Geology of the Athabasca Oil Sands

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Alberta's oil sands deposits differ from conventional oil fields in two significant ways. First, the oil sands are orders of magnitude larger than conventional oil pools. The Athabasca Deposit, for instance, is now estimated to contain 869 billion barrels of bitumen in place (*1*). By comparison, the Prudhoe Bay field, which is one of the ten largest conventional oil pools in the world, contains approximately 15 billion barrels. The total in-place reserves of Alberta's four major Cretaceous oil sands deposits (Fig. 1) are now estimated at 1350 billion barrels (Table 1), almost twice the recoverable conventional reserves in the entire world.

Second, the physical characteristics of oil sands bitumen differ greatly from those of conventional crude oil. Oil sands bitumen is much heavier [API (American Petroleum Institute) gravity about 8° to 10°, compared to 25° to 40° for most conventional crudes] and much more viscous (100,000 to 1,000,000 centipoise). Under reservoir conditions the bitumen is essentially immobile. It has the consistency of a tar and can be induced to flow only when reservoir conditions are suitably altered, as by heating. At an outcrop, the oil bleeds from the exposed faces only on the hottest summer days, when the heat from the sun is sufficient to lower the viscosity of the bitumen to the point where it can ooze from the outermost veneer of the outcrop (Fig. 2).

Aside from these two considerations, the oil sands deposits can be said to exhibit all the fundamental geological attributes of conventional oil reservoirs. The oil is contained within the pore spaces between the framework sand grains. The degree of oil saturation is a direct function of the porosity and permeability of the host sediments. The distribution of rich and lean zones is controlled by the configuration of the porous sand bodies relative to the interbedded shaly strata. Considerations of source rocks, cap rocks, oil migration history, trapping mechanisms, and oil maturation and differentiation are all subject to the same types of geological analyses that would apply in a conventional oil pool.

Summary. In-place bitumen resources in the Alberta oil sands are estimated at 1350 billion barrels. Open-pit mining and hot water extraction methods, which involve the handling of huge tonnages of earth materials, are being employed in the two commercial plants now operating. In situ recovery methods will be required to tap the 90 percent of reserves that are too deeply buried to be surface mined. Development of in situ technologies will be painstaking and expensive, and success will hinge on their compatibility with extremely complex geological conditions in the subsurface.

More than 90 percent of the Cretaceous oil sands reserves in Alberta are too deeply buried to be considered potentially recoverable by established surface mining techniques. Thus, there is a pressing need to develop technologies capable of recovering bitumen in situ. These technologies involve drilling into the subsurface reservoir and supplying enough energy to mobilize the bitumen so that it can be pumped to the surface. To say that there are tremendous engineering difficulties involved in in situ recovery is an understatement of the problem.

The technological difficulties associated with oil sands development can be understood only through a fundamental knowledge of the geological properties of he deposits. Thus, the first part of this overview article deals with the basic geology of the resource, using as an example Alberta's largest deposit, the Athabasca oil sands (*2–8*). The second part deals with existing and projected extraction technologies, and focuses on how the geology influences practically all aspects of the engineering work.

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Geological Characteristics

Alberta's oil sands (Fig. 1) are Early Cretaceous in age, which means that the sands that contain the bitumen were originally laid down about 110 million years ago. Details of the stratigraphic relationships among the various deposits are shown on the correlation chart, Fig. 3. Data pertaining to the depth, size, thickness, and reserves of the various deposits are given in Table 1.

In the Athabasca Deposit, virtually all the reserves are contained within a single contiguous reservoir, the Lower Cretaceous McMurray-Wabasca interval (Fig. 3). In the other deposits, the reservoirs are stacked, physically segregated from one another by thick impervious shale strata (Fig. 3).

Itemized below are the standard compositional and textural parameters used in defining the overall petrology of oil sands, as exemplified by the McMurray Formation in the Athabasca Deposit. Some discussion of how these parameters influence recovery technology is included.

Grain size. High-grade oil-bearing sands in Athabasca are dominantly very fine to fine-grained (62.5 to 250 micrometers, Fig. 4), although coarser sands and local conglomerates are known. Shale beds within the oil sands consist of silt- and clay-sized material and only rarely contain significant amounts of oil.

Composition. In general, the mineralogy of Athabasca oil sand is extremely mature and stable (Fig. 4): about 95 percent quartz grains, 2 to 3 percent feldspar grains, 2 to 3 percent mica flakes and clay minerals, and traces of other minerals. Because quartz is a very hard mineral, the sands are extremely abrasive. Wear on heavy excavation equipment in the surface mines is consequently pronounced. The presence of clay minerals, dominantly kaolinite and illite with minor amounts of montmorillonite, is of particular importance in that they have a deleterious effect on the efficiency of extraction processes, as will be discussed later.

Sorting. Most of the reservoir stands in the Athabasca Deposit are moderately well sorted (Fig. 4), meaning that a large percentage of the grains are approximately the same size. The small amount of matrix fines, which would tend to occlude the pore space between the modal grains, is a principal reason for the excellent reservoir quality of the sands.

Porosity. High-grade Athabasca oil sands have porosities of 25 to 35 percent (Fig. 4), considerably higher than most petroleum reservoir sandstones (5 to 20

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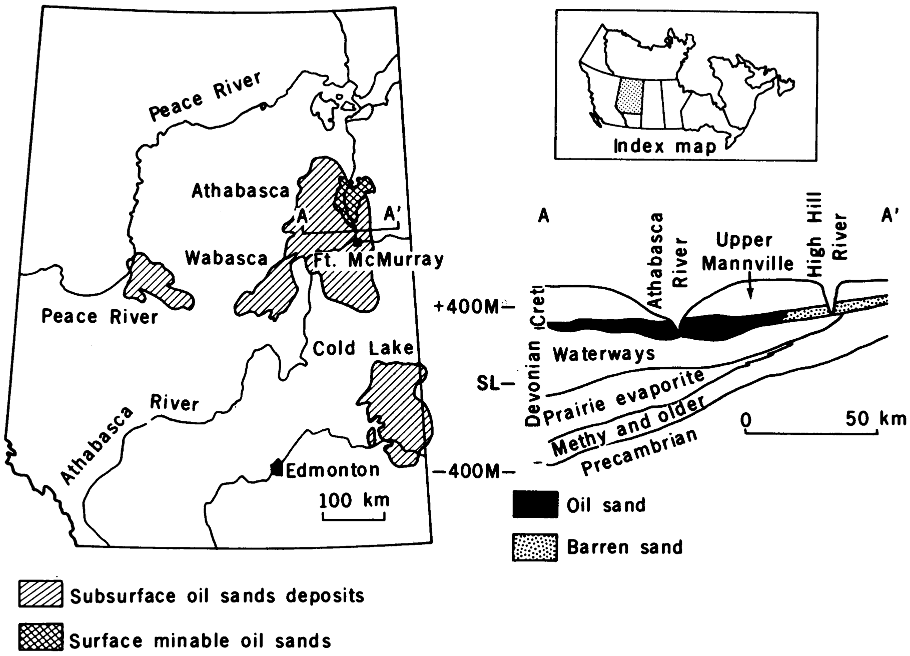


Fig. 1. Map of the Alberta oil sands accumulations and schematic cross section of the Athabasca Deposit. Note the steeply inclined oil-water contact at the updip eastern edge of the reservoir.

percent). The high porosity is mostly attributable to the lack of mineral cement in the oil sands, cement that in most sandstones occupies a considerable amount of what was void space in the original sediment. The McMurray Formation has had a history of shallow burial (approximately 1000 meters) and cementation and other diagenetic processes have had minimal impact on the sand textures. It is because the sediment is not consolidated, with no cementing agent to indurate the material and give it strength, that the deposits are called oil sands, not sandstones. Another consequence of the sands' unconsolidated character is that, in a flowing in situ well, special precautions must be taken to prevent production of the sand grains along with the oil.

Permeability. The permeability of oil-free McMurray Formation sand is very high; fluids can be easily transmitted through it. Assessing the permeability of the bitumen-saturated sand is very difficult, however. The bitumen is immobile in its natural condition and its presence greatly inhibits the flow of fluids through the porous medium. The high native permeability of the sand is a fortunate feature, because if the bitumen can be rendered less viscous, transmittal of the fluid through the pore system to a production well is greatly facilitated.

Saturation. Saturation is a measure of the extent to which the voids in a sediment are filled by various fluids and is expressed as percentage by weight or volume of the total bulk. The highest grade oil sands in the Athabasca Deposit (Fig. 4) have oil saturations of about 18 percent by weight (~ 36 percent by volume), with water saturations of about 2 percent by weight (~ 4 percent by volume). Anything with more than 10 percent bitumen by weight is considered rich oil sand, 6 to 10 percent is moderate, and less than 6 percent is lean.

Microscopic habitat of bitumen. Perhaps the single most characteristic feature of the Alberta oil sands, and almost certainly the most fortunate, is that the grains are water wet or hydrophilic. The oil in the pores is not in direct contact with mineral grains. Rather, each grain is surrounded by a thin film of water beyond which, in the center of the pore, is the oil (Fig. 5). This hydrophilic ten-

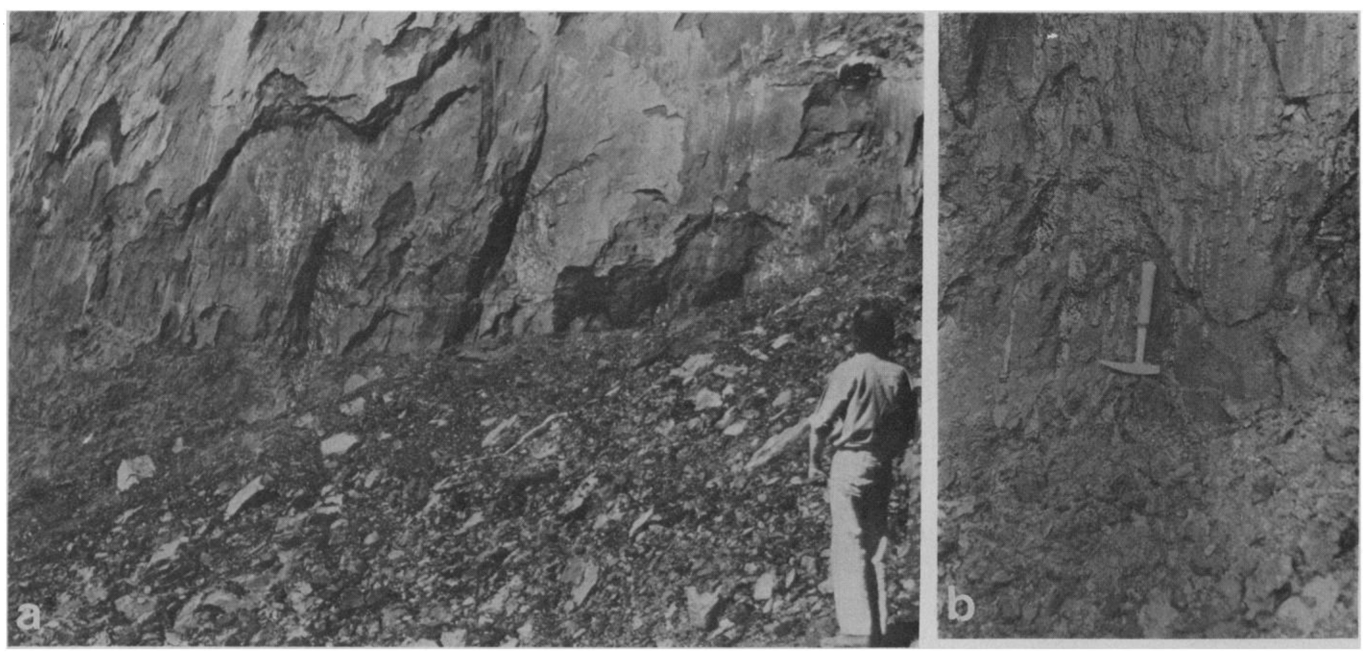


Fig. 2 (a and b). High-grade oil sands in a natural exposure of the lower part of the McMurray Formation, showing the thick-bedded character of the rich sands where they are virtually free of shale intercalations. Slabs of oil sand break off from the exposed face and accumulate in the talus. Fresh oil sand, newly exposed to the sun, oozes bitumen from the outermost 3 to 5 millimeters. The glistening bitumen creeps down the face in sticky black rivulets.

dency of the oil sands is fortunate because the hot water extraction process would not work if the grains were other than water wet. Some oil sands in the United States and elsewhere in the world are oil wet, meaning that the oil is in intimate contact with the grain surfaces. In such materials, the interfacial forces between the bitumen and the quartz are such that hot water extraction is not possible. Technological research on Alberta's oil sands would have a markedly different thrust, and would probably be even more painstaking than it is, if the deposits lacked this hydrophilic aspect. As it is, the extraction of bitumen from the sand is very straightforward. Oil sand is agitated in hot water, with a small amount of caustic added to raise the pH to approximate neutrality. The sand grains readily settle to the bottom of the vessel and the oil froths to the surface. Fine particulate matter, dominated by clay minerals, remains suspended in what are called the middlings. Middlings processing and tailings pond settling of the clay minerals have proved to be the only persistent problems associated with the process.

The hot water extraction process was pioneered and developed in the 1920's by K. A. Clark of the Alberta Research Council. Both existing commercial mines utilize the hot water extraction process.

Geological History

The role of the oil sands geologist is twofold. His first responsibility is to describe and characterize the rocks in concise terms, both for ease of communication with other scientists and engineers and for the purpose of quantifying rock properties in a manner conducive to reservoir modeling and formation element testing. Most of the key parameters involved in this descriptive element of the geologist's work have been outlined above.

The second responsibility involves seeking to understand the geological controls on reservoir variability so as to be able to predict the geometry of the sand bodies in the subsurface, away from the boreholes. This latter task is accomplished largely through the process of facies analysis, in which the sedimentary features and structures are mapped and then compared with the features and structures known to be associated with specific depositional environments. For example, the geometry of sand bodies deposited by the action of meandering rivers is quite different from that associ-

Table 1. In-place bitumen resources and reservoir data for the Cretaceous oil sands deposits of Alberta.

Deposit	Formation	Areal extent (10^3 km^2)	Depth range (m)	Mean pay zone thickness (m)	Bitumen in place 10^9 m^3	Bitumen in place 10^9 barrels
Athabasca	McMurray-Wabiskaw	32.0	0 to 500	27.0	138.1	869
Cold Lake A	Grand Rapids	9.5		10.9	31.2	
Cold Lake B	Clearwater	3.9	300 to 600	11.0	6.4	270
Cold Lake C	McMurray	4.5		8.5	5.4	
Wabasca A	Grand Rapids	6.1	75 to 750	12.1	10.5	119
Wabasca B	Clearwater	8.8		7.3	8.4	
Peace River	Bluesky-Gething	6.9	300 to 750	14.3	14.6	92
Total		58.5*			214.6	1350

*Areas are not additive because of deposit overlap.

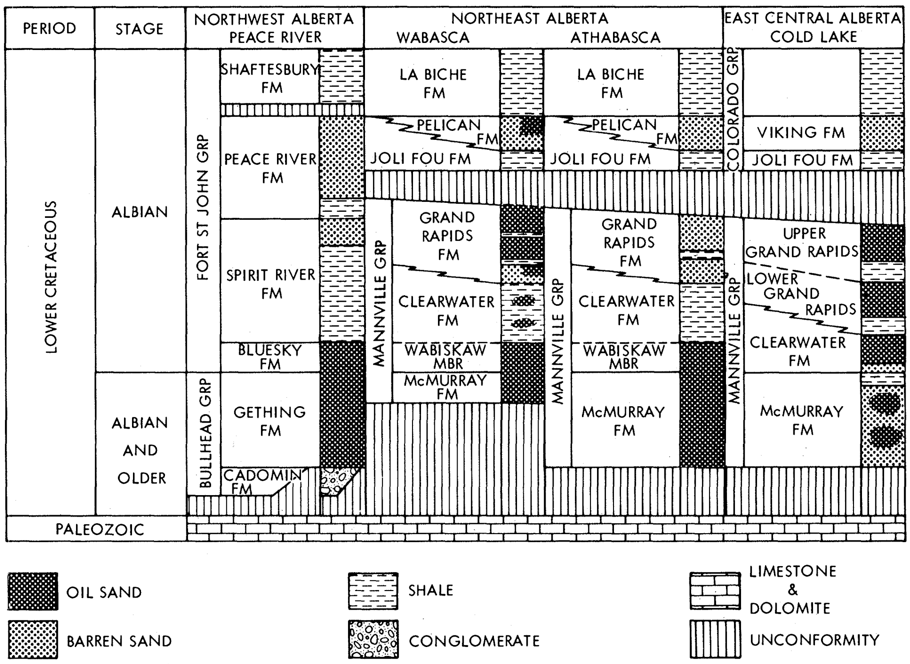


Fig. 3. Correlation chart of Mannville Group formations in the bitumen-bearing regions of Alberta [after Kramers (21)]. Any horizontal line drawn across the chart denotes synchroneity of deposition in the various areas. Thus, for example, while basal Gething Formation sands were accumulating in the Peace River area, McMurray Formation sands were being deposited in the Athabasca and Cold Lake regions. In the Wabasca area, there was no net deposition at that particular time.

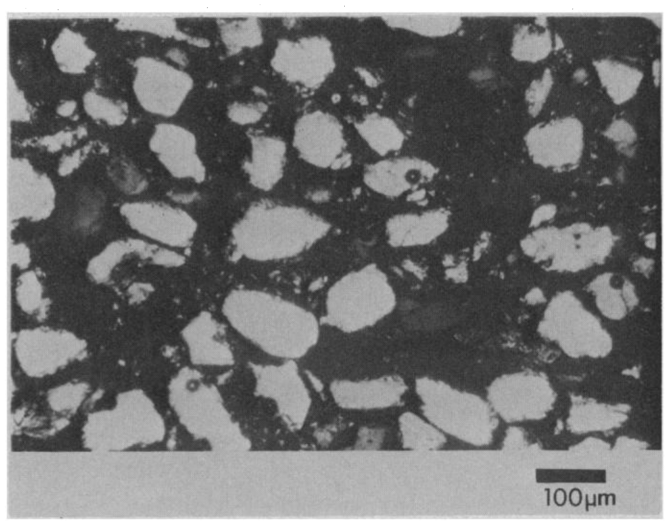


Fig. 4. Thin section of Athabasca oil sands, viewed under crossed Nicol prisms in the petrographic microscope. All of the white and gray grains are quartz. Black areas between the grains represent the bitumen-filled pore spaces. Note the uniformity of grain size and the comparative lack of fine matrix particles. As is commonly the case, there is no mineral cement binding the grains together. Black circles are air bubbles in the epoxy used to impregnate the sample.

ated with deposition in marine barrier bars. Establishing depositional environments thus leads directly to a reasonable predictive capability regarding the form and configuration of the reservoir sand bodies, the extent of their lateral persistence, and the chances of encountering specific discontinuities. This type of predictive capability is particularly crucial in devising in situ recovery schemes, where the steam flood or fire flood will be heavily influenced by impermeable heterogeneities within the reservoir and by preferred permeability trends within the sands.

Facies patterns. The principal control on the grade of the oil sands in the Athabasca reservoir is the distribution of primary porosity and permeability in the McMurray Formation sediments. In zones where the modes of sediment transport and deposition were sluggish or stagnant (such as floodplain marshes), much fine silt and clay was deposited, yielding shales or shaly sands that lack good porosity or permeability. When oil migrated into the McMurray Formation, these shaly zones, or shaly facies, could not accept significant amounts of oil and are preserved today as lean zones. Conversely, in zones originally occupied by river channels, the depositional flow regime was strong. Fine silts and clays were kept in suspension and only well-sorted sands were deposited. These sands characteristically have high porosity and permeability. They were able to accept considerable volumes of the oil to which they had access. In other words, the zones where the sand facies reached maximum depositional development are today the zones of thick, high-grade oil sands.

This dichotomy between sandy and shaly facies, apparently very straightforward, is in fact extremely complex. The two facies are intricately interrelated. Extreme lateral and vertical variability in facies is the rule rather than the exception. Migrating channels continually eroded, or partially eroded, previously deposited floodplain silts and clays. Channels were abandoned. Sediment supply varied. From these considerations, it is clear that the business of deciphering the complex facies patterns in the McMurray Formation is highly interpretative.

The complex puzzle of McMurray Formation facies development is as yet incompletely understood. In the detailed studies that have been carried out to date, workers have identified facies sequences associated with fluvial, deltaic, and estuarine sedimentary environments (*6, 8-11*). Among the very best ore bodies are those located along the trends of what are interpreted to have been very deep channels (*8*). These river or upper-estuarine channels were up to 45 m deep and several thousand meters across. Catchment for the river system may have extended as far south as Arizona and New Mexico. Where the deep channels reworked the McMurray Formation sediment, they left behind a facies sequence with a very high sand/shale ratio, excellent porosity and permeability characteristics, and relatively uniform facies distribution. Both of the existing commercial development sites are located along such a channel trend.

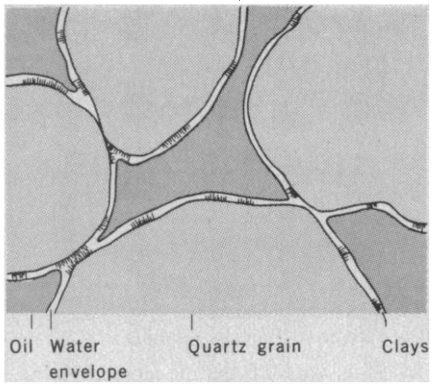


Fig. 5. Schematic representation of the microscopic habitat of the bitumen in the pore spaces. The quartz grains are all in direct contact with one another, and they constitute a stable framework that remains virtually unchanged when the fluids are mobilized. The water film around the grains, only a few micrometers thick, forms a physically continuous sheath that prevents direct contact between quartz and bitumen. Its presence allows the hot water extraction process to work. The bitumen phase is also continuous, linked from one pore to the next through the three-dimensional network of pore throats. Clay minerals are attached to the grain surfaces, and it is unlikely that they protrude through the water envelope.

Geological record. McMurray Formation deposition began in the Athabasca region in Early Cretaceous time. The surface on which the initial sediments were laid down was an exposed landscape of Devonian limestone. During McMurray time the region underwent gradual subsidence, with the Boreal Sea slowly transgressing across it from the north. McMurray sand deposition ceased when the sea eventually transgressed the entire area, giving rise to deposition of Clearwater Formation marine shales (Fig. 3).

Subsequent Cretaceous deposition in the Athabasca region produced several hundred meters of mixed marine and continental sediments. During the Tertiary Period, there was gentle tilting of the strata toward the southwest and differential erosion of several hundred meters of Cretaceous strata. In the Pleistocene Epoch, the region was subjected to repeated glaciations (ice up to 3000 m thick), which produced considerable scour and deposited a variable thickness of glacial drift over the entire area. Tertiary and Pleistocene erosion was greatest in what is now the surface-minable area of the deposit. Locally, the entire McMurray Formation was removed. In the southern and western parts of the Athabasca Deposit area, there remains up to 500 m of Cretaceous overburden above the McMurray Formation. During the last 10,000 years, a muskeg-soil profile has developed and forest cover has been established.

There remains considerable debate about all questions associated with the origin of the oil in the oil sands. A large body of geochemical evidence indicates that Athabasca bitumen has been subjected to extensive biodegradation and water washing in the near-surface realm (*12, 13*). Washing by percolating surface waters leaches light components from a pooled crude. Biodegradation has a similar effect in that it results in the loss of light ends through the action of hydrocarbon-metabolizing bacteria. One school of thought is that the parent petroleum was a thermally mature crude (*12, 13*). Other work (*14, 15*) suggests just the opposite—that the bitumen is an immature crude. Geological observation of the distribution of the oil within the McMurray Formation reservoir indicates that at the time the oil was pooled, it was much less viscous and probably lighter than at present. The oil has found its way into virtually every porous and permeable zone in the reservoir. This observation supports the proposal that the pooled crude was degraded in situ.

Controversy about the source rocks for the original oil is as yet unresolved (*12*). Geochemical indexing of Athabasca crude indicates strong affinities with other Mannville Group oils in Alberta, suggesting that the oil originally migrated down from Clearwater Formation source beds into porous and permeable McMurray Formation sands, where it was ultimately trapped. On the other hand, there is no discrete geochemical evidence that the oil could not have originated from Paleozoic source beds in the Alberta basin to the southwest. Devonian and Mississippian strata that are prolific conventional oil producers in the subsurface come to subcrop beneath the oil sands region. It is thus possible that at least some of the oil originated in these Paleozoic strata.

Details of the trapping mechanism at Athabasca are difficult to establish. The impermeable Clearwater Formation shales clearly acted as the cap for the trap. But how the reservoir was laterally confined is a matter for conjecture. The outer limits of the deposit are not marked by structural closure or significant permeability barriers. The steeply dipping oil-water contact along the eastern edge of the deposit (Fig. 1) may have arisen in response to vertical collapse movement associated with dissolution of underlying Devonian evaporites (*16*). Alternatively, it is possible that the updip edge of the reservoir was sealed by a bitumen plug, the oil having been subjected to degradation during migration, until finally the petroleum could move no farther.

Surface Mining

Of the 869 billion barrels of oil in place in the Athabasca Deposit, only about 74 billion barrels lie in what is considered the surface-minable region, where there is less than 50 m of overburden (Fig. 1). It is in this surface-minable area that the two existing commercial production facilities are located: the pioneering Great Canadian Oil Sands operation, built in the middle 1960's at a cost of about $235 million, producing approximately 50,000 barrels of synthetic crude oil per day, operated as a wholly owned subsidiary of Sun Oil Corporation (*17*); and Syncrude, built in the middle to late 1970's at a cost of $2.2 billion, with design capacity for production of 125,000 barrels of synthetic crude oil per day, run by a consortium that includes Esso Resources Canada Limited, Canada-Cities Service Limited, Gulf Oil Canada Limited, and the governments of Canada, Alberta, and Ontario (the latter three having bought into the project when Atlantic Richfield withdrew in 1975) (*18*).

From a geological point of view, the principal base requirements for a viable mine are (i) that there be sufficient reserves to support a plant life of 20 to 30 years and (ii) that the ore body be continuous enough to allow for a reasonable mine layout—ore being defined as oil sand with more than 8 percent bitumen by weight. The reason 8 percent bitumen is used as the cutoff between ore and "reject" is that the excessive amounts of clay in the material with less than 8 percent bitumen introduce serious difficulties in the Clark hot water extraction process. Existing mining projects are designed to utilize feed averaging 11 to 12 percent bitumen by weight.

Great Canadian Oil Sands. The GCOS operation is located on the banks of the Athabasca River about 40 kilometers north of the town of Fort McMurray (Fig. 6). Within the confines of the 4000-acre lease site, it is estimated that there are approximately 1 billion barrels of bitumen in place, of which 630 million are deemed recoverable.

Clearing of the black spruce and tamarack brush is accomplished by wide-track crawler tractors and brush rakes. All clearing operations must be carried out in January, February, and March, when frost penetration into the underlying muskeg is sufficient to allow for support of heavy vehicles.

The muskeg layer, which consists of water-saturated sphagnum moss and organic detritus, averages between 2 and 6 m in thickness on the GCOS lease. Drainage ditches are excavated and the muskeg is dewatered for 2 years, after which it is removed by front-end loaders and trucks, again in the winter. The muskeg is stored in constrained stockpiles for subsequent use in reclamation; it must be enclosed within earth dikes to prevent it from rambling all over the countryside when it thaws in the spring.

Overburden on the GCOS property consists of glacial drift, Clearwater Formation shale, and a small amount of lean upper McMurray oil sand. About 80 percent of the overburden is used on the site to build dikes for the containment of tailings and muskeg. The overburden averages about 16 m in thickness and is removed by use of a large bucket wheel excavator in conjunction with 150-ton trucks. Because of the diverse geotechnical properties of the various overburden materials, they must be typed and sorted for deployment in various specific site construction operations.

The ore body at GCOS averages 50 m in thickness (Fig. 6). It is mined on two benches by large bucket wheel excavators. The mined material is transferred through belt wagons and hoppers to a conveyor belt system, which carries it directly to the extraction plant.

Fluffing of the oil sands before excavation is accomplished through blasting. The main benefit of blasting is that it insulates the material and minimizes winter frost penetration. In cold operating conditions, "a mining face that has not been disturbed is similar to concrete but tougher; it will not shatter. . . . Teeth glow red and can be torn out of the sockets, and the thick steel plates from which the buckets are made can be torn" (*19*). Winter operations, in temperatures that are often between −30° and −40°C, are also hampered by equipment icing and visibility loss due to ice fog. In summer, benches underlain by rich oil sand become extremely sticky and heavy equipment tends to sink. Among the numerous other problems in mine pit operations are those associated with chemical attack on rubber tires and hoses by bitumen and all manner of abrasion problems from the sand itself. The combined effects of corrosion, abrasion, and cold result in equipment maintenance costs that are about double what they would be in a similarly sized hard rock operation. The

Fig. 6. The mine pit at Great Canadian Oil Sands. In the foreground is the mined-out area, with exposed Devonian limestone (light tones) and the beginnings of a wide dike, primarily made up of transferred overburden materials (striated by compactor vehicles). The two bench faces of black oil sand are being mined by bucket wheel excavators. Above the upper bench is the scarp face where overburden already has been removed.

Fig. 7. The Syncrude mine. At the right is the excavated pit, flanked by windrows of oil sand cast to the side by drag lines and subsequently reclaimed by bucket wheel excavators. This initial box cut is more than 4 km long. To the left of the active mine is an area where overburden is being removed by surface vehicles. Farther left is an area of muskeg, scarred by drainage ditches. Oil sands feed from the mine is collected in arcuate surge piles (center), after which it is conveyed to the extraction plant (large building at near left center). Upgrading and utility installations are at the extreme lower left.

economics of surface mining necessitate continuous operation, 24 hours a day, 365 days a year. A prolonged breakdown in the mine can make it necessary to shut down the extraction and upgrading operations, and the considerable time lost before they are restarted can prove very costly.

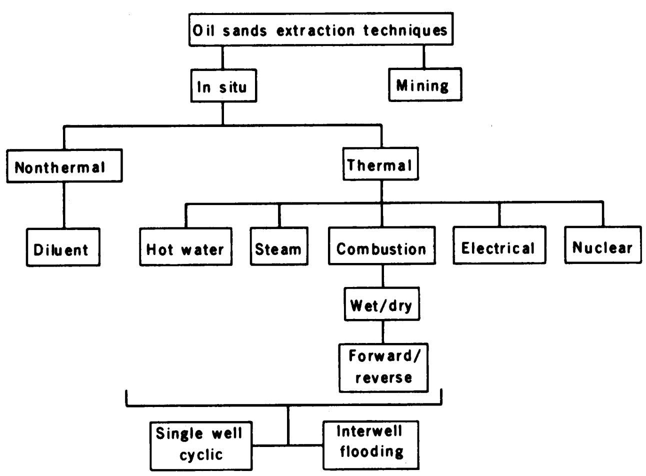
From the mine pit, the oil sands are conveyed directly into conditioning drums, where steam, hot water, and caustic are added. After passing through a screen to eliminate oversize material (concretions and frozen lumps of oil sands), the various slurry streams pass into banks of separation cells, where the sand sinks to the bottom and is pumped off to the tailings pond and the oil froths to the surface and is skimmed. Middlings in the separation cells are recycled and scavenged. The bitumen is subjected to two cycles of centrifuging to remove the last vestiges of mineral matter. Overall, this type of commercial extraction process has proved to be on the order of 92 percent efficient. Only 8 percent of the input bitumen ends up in the tailings pond.

At GCOS, raw bitumen from the extraction plant is upgraded to synthetic crude oil through a process of delayed coking. Various relatively pure liquid hydrocarbons are drawn from the coker (including gas oil, kerosene, and naphtha) and then blended together to form a synthetic crude product that can be pipelined to Edmonton for subsequent refining.

The principal by-products of the upgrading process are sulfur, of which the original bitumen contains nearly 5 percent, and coke, much of which is utilized on-site to fuel generators, which produce all on-site power. The burning of the coke results in emission of sulfur into the atmosphere in the form of SO_2. The Clean Air Act in Alberta sets out rigid guidelines for the amount of sulfur emission that can be tolerated.

Revegetation of tailings sand has proved a major difficulty. The sand is remarkably sterile, having been subjected to boiling and caustic treatment. Nonetheless, with the addition of fertilizers and certain organic additives, botanists have been successful in establishing ground cover foliage that provides a first step toward satisfactory land reclamation.

Syncrude. The Syncrude operation (Fig. 7), located immediately adjacent to the GCOS lease, has many elements in common with its older relative. It also has the following unique features: the ore body is excavated by drag lines, with the oil sand cast into windrows adjacent to the pit, where it is reclaimed by bucket wheel excavators; there is an elaborate surge handling facility that renders the extraction plant less susceptible to shutdown because of mine breakdown; bitumen upgrading is by the fluid coking method rather than delayed coking; utilities are fired by natural gas rather than



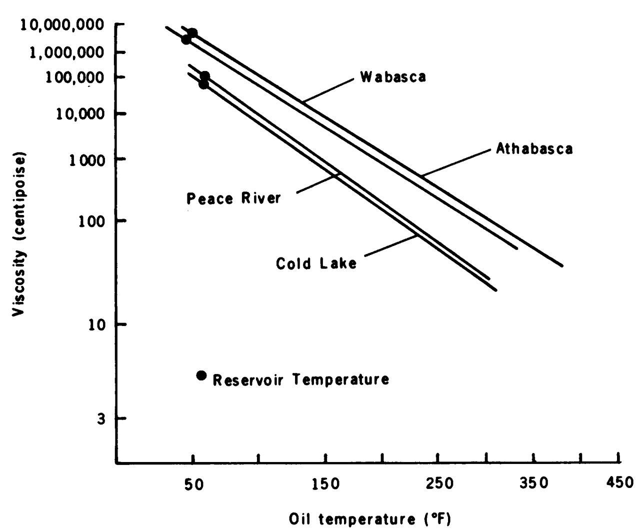


Fig. 8 (left). Schematic chart of the various approaches to oil sands development. Fig. 9 (right). Viscosity-temperature relationships for oil sands bitumen [after Nicholls and Luhning (*20*), p. 528].

coke; and tailings will be disposed of initially in an area underlain by potentially minable oil sands, rather than in a separately constructed pond.

Syncrude has now been in production for about 1 year and has built up its synthetic crude output to approximately half its design capacity of 125,000 barrels per day. Of the inevitable start-up problems, the two most serious are related to (i) severe winter freezing of the windrows, which the bucket wheels are incapable of reclaiming, and (ii) combinations of problems related to the angle of repose of the cast materials and the boom length of the drag line, which may render it impossible for the drag lines to handle overburden in the envisaged manner.

A third commercial mining plant is now under consideration. The Alberta Energy Resources Conservation Board has received an application from the Alsands consortium, headed by Shell Canada and Shell Explorer, to construct a mining facility about 70 km north of Fort McMurray. It is projected to produce 140,000 barrels of synthetic crude oil per day for 25 years. The Alsands project is modeled to a large extent on Syncrude. Estimated capital expenditure to start-up in the middle to late 1980's is on the order of $5 billion.

Oil sands mines are the largest earthmoving operations in the world. A rule of thumb is that it takes approximately 2 tons of oil sand to produce 1 barrel of synthetic crude oil. Adding in the handling of tailings material and overburden, the figure reaches 5 tons per barrel produced. At its design capacity of 125,000 barrels per day, Syncrude must handle more than 600,000 tons of earth material daily.

In situ Recovery

Technology related to surface mining operations can now be considered proved on a commercial scale. Small improvements in all areas are still possible, but scope for the introduction of innovative technology is diminishing. Consortia with billions of dollars at stake are loath to commit themselves to alternative technologies unless they can be assured both that they will work on at least the scale of a large pilot plant and that they will result in considerable economic gain.

Conversely, the development of in situ recovery technology is in its comparative infancy. At present, there is no in situ technology that has been proved viable on a commercial scale. Furthermore, there seems little likelihood that a single recovery concept will be adaptable to all geological conditions. What works in the Cold Lake B Deposit may not work in a specific region of Athabasca. The one thing that does seem certain is that whatever technologies emerge, they will be highly complex.

Figure 8 schematically illustrates the various approaches to bitumen recovery from oil sands. Of the in situ recovery concepts, a small number are based on nonthermal processes, involving the addition of diluents or emulsifiers to reduce the viscosity of bitumen to the point where it can be mobilized through the porous medium. At present, most workers agree that a recovery program built solely around nonthermal precepts is unlikely to be economically attractive. In the future, solvents are likely to be used only for reservoir preconditioning and as additives in thermal processes.

The various thermal recovery processes (Fig. 8) are all predicated on the relationship shown in Fig. 9. At the reservoir temperature, the bitumen is virtually immobile. As the temperature is raised, the viscosity drops in an exponential manner until, at a temperature of about 300°F, the bitumen is fluid enough to flow through the pore system. Of the many field pilot projects that have been conducted to date in the various deposits (*20*), the vast majority are based on steam, hot water, or combustion approaches.

Electrical heating of oil sands (Fig. 8) has achieved some prominence of late because of its potential for preconditioning the reservoir prior to the application of more standard thermal methods. In electrical preheating, closely spaced wells are used as electrodes and the current energy transmitted through the reservoir is at least partially converted to heat. Another approach that is periodically suggested involves the use of nuclear energy in exploiting the bitumen resources. A scheme proposed in 1959 by Atlantic Richfield involved the detonation of an explosive nuclear device near the base of the oil sands reservoir. The creation of a cavern and a surrounding shattered zone, in conjunction with the liberation of enormous quantities of heat, was projected to result in the creation of an easily tapped pool of hot bitumen. Proposals along this line are invariably rejected on the basis of environmental hazard. Furthermore, it can be argued that for the same cost, more thermal energy can be imparted to the reservoir by much safer and more conventional means.

The three most prominent and advanced in situ recovery schemes are shown in Fig. 10. Perhaps the simplest of these is a single well process called cyclic steam stimulation, or "huff-and-puff." This approach has undergone extensive field pilot testing, particularly in the Cold Lake B Deposit by Esso Resources. In its most elementary form, huff-and-puff involves injecting steam (with or without additives) into the reservoir for a period of weeks to months, shutting the well in and allowing the heat to penetrate a considerable zone around the well, and then putting the well on production to pump off the bitumen that has been rendered mobile. The process can be repeated a number of times, either until it becomes uneconomic to continue or until there is breakthrough to an adjacent well, at which time conversion to a steam drive process becomes possible.

The other prominent recovery schemes (Fig. 10) involve interwell communication, meaning that there must exist a permeable conduit through which fluids can be induced to flow from the very beginning of operations. If natural communication paths do not exist, it is possible that they can be produced through artificial fracturing of the formation. Most interwell schemes feature a central injection well surrounded by four to six production wells at spacings of 60 to 150 m. In the steam injection process, the steam front moves from the vicinity of the injection well outward toward the production well. The heated bitumen ahead of the front is mobilized downward by gravity through the porous medium into the communication path at the base, from which it is drawn to the production well.

The most prominent of the combustion processes is that developed by Amoco and referred to as COFCAW (combination of forward combustion and waterflood). COFCAW involves igniting the formation in the vicinity of the injection well, supplying air to keep the combustion going and water to create a steam pressure. A portion of the bitumen is, of course, consumed in the combustion zone. Bitumen in the region outside the burned zone is mobilized through the porous medium into the previously established communication path, from which it is pumped to the surface at the production wells.

All of the leading in situ production schemes are based on concepts originally developed for enhanced recovery in conventional oil fields. Still, it must be said that the engineers who are grappling with in situ recovery of bitumen face enormous challenges. They are dealing with an extremely stubborn product in a

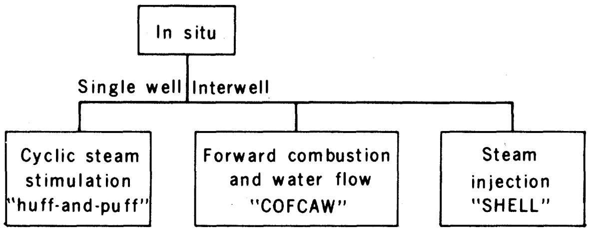


Fig. 10. The three leading in situ techniques for extraction of bitumen in the subsurface.

highly complicated geological setting. Because of the complexities, the emerging technologies are likely to prove very expensive.

At present, Esso Resources Canada Limited has an application before the Alberta Energy Resources Conservation Board for permission to build the first commercial-scale in situ plant to recover bitumen from the Cold Lake B Deposit. The projected initial investment is between \$4 billion and \$5 billion for a facility that will produce on the order of 140,000 barrels of synthetic crude oil per day. If the application is successful and the project goes ahead, production from the Esso facility could begin in the middle 1980's.

A commercial project of the type proposed by Esso, operating over a 25-year life, will probably involve the drilling of about 16,000 wells, at a 100-m spacing, over an area of about 100 km^2. Specialized drilling and well completion methods will probably be employed (perhaps directional drilling of numerous wells from a single platform, drilling from underground tunnels, horizontal drilling and completion, and so on) but even then, more than half of the total capital outlay will be consumed in obtaining well access to the reservoir.

From a geological point of view, the most crucial input into in situ recovery designs is related to providing predictive capability beyond the borehole, furnishing a three-dimensional picture of the geometry of the reservoir sand bodies and the intervening shaly strata. It is the internal discontinuities and permeability barriers within the reservoir that control the pattern of steam or combustion sweep. In order to achieve some predictive capability, the geologist must come to grips with all aspects of the depositional environments as they relate to the facies patterns.

Discussion

It can be argued that Alberta's oil sands deposits are ideally located. Pipelines less than 500 km long are required to deliver the synthetic crude oil to Edmonton, where there is major refining capacity. From there, it has access to an elaborate and far-flung distribution system. On the other hand, it can be said that the deposits are situated in relative wilderness. The land is not productive from an agricultural or forestry standpoint. If the oil sands were located in areas of good farmland, resource development decisions would be much more difficult than they are.

The environmental implications of continued and expanded oil sands development are numerous and far-reaching. To date, the oil sands industry has shown itself to be responsive to the concerns of government and special interest groups alike.

Various economic analyses of the relative merits of mining and in situ development indicate that although the technological risk associated with in situ recovery is currently higher than that for mining, the potential rates of return of the two types of operation are approximately equal. Total capital expenditure for an in situ operation will almost certainly exceed that for a similarly sized mining plant. In a mining operation, however, practically all of the capital costs are incurred before production in the construction of the facility. Interest charges on front-end debt capital act to reduce the profitability of the venture as a whole. In the in situ case, revenue from production begins well before most of the well-drilling capital is expended. It is thus largely because of the differences in the investment profiles that the two types of projects are seen as roughly comparable.

From an engineering standpoint, it is true that the practical difficulties associated with in situ extraction exceed those associated with mining. In the final analysis, however, in situ production involves mobilization of the target product only. Very significant economies result from the fact that the sand remains in place. Thus, if the multitudinous technical problems can be overcome, the future of in situ development appears promising.

In conclusion, it is perhaps appropriate to reiterate that the oil sands deposits of Alberta constitute a vast energy resource. Yield from this resource is in a form that the industrialized world craves, namely, liquid fuel. In the short to medium term, at least until we can adapt to alternative energy sources, the oil sands appear to offer one of the most attractive options for fuel supply. Optimism about the future of oil sands development nevertheless must be tempered with awareness of the enormous technological difficulties and huge capital expenditures that are involved. My plea in this article is that sufficient attention be paid to the fundamental geological nature of the deposits. Development based on incorrect or naïve concepts of the nature of the resource can only lead to costly mistakes.

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17. Since the preparation of this article, GCOS has changed its name to Suncor.
18. After this article was written, participation in Syncrude changed because of the sale of the Ontario share and the exercising of participation options by various resource companies. Percentage holdings in Syncrude now break down as follows: Esso Resources Canada, 25.0; Canada-Cities Service, 17.6; Gulf Canada Resources, 13.4; Petro-Canada Exploration, 12.0; Alberta Energy Company, 10.0; Alberta government, 8.0; Hudsons Bay Oil and Gas, 5.0; Petrofina Canada Exploration, 5.0; and PanCanadian Petroleum, 4.0.
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