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Safe Mud Pump Management while Conditioning Mud: On the Adverse Effects of Complex Heat Transfer and Barite Sag when Establishing Circulation

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Abstract: For complex drilling operations with narrow geo-pressure windows, it is not uncommon to have problems with formation fracturing, due to erroneous mud pump management. To assist the driller in managing the circulation, it is possible to limit both the acceleration of the mud pumps whilst changing the flow-rate as well as the actual flow-rate, to avoid generating downhole pressure above the fracturing pressure gradient of the open hole section. Such mud pump operating limits are dependent on the operational parameters (*e.g.* drill-string axial and rotational velocities), and the *in situ* conditions downhole. The *in situ* conditions evolve with time due to the changes of bit and bottom hole depths as well as the variations in temperature, mud properties and cutting concentrations. When starting to condition mud after a long period of time without circulation, the changes in temperature can be very large. Furthermore, in the eventuality of barite sag, lifting up drilling fluids containing a large concentration of high gravity solid can cause much increase of the downhole pressure. This paper presents a methodology that is used in an automatic drilling control system to account for all those factors in order to have a safe mud pump management including circumstances where mud is being conditioned.

Keywords: drilling automation, safe guard, physical model, mud pump management, mud pump acceleration, maximum flow-rate, formation fracturing gradient, mud losses, barite sag, heat transfer.

1. INTRODUCTION

An excessive mud pump acceleration or a too large flow-rate can generate downhole pressures that exceed the fracturing pressure gradient of the open hole formation therefore causing mud losses and in the worst case scenario, a loss circulation incident. The maximum tolerable pump accelerations and flow-rates are very context dependent (Iversen *et al*. 2009). Both the drilling operational parameters and the downhole conditions dictate the well safe guards to be used. When drilling is well established, the time dependence of those limits is mostly influenced by the change of depth. But while conditioning mud after a long period of time without mud circulation, the downhole conditions change quickly because of the combined effect of heat exchange happening with the cold fresh mud being pumped into the well and the displacement of the mud in place which properties may have been altered during the period of inactivity. This paper describes an automatic system that attempts at enforcing mud pump safe guards that adapt themselves to the current downhole conditions.

2. AUTOMATION OF MUD PUMP MANAGEMENT

In this section, we will first describe the fundamental physical characteristics of the drilling hydraulic system and then we will present the method used to solve the problem of managing the mud pumps during a drilling operation.

2.1 Drilling hydraulics

In conventional drilling and with a simple drill-string and BHA (Bottom Hole Assembly), the drilling hydraulic system is composed of two branches connected together at the level of the bit: the drill-string branch and the annulus branch (see Fig. 1). Note that if the bit is off bottom, the annulus branch is longer than the drill-string one.

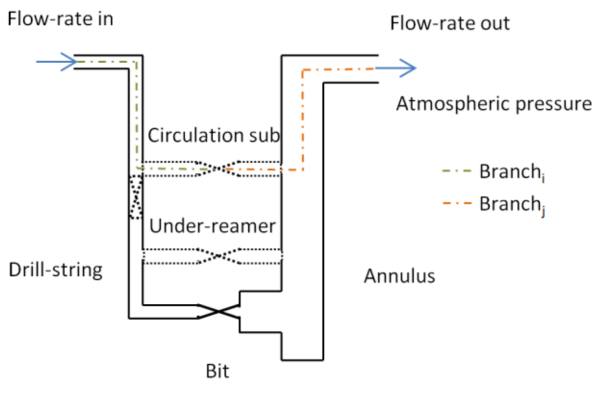

Fig. 1: The drilling hydraulic system can be seen as a network of interconnected branches.

But several junction points may exist, if there are components like circulation-subs, hole openers, under-reamers, downhole motors, *etc.* in the drill-string because such elements provides access from the inside of the drill-string to the annulus at other places than the bit. The result is a network of inter-connected branches. The condition to be respected by this network is that the pressures on both sides of the junction point between the two branches are equal.

To describe the behaviour of the drilling fluid in each branch we can use a cross sectional averaging of the Navier-Stokes equation (Fjelde *et al.,* 2003). There are three balance equations that describe the interface exchange of mass, momentum and energy.

The mass balance can be written:

$$\frac{\partial}{\partial t}(A\rho) + \frac{\partial}{\partial s}(A\rho v) = q, \tag{1}$$

where t is time, s is the curvilinear abscissa, A is the cross-sectional area of a fluid element, ρ is the averaged density, v is the average velocity, q is the source term, a mass per length per time through the fluid element side walls.

In a multi-phase context, it is more complicated to write the momentum balance. The assumption made here is to use a drift-flux formulation where the different phases are mixed together but each phase has a slip velocity compare to a reference one. The momentum balance can then be written as follow:

$$\frac{\partial}{\partial t}(A\rho v) + \frac{\partial}{\partial s}(A\rho v^2) + A\frac{\partial}{\partial s}p = -A\big(K - \rho g cos(\theta)\big), \tag{2}$$

where p is the pressure, K is the friction pressure-loss term, θ is the average inclination of the fluid element, g is the gravitational acceleration of the earth.

Finally, the energy conservation can be written (Marshall and Bentsen, 1982):

$$\frac{\partial}{\partial t}(\rho H) - \nabla\big(Q_f + Q_c\big) - q_s = 0, \tag{3}$$

where H is the enthalpy per mass unit, Q_f is the forced convective term, Q_c is the conductive and natural-convective term, q_s is the heat generated by mechanical and hydraulic frictions.

The forced convective term can be expressed:

$$Q_f = \rho H v, \tag{4}$$

The conductive and natural-convective term does not have a general expression. In the case of purely convective isotropic material, we can use:

$$Q_c = \lambda \nabla T, \tag{5}$$

where λ is the thermal conductivity, T is the temperature,

2.2 Drilling fluid density

The partial differential equations (1), (2) and (3) are all dependent upon the local density of the drilling fluid element. It is therefore important to have a precise estimation of the *in situ* density of the mud.

A drilling fluid is constituted of a liquid, a solid and a gas phase. The liquid phase is either solely based on a brine solution (water-based mud) or on a mix of oil and brine (oil-based mud). The solid components of the mud are low gravity solids (like bentonite clay), high gravity solid (like barite) and rock cuttings. Except for special drilling applications such as using a foam as a drilling fluid (Kuru *et al.*, 2005) or particular dual-gradient managed pressure drilling (MPD) solutions using gas to reduce the mud density within the upper part of the well annulus (Scott, 2009), the presence of gas in the mud is not planned, but arises from contamination of the drilling fluid with air in the surface installation or because of formation gas mixing downhole with the drilling fluid. Accounting for the different components of the drilling fluid, one can express the mud density as:

$$\rho_{mud} = \sum_{i\in E} f_i \rho_i, \tag{6}$$

Where E is a set of indices representing the different constituents of the drilling fluid (*i.e.,* brine, oil, low-gravity solid, high-gravity solid, cuttings and gas), f_i is the mass fraction of the i component of the drilling fluid, ρ_i is the density of the i component of the drilling fluid.

In addition, the following relationship shall be respected:

$$\sum_{i\in E} f_i = 1 \tag{7}$$

The thermal expansion and compressibility of the liquid phases (*i.e.* brine and oil) used in drilling fluids (see Fig. 2) can be well approximated through a 6-parameters model (Ekwere *et al.*, 1990) as defined in the following relationship:

$$\rho_{liquid} = (A_{00} + A_{01}T) + (A_{10} + A_{11}T)p + (A_{20} + A_{21}T)p^2, \tag{8}$$

where ρ_{liquid} is the density of the brine or oil phase of the drilling fluid element, T is the temperature of the fluid element, p is the pressure of the fluid element, A_{ij}, i=0, 1, 2 and j = 0, 1 are the coefficients of the model.

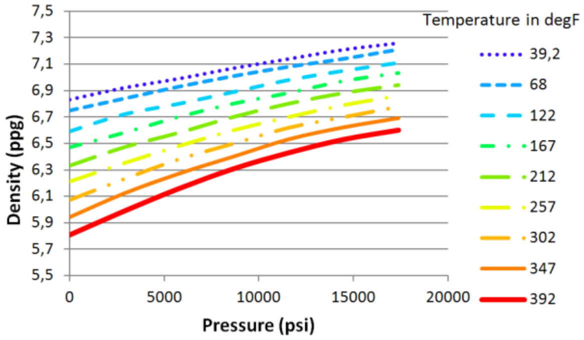

Fig. 2: Base oil density in pounds per gallon (ppg) of a typical low viscosity oil-based mud as a function of temperature and pressure.

At high pressure, gas may be dissolved in the liquid phase (especially with oil-based mud) and therefore affects the compressibility and thermal expansion of the liquid phase (Monteiro *et al.*, 2010). However, when the pressure decreases below the bubble point, free gas is present in the drilling fluid. Its density is then governed by the ideal gas law:

$$\rho_g = Mp/RT, \tag{9}$$

where M is the molar mass of the gas, R is the ideal gas constant.

By solving the partial differential equation (3) using a finite difference method (Corre *et al.*, 1984), it is possible to estimate the evolution of the temperature of the drilling fluid as a function of depth and time (see Fig. 3).

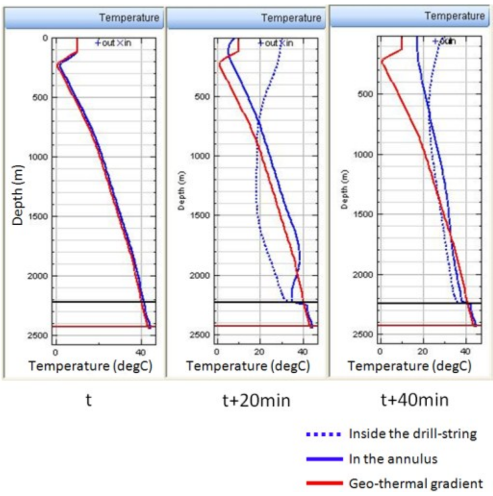

Fig. 3: Those three graphs show the evolution of the temperature of the fluid inside the drill-string and in the annulus.

The calculated local temperature along the drill-string and the annulus can then be used together with the modelled local pressure to estimate the *in situ* density of the liquid and gaseous phases of the drilling fluid.

The density of the solid particles does not change much with pressure and temperature. However the concentration of the different solid phases in the drilling fluid greatly influences the mud local density.

While drilling, rock cuttings are transported along the annulus as part of the cuttings removal process. The cuttings production is simply the product of the rate of penetration (ROP) by the footprint of the bit (and the one of the under-reamers or hole-openers if any is in use). The cuttings transport (see Fig. 4) is much more complicated to estimate and depends on many parameters like the cuttings particle size distribution, the cuttings density, the fluid velocity and density, the rotational velocity of the drill-string, the inclination of the borehole (Larsen *et al.*, 1997).

Fig. 4: These three graphs show how cuttings are generated while drilling and transported along the annulus by the circulation of drilling fluid.

As a result the mass fraction of cuttings varies along the annulus due to the different operations performed during the drilling process. At a given depth, the local concentration of cuttings contributes to the changes in the local mud density (see Fig. 5) which is influenced by the local temperature and pressure as previously discussed.

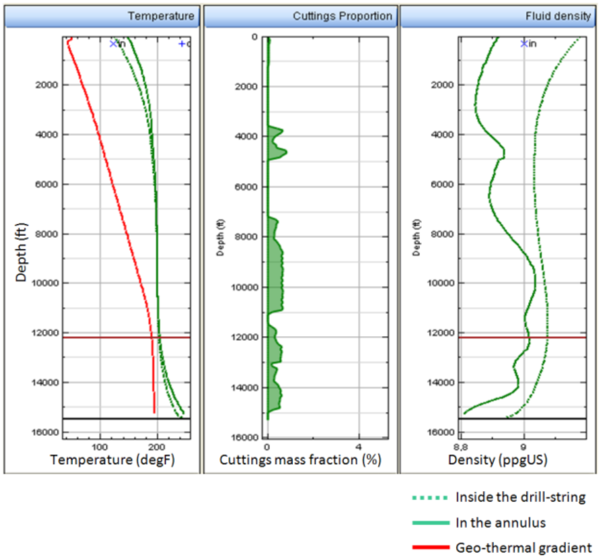

Fig. 5: Effects of pressure, temperature and cuttings load on local mud density inside the drill-string and the annulus.

Drilling fluids are thixotropic (*i.e.* they become more viscous when there are no fluid movements) in order to maintain the solid particles in suspension when circulation is stopped. This thixotropic suspension or gelling effect applies to both the cuttings particles and the mud weighting materials. The high specific gravity solid particles used to weight the drilling fluid have a high density (*e.g.,* the density of barite is typically 4500kg/m^3) and this means that the added barite can easily segregate from the rest of the drilling fluid if the mud does not gel: this effect is termed dynamic sagging.

During dynamic sagging, when the mud flow rate is very low, no gelling takes place because the fluid is not at rest, yet the fluid velocity may not be strong enough to counteract the slip velocity of the high gravity solid particles and therefore barite may segregate from the rest of the fluid (Aas *et al.*, 2005). This effect is also termed barite sag.

In inclined (*i.e.* non vertical) wells, when fluid circulation is stopped, dynamic sagging may also occur simply because of natural convection flows within the well, due to variations of the mud density in a cross-sectional area, which prohibit gelling to take place (Dye *et al.*, 2001). A radial temperature gradient caused by a large temperature difference between the interior of the drill-string and the formation may initiate convection currents that tend to accelerate the barite settling process. When the heavy particles settle on the lower side of the inclined borehole, they create a thick bed that can then slide down the well bore toward deeper depths and cause large concentrations of high gravity solids at the bottom of the hole while the density of the mud at shallower depths is reduced accordingly.

2.3 Drilling fluid rheology

The pressure loss calculations depend on the viscosity of the drilling fluid. Drilling muds are non-Newtonian fluids, which rheology is following a Herschel-Buckley type of behaviour. However a variation of the Herschel-Buckley rheology has been proposed (Robertson and Stiff, 1976) that has better properties to describe drilling hydraulic flow:

$$\tau = A\,(\dot{\gamma} + C)^B, \qquad (10)$$

where τ is the shear stress, $\dot{\gamma}$ is the shear rate, A, B and C are the coefficients of the model.

But as with any other fluid, the rheology of drilling mud depends on temperature. In addition, the mud viscosity increases exponentially with larger pressures, this being true at any temperature (Houwe and Geehan, 1986), following an Arrhenius type of law (see Fig. 6).

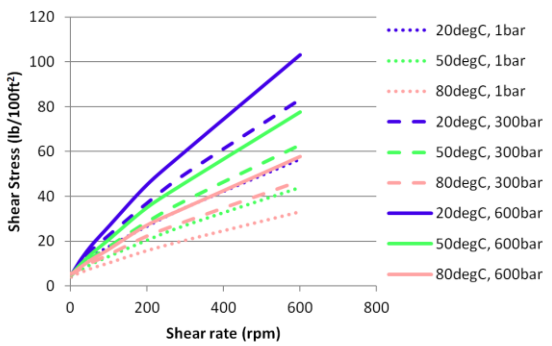

Fig. 6: The viscosity of drilling fluids decreases when temperature increases but increases when pressure increases.

As a consequence, the rheology of the drilling fluid changes with depth and time because of the variation of temperatures and pressures along the drill-string and the annulus (see Fig. 7).

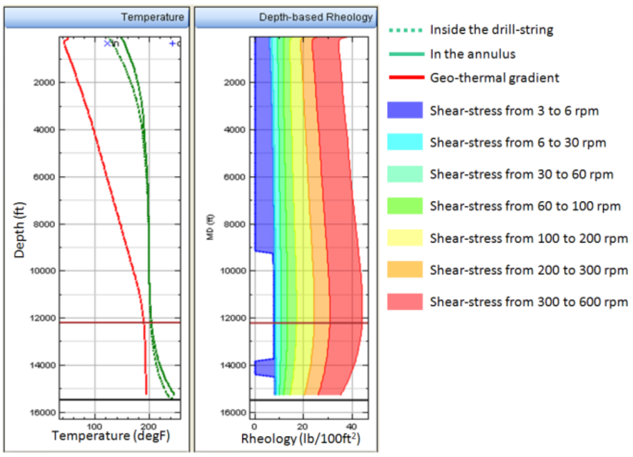

Fig. 7: The local rheology of the drilling fluid in the annulus as a function of depth.

2.4 Continuous wellbore status evaluation

As seen in Fig. 5 above, the cuttings concentration along the annulus depends on the performed sequence of drilling operations (*e.g.* drilling, circulating off bottom, *etc.*). For a normally long well (*e.g.* several kilometres in length) it may take hours to displace the cuttings up to the surface.

Similarly, the temperature inside the wellbore varies as a function of the different drilling parameters being used (*e.g.* bit depth, drill-string rotational velocity, circulation rate, whether drilling or not). After a period of drilling, it may take many days before the temperature inside the wellbore returns to the surrounding geothermal conditions. As it has been mentioned above, during such a temperature equalisation period, barite sag can occur, therefore changing the downhole conditions even though no drilling actions are performed on the well.

As a consequence, it is necessary to monitor the whole drilling process without interruptions, in order to evaluate the current downhole conditions and this from the start to the drilling operation, which is the only moment at which the initial conditions can be reasonably estimated without making reference to a temporal context. This is performed by continuously computing the evolution of the physical parameters characterizing the downhole conditions. There are three main operations involved in this process:

1. The continuous calculation of the physical quantities.
2. The real-time calibration of the thermo-hydraulic model, to account for ill-defined or unknown structural parameters.
3. The continuous estimation of down-hole conditions, to account for the evolution of unknown and non-measurable quantities.

The modelling of the wellbore status can therefore provide estimates in real-time of most of the measured physical values that are not commands to the process (examples of process commands include the flow-rate, the top of string velocity, the top of string rotational speed). This estimation is associated with a tolerance (see Fig. 8) that is dependent on the current quality of the model calibration and the expected precision of the actual measurements. It is therefore possible to compare the actual measurements with their calculated counterpart to determine if there are abnormal downhole conditions.

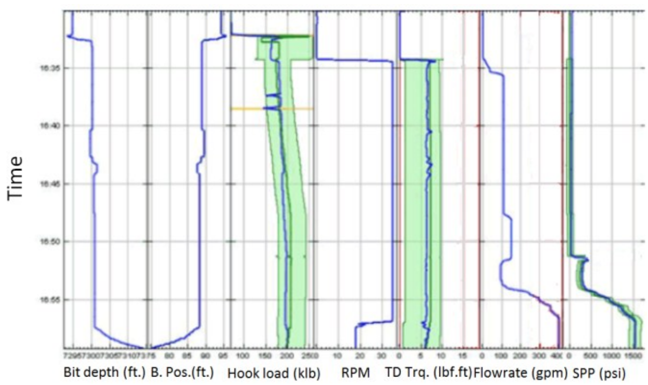

Fig. 8: The blue curves represent actual measurements. The green curves and semi-transparent green regions represent the estimated physical quantities and their associated tolerances based on calibrated physical models of the physical process.

An additional calibration difficulty occurs when there is a long period of time without any measurements, such as when it is necessary to pull out of hole (POOH) the drill-string to perform the next drilling operation, or to replace a faulty component in the BHA. In such cases, it is still possible to perform the continuous calculation of the internal state of the wellbore, but the error or uncertainty regarding the real downhole conditions dramatically increases as it is no longer possible to calibrate the physical models due to the lack of real-time downhole measurements. Furthermore, heat transfer in both natural convection and barite sag models are far from accurate in those circumstances, thereby increasing the uncertainty on the actual downhole conditions when the drill-string is run back into the hole.

2.5 Mud pump start-up

The mud pump acceleration rates are ramped or stepped up in such a manner that downhole pressures do not exceed the fracturing pressure of the open hole formations. It is important to estimate the effect of the downhole pressure variations for the entire open hole well section and not only at the casing shoe depth or at the bit depth, as is often done for the sake of simplicity. In situations with complex or narrow geo-pressure margins, the regions of maximum limitations can be situated at various places along the open hole section.

The acceleration of the mud pumps must not set so as to induce a downhole pressure pulse that exceeds the maximum tolerable rock fracture limit. Such transient pressure surges would not be visible using a steady state hydraulic model and would result in allowing prohibitive mud pump accelerations that could result in fracturing the formation. Our system solves equations (1) and (2) using a finite difference method that permit the estimation of acceleration effects on downhole pressure along the open hole section of the well (see Fig. 9).

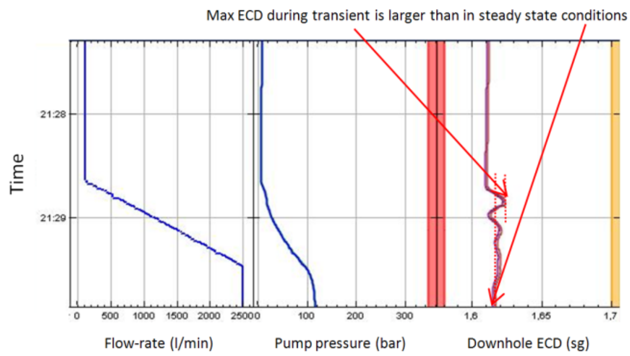

Fig. 9: Effect of ramping up the mud pumps on pump and downhole pressures.

Ideally, to reduce pump start-up time, the flow rate should be increased gradually and continuously to the target flow rate. In practice, several stops need to be performed while starting the mud pumps. Often, the driller desires to use several intermediate steps to check that the pump pressure is evolving normally. Each of these acceleration steps generate a pressure build-up that stabilizes when steady state conditions are reached. Therefore, independent pump accelerations must be used for each single step, depending on the current conditions and the following pump rate level.

It is therefore possible to calculate the maximum pump acceleration from any given starting flow-rate to any other target flow-rate while respecting the two conditions described above: stay within the geo-pressure window and have a monotonic increase of the pump pressure (see Fig. 10).

Using this 2 dimensional pump acceleration function, it is possible to optimize the pump start-up procedure for any number of stages in the ramping procedure.

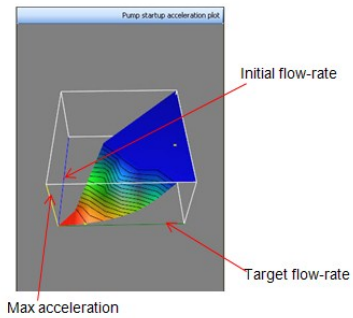

Fig. 10: This graph shows the maximum acceptable pump acceleration while starting from a given flow-rate to reach a target flow-rate.

2.6 Maximum pump rate

Based on the maximum downhole pressure limit (for example using the fracturing pressure prognosis), it is possible to calculate an absolute maximum flow rate that guarantees that the downhole pressure will remain below the upper pressure boundary. To calculate that flow-rate limit, only steady state conditions are necessary (no need to account for mud pump accelerations) and therefore a simpler version of the hydraulic model can be used. The partial derivative on time of equation (2) can be considered to be 0 and the axial velocity of drill-string is supposed to be constant. The resulting simplified equation can easily be solved by integrating along the curvilinear abscissa for each branch of the hydraulic circuit:

$$\mathrm{p(MD)} = \mathrm{p}_0 + \int_{\mathrm{MD}_0}^{\mathrm{MD}} \rho(s) g \cos\big(\theta(s)\big) + \frac{dK}{ds}(s)\, ds, \tag{11}$$

where p is the pressure that should be calculated, MD is the measured depth at which the pressure shall be calculated, MD_0 is the initial measured depth of the branch, p_0 is the initial pressure at MD_0, $\theta(s)$ is the inclination at the curvilinear abscissa s, $\frac{dK}{ds}$ is the frictional pressure loss gradient.

This maximum flow rate changes with time, bit depth and other operational parameters like the rotational velocity or the axial velocity of the string. The dependency on time is due to downhole temperature variations. Another dependency is depth. The position of larger BHA elements with regard to different formation layers influences the maximum tolerable flow rate. The rotational velocity of the drill-string is also affecting the pressure losses in the annulus and it must be accounted for during the estimation of the maximum flow rate. By accounting for all possible axial and rotational velocities, it is possible to estimate the maximum permissible flow-rate for the current downhole conditions (see Fig. 11).

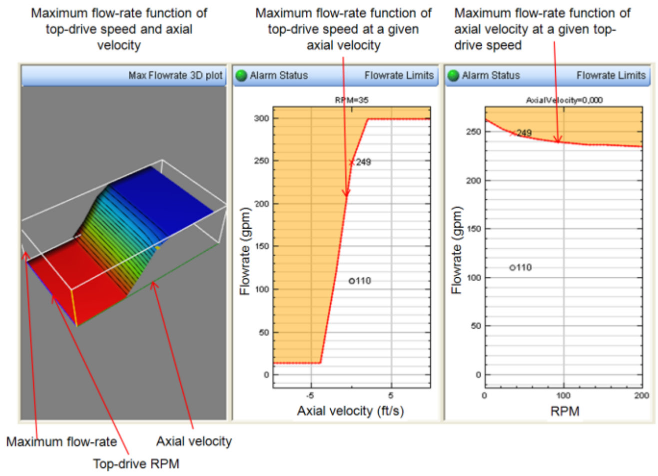

Fig. 11: For given drilling conditions (bit depth, downhole conditions, etc.), the maximum flow-rate is a function of the drill-string axial velocity and its rotational speed.

The drilling control system enforces that the pump rate cannot be increased above the highest acceptable limit at any time and in any drilling conditions. Furthermore, it can reduce, if necessary, automatically the pump rate when the downhole conditions change (Cayeux *et al.,* 2011).

3. AN EXAMPLE OF A PROBLEMATIC MUD CONDITIONING OPERATION

In this section, we will analyse a drilling problem that occurred at the start of a rock coring run in the middle of a 12 ¼" section of a well drilled in the North Sea. While conditioning mud prior to starting the coring operation, severe mud losses were experienced. As a consequence, it was not possible to continue with drilling and the well section had to be plugged back and side-tracked. Note that the system described in this paper was not in used during this operation.

This example shows how difficult it can be to evaluate the actual borehole conditions after a long period without any downhole measurements. However, with the correct estimation of the downhole conditions, it is possible to control the drilling operation safely.

3.1 Annulus temperature and mud density

At the end of the previous BHA run, the temperature in the annulus was quite high. The temperature of the mud in the pit was 122degF and the downhole temperature 200degF (i.e., 70degF above the geothermal temperature). At that time, the annulus was filled with an oil-based mud having a density of 14.5ppg at 122degF, 1 atmosphere.

Thereafter, the previous BHA was pulled out of hole and a cooling process of the mud within the annulus has commenced. Due to the removal of the drill-string volume, mud is also displaced downward as the drill-pipes are removed from the borehole and the top of the annulus is then filled with the mud from the trip tank.

During the run in hole of the coring equipment assembly, the mud within the annulus continued to cool down. At the same time, the mud is pushed upward due to displacement due to the drill-string occupying space in the annulus. The estimated temperature after running in hole the coring assembly is shown on Fig. 12 and it is calculated that the mud density in the annulus is between 14.6ppg and 14.7ppg.

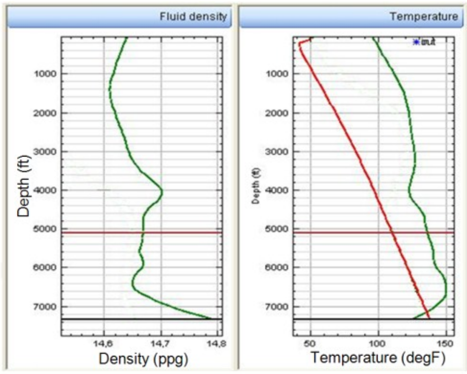

Fig. 12: Density and temperature of the mud in the annulus after running in hole with the coring assembly.

3.2 Mud temperature in the pit

At the end of the previous BHA run, the mud used to circulate the hole clean was an oil-based mud with a density of 14.5ppg at 128degF, 1atm. Based on the PVT (Pressure Volume Temperature) property of the base oil used in the mud, we can derive the density dependence of the mud contained in the pit (at atmospheric pressure) as a function of temperature (see Fig. 13).

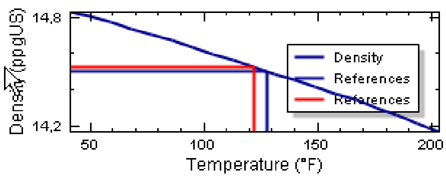

Fig. 13: Mud density in the pit (i.e. at atmospheric pressure) as a function of temperature for the mud used during the previous run.

While pulling out of hole with the previous BHA and running in hole with the new assembly, the temperature in the mud pit reduced to 65degF (see Fig. 14). As a result, the density of the mud in the pit was 14.75ppg before starting the circulation.

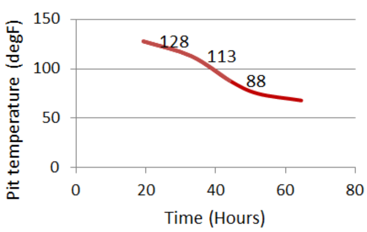

Fig. 14: Evolution of the pit temperature after stopping circulation with the previous BHA run.

The density difference between the mud being pumped from the mud pit and the downhole drilling fluid is confirmed by a gravity induced mud displacement while filling the drill-string before starting the mud conditioning operation. It is observed burst of flow in the return channel much earlier than any pump pressure could indicate that the drill-string was filled. Furthermore the volume of fluid being pumped to fill the drill-string was much larger than anticipated (see Fig. 15).

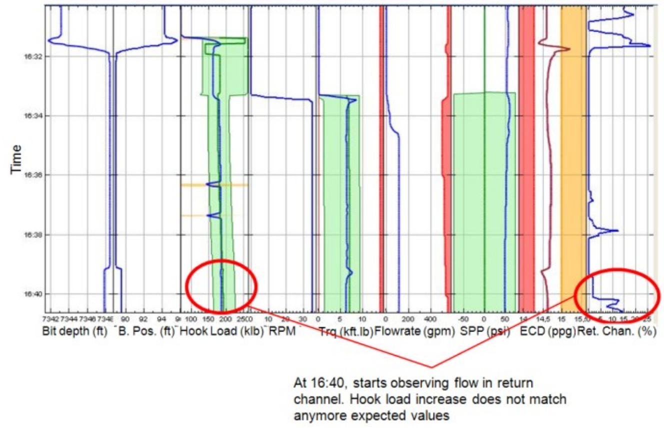

Fig. 15: After filling the pipes for 7 minutes, mud returns could be observed in the return channel.

3.3 Circulation

At the start of the circulation process, the observed and calculated SPP (Stand Pipe Pressure) almost perfectly matched. However, after a further 13 minutes of circulation, a deviation between the observed and calculated SPP could be noticed (see Fig. 16).

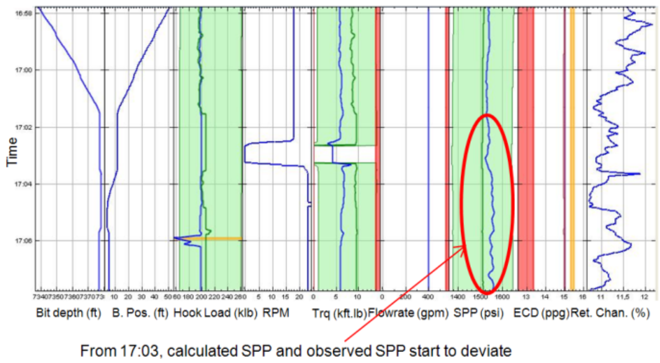

Fig. 16: Deviation between measured and calculated SPP.

This deviation amplified itself and then stabilized to a maximum of 70psi (*i.e.,* 5 bars). If the abnormally high SPP was due to an increase of the pressure within the annulus, then the downhole pressure could be very close to the fracturing pressure gradient.

We notice that both the calculated and observed SPP increase during the circulation process. This is because the calculated pressure accounts for the heat transfer and the estimated local mud density being transported out of the hole. But the temperature effect is not enough to explain the discrepancy between the modelled values and the actual SPP measurements.

However, we can also notice that the deviation between the calculated and observed SPP begin a few minutes after lowering the drill-string to the bottom of the hole. A supposition could be that the last 100ft were filled with a very heavy mud due to barite sag.

3.4 Simulation of barite sag

Assuming that there has been barite sag, a new simulation was performed. The revised simulation shows a good match between the calculated values and the measurements (see Fig. 17).

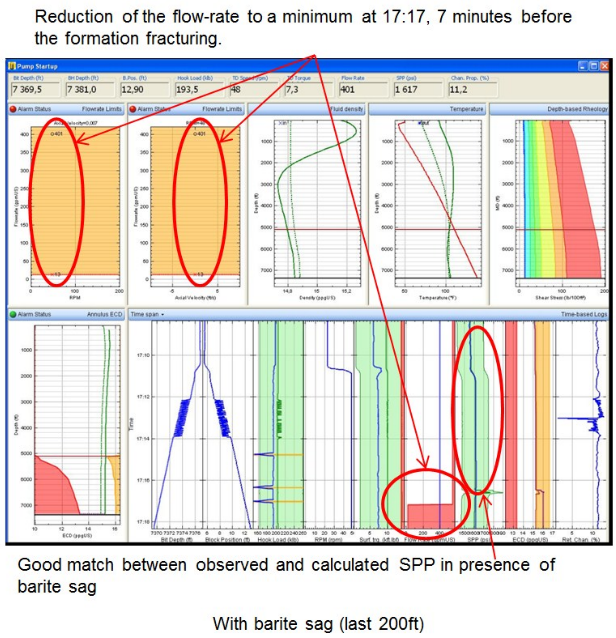

Fig. 17: Last part of the simulation with barite sag.

As expected, due to the heavier mud being transported out of the well and the cooling of the drilling fluid in the annulus, the resulting downhole pressure increases so much that it goes above 15.3ppg equivalent mud weight (EMW) at the casing shoe and can therefore fracture the formation.

The system managing the maximum allowable flow-rate takes into account the situation in real-time, and re-calculates a very low maximum flow-rate for almost all possible operational conditions. This reduction of the flow-rate would have happened 7 minutes before the actual formation fracturing therefore providing drilling personnel with an opportunity to save the drilled section from the major loss circulation incident.

4. DYNAMIC EVALUATION OF POSSIBLE BARITE SAG

The wellbore status evaluation process accounts for many different factors that evolve as a function of both depth and time (*e.g.* temperature, pressure, cuttings concentration, *etc.*). All of those factors or parameters have a direct influence on the time dependence of the maximum flow-rate limits, which is in itself a function of drilling parameters (*i.e.*, the axial and rotational velocity of the drill-string). However, as shown in the above example, barite sag can have a major influence on the acceptable maximum flow-rate to be used during mud conditioning. Unfortunately, it is difficult to have a barite sag model that is accurate enough to reflect the real downhole conditions simply because the barite sag properties of the mud are not measured during drilling operations.

An alternative solution is to assume that there has been barite sag in the well and to then fit the side effects of such an uneven concentration of weighting materials along the annulus with the observed evolution of the downhole pressure (if it is available) and the pump pressure. An Unscented Kalman filter technique is very well suited for such a dynamic fitting (Gravdal *et al.*, 2010). Using the current best estimate of the mud density concentration prior to the start of circulation, it is possible to adjust the actual limits of the flow-rate to lift up the dense, concentrated mud during a drilling fluid conditioning operation and therefore improve the desired safe operating window for the mud pumps.

5. CONCLUSIONS

This paper has described the complexity in safely managing mud pump operations to avoid formation fracturing. The pump operating limits to be applied are context dependent both in terms of operational parameters but also as a function of the downhole conditions. It is especially challenging to obtain a safe flow-rate management when conditioning mud because the temperature evolution can drastically change within a short period of time. It is even more complicated to account for potential barite sag conditions because little information is available before the circulation is effectively started, but dynamic calibration of plausible concentrations of high gravity solids along the annulus can help determine the maximum flow-rate acceptable to condition the mud.

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