CRUDE OIL BY RAIL: PART I POTENTIAL FOR THE MOVEMENT OF ALBERTA OIL SANDS CRUDE OIL AND RELATED PRODUCTS BY CANADIAN RAILWAYS

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There is a very significant current interest in the enormous potential in Canada from the future development of energy sources such as the Alberta oil sands. The crude oil from these sources is traditionally transported to markets by pipeline. However, the large quantities of product involved will require the development of new transmission pipeline capacity, and there is controversy over the construction of new transmission pipelines such as the northern gateway and the keystone XL pipelines.

While these controversies get resolved, there is a potential for the movement of crude oil and related products by Canadian railways. This two-part paper will provide a broad overview of these issues, including the current movement of crude oil and related traffic and approximate estimates of the rail capacity to handle future volumes.

The Alberta Oil Sands

The Canadian oil sands are situated entirely in Alberta in three distinct locations – the Athabasca, Cold Lake and Peace River oil sands (see Figure 1). A schematic of the oil sands taken from a primer written by the Energy Policy Research Foundation Inc. [1] is presented in Figure 2 that identifies some of the principal characteristics. The following points may be noted:

- The vast volume of recoverable barrels of oil at an extraction rate of 5 million barrels per day (b/d) would last over 90 years;
- In situ methods of extraction – which involve drilling to greater depths – will eventually recover some 80% of the oil, with land disturbance only slightly more than conventional oil;
- Mining extraction is limited to the Athabasca oil sands, with land disturbance over an area equivalent to a square footprint with sides of only 15 miles.

Figure 1

The immediate product of the oil sands is bitumen and since it is a very viscous oil it must either be upgraded into synthetic crude oil (SCO) or mixed with a diluent so it can flow down a pipeline. In situ produced bitumen is typically mixed with a diluent; mined bitumen is typically upgraded to SCO.

The focus of this paper will be the outbound movement of the SCO and diluted bitumen – also referred to as blended bitumen, dilbit, or just crude oil – but also to a lesser extent the inbound movement of diluent.

The predominant movement of outbound product is by liquid pipeline. As indicated by the Canadian Energy Pipeline Association [2]:

> Producing oil fields commonly have a number of small diameter **gathering** lines that gather crude oil from the wells and move it to central gathering facilities called oil batteries. From here, larger diameter **feeder** pipelines transport the crude oil to nearby refineries and to long-haul pipelines. The largest pipelines, called **transmission** lines, transport crude oil and other liquids across the country.[2]

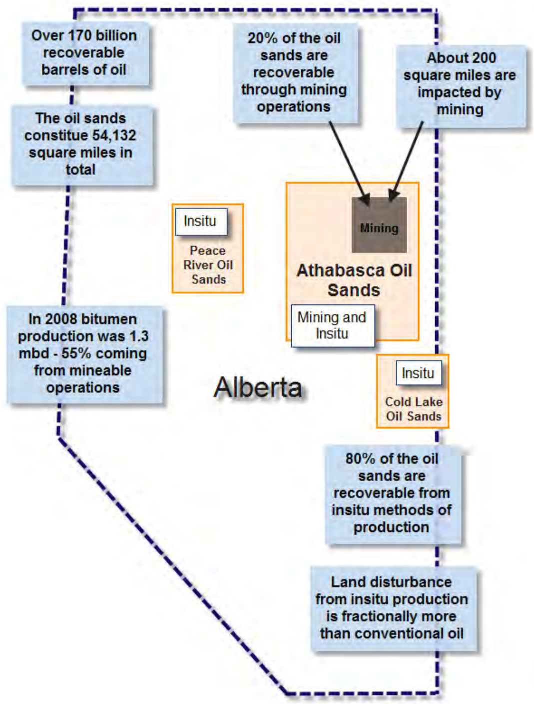

Figure 2

The important point here is that there is no direct rail service into the oil sands, and all the outbound product is initially transported by gathering and feeder pipelines. Figure 3 is taken in part from the Canadian National (CN) website [3] and shows some of the Athabasca and Cold Lake oil sands project sites as well as the CN rail line to Fort McMurray. While it may appear that CN provides direct rail service, in fact many of the Athabasca sites are north of the Athabasca River, and it would need a rail bridge across this river that has a prohibitive cost estimate of several hundred million dollars in order for CN to provide direct rail service. Neither does CP provide direct rail service into the oil sands, but it does have rail service at Edmonton and the Alberta Industrial Heartland location northeast of

Edmonton, as well as service at Hardisty, Alberta, as will be seen below. Both of these locations are the termini of the feeder pipelines.

Figure 3

In order to better understand the operations of the feeder pipeline network, Figure 4 presents an approximate summary of the various feeder pipeline companies, their pipelines and locations, the product carried, and their capacities. The following points may be noted:

EXHIBIT 4

Company	Feeder Pipeline Name	Origin	Destination	Length (km)	Product	Shipper	Capacity (b/d)
ENBRIDGE							
	Athabasca	Fort McMurray	Hardisty	540	Crude Oil		570,000
	Athabasca Twinning	Cold Lake (Christiana Lake)	Hardisty	345	Crude Oil	Cenovus	450,000-800,000
	Waupisoo	Cheecham (70km south of Ft M)	Edmonton	380	Crude Oil		600,000
	Waupisoo Expansion	Cheecham (70km south of Ft M)	Edmonton	380	Crude Oil		65,000-255,000
	Woodland	Fort McMurray (Kearl Lake)	Cheecham (70km south of Ft M)	140	Blended Bitumen	Imperial Oil	200,000
INTER PIPELINE							
35%	Corridor	Fort McMurray	Edmonton (Scotford)	500	Diluted Bitumen	Shell/Chevron/Marathon	296,000
	Cold Lake	Cold Lake (La Corey)	Edmonton	250	Blended Bitumen	Cenovus/CNRL/Imperial Oil	490,000
		Cold Lake (Foster Creek)	Hardisty	320	Blended Bitumen	and Shell	
	Cold Lake Expansion	Cold Lake (Narrows Lake)	Cold Lake (Foster Creek)	85	Blended Bitumen	Cenovus	190,000
		Cold Lake (Foster Creek)	Cold Lake (La Corey)	80	Blended Bitumen	Cenovus	710,000
		Cold Lake (La Corey)	Hardisty	240	Blended Bitumen	Cenovus	540,000
	Polaris	Edmonton (Scotford)	Fort McMurray (Muskeg River)	460	Diluent		90,000
	Polaris Expansion	Edmonton	Cold Lake (Christina Lake)	240	Diluent		700,000
		Cold Lake (Christina Lake)	Cold Lake (Foster Creek)	75	Diluent		120,000
		Cold Lake (Christina Lake)	Cold Lake (Narrows Lake)	20	Diluent		55,000
PEMBINA							
30%	Syncrude	Fort McMurray (Syncrude)	Edmonton	500	Synthetic Crude Oil	Syncrude	389,000
	Horizon	Fort McnMurray (CNRL)	Edmonton	550	Synthetic Crude Oil	CNRL	250,000
	Cheecham Lateral	Syncrude pipeline outlet	Cheecham	56	Synthetic Crude Oil	Conoco/Total/Nexen/CNOOC	136,000
	Nipisi	Peace River (Seal)	Edmonton	190	Diluted Bitumen	CNRL/Cenovus	100,000
	Mitsue	Edmonton	Peace River (Seal)	255	Diluent	CNRL/Cenovus	22,000
ACCESS							
	Access (1)	Edmonton	Cold Lake (Christiana/Jackfish)	345	Diluent	MEG Energy/Devon	na
	Access (2)	Cold Lake (Christiana/Jackfish)	Edmonton	345	Blended Bitumen	MEG Energy/Devon	na
	Northeast Expansion	Cold Lake (near Conklin)	Edmonton	297	Blended Bitumen		350,000
SUNCOR							
	Firebag	Fort McMurray (Firebag project)	Fort McMurray (Suncor base plant)	40	Diluted Bitumen	Suncor	368,000

Sources: Various industry websites

Figure 4

- Most of the feeder pipelines move SOC or blended bitumen southbound and diluent northbound, although there are some pipeline segments that move product laterally within the oil sands region;
- There are only two locations that are the destinations for the southbound movements – Edmonton and the Alberta Industrial Heartland to the north east, and Hardisty, which is a location some 200 km to the southeast of Edmonton;
- The capacities of the feeder pipelines are estimates of the current maximum capacities. However, these capacities vary with the product – the flow rate for SCO will differ from the

heavier blended bitumen, for example. Moreover, the situation is more complicated if the pipeline is segmented, and overall the figures may only be taken as approximate;[3]

- Interline pipeline indicates that its current total southbound capacity of 786,000 b/d represents 35% of the total of all feeder pipelines, while Pembina indicates that its current total southbound capacity of 639,000 b/d represents 30% of the total of all feeder pipelines. While these figures do not agree precisely they suggest that the total current southbound feeder capacity is a little over 2 million b/d.

EXHIBIT 5

Company	Transmission Pipeline Name	Origin	Destination	Length (km)	Product	Capacity (b/d)
I EXISTING						
ENBRIDGE						
	Enbridge and Lakehead System	Edmonton and Hardisty	Montreal, US mid-west, Cushing Oklahoma and US Gulf Coast	5,363	Crude oil, Natural Gas Liquids and Refined Petroleum	2,500,000
	Southern Lights	Manhatten, Illinois	Edmonton	1,086	Diluent	180,000
KINDER MORGAN						
	Trans Mountain	Edmonton	Burnaby, BC and Washington State	1,150	Crude oil and Refined Petroleum	300,000
	Express	Hardisty	Casper, Wyoming	1,263	Crude oil	280,000
	Platte	Casper, Wyoming	Wood River, Ilinois	1,500	Crude oil	164,000
TRANSCANADA						
	Keystone - Phase 1	Hardisty	Steele City, Nebraska and Wood River, Illinois	3,456	Crude oil	590,000
	Keystone - Phase 2	Steele City, Nebraska	Cushing, Oklahoma	480		
II PROPOSED NEW AND EXPANSIONS						
ENBRIDGE						
	Northern Gateway	Edmonton	Kittimat, BC for offshore	1,177	Crude oil	525,000 - 850,000
		Kittimat, BC	Edmonton	1,177	Diluent	193,000
KINDER MORGAN						
	Trans Mountain expansion	Edmonton	Burnaby, BC and Washington State	900	Crude oil	450,000
TRANSCANADA						
	Keystone XL - Phase 4	Hardisty	Steele City, Nebrasca	1,897	SCO and blended bitumen	830,000
	Keystone XL - Phase 3	Cushing, Oklahoma	Houston, Texas	856		

Sources: Various Industry websites

Figure 5

The building of new oil sands feeder pipelines, or the expansion of the existing pipelines, requires the regulatory approval of the Energy Resources Conservation Board (formerly the Alberta Energy and Utilities Board) and this agency, dealing with matters entirely within Alberta, are likely to give less consideration to interference from political and environmental interests outside the Province.

Turning now to the transmission pipelines that move product between Edmonton/Hardisty and markets across the continent and overseas, Figure 5 presents an approximate summary of the various transmission pipeline companies, their existing pipelines and locations, the product carried, and their capacities – together with some of the proposals for new pipelines or the expansion of existing pipelines. The following points may be noted:

- Enbridge has a comprehensive existing system that takes crude oil from Edmonton and Hardisty east to Montreal and south as far as the US Gulf coast, with a total capacity of 2.5 million b/d. It also has a northbound pipeline from Illinois to Edmonton that brings in diluent;
- Enbridge has plans for a northern gateway system that would take crude oil from Edmonton to Kittimat, BC, for shipment offshore, with an initial capacity of 525,000 b/d rising to 850,000 b/d. This system also includes a pipeline from Kittimat to Edmonton for diluent with a capacity of 193,000 b/d;
- Kinder Morgan has the trans-mountain pipeline that takes crude oil from Edmonton to Burnaby, BC, and to Ferndale and Anacortes on the coast of Washington State, with an existing capacity of 300,000 b/d. It has plans to expand the trans mountain pipeline along the existing right-of-way to provide an additional capacity of 450,000 b/d;
- Kinder Morgan also has the express and platte pipeline systems that takes crude oil from Hardisty south to Casper, Wyoming, and then east to Wood River, Illinois; the first segment has a capacity of 280,000 b/d and the second segment 164,000 b/d;
- TransCanada has the keystone system that may be described in four phases as identified in Figure 6 taken from [4]. The

existing phase 1 moves crude oil from Hardisty south to Steele City, Nebraska, and then east to Wood River, Illinois. The existing phase 2 moves crude oil from Steele City to Cushing, Oklahoma. Phases 1 and 2 have a combined capacity of 590,000 b/d;

- TransCanada has plans for new keystone XL pipelines. Phase 3 that is currently under construction will move crude oil from Cushing to Houston, Texas. Phase 4 would move crude oil over a new route from Hardisty to Steele City – this is the controversial phase that has received approval from the Governor of Nebraska, but at time of writing still requires approval from the US federal government. If completed, keystone XL would have a combined capacity of 830,000 b/d.

Figure 6

Overall, the total transmission pipeline existing capacity for the continental movement of crude oil from Edmonton and Hardisty – keeping clearly in mind that conventional crude oil, refined petroleum and other products also use this pipeline network – is some 3.5 million b/d. If all the new and expansion projects were completed, an additional capacity of some 2 million b/d would become available. For the inbound movement of diluent, the existing capacity is 180,000 b/d with plans for an additional 193,000 b/d.

Finally, to complete this section Figure 7 presents the current storage capacity in millions of barrels for selected companies at facilities in the Edmonton area and Hardisty

EXHIBIT 7	**Storage Capacity**	
	HARDISTY	**EDMONTON**
	(milions of barrels)	
ENBRIDGE		
Cavern Storage	3.1	
Surface Stoage Facility	7.5	
TRANSCANADA	2.6	
KINDER MORGAN		4.5
INTER PIPELINE		3.5
PEMBINA		>0.3
Source: Various Industry websites		

Figure 7

Outlook for the Production of Crude Oil from Alberta Oil Sands

In Figure 8 is presented the outlook to 2035 for the production of crude oil from the Alberta oil sands compiled by the National Energy Board in its energy market assessment dated November 2011 [5].
The assessment makes the following comments:

> Oil sands production forecasts released by the Canadian Association of Petroleum Producers (CAPP) and the Energy Resources Conservation Board (ERCB) are shown. In 2020, the ERCB projection is about six per cent higher than the NEB Reference Case, while CAPP is about two per cent higher.
>
> By 2035, in the Reference Case, oil sands bitumen production is projected to reach 5.1 million b/d, three times the production for 2010. The majority of the growth occurs in the in situ category.

In situ projects are smaller and less expensive to build so the cost of entry is lower. Also, 80 per cent of the oil sands reserves are considered well suited to in situ extraction, versus 20 per cent for mining methods.

Over the longer-term, the list of currently proposed projects, many of which are in the early planning stage, suggest that bitumen production could reach 8.3 million b/d.

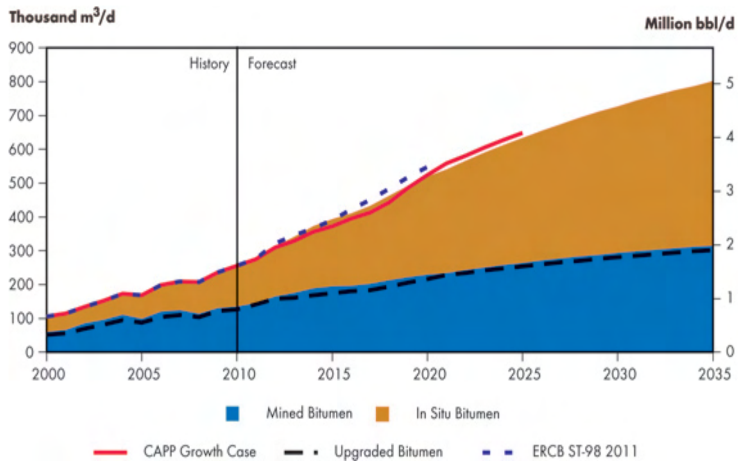

Figure 8. Oil Sands Production, NEB Reference Case

A close inspection of Figure 8 suggests that the NEB were projecting a figure of perhaps 2 million b/d in 2012. The same NEB report suggests that the production of conventional crude oil in 2012 would result in some 1 million b/d. Later estimates provided by the Canadian Association of Petroleum Producers (CAPP) [6] indicate that oil sands production will rise from 1.6 to 2.3 million b/d between 2011 and 2015, and that conventional production will rise from 1.1 to 1.3 million b/d over the same time period. Given the uncertainty of such projections and estimates it is not surprising that, at time of writing, media reports suggest that the actual total crude production has run up against the transmission pipeline capacity constraint.[4]

The increasing supply of crude oil and the associated tightening of pipeline capacity has resulted in a gap developing between the West Texas Intermediate price received by oil sands producers and the global Brent price. The National Energy Board [7] has described commodity price changes as follows:

> When there is adequate pipeline capacity between two market hubs, commodity prices will be connected and the price differential will be equal to, or less than, the transportation costs between the two points. As long as the price differential is less than the toll, the market is indicating that there is adequate pipeline capacity between the two pricing points. Where inadequate capacity exists, the product cannot get to market, resulting in higher prices for downstream consumers or lower revenues to producers, creating a higher differential in price between the two end points.

The current price discounting began in early 2011 and at time of writing has reached $20 per barrel [8]. Several media commentators are also suggesting the discount has spiked to between $37 and $40 per barrel. Cenovus is quoted as suggesting a discount of $28 per barrel in 2013, and in [8] longer-term projections are stated as follows:

> Under the current futures market pricing the differential between Brent and WTI narrows over the next few years, falling below $9 per barrel in 2015 and below $5 per barrel by 2019. However, the futures price could be misleading, as investors have likely assumed the approval and future completion of keystone XL and/or a west coast pipeline, which is why the spread declines over time. If pipeline capacity is not increased, spreads will likely remain much higher.

One important implication of continuing price discounts is the possibility of a scaling back of oil sands production, and the postponement or cancellation of new production projects. However, part II of this paper will focus instead on the opportunities for Canadian railways to handle a significant volume of the oil sands production of crude oil, and the economics of such movements.

References

[1] Energy Policy Research Foundation Inc. Washington, DC, November 2010.

[2] Canadian Energy Pipeline Association, at www.cepa.com/about-pipelines/types-of-pipelines/liquids-pipelines

[3] Canadian National railway at www.cn.ca/documents/Investor-Factbook-current/2011-IFB-Markets-en.pdf

[4] http://en.wikipedia.org/wiki/Keystone_Pipeline

[5] National Energy Board, Canada's Energy Future, Energy Supply and Demand Projections to 2035, An Energy Market Assessment, November 2011.

[6] Canadian Association of Petroleum Producers, Crude Oil Forecast, Markets and Pipelines, June 2012.

[7] National Energy Board, Canadian Pipeline Transportation System, Transportation Assessment, July 2009.

[8] TD Economics, Pipeline Expansion is a National Priority, December 2012.

Endnotes

[1] Malcolm Cairns, formerly with CP, is sole proprietor of Malcolm Cairns Research and Consulting.

[2] This description is reminiscent of freight rail, where a producing plant may have some local tracks in the plant served by a plant locomotive, which delivers loaded and empty cars to and from a siding. Then a shortline railway might take the cars to an interchange with a main line railway such as CP or CN for furtherance to markets across the continent.

[3] This is again reminiscent of freight rail, where a density map of traffic by rail line segment varies by segment and by direction.

[4] It is also probable that the feeder pipelines from the Alberta oil sands are also near or at full utilization.

CRUDE OIL BY RAIL: PART II POTENTIAL FOR THE MOVEMENT OF ALBERTA OIL SANDS CRUDE OIL AND RELATED PRODUCTS BY CANADIAN RAILWAYS

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This is the second part of a two-part paper that follows on directly from Part I.

Opportunities for Canadian Rail

The movement of crude oil by rail is a relatively new but rapidly growing market for CP and CN. CP in [1] is anticipating moving 70,000 carloads of crude in 2013 and CN in [2] is expected to move approximately 60,000 carloads of crude. This is a significant level of growth given that CP only moved 500 carloads of crude in 2009 whereas CN didn't move any crude oil. CP and CN moved approximately 7.8 million total carloads in 2012 as reported in [3]. As such, crude carload volumes represent approximately 1-2% of total carload volumes for the two railways.

The growth in North American crude volumes moved by rail is primarily driven by three factors. One is the rapid development of non-conventional crude as is currently taking place in the Bakken formation located in southern Saskatchewan and North Dakota. The Bakken region does not have sufficient pipeline infrastructure in place to move crude from the wellhead to transmission pipelines. At the time of writing, 58% of oil produced in the Bakken is moved by rail, up from 22% a year ago according to [4]. Typically, oil produced in the Bakken is moved via truck to a rail transload facility for movement to market. Given the extensive rail infrastructure throughout the Bakken region, rail is well positioned to move the production of nonconventional crude. Figure 1 illustrates CP's market reach for the movement of crude oil. It should be noted that CP has direct access to the Alberta Industrial Heartland, Hardesty, the Bakken Formation and the Marcellus Shale. CN has access into the oil sands region and the Bakken Formation.

Figure 1. Canadian Pacific Network

Second, as is the case for Alberta, the transmission pipelines are operating at or near capacity and rail is being used as an option for moving crude. The lack of pipeline capacity is leading to extensive price differentials between Alberta grades of oil, namely Western Canadian Select (WCS), the Canadian heavy oil benchmark, relative to the North American benchmark West Texas Intermediate (WTI). WCS was trading at $57.84 per barrel in December 2012, or $34.41 a barrel less than WTI. The discount has widened to $36.94 a barrel in February 2013 and based on future contracts the discount is expected to be $36 a barrel in March 2013. The second discount is between WTI and the European benchmark Brent. The WTI discount to Brent has remained at approximately $15 per barrel since 2011 because of insufficient capacity between the Cushing, Oklahoma, hub and the refineries located on the US Gulf Coast. It should be noted that Mayan crude from Mexico, which is a heavy crude similar to that produced in Alberta is priced at approximately $100 per barrel because it is transported by tanker and shipped directly to the US Gulf coast refineries [5].

The third driver for the growth of crude oil by rail is the ability of rail to reach refineries that are not served or are underserved by pipelines. A majority of refineries are near tide water and are generally located on the east, south and west coasts of North America. They are primarily served by ocean tanker. Oil producers located in Alberta or the

Bakken are shipping oil by rail to coastal refiners where they can fetch the world price for their oil. For example, as reported in [6], Southern Pacific Resource Corp, a small Alberta producer, is moving oil to the US Gulf Coast where it is receiving the Brent price for its crude. Refiners are also sourcing crude from Alberta and the Bakken. For example, the Irving Oil refinery, located in Saint John, NB, refines approximately 300,000 barrels per day, and has built a train offloading site near its refinery able to receive about 70,000 barrels a day of Bakken and Western Canadian oil [7].

Moving crude by rail offers other advantages: the relatively low levels of capital investment to develop a crude transload facility; heavy oil does not require diluent to be transported; speed to market; flexibility of routing options; supply chain diversification; and the scalability of volumes. In addition, bitumen can be loaded into coiled tube cars that can be heated to ensure the bitumen flows, and therefore avoids the use of diluent [8]. Moreover, energy firms do not have to enter into long-term contracts for the movement of crude by rail. Typically, oil producers must enter into long-term contracts in order to access pipeline capacity. Rail also transports a number of inputs used for crude production, including: fracking sand; steel pipe; other oil field tubular products; aggregates; chemicals; fuel; condensate; construction materials; and dimensional cargo [9].

Evidence to date suggests that rail markets for the movement of Alberta oil are developing more slowly than in the Bakken. It is estimated that less than 20,000 carloads of crude moved out of Alberta in 2012 as compared to 180,000 carloads out of the Bakken. However, given that Alberta holds the world's third largest crude deposit and the pipeline capacity constraints to domestic, North American and international markets, Alberta is well positioned to be a significant crude-by-rail market.

With respect to opportunities for the oil sands, both CP and CN could undertake to build new rail lines to provide direct rail service into the oil sands. Short build-ins are feasible: for CP into the Alberta Industrial Heartland; for CN into project sites along its line south of the Athabasca River; and for CN to connect using a 30 km build-in to

Hardesty. However, the construction of an extensive rail network is generally unlikely, due to the expense, and it would be in direct competition with the existing and extensive network of feeder pipelines that are owned and operated by pipeline companies closely associated with the oil companies that are extracting the oil sands product.

There are media reports of interest in building a new railway from the oil sands to Alaska, or upgrading the rail line to Churchill, but such projects have significant problems of their own – beyond the enormous capital costs. A railway to Alaska would require approval of the US federal government, crude oil through Churchill would see shipping oil in tankers in Arctic waters over a restricted summer period.

More promising immediate opportunities exist with the use of transload facilities to load crude oil into rail cars on existing rail lines. Figure 2 shows such a facility under construction on the CN line at Fort McMurray taken from [10] that is due to be operating in 2013. Also, Gibson Energy Inc. signed a letter of intent with CP in September 2012 to examine the construction of a unit train facility at Hardesty that would connect to CP's north main line for transporting crude oil by rail [11].

Figure 2

What volumes of oil sands crude oil might be handled by CP and CN from such future developments?

First, it should be pointed out that oil producers might prefer that rail handle increasing volumes of conventional crude oil from other locations to free up pipeline capacity for oil sands crude oil – see the quote from Cenovus reported in the *Calgary Herald* [12]

> For 2013 we're looking at about 10,000 b/d to help offset some of the congestion. And we'll look to potentially expand that because we see congestion being a continuing problem for the next couple of years. Cenovus is using the rail cars primarily to send its medium-light oil from conventional Alberta and Saskatchewan plays to the Irving refinery in New Brunswick or to the US Gulf Coast.

Returning now to the opportunities for moving crude oil southbound from the oil sands by Canadian rail, Figure 3 presents an order of magnitude approximation of the possibilities.

One barrel of crude oil - gallons	42	
One tank car - gallons	30,000	
Number of barrels per tank car	714	525 - 650
Number of tank cars per unit train		120
Number of barrels per train		63,000 - 78,000
Average train cycle time - days		15
Number of train sets required for one train-start per day		15
Volume moved in one train-start per day - b/d		**63,000 - 78,000**
Number of locomotives required - 2 per train		30
Number of tank cars required		1,800
Number of barrels in 10 train-starts per day - b/d		**630,000 - 780,000**
Number of locomotives required - 2 per train		300
Number of tank cars required		18,000

Figure 3. Potential Train capacity and Equipment Requirements

The following points may be noted:

- A simple calculation relating the gallons in a barrel with the gallons in a tank car suggest 714 barrels per tank car. CP has found that crude from the Bakken shale deposit is moved with 600 to 650 barrels per tank car. Elsewhere the tank car capacity for heavy crudes is approximately 525 barrels. Two of these figures are carried forward;
- Assuming a two-locomotive train hauls 120 tank cars, then one such train hauls between 63,000 and 78,000 barrels of crude oil;
- Assuming a rough average cycle time for a train from origin to destination and back is 15 days then 15 train sets are required to provide one train-start per day. This would need 30 locomotives and 1,800 tank cars;
- One train-start per day would handle 63,000 to 78,000 b/d of crude oil;
- By scaling up, 10 train-starts per day would handle 630,000 to 780,000 b/d of crude oil, and require 300 locomotives and 18,000 tank cars.[2]

To put this in perspective, the combined locomotive fleets of CP and CN operating in Canada numbered approximately 2,400 locomotives and 65,000 freight cars in 2011. Moreover, if each of CP and CN had a 50% share of the traffic, then each would be moving 5 train-starts per day – perhaps 2 west to the BC coast, 2 south to the US and 1 eastbound. For CP this would imply moving an additional 4 trains per day between Edmonton/Hardesty and Calgary, 2 trains per day to Vancouver, 2 trains per day through Portal to the US, and finally 1 train per day east bound from Edmonton/Hardesty east. A similar calculation pertains to CN.

To put this further in perspective, CP currently handles approximately 30-35 trains per day west to Vancouver, and, to give an idea of rail industry capabilities, UP and BNSF on their western corridors handle more than 100 trains per day.

It would appear that handling between 600,000 and 800,000 b/d by rail is manageable, although handling the additional 3 million b/d that is projected to be produced by 2035 might be a stretch too far.

CP and CN do not disclose the rates they charge for moving oil as this is confidential to the railway and the customer. It is generally acknowledged that moving oil by rail is more expensive than transporting it via pipeline. The question is how much more expensive? The answer depends on a number of factors. Figure 4 provides estimates of the cost of shipping western Canadian crude by pipeline to various North American markets.

Destination	Costs in $ per barrel
US Gulf Coast	$7.00
West Coast of British Columbia	$3.00
Montreal, Quebec	$3.00
Quebec City, Quebec	$6.50
Saint John, New brunswick	$8.00

Source: TD Economics

Figure 4. Potential Train capacity and Equipment Requirements

In the case of rail, the cost of moving oil is dependent on volume and distance. The greater the distance the more it will cost to move the oil via rail tank car. If a shipper is moving large volumes then there may be opportunities to move the crude via a unit train thus lowering the cost of moving oil on a per unit basis (i.e. per barrel). One of the factors that narrows the cost difference between rail and pipeline is that heavy oil that requires expensive thinner called diluent to be transported by pipeline. Heavy oil can be moved by rail without the use of diluent as indicated earlier.

With regard to the cost differentials of moving oil by pipeline versus rail, the public estimates vary greatly. According to Scott Saxberg, CEO, Crescent Point Energy Corp. in [13] “The cost of rail versus pipe isn’t hugely significant these days, especially now with the increased regulations and delays on pipelining. We see it being is the $2 a barrel range". Crescent Point produces light oil that does not require the use of diluent to ship via pipeline. It has built its own facility to load rail cars and is moving 15,000-16,000 barrels a day, or a fifth of its production via rail. The markets that Crescent Point are accessing for its oil are paying so much more for the oil that the company expects to pay off the loading facility within a year [14]. It is clearly economical for Crescent Point to use rail to transport oil.

It has been reported elsewhere that it can cost nearly four times as much to ship oil by rail versus pipelines. Southern Pacific Resource Corp, a small Alberta producer, estimates that it costs $31 a barrel to moves its Canadian oil sands–mined heavy crude by rail to the US Gulf Coast, with the comparable pipeline cost of $8 per barrel [15]. However, as mentioned earlier Southern Pacific Resource Corp receives the Brent price for its oil in the US Gulf, thus it makes economic sense to move its oil to that market.

The publicly available evidence suggests that the additional total cost of moving oil by rail as compared to pipelines is in the $2 to $20 per barrel range.

Conclusions

The analysis presented in this two-part paper suggest the following preliminary conclusions:

- The current feeder pipeline network serving the Alberta oil sands has the capacity to handle some 2 million b/d of outbound crude oil, and this capacity can likely be expanded relatively easily given that licensing is regulated by a provincial authority;
- The feeder network connects with the trans-continental transmission pipeline network at two locations: the Alberta Industrial Heartland just northeast of Edmonton, and Hardesty, Alberta;
- Both of these locations have direct rail service and very significant existing storage capacity;

- The transmission pipeline network from these two locations – keeping in mind that it handles not just Alberta oil sands crude, but also conventional crude and other related products – is some 3.5 million b/d;
- Current expansion plans would see additional transmission pipeline capacity of some 2 million b/d;
- Official projections indicate that Alberta oil sands production could increase from 2 million b/d to 5 million b/d by 2035, and possibly 8 million b/d at a later date;
- Pipeline capacity constraints are a factor in the current discounting of the price of Alberta oil sands crude oil from world prices by anywhere in the range $10 to $30 per barrel;
- The additional total costs of moving crude oil by railway over transmission pipeline is likely in the range from $2 to $20 per barrel depending upon the markets being served. It would therefore appear that with the current discounting, the movement of Alberta crude oil by rail would be economic;
- An order of magnitude estimation suggests that CP and CN combined could move 600,000 to 800,000 b/d with a manageable increase in equipment and infrastructure.

It therefore appears that the railways could provide a significant capacity to move Alberta oil sands crude oil, during any transitional period while transmission pipeline capacity is expanded, and as a long-term source of flexibility. However, the handling of the full 3 million b/d anticipated by 2035 is probably a stretch too far.

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Endnotes

[1] Malcolm Cairns, formerly with CP, is sole proprietor of Malcolm Cairns Research and Consulting.
[2] It should be noted that tank cars are usually provided by the shipper rather than the railway.