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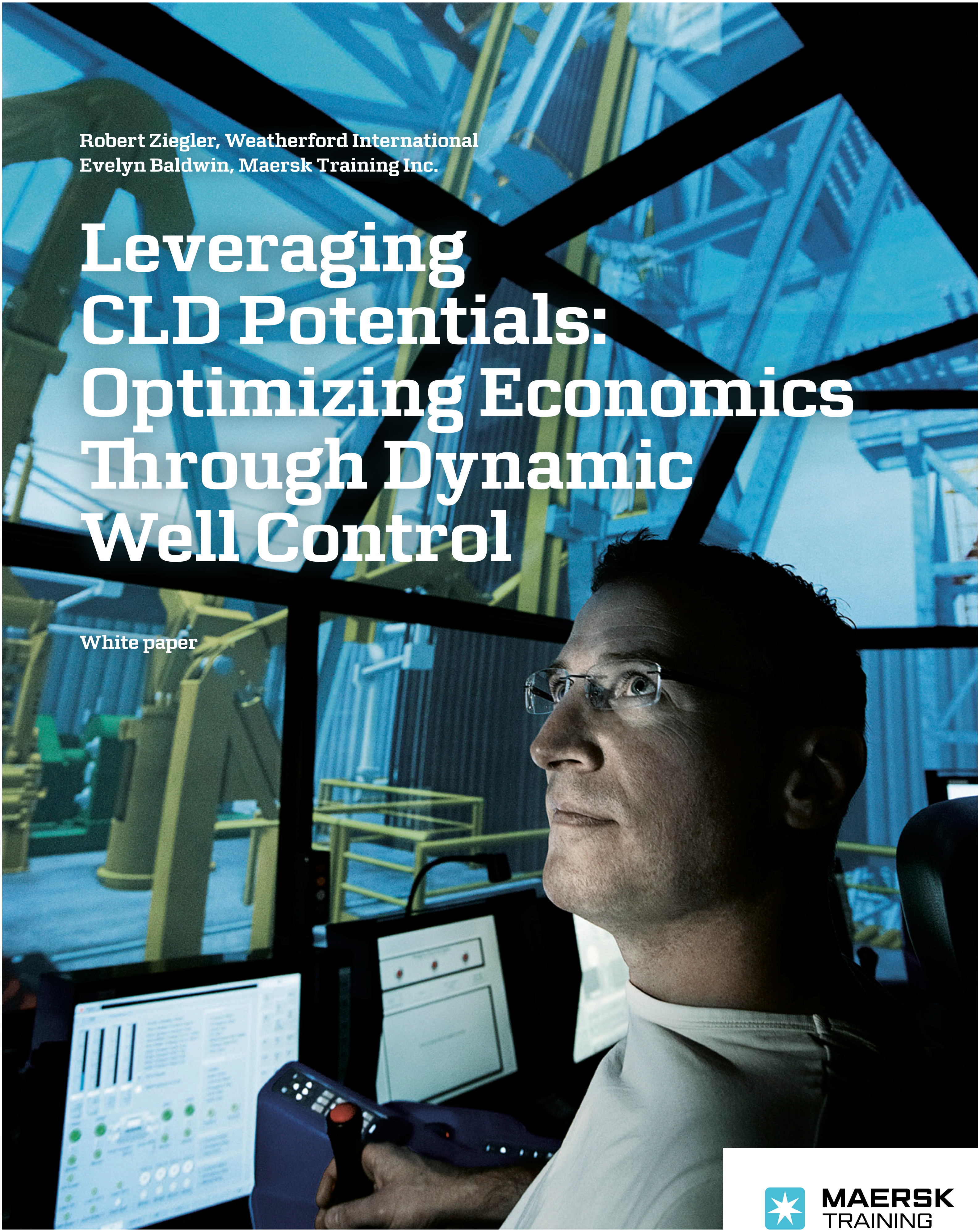
White paper



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Leveraging CLD Potentials: Optimizing Economics Through Dynamic Well Control

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Abstract

When the oil price is down, the gloves come off! Maximizing the full potential of closed-loop drilling (CLD) techniques to achieve dynamic well control and effectively slash costs is one often overlooked solution: Leveraging on the experience of numerous operations, this paper will showcase the operational impact of CLD to demonstrate why CLD technologies are one of the most underutilized performance drilling tools available to the market, yielding operational process safety improvements and cost-savings unattainable with conventional methods.

Introduction

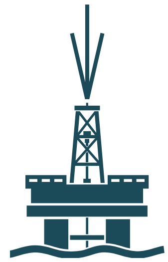
The proponents of managed pressure drilling (MPD), confident of the superior abilities of their modern drilling method compared to traditional open-to-environment (OTE) drilling systems, have often focused on the small group of wells that are undrillable without the use of MPD. While these wells are the most obvious examples of the superiority of the technology, a large part of the wider drilling community still fails to consider MPD the modern way of drilling all oil and gas wells, which will be referred to as the "new drilling convention" (NDC) in this paper. Instead, they consider it just another tool in the portfolio of the drilling engineer. MPD is only considered applicable if the old OTE drilling system reaches its limit during the planning phase of the well, mainly because of narrow drilling margin estimates, troublesome offset wellbore stability history, or lack of a sufficient number of casing strings to reach the planned target. Because the notoriously overloaded drilling engineer always tries to get by with the minimum amount of tangible equipment (and costs), this approach often leads to unforeseen problems during execution when the uncertainties in geology and pressure are not appropriately taken into account. In quite a few cases, this leads to an emergency mobilization of MPD equipment, often after already having issued supplemental AFEs for sidetracks, with associated issues – including equipment availability, excessive rapid mobilization costs, ad-hoc rig integration, and lack of training and preparation – which in turn leads to a suboptimal use of the technology. While MPD often is the tool that finally enables operators to reach the objective, the big successes with major cost savings over OTE drilling come when MPD is considered as the NDC and thus integrated in the well planning process from the beginning. This paper will make the case for using MPD in its complete form for all high time-related cost operations, and in its minimalist form (RCD and set point choke) for all remaining operations.

MPD for Closed System Drilling: The NDC for Safety and Environmental Protection

Not too long ago, the top drive was in a similar position on the technology adoption curve as MPD is today. The industry was in a downturn at that time, too, oil prices were low, cost pressure was enormous, and horizontal drilling had just taken off as the way of extracting significant extra value from wells in challenging environments. The top drive rental business was booming, and the moment the directional phase of the well was reached, the top drive was mobilized and that section drilled with it. Drillers soon started to like the additional abilities the top drive gave them, such as reducing nonproductive time and especially mitigating stuck pipe events. Yes, there were long holdouts of the traditional Kelly drilling fraternity, which claimed that the top drive failures were still too high and their drilling crews were faster than any mechanical system could possibly be. But interestingly, when the 2000 rig fleet shrank to just a few hundred in the current downturn, it was the most advanced super singles with top drives and higher levels of automation (and in 75% of the cases, at least an RCD) that kept operating, while the last few simple rigs were very quickly laid down and may never be reactivated again. Even in the cost-sensitive land market, the top drive can be considered standard equipment for drilling today, as it has been offshore for quite a while already.

Most interestingly, for MPD equipment it is exactly the other way around. While the land market in the US has adopted the RCD as standard equipment, offshore in the Gulf of Mexico, where many of the most challenging wells are being drilled, the penetration of the technology has been less than satisfactory. While famously, the Mars-Auger infill drilling campaigns from TLPs have used RCDs and the constant bottomhole pressure (CBP) form of MPD extensively, floaters have only seen a single installation of a full closed system drilling (CSD) drilling system to date (no longer active, a victim of the downturn) and makeshift MPD methods – like bottling up, i.e., trapping pressure with the annulus during connection – are still the widespread form of MPD.

However, in other areas of the world MPD adoption is different. Most notably, in Southeast Asia in loss-prone carbonates, in the subsalt environment of Brazil, and to a certain extent in Angola, MPD from floaters has been far more widespread. In the case of Brazil, it has become a standard operating procedure (SOP) for the largest operator, similar to the penetration it has in the US land market. Also, the United Kingdom North Sea has seen extensive offshore application, most of which use underbalanced drilling (UBD) techniques. This covers HPHT environments, where operators principally work from jackups. The authors are also aware of a single application of UBD in Norwegian waters.



90%

decrease in risk of Blowouts on rigs with RCD

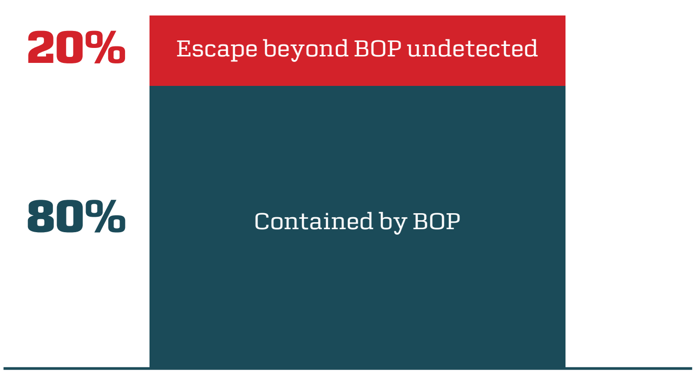
In international land operations, the adoption of MPD and UBD is not as prevalent as it is in the US land market. One of the principal reasons is that insurance companies providing blowout insurance in the US have traditionally granted a discount to rigs using an RCD, a practice that has been validated by a recent study by UT Austin. The study? takes advantage of the large sample size of rigs operating with RCDs and demonstrates a reduction in the blowout frequency of rigs equipped with RCDs by roughly an order of magnitude (i.e., 1/10 as likely). The magnitude of this reduction may surprise some because on a land rig the BOP is easily accessible, has simple controls, and is able to close on and immediately stop a flowing well. This is contrary to a subsea BOP, where the riser is completely open in most cases, and any hydrocarbons that make it in the riser have a free path to the rig floor, with only the unreliable diverter as a final protective device, prone to washouts and other failures.

This paper has already covered the proven effects of CSD on US land wells and now will explain the effect of CSD on the offshore well-control safety process. The experience in land wells can be safely transferred to offshore surface BOP operations, i.e., on jackups, TLPs, tender-assisted drilling, and other platform rigs. The advantage offshore is that the rig moves are much simpler than for land operations, so complex piping for full MPD operations can remain in place. And because offshore is a time-related-cost-dominant environment, the case can be made that full MPD installations should be the default for offshore surface BOP applications. In any case, a reduction of blowout frequency by a factor of 10 is also most likely for these offshore applications, which alone should be enough justification for installation of MPD. It may even be argued that MPD equipment conveys a greater reduction in blowout risk than the blowout preventer (BOP) itself.

But the most important application of CSD for safety and environmental reasons is on subsea BOP operations. The authors had access to an unpublished well control database encompassing some 5,000 wells over a 5-year period, which covered the majority of all floating drilling worldwide. From this, several valuable lessons can be learned. First, actual well control events on these rigs are rare events. Because of prudent practices, well trained and aware crews are generally a more risk-averse culture than often prevalent in land operations, with wells often being drilled in the drilling window close to the formation strength instead of pore pressure, often accepting frequent and substantial lost-circulation events. Thus, a well control event in which the BOP is closed to shut in the well occurs roughly every 18 to 24 rig months, depending on the well type and operating area. Because of the described practices and the often narrow drilling margins, a lot of false indications, such as ballooning and breathing, can lead to the BOP being closed. In a final analysis, only half of these well control events were caused by an actual influx. Therefore, a rig has to handle an actual influx only every 3 to 4 years. An experienced driller who is on duty for a quarter of the rig time in 10 years, he may only experience one or two actual kicks.

This then compares to the frequency of riser unloading events, which occur in this database roughly every 2 decades of rig time. This may seem rare until it is put in context with the frequency of actual influxes. If an actual influx occurs every 3 to 4 years, and a riser unloading every 20 years, that means that a fifth of hydrocarbons entering the wellbore make it past the subsea BOP undetected. Therefore, the subsea BOP in the best case only contains 80% of influxes. Furthermore, these statistics only cover real riser unloading events in which the diverter has been closed, not high gas events in which the alarms go off in the shaker room but the fluid level in the riser remains stable.

HYDROCARBONS ENTERING THE WELLBORE



When looking at kick intensity and volume in this database, the fact emerged that the median (i.e., most likely) kick intensity was 0.5 lb/gal and kick volume just 10 bbl. This indicates that the conventional kick detection capability of drilling crews is very good, especially given the rarity of these events. However, the entire dataset of kick intensity and volume paints a very worrisome picture. There are a significant number of kicks with an intensity of several pounds per gallon (up to 5.3 lb/gal) and triple digit barrels (up to 250 bbl) that occurred with very reputable operators. This data shows the serious limitations of pore pressure prediction and conventional pressure control when control of the well only occurs after shutting the BOP and reading a stabilized standpipe pressure. Until then, everything is estimates and assumptions, thus if permeability is low enough, inadvertent drilling can occur into pressure ramps that are beyond the capacity of the casing design used for the well and maybe even the rating of the BOP.

CSD is able to provide safe solutions for both problems: the inadvertent entry of gas into the riser and the inadvertent drilling into pressure ramps that exceed the design limitations of the well.

For the gas in riser, the solution is apparent. With the riser permanently closed, it cannot unload in an uncontrolled manner and endanger the rig-floor personnel and even the rig itself. (After all, the event that killed the 11 crew members on the Deepwater Horizon and set the rig on fire was initially a riser gas event. It only later turned into a full blowout.) Alternative solutions via a human activated device, commonly known as a riser-gas handler, will have the same shortcoming as the BOP on land wells without the RCD. The human factor involving activation of the device for an event that may occur only every 2 rig decades – or not even once in many a driller's career – is not reliable enough. Also, the methods are often too slow, as there is evidence of riser gas events that lasted only 5 seconds, which still led to loss of crew members. There is no time to close even the fastest closing riser-gas handlers. Thus, it can safely be said that the effect of the closed riser will be at least as significant as the RCD use on land wells, and even much better, meaning a more than order of magnitude reduction in blowouts for subsea BOP rigs routinely using an RCD on top of the riser. There were approximately 30 years in between Ixtoc and Macondo – the two most significant blowout events with subsea BOPs in the Gulf of Mexico. Introducing an RCD on every deepwater rig would extend this time period to some 300

"Given the total cost of the Macondo event, including lost exploration opportunities, amounts to a US dollars figure in the billions in triple digits. This case alone would economically warrant and pay for the adoption of the closed system drilling by the entire offshore industry today."

years or more. The next event would likely happen long after the hydrocarbons in the Gulf of Mexico are exhausted, or never. Given the total cost of the Macondo event, including lost exploration opportunities, amounts to a US dollars figure in the billions in triple digits. This case alone would economically warrant and pay for the adoption of the closed system drilling by the entire offshore industry today. Furthermore, another Macondo type event could lead to significant lost opportunities and the forfeiture of the social license to operate for the entire industry. The likelihood of such an event increases if nothing significant changes during a frenzied upturn with green crews and destacked rigs. The last event happened on one of the best and most experienced rigs in the Gulf of Mexico.

The second top risk extracted from the well control database analysed is the risk of inadvertently drilling into significant pressure ramps (and experiencing high volume kicks), which can be mitigated with one of the most interesting capabilities of a full MPD system. This is the ability to determine the actual pore pressure and the actual formation strength in the open hole in real time, without an interruption in drilling. This process, with the trade name Microflux system, can be done automatically and as frequently as desired. A full picture of the actual drilling window for the entire section drilled can be constructed, which avoids pore pressure surprises and provides the ability to optimize the casing seat. Also, the value of this data for the petroleum engineers and geologists cannot be underestimated, as it may very well replace pressures taken with a wireline formation tester.

The Coriolis flowmeters and the multisensor input process control OneSync software have a kick detection sensitivity of a few gallons in a large circulation system of many thousands of barrels. This capability further enables avoiding any significant influx sizes that would necessitate reverting to conventional secondary well control via the BOP and the rig well control choke system.

As has been demonstrated, the process safety improvements of CSD alone should lead to the general adoption of this NDC by any operator serious about their hazard and event management system, and the argument should end here. However, this paper covers not only the mitigation of the described rare high-impact events that can change the course of the entire industry, but also the daily drilling performance issues the industry faces in its work, which are so important to pick up or continue well construction activity in these times of low oil prices.

Well Construction Performance in the New Drilling Convention

This section is split into two parts: the first part covers technical and mechanical challenges, and the second covers human factors and training.

Well construction performance is often measured by how close to the technical limit an actual operation is performed. In recent years, more and more drillers speak about well construction and no longer drilling. On one hand, the attention to well construction is correct given the significantly higher complexity of today's deeper, directional, and extended reach wells. But on the other hand, it is a good excuse for spending comparatively very little time of the total operating time on the reason there is a drilling rig on site – making hole. In a very strict performance view, any time the rig spends not extending the wellbore is nonproductive time. This brings us closer to the understating of true performance drilling, which is the elimination of invisible NPT or invisible lost time (ILT) recorded as productive time in the daily drilling report. Elimination of NPT is simply a deficiency correction not a performance improvement, and it may not even be first priority as too much focus on NPT could lead to overall performance degradation. Typical examples of ILT include wellbore cleaning after it has been drilled, fingerprinting for well control during connections, ROP limitations for the capability of the fluid to carry cuttings, ROP limitations for MWD performance, picking up and orienting for directional drilling, check trips, short trips, difficulty installing casing, unnecessarily installing casing strings, cementing issues, and running sand control and other completion equipment in suboptimal conditions.

It can easily be seen that many of the established drilling practices need to be challenged and eliminated to reach new performance levels. When it is too expensive to drill wells the old way, it is not enough to do better than yesterday or better than peers. It is simply not good enough and will not make a project pass the decision gate. The industry must reach new performance standards, which is the reason for proposing a new way of drilling called the new drilling convention. In the general industry, the term lean manufacturing has been used but is only partially applicable because every well presents surprises through geology. A more tactical, or militaristic, approach is needed, which takes advantage of unexpected opportunities and mitigates unexpected difficulties. One of the key success factors of such military tactics is the existence of a reserve that can be deployed to take advantage of opportunities or mitigate surprising shortcomings of the planned approach. Another key success factor of military tactics is situational awareness (i.e., becoming aware in time of difficulties or opportunities), so the former can be corrected before becoming too large and the latter can be taken full advantage of. The new drilling convention, or using MPD equipment, provides both of these success factors. Instead of having a primary barrier that is breached by surprises requiring activation of a potentially effective, but far less efficient secondary barrier, MPD provides an active primary barrier that can be adjusted in real time to mitigate uncertainties in pressure and formation strength and take advantage of other drilling opportunities. Drilling for hydrocarbons is different from all other drilling processes because it not only focuses on destroying rock (like mining and construction drilling, which are routinely done as underbalanced as possible to optimize ROP), but also on managing pressures of a potentially hazardous substance, such as highly flammable hydrocarbons and highly toxic hydrogen sulfide. Today traditional OTE drilling, especially offshore drilling after the Macondo incident, focuses on erring on the perceived safe side of pressure control, so that mud weights are designed to be closer to the estimated formation strength than the estimated pore pressure. The industry walks the drilling window in constant threat of mud losses because things are not exactly as estimated. When looking at the company that traditionally had the best drilling performance, the old Unocal, it is apparent that one of the many tricks they had was drilling close to the pore pressure, which not only made them experts in fast and efficient secondary well control practices, but also gave them a reputation of drilling for kicks. Today's drillers would consider some of these tactics unconventional, and the more risk averse (and less performance oriented) drillers would never do that. (Incidentally, Unocal also carried the highest NPT figures, simply because an equipment failure causing a lost day on a 7-day well is far more percentage-wise than the same equipment failure on a similar 60-day well of another operator.)

The new drilling convention combines the best of two worlds: First, MPD enables drilling very close to the real-time determined pore-pressure line of the drilling window, which takes advantage of a vastly superior ROP. Second, MPD provides the possibility for no kicks to the more risk-averse drilling teams of today. Thus MPD is not drilling for kicks, but it is drilling with no kicks (or losses) with performance equivalent that of Unocal.

In addition to MPD providing the most efficient way to destroy rock, it gives other performance advantages on every well.

Wellbore stability is often a major concern, often costing one-fourth to one-third of total drilling time. Many papers have been published on this subject, and they reflect a fact known to the practical driller all too well. Often, open-hole sections have a time limit, after which they become unstable. Many times mud chemical reaction, especially with shales, is cited as a cause, and at other times tectonic stresses. In the MPD world it is understood that there is also a mechanical factor, i.e., formations have a limited number of times that they can be exercised or cycled during connections, with often more than a 1,000 psi pressure differential in between ECD and static mud density. This is mitigated by two MPD methods: either trapping pressure during connections or continuing circulation and maintaining ECD during the connection process via a continuous flow system. The second method is clearly the more efficient and modern one because it has multiple further advantages. With a volumetric MPD system, maintaining a steady state of flow is advantageous for the detection of flow anomalies (such as influxes or losses. The disruption during the connection process is far harder to monitor. Conventional drillers will argue that they need the connection to see if they get into a pressure ramp and can fingerprint, but with the existence of the Microflux system, this crude and inefficient method of determining the proximity to pore pressure should be eliminated for good. Looking at the more extreme cases of OTE drilling again, this alone, and the elimination of ballooning and breathing, warrants the use of MPD on every well prone to this effect. With half the kicks being fake, as described earlier, it is certainly time for a better way to determine the real-time location within the drilling window.

What happens if during OTE drilling when getting too close to the pore pressure of formation strength? The mud weight must be changed, which is a 2 day (or $2 million) affair on a deepwater rig at best and not recorded as NPT. However, it is instantaneous with a properly designed MPD system, in which the specific gravity, ECD, and backpressure work together to create a stable pressure environment downhole. It is most often possible to design MPD operations to cover the entire pore pressure and formation strength uncertainty of a well without ever having to roll over and change the mud weight.

The same applies for salt exit strategies when drilling from overpressured shales into normal pressured carbonates and many other pressure challenges in today's complex wells. With modern RCD systems providing 5,000 psi static pressure and up to 3,500 psi dynamic pressure at drilling rpm (i.e., +ECD, so the static rating can be used as the backpressure window for system design, especially when combined with a continuous flow system), there is no well where MPD does not solve the pressure challenges.

Another major advantage of the below-tension-ring (BTR) RCD on floaters is the decoupling of mud returns from the pumping of the slip joint, and the movement of the rig, which brings kick detection to land levels. As mentioned before, the riser is already closed. If 90% of success in well control is closing the BOP in time, then the control with this method is always there.

Also, the strength of modern risers combined with the capability of modern BTR RCDs mean that all gas expansion happens behind the choke, so that any gas can be removed at high pump rates and is only limited by the capacity of the mud-gas separator.

The continuous flow system on its own opens a whole new world of drilling-fluid design capabilities, which dramatically improves hole cleaning and has a major positive effect on MWD/LWD.

"Drillers witnessing this invented a new meaning for the acronym MPD: make problems disappear."

With the mud no longer having to suspend cuttings in static conditions and with circulation going on during connections (at 300 ft/hr, i.e., three connections), continued pumping could almost double the total fluid volume circulated without increasing the pump rate and just keeping the pumps on. In this way, the gel strength can be significantly reduced, so there are no more losses kicking in circulation (if ever necessary). There is also a lower overall ECD, which allows a wider MPD drilling window, and better ROP, with the thinner mud. With double the volume of mud per hour circulating, it is doubtful that the well will have to be drilled with dumb iron because it is too hot for MWD. . It is true that cooler mud has been determined to reduce fracture strength, but this effect can be mitigated by using the appropriate MPD system design to stay in the new, smaller drilling window.

Another major advantage of MPD for managing the drilling window is that it can be widened by targeted strengthening of weak formations, if required. Field results achieved by Weatherford show that more than a 3-lb/gal improvement after a targeted mini-frac treatment to place the proppant right into the weak zone instead of just adding it to the large mud volume and hoping it would eventually reach the target zone.

Similarly, with the circulation system always on, there is more time for transmission of MWD data via the mud pulse system.

Another scourge of drilling in permeable formations, differential sticking is easily averted with MPD, which simply temporarily reduces backpressure so that the pipe pops off and can move again. Drillers witnessing this invented a new meaning for the acronym MPD: make problems disappear.

This brings up another potential major lost time factor, especially in deepwater well control events. Here, the dynamic well control capabilities of MPD systems really shine. Even with the highest possible inflow performance, there is no scenario where the inflow cannot be removed by continuing normal circulation and letting the gas expand behind the choke. This means no more bullheading with the associated weeks of lost time and no more potentially lost wellbores when a narrow margin well is shut in with a kick and the annulus full of cuttings. This dynamic method – combined with appropriate levels of automation such as achieved today with the OneSync process control package – should also be considered as the well control method of choice for 20,000-psi wells, in which using the driller's method type of well control is even less likely than for less challenging wells.

Another major advantage of MPD system availability comes during cementing operations. For the first time, a cement job can be modified during execution to take losses or gains into account and can be designed with unweighted spacer fluids using backpressure instead, which leads to much better mud removal and cement quality. Backpressure can be kept during the gelling phase of the cement, which avoids gas influx and microannuli, a major cause of sustained annular pressure. Finally, for the negative or inflow test after the cement job, there is nothing easier than taking off the backpressure and monitoring the fluid volume.

The most important performance improvements and ILT removal, however, happen early in the well construction process when MPD is introduced. In wells where casing strings have to be set for kick tolerance or other pressure reasons, MPD will enable the elimination of one or several casing strings compared to a well designed for OTE drilling. This becomes more important in time-related, cost-dominant environments, and especially in deepwater, where a combination of dual gradient for the shallower part of the well and backpressure MD for the deeper part are the optimum. For this reason, dual-gradient systems must be designed for the high flow rates of larger hole sizes. Because of the complexity of installation, it is recommended that MPD systems on deepwater rigs become part of the standard rig equipment package, and it is not unlikely that the entire cost of MPD system procurement and installation can be more than recovered on the first well drilled when using the full capabilities of the system.

Some Measures to Improve CLD Equipment Reliability to Avoid New Sources of NPT

One of the big advantages of CLD is the accurate material balance established via quantitative flow measurement: Coriolis Meters have proven the most reliable method of flow measurement in CLD field operations. This measurement has to be critical-error-free and highly reliable to add value and build the necessary trust of the operator. Therefore, the setup and also sizing of these meters in the return flow line is extremely critical, and it is also important not to rely only on flow measurement: For instance in case of a mud pump washout, pump strokes per minute remain the same, but flow out decreases: Thus, if no other sensors correcting this information are employed, the MPD operator will think losses occur, and open the choke: So backpressure is reduced, and several major kicks have historically occurred in MPD operations because of this deficiency. In modern control systems, such failure cannot occur any more, as pump wash-outs are detected via other sensors and no incorrect action can be taken any more. To overcome this deficiency, some operators had decided to install multiple Coriolis Meters in between the supercharger pump and the mud pump. However, it turned out to be extremely difficult to calibrate these multiple meters. The solution of incorporating the standpipe pressure sensor into the material balance algorithm was the better approach. Recently, the new development of high pressure Coriolis Meters could change that, as a Coriolis Meter in the Standpipe will allow not only accurate single point flow-in measurements, but also the real time integration of fluid density under high pressure for more accurate bottom hole pressure determination. This high pressure Coriolis Meter is practically field ready. On the flow-out side, the Coriolis Meter especially must not be too big, as a pressure drop of some 30-50PSI across the Coriolis Meter is desireable for accuracy. Thus, large, stand-alone Coriolis Meters used in non-CLD settings lack the required accuracy to build the confidence of the drilling crew.

Another major issue for CLD operations is the reliability of the bearing element and the elastomeric seal of the RCD: While the bearing element of the latest generations of Weatherford 16RCD certified heads lasts over several wells, the sealing element can be critical, as it should also perform at least throughout the openhole section to be drilled. In order to achieve this, several things need to be in place:

The first thing that needs to be checked is the verticality of the derrick, and the static and especially dynamic alignement and centering of the topdrive: On some rigs it has been observed that especially under high torque load the topdrive can move many inches out of vertically centered, putting high sideload on the RCD. Modern green lasers in a sub and a bulls eye on the rotary are ways to check static alignement, and a green laser mounted to the top drive housing and a corresponding target on the rig floor are suitable to measure dynamic alignement. There is also at least one company that is specialized in rig alignement surveys.

Next is the interface drillpipe-RCD. Here any sharp edges on the drillpipe need to be avoided, as element failure always commences at a cut caused by such edges. Things like rounded stress relief groves, smooth hardfacing, no sharp edges on implanted RFID chips, and especially low penetrating dies on properly adjusted and handled iron roughnecks / tongs are of utmost importance. Recent trials with changed drillpipe geometry (18 deg angle on both pin and box instead of 35 deg angle on pin upset) have been very promising, more than doubling element life during 16RCD stripping tests.

The current RCD ratings of up to 3500 PSI dynamic and up to 5000PSI static have reached the technical limit of the technology, and together with the generally benign, non-catastrophic failure modes allow the drilling of even the most challenging well imaginable with a CLD system. While there were several tries of active RCD development, the industry has gone away from this concept due to complexity-related NPT and the understanding that the required pressure control performance can be achived with the advanced passive heads as they exist today.

Lastly, it is desireable to interconnect MPD and well control choke systems for additional redundancy and the ability to use the far more precise and controllable (and automated) MPD chokes also for more conventional well control situations. Naturlly, for regulatory reasons, these chokes must have the capability to be isolated with valves rated to the rig choke manifold pressure rating.

People, Training and Human Factors

Alongside changing the way wells are drilled, perspectives need to change on the way crews are trained. Increased challenges and risks accentuate the need for high competence in the field. While automation can ease the burden of frequent human response and reduce false alarms, it doesn't fully eliminate the crew. Furthermore, when automation is introduced, required competencies tend to shift from rote skill and procedural discipline to a more cognitive nature. For example, while automation may reduce false events and mitigate near-misses (and reduce the constant need for human interference), how should crews be trained when the event requires human intervention.

Aviation accidents such as Colgan Air 3407 (NTSB, 2010), Air France 447 (NTSB, 2012), Asiana 214 (NTSB, 2014a), and UPS 1354 (NTSB, 2014b) highlight the importance of human interaction. All these accidents came down to one thing – pilot error. However, further exploration of the root causes reveals that the problem was not merely a lack of pilot skill or basic flying knowledge, but rather the pilots' lack of understanding of their automated systems and their inability to respond to critical off-nominal events (Wickens, Gordon-Becker, Liu, and Lee, 2004). In other words, automation requires an increased need for situational awareness and a stronger understanding of how to interpret the data and telemetry provided by the automated software. Other teamwork competencies such as communication and coordination also become extremely important in responding to off-nominal situations.

Unfortunately, current training programs and philosophies are largely lagging behind current drilling practices, technologies and increasing risks and challenges. The industry is no longer adequately training crews to ensure that they are successful in preventing and mitigating errors on the rigs. Now is the time to revisit training curriculum with the goal of better preparing crews. Focus should be on integrating crew resource management skills (such as situation awareness, decision making, teamwork, and communication) into training programs in a manner consistent with the way people learn best (Flin, Martin, Goeters, Hoermann, Amalberti, Valot, and Nijhuis 2003). Training events should use appropriate training tools, methodologies, and devices. The goal should be to achieve maximum understanding and mastery of the complex drilling scenarios required for deep water.

Four areas stick out when dissecting failures in human behavior during off-nominal response and action: memory overload, lack of understanding, decreased confidence, and failure to employ team resources. Learning occurs when the knowledge moves from short-term to long-term

"Crews must train together in varied scenarios and employ a number of skills in situations that challenge their understanding."

memory. However, with increasingly complex systems, the amount of operational data, processes and procedures can start to overload the working memory of crews (Wickens, Gordon-Becker, Liu, and Lee 2004). They are prime targets for information overload. Furthermore, decreased working memory capacity coupled with sleep deprivation and mental fatigue can reduce situational awareness and impact operational decision making (Endsley 1995). To free up working memory in off-nominal events, standard operational procedures for nominal events should be practiced with repetition and within operational contexts. Additionally, new information regarding systems and processes should leverage old knowledge and be taught with the goal of enhancing the crew's ability to make operational decisions.

Aside from working memory overload, current training programs, which are mostly anchored in generic, conventional well control methods, aren't going far enough to achieve a thorough understanding of their specific systems and drilling programs. Traditional well control courses encourage a memorized response to a standard well control situation. Studies show that rote memorization of performance is generally good when the assessment is expected. However, when the event is unexpected and the crew is caught off-guard, expected behaviours and actions are not performed with accuracy (Casner, Geven, and Williams 2013). Therefore, rote memorization is not a good standard for performance in off-nominal situations. A thorough understanding of the systems and the well are necessary. While time may be spent with the crew outlining expectations with the drilled well on paper exercise, it is argued that this is not enough for developing a strong cognitive understanding. More time spent working out procedures and testing understanding of systems in varied off-nominal scenarios is necessary to build a higher-order cognitive knowledge.

Finally, decreased confidence and failure to employ team resources lead to decreased situational awareness, slow response, and poor overall performance and decision making. To increase a crew's confidence that they have the skill set to work together and solve off-nominal situations, deliberate practice is necessary. Crews must train together in varied scenarios and employ a number of skills in situations that challenge their understanding. They must also receive structured feedback and see success over a number of runs to build up trust and confidence as a team (Salas, Burke, and Cannon-Bowers 2002).

Building on the high success found within the aerospace, military, and medicine fields, well control and other drilling training programs should also be designed with a major focus on high fidelity simulation training. Following best practices from outside industries, it is recommended that training programs engage students in real-life scenarios for at least 50% of the course time. This enables the students to put their textbook knowledge to practice in a world of simulated versus actual consequences. They learn through first-hand experience what works and what does not, both from a technical and a team-skills perspective. The result is a crew with practice in well-control situations that knows how to react as a matter of instinct using cognitive understanding versus rote memorization. Moreover, simulations create active learning that increases the learner's knowledge and process retention. Learners become actively aware of consequences of their decisions, errors, and successes (Gaba 2006). This helps build their experience base and situational awareness, which enables them to respond more quickly to planned and unplanned situations in real time. Learners are also able to more easily relate past experience to the well plans when in simulations. This increases understanding, acceptance, and retention of new materials, processes, and procedures (Gabas, Howard, Fish, Smith, and Sowb 2001). Simulations develop learners who have increased situational awareness and are thus able to respond to events faster and with improved decision-making abilities. Finally, simulations increase productivity by increasing muscle memory and decrease incidents by increasing deeper understanding of procedures and environment (perfect practice makes perfect performance) (Lewis, Strachan, and Smith 2012).

When focusing on the four critical areas for human performance problems – memory overload, lack of understanding, decreased confidence, and failure to employ team resources – it is clear that there is a strong need for training programs to be based in high-fidelity simulations. These simulations enable crews to see, touch, and experience how automation works in their situations. Experiencing reactions in various nominal and off-nominal scenarios will chunk and move knowledge from short-term to long-term, thus freeing up working memory. Furthermore, through repetitive practice in running through drilling programs while experiencing various, unexpected off-nominal events, the crew will increase its understanding of how the systems work, what data to look for, and how to work as a crew to better adapt to different problems. Finally, through deliberate practice, structured feedback and frequent successful runs in the simulator, crew confidence is improved. Trust among the team is also increased which allows for better teamwork, communication, coordination, and problem-solving. It is clear that training needs to shift away from infrequent generic classroom training to a more holistic approach. High-fidelity simulators with varied, highly scripted scenarios and focused debriefs will provide a stronger understanding of systems while increasing crew confidence and trust. Practice of low frequency, high impact off-nominal events is necessary if we want our crews to perform safely and effectively. These practice sessions should occur frequently, perhaps as frequent as every six months, using the realistic simulators with guided feedback.

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