Oil sands

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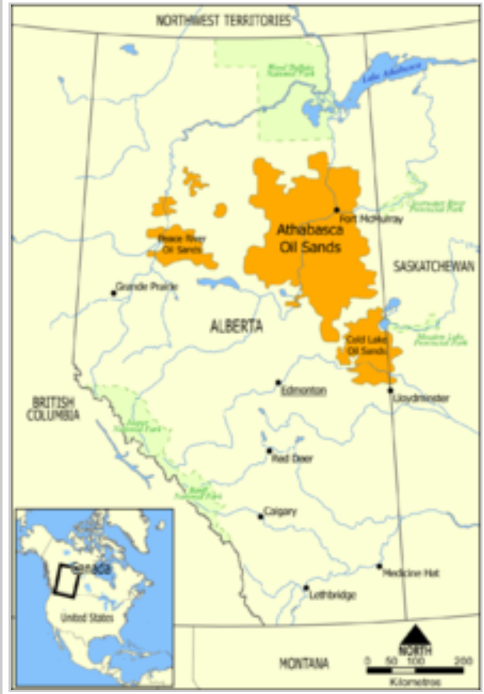
Oil sands, tar sands or, more technically, **bituminous sands,** are a type of unconventional petroleum deposit.



The Athabasca oil sands in Alberta, Canada, are a very large source of bitumen, which can be upgraded to synthetic crude oil.

Oil sand is either loose sand or partially consolidated sandstone containing a naturally occurring mixture of sand, clay, and water, saturated with a dense and extremely viscous form of petroleum technically referred to as bitumen (or colloquially tar due to its similar appearance, odour and colour). Natural bitumen deposits are reported in many countries, but in particular are found in extremely large quantities in Canada.[1][2] Other large reserves are located in Kazakhstan and Russia. The estimated worldwide deposits of oil are more than 2 trillion barrels (320 billion cubic metres);[3] the estimates include deposits that have not yet been discovered. Proven reserves of bitumen contain approximately 100 billion barrels,[4] and total natural bitumen reserves are estimated at 249.67 Gbbl (39.694×10^9 m^3) globally, of which 176.8 Gbbl (28.11×10^9 m^3), or 70.8%, are in Canada.[1]

Oil sands reserves have only recently been considered to be part of the world's oil reserves, as higher oil prices and new technology enable profitable extraction and processing. Oil produced from bitumen sands is often referred to as unconventional oil or crude bitumen, to distinguish it from liquid hydrocarbons produced from traditional oil wells.

Tar sandstone from California, United States.

The crude bitumen contained in the Canadian oil sands is described by the National Energy Board of Canada as "a highly viscous mixture of hydrocarbons heavier than pentanes which, in its natural state, is not usually recoverable at a commercial rate through a well because it is too thick to flow."[5] Crude bitumen is a thick, sticky form of crude oil, so heavy and viscous (thick) that it will not flow unless heated or diluted with lighter hydrocarbons such as light crude oil or natural-gas condensate. At room temperature, it is much like cold molasses.[6] The World Energy Council (WEC) defines natural bitumen as "oil having a viscosity greater than 10,000 centipoise under reservoir conditions and an API gravity of less than 10° API".[1] The Orinoco Belt in Venezuela is sometimes described as oil sands, but these deposits are non-bituminous, falling instead into the category of heavy or extra-heavy oil due to their lower viscosity.[7] Natural bitumen and extra-heavy oil differ in the degree by which they have been degraded from the original conventional oils by bacteria. According to the WEC, extra-heavy oil has "a gravity of less than 10° API and a reservoir viscosity of no more than 10,000 centipoise".[1]

According to the study ordered by the Government of Alberta and conducted by Jacobs Engineering Group, emissions from oil-sand crude are 12% higher than from conventional oil.[8]

Contents

History

The exploitation of bituminous deposits and seeps dates back to Paleolithic times.[9] The earliest known use of bitumen was by Neanderthals, some 40,000 years ago. Bitumen has been found adhering to stone tools used by Neanderthals at sites in Syria. After the arrival of Homo sapiens, humans used bitumen for construction of buildings and waterproofing of reed boats, among other uses. In ancient Egypt, the use of bitumen was important in preparing Egyptian mummies.[10]

In ancient times, bitumen was primarily a Mesopotamian commodity used by the Sumerians and Babylonians, although it was also found in the Levant and Persia. The area along the Tigris and Euphrates rivers was littered with hundreds of pure bitumen seepages. The Mesopotamians used the bitumen for waterproofing boats and buildings. In Europe, they were extensively mined near the French city of Pechelbronn, where the vapour separation process was in use in 1742.[11][12]

Nomenclature

The name *tar sands* was applied to bituminous sands in the late 19th and early 20th century. People who saw the bituminous sands during this period were familiar with the large amounts of tar residue produced in urban areas as a by-product of the manufacture of coal gas for urban heating and lighting.[13] The word "tar" to describe these natural bitumen deposits is really a misnomer, since, chemically speaking, tar is a human-made substance produced by the destructive distillation of organic material, usually coal.[14]

Since then, coal gas has almost completely been replaced by natural gas as a fuel, and coal tar as a material for paving roads has been replaced by the petroleum product asphalt. Naturally occurring bitumen is chemically more similar to asphalt than to coal tar, and the term *oil sands* (or oilsands) is more commonly used by industry in the producing areas than *tar sands* because synthetic oil is manufactured from the bitumen,[14] and due to the feeling that the terminology of *tar sands* is less politically acceptable to the public.[15] Oil sands are now an alternative to conventional crude oil.[16]

Early explorers

In Canada, the First Nations peoples had used bitumen from seeps along the Athabasca and Clearwater Rivers to waterproof their birch bark canoes from early prehistoric times. The Canadian oil sands first became known to Europeans in 1719 when a Cree native named Wa-Pa-Su brought a sample to Hudsons Bay Company fur trader Henry Kelsey, who commented on it in his journals. Fur trader Peter Pond paddled down the Clearwater River to Athabasca in 1778, saw the deposits and wrote of "springs of bitumen that flow along the ground." In

1787, fur trader and explorer Alexander MacKenzie on his way to the Arctic Ocean saw the Athabasca oil sands, and commented, "At about 24 miles from the fork (of the Athabasca and Clearwater Rivers) are some bituminous fountains into which a pole of 20 feet long may be inserted without the least resistance."[17]

Pioneers

The commercial possibilities of Canada's vast oil sands were realized early by Canadian government researchers. In 1884, Robert Bell of the Geological Survey of Canada commented, "The banks of the Athabasca would furnish an inexhaustible supply of fuel... the material occurs in such enormous quantities that a profitable means of extracting oil...may be found". In 1915, Sidney Ells of the Federal Mines Branch experimented with separation techniques and used the material to pave 600 feet (200 m) of road in Edmonton, as well as in other places. In 1920, chemist Karl Clark of the Alberta Research Council began experimenting with methods to extract bitumen from the oil sands and, in 1928, he patented the first commercial hot water separation process.[18]

Commercial development began in 1923 when businessman Robert Fitzsimmons began drilling oil wells at Bitumount, north of Fort McMurray, but obtained disappointing results with conventional drilling. In 1927 he formed the International Bitumen Company and in 1930 built a small hot-water separation plant based on Clark's design. He produced about 300 barrels (50 m^3) of bitumen in 1930, and shipped it by barge and rail to Edmonton. The bitumen from the mine had numerous uses, but most of it was used to waterproof roofs. Costs were too high and Fitzsimmons went bankrupt. In 1941 the company was renamed Oil Sands Limited and attempted to iron out technical problems, but was never very successful. It went through several changes of ownership, and in 1958 closed down permanently. In 1974 Bitumount became an Alberta Provincial Historic Site.

In 1930 businessman Max Ball formed Canadian Oil Sand Product, Ltd, which later became Abasand Oils. He built a separation plant capable of handling 250 tons of oil sands per day, which opened in 1936 and produced an average of 200 barrels per day (30 m^3/d) of oil. The plant burned down in late 1941, but was rebuilt in 1942 with even larger capacity. In 1943 the Canadian government took control of the Abasand plant under the War Measures Act and planned to expand it further. However, in 1945 the plant burned down again, and in 1946 the Canadian government abandoned the project because the need for fuel had diminished with the end of the war. The Abasand site is also an Alberta Historic Site.[18]

Geology

The world's largest oil sands are in Venezuela and Canada. The geology of the deposits in the two countries is generally rather similar. They are vast heavy oil, extra-heavy oil, and/or bitumen deposits with oil heavier than 20°API, found largely in unconsolidated sandstones with similar properties. "Unconsolidated" in this context means that the sands have high porosity, no significant cohesion, and a tensile strength close to zero. The sands are saturated with oil which has prevented them from consolidating into hard sandstone.[19]

Size of resources

The magnitude of the resources in the two countries is on the order of 3.5 to 4 trillion barrels (550 to 650 billion cubic metres) of original oil in place (OOIP). Oil in place is not necessarily oil reserves, and the amount that can be produced depends on technological evolution. Rapid technological developments in Canada in the 1985-2000 period resulted in techniques such as steam-assisted gravity drainage (SAGD) that can recover a much greater percentage of the OOIP than conventional methods. The Alberta government estimates that with current technology, 10% of its bitumen and heavy oil can be recovered, which would give it about 200 billion barrels (32 billion m^3) of recoverable oil reserves. Venezuela estimates its recoverable oil at 267 billion barrels (42 billion m^3).[19] This places Canada and Venezuela in the same league as Saudi Arabia, having the three largest oil reserves in the world.

Canada

The oil sands of the Western Canadian Sedimentary Basin (WCSB) were formed as a result of the formation of the Canadian Rocky Mountains by the Pacific Plate overthrusting over the North American Plate as it pushed in from the west, carrying the formerly large island chains which now compose most of British Columbia. The collision compressed the Alberta plains and raised the Rockies over the plains, forming the Canadian Rockies. This mountain building process buried the sedimentary rock layers which underlie most of Alberta very deep, creating high subsurface temperatures, and producing a giant pressure cooker that converted the kerogen in the deeply buried organic-rich shales to light oil and natural gas.[19][20] These source rocks were similar to the American so-called oil shales, except the latter have never been buried deep enough to convert the kerogen in them into liquid oil.

The overthrusting also tilted the pre-Cretaceous sedimentary rock formations underlying most of the sub-surface of Alberta, depressing the rock formations in southwest Alberta up to 8 km (5 mi) deep near the Rockies, but to zero depth in the northeast, where they pinched out against the igneous rocks of the Canadian Shield, which outcrop on the surface. This tilting is not apparent on the surface because the resulting trench has been filled in by eroded material from the mountains. The light oil migrated up-dip through hydro-dynamic transport from the Rockies in the southwest toward the Canadian Shield in the northeast following a complex pre-Cretaceous unconformity that exists in the formations under Alberta. The total distance of oil migration southwest to northeast was about 500 to 700 km (300 to 400 mi). At the shallow depths of sedimentary formations in the northeast, massive microbial biodegradation as the oil approached the surface caused the oil to become highly viscous and immobile. Almost all of the remaining oil is found in the far north of Alberta, in Middle Cretaceous (115 million-year old) sand-silt-shale deposits overlain by thick shales, although large amounts of heavy oil lighter than bitumen are found in the Heavy Oil Belt along the Alberta-Saskatchewan border, extending into Saskatchewan and approaching the Montana border. Note that, although adjacent to Alberta, Saskatchewan has no massive deposits of bitumen, only large reservoirs of heavy oil >10°API.[19][20]

The largest Canadian oil sands deposit, the Athabasca oil sands is in the McMurray Formation, centered on the city of Fort McMurray, Alberta. It outcrops on the surface (zero burial depth) about 50 km (30 mi) north of Fort McMurray, where enormous oil sands mines have been established, but is 400 m (1,300 ft) deep southeast of Fort McMurray. Only 3% of the oil sands area containing about 20% of the recoverable oil can be produced by surface mining, so the remaining 80% will have to be produced using in-situ wells. The other Canadian deposits are between 350 to 900 m (1,000 to 3,000 ft) deep and will require in-situ production.[19][20]

Venezuela

The Eastern Venezuelan Basin has a structure similar to the WCSB, but on a shorter scale. The distance the oil has migrated up-dip from the Sierra Orientale mountain front to the Orinoco oil sands where it pinches out against the igneous rocks of the Guyana Shield is only about 200 to 300 km (100 to 200 mi). The hydrodynamic conditions of oil transport were similar, source rocks buried deep by the rise of the mountains of the Sierra Orientale produced light oil that moved up-dip toward the south until it was gradually immobilized by the viscosity increase caused by biodgradation near the surface. The Orinoco deposits are early Tertiary (50 to 60 million years old) sand-silt-shale sequences overlain by continuous thick shales, much like the Canadian deposits.

In Venezuela, the Orinoco oil sands range from 350 to 1,000 m (1,000 to 3,000 ft) deep and no surface outcrops exist. The deposit is about 500 km (300 mi) long east-to-west and 50 to 60 km (30 to 40 mi) wide north-to-south, much less than the combined area covered by the Canadian deposits. In general, the Canadian deposits are found over a much wider area, have a broader range of properties, and have a broader range of reservoir types than the Venezuelan ones, but the geological structures and mechanisms involved are similar. The main differences is that the oil in the sands in Venezuela is less viscous than in Canada, allowing some of it to be produced by conventional drilling techniques, but none of it approaches the surface as in Canada, meaning none of it can be produced using surface mining. The Canadian deposits will almost all have to be produced by mining or using new non-conventional techniques.

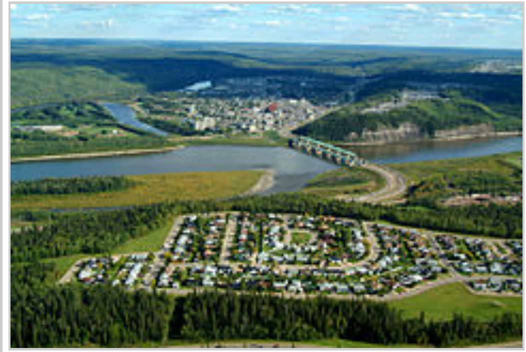
Major deposits

There are numerous deposits of oil sands in the world, but the biggest and most important are in Canada and Venezuela, with lesser deposits in Kazakhstan and Russia. The total volume of non-conventional oil in the oil sands of these countries exceeds the reserves of conventional oil in all other countries combined. Vast deposits of bitumen - over 350 billion cubic metres (2.2 trillion barrels) of oil in place - exist in the Canadian provinces of Alberta and Saskatchewan. If only 30% of this oil could be extracted, it could supply the entire needs of North America for over 100 years. These deposits represent plentiful oil, but not cheap oil. They require advanced technology to extract the oil and transport it to oil refineries.[21]

Most of the Canadian oil sands are in three major deposits in northern Alberta. They are the Athabasca-Wabiskaw oil sands of north northeastern Alberta, the Cold Lake deposits of east northeastern Alberta, and the Peace River deposits of northwestern Alberta. Between them, they cover over 140,000 square kilometres (54,000 sq mi)—an area larger than England—and contain approximately 1.75 Tbbl (280×10^9 m^3) of crude bitumen in them. About 10% of the oil in place, or 173 Gbbl (27.5×10^9 m^3), is estimated by the government of Alberta to be recoverable at current prices, using current technology, which amounts to 97% of Canadian oil reserves and 75% of total North American petroleum reserves.[2] Although the Athabasca deposit is the only one in the world which has areas shallow enough to mine from the surface, all three Alberta areas are suitable for production using *in-situ* methods, such as cyclic steam stimulation (CSS) and steam assisted gravity drainage (SAGD).

Athabasca

The **Athabasca oil sands** lie along the Athabasca River and are the largest natural bitumen deposit in the world, containing about 80% of the Alberta total, and the only one suitable for surface mining. With modern unconventional oil production technology, at least 10% of these deposits, or about 170 Gbbl (27×10^9 m^3) are considered to be economically recoverable, making Canada's total proven reserves the third largest in the world, after Saudi Arabia's conventional oil and Venezuela's Orinoco oil sands.



The City of Fort McMurray on the banks of the Athabasca River

The Athabasca oil sands are more or less centered around the remote northern city of Fort McMurray. They are by far the largest deposit of bitumen in Canada, probably containing over 150 billion cubic metres (900 billion barrels) of oil in place. The bitumen is highly viscous and is often denser than water (10°API or 1000 kg/m^3). The oil saturated sands range from 15 to 65 metres (49 to 213 ft) thick in places, and the oil saturation in the oil-rich zones is on the order of 90% bitumen by weight.[21]

The Athabasca River cuts through the heart of the deposit, and traces of the heavy oil are readily observed as black stains on the river banks. Since portions of the Athabasca sands are shallow enough to be surface-mineable, they were the earliest ones to see development. Historically, the bitumen was used by the indigenous Cree and Dene Aboriginal peoples to waterproof their canoes. The Athabasca oil sands first came to the attention of European fur traders in 1719 when Wa-pa-su, a Cree trader, brought a sample of bituminous sands to the Hudson's Bay Company post at York Factory on Hudson Bay.

In 1778, Peter Pond, a fur trader for the rival North West Company, was the first European to see the Athabasca deposits. In 1788, fur trader and explorer Alexander Mackenzie from the Hudson Bay Company, who later discovered the Mackenzie River and routes to both the Arctic and Pacific Oceans, described the oil sands in great detail. He said, "At about 24 miles (39 km) from the fork (of the Athabasca and Clearwater Rivers) are some bituminous fountains into which a pole of 20 feet (6.1 m) long may be inserted without the least resistance. The bitumen is in a fluid state and when mixed with gum, the resinous substance collected from the spruce fir, it serves to gum the Indians' canoes."

Oil sands on the banks of the Athabasca River, c. 1900

in 1883, G.C. Hoffman of the Geological Survey of Canada tried separating the bitumen from oil sand with the use of water and reported that it separated readily. In 1888, Robert Bell of the Geological Survey of Canada reported to a Senate Committee that "The evidence ... points to the existence in the Athabasca and Mackenzie valleys of the most extensive petroleum field in America, if not the world." In 1926, Karl Clark of the University of Alberta patented a hot water separation process which was the forerunner of today's thermal extraction processes. However, it was 1967 before the first large scale commercial operation began with the opening of the Great Canadian Oil Sands mine by the Sun Oil Company of Ohio.

Today its successor company, Suncor Energy (no longer affiliated with Sun Oil), is the largest oil company in Canada. In addition, other companies such as Royal Dutch Shell, ExxonMobile, and various national oil companies are developing the Athabasca oil sands. As a result, Canada is now by far the largest exporter of oil to the United States.

The smaller **Wabasca** (or Wabiskaw) **oil sands** lie above the western edge of the Athabasca oil sands and overlap them. They probably contain over 15 billion cubic metres (90 billion barrels) of oil in place. The deposit is buried from 100 to 700 metres (330 to 2,300 ft) deep and ranges from 0 to 10 metres (0 to 33 ft) thick. In many regions the oil-rich Wabasca formation overlies the similarly oil-rich McMurray formation, and as a result the two overlapping oil sands are often treated as one oil sands deposit. However, the two deposits are invariable separated by a minimum of 6 metres (20 ft) of clay shale and silt. The bitumen in the Wabasca is as highly viscous as that in the Athabasca, but lies too deep to be surface-mined, so in-situ production methods must be used to produce the crude bitumen.[21]

Cold Lake


Cold Lake viewed from Meadow Lake Provincial Park, Saskatchewan.

The Cold Lake oil sands are northeast of Alberta's capital, Edmonton, near the border with Saskatchewan. A small portion of the Cold Lake deposit lies in Saskatchewan. Although smaller than the Athabasca oil sands, the Cold Lake oil sands are important because some of the oil is fluid enough to be extracted by conventional methods. The Cold Lake bitumen contains more alkanes and less asphaltenes than the other major Alberta oil sands and the oil is more fluid.[22] As a result, cyclic steam stimulation (CSS) is commonly used for production.

The Cold Lake oil sands are of a roughly circular shape, centered around Bonnyville, Alberta. They probably contain over 60 billion cubic metres (370 billion barrels) of extra-heavy oil-in-place. The oil is highly viscous, but considerably less so than the Athabasca oil sands, and is somewhat less sulfurous. The depth of the deposits is 400 to 600 metres (1,300 to 2,000 ft) and they are from 15 to 35 metres (49 to 115 ft) thick.[21] They are too deep to surface mine.

Much of the oil sands are on Canadian Forces Base Cold Lake. CFB Cold Lake's CF-18 Hornet jet fighters defend the western half of Canadian air space and cover Canada's Arctic territory. Cold Lake Air Weapons Range (CLAWR) is one of the largest live-drop bombing ranges in the world, including testing of cruise missiles. As oil sands production continues to grow, various sectors vie for access to airspace, land, and resources, and this complicates oil well drilling and production significantly.

Peace River

The Peace River oil sands located in northwest-central Alberta are the smallest of the three major oil sands deposits in Alberta. The Peace River oil sands lie generally in the watershed of the Peace River, the largest river in Alberta. The Peace and Athabasca rivers, which are by far the largest rivers in Alberta, flow through their respective oil sands and merge at Lake Athabasca to form the Slave River, which flows into the MacKenzie River, one of the largest rivers in the world. All of the water from these rivers flow into the Arctic Ocean.

The Peace River oil sands probably contain over 30 billion cubic metres (200 billion barrels) of oil-in-place. The thickness of the deposit ranges from 5 to 25 metres (16 to 82 ft) and it is buried about 500 to 700 metres (1,600 to 2,300 ft) deep.[21]


Peace River

Whereas the Athabasca oil sands lie close enough to the surface that the bitumen can be excavated in open-pit mines, the smaller Peace River deposits are too deep, and must be exploited using in situ methods such as steam-assisted gravity drainage and Cold Heavy Oil Production with Sand (CHOPS).[23]

Orinoco


Panorama of the Orinoco River.

The Orinoco Belt is a territory in the southern strip of the eastern Orinoco River Basin in Venezuela which overlies one of the world's largest deposits of petroleum. The Orinoco Belt follows the line of the river. It is approximately 600 kilometres (370 mi) from east to west, and 70 kilometres (43 mi) from north to south, with an area about 55,314 square kilometres (21,357 sq mi).

The oil sands consist of large deposits of extra heavy crude. Venezuela's heavy oil deposits of about 1,200 Gbbl (190×10^9 m^3) of oil in place are estimated to approximately equal the world's reserves of lighter oil.[1] Petróleos de Venezuela S.A. (PDVSA), Venezuela's national oil company, has estimated that the producible reserves of the Orinoco Belt are up to 235 Gbbl (37.4×10^9 m^3)[24] which would make it the largest petroleum reserve in the world.

In 2009, the US Geological Survey (USGS) increased its estimates of the reserves to 513 Gbbl (81.6×10^9 m^3) of oil which is "technically recoverable (producible using currently available technology and industry practices)." No estimate of how much of the oil is economically recoverable was made.[25]

Other deposits

In addition to the three major Canadian oil sands in Alberta, there is a fourth major oil sands deposit in Canada, the Melville Island oil sands in the Canadian Arctic islands which are too remote to expect commercial production in the foreseeable future.

Outside of Canada and Venezuela, numerous other countries hold oil sands deposits which are smaller by orders of magnitude. In Kazakhstan, the bitumen deposits are located in the North Caspian Basin. Russia holds oil sands in two main regions. Large resources are present in the Tunguska Basin, East Siberia, with the largest deposits being Olenek and Siligir. Other deposits are located in the Timan-Pechora and Volga-Urals basins (in and around Tatarstan), which is an important but very mature province in terms of conventional oil, holds large amounts of oil sands in a shallow permian formation.[1][26]

In Madagascar, Tsimiroro and Bemolanga are two heavy oil sands deposits, with a pilot well already producing small amounts of oil in Tsimiroro.[27] and larger scale exploitation in the early planning phase.[28] In the Republic of the Congo reserves are estimated between 0.5 and 2.5 Gbbl (79×10^6 and 397×10^6 m^3).

In the United States, oil sands resources are primarily concentrated in Eastern Utah, with a total of 32 Gbbl (5.1×10^9 m^3) of oil (known and potential) in eight major deposits in Carbon, Garfield, Grand, Uintah, and Wayne counties.[29] In addition to being much smaller than the oil sands deposits in Alberta, Canada, the U.S. oil sands are hydrocarbon-wet, whereas the Canadian oil sands are water-wet.[30] As a result of this difference, extraction techniques for the Utah oil sands will be different from those used for the Alberta oil sands.

Location of Melville Island

Production

Bituminous sands are a major source of unconventional oil, although only Canada has a large-scale commercial oil sands industry. In 2006, bitumen production in Canada averaged 1.25 Mbbl/d (200,000 m^3/d) through 81 oil sands projects. 44% of Canadian oil production in 2007 was from oil sands.[31] This proportion is expected to increase in coming decades as bitumen production grows while conventional oil production declines, although due to the 2008 economic downturn work on new projects has been deferred.[2] Petroleum is not produced from oil sands on a significant level in other countries.[30]

Canada

The Alberta oil sands have been in commercial production since the original Great Canadian Oil Sands (now Suncor Energy) mine began operation in 1967. Despite the increasing levels of production, the process of extraction and processing of oil sands can still be considered to be in its infancy; with new technologies and stakeholders oversight providing an ever lower environmental footprint. A second mine, operated by the Syncrude consortium, began operation in 1978 and is the biggest mine of any type in the world. The third mine in the Athabasca Oil Sands, the Albian Sands consortium of Shell Canada, Chevron Corporation, and Western Oil Sands Inc. [purchased by Marathon Oil Corporation in 2007] began operation in 2003. Petro-Canada was also developing a $33 billion Fort Hills Project, in partnership with UTS Energy Corporation and Teck Cominco, which lost momentum after the 2009 merger of Petro-Canada into Suncor.[32]

By 2013 there were nine oil sands mining projects in the Athabasca oil sands deposit: Suncor Energy Inc. (Suncor), Syncrude Canada Limited (Syncrude)'s Mildred Lake and Aurora North, Shell Canada Limited (Shell)'s Muskeg River and Jackpine, Canadian Natural Resources Limited (CNRL), Horizon, Imperial Oil

Resources Ventures Limited (Imperial), Kearl Oil Sands Project (KOSP), Total E&P Canada Ltd. Joslyn North Mine and Fort Hills Energy Corporation (FHEC).[33] In 2011 alone they produced over 52 million cubic metres of bitumen.[33]

Syncrude's Mildred Lake mine site and plant near Fort McMurray, Alberta

Venezuela

No significant development of Venezuela's extra-heavy oil deposits was undertaken before 2000, except for the BITOR operation which produced somewhat less than 100,000 barrels of oil per day (16,000 m^3/d) of 9°API oil by primary production. This was mostly shipped as an emulsion (Orimulsion) of 70% oil and 30% water with similar characteristics as heavy fuel oil for burning in thermal power plants.[19] However, when a major strike hit the Venezuelan state oil company PDVSA, most of the engineers were fired as punishment. Orimulsion had been the pride of the PDVSA engineers, so Orimulsion fell out of favor with the key political leaders. As a result, the government has been trying to "Wind Down" the Orimulsion program.

Despite the fact that the Orinoco oil sands contain extra-heavy oil which is easier to produce than Canada's similarly-sized reserves of bitumen, Venezuela's oil production has been declining in recent years because of the country's political and economic problems, while Canada's has been increasing. As a result, Canadian heavy oil and bitumen exports have been backing Venezuelan heavy and extra-heavy oil out of the US market, and Canada's total exports of oil to the US are now several times as great as Venezuela's.

Other countries

In May 2008, the Italian oil company Eni announced a project to develop a small oil sands deposit in the Republic of the Congo. Production is scheduled to commence in 2014 and is estimated to eventually yield a total of 40,000 bbl/d (6,400 m^3/d).[34]

Methods of extraction

Except for a fraction of the extra-heavy oil or bitumen which can be extracted by conventional oil well technology, oil sands must be produced by strip mining or the oil made to flow into wells using sophisticated *in-situ* techniques. These methods usually use more water and require larger amounts of energy than conventional oil extraction. While much of Canada's oil sands are being produced using open-pit mining, approximately 90% of Canadian oil sands and all of Venezuela's oil sands are too far below the surface to use surface mining.[35]

Primary production

Conventional crude oil is normally extracted from the ground by drilling oil wells into a petroleum reservoir, allowing oil to flow into them under natural reservoir pressures, although artificial lift and techniques such as horizontal drilling, water flooding and gas injection are often required to maintain production. When primary production is used in the Venezuelan oil sands, where the extra-heavy oil is about 50 degrees Celsius, the typical oil recovery rates are about 8-12%. Canadian oil sands are much colder and more biodegraded, so bitumen recovery rates are usually only about 5-6%. Historically, primary recovery was used in the more fluid areas of Canadian oil sands. However, it recovered only a small fraction of the oil in place, so it not often used today.[36]

Surface mining

The Athabasca oil sands are the only major oil sands deposits which are shallow enough to surface mine. In the Athabasca sands there are very large amounts of bitumen covered by little overburden, making surface mining the most efficient method of extracting it. The overburden consists of water-laden muskeg (peat bog) over top of clay and barren sand. The oil sands themselves are typically 40 to 60 metres (130 to 200 ft) thick deposits of crude bitumen embedded in unconsolidated sandstone, sitting on top of flat limestone rock. Since Great Canadian Oil Sands (now Suncor Energy) started operation of the first large-scale oil sands mine in 1967, bitumen has been extracted on a commercial scale and the volume has grown at a steady rate ever since.

Mining operations in the Athabasca oil sands. NASA Earth Observatory image, 2009.

A large number of oil sands mines are currently in operation and more are in the stages of approval or development. The Syncrude Canada mine was the second to open in 1978, Shell Canada opened its Muskeg River mine (Albian Sands) in 2003 and Canadian Natural Resources Ltd (CNRL) opened its Horizon Oil Sands project in 2009. Newer mines include Shell Canada's Jackpine mine,[37] Imperial Oil's Kearl Oil Sands Project, the Synenco Energy (now owned by Total S.A.) Northern Lights mine, and Suncor's Fort Hills mine.

Cold Heavy Oil Production with Sand (CHOPS)

Some years ago Canadian oil companies discovered that if they removed the sand filters from heavy oil wells and produced as much sand as possible with the oil, production rates improved significantly. This technique became known as Cold Heavy Oil Production with Sand (CHOPS). Further research disclosed that pumping out sand opened "wormholes" in the sand formation which allowed more oil to reach the wellbore. The advantage of this method is better production rates and recovery (around 10% versus 5-6% with sand filters in place) and the disadvantage that disposing of the produced sand is a problem. A novel way to do this was spreading it on rural roads, which rural governments liked because the oily sand reduced dust and the oil companies did their road maintenance for them. However, governments have become concerned about the large volume and composition of oil spread on roads.[38] so in recent years disposing of oily sand in underground salt caverns has become more common.

Cyclic Steam Stimulation (CSS)

The use of steam injection to recover heavy oil has been in use in the oil fields of California since the 1950s. The cyclic steam stimulation (CSS) "huff-and-puff" method is now widely used in heavy oil production world-wide due to its quick early production rates; however recovery factors are relatively low (10-40% of oil in place) compared to SAGD (60-70% of OIP).[39]

CSS has been in use by Imperial Oil at Cold Lake since 1985 and is also used by Canadian Natural Resources at Primrose and Wolf Lake and by Shell Canada at Peace River. In this method, the well is put through cycles of steam injection, soak, and oil production. First, steam is injected into a well at a temperature of 300 to 340 degrees Celsius for a period of weeks to months; then, the well is allowed to sit for days to weeks to allow heat to soak into the formation; and, later, the hot oil is pumped out of the well for a period of weeks or months. Once the production rate falls off, the well is put through another cycle of injection, soak and production. This process is repeated until the cost of injecting steam becomes higher than the money made from producing oil.[40]

Steam Assisted Gravity Drainage (SAGD)

Steam assisted gravity drainage was developed in the 1980s by the Alberta Oil Sands Technology and Research Authority and fortuitously coincided with improvements in directional drilling technology that made it quick and inexpensive to do by the mid 1990s. In SAGD, two horizontal wells are drilled in the oil sands, one at the bottom of the formation and another about 5 metres above it. These wells are typically drilled in groups off central pads and can extend for miles in all directions. In each well pair, steam is injected into the upper well, the heat melts the bitumen, which allows it to flow into the lower well, where it is pumped to the surface.[40]

SAGD has proved to be a major breakthrough in production technology since it is cheaper than CSS, allows very high oil production rates, and recovers up to 60% of the oil in place. Because of its economic feasibility and applicability to a vast area of oil sands, this method alone quadrupled North American oil reserves and allowed Canada to move to second place in world oil reserves after Saudi Arabia. Most major Canadian oil companies now have SAGD projects in production or under construction in Alberta's oil sands areas and in Wyoming. Examples include Japan Canada Oil Sands Ltd's (JACOS) project, Suncor's Firebag project, Nexen's Long Lake project, Suncor's (formerly Petro-Canada's) MacKay River project, Husky Energy's Tucker Lake and Sunrise projects, Shell Canada's Peace River project, Cenovus Energy's Foster Creek[41] and Christina Lake[42] developments, ConocoPhillips' Surmont project, Devon Canada's Jackfish project, and Derek Oil & Gas's LAK Ranch project. Alberta's OSUM Corp has combined proven underground mining technology with SAGD to enable higher recovery rates by running wells underground from within the oil sands deposit, thus also reducing energy requirements compared to traditional SAGD. This particular technology application is in its testing phase.

Vapor Extraction (VAPEX)

Several methods use solvents, instead of steam, to separate bitumen from sand. Some solvent extraction methods may work better in *in situ* production and other in mining.[43] Solvent can be beneficial if it produces more oil while requiring less energy to produce steam.

Vapor Extraction Process (VAPEX) is an *in situ* technology, similar to SAGD. Instead of steam, hydrocarbon solvents are injected into an upper well to dilute bitumen and enables the diluted bitumen to flow into a lower well. It has the advantage of much better energy efficiency over steam injection, and it does some partial upgrading of bitumen to oil right in the formation. The process has attracted attention from oil companies, who are experimenting with it.

The above methods are not mutually exclusive. It is becoming common for wells to be put through one CSS injection-soak-production cycle to condition the formation prior to going to SAGD production, and companies are experimenting with combining VAPEX with SAGD to improve recovery rates and lower energy costs.[44]

Toe to Heel Air Injection (THAI)

This is a very new and experimental method that combines a vertical air injection well with a horizontal production well. The process ignites oil in the reservoir and creates a vertical wall of fire moving from the "toe" of the horizontal well toward the "heel", which burns the heavier oil components and upgrades some of the heavy bitumen into lighter oil right in the formation. Historically fireflood projects have not worked out well because of difficulty in controlling the flame front and a propensity to set the producing wells on fire. However, some oil companies feel the THAI method will be more controllable and practical, and have the advantage of not requiring energy to create steam.[45]

Advocates of this method of extraction state that it uses less freshwater, produces 50% less greenhouse gases, and has a smaller footprint than other production techniques.[46]

Petrobank Energy and Resources has reported encouraging results from their test wells in Alberta, with production rates of up to 400 bbl/d (64 m^3/d) per well, and the oil upgraded from 8 to 12 API degrees. The company hopes to get a further 7-degree upgrade from its CAPRI (controlled atmospheric pressure resin infusion)[47] system, which pulls the oil through a catalyst lining the lower pipe.[48][49][50]

After several years of production in situ, it has become clear that current THAI methods do not work as planned. Amid steady drops in production from their THAI wells at Kerrobert, Petrobank has written down the value of their THAI patents and the reserves at the facility to zero. They have plans to experiment with a new configuration they call "multi-THAI," involving adding more air injection wells. [51]

Combustion Overhead Gravity Drainage (COGD)

This is an experimental method that employs a number of vertical air injection wells above a horizontal production well located at the base of the bitumen pay zone. An initial Steam Cycle similar to CSS is used to prepare the bitumen for ignition and mobility. Following that cycle, air is injected into the vertical wells, igniting the upper bitumen and mobilizing (through heating) the lower bitumen to flow into the production well. It is expected that COGD will result in water savings of 80% compared to SAGD.[52]

Input energy

Approximately 1.0–1.25 gigajoules (280–350 kWh) of energy is needed to extract a barrel of bitumen and upgrade it to synthetic crude. As of 2006, most of this is produced by burning natural gas.[53] Since a barrel of oil equivalent is about 6.117 gigajoules (1,699 kWh), its EROEI is 5–6. That means this extracts about 5 or 6 times as much energy as is consumed. Energy efficiency is expected to improve to average of 900 cubic feet (25 m^3) of natural gas or 0.945 gigajoules (262 kWh) of energy per barrel by 2015, giving an EROEI of about 6.5.[54]

Alternatives to natural gas exist and are available in the oil sands area. Bitumen can itself be used as the fuel, consuming about 30–35% of the raw bitumen per produced unit of synthetic crude. Nexen's Long Lake project will use a proprietary deasphalting technology to upgrade the bitumen, using asphaltene residue fed to a gasifier whose syngas will be used by a cogeneration turbine and a hydrogen producing unit, providing all the energy needs of the project: steam, hydrogen, and electricity.[55] Thus, it will produce syncrude without consuming natural gas, but the capital cost is very high.

Shortages of natural gas for project fuel were forecast to be a problem for Canadian oil sands production a few years ago, but recent increases in US shale gas production have eliminated much of the problem for North America. With the increasing use of hydraulic fracturing making US largely self-sufficient in natural gas and exporting more natural gas to Eastern Canada to replace Alberta gas, the Alberta government is using its powers under the NAFTA and the Canadian Constitution to reduce shipments of natural gas to the US and Eastern Canada, and divert the gas to domestic Alberta use, particularly for oil sands fuel. The natural gas pipelines to the east and south are being converted to carry increasing oil sands production to these destinations instead of gas. Canada also has huge undeveloped shale gas deposits in addition to those of the US, so natural gas for future oil sands production does not seem to be a serious problem. The low price of natural gas as the result of new production has considerably improved the economics of oil sands production.

Upgrading and/or blending

The extra-heavy crude oil or crude bitumen extracted from oil sands is a very viscous semisolid form of oil that does not easily flow at normal temperatures, making it difficult to transport to market by pipeline. To flow through oil pipelines, it must either be upgraded to lighter synthetic crude oil (SCO), blended with diluents to form dilbit, or heated to reduce its vicosity.

Canada

In the Canadian oil sands, bitumen produced by surface mining is generally upgraded on-site and delivered as synthetic crude oil. This makes delivery of oil to market through conventional oil pipelines quite easy. On the other hand, bitumen produced by the in-situ projects is generally not upgraded but delivered to market in raw form.

When the first oil sands plants were built over 50 years ago, most oil refineries in their market area were designed to handle light or medium crude oil with lower sulfur content than the 4-7% that is typically found in bitumen. The original oil sands upgraders were designed to produce a high-quality synthetic crude oil (SCO) with lower density and lower sulfur content. These are large, expensive plants which are much like heavy oil refineries. Research is currently being done on designing simpler upgraders which do not produce SCO but simply treat the bitumen to reduce its viscosity, allowing to be transported unblended like conventional heavy oil.

The first step in upgrading is vacuum distillation to separate the lighter fractions. After that, de-asphalting is used to separate the asphalt from the feedstock. Cracking is used to break the heavier hydrocarbon molecules down into simpler ones. Since cracking produces products which are rich in sulfur, desulfurization must be done to get the sulfur content below 0.5% and create sweet, light synthetic crude oil.[56]

In 2012, Alberta produced about 1,900,000 bbl/d (300,000 m^3/d) of crude bitumen from its three major oil sands deposits, of which about 1,044,000 bbl/d (166,000 m^3/d) was upgraded to lighter products and the rest sold as raw bitumen. The volume of both upgraded and non-upgraded bitumen is increasing yearly. Alberta has five oil sands upgraders producing a variety of products. These include:[57][58]

- Suncor Energy can upgrade 440,000 bbl/d (70,000 m^3/d) of bitumen to light sweet and medium sour synthetic crude oil (SCO), plus produce diesel fuel for its oil sands operations at the upgrader.
- Syncrude can upgrade 407,000 bbl/d (64,700 m^3/d) of bitumen to sweet light SCO.
- Canadian Natural Resources Limited (CNRL) can upgrade 141,000 bbl/d (22,400 m^3/d) of bitumen to sweet light SCO.
- Nexen, since 2013 wholly owned by China National Offshore Oil Corporation (CNOOC), can upgrade 72,000 bbl/d (11,400 m^3/d) of bitumen to sweet light SCO.
- Shell Canada operates its Scotford Upgrader in combination with an oil refinery and chemical plant at Scotford, Alberta, near Edmonton. The complex can upgrade 255,000 bbl/d (40,500 m^3/d) of bitumen to sweet and heavy SCO as well as a range of refinery and chemical products.

Modernized and new large refineries such as are found in the Midwestern United States and on the Gulf Coast of the United States, as well as many in China, can handle upgrading heavy oil themselves, so their demand is for non-upgraded bitumen and extra-heavy oil rather than SCO. The main problem is that the feedstock would be too viscous to flow through pipelines, so unless it is delivered by tanker or rail car, it must be blended with diluent to enable it to flow. This requires mixing the crude bitumen with a lighter hydrocarbon diluent such as condensate from gas wells, pentanes and other light products from oil refineries or gas plants, or synthetic crude oil from oil sands upgraders to allow it to flow through pipelines to market.

Typically, blended bitumen contains about 30% natural gas condensate or other diluents and 70% bitumen. Alternatively, bitumen can also be delivered to market by specially designed railway tank cars, tank trucks, liquid cargo barges, or ocean-going oil tankers. These do not necessarily require the bitumen be blended with diluent since the tanks can be heated to allow the oil to be pumped out.

The demand for condensate for oil sands diluent is expected to be more than 750,000 bbl/d (119,000 m^3/d) by 2020, double 2012 volumes. Since Western Canada only produces about 150,000 bbl/d (24,000 m^3/d) of condensate, the supply was expected to become a major constraint on bitumen transport. However, the recent huge increase in US tight oil production has largely solved this problem, because much of the production is too light for US refinery use but ideal for diluting bitumen. The surplus American condensate and light oil is being exported to Canada and blended with bitumen, and then re-imported to the US as feedstock for refineries. Since the diluent is simply exported and then immediately re-imported, it is not subject to the US ban on exports of crude oil. Once it is back in the US, refineries separate the diluent and re-export it to Canada, which again bypasses US crude oil export laws since it is now a refinery product. To aid in this process, Kinder Morgan Energy Partners is reversing its Cochin Pipeline, which used to carry propane from Edmonton to Chicago, to transport 95,000 bbl/d (15,100 m^3/d) of condensate from Chicago to Edmonton by mid-2014; and Enbridge is considering the expansion of its Southern Lights pipeline, which currently ships 180,000 bbl/d (29,000 m^3/d) of diluent from the Chicago area to Edmonton, by adding another 100,000 bbl/d (16,000 m^3/d).[59]

Venezuela

Although Venezuelan extra-heavy oil is less viscous than Canadian bitumen, much of the difference is due to temperature. Once the oil comes out of the ground and cools, it has the same difficulty in that it is too viscous to flow through pipelines. Venezuela is now producing more extra heavy crude in the Orinoco oil sands than its four upgraders that were built by foreign oil companies over a decade ago can handle. The upgraders have a combined capacity of 630,000 bbl/d (100,000 m^3/d), which is only half of its production of extra-heavy oil. In addition Venezuela produces insufficient volumes of naphtha to use as diluent to move extra-heavy oil to market. Unlike Canada, Venezuela does not produce much natural gas condensate from its own gas wells, and unlike Canada, it does not have easy access to condensate from new US shale gas production. Since Venezuela also has insufficient refinery capacity to supply its domestic market, supplies of naptha are insufficient to use as pipeline diluent, and it is having to import naptha to fill the gap. Since Venezuela also has money problems as a result of its economic problems, and has political disagreements with the US government and oil companies, the situation remains unresolved.[60]

Transportation

A network of gathering and feeder pipelines collects crude bitumen and SCO from Alberta's northern oil sands deposits (primarily Athabasca, Cold Lake, and Peace River), and feeds them into two main collection points for southbound deliveries: Edmonton, Alberta and Hardisty, Alberta. Most of the feeder pipelines move blended bitumen or SCO southbound and diluent northbound, but a few move product laterally within the oil sands region. In 2012, the capacity of the southbound feeder lines was over 300,000 m^3/d (2 million bbl/d) and more capacity was being added. The building of new oil sands feeder pipelines requires only the approval of the Alberta Energy Regulator, an agency that deals with matters entirely within Alberta and is likely to give little consideration to interference from political and environmental interest from outside Alberta.[61]

Existing pipelines

From Edmonton and Hardisty, main transmission pipelines move blended bitumen and SCO, as well as conventional crude oil and various oil and natural productions to market destinations across North America. The main transmission systems include:[61]

- Enbridge has a complex existing system of pipelines that takes crude oil from Edmonton and Hardisty east to Montreal and south as far as the Gulf Coast of the United States, with a total capacity of 2.5×10^6 bbl/d (400,000 m^3/d). It also has a northbound pipeline that takes diluent from refineries in Illinois and other Midwestern states to Edmonton with a capacity of 160,000 bbl/d (25,000 m^3/d) of light hydrocarbons.
- Kinder Morgan has the Trans Mountain Pipeline that takes crude oil from Edmonton over the Rocky Mountains to the west coasts of British Columbia and Washington State, with an existing capacity of 300,000 bbl/d (48,000 m^3/d). It has plans to add an additional 450,000 bbl/d (72,000 m^3/d) of capacity to this pipeline within the existing pipeline easement.
- Kinder Morgan also has a system of pipelines that takes crude oil from Hardisty south to Casper, Wyoming and then east to Wood River, Illinois. The first segment has a capacity of 280,000 bbl/d (45,000 m^3/d) and the second segment 160,000 bbl/d (25,000 m^3/d).
- TransCanada Corporation has the Keystone Pipeline system. Phase 1 currently takes crude oil from Hardisty south to Steele City, Nebraska and then east to Wood River, Illinois. The existing Phase 2 moves crude oil from Steele City to the main US oil marketing hub at Cushing, Oklahoma. Phases 1 and 2 have a combined capacity of 590,000 bbl/d (94,000 m^3/d).

Overall, the total pipeline capacity for the movement of crude oil from Edmonton and Hardisty to the rest of North America is about 3.5×10^6 bbl/d (560,000 m^3/d). However, other substances such as conventional crude oil and refined petroleum products also share this pipeline network. The rapidly increasing tight oil production from the Bakken formation of North Dakota also competes for space on the Canadian export pipeline system. North Dakota oil producers are using the Canadian pipelines to deliver their oil to US refineries.

In 2012, the Canadian export pipeline system began to become overloaded with new oil production. Enbridge introduced apportionment on its southbound pipelines, and Kinder Morgan on its westbound pipeline. This rationed pipeline space by reducing the monthly allocation of each shipper to a certain percentage of its requirements. The Chevron Corporation Burnaby Refinery, the last remaining oil refinery on Canada's west coast, applied to the NEB for preferential access to Canadian oil since American refineries in Washington and California were outbidding it for pipeline space, but was denied because it would violate NAFTA equal access to energy rules. Similarly, new North Dakota tight oil production began to block new Canadian production from using the Enbridge, Kinder Morgan, and TransCanada southbound systems.[57]

In addition, the US oil marketing hub at Cushing was flooded with new oil because most new North American production from Canada, North Dakota, and Texas converged at that point, and there was insufficient capacity to take it from there to refineries on the Gulf Coast, where half of US oil refinery capacity is located. The American pipeline system is designed to take imported oil from the Gulf Coast and Texas to the refineries in the northern US, and the new oil was flowing in the opposite direction, toward the Gulf Coast. The price of West Texas Intermediate delivered at Cushing, which is the main benchmark for US oil prices, fell to unprecedented low levels below other international benchmark oils such as Brent Crude and Dubai Crude. Since the price of WTI at Cushing is usually quoted by US media as *the price of oil*, this gave many Americans a distorted view of world oil prices as being lower than they were, and the supply being better than it was internationally. Canada used to be in a similar position to the US in that offshore oil was cheaper than domestic oil, so the oil pipelines used to run westward from the east coast to Central Canada, now they are being reversed to carry cheaper domestic oil sands production from Alberta to the east coast.

New pipelines

Lack of access to markets, limited export capacity, and oversupply in the US market have been a problem for oil sands producers in recent years. They have caused lower prices to Canadian oil sands producers and reduced royalty and tax revenues to Canadian governments. The pipeline companies have moved forward with a number of solutions to the transportation problems:[57]

- Enbridge's line from Sarnia, Ontario to Westover, Ontario near the head of Lake Erie has been reversed. This line used to take offshore oil to refineries in the Sarnia area. Now it takes Alberta SCO and blended bitumen to most refineries in Ontario.
- Enbridge has applied to reverse its line from Westover to Montreal, Quebec. This line used to take offshore oil to refineries in southern Ontario. After reversal, it will take Alberta SCO and bitumen to Montreal. Since Suncor Energy owns a very large oil sands mine and upgrader in Alberta and also owns a large oil refinery in Montreal, it finds this project appealing. The alternative is closing the refinery since it is noncompetitive using offshore oil.
- TransCanada is evaluating converting part of its mainline natural gas transmission system from western Canada to eastern North America to transport oil. Eastern North America is well supplied with natural gas as a result of the recent increases in US shale gas production, but has problems with oil supply since most of their oil comes from offshore.
- Enbridge's Seaway Pipeline which used to take oil from the US Gulf Coast to the oil trading hub at Cushing was reversed in 2012 to take oil from Cushing to the Coast, helping to alleviate the bottleneck at Cushing. It has a capacity of 400,000 bbl/d (64,000 m^3/d) but Enbridge is twinning the pipeline to add an additional 400,000 bbl/d (64,000 m^3/d).
- Following the denial of a US regulatory permit for its Keystone XL pipeline, TransCanada went ahead with the southern leg of the Keystone project. This will deliver 830,000 bbl/d (132,000 m^3/d) from

Cushing to the Coast. Since it is entirely within the states of Oklahoma and Texas, it does not require US federal government approval.

Future pipelines

With the main constraint on Canadian oil sands development becoming the availability of export pipeline capacity, pipeline companies have proposed a number of major new transmission pipelines. Many of these became stalled in government regulatory processes, both by the Canadian and American governments. Another factor is competition for pipeline space from rapidly increasing tight oil production from North Dakota, which under NAFTA trade rules has equal access to Canadian pipelines.[57]

- Enbridge has announced its intention to expand its Alberta Clipper line from 450,000 bbl/d (72,000 m^3/d) to 570,000 bbl/d (91,000 m^3/d) and its Southern Access line from 400,000 bbl/d (64,000 m^3/d) to 560,000 bbl/d (89,000 m^3/d). It is also proposing to build a Flanagan South line with an initial capacity of 585,000 bbl/d (93,000 m^3/d) expandable to 800,000 bbl/d (130,000 m^3/d).
- Enbridge is proposing to build the Northern Gateway Pipeline from Bruderheim, near Edmonton, Alberta to the port of Kitimat, BC for loading on supertankers with an initial capacity of 525,000 bbl/d (83,500 m^3/d) with a reverse flow condensate pipeline to take diluent from tankers at Kitimat to Alberta. This was approved by the Canadian federal cabinet on June 17, 2014, subject to 209 conditions. After this point, the company has to satisfy most of the conditions to National Energy Board satisfaction before construction can start. Satisfying the conditions is expected to take a year or more. The leaders of both main opposition parties promised to reverse the decision if they form the government in the next election, expected in 2015.[62]
- Kinder Morgan is proposing to increase the capacity of its Trans Mountain pipeline through British Columbia to 900,000 bbl/d (140,000 m^3/d) by 2017. Kinder Morgan is also proposing to build the Trans Mountain Expansion pipeline which will add 550,000 bbl/d (87,000 m^3/d) of capacity to the West Coast of Canada and the US.
- TransCanada has proposed to build the Keystone XL extension to its Keystone Pipeline which would add 700,000 bbl/d (110,000 m^3/d) of capacity from Alberta to the US Gulf Coast. This project is current stalled indefinitely by the United States cabinet.
- TransCanada has also proposed to build the 4,600 km (2,900 mi) Energy East Pipeline, which would carry 1.1×10^6 bbl/d (170,000 m^3/d) of oil from Alberta to refineries in Eastern Canada, including Quebec and New Brunswick. It would also have marine facilities that would enable Alberta production to be delivered to Atlantic markets by oil tanker.[63] The Irving Oil Refinery in New Brunswick, which is the

largest oil refinery in Canada, is especially interested in it since its traditional sources such as North Sea oil are shrinking and international oil is more expensive than Alberta oil delivered to the Atlantic coast.

In addition, there are a large number of new pipelines proposed for Alberta. These will likely be approved rapidly by the Alberta Energy Regulator, so there are likely to be few capacity problems within Alberta.

Rail

The movement of crude oil by rail is far from new, but it is now a rapidly growing market for North American railroads. The growth is driven by several factors. One is that the transmission pipelines from Alberta are operating at or near capacity and companies who cannot get pipeline space have to move oil by rail instead. Another is that many refineries on the east, west, and Gulf coasts of North America are under-served by pipelines since they assumed that they would obtain their oil by ocean tanker. Producers of new oil in Alberta, North Dakota, and West Texas are now shipping oil by rail to coastal refiners who are having difficulty obtaining international oil at prices competitive with those in the interior of North America. In addition, crude bitumen can be loaded directly into tank cars equipped with steam heating coils, avoiding the need for blending it with expensive condensate in order to ship it to market. Tank cars can also be built to transport condensate on the back-haul from refineries to the oil sands to make additional revenue rather than returning empty.[61]

A single-track rail line carrying 10 trains per day, each with 120 tank cars, can move 630,000 bbl/d (100,000 m^3/d) to 780,000 bbl/d (124,000 m^3/d), which is the capacity of a large transmission pipeline. This would require 300 locomotives and 18,000 tank cars, which is a small part of the fleet of a Class 1 railroad. By comparison, the two Canadian Class 1 railways, Canadian Pacific Railway (CP) and Canadian National Railway (CN), have 2,400 locomotives and 65,000 freight cars between them, and CP moves 30-35 trains per day on its main line to Vancouver. Two US Class 1 railways, Union Pacific Railroad (UP) and BNSF Railway handle more than 100 trains per day on their western corridors.[61] CN Rail has said that it could move 1,500,000 bbl/d (240,000 m^3/d) of bitumen from Edmonton to the deepwater port of Prince Rupert, BC if the Northern Gateway Pipeline from Edmonton to the port of Kitimat, BC was not approved.

With many of their lines being underused, railroads find transporting crude oil an attractive source of revenue. With enough new tank cars they could carry all the new oil being produced in North America, albeit at higher prices than pipelines. In the short term, the use of rail will probably continue to grow as producers try to bypass short-term pipeline bottlenecks to take advantage of higher prices in areas with refineries capable of handling heavier crudes. In the long term the growth in rail transport will largely depend on the continued pipeline bottlenecks due to increased production in North America and regulatory delays for new pipelines. At present rail moves over 90,000 bbl/d (14,000 m^3/d) of crude oil, and with continued growth in oil production and building of new terminals, rail movements will probably continue to grow into the foreseeable future.[57]

By 2013, exports of oil from Canada to the US by rail had increased 9-fold in less than two years, from 16,000 bbl/d (2,500 m^3/d) in early 2012 to 146,000 bbl/d (23,200 m^3/d) in late 2013, mainly because new export pipelines had been held up by regulatory delays. As a result, Canadian farmers suffered an acute shortage of rail capacity to export their grains because so much of Canada's rail capacity was tied up by oil products. The safety of rail transport of oil was being called into question after several derailments, especially after a train with 74 tank cars of oil derailed and caught fire in Lac Megantic, Quebec.[64]

The ensuing explosion and firestorm burned down 40 buildings in the town center and killed 47 people. The cleanup of the derailment area could take 5 years, and another 160 buildings may need to be demolished. Ironically, the oil was not Canadian bitumen being exported to the United States but Bakken formation light crude oil being imported into Canada from North Dakota to the Irving Oil Refinery in New Brunswick. Although near a huge oil import port on the Atlantic Ocean, the Irving refinery is importing US Bakken oil by rail because oil from outside North America is too expensive to be economic, and there are no pipelines to deliver heavier but cheaper Western Canadian oil to New Brunswick. It was subsequently pointed out that the Bakken light oil was much more flammable than Alberta bitumen, and the rail cars were mislabeled by the North Dakota producers as to their flammability.

By 2014, the movement of crude by rail had become very profitable to oil companies. Suncor Energy, Canada's largest oil company declared record profits and attributed much of it to transporting oil to market by rail. It was moving about 70,000 bbl/d (11,000 m^3/d) to Cushing, Oklahoma, and putting it into TransCanada's new Gulf Coast pipeline - which was originally going to be the southern leg of the Keystone XL pipeline, before the northern leg across the border from Canada was stalled by US federal government delays.[65]

Suncor has also been moving 20,000 bbl/d (3,200 m^3/d) of Alberta bitumen and North Dakota tight oil by rail to its Montreal Refinery with plans to increase it to 35,000 bbl/d (5,600 m^3/d). Suncor claimed this saved about $10/bbl off the price of buying offshore oil. However, it was also anticipating the reversal of Enbridge's Line 9 from southwestern Ontario to Montreal to deliver 300,000 bbl/d (48,000 m^3/d) oil even cheaper. Suncor has been considering adding a coker to its Montreal refinery to upgrade heavy oil sands bitumen, which would be cheaper than adding another upgrader to its oil sands operation. It was also shipping marine cargoes on an "opportunistic basis" from Texas and Louisiana "at significant discounts to the international crudes we would typically run in Montreal", thereby taking advantage of the recent US tight oil glut in addition to increased supplies of cheap Canadian oil sands bitumen.[66]

Refining

Heavy crude feedstock needs pre-processing before it is fit for conventional refineries, although heavy oil and bitumen refineries can do the pre-processing themselves. This pre-processing is called 'upgrading', the key components of which are as follows:

1. removal of water, sand, physical waste, and lighter products
2. catalytic purification by hydrodemetallisation (HDM), hydrodesulfurization (HDS) and hydrodenitrogenation (HDN)
3. hydrogenation through carbon rejection or catalytic hydrocracking (HCR)

As carbon rejection is very inefficient and wasteful in most cases, catalytic hydrocracking is preferred in most cases. All these processes take large amounts of energy and water, while emitting more carbon dioxide than conventional oil.

Catalytic purification and hydrocracking are together known as hydroprocessing. The big challenge in hydroprocessing is to deal with the impurities found in heavy crude, as they poison the catalysts over time. Many efforts have been made to deal with this to ensure high activity and long life of a catalyst. Catalyst materials and pore size distributions are key parameters that need to be optimized to deal with this challenge and varies from place to place, depending on the kind of feedstock present.[67]

Alberta

There are four major oil refineries in Alberta which supply most of Western Canada with petroleum products, but as of 2012 these processed less than 1/4 of the approximately 1,900,000 bbl/d (300,000 m^3/d) of bitumen and SCO produced in Alberta. Some of the large oil sands upgraders also produced diesel fuel as part of their operations. Some of the oil sands bitumen and SCO went to refineries other provinces, but most of it was exported to the United States. The four major Alberta refineries are:[68]

- Suncor Energy, the largest oil company in Canada, operates the Petro-Canada refinery near Edmonton, Alberta which can process 142,000 bbl/d (22,600 m^3/d) of all types of oil and bitumen into all types of products.
- Imperial Oil, controlled by ExxonMobil, operates the Strathcona Refinery near Edmonton, which can process 187,200 bbl/d (29,760 m^3/d) of SCO and conventional oil into all types of products.
- Shell Canada, a subsidiary of Royal Dutch Shell, operates the Scotford Refinery near Edmonton, which is integrated with the Scotford Upgrader, and which can process 100,000 bbl/d (16,000 m^3/d) of all types of oil and bitumen into all types of products.
- Husky Energy, a Canadian company controlled by Hong Kong billionaire Li Ka-shing, operates the Husky Lloydminster Refinery in Lloydminster on the Alberta/Saskatchewan border, which can process 28,300 bbl/d (4,500 m^3/d) of feedstock from the adjacent Husky Upgrader into asphalt and other products.

In addition, a fifth major Alberta refinery is under construction by North West Upgrading at Redwater, Alberta, near Edmonton. This is the first new greenfield oil refinery to be constructed in all of North America in the last 30 years. The plant is designed to convert up to 150,000 bbl/d (24,000 m^3/d) of crude bitumen directly to diesel fuel. The NWU project is perhaps not technically a refinery because it will upgrade half of the bitumen directly to diesel rather than SCO, and sell the rest of the product stream to other nearby refineries to produce other products, but the distinction is somewhat academic since diesel is normally a refinery product and an upgrader is basically just the front-end of a heavy oil refinery.

The Alberta government has guaranteed NWU's loans and signed a firm contract for feedstock deliveries because of some economic issues. Alberta levies royalties on bitumen at "before payout" (2%) and "after payout" (25%) rates, and accepts payments "in kind" rather than "in cash", so it collects bitumen instead of money. With bitumen production expected to reach 5,000,000 bbl/d (790,000 m^3/d) by 2035, it means that after the projects pay out, the Alberta government will have 1,250,000 bbl/d (200,000 m^3/d) of bitumen to sell. Since Alberta has a chronic shortage of diesel fuel, the government would prefer to sell diesel fuel rather than bitumen to Alberta and international oil companies. Commercial partner Canadian Natural Resources Limited agrees.[69]

Rest of Canada

Canadian oil exports have increased tenfold since 1980, mostly as the result of new oil sands bitumen and heavy oil output, but at the same time Canadian oil consumption and refining capacity has hardly grown at all. Since the 1970s, the number of oil refineries in Canada has declined from 40 to 19. There hasn't been a new oil refinery (other than oil sands upgraders) built in Canada since 1984.

Most of the Canadian oil refining industry is foreign-owned, and except for Alberta, international companies preferred to build refining capacity elsewhere than in Canada. The result is a serious imbalance between Canadian oil production versus Canadian oil refining. Although Canada produces much more oil than it refines, and exports more oil and refined products than it consumes, most of the new production is heavier than traditional oil and concentrated in the landlocked provinces of Alberta and Saskatchewan. Canadian refineries have pipeline access to and can process only about 25% of the oil produced in Canada. The remainder of Canadian oil production is exported, almost all of it to the US. At the same time Canada imports 700,000 bbl/d (110,000 m^3/d) of crude oil from other countries and exports much of the oil products to other countries, most of it to the US.[70]

Canadian refineries, outside of the major oil producing provinces of Alberta and Saskatchewan, were originally built on the assumption that light and medium crude oil would continue to be cheap in the long term, and that imported oil would be cheaper than oil sands production. With new oil sands production coming on production at lower prices than international oil, market price imbalances have ruined the economics of refineries which could not process it. Most of the Canadian oil refineries which closed were in the oil deficient regions of Quebec, the Atlantic Provinces, and British Columbia where they had no access to cheaper domestic Canadian production. They also were not designed to refine the heavier grades which comprised most new Canadian production. These refinery closures were part of an international trend, since about a dozen refineries in Europe, the Caribbean and along the US east coast have shut down recent years due to sharp increases in the cost of imported oil and declining domestic demand for fuel.[70]

United States

Prior to 2013, when China surpassed it, the United States was the largest oil importer in the world.[71] Unlike Canada, the US has hundreds of oil refineries, many of which have been modified to process heavy oil as US production of light and medium oil declined. The main market for Canadian bitumen as well as Venezuelan extra-heavy oil was assumed to be the US. The United States has historically been Canada's largest customer for crude oil and products, particularly in recent years. American imports of oil and products from Canada grew from 450,000 barrels per day (72,000 m^3/d) in 1981 to 3,120,000 barrels per day (496,000 m^3/d) in 2013 as Canada's oil sands produced more and more oil, while in the US, domestic production and imports from other countries declined.[72] However, this relationship is becoming strained due to physical, economic and political influences. Export pipeline capacity is approaching its limits; Canadian oil is selling at a discount to world market prices; and US demand for crude oil and product imports has declined because of US economic problems.

For the benefit of oil marketers, in 2004 Western Canadian producers created a new benchmark crude oil called Western Canadian Select, (WCS), a bitumen-derived heavy crude oil blend that is similar in its transportation and refining characteristics to California, Mexico Maya, or Venezuela heavy crude oils. This heavy oil has an API gravity of 19-21 and despite containing large amounts of bitumen and synthetic crude oil, flows through pipelines well and is classified as “conventional heavy oil” by governments. There are several hundred thousand barrels per day of this blend being imported into the US, in addition to larger amounts of crude bitumen and synthetic crude oil (SCO) from the oil sands.

The demand from US refineries is increasingly for non-upgraded bitumen rather than SCO. The Canadian National Energy Board (NEB) expects SCO volumes to double to around 1,900,000 bbl/d (300,000 m^3/d) by 2035, but not keep pace with the total increase in bitumen production. It projects that the portion of oil sands production that is upgraded to SCO to decline from 49% in 2010 to 37% in 2035. This implies that over 3,200,000 bbl/d (510,000 m^3/d) of bitumen will have to be blended with diluent for delivery to market.

For administrative purposes the US government divides the US into five Petroleum Administration for Defense Districts (PADDs). These were created during World War II to help organize the allocation of fuels, including gasoline and diesel fuel. Today, these regions are still used for data collection purposes.

PADD 1 (East Coast)

PADD 1 covers the East Coast of the United States. Due to their location, refineries in the central US have enjoyed cheap domestic tight oil and discounted oil sands production from Canada. Meanwhile, refineries on the East Coast have been forced to buy oil from overseas at higher world prices due to North American pipeline bottlenecks. Five refineries on the US East Coast have been forced to close since 2010, and three more were threatened with closure before they sold at discounted prices. Pipelines are the cheapest and safest method of oil transportation in North America. However, due to the lack of pipelines, East Coast refineries must bring in domestic North Dakota Bakken oil and imported Western Canadian oil sands production by rail.[73] Imports account for the vast majority of PADD 1 refinery feedstock, but only a small portion of it comes from Canada, mostly Canadian Atlantic offshore production. Very little comes from the Canadian oil sands. Most of the refineries can handle only sweet, light crude oil, so even heavy, sour Western Canadian Select would not be a good feedstock. Imports of heavy oil from Western Canada could rise in the next few years via deliveries by rail, but it is unlikely that much oil sands production will be processed there.[74]

PADD 2 (Midwest)

PADD 2 covers the Midwestern United States. In recent years, many of the refiners in PADD 2 added coker units to handle heavier Canadian feedstockS to replace declining domestic oil production. Canadian oil was readily available since Canadian oil pipelines from Alberta to Ontario ran through the US Midwest, and it has almost completely backed out competing sources of imported oil due to its lower cost. US Midwest refiners have become by far the largest refiners of Canadian oil sands production. Unexpectedly, North Dakota production also increased because of hydraulic fracturing in the Bakken formation, making ND the second largest US producing state after Texas. Oil production from ND was delivered through the Canadian pipeline system, so the glut of new oil forced feedstock prices to US refineries on the Canadian pipelines down and made them much more profitable than refineries elsewhere in the US or Europe.[73][74]

PADD 3 (Gulf Coast)

PADD 3 (United States Gulf Coast) has half of the oil refining capacity in the US. The vast majority of the refineries are in Texas and Louisiana. Crude oil demand by Gulf Coast refineries was almost 8,000,000 barrels per day (1,300,000 m^3/d) in 2012, of which 2,200,000 barrels per day (350,000 m^3/d) was imported heavy oil.[74]

Most of the Gulf Coast refineries have the capacity to process very heavy crude oils from Venezuela and Mexico. However, exports from those countries has been declining in recent years, and more of Venezuela's exports are going to other countries, notably China. US domestic oil production has been increasing since 2010 due to horizontal drilling and hydraulic fracturing in tight oil fields, notably the Eagle Ford Formation of Texas. Some Gulf Coast refineries have completely replaced imported light and medium oil with new Texas tight oil. Unfortunately, most of it is too light for the Gulf refineries. Much new US tight oil is being exported to Canada for use as oil sands diluent and returning in blends which are a better feedstock for heavy oil refineries.

For Canadian oil sands producers this is a chance to back Venezuelan, Mexican, and Arabian heavy oil out of the Gulf Coast market and help achieve North American energy independence. The main problem has been pipeline capacity. As a result of delays in US government approval of the Keystone XL system and other pipelines, only 100,000 barrels per day (16,000 m^3/d) of Canadian crude reached the Gulf Coast in 2012. Since Canadian heavy oil and bitumen was much lower in price than heavy oil from other countries, oil companies started buying up and reversing idle pipelines which used to carry imported oil from the Gulf Coast to the Midwest to carry Canadian oil in the other direction. Canadian exports of oil by rail increased 900% from early 2012 to late 2013. This was more expensive and arguably more hazardous than moving oil by pipeline, but cost-effective for refineries given the lower cost of heavy oil imports from Canada versus other countries.

PADD 4 (Rocky Mountain)

PADD 4 covers the Rocky Mountain States of the US. Refineries in the region have been in a similar position to Midwest refineries, having access to cheap Canadian imports. Recent increases in North Dakota production has also flooded the market with domestic oil and reduced prices. Although their market volumes have been much less than in other regions, refineries in the Rocky Mountains have generally sold fuel at the lowest prices in the US due to their lower feedstock costs. If Canadian heavy oil continues to be priced at an attractive discount, refineries are expected to continue to take large volumes despite the light crude oil surplus in the region.[74]

PADD 5 (West Coast)

PADD 5 (West Coast of the United States) is a large potential market for increasing Canadian oil sands output as production of oil from its historic sources in Alaska and California has declined steeply in recent decades, and it has no pipeline access to new US production in North Dakota or Texas. Imports from countries outside North America have been increasing in volume although most of it is significantly more expensive than Canadian or domestic American oil. Many of the refineries in California and Washington State are capable of processing heavy oil because much of the oil production in California is heavy, as is much imported oil. They have also noted that a mix of 55% North Dakota Bakken oil and 45% Western Canadian Select is a reasonable substitute for badly diminished supplies of Alaska North Slope oil. PADD V is physically disconnected from the pipeline systems of the rest of the United States, but the Trans Mountain Pipeline delivers oil of all types from Alberta across British Columbia to refineries in Washington, which in 2012 processed 240,000 barrels per day (38,000 m^3/d) of imported oil, 60% of which came from Canada. If the Trans Mountain Expansion and Northern Gateway pipelines are completed, total capacity from Western Canada to the West Coast could exceed 1,400,000 barrels per day (220,000 m^3/d) by 2018.[74][75]

California has no pipeline connections that could deliver oil from other producing states or Canada, and in 2012 imported 780,000 barrels per day (124,000 m^3/d) of oil, only 5% of which came from Canada and two-thirds from Saudi Arabia. Canadian (and North Dakota) oil has been much cheaper than Arabian oil so potential exists for delivering oil sands production to California from the West Coasts of British Columbia and Washington by tanker. However, a big question mark hanging over the California refining market is the California Low Carbon Fuel Standard.

Asia

Demand for oil in Asia has been growing much faster than in North America or Europe. In 2013, China replaced the United States as the world's largest importer of crude oil, and its demand continues to grow much faster than its production. The main impediment to Canadian exports to Asia is pipeline capacity - The only pipeline capable of delivering oil sands production to Canada's Pacific Coast is the Trans Mountain Pipeline from Edmonton to Vancouver, which is now operating at its capacity of 300,000 barrels per day (48,000 m^3/d) supplying refineries in B.C. and Washington State. However, once complete, the Northern Gateway pipeline and the Trans Mountain expansion currently undergoing government review are expected to deliver an additional 500,000 barrels per day (79,000 m^3/d) to 1,100,000 barrels per day (170,000 m^3/d) to tankers on the Pacific coast, from where they could deliver it anywhere in the world. There is sufficient heavy oil refinery capacity in China and India to refine the additional Canadian volume, possibly with some modifications to the refineries.[75] In recent years, Chinese oil companies such as China Petrochemical Corporation (Sinopec), China National Offshore Oil Corporation (CNOOC), and PetroChina have bought over $30 billion in assets in Canadian oil sands projects, so they would probably like to export some of their newly acquired oil to China.[76]

Economics

The world's largest deposits of bitumen are in Canada, although Venezuela's deposits of extra-heavy crude oil are even bigger. Canada has vast energy resources of all types and its oil and natural gas resource base is large enough to meet Canadian needs for generations. Abundant hydroelectric resources account for the majority of Canada's electricity production and very little electricity is produced from oil. Since Canada will have more than enough energy to meet its growing needs, the excess oil production from its oil sands will probably go to export. The major importing country will probably continue to be the United States, although there is increasing demand for oil, particularly heavy oil, from growing in Asian countries such as China and India.[77]

Canada has abundant resources of bitumen and crude oil, with an estimated remaining ultimate potential of 54 billion cubic metres (340 billion barrels). Of this, oil sands bitumen accounts for 90 per cent. Alberta currently accounts for all of Canada’s bitumen resources. **Resources** become **reserves** only after it is proven that economic recovery can be achieved. At current prices using current technology, Canada has remaining oil reserves of 27 billion m^3 (170 billion bbls), with 98 per cent of this attributed to oil sands bitumen. This puts its reserves in third place in the world behind Venezuela and Saudi Arabia.

Costs

An oil price of $100/bbl is sufficient to promote active growth in oil sands production. Major Canadian oil companies have announced expansion plans and foreign companies are investing significant amounts of capital, in many cases forming partnerships with Canadian companies. Investment has been shifting towards in-situ steam assisted gravity drainage (SAGD) projects and away from mining and upgrading projects, as oil sands operators foresee better opportunities from selling bitumen and heavy oil directly to refineries than from upgrading it to synthetic crude oil. Cost estimates for Canada **include** the effects of the mining when the mines are returned to the environment in "as good as or better than original condition". Cleanup of the end products of consumption are the responsibility of the consuming jurisdictions, which are mostly in provinces or countries other than the producing one.

The Alberta government estimated that in 2012, the supply cost of oil sands new mining operations was $70 to $85 per barrel, whereas the cost of new SAGD projects was $50 to $80 per barrel.[57] These costs included capital and operating costs, royalties and taxes, plus a reasonable profit to the investors. The price was based on price in US dollars of benchmark West Texas Intermediate oil at Cushing, Oklahoma. Since the price of WTI rose to $100/bbl beginning in 2011,[78] it was highly profitable assuming it could be delivered to that point. The main market was the huge refinery complexes on the US Gulf Coast, which are generally capable of processing Canadian bitumen and Venezuelan extra-heavy oil without upgrading.

The Canadian Energy Research Institute (CERI) further refined the numbers and estimated that in 2012 the average plant gate costs (including 10% profit margin) of primary recovery was $30.32/bbl, of SAGD was $47.57/bbl, of mining and upgrading was $99.02/bbl, and of mining without upgrading was $68.30/bbl.[79] Thus, all types of oil sands projects except new mining projects with integrated upgraders were consistently profitable from 2011 onward. Since the larger and more sophisticated refineries preferred to buy raw bitumen and heavy oil rather than synthetic crude oil, new oil sands projects avoided the costs of building new upgraders. Although primary recovery such as is done in Venezuela is cheaper than SAGD, it only recovers about 10% of the oil in place versus 60% or more for SAGD and over 99% for mining. Canadian oil companies which are in a more competitive market and have access to more capital than in Venezuela preferred to spend the extra money on SAGD or mining and recover more oil.

Production forecasts

Oil sands production forecasts released by the Canadian Association of Petroleum Producers (CAPP), the Alberta Energy Regulator (AER), and the Canadian Energy Research Institute (CERI) are comparable to National Energy Board (NEB) projections, in terms of total bitumen production. The list of currently proposed projects, many of which are in the early planning stages, suggest that by 2035 Canadian bitumen production could potentially reach as much as 1.3 million m^3/d (8.3 million barrels per day) if most were to go ahead.

A more likely scenario is that by 2035, Canadian oil sands bitumen production will reach 800,000 m^3/d (5.0 million barrels/day), 2.6 times the production for 2012. The majority of the growth will likely occur in the in-situ category, as in-situ projects usually have better economics than mining projects. Also, 80% of Canada's oil sands reserves are well-suited to in-situ extraction, versus 20% for mining methods.

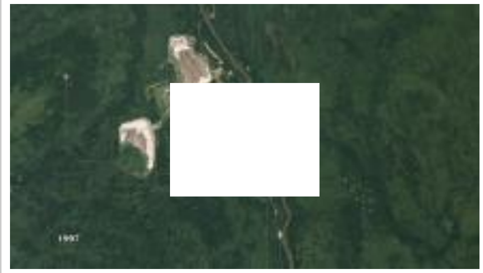
A key assumption is that there will be sufficient pipeline infrastructure to deliver increased Canadian oil production to export markets. If this is not the case, there may be impacts on Canadian crude oil prices, and there may be reductions in future production growth. Another assumption is that US markets will continue to absorb increased Canadian exports. Rapid growth of tight oil production in the US, Canada's primary oil export market, could reduce US reliance on imported crude. The potential for Canadian oil exports to alternative markets such as Asia is also uncertain. There are increasing political obstacles to building any new pipelines to deliver oil in Canada and the US. In the absence of new pipeline capacity, companies are increasingly shipping bitumen to US markets by railway, river barge, tanker, and other transportation methods. Other than ocean tankers, these alternatives are all more expensive than pipelines.

A shortage of skilled workers is developing in the Canadian oil sands as overall demand for labor increases. The oil and gas industry needs to fill tens of thousands of job openings in the next few years as a result of industry activity levels as well as age-related attrition. In the longer term, under a scenario of higher oil and gas prices, the labor shortages will continue to get worse. A potential labor shortage may increase construction costs and slow the pace of oil sands development.[77]

The skilled worker shortage is much more severe in Venezuela because the government controlled oil company PDVSA fired most of its heavy oil experts after the Venezuelan general strike of 2002–03, and wound down the production of Orimulsion, which was the primary product from its oil sands. Following that, the government re-nationalized the Venezuelan oil industry and increased taxes on it. The result was that foreign companies left Venezuela, as did most of its elite heavy oil technical experts. In recent years, Venezuela's heavy oil production has been falling, and it has consistently been failing to meet its production targets.

Environmental issues

In their 2011 commissioned report entitled "Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources," the National Petroleum Council, an advisory committee to the U.S. Secretary of Energy, acknowledged health and safety concerns regarding the oil sands which include "volumes of water needed to generate issues of water sourcing; removal of overburden for surface mining can fragment wildlife habitat and increase the risk of soil erosion or surface run-off events to nearby water systems; GHG and other air emissions from production."[80]



Satellite images show the growth of pit mines over Canada's oil sands between 1984 and 2011.

Oil sands extraction can affect the land when the bitumen is initially mined, water resources by its requirement for large quantities of water during separation of the oil and sand, and the air due to the release of carbon dioxide and other emissions.[81] Heavy metals such as vanadium, nickel, lead, cobalt, mercury, chromium, cadmium, arsenic, selenium, copper, manganese, iron and zinc are naturally present in oil sands and may be concentrated by the extraction process.[82] The environmental impact caused by oil sand extraction is frequently criticized by environmental groups such as Greenpeace, Climate Reality Project, Pembina Institute, 350.org, MoveOn.org, League of Conservation Voters, Patagonia, Sierra Club, and Energy Action Coalition.[83][84] In particular, mercury contamination has been found around tar sands production in Alberta, Canada.[85] The European Union has indicated that it may vote to label oil sands oil as "highly polluting". Although oil sands exports to Europe are minimal, the issue has caused friction between the EU and Canada.[86] According to the California-based Jacobs Consultancy, the European Union used inaccurate and incomplete data in assigning a high greenhouse gas rating to gasoline derived from Alberta's oilsands. Also, Iran, Saudi Arabia, Nigeria and Russia do not provide data on how much natural gas is released via flaring or venting in the oil extraction process. The Jacobs report pointed out that extra carbon emissions from oil-sand crude are 12 percent higher than from regular crude, although it was assigned a GHG rating 22% above the conventional benchmark by EU.[87][88]

In 2014 results of a study published in the Proceedings of the National Academy of Sciences showed that official reports on emissions were not high enough. Report authors noted that, "emissions of organic substances with potential toxicity to humans and the environment are a major concern surrounding the rapid industrial development in the Athabasca oil sands region (AOSR)." This study found that tailings ponds were an indirect pathway transporting uncontrolled releases of evaporative emissions of three representative polycyclic aromatic hydrocarbon (PAH)s (phenanthrene, pyrene, and benzo(a)pyrene) and that these emissions had been previously unreported.[89][90]

Air pollution management

Since 1995, monitoring in the oil sands region shows improved or no change in long term air quality for the five key air quality pollutants – carbon monoxide, nitrogen dioxide, ozone, fine particulate matter (PM2.5) and sulfur dioxide – used to calculate the Air Quality Index.[91] Air monitoring has shown significant increases in exceedances of hydrogen sulfide (H_2S) both in the Fort McMurray area and near the oil sands upgraders.[92]

In 2007, the Alberta government issued an environmental protection order to Suncor in response to numerous occasions when ground level concentration for hydrogen sulfide (formula H_2S) exceeded standards.[93]

Land use and waste management

A large part of oil sands mining operations involves clearing trees and brush from a site and removing the overburden— topsoil, muskeg, sand, clay and gravel – that sits atop the oil sands deposit.[94] Approximately two tons of oil sands are needed to produce one barrel of oil (roughly 1/8 of a ton). As a condition of licensing, projects are required to implement a reclamation plan.[95] The mining industry asserts that the boreal forest will eventually colonize the reclaimed lands, but their operations are massive and work on long-term timeframes. As of 2013, about 715 square kilometres (276 sq mi) of land in the oil sands region have been disturbed, and 72 km^2 (28 sq mi) of that land is under reclamation.[96] In March 2008, Alberta issued the first-ever oil sands land reclamation certificate to Syncrude for the 1.04 square kilometres (0.40 sq mi) parcel of land known as Gateway Hill approximately 35 kilometres (22 mi) north of Fort McMurray.[97] Several reclamation certificate applications for oil sands projects are expected within the next 10 years.[98]

Water management

Between 2 to 4.5 volume units of water are used to produce each volume unit of synthetic crude oil in an *ex-situ* mining operation. According to Greenpeace, the Canadian oil sands operations use 349×10^6 m^3/a (12.3×10^9 cu ft/a) of water, twice the amount of water used by the city of Calgary.[99] However, in SAGD operations, 90–95% of the water is recycled and only about 0.2 volume units of water is used per volume unit of bitumen produced.[100]

For the Athabasca oil sand operations water is supplied from the Athabasca River, the ninth longest river in Canada.[101] The average flow just downstream of Fort McMurray is 633 m^3/s (22,400 cu ft/s) with its highest daily average measuring 1,200 m^3/s (42,000 cu ft/s).[102][103] Oil sands industries water license allocations totals about 1.8% of the Athabasca river flow. Actual use in 2006 was about 0.4%.[104] In addition, according to the Water Management Framework for the Lower Athabasca River, during periods of low river flow water consumption from the Athabasca River is limited to 1.3% of annual average flow.[105]

In December 2010, the Oil Sands Advisory Panel, commissioned by former environment minister Jim Prentice, found that the system in place for monitoring water quality in the region, including work by the Regional Aquatic Monitoring Program, the Alberta Water Research Institute, the Cumulative Environmental Management Association and others, was piecemeal and should become more comprehensive and coordinated.[106][107]

Greenhouse gas emissions

The production of bitumen and synthetic crude oil emits more greenhouse gases than the production of conventional crude oil. A 2009 study by the consulting firm IHS CERA estimated that production from Canada's oil sands emits "about 5% to 15% more carbon dioxide, over the "well-to-wheels" (WTW) lifetime analysis of the fuel, than average crude oil."[108] Author and investigative journalist David Strahan that same year stated that IEA figures show that carbon dioxide emissions from the oil sands are 20% higher than average emissions from the petroleum production.[109]

A Stanford University study commissioned by the EU in 2011 found that oil sands crude was as much as 22% more carbon intensive than other fuels.[110][111]

Greenpeace says the oil sands industry has been identified as the largest contributor to greenhouse gas emissions growth in Canada, as it accounts for 40 million tons of CO_2 emissions per year.[112]

According to the Canadian Association of Petroleum Producers and Environment Canada the industrial activity undertaken to produce oil sands make up about 5% of Canada's greenhouse gas emissions, or 0.1% of global greenhouse gas emissions. It predicts the oil sands will grow to make up 8% of Canada's greenhouse gas emissions by 2015.[113] While the production industrial activity emissions per barrel of bitumen produced decreased 26% over the decade 1992–2002, total emissions from production activity were expected to increase due to higher production levels.[114][115] As of 2006, to produce one barrel of oil from the oil sands released almost 75 kilograms (165 lb) of greenhouse gases with total emissions estimated to be 67 megatonnes (66,000,000 long tons; 74,000,000 short tons) per year by 2015.[116] A study by IHS CERA found that fuels made from Canadian oil sands resulted in significantly lower greenhouse gas emissions than many commonly cited estimates.[117] A 2012 study by Swart and Weaver estimated that if only the economically viable reserve of 170 Gbbl (27×10^9 m^3) oil sands was burnt, the global mean temperature would increase by 0.02 to 0.05 °C. If the entire oil-in-place of 1.8 trillion barrels were to be burnt, the predicted global mean temperature increase is 0.24 to 0.50 °C.[118] Bergerson et al. found that while the WTW emissions can be higher than crude oil, *the lower emitting oil sands cases can outperform higher emitting conventional crude cases*.[119]

To offset greenhouse gas emissions from the oil sands and elsewhere in Alberta, sequestering carbon dioxide emissions inside depleted oil and gas reservoirs has been proposed. This technology is inherited from enhanced oil recovery methods.[120] In July 2008, the Alberta government announced a C$2 billion fund to support sequestration projects in Alberta power plants and oil sands extraction and upgrading facilities.[121][122][123]

Aquatic life deformities

There is conflicting research on the effects of the oil sands development on aquatic life. In 2007, Environment Canada completed a study that shows high deformity rates in fish embryos exposed to the oil sands. David W. Schindler, a limnologist from the University of Alberta, co-authored a study on Alberta's oil sands' contribution of aromatic polycyclic compounds, some of which are known carcinogens, to the Athabasca River and its tributaries.[124] Scientists, local doctors, and residents supported a letter sent to the Prime Minister in September 2010 calling for an independent study of Lake Athabasca (which is downstream of the oil sands) to be initiated due to the rise of deformities and tumors found in fish caught there.[125]

The bulk of the research that defends the oil sands development is done by the Regional Aquatics Monitoring Program (RAMP). RAMP studies show that deformity rates are normal compared to historical data and the deformity rates in rivers upstream of the oil sands.[126][127]

Public health impacts

In 2007, it was suggested that wildlife has been negatively affected by the oil sands; for instance, moose were found in a 2006 study to have as high as 453 times the acceptable levels of arsenic in their systems, though later studies lowered this to 17 to 33 times the acceptable level (although below international thresholds for consumption).[128]

Concerns have been raised concerning the negative impacts that the oil sands have on public health, including higher than normal rates of cancer among residents of Fort Chipewyan.[129] However, John O'Connor, the doctor who initially reported the higher cancer rates and linked them to the oil sands development, was subsequently investigated by the Alberta College of Physicians and Surgeons. The College later reported that O'Connor's statements consisted of "mistruths, inaccuracies and unconfirmed information."[130]

In 2010, the Royal Society of Canada released a report stating that "there is currently no credible evidence of environmental contaminant exposures from oil sands reaching Fort Chipewyan at levels expected to cause elevated human cancer rates."[130]

In August 2011, the Alberta government initiated a provincial health study to examine whether a link exists between the higher rates of cancer and the oil sands emissions.[131]

In a report released in 2014, Alberta’s Chief Medical Officer of Health, Dr. James Talbot, stated that "There isn’t strong evidence for an association between any of these cancers and environmental exposure [to tar sands]." Rather, Talbot suggested that the cancer rates at Fort Chipewyan, which were slightly higher compared with the provincial average, were likely due to a combination of factors such as high rates of smoking, obesity, diabetes, and alcoholism as well as poor levels of vaccination."[130]

See also

- Athabasca oil sands
- Cold Lake oil sands
- Peace River oil sands
- Melville Island oil sands
- Oil shale
- Oil megaprojects
- Petroleum industry
- Project Oilsand

- Wabasca oil sands
- Orinoco oil sands
- Beaver river sandstone
- Bituminous rocks
- History of the petroleum industry in Canada (oil sands and heavy oil)
- Pyrobitumen
- RAVEN (Respecting Aboriginal Values & Environmental Needs)
- Steam injection (oil industry)
- Shale gas
- World energy resources and consumption
- Thermal depolymerization
- Utah Oil Sands

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Further reading

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External links

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- Edward Burtynsky, An aerial look at the Alberta Tar Sands (http://www.theglobeandmail.com/v5/content/features/oilsands/index.html)
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- Jiri Rezac, Alberta Oilsands (http://www.jirirezac.com/stories/oilsands/) photo story and aerials
- *Exploring the Alberta tar sands*, Citizenshift, National Film Board of Canada (http://citizen.nfb.ca/tar-sands/)
- Indigenous Groups Lead Struggle Against Canada's Tar Sands (http://www.democracynow.org/2010/6/25/tar_sands) – video report by *Democracy Now!*
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