

## Executive Summary

- Given the current export infrastructure available in western Canada, the ongoing ramp-up of oil-sands production in Alberta risks overwhelming existing takeaway capacity in the near term and hence further steepening the already sheer discount at which the Western Canadian Select (WCS) benchmark trades to West Texas Intermediate (WTI). The overwhelming majority of oil-sands output is currently shipped to refiners in the US Midwest and priced off the WCS benchmark. So absent a material expansion in Alberta's export capacity over the rest of this decade the commercial viability not only of planned new oil-sands projects but also of existing plays will become increasingly questionable, with most new projects simply unviable and existing plays at risk of having to shut in a growing share of their production. In short, the economic stakes at issue over new export infrastructure for oil-sands output could hardly be higher, and it is against this backdrop that the proposed Keystone XL (KXL) pipeline has assumed such extraordinary significance.
- The proposed KXL pipeline would link Alberta with the US Gulf Coast (USGC), providing 830kbd of new export capacity in total, of which we estimate that c.730kbd would be available for oil-sands producers and c.100kbd for US tight-oil producers in the Bakken plays. As such, approval of the KXL pipeline would offer a twofold boon to Alberta's oil-sands producers: (i) it would relieve the growing pressure on existing export routes, and hence on WCS prices in the US Midwest; (ii) by establishing a direct link to the USGC it would potentially enable some oil-sands producers to achieve greatly improved pricing as the WCS blend is close in quality to that of the Mexican Maya benchmark, which generally trades very close to the WTI price. There are, though, uncertainties over the amount of capacity available to refine higher levels of oil-sands exports to the Gulf.
- KXL requires approval from the US State Department, with a key consideration in its decision-making process being the extent to which KXL would create additional CO<sub>2</sub> emissions beyond what would be emitted by the future expansion of oil-sands production even without KXL. At this stage it is unclear whether KXL approval might be contingent upon some form of CO<sub>2</sub>-pricing to cover any emissions deemed additional, but we think that even without CO<sub>2</sub> pricing the improved economics offered by KXL would be far less clear-cut than widely assumed such that future oil-sands projects would still be highly risky.

## The Keystone XL Pipeline (KXL): A Potential Mirage for Oil-Sands Investors

*The Carbon Tracker Initiative has focused on the mismatch between a global carbon budget that delivers a 2°C climate outcome and the amount of carbon already potentially ready for release in fossil-fuel reserves and resources. This has led to a new focus on the impact of developing high-cost, high-carbon content fossil fuels in terms of wasted capital and potentially stranded assets.*

*This analysis looks at the implications for the project economics of different Canadian oil-sands export options with particular emphasis on KXL.*

*We find that without export options such as KXL, oil-sands production with break-even costs of \$65/bbl and above makes little economic sense. With KXL, there is more return but the economics remain weak and risky particularly as the costs of production will rise in coming years to \$75/bbl and above. This is also the case with transport by rail. Increased production therefore looks like a bet on strongly rising oil prices with little or no cost inflation.*

*So, KXL has the potential to be a catalyst for additional production. This has led to the discussion of carbon offsets which would increase prices further. From a carbon-budget perspective this is an unsustainable outcome laying the foundations for what may then become stranded assets.*

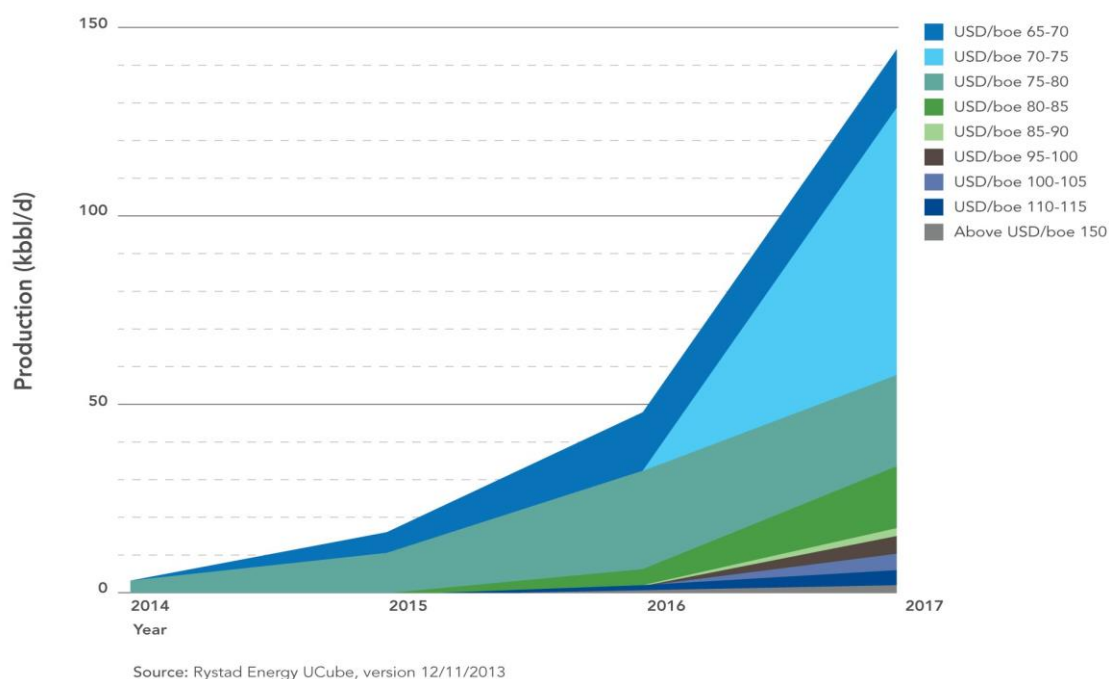
### Analysts CTI: External Research Advisors:

James Leaton	Mark Fulton
Reid Capalino	Mark Lewis
Luke Sussams	

- Although KXL would offer short-term pricing upside to oil-sands producers (and potentially significant upside), there are also increased risks to costs for the industry entailed by the approval of KXL: (i) to the extent that KXL approval would be seen as a major political milestone green-lighting the further expansion of the industry, it would likely lead to an immediate burst of new activity and thereby continue and intensify the trend observed in the last two to three years whereby costs in Alberta have risen much faster than relevant benchmark prices (indeed our key source for production costs sees break-even prices rising in the coming years); (ii) KXL would only provide temporary relief to the oil-sands industry, as the extra capacity it offers would likely be contracted very quickly, such that further production increases would require more new infrastructure and hence potential further cost increases and/or approval delays; (iii) adding KXL would in our view encourage increased production and hence additional emissions, and even if CO<sub>2</sub> offset pricing were to be introduced only at the margin, this would increase costs by a non-trivial \$2/bbl; (iv) there is a risk that new heavy-oil refinery capacity would be needed on the USGC, implying material capital outlays and hence weaker margins than a simple comparison of the current spread between the WCS and Maya benchmarks would imply.
- Despite recently announced plans for multiple new rail-loading terminals within Canada, rail transport is unlikely anytime soon to displace pipelines as the preferred means of exporting heavy oil from Western Canada to the US. Key reasons for this include: (i) a need to build out specialized infrastructure such as “heated-and-coiled” rail cars and heated storage facilities; (ii) logistical challenges (e.g. loss of time waiting for bitumen to heat up for unloading) that disadvantage the economics relative to rail transport of conventional, light oil; (iii) potentially stricter safety regulations in response to recent oil-train crashes in Quebec and Calgary; and (iv) the current reluctance of Canadian heavy-oil producers to provide the “firm-throughput” commitments that Gulf Coast refiners require to justify the investment in building heated-rail-unloading facilities. Again, the economics of production with transport by rail are risky.
- In the final analysis, oil sands are at the upper end of the upper quartile of the global industry cost curve and are more carbon-intensive than conventional crude oil; as such they should immediately hit investors’ higher-risk screens. Although the International Energy Agency (IEA) assumes rising oil prices over the long term, it also sees rising industry costs, while many market analysts see downward risk to WTI prices in the short term as US tight-oil production continues to ramp up. As WTI is the ultimate benchmark for all oil sold in North America, this has to be a further concern for oil-sands producers, and hence another flashing light for investors.
- From the standpoint of a global carbon budget, continued investment in oil sands signals either: (i) an increasing likelihood that emissions from unconventional oil-and-gas production will be decisive in pushing global CO<sub>2</sub> emissions beyond a 2°C threshold as less than a third of global oil, coal and gas reserves can be commercialized by 2050 if climate goals are to be met, or (ii) that investors are in effect allocating more capital toward assets that are likely to become stranded as a result of more stringent emissions regulation. Indeed, both Canada and the US need to reduce greenhouse-gas emissions by 80% by 2050 if the budget is to be achieved. Both countries are committed to cuts of 17% by 2020 from 2005 levels. While the US is on track, Canada's emissions are way off course; large-scale projects that increase emissions in either country or both therefore simply do not help.

*This note seeks to deepen understanding of the economics underlying oil-sands projects, as well as how construction of TransCanada's proposed KXL pipeline might affect those economics. A large part of the debate over KXL has focused on whether the pipeline, by spurring increased production from oil sands, will result in a net increase in CO<sub>2</sub> emissions. Surveying many market studies we conclude that KXL would indeed prove a catalyst for more production, but also – and crucially – for more investment and hence, in time, even greater production.*

*We consider how KXL might improve highly uncertain project returns enough to tempt producers to move ahead. Our analysis is based around data from Rystad showing very wide ranges of break-even prices for production of between \$65/bbl and over \$100/bbl for new “in situ” facilities.<sup>1</sup> Other research confirms this range. To be conservative our analysis focuses on the bottom end of that range but over the next few years \$75/bbl looks more like the median price.*



### **Using the \$65/bbl starting point we look at a pre- and post-KXL set of results.**

*Assuming minimal carbon offset costs, KXL can shift projects from being unprofitable to being marginally profitable. This change occurs owing to the higher price for heavy crude in the Gulf Coast (where refiners may be willing to pay prices equivalent to the Maya benchmark for heavy Mexican crude) relative to in the US Midwest (where the benchmark price for Western Canadian Select has recently traded at a \$40 discount to the West Texas Intermediate for light, sweet oil). Results are similar for a rail-based analysis. This suggests that: (i) investors in oil-sands projects are banking on a prolonged period of high oil prices generally, with no cost inflation or continued discounting; and (ii) given the moderate profit margins even under favorable assumptions, investors in such projects will continue to face significant risks irrespective of the outcome of KXL.*

<sup>1</sup> One outlier exists between \$50-55/bbl break-even price for Cenovus's Foster Creek Phase 1F project.

Cost type	(\$/barrel of bitumen transported)*	No KXL			KXL	
<b>Break-even Price<sup>(1)</sup></b>	Base case	\$65.0	\$65.0	\$65.0	\$65.0	\$65.0
<b>Bitumen Transport Costs<sup>(2)</sup></b>	Pipeline to USMW	\$8.0				
	Rail** to USGC (raw bitumen)		\$24.0			
	Rail to USGC (diluted bitumen)			\$24.0		
	Pipeline to USGC				\$11.0	\$11.0
<b>Diluent Transport Costs<sup>(3)</sup></b>	Pipeline to USMW	\$3.1				
	Rail to USGC (raw bitumen)					
	Rail to USGC (diluted bitumen)			\$4.9		
	Pipeline to USGC				\$4.3	\$4.3
<b>Diluent Differential Loss<sup>(4)</sup></b>	Pipeline to USMW***	\$11.0				
	Rail to USGC (raw bitumen)					
	Rail to USGC (diluted bitumen)			\$1.7		
	Pipeline to USGC				\$3.3	\$3.3
<b>Total Transport Costs</b>		\$22.1	\$24.0	\$30.6	\$18.5	\$18.5
<b>Oil price</b>	WCS 2015	\$69.0				
	Maya 2015		\$89.0	\$89.0	\$89.0	\$89.0
<b>Producer netback after transport (Oil price - transport costs)<sup>(5)</sup></b>		\$46.9	\$65.0	\$58.4	\$70.5	\$70.5
<b>Profit / Loss (netback - break-even price)<sup>(6)</sup></b>		-\$18.1	\$0.0	-\$6.6	\$5.5	\$5.5
<b>Carbon Offset Costs</b>	Incremental increase				\$2.0	
	Production increase					\$16.0
<b>PNL after offsets<sup>(6)</sup></b>					\$3.5	-\$10.5

\* Note that these figures are per "barrel of bitumen transported"; for all transport options other than rail transport of raw bitumen, use of diluent alters the energy density of the product being transported - making simple \$/bbl figures inappropriate for comparing different transport options.

\*\* Rail costs in the midpoint of range between (more expensive) manifest trains and (less expensive) unit trains.

(1) Break-even price is the price at which the NPV equals 0. This is done on an asset level but can be aggregated up to a company level. For production, all the expected future production of the asset is taken into account. This includes the production from newly drilled wells, and also the base production from wells already drilled. The oil price is assumed flat with 2.5% inflation. The breakeven price is calculated for the free cash flow. This is in other words after deducting royalties, government profit, income tax and capex and opex. Calculation assumes a 10% discount rate.

(2) For pipeline, "Bitumen Transport Costs" include \$2.40/bbl in "Alberta hub costs," which include the cost of transporting and storing bitumen at a hub within Alberta; the balance reflects the cost of pipeline tolls to the US. For rail, "Bitumen Transport Costs" reflects fixed (i.e. terminal and rail lease) and variable costs of rail transport.

(3) Reflects added pipeline tolls/rail fees from having to transport greater volumes of a diluted product (relative to transport volumes for an undiluted product). For pipelines, assumes product is 28% diluent and 72% bitumen; for rail, assumes product is 17% diluent and 83% bitumen.

(4) This table is based upon a bitumen-equivalent set of calculations for consistency across transport options. Accordingly, we adopt the methodology for dealing with the cost of diluent that reflects the added cost due to the difference in \$/bbl-price between what a producer pays for diluent in Edmonton and is paid for diluted bitumen in the US Midwest or US Gulf Coast -- in this case WCS or Maya. Assumes a price for diluent (C5+ Edmonton) of \$97/bbl. Assumes same diluent/bitumen ratios as listed above. Note that there is some uncertainty among commentators as to the exact configuration of diluents-differential economics. \*\*\*In particular, this methodology leads to a significant net-diluent cost in USMW.

(5) Reflects the price a producer receives net of transport and diluent-related costs. Note that in order to facilitate comparison across different transport options these "netbacks" are calculated on a bitumen-equivalent basis (i.e. by looking at the cost of shipping one barrel of bitumen across all different transport options). Offset costs are excluded, as this analysis considers those to be costs related to production.

(6) Profit/loss is after producer netback post transport less the break-even price.

*The above results suggest that KXL can improve economics enough to stimulate extra production and therefore emissions. Moreover, extra revenues resulting from higher off-take prices -- and reflected in improved equity valuations and credit ratings for oil-sands producers with KXL in place -- will likely encourage further investment in oil-sands production. Without sustained high oil prices, however, in the long term such projects may still result in wasted capital and stranded assets.*

## Acknowledgements

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## 1. Background

### *Canada's oil sands and a 2°C global carbon budget*

Carbon Tracker has brought the concept of carbon budgets to the financial markets, getting analysts thinking about what the implications of reduced demand and lower prices may mean for their view of the market. The IEA has confirmed that two-thirds of global proven coal, oil and gas reserves cannot be burnt unmitigated within a budget which restricts global warming to 2°C.<sup>1</sup> This has been matched against known listed fossil-fuel reserves to show a clear mismatch between a sustainable climate outcome and burning those reserves. Given that some reserves will become "unburnable" over the next few decades in a transition to a low-carbon economy, the market is starting to see that the most expensive and carbon-intensive fossil-fuel reserves are least likely to have a place within the carbon budget.

### *Questionable economics -- oil sands at the wrong end of the cost curve*

In order for any large infrastructure project to attract the capital needed to develop it in the first place, it must offer potential investors the prospect that over its lifetime it will: (i) pay back all of the costs associated with it; and (ii) give them the rate of return on their capital appropriate to the level of risk they see associated with it. As oil fields have long lifetimes (generally 30 years or more in the case of oil-sands projects), estimating these costs – and the revenues required to cover them while also giving the desired rate of return on their capital investment – is a complicated exercise that entails detailed modelling of future costs and cash flows under a range of different scenarios for the key variables.

Since oil projects ultimately produce oil sold in barrels that are priced in US\$, the convention in the oil market is for analysts looking at any new project anywhere in the world to estimate its break-even costs in terms of the price per barrel required to cover all costs and give the required rate of return. In this respect, the three main cost components in any oil project are: (i) capital costs; (ii) operating costs; and (iii) any royalties that need to be paid to the government (these can vary significantly across the world).

As a result, when evaluating the economics of any new oil-sands project in Canada, the crucial questions are: (i) the oil price required to cover total production costs (capital costs, operating costs, income taxes, and royalties); (ii) how this price compares with other potential new projects elsewhere in the world; and (iii) the availability of cost-effective access to markets that will pay at least a project's break-even price for oil-sands product.

In attempting to answer these questions, note that the costs of producing oil from oil sands varies by the specific method used. In-situ or steam-assisted-gravity-drainage (SAGD) projects have the lowest cost of production, followed by non-upgraded mining production, with integrated mines and up-graders being the most expensive.<sup>2</sup>

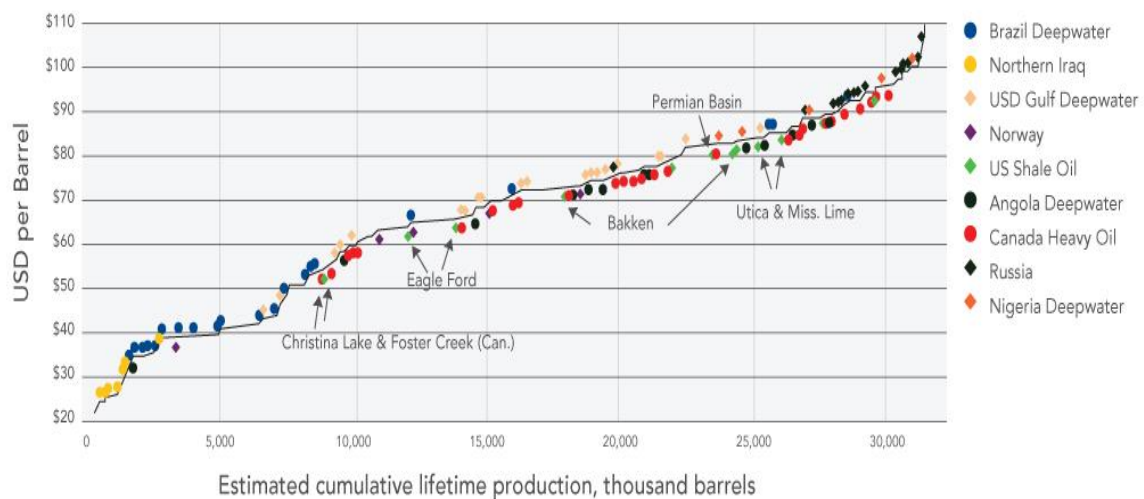
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<sup>2</sup> Note, however, that the significant fuel requirements of SAGD projects (which must heat up bitumen in order for it to flow) make the costs of these projects sensitive to the price of natural-gas prices in Alberta.

Looking at a sample of market analysis of the economics of new oil-sands projects, we find that the cost ranges break down as follows:

- Wood Mackenzie data indicates that new oil-sands projects require a break-even oil price of \$60-100/bbl. This is based on a 10% discount rate and a 40% bitumen differential to WTI prices.<sup>ii</sup>
- IHS CERA put the break-even prices for the whole spectrum of oil-sands projects at \$75-100/bbl, and for SAGD projects at \$65-85/bbl.<sup>iii</sup>
- BMO Capital Markets assess all-in production costs at \$50-90/bbl.<sup>iv</sup>
- Goldman Sachs states that no "new" (i.e. recently producing, under development, or pre-sanction) oil-sands projects in Canada have had all-in costs below \$70/bbl in the past two years, and that most have had costs in the range of \$80-100/bbl.<sup>v</sup>
- Looking at Rystad Energy's global exploration & production (E&P) database<sup>vi</sup>, we see a break-even price range for discovered in-situ facilities - which, are seeking investment decisions going forward<sup>vii</sup> - of \$65-150/bbl. To be conservative, our analysis focuses on projects with a break-even price of \$65/bbl. Note, however, that looking out to 2015, the median break-even price for such facilities may actually be closer to \$75/bbl and above (onwards, some projects expected to come online have projected break-even prices above \$80/bbl).

**Figure 1: Cost curve for new projects (recently producing, under development or pre-sanction)**



**Source:** JPMorgan, "Eye on the Market. Our annual energy update: a reality check", October 28 2013. Underlying data from Goldman Sachs, "380 projects to change the world - from resource constraint to infrastructure constraint", April 12 2013.



Acknowledging that: (i) all-in project costs vary by method of production, and (ii) a handful of recently producing and under-development projects have estimated total production costs of \$50-55/bbl<sup>3</sup>, the costs of production from Canada's oil sands tend to be among the highest for any form of oil anywhere in the world. Carbon Tracker's 2013 *Unburnable Carbon* analysis highlighted how fossil-fuel projects with greater than average marginal costs of production -- those on the wrong end of the cost curve -- are most at risk of being cancelled. For example, Citibank's analysis of the largest 300 oil and gas projects to 2020 indicated that many unconventional assets, including Canada's oil sands, were at the more expensive end of the list and were at risk of becoming a stranded asset and therefore of being written down or even written off completely.<sup>viii</sup>

In the following sections we examine the pricing and hence revenue implications of exporting Canadian oil-sands product to the US Gulf via the KXL pipeline. Although such exports would improve project economics relative to the *status quo*, the long-term outlook for oil sands development in a carbon-constrained world remains questionable.

### *Key attributes of Canada's oil sands*

#### Greater carbon intensity relative to conventional oil

Per barrel of oil produced, Canada's oil sands result in on average 17% more CO<sub>2</sub> emissions than conventional oil.<sup>ix</sup> This is because of the extra energy expended to extract, refine, and process the oil sands. Therefore, barrel for barrel, using this resource rather than conventional alternatives will increase overall CO<sub>2</sub> emissions.

#### Plans to significantly increase production

Despite this high-carbon, high-cost background, Canadian oil-sands producers have very ambitious targets to expand production. The table below illustrates the latest Canadian Association of Petroleum Producers (CAPP) forecasts for future production.<sup>x</sup> From an estimated 2012 level of 1.8 million barrels per day (mbd), production from oil sands is forecast to increase 27% by 2015, 77% by 2020, and nearly 200% by 2030.<sup>4</sup> Achieving this ramp-up in production will require significant and sustained capital investment. Through 2046, a reference-case scenario from the Canadian Energy Research Institute (CERI) calculates initial capital investment in expanding oil-sands production of \$230 billion, or an average of roughly \$8.7 billion per year.<sup>xi</sup>

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<sup>3</sup> These include the (commercially producing) Foster Creek and (under development) Christina Lake projects, both a joint venture of Cenovus Energy and Conoco Phillips.

<sup>4</sup> Note that growth in oil-sands production will come chiefly from new in-situ projects (such as SAGD); from a 2012 level of 1mbd, CAPP projects in-situ production to increase to 1.3mbd by 2015 and to 3.5mbd by 2030.

**Table 1: CAPP Projections of Oil Production**

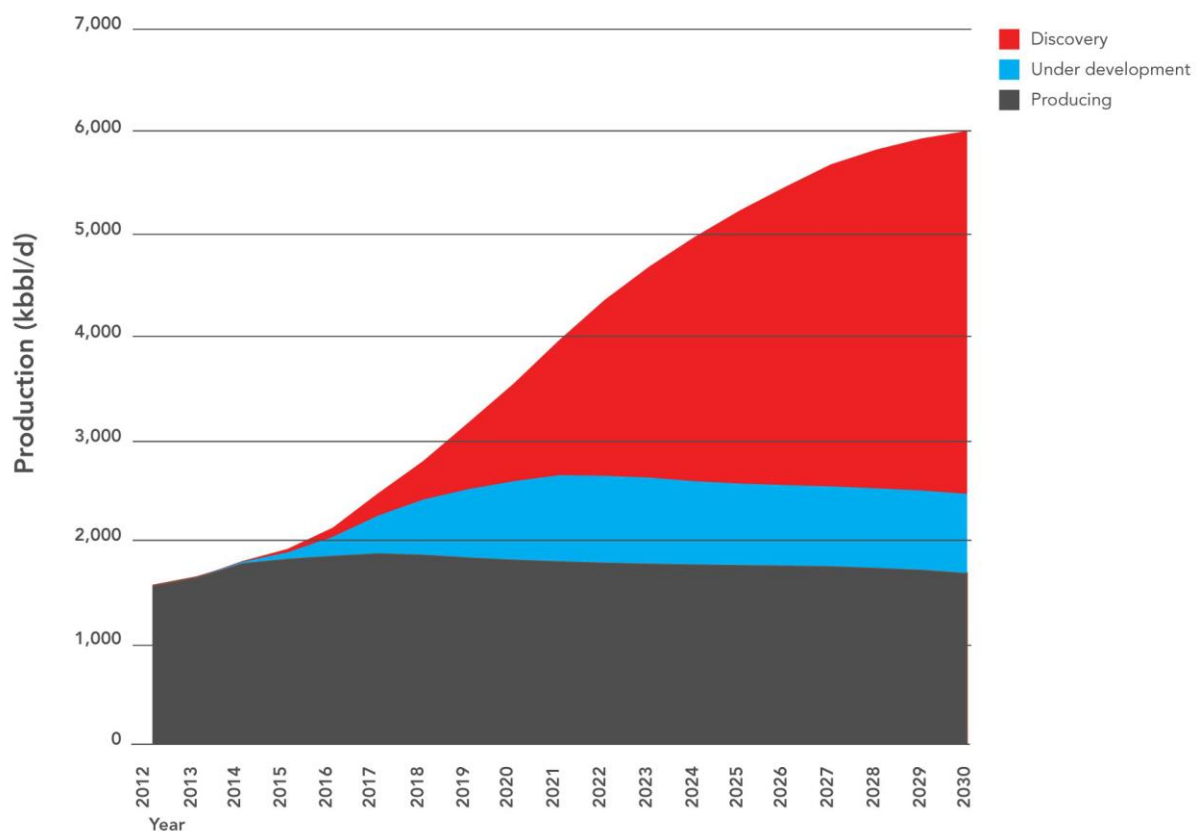
	Million b/d	2012	2015	2020	2025	2030
<b>Total* Canadian (including oil sands)</b>		<b>3.2</b>	<b>3.9</b>	<b>4.9</b>	<b>6.0</b>	<b>6.7</b>
Eastern Canada		0.2	0.2	0.2	0.2	0.1
Western Canada Conventional (including condensate)		1.2	1.4	1.4	1.4	1.4
Oil sands		1.8	2.3	4.5	5.2	5.2

\*Totals may not add up due to rounding

Source: Canadian Association of Petroleum Producers (CAPP), "Crude Oil: Forecast, Markets, & Transportation," June 2013.

Although estimates of future production from Rystad Energy vary slightly compared with those of the CAPP, the graph below illustrates the extent to which the future growth of Canada's oil sands relies on investment decisions yet to be made – represented by those assets classified still in 'discovery'.

**Figure 2: Oil sands production by life-cycle stage**



Source: Rystad Energy UCube, version 12/11/2013



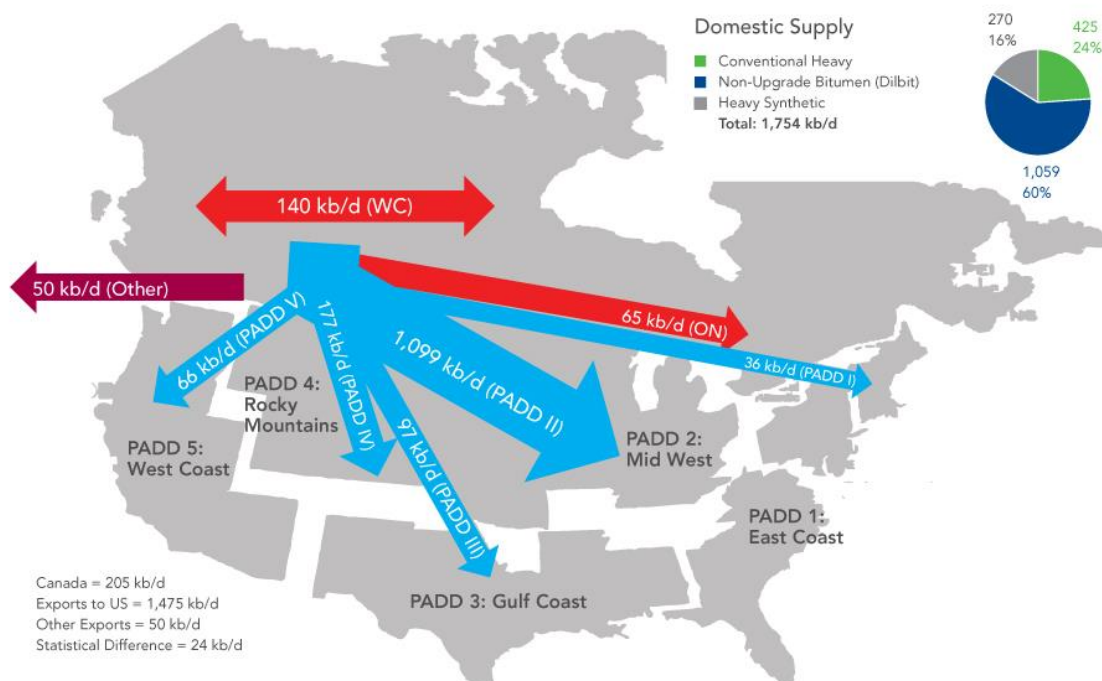
### Limited export capacity as the major constraint on planned production ramp-up

Forecasts for increased production from Canadian oil sands assume sufficient export capacity to bring that oil to world markets, and, as will become apparent, how rapidly this capacity is added, and the method of transit selected can significantly alter the economics of oil sands production.

As it can only be processed in refineries that have installed special equipment to handle heavy oil, crude from Canadian oil sands has a more restricted market than lighter Canadian or conventional US production. Western Canada has just 260kbd of refining capacity for heavy oil<sup>xii</sup> (i.e. enough to process only 15% of Western Canada's current heavy-oil production), so with the exception of heavy oil that is upgraded into synthetic light crude oil (SCO) and processed by light-oil refineries, the majority of heavy-oil production must go to refineries capable of processing this volume of heavy oil, the majority of which exist in the US Midwest and Gulf Coast regions.

The combined refining capacity for medium and heavy oil in these two regions exceeds 8mbd.<sup>xiii</sup> Canada already exports 1.1mbd of heavy oil to the US Midwest - an area known as PADD (Petroleum Administration for Defence District) II<sup>xiv</sup> - and that amount might rise to 1.6mbd by 2016. This surge in heavy-oil exports to the US Midwest, however, plus an infrastructure bottleneck that is constraining flows to the US Gulf Coast (USGC), is creating localized gluts that are depressing prices for Western Canadian Select (WCS), the benchmark pricing indicator for oil-sands product. As discussed below, the spread between WCS and West Texas Intermediate (WTI) -- the benchmark for light, sweet oil -- has recently been up to \$30/bbl.

**Figure 3: Canadian Heavy Crude Oil Supply and Disposition, 2011**

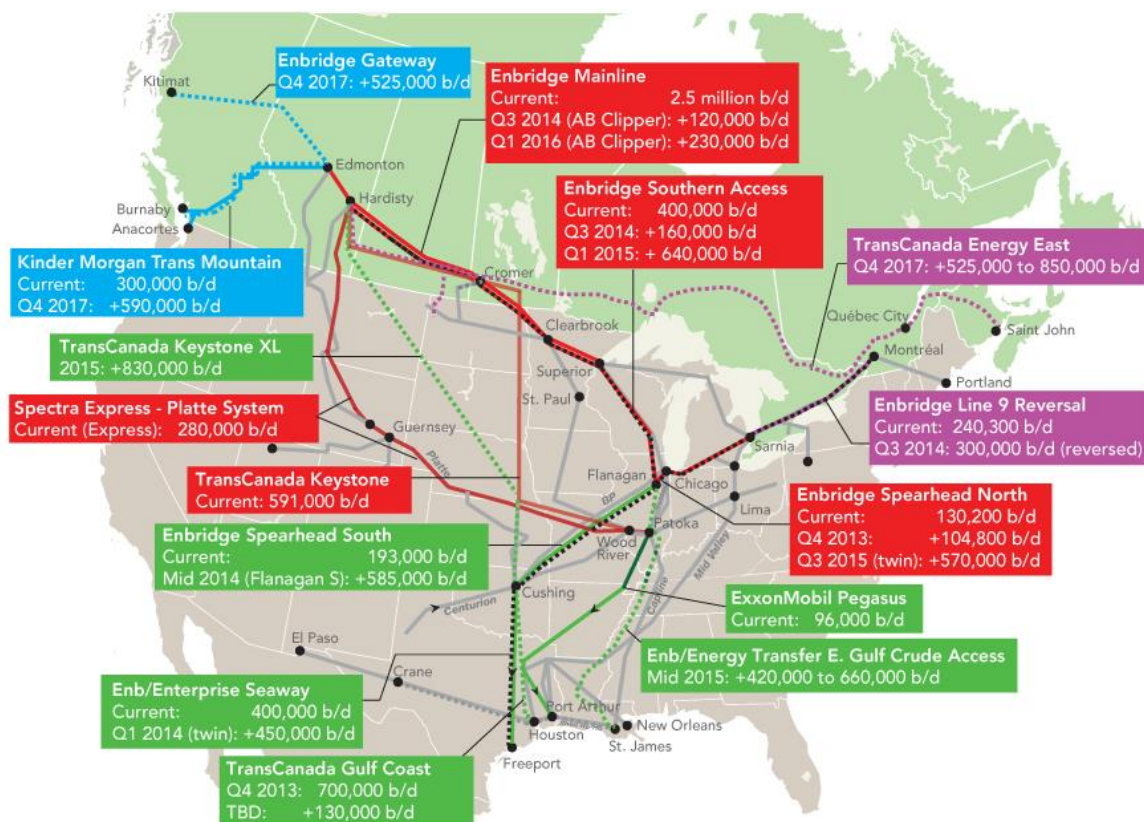


**Source:** Canadian Energy Research Institute (CERI), "Canadian Oil Sands Supply Costs and Development Projects (2012-2046)", May 2013. Data from Canada's National Energy Board; maps from the Royal Astronomical Society of Canada (RASC) and the US Energy Information Administration (EIA).

Widening price differentials between WCS and other forms of oil -- which, by some estimates, are costing Canadian producers tens of millions of dollars per day<sup>xv</sup> -- are driving the push to build more infrastructure to deliver Canadian heavy crude to refineries in the PADD III market on the US Gulf Coast (where, as explained below, it is likely to receive higher prices).

Though producers are also exploring new pipelines to send Canadian crude *west* (to refineries on the US West Coast and, possibly, Asia) and *east* (to refineries on the East Coast of Canada and, from there, potentially the US East Coast, India, or Europe), the most likely near-term export expansions will bring crude *south* to the USGC. Realising forecasts of long-term production growth is contingent on adding enough pipelines and other infrastructure to resolve the current bottleneck and enable Western Canada to export greater volumes of oil-sands product.

Figure 4: Canadian & U.S. Crude Oil Pipelines and Proposals



Source: Canadian Association of Petroleum Producers (CAPP), "Crude Oil: Forecast, Markets, & Transportation," June 2013.

### *Demand Risk*

Meanwhile, the US market has changed, raising questions about where increased oil-sands production could end up once it reaches the USGC. This opens up possibilities of exporting refined product, or even crude. However the energy-security argument for the US increasing Canadian imports is fading as domestic production increases, and efficiency of use improves, weakening demand.

#### **Surging US production and more efficient vehicles weaken demand for Canadian imports**

Even if Canada can cost-effectively produce, process, and transport oil from oil sands, there is the question as to who will buy it. For example, in combination with energy-efficiency standards that are reducing oil demand from transportation, the recent boom in US oil production raises the possibility that the country will become a net energy exporter by 2020-2025.

The US Energy Information Administration (EIA) predicts continued growth of US shale/tight-oil production. Having already grown by 1.5mbd over the past two years (making the US the number one global producer of oil and natural gas in 2013),<sup>xvi</sup> the EIA's "high-resources" case projects that production could increase by a further 4mbd by 2020. Coming largely from the Bakken formation in North Dakota and Montana, growing US oil production is competing directly with oil-sands imports for pipeline capacity to the Gulf of Mexico (and, ultimately, end-user demand). Other things being equal, greater domestic US oil production means reduced demand for Canadian imports.

Concurrently, recently heightened corporate average fuel-economy (CAFE) standards in the transportation sector are expected to double vehicle efficiency by 2030 and reduce oil consumption by 3mbd at the end of this period.<sup>xvii</sup> More efficient transport has been one reason why US imports of crude oil and products have declined in recent years from 12mbd in 2007 to 7mbd in 2012. A continuation of this trend would erode the US energy-security argument for new oil-sands projects.

Once more this points to the importance for oil-sands producers of opening global export markets.

## 2. Export options

### *Getting to global export markets via pipelines and rail*

Given that adding new export capacity -- and in particular providing access to refineries with access to global markets and hence improved pricing -- is a pre-requisite to further expanding oil-sands production, the KXL pipeline linking Alberta to the Gulf-coast refineries is essential to the industry's growth plans.

As discussed below, its size, the industry preference for pipelines, and a lack of alternative export routes makes it highly likely that construction of KXL will send a crucial signal to producers of oil sands. Rail is increasingly talked about but has significant infrastructure-development issues as well as cost uncertainties.

### *The Proposed KXL Pipeline*

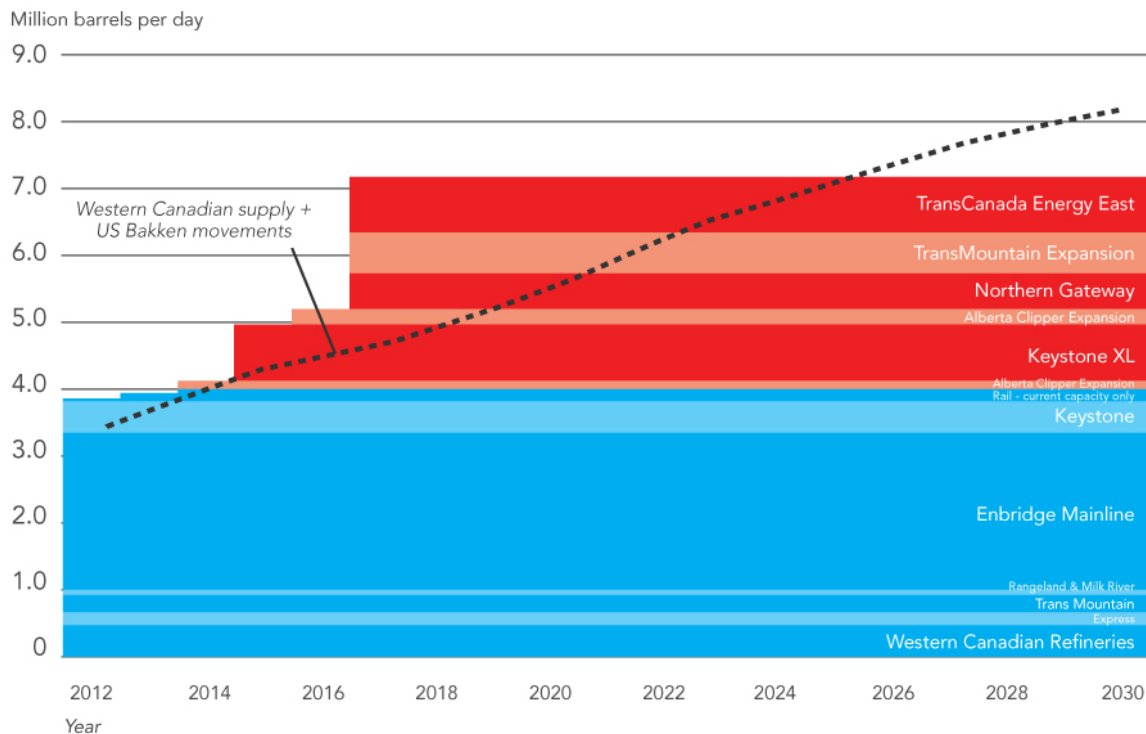
TransCanada's proposed KXL pipeline is a \$7bn project that will connect Hardisty, Alberta with Port Arthur and Houston, Texas (by way of Steel City Nebraska). If built, the pipeline's \$5.3 billion "northern leg" (from Hardisty to Steele City) will connect with the already under construction "southern leg", which connects Cushing, Oklahoma with Nederland, Texas. In the context of the economics of Canadian oil sands, the long-running debate over the merits of the proposed KXL pipeline raises the question of the potential for stranded assets.

A key issue which has emerged from President Obama's statements concerns whether the pipeline would result in an increase in CO<sub>2</sub> emissions. Indeed the US State Department has made the key environmental test to be whether KXL causes more oil production rather than just being another conduit for a source that is coming to market anyway. We discuss this in more detail below.

Several attributes underpin KXL's leading role in plans for new export capacity from Western Canada:

- **Size:** KXL would have a nameplate capacity of 830kbd. Given TransCanada's plans to allocate roughly 100kbd of this amount to light oil from North Dakota's Bakken formation, KXL would bring around 730kbd of heavy oil into Gulf Coast refineries. Note that this is an amount: (i) equal to nearly half of Western Canada's current takeaway capacity for heavy oil; and (ii) as large as (or larger than) the capacity of any other planned or proposed new pipeline.
- **Industry wanting all of the above:** The economic impacts of export additions such as KXL begin to be demonstrated by considering the volume of existing takeaway capacity. Analysts estimate the current takeaway capacity for Western Canadian oil to be roughly 3mbd – with roughly 1.5mbd of this amount allocated to “heavy oil” such as that from oil sands.<sup>xviii</sup> In other words, in 2012 production from oil sands in Western Canada already exceeded available takeaway capacity by at least 0.3mbd.<sup>xix</sup> The figure below illustrates how industry projections for future oil-sands production growth already include all potential export routes (even those with significant challenges) as complements to, rather than substitutes for, KXL. Owing to rising production from Western Canada and the US Bakken formation, CAPP projects a need for Canada's total export capacity to double by 2030 (i.e. to 8mbd); *even if all proposed pipelines (including KXL) are built, from 2025 Canada will still need to add an additional 1mbd of export capacity.*<sup>xx</sup>

**Figure 5: Western Canadian Sedimentary Basin (WCSB) Takeaway Capacity vs. Supply Forecast**



Source: Canadian Association of Petroleum Producers (CAPP), "Crude Oil: Forecast, Markets, & Transportation," June 2013.

- **The lack of easy alternatives:** Alternatives to KXL -- be they other pipelines or increased use of rail transport -- face challenges that have delayed (and in many cases will continue to delay) their completion. The paragraphs below survey some of these challenges.

### Alternative pipeline routes

Though several projects have been proposed, linking the oil sands to the East or West coasts of Canada is a challenging prospect. Canada has put in strong rights for its First Nations communities, who would have to agree to any pipeline crossing their lands. For example, Enbridge's Northern Gateway pipeline proposal to link Alberta to Kitimat in British Columbia, faces significant opposition as it would have to cross ancestral lands.

Additionally, in order to transport bitumen to market in pipelines, a diluent needs to be added at around 28% of the volume transported to create what is termed "dilbit". This negatively impacts the economics.

### Increase use of rail transport

As opposed to being moved via pipeline, oil can also be loaded onto freight cars and moved by rail. The sections below briefly describe rail transport of Canadian heavy oil, its current status, and challenges of scaling it up.



### Rail basics

When discussing shipment of bitumen by rail, two important distinctions to keep in mind concern the difference between *diluted bitumen* and *raw bitumen*, and the difference between *unit* trains and *manifest* trains.

- **Diluted bitumen versus raw bitumen:** As raw bitumen has the density of peanut butter, it must be diluted in order to flow. This is true in the case of pipelines and, to a lesser extent, in the case of rail. Most trains now moving bitumen ship a form of diluted bitumen in a ratio of 17% diluent to 83% bitumen (i.e. a producer must ship 1.2 barrels of diluted bitumen in order to deliver 1 barrel of bitumen). It is also possible, however, to ship "raw" bitumen that contains little to no diluent. Doing so requires removing any diluent with a diluent recovery unit (DRU) prior to rail loading. Though in sparse use at this time given a lack of adequate infrastructure, this option appeals to producers as a way to minimize expensive diluent use.
- **Unit trains versus manifest trains:** The most economic way to ship Canada's heavy crude oil is through use of dedicated or "unit" trains - 100 or more dedicated crude-car convoys that move together as a unit. A less efficient method involves so-called "manifest" trains that comprise groups of railcars carrying different varieties of freight from different locations. Relative to unit trains, analysts estimate the added cost of manifest trains at \$3/bbl.<sup>xxi</sup>

### Current status of heavy oil rail transport from Western Canada

Even after a year of significant growth, in 2013 Canada's oil exports to the US by rail will be only 180kbd.<sup>xxii</sup> Moreover, 60-80% of this amount is conventional "light" oil, rather than the heavy oil from oil sands operations. That said, export bottlenecks are generating interest among companies in adding new rail terminals dedicated to heavy oil; if completed, a slew of planned and recently announced projects could over the next five years increase Canada's rail-loading capacity to 900kbd (i.e. greater than the capacity of KXL). As discussed below, however, completing these projects will involve overcoming significant challenges.

### Challenges of rail

The eye-popping cumulative capacity addition notwithstanding, there is significant uncertainty as to how much of Western Canada's proposed new rail capacity will actually be built – and, if it is, on what timeframe. This uncertainty stems from several sources:

- **Need for special rail cars and other infrastructure:** Continuing to increase rail shipments from Western Canada depends on manufacturers of "heated-and-coiled" rail cars being able to deliver promptly on a significant backlog of orders beginning in 2014. For order of magnitude, to enable the capacity to unload 20-30kbd of Canadian crude, one Gulf Coast refinery will use 1,600 heated-and-coiled tank cars, as well as heated pipelines and a heated storage facility.<sup>xxiii</sup> One market analyst captures the challenge of doing this by noting that "moving heated crude is a complicated and messy process and the investment required is significant".<sup>xxiv</sup> Moreover, there is a particular shortage of unit-train facilities dedicated to heavy oil.



- **Significant logistical challenges add cost:** The “messy process” of moving heated heavy-crude oil adds cost relative to the rail transport of conventional light oil. For example, rail cars have restrictions on maximum weight, meaning that the greater density of bitumen (relative to light oil) reduces the number of barrels that each car can carry. Similarly, the additional time required to heat bitumen so that it can be unloaded reduces the numbers of barrels of heavy oil the cars can transport per day. Both of these factors disadvantage the economics of heavy-oil rail transport.
- **High-profile accidents highlight safety concerns:** The Lac-Mégantic train tragedy in Quebec in early July 2013<sup>xxv</sup>, and a second accident in Calgary in September, have put the spotlight on oil-transit safety and brought new scrutiny about safety requirements. Community and regulatory reaction to such disasters could pose major obstacles to the expanded use of rail transport for oil sands oil.
- **Chicken-and-egg problems may delay actual investment:** Companies are reluctant to build rail-loading terminals in Canada without certainty that there will be unloading facilities in desirable markets (chiefly the US Gulf Coast) capable of handling heavy oil. By the same token, Gulf Coast refiners are reluctant to make the sizeable investment needed to unload heavy crude by rail without “firm-throughput” commitments from producers in Western Canada. Such commitments, however, have so far not been widely forthcoming; as a result, currently only one Gulf Coast refinery is adding a heated rail terminal to *directly* unload 30kbd of Canadian heavy crude.<sup>xxvi</sup> Other refiners seeking to accept diluted or raw bitumen will have to do so via heated barge or pipeline from external unloading facilities (thereby adding cost). Though several new such facilities are under construction, (or have been proposed),<sup>xxvii</sup> it is unclear how many of these projects will reach completion. All told, adding even 200kbd of heated rail unloading capacity on the Gulf Coast by 2015, (i.e. around one quarter of KXL’s projected capacity for Canadian crude), would be an optimistic projection.

Given the absence of alternatives to KXL that are not already embedded in industry projections -- and the significant challenges for many of the alternatives that are -- KXL continues to be a significant determinant of future production growth in Canada’s oil sands.

### 3. Pricing

#### *Beyond WCS to Maya*

One major challenge to the economics of *in-situ* oil sands production has been a lack of access to refining capacity. Because of its heaviness and high sulphur content relative to Canadian or US conventional oil, oil-sands product can be handled only by the limited number of refineries that have invested in such technology close to Western Canada.

Indeed, the recent surge in oil-sands production has outstripped the refining capacity available to process it in the Canadian and US mid-continent markets (which oil-sands producers can access with existing infrastructure). As a result of this supply glut, over the past five years the price for Western Canadian Select (WCS) heavy, sour oil -- a benchmark indicator of pricing for oil-sands product -- has traded at an increasingly steep discount to the price for West Texas Intermediate (WTI) light, sweet oil (i.e. beyond what might be expected based on differences in processing cost alone).

For example, over the last 12 months WCS has fetched prices on average 24% lower than those for WTI, thereby pressuring profit margins for oil-sands producers. By contrast, Maya has managed to stay much closer to the WTI price.

**Figure 6: Price differential between Maya, WTI and WCS (\$/bbl), over preceding 2 years**



Source: Bloomberg LP

In its physical characteristics (sulphur content and heaviness), oil-sands output is most similar in terms of quality to the Mexican heavy-crude exports which set the benchmark Maya price.<sup>xxviii</sup> Analysts therefore expect WCS output to achieve similar levels to Maya, (adjusted for transport costs), once

WCS can access USGC markets.<sup>5</sup> Gulf Coast refiners with the capacity to process heavy crude have a strong incentive to expand and diversify their supply sources. Since heavy crude yields a higher proportion of diesel than does light crude -- and since diesel earns a premium price in export markets -- ensuring a reliable, diverse supply of heavy crude can be a key strategy for these refiners to maximize profits.

By enabling oil-sands oil to reach these Gulf Coast refiners, the KXL pipeline might significantly increase the prices that oil-sands producers receive for their product. For example, RBC finds that construction of KXL would shrink the overall WCS-WTI price differential to roughly half of what it would be without KXL; TD Economics similarly concludes that oversupply in the Midwest and the lack of infrastructure means oil sands production could see higher prices with KXL.<sup>xxix</sup> Furthermore, Goldman Sachs estimates that bringing KXL online in the second half of 2015 would help to reduce the spread between WCS and WTI by \$10-\$16/bbl.<sup>xxx</sup> The result of KXL providing access to export markets would be stronger top-line revenues for oil-sands producers (although as explained in Section 4 below, this does not necessarily mean greater bottom-line profits). Emphasizing the potentially major impacts of better pricing, Standard & Poor's has described new export pipelines as "necessary to alleviate bottlenecks from increasing production" and "key elements in the relative economics of Canadian heavy crude compared with U.S. conventional production".<sup>xxxi</sup>

### *Additionality: By adding export capacity, KXL would encourage increased oil sands production*

The evidence presented so far suggests that by relieving export constraints and improving the projected revenues of new projects, it is highly likely that the approval and subsequent construction of KXL would indeed increase production from Canada's oil sands. Moreover, as a result of improved perceptions of pricing, the perceived creditworthiness of oil-sands producers would likely improve, thereby reducing their cost of capital and potentially triggering investment in *new* high-cost, high-risk projects that, absent significantly larger export capacity, would not make economic sense.

The US State Department's March 2013 Draft Supplemental Environmental Impact Statement (DSEIS) concluded that because alternative export routes were readily available construction of KXL was unlikely to increase production from Canada's oil sands. However, market analysts have reached exactly the opposite conclusion from the State Department with respect to the impact of KXL on oil-sands production. Work from RBC suggests that the absence of KXL could reduce oil sands output by up to 0.45mbd during the period 2015-17 (i.e. an amount equal to 25% of total 2012 oil sands production), resulting in 2020 output nearly 0.3mbd lower than its base-case estimate.<sup>xxxii</sup> Similarly, Bloomberg New Energy Finance forecasts that absence of KXL would reduce 2025 oil-sands production by 0.8mbd -- in other words, that KXL would lead 2025 production to be 20% greater than it otherwise would be.<sup>xxxiii</sup> These projections match the sentiment of leaders within Canada. Summing up the situation of his province, Alberta's Energy Minister has indicated that unless additional export capacity is developed to match the planned expansion of oil sands production "by 2020 we will be landlocked in bitumen."<sup>xxxiv</sup>

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<sup>5</sup> Integrated oil sands producers which upgrade heavy oil into synthetic crude oil (SCO) before refining, may be able to capture Brent-price levels for their products. As there is little sign of the high levels of capital investment required for increased upgrading capacity in Canada, however, we focus on the options for WCS production and exports.

### *Offsets – an implicit CO<sub>2</sub>-price approach, but complex*

In a July 2013 interview in the *New York Times*, President Obama noted that “there is no doubt that Canada at the source in those oil sands could potentially be doing more to mitigate carbon release.”<sup>xxxv</sup> In response to such pressure, Canadian Prime Minister Stephen Harper reportedly sent a letter to President Obama proposing that increased US-Canadian cooperation to reduce CO<sub>2</sub> emissions from the oil-and-gas sector be coupled with approval of KXL.<sup>xxxvi</sup> This is ironic given that the growth of the oil sands over recent years has been responsible for the growth of Canada’s greenhouse gas emissions, which led to Canada reneging on its Kyoto commitments.

If Canada were to offer to offset the extra emissions, this would in effect acknowledge “additionality” from the pipeline and oil sands in general. This implicit CO<sub>2</sub>-price based approach would also require the quantification, attribution and pricing of such measures. For example, it would raise the following questions:

- Would only the incremental emissions per barrel be offset (i.e. the extra emissions generated by a barrel of oil sands relative to a barrel of conventional crude oil), or the total increase in oil-sands production associated with KXL approval?
- What would be the additional cost per barrel, would sufficient credible offsets be available and how much would paying for the offsets impact the economics of oil sands?
- What assurances could Canada give regarding delivering the offsets, given its poor record on climate-change commitments in recent years?
- Who would pay for this? Would the full CO<sub>2</sub> price be borne by the producers or would royalties and other taxes be reduced? Would the cost of the emissions from transporting, upgrading and refining in the United States be borne by Canada?

At this stage, it is unclear whether KXL approval might be contingent upon some form of CO<sub>2</sub>-pricing via offsets to cover any emissions deemed additional. But what is certain is that if CO<sub>2</sub>-pricing were introduced into the approval equation, this would undermine the economic case for shipping oil-sands output through KXL by either \$2/bbl or \$16/bbl, depending as follows on whether the CO<sub>2</sub> price were imposed either (i) only on the incremental emissions per barrel relative to conventional crude, or (ii) on the total emissions per barrel of all oil-sands output passing through the pipeline:

- The social cost of CO<sub>2</sub> for regulatory-impact analysis in the United States has been updated to \$32/metric ton.<sup>xxxvii</sup>
- The EPA standard for conventional oil is 0.43 metric tons CO<sub>2</sub> /barrel<sup>xxxviii</sup>
- If this figure is increased 17% to reflect the increased emissions per barrel from oil sands this gives 0.503 metric tons CO<sub>2</sub> / barrel, so an extra 0.073.
- If it was just the extra that was being offset, it would be: 0.073 \* \$32 = **\$2.34 / barrel**
- If it was the total being offset as extra production it would be: 0.503 \* \$32 = **\$16.10 per barrel**

A \$2/bbl cost would be similar to the level proposed by the Pembina Institute in Canada, and under their sensitivity analysis CO<sub>2</sub>-pricing at this level delivered significant emissions cuts from oil sands.<sup>xxxix</sup> However, given that KXL would facilitate extra production, it could be argued that the entire extra production should be subject to a carbon cost, which would equate to over \$16/bbl.

#### 4. The economics of new oil-sands projects appear risky

Although KXL would offer short-term pricing upside to oil-sands producers (and potentially significant upside), there are also increased risks to costs for the industry entailed by the approval of KXL such that the overall economics for oil-sands producers offered by KXL would be far less clear-cut than widely assumed – to such a point, indeed, that future oil-sands projects would still be highly risky.

##### Estimating improved margins with access to international prices

The paragraphs below examine how KXL will affect the profitability of Canadian oil-sands projects. To focus in particular on in-situ projects with relatively lower marginal costs of production, we assume a break-even price of \$65/bbl. We then calculate producer “netbacks” (i.e. prices adjusted for transport and diluent-related costs) and, most importantly, profits and losses in terms of the net-revenue less the break-even price. The goal is to estimate how these profits and losses vary depending on: (i) prices in different markets (e.g. the US Midwest (USMW) versus the US Gulf Coast); (ii) different means of transport (pipeline, rail of raw bitumen and rail of diluted bitumen); and (iii) the presence of any costs related to offsetting of carbon emissions.

The four export alternatives that we examine are:

- A. **Pipeline to USMW:** This alternative simulates export via pipeline from Alberta to a key hub in the US midcontinent market such as Cushing, Oklahoma. Using the current December 2015 futures price for WCS, we assume that producers selling into this market earn \$69/bbl. Additionally, recall that in order for bitumen to flow through a pipeline it must be combined with a diluent such as natural-gas condensate, usually in a ratio of 28% diluent to 72% bitumen. In other words, a producer must ship 1.39 barrels of diluted bitumen in order to deliver 1 barrel of bitumen.
- B. **Rail to USGC (diluted bitumen):** This alternative simulates export via rail from Alberta to refineries on the US Gulf Coast. Using the current December 2015 futures price for Maya, we assume that producers selling into this market earn \$89/bbl.<sup>6</sup> Relative to use of a pipeline, transporting diluted bitumen by rail reduces the use of diluent -- in this case, to a ratio of 17% diluent to 83% bitumen (i.e. a producer must ship 1.2 barrels of diluted bitumen in order to deliver 1 barrel of bitumen).
- C. **Rail to USGC (raw bitumen):** In the case of rail, it is possible to ship “raw” bitumen that contains little to no diluent. Doing so requires removing any diluent with a diluent-recovery unit (DRU) prior to rail loading. Though in sparse use at this time given a lack of adequate infrastructure, this option appeals to producers as a way to minimize diluent use.
- D. **Pipeline to USGC:** This alternative simulates export via pipeline from Alberta to refineries on the US Gulf Coast - as would occur in the KXL pipeline.

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<sup>6</sup> A more precise analysis might introduce slight price discounts relative to Maya, particularly for diluted bitumen transported via pipe or rail.

The input variables in our analysis include:

- **Break-even Price:** Since by 2014 in-situ production methods such as SAGD will overtake mining to become the dominant form of oil-sands production by volume<sup>7</sup>, we focus on the "break-even price" for a new SAGD project.<sup>7</sup> Rystad Energy's global exploration & production (E&P) database<sup>xli</sup> suggests Canadian SAGD projects to have break-even prices in the range of \$65-150/bbl. To be conservative, our analysis below focuses on projects with a break-even price of \$65/bbl. Note, however, that looking out to 2015 the median break-even price for such facilities may actually be closer to \$75/bbl and above (from 2015 onwards, some projects expected to come online have projected break-even prices above \$80/bbl).
- **Bitumen Transport Cost:** For all export alternatives except rail transport of raw bitumen, the use of diluent increases the total volume of product to be shipped and thereby increases transportation costs. We reflect this by distinguishing between "bitumen transport costs" and "diluent transport cost." Note that for the two pipeline alternatives, the "bitumen transport cost" includes the cost of pipeline tolls to the US, as well as \$2.40/bbl in "Alberta hub costs", which include the cost of transporting bitumen from the field to a hub within Alberta (e.g. Edmonton or Hardisty), where it is stored before shipment to the US. For rail, transport costs include both fixed (i.e. terminal and rail lease) and variable costs of rail transport.

Note that the assumed cost of pipeline transport from Alberta to the Gulf Coast (which is built up from Standard & Poor's data<sup>xlii</sup>) is on the low end of published estimates. Our figure of \$15/bbl of bitumen delivered (i.e. bitumen transport cost + diluent transport cost) is well below RBN Energy's estimate of \$25.72/bbl bitumen<sup>xliii</sup>, and just below an estimate for large shippers cited by Raymond James of \$17.50/bbl bitumen.<sup>xliiv</sup> Inasmuch as actual costs for pipeline transport are higher than our assumed figure, this will diminish the profitability of pipeline export to the Gulf to below what our results suggest.

- **Diluent Transport Cost:** Reflects added pipeline tolls/rail fees associated with shipment of the diluent portion of diluted bitumen. For pipelines, we assume product is 28% diluent and 72% bitumen; for rail, we assume product is 17% diluent and 83% bitumen.
- **Diluent Differential Loss:** Reflects added cost owing to difference in \$/bbl price between what producers pay for diluent and what they are then paid for their diluted bitumen. This assumes a price for diluent (C5+ Edmonton) of \$97/bbl.
- **Offset costs:** Reflects costs related to additional offsetting of CO<sub>2</sub> emissions associated with oil sands production, as discussed above.<sup>8</sup>

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<sup>7</sup> Break-even price is the price at which the NPV equals 0. This is done on an asset level but can be aggregated up to a company level. For production, all expected future production of the asset is taken into account. This includes the production from newly drilled wells and also the base production from wells already drilled. The oil price is assumed flat with 2.5% inflation. The break-even price is calculated for the free cash flow. This is in other words after deducting royalties, government profit, income tax and capex and opex. This calculation assumes a 10% discount rate.

<sup>8</sup> Note that carbon-offset assumptions do not include Emissions Compliance Costs of current projects, which for SAGD projects the Canadian Energy Research Institute estimates are \$0.70/bbl.



**Table 2: Economics of \$65/bbl oil sands production with different transport options/end market pricing**

Cost type	(\$/barrel of bitumen transported)*	No KXL			KXL	
<b>Break-even Price<sup>(1)</sup></b>	Base case	\$65.0	\$65.0	\$65.0	\$65.0	\$65.0
<b>Bitumen Transport Costs<sup>(2)</sup></b>	Pipeline to USMW	\$8.0				
	Rail** to USGC (raw bitumen)		\$24.0			
	Rail to USGC (diluted bitumen)			\$24.0		
	Pipeline to USGC				\$11.0	\$11.0
<b>Diluent Transport Costs<sup>(3)</sup></b>	Pipeline to USMW	\$3.1				
	Rail to USGC (raw bitumen)					
	Rail to USGC (diluted bitumen)			\$4.9		
	Pipeline to USGC				\$4.3	\$4.3
<b>Diluent Differential Loss<sup>(4)</sup></b>	Pipeline to USMW***	\$11.0				
	Rail to USGC (raw bitumen)					
	Rail to USGC (diluted bitumen)			\$1.7		
	Pipeline to USGC				\$3.3	\$3.3
<b>Total Transport Costs</b>		\$22.1	\$24.0	\$30.6	\$18.5	\$18.5
<b>Oil price</b>	WCS 2015	\$69.0				
	Maya 2015		\$89.0	\$89.0	\$89.0	\$89.0
<b>Producer netback after transport (Oil price - transport costs)<sup>(5)</sup></b>		\$46.9	\$65.0	\$58.4	\$70.5	\$70.5
<b>Profit / Loss (netback - break-even price)<sup>(6)</sup></b>		-\$18.1	\$0.0	-\$6.6	\$5.5	\$5.5
<b>Carbon Offset Costs</b>	Incremental increase				\$2.0	
	Production increase					\$16.0
<b>PNL after offsets<sup>(6)</sup></b>					\$3.5	-\$10.5

Sources: Rystad Energy, Standard & Poor's, RBN Energy, Carbon Tracker analysis 2013

\* Note that these figures are per "barrel of bitumen transported"; for all transport options other than rail transport of raw bitumen, use of diluent alters the energy density of the product being transported - making simple \$/bbl figures inappropriate for comparing different transport options.

\*\* Rail costs in the midpoint of range between (more expensive) manifest trains and (less expensive) unit trains.

(1) Break-even price is the price at which the NPV equals 0. This is done on an asset level but can be aggregated up to a company level. For production, all the expected future production of the asset is taken into account. This includes the production from newly drilled wells, and also the base production from wells already drilled. The oil price is assumed flat with 2.5% inflation. The breakeven price is calculated for the free cash flow. This is in other words after deducting royalties, government profit, income tax and capex and opex. Calculation assumes a 10% discount rate.

(2) For pipeline, "Bitumen Transport Costs" include \$2.40/bbl in "Alberta hub costs," which include the cost of transporting and storing bitumen at a hub within Alberta; the balance reflects the cost of pipeline tolls to the US. For rail, "Bitumen Transport Costs" reflects fixed (i.e. terminal and rail lease) and variable costs of rail transport.

(3) Reflects added pipeline tolls/rail fees from having to transport greater volumes of a diluted product (relative to transport volumes for an undiluted product). For pipelines, assumes product is 28% diluent and 72% bitumen; for rail, assumes product is 17% diluent and 83% bitumen.

(4) This table is based upon a bitumen-equivalent set of calculations for consistency across transport options. Accordingly, we adopt the methodology for dealing with the cost of diluent that reflects the added cost due to the difference in \$/bbl-price between what a producer pays for diluent in Edmonton and is paid for diluted bitumen in the US Midwest or US Gulf Coast -- in this case WCS or Maya. Assumes a price for diluent (C5+ Edmonton) of \$97/bbl. Assumes same diluent/bitumen ratios as listed above. Note that there is some uncertainty among commentators as to the exact configuration of diluents-differential economics. \*\*\*In particular, this methodology leads to a significant net-diluent cost in USMW.

(5) Reflects the price a producer receives net of transport and diluent-related costs. Note that in order to facilitate comparison across different transport options these "netbacks" are calculated on a bitumen-equivalent basis (i.e. by looking at the cost of shipping one barrel of bitumen across all different transport options). Offset costs are excluded, as this analysis considers those to be costs related to production.

(6) Profit/loss is after producer netback post transport less the break-even price.

**Pricing uplift enabled by KXL might make investment in new oil-sands projects more tempting...**

Based on a 2015 \$69/bbl forward price for WCS, this analysis finds \$65/bbl oil-sands projects exporting to the US Midwest to be hugely unprofitable (-\$18/bbl), but even if output from new projects were able to reach the Gulf Coast by rail the economics would still be prohibitive for dilbit (-\$6/bbl) and break-even at best for raw bitumen.

KXL would improve these economics, and as can be seen in the table above, transportation by KXL with no CO<sub>2</sub> pricing would enable investors to reap a \$5.5/bbl surplus over their required rate of return (i.e. the break-even price). In particular, the very large differential between the returns currently available in our least favourable scenario without KXL and our most favourable scenario with it – transporting dilbit to the Gulf Coast via KXL would yield \$24/bbl more to a producer than is currently available from transporting raw bitumen to the Midwest by rail – could tempt producers into a rush of new project development if KXL were approved, especially in the absence of any CO<sub>2</sub>-pricing requirement.

**... but beware the mirage effect...**

Given the numbers in our scenario analysis above, we do not think that KXL approval would improve the economics of new oil-sands projects by as much as is widely assumed (at least not against the current forward curve for oil prices), and it is clear that the introduction of CO<sub>2</sub>-pricing would be a significant and/or terminal extra cost factor depending on whether it was introduced on the incremental or total emissions per barrel.

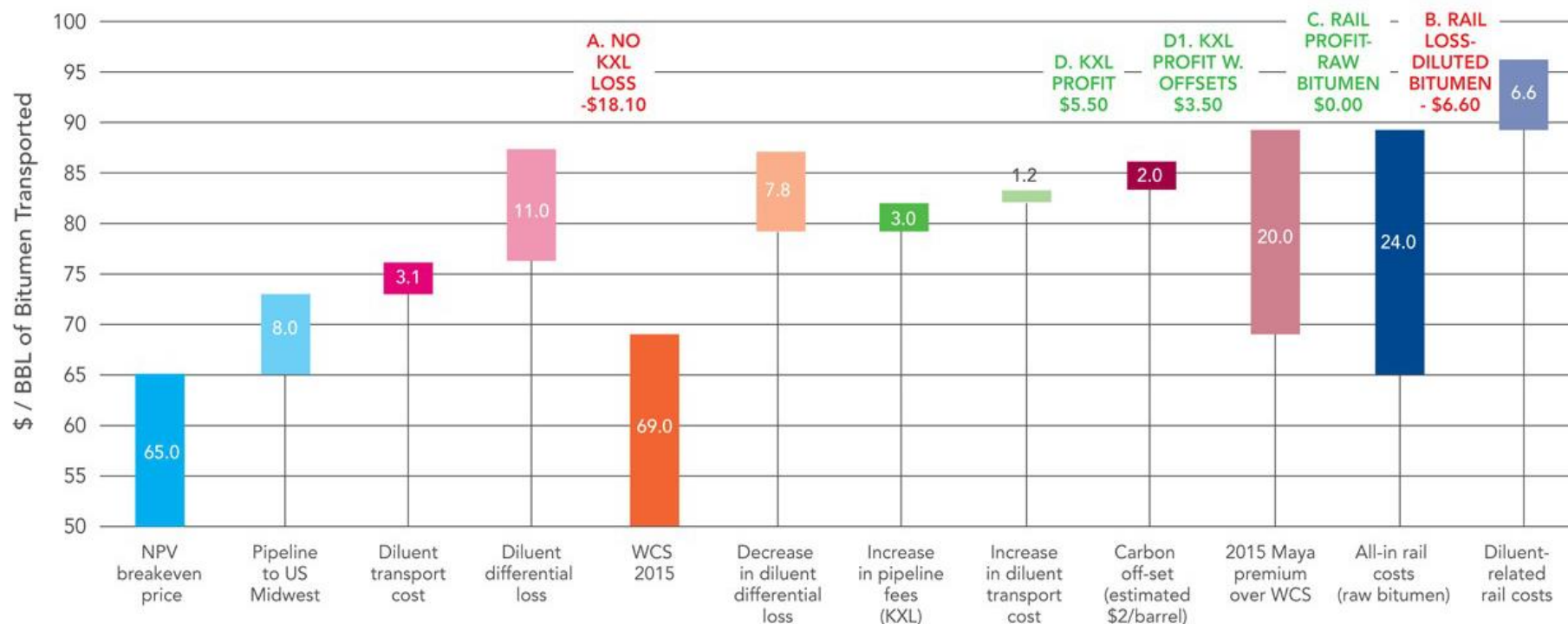
We would also emphasize that the oil industry is notoriously volatile in terms of both costs and prices, which means that projects that are already at the upper-end of the industry's cost curve – such as Canadian oil sands – are exceptionally vulnerable to both (i) higher costs than assumed, and /or (ii) lower prices than assumed.

In terms of our sensitivity analysis above, for example, it can be seen that higher costs or lower prices of only \$6/bbl than those we have assumed would mean that not even the most favourable of our scenarios -- KXL transportation of dilbit to the Gulf Coast with no CO<sub>2</sub>-pricing -- would meet its break-even requirement.

In short, unless investors are very confident about sustained higher oil prices over the medium to long term or technological improvements that would result in lower costs than those we are assuming here, the economics of new oil-sands projects with an assumed break-even of \$65/bbl look marginal even with KXL and without CO<sub>2</sub>-pricing.

We would also make the point that using a higher discount rate than the 10% used here would pressure the economics of new projects further. Indeed, given the special factors surrounding oil-sands projects – in particular, their high cost and CO<sub>2</sub>-intensity – it is legitimate to ask whether over time investors will increase the rate of return they require from investing in the oil-sands industry.

Figure 7: Breakdown of export profits for oil sands projects (\$65/bbl break-even price) with and without KXL



Sources: Rystad Energy, Standard & Poor's, RBN Energy, Carbon Tracker analysis 2013

Break-even price is the price at which asset NPV equals 0. The oil price is assumed flat with 2.5% inflation. The breakeven price is calculated for the free cash flow. Calculation assumes a 10% discount rate.

"No KXL" case assumes export to the US Midwest and Western Canada Select (WCS) pricing; "KXL" case assumes export to the US Gulf Coast and Maya (Mexican crude) pricing.

"Diluent Transport Cost" reflects added pipeline tolls/rail fees from having to transport greater volumes of a diluted product

(relative to transport volumes for an undiluted product). For pipelines, assumes product is 28% diluent and 72% bitumen; for rail, assumes product is 17% diluent and 83% bitumen.

"Diluent Differential Loss" reflects added cost due to difference in \$/bbl price between what a producer pays for diluent and is paid for diluted bitumen.

Assumes a price for diluent (C5+ Edmonton) of \$97/bbl. Assumes same diluent/bitumen ratios as listed above.

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*... and other significant risk and longer-term issues remain*

The economics of projects with costs in the \$60-70/bbl range could be imperilled by three other factors that we have not taken into consideration in our scenario analysis above:

- **Production cost inflation owing to a “KXL boom”:** Approval of KXL is likely to spur new development activity that further stretches Alberta's already tight local markets for energy, labour and materials.<sup>xlv</sup> Such pressures could potentially increase the total cost of production by 10% - in this case, diminishing profits and increasing losses by \$6.5/bbl relative to the results above.
- **Discount in Gulf Coast price relative to Maya:** This analysis has optimistically assumed that Gulf Coast refiners will pay the Maya price (i.e. the price for heavy Mexican crude) for diluted bitumen from Canada. The eagerness of refiners to maximize profits by refining heavy oil into diesel notwithstanding, added processing costs could cause the Gulf Coast price for diluted bitumen to trade at a discount to the Maya price. Moreover, further discounts might be necessary to entice Gulf Coast refiners to incur the cost of switching to a new supplier.
- **Competitive pressures reducing the Maya price:** Finally, if and when Canadian imports into the Gulf Coast were to rise, Mexico's state-owned oil company (PEMEX) might seek to maintain its market share by accepting lower prices. In so far as heavy-oil refining capacity on the Gulf were to diminish in future years -- for example, owing to refiners converting their facilities to process more of the light oil flooding in from Bakken producers<sup>xlvi</sup> -- such price competition would become more likely. If competitive pressures were to reduce future Maya prices below the \$89/bbl level we have used in our analysis above, then profits from Canadian exports to the Gulf might evaporate.

To the extent that any of the above developments might occur, doubts about the long-term economics of oil-sands projects with even moderate cost profiles would increase further. Moreover, to the extent that new projects come online with costs above \$65/bbl (as is likely to happen, as projects from 2015 onwards have break-even prices north of \$80/bbl), this similarly increases risks to oil sands profitability.

Finally, in the medium to long-term, KXL will by itself not solve the problem of insufficient export capacity for Western Canada's heavy oil; as noted above, even if all current pipeline projects are approved, by just 2025 Canada will need to add 1mbd of additional export capacity just to keep pace with rising demand.<sup>xlvii</sup> Hence, after a short reprieve, projects brought on-line as a result of KXL might soon again be facing depressed prices.

### *Prices and production: how the market would likely respond to KXL*

The upshot of the above discussion is that approving KXL might significantly increase spending on new oil-sands projects. For example, analysts at RBC Capital Markets have estimated that between 2014 and 2017 up to \$9.4 billion of investment in oil-sands projects may hinge on the outcome of KXL.<sup>xlviii</sup> Beyond direct execution of projects already planned, KXL approval might lower the cost of financing additional rounds of new project investment by making oil sands producers more attractive to financial investors.

**Higher predicted revenues will improve creditworthiness and access to capital**

Higher revenues and incremental cash flows as a result of KXL would likely increase the perceived creditworthiness of oil-sands producers, thereby lowering their cost of debt and making investments to expand production more financially attractive.

Standard & Poor's has clearly articulated the credit implications of new export routes for Canadian oil-sands oil, noting that "should pipelines be delayed or cancelled, we believe the credit profiles of companies that have a lot of heavy crude oil in their product mix will deteriorate."<sup>xlix</sup> Standard & Poor's analysts judge this to be significant since "all of these speculative-grade companies require external debt and equity funding to develop their oil-sands resources" and "access to capital markets is neither predictable nor certain for companies with weak or inadequate internal liquidity."<sup>l</sup>

For smaller companies without sufficient internal cash-flow to self-finance new investments, the higher profitability -- and hence lower perceived business risk -- enabled by KXL could tip the balance toward giving these companies the external capital to expand oil sands production even further.

For the largest oil-sands producers, stronger WCS pricing could also materially affect cash-flow, debt coverage ratios, and hence access to credit. Goldman Sachs has estimated that every \$1/bbl move in the WCS price can affect EBITDA by 0.1-1.2%.<sup>li</sup> The higher end of this range suggests that an \$8/bbl increase in the WCS price -- such as KXL might help to precipitate -- could increase the EBITDA of large oil-sands producers by up to 10%.

**KXL has an impact on analyst pricing of oil-sands producers**

Analysis by RBC during 2013 has indicated the range of valuations analysts are placing on oil-sands operators with and without KXL. If KXL made no difference to future production and revenues then there would be no share-price impact. RBC indicate that the Net Asset Value of some oil-sands operators would be affected by up to 8% if KXL were not to be approved.<sup>lii</sup> Values would be compressed even further by a widening price differential between Brent and Western Canadian Heavy Oil.

## 5. Conclusion: KXL is a potential mirage for oil-sands investors

### *KXL risks creating stranded assets even without CO<sub>2</sub> pricing*

By removing the key bottleneck on expansion of oil production from Canada's oil sands -- a lack of export capacity -- KXL could increase production of more carbon-intensive oil sands by up to 20% over the next decade. However, even if KXL were to provide a temporary respite to the oversupply of Western Canadian heavy oil, heavy price-discounting might return to harm projects in two to three years unless further export routes could be found.

As our analysis has shown, the price sensitivity of oil sands projects makes them vulnerable with or without KXL, especially for projects above \$65/bbl used for analysis in this report. KXL might therefore only temporarily give false confidence in marginal oil-sands projects which would struggle again once the extra export capacity provided by KXL was used up.

In the final analysis, oil sands are at the upper end of the upper quartile of the global oil-industry cost curve and are more carbon-intensive than conventional crude oil; as such they should immediately hit an investor's higher-risk screen. Our analysis has shown that even without carbon pricing new oil-sands projects are a risky investment at current oil prices, and hence all the more so if either: (i) the ongoing US tight-oil boom puts further and prolonged downward pressure on WTI prices (the ultimate benchmark for all oil sold in North America); or (ii) carbon pricing were imposed as a condition of KXL approval. These risks should therefore be flashing lights on investors' risk screens.

Over the longer term, and from the standpoint of a global carbon budget, continued investment in oil sands signals either: (i) an increasing likelihood that emissions from unconventional oil-and-gas production will be decisive in pushing global CO<sub>2</sub> emissions beyond a 2°C threshold as less than a third of global oil, coal, and gas reserves can be commercialized by 2050 if climate goals are to be met; or (ii) that investors are in effect allocating more capital toward assets that are likely to become stranded -- owing to their product becoming unburnable -- as a result of more stringent emissions regulation in the future.

**Indeed, given the special factors surrounding oil sands projects -- in particular, their high cost and high carbon intensity -- it is legitimate to ask whether over time investors will increase the rate of return they require from investing in the oil sands industry. Using a higher discount rate than the 10% we have used in our analysis in this report would pressure the already questionable economics of new oil-sands projects further.**



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