Chapter 4

Natural Bitumen and Extra-Heavy Oil

COMMENTARY

Introduction

Crude oil is found in sedimentary rocks throughout the world, except, thus far, in Antarctica. In many places the oil has been degraded, so that it is represented by viscous black oil that is difficult to recover, transport, and refine. Depending upon the degree of degradation the result is extra-heavy oil or, in the extreme case, natural bitumen. Except in Canada, precise quantitative reserves and oil-in-place data on a reservoir basis are seldom available because most countries and companies consider such information to be proprietary.

Natural bitumen is the oil contained in clastic and carbonate reservoir rocks, most frequently in small deposits at, or near, the earth's surface. These rocks are commonly referred to as tar sands or oil sands and have been mined since antiquity for use as paving. Occasionally such deposits are extremely large in areal extent and in contained resources, most notably those in northern Alberta, Canada. In 2003 only the Alberta bitumen deposits were being exploited as a source of crude oil.

Similarly, reservoirs containing extra-heavy oil are geographically widespread but only one such deposit is sufficiently large to have a major supply and economic impact. That deposit is the Orinoco Oil Belt in Eastern Venezuela. Nowhere else in the world is such a concentration of extra-heavy oil known or likely to exist.

Definitions of terms used in this commentary may be found immediately prior to Table 4.1. The resource definitions are those of the World Petroleum Congress-Society of Petroleum Engineers-American Association of Petroleum Geologists, with minor additions. One such addition, e.g. is the term Original Reserves, comprised of Proved Reserves plus Cumulative Production, which tends to place new and mature reservoirs on a more nearly comparable basis than either term alone.

Chemistry

Extra-heavy oil and natural bitumen represent crude oils which have been severely degraded by microbial action, as evidenced by their paucity of low-molecular-weight saturated hydrocarbons. Fig. 4.1 provides a comparison of salient attributes of crude oil and natural bitumen.

2004 Survey of Energy Resources

	Conventional oil	Medium oil	Heavy oil	Extra-Heavy oil	Natural bitumen
Reservoirs (number)	8 102	816	1 375	57	324
Depth to top of reservoir (ft)	5 140	3 284	3 200	3 628	484
Coke in crude oil (wt%)	10.4	17.6	21.8	28.1	
Asphalt in crude oil (wt%)	8.8	25.0	38.4	61.9	69.6
Gasoline yield (vol%)	9.2	2.8	2.0	1.3	1.4
Gas Oil yield (vol%)	17.4	21.9	15.9	16.9	7.2
Residuum yield (vol%)	21.9	39.5	52.6	62.6	18.1
Pour point of crude oil (ºF)	16	9	20	66	89
Crude oil density (g/cm³)	0.836	0.920	0.958	1.018	1.041
Crude oil gravity (ºAPI)	38.1	22.3	16.3	7.5	5.0
Crude oil dynamic viscosity (cP, 100ºF)	9	63	593	7 936	292 991
Resins (wt%)	6.1	19.3	24.2	21.2	25.2
Asphaltenes (wt%)	2.1	6.6	12.4	13.2	30.6
Total BTEX volatiles (ppm)	10 157.4	4 909.0	2 487.1	N/A	N/A
Total VOC volatiles (ppm)	16 736.1	8 018.3	4 518.2	N/A	N/A
Nickel (ppm)	8.0	33.4	54.0	129.9	78.2
Vanadium (ppm)	18.2	88.2	170.9	777.7	183.0
Nitrogen (wt%)	0.1	0.2	0.5	0.6	0.7
Sulphur (wt%)	0.4	1.5	2.9	4.9	3.3

FIGURE 4.1 Comparative chemical analysis of world oils and natural bitumen.

The numbers of reservoirs involved show that many fewer analyses are available for extra-heavy oil and natural bitumen, which causes the averages to be weighted by a few large deposits with numerous analyses. Nevertheless, the chemical and physical differences among the oil types are clear. From conventional oil to natural bitumen there are increases in density; coke, asphalt, asphaltene, and resin contents; residuum yield; pour point; dynamic viscosity; and in the content of the metals nickel and vanadium and non-metals nitrogen and sulphur. Conversely, the API gravity, gasoline and gas oil yields, and volatile organic compounds (Benzene, Toluene, Ethylbenzene and Xylenes—BTEX and volatile organic compounds—VOC) all decrease. There is also a decrease in average reservoir depth. Very little of the extra-heavy oil and natural bitumen originated with these chemical attributes, which are rather the result of the degradation of originally conventional crude oils, with the consequent loss of most of their low-molecular-weight volatiles.

The degradation has resulted in crude oils which are very dense, highly viscous, and black. The degradation, principally bacterial, requires an active water supply to carry the bacteria, inorganic nutrients and oxygen, and to remove toxic by-products, such as hydrogen sulphide; contact with the reservoir containing the low-molecular-weight hydrocarbon food; and temperatures generally below about 200 °F (Barker, 1979). Other low-molecular-weight components are lost through water washing in the reservoir, thermal fractionation, and evaporation when the reservoir is breached at the earth's surface.

Resources

World summaries of natural bitumen and extra-heavy oil resources are given in Tables 4.1 and 4.2. Although natural bitumen and extra-heavy oil are worldwide in occurrence, a single extraordinary deposit in each category is dominant. The three Canadian oil sands deposits in Alberta together contain at least 63% of the discovered world total bitumen in place and constitute the only bitumen deposits that are economically recoverable as sources of synthetic oil. Additionally, Alberta has about 90% of the world's undiscovered or poorly known natural bitumen. Canada's known bitumen in place amounts to about 1 700 billion barrels. Similarly, the extra-heavy crude oil deposit of the Orinoco Oil Belt, a part of the Eastern Venezuela basin, represents about 98% of that known to be in place or some 2 000 billion barrels. Between them, these two deposits contain about 3 700 billion barrels of oil in place. These are only the remaining, degraded remnants of petroleum deposits that must have originally totalled as much as 18 000 billion barrels of oil in place.

Extra-heavy oil is recorded in 91 deposits. Some of these represent separate reservoirs in a single field, of which some are producing and others abandoned. The deposits are found in 21 countries, with 11 of the deposits being offshore or partially offshore.

Natural bitumen is found in 183 identified deposits in 21 countries. These are generally reported as tar sands or, in Canada, oil sands. Clearly, many more such deposits are identified but, as in the case of oil seepages, no resource estimate is possible. Very large resource deposits are known in eastern Siberia in the Russian Federation but insufficient data are available to make more than conservative-size estimates.

Two types of basins contain, respectively, most of the world's natural bitumen and extra-heavy oil and, indeed, contain about three-quarters of all the oil reserves in the world. These basins are architecturally similar, either lying within or accreted to continental cratons. In profile, the sediments are thick and strongly folded or rift-faulted in the seaward direction and become thinner and structurally higher as they encroach upon the craton. Oil is generated in the deeply buried, thick seaward sediments and migrates upward to be trapped adjacent to the craton. Biodegradation is promoted at the cratonic edge, where the sediments have been brought near to the earth's surface. This permits an influx of fresh water, providing oxidising conditions, and both evaporation and washing out of light, high API gravity oil components. Complete degradation results in highly viscous, very low-API gravity bitumen exemplified by the Alberta deposits. If the edge is reburied before the oil is completely degraded, the result is likely to be extra-heavy oil like that in the Venezuelan Orinoco Oil Belt, which is somewhat less viscous and of higher API gravity than the natural bitumen.

Production Methods

The chemical and physical attributes of extra-heavy oil lead to an array of problems with respect to exploitation, transportation, storage, and refining. This, of course, is reflected in the increased cost of extraction and processing and physical limitations on production capacity. Due to the high viscosity of the crude, some form of improved recovery is usually required for production. Steam injection has been common practice, in both vertical and lateral wells. A notable addition to recovery technology has been SAGD, or steam-assisted gravity drainage, combined with horizontal drilling. In this method a horizontal steam-injection well is drilled a few metres above a production well. A similar technology involves the injection of solvent rather than steam in the superjacent well. It is also common practice to inject a low-API gravity hydrocarbon fluid (frequently gas condensate) as a diluent into the reservoir to improve mobility. An important production improvement is recovery of cold heavy oil with sand (CHOPS). Cold production is achieved in Venezuela through horizontal lateral wells in combination with electric submersible pumps and progressing cavity pumps. Finally, efforts are continuing to improve production of viscous oil through down-hole electrical resistance heating.

Natural bitumen is immobile in near-surface reservoirs, where it can be recovered only by mining and surface separation of the bitumen from the rock. Where the bitumen is buried deeply enough to prevent severe heat loss, it may be produced from wells by the use of

FIGURE 4.2 Canadian Oil Sands Mine Truck & Shovel (Source: Suncor Energy Inc.).

steam injection from vertical wells, by taking advantage of horizontal well technology, or by utilising SAGD. In these cases the bitumen is actually extra-heavy oil. For the bitumen in reservoirs too deep to strip-mine economically but too shallow for steam injection from wells to be effective, a combination of mining and steam injection has been developed, with injection wells emplaced from within the mine tunnel, the oil being recovered by gravity drainage.

Most production schemes for both extra-heavy oil and natural bitumen entail the incorporation of upgrading facilities at or near the production sites. The benefit is the simplification of pipeline movement of the upgraded oil.

Upgrading and Refining

Two fundamental upgrading processes are presently employed to prepare heavy oil and natural bitumen for transportation and refining to finished products. These processes are carbon rejection and hydrogen addition. Each process improves the hydrogen-to-carbon ratio but by following different paths. Carbon rejection, such as Flexicoking, yields a large quantity of low-Btu gas at the expense of produced liquids, a large amount of petroleum coke, and therefore moderate conversion at low pressure. A hydrogen addition process, such as VEBA-Combi-Cracking (VCC) heats the raw material under pressure, the resulting gas being combined with added hydrogen to maximise liquids yield through high conversion. High conversion carries an economic penalty because of the cost of the added hydrogen and the high pressures required. The choice, therefore, is economic, being related to demand for the resulting products.

The yield of upgraded oil (synthetic crude oil) from the natural bitumen, based on the Alberta experience, varies with the technology employed, the consumption of product for fuel in the upgrader, the extent of natural gas liquids recovery, and the degree of residue upgrading. The Canadian company Suncor uses delayed coking for a yield of 0.81, whereas Syncrude (another Canadian company) obtains a yield of 0.85 through fluid coking combined with hydrocracking. The expected yield for the Albian Sands sub-project of the Shell/Chevron/Western Athabasca Oil Sands Project is 0.90, using hydrocracking.

Company	Project	Location	Recovery method	Company production 2002 (b/d)	Company production target (b/d)	Company production target (year)	Targets
Canadian Natural Resources	Brintnell, Pelican Lake	Athabasca In situ	Primary	7 791			
Canadian Natural Resources	Wabasca	Athabasca In Situ	Primary	21 270			
EnCana	Pelican Lake, Woodenhouse	Athabasca In Situ	Primary	13 656	35 000	2004	w/o Syncrude
Koch Exploration Canada	North Wabasca	Athabasca In Situ	Primary	185			
Canadian Natural Resources	Kirby Thermal	Athabasca In Situ	SAGD	223			
ConocoPhillips	Surmont (43.5%)	Athabasca In Situ	SAGD		100 000	2012	Total Surmont
Deer Creek	Jocelyn	Athabasca In Situ	SAGD		30 000	2012	Total Jocelyn
Devon	Dover	Athabasca In Situ	SAGD	1 470			
Devon	Surmont (13%)	Athabasca In Situ	SAGD				[Surmont]
Devon	Jackfish	Athabasca In Situ	SAGD		35 000	2003	Total Jackfish
EnCana	Foster Creek	Athabasca In Situ	SAGD	14 563			
EnCana	Christina Lake	Athabasca In Situ	SAGD	1 087			
Husky Oil	Kearl Lake	Athabasca In Situ	SAGD		100 000	2012	Total Kearl Lake
Japan Canada Oilsands	Hangingstone	Athabasca In Situ	SAGD	4 932	60 000	2012	Total Hangingstone
Nexen	Long Lake (50%)	Athabasca In Situ	SAGD/Upgrader		70 000	2007	Total Long Lake
Opti	Long Lake (50%)	Athabasca In Situ	SAGD/Upgrader				[Long Lake]
Petro-Canada	MacKay River	Athabasca In Situ	SAGD	6 672	30 000	2004	Total MacKay River
Petro-Canada	Meadow Creek	Athabasca In Situ	SAGD		80 000	2008	Total Meadow Creek
Suncor	Firebag	Athabasca In Situ	SAGD				[Suncor]
TotalFinaElf	Surmont (43.5%)	Athabasca In Situ	SAGD				[Surmont]
Canadian Natural Resources	Horizon	Athabasca Mining	Mining/Upgrader		232 000	2012	Total Horizon
Canadian Oil Sands Trust	Syncrude (21.7%)	Athabasca Mining	Mining/Upgrader	58 601			[Syncrude]
ChevronTexaco	Athabasca Oil Sands Project (20%)	Athabasca Mining	Mining/Upgrader	<100			[AOSP]
ConocoPhillips	Syncrude (9%)	Athabasca Mining	Mining/Upgrader	24 305			[Syncrude]
EnCana	Syncrude (15%)	Athabasca Mining	Mining/Upgrader	40 508			[Syncrude]
ExxonMobil	Kearl Mine	Athabasca Mining	Mining				[Kearl Mine]
Imperial Oil	Syncrude (25%)	Athabasca Mining	Mining/Upgrader	67 513	550 000	2012	Total Syncrude
Imperial Oil	Kearl Mine	Athabasca Mining	Mining		200 000	2012	Total Kearl Mine
Mocal	Syncrude (5%)	Athabasca Mining	Mining/Upgrader	13 530			[Syncrude]
Murphy Oil	Syncrude (5%)	Athabasca Mining	Mining/Upgrader	13 503			[Syncrude]
Nexen	Syncrude (7.2%)	Athabasca Mining	Mining/Upgrader	19 444			[Syncrude]
Petro-Canada	Syncrude (12%)	Athabasca Mining	Mining/Upgrader	32 406			[Syncrude]
Shell Canada	Athabasca Oil Sands (60%)	Athabasca Mining	Mining/Upgrader	<100	525 000	2012	Total AOSP
Suncor	Suncor Mine (Steepbank & Millenium)	Athabasca Mining	Mining/Upgrader	269 781	550 000	2010	Total Suncor
Synenco	Northern Lights	Athabasca Mining	Mining		80 000	2008	Total Northern Lights
TrueNorth Energy	Fort Hills (78%)	Athabasca Mining	Mining		[190 000]	2008	Total Fort Hills
UTS	Fort Hills (22%)	Athabasca Mining	Mining				[Fort Hills]
Western Oil Sands	Athabasca Oil Sands Project (20%)	Athabasca Mining	Mining/Upgrader	<100			[AOSP]
Baytex	Reita Lake	Cold Lake	Primary	2 300			
Bonavista Petroleum	Frog, Swimming, Irish, Elk Pt, Fishing	Cold Lake	Primary	4 320			
Canadian Natural Resources	16 projects	Cold Lake	Primary	32 119			
Crispin Energy	Mann Lake, Mann North	Cold Lake	Primary	222			
Devon	Manatokan, Tulabi John Lake	Cold Lake	Primary	4 896			
Husky Oil	Frog Lake, Cold Lake	Cold Lake	Primary	3 286			
Krang Energy	Lindbergh South	Cold Lake	Primary	100			
Murphy Oil	Lindbergh	Cold Lake	Primary	296			
Petrovera	Elk Point/Frog Lake/ Lindbergh	Cold Lake	Primary	4 391			
Ricks Nova Scotia	Beaverdam	Cold Lake	Primary	94			
Risa Energy	John Lake	Cold Lake	Primary	94			
Blackrock Ventures	Hilda Lake	Cold Lake	SAGD	500			
Blackrock Ventures	Orion	Cold Lake	SAGD		20 000	2007	Total Orion
Canadian Natural Resources	Primrose	Cold Lake	CSS/SAGD	32 007			
Canadian Natural Resources	Burnt Lake Crown Agreement	Cold Lake	SAGD	1 145			
Canadian Natural Resources	Wolf Lake Crown Agreement	Cold Lake	CSS/SAGD	4 615			
Husky Oil	Tucker	Cold Lake	SAGD		30 000	2006	Total Tucker
Imperial Oil	Cold Lake	Cold Lake	CSS	111 423	180 000	2008	Total Cold Lake
Blackrock Ventures	Seal I, II	Peace River	Primary	1 111	15 000	2005	Total Seal
Shell Canada	Peace River	Peace River	Pressure Pulse/SAGD	8 854	17 000	2005	Total Peace River

FIGURE 4.3 Canadian Oil Sands Projects, 2002.

Type	Company	Project	Sub-project	Initial production (b/d)	Supply (tonnes/year)
Orimulsion	PDVSA Bitor	South Korea	Orimulsion (2003 actual)		300 000
	PDVSA Bitor	South Korea	Orimulsion (design)		2 000 000
	PDVSA Bitor	Singapore	Orimulsion (signed)		
	PDVSA Bitor	Italy	Orimulsion (signed)		
	PDVSA Bitor	China	Orimulsion (signed)		
	PDVSA Bitor	Canada	Orimulsion (agreed)		
	PDVSA Bitor	Thailand	Orimulsion (proposed)		
	PDVSA Bitor	Philippines	Orimulsion (proposed)		
Extra-heavy oil	ConocoPhillips/PDVSA	Petrozuata	Produce, transport, upgrade (2003)	120 000	
	ExxonMobil/PDVSA/Veba	Cerro Negro	Produce, transport, upgrade (2003)	121 000	
	TotalFinaElf/PDVSA/Statoil	Sincor	Produce, transport, upgrade (design)	200 000	
	ConocoPhillips/ChevronTexaco / PDVSA	Hamaca	Produce, transport, upgrade (2003)	85 000	
	Ameriven (ARCO/PDVSA/ ConocoPhiliips/ChevronTexaco)	Hamaca	Produce, transport, upgrade (2003)	41 000	
	Ameriven	Hamaca	Produce, transport, upgrade (design)	165 000	

FIGURE 4.4 Venezuelan Extra-Heavy Oil Projects.

Conclusions

The recoverable volumes of oil contained in deposits of extra-heavy oil and natural bitumen are immense. If oil in place for conventional oil is estimated to be about three times original reserves, then remaining oil in place, after deduction of cumulative production, is about 4 925 billion barrels. On the same basis, the remaining oil in place in Venezuela's Orinoco Oil Belt is about 1 968 billion barrels, plus 235 billion barrels of contingent resources, and, in northern Alberta, Canada, an additional 1 455 billion barrels of natural bitumen plus 917 billion barrels of bitumen in place in the less well known carbonate deposits. Future deposits on the scale of the Orinoco Oil Belt are not expected but additional exploitable natural bitumen deposits are known in the Russian Federation, the United States, and elsewhere.

Relatively small portions of the two major deposits are currently being produced, with this production increasing annually. New technologies have allowed production rates comparable to those of conventional oil reservoirs. Major cost-reduction breakthroughs in upgrading, transportation, and refining are enhancing the movement of these hydrocarbons into mainstream world oil supply.

Richard F. Meyer
Emil Attanasi
US Geological Survey

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DEFINITIONS

In Tables 4.1 and 4.2 the following definitions apply:

Original oil in place: Discovered original oil in place.

Reserves: Those amounts of oil commonly reported as reserves or probable reserves, generally with no further distinction; only in Canada are reserves reported separately as recoverable by primary or enhanced methods. Russian A, B, and C_1 reserves are included here. The term reserve generally refers to quantities of petroleum that are anticipated to be recoverable from known accumulations.

Contingent resources: Quantities of petroleum estimated to be potentially recoverable from known accumulations but not commercially recoverable at the time of reporting, including, in Russia, C_2 deposits.

Undiscovered original oil in place: The original oil in place in undiscovered deposits. This category also includes material that is identified but is too poorly known to be considered as discovered.

Prospective resources: Quantities of petroleum potentially recoverable from undiscovered deposits. This category includes some oil categorised by the authors as possible, speculative, undiscovered recoverable or, in Russia, C_3, D_1, and D_2.

Original reserves: Reserves plus cumulative production. This category includes oil that is frequently reported as estimated ultimate recovery, particularly in the case of new discoveries.

Cumulative production: Total of production to latest date.

Annual production: Production for latest year reported.

Conventional oil: API gravity above 25° (density below 0.904 g/cm^3).

Medium oil: API gravity 20–25° (density 0.934–0.904 g/cm^3).

Heavy oil: API gravity 10–20° (density 0.934–1.000 g/cm^3).

Extra-heavy oil: API gravity below 10° (density above 1.000 g/cm^3).

Natural bitumen: Dynamic viscosity above 10 000 mPa s. (Natural bitumen is immobile in the reservoir. Because of lateral variations in chemistry as well as in depth, and therefore temperature, many reservoirs contain both extra-heavy oil, and occasionally heavy oil, in addition to natural bitumen).

Oil Field: A geographic area below which are one or more discrete reservoirs from which petroleum is produced. Each reservoir may be comprised of one or more zones, the production from which is commingled. The production of the reservoirs themselves may be commingled, in which case production and related data cannot be distinguished. This is a vexing problem if one or more of the reservoirs contains heavy or extra-heavy oil and others, medium or light oil.

Table Notes

The data in the tables are largely estimates by Richard Meyer of the US Geological Survey. They have been based upon a detailed review of the literature combined with available databases, and suggest (but do not define) the resource volumes that could someday be of commercial interest.

TABLE 4.1

Natural Bitumen: resources, reserves and production at end-2002

	Fields (number)	Reservoir depth (average, m)	Original oil in place—undiscovered (million barrels)	Prospective resources (million barrels)	Original oil in place—discovered (million barrels)	Cumulative oil production (million barrels)	Reserves (million barrels)	Original reserves (million barrels)	Contingent resources (million barrels)	Annual oil production (million barrels)
Angola	2				4 511		465	465		
Congo (Brazzaville)	1				214		6	6		
Congo (Dem. Rep.)	1				600		30	30		
Madagascar	1	10			1 750		221	221	192	
Nigeria	1		32 580		421 124		574	574	41 538	
Total Africa	**6**		**32 580**		**428 199**		**1 296**	**1 296**	**41 730**	
Canada	18	329	917 141		1 633 307	3 591	174 951	178 542	258 220	271
USA	85	89	19 775		42 119	64		64	148	
Total N. America	**103**		**936 916**		**1 675 426**	**3 655**	**174 951**	**178 606**	**258 368**	**271**
Peru	1				132					
Trinidad & Tobago	16				1 127				67	N
Venezuela	1				62					
Total S. America	**18**				**1 321**				**67**	**N**
Azerbaijan	3				90		<1	<1		
China	4	2			1 593					
Georgia	1				630		3	3		
Indonesia	1				8 912	24	422	446		3
Kazakhstan	6	36			252 922		42 009	42 009		
Total Asia	**15**				**264 147**	**24**	**42 434**	**42 458**		**3**
Germany	1	250			220	<1		<1		
Italy	1				1 260		210	210		
Russian Federation	36	116	51 345	10 650	202 087	14	28 386	28 400		
Switzerland	1				10					
Total Europe	**39**		**51 345**	**10 650**	**203 577**	**14**	**28 596**	**28 610**		

(*continued on next page*)

TABLE 4.1 (*Continued*)

	Fields (number)	Reservoir depth (average, m)	Original oil in place—undiscovered (million barrels)	Prospective resources (million barrels)	Original oil in place—discovered (million barrels)	Cumulative oil production (million barrels)	Reserves (million barrels)	Original reserves (million barrels)	Contingent resources (million barrels)	Annual oil production (million barrels)
Bahrain	1				320					
Syria (Arab Republic)	1				13				1	1
Total Middle East	**2**				**333**				**1**	**1**
Total World	**183**		**1 020 841**	**10 650**	**2 573 003**	**3 693**	**247 277**	**250 970**	**300 166**	**275**

Source: R.F. Meyer, US Geological Survey.

TABLE 4.2

Extra-Heavy Oil: resources, reserves and production at end-2002

	Fields (number)	Of which: fields offshore (number)	Reservoir depth (average, m)	Original oil in place—discovered (million barrels)	Cumulative oil production (million barrels)	Reserves (million barrels)	Original reserves (million barrels)	Contingent resources (million barrels)	Annual oil production (million barrels)
Egypt (Arab Rep.)	1		594	500	<1	50	50		<1
Total Africa	**1**			**500**	**< 1**	**50**	**50**		**< 1**
Canada	5		916						
Mexico	2		2 499	60	5	1	6		<1
USA	41	1	2 101	2 801	175	16	191		1
Total N. America	**48**	**1**		**2 861**	**180**	**17**	**197**		**1**

	Fields (number)	Of which: fields offshore (number)	Reservoir depth (average, m)	Original oil in place—discovered (million barrels)	Cumulative oil production (million barrels)	Reserves (million barrels)	Original reserves (million barrels)	Contingent resources (million barrels)	Annual oil production (million barrels)
Colombia	1		2 335	145	9	16	25		2
Cuba	1	1	1 500	960	27	50	77		2
Ecuador	3		2 462	438	30	25	54		
Peru	2		2 956	66	15	5	20		2
Trinidad & Tob.	1		76	300					
Venezuela			1 341	2 027 271	12 026	47 218	59 244	235 440	181
Total S. America	**8**	**1**		**2 029 180**	**12 107**	**47 314**	**59 420**	**235 440**	**187**
China	1		600	1 500	137	463	600		
Indonesia	1		169	< 1	< 1		< 1		
Uzbekistan	1								
Total Asia	**3**			**1 500**	**137**	**463**	**600**		
Albania	3		1 176	2 174	179	83	261		4
Italy	14	6	2 219	2 371	152	81	234		4
Poland	2		767	12					
Russian Federation	6		1 716						
United Kingdom	2	2	1 562	2 428	918	96	1 014		9
Total Europe	**27**	**8**		**6 985**	**1 249**	**260**	**1 509**		**16**
Iran (Islamic Republic)	2	1	871	23 030		250	250		
Iraq	1								
Israel	1		1 551	< 1	< 1	< 1	< 1		< 1
Total Middle East	**4**	**1**		**23 030**	**< 1**	**250**	**250**		**< 1**
Total World	**91**	**11**		**2 064 056**	**13 674**	**48 354**	**62 026**	**235 440**	**205**

Source: R.F. Meyer, US Geological Survey.

COUNTRY NOTES

The Country Notes on Natural Bitumen and Extra-Heavy Oil have been compiled by the commentary authors and the editors. Since 2001 there has been considerable activity on both the Canadian and Venezuelan fronts.

In addition to material provided by the commentary authors, information has been drawn from the companies directly involved with the resource extraction and from national and governmental organisations. Recourse has also been made to the papers given at the 7th UNITAR International Conference on Heavy Crude and Tar Sands (1998).

Albania

Three of Albania's oil fields contain extra-heavy oil, with perhaps 4 million barrels of annual production. The fields lie in the Durres Basin, a continental interior basin. In addition, the Selenzza natural bitumen deposit lies in the immediate area of the oil fields. This deposit, the most extensive of European bitumen deposits, contains an estimated 371 million barrels of bitumen in place (Walters, 1974).

Angola

Two natural bitumen deposits are located in the Cuanza Basin, Bengo Province. They contain about 4.5 billion barrels of bitumen in place but have not been worked as an energy source and are not likely to be. When conventional oil resources have been exhausted and the political stability required for mining facilities is established, exploitation could be an option.

Azerbaijan

The natural bitumen deposits are small and will probably never serve as sources for energy. They fall within the South Caspian Basin. The best known of the three is Cheildag, near Baku oil field, which has been reported frequently and contains an estimated 24 million barrels of oil in place (Walters, 1974).

Bahrain

One small natural bitumen deposit is found in Bahrain. It lies within the enormously productive Arabian Basin.

Canada

Resource information for Alberta bitumen deposits is derived from Alberta Energy and Utilities Board (2002), supplemented by estimates of undiscovered resources for Peace River (Harrison, 1984) and Athabasca (McPhee and Ranger, 1998 and Harrison, 1984). The deposits are found in Lower Cretaceous sandstones and in the Mississippian and Devonian carbonates unconformably overlain by the Lower Cretaceous. The oil sands occur along the up-dip edge of the Western Canada Sedimentary Basin.

East of the Athabasca and Cold Lake deposits, in Alberta and Saskatchewan, large quantities of heavy and medium oil are found in the Lower Cretaceous sandstones but occurrences of extra-heavy oil are few and of little economic importance.

The data in Fig. 4.3, derived from the Alberta Department of Energy (2003), represent oil sands production, by company, for 2002. Many of the companies are participants in major oil sands projects, as shown by their percentage shares in the projects. The projected future production from the projects appears as the target production for the target year.

Substantial production in the Athabasca in-situ and Cold Lake areas is primary. This bitumen is of sufficiently low viscosity to permit it to flow, albeit with two to three times the amount of sand accompanying heavy oil production. Most primary production is outside the oil sands projects and much of it falls within the conventional royalty regime. On the other hand, nearly all the oil sands project production falls within the oil sands royalty regime, permitting low royalties until capital costs are recovered. Of the oil sands royalty production, 65.5% is from mining projects, 22.8% from in situ, thermally assisted projects, and 11.7% is primary.

If all the currently proposed and approved projects move forward, production from oil sands would be about 3 million barrels per day in 2012. This amount would be supplemented by projects presently on hold, by new projects, and by continued primary production.

The National Energy Board (NEB) distinguishes between two types of non-conventional oil obtained from deposits of oil sands, defining them as follows:

- Bitumen (also known as crude bitumen)—'a naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentanes that may contain sulphur compounds and other minerals, and that in its natural viscous state is not recoverable at a commercial rate through a well'.
- Upgraded Crude Oil (also known as synthetic crude)—'a mixture of hydrocarbons similar to light crude oil derived by upgrading oil sands bitumen'.

Canada's 'original reserves' (corresponding to NEB's 'initial established reserves') of oil sands bitumen are given in Table 4.1 as 178.5 billion barrels, of which 'cumulative production' is about 3 600 million barrels. Only some 11% of the 'original oil in place discovered' is regarded as recoverable.

Within these huge resources, the 'remaining established reserves' (representing only 'those recoverable from developed experimental/demonstration and commercial projects') at end-2002 have been assessed by the Canadian Association of Petroleum Producers (CAPP) as 775.6 million m^3 of mining-integrated SCO and 321.7 million m^3 of in situ bitumen.

Although the existence of oil sands deposits was noted in the 18th century, it was not until 1875 that a complete survey was undertaken and it was the 20th century before exploitation was embarked upon. The deposits range from being several hundred metres below ground to surface outcroppings. The extraction of bitumen from the oil sands was initially based on surface-mining but in situ techniques became necessary in order to reach the deeper deposits.

There was much experimentation with oil sands technology in the first half of the 20th century but it was not until the effects of the economic climate of the 1950s and early 1960s began to be felt that commercial development became viable. The Government of Alberta's oil sands development policy was announced in 1962.

There are now many different oil sands projects, both mining and in situ, at different stages of development. The following are the main ventures:

Suncor: control of the Great Canadian Oil Sands (GCOS) project passed to Sun Oil Company in 1963 and in 1967 the world's first integrated oil sands production and upgrading plant was started up by Suncor (formerly Sun Oil). Suncor's area of operation, 40 km north of Fort McMurray, is within the Athabasca deposits. The processing capability of the original Oil Sands Plant has been steadily increased so that by 2002 production had reached a record average of 205 800 b/d. Sales in 2002 amounted to 104.7 tb/d light sweet crude oil, 23.0 tb/d diesel, 68.3 tb/d of light sour crude oil and 9.3 tb/d bitumen.

At the beginning of 1999 the company announced its 'Project Millennium', a phased series of expansions to the Steepbank mine (on the opposite side of the Athabasca River), adding bitumen extraction plants and increasing upgrader capacity. December 2001 saw the project, with a design capacity of 225 000 b/d, move from construction to production.

In early 2000, the establishment of a four-stage in-situ project at Firebag (40 km north-east of the Oil Sands Plant) was announced. The first stage is on schedule and is expected to begin commercial bitumen production in 2004. By mid-2005 it is intended that full production from the first stage will be 35 000 b/d of bitumen. It is planned that the first stage of Firebag, in conjunction with the further development of the upgrading facility, will result in Suncor production capacity reaching 260 000 b/d in 2005. In February 2003 it was reported that development of the second stage was underway and, on completion of all four stages, Firebag's combined bitumen production potential will be 140 000 b/d.

Suncor's plan is to increase overall production capacity to 500 000–550 000 b/d in 2010–2012. To this end the company announced (in late 2001) its multi-phased Voyageur growth strategy encompassing the Firebag project. Details of the first phase, released in April 2003, stated that the increased production capacity would reach 330 000 b/d by late-2007.

To achieve greater sustainability whilst vastly reducing the impact on the environment, Suncor is employing Steam Assisted Gravity Drainage (SAGD) technology. SAGD uses underground wells to inject steam into the oil sands deposits thereby collecting the bitumen released by heat. Additionally, all water used in the Firebag project will be recycled. To enable the impact on the environment to be reduced even further, Suncor is investigating ways in which CO_2 and light hydrocarbons could be injected into the deposits in order to decrease emissions and achieve a reduction in the quantities of natural gas used to generate steam. Another possibility being studied is the use of the in situ reservoir as a permanent repository for GHG.

Syncrude: is a joint venture with eight participants: Imperial (a subsidiary of ExxonMobil, with a 25% holding), Mocal, Murphy, Nexen, ConocoPhillips, Petro-Canada, EnCana and Canadian Oil Sands Trust (COS-Trust—which became the majority shareholder in early 2003). As at October 2003, COS-Trust had a 35.49% share. Imperial Oil operates the Lake Mildred plant, also 40 km north of Fort McMurray. Production began in 1978 and, using open-pit mining methods, the shallow deposits are recovered for bitumen extraction and for the production of an upgraded light sweet crude oil (Syncrude Sweet Blend® or SSB). SSB possesses no residual bottoms and at the present time the crude is rated with the lowest sulphur content in North America. In 2002 Syncrude shipped 83.8 million barrels of SSB.

Syncrude 21, an expansion project launched in 1996, is designed to take production in five stages to 200 million barrels per year by 2013–2015.

Stages 1 and 2 have been completed, bringing production from 73.5 million barrels/yr in 1996 to 81.4 million barrels/yr in 1999 and then to 94 million barrels/yr by 2001. Stage 2 included the start-up of the Aurora mine—a 35 km extension from Lake Mildred that began operating in July 2000. The mine's output is partially processed on-site and then pipelined (using hydrotransport technology) to the upgrader for further treatment.

Stage 3 (2001–2005) is currently underway. It is planned that the design capacity will be increased to 128 million barrels/yr by 2005. A second bitumen production train at the Aurora mine, scheduled for completion in the fourth quarter 2003, will feed the first phase of expansion of the Lake Mildred upgrader (completion expected first quarter 2005).

Stage 4 (2006–2010) is planned first to increase production to 150 million barrels/yr, secondly to bring into operation a new production train at Aurora South and thirdly to complete the second phase of expansion to the Lake Mildred upgrader. By 2010 processing facilities will also have been upgraded to increase the yield and quality obtained from the bitumen.

At end-2003 Stage 5 (2011–2015) was still in a planning mode. It would involve the addition of a new bitumen production train at Aurora South and further upgrading of the Lake Mildred plant.

Imperial: the Cold Lake oil sands deposits area is operated by Imperial Oil. The company began commercial development in 1983 and has since gradually expanded facilities in a series of phases. The first 10 phases were completed by 1996 and in 2002 production of bitumen and syncrude were 112 000 and 57 000 b/d, respectively.

Regulatory approval for phases 11–13 was sought in 1997, granted in 1999 and a decision made to proceed taken in 2000. Production began in late-2002, enabling an estimated additional 30 000 b/d of crude bitumen to be brought on line. In May 2003 it was reported that production was averaging 140 000 b/d.

In 2002, Imperial sought approval for phases 14–16. If the necessary approval is granted and market conditions are favourable enough to allow development to occur, bitumen production would again increase by 30 000 b/d in 2007. By 2010 production could reach 180 000 b/d.

The majority of Cold Lake production is taken by US refineries, with some sent to the heavy oil upgrader in Lloydminster (Saskatchewan) and also to Imperial's own refineries.

Imperial also plans to proceed with its Kearl Oil Sands Project (some 70 km north of Fort McMurray). Environmental surveys are being undertaken and if the mine and upgrading facilities are proceeded with, production could reach 200 000 b/d.

Shell: Commercial production of Shell Canada's Peace River in situ deposits (Northwestern Alberta) began in 1986. Bitumen production capacity is set at approximately 12 000 b/d but during first half 2000, output was running at only 4 300 b/d. Over the period August 2001–December 2002 Shell drilled 33 new production wells on four drilling pads using horizontal cyclic steam technology and over the first 10 months of 2003 was producing an average of 9 700 b/d. Although the company is continuing to assess the potential for future development, it has not yet made a decision to enlarge the project.

The Athabasca Oil Sands Project (AOSP), a joint venture between Shell Canada (the majority shareholder, with 60%), Chevron Canada and Western Oil Sands will, on completion, be capable of supplying 10% of Canada's oil needs.

The project consists of two main components: the Muskeg River Mine (75 km north of Fort McMurray), operated by Albian Sands Energy Inc. (a new company formed by the joint venture) and the Scotford Upgrader (some 500 km south and adjacent to Shell's Scotford Refinery), operated by Shell.

The oil sands deposit at the Muskeg River Mine is both close to the surface and contains a high concentration of oil. The plant is designed to produce 155 000 b/d of bitumen. Using hydrogen-addition technology to upgrade the high-viscosity bitumen, the Scotford Upgrader will upgrade the extra-heavy oil into a range of premium quality low-sulphur and low-viscosity SCOs. These will be refined to make high quality transport fuels and other products.

The Corridor Pipeline system connecting the Mine to the Upgrader consists of 2 pipelines, one capable of transporting 215 000 b/d of diluted bitumen and one capable of transporting 65 000 b/d of diluent back to the Mine for re-use.

Construction of the Mine was completed in mid-2002; the Pipeline followed during third quarter 2002, the Upgrader being completed during fourth quarter 2002. Production of bitumen began in December 2002. Development of the project continued throughout 2003 as Trains 1 and 2 of the Mine were brought into service during the first half of the year. Trains 1 and 2 of the Scotford Upgrader took delivery of the bitumen and production of SCO began. By June 2003 all facilities at both Mine and Upgrader were fully operational. Production during third quarter 2003 averaged 115 000 b/d as the project moved towards achieving the design capacity of 155 000 b/d.

It has been reported that a possible expansion of the Muskeg River plant to 250 000 b/d could occur in 2006–2007. The application for regulatory approval of the 200 000 b/d Jackpine Mine submitted by Shell Canada on behalf of the joint venture owners was completed in October 2003. It has been reported that the Mine could ultimately be expanded to 300 000 b/d.

Phase 1 of Jackpine, east of the Muskeg River Mine, would have the capacity to produce in the region of 200 000 b/d of bitumen. Phase 2 would access further reserves enabling capacity to increase by 100 000 b/d. If the plan is adhered to, the timescale for startup production from the Jackpine Mine is estimated as 2008–2010.

Petro-Canada: the first oil from Petro-Canada's in-situ MacKay River development was produced in fourth quarter 2002. It is expected that full production will be attained by end-2003 at a rate of 30 000 b/d. There are further development opportunities at Meadow Creek (45 km south of Fort McMurray), which could be commissioned and started up during 2006. A decision on whether to proceed, together with a decision regarding the upgrading of the company's Strathcona refinery in Edmonton, are expected by end-2003.

EnCana: currently has two oil sands projects: the in-situ Foster Creek Thermal Project and a pilot plant at the Christina Lake Thermal Project.

Foster Creek was producing an average of about 22 000 b/d in third quarter 2003. It is planned that within Phase 1 production will be increased to about 30 000 b/d in 2004. Following construction of Phase 2, production would be further increased by 2006 resulting in a capacity of 100 000 b/d. In May 2003 the Foster Creek co-generation plant began delivering electricity into the Albertan power system.

The first phase of the Christina Lake pilot project is producing about 3 500 b/d using SAGD technology. The design capacity of the project is 10 000 b/d. EnCana carries out evaluation and development methods to aid production and to this end has recently applied to use solvent aided process (SAP), an enhancement to SAGD, in which viscosity can be lowered.

ConocoPhillips: regulatory approval has been granted for ConocoPhillips to develop and operate its Surmont in situ oil sands deposit. If the project proceeds, it is planned that production could begin in 2006 and ultimately reach 100 000 b/d.

Jacos: approximately 50 km southwest of Fort McMurray lies the Japan Canada Oil Sands (JACOS)-operated SAGD pilot plant at Hangingstone lease. Phase 1 of the demonstration project started producing in 1999 with Phases 2 and 3 following in 2000 and 2002 respectively. By end-2002 production had reached 10 000 b/d. If it is decided to develop a commercial SAGD plant, production could be expected to be up to 50 000 b/d and to begin by late 2005.

Opti Canada (a member of the ORMAT group) and Nexen, its joint-venture partner (50/50), are developing the Long Lake Project (about 40 km southeast of Fort McMurray). The initial application for approval was for a 70 000 b/d bitumen extraction and upgrader plant. This was subsequently amended to include an additional 70 000 b/d of upgrading capacity. Since April 2001 a 500 b/d demonstration upgrader (near Cold Lake) has been successfully operating. However, the plan is for commercial production to begin in 2006 and the upgrader to come into operation the following year. This will then represent the first integrated SAGD and field upgrading operation: the bitumen production will be sent to Opti Canada's proprietary OrCrude™ process where it will be partially upgraded. In addition, the liquid asphaltenes concurrently produced will be sent to a gasifier and converted into a synthetic hydrogen-rich gas. The separated hydrogen will be utilised in a hydrocracker, completing the upgrading of the bitumen into a high-grade synthetic oil. The remaining syngas will be used for power generation, thus ensuring almost complete power self-sufficiency.

TrueNorth: as operator, TrueNorth was granted approval to develop the Fort Hills Project located about 90 km north of Fort McMurray. The application was for bitumen production of up to 235 000 b/d. However, as at end-2003 development has been deferred and it has been reported that an amended application for a smaller plant was being considered.

Canadian Natural Resources (CNRL): Primrose/Wolf Lake in-situ Oil Expansion Project was granted permission during 2002 to expand the current production of 40 000 b/d to more than 120 000 b/d. The first stage of expansion, beginning in 2003, will take place over a period of 15–20 years, as deemed economically viable.

An application has been made for CNRL's Horizon Oil Sands Project. It is a multi-phase 5-year project that includes a mine and integrated upgrader. The first synthetic oil production (at a rate of 110 000 b/d) is planned for first-half 2008. By 2010 an additional 45 000 b/d SCO would be added and by 2012, production would be in excess of 230 000 b/d. CNRL is currently developing ancillary facilities.

Fort McKay First Nation: although the 35 000 b/d Fort McKay First Nation oil sands project has been publicly debated, no firm details have emerged for its development.

Devon Energy: if Devon Energy's application for its Jackfish SAGD Project (October 2003) is approved, then the 35 000 b/d (design capacity) plant (located near Conklin) could produce its first oil in 2006/2007. As with many other oil sands operators, Devon is undertaking technological research in order to reduce the quantity of natural gas (and thus CO_2) required during conventional SAGD operations. In this instance Vapex technology, using vaporised solvents in place of steam to extract the in-situ oil, is being employed.

Synenco's Northern Lights Project: located northeast of Fort McMurray, is planned to be an integrated plant incorporating mining, bitumen extraction and upgrading. During 2003 development of plans for the 100 000 b/d, 41° API SCO plant continued. It has been reported that the anticipated start-up date is 2008.

Husky Energy is involved with two in-situ oil sands projects: the Kearl Project and the Tucker Thermal Project. A third property, Caribou, is not currently being developed.

It is estimated that the Kearl Project will first produce 50 000 b/d during 2006/2007, followed by staged, incremental expansions of 50 000 b/d. By 2012 total production is expected to be between 100 000 and 150 000 b/d.

If the Tucker Thermal Project is approved, construction could begin in 2004, with commercial production of around 30 000 b/d by 2005/2006.

Deer Creek: Phase 1 of the Joslyn Oil Sands Project is currently being constructed by Deer Creek Energy. It is anticipated that start-up of Phase 1 of the SAGD plant will occur in 2004, with full production of 600 b/d in 2005. If Phase 2 receives approval, it is expected that construction to raise production to 10 000 b/d will begin in 2004, start up in 2006 and full production in 2007. Further phases could add up to 60 000 b/d by 2012.

BlackRock is the operator of the Hilda Lake (Orion) Project. The company has successfully operated a 5-year SAGD pilot project and has now applied for approval of the commercial development of the deposit. This would involve an expansion in production to 20 000 b/d.

Of the Canadian total synthetic and bitumen production, the former contributes approximately 59% and the latter 41%. Together they represent some 26% of Canada's total production of crude oil and NGL (as at end-2002).

China

A small amount of extra-heavy oil is present in one field, Liaohe Shuguang, in the Huabei Basin. Four natural bitumen deposits have been identified in the Junggar Basin with resources of about 1.6 billion barrels of bitumen in place.

Colombia

The basins of Colombia are rich in heavy oil but extra-heavy oil is identified in only a single field. Numerous oil seepages and small deposits of natural bitumen, especially in the Middle and Upper Magdalena Basins, also characterise the country. None of these deposits appears to be sufficiently large to be of economic importance as a source for synthetic oil.

Congo (Brazzaville)

Heavy oil is found in reservoirs offshore Congo but no extra-heavy oil is known. The natural bitumen deposit at Lake Kitina in the Cabinda Basin has been exploited as road material.

Congo (Democratic Republic)

A natural bitumen deposit occurs in the Democratic Republic of Congo, in the Cabinda Basin near the border with Cabinda. It has served as a source of road material, with nearly 4 000 metric tons having been extracted in 1958. This deposit is not likely to become a source of synthetic oil.

Ecuador

Ecuador is endowed with large amounts of heavy oil but only a small amount, all in the Oriente Basin, is extra-heavy. Natural bitumen is restricted to scattered oil seepages.

Egypt (Arab Republic)

Many fields containing heavy oil are found in Egypt but very little of this is extra-heavy.

Georgia

The only significant natural bitumen deposit in Georgia is in the South Caspian basin, at Natanebi. Neither heavy nor extra-heavy oil are known in Georgia, although conventional oil has been produced there for more than a century.

Germany

Heavy oil is produced from many fields in Germany but extra-heavy oil has not been reported. Extremely viscous natural bitumen is present in the Nordhorn deposit, in the North-west German basin.

Indonesia

In Indonesia a very small amount of extra-heavy oil is reported from a single reservoir in the east Java Basin, although many fields produce heavy oil. Natural bitumen occurs in the well-known Buton Island deposit. This has long been utilised as a source of road asphalt.

Iran (Islamic Republic)

Two fields in Iran contain extra-heavy oil, one (F-Structure) being an offshore discovery. The other, Kuh-e-Mund, was discovered in 1931 and was still producing fifty years later. A number of Iranian fields produce heavy oil.

Iraq

Oil seepages have been known and utilised in Iraq throughout historical times, but are insufficient to serve as sources of synthetic oil. Although heavy oil fields are productive in the country, very little extra-heavy oil is present.

Israel

Little more than a trace amount of extra-heavy oil is known from Israel. Natural bitumen occurs only as the Dead Sea asphalt, blocks of which occasionally rise to the surface.

Italy

The 234 million barrels of original reserves of extra-heavy oil in Italy have evolved in four separate basins, similar geologically to the Durres basin of Albania. Most important of these is the Caltanisetta Basin, mostly offshore and including the Gela field. These basins are all found in the foredeep portion of the basins, where the sediments are thickest and most structurally disturbed. The viscous nature of the oil, the offshore situation, and the limited resources create enormous problems in the exploitation of these fields.

Kazakhstan

Although Kazakhstan possesses large resources of conventional and heavy oil, it contains little if any extra-heavy oil. It does have significant resources of natural bitumen (Table 4.1) in the North Caspian Basin. As with nearly all the large natural bitumen deposits, the geological setting, like that of the Western Canada Sedimentary Basin, is conducive to the development of natural bitumen. In the light of the very large resources of conventional oil and natural gas in this country, exploitation of the bitumen as a source of synthetic oil is unlikely in the foreseeable future.

Madagascar

Bemolanga is the only natural bitumen deposit in Madagascar. It is large, but attempts to produce it for synthetic oil have thus far failed. A large heavy-oil deposit, Tsimiroro, has similarly been the subject of a number of unsuccessful production tests, but no extra-heavy oil is present in the country.

Mexico

Mexico, with numerous heavy oil fields, includes very few extra-heavy oil reservoirs. The latter are small in resources and production. Oil seepages are common in the country but no large natural bitumen deposits are present.

Nigeria

Natural bitumen in place possibly totalling as much as 450 billion barrels is located in southwestern Nigeria, in the Ghana Basin. This extensive deposit has not yet been evaluated as a source of synthetic oil and its exploitation will no doubt be delayed as long as Nigeria is a leading producer of conventional oil.

Peru

Peru contains numerous heavy oil deposits, mostly in the Oriente Basin. However, its extra-heavy oil and natural bitumen deposits are small and of little economic impact.

Poland

The two extra-heavy oil reservoirs of Poland are of little interest. They are very marginal quantitatively.

Russian Federation

Extra-heavy oil has been identified in the Russian Federation in small amounts in the Volga-Urals and North Caucasus-Mangyshlak Basins. As is the case with many countries, accurate and timely data are insufficient for making estimates.

Information on natural bitumen deposits indicates that very large resources are present in Eastern Siberia in the Lena-Tunguska basin. This is harsh terrain and only the Olenek deposit has been studied in sufficient detail to permit an estimation of discovered bitumen in place. The Siligir deposit has been frequently cited in reports of world bitumen deposits, but the origin of the primary source for these citations is unknown. It may be assumed that the estimate of more than 51 billion barrels for the basin is conservative. This area is so remote, and Russia's conventional oil and gas resources so great, that it is unlikely that attempts will be made in the near future to exploit this natural bitumen. Most of the other Russian bitumen deposits are located in the Timan-Pechora and Volga-Urals Basins, which are geologically analogous to the Western Canada Sedimentary Basin. However, these deposits are scattered and the recoverable portions are not quantitatively large. The deposits in the Tatar Republic have been studied extensively and efforts to exploit them may be conducted in the future.

Switzerland

The Val de Travers natural bitumen deposit in Switzerland is small but representative of many such occurrences in Western European countries. Most of these have been known for centuries and a few have been mined, mainly for road material. Asphalt was mined at Travers from 1712 until 1986.

Syria (Arab Republic)

The Babenna natural bitumen in Syria has been mined for many years. It is one of many such deposits throughout the Middle East, those in Syria and Iraq being especially prominent since antiquity. They are of little interest as synthetic oil sources. Syria's annual output of natural bitumen has been 110–120 thousand tonnes in recent years.

Trinidad & Tobago

Trinidad and Tobago is rich in heavy oil but only a small amount of it, perhaps 300 million barrels of oil in place, is extra-heavy. The country has more than 1.1 billion barrels of oil in place in natural bitumen deposits, including Asphalt (Pitch) Lake. All these deposits are located in the Southern Basin, which is small, strongly faulted, but highly productive.

Asphalt (Pitch) Lake, at La Brea, contains a semi-solid emulsion of soluble bitumen, mineral matter, and other minor constituents (mainly water), and has been mined, mostly for use as road surfacing material, since at least 1815. The Lake contains 60 million barrels of bitumen, a sufficient supply for the foreseeable future.

Lake Asphalt of Trinidad and Tobago (1978) Ltd (TLA), a state-owned company, produces between 10 000 and 15 000 metric tons per year, most of which is exported. In combination with asphalt from refined crude oil, the product is used for road construction. In addition, it can be used in a range of paints and coatings and for making cationic bitumen emulsions. Production of these emulsions of bitumen, water, and soap began in late 1996 and the emulsions are now used widely throughout the industrialised world in place of solvent-based bitumen emulsions.

United Kingdom

The United Kingdom has two offshore extra-heavy oil deposits. One is a discovery in the West of Shetlands Basin, for which few data are available. The other is the producing Piper field in the North Sea Graben, which contains oil between 8.7 and 37° API gravity.

United States of America

The United States was endowed with very large petroleum resources, which are to be found in nearly all the various types of geological basins. The resources of extra-heavy oil and natural bitumen are likewise distributed in numerous geological settings, but the amounts in each are strikingly different.

More than 98% of the extra-heavy oil is found in basins which evolved along the rift-faulted, convergent continental margin of California. The island arcs which originally trapped the sediments against the land mass to the east have been destroyed.

About 73% of the undiscovered and poorly known natural bitumen in place and 80% of that in discovered deposits has accumulated in deposits of the Western Canada type, reflecting the fact that such basins possess ideal conditions for occurrences of degraded oil.

Distillation of oil from Casmalia tar sands in California was attempted in 1923. Many tar sands deposits in the United States have served as sources of road asphalt, but this industry disappeared with the advent of manufactured asphalt tailor-made from refinery stills.

A 1985 review (Marchant, 1988), with tar sands defined as reservoirs containing oil with a minimum viscosity of 10 000 cP, listed 43 projects, down from 52 in 1984. The projects included 34 in-situ and 9 mining and plant extraction. Marchant's review used as a mining criterion a ratio of overburden to reservoir thickness of less than one. On this basis only about 15% of the US natural bitumen resource would qualify.

In October 2003 the US House of Representatives approved a measure to remove certain leasing uncertainties relative to tar sands. In effect the bill would separate tar sands leases from oil and gas leases covering the same areas (Oil & Gas Journal Online, 2003, November 19). The objective is to revive tar sands exploitation, which has essentially ceased since the mid-1980s.

Uzbekistan

A single occurrence of extra-heavy oil is reported from the Khaudag deposit in the Amu Daria Basin. Its size is unknown.

Venezuela

A certain amount of extra-heavy oil is found in the Maracaibo Basin but the resources of worldwide significance lie in the Orinoco Oil Belt along the southern, up-dip edge of the Eastern Venezuela Basin.

One natural bitumen deposit, Guanoco Lake, is found near the Caribbean coast, on the north side of the Eastern Venezuela Basin. Wells drilled in its vicinity failed to discover recoverable oil resources. The deposit has been estimated to contain 62 million barrels of oil in place (Walters, 1974).

Four joint ventures for the exploitation of extra-heavy crude have been approved and two have been proposed. As of 2003, these projects suggest future production of about 732 000 barrels per day but this does not indicate the proposed production of all at maturity. All the projects, in one way or another, involve production, transportation, and upgrading facilities. Petróleos de Venezuela (PDVSA), the state oil company, has a minority interest in all four.

- Initial production from the *Petrozuata* project, a joint venture between ConocoPhillips and PDVSA, began during the fourth quarter of 1998. The project is designed to transport extra-heavy oil (EHO) from the Zuata region to the north coast where it is upgraded into a 19–26° API SCO.
  Commercial operations began in April 2001 following the completion of a 120 000 b/d upgrader. The resultant gasoil, LPG, sulphur and petroleum coke are marketed whilst the SCO is used as a feedstock for the Lake Charles and Cardón refineries in the USA and Venezuela respectively.
  In the second quarter of 2003 it was reported that production of EHO was averaging 130 000 b/d, yielding approximately 112 000 b/d of SCO.
- The *Cerro Negro* project, a joint venture between ExxonMobil, PDVSA and Veba Oel, has taken nearly 40 years to come to fruition from the time the resource was first identified. Initial production began in November 1999 and by end-June 2003 was averaging more than 121 000 b/d of EHO.
  The 8.5° API crude is first diluted with naphtha, pumped to the upgrader (located at the port of José on the north coast, completed August 2001) where it is converted to a 16° API crude oil. The installed capacity of 120 000 b/d is

capable of producing 108 000 b/d of upgraded heavy crude, sulphur and coke. The heavy-sour crude, especially well-suited for coking/high conversion refineries which possess cat feed hydrotreating, is refined at the ExxonMobil Chalmette refinery in the USA.

In mid-2003 ExxonMobil announced that in the short term it was planned to expand the project by 10–20%, and in the long term to double capacity.

- Following construction of the *Sincor* project, a joint venture between TotalFinaElf, PDVSA and Statoil, commercial production of SCO began in early 2002. The objective of the project is to produce approximately 200 000 b/d of 8.5° API extra heavy oil, creating a lighter crude (17° API) by means of dilution, transporting it by pipeline to the upgrader and converting it into 180 000 b/d of 32° API low-sulphur crude for international marketing. In addition, about 860 tonnes per day of sulphur and 6000 tonnes of coke are produced as by-products—the former for pharmaceutical use and the latter destined for the electric power industry.
- At the present time the *Hamaca* project is undergoing development. It is a joint venture between ConocoPhillips, ChevronTexaco and PDVSA and is designed to upgrade up to 190 000 b/d EHO that will produce approximately 180 000 b/d SCO for export.

  Drilling of development wells began in January 2001 with production of EHO beginning in the fourth quarter of that year. By end-2001 production of the 8.7° API crude was running at 35 000 b/d, being blended with 30 000 b/d of lighter crudes for the international market. During 2002 the project exported in excess of 9 million barrels of EHO and by year-end, the wells were capable of producing 85 000 b/d EHO. Construction of the heavy-oil upgrader, pipelines and production facilities began in June 2000. Completion is scheduled for mid-2004 and thereafter it is expected that the 26° API syncrude, intended for the US third-party market, will be produced in commercial quantities.

In the early 1980s Intevep, the research affiliate of the state oil company PDVSA, developed a method of utilising some of the hitherto untouched potential of Venezuela's extra-heavy oil/natural bitumen resource. Natural bitumen (7.5–8.5° API) extracted from the reservoir is emulsified with water (70% natural bitumen, 30% water, <1% surfactants), the resulting product being called Orimulsion®. Orimulsion® can be pumped, stored, transported and burnt under boilers using conventional equipment with only minor modifications. Initial tests were conducted in Japan, Canada and the UK and exports began in 1988.

Orimulsion® is processed, shipped and marketed by Bitúmenes del Orinoco S.A. (Bitor), a PDVSA subsidiary, but with the fuel's relatively high sulphur content and its emission of particulates, Intevep continues to seek improvements in its characteristics in order to match increasingly strict international environmental regulations. Bitor operates an Orimulsion® plant at Morichal in Cerro Negro with a capacity of 5.2 million tonnes per year. The company hopes to produce 20 million tonnes per year by 2006.

Following manufacture at the plant, the Orimulsion® is transported by pipeline about 320 km to the José export terminal for shipment. During the 1990s other markets were developed and currently Barbados, Brazil, Canada, China, Costa Rica, Denmark, Finland, Germany, Guatemala, Italy, Japan, Lithuania, Northern Ireland, Philippines, Singapore, South Korea, Taiwan, Thailand and Turkey either consume or are considering consuming the product.

In addition to being used in conventional power plants using steam turbines, Orimulsion® can be used in diesel engines for power generation, in cement plants, as a feedstock for Integrated Gasification Combined Cycle and as a 'reburning' fuel (a method of reducing NO_x by staging combustion in the boiler).

During third quarter 2003, the Venezuelan government announced that it intended to absorb

Bitor's operations into PDVSA East (one half of the decentralised PDVSA). The uncertain climate generated by the Venezuelan economic upheaval in 2002/2003 has resulted in a general lack of information regarding PDVSA's activities.

Orimulsion® is a registered trademark belonging to Bitúmenes Orinoco S.A.