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CANADA'S OIL SANDS

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INTRODUCTION

Northern Alberta contains one of the world's largest reserves of bitumen – a black, viscous, asphalt-like hydrocarbon that can be used as a feedstock in conventional petroleum refineries to produce commodities such as gasoline and diesel fuel. Before it can be used, however, bitumen has to be extracted from the ground, where it lies mixed with sand, clay and water in deposits known as oil sands. The bitumen is separated from the other substances and then chemically upgraded to produce synthetic crude oil. About two tonnes of oil sands must be processed to make one barrel of oil.(1) Each step of this process is energy-intensive and, like most industrial processes, presents challenges with respect to costs and environmental impacts.

Canada's oil sands deposits are found primarily in the Athabasca, Cold Lake, and Peace River regions of northern Alberta, with the majority of activities centred on the largest reserves near the city of Fort McMurray.(2) The deposits underlie an area of some 141,000 square kilometres.(3)

Oil sands production began in Canada in 1967, when Great Canadian Oil Sands (now known as Suncor Energy) started operating a mine and an upgrading facility north of Fort McMurray. In 1978, the Syncrude consortium built a similar, but much larger, operation nearby.(4) Since then, the number of oil sands operations has grown, existing plants have been expanded, and technological advances have reduced both the cost per barrel and the environmental impacts of production.

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(1) Alberta Energy, *Introduction to Oil Sands*, http://www.energy.gov.ab.ca/com/Sands/Introduction/ Oil_Sands.htm, accessed 13 January 2004.

(2) Alberta Energy, *Oil Reserves and Production*, p. 4, http://www.energy.gov.ab.ca/com/Sands/default.htm, accessed 10 February 2004.

(3) Alberta Energy, *Introduction to Oil Sands*.

(4) Alberta Economic Development, *Oil Sands Industry Update: October 2003*, http://www.alberta-canada.com/oandg/pdf/oilsands_sept04_revised.pdf , accessed 9 February 2004.

As production from conventional oil wells in Canada's Western Sedimentary Basin continues to decline, oil sands operations are increasingly important to Alberta's economy. The oil sands also play a significant and growing role in supplying oil for the North American market. The expansion of oil sands production offers significant economic and energy security benefits; however, it brings with it a host of ongoing environmental concerns. This paper will provide an overview of the oil sands resource, how bitumen is extracted and processed, production levels and costs, the environmental issues surrounding oil sands development, and how the industry is responding to cost and environmental concerns.

ESTIMATED VOLUME OF OIL IN CANADA'S OIL SANDS

According to an Alberta Energy estimate, the oil sands contain an initial volume of 1.6 trillion barrels of crude bitumen.(5) Of that total, 174.4 billion barrels are classified as "established reserves," which are those considered recoverable under current technology and present or anticipated economic conditions. A further 311 billion barrels of bitumen are thought to be ultimately recoverable.(6) When processed at an upgrading facility, each barrel of bitumen produces about 0.9 barrels of synthetic crude oil.(7)

Every year, the *Oil and Gas Journal* publishes a list of established oil reserves for all of the world's oil-producing countries. At the end of 2002, the list incorporated the oil sands as part of Canada's established oil reserves for the first time. This move bumped up Canada's reserves estimate from 5 billion barrels in 2001 to 180 billion barrels in 2002. The revised estimate was significant, as it now ranks Canada's established reserves second only to those of Saudi Arabia, which are estimated at 264 billion barrels (and ultimate potential resources of about 1 trillion barrels of crude oil).(8) The inclusion of Canada's oil sands reserves drastically

(5) Alberta Energy, *Oil Sands*, http://www.energy.gov.ab.ca/com/Sands/ default.htm, accessed 21 May 2004; see also R. Dunbar *et al.*, *Oil Sands Supply Outlook: Potential Supply and Costs of Crude Bitumen and Synthetic Crude Oil in Canada: 2003-2017*, Canadian Energy Research Institute Study No. 108, March 2004.

(6) Alberta Energy, *Introduction to Oil Sands*.

(7) Stephen Rodrigues, Research Manager, Canadian Association of Petroleum Producers, Personal communication, 20 February 2004.

(8) Alexander H. Tullo, "A New Source," *Chemical and Engineering News*, Vol. 81, No. 34, 25 August 2003, p. 16.

decreased the percentage of the world's oil reserves attributed to OPEC countries.(9) Given the political instability and volatility in dominant oil-rich regions, such as the Middle East, Canada's oil supply is increasingly valuable not just domestically, but also to the United States. Canada's "stable government, predictable investment conditions, highly developed infrastructure, integrated pipeline networks, [and] free and open trade"(10) make its growing oil sands industry extremely appealing to the world's foremost oil consumer.

EXTRACTION PROCESSES

There are two methods for recovering crude bitumen from oil sands deposits: surface mining and extraction, and in situ recovery.

A. Surface Mining and Extraction

If the deposits are relatively shallow (less than 75 metres below the surface), surface mining is used. It is estimated that only about 10% of Alberta's oil sands are suitable for surface mining; those deposits occur primarily in the Athabasca Oil Sands area, north of Fort McMurray, on both sides of the Athabasca River.(11) Being the most easily accessible part of the oil sands resource, these 40- to 60-metre-thick deposits were the first to be developed (by Suncor and Syncrude).

Before surface, or open-pit, mining can take place, all of the overburden has to be removed. First, the water-laden muskeg is drained and then it is removed, along with any surface vegetation and tree cover. Any suitable soil cover is selectively excavated and stockpiled, for use in site reclamation.(12) Once the oil sand deposit is exposed, it is dug up and transported to the processing facility. The initial Suncor and Syncrude mines used huge bucket wheel excavators and/or drag-lines to dig up the oil sand and deposit it onto conveyor belts,

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(9) Marilyn Radler, "Worldwide reserves increase as production holds steady," *Oil and Gas Journal*, Vol. 100, No. 52, 23 December 2002.

(10) Canadian Association of Petroleum Producers, *Canadian Crude Oil: Increasing Energy Security*, http://www.capp.ca/raw.asp?NOSTAT=YES&dt=NTV&e=PDF&dn=57272, accessed 16 January 2004.

(11) Dunbar (2004), p. 35.

(12) *Ibid.*, p. 23.

which moved the material into the preparation facility. These systems have gradually been replaced by a more flexible, reliable system using large electric and hydraulic power shovels to load oil sand into mining trucks capable of carrying up to 400 tons of material at a time. The trucks deliver the oil sand to a preparation facility where crushers reduce the material to the desired size. In the early years, the crushed oil sands were subsequently transported to the extraction plant by means of another conveyor belt system. More recently, however, a new technique known as "hydrotransport" has largely replaced this part of the operation. In hydrotransport, the crushed oil sands are mixed with hot water to create a slurry, which is then pumped via pipeline to the extraction plant.

At the extraction plant, the oil sand is mixed with hot water and agitated to separate the bitumen from the sand. The bitumen floats to the top of the separation tanks and is extracted.(13) With the use of hydrotransport, the oil sand material is actually preconditioned for the extraction process. It is already mixed with hot water to form a slurry, and the movement of the slurry through the pipeline agitates the material, beginning the separation process. This means that less heat is needed at the extraction phase, saving energy and improving the overall environmental performance of the production process. It is easier for a pipeline than a conveyor belt system to follow circuitous routing over uneven terrain. Hydrotransport also allows oil sand deposits located some distance from the extraction plant to be mined and transported for processing at these existing facilities.

From the extraction plant, the bitumen goes to an upgrading facility where it is converted from a viscous oil into a high-quality "upgraded" or "synthetic" crude oil (SCO). Like conventional crude oil, bitumen is a hydrocarbon. However, in bitumen there is a higher ratio of carbon to hydrogen. To upgrade bitumen, two processes have been developed. One, known as coking, removes some of the carbon. The other process, known as hydro-conversion, adds hydrogen. In both processes, the high sulphur content of the bitumen is reduced and the resulting SCO has similar density and viscosity characteristics to conventional light, sweet crude oil. SCO can then be processed in most existing oil refineries.

Both Suncor and Syncrude have upgrading facilities on-site, integrated with their mining and extraction facilities. They use the coking process for upgrading bitumen. In 2002, a

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(13) Government of Alberta, *The Oil Sands Story: Extraction*, Oil Sands Discovery Centre, http://www.oilsandsdiscovery.com/oil_sands_story/extract.html, accessed 13 January 2004.

third integrated mining, extraction and upgrading project began operation. This Athabasca Oil Sands Project differs from the other two in that its upgrading facility is not on-site near the Fort McMurray area mine, but is near Edmonton. Diluted bitumen is transported via pipeline to the upgrader, which uses the hydro-conversion process.

Canada also has two stand-alone upgraders that handle bitumen from in situ production sites (discussed below). They also process heavy crude oil. One of these upgraders is the Husky Bi-Provincial Upgrader located at Lloydminster on the Alberta-Saskatchewan border; the second is the Federated Co-op NewGrade Upgrader in Regina, Saskatchewan. Petro-Canada is also planning to reconfigure its Edmonton refinery to allow it to upgrade bitumen. This new facility will not begin operation before 2008 and is still subject to regulatory approval.

B. In Situ Recovery

Most of Alberta's oil sands are too far below the surface to be economically produced using surface mining methods. These deposits can be recovered only by in situ ("in place") methods. In situ extraction is similar to conventional crude oil production in that the bitumen is recovered through wells. In a few places, this can be done without having to pretreat the bitumen at all (primary or cold production). However, in most of the oil sands deposits, the bitumen is too heavy and viscous to flow under normal reservoir temperature and pressure conditions. A variety of technologies have been developed to heat the bitumen to reduce its viscosity so it can flow to the well bore and be pumped to the surface.

The most common techniques involve the injection of steam to heat the bitumen. The oldest technology is Cyclic Steam Stimulation (CSS), nicknamed "huff and puff." Steam at a temperature of 300^{o} Celsius and a pressure of 11,000 kilopascals (kPa) is injected into the oil sands deposit for four to six weeks. For another four to eight weeks, the steam is allowed to "soak" into the deposit. This is followed by three to six months of production, and then the process is repeated. A newer technology now being introduced by some producers is Steam-Assisted Gravity Drainage (SAGD). Pairs of horizontal wells are drilled into the deposit about five metres apart. Steam is pumped into the upper well, heating the bitumen, which flows under gravity down to the production well and is pumped to the surface.

These thermal recovery techniques use large quantities of fuel (primarily natural gas) to produce the steam. In situ production uses an estimated 1,000 cubic feet of natural gas for every barrel of bitumen recovered. (By contrast, an oil sands mining operation uses 250 cubic feet per barrel).[(14)]

The current high price of, and demand for, natural gas have companies looking for new methods of in situ recovery. Among those under development is a process that involves in situ combustion. Air would be injected into the reservoir, and residual bitumen left behind from earlier production would be burned in the reservoir to heat additional bitumen. Another process being developed involves the use of vaporized hydrocarbon solvents instead of steam to reduce the viscosity of the bitumen. This process, known as VAPEX, does not require the production of steam, offering a potential reduction in CO_2 and other greenhouse gas emissions of up to 85% compared to thermal extraction methods. The VAPEX method is currently being field-tested at a site near Fort McMurray.[(15)]

CURRENT PRODUCTION VOLUME AND COSTS

A. Production Volume

Until 1995, surface mining (e.g., the Suncor and Syncrude projects) accounted for up to 75% of all oil sands production. By 2002, that percentage had dropped to 64% with the development of additional in situ operations, such as Imperial Oil's Cold Lake Project.

In 1990, total crude bitumen production from Alberta's oil sands stood at 360,000 barrels per day (b/d). By 2002, it had reached 829,000 b/d, and by November 2004 the one million b/d mark was surpassed.[(16)] The oil sands have become an increasingly important part of Canada's oil production capability over the years as production from conventional sources has begun to decline. Today, the oil sands account for 30% of Canada's total production. On a regional basis, by 2010, they will account for more than 60% of oil production from western Canada.[(17)]

(14 Alberta Chamber of Resources, *Oil Sands Technology Road Map: Unlocking the Potential*, 30 January 2004, p. 14.

(15) Dunbar (2004), p. 22.

(16) Utilis Energy, *Oil sands – Alberta 2005: Projects, participants and market opportunities*, New York, 17 November 2004, http://utilisenergy.com/oilsandscontents.pdf, accessed 17 November 2004.

(17) Canadian Association of Oil Producers, *Industry Facts and Information: Oil Sands*, http://www.capp.ca/default.asp?V_DOC_ID=688, accessed 11 June 2004.

By the end of 2003, there were 19 major oil sands projects in operation or under construction. Nine of these began operation before 1999, and the remainder will all be in operation by 2005.[18] In addition, applications to construct 16 more projects have been made to the Alberta Energy and Utilities Board; some of these applications have already been approved. It is estimated that investment in these new projects would total nearly $22 billion if they all proceed. Companies have also made public announcements that they are considering another 13 projects, with an expected investment of an additional $28 billion. Uncertainty over the impact of Canada's Kyoto implementation plans and the high price of natural gas, which is a major input cost for oil sands operations, are two issues that may slow the pace of development over the next few years.

B. Production Costs

1. Surface Mining and Extraction

The cost of producing each barrel of oil from the oil sands has dropped significantly since the first projects began operation. Companies have managed to reduce both operating costs and capital costs over the years. Integrated oil sands mining and upgrading costs were initially about $35 per barrel. These costs dropped to between $15 and $18 per barrel by 2000, with the expectation that further technology and operating improvements will reduce the figure to $8-10 per barrel by 2015.[19]

2. In Situ Recovery

The supply costs for in situ operations vary considerably depending on the price of natural gas, economies of scale, the production process being used and, most importantly, the quality of the particular reservoir being developed. Costs vary from a low of $7 per barrel to a high of $16 per barrel.[20]

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(18) Dunbar (2004), p. 41.

(19) National Energy Board, *Canada's Oil Sands: A Supply and Market Outlook to 2015*, October 2000, p. 35. Costs quoted here are National Energy Board "total supply costs" estimates, which include all costs associated with exploration, development and production, including capital costs, operating costs, taxes, royalties and a 10% real rate of return to the investor. They are stated in 1997 dollars.

(20) *Ibid*.

ENVIRONMENTAL CONCERNS

As is often the case with natural resource development, the development of the oil sands resource raises a range of environmental issues. Oil sands development can be roughly divided into four main processes, each with the potential to have an impact on the environment – mining, extraction, upgrading and in situ operations:

- surface mining – the main environmental issues are land disturbance, productivity and stability of reclaimed land, surface and groundwater issues and air emissions (including greenhouse gas emissions);
- extraction – air emissions, storage and disposal of tailings and wastewater treatment;
- upgrading – air emissions and waste materials (coke, sulphur and wastewater);
- in situ recovery – land disturbance and habitat fragmentation, surface and groundwater use and quality, and air emissions.

The one environmental issue shared by all oil sands processes is air emissions, and a large proportion of those emissions are greenhouse gases (GHGs) that derive from the high level of energy used in each process.

A. Greenhouse Gas Emissions and Kyoto Protocol Commitments

Given the Canadian government’s commitment to reducing GHG emissions under the Kyoto Protocol, there is significant concern in some sectors regarding the expected expansion of oil sands production. In 2000, GHG emissions from synthetic crude oil production were about 13.0 megatonnes (MT), with another 8.2 MT from bitumen production.[21]

Not only will the oil from the oil sands ultimately emit GHGs when combusted; in addition, the oil sands extraction, recovery and upgrading processes are themselves significant emitters. About 85% of the GHG emissions are from the final end use, while 15% are related to production.[22] It has been estimated, for example, that on a life-cycle basis, total carbon dioxide

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(21) *Ibid*., p. 88 (“bitumen” here refers to crude bitumen that is used as asphalt, etc., without being upgraded to synthetic crude oil).

(22) Alberta Chamber of Resources (2004), p. 64.

emissions from transportation fuels derived from surface-mined oil sands are 15% higher than from fuel made from imported conventional oil.(23)

Given the GHG emissions and other air pollution associated with burning fossil fuels, as well as the rising cost of and increasing demand for natural gas, the expected expansion of oil sands production has triggered a search for alternatives sources of energy. Nuclear energy has been proposed as one potential alternative.(24) It is, in fact, the only alternative energy source that would not increase GHG emissions. The other options address only the need to find a fuel other than increasingly expensive natural gas.(25)

A nuclear power plant could produce steam for SAGD or other thermal extraction techniques and electricity for hydrogen production to supply bitumen upgrading facilities, without producing GHG emissions. In such a scenario, Canada's Kyoto obligations would no longer threaten to curtail growth in oil sands production.(26) A recent study compared the costs of using a modified Advanced CANDU Reactor (ACR-700) and a natural gas-fired facility to supply steam for a hypothetical SAGD project in northeastern Alberta. The study showed that a nuclear facility would be competitive with a natural gas-fired facility. The nuclear facility would be very sensitive to variations in capital costs, while the natural gas facility would be sensitive to the price of natural gas.(27) The study also notes that, to be viable, the nuclear plant would have to be located close to the bitumen source, since it is not efficient to transport steam over long distances. This presents a problem, since in situ production is typically from smaller sites scattered over a wide area.

Despite the study's positive findings, the Alberta government has decided against the nuclear option at this time because of past experience with cost overruns, and concerns over

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(23) Natural Resources Canada, *Advanced Separation Technologies: Oil Sands Environmental Issues*, http://www.nrcan.gc.ca/es/etb/cwrc/English/AST/what_we_do_e.html, accessed 20 January 2004.

(24) R. B. Dunbar and T. W. Sloan (Canadian Energy Research Institute), *Does Nuclear Energy Have a Role in the Development of Canada's Oil Sands?*, paper presented at Canadian International Petroleum Conference, 10-12 June 2003.

(25) Other options include coal, coal bed methane and bitumen, bitumen residue and upgrader by-products.

(26) John K. Donnelly, "Nuclear Energy in Industry: Application to Oil Production," published in the *Proceedings of the 20th Annual Conference of the Canadian Nuclear Society*, Montréal, 30 May 1999.

(27) Dunbar and Sloan (2003), p. 1.

health and safety issues (including vulnerability to terrorist attacks), waste disposal and possible public opposition. Moreover, the new ACR-700 is not yet licensed for operation in Canada.[28]

In addition to the emissions from fossil fuel combustion, GHG emissions are also caused by overburden removal and landscape destruction from surface mining, given that soils, muskeg and forest cover store significant amounts of carbon.[29] Consequently, environmentalists question how Canada can promote growth in such an industry if it plans to respect its Kyoto commitments.[30] The Alberta Chamber of Resources' *Oil Sands Technology Road Map* suggests that improving the overall energy efficiency of operations will contribute to reducing emissions and that, over the long term, major reductions will likely result from development of carbon sequestration technologies.[31]

Potential oil sands investors also question the possible added production costs associated with meeting Kyoto-related emission reduction requirements. A survey of oil sands companies by a New York-based investment company came up with a typical range of added costs of between 5 and 30 cents per barrel, although some companies claim that their added cost will be closer to $3 per barrel.[32]

B. Sulphur Dioxide, Nitrogen Oxides and Volatile Organic Compounds

There are a number of sources of sulphur dioxide (SO_2) in oil sands operations. For example, the burning of petroleum coke, the use of diesel equipment and the upgrading process all produce significant amounts of SO_2, which can reduce air quality and also result in acid precipitation. Acid precipitation can, in turn, acidify soils and water bodies, causing damage to vegetation and aquatic life.

Like all producers of SO_2, oil sands operators must meet Alberta's *Ambient Air Quality Guidelines* for SO_2 emissions. This is another area in which technological improvements are helping reduce the environmental impact of oil sands production. Despite the doubling of oil

(28) Shawn-Patrick Stensil and David H. Martin, "No nukes is good news," *Calgary Herald*, 16 November 2003, p. A13.

(29) Martin Von Mirbach, *Forests, Climate Change, and Carbon Reservoirs*, Sierra Club of Canada, Ottawa, 2003, p. 1.

(30) Sierra Club of Canada, *Submission from the Sierra Club of Canada to the Alberta Energy and Utilities Board and the Canadian Environmental Assessment Agency*, 25 September 2003.

(31) Alberta Chamber of Resources (2004), p. 64.

(32) "Kyoto Ratification to have limited effect on Alberta's oil sands," *Alexander's Gas and Oil Connections*, Volume 8, Issue 23, 27 November 2003, as cited in Dunbar (2004), p. 89.

production over recent years, SO_2 emissions from oil sands operations have not increased. This is largely due to the installation of flue gas desulphurization units at the Suncor facility in 1998, and more recently at the Syncrude facility. The units remove about 95% of the SO_2 produced at these facilities from burning coke to produce steam and electricity.

Nitrogen oxides (NO_x) sources in oil sands operations include diesel engines, extraction and upgrading plants, co-generation facilities and various heaters and boilers. NO_x emissions also contribute to soil and water acidification as well as ground-level ozone; like SO_2 emissions, they are subject to regulatory control. The principal technologies being used to address this pollution include the introduction of low-NO_x burners, increased use of natural gas for power generation, and the introduction of lower-emission vehicles (in the mine fleet, for example) as older vehicles are replaced.

Volatile organic compounds (VOCs) are emitted from tailings ponds, extraction plant vents and fugitive emissions from process tank areas and the mine face. They contribute to ground-level ozone, and some VOCs have been identified as toxic substances. The major effort to reduce VOCs has been aimed at the tailings ponds. Solvents that are used to help extract the bitumen from the sand end up in the mine tailings, and escape into the atmosphere from the pond surface. Companies are working to institute better solvent recovery processes and to use less-volatile solvents to address this problem.

C. Habitat Fragmentation

Canadian oil sands developments are situated in the boreal forest region, a continuous stretch of mixed deciduous and coniferous trees that spans most of northern Canada and Alaska, covering approximately 35% of Canada's total land mass. Recognized for its significant biodiversity, the forest is home to a wide variety of flora and fauna. It also plays an important role in ongoing climate change debates, given its ability to store carbon dioxide in its soils and vegetation.[(33)] Along with academics and environmentalists, the Senate Subcommittee on the Boreal Forest declared the boreal forest "under siege": threatened not only by climate change, ozone depletion, acid deposition, and over-cutting, but also by mineral and petroleum exploration and extraction.[(34)]

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(33) Boreal Forest Network, *Boreal Overview*, http://www.borealnet.org/overview/index.html, accessed 20 January 2004.

(34) Standing Senate Committee on Agriculture and Forestry, Subcommittee on the Boreal Forest, *Competing Realities: The Boreal Forest at Risk*, 1999, http://www.parl.gc.ca/36/1/parlbus/commbus/senate/com-e/bore-e/rep-e/rep09jun99-e.htm# PREFACE, accessed 20 January 2004.

Oil sands development contributes to this "siege" in large part because of the cumulative effects of simultaneous development at many adjacent sites. Environmental impact assessments are required for each individual proposed project, but the combined impact of numerous large projects in the same area is more than the sum of its parts. In the case of the oil sands, changes to the region have been deemed "enormous."(35)

Overburden removal and open pit mining have an obvious and visual impact on forest habitat. In situ extraction is sometimes seen as more environmentally friendly, since it does not involve these processes. However, wildlife, vegetation and wetlands can be disrupted by the complex network of seismic lines, roads, power-line corridors and pipelines associated with in situ developments. This so-called "linear disturbance" fragments habitats and ecosystems, negatively affecting sensitive species. The roads also open previously inaccessible areas to human activities, further disrupting the wildlife.(36)

D. Water Use and Quality

Oil sands operations require a significant amount of water, for both bitumen processing activities and oil sands extraction procedures. For example, SAGD and other thermal in situ extraction techniques require large quantities of water for making steam to heat bitumen so that it can be pumped to the surface. Even though close to 90% of this water is recycled, a significant volume cannot be recovered. In surface mining operations, the muskeg overburden must be drained before it can be removed to expose the deposit. This can negatively affect local groundwater levels. In addition, in new hydrotransport operations, warm water is mixed with the oil sand to create a slurry that is pumped to the extraction plant. Some water is recovered following extraction, but most is disposed of in large tailings ponds. After either in situ recovery or mining and extraction, additional water must be used to upgrade the bitumen into synthetic crude oil. On average, approximately one barrel of water is used for every barrel of oil produced from the Alberta oil sands.(37)

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(35) Sierra Club of Canada (2003), p. 11.

(36) National Energy Board (2000), p. 82.

(37) Mary Griffiths and Dan Woynillowicz, "Oil and Troubled Waters," Pembina Institute for Appropriate Development, April 2003, pp. 9-11, http://www.pembina.org/pdf/publications/OilandTroubledWaters.pdf, accessed 15 January 2004.

Water use associated with oil sands production is causing concern among citizens and governments alike. For instance, residents in the Cold Lake region have felt the impacts of large-scale groundwater removal. Local lakes' levels have dropped, landowners have had to drill deeper wells, and deeper well-water has proven to be of inferior quality. Environmentalists warn of the potential ecological impact of diminished surface and groundwater on wetlands and aquatic life, and consequently on wildlife and the Aboriginal hunters and trappers who depend on wildlife for their well-being.(38)

Provincial relations may also be affected, as much of Saskatchewan's water supply flows through Alberta first. Alberta is allowed to take up to 50% of flow, but it currently uses closer to 20%. Should Alberta need to take its maximum amount in the future as oil sands production increases, farmers in Saskatchewan may be deprived of water they currently rely on for crops and livestock.(39) Given that Alberta is already threatened by more frequent drought due to climate change, the protection of water resources is becoming increasingly important.(40)

In November 2003, the Alberta government responded to concerns about water in the province with a plan entitled *Water for Life: Alberta's Strategy for Sustainability*. The strategy includes plans to create a committee to restrict the oil industry's water use, to map and inventory groundwater supplies, and to cut provincial water use by 30% (to 2005 levels) by 2015.(41) Other possible water-saving measures, such as using brackish water for operations instead of groundwater, and developing non-thermal methods using solvents instead of steam for in situ recovery, are also being developed. It is clear that current water-use patterns in oil sands production will have to change if surface water and groundwater are to be protected as production triples by 2020, as some predict.(42)

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(38) Griffiths and Woynillowicz (2003), pp. 9-11.

(39) Graham Thompson, "Alberta water blueprint will have huge implications," *The Leader Post* [Regina], 2 December 2003, p. B7.

(40) Griffiths and Woynillowicz (2003), pp. 9-11.

(41) Government of Alberta, *Water for Life: Alberta's Strategy for Sustainability*, http://www.waterforlife.gov.ab.ca/index.html, accessed 20 January 2004.

(42) Griffiths and Woynillowicz (2003), pp. 9-11.

E. Tailings

Surface mining operations and the associated water-based extraction process produce large volumes of tailings – a mixture of water, residual bitumen, sand, silt, clay and solvents. The tailings are pumped into large ponds, where the heavier sand component quickly settles. The silt and clay fractions settle out much more slowly, producing a fine sludge-like sediment. Syncrude has an estimated 350 million cubic metres of material in its tailings ponds dating back to its opening in 1978, while Suncor has 90 million cubic metres of tailings to treat.(43)

The environmental threats posed by tailings ponds include possible migration of pollutants into groundwater and the risk of leaks into surrounding soil and surface water. The ponds and the areas near them are monitored and maintained to prevent leakage and detect any pollutant migration. Historically, the ponds were usually reclaimed by topping them with water to create artificial lakes. More recently, a dry reclamation technique is being developed and implemented at some sites. Gypsum is added to the tailings to speed consolidation of the settled particles, releasing water more quickly and allowing for a dry landscape to be developed on the site. The search is still on for better tailings management options.

ACTION TO ADDRESS ENVIRONMENTAL ISSUES

In response to the conflicting need to increase oil sands development to meet growing demand for crude oil, and the desire to reduce adverse environmental effects – notably GHG emissions – both governments and industry continue to invest in oil sand technology R&D. The major contribution to technological advancements in oil sands production, including improved environmental performance, has come from the cooperative efforts of industry, universities and governments, primarily under the auspices of the Canadian Oil Sands Network for Research and Development (CONRAD). CONRAD's members include 15 industry members, five government institutions (both federal and provincial) and three associate members (two universities and one industry association).

According to Environment Canada, a combination of new technologies for extracting and upgrading, coupled with better management to improve energy efficiency, have succeeded in reducing GHG emissions by 22% per unit of output in the last decade. This is the

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(43) National Energy Board (2004), p. 84.

best per unit emissions reduction achievement of any industry, and Environment Canada and the Government of Alberta predict continued improvements in the future – down to 45% of 1990 GHG emission levels by 2010.(44) This improvement per unit of output, however, has to be viewed in the context of an absolute increase in emissions due to the rapid expansion in the rate of production from the oil sands. In fact, emissions associated with synthetic crude oil production are predicted to grow from 13 MT in 2000 to 31.7 MT by 2015. Comparable figures for bitumen production are 8.2 MT in 2000 and 17.2 MT by 2015.(45)

In addition to investing in R&D, the major oil sands companies are addressing environmental issues by developing corporate climate change plans that include such measures as: making their facilities more energy-efficient; investigating emissions-trading opportunities;(46) establishing climate change advisory panels;(47) investing in projects to capture and reuse wasted energy;(48) funding renewable energy sources such as wind power;(49) and participating in projects that capture and store CO_2.(50) Many of the companies involved in the oil sands also participate in Canada's Climate Change Voluntary Challenge and Registry, a program that records industry actions to reduce GHG emissions.(51)

A number of regional, multi-stakeholder groups have been established over the years to address the environmental impacts of oil sands development. The Clean Air Strategic Alliance (CASA) was established in Alberta in 1994 to manage air quality issues in the province. One of the Alliance's members, the Wood Buffalo Environmental Association (WBEA), is a

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(44) Environment Canada, *Fact Sheet: Oil, Gas, and Coal*, http://www.ec.gc.ca/press/2002/020403-5_f_e.htm, accessed 19 January 2004; and Alberta Energy, *Does Oil Sands "Mining" Affect the Environment?*, accessed 13 January 2004.

(45) National Energy Board (2000), p. 88.

(46) Shell Canada, *Climate Change and the Athabasca Oil Sands Project*, http://www.shell.ca/code/values/climate/climate_asop.html, accessed 19 January 2004.

(47) *Ibid*.

(48) Suncor Energy, *A Shared Environment*, http://suncor.com/data/1/rec_docs/30_SuncorSDReport2003_environment.pdf, accessed 19 January 2004.

(49) Suncor Energy, *Renewable Energy Sources*, http://www.suncor.com/bins/content_page.asp?cid=2-1464-1466-1470, accessed 19 January 2004.

(50) Suncor Energy, *A Shared Environment*, http://suncor.com/data/1/rec_docs/30_SuncorSDReport2003_environment.pdf, accessed 19 January 2004.

(51) Canadian Association of Petroleum Producers, *2001 Environment, Health, and Safety Stewardship Progress Report*, 2001, p. 9 http://www.capp.ca/raw.asp?NOSTAT=YES&dt=NTV&e=PDF&dn=31842, accessed 20 January 2004.

community-based association set up to monitor air quality and air emission impacts specifically within the oil sands area, as part of CASA's ecological effects monitoring program.

As noted earlier in this paper, there is concern over the cumulative environmental effects caused by the proliferation of oil sands projects. In response to this concern, the Cumulative Effects Monitoring Association (CEMA) was established in 1997. Its mandate is "to develop management systems to address the cumulative effects of regional development in northern Alberta."(52) CEMA has brought together the various levels of government and industry representatives to develop and put in place a management system to control emissions of NO_x, SO_2 and VOCs from oil sands projects.

There are a number of other regional initiatives that address different aspects of oil sands development. These include the Regional Aquatics Monitoring Program, the Reclamation Advisory Committee, the Heavy Metals Working Group and the Sustainable Ecosystems Working Group, to name just a few.

CONCLUSION

Production of conventional crude oil in both Canada and the United States has started to decline. It is further predicted that annual world oil production from conventional sources will peak within about 10 years at 26 billion barrels, and decline to just 6 billion barrels by 2050. At the same time the demand for oil shows no sign of slowing down. This scenario highlights the important role that Canada's oil sands can be expected to play in the coming decades. It also points to the urgency of finding solutions to the environmental issues faced by the industry.

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(52) National Energy Board (2000), p. 81.