Heavy oils: A worldwide overview

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Heavy oil is defined by the U.S. Department of Energy as having API (American Petroleum Institute) gravities that fall between 10.0° and 22.3° (Nehring et al., 1983). Extra-heavy oils are defined as having API gravities less than 10.0° API. Heavy oils are classified as such using API gravity rather than viscosity values. Two important distinctions must be made between API gravity and viscosity. First, viscosity determines how well oil will flow while API gravity typically determines the yield from distillation. Additionally, temperature and paraffin content can have a large effect on viscosity values while API gravity is not affected by these parameters.

Heavy oil has recently become an important resource as conventional oil reservoirs are in decline. More than 6 trillion barrels of oil in place have been attributed to the heaviest hydrocarbons. This is more than three times the amount of combined world reserves of conventional oil and gas. Of particular interest are the large heavy oil deposits of Canada and Venezuela, which together may account for about 55–65% of the known < 20° API oil deposits in the world (Kopper et al., 2002).

Compositions. Heavy oils usually begin as lighter oils (30–40° API) and are then altered, often by biodegradation. With aerobic biodegradation, meteoric water supplies nutrients, and oxygen and bacteria attack the lighter alkanes (straight chains) by oxidation, leaving the more complex compounds such as resins and asphaltenes behind (Box 1). This is the most common mechanism for shallow heavy oils.

In contrast, in deep reservoirs, anaerobic alteration can take place. In this case, the lighter alkanes are reduced to methane. This produces the seemingly contradictory result of producing heavy oils but the associated gases become lighter. A completely different potential mechanism involves the precipitation of asphaltenes. The solubility of asphaltenes in crude oil is strongly pressure dependent. As oils migrate, or the reservoir is slowly raised from greater depths, asphaltenes drop out of solution and form tar mats. Heavy oil rims or mats may be much more common than expected, due to the difficulty in distinguishing these in standard logs.

Unfortunately, many of the geophysical properties of heavy

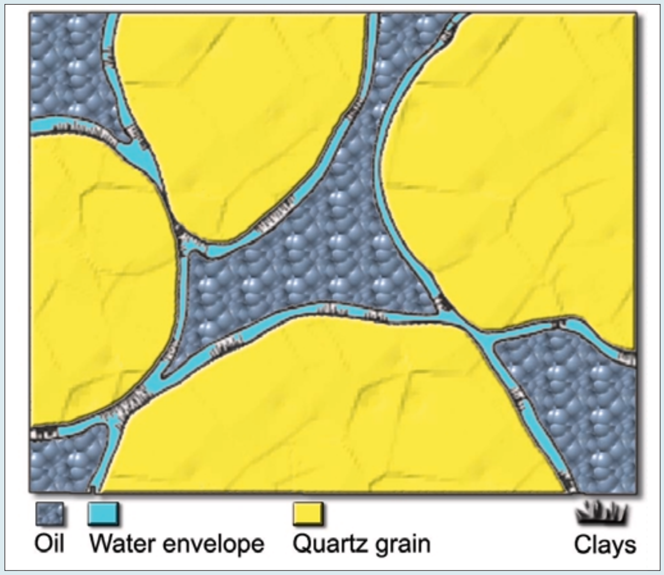

Figure 1. Schematic view of the water coating each sand grain (from Mossop, 1979).

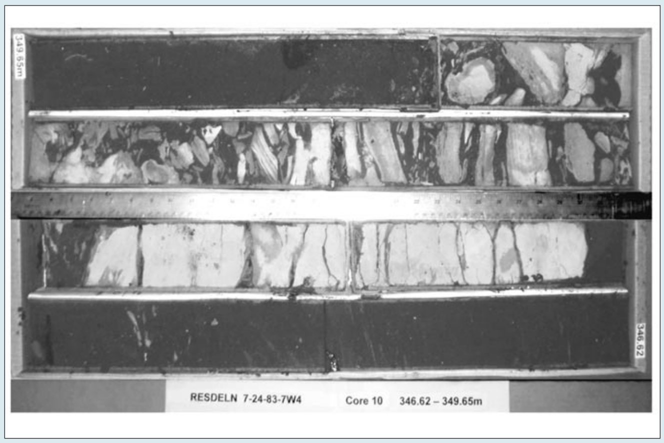

Figure 2. A section from the Resdeln core (Athabasca) shows how the oil sand (black) can be broken by shale lenses (gray).

Table 1. *Compositions of several heavy oils, both from fluid samples (A) or extracted from rock samples (B).*

A. Fluids	Sample	Saturates		Aromatics		Resins		Asphaltenes		Recovery
Sample ID	mass (mg)	(mg)	(%)	(mg)	(%)	(mg)	(%)	(mg)	(%)	(%)
Ugnu-1	75.5	17.5	23.2	16.7	22.1	26.5	35.1	13.8	18.3	98.7
Ex-1	44.6	6.7	15	10.3	23.1	8.6	19.3	4.6	10.3	67.7
H-1	42.7	8.1	19	13.6	31.9	12.4	29	7.8	18.3	98.1
CL-1	75.9	13.8	18.2	20.4	26.9	20.6	27.1	11.4	15	87.2
Pt. Ped. DST3	79.4	26.5	33.4	20.3	25.6	23.1	29.1	8.7	11	99
B. Extracted	**Sample**	**Saturates**		**Aromatics**		**Resins**		**Asphaltenes**		**Recovery**
Sample ID	mass (mg)	(mg)	(%)	(mg)	(%)	(mg)	(%)	(mg)	(%)	(%)
GoM Tar Mat 1	115.4	15.8	13.7	9.4	8.1	14.9	12.9	60.0	52.0	86.7
Monterrey Goleta	38	2.0	5.3	4.1	10.8	14.3	37.6	17.2	45.3	98.9
Anacacho Uvalde	43.1	1.5	3.5	7.3	16.9	16.0	37.1	18.3	42.5	100.0
SR-1	32.1	4.5	14.0	7.6	23.7	10.7	33.3	7.8	24.3	95.3

oils are still poorly understood. As the alkanes decrease and resins and asphaltenes increase, oils become more dense and viscous. Table 1 presents the liquid chromatographic analysis of our heavy oil samples. These are samples from Canada, Venezuela, Alaska, Texas, and California. The high asphaltene and resin contents are recorded in the outcrop samples (Uvalde, Goleta) and are a result of the intensive biodegradation common in the very near surface. The exception is the Tar Mat 1 sample recovered from the deepwater Gulf of Mexico which contains the highest asphaltene content (52%). It has been reported that this mat is a result of anaerobic biodegradation (Tim Lane, personal communication), but the low resin content and high saturates suggest some asphaltene precipitation. The outcrop samples also show relatively high sulfur content (Table 2).

Figure 3. Heavy-oil reservoirs are broadly distributed across the earth.

Table 2. *Sulfur content of the heavy oils.*

Sample ID	Sample type	Sulfur content (%)
GoM Tar Mat 1	Extract	6.11
Monterrey Goleta	Extract	5.06
Anacacho Uvalde	Extract	9.13
SR-1	Extract	5.27
Ugnu-1	Oil	1.54
Ex-1	Oil	2.54
H-1	Oil	3.68
CL-1	Oil	3.93
Pt. Ped. DST3	Oil	2.25

Argillier et al. (2001) conducted a rheological study of several heavy oils and concluded that the asphaltene content was a controlling factor for viscosity. Their data indicate that when the asphaltenes passed a critical weight fraction (around 10%), viscosity increased dramatically. They speculate that the long asphaltene chains begin to conglomerate and tangle. In contrast, increased resin content actually decreased viscosity. However, a recent analysis by Hossain et al. (2005) found no strong viscosity correlation with asphaltene content. Because viscosity partly controls our seismic velocities, the influence of asphaltenes and resins will need to be examined more thoroughly. Details of velocity and viscosity analysis are presented in following section.

Oil sands. Heavy oil reservoirs tend to be shallow with less effective seals than traditional reservoirs possibly allowing for some light hydrocarbons to escape early in the migration process. Clay contents vary considerably and may have adverse effects on extraction techniques. One important aspect of oil sands is the water versus oil wettability. In some heavy oil reservoirs, the crude oil bonds directly to mineral surfaces displacing water. This situation is considered oil wet. By contrast, water wet sands maintain a rim of water around each grain (Figure 1). In this case, a continuous film of water persists through the rock preventing direct contact between the oil and mineral surfaces. Such water wet sands release oil more easily during surface processing and hot water extraction. These water coatings are important to the rock physical properties, such as capillary pressure and relative permeability, and can be disturbed or lost if the core is improperly stored.

These heavy oils can hold much less gas in solution than light oils, but the small amount they do contain can have a major impact. Gas going in and out of solution as pressure changes during various recovery processes may produce the largest seismic response. Another issue is core disturbance due to gas generation as the core is brought to the surface. The high viscosity of the oil prevents rapid gas escape. Because many oil sands are unconsolidated, this gas can result in substantial swelling. Initial measurements of core porosity can be higher than 50%. However, after application of even low confining pressures, the porosity rapidly drops to values in the mid-30% ranges. This does not mean that all damage has been completely reversed.

Oil sands can be quite complex, so preproduction reservoir description can be a primary goal of geophysical investigations. In recovery processes such as steam-assisted gravity drainage (SAGD), sand continuity can be critical. The mobilized oil resulting from injected steam in an upper horizontal well must communicate with a lower producing well. However, shale lenses and layers are common in fluvial depositional environments typical of many oil sands (Figure 2). There has been some recent success using geophysical techniques to differentiate zones of high shale content. Unfortunately, the difference in compressional velocities of the shales and sands may be very similar and may not allow them to be distinguished directly. AVO techniques show some promise in identifying lithologies.

Heavy oil reservoirs. In this section, we will compare some of the world's major heavy oil reservoirs (Figure 3) and discuss some of the problems faced in producing these reservoirs.

There are several prevailing issues that will be seen repeatedly in various fields around the world. The heavy oil reservoirs tend to consist of unconsolidated sandstone which creates two important challenges. The first is how to make accurate rock property (especially porosity) measurements when the core is almost always severely disturbed. The second deals with the fact that sand is often produced with the oil in order to maintain economic levels of production. The creation of *wormholes*, or high permeability zones created by sand production, can greatly increase well productivity. It is still not well understood how the production of sand with oil will change porosity, permeability, and formation stability.

Another phenomenon that is not yet fully understood is referred to as *foamy oil*. This is a phenomenon where gas comes out of solution but becomes entrained in the oil phase, and the flow behavior remains that of single phase oil with a higher compressibility (Ehlig-Economides et al., 2000). This behavior can also drastically increase well productivity.

Finally, it is often necessary to perform extensive steam injection to reduce the viscosity of the heavy oils so that it will flow to production wells. Therefore, it will be extremely important to understand and be able to monitor the steam front. This will allow for the appropriate determination of steam paths and the effects of steam injection on the reservoir and production.

Kern River Field, Bakersfield, California. The Kern River Field in Bakersfield, California, was discovered in 1899. There is an excellent discussion of this field in the autumn 2002 *Oil Review*.

Table 3. *A summary of heavy oil properties worldwide.*

	API gravity	Viscosity (cp)	OOIP	Production issues	Porosity (%)	Permeability (md)	Pay thickness	Reservoir depth
Kern River Field, Bakersfield, California	10–15°	500–10 000	4 billion	Monitoring of steam fronts	31	1000–10 000	190 ft	700–1000 ft
Ugnu Field, North Slope, Alaska	8–12°	200–10 000+	2 billion	Environment, climate	25	1000–10 000	80–120 ft	2715–3260 ft
West Sak Field, North Slope, Alaska	17–21°	20–90	3 billion	Environment, climate	< 20	50–100	70–100 ft	3750–4040 ft
Duri Field, Indonesia	20	330	5.3 billion	Monitoring of steam fronts, sand production, corrosion	34	1500	40 ft	500 ft
Athabasca Sands, Alberta, Canada	8.5–9.5 (within Athabasca sands)	Up to 1 000 000 cp	2.2 trillion	Highly immobile oils; steam monitoring; sand production effects on formation; distinguishing sand and shale	30–35	500–5000	100–115 ft	0–1300 ft
Faja del Orinoco, Venezuela	8.5–10	1000–5000	1.2 trillion	Distinguishing sand and shale; implementing new technologies	27–32	2000–15 000	130–150 ft	1700–2350 ft
Utah heavy oil	8–14 (30 for NW Asphalt Ridge tar sand)	(> 106 cp for NW Asphalt Ridge tar sand)	8 billion	Environment; land access	(28 for NW Asphalt Ridge tar sand)	(10 for NW Asphalt Ridge tar sand)	(1–40 ft for NW Asphalt Ridge tar sand)	
Bikaner-Naguar Basin, India		10 000–16 000	14.6 million tons	Transport of viscous oil				
Bohai Sea, China			1.3 billion					
Offshore Brazil	15–20			Related to offshore environment; horizontal drilling; sand production; enhanced recovery; and separation of heavy oils				

Some facts in that article are summarized in this section. The oil is approximately 10–15° API density and 500–10 000 cp viscosity. The field, with an aerial extent of 6 × 4 mi, is estimated to contain 4 billion barrels of original oil in place (OOIP). However, cold production peaked in the field at just over 40 000 b/d in the early 1900s (Figure 4).

The operator, Chevron, initially placed bottomhole heaters in the wells in the mid-1950s; this was able to slightly increase production. Then, in the 1960s, steam injections proved to be extremely successful. There was a dramatic decrease in oil viscosity and by 1973, 75% of Kern River production was from steam injection projects. Due to this fact, one of the most important challenges in this field will be monitoring heat distribution. Chevron has used a variety of technologies to mon-

Box 1. *Short glossary of terms related to heavy oils (modified from Hunt, 1996).*

Aromatics: (Arene) (AR) Hydrocarbons containing one or more benzene rings. Monoaromatics have the molecular formula C_nH_{2n-6}. Benzene, toluene, and the xylenes are arenes. Polycyclic aromatic hydrocarbons (PAH) contain several rings with two or more carbon atoms shared between rings.

Asphaltenes: Asphaltic constituents of crude oil that are soluble in carbon disulfide but insoluble in petroleum ether or n-pentane. Asphaltenes are agglomerations of molecules with condensed aromatic and naphthenic rings connected by paraffin chains. They have molecular weights in the thousands.

Biodegradation: The destruction of petroleum and related bitumens by bacteria. At temperatures below 88°C, the petroleum in reservoirs, oil seeps, and asphalt paving, as well as the gasoline in storage tanks are susceptible to bacterial degradation, which converts hydrocarbons to alcohols, acids, and other water-soluble products.

Bitumens: Native substances of variable color, hardness, and volatility, composed principally of the elements carbon and hydrogen and sometimes associated with mineral matter, the nonmineral constituents being largely soluble in carbon disulfide.

Paraffin: (Alkane) A hydrocarbon with the molecular formula C_nH_{2n+2}. It includes normal straight-chain paraffins and branched alkanes, such as methane, ethane, propane, and isobutane.

Pyrobitumen: Black to dark brown, hard bitumens that are infusible and relatively insoluble in carbon disulfide. Albeftite, wurtzilite, and impsonite are pyrobitumens.

Resin: Petroleum resins are the fraction of residuum that is insoluble in liquid propane but soluble in normal pentane. Plant resins are terpenoids ranging in molecular size from sesquiterpenes (C_{15}) to tetraterpenes (C_{40}). They contain the olefinic double bonds of the isoprene building block that, when exposed to air, causes the liquids to polymerize and oxidize to hard resins. Balsam and mastic are plant resins.

itor steam fronts including crosswell EM surveys, electromagnetic propagation tools, and reservoir saturation tools for modeling purposes.

Ugnu and West Sak fields, North Slope, Alaska. There is considerable variety in the heavy oils that reside on the North Slope of Alaska. West Sak Field has much lower permeability, slightly higher temperature, and a higher GOR than Ugnu Field. Perhaps the most substantial difference is the fact that West Sak oil has an API gravity value of 17–21°, locating this oil at the lightest end of heavy oils. Meanwhile, Ugnu Field contains oil with API gravity values of 8–12°, classifying this oil as extra heavy oil. There is also a substantial difference in viscosity: 20–90 cp for West Sak oil versus 2000–10 000+ cp for Ugnu oils. Clearly these fluid properties will have a large effect on the challenges faced by operators in producing these areas (Weiss, 2004).

The unique Alaskan environment also presents a challenge for heavy-oil production in Alaska. Permafrost can affect steam quality. There are environmental damage concerns that do not exist outside of the fragile Alaskan ecosystem. Additionally, the harsh climate can cause corrosion, well leakage, and heat losses.

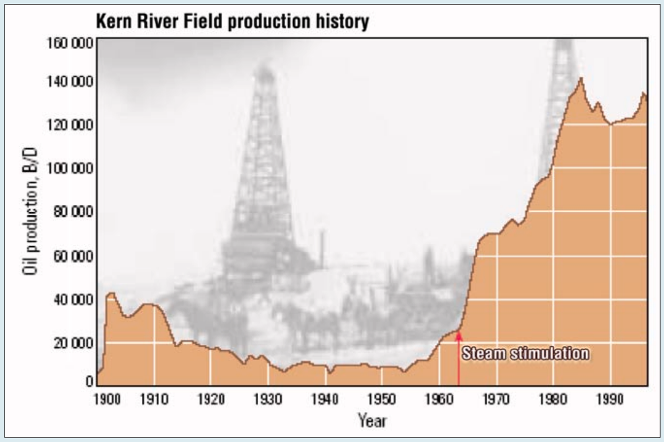

Figure 4. *History of oil production from the Kern River Field. Low primary recovery using cold-production techniques ended in the 1960s, when steam-injection methods rejuvenated the field—a program that continues today (from Kopper et al., 2002).*

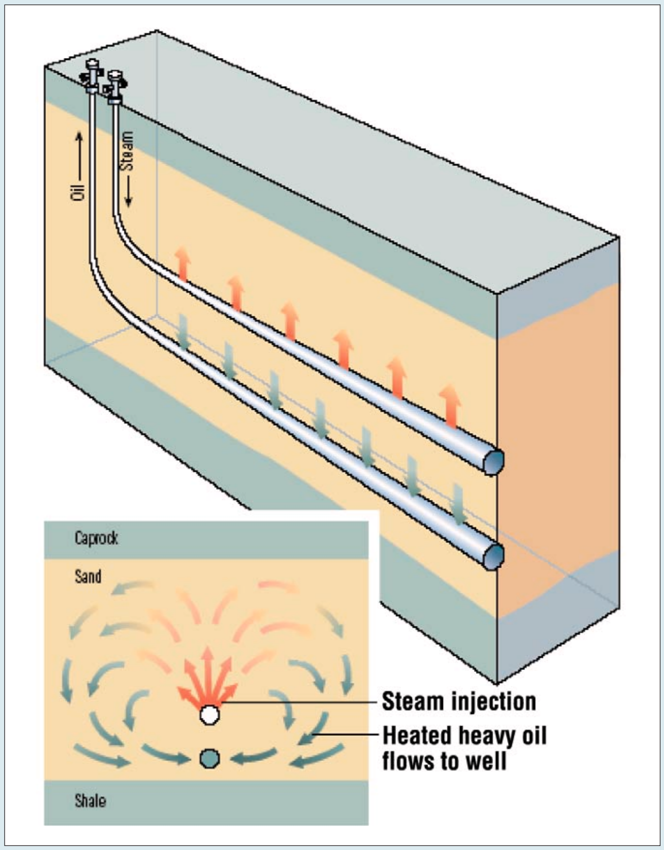

Figure 5. *The concept of steam-assisted gravity drainage (SAGD). Horizontal wells drilled in stacked pairs form the basic unit of SAGD project (top). Steam injected into the upper well melts surrounding oil (bottom). Gravity causes the mobilized oil to flow downward to the lower well for production. SAGD well pairs can be drilled to track depositional features or in patterns for optimal recovery (from Kopper et al., 2002).*

Duri Field, Indonesia. Duri Field contains oil that has 20° API gravity, meaning it is light relative to most heavy oils and will have different properties than the extra heavy oils referenced elsewhere in this paper. For example, it has a fairly low viscosity and tends to have a higher GOR. The oil is still heavy enough to make production a challenge, and primary production peaked in this field at 65 000 b/d in the mid-1960s. It was thought that ultimate recovery would be only 7% of OOIP

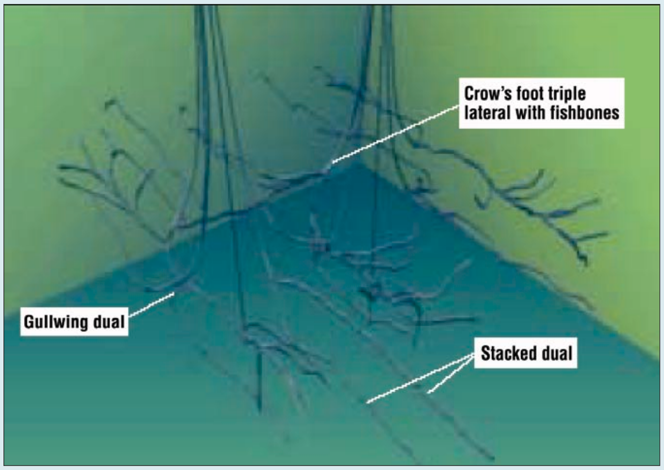

Figure 6. Actual well paths of 10 multilateral wells, four of which have fishbones, drilled from two pads in the Zuata area of the Faja. The ability to drill these complex wells has resulted in more effective tapping of sand bodies and higher production (from Kopper et al., 2002).

(Kopper et al., 2002). Steam injection proved to be highly successful in Duri Field improving production to nearly 230 000 b/d and improving estimated oil recovery factors. Today this field is the largest steamflood operation in the world (Kopper et al., 2002).

In order to monitor the steam injection, PT Caltex Pacific Indonesia (CPI) has employed many of the same techniques seen in Bakersfield as well as tracer surveys and fiber-optic temperature surveys (Kopper et al., 2002). However, to get a complete spatial picture of the steam front, 4D seismic has been an important monitoring technique. Other issues due to steamflooding include sand production, corrosion, and scaling. Sanding has been attacked using screened liners, curable resin-coated sand packs, and materials such as PropNET propant-pack additives in fractures. However, openhole gravel packing is still the standard in most wells. Jet blasting screens have proved to be an economic alternative to replacing screens where scale has built up. For a more extensive discussion of some of these problems, see autumn 2002 *Oilfield Review*.

Heavy-oil belt and oil-sands deposits in Alberta and Saskatchewan. The heavy-oil deposits in Canada are vast with an estimated 2.2 trillion barrels of OOIP (Dusseault, 2001). Canadian oil deposits are almost all Middle Cretaceous in age and tend to be extremely shallow. The Athabasca oil sands, which are considered to be the largest reservoir in Canada, are actually at the surface north of Ft. McMurray and have a maximum burial depth of 400 m. Other reservoirs range in depth 350–900 m.

A great resource for a comparison of Venezuelan and Canadian heavy-oil sands is Dusseault's paper from the 2001 Canadian International Petroleum Conference. Many of the concepts from this paper are presented in this section and the following section for discussion purposes.

The heavy oil in Canada displays a range of API gravities between 8.5° and 15°. One very difficult problem faced in the production of Canadian heavy oils is its high viscosity. Although values as low as 100 cp can be found, the surface deposits of Athabasca reach viscosity values of >1 million cp. Dusseault noted that even after all parameters (T, p, μ, k) have been corrected for, Canadian oils are still notably less mobile than Venezuelan oils. This may be due to the fact that Canadian oils have substantially higher asphaltene content in general.

Another interesting characteristic of Canadian reservoirs is that the pore pressure tends to be about 15% less than hydrostatic pressure. This means that less gas will be present in solution than with Venezuelan oils. Therefore, gas exsolution will not be such a large energy drive in Canadian reservoirs. Finally, Canadian reservoirs tend to have permeabilities on the range of .5–5 darcy, which is significantly lower than Venezuelan reservoirs.

Due the difficult nature of producing the oils in Canada, many new technologies have been developed here. Horizontal well drilling was pioneered by the Canadian oil industry. CHOPS (cold heavy-oil production with sand) is a popular production approach where sand is encouraged to enter the well rather than blocked by screens or gravel packs. This method has several advantages because permeability is increased and plugging near the wellbore is prevented.

SAGD, a relatively new approach to production, consists of drilling two parallel horizontal wells—one used for steam injection, the other used for oil production (Figure 5). The idea is that the heated steam will rise while water and heavy oil will flow downward due to gravity flow. Once again, monitoring the steam front and its effects on the formation become an important consideration.

Faja del Orinoco, Venezuela. Venezuela also has extremely large heavy-oil deposits with an estimated OOIP in place of 1.2 trillion barrels. Due to more favorable reservoir conditions than Canada, horizontal wells have been the major technology used in Venezuela. The wells often take on very complex geometries (Figure 6). Another common procedure is to inject lighter oils into the wells in an attempt to lower the viscosity of the heavy oils. Other technologies may be increasingly employed in the near future if production slows.

The oil in the Faja del Orinoco ranges in oil density values from 8.5° to 10° API. As previously stated, the major difference between Venezuelan and Canadian heavy oils are the viscosity values found in each location. Venezuela oil ranges from 1000 to 5000 cp. This is partially because the Canadian Athabasca producing sands reside at a much shallower depth than the Faja del Orinoco producing sands (Table 3). Therefore, lower formation temperatures exist in the Athabasca reservoirs. However, even with all other parameters set equal, Canadian oil still has a much lower viscosity than Venezuelan oil. This may be due to lower asphaltene content in Venezuelan oil. In general, permeability in the Venezuelan reservoirs ranges from 2 to 15 darcy.

In the future it may be important to experiment with new technologies beyond horizontal drilling in order to maximize production in the Faja del Orinoco. Three-dimensional imaging using seismic data has also proved challenging in this area. It is still not entirely understood why seismic data are not very diagnostic in this region even at relatively shallow depths.

Other significant heavy oil deposits worldwide. There are several very large heavy-oil deposits in eastern Utah that are estimated to contain more than 8 billion barrels of 8–14° API oil in place (Schamel and Baza, 2003) in fields such as Sunnyside, Circle Cliffs, Asphalt Ridge, and the Tar Sand Triangle. In addition to the technical challenges of producing this heavy oil, environmental concerns and land access have created challenges for producing these reserves.

Heavy-oil reserves were discovered in the Bikaner-Nagaur Basin in India in 1991. The estimated OOIP is 14.6 million tons. PDVSA and Oil India Ltd. (OIL) were expected to start drilling for heavy oil in August 2005. The heavy oil in the North Cambay Basin in India is difficult to transport because of its high viscosity (10 000–16 000 cps). Oil-in-water emulsions have been proved to reduce viscosity by as much as two orders of magnitude.

In Brazil, special technological challenges will be faced in many heavy-oil fields because they are located in an offshore environment. This makes implementing thermal technologies such as SAGD extremely challenging and CHOPS uneconomic (Trindade and Branco, 2005). The heavy oil in this area tends to be of a lighter variety, around 15–20° API. A discussion of the challenges faced in developing this area can be found in Trinidade and Branco's paper from the SPE Latin American and Caribbean Petroleum Engineering Conference in June 2005. Some of the challenges are listed here:

- drilling of extended horizontal wells in a deepwater environment
- controlling sand production
- economic means of enhanced recovery (specifically artificial lift)
- economic separation of the heavy oils on offshore platforms

Additionally, there have been some reports of heavy-oil discoveries in the Bohai Sea of China, which has reserves estimated at 1.3 billion barrels. CNOOC's Luda heavy-oil field, which came on production in 2005, is producing about 40 000 b/d. There has also been heavy-oil production from Liahe, Shengli, Xinjiang, and Henan fields (He et al., 1995). There are most likely many other heavy-oil deposits that have not yet been explored around the world.

Conclusion. Several known properties of many large heavy-oil deposits around the world have been summarized in this paper (Table 3). As can be seen, the summary is still incomplete, especially when it comes to properties such as wettability. It is difficult to find thorough discussions on the heavy oils of China, India, and deepwater Brazil, and there are probably heavy-oil deposits in many parts of the world that have not yet been discovered. As alternative energy resources become increasingly important in the near future because of declining conventional reserves, it will be imperative to quantify the properties of heavy oil, one of the largest alternative fuels that remain largely unexplored.

Suggested reading. "Influence of asphaltene content and dilution on heavy oil rheology" by Argillier et al. (SPE 69711, 2001). "Comparing Venezuelan and Canadian heavy oil and tar sands" by Dusseault (Canadian International Petroleum Conference, Petroleum Society: Canadian Institute of Mining, Metallurgy, and Petroleum, Paper 2001-061, 2001). "Global experiences and practice for cold production of moderate and heavy oil" by Ehlig-Economides et al. (SPE 58773, 2000). "The feasible conditions study of steamflooding for heavy oil reservoirs in China after cyclic steam injection" by He et al. (SPE 30303, 1995). "Biologic activity in the deep subsurface and the origin of heavy oil" by Head et al. (*Nature*, 2003). "Assessment and development of heavy oil viscosity correlations" by Hossain et al. (SPE 97907, 2005). *Petroleum Geochemistry and Geology, 2nd edition* by Hunt (W. H. Freeman Co., 1996). "Enhanced oil recovery of Ugnu tar sands of Alaska using electromagnetic heating with horizontal wells" by Islam et al. (SPE 22177, 1991). "An analytic model for analyzing the effects of dissociation of hydrates on the thermal recovery of heavy oils" by Kamath et al. (SPE 14224-PA, 1988). "Heavy-oil reservoirs" by Kopper et al. (*Oilfield Review*, 2002). "Effects of biodegredation on oil and gas field PVT properties and the origin of rimmed gas accumulations" by Larter and diPrimio (*Organic Geochemistry*, 2005). "Case history of steam soaking in the Kern River Field, California" by Long (*Journal of Petroleum Technology*, 1965). "Geology of Athabasca oil sands" by Mossop (*Science*, 1979). "The heavy oil resources of the United States" by Nehring et al. (R-2946-Doe, 1983). "Heavy oil resources of Utah: An emerging opportunity?" by Schamel and Baza (AAPG Annual Convention Abstracts, 2003). "Pipeline transportation of heavy/viscous crude oil as water continuous emulsion in North Cambay Basin" by Sharma et al. (SPE 39537, 1998). *Historical Geography of the Holy Land, 26th edition* (1st edition published in 1894) by Smith (Harper and Brothers, 1935). "The offshore heavy oil development challenges in Brazil" by Trindade and Branco (SPE 97381, 2005). "CSAMT mapping of a Utah tar sand steamflood" by Wayland et al. (*Journal of Petroleum Technology*, 1987). "Origin of tar mats in petroleum reservoirs. Part II: formation mechanisms for tar mats" by Wilhelms and Larter (*Marine and Petroleum Geology*, 1994).

Appendix: Early application of heavy oils. Knowledge and use of heavy oils has persisted since antiquity. For example, so many tar seeps were common around the Dead Sea, that it had an alternative name associated with heavy oil.

From Smith (1935):

> "Along the shore are deposits of sulphur and petroleum springs. The surrounding strata are rich in bituminous matter, and after earthquakes lumps of bitumen are found floating on the water so as to justify its ancient name of Asphaltitis."

Bitumen is petroleum hardened by evaporation and oxidation (Dawson, *Modern Science in Bible Lands, 1889*). The bituminous limestone, which burns like bright coal, is the so-called Dead Sea stone from which articles are made for sale in Jerusalem and Bethlehem. The floating lumps probably are from petroleum springs in the seabed. These springs were more common in ancient times. Genesis says the Vale of Siddim was wells—wells, i.e., full of wells, of bitumen.

It is suggested that the conflagration that consumed the legendary towns of Sodom and Gomorrah was a result of combustion of the local heavy-oil deposits.

> "And Yahweh rained upon Sodom and Gomorrah sulphur and fire—from Yahweh, from the heavens—and He overturned those cities, and all the Circle, and all the inhabitans of the cities, and that which grew upon the ground. And Lot's wife looked back as they fled to Soar and became a pillar of salt. And Abraham looked down upon Sodom and Gomorrah, upon all the land of the Circle, and saw, and, behold, the smoke of the land went up like the smoke of a furnace." (Genesis 19:24-28).

Again from Smith (1935):

> "Some have taken these words to describe such an eruption as that of Vesuvius upon Pompeii. But there is no need to invoke the volcano, and those are more in harmony with the narrative, who judge that in this bituminous soil took place one of those terrible explosions and conflagrations, which have broken out in the similar geology of the oil districts of North America. In such soil reservoirs of oil and gas are formed, and suddenly discharged by their own pressure or by earthquake. The gas explodes, carrying high into the air masses of oil which fall back in fiery rain, and are so inextinguishable that they float afire on water. Sometimes brine and saline mud are ejected, and over the site of the reservoirs are tremors and subsidence. Such a phenomenon accounts for the statements of the narrative."TLE

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