IMPROVED FLUID CHARACTERISTICS WITH CLEAR CALCIUM CHLORIDE BRINE DRILLING FLUID

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This paper was presented at the 13th Offshore Mediterranean Conference and Exhibition in Ravenna, Italy, March 29-31, 2017. It was selected for presentation by OMC 2017 Programme Committee following review of information contained in the abstract submitted by the author(s). The Paper as presented at OMC 2017 has not been reviewed by the Programme Committee.

ABSTRACT

In a time when drilling efficiencies are significant, the advancement of conventional clear brine systems has led to both economic and technological breakthroughs. Clear brine fluids have been in the industry since the 1950's, and since inception, different base brines have been utilized to maintain different densities.

Calcium chloride is a great base fluid due to its natural density and highly lubricious nature. By adding calcium nitrate, densities have been increased to 1.6 sg (13.35 lb/gal), exceeding the density of potassium formate 1.57 sg (13.1 lb/gal). These calcium brine systems can be cost effective providing a reduction in cost for base fluid up to 90% as compared to formate or bromide systems. However, divalent brines are known for having excessively high corrosion rates and compatibility issues when used with polymers.

By focusing efforts on process control and product compatibility, low corrosion rates can be achieved in a brine system. After exhaustive autoclave testing, a corrosion package was developed and perfected in the field. Results of a 140-well dataset showed the calcium chloride system with a novel corrosion package yielded better results than formate brines employed in the same area. The exhaustive efforts in the field also led to determining a suitable flocculent polymer that can hydrate in the calcium chloride/calcium nitrate dual-brine system. This novel application of a polymer provided improvements in both corrosion and drilling performance.

This paper discusses the use of clear calcium chloride brine drilling fluids in drilling over 140 wells and the challenges overcome. It also details the equipment used and highlights the comprehensive technique for evaluating all aspects of the drilling fluid.

INTRODUCTION

Clear brine fluids create density without the need to maintain viscosity solely to carry weight-material particulates as all the weight-material is totally dissolved. The fluid density is dictated by the amount and type of salt used. Each salt has a maximum concentration before it reaches saturation limiting the maximum density of the solution. Thermal expansion of water affects the solubility, crystallization point, and density of clear brine.

Clear fluids are often used within completions, as the presence of solids is a major contributor to formation damage. When used as drilling fluids, the solids-free nature of brine operationally improves the rate of penetration (ROP), stabilization of sensitive formations, density, and abrasion or friction.[1] Clear brine fluids are easier to maintain than conventional solids-laden fluid systems due to the large amount of materials needed to maintain desired fluid properties of conventional drilling fluids. When properly run, clear systems require very little maintenance as many functional issues are inherently solved by the dissolved salt(s). Clear brine fluids also allow for drillsite cost reductions due to the ability to reuse the fluid.[2]

Brine fluids can be prepared with one salt or a combination of salts. All salts provide unique properties to the base fluid. The first property that must be considered is the required density to achieve well control. Density is the primary property defined by the drilling program; all other properties are defined by the salt concentration. Increasing density without adding solids through additions of soluble salts has led to breakthrough performance. This has proven to be a step change, greatly changing the economics of some of North America's most important unconventional plays.

Density as being the primary defined property, dictates the salt selection where sodium chloride or potassium chloride is limited to less than 1.2 sg (10.0 lb/gal). Calcium chloride allows for density to 1.4 sg (11.6 lb/gal). When dictated, a higher density will require a mixed-salt system where use of calcium nitrate can achieve densities over 1.56 sg (13.0 lb/gal).

Saturated brines provide excellent inhibitive properties and lubricity as compared to conventional aqueous fluids. With optimal heat transference characteristics, they can greatly improve bit life and increase rate of penetration (ROP) over non-aqueous fluids (NAFs) in hard rock drilling.

Formate brine application is ever increasing in popularity but a significant disadvantage is the almost 10 times the cost of formate brine over halide brines. Formates contain nearly all the same advantages to halide brines but generally are less corrosive. Controlling the corrosivity of divalent brines would provide an economic advantage over formate brines.

Calcium chloride has been the primary salt selection of choice due to its broad range of densities, availability, low cost, and its ability to reduce the water activity of the fluid. The general downfall of calcium chloride has been its reputation around severe corrosion which has limited its application in the past. The lab work in developing a clear brine drilling fluid tackled this major issue of corrosion, then optimized the system to insure adequate dewatering, water activity, crystallization point, and lubricity. Finally the paper reports on the use of the novel system in the field.

CORROSION

Corrosion of drillpipe, casing, downhole tools, and all the circulating system on a rig is recognised as a serious problem requiring corrosion control measures especially when dealing with divalent brines like calcium chloride. Corrosion, manifest as scale, stress cracking, pitting, etc., costs the United States industries an estimated $276 billion annually, as reported in a 2002 federal study initiated by NACE.[3]

Initial developmental work used the rotating cylinder electrode (RCE) test and linear polarization resistance (LPR) using standard procedure, four different brines and two novel corrosion inhibitors evaluated in Tables 1 and 2. LPR is a commonly used method of measuring corrosion rates electrochemically. LPR measurements are performed by scanning through a potential range of E_{corr} ±20 mV. The measured polarization resistance, Rp, is converted to the corrosion current density using the Stern-Geary Equation.[4]

Tab. 1: Initial RCE Test on Common Brines

Product	Fluid	Concentration (ppm)	Corrosion Rate - Blank (mpy)	Corrosion Rate with Inhibitor (mpy)	Inhibition Efficiency (%)
Novel Corrosion Additive 1	20% NaCl	5000	36.62	10.46	71.4%
Novel Corrosion Additive 2	20% NaCl	2800	29.79	17.98	39.6%
Novel Corrosion Additive 1	20% NaCl + 1% $CaCl_2{\bullet}2H_2O$	5000	46.13	3.56	92.3%
Novel Corrosion Additive 2	20% NaCl + 1% $CaCl_2{\bullet}2H_2O$	2800	37.40	28.61	23.5%
Novel Corrosion Additive 1	20% NaCl + 5% $CaCl_2{\bullet}2H_2O$	5000	29.29	9.22	68.5%
Novel Corrosion Additive 2	20% NaCl + 5% $CaCl_2{\bullet}2H_2O$	2800	29.62	46.53	-57.1%
Novel Corrosion Additive 1	32% Potassium Formate (HCOOK)	5000	23.41	119.84	-411.9%
Novel Corrosion Additive 2	32% Potassium Formate (HCOOK)	2800	22.25	6.43	71.1%

Tab. 2: Initial LPR Test on Common Brines

Product Tested	Dosage (ppm)	Fluid	Corrosion Inhibition Efficiency (%)
Novel Corrosion Additive 1	5000	20% NaCl	Immediate reduction (84.6)
Novel Corrosion Additive 1	5000	26% NaCl	Immediate reduction (73)
Novel Corrosion Additive 1	5000	32% CaCl	Immediate reduction (84.8)

Early developmental work on corrosion control led to initial studies being performed using an autoclave testing applied under different concentrations of hydrogen sulphide and carbon dioxide. Some of the testing is shown below in Figures 1 - 3. Autoclave testing shows valuiable information when associated to acid gasses. As seen below the introduction of CO_2 and H_2S would have minimal impact with the novel corrosion package.

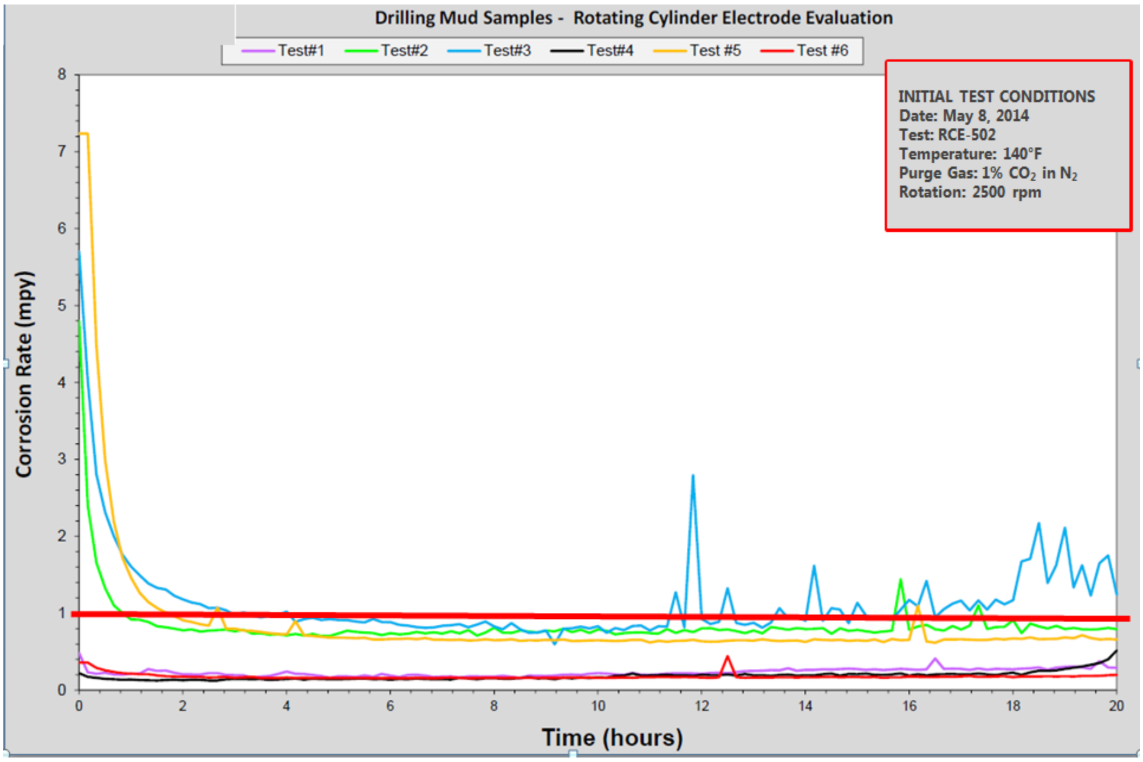


Fig 1: Initial Autoclave test in 1% CO_2 purged with Nitrogen

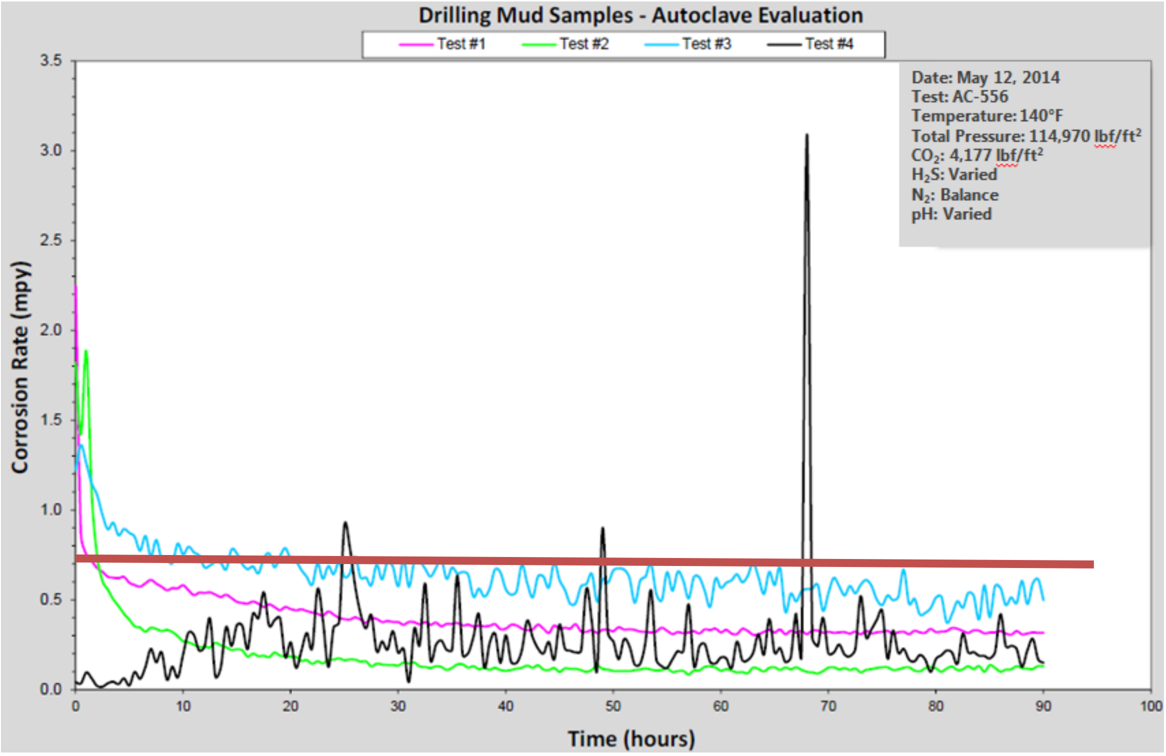


Fig 2: Initial Autoclave test in 4% CO_2 and H_2S Varied purged with Nitrogen

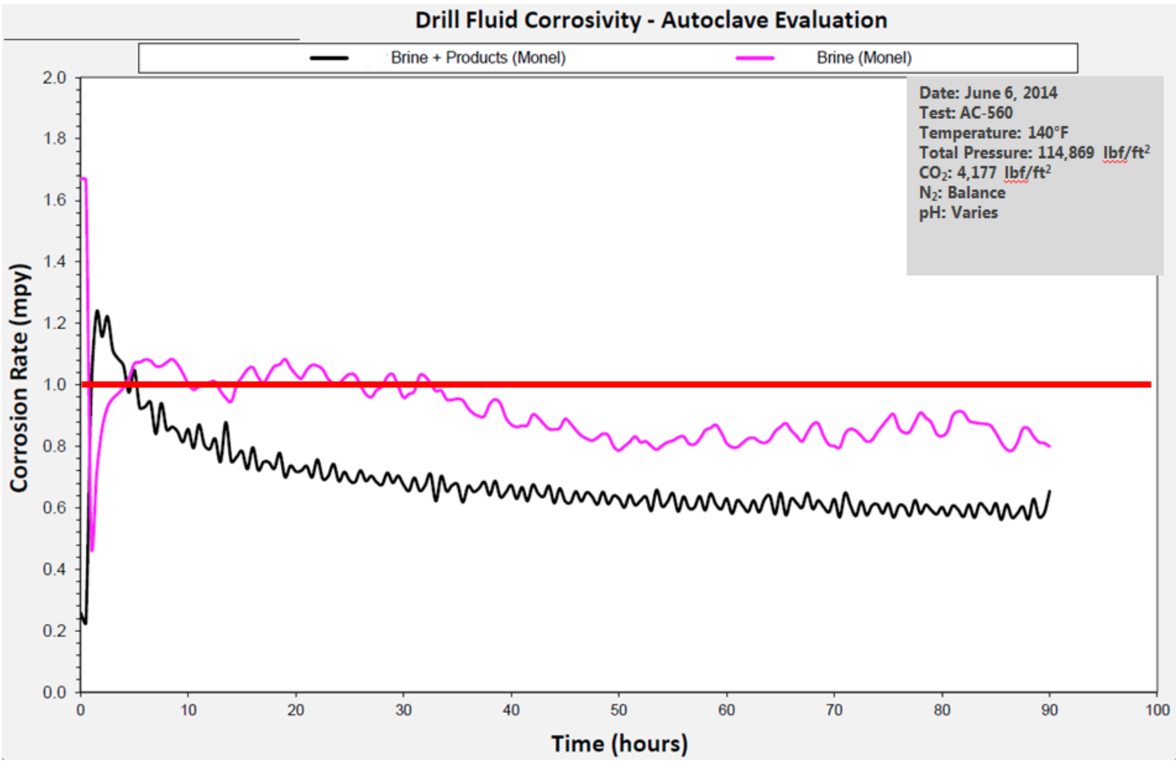


Fig 3: Initial Autoclave test for Non-Magnetic Drill Collar Coupon in 4% CO_2 purged with Nitrogen

To extend the testing from common test coupons, materials used in downhole tools from two manufacturers were evaluated against a 1018 carbon steel electrode. Samples from a rotor, drill collar and a stator were sent to a machinist to mill electrodes. The fabrication of electrodes from the material samples allowed for installation in the autoclave apparatus. Table 3 shows the components for the materials test.

Tab. 3: Materials for Autoclave Evaluation of Corrosivity

Material	Source	Density (g/cm^3)
Non-Magnetic Alloy	Tool Company #1	N/D
Rotor		8.8
1018 Carbon Steel		7.87
Stator	Tool Company #2	N/D
Monel		8.8

Two drilling fluids were submitted for the material corrosivity testing – one fluid a brine blank fluid, the other a treated fluid. The first fluid (Fluid #1 – the blank brine) included 36% calcium chloride. Fluid #2 was a 36% calcium chloride with Novel Corrosion Additive 1, Novel Oxygen Scavenger, and a high-performance brine lubricant designed for use with divalent brines. The two fluids were evaluated in a stirred autoclave apparatus.

Autoclave corrosion testing was performed with 200 kPa of CO_2 and 5300 kPa of N_2. All testing was conducted according to an industry developed protocol.[5] The CO_2 content was based on a 1% gas concentration at a total pressure of 20,000 kPa. The autoclave cells were brought up to a maximum deliverable pressure of 5500 kPa with N_2. All testing was performed at a desired set temperature of 60°C. Sealed autoclaves were placed inside individual mantles and heated to the specified test temperature. Proportional temperature controllers accurate to ±2°C were used to maintain the set temperature. Table 4 shows the results of this testing on the downhole tool materials.

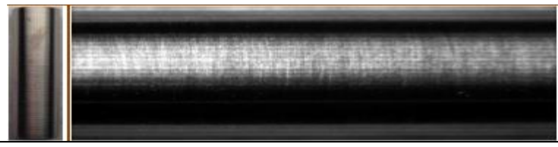
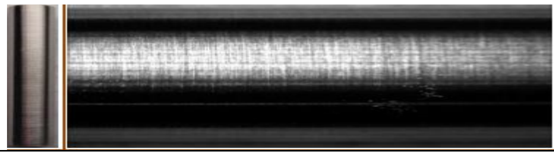
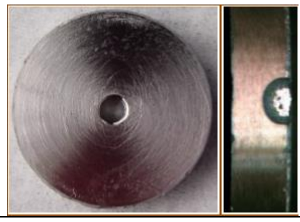
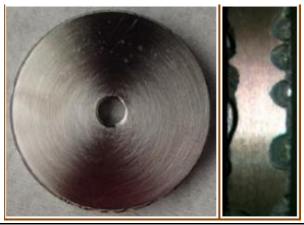
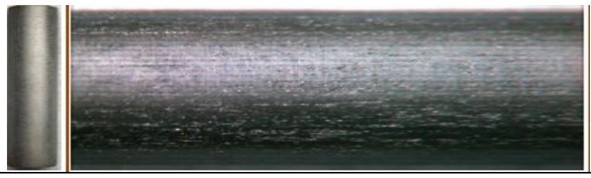
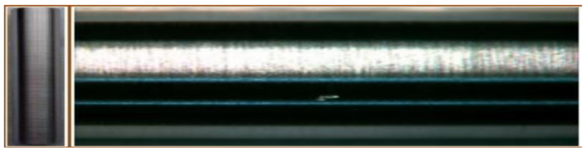
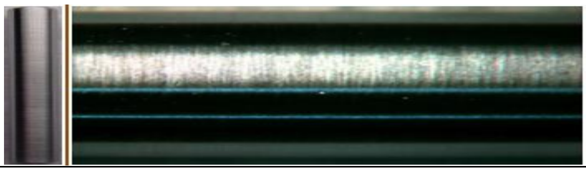
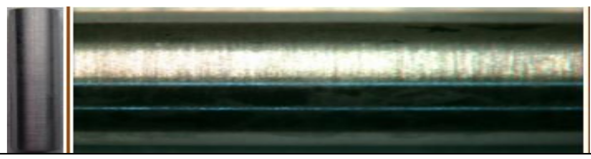
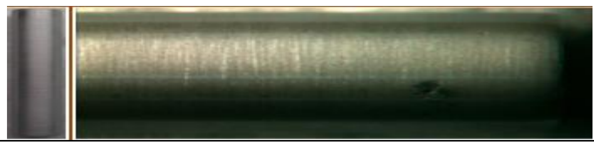
Tab. 4: Autoclave Corrosivity Evaluation of Fluid #1 vs Fluid #2

Test #	Fluid #	Material	Initial LPR (mpy)	Final LPR (mpy)	Weight Loss (mg)	Weight Loss (mpy)
1	2- Additive	Non-Magnetic Alloy 1	0.26	0.65	0.75	0.41
2	1	Non-Magnetic Alloy 1	1.67	0.8	0.8	0.44
3	2- Additive	Rotor 1	0.56	8.66	11.95	9.37
4	1	Rotor 1	3.93	19.08	30.10	23.61
5	1	1080 Carbon Steel 1	4.67	10.33	23.85	14.69
6	2- Additive	Stator 2	.04	0.21	0.80	0.43
7	1	Stator 2	0.81	0.94	2.40	1.29
8	2- Additive	Non-Magnetic Alloy 2	0.08	0.13	0.55	0.33
9	1	Non-Magnetic Alloy 2	1.07	0.59	2.5	1.51

In Test #1 as compared to Test #2, the Novel Corrosion Additive Fluid #2 was able to reduce the observed corrosion rate as compared to the corrosion rate measured in pure calcium chloride brine (Fluid #1). The reduction was more evident with the corrosive-resistant rotor material. The low corrosion rates seen in the rotor material is attributed to the passive nickel oxide layer present on the electrode surface. It is unclear the degree to which the mechanical damage on the rotor electrodes influenced the corrosion damage. However, Fluid #2 was able to reduce the corrosion rate and severity of the corrosion on these electrodes in the conditions as tested.

Testing on the non-magnetic alloy 2 (Tests #8 and #9) and the stator 2 (Tests #6 and #7) from Tool Company #2, showed that the Novel Corrosion Additive Fluid Fluid #2 was able to reduce the observed corrosion rate in both material electrodes. Non-magnetic alloy ("Monel") is a known corrosion-resistant, high-nickel alloy. The stator material is likely a corrosion-resistant alloy as corrosion rates in the pure calcium chloride Fluid #1 (Test #7) were significantly lower than those of the 1018 carbon steel (Test #5). However, the pitting noted on the stator material in the blank calcium chloride Fluid #1 (Test #7) indicates the material is prone to localised corrosion activity in the conditions as tested.. Pictures below show findings from the testing.

Tab. 5: Visual Inhibitor Evaluation of Corrosivity Data Summary

Test #	Fluid #	Weight Loss (mpy)	Visual Description	Pit Depth (mils)	Electrode Photo
1	2- Additive	0.41	Overall shiny surface	N/A	
2	1- CaCl Blank	0.44	Overall shiny surface	N/A	
3	2- Additive	9.37	Mild etched spots on face with moderate edge attack.	N/A	
4	1- CaCl Blank	23.61	Mild etched spots on face with moderate edge attack.	N/A	
5	1- CaCl Blank	14.69	Overall dull surface etch with heavier etched patches.	N/A	
6	2- Additive	0.43	Overall shiny surface with etched spots	N/A	
7	1- CaCl Blank	1.29	Overall shiny surface with etched spots	N/A	
8	2- Additive	0.33	Overall patchy surface etching	N/A	
9	1- CaCl Blank	1.51	Overall dull, surface etching with pitting	3.0	

The basic causes of corrosion in the oilfield are oxygen, hydrogen sulphide, and carbon dioxide. Oxygen is 50 times more detrimental than hydrogen sulphide and 100 times more detrimental than carbon dioxide. Therefore, oxygen is the primary concern due to its detrimental effects.[6] The autoclave testing lacks the ability to continuously control the concentration of oxygen. The inability to adequately test with the oxygen contaminant in autoclaves has led to test results inadequately reporting low-to-moderate corrosion rates but field results with calcium chloride brine showed it to be very detrimental and associated with severe corrosion rates. At the rigsite, a few pragmatic tests can easily detect oxygen as a potential contaminant and identify situations that would benefit from treatment with oxygen scavengers to minimize the contaminant and control the potential for corrosion. Thus the protocol is to leverage a novel oxygen scavenger with additional rigsite monitoring of oxygen levels.

Due to the inherent limitations of laboratory testing, it is very difficult to completely mimic the effects contaminates have on the drillstring under field conditions. The criterion for testing, which used in conjunction with general oilfield specifications, evaluates the corrosion rate in mpy (mils per year) and provides a standardized comparison of lab-produced test results.

Low	<1.0 mpy
Moderate	1.0 – 4.9 mpy
High	5.0 – 10 mpy
Severe	>10 mpy

The standard corrosion rate formula used for these calculations is:

$$Corrosion\ Rate\ (mpy) = \frac{Coupon\ weight\ loss\ (g)\ \text{x}\ \ 2.23\ \text{x}\ 104}{Total\ exposed\ area\ of\ coupon\ (in^2)\ \text{x}\ Exposure\ time\ (days)\ \text{x}\ metal\ density}$$

Oxygen scavengers, revolving around a sulphite ion, are widely used within the industry; treatments are varied and the general rule is 10 pounds of oxygen scavenger will remove 1 pound of oxygen per million pounds of fluid. A granular, novel oxygen scavenger was developed for the proprietary system reviewed in this paper. The granular nature of the oxygen scavenger allows for consumption of the product only when oxygen is present, thus using minimal concentrations.

The introduction of additional test equipment on the rigsite allows for interpretation from the onsite drilling fluids technician. The equipment allows for routine testing as an important part of corrosion control. A major benefit of the fluid technician performing tests and treatments is the ability to tailor concentrations according to the drilling situations. The ability to continuously monitor the condition of the fluid, allows for continuous improvement, building upon lessons learned and implementing a cultural shift in previous corrosion control techniques. Monitoring the fluid is of major importance when using a clear brine system as, for example, solid particulates can increase corrosion rates.

Corrosion rings are designed to measure the corrosive effects of the drilling fluid environment during operations.[6] They come in varying sizes designed to fit specific connections. The valuable implementation of corrosion rings also allows for continuous improvements. Since corrosion rings use a standard formula (K factor provided by the manufacturer) to account for the exposed surface area, this can often lead to inaccurate calculated corrosion rates. However, extending the exposure time beyond 96 hours serves to decrease error in the corrosion rate calculation. This information is valuable to the operation and adjustments within the treatment of corrosion chemicals. Corrosion rings are analysed for pitting, scale, and weight loss, which provide valuable information for corrosion treatment procedures.

DEWATERING

Demands for improved fluid performance have also brought an environmental demand to minimize waste and reduce or remove the volume of fluids requiring disposal. Dewatering is the ability to reclaim the water or brine from suspended solids. Chemical flocculation allows a centrifuge to remove small particles from the fluid. The use of chemical flocculation does not affect the salinity or any other additive that goes into solution. Thus, dewatering through chemical flocculation allows for the removal of solids without affecting the density of the base brine.[7] However, fresh water is usually required to fully hydrate the flocculent, fresh water additions to the fluid can affect the brine by diluting the salt concentration and lowering the density. A core technology for clear brine drilling requires a flocculent that is 100% hydratable within the base brine and is effective in fully saturated systems. Using a flocculent that is 100% hydratable in the base brine will eliminate the costs associated with treating dilution caused by the dewatering process.

Effluent for the purposes of this paper is defined as the processed fluid after the solids control equipment. When using a clear brine system, polymer carryover through the effluent into the drilling fluid is unacceptable, as it will create a change in the rheological profile. Therefore, any flocculent polymers used, must be removed with minimal treatment.

Considering the aforementioned concerns, the flocculent for this novel brine system must exhibit the following conditions.

- Hydratable in 100% brine
- Usable across wide variety of brines
- Effective in highly saturated brines
- Efficient removal with minimal polymer carryover

Evaluations confimed a solution – a polymer meeting all these requirments capable of being used within the polymer injection dewatering process.

Process changes on the rigsite were made accordingly to yield better solids removal. The centrifuge selection, settings, and polymer injection were very dependent upon several factors. During drilling operations, primary focus on solids seperation is maintained on the shale shakers and screen size and quality. Adjustments were made to accomodate the finest shaker screens with the longest run life. API 170-200 shaker screens were used primarily on all wells outined within this paper.

WATER ACTIVITY

Water activity is a measurement of inhibition to prevent migration of fresh water into the formation, an important characteristic within water-based drilling fluids. Dissolved solids effect which solutes interact with water through dipole-dipole, ionic, and hydrogen bonds; the water activity equipment measures the relative humidity in the airspace above the fluid and reports the amount of available water as a function of the vapor pressure. To measure the ability of fluids to inhibit water transport into the formation, water activity instruments measure the amount of active water present in the drilling fluid and provide a quantified measurement of the rate at which drilling fluids chemically transport water to the formation.

In non-aqueous fluids, the ability for the fluid to build an osmotic membrane and a pressure differential allows for fluid to move from the formation (low-salinity) into the drilling fluid (high-salinity side). Within a clear brine system, no membrane is present; diffusion, governed by Fick's law, will drive water and solute from high concentration to low concentration until equilibrium is established, resulting in the ability to move fluid from the formation into the drilling fluid which allows for an effective means of inhibition by control of the water activity.[8] Ultimately the water activity should be slightly lower than the water activity of the formation.

Based on findings with non-aqueous drilling fluids, we know a general target of 0.66 water activity (aw) in the water or internal phase is generally acceptable to mitigate the movement of water into the formation. This of course generalizes all formations and to correctly asses the desired water activity of the fluid core sample of the formations should be examined.

CRYSTALLIZATION POINT OF BRINE

Concentrated salt solutions have been used within the industry for decades based on the natural characteristics that define each salt. For effective use, an accurate measurement of the brine's crystallization point needs to be distinct. Blends of mixed salts can achieve crystallization points low enough to meet the demands of the operational environment. In cold weather applications, this becomes a necessity to avoid operational failure. Even with careful measurement and using defined mathematical equations, crystallization points can vary as much as 10°C.

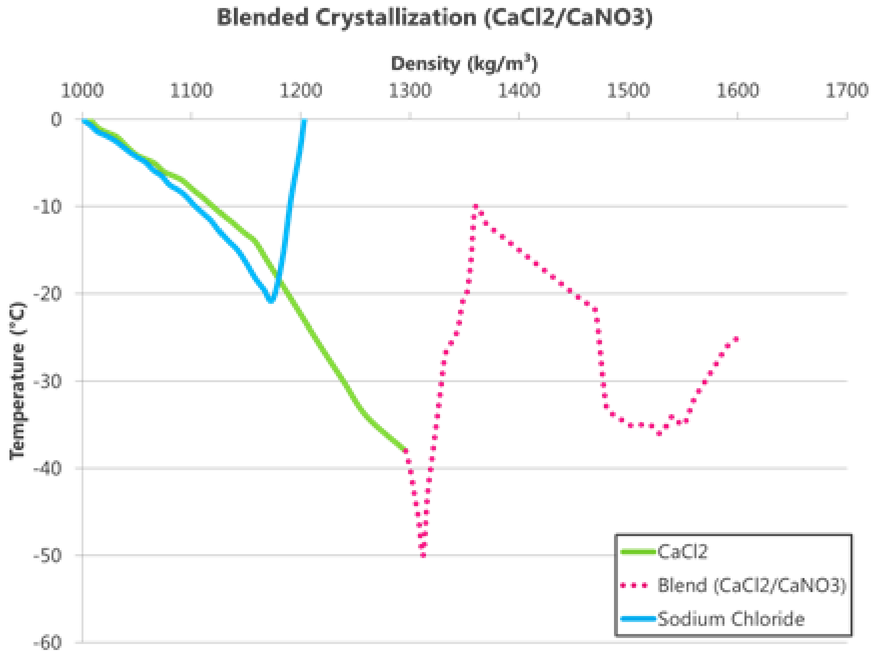


Fig 4: Crystallization Point of Blended Calcium Chloride and Calcium Nitrate

LUBRICITY

A primary function of drilling fluids is reduction of frictional forces that can potentially limit the drilling capabilities of a rig. Lubricity meters are a tool to predict the fluids capacity to manage friction. Laboratory measurements of base brines are noticeably different from that expected of fresh water. A baseline is 0.34 Lubricity Coefficient (CoF) as it is the standard CoF for deionized water.[9] A noticeable difference in the fluids CoF is observed as salt concentrations are increased (Figure 5).

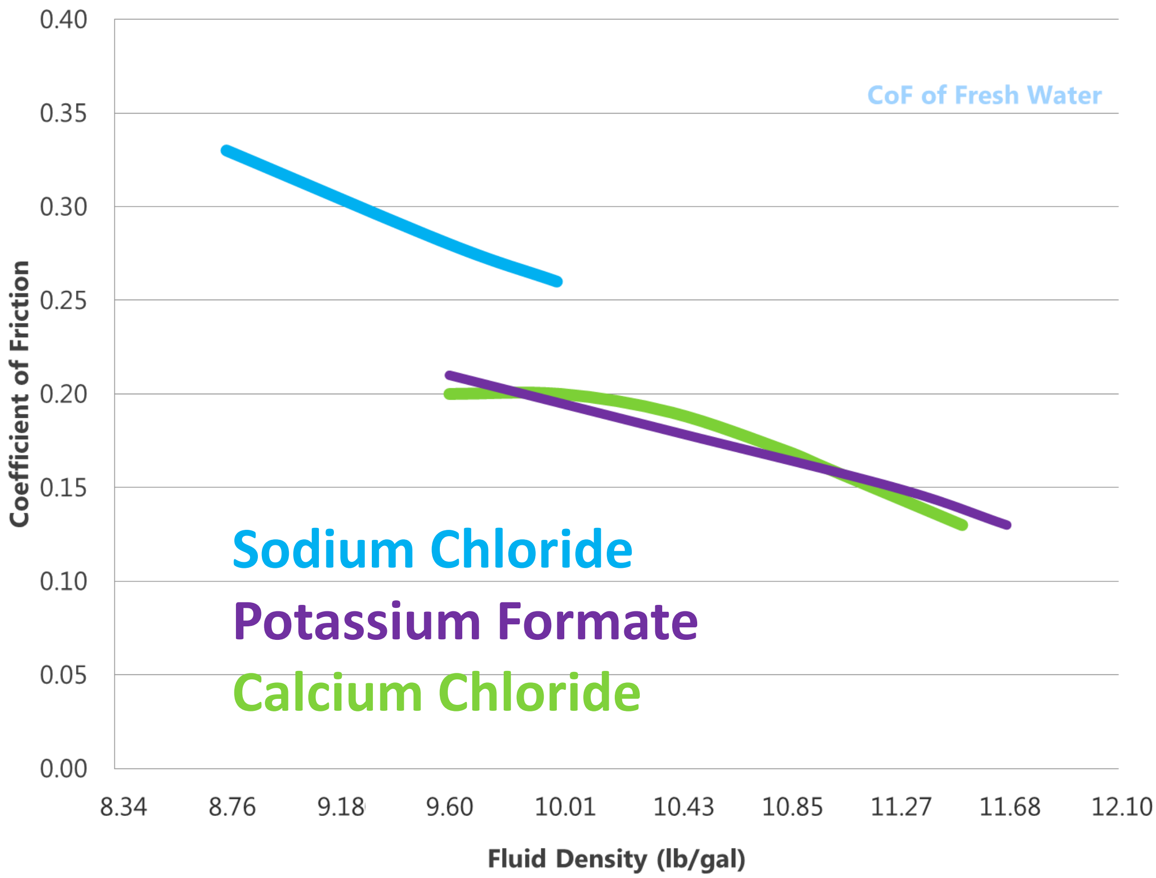


Fig 5: Lubricity of Base Brine by Measurement of EP/Lubricity Meter Model 112

The CoF is a dimensionless number that can indicate the mechanical interaction between two moving surfaces. The lower the coefficient of friction, the easier it is to move across the two surfaces. Every well encounters losses of transitional power to drill a well whether it is directional or a vertical well. A lubricious fluid helps to overcome some of the negative forces resulting in better weight transfer to the bit and also an increase in ROP. Additionally, there are other benefits to operators from a reduction in friction including longer laterals, reduced wear on tools, reduced casing wear, and reduction in vibration.

Brines can be extremely lubricious when saturated. When compared to NAF systems with a high amount of solids, highly saturated calcium chloride brine can be more lubricious than NAF in metal-on-metal testing. Controlling the drilling fluid lubricity within specified ranges and comparing the lubricity coefficient to wellbore torque and drag is one method of assessing performance of lubricants in critical applications.

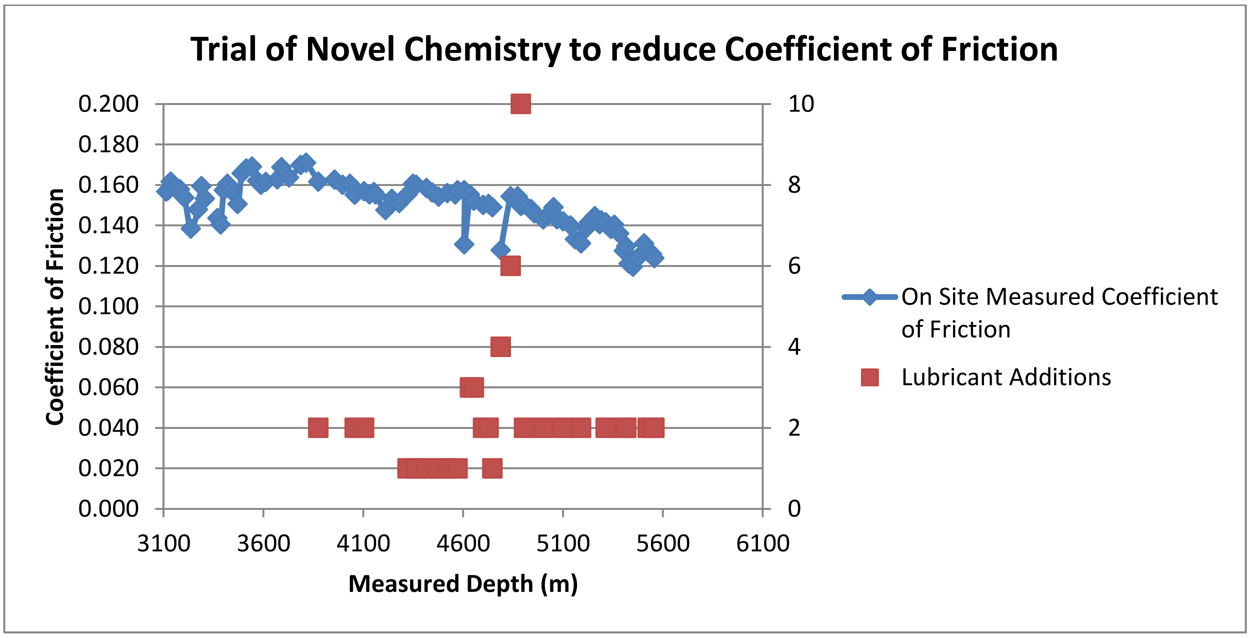


Fig 6: Impact of Novel Lubricant on Lubricity CoF

While naturally lubricious, brine fluids frequently are not compatible with lubricants. The potential pitfall of brine fluids and lubricants is their ability to saponify (or form a soap), as seen in Figure 7. The conditions on a rigsite make the perfect environment for severe issues like “greasing” to occur.

Fig 7: Saponification of Conventional Lubricants in Calcium Chloride Brine

With current drilling programs pushing the boundaries to longer laterals, a lubricant is generally required to maintain torque within the limits of the rig and drillstring. Figure 8 shows the additional depth achieved by the use of lubricants.

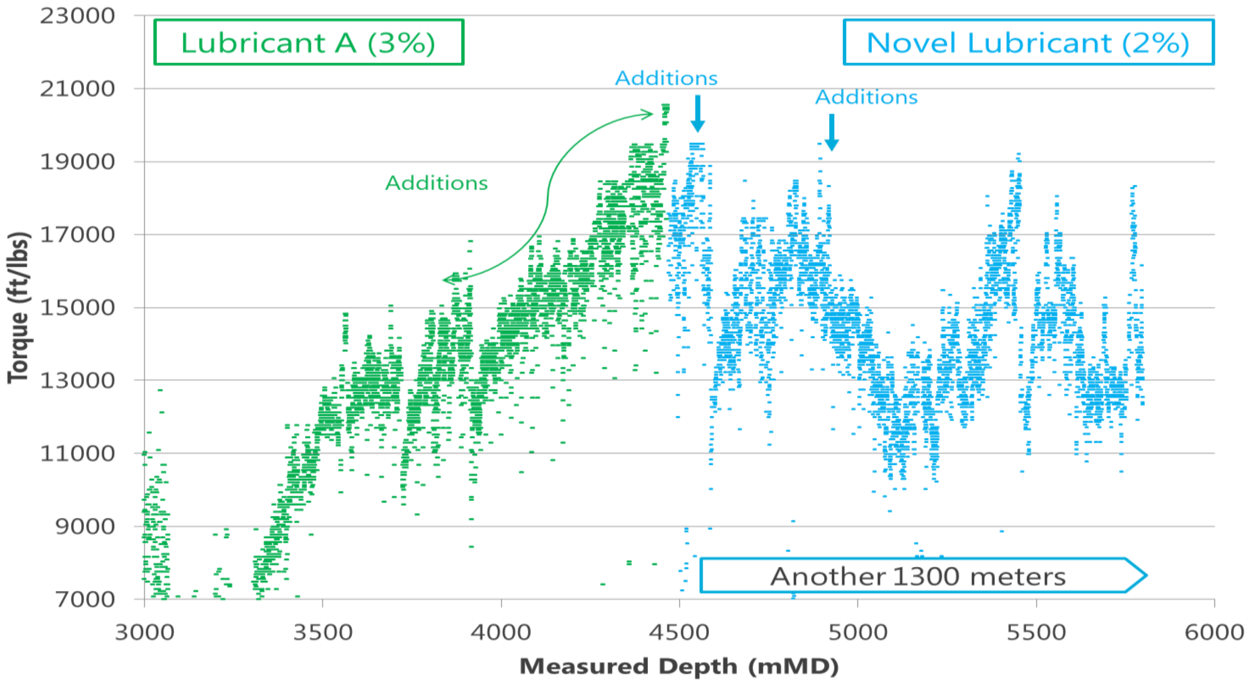


Fig 8: Example of Compatible Novel Chemistry Impact on Rotary Torque in Calcium Chloride Brine

CASE HISTORY

The clear brine drilling fluid system was initially developed for the Western Canadian Basin where hard zones of the Montney traditionally result in extremely low ROP and short bit runs in the Kakwa region. Costly NAFs, weighted with barite, severely limit penetration rates with lateral ROP averaging only 6.5 ft/hr (2.0 m/hr). Water-based potassium formate muds, costly and incompatible with conventional lubricants, inhibit achieving potential lateral length – one solution did not drill fast enough and the other did not drill far enough.

The first attempt at solving both issues was underbalanced managed pressure drilling (MPD) with low-density, low-solids, synthetic olefin-based NAF. This solution allowed the operator to control wellbore pressures with a solids-free fluid. While successful in drilling, this technique added $1 million in well costs and increased complexity leading to potential safety and environmental concerns. These costs and concerns stemmed from the flow of formation fluid into the drilling fluid while drilling under-balanced. The formation fluid incursion included natural gas, low flash point condensate, CO_2 and H_2S. The natural gas incursion required the installation of flare equipment and the H_2S caused additional safety concerns. Condensate disposal added additional waste expense. All these issues led to increased CO_2 emissions and costs.

Another potential solids-free solution, calcium chloride brine, is extremely corrosive. With these brines, Monel drill collars must be replaced every well. However, the long-term impact of corrosion can be far more costly. A corroded pipe or mud motor can lead to downtime while drilling, resulting in additional trips, potential fishing and replacement costs. In a few extreme cases, operators replaced entire sets of drill strings at costs exceeding $500,000.

The engineered solution using the novel chemistry developed for the clear brine Fusion™ system was a promising solution for an operator facing the challenges of the Montney basin. This novel system enabled the operator to reuse their production water, obtain better lubricity than conventional invert emulsion systems, and control problematic corrosion typically associated with saturated brines. Calcium chloride additions replaced barite as the weighting agent without adding solids. The novel chemistry resulted in torque reductions (Figure 9), ROP improvements of 35%, and lateral bit life improved 300%. A synergistic corrosion package mitigated the corrosivity of calcium chloride.

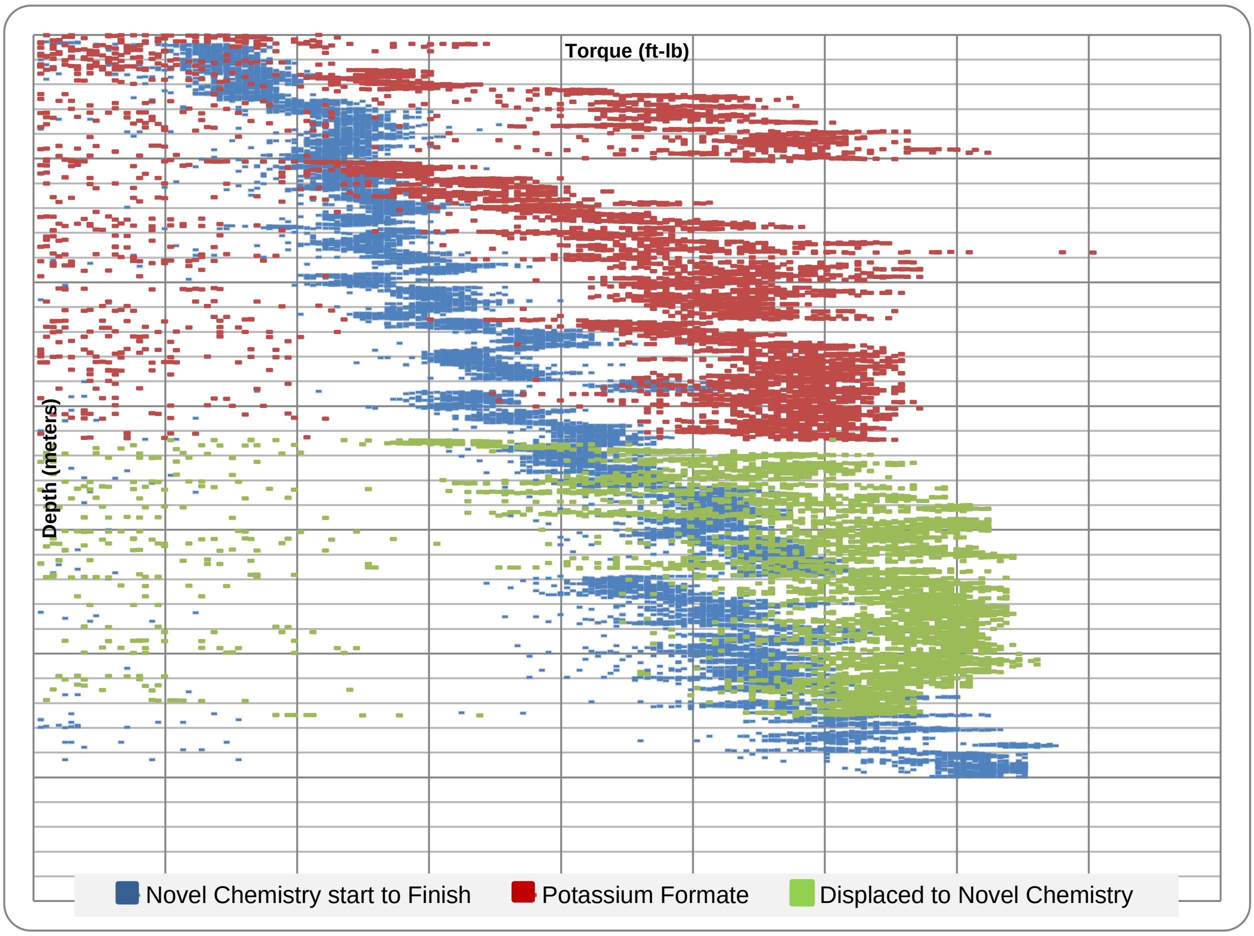


Fig 9: Torque Comparisons between Potassium Formate And Novel Chemistry

As mentioned earlier in the paper, this clear brine system with corrosion control measures, a compatible dewatering flocculent, improved lubricity, and careful monitoring by the drilling fluids engineer has proved successful in 140 wells. The system can be customized to use calcium chloride salt blends to achieve the necessary weight requirements.

In one particular case, the clear brine system resulted in low corrosion rates in some of the harshest conditions, drilling H_2S critical wells as hot as 121°C (250°F). The rate of damage to Monel drill collars has been significantly reduced as compared to the prior to the system, saving the operator $18,000 per well.

Operators value the novel chemistry for additional benefits as well. The system's buoyancy and low-viscosity profile create the optimal fluid for cutting transport in horizontal wellbores. It has better lubricity than invert emulsion systems, with lubricity coefficients of 0.04. The system allows for increasing fluid density while being solids free by using salts in solution. This reduces pump pressures and provides superior bit hydraulics, all while meeting density requirements.

Since inception, the novel chemistry and system has been expanded across other regions. The novel chemical package used is customized to each unique fluid system, which addresses: corrosion, solids removal, and improve lubrication for extended-reach horizontal drilling. In field use, the system is successful in sour critical wells with bottomhole temperatures as high as 266°F (130°C), mud densities as high as 1.6 sg (13.35 lb/gal), and has been used to drill horizontals over 3300 m (11,000 ft).

CONCLUSIONS

- Use of cost-effective solids-free brine drilling fluid systems can result in significant gains in ROP and bit life especially in hard, compacted formations
- Successful corrosion control requires careful monitoring of the brine drilling fluid at the rigsite, as lab corrosion testing is not always representative of field conditions. .
- Process controls play a significant role in corrosion control and maintaining optimal brine properties
- Brines can be engineered with various salts resulting in different fluid properties such as crystallization temperatures, viscosity, inhibition, lubricity and density
- Different brine types can result in product incompatibilities and careful screening and selection of additives relative to fluid types must be considered.

ACKNOWLEDGEMENTS

The authors would like to thank: Newpark Drilling fluids for the opportunity to present the paper; Newpark Drilling Fluids Canada and Pragmatic Drilling Fluids Additives Ltd (a Newpark Company) for the innovations; along with Canadian fluids technicians for their valuable contributions.

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