From *SIAM News*, Volume 39, Number 4, May 2006

Heavy Oils, Part II

By Zhangxin (John) Chen

After introducing heavy oils and some of their defining concepts, the first part of this article (SIAM News*, April 2006, page 1) briefly discussed recovery considerations specific for heavy oils, particularly the large yields from some foamy oil reservoirs. Like foamy oil, sand production (simultaneous extraction of sand along with the oil)—the subject of this part of the article—has been associated with enhanced heavy oil recovery. Also as with foamy oil, sand production is not well understood mathematically, and the petroleum industry is attempting to evaluate its impact on reservoir performance, in terms of both well deliverability and ultimate recovery.*

Sand: Control and Exploitation

Sand long represented little more than a costly problem and a safety hazard for the petroleum industry. Sand-related problems include:

- erosion of equipment, such as valves, pump stators, tubing, and surface pipes;
- subsidence of the reservoir matrix and collapse of casings;
- blocked tubing assemblies and plugged surface facilities, leading to well blockage;
- decreased conductivity of the reservoir matrix and, consequently, reduced efficiency of oil recovery;
- need for disposal procedures; and
- need for extensive work to replace or repair equipment and clean wells.

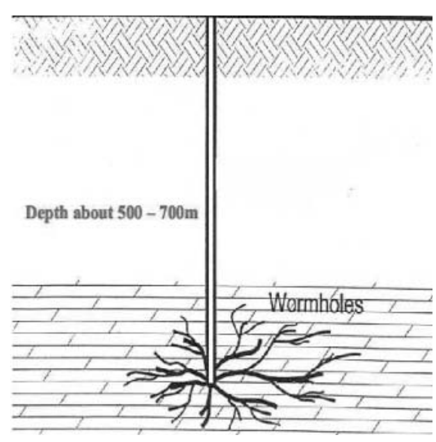
Many techniques have been developed to prevent the mobilization of sand—that is, to control it. These techniques range from chemical consolidation (e.g., via the injection of resin) to physical exclusion (via slotted liners, prepacked screens, and gravel pack placement). Use of these techniques usually leads to diminished well productivity and, if problems arise, additional time-consuming work. Hence, the optimization of sand-prediction techniques and their use in completion (the technology used to bring a well to production) and production de-signs to minimize sand-related risks are of great economic importance.

In the 1980s, petroleum engineers realized that sand production can lead to a significant boost in heavy oil recovery. In fact, continuous sand production has been found to be a key factor in the primary production of non-conventional oil sand (a stratum of sand or sandstone that contains oil) reservoirs in Canada, Venezuela (Faja del Orinoco), Oman, and China (Bohai Bay, Xinjiang, and Liaohe Basin [6]). The increased oil recovery resulting from sand production has been attributed to the following factors [4]:

- enhanced porosity and permeability of the rock matrix resulting from the subtraction of sand;
- increased oil mobility and, thus, from Darcy's law, a higher production rate (if sand can move, resistance to fluid movement is reduced); and
- increased compressibility and pore dilation, leading to compression of the reservoir matrix.

Many complex processes are involved in sand production. Among the most important are stress concentration and redistribution, shear dilation, weakening of the rock matrix, stress arching, nonlinear elastic behavior, hydraulic erosion, solid transport, sand recapture, perforation blockage, propagation of sand failure (the permanent deformation of sand so as to reduce its structural integrity and supportive capabilities), and fluid flow. Even though much effort has been devoted to the study of these processes, most of them are not fully understood.

In general, sand production can be divided into two stages: (1) sand failure, which involves stress concentration, shear dilation, and rock matrix weakening, and (2) detachment of sand grains from the rock skeleton as a result of erosional failure. Much effort, both in the laboratory and in the field, has been devoted to the clarification of sand failure propagation, based on sanding (sand and oil mixing) rates that are quantified through careful monitoring strategies. The propagation of failure involves cavities, tubular piping channels (i.e., wormholes), and compact growth, in a partition of different regions.



Wormhole growth pattern near a production well [2].

Wormholes

Wormhole generation is believed to start at the wellbore, after which it propagates into the field during the initial phase of cold production. The main cause of wormhole formation is believed to be the flux of fluids through unconsolidated sand. This flux exerts a drag force strong enough to overcome the forces that hold sand grains together, and sand grains are transported along the wormholes. A flux-induced erosion process of this type is local at the wormhole tip, as indicated from X-ray computed tomography images of a wormhole as it grows in a sand pack [9].

Experiments [9] have further revealed that one of the essential parameters in determining whether a wormhole will form is the ratio of the pressure gradient to the cohesive strength of the sand matrix. In fact, for a sand matrix to erode, the pressure gradient must exceed a critical value [10].

When the pressure gradient is large enough for erosion to occur, a wormhole will form, growing into regions in which the ratio of the pressure gradient to the cohesive strength of the sand matrix is the highest. Thus, in the case of a sand matrix that is uniform in strength over space, the wormhole will grow along a path of greatest pressure gradients. Similarly, when the pressure gradients are uniform in all directions, the wormhole will grow in the direction in which the sand matrix is weakest—that is, it will develop in higher-porosity regions of a sand pack. Wherever a wormhole develops, it changes both the surrounding pressure distribution and the sand stress distribution.

Wormholes in an oil field also branch as they grow. Although not yet understood, the mechanism of branching can be viewed as a process of self-adjustment to the pressure distribution outside the wormholes. For example, a wormhole might stop growing if it becomes too long as the pressure difference between the wormhole tip and the reservoir becomes extremely small. A new open channel can then form at the tip of the wormhole. During cold production, wormholes can grow into a network, analogous to the growth of the root system of a plant. As the roots grow in the direction of higher nutrient concentrations, the nutrient concentration field around the roots, in turn, is changed. Root splitting is also common in plants.

A coupled reservoir model for sand production must include a model of fluid flow in the reservoir formation, a model of slurry transport inside each wormhole, and a model of wormhole propagation. A mathematical model capable of closely integrating these three components is not available. In very rough terms, the fluid flow model involves variables of three main types: formation strains (or effective stresses), pore pressures, and phase saturations. During production, especially from poorly consolidated sandstone, sand particles can be continuously removed and carried into the production well as a slurry. The classic geomechanics model needs to be modified before it can be applied to slurry transport. Finally, a balance of material conditions can be used to derive the wormhole propagation model, with the slurry mass traveling toward the well balanced by the wormhole propagation and sand influx from the reservoir matrix:

$$v_s A - q_o = A \frac{\partial y}{\partial t} (\phi_s - \phi_m),$$

where v_s is the average slurry velocity, A denotes cross-sectional area, q_o volumetric oil flux, and y wormhole length; ϕ_s and ϕ_m represent slurry and yielding porosities, respectively.

Enhanced Recovery Efforts Under Way Worldwide

Once primary production has reached its economic limit, an oil company turns to the next stage of production, thermally en-hanced recovery. In a cyclic steam injection technique (sometimes called “huff and puff” or “steam soak”), production wells are stimulated by steam injection and then returned to production. Cyclic steam injection can increase recovery factors to 20–40%. In another technique, termed “steamflooding,” steam pumped into chosen injection wells heats viscous oil that is then recovered at production wells. Well locations and injection schedules depend strongly on reservoir and fluid properties. Recovery factors can reach 80% in some steamflooding applications.

Heavy oil production is a long-term investment. Transport of heavy oils is quite difficult, and they require special, more costly refining technologies to yield marketable products. The value of a technology is based on its ability to reduce total cost. Because most heavy oil reservoirs are shallow, drilling costs may not be dominant, although the growing use of complicated horizontal and multilateral wells is adding significant costs at this stage of development. The major cost lies in the energy required to generate and inject the steam used in enhanced recovery of heavy oils. In some situations, these heavy operating costs are projected to persist for long times [3].

Different regions of the world have oils with different chemical and physical properties and are at different stages of production; each region thus has its own development and production methods. The remainder of this article briefly reviews heavy oil reservoirs in four countries—Venezuela, Canada, the U.S., and Indonesia [3]—along with some of the production methods in use.

Venezuela. Venezuela has the world’s largest accumulation of heavy oil. Its first important heavy oil field, Mene Grande, was discovered in 1914. Shallow sands, at a depth of 550 ft, produced oil with API gravity as low as 10.5° at an average rate of 264 B/D (barrels/day) per well. In 1956, steam injection was introduced at this field. When steam from the shallow formation erupted at the surface, the injection was stopped; the injection wells, when reopened for further release of pressure, produced oil. This, in summary, is the story of the fortuitous discovery of cyclic steam injection.

Of the many heavy oil fields in Venezuela, none is more important than the 55,000-km^2 Faja del Orinoco, the largest reserve of heavy and ultraheavy oils in the world. Despite a well that in 1935 was producing oil of 7° API at a rate 60 B/D, this region was not studied in detail until 1968. The studies resulted in a major five-year campaign by PDVSA (Petróleos de Venezuela S.A.) in which a variety of cold and hot production technologies were assessed. According to a recent evaluation, the region has an estimated 1.36 trillion barrels (216 billion m^3) of oil in place. The Orinoco Heavy Oil Strategic Association, established to develop the Orinoco reserves, is composed of four major joint-venture companies [7]: Operadora Cerro Negro (PDVSA, ExxonMobil, and Veba Oil & Gas) in the Cerro Negro area, Petrozuata (PDVSA and ConocoPhillips) and Sincor (PDVSA, Statoil, and TotalFinaElf) in the Zuata area, and Ameriven (PDVSA, ChevronTexaco, and ConocoPhillips) in Hamaca. The goal is to maintain the production rate of 600,000 B/D, reached in 2005, for 35 years. The China National Petroleum Corporation (CNPC) also has a project in the Orinoco region, with Orimulsion production of 6 million tons per year; two additional projects are slated to begin in the next few years [11].

Canada. Canada has the largest share of the world’s ultraheavy and bitumen accumulations, at 2.5 trillion barrels (400 billion m^3). The best known reserve, the Athabasca oil sands in Alberta, was first discovered in the late 1700s. In the early 1900s, mining-style techniques were employed to dig out the asphalt-like oil for use as paving material. Today, several companies, such as Shell Canada, Syncrude Canada, and Suncor Canada, are designing development projects to tap these sands, which hold 7.5° to 9° API bitumen with a viscosity of up to 1,000,000 cp at a reservoir temperature of 59°F (15°C). With these companies extracting crude oils from pit mines, surface mining of the sands has become an important and growing industry in the region. The Athabasca oil sands currently account for almost half of total Canadian oil production [5].

Another Canadian oil company, EnCana, is in the first phase of a three-phase thermal project at Christina Lake that expects to produce approximately 600 million barrels (95 million m^3) of oil from the sands of the McMurray formation over its 30-year life [8]. In the steam-assisted gravity-drainage technique used for production, steam injected into upper wells heats a volume of surrounding oil, reducing its viscosity sufficiently that it flows downward to lower production wells. This technique was developed in Canada and tested in several pilot studies.

The Alberta oil sands are rich in bitumen, a tarry form of oil. From Dallas Morning News.

PetroCanada is using a similar technique to produce oil in the MacKay River field. Seismic surveys, core, and well logs have identified an estimated reserve of 230 to 300 million barrels (36 to 47 million m^3) in this field. Using the steam-assisted gravity-drainage technique, Canadian practitioners are able to exploit their oil-sand resources more efficiently and economically than possible by surface-mining techniques.

United States. In the late 1800s, settlers and prospectors in California discovered oil when drilling near surface seeps of heavy oil and tar. Of the six supergiant oil fields in California today, three—Kern River, Mid-way Sunset, and South Belridge—are heavy oil fields. To date, each has produced one billion barrels (160 million m^3) of heavy oil.

A few details about the Kern River field, located near Bakersfield, give an idea of developments in these heavy oil fields. The field was discovered in 1899 when a hand-dug discovery well encountered oil at 43 ft. The well contained an estimated 4 billion barrels (640 million m^3) of OOIP, but the viscosity (500 to 10,000 cp) and density (10° to 15° API), together with low initial reservoir temperature and pressure, led to low cold production rates. Cold production from the Kern River field peaked at just over 40,000 B/D (6,356 m^3/D) in the early 1900s. Experiments with steam injection in the 1960s proved the potential of thermal recovery techniques: By 1973, 75% of Kern River production came from steam displacement projects. ChevronTexaco is a major operator in the Kern River field.

Indonesia. A large shallow field in Duri, Indonesia, has the largest steamflood operation in the world, in terms of both oil produced and steam injected. This field, discovered in 1941, became active only with the completion of a pipeline in 1954. Cold production, mostly from solution gas and compaction drive, was estimated at 65,000 B/D (10,300 m^3/D) in the 1960s and was expected ultimately to recover only 7% of OOIP. The cyclic steam injection technique, having proved helpful in individual wells, was implemented in a pilot steamflood project in 1975. The pilot project led to recovery of 30% of OOIP, and the first major project began operation in 1985. The Duri field currently produces about 230,000 B/D (36,500 m^3) from the injection of 950,000 BCWE/D (barrels of cold water equivalence per day) of steam, with ultimate recovery factors projected at 70% for some areas. PT Caltex Pacific Indonesia (CPI) is operating the Duri field under a production-sharing contract with the government of Indonesia.

Increased Heavy Oil Production: Mathematical/Computational Issues

While the vast heavy and ultraheavy oil fields will dominate the world's oil production in the next several decades, many of the heaviest hydrocarbon fields await new technologies that will transform them into economically feasible projects. A mathematically and numerically based understanding of effective production mechanisms for these reserves is urgently needed.

Many researchers are studying the behavior of foamy oil in heavy crude fields. The recovery rates reported for some of these fields have been much higher than expected. The mechanism, as discussed in Part I of this article, remains poorly understood; additional laboratory, mathematical, numerical, and simulation studies are required.

Some heavy oil reservoirs, as described in this concluding part of the article, have produced oil at unexpectedly high rates and volumes when sand is produced simultaneously. The fracture-like wormholes formed enhance the permeability and porosity of reservoirs of this type. Encouraging sand production while ensuring stability of the reservoir formation is a challenge for heavy oil practitioners. Dealing with the sand produced is another tough task. As with foamy oil, more refined mathematical and numerical models and computer simulations are needed.

Finally, foamy oil and sand production mechanisms coexist in some heavy oil fields. How to combine them effectively and understand the combined features mathematically is perhaps the greatest challenge of all.

References

[1] Z. Chen, *Heavy oils*, *Part I*, SIAM News, 39:3 (2006).

[2] Q. Chen, *Time-lapse seismology to determine foamy oil and wormhole footprints in a heavy oil cold production reservoir*, M.S. Thesis, Department of Geology and Geophysics, Calgary, Alberta, December 2004.

[3] C. Curtis, R. Kopper, E. Decoster, A. Guzmán-Garcia, C. Huggins, L. Knauer, M. Minner, N. Kupsch, L.M. Linares, H. Rough, and M. Waite, *Heavy oil reservoirs*, Oilfield Rev., Autumn 2002, 30–51.

[4] M.B. Dusseault and F.J. Santarelli, *A conceptual model for massive solids production in poorly consolidated sandstone*, Proceedings of the International Symposium on Rock at Great Depth, A.A. Balkema, ed., Rotterdam, 1989, 789–797.

[5] Government of Alberta, http://www.energy.gov.ab.ca/com/Sands/default.asp.

[6] M.P. Koopmans, S.R. Larter, C. Zhang, B. Zhang, T. Wu, and Y. Chen, *Biodegration and mixing of crude oils in Eocene Es3 reservoirs of the Liaohe basin, northeastern China*, AAPG Bull., 86 (2002), 1833–1843.

[7] I. Layrisse, *Heavy oil production in Venezuela: Historical recap and scenarios for the next century*, Paper SPE 53464, presented at the SPE International Symposium on Oilfield Chemistry, Houston, Texas, February 16–19, 1999.

[8] J. Suggett, S. Gittins, and S. Youn, *Christina Lake thermal project*, Paper SPE/Petroleum Society of CIM 65520, presented at the SPE/Petroleum Society of CIM International Conference on Horizontal Well Technology, Calgary, Alberta, Canada, November 6–8, 2000.

[9] B.G. Tremblay, G. Sedgwick, and K. Forshner, *Imaging of sand production in a water-saturated horizontal sand pack by X-ray computed tomography*, AACI Research Program Report 9697–6, 1996.

[10] J.Y. Yuan, A. Babchin, and B.G. Tremblay, *Modeling the wormhole flow in cold production*, Paper 98–62, 49th Annual Technical Meeting of the Petroleum Society of CIM, Calgary, Alberta, Canada, June 8–10, 1998.

[11] R. Wang, J. Qin, M. Zhao, and Z. Chen, *Performance of drainage experiments with Orinoco Belt Heavy Oil in a long laboratory core in imitated reservoir conditions*, SPE J., to appear.

Zhangxin (John) Chen (zchen@mail.smu.edu) is a member of the staff at the Center for Scientific Computation, Southern Methodist University, the Research Center for Science, Xi'an Jiaotong University, China, and the Center for Advanced Reservoir Modeling and Simulation, College of Engineering, Peking (Beijing) University, China.