Drilling depleted zones takes planning, special care

DRILLING THROUGH DEPLETED zones can prove troublesome. Fracture gradients change and their relationship to mud weights needed to maintain wellbore stability can shift.

Planning and care during the drilling operation are the keys to success.

The importance of successfully drilling in these formations is emphasized by the session scheduled for the 2001 SPE/IADC Drilling Conference, "Drilling in Depleted Zones." The session is to be chaired by **G King**, **ExxonMobil** and **G Beck**, **Nabors Drilling USA**.

FRACTURE GRADIENT

To successfully drill a hole section requires the selection of a mud weight that will be sufficient to prevent the influx of formation fluids while not exceeding the fracture resistance of the formations exposed.

In SPE/IADC paper 67440, "Fracture Gradients in Depleted Reservoirs—Drilling Wells in Late Reservoir Life," **M W Alberty** and **M R McLean**, **BP**, propose a theory about fracture gradients that contradicts conventional wisdom.

Conventional wisdom says that the fracture resistance is closely related to the horizontal stress within a formation. The Poisson effect in response to depositional loading is primarily responsible for the build up of earth horizontal stresses.

Among the most commonly occurring formations, sands will typically have the lowest Poisson's ratio and hence the lowest build up of horizontal stress. Therefore, excluding formations with conductive natural fractures, conventional wisdom identifies sands as the primary danger zones for uncontrolled mud losses.

The perceived dangers associated with major losses in sands are magnified when dealing with pressure depleted reservoirs where the sand horizontal stress may have reduced significantly. However, a number of field observations suggest that fracture gradient associated problems in depleted reservoirs are not nearly as great as theory would lead us to believe.

The authors present drilling observations that contradict conventional wisdom and propose a theory to explain these differences. This new theory may significantly change the approach to planning and drilling wells in depleted reservoirs, according to the authors.

BRENT INFILL DRILLING

The Brent reservoir in the North Sea has been under production since the 1970s. The reservoir management has involved water injection for pressure maintenance for a number of years.

However, since 1998 the reservoir has been heavily depleted using voidage wells, in order to maximize the gas production from the reservoir.

In "Brent In-Fill Drilling Programme: Problems Associated With Drilling Depleted Reservoirs," the authors describe the problems associated with an infill drilling program and detail solutions. SPE/IADC paper 67441 was prepared for the conference by **M A Addis**, **Shell International Exploration and Production**; and **M B Cauley** and **C Kuyken**, **Shell UK Exploration and Production**.

The average field depletion rate in Brent is estimated to be about 500 psi/year, decreasing the reservoir pressure from the original 6,000 psi to approximately 2,500 psi.

Drilling the high angle (>70°) infill wells in the depleting Brent reservoir has proved troublesome.

The Brent and Statfjord formations comprising the Brent Field contain shale layers of "sub-seismic" thicknesses interbedded between the productive intervals. The depletion has resulted in a gradually decreasing fracture gradient, while the shales require a minimum mud weight to maintain stability.

The depletion is now such that the fracture gradient in the sandstone reservoir intervals is only marginally above, or equal to, the minimum mud weight allowable to maintain stability of the shales. This has resulted in severe losses and/or shale instability when drilling the high angle wells.

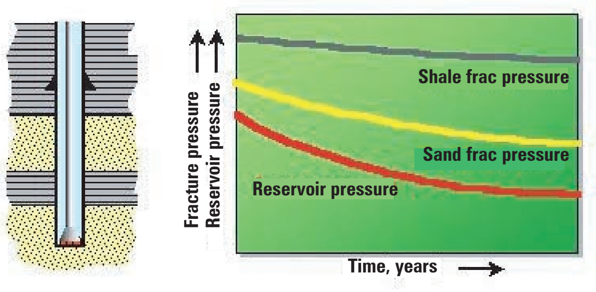
The authors describe the problems encountered in the infill drilling program, the field estimation of the depletion constant—which differs markedly from the laboratory calculated value—and the variation of the losses in wells of different orientations, and inclinations.

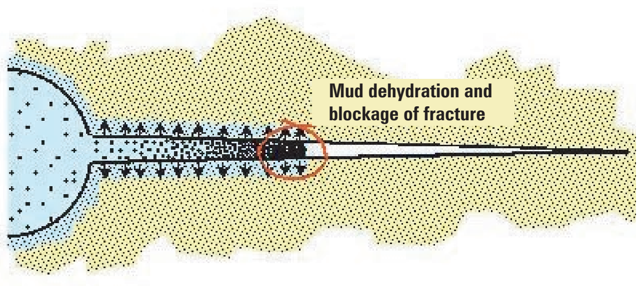
The role of temperature on the occurrence of losses is illustrated using a field example. The authors discuss the measures used to eliminate the problems experienced in the high angle wells in conventional wells and in coiled tubing infill wells.

The role of temperature is identified and the allowable mud weights used to minimize losses. The degree of underbalanced drilling needed to drill through the shale layers is also discussed, and the field recommendations successfully applied by the operating groups.

The variation of the losses across the field in different faulted blocks is discussed along with the observation that

Pressure relationships





the proximity of older wells and fractured formations results in increased risks of severe uncontrollable losses.

DIAGNOSING FRACTURES

Major problems are often encountered in relaxed basins when extended reach wells are drilled through depleted reservoirs. As wellbore inclination increases, the imbalance between vertical and horizontal stresses causes breakouts that lead to increased cuttings and stuck pipe.

In SPE/IADC paper 67442, "How to Diagnose Drilling Induced Fractures in Wells Drilled with Oil Based Muds with Real Time Resistivity and Pressure Measurement," the authors provide a methodology for diagnosing drilling induced fractures so prompt action can be taken. The paper was prepared for the Conference by **T R Bratton**, **I M Rezmer-Cooper**, **J Desroches**, **Y-E Gille** and **D Omeagic**, **Schlumberger**; and **M McFadyen**, **Texaco**.

Higher mud densities can stabilize the imbalance and facilitate cuttings transport, but increase the risk of differential sticking and lost circulation. Additionally, higher mud densities can create fractures that take mud while drilling and return mud during connections.

This "ballooning" complicates the correct diagnosis and increases the risk of losing the well. Early identification of these competing mechanisms is critical to successful drilling.

Real-time resistivity-at-the-bit images are now possible to aid diagnosis, but are currently limited to water-based muds. Nevertheless, conventional resistivity measurements can still be used in wells drilled with oil-based muds.

The authors describe a case study of a highly deviated Gulf Coast well drilled with synthetic oil based mud that penetrated a severely depleted reservoir. After losing two wellbores, the project was abandoned due to the wellbore instabilities and limited reserves.

Investigations into the lessons learned highlight how multiple passes with both resistivity and annular pressure measurements could be used to predict the failure of the borehole, and hence suggest appropriate action.

Indeed, the resistivity data responded to the fractures hours before any changes in equivalent circulating density (ECD). Diagnosis of the mechanisms of wellbore ballooning, breakouts and fractures was validated with geomechanical modeling, downhole measurements, fracture volume calculations and flowback observations.

The authors provide a methodology for diagnosing drilling induced fractures from the real-time measurements, so that remedial actions can be promptly taken.

DEPLETED LOUISIANA SAND

BP Amoco has successfully drilled with up to 13,000 psi differential pressure through a depleted sand in a South Louisiana well. Close attention to operational procedures avoided stuck pipe and unmanageable mud losses.

BP Amoco successfully drilled with 13,000 psi differential pressure through a depleted sand in South Louisiana.

Total costs were reduced by avoiding downtime associated with the high differential and by managing the sand without increasing casing sizes.

Bit selection and performance, BHA design along with mud system, cement program and casing design for this well are reviewed in SPE/IADC alternate paper 67744, "Successfully Drilling Highly Depleted Sands," prepared for the Conference by **J Shaughnessy** and **R Fuqua**, **BP.**

REDEVELOPMENT CASE

A study of the evolution of the drilling fluid systems and techniques used to redevelop a dolomite formation located in Indian Basin, New Mexico, is the focus of SPE/IADC paper 67743, "Case History: Drilling Techniques Used In Successful Redevelopment of Low Pressure H_2S Gas Carbonate Formation."

The paper was prepared for the Conference by **D Kinchen**, **Kerr-McGee**; **M A Peavy**, **Kerr-McGee Oil & Gas Onshore LLC**; **T Brookey**, **Actisystems**; and **D Rhodes**, **M-I LLC**.

The redevelopment began in the late 1990s. The field, discovered in 1963, produces from the Upper Pennsylvanian formation, a fractured, vuggy dolomite located at approximately 7,500 ft.

The study described by the authors compares well data on 14 wells drilled by Kerr-McGee where gas productivity ranges from 500 Mcf/d to 10,000 Mcf/d/well. Bottom hole pressure averages 500 psi (1.28 ppg equivalent mud weight) resulting in significant fluid loss which imposed a major obstacle to the drilling and completion efforts.

The drilling challenge was further complicated by high H_2S concentrations within the formation gas (8,000 to 10,000 ppm).

The drilling fluid systems used were as follows.

A conventional system was used on 5 wells. Wells were drilled using fresh water mud systems with LCM materials to control fluid losses. Initially, full returns were required which were modified to incorporate drilling "blind" without returns. Fluid losses ranged from 15,000 to 20,000 bbl per well with this type of operation.

An air/mist system was used on 3 wells. This method required setting the production casing string at the top of zone, then drilling through the reservoir with an air/mist system leaving an open hole completion. Fluid losses ranged from 0-100 bbl per well.

Finally, an aphronics fluid system was used on 6 wells. This method involved displacing to an "Aphron" mud system prior to drilling into the main pay.

This system uses microencapsulated air bubbles to minimize fluid losses that averaged 500-1,000 bbl per well. ■