

Canada's Oil Sands - A World-Scale Hydrocarbon Resource



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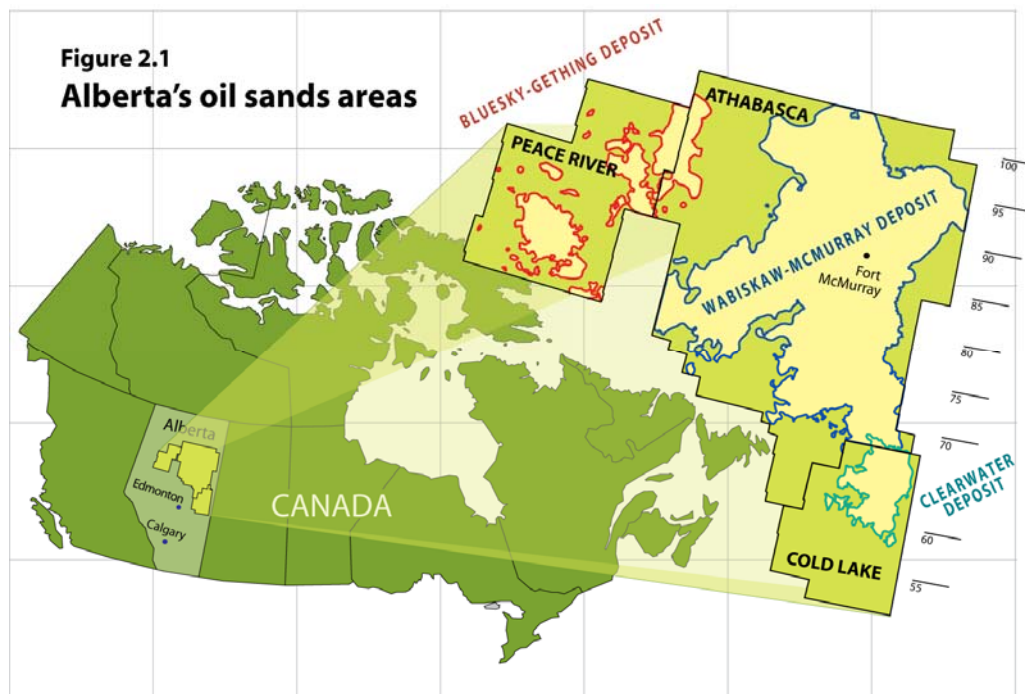
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1. Introduction

With an estimated initial volume in-place of approximately 1.7 trillion barrels (270 billion m³)¹ of crude bitumen, Canada's oil sands, located in the Province of Alberta, are one of the world's largest hydrocarbon accumulations. When the Oil and Gas Journal released its estimates of global proved petroleum reserves at year-end 2002, it increased Canada's proved oil reserves to 180 billion barrels (29 billion m³), compared to 4.9 billion barrels (780 million m³) the previous year. This almost forty-fold increase catapulted Canada into second position for total oil reserves behind only Saudi Arabia, and cut the Organization of Petroleum Exporting Countries' (OPEC's) share of world oil reserves by more than 10 percent.²

The three designated Oil Sands Areas (OSAs) in Alberta as of the end of 2007 are shown in Figure 1-1.

**Figure 1-1:
Oil Sands Areas**



Source: Alberta Energy Resources Conservation Board

¹ Source: Alberta Energy Resources Conservation Board; Alberta's Energy Reserves 2007 and Supply/Demand Outlook 2008-2017; ERCB ST98-2008, June 2008

² Source: Oil & Gas Journal; Worldwide Report: Worldwide Reserves Increase as Production Holds Steady; Marilyn Radler; December 23, 2002

Alberta's massive crude bitumen resources are contained in sand (clastic) and carbonate formations in the three OSAs shown in Figure 1-1. Contained within the OSAs are 15 Oil Sands Deposits (OSDs), which designate the specific geological zones containing the oil sands. Each OSA contains a number of bitumen-bearing deposits.

The known extent of the largest OSD, the Athabasca Wabiskaw-McMurray, as well as the significant Cold Lake Clearwater and Peace River Bluesky-Gething deposits, are shown in Figure 1-1. The bitumen in these three OSDs is contained in sand (clastic) formations. Most of the development activity to date has occurred in these three OSDs.

The bitumen in four of the 15 OSDs is contained in carbonate formations. While there is no commercial production of bitumen from the carbonate deposits, several companies have acquired oil sands carbonate leases and are developing recovery technologies.

As an indication of scale, the right-hand edge of Figure 1-1 shows township markers that are about 50 kilometres (km) (30 miles) apart. Together the three OSAs occupy an area of about 140,000 km² (54,000 square miles).

While most industry activity to date has focussed on Alberta, several companies have leased land in northwest Saskatchewan and are evaluating the extent of the Saskatchewan oil sands resources and are investigating bitumen recovery technologies. The remainder of this document focuses on oil sands industry activity in Alberta.

2. Oil Sands Resources and Reserves

Oil sands are a mixture of sand and other rock materials that contain crude bitumen (extra-heavy non-conventional crude oil). Oil sands are composed of approximately 80-85 percent sand, clay and other mineral matter, 5-10 weight percent water, and anywhere from 1-18 weight percent crude bitumen.

Crude bitumen is a thick, viscous crude oil that, at room temperature, is in a near solid state. The definition used in the industry is that crude bitumen is "a naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that, in its naturally occurring viscous state, will not flow to a well".³

2.1. Initial Volume In-Place

At year-end 2007, the Alberta Energy Resources Conservation Board (ERCB) estimated the Initial Volume In-Place of crude bitumen in Alberta's oil sands to be 1,712 billion barrels (272.0 10^9m^3).⁴

The ERCB reported that 6% of the volume in-place, 101 billion barrels (16.1 10^9m^3), is contained in shallow deposits – that are less than 250 feet (75 m) to the top of the oil sands zone. All of the shallow oil sands deposits are located in the Athabasca Oil Sands Area. Surface mining and extraction is used to recover crude bitumen from these shallow deposits.

The remaining 94% of the volume in-place, 1,610 billion barrels (255.9 10^9m^3), is contained in deeper deposits. Deep oil sands deposits are present in all three Oil Sands Areas. In situ recovery techniques are used to recover crude bitumen from the deeper deposits.

The ERCB's estimates of initial volume in-place are given in Table 2-1.

**Table 2-1:
Initial Crude Bitumen Volume In-Place**

	Billion Barrels	Billion m^3
Mineable:	101	16.1
In Situ:	1,610	255.9
Total	1,712	272.0

³ Source: Alberta Statutes and Regulations; Oil Sands Conservation Act, Section 1(1) (c)

⁴ Source: Alberta Energy Resources Conservation Board; Alberta's Energy Reserves 2007 and Supply/Demand Outlook 2008-2017; ERCB ST98-2008, June 2008

These figures represent the ERCB's best estimates of volume in-place. However, only a fraction of the volume in-place is expected to be technically and economically recoverable. The amounts estimated to be recoverable are classified as reserves and are discussed in the next section.

2.2. Reserves

The ERCB estimates that approximately 10% of the bitumen in-place is recoverable. Its estimates of Initial Established Reserves are given in Table 2-2.

**Table 2-2:
Initial Established Crude Bitumen Reserves**

	Billion Barrels	Billion m ³
Mineable:	35.2	5.59
<u>In Situ:</u>	<u>143.4</u>	<u>22.80</u>
Total	178.7	28.39

To year-end 2007, approximately 3% of the initial established reserves had been produced. Cumulative production to year-end 2007, as reported by the ERCB, is summarized in Table 2-3.

**Table 2-3:
Alberta Crude Bitumen Production to Year-end 2007**

	Billion Barrels	Billion m ³
Mineable:	3.9	0.63
<u>In Situ:</u>	<u>2.0</u>	<u>0.32</u>
Total	5.9	0.94

The ERCB's estimates of Remaining Established Reserves at year-end 2007, after accounting for cumulative production, are reported in Table 2-4.

**Table 2-4:
Remaining Established Crude Bitumen Reserves**

	Billion Barrels	Billion m ³
Mineable:	31.2	4.96
<u>In Situ:</u>	<u>141.5</u>	<u>22.49</u>
Total	172.7	27.45

Only a fraction of these reserves are associated with active development projects. The ERCB's estimate of Remaining Established Reserves "Under Active Development" at year-end 2007 is reported in Table 2-5.

Table 2-5:
Remaining Established Crude Bitumen Reserves under Active Development

	Billion Barrels	Billion m ³
Mineable:	18.3	2.91
In Situ:	3.7	0.59
Total	22.0	3.50

The reserve figures in Table 2-4 are roughly comparable with reserve estimates reported by the Canadian Association of Petroleum Producers (CAPP). CAPP reported remaining reserves for developed (producing) oil sands projects of 8,871 and 4,706 million barrels for mining and in situ bitumen respectively (1,410 and 748 10⁶m³) at year-end 2006.⁵ CAPP's reserve estimates for year-end 2007 were not available at the time of publication of this report.

2.3. Ultimate Potential

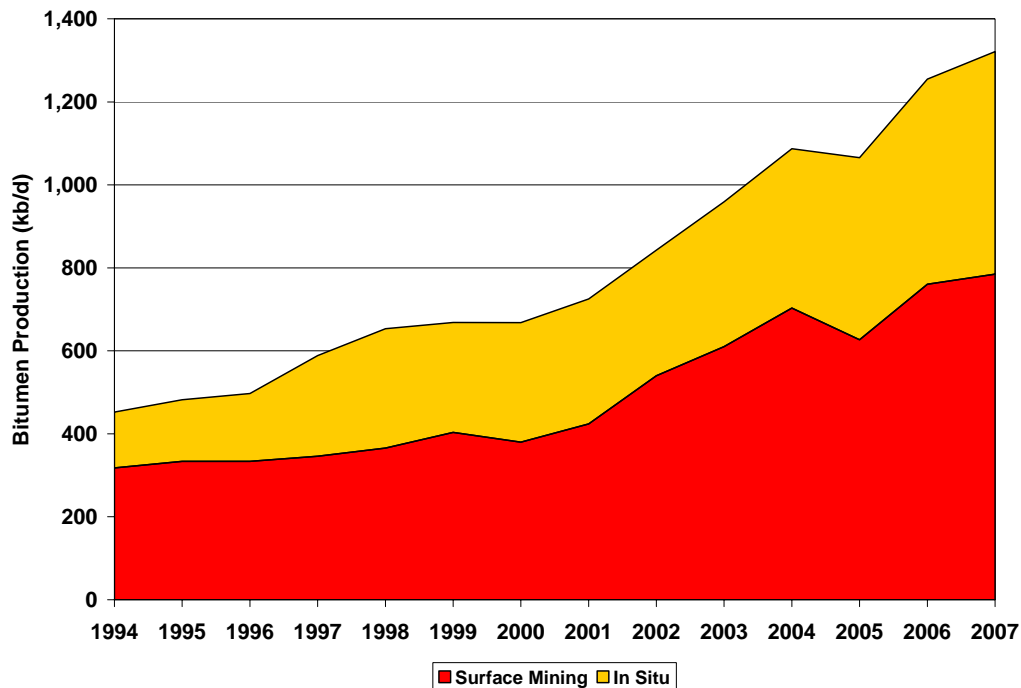
The ERCB estimates the ultimate potential of crude bitumen recoverable by in situ recovery methods from Cretaceous sediments to be 33 10⁹m³ (~210 billion barrels) and from Paleozoic carbonate sediments to be some 6 10⁹m³ (~40 billion barrels). Nearly 11 10⁹m³ (~70 billion barrels) is expected from within the surface-mineable boundary, with a little more than 6 10⁹m³ (~60 billion barrels) coming from surface mining and about 0.4 10⁹m³ (~3 billion barrels) from in situ methods. The total ultimate potential crude bitumen is therefore about 50 10⁹m³ (~315 billion barrels).

⁵ Source: Canadian Association of Petroleum Producers ; <http://www.capp.ca/>

3. Historical Bitumen and Synthetic Crude Oil Production

While Western Canadian conventional heavy oil production is in decline, bitumen production from Alberta's oil sands has been increasing as illustrated in Figure 3-1.

**Figure 3-1:
Alberta Bitumen Production (1994-2007)⁶**

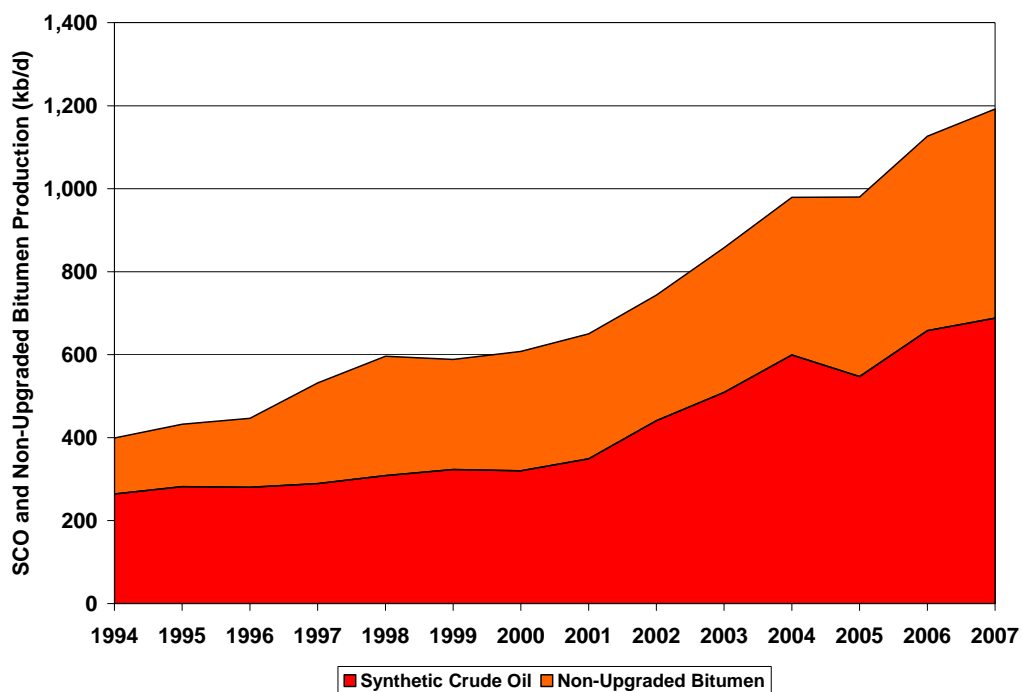


The sharp drop in production in 2005 occurred due to the extended shutdown of Suncor's Millennium upgrader after a fire in January 2005.

Over the last several years, about 60-65% of all bitumen produced in Alberta has been upgraded to synthetic crude oil (SCO) and other products before being delivered to downstream refineries for further processing or other uses. To date, almost all Alberta SCO has been produced at upgraders that are integrated with oil sands mining projects (Suncor, Syncrude and AOSP). In 2005, the fraction of bitumen that was upgraded dropped to 59% of all bitumen produced due to the extended shutdown following the January 2005 fire at Suncor's Millennium upgrader and outages at AOSP's Scotford upgrader. The production of synthetic crude oil and non-upgraded bitumen in Alberta since 1994 is illustrated in Figure 3-2.

⁶ Source: Source: Alberta Energy Resources Conservation Board; Alberta's Energy Reserves 2007 and Supply/Demand Outlook 2008-2017; ERCB ST98-2008; June 2008

Figure 3-2:
Alberta SCO and Non-Upgraded Bitumen Production (1994-2007)⁷



⁷ Source: Ibid

4. Bitumen Recovery and Upgrading Technologies

The hydrocarbon component of the oil sands, crude bitumen, must be separated from the sand, other mineral materials and formation water before it is delivered to downstream upgraders or refineries. Shallow oil sands deposits, less than about 75 m (250 feet) to the top of the oil sands zone, are exploited using surface mining to recover ore-grade oil sands, which are then delivered to an extraction plant for separation of bitumen from the sand, other minerals and connate water. Deep oil sands, greater than about 75 m (250 feet) to the top of the oil sands zone, are exploited using in situ recovery techniques, whereby the bitumen is separated from the sand in situ ("in place") and produced to the surface through wells.

4.1. *Oil Sands Mining and Bitumen Extraction*

Over time, different techniques have been used for oil sands mining. Suncor started its mining operations using bucketwheel excavators that discharged their loads onto conveyor belts. The initial Syncrude operation used large draglines to remove oil sands ore from the mine-face and place it in windrows from which bucketwheel reclaimers loaded it onto conveyor belts for transportation to the extraction plant. Suncor and Syncrude have now retired their bucketwheel- and dragline-based mining systems.

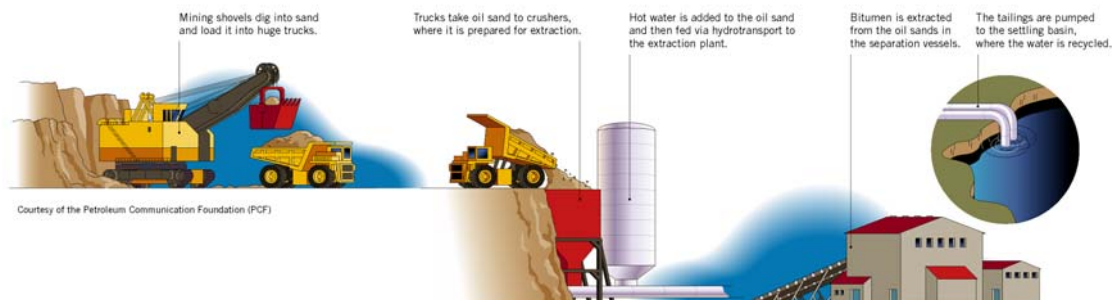
Large mining trucks and power shovels were introduced to replace these early mining systems. By the early 1990s, Syncrude was mining about one-third of its ore using trucks and shovels, while Suncor totally converted to a truck and shovel operation in 1993. Truck and shovel mining is considerably more flexible and less prone to interruption of service than the earlier systems used. In mining systems today, trucks capable of hauling up to 380 tonnes of material are loaded by electric- and hydraulic-power shovels with bucket capacities up to 44 cubic metres. The trucks transport the oil sands to ore preparation facilities where the ore is crushed and prepared for transport to the extraction plant (where bitumen is separated from the sand). In their early operations, Suncor and Syncrude used long conveyor systems for ore transportation. These systems have been replaced by hydrotransport with the first commercial applications of this technology occurring in the early 1990s. For hydrotransport, the oil sands ore is mixed with heated water (and chemicals in some cases) at the ore preparation plant to create oil sands slurry that is pumped via pipeline to the extraction plant. Hydrotransport preconditions the ore for extraction of crude bitumen and improves energy efficiency and environmental performance compared to conveyor systems.

At the extraction plant, bitumen is separated from the sand, other minerals and connate water using variations on the hot water extraction process, developed by Dr. Karl Clark of the Alberta Research Council in the 1920s. Considerable effort is underway to reduce the energy required for bitumen extraction. At its Aurora Mine, opened in 2000, Syncrude installed a low-energy extraction process, which operates at approximately 35°C. It is designed to consume about one-third of the energy of the traditional 80°C hot water extraction process.

Tailings are a byproduct of the oil sands extraction process. After bitumen extraction, the tailings, a mixture of water, sand, silt and fine clay particles, are pumped to a settling basin. Tailings also contain residual bitumen that is not recovered and residual solvents used in the extraction process. Coarse tailings settle rapidly and can be restored to a dry surface for reclamation. Fine tailings, consisting of slow-settling clay particles and water, are more problematic. The industry is expending considerable effort to overcome the challenges associated with tailings consolidation and ultimate site reclamation.

The overall configuration of the oil sands mining and bitumen extraction operations is shown in Figure 4-1.

**Figure 4-1:
Oil Sands Mining and Bitumen Extraction**



At remote mines, primary extraction occurs at the mine site. After primary extraction, bitumen froth is transported to a central site by pipeline for secondary extraction and upgrading. Syncrude has remote primary extraction at its Aurora Mine, 35 km (22 miles) north of the Mildred Lake Plant. Suncor has remote primary extraction at its Millennium Mine on the east side of the Athabasca River.

4.2. *In Situ Bitumen Recovery*

In general, the heavy, viscous nature of the bitumen means that it will not flow under normal reservoir temperature and pressure conditions. For recovery of bitumen from deep deposits, the bitumen viscosity must be reduced in situ to increase the mobility of bitumen in the reservoir. This enables flow to wellbores that bring the bitumen to the surface. Bitumen viscosity can be reduced in situ by increasing reservoir temperature or injecting solvents. Steam-based thermal recovery is the primary recovery technique used in Athabasca, Cold Lake and Peace River. The industry is also conducting field tests of other in situ recovery methods including solvent-based recovery, co-injection of steam and solvents, co-injection of steam and non-condensing hydrocarbons, in situ combustion and electric heating.

4.2.1. Primary Recovery

Bitumen can be produced from some oil sands reservoirs using primary recovery or "cold production"; no external energy is applied to the reservoir to mobilize the bitumen in the reservoir. The oil in these reservoirs is less bio-degraded and less viscous than the oil in other oil sands reservoirs but is still classified as crude bitumen because it is contained within designated Oil Sands Deposits.

Several primary recovery projects are operating in the Athabasca (Wabasca), Cold Lake, and Peace River Oil Sands Areas. Early primary production in the Cold Lake Oil Sands Area was ridden with problems caused by extreme wear on the pumps used to bring bitumen to the surface. Beginning in the early 1990s, introduction of the progressing cavity pump represented a significant innovation, with the new equipment being better suited to handle sand. Operators found that producing sand along with the bitumen, especially early in a well's life, was conducive to higher production rates. This was because a system of preferential fluid flow paths, or "wormholes", were formed and expanded in the reservoir as the sand was produced. This resulted in significantly higher production rates, lower operating costs and improved economics. This type of production technology is commonly referred to as cold heavy oil production with sand (CHOPS). Recovery factors range from three to ten percent using CHOPS in this area.

Development in the Wabasca area gained interest with the advent of horizontal well technology in the 1990s that yielded higher production rates. The reservoirs are relatively thin (five metres) and consolidated, with no significant sand production problems, and better suited to primary production by means of horizontal wells. The horizontal well technology has advanced to the stage that very long single-leg and "multi-leg" or "multilateral" producing wells can be drilled and

successfully operated. Recovery factors of seven to ten percent are achieved using primary recovery in this area.

Primary production in the Peace River Oil Sands Area has also been growing rapidly over the last few years.

4.2.2. Secondary Recovery

Several operators have also been having success with application of secondary recovery techniques (water and polymer flooding) in the Brintnell region of the Athabasca Oil Sands Area.

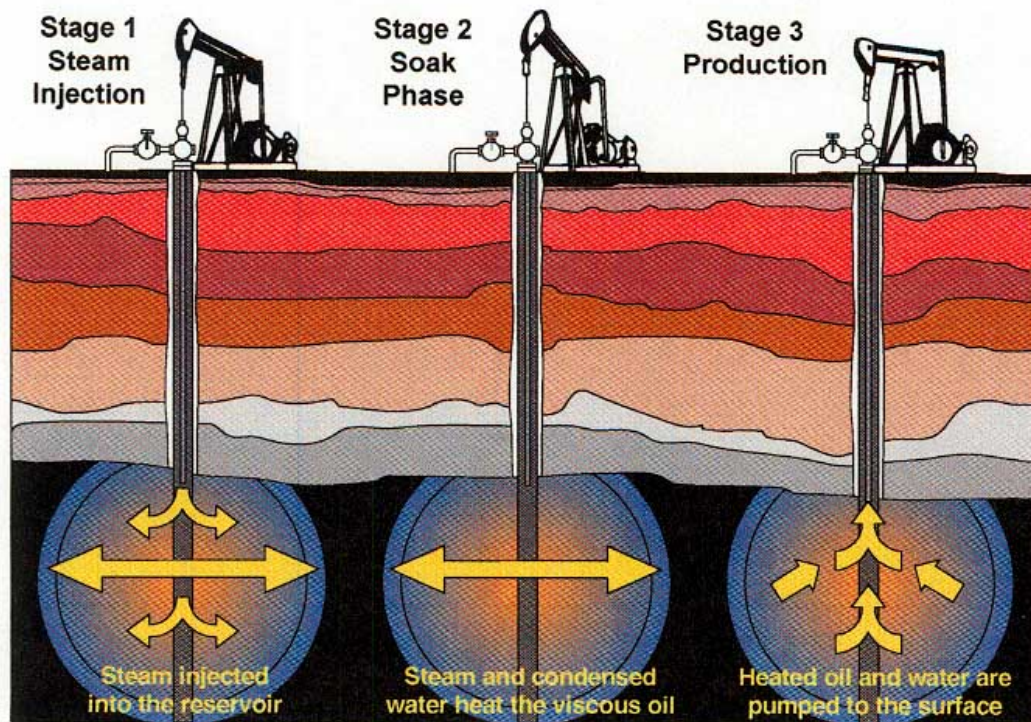
4.2.3. Steam-Based Thermal In Situ Recovery

In general, the heavy, viscous nature of the bitumen means that it will not flow under normal reservoir temperature and pressure conditions. Numerous in situ recovery technologies have been developed that apply thermal energy to heat the bitumen and reduce its viscosity thereby allowing it to flow to the well bore.

The most common thermal techniques involve steam injection into the reservoir using either cyclic steam stimulation (CSS) or steam assisted gravity drainage (SAGD). Steam is injected into the oil sands zone using vertical, deviated, horizontal or horizontal multi-lateral wells. The steam heats the bitumen, lowers its viscosity, and increases its mobility in the reservoir so it can be brought to the surface through wells using reservoir pressure, gas lift or downhole pumps.

CSS is a cyclic 3-stage process. During the initial injection cycle, steam is injected into the reservoir at high temperature and pressure. The wells then enter the soak cycle during which heat from the injected steam dissipates into the reservoir to heat the bitumen and lower its viscosity. During the final production cycle, the heated bitumen and condensed steam are produced to the surface. Bitumen, water and produced gas are separated in surface production-treating facilities. During the separation process, produced bitumen is mixed with the diluent that enables pipeline transportation to upgraders or heavy-oil refineries. Produced water is treated and recycled to the maximum extent possible. Produced natural gas is used on site as fuel. CSS is effective in reservoirs with limited vertical permeability and is best suited to operations in the Cold Lake and Peace River Oil Sands Areas. The CSS process is illustrated in Figure 4-2.

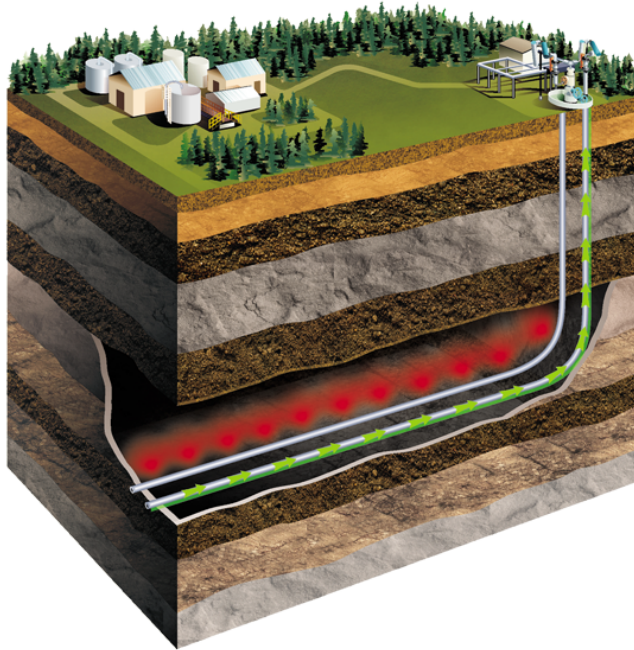
Figure 4-2:
Cyclic Steam Stimulation Process



The concept of utilizing continuous heating and production, rather than the discontinuous CSS process, led to the development of the SAGD process during the late 1970s and early 1980s. SAGD uses horizontal well pairs, up to 1,000 m (3,300 feet) in length, which are completed near the base of the oil sands zone. The upper horizontal well is drilled and completed about 5 m (16 feet) above the lower horizontal well. Steam is injected into the upper well to heat the bitumen, reduce its viscosity and cause it to drain by gravity into the lower part of the reservoir. The bitumen and condensed steam are collected and produced to the surface through the lower well. SAGD is applied in thick reservoirs, with high vertical permeability, and is being successfully used in the Athabasca Oil Sands Area.⁸ The SAGD process is illustrated in Figure 4-3.

⁸ Testing of SAGD is underway, but large-scale commercial application of SAGD in the Cold Lake and Peace River Oil Sands Areas has not taken place.

**Figure 4-3:
Steam Assisted Gravity Drainage Process**



The primary disadvantage of steam-based thermal recovery techniques is the large amount of energy and water that must be consumed for the generation of steam. A common industry rule-of-thumb is that 1,000 standard cubic feet of natural gas (~1 GJ of energy) is consumed for every barrel of bitumen produced; however, many projects are using much more.

4.2.4. Other In Situ Recovery Technologies

Because of the high energy and water consumption associated with steam-based thermal recovery techniques, the industry is conducting field trials of modified and new in situ recovery technologies. These include:

- VAPEX: (Vapour Extraction) the injection of a vapourized hydrocarbon solvent instead of steam into the reservoir with injection and production via horizontal well-pairs
- THAI: (Toe to Heel Air Injection) in situ combustion using vertical air injection wells and horizontal production wells
- Hybrid processes: injection of both steam and hydrocarbon solvents or gases into the reservoir

- Electrical Heating

All of the above in situ recovery techniques are being tested in the field.

4.3. Bitumen Upgrading Technologies

Bitumen from mining/extraction and in situ operations is either blended with a diluent (light low-viscosity hydrocarbon liquid) for shipment to market (downstream refineries) by pipeline or upgraded to a higher value synthetic crude oil or other petroleum products. Upgraders may be located on-site or off-site and may be either dedicated to a specific project or standalone facilities that process crude bitumen from many projects on a fee-for-service or other commercial basis. After upgrading, the synthetic crude oil is shipped via pipeline to downstream markets (refineries) for conversion into refined petroleum products (gasoline, diesel, jet fuel, fuel oils, etc.).

In the upgrading process, bitumen is converted from a viscous oil that is deficient in hydrogen and with high concentrations of sulphur, nitrogen, oxygen and heavy metals, to a high quality "synthetic" or "upgraded" crude oil that has density and viscosity characteristics similar to conventional light sweet crude oil, but with a very low sulphur content (0.1- 0.2 percent).⁹

4.3.1. Primary Separation

Oil sands upgraders typically employ front-end primary separation processes (atmospheric and vacuum distillation) to achieve initial segregation of hydrocarbon constituents in the feedstock based on their physical properties (distillation cuts). In a typical configuration:

- Primary separation occurs in atmospheric and vacuum distillation units;
- Sour hydrocarbon gases are recovered and delivered to gas recovery and gas treating facilities where they are treated for use as plant fuel gas;
- Diluent is recovered and returned to bitumen producers for reuse as a blending agent;
- Sour distillates are delivered to secondary upgrading for further processing; and
- The residue from primary separation (atmospheric or vacuum bottoms) is delivered to primary upgrading for further processing.

⁹ This statement describes the normal upgrading process. In some cases, bitumen may be partially upgraded and sold as a sour synthetic crude oil or may be more completely upgraded/refined to produce refined petroleum products (i.e., ultra low sulphur diesel).

4.3.2. Primary Upgrading

Residue from primary separation is processed in primary upgrading to increase the hydrogen-carbon ratio of the upgrader's hydrocarbon product(s) using either carbon rejection (coking) or hydrogen addition (hydro-conversion) processes. Solvent deasphalting may also be employed for "carbon rejection". Upgraders employing coking typically achieve volumetric liquid yields (synthetic crude oil/bitumen feed) of 80 – 90%, while upgraders employing hydro-conversion can achieve volumetric liquid yields of 100% or more.

Two coking processes have been applied in the oil sands industry: delayed coking and fluid coking. With delayed coking, the heated charge (typically residue from vacuum distillation) is transferred to large coke drums that provide the long residence time needed to allow thermal cracking reactions to proceed to completion. After the coke reaches a predetermined level in one drum, the feed is diverted to another drum to maintain continuous operations. The full drum is steamed to strip out uncracked hydrocarbons, cooled by water injection, and decoked by mechanical or hydraulic methods. The Suncor Base and Millennium, CNRL Horizon, and Husky Lloydminster upgraders, and other proposed upgraders, use delayed coking for primary upgrading.

Fluid Coking is a continuous fluidized-bed process that operates at temperatures higher than delayed coking. In Fluid Coking, thermal cracking occurs through heat transfer with hot, recycled coke particles in a reactor. The Syncrude Mildred Lake upgrader uses Fluid Coking.

The coke produced via either delayed or Fluid Coking has high energy content but also contains high concentrations of sulphur and other contaminants. Suncor is selling some of the coke it produces at the Base and Millennium upgraders; the remainder is stockpiled. Syncrude stockpiles its coke at Mildred Lake. CNRL stockpiles coke at its Horizon upgrader.

Because of its high energy content, coke is a potential feedstock for production of fuel and hydrogen using partial oxidation (gasification). Several projects plan gasification of bitumen residues as discussed later in this document.

Hydro-conversion is a continuous catalytic process whereby heavy feedstock (i.e., vacuum bottoms) is cracked in the presence of hydrogen to produce more desirable products. The process takes place under high pressure and high temperature conditions. The LC Fining ebullated bed hydro-conversion process is used at both the Syncrude Mildred Lake upgrader and

the AOSP Scotford upgrader. The H-Oil ebullated bed hydro-conversion process is used at the Husky Lloydminster upgrader.

4.3.3. Secondary Upgrading

Catalytic hydrotreating is used for secondary upgrading to remove impurities and enhance the quality of the final synthetic crude oil product. In a typical catalytic hydrotreating unit, the feedstock is mixed with hydrogen, preheated in a fired heater and then charged under high pressure to a fixed-bed catalytic reactor. Hydrotreating converts sulphur and nitrogen compounds present in the feedstock to hydrogen sulphide and ammonia. Sour gases from the hydrotreater(s) are treated for use as plant fuel. Fixed bed hydrocracking may also be employed at this stage to improve product yields and quality.

4.3.4. Hydrogen Production

With one exception, operating oil sands projects are meeting their hydrogen requirements using the Steam Methane Reforming (SMR) process with natural gas used for both feedstock and fuel. However, partial oxidation (gasification) is an alternative technology for hydrogen (and synthetic fuel gas – syngas) production that has been adopted at the operating Nexen/OPTI Long Lake project and is proposed or being considered by others.

- The Nexen/OPTI Long Lake upgrader processes crude bitumen using atmospheric and vacuum distillation, followed by solvent deasphalting and a patented thermal cracking process. The asphaltene stream is gasified for the production of hydrogen and syngas. Syngas is used for the generation of steam for the Nexen/OPTI Long Lake SAGD operations and for upgrader fuel. Hydrogen is used in the upgrading operations where distillates are processed in a hydrocracking unit for the production of a 39°API synthetic crude oil product. Startup of the upgrader and associated gasification facilities occurred in Q4 2008.
- Suncor Energy is considering gasification of 20% of its petroleum coke production as part of its Voyageur Phase II upgrader expansion. The project was approved in November 2006; however, construction has been suspended.
- North West Upgrading plans to build an independent upgrader in Alberta's Industrial Heartland (AIHL) outside of Edmonton. The project would use residual hydrocracked

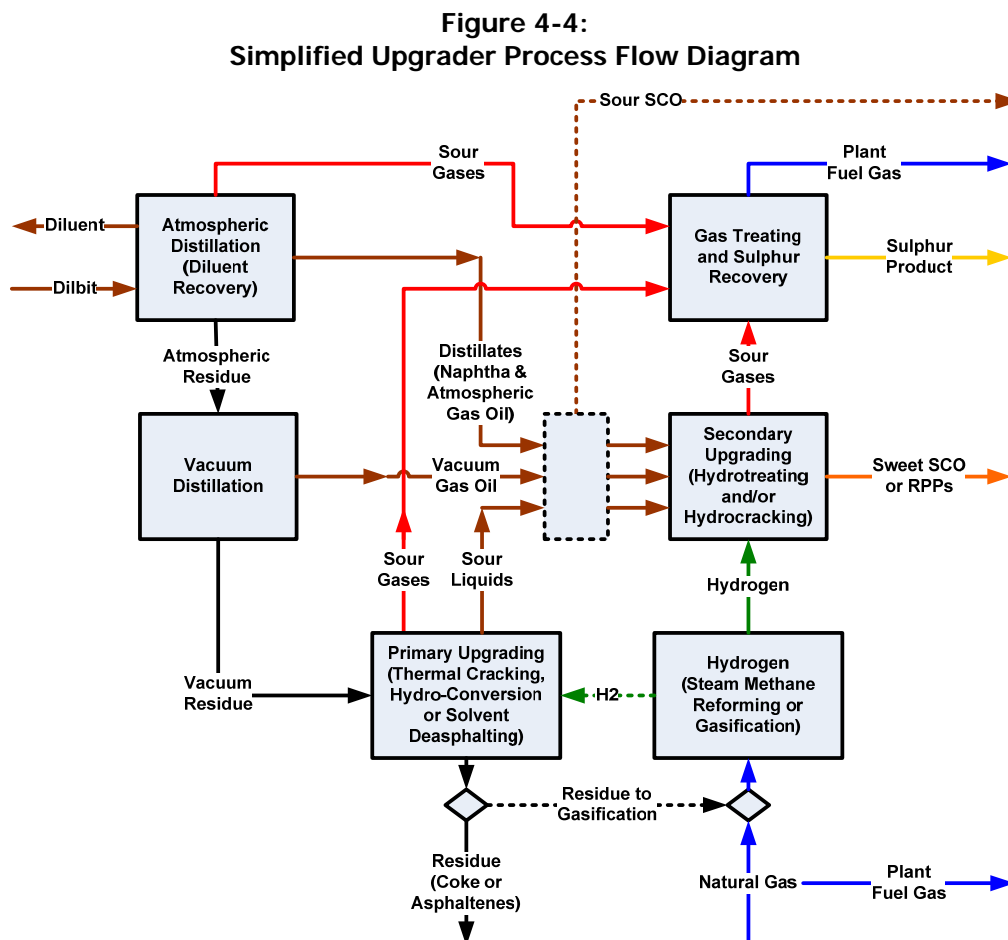
bottoms as fuel in a gasifier to produce hydrogen and synthetic fuel gas. The project has been approved but is on hold.

- Shell proposes to install gasification facilities at its Scotford Upgrader 2. Applications were filed with provincial regulators in July 2007.

Others have announced they are considering gasification of bitumen residues but most have not made final decisions (CNRL Primrose, CNRL Horizon Phases 4&5, North American Kai Kos Dehseh and Petro-Canada Sturgeon Phases 2&3).

4.3.5. Typical Upgrader Configuration

A simplified process flow diagram for a typical oil sands upgrader is shown in Figure 4-4.



4.3.6. Utilities and Offsites

Utilities and offsites such as those listed below are not shown on Figure 4-4.

- Electricity, Steam & Hot Water
- Boiler Feedwater
- Potable Water
- Fire Water
- Surface Water Management
- Instrument & Utility Air
- Nitrogen and Oxygen
- Waste Water & Solid Waste Disposal
- Fire & Smoke Detection
- Flare & Relief
- Tankage

5. Industry Challenges

The oil sands industry is working hard to overcome many challenges:

- Limited capital availability due to the recent collapse of global capital markets.
- Low prices for the light-sweet and heavy-sour oils produced by the oil sands industry.
- Environmental impact: air emissions including greenhouse gases and criteria air contaminants; water consumption; liquid waste disposal including tailings from mining operations; surface disturbance; and site reclamation are all serious environmental issues.
- Energy consumption: the industry's substantial external energy requirements are currently being met using purchased natural gas. Conventional gas production in Alberta peaked in 2001 and has been declining since.
- Project costs: many projects have experienced serious cost overruns; the industry is working hard to reduce both capital and operating costs.
- Labour availability and productivity: the industry has experienced serious shortages of skilled labour for both construction and operations.
- Infrastructure: road and rail capacity and other Northern Alberta infrastructure are inadequate.
- Diluent supply: condensate, the traditional blending agent for pipeline-delivery of non-upgraded bitumen to market, is in limited supply.

6. Industry Outlook

Strategy West Inc., a Calgary-based consulting company, maintains a comprehensive database of existing and proposed Canadian oil sands projects and has prepared long-term industry outlooks for several clients. These outlooks have included project-by-project and aggregated projections of oil sands industry:

- Bitumen production
- Synthetic crude oil and non-upgraded bitumen supply
- Purchased natural gas requirements
- Thermal energy (steam and hot water) requirements
- Electricity requirements
- Hydrogen requirements

Several other organizations also prepare outlooks for the Canadian oil sands industry including the Alberta Energy Resources Conservation Board (ERCB),¹⁰ the Canadian Association of Petroleum Producers (CAPP)¹¹ and the National Energy Board (NEB).¹² A long-term vision for the industry was released by the Alberta Chamber of Resources in 2004.¹³

Copies of Strategy West's most recent oil sands industry outlook and the others referred to in this section may be downloaded at www.strategywest.com.

¹⁰ Source: Alberta Energy Resources Conservation Board; Alberta's Energy Reserves 2007 and Supply/Demand Outlook 2008-2017; ERCB ST98-2008; June 2008

¹¹ Source: Canadian Association of Petroleum Producers; Crude Oil Forecast, Markets & Pipeline Expansions; June 2008; and CAPP's Crude Oil Forecast - Interim Update; December 11, 2008

¹² Source: National Energy Board; Canada's Energy Future – Reference Case and Scenarios to 2030; An Energy Market Assessment; November 2007

¹³ Source: Alberta Chamber of Resources; Oil Sands Technology Roadmap; January 30, 2004