DRILLING FLUIDS TECHNOLOGY

DRILLING SALT FORMATION

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Salt drilling

Salt formations are encountered in many oil-producing regions of the world. These salt zones can be in a variety of forms; salt domes, massive beds and sheets or lenses. The chemistry of salts can very significantly even in a single bed, from pure sodium chloride to very complex blends of mixed chloride. The main salt types are:

Halite ($NaCl$)

Sylvite (KCl)

Bichofite ($MgCl_2.6H_2O$)

Carnalite ($KMgCl_3.6H_2O$)

Polyhalite ($K_2MgCa_2(SO_4)_4.2H_2O$)

Tachydrite ($CaCl_2.MgCl_2.12H_2O$)

There are also physical or mechanical differences in salt structures.

Salt is impermeable and deformable. Salt domes and to a lesser extend massive beds, are plastic and can readily deform, depending on the temperature and overburden pressure. Some salts are mobile while others are fractured. Salt formations often have other evaporate minerals such as anhydrite, gypsum, kieserite, limestone or dolomite associated with their structure.

Although drilling salt may appear to be simple, salt behavior can be complex. Drilling fluids saturated with drill cuttings from these mixed salt formations have a particularly complex chemistry which can be difficult to understand and control.

There are several problems that can occur while drilling salt section.

- Dissolution of salt resulting in hole enlargement
- Due to chemical variation
- Due to subsaturation
- Due chemical variation
- Due to temperature fluctuations
- Deformation of salt, reducing the hole diameter and leading to stuck pipe.
- Well control-flow of hydrocarbons, CO_2, H_2S or brine liquids and lost circulation.
- Recrystallization of salt and other precipitates, stripping emulsifiers and wetting agents from oil – and synthetic – base muds, resulting in water wet solids.

Drilling fluid option

Water base mud

1. Saturated – saltwater – base system

Water – base drilling fluids should be designed to be compatible with the salt to drill. This can be difficult for mixed solutions, like carnalite, where non-standard oilfield salts, like magnesium chloride, would be required and may not be readily available. It is important to have the system completely saturated when the salt is first penetrated to prevent excessive hole enlargement in the top of the salt. While the salt is being drilled, the system will stay mostly saturated. These saturated are different from other water-base mud in that they really mainly on polymers, not clay to obtain good properties. Because when prehydrated fresh water bentonite slurry is add to a saturated fluid, the clays will flocculate-generated viscosity will diminish with time. Polymers like XCD or PAC R will yield to provide low shear rate viscosity, critical for suspension.

Fluid-loss control can obtained with STARCH or PAC LV, and it should be noted that the performance of many polymers is reduced in the presence of high-hardness brines, particularly anionic polymers such as PACs .

2. Under saturated water-base system.

In some areas, the use of under saturated salt system has been perfected so that the rate of salt dissolution is matched to the rate or salt creep. One difficulty with this approach is that for long salt sections, the rate of creep can vary widely from top to bottom, and the mud in the annulus may become saturated at the bit (from salt cutting) so that it cannot dissolve any more salt as it circulates in the annulus. This method should only practice on offset wells.

3. Invert-emulsion system.

Oil- or synthetic base muds can also be used to drill salt section. The oil wetting ability and lower water content reduce salt dissolution and control hole enlargement, but salts will still dissolve into the water phase, keeping it saturated. There are several reactions that can occur due to the excess lime concentration and high chlorides. The reactions can be unpredictable and very depending on salt composition and temperature. These systems can be formulated with a variety of salts in the water phase as an alternative of calcium chloride. Sodium chloride and magnesium chloride internal phase systems have been used successfully.

Although oil base systems are preferred for drilling salts, can actually be more detrimental to invert emulsion muds than to water base muds. The most damaging aspects are recrystallization of salt and magnesium hydroxide precipitation. Both reactions produce extremely fine particles with a tremendous surface area. This can lead to a rapid depletion of emulsifiers and oil-wetting agents. Consumption of the emulsifiers and wetting agents can result in water-wetting of solids.

Water wetting is most obvious by a grainy, not glossy appearance and by removal of water wet solids (Barite) at the shale shaker. Several tests can be used to anticipate a water-wetting problem, including weight-up test and glass jar test.

Treatments to avoid mud instability in oil-base muds include adding water to dissolve the precipitates, and significantly increased treatments of emulsifier and wetting agent. Complete saturation should be avoided; calcium chloride this is roughly 38%wt. the addition of water is especially important for high-temperatures cause the evaporation of water leading to saturation and precipitation of salt crystals.

Problems encountered during drilling salt formations;

- **Dissolution – hole enlargement**

Water – base fluids should be saturated with respect to the composition of salt formation prior to drilling the salt section, in order to minimize the amount of salt dissolved and the resulting washout.

Maintaining a near-gauge wellbore improves cementing across these sections and will minimize potential for casing failures due to salt deformation.

The solubility of different salts in a given fluid will control the amount of formation dissolved. $CaCl_2$ and $MgCl_2$ are more soluble than NaCl and KCl. The importance of the relative solubility of salt is that in solution, the salt with the lowest solubility will precipitate first.

For example; if $CaCl_2$ (higher solubility) were mixed into water saturated with NaCl (lower solubility), NaCl would immediately precipitate.

Therefore, if a saturated NaCl drilling fluid is use to drill a salt section contenting $CaCl_2$, the $CaCl_2$ will go into solution and NaCl will be precipitated.

Depending on the solubility of each salt, a mutual solubility equilibrium will be rached.

Figure 1 shows the mutual solubility for $CaCl_2$ and KCl salts.

Mutual solubility can be very complex. There is considerable variability concerning which salt goes into solution and when it will go into solution. It depends on which salt are present, in which order they added, in what concentration and at what temperature. The solubility of salts are listed in the following order from most soluble to least; $CaCl_2$> $MgCl_2$> NaCl> KCl.

As different types of salts are drilled, this complex equilibrium can shift. $CaCl_2$ is the preferred salt. It will stay in the solution at higher concentration when others salts are added to the fluid, although some $CaCl_2$ can be displaced by others salts.

Another reason for dissolution is related to temperature effects.

More salt will go into solution down hole at higher temperatures. As the circulating fluid approaches the surface, the temperature will decrease, crystallizing salt, and a portion of the salt crystals will be removed by solids control equipment. As circulating continues, the fluid reheated down hole, and there is more capacity for salts to go into solution. This heating and cooling cycle is repeated on each subsequent circulation, resulting in greater salt dissolution and larger hole diameter. Chemical crystallizing inhibitors and heated mud pits can be used to maintain saturation down hole. This change in solubility with temperature also indicates that salt crystals are absent, the mud is probably, not saturated under down hole conditions.

- **Deformation-plastic flow**

Salt section exhibit plastic-flow characteristic under sufficient temperature and pressure.

It is a known fact that a salt section tends to be more sensitive to temperature and pressure then to adjacent formations.

Salt formations are rarely plastic or problematic if they are at depths of less than 5000 ft. at temperature below 200 F, or less than 1000 ft thick. In case of salt beds, deformation can be much less apparent. When a well is drilled through a salt section, stress within the salt section is relived and the salt flows toward the wellbore. For this reason, salt sections should be short tripped and reamed on regular basis.

A salt can flow (creep) sufficiently to close off the wellbore and stick the drill string. Fresh water sweeps can be used to dissolve the salt that creeping and to liberate stuck pipe. A fresh water pill of 25 bbl to 50 bbl is usually sufficient to free stuck pipe. Good drilling practices can also minimize salt-deformation problems. Drilling each joint or stand and wiping over that section prior to making the next section will help ensure the salt has been opened sufficiently and stabilized. Regular wiper trips back through the salt to casing will also help ensure the hole remained open.

Increasing the mud weight is the only practical way to control the rate at which the wellbore closes. The closure may never be eliminated, but it can be controlled to an acceptable level during the interval of time it takes to drill the section.

In case of completed well, salt can flow sufficiently to collapse casing. In some cases, the movement of salt is so slow; it takes years before this problem is manifested. High-strength casing and a good cement job after drilling a nearly gauge wellbore tend to distribute the salt loading more evenly over the interval, thereby reducing the potential for casing collapse.

Experience has shown that it is a good practice to use high-compressive-strength, salt-saturated-resistant cement and high-strength casing designed for 1.0 psi/ft collapse.