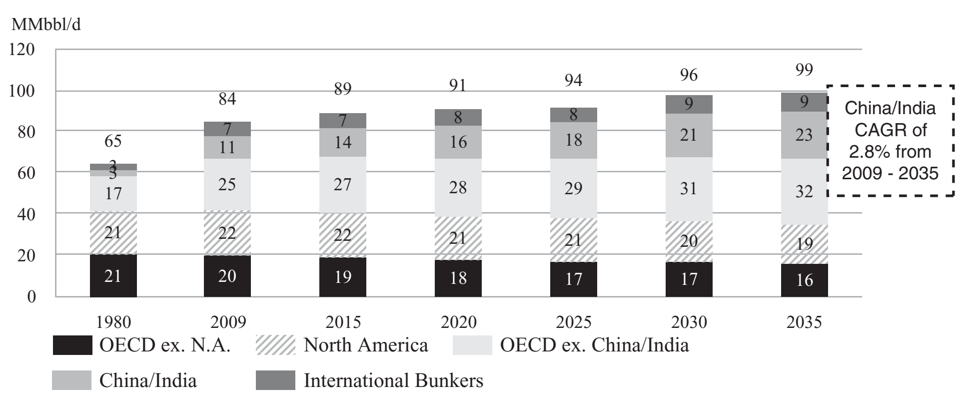
Unless otherwise specified, all of the information, data and statistics set out in this section have been extracted from various official government publications, private publications and industry sources. We believe that the sources of this information are appropriate sources for such information and have taken reasonable care in extracting and reproducing such information. We have no reason to believe that such information is false or misleading or that any fact has been omitted that would render such information false or misleading. The information has not been independently verified by us, the Joint Sponsors, the Underwriters or any other party involved in the Global Offering and no representation is given as to its accuracy or completeness.

SUPPLY AND DEMAND IN GLOBAL OIL MARKETS

According to the BP Statistical Review of World Energy 2011 ("**BP Statistical Review**"), worldwide demand for oil in 2010 was 87 MMbbl/d, and approximately 53% of the total was consumed in OECD nations. Of that, approximately 22% was consumed within the United States, which is the world's single largest oil market. According to the International Energy Agency, world demand for oil is expected to grow to 99 MMbbl/d by 2035, with a significant portion of this growth expected to come from non-OECD countries such as China and India, which will account for approximately 23% of total demand in 2035. North America is also projected to remain a material consumer of oil, representing approximately 20% of total demand in 2035.

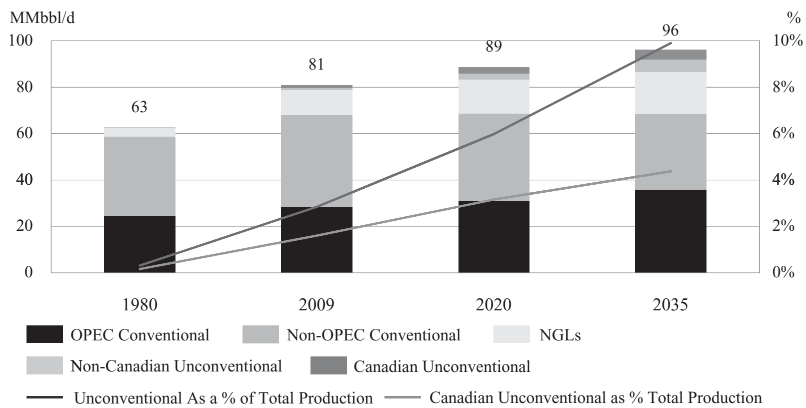
Primary Oil Demand By Region (1980 – 2035)



Source *IEA, World Energy Outlook 2010*

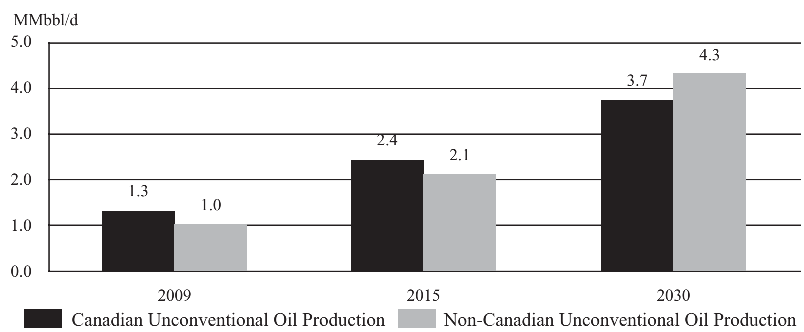
The IEA estimates that approximately one-third of the world's ultimately recoverable conventional oil resources have already been produced. By 2035, it is expected that over one-half of the world's ultimately recoverable conventional oil resources will have been produced. Non-OPEC conventional production is not expected to be sufficient to keep pace with growing demand. As a result, in order to meet projected demand, global oil production is expected to undergo a transition towards increased reliance on OPEC production and unconventional sources of crude oil (predominantly from extra heavy oil and bitumen). Specifically, growth in the production of unconventional oil is expected to contribute significantly to global oil production growth. Production from Canada's oil sands is expected to be a meaningful contributor to this growth. In 2009, approximately 2.3 MMbbl/d (2.8% of the total) of global oil production was classified as unconventional and approximately 1.3 MMbbl/d of this represented production from Canada's oil sands. By 2035, unconventional oil production of approximately 9.5 MMbbl/d is expected to account for 9.9% of global production, and production from Canada's oil sands is expected to contribute approximately 4.2 MMbbl/d, representing a growth rate of 4.6% annually during that period.

Oil Production By Region (1980 –2035)



Source *IEA, World Energy Outlook 2010*

Unconventional Oil Production (1) (2)



Source: IEA, World Energy Outlook 2010
Notes:
(1) "Unconventional Oil" means extra heavy oil (including extra heavy oil secured from Venezuela), natural bitumen derived from oil sands, chemical additives, gas-to-liquids and coal-to-liquids (and excluding biofuels)

CANADIAN CONVENTIONAL HEAVY OIL

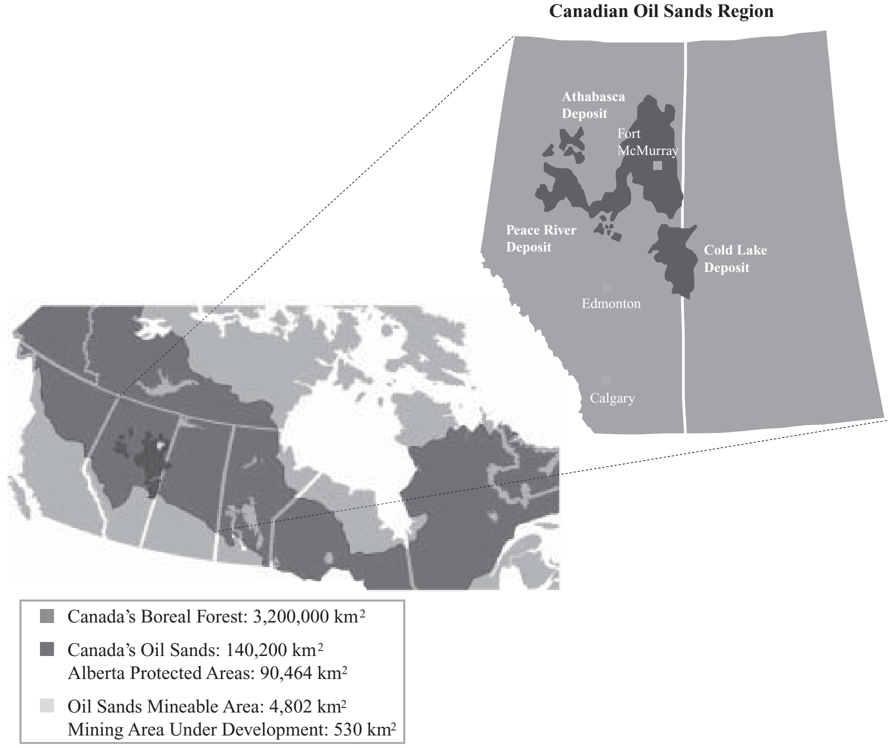
Canadian conventional heavy oil is generally defined as crude oil that is found in a liquid state in the ground, has the ability to flow into a wellbore, has a specific gravity of less than or equal to 20° API and is comprised of up to approximately 5% sulphur (depending on the heavy oil type). It is heavier and more sour than West Texas Intermediate, which has a specific gravity of 39° API with 0.34% sulphur. Heavy oil in Canada is produced through relatively shallow wells (depths of 350-1,000 metres) found mainly in the Heavy Oil Belt straddling the Alberta-Saskatchewan border, and in areas to the west and southwest of the Cold Lake oil sands deposit. Conventional heavy oil generally sells at a discount to light oil, reflecting the relative market value of the end products to refineries. At the end of 2010, conventional heavy oil accounted for approximately 13% of total Canadian oil production. According to the NEB, Canadian conventional heavy crude deposits are estimated to contain 470 MMbbl of petroleum-initially-in-place that are recoverable with known technology.

Heavy oil recovery methods include primary production, cold enhanced oil recovery and thermal production. The selection of these methods generally depends on factors such as the stage of production, formation and fluid properties, reservoir geology and available production and transportation facilities. Primary recovery is the first stage of heavy oil production in which natural reservoir energy, such as gravity drainage, displaces the oil from the reservoir into the wellbore and is pumped to the surface. As reservoir pressure drops, artificial lift systems must be used to recover oil. CHOPS is a primary recovery technique involving the continuous production of sand to improve the recovery of heavy oil from the reservoir. Cold EOR is the recovery of heavy oil using non-thermal methods including production from horizontal and multilateral wells with water, solvent and gas injection. Waterflooding is the most common EOR approach, which involves the injection of water to displace heavy oil. Thermal methods typically involve the injection of steam or hot water into the reservoir to improve the mobility of the heavy oil and provide a displacement mechanism. Of the three methods, thermal provides the highest recovery factors, but also results in the largest potential capital expenditures and operating costs.

OVERVIEW OF CANADA'S OIL SANDS

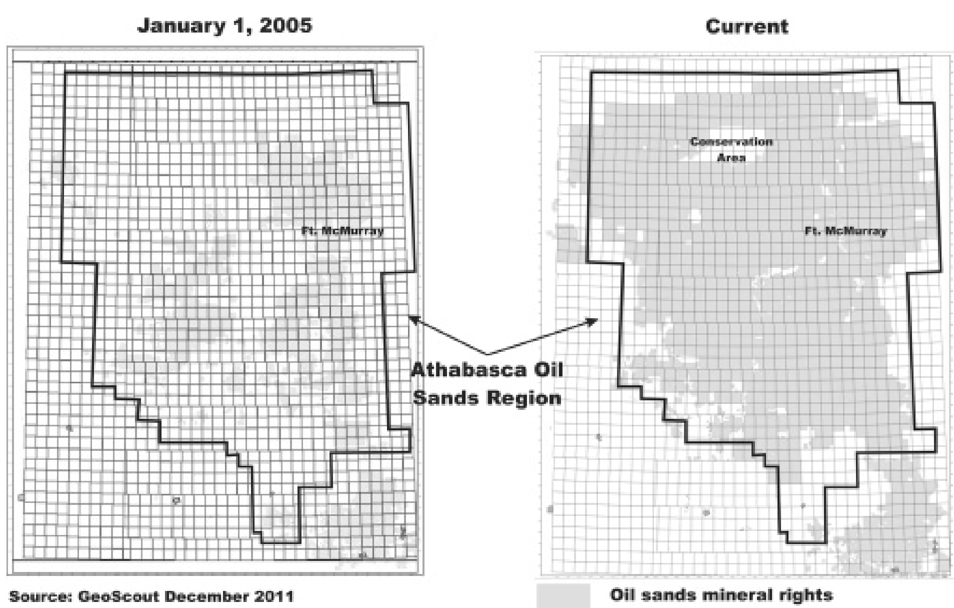
Canada's three main oil sands deposits are located in the Athabasca, Peace River and Cold Lake areas in the Province of Alberta. According to the Department of Energy, these deposits underlie a total land base of approximately 14,020,124 hectares (140,200 square kilometres) in northern Alberta. The Athabasca region is the largest area, representing approximately 66% of the total Alberta oil sands land. According to the Department of Energy, 70% of the Athabasca region is currently under lease.

Canadian Oil Sands Region



The Government of Alberta owns 97% of all oil sands mineral rights, and freehold owners hold the remaining 3%. The Department of Energy manages Crown-owned mineral rights on behalf of the citizens of the province. The majority of Oil Sands Leases are issued through public offerings commonly referred to as land sales. In land sales, the Crown sells the right to the minerals associated with a particular piece of land for a set term in exchange for a bonus payment, a one-time fee of C$625, a rental fee for the first year of the agreement, calculated at the rate of C$3.50 per hectare or a minimum amount of C$50.00, and a royalty on recovered minerals. Oil sands rights are leased to the highest bidder. Oil Sands Lease types and terms have been standardised under two categories: primary leases, which are issued for a standard term of 15 years, and continued leases, which are extensions of primary leases and are classified as producing or non-producing. Oil Sands Leases are continued, or extended for an indefinite period, if a minimum level of evaluation at the relevant property is established under the Oil Sands Tenure Regulation. Minimum level criteria is based on a set amount of drilling and seismic work completed on the land prior to application for lease continuation. If leaseholders do not apply for continuation, the lease will expire. Oil Sands Permits are alternatives to leases, which are issued for terms of five years. Permit holders who have evaluated and proved up the land to an established minimal level may apply for lease selection at the end of their permit terms. The Department of Energy allows applicants to choose whether they wish to post a permit or a lease agreement. Since 2005, the oil sands sector has witnessed a significant influx of new entrants acquiring high quality lease positions, specifically in the Athabasca region. For more information, please refer to the section entitled “Laws and Regulations in the Industry — Laws and Regulations Relating to Land” in this Prospectus. The increase in activity over the last several years has left a small amount remaining of high quality Oil Sands Lease positions as seen in the maps below.

Oil Sands Mineral Rights in the Athabasca Region



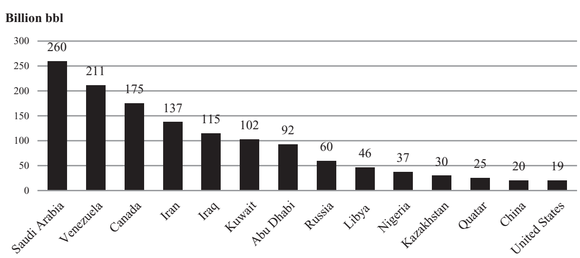
Canada’s oil sands contain crude deposits that are substantially heavier and more viscous than conventional crude oils. Oil sands are composed primarily of sand, clay, bitumen and water. Bitumen, like heavy crude oil, is a complex mixture of hydrocarbon components. It has a high content of carbon relative to hydrogen compared to conventional light crude oil. At room temperature, bitumen is viscous and therefore not suitable for transportation by pipeline. In order to become transportable and marketable, bitumen is processed into two principal forms: either as a bitumen blend, wherein bitumen is mixed with a diluent so that it can be transported through pipelines, or as an SCO, which is the resulting product after raw bitumen has been upgraded.

Bitumen resources in the oil sands are known to be contained in two distinct types of formations, clastics and carbonates. Clastics sediments form the largest portion of the reservoirs which are currently producing bitumen and heavy oil. Clastic reservoir systems are formed through the deposition of rock fragments by moving fluids in a variety of fluvial systems, such as rivers, deltas, shorelines and estuaries. Clastics are the formations from which all current commercial bitumen production in Alberta is derived. Clastic reservoir systems are formed through the sedimentation of rock fragments and are the product of sedimentary disposition at the cut-banks, beds and mouths of prehistoric rivers. In Alberta's case, these were formed in the Cretaceous period. Well-known clastic formations in the Alberta oil sands include layers such as the Wabiskaw and McMurray formations, which are located between 150m and 450m below the surface. The benefit of extracting from a clastic reservoir is that permeability and porosity are largely predictable. Examples of common clastic sedimentary rocks include siliciclastic rocks such as conglomerate, sandstone, siltstone and shale. "Carbonate" means a class of sedimentary rock whose chief mineral constituents (95% or more) are calcite, aragonite and dolomite. Carbonates are the product of prehistoric coral reefs from the Devonian Period. Carbonate rocks are common hydrocarbon reservoirs, and contain more than 60% of the world's proved oil reserves. However, because of the unique technical challenges involved in the production of bitumen from carbonate reservoirs, there is currently no commercial production from bitumen-bearing carbonate formations in Alberta. One of the major challenges facing companies trying to extract bitumen from carbonate reservoirs is that the permeability and porosity of the rock tends to be very complex and difficult to predict. Despite the challenges, there are several ongoing early stage initiatives being undertaken by numerous industry participants.

Laricina Energy Limited recently achieved Canada's first successful carbonate SAGD results at its Saleski pilot project in northern Alberta. The Saleski pilot project is targeting carbonates from the Grosmont formation. Laricina began injecting steam at Saleski in December 2010 with intentions of reaching targeted production rates of 1,800 bbl/d. Concurrently in December 2010, Laricina submitted a regulatory application for its first commercial expansion phase at Saleski of 10,700 bbl/d, with start-up anticipated in 2013. Other companies targeting bitumen production from carbonates include AOSC, Husky Energy Inc., Osum Oil Sands Corp., Shell Canada Limited and our Company.

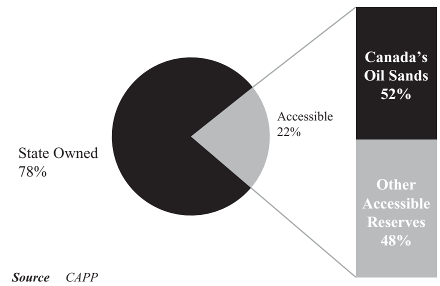
According to the Oil & Gas Journal, Canada currently ranks third behind Saudi Arabia and Venezuela in terms of proved world crude oil reserves, with the majority of Canada's reserves attributable to oil sands. The ERCB estimates that approximately 169 billion bbls of bitumen are remaining established reserves that can be recovered using current technology, and that up to 315 billion bbls may ultimately be recoverable. Not included in this estimate are bitumen volumes found in carbonate formations. The ERCB estimates that there are over 400 billion bbls of bitumen resources in place in carbonate formations in Canada's oil sands.

Estimated World Crude Oil Proved Reserves



Source *Oil & Gas Journal (December 2010)*

World Oil Reserves

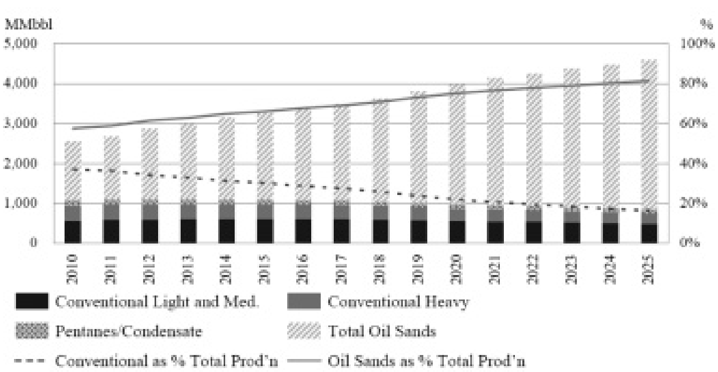


Source *CAPP*

Current and Projected Oil Sands Production

Companies have been producing from Canada's oil sands since the 1960s. According to the CAPP, 2010 oil sands production of 1.5 MMbbl accounted for 52% of Canadian crude oil output. By 2015, oil sands production is expected to grow to 62% of total Canadian crude oil output and 16% of total North American crude oil output. The CAPP estimates based on announced projects indicate the potential for oil sands production to increase to approximately 2.2 MMbbl in 2015 and up to 3.7 MMbbl in 2025. The expected increase in oil sands production is anticipated to occur over a period in which conventional oil production in Canada declines. Current production estimates from oil sands do not account for potential growth from bitumen bearing carbonate formations given the absence of commercial activity to-date.

Canadian Oil Production (2010 – 2025)



Source: CAPP 2011 – 2025 Crude Oil Production Forecast

Oil Sands Production Methods

There are two general types of oil sands production methods. Bitumen resource is extracted from oil sands reservoirs using either thermal methods or surface mining. Bitumen extraction using thermal methods is referred to as *in situ*, or "in place" recovery. The determination of whether surface mining or *in situ* recovery is appropriate is dependent primarily upon the depth of the reservoir. In most cases, if a particular reservoir is more than approximately 75 metres deep, oil sands are extracted utilising a form of the *in situ* method. The ERCB estimated in 2010 that approximately 80% of the total bitumen ultimately recoverable in Canada will be recovered using *in situ* techniques. In contrast, if the targeted reservoir is less than approximately 75 metres deep, oil sands are typically extracted using open pit surface mining operations.

Surface mining

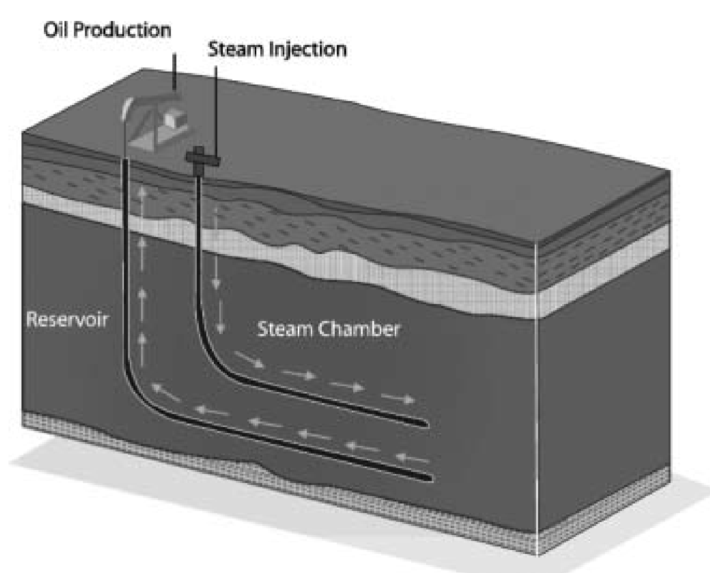
In 2010, the ERCB estimated that approximately 20% of the total bitumen recoverable in Alberta was suitable for surface mining methods. Original oil sands mining techniques employed the use of draglines and bucket wheel excavators which transported sand and bitumen to processing facilities by conveyor belts. However, it is now more common, and more economic, to use power shovels and large dump trucks to perform similar operations. Oil sands surface mining operations produce tailings ponds containing a mixture of water, sand, clay, and bitumen, which are ultimately reclaimed. Tailings ponds are required to settle the fine particles remaining in the water following the separation of bitumen in the mining process.

***In situ* recovery (thermal production methods)**

In situ production methods currently in commercial use apply heat to targeted reservoirs to decrease the viscosity of bitumen, which allows it to flow into wells and be pumped to the surface. *In situ* recovery methods create significantly less surface disturbance than mining operations and do not produce tailings ponds. The two *in situ* production methods currently in commercial use are SAGD and CSS. The determination as to whether SAGD or CSS is employed is dependent upon various reservoir characteristics.

Steam assisted gravity drainage

The SAGD process was developed in the 1970s and was first tested in the Athabasca oil sands region in the 1980s. With the advent of horizontal well technology in the 1980s, well pairs could be drilled from the surface similar to how wells are drilled for conventional enhanced oil operations. In SAGD operations, two horizontal wells are drilled into the targeted reservoir, one near the bottom of the formation and a second approximately five metres above it. The wells are typically drilled in groups from central pads and can extend over one km horizontally from the surface location. In each well pair, steam is injected into the upper well bore and heat from the steam reduces viscosity of the bitumen allowing it to flow into the lower well bore where it is lifted to the surface. The ERCB indicates typical SAGD recovery factors of 40-50% and experienced SAGD operators, like Suncor Energy, report recovery factors of up to 60%.



The commercialisation of SAGD has occurred through the development of numerous projects since the late 1990s. Development and refinement of directional drilling techniques has led to an increase in SAGD use in the oil sands, as wells have become more accurate, less expensive to drill, and more efficient to operate. Additionally, the ongoing evolution of technology continues to drive significant improvements in recovery rates and cost efficiency levels.

Producing SAGD Projects in Alberta Oil Sands

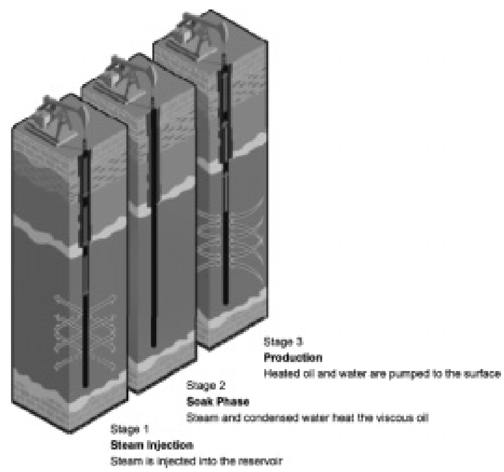
Project	Operator	Capacity bbl/d	Start-up
Foster Creek (Phases 1A - 1E + debottleneck)	Cenovus	120,000	2001
Firebag (Phases 1 - 3 + cogeneration & expansion)	Suncor Energy	157,500	2004
Long Lake (Phase 1)	Nexen	72,000	2008
Jackfish (Phase 1 - 2)	Devon Canada	70,000	2007
MacKay River (Phase 1)	Suncor Energy	33,000	2002
Tucker (Phase 1)	Husky Energy	30,000	2006
Surmont (Phase 1 + Pilot)	Conoco	28,200	1997
Christina Lake (Phase 1 - 2)	MEG	25,000	2008
Great Divide (Pod 1 + Pod 2)	Connacher	20,000	2007
Christina Lake (Phases A - C)	Cenovus	58,800	2002
Orion (Phase 1)	BR Oil Sands (Shell)	10,000	2007
Hangingstone (Pilot)	JACOS	11,000	1999
Kai Kos Dehseh (Pilot)	Statoil Canada	18,750	2010

Source: Government of Alberta, Alberta Oil Sands Industry Quarterly Update (Winter 2011)

SAGD producers have been continuing to optimise operations and enhance project economics through the incorporation of evolutionary process improvements. Some of these improvements involve the enhancement of proven processes and technologies, such as the injection of steam additives into reservoirs in order to increase bitumen recovery factors and reduce natural gas requirements. Some methods are based on different technology than SAGD, such as high-pressure air injection and electrical conduction heating. Other evolving process improvements involve the utilisation of alternate well configurations in order to improve bitumen sweep efficiency and bitumen recovery factors, including “infill wells”, which are infill horizontal wells drilled between established, producing SAGD well pairs. Industry experts continue to study and test technologies focused on improving recovery efficiency late in the *in situ* process. Please refer to the section entitled “— Overview of Canada’s Oil Sands — Oil Sands *in situ* Recovery Technologies” in this Prospectus.

Cyclic Steam Stimulation

CSS has been employed commercially in Alberta since the 1980s. Pioneered by Imperial Oil Limited at Cold Lake, several other key industry participants are producing from commercial CSS projects in Alberta, including Canadian Natural Resources Limited at Primrose and Wolf Lake and Shell Canada Limited at Peace River. The CSS process involves high pressure, high temperature steam being injected into a single well which acts as both the injection well and the production well. The steam is allowed to soak the reservoir for a period of time sufficient to reduce the viscosity of the bitumen. Upon reaching a viscosity that will allow the bitumen to flow and be pumped, the wells are switched from steam to production mode to allow bitumen to be pumped out of the well for a period of months. Once production falls below a predetermined target level, the cycle is repeated. This multi-stage process normally involves several weeks of initial steaming, followed by several weeks of reservoir soaking, and finally ending with an extended production phase. CSS can be completed through vertical, deviated, or horizontal wells. The CSS method has historically achieved lower recovery factors than the SAGD method. Recovery factors achieved using the CSS method are typically 20% to 30%.



Producing CSS Projects in Alberta Oil Sands

Project	Operator	Capacity bbl/d	Start-up
Cold Lake (Phases 1 - 10)	Imperial Oil	110,000	1985
Primrose South	Canadian Natural Resources	45,000	1985
Primrose East (Burnt Lake)	Canadian Natural Resources	32,000	2008
Primrose North	Canadian Natural Resources	30,000	2006
Cold Lake (Phases 11 - 13)	Imperial Oil	30,000	2002
Wolf Lake	Canadian Natural Resources	13,000	1985
Carmon Creek (Cadotte Lake)	Shell Canada	12,500	1986
Red Earth CSS Pilot	Southern Pacific Resources	1,000	2009

Source: Government of Alberta, Alberta Oil Sands Industry Quarterly Update (Winter 2011)

Oil Sands *in situ* Recovery Technologies

There currently exist several evolving *in situ* recovery methods that are focused on improving bitumen recovery factors (i.e. the percentage of the PIIP that can be produced), reducing both capital and operating costs, lowering fuel consumption and CO_2 emissions, and reducing surface footprint. Some of these improvements involve the enhancement of commercially proven processes. Examples of recent and developing process improvements and new extraction techniques are set out below.

Electric Submersible Pumps ("**ESP**"): ESP is an artificial-lift system that utilises a downhole pumping system that is electrically driven. The pump typically comprises several centrifugal pump sections that can be specifically configured to suit the production and wellbore characteristics of a given application. ESP systems are a common artificial lift method, providing flexibility over a range of sizes and output flow capacities. These can operate under water and reduce the amount of steam required per unit of bitumen production, which results in less water and natural gas usage leading to lower operating costs and reduced CO_2 emissions per unit. ESPs are commonly used at commercial SAGD projects.

Infill Wells: Typical SAGD wells are drilled approximately 100m apart. After several years of production, steam chambers expand to the point where they begin to commingle and overlap, leaving an area of unproduced oil between the well pairs at the base of the reservoir. An infill well is an incremental horizontal producer well drilled between two existing well pairs to capture remaining bitumen with minimal incremental steam injection. Cenovus first tested this process at its Foster Creek SAGD property, and has since proven it works at its Christina Lake SAGD property. Cenovus has cited potential increases in recovery factors of approximately 10% as a result of implementing infill wells. Infill wells work to increase bitumen recovery rates and decrease the SORs, resulting in lower overall operating costs and reduced CO_2 emissions.

Solvent-aided Process ("**SAP**"): SAP involves adding a small amount of hydrocarbon solvent (for example, butane or propane) to steam used for injection in an otherwise regular SAGD process. The addition of solvents works to lower heat requirements and maximise energy efficiency of injected steam. The lower heat requirement implies a reduced requirement of steam and natural gas, therefore driving lower operating costs and reducing CO_2 emissions. Cenovus is currently testing SAP at its Christina Lake SAGD project, and has cited reductions of approximately 3% in annual fuel gas usage, 30% improvements in production rates and 15% incremental total oil recoveries as a result of co-injecting solvents. Currently, SAP appears to be a technical success; however, in order to determine the commerciality of the process, more time will be required to understand the amount of solvent that can be recovered. Companies experimenting with solvent co-injection include Cenovus, Imperial Oil and Laricina.

CO_2 Injection: Similar to the injection of solvents with steam, SAGD producers have been experimenting with the injection of CO_2 at the point when SAGD wells reach maturity phase and go into wind-down mode. In wind-down mode, bitumen production rates begin to decline, and SORs increase due to lower bitumen rates and increased heat loss in the reservoir. The injection of CO_2 helps to offset declining bitumen production rates, and therefore extend the life of the wells.

Thermal Assisted Gravity Drainage ("**TAGD**"): TAGD is a process wherein horizontal wells have electric cables inserted into the well bores (as opposed to steam) which act to heat the reservoir. The primary benefit of TAGD relative to SAGD is that the processes of building surface facilities, generating steam and water handling / treatment do not exist, and is therefore likely to result in lower operating and capital costs. The main disadvantage of using TAGD is that reach of the subsurface heat dispersion will be less extensive, and therefore will require the use of more heating wells. Testing of this technology is at its early stages. AOSC is in the process of heating its first field test pilot at its Leduc Carbonate play in the Dover West area.

Toe-to-Heel Air Injection ("**THAI**"): THAI technology is a proprietary *in situ* combustion technology owned by Petrobank Energy and Resources Ltd. The process has been in the piloting stage at Petrobank's Whitesands project since 2006. The THAI process combines a vertical air injection well with a horizontal production well. The vertical air injection well creates a high temperature combustion front which burns part of the oil in the reservoir, reducing the viscosity of the remaining oil. Primary advantages of THAI include higher recovery rates, a semi-upgraded product, and its potential ability to open up parts of the reservoir previously thought to be beyond the limits of SAGD. Additional benefits of THAI involve a reduction in both capital and operating costs and potential for recovering higher volumes of oil. Reliability has been the biggest challenge in achieving commerciality, as tests to date have encountered high levels of sand production.

Electro-Thermal Dynamic Stripping Process ("**E-T - DSP**"): E-T - DSP is a proprietary technology developed by E-T Energy Ltd. ("**E-T**"), which combines heat transfer mechanisms (electro-thermal, conduction and convection) into an environmentally friendly method of heating the oil sands. The process involves passing an electric current from surface generators down to steel electrodes suspended in a reservoir, which are spaced in a grid pattern. Bitumen in the ground is heated as the current passes through water in the formation. The process involves minimal water use, efficient recovery of affected lands, low energy use, and reduced greenhouse gas emissions. In April 2011, E-T signed a technology cooperation agreement with Total SA to participate in additional field testing as E-T prepares for commercial development at its Poplar Creek property in northern Alberta.

Oil Sands Capital Cost Trends

Prior to the second half of 2008, for several years oil sands developers experienced significant inflation in capital costs primarily related to global competition for the skilled labour and materials used in project construction. Rising costs were driven by strong global economic growth, rising commodity prices and significant access to capital markets. The demand for labour and materials in Alberta was exacerbated by the fact that several oil sands producers sanctioned the development of large scale projects, in most cases involving the construction of an upgrader.

Soon after the financial crisis of late 2008 and early 2009, the global recession and a decrease in oil and steel prices from record highs, a number of planned oil sands projects were withdrawn or postponed pending an improvement in macroeconomic conditions. The slowdown in project development resulted in a reduction in capital spending for the overall oil sands industry. Recently, the oil sands sector has returned to a period of accelerated development; however, various key industry dynamics have changed which are expected to mitigate the inflationary pressures experienced through the previous cycle.

Trend towards increased in situ development versus mining: The majority of growth over the near-term will be focused on *in situ* development, particularly non-integrated SAGD versus integrated mining. Average *in situ* projects are built in phases ranging from 10,000 bbl/d to 30,000 bbl/d. Due to the smaller size and scope relative to integrated mining projects, *in situ* projects are easier to manage, require a smaller peak labour force, and are therefore less likely to incur budget overruns.

Increased labour availability: The pace of construction during the previous inflationary cycle drove significant demands on the labour force across Canada. Depletion of Canada's labour pool forced oil sands developers to pursue additional resources internationally. Recently, however, labour availability has become more abundant in Canada, and more broadly, across North America resulting from the economic recovery following the financial crisis. Current unemployment rates in the United States of 8.6% are significantly higher than levels of 5.8% seen in 2008 at the peak of the cycle. Additionally, there are fewer large scale projects in the region that are competing for labour, for example, during the previous inflationary cycle, construction related to the Vancouver 2010 Winter Olympics competed aggressively for similar labour resources.

Fewer competing large scale projects: Oil sands industry consolidation, particularly in the mining sector, has created an increased level of coordination and reduced levels of competition. During the previous cycle, there were seven major mining projects competing for the same resources: Shell Canada Limited's Athabasca Oil Sands Project; Canadian Natural Resources Limited's Horizon; Imperial Oil/ExxonMobil's Kearl Lake and Syncrude; Suncor Energy's Voyageur, Petro-Canada's Fort Hills and Total SA's Joselyn. Since the previous cycle, consolidation has changed the composition of project ownership in the oil sands considerably. For example, as a result of its merger with Petro-Canada in 2008, and its joint venture with Total SA in 2010, Suncor Energy now holds significant influence over Syncrude, Fort Hills, and Joselyn in addition to its Voyageur Project. This consolidation has allowed for less competition related to project scheduling, which is a significant change from when all projects were competing independently.

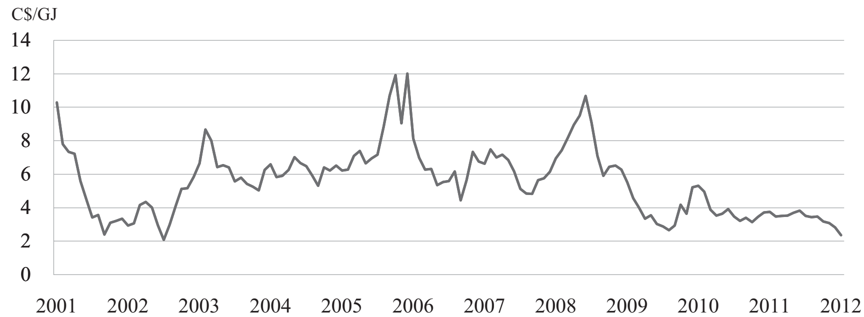
Experiences gained from the late 2008 and early 2009 period in the oil sands industry have altered the way industry participants approach new developments. New projects expected to be developed in the near-term will not involve the construction of upgraders; a trend towards constructing smaller and more manageable phases, or 'modular' growth in production is underway amongst *in situ* producers. As the global economy strengthens, industry participants are closely monitoring increases in the cost of materials, particularly steel. Steel, one of the largest input costs for oil sands projects, currently stands at materially lower levels than seen during the peak inflationary period of 2008. As of year-end 2010, steel prices were 55% below peak levels in 2008. Given the historical commodity price relationship between WTI and steel, cost escalation will need to be closely monitored and managed given the increase of oil sands project being approved and constructed.

Natural Gas and Diluent Supply

Extracting bitumen using SAGD and blending bitumen to make it transportable by pipeline requires the use of natural gas and diluent. Natural gas is used as an energy input, primarily to produce steam from water in a steam generating facility at the *in situ* extraction site. The amount of steam required to extract one barrel of oil is commonly referred to as the steam-to-oil ratio or "SOR". A higher SOR indicates that more steam, and therefore more natural gas is required, increasing the cost of development and operation.

CSUG estimated that in 2010 Canada had a remaining marketable natural gas resource base of approximately 700 to 1,300 trillion cubic feet, inclusive of unconventional gas resources (tight gas and shale gas). Western Canada natural gas production was approximately 14.2 billion cubic feet per day in 2010 according to the NEB and is expected to increase in the long-run as technologies to extract unconventional gas resources continue to improve. Based on supply projections made by the NEB, a sufficient supply of natural gas should be available on a cost effective basis over the long term.

Historic AECO Price(1)



Source: Bloomberg
Notes
(1) The historic price is calculated as the monthly average of the AECO price from 2001 to 2012 (through 31 January 2012).

In order to create a bitumen blend that can be transported by pipeline, bitumen must first be blended with a diluent such as condensate or SCO. Diluents are less viscous than bitumen, and comprise approximately 30 – 50% of the total volume of a bitumen blend, depending on the type of diluent used and the viscosity and density of the bitumen. Condensate is less viscous than SCO. Consequently, a bitumen blend mixed with condensate, commonly referred to as dilbit, has a lower proportion of diluent (approximately 30%) than a bitumen blend mixed with SCO, commonly referred to as synbit (approximately 50%). Since condensate and SCO are similarly priced, the reduced diluent cost associated with dilbit typically enhances realised bitumen revenue for producers.

Condensate for blending is either sourced from regional production or imported into Canada, while SCO for blending is sourced from regional oil sands upgraders. According to CAPP, in 2010 an average of over 116,000 bbl/d of combined butane, diluents from upgraders and imported condensates supplemented the locally produced condensate supply. The NEB estimates that the requirement for imported diluent will reach 250,000 – 300,000 bbl/d by 2020 due primarily to the significant growth outlook from oil sands production. The oil sands industry has devoted substantial resources to increasing the supply of diluents by increasing rail imports of condensate and building new diluent import capacity. A large portion of this imported diluent will be shipped into Alberta by the 180,000 bbl/d Enbridge Inc. Southern Lights pipeline from the midwest United States, which has been in service since July 2010. The Southern Lights pipeline can be expanded to 330,000 bbl/d with minor looping, and to over 400,000 bbl/d with full looping. Additionally, as part of its Northern Gateway crude oil pipeline project, Enbridge Inc. is proposing a 193,000 bbl/d diluent import pipeline that would extend from Kitimat, British Columbia to Edmonton, Alberta. The NEB has scheduled a hearing on this project for January 2012.

Markets and Transportation for Bitumen Blend

Bitumen blends are priced using several benchmarks in Alberta at the Hardisty Hub, the most common benchmarks being Lloyd Blend, Bow River and more recently Western Canada Select. Bitumen blends trade at quality discounts to conventional light oil such as WTI or Edmonton Par. WTI is a light sweet crude oil, which is used as a benchmark grade of crude oil for North American price quotations and is referenced at a sales point in Cushing, Oklahoma. CAPP categorises various crude oil types that comprise western Canadian crude oil supply into four major categories: Conventional Light, Conventional Heavy, Upgraded Light and Oil Sands Heavy. The different grades of crude are categorised by their respective density and sulphur content.

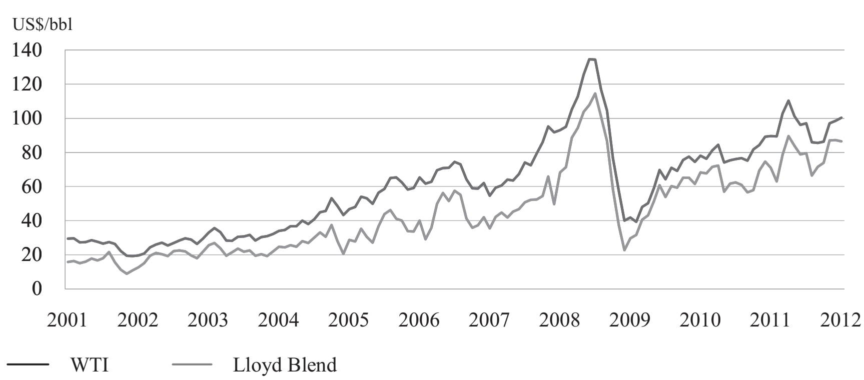
Oil Specifications by Type

Crude Type	2010 Year-end Price	Gravity	Sulphur Content
	C$/bbl	°API	% Weight
Benchmark Prices			
WTI @ Cushing	$91.20	39.0 – 40.0	0.34%
Edmonton Par @ Hardisty	$85.46	40.0	0.50%
Bow River @ Hardisty	$77.03	26.7	2.10%
Lloyd Blend @ Hardisty	$73.77	20.7	3.15%
Western Canadian Select @ Hardisty	$71.24	20.6	3.40%
Cold Lake Blend @ Hardisty	$75.04	21.2	3.70%
Diluents			
Sweet Synthetic Blend @ Hardisty	$87.28	30.0 – 32.0	0.10% – 0.20%
Condensate	$92.85	65.0	0.10%

Source: Bloomberg, Syncrude, Centre for Energy and Environment Canada as per the Oil & Gas Journal

The discount of heavy oil to light oil (commonly referred to as the "heavy oil differential") has historically been volatile, but has narrowed during the last four years, and is currently estimated by the petroleum engineering firms referenced below to average between 18% and 20% through 2015.

Historic WTI and Lloyd Blend Prices(1)

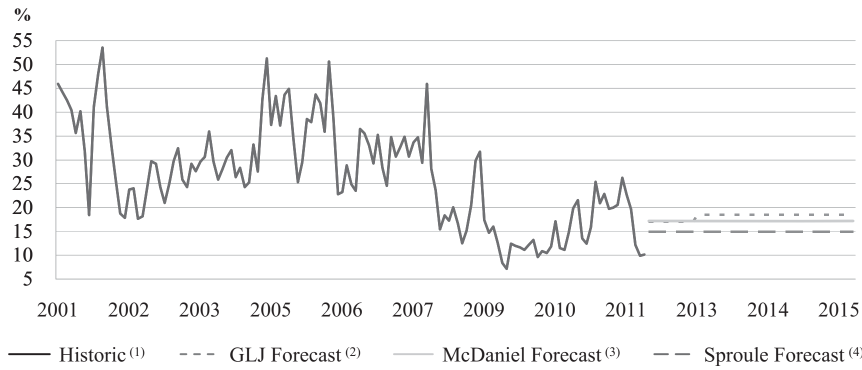


Source: Bloomberg

Notes:

(1) The historic prices are calculated as the monthly average of the WTI and Lloyd blend prices from 2001 to 2012 (through 31 January 2012).

Historic and Forecasted Heavy Oil Differential



Source: Bloomberg
Notes:

(1) The historic differential shows the average of the monthly Lloyd Blend differential from 2001 to 2012 (through 31 January 2012). It is calculated by dividing Lloyd Blend by Light Sweet Crude at Edmonton, and subtracting that number from one.
(2) The GLJ forecast is as of 1 January 2012. The differential is calculated by dividing Lloyd Blend Crude Oil Stream Quality at Hardisty by Light Sweet Crude Oil (40 API, 0.3% sulphur) at Edmonton, and subtracting that number from one.
(3) The McDaniel & Associates Consultants Ltd. forecast is as of 1 January 2012. The differential is calculated by dividing Alberta Bow River Hardisty Crude Oil by Edmonton Light Crude Oil, and subtracting that number from one.
(4) The Sproule Associates Limited forecast is as of 31 December 2011. The differential is calculated by dividing Hardisty Lloyd Blend (20.5 API) by Edmonton Par Price, and subtracting that number from one.

The markets for Canadian oil have traditionally been in Western and Eastern Canada and the Midwest and Rocky Mountain regions of the United States, with small amounts transported to the west coast of the United States. According to the ERCB, the majority of the future incremental production volumes from Canada's oil sands are likely to be consumed in the United States. Asia also represents a significant potential future market for incremental Canadian oil sands production. Asia is currently the second largest global oil market after North America, and China is the second largest consumer of oil after the United States. Our Company's potential customers are local and international companies with operations in North America, including refiners, upgraders, marketers who are intermediaries that connect producers and suppliers, and other oil sands companies who have their own upgrading operations, amongst others.

According to the EIA, as of 2010, Canada was the largest supplier of crude oil to the United States. Approximately 2.0 MMbbl/d or 22% of United States daily demand was imported from Canada. A large percentage of the United States' imported oil is sourced from regions that are, or have the potential to be, politically unstable. Over time, the growth in Canadian heavy crude production volumes, including oil sands volumes, is expected to partially meet increasing demand from the United States.

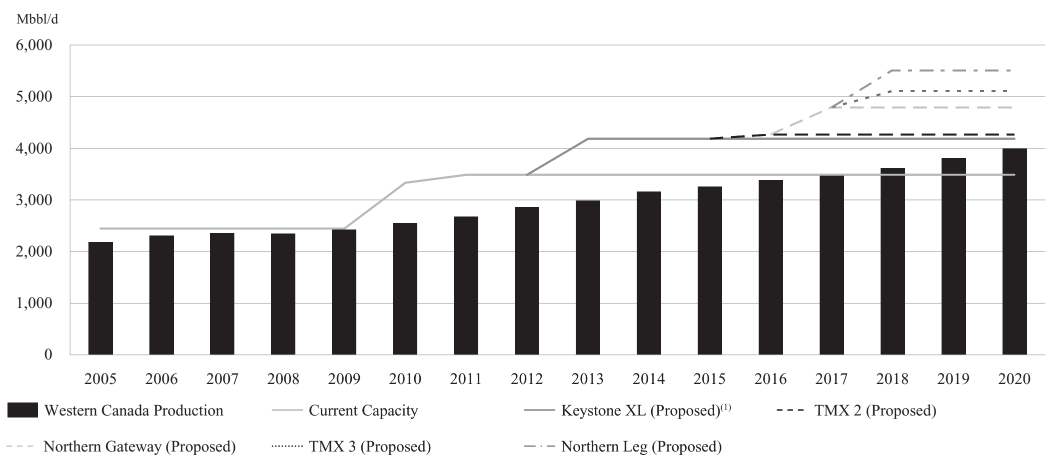
Western Canadian Crude Oil Demand

Area	PADD 2010 Refining Capacity	2010 Actual Demand	2015 Potential Additional Demand	2015 Forecasted Demand
	mbbl/d	Mbbl/d	Mbbl/d	Mbbl/d
PADD I (East Coast)	1,312	55	10	65
PADD II (Mid West)	3,736	1,231	483	1,714
PADD III (Gulf Coast)	8,996	119	380	499
PADD IV (Rockies)	613	237	8	245
PADD V (West Coast)	2,731	205	64	269

Source: CAPP 2011 – 2025 Crude Oil Production Estimate

Significant pipeline expansion and refining reconfiguration projects are forecast to increase transportation and refining capacity for Canadian oil sands production. In response to increased crude oil demand, several refinery expansion plans have been announced both in the United States and abroad. A significant portion of this expansion will allow refineries to process heavier grades of crude oil, such as Canadian oil sands volumes. According to CAPP, in 2010, in the U.S., the Midwest (PADD II) was Canada's largest market for bitumen and conventional heavy oil due to its close proximity, large size and established pipeline network. Several refiners have announced expansions or conversions at PADD II and PADD III to accommodate growing heavy crude oil demand, including bitumen blend (please refer to "Announced Refinery Upgrades" tables below). The steep decline of Mexico's Cantarell oil field, changing Venezuelan export dynamics, and increasing heavy oil transportation capacity are continuing to expand the U.S. Gulf Coast PADD III market for Canadian bitumen blends.

Western Canadian Production and Pipeline Capacity



Source: *CAPP 2011 – 2025 Crude Oil Production Forecast, EnSys Keystone XL Assessment Report*

Notes:

(1) In January 2012, the US State department rejected the issue of a permit for the Keystone XL pipeline.

Announced Refinery Upgrades in Eastern PADD II

Operator	Location	Current Capacity	Scheduled In-Service	Description
		mbbl/d		
WRB Refining	Roxana, IL	306	2011	Add a 65,000 bbl/d coker; increase total crude oil refining capacity by 50,000 bbl/d; increase heavy oil refining capacity to 240,000 bbl/d
BP	Whiting, IN	400	Late 2012 to Mid 2013	Construction of a new coker and a new crude distillation unit
Marathon	Detroit, MI	102	Mid 2012	Increase heavy oil processing capacity by 80,000 bbl/d and increase total crude oil refining capacity to 115,000 bbl/d

Source: *CAPP 2011 – 2025 Crude Oil Production Estimate*

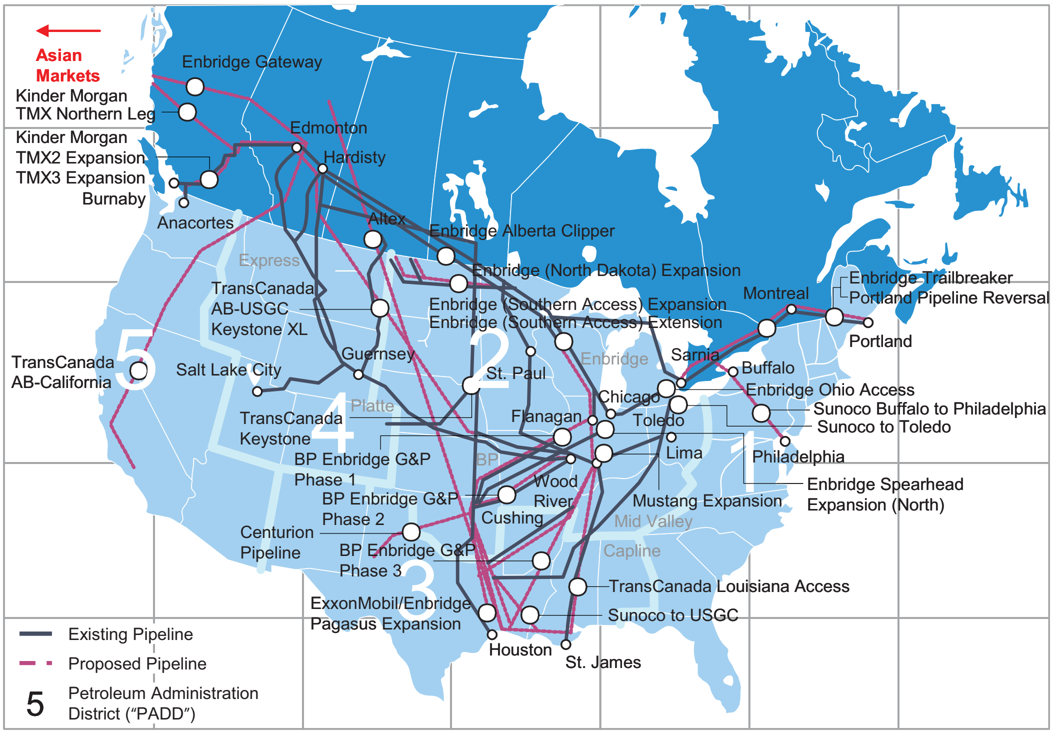
Announced Refinery Upgrades in Eastern PADD III

Operator	Location	Current Capacity	Scheduled In-Service	Description
		mbbl/d		
Hunt Refining	Tuscaloosa, AL	72	2010	Increased capacity from 52,000 bbl/d to 72,000 bbl/d. Delayed coker was expanded to double in size to 32,000 bbl/d
Total	Port Arthur, TX	232	2011	Increased capacity from 175,000 bbl/d to 232,000 bbl/d. Project included a 50,000 bbl/d coker; a 55,000 bbl/d vacuum distillation unit and a 64,000 bbl/d distillate hydrotreater
Motiva Enterprises	Port Arthur, TX	285	2012	Increase capacity by 325,000 bbl/d to over 600,000 bbl/d
Valero	McKee, TX	170	2014	Increase capacity by 25,000 bbl/d. Expansion will process WTI and locally produced oil

Source: CAPP 2011 – 2025 Crude Oil Production Estimate

Asian markets represent a very material potential growth opportunity for bitumen blends. Bitumen blends from the oil sands could potentially be exported to world markets as early as 2016/2017, assuming Enbridge Inc.'s Northern Gateway pipeline and a terminal on the west of Canada at Kitimat, British Columbia are completed as scheduled. Kinder Morgan Canada is also pursuing new pipeline expansions, including a significant expansion of its TransMountain Pipeline. If completed, these future pipelines will potentially allow oil sands producers to compete with other regions such as the Persian Gulf and South America given the proximal nautical distance between Kitimat and east Asia. These pipeline projects are currently being evaluated and constructed in response to strong support from oil sands producers.

Existing and Proposed Pipelines in North America



Source: ERCB, CAPP

Notes:

(1) In January 2012, the US State department rejected the issue of a permit for the Keystone XL pipeline.

Upgrading

Upgrading is a process performed by specialised refineries called upgraders that transform bitumen into higher value hydrocarbons, most of which require additional processing at a refinery to be turned into products which can be used by end users. The primary output of oil sands upgraders is SCO, which is a light crude oil. All oil sands mining projects currently in operation are integrated with upgraders, while most *in situ* projects are not integrated. In recent years, the differential of heavy crude oil pricing to light crude oil pricing has narrowed considerably. The increased demand for bitumen relative to the available supply has reduced the economic attractiveness of upgrading and has resulted in higher netbacks for non-upgraded bitumen.

ENVIRONMENTAL CONSIDERATIONS AND REGULATIONS

The rapid pace of investment for development in Canada's oil sands has attracted significant attention from environmental groups, the general public and governments. Similar to other large scale natural resource projects such as a hard-rock mining or large-scale hydroelectricity generation, oil sands projects face a number of environmental challenges. Oil sands development in Alberta is controlled by extensive provincial and federal government-approved environmental requirements. Detailed project applications, which are preceded by stakeholder consultation, are required to be submitted and are carefully reviewed by regulators before approvals are granted for projects. Once constructed, extensive environmental monitoring and reporting is an ongoing requirement from production to reclamation phase for oil sands projects.

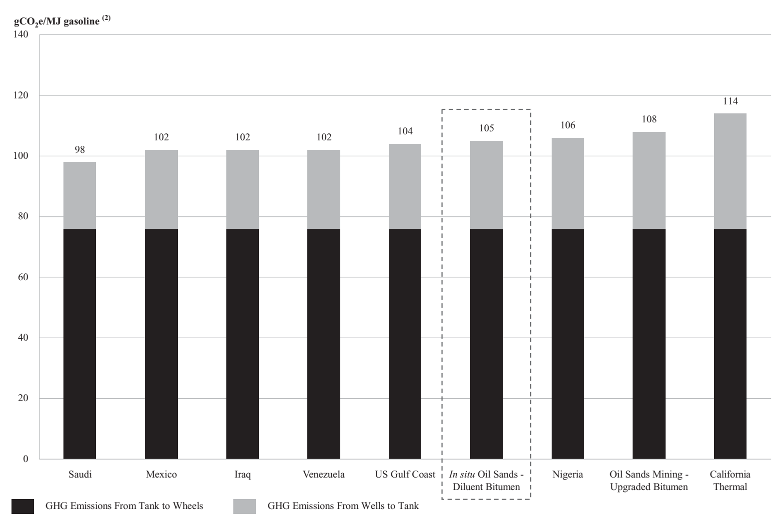
According to CAPP, the three most common environmental considerations are: GHG emissions, water use, and land use.

Greenhouse Gas Emissions

Production from oil sands cause higher GHG emissions than production from most conventional, light oil sources, although GHG emissions from oil sands production is comparable to GHG emissions from the production of many other oil sources from around the globe. Representatives of industry and government are currently focusing their efforts on finding technological solutions to reduce GHG emissions.

Many consultants use a full life-cycle approach when comparing GHG emissions. A full life-cycle approach compares the total emissions from various oil sources from extraction to its end use (typically being burned as gasoline) or as commonly referred to as, "wells to wheels." Research from the Alberta Energy Research Institute has found that ordinarily the majority of the GHG emissions on a life-cycle basis are from the burning of gasoline in motor vehicles, or from "tank to wheels."

Carbon Dioxide (CO_2) from Wells to Wheels(1)



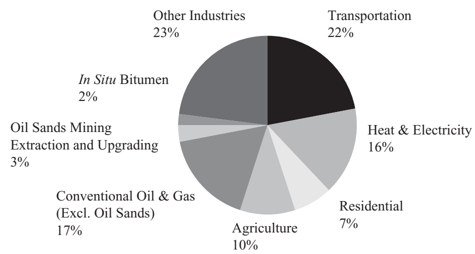
Notes:

(1) Jacobs Consultancy, Life Cycle Assessment of North American and Imported Crudes, June 2009 and CAPP presentation titled "Canada's Oil Sands — Partners in America's Energy Future".

(2) The term "gCO_2e/MJ" means grams of carbon dioxide equivalent per megajoule.

According to a report released by CAPP in 2011, total GHG emissions from the oil sands account for approximately 5% of Canada's total GHG emissions — that amount is equal to 0.5% of total U.S. GHG emissions and 0.1% of global GHG emissions. Provincial and Federal governments, together with oil sands producers are taking several steps to reduce GHG emissions from the oil sands, including introducing new government regulations and making investments in carbon capture and storage projects. *In situ* projects will likely see new technologies and methods to reduce the industry's reliance on natural gas.

Canada's GHG Emissions by Sector



Source: Environment Canada, National Inventory Report Part I Greenhouse Gas Sources and Sinks in Canada (April 2010)

Existing *in situ* extraction technologies are being refined to reduce the amount of steam required to be injected into the reservoir to heat bitumen, and a number of enhanced oil technologies are being developed to reduce or eliminate this need. Using less steam reduces GHG emissions caused by the burning of natural gas and also reduces the amount of water used to generate steam.

Greenhouse Gas Regulations

The Government of Alberta implemented GHG regulations in 2007 that requires facilities that generate in excess of 100,000 tonnes of GHG emissions per year to meet a 2% annual reduction in emissions intensity over a six-year period based on a baseline established in the third year of commercial operations. GHG emitters that cannot meet the targets must either pay a fee to the Climate Change and Emissions Management Fund, the proceeds of which are directed to research and technology development focused on reducing GHG emissions, or purchase emissions performance or emission offset credits. The Federal Government is also developing a carbon pricing system that is intended to drive further reductions in GHG emissions and create additional funds for technology development. The details of the Federal Government's proposed regulations have not been released but it is expected that federal GHG emissions reduction requirements will include an absolute cap on emissions rather than the emissions intensity approach used in Alberta.

Water Use

Both surface mining and *in situ* oil sands production use water as part of the extraction process. Mining requires fresh water to separate bitumen from sands. Mines also require large tailings ponds to settle the fine particles remaining in the water following the bitumen separation process. *In situ* production using SAGD or CSS requires water to produce steam that is injected into the reservoir. Water treatment facilities at *in situ* project sites enable a large quantity of the water to be recycled (in excess of 90%). To minimise the use of fresh water, SAGD and CSS oil sands projects may also use saline and other non-potable water sources. Evolving water treatment technology is expected to reduce water demand even further in the future.

Land Use

While both oil sands mining and *in situ* production methods impact the land, the surface footprint of *in situ* production is significantly smaller than that of a mine. An open pit mine's footprint ultimately affects the entire surface area over the resource and also requires tailings ponds, while *in situ* production requires only well pads on the surface for wellheads, similar to conventional oil and gas, but, with more barrels typically recovered per well pad. Both mining and *in situ* production are subject to government reclamation requirements under Conservation and Reclamation Regulation under the EPEA, but the cost of reclamation for *in situ* producers is much lower and can be accomplished sooner.

COMPETITION

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of resource interests, access to third party infrastructure and the distribution and marketing of petroleum products.

The World Energy Outlook estimates that global primary oil demand will exceed global oil production into the foreseeable future. Oil sands is expected to be a major contributor to future global oil production and will be in competition with other crude oil sources around the globe.

There are currently 14 companies producing from *in situ* oil sands using SAGD and CSS extraction technologies according to information provided by the Government of Alberta (please refer to the section entitled "— Overview of Canada's Oil Sands — Producing SAGD Projects in Alberta Oil Sands" above). Furthermore, a number of these companies and others have proposals to construct new *in situ* oil sands projects or expand existing projects.

Current and Proposed SAGD Projects in Alberta Oil Sands

Operator	Project(s)	Capacity
		bbl/d
Alberta Oilsands Inc.	Clearwater West	29,350
AOSC	Dover, Dover West Clastics, Dover West Leduc Carbonates, Hangingstone, MacKay River	567,000
BlackPearl Resources Inc.	Blackrod	80,000
CNRL	Birch Mountain, Gregoire Lake, Grouse, Kirby, Leismer	390,000
Cenovus	Christina Lake, Foster Creek, Grand Rapids, Narrows Lake, Telephone Lake/Borealis	660,000
Connacher	Great Divide	24,000
Conoco	Surmont	109,000
Devon Canada Corporation	Jackfish	35,000
E-T Energy Ltd.	Poplar Creek	10,000
Grizzly Oil Sands ULC	Algar Lake	11,300
Harvest Operations Corp.	BlackGold	30,000
Husky Energy Inc.	Caribou, Sunrise	220,000
Ivanhoe Energy Inc.	Tamarack	40,000
JACOS	Hangingstone	35,000
Koch Exploration Canada, LP	Gemini	10,000
Laricina	Germain, Saleski	165,700
MEG	Christina Lake, Surmont	285,000
Nexen Inc.	Long Lake	296,000
Osum Oil Sands Corp.	Taiga	35,000
Pengrowth Corporation	Lindbergh	13,200
Petrobank Energy and Resources Ltd.	Dawson, May River, Whitesands	111,900
Shell Canada Limited	Orion	10,000
Southern Pacific Resource Corp.	STP-McKay	36,000
Statoil ASA	Corner, Hangingstone, Leismer, Northwest Leismer, South Leismer, Thornbury	240,000
Suncor Energy	Chard, Firebag, MacKay River, Meadow Creek, Lewis	450,500
Sunshine Oilsands Ltd.	Legend Lake, Thickwood, West Ells	200,000
Value Creation Inc.	Terre de Grace, TriStar	91,000

Source: Government of Alberta, Alberta Oil Sands Industry Quarterly Update (Winter 2011)

Current and Proposed CSS Projects in Alberta Oil Sands

Operator	Project(s)	Capacity
		bbl/d
Imperial Oil Limited	Cold Lake	30,000
Shell Canada Limited	Carmon Creek	80,000
Southern Pacific Resource Corp.	Red Earth	13,000

Source: Government of Alberta, Alberta Oil Sands Industry Quarterly Update (Winter 2011)

The simultaneous construction of a number of SAGD projects can lead to a tight supply of skilled labour and materials. SAGD projects compete amongst each other and other construction projects in Alberta and the rest of Canada to secure engineering and construction personnel and procure building materials. A tight supply of skilled labour and materials may lead to significant cost inflation or project delays. Once operational, SAGD producers will compete amongst each other and other oil sands producers to secure a source of diluent, natural gas and other fuels, and take-away pipeline capacity and storage.

Most of the oil sands properties in the Athabasca region have been leased, many by large international oil and gas companies. New entrants to Canada's oil sands will likely have to make an asset acquisition from, or corporate acquisition of, a company with existing oil sands properties. The scale of Canada's oil sands generally limits material acquisitions to large international companies with strong access to low cost capital.