Using Downhole Annular Pressure Measurements to Improve Drilling Performance

When monitored downhole in the context of other parameters, pressure in the borehole annulus can be used to identify undesirable well conditions, help suggest and evaluate remedial procedures and prevent serious operational drilling problems from developing.

To survive and prosper in today’s low-price oil and gas market, operating companies are continually challenged to lower their finding and producing costs. To tap the full potential of existing reservoirs and make marginal fields more productive, many wellbores are becoming both longer and more complex. However, keeping costs low requires operating companies to improve drilling efficiency. The rig floor is sometimes like a hospital surgical theater. Instead of finding physicians and nurses, one finds drillers, engineers and other crew members working with one objective: to keep their patient, the borehole, alive and healthy. Just as biological vital signs, like blood pressure and heart rate, are monitored during an operation, so the life signs of the borehole construction process—downhole pressure and mud flow rates—are monitored during drilling.

The measurements described in this article are the “sight and touch” of the driller, enabling him to “see and feel” the dynamic motions of the...
drillstring, and the downhole behavior of the drilling fluid, so that optimal decisions can be made. Vibration and shock data along with torque and weight on bit can be used to modify drilling parameters for increased bit and bottom-hole assembly (BHA) reliability and performance. The lifeblood of the drilling process is the drilling fluid, and downhole mud pressure—measured in the annulus between the drill collar and the borehole wall—is one of the most important pieces of information that the driller has available to sense what is happening as the drill bit enters each new section of formation, or during running the bit into or out of the hole.

Monitoring downhole annular pressure is being used in many drilling applications, including underbalanced, extended-reach, high-pressure, high-temperature (HPHT) and deep-water wells. Such measurements are provided by a number of service companies, and operators have been using them for a wide variety of applications including monitoring the effects of pipe rotation, cuttings load, swab and surge, leak-off tests (LOT), formation integrity tests (FIT), and detecting lost circulation (see “How Downhole Annular Pressure is Monitored,” page 42).2

In underbalanced directional drilling, the use of downhole annular pressure sensors keeps the operation within safe pressure limits and monitors the use of injected gas, which results in more efficient, lower cost drilling. In extended-reach drilling (ERD), annular pressure measurements can be used to detect poor hole cleaning and help the operator modify fluid properties and drilling practices to optimize hole cleaning. In conjunction with other drilling parameters, real-time annular pressure measurements improve rig safety by helping avoid potentially dangerous well-control problems—detecting gas and water influxes. These measurements are often used for early detection of sticking, hanging or balling stabilizers, bit problem detection, detection of cuttings buildup and improved steering performance. While real-time pressure data are of significant value, the information from these measurements is also useful in planning the next well.

This article examines the physical processes associated with downhole hydraulic systems and the use of annular pressure in monitoring the downhole drilling environment. We will look at field examples that show the dynamics of common drilling problems and demonstrate how a basic understanding of hydrodynamic processes—together with a knowledge of drilling parameters—can help provide advance warning of undesirable and preventable events. The examples illustrate three important drilling applications in which downhole pressure measurements are valuable:

- Extended-reach wells, where efficient hole cleaning and cuttings transport are essential in preventing stuck tools and packoff events, which may damage formations and lead to expensive fluid loss.
- Deep-water wells, where there is a narrow pressure window between pore pressure and formation fracture pressure, and both fluid influx detection and wellbore stability are critical.
- Improved drilling efficiencies, with downhole annular pressure measurements providing accurate LOT and FIT pressures, and a more realistic determination of formation stress.

Wellbore Stability
Successful drilling requires that the drilling fluid pressure stay within a tight mud-weight window defined by the pressure limits for wellbore stability. The lower pressure limit is either the pore pressure in the formation or the limit for avoiding wellbore collapse (above). Normal burial trends lead to hydrostatically pressured formations, where the pore pressure is equal to that of a water column of equal depth. If the drilling fluid pressure is less than the pore pressure, then formation fluid or gas could flow into the borehole, with the subsequent risk of a blowout at surface or underground.

The upper pressure limit for the drilling fluid is the minimum that will fracture the formation. If the drilling fluid exceeds this pressure, there is a risk of creating or opening fractures—resulting in lost circulation and a damaged formation. In the language of drilling engineers, pressures are often expressed as pressure gradients or equivalent fluid densities. The upper limit of the pressure window is usually called the formation fracture gradient, and the lower limit is called the pore pressure, or collapse, gradient.


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How Downhole Annular Pressure is Monitored

The history of annular pressure measurements extends as far back as the mid 1980s when Gearhart Industries, Inc. provided annular pressure sensors on their measurements-while-drilling (MWD) tools. Since then, Anadrill and other service companies have developed sensors for downhole annular pressure measurements while drilling.1 The first application of these measurements has been primarily for drilling and mud performance, kick detection and equivalent circulating density (ECD) monitoring. Adding internal pressure sensors, combined with annular pressure measurements, enables differential pressure to be determined, which can be used to monitor motor torque and power performance.

Sperry-Sun was an early proponent of recording ECD measurements during connections, and while pulling out and running in hole to monitor swab-and-surge effects.2 Their PWD (Pressure-While-Drilling) service uses a quartz pressure gauge capable of measuring up to 20,000 psi [138 MPa], and is available in collar sizes from 3 1/2 to 9 1/2-in.

Today, Anadrill provides APWD Annular Pressure While Drilling measurements both in real time and recorded mode using an electromechanical or bellows resistor device installed on the side of the 150°C-[300°F]-rated CDR Compensated Dual Resistivity tool and the 175°C-rated Vision475 tool (right). The CDR tool is available in 6 1/2-, 8 1/4- and 9 1/2-in. collar sizes. These tools can measure several pressure ranges, up to 20,000 psi, with an accuracy of 0.1% of the maximum rating and a resolution of 1 psi. They are also capable of continuous monitoring during no-flow conditions, which enables real-time dynamic testing while mud pump motors are shut down—such as during leakoff testing. Other parameters measured while drilling, such as downhole torque and weight on bit, can be combined with APWD measurements to evaluate hole-cleaning efficiency and early detection of sticking, hanging or balling stabilizers, to detect bit problems and cuttings buildup, as well as to improve drilling and steering performance.

For operators trying to reduce drilling and completion costs by downsizing from conventional hole sizes, the Anadrill 4 1/2-in. Vision475 tool enables simultaneous real-time APWD measurements as well as drilling, directional surveying and formation evaluation of boreholes as slim as 5 1/2-in. (see “Pushing the Limits of Formation Evaluation While Drilling,” page 29). HPHT upgrades for 25,000 psi [172 MPa] and 350 °F [175 °C] are available, and a new system with APWD capability for larger boreholes, called Vision675, will be available soon.

For underbalanced operations, a coiled tubing drilling system, the VIPER system, offers real-time internal, annular and differential pressure measurements. The use of a wired BHA such as in the VIPER system can be used in standpipe gas injection applications such as nitrified fluids and foams. APWD measurements in such underbalanced operations enable the driller to optimize production by maintaining planned downhole pressures selected to minimize or eliminate invasion and formation damage. Under these conditions, the rate of penetration will also be improved.

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1. Hutchinson and Rezmer-Cooper, reference 5, main text.

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^ Annular pressure sensor. Resistor-based bellows gauges (insert) are used for APWD measurements in the CDR Compensated Dual Resistivity tool, and are available in three pressure ranges to meet the expected wellsite conditions. These tools are mud pulse-operated, so no information is sent in real time when the mud pumps are off. However, they can record pressures when the pumps are on, and once pumping is re-established, this information can be sent to the surface. Master calibrations are performed over a range of temperatures using a dead-weight tester. At the location or wellsite, hydraulic tests using a hand pump are performed on these gauges before and after use in each well to verify calibrations.
Pore pressure—One ongoing oilfield challenge is determining the pore pressure in shales, and almost all pore pressure prediction is based on correlation to other measured properties of shales. Shales start their life at the surface as clay-rich muds, and water is expelled from them as they are buried and subjected to increasing loading from the overburden above them. If the burial is sufficiently slow, and there is an escape route for the water, the pressure in the pore fluid remains close to hydrostatic, and the overburden is supported by increased stresses in the solid parts of the rock. The water content, or porosity, decreases, and this variation of porosity or other water-dependent properties with depth is known as the normal compaction trend.

However, if burial is very rapid, or the fluid cannot escape—because of the low permeability of shales—the increasing overburden load is supported by the increasing pore pressure of the fluid itself. The stress in the solid parts of the rock remains constant, and the water content, or porosity, does not decrease. After rapid burial, the shale is not normally compacted; its pore pressure is above hydrostatic, and its water content is higher than it would be for normally-compacted shale at that depth. The shale becomes overpressured as a result of undercompaction. Detecting overpressured zones is a major concern while drilling, because water or gas influx can lead to a blowout.

Fracture gradients—Fracture gradients are determined from the overburden weight and lateral stresses of the formation at depth and from local rock properties. Density and sonic logging data help provide estimates of rock strengths.3 Calculating offshore fracture gradients in deep water presents a special problem. The uppermost formations are replaced by a layer of water, which is obviously less dense than rock. In these wells, the overburden stress is less than in a comparable onshore well of similar depth. This results in lower fracture gradients and, in general, fracture gradients decrease with increased water depth. Thus, increasing water depth reduces the size of the margin between the mud weight required to balance formation pore pressures and that which will result in formation breakdown.

Downhole Pressure
After the wellbore stability pressure window has been determined, the driller has more to do than keep the drilling fluid within these limits. To correctly interpret the response of a downhole annular pressure measurement, it is important to appreciate the physical principles upon which it depends. The downhole annular pressure has two components. The first is a static pressure due to the density gradients of the fluids in the borehole annulus—the weight of the fluid vertically above the pressure sensor. The density of the mud column including solids (such as cuttings) is called the equivalent static density (ESD), and the fluid densities are pressure- and temperature-dependent.

Second is dynamic pressure related to pipe velocity (swab, surge and drillpipe rotation), inertial pressures from string acceleration or deceleration when tripping, excess pressure to break mud gels, and the cumulative pressure losses required to move drilling fluids up the annulus. Flow past constrictions, such as cuttings beds or swelling formations, changes in hole geometry, and influxes or effluxes of liquids and solids to or from the annulus all contribute to the dynamic pressure. The equivalent circulating density (ECD) is defined as the effective mud weight at a given depth created by the total hydrostatic (including the cuttings pressure) and dynamic pressures.

Understanding the different pressure responses under varying drilling conditions also requires an appreciation of the drilling fluid’s rheological properties, including viscosity, yield and gel strength, and dynamic flow behavior. Is the flow laminar, transitional or turbulent? The variation of the rheological properties with flow regime, temperature and pressure singly, and in combination, affects the total pressure measured downhole.4 Some of these downhole parameters, such as flow rate, can be controlled by the driller. Others, such as downhole temperature, cannot.

Pressure Losses
Until recently, the industry had been divided on the effects of drillpipe rotation on pressure losses. Some researchers have explicitly stated that rotation acts to increase axial pressure drop, while others have taken the opposing view, that an increase in rotation rate decreases annular pressure drop. In fact, both of these seemingly conflicting views can be correct, and both effects have been observed. Annular pressure losses or axial pressure drop depend upon which part of the flow regime predominates when the rotation rate is changed (below).


Experiments performed with the 50-ft [15-m] flow loop at Schlumberger Cambridge Research (SCR), in England confirmed the complex effects of rotation on annular pressure losses (left). At low flow rates, the pressure drop decreases with increasing rotation rate. At higher flow rates, the opposite effect is observed. However, in nearly all field examples, with typical drilling muds in conventional borehole sizes, only the increase in annular pressure loss with increased rotation rates has been observed (middle left). This is an area of ongoing research.

Hole Cleaning

Efficient hole cleaning is vitally important in the drilling of directional and extended-reach wells, and optimized hole cleaning remains one of the major challenges. Although many factors affect hole-cleaning ability, two important ones that the driller can control are flow rate and drillpipe rotation (bottom left).

Flow rate—Mud flow rate is the most important parameter in determining effective hole cleaning. For fluids in laminar flow, fluid velocity alone cannot efficiently remove cuttings from a deviated wellbore. Fluid velocity can disturb cuttings lying in the cuttings bed and push them up into the main flow stream. However, if the fluid has inadequate carrying capacity—yield point, viscosity and density—then many of the cuttings will fall back into the cuttings bed. Mechanical agitation due to pipe rotation or back-reaming can aid cleaning in such situations, but sometimes are inefficient or worsen the situation. Agitation that is too vigorous, such as rotating too fast with a bent housing in the motor, can have a detrimental effect on the life of downhole equipment.

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> Cuttings transport. The cuttings transport mode affects hole-cleaning ability, especially in deviated wells. At low flow rates, the cuttings can fall out of suspension to the low side of the borehole—building a cuttings bed and increasing the ECD due to cuttings restriction in the annulus. As the flow rate is increased, the cuttings will start to roll along the wellbore eroding the cuttings bed. As the cuttings bed is partially eroded, the annular gap increases and the ECD will start to decrease. As the flow rate increases further, the majority of the cuttings are transported along the low side of the wellbore, with some suspended in the fluid flow above the bed (asymmetric suspension) leading to an increase in ECD. At higher flow rates frictional pressure losses are significant, and the cuttings are transported completely suspended in the fast-moving fluid (symmetric suspension). [Adapted from Grover GW and Aziz A: The Flow of Complex Mixtures in Pipes. Malabar, Florida, USA: Robert E. Krieger Publishing Company, Inc., 1987.]

< Packing off. The driller responds in real time to an increase in the ECD (red curve), shown in track 4, as the annulus packs off above the measurements-while-drilling (MWD) tool. Surface torque and rotation rates, shown in track 2, start to become erratic as the drillpipe begins to pack off. Standpipe pressure, shown in track 3, increases slightly. By temporarily reducing the mud flow (green curve), shown in track 3, and working the pipe, the annulus becomes clear again.

Drillpipe rotation—Another example demonstrates the effect of pipe rotation on hole cleaning (above). At 15:00, pipe rotation was stopped to enable drill-bit steering. The ECD decreased for 20 minutes as the cuttings fell out of suspension. A few swab-and-surge spikes were observed. These pressure spikes were introduced as the pipe was moved up and down to adjust mud motor orientation. After steering for a total of 1¾-hours (at 16:15), rotary drilling was resumed, and the ECD abruptly increased as the cuttings—accumulated during the sliding interval—were resuspended in the drilling fluid. Here, real-time APWD data helped determine the minimum rate of rotation required to effectively stir up cuttings and clean the wellbore.


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Improving Efficiency in Extended-Reach Drilling

BP encountered severe wellbore instability problems when drilling development wells in Mungo field in the Eastern Trough Area Project (ETAP) of the North Sea. These instability problems were due in part to large cavings formed while drilling the flanks of salt diapirs. Long S-shaped 12 1/4-in. [31-cm] sections are generally the most problematic. The volume of cavings—coupled with highly inclined wellbore trajectories—results in poor hole-cleaning conditions. The main cause of the poor hole cleaning is believed to be the formation of cuttings and cavings beds on the highly inclined 60° section. These beds are manageable while drilling, but present a major hazard when tripping and running in casing. Most of the early wells experienced extreme overpulls, packing off and stuck-pipe incidents when pulling out of the hole. In addition, severe mud losses had been encountered when drilling inadvertently into the chalk at total depth.

Based on this experience with borehole instability, BP revised its drilling program with a combination of better fluid management and hydraulics monitoring aimed at improving both hole cleaning and drilling practices. The results were impressive. In the first well in the second phase of the Mungo development, nonproductive time was reduced from 34%—the average experienced on earlier wells—to 4%, with estimated cost savings of over $500,000. Drilling rate performance increased 10%, while the incidence of stuck pipe decreased.

The logs from this well exemplify how new hole-cleaning practices, supported by APWD monitoring, led to a successful drilling program (above). The pumps were switched on at 19:05, and the flow rate increased to 1000 gal/min [3785 L/min]. The standpipe and the downhole annular pressure responded almost instantaneously and after a few minutes, the driller started rotating the pipe. The increased downhole ECD (black curve) can be seen in track 6. After Kelly down, shown by the block position in track 1, the driller starts hole cleaning by reciprocating the pipe in and out. After the hole cleaning is completed, the driller makes a new connection and starts the next drilling cycle at 20:30.
As the stand was being drilled, the ECD log showed the effects of rotating and sliding. During rotary drilling, ECD values were approximately 1.70 sg. When the drillstring was picked up to set the toolface for sliding, the hole was swabbed and the ECD dropped slightly to 1.69 sg. As the drillstring was lowered, the hole was surged about the same amount, raising the ECD to 1.71 sg. Once rotation stopped, the ECD again fell to 1.68 sg and continued to fall, as the cuttings started to settle in the hole, due to the lack of mechanical agitation—reducing the cuttings contribution to the ECD.

Even though drilling continued during sliding, and cuttings were being produced at a steady rate, the ECD did not increase. This demonstrates that the hole was not being cleaned as efficiently as it had been with rotary drilling. This was confirmed by the lack of cuttings over the shale shakers.

The last part of the stand was also rotary drilled. Rotation resumed at 19:46, and the ECD increased immediately and continued to show an increasing trend. Increasing ECD was caused by turbulence and axial flow in the mud column in the annulus as it stirred cuttings that settled on the bottom of borehole. The cuttings added to the hydrostatic pressure and increased the ECD. At 19:54 the driller picked up the string and started the hole-cleaning procedure.

The bell-shaped profile of the ECD curve during rotary drilling was formed by the increasing ECD due to the rotation and stirring of pre-existing cuttings beds as well as increased cuttings load resulting from drilling ahead. The ECD reached its peak value when the stand was drilled down. As the hole was cleaned by reciprocating the pipe (maintaining a constant mud flow and rotary speed), the ECD decreased. When the value returned to nearly 1.71 sg, the hole was deemed to be sufficiently cleaned. After pipe reciprocation and flow were stopped, a survey was taken at 20:19. After completion of this operation, a connection was made and drilling resumed successfully at 20:30 with good hole cleaning.

Another example—using APWD monitoring to avoid stuck pipe—shows how an indication of cuttings accumulation during a drilling break can take several hours to appear in the ECD log because of the horizontal wellbore traveltime in extremely long ERD wells. In BP’s most recent record-breaking horizontal well at Wytch Farm, England, a cuttings cluster traveled along the horizontal leg of the wellbore for almost five hours after the drilling break at 12:00 before reaching the vertical section of the well (above). Finally, at 4:40 the ECD readings started increasing—approaching the fracture gradient of the formation. The driller, anticipating potentially severe well problems, decided to stop drilling early, and clean out the cuttings accumulated in the borehole by reciprocating the pipe. This is another success story. Without advance notice from the APWD measurement, the drillstring might have become stuck.
Kick Detection

The influx of another fluid into the wellbore due to unexpected high formation pressure is one of the most serious risks during drilling. The character of the fluid influx will depend primarily upon influx fluid density, rate and volume, drilling fluid properties and both borehole and drillstring geometry (right). Simulations performed by The Anadrill SideKick software model are frequently used to understand the pressure responses expected downhole and at the surface due to gas influxes. (see “Simulating Gas Kicks,” page 50). During gas kicks, ECD responses for typical boreholes and slim wellbore geometries are dominated by two phenomena—reduced density of the mud column as heavier drilling fluid is replaced by less dense gas, and increased annular pressure loss due to friction and inertia when accelerating the mud column above the gas influx.

The reduced annular gap in slimhole wells can cause unique drilling problems. For example, in slim holes the acceleration of the kick fluid into the wellbore can lead to a sudden increase in frictional pressure loss in the annulus due to acceleration of the mud ahead of the kick fluid. In addition, evidence of the influx may not be seen until the pumps are shut down. In typical hole sizes, the hydrostatic imbalance between the drillpipe and the annulus outweighs any frictional losses, and a decrease in the bottomhole annular pressure is evident.

Constant monitoring of all available drilling data is critical in detecting a downhole kick event. In an example of a gas kick, an operator was drilling a 12½-in. hole section in a well in the Eugene Island field in the Gulf of Mexico (next page). The formations were sequences of shales and target sands, and several of the sands were likely to be depleted by previous production. In offset wells, the low-pressure sands led to problems including stuck pipe, twist-offs and stuck logging tools.

Maintaining a minimum mud weight was required to avoid differential sticking in the depleted sands. Due to faulting in the area, zonal communication was uncertain and the pore pressure limits were difficult to anticipate. Anadrill was using the CDR Compensated Dual Resistivity tool for formation resistivity and the Multiaxis Vibrational Cartridge (MVC), Integrated Weight-on-Bit (IWOB) tool and APWD sensors for monitoring drilling performance. The plan was to set a liner below a normally pressured zone before drilling into the underpressured sand beds.

Kick detection. In a typical wellbore geometry (top left), the annular pressure (orange curve) can be seen to decrease as the displacement of heavier drilling fluids by a gas influx dominates the pressure response. For slimhole geometry (top right) the annular pressure (orange curve) can increase initially during a gas influx as the inertia of the mud column dominates the response. One major benefit of downhole annular pressure monitoring is early kick detection. Mud-pit gain (red curves in upper plots), standpipe pressure (green curves in lower plots), and frictional pressure loss (yellow curves in lower plots) help the driller identify gas kicks.

Gas influx. When gas mixes with drilling fluid, the density of the drilling fluid decreases. Fifty minutes after the ECD (blue curve), shown in track 3, started to decrease, a flow check confirmed that a small gas influx had occurred. Note the increase in annular temperature, shown in track 2, as the formation fluid warmed the borehole.
During drilling through a shale zone just before 14:00, a few indications of increasing formation pressure were seen in the APWD data and several connection and background mud gas indications were detected in the mud flow. Oil-base mud weights during this run were increased from 11.5 to 12.0 lbm/gal [1.38 to 1.44 g/cm³]. Just before the sand was entered at 17:10, the real-time ECD measured downhole was 12.5 lbm/gal [1.50 g/cm³]. At this point, the ROP abruptly increased and drilling was stopped—10 ft [3 m] into the sand zone—to check for mud flow. Although the potential for a kick was a concern, the fact that there was no evidence of a kick or mud flow suggested that it was safe to proceed.

As drilling progressed after 18:10, the ECD measurement decreased slowly to 12.35 lbm/gal [1.48 g/cm³] over a period of 90 minutes. Suddenly at 19:20, the ECD dropped to 12.0 lbm/gal [1.44 g/cm³] while drilling the next 9 ft [2.7 m] of the well. The drilling foreman noticed the large drop in ECD readings—signaling an influx. Increased pit volumes were noticed at this time and the well was immediately shut in at 19:50. The kill took 24 hours with an additional 30 hours to repair blowout preventer (BOP) damage.

At what point did the kick first become apparent on the downhole ECD log? The first ECD drop from 12.5 to 12.35 lbm/gal probably could be attributed to the decrease in ROP. Such changes were seen earlier in this well. Statistical variations in ECD, due to drilling noise, can be as high as 0.2 lbm/gal. On the other hand, the systematic change from 12.35 to 12.0 lbm/gal is a clear signal that an influx is already in the mud column. Monitoring the ECD constantly, using alarms set to detect the first sign of ECD changes, and checking corroborating drilling indications, such as ROP, can provide earlier warning of such occurrences.

In another example, use of APWD data helped save a well. In this well, drilling was proceeding without any indication of an influx either from pit gain or in mud flow rates in or out of the well (previous page, bottom). However, the ECD started to decrease at 11:00 and continued for 50 minutes. At the same time, an increase in the annulus temperature was observed, due to the formation fluid warming the borehole fluid. Guided by the ECD response, the driller stopped drilling and safely circulated out a small gas influx.

^ Kick alert in the Gulf of Mexico. A sudden increase in the rate of penetration (ROP) (blue curve), shown in track 1, at 17:10 alerted the driller that the bit had entered a sand zone and that an influx was possible. Drilling restarted after having seen no evidence of flow in the mud-flow measurements or pit volume. However, as drilling progressed into the sand zone, the ECD (pink curve), shown in track 5, started to decrease slowly at 18:10 and continued until 19:20. At this time, the rate of decrease suddenly increased. After drilling ahead for 30 minutes with rapidly decreasing ECD and increasing pit volume, the driller recognized that an influx had occurred and the well was shut in.

8. In this article, slimhole wells are defined as those with an average pipe-to-annular radius ratio greater than 0.8.
Simulating Gas Kicks

The growth in deep-water drilling activities in many regions of the world is attracting increased attention to the specific problems of gas influx and well control. Deep water poses special problems related to both the depth and temperature of the water. Reduced margins between pore pressure and fracture gradient require accurate understanding of downhole fluid behavior.

Various definitions of kick tolerance exist and may be given in terms of pit gain, mud weight increase or even underbalance pressure. Whatever way it is expressed, kick tolerance is a measure of the size and pressure of kick the well can take and still be controlled without fracturing the formation. Kick tolerance decreases as drilling proceeds deeper, and once the limit is reached, additional casing must be set to protect the formation. Kick tolerance is a complex concept as it varies as a function of the formation pressure driving the kick, the amount of influx entering the well and the distribution of the influx in the annulus. Balancing this complexity makes a simulator an ideal choice for computing kick tolerance.

Scientists at BP and Schlumberger Cambridge Research, England have spent years studying the behavior of gas kicks. Their work, along with engineering development at the Schlumberger Sugar Land Product Center in Texas, has produced the Anadrill SideKick-PC software model, which simulates gas kicks and helps plan methods of detecting and controlling them. SideKick-PC models include the effects of gas distribution in the annulus. This produces a more realistic and less conservative kick tolerance, which leads to the use of fewer casing strings and substantial cost savings. Kick tolerance is illustrated in user-friendly, automatically generated plots of safe pit gain versus safe formation pressure (below). The simulator helps engineers anticipate and meet the challenges of a wide variety of drilling environments.

The simulator can be used in planning underbalanced drilling programs, which require estimates of wellbore pressures and fluid production rates. In addition, the cost-effectiveness of using the underbalanced methods must also be evaluated. Other simulators have helped address these issues, but have looked only at stabilized steady-state conditions. This simulator is a fully transient numerical simulator that can determine the optimum amount of nitrogen necessary to reach a desired underbalance.

The SideKick-PC program also introduces the concept of the Maximum Allowable Blowout Pressure (MABOPP). This gives an improved indication of the potential for shoe fracture during a kill using a BOP pressure measurement to remove uncertainties involved in fluid properties in long choke and kill lines.

Simulations have shown that a simple technique can minimize the risk at the end of a deep-water kill by slowing the pumps when the choke is wide open to minimize pressure in the annulus. This technique has been shown to be preferable to other methods, such as using a reduced slow-circulation rate over the whole kill or arbitrarily reducing the flow rate, and is now an integral feature of the simulator.

The SideKick-PC program has proved effective in allowing engineers to run many complex simulations easily and quickly. Coupled with defining safe operating envelopes in minutes rather than hours or days of well planning, gas-kick simulation is helping to enhance overall performance by improving efficiency and reducing well construction costs.


2. A fully transient simulator is one that allows for the temporal development of fluid behavior in the borehole as the fluids are circulated, or while the well is shut in. This has the advantage over steady-state models, where the imposed state does not change fluid properties over time, and cannot allow for effects such as gas solubility as the gas cloud migrates after circulation has stopped. Furthermore, such a transient simulator can indicate whether steady state can even be reached.

Deep-Water Wells

Unconsolidated sediments typically encountered in deep-water formations tighten the wellbore stability window between pore pressure and formation fracture pressure. At a given depth, fracture gradient decreases with increasing water depth, and can result in a very narrow pressure margin.\(^9\)

Additionally, cooling of the mud in the deep-water riser can cause higher mud viscosity, increased gel strength, and high frictional pressure losses in choke and kill lines during well-control procedures. Combined, these factors increase the likelihood of lost-circulation problems, and drilling engineers must take appropriate steps to avoid exceeding formation fracture gradients.

Staying within the pressure window—Keeping the ECD within the pressure window is a constant struggle, especially in deep water and HPHT applications. In a well in the Gulf of Mexico, EEX Corporation experienced a kick while drilling at near-balance conditions in Zone A (right). After the kick was taken and the well was under control, increased mud weight was needed to continue safely. A 13\(\frac{3}{8}\)-in. [34-cm] casing string was set because the heavier mud weight exceeded the previous leakoff test.

The next two hole sections were drilled without incident. However, as drilling proceeded deeper into the third section, the increasing pore pressure eventually approached the pressure exerted by the heavier mud and another kick was experienced in Zone B. A 9\(\frac{5}{8}\)-in. [24-cm] casing was needed to permit another increase in mud weight. As drilling continued, increases in the cuttings load caused the mud pressure to exceed the overburden pressure in Zone C, resulting in some lost circulation over a period of several days. Lost-circulation material helped minimize mud losses, and drilling continued successfully thereafter. At the narrowest point shown in this example, the pressure window was only 700 psi [4827 kPa].

Dynamic kill procedure—Real-time analysis of downhole annular pressure helped BP Exploration monitor a dynamic kill procedure used to stop an underground flow in a deep-water well in the Gulf of Mexico. Drilling unexpectedly entered a high-pressure zone, where a water influx fractured the formation at the casing shoe. Real-time APWD measurements were combined with standpipe pressure to monitor the process of the dynamic kill.

The procedure circulated kill-weight mud fast enough to "outrun" the influx and obtain a sufficient hydrostatic gradient to kill the well. Drilling fluid used in this well weighed 11.8 lbm/gal [1.41 g/cm\(^3\)], and the kill-weight mud was 17.0 lbm/gal [2.04 g/cm\(^3\)]. During the kill procedure, BP’s Ocean America operating crew monitored the standpipe pressure to determine if

kill weight mud was outrunning the influx fluid by filling the annulus (below). However, under flowing conditions, the standpipe pressure could not be used to accurately determine bottomhole pressure. APWD measurements showed that bottomhole pressure was increasing due to the kill mud, and confirmed that the new dynamic kill procedure was working. This process, monitored with downhole annular pressure measurements, has been incorporated into BP’s recommended drilling practices.

Shallow-water flow—According to a recent Minerals Management Services survey covering the last 14 years, shallow-water flow occurrences have been reported in about 60 Gulf of Mexico lease blocks involving 45 oil and gas fields or prospects. Problem water flow sands are typically found at depths from 950 to 2000 ft [290 to 610 m], but some have been reported as deep as 3500 ft [1067 m] below the seafloor. Frequently, these problems are due to overpressurized and unconsolidated sands at shallow depths below the seafloor. They can lead to formation cave-in when uncontrolled water production occurs. If an influx is severe enough, wells can be lost due to continuous water flow. Extensive washouts can undermine the large casing that is the major support structure for the entire well.

Monitor dynamic kill procedure. A water influx was encountered in a Gulf of Mexico deep-water well that was strong enough to fracture the casing shoe, resulting in an underground flow. In track 6, both the standpipe pressure (green curve) and downhole annulus pressure (purple curve) showed a steady increase at 18:30 while the kill mud was being circulated in the wellbore.
In many deep-water wells, the first casing or conductor pipe is usually 30 or 36 in. [76 or 91 cm] in diameter. The next hole section, typically 24 or 26 in. [61 or 66 cm], is often drilled without a riser. In these wells, spent drilling fluid and cuttings are returned to the ocean floor around the wellhead (previous page, top). Since the drilling fluid is not recovered under these conditions, expensive synthetic- or oil-base muds typically are not used. Instead, either seawater or inexpensive water-base mud is used.

Standard operating practices in deep-water wells use a remote operating vehicle with a camera at the mud line to monitor flow coming out of the wellhead. At a connection, the driller will hold the drillpipe stationary and turn off the pumps for a few minutes, to allow fluid u-tubing oscillations to stabilize, and to observe whether there is flow at the wellhead.

**Downhole pressure measurements detect shallow-water flow**—Monitoring ECD helps the operator assess both the depth and severity of the water flow, and decide whether the flow is serious enough to stop drilling. Most conventional hydraulics models do not consider the effects of mud returns to the seafloor, and thus cannot accurately predict the expected ECD in these wells. A direct measurement of downhole mud pressure solves this problem.

Operators are starting to use downhole pressure measurements as a way to detect the onset of and prevent serious damage from shallow-water flows. 12 In a deep-water well in the Gulf of Mexico, a water sand in Zone A was encountered at X090 ft (right). The ECD suddenly increased in this zone as the sand was penetrated—indicating water and possible solids entry. The rise in annular pressure and an ensuing visual confirmation of the mudline flow confirmed water entry. The flow was controlled by increasing mud weight and drilling proceeded. The same trends—increased ECD with a corresponding annular temperature increase—were seen in the lower section of the next sand, Zone B, and in the sand in Zone D below. The influxes were not severe and were safely contained by the increasing ECD of the drilling fluid. Knowledge of the location and severity of the contained water influxes and quick response to early warning from annular pressure measurements made it possible to continue drilling successfully to the planned depth for this hole section.

**Improving Drilling Efficiency**

With higher rig costs on many drilling projects, such as extended-reach and deep-water wells, time savings and precise measurements are critical. Accurate leakoff tests (LOT) are essential to enable efficient management of the ECD within the pressure window, and the corresponding mud program.

**Leakoff Testing**—A LOT is usually performed at the beginning of each well section, after the casing has been cemented, to test both the integrity of the cement seal, and to determine the fracture gradient below the casing shoe. In general, these tests are conducted by closing in the well at the surface or subsurface with the BOP after drilling out the casing shoe, and slowly pumping drilling fluid into the wellbore at a constant rate (typically 0.3 to 0.5 bbl/min [0.8 to 1.3 L/sec]), causing the pressure in the entire hydraulic system to increase. Downhole pressure buildup is traditionally estimated from standpipe pressure, but can be monitored directly with APWD sensors. If pressure measurements are made in the standpipe, then complex corrections must be made for the effects of temperature on mud density, and other factors on downhole fluid pressure.

Pressures are recorded against the mud volumes pumped until a deviation from a linear trend is observed—indicating that the well is taking mud. This could be due either to failure of the cement seal or initiation of a fracture. The point at which the nonlinear response first occurs

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10. The Department of Interior Minerals Management Services manages the mineral resources of the Outer Continental Shelf and collects, verifies and distributes mineral revenues from Federal and Native American lands. They can be located at URL: http://www.mmm.gov/


is the leakoff test pressure used to compute the formation fracture gradient. Sometimes, the procedure is to stop increasing the pressure before the actual leakoff pressure is reached. In such cases, the planned hole section requires a lower maximum mud weight than the expected fracture pressure, and the test pressures only up to this lower value with no evidence of fracture initiation. This is called a formation integrity test (FIT). If pumping continues beyond the fracture initiation point, the formation may rupture, pressure will fall, and the fracture will propagate.

APWD measurements helped monitor downhole pressure in a leakoff test performed by BP Exploration in a deep-water well in the Gulf of Mexico (below). As the pumped volume increased to 3.5 barrels, the standpipe pressure increased to 520 psi [3585 kPa]. Downhole ECD increased from 9.8 lbm/gal (hydrostatic) to 10.9 lbm/gal [1.17 g/cm³ to 1.31 g/cm³]. At this point, the pumping stopped, and the ECD dropped exponentially to 10.7 lbm/gal [1.28 g/cm³], indicating that the formation was taking fluid. The pressure margin determined from this test was sufficiently high to allow drilling to proceed without incident.

Before a well is pressure tested, in order to estimate downhole pressures from surface measurements, the drilling fluid is often circulated to ensure that a homogeneous column of known density mud is between the surface and casing shoe. However, the downhole annular pressure measured at the casing shoe provides a direct measurement, and therefore the mud conditioning process is not required—saving the cost of additional circulations. Downhole pressure measurements remove uncertainties caused by anomalies in mud gel strength or inhomogeneities in the mud column density due to pressure and temperature effects.

Technologies from Schlumberger Wireline & Testing, Anadrill and Dowell were combined to perform a real-time downhole formation integrity test in a deep-water well in the Gulf of Mexico. During this test, an Anadrill CDR tool was included in the BHA used to drill the casing shoe. The CDR tool contained an APWD sensor to monitor downhole pressure. In typical logging-while-drilling (LWD) applications, sufficient mud is pumped to enable the BHA to communicate to the surface through mud-pulse telemetry. This is not the case with slow pumping rates used during a typical LOT or FIT. However, downhole pressure can be monitored in real time through the use of a wireline-operated LINC LWD Inductive Coupling tool that sits inside the CDR tool and transmits pressure data to the surface.

With this arrangement, the operator can simultaneously view the surface and downhole pressure buildup as the test proceeds. In the absence of compressibility and thermal effects, the rate of pressure rise downhole would be the same as that at the surface. The operator can use downhole pressure measured with the APWD sensor to calibrate formation integrity while using the pressure buildup differences to monitor the compressibility of the drilling fluid. Because of shallow water flow concerns in deep-water wells with narrow wellbore stability margins, differences of a few tenths of a lbm/gal can make the difference between one or two extra strings of casing being needed to protect shallow intervals.

Real-time downhole annular pressure measurements offer at least three advantages during LOT and FIT testing. First, the operator does not want to overpressure downhole too far—leading to formation fractures or a damaged casing shoe. A change in the slope of the pressure buildup curve with pumped volume is a signal to stop the test. This is the pressure used to determine the fracture gradient of the formation. The use of real-time annular pressure measurements provides the operator with an instantaneous signal to stop the test.

Next, monitoring surface pressure alone can lead to incorrect estimates of bottomhole pressure because of uncertainty in correcting for the compressibility of the drilling fluid, particularly significant when synthetic- or oil-base muds are involved.

Finally, the unsteady nature of surface pressure data can lead to errors in LOT estimates of fracture gradient. An accurate measurement of fracture gradient is required to determine the ability of the formation and casing cement to support the drilling fluid pressure during the next section of drilling. The use of stable and accurate downhole annular pressure measurements helps make drilling ahead a more exact and safer process.

The Big Picture
In wireline logging, the log represents a state of the well—showing the more-or-less static formation properties, such as lithological beds and fluid saturations. Getting the data is most important, but decisions made at the time of acquisition are not necessarily critical. However, logs of downhole annular pressure and other drilling performance parameters show a process—a process that is evolving with time. The evolution of the log in real time must be monitored as downhole conditions are dynamic, and timely decisions are essential. Delay or indecision can lead to serious risks and added costs.

The format of drilling performance logs is different from wireline logs. Drilling problems generally result in slower rates of penetration and data are compressed on a depth scale. Therefore, a time-based presentation is often better suited for detailed analysis during problematic drilling intervals. Still, depth-based presentations are important for assessment of drilling events in the context of BHA position relative to lithological boundaries.

Drilling parameters should be presented in relation to one another on the log. Wireline logs, such as the triple-combo used for formation evaluation, have a standard layout that helps analysts learn how to quickly spot the important productive zones. A standard layout for drilling performance logs has recently been proposed (previous page).14

The proposed layout enters geometric parameters such as bit depth, ROP, and block speed in track 1, followed by weight parameters such as hookload and downhole weight-on-bit in track 2. Time or true vertical depth (TVD) are shown in the next column. Next, torque parameters in track 3, rotation rates along with lateral shock and motor stall in track 4, and flow parameters such as mud flow rates, differential flow, total gas, mud pit level and turbine rotation rate in track 5. Finally, pressure measurements such as ECD, ESD, annular pressure, annular temperature, swab-and-surge pressures, estimated pore and fracture pressure limits and standpipe pressure are all shown in track 6.

Downhole annular pressure interpretation is an evolving technique. All possible downhole events have not yet been observed. Sometimes the data are enigmatic. Nonetheless, certain clearly identifiable and repeatable signatures can be used to help diagnose problems (left). Combining the information gleaned from downhole annular pressure logs with other drilling parameters creates an overall assessment, or the big picture. This global view helps decipher the individual measurements used to detect drilling problems downhole.

Downhole real-time annular pressure measurements have a significant impact on today’s drilling practices with applications in every aspect of drilling. For example, many of the lessons and efficiency improvements made in high-cost ERD and deep-water wells can be applied to simpler wells. Monitoring downhole annular pressure along with other drilling parameters provides an integrated view of a healthy drilling environment—one that puts emphasis on anticipation and prevention rather than reaction and cure.15 Such improved operational procedures will lead to decreases in nonproductive time and increases in drilling efficiency. —RCH

<table>
<thead>
<tr>
<th>Event or procedure</th>
<th>ECD change</th>
<th>Other indications</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mud gelation / pump startup</td>
<td>Sudden increase possible</td>
<td>Increase in pump pressure</td>
<td>Avoid surge by slow pumps and break rotation (rotation first)</td>
</tr>
<tr>
<td>Cuttings pick-up</td>
<td>Increase then leveling as steady-state reached</td>
<td>Cuttings at surface</td>
<td>Increase may be more noticeable with rotation</td>
</tr>
<tr>
<td>Plugging annulus</td>
<td>Intermittent surge increases</td>
<td>• Standpipe pressure • Surge increases • Torque/RPM fluctuations • High overpulls</td>
<td>Packoff may “blow-through” before formation breakdown</td>
</tr>
<tr>
<td>Cuttings bed formation</td>
<td>Gradual increase</td>
<td>• Total cuttings expected not seen at surface • Increased torque • ROP decreases</td>
<td>If near plugging, may get pressure surge spikes</td>
</tr>
<tr>
<td>Plugging below sensor</td>
<td>Sudden increase as packoff passes sensor – none if packoff remains below sensor</td>
<td>• High overpulls • “Ready” increase in standpipe pressure</td>
<td>Monitor both standpipe pressure and ECD</td>
</tr>
<tr>
<td>Gas migration</td>
<td>Increase if well is shut-in</td>
<td>Shut-in surface pressures increase linearly (approx.)</td>
<td>Take care if estimating gas migration rate</td>
</tr>
<tr>
<td>Running in hole</td>
<td>Increase – magnitude dependent on gap, rheology, speed, etc.</td>
<td>Monitor trip tank</td>
<td>Effect enhanced if nozzles plugged</td>
</tr>
<tr>
<td>Pulling out of hole</td>
<td>Decrease – magnitude dependent on gap, rheology, speed, etc.</td>
<td>Monitor trip tank</td>
<td>Effect enhanced if nozzles plugged</td>
</tr>
<tr>
<td>Making a connection</td>
<td>Decrease to static mud density</td>
<td>Pumps on/off indicator Pump flow rate lag</td>
<td>Watch for significant changes in static mud density</td>
</tr>
<tr>
<td>Barite sag</td>
<td>Decrease in static mud density or unexplained density fluctuations</td>
<td>High torque and overpulls</td>
<td>While sliding periodically or rotating wiper trip to stir up degenerated beds, use correct mud rheology</td>
</tr>
<tr>
<td>Gas influx</td>
<td>Decreases in typical size hole</td>
<td>Increases in pit level and differential pressure</td>
<td>Initial increase in pit gain may be masked</td>
</tr>
<tr>
<td>Liquid influx</td>
<td>Decreases if tighter than drilling fluid Increases if influx accompanied by solids</td>
<td>Look for flow at mudline if relevant</td>
<td>Plan response if shallow water flow expected</td>
</tr>
</tbody>
</table>

^ Interpretation guide. Monitoring ECD with downhole annular pressure measurements along with other drilling parameters helps the operator know what is happening downhole in the wellbore. Some of the known, clearly identifiable, and repeatable signatures of ECD changes are shown along with secondary or confirming indications, such as those seen in surface measurements.