SPECIAL REPORT

TD Economics

November 10, 2014

CANADA'S OIL PATCH TO WEATHER LOWER PRICES, LONGER-TERM CHALLENGES REMAIN

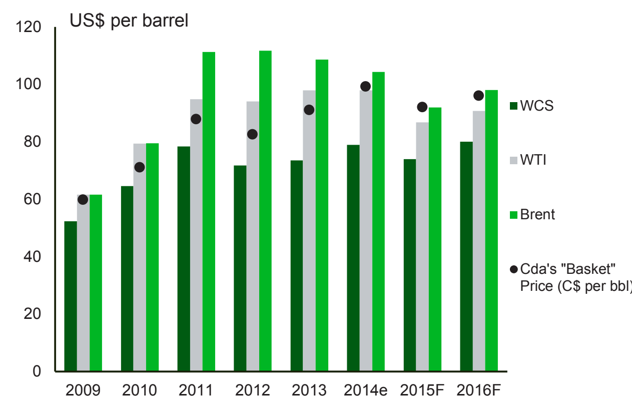
Highlights

- Canada's oil patch has been a key engine of economic growth since the recession. The roughly 25% drop in oil prices since July has understandably raised concerns about the industry's prospects and the impact on the Canadian economy. TD Economics has lowered its crude oil price forecasts for 2015 as supply growth has outstripped demand recently, and it will take markets time to adjust.
- Several factors, including a weaker Canadian dollar and lower discounts for Canadian crude oil mean that the recent hit to prices received by Canadian producers is less severe than the global oil price decline suggests. The average price of Canada's crude oil basket over the past month was 8% higher than its average level since 2010, whereas the Brent price was 10% lower.
- Looking ahead, even under TD Economics' lower oil price forecast, Canada's crude oil basket in Canadian dollar terms remains higher in 2015-2016 than it was during the 2011-2013 period. Moreover, a lower oil price forecast is not expected to crimp near-term production in Canada's oil patch. TD Economics expects Canada is on track to expand oil output 5-6% annually in barrel terms over the next couple of years.
- However, recent price declines have turned the spotlight back on some of the longer-term challenges facing the industry. Headwinds to new investment in the sector include uncertainty about wider market access, volatile price differentials, heightened public scrutiny of projects, and cost inflation. These challenges have likely already contributed to more modest capital spending growth for nonconventional oil and gas in 2014.

Canada's crude oil sector has been a key engine of economic growth in recent years. It has been a force pushing Canada's trade deficit back into surplus and punches above its weight when it comes to investment. The oil and gas industry has contributed over 20% of all private sector capital expenditures since the recession, despite only accounting for 6% of GDP by industry. Moreover, crude oil production has been one of the leading growth areas in Canada's economic landscape over the past three years. The roughly 25% drop in the price of oil since its July peak has markets understandably concerned about the industry's prospects and the potential economic fallout of lower prices on the Canadian economy.

Lower prices present a headwind to the industry, will be a hit to Canada's national income (see Of Oil and Output), and take a sizeable chunk out of government coffers of oil-producing provinces (for example, the Alberta government derives 25% of revenues from royalties). But, while we are likely to see projects with more marginal economics shelved in the coming months, the overall near-term impact on crude oil production is likely to be limited. A weaker Canadian dollar, lower discounts for heavy

CHART 1. MODEST OUTLOOK FOR OIL PRICES



Source: Haver Analytics; Forecast by TD Bank
Canada's basket is weighted using the Bank of Canada's commodity price index weights and TD Bank forecasts

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oil, a smaller differential between the North American (WTI) and the world price of oil (Brent), producer hedging, and lower natural gas prices (a key variable cost), all mean that the hit to Western Canadian producers from the recent price correction is less severe than it appears. Furthermore, while we've marked down our average annual oil price forecast for 2015 (see Chart 1). We believe that prices are at, or near, a bottom and are likely to gain some modest traction over the course of next year reflecting an improvement in global demand, and supply adjustments at the margin. All said, profits will feel the pinch in the coming months, but oil producers are used to swings in prices, and a lower price profile over the next couple of years is unlikely to prove to be the knock-out punch for the industry.

Still, the near-term price movements have turned the spotlight back on some of the longer-term challenges to the industry's expansion, the foremost being gaining access to new markets, the heightened public scrutiny of projects and the constant challenge of cost inflation. These factors have been a headwind on capital spending growth for the nonconventional oil and gas sector – which had expanded at a double-digit pace for the past ten years, but fell to a more modest 2.3% pace in 2014. A slower pace of investment spending could help cool cost inflation somewhat, as producers are more disciplined in staging the construction of major projects.

Canadian producers somewhat shielded from oil price declines

The recent decline in commodity prices, and oil in particular, has been one of the more dramatic developments on financial markets. The world price of oil (Brent) has fallen roughly 25% – to around $86/barrel – from its peak in June. Prior to the recent slide, the price of Brent crude had fluctuated within a relatively narrow band between US$107-112/barrel for over a year. The stable price environment had occurred as disruptions to OPEC supply were offset by increased U.S. production and weaker-than-expected non-U.S. global demand[1]. However, as Libyan oil production came back on the market, and global demand forecasts continued to be ratcheted down, oil markets began to look increasingly over-supplied, which led to a sharp decline in prices.

Lower prices are a benefit to net oil consuming countries, like the United States, but will be a strain on net oil exporters, like Russia. It remains to be seen how OPEC will respond to the price declines, with some countries favoring production cuts to bolster prices. Saudi Arabia has already cut production by 400,000 barrels per day (b/d), and could make further production cuts in an effort to shore up prices. OPEC meets at the end of November, and the outcome of the meeting will be critical to the market price dynamics.

The most relevant price for Western Canadian producers is WTI, the price at the market hub in the U.S. Midwest where the bulk of oil exports are shipped (see text box for a description of Canada's crude grades). Since 2011, WTI has oscillated within the US$85-$105 per barrel range. It also saw price corrections in 2011 and 2012, both slightly larger than what we have seen so far in 2014, and prices quickly rebounded. While we are not suggesting there will be a relief rally, the worst of the correction is likely behind us. There has been a recalibration of the global supply-demand balance as markets recognize softer growth in global consumption against a backdrop of healthy growth in supply. We have revised our forecast for the price of oil downward slightly (see Table 1) but we still expect prices to grind higher in 2015 and 2016, underpinned by stronger global growth.

However, it is worthwhile pointing out a couple of offsetting factors that make the recent oil price decline less severe for Canada producers. First, the "discounts" that have persisted for Western Canadian oil relative to the world price

Table 1. Oil Prices (US$ per barrel*)

	WCS	WTI	BRENT	Implied Bitumen	Canada's Crude Oil Basket**		C$	Canada's Crude Oil Basket**	
weight	*37%*	*55%*	*8%*	*(WCS less diluent)*		*% chg.*	*(in US$)*	*(C$ terms)*	*% chg.*
2009	52	62	62	49	57		0.96	**60**	
2010	65	79	79	57	71	24.8	1.01	**71**	**18.7**
2011	78	95	111	67	86	21.0	0.98	**88**	**23.7**
2012	72	94	112	59	83	-4.0	1.00	**82**	**-6.0**
2013	74	98	109	61	86	3.3	0.94	**91**	**10.3**
2014e	79	98	104	71	88	3.2	0.89	**99**	**9.0**
2015F	72	87	92	66	79	-10.2	0.88	**91**	**-8.6**
2016F	75	90	98	68	82	3.8	0.89	**92**	**2.1**

**Unless otherwise indicated. **Basket is a weighted sum of oil price forecasts, netting out cost of diluent from WCS price. Weights shown are for 2014.*

have improved dramatically over the past year. Second, commodities are priced in U.S. dollars, so the weaker Canadian dollar that has been part of the market rout means exporters' US$ revenues are worth more back in Canada. Natural gas is the single highest operating cost for in situ projects, so lower gas prices recently are also giving producers a bit of a break. Finally, oil sands producers have to dilute their bitumen with a pricey lighter oil product in order to transport it. The price of this condensate has fallen back sharply this year, lowering a key cost for bitumen producers.

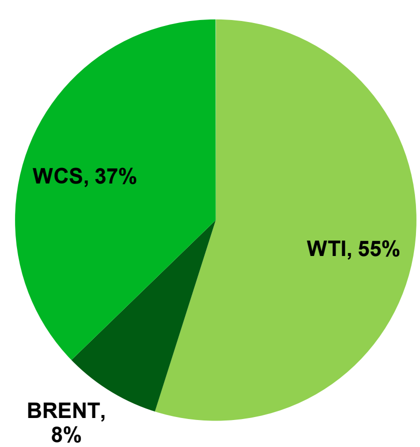
Calculating a basket price for Canadian oil producers based on the production weights in the Bank of Canada's commodity price index for energy – this includes prices for Western Canada Select (less the cost of diluent), WTI and Brent grades, and converting it into Canadian dollars helps to approximate prices received by Canadian producers in aggregate. Over the past 30 days, Canada's basket price is slightly higher than its average level over the past 4½ years, whereas the Brent price is about 15% lower (see Chart 2). True, this is a bit like being the cleanest dirty shirt. A persistently lower price environment will still be felt by Canadian producers and government coffers, regardless of where prices were in the past. But, Western Canadian producers have been dealing with a challenging pricing environment for a few years now and the potentially tougher pricing environment going forward should come as less of a shock.

Furthermore, while the spot price of oil has dropped sharply since June, market expectations for the price of oil over the longer-term has moved less (see Chart 3). Looking further out into the future, to the end of 2018, the expected price of WTI has actually shifted little from a year ago. While the spot price matters for current revenues and industry cash flow, investment decisions of oil sector projects, particularly in the oil sands are very long-term in nature and are not based

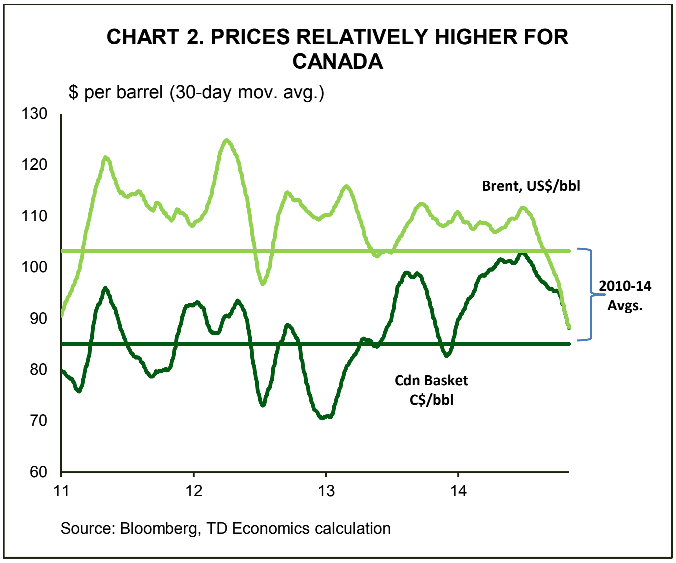
Crude oil primer

While most people think of oil as a single commodity, there are actually many different grades of crude oil, priced at different trading hubs, each with their own benchmark prices. There are separate markets for each, subject to unique supply and demand dynamics and frequently price trends diverge. From a high level, Canada's production can be grouped into three different types of crude oil and classified according to which price benchmark, roughly speaking, they are sold at. These are the three prices the Bank of Canada uses for its commodity price index – Brent, West Texas Intermediate (WTI) and Western Canada Select (WCS). Brent Crude is extracted from the North Sea and is a major trading classification of light sweet crude oil that serves as a major benchmark price for purchases of oil worldwide. Since the price of Brent diverged from WTI in late 2011 due to rising production in inland North America, the Brent price has become the benchmark for "seaborne" crude oil (i.e. crude that can easily be shipped by ocean tanker). This is the relevant benchmark price for Newfoundland's offshore oil production, which represents approximately 8% of Canada's total output. WTI is the price for light sweet crude at the inland U.S. hub of Cushing, Oklahoma. Due to rising production from Canada and tight oil formations in the U.S., and insufficient infrastructure to easily get inland crude oil to coastal markets, the WTI price had diverged significantly from the Brent benchmark starting in early 2010. Finally, WCS is for heavier grades of crude, or diluted bitumen from the oil sands, which is typically priced lower than light sweet crude (WTI) due to greater refining requirements. This grade has been particularly volatile in recent years, ranging from a low of only $8 less per barrel than light crude to a high of $42 less per barrel. This heavy differential can be affected by many market forces, such as refinery shutdowns. Digging a bit deeper, the WCS price isn't actually a pure bitumen price, it is diluted bitumen, which means producers have to blend bitumen with a lighter product – condensate – so that it will flow through pipelines, and a barrel of WCS includes roughly 30% condensate. Backing the price of condensate out of WCS yields an implied bitumen price, which can differ depending on the price of condensate. The chart below shows what portion of Canadian oil production is priced at each benchmark.

CANADA'S CRUDE OIL BASKET



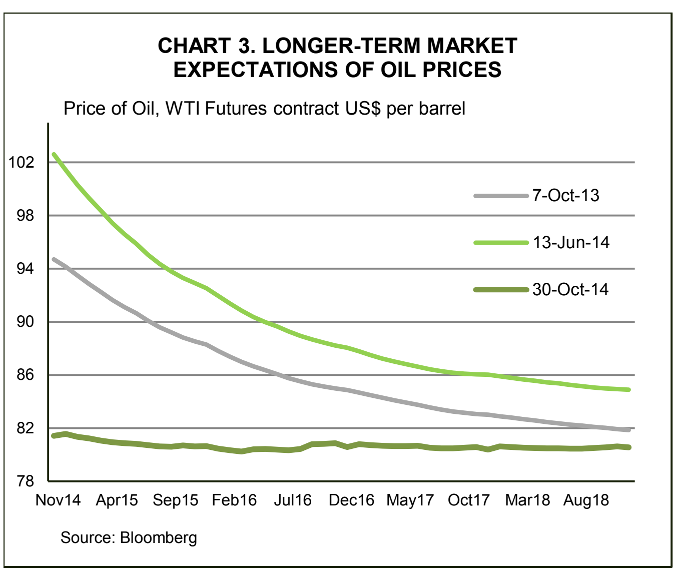
Source: Bank of Canada



solely on the spot price.

TD Economics does expect the price of oil to grind higher next year as global growth improves and oil supply adjusts at the margin. In fact, the recent fall in the price of oil should provide a boost to global growth. A drop in the price of oil acts like a tax cut, allowing consumers to spend more on other things. This is offset somewhat by lower incomes for oil producers, but on net, global growth should receive a boost from lower prices.

While oil prices are expected to trend up from their current levels in 2015, they will likely be lower on an annual average basis versus 2014 (see Table 1). This is due to the high prices seen earlier in 2014 as significant geopolitical uncertainty due to Russian incursions into Ukraine and ISIS violence in Iraq kept prices elevated. However, a weaker Canadian dollar will mute the impact of the price decline for Canada's basket price measure. Moreover, prices for Canadian producers are expected improve once again in 2016. Canada's basket price in level terms should also remain higher than it was during 2011-2012, the worst period of discounting for both heavy oil (WCS) and WTI versus Brent. So, while producing countries that receive Brent pricing are expected to see lower prices versus the 2011-2012 period, pricing for Canada as a whole, should actually be slightly better.



Crude oil production to grow strongly over medium term

According to Statistics Canada, production of crude oil is up 6.4% in volume terms from January to July, versus last year. That is in line with the 6.7% average annual growth in production since the recession. This is an enviable growth rate. It is unlikely the industry will keep up this blistering pace over the next couple of years. But, production still looks set to grow at a respectable 5-6% pace in barrel terms over the next two years.

The price declines we've seen so far will no doubt crimp profits in the industry, but they are unlikely to have too much short-term impact on Canada's oil production. Industry "break-evens" are often quoted in the media, but are frequently misinterpreted as production break-evens, when in fact they are the price required for investment in *new* capacity to generate an acceptable rate of return. Operating costs for current output are much lower, and producers are unlikely to turn off the taps due to short-term price fluctuations. However, the lower cash flow will mean that companies have less funds available to invest in expansion down the road. Supply, at a global level, will eventually adjust, but it will take some time before we see this impact in overall production.

Demand for Canada's barrels remains, even if it is at a lower price. Increases in fuel efficiency mean that growth in oil consumption is very modest in North America, so it begs the question, where will the market for this production growth come from? While Canada continues to lack easy access to overseas markets by tanker, there is still room for Canadian oil to gain market share both at home and in the United States. Ultimately, it is best for the industry to have access to diverse markets, particularly in Asia where demand growth is expected to be much stronger. But, until then, expected production growth can still be met through markets within North America.

More oil to flow east within Canada

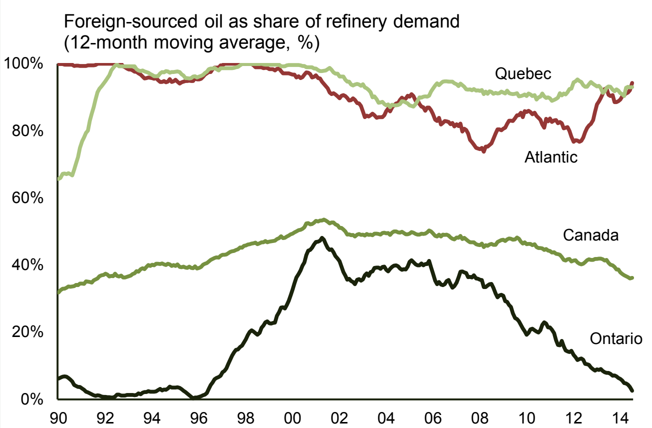
Similar to many advanced economies, demand for refined petroleum products is quite flat in Canada. However, there is still room for Canadian crude oil producers to expand their markets within Canada by accessing refineries in Eastern Canada. Canada may be a net exporter of crude oil, but refineries in eastern provinces have traditionally relied on imported oil, as that was the lower cost option relative to shipping Western Canadian crude across the country. Since 2007, the share of foreign-sourced oil in Canadian refineries has steadily decreased, and over the last 12 months accounts for 36% of oil shipped to refineries. This has primarily been driven by a falling share of imports used in Ontario refineries (see Chart 4). Quebec and Atlantic Canada still refine more than 90% foreign-sourced oil.

However, that is set to change in the near future. Enbridge's Line 9B, which runs from Ontario to Montreal, and in recent years transported foreign oil to Ontario refineries, is set to be reversed. The pipeline originally carried oil west-to-east, but shifting market dynamics saw it reversed in the late 1990s. This reversal would enable more Western Canadian oil to reach Quebec refineries, and potentially be exported via the St. Lawrence River.

Line 9B's capacity will be approximately 300K b/d (thousands of barrels per day), enough to supply the Montreal refinery (see Table 2), and much of the refinery outside Quebec city. Valero, who operates the refinery outside of Qeubec City, plans to use oil tankers to transport oil the remaining distance down the St. Lawrence River to their refinery[2].

Farther out on the horizon, TransCanada's proposed

CHART 4. CDN REFINERY FEEDSTOCK INCREASINGLY DOMESTIC



Source: Statistics Canada, Table 126-0001

Table 2. Oil Refinery Capacity in Eastern Canada

Name	Location	Capacity (b/d)
Suncor	Montréal, QC	137
Valero	Lévis, QC	265
Irving	Saint John, NB	320
North Atlantic*	Come by Chance, NF	115
	Total	**837**

Source: The Canadian Association of Petroleum Producers
*Largely supplied by offshore production from Newfoundland

Energy East project would be a mix of new pipeline and conversion of existing natural gas pipeline to oil, in order to transport 1.1 million b /d to refineries in Quebec, and further on to Saint John. It would also include building two export terminals, one on the St. Lawrence River in Quebec and the other in Saint John to enable exports by tanker. This project is longer-term in nature, expected to optimistically be in service at the end of 2018 (see Table 3). The Canadian Association for Petroleum Producers projects that an incremental 300K b/d of demand for Western Canadian crude oil will come from domestic refineries by 2020[3], but it is likely the tally will be higher than that.

Canada to gain further U.S. market share

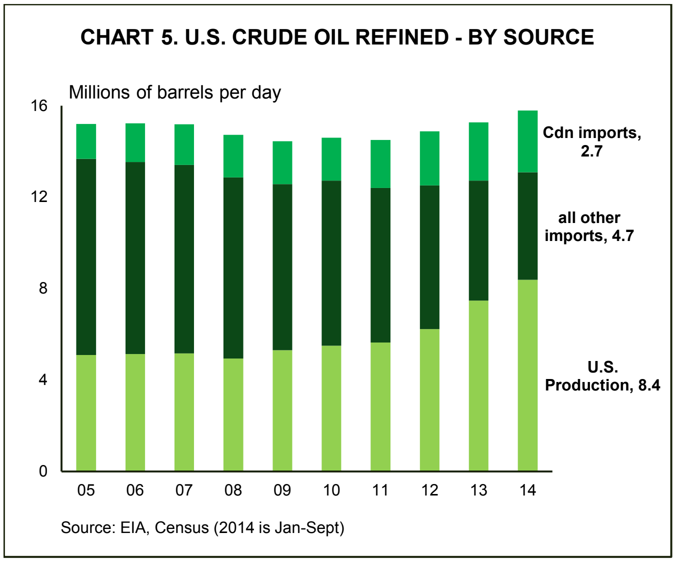
As the U.S. surpasses Saudi Arabia this year as the world's largest oil producer, there is a misconception out there that U.S. energy "independence" will spell the end of this key market for Canada. The reality is far different. Canadian crude oil exports to the U.S. have continued to grow despite the increase in shale oil production south of the border, gaining market share. Recent debottlenecking in the U.S. enabled by pipeline expansion to the U.S. Gulf Coast, and increasing use of rail to ship oil, means that Canada's crude oil exports to the U.S. are expected to continue to

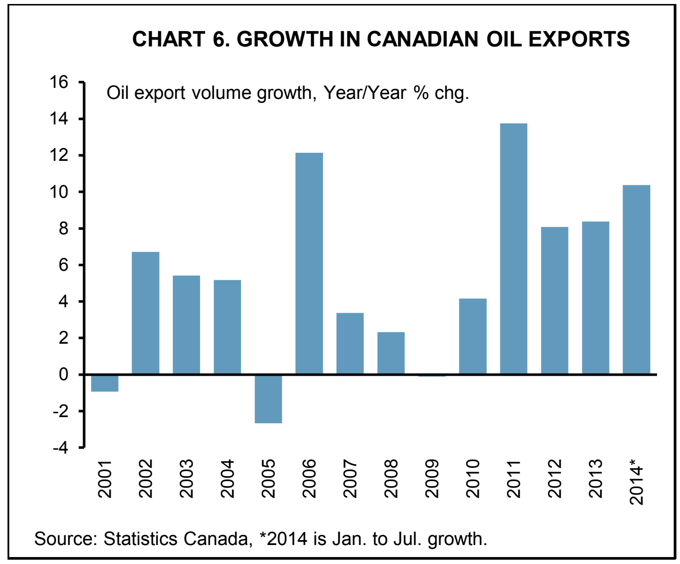
Table 3. Proposed Western Canada Export Capacity Additions

	capacity (000s b/d)	Target in-Service
Rail (end of 2015)*	700	end 2015
AB Clipper expansion (Q3 2015)	350	Q3 2015
Keystone XL (2017**)	830	2017**
Trans Mountain expansion (by 2018)	590	Q4 2017
Northern Gateway (Q3 2018)	525	Q3 2018
Energy East (Q4 2018)	1,100	Q4 2018
Total propsed capacity additions	**4,095**	

** Could be as high as 1.4 Mbpd*

*** If approved by end of 2014*





grow in the near term.

True, the shale oil revolution in the U.S. has enabled that country to dramatically increase its oil production, which combined with flat demand for petroleum products, has seen oil imports drop. However, due to proximity and extensive pipeline network, Canada has still increased its exports to the U.S. market, while most other suppliers have seen their share fall (see Chart 5). Moreover, there is still room for Canada to expand its exports into the U.S. market, backing out overseas suppliers.

The U.S. remains the world's largest consumer of crude oil. The media has written a lot on the potential for energy independence in the U.S., but for oil, as Chart 5 shows, that is a long way off. The Energy Information Administration's (EIA) current forecast sees the U.S. continuing to import crude oil though to 2030, and Canada is likely to be an increasingly important part of those imports.

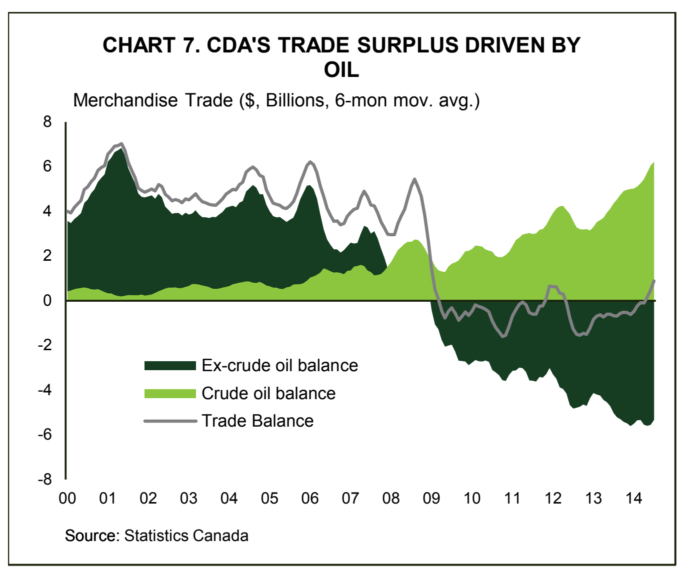
Despite pipeline concerns, export growth has been strong

For the past few years, Canada's oil sector has emphasized how it is essential to build new export pipeline capacity to enable the future growth in the sector, and to diversify markets. Market diversification is important to prevent the steep discounts producers faced in recent years due to their singular dependence on the oversupplied U.S. Midwest market. Despite these discounts, Canada has continued to post impressive year-on-year gains in crude oil exports, largely to the United States (see Chart 6). This has been achieved in part by pipeline capacity expansion in the U.S. which has helped to debottleneck the Cushing, Oklahoma hub, and by the increased use of rail.

In fact, Canada's trade surplus in crude oil has expanded in recent years, and has helped improve Canada's trade position (see Chart 7). Crude oil has accounted for roughly 18% of Canada's goods exports so far in 2014. As crude exports continue to expand, and Eastern Canadian refineries process more Western Canadian oil, thereby reducing Canada's imports, Canada's crude oil surplus should continue to grow.

Trains help fill the gap

With pipeline bottlenecks and high price differentials between in-land oil production and coastal markets in recent years, the growth in shipping of crude oil by rail has been impressive. Current crude-by-rail loading capacity is estimated to be 300K b/d in Western Canada, and is expected to increase to 1 MMb/d by the end of 2015. Rail enables crude



oil to reach markets not currently accessible by pipeline. In 2013, 45% of crude-by-rail exports went to the U.S Gulf Coast, 44% went the U.S. East Coast (PADD 1) and 9% to the West Coast (PADD 5).

At first glance, rail looks cost prohibitive relative to pipelines on a cost-per-barrel basis, and initially seemed to only be a short-term solution to pipeline bottlenecks. However, the very long timelines for pipeline approvals, and other advantages of shipping crude oil by rail has triggered a massive investment in rail loading infrastructure in North America.

There are several advantages to shipping crude oil by rail which help to offset the higher cost. These include[4]:

1. Speed to market – oil travelling by train gets to the refinery faster, and loading terminals can be constructed in less than a year
2. Flexibility – the ability to reach markets inaccessible by pipeline using existing tracks
3. Lower diluent cost (see text box) – less or no diluent is required to ship bitumen in rail cars, representing a significant cost savings to bitumen producers. There is also the ability to backhaul diluent from lower-priced markets on the U.S. Gulf Coast
4. Scalability – producers have the ability to adjust volumes shipped
5. Product integrity – since oil can be isolated in rail cars, it easier for Canadian crude oil to by-pass the U.S. export ban[5]
6. Low capital cost – rail terminals cost between $3-50 million with a capital payout of five years or less.

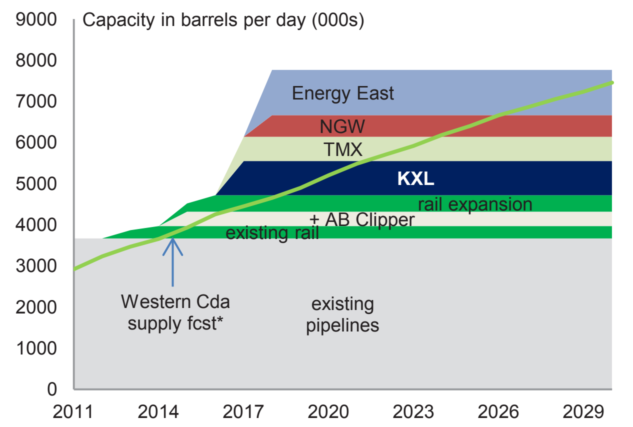
It's clear from the investments being made in rail infrastructure that it is likely to play a key role in transporting crude oil over the near and medium term. And, given the advantage listed above, particularly for transporting bitumen, it will likely still have a niche roll to play even when differentials come to more "normal" levels.

Add it all up and with the addition of rail shipping capacity, the current forecast for production growth is attainable even with the long timelines of the major export pipeline proposals (see Chart 8).

Future investment in Canada's oil patch faces challenges

Given the recent declines in oil prices, worries have increased about planned investment in Canada's oil patch, and particularly in the oil sands. A couple of high-profile

CHART 8. PROPOSED EXPORT CAPACITY ADDITIONS WESTERN CANADA

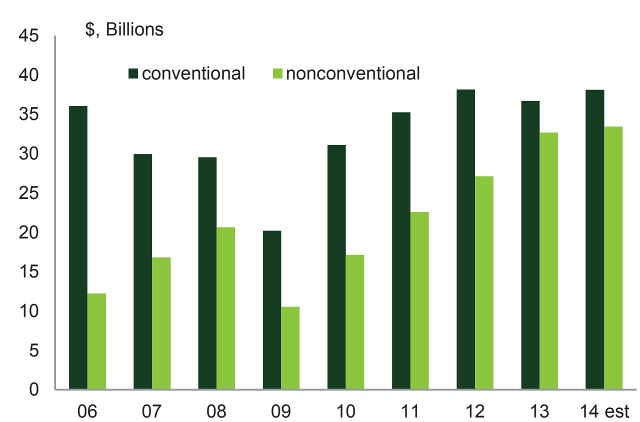


Source: *CAPP

projects have been shelved in 2014, lending support to the view that market access challenges and now lower prices are sounding the death knell for further investment in the sector. The challenge of market access is long-standing, and has likely been a factor in the pace of planned investment spending in the nonconventional oil sector slowing notably in 2014 (see Chart 9).

With lower prices, there is much discussion of whether planned oil sands expansions are still "economic" at the new price reality. Each oil sands project faces its own cost structure and break-even price hurdle that depends on a variety of factors, including the quality of the resource. The method of extraction also affects the hurdle rate for new investment. Oil sands development can be either mining or in situ, with mining projects being higher cost, and requiring

CHART 9. NONCONVENTIONAL OIL INVESTMENT HAS GROWN DESPITE CHALLENGES

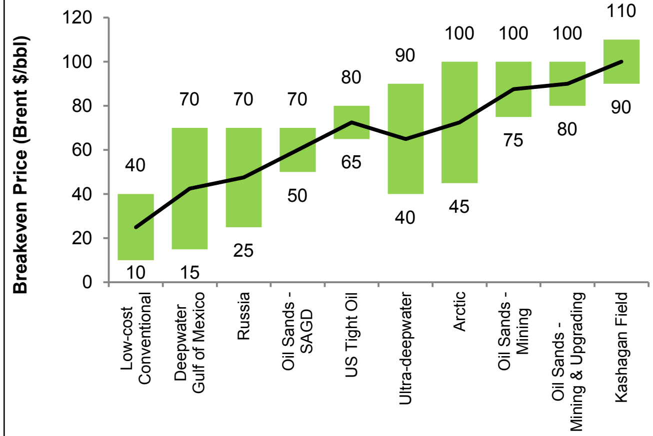


Source: Statistics Canada, Investment Intentions a higher oil price to break even (see Chart 10). Moreover, expansions at existing facilities (brownfield) as opposed to new projects (greenfield) have a lower hurdle price. These realities mean that much of the growth in production over the coming years is expected to come from in situ developments, and many companies have been emphasizing expansions at existing facilities. Moreover, as development in the oil sands regions matures, more production is likely to come through expansions at existing facilities, rather than new greenfield expansion, dampening the pace of investment growth going forward.

While the lower price forecast undoubtedly means some higher-cost projects will be shelved, most in situ expansions still look profitable given our oil price forecast, and many mining projects too. Cost inflation also remains a constant concern. Compared to the pre-recession period when the price of oil rose at a double-digit pace over an eight year period; the post-recession price environment, particularly in Western Canada, has remained far more modest forcing companies to be more aggressive at containing costs.

For example, earlier this year the $11 billion Joslyn oil sands mine development was suspended, and industry watchers highlighted the difficult economics of oil sands mining expansion. However the companies involved have in fact applied to expand the project by more than 50% in order to improve the economies of scale of the project and to better align its timing so it isn't competing for labour and resources with other mega projects under construction. Suncor, who is a joint-venture partner on Joslyn, is also currently building the Fort Hills mining project and has no desire to fuel cost inflation by building simultaneous projects. This is one example that shows the industry is becoming more disciplined about staggering development

CHART 10. GLOBAL PRICES REDUCE INCENTIVES FOR HIGHER COST PRODUCTION

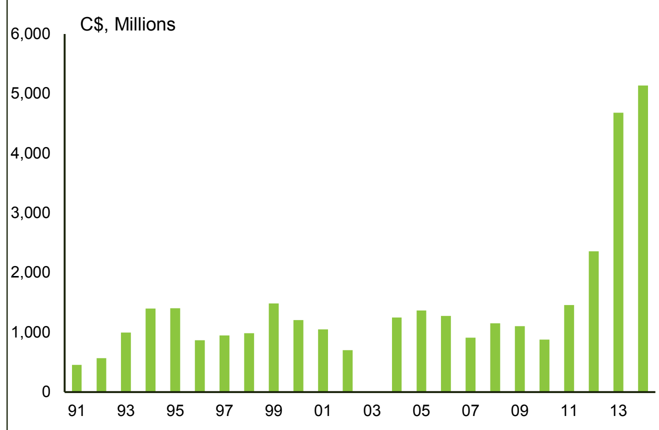


Source: TD Securities, Rystad Energy, CITI Research, Enbridge, Company Reports, Other contributors.

Newfoundland & Labrador Offshore Oil Production

Newfoundland's oil production occurs offshore, and has access to Brent-linked pricing, so it is often influenced by different factors than the industry in Western Canada. Because it is small relative to Canada's total production, it is often dwarfed by concerns in Western Canada's oil sector. Newfoundland's offshore oil production may only account for 7% of Canada's output, but it is the largest contributor to GDP in the province. The industry accounts for approximately 30% of total provincial revenues and 28% of GDP. Capital spending by the industry has accounted for about half of all private sector investment in the province in recent years. After a slow start to 2014, oil production in the province is projected to be fairly flat for 2014 as a whole, but is expected to pick up again in 2015-16. Longer-term, production has been declining offshore due to natural declines at the Hibernia field. Investment in the sector has grown by leaps and bounds in recent years (see chart). In fact it has grown much more strongly in percentage terms than in Alberta, since the recession. Industry hiring has also been very strong in 2014. Investment has ramped up in preparation for the fourth offshore project, Hebron, which is expected to start producing in 2017. Hebron is expected to help offset declining output at older fields in the coming years.

OIL & GAS INVESTMENT HAS SURGED IN NEWFOUNDLAND & LABRADOR



Source: Statistics Canada

to contain cost inflation.

Another example shows that even in situ developments are not immune to challenges. Statoil recently shelved its in situ Corner development. Once again, it cited cost inflation, but it also was the first delay to cite the issue of pipeline access as being an increasing challenge to the economics of the project.

Under TD Economics's price forecast, most investment in oil sands expansions remain profitable. However, prices are not the only concern, and Canadian producers have been dealing with a tougher environment.

The oil sands' environmental challenge

Another headwind the industry faces is increased public scrutiny of its environmental impact. The industry is being held to higher public scrutiny on its operations and expansion projects. Canada's oil sands industry faces many concerns on many fronts, including local pollution and environmental impacts in the production region, and risks of spills during transportation. But greenhouse gas (GHG) emissions from production have become a high-profile concern globally. Oil sands production is often singled out for being particularly polluting or producing more greenhouse gas (GHG) emissions during the extraction process. For example, the EU's planned fuel quality directive was intended to require fuel suppliers to reduce their GHG-intensity of their fuels by 6% from 2010 levels by 2020. Initially, oil sands were going to be singled out as a high emission source of oil. The part of the regulation singling out oil sands has now been dropped.

There is considerable confusion about emissions. The lifecycle emissions of crude oil, often referred to as wells-to-wheels, differs depending on the extraction process and type of crude oil. Final combustion of the oil (mainly from the tailpipe of our cars) is responsible for 70-80% of GHG emissions, and depends on the efficiency of the vehicle not the fuel source[6.] Wells-to-wheels emissions from oil sands crude oil are higher than most conventional oil sources worldwide. However, emissions are within the range of heavier crudes such as those from Venezuela, California heavy and lighter crude production that flares associated gas (Nigeria).

Through technological progress, the per barrel GHG emissions from the oil sands has fallen 26% since 1990. However, overall emissions have grown as production growth has dwarfed efficiency gains. Oil sands accounts for roughly 8% of Canada's GHG emissions, but due to the impressive growth in the industry, it has produced 36% of the growth in Canada's GHG emissions from 1990-2011[8]. Alberta is the only jurisdiction in North America that has mandatory reduction targets for large emitters across all sectors. Large emitters must meet mandatory reduction targets or pay $15 per tonne into a clean energy fund or purchase carbon offset credits.

The Government of Canada has stated that it is working on GHG emissions regulations for the oil and gas sector. It has been pursuing a sector-by-sector approach, with regulations on coal-fired electricity released in 2012. So far, no draft regulations for oil and gas have been released. Most recently, the government has indicated that it wants any regulations to be imposed in concert with the United States. The government is hoping to do this over the next couple of years, but at time of writing there was no firm timetable for any GHG regulations for oil and gas.

Recent work conducted by University of Alberta economists (Leach and Boskovic 2014) explore the impact on the returns to oil sands projects of a variety of GHG regulation scenarios[8]. Their analysis shows that overall future production from the oil sands could be adversely affected by a carbon price applied broadly on consumption, depending on to what degree the incidence of tax is born by producers or consumers. But, a levy on production emissions alone has a minimal impact on a project's returns. A charge on production emissions might have an added benefit of improving the ability of Canada to diversify its markets, by helping to ameliorate concerns about higher GHG emissions from oil sands production.

The Bottom line

2014 started out looking pretty good for Canadian oil producers, discounts were down, exports were booming and prices were high. The recent price slide, however, has knocked some wind out of the sails of the sector. Going forward, near-term production growth should still be a key driver of Canadian exports and the broader economy. However, there are clouds on the longer-term investment horizon, many of which have been the same for several years now, such as longer-term market access, cost inflation and the impact of potential GHG regulations. Now a lower price backdrop is also casting a shadow. The industry has already weathered a difficult pricing environment in recent years, and is likely better prepared to endure the current slump. Moreover, we do not expect the price correction to be long-lived, with prices expected to grind gradually higher over the coming years, in line with stronger global growth.

End Notes

1. EIA http://www.eia.gov/petroleum/weekly/archive/2014/140924/includes/analysis_print.cfm
2. http://business.financialpost.com/2014/03/20/valero-strikes-deal-to-ship-line-9-crude-from-montreal-to-quebec-city-by-tanker/?__lsa=6182-0372
3. CAPP "Crude Oil Forecast, Markets and Transportation" June 2014.
4. CAPP "Transporting Crude Oil by Rail in Canada" March 2014. http://www.capp.ca/getdoc.aspx?DocId=242427
5. Due to export restrictions on US crude oil, Canada can only export its crude oil out of US ports if it can prove that it hasn't co-mingled with any U.S. oil. This is easier to prove if the shipment came in a railcar than in a pipeline.
6. http://www.oilsands.alberta.ca/ghg.html
7. http://www.oilsands.alberta.ca/ghg.html
8. Branko Boskovic and Andrew Leach. 2014. "Leave it in the ground? Incorporating the social cost of carbon into oil sands development".