The science of oil drilling goes deep

Philip Ball

Advanced techniques can characterize the physical and chemical properties of oil and the porous rock containing it, but the proof is in the drilling. Spills are an inevitable risk, but natural microorganisms that feed off the hydrocarbons can help to clean them up.

One of the few useful outcomes of BP's Deepwater Horizon fiasco is that now everyone can appreciate how difficult it is to drill in deep water. But as about half of the world's undiscovered oil is thought to lie offshore, deepwater drilling will continue despite the risks. Some estimates indicate that oil extraction from deep offshore reservoirs might double by 2015.

Yet while oil spills capture the headlines, some of the biggest risks in oil exploration are more mundane. Because full-scale drilling costs billions of dollars, it is vital to know in advance that the effort will bring rewards. Even if exploratory drilling at a candidate site hits oil, how do you know how much there is and what sort it will be? The need to answer those questions is now driving the development of innovative scientific tools that regard an oil reservoir as a complex materials system.

Making oil

The abundance of oil below the sea is unsurprising, since that is where oil formation begins. The raw organic material that gets broken down, by geothermal heat, pressure, and time, into hydrocarbons comes mostly from dead microscopic marine life: algae and plankton that rain down onto the ocean floor to form sediments.

Ocean productivity is particularly high just offshore on the continental shelf, fed by nutrients in rivers and wind-stirred sediment. And so a significant number of new oil discoveries —around 20% of the total in 2009—are on these shelves at a relatively shallow depth. The big rivers that empty into the Gulf of Mexico, along with its relative isolation from the open ocean, make this region a particularly fertile hunting ground for offshore oil.

Yet many new discoveries—typically between one-third and one-half of the annual totals in the past decade—are in deep water. In 2006, the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement estimated that there are 66.6–115.3 billion barrels of oil and 326.4–565.9 trillion cubic feet of natural gas still undiscovered offshore and technically recoverable by conventional means in the United States and Canada, about 60% of the total oil and 40% of the total natural gas in undiscovered North American fields.

The exploration process

Discovering a new reservoir usually begins with a seismic survey of a candidate site to identify geological structures that can trap hydrocarbons. Seismic waves may reveal their approximate boundaries, since hydrocarbons (particularly gas) in the porous rock alters the way seismic waves travel through it. Seismology has been supplemented in recent years by "electroseismology," which exploits the way seismic waves can induce electromagnetic fields and detects hydrocarbons because of their high resistivity.

Only when "discovery wells" are drilled, however, can one obtain direct evidence of oil and discover what it is like. This drilling is part of the "appraisal" phase, in which the size, capacity, and quality of the oil field are estimated.

Reservoir appraisal typically costs several hundred million dollars, but most of the money is spent during the subsequent development phase, when drilling platforms and production and export facilities are put in place, and the production wells are drilled. Oil may have to be extracted from the reservoir by pumping in water, in which case the nature of the pore space and the oil–water interface becomes important. Ideally the oil would simply be pushed in front of a moving two-phase interface. But the morphology of the pore network (the pore size distribution and connectivity), the thermodynamics of the confined two-phase system, and the wetting characteristics of the rock, can all affect the way this interface develops, with consequences for how the pressure in the reservoir varies.

The mechanical characteristics of the reservoir rock can also be critical. Weak, friable rock may break up into sandy debris that contaminates the oil and complicates extraction. The ideal is for rock that is highly porous, permeable, and strong. New analytical techniques such as magnetic resonance imaging, x-ray and neutron scattering, and ultrasound are proving essential for mapping out the composition and shape of the host rock.

Looking into the reservoir

An oil reservoir is not merely a fluid-filled cavity but a highly complex material system. The hydrocarbon material may vary from a very light, low-molecular-weight fraction—basically

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natural gas—to a virtually solid, tarry substance made from partly aromatic compounds called asphaltenes. This composition may vary hugely from one part of a reservoir to another. The phase of the hydrocarbons—whether gas, liquid, or solid—determines how extraction should be done. If a company has geared their extraction procedure to viscous crude only to find the borehole discharging volatile liquids or gas, they could waste billions of dollars. "Black oil and gas need totally different systems," said oil scientist Oliver Mullins at Schlumberger-Doll Research in Cambridge, Mass.

What's more, the field might be compartmentalized: Geological barriers might prevent the fluids in one part from reaching another. If a reservoir is highly compartmentalized, it may be too expensive to drill many recovery holes in order to empty it: Each offshore well typically costs around $100 million. For such reasons, most deep-water reservoirs have produced oil yields below expectation. To make matters worse, compartmentalization is expected to be more prevalent in the deeper reservoirs that the industry is likely to try to tap in the future, because the higher pressure promotes sealing of permeable rock. "The largest uncertainty in the oil industry today is the reservoir," said Mullins.

He and his co-workers have developed a methodology called downhole fluid analysis (DFA) for characterizing the reservoir fluids *in situ*. It deploys a suite of techniques, including near-infrared spectroscopies to look for different types of alkanes and carbon dioxide, and optical absorption spectroscopy to study asphaltenes. All the instrumentation is housed in a steel cylinder that is lowered into the borehole, with pumps to extract fluid samples from the rock and direct them into sample bottles. This automation makes it relatively easy to sample downhole fluids many times, contrary to the usual practice of taking only a few samples.

DFA also can spot signs of reservoir compartmentalization. For example, if dense oil is found higher in the reservoir, the chances are that its sinking has been prevented by some impermeable barrier. Equilibration of the fluid phases, and particularly the asphaltene content, is also a measure of how interconnected the entire reservoir is: Equilibrium requires large-scale fluid flow in the reservoir and thus implies connectivity.

Oil composition can vary significantly within the reservoir. All of these samples were extracted from a single column. Image courtesy of Hani Elshahawi, Shell International E&P.

Cleanup

Although the Deepwater Horizon oil spill has highlighted the environmental risks of oil production in unprecedented fashion, ecosystems are constantly exposed to crude oil via natural processes. Oil escapes from reservoirs in seeps, which, operating continually on a small scale, inject far more of the stuff in total than is released by human activities. Some bacteria and fungi have adapted to metabolize the energy-rich hydrocarbons, and one of the most effective remediation strategies for oil spills aims to boost the abundance of these hydrocarbon degraders by adding nutrients such as nitrogen and phosphorus to the environments that harbor them. This approach was heavily promoted after the spill from the Exxon Valdez tanker in Prince William Sound, Alaska, in 1989. Russ Chianelli of the University of Texas at El Paso was working for Exxon's Corporate Research Laboratory at the time and was lead scientist of the bioremediation project on the Alaskan beaches. He said that after the addition of nutrients, "the oil on the beaches was consumed in approximately two weeks." The key to long-term remediation of oil spills may now be a better understanding of the complex ecology of microbial hydrocarbon degraders.

Consumption of oil by hydrocarbon degraders is accelerated by dispersing slicks into a more amenable form using surfactants to emulsify them. This also helps to reduce the most familiar and distressing (if not ultimately the most damaging) outcome of a spill: marine and coastal animals physically clogged with thick crude. Dispersants have been a crucial part of the armory in other major spills, such as that from the exploratory well Ixtoc I in the Gulf of Mexico in 1979. A dispersant called Corexit 9527—basically a solution of an organic sulfonate surfactant in an organic solvent—was used there to reduce the impact of the spill on the shores of Texas and Mexico, while booms and skimmers prevented the slick from reaching the ecologically sensitive bays and lagoons on the Texan coast.

Although crab, fish, and octopus communities were badly hit by the Ixtoc I event, the long-term effects were not as dramatic as feared. Some hope that this will be the case for Deepwater Horizon too. BP has so far used more than a million gallons of other formulations of Corexit dispersant and has taken the unprecedented step of employing it a great depth to try to prevent flammable and volatile hydrocarbons from posing a danger to ships working at the surface.

But these dispersants, although approved by the Environmental Protection Agency, are themselves somewhat toxic. According to Terry Hazen, a microbial ecologist at Lawrence Berkeley National Laboratory in California, the use of Corexit 9500 appears to have been effective and caused little toxic hazards—but there is still a need for detailed studies to look at long-term effects. □

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