UPPSALA UNIVERSITY 2006-06-08

Accepted by Energy Policy.
http://www.elsevier.com/wps/find/journaldescription.cws_home/30414/description#description

A Crash Program Scenario for the Canadian Oil Sands Industry

Bengt Söderbergh, Fredrik Robelius and Kjell Aleklett

Contact: Kjell Aleklett

Uppsala Hydrocarbon Depletion Study Group

Uppsala University, Box 535, SE-751 21, Sweden

Contact e-mail: Aleklett@tsl.uu.se

Abstract

The report *Peaking of World Oil Production: Impacts, Mitigation and Risk Management,* by Robert L. Hirsch et al., concludes that Peak Oil is going to happen and that worldwide large-scale mitigation efforts are necessary to avoid its possible devastating effects for the world economy. These efforts include accelerated production, referred to as *crash program production*, from Canada's oil sands. The objective of this article is to investigate and analyse what production levels that might be reasonable to expect from a crash program for the Canadian oil sands industry, within the time frame 2006-2018 and 2006-2050. The implementation of a crash program for the Canadian oil sands industry is associated with serious difficulties. There is not a large enough supply of natural gas to support a future Canadian oil sands industry with today's dependence on natural gas. It is possible to use bitumen as fuel and for upgrading, although it seems to be incompatible with Canada's obligations under the Kyoto treaty. For practical long-term high production, Canada must construct nuclear facilities to generate energy for the in situ projects. Even in a very optimistic scenario Canada's oil sands will not prevent Peak Oil. A short-term crash program from the Canadian oil sands industry achieves about 3.6 mb/d by 2018. A long-term Crash program results in a production of approximately 5 mb/d by 2030.

Key Words:

Oil Sands, Canada, Peak Oil, Crash Program Production

Table of Contents

1. Introduction

It is often claimed that non-conventional oil production, such as Canadian oil sands production, may play an important roll for bridging the coming gap between the world's soaring oil demand and global oil supply. In February 2005 the report *Peaking of World Oil Production: Impacts, Mitigation and Risk Management* (Hirsch, 2005), by Robert L. Hirsch, Roger Bezdek and Robert Wendling, was released. The report gave an overview of the subject of peaking of world oil production and possible mitigation measures in order to dampen the effects of increased scarcity of oil. The report explained that the peaking of world oil production is such a serious problem that without preventive actions, "the economic, social, and political costs will be unprecedented".

Consequently, the report declared that the challenge of oil peaking deserves immediate and serious attention if the problem area is to be fully understood and mitigation begun in time. The pace that governments and industry choose for mitigation actions are defined as "overnight go-ahead decision making", also referred to as *crash programs*. These efforts include a broad variety of measures, the most important would be fuel efficient transportation, heavy oil/oil sands, coal liquefaction, enhanced oil recovery and gas-to-liquids. The mitigation options focus on large-scale, physical mitigation defined as: 1) implementation of technologies that can substantially reduce the consumption of liquid fuels (improved fuel efficiency) while still delivering comparable service. 2) The construction and operation of facilities that yield large quantities of liquid fuels.

Regarding converting biomass to liquid fuels the report states that ethanol production from cellulosic biomass may become more economic than current processes. However, at present there are no developed biomass-to-fuels technologies that are near to be cost competitive.

The report said that waiting until world oil production peaks before taking necessary decisions and actions would leave the world with a significant shortage of liquid fuels for more than two decades. The initiation of a mitigation crash program 10 years before the time of peaking would give approximately a decade of liquid fuels shortfall. According to the report, the only way of preventing a world liquid fuels shortfall would be to initiate a mitigation crash program 20 years before world oil peaking.

The report concludes, "We know of no comprehensive analysis of how fast the Canadian and Venezuelan heavy oil production might be accelerated in a world suddenly short of conventional oil." The objective of this article is to investigate and analyse what results that might be reasonable to expect from a massive scale-up of the Canadian oil sands production in order mitigate the effects of a coming global peak production of conventional oil

The Hirsch report makes some assumptions for the Canadian oil sands industry's potential capacity. Firstly, accelerated oil sands production might commence three years after a decision to proceed with a crash program. This is largely based on the fact that Canada already has a significant production underway. The report states that the general opinion of the oil industry in Canada is that by 2030 the oil sands industry might produce 3 mb/d (million barrels per day) of synthetic crude oil (SCO). Further, the report makes the assumption that this level of production might be achieved 10 years after initiation of a crash program, significantly faster than today's projection of 25 years. Thus, roughly, a total production level of three million barrels of SCO would be reached 13 years from a decision to launch a crash program. The report describes a number of factors that would challenge a crash program expansion of the Canadian oil sands production. Such challenges are the need for massive supplies of energy – especially for natural gas, huge land and water requirements, environmental management and the harsh climate of the region. (Hirsch, 2005)

Using a similar time-framework as the oil sands production predictions in the Hirsch report, we have performed a twelve–year short–term oil sands production forecast, as well as an extended long-term forecast. The short-term forecast covers the twelve-year period 2006-2018, and the long-term stretches further than the year 2030, covering the period 2006-2050.

2. Methodology

2.1 Overview

To illustrate the importance of future high production levels of oil from the Canadian oil sands some serious concerns about the assessments of the discovery of petroleum reserves between 1995 – 2025, made by the U.S. Geological Survey (USGS), are described. Since far less oil than expected by the USGS have been found until today, the International Energy Agency's (IEA) low resource scenario for world oil production, published in 2004, seems more likely and is therefore presented here. According to the IEA's World Production Outlook for the Low Resource Case, non-conventional oil production in 2030 is forecast to be 37 mb/d.

Having placed the importance of future oil sands production in its global context (section 3), an overview of the Canadian oil sands industry is given in section 4. Oil sands deposits as well as bitumen are briefly explained, followed by a description of the production technologies, the Canadian reserves of bitumen, some investment aspects as well as the environmental damage caused by the oil sands production. After that, a *Short-term Production Forecast* covering the oil sands production for the period 2005-2018 is presented in section 5. The Short-term Production Forecast is based on current companies' plans for future oil sands production.

Thereafter, the need for energy and hydrogen, today mainly supplied by natural gas, is also explained in section 6. However, since the supply of natural gas in North America is near a state of decline, this is also discussed in section 7, together with a description of current use of the Canadian natural gas supply. Then follows a presentation of the demand of natural gas for the Short-term Crash program in order to illustrate the potential problems of energy supplies to a scaled up oil sands industry. Subsequently, in section 8, the potential greenhouse gas emissions problems associated with the implementation of a crash program is presented

In section 9 a comparison is then performed between the *Short-term Crash Program Production Forecast* and the combined production from the North Sea basin plus the declining conventional crude oil production in Canada. This is done in order to illustrate that the Canadian oil sands industry alone will not even manage to compensate for this ongoing oil production decline. Finally, in section 10, a possible *Long-term Crash Program Forecast* is presented. The article ends with final conclusions and recommendations around the issue.

2.2. Limits of this study

We have not dealt with a number of important subjects like pipeline capacity, refinery capacity and water consumption forecasts. These aspects have been considered of less importance than the subjects treated in the article. It has been assumed that these matters will not restrict the development of the Canadian oil sands industry.

2.3. Data Gathering

The data for the short-term production forecast have been collected mainly from official information from oil companies and/or specific oil sands projects. The data consist of project specific data of estimated future production levels. For a more detailed description of the projects see the background report, Söderbergh et al., 2005. Other valuable sources of information for specific projects and official oil sands production forecasts, have primarily been the report *Canada's Oil Sands: Opportunities and Challenges to 2015* (The report was published in May 2004 by the National Energy Board of Canada (NEB).), The *Oil Sands Industry Update* (The report was published in March 2004 by Alberta Economic Development (AEUB).) and the report *Canadian Crude Oil Production and Supply Forecast* (The report was published in July 2005 by the Canadian Association of Petroleum Producers (CAPP)). The project specific statistics originating from oil company sources ought to be reliable since oil projects are associated with high costs and in most cases with multiple parties involved. The same goes for similar information and other data from the three latter sources mentioned, since they are published by national and regional Canadian authorities.

As for other information regarding oil sands activities, including oil sands production forecasts, the report *Oil Sands Technology Roadmap* (OSTRM) (The report was published in January 2004 by the Alberta Chamber of Resources.) has been of great use as well as other various sources such as articles, primarily from *Oil & Gas Journal*. Finally, production data for the North Sea and world oil production have their origin in the researches done by Colin Campbell and ASPO.

2.4. The Short-term Crash Program Production Forecast 2006-2018

In order to make a short-term crash program production forecast the future production from the 8 largest mining projects and 18 major in situ projects have been estimated and added together. For the Short-term Crash Program Production Forecast it has been assumed that all major proposed oil sands projects currently planned are carried out and developed on schedule. It has thus been assumed that supply growth is unconstrained by pipeline capacity, availability of investment capital, increasing natural gas prices, CO_2E-emissions and environmental issues such as ground and water pollution. If natural gas were to become too expensive it is assumed that large-scale residue burning for fuel will be possible with no regard being paid to resulting acceleration of CO_2E-emissions. With all these assumptions taken into consideration it is possible to estimate the short-term maximum production capacity of the Canadian oil sands industry. Production rates of bitumen/oil are measured in barrels since, in the oil industry, it is by tradition more used than the unit m^3. One barrel corresponds to 0.159 m^3.

The Short-term Crash Program Production Forecast is also presented in the form of two forecasts, a mining forecast and an in situ forecast. This is done since the oil sands industry in fact consists of two separate branches, mining and in situ production. The oil sands mining industry is currently the by far largest industry of the two, although the long-term future of the Canadian oil sands industry lies with in situ production.

2.5. The Long-term Crash Program Production Forecast 2006-2050

The Long-term Crash Program Production Forecast is based on a long-term forecast of all mining projects, consuming roughly all the current Canadian oil sands mining reserves of bitumen plus an estimate of long-term in situ production .

Assumptions for the long-term mining forecast

The forecast of all mining projects is made by adding the planned production for the eight largest mining projects between 2005 and 2050. When planned long-term production figures for a project were not available, estimations have been made based on the reported reserves of the mining project. The mining forecast results in a bitumen production of about 30 giga barrels, while the established reserves are 32 giga barrels. It is further assumed that all bitumen from mining production is upgraded. Regarding the ending of the forecast, one mining project is assumed to end each second year from 2035. The ending process will be very dependent on the oil price of the time.

Assumptions for the long-term in situ production forecast

The long-term in situ forecast is created by assuming that the production levels given by the short-term in situ crash program forecast, after 2018 will increase linearly to 4.5 mb/d by 2050. This is assumed since in situ projects require much lower investments than mining projects and it is likely that 10-15 years after the initiation of a crash program, many new in situ projects will be planned and accomplished. In addition it does not seem to be a constraint for the development of in situ production in regard of reported reserves.

2.6. General Assumptions

The distribution between upgraded/non-upgraded bitumen from in situ production in the public forecasts from CAPP, NEB and AEUB, have been unknown. In order to describe future CO_2E emissions from different official production forecasts, as well as demand of natural gas, some assumptions have been made.

In these cases the distribution ratio between in situ produced upgraded and non-upgraded bitumen from the OSTRM scenario has been used. According to the OSTRM forecast, in 2003 a negligible part of the in situ production consisted of synthetic crude oil (SCO). In 2012, 51% of the in situ production is expected to be upgraded to SCO, and in 2030 66%. For reasons of simplicity a linear development of the amount of upgraded in situ production is assumed. For the description of CO_2E emissions a ten-year stepwise switch from natural gas to using residue bitumen for fuel and hydrogen has been assumed. These cases are described referred to as adjusted (adj.).

3. The Concept of Peak Oil

The Hirsch report says that world oil peaking, *Peak Oil*[1], is going to happen. However, although peaking will happen, the timing remains uncertain. Predicting the time for Peak Oil is extremely difficult because of geological complexities, measurement problems, pricing variations, demand elasticity and political influences.

The U.S Geological Survey (2000) has made an assessment for world undiscovered petroleum reserves. The forecast span is 30 years, between 1995-2025, during which 732 billion barrels of oil is to be found in new oil fields. To this should be added a further 688 billion barrels from reserve growth from conventional reserves. However, the ten years that have passed since 1995 are one third of the 30-year forecast span. Between 1995 and 2004 approximately 122 billion barrels have been found. (Koppelaar, 2005) According to the USGS projections about 220 billion barrels should have been found. If anything, the amounts that were found are in line with what is expected by the USGS with a probability of 95%, i.e. 400 billion barrels between 1995 and 2025, since about 133 billion barrels have to be found every decade for this outcome. (USGS, 2005)

Consequently, the low resource case presented by the International Energy Agency in the annual report *World Energy Outlook 2004*, seems to be a scenario based on much more realistic assumptions regarding the resource base of conventional oil. In this scenario, conventional production is estimated to peak around 2015, and non-conventional oil meets just under a third of the world's oil needs of 115 mb/d in 2030. Production from unconventional oil is primarily expected from Canada's oil sands and the Orinoco belt with extra heavy crude oil in Venezuela.

[1] ASPO homepage. www.peakoil.net

Table 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)

3.1. The Canadian Oil Sands Are Supposed to Bridge the Gap.

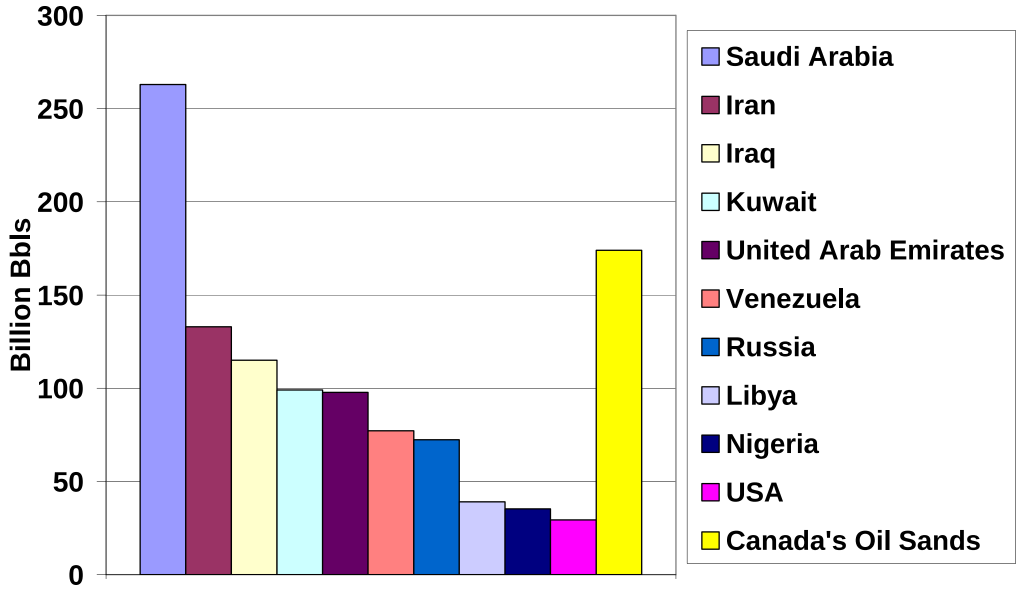
The world's non-conventional oil initially in place, could amount to as much as 7 trillion barrels. Extra-heavy oil in Venezuela, tar sands in Canada and shale oil in the United States, account for more than 80% of these resources. However, the amount of oil that could be recovered from these resources is very uncertain. IHS Energy estimates that there were 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)

It is often claimed that non-conventional oil production, such as Canadian oil sands production, may play an important roll for bridging the coming gap between the world's soaring oil demand and global oil supply. Great achievements are expected from primarily the Canadian oil sands industry and Venezuela´s heavy oil production. This belief is well illustrated both in the Hirsch report as well as in *World Energy Outlook 2004*.

Canada's oil sands are a significant resource, and the initial volume of crude bitumen in place is estimated to be approximately 1.7 trillion barrels (279 billion cubic meters), with 11 percent or 174 billion barrels (27.7 billion cubic meters) recoverable under current economic conditions. (AEUB, 2005) By looking at these figures there is no doubt that a massive expansion in production of these resources is an interesting mitigation option (see Fig. 1. for a comparison with other countries oil reserves). In 2003 the oil sands reserves were included in Canada's estimated proven reserves, thereby increasing from 5 to 180 billion barrels. (National Energy Board, 2004) Today, Canadian oil production from oil sands is about one mb/d. Total world production is around 84 mb/d.

For Venezuela's production of heavy oil, the Hirsch report made the following assumptions, based on statements by the World Energy Council: After three years from the decision to implement a crash program, Venezuelan heavy oil production will have started to accelerate. This is expected to result in a production around 5.5 million barrels within 13 years. While it might be technically possible to step up production of Extra Heavy Oil in Venezuela to as much as 5.5 Mb/d with thirteen years, it is well to remember that this not may be feasible under the government's policy.

Figure 1. Top Ten Countries with Proven Conventional Oil Reserves Compared with Canada's Oil Sands Reserves (Billion Barrels, end of 2004)



Source: BP (2005)

4. The Canadian Oil Sands Industry

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 (43 square kilometers), Cold Lake (7.3 square kilometers) and Peace River Oil Sands Areas (9.8 square kilometers).

The development of oil sands resources requires great efforts from oil 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. Most important problems to deal with are higher natural gas prices, capital cost overruns and environmental impacts.

4.1. Oil Sands and Bitumen

The oil sands themselves typically consist of friable rock of which 75-80% consists of sand, silt and clay, impregnated with bitumen. Heavy minerals including ilmenite, rutile, zircon, tourmaline and pyrite are also present. The deposits are however far from homogenous being subject to important, and not always recognized, variations from area to area. So far only more favourable sites have been developed.

The bitumen itself is a thick black tar-like substance, often containing sulphur and heavy metals. It has a high density in the range of 970-1015 kg/m3 (8-14o API) and viscosity greater than 50,000 centipoises. Since bitumen is deficient in hydrogen it must be upgraded into higher quality synthetic crude oil (SCO) to make it an acceptable feedstock for conventional refineries. This is accomplished through the addition of hydrogen or the rejection of carbon, or both. 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.

4.2. Production Technologies

The oil sands of Canada are extracted in two ways: open cast mining; and in situ thermal extraction through wells. Varying amounts of overburden have to be removed to reach the deposit with 75 m being the current economic limit. Huge pits are excavated and what amount to industrial plants erected to separate the bitumen from the sand. Large volumes of waste product made up of a complex system of clays, minerals and organic material, termed fine tailings, are produced in the operation and used to refill the pits. Large volumes of water are used, some being re-cycled. Only 20% of the reserves are shallow enough to be mined, within the current economic limit for over burden removal (AEUB, 2004).

In situ methods have to applied to extract bitumen from deposits too deep for surface mining. They rely on reducing the viscosity of the bitumen with the help of solvents, steam or underground combustion. Steam injection is the most widely used method, but is energy intensive relying on local natural gas to fuel the steam generators, delivering a low net energy yield. There are two principal methods of steam injection.

Cyclic Steam Stimulation is applied where there is an overburden of more than 300m and comprises a three-stage process whereby steam is injected through a borehole; production is then halted while the heat is absorbed, and finally the well is placed on production. The injected steam itself creates fractures in the rock facilitating the flow. Between 20% and 25% of the bitumen in place in the rock is extracted in this method. Typical steam-to-oil ratios for CSS methods are 3:1 to 4:1; i.e., it takes 3 – 4 barrels of water to extract one barrel of bitumen.

Steam Assisted Gravity Drainage is still at the development stage although already in use in some operations. It involves drilling two highly deviated wells running parallel with the formation for about 1000m and vertically separated one from the other by about 5m. Steam is injected into the upper borehole to mobilize the bitumen, which is extracted through the lower one. It allows relatively thin zones to be tapped and improves the recovery to 40-60%, delivering a better net energy yield and reducing the consumption of water. For SAGD methods, the steam-to-oil ratios range from 2.5:1 to 3.0:1.

4.3. Canadian Reserves of Crude Bitumen

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 the installation of facilities and the successful operation of the project have verified the reserves. On the other hand the use of such stricter definitions would make it difficult to correctly illustrate the realistic potential for the economic development of the oil sands resources. (National Energy Board, 2004) Table 2 presents Canada’s resources of bitumen.

Table 2. Canada's Bitumen Resources

(Billion barrels)	Initial Volume In Place	Initial Established Reserves	**Remaining Established Reserves**
Mineable	110	35.2	**32.1**
Total In Situ	1590	143.6	**142.2**
Total	1700	178.8	**174.3**

Source: AEUB (2005)

4.4. Oil Production Investment Aspects

As a result of recent year's high profitability for the oil sands industry, in combination with expectations of sustained high oil prices, many new bitumen recovery projects or expansion projects have been announced. Capital expenditure of about $60 billion is expected to be required within the 2004 to 2012 time frame. (National Energy Board, 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). In addition, cost overruns have plagued the industry. For example, Syncrude recently announced a 35% cost increase for its Stage 3 expansion, bringing the total from $5.7 billion (Can) to $7.8 billion. (Fletcher, 2005) In table 3 are already made and planned investments in Canadian oil sands production summarized.

Table 3. Existing 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 table 4, is a summary of supply costs for crude bitumen from Athabasca and Cold Lake. These figures are representative of typical projects.

Table 4. Typical Oil Sands Production costs (2004)

	Plant Gate (C$/b)
Cold Lake CSS	14.51
Athabasca SAGD	15.54
Mining, Extraction & Upgrading	30.5
Standalone Upgrading	12.71

Source: CERI (2004)

4.5. Environmental Impacts

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.

The surface disturbance from mining operations and processing of bitumen result in leakage of pollutants, lowering of groundwater levels and diversion of water flow, which are the main concerns regarding water use. 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. Further, the land clearing activities result in deforestation of woodlands, and have a negative impact on fish and wildlife populations.

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_2) and some methane (CH_4) gas and nitrous oxide (N_2O). Emissions of greenhouse gases are measured in CO_2 "equivalents”; or CO_2E.

5. Short-term Crash Program Production Forecast

In 2004 there were around 44 major oil sands projects planned: 18 mining and 26 in situ. For the most part, the initiators 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´s Athabasca Oil Sands Project and Imperial's Cold Lake. These projects, except from Cold Lake, produce Synthetic crude oil (SCO). All currently operating major oil sands mining projects are situated within the Athabasca Oil sands area, which contains the largest volume of crude bitumen, nearly 1300 billion barrels initial in place. For a more complete survey of existing and planned oil sands projects see the background report. In order to make a mitigation production forecast an investigation of 26 major oil sands projects' reserves and the projects' planned production levels has been performed. This investigation has resulted in a forecast termed *Short-term Crash Program Production Forecast*. In table 5 are the studied oil sands projects presented.

Table 5. Studied Oil Sands Projects

Mining Projects	**Athabasca In Situ Projects**	**Cold Lake In Situ Projects**
Suncor	Surmont (SAGD)	Cold Lake (CSS)
Syncrude	Christina Lake (SAGD)	Foster Creek (SAGD)
Athabasca Oil Sands	MacKay River (SAGD)	Primrose and Wolf Lake (SAGD & CSS)
Fort Hills	Firebag (SAGD)	Tucker Lake (SAGD)
Kearl Oil Sands	Meadow Creek (SAGD)	Sunrise Thermal project (SAGD)
Horizon	Lewis (SAGD)	Orion (SAGD)
Northern Lights	Jackfish (SAGD)	**Peace River In Situ Projects**
Joslyn Creek	Kirby (SAGD)	
	Joslyn Creek (SAGD)	Shell - Peace river (CSS & SAGD)
	Hangingstone (SAGD)	
	Long Lake (SAGD)	

For the Short-term Crash Program Production Forecast it has been assumed that all major proposed oil sands projects are carried out and developed on schedule. It has also been assumed that supply growth is unconstrained by pipeline capacity, availability of investment capital, increasing natural gas prices, CO_2E-emissions and environmental issues such as ground and water pollution. If natural gas were to become too expensive it is assumed that large-scale residue burning for fuel will be possible with no regard being paid to accelerating CO_2E-emissions.

The Short-term Crash Program Production Forecast is presented on a project-by-project basis, see Fig. 2 and Fig. 3, and then together with four public forecasts of Canadian oil sands production in Fig. 4. The forecasts have their origin from the following publications:

Canada's Energy Future – Scenarios for Supply and Demand to 2025 (NEB)

Alberta's Reserves 2004 and Supply/Demand Outlook 2004-2014 (AEUB)

Oil Sands Technology Roadmap – Unlocking the Potential (OSTRM)

Canadian Crude Oil Production and Supply Forecast, 2005 – 2015 (CAPP)

Figure 2. Crash Program Forecast, Mining

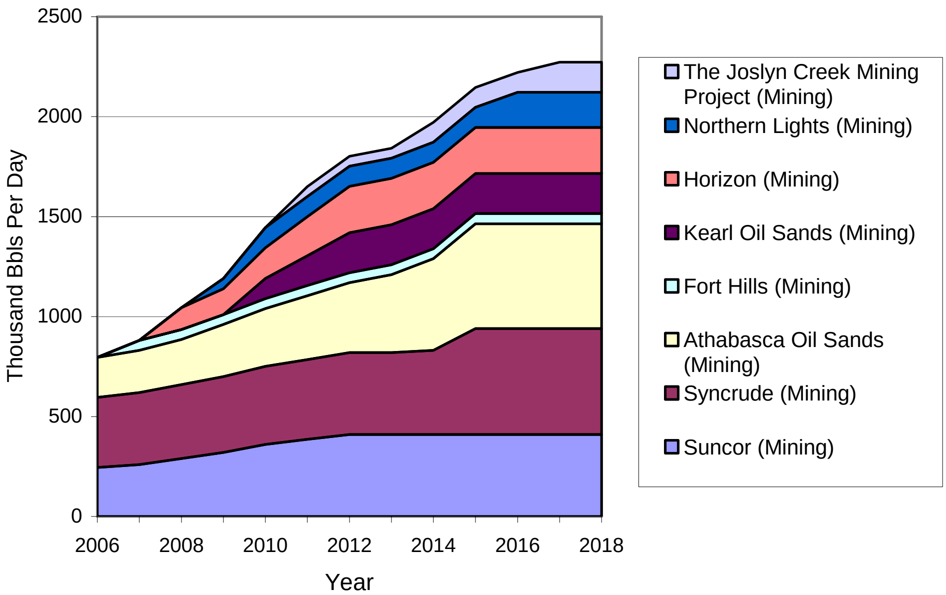


Figure 3. Crash Program Forecast, In Situ

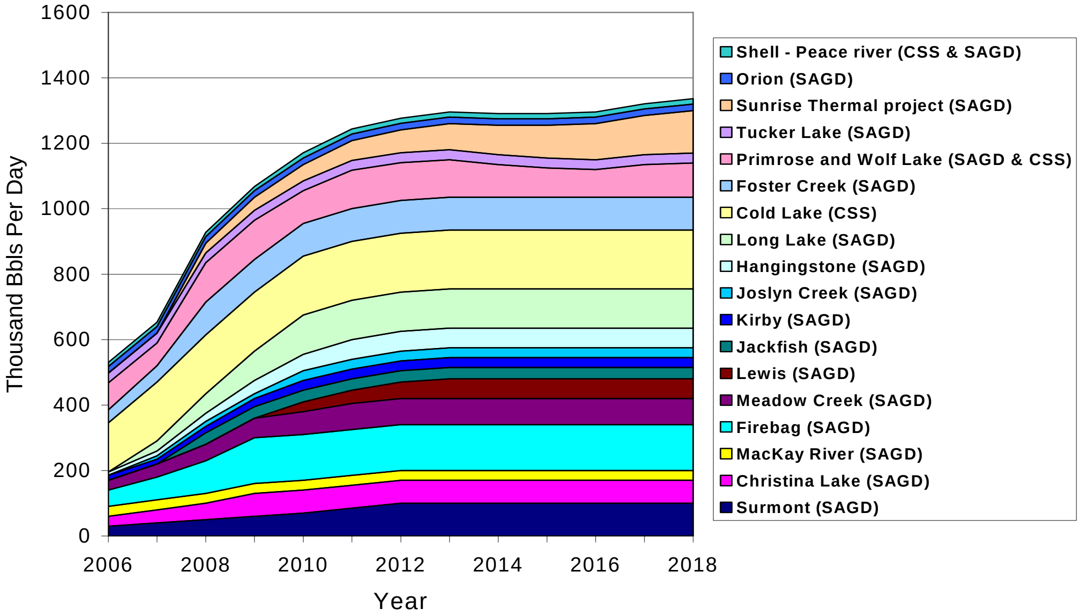


Figure 4. Different Oil Sands Production Forecasts

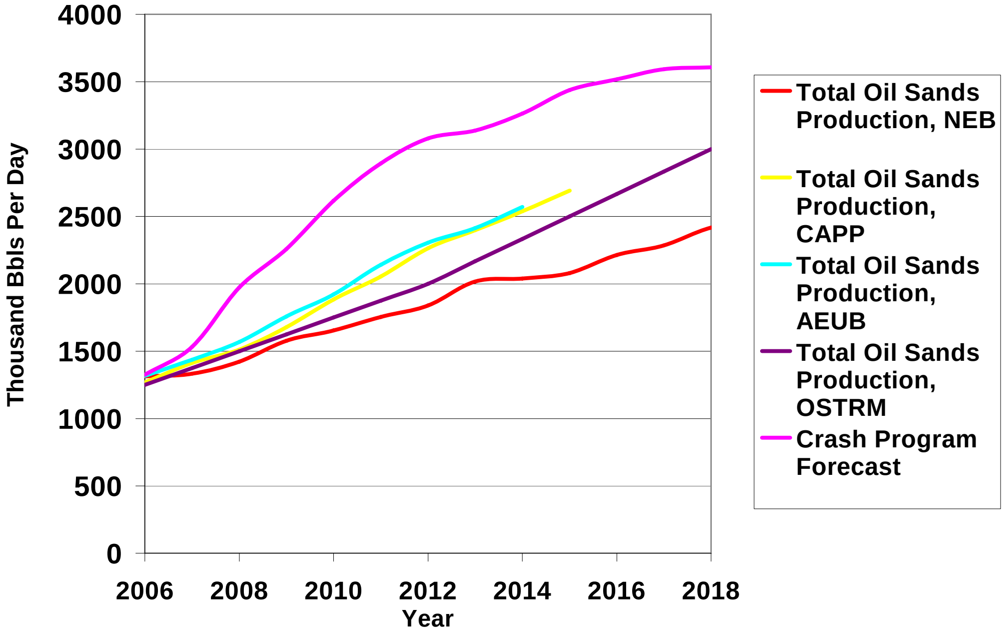


Fig. 4. The figure shows four official oil sands forecasts together with the Short-term Crash Program Production Forecast. The forecasts from CAPP and AEUB range to 2015 and 2014 respectively.

In 2012 (see Fig. 4) the difference between the crash program forecast, and an average of the four public forecasts is approximately one mb/d. To put this figure in perspective, this figure is slightly more than current daily average oil production from the OPEC country Indonesia. (Oil & Gas Journal, 2005) In 2018 the difference to the OSTRM forecast is about 0.60 mb/d, while the span to the NEB forecast is 1.1 mb/d.

6. The Need for Natural Gas

Natural gas-fired facilities generate steam and provide process heat for bitumen recovery, extraction and upgrading. Further, natural gas also provides a source of hydrogen used in hydroprocessing and hydrocracking as part of the upgrading process. In this article the reserves, production and consumption of natural gas are measured in standard cubic feet. One cubic feet corresponds to about 0.028 m^3. Although there is considerable variation between individual projects, an industry rule of thumb is that it takes 1000 cubic feet of natural gas to produce one barrel of bitumen. The demand for mining recovery is a more modest 250 cubic feet per barrel. 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 cubic 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 SCO may require more than 1700 standard cubic feet of natural gas (see table 6). 1700 cubic feet of natural gas is energy equivalent to 0.3 barrels of oil.

There are alternatives to natural gas as hydrogen source as well as energy source. However, alternative hydrogen sources, predominantly partial oxidation gasification of coal or oil sands residues have low efficiency, negative environmental impacts and a more complicated process for purification of hydrogen. (Alberta Chamber of Resources, 2003)

Coal combustion in advanced boilers or gasification of residue bitumen, is an option to replace natural gas for energy although greenhouse gas emissions would increase significantly. However, nuclear energy is another possible source of electricity and steam.

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. Upgrading expansions for meeting the demand of higher quality SCO will require incremental hydrogen supply. At the same time a reduction of natural gas 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 6. 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

Source: Alberta Chamber of Resources (2004)

7. The Natural Gas Situation

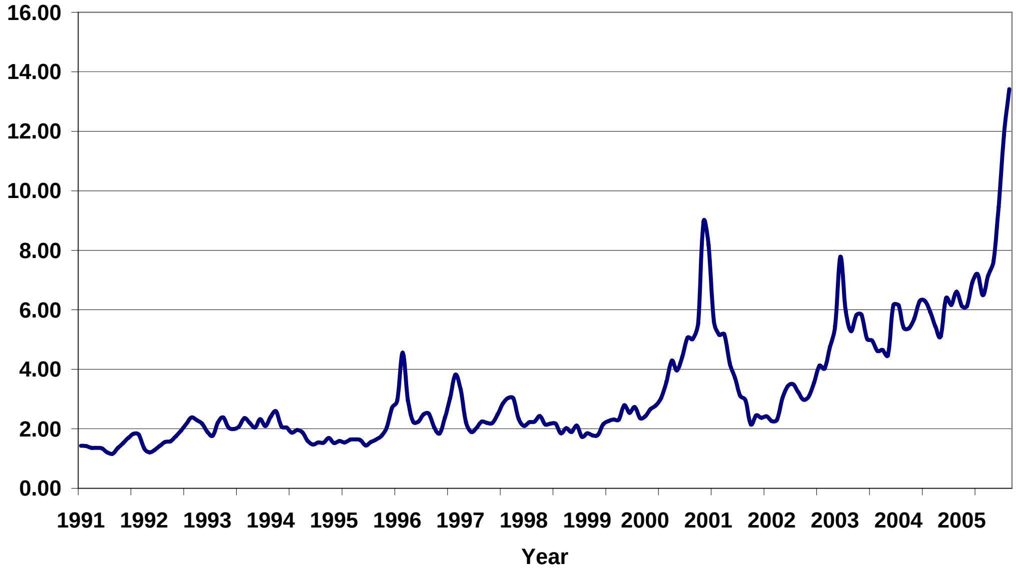
In 1986, Canadian natural gas prices were deregulated and freer access was provided to the U.S. market. Between 1986 and 1999 Canadian gas production more than doubled, and exports to the U.S. increased more than four times. Canadian and U.S. natural gas markets have increasingly evolved into an integrated North American market, through an extensive North American pipeline grid. (National Energy Board, 2004b) 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. (The Canadian Gas Association, 2003)

Recent drilling and production data suggest that the Canadian natural gas production will soon fall into decline. The production has already flattened out at about 16.7 – 16.9 Bcf/d despite record levels of drilling activity (National Energy Board, 2005). The size of Canada's natural gas resource base is a significant uncertainty, especially for the frontier regions and the unconventional natural gas reserves (see Fig. 6). Very little development of unconventional natural gas has occurred to date. Most frontier resources are situated in areas that are not currently producing natural gas, and today they remain without access to transportation systems. Some of these regions, such as the Arctic Islands, 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)

As for unconventional gas resources, i.e. primarily coal bed methane, the development of the Canadian reserves of coal bed methane 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 future for the exploitation of this resource is to a large extent unknown. (National Energy Board, 2003)

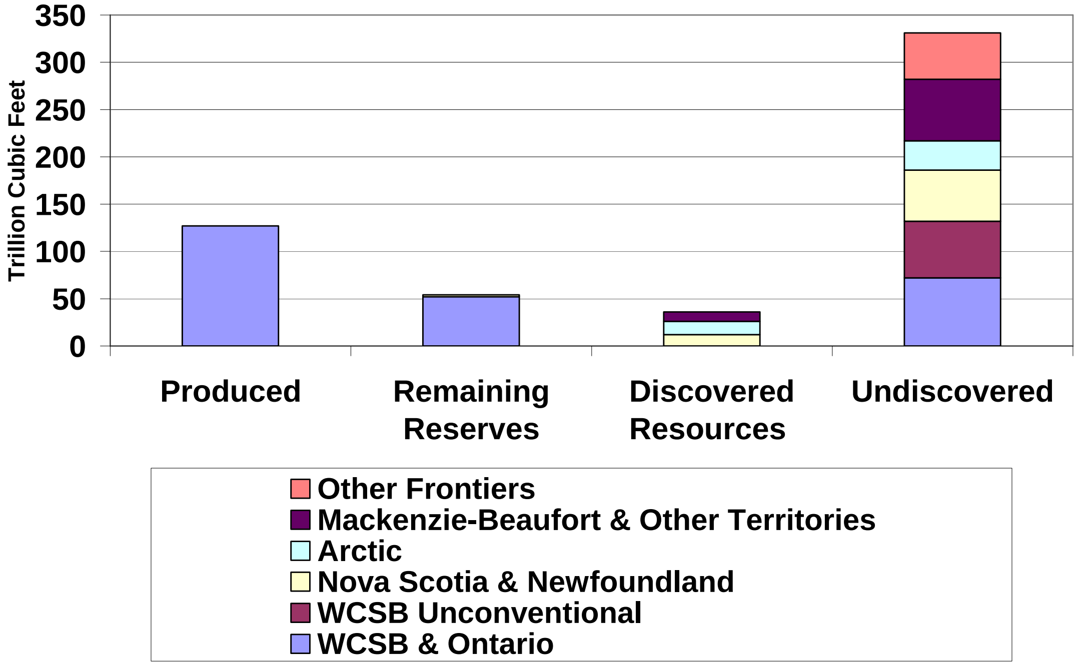
Throughout the 1990s, natural gas prices were relatively low. Over the last three years, natural gas prices have increased significantly as a result of tighter balances between natural gas supply and demand, partly caused by the emergence of electric power generation sector as a major source of gas demand (see Fig. 5). Many analysts believe that there has been a step-change in the level of natural gas prices. (National Energy Board, 2004b)

Figure 5. Natural Gas Prices for the last 15 years



Source: Canadian Gas Association (2005)

Figure 6. Natural Gas Resources in Canada, Supply Push Scenario



Source: National Energy Board (2003)

Fig. 6. More than two-thirds of Canada's natural gas reserves have already been produced. The future of Canada's natural gas supply is heavily dependant on new discoveries. Will adequate resources for sure be discovered, and when can they be brought in production?

7.1. Use of Canadian Natural Gas

In 2004, natural gas supplied about 26% of the total primary energy consumption in Canada, consuming about 7.7 Bcf/d of natural gas per day, split approximately equally between three sectors: residential/commercial, industrial, and other. Present distribution data indicate that about 9.5 Bcf/d is exported to the U.S. (National Energy Board, 2005) By 2015, Canadian gas demand is expected to reach the 9.5 - 11 Bcf/d range and by 2025, Canadian gas demand is expected to be in the 8.8 - 12.7 Bcf/d range. The power generation and industrial sectors (the latter includes oil sands) are expected to account for the bulk of natural gas demand growth. (North American Natural Gas Vision, 2005) The oil sands industry in 2004 consumed about four percent of the Canadian natural gas supply. (National Energy Board, 2005) Canadian gas-fired electric power generation currently consumes 0.6 Bcf/d of natural gas; by 2015 this is expected to reach the 2.0 Bcf/d range; and by 2025, 2.7 Bcf/d. (National Energy Board, 2003)

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 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/d to more than 90 Bcf/d by 2010. Current and future supply distribution is presented in table 6.1.

Table 7. Natural Gas Supply for the U.S. (Bcf/d)

	2004		2010
U.S. Production:	52	**U.S. Production:**	40
Canadian Imports:	7.3	**Canadian imports + LNG:**	10
LNG:	0.7		
Total:	**60**	**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/d in 2010, thereafter gradually decline to 7 Bcf/d 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. (EIA, 2004)

7.2. Short-term Crash Program Demand for Natural Gas

In 2004 about 0.72 Bcf/d of natural gas was used by oil sands projects to produce electricity, provide process heat in bitumen recovery, as a source of hydrogen and to produce steam for in situ recovery. According to the National Energy Board of Canada, by the end of 2006, natural gas consumption is expected to reach 1.01 Bcf/d. (National Energy Board, 2005) Our estimations of natural gas demand from the four forecasts, OSTRM, NEB, CAPP and AEUB, presented earlier in the report, would result in an average demand of 1.6 Bcf/d by 2010. By 2025 the NEB forecast would translate in to a demand of 2.7 Bcf/d. The OSTRM-forecast would give a natural gas demand of 5.4 Bcf/d by 2030. (See the background report for more details.)

A scaled up oil sands production as a result of a crash mitigation program, would result in a natural gas use of about 3.1 – 3.2 Bcf/day by 2018, which means more than four times more natural gas use than the level of 2004. This will occur in the same period of time as the U.S. continues to import a considerable part of Canadian natural gas production! Canada is also itself dependent on natural gas for a significant part of its electricity generation. Thus, in order 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 illustrated in Fig. 7, together with the forecast Canadian Natural Gas Production and the demand from the oil sands industry. The future available gas for other consumption is also shown.

Figure 7. Available Canadian Natural Gas for Other Consumption

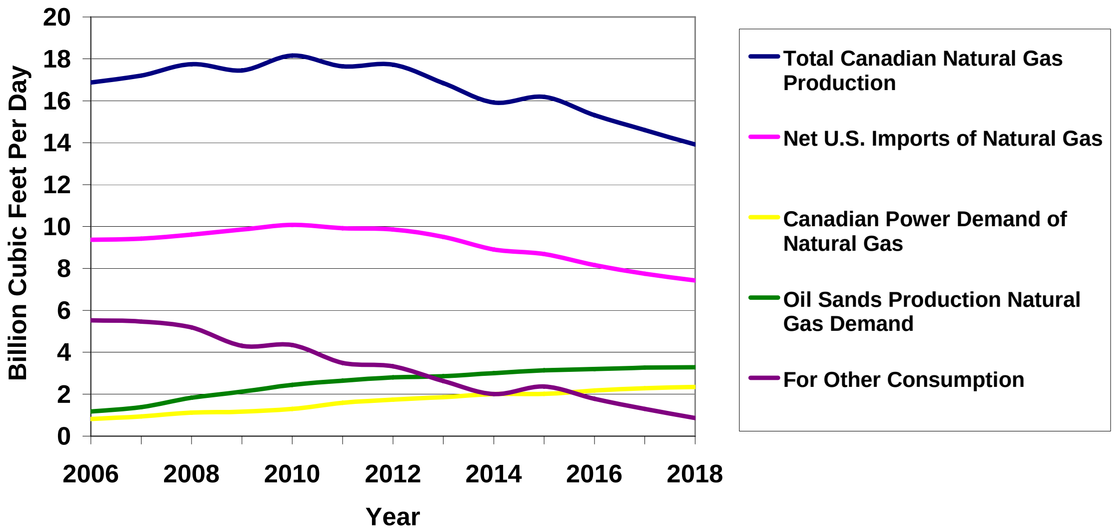


*Fig 7. The curve named **For Other Consumption** illustrates a probable future increasing scarcity of natural gas for other consumption in Canada. This is likely to imply constant or even higher natural gas prices in the future. High prices will increase the uncertainty for primarily in situ oil sands investments and might dampen the will to invest, thus slowing the development pace for the Canadian oil sands industry.*

When making a short-term crash program forecast based on all planned projects it is important to have in mind that most projects were planned when the price of natural gas was about half of the price of today. Consequently the forecast tends to be based on very optimistic assumptions since the price development for natural gas is not taken into consideration. The overall demand for natural gas in North America is steadily increasing. It is unlikely that unconventional gas and LNG imports can prevent the decline of available natural gas supply in North America. In the near future (5-10 years), Canada's supply of natural gas cannot any longer simultaneously meet the demand from the oil sands industry and the U.S.

The crash program will consume approximately more than 12 TcF of natural gas between 2006 and 2018. Canada's remaining natural gas reserves amount to 54 TcF and its discovered reserves to 36 TcF. It is obvious that the current dependence on natural gas is unsustainable for the expanding Canadian oil sands industry as U.S imports under same period amounts to 43 TcF and Canadian power demand reaches 7.8 TcF. Thus by 2018 all proven reserves would have been produced and in addition 24% of all additional discovered natural gas resources. As consequence natural gas prices are likely to become higher and even more volatile in the future and another source of energy and upgrading is needed for the oil sands industry, most likely as early as at the beginning of the next decade

8. CO_2E Emissions from the Short-term Crash Program

As part of the Kyoto Protocol, Canada has agreed to a 6% reduction in greenhouse gas emissions from the 1990 level of 612 Mega-tonnes by the period 2008-2012. (Canada's First National Climate Change Business Plan, 2000) This 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) The Canadian oil and gas sector is expected to reduce emissions by lowering the emissions intensity of oil and gas production and distribution, while continuing to grow. To fulfil these expectations, the oil sands industry needs to do much better than a "business as usual" scenario. However, the likely replacement of natural gas consumption with internal sources of energy such as burning residue for fuel will result in accelerating emissions of greenhouse gases. (Alberta Chamber of Resources, 2004)

Two different forecast scenarios, the OSTRM and CAPP have been studied together with the crash program scenario. Assumptions of CO_2E emission per barrel are as follows:

The emissions from mining-based recovery is estimated to 40 kg CO_2E per barrel, with natural gas as feed, the use of residues or selected residues for upgrading to 90 kg of CO_2E and upgrading with natural gas to 70 kg per barrel. (Alberta Chamber of Resources, 2004)

In situ bitumen production using natural gas as a fuel will emit about 60 kg CO_2E per barrel. SAGD using bitumen residue as fuel will emit 80kg CO_2E per barrel. Upgrading the bitumen to SCO using hydrogen from natural gas emits 70kg/bbl and upgrading with residue gasification emits 90 kg/bbl

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 170 kilograms of CO_2E emissions per barrel of SCO. However, the figure 170 kg/bbl has been adjusted downward to160 kg/bbl for the calculations of CO_2E emissions scenarios, as this is the figure presented in the Oil Sands Technology Roadmap report. (Alberta Chamber of Resources, 2004)

These emissions levels per barrel have been assumed to stay unchanged. When the distribution between upgraded/non-upgraded bitumen in a forecast, has not been specified, the same distribution from 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. Using these estimations, calculations have made for six scenarios presented in Fig. 8.

In 2001 Canada's Emissions of CO_2E were 720 mega-tonnes. Of this amount it is reasonable to assume that the emissions of CO_2E from the oil sands industry did not exceed 30 mega-tonnes. It is interesting to notice that the CO_2E emissions from Canada's oil sands industry under a crash program will likely be somewhere between 135 and 165 mega-tonnes per year by 2018. A full conversion to burning residue for fuel and upgrading seems to be impossible to combine with the fulfilment 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.

Figure 8. CO_2E Emissions for the Crash Program Production Scenario Compared with Public Production Forecasts

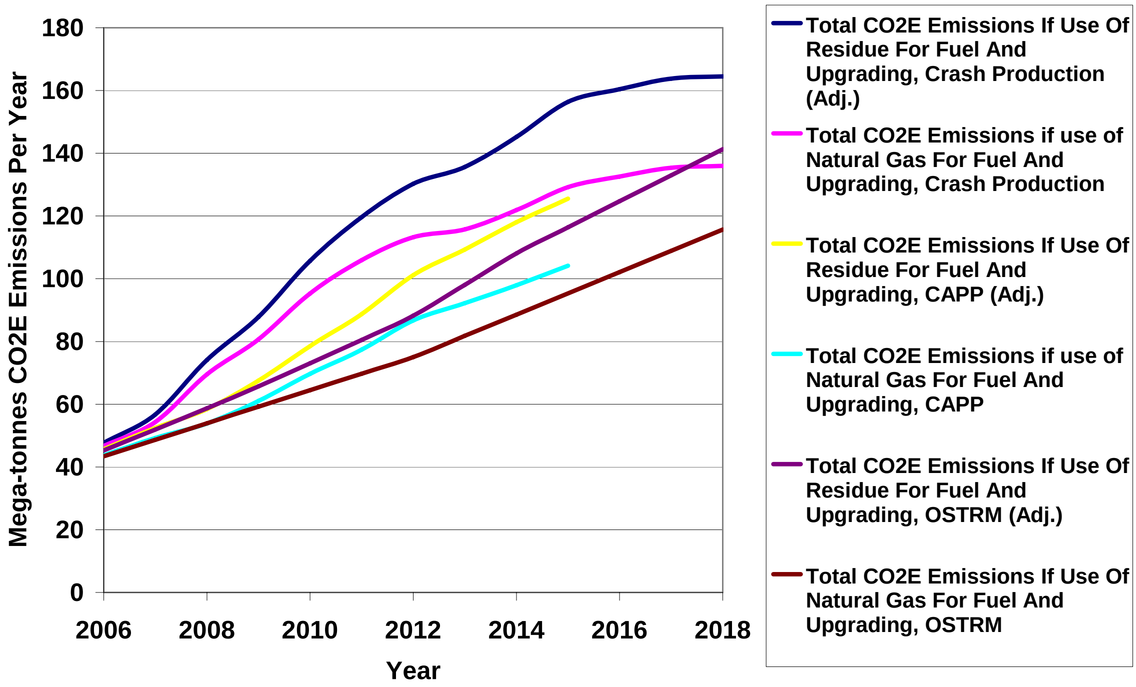


Fig. 8. The figure illustrates potential CO_2E emissions from three oil sands production forecasts; The Crash Program Production Forecast, the CAPP-forecast and the OSTRM-forecast. For each of the three forecasts, two CO_2E-emissions forecasts are presented, one when natural gas has been assumed as the primary fuel for heat and upgrading and a scenario when bitumen gradually replaces the need of natural gas. The latter is referred to as Adj. (Adjusted).

9. A Comparison with the North Sea and Canadian Conventional Oil Production

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

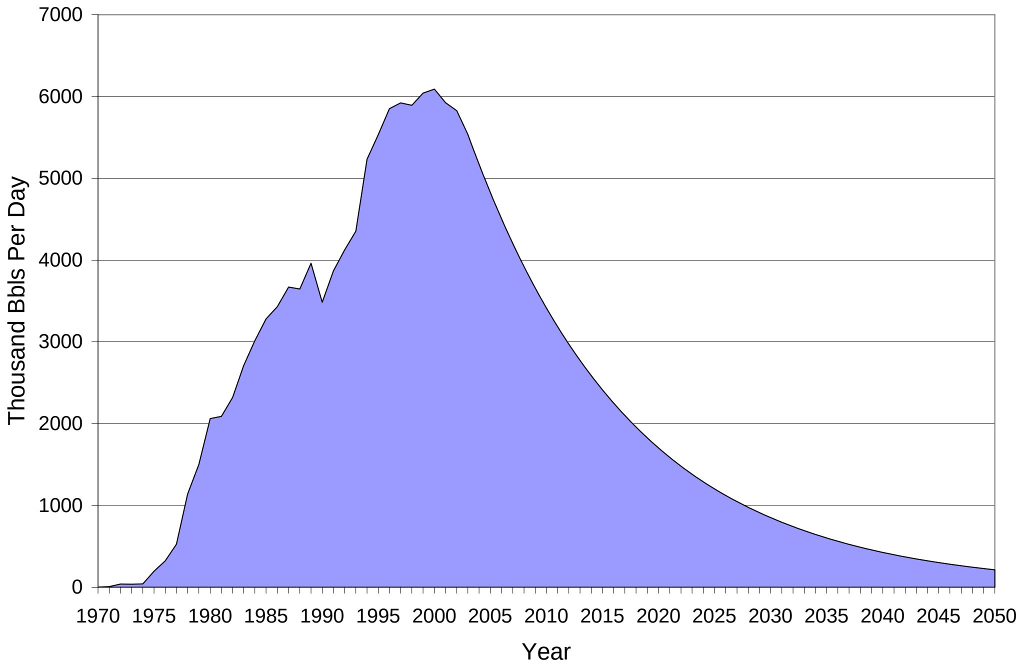
Despite soaring oil prices, European exploration and development have declined sharply in the last few years, as prospects have deteriorated. Several of the leading international oil companies are selling assets in the region. Independent operators are becoming more important for exploiting remaining 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 mb/d. Production by 2010 is expected to be 635,000 b/d. In 2030 production will have diminished to about a mere 200,000 b/d.

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 decline? 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. In Fig. 9 the declining conventional crude oil production from the North Sea is illustrated. 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 in Fig. 10 added to the Crash Program Production Forecast, in order to get a resulting oil production curve. This resulting oil production curve shows how the combined production of oil from the Canadian oil sands, the North Sea and conventional Canadian oil production develops with the production of year 2005 as a starting zero point.

A crash program merely compensates the combined decline within a thirteen-year time frame. Neither the two official Canadian oil sands production forecasts, NEB or OSTRM, manage to compensate for the declining conventional crude oil production from the North Sea plus Canada by 2025 and 2030 respectively. For more details, see the background report.

Figure 9. North Sea Crude Oil Production 1970 - 2050, Including Norway, Denmark and the UK



Source: Campbell (2005)

Fig. 9. The combined North Sea crude oil production from Norway, Denmark and the UK peaked in 2000 with a production of about 6 mb/d. North Sea crude oil output is projected to drop to 3.4 mb/d by 2010, and dwindle to 0.85 mb/d in 2030.

Figure 10. Canadian Conventional + The North Sea + Canadian Oil Sands Crash Program Crude Oil Production 2006 – 2018

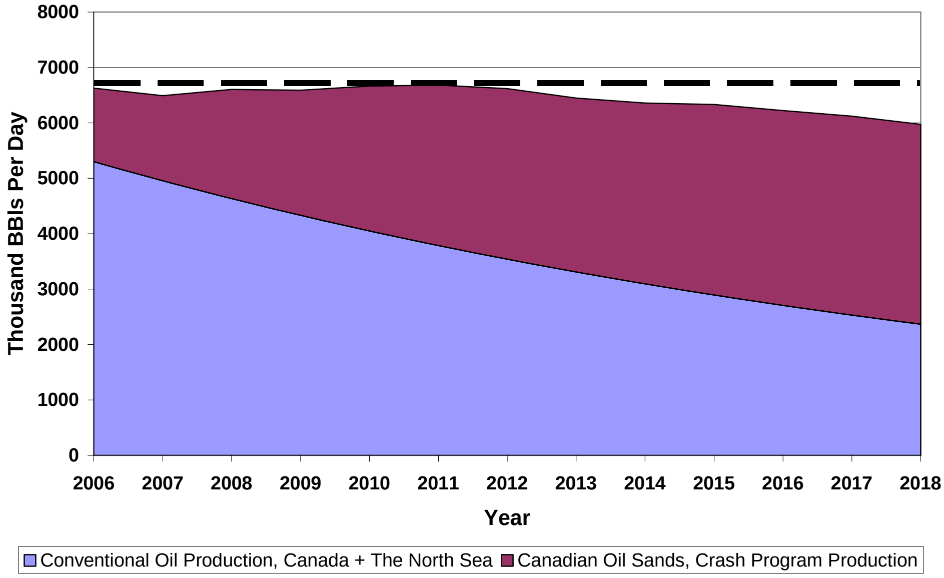


Fig. 10. The conventional crude oil production from Canada has been added to the North Sea's crude oil production. The oil sands production from the Crash Program Production forecast is also illustrated in the figure. The figure shows that the Crash Program Production Forecast may not even offset the combined decline from crude oil production of the North Sea and Canada's conventional crude oil production.

10. A Long-term Crash Program

The implementation of a long-term crash program for the Canadian oil sands industry is associated with serious difficulties. The supply of natural gas in North America is not adequate 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.

However it is possible to use bitumen as fuel and for upgrading, although large-scale implementation of CO_2E-sequestration will not be functioning within the coming 15 years. Is Canada willing to abandon the Kyoto treaty in order to allow accelerating emissions from the oil sands industry crash-program? Today the cost of emitting CO_2E 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 other serious environmental problems, primarily associated with oil sands mining, such as land destruction, ground water drainage and large lakes filled with oil sands by-products. Are the Canadians willing to create an environmental disaster in Alberta in order to provide the world market with oil?

10.1. Long-term Crash Mining Forecast

However, should a crash program be seriously implemented 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_2E emissions might easily be paid off with record oil revenues. A prolonged crash program production scenario, 2006-2050, for the mining sector of the Canadian oil sands industry has been performed. An interesting conclusion from the implementation of a long-term crash program is that the mining production will reach a plateau production and then decline. The mining production forecast based on all major mining projects, specifically presented in Fig. 11, results in a mining production of 30.2 giga barrels of bitumen. The established remaining mineable reserves are 32.1 giga barrels, as of December 31, 2004. 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 would have been produced by around 2050.

Figure 11. Crash Program Oil Sands Mining Forecast

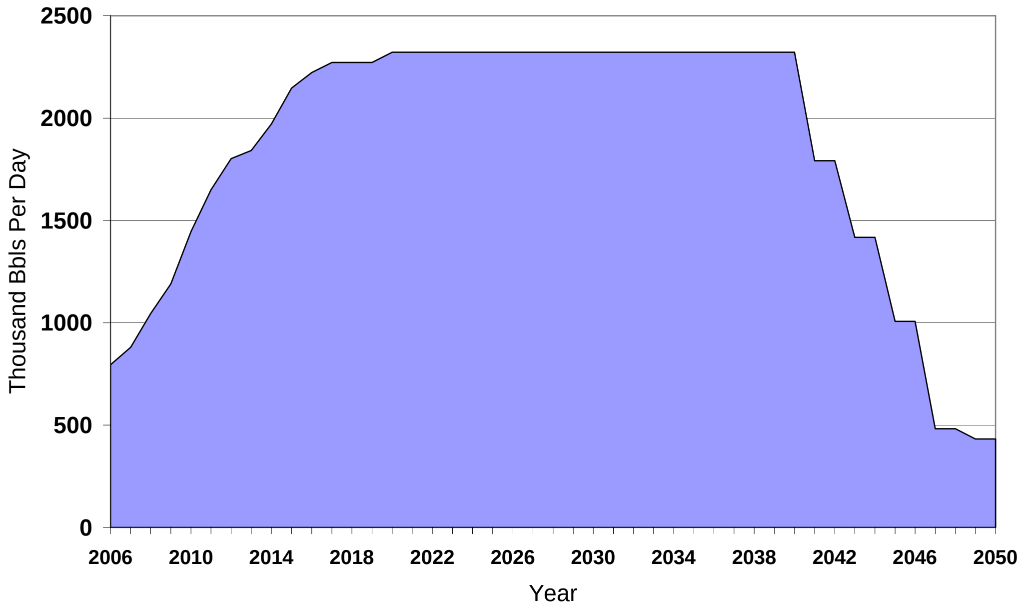


Fig. 11. The mining production forecast based on all major mining projects, results in a mining production of 30.2 giga barrels of bitumen. The established remaining mineable reserves are 32.1 giga barrels, as of December 31, 2004. Consequently the whole established mineable reserve of bitumen would have been produced by around 2050. Regarding the ending of the forecast, one mining project is assumed to end each second year from 2035.

10.2. Future In Situ Production – The Big Question Mark

The great uncertainty associated with forecasting the long-term effects of a crash program for the Canadian oil sands industry is the potential of the in situ oil sands production. However, the long-term future is in the situ production, since all of the mining reserves roughly only covers one year of the world's oil consumption. In situ production involves relatively new techniques associated with some significant uncertainties. First, the question is whether there will be an adequate supply of energy developed in time for a continuous large-scale expansion of the in situ production industry, since it requires large amounts of natural gas. 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 b/d of production has been put in production. Third, how many of the oil sands deposits may be considered as high quality reservoirs for in situ production?

Most likely the Canadians will have to construct nuclear plants to provide energy for a more durable long-term crash program with a large share of in-situ production. Nuclear power is an energy source largely free from greenhouse gas emissions, which would allow the oil sands industry to accelerate production without making it impossible for Canada to meet its commitments to the Kyoto Agreement.

But constructing nuclear power plants is a complicated matter. The development of this energy source has obvious social and economic constraints. It will take at least seven years to implement a full-scale expansion program of nuclear plants for oil sands industrial use. Needless to say it will take time to convince the public of the necessity to construct these facilities. However, for a 150,000 b/d SAGD operation advanced CANDU reactors seem to be economical at natural gas and electricity prices of $4.25/GJ and $50/MWh at the plant gate. The reactor would have to be located within reasonable proximity to the in situ operation. (Dunbar, Sloan, 2003) It will probably take more than 10 years from the start of a mitigation program until reactors have started to generate energy to oil sands operations. As consequence the impact of new nuclear reactors may be significant after 10-15 years, thus making oil sands operations more durable.

10.3. A Possible Resulting Long-term Crash Program Production

The long-term oil sands crash program scenario described below (see Fig. 13) consists of an in situ forecast and the Long-term Crash Program Mining Forecast, which together result in a production of approximately five mb/d by 2030. The curve for in situ production (see Fig. 12) has its origin from the forecast made from all major oil sands projects but have been modified after 2018 so it follows a straight linear curve, thus reaching a production at about 4.5 mb/d by 2050. The part of the in situ production curve between around 2012 – 2018 may reflect a dampened will for in situ project investments due to high natural gas prices, uncertainties regarding costs for CO_2E emissions as well as initial technical problems to achieve high production rates for large-scale in situ production projects.

If fueled only by natural gas the in situ forecast alone consumes 12 Tcf, by 2025, at the same time the U.S. is forecasted to have imported 61 TcF and power production have consumed 14 TcF, hence a total natural gas consumption of about 90 TcF. If the crash program mining forecast also is supposed to be fueled on natural gas alone, another 10 TcF should be added. To be able to produce these quantities of natural gas will indeed be a challenge for the Canadian gas industry since Canada’s combined remaining reserves and discovered resources are just 90 TcF.

The calculations presented above illustrate the great difficulties of rapidly expanding the oil sands industry of Canada in any practical way. Either CO_2E-emissions must be neglected or a lower production pace than expected is achieved. However if and when nuclear energy makes its entry for producing energy as well as large-scale CO_2-sequestration techniques begin to function, the use of natural gas may be phased out, while in situ operations continue to grow although reservoirs of lower quality are accessed. These efforts could result in the linear increasing curve after 2018 in the Long-term Crash Program Production Forecast presented in Fig. 13. This forecast would give a production of approximately 5 mb/d by 2030, and five to ten years later even slightly higher almost 6 mb/d of oil sands production by 2035-2040 followed by a plateau production for some years then turning into a continuous slow decline. For obvious reasons this ought to be considered as a very optimistic production forecast since the in situ production of Canada alone, by 2025, would produce slightly more than the current production rates for Venezuela.

Figure 12. Long-term In Situ Crash Program Production Forecast

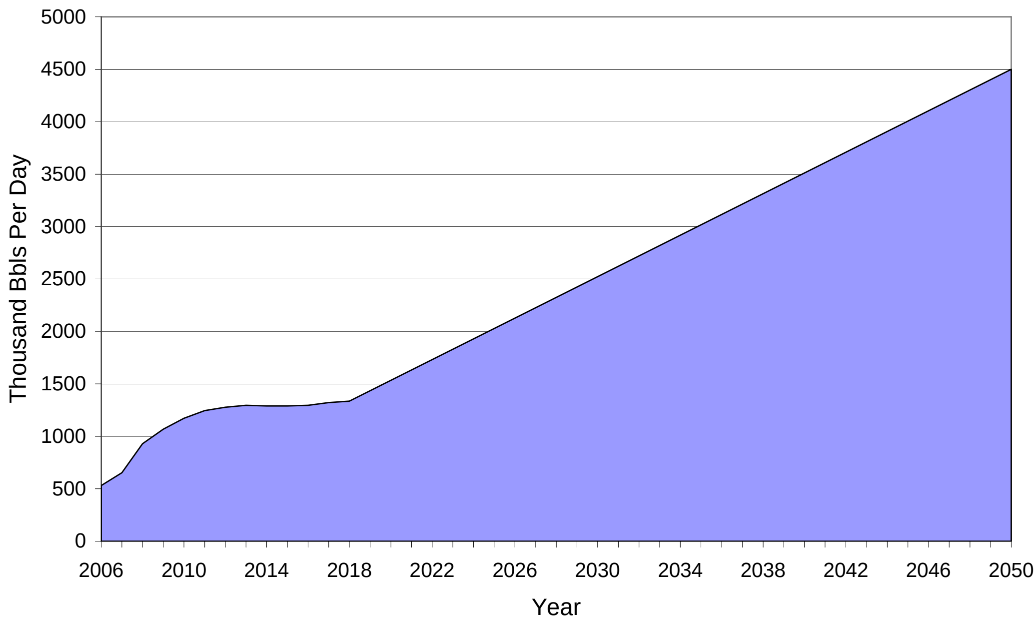


Fig. 12. The great uncertainty associated with forecasting the long-term effects of a crash program for the Canadian oil sands industry is the potential of the in situ oil sands production. It does not seem to be a constraint for the development of in situ production in regard of reported reserves. After 2018 it is assumed that production will increase linearly to 4.5 mb/d by 2050.

Figure 13. Long-term Oil Sands Crash Program Production Forecast

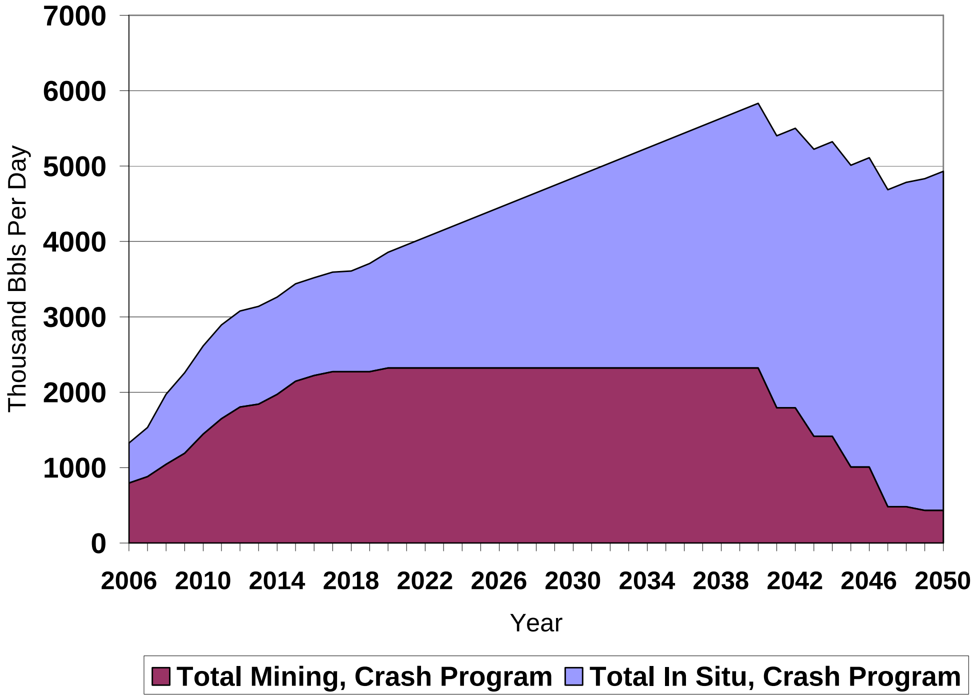


Fig. 13. The Long-term Oil Sands Crash Program scenario consists of the Long-term In Situ Crash Program Production Forecast and the Long-term Crash Program Mining Forecast. Together they result in a production of approximately 5 mb/d by 2030.

11. Final Conclusions and Recommendations

By evaluating the short-term crash program production forecast together with the long-term crash program production forecast, it is possible to make some predictions. Based on the presented assumptions and definitions, a short-term crash program starting at 2006, by 2018 achieves a production of 3.6 mb/d of bitumen, of which 2.9 mb/d is SCO. Of the total production of 3,6 mb/d, upgraded bitumen from mining accounts for 2.3 mb/d, upgraded in situ production for 0.61 mb/d and non upgraded in situ produced bitumen for 0.73 mb/d.

Unfortunately, while the theoretical future oil supply from the oil sands is huge, the potential ability for the Canadian oil sands industry to meet expectations of bridging a future oil supply gap is not based on reality. Even if a Canadian crash program were immediately implemented it may only barely offset the combined declining conventional crude oil production in Canada and the North Sea. The more long-term oil sands production scenario outlined in this report, does not even manage to compensate for the decline by 2030. Today, world wide, there are many oil producing areas in decline whose productions have to be offset by new production. With the exception of ultra-deep off shore fields, of the world's 65 oil-producing countries, 54 have passed their peak production and are in a state of continuous decline.

There are some areas that need the immediate attention by the world's energy planners. Firstly, the future for the Canadian in situ oil sands production. How much can these activities grow without serious fuel costs problems as well as accelerating CO_2E-emissions arise? Secondly, how effective will large scale SAGD in situ projects be for reservoirs of lower quality? Thirdly, is it realistic to include the construction of nuclear facilities for input energy for oil sands projects when making production forecasts? If not, how is the energy going to be provided and how much additional energy supply will be needed in order to extract the bitumen at the required high production levels? The Hirsch report has shown that the Canadian oil sands resources play a vital role for future energy planning, thus it is of outmost importance that these questions are thoroughly investigated as soon as possible.

Finally it may be of interest to recapitulate that the International Energy Agency claims that 37 mb/d 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 mb/d. Venezuela may perhaps achieve a production of 6 mb/d. Who will be the producers of the remaining 26 mb/d? It is obvious that the forecast presented by the IEA has no basis in reality.

Figure 14. The Impact of Canadian Oil Sands production on Global Oil Supply

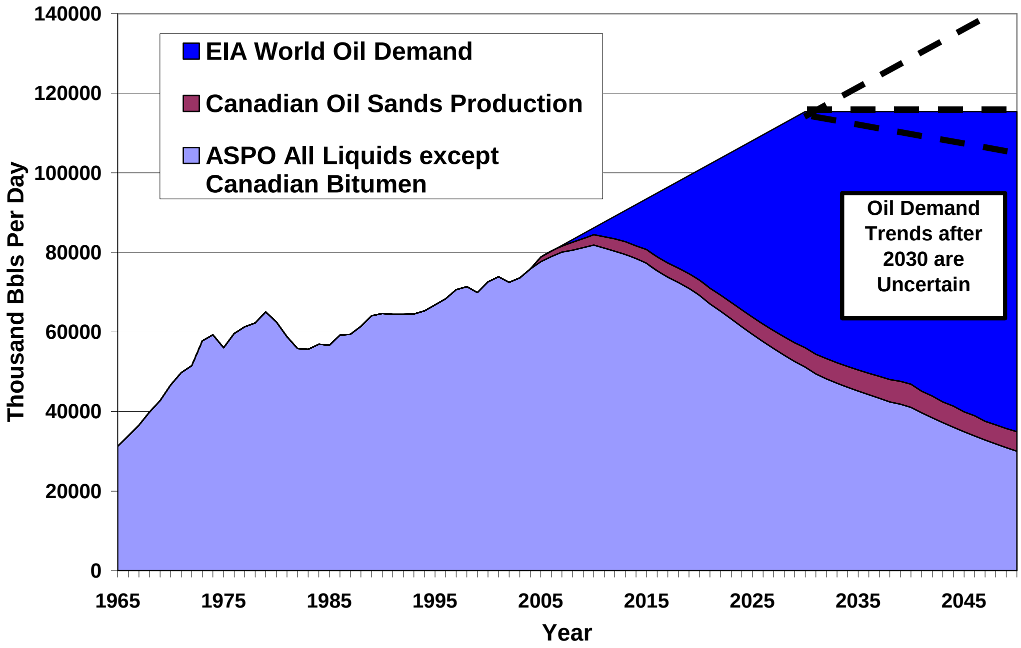


Fig. 14. The impact from the Canadian Long-term Crash program will, in spite of its impressive production figures, have a relatively limited impact for the long-term global oil supply situation.

12. Acknowledgements

We would like to thank Bruce Robinson for proofreading the manuscript and for giving us a lot of useful and important advise. The work had financial support from Stena AB, Vostok Nafta Investment Ltd, Lundin Petroleum Ltd and Lundin SA.

13. References

Alberta Chamber of Resources (2004). *Oil Sands Technology Roadmap*. January 2004.

Alberta Chamber of Resources (2003). *DRAFT Oil Sands Technology Roadmap*. December 2003.

AEUB, (2005). Alberta Energy and Utilities Board. *Alberta's Reserves 2004 and Supply/Demand Outlook 2005-2014*. www.eub.gov.ab.ca (2005-10-15). ISSN 1499-1179. Calgary, Alberta: AEUB, 2005.

AEUB, (2004). Alberta Energy and Utilities Board (AEUB). *Alberta's Reserves 2003 and Supply/Demand Outlook 2004-2013*. www.eub.gov.ab.ca. ISSN 1499-1187. Calgary, AB: AEUB, 2004.

ASPO, 2005b, Newsletter No. 59, November 2005.

BP, (2005). British Petroleum. *Putting Energy in the spotlight, BP Statistical Review of World Energy 2005.* www.bp.com (2005-10-30).

Campbell, C., (2004). Conversations in Ballydehob, Ireland, November 2004.

Campbell, C., (2005), March 2005.

Canada's First National Climate Change Business Plan (2000). National Climate change Process, October 2000

Canadian Gas Association (2005). (www.cga.ca/publications/gasstats). [2005-12-15]

CAPP, (2005). Canadian Association of Petroleum Producers. *Canadian Crude Oil Production and Supply Forecast 2005-2015.* July 2005.

CERI, (2004). Oil Sands Supply Outlook – Potential Supply and Costs of Crude Bitumen and Synthetic Crude Oil in Canada, 2013-2017. CERI Media briefing, March 3, 2004.

Climate Change Plan for Canada (2005), Government of Canada, www.climatechange.gc.ca [2005-03-10].

Dunbar R. B., Sloan T. (2003) *Does Nuclear Energy Have a Role in the Development of Canada's Oil Sands?* Petroleum Society Canadian Institute of Mining, Metallurgy & Petroleum. PAPER 2003-096.

EIA, (2005). Energy Information Administration. *International Energy Outlook 2004.* April 2004.

Fletcher, S. (2005). North American unconventional oil a potential energy bridger, Oil & Gas Journal, 2005-04-27.

Hirsch, H.L., Bezdek, R. Wendling, R. (2005). *Peaking of World Oil Production: Impacts, Mitigation, & Risk Management*. February 8, 2005. Report to US DOE, http://www.aspo-australia.org.au//References/hirsch0502.pdf

Koppelaar, R. H.E.M. (2005). *World Oil Production & Peaking Outlook.* www.peakoil.nl, 2005-12-14.

Moritis. M. (2004). Oil sands drive Canada's oil production growth. *Oil and Gas Journal*, pp 43-52. 2004-06-07.

Mortished, C. (2005). Can Shell's Canadian Sands yield more oil than the Saudi deserts? *TimesOnline.* 2005-03-04. (www.business.timesonline.co.uk) [2005-03-10].

National Energy Board (NEB). (2003) *Canada's Energy Future, Scenarios for Supply and Demand to2025*. Calgary, AB: NEB July 2003.

National Energy Board (NEB). (2004a) *Canada's Oil Sands: Opportunities and Challenges to 2015. Calgary*, AB: NEB, May 2004.

National Energy Board (NEB). (2004b)*Short-term Outlook for Natural Gas and Natural Gas Liquids to 2006*. Calgary, AB: NEB, October 2005.

National Energy Board (NEB). (2005) *Looking ahead to 2010 - Natural Gas Markets in Transition*. Calgary, AB: NEB, August 2004.

North American Natural Gas Vision (2005). North American Energy Working Group Experts Group on Natural Gas Trade and Interconnections, January 2005

Oil & Gas Journal, (2005) Statistics, *Worldwide crude oil and natural gas production*. November 14, 2005.

Simmons, M. "The Story of Natural Gas: Supply, Demand And A Brick Wall", Enskilda Securities Institutional Investor Meeting, Kitzbuhel, Austria, March 12, 2004. http://www.simmonsco-intl.com/research.aspx

Simmons, M. "The Natural Gas Riddle: Why Are Prices So High? Is A Serious Crisis Underway?, IAEE Mini-Conference, Houston, Texas December 11, 2004. http://www.simmonsco-intl.com/research.aspx

Staffer, G. (2004) Oil sands costs may rise 35%. Energy Bulletin. November 2004. (www.energybulletin.net) [2004-12-13].

Söderbergh, B. Robelius, F. Aleklett, A., (2005). *Canada's Oil Sands Resources and Its Future Impact on Global Oil Supply*. May 2005. Uppsala Hydrocarbon Depletion Study Group. Uppsala University, Sweden.

The Canadian Gas Association. *Understanding the North American Natural Gas Market*, October, Ottowa, 2003.

USGS Energy Resources Program, (2005). *Global Resource Estimates from Total Petroleum Systems.* ISBN: 0-89181-367-5, The American Association of Petroleum Geologists, 2005.

World Energy Outlook. (2004). IEA Publications, ISBN 92-64-1081-73-2004, pp. 81-127.