MPD planning: How much is enough?

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THIS ARTICLE ADDRESSES the key drivers and risks associated with the use of applied backpressure managed pressure drilling. One of the two key issues that must be understood early on is whether the well can be drilled statically overbalanced or if it needs to be drilled with a statically underbalanced fluid. The second issue to comprehend is the level of service needed to avoid compromising safety and well objectives. Answering these two questions defines the path to be followed for adequate planning.

Detailed planning aspects, such as flow modeling, crew training, operational procedures, process flow diagrams and HAZID/HAZOP meetings are also described here. By asking the “what if” questions prior to operations, it should become apparent what additional surface equipment is required to safely and efficiently drill in MPD mode. Control of the “what if’s” should help to keep the planning and rig-up both reasonable and cost effective.

INTRODUCTION

Managed pressure drilling (MPD) in the form of applied backpressure (ABP) or constant bottomhole pressure (CBHP) is becoming increasing popular as a means of overcoming certain drilling problems. However, its entry into the market has come several years after the adoption of industry best practices and regulations for planning underbalanced (UB) wells.

Because reservoir fluids are typically handled at surface, UB wells require extensive study and planning before being implemented. One problem now confronting our industry is the level of study and planning required for ABP MPD wells drilled overbalanced. By understanding key application aspects, such as the proposed mud weight, required level of service, and company and regulatory policy on the use of well control equipment, it is possible to determine the appropriate amount of planning needed for the project to be successful.

MPD APPLICATION DRIVERS

Before planning an MPD project, the driver for application should first be understood and quantified. This exercise is typically performed by the operator and falls into one or more of the following categories:

- Minimize overbalance to:
  - Increase ROP.
  - Avoid differential sticking.
  - Prevent lost returns.
  - Reduce formation damage.
- Maintain constant BHP to avoid wellbore ballooning.
- Extend the depth between casing setting points to:
  - Narrow kick tolerances.
  - Deplete tight gas zones containing nuisance gas.
- Faster kick detection because of better flow measurements.
- Enable dynamic well control methods.

If commercial benefits are difficult to justify, other factors should be explored before discounting MPD and reverting to a conventional well with its associated drilling problems.

Reviewing offset well data will help quantify the potential nonproductive time (NPT) on the well. By asking the right questions about MPD, it may become apparent that it offers solutions in more than one problematic area.

MPD RISK FACTORS

The downside risk of applying MPD should also be identified early in the planning process. Risk considerations fall into three main categories:

- Pressure tolerance between minimum and maximum limits to avoid kicks and lost circulation.
- Flow potential of the well if a kick is encountered.
- Difficulty of control due to pressure transients, measurement errors, and equipment response characteristics or failures.

Under ideal conditions, simple MPD control systems can be used to drill formations with low flow potential and wide pressure containment windows. Unfortunately, few MPD wells are drilled under these conditions. Pressure tolerances can be reduced due to wellbore stability limits and/or pressure reversals or depleted zones. Parameters that describe the flow potential of the well are defined by Darcy’s flow equation (permeability, contact area, differential pressure and fluid composition). Control complexity is driven by a variety of factors, including well geometry, equipment performance and human response factors.

The application of MPD in deep HPHT well environments represents the most challenging combination of risk factors.
Elevated temperatures can create significant BHP transients and measurement errors due to its effect on fluid densities and rheologies. Highly pressured formations are typically drilled with high-density fluids and can result in high surface pressures if gas kicks are encountered and circulated to surface. Deep wells are also usually drilled with slimhole well geometries that can create significant frictional pressures while circulating.

**STATICALLY OVERBALANCED OR STATICALLY UNDERBALANCED**

This condition generally dictates the path down which MPD planning will go. In the proposed MPD section of the well, if all surface pressure is removed from the well, will the well remain statically overbalanced? If the answer is yes, then quite often MPD is being used to maintain a constant BHP during “pumps off” periods such as connections. Figure 1 illustrates this condition, whereby a defined “set point BHP” has been established and is maintained when the equivalent circulating density (ECD) is lost in the wellbore.

Being statically overbalanced means that normal operations, such as running in hole and tripping out of hole, are unaffected by ABP MPD. If power supply to the MPD pump fails, or the MPD backpressure pump develops mechanical problems during a connection (rig pumps off), then the worst case is wellbore pressure drops to the statically overbalanced state.

If a statically underbalanced fluid is required to achieve the MPD objectives, then a series of additional considerations must be made. For this, it is recommended that comprehensive upfront planning be undertaken. Figure 2 illustrates the wellbore condition with a statically underbalanced fluid. Sudden loss of the applied surface backpressure could result in an influx, which must be detected and safely removed from the wellbore.

**WHAT LEVEL OF SERVICE?**

If “in-house” MPD expertise is not available, the operator should set aside planning time to work with either a third-party engineering company or directly with an MPD service provider. MPD service companies offer various levels of service.

If the operator clearly understands his well problems and the solutions available from all ABP MPD providers, he can directly approach the vendor. If unclear of the solutions and service level options, it may be prudent to seek advice.

Certain ABP MPD control systems offer a fully automated system that utilizes process control logic (PLC) software to control BHP. These systems run dedicated flow models that, when using annular pressure subs in the bottomhole assembly, are self-calibrating. This level of service has the ability to offer the most accurate control of BHP.

A less sophisticated system enables the MPD choke to be set to maintain a fixed surface pressure. The required pressure is manually entered, and the control system automatically manages the choke to maintain this condition. Knowing what BHP is required, the rig site MPD engineer maintains a steady state flow model to determine the required surface pressure.

The simplest type of MPD control requires a person to manually operate the choke to try to maintain the choke pressure advised by the person flow modeling. While there is an application for this, its performance is very dependent on the individual’s ability to operate a choke for an extended period of time. In some instances, operation of the choke is required only during “pumps off” periods where the pressure loss is captured at the choke.

Each of these service levels has its rightful application. To avoid deploying a premium service on a well that does not warrant the level of accuracy in managing BHP, a degree of planning should be done. Deployment of a simpler service on a well requiring more stringent BHP control has obvious negative consequences.

At a minimum, planning should at least determine what level of control is required and whether the drilling fluid needs to be statically underbalanced or statically overbalanced to stay within the pressure tolerance window.

Irrespective of the level of service, the MPD service company will need to visit the rig site to assess the equipment required. As with UBD, there will be a series of “tie-ins” where the MPD provider will need to draw and discharge fluid. Adequate room beneath the drill floor must be confirmed to ensure the rotating control head will fit. Data exchange between the rig, mud logger and MPD service company must be verified. This is normally simplified by the adoption of WITS. If the MPD service company uses a high-pressure pump, then a high-voltage, high-current supply is required.

Most of this information can be gathered from a rig visit. In an ideal world, the interfaces between the rig, mud logger and MPD service company can be resolved over several weeks, and MPD can start quickly. Drilling is far removed from the ideal world, and so planning normally takes several months. Some
FLOW MODELING

Again, wellbore flow modeling for ABP MPD will be more straightforward than for an underbalanced well. What should not be overlooked, though, is the greater influence surface lines and components will have on the performance and objectives of the well.

What the objectives of MPD are will dictate what evaluations are made with flow modeling. Quite often MPD is being deployed to reduce the ECD, so modeling of different mud weights and properties are necessary to see if reductions can be achieved. However, additional consideration should be given to sensitivity studies into what increases in velocity can be gained by reducing mud weights, what maximum surface pressures are likely, etc.

Flow modeling of pressure loss through the surface lines is paramount for MPD. There have been more than one occasion where this has been underestimated, resulting in surface backpressures affecting the required BHP objectives. Flow modeling should investigate line sizes required (normally 4 in. or 6 in.) and the impact of elbows, pressure loss across the chokes and through a flow meter. It may be necessary to reduce the mud weight by a few points to obtain the same degree of control on the bottomhole pressure if surface pressure are higher than anticipated.

PROCEDURES, TRAINING

As with underbalanced drilling, this is the key to success. Often the planning for MPD is done in isolation from the rig crew and some of the key members of the drilling team. As a result, many people will have apprehensions about MPD. To quell these concerns and to ensure a common understanding is reached among the rig crew, the MPD crew and the operator’s drilling staff, detailed procedures should be developed.

Procedure development normally serves as a learning process for all involved. By writing a procedure, it offers a document around which discussion can be held. As with UBD, the development of a process flow diagram, as a minimum, should be done. It will serve as a record on which line sizes, pressure ratings, isolation valves and relief valves can be captured. If the valves are labeled, procedures can be written to refer to these valve numbers. Several papers have been written on this approach, including SPE/IADC 85294 (“A Safe Approach to Drilling Underbalanced Starts with Project Management,” 2003.)

Time spent on procedures and drawings is seldom wasted. The end product should serve as a tool to be used and updated once at the rig site. More importantly, and what is often overlooked, is that development of both procedures and drawings is what brings all the parties together to reach a common understanding of what is required and the best way it can be achieved.

Procedures should consider both routine operational tasks, as well as contingency mitigation actions identified during HAZID/HAZOP meetings. There must be procedures on tasks such as how to make a connection and how to change out the RCD element. Discussion on RCD element change will lead into the possibility of additional pipework or circulation. If the well is statically overbalanced, surface pressure can be bled off, and the element change-out is simplified. If the fluid is statically underbalanced, then surface pressure must be maintained while changing out the element. This is normally achieved by either trapping pressure or maintaining pressure through the rig’s choke line with the annular and upper pipe rams closed.

At a minimum, contingency procedures should include the failure of BHA non-return valves, failure of surface equipment and failure of the rig equipment. If rig power fails and the MPD pump is powered from the rig, then maintaining surface pressure will be affected. These issues must be thought through in order to have a plan in place. Whilst the solution may be straightforward to some, a common understanding should be developed to ensure that everyone is aware of the contingency plans.

The number of procedures and the complexity of them will likely be driven by the use of an underbalanced or overbalanced drilling fluid.

Training should never be underestimated when contemplating MPD. You get out of it what you put into it. If time does not permit for complete training, the following should at least be understood prior to drilling in MPD mode:

• How a connection is to be made.
• How to change out the RCD element.
• What to do in the event of an influx.

• Who is responsible for what should certain events occur.

What to do in the event of an influx is paramount. The first objective is to decide who confirms an influx has been taken. The MPD operators are monitoring the flow in and out, but they are not well control experts. Training should include the reporting structure so that the correct person is immediately made aware of a possible influx. From there, the sequence of operations should be understood by all.

It may have been planned to circulate out an influx through the MPD equipment, or through the rig’s well control equipment. For the former to occur, all surface equipment must be rated to the maximum anticipated surface pressure. If well control is to be managed between the rig and the company representative, a procedure must be in place to close in the well, estimate the size of the kick and line up to the rig’s well control equipment. As with underbalanced drilling, there will be non-return valves in the BHA, so standpipe pressure can only be established by slowly pumping the non-return valves open.

Because training standards are driven by operator, drilling contractor and regulatory policies, requirements vary widely. NPT on offshore wells with expensive rigs has a greater dollar impact than the same NPT on lower-cost land rigs. However, the science behind MPD does not vary for geographical location, so the same errors will have the same consequences on the well and possibly personnel.

Training on certain ABP MPD wells has relied heavily on the continual supervision by the lead MPD supervisor. Drilling could not wait for MPD training, so many of the procedures were explained to the rig crew whilst on the drill floor. In some cases, the training for a procedure is in the form of a toolbox talk prior to conducting the task. There have been no catastrophes to date, but it is a stressful tour for both groups. In addition, there are no toolbox talks when something goes unexpectedly wrong.

There will always be dependence on individuals such as the driller and MPD supervisor to do the right thing at the right time. However, and, as with many UBD wells, all eyes are on these individuals during MPD operations; so “on-the-job” training only places additional stress on them. When mistakes happen, quite often the root cause leads back to
a lack of training or failure to communicate. Therefore, provision of training that sets out the lines of communications ahead of time will go a long way to avoid these failures.

As an ideal, and based on experience, it is prudent to give a basic introduction about MPD to all office personnel involved in the project. This should include personnel from the operator as well as the drilling contractor. It stimulates thought from all, and the feedback gained is insightful.

As the project develops and procedures and the process flow at the rig site is more clearly understood, a more focused level of training should be given. This need only include those more directly involved in the drilling. These training sessions should be two-way and discuss the procedures and philosophies behind them. If a HAZOP was conducted earlier in the planning stage, then many of these discussions will be a re-visit of issues raised at the HAZOP. However, at this stage, there should be clarity as to who is responsible for what at the rig site.

Practical training inside the casing shoe is always valuable. While it may add time to the well, it will let the rig and MPD crews become familiar with physically conducting the most important procedures. Interaction between the driller and MPD crew is paramount. One is controlling the flow rate in, and the other is controlling the flow rate out. A miscommunication between the two has obvious consequences.

The driller must become proficient in working with the choke operator when bringing the mud pumps up and down so as to maintain accurate bottomhole pressure. In some instances, where backpressure must be captured at the choke, the driller and choke operator must work in unison to avoid deadheading against the choke or trapping insufficient pressure.

EQUIPMENT, CONFIGURATION

In its simplest form, ABP MPD could be run using a RCD and the rig’s well control equipment. The rig choke is used to control backpressure perhaps on connections, and all returns are directed to the shakers. If a more sophisticated set is required, then a RCD will be deployed onto the annular, with a dedicated line to the MPD choke manifold. There may be an MPD pump, pressure-rated isolation valves, a low-pressure flow meter and a return line to the shakers. This again would be the simpler configuration suitable for the majority of the operation.

However, during the planning stage, scenarios may have been considered that require the rig-up of additional equipment. The effects of these scenarios may lead to a similar rig-up ad depicted in Figure 3. Scenarios may include:

- Wanting to do a flow check while holding backpressure on the well. In this instance, it is necessary to line the discharge from the flow meter up to the trip tank. If an MPD pump is being used, it must be able to draw from the trip tank, thus creating a closed flow loop, while being able to hold backpressure on the well.

- Wanting to hold pressure on the well while changing out the RCD element. The simplest means of accomplishing this is to trap pressure below...
the upper pipe rams using the rig’s choke line and choke manifold. As long as pressure does not start to bleed off to the formation, the pressure can be held on the wellbore while the RCD element is changed out. If pressure starts to bleed off, it can be reimposed using the rig pumps down the kill line and across the well head. These may not be the most elegant solutions, and they involve the use of rig BOP equipment. Depending on the operator’s viewpoint, this may not be an acceptable solution.

As with many UBD wells, a secondary flow line between the MPD choke and below the upper pipe rams offers a dedicated line that allows the MPD choke to be in direct communication with the wellbore. If the system uses an MPD pump, the pump can be operating as it would during a connection and back-pressure applied directly to the well. To facilitate this crossover, additional valving and pipework/hose will be required. Care will also be needed to ensure well control equipment is not de-rated by having lower pressure rated lines/valves exposed during a well control event.

• Circulating out background gas. By having a closed system in the form of a RCD installed on the annular, the rig is better equipped to contend with the various forms of entrained gas that may be present in the mud returns. In addition, in HPHT wells where small-volume, high-pressure influxes pose continuous problems, MPD will allow gas to be circulated out without interruption to drilling. To facilitate this, however, a connection to the rig’s mud gas separator (MGS) will be necessary. This will mean an additional line from the back of the flow meter to either the back of the rig choke or inlet into the MGS. This now brings about the possible need for a flow manifold downstream of the flow meter to direct flow to the various discharge points depending on the condition.

• Tripping in and out of hole.

The biggest challenge faced in using a statically underbalanced fluid is getting in and out of the well. If surface pressure is being applied when static, at some point a pipe light situation will occur when pulling out of hole. Solutions to this are similar to UBD. A downhole isolation valve may be deployed to isolate the formation. The mud system can be weighted up, then slowly circulated over to kill the well. This would require a slow circulation to avoid the ECD issues that MPD is being used to mitigate. A heavy pill could be spotted either across the open hole or further up in the cased hole. The well could be isolated using a gunk plug. A snubbing unit could be used to snub in and out of the well. Many options are available, and each has its pros and cons.

Details of isolations valves are fairly well documented. Weighting up mud or spotting pills requires a good and often large mud system. There may be offshore rigs that do not have the pit volume to accommodate this option. Time is also associated with weighting up, circulating and then reducing the mud weight to resume drilling. Use of a snubbing unit requires a lot of planning, personnel and equipment. Trip times are also slowed down. Unlike UBD wells, which may wish to preserve the undamaged formation, MPD will gain fewer benefits from use of a snubbing unit.

There are other issues that may need to be considered, such as what if flow meters start to plug up, what if a line or choke manifold plugs up, leading to excessive backpressure or an overpres-
ABP MPD MOVING AHEAD

MPD service companies are still finding their way in this emerging market. Each have unique products with application to drilling challenging wells. MPD equipment is being improved as feedback from the field and customers define what works, what doesn’t, what is necessary and what is “just nice to have.” All the time, MPD crews are gaining experience, and their numbers are growing. As procedures and process flows for rig-ups become more standard, the need for detailed upfront planning will be reduced.

MPD has been conducted remotely with the backpressure being controlled from the shore for an offshore well. There is, however, a stage before this whereby the flow rate into the well is automatically controlled as part of the MPD process. The technology is there, and its integration will remove a further possible hazard associated with human intervention. At the moment, it is “not necessary.”

The other perspective is that as rig crews become trained in the use of MPD equipment, they will become able to take full control of the choke, so a dedicated MPD crew may not be required. The equipment may end up becoming a rental item called out by the rig, rigged up and operated wholly by the crew.

CONCLUSIONS

MPD in the form of applied backpressure lies between an equivalent conventional well and an equivalent UBD well. Initially, it will cost more than a conventional well, though the initial cost should be less than for a similar UBD well. Being statically overbalanced or statically underbalanced will be the major factor in determining how much planning is required. If formation uncertainties are low and there is a clear understanding of what MPD will deliver, planning may be fast-tracked. Still, certain facets will pay off if done diligently at the start: training, procedures, and a clear understanding of roles and responsibilities at the rig site.

A statically underbalanced MPD well with several uncertainties will require significantly more planning and may reach a level similar to that of an UBD well. Many of the same elements of a UBD well arise in ABP MPD, and failure to consider them could result in significant influxes and well control problems. The difference is that the well is being controlled by two parties – the driller and the MPD choke operator.

Asking “what if” questions will add to the complexity of the well design, as well as equipment, training and procedures, and increase the overall scope of MPD. The key to managing “scope creep” often lies in remaining pragmatic during HAZIDs and HAZOPs. Both serve as great milestones in the planning stage. Control of these events will often control the scope of the project.

As ABP MPD moves forward, the procedures, process flow diagrams and HAZID/HAZOPs will become more standard. At that stage, the planning phase should reduce as the MPD service company swiftly identifies anything unique to a well/rig, makes the necessary changes to standard practices and implements MPD far quicker and safer than possible today.