Kirk-Othmer Encyclopedia of Chemical Technology.

TAR SANDS

In addition to conventional petroleum (qv) and heavy crude oil, there remains another subclass of petroleum, one that offers to provide some relief to potential shortfalls in the future supply of liquid fuels and other products. This subclass is the bitumen found in tar sand deposits (1, 2). Tar sands, also known as oil sands and bituminous sands, are sand deposits impregnated with dense, viscous petroleum. Tar sands are found throughout the world, often in the same geographical areas as conventional petroleum.

Petroleum, and the equivalent term crude oil, cover a vast assortment of materials consisting of gaseous, liquid, and solid hydrocarbon-type chemical compounds that occur in sedimentary deposits throughout the world (3). When petroleum occurs in a reservoir that allows the crude material to be recovered by pumping operations as a free-flowing dark- to light-colored liquid, it is often referred to as conventional petroleum.

Heavy oil is another type of petroleum, different from conventional petroleum insofar as the flow properties are reduced. A heavy oil is much more difficult to recover from the subsurface reservoir. These materials have a high viscosity and low API gravity relative to the viscosity and API gravity of conventional petroleum (Fig. 1) (3, 4), and recovery of heavy oil usually requires thermal stimulation of the reservoir.

The definition of heavy oil is usually based on API gravity or viscosity, but the definition is quite arbitrary. Although there have been attempts to rationalize the definition based on viscosity, API gravity, and density (2, 3), such definitions, based on physical properties, are inadequate, and a more precise definition would involve some reference to the recovery method.

In a general sense, however, the term heavy oil is often applied to a petroleum that has a gravity $<20^\circ\text{API}$. The term heavy oil has also been arbitrarily used to describe both the heavy oil that requires thermal stimulation for recovery from the reservoir and the bitumen in bituminous sand (also known as tar sand or oil sand) formations, from which the heavy bituminous material is recovered by a mining operation. Extra heavy oil is the subcategory of petroleum that occurs in the near-solid state and is incapable of free flow under ambient conditions. The bitumen from tar sand deposits is often classified as an extra heavy oil.

Tar sand, also variously called oil sand (in Canada) or bituminous sand, is the term commonly used to describe a sandstone reservoir that is impregnated with a heavy, viscous black extra heavy crude oil, referred to as bitumen (or, incorrectly, as native asphalt). Tar sand is a mixture of sand, water, and bitumen, but many of the tar sand deposits in the United States lack the water layer that is believed to cover the Athabasca sand in Alberta, Canada, thereby facilitating the hot-water recovery process from the latter deposit. The heavy asphaltic organic material has a high viscosity under reservoir conditions and cannot be retrieved through a well by conventional production techniques.

It is incorrect to refer to bitumen as tar or pitch. Although the word tar is somewhat descriptive of the black bituminous material, it is best to avoid its use in referring to natural materials. More correctly, the name tar is usually applied to the heavy product remaining af.ter the destructive distillation of coal (qv) or other organic matter. Pitch is the distillation residue of the various types of tar (see Tar and pitch).

Physical methods of fractionation of tar sand bitumen usually indicate high proportions of nonvolatile asphaltenes and resins, even in amounts up to 50% wt/wt (or higher) of the bitumen. In addition, the presence of

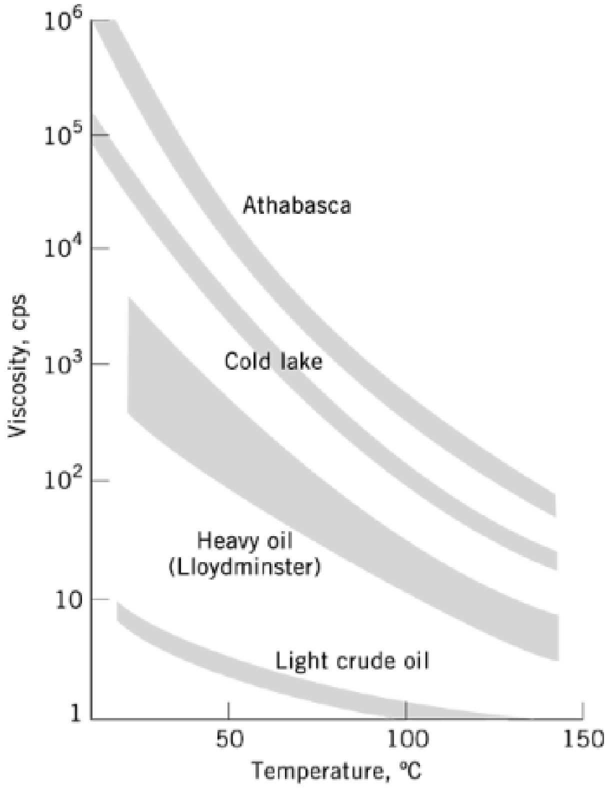

Fig. 1. Relative viscosity data for conventional petroleum, heavy oil, and bitumen.

ash-forming metallic constituents, including such organometallic compounds as those of vanadium and nickel, is also a distinguishing feature of bitumen.

Asphalt (qv) is prepared from petroleum and often resembles bitumen. When asphalt is produced simply by distillation of an asphaltic crude, the product can be referred to as residual asphalt or straight-run petroleum asphalt. If the asphalt is prepared by solvent extraction of residua or by light hydrocarbon (propane) precipitation, or if blown or otherwise treated, the term should be modified accordingly to qualify the product, eg, propane asphalt.

1. Origin of Bitumen

There are several general theories regarding the origin of the bitumen. One theory is that the oil was formed locally and has neither migrated a great distance nor been subjected to large overburden pressures. Because under these conditions the oil cannot have been subjected to any thermal effects with the resulting decomposition or molecular changes, it is geologically young and therefore dense and viscous.

Another theory promotes the concept of a remote origin for the bitumen, or, more likely, the bitumen precursor, both geographically and in geological time. The bitumen precursor, originally resembling a conventional crude oil, is assumed to have migrated into the sand deposit, which may originally have been filled with water. After the oil migrated, the overburden pressures were relieved, and the light portions of the crude evaporated, leaving behind a dense, viscous residue.

Table 1. Bitumen vs Conventional Petroleum Properties

Property		Bitumen	Conventional
gravity, °API		8.6	25–37
distillation	Vol %	IBP[a], °C	
	5	221	
	10	293	
	30	437	
	50	543	
viscosity, suspension			
at 38°C		35,000	<30
at 99°C		513	
pour point, °C		10	≤0
elemental analysis, wt %			
carbon		83.1	86
hydrogen		10.6	13.5
sulfur		4.8	0.1–2.0
nitrogen		0.4	0.2
oxygen		1.1	
hydrocarbon type, wt %			
asphaltenes		19	≤5
resins		32	
oils		49	
metals, ppm			
vanadium		250	≤100
nickel		100	
iron		75	
copper		5	
ash, wt %		0.75	0
Conradson carbon, wt %		13.5	1–2
net heating value, kJ/g[b]		40.68	ca 45.33

[a] IBP = initial boiling point.

[b] To convert kJ/g to btu/lb, multiply by 430.2.

Included in the remote origin theory is the postulate that the light hydrocarbons were destroyed by bacteria carried into the petroleum reservoirs in oxygenated, meteoric waters. The remote origin theory would explain the water layer surrounding sand grains in the Athabasca deposit. However, because the metals and porphyrin contents of bitumen are similar to those of some conventional Alberta crude oils of Lower Cretaceous age and because Athabasca bitumen has a relatively low coking temperature, the bitumen may be of Lower Cretaceous age. This is the age of the McMurray formation (Canada), which is geologically young. This evidence supports the theory that the oil was formed *in situ* and is a precursor, rather than a residue of some other oil. The issue remains unresolved as of this writing (ca 1997).

2. Occurrence

Many of the reserves of bitumen in tar sand formations are available only with some difficulty, and optional refinery methods are necessary for future conversion of these materials to liquid products, because of the substantial differences in character between conventional petroleum (qv) and bitumen (Table 1).

Because of the diversity of available information and the continuing attempts to delineate the various world oil sands deposits, it is virtually impossible to reflect the extent of the reserves in terms of barrel units with

Fig. 2. Principal tar sand deposits of the world, where ● represents $>2,385,000\mathrm{m}^3(>15\times10^6\mathrm{bbl})$ bitumen; ▲, probably $<159,000\mathrm{m}^3(<1\times10^6\mathrm{bbl})$ bitumen; and ▼, reported occurrence information limited.

Table 2. Tar Sand Deposits and Mode of Entrapment[a]

Number	Deposit	Location
1.	stratigraphic trap: structure of little importance; short-distance migration assumed	Sunnyside, P.R. Springs, Santa Cruz
2.	structural/stratigraphic trap: folding/faulting and unconformity equally important	Oficina–Temblador tar, Bemolanga, Asphalt Ridge, Melville Island, Guanoco, Kentucky deposits
3.	structural trap: structure important; long-distance migration assumed; unconformity may be absent	Whiterocks, La Brea
4.	intermediate between 1 and 2	Athabasca, Edna, Sisquoc, Santa Rosa
5.	intermediate between 2 and 3	Selenizza, Derna

[a] See Fig. 3.

a great degree of accuracy. The potential reserves of hydrocarbon liquids that occur in tar sand deposits have, however, variously been estimated on a world basis to be in excess of $477\times10^9\ \mathrm{m}^3\ (3\times10^{12}\ \mathrm{bbl})$. Reserves that have been estimated for the United States are believed to be in excess of $795\times10^4\ \mathrm{m}^3\ (50\times10^6\ \mathrm{bbl})$, although estimates vary. Bitumen reserves throughout the world can compare favorably with reserves of conventional crude oil.

Tar sand deposits are widely distributed throughout the world (Fig. 2) (5, 6) and the various deposits have been described as belonging to two types: stratigraphic traps and structural traps (Table 2; Fig. 3) (7). However, there are the inevitable gradations and combinations of these two types of deposits, and thus a broad pattern of deposit entrapment is believed to exist. In general terms, the entrapment character of the very large tar sand deposits involves a combination of both stratigraphic and structural traps.

Fig. 3. Types of traps for tar sand deposits, where ○ represents a stratigraphic trap, ×, an intermediate between stratigraphic and structural/stratigraphic traps; ■, a structural/stratigraphic trap; •, an intermediate between structural/stratigraphic and structural traps; and △, a structural trap.

The largest tar sand deposits are in Alberta, Canada, and in Venezuela. Smaller tar sand deposits occur in the United States (mainly in Utah), Peru, Trinidad, Madagascar, the former Soviet Union, Balkan states, and the Philippines. Tar sand deposits in northwestern China (Xinjiang Autonomous Region) also are large; at some locations, the bitumen appears on the land surface around Karamay, China. The largest deposits are in the Athabasca area in the province of Alberta, Canada, and in the Orinoco region of east central Venezuela.

The Athabasca deposit, along with the neighboring Wabasca, Peace River, and Cold Lake heavy oil deposits, have together been estimated to contain 1.86×10^{11} m^3 ($>1.17 \times 10^{12}$ bbl) of bitumen. The Venezuelan deposits may at least contain $>1.60 \times 10^{11}$ m^3 (1.0×10^{12} bbl) bitumen (2). Deposits of tar sand, each containing $>3 \times 10^6$ m^3 (20×10^6 bbl) of bitumen, have also been located in the United States, Albania, Italy, Madagascar, Peru, Romania, Trinidad, Zaire, and the former Soviet Union, comprising a total of ca 450×10^9 m^3 (2.8×10^{12} bbl).

The Alberta (Athabasca) tar sand deposits are located in the northeast part of that Canadian province (Fig. 4). These are the only mineable tar sand deposits undergoing large-scale commercial exploitation as of this writing (ca 1997).

The Athabasca deposits have been known since the early 1800s. The first scientific interest in tar sands was taken by the Canadian government in 1890, and in 1897–1898, the sands were first drilled at Pelican Rapids on the Athabasca River. Up until 1960, many small-scale commercial enterprises were attempted but not sustained. Between 1957 and 1967, three extensive pilot-plant operations were conducted in the Athabasca region, each leading to a proposal for a commercial venture, eg, Suncor and Syncrude.

The Venezuelan tar sands are located in a 50–100-km belt extending east to west for >700 km, immediately north of the Orinoco River. The precise limits of the deposit are not well defined because exploration efforts in the past concentrated on light and medium crude accumulations.

The geological setting of the Orinoco deposit is complex, having evolved through three cycles of sedimentation. The oil is contained by both structural and stratigraphic traps, depending on location, age of sediment, and

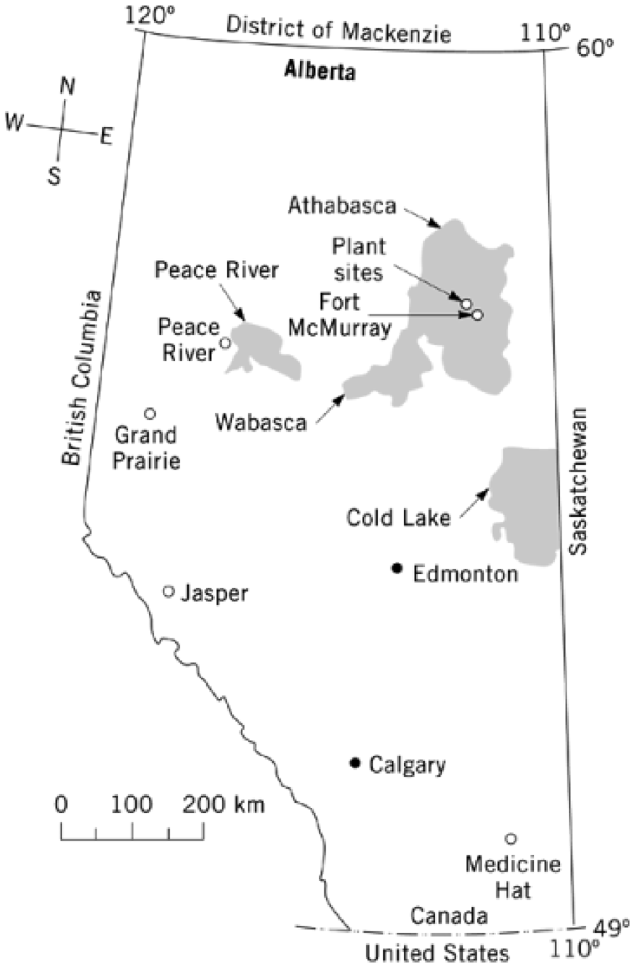

Fig. 4. Tar sand and heavy oil deposits in Alberta, Canada.

degree of faulting. The tar sands are located along the southern flanks of the eastern Venezuelan basin, where three distinct zones are apparent from north to south: a zone of tertiary sedimentation, a central platform with transgressive overlapping sediments, and a zone of erosional remnants covered by sediments. The deposit also contains three systems of faulting. All the faults are normal and many are concurrent with deposition.

Tar sands in the United States are contained in a variety of separate deposits in various states (Fig. 5) but because many of these deposits are small, information on most is limited (8). Attempts at development of the deposits have occurred primarily in Utah.

3. Properties

Tar sand has been defined as sand saturated with a highly viscous crude hydrocarbon material not recoverable in its natural state through a well by ordinary production methods (2–8). Technically the material should perhaps be called bituminous sand rather than tar sand because the hydrocarbon is bitumen, ie, a carbon disulfide-soluble oil.

The data available are generally for the Athabasca materials, although workers at the University of Utah (Salt Lake City) have carried out an intensive program to determine the processibility of Utah bitumen and considerable data have become available. Bulk properties of samples from several locations (Table 3) (9) show that there is a wide range of properties. Substantial differences exist between the tar sands in Canada and those in the United States; a difference often cited is that the former is water-wet and the latter, oil-wet (10).

Canada	United States
sand is water-wet, thus disengagement of bitumen is efficient using hot-water process (caustic = sodium hydroxide; bitumen recovery $>98\%$)	sand is oil-wet, thus efficient dis-engagement of bitumen requires high shear rates (caustic = sodium carbonate; bitumen recovery $\sim95\%$)
formations usually unconsolidated	formations usually consolidated to semiconsolidated by mineral cementation
few deposits have been identified (Alberta contains ca 0.4 m^3 bitumen)	numerous deposits identified (33 major deposits = 12 m^3 bitumen; 20 minor deposits = 12 m^3 bitu-men); total resource = 6.5 m^3 bitumen (2.6 m^3 measured and 3.8 m^3 billion speculative)
problems exist in settling and removal of clay from tar sand deposits and process streams	little is known about the nature and effect on processing of clays
bitumen properties fairly uniform (sulfur = 4.5 – 5.5 wt%, nitrogen = 0.1–0.5 wt %; H/C ratio ~1.5; API gravity from 6 to 12°)	bitumen properties diverse (sulfur = 0.5 – 10 wt%, nitrogen 0.1–1.3 wt %; H/C ratio = 1.3– 1.6; API gravity from – 2 to 14°)
bitumen deposits large with uniform quality; recovery and upgrading plants on-stream since 1970s	bitumen deposits small and not of uniform quality; recovery and upgrading methods need to be site-specific

The sand component is predominantly quartz in the form of rounded or angular particles (11), each of which is wet with a film of water. Surrounding the wetted sand grains and somewhat filling the void among them is a film of bitumen. The balance of the void volume in the Canadian sands is filled with connate water plus, sometimes, a small volume of gas. Usually the gas is air but methane has been reported from some test borings in the Athabasca deposit. Some commercial gas deposits were developed in the late 1980s. The sand grains are packed to a void volume of ca 35%, corresponding to a mixture of ca 83 wt % sand; the remainder is bitumen and water which constitute ca 17 wt % of the tar sands.

3.1. Bitumen

There are wide variations both in the bitumen saturation of tar sand (0–18 wt % bitumen), even within a particular deposit, and the viscosity. Of particular note is the variation of density of Athabasca bitumen with temperature, and the maximum density difference between bitumen and water (70–80°C (160–175°F)); hence the choice of the operating temperature of the hot-water bitumen-extraction process.

Table 3. Bulk Properties of Tar Sands

Property	Alberta	Asphalt Ridge[a]	P.R. Springs[a]	Sunnyside[a]	Tar Sand Triangle[a]	Texas	Alabama
bulk density, g/cm^3	1.75–2.19		1.83–2.50				
porosity, vol %	27–56	16–27	6–33	16–28	9–32	32	6–25
permeability, m^2 × 10^{-16}[b]	99–5,900	4,905–5,950	553–14,902	5,265–7,402	2,043–7,777	3158	9.9–6,316
specific heat, J/(g·°C)[c]	1.46–2.09						
thermal conductivity, J/(s·°C·cm)[c]	0.0071–0.0015						

[a] Deposit in Utah.
[b] To convert m^2 to millidarcies, multiply by 1.013×10^{12}.
[c] To convert J to cal, divide by 4.184.

Fig. 5. Tar sand deposits in the United States.

The API gravity of tar sand bitumen varies from 5 to ca 10°API, depending on the deposit, and the viscosity is very high. Whereas conventional crude oils may have a high $(> 100\text{MPa·s}(= \text{cP}))$ viscosity at 40°C, tar sand bitumen has a viscosity on the order of $10 - 100\text{kPa·s}(10^5 - 10^6\text{P})$ at formation temperature (ca 0–10°C), depending on the season. This offers a formidable obstacle to bitumen recovery and, as a result of the high viscosity, bitumen is relatively nonvolatile under conditions of standard distillation (Table 4) (12, 13), which influences choice of the upgrading process.

Table 4. Distillation Data for Various Bitumens

Cut point, °C	Athabasca, wt % distilled[a]	NW Asphalt Ridge, wt % distilled[a]	P.R. Springs, wt % distilled[a]	Tar Sand Triangle, wt % distilled[a]
200	3.0	2.3	0.7	1.7
225	4.6	3.3	1.4	2.9
250	6.5	4.4	2.4	4.4
275	8.9	5.8	3.8	5.9
300	14.0	7.5	4.9	8.4
325	25.9	8.8	6.8	12.4
350	18.1	11.7	8.0	15.2
375	22.4	13.8	10.1	18.6
400	26.2	16.8	12.5	22.4
425	29.1	19.5	16.0	26.9
450	33.1	23.7	20.0	28.9
475	37.0	28.4	22.5	32.3
500	40.0	34.0	25.0	35.1
525	42.9	40.0	27.3	38.5
538	44.6	44.2	28.0	40.0
538+	55.4	55.8	72.0	60.9

[a] Cumulative.

3.2. Minerals

Usually $>99\%$ of the tar sand mineral is composed of quartz sand and clays (qv). In the remaining 1%, more than 30 minerals have been identified, mostly calciferous or iron-based (14). Particle sizes range from large grains (99.9% finer than 1000 μm) to 44 μm (325 mesh), the smallest size that can be determined by dry screening. The size between 44 and 2 μm is referred to as silt; sizes $<2\mu$m (equivalent spherical diameter) are clay.

Clays (qv) are aluminosilicate minerals, some of which have definite chemical compositions. In regard to tar sands, however, clay is only a size classification and is usually determined by a sedimentation method. According to the previous definition of fines, the fines fraction equals the sum of the silt and clay fractions. The clay fraction over a wide range of fines contents is a relatively constant 30% of the fines.

The Canadian deposits are largely unconsolidated sands having a porosity ranging up to 45% and good intrinsic permeability. However, the deposits in Utah range from predominantly low porosity, low permeability consolidated sand to, in some instances, unconsolidated sands. In addition, the bitumen properties are not conducive to fluid flow under normal reservoir conditions in either Canadian or U.S. deposits. Nevertheless, where the general nature of the deposits prohibits the application of a mining technique, as in many of the U.S. deposits, a nonmining technique may be the only feasible bitumen recovery option (6).

4. Recovery

Oil prices and operating costs are the key to economic development of tar sand deposits. However, two technical conditions of vital concern for economic development are the concentration of the resource (percent bitumen saturation) and its accessibility, usually measured by the overburden thickness.

The remoteness of the U.S. tar sands is often cited as a deterrent to development but topography of the site, overburden-to-ore body ratio, and richness of the ore body are also important. In the 1990s context of mining tar sand deposits in the United States, the Utah deposits (Tar Sand Triangle, P.R. Springs, Sunnyside, and Hill Creek) generally have an overburden-to-net pay zone ratio above the 0.4–1.0 range, with a lean oil

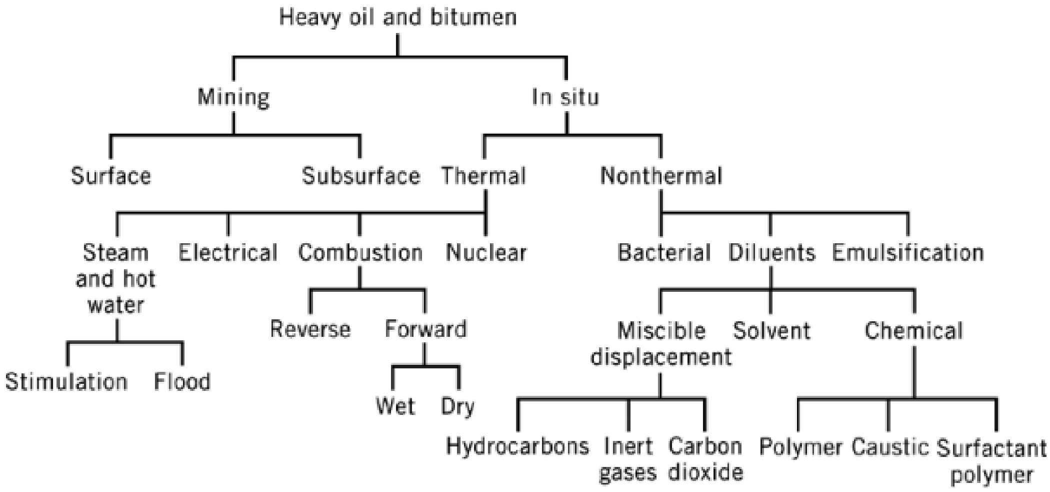

Fig. 6. Recovery processes.

content. On the other hand, the Asphalt Ridge deposit is loosely consolidated and could be mined using a ripper/front-end loader (without drilling and blasting) at the near-surface location of the deposit.

Recovery methods are based either on mining combined with some further processing or operation on the oil sands *in situ* (Fig. 6). The mining methods are applicable to shallow deposits, characterized by an overburden ratio (ie, overburden depth-to-thickness of tar sand deposit) of ca 1.0. Because Athabasca tar sands have a maximum thickness of ca 90 m and average ca 45 m, there are indications that no more than 10% of the in-place deposit is mineable within 1990s concepts of the economics and technology of open-pit mining.

The bitumen in the Athabasca deposit, which has a gravity on the API scale of 8°, is heavier than water and very viscous. Tar sand is a dense, solid material, but it can be readily dug in the summer months; during the winter months when the temperatures plunge to $-45^\circ\mathrm{C}$, tar sand assumes the consistency of concrete. To maintain acceptable digging rates in winter, mining must proceed faster than the rate of frost penetration; if not, supplemental measures such as blasting are required.

4.1. Nonmining Methods

Nonmining (*in situ*) processes depend on injecting a heating-and-driver substance into the ground through injection wells and recovering bitumen through production wells. Such processes need a relatively thick layer of overburden to contain the driver substance within the formation between injection and production wells (2).

In principle, the nonmining recovery of bitumen from tar sand deposits is an enhanced oil recovery technique and requires the injection of a fluid into the formation through an injection well. This leads to the *in situ* displacement of the bitumen from the reservoir and bitumen production at the surface through an egress (production) well. There are, however, several serious constraints that are particularly important and relate to the bulk properties of the tar sand and the bitumen. In fact, both recovery by fluid injection and the serious constraints on it must be considered *in toto* in the context of bitumen recovery by nonmining techniques (see Petroleum, enhanced oil recovery).

Another general constraint to bitumen recovery by nonmining methods is the relatively low injectivity of tar sand formations. It is usually necessary to inject displacement/recovery fluids at a pressure such that fracturing (parting) is achieved. Such a technique, therefore, changes the reservoir profile and introduces a series of channels through which fluids can flow from the injection well to the production well. On the other hand, the technique may be disadvantageous insofar as the fracture occurs along the path of least resistance, giving undesirable or inefficient flow characteristics within the reservoir between the injection and production wells, which leave a part of the reservoir relatively untouched by the displacement or recovery fluids.

In steam stimulation, heat and drive energy are supplied in the form of steam injected through wells into the tar sand formation. In most instances, the injection pressure must exceed the formation fracture pressure in order to force the steam into the tar sands and into contact with the oil. When sufficient heating has been achieved, the injection wells are closed for a soak period of variable length and then allowed to produce, first applying the pressure created by the injection and then using pumps as the wells cool and production declines.

Steam can also be injected into one or more wells, with production coming from other wells (steam drive). This technique is effective in heavy oil formations but has found little success during application to tar sand deposits because of the difficulty in connecting injection and production wells. However, once the flow path has been heated, the steam pressure is cycled, alternately moving steam up into the oil zone, then allowing oil to drain down into the heated flow channel to be swept to the production wells.

If the viscous bitumen in a tar sand formation can be made mobile by an admixture of either a hydrocarbon diluent or an emulsifying fluid, a relatively low temperature secondary recovery process is possible (emulsion steam drive). If the formation is impermeable, communication problems exist between injection and production wells. However, it is possible to apply a solution or dilution process along a narrow fracture plane between injection and production wells.

To date (ca 1997), steam methods have been applied almost exclusively in relatively thick reservoirs containing viscous crude oils. In the case of heavy oil fields and tar sand deposits, the cyclic steam injection technique has been employed with some success. The technique involves the injection of steam at greater than fracturing pressure, usually in the 10.3–11.0 MPa (1500–1600 psi) range, followed by a soak period, after which production is commenced (15).

Variations include the use of steam and the means of reducing interfacial tension by the use of various solvents. The solvent extraction approach has had some success when applied to bitumen recovery from mined tar sand but when applied to unmined material, losses of solvent and bitumen are always an obstacle. This approach should not be rejected out of hand because a novel concept may arise that guarantees minimal acceptable losses of bitumen and solvent.

Combustion has also been effective for recovery of viscous oils in moderately thick reservoirs where reservoir dip and continuity promote effective gravity drainage, or where several other operational factors permit close well spacing. During *in situ* combustion or fire flooding, energy is generated in the formation by igniting bitumen in the formation and sustaining it in a state of combustion or partial combustion. The high temperatures generated decrease the viscosity of the oil and make it more mobile. Some cracking of the bitumen also occurs, and the fluid recovered from the production wells is an upgraded product rather than bitumen itself.

The recovery processes using combustion of the bitumen are termed forward combustion or reverse combustion, depending on whether the combustion front moves with or counter to the direction of air flow. In either case, burning occurs at the interface where air contacts hot, unburned oil or, more likely, coke. Thus, if the flame front is ignited near the injection well, it propagates toward the production well (forward combustion). However, if the front is ignited near the production well, it moves in the opposite direction (reverse combustion). In forward combustion, the hydrocarbon products released from the zone of combustion move into a relatively cold portion of the formation. Thus, there is a definite upper limit of the viscosity of the liquids that can be recovered by a forward combustion process. On the other hand, because the air passes through the hot formation before reaching the combustion zone, burning is complete; the formation is left completely cleaned of hydrocarbons. In reverse combustion, some hydrocarbons are left in the formation. The theoretical advantage of reverse combustion is that the combustion products move into a heated portion of the formation and therefore are not subject to a strict viscosity limitation. However, most attempts to implement reverse combustion in field pilot installations have been unsuccessful. In many cases, the failure resulted from the onset of secondary combustion at the production well.

Using combustion to stimulate bitumen production is attractive for deep reservoirs and in contrast to steam injection usually involves no loss of heat. The duration of the combustion may be short (days) depending on requirements. In addition, backflow of oil through the hot zone must be prevented or excessive coking occurs (15, 16). Another variation of the combustion process involves use of a heat-up phase, then a blow-down (production) phase, followed by a displacement phase using a fire–water flood (COFCAW process).

4.2. Mining Methods

The alternative to *in situ* processing is to mine the tar sands, transport them to a processing plant, extract the bitumen value, and dispose of the waste sand (17, 18). Such a procedure is often referred to as oil mining. This is the term applied to the surface or subsurface excavation of petroleum-bearing formations for subsequent removal of the oil by washing, flotation, or retorting treatments. Oil mining also includes recovery of oil by drainage from reservoir beds to mine shafts or other openings driven into the oil rock, or by drainage from the reservoir rock into mine openings driven outside the oil sand but connected with it by bore holes or mine wells.

On a commercial basis, tar sand is recovered by mining, after which it is transported to a processing plant, where the bitumen is extracted and the sand discharged. For tar sands of 10% wt/wt bitumen saturation, 12.5 metric tons of tar sand must be processed to recover 1 m^3 (6.3 bbl) of bitumen. If the sand contains only 5% wt/wt bitumen, twice the amount of ore must be processed to recover this amount. Thus, it is clear that below a certain bitumen concentration, tar sands cannot be processed economically (19).

The Athabasca tar sands deposit in Canada is the site of the only commercial tar sands mining operations. The Suncor operation (near Fort McMurray, Alberta), started production in 1967. The Syncrude Canada project, located 8 km away, started production in 1978. In both projects, about half of the terrain is covered with muskeg, an organic soil resembling peat moss, which ranges from a few centimeters to 7 m in depth. The primary part of the overburden, however, consists of Pleistocene glacial drift and Clearwater Formation sand and shale. The total overburden varies from 7 to 40 m in thickness, and the underlying tar sand strata averages about 45 m, although typically 5–10 m must be discarded because of a bitumen content below the economic cut-off grade of ca 6% wt/wt.

Mining of the Athabasca tar sands presents two principal issues: in-place tar sand requires very large cutting forces and is extremely abrasive to cutting edges, and both the equipment and pit layouts must be designed to operate during the long Canadian winters at temperatures as low as $-40^{\circ}\mathrm{C}$.

There are two approaches to open-pit mining of tar sands. The first uses a few mining units of custom design, which are necessarily expensive, eg, bucket-wheel excavators and large drag lines in conjunction with belt conveyors. In the second approach, a multiplicity of smaller mining units of conventional design is employed at relatively much lower unit costs. Scrapers and truck-and-shovel operations have been considered. Each method has advantages and risks. The first approach was originally adopted by Suncor and Syncrude Canada, Ltd., with Suncor converting to large-scale truck and shovel technology in 1993.

In the Suncor pit design, the ore body is divided into two layers (benches), each nominally 23 m high. The pit floor and the dividing plane between the upper and lower bench are roughly horizontal, and 7300-t/h bucket-wheel excavators are employed as the primary mining equipment (Fig. 7). Tar sands loosened from the face of each bench by the bucket-wheels are discharged onto a series of conveyors. The overburden is stripped by an electric shovel that discharges to trucks for removal of the overburden material. Syncrude utilizes a single-bench design with four 60-m^3 capacity draglines as the primary mining equipment (Fig. 8). The draglines pile tar sands in windrows along the edge of the pit; four 60,000-t/h bucket-wheels transfer the tar sands to a system of trunk conveyor belts that move the material to the extraction plant. The mining operations at the two plants differ by choice of the primary mining equipment; the bucket-wheel excavators sit on benches, whereas the draglines sit on the surface.

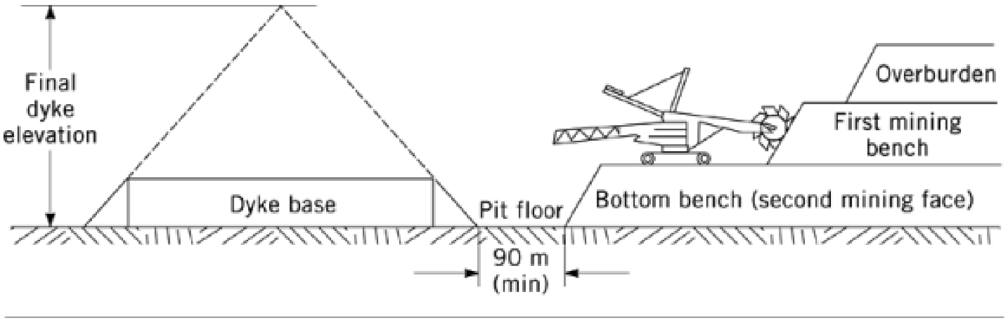

Fig. 7. Mining with a bucket-wheel excavator, where (_) represents the ultimate size of the dyke.

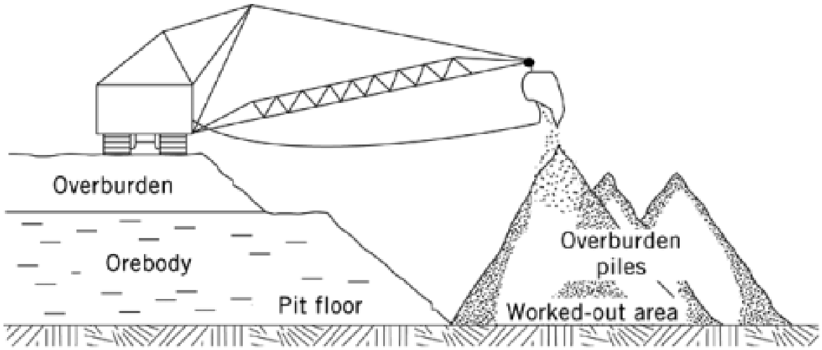

Fig. 8. Mining with dragline.

Bucket-wheel excavators use units having a 10 m dia digging wheel on the end of a long boom. Each wheel has a theoretical capacity of 8700 t/h, but the average output from digging is about 4500 t/h. At the rate of 122,000 t/d, tar sand can be transferred from mine to plant by a system of 152-cm wide conveyor belts and 183-cm trunk conveyors, operating at 333 m/min. The bucket-wheel excavators are supplemented by front-end loaders used to dig overburden and load it through twin chutes onto ca 135 t capacity trucks. Additional equipment is used for maintaining the haul roads and for spreading and compacting the spoiled material. Overburden may be stripped with 14-m^3 hydraulically operated shovels and a fleet of ca 135 t trucks.

Draglines are equipped with a 71-m^3 bucket at the end of a 111-m boom and can be employed to dig both a portion of the overburden, which is free-cast into the mining pit, and the tar sand, which is piled in windrows behind the machine. Bucket-wheel reclaimers, similar to bucket-wheel excavators, load the tar sand from the windrows onto conveyor belts which transfer it to the plant.

5. Processing

5.1. Hot-Water Process

The hot-water process is the only successful commercial process to be applied to bitumen recovery from mined tar sands in North America as of 1997 (2). The process utilizes linear and nonlinear variations of bitumen density and water density, respectively, with temperature so that the bitumen that is heavier than water at room temperature becomes lighter than water at 80°C. Surface-active materials in tar sand also contribute to

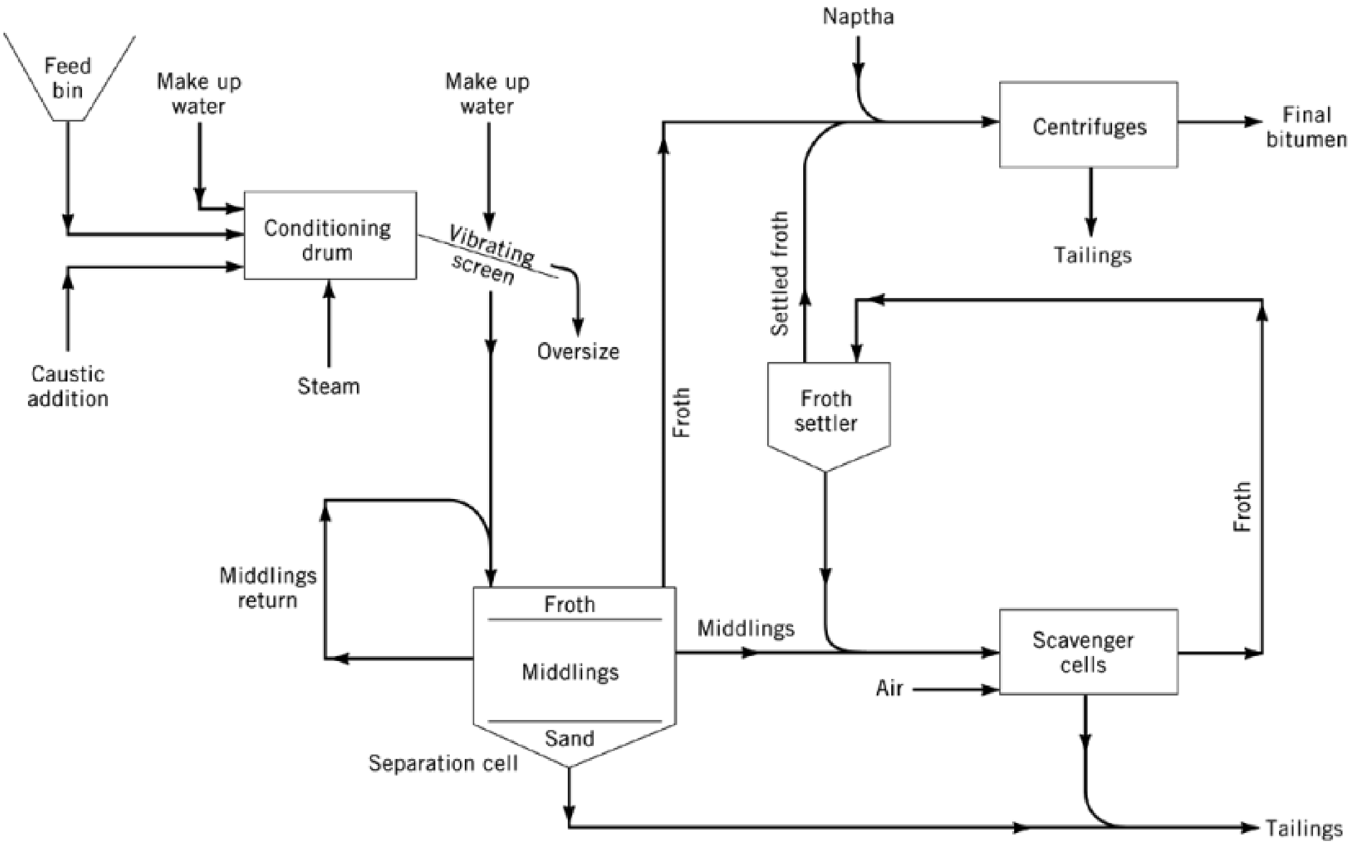

Fig. 9. Hot-water recovery process.

the process (2). The essentials of the hot-water process involve conditioning, separation, and scavenging (Fig. 9).

In the conditioning step (mixing or pulping), tar sand feed is heated and mixed with water to form a pulp of 60–85% solids at 80–90°C. First the lumps of tar sand as mined are reduced in size by ablation, ie, successive layers of lump are warmed and slough off, revealing cooler layers. The pulp is mechanically mixed, reacts with any chemicals added, is further heated to the process temperature, and is conditioned by open-steam heating in a horizontal rotating drum. With regard to equipment scale-up, conditioning is essentially a heat-transfer process. The effluent from the conditioning drum is screened to remove tramp material or lumps that were not sufficiently reduced in size. The screened pulp is mixed with any added water, adjusted to the proper consistency for pumping as described below, and sent to the separation cell.

The separation cell is an open vessel with straight sides and a cone bottom. Mechanical rakes on the bottom move the sand toward the center for discharge. Wiper arms rotating on the surface push the froth to the outside of the separation cell, where it overflows into launders for collection. The cell acts like two settlers, one on top of the other. In the lower settler sand settles down; in the upper settler, bitumen floats. The bulk of the sand in the feed is removed from the bottom of the separation cell as tailings. A large portion of the feed bitumen floats to the surface of the separation cell and is removed as froth. A middlings stream consists mostly of water, with some suspended fine minerals and bitumen particles. A portion of the middlings may be returned for mixing with the conditioning drum effluent in order to dilute the separation cell feed for pumping.

The remainder of the middlings is called the drag stream, which is withdrawn from the separation cell to be rejected after processing in the scavenger cells.

Tar sand feed contains a certain portion of fine minerals that, if allowed to build up in concentration in the middlings, increases viscosity and eventually disrupts settling in the separation cell. The drag stream is required as a purge in order to control the fines concentration in the middlings. The amounts of water that can enter with the feed and leave with the separation cell tailings and froth are relatively fixed. Thus, the size of the drag stream determines the makeup water requirement for the separation cell.

The third step in the hot-water process is scavenging. Depending on the drag-stream size and composition, enough bitumen may leave the process in the drag stream to make another recovery step economical. Froth flotation with air is usually employed, and the scavenger froth is combined with the separation cell froth to be further treated and upgraded to synthetic crude oil. Tailings from the scavenger cell join the separation cell tailings stream and go to waste. Conventional froth-flotation cells are suitable for this step.

Froth from the hot-water process may be mixed with a hydrocarbon diluent, eg, coker naphtha, and centrifuged. The Suncor process employs a two-stage centrifuging operation, and each stage consists of multiple centrifuges of conventional design installed in parallel. The bitumen product contains 1–2 wt % mineral (dry bitumen basis) and 5–15 wt % water (wet diluted basis). Syncrude also utilizes a centrifuge system with naphtha diluent.

An attempt has been made to develop the hot-water process for the Utah sands (Fig. 10) (20). With oil-wet Utah sands, this process differs significantly from that used for the water-wet Canadian sands, necessitating disengagement by hot-water digestion in a high shear force field under appropriate conditions of pulp density and alkalinity. The dispersed bitumen droplets can also be recovered by aeration and froth flotation (21).

The hot-water separation process involves extremely complicated surface chemistry with interfaces among various combinations of solids (including both silica sand and aluminosilicate clays), water, bitumen, and air. The control of pH is critical. The preferred range is 8.0–8.5, achievable by use of any of the monovalent bases. Polyvalent cations must be excluded because they tend to flocculate clays and thus raise viscosity of the middlings in the separation cell.

One problem resulting from the hot-water process is disposal and control of the tailings. Each ton of oil sand in place has a volume of ca 0.45 m^3, which generates ca 0.6 m^3 of tailings and gives a substantial volume gain. If the mine produces 200,000 t/d of oil sand, volume expansion represents a considerable solids disposal problem.

Environmental regulations in Canada and the United States do not allow the discharge of tailings streams into the river, onto the surface, or onto any area where contamination of groundwater domains or the river may occur. The tailings stream is essentially high in clays and contains some bitumen; hence the need for tailings ponds, where some settling of the clay occurs (Fig. 11). In addition, an approach to acceptable reclamation of the tailings ponds must be accommodated at the time of site abandonment. Problems may be alleviated somewhat by the development of process options that require considerably less water in the sand–bitumen separation step. Such an option would allow a more gradual removal of the tailings ponds.

5.2. Cold-Water Process

The cold-water bitumen separation process has been developed to the point of small-scale continuous pilot plants. The process uses a combination of cold water and solvent. The first step usually involves disintegration of the tar sand charge, which is mixed with water, diluent, and reagents. The diluent may be a petroleum distillate fraction such as kerosene and is added in a ca 1:1 weight ratio to the bitumen in the feed. The pH is maintained at 9–9.5 by addition of wetting agents and ca 0.77 kg of soda ash per ton of tar sand. The effluent is mixed with more water, and in a raked classifier the sand is settled from the bulk of the remaining mixture. The water and oil overflow the classifier and are passed to thickeners, where the oil is concentrated. Clay in the tar sand feed forms emulsions that are hard to break and are wasted with the underflow from the thickeners.

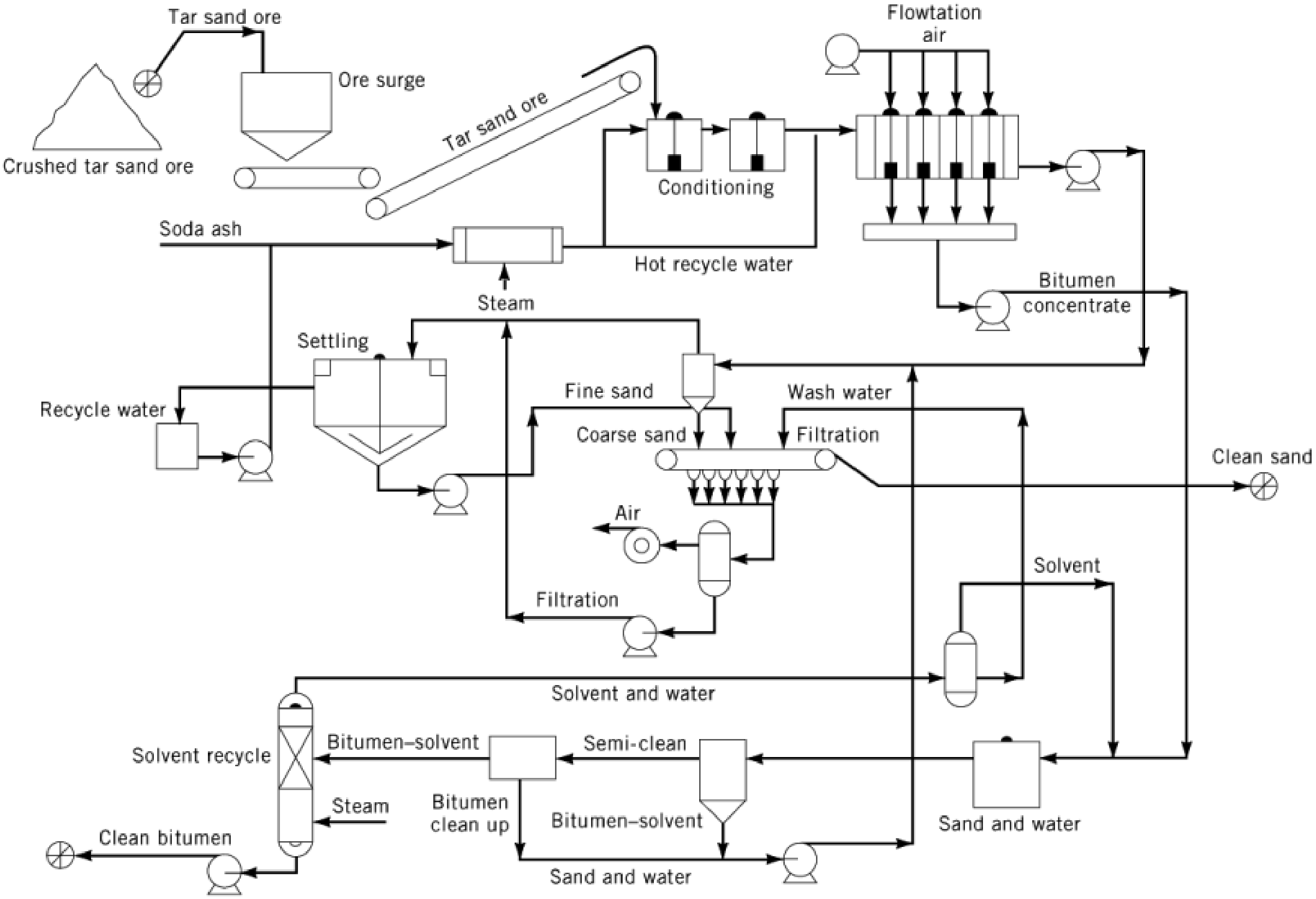

Fig. 10. Hot-water recovery for Utah bitumen.

The sand reduction process is a cold-water process without solvent. The objective is removal of sand to provide a feed suitable for a fluid coking process. In the first step, the tar sand feed is mixed with water at ca 20°C in a screw conveyor at a ratio of 0.75–3 t/t tar sand (lower range preferred). The mixed pulp from the screw conveyor is discharged into a rotary-drum screen, which is submerged in a water-filled settling vessel. The bitumen forms agglomerates that are retained by an 840-μm (20-mesh) screen. These agglomerates settle and are withdrawn as oil product. The sand readily passes through the 840-μm (20-mesh) screen and is withdrawn as waste stream. Nominal composition of the oil product is 58 wt % oil (bitumen), 27 wt % mineral, and 15 wt % water.

A process called spherical agglomeration closely resembles the sand-reduction process. Water is added to tar sands and the mixture is ball-milled. The bitumen forms dense agglomerates of 75–87 wt % bitumen, 12–25 wt % sand, and 1–5 wt % water.

5.3. Solvent Extraction

An anhydrous solvent extraction process for bitumen recovery has been attempted and usually involves the use of a low boiling hydrocarbon. The process generally involves up to four steps. In the mixer step, fresh

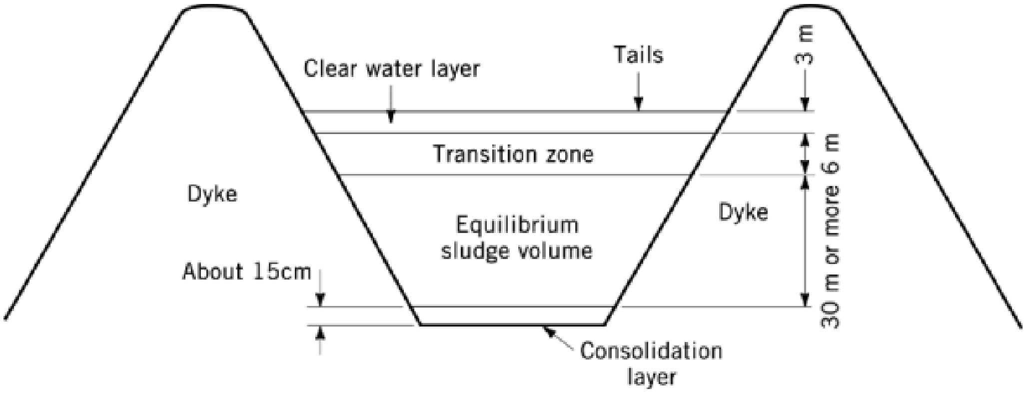

Fig. 11. Aqueous zones in tailings pond.

tar sand is mixed with recycle solvent that contains some bitumen and small amounts of water and mineral. Solvent-to-bitumen weight ratio is adjusted to ca 0.5. The drain step consists of a three-stage countercurrent wash. Settling and draining time is ca 30 min for each stage. After each extraction step, a bed of sand is formed and the extract drained through the bed until the interstitial pore volume of the bed is emptied. The last two steps of the process are devoted to solvent recovery from the solids. Although solvent extraction processes have been attempted and demonstrated for the Athabasca, Utah, and Kentucky tar sands, solvent losses influence economics of such processes and they have not yet been reduced to commercial practice.

6. Bitumen Conversion

Bitumen is a hydrogen-deficient oil that is upgraded by carbon removal (coking) or hydrogen addition (hydrocracking) (2, 4). There are two methods by which bitumen conversion can be achieved: by direct heating of mined tar sand and by thermal decomposition of separated bitumen. The latter is the method used commercially, but the former has potential for commercialization (see Fuels, synthetic).

6.1. Direct Heating of Mined Tar Sand

An early process (Fig. 12) involved a coker for bitumen conversion and a burner to remove carbon from the sand (22). A later proposal suggested that the Lurgi process might have applicability to bitumen conversion (23). A more modern approach has also been developed which also cracks the bitumen constituents on the sand (24). The processor consists of a large horizontal rotating vessel which is arranged in a series of compartments, a preheating zone, and a reaction zone.

Direct coking of tar sand using a fluid-bed technique has also been tested. In this process, tar sand is fed to a coker or still, where the tar sand is heated to ca 480°C by contact with a fluid bed of clean sand from which the coke has been removed by burning. Volatile portions of the bitumen are distilled, whereas nonvolatile material is thermally cracked, resulting in the production of more liquid products and the deposition of a layer of coke around each sand grain. Coked solids are withdrawn down a standpipe, fluidized with air, and transferred to a burner or regenerator, operating at ca 800°C where most of the coke is burned off the sand grains. The clean, hot sand is withdrawn through a standpipe. Part (20–40%) is rejected and the remainder is recirculated to the coker to provide the heat for the coking reaction. The products leave the coker as a vapor, which is condensed

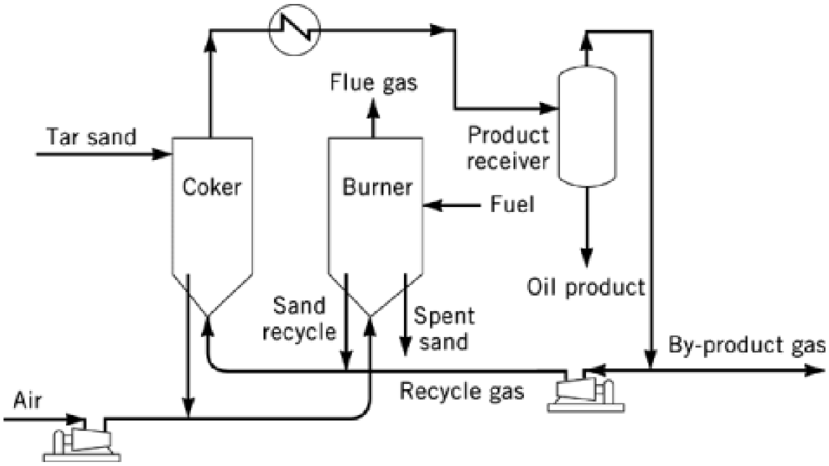

Fig. 12. Direct heating of tar sand for oil recovery.

in a receiver. Reaction off-gases from the receiver are recirculated to fluidize the clean, hot sand, which is returned to the coker.

6.2. Conversion of Separated Bitumen

The overall upgrading process by which bitumen is converted to liquid products is accomplished in two steps (Fig. 13). The first step is the primary upgrading process, which improves the hydrogen-to-carbon (H/C) ratio by either carbon removal or hydrogen addition, cracking the bitumen to lighter products which are more easily processed downstream. The secondary upgrading process involves hydrogenation of the primary products and is the means by which sulfur and nitrogen are removed from the primary products. The upgraded or synthetic crude can then be refined to consumer goods such as gasoline, jet fuel, and home heating oil by conventional means.

Conversion of petroleum feedstocks is accomplished using two basic process concepts: carbon rejection, of which the coking processes are examples, and hydrogen addition, of which the hydroprocesses are examples (3). The conversion of a feedstock such as tar sand bitumen has added another dimension to upgrading insofar as the feedstock is one of the most complex accepted by any refinery. Thus, coking has become the process of choice for bitumen conversion and bitumen is converted commercially by delayed coking (Suncor) and by fluid coking (Syncrude). In each case the charge is converted to distillate oils, coke, and light gases. The coke fraction and product gases can be used for plant fuel. The coker distillate is a partially upgraded material in itself and is a suitable feed for hydrodesulfurization to produce a low sulfur synthetic crude oil. In each case, bitumen conversion to liquids is on the order of $75\%+$. Fluid coking gives a generally higher $(+1 - 5\%)$ yield of liquids compared to delayed coking. The remainder appears as coke (ca 15% wt/wt) and gases.

Sulfur is distributed throughout the boiling range of the delayed coker distillate, as for distillates from direct coking. Nitrogen is more heavily concentrated in the higher boiling fractions but is present in most of the distillate fractions. Raw coker naphtha contains significant quantities of olefins and diolefins which must be saturated by downstream hydrotreating. The gas oil has a high aromatic content typical of coker gas oils.

Finishing and stabilization (hydrodesulfurization and saturation) of the liquid products are achieved by hydrotreating the liquid streams as two or three separate streams, because of the variation in conditions and catalysts necessary for treatment of a naphtha fraction relative to conditions necessary for treatment of a gas oil (13). It is more efficient to treat the liquid product streams separately and then to blend the finished liquids

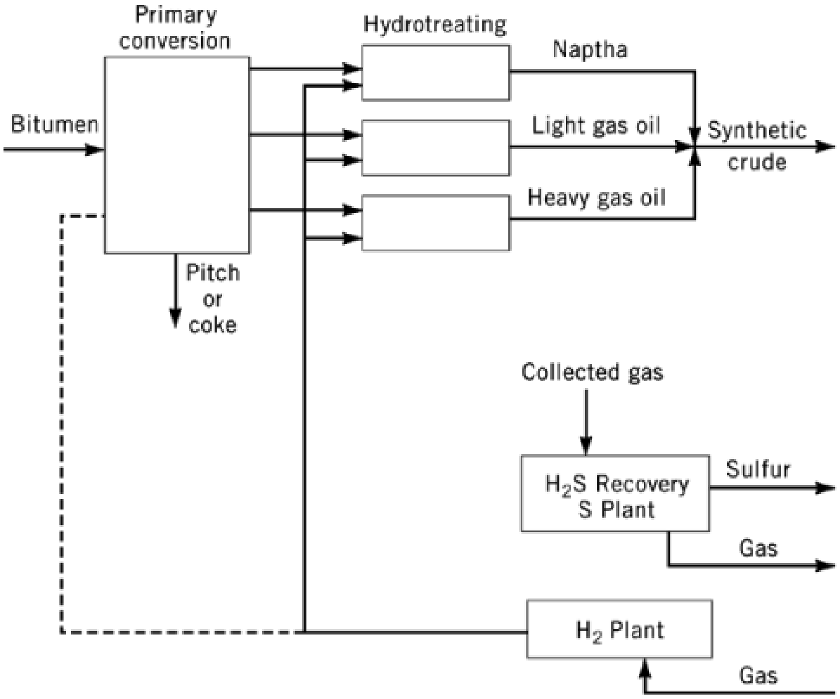

Fig. 13. Conversion of separated bitumen.

to a synthetic crude oil. In order to take advantage of optimum operating conditions for various distillate fractions, the Suncor coker distillate is treated as three separate fractions: naphtha, kerosene, and gas oil. In the operation used by Syncrude, the bitumen products are separated into two distinct fractions: naphtha and mixed gas oils. Each plant combines the hydrotreated fractions to form synthetic crude oil (Table 5), which is then shipped by pipeline to a refinery (see Pipelines). Other processes which have received attention for bitumen upgrading include partial upgrading (a form of thermal deasphalting), flexicoking, the Eureka process, and various hydrocracking processes.

Table 5. Properties of Synthetic Crude Oil

Property	Value
gravity, °API	32
sulfur, wt %	0.15
nitrogen, wt %	0.06–0.10
viscosity, at 37°C, mm^2/s (=cSt)	<10
components, vol/vol %	
C_4	4
C_5/220°C	24
430/346°C	32
650/550°C	40
550°C+	0

Partial coking or thermal deasphalting processes provide minimal upgrading of bitumen. In partial coking, the hot-water process froth is distilled at atmospheric pressure, and minerals and water are removed. In flexicoking a gasifier vessel is added to the system in order to gasify excess coke with a gas–air mixture to a low heating value gas, which can be desulfurized and used as a plant fuel. The Eureka process is a variant of delayed coking and uses steam stripping to enhance yield and produce a heavy pitch rather than coke by-product. Hydrocracking has also been proposed as a means of bitumen upgrading. The overall liquid yield of direct hydrogenation or hydrocracking of bitumen is substantially higher than that of coking, and significant amounts of sulfur and nitrogen are removed. Large quantities of external fuel or hydrogen plant feedstock are required, however. To prevent coking, the processes operate at high pressure, with direct contact between bitumen feed and circulating hydrogen. Hydrocracking processes include the H-Oil process, the LC-Fining process, the Vebe process, and the Chiyoda process.

The hydrocracker products have higher hydrogen and lower sulfur and nitrogen contents than those from the coking route and require less secondary upgrading. However, disadvantages of the hydrogen route include relatively high hydrogen consumption and high pressure operation. Processes that use conventional, eg, Co–Mo or Ni–Mo, catalysts are susceptible to metals poisoning, which may limit applicability to, or economics of, operation on feeds high in metals such as bitumen.

7. Health and Safety Factors

Health and safety factors associated with tar sand processing depend on the nature of the process and products (Table 6; Fig. 14). Issues arising from tar sand mining (Table 7) (25) are similar to other large-scale surface mining operations involving large equipment and the movement of huge quantities of material. The principal environmental consideration relating to the mining process is land reclamation following the completion of the mining and, in particular, those areas affected by the deposition of tailings. Both air and liquid effluents are subject to controls.

Table 6. Emissions from Tar Sand Plant

Source	Potential contaminant
process wastewater	suspended solids, dissolved solids, phenols, ammonia, oils, organics, sulfides, metals
sanitary wastewater	suspended solids, dissolved solids, biochemical oxygen demand, organics, nitrates, phosphate, residual chlorine, coliform organisms, metals
runoff from upgrader area: coke storage pile, sulfur storage pile, solid waste landfills	suspended solids, oils, organics, inorganics, sulfur, metals
power plant stacks	particulates, SO_2, NO_x, CO
sulfur plant stacks	sulfides, SO_2, H_2S, particulates
upgrader heaters	SO_2, NO_x, CO_2, hydrocarbons, particulates

Health and safety factors in *in situ* operations are associated with high temperature, high pressure steam, or high pressure air. Environmental considerations relate to air and water quality and surface reclamation.

Table 7. Environmental Impact of Surface Mining Operations

Operation or source of impact	Surface changes						Changes in ground water regime	
	Increased landslide risk	Destruction of existing vegetation	Alteration of habitats	Topographic changes	Drainage diversion	Increased noise	Physical	Chemical
site preparation		+	+	+	+	+		
surface cleaning (cleared area)		+	+	+	+	+		
stripping (stripped area)		+	+	+			+	+
tar sand extracting (mined area)				+		+	+	+
haul road transportation (construction)		+	+	+	+	+ +		
tailings disposal						+		
bitumen in tailings or low grade tar sand waste		+						+
fines in tailings								
stripped waste								
solubles or water transportation			+				+	+
particles in overburden								
new surface								+
increases in surface slope from waste disposal	+							
rehandling of materials: back-filling, grading, and recontouring						+		

In some environmentally sensitive areas such as the oil sands deposits in Utah, environmental considerations may make development unfeasible.

Table 8. Projects for Bitumen and Heavy Oil Recovery / Conversion

Project	Investment, $ × 10^6	Timing	Description[a]	Production, m^3/d (bbl/d)[b]
Amoco				
Primrose	500	immediate	SAGD heavy oil production	6,000 (50,0000) heavy oil
Alberta Energy Co., Ltd.				
Cold Lake	13	immediate	SAGD heavy oil pilot plant	120 (1,000) heavy oil
Foster Creek	200	1997–1998	commercial heavy oil	3,600 (30,000) heavy oil
Elan Energy, Ltd.				
Lindbergh	60	immediate	SAGD heavy oil plant	
Elk Point				increased 1,680–2,640 (14,000–22,000)
Gibson Petroleum, Ltd.,	7	1996–1997	SAGD bitumen project	
Utf				increased 240–540 (2,000–4,500)
Gulf Canada Resources, Ltd.				

Table 8. ***Continued***

Project	Investment, $ \$ \times 10^6 $	Timing	Description[a]	Production, m^3/d (bbl/d)[b]
Surmont	30	1996 1998–1999	phase 1 SAGD heavy oil phase 2	360 (3,000) increased 2,400 (20,000)
Imperial Oil Limited				
Cold Lake	250	immediate	phases 9–10 *in situ* bitumen production	increased 14,400; 3,000 (120,000; ~25,000+)
Cold Lake (proposed)	250	1997	phases 11–12 *in situ* bitumen production following completion of phases 9–10	add 2,400 (~20,000)
Imperial				
Cold Lake	40	immediate	heavy oil development below current Cold Lake lease	1,128 (9,400) heavy oil
Koch Oil Co., Ltd.				
Cold Lake		1997–1998	*in situ* bitumen project	6,000 (50,000)
Reita Lake				
Shell Canada Ltd.				
Peace River	3	immediate	SAGD heavy oil project	increased
Solvex				
Bitumount	170	1997	bitumen mine/extraction complex, minerals extraction plant	168 (14,000) bitumen, 100,000 t alumina, 200,000 t synthetic silica (tailings)
Suncor Inc.				
Primrose	17	1996–1997	phase 1, SAGD pilot plant	300 (2,500) heavy oil
Burnt Lake	122	1998–1999	phase 2, commercial plant	increased 1,500 (12,500) heavy oil
Suncor Inc., Osg				
Steepbank Mine	300	2001	new bitumen mine	increased production 10,800 (90,000+) light sweet crude, custom blends
Fort McMurray	300	1998–2001	upgrader improvements, plant modifications	increased 9,600 (80,000) light sweet crude, custom blends
Fort McMurray	190	immediate	environmental measures	reduced SO_2 emissions
Syncrude Canada, Ltd.				
North Mine Mildred Lake	500	1998	new bitumen mine, debottlenecking plant	increased 13×10^6 m^3
Syncrude Canada, Ltd.				
Aurora Mine	500	2001	new bitumen, remote plant, debottleneck	first train, 2001; increased 11.3 (94×10^6 bbl/yr)
Total	*3,452* $ \$ \times 10^9 $			

[a] SAGD = steam – assisted gravity draining.
[b] To convert m^3/d to bbl/d, multiply by 6.29.

8. Future Outlook

The government of the Canadian Province of Alberta has announced a standard royalty formula for the oil sands industry and embraced the principles and, to a large degree, put into practice the recommendations of the National Task Force on Oil Sands Strategies. The Canadian government plans to extend the mining tax

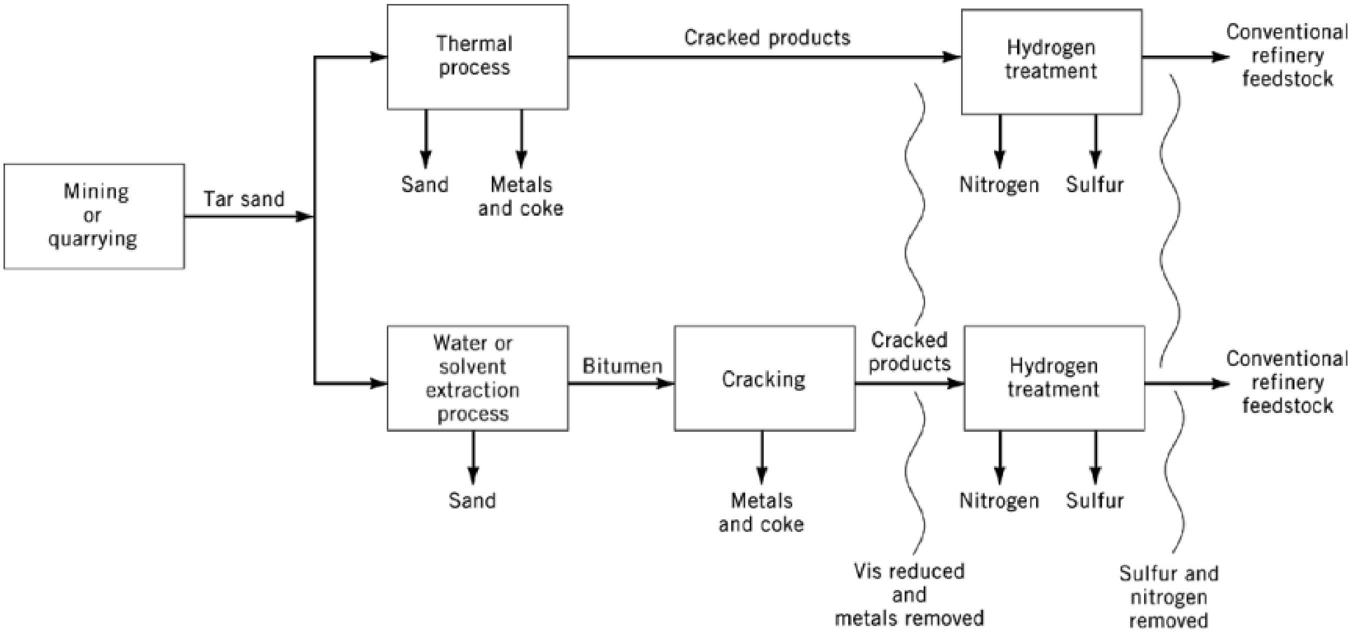

Fig. 14. Products from tar sand processing.

regulation to include *in situ* operations. Over $3,400,000,000 (Canadian $) in new projects and expansions have been set aside to allow the industry to move forward with projects in the initial stages of development (Table 8) which should encourage further development of Canadian tar sand resources.

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