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Accurate Placement of Vertical Wells with Rotary Steerable System Technology: Case Studies in South Texas, USA

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Abstract

A safety-conscious, efficient wellbore drilling method features highly accurate wellbore placement, reduced drilling time, and improved safe drilling practices. Rotary steerable system (RSS) technology provided a cost-efficient solution in a high-volume environment for a US-based oil and gas exploration company drilling 80 to 100 wells per year in South Texas, USA.

Although vertical drilling has been in practice since the birth of the industry, maintaining verticality is still challenging and requires alternative drilling strategies. Traditionally, downhole positive displacement motors (PDMs) have been used to control the wellbore vertically in this drilling environment. This drive system typically requires one or two additional bit runs to achieve the target objectives. A reduction of the weight on bit (WOB), or feathering, was also required to maintain a vertical wellbore. The combination of this drive system coupled with the lower-than-optimum WOB leads to a dramatic reduction in rate of penetration (ROP) when steering is required, which is neither cost-efficient nor desirable. The introduction of RSS technology has addressed both of these concerns by allowing the application of higher WOBs for faster ROP while maintaining high levels of wellbore placement accuracy.

RSS technology in this environment increased the number of drillsites available, as the surface location can be right on the “hard-line” of 467 ft from the lease line required by the Texas Railroad Commission. Previously, fewer lease-line wells were drilled owing to the problems of keeping the accumulated displacement inside the lease dimensions.

This paper presents field studies from 2004 to 2006 demonstrating RSS success in maintaining verticality where the bit tends to walk related to highly faulted, fractured, and dipping formations. The RSS system provided real-time response and a vertical wellbore. Instantaneous wellbore corrections reduced drilling time in some cases more than 40%.

Introduction

In the South Texas region, USA, vertical wells that might drift close to the lease line and thus require corrective action were avoided owing to the expense of drilling them. However, as a result of recent increase in gas prices plus a need to more fully exploit existing leases, the decision was made in 2004 by a US-based oil and gas exploration company to drill more lease-line wells.

These lease-line wells were initially drilled with conventional rotary assemblies, and if the well built angle, the first corrective action was to reduce WOB to get the bit to drop angle. However, this would significantly lower ROP and dramatically increase the time to drill a well. This has been exacerbated recently because current polycrystalline diamond compound (PDC) bit technology is progressing toward more aggressive, heavier-set bits for durability and to permit higher WOB to achieve higher ROP.

If the lower WOB did not provide sufficient correction, a steerable motor assembly was run in the production hole interval to steer away from the lease line. But this was done with slimhole tools in oil-based mud in a hot-hole, so tool run-time posed a problem. Also, starting in 2004, availability of the high-temperature slimhole tools was becoming problematic, which led to the use of RSS tools in the intermediate hole section.

The goal was to keep the well vertical until reaching the intermediate casing point, thus keeping accumulative drift inside the lease line. This allowed the operator to maintain high ROP in the intermediate- and production-hole intervals and to use conventional bottomhole assemblies (BHAs) in the slimhole production interval. This scenario also provided a secondary benefit of mitigating depletion concerns in the Perdido Sand interval.

Traditionally, RSSs were generally used only in complex, high-cost offshore projects where the savings realized were significant as a result of the relatively high daily spread rates. The industry has been slower to adopt the use of RSS for onshore vertical drilling applications, and steerable PDM assemblies have been used for the majority of such applications for the last several decades. Unfortunately, this type of assembly is often very inefficient owing to difficulties associated with sliding and with maintaining optimum WOB for maximum ROP.

However, more recent experience in drilling vertical wells in South Texas has shown significant benefits from the use of a fully rotating RSS for vertical drilling applications in highly faulted and dipping formations where vertical control is paramount. In this environment, RSS technology has permitted an increase in the number of drillsites available by making it possible to locate wells much closer to the lease line, even on the hard-line maximum of 467 ft set by the Texas Railroad Commission, which regulates drilling in the state. Previously, very few lease-line wells were drilled owing to the problems of keeping the accumulated displacement inside the lease dimensions. With the use of RSS, optimum recovery of each lease's resources becomes economically viable. Failure to stay within the 467-ft limit can have significant economic consequences. The operator cannot produce from any section of the well that crosses the line. If the well is brought back within the limits, the corrected sections can be produced, but this is seldom economically feasible.

Limitations of PDM and Traditional Rotary Drilling

Historically, the number of wells placed near lease lines has been limited by 1) the difficulty in maintaining verticality, 2) slow ROPs as a result of the requirement to slide the BHA to steer the well path back to vertical, and 3) the resulting increase in time and cost to complete the wells.

To use a steerable motor requires that the orientation of the bend is maintained to achieve the desired toolface setting. However, reactive torque from the PDM makes it difficult to accurately control toolface direction. The magnitude of this problem depends on the torque generated at the bit, which in turn, is a function of bit aggressivity, PDM torque output, drilling parameters, and the formation. As a result, steerable PDM drilling often requires a compromise in bit selection and drilling parameters.[1]

To better control the toolface while navigating the wellbore back to vertical using PDM, a roller-cone bit is used instead of a PDC bit, at the cost of additional trips for the hole section. The operator routinely pulls roller-cone bits for examination after ~300K revolutions. PDC bits are primarily used for conventional and RSS drilling.

To orient a PDC bit can be time-consuming and inefficient. The bit is frequently pulled off-bottom to control the reactive torque, and a reduction in WOB is often required to maintain the desired toolface. Toolface angle is proportional to the torque generated by the bit. The PDC bits, by nature, generate high levels of torque. If external force acting on the bit causes a PDC bit to over-engage, a large change in downhole torque is typically produced, thus causing rotation of the drillstring and loss of toolface orientation. This combination—the drive and bit system coupled with the lower-than-optimum WOB—leads to a dramatic reduction in ROP.

Use of a conventional rotary BHA can also result in inefficient drilling when strict verticality is required. As with a steerable PDM assembly, the directional behavior of the conventional rotary assembly is a function of the formation, drilling parameters, and stabilizer gauge and placement.[1] To maintain verticality, drilling parameters must often be adjusted to less-than-optimum requirements, with a sacrifice in ROP.

RSS Technology Evolution

First introduced in the late 1990s, RSS technology continues to evolve. The effect of the technology on the drilling process has been recognized within the industry.[1–4] Two types of RSS are presently available: push-the-bit and point-the-bit systems. Point-the-bit systems aim the bit at an angle in the desired direction, creating the curvature necessary to deviate the wellpath while continuously rotating the drillstring. One form of this form of RSS technology is available in a new tool that achieves point-the-bit operation with no sliding stabilizers or exposed steering mechanisms. Instead, an internal servomotor constantly controls the bit shaft toolface. The servomotor holds the toolface orientation of the angled bit shaft geostationary (not moving with respect to the formation). This produces consistent steering control in a wide variety of hole conditions. When steering with this RSS technology, the tool will rotate the offset in the opposite direction of the collar. If the motor is driven at collar RPM (but backwards), the toolface becomes stationary in the hole. The bit shaft now remains pointed in a constant direction. The tool is now steering while the collar is rotating. A major benefit of the tool is its ability to steer with bicenter bits. Figure 1 illustrates the components of this system.

Push-the-bit RSS steers by using hydraulically actuated pads to push against the side of the wellbore, thus displacing the tool and the bit in the direction desired.

For the case studies described in this paper, a push-the-bit configuration was used with three pads sequentially pushing against the side of the borehole as the drillstring rotates, while the central control valve remains stationary. Figure 2 illustrates the components of this system

The Bias Unit consists of an internal rotary valve, which controls the hydraulic actuation of three externally mounted pads.

The Control Unit is a geostationary electronics package mounted within the collar. The Control Unit derives power from the flow of drilling fluid across an impeller. It houses the control electronics and directional instrumentation required to control the tool's behavior and is able to hold itself stationary inside the rotating collar.

Attached to the downhole end of the Control Unit is a control shaft that extends into the Bias Unit. When the Control Unit is stationary, so is the control shaft. A valve on the end of this rod seats over three ports that rotate together with the rest of the Bias Unit. As each port passes beneath the stationary valve, drilling fluid is diverted into it, activating one of the three pads. The process results in each pad pushing out at the same relative position in the borehole to force the bit in the opposite direction. The amount of time that the Control Unit is held stationary over a given period of time determines the dogleg capability of the tool.

A Stabilizer acts as a third point of borehole wall contact for directional control. Selection of the option of string, integral blade, or sleeve-type stabilizers allows the position and size to be varied to fine-tune the BHA behavior in different environments. An optional flex joint can be used to increase the dogleg capability of the system.

Like all steerable tools, the RSS tool is placed in the BHA directly above the bit and below the measurement-while-drilling/logging-while-drilling (MWD/LWD) equipment. The bit is screwed into the lower connection of the RSS and the MWD/LWD tools are screwed onto its upper connection.

Case Studies: Charco Field Drilled with RSS

The portion of the Charco field under discussion here consists of approximately 35,000 acres and is divided into east and west segments by three large faults (1,000-ft to 1,500-ft throw) that trend northeast to southwest. There are two primary pay intervals: the Perdido and Lobo sands. Figure 3 shows a schematic cross section of the geologic environment.

The upper pay interval is the Perdido sand package, part of the Middle Wilcox formation. The Perdido is characterized by multiple-stacked gas reservoirs, with the three primary reservoirs named A, A-1, and B. Formation tops range from 8,400 ft subsea (west of the big fault) to 10,600 ft subsea (east of the big fault). The Perdido sands can have a dip that varies from 3° to 45°.

The lower pay interval is the Lobo sand package, part of the Lower Wilcox formation. The pay sands are the Lobo 1, 3, and 6 sands with the occasional stray sand. Formation tops range from 12,000 ft subsea (west of the big fault) to 14,400 ft subsea (east of the big fault). The Lobo has multiple fault planes with dip varying from 35° to 70°. It is common to drill through multiple faults with 30-ft to 100-ft throw in a single wellbore in the Lobo section.

The geologic intervals encountered while drilling are as follows (all depths are subsea)

1. Jackson Shale, extending from the surface casing shoe to 1,500 ft.
2. Yegua-Cook Mountain-Sparta complex to 3,600 ft.
3. Queen City to 4,600 ft.
4. Reklaw Shale to 6,400 ft.
5. Carrizo Wilcox to around 7,800 ft.
6. Vela Shale at 8,000 ft.

Intermediate casing is set well into the transition zone in the Vela Shale. While steering using conventional steerable motor assemblies, the Queen City can be problematic because of the variability in formation compressive strengths encountered (from 2,000 to 30,000 psi), thus making it very difficult to hold toolface while sliding. The problem is even more acute in the Carrizo Wilcox (9,000 to 15,000 psi compressive strengths). Even though the variability in compressive strength is less, the average compressive strength is higher, and the greater depths result in lower ROP. Thus, more time is spent sliding and trying to control toolface. In addition, the Carrizo Wilcox has the occasional pyrite-rich interval, which has been found to be very detrimental to PDC bits (at rotating speed above 120 rpm at the bit).

As shown in Figure 4, the leaseholder has traditionally drilled the Lobo wells using one of two methods:

1. Where strict vertical control was critical, the intermediate section was drilled conventionally followed by a high-temperature PDM and MWD tool in the production-hole section.
2. Where strict vertical control was not required, the entire well was drilled with conventional rotary BHA.

The problem of drilling near the lease line, which is subject to the Texas Railroad Commission's 467-ft rule, is highlighted in the two graphs of Figure 5. These two wells were drilled well within the boundaries of the lease, and no correction was required. The accumulated displacement is between 400 and 500 ft in each case, more than enough to cause the operator to want to take appropriate measures to ensure verticality in the lease-line wells. To have a cost-effective means to steer the wells vertically with a fully rotating BHA and to achieve less tortuous trajectories produces a significant increase in return on investment (ROI).

The wells that require strict vertical control are those positioned on or close to the hard-line of 467 ft from the lease line. The introduction of RSS technology has addressed the inefficiencies of both the conventional rotary and steerable PDM assemblies. Furthermore, RSS technology allows the application of optimum drilling parameters, selection of more aggressive PDC bits, and elimination of sliding intervals for faster ROPs and reduced number of BHA trips—all achieved while maintaining high levels of wellbore placement accuracy.

The following case studies demonstrate the improved economics of drilling with RSS in several South Texas Lobo lease-line wells. Figure 6 shows the location of the study area in South Texas, USA.

In all wells, the drilling fluid was a standard South Texas program of water-based mud in the intermediate section and oil-based mud in the production section.

The locations of these well groups are shown in Figure 7.

Group A Wells

Results: Accumulated Displacement

In Group A, two wells were drilled using conventional techniques, one well using PDM, and two wells using RSS. The two RSS wells exhibit less than 100 ft accumulated displacement, whereas the conventional wells exhibit almost 300 ft. The PDM well drifted off by almost 450 ft from vertical (Figure 8).

Results: Depth versus Days

Of the five wells in this group, Well 3, drilled with PDM, required 26 days and the greatest number of days to TD by far. Wells 2 and 4, using RSS, reached TD in 19 days, which was as fast as in Wells 1 and 5 drilled with a conventional rotary assembly, but better verticality of the borehole was maintained (Figures 9 and 10).

Results: Depth versus Cost

In Group A, the lowest cost was achieved by the two conventional wells, whereas the highest cost was accrued by the PDM well. The two wells drilled with RSS achieved superior verticality at slightly higher cost than the wells drilled with conventional BHAs (Figures 11 and 12).

Group B Wells

Results: Accumulated Displacement

Of the Group B wells selected for this study, two were drilled using RSS, one with PDM, and one using a conventional approach. As with the previous group, the RSS wells achieved significantly less displacement, < 50 ft. The PDM and conventional wells exhibited displacements > 350 ft and 450 ft, respectively, as shown in Figure 13.

Results: Depth versus Days

In Group B, Well 4, drilled with RSS, reached TD 7 days sooner than the PDM well and ~22 days sooner than the conventional well as shown in Figures 14 and 15. Well 3 in this group was intentionally drilled to only 11,655 ft as a test of the Perdido sand.

This well holds the county record for fastest ROP from drillout to TD for an 8 3/4-in intermediate section. RSS was used to help fight deviation trends in the section and to stay within the extremely tight lease lines. RSS kept the hole vertical, thus allowing the rig to keep constant WOB with no need to fan the bit or backream, which can add hours to drilling time. The bit was able to drill the entire interval at such a high ROP that drilling time was cut by 50%; this more than offset the additional cost of the RSS technology.

Results: Depth versus Cost

This group of wells showed a clear cost advantage for the RSS approach, as shown in Figures 16 and 17. True comparison between wells 1, 2, and 4 shows a saving with RSS of $260 thousand and $593 thousand, respectively, over a conventional and PDM approach, in addition to better verticality.

Group C

Results: Accumulated Displacement

In this example, the RSS wells have 132 ft and 211 ft of accumulated displacement, whereas the conventional and PDM wells exhibit a range from 321 ft to 480 ft, as shown in Figure 18.

Results: Depth versus Days

Of the first three wells to be completed, two were drilled using RSS; the other wells exhibit drill times ranging from 3 to 11 days longer, as shown in Figure 19. Figure 20 shows the average days per 1,000 ft for the three different drive systems.

Results: Depth versus Cost

Examination of the six wells in this series reveals only one that provided a marginally lower cost than those drilled with RSS, as shown in Figures 21 and 22, but it took longer to drill than its RSS competitor.

Conclusions

The RSS technology previously reserved for high-cost offshore or remote locations has proven to be cost-effective for use in low-margin onshore drilling environments. The technology has proven to be more reliable and effective than conventional steerable motor technology. It has allowed vertical wells to be drilled faster and at lower cost while maintaining the near verticality required for small targets or lease-line obligations.

The operator estimates that only 80% of the lease-line wells drilled would be drilled using PDM if RSS technology was unavailable, but the remaining 20% (average of five wells) would not be drilled at all. These wells are estimated to yield 1.5 BCF of gas production per well over the life of the wells, adding 7.5 Bcf of gas production.

Better weight transfer to the bit and the use of more aggressive bits to reduced drilling time is another key element in the economic impact of RSS. Taking an average across the field of days spent drilling with RSS versus PDM or versus. conventional drilling; the time from spudding-in to first sales was reduced by an average of five days, which translates into the ability to drill an additional two lease-line wells per year. When used as a directional drilling device, it allows higher ROPs and better borehole control.

With the increasing trend toward denser well placement, the ability of RSS technology to economically drill in close proximity to lease-line limits can have a significant impact on resource recovery and the overall economics of a field. In some cases, if RSS technology were not available, the wells could not be drilled at all, or only at a prohibitively higher cost.

Overall, the RSS technology has allowed the operator to cost-effectively optimize the remaining reserve value of its producing leases and fully exploit the remaining potential in the fields.

Acknowledgments

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SI Metric Conversion Factors

acre	× 4.046 873	E+03 = m^2
ft	× 3.048*	E-01 = m
in.	× 2.54*	E+00 = cm
psi	× 6.894 757	E+00 = kPa

*Conversion factor is exact.

Figures

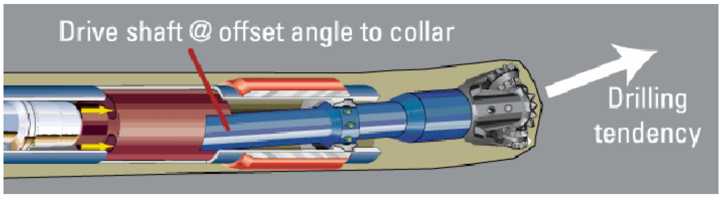


Figure 1. Point-the-bit RSS

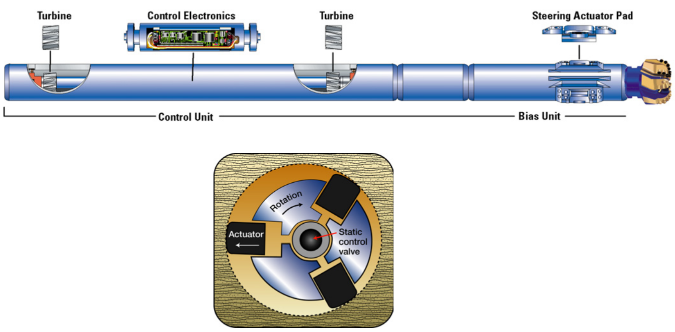


Figure 2. Push-the-bit RSS

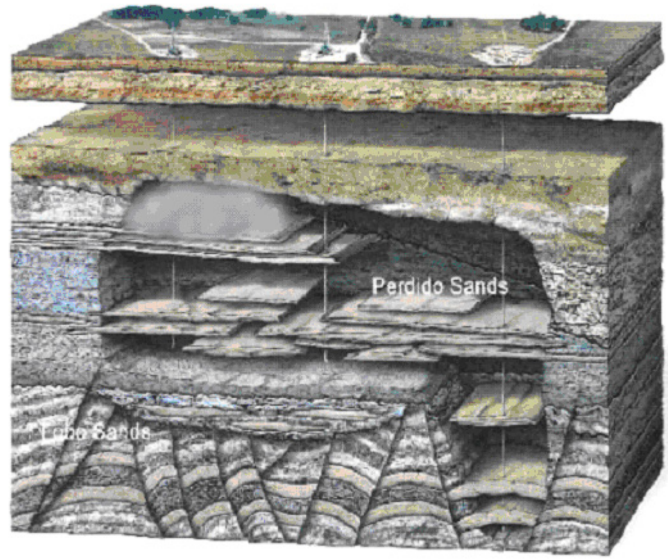
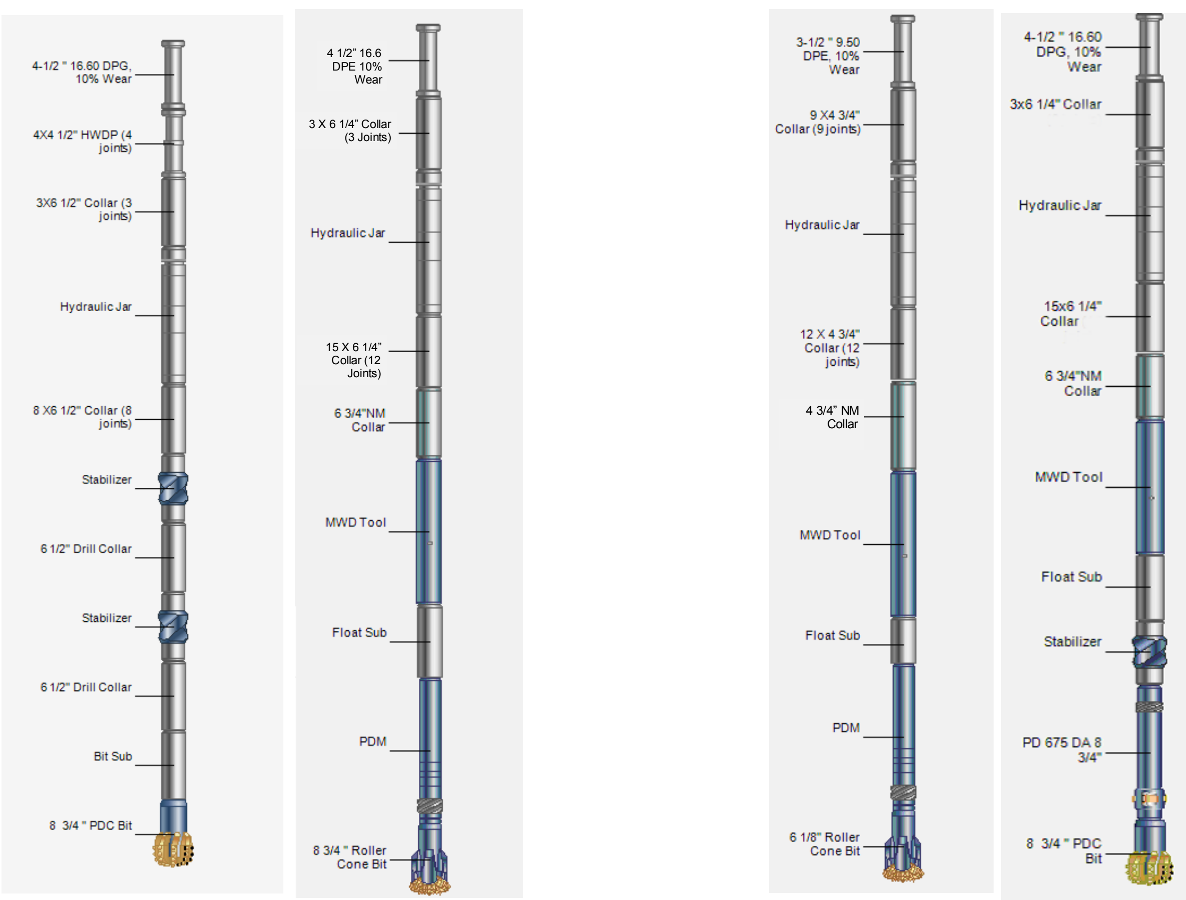


Figure 3. Schematic cross section of the geologic environment



6 1/8-in Hole Section PDM Assembly 8 3/4-in Hole Section RSS Assembly

6 1/8-in Hole Section PDM Assembly 8 3/4-in Hole Section RSS Assembly

Figure 4. Typical BHAs used

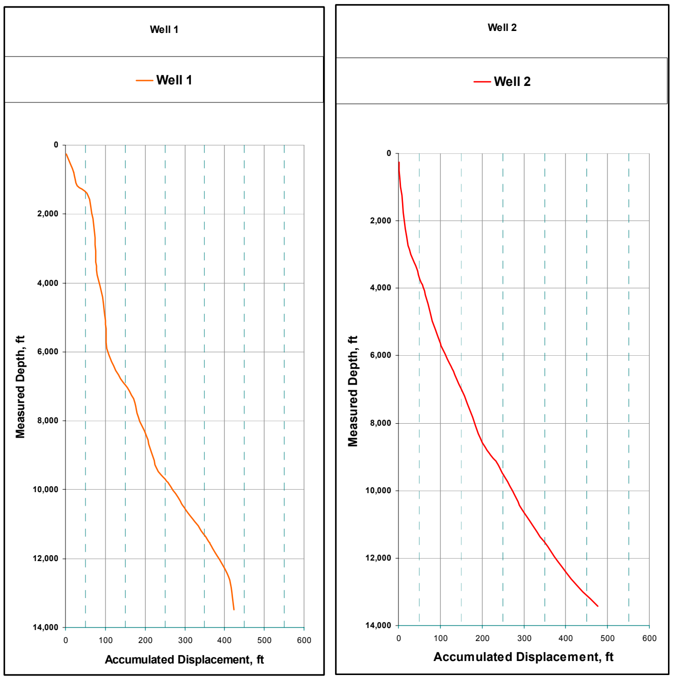


Figure 5. Typical accumulated displacement without correction

Figure 6. Location of the study area in South Texas, USA

Figure 7. Locations of the well groups

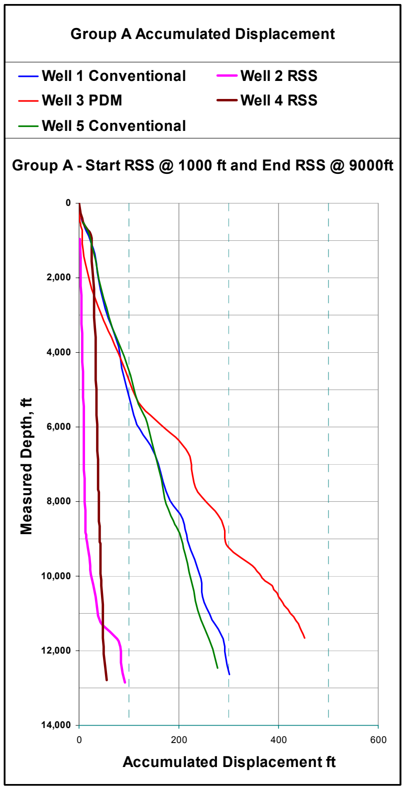


Figure 8. Group A accumulated displacement

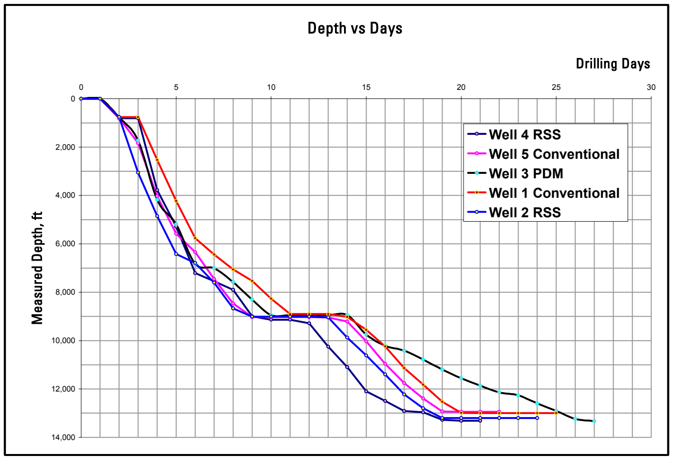


Figure 9. Group A depth versus days

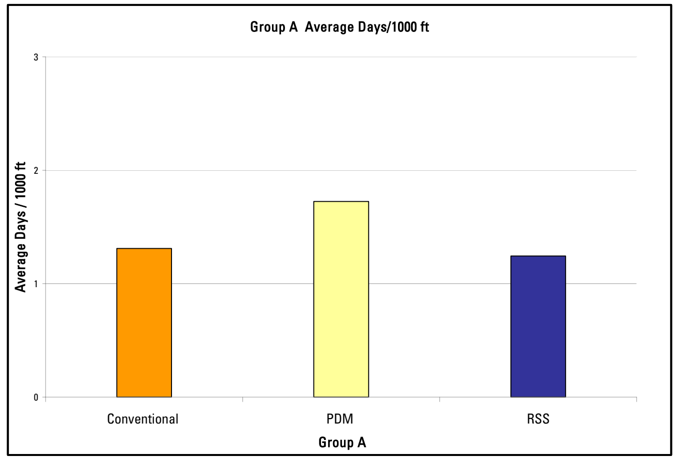


Figure 10. Group A average days/1,000 ft

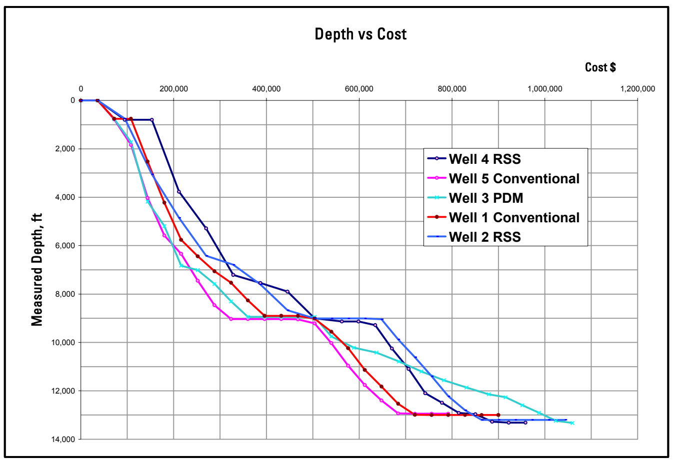


Figure 11. Group A depth versus cost, $

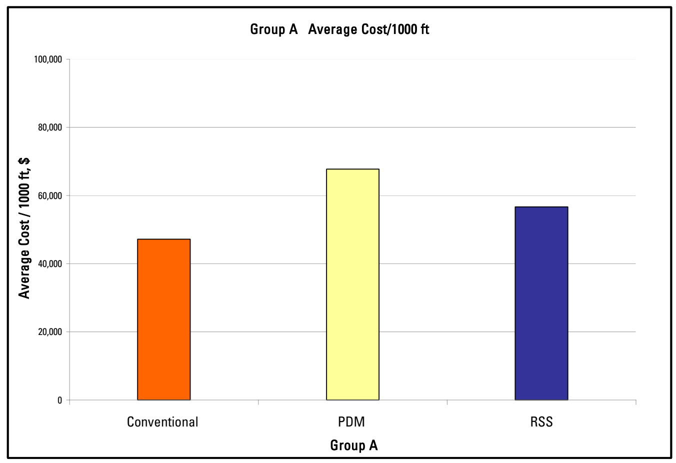


Figure 12. Group A average cost/1,000 ft

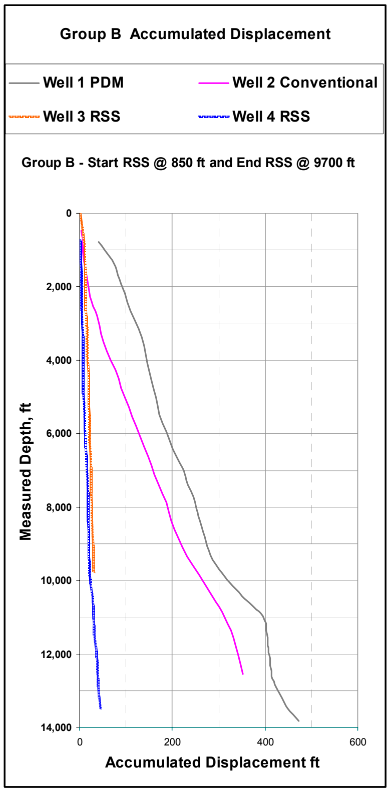


Figure 13. Group B accumulated displacement

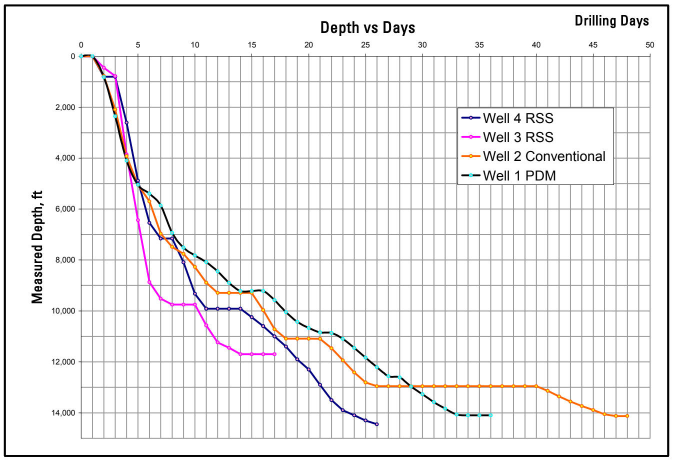


Figure 14. Group B depth versus days

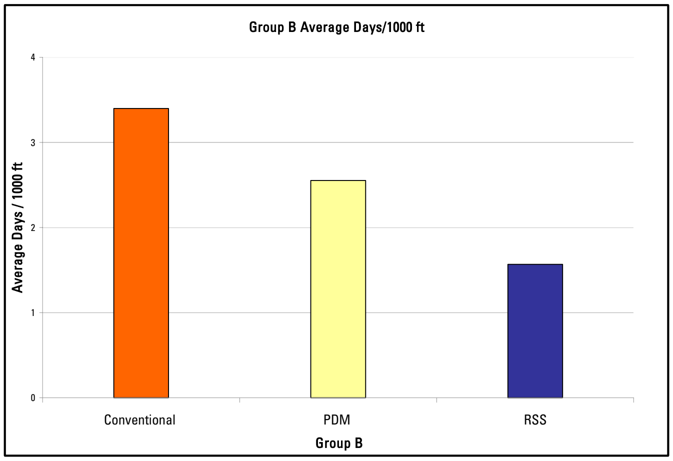


Figure 15. Group B average days/1,000 ft

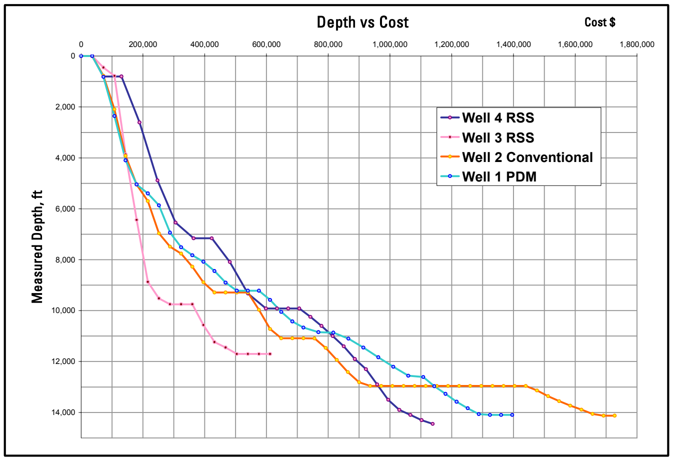


Figure 16. Group B depth versus cost, $

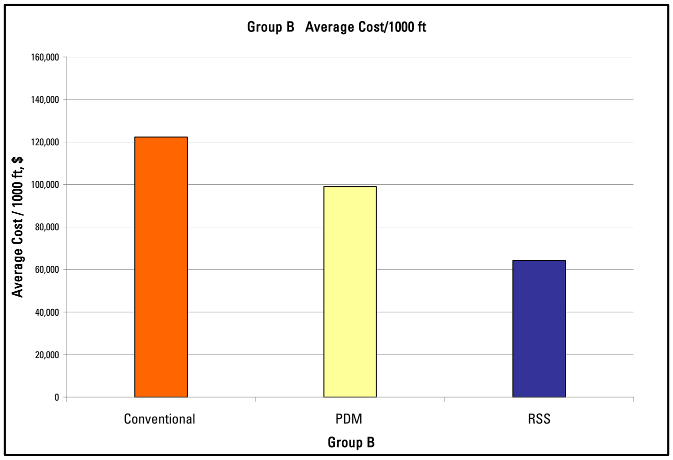


Figure 17. Group B average cost/1,000 ft

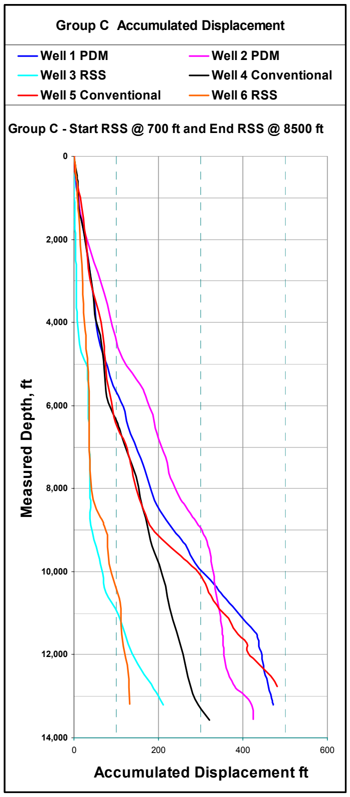


Figure 18. Group C accumulated displacement

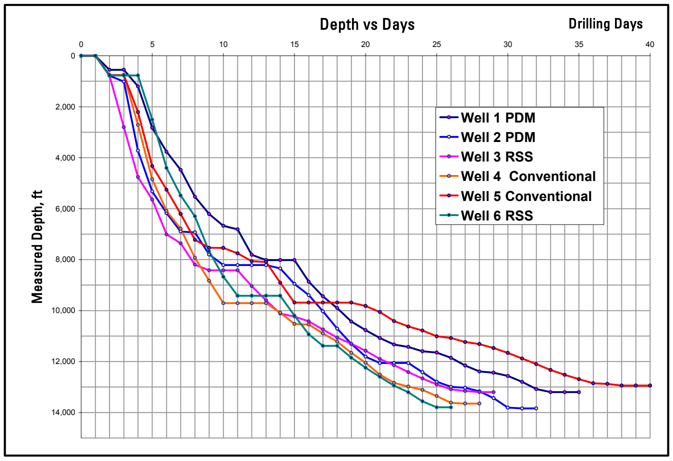


Figure 19. Group C depth versus days

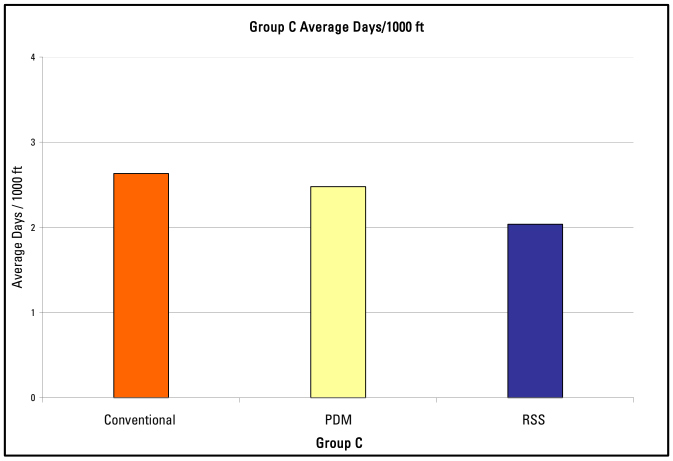


Figure 20. Group C average days/1,000 ft

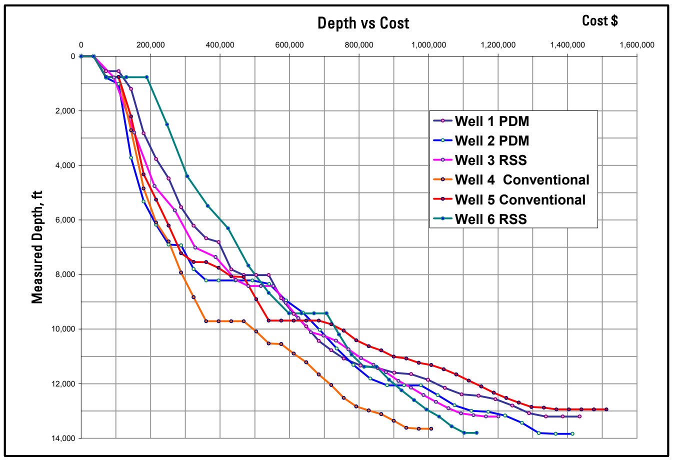


Figure 21. Group C depth versus cost, $

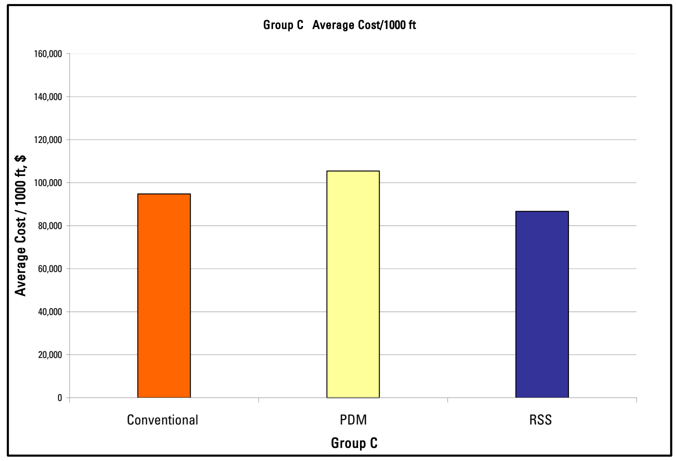


Figure 22. Group C average cost/1,000 ft