

Heavy Oils, Part I

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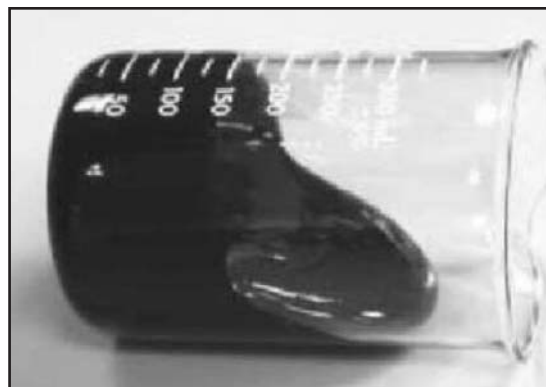
The world wants enormous new crude oil reserves. No economical, abundant substitute for crude oil is available, or will become available in the next several decades. Even at a price of more than \$60/barrel, maintaining the supply needed to support the economies of industrial countries and enable them to grow will require the development of significant additional crude oil reserves.

Conventional (light and medium) oil reserves as of the end of 2002 (see Table 1) will last at most 40 years at the 2002 production rate [2]. Additional resources will thus be primarily in the form of the sole alternative: heavy crudes.

The heaviest hydrocarbons account for more than six trillion barrels (one trillion m^3) of the oil in place worldwide—triple the combined world reserves of conventional oil and gas. Natural crude oils usually exhibit a continuum of densities and viscosities. Viscosity at reservoir temperature, which determines how easily oil flows, is often the most important measure to an oil producer. Density, a better indicator of the yield from distillation, may be more important to an oil refiner. Unfortunately, no clear correlation exists between the two: Medium-density or light crude with high paraffin content in a shallow cool reservoir can have a higher viscosity than heavy, paraffin-free crude in a deep hot reservoir. Viscosity varies greatly with temperature, while density varies little. Density has become the more commonly used oil field standard for categorizing crude oils.

Density is usually defined in terms of API (American Petroleum Institute) gravity, which is related to specific gravity—the denser the oil, the lower the API gravity [3]. API gravities for liquid hydrocarbons range from 4° , for tar-rich bitumen, to 70° , for condensates. Heavy oil occupies a range along this continuum between ultraheavy oil and light oil. The U.S. Department of Energy defines heavy oil as having API gravity between 10° and 22.3° [7]. Nature does not recognize such boundaries, however: In some reservoirs, oil with gravity as low as 7° or 8° is still considered heavy rather than ultraheavy, because it can be extracted by heavy oil production methods.

In this article, we discuss reservoirs of oil with API gravity between about 7° and 20° and the technologies used to develop them, particularly those that are not typically used for light or medium oils. As an indication of the problems that arise, the most viscous tar, pitch, and bitumen deposits at even lower API gravities often require mining-style techniques for economic exploitation.



The viscosity of heavy oil can be similar to that of honey [4].

Total Discovered	Cumulative Amount Produced	Remaining Recoverable	Percent Remaining	Amount Produced in 2002
2,139, 249	985,057	1,154,192	54	26,721

Table 1. Conventional liquid hydrocarbon resources through the end of 2002 (in millions of barrels).

Heavy Oil Recovery: Special Considerations

On original generation from petroleum source rock, crude oil is not heavy. Almost all crude oils originate with API gravity between 30° and 40° ; oil becomes heavy only after substantial degradation during migration and after entrapment [4]. A variety of biological, physical, and chemical processes have been implicated in degradation. Bacteria borne by surface water metabolize paraffinic, aromatic, and naphthenic hydrocarbons into heavier molecules [10]. Formation water washes away some of the lighter, highly water-soluble hydrocarbon molecules. In a process called devolatilization, a poor-quality seal allows lighter molecules to separate and escape.

Heavy oils are typically produced from geologically young reservoirs: Pleistocene, Pliocene, and Miocene. Because these reservoirs are shallow, they have less effective seals and are thus exposed to conditions conducive to the formation of heavy oils. The fact that most heavy oil reservoirs are shallow is an indication that many of them were discovered as soon as human beings settled nearby. Collecting oil from seeps and digging by hand were the earliest and most primitive means of recovery, followed by mining and tunneling.

In the early 1900s, these primitive techniques were replaced by other techniques, some of which are still employed today to recover heavy oils. Most practitioners try to produce as much heavy oil as possible by primary recovery methods, named “cold production” for being carried out at reservoir temperature. Typical recovery factors (percentage of the oil in a reservoir that can be recovered) for cold production range from 1% to 10%. Depending on the properties of the oil in a reservoir, primary production with artificial lift, e.g., injection of a light oil, or diluent, to reduce viscosity, can be very useful. Many fields produce most efficiently with horizontal production wells. In some cases, exploiting foamy oil behavior and/or encouraging the production of sand along with the oil turn out to be the preferred production strategy. Choosing the optimal cold production strategy requires an understanding of rock and fluid properties.

A cold production oil reservoir is a “solution gas drive reservoir” if the major reservoir energy for primary depletion is supplied by the release of gas from the oil and the expansion of the in-place fluids as reservoir pressure declines. The fraction of original oil in place (OOIP) that can be recovered by solution gas drive decreases with increasing oil viscosity. For heavy oil reservoirs, the expected recovery factor by solution gas drive is typically about 5%. A number of heavy oil reservoirs under solution gas drive, however, have obtained anomalous primary performance results: low production gas–oil ratios, high oil production rates, and recovery of unexpectedly large amounts of oil. This unusual behavior has been attributed to a couple of production mechanisms.

In the first, gas bubbles expand, giving the oil a foamy character as the bubbles are trapped by the oil; recovery is then enhanced by solution gas drive. Ultimate oil recovery with primary techniques can be as high as 20% for some heavy foamy oil reservoirs. The second mechanism is internal erosion in unconsolidated sand reservoirs, which can create a network of high-permeability channels, termed “wormholes.” This mechanism can enhance drainage by a factor of 10 or more. Wormhole formation and localization are not completely understood, which makes it difficult to optimize production.

The remainder of the discussion here is devoted to foamy oil. Part II of the article, which will appear in the next issue of *SIAM News*, will discuss sand production and wormholes.

Foamy Oils

In all solution gas drive reservoirs, gas is released from solution as reservoir pressure declines. Gas initially exists in the form of small bubbles within individual pores in the rock. As time passes and pressure continues to decline, the bubbles grow to fill the pores. With further declines in pressure, the bubbles created in different locations become large enough to coalesce into a continuous gas phase. Traditional wisdom is that discrete bubbles larger than pore throats remain immobile, trapped by capillary forces; gas flows only after the bubbles have coalesced into a continuous gas phase. Once the gas phase becomes continuous (i.e., when gas saturation exceeds the critical level, the minimum saturation at which a continuous gas phase exists in porous media [1]), traditional two-phase (oil and gas) flow with classical relative permeabilities occurs. As a result, the production gas–oil ratio (GOR) increases rapidly after the critical gas saturation has been exceeded.

Field observations in some solution gas drive heavy oil reservoirs, however, are not consistent with this description, in that the production GOR remains relatively low. The recovery factors in such reservoirs are also unexpectedly high. A simple possible explanation of these observations is that the critical gas saturation in these reservoirs might be high. This explanation cannot be confirmed by laboratory experiments. An alternative explanation of the observed GOR behavior is that gas, instead of flowing only as a continuous phase, also flows in the form of a gas-in-oil dispersion. Such a flow is what is referred to as “foamy oil flow.”

The actual structure of foamy oil flow and its mathematical description are still not well understood. Much of the earlier discussion of such flows was based on the concept of microbubbles (i.e., bubbles that are much smaller than the average pore-throat size and are thus free to move with the oil during flow [8]). Dispersion of this type can be produced only by nucleation of a very large number of bubbles (explosive nucleation) and by the availability of a mechanism that prevents these bubbles from growing into larger bubbles with decline in pressure [5]. This hypothesis has not been supported by experimental evidence.

A more plausible hypothesis for the structure of foamy oil flow has much larger bubbles migrating with the oil, with the dispersion created by breakup of bubbles during migration. The major difference between conventional solution gas drive and foamy solution gas drive is that the pressure gradient in the latter is strong enough to mobilize gas clusters once they have grown to a certain size. Maini [6] presented experimental evidence that supports this hypothesis for foamy oil flow. The hypothesis seems to be consistent with visual observations in micromodels showing bubble size to be larger than pore size. The mechanism for foamy oil behavior, however, remains poorly understood.

To date, a mathematical model of foamy solution gas drive that incorporates the physics of generation and flow of gas-in-oil dispersions is not available. Numerical simulation of primary depletion in foamy oil reservoirs is still based primarily on empirical adjustments to the conventional two-phase (oil and gas) model:

$$\begin{aligned} \frac{\partial}{\partial t} \left[\phi \left(\frac{\rho_{Gs}}{B_g} S_g + \frac{R_{so} \rho_{Gs}}{B_o} S_o \right) \right] &= \\ - \nabla \cdot \left(\frac{\rho_{Gs}}{B_g} \mathbf{u}_g + \frac{R_{so} \rho_{Gs}}{B_o} \mathbf{u}_o \right) + q_G & \\ \frac{\partial}{\partial t} \left(\frac{\phi \rho_{Os}}{B_o} S_o \right) &= - \nabla \cdot \left(\frac{\rho_{Os}}{B_o} \mathbf{u}_o \right) + q_O \\ \mathbf{u}_\alpha &= - \frac{k_{r\alpha}}{\mu_\alpha} \mathbf{k} (\nabla p_\alpha - \rho_\alpha \varphi \nabla z), \quad \alpha = o, g, \end{aligned}$$

where ϕ and $\mathbf{k}$ denote porosity and permeability; ρ_α , S_α , μ_α , p_α , $\mathbf{u}_\alpha$, B_α , and $k_{r\alpha}$ density, saturation, viscosity, pressure, volumetric velocity, formation volume factor, and relative permeability of the α -phase, respectively, $\alpha = o, g$; R_{so} indicates gas solubility; $\rho_{\beta s}$ (at standard conditions) density; q_β the volumetric rate of the β component, $\beta = O, G$; φ the magnitude of gravity; and z depth. Incorporation of the foamy oil phenomenon will require modification of some key transport properties of crude oils, such as the formation volume factors, bubble point pressure, foamy oil density and viscosity, gas solubility, and effects of depletion rates.

Typical recovery factors (percentage of the oil in a reservoir that can be recovered) for cold production range from 1% to 10%.

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