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Refining Best Practices of Horseshoe Wells – A New Case History

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Abstract

A new horseshoe well in Oklahoma utilized brine and lubricant to drill and run casing without issues. While horseshoe wells are becoming a new standard to improve well economics, oil- or synthetic-based drilling fluid is the standard to mitigate risk of excess torque and drag. Engineering best practices and hazard considerations demonstrated the feasibility of drilling a tortuous well with clear fluid. The well design accounted for sliding requirements, risk of losses, and wellbore instability cited in prior case histories. With these concerns mitigated, the horseshoe well was delivered without issue with lower cost.

The drilling campaign, taking place within the Anadarko basin, consisted of two 1-mile lateral wells and the single 2-mile horseshoe well. Proper risk mitigation across the horseshoe well operation resulted in approximately 10,900 feet of producing footage and approximately 12,500 total lateral footage in 16 days. By comparison, the two 1-mile lateral wells required 18 days to achieve approximately 10,000 feet of producing footage in the same predominately limestone-based Osage producing formation.

This paper discusses the principles of horseshoe wells, including drilling assemblies, torque and drag considerations, and well operations. A brief review of the completion design and results are also highlighted. The authors will compare other case histories and discuss distinctions between horseshoe well requirements.

Introduction

The term "horseshoe" well refers to wells where a traditional lateral is drilled followed by a 180º turn with a second lateral, creating an azimuthal shape like a horseshoe. Another common term used interchangeably with horseshoe well is a u-turn well.

Well Path

The horseshoe well profile can be separated into its constituents based on well trajectory (Huycke 2024). These terms aid the discussion on drilling and completion practices (Figure 1):

- Intermediate section – the vertical section between surface and production which may or may not include the curve
- Curve – the traditional section where the vertical wellbore transitions to a horizontal well
- Outgoing Leg – the traditional horizontal wellbore
- Turn – the 180-degree curve across the horizontal plane
- Return Leg – the lateral drilled back towards the intermediate section

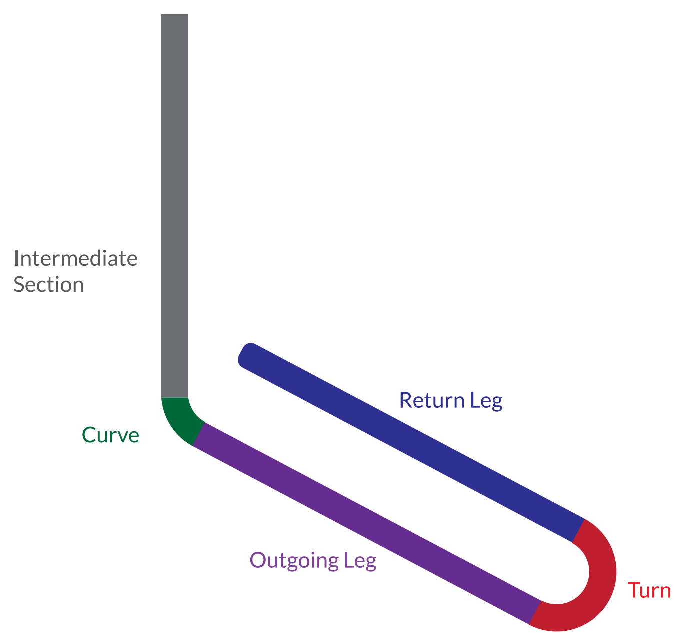

Figure 1: Perspective view of horseshoe well features

Most horseshoe wells are drilled with a single mile outgoing leg and a mile return leg, but longer lengths have been drilled. Other variations include j-hook wells where the drilling location is centered on the lease. A short lateral extends to the lease line, followed by the turn, and a return leg running the length of the lease. An second j-hook lateral extends to the opposite side of the lease with the turn extending across the other lease line. This has the potential to replace three conventional laterals with two j-hooks as shown in Figure 2 (Vital Energy, 2025).

Figure 2: J-well concept (Vital Energy, 2025)

Spacing

The spacing between the outgoing and return leg varies by well objectives and practical dogleg severity. In some cases, the horseshoe surrounds a producing well (Schultz and Kiefner 2022). In most cases, spacing is calculated to prevent interference between legs during hydraulic fracturing and production (Figure 3).

The distance between legs also impacts the dogleg severity of the turn. In most cases, spacing between legs is between 1100 ft and 2000 ft – although spacing has been as high as 3000 ft (Turning Point E&P Consultants 2024).

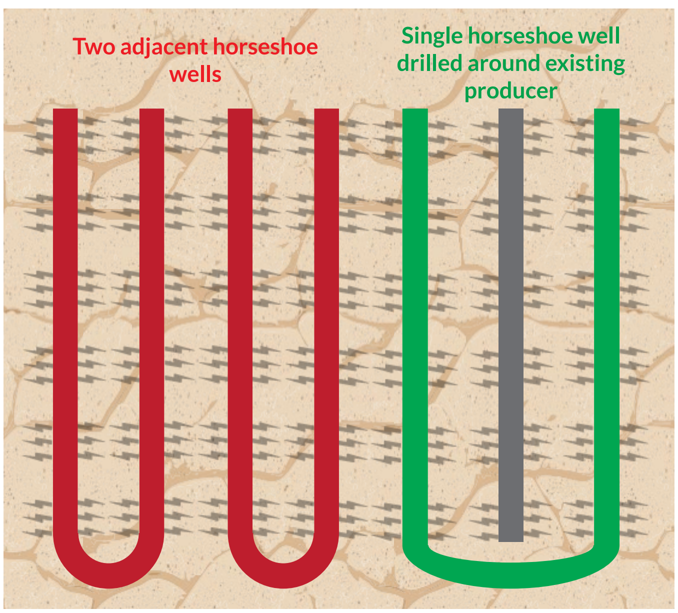

Figure 3: Horseshoe well leg spacing is determined by potential interference with stimulation treatments or nearby existing wells

History and Applications

As with many complex well trajectories, horseshoe wells originate out of the need to access reservoirs that cannot be reached via simple well paths. The first known horseshoe well drilled in an unconventional reservoir is attributed to Shell in the Permian Basin (Jacobs 2020). Prior to this, other complex well trajectories – including the horseshoe shape discussed in this paper- were drilled to access conventional reservoirs.

When the ratio of measured depth to true vertical depth achieves a ratio of 2:1 or greater, it is classified as an extended reach well. This does not account for other complexities in the well trajectory, such as s-curves or significant changes in azimuth like those in horseshoe wells.

The directional difficulty index (DDI) is an effort to characterize well complexity as a function of measured depth, along hole displacement, tortuosity, and true vertical depth (Oag and Williams 2000). Schultz and Kiefner (2022) evaluate well complexity using the DDI and total cumulative degrees for tortuosity. The DDI comparison indicated well complexity fell within a feasible range of other wells drilled in South Texas which did not have a horseshoe path, but included longer wells.

Conventional Targets

Pardy et al (2013) review development of the White Rose field in offshore Newfoundland. The West White Rose satellite field required wells drilled from existing subsea infrastructure, requiring horseshoe well paths to reach well targets. These wells featured more gradual curve sections, meaning the horseshoe paths were not drilled at 90º.

Teeratananon et al (2020) discuss development of the Nong Yao Field in the Gulf of Thailand. In this example, reprocessed seismic data revealed additional undeveloped oil reservoirs. To access the undeveloped targets, a complex horseshoe trajectory was required to avoid collisions with existing wells and water contact. The well featured a total tortuosity of 319 degrees where the return leg featured an additional turn in the outgoing leg's direction.

Unconventional Wells

Horseshoe wells have become common in the Permian Basin and Eagle Ford, but their use extends to most unconventional shale basins across the United States. Where conventional wells have used horseshoe paths to access a reservoir, unconventional wells use horseshoe paths to increase reservoir exposure.

The Shell case study was an effort to recover a potentially lost reservoir while demonstrating feasibility of the horseshoe concept. In this case, an intermediate section was lost due to uncontrolled losses. To salvage the lost production area, an adjacent well was extended from a traditional lateral to include a horseshoe path with the return leg covering the lost production section (Jacobs 2020).

A traditional section of land is 640 acres or one square mile. Longer laterals are preferred for their economics, but isolated sections or limited lease agreements can leave potential drilling locations limited to single mile laterals. In Colorado, tighter regulations limit surface locations, particularly in areas developed in prior years. (Enverus 2024). Schultz and Kiefner (2022) discuss horseshoe wells as part of a strategy to economically recover stranded acreage where combining single-mile laterals into horseshoe wells returns areas to economic viability.

While the law varies by state, it is legal in some areas to drill the turn section across the lease line while not completing that section of the well. In other scenarios, it may be possible to secure permission from the adjacent leaseholder.

Economics

Overall, a horseshoe well offers a rate of return between 25% and 40% in the Delaware Basin with a cost reduction ranging between \$3.5 million and \$4 million (Huycke 2024).

Horseshoe wells are inherently cheaper to drill relative to two individual wells. A surface, intermediate, and curve section and a tubing string with duplicated costs of fracturing two separate wells are eliminated.

Production performance depends upon completed footage. Production comparisons normalize completed footage, which may exclude the turn if it is not produced.

Some operators do not fracture the turn section of the well for different reasons. Assuming the turn section aligns with the maximum horizontal stress, it is possible that fractures will not propagate laterally from the wellbore. In this case, the operator may choose to place the turn through an adjacent lease and forego fracturing the turn (Schultz and Kiefner).

Merzoug et al (2023) present modeling that shows the turn is a productive interval due to the interconnected nature of fractures. This aligns with the concept that the far field stress regime does not change.

Operators Chesapeake, Matador, and Vital Energy published that well results met or exceeded production of equivalent single-mile laterals on a per-foot basis (Schultz and Kiefner 2022, Matador Resources 2023, Darbonne 2024).

Drilling Methods

As the number of horseshoe wells continues to grow, drilling techniques continue to evolve based on lessons learned and continued success.

Drilling Assemblies

Horseshoe wells have been drilled using both mud motor and rotary steerable system (RSS). Conventional mud motor assemblies provide a lower cost solution and better chances of meeting the required dogleg severity required for a successful turn. RSS offer faster drill rates and improved hole cleaning through continuous pipe rotation without sliding. Wiper trips are avoided with the inclusion of a reamer.

With conventional motors, separate assemblies may be used for the outgoing let, turn, and return leg. In most cases, this is avoided whenever possible to eliminate the cost of extra equipment and trips, but torque and build angle may require changing equipment. Many horseshoe wells have been drilled with two assemblies, and there are select cases where a single drilling assembly delivered the entire lateral section.

Mud Weight Selection and Wellbore Stability

Where sufficient data is available, a mechanical earth model is recommended to determine the appropriate mud weight for pressure control and wellbore stability.

Unlike a traditional lateral, a horseshoe well includes a trajectory parallel to the maximum horizontal stress (Figure 4), increasing the risk of wellbore breakout. Wellbore instability under these conditions requires several important considerations:

- The required mud weight will likely be on the higher end of the range output by a mechanical earth model. Offset laterals may present much lower mud weights than necessary for a horseshoe well.
- Otteson (2010) suggests that a higher initial mud weight providing stable rock will be lower than the mud weight required to stabilize rock after it has failed.
- A good formation integrity test (FIT) will provide confidence in raising the mud weight should wellbore breakout occur. A failed FIT presents the opportunity to strengthen the shoe before complex directional work begins.
- Wellbore collapse increases hole cleaning challenges, particularly while sliding where larger cavings must be circulated to surface and the wellbore is enlarged, lowering annual velocities
- Monitor the shakers and data recorder for signs of cavings, and be prepared to respond quickly to increase the mud weight to regain stability.

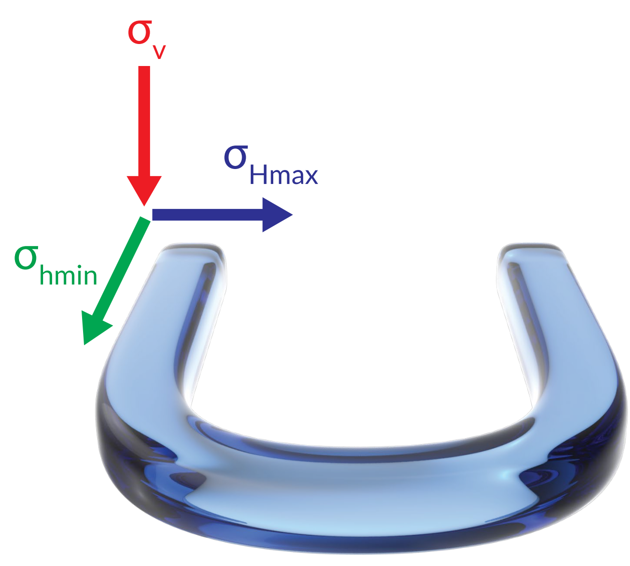

Figure 4: Lateral legs are drilled in the direction of the minimum horizontal stress. The turn section requires drilling through the horizontal maximum stress, increasing risk of wellbore breakout.

Fluid Selection and Hole Cleaning

Oil-based drilling fluid was used in almost every known horseshoe well for its inherent lubricity. Water-based drilling fluid, particularly clear fluid with a supplemental lubricant, is another viable option in generally non-reactive unconventional shale reservoirs (Farnum, Toomes, and Offenbacher 2023). The Osage formation is primarily limestone, making it well suited to use a lower-cost aqueous drilling fluid.

Production sections feature small hole sizes, usually ranging from 6” to 8 ¾”. These intervals, despite well tortuosity in a horseshoe path, allow for sufficiently high annular velocity to provide good hole cleaning. While horseshoe wells have distinct directional profiles, hydraulic modeling will provide reassurance that significant fluid property changes are not necessary to clean the hole while rotating.

When sliding is required, hole cleaning is limited due to the inability to rotate. A sweeps program and careful monitoring of torque trends will aid to identify hole cleaning issues.

Mitigating Loss Circulation Risk

Loss of circulation is best avoided, but the challenged to maintain an elevated mud weight for wellbore stability increases inducing losses. This creates significant drilling challenges:

- Loss of full returns limits circulating rates, impacting hole cleaning. This can be particularly detrimental during sliding.
- Partial returns creates difficulty maintaining density downhole, which increases the risk of wellbore collapse. Lowering the mud weight to regain returns could result in wellbore breakout.

A treatment plan should be determine in advance, including wellbore strengthening squeezes at the shoe if the FIT fails or when significant losses occur. A bypass sub may facilitate more aggressive treatments with the drilling assembly downhole while preventing plugging of critical tools.

Torque and Drag

Torque and drag modeling prior to and while drilling provides useful insight into directional issues and their impact on the well as they develop. Trend mapping with historical wells can increase confidence in the reliability of models.

Tortuosity scenarios can be modeled in advance with additional drag points and rotation/non-rotation on trips. Similar considerations can be used for casing runs, which may be the greatest risk to well delivery. Most casing runs utilize floatation - with or without rotation (Huycke 2024).

Case History

Canvas Energy is a privately held operator focused on the liquid-rich portion of the Anadarko Basin. The horseshoe well was drilled due to surface/pad constraints and a known geologic constraint.

The wells in comparison include 2 x 1-mile lateral wells and 1 x 2-mile horseshoe lateral well targeting the Osage producing formation, all located in Kingfisher County, Oklahoma. Table 1 details well profile and select well attributes. From spud to rig release, the 2 x 1-mile laterals required a cumulative 18.1 days while the 1 x 2-mile horseshoe well required 16.5 days. Issues with drilling torque in the return leg prevented faster drilling, as discussed in more detail below. The basis for drilling the horseshoe well was due to spacing constraints. Figure 5 provides the survey plot of the horseshoe well upon TD.

Risks, Challenges, and Contingencies

- Torque and drag, hydraulics must be accurately modeled
- Risk of pipe buckling with 4 in. drill pipe and 6-⅛” in slim hole
- Rig and drill pipe limitations to be tested
- Contingency planning if wellbore instability prevents successful turn
- Displace to oil-based mud if pickup/slack-off/torque became too high
- Pick up rotary steerable system if unable to get effective slides
- Liner/production casing overcome by floating casing and the ability to rotary if necessary
- Run dissolvable frac plugs in the return leg to overcome expected issues during drill out

Table 1: Select well attributes of 2-mile horseshoe well vs. 1-mile offsets

Well Property	Traditional Well #1 (1-mile lateral)	Traditional Well #2 (1-mile lateral)	Horseshoe Well #1 (2-mile lateral)
Lateral open-hole diameter, in.	6.125	6.125	6.125
Fluid System	Fresh water w/ lubricant	Fresh water w/ lubricant	Fresh water w/ lubricant
Avg. Fluid Density, lb/gal	8.3 - 8.4	8.3 - 8.4	8.3 - 8.4
Total Lateral, ft	4,965	4,963	12,499
Completed Lateral, ft	9,928		10,929
Spud to Rig Release, Days	9.2	8.9	16.5

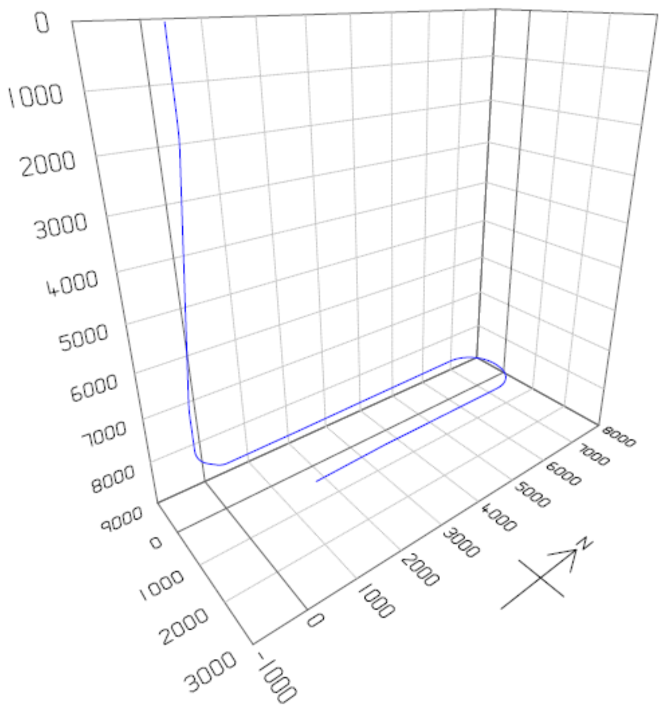

Figure 5: Horseshoe survey plot

Drilling Assembly

The lateral section was drilled with a conventional mud motor assembly. There were two planned BHA runs. Both BHAs included the components below:

- 1.83 deg motor with MWD
- Outgoing BHA: 1 x agitators at 3,500' behind the bit (dart activated). Return BHA: 2 x agitators at 3,500' and 6,000' behind the bit (dart activated)
- 1,800' of HWDP 'push pipe'

BHA run #1 drilled the first outgoing leg and turn. The HWDP, or "push pipe" was arranged such that it would reach just past kick off point after the turn. BHA #2 drilled the return leg. The second agitator was not activated until after the turn.

Modeling & Drilling Discussion

Hydraulic modeling was run to provide guidance on hole cleaning expectations, given the unviscosified rheological profile of the fresh water system. Figure 6 shows the minimum flow rate required to adequately clean the hole at TD, which did not exceed 200 gal/min. Circulation modeling was also performed to ensure pressures across the lateral were within expectation (Figure 7).

Well planning included torque and drag modelling for drilling and liner running (Figure 8 and 9 shown utilizing WBM). Modeling considered tortuosity and was calibrated to offset wells with similar formation types. The torque and drag modelling was run on several scenarios, including WBM versus OBM. The maximum tensile hook load of 403,000 lb. at planned TD for 4" 14.0 lb/ft S-135 VX-39 drill pipe. An 85% safety margin is approximately 343,000 lb. Hook load modeling indicated operations are beneath this threshold at 0.30 friction factor. Torque modeling also indicated estimated torque well below make-up torque of drill pipe.

Table 2 provides select drilling parameters in the lateral section of the horseshoe well. While drilling the lateral section, fluid treatments included periodic viscosified sweeps throughout the outgoing leg, turn, and return leg. To alleviate torque, lubricant was added at the suction pit and pumped in sweeps as required. Sweeps containing graphite/walnut were also utilized during slides. Sliding was performed as needed to produce 8° per 100-foot turn to 180° azimuth. Throughout the turn section, surveys were taken approximately every 30 feet. Inclination control was a challenge, resulting in a range of 87 – 93°.

Table 2: Drilling parameters

Parameter	Outgoing Leg	Turn	Return Leg
Weight on Bit, klbf	25 – 30	30 - 33	20 – 33
Flow Rate, gal/min	300	325	325
Standpipe Pressure, psi	2800 – 3100	4000	4900
Rotating Speed, rev/min	40 – 60	60	60 – 80
Drilling Torque, ft-lb	9000 – 12,000	10,000 – 12,000	18,000 – 22,000

A decision was made at 16,435 ft. MD to trip out of hole, lay down lateral assembly #1, and pick up lateral assembly #2, as planned – which included a new bit and re-orientation of heavy weight "push" pipe. At approximately 1/3 of the way drilling the return leg, the active pits were dumped and refilled with fresh makeup water/brine due to excessive drill solids. Consequently, the drilling fluid system required time to re-accumulate lubricant concentration. Pickup and slack off weights stayed manageable, but drilling torque became a challenge over the last half mile. Sliding capabilities were also a challenge during the return leg. The remaining return leg was control drilled to TD to minimize wear on rig equipment and the drill string. The outgoing leg required 49 hours to drill 5,416 ft at 110 ft/hr, while the return leg required 47 hours to drill 4,049 ft at 86 ft/hr. Approximately +/- 12 hours of increased drilling time can be attributed to the reduced drilling rate during the return leg.

At TD, the well was circulated a total of 3 x bottoms up circulations, including 2 x 20 bbl high viscosity sweeps. No issues were encountered tripping out of the hole with the drilling assembly. A bottoms up circulation was made at approximately 16,000 ft M.D – ahead of the turn section. Another bottoms up circulation was performed at approximately 11,500 ft MD (halfway through the first leg) and at 8,500 MD (landing point). A lubricant pill was spotted at each circulation point.

Figure 10 illustrates actual hookload plots with the outgoing leg BHA – 6-⅛ in. bit, mud motor, 1 x agitators, 1800' of

HWDP. Figure 11 illustrates actual hookload plots with the return leg BHA – 6-⅛ in. bit, mud motor, 2 x agitators, 1800' of HWDP. Pick up averaged between 0.1 to 0.15 friction factor during both legs. Slack off friction factors averaged closer to 0.20 on the return leg.

Figure 12 illustrates actual off-bottom torque plots with the outgoing leg BHA – 6-⅛ in. bit, mud motor, 1 x agitators, 1800' of HWDP. Off-bottom torque average began to follow 0.20 friction factor after ~13,000 ft. MD - this coincided with increasing lubricant introduction to the system. Figure 13 illustrates actual off-bottom torque plots with the return leg BHA – 6-⅛ in. bit, mud motor, 2 x agitators, 1800' of HWDP. Friction factors followed closer to 0.25 while drilling the return leg. Drilling parameters were adjusted due to on-bottom increasing torque values. It is surmised that the 4 in. drill pipe could have undergone moderate buckling when considering the 0.25 friction factor off-bottom torque vs. lower friction factor in hookload chart.

Torque and Drag – Liner

Figure 14 shows liner run hookload versus string depth modeling without rotation. Concern with 0.28 friction factor line model was mitigated by ability to rotate liner, if required. Figure 15 shows modeled hookload versus string depth modeling output with rotation. Figure 16 shows surface torque versus string depth modeling if rotation is necessary.

Ahead of the liner run, a lubricant pill was spotted across the open hole while tripping out with the final drilling BHA. Friction factors during the trip out were reduced approximately 35% (.13 vs .2) versus the trip in with the final BHA due to the spotted lubricant pills. The 4-½ in. (11.6 lb/ft) liner was floated in with a flotation sub with the liner hanger set at 55-degree point. 30 - 4-⅞ in. collars for additional weight were also picked up above the liner hanger. Figure 17 shows actual hook load plot of liner run. No issues were encountered getting the liner to bottom. The operator ran a rotatable hanger and casing thread but did not require it.

Economics

The operator notes a general reduction in cost per lateral foot of 34% by drilling a standard 10,000 foot lateral versus a standard 5,000 foot lateral in their core assets. Cost comparisons revealed a 3% reduction in total well cost for the 2-mile horseshoe well versus 2 x 1-mile wells. The cost per completed lateral foot resulted in a 13% reduction versus the offset 2 x 1-mile lateral wells (Table 3). The spud-to-RR days for the horseshoe well (16.5) can be improved with learning such as proactive solids control measures and lubricant management. At time of publication, operator had successfully drilled a second horseshoe well, in which these learnings were applied.

Table 3: Well comparison

Cost Metric	Versus standard 2-mile offset	Versus 2 x standard 1-mile offsets
Total Well Costs for 2-mile Horseshoe well	9.7%	-2.8%
Cost/lateral foot for 2-mile horseshoe well	-5.1%	-13.3%

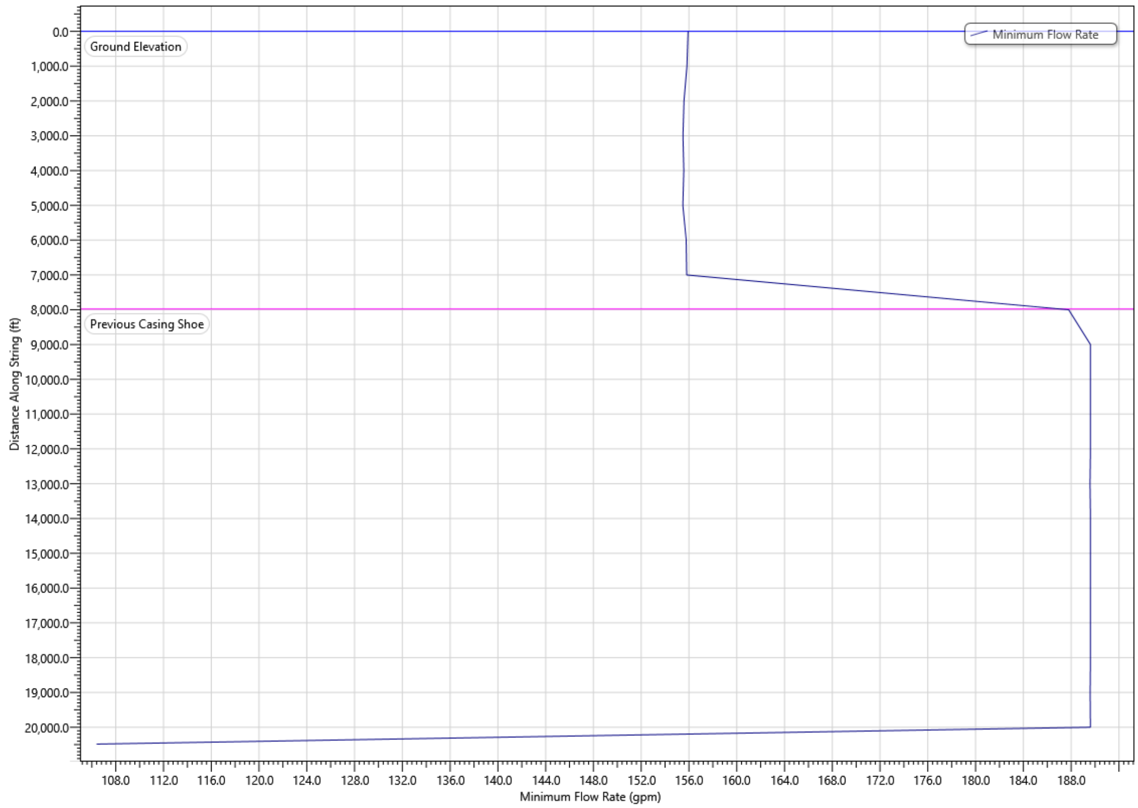

Figure 6: Minimum flow rate required to clean the hole at TD of the horseshoe well

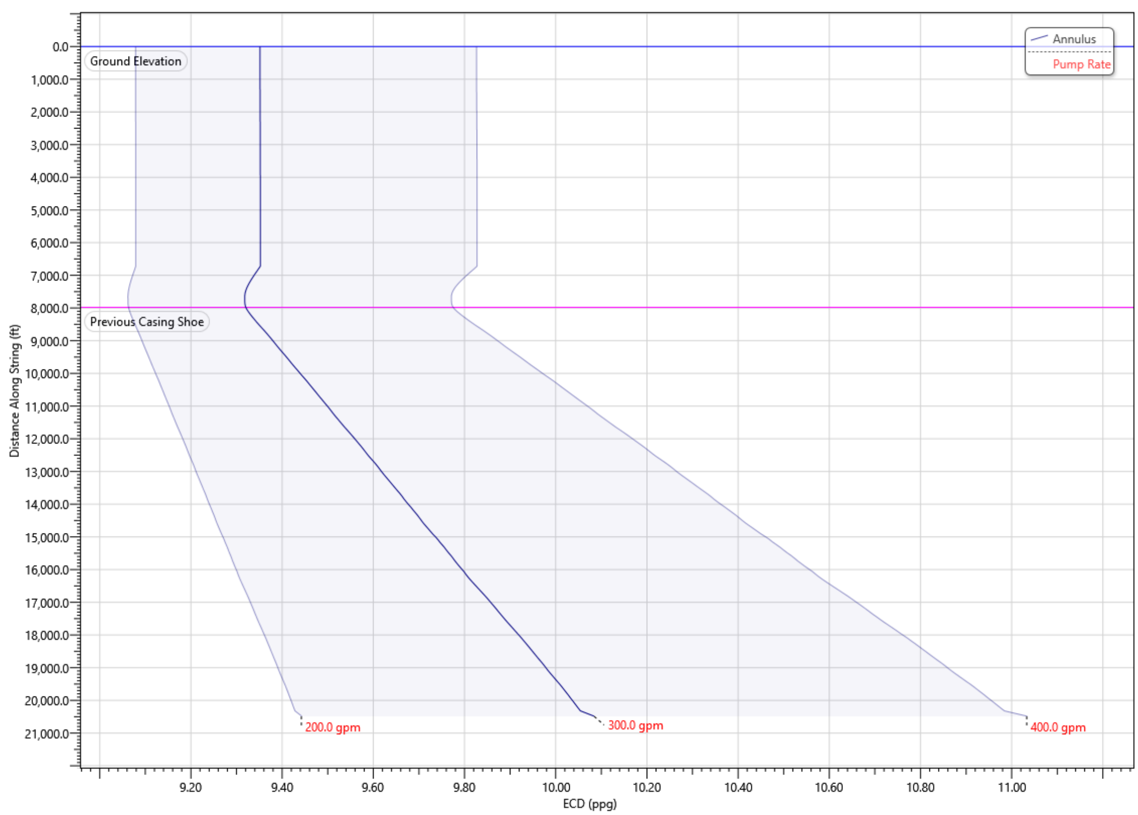

Figure 7: Equivalent Circulating Density modeling at various pump rates

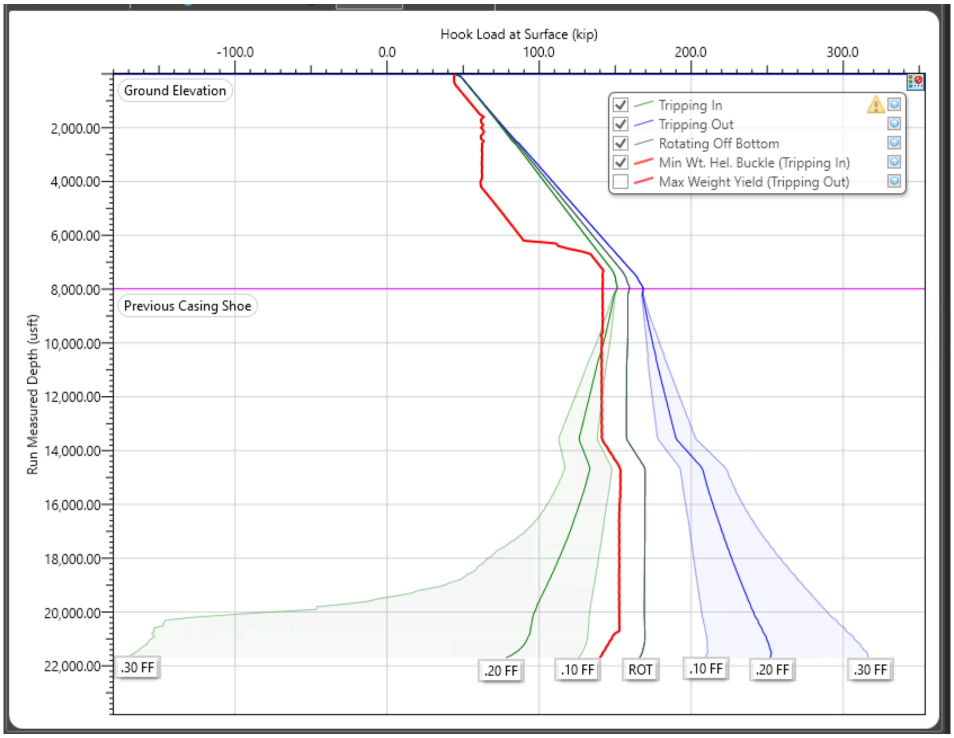

Figure 8: Hookload modeling with WBM

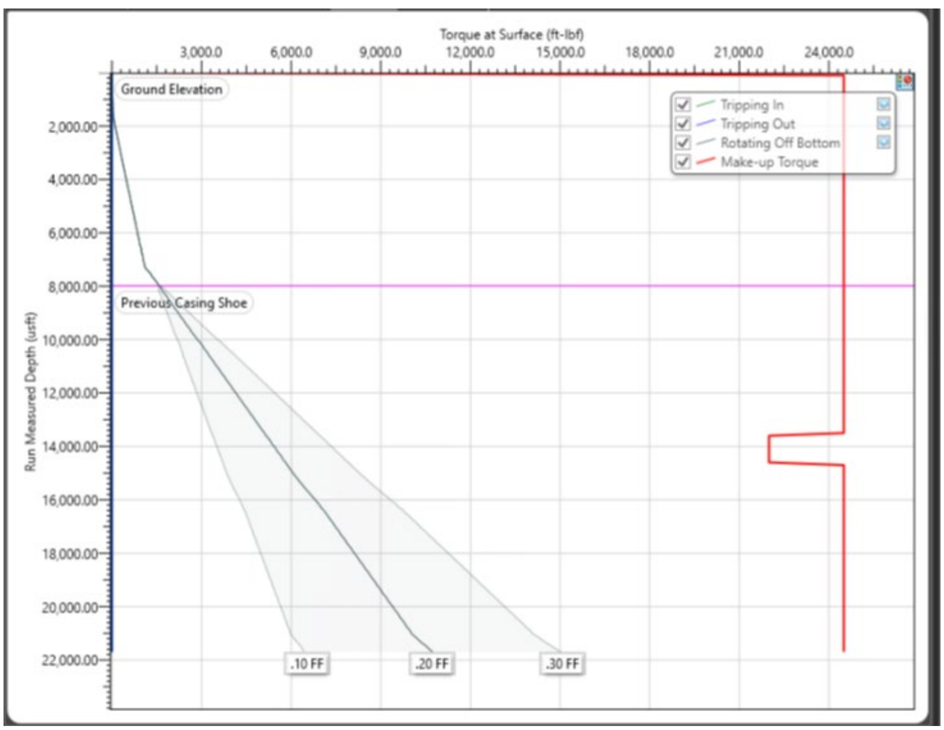

Figure 9: Drilling torque modelling with WBM

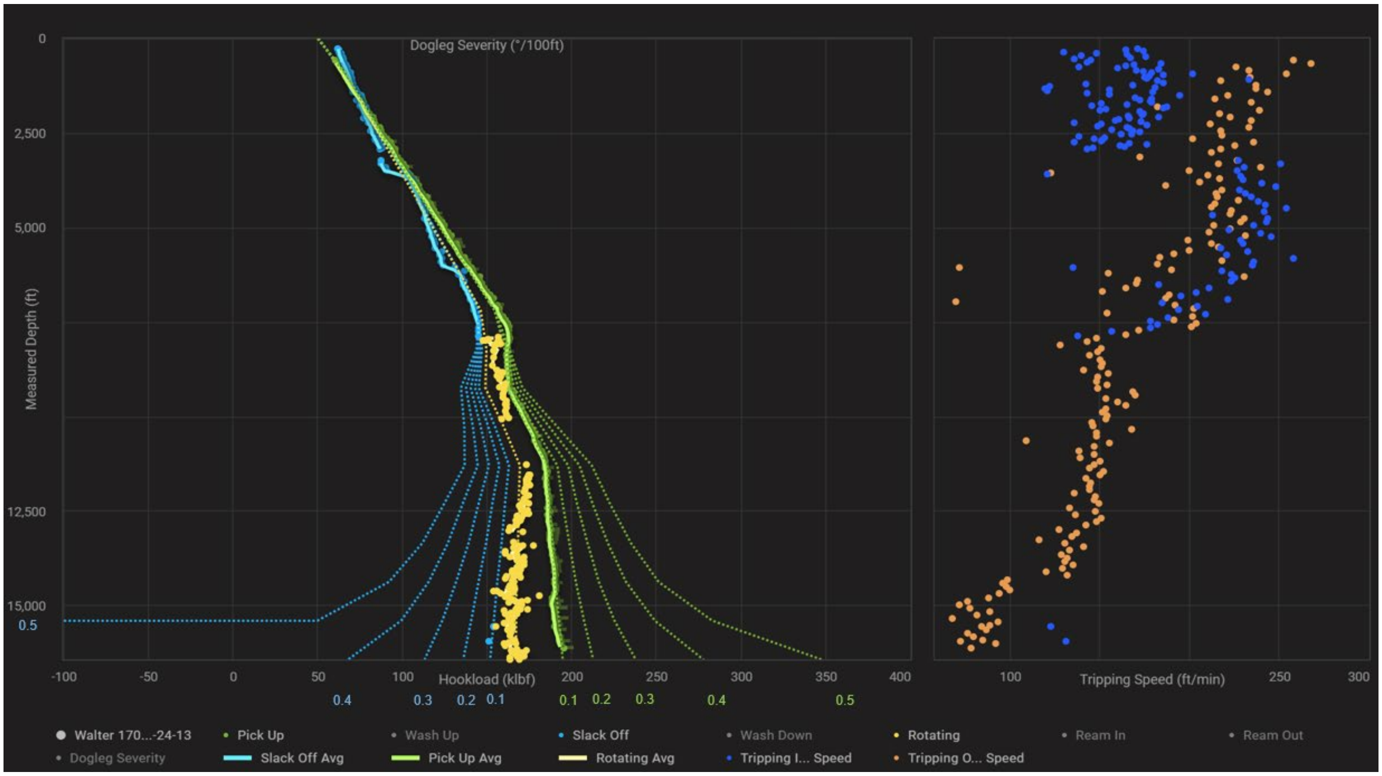

Figure 10: Actual hookload with FF overlay – outgoing leg BHA (6-⅛” bit, mud motor, 1 x agitator, 1800 ft. HWDP)

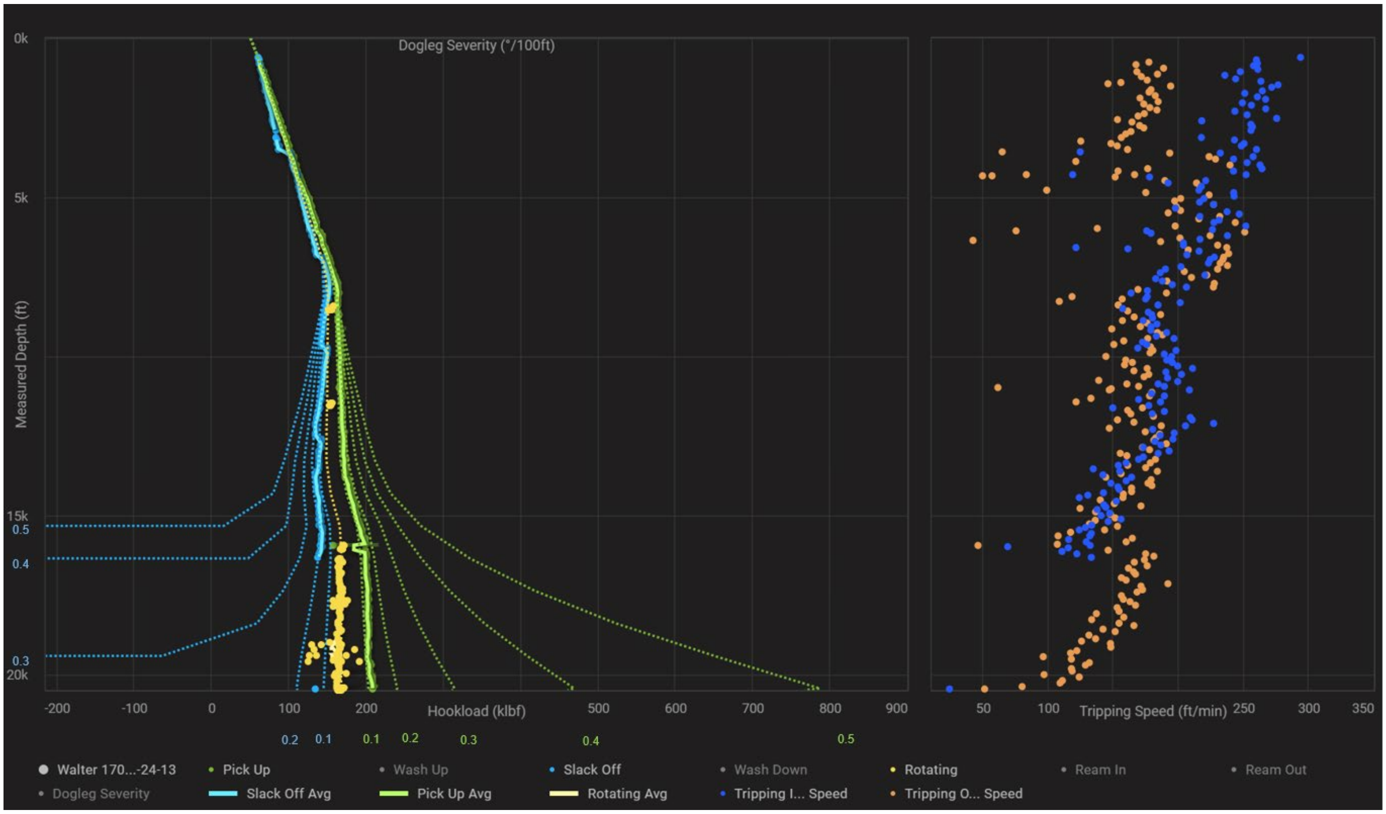

Figure 11: Actual hookload with FF overlay – return leg BHA (6-⅛” bit, mud motor, 2 x agitator, 1800 ft. HWDP)

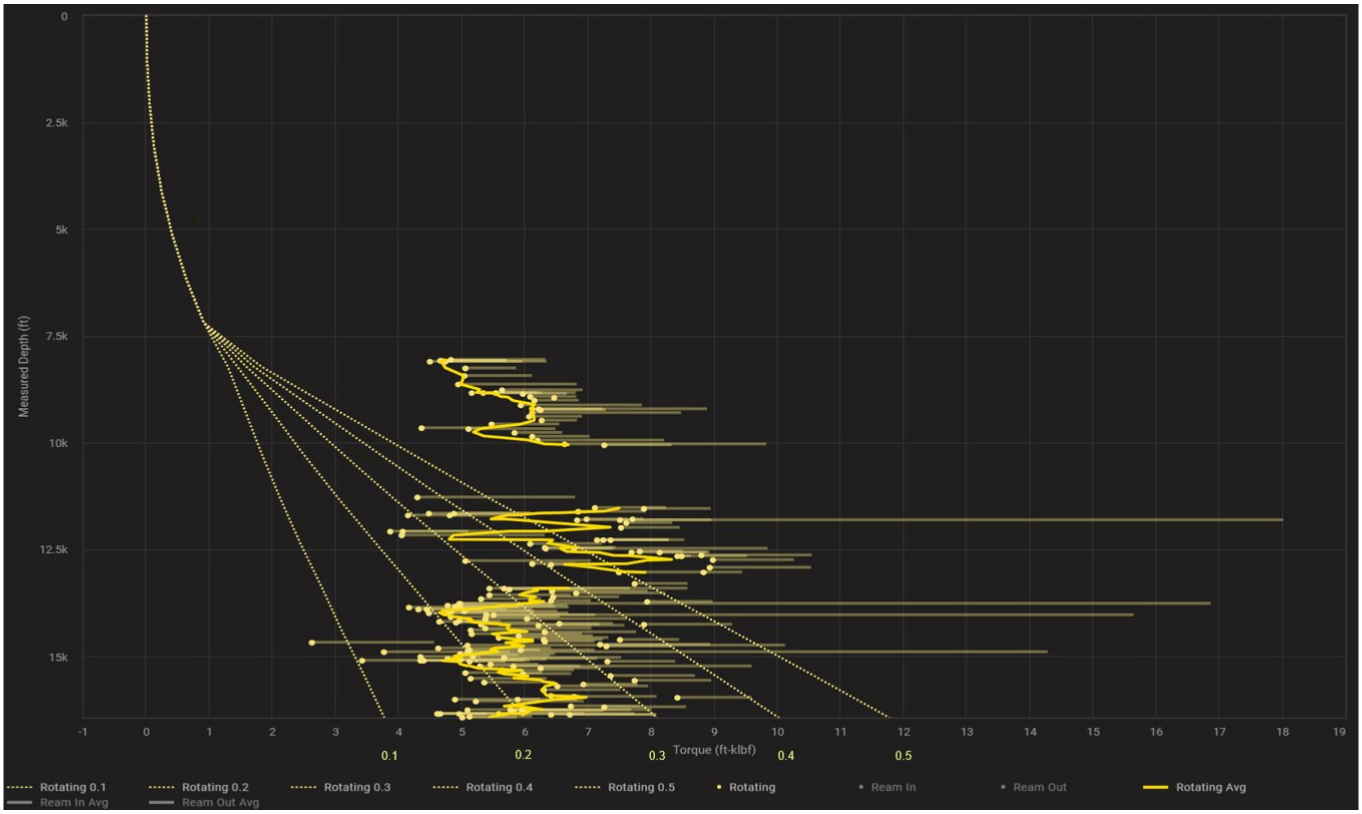

Figure 12: Actual off-bottom torque plot with FF overlay – outgoing leg BHA (6-⅛" bit, mud motor, 1 x agitator, 1800 ft. HWDP)

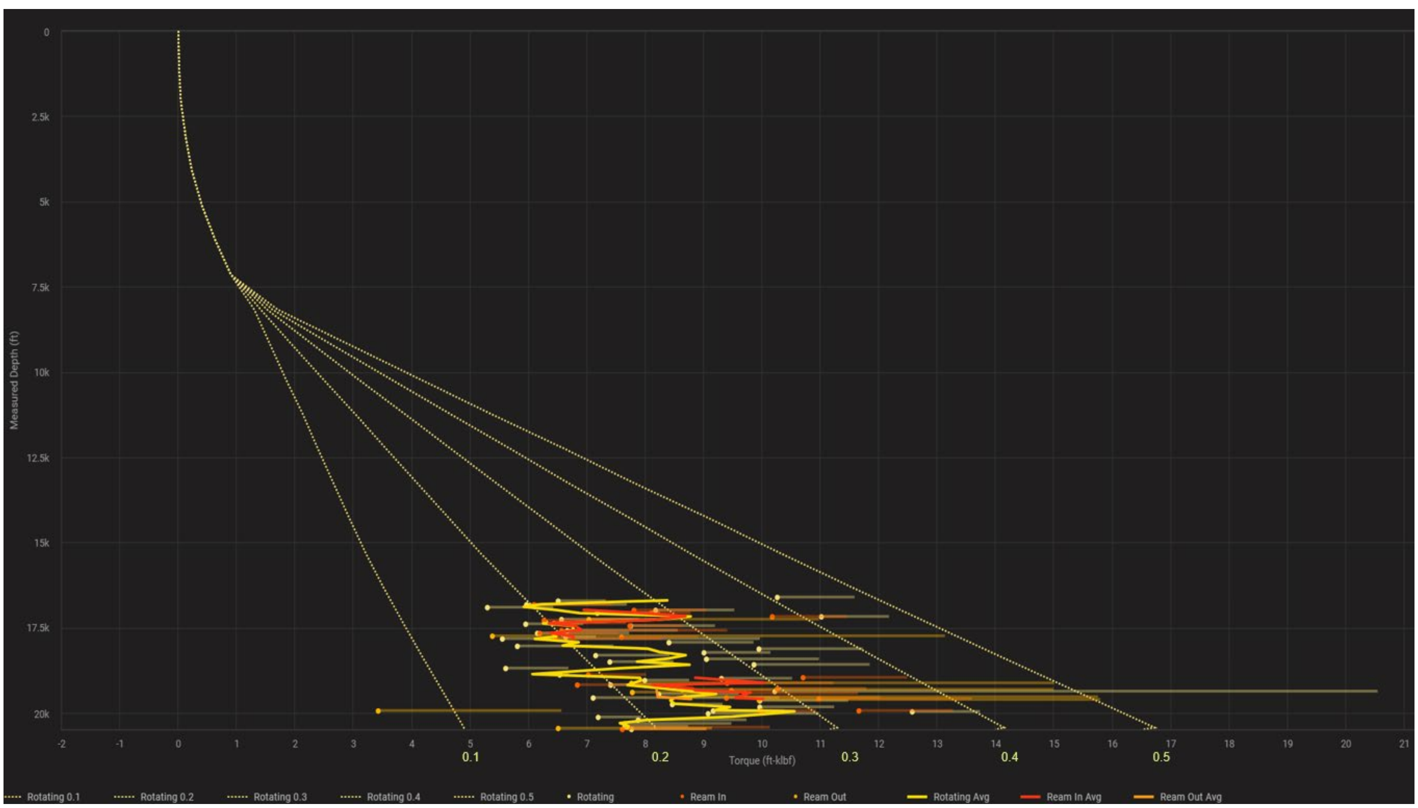

Figure 13: Actual off-bottom torque plot with FF overlay – return leg BHA (6-⅛" bit, mud motor, 2 x agitator, 1800 ft. HWDP)

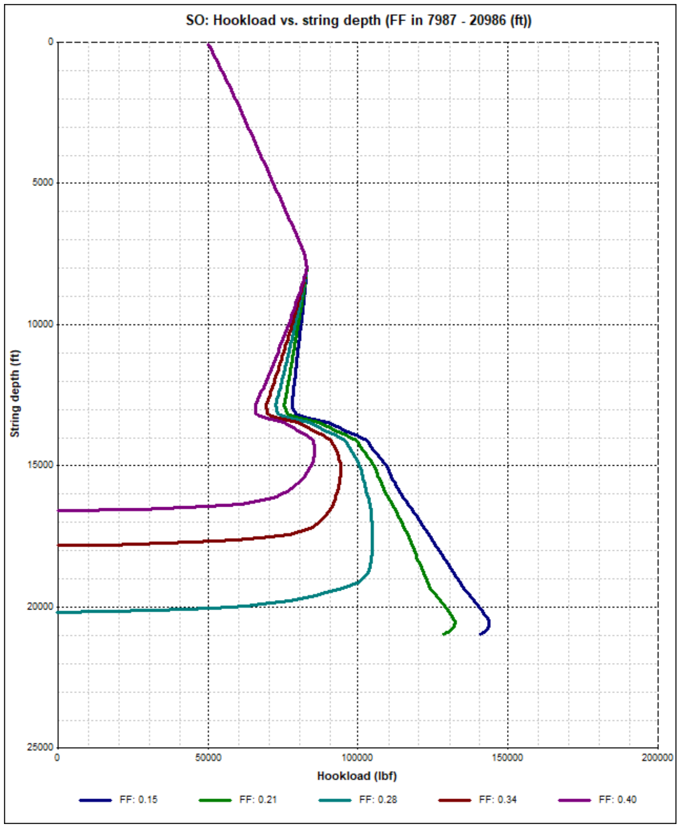

Figure 14: Liner run model – floatation with no rotation

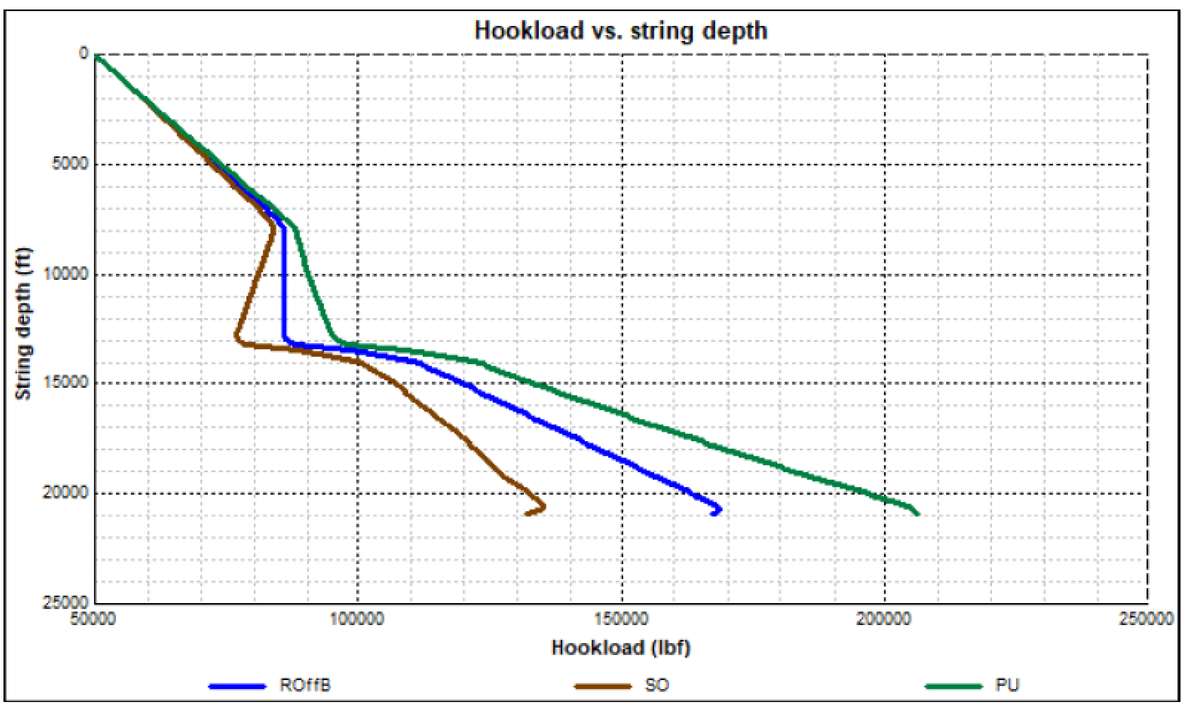

Figure 15: Liner run model with rotation

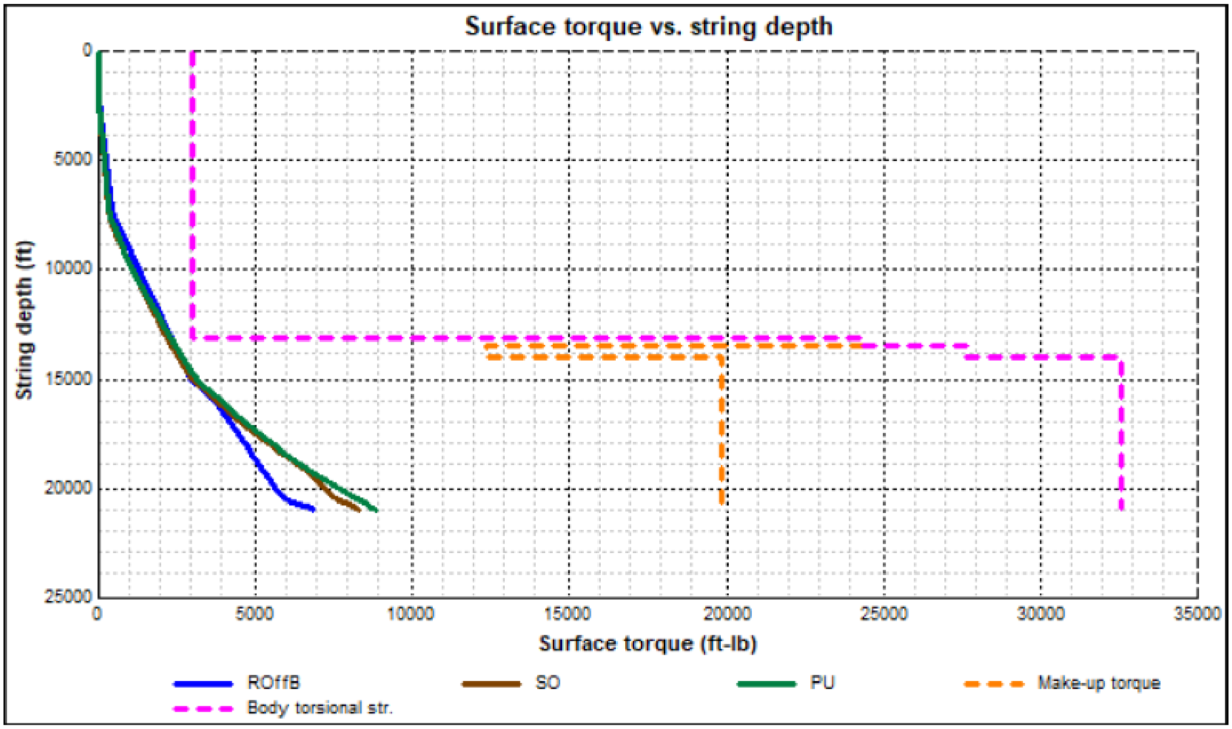

Figure 16: Surface torque versus string depth with rotation

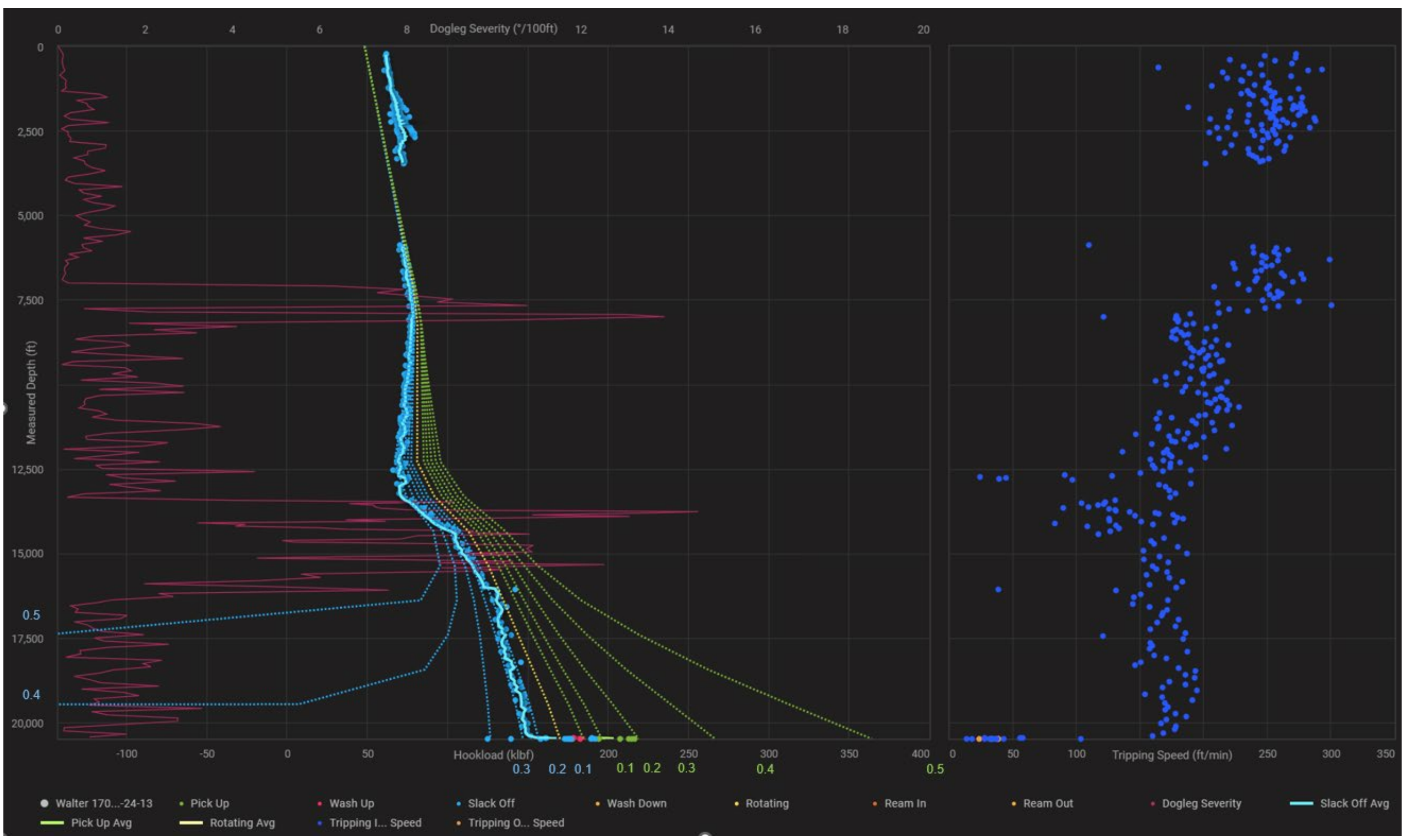

Figure 17: Actual hookload plot from the liner run

Conclusions

- Horseshoe well techniques continue to mature as they become a standard method to economically recover stranded assets. The future may include longer legs to further reduce surface location requirements.
- Horseshoe wells allow for improved drilling and completions costs in sections stranded by lease lines or geologic hazards by leveraging economics of longer laterals.
- With proper modeling and planning using conventional engineering tools, horseshoe well complexities can be mitigated.
- Simplified water-based drilling fluid can be utilized to drill horseshoe wells provided the correct application and implementation of proper engineering measures.

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Nomenclature

BHA - bottom hole assembly
DDI - directional difficulty index
DJ - Denver-Julesburg
ECD - equivalent circulating density
FIT - formation integrity test
HWDP - heavy weight drill pipe
MD - measured depth
MWD - measurement while drilling
OBM - oil base mud
PU - pick up
RSS - rotary steerable system
SO - slack off
TD - total depth
WBM - water base mud
RR – rig release
FF – friction factor

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