SPE/IADC-221433-MS

MPD Deepwater Drilling: A Case Study of MPD Surface Back Pressure Implementation for a Sidetrack Exploration Well in the Gulf of Mexico

R. A. Gonzalez Luis, Technology Development Engineer, Blade Energy Partners, Frisco, Texas, United States of America; R. Happoff, E. Meyer, and K. Hampshire, Murphy Oil Corporation, Houston, Texas, United States of America; A. Taques and N. Scott, Blade Energy Partners, Frisco, Texas, United States of America; L. Duong and I. Barker, Noble Corp, United States of America

This paper was prepared for presentation at the SPE/IADC Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition held in Rio de Janeiro, Brazil, USA, 17 – 18 September, 2024.

Abstract

Managed Pressure Drilling (MPD) was identified as the differentiating technology to successfully execute a sidetrack deepwater exploration prospect in the Gulf of Mexico. Conventional drilling efforts were suspended on the original hole due to multiple pressure management issues, such as losses, ballooning, and wellbore instability. MPD was selected as an enabler for overcoming these challenges. The sidetrack was planned to exit the existing 14-inch casing and run three additional strings of casing/liners to a planned total depth (TD) over 31,000 ft MD. MPD was strategically integrated to address operational hurdles and acquire valuable subsurface data. MPD enabled the liners' shoe to be set deeper in two sections than the original wellbore, increasing the probability of reaching well TD. Given the well's exploratory nature and lack of offset information, a statically underbalanced mud was used, giving maximum flexibility to manage and test the pressure profile. MPD techniques for real-time pressure estimation were successfully used to obtain critical reservoir information.

This paper offers a comprehensive overview of the sidetrack design, delineating some operational challenges. It also delves into MPD's role in effective equivalent circulating density (ECD), mud weight (MW) management, and tripping strategies needed to comply with regulatory requirements. By presenting key highlights, lessons learned, and recommendations gathered from the operation, this case contributes to the understanding and application of MPD in deepwater exploration.

Introduction and Background

In deepwater operations, where extreme pressures and uncertain formations pose significant risks, MPD provides a tool to enhance safety, mitigate drilling hazards, and optimize well construction (Gabaldon et al., 2020; Moghazy S. et al., 2020). By precisely controlling the wellbore pressure, MPD enables operators to account for pore pressure/fracture gradient uncertainty, proactively manage influxes/losses, and minimize the risks for loss of well control, thus safeguarding both personnel and the environment.

Additionally, MPD reduces non-productive time due to pressure-related issues (e.g., ballooning) and improves drilling efficiency (e.g., ROP improvement), thus enhancing overall project economics. Its ability to adapt to and manipulate downhole conditions almost instantly and its compatibility with advanced drilling technologies make MPD indispensable in unlocking the vast potential of deepwater reserves while maintaining operational integrity.

The work presented in this paper discusses the drilling of a deepwater exploration well and its sidetrack with limited offset information. The original well was spud in late 2022 and drilled conventionally to a total depth of slightly over 24,680 ft, which was #6,600 ft shallower than the planned total depth of the well. The original wellbore was planned for slightly over 50 days, and it was temporarily abandoned in early 2023 due to critical risks associated with narrow margins, wellbore instability, and pressure-related issues, which accounted for slightly over 90 days of operations without reaching the well objectives. Significant challenges in the original well were observed, including the inability to reach planned casing setting depths (running out of contingencies), ballooning, losses during drilling and cementing operations.

Based on these results, a sidetrack out of the 14-inch. casing below a salt suture, was proposed to reach the target formations. The sidetrack well discussed in this paper was drilled using a seventh-generation deepwater drillship, and the MPD system was owned/procured and maintained by the rig contractor. The drillship had been used to drill multiple offshore wells with MPD, starting with the initial campaign in US-GoM in 2016, followed by international assignments in Mexico, Columbia, and Suriname. The institutional MPD knowledge of key drilling rig team personnel was a distinctive advantage.

There were significant operational challenges faced during the original wellbore drilling efforts; these included:

- High level of subsurface uncertainty, with potential for narrow drilling margins (<0.5 ppg).
- Inability to manage mud weight (MW) and equivalent circulating density (ECD) within the available operational window through hydrocarbon zones.
- Higher than expected annular friction losses.
- Bottomhole pressure-related issues, such as differential sticking and ballooning.

Anticipating similar challenges on the sidetrack, the operator planned to employ the surface back pressure (SBP) MPD system with CBHP (constant bottom hole pressure) as a new technology application in this prospect. The utilization of MPD was aimed at enhancing safety and increasing the likelihood of successfully reaching the well's target depth. An overview of the main goals of the technology is presented below:

- Maximize the probability of achieving the planned Target Depth (TD) of the well by managing the annular pressure profile throughout the operation, i.e., drilling and connections.
- Manage pore and fracture pressure uncertainty with the ability to navigate tight margins and pressure ramps without compromising shoe integrity. There was the potential for steep pressure ramps leading to narrow drilling margins (<0.5 ppg) and abnormally pressured sands. This was identified during the early planning stages, and contingencies were managed through the MPD design and engineering.
- Real-time pressure profile testing Dynamic Step Down Test (DSDT), Dynamic Step Up Test (DSUT), and Dynamic Leak of Test (DLOT) to map out subsurface pore pressure/frac gradient boundaries accurately. The DSUT is an example of this application, as it was used to test the upper end of the drilling margin at critical depths (e.g., Base of Salt). This increased the operational window by 0.1+ ppg from a theoretical weak point to a measured point.
- Minimize the potential for instability by reducing pressure cycling between pumps on and pump-off operations.

- Optimize casing design by safely reducing kick tolerance limitations through dynamic influx management, enhancing the safety of early kick and loss detection (EKLD), and combating and mitigating pressure-related problems presented in the original well operations. This was extremely important for setting the liner shoes at critical depths (deeper than the original hole set points), maximizing the likelihood of reaching the well objectives.
- Improved early kick and losses detection (EKLD) and Dynamic Influx Management (DIM). Adjusting surface back pressure allowed quick reaction to unexpected loss/gain events, thus reducing the likelihood of inducing ballooning, loss/gain events, and associated NPT

Overview of Managed Pressure Drilling (MPD) System

SBP MPD systems incorporate a rotating control device (RCD) and choke to establish a closed-loop mechanism. This configuration enables the addition or subtraction of SBP to manipulate the annular pressure profile. Common variants include maintaining constant bottom hole or anchor point pressure under dynamic and static conditions. In MPD applications, bottom hole pressure (BHP) comprises the hydrostatic pressure of the drilling fluid, annular friction losses during circulation, and the applied SBP. The closed-loop system design ensures flow-in equals flow-out, facilitating precise detection of any wellbore losses or gains. Utilizing a Coriolis mass flow meter, the MPD system accurately measures the flow out versus the flow from mud pumps, monitored through stroke counters or other means. These features enhance the efficiency and safety of drilling operations by enabling rapid detection and response to unexpected margin-related events that can happen nearly instantaneously.

A risk assessment (Hazop/Hazid) was facilitated to review the MPD system on the drillship and determine any potential issues that would require attention before operations. A high-level overview of the main components of the MPD system (see Fig. 1) is outlined below, and their pressure capabilities:

- *MPD riser joint (also known as IRJ, see* Fig. 2). This riser joint contains the rotating control device (RCD), an annular blowout preventer (BOP) used as a backup isolation tool, and the flow spool where two flowline hoses are connected to send drilling fluid returning from the well to the Buffer and MPD choke manifolds installed on the drillship. The main three components in this joint are the RCD, the riser isolation device, and the flow spool. All these components are remotely controlled and have choke/kill and booster auxiliary lines. The riser system pressure rating was set based on a riser analysis study, which accounted for the maximum MWs and SBP estimates for every section.
    - *Rotating Control Device (RCD)* is a hydraulically controlled wellbore dual sealing system designed to trap pressure while diverting the returns to MPD surface equipment via a flow spool and hoses. The RCD was API 16RCD qualified. RCD operational pressure rating depends on multiple factors, including the sealing element compound, mud type, drill pipe size, and RPM. Thus, the project team agreed on the following limits: a) dynamic rotating working pressure of 1,200 psi at 90 rpm, b) 1500 psi at 50 rpm for stripping operations, and 2000 psi for static operations.
    - *A riser isolation device is used to close the riser for RCD seal sleeve change-outs under pressure,* holding MPD SBP and RCD contingency/redundancy. This system had a maximum of 2,000 working pressure on pipe, a 1,000-psi closed without pipe, and a 1,500-psi maximum hydraulic operating pressure.
- *The MPD Choke Manifold* controls the SBP applied to the well at any time. The robust manifold comprises four legs (for redundancy), each with two sizes (i.e., 6 in. and 3 in.) of electrical chokes. Normal operations are planned to be conducted with either size choke, thus allowing flow to be routed through alternative flow paths, if required. The manifold is controlled by a proprietary MPD control system that monitors and adjusts the required SBP in the well using the MPD chokes. Note

that the MPD control system was integrated with the drilling control system and, with a proprietary hydraulic model, formed a single integrated control system with the inputs and outputs of both drilling and MPD systems detailed within the rig. The working pressure rating of the manifold is up to 3,000 psi.

- *Flow Meter Manifold*: The MPD system has two 8-in flow meters on the return side. The Coriolis flow meters are downstream of the MPD chokes. Normal operations were planned to be conducted with one flowmeter, which would be isolated and replaced in the event of failure. The pressure rating of the flow meter manifold was 1,440 psi at a maximum flow rate of 2,000 gpm.

The lowest pressure-rated equipment limits this MPD system's pressure rating. In this case, the flow meters (up to 1,440 psi). With the RCD installed under the tension ring, the circulation system becomes a closed fixed-volume system, improving early kick and loss detection ability.

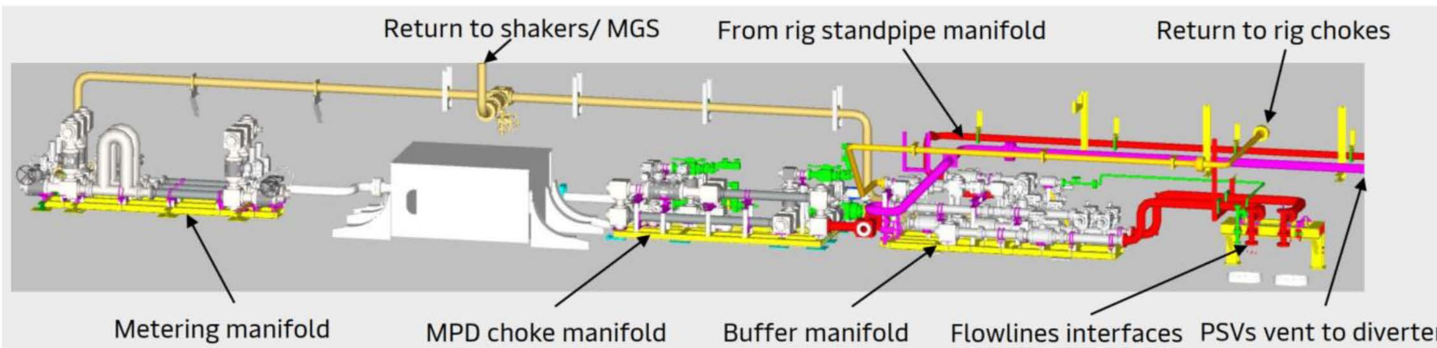


Figure 1—High-Level Rig's MPD Equipment Set-Up (Courtesy of Noble)

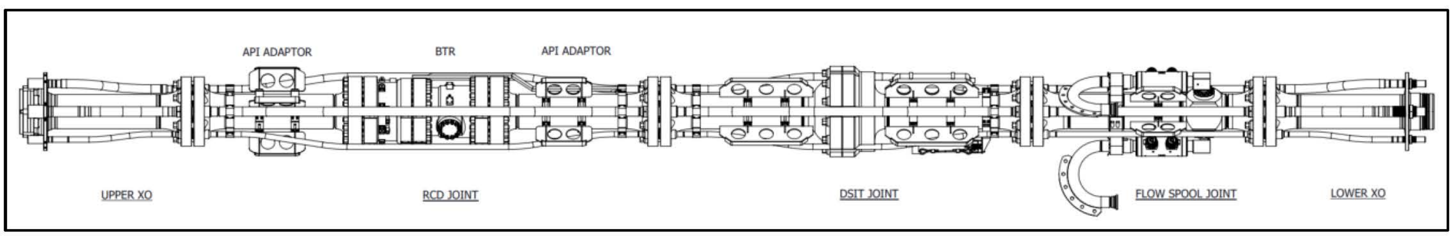


Figure 2—Rig's Integrated Riser Joint (Courtesy of Noble)

Managed Pressure Drilling (MPD) Strategy Overview

MPD Design and Engineering

Based on a conventional approach for well design, kick tolerance, and drilling/operating loads, the operator had a preliminary sidetrack plan. Once MPD was selected as an enabling technology, MPD well design and strategy were integrated into the original plan to optimize the sidetrack design. Design concerns such as the mud weight (MW) and surface back pressure (SBP) ranges, MPD anchor point (AP), and casing seat selection were methodically optimized to provide the required drilling window to reach each section's desired TD that was necessary to meet the well objectives. The MPD adaptive well design approach has recently become more widely used (Gabaldon et al., 2020; Moghazy S. et al., 2020). One key aspect of this approach is the ability to measure the operating window via real-time and dynamic pressure measurements. By incorporating these measurements, the well design can be further optimized based on actual well conditions and a more precise kick tolerance approach. This approach provides additional flexibility for multiple well configurations that can be incorporated into the drilling program, thus building operational flexibility.

Pore pressure and fracture gradients were initially assumed based on offset data. The initial planning was centered on the "base" case pore pressure fracture gradient (PP/FG) profiles (see Fig. 3). MPD played a significant role in validating and determining these pressure limits and adjusting the planned strategy to manage the BHP based on combinations of mud density and SBP and circulating flow rates. Figure 4 presents the (a) original wellbore plan, (b) the original wellbore actual, and (c) the sidetrack actual configurations.

Based on the significant amount of subsurface data gathered during the drilling of the original wellbore, especially in the intermediate sections, it was determined that a conventional approach would not be feasible for drilling the sidetrack. The design would require an additional casing string, leading to higher ECDs and a reduced drilling margin, and represented a significant risk to reaching the wells' target objectives. The base plan was to drill the well to a maximum TD over 32,000 ft MD. Given the significant uncertainty in PP/FG and the potential for higher than prognosed limits, the alternative sidetrack plans were explored using a contingency 7-¾ -inch liner and drilling an additional 6-1/2 × 7 1/2-in. hole section. A different approach was needed to manage the risks better, and thus, it was essential to incorporate MPD as an enabling technology.

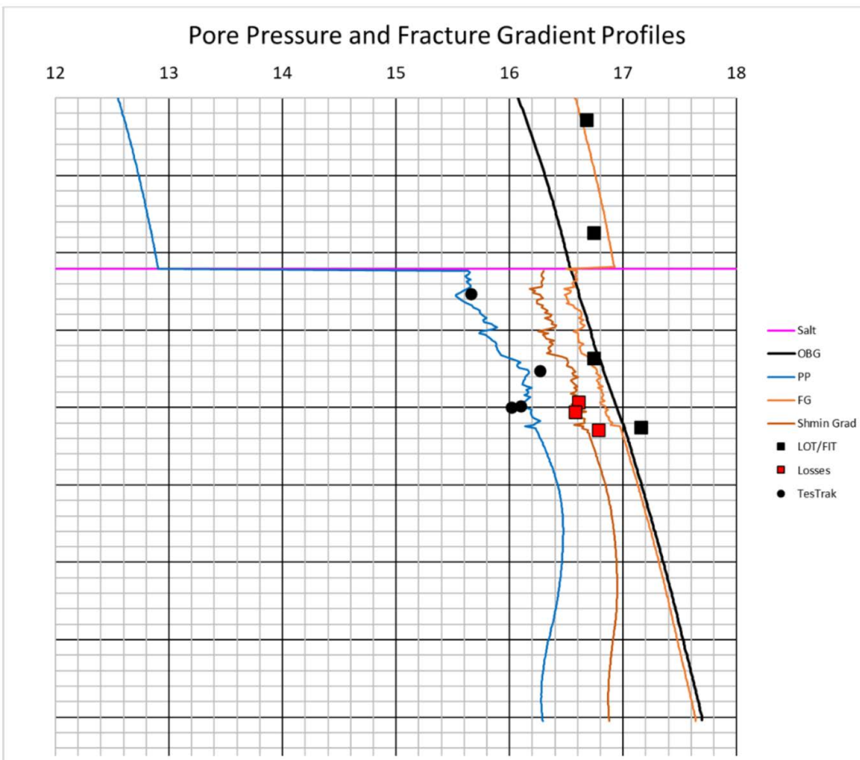


Figure 3—PP/FG scenarios demonstrating an example of the expected pre-sidetrack drill subsurface uncertainty

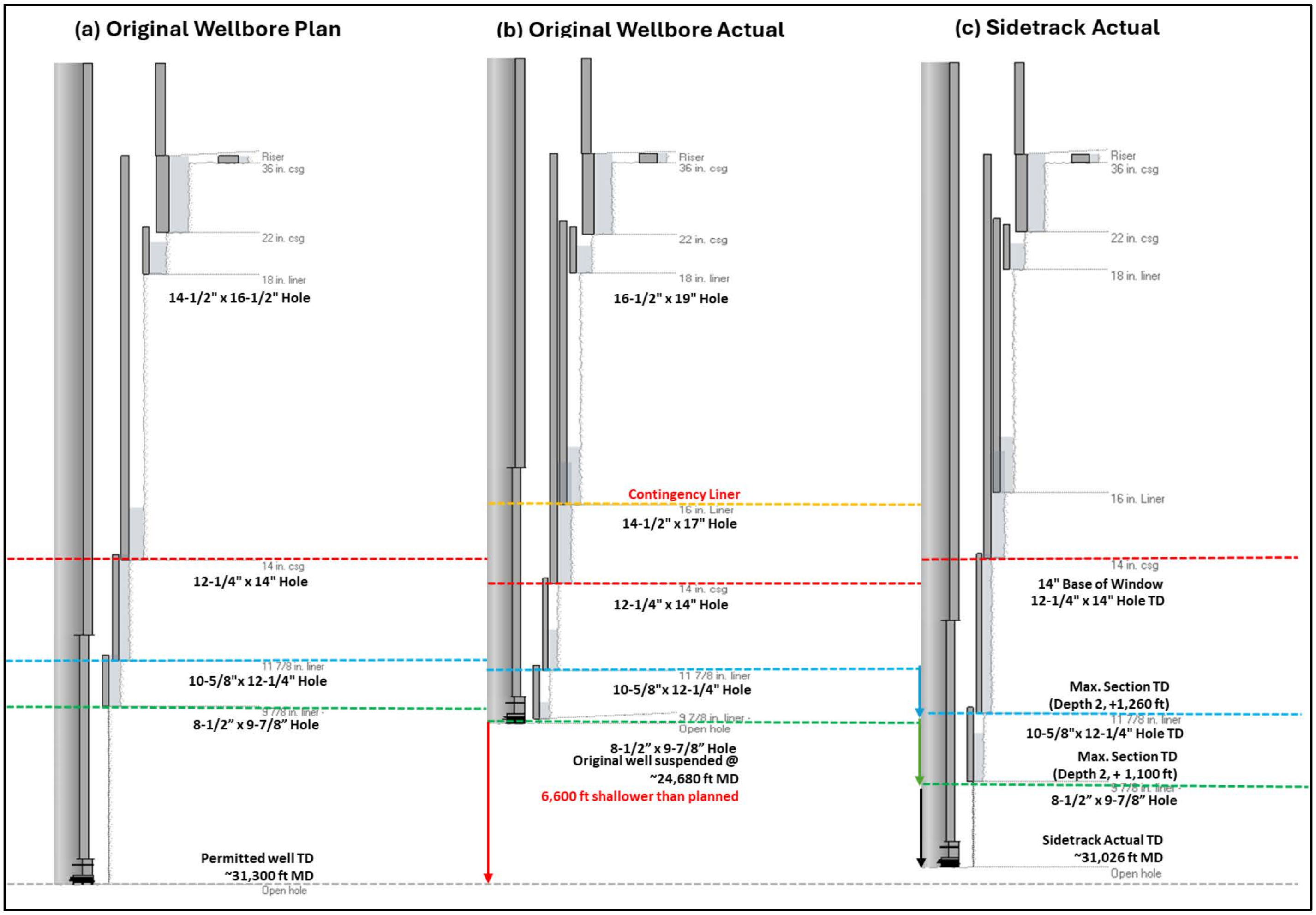


Figure 4—(a) Original Wellbore-Planned, (b) Sidetrack – Planned and (c) Sidetrack- Actual Configurations

The implementation of MPD enabled the team to optimize the well design based on constant bottom-hole pressure and reduced kick tolerance (Sugden et al., 2014; Calleiro et al., 2024). The intent was to extend/push the liner shoe setting depths while still allowing for enough margin to circulate to kill mud weight (KMW), trip out with the BHA, trip into the hole with the required liner/casing, and perform the cement job. This is possible by managing bottom-hole conditions to minimize losses, ballooning, and the potential for well-control events. The more precise kick tolerance approach, typically used in Influx Management Envelope (IME) and MPD Designs, included three basic premises:

- Optimization of the overbalance required above the predicted pore pressure; typically, a trip margin is needed in conventional drilling. With MPD CBHP applications, this is set aside in favor of an overbalanced condition anchor point. This was key for managing high annular frictional losses and the ECD/EMW. Lower surface mud weight enables the mud weight profile to remain within the safe margin from the operational window limits prognosed. Thus, MPD adds flexibility to the well design. Based on the current Gulf of Mexico (GOM) regulator's requirements, with MPD, the plan to maintain "*a downhole overbalanced state must be kept in the MPD system using mud density, surface back pressure (SBP), and annulus friction pressure at all times*" (NTL No. 2008-G07, 2008).
- Optimization of the maximum tolerable volume criteria. MPD enables faster influx detection and response time, but more importantly, immediate control over bottom hole pressure; this allows the modification of the acceptable maximum kick volume criteria, which will, at the same time, enable

the optimization of the casing/liner setting depths. Given the uncertainty on PP/FG, the engineering analysis accounted for a range of possible section TDs for every section.

- Verification of casing/liner drilling and operational loads. The operator's drilling engineers verified that the alternative MPD well configurations proposed meet all the regulatory requirements from the conventional well design analysis standpoint. Periodic casing design checks were performed under MPD conditions, including load analysis with MPD MW and SBP to represent MPD drilling conditions and safety factors.

The MPD plan included the estimated SBP required to maintain the EMW while drilling and pumps off at the section depth. Hydrostatically underbalanced mud weight was selected to manage the PP/FG uncertainty, but the MPD strategy was always to maintain dynamically overbalanced EMW against pore pressure with SBP. MPD hydraulics and influx management modeling were performed to provide the preliminary parameters (MW, SBP, and flow rates) for drilling with MPD and to define the equivalent mud weight (EMW) management plan. Modeling and MPD strategies were updated as operations were ongoing, calibrated during cased hole trials (fingerprinting), and additional information about the subsurface was obtained via real-time measurements. One crucial factor contributing to the success of this application was the teamwork among the MPD specialists, the proficient design team, and the personnel conducting operations on-site.

Three sections were explored as part of the MPD well design and engineering. Table 1 presents a high-level summary of the main challenges and considerations for every hole section. MPD engineering analysis included single and multiphase transient simulations for the following operations: drilling, connections, dynamic influx management, tripping (i.e., swab and surge), rollover to kill mud, and cementing. Figure 5 presents an example of drilling and hydraulic connections.

Table 1—High-level overview of considerations for MPD engineering and strategy

Hole Section	Challenges	Design Constraints
12 1/4 × 14 -inch.	* Salt exit. * Maintain SBM properties within programmed parameters. * Losses while running and cementing operations. * Pressure regression in sand formations. * Wellbore instability and ballooning.	* The main objective was to validate the MPD system functionality and familiarize the crew with MPD equipment and procedures. * Hydrostatically underbalanced mud (#0.2 ppg) only for the last #1,500 ft of the section. * The difference between SMW and DH EMW due to compressibility and thermal effects was estimated at 0.2 ppg. * 300 psi estimated annular friction for a 15.7 ppg DHMW at total flow rates. * MPD KI (i.e., based on IME) was 0.12 ppg (#150 psi)
10 5/8 × 12 1/4 -inch.	* Limited subsurface data from the original wellbore at this depth. * High uncertainty in PP/FG profiles. * Drilling out of the shoe with hydrostatically underbalanced mud. Potential for equipment plugging. * Differential Sticking. * Maintain SBM properties within programmed parameters. * Loss of circulation.	* Hydrostatically underbalanced mud (#0.4 ppg). * Minimum fracture gradient prognosed #0.2 ppg lower than most likely fracture pressure. * 0.2 ppg difference between SMW and DH EMW due to compressibility and thermal effects was estimated. * 350 psi estimated annular friction for a 15.8 ppg DHMW at total flow rates. * MPD KI (i.e., based on IME) was 0.11 ppg (#150 psi) * Drill string annular pressure loss was considered in the design.
8 1/2 × 9 7/8 -inch.	* No subsurface data from the original wellbore at this depth. * High uncertainty in PP/FG profiles. * Drilling out of the shoe with hydrostatically underbalanced mud. Potential for equipment plugging. * Potential for pressure ramp (#3000 ft into the section), which will trigger contingency liner and subsequent hole section. * Hydrocarbons from formations drilled. * Maintain SBM properties within programmed parameters. * Lost circulation and differential sticking.	* Hydrostatically underbalanced mud (#0.3 ppg). * Minimum fracture gradient prognosed #0.3 ppg lower than most likely fracture pressure. * The difference between SMW and DH EMW due to compressibility and thermal effects was estimated at 0.3 ppg. * 400-500 psi estimated annular friction for a 16.0 ppg DHMW at total flow rates. * MPD KI (i.e., based on IME) was 0.23 ppg (#320 psi) *Drill string annular pressure loss was considered in the design.

Hole Section	Challenges	Design Constraints
Contingency	* Significant uncertainty in PP/FG and the potential for higher than prognosed limits. *No subsurface data from the original wellbore at this depth. * Lost of circulation *Wellbore stability, differential sticking. * Hydrocarbons from formations drilled.	The base plan was to drill the well to a maximum TD. One contingency case was explored as part of the initial planning and strategy, including a contingency 7 3/4 -inch. liner to drill an additional 7 1/2 × 6 1/2 -inch. hole section.

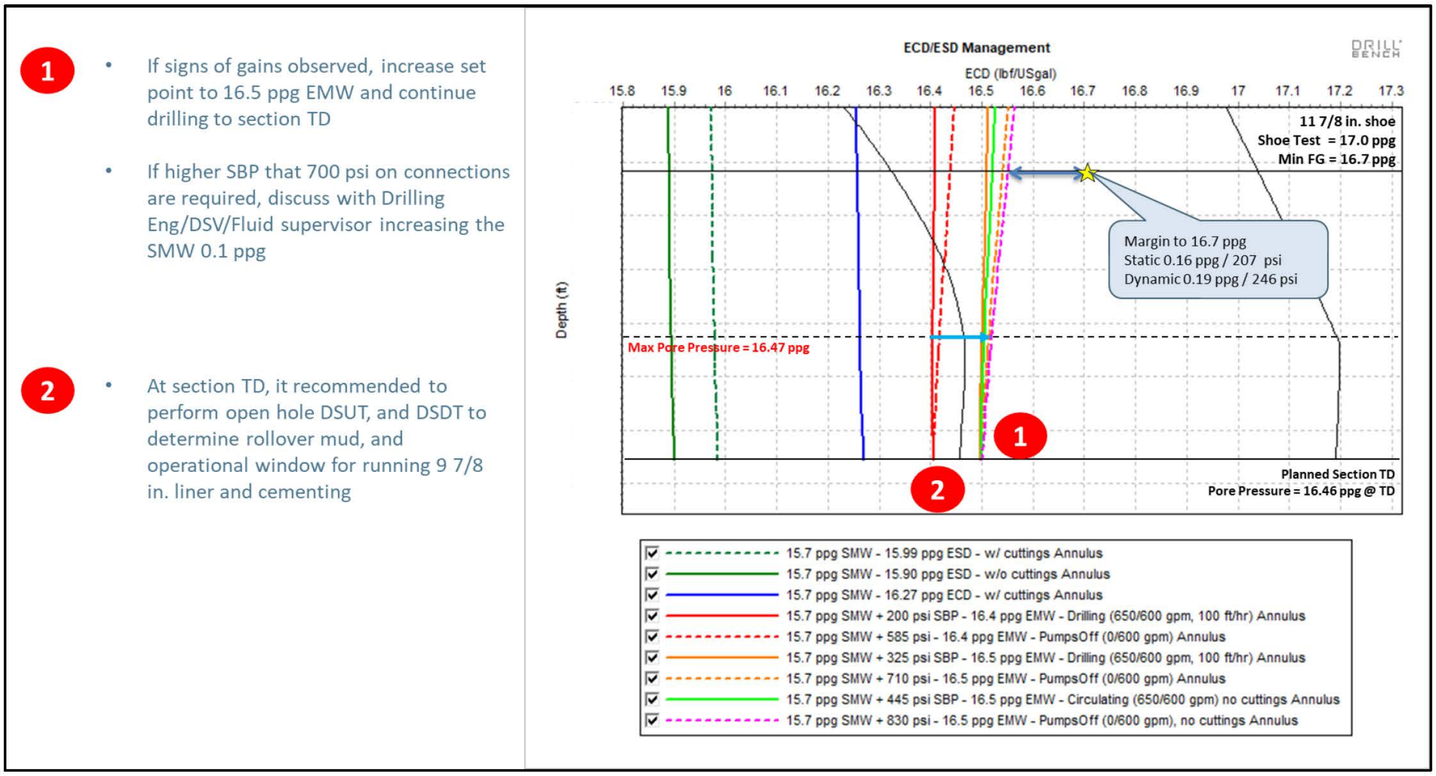


Figure 5—EMW management strategy, for hole section

The three MPD sections followed a similar strategy and approach. Figure 5 shows an example of a representative section of the well and the worst-case assumption for the surface back pressures at section depth. The approach for this section was to drill with MPD CBHP from the previous shoe to a section depth of approximately 3,000ft while holding a target EMW above pore pressure (chokes fully open + snap position) to the maximum target EMW at section TD of 16.5 ppg. This would enable the EMW to remain below the prognosed minimum fracture gradient of 16.7 ppg. The plan included a sequential increase in the EMW at critical depths using SBP to define the pore pressure and enabling dynamic pressure testing points at critical depths of the interval.

MPD Operational Strategies and Techniques

Drilling. The drilling process with MPD implementation is a meticulous and systematic approach aimed at enhancing safety, efficiency, and drilling performance. The same MPD strategy was implemented for every section. Below is a detailed step-by-step overview of the process, highlighting key milestones and decision points implemented during the MPD operations.

a. **MPD System Initial Testing and Calibration:** The MPD system undergoes rigorous initial testing and calibration before commencing drilling operations. This phase ensures that the system functions and is pressure tested as per the design requirements. The MPD system was function-tested and pressure-tested, and the IRJ was picked up and run into the moonpool, where it could be fully connected to the umbilical and MPD hoses. During operations, it was planned to do online and offline testing of all the integrated riser joint (IRJ), including the RCD, Drill String Isolation Tool (DSIT), and Flow spool valves, MPD hoses, Pressure Relief Valves (PRVs), Buffer Manifold, Choke Manifold, and Metering Manifold. Additional testing was planned for the MPD system between sections, which is especially important for the control system calibration.

b. **Fingerprinting and Training/Drills:** Fingerprinting involves acquiring data and calibrating the system behavior to establish a baseline understanding. Training and drills are conducted to familiarize personnel with MPD equipment, procedures, and contingency protocols. Fingerprinting was merged with Level 3 (hands-on) crew training and was planned to be conducted before drilling every section of the well. This was done to ensure the on-tour crews were fully trained and prepared for the upcoming hole interval. The fingerprinting of the first section was planned to be exhaustive and was forecasted to take around 24 hours to complete. Subsequent sections included a simplified version of the fingerprinting procedure, and was estimated to take around 6 hours to complete. The actual duration of the fingerprinting operations was optimized, and 21 hours were required in the first section and approximately 3.5 hours for the remaining two sections in the well. Fingerprinting operations included:

   a. MPD friction loss, hydrostatic pressure, and compressibility estimations.
   b. Hydraulic model and MPD system calibration/validation.
   c. Training the rig crew on MPD operational and contingency procedures (i.e., connections, dynamic pressure testing, influx management, pump failure, PRVs activation, etc.).

c. **Drilling Out Casing Shoe:** The plan was to drill out of the shoe with hydrostatically underbalanced mud. For this reason, the MPD system was planned to be online while drilling the casing shoe. This added additional consideration to the potential of equipment plugging during these operations. These risks were defined and assessed, mitigation strategies were set in place, and no problems with MPD system surface plugging in actual operations were encountered. As a good practice, the team established a sequence of steps and flow path that temporarily bypassed the Coriolis flow meter while drilling out the shoe track. The high-level overview of the operation included:

   a. Conduct fingerprinting/training as required.
   b. Drill the float collar and cement on the shoe track.
   c. Circulate bottoms-up.
   d. Install the RCD bearing assembly bring the MPD system online (bypassing the Coriolis flow meter).
   e. Finish drilling the cement and shoe (#10ft of new formation).
   f. Circulate bottoms-up and line-up of the MPD system through the main flow path (bring Coriolis online).
   g. Perform dynamic and conventional shoe tests as required.
   h. Continue drilling.

d. **Drilling Ahead to Section Total Depth (TD)**: The drilling continued with constant bottom hole pressure, maintaining the annular pressure above pore pressure and below the pre-defined upper limit at the shoe/weak point. The main goal was to maintain minimal overbalance to map the pressure window and adjust the BHP as required with SBP. The following essential MPD techniques were planned as part of the strategy.

   - Dynamic Influx Management. Dynamic influx management strategies were planned to mitigate risks and maintain control over the wellbore within the primary barrier envelope when influxes occur within the predefined limits.

- Mud weight, operating parameters, and the Influx Management Envelope (IME) / MPD Operations Matrix were adjusted to maintain control and adapt to downhole and operational conditions. This reduced and significantly managed the necessity for mud weight changes observed in the original well by enabling adjustment in SBP to compensate for fluid properties inconsistencies to maintain the required overbalance; this was critical to optimize the mud density, which was assumed to be around 15.8 ppg – 16.0 ppg during the planning stages and gradually reduced to 15.7 to 15.9 ppg for MPD operations.
- Early kick and loss detection mechanisms were employed to enhance safety and promptly address pressure anomalies.
- Dynamic pressure tests for operational window determination. Two tests at critical depths were planned as part of the strategy: a dynamic step-up test (DSUP) to assess the upper boundary of the window and a dynamic step-down test (DSDT) to assess the lower limiting boundary. None of the tests were planned to exceed previously obtained values for formation strength determination. For the DSDT, managing influx volumes and surface pressures within predefined limits outlined in the IME/MPD Operations Matrix was planned and followed.

e. **Displacement and tripping at Section TD**: Upon reaching Section TD, the well was planned to be displaced to overbalance tripping mud weight using MPD rollover from the lighter drilling fluid to the kill mud weight. SBP was adjusted to remain within the target operating window throughout the displacement process and compensate for swabbing and surging effects during conventional tripping operations, ensuring stable wellbore conditions were maintained and minimizing losses.

Continuous monitoring, analysis, and parameter adjustment throughout each phase of the drilling process were vital to successfully drilling every section. Real-time data, engineering calculations, and adherence to the predefined operational envelopes and procedures informed operators' decision-making. Collaboration between drilling engineers, well site personnel, and MPD specialists ensured the drilling operation proceeded safely and efficiently. The following sections of this work present a high-level overview of the actual operations.

Dynamic Influx Management. A dynamic influx management approach was planned for this well. This method enables influx detection, control, and circulation by maintaining constant bottom-hole pressure through the primary barrier envelope. Thus, it does not require shutting the well and maintaining pipe movement while managing the influx.

The MPD well design and strategy introduced the multiphase dispersed kick tolerance approach, maximizing shoe setting depths while respecting the shoe's margins or weak points in the open hole. The dynamic influx management strategy for this well counted with two main components: (a) Influx Management Enveloped and MPD Operational Matrix, and (b) early detection and circulation with MPD system procedures that aim at reestablishing the primary barrier and removing the influx.

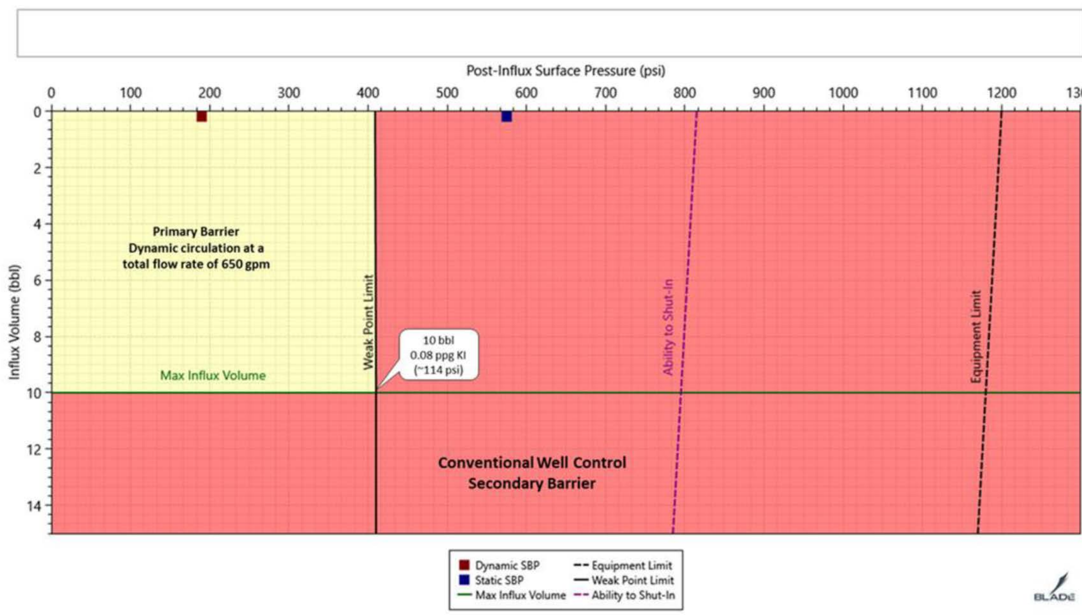
Influx Management Enveloped and MPD Operational Matrix

As part of the Dynamic Influx Management strategy, MPD hydraulics and dynamic influx circulating simulations were run for every hole section. EMW/SMW were assessed individually based on the available operating window and risks associated with each section. As Bureau of Safety and Environmental Enforcement (BSEE) regulations in the Gulf of Mexico required, the MPD operations matrix was developed for every interval and utilized as a decision-making tool during operations. This matrix originated from limits defined by an Influx Management Envelope (IME). The IME was defined by parametric analysis to determine the influx limits (volume and intensity) that can be circulated within the primary barrier. The IME considered the limits imposed by the weakest fracture gradient, surface equipment ratings, and mud gas separator (MGS) capacity.

The IME/MPD Operations matrix accounted for the following:

- Expected operating range within the primary well barrier (i.e., MPD -mud hydrostatic + friction + SBP),
- Defining when to shift from the primary barrier to the secondary well barrier (i.e., subsea BOP) and
- Determining when to execute well control with the secondary well barrier.

This approach was incorporated into the MPD operations and contingency procedures as required. Operationally, the IME/MPD Operations Matrix was updated when downhole conditions and operating parameters differed from the original plan. An example of an IME/MPD Operations Matrix used for this well is presented in Fig. 6.



Sidetrack Well 10 5/8 x 12 1/4 in. Hole 15.8 ppg SMW		MPD Operations Matrix Surface Back Pressure Indicator (psi) SBP limits are calculated using a minimum fracture gradient @ 11 7/8" Shoe, 16.0 ppg DHMW		
		Drilling SBP ≤ 410 psi	**Pumps Off SBP ≤ 795 psi**	**Drilling SBP > 410 psi Pumps Off SBP > 795 psi**
Gain Indicator: MPD EKD System (Volume Totalizer) Pit Gain (Rig PVT)	No Gain	1. Continue drilling 2. Monitor trends and drilling parameters 3. If required, adjust MW and drilling parameters to maintain EMW within dynamic limit.	1. Continue operations. 2. Monitor trends and pumps off parameters 3. If required, adjust MW to maintain EMW within static limit.	1. Stop drilling and adjust parameters to remain within MPD system limits 2. Consider increasing MW 3. Discuss forward plan
	Gain ≤ 10 bbl	1. Stop drilling, maintain constant pump rate and reduce rotation 2. Increase SBP / EMW within operational limits 3. Once gain is controlled, maintain SPP constant 4. Discuss forward plan	1. Stop operations 2. Increase SBP / EMW within limits 3. Once gain is controlled, start main pumps 4. Once at circulating rates, maintain SPP constant 5. Discuss forward plan	1. Stop operations 2. Pick-up to the pre-determined hang-off position. 3. Shut in on subsea BOP.
	Gain > 10 bbl	1. Stop operations 2. Pick-up to the pre-determined hang-off position 3. Shut in on subsea BOP.	1. Stop operations 2. Pick-up to the pre-determined hang-off position 3. Shut in on subsea BOP.	1. Stop operations 2. Pick-up to the pre-determined hang-off position. 3. Shut in on subsea BOP.

Figure 6—MPD Operations Matrix/IME for Section No. 2 of the prospect well

The main premise of these analyses was to ensure that the more precise kick tolerance calculation would still enable managing the required volume within the available operating window and equipment pressure and flow capabilities. Several aspects were of importance and considered in this work: a) using transient simulations was significant in enhancing the allowable volume and kick intensity and representing influx behavior with worst-case assumptions, b) evaluation of the weak point in the open hole was the case of prevalence for all the sections explored, and c) where applicable and relevant IME operational windows were evaluated for consideration of the multiple setting depths considered.

Detection and circulation with MPD operational and contingency procedures

The MPD system enables early kick and loss detection (EKLD) capabilities by comparing the flow measured by the Coriolis meter with the flow in. This meter is designed to detect slight variations in fluid density and rate, thus allowing influx volumes to be minimized when compared with conventional indicators. Once the influx was detected, the planned strategy established flow in = flow out. After the influx is controlled and the volume and pressure/intensity are compared against the section IME/MPD Operation Matrix, the influx may be circulated using MPD equipment while simultaneously establishing the primary barrier envelope.

A rig and operation-specific MPD influx detection and removal procedure were developed and used as a guideline for all three levels of training. The procedure scope included four main areas: the dynamic detection and circulation of influxes within the MPD system (primary barrier envelope), diagnostics for well ballooning, and transitioning from MPD operations to conventional well control (secondary barrier) and vice versa.

Tripping. The primary tripping strategy for each hole section involved conducting dynamic pressure tests for both Pore Pressure (PP) and Formation Integrity Test (FIT) upon reaching the Target Depth (TD) of the section. The well was subsequently displaced to an overbalanced tripping mud weight (MW) using a Managed Pressure Drilling (MPD) rollover schedule, adjusting the Surface Back Pressure (SBP) to remain within the target operating window. When feasible, the mud rollover flow rate was maintained at a level sufficient to enable real-time Pressure While Drilling (PWD) readings without exceeding the FIT limits or compromising weak zones.

For contingency scenarios, although not implemented in this project, the tripping in or out of hole plan included two alternative strategies using hydrostatically underbalanced mud. Depending on the specific contingency scenario and well conditions, a trip procedure would be prepared and submitted to the BSEE, exploring the following methods, summarized at a high level:

i. Utilizing the Subsea Blowout Preventer (SSBOP) to trap pressure:

   a. Trip while maintaining pressure below the Rotating Control Device (RCD) until the drill string is above the SSBOP.
   b. Once the Bottom Hole Assembly (BHA) is above the SSBOP stack, close the blind shear rams (BSR) to trap pressure below the BSR, isolating the riser from the wellbore during the bearing assembly retrieval and subsequent trip to the surface. Continuously monitor the pressure at the SSBOP stack and rig choke and kill lines, adjusting, as necessary.

ii. Riser Cap Method:

   a. Displace the riser with heavier mud (riser cap) to balance the well.

The tripping margin was evaluated considering the following factors:

- Updated operational window with real-time pore pressure analysis or by conducting dynamic pressure testing before Pulling Out of Hole (POOH).
- Thermal effects on downhole mud weight to ensure the well remains statically overbalanced and below the threshold of losses.

- Considerations of swab, surge, and annular friction losses, updated for actual mud density and rheology.

A high-level, operational summary of the well implemented strategy is presented below:

The 12 ¼ × 14-inch. hole section was drilled with 15.7 ppg SBM using the MPD system in CBHP mode to maintain a 16.3 ppg EWM at the bit. A DSUT was performed at section TD to assess potential weak zones in the open hole, followed by a DSDT to confirm potential pore pressure. Upon completing these tests, the operational window for tripping out of the hole was estimated to be between 16.2+ ppg, limited by pore pressure confirmation, and 16.4+ ppge, limited by the dynamic FIT. A 16.1 ppg SBM was circulated, with an estimated 16.3 ppg Downhole Equivalent Mud Weight (DHEMW). Once the 16.1 ppg SBM was in place, a dynamic flow check was conducted, followed by a static flow check via the rig's choke line to the stripping tank. The drill string was pumped out of the hole until it was above the 14-inch casing to avoid reducing BHP due to the swabbing effect. Subsequently, the RCD was removed after performing the flow check. The drill string was then POOH to the surface conventionally.

The second MPD section, a 10 5/8 × 12 ¼-inch. hole, was drilled with 15.7 – 15.8 ppg SBM using the MPD system in CBHP mode to maintain a 16.3 ppg EWM at the bit. In section TD, the DSDT was conducted to address significant uncertainties associated with the pore pressure trending toward the higher end. The pore pressure prediction, initially estimated to be 16.5 ppge, was confirmed to be 16.4+ ppge with a gain below 2 bbl. in the Active System and Coriolis flow in/out difference during the dynamic test. After circulating bottoms up from that event, a DSUT reached 16.6+ ppge. A planned 16.1 ppg SBM was circulated, which is estimated to provide a 16.3 ppg DHEMW. Similar to the first section, once the 16.1 ppg SBM was in place, a static flow check was conducted via the choke line to the stripping tank. The drill string was pumped out of the hole through the MPD manifold with the chokes fully open. The initial strategy proposed is to retrieve the RCD Bearing Assembly (BA) at the top of the liner and continue POOH conventionally. However, after performing two dynamic flow checks at the casing shoe, it was determined that removing the RCD BA was the best approach to reduce additional friction. The crew continued POOH to the surface conventionally, starting with tripping speeds of five stands per minute, increasing to 1 stand per minute, while observing minor losses. The 9 7/8-inch liner was then run and cemented conventionally.

The final MPD section, an 8 1/2 × 9 7/8-inch. hole, was drilled with 15.9 ppg SBM using the MPD system in CBHP mode to maintain a 16.7+ ppg EWM at the bit. A final formation pressure test with BHA formation pressure and sampling tool was executed at section TD, obtaining a 15.79 ppg pore pressure. Bottom-up was circulated after calling the well TD, and a DSUT was performed, reaching 16.70 ppg. The mud was rolled over to 16.3 ppg kill mud weight per the initial plan. The tripping model was updated with the final MW, trip speed limitations, flow rates, and surface back pressure needed to compensate for the swab. Finally, it was decided to pump out of the hole at a tripping speed of 4 minutes per stand to mitigate the swab.

Regulatory Compliance

As part of the Code of Federal Regulations, and as detailed in the Notice to Lessees and Operators (NTL) No. 2008-G07 Managed Pressure Drilling Projects, the operator submitted to BSEE the New Technology Plan (NTP) and the MPD Application to Permit to Drill (APD) program (30 CFR 250.414). The NTP contained the following items outlined in the NTL, but not limited to:

- New Technology Overview
- Key Mechanical Components
- MPD Well Barrier Elements
- MPD System Overview

- Equipment Schematics
- MPD Drilling Program
- Testing and Validation Plan
- Operational Procedures
- HAZOP/HAZID Report
- Training/Competency Plan

3rd Party Verifications (procedures, equipment, and riser analysis)

Once its review was completed, BSEE approved using the MPD system to drill the prospect well. The NTP permit counted with approval conditions addressed as required before operations commencement and during ongoing operations.

Training

In coordination with the drilling contractor and third-party providers, the operator prepared a comprehensive training program for all critical personnel participating in the MPD operations on prospect well. The training program was provided in the classroom with a simulator prior to operations and at the rig site during fingerprinting exercises.

The training included (a) MPD concepts and specific applications for the well, (b) Rig-specific MPD package, control system, and hydraulic model, and (c) Key rig and well-specific operational and contingency procedures via simulator firsthand training conducted at the rig site. These topics were divided into three primary levels of training:

- Level 1: MPD fundamentals and general overview of the MPD system.
- Level 2: Procedures and strategies
- Level 3: Hands-on MPD training

Before operations, Levels 1 and 2 were conducted with two classroom and simulator training days. As the rig crew and third-party providers boarded, a condensed version was given in multiple sessions at the rig site. The intent was to ensure that all upcoming personnel involved in the operations would follow the training plan developed for the ongoing operations. To accomplish this, the MPD training matrix was periodically updated based on the most recent POB, and training was provided for both shifts as required. Level 3 training was conducted with all the drilling crews during cased hole fingerprinting. This training aimed to familiarize the crew with the essential MPD operational and contingency procedures. Some examples of these included:

- Running and retrieving the bearing assembly.
- MPD connections (practicing pump ramp down and ramp up).
- Tripping, simulating effects of swab and surge.
- Pressure testing (i.e., dynamic step-up and dynamic step-down tests).
- Well control drills.
- Boost pump failure and recovery.
- Loss event.
- Influx detection and circulation event.

The classroom training sessions were critical for technical discussions. These sessions helped fill technical gaps and provided opportunities to peer review and align on critical operational, contingency, and well control issues. Key operations personnel's participation also provided excellent team-building opportunities. In addition to training, procedure review sessions were conducted with all parties involved. All essential documents were updated based on technical feedback received during training.

An essential aspect of the training is the participation of the rig crew and MPD equipment/service providers, which should be encouraged if not mandatory. Where possible, live simulator sessions should be included on the training agenda. Extra time is usually required to ensure smooth integration between the simulator and the MPD service provider's control system. This preparation work is critical in ensuring a smooth and uninterrupted process during the live training session.

Operational Execution

Operational Overview

Operations to drill the sidetrack were restarted once the rig became available and regulatory approval was obtained. Once the rig started to transit to the location and OTC (Greenlight) was available, a pressure test of the Choke and Metering manifold was completed offline according to the rig testing procedures. Subsequently, the IRJ was run, and the flow spool valves, goosenecks, and PRVs were tested. Per GOM regulatory requirements, procedures were signed off and verified by an independent third-party.

The sidetrack started by installing a whipstock and milling out of the 14-inch casing below a salt suture encountered in the original wellbore. The main objective was to reach the exploration reservoir formation, which was anticipated to be deeper than in the original well. There were two prognosed sand intervals before reaching the planned TD. The sidetrack was drilled with MPD using a hydrostatically underbalanced mud weight, and surface back pressure was applied to stay overbalanced and maintain CHBP during dynamic (circulating/pumps on) and static (pumps off) conditions. Table 2 presents a high-level summary of every section's operational parameter and performance. The entire sidetrack operations required approximately 40 days, of which 19 days were on MPD operations, for a total footage drilled of ~12,000 ft.

Table 2—MPD Operational Parameters (actual)*

Section	12 1/4 × 14-inch.	10 5/8 × 12 1/4-inch.	8 1/2 × 9 7/8-inch.
MPD Ops Duration (days)	6	8	5
Drilling Time (hours)	130	162	120
Total Feet Drilled (ft)	6000	2650	3240
SMW (ppg)	15.65 – 15.7	15.7 – 15.8	15.7 – 15.9
DHMW (ppg)	15.85 – 15.9	15.9 – 16.0	15.97 – 16.17
Target EMW (ppg)	16.25 – 16.3	16.3 – 16.5	16.5 +- 16.6+
$SBP_{Drilling}$ (psi)	100 – 160	225 – 400	80 – 110
$SBP_{PumpsOff}$ (psi)	400 – 590	500 – 860	800 – 945
ROP	50 – 100	45 – 50	20 – 35
DS Pump Rate (gpm)	750	484 – 500	500
Boost Pump Rate (gpm)	415 – 700	600 – 795	650 – 665
BHT max (deg F)	194	205	280

*** Some numbers have been modified due to confidentiality agreements and to respect proprietary information.**

The first section of the sidetrack, the 12 1/4 × 14-inch. hole section was drilled with 15.7 ppg SBM while maintaining 16.3 ppg EMW at the bit. The strategy for normal drilling/circulation operations was to utilize one 6in. choke flowpath (see Fig. 7). Based on real-time data and the execution of a DSUT at the Base of Salt (BoS), 0.1 ppg higher than expected, the section TD was extended by ~1300 ft deeper than planned. An open hole of ~6,000 ft was drilled in eight days. Once at section TD, the well was rolled over from the 15.7 ppg drilling mud to a 16.1 ppg SMW kill weight mud. No losses, influx, wellbore instability issues, or ballooning were observed during this interval. The 11 7/8-inch. liner was run and cemented conventionally. Once the cement top was determined, approval was obtained to drill out the shoe; operations continued by drilling the float collar and cement shoe track to ~10 ft of new formation with the mud system in the hole (16.1 ppg). Subsequently, fingerprinting and drill exercises were conducted with the rig crews using an optimized procedure requiring approximately 3.5 hours.

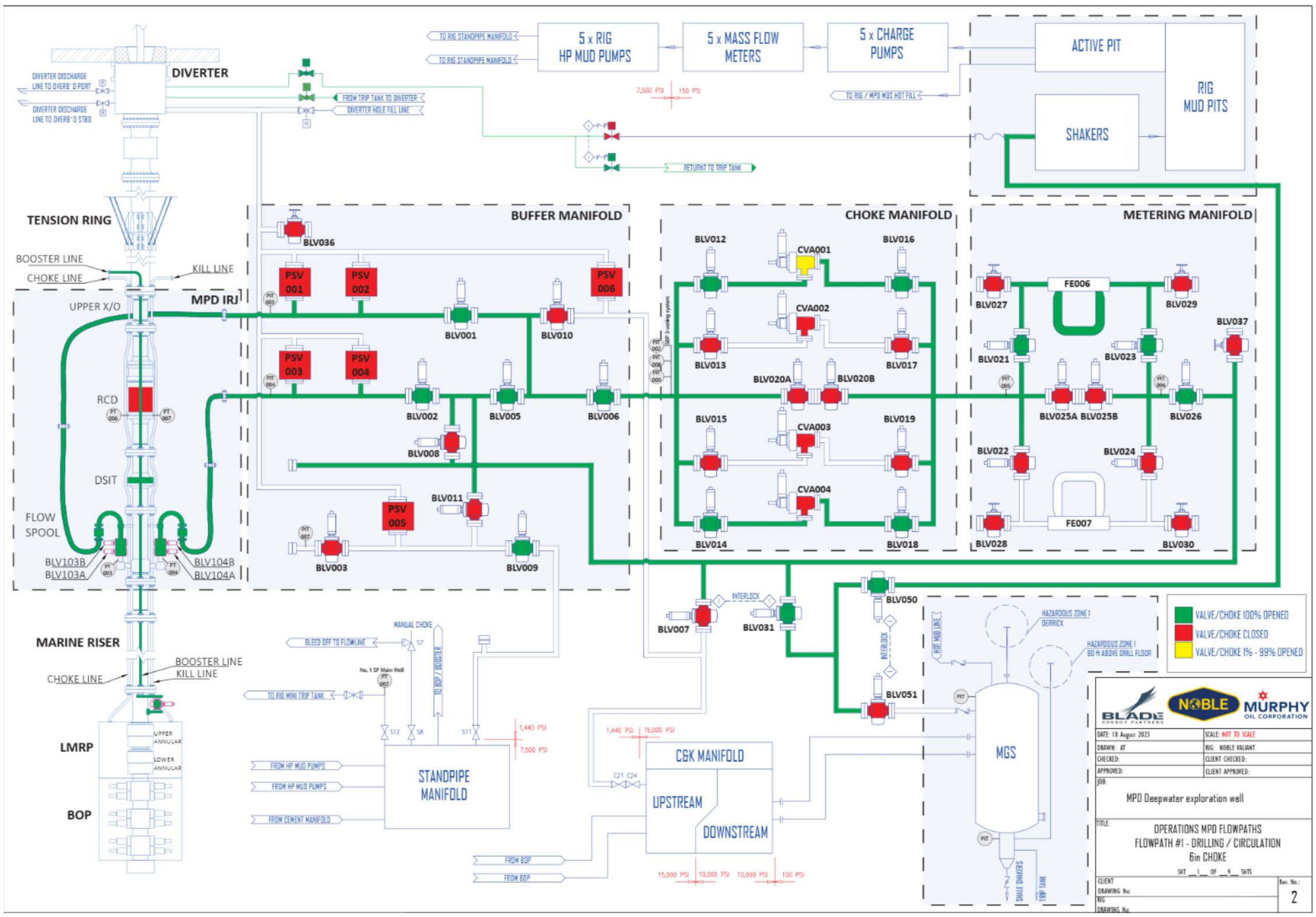


Figure 7—MPD Operations flowpath for drilling through the 6 in. choke

The 10 5/8 × 12 1/4-inch. hole section was drilled with 15.7 – 15.8 ppg SBM while staging up the equivalent circulating density at the bit from 16.3+ ppg to 16.5+ ppg or as dictated by the well. This was in consideration of potentially higher-than-expected pressure. For this section, since the downhole mud weight was hydrostatically underbalanced against the prognosed pore pressure, drilling out of the shoe was performed with MPD online as part of the MPD planned strategy. The main concern for drilling out the shoe track was potentially damaging or plugging the MPD equipment due to debris. A risk assessment was conducted early in the planning stage to establish the process and mitigations for this operation that allowed for bypassing the MPD Coriolis flow meters as part of the strategy. Once the drill out was completed, the RCD bearing assembly was installed and pressure tested. The well was then circulated to 15.7 ppg SMW and well control was maintained at a 16.2 ppg DHMW with MPD. As part of the strategy, and in preparation for the fingerprinting, the decision was made to perform a step-down test to minimum static equivalent mud weight (15.9 ppg) to negative test the top of the liner (TOL). This test was performed to confirm the last known pore pressure measured with MPD dynamic pressure mapping in the previous section was 16.1+ ppg; thus, bringing the drill string pumps down would reduce the expected downhole mud weight to a lower value. To accomplish this, SBP was reduced in intervals of 100 psi to choke fully open, the drill string and boost pumps staged shutdown, and the well was observed for 30 minutes through the MPD manifold to the mini trip tank. After the test was conducted on the 11 7/8-inch liner top, the well was lined up for drilling operation through the MPD system and a dynamic step-up test on the liner shoe was performed. The LOT resulted in 0.2 ppg less than the prognosed, indicating the that the minimum fracture gradient was based on Shmin estimation instead of the most likely case.

The 10 5/8. × 12 1/4-inch. hole section drilling continued to a section-extended TD. A total of ~ 2650ft of open hole was drilled in eight days, including non-productive time due to unexpected events unrelated to hole problems. No losses were observed; however, approximately 10 bbl. gain was observed in the active volume. The decision was made to shut the well in on the SSBOP. Upon circulation, no gas or water was observed. Details of this event cannot be disclosed at this time, so subsequent activities are not included or presented in this work. However, a brief description of the lessons learned is presented in the following section. Once at section TD, the well was rolled over from the 15.8 ppg drilling mud to a 16.3 ppg SMW kill mud, which aligned with the initial plan. The 9 7/8 -inch. liner was run and cemented conventionally. It is worth mentioning that with dynamic pore pressure testing, an effective drilling window of 0.25 ppg (340 psi) was confirmed; this enabled the 9 7/8-inch. liner to be set ~1,100 ft deeper than initially planned.

Regulatory approval was granted to continue drilling operations based on confirmation of the top of cement in 10 5/8 × 12 ¼ -inch. annulus). A similar strategy to the previous section followed for drilling out of the shoe track, installing and testing the RCD, testing the 9 7/8-inch. liner, and simplified fingerprinting and drill exercises.

The last section of the well, an 8 1/2 × 9 7/8-inch. open hole section, was drilled to well TD. This section was drilled with a 15.9 ppg SBM while controlling drilling parameters to maintain the minimum equivalent mud weight at the bit of 16.7+ ppg. This was due to natural surface line friction as the chokes worked at the snap position. CBHP at the bit was maintained throughout the interval using the same strategy as in previous sections. Indications of the pore pressure regression were observed from the BHA formation pressure and sampling tool measurements, and the decision was made to reduce the surface mud weight by 0.2 ppg to manage the ECD generated by the high annular frictions. With MPD chokes working at the snap position, the equivalent mud weight observed was 16.5+ ppg. This facilitated an ECD reduction, increasing the safety margin from the prognosed weak zone. This section used the BHA formation pressure and sampling tool and dynamic pressure testing (DSUT and DSDT) at multiple critical depths to map the pore pressure and fracture gradient window. Drilling continued until TD was called. The ~3,240 ft of open hole section was drilled in 5 days. After calling TD, dynamic pressure testing was conducted to determine the operational window. An effective operational window between PP and FG of 0.34 ppg (~542 psi) was confirmed. Subsequently, the mud was rolled over from 15.7 ppg to 16.3 ppg kill mud weight as per the initial plan, and the bearing assembly was removed.

Operational Results, Lessons Learned, and Recommendations

The main highlights from MPD operations on the prospect well are as follows:

- The well was drilled utilizing six (06) casing strings to slightly over 31,000 ft MD depth. MPD was used for the entire sidetrack portion of the well, completed in three-hole sections after milling the 14-inch window. MPD enabled the liner shoes to be set deeper than prognosed in two hole sections, which increased the probability of reaching the exploration targets. Evaluation of different well design cases during the planning stages, including base or contingency cases, was key to completing the well. Incorporating feedback from all operational parties led to these results.

- MPD facilitated the safe drilling of the three sections using statically underbalanced fluid. Surface backpressure was adjusted to manage the BHP and EMW within the operational window, adapting to downhole conditions while drilling and helping avoid unnecessary fluid density changes. The MPD strategy for the three sections was sound and optimized based on real-time measurements and fingerprinting. The EMW was maintained between the targeted EMW, and no drilling issues on the original well were observed in any of the intervals.
- Advanced MPD techniques, such as Dynamic Formation Integrity Tests (DFIT), Dynamic Step-Down Tests (DSDT), and Dynamic Step-Up Tests (DSUT), were successfully used to obtain critical downhole information. This was critical while exiting the salt, after reaching section TD, and after suspicion of influxes in the wellbore.
- Connections were performed using the MPD system to maintain CBHP. The anchor point was updated on every connection. No significant issues were encountered during the connections, and the targeted DHEMW was maintained with an average deviation from PWD between 0.03 ppg and 0.06 ppg. The average connection time was ~23 minutes. A recommendation during implementation was to increase the set point by 50-70 psi to lead the choke and allow the choke to close before decreasing the flow rate. Upon ramping down completion, this extra pressure was removed.
- MPD helped to regain control and close the well quickly when an influx was suspected. Even though nothing was observed at the surface upon circulation, the reaction of the personnel and equipment was always adequate, following the protocol for influx management and riser gas handling procedures.
- The performance of the RCD sealing elements was exceptional. Even those used to enlarge the hole and strip pipe showed slight to moderate wear. According to the plan, RCD rubbers were changed on every new BHA/trip. One set of rubbers, three natural and three high fatigue (HF) polys, was used for each drilled section of the operation. No leaks occurred, and no changeouts under pressure were required.
- Procedure review sessions with operators and all parties involved (e.g., rig contractor, service provider, consultants, etc.) helped achieve alignment on critical operational, contingency, and well control topics. All rig personnel were proactive during the training sessions (Levels 1, 2, and 3) and knowledgeable of the MPD and well control procedures.
- Although MPD was successfully used to drill these three sections, several events could have jeopardized the operation if proper actions were not taken. A brief count of them is presented below:
    - Equipment issues related to the control system. This situation resulted in a more hands-on approach to manually adjusting the SBP when the automatic AP selection was disabled, as initially identified in the operational risk assessments and contingency procedures. As part of the lessons learned, it was recommended that a maintenance program be established for both the hardware and the software of the MPD systems. This is especially important for older installations and when the equipment/control system ownership is transferred to the rig contractor.
    - While drilling the second section, a gain event occurred while performing downlinking operations. Although specific details of the operations cannot be disclosed due to confidentiality and proprietary information, note that there are two aspects of importance worth mentioning: a) PWD readings are delayed or missed due to flow rate requirements for data transmission,

and b) volume measurement with the Coriolis in these cases is not entirely accurate due to deviation of the flow. Thus, given that the volume measurement was more significant than planned for handling influxes with the MPD system, the decision was made to shut the well in on the SSBOP. Upon circulation of bottoms up, no indication of formation fluid entering the wellbore was observed. As part of the lessons learned, it was recommended to a) establish protocols for accounting for the deviations and impact of downlinking on drilling operations, b) ensure software calibration aligning with PWD reading is key when data from PWD is missed or delayed, and c) it was also recommended to fingerprint the amount of SBP required to compensate for downlinking.

- The bearing assembly was damaged while drilling the last hole section due to sudden and extremely high heave. Despite the efforts on weather monitoring, trend evaluation of the metocean conditions, and previous experience in similar situations, a piece of the bearing assembly was lost to the hole. One-trip fishing operations were successfully conducted, and the broken element was recovered. As part of the lessons learned, although not a contributing factor, but more so to guide future operations, it was recommended to include in the procedures maximum heave requirements based on rig equipment/capabilities and RCD provider recommendations.

Conclusion

- A case study was presented for a sidetrack deepwater exploration well in the Gulf of Mexico in over 3,400 ft of water. The initial attempt at drilling the original wellbore conventionally was suspended due to a lack of an operational window and continuing issues of losses and wellbore instability. Due to those issues, the well was suspended, and MPD was identified as the singular enabling technology. The sidetrack well was successfully drilled with MPD, and MPD enabled us to meet all the well strategic objectives.
- Key to the successful implementation was integrating MPD technology considerations into the well design and planning process at an early stage; this is particularly important for complex and deepwater exploration or development wells. The use of in-house expertise and third-party resources as required was instrumental.
- Despite the challenges encountered, the operation's success was attributed to proactive involvement and commitment from the operator's drilling engineers, rig site representatives, and management. Their timely decision-making and continuous participation were instrumental in overcoming obstacles and ensuring the successful application of MPD in the prospect well.

Acknowledgment

The authors would like to acknowledge Murphy Oil Corporation, Noble Drilling, Blade Energy Partners, and all others who made this project possible. The team's hard work and commitment made it a success.

Nomenclature

AFL	Annular Friction Losses
AP	Anchor point, also known as set point or pivot point
APD	Application To Permit to Drill
BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BOP	Blowout preventer
BSEE	Bureau of Safety and Environmental Enforcement

BSR	Blind Shear Rams
CBHP	Constant Bottom Hole Pressure
DHMW	Downhole mud weight
DIM	Dynamic Influx Management
DLOT	Dynamic Leak of Test
DSDT	Dynamic Step-Down Test
DSIT	Drill String Isolation Tool
DSUT	Dynamic Step-Up Test
ECD	Equivalent circulating density
EKLD	Early kick and loss detection
EMW	Equivalent Mud Weight
FG	Fracture Gradient
FIT	Formation integrity test
gpm	Gallons per Minute
HF	High Fatigue
IME	Influx Management Envelope
in	Inches
IRJ	Integrated Riser Joint
KI	Kick Intensity
KT	Kick Tolerance
KWM	Kill Mud Weight
LOT	Leak Off Test
MD	Measured Depth
MGS	Mud Gas Separator
MPD	Managed Pressure Drilling
MW	Mud Weight
MWD	Measurements While Drilling
NPT	Non-Productive Time
NTL	Notice to Lessees and Operators
NTP	New Technology Plan
POOH	Pull out of the hole
PP	Pore Pressure
PPFG	Pore Pressure and Fracture Gradient
ppg	Pounds per Gallon
PRV	Pressure Relief Valves
psi	Pound per square inch
PWD	Pressure While Drilling
RCD	Rotating Control Device
RHG	Riser Gas Handling
RPM	Rotations per minute
SBM	Synthetic-Based Mud
SBP	Surface Back Pressure
SSBOP	Subsea BOP
TD	Total Depth
TVD	True Vertical Depth

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