



Formate Fluids Optimize Production Rate

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Abstract

Formate brines make unique drilling and completion fluids that can add significant value to well construction projects. They do this by:

- Increasing well productivity
- Reducing the risk of NPT incidents
- Improving well integrity and lifetime
- Enabling complex well constructions
- Facilitating access to difficult reserves
- Reducing waste disposal costs
- Reducing waste liability

Formate brines have been in regular use as reservoir drill-in and completion fluids since 1993.

This paper reviews what has been published in the oilfield literature over the past 12 years about well production rates after drilling and/or completing with formate brines. The conclusion of the review is that formate-based fluids significantly reduce formation damage and increase well productivity.

The remarkable field performance record of formate brines in terms of well productivity improvement is explained by reference to the industry's current understanding of formation damage mechanisms. It is questioned whether or not the use of linear core flooding is a valid laboratory test method for predicting the likely impact of formate brines on well productivity.

Introduction

Formate brines are revolutionary fluids that can be used to create solids-free drilling and completion fluids with densities of up to 19.2 lb/gal. At least 400 wells have been drilled and/or completed with formate brines since their introduction in 1993 and they have been the subject of more than 30 SPE papers.

The remarkable properties of the formate brines make them collectively an "enabling technology" that helps operators deliver wells that are optimized in terms of:

- Cost
- Productivity
- Lifetime
- Environmental impact
- Liability

The formates are particularly valued as drilling and completion fluids in challenging operational environments such as:

- HT/HP
- Extreme well configurations (ERD, TTD, CTD)
- Sites of ecological sensitivity

The foundations of the formate brine technology in use today were developed principally in Shell Research by the authors of this paper,¹⁻⁴ building on an invention filed by Clarke-Sturman and Sturla in 1987.⁵ The inventors discovered that the temperature stability of common drilling fluid polymers was increased when they were dissolved in aqueous solutions containing high levels of alkali metal formates. The formates gave Shell the ability to formulate simple water-based drilling and completion fluids for HT/HP well construction operations. As an added bonus, the almost solids-free drilling fluids prepared from formate brines could reduce ECD, eliminate barite sag problems, and reduce the risk of differential sticking.

Shell Research saw that formate-based brines could answer the need for high performance fluids necessary for the implementation of the new drilling and completion techniques that were being introduced in the early-1990s. The new techniques were aimed at creating increasingly extreme well configurations and included long horizontal, extended reach, slim hole, through tubing and coiled tubing drilling. These drilling techniques needed solids-free drilling fluids that could minimize circulating pressure losses and ECD. The formate brines provided the ideal basis for such drilling fluids, with the added advantage that they could also function as completion fluids.

Further laboratory work over the past 15 years has clearly shown that the formate brines in general have very good environmental properties,⁶ stabilize shales,⁷ inhibit hydrate formation, minimize corrosion, reduce well control problems and minimize formation damage. In short, they appear to be the ideal universal drilling and completion fluids that the oil industry needs in the 21st century.

Shell carried out the first field trial of sodium formate brine in a coiled-tubing drilling job in The Netherlands in 1993. This was followed less than a year later by the first field trial of potassium formate brine in a reservoir drill-in operation in Norway. Since then sodium and potassium formate brines have been successfully used as drilling, completion, packer and gravel packing fluids in at least 400 wells in 15 countries around the world.

The final breakthrough in the development of formate brine technology was when cesium formate became commercially available in 1998. In the past 6 years cesium formate brine has been used in 60 HT/HP drilling and completion operations in the North Sea and the Gulf of Mexico.

In recent years the refinement and further development of formate technology has reached a new level of intensity, resulting in inventions such as shale stabilization with low concentration formate brines⁸⁻¹⁰ and formate-based drilling fluids stable up to 400°F.¹¹ In addition, formate brines have been passing the most severe corrosion tests.¹²⁻¹³

As hydrocarbons become more difficult and expensive to access, it seems inevitable that the oil industry will place more emphasis on selecting drill-in and completion fluids that will minimize formation damage and optimize production without the need for further intervention. The purpose of this paper is to look at how formate brines fit the profile of non-damaging fluids, first examining how they score from a theoretical perspective and then reviewing the information available in the oilfield literature on the productivity of wells drilled and/or completed with formate brines.

How Formate Brines Reduce Formation Damage

Formate brines are the simple sodium, potassium, and cesium salts of formic acid. Field use has demonstrated time and time again that drilling and completion fluids based on formate brines are inherently non-damaging to oil and gas reservoirs. The authors are not aware of any instances where formation damage has been reported from the field as a consequence of using formate brines. In fact in nearly all reported field case histories of formate use in drilling or completion, the well production rates have been significantly higher than expected.

The apparent absence of formation damage in reservoirs contacted by formate-based fluids indicates that the formate formulations cause minimal permanent changes in the relative permeability of the reservoir to hydrocarbons. To achieve this effect the formate brines and additives must effectively leave the rock matrix, the porosity, the pore-lining minerals and the residual reservoir fluids in a near-native condition following their removal from the near-wellbore area as a result of production. Alternatively, if they do cause a degree of formation damage it must be temporary or they must simultaneously stimulate the reservoir in such a way that the overall measured skin is relatively low.

In order to understand how formates can have this effect it is instructive to look at the known causes of formation damage. Bennion and Thomas¹⁴ present the following list of formation damage mechanisms, which are common to both horizontal and vertical wells:

Fluid-Fluid Incompatibilities – the adverse

*reactions between invading drilling or completion fluid filtrates and the in-situ fluids (oil or formation brine) to form scales, insoluble precipitates, asphaltic sludges, or stable emulsions.*¹⁴

Formate brines contain nothing that can cause adverse reactions with formation fluids. They are free from surfactants and multivalent ions, making it impossible for them to create emulsions or scales. It is occasionally possible to create precipitates in laboratory experiments by mixing concentrated formate brine with some highly saline reservoir waters at unrealistic ratios but it is important to note that:

- a) The authors are not aware of any such interactions having been reported from realistic core flooding tests at reservoir conditions.
- b) Any precipitates formed are not scales – *i.e.* they are inherently water-soluble (*e.g.* KCl).

By contrast, Morgenthaler¹⁵ showed in his experimental work that unfavorable interactions with formation waters are a major cause of formation damage with conventional heavy brines based on halides. He found that brines formulated with CaBr₂ and/or CaCl₂ can cause precipitation of scaling calcium salts.

Rock-fluid incompatibilities – the adverse reactions between invading water-based filtrates and sensitive pore-lining clays leading to fines mobilization and associated reductions in near wellbore permeability.¹⁴

Pore-lining smectite clays can swell and disintegrate when contacted by a filtrate fluid that has a **lower salinity** than the native reservoir brine. As formate brines usually contain inhibitors of clay swelling (K and Cs ions) and are rarely used at salinities lower than the formation water, it seems unlikely that they could cause this type of formation damage.

Deflocculation of certain types of pore-lining clays is known to be another cause of formation damage in low salinity brines.¹⁶ When low salinity brines invade the reservoir, the pore-lining clays undergo a process of separation and movement through the pore system, leading to bridging and plugging of pore throats.

In 1997 Bishop¹⁷ found that certain **high salinity** brines could cause formation damage by flocculating kaolinite-type clays. Bishop investigated the difference between saturated NaCl brine and potassium formate brine at the same density. He found that the NaCl brine caused severe formation damage in his core flooding tests (74% reduction in return permeability), whilst in the potassium formate brine this was significantly reduced (15% reduction in return permeability). Whether kaolinite flocculation will occur or not depends on the critical concentration of electrolyte required for flocculation, *i.e.* the flocculation value. The flocculation value is known to be lower for brines containing divalent ions than for those based on monovalent ions, something that favors the formates over alternative high density halide brines (CaCl₂, CaBr₂, ZnBr₂).

Solids Invasion – Penetration and blocking of the reservoir pore throats by solids suspended in drilling and completion fluids. The permanent lodging of solids in the formation pore throats can severely reduce permeability.¹⁴

Formate brines can provide the full density requirements of a drilling and completion fluid, and so the use of intractable solid weighting agents such as barite can be avoided. If solid particles are required in the brine as filtercake or bridging agents, they can be screened and selected on their ability to minimize formation damage potential. When solids are required as filtercake material in formate-based drilling fluids, it is common practice to use sized calcium carbonate particles. Calcium carbonate used as bridging material has the advantage that it can be sized to fit the pore throat, and it is acid soluble.

There have been cases (e.g. in Alaska) where formate brines have been successfully used as entirely solids-free drill-in fluids, relying on viscosifying additives to provide fluid-loss control. In contrast to other high density brines (CaCl₂, CaBr₂, ZnBr₂), formate brines have the advantage of being compatible with polymers to high temperature, allowing the formulation of solids-free drill-in fluids for all well conditions.

Solids invasion is a common source of formation damage in conventional drill-in fluids containing solid weighting agents such as barite. Indeed, it could be argued that the practice of adding barite to drilling fluids from the 1920s onwards has had a negative effect on the efficiency of hydrocarbon recovery over the past 80 years, requiring the need to develop a range of well stimulation techniques to circumvent the formation damage caused by the barite.

Phase trapping/blocking - The invasion and permanent entrapment of oil or water filtrates in the near wellbore region. These trapped fluids can substantially reduce the relative permeability of the reservoir to hydrocarbons.¹⁴

Comparisons of logging data obtained during (LWD) and after (wireline) drilling with formate brines show that the formate filtrates appear to disappear (possibly via gravity drainage or slumping) quite quickly from the near wellbore area. Unfortunately this vanishing trick cannot be simulated in laboratory-scale linear core flooding tests, with the result that some laboratory tests can show a 30-40% reduction in relative permeability to hydrocarbons due to the formate brine phase occupying some part of the core porosity behind residual filtercake deposits. In the authors' experience this laboratory artifact is the leading reason for formate brines being occasionally rejected for use in drill-in jobs after being screened by core-flood testing.

Chemical adsorption/wettability alteration – The alteration of the reservoir's permeability to hydrocarbons

as a result of changes in the wettability of the pore walls and throat surfaces.¹⁴

Conventional drilling muds and completion fluids may contain surface-active chemicals (e.g. oil-wetting agents and corrosion inhibitors) that have been deliberately added to improve fluid performance and/or mitigate performance deficiencies. The absorption of these chemicals onto the reservoir rock can change wettability and so alter the permeability of the rock to hydrocarbons.

Formate-based fluids have no surface activity, and are free from surface-active agents, so they should not cause any changes in the wettability of reservoir rocks.

Biological activity – The reduction of formation permeability to hydrocarbons as a result of microbial activity promoted by drilling or completion operations.¹⁴

Drilling and completion operations can introduce new micro-organisms into reservoirs, or stimulate the activity of the native micro-organisms that are already present in the reservoir. Conventional drilling fluids contain nutrients that encourage the growth of micro-organisms.

Formate brines have a low water activity and are naturally biostatic or biocidal at densities higher than 1.05 sg (8.76 lb/gal). For this reason they do not biodegrade or support any form of microbial growth, either at the surface or downhole. Reservoir waters are rich in formates,¹⁸ indicating that the indigenous micro-organisms are limited (by the lack of another essential nutrient) in their ability to use formates as their carbon and energy source.

Laboratory Core-Flood Testing

Although there is still no generally accepted or approved laboratory screening method for evaluating the compatibility between drilling and completion fluids and reservoirs, it is common practice to use core-flood testing (also known as return permeability testing).¹⁹

The more sophisticated laboratories use reconditioned reservoir core plugs and simulated reservoir fluids and gases. They also conduct the tests at close to reservoir pressure and temperature for realistic time periods. The relative permeability of the reconditioned plug to a specific hydrocarbon phase is measured after a simulated drawdown to remove the filtrate and filtercake residues.

As the original plug permeabilities are measured at residual water saturation, some laboratories return the plugs to residual water saturation before measuring the return permeability. This allows some meaningful comparison between the relative permeability of the plug before and after exposure to the test fluid.

Byrne, *et al.*²⁰ published a review of more than 40 core flooding tests carried out by Corex Ltd. on formate brines over the period 1996-2001 for a variety of operators. The tests had been conducted on many

different reservoir cores and some of the formation waters were highly saline with salt concentrations greater than 200,000 ppm. Although less conclusive for oil reservoirs than gas reservoirs, this study concluded that the formates performed as well as, if not better than any conventional oil or water-based fluids, and there was no evidence of any formate-specific damage mechanisms.

This was a positive outcome, but there is evidence that the performance of formates in the field may be better than the performance predicted by reservoir-conditions core-flood tests. One possible explanation for this could be that the laboratory tests are typically performed in linear test cells, which tend to promote a high level filtrate invasion from brine-based fluids, whilst in the field the fluid flow away from the wellbore face is radial.

Powell, *et al.*²¹⁻²² demonstrated the ability of visco-elastic fluids to control seepage losses and depth of invasion into permeable sandstone matrix according to Darcy's law. As the fluid, or filtrate, migrates radially away from the well bore into the formation, its velocity and shear rate is inversely proportional to the distance from the wellbore. The xanthan viscosified filtrates of brine-based drill-in fluids exhibit a true yield stress, which in a radial flow will limit the depth of filtrate movement away from the well bore.

The fact that just about all reservoir condition core-flood testing is conducted under linear flow conditions could disfavor low-solids, xanthan/brine-based fluids such as formates when they are compared to conventional solids-laden oil and water-based muds.

Published Field Cases

Many hundreds of oil and gas reservoirs have been drilled or completed with formates over the past 11 years. Those field case histories that have been published in the oilfield literature to date indicate that well production rates after drilling and/or completing with formates are considerably higher than expectations:

Statoil, Gullfaks Field, Offshore Norway, 1994²³

A potassium formate drilling fluid weighted with manganese tetraoxide was used for drilling and completing the reservoir section of Statoil's Gullfaks well C-18. This was the first ever field trial of potassium formate brine. The formate-based fluid system was selected because it allowed Statoil to drill and complete the unconsolidated, pressure sensitive reservoir with the same fluid. A fluid with minimal solids content was required. As cesium formate was not commercially available at that time, manganese tetraoxide was selected as a weighting material to achieve the required fluid density (1.70 g/cm³; 14.2 lb/gal) and at the same time facilitate filtercake removal through the screens (due to its small particle diameter of 0.5 micron).

The reservoir matrix contained a significant

percentage of reactive clays (some with kaolinites and illites, and some with smectites as the dominating species). The presence of these clays required the drilling fluid to be inhibitive in order to prevent swelling and/or dispersion of clays, which could lead to impairment of the reservoir permeability.

The reservoir consisted of relatively shallow, highly porous, poorly consolidated sands, with permeability varying from 250 mDarcy to 10 Darcy. A special feature of the reservoir was the small margin between the fracture pressure and the pore pressure, necessitating the use of a drilling fluid with low ECD. Traditionally the Gullfaks wells had been completed with liners and selective perforating. Due to rate limitations caused by sand production and water break-through, the completion strategy was changed to cased-hole gravel packing in 1989. Previous field experience with this completion technique was not satisfactory due to loss of productivity, and openhole completion was seen as a favorable completion method for Gullfaks. For C-18 an openhole completion with pre-packed screens was chosen.

The fluid system selected was a near-saturated potassium formate brine containing polymeric additives for viscosity and fluid-loss control and a small quantity of manganese tetraoxide to achieve the required mud weight. Some sized salt was added to control the particle-size distribution. A solution of potassium formate containing 10% by weight citric acid was found to be the most effective breaker fluid, showing rapid degradation and particle dispersion.

The hole was completely stable during drilling and tripping. Shale was encountered at up to 40% by volume. The shale cuttings were soft to firm and more discrete than had previously been observed with water-based muds. The well was brought on production three weeks after installation of the openhole completion equipment. The well was beamed up slowly to let solids flow through the screen. The initial production rate was as expected with no water production, and the PI was as expected at 500 Sm³/day/bar. This result indicated a good removal of the filtercake, and vindicated the choice of breaker fluid system used to dissolve and disperse the filter cake.

Oriente, Ecuador, 1997²⁴

Several horizontal wells were drilled with a sodium formate drill-in fluid in the Amazon rainforest. The fluid was chosen due to its non-damaging and environmental characteristics. Success with the first well was necessary to prove that the technology was appropriate for future horizontal drilling.

The well was drilled without any hole problems. Connections and short trips required no extra circulation time, and fill was never observed. There was no excess torque and drag during connections and trips, and there was no problem in getting weight to the bit and achieving

excellent penetration rate. The calcium carbonate filtercake was cleaned up with a breaker fluid containing lithium hypochlorite that was allowed to soak for three hours.

The horizontal section was drilled in 30% of the AFE time planned. The well was tested and brought onto production with zero skin damage, a productivity index of 14 and a production volume of 13,000 bbl/day. These results far exceeded the production from an offset well drilled in the same formation by another operator using a different mud system.

NAM, Offshore Netherlands, 1997²⁵⁻²⁶

The development well K14-FB 102 was completed as a dual lateral to optimize production capacity and reservoir drainage from a tight Rotliegend sandstone in an offshore gas play in the Dutch sector of the North Sea. The two 5 $\frac{7}{8}$ -in. horizontal production intervals were drilled and completed open hole using a sodium formate drill-in fluid. Sodium formate was chosen in order to maximize production from an area of the field with poor reservoir quality.

A previous well, K14-8, had been drilled, completed, and tested in 1979 in the same area of the field. Despite being perforated under drawdown conditions, this well, which was drilled with a low-toxicity oil-based mud followed by mud-acid stimulation, failed to produce at commercial gas rates.

For K14-FB 102, the fluid was formulated with sodium formate as the base fluid, calcium carbonate as the bridging agent, purified xanthan biopolymer as the rheology modifier, and a modified starch for fluid-loss control. The system was rheologically engineered for the targeted interval with, minimum solids content, and designed around the desired LSRV measured at low shear rate for hole cleaning, overall drilling performance, and minimizing filtrate invasion. The use of a sodium formate drill-in fluid instead of mineral oil-based fluid allowed for beneficial modifications to the standard drilling practice with positive results:

- It exhibited superior hole-cleaning qualities throughout the entire interval and no significant drag was observed during drilling. It eliminated the need for pills to assist with hole cleaning.
- Flow rates could be increased from typical 195-250 gal/min to 290 gal/min because of the reduced frictional pressure losses of the formate system. A pressure reduction of 33% was achieved.
- It reduced the need for backreaming out of the hole for hole cleaning.
- It achieved faster than expected penetration rates because increased flow rates enhanced turbine performance. As a result of the high ROP, a 35% reduction in total reservoir drilling time was achieved.

The well was completed, one leg barefoot, and one with a pre-drilled liner (PDL), and lifted into production using nitrogen pumped through coiled tubing into the PDL leg. A 1.27-sg (10.6-lb/gal) sodium/potassium formate brine was used as the completion fluid. No stimulation or remedial work was applied. The well exhibited a "self-cleaning" behavior, indicating that the planned filtercake lift-off approach had been successful. The resulting production capacity was 40% above expectation and a near-zero mechanical skin indicated that the well had been completed with a minimal residual drilling induced damage. The increase in production compared to expectation was concluded to be a combined effect of the extra lateral that was drilled and the low impairment of the sodium formate drill-in fluid.

An MPLT log was run to determine the effectiveness of the cleanup, and the extent to which varying permeability zones were contributing. Significant contribution was seen from the original hole. This confirmed the well's 'self cleaning' attributes as a result of the drill-in fluid and filtercake design. The pressure build-up data yielded a near-zero skin for the well. The low total skin value indicates that the reservoir interval was completed with minimal residual drilling-induced damage.

BP, Harding Field, Offshore UK, 1999²⁷

A high-angle, openhole, gravel-pack well was drilled with a potassium formate drill-in fluid. The reservoir consisted of sand/shale sequences with a net-to-gross of approximately 60%. The intra-reservoir shale comprised layers varying in thickness from several meters to less than a millimeter. It also contained a high level of reactive smectite clay (80% of the clay content). The individual sand bodies comprised clean, well sorted, 3-4 Darcy unconsolidated sands.

The potassium/sodium formate drill-in fluid was chosen because of its ability to stabilize these highly reactive intra-reservoir clays, as well as its ability to deliver a gauge hole, give minimal formation damage, form an easily removable filtercake, and give a minimal screen plugging potential. The fluid also had to present no handling and operational problems with regard to HSE impact.

Laboratory work was part of the selection process; cage dispersion tests on reservoir shale gave greater recoveries in the presence of formate brine, compared with conventional sodium chloride or sodium/potassium chloride brines with glycol added. The drilling fluid formulation was simple, consisting of potassium/sodium formate brine, 4-lb/bbl biopolymer viscosifier, 5-lb/bbl modified starch for fluid-loss control, and sized calcium carbonate as bridging agent.

The reservoir section was drilled without any problems, and the gravel pack placed was placed with a Viscoelastic Surfactant (VES) carrier fluid based on 5% sodium chloride. An enzyme-based breaker fluid was

used to remove the filtercake. The well was cleaned up very rapidly.

BP could not gauge the exact magnitude of the mechanical skin due to the uncertainty of the estimate of the formation kv/kh. Nevertheless, BP concluded that the operation was a complete success based on the excellent well performance data (IPR vs. TPR).

ExxonMobil. HTHP Gas Fields, Germany, 1996-2000²⁸

ExxonMobil has used formate-based reservoir drilling and completion fluids in more than 15 high-temperature gas wells in Northern Germany. The performance of these fluids was reviewed in 2000.²⁸

Formate brines were chosen in an attempt to eliminate the drilling problems that had occurred in previous wells. The problems encountered with conventional water-based polymer mud included inadequate solids suspension, poor solids transport, stuck pipe, and tight holes. ExxonMobil's migration to formate-based fluids eliminated most of their problems and brought well construction costs under control.

The drilling fluids were formulated using sodium formate, potassium formate, or a blend of the two. Biopolymers were added for viscosity control, fluid-loss agents, and sized calcium carbonate (1-3%) for pore bridging. Laboratory core flooding testing was conducted to assess the potential for formation damage. A sodium formate-based fluid system was compared to an oil-based drilling fluid. Core permeability to gas was measured before and after a mechanical clean-up with a jetting tool. The results indicated a significant increase in return permeability with the formate-based fluid.

The formate brines were used in the 8¾-in. holes drilled through the pay zone with the emphasis on hole cleaning, minimizing formation damage, and optimal hydraulics. The maximum fluid density was 12.9 lb/gal (1.55 sg). The majority of wells were drilled and completed in the reservoir section without any borehole or fluid-related problems. There were no sticking problems, no cuttings beds encountered, and the torque and drag was immediately reduced after displacing to formate mud. A number of wells encountered a considerable amount of salt formation.

The total fluid cost and maintenance cost were significantly reduced in the overall project. Other benefits attributed to the formate-based reservoir drilling fluid included:

- 25% lower pump pressure
- 25% increased ROP
- 100% success rate in running production liner

Once the wells had reached TD, the used drilling fluid was processed through normal solids-control equipment to remove the majority of bridging agents and drill solids. The processed fluid was then used as a completion fluid during the completion phase. The wells were put on

production with a typical production rate 35% higher than expected. (Or higher than previous offset wells)

Western Canada, 1999-2004⁸⁻¹⁰

Over 300 wells have been drilled in Western Canada over the past 5 years with a low concentration potassium formate drilling fluid. Low concentration potassium formate brine has been found to stabilize troublesome shales (Blackstone, Fernie, and Fort Simpson) in Alberta and British Columbia. The use of this shale stabilizing fluid, even in small amounts, not only has greatly improved drilling performance by reducing trouble time and eliminating stuck pipe, it has produced gauge holes and improved well production.

Statoil, Huldra Field, Offshore Norway, 2001²⁹

Huldra is a gas condensate field in the Norwegian sector of North Sea operated by Statoil ASA. During drilling and completion of this field, high temperature and pressure conditions were encountered in the reservoir section (675 bar, 150°C). The difference between the pore pressure and fracture pressure gradient was small in the reservoir. The Huldra gas stream contained 3-4% CO₂ and 9-14 ppm H₂S. The wells were drilled at a 45° - 55° inclination through the reservoir and completed with 300-micron single-wire-wrapped screens.

When the first production well was drilled in this field, with oil-based mud, a severe well kick was experienced while running the sand screens. The main reason for the kick was a loss of drilling-fluid density due to barite sag during the wiper trip. A cesium formate-based drill-in fluid was therefore selected for the following wells primarily for well control. The cesium formate fluid went through thorough evaluation and testing. The main benefits identified with the cesium/potassium formate brine compared with the oil-based fluid were: no sag potential, low ECD, less screen plugging risk, (low solids), use of solids that could be acidized (CaCO₃), low gas solubility, environmentally friendly, and quick thermal stabilization during flow checks.

Return permeability testing was carried out and the predicted formation damage was found to be acceptable. No compatibility problems were expected with formation water. The drilling operation itself was characterized by good hole stability, low ECD and good hole cleaning. The excellent rheology and thermal stability of the drilling fluid led to rig-time savings from faster tripping speeds, faster casing-running speeds, less mud conditioning and fewer wiper trips. The ROP was also good. The drilling fluid was circulated over a combination of 250, 300, and 400-mesh shaker screens before the completion screens were run. After running the screens, the drilling fluid was replaced with filtered potassium/cesium formate completion brine.

Statoil report that the 6 Huldra wells drilled and completed with formate brines are each producing with excellent average Productivity indices of around 1.9

million scf/day/psi. In fact plateau production rates were achieved from the first three wells of the six well project. The Huldra project manager is quoted as saying: "For the specific conditions of the Huldra field there is no realistic fluid alternative for successfully drilling and completing the wells".

Shell, Brigantine Field, Offshore UK, 2000-2001³⁰

Between October 2000 and March 2001, Shell drilled three horizontal wells in the North Sea Brigantine field and completed them using ESS (Expandable Sand Screen) technology. For these ESS operations, a mud system was required that performed the following functions / properties:

- Provides a gauge hole.
- Maintains borehole stability during drilling and ESS running / expanding.
- Aids good hole cleaning.
- Exhibits good fluid-loss control by formation of an external filter cake on the wellbore.
- Maintains hydrostatic well control.
- Reduces friction while running and expanding the ESS.
- Flows through ESS during expansion without blocking 230-micron screens.
- Is non-damaging to the formation, sand screens and the environment.

The mud systems considered were: potassium chloride polymer, sodium chloride polymer, sodium formate, LTOBM, and sodium / potassium formate. The LTOBM was rejected because it did not pass the flow test through the 230-micron screen. A formate system was preferred over the chloride systems due to the beneficial shale-stabilizing properties that had been demonstrated during previous use of formates by Shell. This, combined with the fact that much of the weight was provided by the base brine, made the formate system the preferred alternative.

The formate fluid was prepared with a calcium carbonate particle-size distribution specifically designed not to plug the 230-micron screens. The testing of this system resulted in return permeability of 70 – 90% as compared to 15 – 55% for LTOBM.

The three wells were drilled and completed 32 days ahead of plan, achieving initial gas production rates that were 23% - 40% higher than expectations.

Norsk Hydro, Visund Field, Offshore Norway, 2002³¹

The Visund field is a subsea development offshore Norway. Norsk Hydro ASA put the field on production in 1999. In 2003, the field was taken over by Statoil ASA.

Visund has proven to be a highly complicated reservoir with a complex geology. Permeabilities were ranging from 300 to 3,000 mD. The wells were drilled and completed with long horizontal sections to reach several targets with one well. The wells have relatively

high pressures and temperatures (440 bar, 115°C). Sand prevention was obtained by oriented perforating in the direction of maximum stress.

The drilling time of these wells was long, which resulted in a long exposure of high overbalanced drilling fluids to the formation. This produced a deep mud filtrate invasion zone around the wellbore. The first wells were perforated with standard oriented perforating system with zinc-cased charges in a 1.65 g/cm³ (13.8 lb/gal) CaCl₂/CaBr₂ perforating kill fluid. When the wells were put on stream, the chokes were plugged by large chunks of zinc oxide.

These wells showed significantly lower productivities than should be expected from the reservoir characteristics. A study was carried out in order to evaluate the problems. Several areas of improvement were identified, including the fluid system. The CaCl₂/CaBr₂ brine formulation proved to be unstable and viscous, making it difficult to achieve a good cleanup. It was also found to be incompatible with the formation water.

Further laboratory studies showed that reactions between zinc powder by-products from the charges and CaCl₂/CaBr₂ brine caused the kill pill to lose its fluid-loss-control properties, which then resulted in formation damage. The idea of replacing the brine with oil-based mud was abandoned because of high particle content. A new perforating system was developed, which among other changes replaced the zinc charges. The CaCl₂/CaBr₂ perforation fluid was replaced with potassium formate brine containing sized calcium carbonate particles for fluid-loss control.

Five new oil-producing wells were drilled and perforated with the new system under dynamic underbalanced conditions. Productivity indexes for the previous wells were in the range of 60-90 Sm³/day/bar, whilst the new wells were ranging from 300 to 900 Sm³/day/bar. It was concluded that the combined effect of the changes to the perforating system, the dynamic underbalance, and the new fluid, had resulted in a 3 - to 6 fold increase in productivity. The formate mud system is believed to be one of the main contributors to the improved well productivity.

BP, Devenick Field, Offshore UK, 2001³²

A 1.68-sg (14.0-lb/gal) potassium/cesium formate reservoir drilling fluid was chosen by BP to drill a horizontal HPHT appraisal / development well in the Devenick field. The low-permeability sandstone matrix of the Devenick reservoir is very hard and is deemed to be a significant challenge to drill and complete. A long horizontal wellbore was required in order to yield sufficient productivity and to penetrate the different reservoir segments.

Formate brine was believed to offer several advantages over an OBM, and was primarily selected on grounds of formation damage characteristics, low ECD

and potential for improving ROP and well control. Return permeability testing on Devenick reservoir core samples indicated that the potassium/cesium formate brine would cause minimal formation damage compared to an oil-based mud, and this was considered important due to the openhole completion selected.

Also, hydraulic modeling suggested that the formate brine would reduce the ECD by approximately 300 psi over an OBM, giving wider safety margins between pore and fracture pressure. Equally important for this well was the fact that the ECD reduction would reduce the apparent rock strength seen by the bit by 23%, arguably yielding a similar improvement in ROP.

Other horizontal HPHT wells drilled previously by BP had suffered well-control problems, and the use of formate brine was believed to offer a much-reduced well-control risk over an OBM fluid. Elimination of barite sag and no diffusion of methane into the horizontal wellbore were the main reasons for this.

The reported results from the well were promising, with good production and zero skin. Operationally the BP project team felt that the well would have been difficult to deliver without the use of potassium/cesium formate brine. In addition to the advantages discussed above, the team felt that the fluid brought a number of HSE advantages such as elimination of the need for skip & ship, no well-control incidents and better integration between drilling and completion. The advantages with the fluid far outweighed the disadvantages, which were fluid cost and increased complexity in the reservoir log analysis.

Unpublished Field Cases

There are many cases of formate brine applications in drilling and completion that have not been published or made available in the public domain. These include on-going operations in Alaska, Saudi Aramco, Canada, and Norway.

One recent success has been the completion of an HTHP well in Marathon's Braemar field in the UK North Sea. The well was re-perforated in an 1.86-sg (15.5-lb/gal) potassium/cesium formate brine and, to quote the Project Drilling Superintendent: "the well is flowing significantly above expectation, proving that no formation damage occurred". The expected production rate was 40-50 million scf/day but the well is actually flowing at 79 million scf/day.

It is interesting to note that two laboratory core flooding tests with the potassium/cesium formate prior to the completion gave results indicating that the brine might cause either a 60% reduction in permeability or a 5% reduction in permeability. The second test results, in conjunction with the field experiences of other operators, provided Marathon with the confidence to proceed with using potassium/cesium formate brine as their perforating fluid.

Sodium and potassium formate brines have been used as drill-in and completion fluids in Kuparuk, Alaska for a few years now. These are horizontal sidetracks drilled with coiled tubing, and completed with slotted liners. The formate fluids replaced monovalent halide brines (KCl, NaCl, NaBr) which could not provide the required fluid density. The operator has clear evidence in the higher density range (>1.17 sg, >9.8 lb/gal) that formates are causing less formation damage than the previously used halide brines.

Potassium formate brine is currently being used as completion fluid in a series of wells offshore Newfoundland. The wells are being drilled with oil-based mud. The selection of potassium formate as completion fluid was made based on laboratory core-flood tests that indicated the probability of less formation damage with formate brine than with the other fluids that were tested.

Conclusions

The amount of information available about field experiences with formates in the oilfield literature is still limited, but there is clear evidence from what has been published over the past 12 years that formate-based drill-in and completion fluids can significantly reduce formation damage and increase well productivity.

The same field information base reviewed in this paper shows unequivocally that formate brines can add further significant value to well construction projects by:

- Reducing the risk of NPT incidents
- Improving well integrity and lifetime
- Enabling complex well constructions
- Facilitating access to difficult reserves
- Reducing waste disposal costs
- Reducing waste liability

Linear core-flood testing is widely used as the preferred screening tool to select the least-damaging drilling and completion fluids. However, experience to date suggests that core-flood testing is still not a precise predictive tool for screening brine-based fluids, and the productivity-improving characteristics of the formates can only be reliably assessed by field use.

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Nomenclature

<i>ECD</i>	=	<i>Equivalent Circulating Density</i>
<i>ESS</i>	=	<i>Expandable Sand Screen</i>
<i>LSRV</i>	=	<i>Low Shear Rate Viscosity</i>
<i>LTOBM</i>	=	<i>Low Toxicity Oil-Based Mud</i>
<i>MPLT</i>	=	<i>Memory Production Logging Tool</i>
<i>PDL</i>	=	<i>Pre-Drilled Liner</i>
<i>ROP</i>	=	<i>Drilling Rate of Penetration</i>
<i>VES</i>	=	<i>Viscoelastic Surfactant</i>

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