

CANADIAN OIL SANDS: A NEW FORCE IN THE WORLD OIL MARKET

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Abstract

ØCanada's oil sands production in the province of Alberta already equals the oil output of Qatar. The output potential from this unconventional source of oil is enormous, as Alberta's proven oil sands reserves rival in size the conventional reserves of Saudi Arabia.

ØOn the strength of expected oil sands output growth and despite declining conventional oil output, Canada can be expected to move from 7th to 5th place in ten years among the world's oil producers.

ØOil sands development interacts with OPEC's output strategy: the restricted output of less costly conventional oil raises the market price and keeps the oil sands on an accelerated expansion path. Just how fast they develop depends largely on how OPEC from now on deals with the increase in global oil demand brought about by China's and India's economic growth. If OPEC's output strategy keeps the price high, it will continue to stimulate oil sands investments.

ØThe rapid increase in the scale of oil sands production is pushing up short-run costs. But eventually input markets and the infrastructure will catch up and together with technical advances stabilize the cost per barrel. At that point, given the huge reserves, the oil sands supply will set an upper limit to the world oil price that OPEC can no longer exceed.

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Introduction. The petroleum industry is turning to unconventional sources of oil and gas, which hold out promise for vast additions to the energy supply. Canada's oil sands in Alberta represent a large potential increment to the world's supply of oil as the recovery technology is proving economical on an increasing scale. Canada's current unconventional oil production alone would rank it twenty-first among the world's crude oil producing nations equal with Qatar. With reserves that rival Saudi Arabia's in size, Canadian oil sands development has the potential to moderate future oil prices in the world market. The main determinants of the oil sands role in the market going forward will be cost and OPEC's output strategy for the large reserves of *conventional* oil it holds. Several key conditions bode well for the development of the oil sands reserves:

- § Privatized oil sector with assured property rights and reasonable royalty payment regime;
- § Oil sands producers are price takers and subject to laws governing competition similar to those in the U.S.;
- § Secure and efficient oil export shipping routes;
- § Transparency in oil reserve estimates, production activity, and development plans.

For the North American crude oil market, the large indigenous reserves under development hold out the prospect of increasing energy security. However, large increases in Canadian oil sands output will take time as they require huge investments and progress in managing costs.



Conventional versus unconventional. “Conventional” production essentially means that well bores tap underground reservoirs of oil in liquid and natural gas in gaseous form and release the resources to the surface without facilitating means, at least initially. In time, secondary recovery methods, such as water injection to restore underground pressure, are applied but in the main these do not fundamentally alter the recovery process or change the resource from its natural state.

Unconventional oil and gas production requires an active extraction effort or additional steps to convert the natural resource to usable form. The technologies to do so are still at an early stage of development and their costs are considerably higher than for conventional oil and gas production. In Canada, a transition from conventional to unconventional oil is underway and likely will proceed with respect to natural gas as

well. Canada's known conventional oil and gas reserves are in decline. Yet Canada has continued to increase its total output of oil and natural gas as well as its exports of oil.¹ The reason for the continued increase in Canadian oil output is oil sands production, which contributes over 40 percent to the total. Since 2003, the Oil & Gas Journal has included Canadian oil sands in its country listing of proven oil reserves, and for 2005 it reports 174.1 billion barrels of reserves from oil sands in addition to 4.7 billion barrels of conventional oil reserves.² This ranks Canada second only to Saudi Arabia (264.3 billion barrels) and far ahead of all other oil reserve holders in the world. In addition, it is estimated that as yet unproven quantities of oil thought to be recoverable from the Alberta sands would bring potential reserves to 315 billion barrels out of a total resource base of 1.7 to 2.5 trillion barrels.³ 315 billion barrels is more than 40 times the current annual U.S. oil consumption. At this time, Alberta oil sands production exceeds 1 million barrels per day (b/d), an amount that would place Canada 21st among the world's oil producing nations tied with Qatar. Including conventional oil, Canada's production currently ranks 7th in the world with 3.1 million b/d.⁴

Canada's conventional proven reserves of natural gas, which is used in the oil sands production process, were 56.1 trillion cubic feet (tcf) in 2004, representing a decline from 64.7 tcf in 1997. But, according to a report issued jointly by the Alberta Energy Utilities Board and Canada's National Energy Board, the remaining ultimate potential for recovery of conventional natural gas in Alberta alone was 101 tcf as of December 2004.⁵ Gas reserves likely will be boosted by supply from remote areas (such as the Beaufort Sea region) and unconventional sources (such as coalbed methane and so-called tight gas trapped in dense layers of rock), but these have not been developed to the point of becoming "proven" reserves and have not entered production on a large scale. Including coalbed methane, Canada's potential natural gas reserves could exceed 500 tcf.⁶

Oil sands, bitumen, and SCO. Alberta's oil sands are located in three distinct areas—Athabasca, the largest, Cold Lake, and Peace River—which together cover an area of 54 thousand square miles, well over twice the size of West Virginia (see Figure 1). Oil sands consist of bitumen, which is soluble organic matter solid at room temperature and host sediment. Raw bitumen within the sands is a tar-like mixture of hydrocarbons often with sulfur compounds. It has an API gravity of around 8°. ⁷ Conventional oil is considered "heavy" if it has an API gravity of less than 22.3°. "Light" crude oil has an

¹ Canada also imports oil that is refined in its eastern and Ontario refineries.

² *Oil & Gas Journal*, December 19, 2005; 103, 47.

³ "Alberta's Oil Sands 2004, Updated December 2005," Alberta Department of Energy, p.2, http://www.energy.gov.ab.ca/docs/oilsands/pdfs/PUB_osgenbrf.pdf; "Annual Energy Outlook 2006," Energy Information Administration (EIA), pp. 52, 53. Only the estimated amounts of oil that are technically and economically recoverable from the sands are considered "reserves."

⁴ Data supplied by EIA.

⁵ Proven natural gas reserve data from "Canada—Country Analysis Brief," EIA, February 2005, p.5; estimate of ultimate potential from EUB/NEB Report 2005-A: "Alberta's Ultimate Potential for Conventional Natural Gas," March 2005, p. vi, www.eub.gov.ab.ca and www.neb-one.gc.ca.

⁶ "Canada—Country Analysis Brief," p.7.

⁷ The API (American Petroleum Institute) gravity scale is the standard method for measuring the relative density of petroleum liquids.

API gravity higher than 31.1°. Light, low sulfur oil is less costly to ship and refine and commands a price premium relative to heavier crude oils.

Producers must decide in what form to bring bitumen to market. Raw bitumen can be used for asphalt but cannot be shipped through pipelines, unless it is blended with lighter commodities to lower its viscosity. The optimal marketable mix of bitumen blends is determined by price differentials for different crude oil grades and supply conditions for blending agents. The premium put on lighter crude oils by refineries, most of which are not designed to process very heavy crude oil, causes almost all bitumen to be blended and more than half to be upgraded to so-called synthetic crude oil (SCO). SCO has an API gravity of 31° to 33° and is comparable to benchmark West Texas Intermediate (WTI).

The production process. North of Fort McMurray in the Athabasca area shallow oil sands deposits are recovered in open-pit mine operations and hauled by truck to processing facilities where steam is used to separate the bitumen from the sand. In other areas, bitumen is buried more than 75 meters beneath the surface and is recovered by drilling wells. There are reservoirs in the oil sands where “primary” or “cold” production is possible. The same types of pumps are employed as in conventional heavy oil production, but the bitumen recovered this way contains two to three times more sand than conventional heavy oil. This method is called CHOPS, cold heavy oil production with sand.

Most underground bitumen will not flow to a well bore and has to be heated. There are various methods to do this. The two most prominent ones are (1) Cyclic Steam Stimulation (CSS), which uses a single well to inject steam and, after soak time, to pump the fluids to the surface, and (2) Steam Assisted Gravity Drainage (SAGD), which uses two wells drilled vertically and then angled horizontally, one above the other, so that steam can be injected into the upper one and the warmed bitumen collected and pumped out through the lower one. Water and natural gas are used in large quantity for bitumen production and in the upgrading process to produce SCO. The search is underway for substitutes to natural gas in power and steam generation, such as burning bitumen and coke gasification. Extraction technologies that reduce or eliminate the need for steam also are emerging such as pulse technology, vapor recovery extraction (VAPEX), and toe-to-heel air injection (THAI).⁸ These methods rely on air blasts from pneumatic systems, solvents, and air or oxygen for in-ground combustion to separate the bitumen and cause it to flow to a well bore. All oil sands production methods employing wells are known collectively as “in situ,” referring to the separation of bitumen from the sand “in place.”

Two-thirds of bitumen output currently is produced by strip mining oil sands and extracting the bitumen off-site, 10 percent by “cold” production, and 24 percent in situ.⁹ But, eighty percent of the recoverable bitumen reserves are buried too deep for strip mining and will have to be recovered by drilling wells.

⁸ “Alberta’s Oil Sands,” p. 3.

⁹ “Alberta’s Oil Sands,” p. 4.

Market-driven oil sector. The Canadian oil industry is operated exclusively by private companies. The Canadian government does not control oil output. A government-owned company, Petro-Canada, was formed in 1975 but privatized beginning in 1991. The Canadian government sold its remaining 20 percent ownership share in 2004. The largest integrated operator in Canada is Imperial Oil, majority-owned by ExxonMobil. The four largest oil sands projects are operated by Suncor, Syncrude (a joint venture composed principally of Canadian Oil Sands Ltd., Imperial, Petro-Canada, and ConocoPhillips), Shell Oil and Chevron, and Imperial Oil. The Alberta Department of Energy reports that there were 29 companies representing 61 projects approved under The Mines & Minerals Act and the Oil Sands Royalty Regulation 1997, as amended (OSRR 97).¹⁰

Canada's anti-trust laws are similar to those in the U.S. The Competition Act of 1889 is the oldest anti-trust statute in the western world, enacted one year before the Sherman Act. A Competition Tribunal and a Competition Bureau headed by a Commissioner of Competition have responsibility for enforcement. The Commissioner entered into cooperation agreements with the U.S. in 1995 and subsequently with a number of other foreign administrations, including the European Commission. The Mutual Assistance on Criminal Matters Treaty (MLAT) between Canada and the United States, in force since 1990, has recently been amended to include cooperation in the administration of civil competition law.¹¹

Ninety-seven percent of Alberta's mineral rights are owned by the provincial Crown and managed by the Alberta Department of Energy.¹² The royalty payment regime is set forth in OSRR 97. It was based on a joint industry-government national task force recommendation. During a project's pay-back period, i.e., until its investment has been recovered, royalty payments are one percent of gross revenue. After the payback period, royalty payments are the greater of one percent of gross revenue or 25% of net revenue, generally amounting to 11 percent of gross revenue. Since 1996 when this royalty regime was first introduced, \$27 billion of investment in the oil sands has occurred. Since 1990, more than \$3.5 billion has been collected in royalties.¹³

Exports to the U.S. Canada sends 99 percent of its crude oil exports to the United States. It is the largest foreign supplier of both crude oil and natural gas to the United States. Canada's share of U.S. crude imports has been increasing steadily over a number of years and since 2004 ranks first, ahead of Saudi Arabia's. As Figure 2 shows, 16 percent of U.S. crude oil imports came from Canada in 2005.¹⁴

¹⁰ "Canada—Country Analysis Brief," p.3; "Alberta Oil Sands," p.4.

¹¹ "Overview of Canadian Anti-trust Law," Yves Beriault and Oliver Borgers, *The Antitrust Review of the Americas*, 2004.

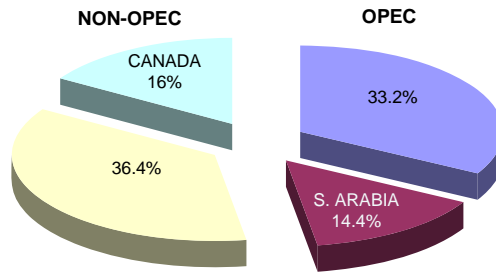
¹² The remaining three percent are held by the federal Crown within Indian reserves, successors to the Hudson's Bay Company, national railway companies, and descendants of original homesteaders through rights granted by the federal Crown before 1887, so-called freehold rights.

¹³ "Alberta's Oil Sands," p. 4, and "Economic Impacts of Alberta's Oil Sands, Volume I," by Govinda R. Timilsina, Nicole LeBlanc, and Thorn Walden, Canadian Energy Research Institute (CERI), October 2005, Study No. 110, ISBN 1-896091-47-4, p.46.

¹⁴ "Canada—Country Analysis Brief," pp.2, 5; and "U.S Imports by Country of Origin," EIA, www.eia.doe.gov. A redistribution of U.S. oil imports among OPEC countries, particularly reductions in

Figure 2

U.S. CRUDE OIL NET IMPORTS 2005



Source: EIA

Fort McMurray in the northern part of the Athabasca oil sands is about 250 miles north of Edmonton, the center of Alberta’s oil industry, which in turn is about 300 miles north of the Montana border. From Edmonton major oil pipeline connections reach into the U.S., as Figure 3 shows.

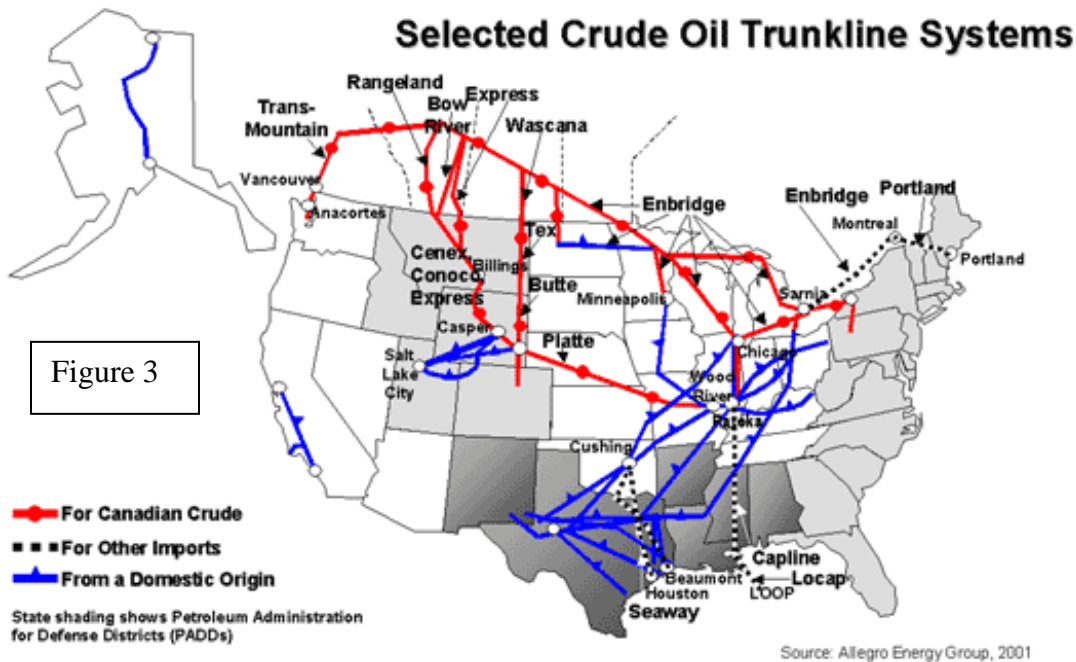


Figure 3

Crude oil produced in Western Canada is shipped to market via three major pipelines, Kinder Morgan’s Trans-Mountain and Express pipelines (both formerly of Terasen Pipelines, Inc.), and Enbridge. The Enbridge system has the largest capacity of more than 2.1 million b/d; the other two have throughput capacities of 280,000 and 225,000 b/d, respectively. Express and Enbridge interconnect with the U.S. domestic network of pipelines.¹⁵ The Trans-Mountain pipeline can supply British Columbia, Washington State, and oil tankers in the port of Vancouver for shipment to California and Asia. The regional distribution of Western Canadian crude oil exports has favored the U.S.

Saudi and increases in Nigerian oil imports, has contributed to the change in the country rankings. U.S. oil imports from Mexico rank second and from Saudi Arabia third.

¹⁵ The two countries’ natural gas pipelines (not shown) are interconnected to an even greater extent.

