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SPE-200508-MS

Three Mud System Allows Successful Completion of >22,000’ Slimhole with 0.5 ppg Window through MPD Optimization of Trip Procedure

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Abstract

The Spirit River Group in Western Canada has always been difficult to drill and complete due to the presence of natural faulting in shaley formations interbedded with coal. MPD techniques allow the successful drilling of these wells; however, completing these wells has been extremely challenging. On this well, getting liner to bottom without total losses should not have been possible.

To address this, a design that used a three mud system in combination with MPD was utilized. With a diversion sub placed at the heel, the wellbore fluid column consisted of a highly underbalanced drilling fluid in the lateral, a descending column of slightly underbalanced stripping fluid placed in the vertical section, and an overbalanced column of kill fluid backfilled into the annulus from surface.

During the liner run, this three-fluid system design smoothly reduces the hydrostatic pressure at proportional rates to the increase in liner surge. This balances the wellbore at the time the RCD is installed behind the liner. The combination of factors saw full returns to surface during the liner run and, once on bottom, allows the rig to break circulation for the final displacement to completions fluids.

With the successful implementation of this 3-fluid system, the operator was able to drill further, past 22,000’, as it is now possible to run and deploy the liner without expecting the loss of the wellbore’s volume of fluid on these tight window wells.

Background

The operator primarily targets formations in the Spirit River Group of Western Canada’s deep basin. The reservoir rock of this group of formations is consistent with low porosity-low permeability shoreline and fluvial sandstone dry gas bearing zones (Newitt, 2017). These zones have shown highly heterogenous fracture gradients and pore pressures resulting in frequent negative drilling windows (combined loss zones along with high pore pressure zones) along the length of the lateral section.

An illustration of the approach of MPD implemented in the region is shown in Fig. 1. Due to the formation risks and a normally narrow drilling window, MPD has been a requirement for most wells regionally and are a prerequisite when drilling laterals beyond certain lengths. By design, drilling density muds are statically underbalanced requiring the use of MPD applied back pressure to prevent gas influxing on pumps down while using AFL to control the well while circulating. During tripping operations, the drill string is stripped to the heel and the vertical section of the wellbore are displaced with a statically overbalanced kill density mud. Displacements to kill density muds on bottom at any circulation rate is not feasible due to ECD generation with yielding pseudoplastic drill mud.

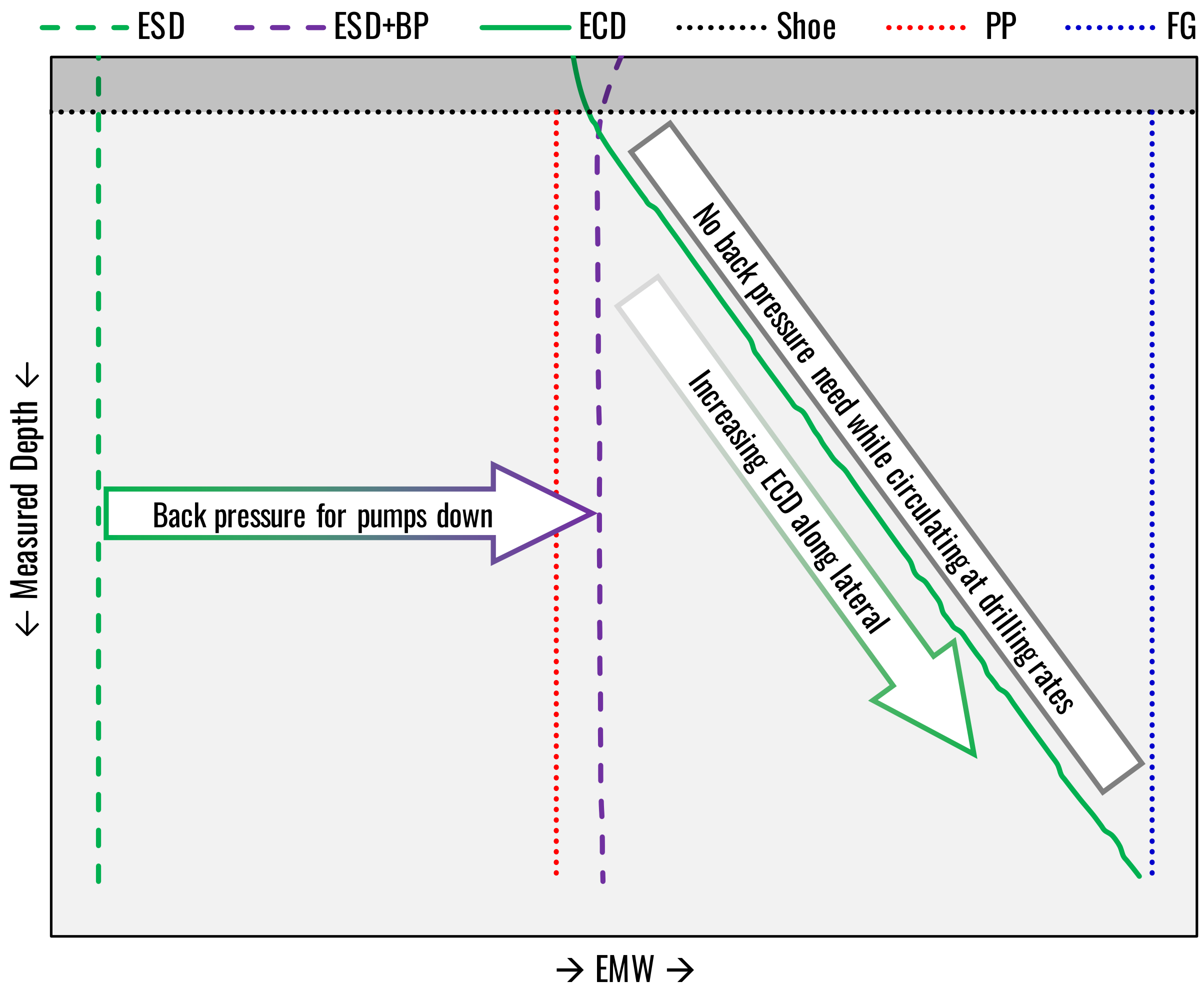

Fig. 1 – Standard MPD lateral well EMW schematic for statically underbalanced mud

Through the development of Canada's deep basin there has been a push by the operator to drill longer lateral sections. The subject of this paper is the longest lateral and the deepest to date (at 10794 ft lateral length and 22277 ftMD TD, respectively) in the target geological Peace River Group. While other constraints such as land, surface geography, and reservoir limits prevent the routine application use of the record setting lateral section, the push to drill longer laterals at deeper vertical depths has resulted in significant progress in recent years as shown below in Fig. 2.

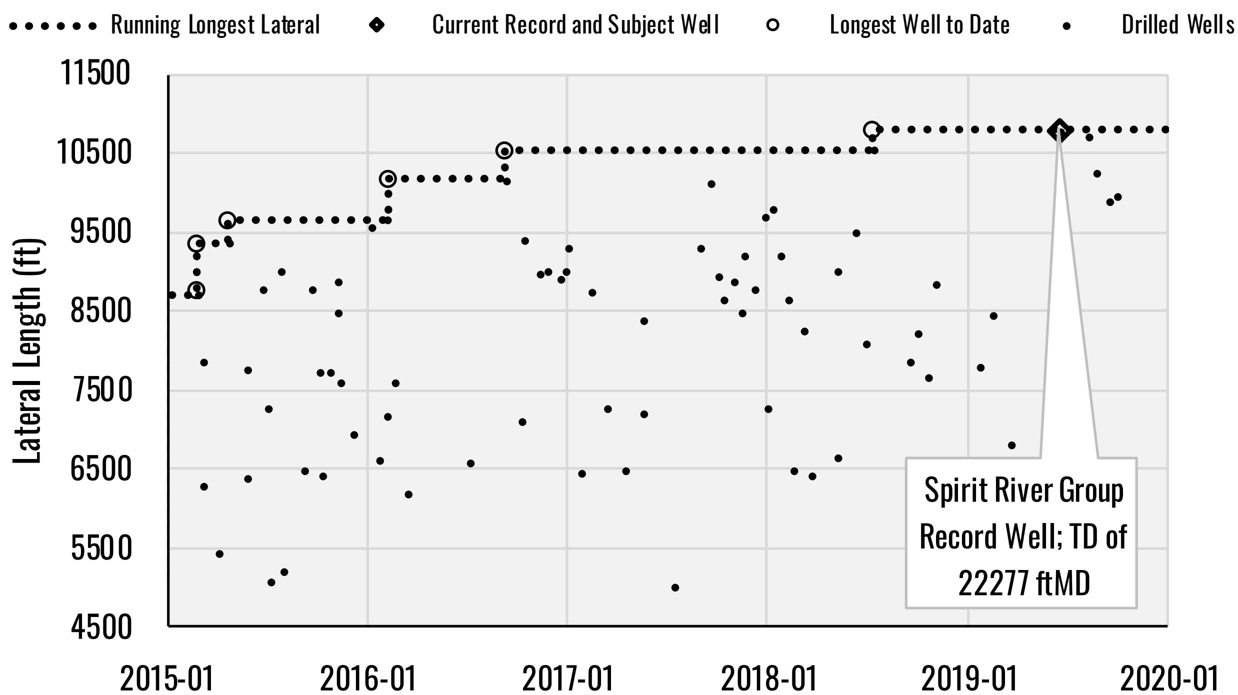

Fig. 2 – Subject operator's lateral length progression over time

Drilling these narrow drilling window wells has resulted in numerous wellbore design advancements and new drilling techniques that improved completion phase outcomes despite drilling challenges. Two innovations relevant to this paper are:

- In-zone setting of the intermediate casing string to isolate overlying coals and allow the use of a chloride brine mud systems to increase drilling performance. This results in short liner strings and deeper liner top packers allowing the earlier installation of the RCD during the liner run.
- Use of a full flow diversion sub to reduce mud losses on rollovers. This is done by displacing only an upper portion of the vertical section to kill mud and utilizing pipe displacement to backfill with a descending column of kill mud.

In addition, difficulties with modelling these wells with commercially available MPD hydraulic software has resulted in the internal development of software capable of effectively modelling multi-fluid swab-surge. The difficulty of these models continues with mud front movement as the result of staged pills and pipe displacement. While neither kill density nor drill density pills were pumped into the annulus on the well subject to this paper due to the wellbore's fracture gradient reducing to below pore pressure a few thousand feet from TD on a relatively new bit, had a bit trip been required in a narrow window well such as this, it would have seen benefit from such modelling. The RCD could be installed as soon as the BHA was through the rig floor, when bit trips are needed prior to TD staged pills can allow trips on very narrow window wells such as this.

Production Drilling Summary

Initially the lateral section of the wellbore did not present any difficulties. At the drill out of the shoe, pore pressure did not present itself during static conditions with what was expected to be a 1.7 ppg underbalanced DMW while a DFIT identified a relatively large drilling window by the area's standards (>3.1 ppg). As drilling progressed, higher pore pressure was encountered and slowly increased throughout the lateral reaching a final working EMW of 12.1 ppg.

While drilling, a fracture (the 1st fracture) was encountered around 18000 ft and fracture gradient dropped by 1.4 ppg. This reduced fracture gradient was built up by 0.4 ppg with wellbore strengthening material mud additives resulting in a 1.3 ppg drilling window. However, at 21500 ft, another fracture (the 2nd fracture) was encountered reducing the drilling window by a further 1.4 ppg. At this point, there was a negative drilling window to -0.2 ppg resulting in continuous losses at the toe along with simultaneous gas influxing at the heel.

Through the continuous circulation of drilling mud well control was maintained, and gas rates steadied out at 30-70 kscf/d. The well was drilled to TD (22277 ftMD) and through the additions of wellbore strengthening material the drilling window was increased to 0.1 ppg. At TD the addition of LCM further increased the drilling window to slightly above 0.5 ppg. With this window, it was possible to circulate gas out of the wellbore.

Fig. 3 shows an illustration of the horizontal wellbore profile projection including the relevant casing string, open hole section, and tie-back depth. In addition, the working laterals drilling window as constrained by the pore pressure and fracture gradient is shown below along with drilling mud density. As shown, after encountering lower FG fractures, drilling mud weight (shown in green) was further reduced to mitigate losses and allow flow drilling as needed.

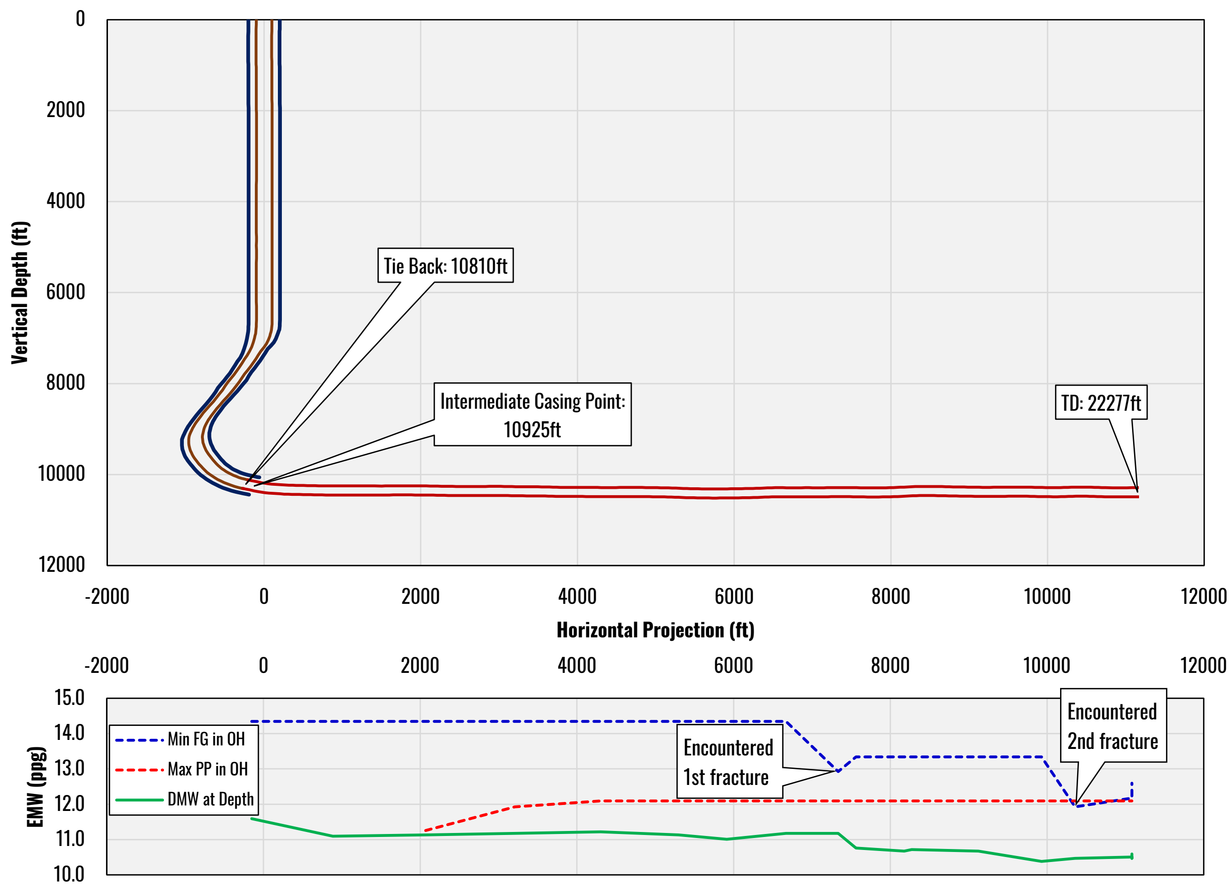

Fig. 3 - Wellbore schematic and running drilling window parameters

Pre-Trip Operation Background

With this drilling window and the long lateral nature of the wellbore, it was not possible to do either of a stripping operation from bottom or to circulate the vertical section of the wellbore without significant losses, let alone successfully run the completions string to TD without total losses due to surge pressure induced losses with such a deep well.

After encountering the 1st fracture in the lateral, the decision to place a full flow diversion sub in the drill string was made during the final bit trip prior to TD. Even with the drilling window, after encountering the 1st fracture, it was known that a dedicated displacement to kill density mud through the bit outside the intermediate casing shoe was not possible due to ECD at even low pump rates.

By the time TD was reached, the option for the diversion sub had to be revised due to the 2nd fracture creating a negative drilling window even after it was built to 0.5 ppg for the trip from TD and following the liner run. Various hydraulic factors pulled in different directions:

- A need for mud density profile that allowed slow circulation rates without major losses while tripping if the hole pulled tight on the trip out was required
- A mud density profile that did not require excessive applied back pressure that could induce RCD element failure or risk injuries as the result of an RCD element failure during stripping operations
- A mud density profile that did not cause surge induced losses on the casing run
- A tripping procedure that did not require excessive pumping out of hole while laying out singles of drill pipe for the liner run; however, enough HWDP was needed for the HWDP conveyed liner that pumping out HWDP was possible
- Additionally, a mud density profile that was resistant to potential losses if surge induced seepage that resulted in low density mud not displacing the kill density mud up the annulus through pipe displacement

As a result, a new approach to with a three mud design was developed to meet these requirements as best possible by adding a third mud that was neither drilling density nor kill density to the system, but something in between that would allow sufficient hydrostatic to strip out without exceeding SABP and have a low enough hydrostatic to prevent losses due to liner surge while running in to TD. Each of the utilized muds can be summarized as:

- A 0.1 ppg overbalanced, 12.18 ppg kill density mud to backfill the well and fill the majority of the vertical section once out of hole
- A 0.5 ppg underbalanced, 11.59 ppg stripping density mud to be placed in the vertical section with the diversion sub and eventually descending into the first portion of the lateral once out of hole
- A 1.6 ppg underbalanced, 10.59 drilling mud to be left in the lower section of the lateral

The usual alternative (a two-mud system without an additional column of stripping density mud) is shown in Fig. A6. A summary of each mud's mud rheology can be found in Table A1.

End of Well TD Tripping Operation

The order of operations for the trip from TD was as follows:

1. Pump out 1640 ft of HWDP with the entire wellbore full of 10.59 ppg drill density mud racking stands for the liner run and applying back pressure during static periods
2. Deploy ball-drop full diversion sub and displace the vertical section from 11319 ft to surface to 11.59 ppg stripping density mud applying back pressure during static periods
3. Strip to surface 20637 ft of drill string while backfilling well with a descending column of 12.18 ppg kill density mud utilizing MPD to offset swab

Fig. 4 shows the mud front positions from the operation after displacement of the vertical to tripping density mud and on to surface. The upper graph is idealized graph of mud columns with drill mud shown in blue, stripping mud shown in red, and kill mud shown in yellow as the bit was tripped from around 20600 ft (1640 ft off bottom) to surface. The lower graph shows the idealized hydrostatic EMW experienced by the lateral as the bit was stripped to surface. Not shown is the applied back pressure to supplement hydrostatic during static period when breaking out singles and overcome swab as needed to ensure the well was overbalanced while tripping.

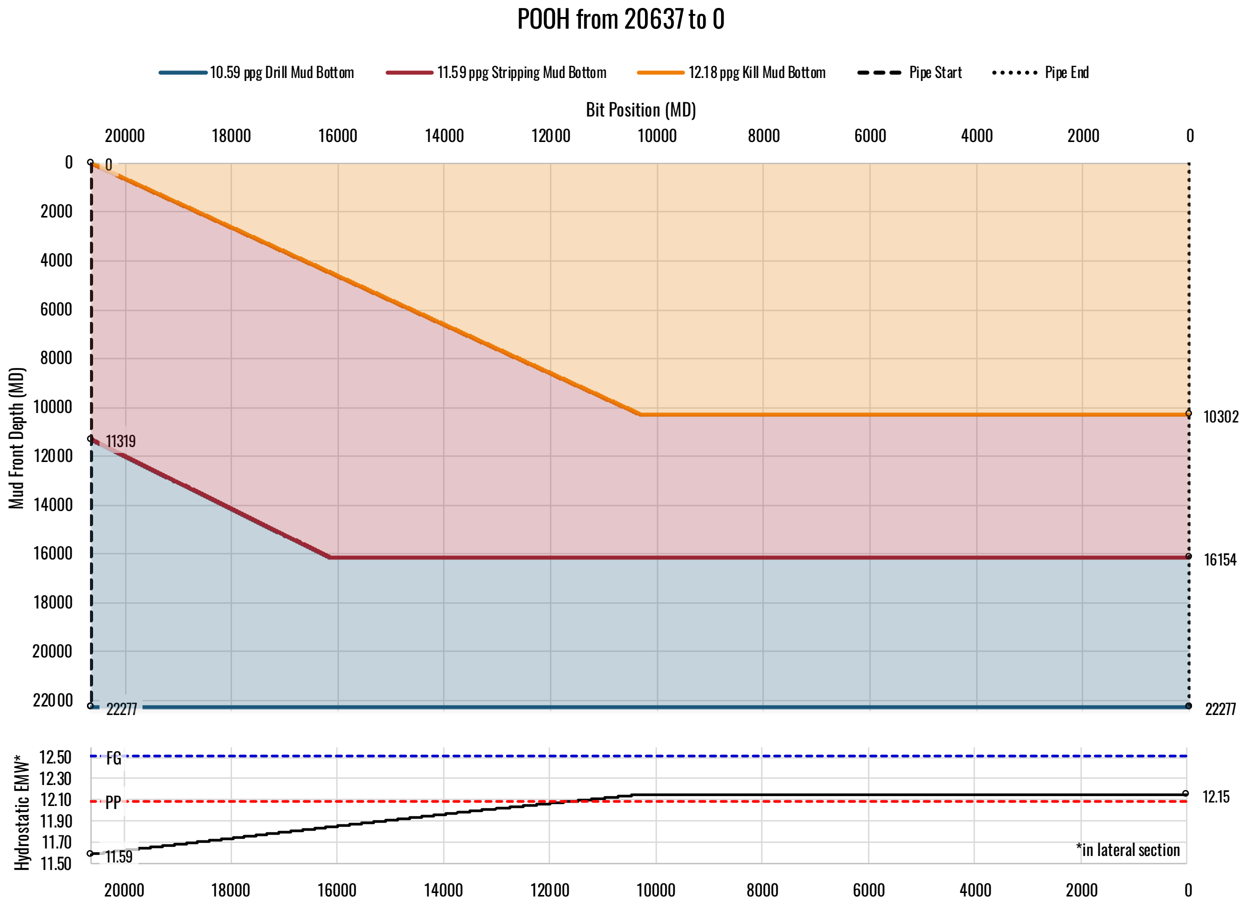

Fig. 4 - TD trip, POOH after backreaming 1640ft

While stripping out, the tripping density mud (shown in red) dropped from approximately 11300 ft to 16100 ft through pipe displacement alone. The column of tripping density mud provided just enough hydrostatic to allow stripping with maximum back pressure to overcome swab while only applying enough back pressure during static periods to ensure the well was kept overbalanced without inducing losses. At the same time the well was backfilled with a kill density mud (shown in yellow) replacing drill string volume and eventually sitting just inside the shoe at around 10300 ft and providing a hydrostatic EMW of 12.15 ppg. The drop in the kill mud column occurred until the bit was pulled through the kill mud interface and allowed a static flow check with the final out of hole EMW that could be expected.

Fig. 5 visually shows the configuration of the different columns of mud once out of hole.

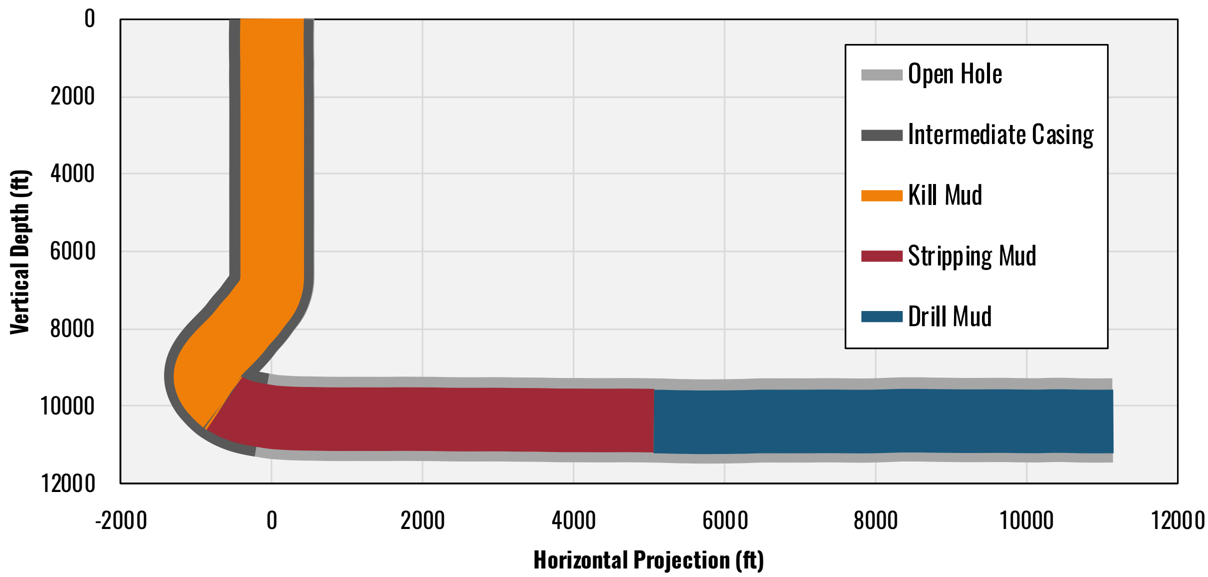

Fig. 5 – Out of hole mud configuration

Once at surface the production packer based frac string liner assembly was made up and run in. The earliest the RCD could be installed was after liner top packer was in the hole; this point was at around 11400 ft. Given that the kill mud front was at 10300 ft once out of hole, at that 11400 ft depth running any further in hole without the application of back pressure would have resulted in underbalancing the well. Note the intersection of the solid black hydrostatic EMW line with the dashed red pore pressure line and the 11400 ft dotted black RCD installation line on the lower graph of Fig. 6.

Fig. 6 also shows the movement of mud fronts and the reduction of hydrostatic EMW in the lateral due to pipe displacement in the same manner as Fig. 4. Note the removal of the kill mud column by pipe displacement around the 20500 ft depth mark as the yellow line reaches surface.

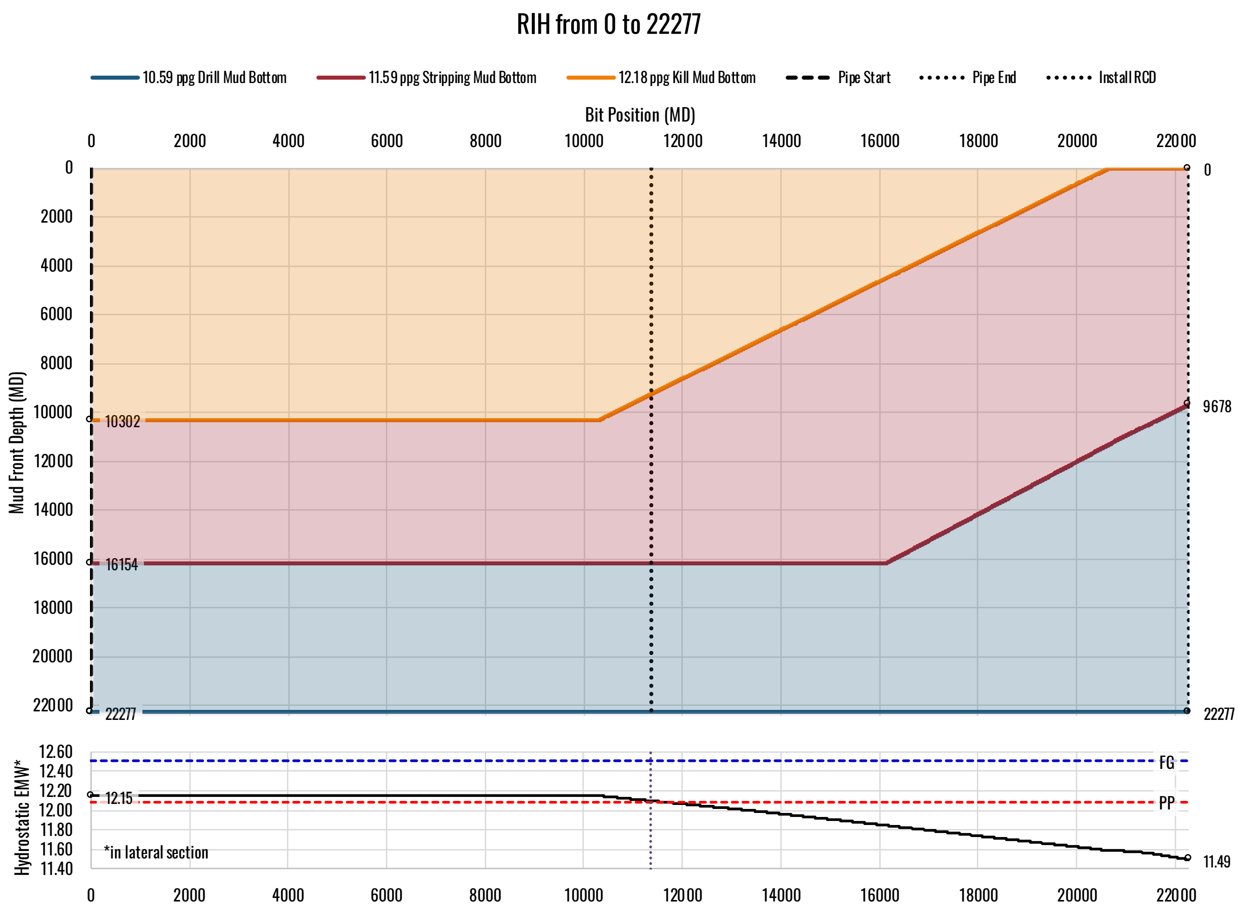

Fig. 6 - TD trip, RIH with drill pipe conveyed liner

Once liner was run to bottom, the well could be circulated to a consistent column of drill density mud at a reduced rate. Once back to a single drill density mud, pump rate could be increased to full flow rate as limited by the liner shoe and the displacement to completions fluid, recovery of invert mud, and deployment of the liner hanger and liner top packer could be completed.

Results

The complexity of the operations presented a number of design challenges that required a number of innovations and novel approaches to overcome the problems surrounding the narrow drilling window of this well. While negative windows are not out of the ordinary in Western Canada's deep basin, a negative window on the both the deepest well and the longest lateral to date presented a combined challenge.

Tools and techniques critical to the success of the well were:

- The use of newly developed internal proprietary software that could effectively perform multi-fluid swab-surge modelling (along with effective mud front tracking) ensured that the hydraulics of this well's TD trip could be modelled effectively.
- The use and proactive placement of a full flow diversion sub was requisite for a successful operation.
- Deep set in-zone intermediate casing to shorten the length of the production liner and thereby allow more aggressive use of MPD applied back pressure during the liner run.

Importantly, while losses to formation were significant after drilling into the 2nd fracture even with a reduced mud density, reduced mud circulation rate, and a gasified annulus reducing hydrostatic, treatment of the wellbore with LCM and wellbore strengthening material lead to effective attenuation of loss rates by providing a positive drilling window of around 0.5 ppg. Essentially all mud pumped during the trip to surface from TD was recovered. Even with the narrow drilling window and the with use of a 3-density mud system, losses on the liner run were mostly attributable to the shakers while stripping the proactively placed LCM from the system on the bottoms up circulation prior to pumping completions fluid.

Equipment Used

The equipment used in this operation is not generally different from full package MPD operations except for a ball actuated full flow diversion sub.

1. RCD: Provides pressure isolation barrier for the annulus
2. Choke manifold including atmospheric MGS: Allows control of the SABP and separation of formation gas from mud returns
3. Ball-drop full diversion sub: Used to provide a flow point in the drill string behind the BHA for placing mud columns while retaining drill string volume below
4. Non-ported floats: Provides redundant pressure isolation along the drill sting though use of string floats, BHA floats, and a profile sub to land a pumpable backup float

Conclusion

Drill this well 3900’ short of final TD would have been a record well 5 years previous. In addition, this would have avoided the difficulty of a narrow window well altogether by missing the weak encountered fractures altogether. However, with the new push to drill longer wells that risk intersecting weak zones, this well became extremely complicated with a negative window necessitating the innovative use of MPD techniques.

By using several preexisting innovations and implementing a newly designed 3 density mud to trip from TD, this well and potential future wells can continue to be drilled without the risk of being called undrillable or seeing catastrophic mud loss when running liner to TD.

Acknowledgements

The authors would like to thank Jupiter Resources Inc and Beyond Energy Services and Technology for their support and permission to publish this paper.

Nomenclature

AFL = Annular friction losses
BP = Back pressure
DFIT = Dynamic formation integrity test
DMW = Drilling mud weight
ECD = Equivalent circulating density
EMW = Equivalent mud weight
ESD = Equivalent static density
FG = Fracture gradient
KMW = Kill mud weight
MGS = Mud-gas separator
MPD = Managed pressure drilling
POOH = Pull out of hole
PP = Pore pressure
RCD = Rotating control device
RIH = Run in hole
SABP = Surface applied back pressure
SMW = Stripping mud weight
Stripping= Tripping with surface applied back pressure

References

Newitt, D. J. 2017. Integrated sedimentology, sequence stratigraphy, and reservoir characterization of the basal Spirit River Formation, west-central Alberta, University of Calgary, Calgary, Alberta (June 2017)

Power, D and Zamora, M. 2003. Drilling Fluid Yield Stress: Measurement Techniques for Improved Understanding of Critical Drilling Fluid Parameters. Paper presented at the AADE 2003 National Technology Conference, Houston, Texas, USA, 1-3 April. AADE-03-NTCE-35

Appendix

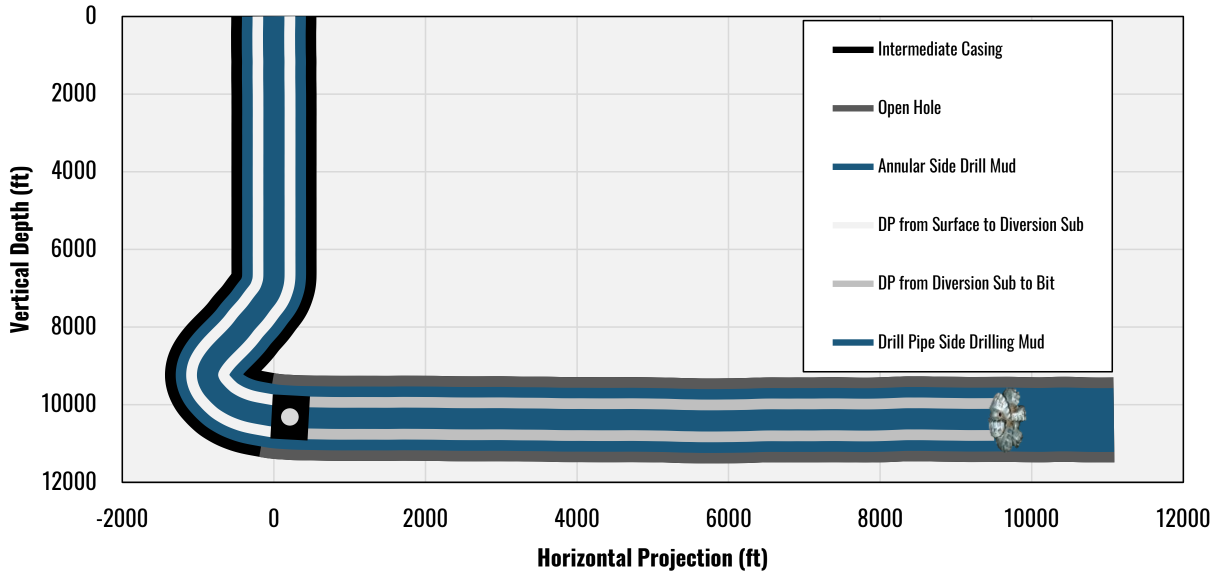

Fig. A1 – Fluid schematic prior to diversion sub deployment

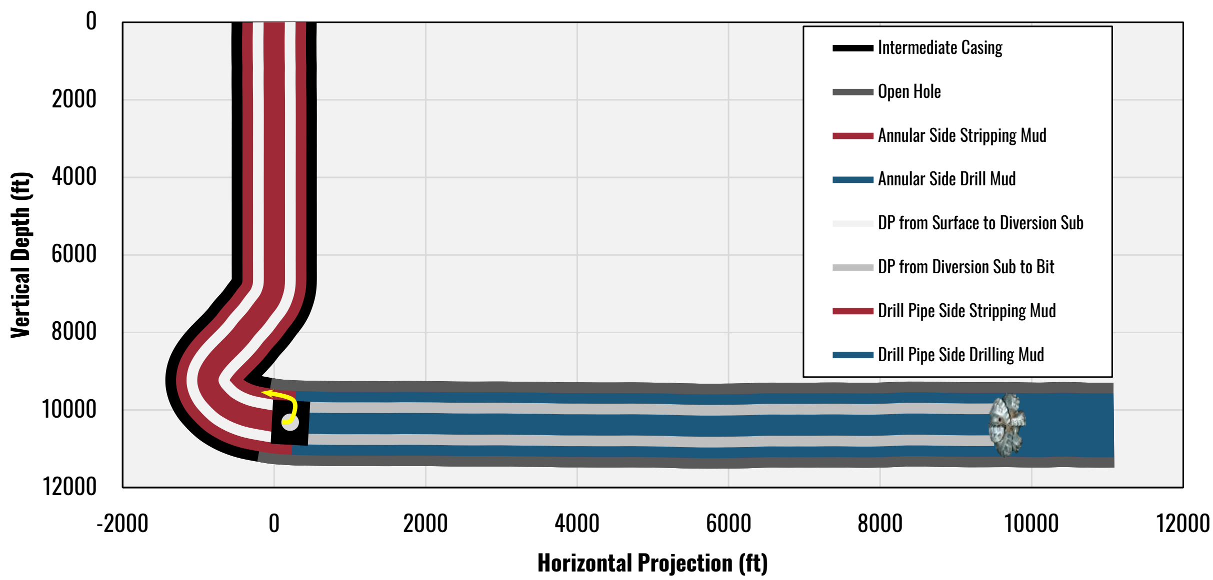

Fig. A2 – Fluid schematic at time of full circulation after diversion sub deployment

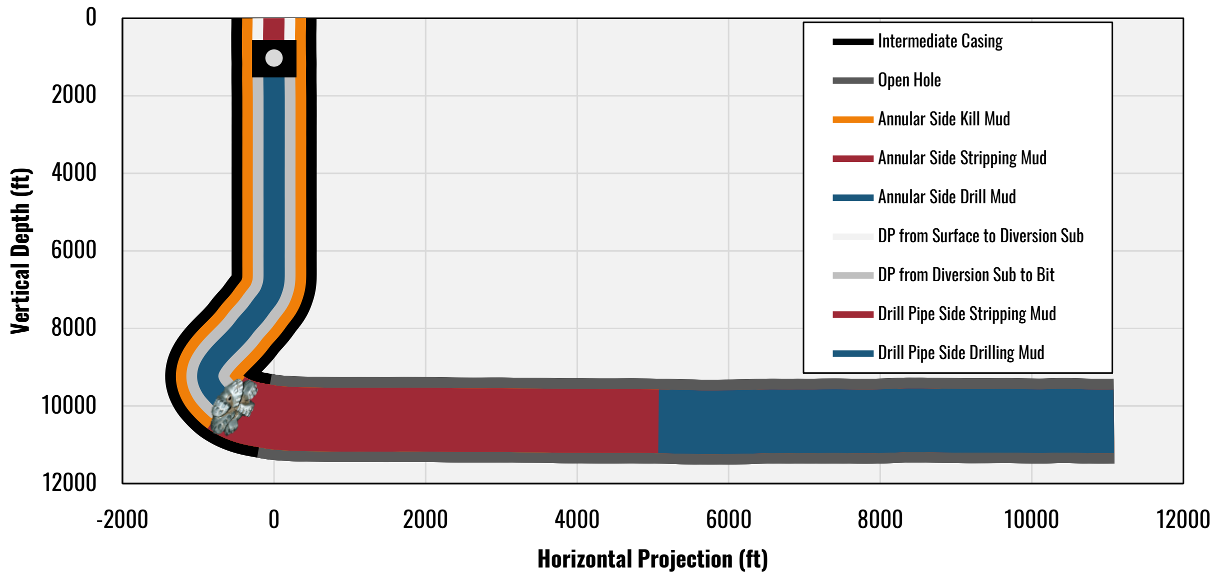

Fig. A3 – Fluid schematic during POOH at 10302ft; fluid fronts static for remainder of POOH sequence

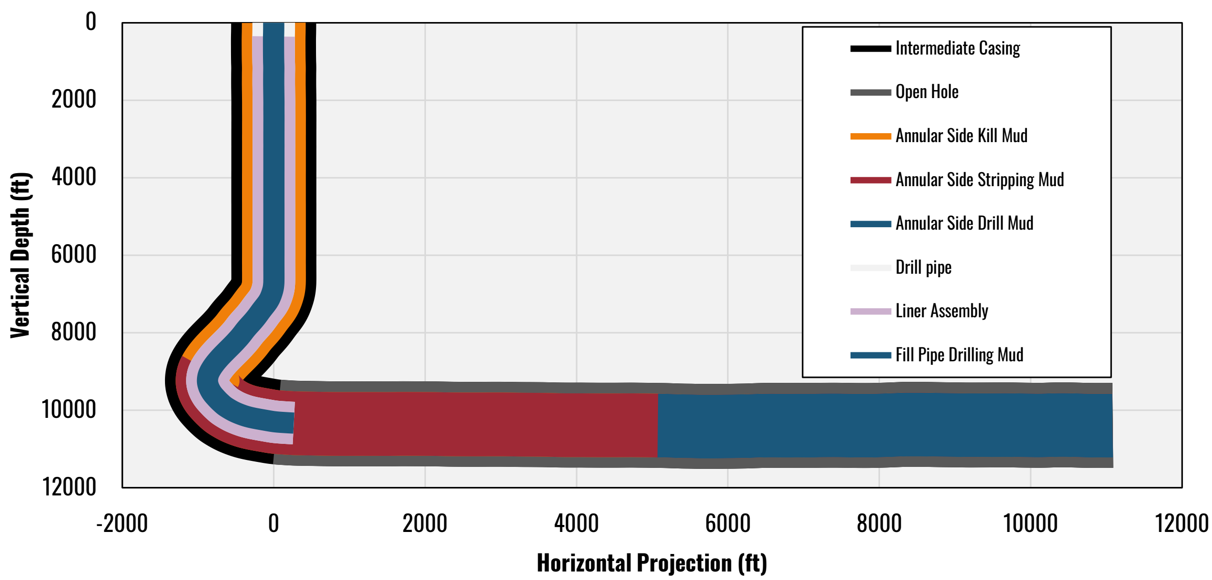

Fig. A4 – Fluid schematic at time of RCD install on liner run

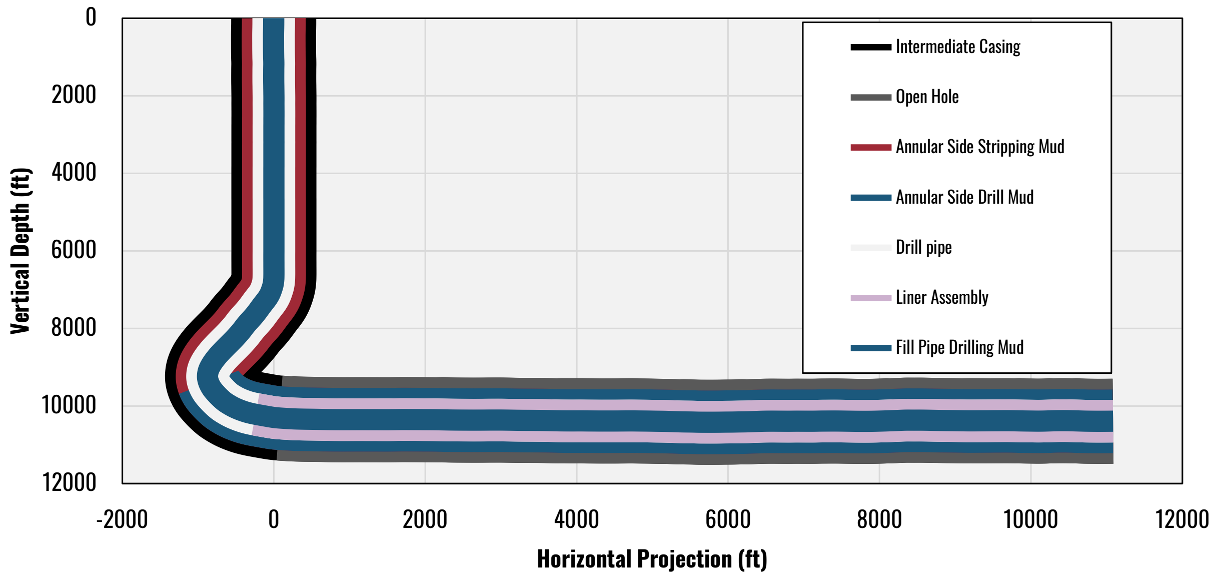

Fig. A5 – Liner on bottom prior to circulation to drill density mud

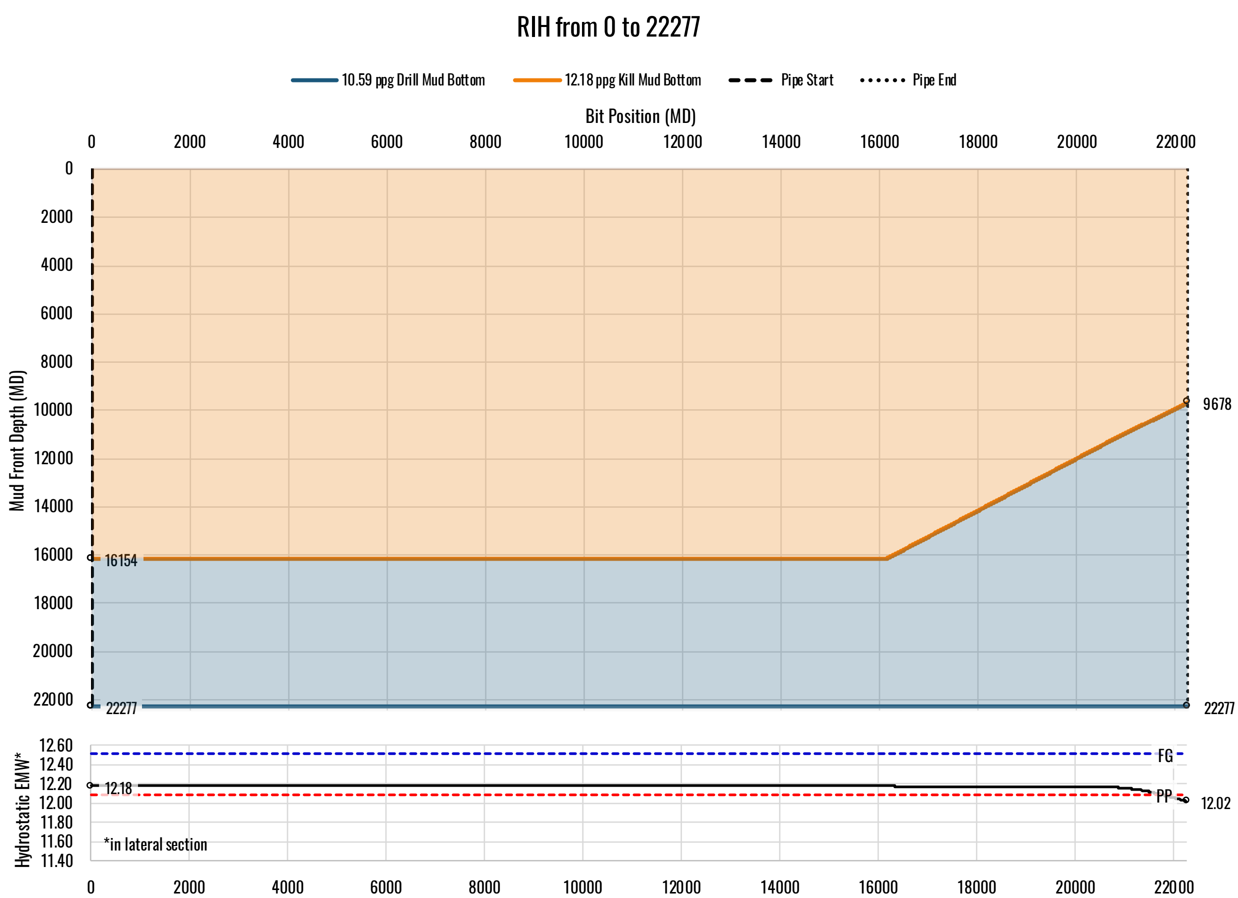

Fig. A6 – Alternative, 2-fluid TD-trip, RIH with liner

Table A1 – Working fluid rheologies

	Kill Mud	Drill Mud
PV ($lb_f/100ft^2$)	26	28
YP ($lb_f/100ft^2$)	11	12
LSYP ($lb_f/100ft^2$) (Power et al, 2003)	3	3

Table A2 – Dimensional data

	Internal Dimension (in)	External Dimension (in)
Intermediate Casing	6.366	
Bit		6 ¼
Drill Pipe		4 ½
Liner		4 ½