



The Canadian Oil Sands

A Backgrounder

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Table of Contents

Preface	ii
Current Issues in the Oil Sands	iii
Underutilized U.S. Refining Capacity and Transportation	iii
Keystone XL Pipeline and Canada-U.S. Energy Policy	iii
Carbon Policies in Consumer Markets	iv
Streamlining Regulatory Review Process – One Project, One Review	iv
Natural Gas Pricing	v
Labour Challenges	v
Introduction	1
Geography and Reserves	1
Production	2
Investment	2
Employment	2
Advantages of Investing in the Oil Sands	3
Challenges	5
Location and Extraction	7
Surface Mining	7
In Situ Extraction	8
Table 1 - Evaluating Your Potential Investment – Mining vs. SAGD	9
Emerging Technologies	10
Players and Projects	12
Major Existing Producing Projects	12
Syncrude	12
Suncor	12
Athabasca Oil Sands Project	13
Other Projects	13
Projects Under Development	13
New Market Entrants	16
Alberta Oil Sands Transactions 2001-2013	16
Table 2 - Alberta Oil Sands Transactions 2001-2013	17
Market Opportunities	19
Transportation	19
Upgrading	20
Derivative Plays	21
Electricity	22
Nuclear	22
Petrochemicals	22
Structuring your Transaction or Project	23
Valuation	23
Table 3 - Summary of Oil Sands Public Offerings	23
Acquisition Structures	24
Foreign Investment Approvals	24
Financing a Project	25
Alberta's Royalty Framework	25
General Royalty Framework	25
The BRIK Program	26
Environmental Concerns	27
Climate Change	27
Project Regulation	28
First Nations Issues	29
Conclusion	30
References	31

Preface

Described by *Time Magazine* as “Canada’s greatest buried energy treasure”, the Canadian oil sands encompass over 140,000 km² (54,054 mi²) underlying northern Alberta and Saskatchewan. Overall crude production from the oil sands is estimated to reach 3.88 million barrels per day by 2020, and 4.34 million barrels per day by 2025, which will meet an estimated 16 percent of North American oil demand. From 2001 – 2011, over \$133.4 billion was invested in the oil sands and almost \$125 billion in oil sands-related projects are underway or proposed. Only about four percent of the initial established bitumen reserves have been extracted to date. The fourth wave of oil sands development is now underway. With the world demand for crude oil expected to exceed 105 million barrels a day by 2030, the Canadian oil sands give investors access to a massive resource base that is politically stable and has a long reserve life.

Oil sands developments are mega-projects with very significant regulatory, capital, commercial and environmental components such that it is imperative that investors seek legal advice from a firm with lengthy experience in the oil industry in general and the Canadian oil sands in particular. Having played an integral role in the development of the Canadian oil and gas industry for nearly 90 years, Bennett Jones LLP has compiled this backgrounder for potential investors in the oil sands.

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1.7 trillion
barrels of crude bitumen estimated in the Alberta oil sands deposits

\$170 billion
invested in oil sands projects

Current Issues in the Oil Sands

Underutilized U.S. Refining Capacity and Transportation

Figures released by the United States Energy Information Administration (EIA) indicate that utilization rates at major U.S. crude processing plants are low – the percent utilization of refinery operable capacity was around 85 to 90 percent for a majority of 2012 and has remained around 80 to 85 percent thus far in 2013, whereas pre-recession levels frequently reached 95 percent or higher. Such low utilization rates have been attributed to factors such as increased competition from “super-refineries” and developing markets, lower profit margins in the refining sector, and fluctuating consumer demand due to high gasoline prices. The success of the Canadian oil sands is seen as a development that could have a rebound effect on the U.S. refining industry. Higher volumes of heavy crudes from Canada offer potential to improve operating margins for U.S. refiners, many of whom long ago made expensive upgrades in complex facilities that favor heavy oil, which was historically imported from Mexico and Venezuela but is now in decline. As oil sands recovery techniques continue to become more efficient and overall oil sands production output continues to increase, the oil sands will have a proximate advantage relative to foreign rivals. Such advantage is predicated on the necessary pipelines and transportation infrastructure such as the Keystone XL pipeline expansion being completed, such that Canadian oil sands production can access the underutilized U.S. Gulf Coast refineries.

Keystone XL Pipeline and Canada-U.S. Energy Policy

TransCanada Corp’s Keystone XL pipeline is a proposed expansion of the existing Keystone Pipeline System, which is currently used to transport crude oil from Alberta’s Athabasca oil sands region to refineries in Illinois and Oklahoma. The project, which would expand capacity by 500,000 barrels a day and extend the line to refineries along the U.S. Gulf Coast, is currently one of the most contentious and controversial topics in Canada-U.S. relations and the North American energy industry. On January 19, 2012, the pipeline approval was delayed when President Obama rejected the construction of the project, stating that a congressionally

imposed deadline did not provide enough time to review all of the potential environmental impacts. President Obama made it clear that he was not denying the pipeline on its merits and encouraged TransCanada to reapply.¹

Proponents of the Keystone XL pipeline say it is a win-win for the U.S. and Canada, as Canada will gain a stable market with steady demand and the U.S. will improve its energy supply and economic security. Alberta-based industry has indicated that the rejection of the Keystone XL pipeline would strengthen the push for export routes to Canada's West Coast to access Asian markets in lieu of American markets. Opponents to the expansion cite environmental concerns, such as the potential consequences of a leak or spill along the route, and question the need to expand existing pipeline capacity between Canada and the U.S.

In May, 2012, TransCanada changed the original proposed route and filed a new application for a Presidential Permit with the U.S. Department of Stat, which is required for building a cross-border pipeline. The Governor of Nebraska, Dave Heineman, approved the new route in Nebraska in January, 2013. TransCanada has also stated that it will move forward with the southern portion of the pipeline, which runs from Oklahoma to the Gulf of Mexico. Pending approval of the northern leg of the pipeline, the entire project is now expected to be operational by 2015.²

Carbon Policies in Consumer Markets

A recent political hurdle that has emerged for Alberta's oil sands production is the introduction of new policies in consumer markets that require oil suppliers to reduce the carbon footprint of their motor fuels. Production in the oil sands is shifting away from traditional mining and towards steam injection, which results in higher emissions due mainly to increased natural gas consumption. A prime example of these new policies is in the state of California, which is the largest gasoline consumer in the United States and which has adopted a low-carbon fuel standard. This standard measures the carbon footprint not just by its emissions, but instead across the full product life cycle, which could potentially force change in the production technologies of the oil sands producers. The evolution of California's low-carbon fuel standard is being closely watched, as eleven further states and even the European Union, are seeking to adopt a similar standard.

Across the Pacific, China's government has introduced a plan to cut carbon dioxide emission per unit of gross domestic product by approximately 45 percent by 2020 and to further reduce greenhouse gas emissions in specific cities. However, the long-term trajectory of China's carbon plan remains unclear, as China's energy demand growth is estimated to grow by 75 percent between 2008 and 2035, accounting for approximately 36 percent of all projected growth worldwide and therefore its emission policies will play an integral role in the future.³

Streamlining Regulatory Review Process – One Project, One Review

Under the Canadian constitution, provinces have ownership over the extraction and commercialization of natural resources, yet the federal government retains concurrent jurisdiction in some areas relating to natural resources such as competition/antitrust, environmental matters, offshore development, and pipelines which cross provincial borders. As a result, proposed natural resource projects in Canada have often required reviews and approvals from a myriad of provincial and federal agencies. In response to industry and stakeholder feedback, as part of the 2012 federal budget the government of Canada announced that it intends to implement a streamlined review process according the principle of "one project, one review", which would be completed in a clearly defined time period. Early statements indicate that major project reviews will now recognize provincial processes as substitutes or equivalents to federal ones as long as they meet the requirements under the Canadian Environmental Assessment Act. The streamlined plan will see three federal agencies responsible for reviews — the Canadian Environmental Assessment Agency, the National Energy Board and the Canadian Nuclear Safety Commission — down from 40. This initiative could drastically reduce the review and approval times for major oil sands projects.

Alberta has taken a step to create a more efficient, effective regulatory system by promulgating the *Responsible Energy Development Act*, which creates a single and arm's-length energy regulator, the Alberta Energy Regulator (AER), for upstream energy resources developments. AER replaces the Energy Resources Conservation Board and assumes certain environmentally-related powers and functions of Alberta Environment and Sustainable Resource Development. The establishment of AER will be a one-window approach to facilitate energy resource activities and to better manage energy resources in an integrated manner.

Natural Gas Pricing

With natural gas inventories in the United States at record levels and recent major discoveries in North America meeting market demand, gas prices are currently low and are projected to remain that way for the foreseeable future. These low prices have created favourable near-term conditions for thermal oil sands production, with natural gas being the largest input cost, employed both in the extraction and refinement of bitumen. Reduced natural gas prices help counter the effect of escalating operating costs such as labour, materials and equipment and lead to increased profitability from oil sands production.

Labour Challenges

The Petroleum Human Resources Council of Canada forecasts that labour demands in Alberta's oil sands operations will increase by 73 percent over the next decade with growing oil sands production as the key driver. In addition, the unemployment rate in Alberta is approximately five percent, which equates to near full employment, meaning that the industry is already stretched in certain areas, such as engineering and trade skills. Further, more than 30 percent of the industry's core workforce is expected to retire within the decade, due to age-related attrition, as the first baby boomers turned 65 in 2011. This has lead to significant labour shortages and increased labour costs as the industry struggles to manage wages in an employee-driven labour market. The oil sands sector will have to give significant thought to effective and efficient strategies to work with the construction, maintenance and support services sectors, which are critical to the growth and sustainability of oil sands operations.⁴

145,000
people employed in Alberta's mining, oil and gas sector

142,200
sq. km of oil sands deposits

Introduction

Investment in the Canadian oil sands has increased rapidly since the resource was first commercialized by Great Canadian Oil Sands (now Suncor) in the 1960s. This growth is forecast to continue, despite fluctuations in the economy and new energy technologies, because of the world demand for oil and the unique advantages of the oil sands.

The latest wave of oil sands development is gathering momentum, with previously shelved expansions now being reactivated and new expansions being initiated. It is believed this latest wave will entail a more disciplined approach to development by both industry and government occupied by continuing scrutiny from non-governmental organizations and non-industry stakeholders. The rapid increase in world oil price, uniquely accompanied by stagnating North American natural gas prices has accelerated development. Construction and operating costs are lower than they have been in several years and all observers wonder whether this trend will be short-lived. The Conference Board of Canada forecasts that while industry costs for Alberta's oil sands projects will climb at a very rapid pace over the next three years, buoyant oil prices should ensure that profits return to pre-recession highs by the end of 2014.

Geography and Reserves

Alberta's oil sands underlie a vast area of the province, located primarily in the regions of Peace River, Athabasca (the Fort McMurray area), Cold Lake (north of Lloydminster) and stretching into Saskatchewan. These areas contain an estimated 1.7 trillion barrels (initial volume in place) of crude bitumen. Of this amount, 168.7 billion barrels are considered to be proven reserves⁵ (about 99 percent come from the oil sands; and the remaining 1.5 billion barrels come from conventional crude oil). Based on these figures, Alberta has the third-largest proven crude oil reserve in the world, accounting for about 11 percent of total global oil reserves.⁶ With new and emerging technologies, this reserve estimate could be increased to as much as 315 billion barrels.⁷ Companies have barely scratched the surface of the resource, extracting only about four percent of the initial established crude bitumen reserves to date.⁸

Production

A report from the International Energy Agency (IEA) states that "unconventional oil is set to play an increasingly important role in world oil supply through to 2035, regardless of what governments do to curb demand... output rises from 2.3 mb/d in 2009 to 9.5 mb/d in 2035" with specific mention of the contribution of Alberta's oil sands, which is approximately 1.5 million barrels per day (bbl/d).⁹ Alberta's Energy Resource Conservation Board (ERCB) forecasts that Alberta's annual bitumen production will total 3.2 million bbl/d for a total of 1.2 billion barrels per year by 2019 and the U.S. EIA estimates that Canadian oil sands operators could reach production levels of 4.5 million bbl/d by 2035.¹⁰ Alberta's current upgrading capacity is approximately 1.13 million bbl/d.¹¹

Since 1999, Canada has been the largest supplier of natural gas and crude oil to the United States.¹² Statistics released by Alberta Energy indicate that Alberta exports about 1.3 million bbl/d of crude oil to the United States, supplying 15 percent of U.S. crude oil imports, or seven percent of U.S. oil demand.¹³

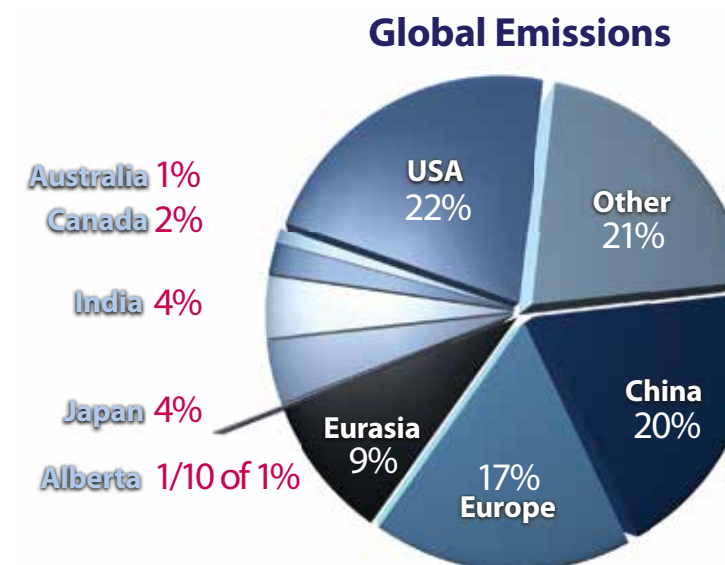
Investment

Investment in the oil sands gives companies a unique opportunity to add reportable reserves at relatively low risk. Business opportunities also exist in ancillary industries such as construction, engineering, petrochemicals, electricity generation, metals, housing, and transportation.

In recent years, investment in Alberta's oil sands has been robust. From 2001 to 2011, an estimated \$133.4 billion was invested in oil sands projects.¹⁴ The oil sands investment reached \$21.6 billion in 2011.¹⁵ However, entering the latest wave of development, oil sands investment is increasing at a modest pace with an estimated \$125 billion in oil sands-related projects currently underway or proposed.¹⁶

Employment

About 136,000 Albertans are directly employed in the oil and gas extraction and mining sectors, which accounts for one out of every 15 jobs in the province. According to the Conference Board of Canada, between 2012 and 2035, development in the oil sands industry will support 880,000 person years of employment over the examined period.¹⁷



Source: Alberta Energy, Alberta's Oil Sands: the Facts (April 2011) online: http://www.oilsands.alberta.ca/factsheets/the_facts_v5_final.pdf



91 active projects in the Alberta oil sands

90 percent recovery rates for mining projects

Advantages of Investing in the Oil Sands

The oil sands are increasingly seen as a critical strategic component of U.S. and global energy security. World crude oil demand is expected to advance one percent a year, from 85 million barrels a day in 2008 to 105 million barrels a day by 2030.¹⁸

The Canadian oil sands represent a viable supply alternative to the world's growing demand for oil and offer significant reserve and production growth potential with little associated strategic or political risk. The location, depth and size of the oil sands deposits can be determined with a high degree of accuracy and at minimal cost compared to conventional exploration. For mining operations in particular, recovery rates approach 90 percent, which is substantially higher than conventional sources.

Investment in the oil sands also provides companies with a unique and relatively low-risk opportunity to add reportable reserves. In Canada, both *in situ* and mined bitumen are recognized as part of typical oil and gas public disclosure. The U.S. Securities and Exchange Commission allows for *in situ* and mineable bitumen reserves to be reported as proved reserves.

One of the most significant drivers of growth in the oil sands has been the reduction of exploration, development and operating costs. While such costs are gradually

Current forecasts indicate that by 2019 bitumen production will increase to 3.2 million barrels per day.

increasing from levels experienced during the recession, industry players are still enjoying low operating costs relative to pre-recession levels. Labour turnover has decreased dramatically, leading to productivity and efficiency gains. Oil sands service providers and equipment manufacturers have been able to rein in prices as a result of the recession and increased competition. These changes have led large developers to reissue project cost projections at significantly lower figures and with the recent upswing in oil prices, investment potential is increasing.¹⁹ Improvements driven by technological innovation and operational experience are anticipated to amplify this trend. Some industry forecasters and observers have warned, however, that as crude prices remain high and new projects are approved, the oil sands should prepare for a potential labour crunch in 2013, particularly in the areas of engineering and construction trades.

Integrated mining and SAGD operations are estimated to be economical at US\$61/bbl (WTI). Any significant escalation in material and labour costs or natural gas and diluent price increases pose a risk to this outlook. However, advancement in recovery and upgrading technologies hold the potential to improve the economics associated with oil sands operations.²⁰

The Canadian oil sands also has a unique opportunity to provide substantial and long-term operating efficiencies for the U.S. refining sector, which has experienced declining margins and an under-utilization of capacity in recent years. U.S. refiners were historically able to maintain reasonable profit margins by taking advantage of the price spread between light and heavy crude oil. However, when the light-heavy crude price spread collapses as it has in recent years and there is little discount between heavy and light oil, heavy refiners are unable to realize any benefits from purchasing heavy crudes. One driver of the tightened spread is the dramatic decline in production and supply to the U.S. of heavy crude oil from Mexico and Venezuela. Provided that the necessary transportation and infrastructure is developed, additional volumes of blended bitumen from the Canadian oil sands could offset such decline and support the economic fundamentals of U.S. refineries.²¹

Analysts forecast a two- to five-fold increase in production by 2030, which will meet an estimated 16 percent of North American demand.



Challenges

Oil sands projects and developers are exposed to various risks and challenges, including:

- **Cost Overruns and Delays.** Many oil sands projects have encountered cost overruns and delays. Historically, some fully integrated oil sands mining projects have faced cost overruns of over 55 percent, largely attributable to labour shortages, engineering-related change requested during the construction phase and the difficulties inherent in managing large-scale projects, particularly those involving upgraders. The risk of recurrence of such overruns has been considerably mitigated through operational improvements, technological innovation and greater industry and government planning.
- **Supply of Diluent.** Condensate and other products are used to dilute unprocessed bitumen product (typically in the 20 to 30 percent by blend volume range), but diluent supply is declining and falling short of demand. To ensure that diluent supply does not hinder oil sands development, industry players are seeking to adapt to shortages and reduce demand, including the potential use of heated pipelines and blending with alternate viscosity reducers (such as

Companies have barely scratched the surface of the resource, extracting only about four percent of the initial established crude bitumen reserves to date.

refinery naphthas and lighter grade conventional and synthetic oils). The Southern Lights pipeline, which went into service July 2010, will help meet the increasing demand for diluent by petroleum producers in Western Canada. This pipeline extends from the U.S. international border to Edmonton, Alberta, and offers petroleum producers in Western Canada a reliable supply of diluents from U.S. refineries and supply centers.

- **Emissions Controls.** Legislative measures have been introduced to address climate change. Alberta became the first jurisdiction in North America to legislate greenhouse gas (GHG) reductions for large industrial facilities. The regulatory regime requires facilities in Alberta emitting over 100,000 tonnes of carbon dioxide equivalent per year to reduce their emissions intensity by a specified amount. Emitters that fail to meet the target have the option of buying Alberta-based carbon offsets, or paying \$15 per tonne over reduction targets into the Climate Change and Emissions Management Fund. The fund supports projects and technologies aimed at reducing GHG emissions in the province. See the Environmental Concerns section located on page 34 for further information regarding emissions control and climate change.
- **Reliance on Natural Gas.** Most oil sands projects rely heavily upon natural gas for energy, steam, power or hydrogen production for use in the upgrading process. It is estimated that the oil sands industry alone is consuming 500 million to 800 million cubic feet (MMcf) per day of natural gas, or approximately three to five percent of total Canadian natural gas production. Using current technology, *in situ* projects require about 1,000 cubic feet of natural gas per barrel of bitumen recovered. Mining projects need 250 cubic feet of natural gas per barrel of bitumen and upgraders use up to 500 cubic feet of natural gas per barrel of synthetic crude. Natural gas usage is estimated to increase as the production from oil sands projects increases dramatically over the next several years.
- **Reliance on Water.** The Water Management Framework imposes strict limits on water usage for the Lower Athabasca River. Together all oil sands projects can withdraw no more than three percent of the average yearly flow of the Athabasca River for their business use. During periods of low river flow, Alberta Environment limits water consumption to 1.3 percent of annual average flow. At times, this can mean that industrial users will be restricted to less than half of their normal requirements given current approved development. Many *in situ* projects recycle up to 90 percent of the water used in their operations and use deep-well saline water as an alternative to river water wherever possible. Industry is continually working on making production more efficient so water usage is further reduced. In mining operations, 7.5 to 10 barrels of water is used for every barrel of upgraded bitumen. However, with recycle rates of 40 to 70 percent, this means only three to 4.5 barrels of water make up is required. For *in situ* operations, about 2.5 to four barrels of water is required for every barrel of bitumen extracted. Recycle rates of 70 to 90 percent for *in situ* operations significantly reduce the required amounts of water make up.

Mindful of these challenges, the industry has implemented general strategies to mitigate cost overruns and avoid risk, which include:

- I. tighter control over project management;
- II. partnering with government bodies to address education concerns and preparing the workforce for future employment opportunities in the industry;
- III. use of temporary worker immigration programs;
- IV. modularizing construction components to improve productivity;
- V. improving materials management practices to help avoid on-site delays;
- VI. increasing emphasis on developing and deploying new technologies that reduce the use of natural gas and fresh water resources; and
- VII. recycling materials where possible.



Location and Extraction

Alberta's oil sands deposits are distributed in three main areas:

- Athabasca region (1.3 trillion barrels);
- Cold Lake (200 billion barrels); and
- Peace River (155 billion barrels).

Together, these areas encompass 140,200 km² (54,131 mi²) of Northern Alberta and contain 15 bitumen-bearing deposits. The government of Alberta currently estimates that 420 km² (162 mi²) are disturbed by oil sands mining, which accounts for 0.3 percent of Alberta's total land area. Exploration continues to expand the boundaries of the recognized deposits, especially in Alberta's neighbouring province of Saskatchewan.

Extraction is accomplished either through mining or via *in situ* methods. Each method is described in more detail below. *In situ* methods are becoming more widely used out of necessity as a greater proportion of the remaining reserves are located too deep underground to be accessed by conventional surface mining. Of the total 168.7 billion barrels remaining as established bitumen reserves, it is estimated that approximately 80 percent of the total proven oil sands reserves will be recoverable via *in situ* techniques. Alberta Energy reports that there are 127 active oil sands projects in Alberta. Of these, five are mining projects with the remaining projects employing various *in situ* recovery methods.

Surface Mining

Surface mining operations involve clearing trees and brush from the site and removing the overburden from the ground surface to reveal the oil sands. Giant hauler trucks, up to three stories in height, transport the oil sands from the mine face to a crusher and slurry operation. The crushers and sizers break up any lumps in the sand. The crushed material is then transported to the processing plant, where it is mixed into a hot water

slurry and pumped through hydro-transport pipelines into a separation vessel. There it settles into three layers: sand, middlings (a sand, clay and water mixture) and bitumen froth.

The bitumen froth is skimmed off the top, cleaned and processed to remove fine clay particles and water. It is diluted with naphtha and processed further to remove any remaining minerals and water. Clean bitumen is transported to a refinery or upgraded on site. The middlings undergo a secondary separation whereby air is injected into the mixture to recover an additional two to four percent of bitumen. The bottom sand is mixed with water and pumped into tailings ponds, where it settles. In August 2010, Shell Canada announced its new Atmospheric Fines Drying Technology as part of its effort to speed up reclamation and minimize the need for increased tailings ponds.²²

In Situ Extraction

In situ methods typically use heat from injected steam to reduce the viscosity of the bitumen, allowing it to be pumped to the surface. The main method of *in situ* extraction is steam-assisted gravity drainage (SAGD).

SAGD involves drilling pairs of horizontal wells into the oil sand deposits. Continuous low pressure steam is injected into the upper well, creating a high-temperature steam chamber. This softens the bitumen so that it flows downwards into the reservoir and through the lower second horizontal well where it is pumped to the surface. The bitumen product is then mixed with a diluent (typically naphtha or condensate) so it can be shipped to market. A SAGD project uses natural gas to generate steam and uses large amounts of water, although, as noted above, up to 90 percent of the water can be recycled. After the water and the remaining sand particles are removed, the bitumen is diluted and shipped by pipeline to an upgrader or refinery.

From 25 to 75 percent of the bitumen in place can be recovered using SAGD, which can be applied to thinner reservoirs by utilizing lower steam injection pressure. SAGD works best in high permeability reservoirs which require lower injection pressures and lower steam-to-oil ratios. SAGD is viewed as the most economical *in situ* method currently used. Operations employing SAGD can be viable at production levels as low as 10,000 to 15,000 bbl/d and can accommodate gradual production increases.

It is estimated that approximately 80 percent of the total proven oil sands reserves will be recoverable via *in situ* techniques.

Table 1 - Evaluating Your Potential Investment – Mining vs. SAGD

Advantages of Mining	Advantages of SAGD
<p>Higher recovery rates: Recovery rates for mining projects can be up to 90 percent compared to the lower and less certain 25 to 75 percent recovery rates for SAGD projects.</p>	<p>Lower capital costs: Up-front capital costs for fully integrated mining projects are greater than <i>in situ</i> projects due to higher construction costs associated with upgrading and overburden removal.</p>
<p>Lower sensitivity to natural gas prices: SAGD operations require roughly 0.8 to 1.2 thousand cubic feet (Mcf) of natural gas for every barrel of bitumen produced, so these projects have almost twice the amount of exposure to natural gas prices because of the need to generate steam in order to extract bitumen. Natural gas costs can account for an estimated 65 to 75 percent of total operating costs for a typical SAGD project, excluding upgrading costs. In contrast, fully integrated mining projects require about 0.5 to 0.7 Mcf of natural gas for every barrel of bitumen upgraded into synthetic crude oil.</p>	<p>Access to markets: All of the recoverable reserves suitable for mining are located in the northernmost part of the oil sands region, resulting in higher transportation costs. As a result, an upgrader may be needed to make a project economically feasible. In contrast, due to their relative proximity to diluent and diluted bitumen pipeline transportation, <i>in situ</i> projects generally do not need to include an upgrader on site and can market diluted bitumen. This means that <i>in situ</i> projects can be commercially completed at lower production levels and scaled up in smaller increments relative to mining operations.</p>
	<p>Lower emissions: Emissions for SAGD projects are around 0.06 tonnes of carbon dioxide equivalent per barrel of bitumen. This is one-third less than emissions for a mined oil sands project producing synthetic crude oil in mining operations.</p>
	<p>Smaller workforce demand: Due to the smaller scale of <i>in situ</i> projects, workforce demand is much lower than that for mining projects.</p>
	<p>Smaller development footprint: Less land is disturbed because most of the work is below ground. Reclamation costs for <i>in situ</i> projects are therefore significantly less than those for mining projects.</p>
	<p>Fewer water-handling issues: According to the Alberta Chamber of Resources, the inventory of process-affected water is much smaller for <i>in situ</i> projects, eliminating the need for on-site containment.</p>



80-95 percent
amount of water that can be recycled in SAGD projects

25
estimated number of years without decline in production

Emerging Technologies

Oil sands players are focusing most of their investment in technological innovation on mitigating extraction and other operating costs.

A number of existing and proposed projects are introducing variants on the traditional mining and *in situ* extraction methods, which are anticipated to reduce operating costs and decrease the environmental impact of operations. Most producers' primary objective, particularly for *in situ* projects, is to lessen reliance on natural gas. A number of techniques have been developed:

- **Toe-to-Heel Air Injection (THAI™)** – The THAI process ignites oil in the reservoir and creates a vertical wall of fire moving from the toe of the horizontal well toward the heel, which burns the heavier oil components and drives the lighter components into the production well. By creating heat *in situ*, the process requires no steam injection from the surface. The process has the potential to upgrade the bitumen in the reservoir; it could therefore substantially reduce production and capital costs, minimize usage of natural gas and fresh water and significantly lower greenhouse gas emissions. A study of the THAI injection method utilized by Petrobank at its Kerrobert project suggests that the recovery factor for proved plus probable reserves rises from 10 percent to 26 percent with the use of the technology.²³
- **Asphaltene Injection** – This technique uses asphaltene residue from the upgrader to produce the gas needed to generate steam and to power the upgrader as well as hydrogen required to feed the hydrocracker unit, the net result of which is a reduction in overall operating costs. This method is primarily associated with the Opti-Nexen Long Lake project, but a variant of this technology is expected to be deployed in the Synenco-Sinopec Northern Lights project.
- **VAPEX™** – This process is very similar to SAGD whereby two parallel wells are drilled. Where SAGD injects steam, VAPEX™ injects a vaporized hydrocarbon solvent such as ethane, propane or butane into the oil sand deposit, along with a displacement gas to thin the bitumen and allow it to be pumped to the

surface. VAPEX burns no natural gas and requires no water processing or recycling. Its carbon dioxide emissions are lower and it can be operated at reservoir temperature with little to no heat loss. Devon Canada Corporation has been conducting field trials with the participation of the Alberta and Federal governments to develop and test the technology. *N-Solv* technology, similar to VAPEX™, uses a solvent-based process that could potentially reduce capital costs by up to 50 percent and energy costs by up to 85 percent when compared to other *in situ* methods like SAGD.

- **Heavy Oil to Light Oil Upgrading Technology (HTL™)** – In 2005, Ivanhoe Energy Inc. acquired the patented process for Rapid Thermal Processing (RTP™) and applied this process to upgrade heavy crude and bitumen. The upgrading process occurs at moderate temperatures, at atmospheric pressure and in the absence of air, to rapidly convert feedstock to high value output by using hot sand to facilitate thermal cracking. The end product requires no diluents or blending agents for pipeline transportation. The process has been successfully tested at a commercial demonstration facility in Bakersfield, California. It is hoped that HTL™ will solve some of the technical problems associated with traditional upgrading technologies and protect the producer from price fluctuations in blending agents and natural gas—all at a lower cost than traditional upgrading technologies. HTL™ will be employed at Ivanhoe’s Athabasca interests.
- **Mobile Ore Preparation Equipment** – In its estimated \$4.4-billion Voyageur South oil sands expansion, Suncor Energy Inc. is expected to use mobile ore preparation equipment instead of the current truck and shovel system. With the new technology, ore is fed with a shovel directly to a mobile ore preparation system that crushes the ore and drops it onto a portable conveyor system where it is then transported to a slurry facility that blends the mined product. From the facility, the blend undergoes hydro-transport through a pipeline that begins to separate the oil and sand through churning action as it makes its way to the central bitumen processing plant. Although costly, one of these machines can replace 15 mine trucks. This is expected to reduce the size of the mine-hauling truck fleet required to transport ore, which in turn reduces air emissions, noise pollution and the number of workers needed for transport.²⁴
- **Liquid Addition to Steam for Enhanced Recovery (LASER)** – After conducting pilot projects since 2002, Imperial Oil Ltd. began phased integration of LASER technology into their commercial operations at Cold Lake. LASER involves injecting light oil into the production well with the steam to enhance recovery, as compared to steam injection alone.
- **Solvent-Aided Process (SAP)** – SAP involves a small amount of hydrocarbon solvent being added to the injected steam during SAGD. The solvent dilutes the oil to reduce its viscosity over and above what is accomplished by heating alone. Cenovus is planning to employ SAP to boost production at its proposed Narrows Lake project.

Oil sands players are focusing most of their investment in technological innovation on mitigating input costs.

Investment in technological improvements has been critical to the viability of the oil sands industry. Our expectation is that innovation will continue to be focused on reducing reliance on natural gas, enhancing the efficiency of the upgrading process and mitigating environmental effects of both extraction and upgrading.



Major Existing Producing Projects

Syncrude

Syncrude Canada Ltd. is the world’s largest producer of synthetic crude oil from oil sands and the largest single source producer in Canada. It supplies about 15 percent of Canada’s oil requirements, with a production capacity of 350,000 bbl/d (56,000 m³/d).

Syncrude has approximately five billion barrels of proven and probable reserves (with an additional 2.2 billion barrels of prospective reserves) situated on three leased sites. By 2016, Syncrude expects to extract 185 million barrels (29,400,000 m³) of oil per year, the equivalent to 500,000 bbl/d (79,000 m³/d). Taking into account fully realized prospective reserves, such a production level could be sustained for well over the next 40 years.

The company is a joint venture between seven partners, including Canadian Oil Sands Limited, Imperial Oil, Suncor Energy, Nexen, ConocoPhillips, Mocal Energy (a subsidiary of Nippon Oil Exploration), Murphy Oil and Sinopec (China’s state-controlled China Petroleum & Chemical Corp.) who purchased ConocoPhillips’ 9.03-percent interest for US\$4.65 billion in April 2010.²⁵

Suncor

Suncor Energy Inc. is an integrated energy company that pioneered the world’s first commercially successful oil sands operation in 1967 near Fort McMurray, in northeastern Alberta. On August 1, 2009, Suncor merged with Petro-Canada and became Canada’s largest energy company by market capitalization. The combined company’s current upstream production is approximately 710,000 barrels of oil equivalent per day (boe/d). Existing upstream production is supported by 7.5 billion barrels of proved and probable reserves.

In the oil sands, Suncor's mining and *in situ* leases cover over 1,800 sq. km and contain nearly 13 billion barrels of bitumen resources. The company has 2,600 employees working on oil sands projects.

Suncor's mining operations are currently located east of its main oil sands facility at Steepbank and Millennium. With the merger of Suncor and Petro-Canada, the Fort Hills Oil Sands Project has been added to Suncor's mineable oil sands assets. The project, in which Suncor has a 60-percent interest, is estimated to contain more than four billion barrels of bitumen resource. Voyageur South – a proposed project to extend Suncor's mining operations – is expected to produce 120,000 bbl/d of bitumen during its estimated 40-year operational life. Suncor currently has two complete upgraders at its Fort McMurray operations, as well as upgrading assets at the company's Edmonton refinery. Suncor's Voyageur upgrader and the Fort Hills Oil Sands Project are outlined in further detail below.

Suncor's *in situ* projects are located at MacKay River and Firebag. The first two stages of Firebag have been in operation since 2003 and 2005, respectively. Together, they produce approximately 60,000 bbl/d. The \$3.6-billion third stage achieved first oil in July 2011 and has planned production capacity of approximately 62,500 bbl/d. Preliminary work is underway on a fourth stage, with production set to begin in late 2012. Suncor recently received approval to develop three additional stages of the project, with stage four of the project expected to begin production in the first quarter of 2013.

Athabasca Oil Sands Project

Shell Canada Energy operates the Athabasca Oil Sands Project, a mining project located 75 km north of Fort McMurray, Alberta, and comprising the Muskeg River Mine, the Jackpine Mine and the Scotford Upgrader. It is a joint venture between Shell Canada (60 percent), Marathon Oil Canada (20 percent; previously held by Western Oil Sands) and Chevron Canada (20 percent).

At full production, the Muskeg River Mine can produce 155,000 bbl/d (24,600m³/d) of crude bitumen, a naturally occurring, semi-solid form of crude oil. The Muskeg River Mine stands on a Shell Canada lease containing more than five billion barrels (790,000,000 m³) of mineable bitumen, 1,650 million barrels (262,000,000 m³) of which is expected to be recovered over the next 30 years. Regulatory approval has been obtained for expansion of the Muskeg River Mine and the Jackpine Mine,²⁶ enabling production up to a total of 470,000 bbl/d.

Other Projects

In January 2010, **Korea National Oil Corporation** (KNOC) won approval to proceed with its 10,000-barrel-per-day BlackGold SAGD project. KNOC purchased 100 percent of the Black Gold oil sand leases from Newmont Mining in August 2006. The leases contain approximately 150 million barrels of recoverable bitumen.

CNRL's Horizon integrated mining, extraction and upgrading project began producing in 2009. While it was at a production capacity of 110,000 bbl/d in 2010, production was delayed due to operational issues at its coker unit that occurred in early 2011 and production resumed in August 2011 and soon was producing at full capacity.

Projects Under Development

In December 2012, **Japan Petroleum Exploration Co., Ltd.** (Japex) approved development of its Hangingstone oil sands project south of Fort McMurray through its subsidiary Japan Canada Oil Sands Ltd (Jacos). The project will use SAGD to produce 20,000 b/d, which might be expanded to 30,000 b/d later. Jacos holds a 75% interest in the project company. Nexen Inc. holds the remainder.

In October 2012, **Baytex Energy** announced that it had acquired a 100 percent working interest in 46 sections of undeveloped oil sands leases in the Cold Lake area of Alberta for \$120 million. Baytex Energy received regulatory approval to construct a bitumen recovery scheme using steam-assisted gravity drainage. Proved plus probable reserves total 43.7 million barrels.

In September 2012, **Osum Oil Sands Corp.** received regulatory approval for the development of a 35,000-barrel-per-day oil sands project using both SAGD and cyclic steam stimulation recovery processes near Cold Lake. Reserves linked to the project are estimated to contain 359 million barrels.

In March 2012, **Koch Exploration** received approval of its Gemini thermal oilsands project in the Cold Lake region in northeastern Alberta. The steam assisted thermal drainage operation will produce 10,000 bbl/d and is estimated to cost approximately \$410 million.

In January 2012, **MEG Energy Corp.** received regulatory approval from the ERCB for 210,000 bbl/d design production capacity for the third phase of its Christina Lake project. The third phase is a multi-stage expansion of the previous two phases, which produced 3,000 bbl/d and 22,000 bbl/d respectively. The third stage is valued at approximately \$6 billion and will use steam assisted gravity drainage.

In December 2011, **Athabasca Oil Sands Corp.** received regulatory approval for its MacKay River oil sands project, which is a 150,000 bbl/d steam assisted gravity drainage project. The first phase is expected to produce 35,000 bbl/d, with construction beginning in 2014. The project is 40-percent owned by Athabasca and 60-percent owned by a subsidiary of **PetroChina**.

In March 2011, **Suncor** announced that it had finalized its strategic alliance with **Total E&P Canada Ltd.** under which Suncor acquired a 36.75-percent working interest in the Total-operated Joslyn joint venture with Total now holding 38.25 percent, **Occidental Petroleum** holding 15 percent and **Inpex Canada Ltd.** holding 10 percent. Suncor will also receive approximately \$1.75 billion from the transaction. Total acquired a 49 percent interest in Suncor's Voyageur upgrader and upon completion, Suncor will operate the planned 200,000 barrel per day facility. Total also acquired a portion of Suncor's interest in the Fort Hills oil sands project resulting in Suncor now holding a 40.8-percent interest, Total holding 39.2 percent and **Teck Resources Ltd.** holding the remaining 20 percent. Suncor and Total have agreed to develop the Fort Hills mine and Voyageur upgrader in parallel so that both come on stream in 2016. The companies have also confirmed the Joslyn North Mine timetable with production expected to begin in 2017, subject to receiving the necessary permits and approvals.

Imperial Oil operates the Leming, Maskwa, Mahihkan and Mahkeses plants in the Cold Lake area. As an expansion to the existing plants, Imperial Oil recently completed its Nabiye plant, which includes a cogeneration plant, sulphur recovery facilities and a drilling plan that reduces the number of well pads. Aggregate production from Imperial's Cold Lake operations averaged 144,000 bbl/d of bitumen in 2010. Inter Pipeline Fund recently announced that it plans to spend \$25 million to expand pipeline systems around Cold Lake, which will include expansions to the Nabiye plant. The company is also developing the country's largest open-pit mining operations at its Kearl oil sands project north of Fort McMurray, which is slated to begin in late 2012. With over four billion barrels of estimated recoverable bitumen resource, Kearl is one of Canada's largest and highest quality oil sands deposits. Initial development will start at around 110,000 bbl/d with a goal of ramping up to 345,000 bbl/d.

The front-end engineering and design for the first phase of **BP** and **Husky Energy's** Sunrise Project, an *in situ* development designed to eventually produce 200,000 bbl/d, was completed in early 2010. BP and Husky also entered into a joint venture in respect of a refinery previously owned by BP, which will be expanded to handle 170,000 bbl/d of oil sands production. Husky also recently purchased a refinery in Ohio, which will be retrofitted to process heavy crude and bitumen from Husky's operations in Alberta.

The first phase of **OPTI Canada** and **Nexen Inc.'s** Long Lake SAGD project with upgrading facilities is complete; bitumen production and on-site upgrading began in October 2008. Regulatory approval has been received for a second-phase, SAGD and upgrader complex, whereby Nexen will phase-in production. Regulatory approval is also in place for a third-phase SAGD project at the same location. In February 2011, production from the project dropped 14 percent from production levels in the previous month. Various operational

difficulties and poor steam-to-oil ratios have continued to increase costs and reduce output. OPTI began restructuring its finances in 2009 and is currently undergoing strategic alternatives review regarding its capital structure. Future expansion and development of the Long Lake project is uncertain.

Total E&P Canada Ltd. is continuing to develop its Joslyn Lease with the Joslyn North Mine in the regulatory approval process and the Joslyn South Mine planned for the future. This project will combine conventional mining with SAGD for a total capacity of 200,000 bbl/d by 2020. Total also owns half of the Surmont SAGD project in a joint venture with the Canadian subsidiary of Houston-based **ConocoPhillips**. Surmont Phase 1 has a design capacity of 27,000 bbl/d of bitumen and is currently producing. Surmont Phase 2, which would increase production to a total of 110,000 bbl/d, has been sanctioned and is scheduled to begin production in 2015. After acquiring **Synenco Energy Inc.**, Total owns a 50-percent share (with Sinopec Corporation owning the remaining 50-percent share) in the Northern Lights Project, which is estimated to have 1.08 billion barrels of bitumen. Total has also received regulatory approval to build a bitumen upgrader near Edmonton, Alberta, which will produce 300,000 barrels of crude oil a day received.

Devon Canada Corporation's Jackfish 1 SAGD project, located 15 km southeast of Conklin, Alberta, is currently producing 35,000 bbl/d. Production commenced in 2011, and with Jackfish 2 and Jackfish 3 currently under evaluation, total production could reach 105,000 bbl/d by 2015.

Statoil Canada Ltd's Kai Kos Dehseh SAGD project is comprised of four proximate fields containing roughly 2.2 billion barrels of bitumen. The project initiated steam injection in September 2010 and commenced production in the first quarter of 2011. Also, during the first quarter of 2011, Statoil sold a 40-percent interest in the project to PTTEP (the Thai national oil company) for US\$2.2 billion. Total capacity of the project is projected to be in the neighbourhood of 200,000 bbl/d by 2020.

Connacher Oil and Gas Limited anticipates combined bitumen production from its Pod One and Algar Great Divide SAGD projects to average between 14,500 bbl/d and 16,500 bbl/d for 2011. The company was also proposing to expand productive capacity to a combined target of 44,000 bbl/d, but in early 2012, the company's board of directors initiated a review process to examine all strategies available.

Shell Canada has disclosed plans for a \$27-billion expansion of its Scotford facility, entitled the Scotford Upgrader 2 Project. The project is expected to increase the facility's capacity by an additional 400,000 bbl/d.

In March 2010, **Devon** announced that it will buy a 50-percent stake in **BP's** undeveloped Kirby oil sands project for \$500 million and will pay an additional \$150 million to cover initial capital costs. Devon will be the operator of the Kirby project, which lies in close proximity to Devon's Jackfish SAGD project. Like Jackfish, Kirby is expected to be a multi-stage SAGD development.

In February 2011, the government of Alberta, NWU and CNRL entered into a partnership agreement to construct and operate a bitumen refinery near Redwater, Alberta. The agreement will allow the province to take oil sands royalties in kind in the form of bitumen rather than in cash under the government's BRIK Program. The first phase, to be completed by the summer of 2014, will process 50,000 bbl/d, three-quarters of which will be provided by the province and the rest by CNRL. The first phase will also capture more than 3,000 tonnes daily of carbon dioxide, which will be transported by the Alberta Carbon Trunk Line for enhanced oil recovery operators. The refinery can be expanded in two additional identical phases of 50,000 bbl/d of bitumen at a future date.

New Market Entrants

Although Canadian companies and U.S.-based multinationals have been an integral part of the development of Alberta's oil sands, more recent market entrants from Asia and Europe have invested in the oil sands. For example:

- In January 2011, Statoil divested 40 percent of its Kai Kos Dehseh Project to **PTT Exploration and Production** (PTTEP) of Thailand for US\$2.2 million in cash. PTTEP is owned 65 percent by PTT Public Company Limited, one of the largest power and utility companies in Southeast Asia, in which the government of Thailand holds a 51 percent interest.
- In May 2010, Penn West Energy Trust joint ventured with China Investment Corp. (CIC) in a transaction worth \$2.6 billion to form a partnership to develop Penn West's bitumen assets located in the Peace River area. Penn West contributed oil sands properties valued at \$1.8 billion, and has a 55 percent stake in the partnership. CIC, the world's largest pool of capital, contributed \$817 million for a 45 percent interest in the partnership. CIC also took a five-percent stake in Penn West for \$435 million.
- In April 2010, China's state-owned **Sinopec** purchased ConocoPhillips' stake in the Syncrude project for \$4.65-billion, marking one of China's largest investments ever in North America.
- In August 2009, **PetroChina International Co. Ltd.** announced that it would buy a 60-percent stake in Athabasca Oil Sands Corp.'s MacKay River and Dover oil sands projects for nearly \$2 billion. Later in 2012, PetroChina bought out Athabasca's remaining 40-percent stake for \$680 million. PetroChina was also an early supporter of Enbridge Inc. in the \$2.5-billion Northern Gateway Pipeline project in 2005, which proposes to deliver an average of 525,000 bbl/d of crude oil to the west coast of British Columbia for export, but has not yet received necessary approvals to proceed.

The catalysts for this influx of overseas investment are identical to the drivers for North American companies – rising prices and decline of conventional reserves. The oil sands represent a dependable source of production with easily estimated reserves that deliver steady returns to balance the volatility of increasingly expensive conventional exploration efforts.

Alberta Oil Sands Transactions 2001-2013

The data in Table 2 outlines major oil sands acquisitions in recent years, many of which involved Bennett Jones as counsel (denoted in the table with *). Pricing is reflected in USD (million).

Table 2 - Alberta Oil Sands Transactions 2001-2013

Company	Date	Deal	Price (\$M)
ConocoPhillips - Imperial Oil & ExxonMobil Canada	Aug. '13	Subject to regulatory approval, ConocoPhillips has agreed to sell its interest in the Clyden oil sands lease for a 226,000-net-acre area of undeveloped land in the Athabasca oil sands region. Imperial Oil Resources will purchase a 27.5 percent interest in the leasehold. ExxonMobil Canada will purchase the remaining 72.5 percent interest.	720
CNOOC - Nexen Inc.	Jul. '12	CNOOC completed a takeover of Nexen Inc. It has been the China's largest outbound takeover by far. Nexen Inc. will operate as a wholly-owned subsidiary of CNOOC.	15,100
Petrobank - Grizzly Oil Sands	Feb. '12	Petrobank Energy and Resources sold its May River oil sands lease for 18,250 hectares located south of Fort McMurray to Grizzly Oil Sands, a privately owned company.	225
PetroChina - Athabasca Oil Sands Corp.	Jan. '12	PetroChina agreed to buy out Athabasca's 40-percent interest in the MacKay River project, becoming the first Chinese state-owned company to wholly own a Canadian oilsands development.	680
Teck - SilverBirch	Jan. '12	Teck Resources Ltd., agreed to buy SilverBirch Energy Corp. to acquire the remaining portion of the Frontier oil-sands project.	435
CNOOC - OPTI*	Dec. '11	China National Offshore Oil Corp. acquired OPTI Canada Inc. through its wholly-owned subsidiary, CNOOC Luxembourg.	2,100
Total-Suncor-Teck*	Mar. '11	Suncor acquired a 36.75-percent working interest in the Total-operated Joslyn joint venture. Total acquired a 49-percent interest in Suncor's Voyageur upgrader. Upon completion, Suncor will operate the planned 200,000 bbl/d facility. Total also acquired a portion of Suncor's interest in the Fort Hills oil sands project resulting in Suncor now holding a 40.8-percent interest, Total holding 39.2 percent and Teck Resources Ltd. holding the remaining 20 percent. Bennett Jones acts as counsel for Teck.	1,750
Devon*-BP	Mar. '11	Devon Energy Corp. enters into a joint venture with BP, pursuant to which Devon purchases a 50-percent interest in the Kirby project. Bennett Jones acts as counsel for Devon.	500
Statoil*-PTTEP	Jan. '11	Statoil divests a 40-percent interest in its Kai Kos Dehseh project to PTTEP. Bennett Jones acts as counsel for Statoil.	2,280
Enerplus-CNRL	Sept. '10	Enerplus Resources Fund sells its entire working interest in the Kirby oil sands lease to Canadian Natural Resources Ltd.	4,050
MEG*	July '10	Bennett Jones acts as counsel to MEG in its initial public offering of approximately 23 million common shares to raise cash for expansion of its oil sands operations.	1,000
Total-UTS	July '10	Total acquires UTS's 20-percent stake in the Fort Hills oil sands project.	1,500
Penn West-CIC	May '10	Penn West Energy Trust partners with China Investment Corp. on a joint venture in the Peace River region, under which CIC acquires a 45-percent interest in a Peace River oil sands project.	2,600
Sinopec	April '10	China-based Sinopec acquires a nine-percent stake in the Syncrude project.	4,650
Imperial Oil / Exxon Mobil	Nov. '09	Imperial and Exxon purchase the UTS half interest in three leases near Firebag River.	250
Korea National Oil Corp.*	Oct. '09	KNOC acquires Harvest Energy Trust, including all of its heavy oil and oil sands interests. Bennett Jones acts as counsel to KNOC on the acquisition.	4,100
Petro-China	Sept. '09	Petro-China International Investment Ltd. agrees to acquire 60 percent of Athabasca Oil Sands Corporation.	1,900
Suncor Energy Inc.	Aug. '09	Suncor Energy Inc. and Petro-Canada formally complete merger.	19,180
Nexen Inc.	Jan. '09	Nexen Inc. completes acquisition of 15 percent additional interest from OPTI Canada in Long Lake Project.	735

Company	Date	Deal	Price (\$M)
Ivanhoe Energy Inc.*	July '08	Ivanhoe Energy Inc. purchases oil sands leases from Talisman Energy Inc. Bennett Jones acts as counsel for Ivanhoe Energy.	90
Shell Canada Products*	July '08	Environmental, aboriginal, regulatory, construction and land matters regarding proposed refinery expansion project. Bennett Jones acts as counsel for Shell.	N/A
MEG Energy	May '07	Bennett Jones acts for MEG in its purchase of Paramount's Surmont lease.	301
Plains Midstream Canada ULC*	June '08	Bennett Jones acts as counsel for Plains in the acquisition of the outstanding shares of Rainbow Pipe Line Company ULC.	683
Synenco*-Total	April '08	Total E&P Canada acquires a 60-percent interest in the Northern Lights Asset, through the purchase of Synenco Energy Inc. Bennett Jones acts as counsel for Synenco.	480
BP	Dec. '07	BP acquires a 50-percent interest in the Sunrise Project with Husky.	2,750
MEG Energy	Jan. '07	Equity financing by way of a private placement of approximately 13.8 million common shares. Bennett Jones acts for MEG in the issuance.	564
Petro-Canada and Teck*	Sept. '07	Petro-Canada and Teck buy 10-percent interest from UTS. Bennett Jones acts as counsel for Teck in the transaction.	750
Marathon Oil Corporation*	July '07	Marathon purchases Western Oil Sands by way of a plan of arrangement. Bennett Jones acts as counsel for Marathon in the transaction.	6,600
MEG Energy*	May '07	Bennett Jones acts as counsel for MEG in its purchase of Paramount's Surmont lease.	301
Statoil ASA*	Apr. '07	Statoil acquires North American Oil Sands by way of take-over bid. Bennett Jones acts as counsel for Statoil in the transaction.	2,200
Teck*	Apr. '07	Bennett Jones acts as counsel to Teck in its acquisition of a 50-percent interest in Lease 14 with UTS.	200
Enerplus Resources	Mar. '07	Purchase of private leases.	182.5
MEG Energy*	Jan. '07	Equity financing by way of a private placement of approximately 13.8 million common shares. Bennett Jones acts as counsel for MEG in the issuance.	564
Canadian Oil Sands	Nov. '06	Purchase of Talisman's Syncrude interest.	475
Newmont Mining*	June '07	Bennett Jones acts as counsel for Korea National Oil Corp. in its acquisition of Newmont's lease.	270
Black Rock*	May '06	Bennett Jones acts as counsel for Black Rock in its acquisition by Shell.	2,347
Teck*	Sept. '05	Teck buys a 15-percent interest in the Fort Hills Oil Sands Project from UTS Energy Inc. and Petro-Canada. Bennett Jones acts as counsel for Teck.	429
Deer Creek*	Aug. '05	Total acquires Deer Creek. Bennett Jones acts as counsel to Deer Creek in the acquisition.	1,462
Sinopec*	May '05	Sinopec buys a 40-percent stake in Northern Lights partnership from Synenco. Bennett Jones acts as counsel for Synenco in the transaction.	105
CNOOC Ltd.*	April '05	CNOOC buys a 16.69-percent interest in MEG. Bennett Jones acts as counsel for MEG in the transaction.	150
Petro-Canada	Mar. '05	Petro-Canada acquires a 60-percent interest in Fort Hills.	256
UTS Energy Corp.	April '04	UTS buys a 78-percent interest in Fort Hills.	125
Enerplus Resources	Aug. '02	Enerplus buys a 16-percent interest in Joslyn project.	20.5
Nexen Energy*	Oct. '01	Nexen acquires a 50-percent stake in Long Lake lease and project. Bennett Jones acts as counsel for Nexen.	42.6



Market Opportunities

The growth in extraction and production has been matched by significant investment opportunities in upgrading facilities and transportation infrastructure.

Transportation

Over 80 percent of bitumen produced in Canada is exported to the U.S. through existing pipelines. The bulk is delivered to upgraders in Petroleum Administration for Defense District (PADD) II (U.S. Midwest region), with the balance delivered to PADD III (Gulf Coast) and PADD IV (Rocky Mountain). The National Energy Board's most recent oil sands report indicates that the industry should maximize its volumes in its traditional markets of PADD II, PADD IV and Washington State, with further market expansions and extensions later in the decade into California, PADD III and the Far East.

As demand for oil grows, markets with great potential for Canadian crude continue to emerge. California and the U.S. Gulf Coast both provide significant demand for medium and heavy crudes. Crude oil is currently shipped to California via pipeline and tanker. The U.S. Energy Information Administration predicts that a new or expanded pipeline to California will eventually be required to serve the growing demand of that market.

Proposed pipeline expansions to new and existing markets include proposals by corporations such as Enbridge Inc., Kinder Morgan and TransCanada Pipelines Limited to build and operate new pipelines and storage terminals.

Enbridge, for instance, has proposed the Northern Gateway Pipeline that would transport crude oil from Edmonton, Alberta, to a new marine terminal in Kitimat, British Columbia, whereby it would be shipped to China and other Asia-Pacific markets. The Northern Gateway Pipeline is currently seeking regulatory approval, and would represent a further expansion to Enbridge's existing pipeline systems in Canada and the U.S. Enbridge's Southern Lights diluent delivery system came into service July 2010 and carries product through 2,556 kilometres of pipeline originating near Chicago, Illinois, and terminating in Edmonton, Alberta. The Southern Lights project also includes the LSr Project, a 313-mile, 20-inch crude oil pipeline from Cromer, Manitoba, to Clearbrook, Minnesota.

It added needed capacity for light/sour crude (thus the LSr name) between Cromer and Clearbrook. The LSr Pipeline was brought into operation in February 2009. Construction and line fill of Enbridge's Alberta Clipper Pipeline from Hardisty, Alberta, to Superior, Wisconsin, was completed in October 2010. Current capacity of the Clipper is 450,000 bbl/d, with ultimate capacity of up to 800,000 bbl/d available.

In June 2010 TransCanada commenced commercial operation of the first phase of the Keystone Pipeline System. Keystone's first phase was highlighted by the conversion of natural gas pipeline to crude oil pipeline and construction of an innovative bullet line that brings the crude oil non-stop from Canada to market hubs in the U.S. Midwest. An extension of the Keystone Pipeline from Steele City, Nebraska, to Cushing, Oklahoma, went into service in February 2011. The further proposed extension is a 2,673-kilometre (1,661-mile), 36-inch crude oil pipeline that would begin at Hardisty, Alberta, and extend southeast through Saskatchewan, Montana, South Dakota and Nebraska. It would incorporate a portion of the Keystone Pipeline (Phase II) through Nebraska and Kansas to serve markets at Cushing, Oklahoma, before continuing through Oklahoma to a delivery point near existing terminals in Nederland, Texas, to serve the Port Arthur, Texas, marketplace. The Keystone XL Pipeline is cited as having an initial commercial capacity of 500,000 bbl/d and is estimated to cost approximately US\$7 billion. In January, 2012, the construction of the project was rejected. In May, 2012, TransCanada changed the original proposed route and filed a new application for a Presidential Permit with the U.S. Department of State. The Governor of Nebraska, Dave Heineman approved the new route in Nebraska in January, 2013. Pending a decision on the Presidential Permit, TransCanada believes the pipeline will still be operational by 2015.

Kinder Morgan completed construction in late 2008 on the Anchor Loop project, its Transmountain Pipeline expansion, which runs across Jasper National Park and Mount Robson Provincial Park. The addition of the Anchor Loop increased the capacity of the Trans Mountain pipeline system from 260,000 bbl/d to 300,000 bbl/d, and helped to alleviate capacity constraints on Kinder Morgan's existing system resulting from increased oil sands production.

Upgrading

Essentially all of the bitumen extracted from the oil sands must be upgraded; oil sands operators must therefore decide whether or not to do field upgrading. Upgrading transforms bitumen into synthetic crude oil, which commands a higher price when sold to refineries. Upgrading requires substantial capital and technological resources. The process enables producers to eliminate risks arising from the heavy oil/light oil price differential and further eliminates diluent cost risk and supply issues. Ultimately, the question for producers is whether the promise of higher, more stable netbacks (that generally result from an upgraded product) will offset the substantial capital costs.

The location of upgrader facilities has been influenced by economies of scale and cost factors such as shortages of skilled labour. Integrated oil sands operators have chosen to locate, expand existing and convert existing upgraders in the U.S. where larger facilities provide cost advantages over Canadian greenfield or expansion projects.

In October 2006, Encana and ConocoPhillips entered into a US\$15-billion joint venture that includes Encana's heavy oil projects in the North Athabasca region, along with ConocoPhillips refineries in the states of Illinois and Texas. The partnership plans to expand processing capacity at these facilities from approximately 60,000 bbl/d to 550,000 bbl/d by 2015.²⁷ Husky Energy and BP have entered into a similar arrangement in their Sunrise project, where Husky transferred 50 percent of its oil sands holdings for 50 percent of BP's refinery near Toledo, Ohio. Husky acquired the Lima refinery in Ohio and plans to reconfigure and expand it to process heavy crude oil and bitumen.²⁸

The possible regulatory and environmental impediments to the addition of oil sands upgrading/refining capacity in the U.S. have yet to be adequately assessed, but in Alberta they are better known and quantifiable. The issues companies confront in acquiring U.S. upgrading/refining capacity may ultimately prove more disruptive to project timelines than the constraints faced in Alberta projects. In addition, there is a significant governmental push to encourage producers to upgrade in Alberta. Currently, there are five operating upgraders in Alberta with a capacity of approximately 1.13 million bbl/d.

13 percent
percentage of total global oil reserves in Alberta oil sands

Derivative Plays

Given the magnitude of projected economic activity, oil sands producers will not be the only beneficiaries of the unprecedented development now underway. Aside from the necessary infrastructure developments, a plethora of ancillary opportunities exist in many sectors, including electricity generation, petrochemicals, heavy metals and construction equipment.

Electricity

Both *in situ* and mining-based oil sands projects require large quantities of electricity and are vulnerable to the electricity grid—in service date delays and to fluctuations in price. To secure power supplies, producers have increasingly turned to generating electricity on their project sites through cogeneration. A cogeneration plant, also known as a combined heat and power (CHP) facility, uses heat recovery and natural gas to run a combustion turbine to power a generator and produce electricity. A heat recovery steam generator then captures the remaining heat that would normally be wasted and uses it to produce low- and high-pressure steam and hot water, which is then used in the oil sands production process.

Cogeneration, with back-up from the electricity grid, provides a reliable supply source and helps oil sands producers meet their needs for electricity. Oil sands producers may choose to generate excess power in order to supply the grid or bilateral power customers, depending on the outlook for Alberta power prices.

Nuclear

Some suggest that the answer to the oil sands' natural gas and electricity requirements may be the construction of nuclear power plants. Alberta's Provincial Energy Strategy (announced December 2008) identified nuclear power as a potential source of clean, low-emission power. In December 2009, the government released the results of the Alberta nuclear consultation. Among its key findings was that most Albertans polled (45 percent) preferred that nuclear power plants be considered on a case-by-case basis. As a result, the Alberta government has decided to maintain its existing policy where power generation options are proposed by the private sector in the province. Any nuclear power proposal would be considered on a case-by-case basis.

Petrochemicals

The massive increase in production also represents a significant opportunity for investors in the petrochemical industry. The bitumen upgrading process produces off-gas from which ethane and other light hydrocarbons could be extracted and used by the petrochemical industry. Currently, ethane and most of the other light hydrocarbons remain in the off-gas and are used as fuel for operations. The National Energy Board has estimated that by 2015 Alberta's bitumen resource base could provide a secure, substantial, and stable-priced feedstock for the petrochemical industry. In Alberta, there may be a significant opportunity for bitumen-based ethylene, comparable to the production that has occurred on the U.S. Gulf Coast.

The potential synergy of extraction, upgrading, refining and petrochemical processing facilities located in close proximity is already being exploited in Alberta. Williams Energy of Tulsa, Oklahoma, for example, has entered into an arrangement with Suncor to remove synthetic gas liquids from off-gas produced by Suncor's upgrader near Fort McMurray. Williams processes the synthetic gas liquids at its nearby facility and ships the extracted olefins mix via pipeline to its Redwater, Alberta, facility, where it produces propane, propylene and olefin concentrate.

The bitumen upgrading process produces off-gas from which ethane and other light hydrocarbons could be extracted and used by the petrochemical industry.



33 percent

estimated decrease in developers' cost

25

estimated number of years without production

Structuring your Transaction or Project

Valuation

Land sale spending in Alberta surged in 2010 due to a combination of new plays, enhanced oil sands technologies and a rebound in oil prices. From April 2010 to March 2011, 365,969 hectares of Crown oil sands leases were sold, totaling \$54.927 million in land sale revenue with an average price of \$150.09 per hectare. This average price is up from \$133.42 per hectare for the same period in 2009/2010. An annual summary of oil sands public offerings is provided in the table below²⁹:

Table 3 - Summary of Oil Sands Public Offerings - By Fiscal Year (April to March) - Leases and Permits

Year	Bonus Received	Hectares Sold	Avg.\$/ha
2012/13	\$13,723,641.34	90,385.16	\$151.84
2011/12	\$78,298,413.54	309,090.79	\$253.32
2010/11	\$54,927,475.58	365,969.60	\$150.09
2009/10	\$8,172,731.78	61,256.95	\$133.42
2008/09	\$214,192,829.81	1,434,248.88	\$149.34
2007/08	\$502,238,130.40	1,020,964.48	\$491.93
2006/07	\$1,326,126,813.60	1,494,182.92	\$887.53
2005/06	\$1,279,784,810.74	741,808.51	\$1,725.22
2004/05	\$91,549,194.88	291,518.12	\$314.04
2003/04	\$20,998,281.70	104,704.00	\$200.55
2002/03	\$15,476,420.01	100,319.20	\$154.27
2001/02	\$82,118,547.99	289,117.20	\$284.03

Year	Bonus Received	Hectares Sold	Avg.\$/ha
2000/01	\$126,503,823.66	141,679.64	\$892.89
1999/00	\$89,229,921.99	261,397.63	\$341.36
1998/99	\$13,329,421.85	169,441.28	\$78.67
1997/98	\$150,314,491.00	324,796.30	\$462.80
1996/97	\$72,280,810.98	138,117.68	\$523.33
1995/96	\$28,152,766.52	130,620.08	\$215.53
1994/95	\$7,210,099.11	66,113.28	\$109.06
1993/94	\$425,032.41	2,597.12	\$163.66
1992/93	\$216,288.00	20,608.00	\$10.50
1991/92	\$3,945,975.48	30,061.33	\$131.26

Acquisition Structures

The vast majority of multi-party oil sands projects are structured as joint ventures or partnerships. Preference for a particular structure is most often based on income tax planning, with commercial objectives being another major consideration.

Acquisitions are generally made by purchasing a participating interest in a joint venture or an interest in a partnership. The operating agreements that come into effect upon closing of an acquisition are often the subject of detailed negotiation and discussion, since these documents set out the ongoing development and governance of the project through its life-cycle.

Foreign Investment Approvals

An oil sands investment, regardless of whether the target is a bitumen extraction project, an upgrader, a transportation project or a derivative play, may be subject to Canadian regulatory approvals, two of the most common being:

- I. **The Investment Canada Act (ICA)**, which governs the acquisition of control of a Canadian business whose total asset book value exceeds \$354 million (for 2014, adjusted annually for inflation). Acquisitions by state-owned foreign enterprises are subject to additional specific guidelines. Investments can also be subject to a national security review.³⁰ State-owned investors should expect to be required to file information to address the following issues:
 - their standards and transparency of corporate governance and public disclosure;
 - the role of their board of directors;
 - the presence and role of independent directors;
 - the mechanisms available to the state to influence the business decisions of the enterprise; and
 - any other matters that might be relevant to determining whether and to what extent the enterprise is likely to be run on a commercial basis.

In June, 2013, amendments to the *Investment Canada Act* were enacted that expand the definition of state-owned foreign enterprises ("Foreign SOEs") to include:

- an entity that is controlled in fact or influenced, directly or indirectly, by a foreign government;
- an individual who is acting under the direction of a foreign government or under the influence, directly or indirectly of such a government.

The amendments will create uncertainty for prospective investors who do not pass the ICA's "bright line" control threshold.

In December 2012 the Federal Government announced that it would not approve investments by Foreign SOEs to acquire control of Canadian oil sands businesses otherwise than in “exceptional circumstances”. No guidance has been given publicly as to what this means.

Amendments to change the financial threshold and its method of calculation have been introduced.

- II. **The Competition Act**, which applies to an acquisition of control where the book value of the project’s or entity’s assets (or its annual Canadian sales) exceed \$73 million (adjusted annually for inflation) and the asset book value or annual Canadian sales of the parties to the transaction and their affiliates exceed \$400 million.

Financing a Project

Generally, large existing producers deemed to be investment-grade risks have had little trouble securing financing for oil sands development. For example, the credit facilities in respect of the CNRL Horizon Project, the Nexen-Opti Long Lake Project and the Total Joslyn Project are standard facilities funded by conventional Canadian banking syndicates.

Project debt financing raises several issues within the framework of a joint venture or partnership. Depending on the partners’ positions, some may have a greater desire for external financing than others. This will become an issue when granting security, as the cooperation of all partners will be required. Matters can be further complicated if the project has a combination of partners with high and low credit ratings. One possible structure is for the partners who have no need for project financing to lend into the partnership at the same rate as the less creditworthy partners, to maintain economic consistency.

The lingering effects of the global economic downturn have had an impact on the availability of debt financing in relation to oil sands projects. This has led some companies active in the oil sands to finance projects through public offerings. Bennett Jones’ Capital Markets Group has significant experience and expertise in assisting clients with such financing.

Alberta’s Royalty Framework

General Royalty Framework

In response to Albertans’ desire to receive a larger share from the development of Alberta’s non-renewable energy resources, the provincial government released *The New Royalty Framework* on October 25, 2007, and the changes went into effect on January 1, 2009. However, the Alberta government recently pulled back from *The New Royalty Framework* in the upstream natural gas and conventional oil sectors with the announcement of the *Alberta Competitiveness Review* changes on March 11, 2010. Citing several factors, including structural market changes, advancements in technology and regulatory barriers, the *Alberta Competitiveness Review* concluded that Alberta had lost competitiveness relative to other competing jurisdictions in Western Canada and the United States. To address this, several changes were implemented, including decreasing the

maximum royalty rates on natural gas and conventional oil. A world oil price sensitive sliding scale has been implemented for oil sands royalty rates ranging from one to nine percent of gross revenue in pre-payout and 25 to 40 percent of net revenue in post-payout.

Depending on the partners’ positions, some may have a greater desire for external financing than others.

In mid-2010, the Alberta government unveiled its *Emerging Resources and Technologies Initiative*, which modified the royalty rate for wells that require use of high-cost technologies. This strengthens a producer’s ability to invest in additional wells, as well as research and development. The government expects that stimulating application of new technologies in resources that have not been tapped will increase overall production, resulting in increased economic activity and secure long-term royalty revenue from new resource discoveries. The *Emerging Resource and Technologies Initiative* will be reviewed in 2014 and the Alberta government has committed to providing three years notice to industry at that time if it decides to discontinue the initiative.

The following provides a summary of oil sands royalty revenue collected by the government of Alberta from 2006 to 2012:

- 2006/07 - \$2.411 billion
- 2007/08 - \$2.913 billion
- 2008/09 - \$2.973 billion
- 2009/10 - \$3.160 billion
- 2010/11 - \$3.723 billion
- 2011/12 - \$4.513 billion

The BRIK Program

Alberta’s BRIK program is a key component of the province’s royalty regime. As the resource owner, the province is entitled to take its royalty share of bitumen production in kind. The decision to exercise the in-kind option for bitumen was identified in October 2007 as a way for the Crown to use its share of bitumen strategically to supply potential upgraders and refineries in Alberta, and to optimize its royalty share by marketing those volumes. A Request for Proposals to purchase or process 75,000 bbl/d of Crown-owned bitumen was issued in July 2009 and negotiations began in May 2010. As previously described, the NWU/CNRL Refinery project and the Alberta Carbon Trunk Line project are the first beneficiaries of the BRIK Program.

The guiding principles for the BRIK program are as follows:

1. The royalty regime will continue to be based on a revenue minus cost scheme.
2. Any changes to royalty systems and obligations will be open and transparent.
3. The BRIK framework will encourage a fair, efficient and openly competitive market.
4. The BRIK market design must provide confidence to investors and customers and be supported by a clear and stable regulatory framework.
5. The BRIK market design should minimize the potential exercise of undue market power and unwarranted transfer of wealth.
6. Where operators are regulated to perform BRIK business functions, they will be compensated appropriately.
7. BRIK program design will seek to minimize costs to both industry and the Crown.
8. BRIK business rules will take operational constraints into consideration.
9. BRIK market design will respect the business investments that have been made in Alberta.
10. The BRIK market design will encourage more value added products based on bitumen in Alberta.

The government of Alberta expects that the BRIK program will stimulate value-added activities (such as upgrading, refining and petrochemical development) and, by assuming some risk and cost associated with processing, enable Alberta to obtain increased revenue compared with taking cash based on bitumen pricing.

13 percent

percentage of total global oil reserves in Alberta Oil Sands

Environmental Concerns

Climate Change

The production of petroleum from oil sands uses significant amounts of energy, almost all derived from the combustion of fossil fuels and resulting in CO₂ emissions. As a result, oil sands operations have been criticized for their GHG emissions, both for the absolute amount (which is increasing rapidly) and in intensity (*i.e.*, tonnes of CO₂ per barrel of oil) in comparison to conventional oil operations. That criticism has also driven opposition to transportation projects that would move bitumen to markets, such as TCPL's Keystone pipeline to U.S. refineries and markets and Enbridge's Gateway project to Pacific markets.

There are alternative perspectives on the oil sands compared to conventional oil emissions intensity difference. For example using a complete life-cycle analysis, the percentage differences between oil sands and conventional oil becomes smaller. Applying the well-to-wheels approach, in which the amount of GHG emissions for the entire life-cycle of oil is included (*i.e.*, including extraction, processing, distribution and end use of the refined product by the consumer), GHG emissions associated with oil sands oil are often stated to be five to 15 percent higher than those for average crude oil operations. The percentage increases, however, if GHG emissions are measured for only a portion of the life-cycle, such as from extraction to distribution, *i.e.*, well-to-pump.

Recently, disputes with the European Union and California have arisen over the treatment of oil sands oil for purposes of the Low Carbon Fuel Standards (LCFS) being developed in those jurisdictions. Canadian government, provincial government and industry officials have argued against the high GHG intensity numbers assigned to oil sands oil for purposes of those standards, suggesting that they are discriminatory and/or inaccurate. In addition, some producers in the oil sands argue that the GHG emissions intensity from their facilities is lower than from other oil sands producers and that oil sands oil should therefore not be treated in a single category. Many argue that there are significant quantities of heavy oil produced in other jurisdictions which have even higher GHG emissions per unit of production than oil from the oil sands but that those sources are not treated in the same way as the oil sands for purposes of the LCFS.

The goals of optimizing the use of oil sands and reducing the amount of GHG emissions may not be mutually exclusive. As more advanced and efficient technology is developed for oil sands mining and *in situ* operations,

the intensity of GHG emissions is expected to decrease, whereas it is expected to increase for conventional crude oil with the shift towards use of heavier crude oil. Industry has certainly responded, not only by the ongoing technological advances which can reduce emissions per unit of production, but also, perhaps belatedly, by a determined public relations effort to ensure the broader public discussion includes a better appreciation of the broader factual context.

Governments are providing incentives to industry to reduce emissions. The government of Canada has committed to reduce GHG emissions in Canada to 17 percent below 2005 levels by 2020 in parallel with the U.S. and its legislation. Currently this commitment seems likely to result in the application of performance standards to large emitters on a sector by sector basis with the government having announced that oil and gas will be the next sector dealt with (vehicle standards are in place and a draft coal-fired electricity standard has been made public). Many in industry favour greater flexibility using market-based approaches like a cap-and-trade with offsets system or even a carbon tax. Alberta has imposed GHG emission intensity reduction obligations on large GHG emitters under the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*. This obligation can be met by operational improvements, by acquiring Alberta-generated carbon credits or by paying to the provincial government \$15 per excess tonne emitted. The Alberta government has also committed approximately \$2 billion towards the development of carbon capture and storage (CCS), a process that involves capturing GHG emissions and storing them indefinitely in geological formations under the earth's surface or using them to enhance production from certain oil fields (Enhanced Oil Production or EOR). It has also announced the intention to give extra carbon offset credits to those who successfully sequester CO₂ in geological formations. The federal government has also committed hundreds of millions of dollars to support CCS. While Alberta will be relying significantly on CCS to manage emissions in the future, CCS is not without its challenges, both technical and economic.

Project Regulation

The primary regulators for oil sands projects are the AER and Alberta Environment. However, depending on the type of oil sands operation (either surface mine or *in situ* extractions) and where the site is located, many other regulators can be involved. The application review process for oil sands mine operations is more in-depth than for *in situ* operations because of the greater land disturbance and necessity of tailings ponds. Each of the oil sands operations may require an environmental assessment and the completion of an Environmental Impact Assessment report, depending on the scope of the proposed project.

If the oil sands operation remains within the province and does not involve a federal authority, the environmental assessment will involve other provincial regulators such as Alberta Culture and Community Spirit; Alberta Health and Wellness; Alberta Tourism, Parks and Recreation; Alberta Transport; the Alberta Utilities Commission; and the Natural Resources Conservation Board.

Where the proposed oil sands project expands beyond the provincial boundaries or involves a federal authority, there will be a joint environmental assessment review conducted by provincial and federal regulators, including federal regulators such as the Canadian Environmental Assessment Agency; Environment Canada; Fisheries and Oceans Canada; Health Canada; Natural Resources Canada; Transport Canada; and Parks Canada. After the environmental assessment review is completed, the application is subject to final approval by the applicable regulatory board to determine if the proposed project is in the public interest. In making this decision, the board will balance economic, social and environmental factors and may require a hearing before a joint panel of representatives from the provincial and federal governments, the AER or a judge, as litigation could result. The board has the authority to impose conditions on any approval granted and it will continually monitor projects to ensure compliance.

The regulatory process has gradually shifted and is becoming increasingly more stringent. The ERCB has released new guidelines for oil sands mining operations and continues to make changes to some of its guidelines. Two recent ERCB directives are: *Directive 081: Water Disposal Limits and Reporting Requirements for Thermal In Situ Oil Sands Schemes* and *Directive 082 Operating Criteria: Resource Recovery Requirements for Oil Sands Mine and Processing Plant Operations*.

Although the regulatory process for Alberta oil sands are becoming more stringent, both the government and the industry remain committed to working together in the most efficient way possible to attain the

goals of maximizing returns and protecting the public interest. This is exemplified by the *Responsible Energy Development Act*, wherein the provincial government creates a single regulatory agency (i.e. AER) replacing the Energy Resources Conservation Board and exercising certain environmentally-oriented powers and functions previously held by the Ministry of Environment and Sustainable Resource Development. AER is responsible for regulating oil, gas, oil sands and coal developments from initial application and construction to production reclamation. The *Responsible Energy Development Act* was designed to establish a more efficient, integrated and collaborative regulatory system at the provincial level to maximize investment appeal.

First Nations Issues

The courts have established that both the federal and provincial governments have a duty to consult with, and where necessary accommodate, First Nations or Aboriginal people if treaty or aboriginal rights may be adversely affected by government actions. Therefore, where the government of Alberta, through its regulatory agencies, intends to approve an oil sands project on or near lands over which First Nations or Métis communities have claimed traditional hunting, trapping or fishing rights, the duty to consult will be triggered.

The provincial government often delegates the procedural aspects of such consultation to project proponents. The government has developed *Alberta's First Nations Consultation Guidelines on Land Management and Resource Development*, which sets out the process for determining whether consultation is necessary and the role of government departments and the project proponent in the consultation process.

The degree of consultation required depends on the strength of the rights claimed by the affected Aboriginal group and the nature and level of the potential impact on those rights. At minimum, consultation will require that the First Nation or Aboriginal group be notified of the scope, location and potential adverse impacts of the project.

Although the ultimate responsibility for the adequacy of consultation efforts lies with the government, the project proponent must meet with the affected First Nation or Aboriginal group to explain the government process and discuss the impacts on the treaty or aboriginal rights claimed, as well as avoidance or mitigation of those impacts. Where consultation is necessary, it must occur before decisions are made, i.e., during the planning of the project before the application for government approval. In addition, the environmental and regulatory approval process for a project may require the project proponent to consult with affected Aboriginal groups. Environmental impact assessments often require identification and assessment of any adverse impacts of a project on Aboriginal and treaty rights. Securing the effective participation of Aboriginal groups in these processes may require that the project proponent fund enter into consultation protocol agreements with Aboriginal groups.

Governments must ensure that adequate consultation has taken place and that appropriate accommodation of affected Aboriginal and treaty interests is undertaken if necessary. Failure to adequately consult and, if necessary, accommodate Aboriginal concerns puts the project developer at risk of having project approvals challenged in Court, and potentially quashed on the basis that they violate constitutionally-protected Aboriginal and treaty rights.

Proponents of large oil sands projects with the potential to significantly impact the traditional territories of Aboriginal groups may also negotiate impact benefit agreements with affected Aboriginal groups to ensure effective consultation and address concerns related to the proposed projects. These agreements may address commitments made in the regulatory and environmental review process, funding arrangements to address social concerns (such as educational and training opportunities), environmental mitigation and consultation and information-sharing protocols for the long term. Increasingly, First Nations and other Aboriginal groups are seeking agreements whereby their communities would secure long-term economic benefits from oil sands development on their traditional lands.



Among the many rewards for investors in the Canadian oil sands are:

- A substantial resource base with a long reserve life and an opportunity to increase reportable reserves.
- A long-range forecast of little or no decline in production over a 25-year period.
- A stable political environment with well-developed, sophisticated and continually improving legal and regulatory regimes.

Investors are strongly advised to take legal advice early in their strategizing from legal counsel with extensive experience in the unique nature of oil sands transactions and projects. Bennett Jones LLP has played an integral role in the Canadian oil and gas industry for nearly 90 years and has extensive contacts throughout the industry. We are happy to answer questions from prospective investors.

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