Multi-technical MPD concept, comprehensive planning extend HPHT targets on Kvitebjørn

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KVITEBJØRN IS LOCATED in the Northern North Sea on the Norwegian Continental Shelf, southeast of the Gullfaks Field (Figure 1). It is classified as a HPHT gas condensate field. The reservoir consists of sandstones in the Mid-Jurassic Brent group and lower Jurassic). The top reservoir is at approximately 4,070 m TVD. Early production during development drilling has induced pressure depletion, creating a convergence between pore pressure and fracture pressure in the reservoir. The initial pore pressure was 775 bar (1.93 SG), and fracture pressure was 875 bar (2.19 SG). The reservoir temperature is 155°C, and the water depth is 190 m.

Nine wells had been drilled into the reservoir prior to introducing the MPD technique. The gas/condensate production started in September 2004 after the second well was drilled and completed. On the last conventionally drilled well, 34/11-A-2, 140-170 bar of depletion was encountered, and massive losses were experienced. Drilling was suspended before reaching TD due to the well control situation created by these mud losses.

The A-2 incident marked the end of the traditional drilling programme as no further drilling on Kvitebjørn would be possible – unless a method could be found to safely operate within Kvitebjørn’s reduced “drilling window.”

After the A-2 incident, Kvitebjørn production was reduced to limit the rate of depletion to complete the primary drilling programme. Production from the field was reduced by 50% in December 2006, then completely shut down by May 2007 when depletion approached 200 bar.

A toolbox with several techniques – including managed pressure drilling (MPD) – was developed to mitigate the problem. MPD offered a solution for the remaining wells but had little precedence in the HPHT environment. If bottomhole pressure (BHP) could be precisely controlled and held just above the highest pore pressure, a safe operating environment could be created to allow drilling to continue. MPD is a technique that uses a reduced mud weight and surface-controlled back-pressure to manipulate the downhole pressure profile.

The HPHT environment requires accurate automated choke control to compensate for BHP variations that arise from downhole temperature changes, drill pipe rotation, swab/surge and several other phenomena that are known to create significant BHP variations in HPHT wells. To allow drilling operations on Kvitebjørn to resume, MPD had to be adapted for HPHT operations. To create a robust overall system, other synergistic technologies were selected to support MPD, which was at the core of this solution.

Kvitebjørn development wells 34/11-A-13 T2 and 34/11 – A-12 were successfully drilled during 2007 using the enhanced MPD system developed.

COMBINING TECHNOLOGIES

A combination of technologies was introduced that helped reduce dependency on any one technology. These included MPD upgrades and enhancements for HPHT application, continuous circulation during connections, and a drilling fluid designed to improve the fracture gradient. The operating strategies, practices, controls and responses are very different from conventional operations. The development of the new methods and techniques were carried out during the planning, testing and commissioning phase of the project.

Professional management is vital to a successful MPD operation. The complexity of MPD operations and the coordination of services, equipment and personnel require a high level of supervision and management. Even the most sophisticated equipment has limitations that need to be considered in planning and execution. The equipment package requires an optimal setup to perform to its full potential. This setup must be based on the planned operations, but it cannot be optimized for every possible situation.

The final setup will be a trade-off, e.g., response time vs accuracy. The MPD crew must be aware of the system’s strengths and weaknesses, and these must be reflected in operational plans, contingency procedures and operational execution. Hydraulic modeling simulations are important during MPD preparations and represent the foundation of all plans, procedures, contingencies and equipment setup.

Unfortunately, experience proves discrepancies between real data and computer simulation. Throughout the MPD operation, constant judgement calls are required, which are all based on human interpretation of real-time parameters.
During MPD operations in general, and especially in HPHT wells, relatively small failures can ultimately cause loss of the well. Hence, it is of utmost importance that everyone has the skills and motivation to do their work properly. This is a management responsibility. MPD must not commence until all personnel are competent for the upcoming tasks. This includes working as a team, as well as performing their individual responsibilities.

On Kvitebjørn there were two aspects that made this challenging. First, there were people from eight or more countries who had to communicate with each other within the drilling and MPD organization. Second, it is hard to find personnel with MPD experience. Trainees have to be integrated into the operation, and they must be allowed to operate the equipment.

MPD centres on the use of a rotating control head (RCH) to provide a dynamic annulus seal that diverts the return mud flow through a surface choke. It is this choke that controls the back-pressure in the annulus and permits the manipulation of the downhole pressure profile. The mud weight is selected to be lower than the well’s initial pore pressure. The annulus friction plus annulus back-pressure brings the downhole pressure profile back to balance, or slightly above balance. In this way the well is kept in balance, at all times preventing influx and hole collapse.

The hydraulic flow model is vital to the adaptation of MPD technology for HPHT applications. HPHT wells have characteristically high BHP variations, not just from the high equivalent circulating densities (ECD). Downhole temperature changes affect mud weight and viscosity, pipe movements, rotation, torque, cuttings load, etc., all of which produce continuous and significant variations in downhole pressure. Only by compensating for these can constant BHP be achieved.

Compensation is performed by manipulating the choke and adjusting the annulus back-pressure. To do this in the HPHT environment, an advanced dynamic flow model running in real time is required. Computing power can become a limitation, as can the accuracy and speed of input data from rig sensors. Calibration of the model with measured downhole pressure data is important to ensure accuracy.

Automatic choke control is an essential requirement. Accurate input to the choke controller from the flow model is one aspect; the accurate and timely control of choke movements is another. Both are required for the system to react fast enough and work well.

Routine drilling operations were characterised by continuous small choke movements to meet the continuous small pressure changes required. However, occasionally, very rapid and accurate choke movements are needed to respond to unwanted events, such as packoff, pump failure, power failure, drillstring washout, etc. This often requires manual intervention.

Flowmeter technology for use with drilling muds has greatly advanced and is well suited for the MPD system. Mass flowmeters are highly accurate and, with the appropriate software, can provide exceptional kick detection and fingerprinting system.

Continuous circulation system (CCS) permits full circulation during drill pipe connections. In HPHT wells, it is only by maintaining full circulation at all times that we can control the impact of downhole temperature changes. By maintaining the downhole temperature profile with minimum variations, we can achieve something close to hydraulic stability in the well. This is a great benefit to choke control and improves the sensitivity for detecting trends in other parameters. Once installed and commissioned, the CCS requires aligning and tuning to the rig systems. However, once this has been completed, the system can perform reliably for extended periods of operation.

Designer mud based on caesium/potassium (Cs/K) formate mud has been introduced. A controlled particle size distribution and blend of calcium carbonate, graphite and nut plug were added. This combination was verified in the laboratory to provide fracture gradient enhancement (FGE) properties in the Kvitebjørn reservoir sandstones. By drilling with this mud, the existing fracture gradient would be supported and possibly enhanced. This was an important element of the combined technology concept providing support to the other technologies in the event of under-performance or failure.

Particle drop-out was a major drawback that caused severe difficulties, but only as a result of extended unplanned periods of non-circulation. An adjustment of the particle concentration and a greater attention to fluid suspension properties has resolved this issue.

A crosslinked isolation mud pill in Cs/K formate base fluid was developed to support weighted mud placed above lighter mud. Minimising the mud interface and preventing the heavy mud “sliding” downhole was a critical requirement when the well was brought into pressure balance to perform trips. Tripping all the way out of the hole with a live HPHT well, relying entirely on mechanical sealing elements for pressure control, was not considered the best option. After tripping approximately two-thirds of the way out of the
hole under MPD control, the well could then be brought into static overbalance using the BMP and weighted mud. The trip could then be completed conventionally. Taking the time to bring the well into static overbalance, although time-consuming, was considered to be a more satisfactory practice. The newly developed balanced mud pill (BMP) allowed this to be done. Extensive laboratory and rig testing were performed during the development of the pill. This isolation pill proved to be very stable, even when non-optimal placement was required following a twist-off, as experienced during the drilling phase of the A-13 well. The pill fully transmitted hydrostatic pressure, providing direct pressure control over the BHP.

The alternative of bringing the well into hydrostatic balance at TD would have produced much higher over-pressures on the reservoir. Surge pressure from tripping would also have been higher and without any MPD compensation.

**PREPARATION, PLANNING**

Preparation and planning for this operation took almost two years. Several technologies were examined and advanced engineering studies performed during the feasibility stages of the project. The strategic philosophy that later defined the actual approach taken was refined during this process.

An extensive series of hazard identifications (HAZIDs), hazard and operability studies (HAZOPs), peer reviews and workshops were conducted, covering every aspect of the proposed operation. These consultations refined the methods, configurations and procedures that were employed and proved an important contributor to the success of the project.

Project control and organisation required special consideration. An organisation of competent members was assembled for the early preparation and planning stage. A separate and much larger organisational structure was needed to perform the operation. The integration of several new companies, personnel, equipment and practices required careful consideration and planning. The importance of project control, organisational structure, reporting lines and operational support roles should not be underestimated. The offshore organisational structure used during MPD operations is shown in Figure 2 to illustrate this point.

Regulatory support from the Norwegian Petroleum Safety Authority (PSA) was an important factor. Early notification and frequent briefings created a beneficial consultative environment.

**EQUIPMENT LAYOUT**

The equipment layout schematic is shown in Figure 3. Key to the adaptation of MPD for HPHT applications is the retention of the high-pressure (HP) blowout preventer (BOP) system below the MPD control stack. This met all well control requirements for HPHT wells. At any time the HP BOP system could be engaged and the established HPHT well-control procedures applied.

In this case, the HP BOP was an 18 ¾-in. 15,000 BOP with four rams and one 10,000 annular. The rams were dressed for the drill pipe with a blind/shear in the upper-middle ram cavity. It was this strategy that permitted the use of the available 5-kpsi (345-bar) MPD control stack for operational control. The MPD control stack consisted of an 11-in. 5,000 rotating control head, a 13 ¾-in. 5,000 stripper ram and a 13 ¾-in. 5,000 stripping annular.

There is scope for the use of the MPD control stack for low-pressure well control incidents (by far the most common event on HPHT wells), but, in this instance, a demarcation was made between well control and operational control.

At the heart of the MPD control system is a pressure control while drilling (PCWD) rotating control head. This item has a long history of successful field use and benefits from an active sealing element ideally suited for stripping drill pipe. The remainder of the MPD stack was configured to provide component redundancy, flexibility and to facilitate efficient PCWD element change-out.

The dual redundant automatic chokes were specifically selected to avoid choke erosion. This is a common concern on well clean-up operations, but less so during MPD operations. The problem has more or less been eliminated through choke design. Some testing was needed to optimise the size of the choke trim. A junk catcher immediately upstream of the choke manifold was considered but discounted as being of little practical benefit.

Pressure relief valves were included in the return flowline to protect equipment and the well. The primary relief valve immediately upstream of the choke manifold was automatically controlled by the choke control software. This valve was set to activate 5-10 bar above the choke set-point pressure, depending on the operation being performed.

When the choke set-point pressure was adjusted by the flow model, the relief valve’s set-point would also automatically change. Once triggered, this automatic relief valve would re-set itself when the pressure drops below the set-point. This provided exceptional protection of the well from over-pressure, and the re-set feature helped prevent underbalanced conditions. This device proved its worth on several occasions and performed exactly as intended.

The mass flowmeter was configured with a bypass to allow for cleaning or unplugging if required. Once configured and calibrated, the meter provided exceptionally high-quality data. Potential exists for this data to be used for online analysis, event determination and automatic sys-
tem response to unwanted events. On this operation, the mass flowmeter was used only for monitoring, with no direct control of the system. Further automation and the reduction of manual intervention is an achievable future goal for MPD control systems.

The auxiliary pump continuously circulated clean mud from the active system across the wellhead, keeping the annulus full and providing a continuous mud flow to allow the choke to maintain the desired back-pressure. This ensures full pressure control over the annulus regardless of the main mud pumps. The concept and function of this additional pump was proven; however, pump reliability, pump pressure fluctuations and pump rate optimisation required more attention.

It became clear that the auxiliary pump is a very important and necessary component of the system. It would benefit from an uninterruptible power supply or diesel power; speed control and improved specification.

**INSTALLATION, COMMISSIONING**

The installation of these new equipment on a fully automated, small-footprint North Sea platform rig required extensive planning. Considerable time was spent commissioning, testing and training. Much of this time was spent integrating the MPD systems with the rig’s automated systems. Interface issues dominated this phase of the operation.

The other main factor, which was imposed by project time constraints, was that much of the final development work on the new systems, tuning, balancing and aligning systems, had to take place offshore. More testing could preferably have been done prior to going offshore. However, advantage was taken of this opportunity for extended training and familiarisation with the new equipment.

Some experimentation, modification and development was needed during commissioning and testing of the choke control system. An early discovery was just how incompressible the Cs/K formate mud system was. Annulus back-pressure fluctuations were transmitted instantaneously without attenuation downhole. This fact meant that choke control, precision and accuracy were a far greater challenge than anticipated.

However, with patience and expert contribution, the choke control logic was tuned to provide fast, accurate response while limiting oscillation responses. Some manual intervention of the choke control was still needed to deal with certain unwanted events. However, further testing and development of both the choke controller and flow model is expected to reduce the need for manual intervention. It is unlikely that manual intervention will ever be fully eliminated, and the need for experienced and attentive operators will remain.

For example, rig power failure, a contingency event, proved particularly troublesome. A power failure would result in complete loss of all pumps; the control system’s response speed to contain the well became a real challenge. The improvements in the choke control system, in particular the automatic detection and response to changes in key parameters, allowed the acceptance criteria to be met. Manual override was therefore able to be reduced to a minimum.

The flow model underwent a continuous process of development, troubleshooting and fine-tuning during this period. It was only once the model had been fully integrated into the real well situation that its capabilities and limitations could be finally determined. Bench testing had been performed, but this could only take the real-time computer model to a certain level.

Data input accuracy and speed proved a surprising limitation. For example, using pump stroke counters was found to be inadequate at slow pump rates. By changing to RPM sensors on the pump crank shafts, reliability and accuracy were greatly improved. It has only been with the experience from actual operations that the bottlenecks and limitations inherent within existing systems could be identified.

The testing of the system was extensive and included the use of fixed downhole pressure gauges to provide direct comparison with annulus pressure while drilling (APWD) results and surface control parameters. A liner was run and retrieved to verify the effects of liner running on downhole pressures. These extensive and rigorous trials probed the limits of the system’s capability, promoted confidence in what could be achieved, and determined which events are the most critical.

Only after commissioning, testing and training had been fully completed did the MPD operations phase begin. Operating procedures were also revised, documented and approved.

**PRESSURE CONTROL**

A pressure-control strategy was adopted based on the formation pressure forecast...
for 34/11-A-13 T2. This strategy is illustrated in Figure 4. The initial reservoir pressure, prior to any depletion, is known from earlier Kvitebjørn wells. This profile is described by a constant gradient from 1.92 SG at top reservoir to 1.86 SG at the base. The risk of encountering an undepleted zone in the reservoir was considered to be high, as was the uncertainty in the depleted fracture gradient.

A target downhole pressure gradient was set at top reservoir of 1.94 SG (0.02 SG above anticipated maximum pore pressure). This target pressure was incrementally reduced as drilling proceeded. This reduction in target pressure was based on the following:

1. Always remaining 0.02 SG above the anticipated maximum pressure for reservoir still to be drilled.

2. Always remaining 0.02 SG above the measured pore pressure of the reservoir drilled. A formation-pressure-while-drilling (FPWD) tool was included in the bottomhole assembly (BHA).

The use of the FPWD was key to this strategy, and formation pressure tests could be taken at any time without tripping or stopping circulation. The FPWD pressure tests recorded are shown in Figure 4.

This strategy makes the most of the available “drilling window” without risking underbalance. The incremental adjustments to downhole pressures can be simply and quickly performed with choke pressure manipulation. The MPD system as installed and operated had been proven to work comfortably within a ±5-bar range during normal drilling operations.

**OPERATIONS SUMMARY**

The 9 7/8-in. casing was set at 6,101 m MD (4,093 m TVD). The well was displaced to 1.84 SG at 50°C cesium/potassium Formate. After drilling out the 9 7/8-in. casing and 25 m of new formation, a formation integrity test was performed to 2.05-SG equivalent mud weight (EMW). The MPD system was installed, commissioned, tested and accepted for MPD operations. Personnel training, familiarization and procedure rehearsals were completed.

The drilling BHA incorporated a comprehensive logging while drilling (LWD) suite that included a FPWD tool (for taking formation pressure points) and an annulus pressure and temperature sensor. Three tested drillstring float valves (517-bar working pressure) and a multi-function circulation sub (MFCS) were also included. A tapered drillstring was used consisting of 4 ½-in. and 5-in. drill pipe to handle the predicted 55 KNm of drilling torque.

Drilling proceeded in MPD mode in 8 ½-in. hole to 6,197 m MD. The mud weight was reduced from 1.84 SG to 1.81 SG at 50°C due to the ECD being 8-10 bar higher than forecast. This improved the operational range of the choke.

A washout in the drillstring was detected and verified. The trip out had just begun when the drillstring parted at 1,900 m, and the well was shut-in on the HP BOP with an applied shut-in casing pressure (SICP) of 42 bar to compensate for the loss of ECD and back-pressure. Manual intervention helped minimize the inevitable underbalance, which was of short duration. No detectable net influx volume was observed. The BMP was employed to bring the well into hydrostatic balance using 2.12-SG heavy mud. With no float valves in the remaining drill pipe, the CCS proved a valuable asset in maintaining pressure on the drillstring when pulling back during fluid placement.

The chokes were able to hold back pressure and maintain control of the well. The flexibility of the inherent design of the combined MPD system proved itself during fishing operations. Several fishing trips were required, including wireline operations before the fish was recovered. The recovery of the fish was hampered by FGE particle dropout from the mud. The drillstring and annulus at the top of the fish were plugged with particles preventing circulation. Large quantities of particles also settled downhole and had to be cleaned out before drilling could resume. The prolonged period without circulation contributed to this problem, but the suspension properties and capacity of the mud system requires further attention. The well configuration at this time is illustrated in Figure 5.

Drilling continued in MPD mode through the remainder of the reservoir to TD at 6,351 m MD. Average drilling parameters were 10 m/hr, 1,000 L/min (mud pumps), 580 L/min (auxiliary pump), 100 rpm and 45-55 KNm. The downhole pressure was maintained at 1.92-SG EMW, with a choke pressure of 14-16 bar. Formation pressure points were recorded, indicating considerable variation in depletion through the reservoir. The highest depletion recorded was 124 bar in the Lower Ness Fm.

At TD and after assessment of the formation data acquired, the well was successfully brought into overbalance for the remainder of the well operations.

**EXPERIENCES**

The well was successfully drilled to meet the objectives under full MPD control despite serious unwanted events.

**Routine drilling**

During periods of stable drilling and circulating, the MPD system controlled the downhole pressure to within 0.4-bar increments. The accuracy and precision of this control demonstrates the capability of automated MPD systems in HPHT environments.

**Connections**

Once the CCS was properly tuned to the drilling rig, connections were reliably made without any interruption to downhole circulating rate. Standpipe pressure fluctuations during a connection were around 6 bar, which indicated less than 2 bar downhole. The make and break of the 5-in. drillpipe tool joints to 63 KNm of torque with the CCS was routinely performed without difficulty.

When required, multiple connections were made without downhole circulation by using a pump ramping process with associated automatic choke modulation to increase choke back pressure as ECD reduced to zero, thus maintaining the desired BHP. Such occasions can arise during contingency procedures and while tripping in the upper hole section.

**LWD surveys and pressure points**

Taking a survey or activating the FPWD for a pressure point involved cycling the pump rate from around 1,000 L/min to 600 L/min to downlink to the tools. Compensating for these changes in flow rate using the automated system proved to be unstable. Manual control was found to produce repeatable results, although with larger pressure fluctuations than preferred. Communicating with the downhole tools in this way resulted in a ±4-bar fluctuation downhole. This was still within the ±5-bar target.

**Drilled gas in returns**

No connection gas or influx gas was observed during the drilling of the reservoir. Drilled gas, which is not dependent on the magnitude of overbalance in the well, was recorded at levels up to 3% gas in mud. This gas produced a 400- to 500-L pit gain, with the gain beginning up to 1 hr before the gas reached surface. The corresponding response in the return flow rate, as measured with the mass
flowmeter, was typically up to 300 L/min.

Identifying gas events, monitoring parameters and relating them to detailed “finger-printing” was found to be the best method to handle these incidents. Once the drilled gas was out of the well, the pit level and flow rate returned to normal with no compromise in safety and minimal influence on BHP. When necessary, drilling was stopped but circulation continued until the gas was removed. Shuttling in the well with the BOP on these events de-stabilised the hydraulic regime and created much larger downhole fluctuations. Making a clear distinction between gas events and potential well influxes avoided numerous shut-ins. Real-time monitoring and interpretation of this data can be performed onshore in future operations.

**Designer mud**

The designer mud formulation was based on detailed lab testing for optimum performance as a low ECD fluid, where particle suspension was, to some extent, sacrificed for ECD optimisation. The initial formulation included nut plug, which caused some plugging of surface equipment. The nut plug was screened out of the system, and no further additions were made.

The large quantities of calcium carbonate did not give any problems when circulation was maintained. As expected, excessive settlement occurred in the 57° hole inclination during the prolonged period without circulation while fishing.

This was a serious detriment to the recovery of the fish. An evaluation with regard to particle suspension properties and the amount of particles needed in future operations, as a compromise between ECD management and particle addition, must be established and set, to deal with unexpected events.

**Flow model vs APWD readings**

The downhole annulus pressure was measured in real time with an APWD sub. The readings from this sensor were used to calibrate the flow model for optimum performance. It was observed during the testing phase that the APWD readings drifted by 12 bar. After careful calibration and attention to the drift correction of these tools, the readings appeared to be more stable.

Throughout the operation, an offset of 8-10 bar existed between the flow model results and the APWD readings. This shows the importance of calibration or at least comparison between the flow model and APWD. In subsequent operations, a correction to mud rheology inputs improved this offset to around 2 bar for extended periods.

The calibration and especially the drift of the APWD is an important consideration when operating at high levels of accuracy. Flow models will always have limitations, although we continually see improvements in their accuracy. We were able to compare readings from the APWD with the FPWD tool, and thereby had two independent measurements of the BHP that we could compare with the flow model. However, accuracy and drift remains a concern for these tools.

**Selecting static mud weight**

The original strategy was to minimize the potential underbalance by selecting a static mud weight that allowed for a minimum practical back-pressure. This resulted in the static mud weight having to be reduced during drilling operations. The ECD proved higher than anticipated. Static mud weight reduction took significant rig time, incrementally stepping down the mud weight with appropriate checks before proceeding to the next step. With increased confidence in the MPD system, the better approach would be to start with a lower mud weight.

Experience showed that choke performance and auxiliary pump function are more stable at higher choke pressures.

The heavy mud pill was also accurate and could be precisely identified by the mass flowmeter in the flowline.

The well was switched back and forth several times from MPD mode to conventional balanced mode using the BMP before fishing operations were successfully completed. Wireline work was safely performed using wireline pressure-control equipment, proving that wireline interventions can be safely conducted with this MPD arrangement.

**Drillstring failure**

A shallow drillstring failure is one of the more serious failures that can occur during MPD operations. Control over the bottomhole pressure is threatened. Fortunately, prompt action from the operators limited the subsequent fluctuation in BHP. An initial washout was detected, and the failure occurred when steps were being taken to recover the drillstring.

Establishing the depth of the failure was achieved with the imaginative use of various markers, including rice, sponges, carbide and heavy mud pills. Carbide proved quite accurate but had to be activated in water before pumping.

**Update**

Following the success of 34/11-A-13 T2, the MPD technology was applied to the next development well 34/11-A-12. This well reached TD in November 2007 under full MPD control. Pressures encountered through the reservoir varied from 130 bar of depletion to full initial pore pressure (zero depletion). A production liner was successfully run and cemented under MPD control without losses. By making full use of the experiences and lessons learned from the previous well, the rig-up, commissioning and testing time were greatly reduced. The reservoir section was drilled successfully without serious incident or mud loss.

StatoilHydro intends to continue to develop and use MPD for the remainder of the Kvitebjørn wells.

This article is based on SPE/IADC 114484, “Highly Advanced Multitechnical MPD Concept Extends Achievable HPHT Targets in the North Sea,” 2008 SPE/IADC Managed Pressure Drilling and Underbalanced Operations Conference & Exhibition, 28-29 January 2008, Abu Dhabi, UAE.