

First Monobore Horizontal Drilling Success in Sublette County, WY

Randy Fletcher, Ultra Petroleum; Matthew Bechaver and Jeffrey Nash, Newpark Drilling Fluids

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Abstract

While horizontal drilling is not new to the oil and gas industry, it is in its infancy in Sublette County, WY. Less than 1% of the approximate 4,800 wells in Sublette County, WY are horizontal. Since the early 1950's, the Lance pool and subsequent formations have been exploited by vertical pad-drilling operations. The first horizontal well was drilled in 2016 in Sublette County, WY. Currently, there are less than 50 horizontal wells in the Upper Green River basin.

The majority of the horizontal wellbore designs in Sublette County, WY are 3 string designs. 9.625" casing to 5,000' MD, 7" casing to approximately 11,500' MD, and 4.5" casing to approximately 20,000' MD. With the use of Managed Pressure Drilling (MPD) and Wellbore Strengthening (WBS) laden drilling fluids, Ultra Petroleum was able to eliminate the 7" casing string to provide a 2-string horizontal well to a TD of 19,118' MD. The focus of this paper will be to highlight the first monobore well that was fully drilled, cased, and cemented on the Pinedale Anticline.

This paper discusses MPD techniques used to drill the Pinedale Anticline in vertical and horizontal wells, WBS laden drilling fluids used to minimize mud losses, and case studies of Monobore applications in Sublette County, WY.

Introduction

This paper focuses on the development of the Pinedale field in Sublette County, WY. This development includes vertical wells, horizontal wells, and many challenges of drilling in an extremely tall lenticular natural gas reservoir. This reservoir is over 6000' vertically. The advancements in drilling fluids and lost circulation materials is also highlighted within this paper. Lastly, the trials leading to the success of the first two string horizontal well is discussed.

Geologic Background

In 1920, the US Geological Survey geologically surface mapped the Upper Green River Basin¹. At that time, it was one of the largest natural gas rich basins in the United States. In 2015, the U.S. Energy Information Administration statistically ranked the Pinedale Field as the sixth largest gas

field in the United States¹. The same study ranked the Pinedale Field as the 85th largest oil reservoir in the United States.

The Pinedale Field encompasses 84 square miles and is approximately 30 miles in length and a maximum of 5 miles in width. Structurally, the field is setup by an anticline fault to the West and the Wind River Thrust to the North and East. To the South, lies the Jonah field, a similar lenticular reservoir set up by 2 main faults. Stratigraphically, the payzone is defined by the Ft. Union formation, currently used for saltwater injection, from ~4,500' to 7,500' which is above the Lance formation. On top of the Lance Formation, the T/K Boundary can be correlated by seismic and logs. The Lance Formation is known as the first commercially productive hydrocarbon bearing zone. Typical depths of the Lance are approximately 7,500' to 13,000'. Underneath the Lance is the Mesaverde formation at approximately 13,000' to 14,500'. Enclosed at the bottom of the Mesaverde formation is the Ericson Sandstone which is easily seen on most seismic logs across the basin².

The Upper Green River Basin is a lenticularly developed basin. The productive zones in the Lance and Mesaverde formation are fluvially deposited sandstones and siltstones, encased by mudstones and shales. The sandstones and siltstones in the field are 5-400' in height and highly uncorrelatable. Porosities in the basin are 5-14% with permeabilities in the 0.001-0.01µD range³.

Upper Green River Basin Development

Since the first well was drilled in the Pinedale field in 1939², the idea of how to efficiently drill and produce the field has mystified operators and service companies alike. Due to the large vertical section of the payzone, the majority of drilling the approximate 4,800 wells in Pinedale and Jonah fields did not begin until the widespread adoption of multistage hydraulic fracturing in the 1990s. Large pad-style drilling locations were preferred for maximum reservoir drainage. Pads in the field can range from 10 to 50 wells. In

the 2000s, operators were drilling 4-string well designs:

- 13.375-inch casing to 2650-feet
- 9.625-inch casing to 9000-feet
- 7.00-inch liner to 12,000-feet
- 4.5-inch casing to 14,500-feet

The last string was a longstring production casing, installed from surface to TD to assist in gas production. These 4-string designs could be drilled at best in 60 days using water-based drilling fluids. The aqueous fluids caused significant wellbore stability issues, especially during non-circulating periods such as casing runs. In 2007, oil-based drilling fluids (OBM) were introduced to alleviate this issue. By 2013, drilling days were reduced to 12 days, through the introduction of drilling rigs with the enhanced pressure capabilities, polycrystalline diamond compact bits, and enhanced oil-based muds (OBM)⁴. Currently, the field record is 6.22 days spud to total depth. This was accomplished with the use of MPD, and experienced rig crews.

The dominant vertical well design in the field is:

- 9.625-inch casing to 3000-feet
- 7.00-inch casing to 11,000-feet
- 4.5-inch longstring casing to 14,500-feet

Typically, water-based mud is used to drill to the top of the Lance formation, then the drilling fluid is swapped on the fly to OBM to drill the rest of the payzone.

Ultra Petroleum's first horizontal well in the Pinedale field was drilled in 2016. Currently, there are only 30 horizontal wells in the Pinedale Anticline and Jonah Field. These horizontals are landed in multiple horizons. Landing depths vary from 10,500' to 13,000' TVD, and lateral lengths vary from 4,100' - 12,200'.

Most horizontal well designs on the Pinedale Anticline are:

- 9.625-inch casing to 5000-feet
- 7.0-inch casing to the end of the curve
- 4.5-inch casing with premium connections to TD

The most efficient horizontal wells drilled in Pinedale are built with rotary steerable systems in both the 8.5" curve and 6.125" lateral. With the lenticular reservoir and the changes in sand and shale sequences, increased hole sizes at the formation transitions caused significant hazards while running casing. For this reason that rotary steerable systems were used to keep the wellbore on the smoothest plan possible. Extra time prior to trips was taken to minimize issues with the production casing run and cement job. This was done to circulate cuttings out of the lateral and enlarged hole sections.

Managed Pressure Drilling in the Pinedale Anticline on Vertical Wells

In 2016, Ultra Petroleum brought MPD to Pinedale. In the beginning, only a Rotating Control Device (RCD) was used to set equivalent circulating density (ECD) pills to get drillpipe out of the hole and replace with casing and cement. The use of the RCD would allow equivalent backpressure to be trapped on the annulus of the wellbore and then trip the bottomhole assembly (BHA) out of the hole to a precalculated depth.

Once at this depth, a high density ECD pill could be pumped to replace the hydrostatic pressure equivalent that was trapped on the annulus of the wellbore and the drillpipe displacement volume equivalent to keep the wellbore at a static condition.

As Ultra Petroleum moved rigs into certain sections of the field other options were evaluated to deal with formation pressure regressions in the certain areas. Historically, Pinedale operators would have set 2 strings above the pressure regression, then set casing again at the bottom of the pressure regression making these the earlier mentioned 4-string well designs. To remain economical, these wells now needed to be drilled with the 3-string design. Surface casing would be set high to isolate fresh water zones, then the intermediate casing would need to be set at the bottom of the pressure regression. Lastly, the bottom section of the well could then be drilled without concern of breaking down weaker zones causing extreme mud loss or complete wellbore loss. The following figure (Fig. 1) shows the regression in the blue circle.

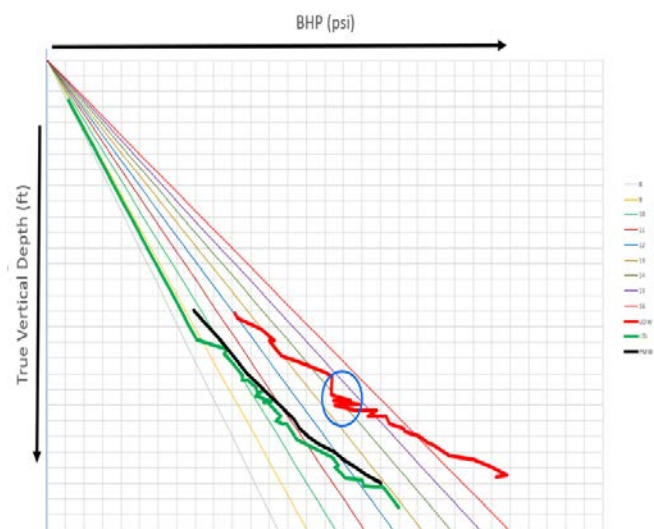


Fig 1. – Drilling window, highlighting pressure regressions

The chart is bottomhole pressure versus true vertical depths. The bold green line is the Lower Drilling Window which is the higher of pore pressure or wellbore stability. The bold red line is the Upper Drilling Window or fracture initiation pressure. The bold black line is the planned mud weight. The spidery multi-colored lines are varied mud weight ECDs at varied depths. Maintaining lower than historical mud weights were needed to drill these wells.

To drill these wells with pressure regressions in the rock, Ultra Petroleum needed to continue to use the RCD with addition of a Coriolis meter and electronic chokes. These were used to not only maintain pressure on the annulus during connections, but also while drilling. Throughout the oil and gas industry, these components are known as a Tier 3 MPD system. The next figure (Fig. 2) illustrates the differences in mud weights used historically in this area and what was planned with the MPD system. The mud weights in blue are what was used on new wells drilled with MPD, and the orange

line are mud weights on historic wells. Mud weights achieved with the MPD system are typically 3.0-5.0ppg less.



Fig. 2 – Differences in historical and new mud weights with and without MPD.

Ultra Petroleum drilled 4 wells without using the Tier 3 MPD system with extreme mud losses. After installing the MPD system, losses can be seen in the Fig. 3. Total mud losses were decreased by 48% with the use of the MPD system.

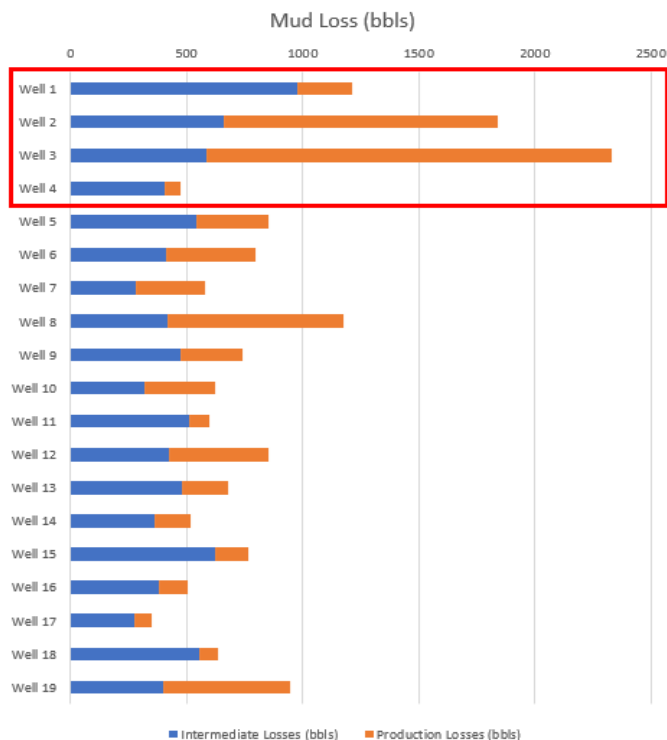


Fig. 3 – Chronological data of mud losses in different hole sections. The Red box denotes Wells without Tier 3 MPD.

The ability to reduce drilling mud weights and apply back pressure to the annulus with electronically controlled chokes

and measuring the outflows with the Coriolis meter has given the ability to drill ahead while keeping the downhole wellbore pressure in a balanced equilibrium. This has allowed Ultra to push the drilling window to new limits.

Another benefit of the Tier 3 MPD system is the ability to have more accurately monitor the outflow of the well compared to the usual pressure/volume/temperature (PVT) alarms on a trip tank. The Coriolis meter is able to detect change in flow as small as 5 gallons. In a natural gas field that is drilled with OBM, kick detection on the rig is critical.

Wellbore Strengthening Laden Drilling Fluids and Vertical Trials

The fluids laboratory analyzed OBM and lost circulation material (LCM) field samples. The laboratory performed particle size analysis (PSA) and slot testing on various mixtures and concentrations of LCM, before recommending a blend of proprietary wellbore strengthening (WBS) products for the trials⁵. This blend provided low-permeability plugging and sealing of porous formations and small induced fractures. The WBS recommendation included use of the WBS products as both a background treatment of the active system and in sweeps to compliment the primary WBS material. Slot testing in the laboratory showed a decrease of 30% in the time required to build and maintain a 2000 psi differential pressure with the addition of the WBS blend.

To trial the WBS suite, four wells were selected to observe benefits and losses. The conventional drilling program used the WBM from the previous interval to drill out the 9.625-inch surface shoe and then displaced to OBM on the fly to drill the interval. On these trial wells, the drilling program was changed so that the WBS laden OBM would be used to drillout of the surface shoe. This allowed the process of plugging and sealing the porous formations and small induced fractures to happen immediately. These trials were successful in drilling the wells to total depths, not seeing significant mud losses, and lifting cement to designed depths for proper zonal isolation.

The WBS suite proved to be a successful solution in aiding the drilling of the monobore lateral in the Upper Green River Basin. By maintaining a concentration of fine WBS material in the active system and routinely pumping sweeps containing a blend of various sizes WBS material, minimal formation losses were encountered while drilling. An increase in fracture gradients and increased wellbore integrity were also observed.

Horizontal Monobore Learning Curve

In Pinedale, most of the horizontal wells are drilled without any geologic control. After a few of the horizontal wells were drilled, data was collected from the toe of the wellbore. Based on bottom hole pressure, temperature, and equipped with WBS laden drilling fluids, Ultra Petroleum attempted 2 monobore horizontal well trials. The idea behind the monobore strategy was to drill to the end of the curve with 8.5" BHAs, then keep going to total well depth (TD) with the

8.5" BHA then run 5.5" casing, while saving the costs of 7" casing and associating cement job.

The first attempt at a monobore horizontal, MB1, was not successful in completely drilling the well to TD with the 8.5" BHA, but valuable information was learned to increase the chance of success on the second attempt. Based on previous formation integrity tests, at the 9.625" shoe the formation will hold a 13.5ppg equivalent mud weight. Similar to the vertical well WBS trials, WBS laden OBM was used drilling out the 9.625" casing shoe. This allowed the process of plugging and sealing the porous formations and small induced fractures to happen immediately compared to drilling out with WBM and swapping to OBM on the fly. On MB1, the tangent section, curve, and 2000' of the lateral were drilled with the 8.5" BHA. At that point the bit box on the motor twisted off and was successfully fished out of the well. The rig drilling, which was not MPD equipped, was running 12.5 lb/gal OBM to control hydrocarbons and keep the well slightly underbalanced. After bringing the fish to surface, losses on MB1 and the kick tolerance were unacceptable. 7.00" casing was landed at the bottom of the 8.5" section. The 6.125" section of the well was drilled without the higher concentration of WBS laden OBM, and losses were also high. MB1 was drilled to TD and cemented successfully. The current theory is that with the multiple attempts at fishing and movement of drillpipe across a 9,800' section of open hole, the WBS concentration depleted and the wellbore filtercake was removed, exposing the formation to the untreated fluid.

The second attempt at the monobore horizontal, MB2, was drilled and cased successfully with 2 strings of casing. WBS laden OBM was used to drill out of the 9.625" casing shoe. The tangent, curve, and lateral were drilled with the 8.5" BHA, this distance was 14,158'. One key to success was minimizing trips in and out of the wellbore. The drilling fluids ingredients on MB2 was the same as MB1. Lastly, the rig that drilled MB2 was Tier 3 MPD equipped and able to TD the well with 11.6 lb/gal WBS laden OBM while holding enough pressure on the annulus to simulate a 12.5 lb/gal equivalent mud weight. Table 1 shows average losses on 3 string casing wells, MB1, and MB2.

	8.5" losses (bbls)	6.125" Losses (bbls)	Total Losses (bbls)
AVG HZs	558.8	359.8	918.6
MB 1	1652	1665	3317
MB2	675	n/a	675

Table 1. Comparison of mud losses on similar horizontal wells versus MB1 and MB2.

As seen in Table 1, losses on MB1 were approximately three times higher compared to the average of similar horizontals.

Losses on MB2 were almost 30% lower than the entire mud loss on the average of similar horizontal wells.

Conclusions

Throughout the 80 years of drilling in Pinedale, WY much has been learned and now the vertical process is close to mastered. The horizontal program in Pinedale, which has just begun, will remain a challenge to operators in the Upper Green River Basin. This paper has shown the developmental history of the Pinedale Anticline for vertical wells, horizontal wells, and the new use of MPD in the field. The history, implementation, and use of WBS laden drilling fluids was highlighted. The success of the first ever 2 string horizontal well in the basin was discussed as well.

Nomenclature

Define symbols used in the text here unless they are explained in the body of the text. Use units where appropriate.

<i>BHA</i>	= Bottomhole Assembly
<i>ECD</i>	= Equivalent Circulating Density
<i>LCM</i>	= Lost Circulation Material
<i>MPD</i>	= Managed Pressure Drilling
<i>OBM</i>	= Oil Based Mud
<i>PSA</i>	= Particle Size Analysis
<i>PVT</i>	= Pressure Volume Temperature
<i>RCD</i>	= Rotating Control Device
<i>TD</i>	= Total Well Depth
<i>TVD</i>	= True Vertical Depth
<i>WBS</i>	= Wellbore Strengthening

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