AADE-16-FTCE-55

Integrated solution for drilling a sidetrack high-pressure production well

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Abstract

An operation in Colombia required drilling a side track for a high pressure production well with a principal objective to minimize skin damage[5] in the reservoir section while maintaining good hole stability. The original well was drilled with a water based drilling fluid at 16.6 ppg weighted with barite; however, during the completion phase several tools were lost in the well due to well bore conditions resulting in a loss of the production zone.

To meet the request, the team elected two different types of applied technology. First, a base fluid consisting of sodium and potassium formate was built to 12.0 ppg and further densified with $CaCO_3$ to a final density of 13.5 ppg in order to reduce formation skin damage.[5] Second, a Managed Pressure Drilling system (MPD) was utilized to apply the additional downhole pressure required to meet the estimated pore pressure of ±16.0 ppg.

To drill the 394 ft of pay zone in the sidetrack, the mud weight was maintained between 13.0 – 13.7 ppg and an additional pressure between 750-900 psi was provided by the MPD system providing an overall downhole equivalent density of 15.83 ppg. Prior to pulling out of the hole, a 16.7 ppg heavy mud pill was spotted 200 ft inside the 7in liner providing an equivalent open hole hydrostatic pressure of 16.2 ppg to allow for successfully running the liner to bottom and then complete the well. After completion, the well was opened with an initial production of 460 bbl/day versus the initial plan of 100 bbl/day.

Introduction

Formate brines are ideal for challenging applications in drilling, completion, reconditioning and fracturing of wells. Formate brines have increasingly improved well productivity and, therefore, increased return on investment. Applications used in the last several years have categorically evidenced that Formate brines are better than traditional fluids and offer an important number of benefits. [1,6]

- They help to reduce Equivalent Circulating Densities (ECD).
- The high compatibility with fluids and minerals of the reservoir maximizes protection of the reservoir and improves productivity of the well.
- Using an extremely versatile fluid in all phases of drilling and completion, eliminates costs incurred for fluid change.
- Provides an optimized hydraulic fluid that maximizes power transmission, facilitates hole cleaning and increases penetration rates.
- Formate systems have alkaline properties that deliver outstanding protection against corrosion.[6]
- Through better ECD management and improve wellbore stability, overall well control is improved which can allow for faster tripping, reducing well time and cost.
- Have excellent compatibility with elastomers and polymers and facilitate faster and more accurate acquisition of data, even in extended reach drilling.
- Have one of the best environmental and safety profiles of all drilling and completion fluids. [6]
- MPD technology is a proven effective method of drilling wells with narrow operating windows between formation and fracture pressures.
- MPD technology is also excellent to prevent formation damage[5].

Well Background

The original exploratory well was drilled in 2009. The 8-½ in section was drilled in a naturally fractured limestone formation to a total measured depth of 8,315 ft. A layer of heavy residual hydrocarbon was found at 8,290 ft, which required increasing the mud density from 13.5 ppg to 13.7 ppg to control the well.

The well was then completed in open hole with a 7 in pre-perforated liner run to 8,316 ft and swelling packers seated at +/- 7,784 ft and at +/- 8,084 ft. During the packer seating operational problems emerged while trying to isolate the production zones and it was necessary to cut the string, leaving several tools in the well, which caused eventual production volumes to not to meet expectations.

The well produced an average of 32 BOPD in natural flow until July 2013, when it was intervened to open a 103 ft window in the 7 in liner underneath the 9 5/8 in casing shoe, in order to improve its production. No improvements in production volume were seen with the intervention. Chemical stimulation attempts were also made but with no success.

As a result, a sidetrack was designed and drilled on the original well in order to recover production in 2014.

Facing the challenge of designing a 13.5 ppg clean fluid without adding Barite to drill the formation of interest with minimal formation damage[5], it was decided to formulate a sodium-potassium formate base fluid, using calcium carbonate as the additional weighting material to reach the final drilling density and to also serve as bridging agent. The Managed Pressure Drilling (MPD) system was used in order to apply additional bottom pressure to balance the formation pore pressure thus reducing surge and swab pressures along with a reduction in fluid circulating density.

Extensive laboratory testing was performed to find a fluid resulting from the combination of the sodium/potassium formate base brine with calcium carbonate that would provide rheological properties optimized for the bottom conditions, providing good filtrate control, effective well control, adequate ECD management and good hole cleaning.

The calcium carbonate was selected by taking into consideration the best particle size distribution for an effective sealing of the exposed formation.

The selection of the polymers to control the filtrate and the rheology were also an important part of the analysis given the inhibiting characteristics of the formates on the polymers and the reduced quantity of free water available for their solubility.

Pilot tests were run on the established formulation in order to determine the best method to mix the products, which was later replicated at the well site.

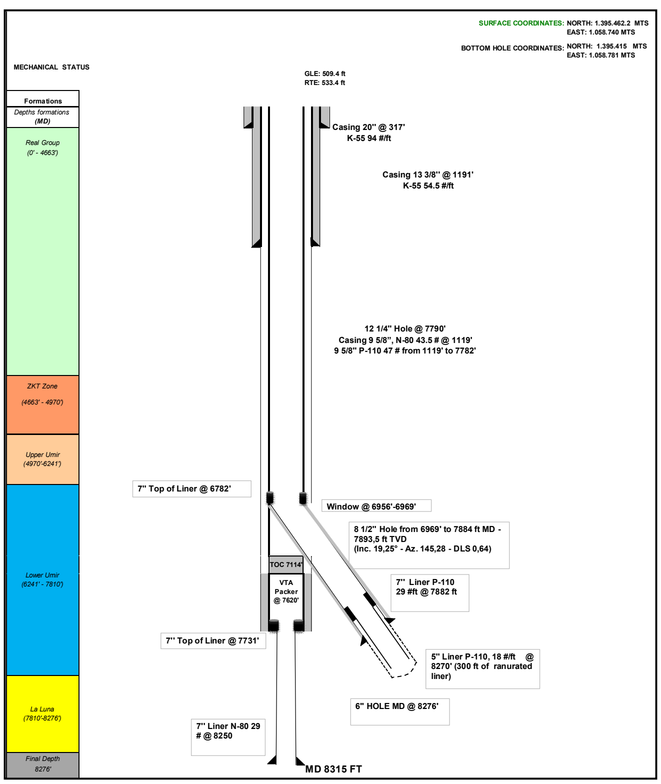

Figure 1. Mechanical Status of the Well.

In addition, taking into consideration that for the completion operation a portion of the sodium-potassium formate base drilling fluid was going to be replaced by a control fluid within the well, compatibility testing of these two fluids was carried out, to confirm that there were no significant variations in the final fluid properties.

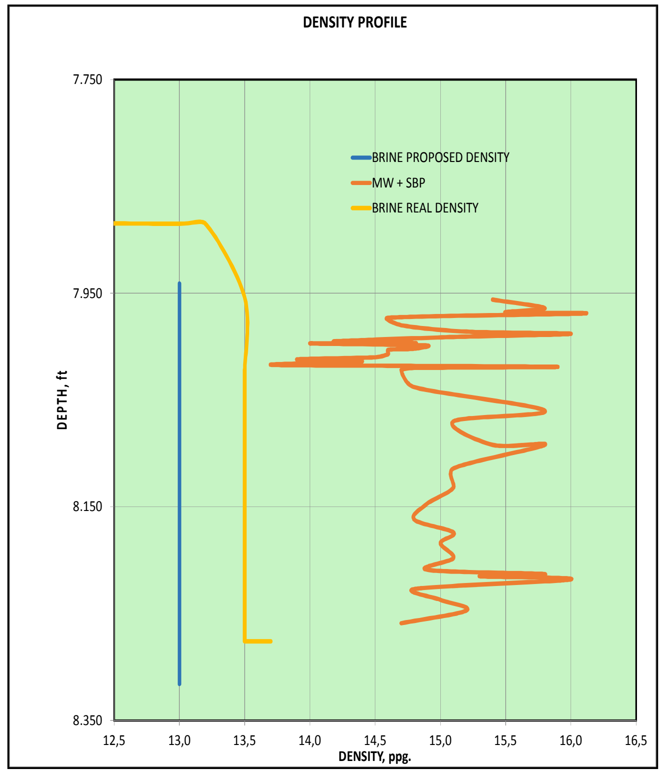

Figure 2. Density Profiles of the proposed versus actual field conditions.

Lab Tests

A 12.5 ppg solids free base fluid consisting of solid sodium formate with liquid potassium formate was mixed based on mixing tables and this fluid was utilized as the base.

Fluid tests were made using xanthan gum for rheology, and various filtrate control polymers, such as starch, polyanionic cellulose and synthetic copolymer to confirm concentrations and to optimize the order of additions. The properties in each case were tested, looking primarily at the rheological behavior both for API[3] conditions and for HPHT conditions. The fluid loss control was also monitored at HPHT conditions (250 °F).[4]

After performing several lab tests it was established that the best formulation to obtain a 13.0 ppg stable fluid based on sodium-potassium formate and adding calcium carbonate to increase the density, is the one shown in **Table 1**.

Table 1. Drilling Fluid Concentrations.

PRODUCT	QUANTITY
Sodium Formate (lpb)	144,5
Potassium Formate (bbl/bbl)	0,495
Xanthan Gum (lpb)	0,7
Polyanionic Cellulose (lpb)	1
Starch (lpb)	1,5
Synthetic Copolymer (lpb)	0,5
Magnesium Oxide (lpb)	1,2
$CaCO_3$ Sized (lpb)	80

The properties of the optimum fluid found above were:

Table 2. Drilling Fluid Properties.

PROPERTY	VALUE
Density (ppg)	13
Funnel Viscosity (seg/qt)	70
Plastic Viscosity (Cp)	45
Yield Point (lbs/100 ft^2)	18
Yield Stress (lb/100 ft^2)	4
Gel Strength (10"/10´/30´)	5/12/17
API Fluid Loss (ml/30 min)	4
HPHT Fluid Loss (ml/30 min),250°F	16

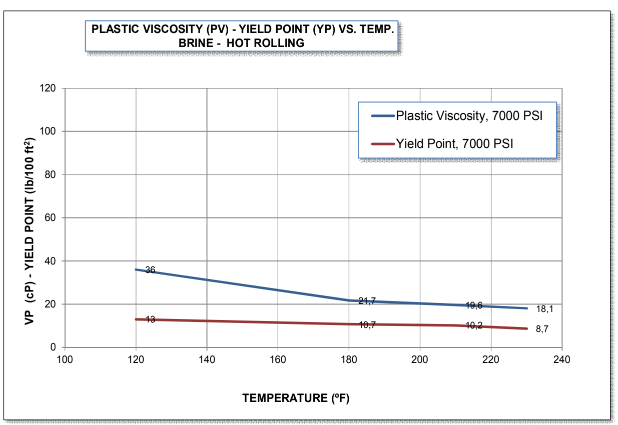

Figure 3. Drilling Fluid HPHT[4] Rheology.

Since the use of a well control fluid utilizing barite was contemplated after drilling was completed with the combination of a barite-free drilling fluid and the MPD system, a 50:50 (V:V) formate base fluid/control fluid (barite based) mix was made and the results of which are shown in **Table 3**.

Table 3. Lab Tests Results for fluids blend.

RESULTS	
pH	11
MW (ppg)	14,6
Ɵ600	107
Ɵ300	68
Ɵ200	53
Ɵ100	35
Ɵ6	10
Ɵ3	8
VP (cP)	39
YP (lb/100 ft^2)	29
YS (lbs/100 ft^2)	6
Gel Strength (10"/10´/30´)	8/12/22
API Fluid Loss (ml/30 min)	5,5
HPHT Fluid Loss (ml/30 min, 250°F)	25

It was observed that the properties of the fluids blended in a 50:50 mix ratio were deemed to be within an acceptable working range, confirming that there was no adverse effect resulting from the combination of such fluids.

Testing Methodology

The methodology established in the lab for mixing the final fluid to be utilized in the field was the following:

For the preparation of sodium-potassium formate Brine with calcium carbonate to 13.0 ppg, in accordance with the recommended product concentrations, the polymers were initially dissolved in fresh water (without salts) to optimize the expansion of their polymeric chains, given the formates inhibitive capacity, which will restrict polymer hydration.

To fabricate the sodium-potassium formate Brine 13.0 ppg with calcium carbonate, the following procedure was followed:

1. Polymers were mixed (xanthan gum, synthetic copolymer and polyanionic cellulose) in the fresh water fraction.
2. The optimum products concentration was: 0.7 lpb of xanthan gum; 1.0 lpb of polyanionic cellulose, and 0.5 lpb of synthetic copolymer.
3. Then, the mix was stirred during 1 hour to hydrate the polymers; 0.495 bbl/bbl of 13.1 ppg saturated potassium formate were added and the resulting mix was stirred to homogenize.
4. 1.5 lpb of starch was added and mixed, stirring to homogenize.
5. 145 lpb of sodium formate was added and mixed, stirring for homogenization, and the 12.5 ppg density was then verified.
6. The densifying material was added as planned: 40.0 lpb of M200 calcium carbonate and 40.0 lpb of M325 calcium carbonate and the 13.0 ppg density was verified.
7. The pH value of the fluid was measured and adjusted to 11.0. Magnesium oxide was used as buffering agent. The pH in formates solutions must be measured with potentiometer or with pH paper. In both cases a dilution with nine parts of

deionized water is recommended to obtain accurate readings. [1,2]

Drilling Operation

The well casing and tubing pressures were reading 0 psi prior to re-opening. The well was opened with a 2-¾ in sliding sleeve with brided line and pressure control equipment. To control the well, a 10.5 ppg water based mud with barite as the weighting material was used.

1. **Control of the original well.** The well was controlled by displacing the crude oil present in the well with 10.5 ppg drilling fluid at 7,790 ft.

2. **Abandonment of the original well.** A 15.8 ppg cement plug for the sidetrack was then pumped and balanced between 7,612 ft and 7,114 ft (498 ft).

3. **Side Track.** A cased hole whipstock was utilized to cut an 8-½ in window in the 9-5/8 in casing between 6,956 - 6,970 ft. The Umir formation was then drilled from 6,970 ft to 7,884 ft, with a 19° inclination. A 7 in liner was then run, seated and cemented at 7,882 ft with a 15.8 ppg cement slurry.

4. **Drilling Reservoir Section.** The 6 in drilling section commenced at 7,891 ft. The drilling program was designed to start with a 13.2 ppg density viscosified brine with a flow rate of 230 gallons per minute (gpm) and 600 psi Surface Backpressure (SBP) resulting in an ECD of 15.0 ppg. In order to check the contact with the pay zone formation, and to identify the pore pressure of the formation, the company decided to start with the system totally opened with a flow rate up to 270 gpm for an equivalent density of 13.7 ppg on bottom.

Drilling operation continued until 7,954 ft with the same parameters, with a total volume gain of 60 bbl seen at surface causing a reduction in the circulating fluid density from 13.2 ppg to 12.7 ppg. Due to the surface volume increase and the fluid density drop, 600 psi SBP was applied with the MPD system to monitor well behavior. It was then decided to shut in the well in order to recondition the brine due to the gas intrusion, recording a 550 psi SIDPP. The control procedure was done flowing through the HCR line of the equipment, controlling the well with the MPD equipment. (**Figure 4**).

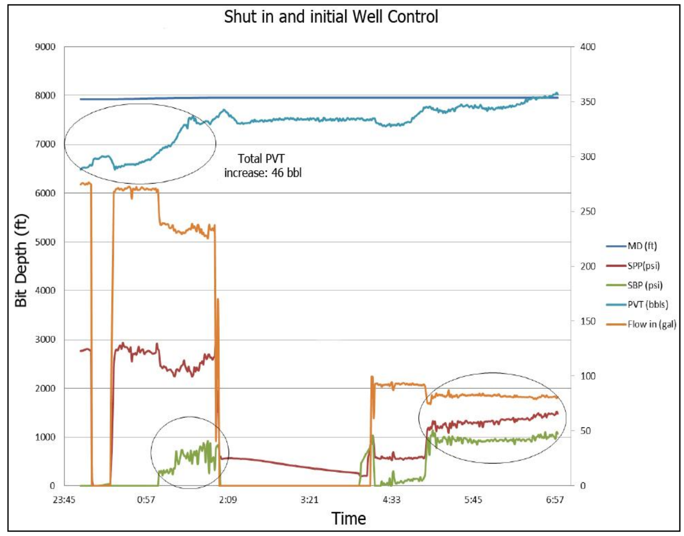

Figure 4. Operating parameters at drilling start-up.

With the well under control, drilling was resumed with the following parameters: 13.5 ppg density drilling fluid; 200 gpm pump rate, and SBP 500 to 800 psi, with an average of 650 psi. Under these conditions, a minimum ECD of 15.2 ppg (500 psi SBP), and a maximum ECD of 15.8 ppg (800 psi SBP) was achieved with an average ECD of 15.5 ppg (650 psi SBP). With the well shut in, it was calculated that the formation pore pressure at this point was 15.5 ppg equivalent, meaning the drilling was performed near balanced pressure. Other indications also included that by reducing back pressure below 650 psi an increase in the active volume was noticed along with the presence of hydrocarbons on surface and the flare burning. (**Figure 5**).

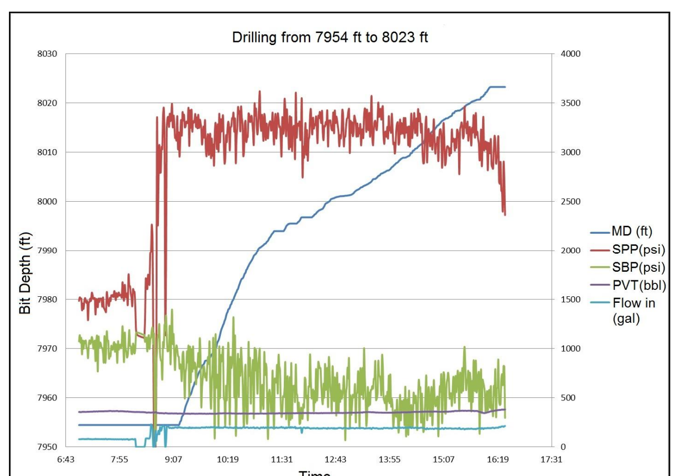

Figure 5. Drilling Operating Parameters up to 8023 ft.

Drilling was continued under conditions of near/under balance with the following drilling parameters: flow rate: 200 - 220 gpm, SPP: 3,100-3,400 psi, SBP: 600 - 900 psi, from

8,031 to 8,276 ft MD where TD was reached, for a total of 245 ft of pay formation. A bottom equivalent density was kept between 15.3 ppg with 600 psi SBP and 16.0 ppg with 900 psi SBP during the drilling. During connections, when turning the pumps off, 1,000 psi back pressure was applied to maintain the well in control. (**Figure 6**).

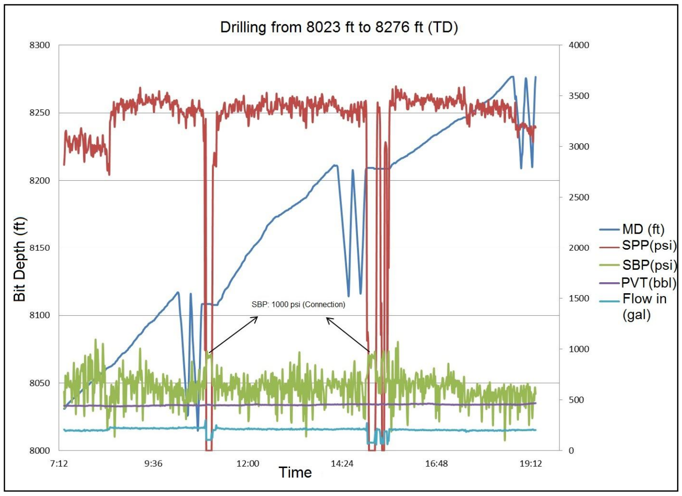

Figure 6. Drilling Operating Parameters up to TD.

Short Trip

Upon reaching final depth, a short trip to the shoe was performed with backpressure applied at surface to maintain the same drilling pressures during the trip. Bottom hole pressure was maintained with 1000 psi SBP filling the well continuously maintaining 16.0 ppg ECD. (**Figure 7**).

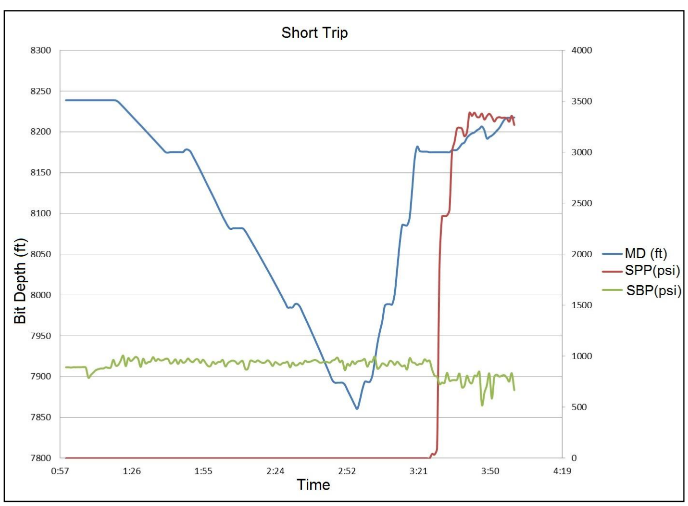

Figure 7. Drilling Operating Parameters – Short Trip to the Shoe.

Well Control

After drilling the formation of interest, the final formation pressure was estimated and it was planned to leave the well with an equivalent density of 16.2 ppg to provide a bottom hydrostatics of 300 psi above the pore pressure. The bit was then positioned at 8,270 ft and the hole was displaced with 13.7 ppg sodium-potassium formate fluid to 6,872 ft. During this procedure, a SBP between 750 psi and 800 psi was maintained.

Once the brine was positioned, the bit was slowly pulled from bottom to the brine top. 40 bbl of 16.7 ppg suspension pill were then pumped (**Table 4**) to isolate the brine from the well control fluid. The bit was then slowly pulled out to the top of the pill and the rest of the formate base drilling fluid was displaced by 16.7 barite based well control fluid.

Table 4. Viscous pill properties.

PROPERTY	HIGH VISCOSITY PILL	
	155 °F-14.7 psi	174°F- 6600 psi
600 RPM	318	292,9
300 RPM	236	228,7
200 RPM	199	191,1
100 RPM	149	142,8
6 RPM	57	48,5
3 RPM	47	39,2
Gel Strength (10"/10´/30´)	46/52/61	35,6/48,8/53,4
VP (cP)	82	64,2
YP (lb/100 ft^2)	154	164,5
YS (lb/100 ft^2)	37	29,9

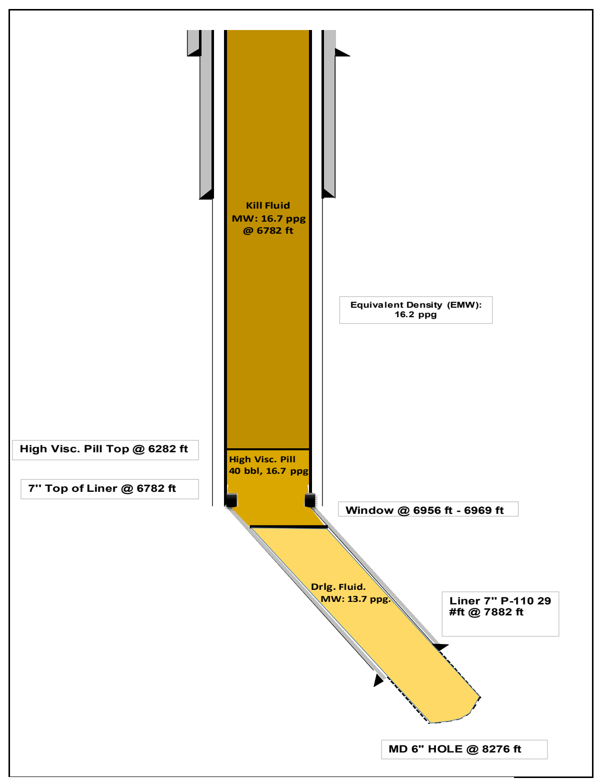

Figure 8. Density Profile proposed for well control.

Figure 9 shows how the control fluid was pumped. The backpressure started at 900 psi and it was maintained until the control fluid reached the bit, where the pressure began to drop until recording 0 psi by the time the 16.7 ppg fluid reached the surface.

After completing the well control fluid pumping, it was confirmed that the well was static and the pipe was pulled out to surface. The final well control fluid equivalent density was 16.2 ppg.

Through this process, a non-damaging clean fluid facing the producing formation was left in the hole, which minimized any formation damage[5], allowing for a successful completion operations while maintaining a stable well.

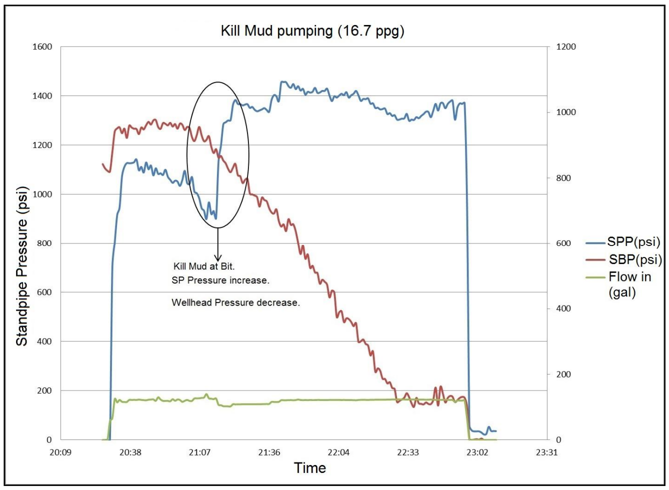

Figure 9. Operating parameters during well control.

While drilling this phase, up to 25% of gas was observed at surface, which required an increase to the circulating drilling fluid density from 13.3 ppg at the beginning of the phase to 13.7 ppg at final depth.

5. Completion. The drilling fluid (sodium-potassium formate brine) was conditioned in the surface with centrifuging and dilution to 10.5 ppg density to be used as completion fluid.

The completion string was run, and the 16.7 ppg control fluid was displaced by the 10.5 ppg sodium-potassium formate completion fluid at 7,716 ft, observing an immediate reaction of the well.

Fluid Performance

The mud used for the reservoir section was a 12.5 ppg sodium-potassium formate clean base fluid densified with calcium carbonate of different sizes to 13.7 ppg density. This fluid was especially formulated to minimize any well formation damage. [5]

Polymers for rheological control, such as xanthan gum and filtrate controllers were added in accordance with the order established in the lab tests. API filtrate control was kept under 4.0 cc/30min with the use of a combination of starch, synthetic copolymer and polyanionic cellulose.

The order of the mix and the way in which polymers were hydrated and homogenized was established in the lab and of outmost importance to achieve a homogeneous fluid with stable characteristics during the live drilling operation.

Density of initial mud was 13.0 ppg but due to the continuous incorporation of crude oil and gas to the circulating system, it had to be readjusted. At the beginning of the operation it was increased to 13.5 ppg and finally up to 13.7 ppg with calcium carbonate (for purposes of well control). The mud properties are shown in **Table 5**.

The drilling operation was performed in near/under balance conditions with the formation pressure, through the combination of hydrostatics provided by the drilling fluid and the backpressure applied by the MPD system. This allowed a dynamic control of the well, by maintaining an equivalent density between 15.2 and 16.0 ppg.

Table 5. Properties of the drilling fluid.

DRILLING FLUID PROPERTIES				
PROPERTY	PROGRAMMED	MINIMUM	MAXIMUM	TYPICAL
Density (ppg)	13	13	13,7	13,5
Funnel Viscosity (sg/qt)	60-70	64	69	66
Plastic Viscosity (cP)	40-45	31	47	42
Yield Point (lb/100ft^2)	12 - 18	22	32	30
Gel Strengtht (10"/10'/30')	05/10/12	5/10/21	6/10/29	6/10/29
pH	9 - 10	10,3	10,5	10,4
API Fluid Loss (ml/30min)	< 5.0	4	5,1	4,8
HTHP Fluid Loss (ml/30 min, 250°F)	< 20	16	18	18
Drilled Solids (%V)	< 6	<1	1	<1
MBT (lb/bbl-eq)	< 7,5	0	0	0

Table 6 shows programmed concentrations of products versus actual concentration used while drilling.

Table 6. Drilling Fluid Concentrations.

DRILLING FLUID CONCENTRATIONS				
PRODUCT	PROGRAMMED	MINIMUM	MAXIMUM	TYPICAL
$CaCO_3$ SIZED (lpb)	30 - 80	33,5	114,61	74,98
XANTHAN GUM (lpb)	0,3 - 1,0	0,67	1,01	0,8
STARCH (lpb)	2,0 - 4,0	0,33	0,86	0,54
POLYANIONIC CELLULOSE (lpb)	1,0 - 2,0	0,58	1,03	0,83
SODIUM FORMATE (lpb)	145	55,98	123,88	84,59
DEFOAMER (lpb)	---	0,01	0,03	0,02
MAGNESIUM OXIDE (lpb)	1,0 - 3,0	0,9	1,52	1,19
POTASSIUM FORMATE (bbl/bbl)	0,495	0,31	0,51	0,43
POLYMERIC THINNER (lpb)	---	0,28	0,38	0,33
SYNTHETIC COPOLYMER (lpb)	0,3- 1,0	0,38	0,75	0,56

During the progress of the drilling operation, it was necessary to conduct certain actions in order to maintain fluid stability and to achieve a successful operation:

1. The use of an antifoaming agent was necessary both, for the water mix, and for the mud, in order to control gas and foam.
2. In addition, it was necessary to use a polymeric dispersant for rheological control due to the high concentration of calcium carbonate that was added to the system in order to increase mud density to 13.7 ppg.
3. In order for polymers to develop their rheology, good agitation, and appropriate time and temperature were required.
4. The fluid pH was maintained with the addition of pre-hydrated magnesium oxide, which was used to contribute the buffer effect[1].

Production Results

After the completion job, when the well control fluid (16.7 ppg) was displaced by spotting the sodium-potassium formate 10.5 ppg fluid, the well immediately showed a good response.

Post sidetrack, the initial high rates of production (approx. 460 BOPD) were the direct result of the minimization of formation damage[5] by an excellent drilling fluid designed, with reduced drilling densities for well control due to the MPD applied pressure. The reservoir pressure expected was around 6,956 psi and the well started production with an 18% drawdown. After a few months, the productivity was stabilized at nearly 210 BOPD and the drawdown was less than 30%, which is a good data for good reservoir management.

After 1 year, the well continues producing crude oil 23°API with an annual declination of 10.2%.

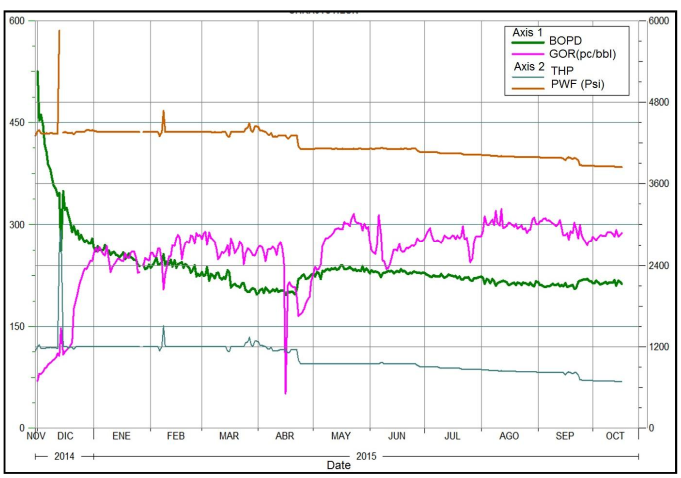

Figure 10. Production curve.

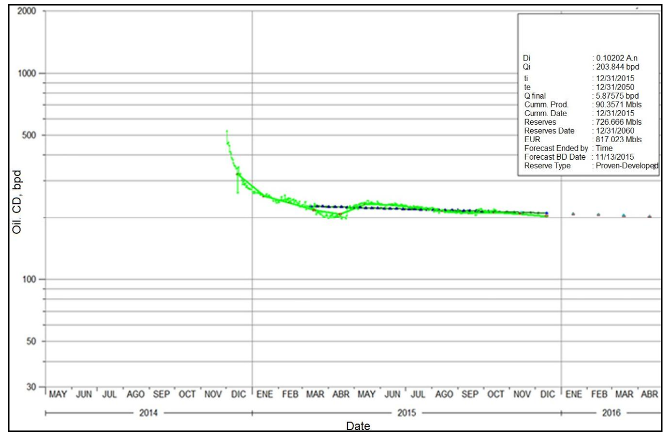

Figure 11. Decline curve.

Conclusions

- The objective of the well was achieved; the producing zone was drilled without formation damage[5] caused by plugging with undesired solids (barite).
- It was verified that the formation of interest has a pore pressure of 15.5 ppg.
- Both, the drilling fluid design based on sodium and potassium formate densified to 13.7 ppg with calcium carbonate, and the use of the MPD system, fulfilled the goal of maintaining control of the well while drilling the pay zone, by keeping a 16.1 ppg equivalent density downhole.
- Despite the fluid density increased by 0.7 ppg above the planned density, good rheological control was maintained and mud properties remained stable.
- Relevant information was obtained for future operations allowing for cost reductions, optimization of the drilling operation, the ability to bring wells to production sooner than expected, reduction in stimulation works, etc.
- A barite base heavy fluid was used to control the well during liner running and completion operations, but clean fluid was always maintained in the reservoir, thereby minimizing formation damage.
- The well was completed with an initial production of 460 bbl/day; after the second shut in, it produced 340 bbl/day, and at present it is producing 210 bbl/day.
- Wells with high pressure areas of interest might be drilled with fluids different from those conventionally used, such as formate based brine fluids which will prevent use of formation damaging materials for the pay zone.

Acknowledgments

The authors would like to thank Petronorte and QMax Solutions Inc for the permission to publish this paper.

Nomenclature

API = *American petroleum Institute*
bbl = *Barrel*
BOPD = *Barrels of oil equivalent per day*
$CaCO_3$ = *Calcium carbonate*
cP = *Centipoise*
ft = *Feet*
HCR = *High closing ratio*
HPHT = *High pressure high temperature*
in = *Inches*
lpb = *Pounds per barrel*
MD = *Measured depth*
ml = *Milliliter*
ppg = *Pounds per gallon*
psi = *pound per square inch*
RPM = *Revolutions per minute*
SIDPP = *Shut-in drill pipe pressure*
SPP = *Standpipe pressure*
TD = *Total depth*

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