Opportunities and Challenges of the Canadian Crude Oil Sector

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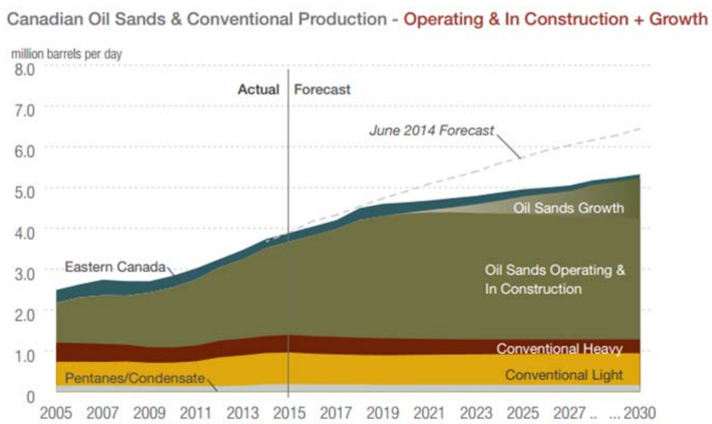
Introduction

Canada is home to vast oil reserves and is on the road to becoming a globally competitive oil exporter, but is presently facing a challenging juncture amid depressed oil prices, mid-stream constraints, and uncertainty surrounding new federal and provincial governments. Canada has the third largest proven oil reserves in the world at an estimated 173 billion barrels, which is around 10% of the world's reserves. In the province of Alberta, the oil sands hold around 97% of total Canadian reserves (NRCAN, 2014). Total crude production in Canada has grown from 2.8 million barrels per day (mb/d) in 2010 to a forecasted average of 3.8 mb/d in 2015 (CAPP, 2015). The primary driver of this growth has been and will continue to be from production in the oil sands, estimated to account for 60% of production in 2015. Due to the recent crash in oil prices, the Canadian Association for Petroleum Producers (CAPP) has reduced forecasts for 2030 to 5.33 mb/d for total Canadian production and 4 mb/d for oil sands production as seen in Figure 1.0.

Figure 1.0- Production Forecast to 2030



Source: CAPP, "Crude Oil Forecast, Markets & Transportation", 2015

Midstream development is in the midst of uncertainties. Regulatory assessments and final decisions on pipeline development will determine Canada's place in the global oil industry. Canada currently sends around 98% of total crude oil exports to the United States. The U.S. is becoming significantly less dependent on imports as domestic production grows substantially. As such, it is crucial for Canada to develop efficient access to new markets. Currently four major pipelines are proposed; Enbridge’s Northern Gateway, Kinder Morgan’s Trans Mountain expansion, TransCanada’s Keystone XL and TransCanada’s Energy East. All have experienced setbacks and controversy within North America, but the project proponents are confident in the eventual development.

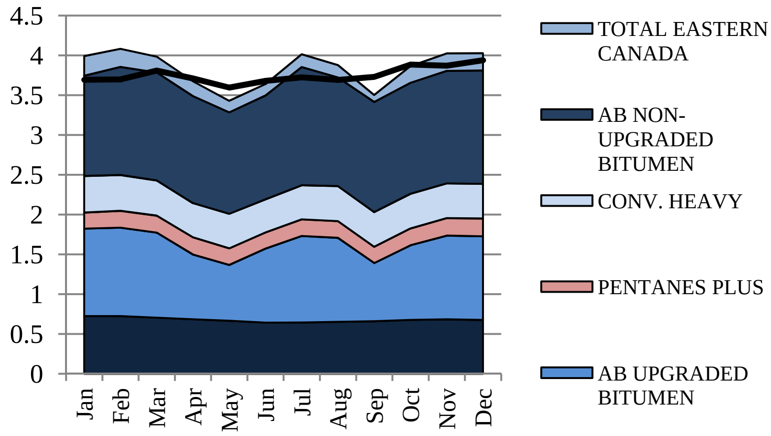
Recent forecasts for production have been lowered; however there are a number of factors that could create a more optimistic outlook for the Canadian oil industry. A new federal government was elected in October 2015, and has discussed plans for reforms in resource regulations and supports pipeline development. The government highlights the importance of getting crude to new markets, although the environment is a priority.

For the entire global energy sector, there is uncertainty in what lies ahead due to the price crash, but Canada’s vast resources and politically stable environment undoubtedly make it an important energy trading partner and a competitive global energy player. This report will aim to look at current issues and opportunities facing the Canadian crude sector.

1. **Production growth is lower than anticipated. This is attributable to oil prices but also production was shut down due to forest fires, upgrader maintenance, and a pipeline spill.**

Production growth has slowed this far in 2015 due to the depressed oil prices and has also experienced some stalls due to a combination of forest fires, upgrader maintenance, and pipeline shut downs. As seen in Figure 1.1, using data taken from the Canadian National Energy Board (NEB), total production dropped 7% in both April and May with Alberta bitumen alone falling 11% and 8% respectively. In the month of April, companies such as Suncor Energy, Shell, and Canadian Oil Sands Ltd, all performed upgrader maintenance which shut down around 255,000 b/d of upgrading capacity. In May, the decrease in production was exacerbated by wildfires in Alberta which shut in another 200,000 b/d of crude. Bitumen production in June and July saw strong growth, 13% and 15% respectively, as maintenance was completed and new projects came online. In August and September production dropped again due to maintenance at U.S. pipelines and refineries which slowed some production of crude in Canada that was destined for the U.S. An unfortunate pipeline spill in the end of July at Nexen's Long Lake project resulted in the Alberta Energy Regulator forcing the shutdown of the project in August which has a production capacity of 72,000 b/d. It was shut down until Nexen could provide adequate records of pipeline maintenance. Operations had restarted fully in October and total Canadian production is forecasted to rise 15% from September to December reaching a high of 4 mb/d at the end of the year.

Figure 1.1- 2015 Estimated Production of Canadian Crude (million barrels per day)



Note: Production levels are forecasted after June
Source: NEB, "Estimated Production of Canadian Crude and Equivalent", 2015

2. The oil sands have been especially susceptible to the crash in oil prices due to the capital intensity, high production cost, and the difficulty to shut already operating projects down. Many oil companies remain confident in the future of the oil sands, while a few are becoming weary.

Companies have made cuts to capital investments, budgets, and staff; planned projects have been delayed and some operations suspended. CAPP has estimated that capital spending will decrease by 33% or $23 billion in 2015, leaving capital investment in Western Canada to be $46 billion, with $25 billion of that allocated to the oil sands

(CAPP, 2015). Alberta has been especially hard hit as several companies have had to reduce staff resulting in the unemployment rate in Alberta forecasted to rise from 4.7% in 2014 to 6.2% in 2016 (Government of Alberta, 2015).

As for project disruptions in the oil sands, some smaller operations have had to suspend around 20,000 b/d of operating production in order to preserve capital as they fall under creditor's agreements until prices recover. Some larger proposed projects have been cancelled such as Shell's 200,000 b/d Pierre River oil sands mine, as they want to focus on making their "heavy oil business as economical and environmentally competitive as possible" (Haggett and Williams, 2015). Shell has also recently halted work on an 80,000 b/d project in Carmon Creek, taking a $2 billion loss. Total has stalled its Joslyn North 100,000 b/d mining project, as well as sold off a 10% stake of its Fort Hills project. Other expansions and projects have been placed on hold while companies wait for oil prices to improve. However, projects already in the construction phase when oil prices crashed are continuing to be built. For example, the Fort Hills project led by Suncor Energy, will continue to advance and will add 180,000 b/d to a total of over 700,000 b/d of capacity additions in Alberta throughout the next five years, which is over a 25% increase.

Although pessimism seems to be rising in the oil sands, many oil and gas companies are still confident in their Canadian assets and staying optimistic. This is because oil sands projects are long life investments and once initial capital is in place, the economies of scale make the projects worthwhile. For example, the Fort Hills project has planned production of 180,000 b/d and this production rate is planned to stably last 50 years. Companies also still publicly support the oil sands. For instance ExxonMobil (subsidy in Canada is Imperial Oil) CEO Rex Tillerson commented in October that the large oil sands projects are still a very important asset and that the scale mixed with the stability of Canada make it this way (Dutta, 2015). A Canadian integrated energy company, Cenovus Energy, has stated they do not let short-term pricing dictate their investments for the long life and high return oil sands projects (Van Loon, 2015). Furthermore, additional capacity is being obtained in the oil sands as valuable assets are now at lower prices. For instance, Suncor purchased the 10% Fort Hills stake from Total and in mid-October this year Suncor (75%) together with Nexen (25%) submitted an application to build a new 80,000 b/d oil sands project, Meadow

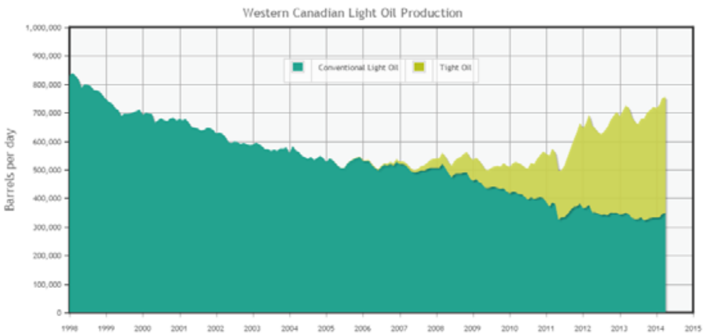
Creek, that would have first oil by 2020. Suncor also has made a hostile takeover bid for Canadian Oil Sands Ltd (COS) which would have increased Suncor's share in the largest oil producing project in Canada, Syncrude (300,000 b/d in August) , from 12% to 48.74%.[1] With a high amount of less diversified and less capitalized junior oil and gas companies operating in Canada it is suspected that a pickup in mergers and acquisitions from larger, well capitalized firms is on the horizon (Gayathri and Williams, 2015).

A focus on technological advancement, environmental efficiency, and an overall goal to make oil sands production less costly will increase the efficiency and competitiveness of the oil sands. Oil sands players are working together to achieve greater efficiency through organizations such as the Canada's Oil Sands Innovation Alliance, which brings together the large oil sands players to share technologies, especially environmental, in order to spur technological innovation more rapidly.

Non-Oil Sands Development

The EIA has reported that Canada has approximately 8.8 billion barrels of technically recoverable shale oil mostly located in the Duvernay/Muskwa basins in Alberta and the Bakken basin in Saskatchewan/Manitoba (EIA, 2015). This does not include a new discovery of 200 billion barrels of shale oil-in-place in the Northwest Territories. Although reports are still early, even 1% of recoverable oil from this region would be a significant 2 billion barrels. Due to the remote location and lack of infrastructure, this northern play would be more costly to develop. Therefore, with current prices it seems this will be a development of longer term interest.

Figure 2.2- Western Canadian Light Oil Production



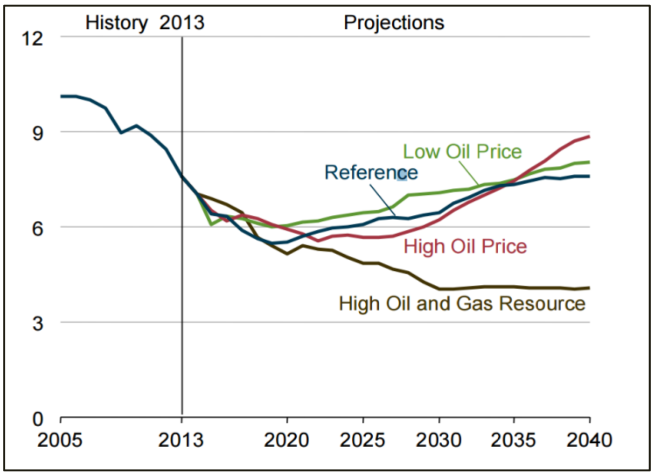
Source: NEB, "Canadian Tight Oil Production Update", 2014

[1] Although the bid was blocked by COS, the deal will face the Alberta Securities Commission at the end of November where a decision will be made unless a prior agreement is made between COS and Suncor.

Tight oil production, primarily in Alberta and Saskatchewan, has doubled from 0.2 mb/d in 2011 to 0.4 mb/d in 2014. Tight oil in Western Canada is expected to replace the declining production of conventional light oil, a trend beginning in 2008 as seen in Figure 2.2 (NEB, 2014). Light oil production is down in this year compared to 2014 with forecasts predicting a 7% fall year over year from .94 mb/d in 2014 to .87 mb/d in 2015. The rig count has decreased from 377 wells on September 19th 2014 to 182 wells on September 18th 2015 (Baker Hughes, 2015). Light oil wells are easier to shut down when oil prices create unattractive economics, which highly differs from the large oil sands projects.

3. Canada exports around 98% of crude exports to the U.S. However, as the U.S. continues to rapidly increase production it will not be sustainable for Canada to solely rely on the U.S. as an export market for crude.

Figure 3.1- EIA forecasts for "U.S. net crude oil imports in four cases 2005-40" (million barrels per day)

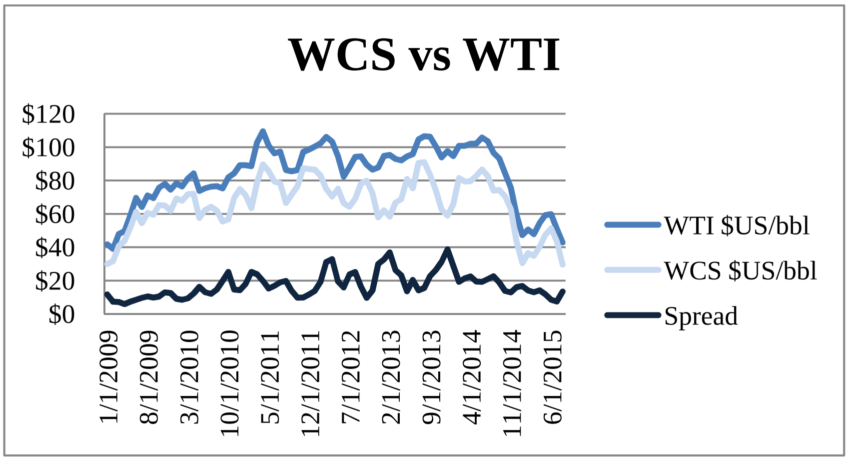


Source: EIA, "Annual Energy Outlook 2015", 2015

It was believed in the early 2000s that the U.S. was going to be in increasing need of crude imports as reserves and production levels were falling rapidly. However, unprecedented production growth has occurred in the U.S. due to technological advances in developing shale resources. Crude production rates hit a low of 5 mb/d in 2008, but the trend reversed and the production rate has reached 8.7 mb/d in 2014, an increase of 75%. This has resulted in total U.S. crude imports dropping over 25% since 2008. Although total U.S. imports have dropped, imports from Canada have still grown over 45% since 2008 from 1.97 mb/d to 2.9 mb/d in 2014. Canada's share in U.S. crude imports has grown from 20% in 2008 to 39% in 2014 as the U.S. reduces its reliance on overseas crudes. Although imports from Canada have grown, the U.S. expects imports to continue to drop increasingly as seen in Figure 3.1.

Why do Canadian imports into the U.S. continue to grow while U.S. total imports decrease? Canadian exports offer several advantages to the U.S. An important factor is that Canadian oil sells at a discount to global benchmarks. This is because the lack of market access reduces the competitiveness of Canadian crude. The Canadian crude benchmark, Western Canadian Select (WCS), has continued to be sold at a discount to West Texas Intermediate (WTI), the U.S. benchmark as seen in Figure 3.2. Discounts will continue as long as there are export constraints, meaning producers will have to accept a lower price in order to sell their oil. Due to the drop in currency from a high of .94 CAD/USD in 2014 to around .75 CAD/USD in mid-2015, some of the discount for Canadian producers is mitigated as they receive U.S. dollars for their oil.

Figure 3.2- Canadian vs U.S. Benchmarks

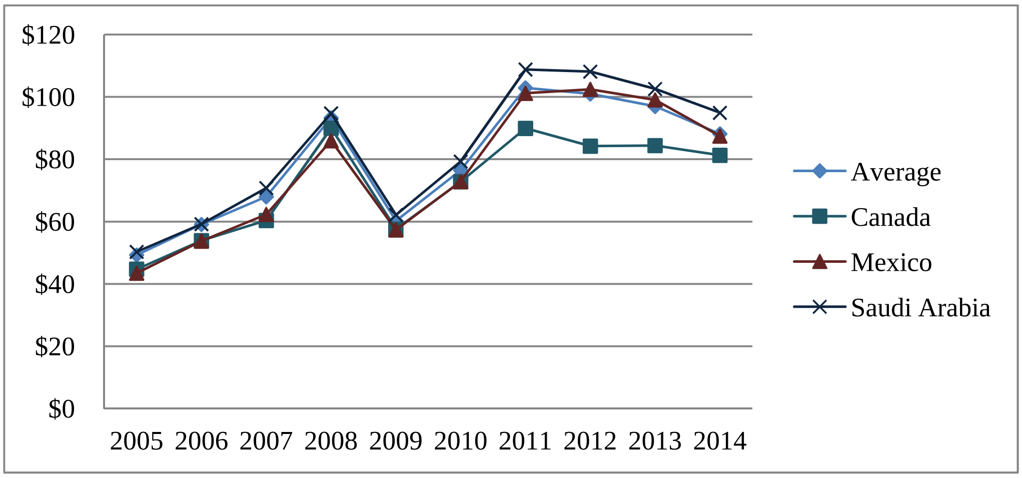


Source: Government of Alberta, "Energy Prices", 2015

The U.S. and Canada also have heavily integrated midstream infrastructure that enables ease of trade and lower transportation costs between the two economies. Lower transportation costs plus the discounted price of WCS makes Canadian oil a better purchase for U.S. refiners rather than importing more expensive oil from overseas (Figure

3.3). A majority of the crude exported to the U.S. is transferred via pipelines and due to growing capacity constraints, exports by rail are significantly increasing as well as small amounts moved by marine tanker. Currently there are several major pipeline systems carrying Canadian crude to the U.S. One is Enbridge's Mainline system with a capacity of 2.6 mb/d that connects Edmonton, AB to Superior, WI where it is then carried to Midwest and East Coast markets. Another pipeline is the Spectra Express-Platte that has a capacity of 280,000 b/d and connects Hardisty, AB to Casper, WY and beyond to Midwest refineries. TransCanada Keystone has a capacity of 590,000 b/d and connects Hardisty, AB to the Midwest and the Gulf.

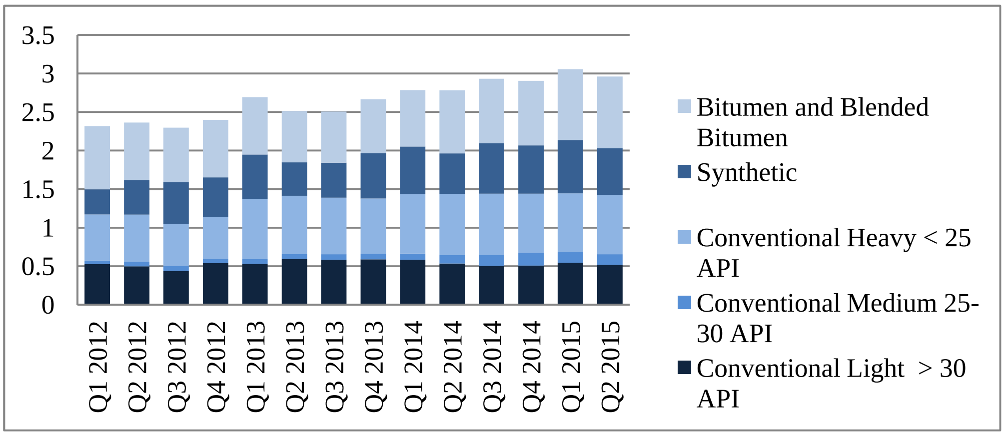
Figure 3.3- Landed Costs of Imported Crude into the U.S.



Source: EIA, "Landed Costs of Imported Crude by Area", 2015

Another important reason as to why Canadian oil exports have been rapidly increasing into the U.S. is because of the capability of U.S. refineries to use heavier grades of oil. Before the U.S. expected to be producing massive amounts of very light oil from domestic shale plays it was expected that imports would consist of heavier crudes from Mexico, Venezuela, and other heavy oil regions. This resulted in the development of many heavy oil refineries along the Gulf. Therefore the U.S. imports a majority of Canadian heavier grades as seen in Figure 3.4 in order to use existing refinery capabilities.

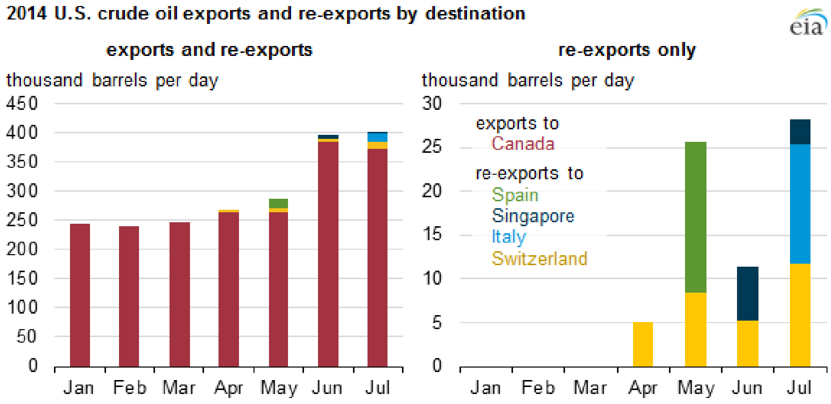
Figure 3.4- Canadian Crude Exports by Type



Note: Synthetic can be any API but generally between 30-35. Bitumen is blended with light hydrocarbons but generally has an API less than 22.
Source: NEB, "Crude Exports by Type and Destination", 2015

Not all of the exports to the U.S. go to American refineries. In fact, increasing amounts of crude from Canada has been making its way to Asian and European markets via the U.S. Since the 1970s there has been a ban on exporting U.S. produced crude oil, but there are exceptions such as re-exports of Canadian crude. Canadian exporters may apply for licenses to the Bureau of Industry and Security (BIS) of the U.S. Department of Commerce in order to export Canadian crude from U.S. ports (Breul, 2015). Figure 3.5 displays Canadian crude that was not commingled with American crude and re-exported from U.S. ports. Re-exports are expected to grow and companies such as Cenovus Energy have recently obtained a license to sell oil to independent refiners in China from U.S. ports. Re-exports will continue to play an important role in Canada's exports beyond the U.S. while pipelines to the Canadian coast lines are waiting to be developed.

Figure 3.5- Canadian produced crude re-exported from U.S. ports

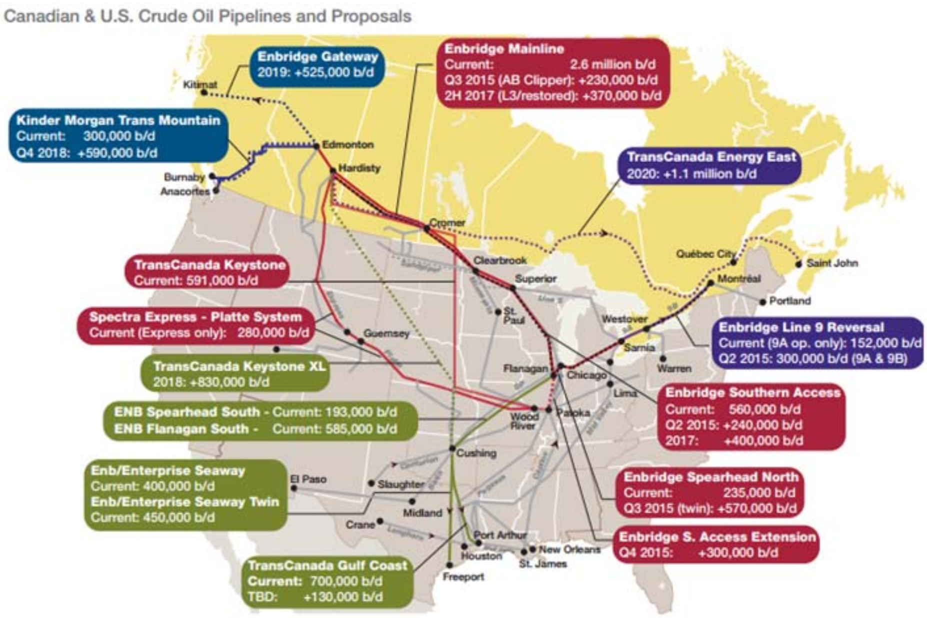


Source: Breul," Crude exports and re-exports continue to rise; some volumes sent to Europe and Asia", EIA, 2015

Although Canadian heavier grades should have a place in U.S. refineries in the foreseeable future, lighter crudes and upgraded synthetic crude could be displaced. U.S. refineries are planning to adjust their refinery input in order to use the growing production of super light crude from U.S. shale. A refinery use survey done by American Fuel & Petrochemicals Manufacturers (2015) asked U.S. refiners of their planned use in the upcoming years. The sample represents about 61% of U.S. refiners, with the respondents relatively equally distributed throughout the U.S. It was discovered that by 2016 respondents are planning to increase the input of super light (41.9-50 API) by 43% from 2014 levels while decreasing their use of medium (24-30.9 API) and light (30.9-41.9 API) crude by 30% and 10% respectively. Planned use of Heavy (<=24 API) crude is expected to see a 3% growth from 2014 levels. In Q2 2015 around 30% of exports from Canada fall in the U.S. definition of light and medium. Also, around 20% of exports were Synthetic crude which can generally fall in the definition of light and medium. Exports of synthetic, light, and medium crude grades, representing around 50% of exports, could suffer as the U.S. refiners replace these grades with super light domestic crude inputs. This is another reason why domestic pipeline development is crucial.

4. **As it becomes increasingly important for Canada to diversify export markets, pipeline development is crucial. Pipelines are the best solution to move crude from Alberta to the market. There are currently four major pipelines proposed.**

Figure 4.1- Map of Current and Proposed Pipelines



Source: CAPP, “Crude Oil Forecast, Markets & Transportation”, 2015

It is a well-known fact that Canada must diversify and expand export markets, but there are many issues facing midstream development. At the forefront of midstream development are stalls in regulatory and government decisions on pipelines, backed by environmental concerns and First Nations land negotiations. Canada currently has four major pipeline proposals that are all at a similar stage in development and waiting to be given approval by the government and supporting regulatory bodies. The four pipelines would greatly increase Canada’s market access and Table 4.1 outlines what tariffs will look like. All pipelines will begin in Alberta with one pipeline to the East Coast, two headed to the West Coast, and a one headed down into the U.S. Gulf. Here is a brief look at the four major crude pipeline proposals.

Possibly the most well-known pipeline, Keystone XL, has been the most controversial of all pipeline proposals and has garnered much media attention since the project first applied for a presidential permit in 2008. The Keystone XL would bring 830,000 b/d of Alberta crude to the U.S. Gulf Coast for use in U.S. refineries and for re-exports beyond the Gulf. The project has just recently been rejected by U.S. President Obama. The decision was backed by climate change action and the conclusion that the pipeline is not in national interest nor improves energy security. The public sentiment has been that the development of Keystone XL would directly result in higher GHG emissions from the notoriously viewed oil sands, although an environmental impact report released by the U.S. Department of State concluded that Keystone XL would not make significant negative environmental impacts.

Although it has been rejected, the project still has potential to be developed as TransCanada has said they would consider reapplying for a presidential permit depending on the results of the U.S. presidential election in late 2016. Almost all the Republican candidates declared displeasure in Obama's decision and candidates such as Marco Rubio and Jeb Bush have both stated they will bring the pipeline back if elected into office. The new Prime Minister of Canada, Justin Trudeau, also supports the pipeline, especially as he has stated he does not prefer the alternative to pipelines, which is an increase in rail exports. Just days after Obama rejected the pipeline there was a derailment that leaked 1000 gallons of oil forcing a local community to evacuate in Watertown, MA and another derailment along the Mississippi river. A truly final outcome for Keystone XL will be determined upon the arrival of a new U.S. president, but for now it will pause on development.

With a stall in the development of the Keystone XL, it can be suspected that TransCanada will focus on the Energy East pipeline that will bring 1.1 mb/d of Alberta crude to the East Coast of Canada. The Energy East Pipeline submitted its application to the National Energy Board in October 2014, but in April 2015 changed the planned route by eliminating previously planned marine and associated tank terminals in Cacouna, Quebec. Therefore, TransCanada is completing an amended application that is expected by the end of 2015. Energy East may face the usual environmentalist and First Nations concern, but only 30% of the project will be new pipeline as the other 70% is utilizing existing gas pipelines reconfigured to oil and half of the newly built pipeline will use already cleared paths (TransCanada, 2015). The Energy East pipeline will allow Alberta crude to be moved to refineries in Eastern Canada as well as exports beyond the Atlantic.

The Kinder Morgan Trans Mountain Expansion (TMX) seems to have the greatest chance to be developed first. The Trans Mountain pipeline, which carries both crude and products, has a current capacity of 300,000 b/d and has proposed to increase the capacity to 890,000 b/d. The National Energy Board must submit a letter of recommendation by May 2016 to the government where a final decision has 90 days be made. There is confidence in approval of the expansion as Trudeau has already publicly stated support for this project. The CEO of Kinder Morgan has expressed the project will go ahead as soon as they have federal approval. As it is an expansion of an already existing pipeline 73% of the proposed route will use the existing right of way, 17% will use other infrastructure right of way such as power lines, and only 10% would be of new passage (Kinder Morgan, 2015).

The Trans Mountain pipeline flows into Burnaby B.C. The Westridge Marine Terminal, owned by Kinder Morgan, will be expanded to handle 34 tankers per month with the largest ships allowed in the Port Metro of Vancouver being the AFRAMAX which has a capacity of 660,000 bbls, but typically carries 585,000 bbls (Kinder Morgan, 2015).[2] Currently the Westridge Marine Terminal likely receives around 81,000 b/d from the Trans Mountain pipeline as it currently handles approximately five tankers per month, leaving the remaining approximate 200,000 b/d to refineries and terminals in the surrounding area. One such refinery that is supplied by Trans Mountain is Chevron's Burnaby Refinery which produces around 57,000 b/d of products that typically supplies B.C. Suncor also has a products terminal fed by Trans Mountain that distributes finished products both to B.C. and abroad.

Enbridge's Northern Gateway pipeline received federal government approval in June of 2014 and is subject to 209 conditions. The Northern Gateway will take 525,000 b/d of crude from Alberta to a marine terminal in Kitimat B.C. able to load 220 tankers per year and plans to export to the Asia Pacific market. The project has until December 31, 2016 to begin construction or the approval will expire. The Northern Gateway project faces a high amount of public disapproval especially due to the perceived disruption increased tanker traffic will have on northern coastal waters. The

[2] Currently the Westridge Marine Terminal currently handles approximately five tankers per month and only one Aframax tanker at a time.

project has also been stalled by a court case brought by First Nations in claims that they were not properly consulted during the planning of the project. The pipeline could face cancellation if a federal court decision is in favor of the First Nations. The verdict of this hearing will be released in mid-2016 (Hussain, 2015). The pipeline also faces headwinds with the possibility of a ban on oil tankers on B.C.'s northern coast, but this would have yet to be debated in the House of Commons to obtain legislation. Enbridge seems more optimistic as a communications manager has said they have made more progress with community and First Nations partnerships than has been publicly perceived and that they "share the vision of Trudeau's government that energy projects must incorporate world-leading environmental standards and First Nations and Metis ownerships" (CBC News, 2015).

Table 4.1- Tariffs of Existing Pipelines

Kinder Morgan (KM) Trans Mountain Pipeline: Edmonton, AB to Westridge Marine Terminal, B.C. (Marine loading included)		
Light		$3.69
Medium		$3.83
Heavy		$4.12
Super Heavy		$4.26
TransCanada (TC) Keystone Pipeline: Hardisty, AB to Cushing, OK		
Committed 10 YR	Light	$2.84
	Heavy	$3.18
Committed 20 YR	Light	$2.77
	Heavy	$3.11
Uncommitted	Light	$3.40
	Heavy	$3.82
Enbridge Line 9: Hardisty, AB to Montreal, QC		
Committed	Light	$5.17
	Medium	$5.55
	Heavy	$6.21
Uncommitted	Light	$6.28
	Medium	$6.75
	Heavy	$7.56

Note: KM and TC prices reported in CAD have been converted into USD using Nov 6, 2015 exchange rate of 1.32 USD/CAD. Enbridge originally reported in USD.
Source: Kinder Morgan, Enbridge, TransCanada, Tariff listings from company webpages, 2015

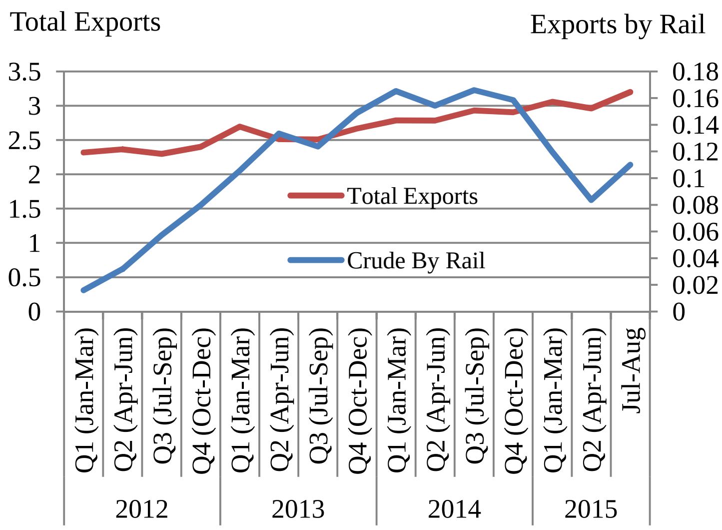
Table 4.2- Proposed Pipeline Projects

Project	Online	Route	Capacity b/d	Other Additions	Status
Kinder Morgan Trans Mountain Pipeline Expansion	2018	Edmonton, Alberta > Vancouver, British Columbia	**Total:** 890,000 **Currently:** 300,000 **Add:** 590,000	12 pump stations, 14 storage terminals in Burnaby, 1 in Sumas, 5 in Edmonton An expansion of three new berths to allow 34 tankers from 5 tankers per month at Westridge Marine Terminal	Final recommendation report from the NEB due by May 2016. Then Federal Cabinet has 90 days to give a decision.
TransCanada Energy East Pipeline	2020	Hardisty, Alberta > Saint John, New Brunswick	1.1 million	New tank terminals in Hardisty, Saskatchewan, Quebec City, and Saint John and marine terminals in Saint John. Project will connect to refineries in Montreal, Quebec city area, and Saint John.	TransCanada is planning to file an amended application by end of 2015. Once received the NEB will have 15 months to make a recommendation.
TransCanada Keystone XL Pipeline	TBD	Hardisty, Alberta > Steele City, Nebraska	830,000	8 new pump stations in Canada and 33 in the U.S.	Has been approved in Canada and rejected by the U.S. A new president in 2017 could reverse the decision.
Enbridge Northern Gateway Pipeline	2019	Bruderheim, Alberta > Kitimat, Bristish Columbia	525,000	10 new pump stations. A Kitimat marine terminal with 2 ship berths and 19 tanks for oil and condensate to seerve 220 tankers per year.	Approved by government with 209 conditions. Is stalled in federal court after First Nations claimed they were not consulted, a decision should come within 6 months. Construction must begin by end of 2016 or permit will expire.

5. **With pipeline development moving slowly, crude has had to move utilizing alternative transportation. Crude by rail has increased substantially over the past five years to help alleviate capacity restraints of pipelines.**

Pipeline capacity is becoming incredibly tight and will continue to face constraints. This has resulted in producers significantly increasing the use of crude by rail. Fuel oils and crude petroleum loading in Canada, which includes domestic and export movements, has grown from an annual total of 64,312 rail car loadings or 5.3 million tonnes of crude in 2010 to 186,614 car loadings or 15.5 million tonnes in 2014.[3]

Figure 5.2- Crude by Rail and WCS-WTI Spread (million barrels per day)



Year	Quarter	WCS-WTI Spread in USD
2013	Q1	$31.93
	Q2	$19.04
	Q3	$17.50
	Q4	$32.08
2014	Q1	$23.20
	Q2	$20.40
	Q3	$20.79
	Q4	$14.26
2015	Q1	$14.64
	Q2	$11.50
	Q3	$13.26

Source: NEB, "Canadian Crude Oil Exports by Rail", 2015 & Government of Alberta, "Energy Prices", 2015

In 2010, a few small shipments of crude by rail to the U.S. totaled 16,000 barrels (43 b/d), which held an insignificant share of total crude exports of around 1.9 mb/d. By 2014, crude by rail exports expanded significantly to 160,000 b/d, accounting for around 6% of total crude exports of 2.9 mb/d. Crude by rail exports decreased at a greater rate than total exports in mid-2015 because the price differential of WCS vs WTI affects the economics of crude by rail (see Figure 5.2). The steeper the discount of WCS, the better the economics of crude by rail as the premium of rail transport will

[3] BNSF Railway suggests approximately 680-720 barrels of crude are carried in a single crude oil railcar (BNSF, 2015).

be mitigated by the cheaper price of Canadian oil. If the spread between Canadian and U.S. crude shrinks then buyers will look for cheaper means of transportation or cheaper crude from another location. This is exemplified when crude by rail decreased to a low of around 65,000 b/d in June of 2015 when the spread was at US$8.53. In August, crude by rail exports increased to around 108,000 b/d as the spread increased to US$13.39. Additionally, the landed cost of Canadian crude in the U.S. dropped from US$55.25 in June to US$38.97 in August. With the halt in the Keystone XL pipeline and stalls in pipeline development, downwards pressure on WCS can be expected, therefore with pipeline development delays included it can be expected that crude by rail will continue to increase.

Figure 5.3- Crude by Rail vs Pipeline Transportation Costs in USD

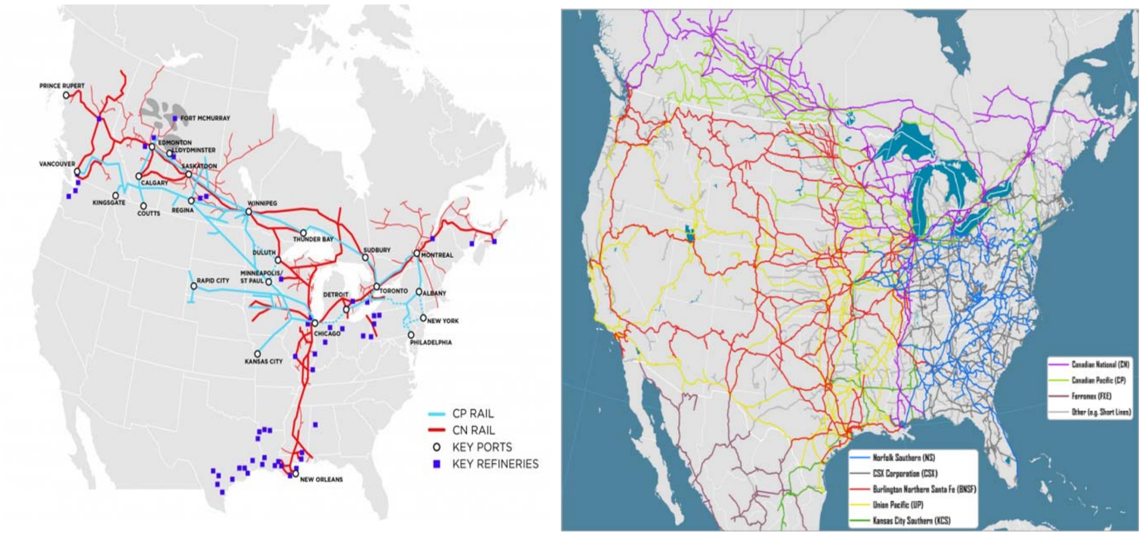
Pipeline			
Origin	Destination	Crude	Rate $/bl
Alberta, CAN	Cushing, TX	Light	$3.78
Alberta, CAN	Cushing, TX	Heavy	$4.54
Cushing, OK	Houston, TX	Light	$2.71
Cushing, OK	Houston, TX	Heavy	$3.26
Rail			
Origin	Destination	Crude	Rate $/bl
North Dakota	Houston, TX	Bakken	$10.38
North Dakota	NY Harbor	Bakken	$10.55
Alberta, CAN	Houston, TX	Canadian Heavy	$16.73

Source: Association of Oil Pipe Lines (AOPL), “About Pipelines”, 2015

Although crude by rail is more expensive than pipelines as seen in Figure 5.3, crude producers are relying on more rail capacity in order to get crude to markets. In 2014, CAPP predicted that crude rail loading capacity could exceed 1.0 million b/d by the end of 2015 as new expansions are set to come through which is up from 180,000 b/d at the beginning of 2013. Earlier this year TransCanada stated they planned to enter the crude by rail business, as well as Kinder Morgan and Enbridge. TransCanada said they wanted to be able to offer solutions to shippers as Keystone’s review process moves slowly (Hussain, 2015a). Rail offers a hedge to pipeline constraints and also allows sellers to access a more diverse set of locations (see Figure 5.4). This is why upstream and midstream players alike are investing in crude loading. Cenovus Energy just purchased a rail terminal, Bruderheim Energy Terminal in Alberta, which gives it access to 70,000 b/d of rail capacity.

As crude by rail increases, rail to marine terminal projects have also picked up, especially along the U.S. north western coast. Proposed rail to marine terminals in Washington could add more than 500,000 b/d of crude export capacity (Clark, Doan, & Murtaugh, 2015). Three projects, Westway Terminal, Imperium Terminal, and Grays Harbor Rail Terminal all stated in their Environmental Impact Statements that shipping crude abroad from Canada is an option. Another project by Tesoro is planning to build a 360,000 b/d rail-to-marine terminal in the Port of Vancouver in Washington (not to be mistaken with Vancouver city in Canada) and has stated that 60,000 b/d will be shipped to refineries in Washington and California while the remaining 300,000 b/d would be commercially available, which could be another option for Canadian crude. The region in which the planned rail-to-marine terminals are located is classified as PADD 5 (West Coast). In 2013 and 2014 exports into PADD 5 from Canada averaged 193,000 b/d and 208,000 b/d respectively with rail accounting for 4% and 6%. From January to July of 2015 exports have averaged 225,000 b/d with rail accounting for 5%.

Figure 5.4- Maps of U.S. and Canada Major Railways



Source: CAPP, Infrastructure and Transportation-Rail, 2015 & Rodrigue, Jean-Paul, “The Geography of Transport Systems”, 2014

6. In October of 2015 a new Canadian Prime Minister was elected as well as a new Alberta Premier. Heavier environmental policies are likely, but there is optimism that a more responsible approach to oil development is what Canada needs in order to move forward with essential projects.

A new party has been elected into the Canadian federal government. Since 2006 the Prime Minster of Canada had been Stephen Harper of the Conservative Party. Influences to the oil sector during his career include; withdrawing from the Kyoto Protocol in 2012, strong government support of oil and gas development, maintaining Canada's strong economic growth through the 2009 economic crisis, and heightened GHG emissions from 699 MT in 2009 to 726 in 2013 (Environment Canada, 2015).[4] Harper has been criticized for his lack of climate change action and praised for his pro-oil stance. Environmentalists and First Nations did not support Harper's government.

The new Prime Minister that was elected in October is Justin Trudeau of the Liberal Party, which won a majority government for the four year term. Although a definitive energy or climate plan has not been announced, it is understood through campaign pledges that Justin Trudeau is supportive of the oil and gas industry, but wants development to be environmentally responsible. Trudeau has stated that Harper was not successful in realizing pipeline development because people did not "trust the government to protect their interests, including providing adequate regulatory oversight or respecting the rights of aboriginal people" (Cattaneo, 2015). People also believe Keystone XL is unpopular with U.S. Democratic leaders because Canada has not taken proper responsibility to reduce GHG emissions and believes the pipeline would continue to promote irresponsible development. While these statements are subjective and can be debated, Trudeau has stated, "Canada takes its environmental responsibilities seriously and we will do more in the fight against climate change," but highlighting that "getting our resources to market is a priority for Canadians and we know that economic success depends on us keeping our word on the environment" (Cattaneo, 2015).

Trudeau has stated support for the TMX, Keystone XL, and Energy East, but is

[4] Canada has been the only country to withdraw from the Kyoto Protocol. Canada had the strongest in the G7 during the 2009 economic crisis and a higher average growth rate from 2010-2014, but is slowly falling behind as growth is forecasted at 1.04% placing Canada in 5th out of 7.

not fully supportive of Enbridge's Northern Gateway. Trudeau has also pledged to invest $200 million each year to create strategies that support innovation and clean technologies in the forestry, energy, and agricultural sectors (Do, 2015). Trudeau aims to focus on environmentally responsible oil and gas development. This could in fact win over the vital stakeholders for pipeline development that distrusted Harper, like First Nations and environmentalists. It is expected that he will create national emissions-reduction targets in time for the United Nations Climate Change Conference in Paris in early December. Increased climate policies will increase costs for oil companies and does create some uncertainty, but Trudeau understands fully the importance of fossil fuels to Canada's economy and has stated how important he sees Alberta is to the entire Canadian economy. It is hopeful that Trudeau's approach will enact positive change for Canada and help move pipeline development forward through an agenda of responsible development, which is increasingly becoming a global standard.

Additionally, a new provincial government was elected mid-2015 in Alberta. This was also a change of leading party from the Progressive Conservatives who held office for four decades, to a more left leaning New Democrats Party. The new premier is Rachel Notley. Many oil companies were in fear at first news, but it seems that the new premier is open to working with the oil sector to find new solutions. Notley announced an economy-wide carbon tax, an emissions cap on the oil sands of 100 MT of GHG per year, and an acceleration of the retirement of coal.[5] Shell, Canadian Natural Resources Limited, Cenovus Energy, and Suncor Energy all publicly support the government's climate plan. Notley supports pipeline development, but will not lobby as aggressively as the past government.

[5] Currently the oil sands emit around 70 MT of GHG emissions per year.

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