HEAVY Oil Recovery
THE ROAD AHEAD
Roughly 10 percent of the world’s daily supply of petroleum is so thick that it can’t flow through pipelines on its own. Even so, the importance of heavy oil – often defined as anything less than 22 API gravity – is escalating. The reason is sheer volume. While proven oil reserves worldwide stand at more than 1,200 billion barrels of conventional crude, the amount of heavy oil in place is five to ten times greater.

In the decades ahead, heavy oil will likely affect global supply dynamics, since 80 percent of known heavy oil reserves are in the Western Hemisphere. Canada and Venezuela account for 90 percent of all known heavy-oil reserves, according to the Alberta Research Council, as reported by the Canadian Society of Exploration Geophysicists. Venezuela has the largest deposits, and by 2015 heavy or “unconventional” oil could make Canada the world’s fifth-largest producer.

The problem, of course, is that heavy crude is notoriously difficult to recover, transport and refine. Of the 6,000 billion to 13,000 billion barrels of heavy oil in place, only about 500 billion to 1,000 billion are considered recoverable with conventional technology. The main technical challenges are to lower the viscosity of the oil to make it flow more easily, and to better understand the composition of the oil, and how to handle heavier components.

The nature of heavy oil
Heavy oil reserves are very different from conventional plays. For one thing, the production time scale is much longer. Heavy oil reservoirs typically produce at a steady rate for decades. Over time, they make a lot of oil. California’s heavy oil region, centered in Kern County, has been productive for more than a century, with four of its largest fields delivering more than a billion barrels each.

Most heavy oil deposits are in poorly consolidated sand, which means that drillers must take extra precautions to maintain the integrity of well bores and manage the production and disposal of sand.

There are also vast differences in the types of heavy oil deposits, even from adjacent fields. Recovery methods that work on one side of the fence may not work on the other.

Reservoir simulation
Given the nature of heavy oil, reservoir models are perhaps more important than they are for conventional plays. Reservoir simulators for heavy oil should be able to take into account a variety of complex reservoir behavior when it is subject to heat, solvents or large geo
mechanical stress; in the latter case, to account properly for reservoir behavior, non-linear geomechanical variables at a resolution of one square metre across the entire reservoir are necessary to estimate surface movement over long production periods.

In the early phase of development, simulation can help engineers optimize the design of the production system, and to evaluate various well trajectories and drainage patterns. After production begins, operators may see a wide range of results from individual wells. In that case, accurate modelling can help optimize production throughout the life of a field.

Intelligent completions and continuous monitoring enable better control of inflow and outflow from the well—providing measurements in real-time for dynamic modelling and automated control. Prior to deployment of any such system, a proper optimization study should be conducted using simulation tools.

As an example of the importance of developing proper reservoir models and simulation tools, we examine the Canadian case, where about 200 steam-assisted gravity drainage (SAGD) well pairs produce approximately 120,000 barrels per day—an average of about 600 b/d per well pair.

The production, however, varies. While one field produces 200 b/d per well pair, a nearby field is producing 35,000 b/d from 10 well pairs. A lot could be learned by the industry if the reasons for this large variation were understood. Perhaps if accurate reservoir models had been built and simulation studies had been carried out, the variation and the ensuing extra costs could have been minimized. It is much more expensive to drill and test a well than to simulate it.

**Strategic engineering decisions**

Any heavy oil operator faces decisions on how to develop their asset. An analysis must be done to classify the different hydrocarbon resources by production method. A prioritization is then made based on financial, marketing, and environmental considerations to develop a production strategy. In all cases, proper reservoir characterization, modelling, simulation, and pilot studies must be carried out. Some examples are cited here to illustrate the many factors and variables, which need to be considered.

In some fields, operators can recover a limited amount of heavy oil from unconsolidated sands by a method known as Cold Heavy Oil Production with...
Sand (CHOPS). Deliberately producing sand along with the oil leaves wormholes or voids in the producing zone that will attract more oil toward the wellbore. The advantage of CHOPS is that it is relatively inexpensive to start up a CHOPS field. The downside of cold production, however, is that recovery rates are normally less than 8 percent. So, in this example the tradeoff is early cash flow and minimal up-front investment versus ultimate recovery factor.

Heating a reservoir, usually with steam, can boost the recovery factor in rare cases to as much as 70 percent, which is far better than most conventional reservoirs achieve. In Kern County, some operators have recovery factors of 50 percent. California-style thermal recovery, however, where banks of locomotive-sized steam generators flood thick, homogeneous reservoirs with steam, is prohibitively expensive in all but the largest fields. In this case, up-front investment is significant; however, recovery factors are quite acceptable.

An alternative thermal-based recovery technique is “fireflooding” or in situ combustion. The technology involves installing downhole heaters and injecting air or oxygen, igniting some of the oil in the reservoir and allowing it to burn at a controlled rate. As the burn front advances through the reservoir, it generates enough heat and combustion gas to lower the viscosity of the oil out front, driving it toward producing wells. This method is commercially used in Romania and in India to produce particular heavy oil fields with recovery factors approaching 50 percent. Variations on this method such as Toe-to-Heel Air Injection (THAI) and THAI using a solid catalyst (CAPRI) are being piloted today in Canada.

Although in situ combustion can achieve high recovery rates, it can be difficult to control and a failure can preclude further attempts to produce the remaining hydrocarbons. Similarly, the same wormholes and voids created by the CHOPS method can close the door to subsequent thermal options because there will be too much communication within the reservoir. Both methods can make new wells into the reservoir harder to drill, which is why selecting the right recovery method and sequence is so important, and why acquiring the best possible range of data about your reservoir plays such a crucial role. CHOPS and in situ combustion can be viable options when the reservoir conditions and field economics are right.

Several Canadian operators have had success with another thermal process called Steam-Assisted Gravity Drainage (SAGD). The technique is quite different from traditional steam flooding or cyclical steam stimulation, and it has a wider range of applications. With SAGD, pairs of horizontal wells are drilled into the producing zone, one about five metres above the other. Steam injected into the top well heats the formation and reduces the viscosity of oil around the wellbore. Gravity then pushes the warm oil toward the producing well below.

Since steam generation is the largest single expense, the trick with SAGD or any steam process is to minimize the steam-to-oil ratio (SOR). Even a small shift in the SOR can significantly impact a field’s overall economics.

Much of Venezuela’s heavy oil is produced with a mix of cold and thermal recovery processes. Solvents or lighter crudes are then blended with the heavy crude to lighten and transport the oil.

Operators in Alaska are producing heavy oil from the West Sak and Schrader Bluff formations by injecting slugs of water alternating with gas (WAG). The gas acts as a solvent to reduce viscosity and the water helps push the thinner oil toward producing wells. The process, while not as effective as thermal, will recover more oil than primary recovery alone.

Since deep reservoirs are naturally warm, even a moderate temperature increase can lower the viscosity of the oil, but heavy oil production is also greatly affected by ambient average surface temperatures. Canadian and Arctic reservoirs, for example, will rarely flow unless the oil is heated artificially. In contrast, multilateral and long horizontal wells in Venezuela have achieved up to 3000 bpd flow rates without thermal stimulus.

Monitoring and managing wells
High-temperature well completions and artificial-lift systems can help manage and optimize the various thermal recovery systems. There are also new ways to monitor and control steam in the reservoir, including temperature, pressure and deep resistivity measurement tools, high-temperature pressure gauges, and instruments that measure cross-well resistivity and record microseismic events.

The economic realities of heavy oil developments make some operators wary of investing in additional...
Numerical Modelling

Numerical modelling enables engineers to predict oil recovery performance by solving a set of flow equations governing the recovery process mechanisms. For non-thermal recovery there are black oil and compositional models. For thermal recovery, there are models that solve flow and energy equations. These energy equations take into account the heat transfer between the reservoir fluids and the rock. The models enable engineers to compare thermal and cold production strategies, and to select the best recovery method. Current developments in advanced thermal modelling incorporate more complicated steam-based recovery processes, such as co-injection of solvent and steam and in situ combustion processes. Because long horizontal and multi-lateral wells are commonly used in heavy oil recovery, sophisticated wellbore models that are able to segment individual sections of wells for a more detailed knowledge of the multi-phase flow within the wellbore are necessary. For accurate modelling of the CHOPS process, geomechanical effects on sand failure and sand production need to be considered. 

A clear environmental plan

In planning new heavy oil projects, it’s not enough to rely on best available technology and hope that it’s clean enough to satisfy lawmakers. Compared to lighter crudes, heavy oil presents special health, safety and environmental (HSE) concerns. That makes HSE as much a part of efficient reservoir planning as selecting the right form of artificial lift.

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