeline Enbridge inc., le 4 juillet 2013, p. 10 (PDF p. 13). Accessed July 21, 2013. https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/130635/969935/A3I8Z0_-_Lettre_de_commentaires_Ville_de_Montréal.pdf?nodeid=970155&vernum=0

> *l'agglomération de Montréal. Un déversement majeur de produits pétroliers dans la rivière des Outaouais ou de l'un de ses affluents aurait pour conséquences de mettre en péril les sources d'approvisionnement des usines de production d'eau potable, dont dispose l'agglomération de Montréal et par conséquent de près de deux millions de personnes. Il s'agit d'un risque dont les conséquences sur la santé publique, l'environnement et la prospérité économique de Montréal seraient majeures et doivent être évaluées.*
>
> *Bien que ce risque soit localisé à l'extérieur des limites géographiques de l'agglomération de Montréal, les conséquences d'un éventuel déversement au point de traverse de la rivière des Outaouais affecteraient directement la sécurité de la population montréalaise.*

3.4. The Need for a Higher Level of Risk Aversion

Time and again, we have historical and ongoing evidence that:

1. malfunctions and accidents occur on pipelines transporting crude oil;
2. these malfunctions/accidents can release ("spill") substantial amounts of crude oil;
3. crude oil spills can be extremely costly and difficult to clean up (especially when the spill is in water and involves dilbit);[32] and
4. the transportation of crude oil can be both dangerous and costly in terms of waterways, the environment, public health and safety and even human lives.

As such, the NEB should be particularly risk averse in approving this Project because just one spill could be extremely costly, and potentially dangerous, in the populous areas along Line 9, which form the heartland of the Canadian economy.

The following are key risk factors associated with the Project that increase the need for risk aversion:[33]

1. uniqueness of pipeline: proximity to people, water, economic activity;[34]

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[32] Diluted bitumen. For the purposes of pipeline transportation, raw bitumen (very heavy tar sands crude) must first be either a) mixed with a petroleum-based diluent (such as naphtha or condensate) to make it less viscous (diluted bitumen/dilbit); or b) upgraded (partially refined) into synthetic crude oil (SCO).

[33] Many of these risk factors are discussed in greater depth in the Kuprewicz Report and particularly in his Conclusions 1-12 on pp. 22-30. See also the other specific sources for each risk factor.

[34] See previous subsection. As cited above, the Kuprewicz Report concurs that "[s]uch a route [situated in significant high consequence areas and highly populated corridors] definitely merits special considerations in IM approaches that actually reflect true conservativeness." See footnote 27.

2. high risk of rupture in early years of the reversal under the operation conditions resulting from the Project;[35]
3. a leak detection system that is inadequate to detect ruptures;[36]
4. inadequate emergency response plans and response times for HCAs;[37]
5. Enbridge's poor safety record and the NTSB's[38] characterization of Enbridge's pipeline operating culture as a "culture of deviance" in its investigation into the Line 6B oil spill in Marshall Michigan;[39]
6. a management culture at Enbridge that refuses to learn and apply the lessons from Line 6B – and to heed some important IM recommendations of the NTSB following the Marshall rupture;[40]
7. Enbridge's culture of denial regarding the strengths of hydrotesting and its highly distorted over-reliance of ILI inspection;[41]
8. the Project's proposed changes in crude slate, especially dilbit, that substantially increase crack growth rates;[42]
9. higher risks of dilbit spills in water (versus a conventional crude spill);[43]
10. high flammability of a Bakken spill, particularly in a highly populated areas or in petrochemical complex of Montreal East;
11. concerns about Enbridge's financial capability and responsibility to mitigate and compensate all the potential damages, especially in a worst-case scenario such as a major accident/spill in an area with a large concentration of people and economic activity.

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[35] Kuprewicz Report, Conclusion 9, p. 28
[36] Kuprewicz Report, Conclusion 10, pp. 28-29
[37] Kuprewicz Report, Conclusion 12, p. 30.
[38] National Transportation Safety Board.
[39] "This investigation identified a complete breakdown of safety at Enbridge. Their employees performed like Keystone Kops and failed to recognize their pipeline had ruptured and continued to pump crude into the environment," said NTSB Chairman Deborah A.P. Hersman. "Despite multiple alarms and a loss of pressure in the pipeline, for more than 17 hours and through three shifts they failed to follow their own shutdown procedures" […] Further, the NTSB attributed systemic flaws in operational decision-making to a "culture of deviance," which concluded that personnel had a developed an operating culture in which not adhering to approved procedures and protocols was normalized." (emphasis added)
NTSB Press Release, "Pipeline Rupture and Oil Spill Accident Caused by Organizational Failures and Weak Regulations," July 10, 2012. Accessed August 3, 2012.
http://www.ntsb.gov/news/2012/120710.html
[40] Kuprewicz Report, Conclusion 6, p. 26.
[41] Kuprewicz Report, Recommendation 1, p. 30.
[42] Kuprewicz Report, Conclusion 3, pp. 25-26.
[43] In light of recent findings regarding Enbridge's Line 6B tar sands crude spill in Marshall, MI, the EPA has recently expressed concerns regarding the additional impacts of tar sands crude spills (versus conventional oil), with a particular concern about spills on waterways. Comments of EPA on the Department of State's Keystone XL Draft Supplement Environmental Impact Statement (DSEIS), http://epa.gov/compliance/nepa/keystone-xl-project-epa-comment-letter-20130056.pdf

3.5. Key Questions for the NEB to Consider in Reviewing the Project

To make a decision whether to approve or reject the Project (in a way that fulfills its mandate of considering the public interest) the NEB needs to answer the following questions:

3. Do the potential benefits justify the potential costs?
4. How are the costs and benefits distributed among the various stakeholders?

Because of the risk factors involved in this case (and particularly the unusual proximity of Line 9 to people, water and economic activity), it is particularly important and challenging for the NEB to weigh the costs and benefits in this Project.

3.6. A Relative Comparison of Costs and Benefits

Given the evidence in the case to date, TGG has determined that there are economic benefits associated with the Project. Enbridge has made some attempt to quantify these benefits; and TGG has reviewed Enbridge's evidence and analyzed the economic benefits of the Project in Section 4. According to the Demke Evaluation[44] (the evaluation of economic impacts of the Project prepared for Enbridge), these benefits are somewhat modest (in the order of less than $1 billion per year and 200 jobs per year over the period 2013-2043 when the Project is assumed to be constructed and operated). TGG has concluded that Project benefits are less than $1 billion/per year and likely less than $0.5 billion/year, especially in the near-term. We also concluded that these benefits are insignificant in the relevant context of the overall Quebec, Ontario, and Canadian economies.

Enbridge has downplayed any potential costs,[45] but the Project has numerous possibilities for potential costs of malfunctions/accidents that range from significant to catastrophic. While TGG can provide an approximation of the benefits of the Project, there is a high degree of uncertainty and a broad range of potential costs. Because of this high degree of uncertainty and broad range of costs, TGG is not in a position to make a precise determination of the costs (or the risks) associated with the Project.

[44] See footnote 25.
[45] See footnotes 7 and 8.

However, as noted above in the discussion of risk factors in Section 3.4, the Équiterre Coalition's pipeline safety expert (Richard Kuprewicz) has determined that there is a high risk of rupture in early years of the reversal under the operation conditions resulting from the Project. In addition, Kuprewicz has raised a number of grave safety concerns regarding the Project, Enbridge's management style, and the risks associated with the transportation of dilbit in this pipeline.[46] Kuprewicz's findings are important in assessing the costs of the Project because the higher the probability of a rupture (and the larger the amount of crude spilled), the higher the expected value of the potential costs.

There will likely be important evidence submitted by other parties on August 6 that will further quantify the costs/risks of project in order to assist the NEB in further estimating the Project's costs. However, even with all the evidence, it will be very challenging (if not impossible) to readily quantify all the costs. The costs of the Project are discussed in Section 5.

Despite the challenge in making a precise determination of the costs (and risks) of the Project, TGG can offer practical guidance to the NEB regarding the relative magnitude of the costs and benefits.

The Section 5 discusses the relative magnitude of the costs and risks of the Project in greater detail.

[46] See footnote 33 and discussion of risk factors in Section 3.4

4. Benefits

4.1. Introduction

As previously discussed in Section 3.1, the Enbridge Application (Filing A3D7I1) claims the following economic benefits for the project:

1. "The Project was initiated in response to requests from eastern Canadian refineries to have access to the growing and less expensive supplies of crude oil production from western Canada and the U.S. Bakken region."[47]
2. The Project "will provide western Canadian and U.S. Bakken producers access to the Quebec refining market while reducing the reliance of Quebec refiners on crude oil from areas of declining, or potentially unreliable, supply."[48]
3. The Project has substantial benefits in terms of allowing refineries in Québec to access lower cost crudes supplies, resulting in increased competitiveness and sizable cost savings for these refineries.[49]
4. The Project has substantial socio-economic benefits, such as increased GDP, increased labour income, and increased employment.[50]

Given the evidence in the case to date, TGG has determined that there are economic benefits associated with the Project. Enbridge has made some attempt to quantify these benefits; and TGG has reviewed Enbridge's evidence and analyzed the economic benefits of the Project. According to the Demke Evaluation[51] (the evaluation of

[47] Filing A3D7I1, Enbridge Application, p. 24, lines 2-4.
[48] Enbridge Application, p. 24, lines 15-19.
[49] Enbridge Application, p. 25, lines 3-6:

> The Project allows refineries in Quebec to access lower cost crude oil supplies from western Canada and the U.S. Bakken region, increasing the competitiveness of these refineries. Over the next 30 years, refinery cost savings of approximately $23 B are expected as a result of the Project.

[50] Enbridge Application, p. 25, lines 7-14:

> Over a 30 year period (2013 – 2043), the Project is expected to result in socio-economic benefits, such as:
> - an impact on Canadian Gross Domestic Product ("GDP") of approximately $25 B, taking into account the Project's total multiplied impact;
> - labour income increase of nearly $350 MM, mostly in the provinces of Ontario and Quebec; and
> - employment increases of approximately 5,500 person years, mostly in the provinces of Ontario and Quebec.

[51] See footnote 25.

economic impacts of the Project prepared for Enbridge), these benefits are somewhat modest (in the order of less than $1 billion per year and 200 jobs per year over the period 2013-2043 when the Project is assumed to be constructed and operated).

The potential economic benefits of the Project in terms of providing western Canadian and U.S. Bakken producers access to the Quebec refining market are discussed in Section 4.2. The potential economic benefits in terms of allowing refineries in Québec to access lower cost crudes supplies are discussed in Section 4.3. The potential socio-economic benefits (such as increased GDP, labour income, and employment) are discussed in Section 4.4. Finally, Section 4.5 considers Project benefits in the Provincial and National Economic Context

4.2. Benefits to Crude Producers

The Project would benefit western Canadian and U.S. Bakken producers by providing access to the Quebec refining market. The Enbridge Application (Filing A3D7I1) does not quantify these potential benefits to crude producers, but Enbridge has provided some additional information in response to IRs.[52]

Based on available information and a number of considerations, it is credible that the Project would benefit crude producers; however, these benefits are both difficult to predict and likely to be of relatively small magnitude. As further discussed in Section 4.3, crude markets are rapidly evolving, highly dynamic, and subject to substantial volatility and uncertainty, both short and long-term. Thus, it cannot be easily predicted how a given project will affect market dynamics and pricing.

And as Enbridge points out,[53] the capacity of the Project is quite small relative to the amount of crude production in both western Canada and U.S. Bakken, such that the project will have a negligible impact on refinery markets outside of Quebec. Moreover, to the extent that the Project could result in higher netbacks for crude producers, this could in turn reduce the benefits to refiners.[54]

[52] Enbridge Response 1.5 to NEB IR No.1; Enbridge Response 2.5 to NEB IR No.2; Enbridge Response 3.6 e) to NEB IR No.3.
[53] Enbridge Response 2.5 to NEB IR No. 2.
[54] The netback price of a barrel of crude oil is calculated by taking the revenue that producers receive for that oil and subtracting all the costs associated with getting that crude oil to a market. All else being equal, if producers receive higher netbacks, refiners will be paying more for their crude supply.

Put another way, the benefits to crude producers are unlikely to be a major factor in terms of the overall evaluation of the relative costs and benefits for the Project. And to the extent that these crude producers are located in the U.S. (notably in the Bakken), as opposed to Canada, the benefits may fall outside of the Canadian public interest of concern to the NEB.

4.3. Benefits to Quebec Refiners

The Project would benefit refineries in Québec by allowing access to lower cost crudes. The Enbridge Application claims that these benefits will be very sizable:

> The Project allows refineries in Quebec to access lower cost crude oil supplies from western Canada and the U.S. Bakken region, increasing the competitiveness of these refineries. Over the next 30 years, refinery cost savings of approximately $23 B are expected as a result of the Project.[55]

Moreover, as made clear in the Demke Evaluation[56] (the evaluation of economic impacts of the Project prepared for Enbridge), the claimed refinery cost savings account for virtually all of the economic benefits claimed for the Project:

> it is the assumptions regarding the refinery input cost savings component of the Project that are the most important and have a huge bearing on the outcome.[57]

> The direct economic impact of the refinery cost savings of $23.5 billion over 30 years (or $2.2 billion over 5 years and $5.5 billion over 10 years) can be compared to the pipeline development and construction phase direct, indirect and induced GDP effect of $113 million, or the pipeline operations phase direct, indirect and induced GDP effect of $1,485 million over 30 years. The predominant effect of the Project is on the refining industry and this effect is shown to overwhelm the pipeline construction and operations impacts. [58]

The Demke Evaluation of refinery cost savings assumes that inland crude oil supplies (from western Canada and the U.S. Bakken region) can be delivered to the Quebec

[55] Enbridge Application (Filing A3D7I1), p. 25, lines 3-6.
[56] See footnote 25.
[57] Demke Evaluation, Adobe p. 11.
[58] Demke Evaluation, Adobe p. 29. All monetary figures from the Demke Evaluation are 2012 C$)

refineries via the Project at a cost substantially below the delivered cost of the offshore crudes assumed to be displaced.

Demke also assumes that the cost differential between inland and offshore crudes will substantially increase over time, such that the Project will result in much larger refiner cost savings in the later years of the 30 year period (2014-2043) over which the Project is assumed to operate. Thus, the Project is estimated to result in annual refinery cost savings averaging about $440 million over the first 5 years of Project operation (2014-2018), $560 million over the next 5 years (2019-2023), and $900 million over the following 20 years (2024-2043).

The Demke Evaluation assumes that the project will deliver 250,000 bpd (barrels per day) to Quebec refineries, with deliveries split evenly between Suncor Montreal and Ultramar Quebec City (St.-Romuald/Levis) such that each receives 125,000 bpd. [59] But the estimated refinery cost savings are mainly at Suncor Montreal, owing to two locational factors. First, the delivered cost of inland crudes is assumed to be about $1/Bbl (barrel) lower for Suncor Montreal than for Ultramar Quebec City.[60] Second, the delivered cost of offshore crudes is assumed to be around $2/Bbl higher for Suncor Montreal than for Ultramar Quebec City.[61]

Thus, the Demke Evaluation assumes that inland crude oil supplies have a delivered cost advantage relative to offshore crudes that is about $3/Bbl greater for Suncor Montreal than for Ultramar Quebec City.[62] Demke assumes that inland crudes have a delivered cost advantage averaging about $6.20/Bbl at Suncor Montreal, vs. $3.40/Bbl at Ultramar Quebec City over the first 5 years of project operation (2014-2018), eventually rising to about $11.30/Bbl at Suncor Montreal, vs. $8.40/Bbl at Ultramar Quebec City over the last 20 years (2024-2043).

Based on available information and a number of considerations, it is credible that the project could benefit Quebec refiners; however, these benefits are both difficult to predict and likely to be of considerably smaller magnitude than assumed by Demke and claimed in the Enbridge Application.

[59] Demke Evaluation, Adobe p. 24.
[60] The Project would terminate in Montreal and can deliver inland crudes directly to Suncor Montreal. For the Project to supply Ultramar, crude must be transported from Montreal to Quebec City, with an assumed additional cost of about $1/Bbl. Demke Evaluation, Adobe pp. 45-46; Attachment 1 to Equiterre IR 3.5 f), g) and i).
[61] Offshore crudes are delivered directly to Ultramar Quebec City via tanker and to Suncor Montreal via tanker to Portland, Maine and then the Portland-Montreal pipeline to the refinery. Demke Evaluation, Adobe pp. 45-46; Attachment 1 to Equiterre IR 3.5 f), g) and i).
[62] Demke Evaluation, Adobe pp. 45-46; Attachment 1 to Equiterre IR 3.5 f), g) and i).

Crude markets are rapidly evolving, highly dynamic, and subject to substantial volatility and uncertainty, both short and long-term. Thus, it cannot be easily predicted how pricing differentials between crudes will evolve over time and specifically how much cost advantage there may be for inland crudes relative to offshore crudes. The Demke Evaluation is based on crude price forecasts and other assumptions that are now over a year old.[63] Meanwhile, crude markets and pricing differentials continue to evolve very rapidly.

In recent years, the North American oil system has been undergoing dramatic shifts that are large, rapid, ongoing, and possibly accelerating. Put very simply, Canadian and US crude production is rapidly increasing, but Canadian and US demand for refining products is stagnant or falling, such that crude imports (from overseas) are rapidly falling and product exports (to overseas) are rapidly rising.

While various forecasts have begun to take these dramatic shifts into account, there is typically a significant lag. So it is fair to say that forecasts are now often a lagging indicator of emerging shifts in petroleum markets. At some point in the future, conditions may begin to stabilize, and forecasts may catch up to more fully reflect emerging future realities. But for now and quite possibly for at least the next few years, each new forecast will reflect major changes then emerging, but later forecasts will reflect even more change.

In particular, petroleum market forecasts will likely continue to be playing catch up until the boom in shale/tight oil production levels off, or at least until it becomes better understood and its future evolution becomes more predictable.

TGG is very aware of the difficulties of energy forecasting and policymaking, in general and especially in a period of very rapid change. TGG shares the view of some other energy market analysts that the recent shifts in North American oil system (notably the rapid increase in production from shale/tight oil, hydraulic fracturing (fracking), and horizontal drilling) are likely to be ongoing and possibly accelerating, as they have been for natural gas. But there are very large uncertainties associated with these shifts, and many (including many environmental organizations) continue to be skeptical that these shifts are likely to be sustained and are sustainable (in a variety of senses).

The lagging nature of petroleum market forecasts (and petroleum market analysis more generally) matters for evaluating the proposed Line 9 Project. There is a wide range of

[63] Demke Evaluation, Adobe pp. 45-46; Enbridge Response 3.5 k) to Equiterre IR No. 2.

opinion regarding future crude prices (for both North American and global markets). Given the shifts underway in North America and globally, some are predicting that crude prices will soften or even decline substantially from current levels.[64] In particular, the decline in waterborne imports into North America is certainly affecting crude pricing in North American markets, and there are increasing indications that this large decrease in imports will also begin to put downward pressure on global crude prices.

The Demke Evaluation assumes that the cost differential between inland and offshore crudes will be sizable and will substantially increase over time. But large pricing differentials between inland North American and offshore global crudes may not be sustainable given evolving market conditions. Thus, while it is credible that the Project would benefit Quebec refiners,[65] these benefits could be of considerably smaller magnitude than assumed by Demke and claimed in the Enbridge Application.

The Demke Evaluation also assumes that refiners will not need to make any capital investments in relation to the Project and shifting from offshore to inland crudes.[66] The July 4, 2013 Letter of Comment from the City of Montreal filed in the current proceeding indicates that both Suncor Montreal and Ultramar Quebec City will be undertaking some capital investments in relation to the Project:[67]

> *la direction de la raffinerie Suncor estime à quelque 55 millions de dollars les investissements nécessaires. Ultramar estime que 110 millions de dollars devront être consentis, dans leurs installations portuaires de Montréal.*

To the extent that Quebec refineries need to undertake capital investments in relation to the Project, this is an economic cost and it will reduce the potential benefits of the Project in terms of refinery cost savings. But any such effect may be relatively small.

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[64] E.g., Verleger http://www.pkverlegerllc.com/assets/documents/TIE_W13_Verleger.pdf
and Citi, Energy 2020: Independence Day https://www.citivelocity.com/citigps/ReportSeries.action
https://ir.citi.com/dY2GZTnBVKoXNrT1sVyHcQCSQNAUUsI%2F8pXCARkTtvUOa8zDR2EckBRtxCGyJoDVW58uAgJ35%2BU%3D

[65] Both Suncor Montreal and Ultramar Quebec City have committed to be shippers on Line 9 under 10 year TSAs (Transportation Services Agreements) and thus provide commercial support for the proposed Project.

[66] Demke Evaluation, Adobe pp. 7, 21.

[67] Lettre de commentaires de la Ville de Montréal présentée à l'Office national de l'énergie dans le cadre de l'audience OH-002-2013, Projet d'inversion de la canalisation 9B et accroissement de la capacité de la canalisation 9 de la compagnie Pipeline Enbridge inc., le 4 juillet 2013, p. 14 (PDF p. 17).
https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/130635/969935/A3I8Z0_-_Lettre_de_commentaires_Ville_de_Montréal.pdf?nodeid=970155&vernum=0

The capital investments identified by the City of Montreal in relation to the Project are relatively small when viewed in terms of the relevant context.

These capital investments identified by the City of Montreal are quite small in comparison with amount of refinery cost savings assumed by Demke. But as explained above, the Project benefits in terms of refinery cost savings could be of considerably smaller magnitude than assumed by Demke and claimed in the Enbridge Application. But even if refiners do undertake some capital investments in relation to the Project. refinery cost savings are likely to be the predominant economic benefits for the Project.[68]

4.4. Socio-Economic Benefits

The Project could result in socio-economic benefits, such as increased GDP, increased labour income, and increased employment. The Enbridge Application claims that these benefits will be significant: [69]

> Over a 30 year period (2013 – 2043), the Project is expected to result in socio-economic benefits, such as:
>
> - an impact on Canadian Gross Domestic Product ("GDP") of approximately $25 B, taking into account the Project's total multiplied impact;
> - labour income increase of nearly $350 MM, mostly in the provinces of Ontario and Quebec; and
> - employment increases of approximately 5,500 person years, mostly in the provinces of Ontario and Quebec.

Demke Evaluation makes clear that the claimed refinery cost savings account for virtually all of the socio-economic benefits claimed for the Project in terms of increased GDP:

> it is the assumptions regarding the refinery input cost savings component of the Project that are the most important and have a huge bearing on the outcome.[70]

[68] To the extent that Quebec refineries do undertake some capital investments in relation to the Project, this could provide some socio-economic benefits (such as increased employment), as will be discussed in Section 4.4.

[69] Enbridge Application, p. 25, lines 7-14.

> the annual saving in feedstock costs was added to Quebec's GDP and counted as a direct economic effect of the Project. [71]

> The direct economic impact of the refinery cost savings of $23.5 billion over 30 years (or $2.2 billion over 5 years and $5.5 billion over 10 years) can be compared to the pipeline development and construction phase direct, indirect and induced GDP effect of $113 million, or the pipeline operations phase direct, indirect and induced GDP effect of $1,485 million over 30 years. The predominant effect of the Project is on the refining industry and this effect is shown to overwhelm the pipeline construction and operations impacts. [72]

As discussed in Section 4.3, while it is credible that the Project would benefit Quebec refiners in terms of cost savings, these benefits could be of considerably smaller magnitude than assumed by Demke and claimed in the Enbridge Application. And to the extent that refinery cost savings are lower than assumed and claimed for the Project, socioeconomic benefits in terms of increased GDP will also be lower than assumed and claimed.

As also made clear in the Demke Evaluation, construction of the Project is estimated to have socio-economic benefits that are very small and short-term:

> Project construction will create about 270 person-years of direct employment in the construction sector for Canadian workers. [73]

> The pipeline development and construction phase effects are short-term (2012 to 2014) and relatively minor in the context of the overall total effects because the modifications to Line 9B can be achieved at relatively low cost. Line 9B is an existing pipeline flowing westward with sunk capital expenditures. [74]

The Demke Evaluation also shows that operation of the Project is estimated to have socio-economic benefits that are extremely small annually, but somewhat more significant if aggregated over the 30 year period assumed for Project operations :

(footnote continued from previous page)
[70] Demke Evaluation, Adobe p. 11.
[71] Demke Evaluation, Adobe p. 8.
[72] Demke Evaluation, Adobe p. 29. All monetary figures from the Demke Evaluation are 2012 C$)
[73] Demke Evaluation, Adobe p. 7.
[74] Demke Evaluation, Adobe p. 9.

> Operations employment equals an estimated 8 full-time-equivalent workers; 4 located in Ontario and 4 located in Quebec. Over 30 years this equals 240 person-years of employment.[75]

> The pipeline operations phase effects are also relatively minor on an annual basis, but over thirty years (2014 to 2043) add up to a significant amount. They represent sustainable long-term economic impacts. In the absence of reversal, Line 9B would be idle.

As was also summarized at the beginning of this section, the Enbridge Application claims the Project will result in socio-economic benefits of nearly $350 million in increased labour income and approximately 5,500 person-years of employment.[76] As explained in the Demke Evaluation, these benefits were estimated using an Input-Output Model and include both direct and indirect effects over the entire period (2012-2043) assumed for Project construction and operations. Project operations accounted for over 80% of the total claimed socio-economic benefits relating to increased labour income and employment; project construction accounted for less than 20% of the total.

It is possible that the Project will result in capital investments being undertaken in addition to those assumed in the Demke Evaluation and the Enbridge Application.[77] As explained in this section above, the socio-economic benefits estimated for Project construction are very small. Similarly, to the extent that the Project will result in additional capital investments being undertaken, the socio-economic benefits of these additional investments are also likely to be quite small.

Various claims have been made that the Project will help to make the Quebec refineries more competitive and thus help to maintain and increase economic activity associated with crude processing.[78] Processing of crudes at refineries is not a labour-intensive activity, and refineries are a very small portion (far less than 1%) of total economic activity in Quebec.[79]

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[75] Demke Evaluation, Adobe p. 7.
[76] Enbridge Application, p. 25, lines 7-14.
[77] As discussed in Section 4.3 and footnote 67, the July 4, 2013 Letter of Comment from the City of Montreal filed in the current proceeding indicates that both Suncor Montreal and Ultramar Quebec City will be undertaking some capital investments in relation to the Project.
[78] See for example Enbridge Application (Filing A3D7I1), p. 25, lines 3-6.
[79] Todd Crawford, Canada's Petroleum Refining Sector: An Important Contributor Facing Global Challenges, The Conference Board of Canada, October 2011, p. 22. Accessed July 18, 2013. http://canadianfuels.ca/userfiles/file/12-051_CanadaPetroleumRefiningSectorFINAL.pdf
"Today, refining activity accounts for 0.2 per cent of real GDP in Quebec"
study was relied upon as an input to the Demke Evaluation (Adobe pp. 33-34). The above figure for Quebec refinery share of total economic activity is broadly consistent with other data sources, including:
(footnote continued on next page)

Moreover, the viability of Quebec refineries (and thus the continuation of related employment, other economic activity, and spinoff effects) in not contingent upon the Project. Quebec refineries can remain open and competitive even without the Project for the following reasons:

- the two refineries have survived and expanded when others have closed, so these are the most profitable and viable survivors;[80]
- they are set up to process light crude and now well-positioned given the shale/tight oil boom and abundance of light crude;
- similar refineries in Northeast US now also have a much more viable future due to the flood of shale crude.

In light of the above, with or without the Project, these two refineries can remain open and will likely improve profitability as these refineries access lower cost crude supply via transport options including rail, water, and pipelines. Overall employment and economic activity associated with Quebec refineries will likely be very similar (and very small overall), regardless of whether the Project goes forward.

The Suncor Montreal refinery is also part of the Montreal East Petrochemical Complex.[81] Business and union organizations have claimed that the Line 9B Reversal and Expansion Project will facilitate Quebec economic development by strengthening the Montreal East Petrochemical Complex, and specifically the polyester supply chain.[82]

(footnote continued from previous page)
Statistics Canada, CANSIM Table 379-0030, GDP data for Quebec Petroleum refineries [32411], Petroleum and coal product manufacturing [324], and All industries [T001] for 2007-2012. Accessed July 18, 2013.
http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=3790030&tabMode=dataTable&srchLan=-1&p1=-1&p2=9

[80] Since the 1980s, the Quebec refining sector has undergone significant restructuring. A number of Montreal refineries have closed, but the remaining refineries (in Montreal and St-Romuald) have expanded. As confirmed by data and analysis provided by the Quebec government and the companies involved in refining, overall refining capacity and output have been relatively constant and have not declined over the long-term.
http://www.mrn.gouv.qc.ca/energie/statistiques/statistiques-production-petrole.jsp
http://canadianfuels.ca/userfiles/file/12-051_CanadaPetroleumRefiningSectorFINAL.pdf pp. 22-23

[81] See footnotes 83 and 110.

[82] Association Industrielle de l'Est de Montréal (AIEM) Press Release, We say YES to the line 9 reversal project, May 29, 2013. Accessed July 20, 2013.
http://www.newswire.ca/en/story/1174043/we-say-yes-to-the-line-9-reversal-project

> A large group of business and union organizations have come together today to officially launch the Coalition in support of the Line 9 reversal project, a project that will safely allow Quebec to become less dependent on oil from Africa, the Middle East and Europe while maintaining nearly 2,000 jobs in the petrochemical refining industry in Quebec.

(footnote continued on next page)

Much like the processing of crudes at refineries, petrochemical processing is not a labour-intensive activity. There are only about 350 jobs in the petrochemical plants most closely tied to the Suncor Montreal refinery.[83] Based on the above figures, these petrochemical plants are a minuscule part of overall provincial (and Montreal) employment.

But in addition to these petrochemical plants directly tied to Suncor Montreal, there may be further downstream linkages with Montreal petrochemical production. In this context, it is useful to consider the scale of the entire Montreal petrochemical industry. Even when viewed in its entirety, production of chemical and plastics products is estimated to employ less than 7500 workers in Montreal; combined with production of petroleum products (refining), the petrochemical industry is still estimated to employs less than 8700 workers in Montreal. [84]

(footnote continued from previous page)

> "Quebec must take advantage of this promising project as well as help save our two remaining refineries by creating and maintaining 2,000 high-paying, direct and indirect jobs. […]
>
> "The Line 9 reversal project is important for the economic development of Montreal East because it will ensure the viability of Quebec's petrochemical industry, its polyester supply chain, and a more competitive source of supply.

[83] Daniel Cloutier (National Representative, Communications, Energy and Paperworkers Union), in response to M. Jamie Nicholls (Vaudreuil-Soulanges, NDP): House of Commons Standing Committee on Natural Resources, Evidence May 9, 2013, p. 9 (Adobe p. 11). Accessed July 17, 2013 http://www.parl.gc.ca/content/hoc/Committee/411/RNNR/Evidence/EV6154633/RNNREV81-E.PDF

> [Translation] **Mr. Jamie Nicholls**: Do you know how many jobs are tied to the polyester chain?
>
> **Mr. Daniel Cloutier**: We know up to a point.
>
> First, the product leaves Petro-Canada and travels to Parachem's petrochemical plant. We're talking about a hundred or so jobs. It also goes to CEPSA. So that's 150 jobs. Neither of those includes the subcontractors. Next, various plants take it back. There's a small facility on the former Shell site, with a hundred jobs or so.
>
> Afterwards, the product travels in all the other directions, and I lose track of it.

[84] Lettre de commentaires de la Ville de Montréal présentée à l'Office national de l'énergie dans le cadre de l'audience OH-002-2013, Projet d'inversion de la canalisation 9B et accroissement de la capacité de la canalisation 9 de la compagnie Pipeline Enbridge inc.,Le 4 juillet 2013, p. 14 (Adobe p. 17). https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/130635/969935/A3I8Z0_-_Lettre_de_commentaires_Ville_de_Montréal.pdf?nodeid=970155&vernum=0

> "Selon les estimations intercensitaires produites par le Comité de recherches économiques de la région de Montréal, il y avait, en 2011, sur le territoire de l'agglomération de Montréal quelque 1 238 emplois dans le secteur de la fabrication de produits du pétrole, 2 712 emplois dans le secteur des produits chimiques (excluant les

(footnote continued on next page)

Thus, Montreal production of chemicals and plastics is less than 0.4% of all employment in Montreal and less than 0.2% of all employment in the entire province. Montreal production of all petrochemicals (petroleum, chemical, and plastic products) is just slightly more than 0.4% of all employment in Montreal and slightly more than 0.2% of all employment in the entire province. So even with the employment for the Quebec City refinery added in, employment in the Quebec petrochemical industry (refineries and potentially related chemical and plastics processing) is still less than 0.3% of the provincial total.

Moreover, the relevant context for evaluating the Project is not solely Quebec. Most of the Project is within Ontario and thus affects the Ontario economy, in terms of both benefits and costs. Any economic activity relating to crude processing in Quebec is an even smaller portion of total economic activity when viewed in the context of the combined Quebec and Ontario economies.

Finally, the Project will not result in lower prices for Canadian consumers (notably in Quebec and Ontario). Refiners want access to lower cost crudes in order to be more profitable, rather than to pass these savings on to consumers. Pricing of refined products for specific refineries typically reflects regional/global market factors (and particularly global crude prices), rather than the crude prices paid by the specific refineries making the products. Especially in coastal locations (such as Quebec), refiners have access to profitable export markets (e.g., US East Coast and Europe) and can sell their products at prices reflecting global crude prices as opposed to lower North American crude prices. Thus, to the extent that refiners have access to inland crudes that may be cheaper than alternative sources of supply, this situation will likely benefit refiners (via higher profits), rather than consumers (via lower product prices).[85]

(footnote continued from previous page)

> produits pharmaceutiques) et 4 728 emplois dans le secteur de la fabrication de produits en plastique. [footnote 9 in original: Source : Statistique Canada, Recensement du Canada 2006, produit personnalisé sur le lieu de travail; estimations intercensitaires, Consortium de la Communauté métropolitaine de Montréal (CMM).] Les entreprises de ces secteurs sont majoritairement localisées sur le territoire de l'Arrondissement Rivière-des-Prairies- Pointe-aux-Trembles et de la Ville de Montréal-Est. À titre d'illustration, mentionnons que la production de polyester dans l'est de l'île représente environ 1% du total de la production mondiale."

[85] As explained by Suncor and Valero to investors, refining is a global business; global market conditions impact refiners in every market because products are generally very storable, transportable, and fungible commodities; prices for refined products are tied to global markets based on Brent (the benchmark for global crude pricing); Quebec is part of the Atlantic Basin where refined products (including gasoline and diesel) are widely traded throughout the intercontinental market; Valero and Suncor are using lower cost crude supply to increase profits and shareholder value, and to return cash to shareholders.
(footnote continued on next page)

4.5. Benefits in the Provincial and National Economic Context

As discussed in Sections 4.1, 4.2, 4.3, and 4.4 above, Project economic benefits assumed in the Demke Evaluation and claimed in the Enbridge Application are in the order of less than $1 billion per year and 200 jobs per year over the period 2013-2043 when the Project is assumed to be constructed and operated. These benefits are very small, especially when viewed in the relevant context of the Quebec, Ontario, and Canadian economies. As shown in the Demke Evaluation, total GDP is in the order of $300 billion for Quebec, almost $600 billion for Ontario, and $1,500 billion for Canada.[86] Likewise, total employment is in the order of 4 million for Quebec, almost 7 million for Ontario, and 17 million for Canada.

When viewed in the relevant context of the Quebec, Ontario, and Canadian economies, economic benefits for the Project are always much less than 1% of the total economic activity. Line 9 traverses Canada's economic heartland. The economic activity along Line 9 is far more significant than any economic activity that will result from the Project.

Moreover, as assumed in the Demke Evaluation, Project benefits are lower in the near term. As discussed in Sections 4.2, 4.3, and 4.4, refinery cost savings refinery cost savings account for virtually all of the economic benefits assumed for the Project. Annual refinery cost savings are assumed to average about $440 million over the first 5

(footnote continued from previous page)
Suncor 2012 Annual Report (especially pp. 7-8, 11, 20-21, 27-29, 39-42, 53, 65) and Q1 2013 Investor Presentation.
http://www.suncor.com/pdf/Suncor_Annual_Report_2012_en.pdf
http://www.suncor.com/pdf/Suncor_IR_Presentation_April_2013_v3.pdf
Valero Citi Global Energy Conference Presentation, May 14, 2013. Accessed May 16, 2013.
http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9MTg1NzM5fENoaWxkSUQ9LTF8VHlwZT0z&t=1
The market analysis described above (and presented to investors by Suncor and Valero) is broadly consistent with other market analysis regarding refinery economics and pricing for gasoline and other refined products (including that presented by federal and provincial government agencies and energy suppliers:
http://www.nrcan.gc.ca/energy/sources/petroleum-products-market/1133
http://www.nrcan.gc.ca/energy/sources/petroleum-crude-prices/1579
http://www.regie-energie.qc.ca/documents/autres/RapportMinistre_ControlePrixProduitsPetroliers_juillet2011.pdf
http://canadianfuels.ca/userfiles/file/CPPI%20Presentation%20to%20Standing%20Committee%20June%202011%20ENG.pdf
http://www.kentmarketingservices.com/dnn/LinkClick.aspx?fileticket=RNZladVtT54%3d&tabid=121
http://www.kentmarketingservices.com/dnn/LinkClick.aspx?fileticket=1vZJ6i_fNXo%3d&tabid=107

[86] Demke Evaluation, Adobe p. 13.

years of Project operation (2014-2018), $560 million over the next 5 years (2019-2023), and $900 million over the following 20 years (2024-2043).

And as also discussed in Sections 4.2, 4.3, and 4.4 above, the Project benefits could be of considerably smaller magnitude than assumed by Demke and claimed in the Enbridge Application. TGG has thus concluded that overall Project benefits are less than $1 billion/per year and likely less than $0.5 billion/year, especially in the near-term. These benefits are insignificant in the relevant context of the overall Quebec, Ontario, and Canadian economies, and even more insignificant when weighed against the cost of a major accident/spill.

5. Costs

5.1. Introduction

As identified in Section 3.1 above, the costs of the Project make up item 3 in the list of items that TGG has considered in its evaluation of the costs and benefits of the project:

5. the potential environmental and other socio-economic effects of the Project, including the potential effects of malfunctions or accidents that may occur insofar as these impacts can be readily and broadly quantified using market economics.

Enbridge has provided no evaluation of these costs, other than to claim that incremental environmental and stakeholder effects will be minimized and that the Project is unlikely to result in significant negative environmental effect (taking into account Project-specific programs and mitigation measures).[87]

This Section will demonstrate the contrary. Due to Line 9B's extraordinary proximity to people, water and economic activities, the costs of the Project, under a range of pipeline malfunction/accident possibilities, vary from significant to catastrophic. Given the Kuprewicz Report's assessment of a high risk of rupture on Line 9, the potential costs of the Project therefore range from significant to catastrophic.

As indicated in Section 3.1, we have limited our cost analysis of the environmental and other socio-economic impacts to those that directly affect economic activity. These impacts are less subjective than impacts on human health and safety, and the broader and cumulative environmental and other socio-economic effects of a spill and can be approximately quantified using market economics. Furthermore we have limited our consideration of the potential environmental and other socio-economic costs to those associated with pipeline malfunctions or accidents. TGG has provided an approximation of the benefits of the Project in Section 4; however there is a high degree of uncertainty and a broad range of potential costs. As such, TGG is not in a position to make a precise determination of costs (or risks) associated with the project. In fact, as indicated in Section 3.6, even with all the evidence from all parties in the case, it is very challenging, if not impossible, to precisely determine the costs (and risks) of the project. Nonetheless, TGG can offer practical guidance to the NEB regarding the relative magnitude of the potential costs and risks.

[87] See footnotes 7 and 8.

5.2. Approach to Estimating the Magnitude of Costs

Apart from the challenges in quantifying the potential costs of Project, TGG did not (in the context of this NEB case) have sufficient time or resources to conduct an in-depth study of potential costs (which would involve modelling the costs/risks associated various pipeline malfunctions/accident scenarios, including pricing out the worst-case scenarios). However, TGG is able to provide the NEB with a range of relative magnitudes for the potential costs under a variety of spill possibilities. This range of cost magnitudes then allows TGG to undertake an order of magnitude comparison with the more readily estimated benefits. The purpose of this order of magnitude comparison is to use a market economic approach to demonstrate to the NEB:

1. Why we are deeply concerned about potentially disastrous costs and loss of life associated with the Project;
2. Why the potential economic costs of the Project could exceed (and, under a range of malfunction/accident conditions, greatly exceed) the potential economic benefits.

To illustrate the range of cost magnitudes and potential effects of an accident or malfunction on Line 9, TGG has selected a variety of relevant examples of pipeline accidents and other disasters. As indicated above, we have limited our cost analysis to environmental and socio-economic impacts that directly affect economic activity and can be somewhat readily (albeit approximately) quantified using market economics.

TGG has not attempted to assign a cost to potential effects on human health and safety, including loss of life. But to illustrate potential effects, especially for worst case scenarios for what could occur in a densely populated urban area, loss of life data are provided for these relevant examples of pipeline accidents and other disasters.

5.3. Consideration of Risk Factors and Their Effects on Costs

Before the discussion of damages from relevant pipeline accidents and other disasters, it is worthwhile to discuss the consideration of risk factors and their effect on costs: the higher the risk, the higher the expected value of potential costs.

Costs and risks are linked in a complex and dynamic relationship. TGG has limited consideration of the potential environmental and other socio-economic costs to those associated with pipeline malfunctions or accidents. As stated above, TGG has not conducted an in-depth study of potential costs (which would involve modelling the costs, and therefore the risks, associated various pipeline malfunctions/accident scenarios, including pricing out the worst-case scenarios). However, we do have a number of conclusions on the pipeline risk factors, which are enumerated below, including the key assessment on risk of rupture from the Kuprewicz Report:

> […] I must conclude there is a high risk that Line 9 will rupture from the SCC/corrosion-fatigue/general corrosion interaction attack in the early years following Project implementation; and that Enbridge's IM approach, which relies on ILI and related engineering assessments, will not prevent rupture under the operating conditions resulting from the implementation of the Project.[88]

This assessment results in a higher expected value of all potential costs of the project associated with a rupture. With an assessment of a high risk of rupture from an international pipeline safety expert (Kuprewicz), the expected value of the Project costs are significantly higher than if the risk of rupture were low or medium.

The 11 risk factors that increase need for risk aversion, enumerated in Section 3.4 and repeated below, are the same ones that further increase the expected value of costs:[89]

1. uniqueness of pipeline: proximity to people, water, economic activity;
2. high risk of rupture in early years of the reversal under the operation conditions resulting from the Project;
3. a leak detection system that is inadequate to detect ruptures;
4. inadequate emergency response plans and response times for HCAs;
5. Enbridge's poor safety record and the NTSB's characterization of Enbridge's pipeline operating culture as a "culture of deviance" in its investigation into the Line 6B oil spill in Marshall Michigan;
6. a management culture at Enbridge that refuses to learn and apply the lessons from Line 6B – and to heed some important IM recommendations of the NTSB following the Marshall rupture;
7. Enbridge's culture of denial regarding the strengths of hydrotesting and its highly distorted over-reliance of ILI inspection;
8. the Project's proposed changes in crude slate, especially dilbit, that substantially increase crack growth rates;
9. higher risks of dilbit spills in water (versus a conventional crude spill);
10. high flammability of a Bakken spill, particularly in a highly populated areas or in petrochemical complex of Montreal East;

[88] See footnote 35.
[89] See Section 3.4 for the references associated with these risk factors.

11. concerns about Enbridge's financial capability and responsibility to mitigate and compensate all the potential damages, especially in a worst-case scenario such as a major accident/spill in an area with a large concentration of people and economic activity.

The 11th risk factor raises concerns about Enbridge's financial capability and responsibility to compensate for all potential damages. Because of the high risks associated with the Project, Enbridge, society and the NEB need to be risk averse. The purchase of sufficient additional insurance is a way to mitigate risks; but there is significant uncertainty around Enbridge's ability and willingness to internalize costs. In other words, can Enbridge compensate for potential damages? And will it be willing and able to pay?

Enbridge's insurance situation and concerns about the internalization of costs in the event of a worst-case scenario will be further discussed in Section 5.7.

5.4. Costs and the Uniqueness of Line 9B (Extraordinary Proximity to People, Water, Economic Activity)

The uniqueness of the pipeline and its extraordinary proximity to people, water and economic activity have been discussed in Section 3.3. The pipeline is extraordinarily proximate to HCAs. As discussed the same section, no other crude oil pipeline in Canada is routed through Canada's economic heartland, coinciding with the largest concentration of population and the highest density, including Canada's two largest metropolitan areas, Montreal and Toronto.

Due to Line 9B's extraordinary proximity to people, water and economic activities, the rupture costs of the Project, under a range of pipeline malfunction/accident possibilities, vary from significant to catastrophic.

With rupture costs that vary from significant to catastrophic and an assessment of a high risk of rupture, the expected Project costs therefore range from significant to catastrophic. Expected costs are much higher for Line 9 than for most pipelines.

5.5. Relevant Examples of Pipeline Accidents and other Disasters

As explained in Section 5.2, to illustrate the range of cost magnitudes and potential effects of an accident or malfunction on Line 9, TGG has selected a variety of relevant examples of pipeline accidents and other disasters in a variety of relevant locations ranging from a populated, but not highly populated area to a small town to a residential area in an urban setting to city-wide disaster.

Some of these examples are more directly comparable than others, but we have provided the range of examples to highlight to the NEB that a major accident/spill on Line 9 will have very high costs with respect to damage and disruption of infrastructure, particularly in metropolitan regions of Toronto or Montreal.

As emphasized throughout the document, we have limited our cost analysis to environmental and socio-economic impacts that directly affect economic activity and can be somewhat readily (albeit approximately) quantified using market economics. These costs escalate very quickly in a more densely populated urban areas. Moreover, as we have witnessed firsthand in Quebec, this summer, Bakken crude is highly flammable and its unsafe transport can result in the loss of human life.

We are highly concerned with the potential for loss of life from this Project in light of Kuprewicz's assessment of a high risk of rupture in early years. Therefore although we have not attempted to assign a cost to potential effects on human health and safety, including loss of life, we have provided loss of life data with each example.

The four relevant examples are:

1. the spill of tar sands dilbit from Enbridge's Line 6B in Marshall, MI (2010)
2. the explosion, fire and spill of Bakken crude from a train derailment in Lac-Mégantic, QC (2013)
3. San Bruno natural gas pipeline rupture, explosion and fire in the San Francisco metropolitan area (2010)
4. widespread devastation to New York City and surrounding area from Hurricane Sandy (2012)

For each example, TGG will provide:

1. description of the disaster;
2. the cost and sources of the cost data;
3. the relevance of the example to the Project.

5.5.1. Enbridge's Line 6B Spill in Marshall, MI (2010)

Description of Disaster:

According to the NTSB, following its investigation of the Enbridge Line 6B Spill (emphasis added):[90]

> On Sunday, July 25, 2010, at about 5:58 p.m., a 30 inch-diameter pipeline (Line 6B) owned and operated by Enbridge Incorporated ruptured and spilled crude oil into an ecologically sensitive area near the Kalamazoo River in Marshall, Mich., for 17 hours until a local utility worker discovered the oil and contacted Enbridge to report the rupture.
>
> The NTSB found that the material failure of the pipeline was the result of multiple small corrosion-fatigue cracks that over time grew in size and linked together, creating a gaping breach in the pipe measuring over 80 inches long.
>
> "<u>This investigation identified a complete breakdown of safety at Enbridge. Their employees performed like Keystone Kops and failed to recognize their pipeline had ruptured and continued to pump crude into the environment</u>," said NTSB Chairman Deborah A.P. Hersman. "Despite multiple alarms and a loss of pressure in the pipeline, for more than 17 hours and through three shifts they failed to follow their own shutdown procedures."
>
> […]
>
> Over 840,000 gallons of crude oil - enough to fill 120 tanker trucks - spilled into hundreds of acres of Michigan wetlands, fouling a creek and a river. A Michigan Department of Community Health study concluded that over 300 individuals suffered adverse health effects related to benzene exposure, a toxic component of crude oil.
>
> Line 6B had been scheduled for a routine shutdown at the time of the rupture to accommodate changing delivery schedules. Following the shutdown, operators in the Enbridge control room in Edmonton, Alberta, received multiple alarms indicating a problem with low pressure in the pipeline, which were dismissed as being caused by factors other than a rupture. "Inadequate training of control center personnel" was cited as contributing to the accident.
>
> The investigation found that Enbridge failed to accurately assess the structural integrity of the pipeline, including correctly analyzing cracks that required repair. The NTSB characterized Enbridge's control room operations, leak detection, and

[90] NTSB Press Release, "Pipeline Rupture and Oil Spill Accident Caused by Organizational Failures and Weak Regulations," July 10, 2012. Accessed August 3, 2012. http://www.ntsb.gov/news/2012/120710.html

environmental response as deficient, and described the event as an "organizational accident."

Following the first alarm, Enbridge controllers restarted Line 6B twice, pumping an additional 683,000 gallons of crude oil, or 81 percent of the total amount spilled, through the ruptured pipeline. The NTSB determined that if Enbridge's own procedures had been followed during the initial phases of the accident, the magnitude of the spill would have been significantly reduced. Further, the NTSB attributed systemic flaws in operational decision-making to a "culture of deviance," which concluded that personnel had a developed an operating culture in which not adhering to approved procedures and protocols was normalized.

The NTSB also cited the Pipeline and Hazardous Materials Safety Administration's weak regulations regarding pipeline assessment and repair criteria as well as a cursory review of Enbridge's oil spill response plan as contributing to the magnitude of the accident.

The investigation revealed that the cracks in Line 6B that ultimately ruptured were detected by Enbridge in 2005 but were not repaired. A further examination of records revealed that Enbridge's crack assessment process was inadequate, increasing the risk of a rupture.

"This accident is a wake-up call to the industry, the regulator, and the public. Enbridge knew for years that this section of the pipeline was vulnerable yet they didn't act on that information," said Chairman Hersman. "Likewise, for the regulator to delegate too much authority to the regulated to assess their own system risks and correct them is tantamount to the fox guarding the hen house. Regulators need regulations and practices with teeth, and the resources to enable them to take corrective action before a spill. Not just after."

As a result of the investigation, the NTSB reiterated one recommendation to PHMSA and issued 19 new safety recommendations to the Department of the Transportation, PHMSA, Enbridge Incorporated, the American Petroleum Institute, the International Association of Fire Chiefs, and the National Emergency Number Association.

Costs and Sources of Cost Data

As of March 31, 2013, Enbridge indicated in its First Quarter Interim Report to Shareholders that the total clean-up for the spill is now estimated to cost approximately

$1 billion. Enbridge's civil penalty for the spill was only $3.7 million.[91] Enbridge also points out that there is a possibility that the clean-up bill will continue to increase as the clean-up is still ongoing.

No lives were lost, but as the NTSB citation above indicates: "over 300 individuals suffered adverse health effects related to benzene exposure, a toxic component of crude oil." Furthermore, "[o]ver 840,000 gallons of crude oil - enough to fill 120 tanker trucks - spilled into hundreds of acres of Michigan wetlands, fouling a creek and a river."

Relevance to the Project

The Enbridge Line 6B spill is highly relevant to the current Enbridge Project for the following reasons:

1. Enbridge is the owner and operator of both pipelines.
2. Line 6B connects at Sarnia to Line 9.
3. Both 6B and 9 are 30" pipelines.
4. 6B was carrying tar sands dilbit at the time of the spill and Enbridge is seeking approval to transport heavy crude, including dilbit on Line 9.
5. In light of recent findings regarding the Line 6B spill, the EPA has recently expressed concerns regarding the additional impacts of tar sands crude spills (versus conventional oil), with a particular concern about spills on waterways.[92]
6. The Marshall spill occurred in an environmentally sensitive area (with wetlands with proximity to waterways and human population), not dissimilar to the many HCAs along Line 9B in Southern Ontario and Quebec.
7. The NTSB investigation is scathing in its criticism of the response of Enbridge personnel to the rupture ("Keystone Kops"); and is very damning regarding Enbridge's management culture, referring to it as a "culture of deviance," in which "personnel had a developed an operating culture in which not adhering to approved procedures and protocols was normalized."
8. The NTSB investigation also clearly indicates that in the case of Enbridge, and with respect to the regulation of pipeline operators, "trust us" isn't good enough.
9. Finally and perhaps the most relevant aspect of all, the Kuprewicz Report's assessment of a high risk of rupture for Line 9B is based, among other reasons,

[91] Enbridge First Quarter Interim Report to Shareholders for the Three Months Ended March 31, 2013, Section 11 Contingencies, Adobe p. 67. Accessed August 3, 2013.
See http://www.enbridge.com/InvestorRelations/FinancialInformation/InvestorDocumentsandFilings.aspx and then click on FIRST QUARTER REPORT under 2013.
[92] See footnote 43.

> on (i) the new information from the NTSB investigation of Marshall; (ii) Enbridge's failure to incorporate the NTSB IM recommendations in the Project.[93]

Although the Line 6B rupture caused widespread devastation to the Kalamazoo and surrounding wetlands and, at $1 billion in clean-up costs, holds the record for the single most expensive onshore spill in US history,[94] it is nowhere near the worst-case scenario for the Project, which runs through densely populated urban areas and could damage and disrupt major infrastructure, and possibly cause loss of life.

5.5.2. Lac-Mégantic Tragedy (2013)

Description of Disaster

According to the Transportation Safety Board of Canada (TSB), "[o]n July 6 2013, a unit train carrying petroleum crude oil operated by Montreal, Maine & Atlantic Railway (MMA) derailed numerous cars in Lac-Mégantic, Quebec, and a fire and explosions ensued."[95]

The train with five locomotives was pulling 72 DOT-111 tanker cars full of light crude oil from the Bakken shale play in North Dakota to the Irving Oil refinery in Saint John, N.B. The train was operated by Montreal Maine & Atlantic Railway. The train broke away and derailed, unleashing an explosive ball of burning Bakken crude, which incinerated the downtown core of this small Quebec town.[96]

> On July 23, Quebec's Department of Sustainable Development, Environment and Parks says it believes 5.7 million litres of crude oil were released into the soil, water and air after the accident. Among its other findings:
>
> A total of 7.2 million litres of crude oil were on the runaway MMA train
>
> 9 tankers, from a total of 72, avoided spilling during the accident
>
> 457,500 gallons of oil were recovered from Lac-Mégantic's city centre
>
> 51,200 gallons of oily water removed from the nearby Chaudière River

[93] See footnote 35.
[94] See footnote 90.
[95] See TSB website, Railway investigation R13D0054, http://www.tsb.gc.ca/eng/enquetes investigations/rail/2013/R13D0054/R13D0054.asp#Lac-M%C3%A9gantic
[96] "Lac-Mégantic: What we know, what we don't," Montreal Gazette, July 22, 2013. Accessed August 2, 2013.
http://www.montrealgazette.com/news/M%C3%A9gantic+What+know+what+know/8626661/story.html

> 150,000 litres of oily water removed from Lac Mégantic.[97]

Costs and Sources of Cost Data

According to an August 1, 2013 press release, the TSB investigation is still ongoing.[98] It is far too early to know the final costs for this disaster but they are estimated to be in the hundreds of millions, and possibly exceed $1 billion. Preliminary clean-up bills for damage to the town doubled in the weeks following the accident from $4 million to almost $8 million. The MMA Railway has stated at the end of July that it was unable to pay clean-up costs because it was not getting funds from its insurers. At the time, MMA had outstanding bills for $7.7 million.

MMA has publicly raised the concern that it may go bankrupt.[99] In response, the Quebec government ordered World Fuel Services Corp. to assist with the clean-up. World Fuel "purchased the oil from producers in North Dakota's Bakken region, then leased and loaded rail cars and arranged for their transport to an Irving Oil refinery in New Brunswick."[100] World Fuel is disputing the cleanup order.

> "In the end, says one expert in civil responsibility, taxpayers could be stuck with a bill in the hundreds of millions of dollars.
>
> Quebec law professor Daniel Gardner says he highly doubts MM&A has enough coverage to absorb the massive, combined financial liabilities of damages like environmental cleanup, emergency-crew salaries and lawsuits.
>
> In fact, he believes the Lac-Megantic derailment could have more financial consequences than any other land disaster in North American history.
>
> "The whole cost of this will be far closer to $1 billion than to $500 million," said the Universite Laval academic, adding he would be surprised if the railway had a total of $500 million in coverage.
>
> "What will probably happen? ...The company will go bankrupt, insurance coverage won't be enough."

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[97] Ibid.
[98] http://www.tsb.gc.ca/eng/medias-media/communiques/rail/2013/R13D0054-20130801.asp
[99] Blatchford, Andy, "Railway says it can't pay for Lac-Mégantic disaster cleanup" http://www.theglobeandmail.com/news/national/mma-lays-off-nearly-one-third-of-quebec-workforce-union/article13496970/#dashboard/follows/
[100] McNish, Jacquie and Justin Giovanetti, "Oil Company Disputes Lac-Méganitc Cleanup Order," Globe and Mail. Accessed August 4. http://www.theglobeandmail.com/news/national/oil-company-disputes-lac-megantic-cleanup-order/article13518237/

Gardner expects governments will wind up covering the difference.[101]

"The catastrophe killed 47 residents and levelled more than 40 buildings." [102]

Relevance to the Project

The Lac-Mégantic tragedy is relevant to the current Enbridge Project for the following reasons:

1. It demonstrates the consequences of a crude oil accident in a small town by a lake, thus proximate to people, water and economic activity.
2. Bakken crude, which caused the explosion and which very light is highly flammable, has been identified by Enbridge as one of the crudes that could be shipped on Line 9B.
3. In addition to the devastation of the town, there has been significant release of crude into soil, air and water (5.7 million litres).[103]
4. There are serious concerns about who will bear the financial responsibility for the disaster.

Although Lac-Mégantic was devastating and may even exceed the costs of the Line 6B spill, it is nowhere near a worst-case scenario for the Project. A large pipeline under pressure such as Line 9 can spill far more than 70 tank cars. Moreover, Line 9B goes through Canada's two most populous cites and its economic heartland. A major spill in Toronto or Montreal could do far more damage (in terms of property, infrastructure and loss of life) than the derailment at Lac-Mégantic. In the aftermath of the tragedy, pipeline safety expert Richard Kuprewicz said:

> "Not to scare anyone, but a rupture on a 30-inch pipeline is going to put more tonnage into an area than railcars ever can, despite that terrible tragedy this past weekend that shows what can happen when respect for hydrocarbons is not grasped."[104]

[101] See footnote 99.
[102] See footnote 100.
[103] There have been concerns that the spill affected water quality and drinking water in Lac-Mégantic and nearby towns. Authorities continue to monitor water quality.
"Government Examining Lac-Mégantic Health Risks," The Record, July 31, 2013. Accessed August 2, 2013.
http://www.sherbrookerecord.com/content/gov%E2%80%99t-examining-lac-megantic-health-risks
[104] Kuprewicz, Richard, email, July 8, 2013.

5.5.3. San Bruno Natural Gas Explosion and Fire (2010)

Description of Disaster

The San Bruno pipeline accident occurred in the San Francisco metropolitan area, near the San Francisco International Airport, in a residential area with many homes highly proximate to the pipeline.[105] As reported by the NTSB:[106]

> Executive Summary
>
> On September 9, 2010, about 6:11 p.m. Pacific daylight time, a 30-inch-diameter segment of an intrastate natural gas transmission pipeline known as Line 132, owned and operated by the Pacific Gas and Electric Company (PG&E), ruptured in a residential area in San Bruno, California. The rupture occurred at mile point 39.28 of Line 132, at the intersection of Earl Avenue and Glenview Drive. The rupture produced a crater about 72 feet long by 26 feet wide. The section of pipe that ruptured, which was about 28 feet long and weighed about 3,000 pounds, was found 100 feet south of the crater. PG&E estimated that 47.6 million standard cubic feet of natural gas was released. The released natural gas ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area.
>
> Probable Cause
>
> The National Transportation Safety Board determines that the probable cause of the accident was the Pacific Gas and Electric Company's (PG&E) (1) inadequate quality assurance and quality control in 1956 during its Line 132 relocation project, which allowed the installation of a substandard and poorly welded pipe section with a visible seam weld flaw that, over time grew to a critical size, causing the pipeline to rupture during a pressure increase stemming from poorly planned electrical work at the Milpitas Terminal; and (2) inadequate pipeline integrity management program, which failed to detect and repair or remove the defective pipe section.
>
> Contributing to the accident were the California Public Utilities Commission's (CPUC) and the U.S. Department of Transportation's

[105] http://www.ntsb.gov/doclib/reports/2011/PAR1101.pdf, Adobe pp. 17, 30, 32.
[106] NTSB website on the Pipeline Accident Report: http://www.ntsb.gov/investigations/summary/PAR1101.html

> exemptions of existing pipelines from the regulatory requirement for pressure testing, which likely would have detected the installation defects. Also contributing to the accident was the CPUC's failure to detect the inadequacies of PG&E's pipeline integrity management program.
>
> Contributing to the severity of the accident were the lack of either automatic shutoff valves or remote control valves on the line and PG&E's flawed emergency response procedures and delay in isolating the rupture to stop the flow of gas. (emphasis added)

Costs of and Sources of Cost Data

TGG was unable to determine final costs for the San Bruno disaster and this could be due to ongoing litigation, as well as the breadth of the problems at PG&E (which go far beyond just the San Bruno disaster. Proceedings are currently underway at the CPUC to respond to the San Bruno accident, as well as extensive other failures by PG&E to properly and safely construct and operate its natural gas system. Very substantial penalties to be levied upon PG&E are under consideration. The CPUC Consumer Protection and Safety Division has proposed that a penalty of US$2.25 billion be levied; the amount of the proposed penalty would have been even higher based on the severity of PG&E's mismanagement, but was limited so as to not impair the company's creditworthiness and ability to serve customers and implement needed improvements.[107] Other parties have proposed penalties ranging from US$1.25-$2.539 billion.[108]

According to the NTSB cited above, the San Bruno accident destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area.

In the case of the San Bruno tragedy, we relied on information of penalties and death toll from the California Public Utilities Commission (CPUC) and NTSB cited above.

Relevance to the Project

1. This example shows what can happen when a major pipeline accident occurs in a residential neighbourhood of an urban area: extensive property damage and loss of life. Particularly in Montreal, Line 9B passes through residential

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[107] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K394/65394561.PDF, especially Adobe pp. 7-42.

[108] http://www.cpuc.ca.gov/NR/rdonlyres/50FD5635-30CD-4E9D-9326-95126F75DF59/0/I1201007etalCPSDReplyBriefonFinesandRemedies.pdf, especially Adobe p. 6

neighbourhoods on narrow right of ways just beside where people live and sleep.[109] Gas is extremely dangerous and we are not trying to equate gas and crude pipelines, but an examination of the San Bruno disaster is relevant because it is an example of an urban pipeline disaster. Typically, there are many more natural gas pipelines in urban areas and in proximity to people water and economic activity than crude pipelines. This is because natural gas is distributed to residences and commerces via pipelines.

2. The NTSB expressed grave concerns with inadequacies in the pipeline integrity management program and emergency response procedures in its investigations of both the Enbridge's Line 6B rupture and PG&E's San Bruno rupture. The Kuprewicz Report expresses similar concerns regarding the Line 9B Project and Enbridge's failure to heed some of the important IM recommendations from the Line 6B rupture.

Because the San Bruno disaster occurred in a highly populated urban area, it is getting closer to a worst-case scenario for the Project. However, a Line 9B spill and explosion near Pearson or the Finch subway could create even more extensive damage and disruption to infrastructure and cause greater loss of life. Moreover, a Line 9B spill and explosion in Montreal-East petrochemical complex has the potential to create a major explosion, by setting off a domino effect in an area with highly explosive facilities.[110]

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[109] See https://maps.google.com/maps?q=Montreal,+QC,+Canada&hl=en&ll=45.659038,-73.57199&spn=0.001215,0.002529&sll=37.269174,-119.306607&sspn=11.253772,20.720215&oq=montreal&hnear=Montreal,+Quebec,+Canada&t=h&layer=c&cbll=45.659079,-73.571876&panoid=I5ydkwFnmxZ9GyFmvv4guQ&cbp=12,245.75,,0,-2.96&z=19
[Line 9 crossing Boulevard Gouin Est in Montreal]
and
https://maps.google.com/maps?q=Montreal,+QC,+Canada&hl=en&ll=45.652561,-73.565113&spn=0.001215,0.002529&sll=37.269174,-119.306607&sspn=11.253772,20.720215&oq=montreal&hnear=Montreal,+Quebec,+Canada&t=h&layer=c&cbll=45.652506,-73.56522&panoid=tAlx9YgDJ3nuSOOgANnfvQ&cbp=12,136.1,,0,7.89&z=19
[Line 9 crossing 5e Rue in Montreal]

[110] The Domino Effect results when an incident at one facility leads to other incident(s) onsite or at other proximate facilities. The Domino Effect is of particular concern in Montreal-East. This area has a large concentration of facilities for transportation, processing, and storage of oil, natural gas, and chemicals, as well as other major infrastructure. Montreal East is on the Island of Montreal, combining very high proximity to population centers (locally and throughout the metropolitan region), and to major water bodies. The Quebec government (BAPE) review of Pipeline Saint-Laurent (a pipeline recently completed by Ultramar to transport petroleum products from the St-Romuald refinery to a terminal in Montreal-East) expressed concerns about the domino effect in Montreal-East.
Bureau d'audiences publiques sur l'environnement (BAPE), Projet de construction de l'oléoduc Pipeline Saint-Laurent entre Lévis et Montréal-Est: Rapport d'enquête et d'audience publique. Rapport 243, July
(footnote continued on next page)

5.5.4. Hurricane Sandy in New York City (and Surrounding Area)

Description of Disaster

Hurricane Sandy, the second most costly hurricane in US history, affected 24 states, but did the most damage in New Jersey and New York. New York City was particularly affected.

The following is a description of Hurricane Sandy as it affected New York City:

> Hurricane Sandy was the worst natural disaster ever to affect New York City. Forty-three New Yorkers lost their lives, many more lost homes or businesses, and entire communities were sent reeling by the storm's devastating impact.
>
> […]
>
> When Hurricane Sandy roared into New York on October 29, it drove the waters around our city right up to, and then over, our doorstep. Forty-three people died in the deluge and untold numbers were injured. Along the shoreline the storm surge smashed buildings and engulfed entire communities. It flooded roads, subway stations, and electrical facilities, paralyzing transportation networks and causing power outages that plunged hundreds of thousands into darkness. Fires raged. Wind felled trees. Heartache and hardship—and at least $19 billion in damage—are the storm's legacy.
>
> An unpredictable series of meteorological phenomena combined to create this disaster— Sandy arrived during a full moon, when the Atlantic tides were at their highest; the storm was enormous and when it collided with other weather fronts, it turned sharply and made landfall in New Jersey, subjecting the city to onshore winds that drove its devastating storm surge right into our coastal communities.[111]

Costs and Sources of Cost Data

(footnote continued from previous page)
2007, p. 85. Accessed May 16, 2013.
http://www.bape.gouv.qc.ca/sections/rapports/publications/bape243.pdf

[111] City of New York, "A Stronger, More Resilient New York", June 11, 2013, Forward and p. 5.
http://nytelecom.vo.llnwd.net/o15/agencies/sirr/SIRR_singles_Hi_res.pdf

For Hurricane Sandy, we have relied on estimates of economic damages and loss of life from the insurance industry and municipal government.[112]

Total economic damages in the US due to Hurricane Sandy ("Sandy") are estimated to be approximately $70 billion, with the insurance industry covering $35 billion. There were an estimated $19 billion of economic damages just in New York City, including over $13 billion in physical damage to assets (such as building and tunnels), and almost $6 billion of lost economic activity (reductions in income and loss of use due to transportation outages and other disruptions to economic activity). Sandy also resulted in large loss of life, with 237 deaths overall and 43 deaths just in New York City.

The above estimates of economic damages for Sandy are based on analyses undertaken by the insurance industry and municipal government, and specifically by Swiss Re (a leading global reinsurer) and City of New York (with input from Swiss Re). These analyses quantify costs in a fairly narrow and limited manner, restricted to the costs that can be most readily estimated based on market economics:

> Total losses
>
> For the purposes of the present sigma study, total losses are all the financial losses directly attributable to a major event, i.e. damage to buildings, infrastructure, vehicles etc. The term also includes losses due to business interruption as a direct consequence of the property damage. Insured losses are gross of any reinsurance, be it provided by commercial or government schemes. A figure identified as "total damage" or "economic loss" includes all damage, insured and uninsured. Total loss figures do not include indirect financial losses – i.e. loss of earnings by suppliers due to disabled businesses, estimated shortfalls in gross domestic product, and non-economic losses, such as loss of reputation or impaired quality of life.[113]
>
> the Swiss Re models only seek to estimate losses that can be readily measured in dollars—namely, physical damage to assets, such as buildings and tunnels, and reductions in income and loss of use due to

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[112] Sources: Swiss Re, "Natural catastrophes and man-made disasters in 2012: A year of extreme weather events in the US", Sigma No 2/2013, pp. 1, 7, 13, 17-19, 37 http://media.swissre.com/documents/sigma2_2013_EN.pdf;
City of New York, "A Stronger, More Resilient New York", June 11, 2013, pp. 5, 13-18, 33 http://nytelecom.vo.llnwd.net/o15/agencies/sirr/SIRR_singles_Hi_res.pdf

[113] Swiss Re, "Natural catastrophes and man-made disasters in 2012: A year of extreme weather events in the US", Sigma No 2/2013, p. 37 http://media.swissre.com/documents/sigma2_2013_EN.pdf

> physical damage (for example, if people in unimpacted areas could not travel to work due to transportation outages). Using this approach total losses caused by Sandy, an estimated $19 billion (according to the City's analysis provided to the Federal government), could be broken down into over $13 billion of physical damage and almost $6 billion of lost economic activity. But of course, not every potential impact can or should be quantified by such a simple metric. For example, the Swiss Re models do not predict loss of life or injury. Nor do they highlight potentially disproportionate impacts on disadvantaged populations such as the elderly or medically vulnerable.[114]

Even within this fairly narrow and limited quantification of costs, Sandy was estimated to result in very large economic damages. The large economic damages and loss of life owing to Sandy reflect the high proximity to people, water, and economic activity. Sandy impacted New York City and other areas which have dense concentrations of people and economic activity, high property values, and complex, high value urban infrastructure systems. These urban infrastructure systems (including transportation, energy, and communications) were damaged and disrupted, resulting in substantial further economic damage.

Relevance to Project

TGG is not implying that a Line 9B spill in Toronto or Montreal is likely to create the same extent of damage as Sandy did in the US, and particularly New York City. However Sandy demonstrates in a way that the other examples do not, how major disasters in urban areas can have very high costs and major adverse impacts on large numbers of people. Aside from direct damage to various other types of property, damage and disruptions affecting urban infrastructure can result in large economic costs. Urban infrastructure is expensive to build, repair, and replace. Moreover, urban infrastructure is typically heavily used and enables a large amount of economic activity. Thus, disruptions affecting urban infrastructure can result in substantial additional economic damages due to lost economic activity. Disasters in urban areas can also result in large loss of life and other adverse impacts on human health and safety.

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[114] City of New York, "A Stronger, More Resilient New York", June 11, 2013, p. 33 http://nytelecom.vo.llnwd.net/o15/agencies/sirr/SIRR_singles_Hi_res.pdf

5.6. Range of Costs

Even a narrow insurance definition of a range of potential costs is very high. As indicated in Section 5.4, due to Line 9B's extraordinary proximity to people, water and economic activities, the rupture costs of the Project, under a range of pipeline malfunction/accident possibilities, vary from significant to catastrophic. The examples of pipeline accidents and other disasters in the previous section have demonstrated a range of costs related to relevant accidents.

From the Marshall MI example, a pipeline accident involving a significant spill in a populated non-metropolitan area would cost about $1 billion.

The Lac-Mégantic example describes the damage and death toll from an explosion in a small town involving a derailed train transporting Bakken crude. It is too early to estimate the costs of this tragedy but they will likely be over $1 billion. A Bakken spill from Line 9 could be much larger and result in even more damage.

While Marshall had devastating effects on wetlands and the Kalamazoo, and Lac-Mégantic was a terrible tragedy, neither is near worst-case in terms of damage and loss of lives, especially for what could occur in a densely populated urban area.

San Bruno and Sandy provide illustrations of how costs can rapidly escalate when a disaster occurs in an urban area, which damages and disrupts infrastructure and affects large numbers of people. The full economic damage of San Bruno was not determined but penalties to PG&E are likely to exceed $2 billion. Damages for Sandy are estimated in the tens of billions. As indicated in the previous section, a Line 9B spill in Toronto or Montreal is unlikely to create the same extent of damage as Sandy. However Sandy demonstrates in a way that the other examples do not, how a major disasters in urban areas can have very high costs and major adverse impacts on large numbers of people.

Under bad to worst-case scenarios, TGG concludes that the potential costs for a major rupture in an HCA but not an urban setting (similar to Marshall) could start at $1 billion (bad scenario). If a major accident occurred in a densely populated area, damaging and disrupting key infrastructure, these costs could escalate to multi-billion dollar damages (potentially as high as $5-$10 billion) (worst-case scenario). Given the flammability of the proposed new crude slate to be carried on Line 9B, which includes both Bakken and dilbit, an accident involving this pipeline could also involve loss of human life.

5.7. Concerns about Enbridge's Capability to Cover Damages in a Worst-Case Scenario

As discussed in Section 5.3, TGG has concerns about Enbridge's financial capability and responsibility to mitigate and compensate all the potential damages, especially in a worst-case scenario such as a major accident/spill in an area with a large concentration of people and economic activity. In light of the a Lac-Mégantic tragedy and concerns around the adequacy of MM&A's (other parties') ability and willingness to pay for damages, we are particularly concerned about the following questions surrounding Enbridge's insurance:

1. To what extent will Enbridge will forced to internalize the costs of a major pipeline accident/spill?
2. Given the uncertainty around (a), to what extent does Enbridge has the proper incentives to buy enough insurance (or to simply trust that the full costs will not be internalized)?
3. Even if Enbridge were willing to buy adequate insurance, to what extent would such insurance be available at an affordable price?

In the context of the current NEB case, TGG has not been able to conduct an in-depth review of Enbridge's insurance situation, and its legal obligations in compensating for damages. But our quick review does raise a number of concerns about Enbridge's capability/responsibility to internalize the costs in the event of a major accident/spill.

As reflected in Enbridge's last quarterly earnings conference call (August 1, 2013), in light of the many recent pipeline spills and the Lac-Mégantic tragedy, Enbridge appears to encountering some resistance from insurers and may not be able to obtain as much coverage as would be optimal (our emphasis):[115]

> Andrew Kuske - Credit Suisse - Analyst
>
> Thanks. Good morning. Just a question as it relates to an increasing issue in the industry, just insurance costs. <u>From what we've seen from some of the recent spills that have happened and then the tragedy in Quebec, how do you think about insurance costs just from a coverage standpoint, the willingness for</u>

[115] Thomson Reuters Streetevents, EDITED TRANSCRIPT ENB. TO – Q2 2013 Enbridge Earnings Conference Call, August 1, 2013, 14. Accessed August 3, 2013. http://www.enbridge.com/~/media/www/Site%20Documents/Investor%20Relations/2013/2013_ENB_Q2_Transcript.pdf, p. 14

insurers to actually cover the industry, costs, deductibles? Is there some kind of Government intervention that actually comes in at some point in the future?

Al Monaco - Enbridge Inc - President & CEO

Richard, do you want to take a shot at that?

Richard Bird - Enbridge Inc - EVP, CFO and Corporate Development

Yes. Well, as you might expect, insurance costs generally have been rising of late, and all aspects of insurance is tougher than it was historically. We were able to modestly increase our coverage this last go around from CAD660 million general liability insurance to CAD685 million. We would have taken more if had been available at a reasonable price, but that was pretty much capping out at least what the market availability was to Enbridge, so -- and recent developments are not going to help that.

Andrew Kuske - Credit Suisse - Analyst

Do you think we're heading down the path of, effectively, surety bonds for the industry for covering certain incidents? I mention that in part just because of some of the criteria that have been imposed on Gateway.

Richard Bird - Enbridge Inc - EVP, CFO and Corporate Development

Well, and not just Gateway. I think you've seen an announcement by the Federal Government to the -- what will be a Canadian-wide regulation requiring provision of financial resources to support addressing any major incident, and I think there is probably going to be a fair bit of thinking done and innovation done on different financial structures that could be put in place to provide the assurance to the Government and the public that there will be resources to address any spill. Of course, the primary line of attack is to minimize the likelihood of such a thing happening in the first place, but you are right, Andrew, there will be alternative financial structures to address that small residual risk.

Andrew Kuske - Credit Suisse - Analyst

So then finally, the final point on this, do you see this as being -- all of these developments effectively being better for the larger companies that are better capitalized, bigger balance sheets, more assets for handling, essentially, the environmental changes, the insurance costs and the obligations are being put on the industry to a much greater degree than the smaller ones that might not be able to operate in that kind of environment.

Richard Bird - Enbridge Inc - EVP, CFO and Corporate Development

That's a possibility. I think it's probably too soon to see that, and I wouldn't rule out the possibility that there is some form of -- and maybe this is something you

> were getting at a little earlier -- some form of industry-wide financial solution, structural solution as opposed to a pipe-by-pipe or company-by-company solution, and that would avoid putting that very difficult circumstance on some of the smaller pipelines that you just referred to.

As per the information provided in this conference call, the key takeaways are the following:

- Enbridge's insurance coverage is apparently limited in availability and expensive,
- Enbridge has only $685 million in insurance.
- There are some initiatives underway to deal with providing assurance of resources to address "any spill."
- This appears to be a work in progress.

According to Enbridge's most recent report to shareholders, the comprehensive insurance program is maintained by Enbridge for all its subsidiaries and affiliates. The renewed coverage for the liability program has an aggregate limit of US$685 million.[116] Whether the total amount is US or CAD$685 million, this would not be enough insurance to a major disaster associated with the Project, especially not if that disaster were in an urban centre. Moreover, $685 million is not a lot of coverage for Enbridge and all of its subsidiaries and affiliates, at a time of frequent and costly pipeline spills with a management culture that lacks attention to pipeline safety.

The July 4, 2013 Letter of Comment from the City of Montreal filed in the current proceeding confirms that the Montreal shares similar concern with respect to Enbridge's financial capability to pay for the potential damages incurred by a malfunction or accident on Line 9B. Montreal asks that the NEB refuse to grant approval for the Project unless Enbridge can demonstrate the financial capability to respond to any incident.[117]

> À ce titre, la Ville de Montréal considère qu'aucune autorisation de procéder au renversement de la conduite 9B ne devrait être accordée par l'ONE sans le respect des conditions suivantes :
>
> - le partage des évaluations d'analyse de risque du pipeline au point de traverse de la rivière des Outaouais et de ses affluents aux autorités responsables de la sécurité civile locale et de l'agglomération de Montréal;
> - le partage des plans d'intervention d'urgence à jour détaillés pour le territoire englobant le point de traverse de la rivière des Outaouais et de ses affluents

[116] Enbridge First Quarter Interim Report to Shareholders for the Three Months Ended March 31, 2013, Section 11 Contingencies, Adobe p. 68. Accessed August 3, 2013; see footnote 90 for link.
[117] See footnote 31.

aux autorités responsables de la sécurité civile locale et de l'agglomération de Montréal ainsi que lors de toute révision et mise à jour;[118]

- la démonstration de la capacité financière de l'entreprise pour répondre à tout incident.

[118] We also note that City of Montreal shares similar concerns regarding risk factors related to proximity to water, as well as the adequacy of city-specific emergency response plans.

6. Relative Weighting of Costs and Benefits

6.1. Results of Sections 4 (Benefits) and 5 (Costs)

Section 4 has demonstrated that the overall benefits of the project, taking into account benefits from the commercial impact of the Project (mainly to refineries) and economic-development-related socio-economic benefits are less than $1 billion/per year and likely less than $0.5 billion/year, especially in the near-term.

Section 5 concluded that due to Line 9B's extraordinary proximity to people, water and economic activities, the rupture costs of the Project, under a range of pipeline malfunction/accident possibilities, vary from significant to catastrophic. With rupture costs that vary from significant to catastrophic and an assessment of a high risk of rupture, the expected Project costs therefore range from significant to catastrophic. Expected costs are much higher for Line 9 than for most pipelines.

Under bad to worst-case scenarios, TGG concludes that the potential economic costs for a major rupture in an HCA but not an urban setting (similar to Marshall) could start at $1 billion (bad scenario). If a major accident occurred in a densely populated area, damaging and disrupting key infrastructure, these costs could escalate to multi-billion dollar damages (potentially as high as $5-$10 billion) (worst-case scenario). Given the flammability of the proposed new crude slate to be carried on Line 9B, which includes both Bakken and dilbit, an accident involving this pipeline could also involve loss of human life.

6.2. Costs Could Greatly Exceed Benefits Under a Range of Accident Conditions

Based on our evaluation of economic costs and benefits, TGG concludes that the potential economic costs could exceed (and, under a range of malfunction/accident conditions, greatly exceed) the potential economic benefits. The range of malfunction/accident conditions are the bad to worst-case scenarios describe in Section 5, which range from $1 billion to multi-billion dollar damages, and which could also involve loss of life. TGG was able to assign a much higher expected cost to these bad-to-worst-case scenarios given that the Kuprewicz Report has concluded that the Project has a high risk of rupture in the early years.

We note once again that we have limited our cost analysis to environmental and socio-economic impacts that directly affect economic activity, and that can be somewhat readily (albeit approximately) quantified using market economics. The consideration of human health and safety and the broader and cumulative environmental and other socio-economic costs will further increase the overall costs of the Project. However, TGG has concluded that our relative comparison of more narrowly defined economic costs and benefits (including a more limited consideration of socio-economic and environmental impacts) is sufficient demonstration that the relative costs can exceed, and in some cases greatly exceed, the benefits.

6.3. Allocation of Costs and Benefits

NEB has a mandate to balance to balance economic, environmental and social consideration. In our review of the costs and the benefits of the Project, we have noted that the costs and benefits are very unevenly allocated among various stakeholders and across regions.

The biggest costs and potential risks of the Project are borne by the inhabitants of urban areas (Montreal and Toronto), where the worst-case scenario related to a major pipeline disaster could occur. Because there is some concern about Enbridge's willingness and ability to pay all of the damages associated with a worst-case scenario, taxpayers in these cities and provinces are also subject to higher risks. Section 4 concludes that the economic-development benefits to Montreal (and Quebec as a whole), are insignificant, particularly when weighed against the risk of a major spill. Moreover, the province receives negligible short-term economic development benefits.

Conversely, Enbridge, the Quebec refineries and the crude producers (tar sands, other Alberta, and Bakken) will benefit from the Project. Suncor and Valero (the Alberta- and Texas-based owners of Quebec refineries) will benefit from increased profits due to lower-priced crudes (Bakken and tar sands). Moreover, crude producers will be able to increase profits by accessing higher priced markets. Furthermore, Enbridge is highly motivated to extend its pipeline network and increase profits. Enbridge is facing considerable uncertainty with respect to its Northern Gateway project and is seeking to increase its capacity to transport tar sands crude. As such, Enbridge, the Quebec refineries and crude producers are even more highly motivated to tout the supposed benefits of these projects to the inhabitants of Ontario and Quebec. In effect though, the vast majority of benefits will flow to Enbridge, the owners of the two refineries in Quebec and crude producers.

7. Recommendations

In light of the following:

4. the results of our relative economic cost benefit analysis, which demonstrates that the potential economic costs could exceed (and, under a range of malfunction/accident conditions, greatly exceed) the potential economic benefits;
5. the highly uneven allocation of costs and benefits among the the stakholders; and across regions;
6. the Kuprewicz Report's conclusion that there is a high risk that Line 9 will rupture in the early years following project implementation due to a combination of cracking and corrosion

TGG strongly recommends that the NEB reject Enbridge's Project.

Because of the uniqueness of this people with its extraordinary proximity to people, water and economic activity, TGG concludes that it would be would be reckless to allow Enbridge run 300,000 bpd of volatile Bakken or dilbit along this route in a pipeline with a high risk of rupture. This is even more true of the Line 9B's routing through Canada's two biggest urban centres. A rupture of flammable crude in either Greater Montreal or Metropolitan Toronto could result in major damage and destruction to urban infrastructure and property, as well as potential loss of life.

TGG believes that the public interest will be served in Line 9B is left idle (reference scenario) and that Canada as a whole will be better off.

If the NEB decides to approve the Project despite our strong recommendation of rejection and our descriptions of worst case scenarios involving major damage to urban centres, impacts on great numbers of people (and even loss of life), TGG recommends the following:

1. The implementation of all the recommendations of the Kuprewicz Report to ensure better pipeline safety; and regular and ongoing monitoring of Line 9B;
2. Better assurance that Enbridge will be responsible for all damages in the case of a major multi-billion dollar spill (similar to the Ville de Montréal recommendation);
3. The maintenance of the same crude slate (with a restriction on heavy crude) that was approved for Line 9A in Phase 1.