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CRS Report for Congress

North American Oil Sands: History of Development, Prospects for the Future

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North American Oil Sands: History of Development, Prospects for the Future

Summary

When it comes to future reliable oil supplies, Canada's oil sands will likely account for a greater share of U.S. oil imports. Oil sands account for about 46% of Canada's total oil production and oil sands production is increasing as conventional oil production declines. Since 2004, when a substantial portion of Canada's oil sands were deemed economic, Canada, with about 175 billion barrels of proved oil sands reserves, has ranked second behind Saudi Arabia in oil reserves. Canadian crude oil exports were about 1.82 million barrels per day (mbd) in 2006, of which 1.8 mbd or 99% went to the United States. Canadian crude oil accounts for about 18% of U.S. net imports and about 12% of all U.S. crude oil supply.

Oil sands, a mixture of sand, bitumen (a heavy crude that does not flow naturally), and water, can be mined or the oil can be extracted in-situ using thermal recovery techniques. Typically, oil sands contain about 75% inorganic matter, 10% bitumen, 10% silt and clay, and 5% water. Oil sand is sold in two forms: (1) as a raw bitumen that must be blended with a diluent for transport and (2) as a synthetic crude oil (SCO) after being upgraded to constitute a light crude. Bitumen is a thick tar-like substance that must be upgraded by adding hydrogen or removing some of the carbon.

Exploitation of oil sands in Canada began in 1967, after decades of research and development that began in the early 1900s. The Alberta Research Council (ARC), established by the provincial government in 1921, supported early research on separating bitumen from the sand and other materials. Demonstration projects continued through the 1940s and 1950s. The Great Canadian Oil Sands company (GCOS), established by U.S.-based Sunoco, later renamed Suncor, began commercial production in 1967 at 12,000 barrels per day.

The U.S. experience with oil sands has been much different. The U.S. government collaborated with several major oil companies as early as the 1930s to demonstrate mining of and in-situ production from U.S. oil sand deposits. However, a number of obstacles, including the remote and difficult topography, scattered deposits, and lack of water, have resulted in an uneconomic oil resource base. Only modest amounts are being produced in Utah and California. U.S. oil sands would likely require significant R&D and capital investment over many years to be commercially viable. An issue for Congress might be the level of R&D investment in oil sands over the long term.

As oil sands production in Canada is predicted to increase to 2.8 million barrels per day by 2015, environmental issues are a cause for concern. Air quality, land use, and water availability are all impacted. Socio-economic issues such as housing, skilled labor, traffic, and aboriginal concerns may also become a constraint on growth. Additionally, a royalty regime favorable to the industry has recently been modified to increase revenue to the Alberta government. However, despite these issues and potential constraints, investment in Canadian oil sands will likely continue to be an energy supply strategy for the major oil companies.

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Introduction

Current world oil reserves are estimated at 1.292 trillion barrels. The Middle East accounts for 58% of world oil reserves, and the Organization of Petroleum Exporting Countries (OPEC) accounts for 70%. The Middle East also leads in reserve growth and undiscovered potential, according to the Energy Information Administration (EIA).[1]

The United States' total oil reserves are estimated at 22.7 billion barrels, a scant 1.8% of the world's total (see Appendix A). U.S. crude oil production is expected to fall from 5.4 million barrels per day (mbd) in 2004 to 4.6 mbd in 2030, while demand edges up at just over 1% annually. Net imports of petroleum are estimated by the EIA to increase from 12.1 mbd (58% of U.S. consumption) to 17.2 mbd (62% of U.S. consumption) over the same time period.[2]

When it comes to future reliable oil supplies, Canadian oil sands will likely account for a larger share of U.S. oil imports. Oil sands account for about 46% of Canada's total oil production, and oil sand production is increasing as conventional oil production declines. Since 2004, when a substantial portion of Canada's oil sands were deemed economic, Canada has been ranked second behind Saudi Arabia in oil reserves. Canadian crude oil exports were about 1.82 million barrels per day in 2006, of which 1.8 mbd or 99% went to the United States. Canadian crude oil accounts for about 18% of U.S. net imports and about 12% of all U.S. crude oil supply.

An infrastructure to produce oil, upgrade, refine, and transport it from Canadian oil sand reserves to the United States is already in place. Oil sands production is expected to rise from its current level of 1.2 (mbd) to 2.8 mbd by 2015. However, infrastructure expansions and skilled labor are necessary to significantly increase the flow of oil from Canada. For example, many refineries are optimized to refine only specific types of crude oil and may not process bitumen from oil sands. One issue likely to be contentious is the regulatory permitting of any new refinery capacity because of environmental concerns such as water pollution and emissions of greenhouse gases.

Challenges such as higher energy costs, infrastructure requirements, and the environment, may slow the growth of the industry. For example, high capital and

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[1] DOE, EIA, *International Energy Outlook, 2006,* p. 29.

[2] U.S. Department of Energy, EIA, *Annual Energy Outlook, 2006.*

energy input costs have made some projects less economically viable despite recent high oil prices. Canada ratified the Kyoto Protocol in 2002, which bound Canada to reducing its greenhouse gas (GHG) emissions significantly by 2012 but according to the government of Canada they will not meet their Kyoto air emission goals by 2012. The Pembina Institute reports that the oil sands industry accounts for the largest share of GHG emissions growth in Canada.[3]

Major U.S. oil companies (Sunoco, Exxon/Mobil, Conoco Phillips, and Chevron) continue to make significant financial commitments to develop Canada's oil sand resources. Taken together, these companies have already committed several billion dollars for oil sands, with some projects already operating, and others still in the planning stages. Many of these same firms, with the U.S. government, did a considerable amount of exploration and development on "tar sands" in the United States, conducting several pilot projects. These U.S. pilot projects did not prove to be commercially viable for oil production and have since been abandoned. Because of the disappointing results in the United States and the expansive reserves in Canada, the technical expertise and financial resources for oil sands development has shifted almost exclusively to Canada and are likely to stay in Canada for the foreseeable future. However, with current oil prices above $60 per barrel and the possibility of sustained high prices, some oil sand experts want to re-evaluate the commercial prospects of U.S. oil sands, particularly in Utah.

This CRS report examines the oil sands resource base in the world, the history of oil sands development in the United States and Canada, oil sand production, technology, development, and production costs, and the environmental and social impacts. The role of government — including direct financial support, and tax and royalty incentives — is also assessed.

World Oil Sands Reserves and Resources[4]

Over 80% of the earth's technically recoverable natural bitumen (oil sands) lies in North America, according to the U.S. Geological Survey (USGS) (see Appendix B). Canadian oil sands account for about 14% of world oil reserves and about 11% of the world's technically recoverable oil resources.

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[3] *Oil Sands Fever, The Environmental Implications of Canada's Oil Sand Rush*, by Dan Woynillowicz, et. al, The Pembina Institute, November 2005.

[4] Reserves are defined by the EIA as estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Resources are defined typically as undiscovered hydrocarbons estimated on the basis of geologic knowledge and theory to exist outside of known accumulations. Technically recoverable resources are those resources producible with current technology without consideration of economic viability.

What Are Oil Sands?

Oil sands (also called tar sands) are mixtures of organic matter, quartz sand, bitumen, and water that can either be mined or extracted in-situ[5] using thermal recovery techniques. Typically, oil sands contain about 75% inorganic matter, 10% bitumen, 10% silt and clay, and 5% water.[6] Bitumen is a heavy crude that does not flow naturally because of its low API[7] (less than 10 degrees) and high sulfur content. The bitumen has high density, high viscosity, and high metal concentration. There is also a high carbon-to-hydrogen molecule count (i.e. oil sands are low in hydrogen). This thick, black, tar-like substance must be upgraded with an injection of hydrogen or by the removal of some of the carbon before it can be processed.

Oil sand products are sold in two forms: (1) as a raw bitumen that must be blended with a diluent[8] (becoming a bit-blend) for transport and (2) as a synthetic crude oil (SCO) after being upgraded to constitute a light crude. The diluent used for blending is less viscous and often a by-product of natural gas, e.g., a natural gas condensate. The specifications for the bit blend (heavy oil) are 21.5 API and a 3.3% sulfur content and for the SCO (light oil) are 36 API and a 0.015% sulfur content.[9]

U.S. Oil Sand Resources

The USGS, in collaboration with the U.S. Bureau of Mines, concluded in a 1984 study that 53.7 billion barrels (21.6 billion measured plus 32.1 billion speculative) of oil sands could be identified in the United States. An estimated 11 billion barrels of those oil sands could be recoverable. Thirty-three major deposits each contain an estimated 100 million barrels or more. Fifteen percent were considered mineable and 85% would require in-situ production. Some of the largest measured U.S. oil sand deposits exist in Utah and Texas. There are smaller deposits located in Kentucky, Alabama, and California. Most of the deposits are scattered throughout the various states listed above. As of the 1980s, none of these deposits were economically recoverable for oil supply. They are still not classified as reserves (see **Figure 1**).

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[5] In-situ mining extracts minerals from an orebody that is left in place.

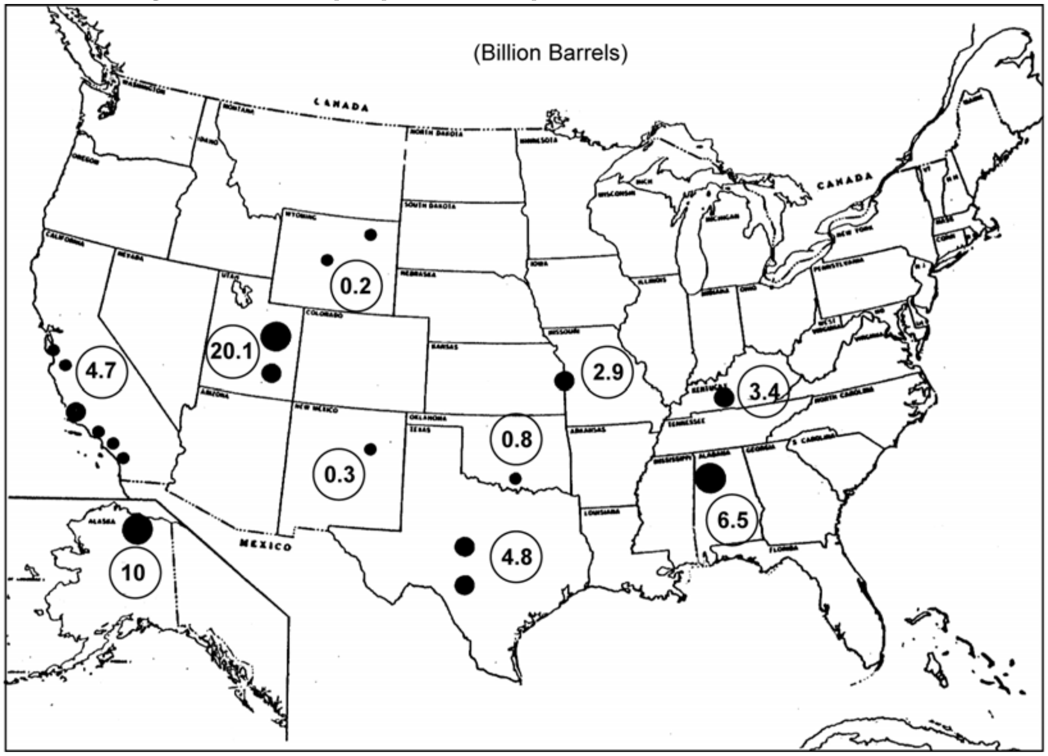
[6] *Canada's Oil Sands: Opportunities and Challenges to 2015, An Energy Market Assessment,* National Energy Board, Canada, May 2004, p. 5.

[7] API represents the American Petroleum Institute method for specifying the density of crude petroleum. Also called API gravity.

[8] Diluents are usually any lighter hydrocarbon; e.g., pentane is added to heavy crude or bitumen in order to facilitate pipeline transport.

[9] *Canada's Oil Sands*, May 2004, p. 10.

Figure 1. Tar (Oil) Sand Deposits of the United States



Source: *Major Tar Sand and Heavy Oil Deposits of the United States,* Interstate Oil Compact Commission, 1984, p. 2.

Canadian Oil Sand Resources

Canadian oil sand resources are located almost entirely in the province of Alberta. The Alberta Energy and Utility Board (AEUB) estimates that there are 1.6 trillion barrels of oil sands in place, of which 11% are recoverable (175 billion barrels) under current economic conditions (see **Table 1**). Mineable reserves at the surface account for 35 billion barrels (20%) and in-situ reserves at 141 billion barrels (80%). The AEUB estimates that the ultimate amount to be discovered (ultimate volume-in place) is 2.5 trillion barrels: about 2.4 trillion in-situ and 140 billion surface-mineable. Of this ultimate discovered amount, about 314 billion barrels are expected to be recovered (175 billion barrels in reserves now and another 143 billion barrels anticipated. See **Table 1**).[10] However, EIA estimates only 45.1 billion barrels (reserve growth and undiscovered potential) to be added to Canada's reserve base by 2025.[11]

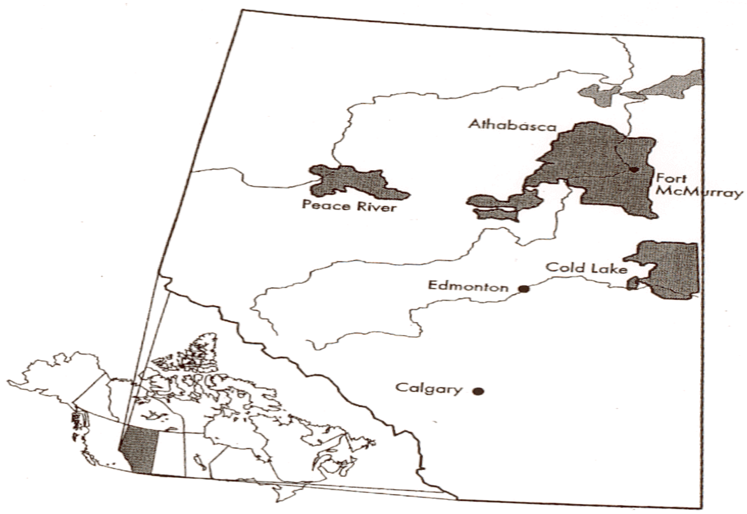
Oil sands occur primarily in three areas of Alberta: Peace River, Athabasca, and Cold Lake (see **Figure 2** below). Current production is 1.1 million barrels per day

[10] *Canada's Oil Sands*, May 2004, p. 4

[11] DOE, EIA, *International Energy Outlook, 2006,* p. 29

and is expected to reach 2.0 mbd by 2010 and 3.0 mbd by 2015.[12] According to the International Energy Agency (IEA), Canada's oil sands production could exceed 5.0 mbd by 2033 but would require at least $90 billion in investment.[13]

Figure 2. Oil Sands Areas in Alberta, Canada



Source: National Energy Board, Alberta, Canada.

Table 1. Canada's Bitumen Resources

Billion Barrels	Ultimate Volume in Place	Initial Volume in Place	Ultimate Recoverable Volume	Initial Established Reserves	Cumulative Production	Remaining Established Reserves
Mineable						
Athabasca	138.0	113.0	69.0	35.0	2.5	32.7
In Situ						
Athabasca	N/A	1,188.0	N/A	N/A	N/A	N/A
Cold Lake	N/A	201.0	N/A	N/A	N/A	N/A
Peace River	N/A	129.0	N/A	N/A	N/A	N/A
Subtotal	2,378.0	1,518.0	245.0	142.8	1.26	141.5
Total	**2,516.0**	**1,631.0**	**314.0**	**177.8**	**3.76**	**174.2**

Source: Alberta Energy Utility Board.

[12] *Canada's Oil Sands*, NEB, June 2006.

[13] *World Energy Investment Outlook, 2003 Insights*, International Energy Agency (IEA), 2003.

As a result of recent high oil prices, 44 new oil sands projects are planned for Alberta between 2004 and 2012, 26 in-situ and 18 surface-mining.[14] If all projects were to go forward, an estimated C$60 billion would be required for construction. Several of the projects are expansions of current operations. The National Energy Board (NEB) projects as much as C$81.6 billion being spent between 2006 and 2016.[15] Eighty-two percent of the projected investment — expected to peak in 2008 — is directed towards the Fort McMurray/Woods Buffalo Region of Alberta. A total of C$29 billion was spent on oil sands development between 1996 and 2004.[16]

History of Development

Role of Industry and Government

U.S. Oil Sands. Interest in U.S. oil sand deposits dates back to the 1930s. Throughout the 1960s and 1970s, 52 pilot projects involving mining and in-situ techniques were supported by the U.S. government in collaboration with major oil companies such as Conoco, Phillips Petroleum, Gulf Oil, Mobil, Exxon, Chevron, and Shell. Several steam-assisted technologies were being explored for in-situ production. These sources have had little economic potential as oil supply. The Energy Policy Act of 2005 (P.L. 109-58), however, established a public lands leasing program for oil sands and oil shale[17] R&D.

Based on the Canadian experience with oil sands production, it was established that commercial success in mining oil sands is a function of the ratio of overburden to oil sand thickness.[18] This ratio should not exceed one. In other words, the thickness of the overlying rock should not be greater than the thickness of the sand deposit. It was estimated by the USGS that only about 15% of the U.S. resource base has a ratio of one or less.

Major development obstacles to the U.S. oil sands resource base include remote and difficult topography, scattered deposits, and the lack of water for in-situ production (steam recovery and hot water separation) or undeveloped technology to extract oil from U.S. "hydrocarbon-wetted" deposits.[19] The Canadian technology

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[14] Canadian Oil Sands, May 2004, p. 25.

[15] The U.S.-Canadian dollar exchange rate fluctuates daily. As of early October 2007 the exchange rate is U.S.$1 = C$0.9969. In December 2006 the exchange rate was U.S.$1 = C$1.15.

[16] *Oil Industry Update*, Alberta Economic Development, Spring 2005.

[17] Oil shale is a compact rock (shale) containing organic matter capable of yielding oil.

[18] U.S. Tar-Sand Oil Recovery Projects — 1984, L.C. Marchant, Western Research Institute, Laramie, WY, p. 625.

[19] Hydrocarbon-wetted oil sand deposits require different technology for bitumen extraction than that used for Alberta's water-wetted deposits. Oil sands are characterized as having a wet interface between the sand grain and the oil coating; this allows for the separation of oil

(continued...)

may not be suited for many U.S. deposits. In Texas, deposits were considered by Conoco Oil to be too viscous to produce in-situ. A Bureau of Mines experiment with oil sands production in Kentucky proved to be commercially infeasible. In Utah, there were attempts at commercial production over the past three decades by several oil companies but projects were considered uneconomic and abandoned. As of 2004, some oil sands were being quarried on Utah state lands for asphalt used in road construction, and a small amount of production is taking place in California.[20] "Since the 1980s there has been little production for road material and no government funding of oil sands R&D," according to an official at the Department of the Interior.[21]

A 2006 conference on oil sands held at the University of Utah indicated renewed interest in U.S. oil sands but reiterated the development challenges mentioned above. Speakers also pointed out new technologies on the horizon that are being tested in Utah.[22] Conference organizers concurred that long-term research and development funding and huge capital development costs would be needed to demonstrate any commercial potential of U.S. oil sand deposits. A recent report[23] on U.S. unconventional fuels (an interagency and multistate collaboration) makes a number of general recommendations (for the development of oil sands and other unconventional fuels), which include economic incentives, establishing a regulatory framework, technology R&D, and an infrastructure plan. A recommendation specific to oil sands calls for closer U.S. collaboration with the government of Alberta to better understand Canadian oil sands development over the last 100 years. The report's task force estimates that based on a "measured" or "accelerated" development pace scenario,[24] U.S. oil sand production could reach 340,000-352,000 barrels per day by 2025.[25]

Canadian Oil Sands. Canada began producing its oil sands in 1967 after decades of research and development that began in the early 1900s. Wells were drilled between 1906 and 1917 in anticipation of finding major conventional oil deposits. The area around Fort McMurray, Alberta, was mapped for bituminous sand

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[19] (...continued)
from the grain. U.S. oil sands do not have a wet interface making the separation difficult.

[20] Phone communication with B. Tripp, Geologist, Utah Geological Survey, May 2004.

[21] Phone communication with Richard Meyers, Department of the Interior specialist in oil sands, September 2004.

[22] Presentation by Earth Energy Resources, Inc., at the Western U.S. Oil Sands Conference, University of Utah, September 21, 2006.

[23] *Development of America's Strategic Unconventional Fuels Resources, Initial Report to the President and the Congress of the United States*, Task Force on Strategic Unconventional Fuels, September 2006.

[24] The measured pace is based on sufficient private investment capital as a result of government policies but little direct government investment. An accelerated pace would imply a global oil supply shortage and rely more on significant government investment.

[25] *Development of America's Strategic Unconventional Fuels Resources, Initial Report to the President and the Congress of the United States*, Reference no. 17.

exposures in 1913 by Canada's Federal Department of Mines. By 1919, the Scientific and Industrial Research Council of Alberta (SIRCA), predecessor to the Alberta Research Council (ARC),[26] became interested in oil sands development. One of its newly recruited scientists, Dr. Karl Clark, began his pioneering work on a hot-water flotation process for separating the bitumen from the sand. In this separation process, the mined oil sand is mixed with water and a sodium hydroxide base and rotated[27] in a horizontal drum at 80 degrees centigrade. Dr. Clark's efforts led to a pilot plant in 1923 and a patented process by 1929. He continued to improve the process through several experimental extraction facilities through the 1940s.

The technical feasibility was demonstrated in 1949 and 1950 at a facility in Bitumont, Alberta, located on the Athabasca River near Fort McMurray. The technology being tested was largely adopted by the early producers of oil sands — Great Canadian Oil Sands (GCOS), Ltd., and Syncrude. Sunoco established GCOS, Ltd., in 1952 and then invested $250 million in its oil sands project. Another major player in the oil sands business in Canada was Cities Services, based in Louisiana. Cities Services purchased a controlling interest in the Bitumont plant in 1958, then in 1964, along with Imperial Oil, Atlantic Richfield (ARCO), and Royalite Oil, formed the Syncrude consortium.[28]

The ARC continued its involvement with oil sands R&D throughout the 1950s and 1960s. Several pilot projects were established during that period. Suncor[29] began construction of the first commercial oil sands production/separation facility in 1964 and began production in 1967, using the hot water extraction method developed and tested by ARC. In 1967, Suncor began to produce oil sands at a rate of 12,000 barrels per day.

Just a year later, in 1968, the government of Alberta deferred an application by Syncrude Canada for a $200 million, 80,000 barrel oil sands facility. Eventually, in 1978, the Energy Resources Conservation Board of Alberta approved Syncrude's proposal to build a $1 billion plant that would produce up to 129,000 barrels per day.

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[26] The ARC was established in 1921, housed at the University of Alberta in Edmonton, and funded by the provincial government of Alberta. Its mandate was to document Alberta's mineral and natural resources. Today, the ARC is a wholly-owned subsidiary of the Alberta Science and Research Authority (ASRA) within Alberta's Ministry of Innovation and Science. The ARC has an annual budget of $85 million.

[27] The Influence of Interfacial Tension in the Hot-Water Process for Recovering Bitumen From the Athabasca Oil Sands, by L.L. Schramm, E.N. Stasiuk, and D. Turner, presented at the Canadian International Petroleum Conference, paper 2001-136, June 2001.

[28] Syncrude Canada Ltd. when first organized as a consortium of major oil companies comprised: Imperial Oil (an affiliate of Exxon), Atlantic Richfield (ARCO), Royalite Oil (later combined with Gulf Canada), and Cities Services R&D (See *The Syncrude Story*, p. 5). Its ownership has changed over the years as indicated in the text. Its current ownership structure is as follows: Canadian Oil Sands Ltd. (31.74%), Imperial Oil (25%), Petro-Canada Oil and Gas (12%), Conoco Phillips Oil Sands Partnership II (9.03%), Nexen Inc. (7.23%), Murphy Oil Co. Ltd. (5%), Mocal Energy Ltd. (5%) and the Canadian Oil Sands Limited Partnership (5%).

[29] GCOS, Ltd., was later renamed Suncor.

However, ARCO, which represented 30% of the project, pulled out of the consortium as costs of the plant climbed toward $2 billion. At that point (1978) the federal and provincial governments joined in. The federal government purchased a 15% share, Alberta a 10% share, and Ontario 5%, making up the 30% deficit. At the time, the Canadian government was promoting the goal of energy self-sufficiency, and the Alberta government agreed to a 50/50 profit-sharing arrangement instead of normal royalties for Syncrude.[30]

The Alberta Energy Company[31] purchased 20% of Syncrude and then sold 10% of its share to Petrofina Canada, Ltd., and Hudson Bay Oil and Gas, Ltd.[32] The consortium grew from four to nine owners. From 1983 to 1988 Syncrude spent $1.6 billion to boost production to 50 million barrels per year. In 1984, the government of Alberta agreed to a new royalty structure for oil sands producers coinciding with Syncrude's capital expansion plans. In 1985, the Alberta government announced that existing oil sands operations and new plants would not be taxed on revenues, and the petroleum gas revenue tax would be phased out. During the same time-frame, Syncrude's cash operating costs were just under $18 per barrel with total costs over $20 per barrel,[33] while the market price of oil fluctuated under $20 per barrel.

Because of huge capital requirements, oil sands producers lobbied for continued royalty relief and thought the government should "defer tax and royalty revenues until project expansions were completed."[34] In 1994, the National Oil Sands Task Force (an industry/government group) was created, and the Canadian Oil Sands Network for R&D (CONRAD) agreed to spend $105 million annually to boost production and trim costs. Costs continued to fall ($15.39/bbl in 1992[35] to under $14/bbl in 1994[36]) as Syncrude ownership continued to change. In 1996, the National Oil Sands Task Force recommended a package of royalty and tax terms to ensure consistent and equal treatment of projects, because oil sand projects previously were treated on a project-by-project basis. The implementation of favorable royalty treatment is discussed below.

The ARC has had a successful partnership with the private sector in oil sands research and development. As a result of favorable royalty and tax terms and Alberta's $700 million R&D investment in oil sands extraction (from 1976-2001), the private sector has invested billions of dollars of development capital in oil sand

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[30] *A Billion Barrels for Canada, The Syncrude Story*, pp. 44-45.

[31] The Alberta Energy Company (AEC) was created by the government of Alberta in 1975. Fifty percent was publicly owned. The government phased out is equity interest and in 1993 sold its remaining interest. The AEC and PanCanadian Energy Corporation merged in 2002 and became EnCana. EnCana sold its interest in Syncrude in 2003. For more details see Alexander's Oil and Gas Connection, "Company News North America," January 15, 2004.

[32] *The Syncrude Story*, pp. 72-73.

[33] Ibid, p. 98-99.

[34] Ibid, p.104

[35] Ibid, p. 122.

[36] Ibid, p. 136.

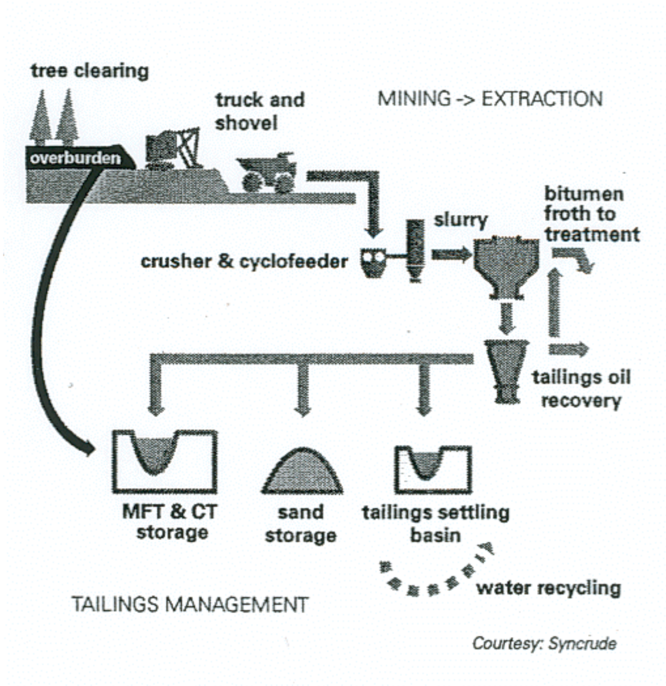
projects.[37] Syncrude has said that "partnering with ARC gave us the ability to explore a potentially valuable technology."[38]

Oil Sands Production Process

Oil sands production measured only 1.3% of total world crude oil production in 2005. By 2025 it may reach 4.1% of total world production. But more importantly, it may mean U.S. access to extensive North American oil reserves and increased energy security.

Oil sands are either surface-mined or produced in-situ. Mining works best for deposits with overburden less than 75 meters thick. Mining requires a hydraulic or electric shovel that loads the sand into 400-ton trucks, which carry the material to a crusher to be mixed into a slurry. Using pumps and pipelines, the slurry is "hydro transported" to an extraction facility to extract bitumen (see **Figure 3**). This process recovers about 90% of the bitumen.[39]

Figure 3. Major Mining Process Steps



Source: *Oil Sands Technology Roadmap,* Alberta Chamber of Resources, January 2004, p. 21.

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[37] The Alberta Energy Research Institute: Strategic Research Plan, 2003.

[38] ARC, Guide to the ARC, 2001-02. The ARC's more recent focus on developing in-situ technologies is beginning to shift back to surface mining R&D. They believe that their role is to help many of the newcomers to the industry develop "best practices" technology. The ARC sees itself as an ongoing player in the R&D business because of the huge challenges related to environmental quality, cost reductions, and the need for new upgrading technologies and refinery expansions.

[39] *Oil Sands Technology Roadmap,* p. 20.

In 2005, mining accounted for about 52% of Alberta's oil sand production (572,000 b/d); in-situ accounted for about 48% (528,000 b/d), one-third of which was produced using the Cold Production method in which oil sands are light enough to flow without heat. The in-situ approach, which was put into commercial production in 1985,[40] is estimated to grow to 926,000 barrels per day by 2012. Currently, the largest production projects are in the Fort McMurray area operated by Syncrude and Suncor (see **Table 4** for leading producers of oil sands).

Extraction Process. The extraction process separates the bitumen from oil sands using warm water (75 degrees Fahrenheit) and chemicals. Extracting the oil from the sand after it is slurried consists of two main steps. First is the separation of bitumen in a primary separation vessel. Second, the material is sent to the froth tank for diluted froth treatment to recover the bitumen and reject the residual water and solids. The bitumen is treated either with a naphtha solvent or a paraffinic solvent to cause the solids to easily settle. The newer paraffinic treatment results in a cleaner product.[41] This cleaner bitumen is pipeline quality and more easily blended with refinery feedstock. After processing, the oil is sold as raw bitumen or upgraded and sold as SCO.

Table 2. Leading Oil Sands Producers

(barrels per day)

Project Owner	Type of Project	2002	2003	2006 1st Quarter	Planned Production Targets
Suncor	Mining	206,000	217,000	264,400	410,000
Syncrude	Mining	230,000	212,000	205,000	560,00
Athabasca Oil Sands (Shell, Chevron, and Marathon Oil)[a]	Mining	N/A	130,000	77,400	525,000
Imperial Oil	In-situ	112,000	130,000	150,000	180,000
CNRL	In-situ	N/A	35,000	122,000	500,000
Petro Canada	In-situ	4,500	16,000	21,000 (2005)	100,000
EnCana	In-situ	N/A	5,300	36,000	250,000

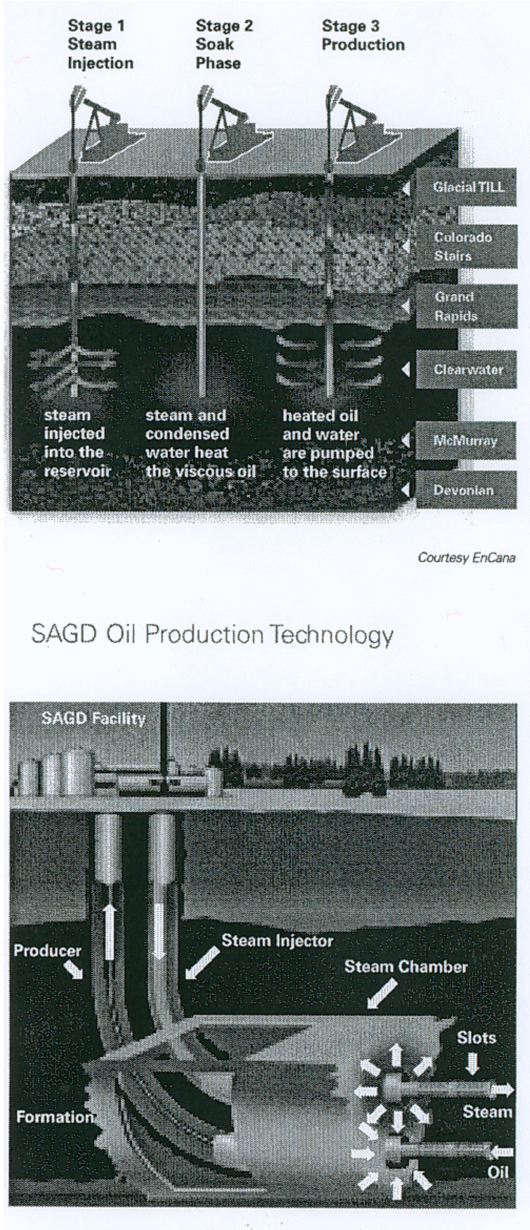
Source: *Oil Sands Industry Update*, Alberta Economic Development, 2004 and 2006.

a. Marathon Oil Corp. acquired Western Oil Sands, Inc. on October 18, 2007.

[40] *Oil Sands Industry Update*, AED, June 2006, p. 7.

[41] *Oil Sands Technology Roadmap: Unlocking the Potential*, Alberta Chamber of Resources, January 2004 p. 23.

Figure 4. In-SITU Recovery



Source: *Oil Sands Technology Roadmap*, p. 28.

Production Technology. For in-situ thermal recovery, wells are drilled, then steam is injected to heat the bitumen so it flows like conventional oil. In-situ production involves using various techniques.

One technique is the Cyclic Steam Stimulator (CSS), also known as "huff and puff." CSS is the most widely used in-situ technology. In this process, steam is added to the oil sands via vertical wells, and the liquefied bitumen is pumped to the surface using the same well.

But a relatively new technology — steam-assisted gravity drainage (SAGD) — has demonstrated that its operations can recover as much as 70% of the bitumen in-place. Using SAGD, steam is added to the oil sands using a horizontal well, then the liquefied bitumen is pumped simultaneously using another horizontal well located below the steam injection well (see **Figure 4**). The SAGD process has a recovery advantage over the CSS process, which only recovers 25%-30% of the natural bitumen. Also, the lower steam to oil ratio (the measurement of the volume of steam required to extract the bitumen) of SAGD results in a more efficient process that uses less natural gas.[42] SAGD operations are limited to thick, clean sand reservoirs, but it is reported by the industry that most of the new in-situ projects will use SAGD technology.[43] A number of enhanced SAGD methods are being tested by the Alberta Research Council. They could lead to increased recovery rates, greater efficiency, and reduced water requirements.

The emerging Vapor Extraction Process (VAPEX) technology operates similarly to SAGD. But instead of steam, ethane, butane, or propane is injected into the reservoir to mobilize the hydrocarbons towards the production well. This process eliminates the cost of steam generators and natural gas. This method requires no water and processing or recycling and is 25% lower in capital costs than the SAGD process. Operating costs are half that of the SAGD process.[44]

A fourth technique is cold production, suitable for oil sands lighter than those recovered using thermal assisted methods or mining. This process involves the co-production of sand with the bitumen and allows the oil sands to flow to the well bore without heat. Imperial Oil uses this process at its Cold Lake site. Oil sand produced using in-situ techniques is sold as natural bitumen blended with a diluent for pipeline transport.

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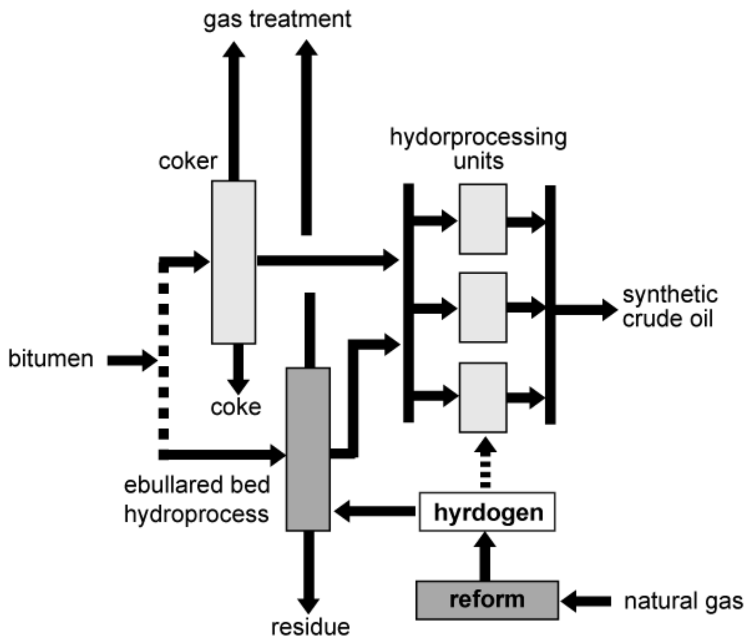
[42] According to the National Energy Board Report, one thousand cubic feet of natural gas is required per barrel of bitumin for SAGD operations. *Canada's Oil Sands*, May 2004.

[43] *Canada's Oil Sands*, June 2006 p. 4.

[44] *Canada's Oil Sands, Opportunities and Challenges to 2015*, *An Energy Market Assessment*, May 2004, National Energy Board, Canada, p. 108.

Figure 5. Upgrading to SCO



Source: *Oil Sands Technology Roadmap*, p. 41.

The overall result of technology R&D has been to reduce operating costs from over $20/barrel in the early 1970s to $8-12/barrel in 2000. While technology improvements helped reduce some costs since 2000, total costs have risen significantly as discussed below, because of rising capital and energy costs.[45]

Upgrading.[46] Upgrading the bitumen uses the process of coking for carbon removal or hydro-cracking for hydrogen addition (see **Figure 5**). Coking is a common carbon removal technique that "cracks" the bitumen using heat and catalysts, producing light oils, natural gas, and coke (a solid carbon byproduct). The coking process is highly aromatic and produces a low quality product. The product must be converted in a refinery to a lighter gas and distillate. Hydrocracking also cracks the oil into light oils but produces no coke byproduct. Hydrocracking requires natural gas for conversion to hydrogen. Hydrocracking, used often in Canada, better handles the aromatics. The resulting SCO has zero residues which help keep its market value high, equivalent to light crude.

Partial upgrading raises the API of the bitumen to 20-25 degrees for pipeline quality crude. A full upgrade would raise the API to between 30-43 degrees — closer to conventional crude. An integrated mining operation includes mining and upgrading. Many of the mining operations have an on-site upgrading facility, including those of Suncor and Syncrude. Suncor uses the coking process for

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[45] *Canada's Oil Sands*, June 2006.

[46] *Overview of Canada's Oil Sands*, TD Securities, January 2004, p. 19.

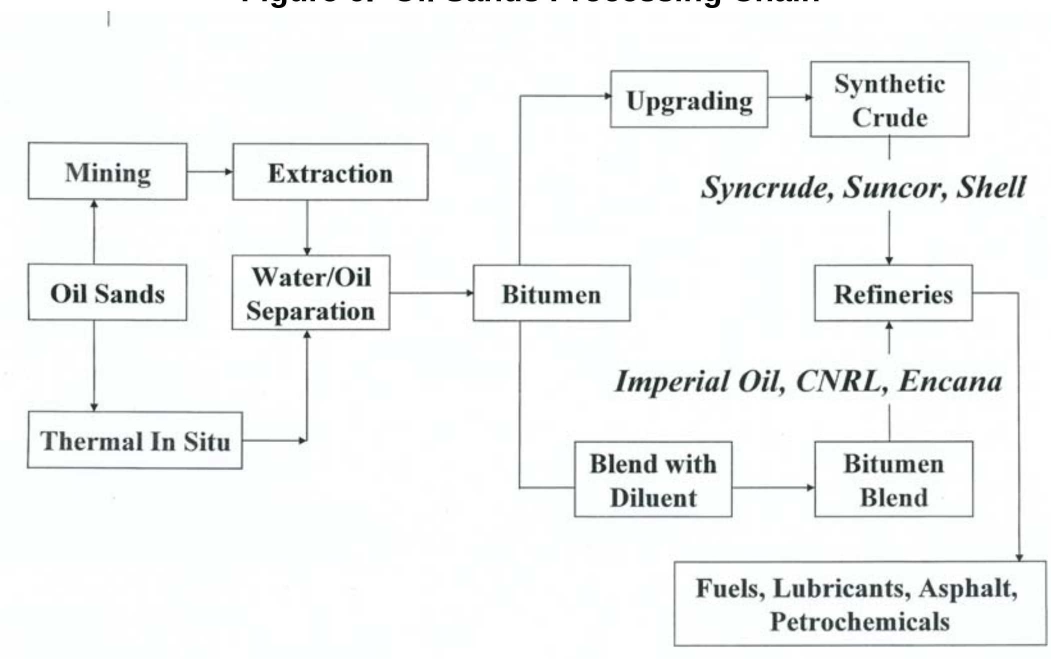
upgrading, while Syncrude uses both coking and hydrocracking and Shell uses hydrocracking. (For the complete oil sands processing chain, see **Figure 6**.)

A major trend among both mining and in situ producers is to integrate the upgrading with the refinery to cut costs; e.g., linking SAGD production with current refinery capabilities. Long-term processing success of oil sands will depend on how well this integration takes place and how well the industry addresses the following issues:

- cost overruns,
- cost effective upgrading, reducing highly aromatic, high-sulfur SCO, and
- dependence on and price of natural gas for hydrogen production (originally used because of its low price but now considered by some to be too expensive).

The wide heavy-oil/light-oil price differential has been an incentive to increase upgrading. The price for heavy crude was as low as $12 per barrel in early 2006 and its market is limited by refineries that can process it and by its end use as asphalt. In its June 2006 report, the NEB describes numerous proposals for building upgraders.[47]

Figure 6. Oil Sands Processing Chain



Source: *Overview of Canada's Oil Sands*, TD Securities, p. 15.

[47] NEB, June 2006, pp. 20-21.

Cost overruns for the integrated mining projects or expansions, sometimes as much as 50% or more of the original estimates, have been a huge problem for the industry. The main reasons cited by the COS report are poor management, lack of skilled workers, project size, and engineering issues.

Cost of Development and Production. Operating and total supply costs have come down significantly since the 1970s. Early supply costs were near C$35 per barrel (in 1970s dollars). Reductions came as a result of two major innovations in the production process. First, power shovels and energy efficient trucks replaced draglines and bucketwheel reclaimers, and second, hydrotransport replaced conveyor belts to transport oil sands to the processing plant.[48]

Operating costs include removal of overburden, mining and hydro transport, primary extraction, treatment, and tailings removal. The recovery rate, overburden volumes, cost of energy, transport distances, and infrastructure maintenance all have an impact on operating costs.

Supply costs (total costs) include the operating costs, capital costs, taxes and royalties, plus a 10% return on investment (ROI). When compared to conventional new oil production starts, an oil sands project may have operating costs over 30% higher than the world average for conventional new starts. However, its nearly nonexistent royalty and tax charge makes the total cost per barrel of energy significantly less than the conventional oil project. The NEB in its Energy Market Assessment estimated that between US$30-$35 per barrel oil is required to achieve a 10% ROI.[49]

Operating costs for mining bitumen were estimated at around C$9-$12 per barrel (C$2005) — an increase of up to C$4 per barrel since the 2004 NEB estimates. Supply cost of an integrated mining/upgrading operation is between C$36 and $40/ barrel for SCO — a dramatic increase over the C$22-$28 estimate made in 2004. These supply costs for an integrated mining/upgrading operation were expected to decline with improvements in technologies (see **Table 3**). However, natural gas prices rose 88% and capital costs rose 45% over the past two years.

Operating costs for SAGD in-situ production in 2005 were about C$10-$14 per barrel of bitumin, up from C$7.40 per barrel in 2004. Recovery rates are lower than with mining, at 40%-70%, and the price of energy needed for production is a much larger factor. The SAGD operations are typically phased-in over time, thus are less risky, make less of a "footprint" on the landscape than a mining operation, and require a smaller workforce. SAGD supply cost for Athabasca oil sand rose from between C$11-$17/barrel (bitumen) to C$18-$22/barrel; using the CSS recovery technique, supply costs are estimated higher at between C$20-$24/barrel, an increase from C$13-$19/barrel. Cost increases/decreases for in-situ operations are largely dependent on the quality of the reservoir and natural gas prices, but as SAGD and other new technologies (e.g. VAPEX) become more efficient, industry is expecting

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[48] COS, 2004, p. 9.

[49] COS, 2006, p. 5.

some cost declines. SAGD (in-situ) supply costs are less sensitive to capital costs than mining projects because the capital investment is far less.

Natural gas is a major input and cost for mining, upgrading, and in situ recovery: Mining requires natural gas to generate heat for the hot water extraction process, upgraders need it for heat and steam, and in situ producers use natural gas to produce steam which is injected underground to induce the flow of bitumen. Natural gas accounts for 15% of the operating costs in mining operations compared to 60% of operating costs in SAGD in-situ production. The major cost for thermal in-situ projects (SAGD, CSS) is for the natural gas that powers the steam-producing generators. For SAGD projects, 1 thousand cubic feet is needed per barrel of bitumen. Reducing the steam-to-oil ratio (SOR) — the quantity of steam needed per barrel of oil produced — is critical for lowering natural gas use and costs.[50] SAGD has a lower SOR than CSS projects but cannot be used for all oil sand in-situ production. However, most new in-situ projects will use SAGD.

Canadian oil sand producers continue to evaluate energy options that could reduce or replace the need for natural gas. Those options include, among other things, the use of gasification technology, cogeneration, coal, and nuclear power.

Table 3. Estimated Operating and Supply Cost by Recovery Type

(C$2005 Per Barrel at the Plant Gate)

	Crude Type	Operating Cost	Supply Cost
Cold Production - Wabasca, Seal	Bitumen	6-9	14-18
Cold Heavy Oil Production and Sand (CHOPS) - Cold Lake	Bitumen	8-10	16-19
Cyclic Stream Stimulation (CSS)	Bitumen	10-14	20-24
Steam Assisted Gravity Drainage (SAGD)	Bitumen	10-14	18-22
Mining/Extraction	Bitumen	9-12	18-20
Integrated Mining/Upgrading	SCO	18-22	36-40

Source: *Canada's Oil Sands, Opportunities and Challenges to 2015*, National Energy Board, Canada, June 2006.

Note: Supply costs for the first five technologies do not include the coat of upgrading bitumen to SCO.

[50] COS, 2004, p. 18.

Tax and Royalty on Oil Sands. In 1997 the Alberta government implemented a "Generic Oil Sands Royalty Regime"[51] specific to oil sands for all new investments or expansions of current projects. Since then, oil sand producers have had to pay a 1% minimum royalty based on gross revenue until all capital costs including a rate of return are recovered. After that, the royalty is either 25% of net project revenues or 1% of the gross revenues, whichever is greater.[52] The 1% pre-payout royalty rate is in stark contrast to conventional world royalties. Net project revenues (essentially net profits before tax) include revenues after project cash costs, such as operating costs, capital, and R&D are deducted. Royalty payments may be based on the value of bitumen or SCO if the project includes an upgrader. Currently, 51% of oil sand projects (or 75% of production volume) under the Generic Royalty regime are paying the 25% royalty rate. Two major oil sands producers, Suncor and Syncrude (accounting for 49% of bitumen production) have "Crown Agreements" in place with the province that have allowed the firms to pay royalties based on the value of synthetic crude oil (SCO) production with the option to switch to paying royalties on the value of bitumen beginning as early as 2009. Royalties paid on bitumen, which is valued much lower than SCO, would result in less revenue for the government. The agreements expire in 2016.

Royalty revenues from oil sands fluctuated widely between 1997 and 2005. For example, royalties from oil sands were less than $100 million in 1999, then rose to $700 million in 2000/2001, but fell in 2002/2003 to about $200 million as production continued to rise. Royalties from oil sands rose dramatically in 2005/2006 to $1 billion, and the Government of Alberta forecasts royalties of $2.5 billion in 2006/2007 and $1.8 billion in 2007/2008.[53] Oil price fluctuations are the primary cause for such swings in royalty revenues.

The Albertan provincial government established a Royalty Review Panel in February 2007 to examine whether Alberta was receiving its fair share of royalty revenues from the energy sector and to make recommendations if changes are needed. In its September 2007 report, the panel concluded that "Albertans do not receive their fair share from energy development."[54] When the oil sands industry was ranked against other heavy oil and offshore producers such as Norway, Venezuela, Angola, United Kingdom, and the U.S. Gulf of Mexico, Alberta received the smallest government share.[55] This is, however, a difficult comparison to make because it is not among oil sand producers only and the fiscal regimes of the various producing

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[51] The generic oil sands royalty regime consists of three parts: the lease sale, a minimum 1% pre-payout gross revenue royalty, and a 25% post-payout net revenue royalty. The payout period is the time it takes a firm to recover all allowable capital costs including a rater of return.

[52] *Oil and Gas Fiscal Regime, Alberta Resource Development of Western Canadian Provinces and Territories*, p. 39, 1999.

[53] *Oil Sands, Benefits to Alberta and Canada, Today and Tomorrow, Through a Fair, Stable and Competitive Fiscal Regime*, Canadian Association of Petroleum Producers, May 2007, Appendix B.

[54] *Our Fair Share*, Report of the Alberta Royalty Review Panel, September 18, 2007, p. 7.

[55] Ibid., p. 27.

countries is dynamic. However, based on a general analysis by T.D. Securities, typically, on average, world royalty rates could add as much as 45% to operating costs while the 1% rate may add only 3% to operating costs.[56]

The Panel recommended keeping the "pre-payout, post-payout" framework intact (see footnote 52), which would retain the 1% pre-payout royalty rate, but in the post-payout phase, firms would be required to pay a higher net revenue royalty rate of 33% plus continue to pay the 1% base royalty.

On October 25, 2007, the Alberta Government announced and published its response to the Royalty Review Panel's report.[57] It retained the "pre-payout," "post-payout" royalty framework but concluded that a sliding-scale rate structure would best achieve increasing the government's share of revenues from oil sands production. The pre-payout base rate would start at 1%, then increase for every dollar above US$55 per barrel (using the West Texas Intermediate or WTI price) reaching a maximum increase of 9% when prices are at or above $120 per barrel. In the post-payout phase, the net revenue rate will start at 25%, then rise for every dollar oil in priced above US$55 per barrel, reaching a maximum of 40% of net revenues when oil is $120 per barrel or higher. The new rate structure will take effect in 2009. The Government of Alberta has initiated negotiations with Suncor and Syncrude in an attempt to include them under the new oil sands royalty framework by 2009.

Oil sand firms pay federal and provincial income taxes and some differences exist in the tax treatment of the oil sands and conventional oil industries. Since the Provincial 1996 Income Tax Act, both mineable and in-situ oil sand deposits are classified as a mineral resource for Capital Cost Allowance (CCA) purposes which means mineral deposits receive higher cost deductions than conventional oil and gas operations (i.e. acquisition costs and intangible drilling costs).[58] The provincial government of Alberta has agreed to the 2007 federal budget proposal to eliminate the CCA deduction for oil sands. The Royalty Review Panel also supported this change in its report. The federal government of Canada, however, provided some balance by reducing the general federal corporate income tax rate from 22.1% to 15% beginning in 2012.[59]

U.S. Markets

Oil sand producers continue to look to the United States for the majority of their exports. Seventy-five percent of Canadian nonconventional oil exported to the United States is delivered to the Petroleum Administration for Defense District (PADD)[60] II in the Midwest. This region is well positioned to receive larger volumes of

[56] *Overview of Canada's Oil Sands,* T.D. Securities, January 2004, p. 7.

[57] *The New Royalty Framework,* October 25, 2007.

[58] *Oil and Gas Taxation in Canada,* January 2000, PriceWaterhouseCoopers.

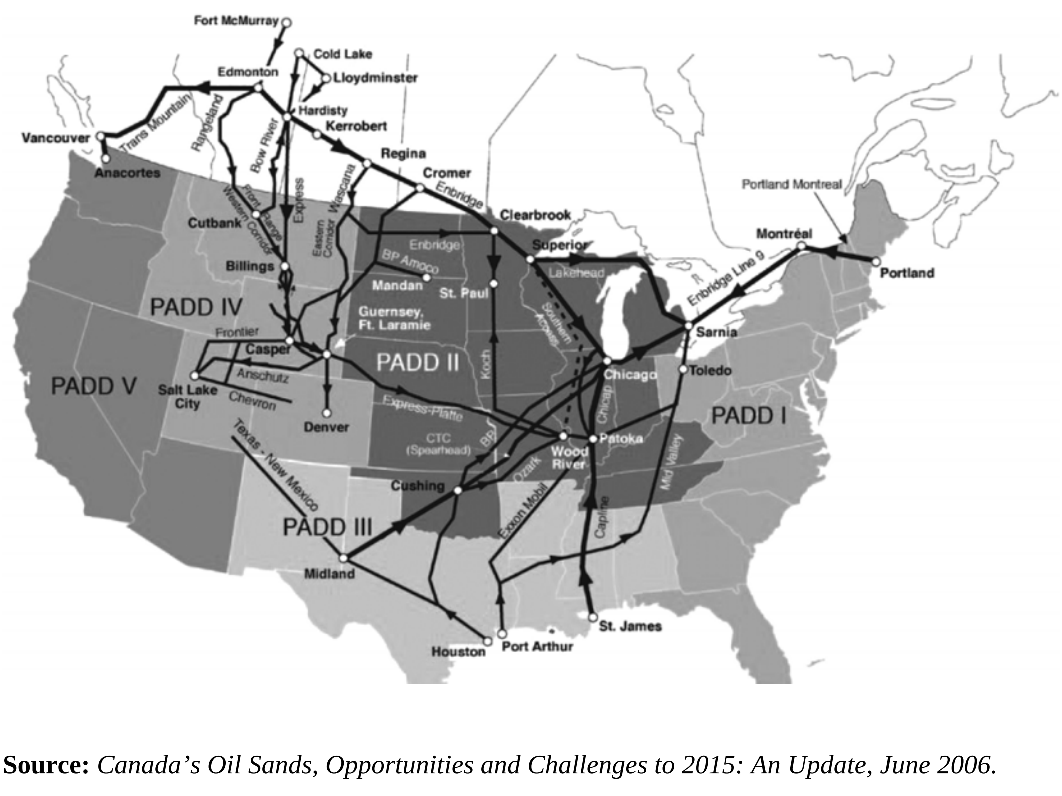
[59] Canadian Department of Finance, Economic Statement, October 30, 2007.

[60] There are 5 PADD's in the United States. PADDs were created during World War II as a way to organize the distribution of fuel in the United States.

nonconventional oil from Canada because of its refinery capabilities. Several U.S.-based refinery expansions have been announced that would come online between 2007-2015. If Canada were to reach its optimistic forecasted oil sands output level of 5 mbd in 2030, and maintained its export level to the United States at around 90%, it would be exporting about 4.5 mbd to the United States. This would mean that imports from Canada would reach nearly 30% of all U.S. crude oil imports. U.S. refinery capacity is forecast to increase from 16.9 mbd in 2004 to nearly 19.3 mbd in 2030,[61] a 2.4 mbd increase — significant but perhaps not enough to accommodate larger volumes of oil from Canada, even if refinery expansions would have the technology to process heavier oil blends. Canada is pursuing additional refinery capacity for its heavier oil.

Pipelines. Oil sands are currently moved by two major pipelines (the Athabasca and the Corridor, not shown in **Figure 7**) as diluted bitumen to processing facilities in Edmonton. After reaching refineries in Edmonton, the synthetic crude or bitumen is moved by one of several pipelines to the United States (see **Figure 7**). The Athabasca pipeline has capacity of 570,000 barrels per day (b/d) while the Corridor has capacity of less than 200,000 b/d. Current pipeline capacity has nearly reached its limit. However, there are plans to increase Corridor's capacity to 610,000 b/d by 2010.

Figure 7. Major Canadian and U.S. (Lower 48) Crude Oil Pipelines and Markets



Source: *Canada's Oil Sands, Opportunities and Challenges to 2015: An Update, June 2006.*

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[61] DOE/EIA, *Annual Energy Outlook 2006 with Projections to 2030*, February 2006.

A number of new pipeline projects have been proposed or initiated that would increase the flow of oil from Canada to the United State's PADDs II, III, and V. Most of the new projects are scheduled to come online between 2008 and 2012. In addition, a couple of U.S. pipelines reversed their flow of crude oil (from south to north) to now carry Canadian heavy crude, originating from oil sands, to Cushing Oklahoma and Southeast Texas. Pipeline capacity could be a constraint to growth in the near term but the NEB predicts some excess pipeline capacity by 2009. An estimated $31.7 billion has been invested in pipeline projects for oil sands in western Canada.[62]

Environmental and Social Issues

The Federal Government of Canada classified the oil sands industry as a large industrial air pollution emitter (i.e., emitting over 8,000 tons CO_2/year) and expects it to produce half of Canada's growth in greenhouse gas (GHG) emissions[63] (about 8% total GHG emissions) by 2010. The oil sands industry has reduced its "emission intensity" by 29% between 1995-2004 while production was rising. CO_2 emissions have declined from 0.14 tons/bbl to about 0.08 tons/bbl or about 88 megatons since 1990.[64] Alberta's GHG goals of 238 megatons of CO_2 in 2010, and 218 megatons CO_2 in 2020 are not expected to be met.[65] Reducing air emissions is one of the most serious challenges facing the oil sands industry. However, according to the Pembina Institute, a sustainable energy advocate, greenhouse gas emissions intensity (CO_2/barrel) from oil sands is three times as high as that from conventional oil production.[66] The industry believes if it can reduce energy use it can reduce its emissions. As emissions per barrel of oil from oil sands decline overall, the Canadian government projects that total GHG emissions will continue to rise through 2020, attributing much of the increase to increased oil sands production.[67]

Water supply and waste water disposal are among the most serious concerns because of heavy use of water to extract bitumen from the sands. For an oil sands mining operation, about 2-3 barrels of water are used from the Athabasca river for each barrel of bitumen produced; but when recycled produced water is included, 0.5 barrels of "make-up" water is required, according to the Alberta Department of Energy. Oil sands projects currently divert 150 million cubic meters of water annually from the Athabasca River but are approved to use up to 350 million cubic

[62] "Oil Sands Producers Facing Pipeline Capacity Constraints," *The Energy Daily*, August 7, 2007.

[63] Greenhouse gas emissions include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

[64] COS, 2004, p. 62.

[65] Ibid., p. 63.

[66] *Oil Sands Fever*, by Dan Woynillowicz, et al., The Pembina Institute, November 2005.

[67] COS, June 2006, p. 39.

meters.[68] Concerns, however, arise over the inadequate flow of the river to maintain a healthy ecosystem and meet future needs of the oil sands industry. Additionally, mining operations impact freshwater aquifers by drawing down water to prevent pit flooding.

The freshwater used for in-situ operations is needed to generate steam, separate bitumen from the sand, hydrotransport the bitumen slurry, and upgrade the bitumen to a light crude. For SAGD operations, 90-95% of all the water used is recycled. Since some water is lost in the treatment process, additional freshwater is needed. To minimize the use of new freshwater supplies, SAGD operators use saline water from deeper underground aquifers. The use of saline water, however, generates huge volumes of solid waste which has posed serious disposal problems.

Wastewater tailings (a bitumen, sand, silt, and fine clay particles slurry) also known as "fluid fine tailings" are disposed in large ponds until the residue is used to fill mined-out pits. Seepage from the disposal ponds can result from erosion, breaching, and foundation creep.[69] The principal environmental threat is the migration of tails to a groundwater system and leaks that might contaminate the soil and surface water.[70] The tailings are expected to reach 1 billion cubic meters by 2020. Impounding the tailings will continue to be an issue even after efforts are made to use alternative extraction technology that minimizes the amount of tails. Tailings management criteria were established by the Alberta Energy and Utilities Board/Canadian Environmental Assessment Agency in June 2005. Ongoing extensive research by the Canadian Oil Sands Network for Research and Development (CONRAD) is focused on the consolidation of wastewater tailings, detoxifying tailings water ponds, and reprocessing tailings. Some R&D progress is being made in the areas of the cleanup and reclamation of tailings using bioremediation and electrocoagulation.[71]

The National Research Council of Canada (NRC) is conducting research to treat wastewater tailings and recover their byproduct residual bitumen, heavy metals, and amorphous solids (fertilizers). A pilot project is underway to clean and sort tailings, and recover metals such as aluminum and titanium.[72]

Surface disturbance is another major issue. The oil sands industry practice leaves land in its disturbed state and left to revegetate naturally. Operators, however, are responsible over the long term to restore the land to its previous potential.[73] Under an Alberta Energy Utility Board directive (AEUB), Alberta's Upstream Oil and Gas Reclamation and Remediation Program has expanded industry liability for

[68] *Oil Sands Fever*, op. cit.

[69] *Canada's Oil Sands* (water conservation initiatives), pp. 66-68.

[70] *Canada's Oil Sands*, p. 68.

[71] Ibid., p. 69.

[72] For more on byproducts, see *Canada's Oil Sands*, p. 70.

[73] Ibid., p. 71.

reclaiming sites. The directive requires a "site-specific liability assessment" that would estimate the costs to abandon or reclaim a site.[74]

The government of Alberta's Department of the Environment established a "Regional Sustainable Development Strategy" whose purpose is, among other things, to "ensure" implementation of management strategies that address regional cumulative environmental impacts.[75] The oil sands industry is regulated under the Environmental Protection and Enhancement Act, Water Act, and Public Lands Act. Oil sands development proposals are reviewed by AEUB, Alberta Environment, and the Alberta Sustainable Resource Development at the provincial level. Review at the federal level may also occur.

Issues for Congress

The Energy Policy Act of 2005 (P.L. 109-58) describes U.S. oil sands (along with oil shale and other unconventional fuels) as a strategically important domestic resource "that should be developed to reduce the growing dependence of the United States on politically and economically unstable sources of foreign oil imports."[76] The provision also requires that a leasing program for oil sands R&D be established. Given U.S. oil sands' strategic importance, but limited commercial success as discussed above, what level of federal investment is appropriate to reach U.S. energy policy goals? While an estimated 11 billion barrels of U.S. oil sands may be significant if it were economic, it represents a small share of the potentially recoverable resource base of unconventional fuels (e.g., 800 billion barrels of potentially recoverable oil from oil shale and another 20 billion barrels of recoverable heavy oil). Where is the best return on the R&D dollar invested for increased domestic energy supply and what are the long-term prospects for commercial application of unconventional fuels technology? Another important consideration to look at is where the oil industry is investing its capital and R&D for oil sands projects.

In light of the environmental and social problems associated with oil sands development, e.g., water requirements, toxic tailings, carbon dioxide emissions, and skilled labor shortages, and given the fact that Canada has 175 billion barrels of reserves and a total of over 300 billion barrels of potentially recoverable oil sands (an attractive investment under current conditions demonstrated by the billions of dollars already committed to Canadian development), the smaller U.S. oil sands base may not be a very attractive investment in the near-term.

U.S. refinery and pipeline expansions are needed to accommodate Canadian oil sands developments. Those expansions will have environmental impacts, but the new infrastructure could strengthen the flow of oil from Canadian oil sands. This expanded capacity will likely lead to even greater investment in Canada.

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[74] Ibid.

[75] *Oil Sands Industry Update*, AED, June 2006, p. 29.

[76] Section 369 of Energy Policy Act of 2005.

Whether U.S. oil sands are developed, Congress will continue to be faced with regulatory matters. Oil imports from oil sands are likely to increase from Canada and the permitting of new or expanded oil refineries will continue to be an issue because of the need to balance concerns over the environment on one hand and energy security on the other.

Prospects for the Future

Because capital requirements for oil sands development has been enormous and risky, government involvement was seen as being essential in Canada, particularly during sustained periods of low oil prices. This private sector/government partnership in R&D, equity ownership, and public policy initiatives over the last 100 years has opened the way for the current expansion of the oil sands industry in Alberta.

Ongoing R&D efforts by the public and private sectors, sustained high oil prices, and favorable tax and royalty treatment are likely to continue to attract the increasing capital expenditures needed for growth in Canada's oil sands industry. Planned pipeline and refinery expansions and new upgrading capacity are underway to accommodate the increased volumes of oil sands production in Canada. U.S. markets will continue to be a major growth area for oil production from Canadian oil sands. Currently, about 5% of the total oil refined in the United States is from Canada's oil sands.

Even though prospects for Canadian oil sands appear favorable, factors such as water availability, waste water disposal, air emissions, high natural gas costs, insufficient skilled labor, and infrastructure demands may slow the pace of expansion.

Prospects for commercial development of U.S. oil sands are uncertain at best because of the huge capital investment required and the relatively small and fragmented resource base. The Task Force on Strategic Unconventional Fuels reported that oil sands comprise only about 0.6% of U.S. solid and liquid fuel resources, while oil shale accounts for nearly 25% of the total resource base.[77]

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[77] *Development of America's Strategic Unconventional Fuels Resources,* September 2006, p. 5.

Appendix A

Table A1. Estimated World Oil Resources

(in billions of barrels)

Region and Country	Proved Reserves	Reserve Growth	Undiscovered	Total
OECD				
United States	22.4	76.0	83.0	180.4
Canada[78]	178.8	12.5	32.6	223.8
Mexico	12.9	25.6	45.8	84.3
Japan United States	0.1	0.1	0.3	0.5
Australia/ New Zealand	1.5	2.7	5.9	10.1
OECD Europe	15.1	20.0	35.9	71.0
Non-OECD				
Russia	60.0	106.2	115.3	281.5
Other Non-OECD Europe/Eurasia	19.1	32.3	55.6	107.0
China	18.3	19.6	14.6	52.5
India	5.8	3.8	6.8	16.4
Other Non-OECD Asia	10.3	14.6	23.9	48.8
Middle East	743.4	252.5	269.2	1,265.1
Africa	102.6	73.5	124.7	300.8
Central and South America	103.4	90.8	125.3	319.5
Total	1,292.5	730.2	938.9	2,961.6
OPEC	901.7	395.6	400.5	1,697.8
Non-OPEC	390.9	334.6	538.4	1,263.9

Sources: Proved Reserves as of January 1, 2006: *Oil & Gas Journal*, vol. 103, no. 47 (December 19, 2005), p. 46-47. Reserve Growth Total and Undiscovered, 1995-2025; U.S. Geological Survey, *World Petroleum Assessment 2000*, website [http://pubs.usgs.gov/dds/dds-060/]. Estimates of Regional Reserve Growth: Energy Information Administration, *International Energy Outlook 2006*, DOE/EIA-0484(2006) (Washington, DC, June 2006), p. 29.

Note: Resources Include crude oil (including lease condensates) and natural gas plant liquids.

[78] Oil sands account for 174 billion barrels of Canada's total 179 billion barrel oil reserves. Further, the Alberta Energy and Utilities Board estimates that Alberta's oil sands contain 315 billion barrels of ultimately recoverable oil. *Canada's Oil Sands: Opportunities and Challenges to 2015: An Update*, June 2006, National Energy Board.

Appendix B

Table B1. Regional Distribution of Estimated Technically Recoverable Heavy Oil and Natural Bitumen

(in billions of barrels)

Region	Heavy Oil		Natural Bitumen (oil sands)	
	Recovery Factor[a]	Technically Recoverable	Recovery Factor[a]	Technically Recoverable
North America	0.19	35.3	0.32	530.9
South America (Venezuela)	0.13	265.7	0.09	0.1
W. Hemisphere	0.13	301.0	0.32	531.0
Africa	0.18	7.2	0.10	43.0
Europe	0.15	4.9	0.14	0.2
Middle East	0.12	78.2	0.10	0.0
Asia	0.14	29.6	0.16	42.8
Russia	0.13	13.4	0.13	33.7[b]
E. Hemisphere	0.13	133.3	0.13	119.7
World		434.3		650.7

Source: U.S. Department of the Interior. U.S. Geological Survey Fact Sheet, FS 070-03 August 2003.

Note: Heavy oil and natural bitumen are resources in known accumulations.

a. Recovery factors were based on published estimates of technically recoverable and in-place[79] oil or bitumen by accumulation. Where unavailable, recovery factors of 10% and 5% of heavy oil or bitumen in-place were assumed for sandstone and carbonate accumulations, respectively.

b. In addition, 212.4 billion barrels of natural bitumen in-place is located in Russia but is either in small deposits or in remote areas in eastern Siberia.

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[79] In-place oil is a continuous ore body that has maintained its original characteristics.

Acronyms and Abbreviations

AEUB	Alberta Energy and Utility Board
API	American Petroleum Institute
ARC	Alberta Research Council
ARCO	Atlantic Richfield Company
CCA	Capital Cost Allowance
CONRAD	Canadian Oil Sands Network for Research and Development
COS	Canadian Oil Sands
CSS	Cyclic Steam Stimulator
EIA	Energy Information Administration
GCOS	Great Canadian Oil Sands Company
GHG	greenhouse gases
IEA	International Energy Agency
mbd	million barrels per day
NEB	National Energy Board
OPEC	Organization of Petroleum Exporting Countries
PADD	Petroleum Administration for Defense District
R&D	research and development
ROI	return on investment
SAGD	steam-assisted gravity drainage
SCO	synthetic crude oil
SIRCA	Scientific and Industrial Research Council of Alberta
USGS	United States Geological Survey
VAPEX	Vapor Extraction Process