APPENDICES 1 - 5

to

A SCIENTIFIC AND LEGAL POLICY FOLLOW-UP REPORT ON CRUDE OIL PIPELINES IN THE GREAT LAKES

FLOW (FOR LOVE OF WATER)
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APPENDIX 1

Engineering and Scientific Issues Affecting the Integrity of Enbridge Line 5 at the Straits of Mackinac

By: Gary Street
August 29, 2015

PREVIOUSLY IDENTIFIED ISSUES

Mussels

Well documented that excrement from Zebra mussels can corrode bare steel.

- ➔ Coating – after 62 years – has deteriorated from abrasion. Subject to corrosion from mussel excrement.

Unrealistic Spill Simulations

Very orchestrated in advance.
Under ideal conditions – not in winter, high winds, or night time.
Meant for PR, not a true test.

- ➔ Do not test actual capability in a true emergency

Dents in Line 5 at the Straits

Enbridge: "There were two minor dents reported in the latest geometry ILI report received in July. They were less than the reporting threshold (less than 2%) but were noted in the report by our ILI vendor. We elected to conduct a visual inspection of the pipe to verify. The final report from this visual inspection has not yet been received from the inspection vendor to confirm the presence of a dent."
Ref: **http://michiganradio.org/post/whats-status-old-oil-pipeline-under-lake-michigan-we-need-more-information-know** (Oct 9, 2014)

- ➔ Enbridge Letters to Task Force in 2014 **do not acknowledge these dents**. (493988-7, p. 11 & 12 and 493944, p. 7)

Enbridge does not share data even with the State

Several issues identified by Task Force were not answered or answered evasively.

Block Valves

Inventory in **each** of the two 20 inch lines ~325,000 gallons.

Valve Closure and Water Hammer (493988-7 – p. 19)
Enbridge claims they can shut block valves in 3 minutes.
Preliminary calculations indicate this may be too fast to prevent water hammer. Depends on line pressure at time of shut down.
If water hammer is severe, line can be destroyed.

ROV Inspection
Done every two years.
Cannot detect small pinhole leaks or “minor” bulges.
Exterior condition obscured by mussels and sediment.

Nearest Response Teams
Bay City
Escanaba

Aerial Patrols
Of little value.
Done every 3 weeks, weather permitting.

- ➔ Strictly a PR exercise. (I have done this in my past life.)

RECENTLY IDENTIFIED ISSUES

Spill Impact and History
Environmental Triangle **(Appendix 1-1)**
Chart – recent spill history **(Appendix 1- 2)**

Amount of leakage due to Material Balance Error (Appendix 1-4)
Enbridge to Task Force: **3350 barrels per day**
Claims 5.3 % accuracy. I calculated 6.25% accuracy (Leak of 3350 bbls/day v. 22.5 million bbls/day).

- ➔ **140,700 gallons per day – could go undetected by mass balance!**

Worst Case Scenario (per Enbridge) – Unrealistic!! --- and Inconsistent!!
Letter to Task Force dated June 27, 2014 (493988-7, p. 22). Worst Case = 8583 barrels (probably both lines).

In another letter dated 02/27/15, worst case for a single line is 4950 barrels (493994, p. 5, item 12). 4950 x 2 = 9900 barrels. **Not Consistent!**

- ➔ **Worst Case – per Enbridge – is NOT the Worst Case!**

Mussels
Most likely Quagga v. Zebra mussels (makes little difference).
(Ref: Ashley Baldridge, PhD, Research Benthic Ecologist, NOAA Great Lakes Environmental Research Laboratory, Ann Arbor, MI)

Issued memo suggesting **mussels could add 27%** to the weight of the pipelines. They were not designed for this extra load.

- ➔ **GLI Report – Opinion only. Does not present scientific evidence to support conclusions. GLI and Enbridge: "Trust Us".**

Impact of Propane to the U.P. if Line 5 is shut down at the Straits (Appendix 1-6)
Propane is currently removed and purified at Rapid River.
Google Earth photo.
EPA confirmation of Depropanizer at Rapid River: **(Appendix 1-6)**

Alternative: Remove and purify Propane at Superior, WI. Pipe it to the existing facility at Rapid River for distribution.

➔ **Conclusion: Shutting down Line 5 <u>at the Straits</u> should have no impact on U.P. propane supply.**

How Much Enbridge Crude goes to MI via Line 5

➔ **Enbridge system maps: <u>1 Q 2015</u> shows NO crude going to MI via Line 5 (Appendix 1-7)**

Number of Supports and Supports at 140 foot Separation (493988-7, 06 27 14) **(Appendix 1-8)**

Enbridge admission of not installing supports every 75 feet. See email by GLS, 08 24 15, and emails by Ed Timm.

➔ **Decided (apparently) without State approval that 140 foot support is adequate.**

Winter Spill Response

AG: Do you have a spill response plan for addressing a potential spill when there is ice cover? (493994-7, item 17)

Enbridge: Yes
Coast Guard: No
DEQ: No

US Coast Guard Commandant Admiral Paul Zukunft is "not comfortable" with current contingency plans for a worst case scenario in the Great Lakes. **(Appendix 1-9)**

September 4, 2014 -- the DEQ's oil spill cleanup chief (Robert Wagner) told leaders and local residents at a public forum on Mackinac Island --- "If the Straits are frozen over, cleanup would be far more challenging."

Previous damage to Line 5 at the Straits (493994-7, items 18 & 19)

Enbridge: Response: The in-line inspection tools can very accurately identify and measure if the pipe is damaged by strikes. As described in Question 18, in 60+ years of operation, **there has never been any damage.**

What about known dents as cited in above in <u>Dents in Line 5 at the Straits</u>?

Volume in the Line when shut down

Per Enbridge: (493994-7, item 19) …………the approximate volume of oil released from a single pipeline between the valves would be 4950 barrels.

➔ **Above is NOT CORRECT for a 20" schedule 60 pipeline that is 4.5 miles long. The correct amount is 7793 barrels.**

Leak Impact (Appendix 1-5)

Enbridge claims 99.99930% non-leak rate (system wide). This is equivalent to ~80 gpd for each 20” line, or 160 gpd for both lines.

Suspend the pipeline under the Mackinac Bridge (Appendix 1-3)

Excessive load, both static and dynamic.
Spills can still occur.

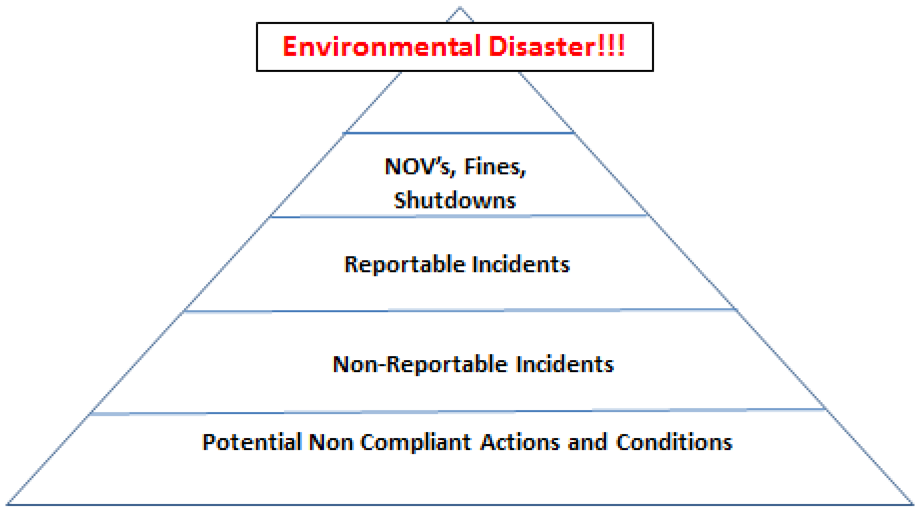
Double Walled Pipe

Enbridge: “We are not aware of any double walled pipelines used for the transmission of oil.” (493994-7, p. 2)
At a presentation in February (?) 2012 at Petoskey -- Enbridge stated that double walled pipe is used under freeways. Contradicts above.

Evacuation of the Line in the event of a Leak (493994-7, item 15)

They are dreaming. The steps outlined will take a very long time to implement and even then may not work.

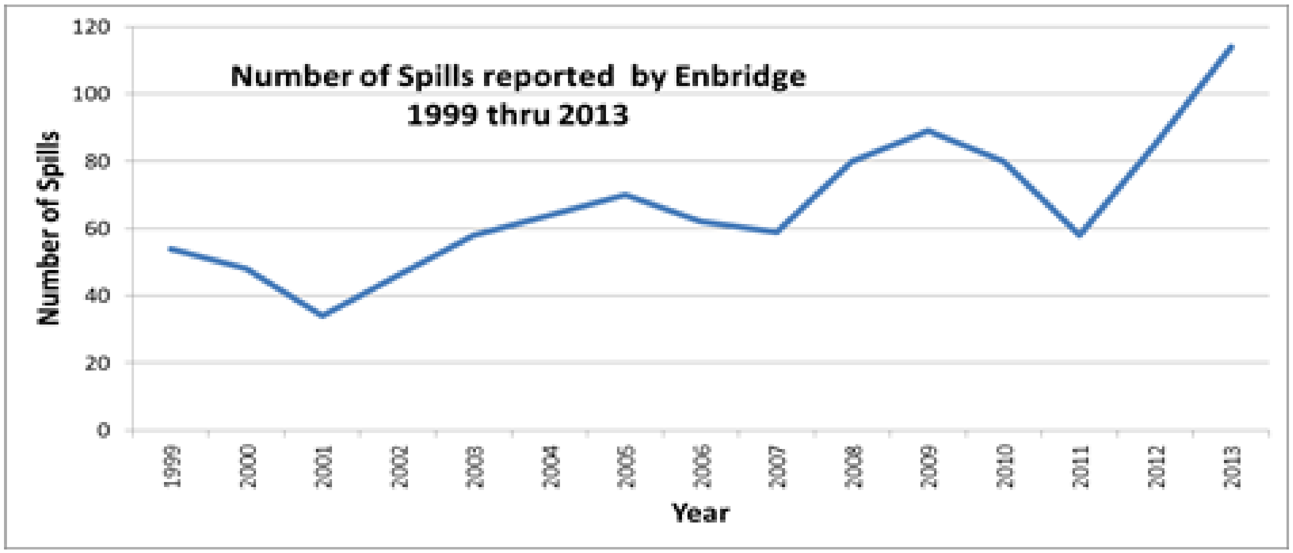
Appendix 1-1



Ladder to an Environmental Disaster !!

Page 6

Appendix 1-2



Page 4

Appendix 1-3

By Gary Street, P.E.

Engineer & FLOW Consultant

What if the two twenty inch diameter pipelines that cross the Straits (part of Enbridge Line 5) were hung from the Mackinac Bridge, rather than immersed in water nearly 300 feet deep?

The engineers on the staff at FLOW took a look at the concept. Is it possible? Does it make the situation less environmentally hazardous? What impact will it have on the Bridge? Was the Bridge designed for the extra load?

So we did some calculations.

The result: In addition to the regular car and truck traffic, for which the Bridge was designed, the pipelines would put the added weight of an additional 2000 to 3500 automobiles onto the Bridge. And not just for a short time, but continuously, 24 hours a day, 365 days per year.

Almost certainly the Bridge was not designed for all this extra weight. And what if the lines were to rupture? The oil still goes into the Straits.

Clearly, not a good idea!

Appendix 1-4

Leak Detection Ability per Enbridge

By: Gary Street

In a June 2014 submittal to the State[1], Enbridge made the following statement:

"The quantity of oil that could be released *without being detected* by the CPM system[2] or line balance calculations is approximately 400m3/day (~3350 bbls/day.) This unlikely scenario assumes that the other overlapping leak detection do not alert the operator of the release."

About 22.5 million gallons of oil per day flow through the two 20 inch pipelines where Line 5 goes under the Straits. Each line therefore carries 11.25 million gallons per day.

Using the Enbridge number of 3350 bbls/day (140,700 gallons per day), for the two lines, taken together, every day 1.25% of the oil in the two 20 inch lines could "leak" almost 141,000 gallons of oil and *not be detected* by Enbridge. If the leak is confined to one line, it could still be 70,350 gallons per day that would NOT be detected.

Ultimately, how would such a leak be detected? Most likely by oil showing up on the water surface, or on the shoreline. And what about a wintertime spill when there is 8 feet of ice in the Straits? It could take days, even weeks before it is detected. In the meantime the spill is continuing to get worse. This is not an acceptable practice, anytime of the year. The damage has been done when the evidence appears!

Using Enbridge's data, they DO NOT have the capability of shutting down the lines based on line balance calculations unless the leak exceeds 140,700 gallons per day (98 gpm). Leaks smaller than this amount could go undetected.

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[1] Correspondence form Enbridge to Attorney General Bill Schuette and DEQ Director Dan Wyant, June 27,2014, entitled: Enbridge Lakehead Systems Line 5 Pipelines at the Straits of Mackinac, p. 21.

[2] Computational Pipeline Monitoring (CPM): Per Enbridge – "Line 5 is protected by a computer-based pipeline monitoring system that utilizes measurements and pipeline data to detect operational anomalies that indicate possible leaks. This system employs a sophisticated computer model of Line 5 to compare the expected pressures and liquid flow rate in each section of the line to the actual measured pressures and flow rate. Discrepancies between the expected and actual values result in a leak alarm that precipitates the shutdown of the line."

Appendix 1-5

Flow Rates are in U.S. gallons								
Flow rate in each 20" line =		**7,876**	**gpm**	**11,342,100**	**gpd**			
Success Rate		Leak Rate		Amt leaked per day		Amt Leaked in:	1	year
99.99000%		1.00E-04	gpm	1,134	gal	413,987	gal	
99.99900%		1.00E-05	gpm	113	gal	41,399	gal	
99.99930%		7.00E-06	gpm	79	gal	28,979	gal	
99.99990%		1.00E-06	gpm	11	gal	4,140	gal	

Appendix 1-6

Propane Supply to the Upper Peninsula if Line 5 at the Straits is Shut Down

Periodically, Enbridge uses Line 5 to transport LPG (liquefied petroleum gas) to various locations, including a terminal and processing center at Rapid River, MI.

At Rapid River, Enbridge operates a unit (a depropanizer) to separate and purify the propane from other compounds that may be present. After separation the liquefied propane is stored under pressure in large steel cylinders. Propane is then loaded into large trucks which haul it to more localized distribution centers. From the distribution center, propane is loaded into smaller trucks and delivered to residences and small businesses.

Rapid River is centrally located on the southern edge Michigan's Upper Peninsula, about half way between Ontonagon and St. Ignace. It is ideally located to provide propane to most of the U.P., as well as northern Wisconsin.

Concern has been expressed that if Line 5 at the Straits were "shut down", this could prevent delivery of propane to the Upper Peninsula.

From a logistics and engineering view point, there is no basis for this concern. Rapid River is 130 miles west of where Line 5 crosses the Straits, very much "up stream" of the Straits. If Line 5 were shut down at the Straits, the Rapid River facility could continue to receive LPG, processed either on site or at Superior, WI, and load propane into trucks for localized delivery. Given the geography of the Rapid River location, receiving propane via Line 5 would not be impacted by a shutdown of the line at the Straits.

Confirmation of Depropanizer at Rapid River:
http://epa-sites.findthedata.com/l/305924/Rapid-River-Depropanizer-and-Storage-Facility

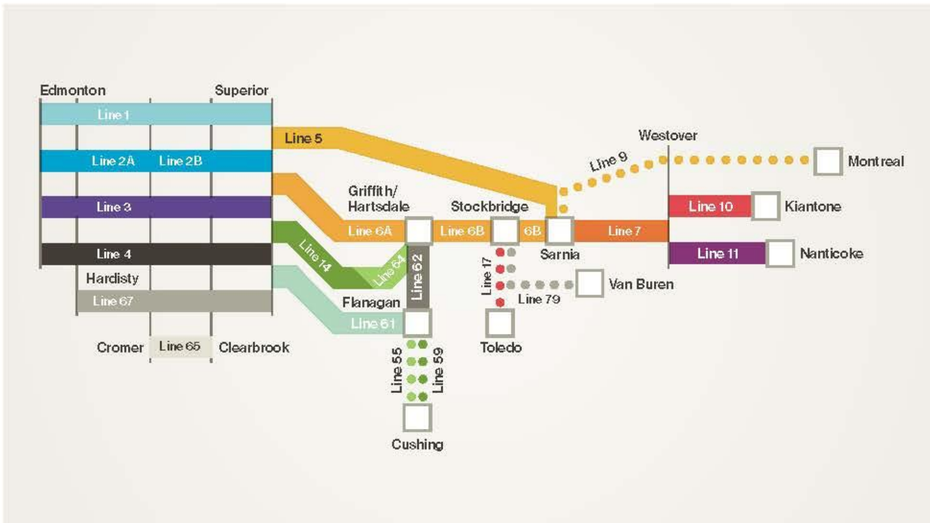
Depropanizer likely located in this area

Enbridge -- Rapid River (MI) Propane Facility

Appendix 1-7

Pipeline System Configuration

Q1, 2015



Line 1
37,600 m³/d (237 kbpd)
18"/20" - 1098 miles
- NGL
- Refined Products
- Light

Line 2A
70,300 m³/d (442 kbpd)
24" - 596 miles
- Condensates
- Light

Line 2B
70,300 m³/d (442 kbpd)
24"/26" - 502 miles
- Light

Line 3
62,000 m³/d (390 kbpd)
34" - 1098 miles
- Condensates (Edmonton to Hardisty)
- Light

Line 4
126,500 m³/d (796 kbpd)
36"/48" - 1098 miles
- Heavy
- Medium (Ex-Clearbrook)
- Light (Ex-Clearbrook)

Line 5
85,900 m³/d (540 kbpd)
30" - 645 miles
- NGL
- Light

Line 6A
106,000 m³/d (667 kbpd)
34" - 467 miles
- Light
- Medium
- Heavy

Line 6B
79,500 m³/d (500 kbpd)
30" - 293 miles
- Light
- Medium
- Heavy

Line 7
28,600 m³/d (180 kbpd)
20" - 120 miles
- Light
- Medium
- Heavy

Line 65
29,500 m³/d (186 kbpd)
20" - 313 miles
- Light
- Medium

Line 10
11,800 m³/d (74 kbpd)
12"/20" - 91 miles
- Light
- Medium
- Heavy

Line 11
18,600 m³/d (117 kbpd)
16"/20" - 47 miles
- Condensates
- Light
- Medium
- Heavy

Line 62
37,400 m³/d (235 kbpd)
22" - 75 miles
- Heavy

Line 14/64
50,500 m³/d (318 kbpd)
24" - 467 miles
- Light
- Medium

Line 61
89,000 m³/d (560 kbpd)
42" - 454 miles
- Light
- Medium
- Heavy

Line 67
90,600 m³/d (570 kbpd)
36" - 999 miles
- Heavy

Not part of the Enbridge Mainline System

Line 9
24,200 m³/d (152 kbpd)
30" - 524 miles
- Light

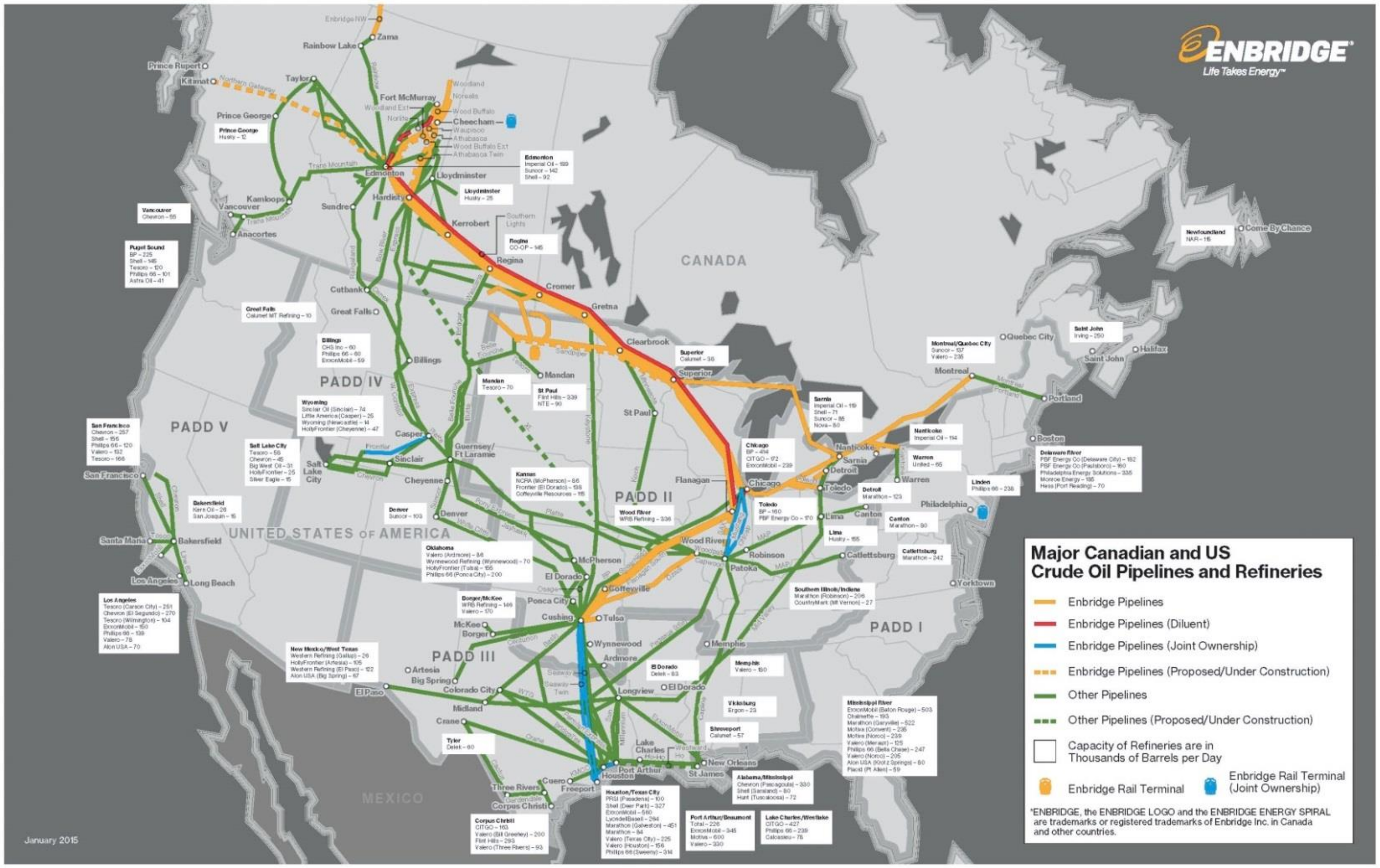
Line 17
16,000 m³/d (101 kbpd)
16" - 88 miles
- Heavy

Line 55
30,700 m³/d (193 kbpd)
22"/24" - 575 miles
- Light
- Medium
- Heavy

Line 59
93,000 m³/d (585 kbpd)
36" - 593 miles
- Light
- Heavy

Line 79
12,700 m³/d (80.0 kbpd)
20"/16" - 62 miles
- Heavy

Notes: Capacities provided are Annual Capacities and do not include current restrictions.


ENBRIDGE
Life Takes Energy
Major Canadian and US Crude Oil Pipelines and Refineries
Enbridge Pipelines
Enbridge Pipelines (Diluent)
Enbridge Pipelines (Joint Ownership)
Enbridge Pipelines (Proposed/Under Construction)
Other Pipelines
Other Pipelines (Proposed/Under Construction)
Capacity of Refineries are in Thousands of Barrels per Day
Enbridge Rail Terminal
Enbridge Rail Terminal (Joint Ownership)
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CANADA
UNITED STATES OF AMERICA
MEXICO
PADD I
PADD II
PADD III
PADD IV
PADD V
January 2015

Appendix 1-8

(letter is abridged)

June 27, 2014

SUBMITTED VIA ELECTRONIC MAIL

Hon. Bill Schuette
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Hon. Dan Wyant
Director
Michigan Department of
Environmental
Constitution Hall
525 W. Allegan Street
P.O. Box 30473
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Re: Enbridge Lakehead System Line 5 Pipelines at the Straits of Mackinac

Dear Attorney General Schuette and Director Wyant:

Thank you very much for the opportunity to discuss Enbridge Energy, Limited Partnership's Line 5 pipeline crossing of the Straits of Mackinac. We appreciate the dialog that has already occurred to provide some clarity and understanding in relation to the information requests that accompanied your letter of April 29, 2014.

To eliminate the possibility of currents washing out existing supports, special double screw anchor supports were selected and have been installed over the past ten years to eliminate that risk.

The pipes were laid in a dredged ditch until they were in at least 65 feet of water depth, a depth that was expected to avoid anchor strikes or ice action. Past 65 feet of depth they were laid on the floor of the Straits in a straight line which has proven to be an excellent decision as recent studies have concluded the risk of an anchor drop or drag impacting the pipeline at its exposed depths is highly unlikely.

Enbridge has developed a safer and more permanent solution to counteract the currents in the Straits and prevent wash-outs of pipeline supports. The peer-reviewed calculations of the day, reconfirmed in 2002, indicated the pipelines would be safe with unsupported spans across the bottom of the Straits of up to 140 feet. The State of Michigan set an initial span length of 75 feet in 1953, with the shorter spacing allowing for an added safety factor as it was difficult in the 1950s to inspect the lines and ensure adequate supports were in place. In 2002, to address currents and possible washouts, Enbridge began installing screw anchor pipe supports. The anchors are ten-foot- long steel screws that are augured into the lake bed on either side of the lines and hold a steel saddle that permanently supports the lines. In the 12 years since installation of the screw anchors, Enbridge has yet to observe any wash out of those very durable supports.

GLS Comment: Nothing is said about reviewing the 140 foot distance with the State, nor getting State approval. The 1953 Easement called for support every 75 feet. This appears to be a violation of the 1953 Easement.

Appendix 1-9

Link: http://www.peters.senate.gov/content/commerce-committee-approves-two-peters-amendments

Peters' second amendment to the *Coast Guard Authorization Act* would require the Coast Guard to work with partner agencies including the National Oceanic and Atmospheric Administration (NOAA) to conduct an assessment on the effectiveness of oil spill response activities in the Great Lakes region.

"Michiganders already know the devastating effects an oil spill can have after the 2010 pipeline spill into the Kalamazoo River," said Senator Peters. "The Great Lakes are an essential part of our way of life in Michigan, supporting more than 500,000 jobs and our multibillion dollar shipping, travel and fishing industries. A spill in the Great Lakes would be catastrophic to Michigan's economy and our environment, and we must be prepared protect this vital resource in the event of a spill."

The Great Lakes are particularly vulnerable to an oil spill from 62-year-old twin pipelines that run through the Straits of Mackinac. A spill in the Great Lakes would also be complicated by the lack of research on cleanup of oil spills in bodies of fresh water, especially under heavy ice cover. Current methods of oil spill response and cleanup, such as oil dispersants and mechanical recovery, are not effective in large bodies of fresh water. **In an April 28th Commerce Committee hearing, U.S. Coast Guard Commandant Admiral Paul F. Zukunft said that he "is not comfortable" with the current contingency plans for a worst-case scenario spill in the Great Lakes.**

The assessment required by Peters' amendment will evaluate new research into oil spill impacts and cleanup plans in fresh water under a wide range of conditions. The evaluation will also focus on new and specific improvements to safety technologies and environmental protection systems used in fresh water oil spill response efforts.

APPENDIX 2
With Appendices 2A-2D

Summary Statement Regarding the Current Condition of Enbridge Line 5

Ed Timm, Ph.D.

September 3, 2015

Since I first joined with FLOW as a technical consultant I have been working to determine whether or not any part of Line 5 can be classified as an imminent threat to life and property. As a licensed professional engineer it would not be ethical for me to take the position that Line 5 presents an imminent hazard unless I can back that opinion up with data and calculations. Until recently, the publically available record simply did not contain enough hard information for me to call Line 5 an imminent hazard. With the release of the Governor's Pipeline Task Force reports and a partial response to a FOIA request to the Michigan Public Service Commission regarding Line 5, I now believe I have enough information to change my position on the issue of imminent hazard and believe the data and calculations I have recently completed support that position.

Specifically, Line 5 appears to have many safety issues that are comparable to the issues resulting in the disastrous ruptures of Enbridge Line 6b, Plains All American Line 901and the Exxon-Mobil Pegasus pipeline. Among these issues are:

1. Pipe wall thinning and cracks caused by corrosion and erosion resulting in unrealistic pressure ratings,
2. The addition and deletion of multiple pump stations which have increased the capacity of the line from an original design of 300,000 bbl/d to the current 540,000 bbl/d without appropriate engineering analysis.
3. Multiple configuration changes to Line 5 including the addition of drag reducing agent injection stations without any MPSC records documenting the appropriateness of these changes.
4. Failure of the external protective coating system on the Straits sections of Line 5 resulting in the loss of mandated abrasion protection with subsequent coal tar water barrier abrasive failure and expected corrosion.
5. Mussel encrustation adding stress and a corrosive environment to the Straits sections of Line 5 which was not addressed by the reports supplied by Enbridge to the Task Force.
6. The unwillingness of Enbridge to supply any summary information regarding the multiple In Line Inspections of Line 5. A root cause of the pipeline failures mentioned above was the poor quality of the associated ILI data coupled with unrealistic repair/replace criteria used by pipeline operators.
7. The encroachment of subdivisions and commercial operations on the right of way of Line 5 which results in a much greater hazard to life and property should Line 5 rupture than was originally intended by the MPSC.

My analysis to date of these issues, as documented by several attached reports, now leads me to the conclusion that Line 5 is far more likely to present an imminent threat to health and property than not. This forces me to the ethical conclusion that immediate action should be taken to assure the safety of Line 5 while the legal deliberations go on. **It is my professional opinion that line 5 should be de-rated to its original design capacity of 300,000 bbl/d to reduce the stress on this very old pipeline and its cargo should be restricted to LPG until a full independent analysis of its safety can be made using modern methods and all the information that exists.**

APPENDIX 2A

Ed Timm, Ph.D.

Regarding Operating Pressure Limits and Wall Thinning by Corrosion in Line 5

When Enbridge's 645 mile Line 5 was originally conceived in 1953 the Michigan Public Service Commission (MPSC) approved plans for a 30" Pipeline (2 x 20" under the Straits) without any pump stations in Michigan and a capacity of 120,000 bbl/d. MPSC Order No. D3903-53.1 dated March 31, 1953 and MPSC Order D-3903—53.2, dated May 29, 1953 allowed for the construction of this pipeline with up to four pump stations in Michigan and a capacity of 300,000 bbl/d.

Through a series of fifteen MPSC orders culminating in MPSC Order U-8701 dated April 14, 1987 the capacity of Line 5 was increased to over 500,000 bbl/d through the construction of additional pump stations. MPSC documentation reveals that as many as 19 pump stations in Michigan were proposed at differing times as required to operate Line 5 at more than four times the flow capacity intended without any pump stations. The historical record is not clear as far as which of these stations were actually constructed or constructed and later abandoned resulting in the current configuration of Line 5 with twelve pump stations in Michigan. Table 1. lists these stations along with their approved maximum discharge pressures while Table 2. lists the pump stations that are mentioned in MPSC documentation but were not constructed or abandoned.

Table 1. Current List of Line 5 Pump Stations

2015 Pump Stations	Present Maximum Discharge Pressure, (psig)
Gogebic	633
Iron River	703
Rapid River	633
Manistique	701
Gould City	775
Naubinway	698
Mackinaw	701
Indian River	703
Lewiston	633
West Branch	642
Bay City	779
North Branch	701

Table 2. List of Line 5 Pump Stations Abandoned or Not Constructed

Pump Stations	Present Maximum Discharge Pressure, (psig)
Wakefield	534
Watersmeet	579
Arnold	498
Eagles Nest	602
Vanderbilt	607
Vassar	654
Brockway	614

According to MPSC documentation it appears that the original construction of the non-Straits sections of Line 5 used 30" pipe with varying wall thickness and strength specifications. It is common to construct cross country pipelines using so called "telescoped" construction where pipe wall thickness is reduced as the distance from a pump station increases and pressure falls due to friction between the cargo and the walls of the pipe. The fact that the non-Straits sections of Line 5 uses pipe with 9/32", 5/16", 11/16" and 3/8" wall thickness at various locations suggests that Line 5 was constructed following usual practice and pipe with quite thin walls is used some places.

When a pipeline like Line 5 is retrofitted with additional pump stations to increase capacity, each section between pump stations is treated as a separate pipeline segment with associated pressure limitations on each section. Enbridge has followed this practice with Line 5 and all the pipe segments between the pump stations listed in Table 1. has an individualized pressure restriction. In the numerous MPSC orders regarding the changes necessary to increase the capacity of Line 5 from its original design of 300,000 bbl/d to its current capacity of 540,000 bbl/d, Enbridge frequently states that the pressure limitations found in Table 1. do not exceed 65% of the calculated yield pressure for that pipe segment. This is consistent with ASME B31.4 "Transportation Systems for Liquid Hydrocarbons and Other Liquids" which has the force of law regarding the design of oil pipelines. ASME B 31.4 requires that the maximum pressure on a pipeline segment be no more than 72% of the system yield pressure which implies a design safety factor of 1.39.

By choosing to operate its system at 65% of yield pressure instead of the 72% allowed under ASME B31.4, Enbridge has increased the safety factor on its system to 1.54. Even though Enbridge could transport more oil by operating its system at the maximum allowed by code it has chosen to add an allowance of 7% (72%-65%) to increase the safety of the system. It is likely that this 7% allowance reflects a conservative rating for what is a very old pipe. Considering this as a corrosion allowance would allow for a 7% wall thickness loss over the service life of the pipe while still complying with ASTM B31.4. Thickness losses of more than 7% would put the non-Straits sections of Line 5 out of compliance with B 31.4 and require repair or replacement of the affected pipe segment.

In spite of the efforts of the Governor's Task Force regarding Line 5, there is very little publicly available data regarding the internal and external corrosion of Line 5 over its current 62 year service life. In a report titled Enbridge Energy Partners, Limited

Partnership, Operational Reliability Plan, Line 5 and Line 5 Straits of Mackinac Crossing (https://www.enbridgepartners.com/~/media/EepEeqMep/Site%20Documents/Shared%20Content/Media%20Center/Enbridge_Line_5_Operational_Reliability_Plan.pdf?la=en) Enbridge presents data on average corrosion rates for Line 5. Table 3. is taken from this 2014 Enbridge report.

Table 3. Enbridge Corrosion Data

Enbridge Operational Reliability Report on Corrosion Rates

P. 14 **Industry Guidelines for CGR Compared to Line 5 CGRS**

Standard/Guideline Recommendations	
NACE RP0102	0.3mm/yr: 80% confidence max rate with 'good' CP
ASME B31.8S	0.31mm/yr max rate for active corrosion in low resistivity soils
GRI-00/0230	0.56mm/yr for pitting; 0.3mm/yr for general corrosion
Line 5 Avg. Rates	External Corrosion 0.038mm/yr – 0.068mm/yr
Line 5 Avg. Rates	Internal Corrosion 0.018mm/yr – 0.046mm/yr
Line 5 Straits of Mackinac	**Int. and Ext. Corrosion No observed corrosion growth**

p. 15 **Line 5 In-Line Inspection Metrics — Cracking**

Depth of ILI Crack Tool Anomalies			
Feature Depth	0.040" - 0.080"	0.080" - 0.120"	> 0.120"
# Features	661	48	0
# Features per Mile	1.032/mi	0.070/mi	0.000/mi

Table 3. compares the average corrosion rates for the non-Straits sections of Line 5 with industry norms and concludes that the rates found for Line 5 are very low compared to the industry norms. Although the rates reported by Enbridge are very low, Line 5 is very old and a calculation of the effect of these rates over time is warranted.

Table 4. is an EXCEL spreadsheet that abstracts the data shown in Table 3. and compares the resultant wall thinning over 62 years of service with the wall thicknesses of the pipe used in Line 5.

Table 4a. Extrapolation of Average Corrosion Rate over Service Life

	Lower Value	Upper Value	Average	
Internal Corrosion Rate, (mm/yr)	0.018	0.046	0.032	
External Corrosion Rate, (mm/yr)	0.038	0.068	0.053	
Average Internal Corrosion Rate, (in/yr)			0.0013	
Average External Corrosion Rate, (in/yr)			0.0021	
Years in Service		62		
Total Internal Corrosion over Service Life, (in)			0.078	
Total External Corrosion over Service Life, (in)			0.129	

Table 4b. Wall Thinning of Line 5 Pipe by Extrapolated Corrosion Rates

Pipe Size	Wall Thickness	Average External Thickness Loss	Average Internal Thickness Loss
30" x 9/32	0.281	46%	28%
30" x 5/16	0.312	41%	25%
30" x 11/32	0.344	38%	23%
30" x3/8	0.375	34%	21%
30" x 1/2	0.500	26%	16%
30" x 11/16	0.687	19%	11%
20" x 7/8*	0.813	16%	10%

* Straits sections of Line 5 have unique pressure restrictions and do not meet the 65% criteria.

As can be seen from Table 4b., the 7% corrosion allowance used by Enbridge to establish safe working pressures on the non-Straits sections of Line 5 appears to have been exceeded by a significant margin over the 62 year life of Line 5. This calculation results in the conclusion that, based on the only data available from Enbridge or other public sources, the pressure limits set by MPSC order in the past no longer comply with the requirements of ASTM B31.4 and should be re-considered based on a thorough examination of all data that exist regarding the current amounts of wall thinning due to corrosion on Line 5.

A further consideration regarding appropriate safety factors and pressure limitations on Line 5 involves the nature of the cargos carried and real estate development that has occurred since 1953 when the line was constructed. As much as 20% of the cargo carried by Line 5 is believed to be Natural Gas Liquids (NGL) which is a mixture of ethane, propane and butane that exists as a gas at atmospheric pressure and temperature. In the event of a rupture, NGL's vaporize and present the fire and explosion hazard typically found associated with high pressure natural gas lines. The fire and explosion hazard associated with gas pipelines has resulted in a separate section of the ASME Piping Code titled ASME B 31.8 "Gas Transmission and Distribution Piping systems."

ASME B31.8 requires gas transmission piping to use much higher design safety factors particularly where the pipes transit heavily habitated areas. This is done because the risk of catastrophic explosion with resultant loss of life is much greater when a gas cloud forms after a pipeline rupture than it would be with an oil spill which primarily presents an ecological hazard. Table 5. is abstracted from ASME B31.8 and presents the safety factors required under code for gas transmission lines in varying areas.

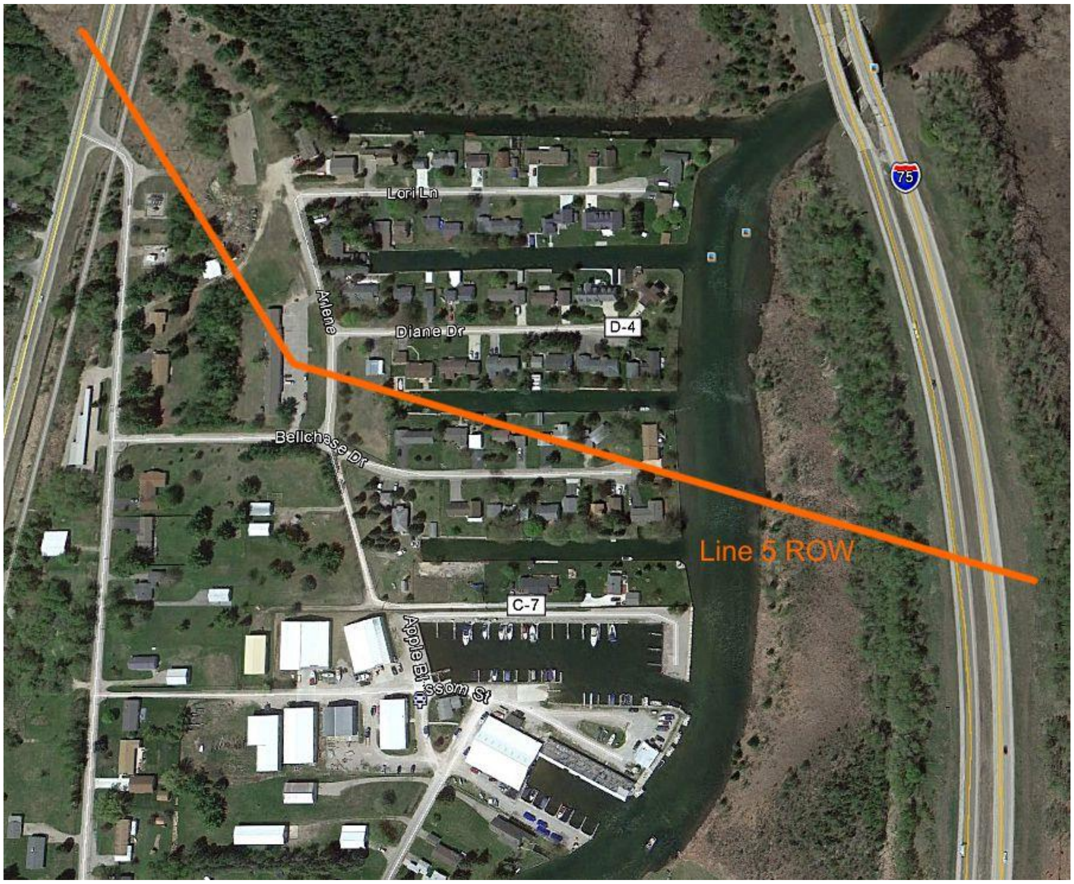
Most of the route take by Line 5 covers rural territory and the safety factor for Class 1, Division 1 or 2 service would be applicable and is consistent with the safety factor required under ASTM B 31.4 as used for the design of Line 5. However, some sections of Line 5 have had developed within the easement location and would meet the requirements of Class 3 or Class 4 service if Line 5 is considered as a gas transmission pipeline when carrying NGLs.

Table 5. ASME B31.8 Limitations for GAs pipelines in Populated Areas

Table 841.114A, Basic Design Factor, F		
Location Class	Design Factor, F	Safety Factor
Location Class 1, Division 1	0.8	1.25
Location Class 1, Division 2	0.72	1.39
Location Class 2	0.6	1.67
Location Class 3	0.5	2.00
Location Class 4	0.4	2.50

A good example of this kind of post construction development can be found where Line 5 crosses the Indian River in Cheboygn County. When Line 5 was constructed the area shown in Figure 1. was a marsh. Now a canal subdivision and marina sit above Line 5.

Figure 1. Indian River Crossing of Line 5 Showing Post construction Development



It is possible to argue that when Line 5 carries NGLs it should legally be classified as an gas pipe line and ASME B 31.8 safety factors should apply. The residents of the area shown in Figure 1. are at the same risk when Line 5 is transporting NGLs as they would be if it was a gas transmission line rated for Division 3 or Division 4 service. The example shown in Figure 1. is one of many areas where development has encroached on the Line 5 right of way. The question of whether the appropriate safety factors exist and Line 5 is in compliance with code should be carefully considered due to this kind of encroachment. Regardless of the niceties of the ASME code, Line 5 presents all the hazards of a gas transmission line when carrying natural gas liquids or propane.

APPENDIX 2B

Ed Timm, Ph.D.

Regarding the Protective Coating and Support Requirements of Line 5.

Effective corrosion protection and support are critical to the longevity of pipelines. This fact was recognized by the State of Michigan when permission to build and operate Line 5 was granted in 1953. The following documents support this conclusion:

1953 Easement Restrictions Regarding Corrosion Protection and Support

(8) Cathodic protection shall be installed to prevent deterioration of the pipe

(9) All pipe shall be protected by asphalt primer coat, by inner wrap and outer wrap composed of glass fiber fabric material and one inch by four inch (1” x 4”) slats prior to installation.

(10) The maximum span or length of pipe unsupported shall not exceed seventy-five (75) feet.

1953 MPSC Order Regarding Corrosion Protection

The entire pipe line will be properly cleaned, primed, and coated with a single application of coal tar. The coating will be reinforced by a spiral wrap of glass material and covered by a spiral wrap of special glass outer wrap. Penetrations will be made for cathodic protection.

Engineering and Construction Considerations for the Mackinac Pipeline Company’s Crossing of the Straits of Mackinac” submitted by Mackinac Pipeline Company/Lakehead Pipeline Company to the Michigan Department of Conservation, January, 1953

After coating with asphalt primer, fiberglass inner wrap and an asbestos felt outer wrap, and after attaching 1” x 4” wood slats to the full circumference of the pipe, it will be lowered onto a previously prepared “bed” on the floor of the Straits.

While there is some inconsistency in these documents concerning the exact details of Line 5, the language regarding the coating system for the Straits sections of Line 5 as found in both the Easement and the Engineering report is consistent. Because the unburied Straits sections of Line 5 rest on a prepared gravel bed and is not supported off the lake bottom, it is critical to the long term longevity of this line that there is a layer of wooden slats around the circumference of the line to prevent abrasion of the coal tar water barrier coating. Otherwise, the motions of the pipe as it shifts on its gravel bed due to temperature gradients, currents and internal pressure changes would cause water barrier coating failure due to mechanical abrasion.

Recent underwater surveys by both Enbridge and the National Wildlife Federation reveal that the mandated slats are no longer in place. At the time Line 5 was placed in the Straits, these slats were held in place by circumferential steel bands. These bands appear to have rusted away and the slats they once secured are missing. Figure 1. is a photo taken by the NWF that shows the rusted out circumferential bands and Figure 2. is a photo clipped from an Enbridge video that appears to show what remains of the slats the previously encircled the pipe.

Figure 1. Picture of Line 5 Taken by NWF that Erroneously Identifies Corroded Circumferential Bands as Broken Supports

Figure 2. Frame Clipped from Enbridge Video Apparently Showing Detached Slats

Because washouts caused by unforeseen currents in the Straits have left sections of the pipe unsupported in violation of seventy five foot requirement stated in the 1953 easement, Enbridge has been retrofitting the Straits Sections of Line 5 with modern, screw anchor supports. Enbridge Table 2. is a summary of these efforts.

Table 2 ROV Inspection and Span Support Installation History of Line 5 Straits of Mackinac

Year of ROV Inspection	Follow up Actions (Anchor Support Installation)	Type of Support Installed
1963	None	
1972	None	
1975	3	Grout Bags
1979	None	
1982	None	
1987	7	Grout Bags
1989	None	
1990	None	
1992	6	Grout Bags
1997	None	
2001	8	Grout Bags and mechanical support
2003	16	Mechanical Screw Anchors
2004	16	Mechanical Screw Anchors
2005	14	Mechanical Screw Anchors
2006	12	Mechanical Screw Anchors
2007	None	
2010	7	Mechanical Screw Anchors
2012	17	Mechanical Screw Anchors

As can be seen from this table, there has been a continuing effort since 1975 to comply with mandated support requirements. This effort culminated in 2014 when a large number of supports were added and a table of all supports in place was submitted by Enbridge to the Attorney General in response to a query about the adequacy of support. This table can be found in the online report of the governor's Pipeline Task Force in the following document. Appendix_B4_493991_7.pdf. By summing the lengths of the supported spans in this document and computing the distance between the burial exits of both segments of the Straits sections of Line 5, it can be shown that about:

1. The East span is supported off the lake bottom for a distance of 1.03 out of 2.1 miles of unburied pipe,

2. The West span is supported off the lake bottom for a distance of 1.02 out of 2.3 miles of unburied pipe.

Based on the numbers presented above, over 50% of the unburied sections of the Straits sections of Line 5 still rest directly on what remains of the bed prepared in 1953 on the Lake Michigan bottom. This part of Line 5 appears to have lost its abrasion resistant lagging of wooden slats due to corrosion of the circumferential retaining bands and is subject to abrasive attack on the coal tar water barrier coating. This is a clear legal violation of the terms of the 1953 easement and is not something contemplated in the original design of Line 5. Technically, it can be expected that the unburied, unsupported off the bottom sections of Line 5 are suspect for coating failure due to mechanical abrasion with resultant accelerated corrosion.

APPENDIX 2C

Regarding Enbridge Line 5 Pump Station Reconfiguration and the Use of Drag Reducing Agents

From March, 1953 when the MPSC granted permission to the Lakehead Pipeline Company to construct Line 5 through April, 1993 the MPSC issued about twenty five orders regarding the configuration of Line 5. Pump stations were added, pressure limitations were changed, new valve stations were inserted and other mechanical details were modified during this period. Following the April, 1993 MPSC order FOIA requests have not revealed any further MPSC orders until July, 2012 when Enbridge notified the MPSC that it intended to make changes to several pump stations along Line 5. This informal notification was followed by a notification of the changes made by Enbridge in June 2014. No formal MPSC orders appear to have been issued regarding these changes or any other changes to Line 5 in the period from April, 1993 until June, 2012.

Line 5 was reconfigured from its original design through a series of MPSC orders culminating in MPSC Order U-8701 dated April 14, 1987 which finalized the maximum allowable discharge pressures at the nineteen pump stations listed below.

1. Arnold
2. Bay City
3. Brockway
4. Eagles Nest
5. Gogebic
6. Gould City
7. Indian River
8. Iron River
9. Lewiston
10. Mackinaw
11. Manistique
12. Naubinway
13. North Branch
14. Rapid River
15. Vanderbilt
16. Vassar
17. Wakefield
18. Watersmeet
19. West Branch

As of the current date, Enbridge documentation shows that there are a total of twelve operating pump stations in Michigan on Line 5. The locations of the current pump stations are listed below.

1. Gogebic

2. Iron River
3. Rapid River
4. Manistique
5. Gould City
6. Naubinway
7. Mackinaw
8. Indian River
9. Lewiston
10. West Branch
11. Bay City
12. North Branch

As can be seen from comparing these lists, Enbridge appears to have abandoned six intermediate pump stations along Line 5. This action has been taken while maintaining the flow capacity of Line 5 above 500,000 bbl/d and without raising pressure ratings. The manner in which this engineering feat was accomplished raises two questions.

1. What technical changes were made that allowed capacity to be maintained while removing six pump stations?
2. Why aren't there any MPSC orders documenting the reconfiguration of Line 5 in the period from 1993 through 2012?

The answer to the first of these questions will be considered below while the answer to the second question is beyond the scope of this document and is legal in nature.

After the 1972 OPEC oil embargo the petrochemical industry developed technology to maximize the flow capability of pipelines. It was found that the injection of small quantities of certain long chain polymers could suppress boundary layer turbulence in pipeline flow resulting in a significant reduction in wall friction. In controlled experiments, it was found that as little as 50 parts per million (ppm) of injected polymer could cut friction losses up to 80%. This technology was enthusiastically adopted by the pipeline industry which resulted in the need for fewer pumping stations to achieve rated flow without increasing pressures. These substances when used in pipelines are called drag reducing agents (DRAs).

In a letter to the MPSC dated July 16, 2012 Enbridge notified the MPSC of a project to modify several Line 5 pump stations. Quoting from this latter: "The scope of this project, referenced as Line 5 - DRA Project ("Project"), involves the installation of new, and replacement of existing, DRA (drag reducing agent) skids, including all valves and appurtenances, as described in more detail on Table No. 1 below. In addition, the Project involves making certain minor modifications to the header piping and pumping assemblies at Indian River and Bay City Station sites, and installing a spare meter run at the existing Marysville Station in Marysville, Michigan."

Table No. 1 Project Scope for Line 5 – DRA Project					
Exhibit No	Station	State	County	Scope of Work	Station Plot Plan
B.1	Gogebic	MI	Gogebic	• Install new DRA skid including all valves and appurtenances	B.1.a
B.2	Iron River	MI	Iron	• Deactivate existing DRA skid • Install new DRA skid including all valves and appurtenances	B.2.a
B.3	Gould City	MI	Mackinac	• Install new DRA skid including all valves and appurtenances	B.3.a
B.4	Indian River	MI	Cheboygan	• Deactivate existing DRA skid • Modify existing pumping assembly including all unit piping, valves and appurtenances • Replace certain station header piping including all valves and appurtenances	B.4.a
B.5	Bay City	MI	Bay	• Deactivate existing DRA skid • Install new DRA skid including all valves and appurtenances • Modify existing pumping assembly including all unit piping, valves and appurtenances • Replace certain station header piping including all valves and appurtenances	B.5.a
B.6	North Branch	MI	Lapeer	• Deactivate existing DRA skid • Install new DRA skid including all valves and appurtenances	B.6.a
B.7	Marysville	MI	St. Clair	• Install spare meter run including all valves and appurtenances at existing meter station site	B.7.a

As shown in the above table, Enbridge notified the MPSC that it plans to make changes to several pump stations primarily involving the addition of skid mounted units intended to inject drag reducing agents into Line 5. The text of this letter makes it clear that some of these skid units are being moved from previous locations on Line 5. An Enbridge letter dated June 5, 2014 confirms the completion of this construction project. These letters coupled with the 1993-2012 chronological gap in MPSC documentation raises several questions of procedure and substance.

1. The documentation gap mentioned above suggests either a loss of critical safety information regarding operation pressures and procedures on Line 5 or a change in MPSC procedures where the documentation of critical changes is either held in confidence or missing.

2. Very significant changes occurred in the 1993-2012 time frame including the apparent abandonment of six pump stations and the addition of many drag reducing polymer injection units. No information is available regarding how these changes impacted Line 5 pressure profiles, compliance with ASME piping codes or other matters that affect Line 5 safety.

3. The use of drag reducing agents to reduce pumping losses in pipelines is a widely employed technology, however, it is not without risk. These agents are usually long chain polymers which break down due to turbulent shear forces and lose their effectiveness. This is why more agent must be added at intervals along the pipeline to maintain the reduced wall friction that makes these agents effective. The use of drag reducing agents can have unintended consequences which affect operational reliability and safety. Among these consequences are the following:

    a. DRA injection modifies the pressure profile along the length of the line. This profile is usually a linear function of distance from the injection point but, because the DRA degrades along the length of the pipe, pressure profiles become non-linear and may exceed expected values.
    b. Failure of DRA injecting equipment can result in sudden pressure spikes resulting in unsafe pressures that exceed code and regulated pressure levels with subsequent possibility of pipe rupture.
    c. Because DRA's are only effective at high flow rates or Reynolds numbers, initiating flow in a line containing DRAs can cause elevated pressures until flow is fully established. This transition from flow rates where DRAs are ineffective to flow rates where DRAs are effective can cause flow instabilities and pressure spikes with unintended consequences.

Because of the chronological gap in the MPSC record for Line 5, it is impossible to determine if Line 5 is being operated in compliance with MPSC orders and applicable codes. Similarly, the use of DRAs in Line 5 seems to have been developed without Enbridge submitted engineering calculations and other descriptions that would have made it possible to address some of the issues mentioned above. Because of these omissions coupled with the considerations raised in the previous briefs, the operating condition of Line 5 cannot be determined from the public record and it appears the MPSC is allowing Enbridge to operate Line 5 in ways that were not contemplated by the original designers and in ways that may present a greater hazard of rupture than was intended by the State of Michigan when it granted permission to construct this line.

APPENDIX 2D

Quality Control and Interpretation of Pipeline In-Line-Inspection (ILI)

Ed Timm, Ph.D.

All aging steel pipelines are structurally degraded as a result of erosion, corrosion, cracking and mechanical damage. The pipeline industry addresses this loss of structural integrity through inspection technology that attempts to determine the extent of this damage in conjunction with structural models that attempt to predict the effect of the damage on safe operation. Since most pipelines are buried and covered with protective coating systems, external inspection is often impractical. The pipeline industry relies on internal inspection technology in the form of instrumented pipeline "pigs" that are pushed through the pipe while recording data. These instrumented pigs or "smart pigs" utilize mechanical, magnetic and ultrasonic sensors to measure the damage to the line and subsequently allow the calculation of the hazard presented by age related damage. The areas of the pipe that are found by smart pigs to be compromised are called "features" and the use of in line inspection (ILI) technology to characterize these features enables the presumably safe operation of aging pipelines.

As is usual in the process industries, pipeline in line inspection is the subject of numerous industry developed standards that describe best practices with the aim of producing reliable, reproducible and accurate measurements. API 1163, In-Line Inspection Systems Qualification, and NACE SP0102, In-Line Inspection of Pipelines, are the cornerstone standards governing the in line inspection of pipelines. These standards lay out in great detail how to conduct an in line inspection, generate appropriate documentation and verify the quality of the data produced. These standards do not cover any aspect of the actual ILI technology used although they do cover how to determine how well the chosen inspection technology conforms to manufacturer's specifications. Neither of these standards say anything about how ILI data is to be interpreted to verify the safety of the line.

Raw ILI data is processed using proprietary computer applications to categorize and quantify the size of the various features detected by the ILI run. Features are categorized as pits, trenches, cracks, crack colonies, overall metal loss, etc. and their locations and sizes are calculated. The most severe of these features are then subjected to engineering analysis to calculate their probable risk of causing a rupture. Pipeline operators use this information to schedule repair or replacement of any pipe with features that exceed company criteria for risk of rupture. Many ILI contractors offer a complete "pipeline integrity management program" that takes responsibility for assuring the integrity of a line and the quality of the ILI data on which decisions are based.

API 1163 provides a complete roadmap to the process of assuring the quality of ILI data. An individual inspection run on a pipeline may be validated as either Level 1, Level 2 or Level 3 depending on the quality of both the documentation and the data. A Level 1 validation means that the measuring instruments appear to have worked to manufacturer's standards and the documentation meets minimal standards. A Level 3 validation requires very extensive documentation as well as testing to determine the accuracy and sensitivity of the instruments used. Many complex statistical criteria are set forth in API 1163 to assure data quality from a Level 3 run. Beyond these internal checks for data quality, API 1163 also recognizes the importance of using ILI data to locate significant features in the pipe wall then digging up the pipe and examining these features in detail. The very best data is produced when the feature is actually cut out of the pipe and examined in a lab where is compared to the ILI data. If the type, location and size of the features found in the metallurgical lab coincides with the information about them produced by the ILI run, the pipeline operater can have high confidence in the data and subsequent risk analysis.

When a group of objects are measured with two different techniques, statisticians have a simple method of visually evaluating the quality of the data. A plot that has the size of features determined by one measurement technique as a horizontal axis and the size of the same features as determined by a different technique as the vertical axis is called a scatter plot. If the size of an individual feature is determined to be the same by both measuring techniques, the point will fall on an equiaxedb line. Points on this line represent perfect agreement between measuring techniques and points off the line indicate the two techniques are giving different results. Usually, the measurement technique considered most reliable is plotted on the horizontal axis.

API 1163 incorporates the scatter plot method (so called because the data scatters around the line of perfect correlation) to quickly assess data quality. In the ILI industry these plots are called "Unity Plots" because they attempt to unify the ILI data with the measurements produced by digging up the pipeline and physically inspecting the significant features. An example of a unity plot is given in API 1163 as Figure C.1. In this plot the size of a feature as a fraction of original pipe wall thickness as determined by physical inspection (the Ditch Depth (wt%)) is on the horizontal axis and the size of the feature as determined by the ILI instrumentation is plotted on the vertical axis (ILI Depth (wt %)). The red line represents perfect correlation between the two measuring techniques, a condition that rarely happens. Since each data point on a unity point is a result of both an ILI inspection run and costly excavation with subsequent physical inspection, unity plots are expensive to produce. However, since hazardous features are repaired during the physical inspection process the overall cost to a pipeline operator is mostly in the form of documentation and analysis.

In Figure C.1, all data points that fall above the red line are of features where the ILI instrumentation measured the feature to be bigger than it turned out to be on examination. Inversely, all data points that fall below the line are of features that turned out to be bigger than the ILI measurement. While a certain amount of scatter will always exist when something is measured using two techniques, a unity plot that shows a lot of data lying far from the line of perfect correlation suggests problems with the overall data quality of the ILI run. Data points far from the correlation line in the lower right corner of the unity plot are particularly undesirable because these are points where the ILI instrumentation has under-measured a feature by a large margin. Under-measurement means there are features that may well cause pipeline rupture in the future that are not examined for potential hazard and subsequent repair.

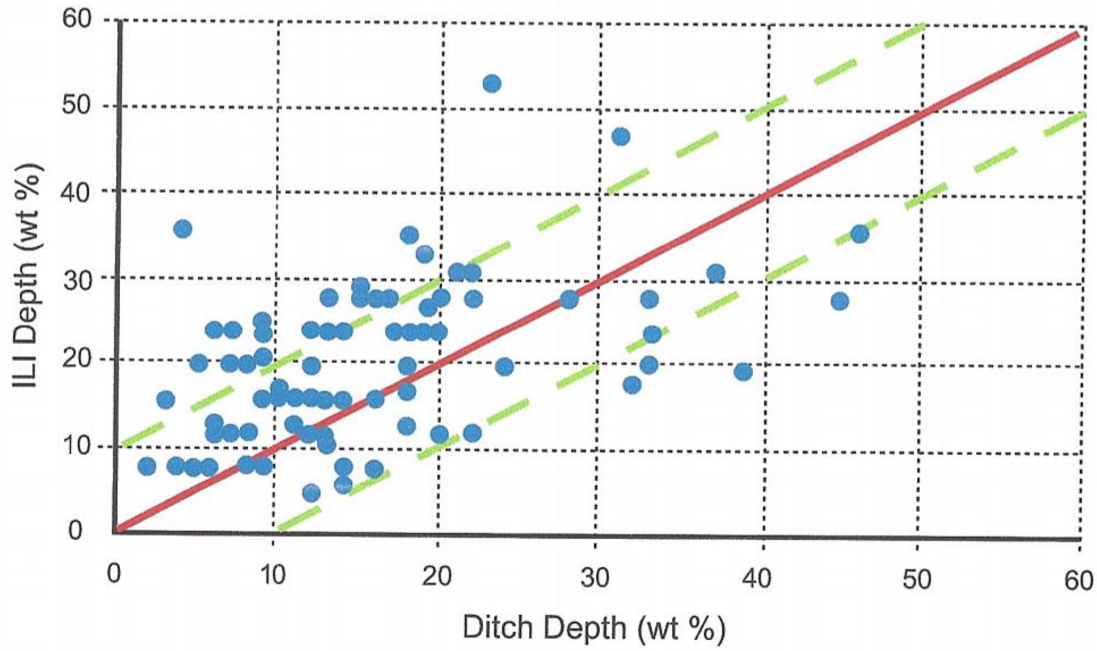


Figure C.1—Unity Chart Example

Figure C.1 is a typical example of a unity plot for pit, trench or other thickness loss features but similar plots can be prepared for measurements of individual cracks and midwall crack colonies.

When pipeline operators discuss In Line Inspection (ILI) and the resultant Integrity Management System (IMS) it is important to remember that all such activity is not equal. An IMS that relies on ILI data that is only validated to Level 1 or Level 2 may well not utilize data of high enough quality to assure pipeline safety. Even an integrity management program that utilizes data validated to Level 3 will not be successful unless the data is analyzed in a way that critical flaws are detected and promptly repaired by the pipeline operator. The critical flaw in Enbridge Line 6B was detected by numerous ILI runs according to PHMSA reports but it was not repaired because the models and criteria Enbridge used to trigger repair action were unrealistic. Ultimately, ILI data should result in lines that are flawed beyond realistic repair being shut down and replaced.

APPENDIX 3

FLOW Technical Advisory Team Line 5 Immediate Implementation and Action Plan for Enbridge Line 5 –

FLOW Science Advisory Team, August 31, 2015

The MPPTF issued recommendations, if implemented through immediate action, will aid risk reduction, safety, and water, environmental, and protection of public property and communities for pipelines in Michigan (*Michigan Petroleum Pipeline Task Force Report, July 2015*[1]) and the Enbridge Line 5 crossing at the Straits of Mackinac, in particular. MPPTF was launched by Governor Snyder and led by Attorney General Bill Schuette and DEQ Director Dan Wyatt. The report was a key MPPTF deliverable, and now the next step is to establish a high priority action plan to act promptly on the recommendations, especially those that are relevant or applicable to the completion of the specific recommendations for Enbridge Line 5.

This paper presents background information for an action framework to implement the recommendations for Line 5. Because of the high level of risk and high magnitude or unacceptable harm that the Enbridge Line 5 poses in and under the Mackinac Straits crossing segment, there are two basic categories of actions that need to implemented, in parallel, immediately:

A. **Convene, Conduct, and Complete the Alternatives Assessment** This will require involvement of multiple stakeholder groups and subject-matter experts. Although the alternative assessment could take some time to complete from the initiation to the implementation of the best alternative to eliminate the risk of a crude oil spill in the Straits of Mackinac, it should be undertaken immediately.

B. **Immediately Impose and Implement Stringent Measures to Reduce the High Level Risk to a Temporary Lower Risk Pending Completion of the Alternatives Assessment and Implementation.** This requires temporary measures that can be immediately imposed and accomplished, including temporary halt or reduction of flow of crude oil through Line 5 under the Straits segment necessary to remove transport of oil in Straits from "Tier 1" or unacceptable risk of high magnitude of harm, additional monitoring, staging of emergency response resources and personnel at the Straits capable of responding to an approved scenario for a major release, assessment of credible worst case release scenario, review and establishment of adequate financial assurance to cover a worst-case release; note that the temporary measures for response capability, and financial insurance and assurances must be maintained until the alternative option for risk elimination is fully implemented.

For convenience, the MPPTF recommendations are listed below in abbreviated form. As noted later in this Immediate Implementation Action Plan Report for Line 5 under the Straits of

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[1] MPPTF Report

Mackinac, it should be noted that general recommendations 5, 9,11, 12, and 13 should be complied with in order to implement the specific Line 5 recommendations 1 through 4.

Straits Specific Recommendations

1. Prohibit transportation of heavy crude oil
2. Independent risk analysis and adequate financial assurance
3. Independent and comprehensive alternatives analysis and assessment
4. Obtain all necessary additional information from Enbridge to implement MPPTF Recommendations for Line 5.

Statewide Recommendations for Petroleum Pipelines in Michigan

5. (1) Coordinate mapping of existing pipelines
6. (2) Collaborate on emergency planning and spill response
7. (3) Coordinated emergency response training exercises and drills
8. (4) Regular consultation with federal Pipeline and Hazardous Materials Safety Administration (PHMSA)
9. (5) Consider legislation on oil spill response plans, reporting and robust civil fines
10. (6) Evaluate a Hazardous Liquids Pipeline Safety Program
11. (7) Consider legislation to improve new petroleum pipeline siting process
12. (8) Consider an Executive Order creating a Pipeline Safety Advisory Committee
13. (9) Create a continuing Petroleum Pipeline Information website

1. High or Unacceptable Risk - The Situation That Exists Today

Substantial risks have been identified within the MPPTF Report and other sources that place it in a "Tier 1" or unacceptably high risk category. Under these conditions standard protocol requires immediate action to (1) if possible reduce the risk below a so-called "Tier 1"[2] category pending implementation of final action; (2) assess, decide, and implement final action to eliminate the high or unacceptable risk. Accordingly, the following information is provided to understand the serious degree of risk and harm regarding the Line 5 segment under the Straits of Mackinac.

Oil and Gas, transportation, and insurance industry and government practices define and manage "risk" as a function of "probability" and "consequences" (risk = probability X consequences). The MPPTF Report highlights the catastrophic consequences of a leak from a Line 5 failure at the Straits. One component of risk, the probability of a leak or major failure is not addressed because Enbridge will not provide the MPPTF or stakeholders with adequate information to understand or determine the likelihood of a failure. Broad, overly optimistic comments by Enbridge on Line 5 operations and mechanical integrity do not standup to basic scrutiny by scientific, engineering and pipeline experts. Based on information that is available, such as other pipeline failures, assessments of failure modes and published probabilities, and pipeline integrity management programs, it is concluded that **the probability that a single or combination of failure modes could lead to a leak in the Straits is a "Tier 1" risk and**

2

<u>unacceptably high. This risk requires immediate temporary and long-term measures to eliminate this high unacceptable risk</u>.

Using the basic definition of "risk" as a function of "probability" and "consequences" (risk = probability X consequences), qualitative and quantitative risk assessments typically categorize risks into 3 tier levels. Required actions for the lowest risk, Tier 3 may include management procedures and close monitoring. Required actions for Tier 2, the medium tier, require elimination or at least a reduction to Tier 3 within 2 years and if an immediate reduction cannot be achieved; temporary measures to reduce the level to a Tier 3 during the mitigation period are required.

Industry actions for the highest risk level, <u>Tier 1, which is the current risk level for Line 5</u> at Straits Crossing, require one of two options.

Option 1: Immediately remove oil from transport through Line 5 in the Straits segment until the high unacceptable risk can be eliminated; or

Option 2: Immediately identify and implement temporary measures to eliminate, impossible, and if no alternatives exist to eliminate the risk; then reduce the risk (consequences, probability) until a permanent solution that eliminates the unacceptable risk is identified and in place. It should be noted as a matter of precaution, that temporary measures are typically not as effective as permanent measures, and are often based on monitoring and procedures that only temporarily mitigate the risk, but do not eliminate the unacceptable risk using inherently safe options or solutions. Approved temporary measures "buy time" for the Operator during the study, engineering and implementation periods for a permanent risk reduction solution.

Based on current information and the above, at present time, Option 2 is recommended as an approach for Line 5 under the Straits, unless at any time in the near future evidence indicates that the temporary measures are failing, insufficient, or there are additional or newly identified risks that render Option 2 no longer viable to mitigate risks to an acceptable level. In such event, Option 1, shutdown of the flow of oil under the Straits segment of Line 5, should be implemented immediately. Generally recognized risk management practice is to identify and reduce the current Tier 1 risk to a Tier 3 through the implementation of temporary measures. In other words, temporary mitigation to Tier 3 risks is not an acceptable final option, but is allowed if it reasonably can reduce risks from Tier 1 risks until a final option or solution is identified and implemented.

<u>2.</u> Immediate Action Plan to Implement Task Force Recommendations and Eliminate Unacceptably High Risk for Line 5

A. Alternatives Assessment

A key MPPTF recommendation is to conduct Alternatives Assessment, Recommendation # 3[1]. An Alternatives Assessment or an "analysis of alternatives" is used to identify, analyze and develop options for risk elimination or reduction. The approach is used to address a wide range of issues including private and government sector infrastructure, facilities, environmental protection, protection of public health, safety, property and communities, and establishment of sustainability projects. The purpose of an Alternatives Assessment is to move beyond the justification of a single alternative, in this case the existing Line 5 Straits Crossing, which continues the underlying conditions and circumstances that result in a high risk category, to an exploration of multiple options to establish the best possible option in a rational defensible manner, which considers all stakeholder requirements for risk, uncertainty, and citizen, environmental, public safety, and public and private property protections.

The Alternatives Assessment will address or require information from several of the MPPTF recommendations, including Straits specific Line 5 recommendations 3 and 4, and statewide recommendations 5, 9, 11, 12, and 13. To identify and analyze possible options, work groups must be established and composed of stakeholders, qualified and independent subject matter experts, government and industry and company personnel. The assessment would identify all feasible alternatives, such as continued use of Line 5, other interstate and/or Canadian pipelines, different shipping modes, restriction of transportation to low environmental impact petroleum materials (NGL's or other lower risk products only), continuation of current operations and etc. After evaluation of this list of alternatives, a shorter-list of alternatives is developed; this short list is they evaluated, studied and analyzed in-depth analysis for feasibility, prudence, safety, health, and impacts on water and natural resources, environmental impact, communities, private and public property, infrastructures, facilities, services, and private and public property and their public and private uses, including commercial and recreational.

Based on the high Tier 3 or unacceptable risk of the Line 5 segment under the Straits, the state should establish immediately, not later than 90 days, an qualified independent board to identify and implement the Alternatives Assessment; the board should be charged with completion of its task as soon as reasonably appropriate, but not later than customary time frames for the risks and circumstances. On completion of the Alternatives Assessment, the alternative identified that eliminates or substantially reduces the unacceptable risk should be implemented.

Because an Alternatives Assessment also require independent risk analysis, including worse-case scenarios, and additional information from Enbridge or others, those recommendations, such as MPPTF specific recommendation 1 and 3, and state-wide recommendations 5, 9. 11, 12, 13 should be implemented simultaneously with the establishment of the Alternatives Assessment. The information and results should be provided to the Alternatives Assessment board.

As noted above and described in section B below, all required interim or temporary measures that are required to reduce the risk below a Tier 1 risk should me immediately identified, implemented, and in place pending completion of the Alternatives Assessment process.

A simplified process diagram for an Alternatives Assessment is presented in the attached **Appendix C.**

B. Immediate Identification and Implementation of Temporary Measures

Actions to reduce the existing Tier 1 risk at the Straits to at least a temporary Tier 3 level during the period when the alterative assessment is completed and a permanent solution identified and implemented are mandatory and normal industry practice. Specific temporary actions can be categorized as follows:

1. Limit the petroleum mix transported to lower environmental impact materials;
2. Establish safer operating conditions and set limitations;
3. Determine credible release scenarios for monitoring and emergency response;
4. Establish continuous monitoring for leaks and pipeline damage; and
5. Put in place a strong, local emergency response capability

1. Limit the petroleum mix transported to lower environmental impact materials [3]

Straits Specific Recommendation # 1 in The MPPTF Report prevents the shipment of heavy crude oil through Line 5. This action will prevent the shipment of the heavy tar sands and diluted bitumen grades of crude oil which are not currently transported in Line 5 and which Enbridge had previously stated that they have no plans for.

Currently, Line 5 transports natural gas liquids and crude oil. Restricting or limiting the petroleum mix to NGL's only would reduce unacceptable risk of harm and damage to a Tier 3 risk. NGL's if released at the Straits would evaporate or could be burned off the water-surface; shoreline and subsurface damage would be lower compared to a crude oil release. A safety risk would obviously still exist and be subject to all required and the other additional temporary measures.

2. Establish safer operating conditions and set limitations[4]

Several physical changes (installation of new pumps, valves, control systems and etc.) and operating condition changes (flow rate, pressure, temperature and etc.) have been made over the years upstream and downstream from Line 5 Straits Crossing. Current operations should be returned to conditions close to the less severe original design conditions to lower the risk for pipeline failure. The physical and operating changes implemented since Line 5 was installed can then be evaluated for risk and compliance to all management-of-change, notification and permitting requirements.

3. Determine credible release scenarios for monitoring and emergency response

[3] Ed Timm reference

[4] Ed Timm reference

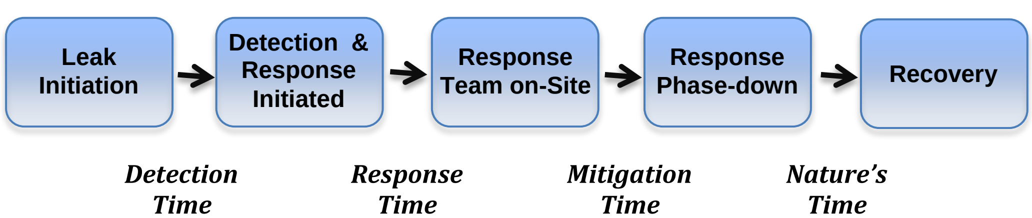
There are at least 2 basic release cases to consider for safety, environmental, community, public and private property and uses protections and response. Detailed, vetted and preferably state regulatory or otherwise legally and scientifically recognized scenarios should be developed for:

> a) Releases (leaks) below the detection threshold for the pipeline leak detection system and operating procedures[5]
>
> b) A "credible worst-case scenario" release from an accident, system failure or natural disaster

Recognized good engineering and emergency response practices for safety and environmental protection address the impact of events that can occur below the detection limits or accuracy of measurement, material balance and control systems. Typical measurement system accuracy for process and pipeline systems is +/- 1.0% to 1.5% of total flow. Given a daily Line 5 flow rate 23 million gallons, this could result in an undetected leak of 230,000 to 345,000 gallons per day. Environmental impact evaluations or assessments use 90 days or less as the period from leak initiation to eventual detection by the operator or a citizen. Discovery is often finding the presence of the spill on the shoreline of a lake or river. For the Straits, the winter ice cover and the absence of people along shorelines increases the probability that a leak below the system detection threshold could occur over a long time period.

An approved "credible worst-case scenario" (WCS) is essential information used in developing emergency response plans and putting resources in place. Current regulatory requirements for calculating a pipeline WCS are inadequate compared to EPA regulations for the refinery and chemical process industries. Several recent pipeline failures and releases are evidence that the failures greatly exceeded the planning scenarios, response plans and resources that were put in place by the pipeline operators. After investigation and corrective actions, the operators return to unrealistic worst-case scenarios, resulting in continued under estimation of planning and response requirements.

Using the release scenarios, the overall objective is then to minimize time lags. These time lags are:



"**Detection time**", the time from leak initiation to detection and initiation of response can be potentially long for leaks that are below the system detection threshold. Detection typically results from citizen reports on safety concerns or observation of environmental damage. For large spills, detection time is affected by Operator confidence in instrument and control systems and management, decision-making procedures.

---

[5] Gary Street reference

“**Response time**”, starts when the alarm is sounded and the necessary resources arrive on-the-scene. Obviously, the more remote the incident is from resources, resource availability and required type all affect the response time.

“**Mitigation time**” covers the time to stop the leak and complete the cleanup protocol. Oil spill cleanup depends on the composition of the material released, resources available, geography and terrain, on-shore, offshore and weather conditions. Time to cleanup can range from months to years and the results are often superficial and ineffective in rough terrain and offshore areas.

“**Nature’s time**” is the period required for natural processes to decompose the petroleum products and for the environment to recover. This period can be generations long in areas such as Northern Michigan where temperatures and biological activity to degrade residual crude oil is very low greatly extending the recovery time.

4. Establish continuous monitoring for leaks and pipeline damage

Normal industry practice, operating company senior management, regulatory agencies and stakeholders demand the implementation of temporary measures to reduce a Tier 1 risk to an interim acceptable level until a permanent solution is in place. “Business as usual” or cursory actions are not acceptable for a Tier 1 risk. Immediate interim actions need to be identified based on input from stakeholders; Enbridge, regulators and these actions should be approved, verified and routinely audited by the State.

Examples of measures that should be implemented include but are not limited to the following with the objective of reducing the critical “detection time” and as an additional layer-of-protection for existing detection system deficiencies:

- Increased oversight of control room operations specifically for Line 5, implement more effective, rapid, fail-safe decision-making processes
- Regulatory agency approved and audited maintenance integrity, calibration and management-of-change processes for Line 5 leak detection and emergency operation equipment (instrumentation, values, back-up electrical systems and etc.). In other words, implement “general duty” requirements as practiced by operators of high hazard processes such as under the Clean Air Act
- Implement daily physical-manual, on-the-scene shoreline and offshore inspections for evidence of spills in high probability areas as determined by modeling and stakeholder input
- Implement weekly physical-manual inspections for evidence of spills in the lower probability areas
- Physical shoreline and offshore inspection during winter conditions meeting daily and weekly requirements as noted above using special inspection processes for ice cover

- Increase underwater inspections (weekly/monthly) using remote-operated vehicles (CCTV/video) to detect Line 5 anomalies, damage, leaks and etc. to reduce the time from leak initiation to detection
- Issue quarterly updates on all near misses, anomalies, shutdown system activations, and challenges to the safety systems and actual incidents to appropriate Michigan regulatory agencies. This may not be required by current law but would be appropriate for an operator with a Tier 1 risk.

5. Put in place a strong, local emergency response capability

The MPPTF Report provides excellent comments and recommendations on information sharing, emergency planning and response. The large drill scheduled for September 2015 at the Straits is a very important element for protection of the Great Lakes. But it is also important to recognize that emergency response is used when a large spill has already occurred and in most cases, the response is limited in effectiveness in preventing widespread environmental damage.

- Extensive planning has occurred with Enbridge, the US Coast Guard, contractors and public sector response agencies for the September 2015 drill based on news reports. As detailed public information is generally not available, subject matter experts from other stakeholder and environmental groups are not in a position to provide input to the drill. **It will be important for these stakeholder groups to have access to the information from the "drill hot-wash" and final conclusions to enable them to participate in developing recommendations for improvement.**

- **For effective response planning, resource allocation and public awareness and approval, it is vital that realistic, credible worst-case scenarios be defined and the alignment and effectiveness of the emergency response plans analyzed and adjusted.**

- **Defining the different spill scenarios that need to be addressed and aligning and effective response plan for each scenario is vitally important.** The public should also have information on the maximum response capability and the effectiveness in attacking the "credible worst-case scenario" release. This is a very important scenario that needs to be communicated, understood and available for comment by all stakeholders. Current regulatory requirements allow pipeline operators to calculate worst-case scenarios using their assumptions which take "mitigation credit" for the functioning of instrumentation, control and mechanical systems and procedures that are not 100% reliable and subject to single mode and common cause failures. Essentially, pipeline operators use "best case" reaction scenarios for planning and public relations and not worst-case. This approach is not allowed for other industrial sectors managing hazardous operations and several recent major spills greatly exceeded the previously publically available information on the worst-case scenarios.

- **A specific integrated contingency plan (ICP) should be developed for Line 5 in the Strait area and made available in an un-redacted version.** The Enbridge ICP covers the "Superior Region" and appears to meet regulatory requirements but it is not specific enough, or easily analyzed or useful due to the redaction of detailed information and the shear scope and coverage of the ICP. ICP information for other hazardous industries is available to the public when it is required for emergency planning and the information is not redacted when required to be made available under citizen and community right-to-know rules. Security specific information can be redacted when required by regulation and vetted as appropriate by the Federal agencies. The extensive redaction of the Enbridge ICP is not a normal industry practice and may violate regulatory processes.

- **Because Line 5 at the Straits is a Tier 1 Risk – extensive emergency response capability should be in place, locally for immediate response.** "Business as usual" in the Straits Crossing and management using a "regional ICP" for a Tier 1 risk not a normal or recommended practice. Extra-ordinary response resources, equipment and personnel should be continuously in place at the Straits as an interim risk reduction measure until the permanent solution defined by the Alternative Assessment is fully implemented.

- In the future, full exercises should be required at the Straits not less than every 18 months as defined in US Coast Guard regulations for high hazard operations.

Alternatives Assessment Process

Planning Meeting

Steering Team & Assessment Coordination Team

Define objectives, key players, consultant/facilitators, master time schedule

Stakeholder Overview Meeting

Panel presentations and Q&A

Hear public concerns and explain the Alternatives Assessment approach

Prepare for Alternatives Assessment

Steering Team, Assessment Coordination Team, Consultant

Discuss process, key players, brainstorming & evaluation approach, schedule

Alternatives Assessment Workshop 1

Kick-off & identification of all Alternatives

Launch Workgroups to develop details on Alternatives – use a defined process

Workgroup 1 | Workgroup 2 | Workgroup 3 | Workgroup ....

Alternatives Assessment Workshop 3

Evaluate and prioritize alternatives

Prepare, Issue Findings and Recommendations

Appendix 3-B

Excerpt from MPPTF Final Report - July 2015

Attorney General Bill Schuette and DEQ Director Dan Wyant

Specific Recommendations regarding the Straits Pipelines

1. Prevent the transportation of heavy crude oil through the Straits Pipelines.
2. Require an independent risk analysis and adequate financial assurance for the Straits Pipelines.
3. Require an independent analysis of alternatives to the existing Straits Pipelines.
4. Obtain additional information from Enbridge relating to the Straits Pipelines.

Statewide Recommendations

1. Coordinate mapping of existing pipelines among state agencies.
2. Ensure that state agencies collaborate on emergency planning and spill response.
3. Ensure coordinated emergency response training exercises and drills.
4. Ensure regular state consultation with the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) on hazardous liquid (including petroleum) pipelines.
5. Consider legislation requiring state review and approval of oil spill response plans, improved spill reporting, and more robust civil fines.
6. Evaluate whether to establish a Hazardous Liquids Pipeline Safety Program in Michigan.
7. Consider legislation or rulemaking to improve siting process for new petroleum pipelines.
8. Consider issuing an Executive Order creating an Advisory Committee on Pipeline Safety.
9. Create a continuing Petroleum Pipeline Information website.

APPENDIX 4

A SCIENTIFIC AND LEGAL POLICY FOLLOW-UP REPORT ON CRUDE OIL PIPELINES IN THE GREAT LAKES

Oil Spill in the Great Lakes?

How Safe Are The Pipelines?

Two aging pipelines owned by Enbridge Energy run across the Straits of Mackinac on Lake Michigan bottomlands, transporting 23 million gallons of oil daily. A University of Michigan study called it *"the worst possible place" in the Great Lakes for an oil spill*.

A presentation by Dr. Ed Timm, PhD

"Using Enbridge's own data I calculated that the non-Straits sections of line 5 have, on the average, lost 45% of their wall thickness due to internal and external corrosion."

Dr. Timm, a retired chemical engineer from Dow Chemical, will discuss the design and condition of Enbridge Line 5 oil pipeline which runs the entire length of Michigan. Carrying oil from Canada and North Dakota, Line 5 traverses at least 45 Michigan waterways before it crosses the St. Clair River to a refinery in Sarnia, Ontario, Canada.

Tuesday, August 4, 6:30 PM

Charlevoix Public Library

220 W. Clinton St., Community Room B

Sponsored by: Friends of the Jordan River Watershed, WATCH (Water Air Team Charlevoix)

Regarding the Design and Condition of Enbridge Energy Partners Line 5 and Straits of Mackinac Crossing

Edward E. Timm, PhD, PE
Harbor Springs, Michigan
EdTimm@gmail.com 231-526-7159

Edward E. Timm, PhD, PE

- BS, MS, PhD in Chemical Engineering from University of Michigan
- Licensed Professional Engineer, Michigan
- Retired as Senior Scientist, The Dow Chemical Company after 27 years
- 26 US Patents
- Expertise in all areas of chemical engineering with an emphasis on innovation, design, troubleshooting and new business analysis
- Hands on experience with most petrochemical and refinery processes
- Last years of Dow career devoted to Environmental Operations and cleanup technology

Sources of Information

Enbridge Energy Partners Limited, Operational Reliability Plan,
Line 5 and Line 5 Straits of Mackinac Crossing, Issued 2014

Michigan Public Service Commission, Opinion and Order D-3903-53 1,
Issued march 31, 1953

Michigan Conservation Commission, Straits of Mackinaw Pipeline
Easement to Lakehead Pipeline Company, April 23, 1953

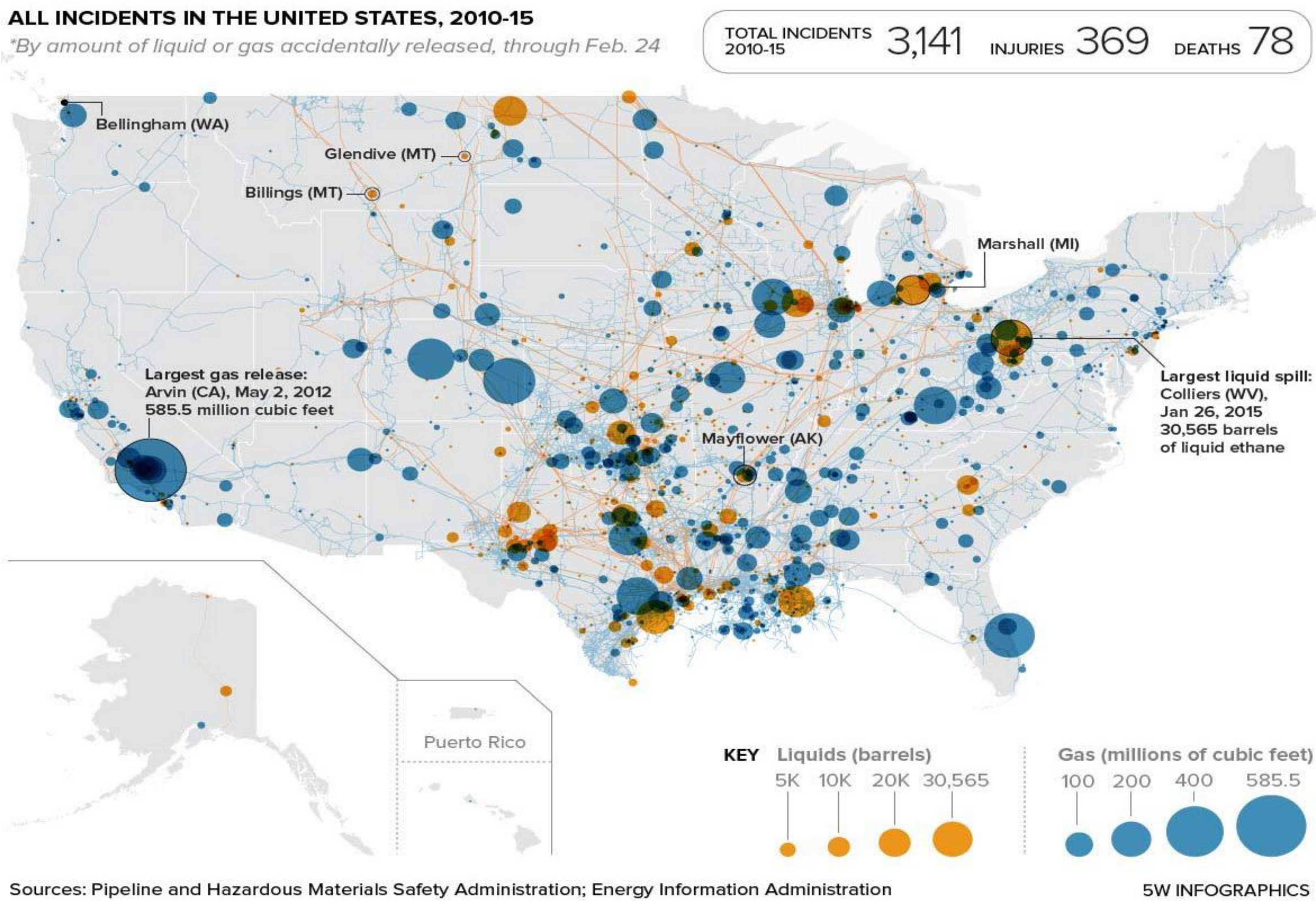
"Engineering and Construction Considerations for the Mackinac Pipeline Company's Crossing of the Straits of Mackinac" and "Report on the Structural Analysis of the Subaqueous Crossing of the Mackinac Straits," submitted by Mackinac Pipeline Company/Lakehead Pipeline Company to the Michigan Department of Conservation, January, 1953

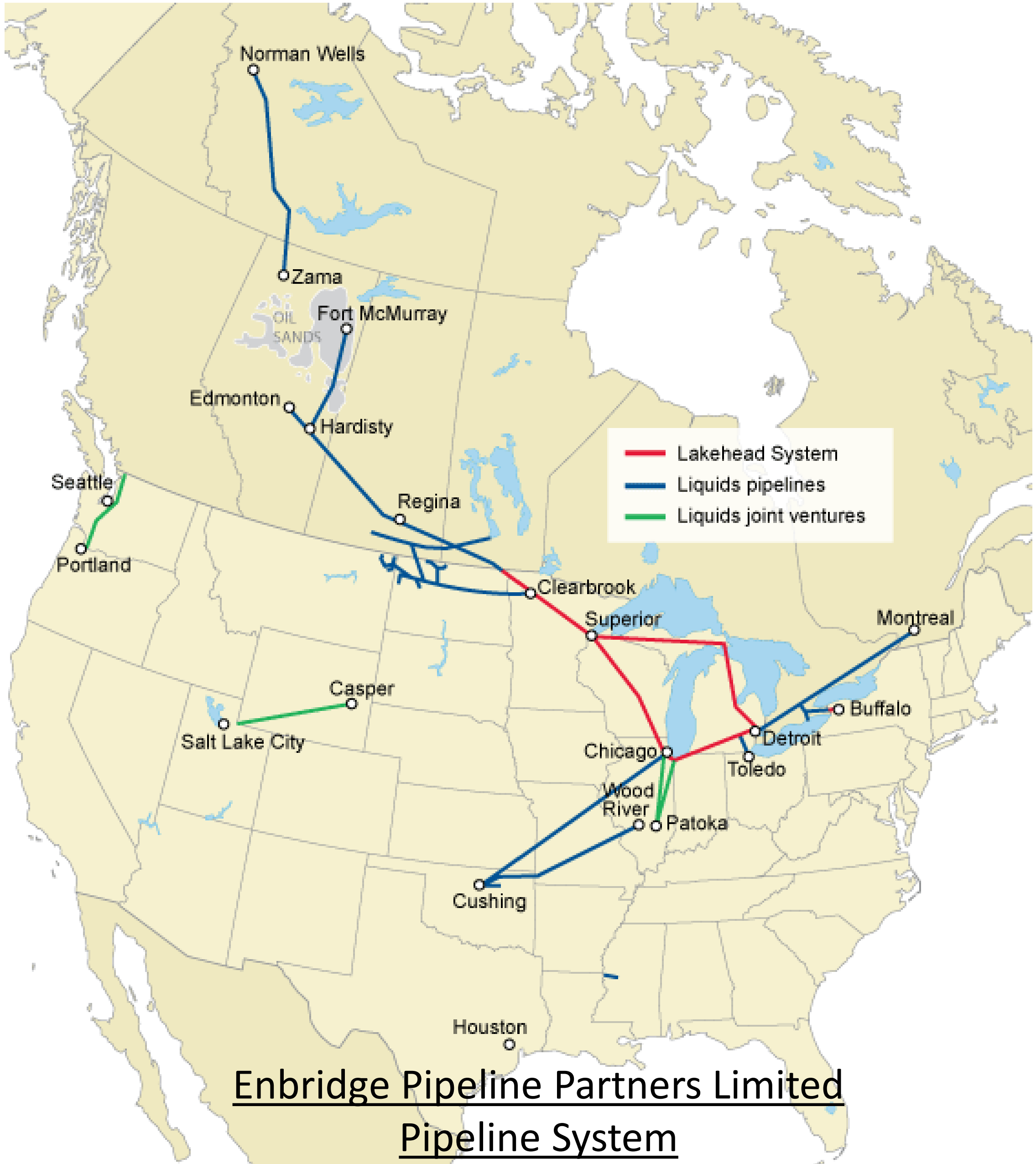
Openly published Enbridge documentation

Information obtained by FLOW from the State of Michigan under FOIA

Numerous technical publications, both current and those available in 1953

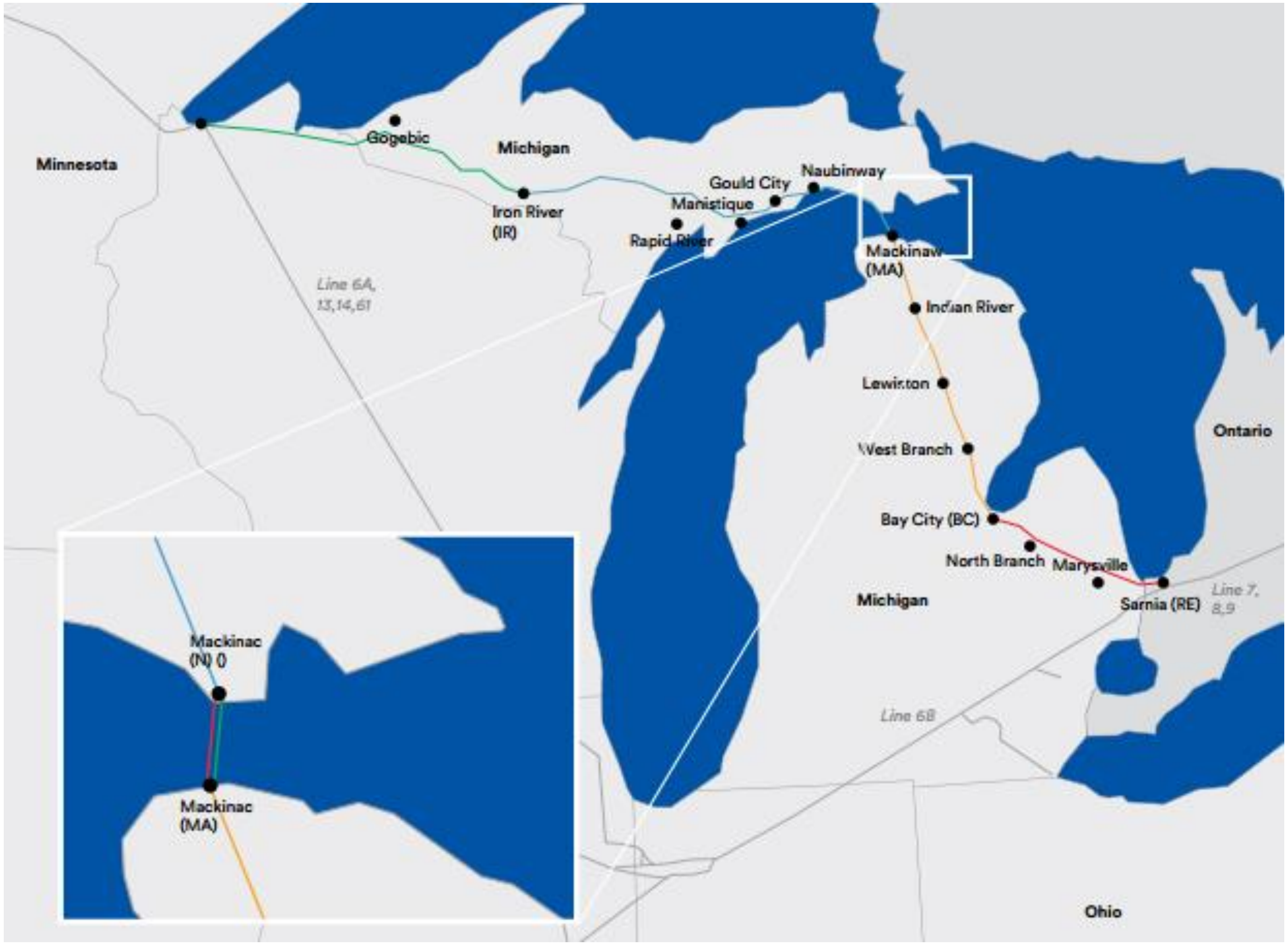
Pipeline Failures Since 2010



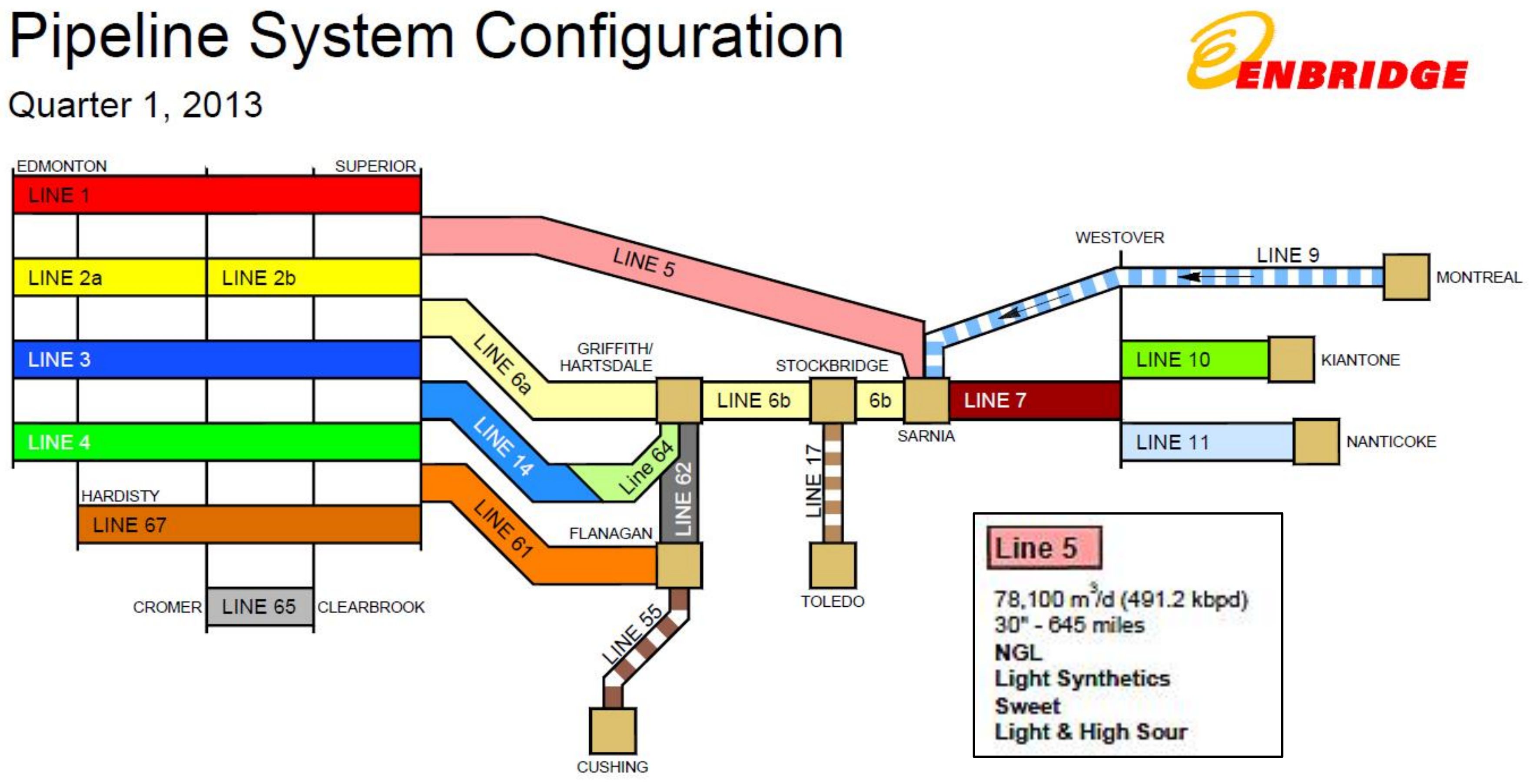


Enbridge Pipeline Partners Limited Pipeline System

Enbridge Line 5, Michigan Route and Pump Stations



Where and What Does Line 5 Transport?



1953 Easement and MPSC Order Do Not Restrict Line 5 Cargo

Rapid River Pump Station and LPG Extraction Facility

Enbridge Energy Limited Partners Line 5

MPSC Order D-309-53.1 of 3/21/1953 Excerpts

“Lakehead Pipeline Company, Inc. is a common carrier for the transportation of oil and petroleum in interstate and foreign commerce.

Pipeline to transport oil from Redwater Area, Calgary, Alberta

No pumping stations to be built in 1953 but in the future there may be stations at:

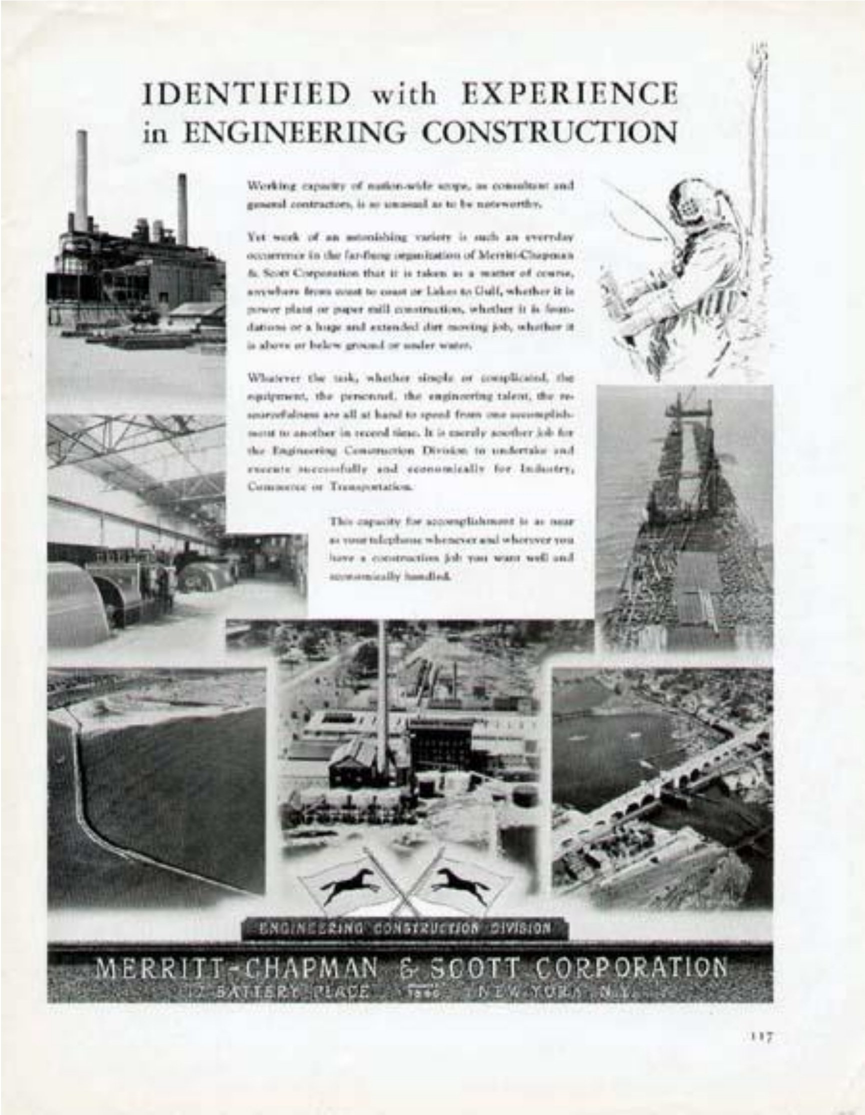
Watersmeet, Gegobic County,
Gulliver, Schoolcraft County,
Indian River, Cheboygan County,
Bay City, Bay County.

The capacity of the line with no pumping stations in Michigan will be **120,000** barrels/day and when all of the four pumping stations are completed and in operation the capacity will be **300,000** barrels/day.”*

- **As of 2012 Line 5 was rated at 490,000 barrels/day using 12 pump stations. How and when the capacity was raised to this level from the design level of 300,000 is not currently known.**

- **In 2013 the capacity of Line 5 was raised to 540,000 barrels/day and the pump stations were extensively upgraded. Line 5 is now operating at 80% higher flow than design.**

The Straits of Mackinac
A Difficult Crossing



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MERRITT-CHAPMAN & SCOTT CORPORATION

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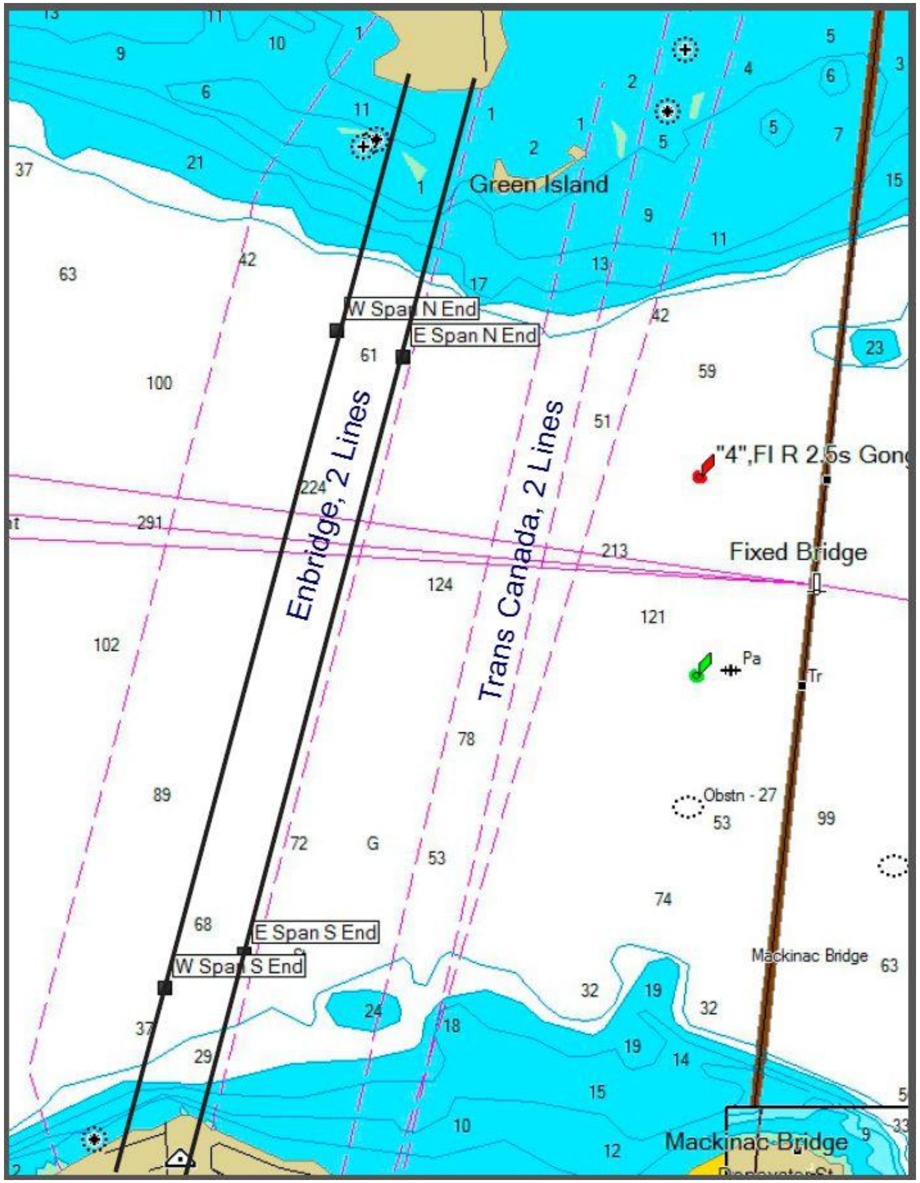
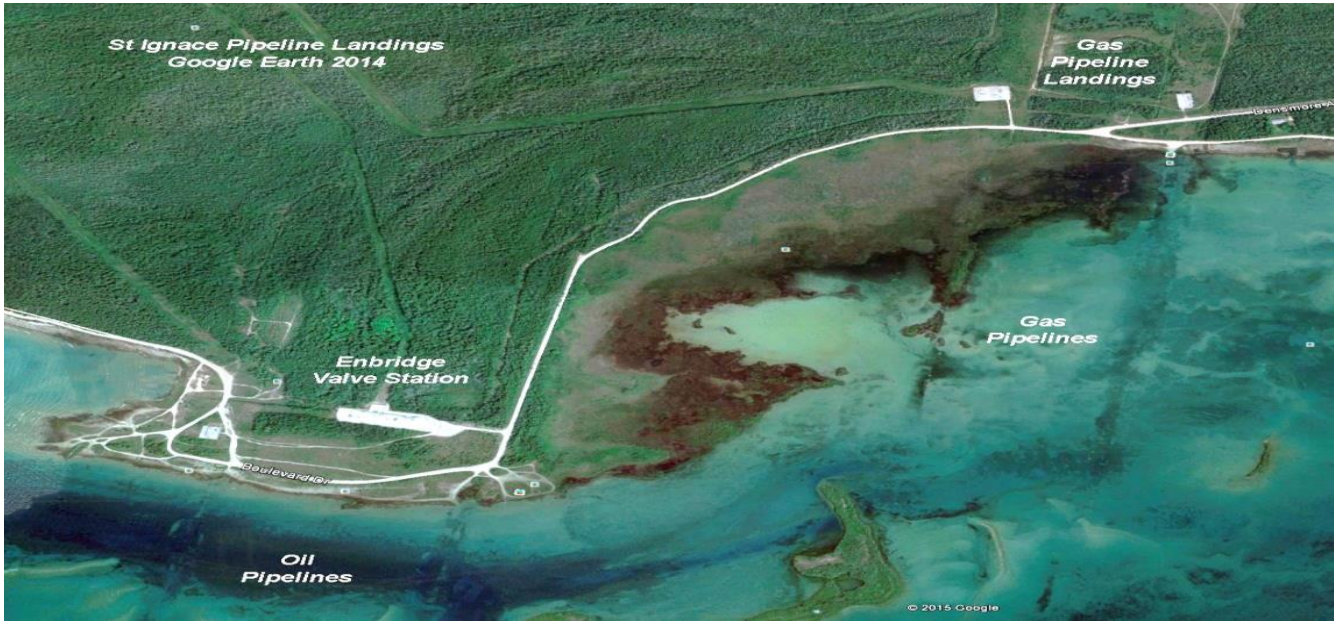
Straits of Mackinac

Two Oil Pipelines, Two Natural Gas Pipelines, Two + Cable Crossings




St Ignace Pipeline Landings
Google Earth 2014
Gas
Pipeline
Landings
Enbridge
Valve Station
Gas
Pipelines
Oil
Pipelines
© 2015 Google


Mackinaw City Pipeline Landings
Gas
Pipelines
Enbridge
Pump
Station
Gas
Pipeline
Landings

Naubinway Pump Station

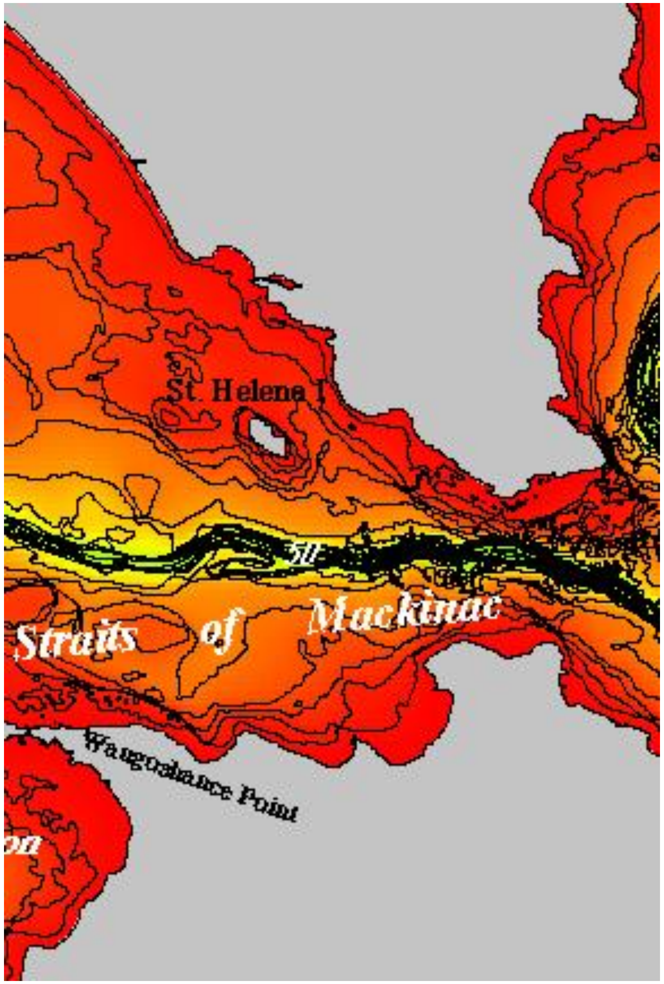
35 Miles to St Ignace

Mackinaw City Pump Station

48 Miles to Wolverine

Wolverine Pump Station

Bottomlands of the Straits of Mackinaw



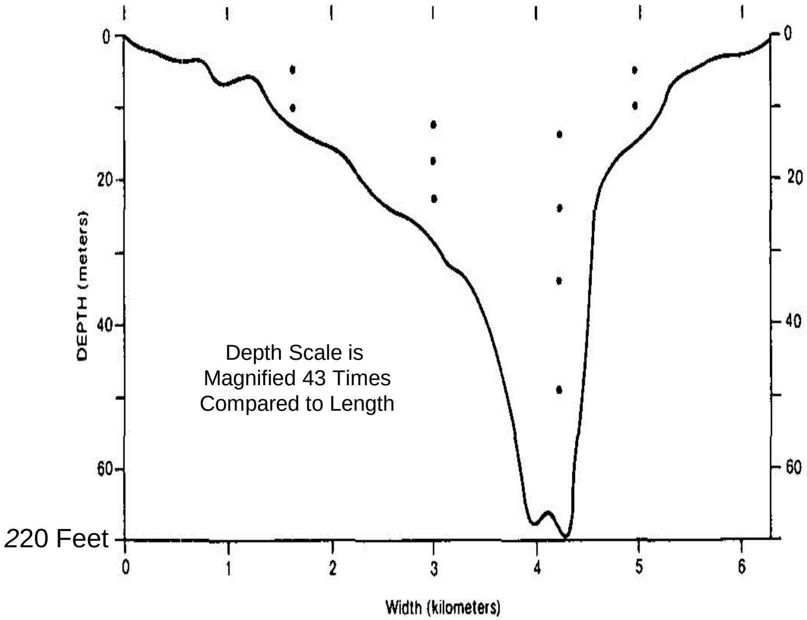
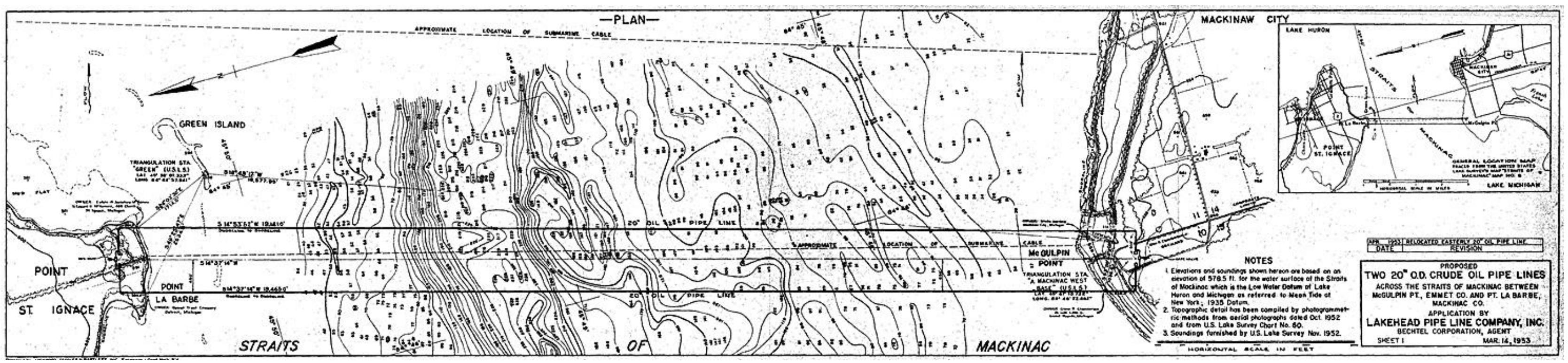
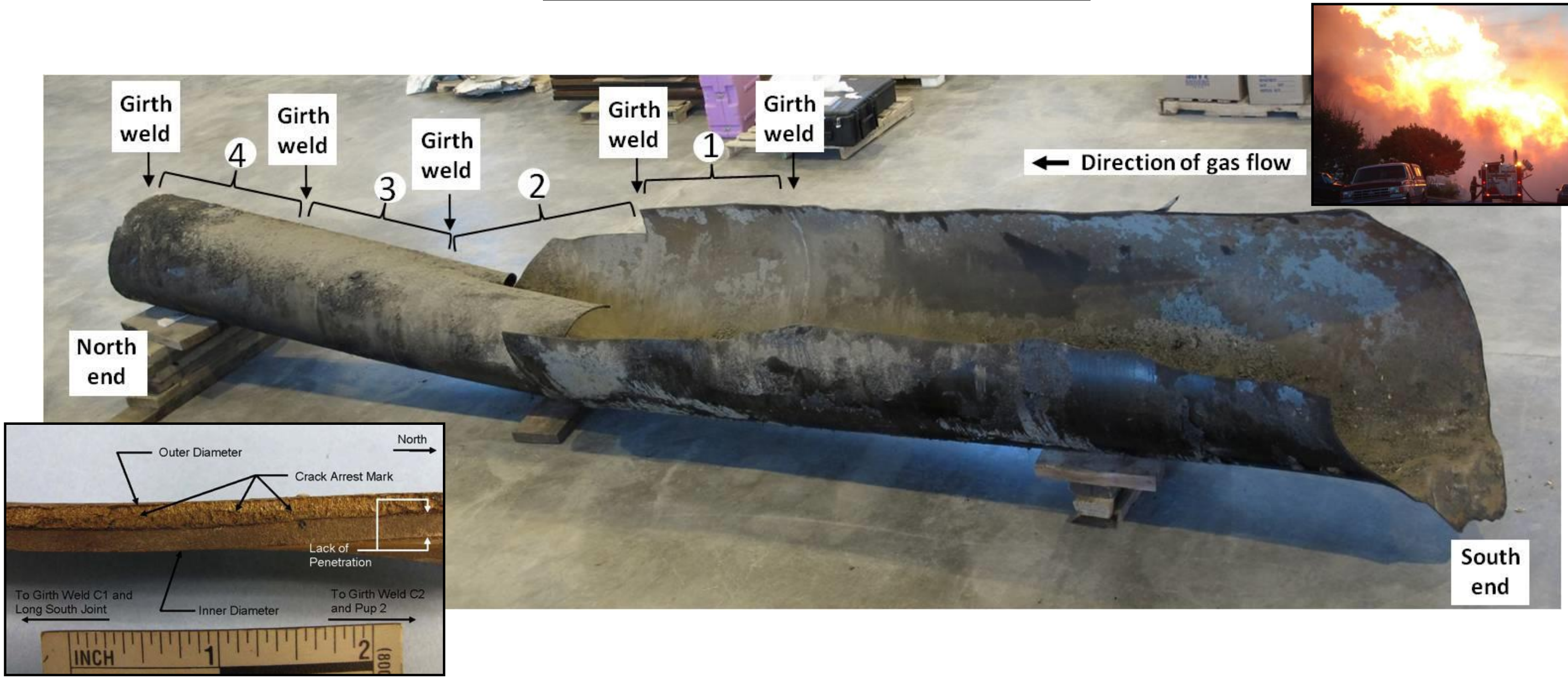


FIG. 2. Straits of Mackinac cross section along the 84°45′W meridian showing current meter configuration.

Pipeline Location Chart from 1953 Easement



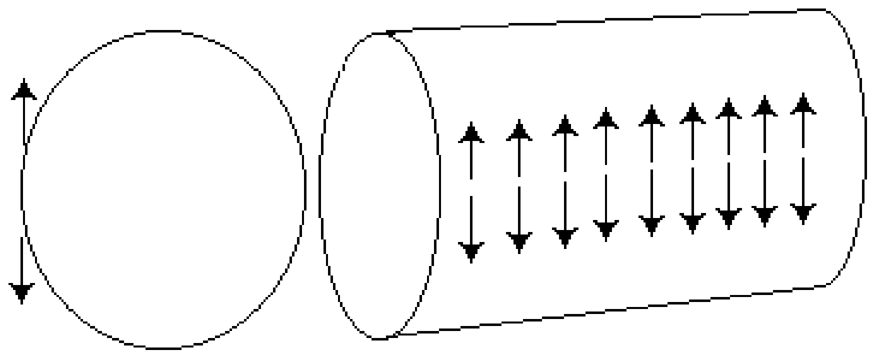
Pipeline Design Considerations



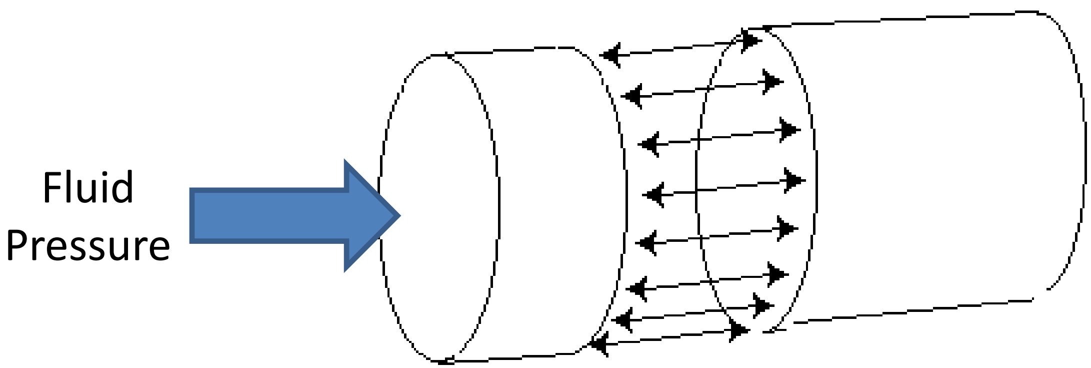
PG&E San Bruno Gas Pipeline Failure - Eight Dead

In January 2011, federal investigators reported that they found numerous defective welds in the pipeline.
The thickness of the pipe varied, and some welds did not penetrate the pipes completely.
As PG&E increased the pressure in the pipes to meet growing energy demand, the defective welds were further weakened until their failure. As the pipeline was installed in 1956, modern testing methods such as X-rays were not available to detect the problem at that time. (Incorrect regarding X-ray availability, ET)

Stresses in a Pipe Caused by Internal Pressure

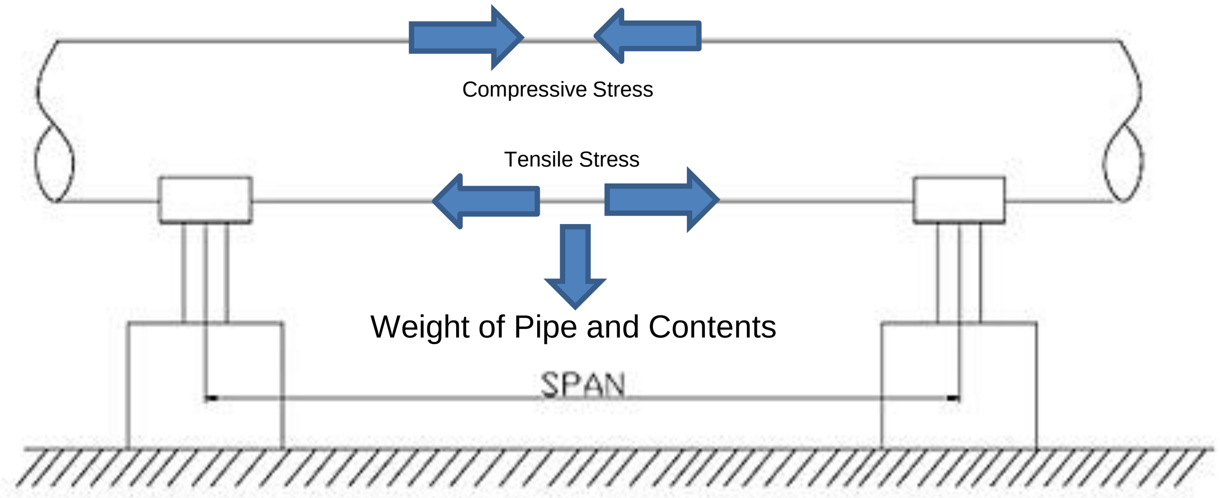


Circumferential Stess or Hoop Stress



Longitudinal Stress or Axial Stress

Bending Stress in a Supported Pipeline Due to Weight of Pipe and Contents



Tensile Stress on Bottom and Compressive Stress on Top between Supports
Compressive Stress on Bottom and Tensile Stress on Top at Supports

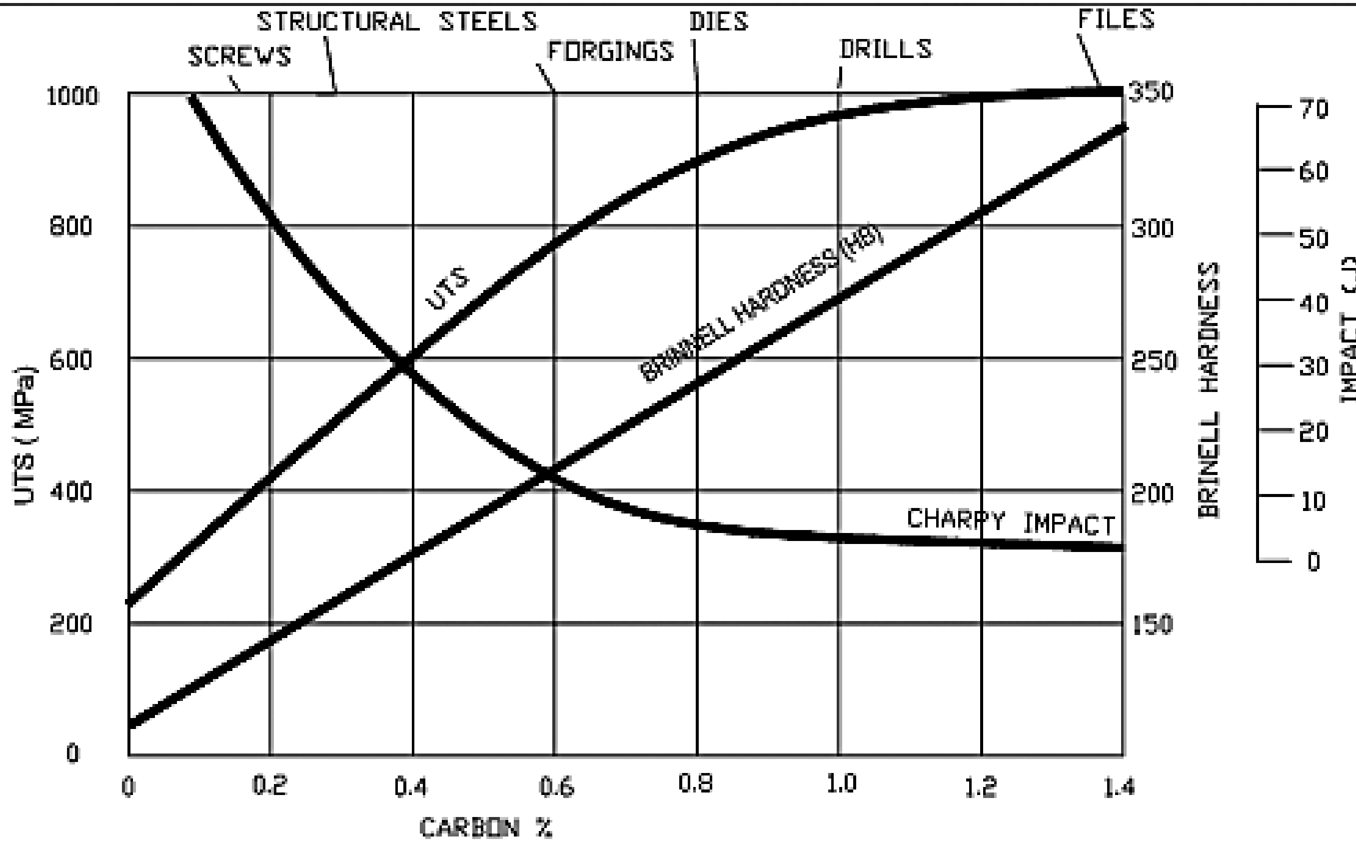
1953 Easement Support Requirement

(10) The maximum span or length of pipe unsupported shall not exceed seventy-five (75) feet.

Iron and Carbon = Steel

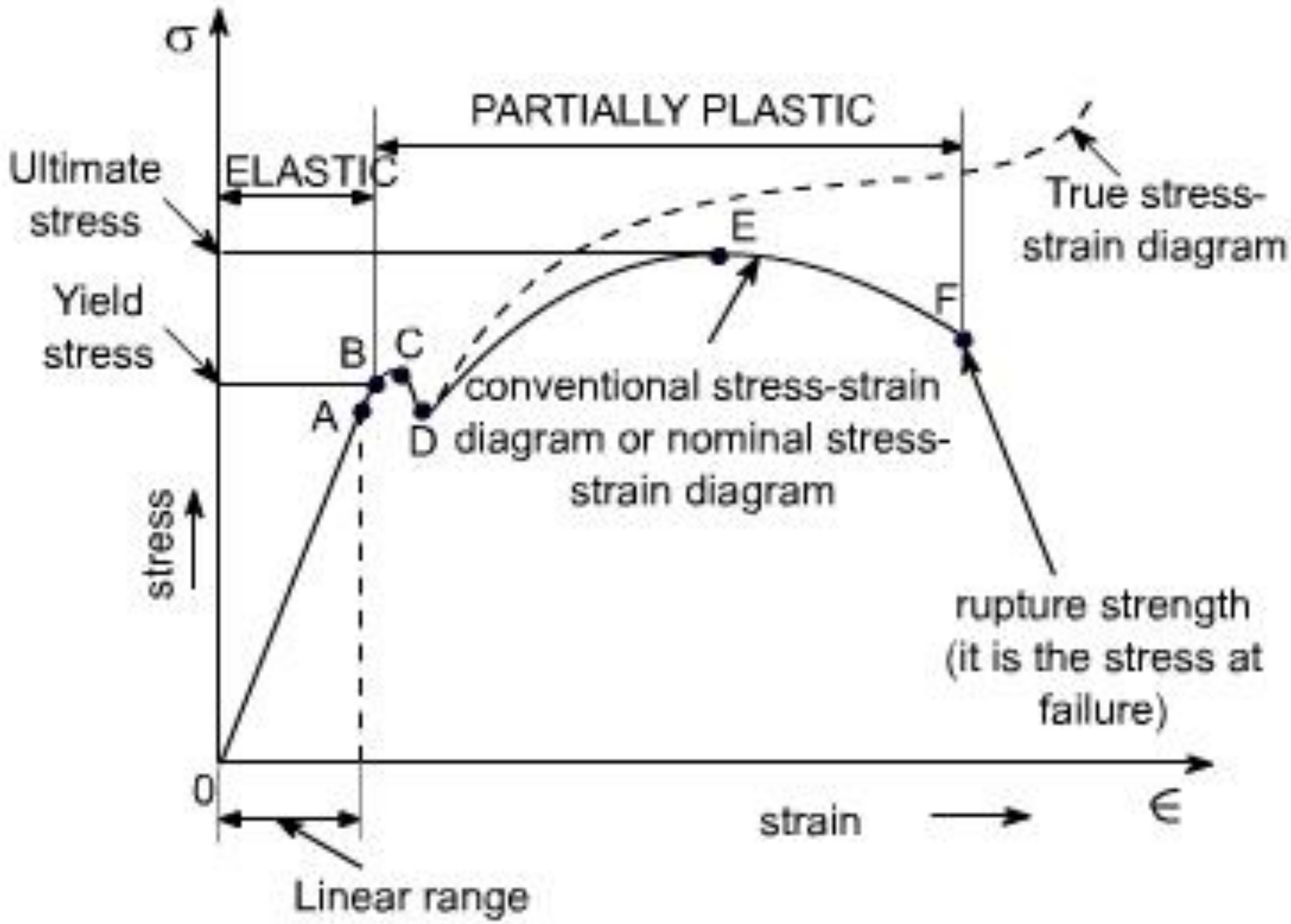
1953 Easement Restriction

(12) The maximum carbon content of the steel from which the pipe is manufactured shall not be in excess of 0.247 percent



STEEL -- EFFECT OF DIFFERENT CARBON CONTENT.

Mechanical Properties of Low Carbon Steel
Stress Strain Plot



Design of a Pipeline for Adequate Strength

Hoop Stress, Longitudinal Stress and Bending Stress
are Combined to Give the Maximum Principal Stress

The Yield Strength of the Steel Divided by the Maximum Principal Stress
is the **Safety Factor**

The Safety Factor Used depends on the Details of the Pipeline Construction
and the Risk Associated with Catastrophic Failure

The Design Process is Iterative Until Operational Requirements
are Met Without the Maximum Principal Stress Exceeding
the Yield Stress Multiplied by the Safety Factor

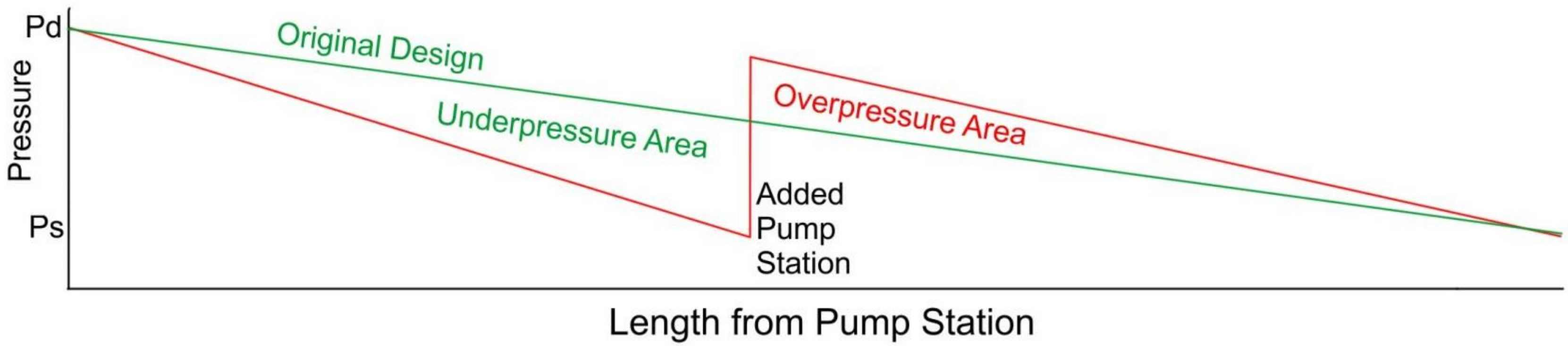
Economics are Always a Important!

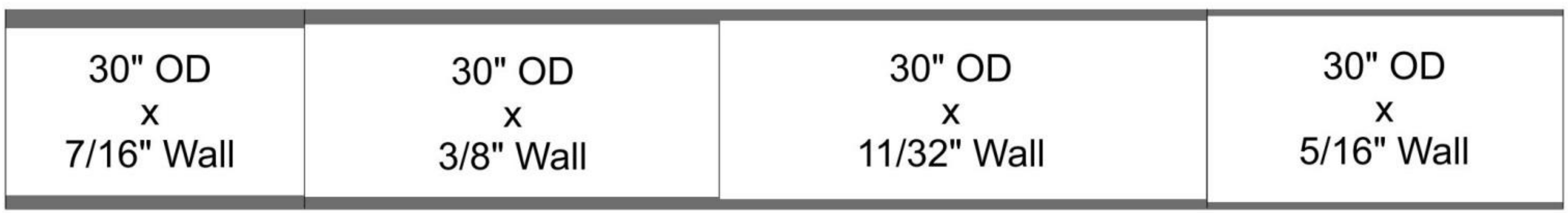
Line 5 Piping Specifications from Enbridge OR Report

Table 1: Line 5 Pipeline Construction Specifications

Pipe Properties	PE-IR	IR-Straits	East Straits	West Straits	MA-BC	BC-RW
Outside Diameter / Wall Thickness / Grade	762mm (30") / 7.14mm, 7.92mm, 8.74mm, 9.53mm (0.281", 0.312", 0.344", 0.375") / 318MPa, 359MPa (X46, X52)	762mm (30") / 7.14mm, 7.92mm, 8.74mm, 9.53mm (0.281", 0.312", 0.344", 0.375" / Grd. B, 318MPa, 359MPa (X46, X52)*	508mm (20") / 20.62mm (0.813") / Grd. B, 241MPa (X35)**	508mm (20") / 20.62mm (0.813") / Grd. B, 241MPa (X35)**	762mm (30") / 7.14mm, 7.92mm, 8.74mm, 17.45mm (0.281", 0.312", 0.344", 0.687") / Grd. B, 318MPa, 359MPa (X46, X52)	762mm (30") / 7.14mm, 7.92mm, 9.53mm, 12.70mm (0.281", 0.312", 0.375", 0.500") / Grd. B, 318MPa, 359MPa (X46, X52)
Coating	Coal Tar Enamel	Coal Tar Enamel	Coal Tar Enamel**	Coal Tar Enamel**	Coal Tar Enamel	Coal Tar Enamel
Long Seam Weld Type	SAW	SAW	SMLS**	SMLS**	SAW	SAW, DSAW***
Vintage	1953	1953	1953	1953	1953	1953
Section Length Km (Miles)	279.631 (173.75)	327.968 (203.79)	6.585 (4.09)	6.585 (4.09)	252.616 (156.97)	170.260 (105.79)
Manufacturer	National Tube (NT), Consolidated Western (CWNT)	National Tube, Consolidated Western, Wickwire Spencer (WS)****	National Tube	National Tube	National Tube, Consolidated Western	National Tube, Consolidated Western

Line 5 Piping Specifications and Telescoped Pipeline Construction





"Telescoped" Pipeline Construction

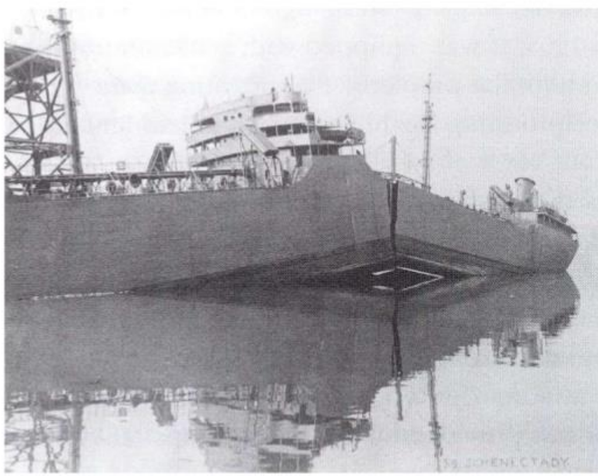
If Line 5 was constructed with telescoped construction and new pump stations were added later has this caused sections of the pipe to be overpressured?

Arc Welded Marine Structures

Shipping demands of World War Two led to the development of arc welding for the rapid production of large marine structures

Lack of understanding of steel properties, weld metallurgy, stress concentration and residual stress led to the failure of many large marine structures

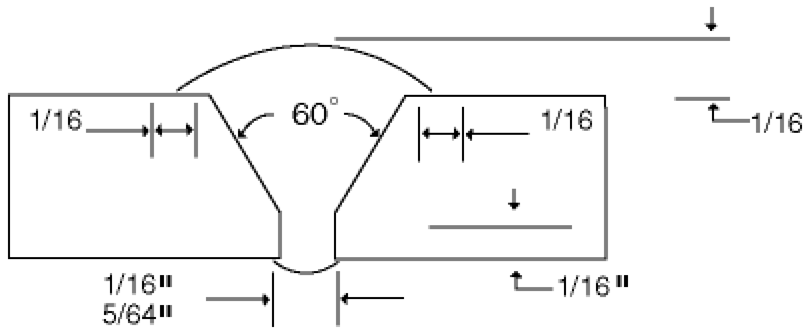
USS Schenectady



Constructed November, 1942 and failed structurally in January, 1943.
Cause of failure is still discussed
Service life = 1 month

Constructed in 1957 and failed structurally in November, 1975.
Cause of failure is still discussed
Service life = 18 years

Pipeline Welding

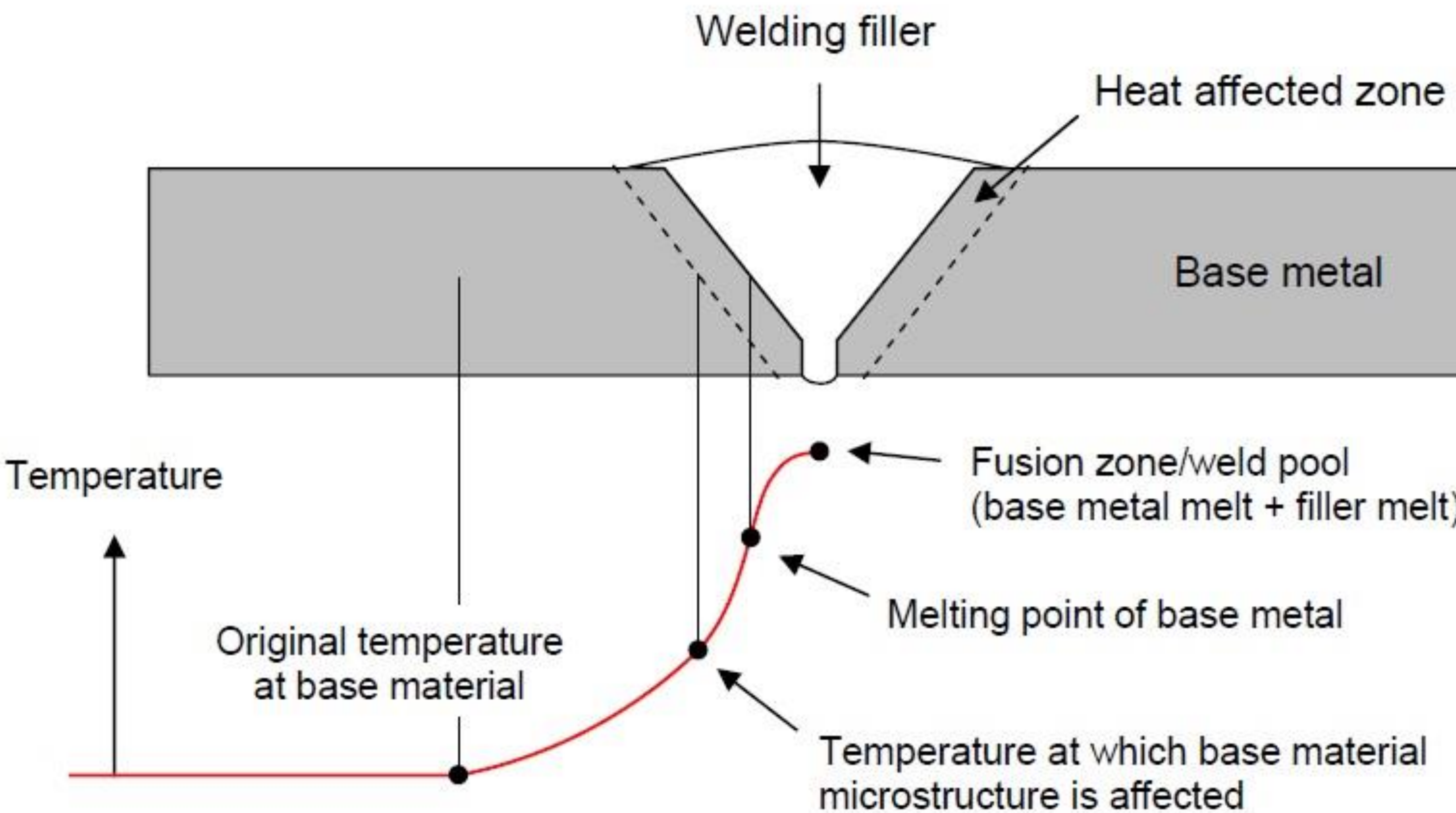


Typical Pipe Joint Detail
FIGURE 3

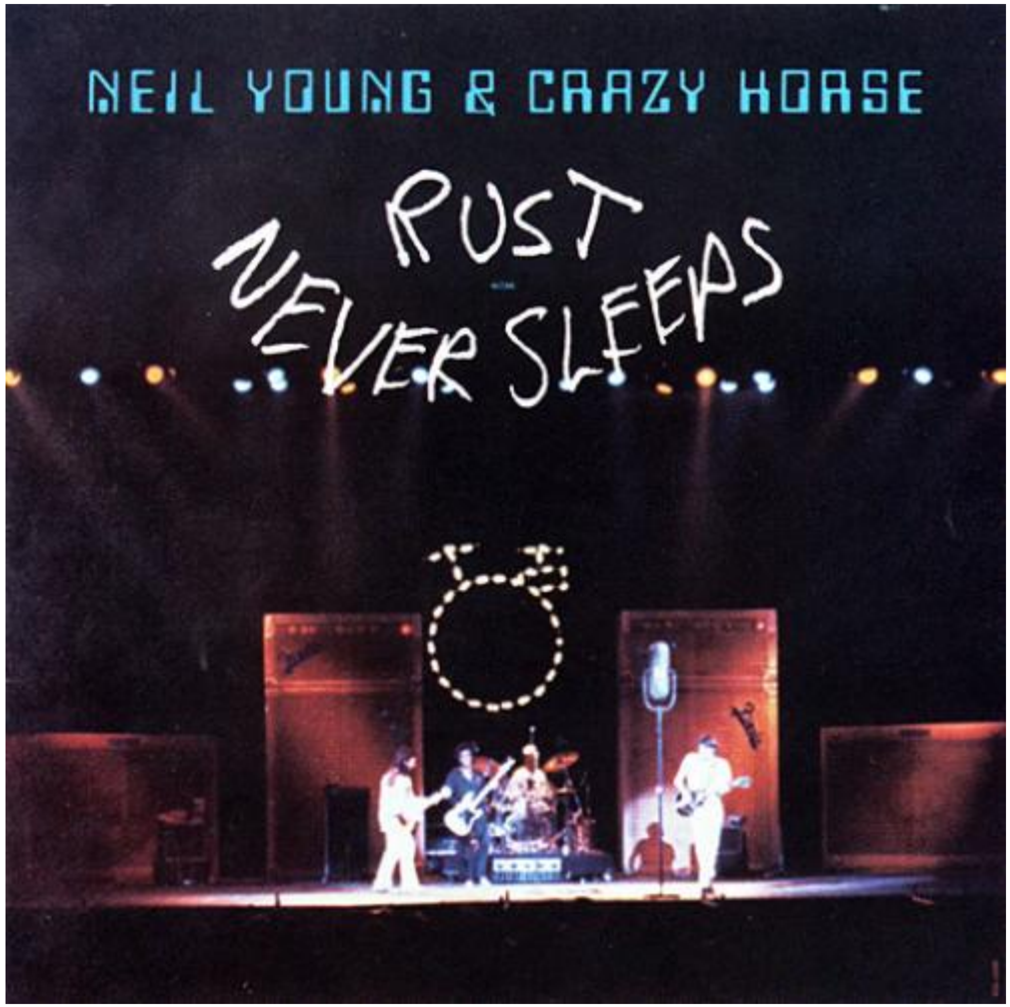
Pipeline Girth Weld Showing Completed Root Pass
and Details of Second Pass

Welding Metallurgy

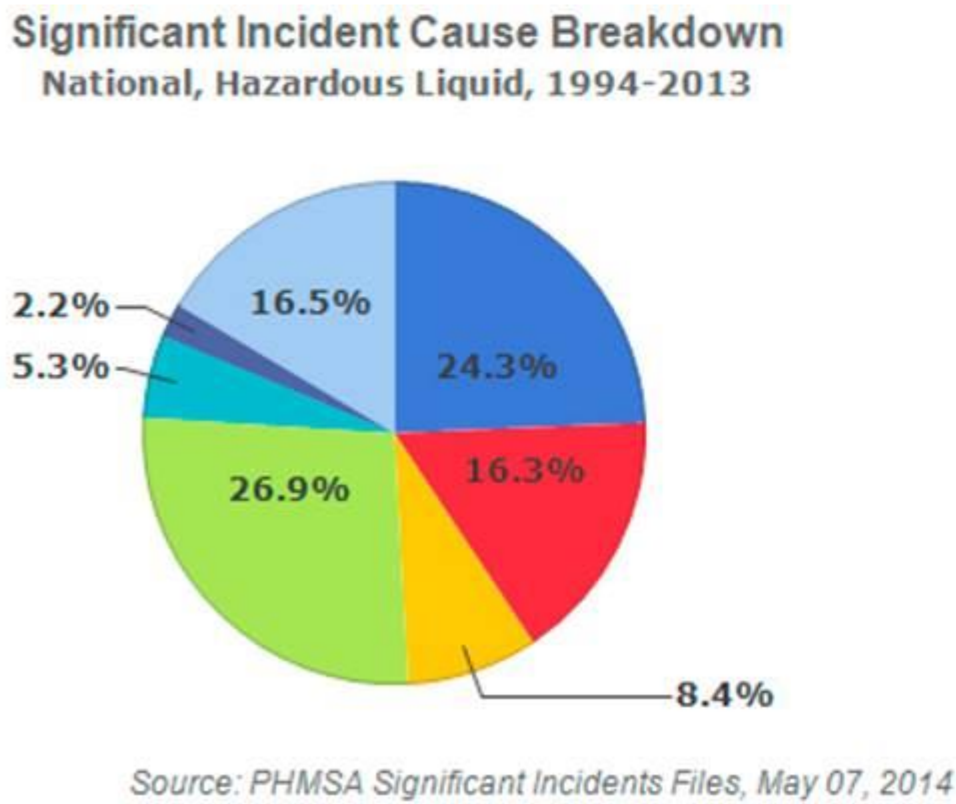
Figure 17.1 Heat Affected Zone



Why Pipelines Fail



PHMSHA Data on Cause of Significant Pipeline Failures



60% of failures are caused by corrosion, mechanical failure or mis-operation.
All these causes are under the control of the pipeline operator.

Erosion and Corrosion
Overstress and Cracking

Erosion is material loss due to abrasive particulates in the cargo

Corrosion is material degradation caused by chemical reactions

Inside and outside of pipelines must be considered separately

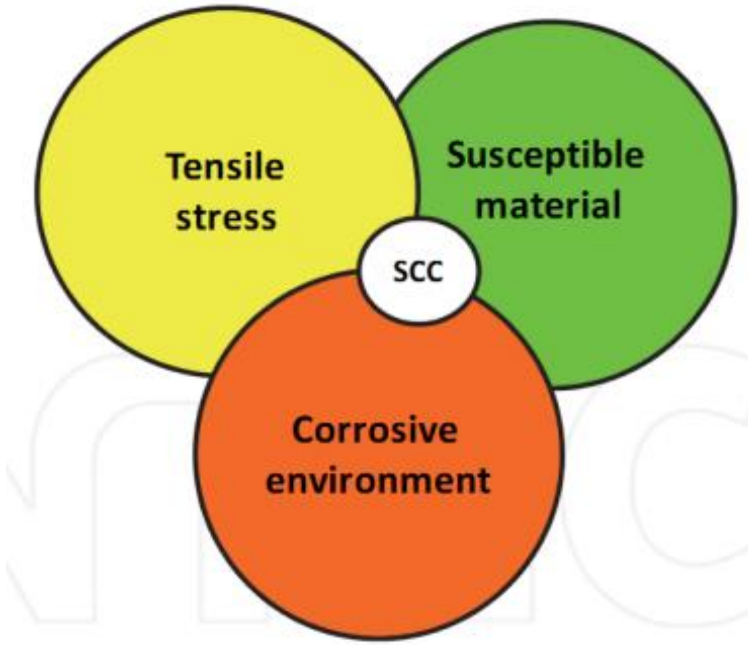
Cracks can form in the bulk of the pipeline wall too.

In low carbon steel pipelines the primary corrosion product is rust

Failure usually results when a crack formed by either wall thinning
or stress corrosion cracking reaches a critical size for the existing stress
and propagates

Mis-operation can always blow up a pipeline.

The Combination of Stress and a Corrosive Environment Can Cause Cracking



Stress corrosion cracking is the most common cause of pipeline failure

Control of SCC requires careful selection of material and protection of that material from the corrosive environment

The Straits section of line 5 is made from low carbon steel because it is not particularly susceptible to SCC compared to higher strength steels.

Even low carbon steel can have SCC problems when Hydrogen Sulfide is present.

Enbridge Line 6B Failure

Failure in the heat affected zone of the longitudinal seam weld.
Crack initiated by stress and corrosion (SCC) due to coating failure
The crack ran nearly ten feet before enough stress was relieved to stop it

"(Richard) Kuprewicz has seen this problem before. He researched the US federal investigation into the Kalamazoo, Michigan dilbit spill – the largest onshore oil spill in US history on behalf of various concerned parties. **The disbondment of PE-tape on Enbridge's Line 6B pipeline and subsequent SCC on the pipe caused the rupture**."

Bridger Pipeline Yellowstone River Spill

<u>Enbridge St Ignace Valve Station, Looking West</u>

1953 Restrictions on Line 5 Operating Pressure

1953 Easement Restrictions for Straits

(2) Minimum testing specifications of the twenty inch (20”) OD pipelines shall not be less than the following:

Shop Test	1,700 pounds per square inch gauge
Assembly Test	1,500 pounds per square inch gauge
Installation Test	1,200 pounds per square inch gauge
Operating Pressure	600 pounds per square inch gauge

1953 MPSC Order for All of Line 5

Pipe Specification	Minimum Mill Test Pressure, (psi)	Maximum Working Pressure, (psi)
30’ OD x ½ “ Wall	1242	894
30” OD x 3/8” Wall	965	695
30” OD x 11/32” Wall	878	632
30” OD x 5/16” Wall	790	570
30” OD x 7/16” Wall	1097	790
20” OD x 0.813 Wall	1700	1200

Pipe line to be designed for a working pressure of 500-550 psi except at the Superior pump station discharge where it is limited to 700 psi until station 2 is put into operation.

The capacity of the line with no pumping stations in Michigan will be 120,000 barrels/day and when all the Michigan pumping stations are completed and in operation the capacity will be 300,000 barrels/day. (Currently approved for 540,000 barrels/day in 2013, 80% Over Original Design)

Reliability of Line 5 Straits Crossing…the Stress due to Pressure

Summary of Pressure Calculations for Line 5

Oil Temperature On Land, (F) = 50

Oil Temperature Underwater, (F) = 41

	Pipeline Cargo			
	Synthetic Light Oil (CNS)	Light Sour Blend (LSB)	Mixed Blend Sour (SO)	Diluted Bitumen (AWB)
API Gravity =	34.8	38.0	31.1	21.7
Flow Rate, (barrels/day) =	540000	540000	540000	540000
	Pressure in PSI			
Pressure at Discharge of Naubinway Pump Station Discharge =	473	485	652	1207
Pressure at St Ignace Valve Station =	167	171	219	303
Pressure at Straits Deep =	237	239	276	417
Pressure at Mackinaw City Valve Station =	44	44	48	62
Pressure at Mackinaw City Pump Station Inlet =	30	30	30	30
Static Head at Straits Deep without Flow =	136	134	139	148
Ambient Pressure at Straits Deep with Flow =	120	122	159	300
Pump Station Power, (Hydraulic Horsepower), =	6396	5016	6284	12984

Summary of non-Isothermal Pressure Calculations for Line 5 with Drag Reduction

Can line 5 transport DILBIT?

	Pipeline Cargo	
	Diluted Bitumen (AWB)	
API Gravity =	21.7	
Flow Rate, (barrels/day) =	540000	
Soil Temperature, (F) =	42	
Water Temperature, (F) =	42	
Temperature at Naubinway Pump Station Discharge, (F) =	**200**	
Temperature at Mackinaw City Pump Station Inlet, (F) =	189.9	
	Straits	Onshore
Drag Reducing Agent Efficiency, (% Friction Reduction) =	**25%**	**25%**
	Pressure in PSI	
Pressure at Discharge of Naubinway Pump Station =	583	
Pressure at St Ignace Valve Station =	166	
Pressure at Straits Deep =	232	
Pressure at Mackinaw City Valve Station =	49	
Pressure at Mackinaw City Pump Station Inlet =	30	
Static Head at Straits Deep without Flow =	148	
Pump Station Power, (Hydraulic Horsepower) =	5129	

“Washout” of Underwater Pipelines

In areas of strong currents, pipelines laid on the bottom can be undercut or “washed out” resulting in unsupported spans

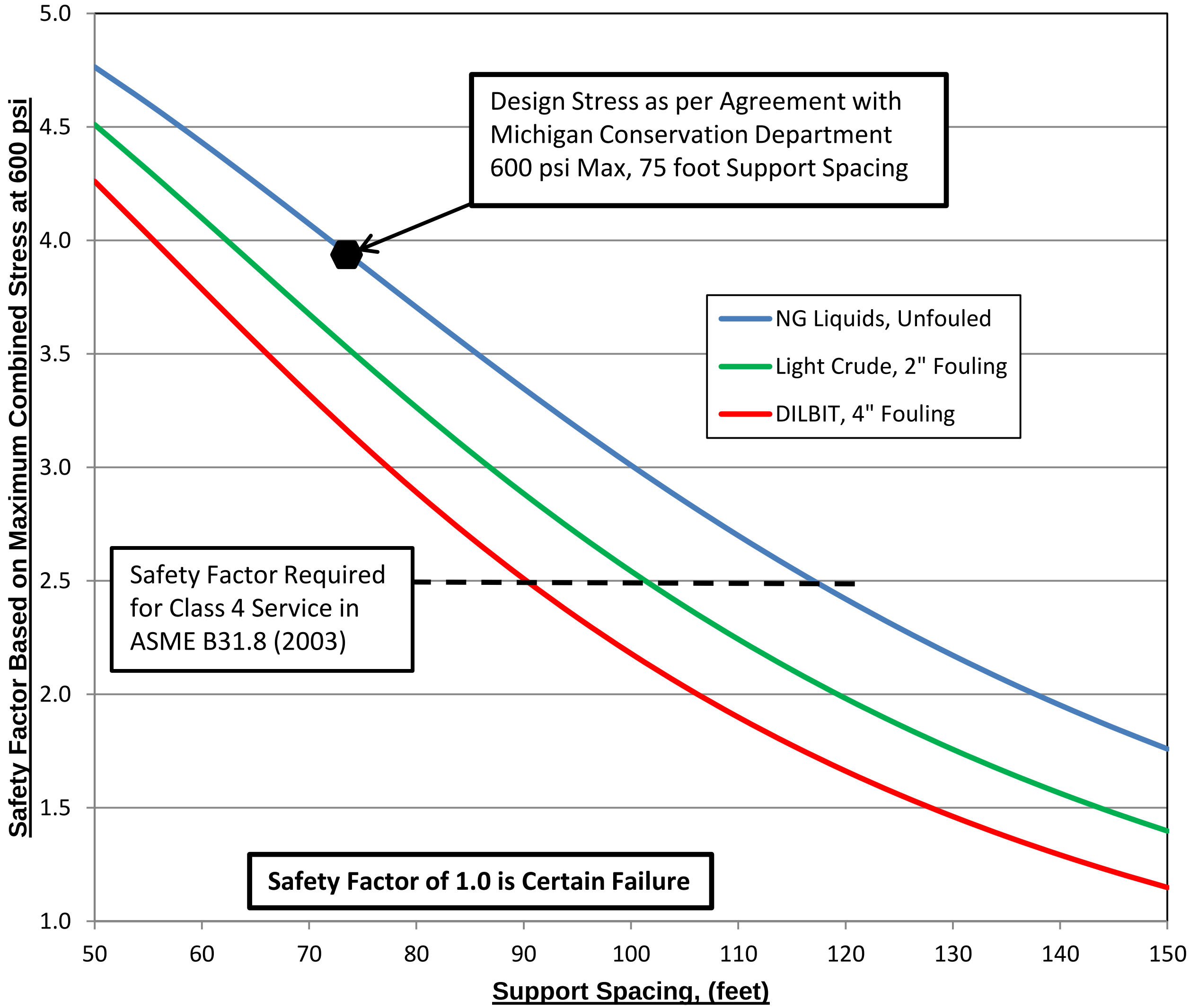
Unsupported Section of Line 5

Line 5 Biological Fouling

Pipeline designers did not contemplate the fouling that came with the introduction of invasive species thought the St Lawrence Seaway which opened in 1959

Is the weight added to line 5 by fouling and cargo changes significant?

Reliability of Line 5 Straits Crossing…the Stress due to Gravity



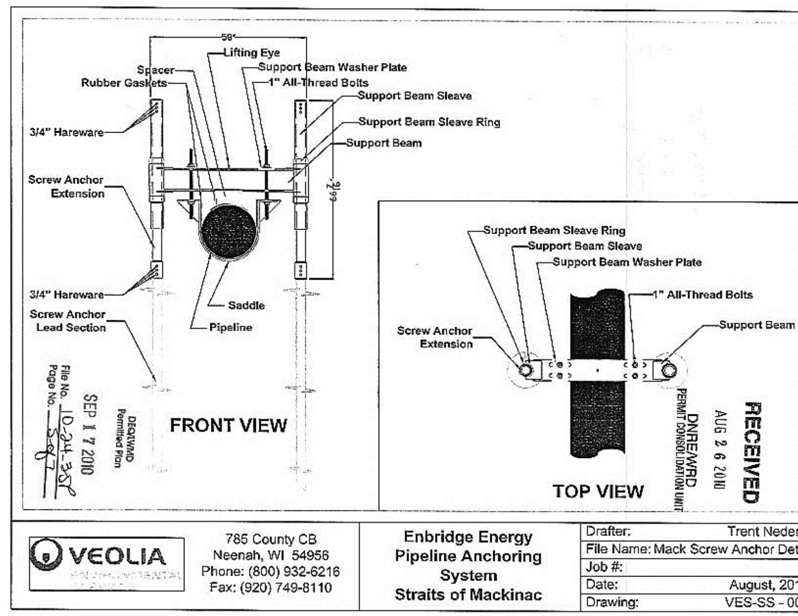
Line 5 Supports

Enbridge Operational Reliability Plan Report 2014

"Federal regulation requires that underwater laterals such as the Straits pipelines be inspected every five years. Enbridge instead chose a more conservative, voluntary inspection cycle of two years. During our regular two-year underwater inspections, if we should find any washout of existing earthen supports, we install new, screw anchor pipe supports at the affected location(s), ensuring a permanent support solution. The maximum spans we have discovered in the last ten years are approximately 90 feet, or about 64 percent of the maximum safe span distance. As a result of the support installation program that ended in 2012, Enbridge achieved an average span length of less than 75 feet, or a "two times" safety factor. With the additional anchors to be installed in 2014 and the existing supports, the average span distance will drop to less than 50 feet or, on average, a "three times" safety margin. This safety margin is reflective of the environmental importance of this significant water crossing."

Enbridge Work Permits Reveal Unsupported Spans of ca. 140 Feet in the Past

Gravel Bed Support



Veolia Screw Anchor Support

Enbridge History of ROV Inspections and Support Additions

Table 2 ROV Inspection and Span Support Installation History of Line 5 Straits of Mackinac

Year of ROV Inspection	Follow up Actions (Anchor Support Installation)	Type of Support Installed
1963	None	
1972	None	
1975	3	Grout Bags
1979	None	
1982	None	
1987	7	Grout Bags
1989	None	
1990	None	
1992	6	Grout Bags
1997	None	
2001	8	Grout Bags and mechanical support
2003	16	Mechanical Screw Anchors
2004	16	Mechanical Screw Anchors
2005	14	Mechanical Screw Anchors
2006	12	Mechanical Screw Anchors
2007	None	
2010	7	Mechanical Screw Anchors
2012	17	Mechanical Screw Anchors

Total of 106 Supports Added by 2012

Enbridge Span Information Supplied to Michigan Attorney General 11/19/14

Span Identifier	2014 Length	2014 Span Height	2014 Support Length	2012 Length	2010 Length	2007 Length	2006 Length	2005 Length	Touch Down Position and Type (Year Install)	Support Depth	Latitude	Longitude
Southern Exposure Point	NA	NA	NA	NA	NA	NA	NA	NA	Only/Sand	66	45.79740051 N	84.76828612 W
E-75	NA	NA	NA	Silted In	70	69	73	80	NA	NA	NA	NA
									NA	NA	NA	NA
E-74A	50	0.5	240' to Bury	80	61	67	67	71	South/Sand	69	45.79803465 N	84.76803487 W
									North/Anchor (2004)	70	45.79817336 N	84.76798054 W
E-74B South	70	0.5	Shared Touch Down ^	56	109	100			South/Anchor (2004)	70	45.79817336 N	84.76798054 W
									North/Anchor (2010)	71	45.79836191 N	84.76790185 W
E-74B North	47	0.5	Shared Touch Down ^	48					South/Anchor (2010)	71	45.79836191 N	84.76790185 W
									North/Anchor (2006)	70	45.79848622 N	84.76785431 W
E-74C	28	1	Shared Touch Down ^	16	13	14			South/Anchor (2006)	70	45.79848622 N	84.76785431 W
									North/Sand	69	45.79855919 N	84.7678226 W
E-71A	30	0.5	111' to E74C North	76	87	86	86	84	South/Sand	71	45.79885179 N	84.76772027 W
									North/Anchor (2014)	71	45.79893197 N	84.76769084 W
E-71B	49	0.5	Shared Touch Down ^						South/Anchor (2014)	71	45.79893197 N	84.76769084 W
									North/Anchor (2005)	72	45.79906039 N	84.76764254 W
E-72	44	0.5	Shared Touch Down ^	40	40	38	36	48	South/Anchor (2005)	72	45.79906039 N	84.76764254 W
									North/Sand	72	45.79917455 N	84.76759603 W
E-77	37	1	9' to E-72	34	44	52	44	42	South/Sand	72	45.79919654 N	84.76758791 W
									North/Sand	72	45.799292 N	84.76754813 W
E-26	54	1	202' to E77	48	54	45	48	51	South/Clay	76	45.79982164 N	84.76734294 W
									North/Sand	76	45.7999639 N	84.76728235 W
E-25A	38	0.5	42' to E-26	87	91	85	84	96	South/Sand	81	45.80007298 N	84.76724349 W
									North/Anchor (2014)	80	45.80017387 N	84.76720464 W
E-25B	48	0.5	Shared Touch Down ^						South/Anchor (2014)	80	45.80017387 N	84.76720464 W
									North/Sand	79	45.80029924 N	84.76715103 W
E-24	44	0.5	114' to E25B	44	50	45	46	37	South/Sand	81	45.80059751 N	84.76703994 W
									North/Sand	82	45.80071223 N	84.76699755 W
E-23A South	28	0.5	96' to E-24	86	85	81	86	84	South/Sand	83	45.80096148 N	84.76690243 W
									North/Anchor (2014)	85	45.80103603 N	84.76687496 W
E-23A North	58	0.5	Shared Touch Down ^						South/Anchor (2014)	85	45.80103603 N	84.76687496 W
									North/Anchor (2003)	85	45.80118708 N	84.7668158 W
E-23B South	61	0.5	Shared Touch Down ^	66	87	86	90	90	South/Anchor (2003)	85	45.80118708 N	84.7668158 W
									North/Anchor (2012)	84	45.80134576 N	84.76674988 W
E-23B North	31	1	Shared Touch Down ^	26					South/Anchor (2012)	84	45.80134576 N	84.76674988 W
									North/Sand	83	45.80142404 N	84.76671263 W
E-27	63	0.5	78' to E23B North	58	69	65	66	74	South/Sand	82	45.80162764 N	84.76663722 W
									North/Sand	81	45.80179248 N	84.76657389 W
E-28A South	37	1	52' to E-27	70	81	73	74	81	South/Sand	82	45.80193012 N	84.76652267 W
									North/Anchor (2014)	83	45.8020281 N	84.76649157 W
E-28A North	38	1	Shared Touch Down ^						South/Anchor (2014)	83	45.8020281 N	84.76649157 W
									North/Anchor (2005)	83	45.80212884 N	84.76645585 W
E-28B	63	1	Shared Touch Down ^	66	69	65	64	72	South/Anchor (2005)	83	45.80212884 N	84.76645585 W
									North/Sand	81	45.80229567 N	84.76639508 W
E-29	59	1	25' to E28B	60	55	44	63	53	South/Sand	81	45.8023587 N	84.76636855 W
									North/Sand	79	45.80251327 N	84.76631514 W
E-30A	38	1	22' to E29	72	83	82	82	89	South/Sand	78	45.80256885 N	84.76629197 W
									North/Anchor (2014)	77	45.80267125 N	84.76626081 W
E-30B	36		Shared Touch Down ^						South/Anchor (2014)	77	45.80267125 N	84.76626081 W
									North/Sand	76	45.80276442 N	84.76622516 W
E-38	36	1	86 to E-30B	34	45	32	37	46	South/Sand	73	45.80299189 N	84.76614415 W
									North/Sand	72	45.80308618 N	84.76611094 W
E-37	56	1	155' to E-38	54	54	50	54	53	South/Sand	74	45.80349412 N	84.7659669 W
									North/Sand	74	45.80363883 N	84.76590965 W
E-36	50	0.5	12' to E-37	42	41	48	42	34	South/Sand	73	45.80366947 N	84.76589995 W
									North/Sand	73	45.80380204 N	84.76585057 W
E-35A	36	0.5	33' to E-36	60	67	66	67	63	South/Sand	73	45.80389819 N	84.76581718 W
									North/Anchor (2014)	75	45.80399347 N	84.7657808 W
E-35B	36	0.5	Shared Touch Down ^						South/Anchor (2014)	75	45.80399347 N	84.7657808 W
									North/Sand	76	45.80408779 N	84.76574484 W
E-34A	58	1	25' to E35B	58	62	54	61	59	South/Sand	77	45.80415409 N	84.76572209 W
									North/Anchor (2003)	79	45.80430605 N	84.76566353 W
E-34B South	53	1	Shared Touch Down ^	73	80	82	74	75	South/Anchor (2003)	79	45.80430605 N	84.76566353 W
									North/Anchor (2014)	78	45.80444616 N	84.76561487 W
E-34B North	21	1	Shared Touch Down ^						South/Anchor (2014)	78	45.80444616 N	84.76561487 W
									North/Sand	79	45.80450136 N	84.76558981 W
E-33	43	1	109 to E34B North	46	52	47	45	39	South/Sand	82	45.80478655 N	84.76548042 W
									North/Sand	86	45.80490015 N	84.76543833 W
E-32A-A	6		21' to E-33	Silted in	11	17			South/Clay	88	45.80495542 N	84.76541633 W
									North/Anchor (2006)	88	45.80497238 N	84.76541225 W
E-32A South	40	1	Shared Touch Down ^	47	92	89			South/Anchor (2006)	88	45.80497238 N	84.76541225 W
									North/Anchor (2012)	92	45.80507422 N	84.76536839 W
E-32A North	47	1.5	Shared Touch Down ^	40					South/Anchor (2012)	92	45.80507422 N	84.76536839 W
									North/Anchor (2003)	94	45.80519687 N	84.76532216 W
E-32B South	67	1	Shared Touch Down ^	88	87	97	85	79	South/Anchor (2003)	94	45.80519687 N	84.76532216 W
									North/Anchor (2014)	96	45.80537562 N	84.76525738 W
E-32B North	22	1	Shared Touch Down ^						South/Anchor (2014)	96	45.80537562 N	84.76525738 W
									North/Clay	95	45.80543416 N	84.7652347 W
E-31	36	1	22' to E32B North	34	36	42	42	37	South/Clay	95	45.80549271 N	84.76521037 W
									North/Clay	96	45.80558613 N	84.76517358 W
E-39	63	1	58' to E-31	74	83	67	78	66	South/Clay	98	45.80573967 N	84.76511784 W
									North/Sand	98	45.80590475 N	84.76505337 W
E-40A	22	1	370' to E39	85	82	80	90	97	South/Sand	103	45.80688466 N	84.7646828 W
									North/Anchor (2014)	104	45.80694103 N	84.7646623 W
E-40B	60	1	Shared Touch Down ^						South/Anchor (2014)	104	45.80694103 N	84.7646623 W
									North/Sand	104	45.80709655 N	84.76459532 W

Discrete Supports Have One Disadvantage

GEI Consultants

Effect of Mussel Encrustation on Line 5

"GEI did not find literature which reported increased bacterial loads on pipes or increase in corrosion rates due to higher bacterial loads. "

"It is GEI's professional opinion based on the literature and examination of these mussels that this relatively thin layering of mussels over the pipe beneath the Straits of Mackinaw result in negligible additional load on the pipe should have no adverse impact on the pipe. "

US Army Corps of Engineers Zebra Mussel Control Handbook for Facility Operators

"When a thick layer of zebra mussels covers a metallic surface, it can cause anoxia and pH reduction, exacerbating corrosion rates."

ET Conclusions Regarding GEI Mussel Encrustation Report

- Report does not contain useful engineering information such as the wet density of the mussels or an estimate of their volume or information on their growth rate
- Report does not address the corrosive environment produced in the mussel colony
- GEI Consultants focused on biology and no stress calculations were done
- Where did Enbridge get that piece of pipe?........(No chain of custody info)

Excessive Curvature and Pipe Bending in Pipe Laying Operations

Bending Stress as a Function of Pipe Curvature

1953 Easement Restriction

(4) The minimum curvature of any section of pipe shall be no less than two thousand and fifty (2,050) foot radius.

$$Sb = (Es*r)/R$$

where Sb = bending stress

Es = Youngs modulus for steel

r = Pipe Radius

R = radius of curvature of pipeline

Young's Modulus for Steel, (psi) =	2.90E+07
Pipe Radius (ft) =	0.83
Radius of Curvature, (ft) =	2050
Calculated Bending Stress, (psi) =	1.18E+04
Calculated Bending Stress, (% Yield) =	34%

Conclusions Regarding Line 5 Stresses

The restrictions in the 1953 easement led to a very conservative and safe design for the Straits crossing of line 5 but my calculations show that the 1953 MPSC Order may have been superseded regarding the 500-550 psi maximum pressure limit.

The 600 psi maximum pressure restriction in the easement is unlikely to be exceeded in normal pipeline operations. Two scenarios could overpressure the line:

1. The line is valved off in Mackinaw City while the pumps are left running in Naubinway (Deadheaded).
2. Mis-operation of the line causes a severe pressure surge (Water Hammer).

The average pressure on the line has been significantly increased by the addition of pump stations in Michigan. Nothing is publically available about how this affects risk!

The seventy five foot maximum unsupported length restriction resulted in very safe bending stresses in line five at the time of design. Since then, changes in cargo density and the growth of marine life on the line has increased the bending stress on line 5 so that the safety factors originally used by the designers and approved by the State of Michigan no longer apply.

Because the pipeline was originally supported by a gravel bed that has proved susceptible to washouts, unsupported spans on the order of 140 feet have resulted in a reduced safety margin compared to that which was originally contemplated by the designers and approved by the State of Michigan.

Enbridge has currently added around 122 (?) discrete supports to the pipeline but about 300 would be required for complete support of unburied segments of the line.

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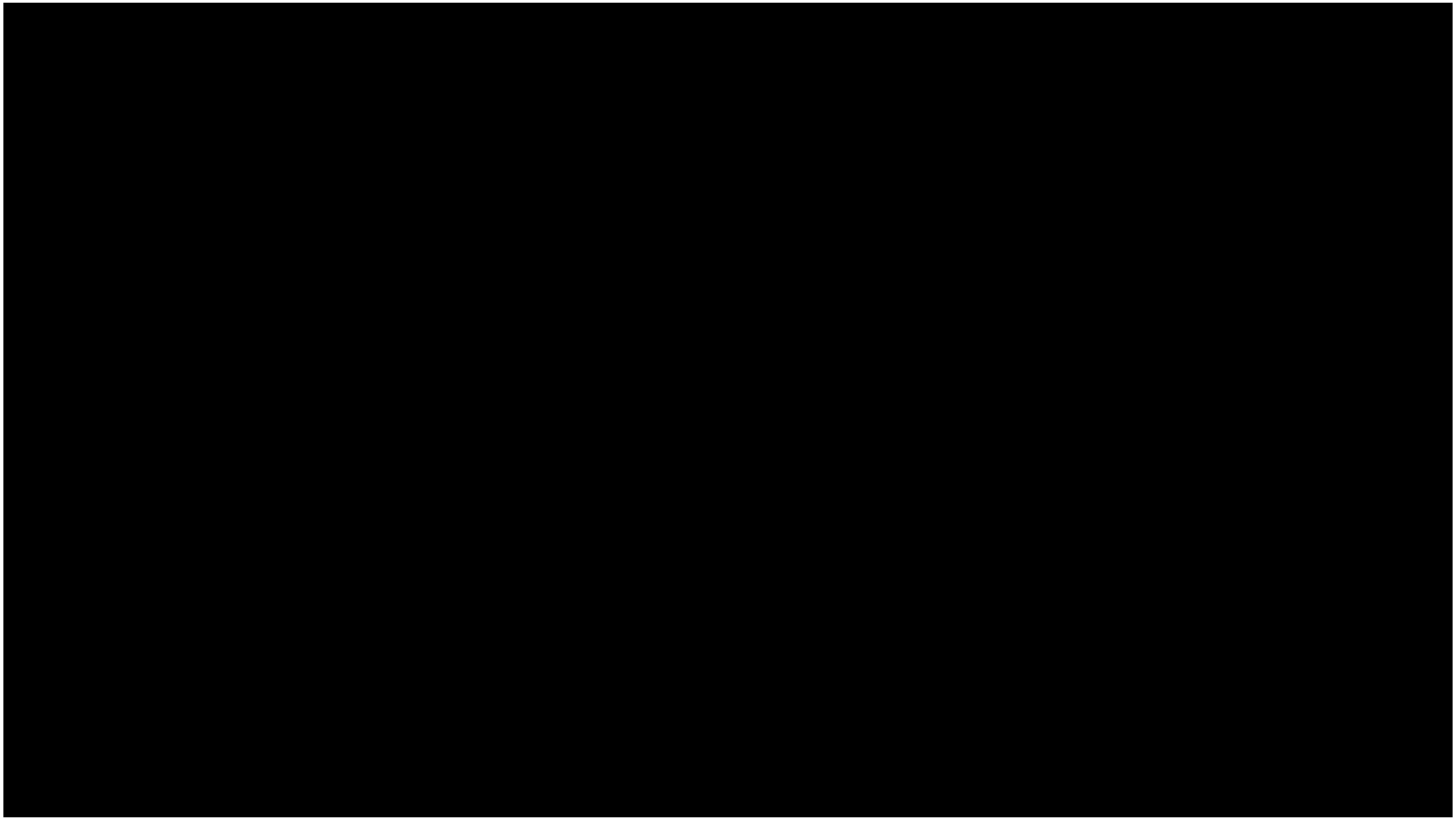
A Diver, a Shovel and a Washout (?)



Pipeline Coating Integrity is Critical for Minimization of Stress Corrosion Cracking

1953 Easement Restrictions Regarding Corrosion Protection

(8) Cathodic protection shall be installed to prevent deterioration of the pipe

(9) All pipe shall be protected by asphalt primer coat, by inner wrap and outer wrap composed of glass fiber fabric material and one inch by four inch (1” x 4”) slats prior to installation.

“Engineering and Construction Considerations for the Mackinac Pipeline Company’s Crossing of the Straits of Mackinac” submitted by Mackinac Pipeline Company/Lakehead Pipeline Company to the Michigan Department of Conservation, January, 1953

“After coating with asphalt primer, fiberglass inner wrap and an asbestos felt outer wrap, and after attaching 1” x 4” wood slats to the full circumference of the pipe, it will be lowered onto a previously prepared “bed” on the floor of the Straits.”

- Enbridge documentation claims that the coating is a coal tar based product not asphalt and has no information about reinforcing fabrics or how the girth welds were coated.

- Enbridge documentation makes no mention of slats or lagging

The Mystery of the Missing Slats

ET Photo of Propeller Shaft for Cutter Mackinaw

Temporary Lagging on a Pipeline for Abrasion Protection

Pipeline Lagging on Line 5

Enbridge Dent Inspection Video

National Wildlife Federation Photo

NIST Special Publication 1044

Advanced Coatings R&D for Pipelines and Related Facilities

The proceedings of a workshop held June 9-10, 2005
at the National Institute of Standards and Technology,

Pipeline Operators Viewpoint on Underground Coatings Issues

Jeff Didas
Colonial Pipeline Company

Coal Tar Adhesion Failure

Failed Coal Tar Coating

Jeff Didas, Colonial Pipeline Company

Summary of Issues

- Repair & Rehabilitation Coatings are the major issue for pipeline operators.
- Deterioration & Aging of Existing Coatings are an ongoing issue for pipeline operators.
- Improving handling properties for new pipeline coatings, flexibility of new coatings, as well as weld joint coatings (quality) and in field repairs (quality) for the coating are major issues for pipeline operators.

Coating Integrity is Critical to Pipeline Longevity

The coating cannot be visually inspected wherever there is lagging or where the line is supported by the gravel bed or where the line is covered with mussels and algae

The cathodic protection system will not prevent local corrosion and can cause coating disbondment

Because of the low conductivity of fresh water, electrical leakage cannot be used to determine coating defects

Enbridge “ensures” coating integrity by using In Line Inspection (ILI) tools to look for metal loss and cracking

The business of running aging steel pipelines depends on ILI technology to find “features” that can be analyzed and compared to corporate risk standards to determine if repair or eventually replacement is warranted. Corporate risk standards vary as do action plans.

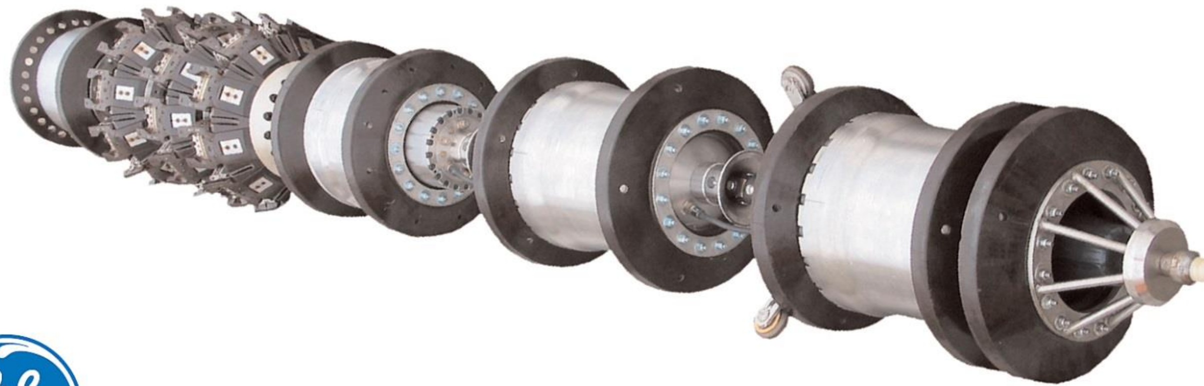
In Line Inspection and Integrity Management Services

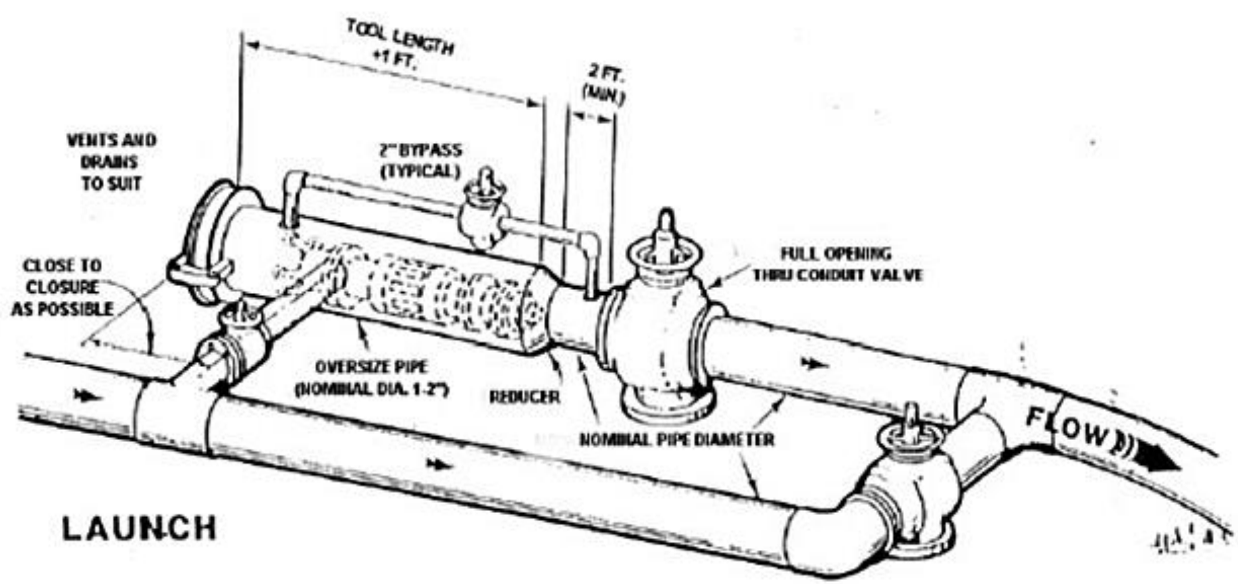
….a very big business

GE is one of many tool, service and integrity management firms

GE Oil & Gas

Complex Pig and Pig Launcher





PII Pipeline Solutions
a GE Oil & Gas and Al Shaheen joint venture

The right technology
for every integrity challenge

Tools not to scale

— Calipers
— Magnetics
— Ultrasonics

● Best fit
● Good fit
○ Optional

Application Specifics

Tool	Gas medium	Liquid medium	Multi/Dual-diameter	Thick wall pipe	High-flow velocity
CalScan EP	Best fit	Best fit	Good fit	Best fit	Good fit
CalScan XR	Best fit	Best fit	Good fit	Best fit	Best fit
MagneScan HR	Best fit	Best fit	Good fit	Good fit	Best fit
MagneScan SHR	Best fit	Best fit	Good fit	Good fit	Best fit
SmartScan	Best fit	Best fit	Best fit	Good fit	Good fit
TranScan TFI	Best fit	Best fit	Good fit	Good fit	Good fit
UltraScan WM	Good fit	Best fit	Good fit	Best fit	Good fit
UltraScan Duo	Good fit	Best fit	Best fit	Best fit	Good fit
UltraScan CD	Good fit	Best fit	Good fit	Best fit	Best fit
EmatScan	Best fit	Best fit	Optional	Optional	Good fit

Metal Loss Features

Tool	General corrosion	Shallow pitting	Deep pitting	Pinholes	Axial groove	Narrow axial external corrosion	Wall thinning/erosion	Laminations
CalScan EP								
CalScan XR								
MagneScan HR	Best fit	Best fit	Best fit	Good fit	Good fit	Good fit		
MagneScan SHR	Best fit	Best fit	Best fit	Best fit	Best fit	Best fit		
SmartScan	Good fit	Good fit	Good fit		Good fit	Good fit		
TranScan TFI	Good fit	Good fit	Good fit		Best fit	Best fit		
UltraScan WM	Best fit	Good fit	Optional	Optional	Best fit	Best fit	Best fit	Best fit
UltraScan Duo	Best fit	Good fit	Good fit	Optional	Best fit	Best fit	Best fit	Best fit
UltraScan CD								
EmatScan								

Crack Features

Tool	Hook/seam weld crack	Hydrogen inducted crack	Fatigue crack	Shrinkage crack	Circumferential crack	SCC	Lack of fusion
CalScan EP							
CalScan XR							
MagneScan HR							
MagneScan SHR							
SmartScan							
TranScan TFI	Good fit	Good fit	Good fit	Good fit		Good fit	Good fit
UltraScan WM							
UltraScan Duo	Best fit	Best fit	Best fit	Best fit	Optional	Best fit	Best fit
UltraScan CD	Best fit	Best fit	Best fit	Best fit	Optional	Best fit	Best fit
EmatScan	Good fit	Best fit	Best fit	Best fit		Best fit	Best fit

Deformation & Geometry

Tool	Plain dent	Dents with metal loss	Small dents (1" diameter)	ID expansions	Buckle/wrinkle	Bend	Bending strain/pipe movement
CalScan EP	Good fit	Good fit	Good fit	Best fit	Best fit	Best fit	Best fit
CalScan XR	Best fit	Good fit	Best fit	Best fit	Best fit	Best fit	Optional
MagneScan HR	Good fit	Best fit	Good fit	Best fit	Best fit	Best fit	Best fit
MagneScan SHR	Best fit	Best fit	Best fit	Best fit	Best fit	Best fit	Best fit
SmartScan							
TranScan TFI	Good fit	Good fit	Good fit	Good fit	Good fit	Good fit	Good fit
UltraScan WM							
UltraScan Duo							
UltraScan CD							
EmatScan							

Integrity Assessments

Tool	Corrosion growth assessment	Fitness-for-purpose (FFP)	Dent strain assessment	Crack threat integrity assessments	Bending strain assessment	Centerline mapping
CalScan EP		Best fit	Best fit		Best fit	Best fit
CalScan XR		Best fit	Best fit		Optional	Optional
MagneScan HR	Best fit	Best fit	Best fit		Best fit	Best fit
MagneScan SHR	Best fit	Best fit	Best fit		Best fit	Best fit
SmartScan	Best fit	Best fit			Best fit	Best fit
TranScan TFI	Best fit	Best fit	Best fit	Best fit	Optional	Optional
UltraScan WM	Best fit	Best fit				
UltraScan Duo	Best fit	Best fit		Best fit		
UltraScan CD		Best fit		Best fit		
EmatScan		Best fit		Best fit		

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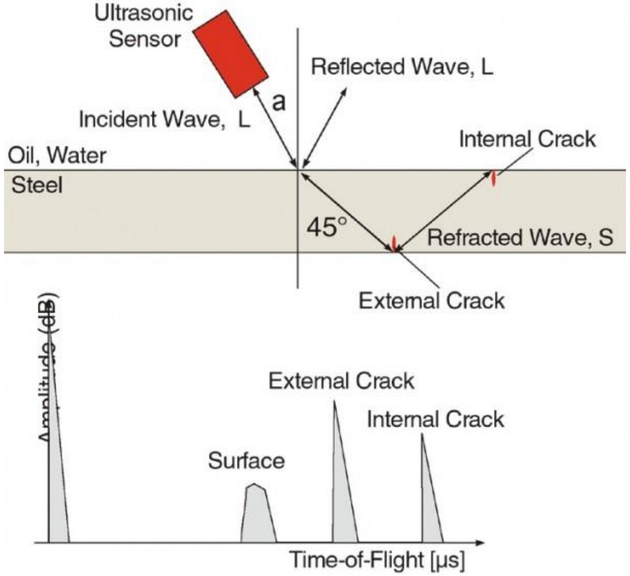
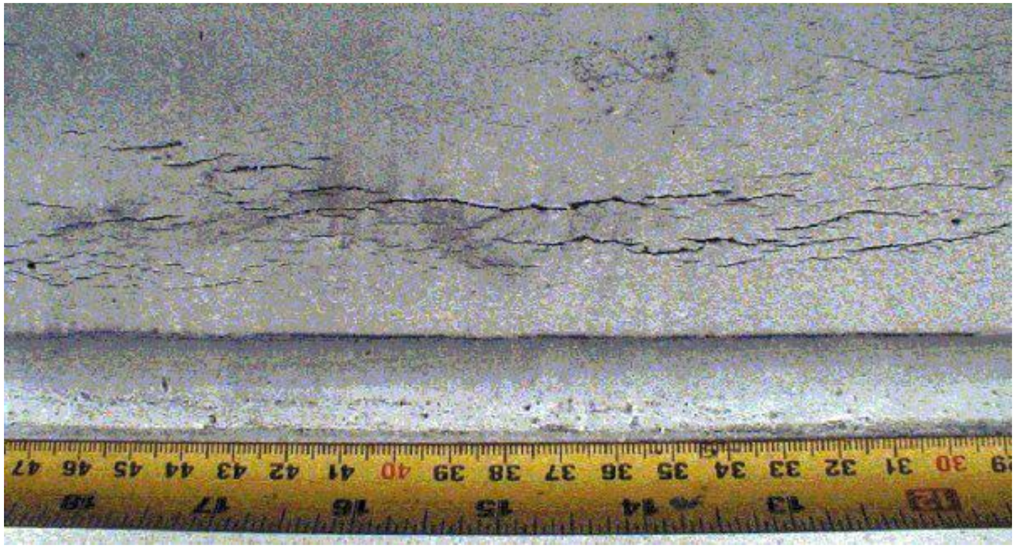
GE Ultrascan CD Intelligent Pig



Ultrasonic Crack Detection

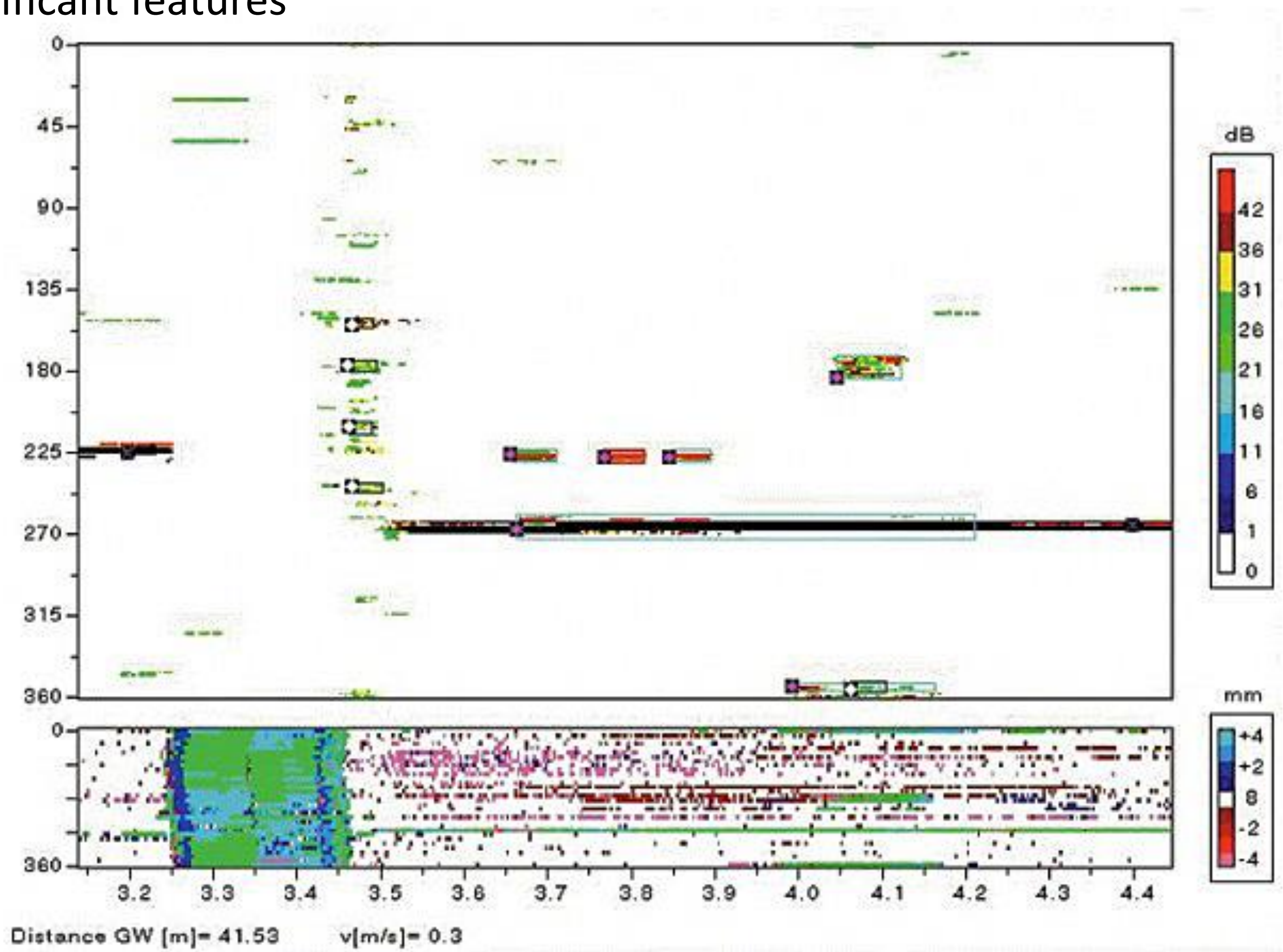
Ultrasonic Array



Stress Corrosion Crack Colony

ILI Inspection Data…Lots of It!

A travel through 100 km of 24” pipeline generates around 100 terabytes of primary data. Data must be processed onboard to compress it for storage and post processed to identify significant features



API 1163 Qualification of In Line Inspection Systems

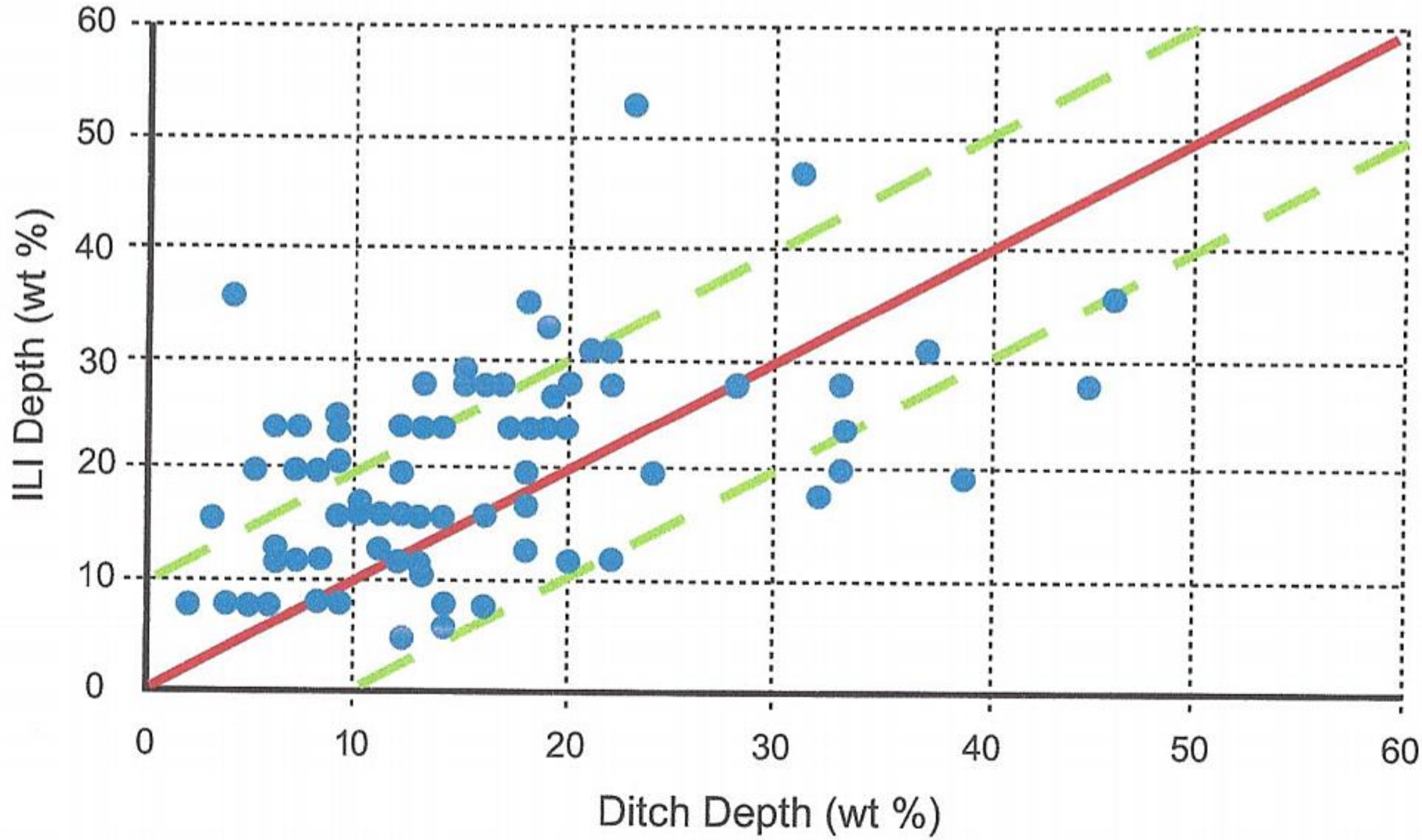


Figure C.1—Unity Chart Example

Can the Remaining Life of Line 5 be Predicted?

PHMSA Report on Enbridge Line 6B Failure

"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."

Three Approaches to Lifetime Prediction

1. Extrapolation of ILI data to endpoint,

2. Statistical prediction based on large data sets,

3. Statistical prediction based on ILI and incident records for an individual pipeline.
   a. All incidents are important. A record of frequent small incidents is predictive of a big one.
   b. Long term successful operation without a major failure is not evidence that it will never happen.

Enbridge Operational Reliability Report
In Line Inspection Data for Corrosion and Cracking

P. 14 **Industry Guidelines for CGR Compared to Line 5 CGRS**

Standard/Guideline Recommendations

NACE RP0102	0.3mm/yr: 80% confidence max rate with ‘good’ CP
ASME B31.8S	0.31mm/yr max rate for active corrosion in low resistivity soils
GRI-00/0230	0.56mm/yr for pitting; 0.3mm/yr for general corrosion

Line 5 Avg. Rates	**External Corrosion 0.038mm/yr – 0.068mm/yr**
Line 5 Avg. Rates	**Internal Corrosion 0.018mm/yr – 0.046mm/yr**
Line 5 Straits of Mackinac	**Int. and Ext. Corrosion No observed corrosion growth**

p. 15 **Line 5 In-Line Inspection Metrics — Cracking**

Depth of ILI Crack Tool Anomalies

Feature Depth	0.040" - 0.080"	0.080" - 0.120"	> 0.120"
# Features	661	48	0
# Features per Mile	1.032/mi	0.070/mi	0.000/mi

Enbridge Corrosion Rate Data Analysis

	Lower Value	Upper Value	Average
Internal Corrosion Rate, (mm/yr)	0.018	0.046	0.032
External Corrosion Rate, (mm/yr)	0.038	0.068	0.053
Total Corrosion Rate, (mm/yr)			0.085
Total Corrosion Rate, (in/yr)			0.0033
Years in Service		62	
Total corrosion over Service Life, (in)			0.207

Pipe Size	Wall Thickness	Average Thickness Loss
30" x 9/32	0.281	74%
30" x 5/16	0.312	67%
30" x 11/32	0.344	60%
30" x3/8	0.375	55%
30" x 1/2	0.500	41%
30" x 11/16	0.687	30%
20" x 7/8	0.813	26%

“Bulge” Repair on Line 5 in 2012
Photo taken between I-75 and Eagles Nest Road at Learning Road

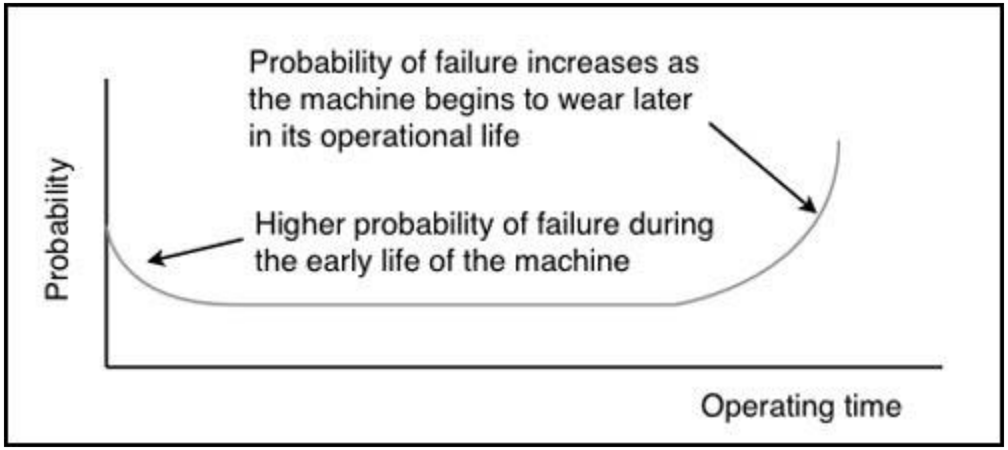
Enbridge Operational Reliability Report on Corrosion Rates

P. 14 **Industry Guidelines for CGR Compared to Line 5 CGRS**	
Line 5 Avg. Rates	External Corrosion 0.038mm/yr – 0.068mm/yr
Line 5 Avg. Rates	Internal Corrosion 0.018mm/yr – 0.046mm/yr
Line 5 Straits of Mackinac	**Int. and Ext. Corrosion No observed corrosion growth**

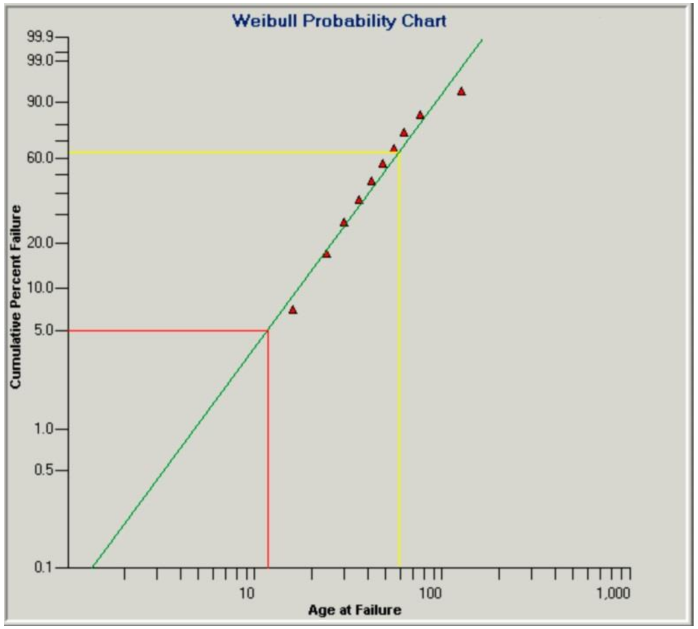
Enclosure to June 27, 2014 (Enbridge) Letter to Hon. Schuette & Hon. Wyant
Responses to Questions and Requests for Information Regarding the Straits Pipelines

The two crossings have been regularly inspected using ILI tools over the years. There are no features that meet excavation criteria reported to date. Note that two corrosion validation digs were executed in 2009 following the 2008 ILI run on the West crossing. Shallow corrosion features were found at ILI tool called area. The field non-destructive examination (NDE) reports of these two digs are provided in the folder titled "C1".

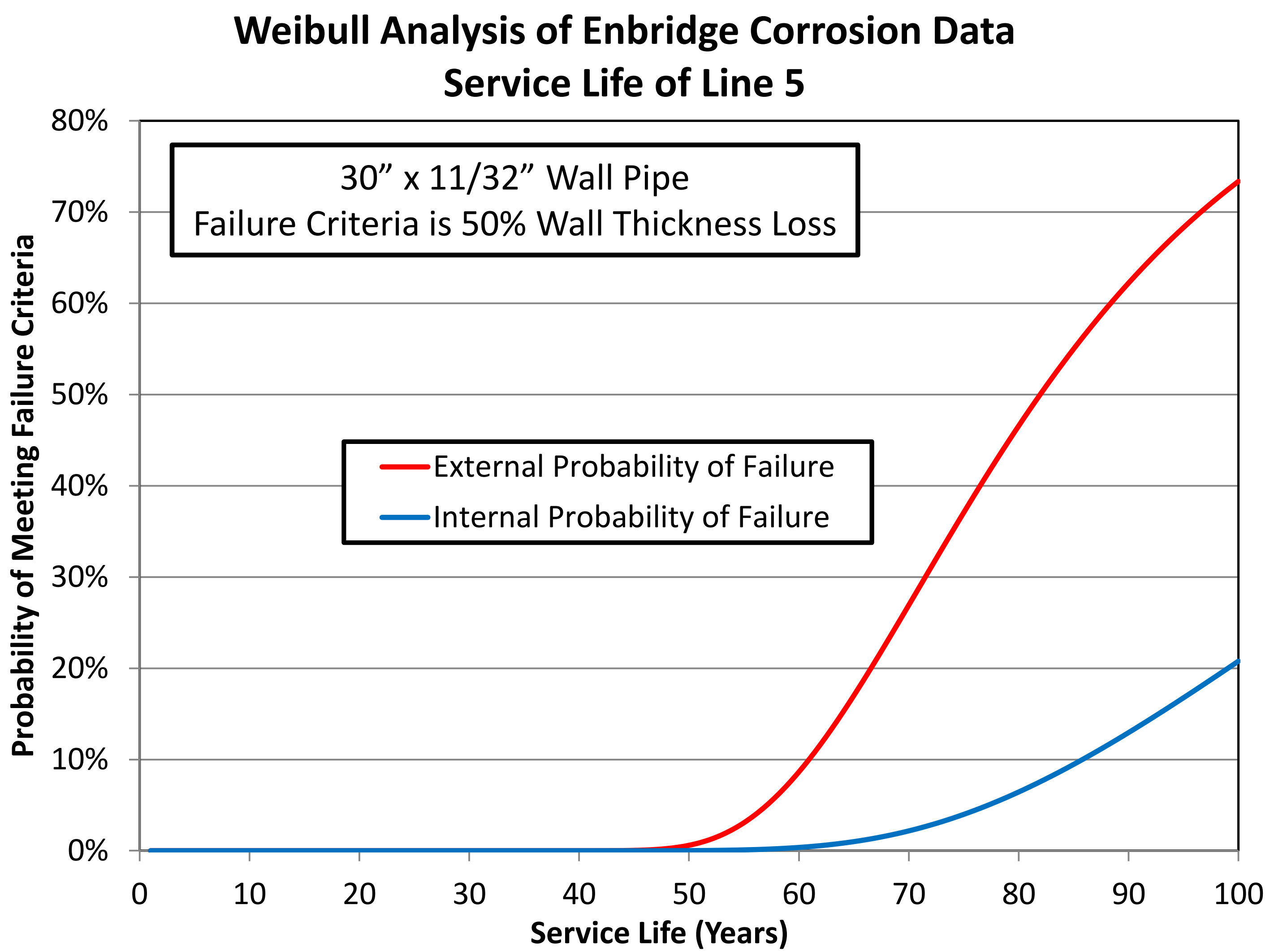
Statistical Reliability Prediction



Failure Probability in an Increment of Time



Cumulative Probability of Failure as Machine Ages


Weibull Analysis of Enbridge Corrosion Data
Service Life of Line 5
30” x 11/32” Wall Pipe
Failure Criteria is 50% Wall Thickness Loss
External Probability of Failure
Internal Probability of Failure
Probability of Meeting Failure Criteria
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
10
20
30
40
50
60
70
80
90
100
Service Life (Years)

Pipelines Can Be Insured
The Best Analysts of Pipeline Risk Work for Insurance Underwriters

- One study in Europe found that age was not a factor in pipeline failures up to the 30 year limit of their data

- No knowledge of how insurance and re-insurance carriers analyze risk

Pipeline Insurance – Technical Aspects Of Underwriting And Claims

Richard Radevsky, Technical Director**,** Charles Taylor Consulting plc, London, UK
Doug Scott, Risk Engineering Consultant, Charles Taylor Consulting plc, London, UK

"Insurance polices protect against a variety of specific perils and not against all causes of damage. For example, it is not possible to insure against corrosion of a pipeline, although the consequences of corrosion, such as clean up costs following leakage of materials from a corroded pipeline are insurable."

Conclusions

- The entire public record including information which has been obtained to date through the FOIA process is insufficient to adequately assess the reliability of line 5
- My analysis to date has raised far more questions than have been answered
- Enbridge's Operational Reliability Report lacks the technical detail necessary to support its conclusions
- Ensuring the safety of line 5 through the use of in line inspection tools is problematic
- Inspection without repair criteria and ongoing repair efforts is meaningless (The fatal line 6B flaw was known to Enbridge management for 5 years without triggering their repair process.)

Enbridge Energy Partners Limited
Line 5, Straits of Mackinaw Crossing
Engineering Opinion Report
Edward E. Timm, PhD, PE, March 14, 2015

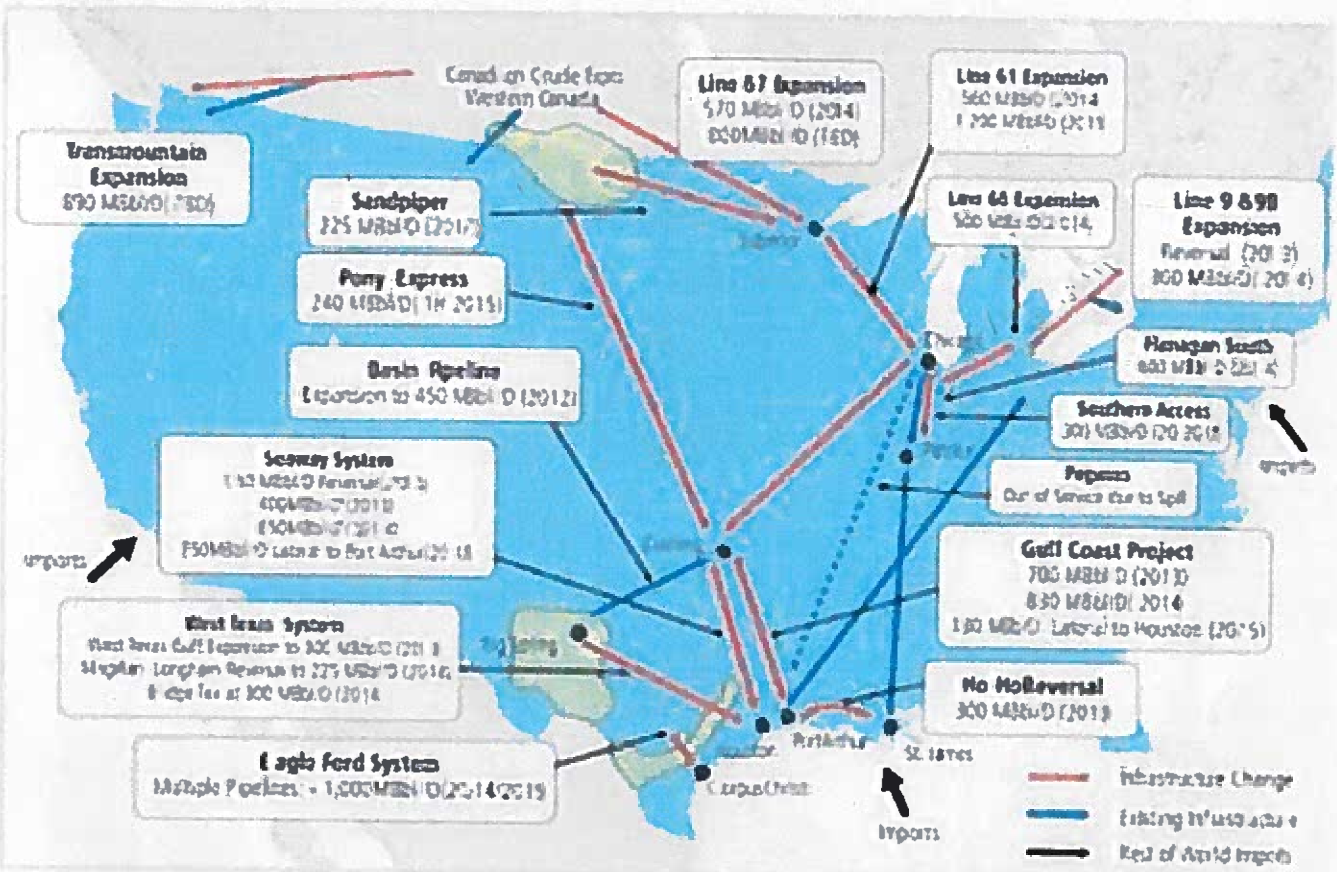
I believe it is likely that line 5 as it exists and operates in 2015 presents unacceptable risk for service that would be considered greater than Class 4 if it were a gas transmission pipeline.

It is my professional opinion that line 5 should be de-rated to its original design capacity of 300,000 bbl/d to reduce the stress on this very old pipeline and its cargo should be restriced to NGL's until a full analysis of its safety can be made using modern methods and all the information that exists.

APPENDIX 5

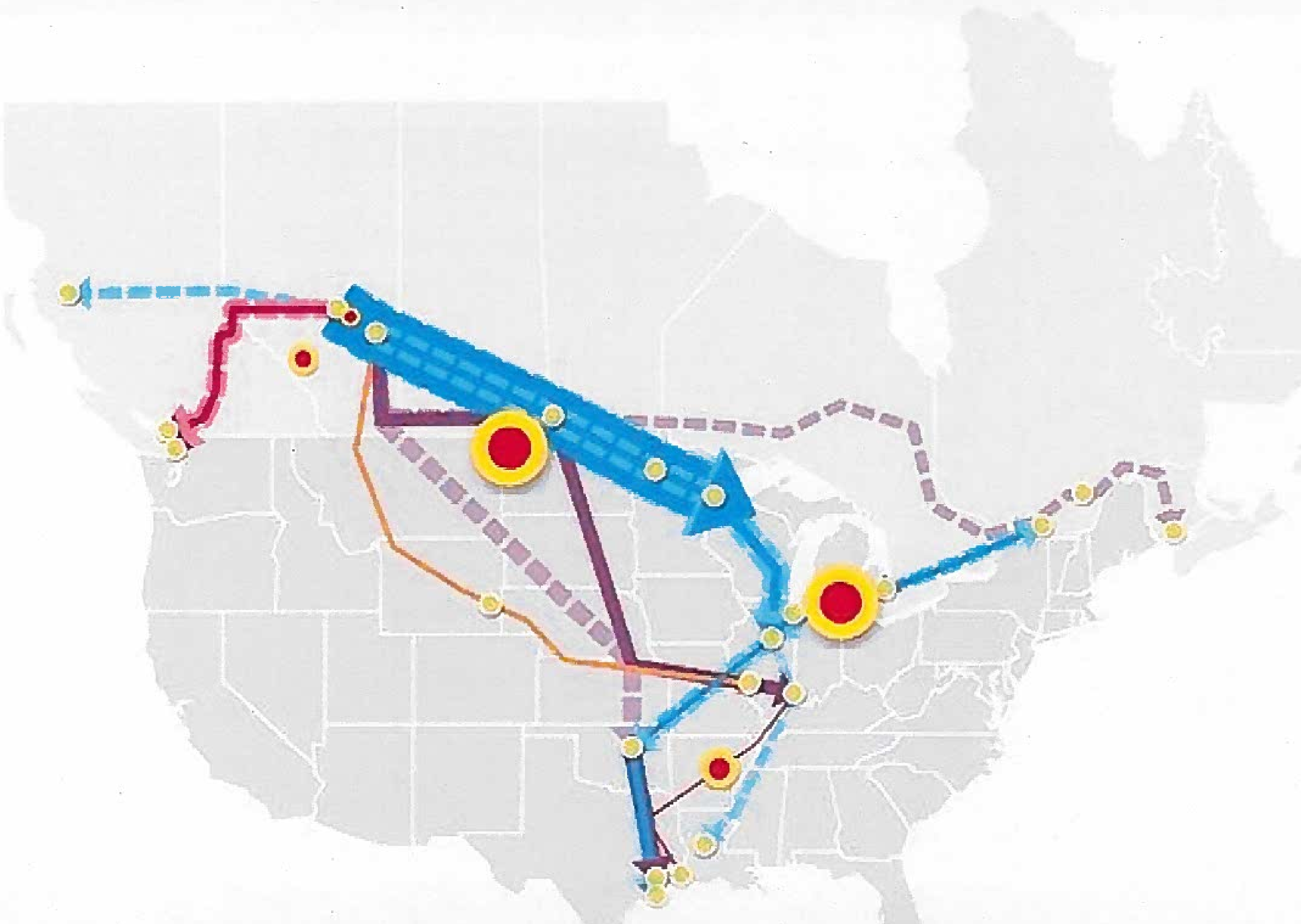
Subject: Map of Pipeline Expansion Plans to Move Tars to Markets through North America

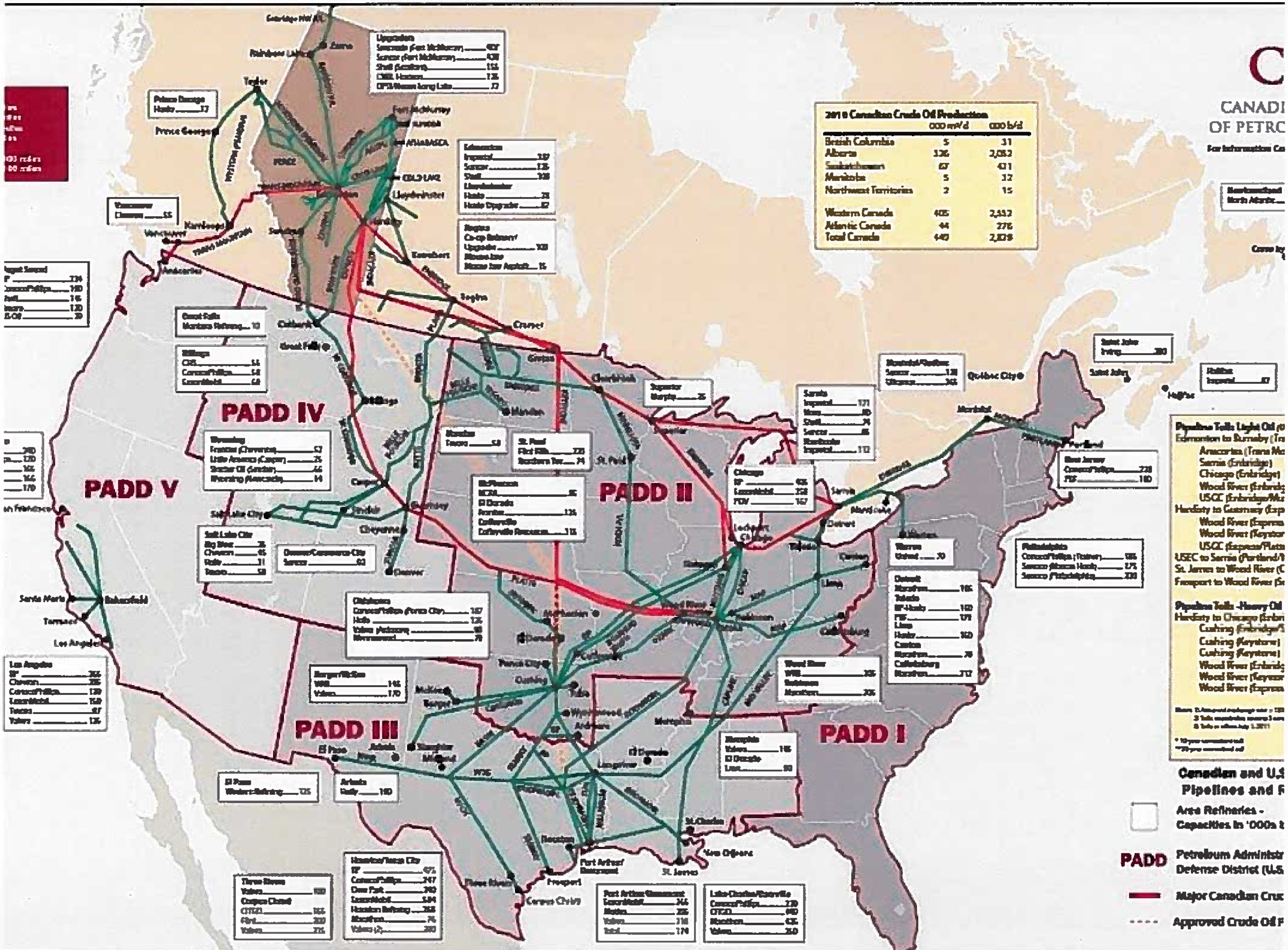
Pipeline & Gas Journal for June 2015, at p. 46, that is great and wanted to share.

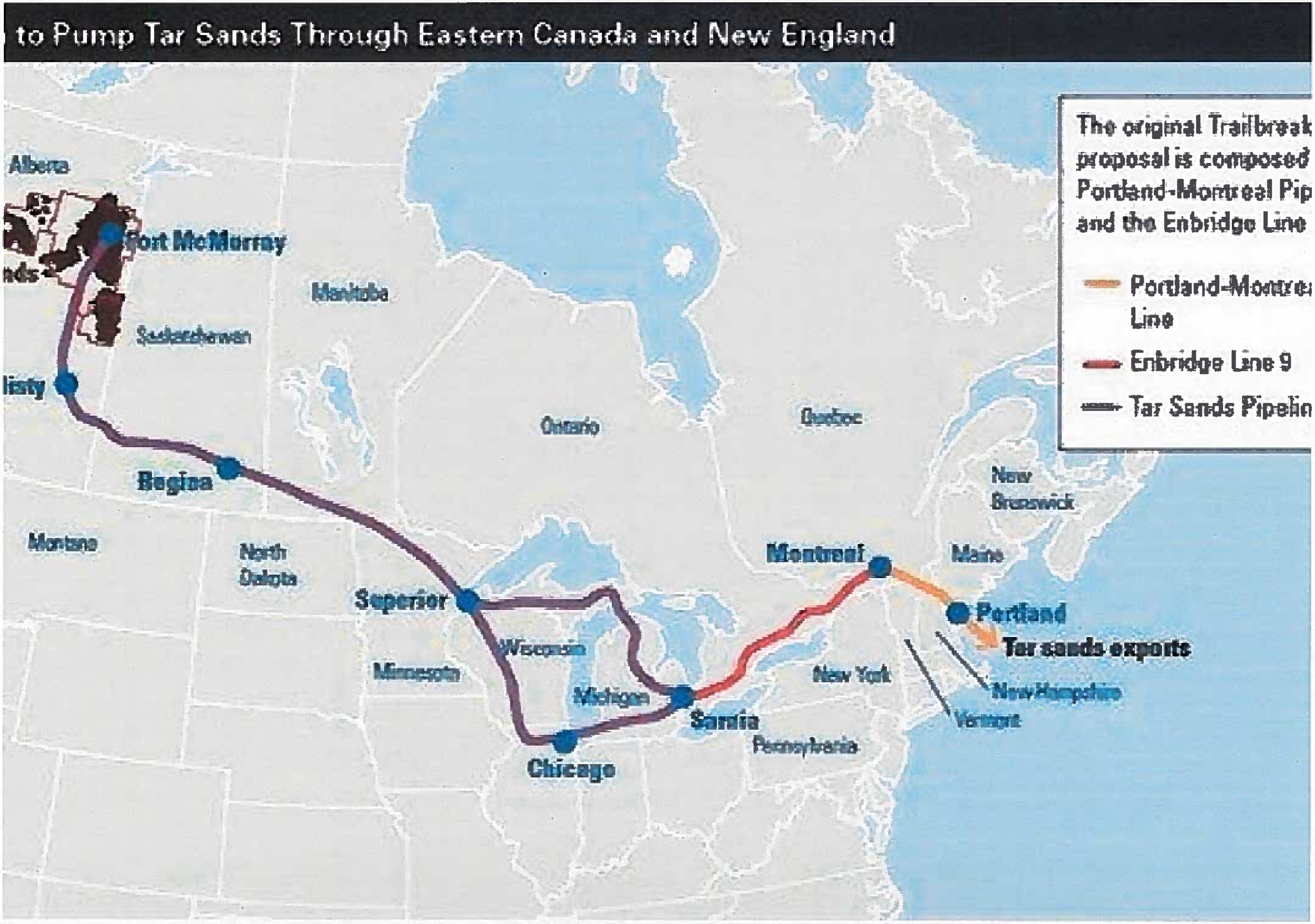


There have been substantial pipeline additions and some reversals of pipeline product flows to accommodate the changes in domestic producti regions and the volumes of product that are being transported.


Proposed Atlantic route
Kitimat
Enbridge Gateway
Trans Mountain
Edmonton
Anacortes
Enbridge Alberta Clipper
Enbridge (North Dakota) Expansion
Express
TransCanada Keystone XL
Clearbrook
Superior
St. Paul
Enbridge
Montreal
Saint John
Portland
Sarnia
Guernsey
Salt Lake City
Platte
Flanagan
Chicago
Philadelphia
TransCanada Keystone & Cushing Extension
Spearhead South
Spearhead North
Wood River
Patoka
Mustang
Cushing
Centurion Pipeline
ExxonMobil/ Enbridge Pegasus
Port Arthur
Houston
Canadian and U.S. Oil Pi
Enbridge Pipelines, AB C and connections to the U
Kinder Morgan Express
Kinder Morgan Trans Mo
TransCanada Keystone
Proposed pipelines to th
Existing / Proposed pipe
Expansion to existing pip



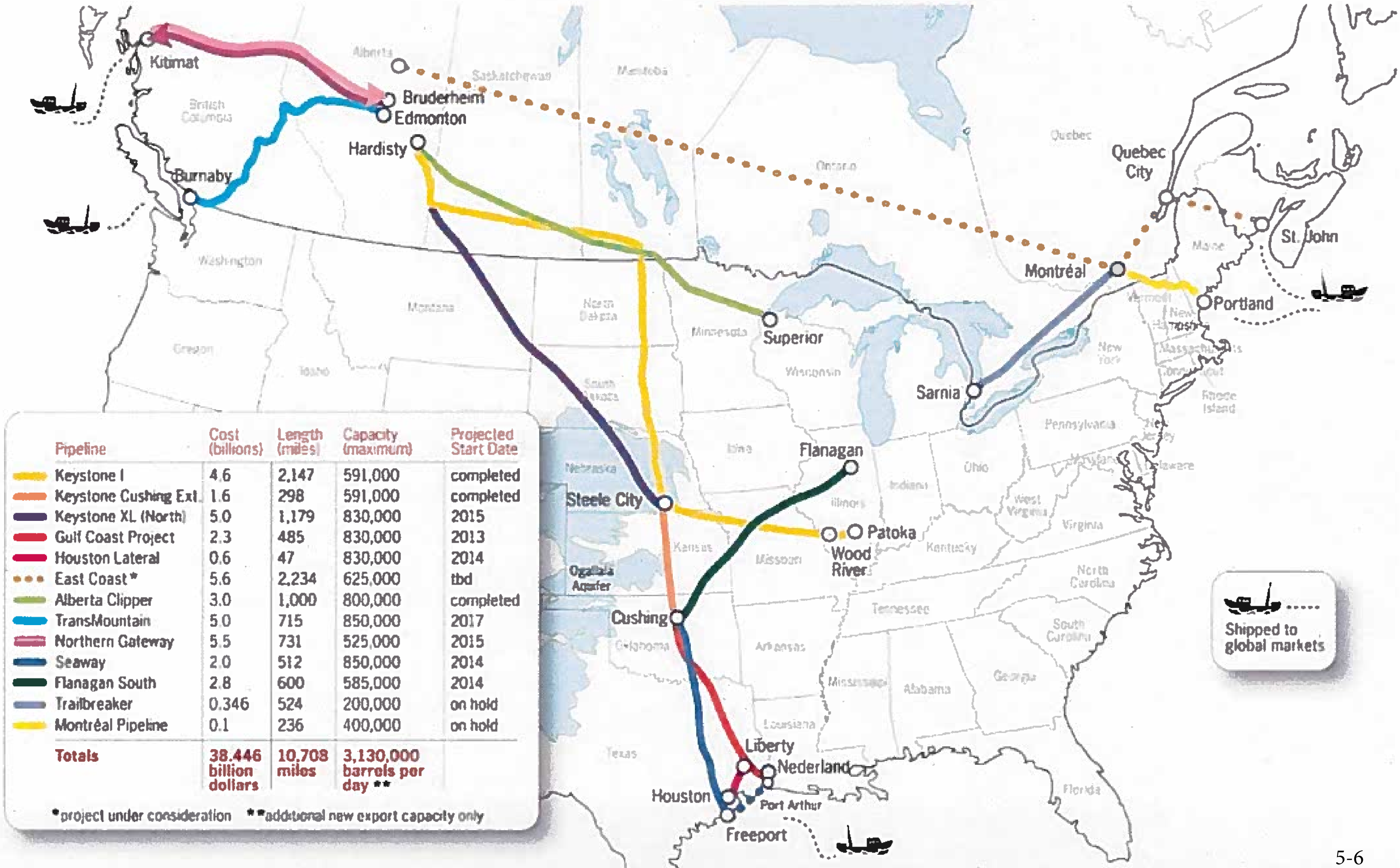

PADD IV
PADD V
PADD II
PADD III
PADD I
Québec City
Saint John
Halifax
Portland
Sarnia
Detroit
Toledo
Chicago
Billings
Great Falls
Casper
Guernsey
Cheyenne
Denver
Salt Lake City
Bakersfield
Los Angeles
Cushing
El Dorado
Memphis
Longview
Houston
Port Arthur
St. Charles
New Orleans
St. James
Freeport
Corpus Christi
Three Rivers
El Paso
Regina
Cromer
Superior
Area Refineries -
PADD


to Pump Tar Sands Through Eastern Canada and New England
The original Trailbreak
proposal is composed
Portland-Montreal Pip
and the Enbridge Line
Portland-Montre
Line
Enbridge Line 9
Tar Sands Pipelin
Alberta
Fort McMurray
Manitoba
Saskatchewan
Ontario
Quebec
Regina
Montana
North Dakota
Superior
Wisconsin
Minnesota
Michigan
Chicago
Sarnia
Pennsylvania
New York
Montreal
New Brunswick
Maine
Portland
Tar sands exports
New Hampshire
Vermont

inside climate news

THE TAR SANDS PIPELINE BOOM

Industry has announced the intention to build more than 10,000 miles of pipelines at a cost of almost $40 billion over the next five years to send an additional 3.1 million barrels a day of crude oil from Canada's oil sands to global markets.

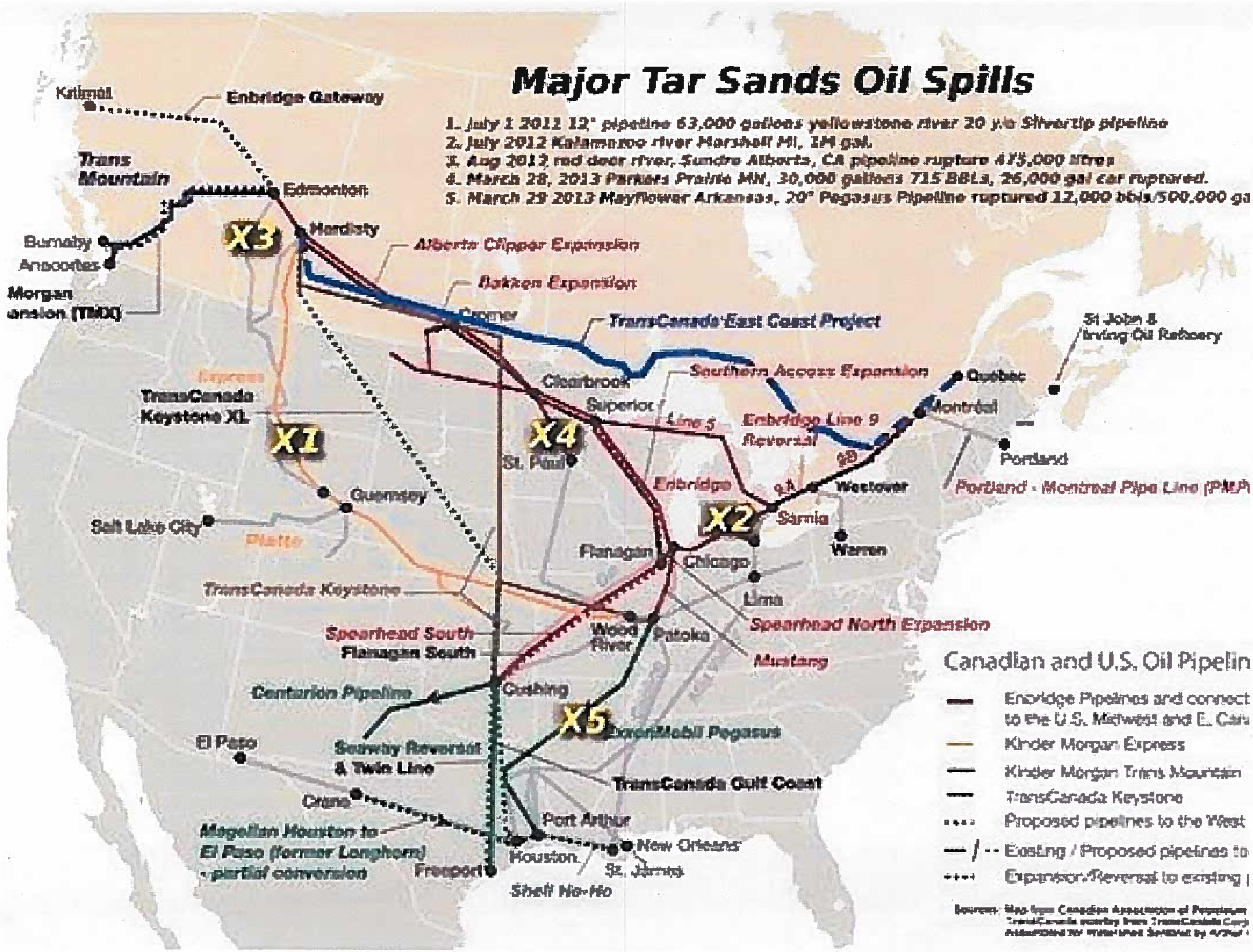


Pipeline	Cost (billions)	Length (miles)	Capacity (maximum)	Projected Start Date
Keystone I	4.6	2,147	591,000	completed
Keystone Cushing Ext.	1.6	298	591,000	completed
Keystone XL (North)	5.0	1,179	830,000	2015
Gulf Coast Project	2.3	485	830,000	2013
Houston Lateral	0.6	47	830,000	2014
East Coast*	5.6	2,234	625,000	tbd
Alberta Clipper	3.0	1,000	800,000	completed
TransMountain	5.0	715	850,000	2017
Northern Gateway	5.5	731	525,000	2015
Seaway	2.0	512	850,000	2014
Flanagan South	2.8	600	585,000	2014
Trailbreaker	0.346	524	200,000	on hold
Montréal Pipeline	0.1	236	400,000	on hold
Totals	**38.446 billion dollars**	**10,708 miles**	**3,130,000 barrels per day ****	

*project under consideration **additional new export capacity only

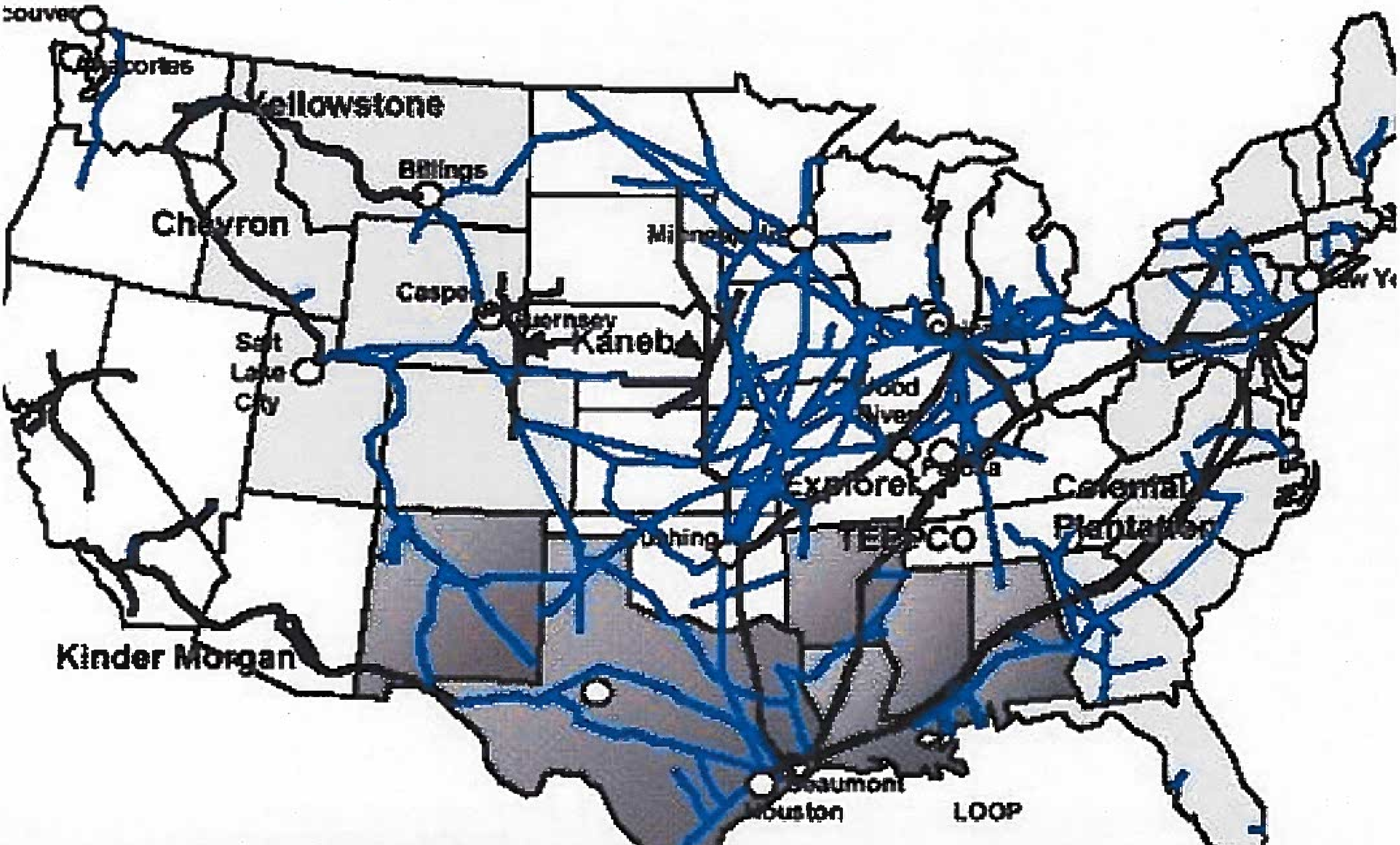
ILLUSTRATION BY Catherine Mann

April 2012



Major Tar Sands Oil Spills
1. July 1 2011 12" pipeline 63,000 gallons yellowstone river 20 y/o Silvertip pipeline
2. July 2012 Kalamazoo river Marshall MI, 1M gal.
3. Aug 2012 red deer river, Sundre Alberta, CA pipeline rupture 475,000 litres
4. March 28, 2013 Parkers Prairie MN, 30,000 gallons 715 BBLs, 26,000 gal car ruptured.
5. March 29 2013 Mayflower Arkansas, 20" Pegasus Pipeline ruptured 12,000 bbls/500,000 ga
X1
X2
X3
X4
X5
Enbridge Gateway
Trans Mountain
Edmonton
Hardisty
Burnaby
Anacortes
Alberta Clipper Expansion
Bakken Expansion
Cromer
TransCanada East Coast Project
Southern Access Expansion
Clearbrook
Superior
Line 5
Enbridge Line 9 Reversal
Quebec
Montréal
St John & Irving Oil Refinery
Portland
Portland - Montreal Pipe Line (PMPL)
TransCanada Keystone XL
St. Paul
Enbridge
Westover
Sarnia
Warren
Guernsey
Salt Lake City
Platte
Flanagan
Chicago
Lima
TransCanada Keystone
Spearhead North Expansion
Wood River
Patoka
Spearhead South
Flanagan South
Mustang
Cushing
Centurion Pipeline
ExxonMobil Pegasus
El Paso
Seaway Reversal & Twin Line
TransCanada Gulf Coast
Crane
Port Arthur
Magellan Houston to El Paso (former Longhorn) - partial conversion
Houston
New Orleans
St. James
Freeport
Shell Ho-Ho
Canadian and U.S. Oil Pipelin
Enbridge Pipelines and connect to the U.S. Midwest and E. Can
Kinder Morgan Express
Kinder Morgan Trans Mountain
TransCanada Keystone
Proposed pipelines to the West
Existing / Proposed pipelines to
Expansion/Reversal to existing

Major Refined Products Pipelines



Source: Allegro Energy Group, 2001