Latest Developments in Canada's Oil Sector

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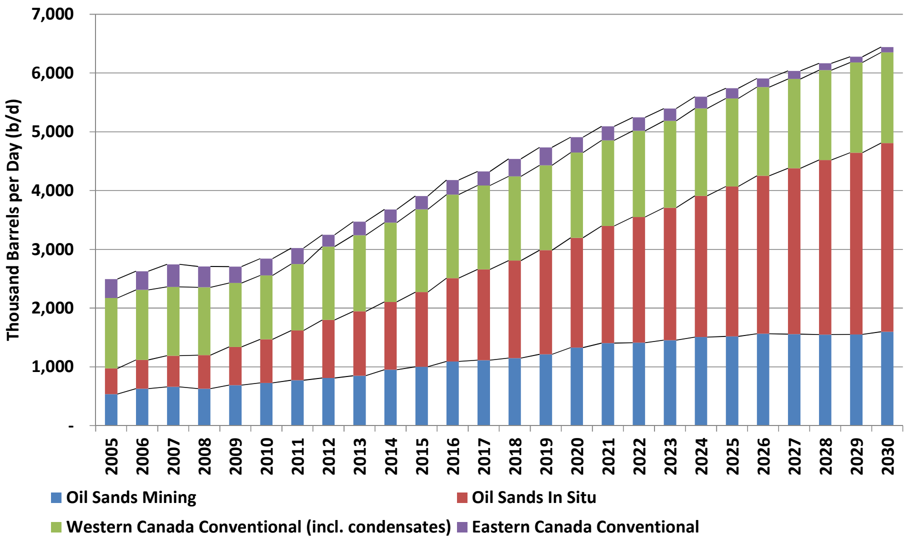
Summary

Canada's oil sands will underpin the country's future production with output forecast to rise from 3.5m in 2013 to 6.4m b/d by 2030 by Canadian Association of Petroleum Producers (CAPP) estimates.[1] Heavy-sour bitumen will make up the largest portion of supply, but light crude output will remain sizable due to a rise in conventional light production and sustained supply of bitumen upgraded into synthetic crude oil (SCO). Expansion/reconfiguration of continental energy transportation infrastructure to help supply reach new markets remains a key challenge. In the short-term, exports to the US Gulf Coast (PADD III) and Eastern Canada will be key, while crude-by-rail, barge and marine transportation will help bridge current gaps in pipeline capacity. In the short- to medium-term Canada can seek to use existing transportation capacity and crude supply to help build new markets in Asia and abroad. In the medium- to long-term, permanent supply arrangements will help Canada to establish itself as a secure supplier of crude to new markets with great potential for heavy crude in Asia, in China and India in particular, as well as possibilities for light crude exports.

Fig 1: Canada Oil Production Forecast



Source: CAPP, "Crude Oil Forecast, Markets & Transportation 2014"

[1] Forecast projections vary by study. Canada's National Energy Board (NEB) estimates production of 5.7m b/d by 2030, while the International Energy Agency (IEA) estimates 6.1m b/d by 2030. CAPP has revised this year's production forecast downward by 0.3m b/d, taking into account changing project development timelines and ongoing challenges associated with energy transportation infrastructure.

1. **The oil sands will drive production growth, led by heavy-sour bitumen output; but light oil remains a sizable share on a sustained supply of bitumen upgraded into light-sweet SCO and growing conventional output.**

Growth in Canada's oil supply will increasingly come from the oil sands as production in the sector climbs. The oil sands will account for the largest portion of incremental supply growth in the future by far, with production forecasted to rise from 1.9m b/d (56% of supply) in 2013 to 4.8m b/d (75% of supply) by 2030. This is in part due to the fact that 96% of Canada's 174.3 billion barrels in oil reserves, the third largest in the world, are located in Alberta's oil sands deposits. The main product of oil sands production, bitumen, is an extra heavy-sour hydrocarbon that is too thick to flow under ambient conditions. Bitumen can either be blended with a diluent like condensate or conventional oil/SCO and sold in this form, which is similar to heavy crude like Mexican Maya, or it can be upgraded into light-sweet SCO, similar to oil such as West Texas Intermediate (WTI) or Brent crude.[2]

Fig 2: Oil Sands Bitumen/SCO Production & Disposition Forecast

(Units: million b/d)	*2013*	*2023*
Non-Upgraded Bitumen	1	2.5
Domestic/International Exports	0.99	2.45
Upgraded Bitumen (SCO)	0.94	1.3
Domestic/International Exports	0.61	0.97

Source: AER, "ST98-2014," May 2014

Heavy bitumen will lead oil sands growth due to an expected rise in production from stand-alone in situ oil sands projects that sell bitumen blends directly to market instead of upgrading into SCO.[3] Upgrading involves significant development costs and with a ready supply of light oil on the continent, bitumen output is expected to outpace forecasted upgrading capacity. Spurred by growth of in situ projects, Alberta's Energy Regulator (AER) forecasts non-upgraded bitumen output will rise from 1m b/d to 2.5m b/d by 2023, with domestic and international exports from Alberta rising from 0.99m to 2.45m b/d.

Even with forecasted heavy crude supply growth, light SCO production will continue to comprise a significant portion of oil sands supply. Currently, nearly all bitumen produced at surface mining projects (and 12% of in situ-produced bitumen) is sent for upgrading into light-sweet SCO. The AER estimates that upgraded bitumen production will grow from 0.94m b/d to 1.3m b/d by 2023. While SCO makes up a larger portion of Alberta's refining feedstock than bitumen (only 12k b/d of bitumen is processed directly in refineries), AER

[2] An example of a bitumen blend is the benchmark Western Canadian Select (WCS) which is a mix of heavy conventional oil, oil sands bitumen and diluent with an average API Gravity of 20.7° and sulphur content of 3.5%. A sample SCO would be Syncrude Sweet Premium which has an average API Gravity of 32.2° and sulphur content of 0.18%.

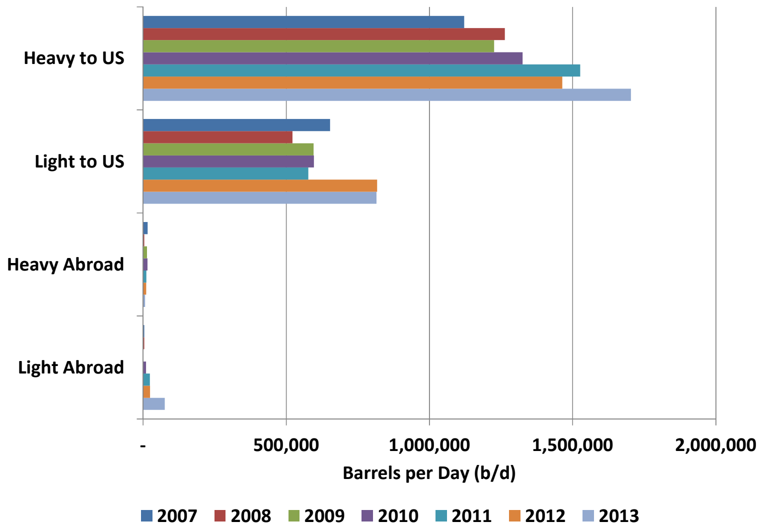
[3] In situ projects most commonly use steam injection at the well-site to heat and extract heavy bitumen deep underground. Growth in situ production is supported by the fact that more than 80% of oil sands reserves are only exploitable through in situ methods as well as by improved recovery techniques and economics over time.

forecasts still suggest exports from Alberta to domestic markets and abroad could increase from 0.61m to 0.97m b/d by 2023, in part because domestic refinery demand in Alberta will remain relatively flat. By the end of the forecast period heavy-sour bitumen will make up approximately two thirds of oil sands output, shifting Canada's oil supply in a heavier direction over time, but with the oil sands still maintaining a significant light component in the future.

Light conventional production is also expected to reverse historical declines and return to growth, with CAPP forecasting a rise from 1.3m to 1.5m b/d by 2020. Conventional output in Western Canada has rebounded as a result of the use of technology like horizontal drilling and hydraulic fracturing at tight oil and natural gas liquids-rich fields in places like Saskatchewan's Bakken, as well as the Montney, Duvernay and Cardium plays in British Columbia and Alberta. To illustrate this trend, after declining over time, Alberta light-medium oil reserves have grown by 315m barrels, and light conventional production has risen from 0.46m b/d in 2010 to 0.58 b/d in 2013. This increase is driven in part by pentanes and field condensate production from Alberta/British Columbia, a product in high demand for use as a diluent in the oil sands sector. In addition, Saskatchewan production has risen by 0.1m b/d between 2000 and 2013, driven by increases in conventional light and heavy production.

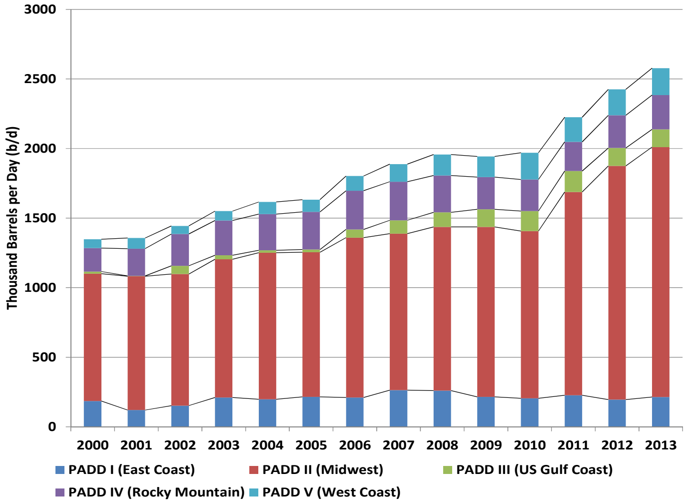
2. **The US remains a vital destination for Canadian heavy crudes, with the Gulf Coast expected to play a key role in the future. Eastern Canada has also shown interest in North American crude.**

Fig 3: Canadian Light/Heavy Crude Exports (by destination)



Source: NEB, "Total Crude Oil Exports Annual," 2014
Note: "heavy crude" = API < 30.1°, "light crude" = API > 30.1°

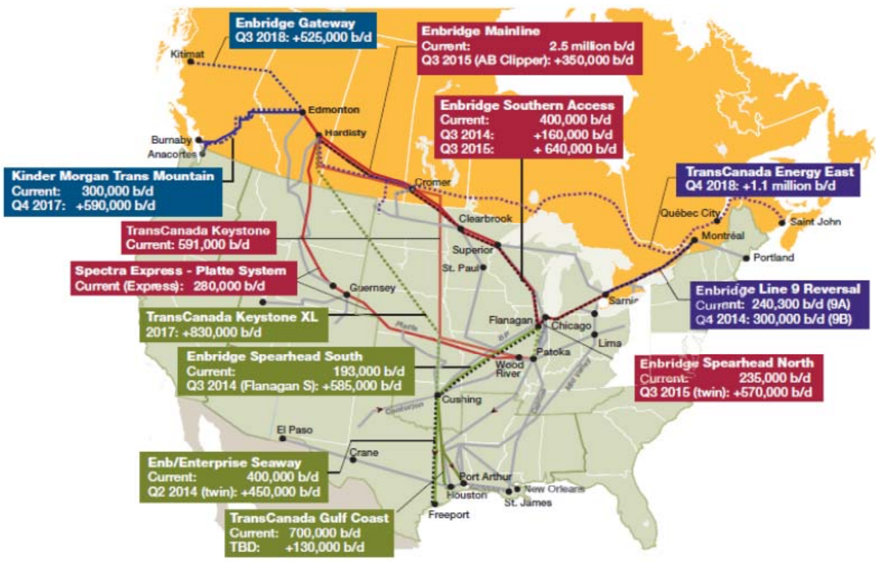
Fig 4: US Imports of Canadian Crude (by PADD)



Source: EIA, "Crude Oil Imports by PADD of Processing," 2014

Canada's crude export base reveals its close market and infrastructure integration with the world's largest source of demand, the United States. Currently, almost all Canadian oil exports (2.6m b/d) are sent to the US, where Canada is the US's largest foreign source of crude, accounting for one third of all imports. Nearly two thirds (1.7m b/d) of Canadian exports are heavy crude (API<30.1°) bound for the US, while almost one third of these are light (API>30.1°, 0.82m b/d). A small remaining portion (83k b/d) of crude sent elsewhere is most often Canadian East Coast offshore light crude and occasional cargos of heavy crude destined for Europe or Asia.

Fig 5: Existing/Proposed North American Pipeline Projects



Source: CAPP, "Crude Oil Forecast, Markets & Transportation 2014"

The US Midwest (PADD II) receives the majority of Canada's crude exports at nearly 1.8m b/d, more than 1.1m b/d of which is heavy supply, while the remainder is comprised of portions of light-sweet and light/medium-sour crudes. According to Canada's National Energy Board (NEB), the US Midwest has absorbed nearly all growth in Western Canadian production since 2007, supported by its well-established refining sector, as well as three recent refinery conversions allowing for an additional 0.43m b/d in heavy crude processing capacity.

While PADD II is Canada's largest export destination, increases in Canadian and American production have led to constrained pipeline capacity and full inventories at hubs like Cushing, Oklahoma. This has depressed pricing for Canadian oil, which is unable to reach new demand centres due to current bottlenecks and under-capacity in the transportation system.

The US Gulf Coast (PADD III), with significant refining capacity in Texas and Louisiana, is a target for Canadian heavy crude as refineries are designed to process heavy Latin American imports, which have declined over time. While PADD III imported 2.1m b/d of heavy crude last year, Canada only accounted for 0.12m b/d due to ongoing transportation constraints. Crude-by-rail and recent pipeline capacity additions and changes have helped to somewhat alleviate an infrastructure capacity gap, but resolution of pipeline development challenges could help Canadian crude make significant inroads in the region. CAPP forecasts that PADD III could process 0.68m b/d or more of Canadian crude by 2020.

Eastern Canada has also shown interest in Western Canadian crude. Currently, Ontario refineries process Western Canadian and US crudes and more expensive globally-priced oil from places like the Middle East, Africa and North Sea. On the back of rising light tight oil (LTO) production, US crude exports to Canada have risen to 0.13m b/d in 2013, nearly double 2012 exports of 67k b/d.[4] To improve access to competitive continental crudes, several steps have been taken, including: Planned reversal and expansion of the Line 9 pipeline system to carry North American crude to Eastern Canadian refineries, increasing crude-by-rail and marine imports from the US/Western Canada to the region, and consideration of the proposed Energy East Pipeline, to carry 1.1m b/d of oil from Alberta as far as St. John, New Brunswick and on to Atlantic tidewater where it could also reach international markets.

3. **Asia will be an important market for Canadian exports in the future. Established cracking and hydrotreating capacity make China and India prospective markets for heavy-sour crude; but growth in light production leaves opportunities for Canada to explore exports of light grades to Asia as well.**

The Asia-Pacific region holds great potential for exports, as North American demand is expected to moderate/decline, and exports would bring higher global prices for Canadian crude and allow the country to diversify its export base. Economic growth in non-OECD Asia is expected to add 4.3m b/d in additional oil demand by 2019, with 3.7m b/d of

[4] In June 2014, US exports to Canada reached 0.38m b/d.

incremental refining capacity and 3.3m b/d in added crude imports, according to the IEA. Of this, China and India are expected to see the largest demand increases at 2.6m b/d between 2013 and 2019. Demand in China and India will surpass domestic production, resulting in increased imports and import dependency in the future.

Fig 6: Major Asian Refining Capacity (2013)

(Units: thousand b/d)	*China*	*India*	*Japan*	*South Korea*	*US*
CDU	13,300	4,343	4,423	2,959	18,094
Catalytic Hydrotreating	7,080	204	4,647	1,502	14,325
FCC/RFCC	3,300	498	911	314	5,669
Coking, Thermal Operations	1,650	242	143	19	2,672
Catalytic Hydrocracking	1,680	166	182	330	1,759
Cracking to CDU Ratio (%)	**49.8%**	**20.9%**	**27.9%**	**22.4%**	**55.8%**
Desulphurization to CDU Ratio (%)	**53.2%**	**4.7%**	**105%**	**13.3%**	**79.2%**

Source: Oil & Gas Journal, "2014 World Refining Survey," 2014 & Institute of Energy Economics, Japan (IEEJ)

Refinery configuration in Asian markets, including cracking and desulphurization capacity, reveals important details about prospects for Canadian exports to the region. [5]

Similar to many US refiners, China and India have invested in upgrading their heavy oil processing capacity. As demonstrated by their cracking to CDU ratios, China and India have installed delayed coking and other conversion units to enable cracking residue volumes present in heavy crudes into value-added products like gasoline and middle-distillates. China has an estimated 1.65m b/d in coking capacity; with India listed at 0.24m b/d. More recently though, India's coking capacity has grown significantly since the country's export-oriented refineries in particular have undergone upgrades as part of a strategy to strengthen refining margins by processing cost-competitive heavy crudes. The IEA forecasts 1.08m b/d in upgrading capacity additions for China and a similar amount for other non-OECD Asia countries between 2013 and 2019 giving the region some of the best prospects for processing heavy crudes like oil sands bitumen blends.[6]

While many Asian refineries have established desulphurization capacity as part of their experience processing sour crudes from regions like the Middle East, others have relatively low hydrotreating to CDU ratios that signal a need for capacity additions if they are to effectively accept sour crude in the future. As heavy oil sands bitumen crudes are normally sour in content, import prospects may be influenced by the pace and scale of hydro-treating additions in target markets. According to the IEA, Asian countries are expected to increase desulphurization capacity with China accounting for one third of net global hydro-treating additions over the next five years, adding 1.4m b/d in capacity, while other Asian countries will add a further 0.6m b/d.

[5] Many heavy types of crude like those from oil sands, Venezuela, and others like Brazilian Marlim have a higher Total Acid Number (TAN) content level, a measure of the crude's organic acid level. Refineries planning to process higher TAN crudes normally undertake corrosion-prevention measures such as proper use of metals at particular points in the refinery, increased inspections and blending down of crudes to mitigate impacts.

[6] Includes additions to coking, hydrocracking, residue hydrocracking, visbreaking, FCC/RFCC capacity.

As established cracking and hydrotreating capacity allow for processing of heavy-sour crudes, several global heavy oil producers that have traditionally sent the majority of exports to the US in the past are now shipping increasing volumes to Asia. For example, Venezuela reports 0.73m b/d in crude exports to Asia (approximately as much as it ships to the US), with India (0.4m b/d) and China (0.29m b/d) representing the main destinations.[7] Mexico also ships approximately 97k b/d of crude to India, mainly reported to be of heavy Maya, with an additional 19k b/d sent to China. Given refinery configuration and existing trade in heavy-sour crude with countries such as Venezuela, Mexico and Colombia, China and India would be well-placed to consider diversifying their feedstock to include Canadian oil of similar quality. If the integrated supply and transportation costs of Canadian crudes are able to compete with existing supplies from other heavy producers, Canada could increase its share of the overall heavy supply to Asia.

While heavy oil will make up the largest portion of future Canadian supply, the arrival of the Shale Revolution and an expected boost in light crude production may allow Canada to explore new export destinations in Asia and abroad for light grades. Recently, surging US production has displaced light-sweet crude imports in the US from countries like Nigeria, which have dropped from 1.1m b/d in 2007 to 0.24m b/d in 2013. To deal with a possible future supply build-up in light North American crude, Canada could examine the potential for new markets in Asia for conventional oil and SCO. For example, as increasingly stringent fuel and emissions standards are put in place in many countries, refineries may need to further increase hydro-treating capacity to reduce sulphur content in refined products like diesel. In the short- to medium-term, if arbitrage opportunities for Canadian light crude are identified in Asia, SCO or light conventional could compete with crudes such as Nigerian Bonny Light to serve as sweet feedstock for refineries without adequate hydro-treating capacity.

4. **Supply/demand trends support potential for diversified Canadian exports, but transportation remains a challenge. In the interim, crude-by-rail, barge and marine shipment are helping to bridge access to new markets. A short-term goal is to diversify exports to the Gulf Coast and Eastern Canada, while examining mid-term possibilities for new markets abroad as infrastructure bottlenecks are addressed. Diversified market access to Asia will help create opportunities for expanding heavy and light Canadian supply in the future.**

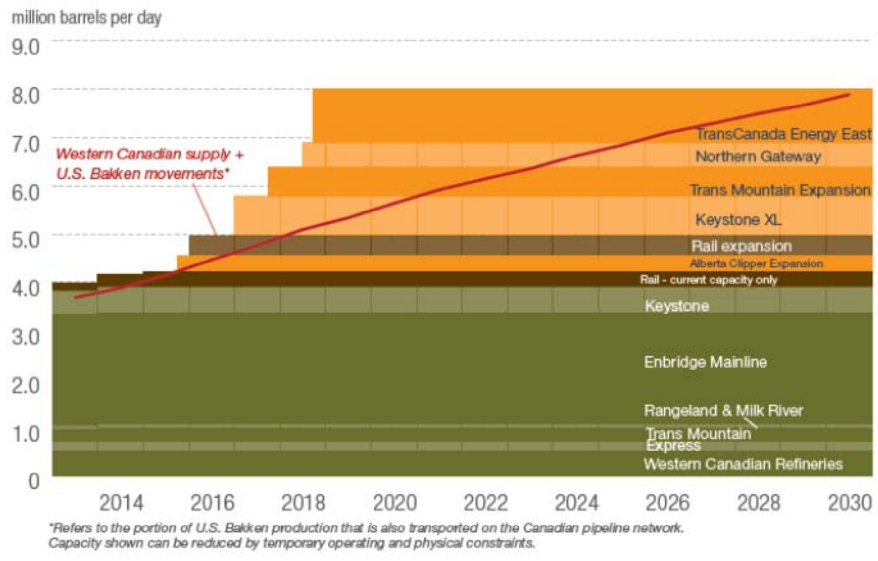
Surging North American crude production combined with moderate demand growth has created a strong incentive for Canada to consider new markets for its oil in Eastern Canada, the US and abroad in regions like Asia. A recent forecast by Canada's National Energy Board (NEB) predicts that 4.2m b/d of heavy crude by 2035 and a peak of 1.6m b/d of light crude by 2025 (tapering to 1.4m b/d in 2035), in net-exports will be available in the future.

[7] China also imports significant quantities of straight-run heavy fuel oil from Venezuela for use as a refinery feedstock.

The key challenge will be successful expansion and reconfiguration of the extensive North American energy pipeline and transportation system to move crude to new markets. Debottlenecking activities such as flow reversal and capacity expansion to existing pipelines, for example with the Seaway and Line 9 reversals and start-up of the Gulf Coast pipeline, are underway and will help to evacuate supply to regions like PADD III and Eastern Canada. New pipelines and capacity expansions in Canada are under development and regulatory approval. Projects like the proposed Trans-Mountain Expansion, Northern Gateway and Energy East projects would open access to Asian markets via Atlantic and Pacific tidewater, contributing to Canadian market expansion abroad.

Given expected supply growth, CAPP predicts all additional transportation to the US, Eastern Canada, Atlantic and Pacific tidewater will be needed to reach new markets. Each route has strategic advantages, as Bentek points out, Keystone XL (0.83m b/d) will provide Canada access to the Gulf Coast, while Energy East (1.1m b/d) opens up Eastern Canadian, European and Indian markets, and Northern Gateway (0.53m b/d) and the Trans-Mountain Expansion (0.89m b/d) support access to new East Asian markets—when combined, providing optionality for Canadian producers seeking exports.

Fig 7: Forecast Crude Production & Existing/Planned Transportation Capacity



Source: CAPP, "Crude Oil Forecast, Markets & Transportation 2014"

While pipeline capacity remains under development, crude-by-rail is emerging to bridge the gap and help carry crude to market. Last year, rail carried 0.13m b/d of Canadian oil to US markets, 57k b/d of which was sent to the Gulf Coast and 56k b/d to the US East Coast. Crude transport by barge and tanker have also been used (often in conjunction with rail) to fill transportation gaps. In its recent outlook, the IEA suggests crude-by-rail and potential for crude re-exports via the United States could help supply up to 0.3m b/d of

Canadian crude to Asian markets by 2019 if capacity is available and permitting is received.

In the short-term, diversification of destinations for Canadian crude in the US, particularly to the Gulf Coast is vital. Increased access to PADD III will give Canadian heavy-sour crude the opportunity to compete with heavy Latin American imports like Mexican Maya and Colombian Castilla/Vasconia. Given the ongoing WCS discount relative to Maya, if WCS has cost-effective transportation options available it would make an attractive feedstock for Gulf Coast refineries with heavy crude processing capacity.[8] Access to East Coast markets will also continue to open as the Line 9 reversal begins operation, delivering additional Canadian and US supply to eastern refineries traditionally reliant primarily on global Brent-priced imports.

In the medium-term, as transportation options continue to develop, Canada can explore new ways to start building exports to future markets. For example, when existing batches of light and heavy crude oil are available, opportunities for exports to Asia and abroad could be examined. Recent examples include: Cargoes of WCS that have been sent to Europe, India's recent purchase of light East Coast offshore crude, and occasional spot purchases of heavy oil for shipment to China and Singapore via the Pacific Coast.

In the medium- to long-term, with infrastructure established, Canada can seek longer-term heavy supply arrangements to countries like China and India that are equipped with cracking and hydrotreating capacity, as well as opportunities for light crude export arrangements. Canadian crude could help Asian countries diversify sourcing of imports, increase the diversity of the crude supply base in terms of light-heavy balance, and contribute to overall supply and price stability, and contributing to improved energy security in the Asia-Pacific region.

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[8] In 2013, the average price of Maya FOB was US$96.87/b, while WCS at Hardisty, Alberta was US$72.84/b.

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