Borehole Stability in Horizontal Wells: Case Histories from the Permian Basin

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SUMMARY

The purpose of this paper is to raise awareness of borehole instability (stuck-pipe) risks when drilling horizontal wells in the Permian Basin. Horizontal wells can suffer instability if the mud weight used is insufficient. The weight of the overburden, the magnitude of horizontal stresses and formation fluid pressure comprise the external (natural) forces acting on the borehole. Resisting these, rock strength and the borehole pressure exerted by the drilling fluid act to help stabilize the borehole. Borehole stability assessment is, therefore, a balancing-act between stabilizing and destabilizing forces acting on the wellbore. Other factors, such as the chemical composition of the drilling fluid, can either enhance stability or promote failure depending upon which side of the balance they act. Mud hydraulics modeling is also important to assure that drilled cuttings and any cavings from the borehole wall are effectively removed from the borehole.

While drilling a near-horizontal borehole, lithology changes frequently occur along the length of the lateral. These can be due to formation dips differing from well inclination and azimuth, faulting, or from geosteering over-corrections while drilling. As lithology changes, so does the mud weight needed to maintain stability in the borehole. Corrections to mud density must be implemented "real-time" while drilling. A borehole integrity management approach is recommended that integrates rock mechanics, mud weight prediction, mud hydraulics and geosteering. Mud weight predictions should be linked with petrophysical analysis to identify the appropriate landing zone. This can be optimized to reduce the risk of stuck-pipe events by recognizing both in-zone and out-of-zone mud weight requirements.

STRESSES & FORMATION PRESSURE

Before the well is drilled

Before drilling, stress directions and magnitudes should be assessed. The overburden (vertical) stress, S_v, can be calculated by integrating density logs with depth. Where data is missing, a vertical stress gradient of 1.06 psi/ft. (2.45 g/cm^3 equivalent) is a good approximation. Two horizontal stresses exist in the earth, and typically these are not equal in magnitude. The minimum horizontal stress, S_{hmin}, is typically referred to as the fracture gradient in shale formations. In sandstones, the fracture gradient can be affected by solids in the drilling fluid, and here the fracture gradient may be higher than the minimum far-field horizontal stress. (The maximum horizontal stress is referred to as S_{Hmax}.)

The relative magnitudes of the stresses define the *stress state* existing in-situ in the location that is being drilled. In the Permian Basin, with few exceptions, a *normal state of stress* exists. Here the overburden is the greatest stress; i.e. $S_v > S_{Hmax} > S_{hmin}$. Westwards, closer to the Rocky Mountains, a *strike-slip state of stress* may occur. Here the maximum horizontal stress is greater than the overburden: $S_{Hmax} > S_v > S_{hmin}$. This state of stress is quite common in mountainous areas. Exceptionally (as far as oil-well drilling is concerned), a *thrust faulting state of stress* may exist in some locations where the vertical stress is the smallest stress $S_{Hmax} > S_{hmin} > S_v$. However, this state of stress is quite uncommon in US hydrocarbon-producing areas (perhaps with the exception of certain parts of California and, possibly, in the Cook Inlet area of Alaska).

The direction of the maximum horizontal stress in much of the Permian Basin is aligned roughly ESE-WNW, though local variations in faulted areas can exist. Caliper breakout analysis or azimuthal sonic velocity profiling from wireline logs can confirm this general trend in specific wells. (It is for this reason, largely, that the majority of horizontal wells are drilled in a north-south direction, so as to create fractures that are oriented transverse to the wellbore – i.e. the well runs north-south and the fractures run east-west.)

Large parts of the Permian Basin have formation fluid pressures that are close to the hydrostatic pressure of brine; i.e. 0.46 psi/ft. / 8.6 ppg. Hydrocarbon-bearing zones may be initially slightly overpressured (i.e. a pressure higher than hydrostatic) at up to 0.52 psi/ft. / 10.0 ppg. Certain horizons in the Delaware Basin in south-eastern New Mexico and west Texas may have fluid pressures as high as 0.75 psi/ft. / 14.4 ppg. Offset production and well drilling experiences will help determine the formation fluid pressure at a new well location. Where data is sparse, or for assured assessment, pore pressure prediction analyses may be carried out.

After the well is drilled

After the well is drilled, formation stresses acting in the far-field are replaced by the mud hydrostatic pressure within the borehole. The subsequent redistribution of stresses creates a *stress concentration* in the near-wellbore region. This extends about 3 to 4 borehole diameters from the wellbore. The stress concentration acting at the borehole wall is easily calculated using appropriate equations – e.g. see Zoback (2007) for a complete description of borehole stress analysis. If the stress concentration is sufficiently large to overcome the effects of the mud pressure and rock strength, borehole instability can occur. Predicting these stress concentrations forms the basis of wellbore stability analysis.

If there is only a small difference in the magnitude of stresses acting perpendicular to the long axis of the borehole, then the borehole may be quite stable. This typically exists when drilling vertical wells in the Permian Basin, as the two horizontal stresses (S_{Hmax} and S_{hmin}) have quite similar magnitudes (i.e. the stress difference is small). Much historical experience in the region has been with drilling vertical wells, and here quite low mud weights – often only notionally greater than water hydrostatic – have been used successfully. Contrast this situation, however, with drilling a horizontal well. Here the difference between the magnitude of stresses acting perpendicular to the long axis of the borehole (S_{Hmax} and S_v) is possibly quite large. Here conditions leading to borehole instability can occur if mud density is insufficient.

BUILDING A GEOMECHANICAL MODEL

There are five basic components needed to build a geomechanical model. Zoback (2007) describes these fully:

- Define the vertical stress – integrate a density log with depth
- Determine the formation pore pressure – offset production, direct measurement using MDTs, and analysis of minifrac pressure fall-off can all be used to assess pore pressure. Analyses of sonic and resistivity logs can also provide estimates of pore pressure.
- Minimum horizontal stress – this can be calculated from wireline log data (principally density and sonic logs), or measured directly by leak-off or minifrac tests.
- Maximum horizontal stress – the magnitude and orientation of this stress can be derived from analysis of drilling-induced features seen in image logs, or they can be constrained empirically from back-analysis of previous drilling experiences in offset wells.
- Rock strength – this is typically derived from established correlations with wireline logging parameters.

GETTING THE WELL DRILLED SUCCESSFULLY

Instability Mechanisms & Cavings Analysis

In general there are three modes of borehole stability that may occur, and each produces characteristically-shaped cavings.

- When the mud hydrostatic pressure is less than the formation pressure (i.e. the well is underbalanced), cavings are typically splintery shards of rock as the higher fluid pressure in the rock ‘pops’ off slivers of rock from the borehole wall. Increasing the mud density will cure this mode of instability.
- Any failure of the rock on the sides of the borehole due to high stress concentrations that creates breakouts is typically characterized by angular, “arrow-head” shaped cavings. In most settings, breakouts will become stable over time (even though they might be large). Increasing mud density will stop this mode of instability from getting worse.
- Less common – though often catastrophically severe when it does happen – is a mode of borehole failure in layered or fissile shale where the weak shale layers separate and fail in a buckling mode on the top and bottom of the borehole. (The sides of the borehole may be quite stable.) This “roof collapse” mode of instability is characterized by blocky, “match-box” sized cavings, with two or more sides defining the individual shale layers. This mode of failure is very difficult to stop once it has occurred. The roof of the borehole will continue to fall-in and increasing mud weight will provide, at best, only temporary relief. Where these formations exist, a mud weight sufficient to prevent this mechanism of instability from occurring in the first-place must be used.

Drilling Fluid Chemistry

The best drilling fluid is one that does not react with the formation. The chemical formulation of water-based drilling fluids (WBM) when drilling reactive, smectite-rich clay shales has received considerable attention in the past. More recently there is a growing appreciation by some that the salinity of the water used in oil-based drilling fluids (OBM) can affect the long-term stability of the borehole (see Rojas *et al*, 2006 for details). Oil-based drilling fluids are typically an emulsion of oil and water, with oil:water ratios often varying between 90:10 and 75:25. It is common practice in the Permian Basin to use oil-based drilling fluids with a brine component that is salt-saturated. This sets up a condition where *osmosis* can occur. Water will flow under *osmotic pressures* from the fresher side (i.e. the formation) to the saltier side (i.e. the drilling fluid). Dewatering of the near-wellbore area can temporarily strengthen the shale; this can allow the well to be drilled with a mud weight lower than would be predicted from conventional stability models that ignore this effect. The dewatering-strengthening effect lasts for a few days. Prolonged exposure to high water-phase salinity OBM can result in desiccation of the borehole wall. (Think of mud drying in the sun.) The resulting 'cracking' of the shale and it forming into chunks that can fall into the borehole can develop into a serious borehole instability problem over time.

Hole Cleaning

Hole cleaning is absolutely critical in horizontal well drilling. What works for vertical wells isn't always effective in the build or horizontal sections of high-angle wells.

- VISCOUS pills are more effective in VERTICAL wells.
- HEAVY (weighted) pills are more effective in HORIZONTAL wells.

Tandem sweeps (heavy followed by viscous) may be the best strategy when drilling the lateral section. The heavy pill will clean the lateral while the viscous sweep will remove the cuttings and any cavings from the vertical section. To achieve this it is necessary to get a good hole cleaning plan by using good hydraulics models. It is recommended that mud company experts or qualified in-house staff to do this. A range of cuttings and caving sizes should be modeled to develop a good hole cleaning program that can be applied to any situation and quality of borehole.

Tripping Practices

When pulling the Bottom Hole Assembly (BHA) and drill-string out of the borehole, the mud hydrostatic pressure in the lateral can be reduced as a result of a 'syringe effect' often referred to a swabbing. Even if mud weights are sufficient to keep the borehole stable, tripping out of the well too fast can lower the downhole pressure so that instability develops at that point in time. It is ironic that, many times, it is the last trip out of the hole prior to running casing that causes the most instability. Tripping speeds should be defined to limit downhole pressure changes to acceptable amounts.

PRACTICAL IMPLEMENTATION

Pre-Drill

A recommended workflow to minimize the risk of instability in horizontal wells would include the following:

- Generate a geomechanical model for the area, based on analysis of offset wells.
- Calculate mud weight required for drilling a horizontal well based on standard analytical equations (e.g. Zoback, 2007).
- Integrate mud weight prediction with petrophysical and hydraulic fracturing stimulation analysis to identify the appropriate landing zone. This should be good for reservoir presence, good for hydraulic fracturing and good for borehole stability

Real-Time

It is recognized that horizontal wells are seldom horizontal, and that geologic uncertainty, complexity and variability will result in different lithologies being encountered along the high-angle lateral of a horizontal well. Geosteering techniques of varying complexity are frequently employed to 'steer' the well in order to intersect the desired rock formations. It is believed that in addition to providing positional and directional advice, geosteering technology can be extended to provide near-real-time mud weight prediction based upon the actual lithology being drilled. Suggested steps for achieving this are as follows:

- Generate a "horizontal well mud weight" profile based in wireline log information in an offset well.

- While geosteering the lateral, generate a mud weight curve depending upon the lithology being drilled.
- In ‘relevant-time’ advise on required mud weight and if changes are needed, e.g. when drilling out of zone.
- Identify instability risks along the wellbore; does mud weight need to be increased because lithology has changed?

CASE HISTORIES
The presentation accompanying this paper presents six case-histories of real-time mud weight up-dates. Some of these were retrospective back-analyses when perfecting the technique in-house at Apache. Others were used real-time to provide recommendations for changing the mud weight being used while drilling.

Example 1: In this well the mud weight was 12.2 – 12.3 ppg, with an equivalent circulating density (ECD) while drilling of 13.2 – 13.4ppg. While tripping, borehole swab pressures were ca. 11.3 – 11.8 ppg. As a consequence of lithology changes along the wellbore, required mud weights for stability varied from 9.65 ppg in stronger rock to 11.8 ppg in the weakest rock. The mud weight used was in excess of this, and the well was drilled successfully to target depth (TD). (The pre-drill wellbore stability analysis for this well recommended a mud weight of at least 12.0 ppg be used in this well).

Example 2: This well was drilled with a 9.9 ppg WBM. Sections of the lateral near the toe of the well were predicted to require 10.45 ppg. A second zone in the curve section prior to going horizontal also needed higher mud weight than that used. The drill-pipe became stuck at 11,500ft. Two 200 bbl. high viscosity pills were pumped; lots of 2-inch-size cavings were recovered from the first pill and some 1-inch-size cavings from pumping the second pill. The drill-string became stuck and subsequently parted when tripping out of the hole. When running back into the hole to clean it up, the borehole was found to be packing-off from 8686 – 8940 ft. (This is the zone in the curve needing more mud weight.) High-viscosity pills recovered cavings up to 3½-inches in size. The driller had to weight up to 11.5 ppg to make progress. The sidetrack was successfully drilled with 11.9 ppg mud.

Example 3: This well became stuck at 13,921 ft. when using 11.6 ppg OBM. Sections along its length were predicted to require 12.3 ppg. Though the ECD would have been higher than this required density, it is thought possible that salinity effects and tripping practices over time resulted in a destabilized borehole.

Example 4: This provides a good example of the OBM water-phase salinity effect. The horizontal well was drilled with an 8.5 ppg OBM with a salt-saturated (ca. 360,000 to 390,000 ppm $CaCl_2$) water-phase salinity. While drilling the well they were constantly adding about 20 sacks of $CaCl_2$ salt per day to keep the salinity up. This was done because fresher water was continuously being pulled from the formation. Sections of the borehole were required to need in excess of 9.5 ppg mud weight for stability. Stability was achieved in the short-term using a lower density mud by virtue of the dewatering-strengthening effect. However, over time the borehole became unstable and was sidetracked. The sidetrack used 8.8 ppg OBM mud (with a slightly less salty 260,000 ppm $CaCl_2$ water-phase salinity), while calculations suggested 9.2 ppg mud weight was needed. The borehole did pack-off near TD, but this was cleaned-up and casing ran with only 128-ft. of the drilled section lost.

Examples 5 & 6: Both these wells were drilled with optimum mud weights and properties. Mud density either matched or slightly exceeded that predicted for stability. These examples show that quality, trouble-free boreholes can be achieved by using mud weights specifically tailored for the formation being drilled.

REFERENCES
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