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Published By: NEWS COMMUNICATIONS since 1977

Saturday August 30th, 2014

## COST-CUTTING FEVER GRIPS OIL SANDS PLAYERS AS ECONOMICS CALLED INTO QUESTION

Canadian oil companies are ruthlessly enforcing capital discipline as project costs creep up and shareholders pressure management to focus only on the most profitable ventures.

Suncor Energy Inc. announced a billion-dollar cut for the rest of the year even though the company raised its oil price forecast.

Others such as Athabasca Oil Corp., PennWest Exploration Ltd., Talisman Energy Inc. and Sunshine Oil Sands Ltd. are also cutting back due to a mix of internal corporate issues and project uncertainty. Cenovus Energy Inc. is also facing cost pressures at its Foster Creek oil sands facility.

“Given that the low-bearing fruit have already been developed, the next wave of oil sands project are coming from areas where geology might not be as uniform,” said Dinara Millington, senior vice president at the Canadian Energy Research Institute.

Cost escalation is causing oil sands participants to rethink the economics of projects

The global oil industry is gripped with the cost-cutting fever amid shareholder pressure, but the oil sands are particularly vulnerable given their baked-in higher development costs, high wages, remote location and infrastructure challenges. In May, France’s Total SA shelved an $11-billion oil sands mine project planned with joint venture partners Suncor, Occidental Petroleum and Inpex Canada.

“Oil sands are economically challenging in terms of returns,” said Jeff Lyons, a partner at Deloitte Canada. “Cost escalation is causing oil sands participants to rethink the economics of projects. That’s why you’re not seeing a lot of new capital flowing into oil sands.”

Existing in-situ oil sands projects in Alberta are produced at a breakeven cost of US$63.50 per barrel on average, while integrated oil sands mining projects have a breakeven cost of US$60 to US$65, including a 9% after-tax return, compared to the Saskatchewan Bakken's US$44.30 a barrel cost.

SAGD operations saw a 5.1% jump from 2011 to 2013 on average, while mining and extraction was up 6.1% and integrated mining and upgrading 7.9% during the period, CERI data shows. Last December, Canadian Natural Resources Ltd. and the Alberta government revised cost estimates of their 50,000-barrels per day upgrading project by 49%.

"Costs in the oil sands are rising faster than general inflation, and it's a culmination of many factors," Ms. Millington said, adding that currently many producers are reporting a bit of a pause in new contract awards and backlog.

Indeed, large-scale developments present "material inflation risks," RBC Capital Markets said in a June report.

Even "smaller SAGD projects like Sunshine's West Ells or Pengrowth's Lindbergh have announced cost increases while Athabasca's Hangingstone has experienced modest scheduling pressure and delays," Canada's biggest bank by assets said.

The trend of cost rationalization is not unique to the oil sands and rippling across the global industry thanks to the "abundance" of assets, according to Barry Munro, oil and gas leader at Ernst & Young.

"It's not about scarcity of resources anymore. Companies are realizing they have far more assets than they are ever going to have capital to be able to exploit — they feel they have to structurally change their business model."

Indeed, business plans are in a state of flux. Oil and gas deals in Canada rose 23% in the first half of the year, according to management consultancy Deloitte LLP, but much of the activity took place outside the oil sands sector.

"Deal activity has cooled in Canada's vast oil sands reserves as producers have struggled with rising costs, in part because of stricter environmental regulations," Deloitte said in a recent report. "Even with oil at more than $100 per barrel, some large producers have been cancelling projects because higher costs have crimped returns."

Richard Grafton, chief executive officer of Grafton Asset Management, says oil prices may have to go higher for new investors to favour oil sands.

"Right now, the [price] band that we are in for a number of years is around $100, and frankly, may be we need at a higher price with access to global market, before we get excited about that [the oil sands]," Mr. Grafton told the Financial Post in an interview last week.

A recent report by London-based Carbon Tracker Initiative estimated that a number of oil sands projects would be economically impractical at oil prices below $130 per barrel.

RBC Capital, which is confident that the existing oil sands players will meet their production targets profitably, estimates the industry will require between $26-billion to $33-billion each year to maintain existing production and raise output by an additional 250,000-bpd annually till the end of the decade.

"Challenges and constraints exist such as pipeline capacity and technology development, however, financing is perhaps the biggest challenge facing development stage oil sands companies at this time," RBC noted.

Stricter government regulations around control of oil sands assets by state-owned enterprises and Chinese investors' disappointment with their Canadian investments may see a further slowdown in new activity.

But the Canadian industry is fighting hard to remain a competitive jurisdiction.

A shift towards smaller in-situ projects that allow more flexibility capital and skilled labour is helping rein in costs, CERI said in its report.

Apart from innovation in technology that has transformed the oil patch and turned Canada into an energy technology hub, innovative financial structures and organizational efficiencies are also helping curb costs.

"The number one mistake producers made is they didn't spend enough time to do front-end engineering and design," which led to cost overruns, Ms. Millington said. Imperial Oil Ltd, for example, has seen cost overruns at its Kearl project and continues to struggle with cost efficiencies and production, disappointing analysts.

Canadian ingenuity and innovation will have to be at the forefront if the industry is to shed its reputation as a high-cost jurisdiction.

"There is a shortage of labour, in this sector, that causes cost to rise," said Charles Knight, partner, M&A Transaction Services, Deloitte Canada. "The infrastructure costs are going to be large so that will weigh on it. The dollar hurts us — it helps from revenue point of view, but it hurts from a cost point of view as the inputs are U.S. dollar-denominated."

The regulatory body is also looking to help with the economics. The Alberta Energy Regulator said it will test a play-based regulatory framework for unconventional oil and gas development, starting with an area in Duvernay, in west-central Alberta. Traditionally, the AER regulates the industry well-by-well.

Under the pilot, companies will submit single applications to gain a better understanding of the basin before they start pumping in investment.

"From the energy company's perspective, they want some confidence as they are going to spend the initial capital, given the long development cycles of these projects," Mr. Munro said.

If successful, the regulatory framework will be rolled across Alberta.

While technology and friendlier regulations will help rein in costs, the external challenges facing the industry remain formidable.

Apart from the well-documented transportation challenges, high labour costs and lack of other infrastructure could impede development, as would a sudden drop in oil prices. Brent and WTI has been trending lower amid high inventories and a slowdown in Europe.

"Oil sands projects that are already producing will be okay… but projects that are approved but haven't started construction, and projects that have just only been announced are definitely at risk — at various degrees of riskiness," Mr. Millington said.

## DETAILS ON HOW ENBRIDGE WILL EXPAND CAPACITY OF ALBERTA CLIPPER OIL SANDS CRUDE PIPELINE WITHOUT US REVIEW

Enbridge has devised a way to ship more oil sands crude from Alberta to the US via its Alberta Clipper pipeline without getting further tangled in the type of review that has kept TransCanada's Keystone XL pipeline proposal mired in limbo for years: switching crude from one pipeline in its existing system to another before it crosses the border and then back again.

The US State Department, which bears the responsibility for approving cross-border energy projects, said that Enbridge can indeed proceed with its plan under authority granted by previously issued permits.

Enbridge says it operates the largest, longest, and most complex petroleum pipeline system in the world: approximately 25,420 kilometers (15,795 miles) of pipe delivers an average of more than 2.2-million barrels per day of crude oil and liquids. The Enbridge Mainline system is the largest conduit of oil into the United States. Enbridge transports 53% of US-bound Canadian production, a figure that accounts for approximately 15% of total US crude oil imports.

The existing Mainline system into the US constitutes four primary pipelines (Lines 1, 2, 3 and 4) as well as related lines, including Line 67—the Alberta Clipper.

In 2009, the State Department issued a Presidential Permit authorizing the construction, operation and maintenance of the 36-inch diameter Line 67 pipeline extending between the US-Canada border near Neche, ND and the first US mainline shut off valve or pumping station in the United States.

That near-border segment of the Pipeline authorized by the 2009 Permit is only 3-miles long. Enbridge constructed the remainder of the Line 67 Pipeline in the United States to its southern terminus at Superior, Wisconsin, pursuant to other local, state and federal permits. Enbridge completed construction and began operations of Line 67 (Alberta Clipper) in 2010; the pipeline currently transports an average annual capacity of approximately 495,000 bpd of crude oil across the border.

In 2012, Enbridge requested that the US Department of State issue a new Presidential Permit to authorize Enbridge to operate the border segment of its existing Line 67 crude oil pipeline up to its full design capacity. Full design capacity for Line 67 is 880,000 bpd for heavy crude. (This will vary based on the type of product transported. For example, the full design capacity of Line 67 would be greater than 880,000 bpd were light crudes transported on the line, which could be case in the future, the company noted.)

However, the permitting process did not proceed as smoothly or quickly as Enbridge had planned. Hence, in a 16 June 2014 letter to the State Department, law firm Steptoe & Johnson explained that:

… shipper needs dictate that the annual average capacity of Line 67 in the United States be increased up to 570,000 bpd by mid-2014 (referred to as "Phase I"), and up to 800,000 bpd by mid-2015 (referred to as "Phase II"). As we explained, the unforeseen Line 67 Project permitting delay at the Department of over a year has led Enbridge to recently assess options for achieving this additional capacity both at the border, albeit not on Line 67, and on the portion of Line 67 south of the border segment, consistent with Enbridge's obligations as a common carrier pipeline operator and its existing Presidential Permits.

… To avoid adverse impacts to shippers of the sort described by the ALJ [Administrative Law Judge], Enbridge has decided to optimize its existing Mainline System to provide the flexibility and efficiency that it would need to transport increased volumes of crude oil from Canada into the United States within the terms of its existing Presidential Permits, as explained below.

The basic plan is to build interconnections between Line 67 and the adjacent Line 3 to give Enbridge the capability to increase the volume of crude oil. The increased flow will:

1. Move on Line 67 in Canada towards the border;

2. be transferred to Line 3 at Enbridge's Gretna, Manitoba station at a point approximately 1.5 miles (2.4 km) north of the US-Canada border;

3. cross the US-Canada border on the Line 3 border segment; and

4. then be transferred back to Line 67 approximately 16 miles (25.7 km) south of the US-Canada border for delivery to Superior.

Enbridge is planning four interconnections between Lines 3 and 67 as part of this project. Two interconnections will be constructed between Line 67 and Line 3 at the Gretna station in Canada to allow crude oil to move between the lines north of the border crossing; and two interconnections will be constructed between Line 67 and Line 3 in the United States to allow crude oil to move between the lines at a point in North Dakota about 16 miles south of the border, which is south of the first US mainline valve for each line.

Enbridge envisions possible future interconnections between Line 3 and Line 4.

The construction and operation of the US interconnections does not require any federal, state, and/or local approvals, the company said. The Canadian interconnections will be constructed within the boundaries of Enbridge's existing Gretna station; Canadian approvals have already been obtained.

The company also has Canadian approval to transport increased volumes of crude oil on Line 67 in Canada up to 800,000 bpd. Enbridge is currently constructing the pump upgrades in Canada to allow for an increase in the authorized capacity of the line in that country. Once construction of those pump upgrades is complete, which is expected in the coming weeks, Enbridge will have the operational flexibility to flow an increased amount of oil on Line 67 in Canada to the Line 3 border segment for transportation across the US-Canada border.

Enbridge said it has also obtained all necessary US approvals to transport an average annual capacity of 570,000 bpd on Line 67 south of the Line 3 interconnection and plans to do so.

Enbridge has already received approval for and has begun construction of a pump upgrade in Minnesota to support 570,000 bpd. However:

… unless and until the Department issues the requested Presidential Permit allowing Enbridge to transport more than 500,000 bpd across the border on Line 67, the interconnections will actually result in a decrease of 105,000 bpd of crude oil across the Line 67 border segment (from the current 495,000 bpd of heavy crude to 390,000 bpd of light crude), and an increase of 180,000 bpd of crude oil (from 390,000 bpd of light crude to 570,000 bpd of heavy crude) across the Line 3 border segment. These cross-border volumes are compliant with the currently applicable Presidential Permits for both lines.

The pipeline interconnections thus provide Enbridge with the operational flexibility to transport crude oil in the range of 800,000 bpd of oil on Line 67 south of the Line 3 interconnection through the construction and operation of the pump upgrade.

The use of pipeline interconnections is a standard industry practice; multiple interconnections already exist between Enbridge Lines 2, 3, and 4 both in Canada and the United States. Enbridge is also constructing an interconnection between Line 67 and Line 4 at Hardisty in the event of a shutdown of Line 4 between Edmonton and Hardisty.

Enbridge said that it will construct the interconnections and pump upgrades, and to operate those facilities to increase the flow of oil on Line 67 south of border segment, whether or not the requested new Presidential Permit is issued by the State Department.

In other words, the interconnections and Pump Upgrades are not a result (either directly or indirectly) of the Department's action on Enbridge's pending application because the Pump Upgrades and interconnections, and any resulting environmental impacts, will occur regardless of whether the Department issues a new Permit to authorize an increased level of flow on the border segment of Line 67.

## BYPASSING KEYSTONE: CANADIAN FIRM USES LOOPHOLE TO SHIP OIL SANDS TO U.S.

Instead of waiting to obtain a "presidential permit" to ship oil sands from Canada to the United States, one Canadian firm has found a workaround, and environmental groups aren't happy about it.

Pipeline operations giant Enbridge has figured out how to avoid having to go through the regulatory process with the U.S. State Department for approval of an oil sands pipeline.

According to EnergyWire, the company plans to build several interconnections on either side of the border between Manitoba and Minnesota. The interconnections will allow the company to transfer heavy oil from its Alberta Clipper pipeline to another pipeline known as "Line 3." It will then be transferred back to the Alberta Clipper line once it is safely across the border in Minnesota.

The Line 3 pipeline would do the same. It is much older and normally does not run at full capacity. A 17.5 mile stretch of the pipeline was retrofitted in order to handle the heavier oil sands from the Alberta Clipper. The lighter oil from Line 3 would be switched over to the Alberta Clipper pipeline until it crosses the border, and then switched back.

The result will be the ability to increase the flow of oil sands to the United States by an additional 75,000 barrels per day without having to obtain White House approval. Both pipelines would meet regulatory requirements under existing permits.

The State Department is going along with the scheme. In an email sent to Enbridge in July and only recently made public, State Department official Patrick Dunn said, "Enbridge's intended changes to the operation of the pipeline outside of the border segment do not require authorization from the U.S. Department of State."

Environmental groups blasted the move, accusing the Obama administration of making backroom deals.

"When it comes to the climate crisis, President Obama's central purpose ought to be, 'Do no harm,' " Marc Fink, an attorney with the Center for Biological Diversity, said in a press release. "The administration's approval of this Alberta Clipper scheme certainly violates that doctrine. President Obama said he wouldn't approve Keystone XL if it significantly exacerbates the problem of carbon pollution. He must hold the same standard when it comes to the Alberta Clipper."

The move to switch pipeline flows and the willingness of the State Department to look the other way would appear to be an effort on behalf of the Obama administration to avoid another protracted fight over a pipeline. The Keystone XL permitting process has dragged on for years, and TransCanada, the company proposing the pipeline, has only scars to show for its six-year battle with environmental groups and the U.S. government.

Enbridge submitted an application back in November 2012 to increase Alberta Clipper line's capacity from 450,000 barrels to 880,000 barrels per day. But it did not want to wait to see its Alberta Clipper line suffer a similar fate as Keystone XL. So it has come up with the plan to swap oil flows between two existing lines.

Enbridge downplayed the significance of the move, calling it a temporary measure until the State Department considers its application for an expansion of Alberta Clipper. "Ultimately this is about meeting shipper requirements for capacity," Enbridge spokeswoman Lorraine

Little said on Aug. 20. "We are utilizing this optimization in order to meet that. We do see it as a short-term solution until the full Department of State review is completed."

The recently released documents depicting the State Department's consent for the plan risks igniting a broader fight from environmental groups over a project that has thus far stayed out of the limelight. They see the Alberta Clipper project as the same as Keystone XL, and will take the administration to task for appearing to abdicate regulatory responsibility over the project.

But it may be too late. Since the State Department says that Enbridge has complied with the law, there is likely little recourse. Enbridge is expected to complete the interconnections in September. Despite the efforts to block Keystone XL, the U.S. is about to see increased flows of oil coming from Canada's oil sands.

## CHEVRON PEGS PRICE OF CANADIAN OIL PROJECT AT USD1.5 BILLION

One of the assets of Chevron Corp is the Duvernay shale formation in Canada. Now, it is in the process of searching for equity investors for the project. The projected amount needed for the project was priced at USD1.5 billion, according to anonymous sources familiar with the transaction.

The sale would be overseen by Chevron's subsidiary in Canada, Chevron Canada Ltd. The assets consist of exploration leases for about 330,000 acres in the Duvernay formation, about 124 miles of Edmonton, Alberta, Canada.

Chevron had sent out a memorandum to offer the ownership to possible investors. The anonymous sources further added that the ideal equity investor for the development is one who looks at the long term, as oil and gas exploration and development takes years for the return on investment to be realized.

The formation, according to the Canadian Energy Resources Conservation Board, 'holds an estimated 443 trillion cubic feet of gas and 61.7 billion barrels of oil.' The process utilized is horizontal drilling and multi stage hydraulic fracturing.

When sought for comment, representatives of Chevron declined to provide any.

Just last October 2013, Chevron Canada had announced it had completed the initial exploration of the Kaybob area in Duvernay. The next step in the plan was to transition to a two rig drilling set in order to efficiently conduct its business as well as comply with the original design for the area.

The money from the equity investment would help address some of the risk in the development of the next programme set for the project. The Duvernay project commenced in 2011 and as of August 2014, completed the drilling of 15 wells. It had completed the infrastructure for 13 of the wells and had connected 10 of the wells to facilities of other project partners for processing of the oil and gas yields.

The main drawback for many equity investors is the length of time for the investment to reap returns. There are some who have expressed interest in short term investments but not ultimately partner with Chevron because the profit yields may take too long for it to become viable.

Chevron has actually increased its exposure in Duvernay by 20%. Just this August, the company bought out Alta Energy Luxembourg from its 68,000 acres of lease holdings in the area.

The San Ramon, CA based company is not the only presence in the Duvernay shale formation area. Amongst the companies in the region are Penn West Petroleum Ltd., Royal Dutch Shell Plc., and Athabasca Oil Corp.

This is not the only project Chevron is seeking a new partner. Another project, the Kitimat LNG venture suddenly became available to the market as the original partner, Apache Corp had pulled out. The plan was to export liquefied natural gas from British Columbia to its purchasers worldwide.

Instead of increasing its interest, Chevron instead took the tact of assuming Apache's 'upstream' business role in the project. With this, it would operate the natural gas drilling operations at the Liard and Horn River areas in northern British Columbia in Canada.

## INTER PIPELINE THRIVES OUT OF KEYSTONE GLARE: CORPORATE CANADA

For Canadian oil-sands pipeline companies, operating under the radar pays.

Inter Pipeline Ltd. is leading shareholder gains among Canadian peers as it operates within the oil-friendly provinces of Alberta and Saskatchewan, avoiding the environmental controversies that have dogged projects from larger competitors such as TransCanada Corp.'s Keystone XL. Pembina Pipeline Corp., with a focus on Western Canada, hit a record high yesterday.

"Inter Pipeline has been an untold story for a long time," Steven Paget, an analyst at FirstEnergy Capital Corp. in Calgary who rates the stock the equivalent of hold, said by phone. "It has a great order book and is possibly adding a lot more to that order book."

The company is profiting from growing demand for shipments of oil-sands crude to nearby hubs as producers from Imperial Oil Ltd. to Suncor Energy Inc. invest more than C$20 billion ($18 billion) a year to tap the world's third-largest reserves. The Calgary-based pipeline operator transports about 40 percent of all oil-sands output.

About C$3 billion of potential contracts in coming years mean business is set to keep growing, Paget said.

Inter Pipeline has surged 40 percent this year in Toronto. That's the most among the five largest Canadian pipeline operators, data compiled by Bloomberg show, and double the 20 percent delivered by TransCanada, whose signature Keystone XL project faces mounting opposition and approval delays in the U.S.

The company is worth C$11.6 billion based on yesterday's stock price, less than a third the market value of TransCanada.

Filling In

Shares of Calgary-based Pembina closed at a record C$49.61 yesterday and have advanced 33 percent this year.

Inter Pipeline has filled in links between oil-sands production sites and transportation hubs like Edmonton and Hardisty in Alberta through 2,600 kilometers (1,616 miles) of pipes, while another 3,700 kilometers connect conventional oil fields in Alberta and Saskatchewan with main lines. It also has 3.8 million barrels of storage capacity.

Its shipments of bitumen and diluent rose 11 percent from a year earlier in the second quarter, reaching 858,000 barrels a day, a bigger volume than Qatar's crude output.

The pipeline operator plans to expand its Cold Lake and Polaris systems as well as to increase its Mid-Saskatchewan network.

Output Outlook

"They have a core backbone of pipe for oil-sands production and diluent that has allowed them to grow dramatically over the past several years," said Jennifer Stevenson, who helps manage about C$100 billion in assets at Dynamic Funds, a unit of Toronto-based DundeeWealth Inc. "The energy infrastructure space in general continues to have a strong long-term growth outlook with sustainable and growing dividends."

Inter Pipeline has no plans to expand its network with big "multi-billion dollar" cross-border projects like Keystone XL or Northern Gateway, said Tony Mate, a company spokesman.

"We think we're fairly well positioned going forward," said Mate in a phone interview. "Our cash flow is going to grow and become more stable." The company expects most of its growth to come from expansion of the oil sands and that its market share is "defensible," he said.

Pembina Pipeline's investor relations department wasn't immediately available yesterday to comment.

Canadian oil production is set to increase 4 percent a year on average to 6.4 million barrels a day in 2030 from 3.5 million last year, according to a June 9 forecast by the Canadian Association of Petroleum Producers.

Less Growth

Inter Pipeline, which also owns storage facilities in Europe and natural gas liquids extraction plants, was originally created in 1997 as a fund and converted to a dividend-paying corporation a year ago, allowing some foreign investors to become shareholders.

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posted second-quarter net income attributable to shareholders of C$81.7 million on Aug. 7, compared with a C$283.9 million loss a year earlier. Full-year net income excluding one-time items will reach about C$372 million, compared with a loss of C$58.1 million last year, according to seven analysts' estimates compiled by Bloomberg. Revenue is forecast to rise 19 percent to C$1.63 billion.

Some analysts see Inter Pipeline's pace of growth slowing in the coming year.

"With an enterprise value of over C$16 billion, we believe it will be tough for Inter Pipeline to maintain its existing level of growth," Robert Hope, an analyst at Macquarie Capital Markets Canada, said in an Aug. 22 note.

Oil Prices

The pipeline company will likely complete its large oil- sands trunk line projects this year, resulting in a "significant step down" in 2015 and 2016 capital expenditures, Hope said in the note.

Still, with prices for the West Texas Intermediate crude benchmark remaining close to $100 a barrel, the company's services will probably be in demand in step with continued production gains.

"We continue to like the stock, which we see as standing out from its peers due to a consistent track record of being able to secure trunk-line expansions at reasonable returns," said Robert Kwan, an analyst with Royal Bank of Canada's RBC Dominion Securities Inc. in Vancouver, in an Aug. 8 note.