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Boosting recovery

Written by Mike Shepherd Friday, 01 July 2016 00:00

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Former BP and Shell geologist Mike Shepherd says the North Sea demonstrates top in class oil recovery factors compared to the rest of the world, but could do better.

The quoted oil recovery factor from both the UK and Norwegian sectors is 46%, the highest of any petroleum province in the world.

This compares to a commonly-quoted average worldwide recovery factor of 30-35%, although this number is a guess rather than anything particularly evidence-based. The authors of a 2007 technical paper stated that the global recovery factor of oil fields could be as low as 22%.1 The same paper quotes an average recovery factor of 39% for the US and 23% for Saudi Arabia.

BP's Magnus platform.Photo from BP.

Why would a high-cost offshore area, such as the North Sea, demonstrate top in class oil recoveries by comparison to onshore production? Because intuitively it's not expected. Favorable geology is one explanation; the reservoirs in the North Sea largely comprise sandstone rock and with only a small proportion of the complex and difficult carbonate reservoir intervals that are common in the Middle East for instance. The prevalence of light oil is another.

Nevertheless, a major factor is the implementation of reservoir management strategies by North Sea oil companies. Part of this is due to lucky timing. The start of oil production in the North Sea followed shortly after the oil price hike of 1973, when oil prices quadrupled. From the end of World War II, up until then, the oil price had been remarkably stable and low, at US$2-3/bbl (about $20-25 in today's money).

That had been enough to bring on stream the enormous oil fields of the Middle East and North Africa, many on primary production, and still make money. With the increase in the oil price, adding water injection wells became more attractive. Waterflooding was, therefore, implemented in most North Sea oil fields from the start of production and there is no doubt that this alone accounts for the much of the high recovery rates. The light oil in many of the reservoirs helps enormously, as waterflooding is more effective in pushing light oil into the production wells.

One other difference came into play in the North Sea. Whereas onshore fields are commonly drilled in spot patterns, with a high density of wells, this was not a feasible option offshore, where the drilling costs were up to 10x higher. Given the greater inter-well spacing forced on operators by the economics of offshore drilling, North Sea wells would have to be carefully placed to maximize their effectiveness. This meant making a big effort to understand reservoirs in detail, both in terms of reservoir continuity and complexity. In turn, there was a drive to improve seismic resolution, improve the geological description of reservoirs and to find cost-efficient means of drilling them. During the lifetime of the North Sea, our knowledge and technology has increased enormously and this has been a major driver for reserves increase in many North Sea fields.

Majestic Magnus

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I used the Magnus field as an example of reserves growth in my recently published book on the history of North Sea oil – "Oil Strike North Sea" (Luath Press 2015). The field was expected to cease production in 1999, but it was still producing 12,000 b/d in 2015.

The field was discovered in 1974 in the northern North Sea. BP originally considered the discovery marginal. Although there were indications of a reasonable amount of oil there, about 450 MMbbl reserves were estimated at that time, the water depth of 186m was a critical factor and at the extreme limit of what could be done with 1970s North Sea technology.

Magnus heavy oil. OE Staff photo.

The field is elongate in shape, extending north–south for 14km. If the water depth had been shallower, two fixed platforms would have sufficed to access the full length of the field. However, at 186m water depth, the cost of the two platforms was prohibitive. BP decided on one fixed steel platform in a central location on the field, developing the northern and southern ends of the field with subsea wells tied back to the platform.

The field came on production in 1983. It was initially thought that the reservoir sandstone had been deposited as a fairly simple connected body of sand and would need only a small number of wells to develop it. As a result, the platform was built with the capability of drilling only 20 wells, which turned out to not be enough.

Six appraisal wells showed that the field would produce more oil than initially thought; the reserves were now estimated as 450 MMbbl out of total oil in place of over 1 billion bbl. By 1987, the ultimate recoverable reserves had grown to 665 MMbbl, out of 1.665 billion bbl oil in place. We knew more about the geometry of the field by that time and the seismic resolution was improving.

As well as being bigger than originally thought, the Magnus reservoir is somewhat more difficult to manage than previously thought. Instead of behaving as one big connected volume, the geology is more complex, with faults and blanket mudstones dissecting the reservoir. As a result, the field could be shown to be divided up into a number of self-contained compartments, like the bulk-head of a ship.

As more and more data came in from the wells, the understanding behind the complexity of the reservoir increased. But, this intimate understanding of field performance has led to improved recovery of the remaining oil, and although the field team has had to do some juggling with the limited number of drilling slots on the platform, that hasn't impeded the reservoir management; new wells have successfully targeted undrained volumes of oil.

Today, BP is trying to push the ultimate recoverable reserves for the field towards a target of 1 billion bbl. BP has implemented enhanced oil recovery methods on the Magnus field using water alternating gas (WAG), which alternates six months of gas injection into the wells, followed by six months of water injection, repeated in yearly cycles. The gas mixes with the oil and makes it more fluid. When the water is subsequently injected into the reservoir, the cushion of water is able to push more oil out.

The Magnus field is just one of many large oil fields in the North Sea showing reserves growth thanks to the technological prowess demonstrated in the North Sea.

Could we do better?

Top in class, but could we do better? Yes in my opinion, and the regulatory authorities certainly think so, too. The new UK Oil and Gas Authority have been charged with the remit of working with government and industry to make sure that the UK gets the maximum economic benefit from its oil and gas reserves. A major part of this is concerned with increasing the reserves from existing fields.

Likewise the Norwegians share a similar focus and one industry group identified a target of 55% basin-wide oil recovery as a target to aim for. It's a stretch target but not unfeasible with improvements in drilling technology, particularly low-cost wells and the widespread implementation of IOR.

Norwegian oil company Statoil has published a mission statement on its website proclaiming that, "Statoil has set world-leading targets for recovery factor, with a goal of 65% as an average for platform operated fields and 55% from subsea-operated fields."2

An interesting area for speculation is to take the North Sea as an example for what could happen elsewhere in the world. If the global oil recovery is only 22%, then there is clearly an enormous resource available in the existing fields if we could somehow apply North Sea reservoir management practice worldwide.

Let's speculate further. If we assume that we have produced close to half the world's oil reserves, let's say 10% of the global oil in place, then an increase in the global recovery factor from 22-32% would produce all the world's oil all over again and that would still be a poorer recovery factor than what is anticipated for the North Sea.

Locating the remaining oil

Surprisingly, there is a technique with a long track record in improving oil recoveries in the North Sea that has not been universally implemented. This is the technique Shell calls "Locating the Remaining Oil," (LTRO) developed in parallel in the 1980s by Shell and the Texas-based Bureau of Economic Geology. Shell were highly successful in implementing their LTRO techniques on their Brent fields in the 1980s and 1990s. Sometime after this, I worked with Caroline Gill of Shell to apply these techniques to the Shell-operated Nelson field and the paper we wrote together is still the most complete exposition of LTRO to date.3

The basic idea behind the technique is the observation that perhaps only six or seven geological or petrophysical features control connectivity and the location of reservoir dead ends in a typical oil field. These features are large-scale, yet they may not be immediately obvious unless you make a big effort to find out what they are, particularly because what matters varies considerably from reservoir to reservoir. The geologist is best-placed to carry out the analysis and it involves stepping beyond pure geology, as it is necessary to integrate the geological framework with production data to do the work. Once you have established the framework controlling flow behavior, then you have a much better chance of working out where the remaining oil is to be found. This reduces the risk on infill well targets.

The problem for modern geologists is that the technique involves stepping out of the standard computerized work flow for producing 3D reservoir models. I call LTRO the "missing workflow" because, as a procedure, it is not integrated within existing geological modeling software. It's not straight-forward to computerize LTRO practices as the process is data-intensive and involves analysis in two dimensions (graphical overlay of production data on geological data) rather than in the three dimensions, which modern geological software is accustomed to.

The problem is that if you don't explicitly model the features that control fluid flow in a reservoir it's a hit or miss issue whether the geologist's model will honor them or not. The features are subtle and often easy to overlook.

I reckon oil companies are becoming more and more aware of the problem of the "missing workflow" and are taking steps to rectify the issue. I certainly don't think it does any harm to actually get young geologists involved in understanding how a reservoir works rather than just modeling it.

Mike Shepherd was born in Aberdeen and witnessed the arrival of the oil industry to the city in his teenage years. Later working for BP and Shell planning oil wells in the North Sea, his childhood dream of becoming a geologist was realized with over 30 years' experience in the oil industry. His previous work includes the textbook Oil Field Production Geology, used for postgraduate study both in the UK and abroad.

Notes

1 I.Sandrea and R.Sandrea, 2007. Global oil reserves - Recovery factors leave vast target for EOR Technologies. Oil and Gas Journal. Part 1: November 5th, 2007. Part 2: November 12th, 2007.

2
www.statoil.com/en/TechnologyInnovation/OptimizingReservoirRecovery/RecoveryMethods/Pages/AboutRecoveryMethods.aspx

3 Gill, C.E. and M.Shepherd, 2010. Locating the Remaining Oil in the Nelson Field. In Vining, B.A. and S.C. Pickering (eds) Petroleum Geology: From Mature Basins to New Frontiers – Proceedings of the 7th Petroleum Geology Conference, P. 349-368. Geological Society, London.

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