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Horizontal Coalbed Methane Wells Drilled with MPD using Produced Water

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Abstract

Horizontal drilling in the Fruitland Formation, a Coalbed Methane (CBM) play located in the San Juan Basin (SJB), found across the states of Colorado and New Mexico can present a number of drilling and production challenges. Examples of these challenges include wellbore instability, severe fluid losses, high mud costs, formation damage, and post-well production issues.

Clear fluid brine systems such as Calcium Chloride ($CaCl_2$) and Calcium Bromide ($CaBr_2$) are usually preferred because of their compatibility with coals and their ability to minimize formation damage. However, these brines can instigate fluid losses, cause fluid handling issues, and create long-term production challenges. Coal instability in the horizontal play has historically led to events such as wellbore collapse, stuck pipe, lost Bottomhole Assemblies (BHAs), and challenges such as getting the pipe out of the hole at Total Depth (TD) and subsequently running completions. Ultimately, these problems led to sidetracks, incurring additional costs, time, and resources.

In May 2019, the Constant Bottomhole Pressure (CBHP) technique of Managed Pressure Drilling (MPD) was introduced to mitigate these challenges. Two wells with eight laterals and combined horizontal footage of ±46,000 ft were drilled using CBHP, maintaining 11.4 ±0.1 pound per gallon (ppg) Equivalent Circulating Density (ECD) and Equivalent Static Density (ESD) in the lateral at ±2800 ft True Vertical Depth (TVD). With a focus on safety and training, the mud weight was staged down from 10.8 ppg on the first lateral to 9.8 ppg on the second. The final six laterals were drilled with 8.6 ±0.2 ppg produced water. This paper will detail the planning, training and staged implementation of CBHP MPD with produced water. It will briefly discuss improvement in wellbore stability, cost reduction for drilling laterals, and enhanced production after switching to produced water.

Introduction

The Operator (Red Willow Production Company or RWPC) is wholly owned by the Southern Ute Indian Tribe and operates over 650 wells in the SJB, located on the Southern Ute Indian Reservation. The North

Carracas area (Figure 1) and the topic for this paper is considered over-pressured and requires approximately 11.0 ppg mud weight to balance reservoir pressures.

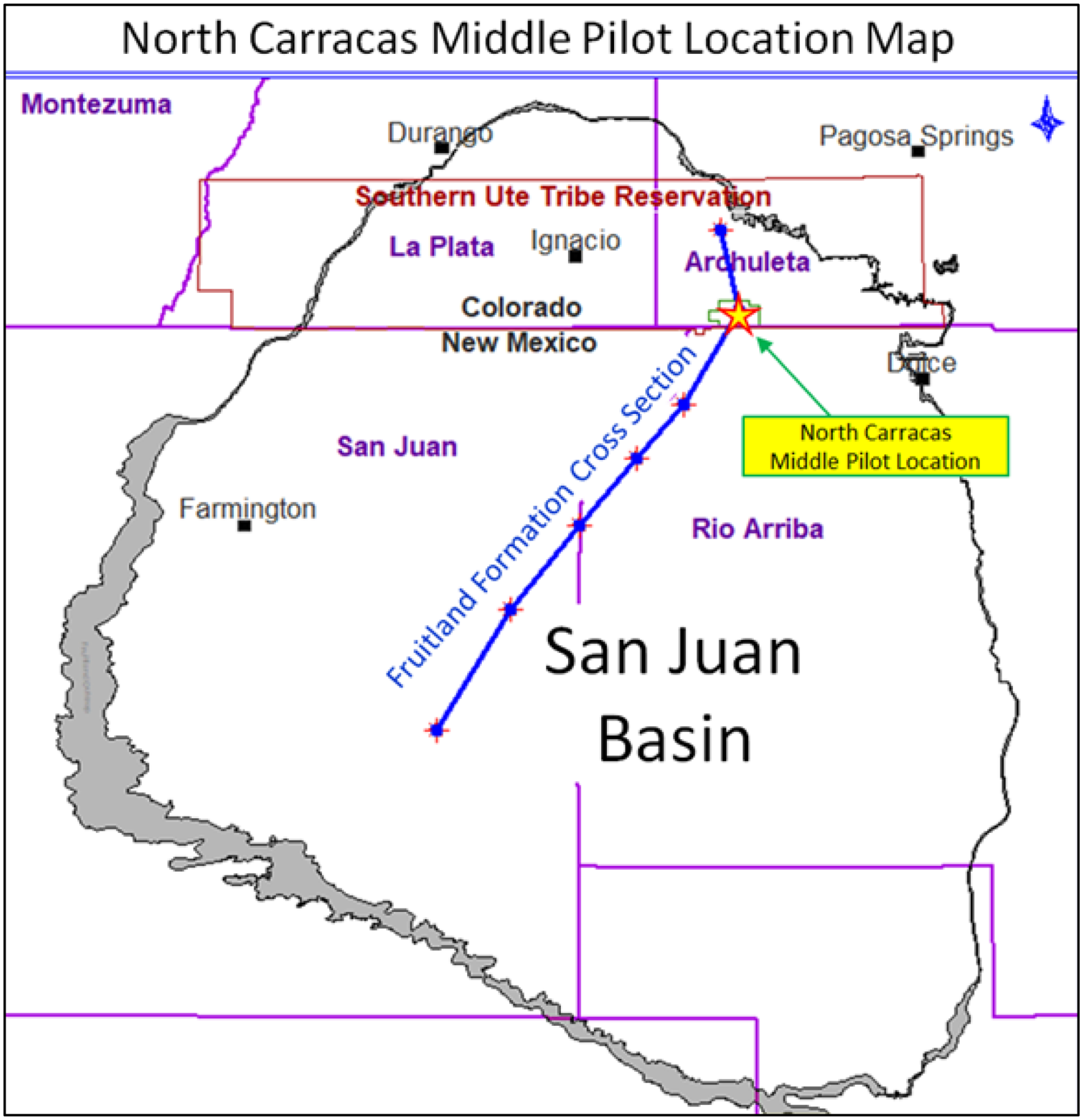

Figure 1—North Carracas project location, located on the Southern Ute Indian Reservation, northern San Juan Basin.

The operator has experience and knowledge drilling wells in depleted and over-pressured coals, in both operated and non-operated drilling projects. When faced with the same challenges (wellbore instability and moderate to severe fluid losses) on their upcoming drilling project, the operator decided to research MPD as a possible solution to the challenges related to drilling Fruitland Formation multi-lateral wells.

To the team's knowledge, MPD has not previously been used in the SJB and has not been recognized for the use in drilling of CBM formations. One of the barriers for implementation was the lack of knowledge on the use of MPD in CBM formations. The biggest challenges would be the cost to implement and the ability to accurately control the annular pressure profiles while drilling in such a shallow formation with laterals between 2798 ft to 2868 ft TVD. Additionally, the requirement for clear (water-based) drilling fluids with its inherent lack of compressibility required extremely accurate pressure control in a challenging wellbore system. Working with their well engineering and MPD service providers, the team jointly developed a staged implementation plan to trial CBHP MPD for this project.

Background

Prior to the 1980s SJB operators considered the shallow Fruitland Formation a geologic drilling hazard and was bypassed due to high water concentrations and other economic factors (described below). Operators preferred to drill gas wells into deeper productive sandstone formations. Beginning in the 1980s with Federal CBM tax credits, higher gas pricing and improved completion technology provided SJB operators the economic incentive to sanction vertical Fruitland Formation full field developments. There have been some brief operations with horizontal activity in the past, but only in recent years have the coals been continuously drilled horizontally. Figure 2 below shows a geological cross-section of the Fruitland Formation within the SJB at the North Carracas project location as shown in Figure 1.

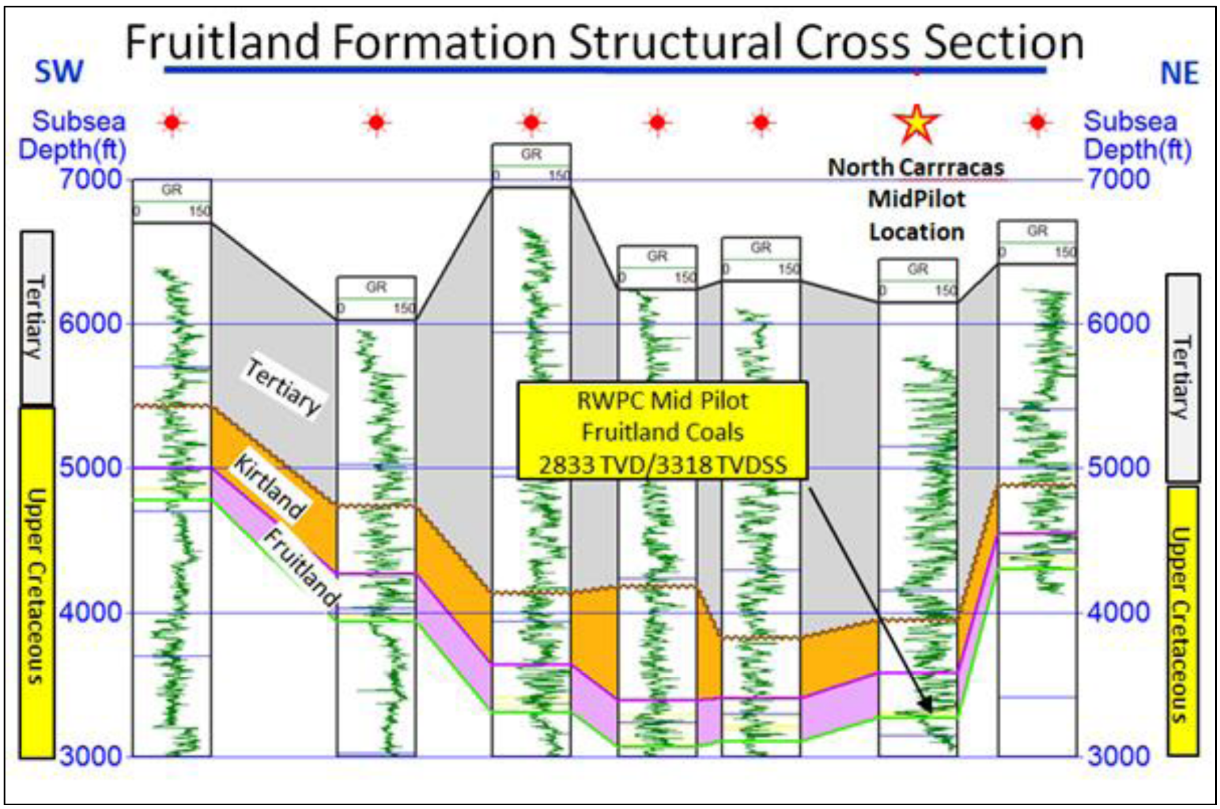

Figure 2—Geological cross-section of the Fruitland Formation within the SJB.

The recent drilling activity has been in both depleted areas around existing production, as well as over-pressured areas in undeveloped areas. In some cases, the horizontal wellbores will transition from low pressure to higher pressure areas making it difficult to maintain wellbore stability. These laterals are problematic to drill, as transitions from low to high (or vice-versa) pressure zones may occur during the drilling of the lateral. For the planning of this operation, the pore pressure was estimated to be 11.0 ppg.

During the last fifteen years, new drilling techniques have evolved for drilling horizontal coal wells. Single-lateral wells have been replaced with multi-lateral wells where heavyweight, clear drilling fluids (calcium chloride fluids) have been used to drill in the over pressured zones. Operators have historically stressed the need to utilize clear fluids while drilling the coal to protect against unwanted skin and formation damage. Therefore, in order to drill horizontal wells in the differentially pressured rock, operators largely used brine drilling fluid systems, believing it to be a relatively benign drilling fluid compared to viscous mud systems.

Although this has been the generally accepted and applied fluid system in the Fruitland Formation coals, it has not been without issues. Some of these issues include fluid loss to the formation, wellbore stability potentially requiring sidetrack operations, and post drilling scale formation build-up in the tubing and surface flow back and production/water disposal facilities. The formation does not require hydraulic fracturing, with completion only requiring the installation of a slotted liner. It is beneficial to run the completions in as clean a fluid as possible to preserve the natural permeability of the formation and reduce possible scale formation at the cleat face, which is another benefit to using MPD and spotting a kill pill higher up in the vertical cased hole section.

This situation has been highlighted by a 2018 scale mitigation workover intervention in a previous pilot well drilled in 2017. The successful workover experience provided additional support to use Fruitland Formation produced water over calcium chloride as a drilling fluid to lower the risk of formation damage due to incompatible water chemistry.

Wellbore Instability and Minimizing Formation Damage

Most operators in the area have experienced some type of drilling issue primarily relating to wellbore instability of the brittle coal. In these coal formations, failure can occur in both tension and compression depending on the induced stress and the geo-mechanical rock properties.

During drilling of the early laterals, operators began drilling these over-pressurized formations slightly underbalanced to keep drilling fluids off the formation to minimize the effects of formation damage. Although Underbalanced Drilling (UBD) helped mitigate some of the formation damage effects; UBD operations had a negative effect on maintaining the required minimum pressure to prevent formation breakout, and the inevitable consequences of wellbore instability. Once the wellbore pressure dropped below the pressure required to prevent formation breakout, wellbore stability became compromised and led to formation breakout into the wellbore. The cyclic pressure swings of conventional drilling between drilling conditions (pumps on) and static conditions (pumps off) equated to a change in Bottomhole Pressure (BHP) of 300 psi or 2.0 ppg at 2790 ft. The constant pressure cycling leads to formation breakout in the wellbore, resulting in mechanical sticking of the BHAs, and in many cases resulted in shorter than planned laterals.

More recently, operators chose to drill slightly overbalanced in order to stabilize the wellbore, but not fracture the rock with the use of a high fluid weight. However, this method resulted in the loss of brine into the Fruitland Formation and now appears to have resulted in surface and downhole scaling issues. Due to the multiple drilling and production issues presented above, a new drilling process was desired.

Holding back the higher reservoir pressures, maintaining wellbore stability, and staying slightly overbalanced while limiting drilling fluid loss is difficult to accomplish in the Fruitland Formation. Similar to other formations that are drilled horizontally, the Fruitland Formation has areas of both higher and lower pressure regions in danger of collapse if the minimum BHP is not maintained.

With the International Association of Drilling Contractors (IADC) definition for MPD being "MPD is as an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore". It was viewed as a potential solution for mitigation of these drilling related issues.

Implementation

As with all operating companies, cost was a major consideration for this operator when looking at MPD. MPD was initially viewed as an additional service with an associated cost to implement. Furthermore, the outcome of using MPD for drilling extremely shallow CBM formations with clear fluids or produced water was unknown. After performing some industry research and evaluation, a specialist MPD service provider was chosen due to their ability to supply highly accurate and fast SBP control, with a small footprint MPD system requiring minimal impact to use with the drilling rig. The MPD service provider also supplied MPD well engineering, training, and experienced field crews.

During the initial contact and project evaluation phase it soon became clear that MPD should be able to help mitigate the wellbore stability issues. Due to the shallow depths (as shown in the wellbore schematic of a North Carracas well, Figure 3), the operating range was such that the MPD technique could help drill the wells with produced water, in place of the costly calcium chloride drilling fluids. In addition to cost savings on drilling fluids, MPD provides other significant upsides.

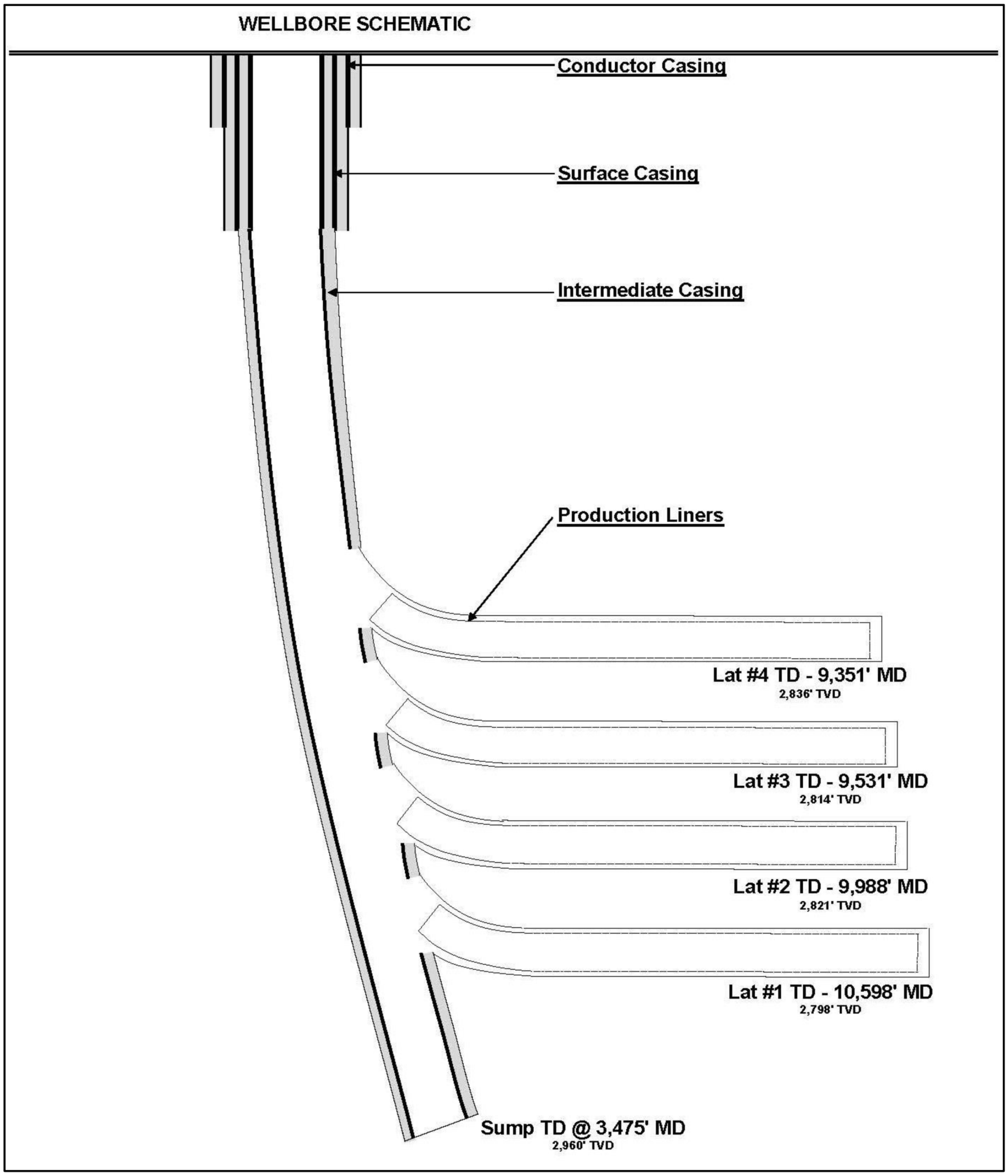

Figure 3—Wellbore Schematic

First, using produced water would mitigate the scaling issues seen after drilling the wells. Second, produced water would minimize the impact on the production facility while cleaning up the wells. Third, the produced water would cause less formation damage than calcium chloride drilling fluids. MPD also assisted in reducing invisible Non-Productive Time (NPT) when compared to conventional wells such as adjusting mud weights. MPD with produced water would potentially provide reduced costs in subsequent well phases in the maintenance and impact on topside facilities. When all factors were considered, the team did a risk benefit analysis to determine not only the cost of MPD, but also the cost of not utilizing it.

The planning phase followed the Recommended Practices (RPs) as per American Petroleum Institute (API) document API RP-92M and industry guidance provided on MPD by IADC. Based on this information, the MPD service provider developed a specific well program (SWP) covering the front-end engineering design and defined the MPD operational limits based on a detailed hydraulics modelling program using the formation and MPD equipment limits. The project team believed it would be too drastic a step to change from the traditionally weighted calcium chloride fluid approach to produced water in one step and chose to implement a staged transition to MPD over three laterals.

The agreed upon approach was to start with 10.8 ppg mud weight on the first lateral and utilize MPD when making connections to maintain the required wellbore pressure, while not holding any surface backpressure when drilling. If successfully executed, then on the second lateral the mud weight would be further reduced to 9.8 ppg and MPD would be used to compensate for this additional 1.0 ppg mud weight reduction. If the MPD implementation on the second lateral too would be successful, then the team would have the required confidence in MPD to move on to the final phase involving drilling the remaining six laterals with the 8.6 ±0.2 ppg produced water. The North Carracas wellsite is shown in the Figure 4 below.

Figure 4—North Carracas Wellsite

Prior to rig operations, the MPD service company provided a two day training class for the project team which included the drilling crew, directional drillers, geo-steering, geology, and engineering. This class provided a learning opportunity for the entire drilling team to gain a full understanding of what was being planned for in the upcoming drilling campaign (two wells with eight laterals) prior to spudding the well.

The training primarily focused on the MPD equipment to be used and its operational philosophy within the context of following the SWP and the wellbore hydraulic requirements at the various phases of the drilling and completion program. With a well-attended drilling and sub-surface team, various scenarios were discussed and with a team approach, put in place prior to spudding the well. It was during this planning stage that the benefit of designing the well rollover to kill fluid became apparent to the completions team. This changed the plan to spotting a heavy pill only in the vertical section (the parent wellbore) and keeping produced water in the laterals.

Pressure Window

Lower Pressure Boundary: The anticipated pore pressure of this formation is ≈ 11.0 pound per gallon equivalent (ppge). Considering the potential for wellbore instability in this formation and adding a reasonable safety factor, the operator decided to maintain a minimum wellbore pressure of 11.4 ppge for the entire duration of the project.

Upper Pressure Boundary: The fracture pressure of these formations are estimated at 0.8 psi/ft ≈ 15.4 ppge. However, the presence of coal seams and cleats in the formation instigated losses at comparatively lesser pressures. The formation leak-off factor was considered close to 12.0 ppge for the purposes of simulations, planning, and execution.

MPD Objective: Since enduring losses was the lesser problem compared to allowing wellbore pressures to reduce below wellbore instability limit, the objective became staying above the 11.4 ppge limit irrespective of the losses. The team optimized the surface backpressures, thereby the wellbore pressures and minimized the amount of losses incurred while drilling.

Phase-1

The first lateral (as shown in the wellbore schematic in Figure 3) would be drilled with 10.8 ppg calcium chloride brine while learning the MPD system by maintaining a minimum wellbore pressure of 11.4 ppge. The MPD system would be rigged up and operational, but no back pressure would to be held while drilling, i.e., the chokes would be 100% open. The Figure 5 illustrates ≈18.0 psi dynamic surface backpressure, which is lower than the actual MPD surface line friction at ≈ 40.0 psi. The objective would be to ensure that everyone involved in the operations becomes comfortable with the operations at hand. The total losses on the first lateral were ≈ 1,323 bbls, which is more than three times the losses experienced with the reduced mud weight systems (ECD at TD ≈12.5 ppge leading to fluid losses).

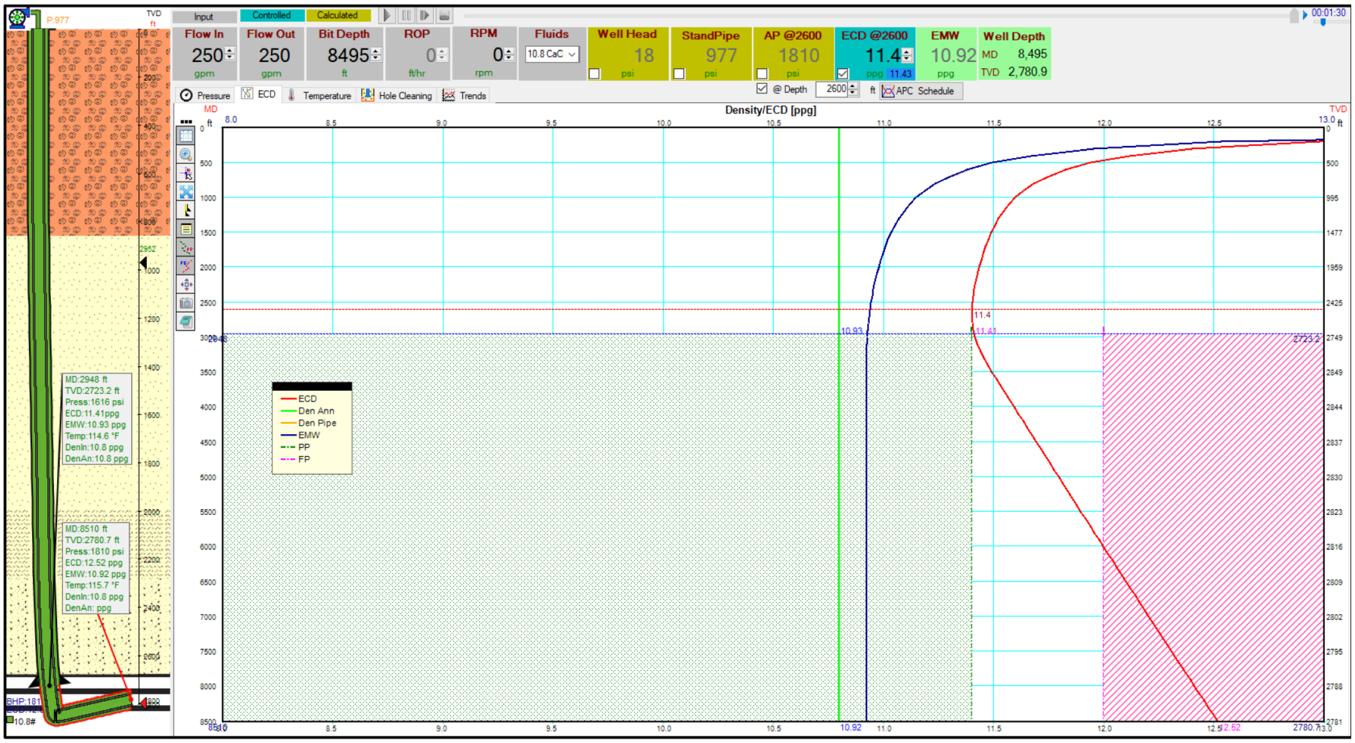

Figure 5—Annular ECD vs Depth plot when circulating 10.8 ppg $CaCl_2$ brine at 250 gpm with 14.0 psi Dynamic SBP.

As illustrated in Figure 6, the required static SBP was ≈ 95.0 psi to maintain the wellbore pressures at 11.5 ppge. The team would follow a simplified ramp schedule when switching the pumps off and on.

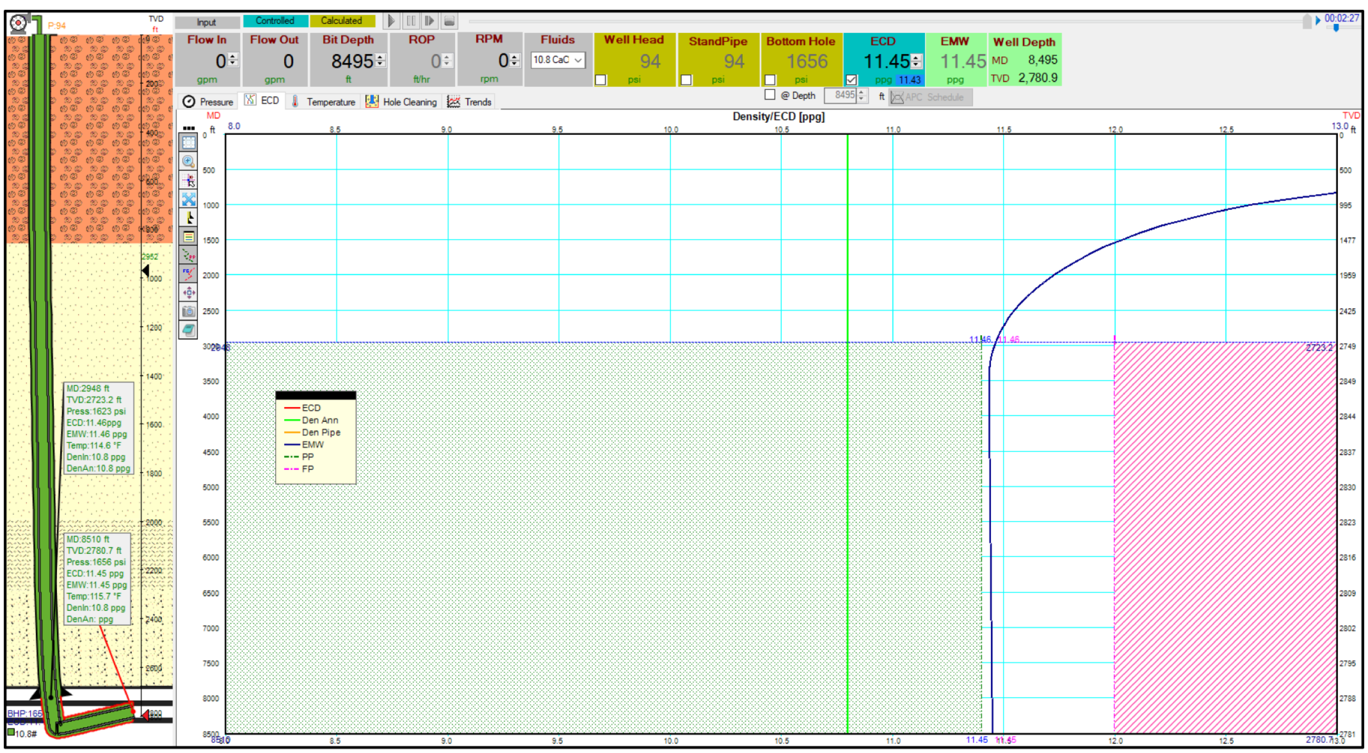

Figure 6—Annular ESD vs Depth plot with pumps off when drilling 10.8 ppg $CaCl_2$ brine with 94.0 psi Static SBP.

Phase-2

The second lateral would be drilled with a reduced mud weight to 9.8 ppg calcium chloride brine, while still maintaining the wellbore pressures above the 11.4 ppge limit (Figure 7). A dynamic SBP of 164.0 psi would be required to stay above the lower pressure boundary.

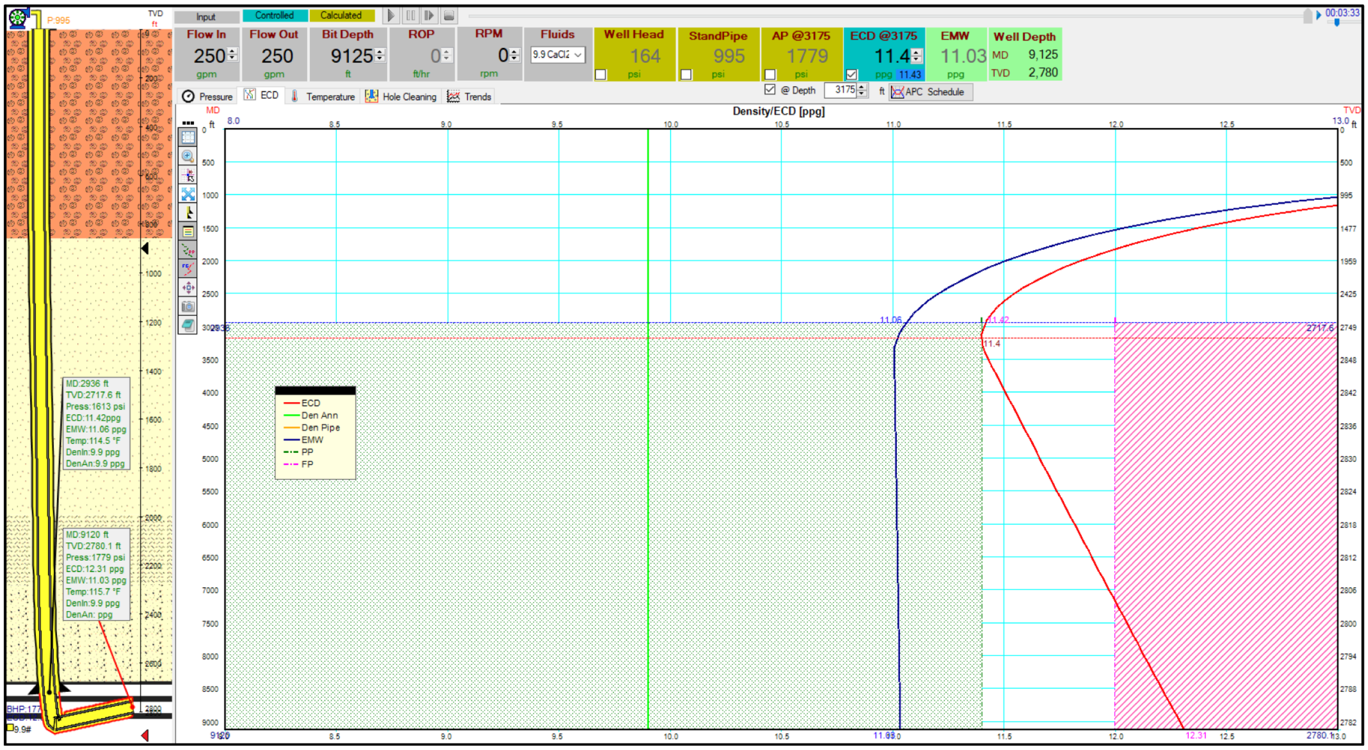

Figure 7—Annular ECD vs Depth plot when circulating 9.8 ppg $CaCl_2$ brine at 250 gpm with 164.0 psi Dynamic SBP.

The key point here, as illustrated in Figure 7, is this lateral can be drilled with a hydrostatically underbalanced mud weight using MPD. The wellbore pressures can still be maintained above the required pressure limit accomplishing wellbore stability. The modelled ECD at TD is ±12.3 ppge. This reduction in ECD/wellbore pressures resulted in a significant reduction in fluid losses while drilling. This fluid was still a calcium chloride mud system with detrimental effects to the formation, although very high volume of fluid was not being lost to the formation.

Figure 8 displays the static surface backpressure ≈ 229.0 psi required to maintain ±11.5 ppge ESD with the pumps off. Observe that the required static (±230.0 psi) and dynamic (±165.0) surface backpressures for the second lateral are slightly higher compared to the surface backpressures required on the first lateral. During MPD execution, the ‘Anchor Point’ CBHP MPD was performed by maintaining wellbore pressures above 11.4 ppge. The anchor point was close to the heel for this lateral.

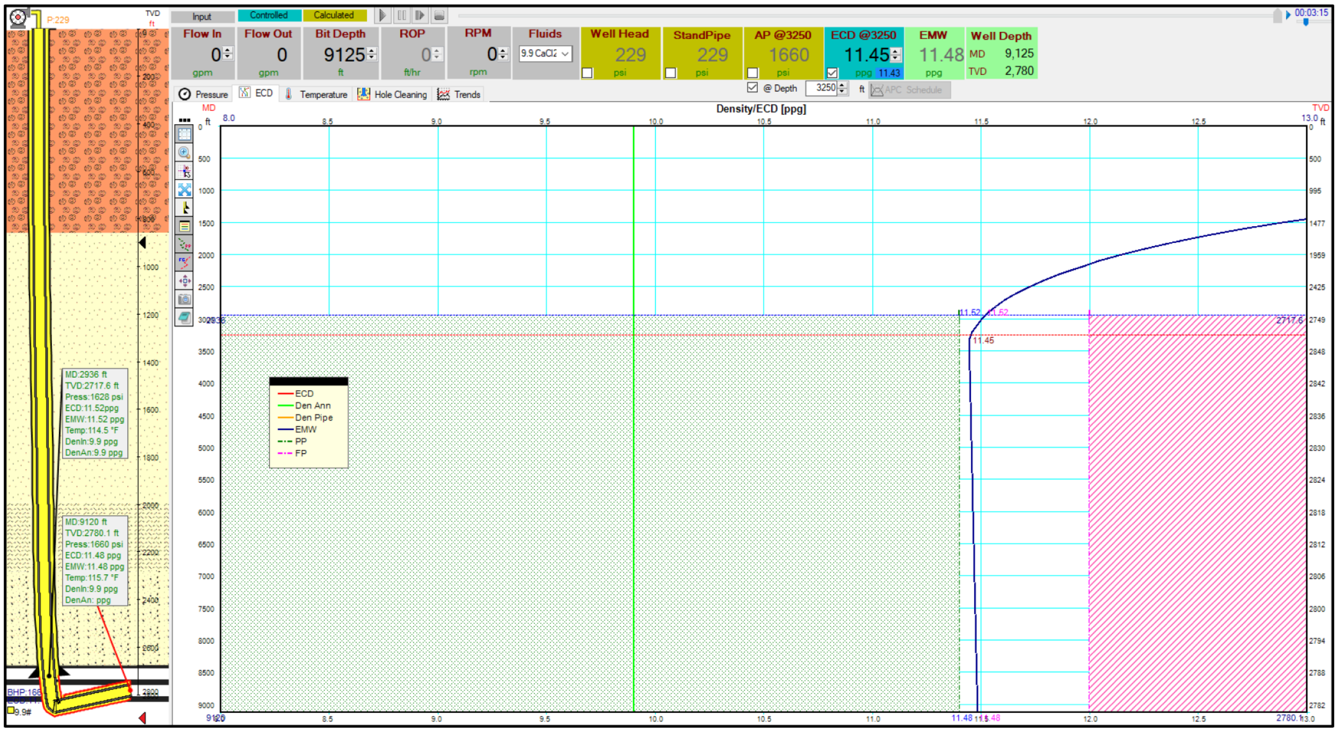

Figure 8—Annular ESD vs Depth plot with pumps off when drilling 9.8 ppg $CaCl_2$ brine with 229.0 psi Static SBP.

Phase-3

Switch out the calcium chloride system with Fruitland Formation produced water (8.6 ±0.2 ppg) and apply the required surface backpressure to maintain the wellbore pressures above the 11.4 ppge limit.

The produced water planned to be used for drilling these laterals would be sourced from wells less than three miles away. Hence, this fluid should be compatible with the formation. The remaining five laterals (after this lateral) were planned and drilled similarly with produced water and surface backpressures.

Due to the shallow TVD on the laterals (±2800 ft), MPD was able to use a produced water fluid system (8.6 ±0.2 ppg) that was significantly below the hydrostatic mud weight (±11.4 ppge) required to prevent influx and maintain the required wellbore stability. Compared to typical MPD projects that have deeper TVDs, these wells are more sensitive to changes in surface backpressure.

MPD can be used to stay above the lower pressure boundary and successfully maintain the stability of the wellbore (Figure 9). The modelled ECD at TD is 12.4 ± 0.2 ppge depending on the fluid properties considered. During execution, this reduction in the ECD/annular wellbore pressure resulted in a significant reduction in fluid loss. The other benefit is that the produced water was very compatible with the formation cleats and induced significantly less formation damage. Using the produced water not only reduced the overall cost of the fluid systems, but also created an environment conducive to better production rates that would require less future maintenance.

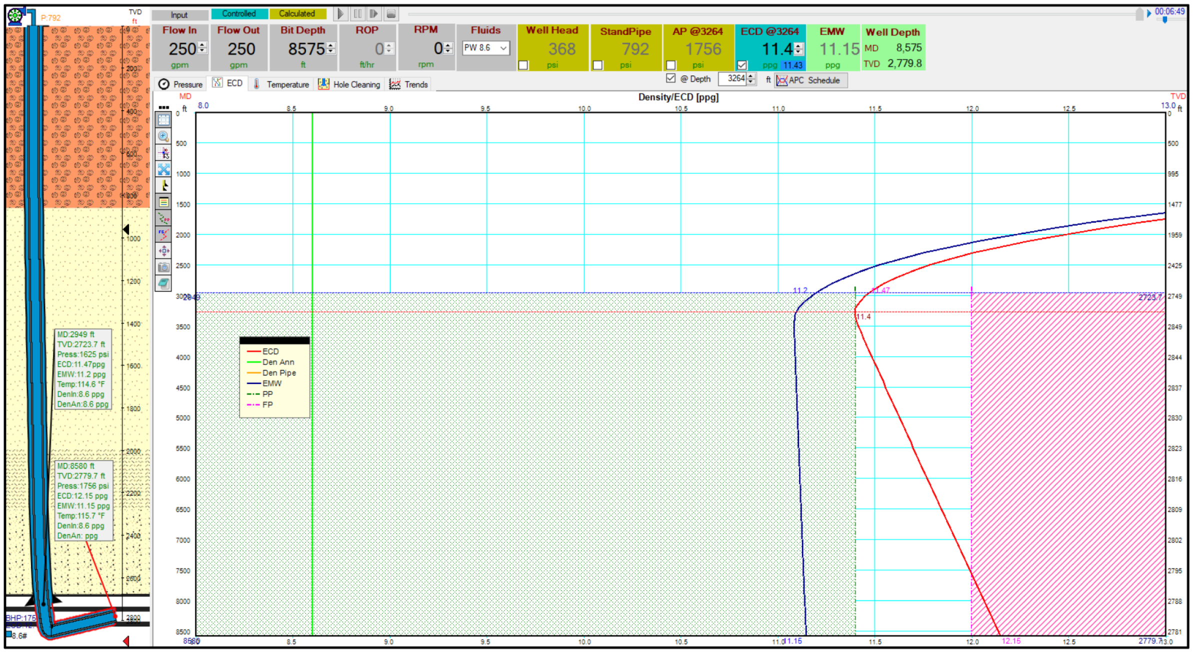

Figure 9—Annular ECD vs Depth plot when circulating 8.6 ppg produced water at 250 gpm with 368.0 psi Dynamic SBP.

Figure 10 below shows the static surface backpressure requirements with the produced water. An anchor point depth close to the heel was used to drill all the laterals while maintaining 11.5+ ppge. A static surface backpressure between 400.0 to 450.0 psi was required to maintain the wellbore pressure above the required wellbore stability limit when drilling with the produced water.

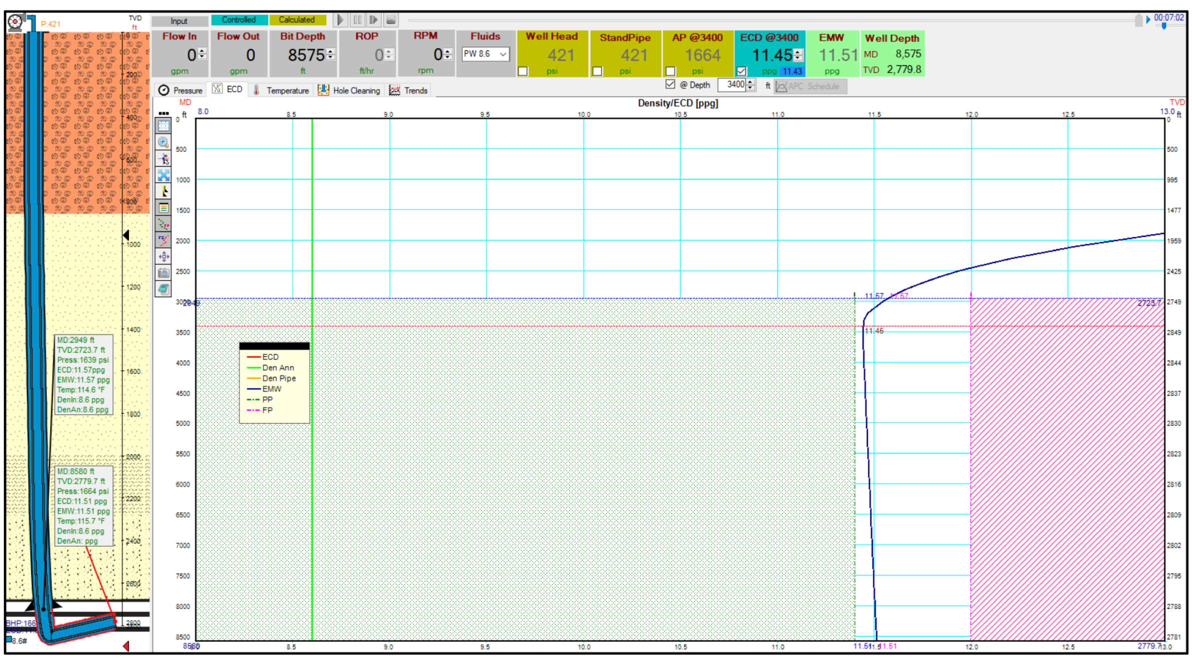

Figure 10—Annular ESD vs Depth plot with pumps off when drilling 8.6 ppg produced water with 421.0 psi Static SBP.

MPD Matrix and Switching from MPD to Well Control

Drilling with a fluid system that is a full 2.0 ppg less than formation pore pressure required a robust plan when switching from MPD to Well Control and vice-versa. The MPD service provider modelled multiple scenarios using Influx Management Envelope (IME) techniques and then generated the guidance supplied in the following MPD Well Control Matrix (Figure 11).

N Carracas 32-4 7F-2; Lat 2 CBHP MPD Operation limits Matrix with Drill pipe		When your current Surface Back Pressure (SBP) is					
		> Minimum Required BP Limit & ≤ Planned Operating Back Pressure Limit		> Planned Operating BP Limit & ≤ Planned Max Back Pressure Limit		≥ Planned Max Back Pressure Limit	
		For Drilling (323 psi < SBP ≤ 608 psi)	For Connections (410 psi < SBP ≤ 706 psi)	For Drilling (608 psi < SBP ≤ 760 psi)	For Connections (706 psi < SBP ≤ 847 psi)	For Drilling (SBP > 760 psi)	For Connections (SBP > 847 psi)
When your current Influx Volume is	No Influx	Continue Operations		Continue Operations Cautiously; adjust system to decrease WHP		Secure well; evaluate next planned action	
	≤ Planned Operating Influx Limit (6.00 bbls)	Continue Operations Cautiously; adjust system to increase BHP		Continue Operations Cautiously; adjust system to decrease WHP and increase BHP		Secure well; evaluate next planned action	
	> Planned Operating Influx Limit & < Planned Max Influx Limit (6.00 bbls < influx < 10.00 bbls)	Continue Operations Cautiously; adjust system to increase BHP		Secure well; evaluate next planned action		Secure well; evaluate next planned action	
	≥ Planned Max Influx Limit (10.00 bbls)	Secure well; evaluate next planned action		Secure well; evaluate next planned action		Secure well; evaluate next planned action	

Continue Operations. Both Pressure and Volume numbers are within the planned limits.

Continue Operations with caution. Adjust operations and work to move into green. One of the parameters is not within the planned limits.

STOP Operations. Secure the well. Either one of the parameters is outside MAX limit or both parameters are above the planned limits.

Figure 11—MPD Well Control Matrix used for the 8.6 ppg produced water section.

Execution

The rig up was a standard MPD process for USA land operations with the MPD service provider supplying the Rotating Control Device (RCD), high pressure pipework, automated MPD choke system, Coriolis meter and then tie back into the rigs flow line for diverting to the Mud Gas Separator (MGS) and flare stack (Figure 12).

Figure 12—MPD choke system and Coriolis meter (left), RCD and MPD flowline (center), and MPD control center and tool shack (right)

The MPD system was an efficient, compact, and fully automated system that was able to be installed, rigged up, and commissioned on location in under 24 hrs (Figure 13).

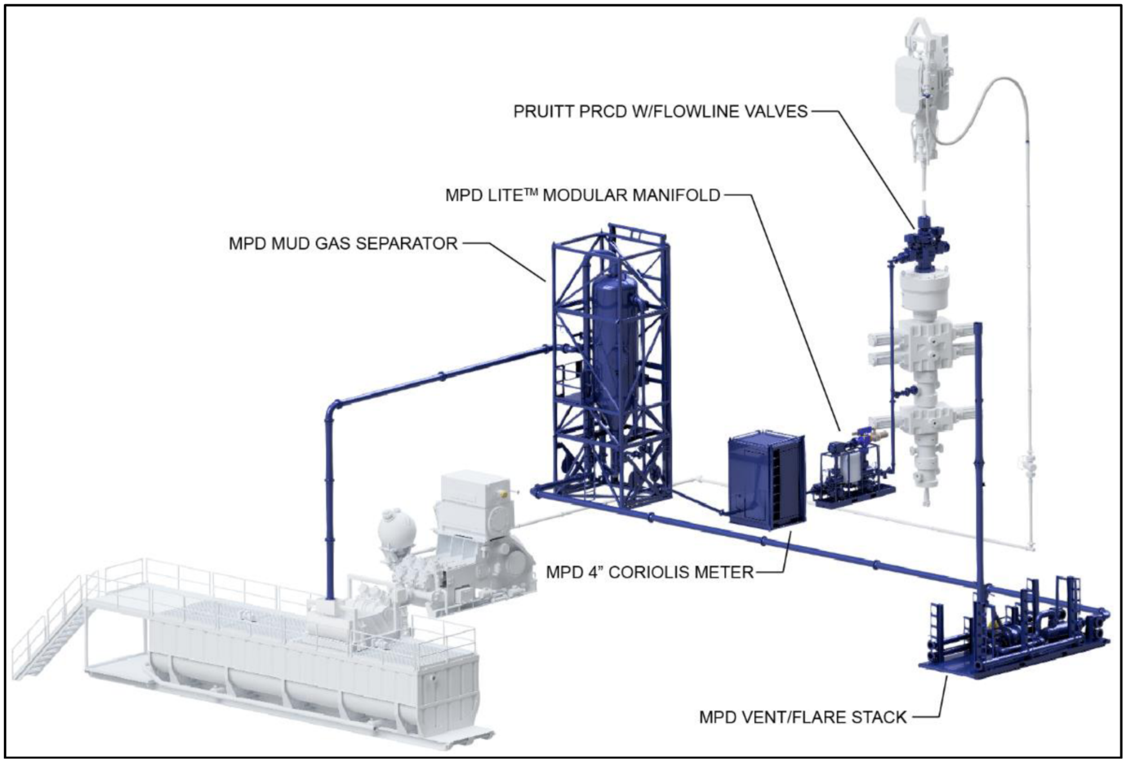

Figure 13—MPD Process overview and various components of the MPD system

Operation Summary Table:

Anchor Point MPD was performed on all laterals. The objective was to maintain a minimum wellbore pressure of 11.4+ ppge in the openhole by applying appropriate surface backpressure based on the drilling fluid density, rheology, flow rate and anticipated friction. The depth with the least ECD was chosen as the anchor point on all the laterals. Adjustments were made to this anchor point depth based on the changing well and surface conditions. An operation summary for all eight laterals is provided in Table 1 below.

Table 1—Operation Summary for all 8 laterals

Lateral	Start Date (mm-dd-yy)	Mud Weight (ppg)	Drilling SBP (psi)	Connection SBP (psi)	Lateral Length (ft)	Days to Drill	Losses (bbls)	Losses (bbls / p 100 ft)
NC32-4#7F-1L1	5-18-19	10.8 $CaCl_2$	0	125	4943	2	1323	27
NC32-4#7F-1L2	5-21-19	9.8 $CaCl_2$	160	300	5755	3	422	7
NC32-4#7F-1L3	5-26-19	8.5 Prod Water	400	550	5211	3	420	8
NC32-4#7F-1L4	5-31-19	8.5 Prod Water	400	550	4383	2	400	9
NC32-4#7F-2L1	6-14-19	8.5 Prod Water	400	550	7141	3	N/A	N/A
NC32-4#7F-2L2	6-19-19	8.5 Prod Water	400	550	6670	3	296	4
NC32-4#7F-2L3	6-24-19	8.5 Prod Water	400	550	5961	3	238	4
NC32-4#7F-2L4	6-28-19	8.5 Prod Water	400	550	6013	3	250	4
Cumulative					**46,077**	**22**		

- Anchor Point MPD was performed on all laterals.
- The objective was to maintain a minimum wellbore pressure of 11.4+ ppge in the openhole by applying appropriate surface backpressure based on the drilling fluid density, rheology, flow rate and anticipated friction.
- No wellbore stability issues where encountered; this is not normal for CBM wells drilled in this area where wellbore stability issues affect a significant number of wells drilled in this region.
- The 8 laterals had a TVD variance of between 2798 ft to 2868 ft.

ECD Summary Plot

With a well TVD variance between 2798 ft to 2868 ft and a water-based system the overall BHP control is extremely good (Figure 14). On all laterals, the wellbore stability requirement was a minimum of 11.4 ppg and was maintained at the anchor point close to the heel. The below graph shows pressure at the bit increasing with additional drilled depth (i.e., the ECD at bit will keep on increasing with additional hole made as the 11.4 ppge pressure is maintained at the anchor point close to the heel). The graph shows three days of well data with an ROP on average of 120 ft/hr and MPD connections taking around 4 mins pumps off to pumps on. This plot includes pressure variations because of connections that resulted in changes in BHP at bit since the anchor point is close to the heel. The plot shows a connection every 45 mins on all eight laterals. It is worth noting that lateral NC 32-4 #7F-1 L1 shown as a dark blue trend is the lateral drilled with the 10.8 ppg calcium chloride. MPD was only partially able to compensate for ECD, and as a result this lateral had the worst cyclic pressure swings of the eight laterals.

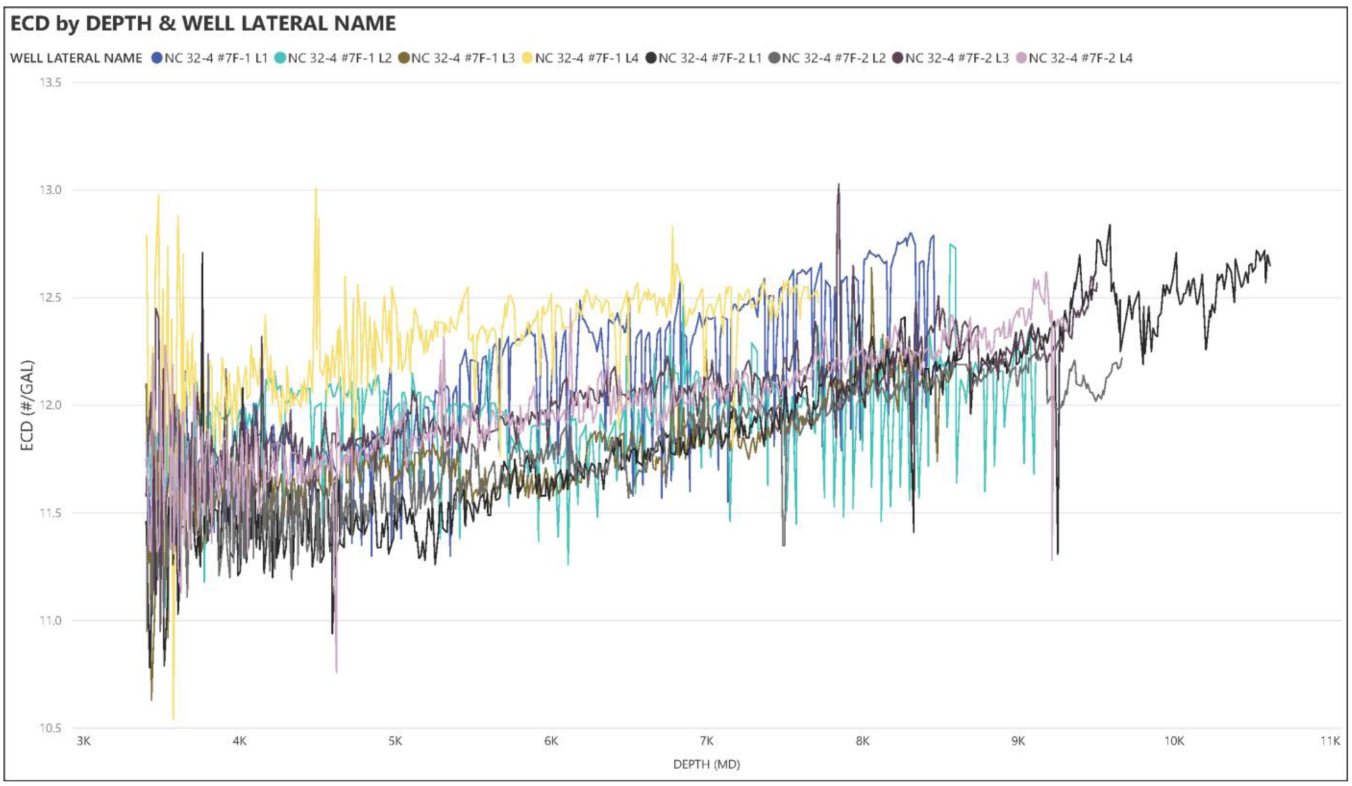

Figure 14—ECD by Depth on the 8 laterals

Benefits & Well Performance Enhancements

The operator anticipated some drilling related cost savings by utilizing MPD during the planning stages; however, the greatest benefits to using MPD were related to well production. This assumption was based on a desire to minimize wellbore damage, reduce well servicing events, and overall reduction of unnecessary production downtime. Cost savings are desired by the operator in the drilling operations, but not at the cost of losing productive wellbores for the life of the well. Using an expensive drilling fluid such as calcium chloride that costs ≈ $70/bbl at 11.6 ppg or possibly calcium bromide that costs ≈ $700/bbl at 14.2 ppg, and losing fluids in order to maintain a slight over balance significantly impacts costs. However, bringing an unproven drilling method into the basin also adds risks to the drilling program. At the end of the project, using the MPD system realized modest cost savings when compared to utilizing a high cost heavyweight drilling fluid approach in an undeveloped Fruitland Formation area.

The wells were drilled with a managed BHP and there were no wellbore stability issues encountered while drilling. Drilling data shows that the well's ECD was maintained throughout the individual laterals and is believed to be the main factor providing wellbore stability. Due to this information, the operator further believes that there will be a significant reduction in future operating costs, as well as production benefits from a reservoir with less damage.

All eight laterals drilled using MPD reached TD and suffered zero wellbore instability issues. Historically, this has not been the drilling experience in this region/formation. The probability of wellbore instability issues materializing is relatively high, and so are the costs associated with sidetrack operations and lost BHAs.

Furthermore, drilling fluid losses in this region have been significant. Although the team does not have a benchmark cost available to us for reference; following fluids costs were observed during the execution phase – $70 per bbl for the calcium chloride brine and $0.05 per bbl for the 8.5 ppg produced water system.

There are some costs savings when using produced water to perform MPD, however, the operator feels the overall cost savings are entirely project specific. It is recommended to consider the following aspects in order to evaluate the cost savings from MPD when drilling with produced water.

- The condition of the reservoir – overpressured and depleted,
- The costs of MPD per lateral and well, and
- The costs of completions and other operations.

For this project (two wells with eight laterals) with an overpressured reservoir, there were positive cost savings with MPD. Furthermore, the operator feels that if the reservoir were depleted or if there were differential formation pressures along the laterals (cycles of high and low pressures), the cost savings with MPD could be significantly higher.

Utility of MPD: Did MPD help? It's hard for an operator to quantify savings on an operation that was performed without any significant problems without cross referencing to previous well performances and the role of geology. It would be safe to say that MPD certainly was, at a minimum, cost neutral and probably had a significant impact on delivering what were eight of the fastest and longest laterals drilled in the region with reduced fluid losses to formation and a cheaper, less damaging drilling fluid.

Several months after this project the MPD service provider was contacted by another operator drilling horizontal coal in a nearby lease. This operator was encountering the same drilling related issues of wellbore instability and was requesting MPD for their sidetrack. Unfortunately the rig that they were using did not have sufficient height for use of an RCD above the Blowout Preventer (BOP).

Post-well Enhanced Production, Scale Mitigation

Production from previous wells has proven that calcium chloride significantly hinders the production phase due to scale build-up (Figure 15).

Previous drilling activity utilizing calcium chloride as a drilling fluid has resulted in above average wellbore/wellhead maintenance activity and ultimately a reduction in expected production rates. The recently drilled MPD wells have been online for over six months and show no significant signs of scale (based on information available at the time of publishing this work). They are currently outperforming other wells drilled with conventional techniques.

Figure 15—Left scale build-up in top side facilities, right scale build on completion

Summary, Conclusions, and Observations:

Summary

CBHP MPD with the help of surface backpressure enabled the drilling of two horizontal CBM wells in the SJB. Careful planning and training enabled safe execution of MPD on these wells.

Conclusions

The team that implemented this project; from operator, consulting engineering company to MPD service provider felt compelled to author this technical paper. This was an unconventional operation where MPD has positively impacted many aspects of the operation. MPD helped as follows:

1. Improved wellbore stability (primary objective).
2. Reduced fluid losses (secondary objective).
3. Enabled switching to a produced water system which in turn brought the following benefits:

    A. Mud system cost savings (achievable; varies by project),
    B. Reduced formation damage (enhanced production from the laterals),
    C. Reduction in scale build-up in the completion components (reduced future remedial workovers),
    D. Reduction in scale build-up in the top side production facilities (reduced operational shut downs).

Observations

1. With the correct MPD system, MPD can be successfully implemented with very shallow/clear fluid systems including produced water systems.
2. The time taken in pre-project planning was highly beneficial to delivering a successful drilling campaign and the introduction of MPD for drilling CBM wells.

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Nomenclature

API = *American Petroleum Institute*
API-RP = *American Petroleum Institute Recommended Practice*
BHA = *Bottomhole Assembly*
BHP = *Bottomhole Pressure*
BOP = *Blowout Preventer*
$CaCl_2$ = *Calcium Chloride*
$CaBr_2$ = *Calcium Bromide*
CBHP = *Constant Bottomhole Pressure*
CBM = *Coalbed Methane*
ECD = *Equivalent Circulating Density*
ESD = *Equivalent Static Density*
IADC = *International Association of Drilling Contractors*
IME = *Influx Management Envelope*
MD = *Measured Depth*
MGS = *Mud Gas Separator*
MPD = *Managed Pressure Drilling*
NPT = *Non-Productive Time*
ppg = *pound per gallon*
ppge = *pound per gallon equivalent*
RCD = *Rotating Control Device*
RP = *Recommended Practice*
RWPC = *Red Willow Production Company*
SJB = *San Juan Basin*
SWP = *Specific Well Program*
TD = *Total Depth*
TVD = *True Vertical Depth*
UBD = *Underbalanced Drilling*

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