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Well Architecture in the Lower Tertiary Gulf of Mexico – Challenges and Potential Solutions

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Abstract

Deepwater wells in the 'Lower Tertiary' play in the Gulf of Mexico are completed through large vertical intervals comprising of multiple high pressure hydrocarbon layers with low permeability. Operators are faced with numerous challenges to economically produce these reservoirs including: low permeabilities requiring multiple hydraulic fractures; highly pressured, deeply buried reservoirs over large intervals to complete and isolate; and high differential pressures during stimulation and production. The technology currently in use tends to address many of these challenges, however the productivity of these wells is still relatively low and the well costs remain high. This paper will review the challenges encountered in these wells, and the technologies currently used to address them. It will also outline potential well design and construction approaches for consideration by industry to improve well productivity and increase reliability.

Introduction

Wood Mackenzie (2015) reports that over 5.7 billion Boe in recoverable reserves have been discovered in the Lower Tertiary (LT) to date, and added that the play contains the largest amount of 'yet-to-find' volumes in the region. It also noted that measures taken to increase recovery factors above the industry-standard value of 10% could result in a significant positive impact on post-tax IRR for these projects. The primary intent of this paper is to foster industry discussion and to promote further collaboration to ensure that these wells provide the maximum value to a growing number of development projects in this important play.

In addition to the technical challenges common in deepwater developments, well design teams are constantly tasked with finding innovative solutions for maximizing the EUR for each well, which is critical for achieving economic targets. The performance and reliability of the producing wells are arguably amongst the most important factors influencing the economic success of a Lower Tertiary project, and in some developments may represent the largest capital investment on a percentage basis. Simply put, the completed wellbore is the 'lifeline' of the project.

The Lower Tertiary Play

The water depth for LT GoM developments ranges from 4,000 ft to 10,000 ft. Well depths have exceeded 35,000 ft TVD in cases, but commonly fall in the 25,000 ft to 32,000 ft TVD range. Many of the fields in the LT play are covered by a salt canopy approaching 20,000 ft thick, and reservoir pressures can reach upwards of 29,000 psi. Bottom hole static temperatures normally range between 250–300°F.

The LT Wilcox reservoir was described by Haddad et al (2011) as large vertically stacked thin beds of sand and finely grained siltstone with very limited vertical permeability, including large shale breaks between some of the pay zones. The reservoir in the field described was encountered at an average depth of 25,600 ft TVD (approximately 17,000 ft TVD-BML), with gross sand thickness of 1,200'. This falls in the range of reservoir target depths between 10,000 ft – 30,000 ft TVD-BML noted elsewhere (Kliewer, 2011). Permeability in these reservoirs ranges between 5–50mD. The reservoir fluid is low GOR under-saturated oil.

Challenges

As these very low permeability reservoirs are typically drained through natural depletion (with no aquifer support), they exhibit a low productivity index coupled with high drawdown pressures. This introduces a constraint on the maximum allowable drawdown to prevent formation and downhole equipment failure. The geological structure of the large reservoir interval also imposes limits on the ability to maximize contact area between the wellbore and formation. In an ideal situation, a deviated well through such a large pay zone with multiple layers could enable greater contact with the reservoir. However the need for hydraulic fracturing in these reservoirs requires a near-vertical inclination of less than 10–15 degrees through the reservoir targets, for the following reasons:

- To ensure that the vertical fractures remain aligned axially with the wellbore to maintain contact with other perforations.
- To minimize near-wellbore tortuosity as the fracture orients itself in the direction of the maximum in-situ stress (assumed vertical) once it propagates into the far field stress region. This promotes effective proppant transport into the fracture, and reduces the risk for early screen-out.
- To facilitate the proper installation and operation of the 'single trip multi-zone″ STMZ lower completion assembly, which would be hindered by a wellbore with high dogleg severity.

The stimulation program must be carefully thought out early in the well planning process, first by performing extensive modeling to establish the appropriate number of vertical fractures required to access as much of the oil in place as possible, then by optimizing the job design to maximize their length for increased reservoir contact area. This objective is made more difficult by the varying mechanical properties of the layers throughout the pay zones. This results in different in-situ stresses throughout the treated interval, which affect fracture behavior. Additionally, there may be water zones nearby that must be avoided by the hydraulic fractures, which must also have sufficient vertical height to drain nearby hydrocarbon layers. This challenges engineers to design and execute the optimum stimulation program that maximizes contact with the pay zones, while minimizing risk of water production (Haddad et al (2011).

The extreme depths and high formation stresses require very high treatment rates to provide adequate energy downhole to facilitate effective hydraulic fracturing, which can result in elevated surface pressures. These high rates also increase the risk of erosion of the equipment by the proppant, which becomes more of an issue when using STMZ systems, because the same assembly is used to treat all of the zones. This coupled with the rating of the equipment, imposes a limit to the number of zones that can be pumped with a single STMZ run.

During production, high drawdown pressures result in tremendous closing stresses on the proppant, which must resist crushing that could impair productivity. For this reason, high strength proppant must be used. The lack of pressure support in the low permeability formation means that production will undergo a steep decline. At that point operators may consider the feasibility of improved recovery equipment such as ESP's or subsea pumps. The additional load capacity required for tubulars and completion equipment to accommodate the anticipated maximum drawdown pressure often results in very tight clearances, increased friction pressures, and may pose risks for mechanical problems during installation.

Current Technology

A literature review of STMZ installations in the Lower Tertiary GoM showed a recent field application that provides an example of the current capabilities of the technology. It consisted of a three-zone STMZ system rated to 12,500 psi differential pressure, coupled with an intelligent well completion that included downhole temperature and pressure gauges, a downhole flow meter, and two downhole control valves rated to 12,000 psi. The system was designed to provide the operator a higher degree of monitoring and control of the Wilcox 1 and Wilcox 2 reservoirs than had previously been available in the field, allowing management of the Wilcox 2 in the event water production becomes excessive (Joseph, 2015).

The immediate / near term well designs in the LT will likely use the field proven cased hole STMZ completions, with suppliers continuing to make improvements in pressure ratings, flow capacity, etc. It is expected that STMZ systems able to withstand differential pressures up to 15,000 psi will be available on the market in the near future, if not already available. For the longer term, industry will need to make advancements in well design and completion techniques to enable significant increases in recovery factors over today's levels, and these efforts are underway.

Potential Future Improvements

As with any endeavor involving such challenges, variables and constraints, the path forward for the LT will involve technical advancements on many fronts to increase well recovery and reliability. Our industry is not new to these types of challenges, and will continue to meet them head-on through collaborative innovation. In fact, many of the industry's most significant technological achievements resulted from other such 'EUR-constrained' undertakings such as unconventional and brownfield developments – the most applicable to this discussion being multizone hydraulic fracturing. Once field-proven, many such technologies have later been applied elsewhere to meet similar challenges, and the LT could be one of those cases.

Topics to be considered for potential improvements are discussed below, focusing on ways to increase EUR from each well by improving reservoir contact, and achieving effective stimulation. Methodologies for improving operational decision-making and assessing well integrity will also be explored.

Well Architecture

Large Hole Sizes One of the most important areas of focus going forward will address the capability to reach the reservoir in the largest hole size possible. Doing so will ease some of the constraints imposed by tight clearances, and allow for more robust completion equipment designs with higher pressure ratings and increased flow areas – beneficial both during the stimulation operation, as well as during production. As a base case, LT wells will likely require at least an 8.5″ drift casing (~12.25″ hole) through the reservoir. However, increasing this diameter even more would facilitate the installation of higher capacity production systems that are designed to withstand the additional loads resulting from increased drawdown pressure. Larger ID casings would also allow more clearance to install any additional downhole equipment that can improve performance, such as intelligent completion equipment for flow control and monitoring, submersible pumps (ESP), and high-capacity multilateral junctions.

Deepwater drilling engineers have long been tasked with finding novel approaches to preserving precious hole diameter through the target objectives. To achieve this, they start by finding ways to increase the diameter of the surface casings, as well as to extend the setting depths for all of the strings, and many approaches have been applied to address these goals. Two of these approaches with potential for the LT are managed pressure drilling (MPD) and solid expandable tubulars (SET), describe below.

Regardless of the technique used to achieve larger hole sizes in deeper sections, the longer strings of large intermediate casings could pose some challenges, mainly due to hookload. Many of the newer generation rigs are being built with 2.5MM lb derrick capacities, which should accommodate these heavier strings. For a very deep-set 14″ intermediate casing however, it is not uncommon to run it in sections – first as a liner, then 'tied back' to surface with an additional run.

Managed Pressure Drilling Various MPD techniques have been used by the industry for decades to drill challenging wells, including those in deepwater environments. MPD is defined by the International Association of Drilling Contractors as ″an adaptive drilling process used to control precisely the annular pressure profile throughout the wellbore″, and includes a variety of tools and techniques to achieve this, by manipulating a combination of such parameters as: fluid density, annular fluid height, back pressure, and circulating rate (Hannegan, 2011). Two variations of MPD that have the most potential for increasing hole sizes in LT wells are described below:

Constant Bottom Hole Pressure (CBHP) The most common of the various MPD methods, CBHP employs a rotating control device (RCD) at the top of the riser – either above or below the tension ring (Hannegan, 2011). Many new generation deepwater rigs are being equipped with these devices during their construction, but they can also be retrofitted into existing rig systems.

With this method, the bottomhole pressure is controlled through a combination of static mud weight, surface back pressure and circulating rate, allowing more precise control of the pressure profile within the wellbore pore pressure and fracture gradient limits. With this enhanced capability, the hole section TD may be extended deeper than would be possible when using conventional drilling methods by expanding the drilling window and enabling fewer casing strings to be run, resulting in larger hole through the reservoir.

As this system is essentially a closed loop and pressurized system, it also improves the ability closely monitor the wellbore while drilling, providing the operations team with enhanced capability to detect, diagnose and mitigate hole problems (such as losses or instability).

Dual Gradient Drilling (DGD) This variation uses a combination of fluid densities and annular fluid height to control the bottom hole pressure, as well as the slope of the pressure gradient from surface to TD. The technique is used with or without a riser, the latter being the most commonly applied. In fact most deepwater wells use a basic riserless DGD approach to prevent shallow gas or water flow, as well as to provide additional wellbore support to enable setting the 22″ casing as deep as possible (which is key to pushing subsequent casings deeper once the BOP in installed). This is accomplished by drilling with a sacrificial weighted mud (water based), which is normally discharged at the seabed. The mud weight is normally in the 12.5 ppg range, when combined with the ~8.5 ppg seawater gradient to the mudline, imparts a bottom hole equivalent mud weight in the 9.0–9.5 ppg range.

Once the riser is installed, the advantage of a DGD technique is that it creates a pressure profile in the wellbore that better matches the natural pressure profile, particularly in the upper portion of the well, enabling longer hole sections than would otherwise be achievable with a 'single gradient' drilling fluid. The industry has put forth significant efforts over the last 20 years or so to develop DGD systems intended for use in sections below the surface casing such as those described by Smith et al. (2001), Kozicz (2007), and Cantrell (2013). The resulting wellbore pressure profile when using DGD compared to conventional 'single gradient' approach, is best illustrated in a diagram, shown below in **Figure 1**.

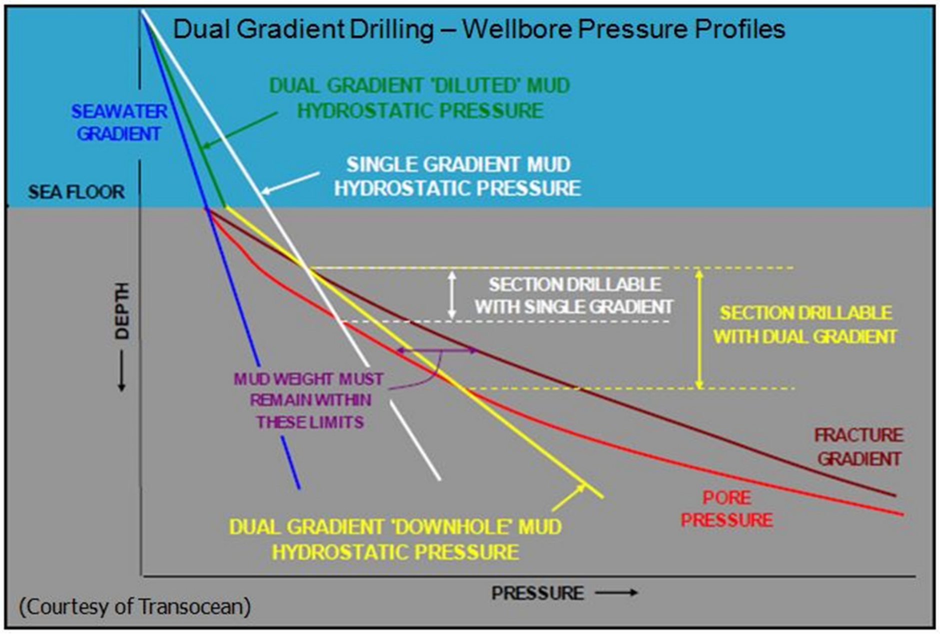

Figure 1—Wellbore pressure profiles associated with Dual Gradient Drilling

One equipment supplier has developed a DGD 'riserless mud recovery' system for recovering fluids to the surface in a riserless drilling application, as well as another method used in risered sections, that controls ECD by varying the height of the fluid in the riser through the use of a subsea pump (Stave, 2014).

Solid Expandable Tubulars Over the last 15 years or so, (SET) systems have been successfully deployed all over the world, enabling well designers to meet their objectives in the planned hole size. This novel solution can be used to retain hole diameter through narrow pore/fracture pressure windows, as well as to provide additional integrity required to reach the originally planned casing depth when unexpected trouble zones are encountered (such as lost circulation or wellbore instability). The deep, high pressure LT conditions combined with the tight clearances associated with the heavy-wall casing architecture used in these wells, demand specific tubular designs to enable the use of SET. In coordination with their customers, the suppliers of SET technology have continually evolved the load capacities and deployment methods to meet such challenges over the years. The current generation of 'High Performance' SET technologies have significantly higher mechanical and temperature ratings than previous offerings, and are commonly used for DW applications in the GoM (Bullock et al., 2014). The evolution of this technology will certainly continue, providing well designers in the LT with additional capability to accomplish their objectives.

Multilateral Wells As with other plays across the globe with similar EUR-related challenges as the Lower Tertiary (primarily those with tight, highly laminated or compartmentalized reservoirs), any discussion on potential technologies to increase reservoir access will inevitably land on multilateral technology (MLT). This is likely due to its proven track record in other plays, although not necessarily having the specific technical challenges faced in the LT. The multilateral technology consists of drilling several branches out of a single borehole, which allows an increase in wellbore-to-reservoir contact while limiting the number of surface penetrations. MLT can be beneficial if the main bore is very difficult / time consuming to drill, or when seabed conditions severely limit the number of surface locations available for the ideal development scenario.

A comprehensive study performed by a major service company revealed that overall, the technology has a very high degree of reliability (approximately 96% for the ~670 wells studied). This level has been achieved despite the complexity often associated with installing it, particularly in subsea environments, which present additional challenges. These are mainly due to rig heave, and the challenges of using surface measurements for key downhole parameters such as weight-on-bit, torque, orientation, and depth. These and other challenges lend towards a design with pre-milled windows installed on a liner for subsea applications (Butler et al., 2015).

For Lower Tertiary wells however, several challenges remain in the way of applying MLT technology such as: (1) increasing the equipment rating to the pressures required for LT; (2) having a firm understanding of the mechanical properties of the reservoir and overlying formations; (3) enhanced drilling technologies that increase the capability to drill more complex well paths, and (4) larger main bores near the reservoir level to accommodate a high capacity junction. Also, while the overall cost may be lower for a multilateral well with the same effective reservoir contact as two conventional wells, the designer must also consider the performance of each option, installation risks, as well as intervention capabilities (Wang, 2012). In any case, industry study required for overcoming the challenges for applying this technology in LT conditions will certainly continue, and at least one operator with significant experience with MLT in other fields suggests that it could be done (McCulley, 2013).

Completion Approaches

STMZ Advancements While several approaches are being examined in the industry to improve EUR in LT wells, the overall objective is to ensure that the completion is able to contact maximum of amount of the reserves in place with highly conductive hydraulic fractures. The first approach towards this goal is to continue enhancing the capability of the field proven STMZ technology by increasing pressure ratings and flow areas, as well as addressing any other constraints that may limit the number of zones that can be stimulated with a single trip system. In some reservoirs (particularly those with extreme vertical heights), this may not be feasible with a single trip system, and designers may have to consider using stacked systems, whether they be STMZ, single zone, or a combination thereof. While this approach will add time, it may be justified if it allows significant gains in reservoir access.

Unconventional-Type Approaches Another approach to potentially stimulate more of the reserves in place could be to apply technologies developed successfully for onshore unconventional plays, designing them to perform in the higher pressure, temperature and load conditions of the LT. These types of systems could potentially allow a larger number of stages over multiple intervals, through the use of sliding sleeves and dedicated fracturing ports such as those described by Wibowo et al. (2014), thereby affording more precise placement of entry points.

In conjunction, different approaches to proppant flowback and sand control should be examined for LT completions that eliminate the drawdown restrictions imposed by the screens, while also eliminating the need for a screen/casing annular gravel pack. This would allow designers to optimize fracture placement and provide higher treatment rates during stimulation, resulting in more effective fractures. In addition, it may also provide more flexibility to recover from a failure during the treatment of a particular zone. This may involve the use of resin coated proppant, sand control screens incorporated into the production casing string, as well as ‘post-frac’ installation of solutions such as stand-alone screens.

Improved Oil Recovery

To achieve higher production and recovery factors than achievable with natural depletion, operators have examined improved oil recovery technologies such as ESP and subsea boosting. If used, the well design must accommodate the higher differential pressures to be imposed on the production system. Currently, the use of subsea boosting is the most common secondary recovery technique for LT developments, mainly due to some of the limitations that must be overcome with ESP technologies. These are mainly associated with the pressure rating, power requirements, and reliability, and the cost of interventions.

Installing or replacing an ESP in a LT-type well is an expensive and risky process, and this is limiting the use of this potentially valuable technology. Robust designs are therefore needed that ensure reliability and maximize the timeframe between well interventions, as well as minimize duration required to perform the operations. Innovative ESP configurations applied in conjunction with upper completion/subsea infrastructure designs that facilitate rig-less intervention systems would also unlock potential for this technology.

Downhole Measurement / Integrity Assurance

The inherent nature of deepwater operations, and in particular the complexity associated with drilling the well and installing an effective and reliable production system, demands a concerted effort across many disciplines and companies, who collectively engage in an extensive amount of planning and preparation before handing over the well program for execution by the operations team. While the quality well design itself is of paramount importance, the key to the ultimate success of the well lies in the operations team's ability to execute the well program with an extremely high degree of HSE and operational excellence – while ensuring that all systems and components perform their engineered functions for the life of the well.

In some cases, integrity issues may only be detected once the well has been in service for some time. When a well goes out of service before its intended life, it may be impractical or uneconomic to intervene or to drill a replacement well. Therefore the value of technologies employed during the construction phase that lower the probability of well failure can be significant. To clarify, 'well construction' means all well activities typically performed by the MODU, from spud through handover to production. These include drilling, tripping, running casing, and cementing, as well as setting and testing casing/liner hangers, seal assemblies, packers and other barrier systems. It also includes installing the lower completion, stimulation operations, and running the upper completion assembly, and all associated integrity testing required throughout.

Achieving 'game-changing' increases in performance and operational excellence can be accomplished with a unified approach – by providing well operations personnel with high quality decision-support tools that are based on more downhole measurements taken during *all* activities in the well construction process, in addition to just drilling ahead. In addition to the actual measurements, this will also involve a combination of enhanced telemetry methods, analytics, and display technologies. Note that this does not imply that surface-based measurements are inadequate in many cases, only that they could be complemented by more downhole measurements to increase the resolution and awareness of the actual downhole conditions at opportune times.

These tools can facilitate 'in-time' detection and diagnosis of problematic events, as well as increase the ability to properly verify critical components upon installation. With these enhanced 'inspection' capabilities, operations personnel may be able to detect anomalies that may otherwise have went undiscovered until later in the well's life, and doing so at the most opportune time to address them (i.e. with better access to the element, without subsequent components in place that may block access, and most importantly, while the rig is still on the well).

Until fairly recently, widespread use of real-time downhole measurements specifically for well construction-related decision making (as opposed to formation evaluation) have remained limited mostly to directional data, bottom hole annular pressure, and temperature. While some real-time LWD data are used for critical drilling-related decisions (i.e. casing seat selection and pore pressure prediction), for the most part this data is used by the geoscientists. Also, these data are normally only available in real-time while drilling/circulating at sufficient rates for mud pulse telemetry, unless wired drill pipe is in use. Otherwise, surface measurements have primarily been used for certain downhole parameters such as weight, torque, static pressure, etc.

Furthermore, for 'non-drilling' applications such as cementing, displacements, setting packers/slips, and pressure testing, surface readings are also predominately used, then often coupled with modeled or assumed wellbore conditions to assess the actual parameters downhole. A recent notable exception to this is in the hydraulic fracturing operation, during which downhole temperature and pressure gauges are employed in the fracturing assembly to provide the engineers with critical downhole information in real-time, so that the fracturing treatment can be optimized ‘on the fly’.

The good news is that all of this is changing, and particularly in the area of drilling dynamics. Systems are available on the market that apply advanced telemetry and analytical methods to downhole and surface data in real-time. This facilitates manual or automated adjustments to optimize drilling parameters, and can also assist in detecting downhole anomalies. These systems are described further in the literature (Cayeux et al., 2013), (Sharma et al., 2010), (Gunderson et al., 2012).

An alternative telemetry method described by Reeves et al. (2013) uses acoustic signals to transmit downhole data in real-time using a standard drill string or work string. An application of this technology for monitoring sweep effectiveness in an onshore horizontal well is detailed in the literature. According to the supplier, this acoustic telemetry network is now providing downhole data in real-time in the deepwater Gulf of Mexico for such applications as: liner running and setting, cement displacement, installation and monitoring of hydraulic fracturing operations, transmitting data while tripping and in no flow environments, across packers and through closed BOP’s. Qualification for deepwater drilling is ongoing, including bi-directionality and the ability to interface with other downhole data providers such as MWD and LWD tools (Hawthorne, 2016).

The integration of such technologies into all phases of the well construction process could increase efficiency, provide more robust integrity verification, as well as improve the learning capabilities of the organization, potentially driving more efficient designs in future wells. Another added benefit is that the organization may be able to de-risk challenging well designs such as multilaterals or any other approach that may not otherwise be attempted without such advanced capabilities.

Conclusions

In these challenging times, the industry should find ways to capitalize on these additional constraints to make step changes in the way these wells are drilled and completed. The outcome of such efforts will facilitate more effective well designs that maximize reservoir contact, with least amount of impact on inflow potential, while also ensuring that the wells last for their intended life, including facilitating the use of enhanced recovery technology such as ESP’s. Overcoming these challenges will result through evolving existing technology, adapting solutions from other types of hydrocarbon plays, as well as the implementation of new technology. Summarized below are some key areas that are expected to open new horizons in LT development:

– Drilling technology such as managed pressure drilling and expandable tubulars that facilitate large hole sizes through the reservoir.
– Novel completion equipment and techniques that maximize reservoir contact area and stimulation efficiency, while reducing flow restrictions.
– Adaptation of unconventional wisdom to the deep offshore and potentially the use of multilateral / branched wells
– Downhole measurement, telemetry, and advanced analytics that enable high quality operational decision support throughout all phases of well construction.
– Improved recovery techniques such as ESP and subsea boosting, including robust well designs that accommodate the higher drawdown, provide clearances for downhole equipment, as well as improving the reliability of these systems.

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Nomenclature

Boe	– barrels of oil equivalent
BHP	– bottomhole pressure
BML	– below mud line
BOP	– blowout preventer
CBHP	– constant bottomhole pressure
DGD	– dual gradient drilling
DW	– deepwater
ECD	– equivalent circulating density
ESP	– electric submersible pump
EUR	– estimated ultimate recovery
GoM	– Gulf of Mexico
GOR	– gas/oil ratio
HSE	– health, safety and environmental
IRR	– internal rate of return
ID	– inner diameter
LT	– lower tertiary
LWD	– logging while drilling
mD	– millidarcies
MD	– measured depth
MODU	– mobile offshore drilling unit (drilling rig)
MPD	– managed pressure drilling
MWD	– measurement while drilling
NPT	– non-productive time
psi	– pounds per square inch
ppg	– pounds per gallon
RCD	– rotating control device
RF	– recovery factor
RMR	– riserless mud return (system)
SET	– solid expandable tubular
STMZ	– single trip multi-zone
TD	– total depth
TVD	– true vertical depth

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