3.0 SUPPLY AND MARKETS

This section provides crude oil supply and market information, including:

- Western Canada Sedimentary Basin (WCSB) crude oil supply
- supply hub connections at Hardisty, AB, Moosomin, SK, and ex-Alberta capacity
- an overview of Eastern Canada, United States (US) East Coast, US Gulf Coast (USGC) and overseas markets potentially served by Energy East
- price discounts on WCSB crude oil supply
- supply- and markets-related benefits of the Energy East Project

Energy East engaged IHS Inc. (IHS) to provide an outlook for crude oil supply and markets and related issues relevant to the Project. The report is current to 2015 and is included in Appendix 3-6: *Supply and Market Study for the Energy East Project* (IHS Report).

Since the filing of the original application in 2014, the price of crude oil in North American and global markets has fallen more than 50% compared to the highest point in 2014. Historical data has shown that crude oil prices are volatile and cyclical. The current crude oil market environment is expected to be short-term relative to the development cycle and operating life of the Project. Canadian crude oil production is expected to continue to increase to meet growing demand and Energy East is an important transportation infrastructure project to provide secure supply and diverse market access for both producers and consumers of Canadian crude oil. In addition, shippers remain committed to the Project despite the downturn in the business cycle.

3.1 WESTERN CANADIAN CRUDE OIL SUPPLY

WCSB production consists of both crude oil and crude bitumen reserves. Globally, Canada is ranked third after Saudi Arabia and Venezuela in proven oil reserves. Overall, Canadian crude oil production forecasts continue to grow but at a slower pace than previously anticipated.

3.1.1 Alberta

Bitumen reserves in the WCSB account for 98% or 26.4 billion m^3 (166 billion bbl) of the 27 billion m^3 (170 billion bbl) of proven reserves. There are sufficient bitumen reserves in Alberta to sustain development of new oil sands projects for decades.

Technically and economically recoverable reserves of conventional oil are 288 million m^3 (1.8 billion bbl). However, the estimate for remaining conventional oil in reservoirs stands at 10.2 billion m^3 (64 billion bbl). This represents a substantial potential for increased recovery through new drilling techniques, such as horizontal drilling and multi-stage fracturing.

For a summary of Alberta's reserves and resources at the end of 2014, see Table 3-1.

Table 3-1: Alberta's Reserves, Resources and Production Summary 2014 (CA Rev.0)

	Crude Bitumen[1]		Crude Oil[1]	
	(million m^3)	(billion bbl)	(million m^3)	(billion bbl)
Initial in-place resources	293,125	1,845	12,927	81.3
Initial established reserves	28,092	177	3,010	18.9
Cumulative production	1,661	10.4	2,722	17.1
Remaining established reserves	26,431	166	288	1.8
Annual production	112	0.76	33.8	0.21
Ultimate potential (recoverable)	50,000	315	3,130	19.7
Shale/siltstone initial in-place resources	–	–	67,320	423.6

Note:
1. Source: ST98- 2015 Alberta's Energy Reserves 2013 and Supply/Demand Outlook 2015-2024

3.1.2 Saskatchewan

Saskatchewan is the second-largest crude oil-producing province in Canada after Alberta. Saskatchewan produces both conventional heavy and light crude. The remaining recoverable reserves are estimated at 206 million m^3 (1.3 billion bbl). The recent significant increase in light crude oil production in Saskatchewan, attributable to production in the Williston Basin in the southeastern corner of the province, is discussed in Section 3.1.4: Tight Oil, of this Consolidated Application volume.

3.1.3 Western Canadian Crude Oil Supply

The market demand for crude oil is the main driver for development of Canadian oil sands reserves. The production growth rate is subject to continuous assessment of market demand, crude oil prices and capital cost projections to develop these projects. However, decisions on oil sands capital projects are based on a long-term outlook, as typical oil sands mining production has a 25- to 50-year lifespan and short-term market conditions typically do not affect these projects.

There are several different forecasts for western Canadian crude oil production, which vary according to each forecast's assessment of remaining reserves, crude oil prices, demand and costs.[1] However, all forecasts show the same trend of continued growth, reflecting growing market demand and the nature of oil sands projects. Once oil sands projects are brought on-stream, they sustain and increase production rates over time through expansions and removal or alleviation of production constraints.

The Alberta Energy Regulator (AER) issues a report annually to provide an independent and comprehensive assessment of the state of reserves, supply and demand for Alberta's energy resources. The report also includes a 10-year supply and

1 AER, Alberta Department of Energy (AB DOE), CAPP, Canadian Energy Resources Inc. (CERI), and IHS.

demand forecast for Alberta's crude oil production. The forecast is based on existing projects, expansions of existing projects and development of new projects based on industry production cost information compiled by the AER. For the AER's Alberta crude oil and condensate (pentanes plus) supply forecast, see Figure 3-1.[2]

The CAPP published a report in June 2015 titled *Crude Oil Forecast, Markets and Transportation* (CAPP forecast). The CAPP forecast projects steady growth in Canadian crude oil production to 2030, with oil sands production reaching 668,000 m^3/d (4.2 million bbl/d) by the end of the outlook. A large volume of the oil sands production in the CAPP forecast is non-upgraded bitumen that must be blended with either light crude oil, such as synthetic crude oil (50:50 ratio), or condensate (70:30 ratio) to meet pipeline specifications for transportation. As a result of this blending, significantly greater pipeline capacity is required to move blended bitumen than conventional oil supply to market.

For CAPP's forecast of Western Canada's conventional, oil sands production and blended supply available to markets, see Figure 3-2.[3]

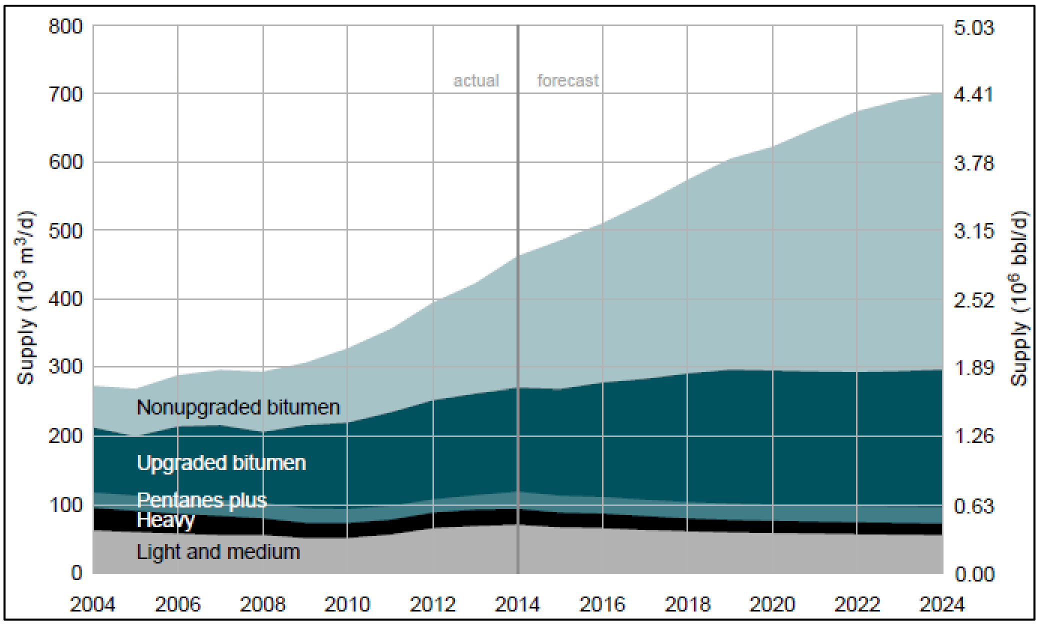

Figure 3-1: Alberta Supply of Crude Oil and Condensate (CA Rev.0)

2 Source: AER ST98- 2015: Alberta's Energy Reserves 2014 and Supply/Demand Outlook 2015-2024.
3 Source: CAPP.2015 Crude Oil Forecast, Markets and Transportation. June 2015

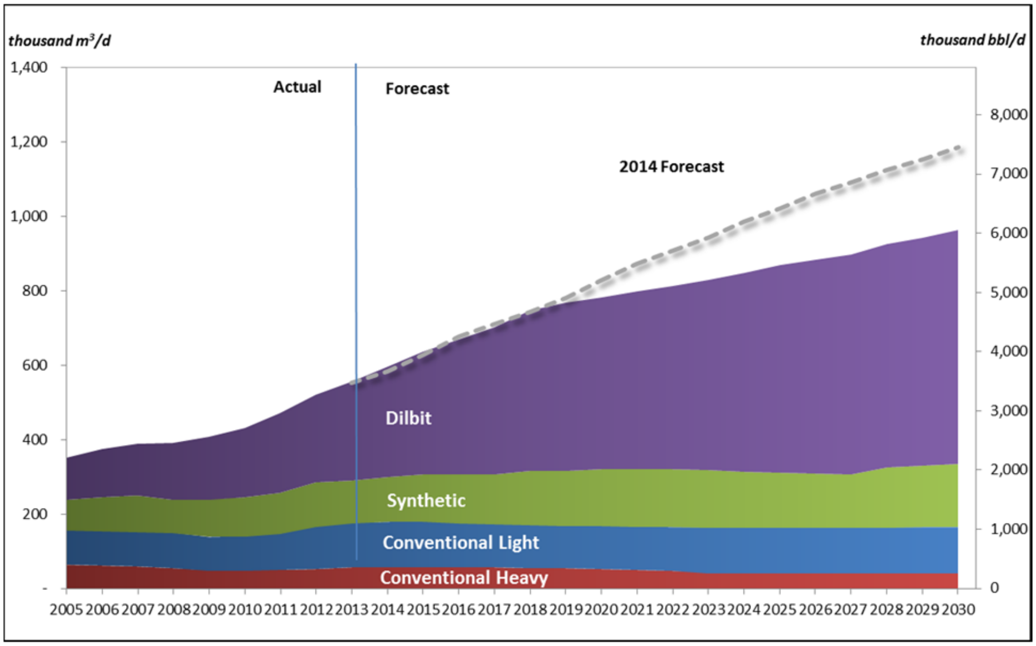

Figure 3-2: Western Canadian Crude Oil Production Forecast – 2015 (CA Rev.0)

In addition to consideration of the CAPP forecast, IHS prepared an independent forecast of western Canadian crude oil production, which is presented in the IHS Report (Appendix 3-6). The IHS forecast is directionally similar to the CAPP forecast, and both outlooks show similar supply growth throughout the forecast period.

According to the CAPP forecast total crude oil production continues to grow but at a slower pace than previously anticipated. The forecast reflects the current low oil price environment and producers continuing to evaluate their growth plans as crude oil prices recover.

3.1.4 Tight Oil

Tight oil refers to conventional oil recovered from very low-permeability light oil reservoirs using horizontal drilling and multi-stage hydraulic fracturing techniques. Recovering tight oil was once generally considered to be uneconomic, but new technology and drilling improvements have made it economically feasible. The development of tight oil resources in the WCSB has not occurred at nearly the same pace as in the US, but production has grown almost 350% between 2010 and 2013.

The NEB December 2011 report *Tight Oil Developments in the Western Canada Sedimentary Basin* highlighted several key emerging tight oil resource plays in the WCSB (see Figure 3-3).

For a summary of the estimates of recoverable reserves for key tight oil plays in Western Canada, see Table 3-2.

Table 3-2: Summary of Tight Oil Formations in Western Canada (CA Rev.0)

Formation	Recoverable Reserves (million m^3)[1]	Recoverable Reserves (million bbl)[1]
Banff/Exshaw	51	320
Cardium	21	130
Viking	9	58
Duvernay	637	4,010
Nordegg	125	790
Muskwa	337	2,120
Williston (SK)	254	1,600
Lower Shaunavon	15	93
Total Recoverable	1,449	9,121

Note:
1. Sources: NEB. 2011. *Tight Oil Developments in the Western Canada Sedimentary Basin*. EIA/ARI. 2013. World Shale Gas and Shale Oil Resource Assessment.

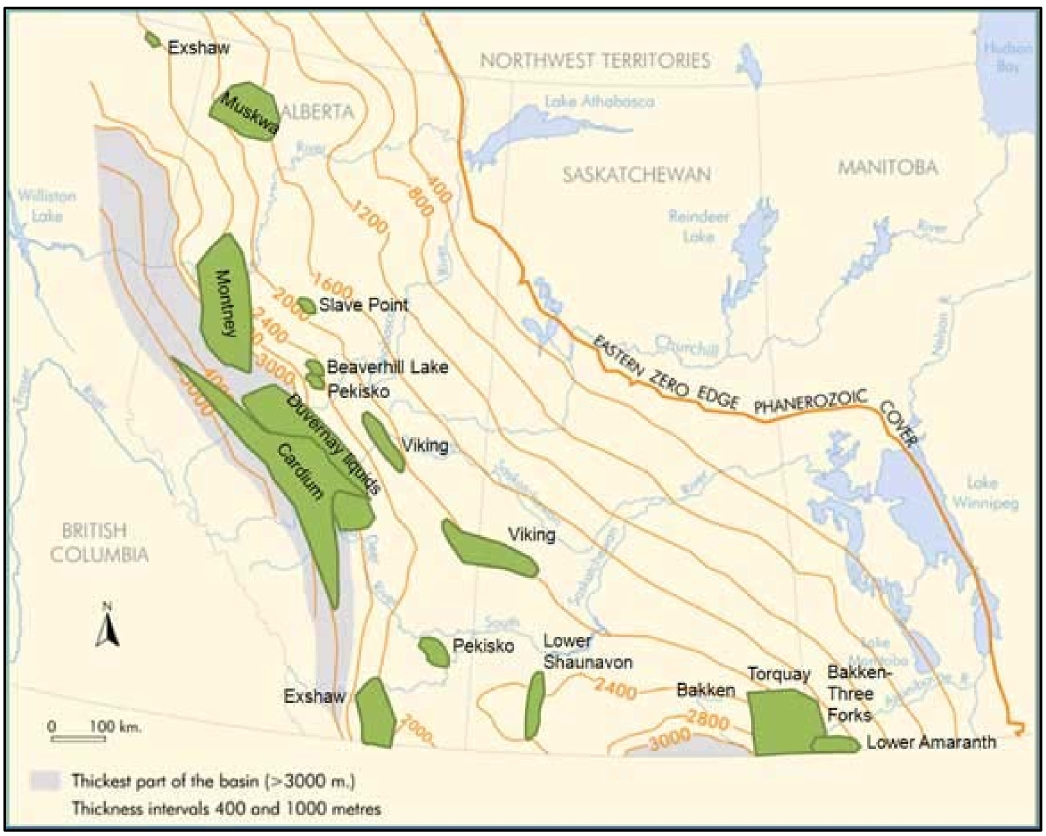

Figure 3-3: Tight Oil Locations in Western Canada (CA Rev.0)

The Alberta government's quarterly report, *Alberta Oil and Gas Industry Quarterly Update*, describes activities across the oil and gas industry. Figure 3-4 from the winter 2013 report shows that tight oil production in Western Canada has grown almost 350% between 2010 and 2013.[4] The majority of the growth comes from Alberta and Saskatchewan. The Williston Basin in southeastern Saskatchewan, which produces mainly light sweet crude, is a principal source of Saskatchewan's record crude oil production in 2012 and 2013.

Figure 3-5 shows the NEB's Market Snapshot released in late 2014 to provide an update on Canadian tight oil production.[5] According to the report, production of tight oil in Western Canada had grown to more than 64,000 m^3/d (400,000 bbl/d) in 2014 which is more than double from 2011.

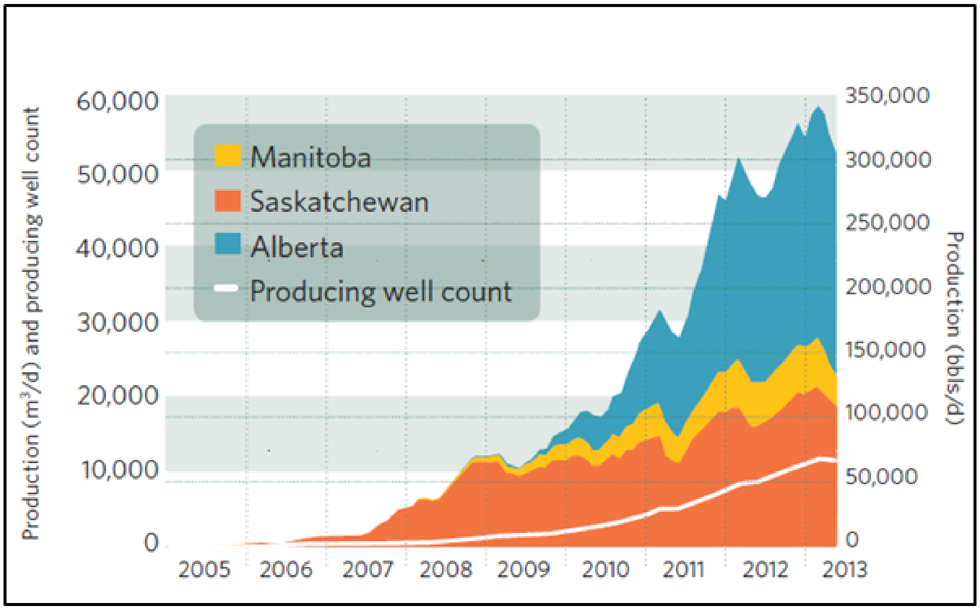

Figure 3-4: Tight Oil Production in Western Canada (CA Rev.0)

About 80% of crude oil exported from Canada is sold to the US markets. However, the surge in US tight oil production from the Williston, Permian and Eagle Ford formations has displaced almost all light crude imports in the US Gulf Coast and some in the US East Coast.

The growing US supply is now pushing into PADD II to compete with Canadian light crude. According to the US Energy Information Administration (EIA) *Annual Energy Outlook* 2015, tight oil could grow at least another 222,000 m^3/d (1.4 million bbl/d) from 2014 to the end of this decade.

For the outlook for US crude oil production, see Figure 3-6.[6]

[4] Source: Alberta Oil and Gas Industry Quarterly Update – Winter 2013.
[5] Source: National Energy Board – Market Snapshot: Canadian Tight Oil Production Update – 2014-10-22.
[6] Source: EIA. 2015. *Annual Energy Outlook 2015*.

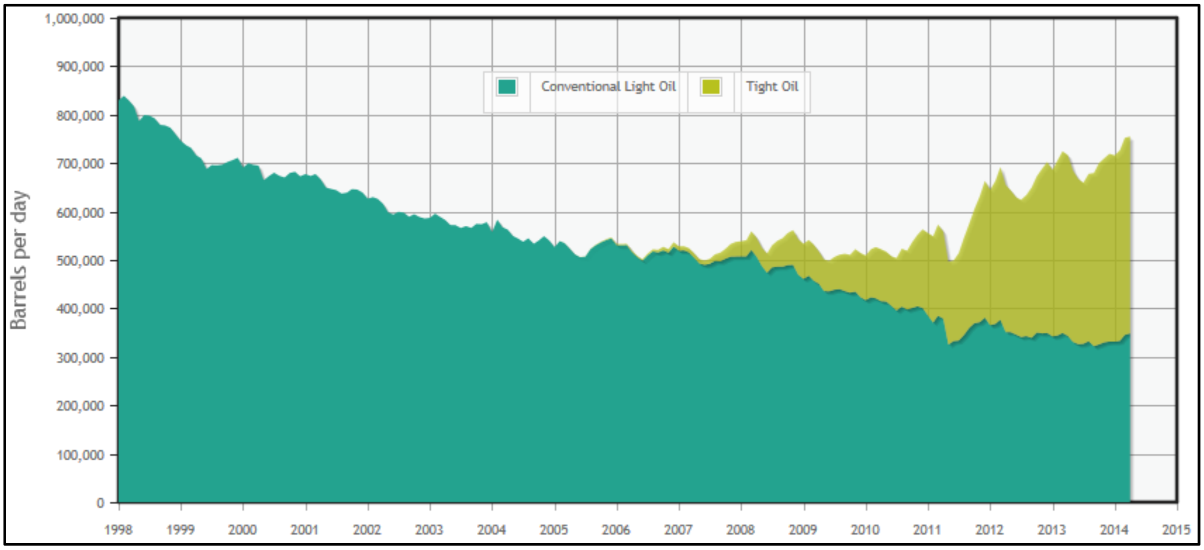

Figure 3-5: Western Canadian Light Oil Production (CA Rev.0)

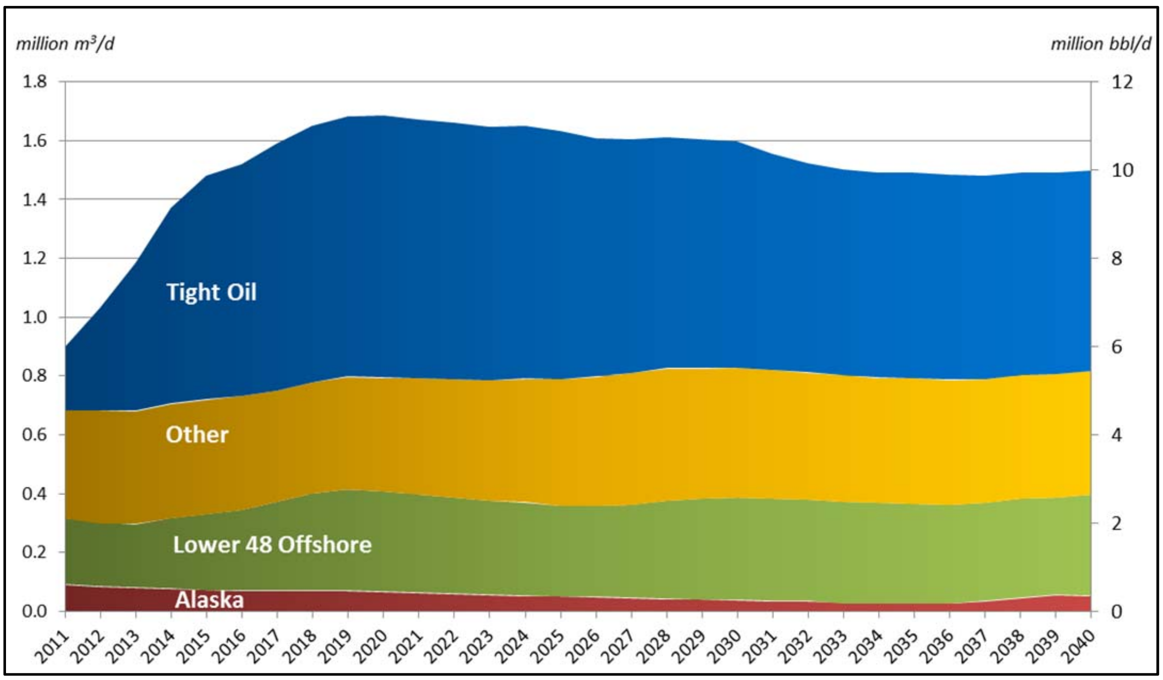

Figure 3-6: US Crude Oil Production Outlook (CA Rev.0)

3.1.5 Market Displacement

In addition to the erosion of the market for Canadian light crude as a result of growing US production, refineries in PADD II, such as BP Whiting and Marathon Detroit, have been converted to process more Canadian heavy crude from the oil sands to improve refinery economics.

Refinery reconfigurations and competition from growing US tight oil are forcing Canadian light crude producers to seek out new markets.

The Project opens access to new light crude oil markets, both domestic and international, that can absorb Canadian light crude released from the traditional US markets.

3.2 TRANSPORTATION SERVICE AGREEMENTS

As at the time of this Consolidated Application, Energy East has entered into long-term firm TSAs through which shippers have committed to ship an aggregate volume of 158,000 m^3/d (995,000 bbl/d)[7] at an average term of 19 years. The Energy East firm shippers include producers, integrated energy companies, refiners and marketers, all of which have access to significant volumes of crude oil supply. Energy East has concluded that the firm shippers would not have made the significant financial commitments associated with the TSAs without being confident that they could reliably source supply over the long term.

3.3 CONCLUSION ON SUPPLY FOR THE PROJECT

Each of the CAPP, IHS and AER forecasts shows significant crude oil supply growth in Western Canada through 2030. At the same time, the continued growth of US tight oil is pushing Canadian light crude out of its traditional US markets. The supply growth in Western Canada, coupled with supply that will be displaced from the US markets, will require access to new markets and takeaway capacity, which underpins the need for the Project.

The Project will create access for this growing supply to new markets on the East Coast that depend on expensive crude oil imported from foreign countries and potentially overseas markets. Currently, there is no pipeline to supply East Coast markets with domestic crude oil nor is there east coast tidewater access.

3.4 TRANSPORTATION

Most of Canada’s crude oil production moves by pipeline to refineries in the US and Canada. The two primary crude oil supply distribution centres in Alberta are located in Edmonton and Hardisty. Crude oil flows into these hubs via a large network of feeder pipelines.

[7] Of this amount, 42,900 m^3/d (270,000 bbl/d) remains under contract pursuant to the unamended Base TSAs. See Volume 3, Section 2.3: Transportation Service Agreements for full details.

3.4.1 Pipelines at Hardisty and Edmonton

Crude oil is transported from Edmonton and Hardisty via trunklines to domestic and export markets. From the Edmonton region, crude oil is transported:

- east on the Enbridge Mainline system
- west on Trans Mountain Pipeline (TMPL)
- south on the Rangeland Pipeline

Hardisty is a major hub for crude oil supply in Western Canada, with multiple interconnecting pipelines from producing regions as well as large storage terminals.

Aggregate pipeline capacity into Hardisty is approximately 477,000 m^3/d (3 million bbl/d).

From the Hardisty region, crude oil is transported to:

- PADD II on the Enbridge Mainline system and Keystone Pipeline
- PADD IV and II on Express/Platte pipelines
- PADD IV on the Milk River Pipeline and Bow River Pipeline

For the capacities of existing systems and the markets they serve, see Table 3-3.

For a map of major crude oil export pipelines from Alberta, see Figure 3-7.

Table 3-3: Pipeline Capacity Ex-Alberta (CA Rev.0)

Pipeline	Destination	Current Capacity (thousand m^3/d)[1]	Current Capacity (thousand bbl/d)[1]
PADD V/West Coast			
TMPL	British Columbia, US West Coast	48	300
US PADD IV			
Express / Platte	US Rocky Mountains, US Midwest	45 / 26	280 / 164
Milk River	US Rocky Mountains	20	125
Rangeland	US Rocky Mountains	14	85
US PADD II			
Enbridge	Eastern Canada, US Midwest	368	2314
Keystone	US Midwest	94	590

Note:
1. Source: Company websites.

3.4.2 Cromer Hub

Cromer, Manitoba, is a gathering hub for light and medium crude oils produced in Saskatchewan and Manitoba. It receives crude oil supply from multiple feeder pipelines and trucks. Aggregate pipeline capacity into Cromer is estimated at 77,000 m^3/d (480,000 bbl/d).

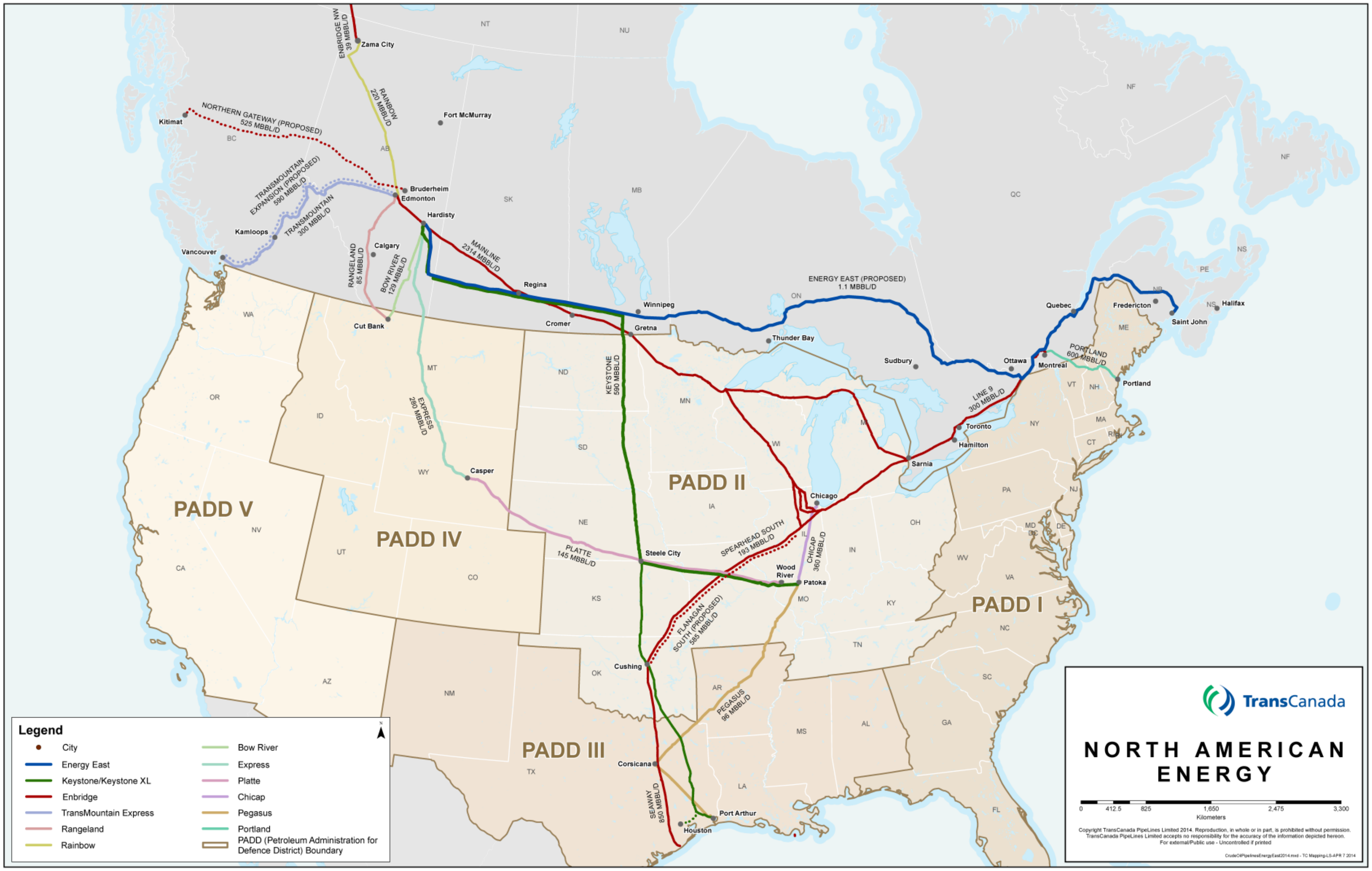

Figure 3-7: Crude Oil Ex-Alberta Pipelines (CA Rev.0)

3.4.3 Pipeline Projects under Development

Several pipeline projects are currently under development in response to the need for more pipeline capacity and market diversity. These pipeline projects are designed to move growing crude oil supply from Western Canada in three directions:

- West (Northern Gateway and Trans Mountain Expansion) **–** Both pipeline projects plan to transport crude oil supply from Alberta to Canada's West Coast. At the West Coast, crude oil will be loaded into marine tankers to access the US West Coast and Asian markets.
- East (Energy East and Enbridge Line 9B Reversal) – Both pipeline projects plan to transport domestic crude oil supply to Eastern Canada. Energy East proposes to add 175,000 m^3/d (1.1 million bbl/d) of new export capacity from Western Canada and will deliver crude oil supply to Montréal, Québec City, and Saint John. Crude oil transported on Energy East can also be loaded onto marine tankers at New Brunswick to access the US East Coast, US Gulf Coast and overseas markets. The Enbridge Line 9B reversal does not add new ex-WCSB capacity from Western Canada, but it extends the Enbridge Mainline to Montréal with capacity up to 48,000 m^3/d (300,000 bbl/d).
- South (Enbridge Gulf Coast Access and Keystone XL) **–** Enbridge Gulf Coast Access project started in late 2014 and is currently delivering Canadian crude oil to the US Gulf Coast. Keystone XL has been denied a US Presidential Permit; however TransCanada will review options that could include potentially filing a new application for border-crossing authority.

3.4.4 Rail Transportation

Shortage of export pipeline capacity has resulted in significant price discounts that have made rail transportation economic for Western Canadian crude oil producers. Western Canadian crude oil by rail volumes have increased from virtually nothing in 2009 to about 42,000 m^3/d (264,000 bbl/d) in 2013 and 32,000 m^3/d (200,000 bbl/d) by the end of 2014, as reported by the Crude Oil Logistics Committee. However, the current transport costs by rail are about two times higher than by pipeline.

3.5 WESTERN CANADIAN SUPPLY AND EXPORT PIPELINE CAPACITY

As discussed in the IHS Report (Appendix 3-6), Western Canadian crude oil supply is expected to exceed export pipeline capacity in the near term. The shortage of export pipeline capacity has created strong demand for rail to move crude oil to markets.

In a scenario where all the proposed expansions and new pipelines were built on their current schedules and crude oil production continued to grow as forecast, there could be spare aggregate ex-WCSB pipeline capacity until the supply growth matches aggregate capacity additions.

The cycle of surplus supply followed by spare capacity is the normal cycle for bringing on new pipeline capacity. Even assuming all proposed ex-WCSB projects are constructed and placed into service in the timeframes currently forecast by project proponents, additional export pipeline capacity would be needed again post 2040 based on the IHS supply forecast.

In an environment where export pipeline capacity is inadequate, producers are forced to accept price discounts, shut in production or turn to more expensive transportation alternatives such as rail, which will result in lower netback at the wellhead. Adequate ex-WCSB pipeline capacity allows producers to choose markets that will give them the best netback.

It is difficult and uneconomic to build pipeline capacity that precisely matches with the supply profile, given the nature of pipeline project design and schedules. Pipeline capacity typically comes on stream in large tranches and allows producers to benefit from the optionality associated with access to multiple markets.

The Project is the result of shippers' decisions to support enhanced market diversity and additional takeaway pipeline capacity from the WCSB. Shippers have made the decision to contractually and financially support the Project independent of other proposed pipeline projects.

From a supply perspective, the Project provides an outlet for growing production and reduces Canadian producers' reliance on traditional markets. As will be discussed in the next section, from a markets perspective, the Project provides cost effective pipeline access for new and expanded markets that have historically relied upon more costly methods of securing supply.

3.6 CRUDE OIL MARKETS OVERVIEW

The expected growth in WCSB crude oil production and displacement of Canadian supplies from traditional US markets will require further penetration into existing markets and expansion to new markets. This section provides a high level view of existing domestic and US markets, and of potential overseas markets.

3.6.1 Québec

Current refining capacity in Québec is about 64,000 m^3/d (402,000 bbl/d), as shown on Table 3-4.

Table 3-4: Québec Refining Capacity (CA Rev. 0)

Refinery	Location	Capacity (thousand m^3/d)[1]	Capacity (thousand bbl/d)[1]
Suncor	Montréal	22	137
Valero	Québec City	42	265

Note:
1. Source: CAPP.

Total crude runs in Québec refineries in 2014 were about 54,000 m^3/d (340,000 bbl/d), and it is estimated that more than 80% of the supply was imported from countries such as Algeria, Angola, Mexico and the US.

Between 2012 and 2014, imports decreased by 12% as more domestic crude oil from Western Canada was shipped to Québec by rail. In the same period, the largest supplier of crude oil to Québec refineries shifted from Algeria (44%) to the US due mainly to growth of US tight oil production.

US tight oil is currently delivered to Québec refineries by rail and marine tanker which are less efficient transportation methods. Historically, these refineries have been unable to access significant volumes of domestic crude oil because of pipeline logistical constraints. As a result, they have been economically disadvantaged compared to the US Midwest refineries that are able to access less expensive domestic crude oil via pipeline. For a breakdown of crude oil supply source for Québec refineries, see Figure 3-8 and Figure 3-9.[8]

Québec refineries are configured to process mainly light crude oil, and the growing conventional and tight oil from Western Canada is a suitable feedstock for the refineries.

Crude oil quality is a main component in price determination. Lighter crude with less sulphur content is worth more than heavier crude with high sulphur content. It is important to refiners that their crude oil quality is preserved while it is being transported to the refinery. The Project is a bullet pipeline that can directly deliver crude oil supply to Québec refineries without using breakout tankage, and thus the quality degradation of the crude oil batches is minimized. The Project will also provide for multiple transportation and/or market options, providing refiners with supply alternatives during outage periods.

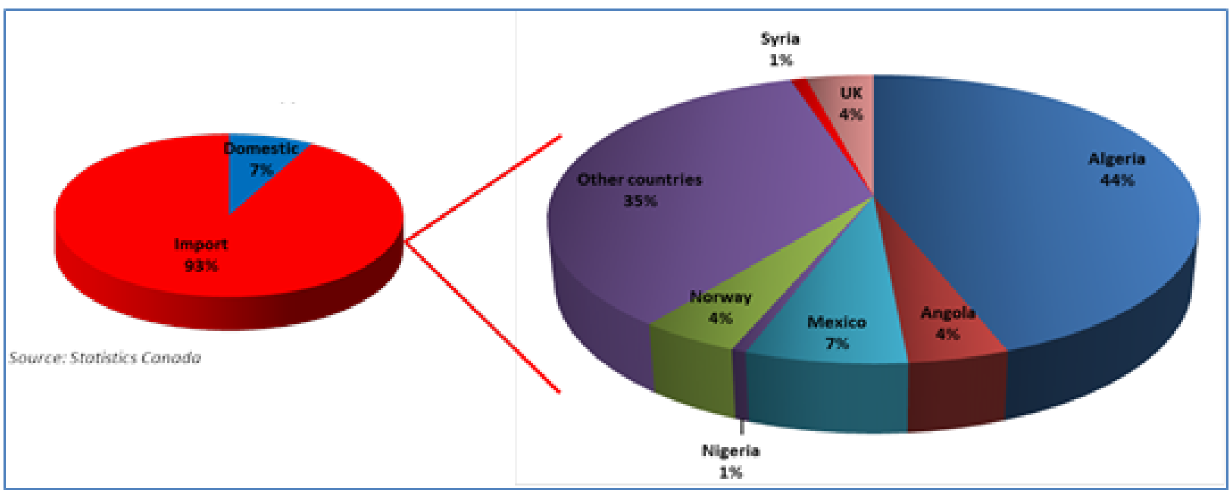

Figure 3-8: Québec Crude Oil Supply Source 2012 (CA Rev.0)

[8] Statistics Canada is the source for Figures 3-7 and 3-8.

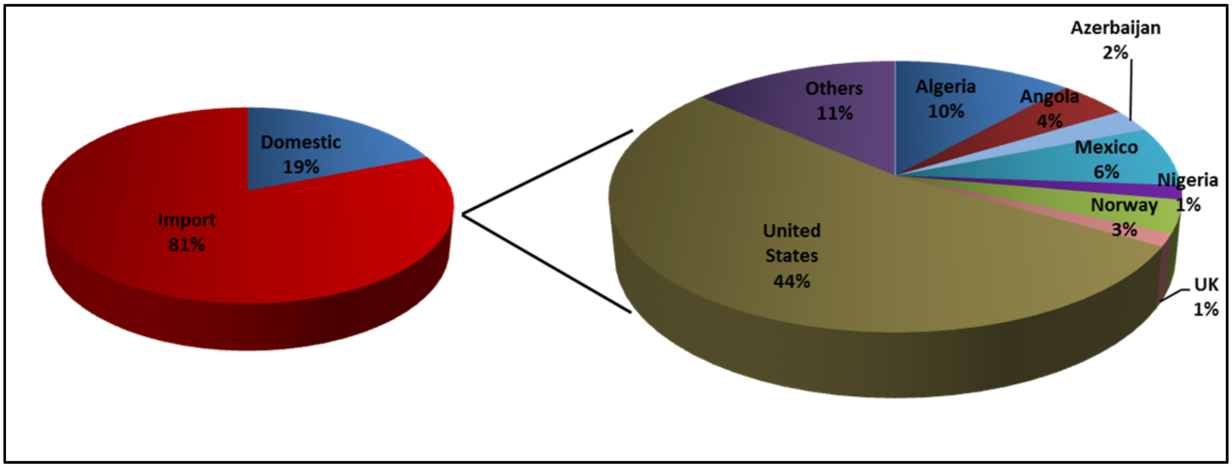

Figure 3-9: Québec Crude Oil Supply Source 2014 (CA Rev.0)

3.6.2 Atlantic Canada

Refining capacity in Atlantic Canada is about 66,000 m^3/d (415,000 bbl/d), as shown on Table 3-5.

Table 3-5: Atlantic Canada Refining Capacity (CA Rev.0)

Refinery	Location	Capacity (thousand m^3/d)	Capacity (thousand bbl/d)
Irving Oil	Saint John, NB	48	300
North Atlantic	Come by Chance, NL	18	115
Source: CAPP			

Total crude runs in Atlantic refineries in 2014 were about 54,000 m^3/d (350,000 bbl/d) and more than 70% of the supply was imported from countries such as Saudi Arabia, Angola, Iraq and the US. Between 2012 and 2014, domestic crude oil supply to Atlantic refineries increased by 6% as a result of crude by rail. In the same period, the US became the largest crude oil supplier to Atlantic refineries due to significant growth in US tight oil production.

US tight oil is delivered to Atlantic refineries by rail and marine tanker which are less efficient transportation methods. Atlantic refineries are currently not being served by pipeline and as a result, they are heavily reliant on the more expensive waterborne crude oil from other countries for their supply. This has made the Atlantic refineries economically disadvantaged compared to their pipeline connected competitors.

For a breakdown of crude oil supply source for Atlantic refineries, see Figure 3-10 and Figure 3-11.[9]

[9] The source for Figures 3-10 and 3-11 is Statistics Canada.

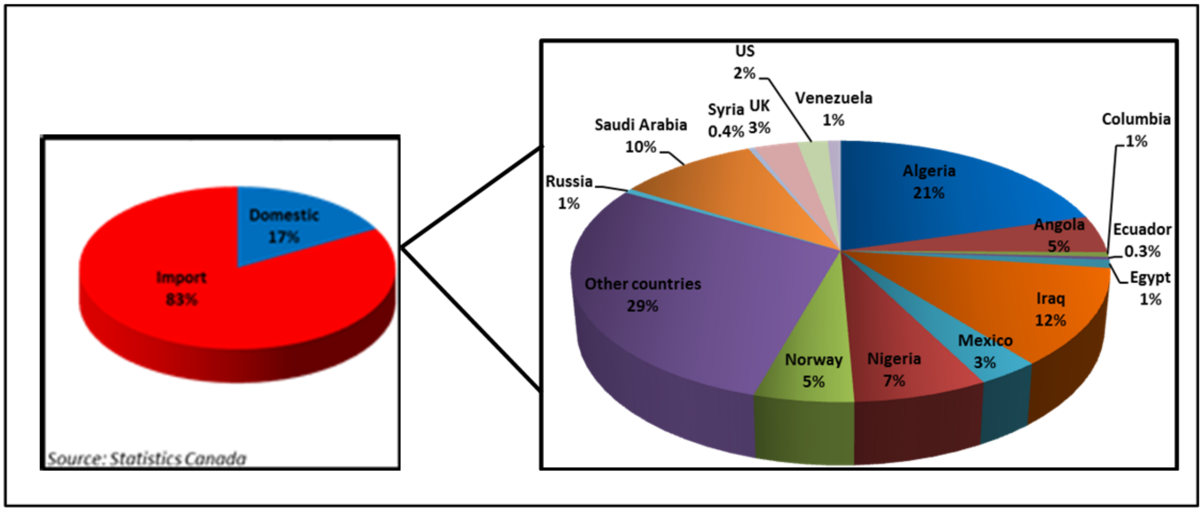

Figure 3-10: Atlantic Canada Crude Oil Supply Source 2012 (CA Rev.0)

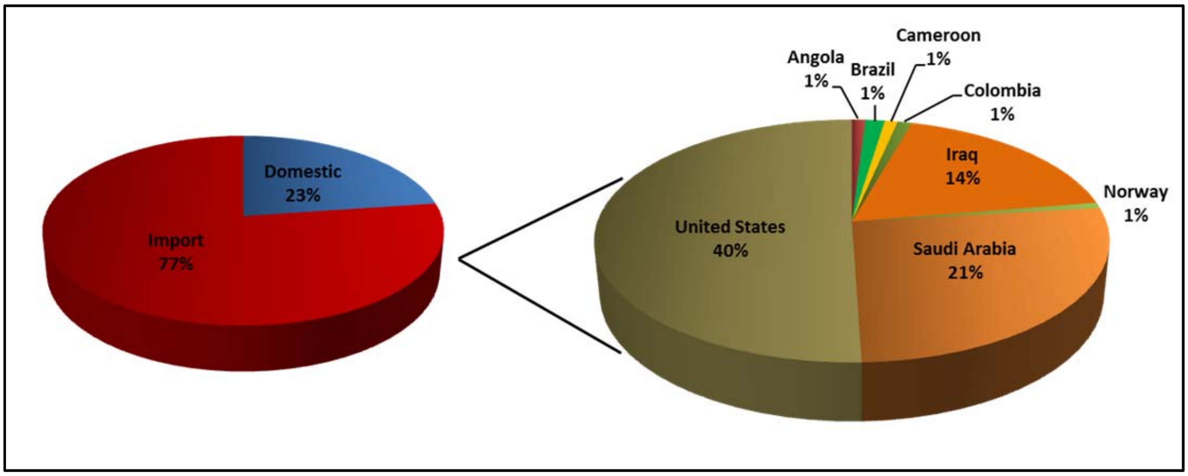

Figure 3-11: Atlantic Canada Crude Oil Supply Source 2014 (CA Rev.0)

Irving Oil and North Atlantic refineries are configured to process mainly light sweet and light sour crude with a small amount of heavy crude. Part of the growing Western Canadian supply consists of light sweet and light sour crude from Saskatchewan and Manitoba, which is gathered into the Cromer, MB hub. Both conventional and Cromer light crudes are suitable feedstock for Irving Oil and North Atlantic refineries.

The Project will be connected to a deep-water port at Canaport, Saint John, NB, which can accommodate up to very large crude carrier (VLCC) tankers and Suez Max tankers.

Larger marine tankers typically provide the lowest unit cost for long-haul transportation. The deep-water port will provide options for shippers who want to access markets beyond Canada’s East Coast.

3.6.3 US East Coast – PADD I

Refining capacity on the US East Coast, also known as PADD I, is about 206,000 m^3/d (1.3 million bbl/d) from 10 refineries (see Table 3-6).

Table 3-6: PADD I Refining Capacity (CA Rev.0)

Refinery	Location	Capacity (thousand m^3/d)[1]	Capacity (thousand bbl/d)[1]
American Refining	Bradford, PA	2	10
PBF	Delaware City, DE	30	190
Ergon	Newell, WV	3	20
Monroe Energy	Trainer, PA	29	185
NuStar	Savannah, GA	5	28
NuStar	Paulsboro, NJ	12	74
PBF	Paulsboro, NJ	29	180
Phil. Energy Solutions	Philadelphia, PA	52	330
Phillips 66	Linden, NJ	38	238
United	Warren, PA	11	70

Note:
1. Source: US Energy Information Administration

Total crude runs in 2014 were about 175,000 m^3/d (1.1 million bbl/d), and 60% of the supply was imported from countries such as Canada, Saudi Arabia, Nigeria, Angola and Venezuela.

Between 2012 and 2014, crude oil imports from Canada increased from 23% to 43% as shown in Figure 3-12 and Figure 3-13.[10] The shift in volume was a result of increased crude by rail from Western Canada when the market conditions allowed such movement.

In addition, supply from US domestic crude oil increased from 15% to 40% due mainly to crude by rail from the Williston Basin. Similar to Atlantic Canada refineries, the majority of crude oil supply to PADD I refineries is primarily waterborne import delivered by tanker.

As shown on Figure 3-13, PADD I represents a significant market for Canadian crude oil to compete with the more expensive imports from the Middle East and Latin America.

[10] The US Energy Information Administration (EIA) is the source for Figures 3-12 and 3-13.

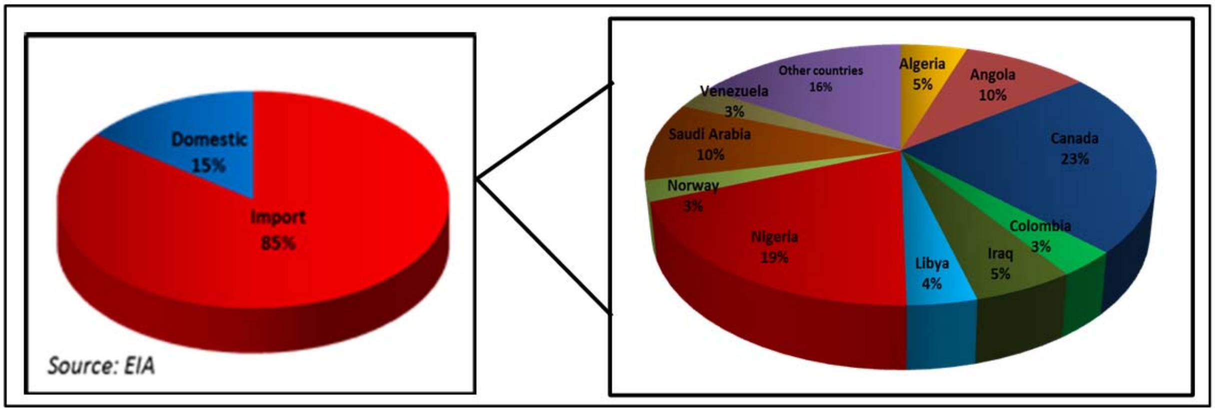

Figure 3-12: US East Coast (PADD I) Crude Oil Supply Source 2012 (CA Rev.0)

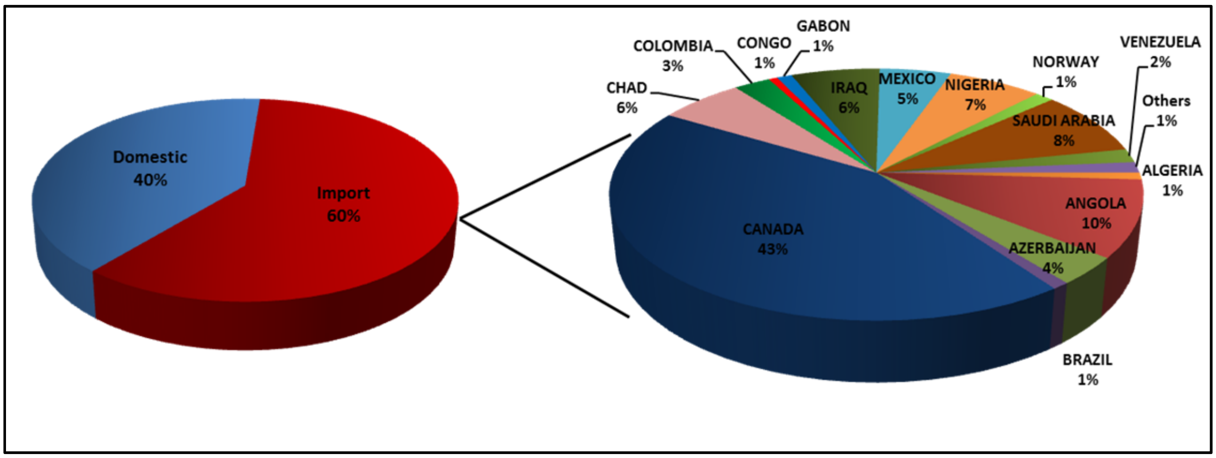

Figure 3-13: US East Coast (PADD I) Crude Oil Supply Source 2014 (CA Rev.0)

3.6.4 US Gulf Coast – PADD III

Refining capacity in the US Gulf Coast, also known as PADD III, is about 1.45 million m^3/d (9.1 million bbl/d), as shown on Table 3-7.

Total crude runs in 2014 were 1.3 million m^3/d (8.4 million bbl/d) with 40% of the supply imported from other countries (see Figure 3-14).[11]

Refineries in PADD III are configured to process mostly heavy crude, and more than 60% of the supply is sourced from Venezuela, Mexico and Saudi Arabia. PADD III represents a significant market for Canadian heavy crude oil to compete with more expensive imports from Venezuela and Mexico.

[11] The EIA is the source for Figure 3-13.

Table 3-7: PADD III Refining Capacity (CA Rev.0)

Refinery	Location	Capacity (thousand m^3/d)[1]	Capacity (thousand bbl/d)[1]
Alon Refining Krotz Springs Inc	Krotz Springs, LA	13	80
Alon USA Energy Inc	Big Spring, TX	11	67
BP Products North America Inc	Texas City, TX	73	460
Calcasieu Refining Co	Lake Charles, LA	12	78
Calumet Lubricants Co	San Antonio, TX	2	14
Calumet Lubricants Co LP	Cotton Valley, LA	2	13
Calumet Lubricants Co LP	Princeton, LA	1	8
Calumet Shreveport LLC	Shreveport, LA	9	57
Chalmette Refining LLC	Chalmette, LA	31	193
Chevron USA Inc	Pascagoula, MS	52	330
Citgo Petroleum Corp	Lake Charles, LA	68	428
Citgo Refining & Chemical Inc	Corpus Christi, TX	26	163
Cross Oil Refining & Marketing Inc	Smackover, AR	1	8
Deer Park Refining Ltd Partnership	Deer Park, TX	52	327
Delek Refining Ltd	Tyler, TX	10	60
Ergon Refining Inc	Vicksburg, MS	4	23
ExxonMobil Refining & Supply Co	Baton Rouge, LA	80	503
Exxon Mobil Refining & Supply Co	Baytown, TX	89	561
ExxonMobil Refining & Supply Co	Beaumont, TX	55	345
Flint Hills Resources LP	Corpus Christi, TX	46	289
Goodway Refining LLC	Atmore, AL	1	4
Houston Refining LP	Houston, TX	41	259
Hunt Refining Co	Tuscaloosa, AL	6	36
Hunt Southland Refining Co	Sandersville, MS	2	11
Lazarus Energy LLC	Nixon, TX	2	11
Lion Oil Co	El Dorado, AR	13	83
Marathon Petroleum Co LLC	Garyville, LA	83	522
Marathon Petroleum Co LLC	Texas City, TX	13	80
Motiva Enterprises LLC	Convent, LA	37	235
Motiva Enterprises LLC	Norco, LA	37	234
Motiva Enterprises LLC	Port Arthur, TX	95	600
Navajo Refining Co LLC	Artesia, NM	17	105
Pasadena Refining Systems Inc	Pasadena, TX	16	100
Phillips 66 Company	Belle Chasse, LA	40	252
Phillips 66 Company	Westlake, LA	38	239
Phillips 66 Company	Sweeny, TX	39	247
Placid Refining Co	Port Allen, LA	9	57
Premcor Refining Group Inc	Port Arthur, TX	46	290
Shell Chemical LP	Saraland, AL	13	80
Shell Oil Products US	Saint Rose, LA	7	45
Total Petrochemicals & Refining USA	Port Arthur, TX	36	226
Valero Energy Corporation	Meraux, LA	20	125
Valero Energy Corporation	Sunray, TX	25	156

Table 3-7: PADD III Refining Capacity (CA Rev.0) (cont'd)

Refinery	Location	Capacity (thousand m3/d)1	Capacity (thousand bbl/d)1
Valero Energy Corporation	Three Rivers, TX	15	93
Valero Refining Co Texas LP	Corpus Christi, TX	32	200
Valero Refining Co Texas LP	Houston, TX	14	88
Valero Refining Co Texas LP	Texas City, TX	36	225
Valero Refining New Orleans LLC	Norco, LA	33	205
Western Refining Company LP	El Paso, TX	19	122
Western Refining Southwest Inc	Gallup, NM	3	22
WRB Refining LP	Borger, TX	23	146

Note:
1. Source: US Energy Information Administration.

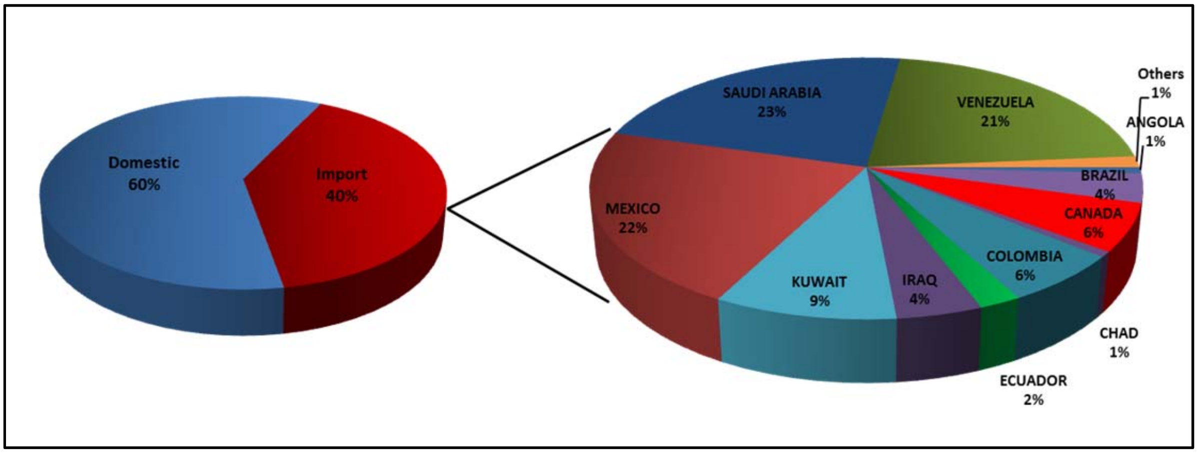

Figure 3-14: US East Coast (PADD I) Crude Oil Supply Source (CA Rev.0)

3.6.5 Overseas Markets – Europe

Europe has a combined refining capacity of 2.4 million m^3/d (15 million bbl/d). The region consumed about 2 million m^3/d (12 million bbl/d) in 2014, and 74% of the supply was imported from non-European countries (see Figure 3-15).[12]

Although most of the refineries in Europe are set up to process light crudes, demand for heavy crude oil is still more than 140,000 m^3/d (900,000 bbl/d). Heavy crude oil is imported from Venezuela, Mexico and Saudi Arabia.

Energy East's Canaport marine terminal is economically positioned to allow Canadian crude oil to compete with international crude oil in European markets, as the marine flat transport rate from the east coast to Europe is competitive with supply from the Middle East.

[12] The sources for Figure 3-15 are the EIA and the IHS Report.

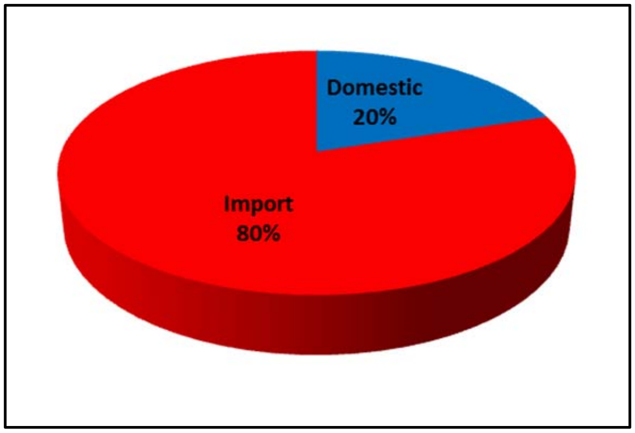

Figure 3-15: Europe Crude Oil Supply 2014 (CA Rev.0)

3.6.6 Overseas Markets – India

India's combined refining capacity is 0.7 million m^3/d (4.6 million bbl/d) and it consumed about 0.7 million m^3/d (4.5 million bbl/d) of crude oil in 2014. India has very limited domestic production, so most of its crude oil supply is imported from other countries (see Figure 3-16).[13] Most of the imports are from the Middle East.

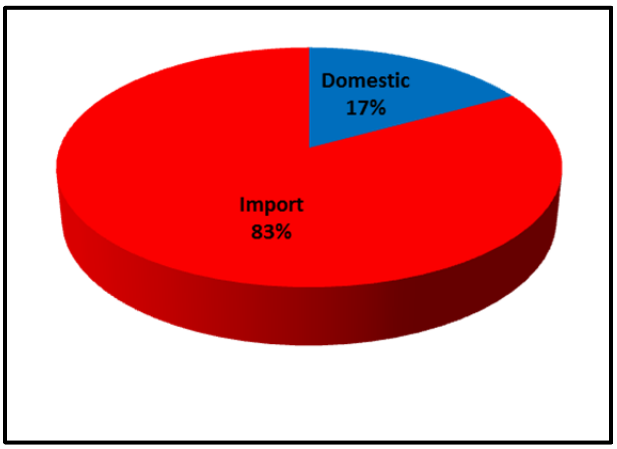

Figure 3-16: India Crude Oil Supply 2014 (CA Rev.0)

India's demand for crude oil is growing and according to the IHS Report, crude oil demand is expected to increase by 50% by 2030. While the transportation economics of Middle East crude oil to India are more attractive compared with Canada, India is looking to enhance the diversity and security of its crude oil supply and Canada is a logical choice.

The Canaport Energy East marine terminal will be a deep-water port that can handle VLCC tankers that are economical for long-haul transportation. Some volume of Canadian crude oil is expected to be exported to markets in India.

[13] The source for Figure 3-16 is the IHS Report.

3.7 PRICE DISCOUNT

Most of the crude oil supply from the WCSB is sold to the nearest market, which is the US, after meeting demands in Western Canada and Ontario. As crude oil supply in WCSB continues to grow beyond existing export pipeline capacity and regional demands, it becomes landlocked and is subject to large price discounts against the US crude oil benchmark West Texas Intermediate (WTI).

For the price discounts for Canadian heavy benchmark crude Western Canadian Select from WTI, see Figure 3-17. As shown, the average price discount for WCS between 2011 and 2014 was $130/m^3 ($20.69/bbl).

The discount was as high as $245/m^3 ($38.94/bbl) in December 2013. Fundamentally, the price differential should be around $63/m^3 ($10/bbl) to reflect the heavy-light quality differences between the two benchmarks plus transportation cost of $38/m^3 ($6/bbl) from Hardisty, AB to Cushing, Oklahoma.

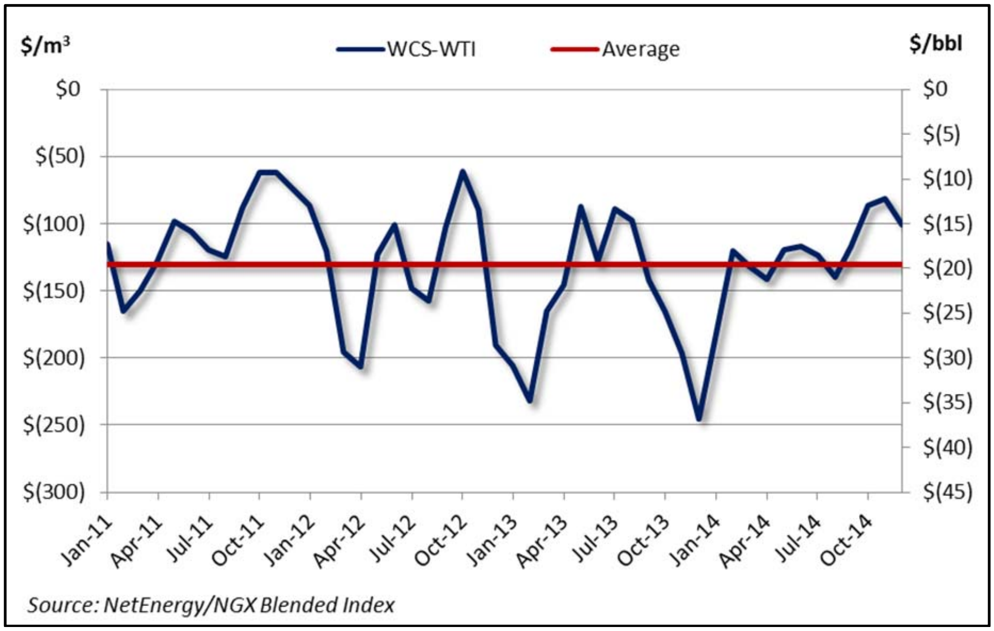

Figure 3-17: Western Canadian Select Discounts to WTI (CA Rev.0)

During the same period, the surge in US shale oil production caused inventory build in Cushing, Oklahoma to exceed pipeline takeaway capacity. Similar to the situation in Western Canada, stranded WTI became heavily discounted against the international benchmark crude Brent and hence, a "double-discount" on WCS was created.

For price discounts for WTI from Brent, see Figure 3-18. The average price discount for the period 2011 to 2014 was $79/m^3 ($12.60/bbl). WTI and Brent are both light crudes with similar quality and historically, Brent was priced below WTI to compete at the US Gulf Coast.

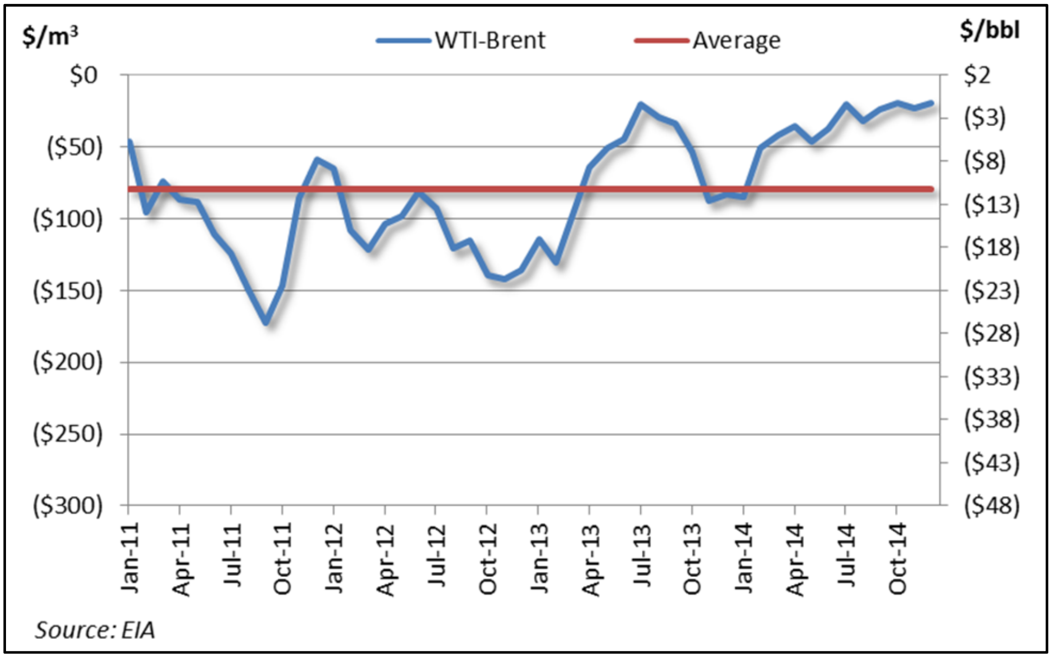

Figure 3-18: WTI Discounts to Brent (CA Rev.0)

The large price discounts for domestic crude oil have been economically advantageous to inland refineries in Western Canada, US PADD IV and PADD II that are served by pipelines, as they are able to purchase lower cost feedstock.

Refineries in Eastern Canada have limited access to domestic crude oil supply and have been required to import more than 80% of their feedstock requirements from foreign countries that are based on the Brent price. The Project will provide eastern Canadian refineries access to lower cost feedstock relative to waterborne supply.

3.8 CONCLUSION

The Project, with 175,000 m^3/d (1.1 million bbl/d) of transportation capacity, is a pipeline that connects landlocked and growing crude oil supply from Western Canada with eastern Canadian refineries that are heavily reliant on more expensive imported crude. Further, the Project's marine terminal in Saint John provides increased market diversity for WCSB crude supply by creating access to markets in the United States and overseas.

The Project will reliably deliver cost advantaged western Canadian crude oil supply to eastern Canadian refineries relative to waterborne supply, while preserving crude oil quality. In addition, the Project will reduce Eastern Canada's dependence on foreign crude oil supply while improving refineries' competitiveness.