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North America's Heavy Crude Future

Western Canadian access, the US refining system, and offshore supply

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STRATEGIC REPORT

North American Crude Oil Markets | Decision Brief

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Contents

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Key implications

Trade flows of western Canadian crude oil have entered a new phase, with incremental growth of heavy oil moving beyond its traditional refining markets in western Canada, the US Midwest, and Rocky Mountain regions. Rising Canadian production will reach new markets, but the question is how and where. With the Keystone XL pipeline and other proposed Canadian pipeline projects still in regulatory limbo, there is uncertainty about the pattern of future Canadian crude flows.

- **Despite the collapse in oil prices, Canadian oil sands production is still set to expand, with exports moving into the US Gulf Coast (USGC).** The USGC is the largest market for heavy crude in the world, consuming over 2 million barrels per day in 2014. For Gulf refineries, heavy bitumen blends from the oil sands are an attractive substitute for declining offshore heavy crude supply from Latin America.

- **The proposed Keystone XL pipeline project represents an effort to create an efficient pathway between western Canadian heavy supply and USGC heavy oil refinery demand.** However, Keystone XL is just one of several advancing transportation options to increase Canadian connectivity to new markets. In the absence of Keystone XL or other pipeline projects, we expect rail to move all incremental barrels out of western Canada.

- **Canadian crude making its way to the USGC will likely be refined there, and most of the refined products are likely to be consumed in the United States.** The vast majority of USGC refined product output—about 70%—is consumed in the United States. This pattern is unaffected by the source and quality of crude oil being refined by USGC refineries.

—February 2015

North America's Heavy Crude Future

Western Canadian access, the US refining system, and offshore supply

Aaron Brady, Senior Director[1]

New markets for Canadian crude oil

The sensational growth in US crude oil production over the past several years has almost overshadowed the other important story in the North American oil market—the continued rise of Canada's oil sands and the search for market access and diversity.

Canadian oil production reached about 3.7 million barrels per day (MMb/d) at the end of 2014, about 1.1 MMb/d above the average for 2008.[2] The largest driver of Canadian production growth has been the oil sands, geographically located inland in western Canada. During the same period, US production grew by 4.1 MMb/d. While Canada's rise may appear modest in comparison to that of the United States, it is still striking, for Canada ranks second in production growth in the world over this period. And despite the recent price drop, growth is likely to continue—at least for the next three years (see the box "Oil sands production—and exports—likely to keep growing despite price collapse").

Oil sands production—and exports—likely to keep growing despite price collapse

The collapse in oil prices over the past several months has cast into doubt the continuation of North American oil production growth. However, typical oil sands projects have a very long time horizon—with a production life lasting as long as 30 to 40 years. They are built to weather the storm and survive periods of low prices. This gives oil sands producers a different perspective from that of other unconventional producers, especially tight oil operators, whose investment and drilling decisions are likely to be more directly influenced by prompt price levels.

IHS still expects significant growth from the oil sands over at least the next three years.

- **Moderate operating costs.** Most oil sands projects have operating costs in the range of $20 to $46 per barrel (bbl) (West Texas Intermediate [WTI]).

- **Sunk capital costs.** Where the majority of project capital has already been spent, projects will continue to operate or proceed to completion. Indeed, based on known projects at various stages of completion in western Canada, we expect that over 450,000 barrels per day (b/d) of incremental oil sands supply will come online between 2015 and 2017.

However, the economics of new oil sands projects that have not reached the construction phase are clearly challenged in the current price environment—especially if prices continue to drop. The longer term pace of growth is likely to be affected if oil prices remain depressed.

If low oil prices persist for a year or longer (with WTI below $50/bbl, for example), additional projects will be delayed and maintenance spending on existing projects could be reduced. Also, the longer oil prices remain below the operating cost of some oil sands producers, the greater the possibility that some high-cost oil sands production could be shut in. But we expect the majority of the supply impact to result from projects not yet under construction—a supply impact closer to 2020 than 2015.*

*See the IHS Energy Decision Brief *Canadian Oil Sands: A steady runner on a lower price track.*

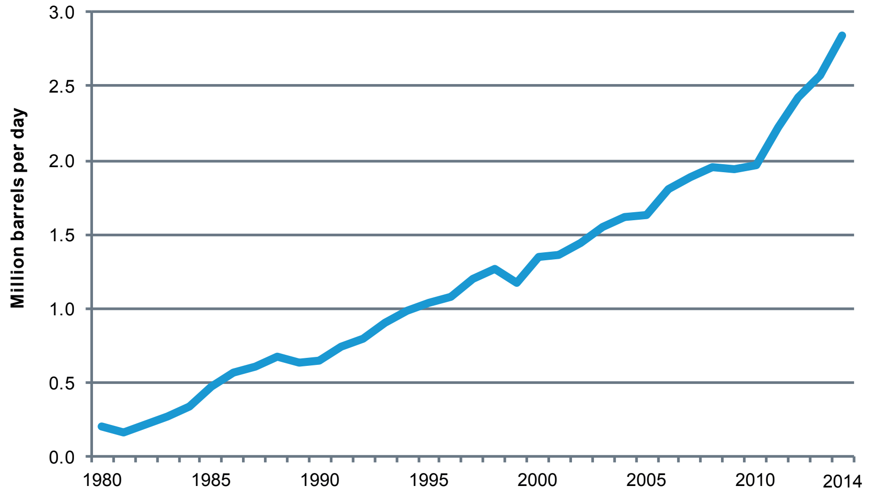
1. Steve Kelly, Kevin Birn, James Fallon, Clarke Lind, Juan Osuna, and Dominik Rozwadowski contributed to this report.

2. This does not include diluent volumes in marketed crude.

The western Canadian supply story is important because exports have entered a new phase, with incremental growth of heavy oil moving beyond the traditional refining markets in western Canada, Ontario, and the US Midwest and Rocky Mountain regions. Demand for heavy crude in these regions is now essentially saturated. Over the past several decades, Midwest and Rocky Mountain refineries have invested in the types of capital-intensive hardware necessary to process heavy oil and have backed out offshore imports in favor of Canadian barrels. This has fueled a steady increase in US imports of Canadian oil, which by the end of 2014 had reached 3 MMb/d—roughly double the level of 10 years prior (see Figure 1).[3]

Figure 1

US imports of Canadian crude oil (annual average)



Source: US Energy Information Administration

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However, additional investment to further expand US heavy oil processing in the Midwest is unlikely for the foreseeable future because the light, tight oil boom has removed much of the incentive to invest in new heavy crude oil processing capacity. Incremental barrels must find new markets.

There are three large proposed pipeline projects that would permit offshore exports from both the East and West coasts of Canada as production grows. But the most obvious and immediate new large export market for heavy Canadian supply is the US Gulf Coast (USGC) refining center. The USGC is the biggest refining market for crude—and particularly heavy crude—in the world, with a large fleet of deep conversion refineries that consume over 2 MMb/d of heavy, sour crudes, mostly sourced from Latin America. Despite the massive increase in US light, tight oil production over the past several years, these refineries have not changed their design diet of heavy crude, nor do we expect them to change in the future. Running light, sweet barrels through refineries designed to process heavy, sour barrels is uneconomic, unless the market offers large, sustained discounts in light oil pricing.

How will the search for new markets play out for Canadian heavy crude over the next few years as production continues to increase? The key questions for the heavy crude market are

- **How will Canadian crude get to the USGC?** There are several proposed logistics solutions to increase connectivity between growing Canadian crude production and USGC refineries, including the Keystone XL pipeline. Crude-by-rail is also increasingly being used to move Canadian crude south.

- **What will be the impact on incumbent heavy suppliers to the USGC?** As Canadian crude reaches the USGC in greater volumes, how will market share evolve between Canada and traditional suppliers such as Mexico and Venezuela?

- **Will Canadian crude move offshore to more distant markets?** Canadian producers have sought for years to realize their goal of diversifying their customer base beyond the United States. This could happen via exports from the west or east coast of Canada.

3. In 2014 about 1.9 MMb/d of US Canadian imports were heavy oil from the oil sands and conventional production. The balance—1.1 MMb/d—was from conventional light and medium grades. Most of these Canadian imported barrels were processed in the US Midwest.

The Gulf Coast: A natural home for heavy crude, including Canadian barrels

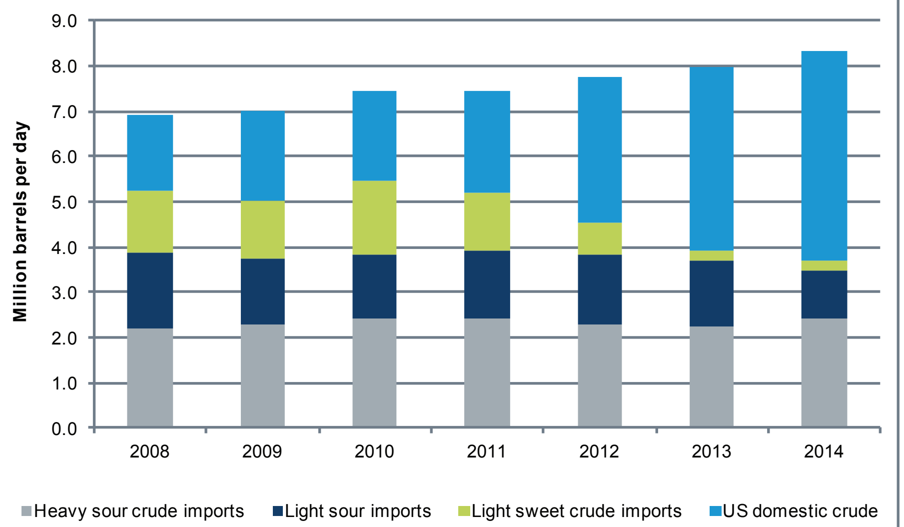
The unconventional crude production boom has drastically increased the availability of light, sweet, tight oil across the US market. The extraordinary growth in US tight oil production has led some to question the need for more Canadian oil in the US market, including the volumes that would be delivered by new pipelines such as the proposed Keystone XL project.

However, although the supply picture has changed dramatically, the demand side has not. The US market—especially the Gulf Coast—still has a very significant need for heavy, sour barrels because of its large contingent of deep conversion refineries that were built specifically to process heavy crude oil.

Those Gulf Coast refineries that are best configured to run the increasingly available volumes of light, sweet tight oil have done so (and backed out imported light offshore barrels, especially from Africa, in the process), but heavy crude runs in the region have not changed appreciably (see Figure 2). In other words, despite the rapidly increasing availability of light, sweet crude oil across the United States (including the Gulf Coast), these volumes are incapable of meeting all of US demand.

Figure 2

USGC refining runs by crude source



Source: IHS, US Energy Information Administration

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About a third of USGC refinery capacity—about 2.7 MMb/d out of 9.2 MMb/d of total capacity—are heavy, sour coking refineries. Rising production in the 1980s and 1990s in Mexico and Venezuela provided an opportunity for USGC refineries to access lower-priced heavy crude oil much closer to market than Middle Eastern oil. Over this period, a wave of investment occurred in the Gulf Coast as many refineries were reconfigured to run the increasingly available Latin American heavy barrels. These investments included several joint ventures and supply agreements between refiners and Mexican and Venezuelan producers.[4]

Today, however, Venezuelan and Mexican heavy oil output is in decline, owing to insufficient upstream investment. Mexican total crude production has fallen by nearly 1 MMb/d since 2004—with most of this drop due to declining heavy crude production. Venezuelan total oil production is down over 700,000 b/d from its late 1990s peak. As production volumes have dropped in both countries, export volumes to the United States have declined as well (see Figures 3 and 4). In the case of Venezuela, exports have also tilted away from the US market and toward Asia as a result of a set of Chinese government loans that carry along a commitment of Venezuelan oil supply.

To combat declines, Mexico has recently begun a historic reform of its oil industry, opening the Mexican oil market to foreign investment for the first time since the industry was nationalized in 1938. But reform is unlikely to reverse the country's output decline for several years. In Venezuela, investment is lapsing and there are no signs of reform.

Since Canadian oil sands–derived bitumen blends have a similar quality to heavy Venezuelan and Mexican Maya blends, they are a natural fit for USGC heavy crude refiners. This explains the interest from both western Canadian producers and USGC refiners to secure efficient pipeline connections, especially as Latin American heavy crude becomes less available.

4. See Appendix A for list of publicly known Gulf Coast refinery crude supply arrangements.

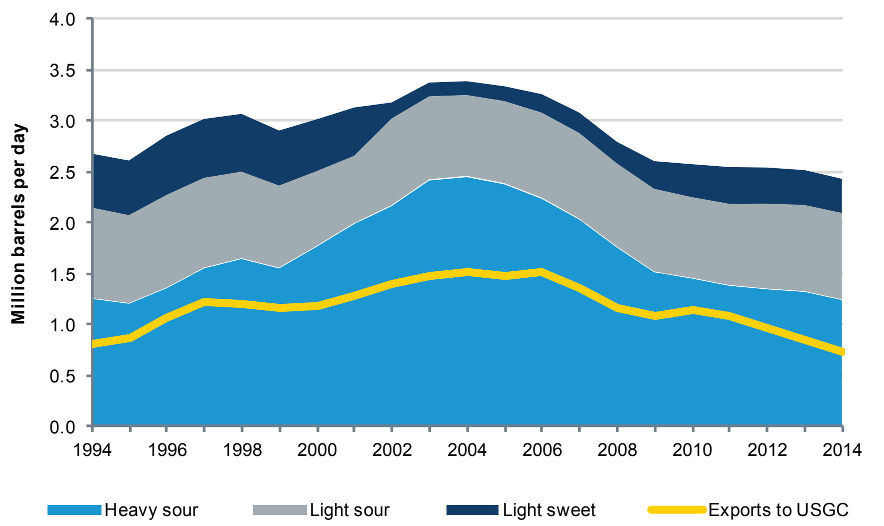
Canadian oil sands have drawn attention because they are relatively carbon intensive. However, because Canadian bitumen blends are similar in greenhouse gas (GHG) intensity to heavy Latin American barrels, particularly Venezuelan heavy crudes, the GHG emission impact in the United States of importing and processing more Canadian barrels is negligible. Previous IHS research has concluded that despite significant growth in US processing of imported Canadian oil over the past decade, there has been no measurable change to the GHG intensity of the average crude consumed in the United States, because similarly carbon-intensive barrels have been displaced.[5]

The contest for market share in the Gulf

The capacity to process heavy crude in the USGC is now at a record high. About a decade ago, the market was sending price signals that incentivized investment in heavy crude oil processing capacity. The light-heavy oil price spread—a key indicator of heavy oil refining profitability—widened dramatically between 2004 and 2008. Investment decisions made during that time have subsequently led to a pronounced increase in USGC coking capacity in the past few years. But utilization of these coking units has not kept up because of declining availability of Latin American heavy crude, leaving a portion of USGC heavy crude coking capacity unused (see Figure 5).

Figure 3

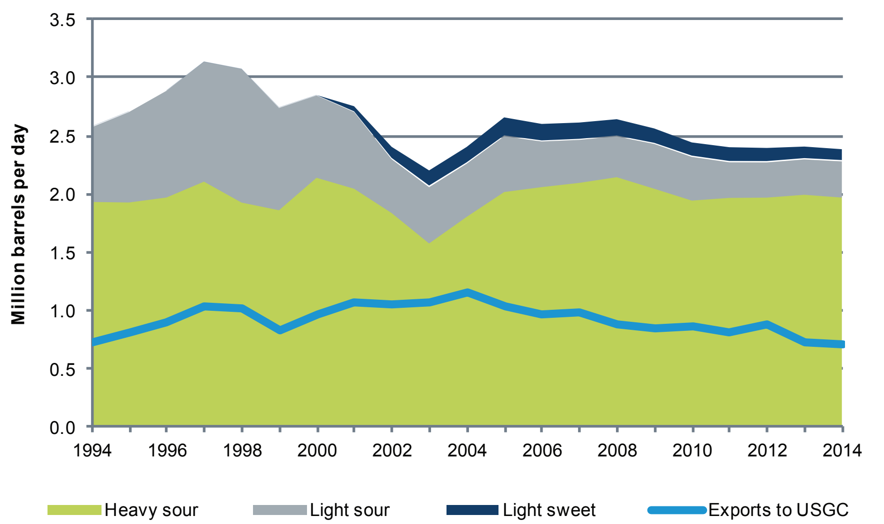
Mexican crude oil production by type and exports to USGC



Source: IHS; US Energy Information Administration © 2015 IHS

Figure 4

Venezuelan crude oil production by type and exports to USGC



Source: IHS; US Energy Information Administration © 2015 IHS

The decline in Latin American heavy crude availability and the increase in USGC coking capacity means that, for the time being, there is "room" for Canadian producers to establish new market share in the Gulf without pushing out Latin American barrels. Indeed, heavy Canadian barrels are starting to reach the USGC in increasing volumes, by rail and the existing Enbridge system. Small volumes are also reaching the US East and West Coast markets.

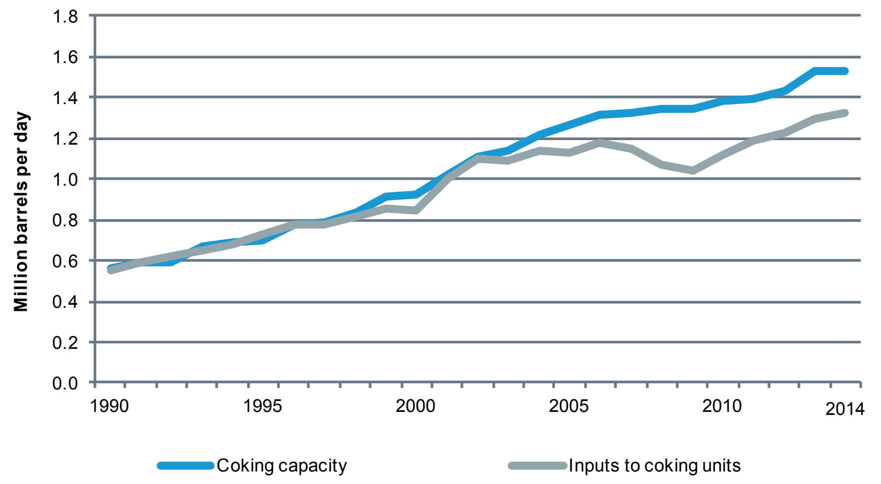
Clearly, however, a contest for market share looms in the USGC between Canadian and Latin American producers, as Canadian supply continues to grow and eventually outpaces the decline in Latin American supply. Latin American suppliers will likely respond to the entry of Canadian heavy crude in the US market. Through a transitional period, we would expect Latin American crude prices to be adjusted to protect market share and Canadian heavy crude to price in

5. See the IHS Energy Special Report *Comparing GHG Intensity of the Oil Sands and the Average US Crude.*

parity with crudes such as Maya—a benchmark heavy grade from Mexico. But, since Latin American crudes have the ability to move offshore, this will occur to a greater extent in order to rebalance the market with Canadian supply in the region.

Figure 5

USGC refinery coking capacity and coking runs (annual average)



Notes: Coking runs are the heaviest portion of the crude oil barrel fed to the refinery coking unit.
Source: IHS; US Energy Information Administration

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Certainly this does not mean the complete disappearance of Latin American heavy crudes in the Gulf; the CITGO heavy crude refineries in Corpus Christi, Texas, and Lake Charles, Louisiana, are subsidiaries of Petróleos de Venezuela S.A. (PDVSA), and they are likely to continue importing some volume of Venezuelan crude, while the Petróleos Mexicanos (PEMEX)/Shell joint venture refinery in Deer Park, Texas, will continue to import equity barrels of Mayan heavy crude. The one caveat would be if PDVSA sold its CITGO refineries. This could alter the landscape for equity processing of Venezuelan crude in the USGC and open the market for additional Canadian supply.

Keystone XL—One of several options for moving Canadian barrels to market

There is a natural relationship between growing heavy oil supply in western Canada and US heavy oil demand. However, with the existing pipeline systems connecting western Canada to the United States at capacity, how will incremental exports move in the years ahead?

With Keystone XL still in regulatory limbo, the existing export pipelines at capacity, and the construction of offshore export pipelines uncertain, western Canadian upstream producers, midstream players, and downstream companies have turned to rail to transport incremental barrels.

Rail transport has become an enabler of growth in western Canada, just as it has been for US tight oil. By end-2014, around 800,000 b/d of rail loading capacity had been built in western Canada. IHS estimates that western Canadian crude-by-rail exports to the United States averaged around 200,000 b/d last year, a figure that will likely increase to 400,000 b/d in 2015. IHS expects most of these crude-by-rail exports will be directed to the USGC market. The ability of the rail industry to scale up to moving very large volumes of crude has already been proven in the Bakken tight oil play. As of fourth quarter 2014, around 800,000 b/d of crude was being transported from North Dakota to markets across North America—a volume similar to what Keystone XL would move. This compares with average volumes of less than 100,000 b/d as recently as 2010.

Rail has its advantages. It provides optionality—giving producers the flexibility to move barrels to markets offering the highest price for their output or to markets that are not served by pipeline. However, a direct pipeline link between western Canada and the USGC (such as Keystone XL) is generally preferable for producers. It has relatively low transportation costs—which improve the netback prices for the producer—and offers better predictability from a planning perspective compared to rail. For example, on average we estimate that rail costs about $8 to $10 more to move a barrel of heavy crude blend from western Canada to the USGC compared with pipelines.[6] Refiners would also prefer the predictability of pipelines—which unlike railroads are rarely impeded by weather and other external factors, such as competition for space with nonpetroleum products.

6. See the IHS Energy Special Report *Crude by Rail: The new logistics of tight oil and oil sands growth.*

The Keystone XL project is therefore about creating an efficient, lower-cost pathway for USGC refiners to access a growing source of heavy crude oil. However, Keystone XL is just one of several potential logistical solutions for Canadian crude to move to new markets in the coming years. In total there are now four major export pipeline proposals that would move crude from western Canada to new markets. Of these projects, the Keystone XL pipeline is the only one that directly targets the USGC refining system. The remaining three projects (Enbridge Northern Gateway, TransCanada Energy East, and Kinder Morgan Trans Mountain Expansion) would provide access to offshore (non–North American) markets, although we expect that if Canadian crude is able to access Canadian coastal waters in large volumes, some is likely to be drawn to the heavy oil market in the USGC.

Incremental Canadian crude exports are also beginning to flow through existing Enbridge pipeline systems to the USGC as the bottlenecked mainline is gradually expanded. Enbridge has two ongoing projects that would accomplish this goal: an expansion of its Alberta Clipper and the replacement and expansion of Line 3—two of several key crude export pipelines that exit western Canada. Although the Alberta Clipper project has also encountered delays in seeking approval from the US government, Enbridge appears to be finding workarounds. Enbridge has also been expanding its system "downstream" of the mainline, increasing connectivity from the northern Midwest (Chicago) area to Cushing and the USGC (see Table 1).[7]

Moving Canadian crude farther offshore

Canadian crude can legally be "reexported" from US ports. Will this occur in large volumes as Canadian crude increasingly reaches USGC tidewater access via a project like Keystone XL?

We think this is highly improbable, at least in volumes beyond the occasional test cargo sent to international refiners. The market economics of global crude trade make it unlikely that producers and shippers of western Canadian crude would bypass the largest market in the world for heavy crude, thereby reducing the price they receive for their product. Shippers would not choose to sell into more distant markets—incurring additional freight and other logistic fees—when they can fetch the world market price for heavy crude in the USGC.

In fact, the prospect of achieving higher prices for producers is one of the key drivers for securing access to the USGC. Canadian producers are seeking access to the Gulf to increase their market but also because it reflects a "world" price

Table 1

Key pipeline projects allowing increased market access for Canadian production

Destination	Pipeline project	Route	Incremental capacity (b/d)	Status	Expected in- service date
US markets	Flanagan South (Enbridge)[1]	Flanagan, Illinois, to Cushing, Oklahoma	585,000	Online	2014 (now streaming)
	Seaway system (Enbridge/ Enterprise)	Cushing to USGC	850,000	Online	2014 (now streaming)
	MarketLink (TransCanada)	Cushing to USGC	700,000	Online	2014 (now streaming)
	Keystone XL (TransCanada)	Hardisty, Alberta, to Port Arthur, Texas	830,000	Under review	2017
	Alberta Clipper expansion (Enbridge)	Hardisty, Alberta, to Superior, Wisconsin	350,000	Under review	2015
	Line 3 rebuild and expansion (Enbridge)	Edmonton, Alberta, to Superior, Wisconsin	370,000	Under construction	2017
Eastern Canada and east coast offshore	Energy East (TransCanada)	Hardisty Alberta, to Montreal Québec, then on to tidewater at Saint John, New Brunswick	1,100,000	Under review	2018
West coast offshore	Northern Gateway (Enbridge)	Bruderheim, Alberta, to Kitimat, British Columbia	525,000[1]	Approved[2]	2019
	Trans Mountain Expansion (Kinder Morgan)	Edmonton, Alberta, to Westridge Marine Terminal in Burnaby, British Columbia	590,000	Under review	2017

1. Northern Gateway Pipeline also includes a parallel import pipeline with capacity to deliver 192,000 b/d of condensate into Alberta for blending with bitumen.
2. Northern Gateway was approved in 2014, subject to 209 conditions, but has been postponed by Enbridge. IHS expects the earliest this project could stream would be in 2019.

Source: IHS Energy

7. See the IHS Energy *Second Quarter 2014 Market Briefing: From Hardisty to Houston: Answering the call for more North American crude oil transportation capacity.*

for heavy crude, a price that Canadian crude has not always attained in the past because of its inability to reach beyond the Midwest and Rocky Mountain markets in large volumes. In the past, Canadian crude price weakness has occurred because of market access constraints—during periods, for example, when incrementally produced barrels out of western Canada had to discount to secure buyers. Increased access to the USGC would reduce this impact, because it would allow bids from a deeper and more diversified heavy crude market. Achieving price parity against Latin American heavy crude is a key objective for heavy crude producers targeting the USGC market.

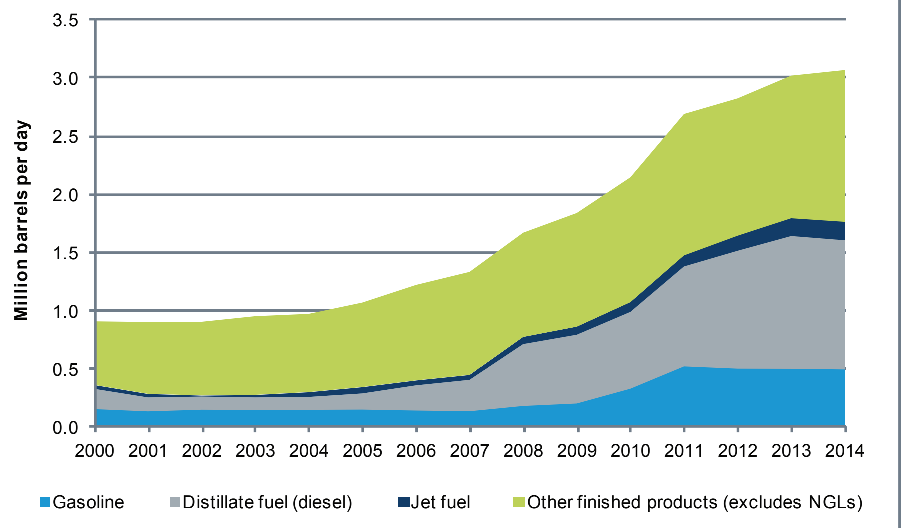
Large-scale exports of Canadian crude to offshore markets are likely only if pipeline projects to the East or West Coast of Canada (that do not cross the US border) are completed—such as Energy East, Northern Gateway, or the Trans Mountain Expansion. These projects are specifically being proposed to access Asian and other heavy crude growth markets. Moreover, it should be noted that rail has begun to be leveraged to reach offshore markets. In 2014 crude oil was railed from Alberta to a port in Quebec, where it was loaded on a tanker destined for Italy.

Will Canadian crude be processed in the USGC only to then be exported in the form of refined products? Not disproportionately so: Canadian crude will be no different from other imported or domestic barrels processed in the USGC. The USGC is the largest refining center in the world, with capacity to produce refined products well in excess of regional demand. About a third of finished products produced in USGC refineries are consumed locally, with the balance split roughly evenly between transfers to other regions of the United States and exports to international markets. These transfers and exports are essential balancing mechanisms for seasonal and longer-term demand trends in US refined products markets. Altogether, then, about two-thirds of Gulf Coast refined product is consumed in the United States.

Regardless of where USGC crude oil is sourced, this product distribution pattern is unlikely to change appreciably in the near future. Growing US exports of refined products is not a new trend: over the past decade, USGC refiners have been ramping up their exports of gasoline, diesel, jet fuel, and other petroleum products owing to their increasingly competitive economic position relative to offshore refiners (see Figure 6). This advantage derives from Gulf refinery access to low-cost input energy (natural gas), an abundance of discounted tight oil, and a high degree of both conversion capacity and petrochemical integration.

Figure 6

US refined product exports



Source: IHS; US Energy Information Administration © 2015 IHS

Canadian heavy crude oil production growth: The question is not if, but how and where

The late 2014 collapse in oil prices will slow the pace of upstream investment around the world—including in heavy crude oil development in Canada. But growth in Canadian heavy crude oil production is already largely locked in for 2015–17 owing to new projects coming onstream. Also, as oil prices eventually recover, heavy crude oil production will continue to grow in Canada. It will reach new markets—the key questions are how and where it will be delivered. The USGC is a very large natural market for Canadian crude oil. But there are other options as well—namely shipments to the east or west coast of Canada, where heavy crude could reach offshore markets. Politics—both local and international—and prices will all play a role in shaping future trade flows of Canadian oil.

Appendix A

Table A-1

Listing of known USGC refinery heavy crude supply arrangements

Refinery	Capacity (b/d)	Operator	Partner	Partnership type
Houston, TX	270,000	LyondellBasell	PDVSA	Supply agreement
Deer Park (Houston), TX	334,000	Shell	PEMEX	Joint venture
Lake Charles, LA	430,000	CITGO	PDVSA	Owner
Corpus Christi, TX	156,000	CITGO	PDVSA	Owner
Chalmette, LA	192,000	ExxonMobil	PDVSA	Joint venture
Sweeny, TX	247,000	Phillips 66	PDVSA	Supply agreement
Baytown, TX	563,000	ExxonMobil	PEMEX	Supply agreement
Port Arthur, TX	319,000	Valero	PEMEX	Supply agreement
Pascagoula, MS	330,000	Chevron	PEMEX	Supply agreement
Port Arthur, TX	610,000	Motiva	Shell/Saudi Aramco	Joint venture

Source: IHS Energy