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Tech Talk - Enhancing Production at Berri

Posted by Heading Out on April 22, 2012 - 5:38am
Topic: Supply/Production
Tags: arab d, berri, crude oil production, esps, mrc, saudi arabia [list all tags]

In the last post I discussed how changing technologies were improving the recovery of the final significant volumes of oil from Abqaiq. New technologies have also brought additional life to the Berri field, which lies along the coast north of Abqaiq. Berri is/was the 22nd largest oil field in the world.

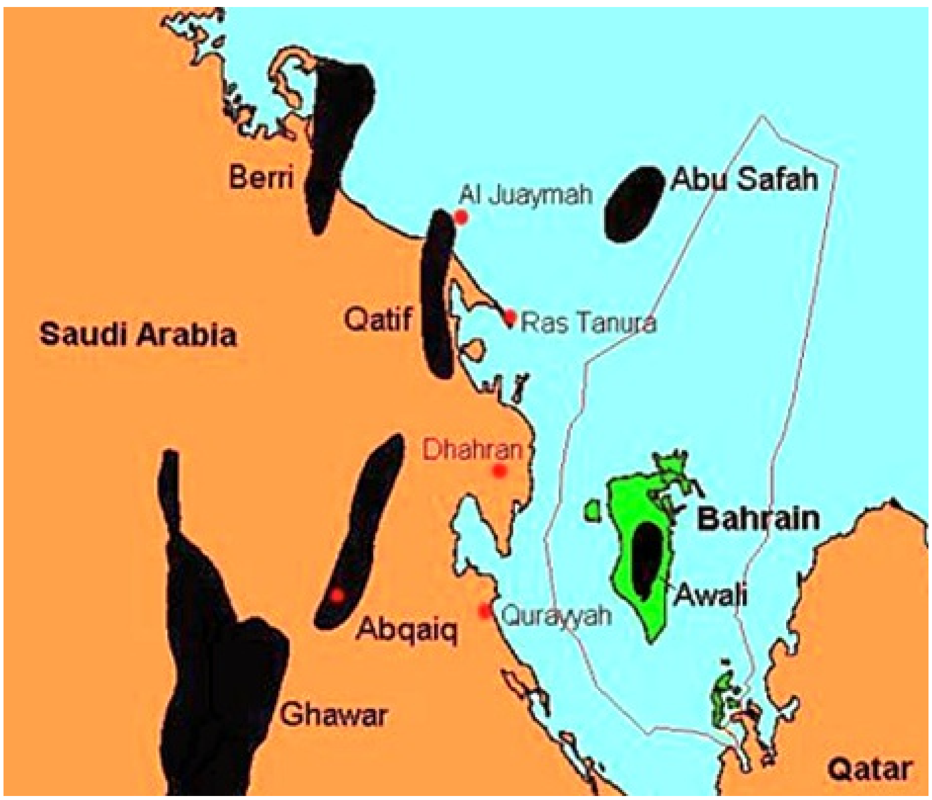

Figure 1. Location of the Berri oilfield. (JoulesBurn at The Oil Drum)

In the past, Rembrandt quoted the late Matt Simmons' "Twilight in the Desert" on the origins of this field and its future. The field was discovered in 1964, and the first wells to find the location of the producing reservoirs were drilled in 1967. The original estimate of the reserve size was made in 1978, at 8.3 billion barrels. In an earlier paper, Matt had plotted the production from the field and showed that it peaked in 1976, at 800,000 bd, when water flooding under the reservoir was introduced to maintain reservoir pressure.

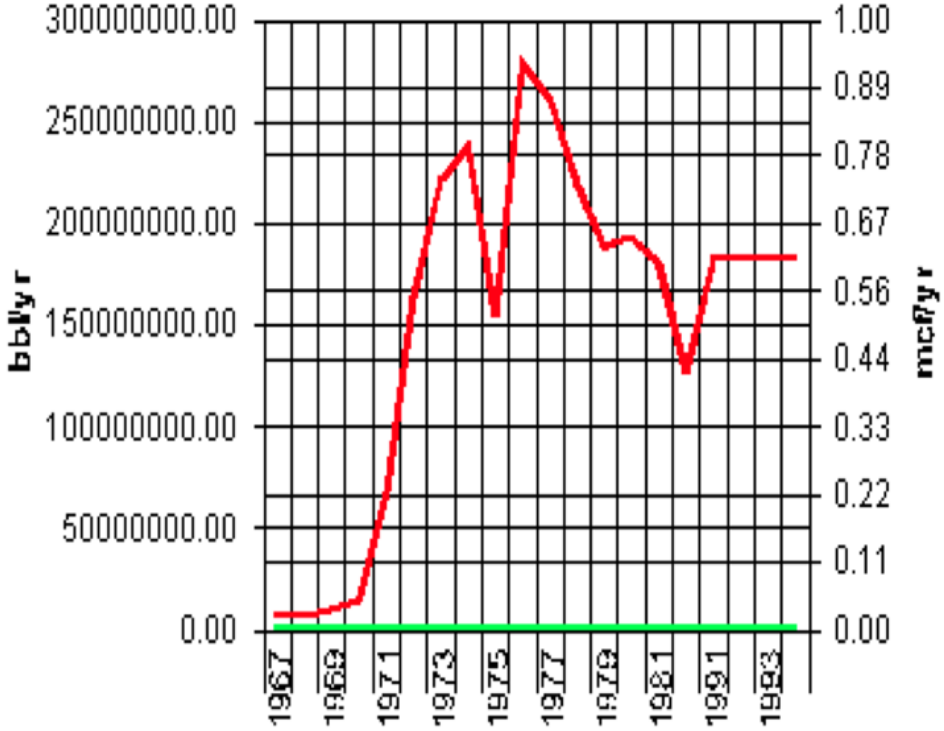

Figure 2. Early production from Berri ([Matt Simmons](#))

This production came from the Hanifa, Hadriya, and Fadhili reservoirs, because at the time, the Arab horizons (A, B and C) had not been productive in this region, which has eight Jurassic-age reservoirs. However, the Arab D horizon has been developed since then and is now in production. That reservoir is anticipated to contribute 25% to overall field production and is anticipated to sustain a relatively steady production of around 85 kbd (giving a total estimated production of around 350 kbd) for ten years, after which the reservoir will see a rapid decline in production.

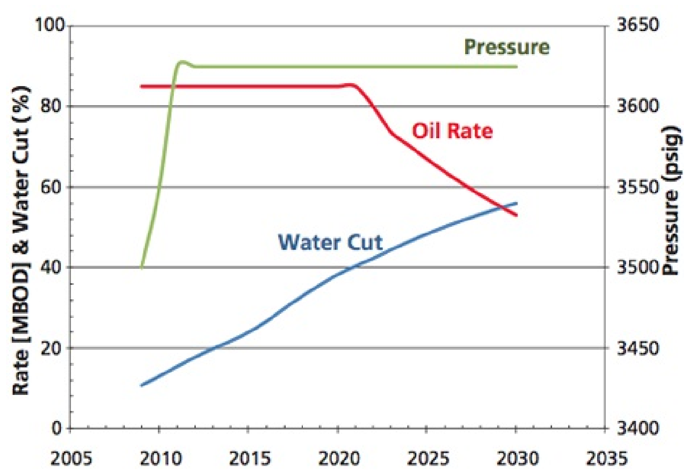

Figure 3. Future estimates of production from the Arab D horizon at Berri ([Jokhio et al](#))

One of the problems that arises when long-hole horizontal wells are used to drain a reservoir is the need to maintain a significant negative pressure difference between the well and the surrounding rock, so that oil will continue to flow into the well. Up to a certain point, the longer the well the greater the production, but beyond that point, as the [drawdown pressure](#) differential falls, so production will also halt in the more distant part of the well.

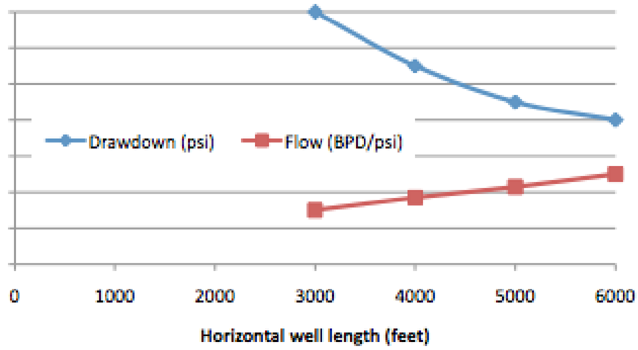

Figure 4. Pressure drop and production with increasing horizontal well length (after Fischbuch et al) (To fit the curves on one plot, there is no scale on the vertical axis, but the production increased from 29 to 50 bpd/psi along with the increase in length. Pressure values are discussed within the post).

In addition, the geological factors in the upper reaches of reservoirs that are now smaller than when these fields were initially developed, means that the horizontal sections are often limited to around 4,000 ft in length. Nevertheless, this length can still initially produce up to 4,000 bd per well. In the case of the Berri wells in the Arab D, the optimal length of each horizontal section was found to be 3,000 ft, based on geology. Further, this requires that a ratio of 1.2 barrels of water be injected for every barrel of oil removed to achieve the pressures needed.

As I noted last time, and as the above plot shows, as horizontal wells get longer it becomes more difficult to sustain that pressure differential at the back of the well. The pressure may then fall to the point where there is little additional production in the rear sections. Therefore, greater production can be achieved from a series of shorter laterals around the well, rather than from a single, longer well. This is the case at Berri, where the new wells have been drilled to give Maximum Reservoir Contract (MCR) by using shorter laterals rather than single longer wells that reach further into the formation. However, because of the geology, these are driven as separate sidetracks from the main well, rather than as laterals from a single main horizontal well.

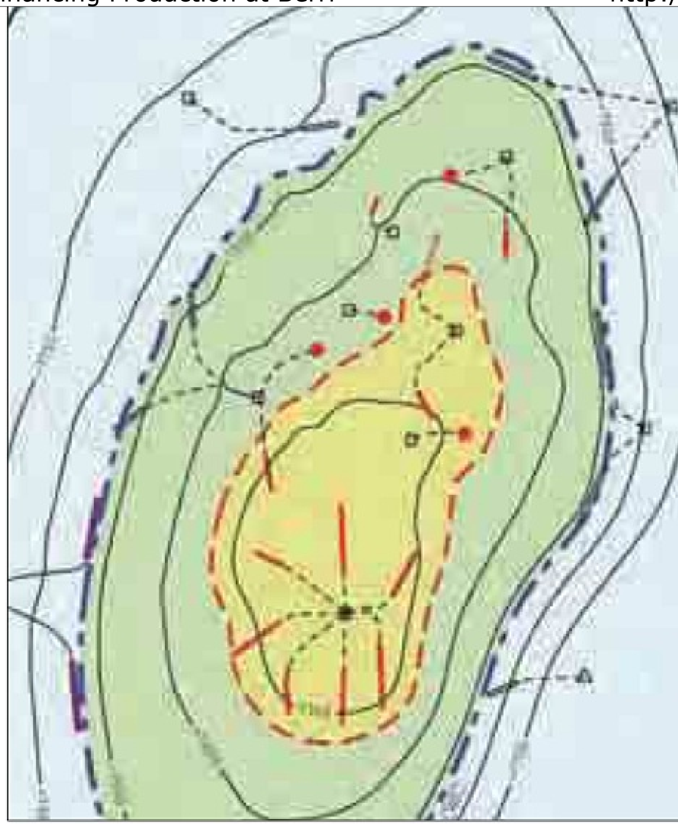

Figure 5. Structure map showing the well layout at Berri (Jokhio et al)

There is an additional snag that arises, because of the pressure drop problem, and that is that Aramco are using valving systems to isolate individual segments of the well. This is done to protect the rest of the well from premature water breakthrough in any one section, but each of those valves also creates a resistance that diminishes the available pressure drop beyond the valve. As a result only a limited number of valves can be used in a well, and this in turn limits the number of divisions that the well can be broken into. This is a particular problem for the Arab D reservoir since, as I noted in an earlier post, this carbonate is permeated with thin, high permeability paths that can, if not isolated or treated, lead to premature watering out of the wells. (One such horizon has been identified at Berri near the top of the field and was cased to isolate it from the well).

Seven production wells were initially drilled into the reservoir in developing the Arab D, but modeling of the reservoir suggested that the wells would rapidly fall in production, due to the inability to sustain production pressure, even with perimeter water flooding. There have been two solutions proposed for this, both of which involve the use of down-hole electric submersible pumps (ESPs). The first was to install these in the wells, to help with pumping out the oil, while the more recent study has been to see if using these pumps to increase water flow into the reservoir can help sustain production.

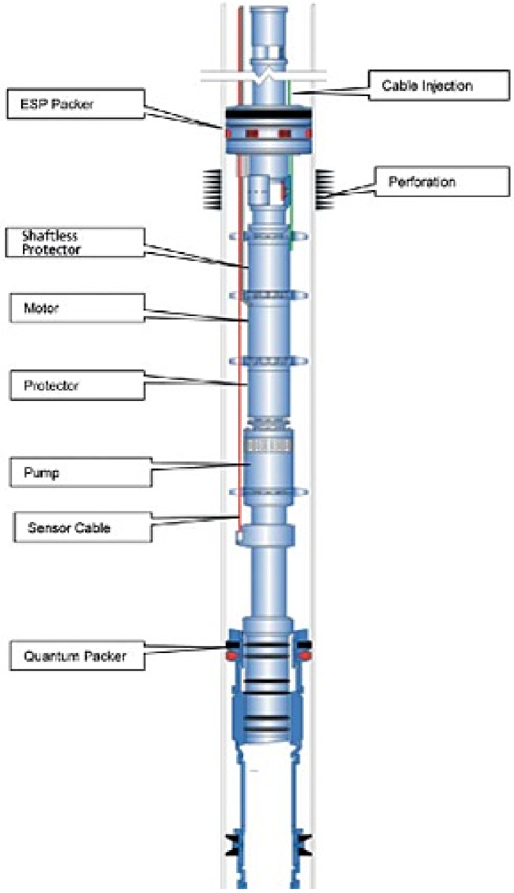

Figure 6. Components of a down-hole electric submersible pump ([Aramco](#))

While the hope with the water injection pumps are that they will be able to draw water from overlying underground water reservoirs and use these as a water source, nevertheless in 2009 Aramco laid new pipes to carry more water to Berri and to remove the oil that it helped produce. (The new injection well array requires some 10,000 – 12,000 bd of water injection.)

Calculations had shown that a drop of 300 psi within a well would be sufficient to drop oil inflow to zero and that this would occur within two years of bringing the reservoir on line. ESPs were therefore installed in each of the seven wells, and when brought on line were able to sustain production at a level of 70 kbd, which was above the anticipated value.

The more recent work to install an inverted down-hole ESP to draw water from the Wasia aquifer and inject it into the Arab D has been in service since December 2008, and has shown an improvement in the pressure in adjacent wells.

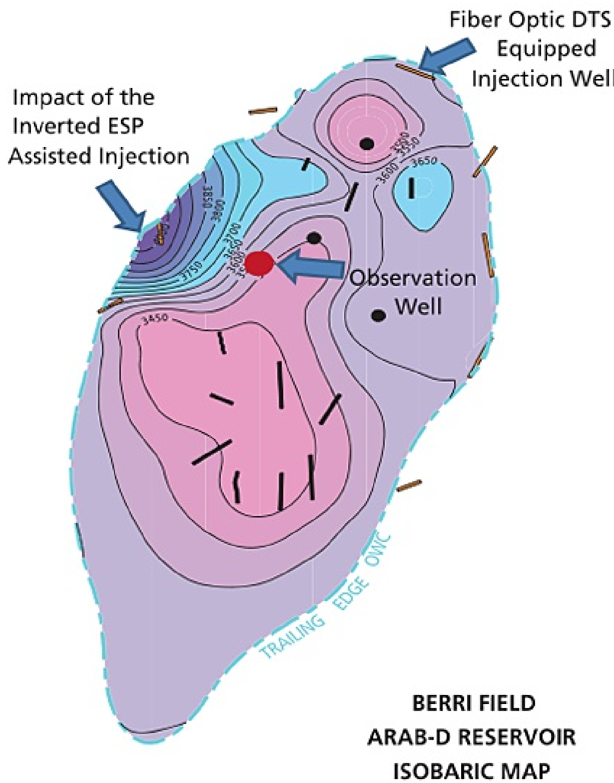

Figure 7. Location of the sub-surface ESP injection well (Jokhio et al)

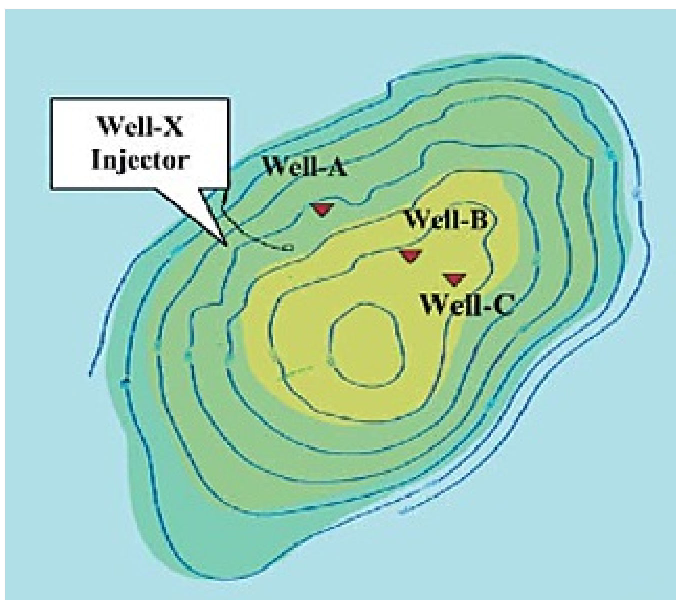

Figure 8. Location of the monitoring wells for the water injection (Shinaiber et al)

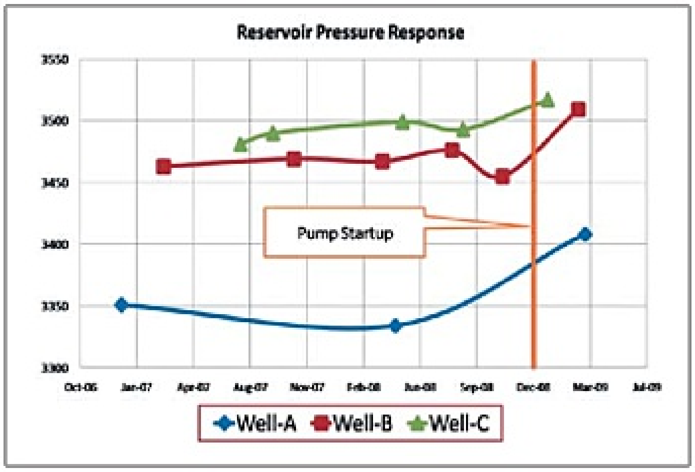

Figure 9. Monitoring well response to the use of a down-hole ESP (Shinaiber et al)

This improvement in technology may well provide a solution, as it allows production from otherwise undevelopable reservoirs and some answers to the questions that, for example, Jud has raised about the long-term viability of the field.

While the development of the Arab D does give a boost to the production at Berri, it should be remembered that this post has only discussed how “new” reservoir development has provided for 25% of Berri production for the next decade, and does not address the production from the main reservoirs of the field.