Energy East Pipeline Conversion Project

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13 April 2015

ORA is a not-for-profit organization with a mission to protect, conserve and restore Ontario river ecosystems - initially started in response to 87 proposals to build hydroelectric facilities on several Ontario rivers, including two on the Petawawa.

ORA is also very concerned about the proposed Energy East Pipeline which would carry tar sands crude from the Manitoba border to Quebec and points east.

This picture shows the sort of thing that concerns us. This is a spill in Burnaby BC. Somebody dug a hole in the bridge, that pierced the pipeline below, and drenched the area with crude oil, which then flowed into the river below.

The Author

- " Al" (Alan Hepburn) Ph.D., P. Eng.
- Member, ORA Board of Directors
- Retired technical manager from AECL
- Extensive experience in the nuclear industry in the analysis and design of safety-related control and protection systems

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My name is Alan Hepburn.

I spent most of my working life as an engineer with AECL, where I became familiar with the probabilistic analysis of safety risks.

I have experience in both the design and operation of safety-related systems.

However, I make no claim to being an ecologist, a civil engineer, or a metallurgist.

Overview of Presentation

- Project overview
- Review of pipeline technology & failure causes
- Concerns about the conversion project as we know it
- Expectations based on Alberta oil pipeline data
- Expectations based on TransCanada's track record
- Environmental Issues
- Possible mitigation measures

Note:

Will only address the pipeline conversion project itself, not the broader issues of oil sands expansion and consequent increase in Greenhouse Gas emissions, though these are certainly legitimate concerns

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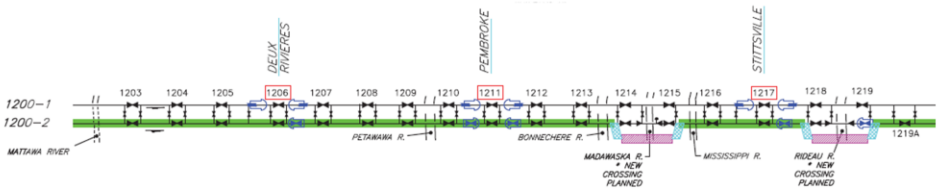
Here's an outline of my presentation:

I will use existing government sources to predict the frequency and size of releases, and compare the results with the proponent's predictions.

Then we'll look at the impacts of crude oils spills and suggest some possible improvements.

“North Bay Shortcut” Route



Now:

- Two parallel gas lines
- Flow can be switched from one line to the other, segment by segment, to permit maintenance of isolated segments

After Conversion:

- Newer (~1990) 42” diameter line will be converted to crude oil
- This line will be the biggest in North American - outside Alaska
  - Almost twice the capacity of Keystone XL
- All cross-connections removed
- Converted line has new pump and valve stations to handle oil

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TC owns a number of natural gas pipelines that basically follow highway 17.

Between North Bay and Iroquois, there are two lines that have been in the ground for 20 to 40 years. The proposal is to convert one of the lines to carry crude oil.

This will kill two birds with one stone:

1. Allow oil sands crude to reach east coast refineries
2. Improve ROI on underutilized gas lines

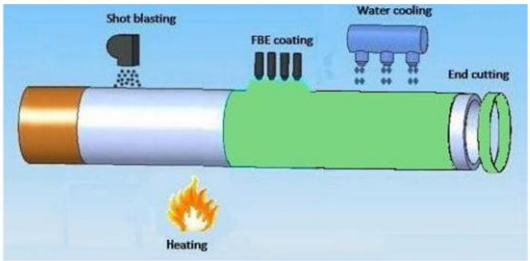
Here is the schematic of the route, showing the two parallel lines

At roughly 70 km intervals along the lines, there are cross ties, which currently enable segments of a line to be isolated for maintenance. These cross ties have valves enabling flow to be shut off and re-routed. There are also pumps to move the gas along the line. Other than these facilities, the lines are buried.

At the start of the conversion process, all the cross ties will be removed and capped off, allowing the unconverted gas line to be returned to service.

After conversion, there will be two separate parallel lines, a few metres apart, one carrying crude oil, and the other natural gas. The converted oil line will have new valves and pumps to handle the different material.

Pipeline Technology



- Steel pipe protected by coating
- Examples:
  - Polystyrene tape wrap
  - Bitumen enamel (better)
  - Fusion bonded epoxy (FBE) coating (best)
- Epoxy applied in the field for joints and repairs
- Converted line will use FBE coating
- Remaining gas line will still use inferior tape or enamel coating
- No coating system is perfect
  - Once coating is broken, it admits corrosive agents from the soil
  - Corrosion is slowed by a cathodic protection system which applies an electrical current

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Pipelines are built from steel sections about 20 m long, welded together, laid in trenches and covered over with fill.

Steel pipes in the ground are obviously going to rust. The prime defense against attack by corrosive agents in the soil is some kind of external coating.

The best available coating is this FBE epoxy.

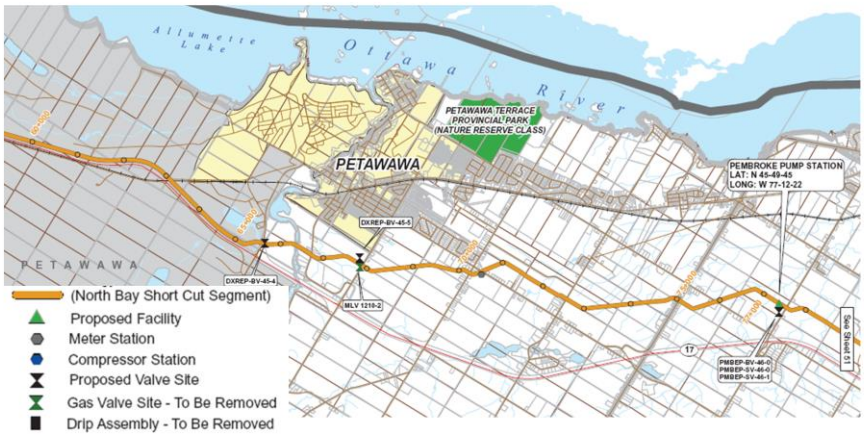
The line to be converted uses 20 – 40 year old FBE coated pipe.

The unconverted gas line is mostly fabricated form older material with inferior, non-FBE coating.

We'll look at the significance of that later.

An electrical "cathodic protection system" also inhibits corrosion.

Petawawa Route



- Extra valve station added east of Petawawa River

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Here's the detailed route through the Petawawa area. It crosses the Petawawa River just north of highway 17. An additional valve station will be added east of the river to allow the river crossing section to be isolated at both ends.

That way "only" about a km of the line can drain into the river if they locate a fault within that segment and get the valves closed – that's about 900 m^3 .

OK, I hear you – "Here goes Hepburn again with his meaningless units". Well, a cubic metre is about the size of a card table, and 1,000 m^3 is the size of two 2,000 sq foot single storey houses.

Current Project Status

- Public hearings have been going on for months
- ORA presented at recent OEB consultation
- EE has filed an application with the NEB
  - Thousands of pages of information, with more to come
  - Major gaps, some of which will be pointed out
- Now moving to NEB hearings
  - ORA has applied for intervener status, which will fund some professional analytical support

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The approval process for this project is a long one. I attended the proponent's public information meeting in Cobden, and became concerned enough to get the ORA involved.

I made a presentation on behalf of ORA to the OEB in Ottawa, and now we have applied for intervener status so we can stay involved and relay our concerns through the upcoming NEB hearings.

Key Questions/Concerns

- How many leaks will there be?
- How much oil will be released?
- What will be the effects on the environment?
- Can things be done better?
- Does the Regulator (NEB) act in Canada's long term best interests?
- Note:
  From the proponent's point of view, the economic imperative to minimize changes to the existing line is overwhelming

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The obvious concern is oil releases to the environment. How often will they happen, and how big will they be?

TC has downplayed the possibility of spills of any magnitude. They state that they can "realistically achieve a failure rate of zero "

Of course, as they point out, most leaks are small.

But it's not the many small ones that are a concern – it's the few big ones. So those are the ones we'll look at.

Estimation of Spill Frequency

- Used data from an Alberta Government database covering pipeline spills of all types in Alberta + incident reports
- Spills of primary concern are not those of beer-can size
  - Initially looked at spills > 10 m^3
  - There were 9 spills in Alberta for large crude oil pipelines over 22 years
  - Only one between 10 and 100 m^3 and it was contained – so ignored it

Incident #	Ø "	Release m^3	Date	Operator	Nature of Failure
20110906	20	4,500	4/29/2011	Plains Midstream	Girth weld failure – previously repaired pipe
19930314	24	2,581	2/4/1993	Rainbow	SCC and corrosion
19931263	24	2,232	7/18/1993	Rainbow	SCC and corrosion
20062487	24	1,200	10/10/2006	Rainbow	SCC and fatigue
20030528	24	350	3/2/2003	Cold Lake	Joint failure
20021635	36	270	7/6/2002	Syncrude	Pipe failure
19910420	16	250	3/10/1991	Federated	Pipe failure
19992067	24	150	9/10/1999	Rainbow	Damage by others

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The Alberta government has a pipeline spill database that covers tens of thousands of incidents of all types over 40 years, but I limited my analysis to crude oil pipes greater than 16" in diameter in the years 1990 – 2012, and spills bigger than 10 m^3.

That left only 9.Omly one of them was between 10 and 100 m^3, and was largely contained. I chose to ignore it.

So then there were eight.

(To come up with my own estimate of failure frequency, I used a database obtained by Global News from Alberta Government records. spanning 44 years.

http://globalnews.ca/news/622513/open-data-alberta-oil-spills-1975-2013)

Observations on Alberta Data

- Average Alberta line diameter: 24”
  - 42” diameter of the converted line can deliver three times as much material as a 24” line
- Average release: 1,400 m^3
- Average recovery of spilled material: 27%
- Length of large crude oil pipeline in Alberta: ~ 5,200 km
- Pipeline in Ontario: ~ 2,000 km

Proportional estimate, for the Ontario pipeline:
One major release every 7 years

- There is no indication in the Application of what conditions will lead to the pipeline being removed from service
  - It will presumably continue to be used until either it becomes too unreliable or the product to be transported runs out

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Here are the average parameters for these 8 Alberta Incidents.

Proportionally, the pipeline in Ontario can be expected to experience a major release once every 7 years.

Stopping Releases Before They Happen

- About 1/3 of Alberta failures are caused by corrosion
  - Particularly prevalent on older technology pipes using coating technologies pre-dating the FBE coating proposed for the proposed converted pipeline in the Ottawa Valley
  - Pipe thinning and deformation are potentially detectable by In Line Inspection (ILI) tools, though not very effective against stress corrosion cracking
  - Will assume that FBE coating + ILI are completely effective in eliminating corrosion failures
  - That still leaves 2/3 of the 7, or 4.7
  - That's about one leak every ten years for the converted line in Ontario

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EE places great emphasis on improvements in leak prediction technology made possible by in-line inspection tools - so-called "smart pigs" - in recent years. But 2/3 of the spills are attributed to causes not detectable by pigs.

Allowing for improved ILI technology, there will still be about one leak every 10 years, based on this Alberta data.

The EE Application does not mention a number of major threats implicit in the conversion process.

Effects of Aging

- Pipe to be converted has already been in the ground for 20 - 40 years
  - Around Petawawa, the line to be converted is FBE coated: good immunity to corrosion when new, but coating can get abraded over time
  - The gas line uses other inferior coating technologies
  - All coatings degrade with age
  - Cathodic protection can slow the rot after it starts, but it has in fact contribute to failures when it is not correctly adjusted
- Metal fatigue
  - Assessed cause of incident #20062487
  - Cyclic stresses imposed by seasonal changes in water levels
- Condition of existing repairs
  - Assessed cause of incident #20110906
  - Repair record of lines not so far available to public
- Failure rate due to aging will increase as the line gets older

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First, Aging:

All coatings age, due for example to abrasion of the coating, and the line will be 90 years old if it stays in service for another 50 years

Another age-related failure mechanism is metal fatigue.

In the 20-40 years this pipe has been in the ground, parts of it will have been subjected to cyclic stresses that may have used up some of its fatigue life, due, for example, to the seasonal variations in buoyancy where it crosses wet lands.

Then, the report on the biggest Alberta spill indicates that a sub-standard repair caused this recent massive release.

An old line, even an epoxy-coated one, has typically undergone many repairs, though we so far have not been able to determine how many.

Basically, old line is more susceptible to failure than a new one.

As time goes on, we can anticipate an increasing number of failures due to aging.

Increased Static Load

- A 10 m section of 42” pipe would contain ~ 500 kg of gas
- A 10 m section of the same pipe would contain ~ 8,700 kg of oil
- That’s an increase of 17 times
- The weight of 10m of pipe + contents goes from 2,800 kg to 11,000 kg
  - 4 times as heavy
- No mention of this in the EE Application
  - Failures are possible both immediately, and after years of settling
  - The overwhelming economic imperative is to do nothing

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Next, the greater density of crude oil.

Quite simply, oil is 17 times heavier than compressed natural gas.

The combined weight if the pipe and its contents is 4 times that of a gas line.

That may result in increased settling of the converted pipe over time, and possible deformation, which will stress the pipeline.

Dynamic Loads

- 8.7 tons of oil flowing at 1.7 m/s has a lot of kinetic energy
  - Inertial loads are 17 times those for the existing gas line when you try to stop movement or change its direction
- No mention of this in the EE Application
  - Can the restraints on valves and on the pipe itself handle this?
  - Existing design presumably relies on being buried
  - Under normal operation, the pipeline cycles off and on, so these inertial loads occur fairly frequently
  - Normal and emergency operations will impose much greater cyclic stresses, and encourage metal fatigue
  - Addition of engineered restraints could be an economic showstopper
  - Can we trust an organization who fires bearers of bad news?
- Recommendation: Static and dynamic loads should be the subject of a detailed independent 3rd party design review

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Dynamic loads are present when flow in the line starts, stops, or changes direction.

These forces will be 17 times greater after conversion. This increase in this force might require design changes, which would be very expensive.

An independent engineering review should confirm that the design meets these more demanding static and dynamic load requirements.

Seismic Analysis

- Ottawa and St. Lawrence River valleys are in known earthquake zone
  - An independent seismic analysis should be conducted

Conclusion: Release Frequency

- Things can only get worse as the pipeline material gets older

...and then there's the hazard presented by the adjacent gas pipeline

  - Will look at that further when we've seen a specific example
- The Bottom line:

While the proponent states that zero leaks is an attainable goal, history says there will be at least 1 leak every 10 years, and probably more, as the line ages

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The Ottawa River Valley is in a known earthquake zone, but the Application doesn't mention seismic analysis.

Perhaps the most significant omission is the small separation between the remaining gas pipeline and the converted oil line. We'll look at this later, once we've seen an example of adjacent gas line failure.

These threats can only increase the 1 in 10 year release frequency derived from Alberta data.

So much for the number of leaks. Now let's look at the size of them.

Leak Detection Systems

- Leak detection, as opposed to leak prediction, is a real time system
- The pipeline code (CSA Z622) requires a leak detection system, but there are no performance requirements for this system
- The industry standard approach to leak detection uses an enhanced "mass balance" algorithm to detect when amount of oil going in is significantly greater than the amount coming out
  - Also looks at other indications, such as pressure drop
- The instrumentation and shutdown valves are typically tens of km from a break site
  - This masks indications
- The proposed leak detection system has a minimum threshold of 1.5% of full flow
  - Anything less will keep leaking until it is found by surface/airborne inspection
  - Typically, several days to forever

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A word on how leaks are detected.

The standard approach, and that proposed by EE, uses instrumentation located at the above ground locations – i.e. pump and valve stations. Typically, the leak site may be many kilometres from this instrumentation. This tends to blur the indications, so the operator has to do a lot of interpretation of the data he sees. And the leak site cannot be localized.

The EE system cannot detect anything less than 1.5% of full flow.

That doesn't sound like a lot, until you translate it into volume. We're talking 2,000 m^3 per day. That's four 2,000 sq foot houses worth.

Anything below this value will not be detected until it shows up on the ground after several days.

Size of Release?

- Database average volume: 1,441 m^3 - Average pipe diameter: 24”
- EE pipeline: 42” diameter – 3 times greater area

  Average predicted spill volume: 1,441 x 3 = 4,300m^3
- According to EE’s Mr. Houston:

  “One could calculate a volume of about 250 m^3 per incident”

  “Our leak detection system has a specification of detecting 1.5% of the flow rate within 2 hours”
- 1.5% leak of a 42” pipe would release 220 m^3 over 2 hours
  - Assumes leaks will be 1.5% and shut down almost immediately
- Why the difference?
  - Not all leaks are at the 1.5% detection threshold
  - A leak must not only be detected – it must be stopped

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Since the 42” line at Petawawa will be 3 times the area of the average Alberta line, the average release volume will triple from 1,400 to 4,300 m^3.

EE has stated that a typical leak will be about 250 m^3. Where did this number come from come from?

A 1.5% release for 2 hours amounts to 220 m^3.

So it looks like he has assumed that

a) an average leak will be at the minimum detectable level of1.5% full flow, and

b) the line will be shut down almost immediately on detection of the failure.

EE says that changes to operating procedures will require that all detected leaks be shut down within 10 minutes.

Is this credible, looking at past experience?

Why Are The Leaks So Large?

- ERCB Investigation Report on Plains Midstream pipeline in 2011:
  - Release was 4,500 m^3
  - Apparently, the leak detection system did detect this whopper
- Clearly, this was a much bigger release rate than 1.5% of full flow
  - A 20" pipe releasing 1.5% for 8½ hours would only account for 360 m^3
  - To release 4,500 m^3 in this period, it must have been a 33% break
- Incident report concluded:

"the Plains' alarm response protocol..."
exhibited a
"potential bias towards inaction"

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The official report on the biggest Alberta spill says that, after the leak detection system "indicated abnormal operating conditions on the pipeline", the operators took 8 ½ hours to decide to shut it down.

To deliver the estimated 4,500 m^3 in 8 ½ hours, they must have had a 33% break, so this was no 1.5% break. The indications were presumably much more obvious than they would have been at 1.5%.

The instrumentation suggests to the operator he may have a problem. He still has to make the shutdown decision.

Look at this quote from the Investigation Report:

> "the Plains' alarm response protocol exhibited a potential bias towards inaction".

Leak Detection/Operator Action

- The information presented to the operator is far from unequivocal
- As a result, shutdown action is frequently delayed for hours
- In just about every case, it took an eyewitness report before shutdown action was actually initiated
  - Do the operators perhaps not trust the leak detection system?
- The standard leak detection instrumentation appears to be designed to detect economically significant leaks only
- There is no definition of an environmentally significant leak
  - From the point of view of the environment, it tends to be the total amount of material released, rather than the leak rate that is important
- Obvious conclusion:
  - The maximum size of an environmentally insignificant leak should be determined
  - Proponents should be required to install systems that can detect any leak above this threshold

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In most cases, the operators typically don't take action until they get a sighting by an onlooker.

Does the leak detection system perhaps raise a lot of false alarms?

Until I see convincing evidence otherwise, I'm sticking with my 4,300 m^3 number for the 42" converted line going by Petawawa.

What about that 1.5% leak detection threshold?

Leak Detection Threshold

- Proposed system cannot detect leaks less than about 1.5%
- Leak shown here was much less
- Caused by malicious damage using a 0.338 rifle
- 0.338” hole would supply 0.005% - though no doubt this was larger
- Leak was below the leak detection threshold
- While bullet damage to an in-ground pipe is unlikely, other small holes will leak indefinitely until the material becomes visible on the surface
- A 1.5% leak for even a single day on line 100-2 would deliver 2,000 m^3
  - That’s 24,000 square foot single story houses
- If the hole was pointing close to straight down, it may never be found until it came out somebody’s tap

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This one happened on the Trans Alaska Pipeline, which is a 48” above-ground installation.

A drunk hunter drilled it with a high powered rifle. This leak is ‘way below the 1.5% threshold, but visual sighting won again.

Of course, the EE line is fairly well protected from wayward bullets. But there are other causes of small leaks. I only show this slide to indicate what a “pin hole” undetectable release amounts to.

Such a release will continue at least until the next airborne inspection. Unless they get lucky and the hole is pointing straight up, it may go on indefinitely.

Would a leak like this be environmentally significant?

To do better, you need to detect the presence of small amounts of material outside the pipe.

I wonder if anybody has looked into that?

External Leak Detection

- To detect environmentally significant leaks, need to look for the much smaller volume of external crude oil > $2m^3$/day?
- This facility (ELDER) in Edmonton has been built to evaluate competing external leak detection technologies
- As of August 2014, four such technologies were being evaluated
- Funded by Enbridge and TransCanada ($1.6M each)
- Apparently, the industry is in agreement that a better mousetrap is required
- But, would any of these systems be economically retrofittable to an existing pipeline?

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It turns out that TC and Enbridge have been evaluating four ELD technologies since 2012.

What did they find? The results are proprietary.

But no proponent in his right mind will apply these technologies unless he is compelled to do so. Why?

Incentive to Improve Leak Detection Technology

- Any *detected* leaks have to be cleaned up at great expense
  - A much publicized 3,000 m3 spill at Kalamazoo, Michigan, cost more than $1B to clean up to date – may never be restored
- There is a very strong incentive not to detect any leaks that are not economically significant
- Northern Gateway has received preliminary approval with only one condition on leak detection:

  The design must be submitted 90 days before the line goes operational
- Conclusion:
  The proponent will never install a system capable of detecting environmentally significant leaks, even if it costs him nothing, unless the regulator insists

Need to tell the regulator that the current requirements – no limits on minimum spill size that can be detected – are environmentally irresponsible

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If you detect a leak, you have to clean it up, and that can cost millions. So, let sleeping crude lie.

To have any chance of improving this situation, the regulator must be persuaded to introduce more demanding leak detection and corrective action requirements.

TC's Record?

- TC only has one crude oil pipeline
  - Keystone pipeline from Hardisty, Alberta to US Midwest & Gulf Coast
  - In service since 2010
  - 864 km is a converted 36" gas line
- Press makes a lot of this line's "disastrous record" in its first year of operation
  - 12 spills
  - In fact, most were relatively small
  - Biggest was the Ludden Spill – 80 m^3

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Let's look at TC's own record. They only has one oil pipeline – this Keystone line.

Most of the 12 releases on the Keystone line in its first year of operation were fairly small, though 80 m^3 is getting there. But how this spill was recorded in the official report is interesting.

The Ludden Spill

- ¾” elbow fitting fractured on a pump station at Ludden, ND
- Spilled 80 m^3, most of which landed within the berm surrounding the pump station
- While operators were considering the indications presented by their leak detection system, the farmer on whose land the station was located called in to report a small crude oil geyser. Within minutes, the line was shut down
- The initial report indicated that the shutdown was as a result of a report from a local citizen
- At TC’s request, the report was subsequently modified to show that the shutdown was prompted by indications from their leak detection system

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Here’s a quote from a report at the time:

> “In a June 2011 order against TransCanada, the Pipeline and Hazardous Materials Safety Administration wrote that the company shut down the flow of oil "after being notified ... by a local citizen" of the leak. The order was subsequently amended "following informal discussions" between TransCanada and the federal regulator to reflect a new version of events: the line was shut down due to a "suspected leak condition" indicated by "a change in flow rates."

TC was clearly sensitive to criticisms of the ineffectiveness of leak detection instrumentation, and took steps to have the official report changed.

Now, let’s take a look at TC’s record on gas pipelines, including the one proposed for conversion. They are, after all, familiar with this business.

TC Track Record, Gas Pipelines

- The TSB has reports for all major pipeline incidents:

TSB Report #	Date	Location	Line #	Failure Type
P11H0011	19 Feb. 2011	Beardmore, ON	100-2	Fire, explosion
P02H0017	14 Apr 2002	Brookdale, MB	100-3	Fire, explosion
P09H0074	12 Sep. 2009	Englehart, ON	100-2	Fire, explosion
P94H0036	23 Jul 1994	Latchford, ON	100-2	Rupture & fire
P09H0083	26 Sep 2009	Martin River, ON	100-1	Rupture
P95H0036	29 Jul 1995	Rapid City, MB	100-4	Rupture & fire
P95H0036	29 Jul 1995	Rapid City, MB	100-3	Rupture & fire
P96H0012	15 Apr 1996	St. Norbert, MB	100-2	Rupture & fire

- 8 incidents identified - 2 on the subject line (100-3), and the rest on lines immediately adjacent to it
- Incidents tend to be violent: explosions and fires
- Environmental impact is relatively minor

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Here is a summary of incidents on the line proposed for conversion, or other lines adjacent to it.

The information is drawn from official Transportation Safety Board reports. As we'll see, they're pretty exciting, even without the benefit of press license.

Track Record of Line 100-3

- Line 100-3 ruptured near Brookdale MB at 23:00 on 14 April, 2002
- First verbal report: 23:10
- "At approximately 23:11, the CGCC received a ...moderate confidence level rating notification of a line break, followed by a substantial confidence rating at 23:14. Between 23:16 and 23:17, the CGCC initiated a series of SCADA system commands to close ... Valves"
- "At approximately 01:30, on 15 April 2002, the isolation of the main line was completed with the closure of upstream and downstream main block valves..."
- "At approximately 02:30, the major fire self-extinguished at the break site due to actions undertaken at 01:30"
- Cause of failure: SCC (enamel coated pipe + atomic hydrogen)

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Line #100-3 failed near Brookdale MB.

Almost immediately, they got a number of low-confidence warnings from their expert system, but the first attention getter was a onlooker report just 10 minutes after the event.

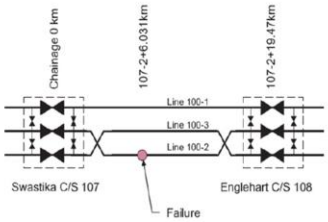
17 minutes after the accident, they took the initial actions to do something about it.

But it wasn't until 2 ½ hours after the accident that they closed the valves that actually stopped the fire an hour later.

OK, anything in Ontario?

Track Record of the Line in Question

- Adjacent 100-2 line ruptured near Englehart, ON - 12 Sep 2009
- Resulting explosion "uncovered" the 100-3 line, which was visually inspected and returned to service



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Line #100-2 failed just north of Englehart Ontario. According to the TSB report,

> "Escaping gas from a pipeline rupture ignited, resulting in the explosion. A large crater was created and two sections of pipe broke from the system, with one section being ejected approximately 150 metres from the rupture site."

This line is made of the older, polystyrene-wrapped pipe. And it still will be, after line 100-3 has been converted.

It was controlled by a Remote Operating Centre (ROC) in Calgary, who knew nothing about the incident until the Englehart Fire Department gave them a call.

> "Approximately 10 metres of Line 100-3 had been exposed during the explosion".

That's the one proposed for conversion. Luckily it was not damaged, but is there a credible threat that it might have been?

Is there an example of one line taking out the other?

Adjacent Lines

- Line 100-4 ruptured near Rapid City, Manitoba, in 1995
- Operator unable to execute local Emergency Shutdown (ESD)
- Operator unable to contact ROC on landline
- Operator ran to gate, and again tried to execute ESD and contact ROC with no success
- Operator eventually contacted ROC on a borrowed cell phone
- ROC couldn't perform an ESD either
- After an hour, the heat caused the adjacent line 100-3 to blow
- ROC eventually succeeded in shutting down using the station 110 km further upstream in Saskatchewan
  - Inferno continued for 2 hours

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This incident happened in western Manitoba in 1995 – 14 years beore Englehart.

A manned valve station was nearby. The operator saw the fire, so no delays studying instrument indications this time.

He tried to execute a local shutdown, but it didn't work.

He then tried to call the Winnipeg ROC, but couldn't.

At that point, he high tailed it for the plant gate, where he again pushed the shutdown button. Still no joy.

He finally reached the ROC using a cell phone borrowed from a bystander. They couldn't perform a shutdown either.

The continuing inferno caused line 100-3 exploded an hour later.

All the control and communications equipment had been disabled by the fire. The design was not fail safe.

Eventually, the ROC was able to shut down both lines from another station, 110 km upstream. It took another two hours for the fire to burn out. So again, co-location was a problem. Only in this case, they didn't get off so lightly. There were 6 adjacent lines at this location. In addition to the line 100-3 fire, one other was damaged.

Does this sound like the Keystone Kops, or what? Was the pipeline named after them?

Other Design Implications – Rapid City

- Explosion took out communications and SCADA gear for at least several of the 6 lines at this site
  - Neither the local operator nor the ROC could effect a local shutdown
- Design was assessed as not being fail-safe
  - To be fail safe, the equipment required to perform a safety function must survive the accident it is supposed to mitigate
  - Typically such designs are simple, localized, and do not require operator action/decision
- Report assessed subsequent corrective action as "fully satisfactory"
  - Was it?
  - No sign that it affected the design near Englehart, 14 years later

There is no indication that conversion design considers adjacent failures

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The Rapids City Incident is particularly concerning because it showed how failure of one line can take down another.

It also demonstrated the consequences of the design not being fail-safe.

Here's what it means for a design to be "fail safe". In this case, the equipment required to shut down the line would have to have survived the fire.

All the valves might, for example, have been designed to close as soon as they lost communication with the rest of the control system.

The gas supply would have been cut off locally, and the fire would rapidly have gone out.

The incident report says that subsequent corrective action was assessed as "fully satisfactory", but was it? The Englehart incident, 14 years later showed that lessons with respect to co located lines had not been learned.

Was the cost of fixing the problem perhaps deemed impractical?

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The Big Bang Theory

- Earlier, we looked at releases for the oil line in isolation, but the converted line will be located within 10 metres of a gas line which has a track record of reliably exploding every few years
  - The aging gas line is built from sub-optimum materials so its failure frequency will surely increase
- Some of these explosions will take out the oil line
  - That wouldn't be a 1.5% release – it would be a major rupture
- What are the impacts of a combined oil and gas fire?
- Is this really a good idea?
- There are no standards for adequate lateral separation
- Proponent says a 10 meter separation is enough
  - Need an independent confirmation of this
- Again, the economic imperative is to ignore this issue
  - Cross your fingers and hope it never happens

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EE has only looked at the converted pipeline in isolation.

But it isn't isolated. It will be located within 10 meters of a source of occasional explosions throughout its entire length.

The adjacent gas line(s) will still have that old SCC-prone tape covering.

Once one of them explodes, the epoxy coating on the oil line won't help.

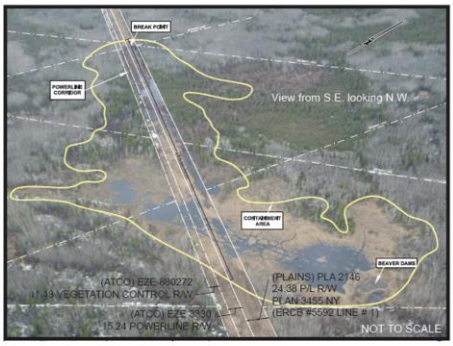
At Petawawa, post conversion, a failure of the old gas line may result in a failure of the crude oil line as well.

I can't imagine what a combined gas/crude oil fire would be like. Can you?

Independent assurance is needed to confirm that this concern is addressed by the design, with some margin to spare.

And part of the analysis better not be that the gas line failure will be detected and shut down in 10 minutes, because the Kops can't do that.

Gas vs. Oil Release Impacts



- A gas line failure has minimal ecological impact
  - Impact within a few 10's of metres is catastrophic, but clean
  - Elsewhere, minimal
  - Long term minor leaks kill a few trees, and can be detected by airborne patrol
- An oil line failure can quickly become an ecological disaster
  - Spreads many km downstream, particularly under ice
  - Only 27% of spilled material recovered
  - Dilbit spills particularly difficult to manage

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The environmental impact of a gas line failure is typically minimal.

If you happen to be sitting on top of a gas line when it blows, or if you're a TC shareholder, you may have a bad day. The owners of the houses at Black Bay Road and Doran might want to think about that.

The long term effects of a dilbit spill are much more serious.

Here's that 4,500 m^3 spill in Alberta. It covered about 75 acres. My average spill 4,300 m^3 would cover about 70 acres.

The effects of such a release on wildlife and domestic water supplies would be devastating, and long lived.

The heavy component of dilbit sinks more readily than conventional crude which makes it more difficult to clean up.

26 companies were involved in the cleanup, and it took up to 300 people.

A smaller, but much publicized spill in Kalamazoo, MI, cost more that $1B to clean up.

Mitigation Measures

- Leak Prevention:
  - Heavier pipe near ecologically significant features
  - New standards to increase lateral separation of gas and crude pipelines and control/pumping equipment
  - Review design in light of a wider range of threats
- Monitoring/Detection/Shutdown:
  - Mandate use of more sensitive detection technology - anything over 0%
  - Design/Operator training emphasize importance of prompt shutdown
    - Training “Biased towards action”, and/or
    - Automate shutdown, make design fail-safe
  - Shut off valves before and after all water crossings
- Independent design and ongoing operations compliance reviews

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Here are some possibilities that should be looked at:

- Heavier grade pipe and spill collection troughs could be used in sensitive areas.
- The current leak prediction and detection systems are not up to the job. In particular, the leak detection system needs to be much more reliable, and capable down to close to zero.
- The NEB is the agency that needs to make this happen.
- Look into automating the shutdown, and making the design fail-safe.
- Operator training should be revised so it is “biased towards action”.
- A third party independent agency should be tasked with reviewing the design of the converted pipeline.
- Once the line is in service, there needs to be independent confirmation that corrective actions have been completed, and any lessons learned have been implemented promptly throughout the system.
- Emergency response plans, operating procedures and reports of deviations should be a matter of public record.

Questions for EE + Other Action

- Spill Frequency?
  - EE's target is, of course, zero spills. They will not admit the relevance of the historic record
  - Ask about adjacent gas line, aging infrastructure and repair history. It is inconceivable that age will not make things worse
- Spill Size?
  - EE says that detected spills will be shut down in 10 minutes. The only way this is achievable all but the most obvious, massive spills are annunciated as "indication anomalies", not subject to shutdown
- Non-detectable spills (less than 2,000 m^3/day)?
  - Waiting until these show on the ground is irresponsible
  - Better instrumentation technologies are available, though may need some further development. Ask where they're at
  - The only agency who could conceivably take action is the NEB
- Letter to NEB: Petawawa (and others) are Unwilling Hosts unless problems fixed

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Here are some areas in which you might press EE next week.

Decide which story makes sense.

Consult with other municipalities along the pipeline route.

I think that approval of the pipeline would be irresponsible unless much more stringent requirements are placed on leak detection.

There are also a lot of technical issues that the Application does not address:

- Pipeline aging
- Maintenance history
- Seismic Events
- Proximity to failure-prone gas lines

Given the cost consequences if any of these issues proves to be significant, the only answer is a truly independent engineering assessment.