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Master of Science  
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# **Canada's Oil Sands Resources and Its Future Impact on Global Oil Supply**

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## Abstract

Approximately 2000 billion barrels of conventional oil may ultimately be extracted. We have soon consumed half of it. Global oil production may peak around 2010. It is claimed that non-conventional oil production, including Canadian oil sands production, may bridge the coming gap between the world's oil demand and global oil supply. In 2003 the oil sands reserves were included in Canada's estimated proven reserves, thus increasing from 5 to 180 billion barrels. The objective of this report is to investigate and analyse the production of heavy oil/bitumen from Canada's oil sands deposits and its future impact on global oil supply.

The report shows that the Canadian oil sands industry's dependence on natural gas is unsustainable. Extensive use of bitumen for fuel and upgrading seems to be incompatible with Canada's obligations under the Kyoto treaty.

The Canadian oil sands industry should be viewed as two separate forms of oil production, in situ production (similar to conventional oil production) and mining. The long-term future of the Canadian oil sands industry is the in situ production, although great uncertainty is associated with its potential.

If a massive effort is made to put the whole oil sands mining area into production, a plateau production and a following decline are expected for the oil sands mining industry. The declining oil sands mining production may cause a peak production for the Canadian oil sands industry as a whole, since it is uncertain if the in situ production may compensate for the declining mining activities.

The future Canadian oil sands production cannot even compensate for the combined declining conventional oil production in Canada and the North Sea. The most optimistic scenario will not manage to compensate the decline by 2030. Canada's oil sands resources cannot prevent a global peak oil scenario.

## Summary in Swedish

### Sammanfattning

Olja har en oerhörd betydelse för mänskligheten. Ungefär 40 % av världens totala energiproduktion och 95 % av transportsektorns energiåtgång kommer från olja. Världens oljekonsumtion har ökat till mer än 80 miljoner fat per dag. Det globala behovet av olja beräknas fortsätta öka till hela 121 miljoner fat per dag år 2030. Antalet nya fynd av oljereservoarer har fallit stadigt sedan 1960-talet. Under det senaste decenniet har nya fynd bara ersatt hälften av den olja som konsumerats. När kommersiell utvinning av olja påbörjades fanns det ungefär 2000 utvinningsbara miljarder fat olja i marken. Av denna resurs har vi hittat 90 %, och hälften har konsumerats. Den globala oljeproduktionen kommer förmodligen att nå ett maximum (peak oil production) omkring 2010, för att sedan börja avta.

Med anledning av det annalkande peak oil-scenariot har världens uppmärksamhet riktats mot Kanadas enorma reserver av okonventionell olja – oljesandsreserverna av tung olja/bitumen. Det hävdas ofta att okonventionell olja, då främst Kanadas oljesandsreserver, kan överbrygga det framtida gapet mellan det globala oljebehovet och världspröduktionen av olja. I januari 2003 ökade Kanadas uppskattade bevisade oljereserver från 5 till 180 miljarder fat, när Kanadas oljesandsreserver inkluderades. Över en natt blev Kanadas oljereserver världens näst största, efter Saudi Arabien. Syftet med denna rapport är att undersöka och analysera produktionen av tung olja/bitumen från Kanadas oljesandsfyndigheter och dess framtida betydelse för den globala oljeproduktionen.

Rapporten visar att om det nuvarande naturgasbehovet för oljesandsindustrin kvarstår, då är det inte möjligt att förse den framtida expanderande kanadensiska oljesandsindustrin med nödvändiga kvantiteter av naturgas. Vidare är ett konsekvent skifte till att använda bitumen för energi och till uppgradering av den utvunna oljan svårt att kombinera med Kanadas åtaganden under Kyoto-protokollet. Generellt sett är oljesandsindustrin förknippad med allvarliga miljöstörningar.

Kanadas oljesandsreserver kan exploateras genom gruvdrift samt in situ-metoder, som är olika modifierade former av traditionell oljeutvinning. Den stora osäkerheten för den kanadensiska oljesandsproduktionen gäller möjligheterna till storskalig oljeutvinning med in situ metoder. Samtidigt är det dessa metoder som har den största långsiktiga produktionspotentialen, eftersom den överväldigande delen av oljesandsreserverna endast kan exploateras på detta sätt. Om massiva ekonomiska insatser genomförs för att sätta hela det potentiella gruvdriftsområdet i produktion kan en platåproduktion och en efterföljande produktionsnedgång förväntas. En avtagande produktion för gruvdriften kan resultera i att hela den kanadensiska oljesandsproduktionen når ett maximum för att sedan börja avta.

En total oljeproduktion på 5 miljoner fat per dag år 2030, kan vara möjlig. Detta kräver dock en utbyggnad av andra energikällor, exempelvis kärnkraft, samt att problemen med koldioxidutsläpp kan hanteras ekonomiskt och/eller tekniskt. Under perioden fram till 2030 kan varken den mest optimistiska officiella kanadensiska produktionsprognosen eller denna rapports mest optimistiska produktionsprognos, inte ens kompensera för den kombinerade nedgången i konventionell oljeproduktion från Kanada och Nordsjön. Kanadas oljesandsresurser kan inte förhindra utvecklingen mot ett globalt peak oil-scenario.

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# 1 Background

Crude oil is of outmost importance for mankind. About 40 % of the world's total supply of energy, and 95 % of the energy need of the transporting sector comes from oil. Global consumption of oil has increased to more than 80 million barrels per day. According to the World Energy Outlook 2004 (WEO), global primary oil demand is projected to grow by 1.6% per year on average from 77 million barrels per day in 2002 to 121 mb/d in 2030. Historically, world oil consumption has very closely followed the path of gross domestic product growth.

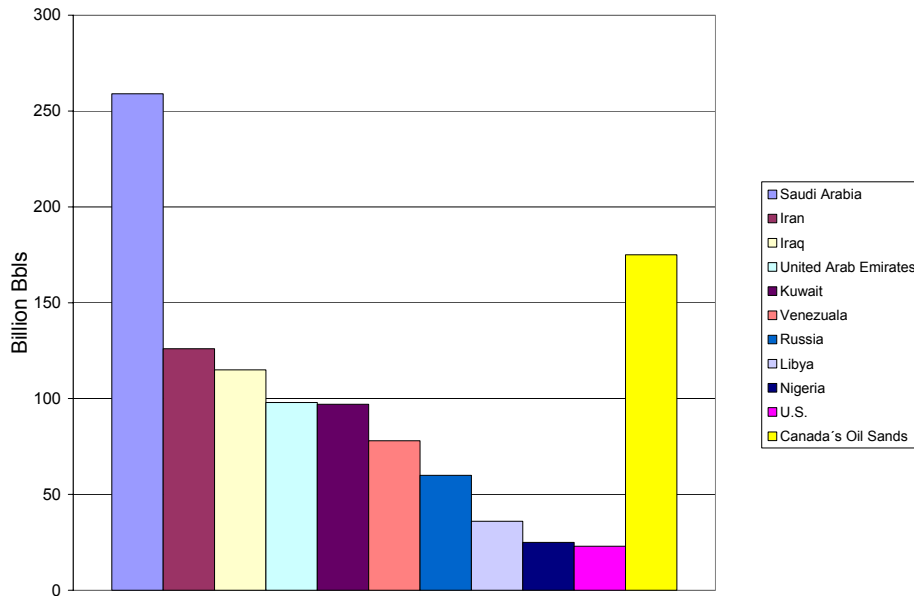
It is estimated that demand for oil will continue to grow most quickly in developing countries. WEO has estimated China's oil use to rise by 3.4% an average per year over the period 2002 –2030. China's Oil demand growth rate is more than twice the world average, although well below the country's extraordinary 11% increase in 2003. China contributed more than a third of the 1.74 mb/d increase in global oil consumption in 2003.

The transport sector will account for 54% of global primary oil consumption in 2030 compared to 47% now and 33% in 1971. (World Energy Outlook, 2004) Preliminary data show that more than two million new cars were sold in China in 2003, and the scope for continued expansion of the country's car fleet is enormous. There are only 10 cars for every thousand Chinese citizen compared with 770 in North America and 500 in Europe. Other populous Asian countries, such as Indonesia and India, are also experiencing a rapid economic growth (gdp increase 5.4% and 6.4% respectively), with following expansion of the countries' car fleets. However, the projected increase of oil demand from the OECD countries is also significant in real numbers. Oil demand from OECD countries is expected to increase with 11.7 million barrels per day between 2002 and 2030. Of this increase, The U.S. and Canada alone account for 6.9 million barrels.

There were approximately about 2000 Giga barrels of conventional oil in the ground when commercial extraction of oil was commenced. We have already found 90 % of this oil and have soon consumed half of it. (Campbell, 2004)

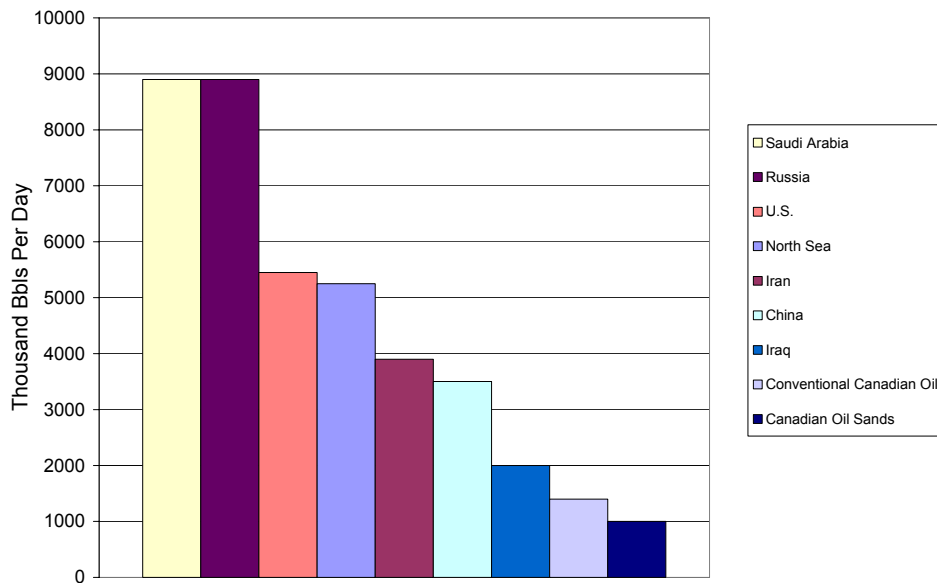
The first of January 2003, Canada's estimated proven reserves were increased from 5 to 180 billion barrels, when Canada's large reserves of unconventional oil – the oil sands deposits - were included. Consequently, over night, Canada's oil resources became the second largest reserves of oil in the world, only surpassed by Saudi Arabia. The following figure describes world oil reserves by country. The second figure illustrates daily average crude oil production from some well-known countries and regions

**Fig 1.1. Top Ten Countries with Proven Conventional Oil Reserves and Canada's Oil Sands Reserves (Billion Barrels, end of 2003)**



Source: World Energy Outlook (2004)

**Fig 1.2. Average Crude Oil Production 2004, Thousand Barrels per Day**



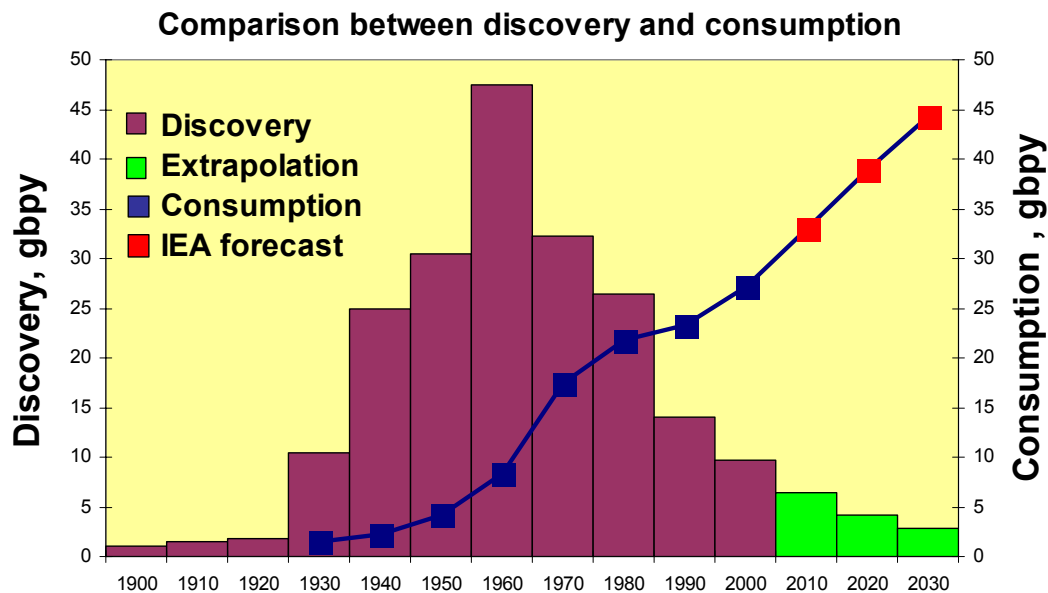
Source: World Energy Outlook (2004)



## 1.1 The Concept of Peak Oil

Reserve additions from discoveries of new oilfields have fallen sharply since the 1960s. In the last decade, discoveries have replaced only half the oil produced. In contrast, the amount of oil discovered in the 1970s was more than a third higher than what was actually produced. The fall in oil discoveries has been most dramatic in the Middle East and the former Soviet Union. In the Middle East, discoveries plunged from 187 billion barrels in 1963-1972 to 16 billion barrels during the decade ending in 2002. (World Energy Outlook, 2004)

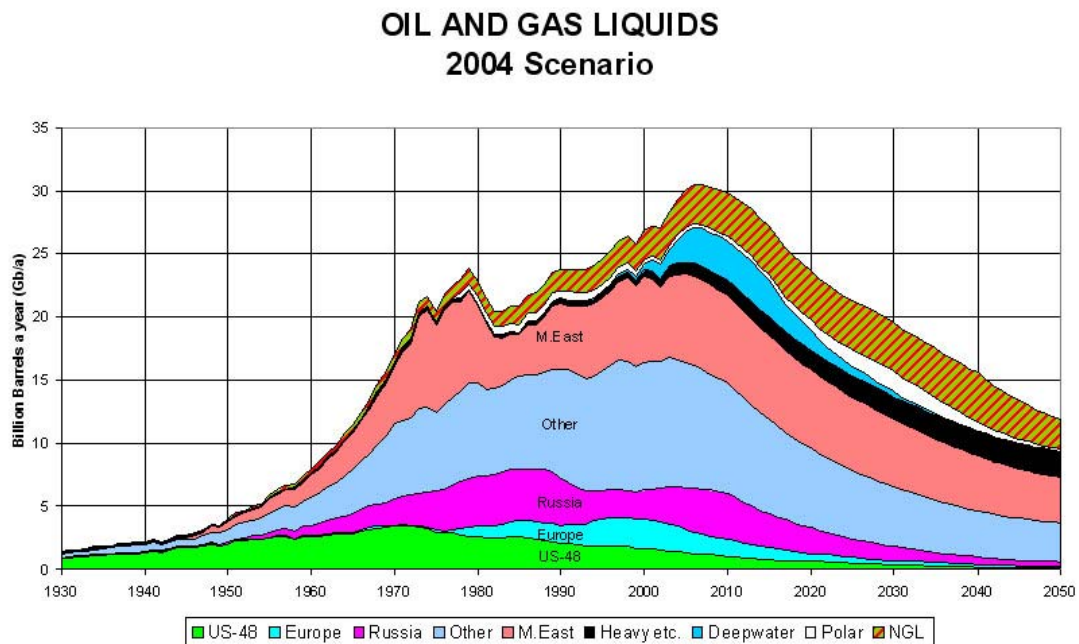
**Figure 1.3. Falling Discovery Trend and Increasing Consumption**



Source: ASPO (2005)

Since it takes millions of years for nature to produce oil, commercial production of oil is obviously a self-depleting activity. Oil companies' first rule of survival is "that once you find oil and pump it out of the ground you have to go ahead and find more, or go out of business". Since more than a hundred years man has commercially extracted oil, now the world is approaching the great rollover point when global oil production peaks at a maximum output capacity, and then starts to decline. This concept of oil depletion is well illustrated by the figure below, which predicts a peak of global oil production around 2010.

**Figure 1.4. World Oil and Gas Liquids Production Curve**



Source: ASPO (2005)

In the perspective of peak-oil, Canada's huge reserves of unconventional oil have drawn the world's attention. It is often claimed that non-conventional oil production such as oil sands production may bridge the coming gap between the world's soaring oil demand and global oil supply. This idea is illustrated by the International Energy Agency in the annual report *World Energy Outlook 2004*. The World Energy Outlook presents three possible oil resource scenarios, referred to as a low resource case, a reference case and a high resource case. In the low resource case, conventional production is estimated to peak around 2015. In this case non-conventional oil meets just under a third of the world's oil needs of 120 million barrels per day in 2030. Production from unconventional oil is primarily expected from Canada's oil sands and the Orinoco extra heavy crude oil belt in Venezuela.

The World Energy Outlook's low resource case is probably the estimation closest to reality. Consequently this illustrates the great achievements that are expected from the Canadian oil sands industry. Today, Canadian oil production from oil sands is about one million barrels per day.

In the report *Peaking of World Oil Production: Impacts, Mitigation, & Risk Management*, sponsored by the U.S. Department of Energy, some assumptions were made about the future heavy oil production from Venezuela. The report says that under business-as-usual conditions, as assumed by the World Energy Council, Venezuela would have a production of 6 million barrels per day in 2030, if the entire area was exploited. This amount would be 5.5 million barrels per day beyond the Venezuelan production of 0.5 million barrels per day in 2003. (Hirsch, 2005)

**Table 1.1. World energy Outlook, World Production Outlook, Low Resource Case**

Remaining ultimately recoverable resources base for conventional oil, as of 1/1/1996 (billion barrels)	1700
Peak period of conventional oil production	2013-2017
Global demand at peak of conventional oil (mb/d)	96
Non-conventional oil production in 2030 (mb/d)	37

Source: World Energy Outlook (2004)

## 1.2 The Global Resource Base of Non-Conventional Oil

The world's non-conventional oil initially in place, could amount to as much as 7 trillion barrels. Extra-heavy oil in Venezuela, tar sands in Canada and shale oil in the United States, account for more than 80% of these resources. However, the amount of oil that could be recovered from these resources is very uncertain. IHS estimates that there were "only" 333 billion barrels of remaining recoverable bitumen reserves worldwide in 2003. This represents about 11 years of current total world oil production. (World Energy Outlook, 2004)

## 1.3 Purpose and Disposition

The objective of this report is to investigate and analyse the production of heavy oil/bitumen from the oil sands deposits of Canada and its future impact on global oil supply.

To illustrate the importance of planned future Canadian oil sands production the concept of peak oil and the coming global oil supply decline have been described. Now the attention turns to the oil sands deposits of Canada, its reserves and production potential.

First the term heavy oil is explained, followed by a description of the Canadian reserves of bitumen, where they are situated, how large the reserves are and what bitumen consists of. After this, different oil sands production technologies are presented and also how synthetic crude oil is derived from the heavy oil/bitumen. Economical as well as environmental aspects of the oil sands production are then covered. The major operating and planned oil sands projects in Canada are thereafter presented.

The need for energy and hydrogen, today mainly supplied by natural gas, is also explained. However, the supply of natural gas in North America is near a state of decline, which is also discussed. The problems associated with natural gas supply are

followed by a chapter which describes the Kyoto agreement and Canadian efforts to reduce emissions of greenhouse gases. This is relevant since the planned expansion of the Canadian oil sands industry is likely to result in accelerating greenhouse gas emissions.

One chapter describes the production costs of oil sands production. The report also presents different official production forecasts as well as some forecasts of my own. The report ends with a comparison between forecasted Canadian oil sands production and the combined production from the North Sea basin and the declining conventional crude oil production in Canada. This is done in order to investigate if the oil sands reserves of Canada are able to compensate for this coming oil production decline. Finally some conclusions of the presented facts are drawn.

## 1.4 Methodology, Literature and Delimitation

For this study information and facts have been mainly searched for through the Internet. The most important sources of information have been four reports of the Canadian National Energy Board (NEB). Reports from the federal State of Alberta have also been used. Especially the report from Alberta Chamber of Resources, *The Oil Sands Technology Roadmap* (OSTRM) and the report *Alberta's Reserves 2003 and Supply/Demand Outlook 2004-2013*(EUB), from the Alberta Energy and Utilities Board, have been most useful. Furthermore, material from the Canadian association of Petroleum Producers (CAPP) has been used, mainly their report *Canadian Crude Oil production and Supply Forecast*. Information from all major operators of oil sands projects has chiefly been reached through their homepages. Thus, much information from many different sources has been treated. It is not of great importance if the information has been biased towards one opinion or another, since I have made prognoses of my own of the consumption of natural gas and greenhouse gases.

As this material is quite voluminous, a number of important subjects like pipeline capacity, refinery capacity and water consumption prognoses have not been dealt with. These aspects have been considered of less importance than the subjects treated in the thesis.

Four prognoses for the Canadian oil sands production from NEB, CAPP, OSTRM and EUB have been presented. These prognoses have been the basis of the calculations of the future natural gas consumption of the oil sands industry and CO<sub>2</sub>E-emissions. When information of the number of upgraded bitumen and raw bitumen production has not been available the proportions which have been accepted for the OSTRM report have become the basis of the other reports as well.

A subject like this is by nature very speculative. Qualified guesswork is, in principle, what you have to rely on concerning forecasts about the future. However, my hope is that my guesswork to the greatest possible extent is well founded.

## 2 Definitions of Heavy Oils

Heavy-oil recovery is traditionally thought of as thermal stimulation of low-API-gravity oil, which may range from 4 to 20° API. In general, heavy oil is defined as having an API gravity of < 20°API. Standard practice in the U.S. uses this gravity definition. Oils with densities less than 10° API have a higher density than water.

The API gravity, however, does not fully describe the flow properties of the crude. The fluid's resistance to flow is better represented by the oil viscosity, measured in Centipoise (cPo). For instance, some crudes may be heavy (low gravity) but have a relatively low viscosity at reservoir temperature compared with some lighter crudes. The oil viscosity and its response to increased temperature control the flow rate under thermal stimulation. Since the flow rate is a much more important factor in the economic exploitation of a reserve than oil gravity, heavy oils are often defined as oils requiring stimulation by heat or by other means, and having viscosities >100 cPo at reservoir conditions. At room temperature, the viscosity of water is 1 cPo. (Briggs, 1988)

Since the term heavy oil includes a variety of different definitions, it might be of use to apply a simple classification into four groups, due to their downhole viscosity, the API value may be overlapping. The first group, Medium Heavy Oil, has a viscosity (u),  $100\text{cPo} > u > 10\text{cPo}$ . The API gravity is  $25^\circ < d^\circ\text{API} > 18^\circ$ . Medium Heavy Oil is mobile at reservoir conditions. The second group is Extra Heavy Oil,  $10,000\text{ cPo} > u > 100\text{ cPo}$ . The API gravity is  $20^\circ < d^\circ\text{API} > 7^\circ$ . Extra Heavy Oil is mobile at reservoir conditions. The third group is tar sands and bitumen,  $u > 10,000\text{ cPo}$ . The API gravity is  $12^\circ < d^\circ\text{API} > 7^\circ$ . Tar Sands and bitumen are non-mobile at reservoir conditions. The final, fourth group, is Oil Shales where the reservoir consists of source rock with no permeability. The only way to extract this resource is by mining. (Cupcic, 2003)

Although the term "bitumen" is used interchangeably with heavy oil, it does tend to signify the heavier end of the heavy-oil spectrum. The United Nations Institute for Training and Research, for example, proposes that bitumen should be defined as having a viscosity > 10,000 cPo and an API gravity of < 10°. However, another commonly used definition of bitumen is that of a naturally occurring viscous mixture consisting mainly of hydrocarbons heavier than pentane that may contain sulfur compounds and which in its naturally occurring viscous state, is not recoverable by conventional means at an economical rate. To sum up, it is possible to define the API of bitumen within the range of 7 – 14° API since the term "tar sand" is often applied to such deposits found in the Canadian Athabasca area. (Briggs, 1988)

### 3 The Canadian Oil Sands Deposits

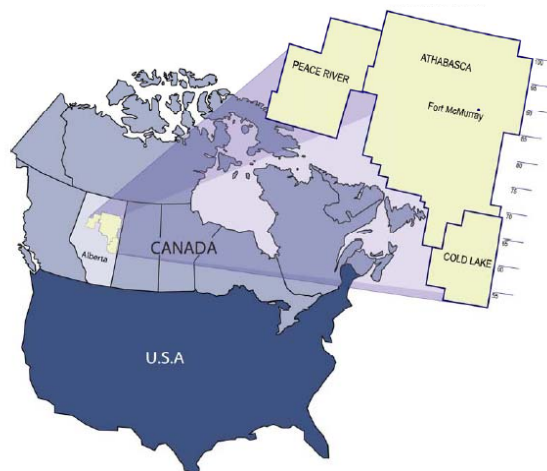
The strong growth in oil demand indicates that Canada's vast resources of oil sand may have a market. However, as the Canadian oil sands industry strives to exploit these resources, significant challenges must be overcome, most importantly higher natural gas prices, capital cost overruns and environmental impacts. (National Energy Board, 2004)

In 2004, Canadian oil sands production will surpass one million b/d. Many forecasts suggest that bitumen production from Canada's oil sands may exceed 2 million b/d by 2010. By 2015, the production is by the EIA expected to have tripled from today's level. In contrast to the oil sands industry, conventional crude oil resources in the WCSB reflect a mature producing environment: 64 percent of recoverable light crude oil resources and 46 percent of heavy oil resources have already been produced. (National Energy Board, 2003) The development of the oil sands resources requires companies to create a manufacturing process that integrates production, upgrading, transportation, and marketing. Typically the projects evolve in stages to maintain a long production plateau of 20-30 years, instead of the short production peak rates of conventional oil production projects.

#### 3.1 Geographical Location

Canada's resources of crude bitumen occur entirely within the province of Alberta in sand and carbonate formations in the northeastern part of the province. These oil sands areas consist of three regions defined as the Athabasca (4.3 million hectares), Cold Lake (729 thousand hectares) and Peace River Oil Sands Areas (976 thousand hectares). The total area of these three regions, nearly 80,000 square kilometers, is comparable in size to the state of South Carolina. (National Energy Board, 2004)

**Figure 3.1. Canada's Oil Sands Area**



Source: Alberta Energy and Utilities Board (2004)

## 3.2 The Creation of the Oil Sands Deposits

The formation of the oil sands deposits required a certain set of conditions. Like for all crude oil, the oil sands deposits of Alberta have its origins from living material. Oil is generally derived from marine organisms, mainly algae and plankton that have been processed for at least one million years at temperatures between 50 and 150 degrees Celsius. The oil sands deposits are the remains of marine life inhabiting an ancient ocean, which covered what today is Alberta. With time the remains of marine organisms formed organic material in the depressions in the pre-historic seabed. The presence of organic material, bacteria, heat and pressure combined with a reservoir for the oil to accumulate, millions of years ago, provided the right circumstances for the creation of oil. (Alberta Community Development, 2005) The age of the source rocks for the oil found in the Alberta oils sands deposits is still a matter of uncertainty. The uncertainty centres on whether the source rocks are Mississippian (320 –355 million years ago) or of Jurassic age (145 –205 million years ago), or perhaps a combination of the two. (National Energy Board, 2000)

The first stages in the creation of the oil sands were in principle similar to the origination of conventional oil. During the creation of the oil, bacteria removed most of the oxygen and nitrogen leaving primarily hydrogen and carbon molecules. Heat and pressure caused by layer upon layer of rock and silt accumulating over time, somewhat pressure-cooked the organic material. Decomposition by microscopic organisms led to a reorganization of their carbon and hydrogen bonds to form hydrocarbons or oil. (Alberta Community Development, 2005)

It is the later stages of development that differ the creation of the oil sands from that of the creation of conventional oil deposits. The generated oil was probably sourced in the deeper portions of the Western Canada Sedimentary Basin (WCSB) in pre-Cretaceous formations due to pressure from the formation of the Rocky Mountains, and then migrated long distances north into the existing sand deposits, left behind by ancient river beds, thus forming the present oil sands. The McMurray and equivalent sands became primary collectors of the generated oil and provided the main channel for migration. There are theories suggesting that the migration path was at least 360 kilometres for the Athabasca Deposit and at least 80 kilometres for the Peace River deposits. For the creation of the oil sands the oil was mixed with fine particles of clay and other minerals such as various metals and sulphur. The lighter oils that remained in the sands deposits were then subjected to biodegradation by microbes, transforming them into bitumen. (National Energy Board, 2000)

The microbial action preferentially decomposed the lighter hydrocarbon molecules, leaving the more complex heavy molecules, heavy minerals and sulphur behind. As a result, the specific gravity and sulphur content of the crude oil increased. For similar reasons the concentration of heavy minerals such as vanadium, nickel, magnetite, gold and silver also increased. It has been estimated that prior to biodegradation, the original volume of oil in the oil sands was two to three times as large as it is today. The characteristics of the bitumen and the reservoir properties of the oil sands are in large part a function of the degree of biodegradation that took place. (National Energy Board, 2000)

### 3.3 Oil Sands and Bitumen

The oil sands deposits are composed primarily of quartz sand, silt and clay, water and bitumen, along with minor amounts of other minerals, including titanium, zirconium, tourmaline and pyrite. Although there can be considerable variation, a typical composition is:

- 75 to 80 percent inorganic material, with this inorganic portion composed 90 percent of quartz sand.
- 3 to 5 percent water.
- 10 to 12 percent bitumen, with bitumen saturation varying between zero and 18 percent by weight.

A key aspect of the oil sand reservoirs is the presence of bound formation water, which surrounds the individual sand grains as layer. The bitumen is trapped within the pore space of the rock itself. This is similar to most conventional oil reservoirs, and the reservoir rock is said to be "water-wet", that is, each sand grain is surrounded by an envelope or film of water about 10 nanometres thick. The presence of the water layer around the grains enables the bitumen to be recovered more easily since the bonding forces between the bitumen and water are much weaker than those between the water and the sand grains.

In comparison to conventional crude oils, bitumen contained in the oil sands is characterized by high densities, very high viscosities, high metal concentrations, high amounts of sulphur and a high ratio of carbon to hydrogen molecules. With a density range of 970 to 1015 kilograms per cubic meter (8-14°API), and a viscosity at room temperature typically greater than 50,000 centipose, bitumen is a thick, black, tar-like substance that pours extremely slowly. The average composition of Alberta's bitumen is 83.2 percent carbon, 10.4 percent hydrogen, 0.94 percent oxygen, 0.36 percent nitrogen and 4.8 percent sulphur, along with trace amounts of heavy metals such as vanadium, nickel and iron.

Average crude oils contain about 84 percent (by weight) carbon, 14 percent hydrogen, 1 to 3 percent sulphur and minor amounts of nitrogen, oxygen, metals and salts. In order to transport bitumen to refineries equipped to process it, bitumen must first be blended with a diluent, commonly referred to as condensate, to meet pipeline specifications for density and viscosity. (National Energy Board, 2000)



## 4 Production Technologies

Some bitumen deposits are recoverable by conventional methods but these volumes are comparatively small and more associated with conventional oil production and hence not covered by this report. There are two major techniques currently employed to produce bitumen, mining and in situ thermal recovery. For mining, huge open-pit mines are constructed and large extraction facilities are used in order to separate the bitumen from the sand. In-Situ thermal recovery resembles conventional oil production. Extraction of the bitumen is accomplished by drilling wells and thereafter injecting steam, thus enabling the bitumen to flow to the surface.

### 4.1 Mining Extraction

A miner's definition of 'ore' includes economic as well as geologic criteria. There have been attempts in the past to define what constitutes "mineable" oil sands. But overburden depth alone is not a true indicator of whether an area is capable of sustaining an economically viable surface mining operation. The ore thickness, grade, clay content, and the extent of reject zones are also important parameters to be considered in the economic evaluation of a potential oil sands mining project. The thickness of overburden, ore, and center reject can be combined to give a waste-ore ratio, (thickness of overburden plus reject zones, divided by the ore thickness) which can be used as an economic indicator of the cost of delivering a unit of ore to the extraction plant. The bitumen content (grade) and clay content give an indication of the amount of bitumen that can be recovered from the unit of ore. Therefore this is an indication of the value of that unit. It is not unusual to use only the bitumen content to define the expected processability of oil sands.

After a mineable area has been outlined, it is necessary to determine the amount of ore in place, in order to arrive at the optimum size of operation. For this various volumetric estimates methods are utilized. Oil sands can only be regarded as 'ore' where there is a deposit of sufficient size to feed a hot water extraction plant profitably. This definition will vary with changes in technology and the international price of oil. (Pearson, 1979)

#### 4.1.1 Mining Operations

The typical surface mining operation in oil sand includes several operations. First the overburden has to be removed with trucks and shovels. In general the overburden is disposed of in-pit but some is moved to out-of-pit dumps where parts are used to construct containment structures for tailings. The mining of the oil sand is done with electric or hydraulic shovels. The oil sand is then transported from the mine face to crushers with trucks. Following various forms of slurring, the oil sand is transported from the mining area to the extraction site using centrifugal pumps and pipelines, which is generally referred to as "hydrotransport". Mining operations use large volumes of water, of which most can be recycled.

The extraction of bitumen from the conditioned ore slurry consists of two main steps. The first is the separation of bitumen froth (60% bitumen, 30% water and 10% fine solids) in the primary separation vessel. The second step is diluted froth treatment in order to recover the bitumen and reject as much residual water and solids as possible. There are currently two approaches in the second step. The original naphtha solvent

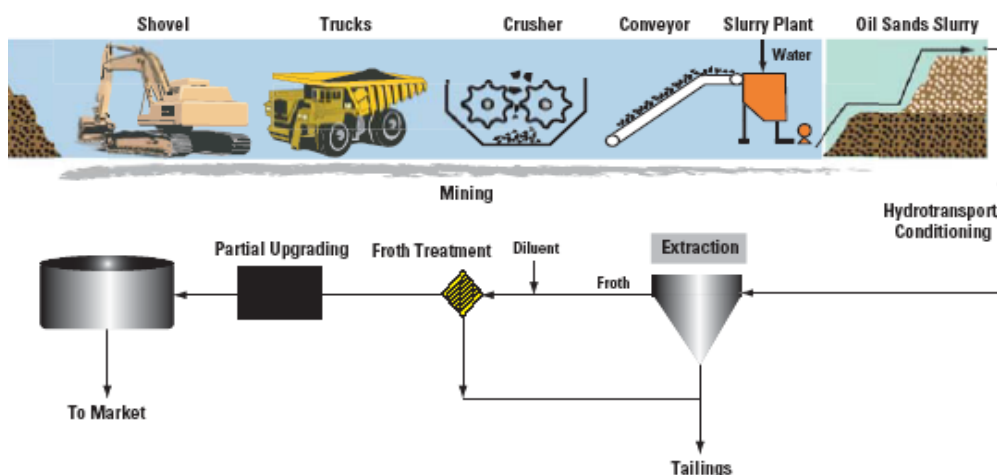
based process requires inclined plate separators and centrifuges to remove residual solids and water. The newer process with paraffinic solvent adds other process vessels, but eliminates high maintenance centrifuges and results in a cleaner product.

Recovery of bitumen today is in the order of 87-90+%, a figure strongly dependant on ore quality. EUB in general requires oil sands operators to achieve 90% recovery or more. The losses of bitumen in the processing operation come from oversize rejects and other mining activities (2-3% of all losses), primary bitumen recovery to the bitumen froth stage (6-8%) and the diluted froth treatment for bitumen recovered (2%). The major causes of loss include instability in operations, variable feed grade, the effect of winter conditions, water chemistry, mechanical reliability, and improper slurry conditioning for some ore types. (Alberta Chamber of Resources, 2004)

#### 4.1.2 Future Mining Technology

For oil sands reserves with less than 50 meters of overburden, The Alberta Chamber of Resources does not expect that any alternative to surface mining will be developed within the following 25 years. The overburden will still need to be stripped to expose the ore body, and oil sand will still have to be mined and processed in a water-based extraction process. (Alberta Chamber of Resources, 2004) In general no revolutionary changes in oil sands mining are expected to emerge, although incremental advances are expected in several fields concerning oil sands mining. Improved materials and equipment that are more durable and better suited to the oil sands industry combined with better monitoring systems for mechanical equipment to reduce production interruptions, is expected. Management systems that reduce transport and handling costs may be enhanced as for decision support and information systems to improve mine management. Some reductions in bitumen loss through primary separation and reductions in the energy intensity of the extraction process may be achieved. Finally, continued improvement in the performance of existing upgrading technologies including increased energy efficiency, catalyst development, and reductions in hydrogen use is likely to take place. (National Energy Board, 2004)

**Figure 4.1. Schematic Description of Current Mining Operations**



Source: Imperial (2004)

## 4.2 In Situ Extraction

The majority of the oil sands reserves in Alberta are too deep for 'open pit' mining. In a conventional oil reservoir the hydrocarbon flows towards a series of producing wells and is pumped to the surface. Various secondary and tertiary recovery techniques may be employed to enhance the natural flow of fluids. These techniques may increase the porosity of the strata, reduce the viscosity of the fluids, or induce a driving force on the fluids, by increasing the pressure in the reservoir. In situ (Latin, in situ, in position) extraction applies variations of conventional tertiary recovery techniques to the oil sands. The most common concepts employ steam, or fire, flooding technology with various stimulation techniques. (Pearson, 1979) Unlike mined bitumen, in-situ production can be handled conventionally in downstream refineries.

In situ extraction methods remove the hydrocarbons and leave the mineral behind. Viscosity, permeability, and reservoir thickness are the major contributing parameters to the evaluation of a reservoir. In situ methods attempt to reduce the bitumen viscosity by introducing a solvent, or heat the reservoir, either by steam or combustion of residual hydrocarbons. Some degree of permeability can be induced by a variety of fracturing procedures, but the natural permeability of the sands is an important characteristic in selecting the site for an in-situ project.

The productive zones within the reservoir are usually combined into a "net pay" which ignores thin zones of low bitumen saturation which are expected to be non-productive. This concept is not possible for a mining operation, which must accept the thin bands of low grade material, since mining equipment is not normally capable of a high degree of selectivity. The absolute bitumen content of the sands is of less importance to in situ projects than to mining, since the concept of "mill heads" has no relevance in an in-situ project. (Pearson, 1979)

Although reservoir evaluation tools and methods are steadily improving, reservoir quality remains one of the greatest uncertainties in project evaluation. Major features that characterize a low-quality reservoir include low vertical permeability and pay thickness, high shale content and the presence of bottom water. A high-quality reservoir is characterized by high vertical permeability, high pay thickness, no bottom water and little shale. (National Energy Board, 2004)

The two most common in situ recovery types, Cyclic Steam Stimulation (CSS) and steam assisted gravity drainage (SAGD), require thermal stimulation of the reservoir to induce the flow of bitumen. There are, however, certain areas in the Athabasca, Peace River and Cold Lake oil sands regions that do not require thermal stimulation. (National Energy Board, 2004)

Steam-to-oil ratio (SOR) is a measure of the quantity of steam required to produce one barrel of oil. Steam is typically produced using natural gas fuelled steam generators; therefore, a lower SOR translates into lower fuel costs. Higher SORs also result in greater volumes of produced water, which increases water handling costs. Therefore the oil sands industry strives to reduce the SOR ratio.

There are many possible theoretical advantages of in-situ recovery over mining operations. Modest size for commercial SAGD operation allows introduction of new technology in smaller steps with lesser business risk compared with mining mega-ventures. Much smaller facility structures mean that the environmental consequences

of disturbed land become much less than for mining. As for process-affected water the volumes are much smaller, eliminating onsite containment. Finally, the demand for workforce is much lower compared with mining and can be satisfied from the conventional oil and gas operations workforce, since Canadian conventional oil production is in decline. (Alberta Chamber of Resources, 2004)

#### **4.2.1 Cyclic Steam Stimulation (CSS)**

One mature process for deep, thicker reserves, such as in Cold Lake and Peace River, involves cycling at single vertical injector/producer wells (this is sometimes referred to as "huff and puff"). An alternative incorporates steam drive between injectors and producers. While these processes originally depended on vertical wells, combinations of vertical and horizontal wells are now used.

CSS is a three-stage process: first, high pressure steam is injected through a vertical well bore for a period of time; second, the reservoir is shut in to soak; and third, the well is put into production. In addition to heating the bitumen, the high pressure steam creates fractures in the formation thereby improving fluid flow. High injection pressures for deep, "huff and puff" processes require an overburden cover of 300 or more meters. Typical steam-to-oil ratios, the major economic factor, are 3:1 to 4:1. (Alberta Chamber of Resources, 2004) For CSS, an estimated 20 to 25 percent of the initial oil in-place is estimated to be recoverable. (National Energy Board, 2004) These recovery rate figures are low compared to SAGD methods, and mining.

#### **4.2.2 Steam Assisted Gravity Drainage (SAGD)**

Advanced horizontal drilling technology laid the foundation for steam assisted gravity drainage (SAGD). Although SAGD is still a developing technology it is already utilised in several commercial projects by various companies. SAGD makes it possible to extract bitumen from thinner reserves than CSS, although good vertical permeability is essential. Consequently the introduction of this technique has considerably increased the recoverable reserve category. The Steam-to-oil ratio for SAGD ranges from 2.5:1, for high quality reservoirs, to 3.0:1. (National Energy Board, 2004) EnCana for example, claim they have achieved an industry leading steam-to-oil ratio, requiring only 2.5:1, and the company's longer-term objective is further improvement to about 2:1. (EnCana, 2004)

SAGD works best in high permeability reservoirs, resulting in lower injection pressures and lower steam-to-oil ratios. In a SAGD operation, several horizontal well pairs are drilled from the same pad extending as long as 1,000 meters horizontally into the oil sands and about 5 meters apart vertically. The top well is used to inject steam to warm up a zone around and below the injector, reducing the viscosity and mobilizing an expanding zone of bitumen, which is then produced through the lower well. Ultimate recovery is anticipated to be in the 40-70% range. (Alberta Chamber of Resources, 2004)

### **4.3 Emerging In Situ Technologies**

The oil sands industry continues looking for ways to improve in situ production economics. The work of improvement includes testing additives such as butane or propane to increase recovery rates and lower the volume of gas required to produce a barrel of oil. These methods are called Solvent Aided Process (SAP). There are a number of other hybrid thermal/solvent processes being tested. The Alberta Research

Council (ARC) is leading research into a number of hybrid steam/solvent processes combining SAGD technology with solvent injections. The new processes are aimed primarily at improving recovery and energy efficiency, and reducing water requirements. These enhanced thermal processes include Expanding-Solvent SAGD (ES-SAGD), Low-Pressure Solvent SAGD, and Tapered Steam Solvent SAGD (TSS-SAGD). (National Energy Board, 2004) Technical improvements such as the development of high-temperature, low-pressure pumps have also resulted in enhanced production efficiency. (EnCana, 2004) Also, a number of in situ processes have been proposed that incorporate co-injection of oxygen to promote a form of in situ combustion or gasification. This would produce the energy to warm up the reserve and mobilize the bitumen. The THAI-method is one of these processes. (Alberta Chamber of Resources, 2004)

#### **4.3.1 VAPEX (Vapour Extraction Process)**

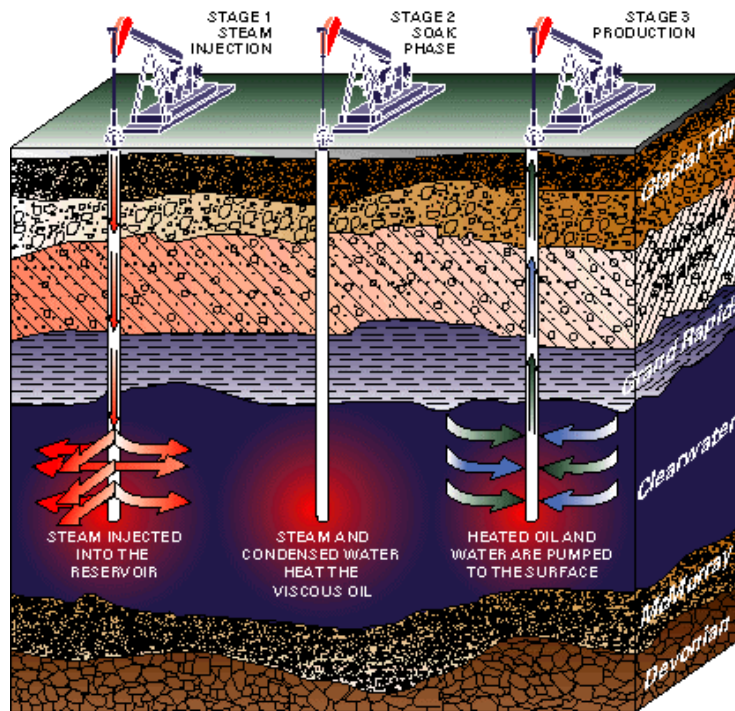
Vapour Extraction Process, or VAPEX, is similar in operation to SAGD. With VAPEX a solvent such as ethane, propane or butane, instead of steam, is injected into the reservoir along with a displacement gas to mobilize the hydrocarbons in the reservoir and move them toward the production well. This gives the cost advantage of not having to install steam generation facilities or purchase natural gas to produce steam. The VAPEX method do not require water processing or recycling, offers lower carbon dioxide emissions, and can be operated at reservoir temperature with almost no loss of heat. The capital costs are estimated to be 75 percent of SAGD costs, while the operating costs are estimated to be 50 percent compared to SAGD. An additional advantage is the possibility of a reduced need of diluent, as some of the solvent diffuses into the bitumen to mobilize it. On the negative side, more wells are needed to achieve similar production rates and rate of recovery. (National Energy Board, 2004)

#### **4.3.2 THAI (Toe-to-Heel Air Injection)**

Toe-to-Heel Air Injection, or THAI, is a proposed method of recovery that combines a vertical air injection well with a horizontal production well. The process ignites oil in the reservoir, thereby creating a vertical wall or front of burning crude (firefront) that partially upgrades the hydrocarbons in front of it and drains the crude to a producing horizontal well. Since the process creates heat in situ, there is no need for injecting steam from the surface. In addition the process offers some potential for upgrading the bitumen in the reservoir as the process proceeds. A THAI variant, named CAPRI, utilizes a catalyst in the horizontal well to promote the precipitation of asphaltenes and thus upgrade the bitumen in situ.

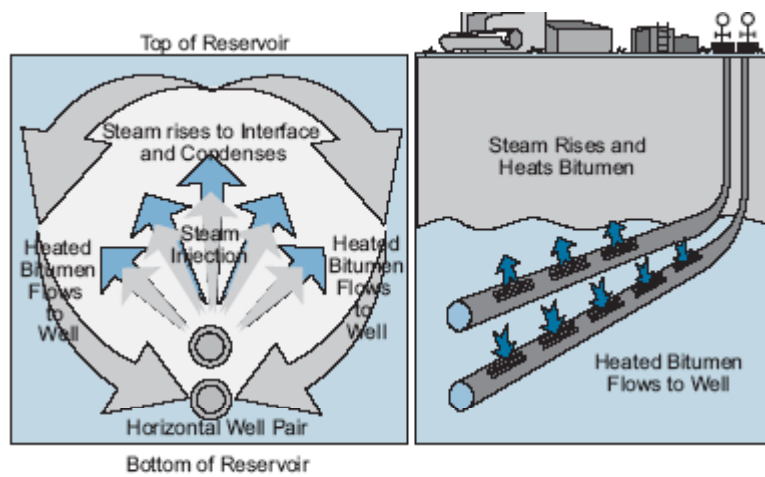
In situ combustion recovery methods were experimented with in heavy oil reservoirs and oil sands deposits in the 1970s and 1980s, using vertical wells, but met with little success, primarily because of an inability to control the direction of the firefront in the reservoir. This generally resulted in poor production performance and often caused damage to downhole equipment. Proponents of the THAI method believe that using a horizontal production well will offer better control of the firefront, but the concept has yet to be proven in the field. In 2004, Orion Oil Canada Ltd., a heavy oil business unit of Petrobank Energy and Resources, filed an application with the AEUB to test the THAI process on the Whitesands oil sands leases near Conklin, Alberta. According to plan, delineation drilling and site preparation will begin in early 2004, with startup in late 2004. (National Energy Board, 2004)

**Figure 4.2. Cyclic Steam Stimulation (CSS)**



Source: Imperial Oil (2004)

**Figure 4.3. Steam Assisted Gravity Drainage (SAGD)**



Source: Husky Energy (2004)

## 5 Canadian Reserves of Crude Bitumen

Canada's oil sands are a significant resource. According to the Alberta Energy and Utilities Board (AEUB), the initial volume of crude bitumen in place is estimated to be approximately 1.6 trillion barrels (259 billion cubic meters), with 11 percent or 175 billion barrels (28 billion cubic meters) recoverable under current economic conditions. (National Energy Board, 2004) Of this amount about 80 percent, is considered recoverable by in situ methods and 20 percent by mining. In early 2003, the Oil & Gas Journal and Cambridge Energy Research Associates, for the first time, recognized AEUB's estimates for established reserves of bitumen in their listing of the world's oil reserves. Consequently, in regard of oil reserves, Canada now ranks second in the world, with only Saudi Arabia ahead. (National Energy Board, 2004)

However there are objections to the evaluation method used by the AEUB. Critics claim that AEUB's evaluation methodology is not sufficiently precise to meet the strict definition of reserves, since large capital investments in facilities are required to develop the resources. Some argue reserves should be recognized on a project-by-project basis, when proven by the installation of facilities and the successful operation of the project. On the other hand the use of such stricter definitions would make it difficult to correctly portray the realistic potential for the economic development of the oil sand resources. (National Energy Board, 2004)

### 5.1 Ultimate Potential of Crude Bitumen

The AEUB estimates the ultimate in-place volume of crude bitumen to be about 2520 billion barrels ( $400 \cdot 10^9 \text{ m}^3$ ). At a depth shallower than approximately 75 meters it is presumed that the primary method of recovery will be through the use of surface-mining techniques, unlike the majority of Alberta's crude bitumen area, where recovery will be through in situ methods. Within the surface mineable area (SMA) 138.6 billion barrels ( $22 \cdot 10^9 \text{ m}^3$ ) may eventually be amenable to surface mining (as well as some limited in situ recovery). The remainder, being deeper deposits, will require the use of in situ recovery or underground mining techniques in order to extract the bitumen resources. (Alberta Energy and Utilities Board, 2004)

Although drilling and log analyses indicate the large ultimate in-place volumes, knowledge of variations in quality and the effect of this on recovery potential is still limited. In addition, there has been little experimentation to date to establish the expected recovery factor for some types of resources, particularly carbonates. Therefore, the portions of in-place volumes for the Cretaceous sand and Paleozoic carbonate deposits that will require the use of in situ recovery methods have been broken down into established and probable categories, and different recovery factors have been applied to each category in establishing the ultimate potential of crude bitumen for the in situ areas. The recovery factors selected reflect the EUB's current knowledge respecting the quality of the in-place resources, the amount of experimentation done to date to establish recovery techniques, and a projection of future improvements in those techniques. (Alberta Energy and Utilities Board, 2004)

## 5.2 Initial in-Place Volumes of Crude Bitumen

Alberta's massive crude bitumen resources are contained in sand and carbonate formations in the Athabasca, Cold Lake, and Peace River oil sands areas. The AEUB estimates Alberta's crude bitumen reserves by separately calculating those reserves likely to be recovered by mining methods and those by in situ methods. (Alberta Energy and Utilities Board, 2004)

AEUB has based the initial in-place volumes of crude bitumen in each deposit using drillhole data and geophysical logs. The crude bitumen within the Cretaceous sands was evaluated using a minimum saturation cutoff of 3 mass percent of crude bitumen and a minimum saturated zone thickness of 1.5 m., for in situ areas. A minimum saturation cutoff of 7 mass percent and a minimum saturated zone thickness of 3.0 m was used for surface-mineable areas. The crude bitumen within the carbonate deposits was determined using a minimum bitumen saturation of 30 per cent of pore volume and a minimum porosity value of 5 per cent. (Alberta Energy and Utilities Board, 2004)

The estimate of the initial volume in-place of crude bitumen within the SMA remains unchanged at 113.4 billion barrels ( $18.0 \times 10^9 \text{ m}^3$ ). The initial volume of crude bitumen in-place for in situ areas for the designated deposits outside of the SMA as of December 31, 2002, is 1515 billion barrels ( $240.9 \times 10^9 \text{ m}^3$ ). As of December 31, 2003, the estimated in place and established mineable and in situ crude bitumen reserves are summarized in the table below (Alberta Energy and Utilities Board, 2004)

**Table 5.1. Canada's Bitumen Resources**

(Billion barrels)	Ultimate Volume In Place	Initial Volume In Place	Initial Established Reserves	Remaining Established Reserves
<b>Mineable</b>				
Athabasca	138.6	113.4	35.2	<b>32.3</b>
<b>In Situ</b>				
Athabasca	n/a	1187	n/a	<b>n/a</b>
Cold Lake	n/a	201.3	n/a	<b>n/a</b>
Peace river	n/a	127	n/a	<b>n/a</b>
Total In Situ	2381	1515.3	143.6	<b>142.4</b>
<b>Total</b>	2520	1628.7	178.8	<b>174.7</b>

Source: AEUB (2004)

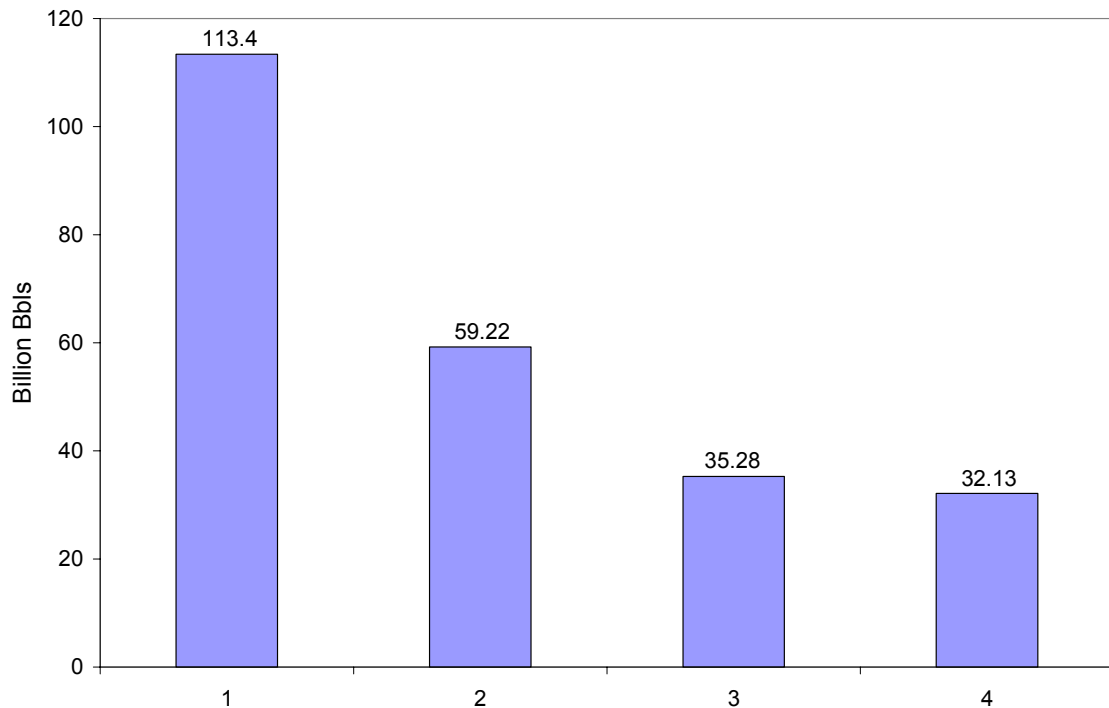


### 5.3 Surface-Mineable Crude Bitumen Reserves

The surface mineable area (SMA) is an EUB-defined area of 37 townships north of Fort McMurray covering that part of the Athabasca Wabiskaw-McMurray deposit where the total overburden generally does not exceed 75 m. The initial mineable volume in place of crude bitumen is estimated as of December 31, 2003, to be 59.2 billion barrels ( $9.4 \times 10^9 \text{ m}^3$ ). Reduction factors were applied to this initial mineable resource volume to determine the established mineable reserve volume. These factors account for ore sterilization due to environmental protection corridors along major rivers (10 per cent), small isolated ore bodies (10 per cent), location of surface facilities (plant sites, tailings ponds, waste dumps) (10 per cent), and mining/extraction losses (18 per cent). The resulting initial established mineable reserve of crude bitumen is estimated to be 35.2 billion barrels ( $5.59 \times 10^9 \text{ m}^3$ ). The remaining established mineable crude bitumen reserve as of December 31, 2003, is 32.3 billion barrels ( $5.13 \times 10^9 \text{ m}^3$ ).

About a quarter of the initial established mineable reserve is under active development. Currently, Suncor, Syncrude, and Albian Sands are the only producers in the SMA, and the cumulative bitumen production from these projects is 2.9 billion barrels ( $461 \times 10^6 \text{ m}^3$ ) as of December 31, 2003. ( Alberta Energy and Utilities Board, 2004)

**Figure 5.1. Mineable Crude Bitumen Resource and Reserve Categories, Billion Barrels of Bitumen**



1. **Initial volume in place.** Gross resource volume of crude bitumen established to exist within the surface mineable area.
2. **Initial mineable volume in place.** Resource volume of crude bitumen calculated using minimum saturation and thickness criteria and based upon the application of economic strip-ratio criteria within the surface mineable area.
3. **Initial established mineable reserve.** Recoverable volume of crude bitumen established within category 2 but excluding mining, extraction, and isolation ore losses and areas unavailable because of placement of mine surface facilities and environmental buffer zones.
4. **Remaining established mineable reserve.** Category 3 minus cumulative production.

Source: (AEUB, 2004)

## 5.4 In Situ Crude Bitumen Reserves

The AEUB has determined an in situ initial established reserve for those areas considered amenable to in situ recovery methods. Recovery factors of 20 per cent for thermal development and 5 per cent for primary development were applied to the areas within the cutoffs. The recovery factor for thermal development is lower than some of the active project recovery factors to account for the uncertainty in the recovery processes and the uncertainty of development in the poorer quality resource areas.

The AEUB's 2003 estimate of initial established reserves for in situ areas increased slightly to 143.6 billion barrels ( $22.80 \times 10^9 \text{ m}^3$ ) from 143.3 billion barrels ( $22.74 \times 10^9 \text{ m}^3$ ) in 2002. EUB's 2003 estimate of the established in situ crude bitumen reserves under active development is 2.78 billion barrels ( $441 \times 10^9 \text{ m}^3$ ). The recovery factors of 40, 50, and 25 per cent for active thermal commercial projects in the Peace River, Athabasca, and Cold Lake areas respectively reflect the application of various steaming strategies and project designs. (Alberta Energy and Utilities Board, 2004)

**Table 5.2. In Situ Crude Bitumen Recovery factors In Areas Under Active Development**

<b>Development</b>	<b>Recovery Factor</b>
<b>Peace River Oil Sands Area</b>	
Thermal commercial projects	40
Primary recovery schemes	5
<b>Athabasca Oil Sands Area</b>	
Thermal commercial projects	50
Primary recovery schemes	5
Enhanced recovery schemes	5
<b>Cold Lake Oil Sands Area</b>	
Thermal commercial projects	25
Primary production within projects	5
Primary recovery schemes	5
Lindbergh primary production	5

Source AEUB (2004)

## 6 Upgrading/Refining

Bitumen is deficient in hydrogen, compared with typical crude oils, which contain approximately 14 percent hydrogen. To make it an acceptable feedstock for conventional refineries, it must be upgraded into higher quality synthetic crude oil (SCO), through the addition of hydrogen or the rejection of carbon, or both. (National Energy Board, 2000) Upgrading bitumen utilizes natural gas as a source of heat and steam for processing, and also as a source of hydrogen for hydroprocessing. Depending on the upgrading employed and depending on the degree of quality improvement of the final product, varying amounts of hydrogen are required. (National Energy Board, 2004) Synthetic crude has some distinct advantages compared to conventional crude. It has essentially no residue remains after refining, and it has low sulphur and nitrogen levels. However, thermally based primary upgrading (coking) results in synthetic crude oils that cannot produce the required quality of certain products. In order to get diesel fuel, jet fuel and asphalt, the refiner must blend the synthetic with other crude. (Alberta Chamber of Resources, 2004)

### 6.1 Upgrading Today

Essentially all of the current bitumen production by mining is upgraded. Of the in situ production, the majority is shipped with light diluents to refineries that are suitably equipped for handling the characteristics of bitumen. (Alberta Chamber of Resources, 2004)

Upgrading is typically viewed in two steps. First is the primary upgrading. Primary upgrading is done either by coking, or the ebullated bed process. The primary step leaves significant sulphur and nitrogen compounds in the lighter products, and a further secondary treating is required. Primary upgrading is largely based on coking, a carbon removal process, whereby the bitumen is cracked by using heat and special catalytic processes, thus forming lighter oils and coke, a solid carbon by product. Cokers typically remove approximately 15% of the original volume as coke, which may be disposed in the mines or in some cases burned as fuel.

The ebullated bed process is a residue conversion process that employs hydrogen addition, and solid catalyst in a semi-fluidized reactor. The technical advantages for the ebullated bed hydroprocessing include more modest operating temperatures. Further, although the process also cracks the bitumen into lighter oils, it yields a product with a volume slightly higher than the original volume since hydrogen is added. Compared with coking the result is a less aromatic product. The process also incorporates significant secondary upgrading, such as sulphur and nitrogen reduction.

All upgrader operators use a variety of licensed hydroprocessing for the secondary upgrading step. Secondary upgrading is normally split between two or three separate streams to accommodate special needs for different primary grader products, especially the naphtha. But secondary upgrading, as a minimum, removes sulphur and nitrogen to levels normally handled in receiving downstream refineries. This situation could change with regulations requiring ultra-low sulphur fuels, thus resulting in an even more extensive upgrading process.

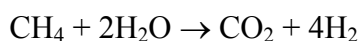
The key issue for current SCO is the poor distillate and gas oil quality. These problems are to some degree worsened by coking, where cracking in the absence of hydrogen promotes the formation of unusually high aromatic hydrocarbon fluids. For

jet and diesel fuels, this is not easily corrected in the conventional refinery processes. This factor alone can limit the percentage of SCO in the typical refinery diet, particularly in the U.S. (Alberta Chamber of Resources, 2004)

## 6.2 Hydrogen Consumption, Upgrading to SCO

Upgrader operators typically produce hydrogen via steam methane reforming in their plants, but some rely on outside suppliers of hydrogen. (National Energy Board, 2004) The stoichiometry of the process demands only 0.25 volume units of natural gas to produce one unit volume of hydrogen. However, imperfect reactions and added energy needs for the process presently raise the ratio to about 0.4 volume units of natural gas per volume unit of hydrogen. Hydrogen consumption is typically 1000 standard cubic feet per barrel of SCO today, but will rise considerably to as much as 1800-plus standard cubic feet per barrel for the kind of high quality SCO envisaged for projects such as the one planned by Nexen/OPTI. (Alberta Chamber of Resources, 2004)

*Steam methane reforming*



## 6.3 Future Upgrading

Delayed and Fluid Coking technology will continue to develop, as for the ebullated beds process. Currently developed alternative processes for moderate primary upgrading include visbreaking and deasphalting especially where residue use for hydrogen and energy is important. Visbreaking is a process designed to reduce residue viscosity by thermal means, but without appreciable coke formation. Deasphalting is a family of processes that use light solvents to selectively reject highly aromatic or asphaltenic fractions. The Nexen/OPTI project is potentially the first upgrader to move away from coking and ebullated bed processes with its proprietary OrCrude process. (Alberta Chamber of Resources, 2004) The project includes the use of partially upgraded bitumen, followed by conventional hydrocracking and gasification. Instead of gas, the process uses asphaltene residue to produce most of the fuel gas and hydrogen required for the operation, cogeneration facility, an upgrading components. Nexen/OPTI claims that their method forms a continuous loop that completely processes the bitumen leaving only source synthetic crude oil and liquid asphaltenes, and does not generate solid coke by-products that require disposal (Moritis, 2004)

Future upgraders may in general be designed to use a portion of the production for hydrogen and other energy needs. Even projects in advanced stages of development, such as the Syncrude and Suncor expansions, may need to reevaluate their dependence on natural gas for hydrogen as long-term policy. As mentioned above, gasification is an existing technology, that might be used to consume the least valuable residue from the bitumen barrel for fuel, power and hydrogen. A SAGD bitumen recovery and upgrader complex may require as much as 20-30% of the recovered bitumen to meet these needs, with 10% for hydrogen alone. The integration of such a process may, however, have a beneficial impact on upgrading process selection, capital and operating costs, because a disproportionate cost of upgrading today is devoted to converting these least valuable residues to feedstocks suitable for

upgrading to liquid product. (Alberta Chamber of Resources, 2004) However it is likely to have a negative environmental impact which will be covered further on.

A more moderate primary conversion is the introduction of hydrocracking as a secondary process to higher value synthetic crudes. Hydrocracking is a well established process, and its continued development is to be expected due to market demand for high quality SCO. However, greater capital cost and greater hydrogen consumption are known deterrents.

Some bitumen recovery processes that are being piloted, or recently introduced, both in mining and in-situ, have the potential to improve produced bitumen quality before further upgrading. Future recovery processes such as the THAI-method may also involve underground partial combustion or gasification, which will reduce the need of some current upgrading steps. Already, in already known developments, light hydrocarbon solvents are used in processes that are either designed to reduce steam use or provide a cleaner bitumen in terms of residual water and solids content . A side benefit, which is expected, and in some cases proven , is a reduction in asphaltenes content. Finally, advanced nano-engineered hydroprocessing catalysts will probably have a great potential for significant future improvements to SCO quality. (Alberta Chamber of Resources, 2004)

## 7 Oil Production Investment Aspects

The World Energy Outlook report projects that general oil-investment needs through to 2030 will be large and will rise progressively. However, the report concludes that capital will be available to meet them. In other words, investment is more likely to be limited through lack of profitable business opportunities rather than through any absolute shortage of capital. Oil prices will play a key role in attracting investment to the oil production sector. In recent years, upstream global oil and gas investment has tended to fluctuate with changes in oil prices. (World Energy Outlook, 2004)

Oil sands mining projects demand enormous capital investments. For example, Shell has invested more than C\$6 billion in the Athabasca oil sands project. (Mortished, 2005) Canadian Natural Resources (Ltd) says that the cost of the first phase of the Horizon project will be C\$6.6 billion. (Staffer, 2004) However, in situ projects demand less investment capital per project than mining projects.

### 7.1 Oil Sands Production Investments

During the period 2000 to 2003, the WTI price averaged about US\$29 per barrel, and provided oil sands producers with favourable netbacks. As result, a strong sense of optimism is present in the oil sands industry. As evidence of this, some 44 new bitumen recovery projects or expansion projects have been announced, 18 mining and 26 in situ, to be implemented in the 2004 to 2012 time frame. Capital expenditure of about \$60 billion will be required to construct these projects. Not all of these projects are likely to proceed, as the construction spending levels appear to be beyond industry capacity. (National Energy Board, 2004)

#### **Already Made and Planned Investments in Oil Sands Production**

**1996 – 2002** \$24 billion (Can.) investment in oil sands

**2002 – 2006** \$7 billion (Can) under construction.

**2007 -** \$25 (Can) billion, new oil sands projects announced and under evaluation.

Source: Moritis (2004)

In oil sands mining, the minimum efficient scale of operation is much higher than for in situ development. Because of this difference, an in situ operation lends itself more easily to a phased approach of adding production. Many variable factors influence the operational performance of an in-situ project and there exists an inherent level of risk that cannot be avoided. Through a phased approach, a company has the significant advantage of being able to reduce business risk by learning from operations and making more informed capital investment decisions as a project progresses. For this reason most proposed in situ projects include plans for many phases of development contingent upon project performance. (National Energy Board, 2004)

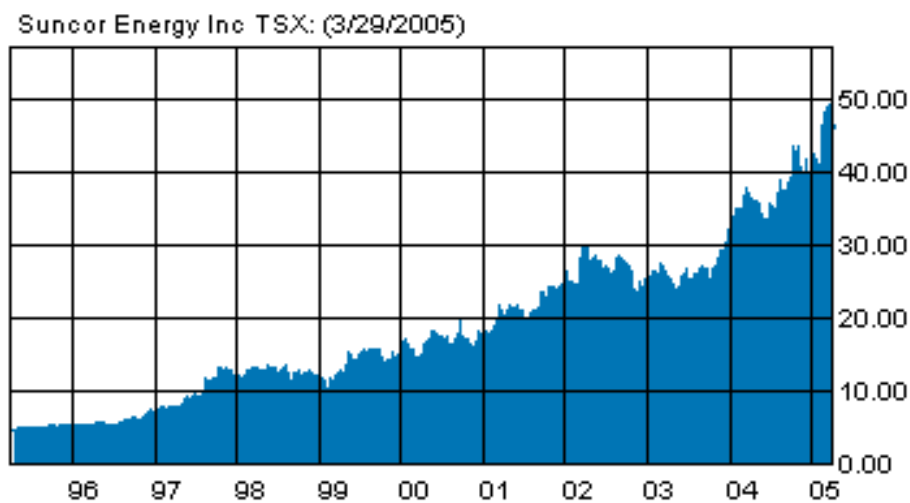
## 7.2 Oil Sands production - A Profitable Business Area

Forward oil prices several years out have the last years risen sharply, suggesting a profound shift in the industry's perception of the medium-term oil supply/demand balance.

The company Canadian Natural Resources Ltd is projecting that it will achieve a 15-per-cent return on capital for the Horizon project, if it meets cost targets and if oil sells for at least \$28 (U.S.) a barrel. This is a projection that indicates that Canadian Natural Resources Ltd believes oil prices will remain high for years to come. (Brethour, 2005) Shell Canada, as well, indicates that the oil sands production in 2004 will average more than \$ 22/bbl (Can.), although its target is a Can \$ 12-14/bbl unit costs at recent natural gas prices. (Moritis, 2004)

For the last years oil sands investments have considerably outperformed in the stock market. The figure below shows the value for the Suncor share, the last ten years. High growth of share prices has also been the case for the shares of Canadian Oil Sands Trust (largest owner of Syncrude), and Western Oil Sands (20 percent shareholder of the Athabasca Oil Sands Project)

**Fig 7.1. Stock Chart for the Share of Suncor**



Source: Suncor (2005)



## 8 Environmental impact

As the Canadian oil sands production is set to enter a period of strong growth and expansion, a number of environmental issues and challenges are facing the industry. Most attention has been given to accelerating greenhouse gas (GHG) emissions but other environmental issues such as surface disturbance, and water conservation also represent serious problems for the operators of oil sand projects.

### 8.1 Surface Disturbance

The surface disturbance from mining operations and processing of bitumen includes land clearing, disturbance of surface strata and soil. These activities result in deforestation of forests and woodlands, and have a negative impact on fish and wildlife populations.

Research is made on the development of methods that will reduce the land required for out-of-pit overburden dumps, open pit operations and tailings management areas. Current industry practice is to leave large areas of land to remain in a disturbed state over many years during which natural processes work to re-establish the landscape. Oil sands operators are obliged, through licensing, to preserve an environment that has an ecological capability at least equal to its condition before oil sands operations. The in situ process is much less harmful in terms of surface damages, and results in limited negative environmental impact to forests, wildlife and fisheries. (National Energy Board, 2004)

### 8.2 Water

Mining as well as in situ bitumen operations consume large volumes of water. Water requirements for oil sands projects range from 2.5 units to 4.0 units of water for each unit of bitumen produced. The primary challenge for process water is that no large-scale water treatment facilities exist near the oil sands. As a result, process water is recycled. Groundwater aquifers are used as the source of process water and a normal operating procedure is the disposal of process-affected water to deep aquifers. The decision to use groundwater or surface water is dependent on whether a source of surface water is available or if it is necessary to drill a well to access subsurface aquifers. Developers have also been devising methods of using brackish water from underground aquifers. (National Energy Board, 2004)

In 2003, Alberta's Environment Minister, initiated a committee to find ways to reduce the oil and gas industry's consumption of fresh water. As part of the province's long-term water strategy, limits may be placed on the volume of fresh water that companies are allowed to use. Alberta Environment Department does not require a license for withdrawal of saline groundwater. There are also industrial trends to use brackish water in place of fresh water. (National Energy Board, 2004)

#### 8.2.1 In Situ Water Use

An in situ facility requires freshwater to generate steam, for various utility functions throughout the plant, separation of the bitumen from sand, hydrotransportation of bitumen slurry and upgrading of the bitumen into lighter forms of oil for transport. However, as water is used to extract the bitumen in the ground, the in situ process has

the negative effect of removing water permanently from the hydrologic cycle. Even though an average of 90 percent of the water is recycled in the SAGD process, the process still requires large volumes of water. The net permanent loss for SAGD and in situ operations is estimated at one barrel of water for every barrel of oil recovered.

There have been several initiatives to develop new technologies and integrated approaches to reduce water consumption. The development of a non-thermal in situ recovery method would reduce in-situ water consumption significantly. Another challenge facing in situ operations is the potential for contamination of groundwater. Design improvements, monitoring and surveillance systems may reduce the risk of damage to the aquifer and minimize the release of fluid to groundwater. (National Energy Board, 2004)

### **8.2.2 Mining**

For mining operations, leakage of pollutants, formation dewatering and diversion of water flow are the main concerns regarding water use. The removal of water from nearby aquifers can lower the overall water level in the area and may affect other aquifers and surface water bodies, including wetlands that are dependent on groundwater recharge.

The current method for the recovery of bitumen from the oil sands via surface mining results in the accumulation of large volumes of fluid wastes called fine tailings. They are stored in large ponds until they can be used to begin filling in the mined out pits. Fine tailings are a complex system of clays, minerals and organics. The prevention of seepage of pollutants from ponds, pits and landfills into freshwater aquifers is, despite technological advances, an ongoing environmental concern. Current production trends indicate that the volume of fine tailings ponds produced by Suncor and Syncrude alone, will exceed one billion cubic metres by the year 2020.

## **8.3 Greenhouse Gases**

Emissions of greenhouse gases are one of the most complicated future environmental issues for the oil sands industry. Oil sands operations emit large amounts of carbon dioxide (CO<sub>2</sub>) and some methane (CH<sub>4</sub>) gas and nitrous oxide (N<sub>2</sub>O). These are heat-trapping "greenhouse" gases that affect the global climate. Oil sands operations include a wide spectrum of other air emissions such as the ones listed below:

### **Oil Sands Industry Air Emissions**

Sulphur dioxide (SO<sub>2</sub>)

Nitrogen oxides (NO<sub>x</sub>)

Hydrogen sulphide (H<sub>2</sub>S)

Carbon monoxide (CO)

Volatile organic compounds (VOC<sub>s</sub>)

Ozone (O<sub>3</sub>)

Polycyclic aromatic hydrocarbons (PAH)

Particulate matter (PM)  
Reduced sulphur compounds (SC<sub>s</sub>)  
Other trace air contaminants.

Source: National Energy Board (2004)

Methane (CH<sub>4</sub>) and nitrous oxide (N<sub>2</sub>O). have a much greater potential global warming impact on a unit basis (factored by 23 and 310 respectively) relative to CO<sub>2</sub>, but are present in much smaller concentrations. The addition of the three factors is referred to as CO<sub>s</sub> "equivalent"; or CO<sub>2</sub>E. CO<sub>2</sub> typically accounts for 85-95% of the total effect. CH<sub>4</sub> is responsible for the majority of the remaining effect. (Alberta Chamber of Resources, 2004)

## 9 All Major Oil Sands Projects

As indicated, there are 44 major oil sands projects planned: 18 mining and 26 in situ. For the most part, the proponents of these projects are principally large Canadian companies or multinational companies with considerable experience in oil sands development. In many cases, the proposed projects are expansions of projects that are being successfully operated today. (National Energy Board, 2004)

Most of the current production comes from four large projects: from Syncrude, Suncor, Shell/Albian and Imperial's Cold Lake. These projects, except from Cold Lake, produce Synthetic crude oil (SCO). Canadian Bitumen blend supply has its origin mainly from Imperial Oil's Cold Lake thermal in situ operation. AED indicated that production from the three active bitumen-mining operations was about 560,000 b/d in 2003. (Moritis, 2004)

### 9.1 Athabasca Oil Sands Area Mining Projects

The Athabasca Oil Sands area contains the largest volume of crude bitumen, nearly 1300 billion barrels initial in place. All currently operating major oil sands mining projects are situated within the Athabasca Oil sands area.

#### 9.1.1 Suncor Millenium and Voyageur

Suncor has operated a surface mining, extraction and upgrading project at Ruth Lake since 1967. The Millennium expansion project was completed between 1999 and 2002 at a cost of \$3.4 billion, increased capacity to 225 mb/d. This expansion included a second processing plant, a second upgrader train, and expansion of the mining area. The operation has the ability to "tailor" its products to meet consumer needs, and thus produces a variety of refinery feedstocks, diesel fuel and by-products. (National Energy Board, 2004.)

Suncor Energy Inc, averaged 217,000 b/d in 2003, up from about 206,000 b/d in 2002., from its mining project. The company expects to produce 225,000-230,000 b/d in 2004. Suncor's cumulative production in 2004 reached 1 billion bbl. In 2001, Suncor outlined a growth strategy, dubbed "Voyageur", that set out a multi-phased plan to increase its oil sands production capacity to the 500 to 550 mb/d range by 2010 to 2012. In early 2003, Suncor announced plans for the first phase of Voyageur, designed to increase upgrader capacity to 330 mb/d by 2007. This includes the installation of an additional vacuum unit to increase capacity to 260 mb/d by 2005, and then to 330 mb/d by 2007. This upgrader expansion is estimated to cost \$1.5 billion, and is designed to accommodate bitumen delivered from Suncor's Firebag SAGD operations. Suncor currently has finished 45% of the construction of the Millennium Vacuum unit, which it says is on schedule and on budget. Suncor plans to spend an additional \$1.5 billion to expand the Firebag project in four phases, each producing about 35 mb/d of bitumen. The first phase of Firebag is expected to be fully operational in 2005.

The third segment of the Voyageur plan is to build a third upgrader in the 2010 to 2012 time frame, bringing overall production capacity to 500 to 550 mb/d. Suncor is considering farther expansion of Firebag and/or mining facilities to supply the third upgrader. (National Energy Board, 2004.)

*Total Reserves (Billion Bbls Of Bitumen)*

Initial mineable volume in place: 5.53

Initial established mineable reserve: 3.8

Source: AEUB (2004)

### **9.1.2 Syncrude – Syncrude 21**

The Syncrude Project is a joint venture operated by Syncrude Canada Ltd. and owned by Canadian Oil Sands Limited Partnership, Canadian Oil Sands Limited, ConocoPhillips Oil Sands Partnership II, Imperial Oil Resources, Mocal Energy Limited, Murphy Oil Company Ltd., Nexen Inc. and Petro-Canada Oil and Gas. Syncrude Canada Ltd. Production averaged about 212,000 b/d in 2003, down from about 230,000 b/d in 2002 as a result of an unscheduled coker turnaround and extended maintenance. Production in December 2003 was 264,000 b/d. The current production capacity is approximately 250,000 barrels per day. (Oil sands Discovery center, 2004)

In its "Syncrude 21" strategy, Syncrude plans to increase capacity through the completion of five stages of expansion between 1996 and 2015. Stages 1 and 2 were completed in 2001, at a cost of \$ 1 billion, and increased Syncrude's production capacity to 246 mb/d of high quality SCO, Syncrude Sweet Blend (SSB). These first two stages featured the development of two new mining areas, the North Mine and Aurora. Large-scale truck and shovel mining, and new technologies, such as hydro-transport and low-temperature extraction, were also introduced. Two processing trains were introduced at North Mine. The Aurora expansion included a processing train and further de-bottlenecking of the Mildred Lake upgrader. The Aurora Mine is located 35 km Northeast of the main Syncrude plant, and extraction takes place at the mine site with bitumen froth moved via hydro-transport to the base plant for upgrading.

Stage three (2001 – 2006) includes the start up of Aurora Train 2 and the first of two stages of expansion of Syncrude's Mildred Lake (base plant) upgrader. Stage three is scheduled for completion by 2006, and will add 100 mb/d to Syncrude's at cost of \$7.8 billion. A second mining and extraction train will be added at Aurora, and an expansion of the Mildred Lake upgrader will be implemented, featuring an additional upgrading train. The mining train was commissioned in late 2003, while the upgrader expansion (UE-1) is expected to be completed in 2006, allowing Syncrude to farther improve the quality of its SCO.

Stage four (2006 -2010) includes the startup of a third mining train at Aurora as well as another stage of expansion of the Mildred Lake upgrader (UE-2). This expansion will increase total production to about 400 mb/d by 2011. This stage will add further improvements to crude oil quality, and also features full implementation of energy efficiency and environmental mitigation technologies.

Stage five(2011 – 2015) includes the startup of a fourth production train at Aurora and further expansion of the Mildred Lake Upgrader (UE-3). This expansion phase is scheduled to take place between 2010 and 2015, and will increase total production to about 530 mb/d. (National Energy Board, 2004)

Canadian Oil Sands claims that total proved reserves alone will allow them to produce, with virtually no decline, for about 35 years. (Coutu, 2004)

<i>Reserves (billion Bbls Of Bitumen)</i>
Initial mineable volume in place: 9
Initial established mineable reserves: 6.04
Source: AEUB, (2004)

### **9.1.3 Athabasca Oil Sands Project**

AOSP is a joint venture between Shell Canada Ltd., 60%, Chevron Canada, 20%, and Western Oil Sands LP, 20%. Albian Sands Energy inc. operates the newest producing mining project, the Muskeg River Mine, situated about 75 km north of Fort McMurray. The Muskeg River Mine and the Scotford Upgrader together comprise the Athabasca Oil Sands Project. The Athabasca Oil Sands Project is currently one of the largest construction projects on the planet, and it is the first new fully integrated oil sands project in 25 years. (Albian, 2004)

Albian Sands Energy Inc.'s Muskeg River averaged 130,000 b/d in the last quarter of 2003, up from 115,000 in the previous quarter. Production operations began Dec. 29, 2002, from the 155,000 b/d design capacity project. Production in 2004 is expected to reach 155 000 bpd of bitumen. (Albian, 2004)

#### *Investment costs*

Capital costs for the mine and upgrader were \$5.7 billion. Shell also invested approximately \$400 million to modify its existing Scotford refinery to utilize the new SCO produced by the Scotford upgrader. The project owners have proposed a debottlenecking and expansion project that would increase capacity by 70 mb/d by 2008, at a capital cost of \$ 750 million. (National Energy Board, 2004.)

#### *Production costs*

Shell's long-term goal is to be the lowest cost producer of synthetic crude oil as measured by unit cash operating costs. The long-term target range for unit cash operating cost is \$10-12 per barrel, based on natural gas prices at \$4.00 per thousand cubic feet in Alberta. At current natural gas price levels, this target range would equate to \$12-14 per barrel. (Moritis, 2004)

### *Assumptions about future production*

Shell Canada Limited today outlined growth plans for the Athabasca Oil Sands Project (AOSP) that would increase bitumen production to between 270,000 and 290,000 barrels per day by 2010.

Over the first year focus was on ramping-up bitumen production to the design of 155,000 barrels per day. Over the next three years, a number of debottlenecking projects are proposed at the Muskeg River Mine and Scotford Upgrader to increase the bitumen production rate to between 180,000 and 200,000 barrels per day.

Over the 2006 to 2010 period, planned expansions of the Muskeg River Mine and Scotford Upgrader are expected to further increase bitumen throughputs by approximately 90,000 barrels per day, taking total expected AOSP production to between 270,000 and 290,000 barrels per day. (Shell, 2004) Further expansion is planned through the development of the Jackpine mine, with Phase 1 calling for a new stand-alone mining and extraction facility with a capacity of approximately 200 mb/d of bitumen production. Jackpine Phase 2 could be mined to extend the life of the overall development and allow for future production growth of approximately 100 mb/d. If all these projects are built, it would result in combined production from Muskeg River and Jackpine of 525 mb/d (National Energy Board, 2004.) Albian claims the Muskeg River Mine will recover 1.65 billion barrels of bitumen over 30 years. (Albian, 2004)

Shell says that the project contains 1.6 billion bbl of bitumen resources, but all its leases in the area contain about 9 billion bbl and they will support additional projects. The combined resource of the Muskeg River Mine and Lease 13 contains more than five billion barrels of mineable bitumen. This is about equal to twice the amount of conventional oil reserves remaining in Alberta. The oil sands deposit is close to the surface and contains a high concentration of oil, making it suited to mining. (Albian, 2004)

#### *Reserves (Billion Bbls Of Bitumen)*

Initial mineable volume in place: 3.62

Initial established mineable reserves: 1.12

Source: AEUB(2004)

### **9.1.4 Fort Hills**

The Fort Hills project is owned by True North Energy L.P. with a 78 percent share and UTS Energy holding the remaining 22 percent. The project is designed in two phases to produce 95,000 barrels of oil per day from the initial mine by 2005 and 190,000 barrels per day by 2008. The bitumen would be shipped as blended bitumen to markets in Canada or the U.S. Project plans included an 80 MW cogeneration unit. Total estimated costs are \$3.5 billion for the first phase.

Although the project received approval from the Alberta Government, TrueNorth, in early 2003, decided to indefinitely defer development of the project, citing escalating capital costs, lack of additional partners and the uncertainty about the economic impact of the Kyoto Agreement. The project now remains on hold while the project sponsors evaluate a range of potential development scenarios. (National Energy Board, 2004.) AED indicates that TrueNorth is investigating options to reduce the initial phase of the project to support a production of 50,000 b/d with an on site upgrader.

#### *Reserves*

The Fort Hills Project is located about 90 kilometers north of Fort McMurray. There are approximately 2.8 billion barrels of mineable bitumen on the leases. According to True North Energy L.P., the reserves could provide for about 40 years of operation. (True North, 2004)

### **9.1.5 Imperial Oil/ExxonMobil – Kearl Oil Sands**

Kearl Oil Sands, a potential joint oil sands mining project proposed by ExxonMobil Canada and Imperial Oil on their Athabasca oil sands leases, is located about 70 km north of Fort McMurray. The Kearl project is planned to consist of oil sands mining and possibly on-site bitumen upgrading, integrated with Imperial's Edmonton refinery or upgrading at the ExxonMobil refinery at Joliet, Illinois. The company indicates a phased approach to the development of the project as the most likely scenario, with an initial phase of 100 mb/d, potentially growing to 200 mb/d by 2012. (National Energy Board, 2004.) According to Imperial Oil, the project's first oil is expected 2009-2010. (Imperial oil, 2004)

#### *Investment costs*

Preliminary cost estimates suggest the development would involve capital spending of about C\$5 billion to C\$8 billion, with the final estimate being highly dependent on the final upgrading option selected. (Imperial Oil, 2004)

#### *Reserves*

When ExxonMobil proposed the Kearl project in 1997, estimated recoverable resources were 1.2 to 1.4 billion barrels. Imperial oil claims it is not unreasonable to expect the recoverable resources for the combined project to be two to three times this size. (Imperial Oil, 2004)

### **9.1.6 CNRL – Horizon**

Canadian Natural Resources Ltd.'s (CNRL) received regulatory approval for the Horizon project, an \$8 billion (Can.) mine and upgrader development with a 270,000 b/d design capacity. The Project is located 70 kilometers north of Fort McMurray, where Canadian Natural owns and operates leases covering 236,000 acres through lease arrangements with the Province of Alberta. CNRL expects construction to commence in 2005 with initial production in 2008 and full production in 2011. (Alberta Economic Development, 2004)



Horizon is slated to feature surface mining and bitumen processing, in situ operations, an upgrader and associated infrastructure. The proposed project includes an open pit, truck and shovel mine, four bitumen processing trains, three upgrading trains, associated utilities and infrastructure, water and tailing management plans, and an integrated development and reclamation plan. The execution strategy phases in production from the project over a five-year period. First oil is expected in the first half of 2008 at a production rate of 110 mb/d of light SCO. The second phase of production is expected in 2010, with an incremental 45 mb/d of SCO. The third and final phase of development is expected in 2012 bringing total production to 233 000 bpd of SCO. (National Energy Board, 2004.)

#### *Investment costs*

Canadian Natural's capital investment for the Horizon Project is estimated to be approximately \$9.7 billion with a contingent risked amount of \$10.5 billion. (Horizon, 2004)

#### *Reserves*

Drilling on the leases indicates an estimated 18 billion barrels of bitumen in place, with approximately 6 billion recoverable barrels under existing mining technologies. At full production, Horizon claims the project will supply about 232,000 barrels per day of sweet synthetic crude oil for a period of more than 40 years, without any declines. (Horizon, 2004)

## 9.2 Other Mining Projects

### 9.2.1 Synenco Energy

AED says that Synenco Energy Ltd.'s formal disclosure document for its Northern Lights project remains on file. The project includes an integrated mine, extraction plant and upgrading facility with a design capacity of 100 000 b/d and an estimated construction cost of \$4-5 billion (Can.) incurred over a five-year period. (Moritis, 2004) The company plans to use bitumen gasification technology to provide heat and hydrogen for processing and upgrading, thus reducing the need for natural gas. Large, high-quality coal deposits exist in the project area and are mineable at surface. In the future, coal may be used for coal gasification as a source of hydrogen for upgrading and for power generation. According to a company announcement, the project is scheduled to come on stream in 2008 - 2009. Later stages of development in 2009 and 2010 would increase production by 175 mb/d. Operating costs are expected to be among the lowest in the industry. (Synenco, 2004)

#### *Reserves*

Based on resource drilling and evaluation studies undertaken to date, Synenco says that its economically recoverable oil sands resources will deliver 1.3 billion barrels of bitumen feedstock to support production from the Northern Lights Project at 100,000 barrels per day for over 30 years. The potential of an additional 600 million barrels of bitumen ensures feedstock to extend the life of the Northern Lights Project as well as provide expansion opportunities. (Synenco, 2004)

## **9.2.2 Joslyn Creek Mining project**

The Joslyn Creek Mining project is being proposed by Deer Creek Energy Inc. This project was announced along with the announcement of the Joslyn Creek in situ project. The project would use truck and shovel mining and hot water extraction technologies, with no on-site upgrading. The decision on whether to proceed with the project will likely depend on the success of the Joslyn Creek in situ project. (National Energy Board, 2004.)

Deer Creek's mining strategy envisions commercial production of 50,000 barrels of bitumen per day by 2011 increasing by three 50,000 barrels per day phases, bringing total mining production to 200,000 barrels of bitumen per day over a nine-year development period and a production life in excess of 30 years. (Deer Creek Energy, 2004) By 2014 Deer Creek would have the financial capacity and economies of scale to develop its own upgrading facilities. (Deer Creek, 2005)

### *Reserves*

Deer Creek Energy estimates a recovery of more than two billion barrels of bitumen divided among two mine pits and adjacent areas. (Deer Creek, 2004)

## **9.3 Athabasca in Situ Projects**

### **9.3.1 Surmont (SAGD)**

The Surmont Project, a \$1 billion (Can.) SAGD in situ facility, located about 60 km southeast of Fort McMurray, is a joint venture between ConocoPhillips Canada (43.5%), TotalFinaElf(43.5%) and Devon Energy (13%), and will be operated by ConocoPhillips. The Surmont Project, received AEUB regulatory approval in May 2003. The project calls for four phases, with initial production to begin in 2006 and to increase to 100 mb/d by 2012. (Moritis, 2004)

Each phase will have its own central facility consisting of steam generators, water recycling facilities, emulsion treating and storage tanks for diluent and blended bitumen. Each phase of the development will be connected by pipeline to allow water, diluent and bitumen to be shipped between any of the locations. (National Energy Board, 2004.)

### *Assumptions about future production*

ConocoPhillips says their technique is expected to be an effective method of economically producing the resource. The reserves represent long-term sustainable production. The company estimates that, using SAGD technology, 5 billion to 10 billion barrels of oil may be extracted from the estimated 20 billion barrels of oil in place at Surmont. Production rate of completed project is estimated at 100,000 barrels of bitumen per day. However, ConocoPhillips stresses that its lease area contains a huge resource that could translate into a daily oil supply of 400,000 barrels for the next 30 to 60 years. (ConocoPhillips, 2004)

### *Reserves*

The oil sands formation is between 300 and 400 meters below the surface, with thickness varying from zero to 60 meters. In-place bitumen is estimated at 20 billion barrels, with potential recovery of 25 to 50 percent. (National Energy Board, 2004.)

Hence, potential recovery is estimated to reach 5 billion to 10 billion barrels of bitumen

### 9.3.2 EnCana – Christina Lake (SAGD)

EnCana's other SAGD project is at Christina Lake in northeast Alberta, which produces about 5,300 b/d from four well pairs and has a 10,000 b/d design capacity. At Christina Lake, EnCana also has a solvent-aided process under test at Christina Lake. The process adds small amounts of solvent to the injected steam to decrease bitumen viscosity. EnCana says its SAGD projects have the lowest steam-oil ratio in the industry of 2.5 bbl of water/1 bbl of oil produced and its long-term objective is to reduce this ratio further to about two times. (Moritis, 2004)

Three phases are planned, with total production scheduled to reach 69 000 b/d in 2009. (Oil sands Industry Update, 2004) Each of the three phases will have its own plant facility consisting of water treatment, steam generation, production separation, heat recovery, water de-oiling, water disposal and oil handling facilities. The project began production in the second quarter of 2002, and in 2003 the project produced 5 mb/d from three SAGD well pairs. (National Energy Board, 2004.)

#### *Reserves*

The lease covers 35 sections that contain an estimated 3 billion barrels of bitumen. (National Energy Board, 2004.)

### 9.3.3 Suncor – Firebag (SAGD)

The steam generators at Firebag, Suncor's SAGD project are designed to burn diesel or natural gas. The company is a net producer of both and will therefore choose to use the commodity with the lowest market value. (National Energy Board, 2004) Steaming in Suncor's Firebag SAGD project started in September 2003, with first oil delivered to the oil sands upgrader in January 2004. Firebag is adjacent to Suncor's bitumen mining operation. Suncor plans to complete enough wells to maintain a bitumen fill rate to its plant with a design capacity of 35,000 b/d. Suncor says Stage 1 of the project consist of two wells with 10 parallel pairs on each pad that drain 781 acres. The company is currently developing Stage 2 of the project that will include an additional two well pads with 10 wells on each, draining 831 acres. Suncor expects the wells to produce for about 10 years, and the plans call for drilling another 40 well pairs during the 30-year life of the plant. Firebag wells are completed at a depth of about 1,050 ft. (Moritis, 2004)

<i>Reserves (Billion Bbls)</i>	
Proved	0.348
Probable	1.482
Proved + Probable	1.83
Source: Suncor, (2004)	

### **9.3.4 Petro-Canada – MacKay River (SAGD)**

In September 2002, Petro-Canada started injecting steam in its 100% working interest MacKay River steam assisted gravity drainage (SAGD) project. The MacKay project is located about 60 km northwest of Fort McMurray, two km east of the Dover project. The company expects the \$290 million (Can.) project to recover bitumen from oil sands lying at about a 300-ft depth (Oil & Gas Journal, 2002)

Due to the success of the Dover project, Petro-Canada took the project directly to commercial development without having a pilot project. The project consists of well pads and facilities, a central processing plant, and a short lateral pipeline connecting to export facilities. MacKay River began producing in the fall of 2002 and produced an average 16,000 b/d in 2003. For 2004, PetroCanada expects to produce an average 25,000 b/d in the facility designed for handling 30,000 b/d. (Moritis, 2004) A 165 MW cogeneration plant is on site, built and operated by TransCanada Pipelines. (National Energy Board, 2004.)

#### *Reserves*

Petro-Canada working interest in MacKay River is encompassing a total of 76 sections of land located approximately 60 kilometers northwest of Fort McMurray, Alta. The current development area covers only 11.5 sections of this land. There are between 230 million and 300 million barrels of recoverable bitumen reserves on this portion of the lease, providing enough resources to produce up to 30,000 barrels of bitumen per day for at least 25 years. (Petro-Canada, 2004)

### **9.3.5 Petro-Canada – Meadow Creek (SAGD)**

The Meadow Creek project, located 45 km southwest of Anzac, Alberta, is to be operated by Petro-Canada. The project will utilise SAGD technology. An application was made to the AEUB in November 2001, with production planned to begin in 2006. The capacity of the project would be 80 mb/d of bitumen, with the product shipped to Petro-Canada's Strathcona refinery. A cogeneration facility is proposed. The capital cost for this project is estimated to be \$800 million. Petro-Canada recently announced it is retrenching its oil sands production plans, proposing a slimmed-down form of upgrader, and delaying its plans at Meadow Creek, until at least the end of the decade. It is possible that Petro-Canada will proceed with Meadow Creek project sooner, but at a reduced scale. (National Energy Board, 2004.) In the applications for regulatory approval in 2001, the project plans were to construct a facility at Meadow Creek that would produce 80 000 barrels per day of bitumen for 25 years. (Petro-Canada, 2004)

#### *Reserves*

n/a

### **9.3.6 Petro-Canada – Lewis (SAGD)**

Petro-Canada's proposed Lewis project is located 40 km northeast of Fort McMurray. SAGD would be used to produce the bitumen at a rate of 80 mb/d. A preliminary disclosure for the Lewis project has been released. The capital cost for the project is estimated to be \$800 million. There would be no on-site upgrading and the production startup date has yet to be determined. In view of Petro-Canada's announcement that it was delaying its plans to proceed with the Meadow Creek project; the Lewis project is

not likely to proceed before the end of this decade. (National Energy Board, 2004.) In a company presentation in 2004, the future production from the Lewis area was described as 40000 b/d and more. (Petro-Canada, 2004)

*Reserves*

n/a

### **9.3.7 Devon - Jackfish (SAGD)**

The proposed Jackfish project would be operated by Devon Canada Corporation. The project is located 15 km south of Fort McMurray. It would produce bitumen using SAGD technology at a rate of 35 mb/d, starting in 2007. Full production is expected in 2008. (Devon, 2004) The estimated capital cost for this project is \$400 to 450 million. (National Energy Board, 2004) In November 2003, Devon filed its application with the AEUB, and a regulatory approval is awaited in late 2004/early 2005 (Devon, 2004).

*Reserves*

Total recoverable reserves are estimated at over 300 million barrels. Devon expects a 25-year production life of the project. (Devon, 2004)

### **9.3.8 CNRL – Kirby (SAGD)**

The project will use SAGD to produce bitumen and is located 85 km northeast of Lac La Biche. The application, filed with the AEUB in April 2002, is still under review. Each of the two phases applied for would produce 15 mb/d of bitumen, with Phase 1 production starting in 2006 and Phase 2 in 2010. Four phases are ultimately planned, with the goal of maintaining production at 30 mb/d. The project does not include an upgrader. The capital cost is estimated to be \$500 million for the two phases. CNRL is currently soliciting proposals for purchase of the Kirby project. (National Energy Board, 2004)

*Reserves*

n/a.

### **9.3.9 Deer Creek – Joselyn Creek (SAGD)**

Deer Creek Energy Ltd. is the operator of the Joslyn Creek in situ project. This is a three phase project, the first commercial phase was approved in January 2003. It is located 65 km north of Fort McMurray and will use dual well-pair SAGD technology. SAGD Phase I is designed to produce up to 600 barrels of bitumen per day as a demonstration phase. The SAGD Phase I well pair and facility were completed in the first quarter of 2004 and steam injection began in April 2004 with first production in September 2004. SAGD Phase II is expected to expand the production level of the Joslyn Project by 10,000 barrels of bitumen per day. and has approval to produce up to 12,000 barrels of bitumen per day. (Deer Creek, 2004). The planned facilities include a small steam generator to test the feasibility of using bitumen instead of natural gas as a fuel source.

The application for Phase 2 was filed with the AEUB in July 2003 and is currently under regulatory review. Phase 2 of the project has an estimated capital cost of \$170 million. (National Energy Board, 2004)

SAGD Phase III is expected to expand the production level of the Joslyn Project by 30,000 barrels of bitumen per day. Deer Creek plans to advance SAGD Phase III in two 15,000 barrels of bitumen per day parts as SAGD Phase IIIA and SAGD Phase IIIB. (Deer Creek, 2004)

#### *Reserves*

Approximately 350 million barrels recoverable by in situ methods.

### **9.3.10 JACOS – Hangingstone (SAGD)**

The Hangingstone project is 75 percent owned by Japan Canada Oil Sands (JACOS) and 25 percent by Nexen Inc., and is located 50 km south of Fort McMurray. A three-stage demonstration project as designed to evaluate the viability of a commercial SAGD project. It began operations in 1999 and achieved production of 7 mb/d in 2003. Production is expected to reach 10 000 barrels of bitumen per day by 2004.

Commercial development plans have been released in a public disclosure. Plans call for construction of facilities to begin in 2005, with first production in 2007. Each of the two phases of the commercial project is designed to produce 25 mb/d, with the second phase scheduled for start-up in 2010, bringing the total expected production for the Hangingstone project to 60 mb/d. (National Energy Board, 2004)

#### *Reserves*

The entire Athabasca Oil Sands Deposit covers an area of approximately 4 million ha or 10 million acres. The PCEJ group of which JACOS is a member, hold the bitumen rights to 137.5 thousand ha (340,000 acres) containing an estimated 30 billion bbls of bitumen in place. In addition, JACOS holds a 100% interest in a further 73.5 thousand ha (181,000 acres) containing an estimated 20 billion barrels of bitumen in place. (JACOS, 2004) A rough estimation of bitumen reserves in the Hangingstone area, based on current information, is 500 million barrels. Once JACOS completes its detailed reservoir mapping study, a more accurate estimate of the bitumen in-place will be known. Based on current information, the project will operate in full production for over 20 years. (JACOS, 2004)

### **9.3.11 Nexen/OPTI Long Lake**

The Long Lake project is a 50/50 joint venture between Nexen and OPTI Canada, and is located 40 km southeast of Fort McMurray. The commercial portion of the Long Lake project was approved in August 2003. Construction is expected to commence in 2004, with production starting 2006, and an upgrader expected in 2007. (National Energy Board, 2004) The OPTI Long Lake project will be the first project to combine SAGD with a field upgrading facility. (Moritis, 2004) The process uses gasification of bitumen to provide fuel gas and hydrogen for the upgrader. This process will nearly eliminate the need to purchase natural gas. The capital cost for the commercial project is estimated at \$3 billion. OPTI plans to add an additional 70 mb/d of bitumen upgrading capacity to process third party bitumen on a fee-for-service basis. (National Energy Board, 2004)

The companies plan to commence Phase 1 SAGD production in 2006 with an upgrader starting in 2007 designed to produce 60,000 b/d of 39° gravity synthetic crude from a 72,000 b/d of bitumen inlet stream. The plans for the project include a second phase that will double production by 2010. (Moritis, 2004) OPTI/Nexen argues that a main advantage of their upgrading technology is that the process

eliminates the need of purchasing natural gas, a volatile cost component of SAGD operations. The companies estimate that this gives the project a \$5-10/bbl (Can.) cost advantage over other SAGD operations. Instead of gas, the process uses asphaltene residue to produce most of the fuel gas and hydrogen required for the operation, cogeneration facility and upgrading components. The companies explain that the OrCrude process forms a continuous loop that completely processes the bitumen, leaving only source synthetic crude oil and liquid asphaltenes, and does not generate solid coke by-products that require disposal. (Moritis, 2004)

#### *Reserves*

Long Lake's lease holdings, which are comprised of Lease 27 and other recently acquired Crown leases, span more than 21,000 hectares (85 sections). This area has been independently estimated to contain over 4 billion barrels of bitumen in place. The Phase 1 commercial area will develop 6,700 hectares (26 sections). Over this area, SAGD recoverable bitumen reserves and resources are estimated at 1.9 billion barrels. The footprint of the commercial site is about 730 hectares (2.9 sections). (Long Lake Project, 2004)

### **9.3.12 Orion Oil – Whitesands**

Orion Oil Canada Ltd. (a 100 percent owned subsidiary of Petrobank Energy and Resources Ltd.) is the operator of the proposed Whitesands pilot project. The project is located 120 km south of Fort McMurray. The pilot project will test Orion's proprietary Toe-to-Heel Air Injection (THAI) technology. The application for this project was filed in October 2003 and, if approved, will begin production in late 2004. The production rate would be 2 mb/d for the five-year life of the project. THAI employs in situ combustion and is expected to use much less water and natural gas than the SAGD process. (National Energy Board, 2004)

### **9.3.13 Dover VAPEX Project (DOVAP)**

Besides thermal projects, Devon Canada operates the Dover VAPEX pilot project. The process has a pair of horizontal lateral similar to SAGD but uses solvents instead of steam. Devon Canada Corporation is leading a consortium, with participation of the provincial and federal governments, which is conducting field trials to develop and test vapour extraction (VAPEX™) recovery technology. The pilot is located at the Dover Underground Test Facility site in the Athabasca oil sands area near Fort McMurray. This research project will consist of two horizontal well pairs and some associated monitoring wells. One well pair will test a cold start-up process and the other well pair will potentially test a hot start-up steam stimulation of the VAPEX™ process. The facilities and operations are integrated with the existing Dover infrastructure to reduce costs. Operations began in 2003 and are expected to continue to 2008. (National Energy Board, 2004)

## **9.4 Cold Lake In Situ Projects**

### **9.4.1 Imperial – Cold Lake (CSS)**

By far the largest cyclic steam project is Imperial Oil Ltd.'s Cold Lake project that in 2003 produced an average 129,000 b/d up from 112,000 b/d in 2002. Imperial currently operates Phases 1 through 13 of the facility. In 2003, Imperial's Cold Lake

production accounted for almost half the bitumen produced by in situ methods in Alberta.

The company has filed an application to construct and operate two additional phases to the Cold Lake Project, the Nabiye and Mahihkan North projects (Phases 14-16), which it expects will add 30,000 b/d by 2007. (Moritis, 2004) Production from the Makheses project (Phases 11 to 13) started in June 2003 and is expected to reach 150 mb/d in 2004. (Imperial, 2004) Thus, total production may reach about 180 mb/ by 2007-2008. (National Energy Board, 2004.) Imperial states that production from the area can result in large variations. (Moritis, 2004)

#### *Investment costs*

Imperial's total investment to date in the Cold Lake area is approximately \$1.7 billion. Construction of the Makheses plant will add about \$650 million of capital expenditures over the next two years. (Imperial, 2004) Phase 14 – 16 and further extensions may require another one billion Can \$.

#### *Reserves*

Total proved reserves at Cold Lake are approximately 850 million barrels. (Imperial, 2004)

### **9.4.2 EnCana – Foster Creek (SAGD)**

EnCana shifted oil sands strategy in 2003, by selling its non-operated interest in Syncrude's mining operation to focus on its in situ projects, the Foster Creek SAGD project. EnCana's Foster Creek project is located north of Wolf Lake in the middle of the Primrose Military Range. An experimental VAPEX™ scheme is also being tested at the Foster Creek site. (National Energy Board, 2004) Foster Creek is Canada's first large-scale commercial SAGD project and its first expansion was completed on time and on budget, increasing production by 50 percent to about 30,000 barrels per day in 2004. (EnCana, 2004)

The next expansion is currently being engineered. The expansion will consist of two consecutive stages - first, a 10 000 barrel per day facility optimization to be completed by the end of 2005, followed closely by a 20,000 barrel per day facility expansion to be completed by the end of 2006. Future expansions are under consideration that could raise production to more than 100,000 barrels per day later this decade. (EnCana, 2004)

#### *Reserves*

n/a

### **9.4.3 CNRL – Primrose and Wolf Lake CNRL (CSS & SAGD)**

CNRL purchased these properties from BP Canada Energy Company (BP) in 1999, and they have been operating commercially since the 1980s. CNRL's Primrose and Wolf Lake thermal heavy oil projects are located approximately 55 km north of Bonnyville in northeastern Alberta. Production in 2003 was about 40 000 b/d. CNRL uses both CSS and SAGD recovery techniques. CNRL has expansion plans that will enhance production in two phases to 60 mb/d by 2006. (National Energy Board, 2004) Currently CNRL has regulatory approval to increase the output to more than 120,000 b/d by 2008/2009. (Moritis, 2004)



CSS is used to target the Clearwater Formation's higher-clay content sands, while SAGD is used in the Grand Rapids zone, which has fewer clay impurities. The CSS process involves drilling horizontal wells rather than vertical or slant wells and injecting steam at a rate above the required reservoir parting pressure. The higher pressure will allow steam to penetrate farther into the oil sands allowing for fewer wells, reduced number of cycles and increased production. By drilling horizontally through the deposit and by substituting a single well for between five and ten conventional wells, CNRL will be able to minimize both cost and surface disturbance. For the Primrose East project CNRL is investigating the use of alternative fuels for steam generation and the possibility for an additional cogeneration plant for power and steam generation. (National Energy Board, 2004)

Reserves

n/a

#### **9.4.4 Husky – Tucker Lake (SAGD)**

Husky Energy Inc. is the operator of the proposed Tucker project in Cold Lake. It is located 30 km west of Cold Lake, and would use SAGD to extract the bitumen. The application for the project was filed in February 2003. The company expects production to start in 2006. (Moritis, 2004) The design capacity of the project is 30 mb/d. The estimated capital cost for the project is \$400 million. (National Energy Board, 2004)

*Resource base*

Husky's current estimate of recoverable reserves is 250 million barrels. The project is expected to produce 30,000 barrels of oil per day for 25 years. (Husky, 2004)

#### **9.4.5 Husky Sunrise Thermal project (SAGD)**

Husky also has a second planned SAGD project, the Sunrise Thermal project. Phase 1 is designed to produce 50,000 b/d, and the company says expansions will increase production to more than 200,000 b/d during the 40-year life of the project. (Moritis, 2004) Husky is planning to begin construction of the project in early 2006 with initial production in 2008. (Husky, 2004)

*Reserves*

The company estimates the recoverable resources to be approximately 2.25 billion barrels. (Husky, 2004)

#### **9.4.6 Black Rock – Orion (SAGD)**

The Orion project, operated by Black Rock Ventures Inc., is located 30 km northwest of Cold Lake. The application for this project was filed in July 2001. The Hilda Lake experimental project (precursor to the Orion project) has been in operation since 1997. The Orion project will use SAGD technology to produce bitumen at a rate of 10 mb/d for each of the two phases. The estimated capital cost for both phases is \$270 million (\$150 million for Phase 1 and \$120 million for Phase 2). (National Energy Board, 2004)

BlackRock has operated a steam assisted gravity drainage (SAGD) pilot project on its lease for over six years. The technology has proven successful and the company has applied for regulatory approval to expand the 500 barrels per day pilot into a 20,000

barrel per day commercial development. Black Rock states the project will have a 25-year project life. (Black Rock, 2004)

*Reserves*

Estimated 191 million barrels of recoverable oil. (Black Rock, 2004)

## 9.5 Peace River In Situ Projects

### 9.5.1 Shell – Peace River (CSS & SAGD)

The Peace River project is owned by Shell Canada Limited. Shell operated a pilot project at this site from 1979 to 1992, which was considered a technical success. More recently, Shell has used both CSS with multi-lateral wells and SAGD. Shell plans to expand this "radial-soak" technique. In 2002, the project achieved its design capacity of 13 mb/d. The technology that is driving the efficient recovery of bitumen will create the opportunity for future expansions at this large resource base. Shell Canada's Peace River leases currently produce about 9,000 b/d through cyclic thermal in situ recovery processes from wells, some of which have multilateral completions. The company has approved a plan to increase production to 16 mb/d by debottlenecking the plant and drilling additional wells. (National Energy Board, 2004)

*Reserves*

The company estimates that its Peace River lease contains about 7 billion bbl of bitumen in place. (Moritis, 2004)

## 10 Different Public Oil Sands Production Forecasts

Four public forecasts of Canadian oil sands production are presented in the figure below. The forecasts have their origin from the following publications:

*Canada's Oil Sands – Opportunities and Challenges to 2015* (NEB)

- The report was published by the National Energy Board of Canada in May 2004.

*Alberta's Reserves 2003 and Supply/Demand Outlook 2004-2013* (EUB)

- The report was published by the Alberta Energy and Utilities Board in May 2004.

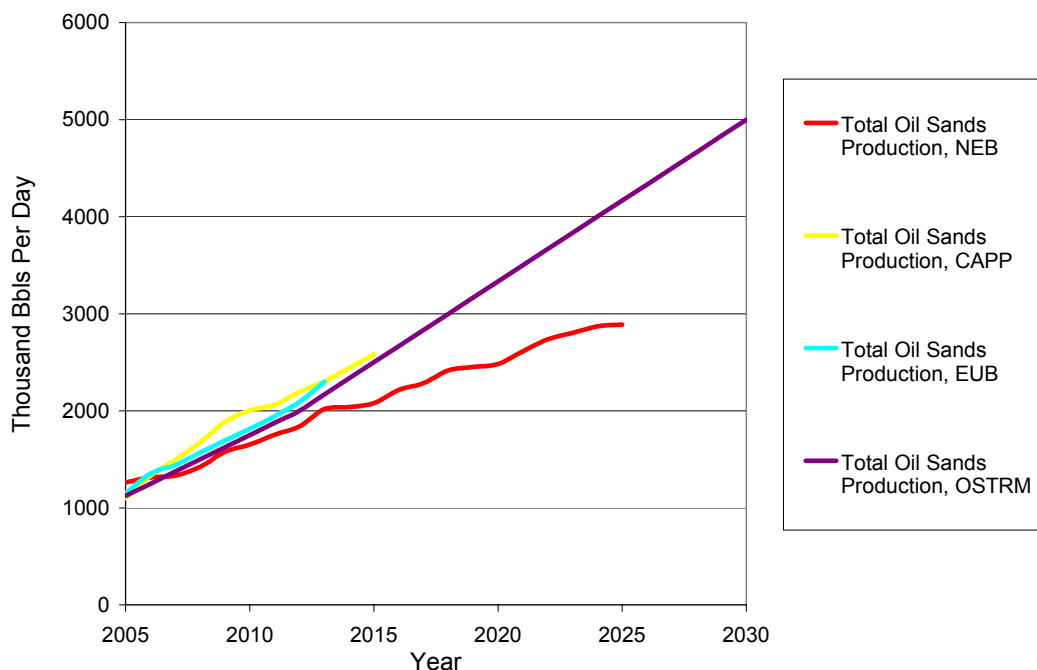
*Oil Sands Technology Roadmap – Unlocking the Potential* (OSTRM)

- The report was published by the Alberta Chamber of Resources in January 2004.

*Canadian Crude Oil Production and Supply Forecast, 2004 – 2015* (CAPP)

- The report was published by the Canadian Association of Petroleum Producers in July 2004

**Fig 10.1. Different Oil Sands Production Forecasts**



The four public forecasts varies in length. The OSTRM forecast has the longest perspective, until 2030. The NEB forecast comes second with 2025. The CAPP ranges until 2015, while the EUB forecast ends by 2013

The four forecasts are relatively close in their views of future Canadian oil sands production. The National Energy Board of Canada has the most conservative forecast of them all while the forecast outlined in the Oil Sands Technology Roadmap represents the most optimistic long-term view.

The four forecasts presented here are used to illustrate the natural gas use dilemma, as well as the problems associated with CO<sub>2</sub>E emissions from the oil sands industry.

## 11 Energy Need

The recovery and upgrading of bitumen from the oil sands are energy intensive activities, consuming large amounts of natural gas, electricity, transportation fuels and hydrogen. (National Energy Board, 2004)

Several oil sands companies have instituted energy generations in the form of cogeneration systems; the simultaneous production of electricity and thermal energy from a single facility (usually gas turbines with heat recovery steam generators). The electricity is used to meet project energy needs, such as operating mine machinery and in-situ well pumps, with excess electricity being supplied to the provincial grid. Cogeneration is better suited for mining or upgrading. For in-situ production cogeneration to generate steam will result in a vast excess of power, and at present there are not sufficient transmission facilities to handle it. (Alberta Chamber of Resources, 2004)

### 11.1 Need of Natural Gas

A large part of the energy requirements for oil sands mining, extraction and upgrading operations, as well as for in situ operations, are met through on-site electricity generation using externally sourced natural gas as fuel. Natural gas-fired turbines generate electricity to operate equipment and facilities, and also provide heat that is used to generate steam and provide process heat for bitumen recovery, extraction and upgrading.

Natural gas also provides a source of hydrogen used in hydroprocessing and hydrocracking as part of the upgrading process. Oil sands operators have historically depended on natural gas as their main source of energy, and as the oil sands production has grown, so has the related demand for gas. This dependency was created due to historically low natural gas prices in Alberta, a situation that has been reversing rapidly the recent years. (National Energy Board, 2004) The consumption per barrel of natural gas for upgrading will rise even further in order to satisfy future demand of higher quality SCO. (Alberta Chamber of Resources, 2004) The current situation of natural gas dependence cannot be sustained in the long run.

#### 11.1.1 Integrated Mining and Upgrading

Integrated mining projects use natural gas to produce heat energy, electric power, and as a source of hydrogen for hydrotreating in the upgrading process. Mining requires energy for the operation of the equipment, such as electric power shovels used to remove overburden and recover oil sands from the mine face, and the operation of the hydrotransport pipelines and facilities that move the oil sands in a water-based slurry to the bitumen extraction sites. Current extraction processes use natural gas as a source of heat for the hot water extraction of the bitumen. (National Energy Board, 2004) As a rule of thumb, integrated mining and upgrading projects today use about 0.4 mcf of natural gas per barrel of oil produced. (National Energy Board, 2003)

#### 11.1.2 In situ Operations

In situ projects, as for mining projects, use natural gas to produce electric power. In addition, natural gas is required for thermal operations as a source of heat to produce

steam. As a rule of thumb, in situ extraction of bitumen use about 1 mcf/bbl. The requirement for purchased natural gas for CSS is comparable with that of SAGD at approximately 1.0 to 1.2 mcf per barrel of production (National Energy Board, 2004)

The Steam-Oil ratio (SOR) measures the volume of steam required to extract the bitumen. For CSS the SOR ranges from 3.0 to 6.0, while SAGD ranges from 2.0 to 3.0. Approximately 0.5 mcf of natural gas is required to produce one bbl of steam, hence a SOR of 2.0 requires approximately 1.0 mcf of fuel gas per barrel of bitumen.

For CSS operations in the Cold Lake area, some 15 percent of natural gas requirements are typically met through produced solution gas, whereas in a SAGD operation in the Athabasca area, these amounts are comparatively minimal. Therefore, although CSS is characterized by higher Steam-oil ratios than SAGD, the requirements for purchased gas are on par with those of SAGD operators. (National Energy Board, 2004)

## 11.2 Upgrading

Current natural gas demand for upgrader hydrogen amounts to approximately 400 standard cubic feet per barrel. Future hydrogen additions for upgrading into higher quality SCO, may reach another 250 feet per barrel. In addition to this, if no coke burning is taking place, yet another 80 standard cubic feet of barrel for upgrader fuel is to be added. Therefore, a future barrel of in situ produced high quality barrel of SCO may require more than 1700 standard cubic feet of natural gas. (Alberta Chamber of Resources, 2004)

### 11.2.1 Alternatives to Natural Gas as Hydrogen Source

Partial oxidation-based gasification of residues is commercially practiced around the world. Gasification of abundant coal or oil sands residues (perhaps even coke) holds the greatest promise at this time to generate hydrogen in the amounts needed, and replace natural gas for this purpose. At the same time, energy and power are natural co-products. About 10% by weight of the original oil sands production needs to be gasified to produce enough hydrogen to convert the remaining 90% into high quality (40° AP1+) synthetic crude oil. (Alberta Chamber of Resources, 2004) Overall efficiency of the process is 50%, which is less than for steam methane reforming (65-75%). Pure oxygen is also required for the process. Compared to natural gas use, partial oxidation/gasification has lower efficiency, higher costs and more a more complicated process for purification of hydrogen. (Alberta Chamber of Resources, 2003)

Several electrolysis methods have been developed and demonstrated for the production of hydrogen. One key consideration is the use of inherently high cost electricity. At present, the cost of hydrogen via electrolysis is close to three times the cost of hydrogen derived from steam methane reforming or residue gasification. At 100% conversion efficiency one giga-Joule of hydrogen would require 278 kWh of electricity with a cost approximately at \$14. Since the actual efficiency of electrolysis is around 65%, the hydrogen cost would be \$21.37/GJ or higher. This compares with about \$7/GJ for steam methane reforming at \$4/GJ natural gas price. The potential cost of producing electricity with a large-scale nuclear plant, thereby providing energy and, via electrolysis, hydrogen, has not been investigated. (Alberta Chamber of Resources, 2003)

### 11.3 Alternatives to Natural Gas as Energy Source

The long-term vision for the oil sands industry sees internal (or possibly external) resources being used for energy and hydrogen. Gasification of residues is a technology that besides generating hydrogen provides energy and power as co-products. Gasification is an existing technology that can be used to consume the residue from the bitumen barrel for fuel, power and hydrogen. At relatively small-scale SAGD sites, combustion of some of the produced bitumen may be economically attractive. In larger scale operations, such as an upgrader, the economics likely swing to selective residue use, at the same time taking advantage of the favorable impact on primary upgrading. (Alberta Chamber of Resources, 2004) The complete substitution of natural gas for fuel requires about 17% of the production for in-situ SAGD and 4 % for Mining. Cogeneration of powers adds to these estimates, but fuel energy needs predominate. (Alberta Chamber of Resources, 2004)

Coal has still an important position in power generation. Cogeneration of energy and power using coal is therefore a thoroughly researched alternative, and there are abundant and relatively inexpensive coal supplies in Alberta. Coal combustion in advanced boilers, is an option to replace natural gas for energy although greenhouse gas emissions would increase significantly. (Alberta Chamber of Resources, 2004)

Nuclear energy is another possible source of electricity and steam. For a 150,000 barrel per day SAGD operation, advanced nuclear reactor technology appears to be competitive at a natural gas price of \$4 per Giga-Joule. (Alberta Chamber of Resources, 2004)

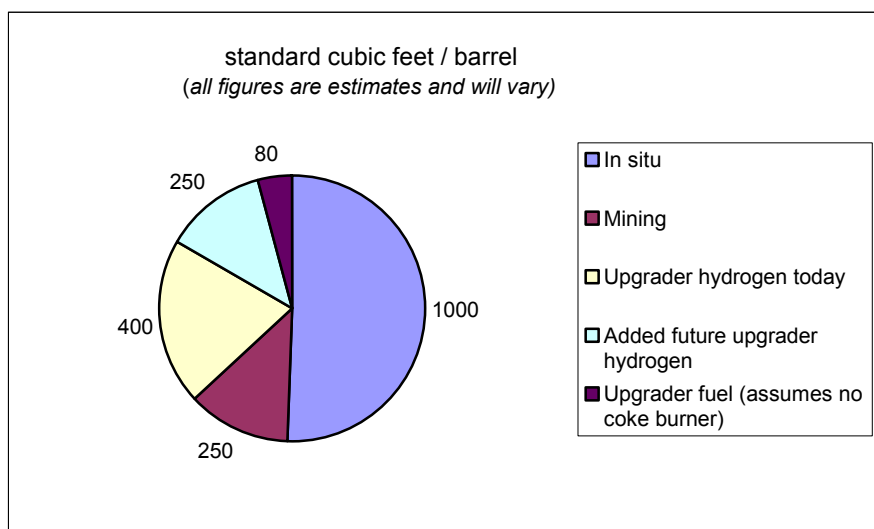
#### 11.3.1 Current Projects with Natural Gas Alternatives

The steam generators at Firebag, Suncor's SAGD project are designed to burn diesel or natural gas; the company is a net producer of both and will therefore choose to use the commodity with the lowest market value. The Nexen/OPTI Long Lake SAGD project is expected to employ its proprietary gasification technology to create synthetic fuel gas and hydrogen from the low value, heaviest portion of the bitumen barrel. This process will nearly eliminate the need to purchase natural gas. (National Energy Board, 2004)

### 11.4 Need Of Natural Gas – Summary

Although there is considerable variation between individual projects, an industry rule of thumb is that it takes 1 mcf of natural gas to produce one barrel of bitumen by in-situ production. (NEB, 2004). Mining recovery demand is a more modest 250 cubic feet per barrel. Upgraders need as much as 500 cubic feet per barrel of synthetic crude for energy and hydrogen today, and this will climb as synthetic crude quality demands increase. The total required purchase of natural gas is approximately 0.75 mcf per barrel of SCO produced by mining. The total demand for natural gas for in situ produced SCO is currently about 1400 - 1500 standard cubic feet of natural gas and is likely to reach more than 1700 cf/b. (Alberta Chamber of Resources, 2004)

**Fig 11.1. Oil Sand Natural Gas Demand**



Source: Alberta Chamber of Resources (2004)

### 11.5 Natural Gas Demand for Oil Sands Forecasts

Projections of natural gas usage for oil sands operations consider the current usage levels as well and make certain assumptions regarding future use patterns. These include recognition of two likely parallel trends. As table 11.1 shows, upgrading expansions for meeting the demand of higher quality SCO will require incremental hydrogen supply. At the same time a reduction of hydrogen demand is possible, due to efficiency gains from technological advances such as new SAGD technologies.

As a consequence of the two opposite natural gas demand trends, the gas requirement per barrel of SCO is assumed to be static in the forecasts presented. This means no increasing demand for greater quality SCO as well as no reduction of demand due to technological advances. It is important to remember that some of the new promising SAGD techniques may be suited only for specific deposit conditions thus reducing the overall potential use.

**Table 11.1. Forecast Assumptions, Use of Standard Cubic Feet Natural Gas per Barrel**

In situ Recovery	1000
Mining Recovery	250
Upgrader Hydrogen Today	400
Upgrader Fuel (Assumes no coke burning)	80



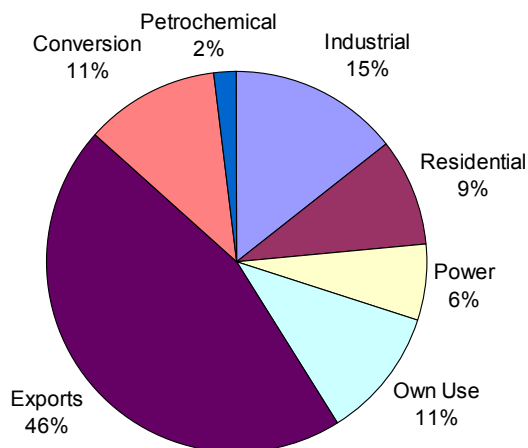
## 12 The Natural Gas Situation

In 2003, natural gas supplied about 30% of the total primary energy consumption in Canada. (BP, 2005.) The North American natural gas demand for power generation has had the strongest growth, with an annual rate of 4.9% between 1990 and 2001. Total demand growth for natural gas in North America from 2002 to 2020 is estimated to be in the range of 1.9% per year. Views on supply growth are more varied, but, in general, outlooks agree that meeting the projected demand growth will require North America to rely increasingly on new sources of gas. (The Canadian Gas Association, 2003.)

In 2003 Primary consumption of natural gas in Canada averaged 3085 BCF, compared with 22,219 BCF consumed in the US. (BP, 2005) To put these numbers into context, one billion cubic feet (BCF) of natural gas can supply the energy needs of over 11,000 homes or 2,000 commercial entities or 90 industrial concerns for one year. (The Canadian Gas Association, 2003.)

Of the natural gas currently produced in Canada annually and moved along the transmission system, 44 percent is destined for export to the U.S.. The Canadian industrial sector consumes the next largest share at 14%. Other major Canadian users are the residential sector (9%), power generation (6%) and own use (11%). Own use, refers to consumption of natural gas by the energy industry to process and move natural gas to market, including export. (The Canadian Gas Association, 2003.)

**Figure 12.1. Canadian Use of Natural Gas**



Source: The Canadian Gas Association (2003)

In July 2003 the National Energy Board of Canada released a report titled Canada's Energy future – Scenarios for Supply and Demand to 2025 (Canada's Energy Future), which identified key issues and uncertainties affecting the long-term supply and use

of energy in Canada. Regarding natural gas the report portrayed futures with limited potential to increase natural gas supply while the demand for natural gas was likely to increase. The scenarios implied that natural gas prices would likely be high and volatile over the medium term unless new supply is achieved or a reduction of consumption takes place. Over the long term additional sources of gas supply were expected as more frontier and unconventional sources become available and import capacity for liquefied natural gas (LNG) increases.

The report adopted a scenario-based approach in which two different possible energy futures for Canada were presented. It was stressed that neither of the scenarios represents a more probable or more desirable energy future. The Supply Push scenario (SP), represented a world in which technology advances gradually and Canadians take limited action with respect to the environment. The main theme of this scenario is security of continental energy supply and the push to develop known conventional sources of energy. (National Energy Board, 2003)

In this report, data from the SP scenario is utilized. The data describe natural gas resources in Canada, and future Canadian natural gas supply.

## 12.1 Supply of Natural Gas

In 1986, Canadian natural gas prices were deregulated and freer access was provided to the U.S. market. Between 1986 and 1999 Canadian gas production more than doubled, and exports to the U.S. increased more than four times. Canadian and U.S. natural gas markets have increasingly evolved into an integrated North American market, through an extensive North American pipeline grid. (National Energy Board, 2004b)

### 12.1.1 Uncertainties Regarding Canada's Natural Gas Resources

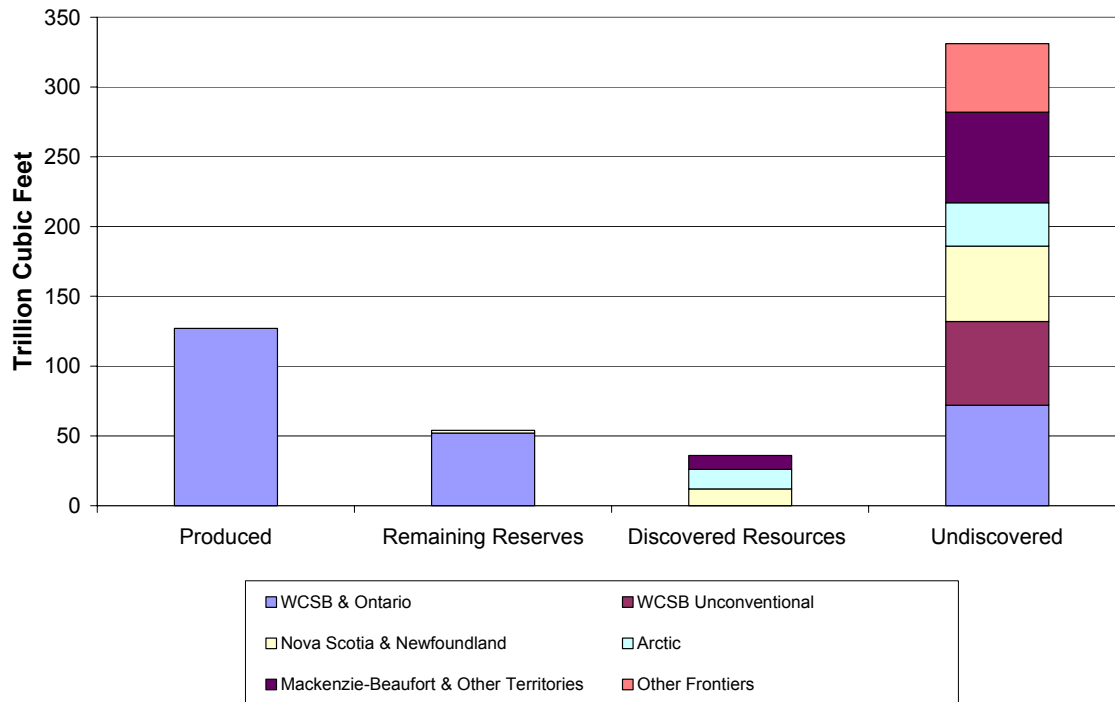
Recent drilling and production data suggest that the Western Canada Sedimentary Basin (WCSB) may be maturing. In the last three years, production from the WCSB has flattened out at about 16 Bcf/d despite record levels of drilling activity. (National Energy Board, 2004) The size of Canada's natural gas resource base is a significant uncertainty, especially for the frontier regions and the unconventional natural gas reserves. Very little development of unconventional natural gas has occurred to date. With the exception of offshore Nova Scotia, most frontier resources are situated in areas that are not currently producing natural gas. Resources in a number of the frontier areas were discovered decades ago, but their exploitation has not been economically feasible, and today they remain without access to transportation systems. Some of these regions, such as the Arctic Islands, may have discovered resources but are not expected to produce any significant amounts of natural gas within the next 20 years, due to the high cost of developing production and transportation facilities in remote areas. (National Energy Board, 2003)

Approximately one-half of the natural gas resources in Canada are located within the WCSB, and of this portion approximately one-half has already been produced. (National Energy Board, 2003) Estimates of Canada's natural gas resources, including undiscovered resources, total 548 Tcf for the SP scenario.

The development of the CBM reserve is not restricted by the size of the resource. This unconventional resource has high potential as large volumes of natural gas may exist. Nevertheless, the exploitation of this resource is very dependent on the industry being

able to consistently find coals with the capability to produce gas at acceptable rates, and being able to develop new technology to reduce costs. (National Energy Board, 2003)

**Figure 12.2. Natural Gas Resources in Canada, SP Scenario**



Source: National Energy Board (2003)

### 12.1.2 Unconventional Natural Gas Resources

Canada's unconventional natural gas resources fall into three categories – gas hydrates, shale gas, and coalbed methane (CBM). Gas hydrates consist of methane molecules trapped in and encased by a cage of ice molecules. Gas hydrates are found on the ocean bottoms, or under the ocean bottoms, and also on land in permafrost areas. The nature of the hydrate deposits and how they perform are still unknown, as well as the technical challenges for extraction. The chance of achieving any commercial methane production from gas hydrates within the coming twenty years is very low. (National Energy Board, 2003)

Shale gas consists of methane adsorbed onto the surface areas of organic matter in the shale. The gas can be released by reduction of pressure. Shale gas is expected to be recovered second to the CBM resources. Several high organic shale deposits in Western Canada have the potential of being shale gas deposits. (National Energy Board, 2003)

CBM consists of methane bonded or adsorbed onto the large internal surface area of coal. The methane can be released by either reducing the pressure within the coal seam or by replacing the molecules with CO<sub>2</sub>. CBM is in general present wherever coal is found. CBM is the first unconventional gas to be commercially developed in

Canada and is expected to provide the majority of the future production of unconventional gas. CBM has been successfully developed for a number of years in the U.S.

In the report *Canada's Energy Future*, it is stated that commercial production of CBM was reached in Canada in January 2002 and a project near Calgary is believed to have been producing about 5 MMcf/d at the end of 2002. There are also several experimental projects underway on the plains of the WCSB, in the mountain regions of Alberta and B.C., and on Vancouver Island, although no further information is available. (National Energy Board, 2003) In the report *Natural Gas Markets in Transition*, from August 2004, it is said that about 1000 CBM wells were drilled in 2004 and the expected production for 2004 was 100 MMcf/d. (National Energy Board, 2004b)

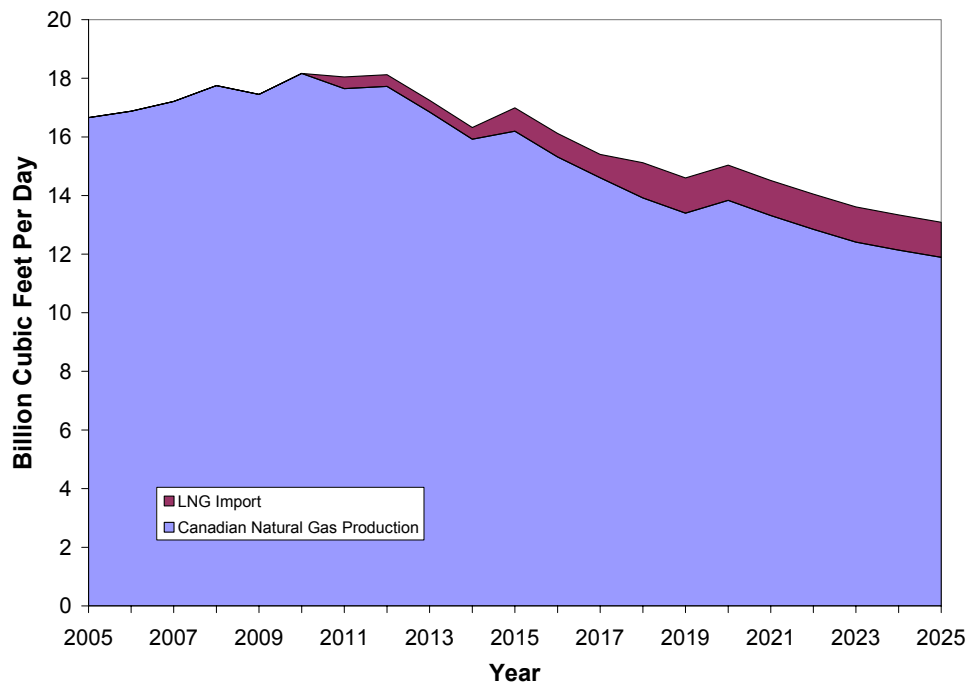
Although it is explained that coal seams in Canada tend to be thinner than coal seams in the U.S. and have lower permeability, it is claimed in the report *Canada's Energy Future*, that CBM development is more a function of cost control than technology development. However, according to the report *Natural Gas Markets In Transition*, there are substantial uncertainties surrounding the economics and development of the CBM resources in the period to 2010. The CBM wells usually have a very low productivity and a greater number of wells are needed to produce the gas. The report states further that the success of ongoing CBM production projects have been mixed. When developing CBM, some projects have experienced fresh or salt water production which presents additional challenges with water disposal and tends to increase costs and impact gas production. Other projects have focused on dry coals that produce gas with no water. Vital problems associated with CBM production are matters such as legal issues over CBM ownership and land controversies. Considering the variability of coals, the range of success amongst existing pilot projects, and the very early stage of CBM development in Canada, there is still significant uncertainty surrounding the future of CBM development. (National Energy Board, 2004b)

### **12.1.3 LNG (Liquefied Natural Gas)**

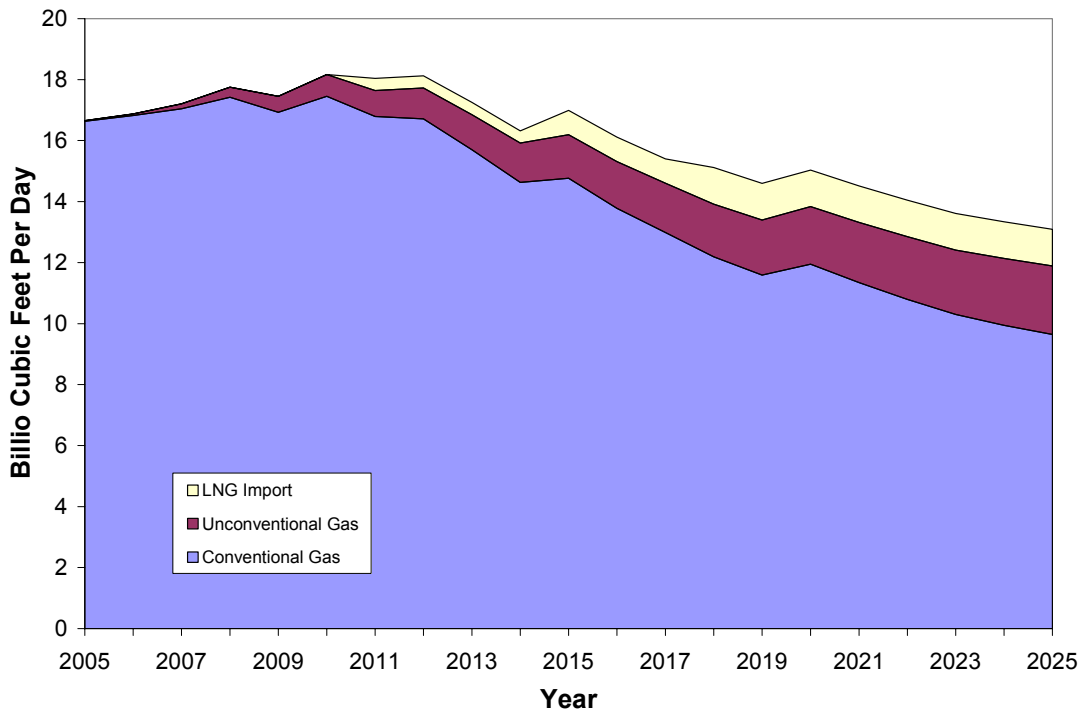
Currently, LNG imports from Angola, Nigeria, Algeria, Trinidad, Venezuela and the Middle East satisfy about 1% of North American demand. (The Canadian Gas Association., 2003) LNG gross imports in the U.S doubled as of 2002 to 2003, from 228 bcf to 540 bcf. For the U.S. the strong growth in LNG is expected to continue. (International Energy Outlook, 2004) Worldwide LNG demand is growing at 6.4% per year. LNG represents 27% of cross-border international gas flows and 5.8% of world demand. (The Canadian Gas Association, 2003)

In the U.S, all four existing receiving terminals are operating with a current capacity of about 2.5 Bcf/d. Further numerous facilities and expansions of existing terminals have been proposed. Nevertheless there are many potential obstacles for developing LNG terminals such as concerns expressed by the local population regarding safety, environmental impact and land use, access to infrastructure and a nearby liquid market and the cost of transporting LNG to the specific sites. There is a lag time of about five to six years to design, obtain approval and construct a new LNG terminal. The approval procedure of new LNG terminal sites is limiting growth from this non-traditional source. (The Canadian Gas Association, 2003) Therefore, LNG can only make a limited contribution to closing the expected supply gap at the end of the decade. (NEB, 2004b)

**Figure 12.3. Canadian LNG Import and Canadian Natural Gas Production**



**Figure 12.4. Canadian LNG Import, Unconventional Gas Production and Natural Gas Production**



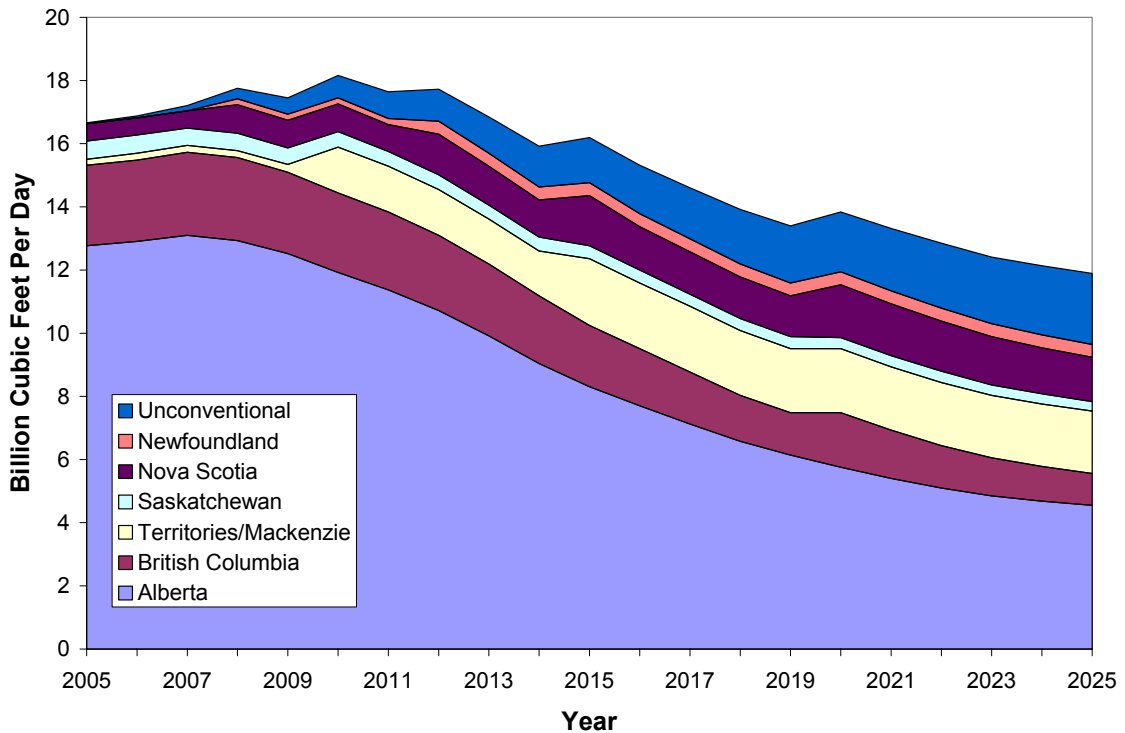
### 12.1.4 The NEB's Natural Gas Supply Scenario

In the SP scenario, Canadian natural gas deliverability peaks around the year 2010, at a rate of about 18 Bcf/d. At this point, unconventional natural gas and frontier areas begin to significantly supplement supply from the WCSB. CBM development is expected to gradually increase, reaching 2.4 Bcf/d by 2025. In 2025, unconventional natural gas and frontier areas provide 50 percent of Canadian deliverability.

Both NEB scenarios assume frontier supply from three additional projects located offshore Nova Scotia, each producing 500 MMcf/d. A project of comparable size, offshore B.C., projected to be in operation by 2020, is included in the SP scenario. The Mackenzie Valley pipeline system is expected to flow natural gas by 2010, at a rate of 1.2 Bcf/d. An expansion by 2015 to 1.9 Bcf/d is assumed for both scenarios. In the SP scenario, Newfoundland production begins at 0.2 Bcf/d in 2008 and increases to 0.4 Bcf/d by 2012. (National Energy Board, 2003)

The development of frontier areas may be constrained by factors other than uncertainty regarding resource estimates. Areas such as Mackenzie-Beaufort and Newfoundland, have a sufficient number of discovered resources to justify the startup of the projects included in these projections. However, these projects have not been developed due to economic limitations, land controversies, and market uncertainty. In contrast, new projects in other frontier areas with less discovered resources are more dependent on exploration success. (National Energy Board, 2003)

Figure 12.5. Canadian Natural Gas Supply, Supply Push Scenario



## 12.2 Natural Gas Demand

Canada currently consumes 8.7 Bcf of natural gas per day, split approximately equally between three sectors: residential/commercial, industrial, and other. Present distribution data indicate that about 9.0 Bcf/d is exported to the U.S. (National Energy Board, 2004) By 2015, Canadian gas demand is expected to reach the 9.5 - 11 Bcf per day range and by 2025, Canadian gas demand is expected to be in the 8.8 - 12.7 Bcf per day range. The industrial (it includes oil sands) and power generation sectors are expected to account for the bulk of natural gas demand growth. (North American Natural Gas Vision, 2005)

Canadian gas-fired electric power generation currently consumes 0.6 Bcf of natural gas per day; by 2015 this is expected to reach the 1.5 - 2.2 Bcf per day range; by 2025, the 2 - 2.9 Bcf per day range. (North American Natural Gas Vision, 2005)

Currently many forecasts represent various views about the future Canadian natural gas demand situation, but the important conclusion is that there is a widespread consensus that markets will be tight at least into the 2010 timeframe. In general, experts see a future where potential demand for natural gas is strong and will require a significant supply response. In the report, *Understanding the North American Natural Gas Market*, from 2003, the Canadian Gas Association presents a survey done among industry experts of how the natural gas demand will develop in North America up to 2020. The results show a forecasted average annual growth in natural gas demand of 1.9% from 2002 to 2020. On the matter of supply, there forecasts were much more divergent with growth rates ranging from 2.3% (max.) to -0.1% (min.) over the period 2002 to 2020.

### 12.2.1 Demand from the Oil Sand Industry

The report *Natural gas Markets In Transition*, says that scenarios for oil sands development indicate that the demand for natural gas is likely to grow from the current 0.6 Bcf/d (about four percent of WCSB production) to between 1.2 and 1.6 Bcf/d by the end of the decade. (National Energy Board, 2004b)

For this report an investigation of the future natural gas demand from the oil sands industry has been made. Natural gas demand from the four forecasts, OSTRM, NEB, CAPP and EUB, presented earlier in the report, have been investigated. The forecasts predict an average demand of 1.6 Bcf/Day by 2010. By 2025 the NEB forecast would translate in to a demand of 2.7 Bcf/Day. The OSTRM forecast predicts a natural gas demand of 5.4 Bcf per day by 2030.

### 12.2.2 U.S. Natural Gas Demand

The U.S. has increasingly become dependant on natural gas as an energy resource. Of all buildings, 65 percent use natural gas for all heat. Of all growth in kilowatts 90 percent now comes from using new generation of gas-fired power plants. The investment bank Simmons & Company International, has estimated that the U.S. gas demand will grow from today's 60 Bcf/day to more than 90 Bcf/day by 2010. Current and future supply distribution is presented in table 12.1 and table 12.2.

**Table 12.1. Natural Gas Supply For The U.S. 2004 (Bcf/d)**

U.S Production:	52
Canadian Imports:	7.3
LNG:	0.7
Total:	60

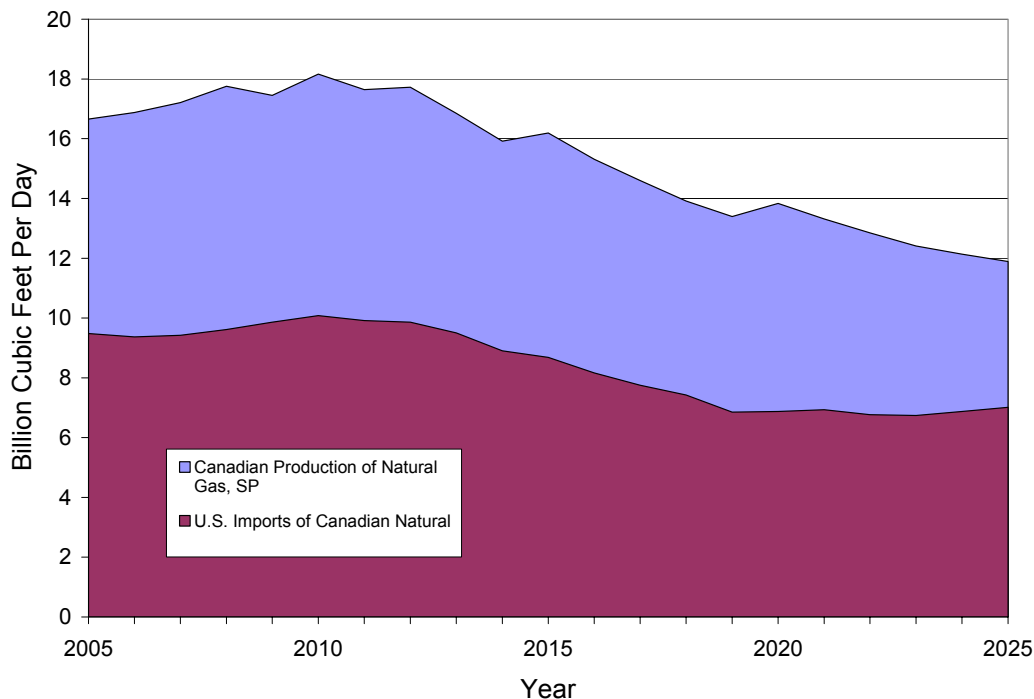
**Table 12.2. Natural Gas Supply For The U.S. 2010 (Bcf/d)**

U.S Production:	40
Canadian imports + LNG:	10
Total:	50

Source: Simmons & Company International (2004)

Consequently there might be a gap of 40 Bcf/d that has to be filled within the coming five years. The Energy Information Agency in the U.S. (EIA) projects that net imports of natural gas from Canada to the U.S. will peak at 10 Bcf/day in 2010, thereafter gradually decline to 7 Bcf/day in 2025. The depletion of conventional resources in the Western Sedimentary Basin is expected to reduce Canada’s future production and export potential. The EIA also claims that the prospects for significant production increases in eastern offshore Canada have diminished over the past few years. (International Energy Outlook, 2004)

**Figure 12.6. EIA Forecast of U.S. Canadian Natural Gas Import compared with Canadian Natural Gas Production, SP Scenario**





## 12.3 Imbalance Between Supply and Demand ?

The NEB scenario projects a tight balance between natural gas supply and demand. Major adjustments of the natural gas markets and actions to increase supply are required to avoid the potential for a severe supply and demand imbalance and consequently volatile prices. (National Energy Board, 2003)

SP projections show natural gas demand growth across all sectors of society, led by increases for natural gas-fired electricity generation and development of grand scale oil sands projects. There is significant uncertainty associated with the overall incremental natural gas demand. All end-users are affected by high prices and great volatility. A large increase in natural gas demand for new natural gas-fired generation and oil sands projects will put pressures on other natural gas users to use alternative fuel, reduce demand and in some cases relocating or discontinuing of operations. Fuel options for the residential and commercial sectors are limited by local delivery infrastructure. Instead of fuel switching the response of these sectors to higher natural gas prices may be limited to conservation and improving the energy efficiency of equipment and buildings. Other end-users, such as some industrials and power generators may to a larger extent consider using alternative fuels and more energy-efficient technology, especially later in the projected SP scenario. (National Energy Board, 2003)

LNG is expected to play a key role in bridging the coming gap in Canadian and even North American supply, especially in the near term with expansions of existing U.S. LNG terminals. It is also declared that there is potential for further development of LNG in North America in the latter part of the projection period as the natural gas supply and demand balance tightens. (National Energy Board, 2003)

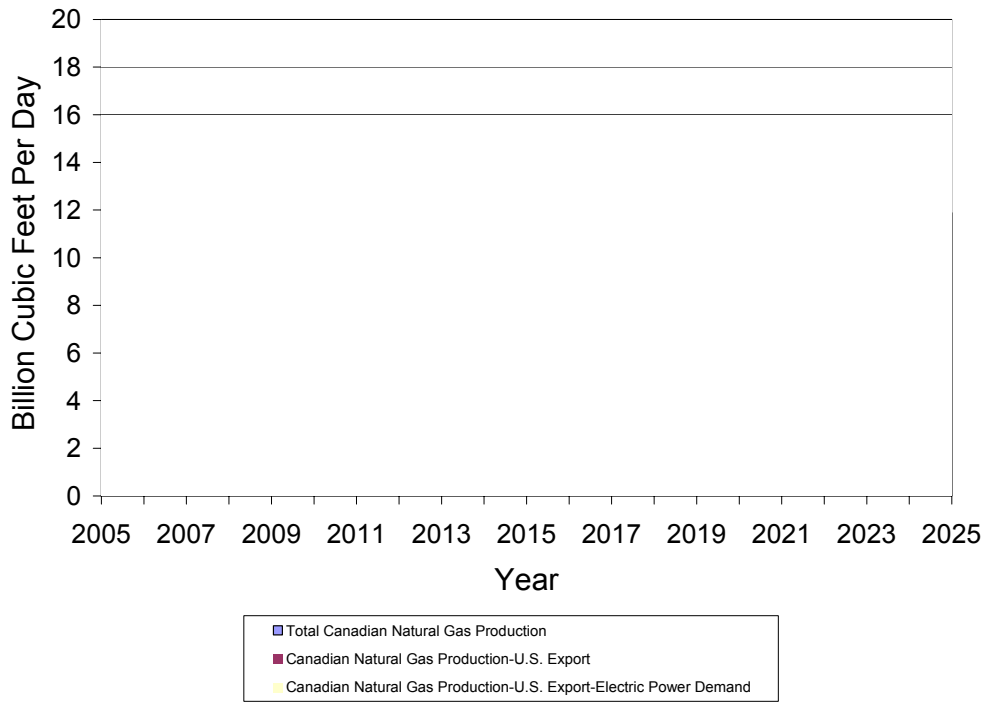
The NEB report concludes that the SP scenario seems to be unsustainable for the natural gas industry without rapid improvements in technology to increase supply or reduce demand. The report states that developers of oil sands deposits and electric power generators may be forced to reconsider their reliance on natural gas. (National Energy Board, 2003)

### 12.3.1 Performed Natural Gas Demand Study

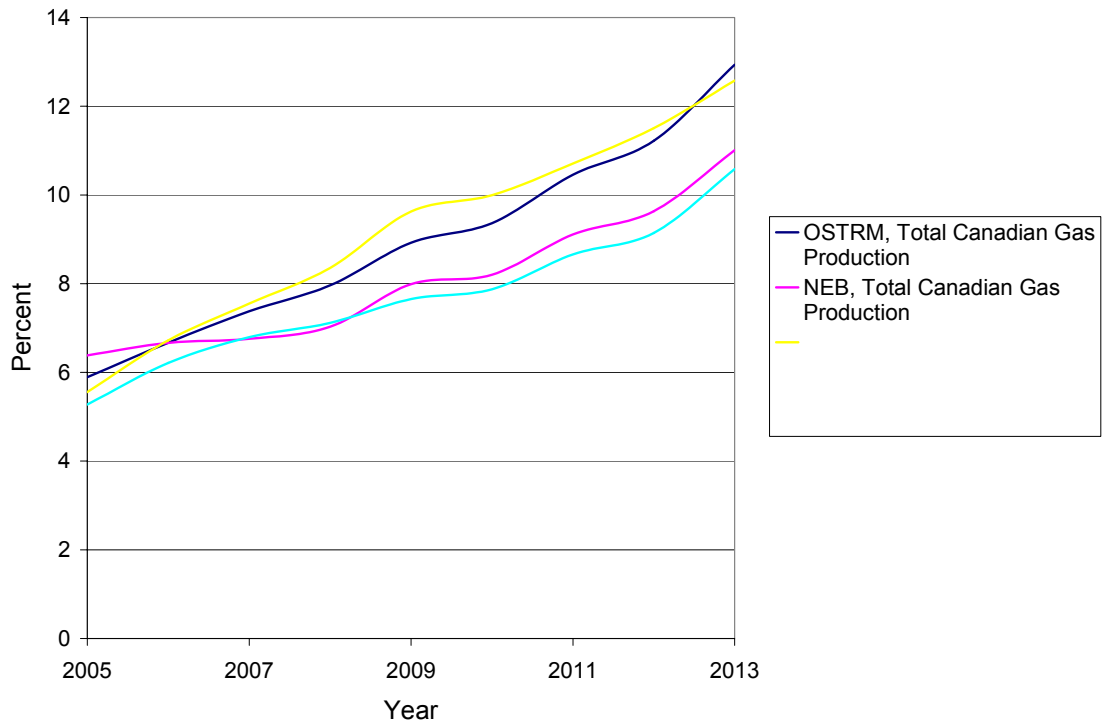
In this report an investigation has been made concerning how much of the available Canadian natural gas supply the oil sands industry will demand in the future. As already mentioned the oil sands industry today consumes about four to five percent of the Canadian natural gas supply. By 2010 calculations show that this share will have approximately doubled to nine percent. This may appear an acceptable increase but it is important to remember that the U.S. imports a significant part of Canadian natural gas production! Canada is also itself dependent on natural gas for electricity generation.

Thus, in order to study the natural gas demand and to more properly illustrate the effects of the oil sands industry's demand for natural gas, the estimated future export to the U.S., as well as Canadian natural gas demand for electricity have been subtracted from the Canadian natural gas supply. When the distribution between upgraded/nonupgraded bitumen in a forecast, has been unknown, the same distribution as for the OSTRM scenario, has been assumed.

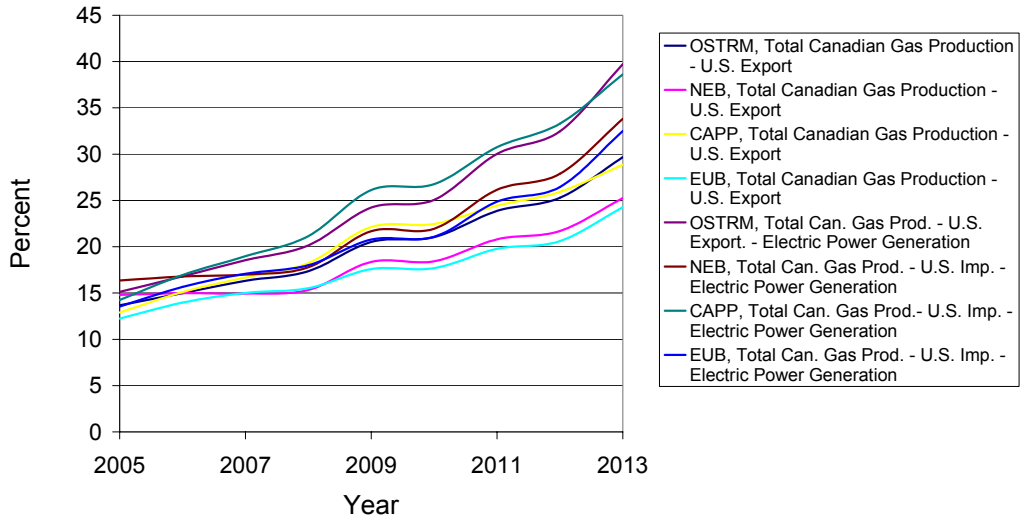
**Fig 12.7. Available Canadian Natural Gas Supply**



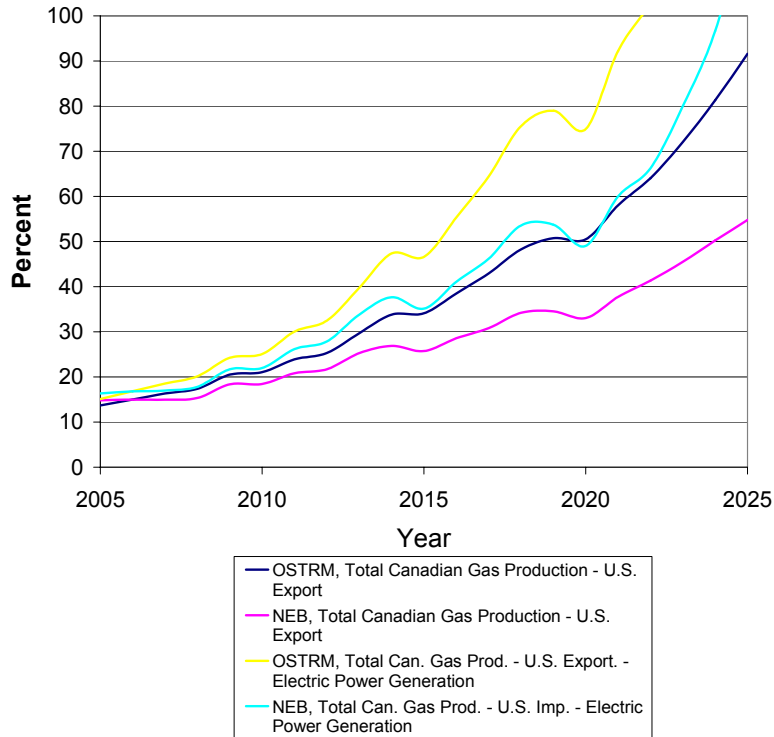
**Figure 12.8. Oil Sands Production Share of Total Canadian Natural Gas Use, no Exclusion, Short Time Perspective**



**Figure 12.9. Oil Sands Production Share of Total Canadian Natural Gas Use, Excluding U.S Imports and Electric power Demand, Short Time Perspective**



**Figure 12.10. Oil Sands Production Share Of Total Canadian Natural Gas Use, Excluding U.S. Export And Electric Power Demand, Long Term Perspective**

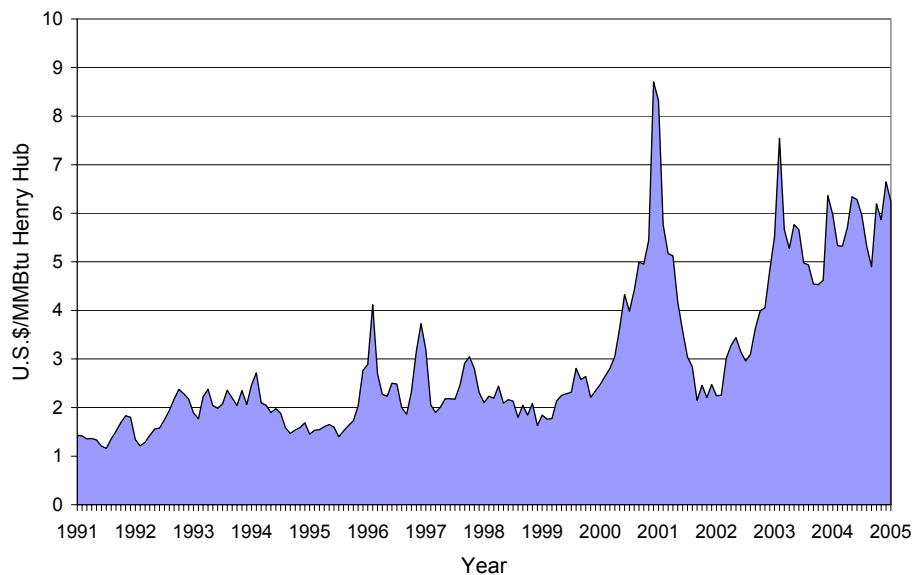


From the figures 12.7 – 12.10 it is possible to draw the conclusion that the oil sands industry's dependence on natural gas of today is unsustainable in the long run. Most likely it is unsustainable as well in a shorter ten-year perspective. There has to be a switch towards other sources for energy and hydrogen.

## 12.4 Natural Gas Prices

Throughout the 1990s, natural gas prices were relatively low. Over the last three years, natural gas prices have increased significantly as a result of tighter balances between natural gas supply and demand. In addition, they have exhibited severe volatility as shown on figure 12.11. Some of the key market developments in recent years include the flattening of continental natural gas production, a reduction in liquidity in the market and the emergence of electric power generation sector as a major source of gas demand. Many analysts believe that there has been a step-change in the level of natural gas prices. There has been some fuel-switching and demand destruction in response to higher prices. But there are many different opinions on just how much capacity there is in the market for switching fuels and how much of fuel switching that is permanent and how much that is temporary. Similarly, it is not clear how much demand has been permanently dampened and how much of demand reduction that was only temporary. Consequently, many observers expect a continuation of the current market conditions, characterized by extreme price volatility and an ongoing need for adjustments on the consuming side of the market. (National Energy Board, 2004b)

**Figure 12.11. Graph Natural Gas Prices for the last 15 years**



Source: Alberta Energy and Utilities Board (2005)

## 12.5 Conclusions

The overall demand for natural gas in North America is steadily increasing. It is unlikely that unconventional gas and LNG can prevent the decline of available natural gas supply in North America. In a five to ten year near future, Canada's supply of natural gas cannot any longer simultaneously meet the demand from the oil sands industry and the U.S.. Due to the limited supply of natural gas and steadily increasing demand, North American natural gas prices are likely to become higher and even more volatile in the future.

It is obvious that the current dependence on natural gas is unsustainable for the expanding Canadian oil sands industry. Another source of energy and upgrading is needed most likely as early as at the beginning of the next decade

## 13 The Kyoto Protocol - Canada's Great Challenge

As part of the Kyoto Protocol, ratified by Canada on December 17, 2002, Canada has agreed to a 6% reduction in greenhouse gas emissions from the 1990 level of 612 Mega-tonnes (Canada's First National Climate Change Business Plan, 2000) by the period 2008-2012. On average, developed countries face a reduction of 5.2%, while no targets have been agreed upon for developing countries. (Alberta Economic Development, 2004)

The Federal Government expects the oil and gas sector to maintain the ongoing process of reducing emissions by lowering the emissions intensity of oil and gas production and distribution. The Government expects the industry to achieve the reductions while continuing to grow. To fulfil these expectations, the oil sands industry needs to do much better than a "business as usual" scenario. However, replacement of natural gas consumption with following drive to internal sources of energy such as burning residue for fuel, will result in accelerating emissions of greenhouse gases. (Alberta Chamber of Resources, 2004)

### 13.1 Canada's Commitment

Canada's commitment to the Kyoto protocol translates into a reduction of 240 MT from a projected "business-as-usual" emissions level of 809 MT in 2010. (Climate Change Plan for Canada, 2005 ) Canada's Kyoto target are emissions of 575 mega-tonnes of CO<sub>2</sub> per year. (Canada's First National Climate Change Business Plan, 2000). In 2001 Canada's emissions of CO<sub>2</sub> were 720 mega-tonnes.

The Kyoto Protocol does give a relative high degree of freedom for each country on how to achieve the country specific emission targets. (Climate Change Plan for Canada, 2005) The Government of Canada states that it takes its obligations to climate change seriously. On November 21, 2002, the Government of Canada released its *Climate Change Plan for Canada*. In the February 2003 budget, \$2 billion was dedicated to implementing *the Climate Change Plan for Canada*, which builds on more than \$1.7 billion already disposed to climate change programs.

#### 13.1.1 The Climate Change Plan for Canada

In the report *Climate Change Plan for Canada*, the Canadian government has described the planned efforts in order to meet Canada's commitments under the Kyoto Protocol. The overall measures outlined in the report reflect the commitments made by the Canadian First Ministers in 1997 and the principles on climate change policy, suggested by provincial and territorial governments in Halifax on October 28, 2002.

The Plan is a three-step approach to meet Canada's emission target. Step 1 includes actions already underway, which are expected to reduce emissions by 80 MT. Step II involves further measures which are expected to reduce emissions by a further 100 MT. Step III will ensure the reduction of the remaining 60 MT. (Climate Change Plan for Canada, 2005)

The Climate Change Plan resulted in protests from the industry and some provincial governments. The main target for the criticism was the plan's lack of specific details on emissions. The complaints resulted in a letter dated December 18, 2002, to the Canadian Association of Petroleum Producers (CAPP) where the Federal Minister of

Natural Resources made a commitment to capping the price for credits at \$15/tonne for corporations. The letter also expressed a promise of setting emissions intensity targets for the oil and gas sector at a level not more than 15% below projected business-as-usual levels for 2010. In a subsequent letter dated 24 July 2003 to CAPP, the Prime Minister of Canada further stated that targets for new projects would be locked in for the first 10 years from start-up. (National Energy Board, 2004)

*The Oil Sands Technology Roadmap report* concludes that by 2012, as consequence of these statements, the reported 85% of “business as usual” emissions per economic unit of production are without penalty, and that the remaining 15% will be assessed at \$15 per tonne of CO<sub>2</sub> emissions, unless the producer is able to secure third party GHG credits at a lower cost. (Alberta Chamber of Resources, 2004)

However, the effects of the Kyoto Protocol after 2012 are still unclear. For the oil sands industry, with long development lead times, and large investments demands it is necessary to have full knowledge well in advance in order to make decisions on development funding. (Alberta Chamber of Resources, 2004)

### **13.1.2 Alberta’s Ambitious Goal**

The report Canada’s Oil Sands, says that the goal for Alberta's greenhouse gas reduction program is a 50 percent emission reduction by 2020 relative to the province's 1990 levels Gross Domestic Product. This is expected to result in total emissions of 238 Mt of CO<sub>2</sub> in 2010, and 218 Mt of CO<sub>2</sub> in 2020. Alberta’s greenhouse gas reduction program includes emission trading systems, mandatory reporting and the creation of a Climate Change and Emissions Management Fund for implementing new technologies, programs and measures for reducing emissions. (National Energy Board, 2004.)

### **13.1.3 Step One – Action underway (80 MT)**

Since 1998, the Government of Canada has committed \$1.6 billion in climate change initiatives, across all sectors and involving every region. Already implemented measures and announced actions are expected to reduce annual emissions by 50 MT over the next five to ten years. (Climate Change Plan for Canada, 2005)

According to the report, Canadian experts estimate that Canada's agricultural soils and forests may act as a carbon sink since they remove CO<sub>2</sub> from the atmosphere and store it in the plant tissue. These mechanisms are expected to bring credits of 30 MT annually to Canada. When combined with the annual 50 MT already noted, this is supposed to bring the total reduction of emissions to 80 MT. (Climate Change Plan for Canada, 2005)

### **13.1.4 Step Two and Three – New actions (100 MT)**

Actions by Canadians and governments in the transportation and building sectors industrial reduction efforts combined with government purchases of emission permits on the international market will cut another 100 MT of CO<sub>2</sub> emissions. The actions already underway and those proposed in the first and second steps of action are expected to achieve a reduction of 180 MT of the 240 MT target. That leaves 60 MT. This substantial remainder will be addressed by actions such as promoting energy efficient innovation in all sectors and existing technology research and development investments. Further, the Government of Canada is trying to achieve acceptance for

the belief that Canada ought to be compensated for its cleaner energy exports. Such a recognition could result in credits of up to 70 MT. (Climate Change Plan for Canada, 2005)

**Table 13.1. Emission Reductions from Step One and Step Two**

	Canadians & Government		Industrial Emitters			Land cover and use	International Market	Totals
	Transportation	Housing and Buildings	Emissions Tradings	Renewable Energy and Innovative Projects	Small and Medium Sized Enterprises and fugitive Emissions	Agriculture, Forestry and Landfill Gas		
Business-as-usual Emissions 2010	206	84	425			94	N/A	<b>809</b>
Step I, Actions Underway	9	4	25			38	2	<b>80</b>
Step II, New Actions	12	4	55	11	5	(Potential offsets at 20 to 28 MT)	10	<b>100</b>
Total Emissions Reduction Targets For Steps I and II	21	8	96			38	12	<b>180</b>

Source: Climate Change Plan for Canada (2005)

**Table 13.2. The Remaining 60 MT Gap**

Partnership Fund for working with provinces, territories, municipalities, Aboriginal communities, private sector and non-governmental organizations as well as infrastructure funding.	20-30 MT
Existing and future technology R&D investments that produce emissions reductions.	10 MT
Provincial and territorial actions underway not involving federal partnerships.	10-20 MT
Community-wide emissions reduction plans by 100 municipalities.	10 MT
A challenge to Canadians to reduce emissions by 1 tonne each (31 million Canadians; only 24 MT included in Step 2 of the Plan).	7 MT
Credits for cleaner energy exports.	Up to 70 MT

Source: Climate Change Plan for Canada (2005)



### **13.1.5 Large Industrial Emitters**

The large industrial emitters can be found in three main sectors, thermal electricity, oil and gas, and mining and manufacturing. The report claims that there is potential for reducing CO<sub>2</sub> emissions in the oil and gas sector. According to the report, reduction of methane leakage from natural gas pipelines and reduction of energy use in oil sands production could cut emissions as well as costs. The extent of these beneficial effects would depend on the size of the investment required and the payback period. The report states that this industry is well underway in achieving these kinds of emissions intensity reductions. As an example the report presents the fact that over the past decade the oil sands sector was a key driver of economic growth, investing \$21 billion and creating 100,000 jobs, while at the same time reducing its emissions intensity by 26 percent. (Climate Change Plan for Canada, 2005)

### **13.1.6 Emission Trading**

The Canadian Industry has expressed interest in covenants as an approach that takes more consideration with individual sector circumstances than a purely regulatory approach. Consequently the report presents emissions trading as a market mechanism that could provide flexibility for the industry in meeting its target. The options under discussion would require companies to have permits to cover their emissions. A large proportion of the expected permit requirements would be provided free to companies, based on their level of production and an emissions intensity factor. Companies would then have a choice with respect to their remaining permit requirements. They could invest in emissions reductions purchase permits or offsets, or a combination of both. Firms with lower emissions intensity in a given sector would need to purchase fewer permits or even have a surplus of permits, which can be traded. The report says this system could provide incentives to reduce emissions, and at the same time it would not place an absolute cap on an industry's or any firm's emissions. (Climate Change Plan for Canada, 2005)

However, the industry expresses concern about the extent of risk it might be exposed to under an emissions permit regime. On quantity, the question has been raised whether the industry might face further targets as part of the remaining 60 MT towards the estimated gap of 240 MT. The report states that the Government recognizes the need for clarity and agrees that the target under emissions trading will not be more than 55 MT. Any amount beyond that target would be achieved through incentives. Another cause for concern to the Government is that there may be exceptional circumstances that make it very difficult to achieve the reductions goals by 2012. The time-frame may be too narrow to achieve required technological development and necessary capital investments. Consequently, the Government is prepared to discuss an approach whereby a pre-approved commitment of larger emissions reductions over the somewhat longer term could be accepted instead of currently planned Canadian greenhouse gas reductions. (Climate Change Plan for Canada, 2005)

## 13.2 Greenhouse Gas Emissions from the Oil Sands Industry

*The Oil Sands Technology Roadmap Report* presents emission intensities for mining as well as in situ recovery. The impact of upgrading and fuel switching for CO<sub>2</sub> emissions are also demonstrated. The various estimations are described below. All the presented cases presume coke burning at typical Suncor/Syncrude level.

### 13.2.1 Mining

Due to the large number of variables there are difficulties associated in making these kinds of estimates. But the *Oil Sands Technology Roadmap Report* says it is evident that emissions from mining-based recovery alone will be as low as 40 kilograms CO<sub>2</sub>E per barrel, with natural gas as feed. The estimated emissions from mining operations also include CO<sub>2</sub>E emissions from mining equipment, the tailings ponds and higher power consumption. The use of residues or selected residues for upgrading may cause emissions up to 90 kilograms of CO<sub>2</sub>E. Upgrading with natural gas may reach emission levels of around 70 kilograms per barrel. (Alberta Chamber of Resources, 2004)

### 13.2.2 In Situ

About 60 kilograms of CO<sub>2</sub>E emissions per barrel are estimated for in situ production, with natural gas as fuel. Burning residue for SAGD fuel will increase CO<sub>2</sub>E emissions to around 80 kg per barrel. Upgrading with natural gas may reach emission levels of 70 kilogram per barrel, while upgrading with residue gasification may reach 90 kilogram per barrel. Similar trends would occur with selected residues as fuel. Combining SAGD recovery using residue as fuel, and upgrading using more residue for hydrogen, will result in as much as 160 kilograms of CO<sub>2</sub>E emissions per barrel of SCO. (Alberta Chamber of Resources, 2004)

## 13.3 Efforts to Reduce CO<sub>2</sub>E Emissions

Efforts have been made by the oil sands industry over the last several years to reduce greenhouse gas emissions. For example, Shell estimated in a feasibility case in 1999 that a 50 percent reduction in emissions from its AOSP can be realized by 2010 by using a combination of reduced energy consumption and improved energy efficiency projects. However this estimation includes actions such as afforestation projects. In association with Tree Canada Foundation, the AOSP owners provided \$200,000 to plant 200,000 trees during 2002, which is expected to yield an estimated offset of CO<sub>2</sub>E just over 90,000 tonnes. Another example of important industrial initiatives regarding the reduction of emission of greenhouse gases is the achievements of Syncrude. The company cut CO<sub>2</sub>E emissions per barrel of oil produced by 26 percent between 1988 and 1999, and Syncrude estimates that by 2008 the total reduction will improve to 42 percent. (National Energy Board, 2004)

To reduce emissions, the oil sands industry is working with technology such as the use of low NOx burners, sour water treaters, and flue gas desulphurization. Other examples of gas emission reduction opportunities include:

- \* Improvements in cogeneration in oil sands and gas plants;
- \* Leak detection programs for pipelines and gas plants;
- \* Reduction in methane emissions from natural gas dehydrators;
- \* Greenhouse gas capture and storage;
- \* Power generation with micro-turbines; and improved energy efficiency of pumps, compressors etc. in field operations.

### **13.3.1 CO<sub>2</sub> Sequestration.**

*The Oil Sands Technology Roadmap Report* describes CO<sub>2</sub> Sequestration as the top of the list of future solutions of reducing greenhouse gas emissions. Included in this solution is not only non-productive (benign) storage in depleted oil and gas reservoirs. There is also an industrial need of CO<sub>2</sub> for enhanced oil recovery and coal bed methane production. On a somewhat smaller scale, the report says CO<sub>2</sub> reinjection for reservoir repressuring may be a solution for the gas-over-bitumen issue.

Nonetheless, the report states that sequestering is only feasible today for more concentrated, and easily aggregated sources of CO<sub>2</sub>. At present that is not the case for energy and power end uses, where the nitrogen from combustion air dilutes the CO<sub>2</sub>. However, hydrogen production via steam methane reforming or gasification, does have the capability to produce CO<sub>2</sub> in more concentrated form. (Alberta Chamber of Resources, 2004)

*The Oil Sands Technology Roadmap Report* explains that high costs are associated with benign storage in depleted oil and gas reservoirs. Using 100 Mega-tonnes as an example, the largest and most accessible depleted reservoirs would provide storage for around 90 years, but at a cost of more than \$75 per tonne. The report states this figure takes into account collection, pipelining via a future network, and injection. The report concludes that there is enough storage space for CO<sub>2</sub> sequestration available for more than 300 years, at a 100 mega-tonnes rate per year. But much work is needed to bring down the associated costs.

## **13.4 Creation of CO<sub>2</sub>E Emissions Scenarios**

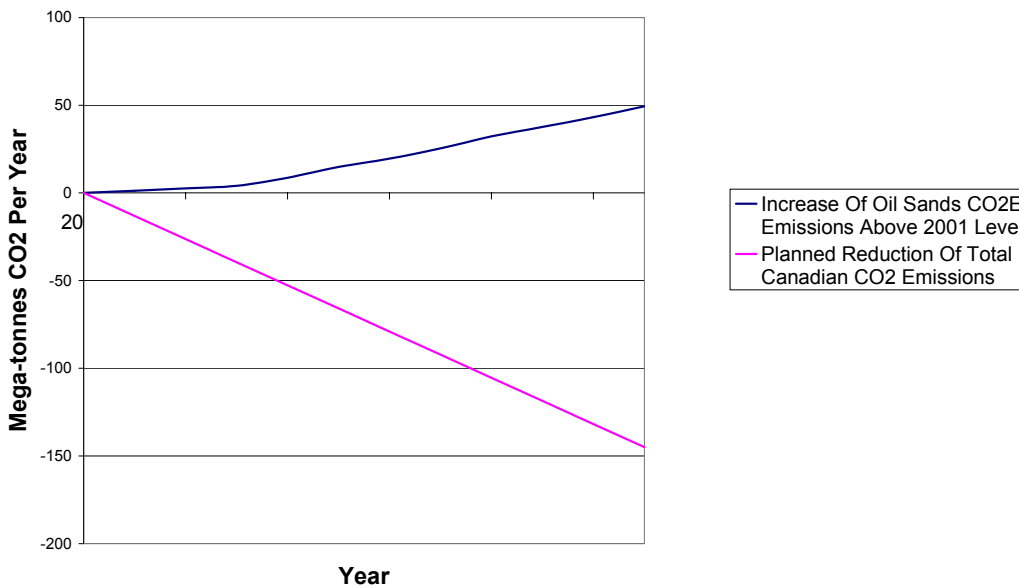
Four different forecast scenarios, the OSTRM, CAPP, NEB and EUB, have been studied. Assumptions of CO<sub>2</sub>E emission of barrels have been as described above. These emissions levels have been assumed to stay unchanged.

When the distribution between upgraded/non-upgraded bitumen in a forecast, has been unknown, the same distribution as for the OSTRM scenario, has been assumed. A ten-year stepwise switch from natural gas to using residue bitumen for fuel and hydrogen has been assumed for those cases. When the ten-year switch period has been used this is illustrated as (Adj) in the forecasts.

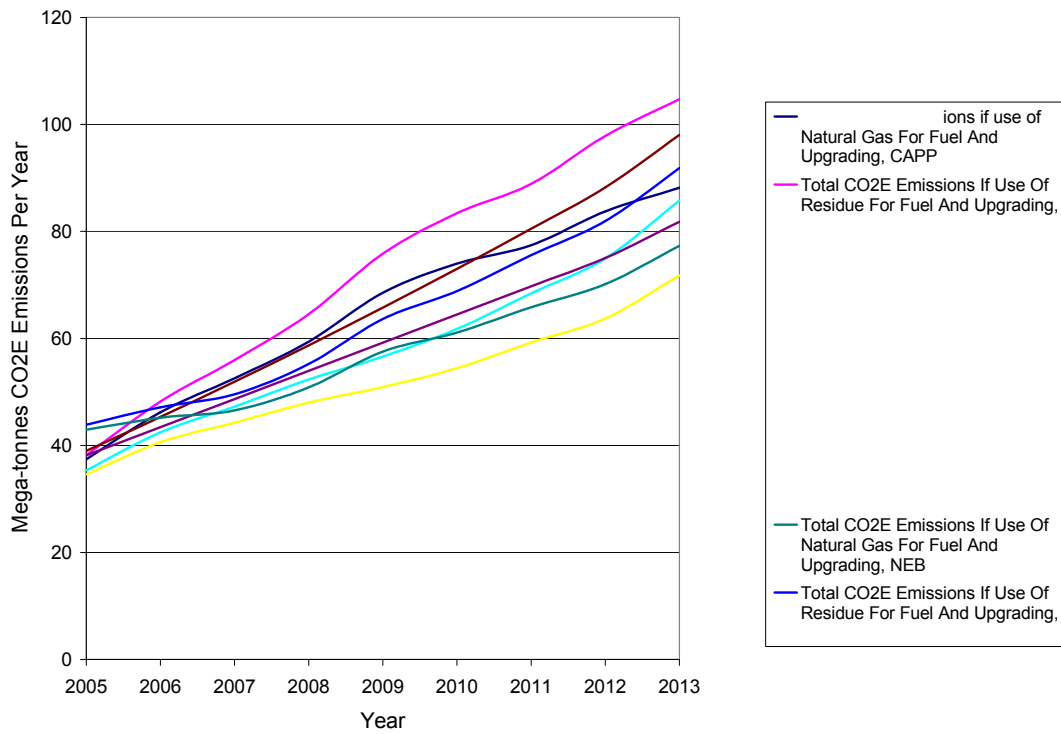
### 13.5 An Impossible Undertaking

In 2001 Canada's Emissions of CO<sub>2</sub>E were 720 mega-tonnes. Of this amount it is reasonable to assume that the emissions of CO<sub>2</sub>E from the oil sands industry did not exceed 30 mega-tonnes. The anticipated increase from 720 to 809 is about 90 mega-tonnes. It is interesting to notice that the CO<sub>2</sub>E Emissions from Canada's oil sands industry alone will likely be somewhere between 60 and 100 mega-tonnes per year by 2012. The massive increase of CO<sub>2</sub>E emissions due to the expanding oil sands industry will make it very difficult for Canada to fulfill its obligations under the Kyoto Agreement. The emissions from the oil sands industry alone create a significant gap of 195 mega-tonnes between increasing emissions and need for reduction. The total gap for Canada is by the government estimated to be 240 mega-tonnes by 2010. It is obvious that this figure is by far underestimated if the oil sand industry is to expand in accordance with official and governmental forecasts. For the figure below a medium value of the eight described CO<sub>2</sub>E emission scenarios is utilized.

**Figure 13.1. A Growing Gap Oil Sands CO<sub>2</sub>E Emissions And Need For Reductions Under The Kyoto Agreement**



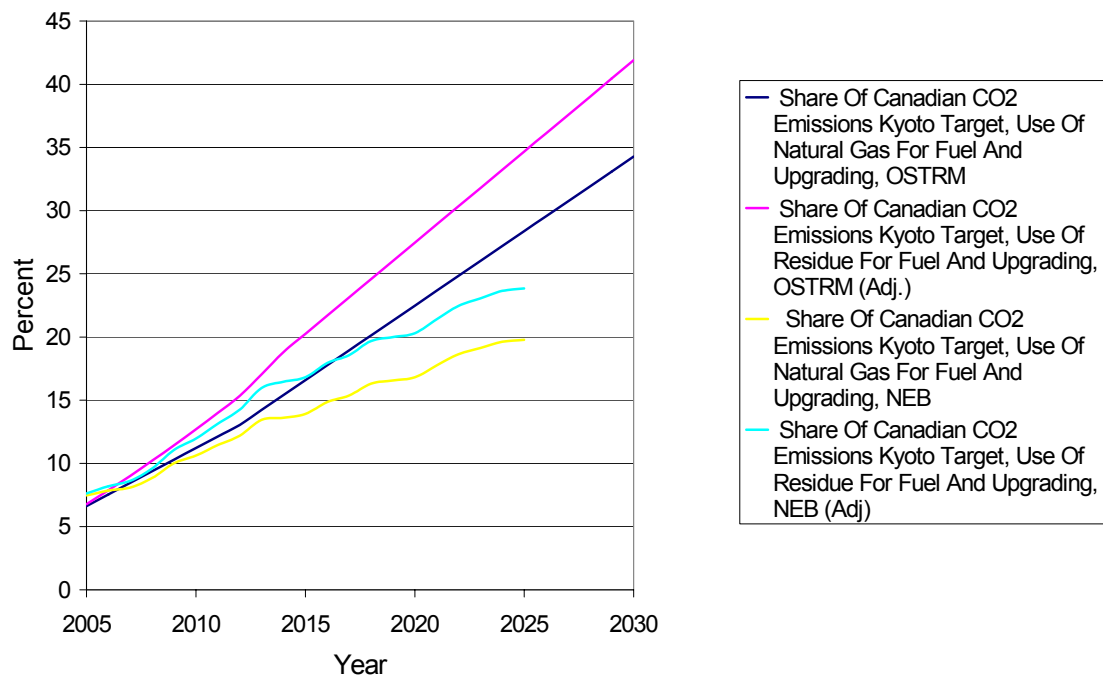
**Figure 13.2. Oil Sands Industry CO<sub>2</sub>E Emissions Between 2005 and 2013**



The CO<sub>2</sub>E forecast for the period until 2013 varies between 75 and 105 mega-tonnes per year by 2013.

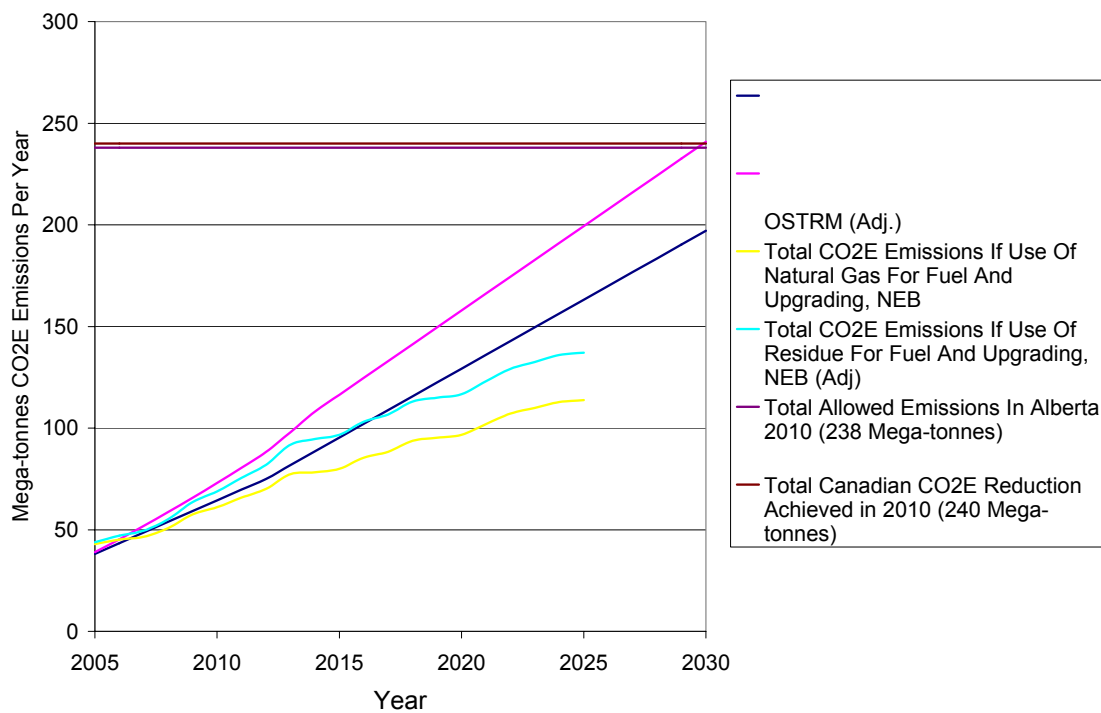
Another way to illustrate the huge increase of CO<sub>2</sub>E emissions the expanding oil sands industry will generate is to compare the two long-term oil sands production forecasts with the target level of 575 mega-tonnes CO<sub>2</sub>E emissions per year by 2012. For the OSTRM scenario the oil sands industry's share of total Canadian CO<sub>2</sub>E emission increases by six or seven times by 2030. The two NEB scenarios indicate shares of 20 percent and 24 percent respectively by 2025.

**Figure 13.3. Oil Sands CO<sub>2</sub>E Emissions in percent of Kyoto Target of 575 Mega-tonnes per Year By 2030**



In real numbers forecasts of the total emissions from the oil sands industry varies between 114 to 199 mega-tonnes per year by 2025. In the Residue-Burning Case total emissions from the oil sands industry will reach 241 mega-tonnes of CO<sub>2</sub> emissions per year. This figure is almost identical to the amount of emissions the whole of Canada is set to reduce by 2010.

**Figure 13.4. Oil Sands Industry CO<sub>2</sub>E Emissions Between 2005 and 2030**



## 13.6 Conclusion

A full conversion to burning residue for fuel and upgrading seems to be impossible to combine with the fulfillment of the obligations under the Kyoto Agreement. Most likely, a mix of both natural gas and residue will be utilized by the oil sands industry. The four described oil sands production cases, in combination with Canadian industrial, power and traffic sector emissions, will almost certainly result in various scenarios of failure for Canada's reduction commitments under the Kyoto Agreement. However, depending on how much oil sand is recovered and upgraded the CO<sub>2</sub>E emission levels varies significantly between the four different scenarios.

Nuclear power is a greenhouse gas emission free energy source that has been debated and is discussed as an alternative energy source for the oil sands industry. However, the development of this energy source has obvious social and economic constraints. It will take many years to implement a full scale expansion program of nuclear plants for oil sands industrial use.



## 14 Oil Sands Production Costs

In the report *Canada's Oil Sands – Opportunities and Challenges to 2015*, published in May 2004, the National Energy Board (NEB) has performed economic evaluations for various oil sands projects. Analyses based on these evaluations will be presented here.

The AEUB has estimated operating and supply costs for various types of oil sands recovery methods. In the estimations a crude oil price of US\$24 (C\$32) per barrel (2003 dollars) for WTI at Cushing, Oklahoma, and a NYMEX natural gas price of US\$ 4.00 (C\$ 5.33) per MMBtu (2003 dollars) has been used. The AEUB report utilizes the expressions “supply costs” and “operating costs”. Supply costs include all costs associated with exploration, development and production. They include capital costs, operating costs, taxes and royalties and a 10 percent real rate of return (12 percent nominal) to the producer. Supply costs do not include any costs to society associated with environmental impacts that have not been mitigated. Operating costs are reflecting the cash costs of operation. The implementation of more strict environmental regulations may affect supply costs. The cost impacts of the Kyoto Agreement are not included in the following production cases.

### 14.1 Upgrading Costs

Upgrading costs, including both capital recovery and operating costs, are currently about \$10-15 per barrel for a “green field” project. However, that number is very dependent on the scale of operation and the extent of upgrading. Full upgrading requires large scale for acceptable economics, but that scale can also be influenced by the degree of integration between the bitumen recovery and upgrading. Some view 100,000 barrels per day as a minimum economic scale, although the Nexen/OPTI project will start at 70,000 barrels per day capacity. The Nexen/OPTI project will be using new approaches to upgrading, including integrated residue gasification for hydrogen, SAGD energy and power production. (Alberta Chamber of Resources, 2004)

### 14.2 The Shortage of Condensate

Bitumen is generally too thick to be transported by pipelines. Therefore it has to be blended with a lighter hydrocarbon (diluent) to become less viscous. The most common diluent today is propane plus, a natural gas condensate, which is a by-product from natural gas production. Other diluent options include naphtha, light crude oil, and SCO. DilBit is bitumen that has been reduced in viscosity through the addition of a diluent such as condensate or naphtha. The projection of condensate supply is directly connected to the natural gas supply. The supply of condensate from the WCSB is forecasted to gradually decrease from 2003 levels of 171,000 b/d to 150,000 mb/d by 2015. The demand is expected to be more than 300,000 b/d by 2015. This future gap must be filled through the use of substitutes. SCO is possible to use, and it is marginally less expensive than condensate. However, a greater proportion of it is required to achieve required specifications. SynBit is the term for a blend of bitumen and synthetic crude oil. It is expected that SynBit will compete with United States Gulf Coast (USGC) medium sour crude, and DilBit will continue to compete with Mexican Maya crude. (National Energy Board, 2004)

The supply projections for most oil sands mining developments are assumed to include upgrading capacity, hence they require no diluent supply. However, some mining and most in situ bitumen projects are assumed to include only partial or no upgrading, and will therefore require significant additional diluent (National Energy Board, 2004)

### 14.3 Integrated Mining/Extraction and Upgrading

The NEB has made a project evaluation model for an integrated mining and upgrading venture. The model consists of a greenfield project for a 200,000 b/d mining/extraction and upgrading operation, with construction beginning in 2004 and first production in 2008. The project is assumed to produce SCO of 36 °API and sulphur content of 0.015 percent, which would be of similar quality and assumed value to conventional light oil. The model indicates a supply cost for SCO at the plant gate of about \$26 per barrel, which equals 19.5 US\$. (National Energy Board, 2004)

The supply cost for mining produced SCO is highly sensitive to capital costs. A 25 percent change in capital costs results in an estimated \$3.70 per barrel change in supply cost. A 10 percent decrease in production, for a given capacity design, results in an increase in supply cost of approximately \$1.50 per barrel. A 15 percent change of the price of natural gas results in a change of about \$0.50 per barrel in SCO supply cost. (National Energy Board, 2004)

Supply costs for mining/extraction without upgrading are estimated to be in the range of \$12 to \$16 per barrel of bitumen. Producers marketing non-upgraded bitumen face the risk of exposure to the price differential between light and heavy crude oil, which can vary widely. When compared with the integrated mining case in which SCO is produced, a mining/extraction has a lower expected rate of return. Thus it is considered as unlikely by the NEB that a non-integrated mining operation, without associated downstream facilities, would be constructed. (National Energy Board, 2004)

There are some variances between the costs for different ongoing mining projects. AOSP, Shell Canada, says that the AOSP in 2004 averaged more than C\$22/bbl (Can.), although its target is a \$14/bbl unit costs at recent natural gas prices. (Moritis, 2004)

### 14.4 Project Economic Evaluation – SAGD

A project evaluation model has been made for a 120 mb/d Athabasca SAGD project with a high-quality reservoir, and a 30 mb/d Athabasca SAGD project with a low-quality reservoir. As in the previously developed mining/extraction case, both of the evaluated SAGD projects are assumed to produce a DilBit of similar quality and value to a Lloydminster Blend. SAGD supply cost is less sensitive to capital cost than mining projects since the capital invested is far less. Historically, in situ projects have also had a better track record of staying on budget. Costs for SAGD as well as CSS are highly dependent on the quality of the reservoir and natural gas prices. (National Energy Board, 2004)

As previously mentioned in the report, an industry rule of thumb for SAGD projects is that the production of one barrel of bitumen requires about 1 Mcf of natural gas. One thousand cubic feet is approximately equal to an energy content of one million Btu. A

15 percent change of the natural gas price results in approximately a \$0.8 per barrel change in the supply cost, with no upgrading included (National Energy Board, 2004)

Natural gas consumption, for upgrading, amounts to some between 400 to 650 cubic feet per barrel. In addition to this another 80 cubic feet is needed for fuel, if no coke burning is assumed. Hence upgrading costs for natural gas may vary between C\$2.5 (C\$2.1 + C\$0.4 for fuel) to C\$4 (C\$3.5 + C\$0.4 for fuel) per barrel of SCO production costs at a \$5.33 per MMBtu natural gas price. Consequently total natural gas cost (production + upgrading) per barrel of SCO ranges between C\$7.5 – C\$9. To this should be added other operating costs and capital costs for upgrading, which amount to about C\$10 – 15 per barrel for a “Green field operation”. (Alberta Chamber of Resources, 2004)

Operating costs are estimated at about 8 to 14 C\$, depending on reservoir quality. Current supply costs for Athabasca SAGD are estimated to be \$11 to \$17 per barrel of bitumen. A SAGD operation with a high-quality reservoir indicates a typical supply cost of about \$19.50 per barrel for DilBit at the plant gate, which gives it a price of US\$ 14.6 per barrel. If SCO is utilized as diluent supply costs may reach \$ 22 per barrel. A SAGD operation with a high-quality reservoir including upgrading, indicate a supply cost of about C\$21-32- per barrel SCO at the plant gate. (National Energy Board, 2004) This results in a price of US\$ 15.5 – 24 per barrel.

CSS, like SAGD, is a thermal process and therefore supply costs are dependent on many of the same factors that affect the economics of SAGD. Current operating costs for CSS are estimated to be in the range of \$8 to \$14 per barrel of bitumen, with supply costs estimated to be in the range of \$13 to \$19 per barrel of bitumen. It is not anticipated that the CSS method will be widely applied outside of the Cold Lake region. (National Energy Board, 2004)

Low-quality reservoirs have well production profiles that are much less productive and the SORs are higher, which result in higher energy costs. In addition, capital costs are significantly higher as more wells must be drilled in order to maintain a stable level of production. This results in relatively poor economic performance. At US\$ 24 per barrel for WTI, the AEUB concludes that an Athabasca SAGD project with a low-quality reservoir is unlikely to be economic. (National Energy Board, 2004)

In situ production has not achieved the step reductions in operating costs that mining and upgrading projects have experienced. Instead, reductions have been driven by technological advancements and steady improvements in energy and operating efficiency. As for mining and upgrading, it is expected that in situ processes will experience improvements in supply costs as new generations of in situ processes mature. Technologies, such as VAPEX, have the potential to reduce energy intensity and the environmental impacts of production. The key issue is if the developments of the SAGD process will counteract the impact of increasing cost of natural gas. Due to the light/heavy differential and the rising cost of diluent, an increased share of in situ projects with upgrading capacity is expected in the future.

**Table 14.1. Estimated Operating and Supply Costs by Recovery Type**

US\$ (2003) per barrel at the Plant Gate	Crude Type	Operating Costs	Supply Costs
Cold Production - Wabasca, Seal	Bitumen	3 to 5	7.5 to 10.5
Cold Heavy Oil Production - Cold Lake	Bitumen	4.5 to 7	9 to 12
Cyclic Steam Stimulation (CSS)	Bitumen	6 to 10.5	10 to 14
Steam Assisted Gravity Drainage (SAGD)	Bitumen	6 to 10.5	8 to 13
SAGD (Blended)	DilBit/SynBit	n/a	14.5 to 16.5
SAGD and Upgrading	Synthetic	n/a	15.5 to 24 *
Mining/Extraction	Bitumen	4.5 to 7.5	9 to 12
Integrated Mining/Upgrading	Synthetic	9 to 13.5	16.5 to 21

Source: NEB, 2004

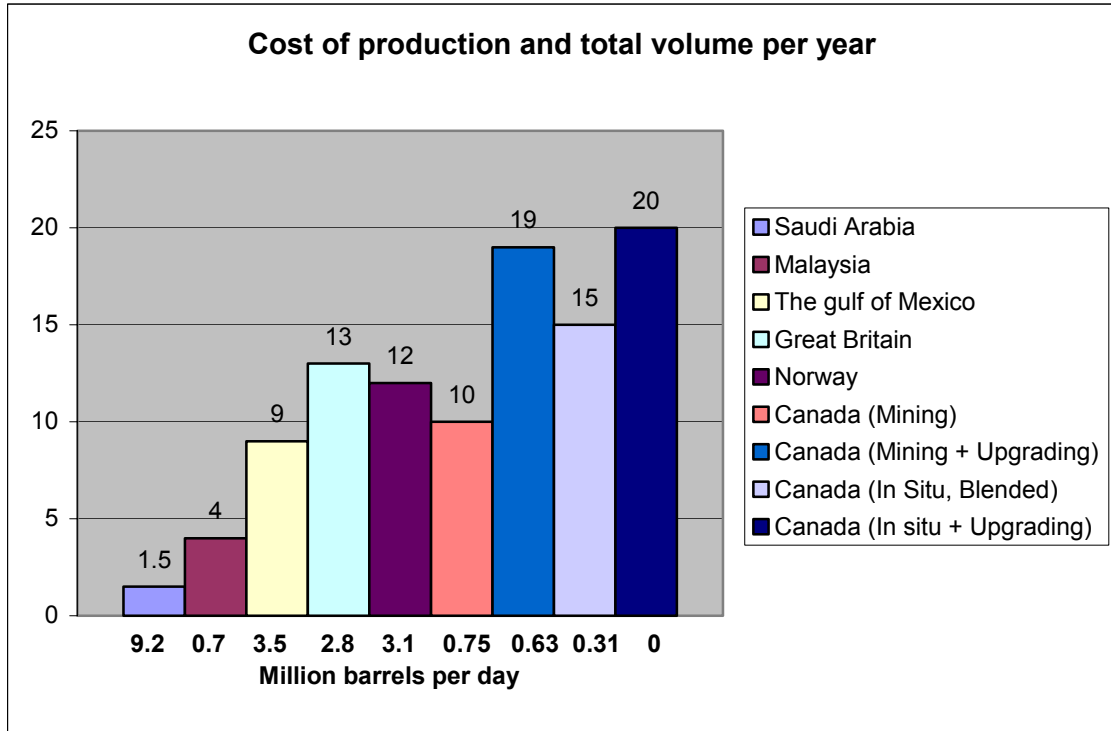
\* Including \$7.5 - 11 for upgrading

#### **14.4.1 The Kyoto Protocol**

Suncor's preliminary analysis of the Kyoto Accord through to 2012 predicts that the impact on supply cost will be manageable at approximately \$0.20 to \$0.27 per barrel. (National Energy Board, 2004)

According to the federal government, the production cost of complying with the first stage of the Kyoto Protocol is estimated to be only about 20 to 30 cents per barrel. However, compliance costs after 2012 have not been projected. (National Energy Board, 2003)

**Fig 14.1. Comparison of Oil Production Costs**



Source: IVA (2002) & NEB (2004)

## 15 All Projects Oil Sands Production Forecast

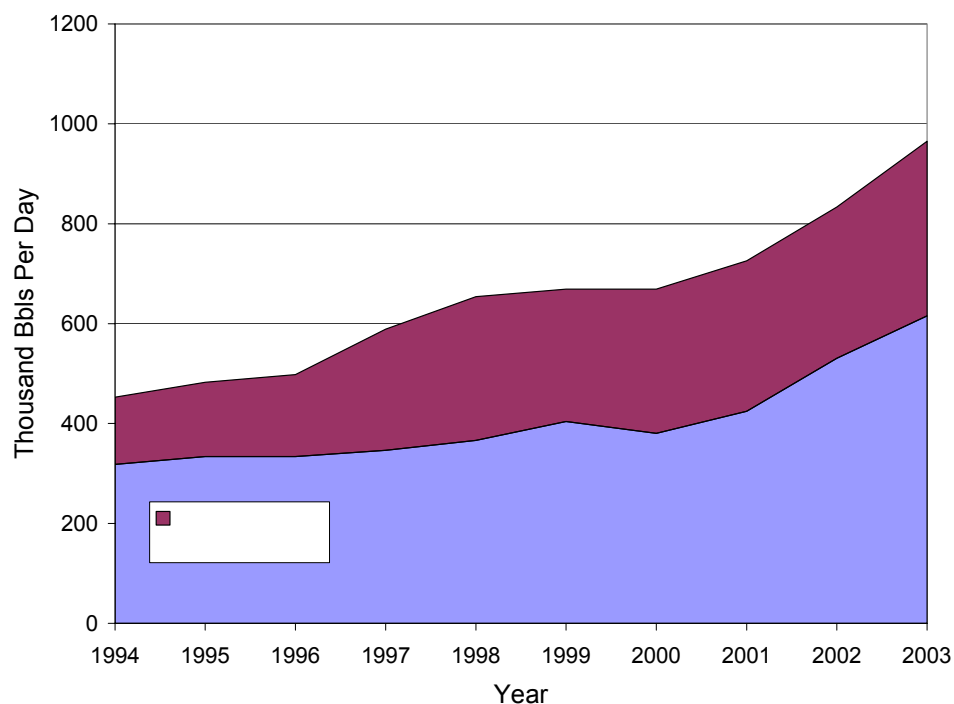
This report presents four public forecasts of Canadian oil sands production. An investigation of my own of oil sands production projects has also been performed. Every large active or planned project has been described including facts about oil sands reserves and planned future production. This material has been used to create different oil sands production forecasts. These forecasts are termed as *All Projects*.

The four public forecasts studied predict a production of bitumen between 2.0 to 2.3 million barrels per day by 2013. The All Projects forecast would result in a production of 3.1 million barrels per day by 2013.

Current Canadian production is approximately one million barrels per day, of which 600,000 are synthetic crude oil produced by mining and 400,000 are non-upgraded bitumen, mainly produced by in-situ methods.

For the last five years the Canadian oil sands production has soared due to high oil prices. Today's stretched oil market has made profitable the most expensive type of large scale oil production in the world.

**Fig 15.1. Historical Canadian Oil Sands Production 1995 - 2003**

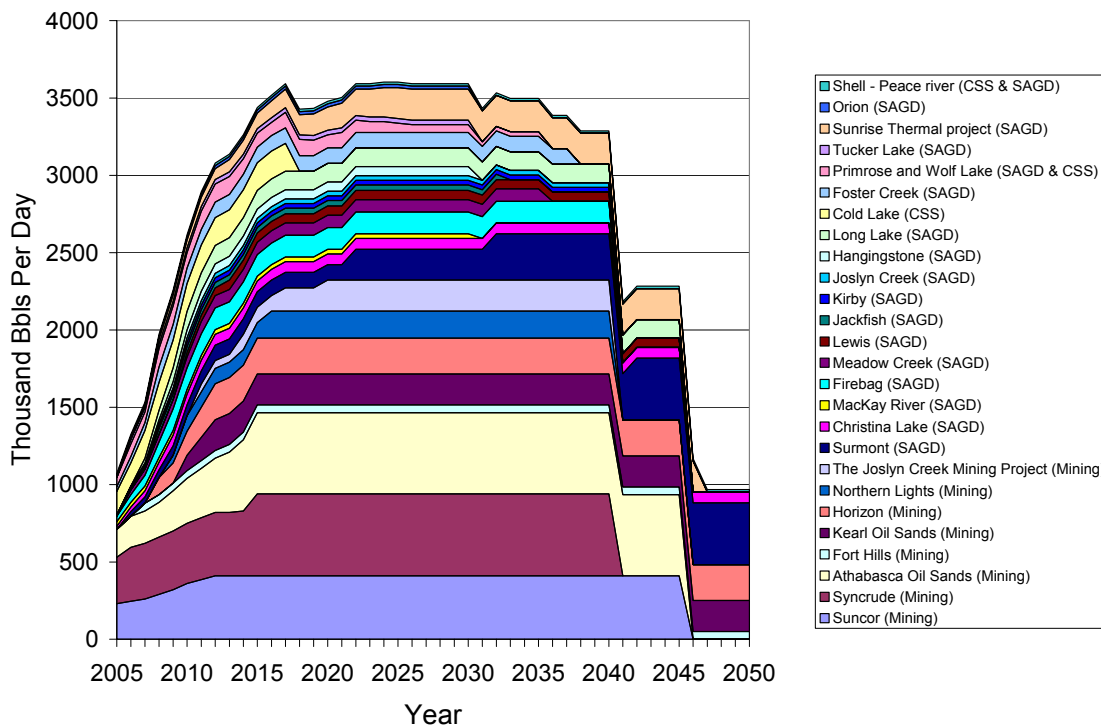


As already mentioned, for this report an investigation of all major oil sands projects' reserves and the projects' planned productions has been performed. This investigation has resulted in a forecast termed *All Projects*. This forecast assumes that all proposed oil sands projects are carried out and developed on schedule. This is obviously an unrealistic scenario since there are significant uncertainties associated with the natural gas situation in Canada, capital costs and the cost of greenhouse gas emissions.

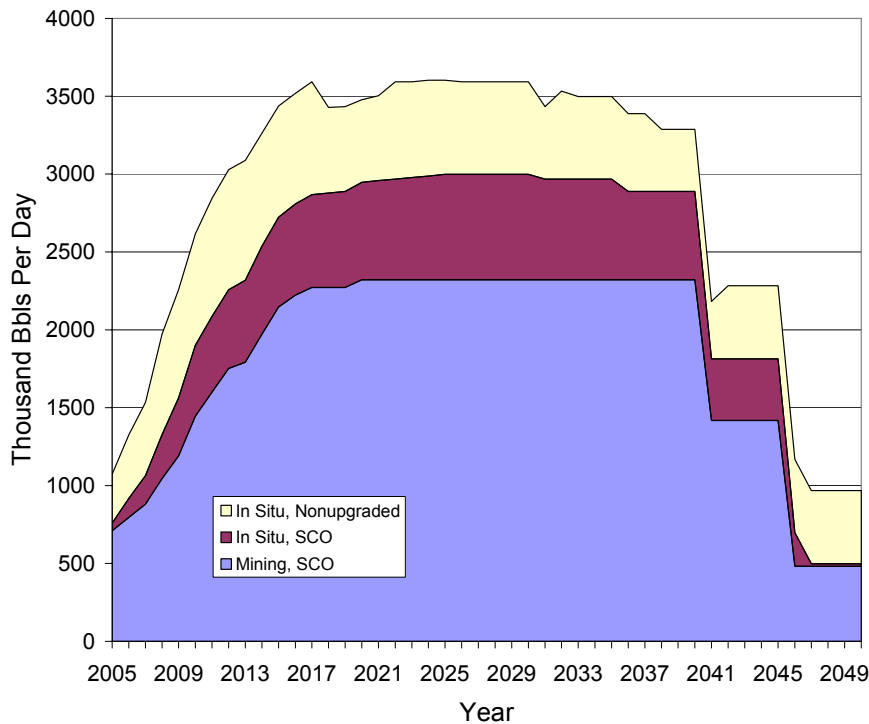
Surface mining production will provide the mainstay of oil sands production for the coming 10 to 15 years. However, in situ production represents the long-term future of the Canadian oil sands industry. The long-term future for the in situ production is not reflected in the All Projects forecast. This is because the in situ production is still a relatively new and unknown technique associated with significant uncertainties about its future potential. Consequently, companies have been very moderate when describing the future development of their in situ projects.

To properly illustrate the coming importance of the in situ production the projections have been adjusted with additions estimating its future production. These additions are obviously speculative.

**Figure 15.2. All Projects Forecast**



**Figure 15.3. All Projects Forecast, In Situ And Mining Production**

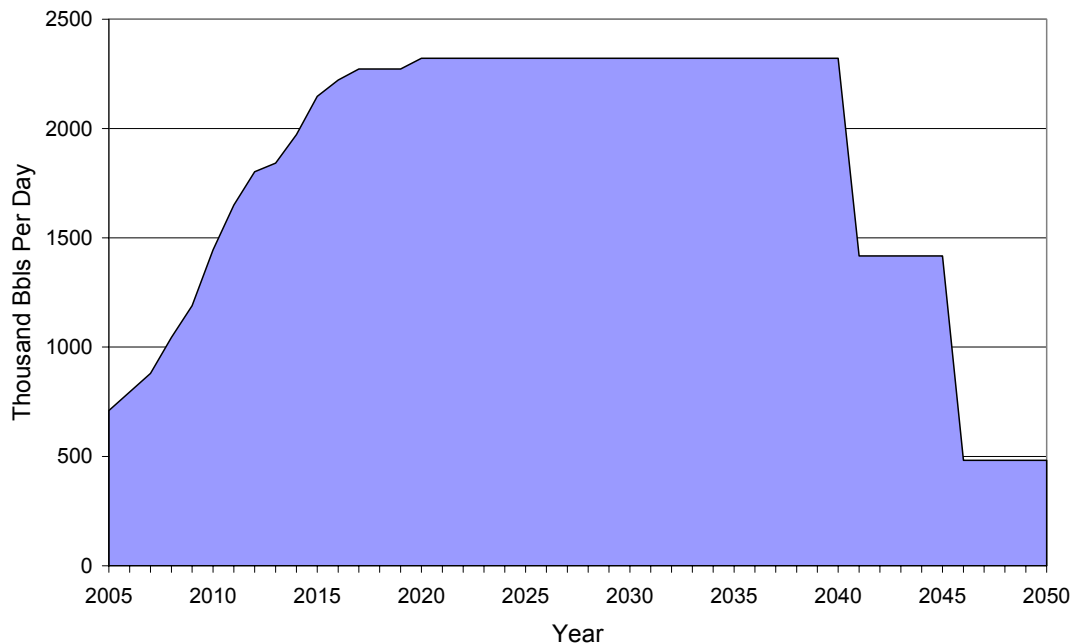




## 15.1 The Canadian Mining Extraction of Oil Sands Will Peak

An interesting conclusion of figure 15.2 and 15.3 is that the mining production will reach a plateau production and then decline. The All Projects oil sands mining production, specifically presented in figure 15.4, results in a mining production of 30.4 giga barrels of bitumen. The established remaining mineable reserves are 32.13 giga barrels. However, additional bitumen will most likely be produced for fuel and to compensate for losses associated with upgrading. Consequently the whole established mineable reserve of bitumen will have been produced around 2050.

**Figure 15.4. All Projects Oil Sands Mining Forecast**

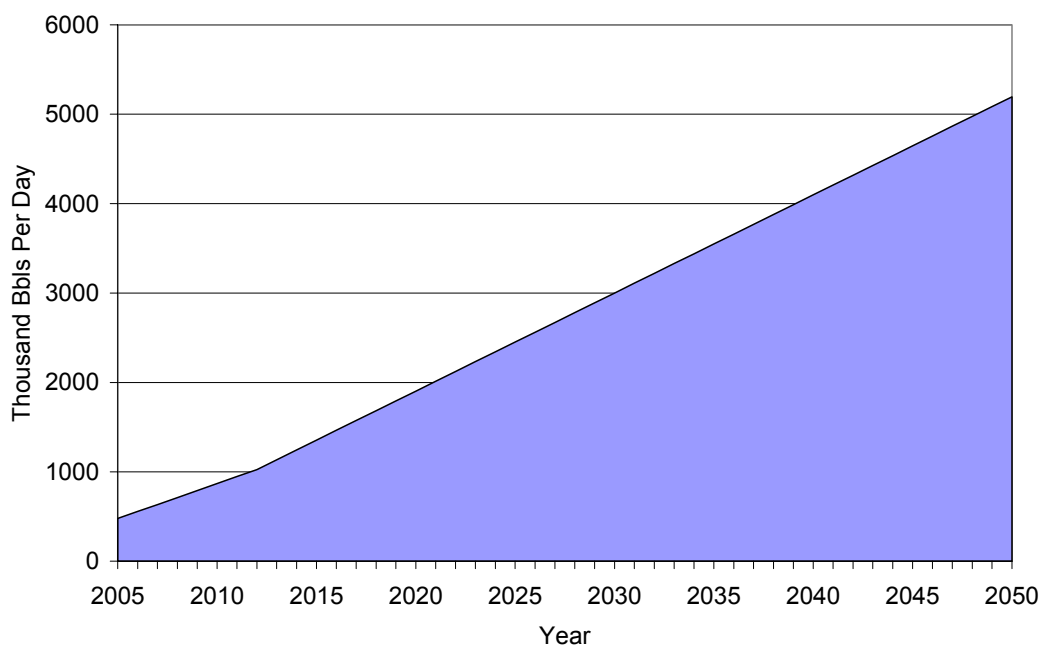


## 15.2 In Situ Production – the Long Term Future

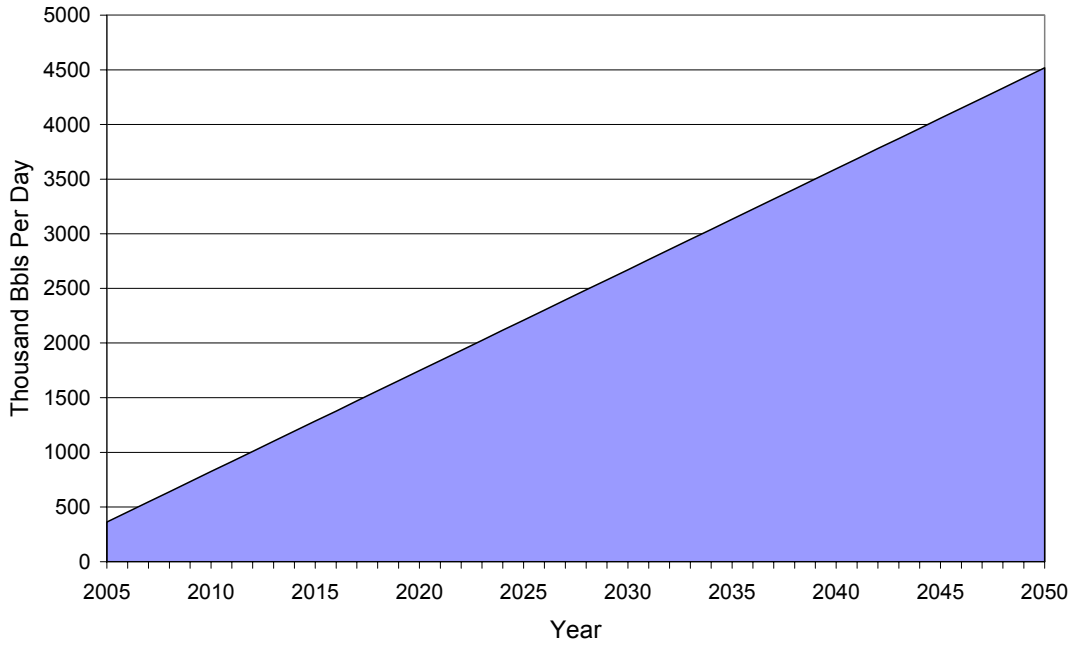
Since the predominant part of Canada’s oil sands reserves can only be extracted by in situ methods, it is important to estimate how this production will develop in the future. Such an estimation is very difficult to make since in situ methods such as SAGD are untried in a larger scale. As earlier described, SAGD methods work best in high quality reservoirs. The potential for emerging in situ technologies are also largely unknown. This report has highlighted the enormous demand for natural gas for in situ production and the accelerating CO<sub>2</sub>E emissions from the oil sands industry. However, below three in situ production scenarios are presented. The first is an extrapolation of the OSTRM scenario. This curve gives a total in situ production of three million bbls per day by 2030. The second scenario is an extrapolated curve of the All Projects in situ forecast which together with mining result in a production of approximately five million barrels by 2030.

The third scenario is an extrapolation of the NEB forecast, which results in a significantly lower production.

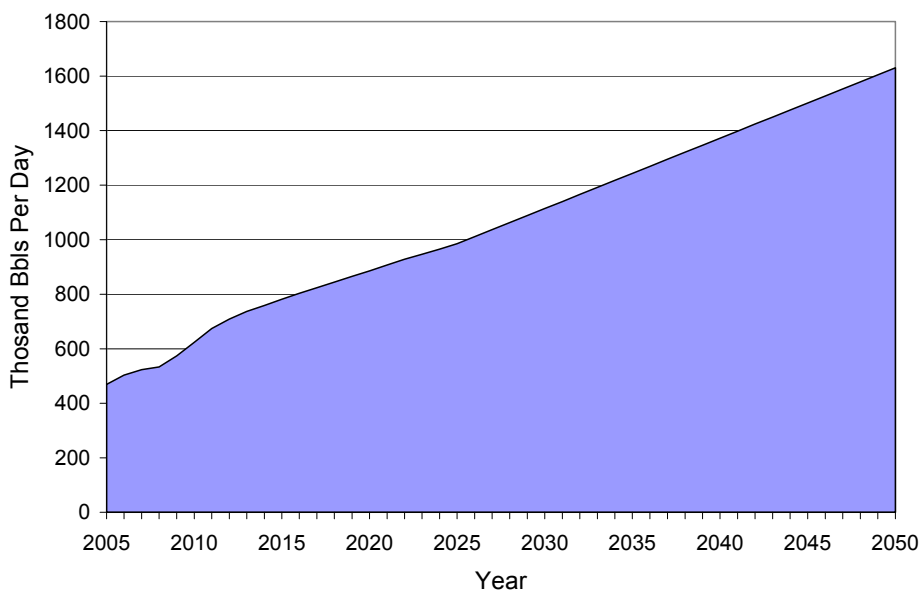
**Figure 15.5. Scenario A. In Situ Production Forecast, Three Million In Situ Produced Bbls per Day by 2030**



**Figure 15.6. Scenario B. In Situ Production Forecast, 2.7 Million In Situ Produced Bbls per Day by 2030**



**Figure 15.7. Scenario C. In Situ Production Forecast, extrapolation of NEB Forecast**



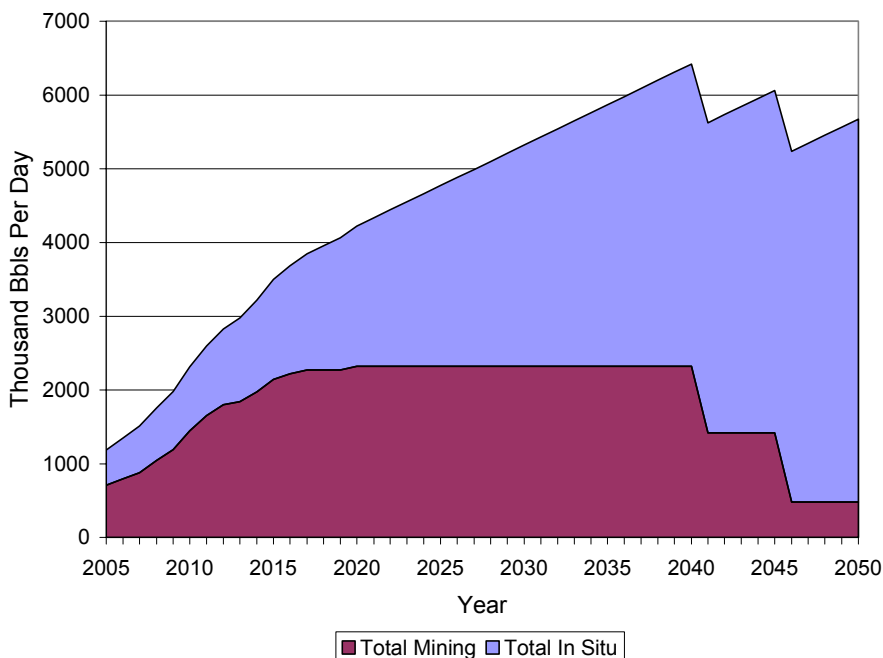
### 15.3 Canada's Total Oil Sand Production May Peak

It is important to remember that the mining production in these scenarios is developed at a much faster pace than what is probably realistic! However if a serious global oil supply shortage would occur it is plausible that all the projects would come on line since high revenues would compensate for accelerating natural gas prices and CO<sub>2</sub>E emissions. But the purpose of these scenarios is not to give an accurate production forecast, but to illustrate that the total Canadian oil sands production will probably have a peak, since the relatively untried in situ method may not compensate the declining mining production.

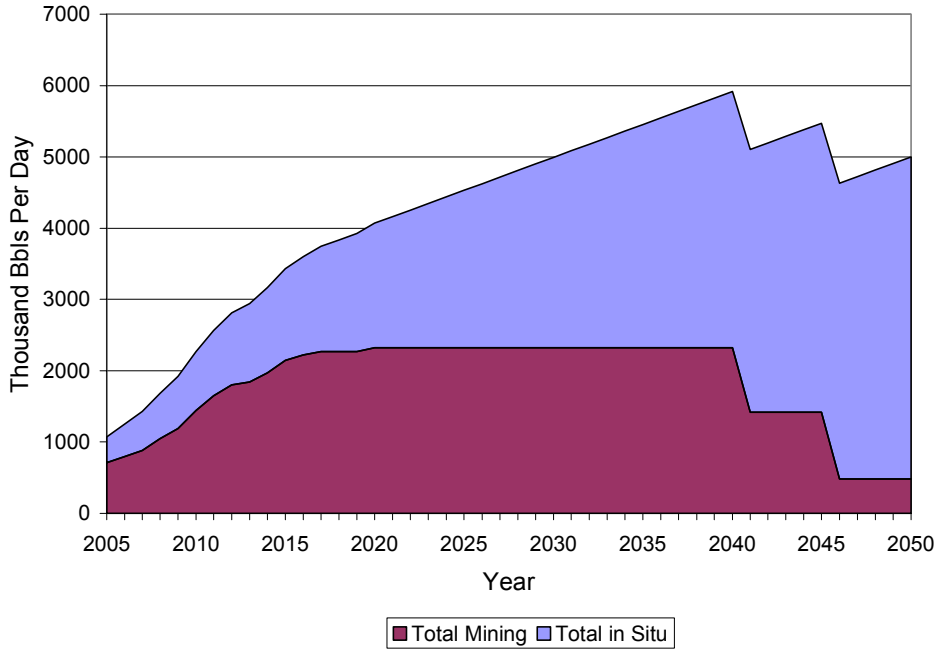
In the three scenarios, 1, 2 and 3, presented below, the three in situ production scenarios have been added to the mining production scenario. The results indicate that there will probably be a peak production for the Canadian oil sands industry.

In any case, due to the global oil supply decline, what happens with Canadian oil sands production after 2050 is relatively uninteresting since the fall of global oil supply by then will have reached such an magnitude that it is impossible to compensate with new production.

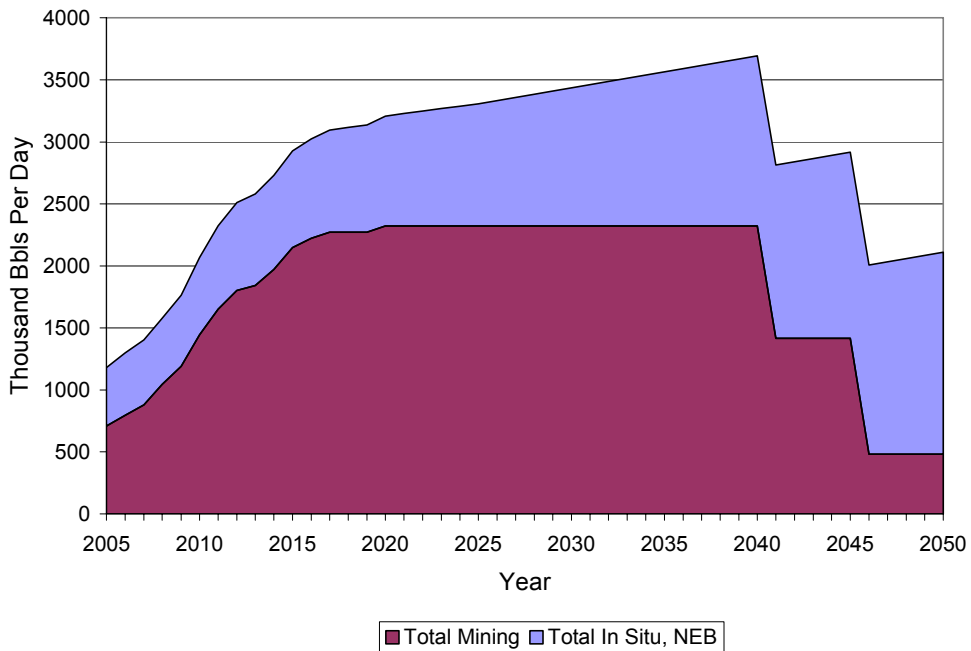
**Figure 15.8. Scenario 1. Mining + Scenario A. In Situ Production Three Million Bbls per Day by 2030**



**Figure 15.9. Scenario 2. Mining + Scenario B. In Situ Production 2.7 Million Bbls Per Day by 2030**



**Figure 15.10. Scenario 15.10 Mining + Scenario C. In Situ Production Interpolation of NEB Forecast**



## 16 A Comparison with the North Sea

Crude oil production from the mature North Sea basins is already in a long-term decline. The North Sea production peaked in 2000 with a production of about six million barrels per day. Output is projected to drop to 3.4 million barrels per day by 2010, about 65 percent of current production, and dwindle to 0.85 million barrels per day in 2030.

Despite soaring oil prices, European exploration and development have declined sharply in the last few years, as prospects have deteriorated. Several of the leading international oil companies are getting rid of assets in the region. Independent operators are becoming more important for exploiting remaining reserves in mature fields and developing smaller fields which would otherwise not have been considered. (World Energy Outlook, 2004)

As for the North Sea, Canada's conventional crude oil production is also in a long-term state of decline. Canada's conventional crude oil production peaked in 1973 with a production of about 1.7 million barrels per day. Production by 2010 is expected to be 635,000 barrels per day. In 2030 production will have diminished to a mere production of about 200,000 barrels per day

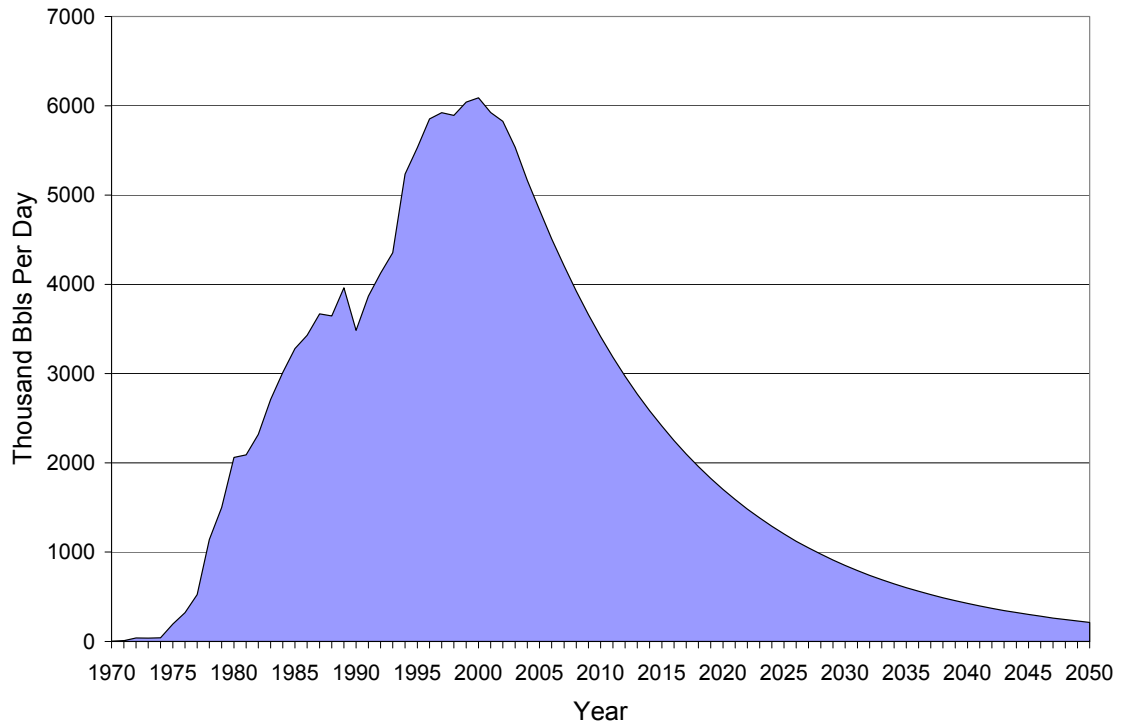
Will the oil sands production of Canada be able to compensate for the ongoing and future shortfall of the North Sea production and Canada's own conventional crude oil production? Apart from compensating, will the Canadian oil sands industry also be able to produce even more than the combined shortfall of conventional crude oil production in the North Sea and in Canada? If not, the oil sands deposits of Canada may not be able to satisfy the soaring world oil demand, forecasted by the IEA, but merely dampen the effects of peaked conventional oil production in the North Sea and Canada. Thus, it is interesting to compare the forecasted oil sands production of Canada with the forecasted total conventional crude oil production in the North Sea and Canada.

### 16.1 Declining Production from the North Sea and Canada

In the following figures the declining conventional crude oil production from the North Sea and Canada is illustrated. The production from the two areas is also illustrated as one production curve in figure 16.3. The North Sea includes oil production from the UK, Norway and Denmark.

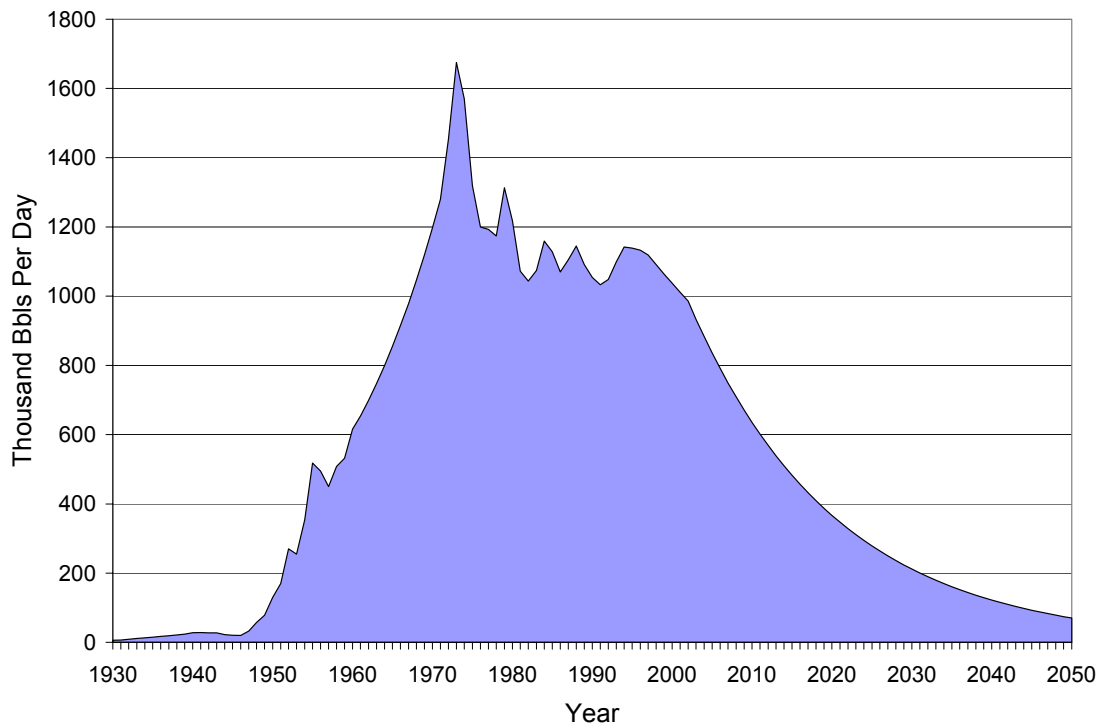
The figures for the declining conventional crude oil production in the North Sea and Canada are also added to the OSTRM oil sands production forecast, the NEB oil sands production forecast (The two long-term forecasts) and also scenario 1 (Three million in situ production level by 2030) in order to get a resulting oil production curve. This resulting oil production curve shows how the net production of oil develops with the production of year 2005 as a starting zero point.

**Fig 16.1. The North Sea Crude Oil Production 1970 - 2050, Including Norway, Denmark and the UK**



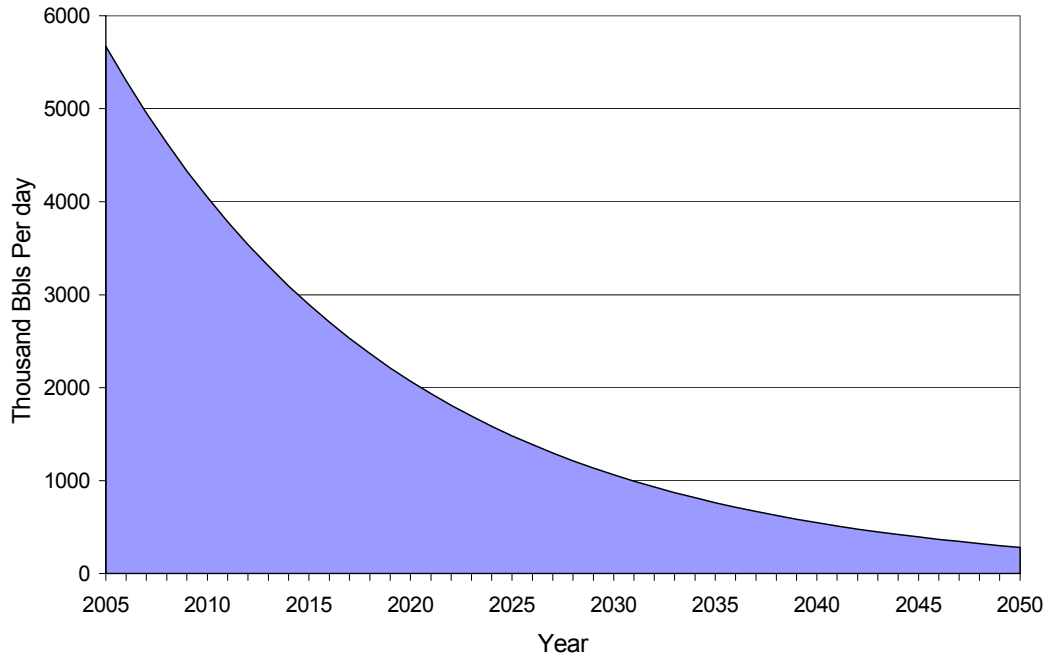
Source: Campbell (2005)

**Fig 16.2. Canadian Conventional Crude Oil Production 1930 – 2050**

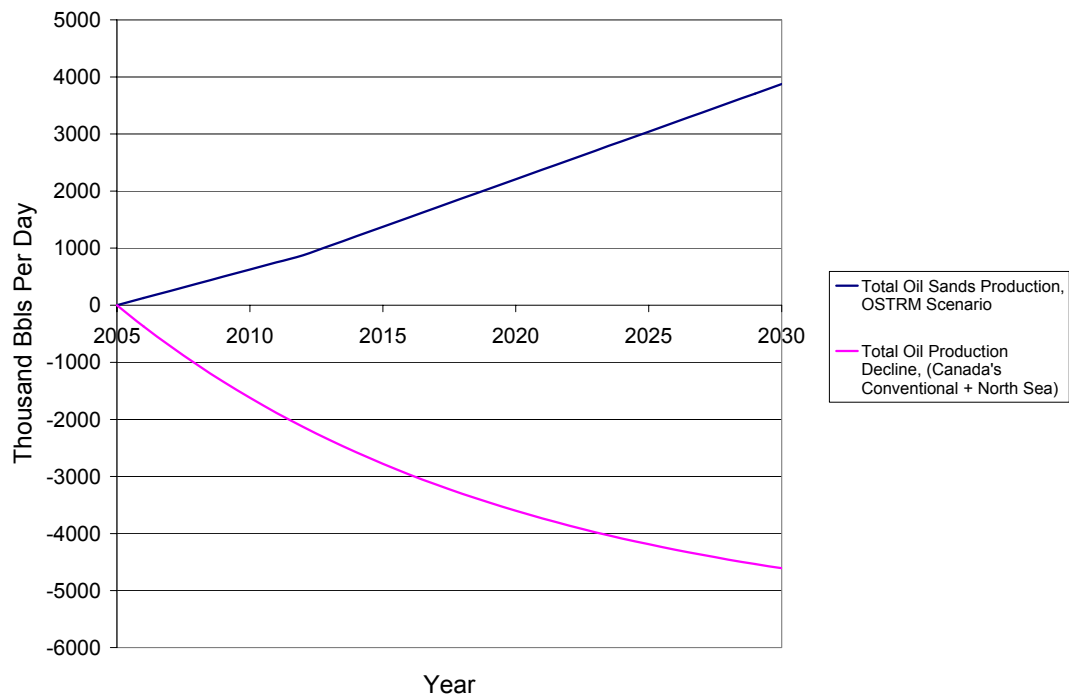


Source: Campbell (2005)

**Figure 16.3. The Combined Conventional Crude Oil Production from the North Sea and Canada 1930 – 2050**

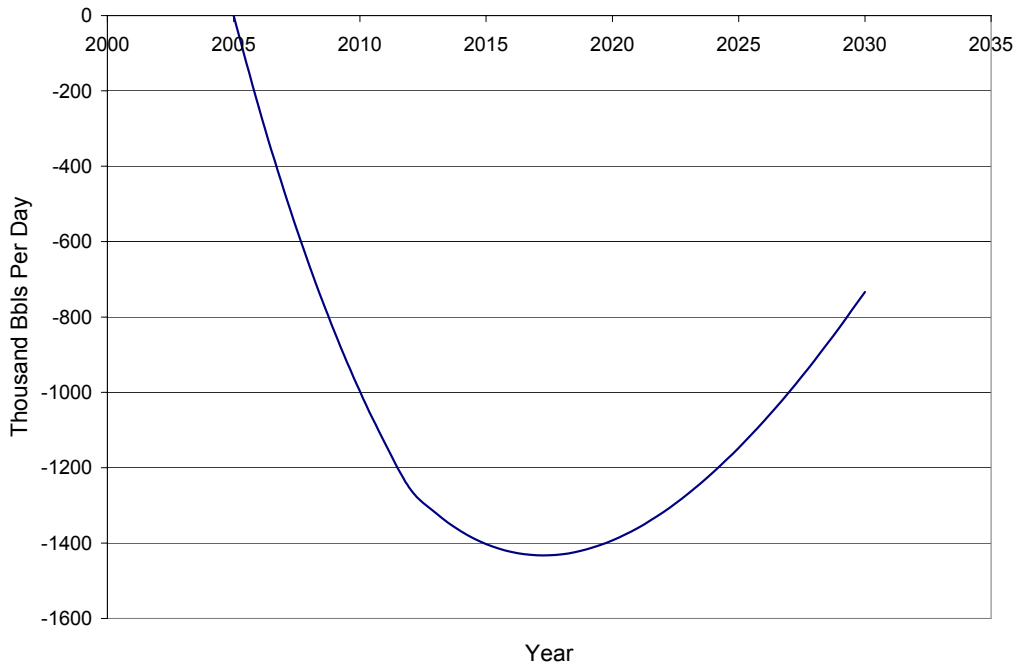


**Figure 16.4. OSTRM Forecast, Compared With Conventional Crude Oil Production from the North Sea and Canada.**

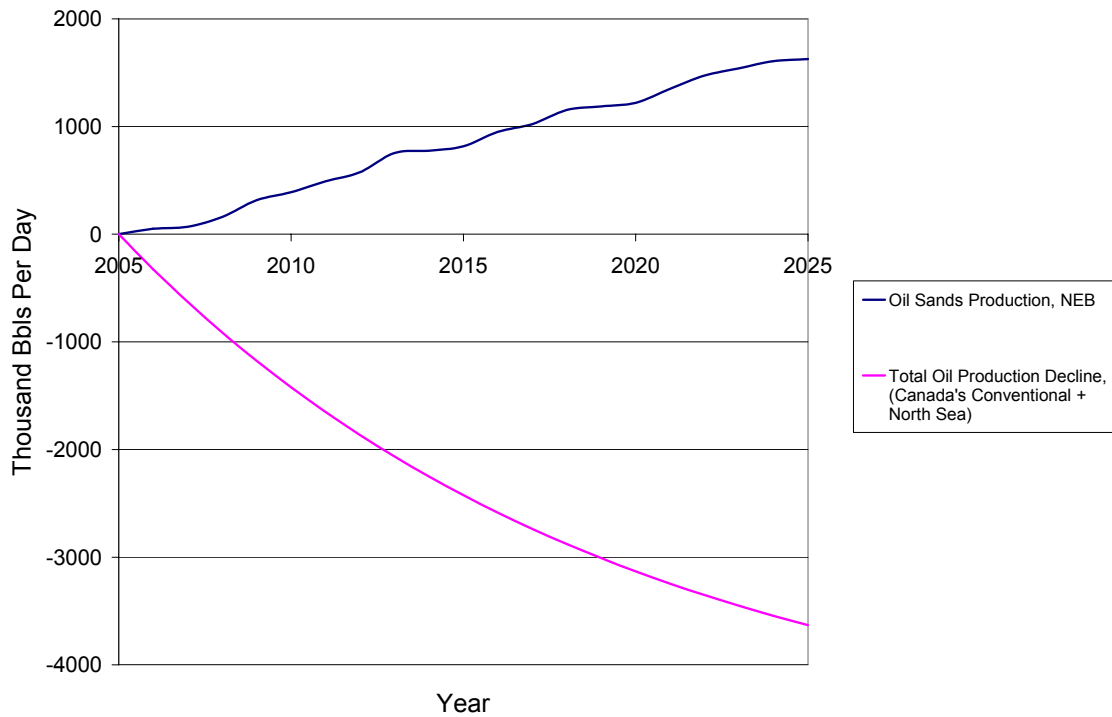




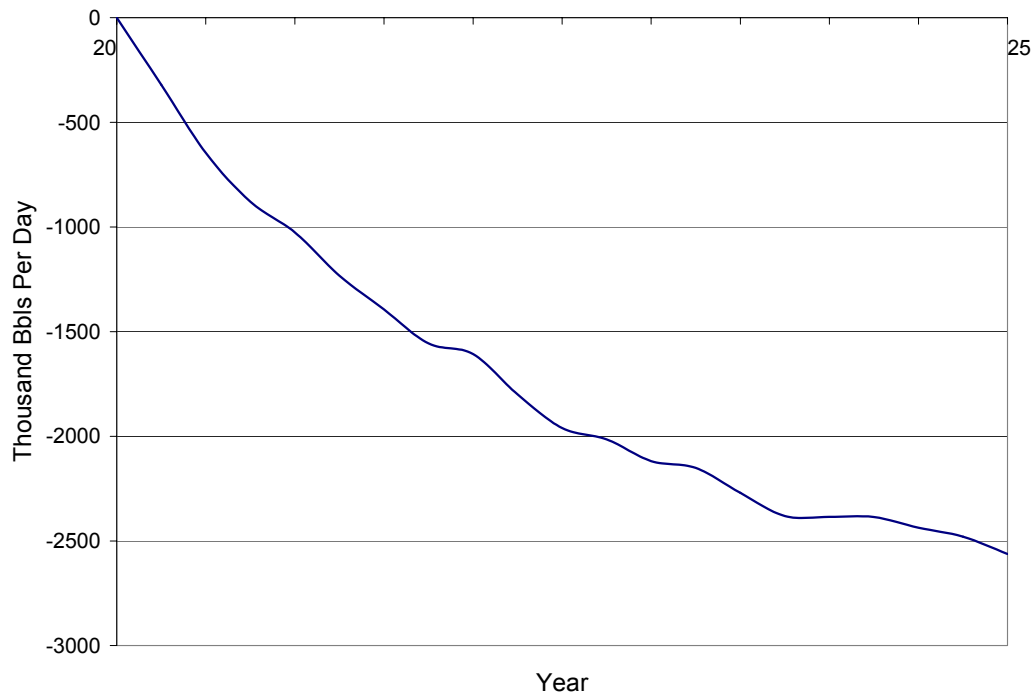
**Figure 16.5. Resulting Net Oil Production, Canada's Oil Sands Production (OSTRM Forecast), Canada's Conventional Production and The North Sea**



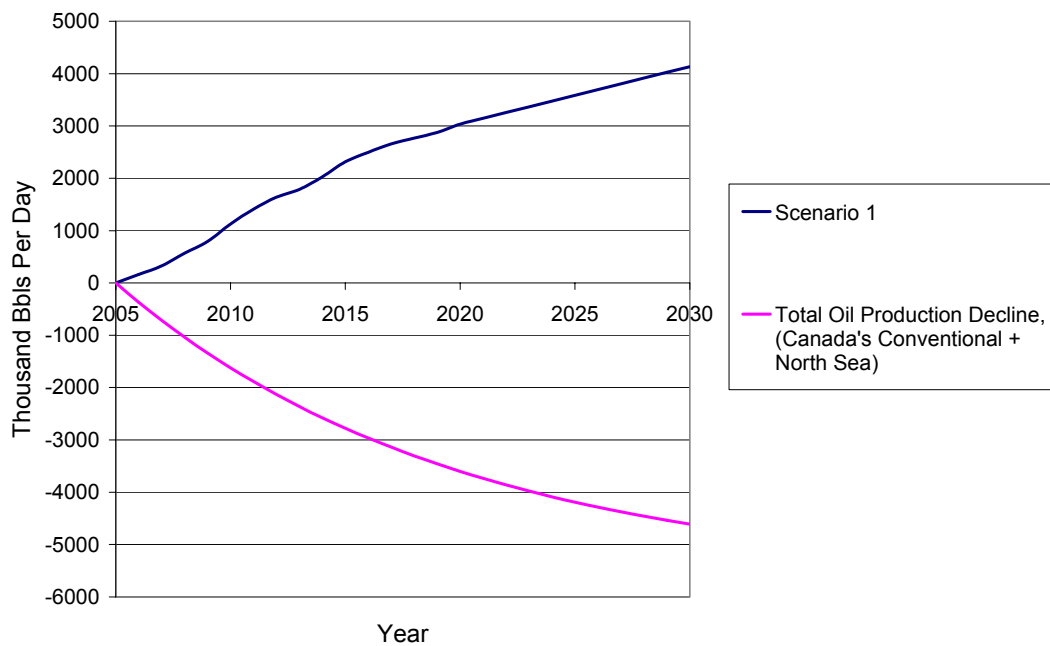
**Figure 16.6. NEB Forecast, Compared With Conventional Crude Oil Production From The North Sea And Canada.**



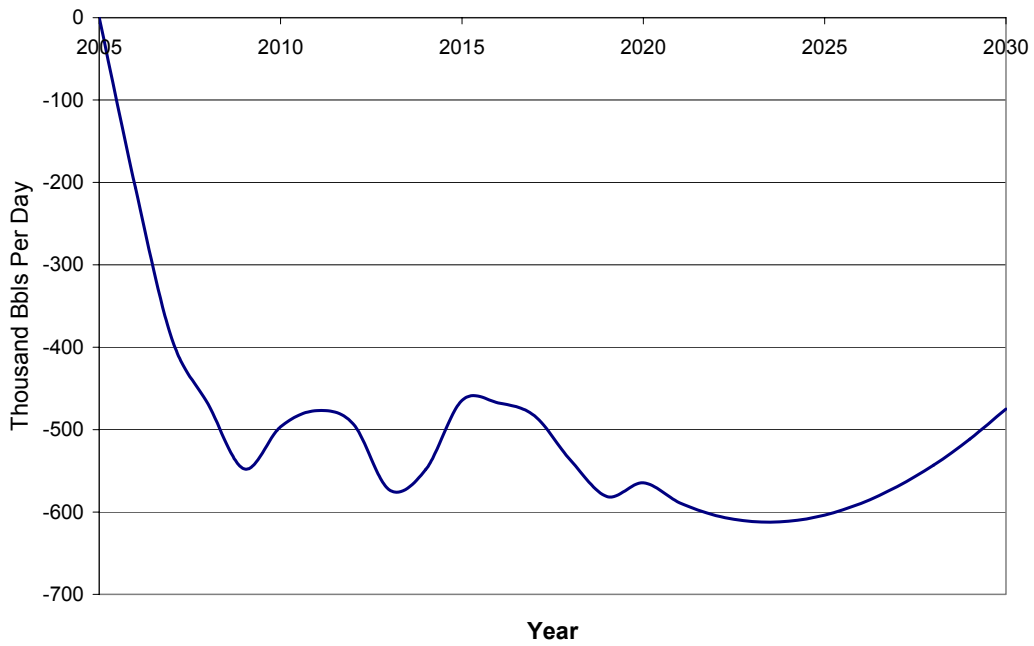
**Figure 16.7. Resulting Net Oil Production, Canada's Oil Sands Production (NEB Forecast), Canada's Conventional Production And The North Sea**



**Figure 16.8. Scenario 1, Compared With Conventional Crude Oil Production from the North Sea and Canada.**



**Figure 16.9. Resulting Net Oil Production, Canada's Oil Sands Production (Scenario 1), Canada's Conventional Production and the North Sea**



## 16.2 Observations

Neither of the two official Canadian forecasts of oil sands production manages to even compensate for the declining conventional crude oil production from the North Sea plus Canada. Not even the more optimistic scenario 1 manages to compensate the shortfall by 2030.

## 17 Discussion and Conclusions

The Canadian oil sands industry should be viewed as two separate forms of oil production, in situ production and mining. In many aspects in situ production has more in common with conventional crude oil production than with oil sands mining production. While the bitumen reserves available by in situ production are estimated to quite enormous 140+ billion barrels, the mining reserves are comparatively more modest with 32 billion barrels.

### 17.1 Development Constraints for the Oil Sands Industry

As this report has shown there is not enough with supply of natural gas in North America to support a future Canadian oil sands industry with today's dependence of natural gas. Fear of soaring natural gas prices will probably dampen the short-term will to invest in billion dollar ventures, since future production costs are so uncertain.

The report has also shown that prospects of using bitumen as fuel and for upgrading are not so bright in the long-term perspective. Is Canada willing to abandon the Kyoto treaty in order to allow accelerating emissions from the oil sands industry? Today the cost of emitting CO<sub>2</sub>E is negligible, but what will the cost be after 2012? This is obviously also a factor that may keep investors from investing in oil sands ventures. One should also keep in mind the enormous environmental problems with the oil sands industry. This report has mostly focused on the CO<sub>2</sub>E problems, but other problems such as land destruction, ground water drainage, large lakes filled with oil sands by-products, are significant. Are the Canadians willing to create an environmental disaster in Alberta only to provide the world market with still relatively cheap oil?

However should there be a severe oil shortage in the near future with soaring oil prices it is possible and also probable that many of today's planned projects will be put in production. Most of the planned large-scale projects are mining projects, which have proved to be profitable already today. The CO<sub>2</sub>E emissions might easily be paid off with record oil revenues. However, as this report has shown, such a scenario will probably result in a peak of the oil sands production.

### 17.2 The Difficulty with Oil Sands Production Forecasts

The great uncertainty associated with the Canadian oil sands industry is the potential of in situ oil sands production. It has been made clear in this report that the long-term future of the Canadian oil sands industry is in the situ production. This is a relatively new technique associated with some significant uncertainties. First, the question is whether there will be enough supply of energy developed in time for a large-scale expansion of the in situ production industry. This report has pointed out that today's Canadian natural gas supply is not enough to satisfy the demand without much higher prices. Second, will the in situ techniques such as SAGD and its different variants achieve a high production also for low quality reservoirs? Today's SAGD projects are naturally situated on the best reservoirs. Still, no SAGD mega-venture with more than 50,000 barrels per day of production has been put in production. Third, how much of the oil sands deposits may be considered as high quality reservoirs for in situ production?

All these factors taken together indicate that all the in situ production scenarios 1, 2 and 3, outlined in this report may be realistic. After all, they are interpolations of official Canadian forecasts. Most likely the Canadians will construct nuclear plants to provide energy for this industry, but this will probably take long.

Some predictions of my own can be made from the different forecasts. A production of 5 million barrels per day by 2030, and five to ten years later even slightly higher (almost 6 million barrels of peaking oil sands production by 2035-2040), is perhaps possible if an expansion of nuclear energy is achieved and the Kyoto treaty not taken into consideration. This ought to be considered as a very optimistic production forecast, since an interpolation of the NEB in situ forecast combined with total mining production (scenario 3) reaches a maximum production of a mere 3.5 million barrels by 2030.

A more realistic forecast is probably a production of five million barrels per day by 2030, followed by a plateau production for some years then turning into a continuous slow decline.

### **17.3 The Canadian Oil Sands Production Will Peak**

Being the most expensive large-scale oil production in the world, oil sands mining is today a well proved technique. In the light of an approaching peak oil scenario, it is reasonable to assume that the oil price will remain high and climb even further. Although associated with great economic and environmental costs the oil sands mining industry might very well continue its high growth. This report has shown that a plateau production and a following decline are expected for the oil sands mining industry in such a scenario. By 2050, in principle all of the 32 billion barrels of mineable bitumen reserves will have been produced.

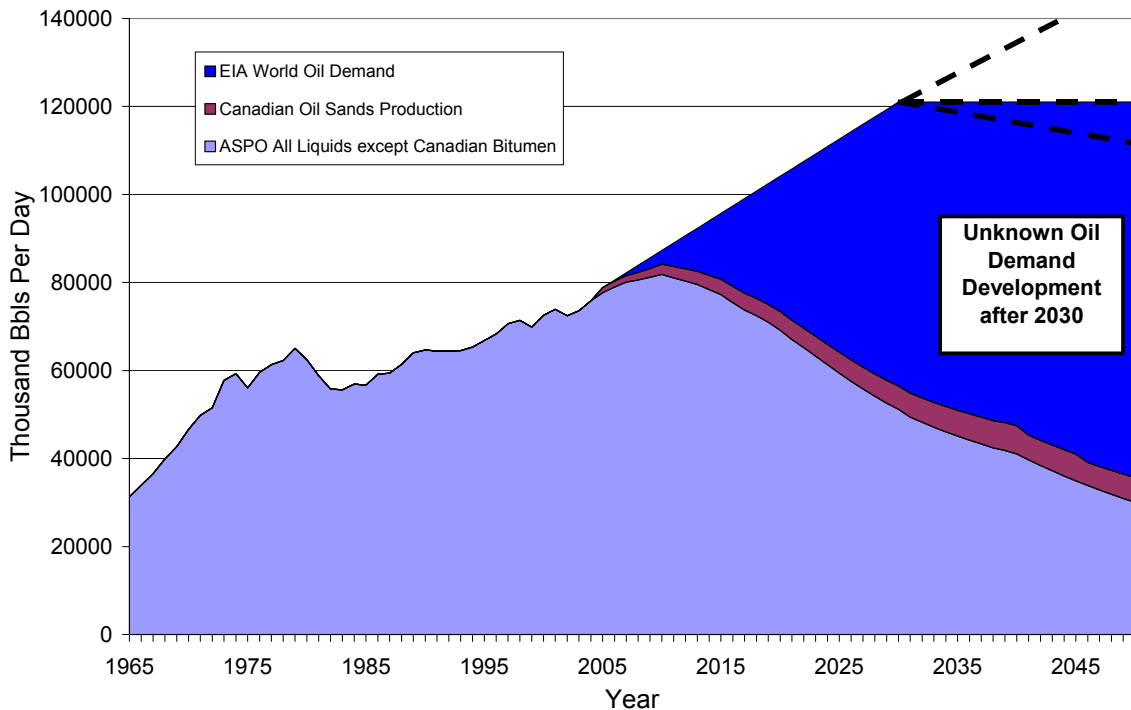
The decline of oil sands mining production will probably result in a total decline for the Canadian oil sands industry as a whole. This because in situ production is an oil production technique without the possibility to achieve large scale production in time and the in situ production projects will not be able to reach the required volumes to compensate for the decline from the oil sands mining projects.

## 17.4 The Canadian Oil Sands will not prevent Global Peak Oil Production

Unfortunately, while the theoretical future oil supply from the oil sands is huge, the potential ability for the Canadian oil sands industry to meet a growing world oil demand, is not based on reality. As this report has shown, none of the official Canadian forecasts result in an oil sands production that can even compensate for the combined declining conventional crude oil production in Canada and the North Sea. Not even the more optimistic scenario 1, outlined in this report, managed to compensate the decline by 2030. Figure 17 below, describes the most optimistic oil sands production scenario in this report and its potential impact on global oil supply.

The International Energy Agency claims that 37 million barrels of unconventional oil must be produced by 2030. Canada has by far the largest unconventional oil reserves. By 2030, in a very optimistic scenario, Canada may produce 5 million barrels per day. Venezuela may perhaps achieve a production of 6 million barrels per day. Who will be the producers of the remaining 26 million barrels per day?

**Figure 17. The Impact of Canadian Oil Sands Production on Global Oil Supply**



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