Managed Pressure Drilling Erases the Lines

Dave Elliott
Shell E&P
The Hague, The Netherlands

Julio Montilva
Shell E&P
Houston, Texas, USA

Paul Francis
The Hague, The Netherlands

Don Reitsma
Jaye Shelton
Houston, Texas

Vincent Roes
Talisman Energy
Calgary, Alberta, Canada

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For generations, prudent drilling engineers have maintained mud density in a well such that its hydrostatic pressure was greater than the pore pressure of the formations being drilled. Engineers today are learning the benefits of managing pressure at the surface to manage drilling conditions downhole, thereby pushing back the limits once imposed on them by wellbore stability and formation-fracture pressures.

Drilling operations exist in a world circumscribed by high and low pressures. The unexpected appearance of either can lead to delays, increased costs and even to failure. With increasing frequency, operators are arming themselves against the consequences of pressure-related surprises with techniques different from those used in the past. One such departure from tradition is called managed pressure drilling (MPD).

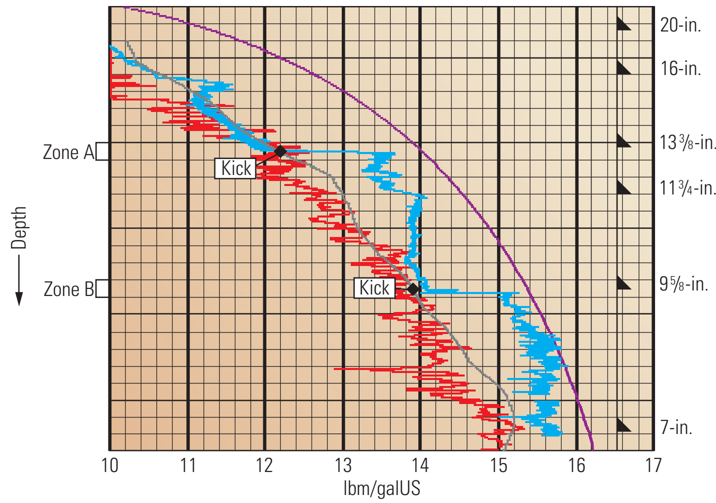
Traditional drilling practices rely on maintaining hydrostatic pressure in the annulus to prevent formation fluids from entering the borehole. Ideally, when drilling fluid, or mud, is circulated down the drillstring and up the annulus, an equivalent circulating density (ECD) is created that is greater than pore pressure, but is below the pressure necessary to fracture the formation being drilled.[1] This pressure is often referred to by drilling experts as the fracture gradient. The pressure range above pore pressure and below fracture initiation pressure is the drilling margin, or pore-pressure–fracture-gradient window. If at any point the ECD goes outside these bounds, operators must set casing and begin drilling the next, smaller hole size.

The practice of maintaining a borehole pressure that exceeds the pore pressure gradient is called overbalanced drilling (OBD). It has been the method of choice for the majority of wells drilled since the early 20th century. But OBD has

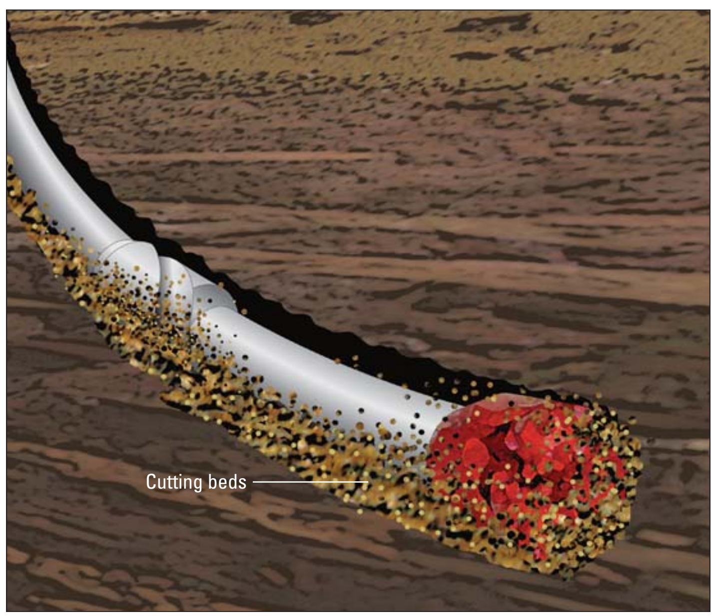
its drawbacks. Foremost among them is its dependence on the use of multiple casing strings to prevent fluid losses as the fluid density required to contain formation pressure is increased and ECD approaches fracture initiation pressure. In some instances, particularly in wells in ultradeep water, pore pressures may be high relative to formation strength even in the shallower sections of the well, which forces the operator to set numerous casing strings before reaching the target formation. The result can be a well whose diameter at TD may be too small to accommodate production tubing large enough to produce economic volumes of hydrocarbons (right). Additional strings of casing usually raise the final cost of the well significantly above initial estimates.

Besides these considerations when drilling overbalanced, mud filtrate and mud solids can cause damage to the formation. When solids invade and are deposited in pore spaces, they may impair productivity and lower ultimate recovery. In addition, high overbalance during drilling can cause differential sticking and other problems related to hole cleaning.[2] Efforts to free stuck pipe routinely result in hours or even days of NPT. In the worst cases, particularly in the presence of other aggravating conditions, such as cuttings beds packing around it, the drillstring may become permanently stuck and the hole may be lost or require a sidetrack (below, right).

The drilling fluids industry has developed chemical additives and practices to reduce the severity and frequency of mud-induced formation damage and stuck pipe. But in the 1980s, as operators drilled horizontal sections to expose enough formation to make their wells profitable, they found it impossible to maintain ECD below the fracture gradient. That is because while the fracture gradient increases with TVD, it remains virtually unchanged from the heel to the toe of horizontal wells; however, as the wellbore lengthens, friction pressure losses increase. Pump pressure must then be increased to maintain

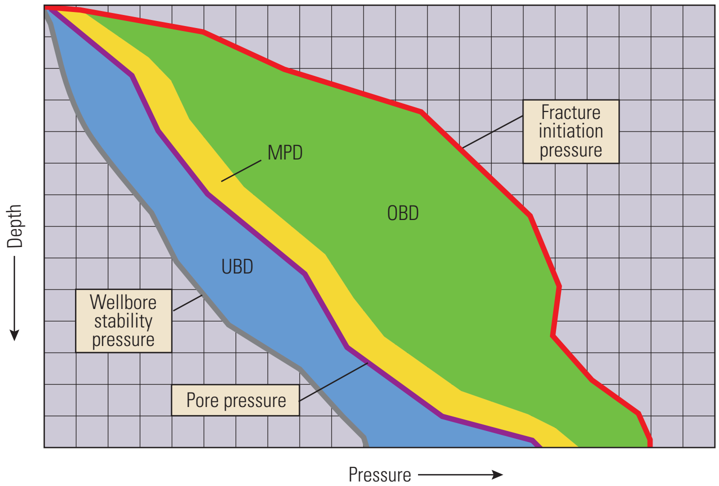


^ Conventional drilling. In response to increased pore pressure (kicks) in zones A and B when drilling overbalanced, the ECD (blue line) is increased by raising mud density, which causes BHP to approach the fracture initiation pressure (purple line). In response, a casing string must be set to protect the formation, which can result in additional casing points and subsequent narrowing of the wellbore diameter (black triangles). In deepwater wells, the window between fracture initiation pressure and pore pressure is often very narrow. In this instance, the operator was forced to set six increasingly smaller–ID casing strings, which resulted in a borehole too small to accommodate economic volumes of oil and gas.



^ Cuttings beds. Though they may occur in any well configuration, beds of cuttings, or solids (light brown), are particularly prevalent in deviated wells where cuttings and cavings settle to the low side of the hole. When the pumps are shut off, the BHA may become stuck in these beds as cuttings and cavings (not shown) slide down the annulus and pack off the drillstring. This phenomenon, known as avalanching, may also occur while pumps are on.

1. ECD is the effective density exerted by a circulating fluid against the formation The ECD is calculated as: ECD = $d + P/(0.052 * D)$, where d is the mud weight in pounds per gallon (lbm/galUS). P is the pressure drop (psi) in the annulus between depth D and surface, and D is the true vertical depth (feet).
2. Differential sticking occurs when the drillstring cannot be moved (rotated or reciprocated) along the axis of the wellbore. Differential sticking typically occurs when high-contact forces caused by low reservoir pressures, high wellbore pressures, or both, are exerted over a sufficiently large area of the drillstring. The sticking force is a product of the differential pressure between the wellbore and the reservoir and the area that the differential pressure is acting upon. This means that a relatively low differential pressure applied over a large working area can be just as effective in sticking the pipe as can a high differential pressure applied over a small area.



^ Managing pressure. Conventional drilling methods are predominantly concerned with containing formation fluid inflow during drilling. This overbalanced drilling (OBD) method uses drilling fluids to create an ECD that results in a BHP greater than pore pressure (purple line) but less than the fracture initiation pressure (red line) of the formation being penetrated. Underbalanced drilling (UBD) is focused on preventing drilling fluid loss to the formation and so maintains an ECD that is less than pore pressure but greater than pressure required to maintain wellbore stability. This allows the formation fluid to flow out of the formation, preventing drilling fluid from flowing into the formation. Managed pressure drilling (yellow) is aimed at overcoming drilling problems by using surface pressure to maintain a constant downhole pressure that prevents the flow of formation fluids into the wellbore while keeping pressure well below fracture initiation pressure. During drilling operations, the ECD of OBD and MPD may, at some depths, be equal.

sufficient circulation rates to lift cuttings to the surface via the annulus. Given sufficient length along a horizontal section, the ECD will result in a bottomhole pressure (BHP) that equals and then exceeds the fracture initiation pressure, with inevitable unacceptable levels of fluid loss.

In wells or sections of wells with very narrow drilling margins, operators have addressed the issue of fluid loss through underbalanced drilling (UBD), during which ECD is kept below the pore pressure of the formation being drilled. As a consequence, fluid from exposed formations are allowed to flow into the wellbore during drilling operations. This prevents drilling fluids from entering even underpressured zones.

But as the industry honed its ability to drill very long extended-reach wells, it was met with challenges other than fluid loss. Operators encountered various pressure-associated challenges while drilling these wells, including wellbore instability and well control problems. Efforts to overcome these challenges gave rise to the development of MPD.[3] MPD is used primarily to drill wells that do not lend themselves to either conventional overbalanced or underbalanced methods, such as in areas where flaring is forbidden, or while drilling through high-permeability formations.

In wells with sufficiently large drilling margins, pressure losses may also be manageable through the manipulation of drilling fluid properties, flow rates and rates of penetration. Drilling fluids experts at M-I SWACO, a Schlumberger company, have developed a micronized weighting agent and a fluid system built around it. The WARP system uses a weighting agent composed of particles ground ten times smaller than conventional barite, with 60% being less than 2 um in diameter. And although accepted wisdom would dictate that such finely ground particles would yield a highly viscous fluid, because of the manufacturing process, WARP fluid systems are characterized by low viscosities, low gel strengths and low sag potential.[4]

Because these characteristics minimize ECD while maintaining good cuttings transport ability, WARP fluid systems are particularly well suited to use with MPD on extended-reach wells. One major operator in the Gulf of Mexico has used the system to drill 13 of its 16 MPD wells.

This article discusses the development and practice of MPD and the techniques and equipment required to execute it. Case histories from US and Australia onshore and offshore wells demonstrate its application in mature fields, high-pressure and high-temperature environments and fractured formations.

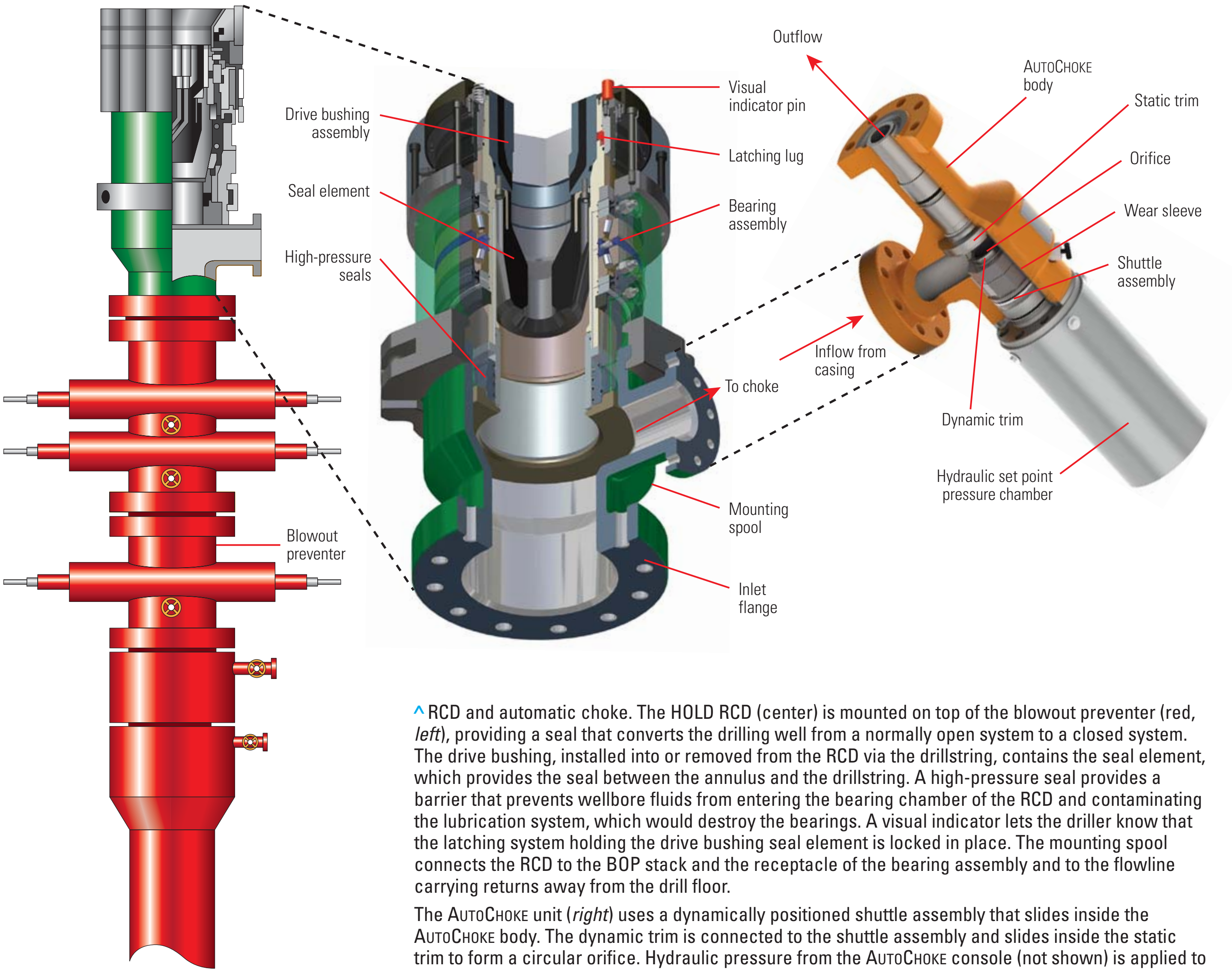
Closed Vessels

Conventionally drilled wells are open systems. As a well is drilled, fluid is pumped down the drillpipe, through the bit and back to the surface along the annulus between the drillstring and the borehole. The return line at the surface—which leads to the shale shaker and mud pits where drilling fluid is processed and stored in preparation for reuse—is open to the atmosphere.

Though they are quite different, UBD and MPD methods use closed systems that deploy a rotating control device (RCD) to divert formation and drilling fluid flow to a separator. Among operators who require two barriers between the well and the surface, the RCD and the drilling fluids are considered primary barriers, and the blowout preventer is a backup. MPD operations use the RCD to create a closed system and a drilling choke manifold and backpressure pump to control downhole pressure. In that way, engineers can maintain a constant BHP during drilling operations while the mud pumps are on and while the pumps are turned off to make connections.

Once the downhole pressure environment has been defined by pore pressures, fracture pressures and wellbore-stability pressures—often through the use of real-time fingerprinting, with annular pressure decreases to induce flow or increases to induce losses—MPD is used to maintain an appropriate annular hydraulic pressure profile. Thus MPD allows operators to keep the ECD within a narrow pore-pressure–fracture-gradient window while still maintaining pressures conducive to wellbore stability. This is accomplished primarily through manipulation of backpressure on the annulus while taking into account factors that affect the ECD such as fluid density, fluid rheology, annular fluid velocity, circulating friction and hole geometry (above left).[5]

Maintaining a constant downhole pressure within the prescribed boundaries minimizes formation damage, prevents mud loss, inhibits formation fluid influx and often results in higher rates of penetration. MPD may permit the operator to extend a casing setting point or even eliminate a casing string. It also offers operators the ability to instantaneously react to downhole pressure variations, which may be used to minimize formation influxes or mud losses without interrupting drilling. Additionally, because its density



^ RCD and automatic choke. The HOLD RCD (center) is mounted on top of the blowout preventer (red, *left*), providing a seal that converts the drilling well from a normally open system to a closed system. The drive bushing, installed into or removed from the RCD via the drillstring, contains the seal element, which provides the seal between the annulus and the drillstring. A high-pressure seal provides a barrier that prevents wellbore fluids from entering the bearing chamber of the RCD and contaminating the lubrication system, which would destroy the bearings. A visual indicator lets the driller know that the latching system holding the drive bushing seal element is locked in place. The mounting spool connects the RCD to the BOP stack and the receptacle of the bearing assembly and to the flowline carrying returns away from the drill floor.

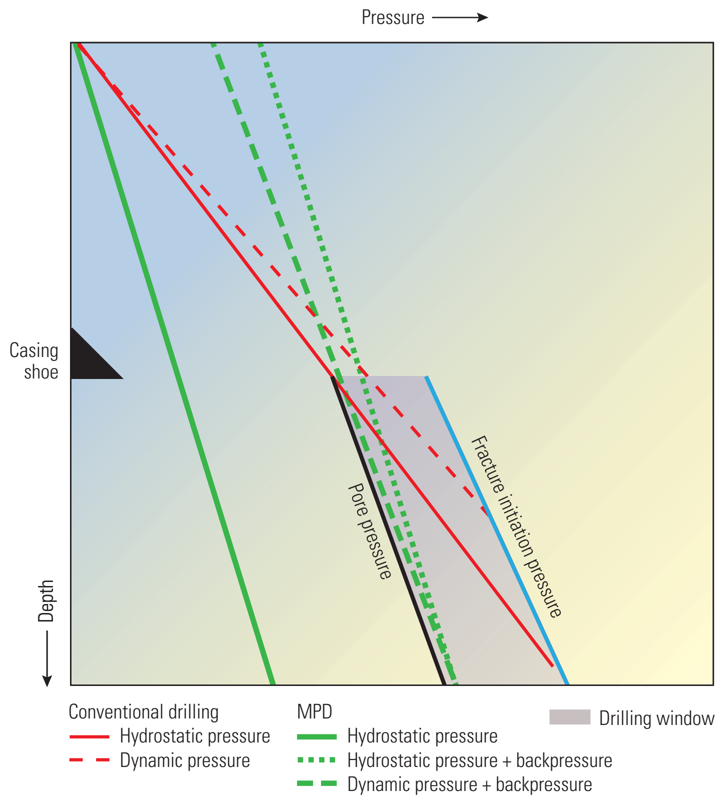
The AutoChoke unit (*right*) uses a dynamically positioned shuttle assembly that slides inside the AutoChoke body. The dynamic trim is connected to the shuttle assembly and slides inside the static trim to form a circular orifice. Hydraulic pressure from the AutoChoke console (not shown) is applied to the backside of the shuttle assembly inside the hydraulic set point pressure chamber, and casing pressure is applied to the front side of the shuttle assembly. If the casing pressure is higher than the hydraulic set point pressure, the shuttle assembly moves back, increasing the orifice size, thus reducing the casing pressure. If the casing pressure is lower than the hydraulic set point pressure, the shuttle assembly moves forward, reducing the orifice size and raising the casing pressure. As the shuttle assembly moves back and forth, it regulates the flow of fluid or gas from the well by automatically adjusting the orifice size as it balances the two pressures.

remains unchanged, there is no need to circulate the mud during these events and so MPD practices save rig time.[6]

Parts That Make the Hole

MPD relies on the driller's ability to maintain, either manually or automatically, a precise target downhole pressure. The key to this ability is the creation of a closed system, which is made possible by the use of the RCD, sometimes called a rotating head. The RCD provides a seal around the drillpipe during rotary drilling operations and diverts drilling fluids to a drilling choke manifold and to the mud pits (above). The choke allows drillers to adjust backpressure on the annulus while the pumps are on and the drilling fluid is being circulated. When the mud pumps are turned off, for example during connections, a dedicated pump supplies required fluid to the system to compensate for the loss of ECD when the system goes from dynamic to static mode.

3. Malloy KP, Stone CR, Medley GH Jr, Hannegan D, Coker O, Reitsma D, Santos H, Kinder J, Eck-Olsen J, McCaskill J, May J, Smith K and Sonneman P: "Managed-Pressure Drilling: What It Is and What It Is Not," paper IADC/SPE 122281, presented at the IADC/SPE Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition, San Antonio, Texas, USA, February 12–13, 2009.
4. Taugbøl K, Fimreite G, Prebensen OI, Svanes K, Omland TH, Svela PE and Breivik DH: "Development and Field Testing of a Unique High-Temperature/High-Pressure (HPHT) Oil-Based Drilling Fluid With Minimum Rheology and Maximum Sag Stability," paper SPE 96285, presented at Offshore Europe, Aberdeen, September 6–9, 2005.
   Sag refers to particles of weighting material settling out of the drilling mud.
5. ECD is often converted to equivalent mud weight in lbm/galUS and is equal to the mud weight required to generate pressure at depth during static operations.
6. van Riet EJ and Reitsma D: "Development and Testing of a Fully Automated System to Accurately Control Downhole Pressure During Drilling Operations," paper SPE/IADC 85310, presented at the SPE/IADC Middle East Drilling Technology Conference & Exhibition, Abu Dhabi, UAE, October 20–22, 2003.



^ Fluid densities and BHP. To keep the BHP between pore pressure (black line) and fracture initiation pressure (blue line) when using conventional drilling methods below a casing shoe, the BHP resulting from the mud weight must be greater than pore pressure so that it may contain formation pressure when the rig pumps are off (solid red line) and less than fracture initiation pressure when the pumps are on (dashed red line). MPD allows the operator to use a drilling fluid that creates a hydrostatic pressure less than pore pressure when the pumps are off (solid green line). When pumps are off, formation pressure is contained by adding backpressure (short-dashed green line) to increase BHP without increasing mud density. When the pumps are on (long-dashed green line), backpressure is reduced to a point that results in a BHP above pore pressure but below fracture initiation pressure.

This manipulation of backpressure in reaction to pressure variations caused by drilling operations is frequently referred to as dynamic pressure control. Downhole pressure is equal to surface pressure plus annular pressure, which is itself made up of a static component and a dynamic component.

Dynamic pressure includes friction pressure losses, and its value is a function of circulating conditions. Therefore, when the pumps are off, the dynamic pressure is equal to zero, and only the hydrostatic pressure of the fluid acts on the formation. Also, during drilling operations with the mud pumps on, dynamic pressure may fluctuate because of variations in the mud pump rate or mud density, or in response to events such as drilling motor stalls, cuttings loading and pipe rotation (above).[7]

With the ability to react to annular pressure variations, the operator can drill with a fluid that creates sufficient ECD to contain formations uphole from the bit, even though the well may become underbalanced when static. Using MPD techniques, the driller can safely stop the pumps while making connections even though the hydrostatic pressure of the mud column alone is less than the pore pressure of the formation.

When wells are drilled through relatively stable formations, with widely separated pore pressure and fracture initiation pressure, there may be sufficient margin to accommodate the difference between dynamic and static downhole pressures. In these cases, reaction to changing conditions need not be overly precise. It is possible to maintain constant BHP through manual manipulation of the choke, mud pumps and dedicated pump.

However, narrow drilling margins, high pressures and temperatures, highly permeable or fractured reservoirs and hole instability are situations for which MPD is particularly suited. These conditions demand adjustments be made with an accuracy and frequency possible only through automated MPD.

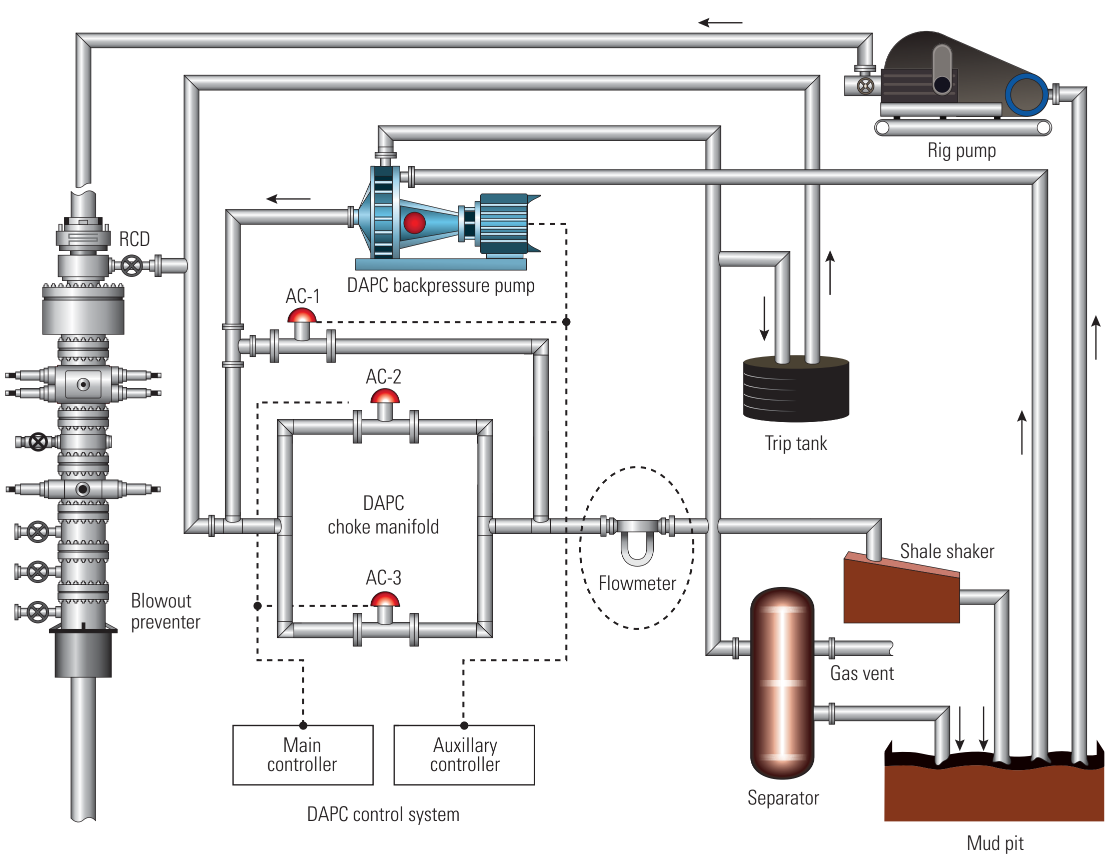
In the early 2000s, engineers at Shell International E&P developed and tested an automated MPD system that incorporated a hydraulically operated choke manifold and connected a positive displacement pump to the annulus.[8] Two computer systems—one to run a hydraulics simulator and another for user interface—and a programmable logic controller adjust the choke manifold. The intent of the automated MPD system was threefold: to automatically calculate in real time the backpressure required to maintain constant downhole pressure, to control the choke and pump that generate backpressure at all times and to provide automatic kick detection.

The resulting dynamic annular pressure control (DAPC) system calculates in real time the backpressure, or set point, required to maintain a desired downhole pressure. It imposes this backpressure on the annulus by continuously adjusting the hydraulically controlled choke and pump settings based on real-time data acquisition (next page).

The control system varies with each application but consists essentially of five parts:
- single-phase hydraulics model
- data communication interface and historical database
- graphical user interface (GUI)
- proportional, integral, derivative (PID) device controller
- programmable logic controller (PLC), sensors and controls.

Drilling engineers use the hydraulics model to calculate the surface pressure set point that will deliver the desired downhole pressure. Input to the model includes frequently changing data, such as pump rate; static values, such as well drillstring geometry; and slowly changing properties, such as mud density and viscosity.

Data are delivered using the wellsite information transfer specifications (WITS) Level II protocol and may be internally measured and logged in a historical database.[9] The GUI allows operators to configure the system with limits on variables, which can be set up to issue warnings when those limits are breached. The GUI is available for manual operation of chokes and valves. The control system, using a PID controller, determines the optimal choke position to control the



^ Automated DAPC system. To maintain constant BHP during transition from drilling to making connections when the pumps are shut off, the DAPC system stabilizes the backpressure by pumping drilling fluid into the choke manifold regulated through choke AC-1. Backpressure is reduced or not applied when the pumps resume for drilling. The DAPC's control system, which is directly linked to the real-time hydraulics analysis and continuous kick detection, stabilizes and controls the BHP through adjustment of the DAPC backpressure pump and chokes AC-2 and AC-3. A flowmeter (dashed oval) connected to the low-pressure side of the choke manifold provides flow-out data, which the pressure manager continuously monitors and compares to flow-in data for kick detection.

backpressure.[10] One PLC runs the PID controllers and another is used as a sensor interface and for choke positioning.

Shell tested the DAPC system in a well-simulation facility that included a fully equipped rig and vertical hole about 1,530-m [5,020-ft] deep, with 5½-in. casing and a 2⅞-in. drillstring run to bottom. The well was configured so that nitrogen could be injected into the annulus to simulate gas kicks. Downhole pressures were recorded in real time.

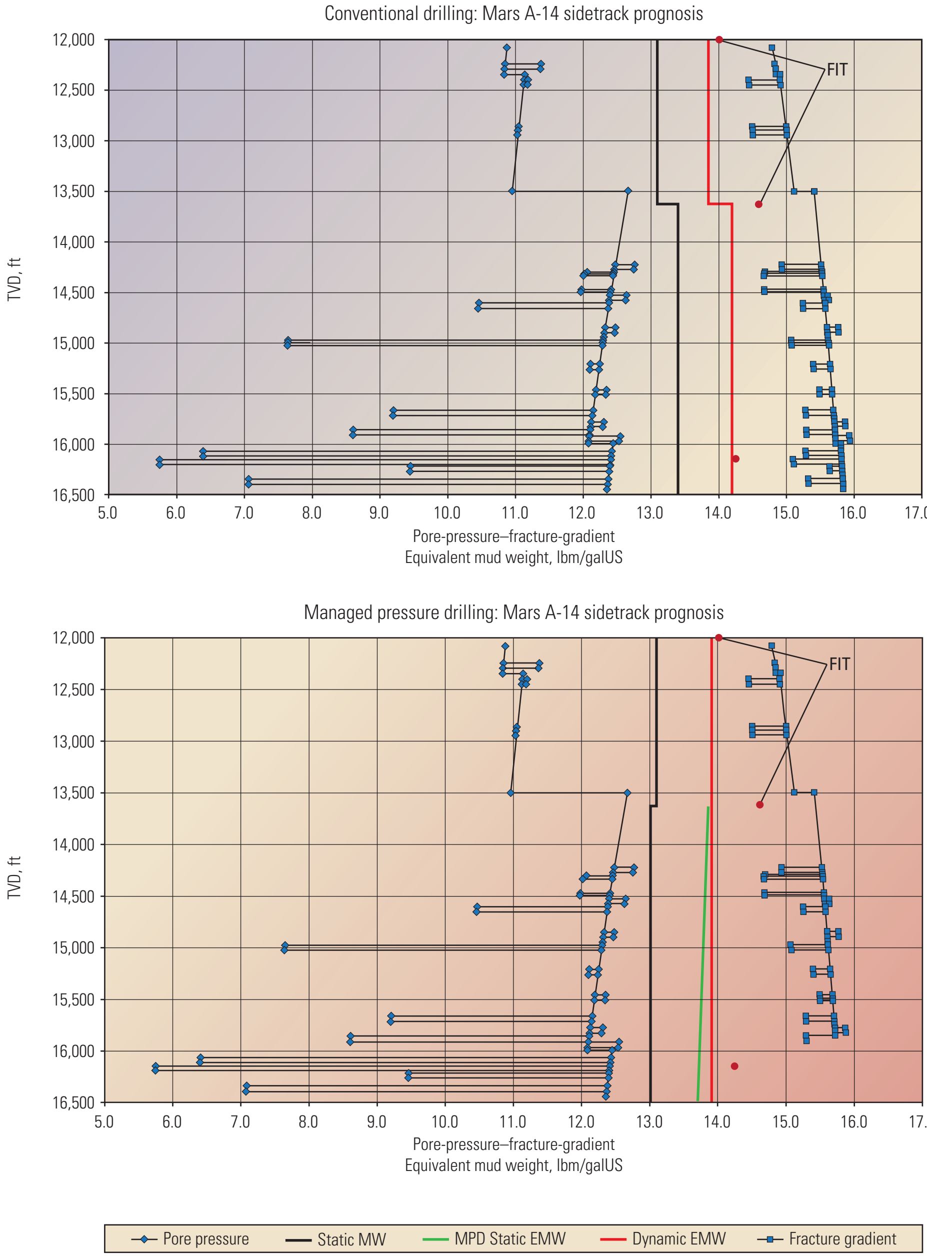
To determine optimal settings, a single operational parameter was changed for each test. Results showed the system was able to significantly reduce pressure variations downhole, and through fine-tuning, engineers were able to further enhance that ability. Test results also indicated that faster cycling of the pumps caused larger pressure variations. Tripping and drilling tests showed the system was able to compensate for pressure variations over a wide range of conditions.

The team also simulated drilling problems such as choke plugging, hole bridging and fluid loss. In all cases, the system compensated for these events and maintained constant downhole pressures. Additionally, the controller was able to use the automated choke and pump to circulate out simulated gas kicks. This was achieved by increasing backpressure at the surface to compensate for the reduction in static pressure caused when nitrogen pumped into the annulus reduced the density of the fluid column.[11]

Taking it to Mars

The Shell DAPC system was first used in deep water at the company's Gulf of Mexico Mars platform located about 130 mi [209 km] southeast of New Orleans in about 3,000 ft [914 m] of water. As in most deepwater fields, the difference

7. Reitsma D and van Riet E: "Utilizing an Automated Annular Pressure Control System for Managed Pressure Drilling in Mature Offshore Oilfields," paper SPE 96646, presented at Offshore Europe, Aberdeen, September 6–9, 2005.
8. van Riet and Reitsma, reference 6.
9. WITS is an industry-standard communications format used to transfer a wide variety of wellsite data from one computer system to another. A WITS data stream consists of discrete data record types, each of which can be turned on and off by the rig operator and assigned sampling rates. WITS also enables computers at remote locations to send instructions to another computer to change parameters, including data type and sampling rate.
10. A PID controller is used in many industrial applications to calculate the difference between a measured variable and a desired set point such as surface pressure. The PID controller attempts to minimize differences between the two by adjusting the process inputs.
11. van Riet and Reitsma, reference 6.



^ Conventional drilling and MPD in deepwater. Diagnoses of two failed sidetracks at the Shell-operated Mars platform led to a prognosis that conventional drilling (*top*) would result in an ECD that was within 0.05 lbm/galUS [0.006 g/cm^3] equivalent mud weight (EMW) of the formation integrity test (FIT) (red dots, *top*) value. Using MPD methods (*bottom*), the EMW could be reduced (green) and, by adding 525 psi [3.62 MPa] annular pressure, the gap between the FIT (red dots) and the ECD would be expanded to 0.3 lbm/galUS [0.036 g/cm^3] equivalent (red dots, *bottom*). (Adapted from Roes et al, reference 12.)

between pore pressure and fracture initiation pressure is often small. In the case of Mars, the field had experienced considerable zonal depletion. This made controlling ECD even more critical and more difficult because deepwater developments typically use high-angle, very long wells to reach stranded or secondary reserves. Consequently, the wellbore must often pass repeatedly through low-pressure depleted zones and high-pressure virgin sands.

Furthermore, hydrocarbon extraction may change rock stress characteristics. Because the wells have been on production since 1996, reservoir and nonreservoir rock formation strength has become reduced. Therefore, lowering mud density has resulted in wellbore instability. However, during attempts to sidetrack the Mars A-14 well, the use of high-density drilling fluids caused lost-circulation problems in depleted zones.

The A-14 well targeted the waterflooded M1/M2 reservoir that contained the majority of the field's reserves. In May 2003, it had been shut in because of sand production; sidetrack operations to reenter the M1/M2 reservoir were begun in 2004. The first attempt failed when the BHA was lost at 21,144 ft [6,445 m] MD, 16,340 ft [4,980 m] TVD, due to lost circulation and wellbore stability problems. An attempt to sidetrack from the previous casing shoe failed when the same problems prevented engineers getting an expandable liner to depth.

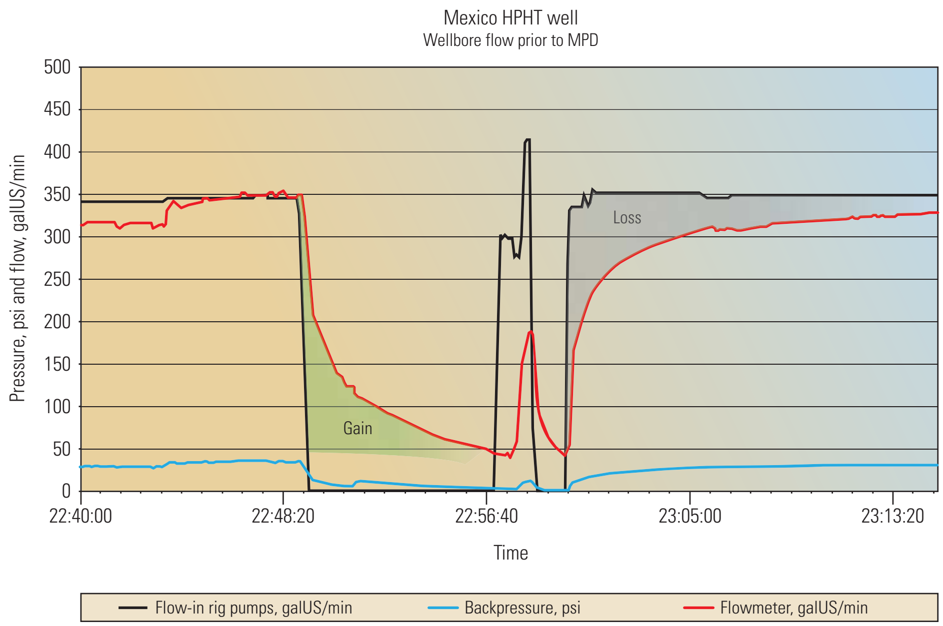
Shell turned to the DAPC system developed by its E&P research arm. At the Mars platform, the DAPC control system was modified to communicate with a third-party choke controller system. The DAPC controller was therefore limited to determining the necessary backpressure and communicating that to the choke controller system.

BHP was calculated in real time using a Shell hydraulics steady-state model that contained static data such as mud weight, BHA configuration, well geometry and directional data, and was updated by rig data every second. Though there was generally good agreement between model and measured BHPs, string rotation was not properly compensated for, which resulted in the actual equivalent mud weight of the BHP being about 0.2 lbm/galUS [0.024 g/cm^3] higher than the model. To address this, the model was manually adjusted with corrected values.

The well was drilled to TD using a mud density of 13.1 lbm/galUS [1.57 g/cm^3], which is 0.3 lbm/galUS [0.036 g/cm^3] less than the previous two attempts. This was made possible by using the DAPC to maintain a BHP set point equivalent to 13.7 lbm/galUS [1.64 g/cm^3] (previous page). Using these specifications, there were no indications of hole instability or lost circulation and the liner was run without incident.[12]

Following this success, Shell chose to use MPD on 11 more wells. In one field, after repeatedly failing to reach TD using conventional methods, engineers reached target depth in six of six tries using MPD. The program was so successful in the maturing field, production facilities reached capacity.

MPD proved to be the solution in two more Shell-operated deepwater fields and six more wells with similar challenging relationships between fracture initiation pressure, pore pressure and wellbore stability. Shell is also applying the technique in other challenging circumstances including cementing wells that prove difficult because of depletion, safely penetrating high-pressure, high-temperature (HPHT) sections and for drilling wells that are otherwise impossible to drill within existing HSE standards.



^ Fingerprinting flowback. This fingerprint of the flowback in one high-pressure, high-temperature (HPHT) well in Mexico was recorded during the second connection by the DAPC system before MPD operations. The volume of flowback, or gain, after the pumps are turned off (green shaded area) is complemented by the losses (gray shaded area) when the pumps are turned back on and the operator goes from static to dynamic drilling mode. (Adapted from Fredericks et al, reference 13.)

High Pressure, Depletion and Cement

MPD is particularly suited to wells targeting high-pressure formations. The subsurface in which these wells locations are found is often marked by uncertain pressures, complex lithology and indeterminate flowback, which is the volume of drilling fluid that flows from the annulus after the mud pumps are shut off. Additionally, in highly pressured formations, apparent kicks, if misdiagnosed or mishandled, are more likely to become well control events than in normally pressured environments.

Typically, HPHT wells are further complicated by narrower drilling margins and little offset well information. Faced with one or both of these situations, drillers must be prepared for the consequences of higher-than-anticipated pressures even when dealing with routine situations. For example, during traditional drilling operations, multiple prediction and detection methods help reduce uncertainty related to pressure. However, some operators are loath to rely on the practice of pore pressure prediction in HPHT wells.

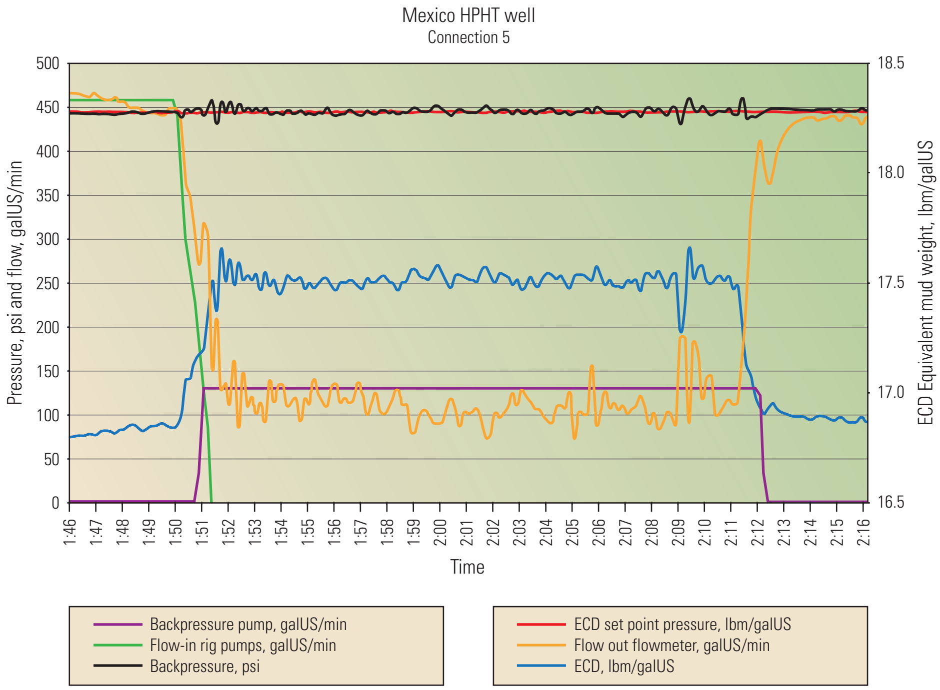
Shell uses MPD equipment on wells characterized by a high degree of pressure uncertainty. By routinely and intentionally inducing flow during MPD operations—essentially using both UBD and MPD in different sections of the well—engineers are able to determine pore pressure in real time. Armed with accurate pore-pressure data, the operator can drill ahead while maintaining a constant bottomhole pressure to stay within the drilling window. Additionally, Shell manipulates the drilling fluid systems to strengthen the borehole, effectively altering the fracture gradient and thus expanding the drilling margin.

Unusual flowback volumes are often an indication of what is known as wellbore breathing or ballooning. This phenomenon occurs when drilling-induced fractures absorb a volume of drilling fluid. When the pumps are shut off and the ECD is reduced, these fractures close and expel the fluid, resulting in flowback at the surface. By recording the flowback volume before and immediately after drilling out of casing—a process known as fingerprinting—drillers can establish a baseline flowback volume to be expected from a particular well when the pumps are shut off (above). When the flowback volume exceeds the fingerprint volume, the excess is often mistakenly interpreted as a kick, a pressure-induced influx of formation fluids rather than wellbore breathing.

Drillers react to a kick by increasing mud density. However, doing so when the volume gain is due to wellbore breathing can have serious consequences; an increase in mud density may turn a slightly overbalanced condition into a severely overbalanced condition that causes even greater fluid loss.

By drilling with an MPD package and maintaining a constant BHP, engineers can eliminate not only the pressure fluctuations between dynamic and static drilling modes that cause

12. Roes V, Reitsma D, Smith L, McCaskill J and Hefren F: "First Deepwater Application of Dynamic Annular Pressure Control Succeeds," paper IADC/SPE 98077, presented at the IADC/SPE Drilling Conference, Miami, Florida, USA, February 21–23, 2006.



^ No wellbore breathing. Pressure data recorded by DAPC during the fifth connection on the same HPHT well as in previous figure show no signs of wellbore breathing (orange line). As the rig pumps are cycled (green), the DAPC backpressure pump pressure and rate (black and purple lines) are increased or decreased automatically to maintain the ECD set point pressure (red line) and density (blue line) in both dynamic and static drilling modes. The absence of gains or losses due to flowback or wellbore breathing indicates the well is at equilibrium at this constant BHP. (Adapted from Fredericks et al, reference 13.)

wellbore breathing but also any possibility of misdiagnosis (above). Moreover, the accuracy and speed with which they can react to pressure variations make automated MPD systems well suited to quickly identifying and addressing numerous common drilling hazards before they become issues.[13]

In some cases, once drilling hazards have been identified, MPD practices may be used with other technologies to overcome them. In the Shell-operated McAllen-Pharr field in Hidalgo County, Texas, USA, for example, the operator was faced with drilling through produced zones in which depletion prediction was complicated by difficult-to-map faulting. Additionally, zones that had been depleted to as much as 5,000 psi [34 MPa] below original pressure were often found between layers of overpressured virgin sands, which made isolating them with a drilling liner impractical.[14]

In nearby fields, as a consequence of raising mud weight in preparation for tripping out of the hole, the operator had experienced severe fluid losses when the liner setting point was reached. Liner or casing drilling—in which the drillstring is replaced by a liner or casing that can be left in the hole, thus eliminating tripping and the need to raise mud density—was used to solve the problem in those wells.

Liner drilling worked in these fields because the low permeability of the zones being drilled prevented flow into the wellbore even when the pumps were shut off and the equivalent mud density fell below pore pressure. Uncertainty about pressure and an expectation of high permeability made use of this strategy alone untenable in the McAllen-Pharr field.

Shell turned to automated MPD equipment, adapting its system to onshore applications. Engineers decreased the size and weight of the choke manifold by reducing the number of chokes, valves and bypass lines, which also drove improvements to the hydraulic power system. The reduced manifold moved from a three-choke to a two-choke design, with one choke dedicated to backpressure management and the other to duty as both a backup and for automated pressure relief.[15] A rig pump, rather than a dedicated pump, provided backpressure when the primary mud pumps were off.

The first well in the field drilled with the modified unit, the Bales 7, was characterized by complex faulting and little offset data. This made it difficult to predict the pore-pressure and fracture-gradient regimes in the target reservoir sands through which Shell intended to drill.

The operator's plan called for a 7⅝-in. casing shoe at about 8,700 ft [2,652 m] MD. A 2,100-ft [640-m] horizontal reach was then to be drilled conventionally in an S-shaped trajectory along a 19° tangent.[16] Next, a 6½-in. hole was to be drilled vertically using jointed pipe and automated MPD to 10,360 ft [3,158 m]. From there the 6½-in. section would be drilled to 11,065 ft [3,373 m] using casing drilling and MPD (next page). The entire 6½-in. section was to be drilled statically underbalanced.

The ECD set point was 14.15 lbm/galUS [1.7 g/cm^3] at the casing shoe, increasing to 14.9 lbm/galUS [1.8 g/cm^3] at TD. On average, the system controlled the ECD to within ±0.12 lbm/galUS [0.01 g/cm^3] of the set point by continuously managing the backpressure between 100 and 200 psi [0.7 and 1.38 MPa]. In the section drilled with conventional drillpipe, this included 16 pump transitions; during these times the pumps were turned off and on for 15 connections and one time to replace leaking seals in the rotary control device.

The second section of the 6½-in. hole met with pore pressures of at least 1.5 lbm/galUS [0.02 g/cm^3] higher than any encountered uphole. Combined with expected depletion levels, it was determined that fluid losses would be too great with a conventional drilling assembly, so engineers opted to casing drill to final TD.[17] Static mud weight for the entire section was 15.7 lbm/galUS [1.8 g/cm^3] and ECD was a constant 16.2 lbm/galUS [1.9 g/cm^3].

Though gas flowed from the well during drilling and the flow volume increased with depth, BHP was held constant to within an average equivalent mud weight of ±0.18 lbm/galUS [0.02 g/cm^3], including through 13 pump transitions. Using MPD to avoid losses while maintaining a constant ECD, engineers reached TD with a 3½-in. casing drillstring.

Finally, engineers used automated pressure control practices to cement the production casing, holding 90 psi [0.6 MPa] of backpressure while circulating bottoms up ahead of cementing. Once returns were stabilized, the pumps were shut down to install a cementing head and the BHP held constant by application of 200 to 210 psi [1.38 to 1.45 MPa] backpressure. After the spacer was pumped, the choke was used to maintain a constant 16.2 lbm/galUS [1.9 g/cm^3] ECD during cementing. As a result, the well was successfully cemented with no fluid losses.

While liner drilling the McAllen-Pharr wells using MPD equipment, gas was circulated through the gas buster. In order to minimize fluid losses, mud weight was occasionally adjusted. Shell used this melding of MPD, UBD and casing drilling to expand its casing drilling program to other fields in South Texas and to avoid the significant expense of using a liner as part of a contingency plan.[18]

Drilling the Impossible, the Very Hot and More

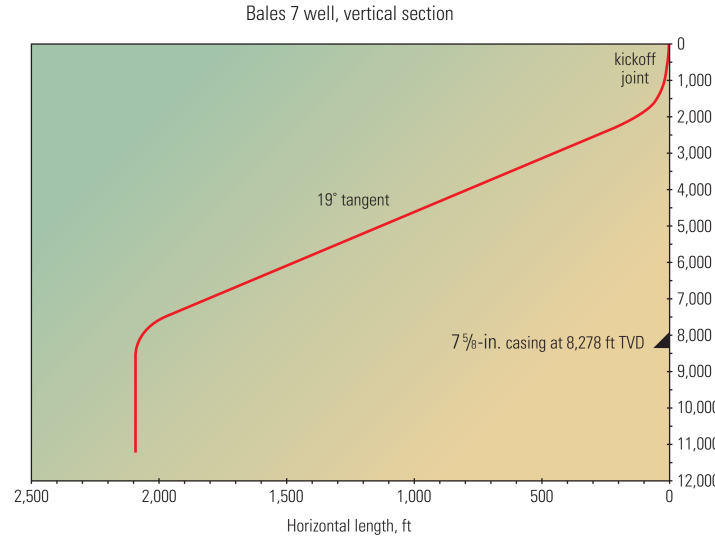
Using externally applied backpressure in a closed drilling system to maintain a constant downhole pressure is a relatively new approach to drilling through narrow drilling margins. Operators continue to discover new applications for MPD as they seek answers to unique pressure-related drilling challenges.

For example, in maturing basins, operators often opt to drill sidetrack wells from existing wellbores to reach stranded reserves with which to shore up falling production. These efforts are often hampered, however, by high annular fluid losses as wellbores pass through depleted zones. Conventional drilling practices in this environment frequently fail to access the stranded oil because of drilling issues such as stuck pipe or difficulty running casing.

While MPD would seem a likely solution, the challenge is further complicated because these slimhole sidetracks are drilled traditionally using positive-displacement motors. These motors create continuous fluctuations in ECD as they move from sliding to rotating mode, making constant BHP nearly impossible. The solution for one operator in the Gulf of Mexico was MPD in combination with a new generation of rotary steerable tools and pressure-while-drilling sensors.[19] Based on this company's success, operators throughout the Gulf are reevaluating opportunities for extending life and profitability from mature fields through slimhole sidetracks.

In Australia, while drilling wells for a geothermal project in the Cooper Basin, Geodynamics Limited found that the granite basement was unexpectedly overpressured by as much as 5,200 psi [36 MPa]. Additionally, the existing stress regime of the granite created conditions that led to kicks and fluid losses. In this first well, drilled using conventional techniques, the operator incurred considerable NPT when it was forced to use a 4.0-lbm/galUS [0.5 g/cm^3] mud density increase to control and kill a fluid influx from the overpressured basement.

The operator then turned to DAPC to maintain the delicate balance between the overpressure and fracture gradient on the next two wells. On the second well, engineers used the system to control and kill a fluid influx in 90 minutes while raising the mud density by only 0.7 lbm/galUS [0.1 g/cm^3]. They also used the system to maintain a constant ECD by manipulating the backpressure between 220 and 295 psi [1.5 and 2.0 MPa] during drilling operations and 525 and 625 psi [3.6 and 4.3 MPa] during connections.[20]



^ Wellbore profile. The Bales 7 well was drilled as a high-angle well to the 7⅝-in. casing point and then turned vertical. The production section was then drilled in two steps aimed at addressing varying pore pressure and fracture initiation pressure regimes that engendered fluid loss in some sections and gas influx in others. (Adapted from Montilva et al, reference 14.)

The Proper Tool for the Proper Job

Due to its flexibility and continuous flow and pressure control, MPD is often a safer and less costly drilling method than either under- or overbalanced drilling. This is especially true for environments with narrow or unknown drilling margins. MPD has been used, for example, in forestalling kicks while crossing the rubble zones in subsalt drilling. It has also been used to replace Coriolis mass flowmeters—which can be sensitive to entrained gas and vibration and highly susceptible to poor maintenance—for early kick detection.[21]

Getting the most value from MPD requires it be applied in drilling situations for which it is best suited. While it is often and correctly viewed as a way to successfully drill wells that would otherwise not reach their targets, it should be thought of neither as the answer to all drilling problems nor the method of last resort. The most appropriate candidates for MPD are for wells with offsets characterized by wellbore instability, excessive drilling fluid losses or those that will be drilled through pressured, virgin zones and depleted, or otherwise underpressured ones. Those parameters alone suggest the number of wells that are good MPD candidates is quite considerable. —RvF

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