An Introduction to Development in Alberta's Oil Sands

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EXECUTIVE SUMMARY

Alberta's oil sands are one of the world's largest hydrocarbon deposits with proven accessible reserves of over 178 billion barrels. Constituted mainly by bitumen mixed with water and sand, it has not been economically viable to develop this massive resource until recently.

Located in north eastern Alberta, the oil sands can be exploited by both open pit mining and in situ methodologies. Mining projects, which have lower marginal production costs are much more capital intensive. Originally oil sands mining involved the use of bucketwheels which have now gone by the way side in favour of shovel/truck combinations which are significantly less expensive. There are two main in situ methods used in the oil sands today Cyclic Steam Stimulation and Steam Assisted Gravity Drainage. Both of these methods rely on using intense amounts of natural gas to heat up water which is injected into the ground. By decreasing the viscosity, the bitumen is able to be extracted.

After extraction it is necessary to separate the sand and water from the resource. Then the remaining bitumen is often upgraded to Synthetic Crude Oil (SCO). Since most refiners are not equipped to handle heavy crude blends, this step is critical for the marketing of the product. However, oil sands producers have been very successful as convincing refiners to take various bitumen blends (e.g. dilbit – a blend of diluent and bitumen) which meet pipeline requirements.

The total supply costs of a typical mining/upgrading operation are between C$22 and C$28 to produce a barrel of SCO. For most in situ technologies the supply costs are about C$13 –C$20 to produce a barrel of bitumen. Total supply cost includes production costs, capital costs and a nominal rate of return for investors. Under this cost structure, oil sands producers can make between 10% and 12% rate of return with a WTI price of $24/barrel.

One of the key challenges currently facing oil sands producers is the risk of capital cost overruns due to low worker productivity. This occurs because there are limited numbers of qualified trades people and poor project management. Companies have worked hard to use materials more efficiently and now build projects in modular phases.

The other challenge facing producers, in particular CSS and SAGD producers is their reliance on natural gas, which can constitute almost 60% of their production costs. Emerging technologies are being developed (e.g. Toe-to-Heel-Air-Injection, VAPEX and the Nexen/OPTI project) to directly address this issue.

With world crude demand steadily growing and conventional oil reserves in decline, Alberta's oil sands stand to figure prominently in international energy markets.

1.0 Introduction

The oil sands in Northern Alberta constitute of the largest hydrocarbon reserves in the world. It is estimated that the total amount of bitumen is over 1.6 trillion barrels with over 178 billion of those recoverable under current economic conditions[1]. Of these amounts, 35 billion barrels are accessible by surface mining with the remainder recoverable by in situ techniques. It is anticipated that by 2005 that crude oil from the oil sands will constitute 50% of Canada's total crude oil production and over 10% of total North American production. To this date, over C$30 billion has been invested in oil sands development projects. This amount is expected to rise to over C$60 billion over the next 15 years based on the number of projects planned to commence over this period. Given that world energy consumption is continuing to grow at phenomenal rate and world wide conventional crude reserves are in decline, Alberta's greatest resource should play an increasingly important role in world energy markets.

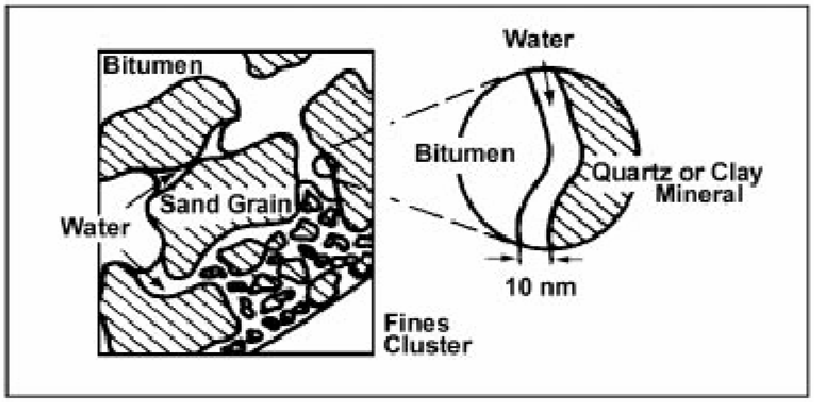
This paper provides an introduction to the development of Alberta's greatest natural resource. This first section will discuss the unique characteristics of Alberta oil sands that make its development economically feasible. It will also provide an over view of where these resources are located and where development has been concentrated. The following section of the paper will examine exploitation and upgrading methodologies including open pit mining as well as in situ recovery techniques. Several emerging exploitation technologies will be also be discussed. The third and final portion of the paper will consider the economics of oil sands development. Topics of focus include markets for synthetic crude and bitumen, capital and production costs and government policy. Subsequently, several challenges facing oil sands development will be considered. Among these are capital and labour constraints, the supply of natural gas, and the impact of the Kyoto Accord.

1.1 What are Oil Sands?

Oil sands are a combination of bitumen, quartz sand, clay, water and trace minerals. The exact proportions of these constituents vary from deposit to deposit but in general, Alberta oil sand will be approximately 75%-80% inorganic materials (sand, clay and minerals), 3%-5% water with bitumen content ranging from 10% to about 18%. The key characteristic of Alberta oil sands that makes them economically recoverable is that the bitumen is encapsulated by water molecules. Figure 1 (following page) shows this graphically. This makes separation of the bitumen from the other constituents feasible from an economical perspective.

While discovered over 100 years ago, development of this vast resource has only occurred over the about the last 38 years. This is because bitumen, while a highly concentrated source of energy, is difficult to use in its current state. Due to its high viscosity and weight, it must be mixed with diluents in order for it to be suitable for transportation by pipeline to refineries. Additionally, there are few refineries in North America that can utilize even diluted bitumen as a feedstock. Companies in Alberta have developed upgrading technologies to convert diluted bitumen to a synthetic crude oil which is similar in its characteristics to WTI blend. This has increased the market size in North America.

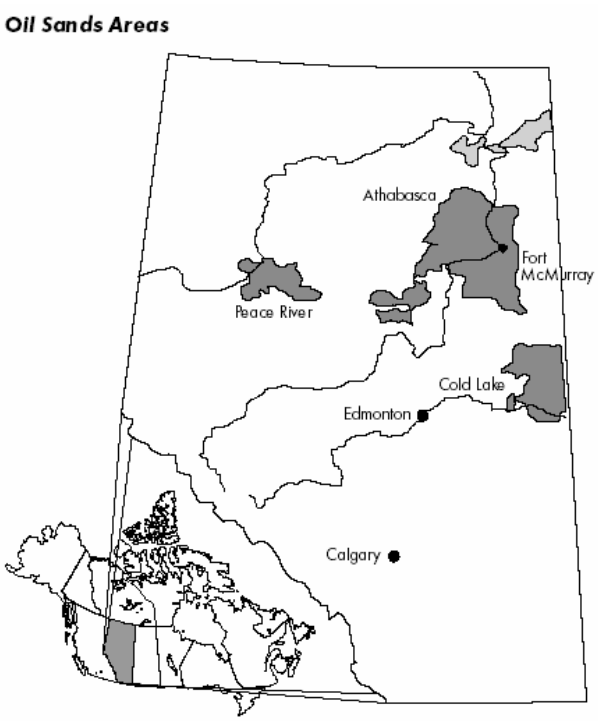
Figure 1: Oil Sands Composition Diagram[2]



1.2 Alberta's Deposits

The bulk of Alberta's oil sands are located in 54,400 sq. mile section in the north eastern part of the province. Figure 2 shows the three major deposits – Cold Lake, Athabasca and Peace River. Each of these deposits has its geological characteristics which dictate which exploitation methods would be most effective.

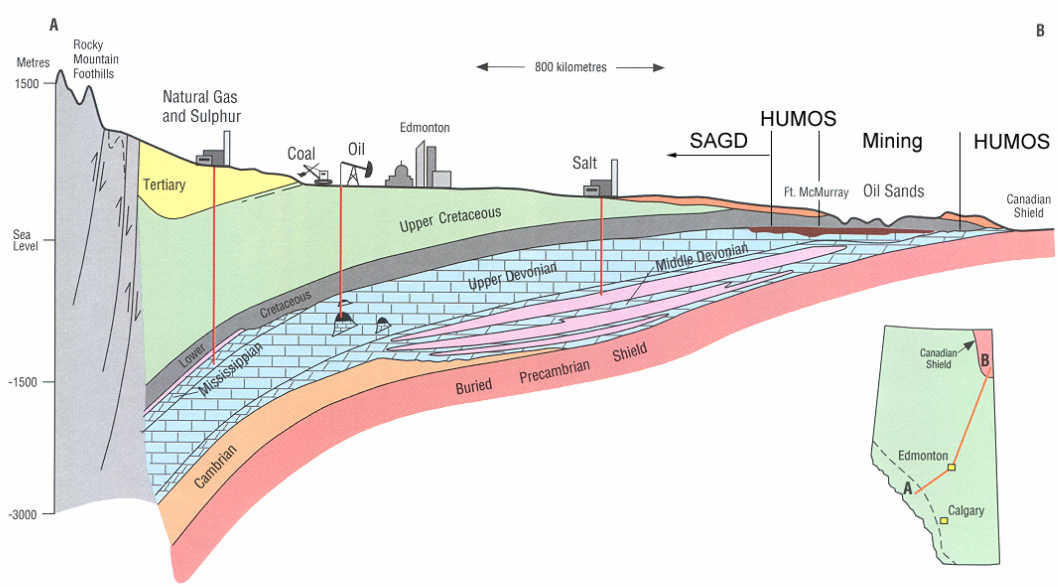
Figure 2[3]:



For example, in the Athabasca oil sands region there are large portions of the deposit with little overburden implying that an open pit mining operation would be the most efficient means of extraction. In Cold Lake, there are CHOPS (Cold Heavy Oil Production with Sand) operations where bitumen is extracted with vertical wells. SAGD production occurs in all three areas where the overburden is substantial.

In the case of Alberta's oil sands the depth of the overburden is typically lower in the eastern part of the deposit gradually becoming deeper moving west. Figure 3 illustrates this by looking at Alberta's geological structure.

Figure 3: Alberta's Geological Structure



2.0 Oil Sands Projects: Infrastructure and Technology

Huge investments were necessary in order to transform Canada's oil sands in a success story. Scientific research, technological innovation supported by a dynamic industry with a wide ranging support infrastructure contributed to a continual improvement in efficiency of crude oil extraction from oil sands. Two main groups of methods have been developed to recover the bitumen deposits:

- Integrated Mining/Upgrading Plants: feasible for bitumen deposits that are close to the surface.
- In-situ recovery: for the bitumen deposits buried too deeply for mining to be economic. The methods mostly used for in-situ recovery are steam assisted gravity drainage (SAGD) or cyclic steam stimulation (CSS).

2.1 Integrated Mining/Upgrading Plants

2.11 Mining

A mining open-pit development implies removal of the overburden. First the water-laden muskeg that covers much of the area must be drained then removed along with trees and other vegetation. The actual overburden consisting of different types of rocks (mostly clay and barren sand) is then removed and deposited into previously mined-out areas. The actual oil sands are typically 40 to 60 meters thick and sitting on top of relatively flat limestone.

The initial mining equipment used consisted of huge draglines, bucket-wheel excavators and conveyors for oil sands transportation. This equipment was difficult to redeploy in the mine and it was also vulnerable to interruption in service that occurred in harsh weather conditions especially in the winter months. Beginning with the 1990s this equipment started to be replaced by trucks and power shovels. The truck and shovel method proved to be much more flexible and less vulnerable in terms of service interruptions. 58 cubic yard capacity buckets and trucks up to 400 tons capacity are used today to move oil sands out of the mine site to the feeder/crusher.

An important innovation, the cyclofeeder, contributed to a significant increase in the efficiency of the process. A cyclofeeder is a massive vessel (approx. 35 meters tall) in which the oil sands are further crushed and mixed with hot water to form a slurry that can be transported through a pipeline to the extraction plant. The development of hydro-transportation brought three main benefits:

- Allows some separation of bitumen from the oil sands as the slurry moves through the pipeline
- Much more flexibility on the terrain because pipelines can follow uneven surfaces more easily than vehicles
- Lower energy extraction: because of the partial separation that takes place during the hydro-transport, operating temperatures can be reduced to 50 degrees Celsius or less

2.12 Extraction

In this stage, oil sand is being slurried by steam hot water (85 Celsius degrees) and caustic soda to condition it for bitumen separation. If oil sand ore is received to the processing plant through the pipeline, the necessary temperature is lower. Large pieces of materials such as rocks and lumps of clay are separated using vibrating screens then the slurry is diluted in pump boxes and pumped to Primary Separation Vessels (PSV). The bitumen rises at the surfaces as a froth and is being skimmed off while the sand settles to the bottom. The froth is further processed by a flotation unit that separates air-bitumen bubbles from the water. Naphta is added as a diluent and the mixture enters a high speed centrifuge to complete the separation. Diluted bitumen is sent to the upgrading unit while the separated material is removed as “tailings slurry” and pumped into holding ponds.

Innovations to this traditional method include Tailings Oil Recovery (TOR) units in order to recover bitumen from tailings discharged by PSV and Diluent Recovery Units to recover naphta from all froth treatment tailings. Both were developed by Syncrude. At the same time, for a better mechanical separation Suncor developed inclined plate settlers (IPS) and disc centrifuges. Due to these innovations, today’s extraction processes are able to extract about 91 percent of the bitumen compared to 84 percent in the past.

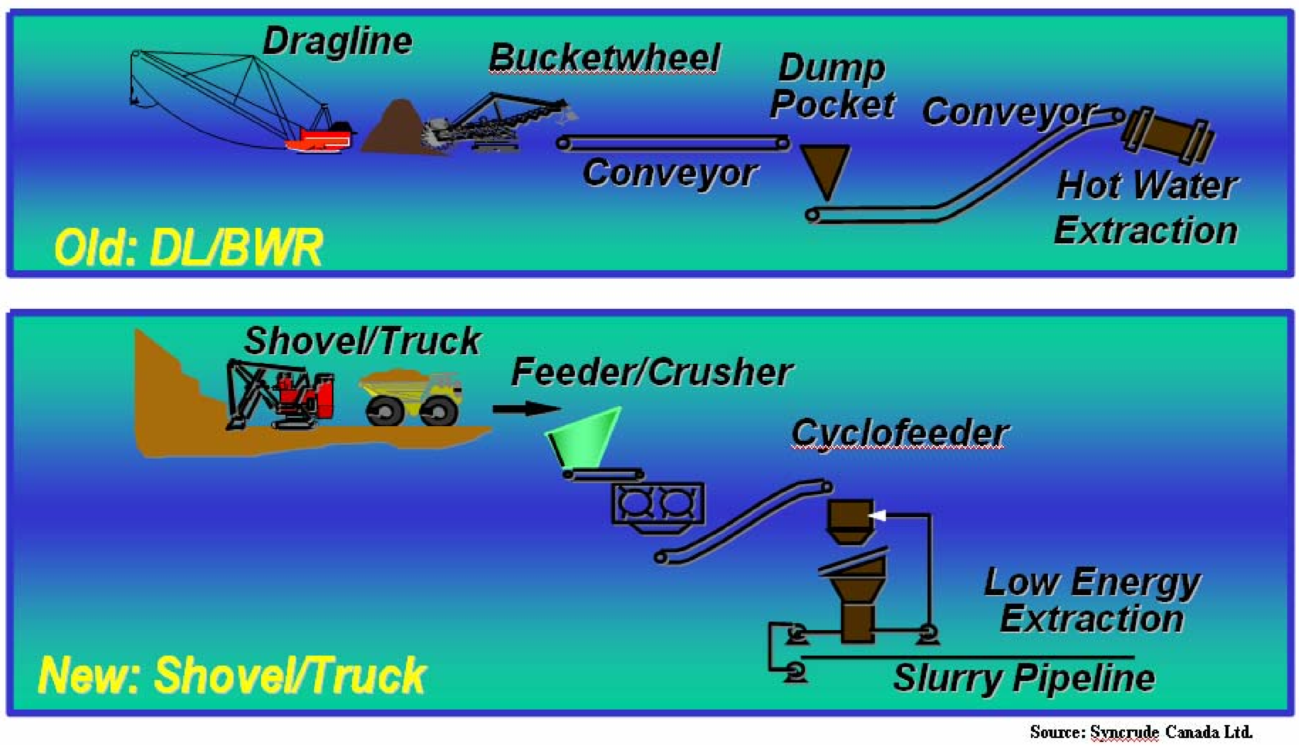


Figure 4: Mining and Extraction Technologies.

2.13 Upgrading

Upgrading consists of processes of coking, desulphurization and hydrogen addition that convert the viscous black bitumen deficient in hydrogen and high in sulphur and heavy metals into a high quality crude oil. The first step is recovery of naphtha which is recycled. The remaining bitumen is sent to high temperatures cokers in which the long bitumen molecules are thermally cracked. Most of the bitumen vaporizes into gases but the carbon-rich material forms coke. Coke is being used as fuel for the cokers or stockpiled to be commercialized or used in other industrial applications. The hydrocarbon gases are sent to fractionators where are separated into naphtha, kerosene and gas oil. Further into a hydrotreater, the vapours react with hydrogen at high temperatures and pressures in the presence of a catalyst. This stage removes sulphur and nitrogen and stabilizes the product stream. Finally, the gas oils and naphtha from the hydrotreaters are blended to make a high grade crude oil. The sulphur converted in elemental sulphur is stored or shipped to market while the nitrogen as ammonia and the fuel gas produced as a by-product are used as energy source throughout the plant.

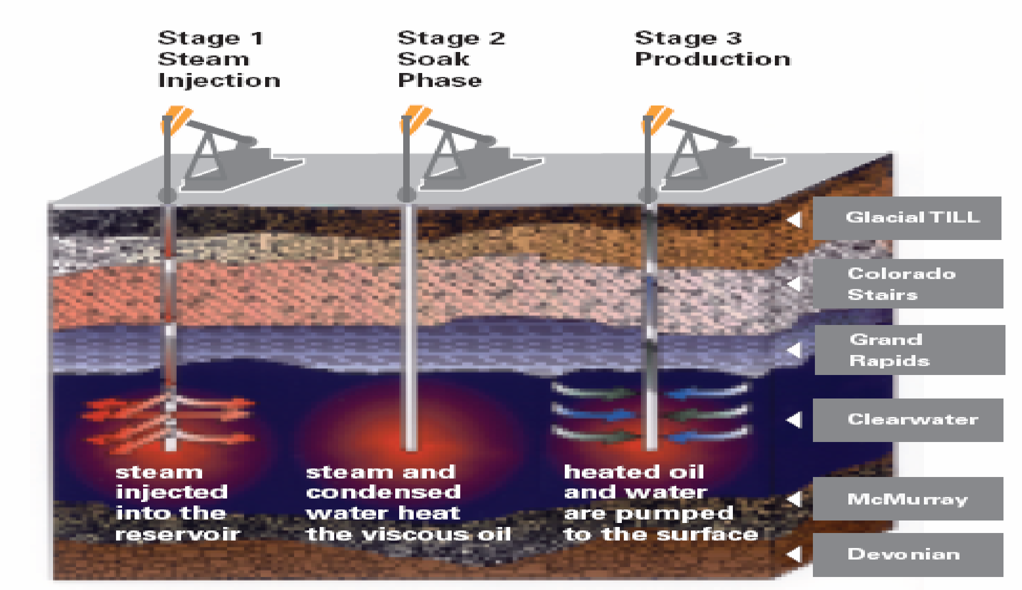
2.2 In Situ Recovery

80% of recoverable oil sands deposits are too deep for an efficient surface mining process. These reserves are estimated to be exploited using *in-situ* methods.

2.21 Cyclic Steam Stimulation

This method began to be commercially used in 1985 by Imperial Oil at Cold Lake after more experiments were conducted in different pilot projects. Steam produced in large boilers is injected down the well bore into the oil sand formation at a temperature of about 300 Celsius degrees and pressures averaging 11,000 kilopascals. Periods of steaming are followed by periods of soaking and then by periods of production when heated oil and water are pumped to the surface. Cycle times are typically six to eight months and the expected recovery factors are 20-25 percent.

Figure 5: Cyclic Steam Stimulation

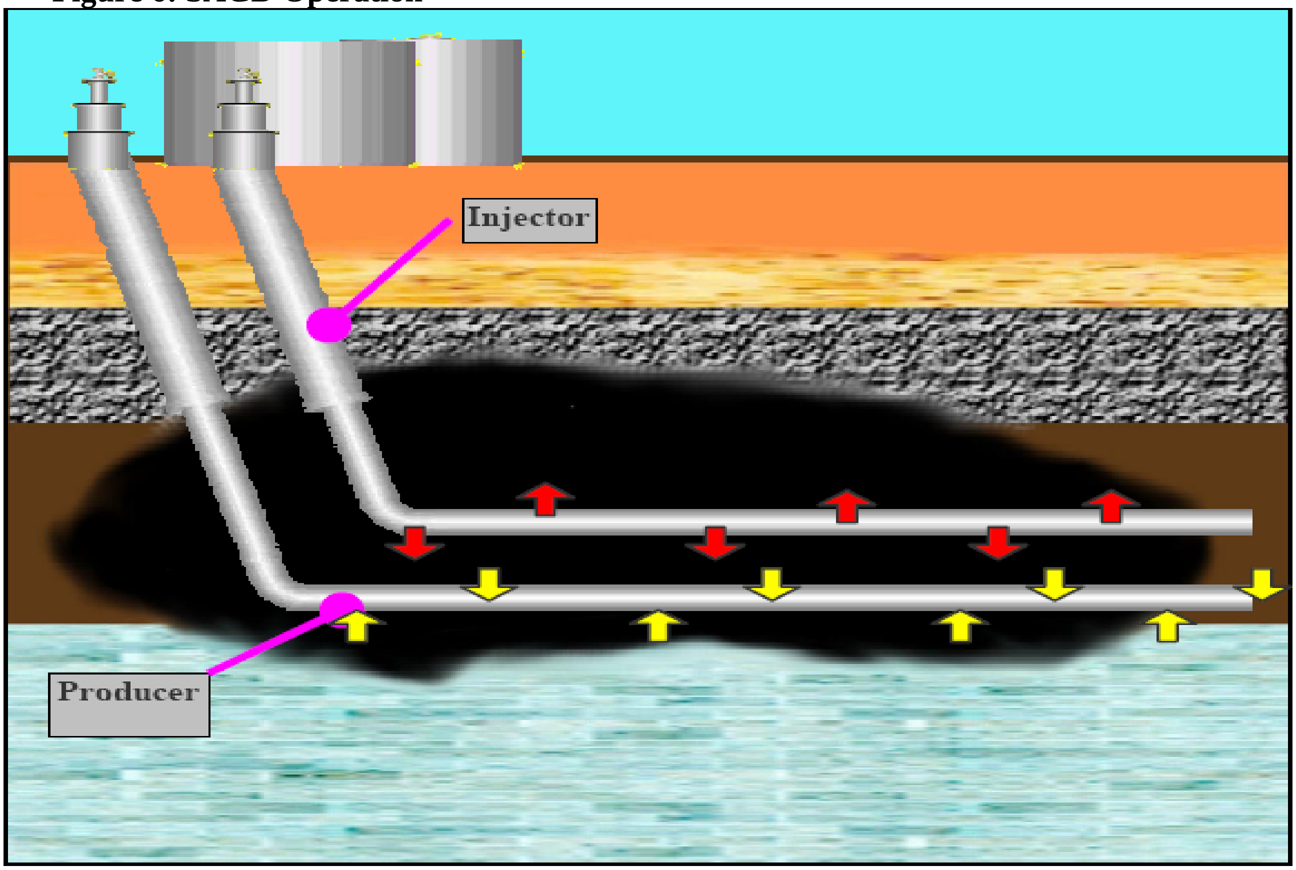


Source: Encana

2.22 Steam-Assisted Gravity Drainage (SAGD)

After several successful experiments, this method is regarded as the main alternative for the deeper deposits with several commercial SAGD projects already in production stage. The key technological advance that made this method possible was the development of horizontal drilling in the late 1980s and early 1990s. For SAGD, the orientation and the separation distance between the injector well and the producer well has to be precisely controlled and this capability was achieved by the mid 1990s. Technically, the method consists of drilling two horizontal wells into the oil sands. The producer well has to be situated near the base of oil sands and the injector well will be situated about five meters directly above the producer. Steam is injected through the upper well heating the oil sands and bitumen. Given there is sufficient permeability, the mobilized bitumen and condensed steam drains by gravity to the producing well and is subsequently pumped to the surface. Recovery factors achieved during the experiments were about 60 %.

Figure 6: SAGD Operation



Source: Japan Canada Oil Sands Ltd.

2.23 Pressure Cycle Steam Drive

The method was developed by Shell in Peace River area in partnership with the Alberta Oil Sands Technical Research Authority (AOSTRA). The process uses the basal water zone underlying the oil sands in this area to heat the oil sand deposit from below. Once a hot link path is established between the wells, continuous steam injection begins with injection and production rates controlled to alternately pressure up and blow down the deposit. Commercial operation was started in 1986 and it was successfully developed until 1990s when it evolved into a SAGD operation combined with multilateral wells employing steam injection.

2.24 Primary Bitumen Recovery

In the Wabasca area and in the southern part of Cold Lake the bitumen has suffered a lesser degree of biodegradation and is lighter and less viscous offering conditions for a "cold" production (no external energy is needed to determine the bitumen to flow to the well bore). Vertical wells are used in the Cold Lake area while in Wabasca area the horizontal well technology produced much better results given the thinness of the reservoir (approx. 5 meters).

2.3 Emerging Technologies

2.31 Mining

The present trend to use increasingly larger mining trucks and power shovels for higher efficiency rates is expected to continue with the introduction of 500 tons trucks in the near future. Mobile crushing stations directly fed by shovels at the front line are also in study. A technology to remove ore at the mine face with high pressure water-jet and transporting oil sands slurry is being studied along with mobile mine-site extraction technology. Mobile extraction operations located near the mine would allow the direct return of tailings back to the mine reducing transportation costs and allowing operations on a smaller scale.

Figure 7: Mobile Crushers directly fed by shovels. (Source:MMD)

2.32 Upgrading

The primary objective pursued by research consists of improving the efficiency of the process and making it less harmful for the environment. The possible innovations being studied include:

- *Aquaconversion*: un upgrading process that utilizes certain additives that in certain conditions would allow the transfer of hydrogen from the steam into the oil.(developed and tested in Venezuela)
- *Biocatalytic Aromatic Ring Cleavage (BioARC)* : the process uses designed strains of bacteria to provide controlled degradation of petroleum in order to reduce the need for hydrogen addition.
- *Partial upgrading methods* that can be done on a small scale and close to the production facilities in order to meet the pipeline specifications. The methods studied are $(HC)_3$ (high conversion/homogenous catalyst process developed by Alberta Research Council and a process developed at the University of

Waterloo that would allow both dewatering and upgrading in a single reactor using hydrogen generated from water in the emulsion.

2.33 In Situ Recovery

VAPEX

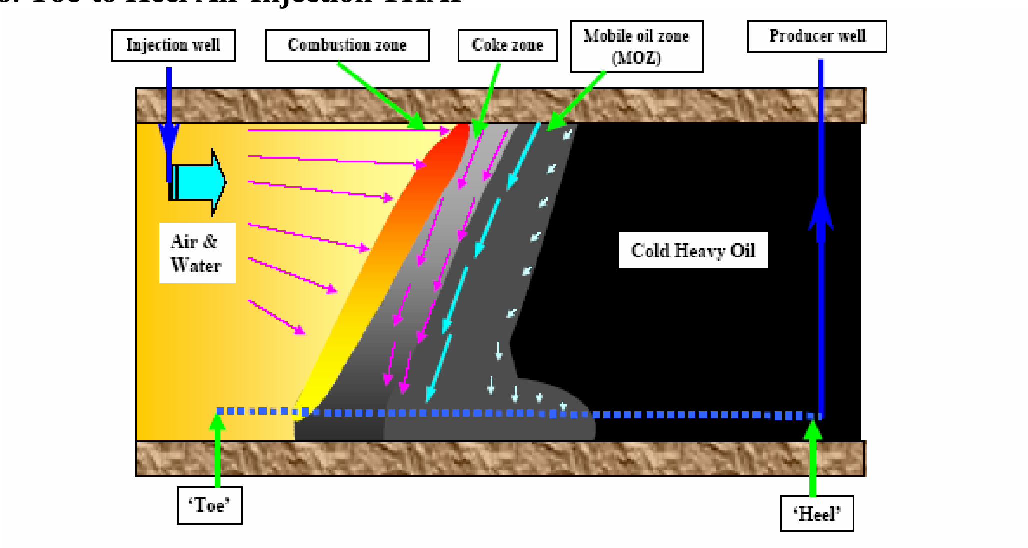
The VAPEX (Vapour Extraction Process) is technically similar to SAGD but instead of steam solvent is being injected into the oil sands resulting in significant viscosity reduction. The advantages envisioned by this innovation are:

- lower injection pressure and temperature
- greater energy efficiency
- no emulsion to deal with
- no clay swelling phenomenon that damage the formation
- partial upgrading within the reservoir resulting from the precipitation of asphaltenes from the bitumen.

Toe-to Heel Air Injection THAI

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.

Figure 8: Toe-to Heel Air Injection THAI



Source: University of Bath

The process ignites oil in the reservoir itself, creating a vertical wall or front of burning crude (fire front) that partially upgrades the hydrocarbons in front of it and drains the crude to a producing horizontal well. By creating heat in situ, the process negates the need for injecting steam from the surface. The process also offers some potential for upgrading the bitumen in the reservoir as the process proceeds. **(Technology Info Session: http://www.ptac.org/cho/chot0202p.html)**

In situ combustion recovery methods were tried in heavy oil and oil sands settings 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. The 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.

NEXEN-OPTI Project

The Long Lake SAGD project, a joint venture between Nexen Inc. and OPTI Canada Inc. is the first oil sands project to integrate SAGD with an onsite upgrader. This unique configuration of proven processes is designed to eliminate or significantly reduce the dependence on outside fuels, mainly solving the issue of volatility of natural gas prices. The project proponents expect this unique configuration to result in a $5 to $10 per barrel operating cost which is below the costs of existing integrated oil sands projects. Commercial SCO production is scheduled to start in 2007.

3.0 Economic Considerations

3.1 Markets

Over the next decade bitumen production is expected to grow from current levels of about 1 million bpd to as much as 2.8 million bpd. While crude oil demand in North America is expected to keep pace, there are still challenges for oil sands producers in finding markets for their products. The problem is that Alberta refinery capacity is already operating at 94% (about 560,000 bpd) with only one major refining project planned for the near future. There are some expansions underway, but most western Canadian refiners are looking to oil sands production to replace declining conventional production. This means that the vast majority of bitumen and bitumen products will have to be exported to other markets for refining. This creates two major issues for producers. The first is finding markets that have the process capacity to handle the sheer volume of production. The second is that many of the accessible markets (PADD II, III and IV) may not be able to process use anything but fully upgraded SCO, which would significantly reduce netbacks for oil sands producers. In response, oil sands producers have been creative in their strategies to get their product upgraded in these markets. The following paragraph looks at some of these strategies. However, these strategies wouldn't make a difference if there was insufficient capacity to take the anticipated volume. This issue will therefore be addressed subsequently.

Oil sands producers have been very successful thus far in finding customers for partially upgraded bitumen products. Some of the strategies used by producers include the following[4]:

- Purchasing refineries
- Tailoring outputs for a specific buyer/facility

- Entering into long term agreements so that refiners can modify their facilities to handle the bitumen based heavy crude
- Upgrading to produce high quality Synthetic Crude Oil (SCO)

Recently, producers have created a variety of bitumen blends to meet the needs of heavy, medium and light crude oil refiners. For example, "Dilbit" is essentially a slurry of diluent and bitumen and can be shipped via pipeline to facilities that can refine heavy crude inputs. Similar blends have been developed for medium and light crude refiners. It is interesting to note that American refiners have been quicker to adapt to accepting heavier crudes than Canadian refiners.

As was alluded to earlier, these innovations would be of little consequence if there was insufficient capacity in accessible export markets. Normally increases in Canadian crude production are absorbed by American refiners. However, these increases have historically been marginal and no where near the scale of the anticipated bitumen volumes. However, declining domestic reserves compounded with steadily increasing energy requirements make the U.S. the world's strongest energy market. In addition, oil sands producers are looking at exporting to Asia.

3.2 Capital and Production Costs

The capital costs of an oil sands development are massive. An average oil sands project costs billions of dollars before it is fully operational. If all planned oil sands projects go forward, it is estimated that capital spending in this industry could top C$60 Billion. The earliest supply costs of Synthetic Crude Oil (SCO) are estimated to have been over C$35 per barrel (1980's dollars). The supply cost includes all of the capital costs, marginal costs of production and a nominal return on the capital invested (most economist use between 10% and 12%). Needless to say dramatic reductions in operational and production costs have been realized since then. Currently, the total supply cost of a barrel of SCO is between C$22 and C$28 with the operating costs being between C$12 and C$18 for an integrated mining/upgrading operation. The primary reason for large range is the differences in the capital expenditures on the facilities. Each project is designed to produce SCO with specific characteristics usually tailored to the specific needs of the customer (refiner).

In Situ supply costs are typically higher than that of mining operations. The most expensive type of in situ extraction process is Cyclic Steam Stimulation (CSS), which has a total supply cost of C$13 to C$19. CHOPS (Cold Heavy Oil Production with Sand) and SAGD (Steam Assisted Gravity Drainage) operations have supply costs ranging from C$12 – C$16 and C$11 – C$17 respectively. These processes only yield bitumen which needs to be processed further before being sold to refiners.

Overall, the implications are that for most oil sands projects a WTI price of about $24USD is all that is necessary for investors to make a return of about 10%-12%. Given the security concerns in the middle east and the continuously increasing world appetite for energy, it appears likely that these projects will remain profitable for a long time.

3.3 Government Policy

In Canada, natural resources are owned and managed by provincial governments. The Alberta government therefore, holds 97% of all oil sands mineral rights[5]. In to paying for the leases, developers must pay royalties based on the volume of production. Prior to 1996, royalties were negotiated with the province on a project by project basis. In 1996, the province introduced a generic oil sands royalty regulation. According to this structure, companies pay a 1% of their gross revenues until the project has reached its payout point. After this, projects pay 25% of their gross revenues to the government. This policy has led to a rapid development of the oil sands. It is worth noting that most projects expand in scope prior to project payout, ensuring that they remain at the lower 1% royalty level. The Alberta government has a reputation for being very pro-business. In addition, Alberta is the only debt free constituency in North America.

3.4 Challenges

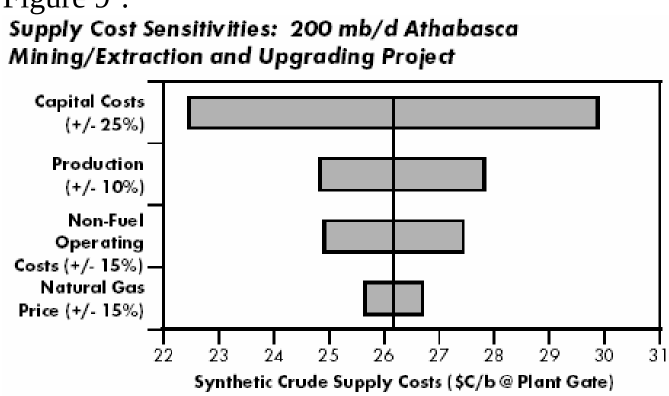
There are several challenges facing future development of Alberta's oils sands resource. The following sections address some of the more salient issues facing producers.

3.4.1 Capital Cost Overruns and Labour

The reason for discussing capital cost overruns and labour in the same section is that the two are often closely related. The history of oil sands development has been filled with stories of project cost overruns that have major impacts on the total supply cost of production. Typical projects (in particular integrated mining/upgrading) are highly complex and massive in scale. There is always the threat that there may be a shortage of skilled trades to complete portions of a project. A good example of this is Phase III of the Syncrude project. Exposure to this risk is likely to increase as more companies commence construction on their projects.

Companies have become keenly aware of how much capital cost overruns impact the bottom line of a project. The following tornado graph (figure 9) shows how sensitive supply cost is to capital cost overruns for a typical integrated mining/upgrading project producing 200,000 bpd of SCO.

Figure 9[6]:



While lower production, operating costs and the price of natural gas have significant impacts on the total supply cost, a 25% fluctuation in capital costs can have a greater impact than all three combined at C$3.70 per barrel of SCO. In recognition of the significance of this factor, companies are working closely with the government of Alberta to ensure that there are adequate numbers of trained trades people available to support these projects. In addition, companies have worked hard at 'modularizing' projects in order to maximize labour productivity. Companies collaborate in scheduling capital projects so that they are not competing for the same workforce. Today, however, labour shortages are still common and therefore companies have to be very careful in moving forward on major capital initiatives.

3.4.2 Natural Gas Supply

Oil sands projects are reliant on natural gas for the bulk of their energy needs. Mining projects use natural gas for a wide variety of tasks including heating water for use in separation of sand from the bitumen, generating electricity and as a feedstock in the upgrading process (for hydrocracking). In situ operations use natural gas to heat water for use in CSS or SAGD extraction methods. For an average in situ project natural gas costs form about 60% of the total operating costs. It is clear therefore, that as oil sands production volumes increase, demand for natural gas will increase as well.

While Alberta has significant natural gas reserves, the province's gas supply is in decline. It is estimated that oil sands production will be using about 1.2 Bcf/d of natural gas by 2010. Alberta's conventional gas reserves (excluding coal bed methane) will be yielding approximately 14.5 Bcf/d by then, meaning that oil sands will be consuming almost 10% of the province's total gas production. Currently, most natural gas produced in the province is exported to the U.S. (about 9Bcf/d). As U.S. and domestic needs for natural gas continue to grow there are concerns that Alberta's supply may not be adequate. Unconventional natural gas sources such as Coal Bed Methane (CBM) may reduce some of the pressure on the declining supply. A greater relief is expected once northern gas from the Mackenzie Delta/Beaufort Sea commences shipping.

While natural gas supply is a key concern for oil sands producers, being so dependent on such a volatile commodity is even more important. Natural gas prices tend to move with crude oil prices, the basis is not constant. That is, natural gas prices do move independently of oil prices, and as such oil sands producers (in particular in situ producers) are highly exposed to NG prices. Aside from risk management strategies, there has been a strong focus on developing technologies that mitigate this dependence. These emerging technologies were discussed in some detail in section 2.

4.0 Conclusions

Alberta's oil sands are one of the world's greatest hydrocarbon deposits. However, due to the highly viscous nature of the bitumen, they were not economically viable to develop until recently. The technologies that have been developed and used to extract and upgrade the bitumen have helped to dramatically bring down the production and capital costs of these projects improving their economic viability.

The keys to continued growth of the oil sands are:

- WTI price of at least $24USD
- Development of new in situ technologies which reduce the reliance on natural gas
- Improved project and materials management to control capital costs
- An increasing trained labour force
- Continuous innovation to further reduce production and capital costs

Rising world wide demand for energy and declining conventional reserves are creating an opening for this resource to become significant on an international level. As long as the above listed conditions it is likely that Alberta's oil sands will be a major supplier of crude oil products to North America and potentially the world.

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[1] National Energy Board **Canada's Oil Sands: Opportunities and Challenges to 2015** (Calgary: National Energy Board, 2004), p. 20.
[2] National Energy Board **Canada's Oil Sands: Opportunities and Challenges to 2015** (Calgary: National Energy Board, 2000), p. 20.
[3]National Energy Board **Canada's Oil Sands: Opportunities and Challenges to 2015** (Calgary: National Energy Board, 2004), p. 3.
[4]National Energy Board **Canada's Oil Sands: Opportunities and Challenges to 2015** (Calgary: National Energy Board, 2004), p. 31.
[5] Alberta Energy *Alberta's Oil Sands* (Edmonton: Alberta Energy, 2004), pp. 3-4.
[6] National Energy Board **Canada's Oil Sands: Opportunities and Challenges to 2015** (Calgary: National Energy Board, 2004), p. 11.