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Liner Drilling Technology as a Tool to Reduce Non-productive Time: An Update on Field Experiences in the Gulf of Mexico

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Abstract

It is increasingly difficult to find hydrocarbon reserves located in benign environments, a situation which has resulted in the oil and gas industry moving to locations where significant drilling challenges are encountered. These challenges often lead to costly non-productive time (NPT) and increased operational risk. To reach their objectives, operators must make decisions "outside the box" to mitigate these risks. Liner drilling (LD) technology has been introduced in recent years as a well construction technique and has proved to significantly reduce NPT and operational risks. As seen in some of the case histories, LD in lieu of conventional drilling methods was identified as the only practical way for the operator to accomplish his objective(s)—well abandonment being the only other alternative.

This paper presents five case histories, in both shelf and deepwater Gulf of Mexico (GOM), where LD technology was applied to mitigate lost circulation, wellbore stability issues, and other drilling hazards. Also included is a discussion of the liner tool and casing bit systems that were implemented as well as brief well histories depicting the drilling hazards mitigated and the eventual outcomes. The operational parameters are highlighted together with the LD results and the associated value to the operator.

Introduction

Liner drilling (LD) is a proven technology for addressing such drilling hazards as lost circulation, depletion, wellbore stability, and wellbore ballooning issues. Perhaps the most outstanding feature of LD is the fact that no rig modifications are required; the same surface equipment that is used for conventional liner running operations is used for LD.

The following features of LD offer the best opportunity for setting the liner at the target or acceptable depth:

- A history of minimizing or even eliminating lost-circulation problems using LD has been established in the industry. The "smear effect"[1] is responsible in part for this outcome. The smear effect is a phenomenon wherein it is conjectured that the proximity of the casing wall to the borehole results in cuttings being smeared against the formation, creating an impermeable wall cake.
- This same proximity results in considerably higher annular velocities for a given circulation rate as compared to conventional drilling, leading to better hole cleaning while drilling—a necessity when drilling through unstable shale sections.
- Unlike regular drilling practices, little or no hole preparation is required because the liner can be landed and cemented almost immediately on reaching target depth with minimal delay for circulation.
- LD has been shown to reduce the rate of fluid loss in the annulus when compared to conventional drilling operations[2], enabling annular fluid loss to be managed with a rig's trip tank pump or other dedicated annulus pump.
- The rigidity of the liner being used as part of the drill string leads to maintenance of both deviation azimuths within the parameters of the existing hole[3].
- The trip margin is eliminated, as there is no need for the liner to be pulled out of the hole.

Case Histories

Each of the five case histories presented in this paper shows that the respective operators were unable to drill the trouble zones using conventional methods. They sometimes included LD strategy in their initial well plans as a technology for decreasing well construction costs, while in other instances LD was implemented only after the respective trouble zones were already penetrated. The case histories presented are "textbook" examples of "fit for problem" solutions to significant drilling challenges. Challenges depicted in the case histories included mitigation of catastrophic lost circulation, wellbore instability, and depleted-sand issues. Casing-while-drilling (CWD) and LD systems require minimal or no modifications to the existing rig equipment for implementation and are used only when required to mitigate the well challenge, allowing the well construction process to continue and minimizing NPT in the process.

Case History One

A deepwater GOM operator needed to drill through and set casing over a pressured shale and a subsequent depleted sand within one hole section which, with conventional methods, would most likely require two strings of casing to achieve.

The well plan would not allow use of this many strings because of severe slimming of the wellbore; to address these zones, the operator decided to ream and drill in a 4,260-ft, 7 5/8-in., 39-lb/ft Q-125, HYD-523 liner [4].

Equipment Selection: CWD Bit. After review of existing bit records and lithology information, a three-bladed 7 5/8-in. × 8 1/2-in. CWD bit **(Fig. 1)** with a thermally stable polycrystalline (TSP) diamond cutting structure was selected for the LD. The CWD bit's cutting structure is designed for formations with unconfined compressive strengths of up to 7,000 psi, which fulfill the definition of being PDC drillable. The CWD bit used had 6-mm-round TSP diamond cutters pressed into aluminum blades containing high-velocity oxy fuel (HVOF) hardfacing, while the design of the tungsten carbide gauge section enabled backreaming capability. The CWD bit was fitted with drillable and interchangeable copper nozzles rather than carbide nozzles, which can severely damage the subsequent shoe-track drill-out bit. The aluminum nose and cutting structure is fully drillable with conventional PDC or roller-cone bits, eliminating a costly dedicated drill-out trip.

Equipment Selection: Liner System. The demanding nature of the proposed LD operation, with extreme loads and torques to which the liner equipment would be exposed on a long-term basis, made the choice of equipment critical to the success of the project. The liner system used for these types of demanding installations must be able to withstand the same extreme dynamic forces that are encountered by open hole drilling tools, while still being able to perform its designated functions at the final installation depth. The premium liner system recommended for this LD application had been proven on multiple occasions where LD provided the means to mitigate similar unstable wellbore environments. As the recommended liner system is hydraulically actuated, differential pressure placed across a piston and/or cylinder with a shear-pinned ball seat determines the setting pressures of all hydraulically activated components. This can present problems when this type of system is run in a wellbore with severe fluid losses, as the shear-pin ratings may become down rated as a result of the constantly changing fluid levels within the wellbore. This situation, coupled with hole stability issues, can lead to unexpected events when running a hydraulic liner system. The key for success with hydraulic liner systems is safe management of the circulating pressures so as not to exceed the differential limit established with the preset shear-pin pressures of the hydraulic components[5].

The liner hanger system chosen was a premium hydraulically set liner hanger, which was designed for extended rotation periods in deep, high-angle applications and to allow for maximum workability during deployment **(Fig. 2).** This type of liner hanger is equipped with special mechanical locking devices, which are deactivated when the hydraulic setting pressure is reached. These devices prevent premature setting while running in the hole (RIH) and allow for the highest of flow rates and pressures to be used, further aiding the workability of the system. The hanger is set by applying hydraulic pressure to shear the pins in the cylinder, which forces the connector ring and slips up the cone and into the host casing; the liner weight is then transferred to the slips by lowering the running string[3].

The setting tool **(Fig. 3)** is used to rotate the liner as required when running in the well and during the LD operation. Hydraulic pressure, coupled with a ball-dropping event, is used to shear the sleeve of the hydraulic cylinder on the setting tool so that it can be mechanically released. Drillpipe weight is slacked off to de-clutch the tool, which is then turned to the right to release the float nut. At that point, hydraulic pressure is re-applied to shear the ball from its seat in the liner wiper plug tool, thereby restoring circulation. The running string is then picked up to check that the setting tool is free, which is confirmed by the loss of the liner weight.

The liner top packer **(Fig. 4)** chosen was a mechanically set premium design that allows for extended rotation periods and maximum workability during deployment. The packing element is designed so that atmospheric pressure is trapped under the element; thus, as the liner system is lowered into the wellbore, the hydrostatic pressure acts to simply vacuum it to the liner-top packer mandrel. This capability prevents swabbing and premature setting while keeping cuttings from under the packing element as they are circulated past, all of which can affect the packer's performance. The packer is set by simply raising the running string to expose the packer actuator, forming a no-go which is set down on the polished-bore receptacle (PBR). The no-go transfers weight through the PBR, shearing the pins in the packer and allowing the element and slips to be set in the host casing and the ratchet rings to lock in the compressive forces. The packer was supplied with a tie-back completion PBR using a patented locking mechanism designed to prevent the PBR from backing off when a liner system encounters tight dogleg sections or a high-debris environment, which can lead to costly fishing operations[5].

LD Operation. The liner was reamed and drilled 107 ft through the pressured shale and depleted sand, using a 7 5/8-in. × 8 1/2-in. CWD bit with a hydraulic liner hanger system as described above. Existing 9 7/8-in. casing was set at 16,156 ft MD with 60° of inclination. The existing 8 1/2-in. × 9 7/8-in. hole total depth (TD) was 20,419 ft measured depth (MD). The 4,260-ft liner was washed and reamed from 20,320 ft to 20,419 ft MD and drilled in an additional 8 ft to 20,427 ft MD. Returns were lost during the LD process; however, the annulus was kept full using the rig's trip tank pump.

The 7 5/8-in. liner setting depth allowed reduction of subsequent mud weight from 14.5 ppg to 10 ppg; as a result, the depleted production sand was drilled with no recorded loss of the synthetic oil-based mud (OBM).

The operating parameters during the drill-in of the liner are shown in **Table 1.**

Table 1: Operating Parameters, Case History One

Weight on bit (WOB)	15,000 to 22,000 lb
Rotary speed	40 rpm
Surface torque	15,000 to 23,000 lbf/ft
Standpipe pressure	1,050 to 1,400 psi
Circulation rate	109 gpm

The next hole section in the same well contained a 13.5-ppge pressured shale overlying a 7.7-ppge depleted sand. A 5 1/2-in., 23-lb/ft, Q-125, HYD-513 liner was reamed in using a 5 1/2-in. × 6 1/2-in. CWD bit with the same bit and liner designs as used in the previous hole section. Use of the LD system resulted in no recorded mud losses while the 328-ft liner was reamed from 20,427 ft to 20,519 ft MD in the existing 6 1/2-in. × 7 1/2-in. hole through the pressured shale and depleted sand. The goal was to case off the 92-ft interval, reaming through the existing pressured shale and depleted sand using a 10-ppg OBM and minimizing the fluid loss. The value to the operator was saving significant time and cost in placing the depleted sand interval behind casing where conventional methods would most likely have failed[4].

Case History Two

After considering several options, a GOM shelf operator determined that the optimal way to successfully complete its drilling objective was to case off an unstable shale section and a severely depleted 2-ppge sand with a 5 1/2-in. liner at a wellbore inclination of 38°. The operator required a 3 1/2-in. production tubing to ensure the well's economic success, which necessitated a minimum 4 1/2-in. hole size to the TD of the well after drilling out the 5 1/2-in. liner.

While running a solid expandable open hole liner was considered, the operator determined that the best option was to drill in a 480-ft, 5 1/2-in., 23-lb/ft Q-125, HYD-513 liner through the 2-ppge sand from 13,779 ft to 13,798 ft MD to place the problem zone behind casing[4].

Equipment Selection: CWD Bit. After review of existing bit records and lithology information, a three-bladed 5 1/2-in. × 6 1/2-in. CWD bit with a TSP diamond cutting structure was selected for the LD (same design as Fig. 1).

Equipment Selection: Liner System. Liner running/ drilling tool selection was important because the liner string would be part of the rotary string, subjected to typical borehole drilling forces and dynamics.

Conventional hydraulic liner hangers and running/setting tools are typically set and released by hydraulic differential pressure between the inside diameter (ID) of the setting tool and the outside diameter (OD) of the liner. The torsional capability of liner running/setting tools is sometimes limited, as they are typically designed for an open hole liner-running operation rather than an LD operation. Because of the potential for lost-circulation and hole-stability issues seen in the original wellbore, the possibility of a differential pressure spike across the setting tool during the LD operation was a major concern in the liner system selection process. The 5 1/2-in. liner running/drilling tool system chosen was specifically engineered for an LD operation with up to 38,000 lbf/ft of drilling torque capability. The tool's release is controlled by differential pressure across an internal ball seat in the setting tool rather than between the ID and OD of the tool. Therefore annular pack-offs or bit-nozzle blockages do not result in initiating an accidental liner release.

The liner running/setting tool is released by dropping a ball to an internal ball seat and applying pressure to shear it out. This allows the ball to pass through; with circulation thus restored, cementing can commence immediately. A second-trip liner-top packer can be run if preferred.

5 1/2-in. Liner Reaming and Drilling Operation. As indicated in **Table 2,** extreme difficulty was encountered in the reaming operation. Approximately 2 hr were spent reaming the pressured shale from 13,685 ft to 13,706 ft MD. The shale was trying to pack off, as evidenced by the increased pump pressures (969 psi to 1,389 psi), and patience was required while working the pipe through the pressured shale interval. The depleted sand interval from 13,704 ft to 13,759 ft MD was washed and reamed in 2 hr without incident. While reaming the previously drilled pressured shale section (13,759 ft to 13,779 ft MD), hole-packing again became a problem; as much as 55,000 lb of over pull was required to work the liner free. Pump pressure had increased to 1,686 psi, with surface torque measured as high as 18,000 lbf/ft while reaming through this shale section; however, no fluid was lost to the formation during the reaming operation.

Table 2: Liner Reaming Parameters, Case History Two

Reaming interval	13,685 to 13,779 ft MD
Total reaming time	6.75 hr
WOB	2,000 to 10,000 lb
Rotary	20 to 40 rpm
Drilling torque	8,500 to 18,000 lbf/ft
Flow rate	196 to 236 gpm
Pump pressure	969 to 1,686 psi
Mud weight in	12.0 to 12.1 ppg
Mud weight out	11.7 to 12.1 ppg

As shown in **Table 3,** 10 hr were spent drilling 19 ft of new hole; as in the reaming phase, no fluid was lost to the formation. The 5 1/2-in. liner was drilled to 13,798 ft MD and became stuck while making a connection; so the running/setting tool was released, and the liner was cemented in place. Subsequently, an 18.3-ppge formation integrity test (FIT) was obtained, enabling the 4 1/2-in. hole that was required for the completion.

Table 3: LD Parameters, Case History Two

On-bottom time	10 hr
New hole drilled	13,779 to 13,798 ft MD
Average rate of penetration (ROP)	1.9 ft/hr
WOB	0 to 13,000 lb
Rotary	26 to 50 rpm
Drilling torque	8,000 to 9,500 lbf/ft
Flow rate	158 to 237 gpm
Pump pressure	1,180 to 1,423 psi
Mud weight in	12.1 ppg (water-based mud, WBM)
Mud weight out	12.1 ppg (WBM)

Case History Three

After performing a thorough cost and risk analysis, a GOM operator determined that implementing LD technology was the optimal way to case off a catastrophic thief zone which could not be cased off using conventional drilling methods. The decision to use LD was made after encountering massive losses on the original wellbore. There was little time for planning the implementation of this technology, but the drilling teams from both the operator and service companies involved reviewed the project and performed the engineering evaluations required to ensure success within a 48-hr time window. The actual results were well within the models and limits set by the team and, with minor exceptions, exactly as planned. The 9 5/8-in., 53.5-lb/ft, HCP-110, SLIJ-II liner was drilled in from 7,367 ft to 7,636 ft MD with no measureable fluid losses[6].

Equipment Selection: CWD Bit. After review of existing bit records and lithology information, a three-bladed 9 5/8in. × 12-in. CWD bit with a TSP diamond cutting structure (same design as Fig. 1) was again selected for the LD.

Equipment Selection: Liner System. The liner system used was the same premium hydraulic liner hanger system as described in Case History One, with the exception that a liner-top packer was not run.

LD Operation. Existing 13 3/8-in. casing was set at 4,520 ft MD with a 12 1/4-in. hole drilled to 7,367 ft MD at a 13.2° inclination angle. A 13.4-ppg WBM system was used for the LD operation. The 9 5/8-in. LD parameters are shown in **Table 4:**

Table 4: LD Parameters, Case History Three

LD interval	7,367 to 7,636 ft MD
LD footage	269 ft
Liner length	3,438 ft (4,198 to 7,636 ft MD)
On-bottom rotating time	35 hr
Total drilling time	36 hr (including connection time)
Average ROP	7.7 ft/hr
Pipe revolutions	89,660 (estimated)
Surface torque	3,000 to14,000 lbf/ft
Weight on bit	1,000 to 35,000 lb
RPM	30 to 50
Circulation rate	500 gpm
Surface pump pressure	935 to 1,100 psi
Water-based mud weight	13.4 ppg
Inclination angle change while LD	1° of inclination built (13° to 14°)
Formation drilled	Sand and shale sequence

The liner was run to 7,069 ft MD without incident. The 12 1/4-in. hole was washed and reamed from 7,069 ft to 7,164 ft MD, with the surface indicator readings shown in **Table 5:**

Table 5: Surface Indicator Readings while Reaming with Liner

Rotary speed	40 rpm
Torque	2,500 to 3,500 lbf/ft
Surface pump pressure	1,100 psi
Circulation rate	500 gpm
Hook loads (HL)	
Rotating	300,000 lb
Pickup	290,000 lb
Slack-off	300,000 lb

The HL readings verified that the open hole was in very good shape. A 40-bbl sweep consisting of 20-lb/bbl nut plug and caustic soda was pumped to minimize gumbo balling, and then the liner washing and reaming operations continued, without incident, to bottom at 7,367 ft MD. Mud weight in was 13.4 ppg, with a 51-sec/qt funnel viscosity; mud weight out was 13.5 ppg to 13.7 ppg, with 57- to 60-sec/qt funnel viscosity readings. The top-drive torque limiter was set at 18,000 lbf/ft. This value was determined from torque/drag models developed before the LD operation, using a model based on 7,000 lbf/ft of rotating torque on bottom, which calculated out to 12,000 lbf/ft of surface torque using a 0.45 open hole friction factor. Drilling then commenced with the parameters shown in **Table 6:**

Table 6: Initial LD Parameters, Case History Three

WOB	1,000 to 8,000 lb
Rotary speed	60 rpm
Rotary torque	3,000 to 10,000 lbf/ft
Circulating pressure	1,015 psi
Circulating rate	500 gpm

The initial ROP was ±10 fph drilling to 7,372 ft MD; and with multiple sweeps of nut plug with caustic soda being pumped during the LD operation, the 9 5/8-in. liner was drilled to 7,636 ft MD. At this depth the stand had been drilled down, and, before making a connection, the drill string was worked with good circulation for 20 min; but it was determined that the pipe was stuck. The pipe could not be picked up or rotated without exceeding the torque limiter setting of 18,000 lbf/ft; and so the liner was set and cemented at that depth. There were no reported mud losses to the formation while LD and cementing the 9 5/8-in. casing. The liner hanger set without incident and the liner setting tool was released and retrieved without problem.

Case History Four

A GOM operator producing in the Carpa field (offshore Veracruz, Mexico) elected to implement LD technology after experiencing 39.65 days of NPT in an offset well. The NPT, with a total economic impact of US$4.78 million, resulted from massive fluid losses in excess of 2,500 bbl, causing stuck pipe, costly fishing operations, and the eventual running of a contingency liner[7].

Drilling in the Carpa field is problematic, as an unstable calcareous shale (Brecha formation) overlies the El Abra production interval, which is composed of fractured limestone and is a known lost-circulation interval. If the fractured limestone is encountered with the unstable Brecha formation exposed, lost circulation results and the Brecha formation collapses, resulting in a stuck-pipe scenario. LD technology with a proven liner system and high-performance 12 1/4-in. CWD bit was implemented to case off the problematic Brecha formation and land the 9 5/8-in., 53.5-lb/ft, L-80, Hyd-513 liner in the top of the El Abra formation, with no reported fluid losses.

Passive directional control was maintained in the 75° hole, using strategically positioned undergauge and near-gauge stabilizers in the LD bottomhole assembly (BHA) to minimize dropping tendency. The CWD bit blades were displaced, and the liner hanger and liner-top packer were each set with success. The operator stated that savings of $5 million and 40 days rig time were realized because lost circulation and a contingency liner were eliminated by implementation of LD technology.

Equipment Selection: CWD Bit. After a review of offset bit records and lithological data, the CWD bit selected was a five-bladed PDC bit with features that allow it to be converted to a drillable drill shoe. This bit has 16-mm PDC cutters and tungsten carbide gauge protection inserts **(Fig. 5),** and the gauge section is designed to allow back reaming capability. This CWD bit can be converted to allow subsequent drill-out with conventional PDC and roller-cone bits.

The CWD bit performs as a PDC bit until TD is reached, at which time a ball is dropped into the string and allowed to fall to the ball-funnel receptacle inside the CWD bit, blocking the drilling nozzles from fluid flow. The casing string is then pressured up to approximately 2,500 psi, and the CWD bit's pins are sheared, forcing the tool's inner piston downward, displacing the steel blades and PDC cutting structure into the casing-open hole annulus and exposing the cementing ports. Fluid circulation is re-established through these cementing ports as the tool's inner sleeve slides down with a latching mechanism engaging at full stroke. The full stroke of the tool fully displaces the entire cutting structure into the annulus, where it is eventually cemented in place. The center piston thus exposed is fully drillable with conventional mill-tooth and PDC bits **(Fig. 6);** a special bit or mill run is not required. This CWD bit's cutting structure is designed for formations with unconfined compressive strength (UCS) values of approximately 15,000 psi but has the capability of drilling up to 20,000-psi UCS formations for limited intervals[8].

Equipment Selection: Liner System. The 9 5/8-in. × 13 3/8-in. liner system deployed was similar to the premium hydraulic liner-hanger system in Case History One, with the exception that the hanger had rotation capability during a cementing operation. Case History One provides a detailed description of the liner system.

LD Operations. The 9 5/8-in., 53.5-lb/ft, L-80, Hyd-513 liner connections were torqued to the optimal makeup torque of 22,000 lbf/ft, and the liner was filled with mud every seven joints while RIH. After running the full liner, RIH continued, using 5-in. drillpipe, which was filled every 10 stands while breaking circulation every 2.5 hr to break mud gels. When the liner reached the existing 13 3/8-in. casing shoe at 5,735 ft MD, hook-load and torque measurements were recorded; then running in the hole continued until bottom was tagged in the existing 12 1/4-in. hole at 9,453 ft MD. The 12 1/4-in. CWD bit was then picked up 20 ft off-bottom, and hook-load and torque measurements were recorded.

LD operations commenced with a 12 1/4-in. hole drilled from 9,453 ft to 9,571 ft MD, where the operator's geologist wanted to circulate bottoms up (CBU), looking for the top of the El Abra formation. A single 6.3-bbl,1.32-SG viscous pill was pumped during this interval, with no hole problems reported. The remaining interval was liner-drilled to 9,718 ft MD without incident; after CBU, it was determined that the top of the El Abra had been penetrated and preparations were made to convert the CWD bit. The 9 5/8-in. LD parameters are shown in **Table 7:**

Table 7: LD Parameters, Case History Four

LD interval	9,453 to 9,718 ft MD (265 ft)
9 5/8-in. liner length	4,954 ft
WOB	10,000 to 15,000 lb
Rotary speed	60 to 80 rpm
Pump rate	483 gpm
Pump pressure	1,200 psi
Surface torque	15,000 to 22,000 lbf/ft
Mud weight (SBM)	1.32 SG
Total rotating time	36.68 hr
Total circulating and connection time	6.25 hr
Total LD time	42.93 hr
On-bottom ROP	7.25 fph (feet/hr)
Average ROP (including circulating and connecting)	6.20 fph
Inclination / azimuth at 9,459 ft MD	75.73° / 353.00°
Inclination / azimuth at 9,754 ft MD	74.16° / 354.54°

CWD Bit Conversion. The CWD bit was picked up to 9,712 ft MD, and the cement head was rigged up, containing the 1 3/4-in. phenolic conversion ball (3.4 SG), which was displaced with the rig pumps while circulating at 250 gpm at 500 psi. After 30 min, the circulating rate was increased to 335 gpm with 750 psi, and the CWD bit blades converted with 2,750 psi. This pressure event also set the liner hanger and released the liner running tool.

9 5/8-in. Liner Cementing Operation. Observation of the loss of liner weight on the rig's weight indicator confirmed that the liner hanger was set and the setting tool released. Approximately 30,000 lb of drillpipe weight was set down on the liner, and the mud was circulated and conditioned for cementing. The spacer, lead, and tail cement slurries were pumped and displaced with SBM, with full returns; after landing the wiper plug, pressure was released to check that the float equipment was holding pressure. There were no reported fluid losses during the cement job. The 9 5/8-in. × 13 3/8-in. liner-top packer was set without incident, with 70,000 lb of drillpipe weight set down on the packer assembly and successfully tested to 2,000 psi for 10 min. The liner setting tools were retrieved without problem; later, the 9 5/8-in. liner was tied back with 9 5/8-in. 53.5-lb/ft P-110 casing and cemented in place.

Case History Five

After two unsuccessful attempts using conventional methods to deal with a catastrophic thief interval, a GOM shelf operator drilling offshore Texas decided to implement LD technology to deploy a 7-in. liner to a competent setting depth to facilitate the required completion geometry. The problem formation, which has been mapped throughout the region, is a blanket structure exhibiting varying degrees of lost-circulation severity through several adjacent blocks[2]. After careful planning sessions with the service and operator engineering and operations personnel, preparations were made to drill a 7-in., 23-lb/ft HCP-110, GB CDE (casing drilling enhanced) liner through the catastrophic loss zone and set it in a competent shale below.

Equipment Selection: CWD Bit. The 7-in. × 8 1/2-in. CWD bit with a displaceable 13-mm PDC cutting structure was selected because the cutting structure was deemed the most suitable for the subject application. No samples of the problem formation had been circulated to the surface in previous attempts; so a CWD drill bit with a cutting structure was considered more than sufficient to drill the proposed hole interval. The CWD drill bit used was a five-bladed PDC bit containing 13-mm PDC cutters with features similar to the 9 5/8-in. × 12 1/4-in. CWD bit in Case History Four. These features enabled conversion of the bit to a drillable casing shoe at TD to allow shoe-track drill-out with conventional PDC or roller-cone bits. The cutting structure is designed for formations with unconfined compressive strengths up to 20,000 psi, and the tungsten carbide gauge protection design provides back reaming capability. The CWD bit can be fitted with drillable copper or ceramic nozzles in lieu of carbide nozzles, which can severely damage the drill bit used for subsequent shoe-track drill out[8].

Equipment Selection: Liner System. The same concerns about liner-running/drilling-tool selection as in Case History Two applied in this situation. As a result, a similar system in the 7-in. size was chosen **(Fig. 7),** which was specifically designed for torque values up to 53,000 lbf/ft. Case History Two provides a detailed description.

LD Operations. The planned liner-drilling procedure called for the 9 5/8-in. production casing to be set approximately 50 ft above the known loss zone. The 9 5/8-in. casing would then be drilled out with conventional means and WBM, with a FIT taken at the shoe, and then the fluid system displaced with an aphron fluid system. At that point the conventional BHA was to be pulled and LD operations commenced to drill the 7-in. liner in an 8 1/2-in. hole to a competent formation below the hazard interval.

The 9 5/8-in. production casing was set and cemented in place at 4,150 ft MD. An 8 1/2-in. mill-tooth bit and "slick"

BHA were used to drill out the 9 5/8-in. casing and 10 ft of open hole to 4,160 ft MD, where an 11.5-ppge FIT was obtained. The 9.4-ppg WBM was displaced with an 8.8-ppg aphron fluid system, and 20 ft of new hole was drilled to 4,180 ft MD. At this point a 2 9/16-in. drillpipe drift was dropped through the drillpipe to ensure sufficient clearance for the CWD bit-conversion ball, liner-setting-tool release ball, and wiper plug to pass. The 8 1/2-in. BHA was then retrieved, and the 7-in. liner-handling equipment was rigged up.

The 7-in. × 8 1/2-in. CWD bit, 837 ft of 7-in. liner, the running tool, and the PBR were run in the well on 5-in., 19.50-lb/ft G-105, 4 1/2-in. IF drillpipe to 4,122 ft MD. Nine 7-in. × 8 1/4-in. solid-body, spiral-blade nonrotating centralizers, straddled by stop rings, were spaced every other joint on the liner. The 8.8-ppg aphron fluid was circulated at the 9 5/8-in. shoe, and the liner was run to 4,180 ft MD; from this point it was drilled to 4,222 ft MD, where returns were lost. The liner was picked up into the 9 5/8-in. shoe, and the well was monitored on the rig's trip tank, with an estimated 96 bbl of fluid lost to the open hole. The liner was run in the hole, and drilling continued to 4,231ft MD, with no returns; the liner was again picked up into the 9 5/8-in. casing shoe,and an estimated 183 bbl of fluid was lost to the open hole while monitoring the annulus on the trip tank. Drilling continued to 4,236 ft MD, with no returns; the liner was picked up into the 9 5/8-in. shoe, with an additional 173 bbl of fluid loss.

The liner was drilled from 4,237 ft to 4,677 ft MD, with no returns; drilling ceased when the ROP became uniform, indicating that the liner shoe was in competent formation. During this interval, seawater was pumped down the liner, with the annulus kept full with aphron fluid. Every 30 ft a 5-bbl aphron sweep was pumped, and the annulus took an average of 20 bbl/hr of aphron fluid while drilling this interval. The parameters shown in **Table 8** were observed during the 7-in. LD operation:

Table 8: LD Parameters, Case History Five

Interval drilled	4,181 to 4,677 ft
Interval length	496 ft
Rotary speed	50 to 80 rpm
WOB	5,000 to 15,000 lb
Surface torque	1,600 to 2,500 lbf/ft
Pump rate	196 to 368 gpm
Pump pressure	245 to 390 psi
Average ROP	22 ft/hr (on bottom)
Mud weight (aphron) (WBM)	8.8 ppg
Total LD time	30.5 hr

The CWD bit was then picked up 3 ft off bottom, and a 1 3/4-in. brass ball was dropped down the drillpipe and pumped at 5 bbl/min, with 297 psi to the bit ball-seat funnel. Pressure was increased to 2,190 psi, with a sudden pressure decrease indicating that the bit had displaced the blades to the annulus. Circulation was resumed at 105 gpm, verifying successful CWD bit conversion.

The liner was set on bottom with an additional 20,000 lb as part of the releasing procedure. A 2 1/4-in. rubber-coated brass ball was dropped down the drillpipe and pumped at 2.3 bbl/min, with 91 psi to the ball seat. The ball-seat shear pins were sheared with 700 psi, and verification of liner-setting-tool release was confirmed with 17,000 lb of liner weight loss.

Approximately 30,000 lb of set-down weight was applied to the liner to counter pump-out forces for the upcoming cement job, and the liner was cemented with a single-cement slurry consisting of 200 sacks of a 16.4-ppg Class H blend. The cement slurry was displaced with 97.5 bbl of fluid, with the liner-wiper plug bumping with 1,000 psi and the float valves holding. The cement job was pumped without fluid returns; however, pump pressure was increasing, with 15 bbl left in the displacement, indicating that there was cement lift around the 7-in. shoe. This outcome was later verified by a subsequent sonic logging suite.

The liner-setting tool was retrieved without incident, and a polishing mill assembly was run through the PBR in preparation for the second-trip liner-top packer run. The mills were retrieved, and the 7-in. × 9 5/8-in. liner-top packer assembly was run with the tieback stem seals properly engaging in the PBR and the packer set testing to 1,500 psi without incident.

A 6 1/8-in. tricone insert bit and BHA were used to drill the 7-in. shoe track and 10 ft. of new formation with 15,000 lb to to 20,000 lb WOB and 60 rpm. Approximately 11.5 hr were required to drill out the landing collar (at 4,576 ft MD), float collar (at 4,623 ft MD), cement, CWD bit (at 4,677 ft MD), and 10 ft of new hole. The liner was tested to 4,000 psi successfully, and an FIT of 11.5-ppg equivalent mud weight (EMW) was performed. The 6 1/8-in. hole was drilled to 5,850 ft, and a dipole sonic tool run up into the 7-in. liner during subsequent open hole logging indicated that the probable top of the 7-in. liner cement was 4,350 ft **(Fig. 8)**[2].

Conclusions

A review of these various case histories provides a clear indication of the benefits of LD technology in difficult drilling environments:

- LD with CWD bits can enable setting liner at planned depth in severe and unstable lost-circulation zones.
- The narrow annular geometry created by LD reduces the rate of fluid loss in the annulus as compared to conventional drilling operations, enabling the annulus to be filled with trip tank or other dedicated annulus pump.
- The reduction in annular geometry seen with LD can enable the smear-effect phenomenon, the mechanism believed for reduced fluid losses observed in CWD.
- LD systems can maintain inclination and azimuth angle sections over hundreds of feet.
- In all cases cited, a considerable impact on NPT and overall costs was apparent.

Acknowledgments

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Figures

Fig. 1. 7 5/8-in. × 8 1/2-in. CWD Bit with TSP Diamond Cutting Structure

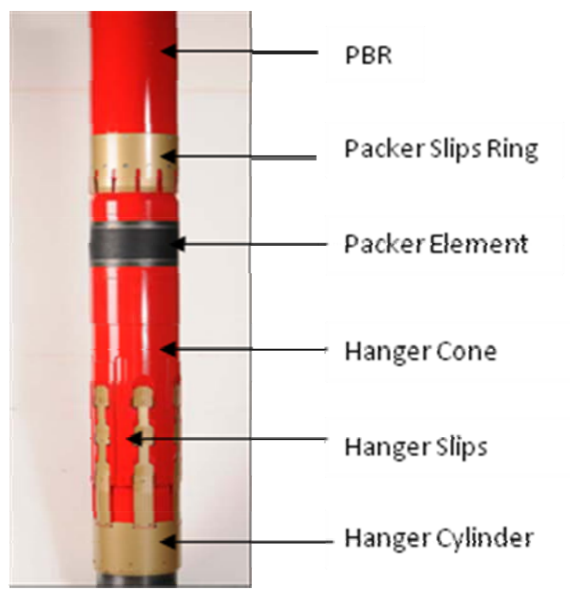

Fig. 2. Liner Hanger System

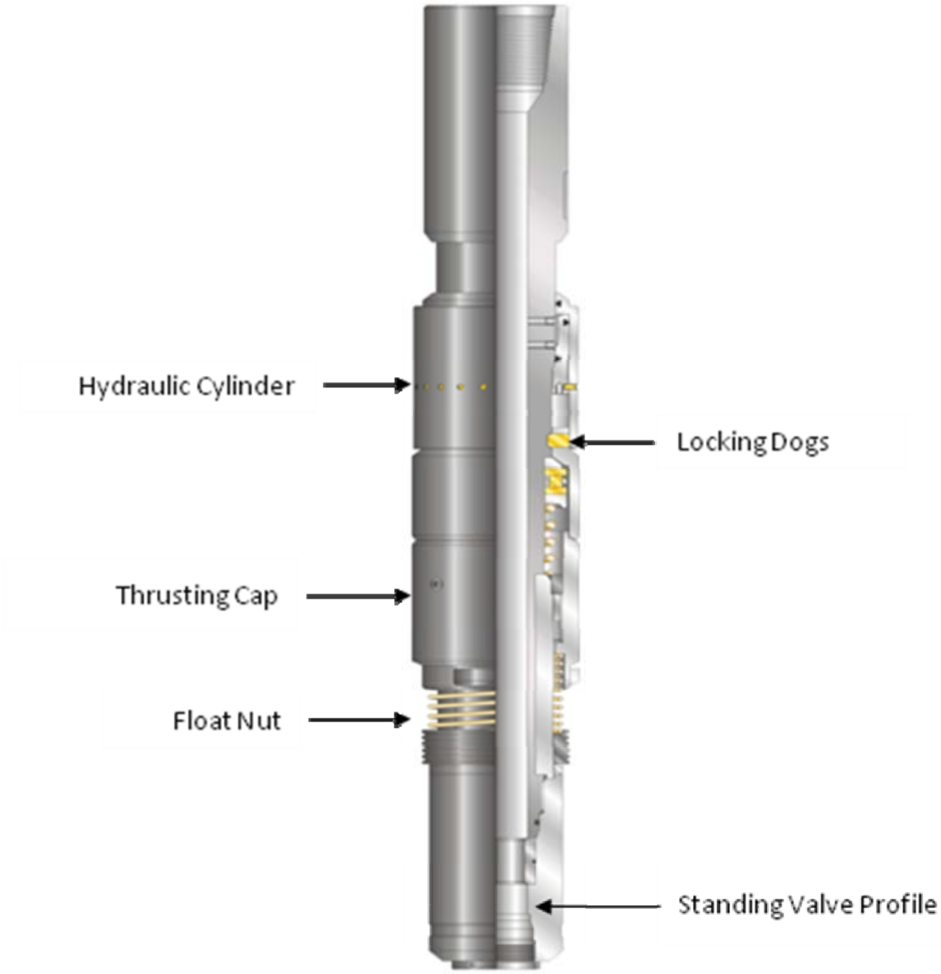

Fig. 3. Liner Setting Tool

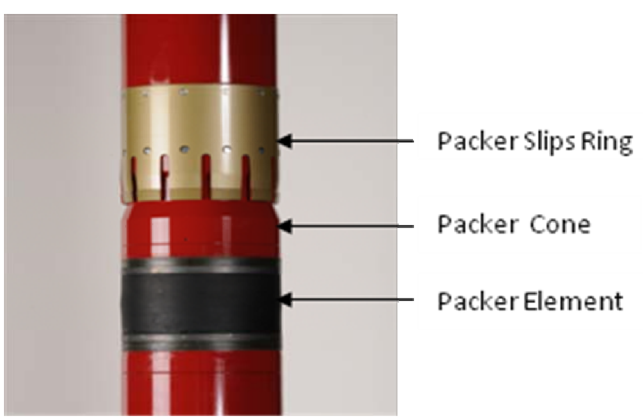

Fig. 4. Liner-Top Packer

Fig. 5. 9 5/8-in. × 12 1/4-in. Displaceable CWD Bit

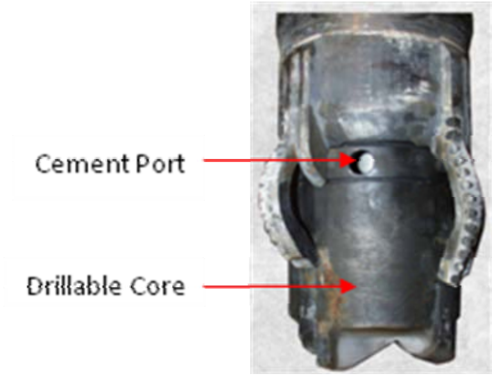

Fig. 6. CWD Bit with Blades Displaced

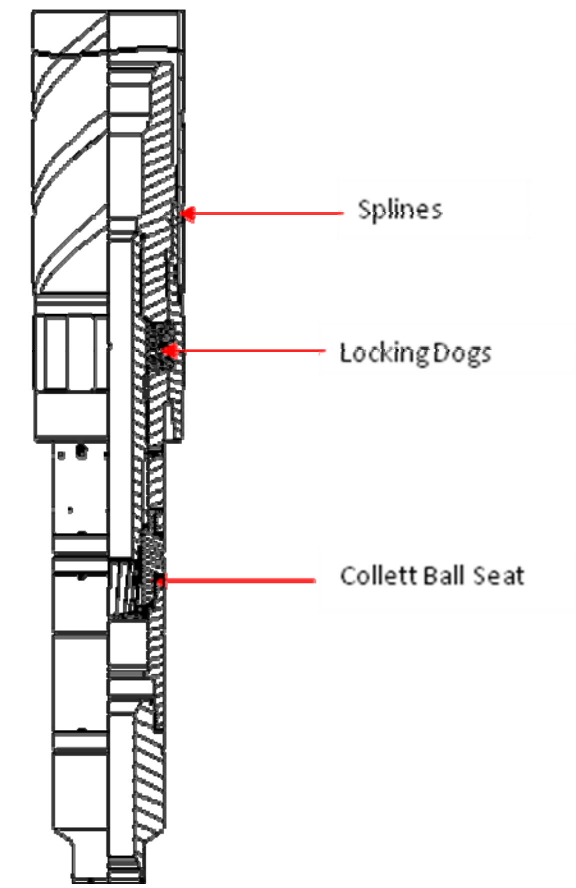

Fig. 7. Hydraulic Liner Setting Tool

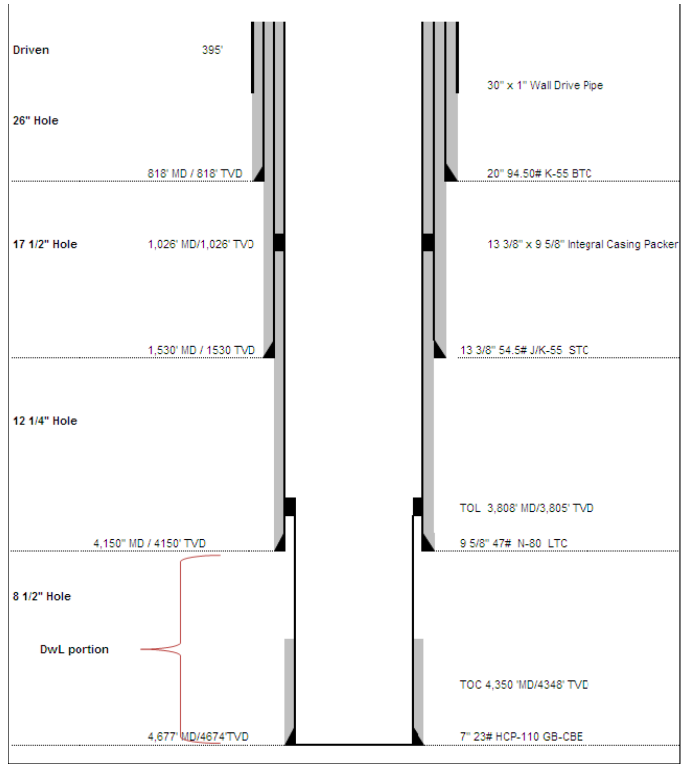

Fig. 8. Case History Five Well Schematic