# CANADIAN ENERGY
# INVESTMENT OUTLOOK 2008

A SUPPLEMENT TO

Oil and Gas Investor

JUNE 2008

The Oil & Gas Asset CLEARINGHOUSE

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**About the cover:**
A Bear Drilling Co. rig looks for natural gas in British Columbia. *(Photo by Lowell Georgia)*

A casual observer might think that the Canadian oil patch is in trouble. It is indeed going through turbulent times, what with Alberta's increased royalty package and a dramatic fall-off in natural gas drilling—which opens up more exploration and development activity in neighboring British Columbia and Saskatchewan.

Cost creep continues to plague every basin in the world and the mature Western Canadian Sedimentary Basin is no exception. The capital-intensive oil-sands projects are even more vulnerable to increased costs for everything from steel to welders' wages. More royalty income trusts have disappeared through merger thanks to regulatory changes.

However, there is always much more to the story, as there are some bright spots as well, despite the surprisingly negative actions of the governments that oversee the Maple Leaf oil patch.

Producers are undaunted as they look for the next big opportunity. Some have found it in the Horn River Basin in northeastern British Columbia, site of the latest in a long list of shale plays throughout North America to gain attention from E&P companies and investors.

A report here from consulting firm Wood Mackenzie outlines details of its high prospectivity. Some think that this shale could hold up to 31 trillion cubic feet of gas.

Based on the preliminary announcements of companies involved such as EnCana and EOG Resources, this shale may be as good as, or better than, the prolific Barnett shale in Texas, although it is still early in its development.

In 2007 five royalty trusts either merged or converted to an E&P format—and one was acquired by the Abu Dhabi National Energy Co. for $C5 billion. More upheaval is to come as the trusts adapt to changes in Canadian tax laws. In upheaval lies opportunity.

The world eagerly awaits more oil production from the oil sands near Fort McMurray in northern Alberta. With costs having tripled since 2001 for a project expected online by 2010, the majors have the most muscle to stay in the game here. However, we chose to shine a spotlight on four smaller companies that are making inroads with new technologies applied for their in-situ operations.

–Leslie Haines, editor-in-chief,
*Oil and Gas Investor*

## CONTENTS


UNCONVENTIONAL
Where are the greatest opportunities found? In our business, they are everywhere.
The fact is, some companies are better at finding opportunity than others. Companies that are adaptive, collaborative and nimble. That are focused and innovative. Companies like Trans-Orient Petroleum Ltd.
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TRANS ORIENT

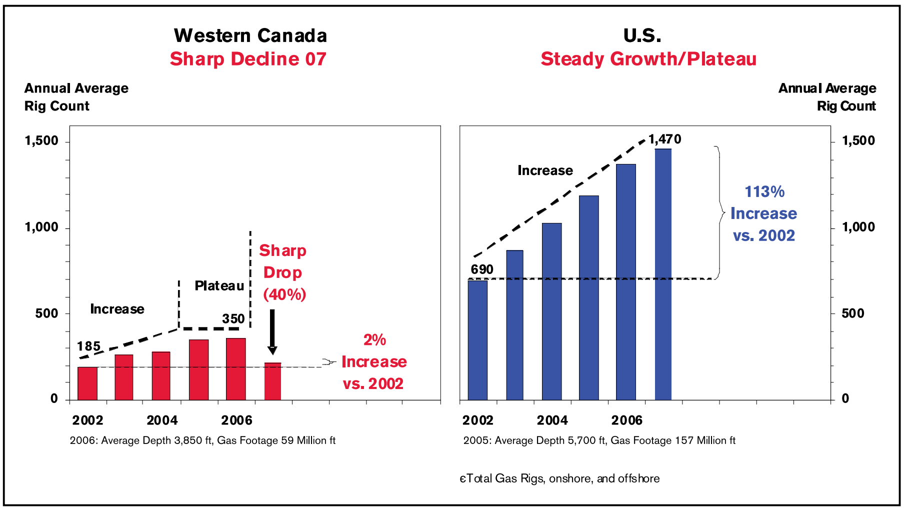
*A Calgary consulting firm provides a quick snapshot of trends in Canadian gas drilling, reserve replacement rates, gas production outlook and exports of Canadian gas to the U.S.*

# Gas Exports to U.S. Appear Threatened

BY BILL GWOZD, *Ziff Energy Group*

A number of negative factors has buffeted the Canadian oil patch over the past two years, ranging from adverse regulatory changes to lower natural gas prices as the Canadian dollar has risen in value. These forces now appear to be affecting drilling activity, and hence, gas production, at least in the near term.

The Canadian government's taxation change for the energy trusts (conveniently issued on the eve of Halloween 2006) will eliminate the perceived trust advantage in 2011. This will adversely impact the longer-term Canadian gas production outlook as these trusts focus on how to meet this tax change, or disappear through mergers with traditional companies.




Canadian gas drilling from 2001 to 2007 has declined, while U.S. drilling has risen steadily.
(Source: Baker Hughes; Ziff Energy Estimates, EIA, Nickles)

## DRILLING DECLINE

Since 2000, Canadian drilling has been typically 60% to 75% directed to natural gas wells, but the numbers have been falling steadily. In 2007, some 12,600 gas wells were completed, down 17% from 2006 and down 19% from the record set in 2004.

The first quarter of 2008 showed gas-directed drilling was down 27% from the already reduced 2007 pace.

Further, gas exploration activity was down a whopping 46% for 2008's first quarter vs. the same quarter in 2007, another early indicator of gas production declines to come. The type of gas wells drilled in 2007 were 80% development and 20% exploration. When comparing Western Canada drilling activity to U.S. activity, it is apparent that Canada is indeed slowing down.

The depth of Western Canadian gas wells drilled in 2007 averaged 3,740 feet, much shallower than the U.S. average. A third of gas drilling occurs in the southeast portion of Alberta/southwestern Saskatchewan (on Montana's northern border). A positive indicator is that dry wells are now below 5% of the total drilled, well down from 14% in the last decade.

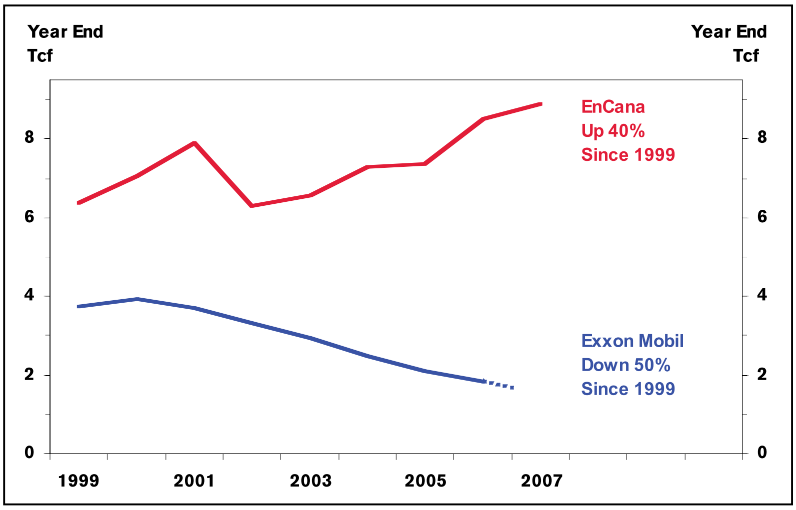
Calgary-based EnCana is the most active producer, drilling the most new gas wells, followed by EOG Resources and ConocoPhillips, both based in Houston; and by Husky Energy and Canadian Natural Resources Ltd., both of Calgary. Leading natural gas trusts include Enerplus Resources, Paramount Energy Trust and ARC Energy Trust.

Drilling of coalbed methane gas wells in Alberta's Horseshoe Canyon formation reached more than 2,100 completions in 2007, 17% of total gas drilling activity, although this number was down 5% from the record CBM completions recorded in 2005. During the past four years, producers completed more than 7,500 CBM wells, typically 2,300 to 2,800 feet deep. Leading operators include EnCana, Quicksilver Resources, Trident and EOG.

## REPLACEMENT RATES, RESERVE LIFE

One means of measuring gas producers' drilling activity and effectiveness is by calculating their proven gas reserve replacement rates and reserve life. Reserve replacement is defined as proven reserves added, divided by gas produced. Adjustments are made to reflect revisions (+/-) and improved recoveries. When replacement rates exceed 100%, the producer is adding reserves. Ideally, over a longer period of time, a successful producer will build its gas reserve base.

Consider EnCana and ExxonMobil, the two leading gas producers




Canadian proven gas reserves (includes royalty volumes) for these two companies diverge. (Source: Company annual reports)

in Canada 10 years ago. During the past decade, EnCana continued to invest in Canada and steadily grew its proven gas reserves by 40%. Conversely, during the same period ExxonMobil implemented a "harvest" producing strategy and thus, its proven remaining Canadian gas reserves have declined by half.

A second metric is proven reserve life index (RLI). This measures the remaining life of the producer's gas reserves assuming that they are produced at current rates. For example, EnCana's RLI is nine years, similar to the top 25 Canadian gas producers' average of 8.9 years. (This is well below the U.S. average of almost 13 years.)

## GAS PRODUCTION OUTLOOK

While 97% of Canada's gas production is in the Western Canadian Sedimentary Basin, a small amount of gas production occurs offshore Nova Scotia, with minor quantities produced in New Brunswick and Ontario. Western Canadian production peaked at 17 billion cubic feet per day and is now struggling to keep flat at 16 Bcf day.

In fact, Western Canadian gas production is starting to show signs of fatigue. Canadian gas supply is slipping mainly due to a reduction in drilling, smaller average gas reserves found for new gas wells, and declining new-gas well productivity. A decade ago, a typical new gas well would produce 0.7 million cubic feet (MMcf) per day—but in 2008 the average new gas well produces only 0.2 MMcf day.

Three gas producers (EnCana, Canadian Natural and ConocoPhillips) comprise a third of Western Canada's gas production, and they have maintained this supply share for the past half-dozen years. The gas-oriented royalty trusts' supply share is about 30%.

For the cheering squad hoping to see more gas production eventually from Canada's "new white hope" in Santa's backyard, the Mackenzie Delta, there are a number of challenges that may prove too great to overcome. For starters, the cost, including gathering, has escalated to more than $10 billion for a 0.8- to 1.5-Bcf-a-day gas pipeline. Contrast this with the $4 billion-plus Rockies Express (Rex) interstate gas pipeline now beginning operations in the U.S., which transports 1.8 Bcf a day from the U.S. Rockies to Ohio.

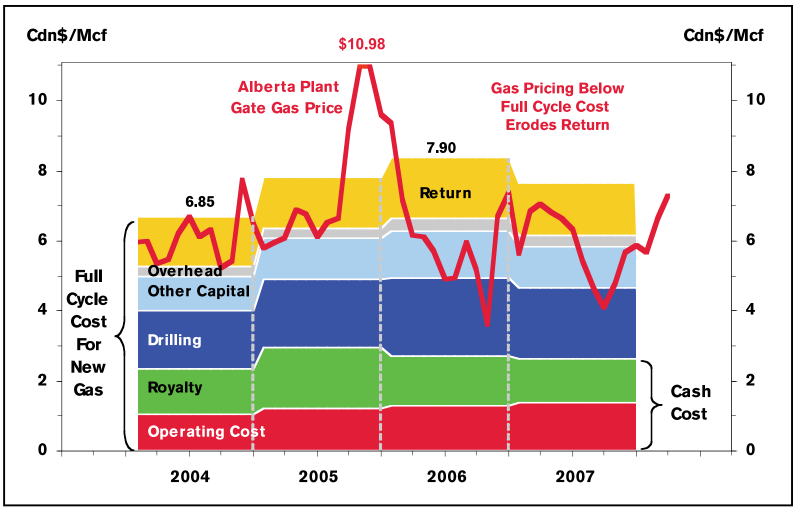
Secondly, the available proven gas resources are not adequate to keep the Mackenzie Delta pipeline full for the 20-year economic life. Notwithstanding these mammoth hurdles, there are many pin-stripes feverishly working to find a way to "skin this cat." If a successful path is found, then the earliest that this new Canadian gas would flow is the middle of the next decade.

## FULL-CYCLE GAS COSTS

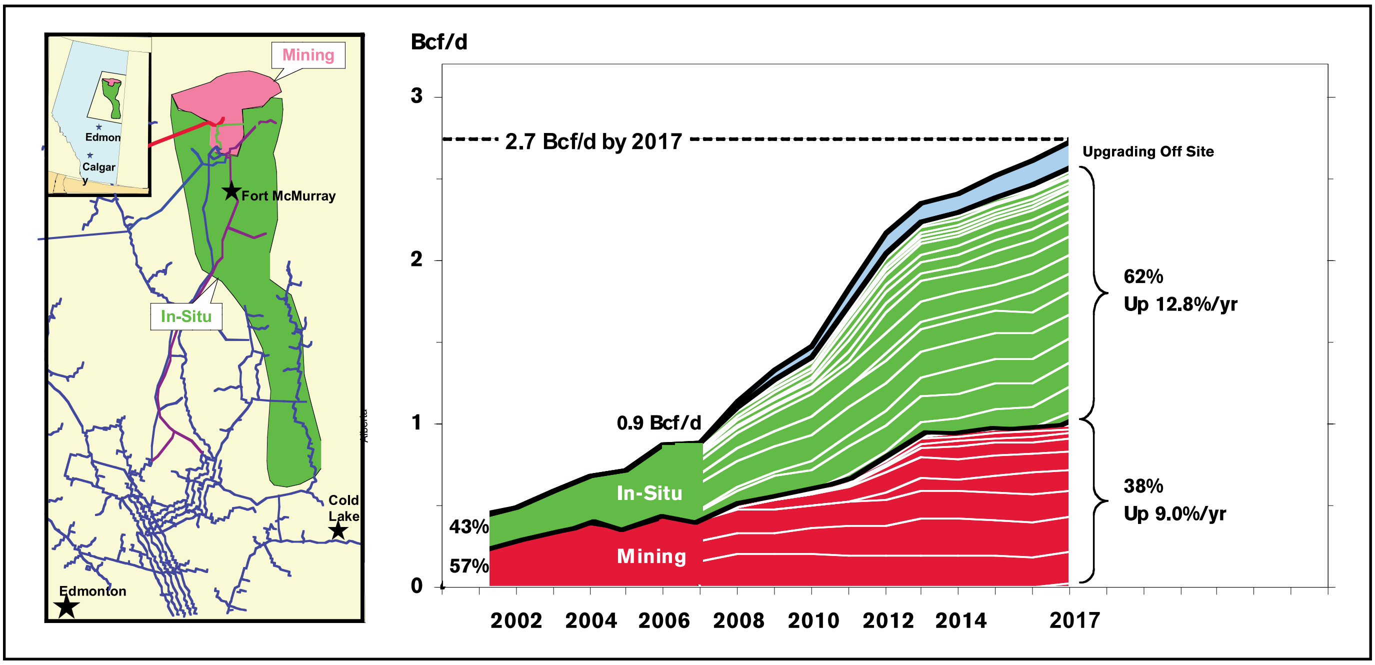
Unfortunately, there is more bad news regarding the future of Canada's gas production. The first biennial Ziff Energy Group full-cycle gas basin cost assessment of 24 North American gas basins (plus three regions of LNG) clearly finds that five of six Canadian gas supply basins are among the higher-cost gas basins in North America.

There are varied data sources available, but this study levers actual data from Ziff Energy's 21st Western Canada Finding and Development Cost study, along with data from Ziff Energy's numerous regional operating cost studies that use actual costs as reported by E&P companies that contributed data to the study.

Ziff Energy's first detailed drilling cost benchmarking study in 2005 systematically examined actual drilling costs for thousands of wells. Several of Western Canada's leading gas producers are currently focusing efforts to finalize data for the second




Full-cycle gas costs continue to rise vs. gas price.




Alberta oil-sands gas demand is expected to rise steadily.

drilling cost study benchmark assessment, in time to have a clear cost-reduction impact on their 2008/09 drilling costs.

## ROYALTY CHANGES

Another "made-in-Alberta" wrinkle is the introduction of a new gas royalty program to take effect on January 1, 2009. If this proceeds as announced, this flawed program will effectively claw back any upside gas potential, thus gas production will decline.

Fortunately, their cries are being heard, and the Alberta government has rolled out a response for the unintended consequences of its misguided policy. Producers hope the royalty clock will be turned back. If damage is averted, then in Ziff Energy's opinion, Western Canadian gas production will fall "only" 20% by 2017. If the flawed royalty scheme proceeds, then gas production will decline even faster.

## IMPACT OF OIL SANDS

Current oil-sands production exceeds Canadian conventional oil production. The Alberta oil-sands facilities will require almost 1 billion cubic feet of gas per day in 2008 to produce enough steam needed to upgrade the oil. Most of this oil is destined for the U.S. through existing and newly proposed oil pipelines.

We expect gas demand for the oil sands to rise to almost 3 Bcf a day a decade from now. Along with normal residential, commercial, industrial and power-generation growth, total Canadian gas demand growth will be considerable when added to incremental usage for oil sands.

In order to produce more $100-per-barrel oil, significant Canadian gas supply will be consumed at home in the oil-sands region, reducing the gas available for export to the U.S.

## CANADIAN LNG IMPORTS

The "foreign marines" are now considering landing some LNG in Eastern Canada. Being at the end of the giant TransCanada pipeline, Eastern Canada needs the foresight to develop a sound strategy to ensure adequate gas supply. It is probable that one LNG terminal will be available in the next few years to backstop the gas supply needs for the people of Quebec. Additional Canadian LNG supply could be used for Maritimes power generation, petrochemical, or related industrial needs.

## EXPORTS TO THE U.S.

The reality is that Canadian gas supply is declining and Canadian consumption is growing. This implies a "double dip downward" outlook for U.S. gas imports.

The state governors in the U.S. Northeast and one presidential candidate are actively launching a frontal assault against the foreign LNG suppliers who are aiming their sights on key U.S. Northeast and traditional Canadian supply end markets, but the outlook for the local gas distributors must seem gloomy. They foresee reduced Canadian gas supply looming around the corner .

The best approach will be to situate LNG regasification facilities offshore, out of the view of constituents who oppose such infrastructure. The alternative is to freeze in the dark. •

*W.P. (Bill) Gwozd is vice president, gas services, for Ziff Energy Group, based in Calgary. A frequent author, advisor and public commentator on gas issues, he holds a chemical engineering degree from the University of Calgary. Contact him at* bill.gwozd@ziffenergy.com *or 403-234-4299.*

*A remote basin in British Columbia holds huge shale-gas resources. Companies are just now revealing their interest, says a report from Wood Mackenzie.*

# Horn River Basin Shales Heat Up

BY FRASER MCKAY AND JOHN DUNN, *Wood Mackenzie Ltd.*

The Horn River Basin of northern British Columbia is the latest in an ever-increasing list of emerging gas shale plays in North America to have caused huge industry interest. Recent corporate announcements and comments, and presentations at the annual meeting of the American Association of Petroleum Geologists (AAPG) in April, have hinted at the potential size of the resource in place and drilling activity to come.

Other shales exist in the area, but the main potential lies in the Muskwa shale.

Until relatively recently, shale formations were considered only to be source rocks…but increasing gas prices, the diminishing size of conventional discoveries and new technology have since opened a number of shale gas plays in the U.S., transforming shale from source rock to producing reservoir.

Our preliminary analysis of potential development scenarios indicates economic returns in the Horn River Basin are in line with other major global gas supply projects, with an estimated breakeven Henry Hub gas price of $6.50 per thousand cubic feet.

Challenges in this play will likely be beneath rather than above ground as British Columbia represents a politically and fiscally stable environment. However, winter-only drilling access in most areas, and pipeline infrastructure needs, may be limiting factors in the near term.

As a result, this play is likely to be developed on a far more incremental basis than the aggressive levels seen in the Barnett shale in Texas in recent years. This will allow time for development of new technologies and techniques, which could ultimately recover more gas at initial lower cost, improving well economics. Further delineation and testing is clearly required before a large-scale commercial investment decision is made.

What developers lose in pace, however, their enforced caution may gain back in improved future economics.

## SIZE ESTIMATES

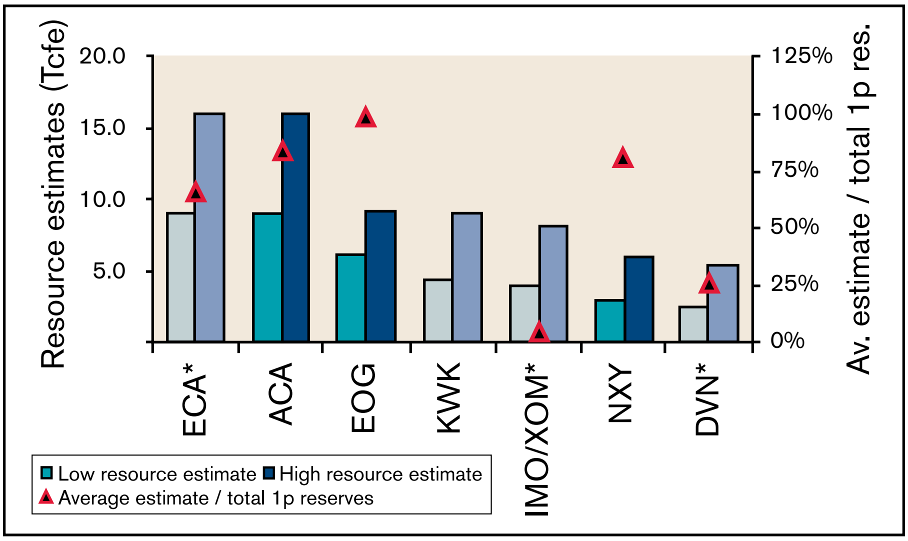
So far a small number of U.S. and Canadian E&P companies have announced their acreage holdings in this emerging Canadian shale play, and even fewer have announced resource estimates attributable to these land positions.

However, the numbers are very large. Combined recoverable gas resources recently announced by Apache Corp., EOG Resources and Nexen range from 18 trillion cubic feet of gas to 31 Tcf. Assuming a similar resource range for Apache's equal joint venture partner, EnCana, this indicates the Horn River Basin could be comparable in size to the anchor fields that would feed into the proposed Alaska gas pipeline.

The Horn River estimates by Apache, EOG and Nexen intimated rock properties and well scenarios which were highly consistent. Each suggested this play could be even more prospective than the prolific Barnett shale.

The current announcements of between 18- and 31 Tcf are based on a recovery factor of 20% of the gas in place, and total $CO_2$ volume of about 10%. Although initial estimates of recovery from the Barnett shale were as low as 10%, depending on operator and location, this now far exceeds 25%. It is now producing nearly 3 Bcf

## ANNOUNCED AND POSSIBLE RESOURCE ESTIMATES




Horn River resource estimates could double total reserves for some companies.
(Source: Wood Mackenzie)

per day and more than 8,000 wells have been drilled.

Estimates of the in-place gas resources per square kilometer in the Horn River Basin could be double those of the Barnett due to the thickness of this shale, its rich organic content and its pressure. Meanwhile, the mechanical rock properties of this shale are loosely analogous, showing reasonable permeability (for a shale) and high silica content—making the structure more brittle and therefore more easily fracture-stimulated.

## KNOWN LAND POSITIONS

| Company | Sq Kilometers | Low resource estimate (Tcf gas) |
|---|---|---|
| Apache Corp. | 838 | 9.0 |
| EOG Resources | 567 | 6.3 |
| Nexen | 344 | 3.0 |
| EnCana Corp.* | 874 | 9.0 |
| Quicksilver Resources* | 514 | 4.5 |
| ExxonMobil/Imperial* | 465 | 4.1 |
| Devon Energy | 308 | 2.7 |
| Total | 3,909 | 40.7 |

Source: Wood Mackenzie and corporate reports of contingent recoverable resources from Apache, EOG and Nexen.
*Estimated resource potential. EnCana's resource potential assumed to be equal to Apache's due to 50-50 partnership.
Remaining potential based on lowest announced estimates per square kilometer (that of Nexen).

Assuming EnCana's position is at least as large as its equal partner Apache's, recoverable resources could already range between 27- and 47 Tcf.

There is also scope for considerable upside to current estimates, with each 1% change in recovery representing an increase of over 1 Tcf of recoverable gas.

Taking the midpoint of this range makes the Horn River shale play larger—on an energy-equivalent basis—than the current reserve estimates for both the Jupiter and Tupi discoveries in Brazil's much publicized, ultra-deepwater, subsalt play.

## ACTIVITY SO FAR

Western Canadian land is often purchased through third parties, so players and their positions can remain private until revealed later. So far a relatively small number of players have announced their acreage holdings in the shale play area, and even fewer have announced resource estimates attributable to their positions.

An early entry was created by some of the players most typically associated with first-mover initiatives in immature, technically driven tight-gas plays: EnCana, EOG and Devon Energy. However, the presence of Apache, in partnership with EnCana and covering a large area in the center of the play, and the material position accumulated by Nexen, was somewhat more surprising. Neither company has extensive unconventional gas experience, although both have coal-bed methane projects underway in Alberta and both have experience in shallow gas exploitation.

Apache has been active in the basin since the start of this decade when leasing in this area began. Three of Apache's Ootla wells, drilled horizontally in the eastern part of the play, flowed at initial rates of 8.8-, 6.1- and 5.3 million cubic feet per day. All were frac'ed.

Apache's and EnCana's area of mutual interest covers about 400,000 acres. Apache's initial announcements of recoverable resource ranged from 3 Tcf to 6 Tcf, but these estimates have subsequently increased to between 9- and 12 Tcf, based on further well testing.

EnCana began acquiring acreage in 2003 and has since built the largest known land position.

EOG Resources was the second company to reveal its Horn River resource potential, following a three-year drilling and evaluation program. Its estimates of recoverable resources are 6.3 to 9.3 Tcf on its 140,000 acres. The majority lies northwest of the Apache-EnCana acreage. The company has drilled and completed three vertical and three horizontal wells. These wells flow-tested at rates of 3.5- to 5 million cubic feet per day. Production is anticipated this summer.

If resource estimates are realized, Horn River will become a material portion of its long-term resource portfolio. Its average resource estimate of 7.8 Tcf is practically equivalent to its total booked reserves of 7.9 Tcf equivalent.

Nexen was third to announce a Horn River resource estimate, suggesting 3 Tcf to 6 Tcf could be recovered from its land position of 123,000 acres. Its holdings are east of the Apache-EnCana acreage. Two wells have been tied into existing infrastructure for long-term flow tests to confirm deliverability.

Devon Energy has 130,000 acres in Canadian unconventional gas plays, with 76,000 of those in the Horn River shale area. At press time, it had not released a resource estimate.

Of the majors, only ExxonMobil in partnership with Imperial Oil, has chosen to take advantage of more recent land sales to accrue a material position here. U.S. junior Quicksilver Resources (*Editor's note: An aggressive Barnett player for its size*) has also created a material position in the Horn River Basin, with about 500 square kilometers.

A number of small players are known to have minor positions, including Stone Mountain Resources, Crew Energy and Storm Ventures International. •

*Fraser McKay and John Dunn are analysts with energy research and consulting firm Wood Mackenzie Ltd.'s U.K. office. This is an excerpt from their report on the Horn River Basin.*

*The energy trusts must plot strategies and fight looming tax changes. Eight have disappeared since 2007 and more consolidation is projected. Some are still growing.*

# Trusts In Transformation

BY GARY CLOUSER, *Contributing editor*

Even as Canadian income and energy trusts continue to vigorously fight planned federal tax changes that beginning in 2011 would tax them at the same rate as corporations, the trusts are contemplating steps to prepare for that dramatic change. Chief executives are trying to determine whether to continue to operate their entities as trusts, change into corporations or another form of business, merge or be acquired.

The tax status of Canadian trusts will change in 2011, when trusts will be taxed like corporations at the full 28.5% rate; thus removing their tax-advantaged status for which they were set up in the first place.

"The taxation changes have had a dramatic impact and will continue to transform the sector as we get closer to January 2011," says Cristina Lopez, research, Tristone Capital in Calgary.

Since the trust legislation was adopted in the 2007 federal budget, PrimeWest Energy Trust merged with Shiningbank Energy Income Fund, and within months was bought by the Abu Dhabi National Energy Co. for C$5 billion in cash.

"The sector has seen a number of mergers with seven trusts merged or acquired from the beginning of 2007 to today. As well, many trusts have been looking at expanding their resource-play exposure. Finally, we have seen some trusts look at ways to increase tax pools in an attempt to pay less taxation when January 2011 hits," Lopez says. An eighth vanished trust, Fairborne Energy Trust, has reorganized itself into an E&P company called Fairborne Energy Ltd.

"2007 was a difficult year for mid- to small-cap producers in Canada and the royalty trust group was no exception, posting only a small total return of 2% during the year, compared to a negative 16% return for the small- and mid-cap Canadian E&Ps in Tristone's coverage universe.

"When looking at just equity returns for the trusts, the group also posted a minus 16% performance, but distributions paid throughout the year improved their overall results. Only five trusts posted positive equity returns during the year, with returns ranging from a gain of 41% for Crescent Point to a negative return of 88% for Enterra Energy Trust," Lopez says.

## M&A OUTLOOK

In a January report titled "2008 Royalty Trust Outlook," Tristone analysts predicted that M&A would be the dominant theme.

"Merger and acquisition activity was somewhat muted during 2007 with many producers sitting on the sideline playing wait-and-see before jumping into the market," the report says. "Activity picked up in Q4-07 with a number of junior E&Ps merging. The royalty trusts did not stay away from the fray with Penn West and Canetic trusts announcing their merger as well as Enerplus acquiring Focus, and Bonavista acquiring C$163 million of assets from a junior E&P.

"In 2007, we saw four trusts either be merged, acquired or convert to an E&P format (Sound Energy Trust, Shiningbank Energy Income Fund, Thunder Energy Trust and Fairborne)," the Tristone report said, noting that, at the time of the report, three other trusts (Focus, Canetic and Vault) had announced plans either to be merged or acquired.

Penn West has since acquired Canetic for C$5.6 billion and also picked up Vault, as it became the country's largest conventional oil and gas trust. Enerplus Resources Fund acquired Focus Energy Trust in an all-stock deal worth about $1.4 billion.

Of the eight royalty income trusts (RITS) that have disappeared since 2007, five sold to or merged with another RIT, says Ryan Ferguson Young, associate with Sayer Energy Advisors, a Calgary-based M&A advisory firm.

The largest transaction involving an exchange of trust units was the aforementioned acquisition of Canetic by Penn West. The largest acquisition by a RIT for cash was the C$517-million acquisition of Capitol Energy Resources Ltd. by Provident Energy Trust, Ferguson Young says.

Notable transactions which involved a concurrent financing include the purchase of Dominion Resources Inc. assets by both Baytex Energy Trust and Paramount Energy Trust. Baytex and Paramount raised approximately C$150 million and C$325 million, respectively, to finance those acquisitions. Trusts completed C$14.2 billion in acquisitions, three of which were over C$1 billion in size.

While M&A activity for oil and natural gas companies throughout Canada, including trusts and non-trusts, set a record for total enterprise value of C$49.8 billion in 2007 (surpassing the previous record of $46.4 billion set in 2001), the median price paid per flowing barrel fell 20% in 2007 to $48,167 per barrel of oil equivalent per day from $60,418 per BOE per day, Ferguson Young says.

He further noted the anticipated

## THE FATE OF EIGHT ROYALTY INCOME TRUSTS

| Buyer | Acquisition |
|---|---|
| PrimeWest Energy Trust | Shiningbank Energy Income Fund |
| Sword Energy Inc. et al | Thunder Energy Trust |
| Abu Dhabi (TAQA) | PrimeWest Energy Trust |
| Advantage Energy Income Fund | Sound Energy Trust |
| Penn West Energy Trust | Vault Energy Trust |
| Enerplus Resources Fund | Focus Energy Trust |
| Fairborne Energy Ltd. | Fairborne Energy Trust (reorganizes into an E&P Company) |
| Penn West Energy Trust | Canetic Resources Trust |

(Source: Sayer Energy Advisors)

tax changes for trusts, combined with broader trends in the oil and gas industry, contributed to factors causing the price decline. Royalty trusts have become more selective in their acquisitions because those trusts, prior to 2007, were predominately buying companies and assets with reliable production, i.e. cash flow. But, due to the October 31, 2006, announcement of impending taxation, the RITS are now limited to the number of acquisitions they are able to carry out until 2011.

Canadian royalty trusts are oil and gas companies that, because of their current special tax status, pay out a large percentage of their cash flow to shareholders, or unit holders, in the form of monthly dividends, called distributions. Those trusts are a subset of a class of investments called Canadian income trusts, which invest in businesses, real estate or utilities.

Canadian royalty trusts are different from U.S. royalty trusts. Both pay out generated cash flow from production, but U.S. trusts are not allowed to acquire new properties. Consequently, their cash flow declines over time as their assets are depleted. Canadian trusts replenish depleted reserves with new acquisitions, and in theory, could operate indefinitely.

### TRUST COALITION

The Canadian trusts have been fighting the federal tax change ever since it was first proposed last October. The government, which has since approved the plan, calls the change "The Tax Fairness Plan," whereas opponents refer to it as "The Halloween Surprise." Within days of that announced plan, energy trusts saw the value of their stocks drop by about C$35 billion, or about 20%. Despite oil prices soaring above US$100 per barrel, few of the trusts have recaptured their pre-October 2006 level.

Ottawa argues that the change is fair because major corporations began converting to the trust structure to avoid paying federal income taxes. Alarmed by that trend, the government says it was losing at least C$500 million annually, and perhaps as much as C$1.3 billion in tax revenue through "tax leakage."

A group of 33 Canadian-based trusts formed the Coalition of Canadian Energy Trusts to fight the structural change. The coalition argues that energy trusts are critical to the Canadian economy and to Canada's role as global energy provider.

In 2005—the last full year prior to the announced tax changes—these trusts accounted for more than 20% of the oil and gas production in Canada, more than 1 million barrels of oil equivalent per day.

Before the announced change, the market capitalization of the trusts was almost C$100 billion. In 2005, the coalition says, the oil and gas trust sector generated some 30% of the tax revenue collected from publicly traded Canadian oil and gas entities, while representing only 16% of the revenue.

In 2006, the trusts generated an estimated C$5.7 billion for governments in Canada including royalties, property and capital taxes, and an estimated C$2.4 billion in personal taxes paid on distributions.

Trusts invest in fields deemed uneconomic for larger E&P companies, and ensure that these oil and gas supplies are produced. Without energy trusts, overall Canadian production, and the royalties attached to that production, will decline, they say. Energy trusts also invest heavily in new technology and processes to successfully maximize production, including carbon capture sequestration and improvements in oil-sands recovery technology, the coalition says.

The coalition's current push is to persuade the government to provide supporting data for its claim that so-called tax leakage is occurring–a claim disputed by the coalition.

The coalition argues that oil and gas trusts are a crucial piece of the Canadian economy because they develop declining oil and gas assets that growth-oriented producers would not. Its members hope they can persuade the current or future government to kill the tax changes before the enactment date in 2011.

The coalition has predicted that its hard-hit shares would lead to takeover by foreign players and consolidation within the sector—predictions it says have proven accurate.

"The trusts are starting to make decisions now and modifying their assets to be better positioned to be a corporate exploration and production company in 2011," says Sue Riddell Rose, president and chief executive officer of Paramount Energy Trust and co-chair of the coalition. Paramount bills itself as Canada's only 100% natural gas royalty trust. Gordon Kerr, president and CEO of Enerplus Resources Fund, is the other co-chair of the coalition.

"Payout ratios have dropped as trusts spend more towards internal growth, and it has led to cuts in distributions to investors who never bargained for that," says Riddell Rose.

"The junior oil sector is no longer vibrant. There is no exit strategy, which was to sell oil and gas assets to trusts," she says. "Trusts were once an easy way for junior drillers to exit developed, mature assets and go looking for more oil and gas."

Meanwhile, some mergers continue. In April, Baytex Energy Trust, which is largely a heavy oil producer, acquired gas-weighted junior Burmis Energy Inc. in a deal with an estimated value of C$181 million. Raymond Chan, CEO, Baytex, said after the acquisition that Baytex has "desirable attributes for an energy investment regardless of the legal structure."

Several trusts had contemplated changing their structure from a trust to a corporation. But, yet another change is causing the trusts to rethink that strategy, Lopez says.

"Recently, the federal government made an adjustment to the taxation of royalty trusts, which effectively will tax them at the exact level that a corporation is taxed. This was not the case previously as a generic provincial tax rate was applied to the trusts, which is 3% higher than the Alberta provincial tax rate. With this most recent change, the incentive to convert back to a corporation from a trust to save 3% in taxes is no longer there, meaning that many trusts will chose to keep the structure versus converting to a corporation," Lopez says.

## ENERGY TRUST TALES

Recent earnings reports from the Canadian energy trusts are peppered with comments and complaints about the pending tax changes—and reassurances for investors. For example:

**Penn West Energy Trust** CEO William Andrew, in a letter to unit holders in February, said Penn West is "continuously monitoring the impact of this (federal) tax on our business strategies." Among those deliberations was whether to remain in the trust structure or convert to a corporate structure "with yield in the form of dividends to facilitate investing a higher portion or all of its funds flow in exploration and development projects."

Andrew added: "Penn West might determine that it's more economic to remain in the trust structure, at least for a period of time, and shelter its taxable income using tax pools and pay all or a portion of its distributions on a return of capital basis, likely at a lower payout ratio"

**Harvest Energy Trust** says it continues to investigate alternatives to its trust structure that would accommodate an efficient distribution to unit holders and enable it to maintain sustainable growth. "Currently, our base case is to maintain our existing structure and then convert to a Canadian corporation. Throughout this transition period, we expect to

## ALBERTA HIKES ROYALTY

Compounding the hit to energy trusts, another planned change announced in Edmonton is being fought by all Alberta oil and gas producers. The Alberta provincial government in October 2007 announced plans to change its royalty formulas, effective in 2009, with the intent to collect about C$1.4 billion per year more in royalties. That would be an increase of about 20% annually.

Sayer Energy Advisors' Ryan Ferguson Young says, "The royalty framework announcement, coupled with the subprime mortgage issue in the U.S., resulted in a flight of capital from the Canadian oil and natural gas industry at the tail end of 2007 and in the early part of 2008, adding to the challenges being faced by the industry."

Tristone Capital called the royalty changes "bewildering" and "punishing regime changes for the already suffering conventional oil and gas space."

It anticipated, however, that royalty changes should have a "minimal impact on the royalty trusts given the number of lower productivity wells that the group has in its overall production base."

Paul Ziff, chief executive for Calgary-based Ziff Energy Group, a consulting firm, doubts the Alberta royalty change will achieve its goal of increasing royalties by C$1.8 billion.

"The unintended consequence of reduced drilling activity, along with cost escalation and lower E&P action, will likely erase any royalty gains and, instead, may cause an energy recession. Unless the proposed royalty program is revised, conventional gas activity will decline sharply, creating a 'made in Alberta' recession in 2008," Ziff says.

The conventional energy industry in Alberta is mainly gas oriented. Since 1998, gas drilling has surpassed oil drilling activity. In 2007, there were more than two gas wells drilled for each oil well. Areas more affected are deep-gas plays in western and northwestern Alberta, and shallow and coalbed methane plays in central and southeast Alberta, Ziff says.

An estimated 80% of companies active in Alberta have reduced their planned conventional spending since the new royalty announcements. Spending in Saskatchewan and British Columbia is booming, however. Ziff also says the number of Texas gas wells drilled in 2008 is expected to increase to a decade high. •

be able to continue with our ongoing business plans… while we continue to distribute a significant portion of cash flow to our investors."

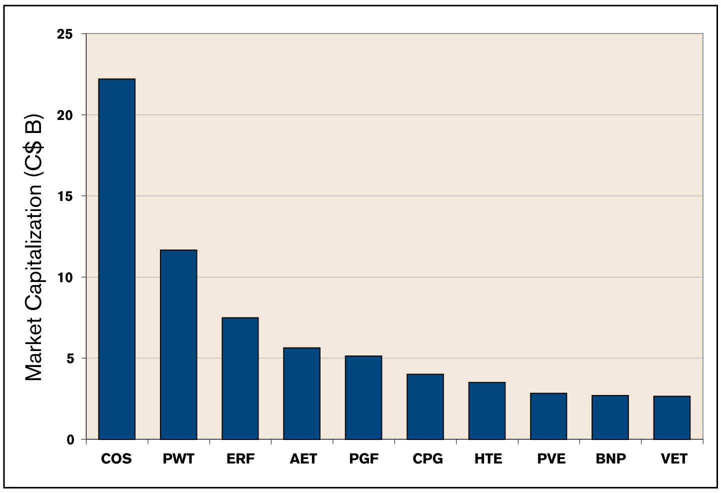
**Vermilion Energy Trust** says it has worked closely with the Canadian Coalition of Energy Trusts in its attempts to reverse the government decision on taxing trust distributions…and oppose the royalty increase. "Fortunately, Vermilion believes that it is well-positioned to maintain its current business plans with minimal impact to unit holders from either of these government initiatives."

**Bonavista Energy Trust** says it will continue to analyze the information that becomes available with respect to the new royalty framework. "Based upon initial documentation, royalty rates will increase substantially on medium-depth natural gas, high productivity natural gas and light oil production in Alberta, and as a result the economics of these opportunities have been negatively impacted under a higher price commodity scenario."

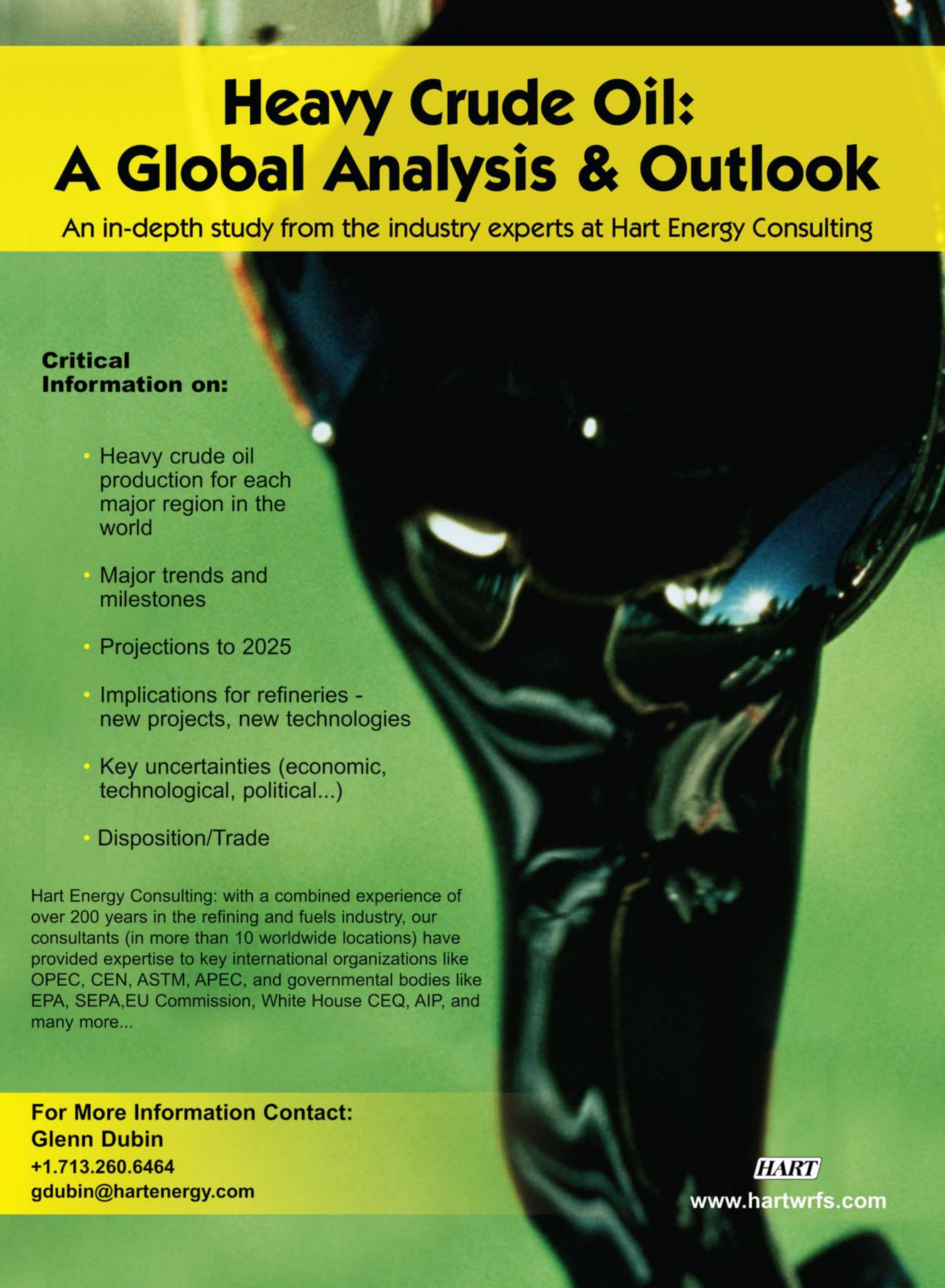
Bonavista will continue to assess the impact that the new royalty framework will have on our existing operations, including our capital allocations for 2008 and beyond.

**Enerplus Energy Trust** says it sees "significant value" in the tax exemption period (until 2011) and "would be hesitant to make major changes to our structure during this period, without compelling reasons to do otherwise that we do not currently foresee." •

## TOP TEN CANADIAN ENERGY TRUSTS, RANKED BY MARKET CAP




(Source: Tristone Capital LLC)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A Global Analysis & Outlook
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• Heavy crude oil production for each major region in the world
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*Meet four risk-averse, yet hardy, smaller companies out to change the face of the oil-sands business.*

# In-Situ Innovations

ARTICLE BY STEPHEN RASSENFOSS, *Contributing editor*

Oil-sands production brings to mind images of towering power shovels scooping up loads of black gunk to be hauled off by equally huge dump trucks. For now that's apt. The greater part of the heavy oil produced from these immense bitumen reserves in Alberta come out of open pit mines.

But that's fast changing as oil companies go after far larger reserves that are too deep to mine. With oil prices above $100 a barrel, this underground production, known as in-situ mining, is growing and profitable. But the high cost of these projects means new ones would generally not be profitable if oil prices fell to $60 to $65 a barrel. That means future growth may depend on advances that cut the cost of getting this crude out of the ground.

Alberta's immense oil-sands reserves, second only to Saudi Arabia, have attracted a cadre of smaller E&P players out to show that innovative newcomers can be winners in a high-cost game.

For now, smaller companies like Connacher Oil and Gas Ltd., Laricina Energy Ltd., OPTI Canada Inc. and Petrobank Energy & Resources Ltd., which barely show up in the production statistics, are drawing notice for in-situ mining innovations.

Connacher expects first production from its 100% owned oil-sands project in northern Alberta in third-quarter 2008, reaching about 10,000 barrels per day by year-end. Laricina has applied for permits to use steam-assisted gravity drainage (SAGD) in a 100% owned pilot at Germain south of Fort McMurray, Alberta.

Production at the OPTI-Nexen joint venture at Long Lake Phase I is also expected by year-end.

"The bigger companies are innovative on a major scale," says Greg Stringham, a vice president of the Canadian Association of Petroleum Producers, and an oil-sands veteran. "If you have a $10-billion project, you don't want to push the envelope on technology, but with 10,000 barrels a day, you can."

The challenge they all face? Finding lower-cost ways to take bitumen, which Stringham describes as "thick as peanut butter" and getting it to where it is "more like molasses," so it can be extracted.

## SAGD

The standard procedure for doing this is to heat the bitumen underground by pumping steam down a horizontal well. The heat produces crude with a syrupy consistency that seeps down to a lower horizontal well shaft where it is pumped out. The process is properly known as steam activated gravity drainage, or SAGD production, generally pronounced Sag-D.

Smaller companies involved in oil-sands projects define innovation in different ways. As Richard A. Gusella, president and chief executive officer of Connacher, explains, "We're like Frank Sinatra: we're doing it our way."

Calgary-based Connacher is known for its ability to quickly build efficient projects using proven technologies. Installing the equipment for its first project in 300 days stands out in a business where construction can take years, and cost overruns are an uncomfortable fact of life.

## AT A GLANCE

173 billion of Canada's estimated 179 billion barrels of reserves are in the oil sands. The total reserve is second only to Saudia Arabia, which claims 264 billion barrels.

### THREE MAIN OIL-SANDS AREAS IN ALBERTA

Athabasca is the biggest area and birthplace of this industry. It features reserves which are mined, as well as the largest number of in-situ projects.
Cold Lake is where all the production is in-situ, including the largest in-situ operation by Imperial Oil.
Peace River is a new area with one project in operation by Shell.

### PROJECTED TOTAL OIL-SANDS PRODUCTION

| | |
|---|---|
| 2006 | 1.1 million Bbl./day ( 7th in world) |
| 2015 | 3.4 million Bbl./day ( 4th in world) |
| 2020 | 4.4 million Bbl./day |

The cost has surged. The cost of a project producing 100,000 barrels a day has gone from C$3.3 billion in 2001 to an estimated C$10- to $11 billion.

Source: Canadian Association of Petroleum Producers, *www.capp.ca*

Petrobank is trying what amounts to a controlled underground burn with its patented THAI process, discovered in 1993. It combines a vertical air-injection well with a horizontal producing well. The goal is to avoid the high cost of natural gas by using the heat generated from burning a relatively small amount of bitumen, to provide the heat needed to sustain production.

It has about 70,000 acres in Alberta's oil-sands region, covering an estimated 2.6 billion barrels (gross) of bitumen in place.

Laricina is adapting SAGD methods to a carbonate formation, which is new in the oil sands. It's testing the idea of replacing steam with solvents to get the bitumen moving. This would greatly reduce its energy costs, and the solvents could be recycled.

OPTI has partnered 50-50 with Nexen to marry production with its onsite, patented crude upgrader that will largely power the operation. The goal is to run the bitumen through what amounts to a refinery, producing higher-value sweet synthetic crude plus a synthetic gas that would ultimately replace 75% of the gas the upgrader would use.

Production is expected to reach 60,000 barrels per day and last 40 years.

While these companies look tiny up against ExxonMobil Corp., Shell or Petro-Canada, they generally still have the financial heft to pay for hundreds of millions of dollars, if not billions. They also need to cope with perils, like the credit crunch or the rising costs that forced one independent to shut down a project and put itself up for sale.

The cost of an oil-sands project producing 100,000 barrels a day of heavy crude has gone from C$3.3 billion in 2001, to from C$10- to C$11 billion for one scheduled to start in 2010, according to the CAPP 2007 outlook.

These smaller players are trying to steer clear of what has been described as the "dis-economies of scale" with projects designed to produce 10,000 barrels a day of oil.

They also generally have other sources of income to keep them going during construction. These include conventional oil and gas operations and in the case of Connacher, a small refinery in Montana. Even with reserves in the ground on the high side of a billion barrels, it's quite possible in this business to run out of cash before production ever begins, or to sell so much stock there's scant payoff for investors.

"The other engineering we have to be good at is financial engineering," says Glen Schmidt, president and CEO of Laricina.

Veterans of the oil sands recall how the business was largely dormant during much of the 1980s and 1990s when

Connacher Oil and Gas Ltd. expects first oil-sands production in third-quarter 2008 at this site.

oil prices dropped. Lately companies have adjusted their projections to reflect wariness about government plans to increase the royalty rates as oil prices rise, and also to impose a tax on carbon emissions.

As Gusella outlines the company strategy, he introduces each point as a risk factor to be addressed.

## LOW-HANGING FRUIT

A common phrase used by these smaller players is that they're looking for "low-hanging fruit." They seek high-quality reserves near the highways and pipelines they need to bring the projects on stream.

For Laricina that means finding oil in formations which are permeable, allowing the oil to flow. These zones would be "world class" if they held higher-quality crude. The challenge of getting this heavy oil to the surface and processing it when it gets there, makes managing these operations like running an auto factory. Being the low-cost producer is crucial. Schmidt says the big question is: "How can you grind the margins?"

Smaller-scale projects allow the use of off-the-shelf hardware, like water-removal equipment originally designed for paper making. This has allowed Connacher to recycle up to 98% of the water it uses for steam. The source of this water is a well tapping a reservoir Gusella describes as "not fit for man or beast."

Connacher builds everything but the storage tanks elsewhere, where labor costs are lower, and then trucks in these modular units for assembly. As a result it was able to "Lego it together" in 300 days. It plans to repeat this process for its second stage, expected to start up in 2009.

While oil sands are the company's engine of growth, by purchasing a refinery and building up natural gas production Connacher has hedged its bets by capturing the high refining margins when crude prices dip, and earning more from gas production when that price leaps.

And as its oil-sands production rises, it plans to expand its natural gas and refining businesses "in lockstep." It is considering a plan to more than triple the output of its Montana refinery, to 35,000 barrels a day, with a final decision expected later this year.

With the profits from these other lines of business, Gusella says Connacher can deal with the risk of a sharp drop in crude prices. "We're still breathing if oil is at $30 a barrel," he says.

## BIGGER STEPS

The payoff for moving away from natural gas to produce oil sands is huge, but it's still the standard.

"It's a waste for us to use natural gas to produce oil but the oil people are conservative… they know how to do these things,“ says Apostolos Kantzas, an engineering professor at the University of Calgary, and a consultant for several smaller oil-sands producers.

Laricina has run a pilot project earlier this year where the oil is held in a carbonate formation–a more permeable rock where it has experimented with using solvents to move the crude rather than using gas-generated steam. These solvents would be separated from the crude produced and used over again, which would sharply reduce operating costs.

Schmidt says the company was pleased with a test earlier this year, but he won’t say what role solvents will play in the operation of its second project, which is set to start up in 2011 or 2012.

Laricina’s first project is steam-heated. It is expected to be in operation early next year. There’s no breakthrough technology, but Schmidt says that after raising $400 million, it’s important to remember that “people will get tired of hearing what you will do for them tomorrow.”

Still, the potential looks great. Third-party engineers say Laricina’s leases could hold 2.3 billion barrels of net recoverable bitumen.

Petrobank has another take on getting away from gas to generate heat—starting a controlled fire underground. With its THAI process, the heat comes from a controlled burn which is fed by air from a vertical well. And it can capture the carbon dioxide produced underground.

“What you are doing is setting the reservoir on fire,” says Kantzas. But others have tried and failed to make the idea work. As he explains: “When you start a fire in your back yard, do you know where it will go? It is a control issue. If they feel comfortable that this control issue will be solved, then kudos to them.”

Richard A. Gusella, CEO of Connacher Oil & Gas Ltd.

Another pioneer, OPTI Canada, has partnered with Nexen. It is building what looks like a refinery on the site of Nexen’s wells, which will upgrade the bitumen into high-quality light synthetic crude (which has been done before), and also produce synthetic gas, which has never been done in the oil sands.

Using proven technology, OPTI expects to replace about 75% of the natural gas now used to power its SAGD operation, says Alison Trollope, investor relations manager.

While gasification is a new thing in the oil sands, the company is using technology licensed from Shell that used such a unit to process heavy crude in the Netherlands and elsewhere. The first phase of the operation has begun and startup of the upgrader is expected to begin midyear 2008. It won’t be in full production at the rate of 72,000 barrels a day until late 2009.

The company hopes to decide on Phase II later this year, but she says it will need further clarity on how the Canadian government plans to tax carbon emissions.

New approaches lowering the cost and environmental impact of in-situ production are inevitable. The amount of oil that can be tapped this way is just so much larger than from mining.

“Open-pit mining is a drop in the bucket,” says Kantzas. He says open-pit mining is likely to go another 40 years or so, while the reserves available for in-situ oil-sands production could last for centuries.

But how long will these smaller oil-sands companies be around? The two options here are to “grow big and large” or “develop and sell,” says CAPP’s Stringham.

OPTI’s Trollope has been asked about takeover rumors but points out, “This company would not be here were it not for the risk-takers that are drawn to a start-up.”

Connacher’s Gusella says he sees the company sticking with its plan to steadily add capacity on its 98,000-acre oil-sands leasehold, adding: “We don’t have an exit strategy; we have a growth strategy.”

Schmidt of Laricina, who’d previously built a company, Deer Creek, and then sold it, says he’s not so certain about the future. Although Laricina is being run for long-term growth, he adds, “You don’t build a company for a single outcome.” •

Oil and Gas Investor.com

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*The vast oil sands of northern Alberta represent a unique opportunity and a daunting challenge as costs and royalties rise, and foreign companies eye the prize.*

# Alberta's Oil Sands

ARTICLE BY BARRY MUNRO, *Ernst & Young, Calgary*

In a world seeking new sources of oil supply, the oil sands of Alberta may represent at least 50% of all new investable reserves accessible in the world today (i.e., reserves that are not subject to restrictive foreign investment policy). What's more, they are located in a free-market economy next to the world's biggest oil-consuming nation, and it's estimated they will last for the next 30 to 50 years.

However, developing this resource is complex, requires massive capital investment and creates a large carbon footprint. There's no question that record high oil prices make many of these projects viable. However, determining what the expected returns are, as well as defining technology needed for future advances, remains a challenge.

Experts believe Asian demand for oil will grow at rates of 4% per year for the next decade. Additional new supply also will be needed to offset natural production decline rates, which on a global basis average 3% to 5% per year. During the next 25 years, new supplies of upwards of 100 million barrels per day may be required. On average, by 2030 the industry will have to find and develop volumes of oil essentially equal to current production of approximately 85 million barrels a day.

Current oil-sands production of 1 million barrels per day is expected to triple over the next decade and by 2030, it could be 5- to 6 million barrels per day. At this rate of growth, about half of North American oil production will come from the oil sands, according to some projections. Photo courtesy of Suncor Energy Inc.

## LOOK NORTH

The Canadian oil sands in northern Alberta are an important piece of the future oil supply puzzle. Recoverable reserves (i.e., recoverable using current technologies and economics) combined with proved conventional reserves, put Canada's total oil reserves second only to those of Saudi Arabia.

The oil-sands deposits in the Athabasca, Cold Lake and Peace River regions of northeastern Alberta cover an area of roughly 54,000 square miles, an area larger than the state of Florida. The sheer size of this resource is driving a spending boom in the region that is expected to be in excess of US$100 billion.

But it is more than size that makes them attractive. The oil sands also offer little-to-no geopolitical risk, and essentially no exploration or geological risk.

Production currently is more than 1 million barrels a day and output is expected to triple over the next decade. By 2030, production could potentially reach 5- to 6 million barrels a day.

At this rate of growth, almost 75% of Canada's oil production, and approximately half of North American oil output, will come from the oil sands. Almost 100 identifiable oil-sands projects are underway or proposed. They range from massive integrated operations to smaller, modularized additions to existing or proposed projects.

Approximately 20% of the established oil sands resource base lies within 165 feet of the surface and can be removed through surface mining/processing operations. However, the remaining 80% of the resource base is too deep for mining and must be extracted via in-situ thermal techniques.

## COSTS RISING

In Alberta, multiple large oil-sands projects are creating enormous stresses on the physical and social infrastructure: extremely tight labor markets, runaway housing costs, thinly stretched public services, rising public safety concerns and aboriginal land use rights issues. Moreover, the oil sands exert a large environmental footprint.

Barrel for barrel, the costs to develop oil sands resources are among the highest in the world. Capital costs (on a per-upgraded-barrel basis) have more than tripled since 2001, and the latest projects expect total capital costs of more than US$100,000 per flowing barrel.

Operating costs now average about US$33 per barrel. Labor, equipment, supplies and services are all in tight supply, with escalating costs and an increased likelihood of project delays.

The benchmark price required to make many of the oil-sands projects economical has risen from about US$25 per barrel to more than US$45 per barrel. More troublingly, the looming 2008-2010 construction peak may drive costs even higher. Rapidly rising costs are eroding project returns.

The oil sands have a rich history of entrepreneurial players driving development. Further, a transparent fiscal and regulatory regime supports new entrants. However, development, regulatory and environmental compliance costs have escalated to the point that returns for smaller players are being squeezed. As a result, consolidation activity is likely to continue.

Foreign companies are increasingly the potential acquirers. In April, Total agreed to acquire Synenco Energy Inc. for C$480 million cash. Synenco's main asset is a 60% stake in the Northern Lights oil-sands mining project northeast of Fort McMurray. Sinopec holds the remainder. Total owns other oil-sands interests in Alberta as well.

## PRODUCTION TO MARKET

Several factors have a direct bearing on bringing oil-sands production to market.

Pipeline plans. The expected increase in supply from the oil sands requires expanding the North American crude pipeline grid, much of which is underway.

New pipelines to the Canadian west coast, such as those planned by the main crude oil pipeline players Enbridge and Kinder Morgan/Terasen, could open new markets for oil-sands crude, including Asia and, most likely, the U.S. West Coast, with its extensive upgraded refining capacity.

Expanding to core markets in the Gulf Coast, Rocky Mountain and Midwest regions also will be critical as incremental Canadian oil replaces declining U.S. inputs, as well as potentially displacing competing heavy/sour foreign crude from Mexico, Venezuela, and the Middle East.

Both Enbridge and Kinder Morgan have increased their export capacity for heavy oil into the United States, while the dominant gas pipeline player, TransCanada, is moving to get in on the action. In addition, Enbridge has reversed the flow on its Spearhead Pipeline, allowing Canadian crude to move into the Cushing, Oklahoma, area, while ExxonMobil has reversed a portion of its crude line into Corsicana, Texas, providing limited access for Canadian crude to Gulf Coast refineries. A new "bullet" line from Alberta to the U.S. Gulf Coast has been proposed, but faces many regulatory and environmental hurdles.

Enbridge and ExxonMobil also are considering a new 400,000-barrel-a-day pipeline from Patoka, Illinois, to the Beaumont/Houston area. If approved, that line could be in service by late 2010.

Refineries. A growing supply of heavy bitumen will pressure existing Canadian and U.S. refineries to expand or reconfigure their processing capabilities to handle the new supply. Several capacity expansions are underway that focus on adding upgrading capacity in northern Alberta.

Significant players in oil sands, including OPTI Canada, Canadian Natural Resources, Suncor and Shell Canada, are adding upgrader capacity that is expected to be brought on line over the next one to five years.

## OTHER CHALLENGES

Greenhouse gas issues are in the forefront as oil sands' emissions are about two or three times those of conventional oil production. Canada signed the Kyoto Protocol but it is expected to fall far short of its original 2010 target reductions. Increasingly, consensus is that the original targets are unachievable.

In April 2007, the Canadian government released a revised plan, "Turning the Corner: An Action Plan to Reduce Greenhouse Gas and Air Pollution." This focuses not on absolute emissions, but rather on "emissions intensity." The government now calls for a 6% per year reduction in emissions intensity, beginning in 2008. Oil-sands facilities will be affected.

From 2010, reductions would be 2% per year. New facilities (i.e., those in service after 2004) would have a three-year grace period before the baseline is established. For older facilities the baseline would be 2006.

Reductions would be made through abatements (e.g., improvements in energy efficiency and energy management systems, or the deployment of carbon capture and storage

## KEY CONSIDERATIONS

By 2030, Alberta oil-sands production could reach 5- to 6 million barrels per day, or about half of total North American oil output.

About 20% can be mined at the surface, the rest by in-situ techniques.

Two tons of oil sands yield 1.2 barrels of raw bitumen, which yields 1 barrel of synthetic crude oil.

The benchmark WTI price to make the oil sands economic has risen to $45 per barrel.

Total capital costs are US$100,000 per flowing barrel.

Operating costs are US$33 per barrel.

technologies) or through contributions to a technology fund that allows companies to "buy" their way to compliance with payments based on per ton of $CO_2$ equivalent emissions.

Royalty pressure. Historically, oil-sands development has benefited from a simple, relatively favorable royalty regime. However, Alberta introduced new rules in October 2007 that substantially alter the way oil-sands royalties are applied.

The news rules, effective January 1, 2009, will result in a price-sensitive structure. The base oil-sands royalty, applied on projects before payout, will range from 1% to 9%, based on a sliding scale and referencing West Texas Intermediate (WTI) oil prices between US$55 and US$120. The net oil-sands royalty, applied on projects after payout, will range from 25% to 40% using the same benchmark prices and sliding-scale formula.

Proponents think the new royalty structure brings Canada in line with other royalty regimes throughout the world. Opponents believe the resulting increase in royalty costs make already tight oil-sands economics even more tenuous. On balance, the new royalty structure most likely will increase the royalties paid by the oil-sands producers. There are several additional revisions still being clarified.

Natural gas and water use. In-situ projects typically are very energy-intensive. Many have questioned whether the required massive increase in natural gas use in the oil sands is the best use of that resource since production of natural gas is in decline. Future Arctic natural gas supplies remain uncertain and under a "best-case" scenario are at least 8 to 10 years away from completion. In addition, if North American natural gas prices stay relatively high, project returns will be squeezed.

The planned oil-sands expansions also would require a massive increase in local water usage. Mining operations use between two and five barrels of water per barrel of bitumen. However, in-situ operations are substantially less water-intensive, and more than 90% of the water used is being recycled.

## IN CONCLUSION

What was once seen as an unconventional resource play appears to be on the brink of providing almost half of the future oil production available in North America. However, highly complex and capital intense projects with substantial environmental and social/political implications require that investors in the Canadian oil-sands are smart, innovative, sophisticated and well- capitalized. Rigorous analysis and diligence is required. •

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