The Viability of Non-Conventional Oil Development

Innovest Strategic Value Advisors

Leading-Edge Tools for Investing in a Carbon-Constrained Economy

With expected operational costs of $65 to $90+/bbl, there is only a slender band of oil prices at which non-conventional oil projects would both be economically viable and supported by the economy as a whole.

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INTRODUCTION

As the end of light, sweet crude comes nearer into view there has been much interest in extracting oil from non-conventional sources such as oil sands. Non-conventional oil (NCO) development, however, is only profitable within a very thin margin space. The viability of the projects is bounded by a price floor of $65-$90/bbl,[1] due to the high cost of production, and by an observed historical price ceiling of ~$100/bbl beyond which oil prices have never remained for long.

These constraints mean there is only a slender band of oil prices at which these projects would both be economically efficient and supported by the economy as a whole. When additional costs are considered, such as the inevitable remediation costs, carbon costs and the potential inflationary costs for materials and labor that would be imposed by the very oil prices required for profitability, it does not appear that these projects are economically viable.

The Alberta oil sands projects place significant value at risk for investors. However, current levels of financial and environmental, social and governance (ESG) disclosure do not fully reveal the extent of these risks. In addition, the business plans issued by the companies to justify these projects do not take into consideration the most overarching risk to their success: the macroeconomic limits of the price of oil and the opportunity costs of natural gas.

[1] Total SA

THE PLAYERS

This Research Note examines the new and emerging macro-economic conditions for oil markets, looking at both production costs and the observed price ceiling on oil. We look at these considerations specifically in the context of Canadian oil sands. Key players in this market are:

	Oil Sands Mining Reserves as % of Proved Reserves in 2007[2]	Projected Production in 2018 (boe/d)	Projected Increase in Production 2018/2007	Projected Emissions in 2018 (million tones)[3]	Projected Increase in Emissions 2018/2007	Annual Carbon Compliance Cost in 2018 (USD millions)	Carbon Netback in 2018 (USD/bbl)	Discounted Annual Compliance Cost as % of 2007 EBITDA*
Suncor[1]	56%	550,000	203%	19.1	171%	$1,335	6.65	13.07%
Imperial	88%	510,000	144%	20.9	143%	$1,461	7.85	11.72%
Petro-Canada	48%	190,000	45%	6.9	112%	$481	6.93	2.83%
Husky	1P n/a yet	160,000	42%	5.8	80%	$285	7.00	2.81%
ConocoPhillips	2%	300,150	16%	11.1	20%	$681	6.21	1.03%
StatoilHydro	1P n/a yet	200,000	12%	7.3	47%	$511	7.00	0.63%
Total SA (France)	1P n/a yet	272,000	11%	8.4	14%	$591	5.95	0.52%
ExxonMobil	3%	508,800	12%	19.3	14%	$1,352	7.28	0.76%
BP	1P n/a yet	100,000	3%	3.7	6%	$256	7.00	0.27%
Shell	9%	141,000	4%	4.1	4%	$285	5.53	0.18%
Chevron	4%	48,400	2%	1.4	2%	$98	5.53	0.11%
Total		**2,980,350**		**107.9**		**7,334**		

[1]The list of largest integrated producers can be expanded to include COST, CNR, Nexen/OPTI, Murphy, Marathon, EnCana, Oxy, Sinopec, Enbridge, TransCanada.
[2] This is mining oil sands reserves only. In-situ reserves are often incorporated into the conventional oil reserve estimates. 1P reserves represent a rough idea of exposure, as several producers with substantial projects in the pipeline have not yet reached a stage in the project development when proved reserves are booked.
[3]2018 estimates are used, as this is when the Canadian federal government intends to implement regulation to either sequester GHG or use offsets. Carbon capture and sequestration cost of USD 70/ton of CO2 equivalent, and Pembina Institute's estimates of projects' carbon emissions are modeled.
*Discounted at 9%

Shell has one of the largest investments in oil sands among oil majors. According to its 2007 financials the company invested $5.06 billion into the oil sands projects over the last two years.

Currently, oil sands constitute 2-10% of the oil major's proven reserves. BP and Total S.A. have yet to go beyond the assessment stages for their projects, although these are estimated to add a potential 100,000 b/d production net to BP, and 272,000 b/d net to Total. The supermajors and major pipeline companies have also committed sizable natural gas resources to the oil sands region and would commit even more, if its pipeline projects from Alaska's North Slope come into play.

Business Risks for Oil Sands Projects

We identify four major business risks for oil sands projects:

- **A ceiling on oil prices**. There is an observed historical price ceiling of approximately ~$100/bbl, beyond which prices rarely remain because demand collapses.

- **A failure to expect carbon pricing**. Oil sands extraction is very carbon intensive, yet most oil sands projects do not anticipate regulatory constraints on CO2 emissions.

- **A rising price of a key input: natural gas**. Natural gas is a key input for transforming oil sands into oil. Yet the price of this input will rise dramatically under the same high oil prices required for the projects to be profitable.

- **Additional business risks**. Oil sands projects face substantial yet undefined costs relating to remediation and infrastructure development in sensitive areas.

A Ceiling on Oil Prices

In 2006, Cambridge Energy Research Associates (CERA) issued a report entitled *Break Point*, which outlined the expected impacts on GDP growth of oil prices above $100 per barrel. The study concluded that when oil price reached the "break point" price of $100 a barrel or higher, GDP growth would slow, stop and reverse. The implication was that general growth in the economy could also not support an ever increasing price for energy, oil in particular.

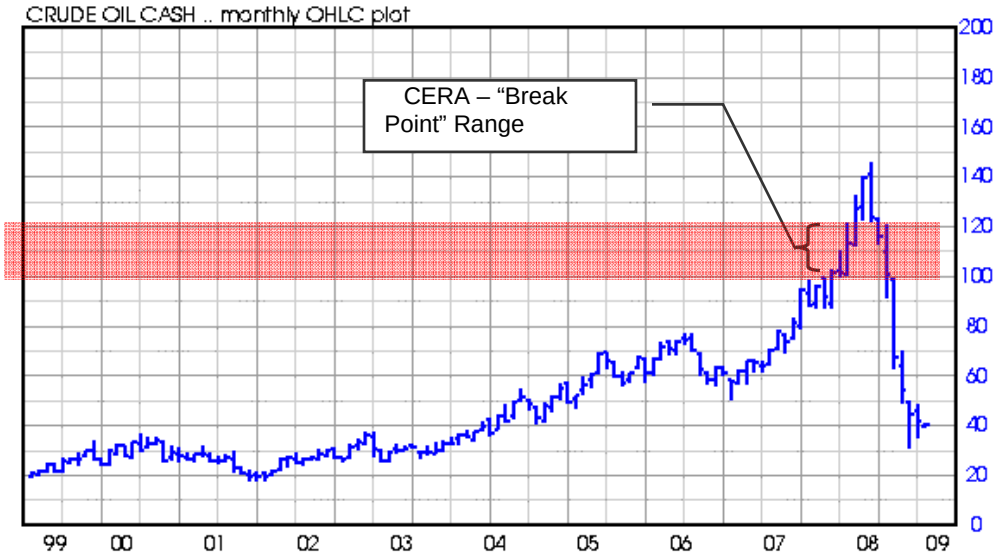
As figure 1 illustrates this prediction was borne out this past summer when oil touched $140/bbl in July '08. Recent analysis by the National Bureau of Economic Research[2] showed that the US economy entered recession in the beginning of 2008. At that time oil was trading around $90/bbl and reached $100 in March.

What this scenario implies for all oil sands and shale oil projects is that with expected operational costs between $65-$90/bbl[3] and higher, there is only a slender band of oil prices at which these projects would both be economically efficient and supported by the economy as a whole. When additional costs are considered, such as the inevitable remediation costs, carbon costs and the potential inflationary costs for materials and labor that would be imposed by the very oil prices required for profitability, it is clear the viability of these projects is far from certain.

[2] "Determination of the December 2007 Peak in Economic Activity", The Natioanl Bureau of Economic Research Business Cycle Dating Committee, 12/01/08

[3] Total SA

FIGURE 1 Macroeconomic Limits of Oil Prices



Source: Cambridge Energy Research Associates; Oil market data from DOE.

It should be strongly noted that upward pressure on oil prices will be considerable given supply constraints, both physical and political, as well as from expanding demand in emerging economies, and these factors will be a constant influence in the oil markets. However, the inability of the global economy to support prices above $100/bbl for any lengthy period will be the limiting factor which prevents oil prices from being high enough over any period of time to support oil sands development. The interplay between the two dynamics will be cause of increased volatility in the energy markets going forward.

With high operating costs for oil sands, even with many of these costs either deferred (environmental remediation), incorporated (water storage requirement) or externalized (carbon costs), these projects require a high sustained oil price, at least above $65/bbl, to remain profitable. This situation reveals a fatal flaw for non-conventional oil projects because their operating budgets will be continually squeezed against oil price environments that are economically unsustainable for the economy as a whole.

The economic retrenchment which follows the high oil prices, as we've seen in the fall of 2008, will pull oil prices down by eroding economic activity and therefore oil demand, which quickly leaves non-conventional oil operations unprofitable. Since the aggregate level of world demand for oil is approaching the limits of access to conventional oil supplies[4], future economic growth will lead to a rapid rise in oil prices with the end game being a resumption of recessionary pressures. Clearly there is the

[4] The Association for the Study of Peak Oil and Gas has data showing oil discovery peaking in the 1960's and the IEA has recently stated that oil production will likely plateau in 2020. [IEA World Energy Outlook 2008 ; http://www.worldenergyoutlook.org/2008.asp]

overriding dominance from the credit crunch crisis dominating the current economic cycle. However, the recent spike in oil prices has been interrelated with turmoil in the financial markets and a key ingredient in the recession. High oil prices in the future will also have the effect of exacerbating any weaknesses in the system, whatever they happen to be at the time. Until the global economy becomes much more energy efficient and moves to alternative energy sources for a greater proportion of its needs, which will take years if not decades even with aggressive public policy, oil price sensitivity will remain.

A Failure to Expect Carbon Pricing

The likelihood of policy implementation of a carbon market in the U.S. and Canada appears very strong, especially as it has been included as a key point in the new US administration's energy plan and Canada's progress towards legislating carbon sequestration options for heavy polluting industries. Yet most oil sands projects do not project in the risk of this cost.

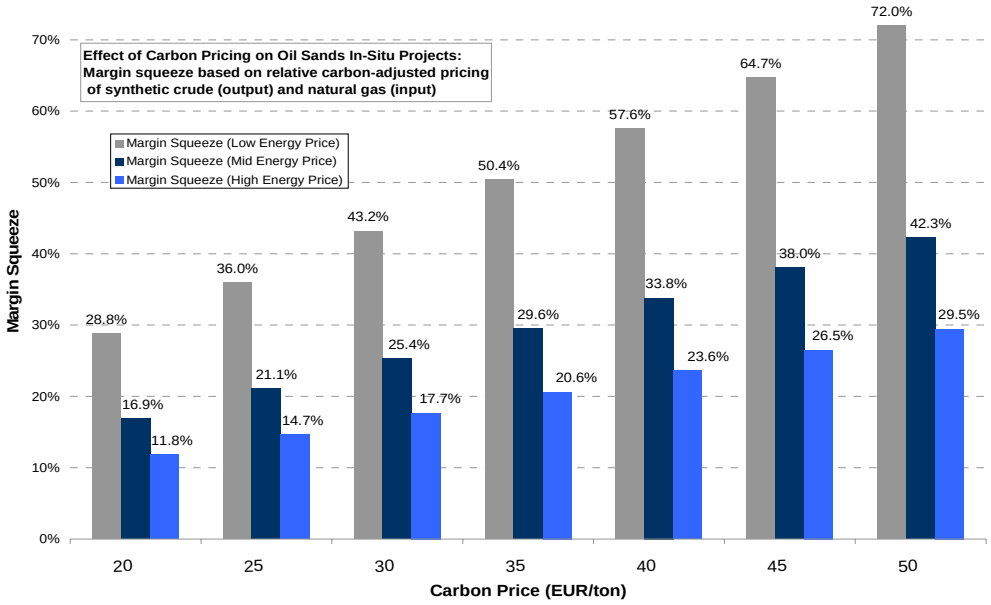
In March 2008, the Federal Government of Canada finalized the Regulatory Framework for Air Emissions and set the stage for Canada's target of absolute 20% reduction in greenhouse gasses from 2006 level by the year 2020. In addition to the announcement in April 2007 of a broad emission reduction framework for all major industrial producers, the policy addresses the oil sands and coal-fired electricity projects that will come on stream in 2012. Specifically, the new projects, including the expansion stages of the exiting projects, will be required to incorporate carbon capture and sequestration (CCS) facilities or achieve an emission reduction through offset mechanisms. The offset targets, which are yet to be set, will be based on the CCS for in-situ, and upgrading will apply beginning 2018.

Presently, the old facilities in Canada's 16 carbon-intensive industrial sectors are subject to the intensity targets of 18% reduction from the 2006 level by 2010, and 2% continuous reduction thereafter. The newer facilities, commissioned in 2004, will be required to achieve further emission reductions from the use of process-specific cleaner fuels (targets are still being discussed). In addition to the CCS requirement for future oil sands projects, Environment Canada intends to achieve an additional 25 megatones reduction by 2020 in the electricity sector, which is equivalent to closing seven large coal-fired power plants.

A price for carbon would put immediate upward pressure on oil sands operating costs thereby intensifying the squeeze between the price level required for profitability and the breakpoint scenario. While both natural gas and synthetic crude oil would have carbon prices applied, the carbon content is significantly lower in natural gas. Innovest anticipates that the carbon-constrained economy will place a premium on the cleaner-combusting natural gas relative to other fossil fuels, as the former emits on average 30% less carbon dioxide than oil and 40% less than coal, and is a minimal source of air emissions compared to the latter two options. Thus, the margin compression would be exacerbated, as the differential in carbon prices raises the value of natural gas in North America, while at the same time increasing the operating costs of synthetic crude to a greater degree.

In figure 2, Innovest estimated the impact of carbon pricing, based on the three different commodity price scenarios. The exact regulatory framework is unknown at this point in time as well as the details of a potential cap & trade system, carbon tax, or the design of the CCS infrastructure. We reviewed the netback effects for a generic in-situ project based solely on the carbon content of input (natural gas) and output (synthetic crude) commodities. We calculated the margin compression in isolation of other production factors, looking only at the impact of carbon taxation of the commodities at combustion. We concentrated on the in-situ projects, as once the 'low-hanging fruit is picked', or mining oil sands are excavated, the majority of the oil sands resources is anticipated to be developed through in-situ recovery, which is four times more natural-gas intensive than mining.

FIGURE 2 Carbon Price Impacts - Generic In-Situ Project



	Synthetic Crude		Natural Gas		Ratios		Commodity Pricing		Carbon Pricing Effects (at EUR 20/ton)		Margins		
Commodity Price Scenarios	SCO Crude Output (bbl)	SCO CO2 Emission Upon Combustion (kg/bbl)	NG Input (ft3)	NG CO2 Emission Upon Combustion (kg/per bbl of SCO)	Oil Sands Production: Energy Output/Input	Oil Sands Production: Carbon Output/Input	Edmonton Par, 2007 average (CAD/bbl)	AECO, 2007 average (CAD/mcf)	Carbon-Adjusted SCO Revenue	Carbon - Adjusted NG Cost (open market purchase)	Carbon Unadjusted Margin	Carbon Adjusted Margin	Margin Compression
2007 Average	1	431	1,000	54	5.7	7.9	$76.65	$6.60	$63.10	$4.89	$70.05	$58.21	-16.90%
High	1	431	1,000	54	5.7	7.9	$110.00	$9.50	$96.45	$7.79	$100.50	$88.66	-11.78%
Low	1	431	1,000	54	5.7	7.9	$45.00	$3.88	$31.45	$2.17	$41.12	$29.28	-28.79%

A Rising Price of a Key Input: Natural Gas

Another key consideration is an alternative application of energy utilized in the process of extracting oil sands, mostly in the form of natural gas. The value of this gas is a significant opportunity cost if utilized in oil sands operations as opposed to being delivered directly to market.

Natural gas has historically been an 'underprivileged' commodity as producers generally redirect capital expenditures to oil drilling in high oil price environments, which has been the case since 2002. In contrast to the oil markets, supply of natural gas has generally kept pace with demand; however the recent trend towards unconventional gas exploration and production of tight gas and coal bed methane indicates the tightening demand/supply balance.

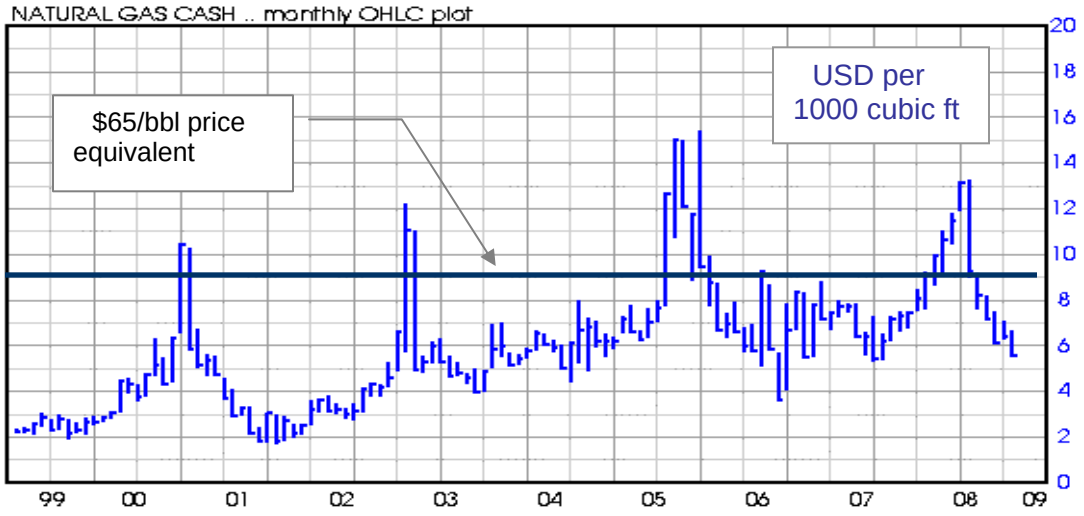
Should the resumption of higher oil prices re-ignite the drive for oil sands, these projects themselves will become demand drivers for natural gas. Natural gas is an input used to transform oil sands extracts into usable oil. A 2005 report by the provincial energy regulator, Alberta Energy and Utilities Board, found that the purchased natural gas requirements for bitumen recovery and upgrading to synthetic crude oil are expected to increase annually from 5.4 billion cubic meters (191 billion cubic feet) in 2005 to 13.8 billion cubic meters (487 billion cubic feet) by 2015[5]. As the oil sands industry boosts the demand for natural gas, producers' cost of labor and materials, which are already under strain from conventional and unconventional oil demand, will rise even higher. While nearly all the major oil sands projects have been delayed in the current low commodity price environment, the resurgent growth in the industry will create a spiraling inflation effect on the costs of production.

The regulatory efforts to address climate change discussed above will very likely push this dynamic even further, as more gas fired generation comes online in the electrical power sector and current plants seek to maximize capacity utilization through combined cycle gas turbines over more energy- intensive options such as coal. This would raise its value tremendously in the North American economy, especially for utilities, should a market for carbon materialize.

Fluctuations in the natural gas markets (figure 3), therefore, will become a significant force determining profitability of non-conventional oil operations, particularly in the oil sands where already substantial use of gas is projected to grow. This is because gas price spikes could either mean further cost inflation for oil sands operations or even worse, require the shutting down of oil operations altogether to redirect that gas onto the market, thus losing revenue from oil sands as facilities stand idle, thus lowering production volumes and lengthening payback timeframes:

[5] The Center for Energy: http://www.centreforenergy.com/silos/NaturalGasPrices/NG-MarketDynamics.asp ; The Center for Energy is a Canadian group that does economic work on the energy markets with a focus on Canada and North America.

FIGURE 3 Natural Gas Opportunity Cost



Source: Innovest; DOE EIA

Control of natural gas reserves when natural gas prices on the market are high presents major oils sands players with a potentially damaging set of economic choices -- profiting from one source is undercut by the inability to profit from the other. It is also important to note that proposed sources for future natural gas supplies for oil sands operations are expected to come from environmentally sensitive arctic fields, which raises another set of externality problems.

Additional Business Risks for Oil Sands Projects

The physical scale of these projects, transcontinental in nature given the pipeline infrastructure and refinery upgrades necessary for production of synthetic crude, also imply significant environmental limits such as greenhouse gases, water use, toxic waste, etc. These are also significant limiting factors, to such an extent that they alone threaten the license to operate.[6] These environmental impacts have been well documented elsewhere.[7]

Other business risks considerations are:

[6] One such example is the U.S. Conference of Mayors meeting in Miami in June 2008, which adopted a resolution aimed at avoiding the use of high carbon fuels such as oil sands, liquid coal, and oil shale. The resolution encourages fuel analyses that include emissions from production, not just from burning the fuel. The state of California is currently developing a low-carbon fuel standard (LCFS). Presendent Barack Obama has also implied that fuel standards that included carbon content limits would be legislated under his administration and a carbon trading scheme has also been announced under the administration's energy plan.

[7] For the most recent scientific data on climate change see the Intergovernmental Panel on Climate Change. www.ipcc.ch ; For discussion in context of the environmental impacts of Canadian Oil Sands and Shale Oil see the following -- "*BP & Shell: Rising Risks in Oil Sands Investments*" Marriott, James; Stockman, Lorne; Kronick, Charlie, Platform and Greeenpeace UK 2008; "*Unconventional Oil: scraping the bottom of the barrel?"* Leaton, James; Baines, Colin, WWWF-UK and The Co-operative Group 2008; "Undermining the Environment", Pembina Institute and WWF 2008.

- Additional long term hidden risks for these projects with significant costs and environmental liabilities remain undefined for shareholders – such as remediation of toxic tailing ponds, water use, and the impacts of existing and planned refining and pipeline infrastructure that stretches some 4000 miles from the North Slope of Alaska to the Gulf of Mexico.

- Current cash flows are ballooning on the strength of netbacks realized from high commodity prices and the ROI of capital investments made in the past. However, these have little relevance in the future, since oil sands development has a radically different cost structure from those associated with conventional oil extraction and development. It is important to note that profits' have not been made yet on oil sands and shale oil as they are still in the capital investment stage. For example Shell reports capital investments in oil sands in 2008 and 2007 of $3.124 and $1.931 billion respectively (or approximately 7% of total capital expenditure) and revenues of only $941 and $582 million in those years (or less than 1% of revenues). 2008 is especially revealing as the operations still required greater capital inputs than revenue even with the unprecedented spike in oil prices. This creates a risky dynamic for both the company and investors as more capital poured into these projects will create even greater pressure to realize ROI on fixed assets for oil sands. This will lead to the expenditure of good money after bad spent on oil sands operations in a vain attempt to get the pay off, an unlikely scenario as markets will not provide favorable conditions for profitability for any **lengthy period** of time. Should these sources become the substantial portion of reserves and production for BP and Shell, they will radically change the cost structure of producers compared to what investors are currently discounting.

- Given the ever increasing global demand for energy and the uncertainty associated with an amount of recoverable resources due to geopolitical and climate change concerns, volatility of commodity prices will be amplified. Stock price volatility for oil sands companies will increase since their thin margins are even more sensitive to oil price futures.

- These projects also lower the barriers to entry for energy efficiency improvements and alternative energy sources which will permanently lose the industry its customer base. This is already happening to a significant extent in the transportation industry with the popularity of hybrid vehicles. Currently most renewables may be costly, but those costs are fixed and knowable, making financing and long term planning easier. In addition, the long term cost trend is downward for renewables, while the long term cost trend for oil is upward. For example, according to the German Federal Environmental Ministry, the cost of electricity generation of solar power decreased about 60% from 1991 to 2003, while CERA's Upstream Capital Cost Index showed an over 100% increase from 2000 to 2008. If carbon costs are added into the price considerations, renewables quickly become the more cost effective option depending on the carbon price level (see below) and the technology employed.

» **Oil sands projects are scientifically and politically highly contentious. With a very large lifecycle carbon footprint, there is a real risk that oil sands oil projects could be banned as part of a CO2 reduction plan. Investors must then consider that from a climate perspective these projects face very significant regulatory risks.** Canada's emissions are currently 35% above its Kyoto commitment, and should all oil sands approved projects proceed, the gap will reach 90 million CO2 tons by 2015. In short, the emissions and impacts from these projects are so large that they will in and of themselves have massive global impacts. Thus these companies by definition are likely to lose their license to operate and this will mean they would be stopped from realizing these projects by regulators and stakeholders as the impacts of the externality costs are calculated and more widely understood. This will place investors at high risk of investment loss due to regulatory blocks on the projects such as a low-carbon fuel standard as a severe constraint on the importation into the US of oil derived from these projects.

Concluding Thoughts

What Keeps on Driving Investment into the Oil Sands Sector?

The core driver is the net asset valuation approach taken for integrated oil and gas companies. One of the key metric analyzed by equity investors in oil & gas companies has historically been the total level of exploitable reserves. As fields dry up and get nationalized, oil majors have had look elsewhere to boost their reserve numbers. In the eyes of the SEC, however, oil sands are not considered reserve assets on par with conventional oil. As a result the SEC mandates that mining reserves are presented separately from conventional reserves, where disclosure is associated with Net Present Value (NPV) estimates from engineers or the companies themselves. Oil sands mining reserve disclosure does not provide NPV estimates, as they are not mandated under current reporting requirements of the SEC. Therefore investors should critically review their Net Asset Value (NAV) valuation approach to oil sands projects.

In addition, these companies have much institutional inertia behind oil exploitation. They have long set themselves up to focus on, and be successful in, one key economic activity: exploration and production of petroleum. The intellectual capital, engineering expertise, employee incentives, training programs, corporate structure and long term goals of these companies are all organized around this one activity. This has been extremely profitable, especially during the recent run-up in prices. But these core competencies may still not be enough to squeeze value out of reticent oil sands.

Test of Management Quality: Long-Term Leadership

"If this is as bad as you say, why would a profit seeking enterprise engage in these investments?" The answer to this question is institutional inertia and poor corporate governance as it pertains to long term incentive mechanisms. Finding and developing oil and gas resources is the oil companies' core expertise, and the institutions are reluctant and slow to deviate from the status quo. Therefore, for example, BP suffers from undervaluation of its alternative energy business, and Shell's many renewable energy ventures have failed and been sold. Instead, the management is encouraged to consider alternative scenarios for investment such as:

- Focusing on getting natural gas resources to market as opposed to directing them to oil sands operations.
- Directing capital flows through a large VC and/or credit operation to third-party alternative energy start-ups, which would function as a large generator of future capital as well as a financial hedge. They would benefit from the success of their competition without having to engage in day-to-day operations management to which they are ill-suited. In addition, this would allow them to own or have quick access to own the means of production in the next energy boom without limiting them to a single strategy.

We suggest that there are a number of questions for investors to get greater detail on from the oil & gas companies' management on their oil sands operations:

1. How have they considered the macroeconomic impacts of high oil price in their business plans? (I.e. do they accept CERA's findings in "BreakPoint")
2. Have the opportunity costs for natural gas been calculated and considered from an alternative business strategy such as bring this gas directly to market?
3. Has the operational cost inflation been in line with energy price increases? If so, how has that affected expected return at higher oil prices levels?
4. Has the cost of carbon been estimated and which effect it had on capital budgeting decisions? How do the costs of carbon capture and storage compare with carbon credits for the company's operations? What price ranges are they using in their projections?
5. What are the estimates of environmental remediation costs for the company's mining or in-situ operations? Have they been incorporated into the capital budgeting decisions and what has been an effect on the projects' NPV?
6. What are the gas pipeline costs to get from Alaska to Athabasca and oil pipeline costs to get from Athabasca to the US Midwest or the Gulf of Mexico? Which environmental and social externalities have been factored into pipeline infrastructure cost estimates?
7. How many refineries have been upgraded and are planned to be upgraded to handle heavier slates of crude and dedicated to oil sands? How much has been invested into the refinery upgraders and what are the effects of the proposed Canada-US climate change pact on the economics of the upgrader projects?
8. What has been the total level of company investment in oil sands? When are revenues expected to justify that investment?