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## **COMPLEX RESERVOIR DRILLING FLUID SOLUTIONS FOR RESERVOIR DRILLING**

**Abstract:** Drilling into a pay zone with a conventional fluid can introduce a host of previously undefined risks, all of which diminish reservoir connectivity with the wellbore or reduce formation permeability. This is particularly true in horizontal wells, where the pay zone can be exposed to the drilling fluid over a long interval. Selecting the most suitable fluid system for drilling into the pay zone requires an understanding of the reservoir. Using data generated by lab testing on core plugs from carefully selected pay zone cores, a reservoir-fluid-sensitivity study should be conducted to determine the morphological and mineralogical composition of the reservoir rock. Natural reservoir fluids should be analyzed to establish their chemical makeup. The degree of damage that could be caused by anticipated problems can be modeled, as the effectiveness of possible solutions for mitigating the risks.

In addition to being safe and economical for the application, a Reservoir Drill-In Fluid should be compatible with the reservoir's native fluids to avoid causing precipitation of salts or emulsions production. A suitable nondamaging fluid should establish a filter cake on the face of the formation and shouldn't penetrate too far into the formation pore pattern. The fluid filtrate should inhibit or prevent swelling of reactive clay particles within the pore throats.

Formation damage commonly is caused by:

- Pay zone invasion and plugging by fine particles.
- Formation clay swelling.
- Commingling of incompatible fluids.
- Movement of dislodged formation pore-filling particles.
- Changes in reservoir-rock wettability.
- Formation of emulsions or water blocks.

Once a damage mechanism has diminished the permeability of a reservoir, it seldom is possible to restore the reservoir to its original condition.

**Keywords:** drilling fluids, reservoir drilling

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## 1. INTRODUCTION

The potential to reduce wellbore productivity while conducting drilling completion and workover procedures has been addressed extensively in petroleum related literature. Productivity impairment was originally recognized in field cases where development wells produced only small volumes of fluid upon completion or where producing wells produced less after work-over procedures. In other instances, where drill stem tests taken while drilling deep wells indicated potentially good production from shallow zones, difficulty was experienced in attaining production from those zones which had remained in contact with drilling muds for an extended time.

Various models which consider formation damage have quantifiable outputs such as Skin Effect, Productivity Index and Formation Damage Index Number. Methods of preventing formation damage continue to be tested, developed and documented.

A greater percentage of wells are now designed as open hole completions, where perforating past the damaged zone is impractical. Consequently, sophistication in fluids testing procedures has increased and frequently operators test whole fluids against their rock. Often fluid samples are obtained from multiple sources. Return permeability tests are regularly used to select the “best” fluid. Unfortunately, if an adequate candidate isn’t found, the data are usually insufficient to redefine the direction testing should take. The process described herein helps to categorize and quantify discrete damage mechanisms. Fluid design is systematically optimized for all damage issues such that ultimately the fluid is compatible with the reservoir.

In actual practice the first line of defense against formation impairment is to keep foreign fluids and solids out of the rock. Thus, when drilling overbalanced, designing an efficient sealing cake or bridging system becomes essential. However, the very nature of bridging systems denotes spurt loss associated invasion. Further, since the efficiency of any bridging system diminishes due to both mechanical degradation and through pore throat heterogeneity, only the effective design of the base fluid will provide assurance that the best overall fluid was chosen to drill the reservoir.

**General description of a “Drilling Fluid” –  
a circulated fluid used during the drilling of a new open-hole interval  
to assist the well construction process**

Provides critical functions that...:

- Enable the drilling process.
- Stabilize the newly created wellbore.
- Prevent undesired flow to or from the open-hole interval.

### **General description of a reservoir drill-in fluid (RDF)**

Same as a drilling fluid, plus...:

- Prevent/minimize drilling related formation damage.
- Exhibit compatibility with completion fluids.
- Facilitate installation of productive completion.

## **2. REVIEW OF FORMATION DAMAGE MECHANISMS**

Common formation damage mechanisms have been categorized as per below.

### **Fluid-fluid interactions**

**Emulsion blocking** – a viscous suspension of two immiscible fluids (usually oil and filtrate) which physically restricts flow. Emulsions may be stabilized by drilling fluid components, particularly oil-wet ultra-fines, or asphaltenes.

**Precipitates and Scales** – caused by incompatibilities between filtrates and connate fluids or by dissolution/precipitation of mineral grains. Some precipitates which could cause physical plugging include:  $\text{CaSO}_4$ ,  $\text{CaCO}_3$ ,  $\text{CaF}_2$ ,  $\text{BaSO}_4$ ,  $\text{SrCO}_3$ ,  $\text{SrSO}_4$ .

**Paraffins and Asphaltenes** – especially associated with underbalanced drilling where the reductions in temperature and pressure associated with the production of crude oil result in asphaltic or waxy sludges being deposited on or in the near-wellbore pore throat system. Asphaltenes act as cationic particles with a potential to oil-wet rock. Mixing of incompatible oil-based filtrates with in-situ liquid hydrocarbons may also result in de-asphalting of the produced crude oil in some situations.

### **Fluid-rock incompatibilities**

**Migrating Clays** – kaolinite tends to shear away from pore throat walls and migrate and plug if interstitial velocities and electrolytic conditions are adverse (i.e., pH above 8.5 or low salinity). Other loosely attached in-situ clays or fines may also be susceptible to migration.

**Swelling Clays** – include smectites and mixed layer clay which expand when contacted by fresh or low salinity water-based filtrates.

**Phase Trapping/Blocking** – refers to adverse relative permeability effects associated with the retention of invaded aqueous or hydrocarbon fluids.

**Chemical Adsorption/Wettability Alteration** – some polymers in water-based fluids and surfactants in oil-based fluids can physically adsorb onto rock surfaces plugging pore throats (due to their large size) or altering wettability, substantially reducing permeability.

**Solids Invasion** – when pulverized drilled solids or commercial solids (clays, weighting or bridging solids) become fine enough to enter into the pore throat system, permanent plugging can result.

**Other damage mechanisms** – include grinding and mashing of solids by the drill string, spontaneous counter current imbibition effects and glazing and surface damage effects caused by insufficient heat conductive capacity of circulating fluids.

### **3. RDF TYPES**

A reservoir drill-in fluid (RDF) is a clean fluid that is designed to cause little or no loss of the natural permeability of the pay zone, and to provide superior hole cleaning and easy cleanup. RDF's can be:

1. Water-based (WBM):
  - Water, seawater or brine as continuous phase.
2. Oil or Synthetic-Based (OBM/SBM):
  - Oil or synthetic hydrocarbon as the fluid continuous phase.
  - Water and solids as dispersed (emulsified) phase.
  - Dispersed materials in these systems are “oil wet”.
3. Gas, Air, Mist or Foam:
  - Compressed gas as base medium.
  - Air & mist: water emulsified internally.
  - Foam: water is external, gas or air is internal.

### **4. RESERVOIR DRILL-IN FLUID DESIGN**

Design process is “a series of actions, changes or functions bringing about a result”. The steps considered are as follows:

1. Completion methods.
2. Reservoir characterization.
3. Fluid design and selection.
4. Bridging package.
5. Testing and optimization.
6. QHSE.

#### **4.1. Completion methods**

Completion methods are typically dictated by the operator and can heavily influence RDF design process especially when fluid request is made in a late planning phase.

- Lower completion:
  - Barefoot completion.
  - Open hole.
  - Open hole completion:
    - Pre-holed liner.
    - Slotted liner.
    - Open hole sand control.
    - Horizontal open hole completions.
  - Liner completions.
  - Perforated liner.
  - Perforated casing.
  - Cased hole completion.
  - Conventional completions.
- Perforating and stimulating:
  - Acidizing.
  - Fracturing.
  - Acidizing and fracturing (combined method).
  - Nitrogen circulation.

## 4.2. Reservoir characterization

Reservoir characterization is determining the physical properties of a reservoir (porosity, permeability, fluid saturation, etc.) and changes in their distribution throughout the reservoir. The first step is to secure all available data relative to reservoir (Fig. 1). In producing fields, most of the data is often available. This is usually the case when designing for horizontal wells. In some instances, relatively, inexpensive testing may be required to complement existing data. At this point the relevance or importance of data to the fluid system design may not be apparent.

The following information should be assembled:

1. Reservoir rock type.
2. Reservoir type.
3. Depth (MD) (TVD).
4. Temperature.
5. Pressure.
6. Porosity/permeability.
7. Pore throat size curves or SEM analysis.
8. Wettability analysis.
9. Fluid saturations.
10. Fluids analysis.
11. Presence of clay and other fine particles.
12. Presence of acid gases.
13. Reservoir history, completion.

# Reservoir Drill-In Fluid Questionnaire



## Instructions

Please complete the form to the greatest extent information is available.

### Well Information

|                              |                                |  |                      |
|------------------------------|--------------------------------|--|----------------------|
| Operator:                    | <input type="text"/>           | Geographic Location:                       | <input type="text"/> |
| Well Type:                   | <input type="text"/>           | Well Status:                               | <input type="text"/> |
| Well Name:                   | <input type="text"/>           | <input type="checkbox"/> Offshore Location | Water Depth:         |
| Production/Injection Fluid:  | <input type="checkbox"/> Gas   | Casing Size:                               | <input type="text"/> |
|                              | <input type="checkbox"/> Oil   | Hole Size:                                 | <input type="text"/> |
|                              | <input type="checkbox"/> Water | Casing Depth (MD/TVD):                     | <input type="text"/> |
| Production/Injection Target: | <input type="text"/>           | Reservoir Depth (MD/TVD):                  | <input type="text"/> |

### Formation Information

|  |                      |   |                      |
|--|----------------------|---|----------------------|
| Required Density:  | <input type="text"/> | Formation Pressure:   | <input type="text"/> |
| Permeability:  | <input type="text"/> | Formation Type:   | <input type="text"/> |
| Bottomhole Temperature:  | <input type="text"/> | Consolidation:  | <input type="text"/> |
| <input type="checkbox"/> Formation Clays Present                                 |                      | <input type="checkbox"/> Core Material Available            |                      |
| <input type="checkbox"/> Faults/Fractures  |                      | <input type="checkbox"/> Petrophysical Data Available       |                      |
| <input type="checkbox"/> Formation/Formation Fluid Incompatibilities with Brines |                      | <input type="checkbox"/> Formation Water Analysis Available |                      |
| <input type="checkbox"/> Formation is Sensitive to Acid Breakers                 |                      | <input type="checkbox"/> Hydrate Risk                       |                      |
| <input type="checkbox"/> Soluble Sulfates/Carbonates                             |                      |   |                      |
| <input type="checkbox"/> Hydrogen Sulfide  |                      |   |                      |
| <input type="checkbox"/> Carbon Dioxide  |                      |   |                      |

### Completion Information

|                    |                      |                   |                      |
|--------------------|----------------------|-------------------|----------------------|
| Completion Method: | <input type="text"/> | Screen Type:      | <input type="text"/> |
| Metallurgy:        | <input type="text"/> | Screen Slot/Size: | <input type="text"/> |
| PCT/TCT Limit:     | <input type="text"/> | Gravel Size:      | <input type="text"/> |

### Additional Information

|   |                      |
|---|----------------------|
| Environmental Restrictions:               | <input type="text"/> |
| Lost Circulation History in Offset Wells: | <input type="text"/> |
| Solids Control Equipment:                 | <input type="text"/> |
| Material Availability:                    | <input type="text"/> |

Comments/Notes

Fig. 1. M-I SWACO Reservoir Drill-In Fluid questionnaire

### 4.3. Fluid design and selection

Once the characteristics of the reservoir have been assembled, the entire team can discuss the probability of specific damage occurring. Assistance with this step may be acquired in number of ways.

At this point samples of reservoir rock, oil, formation water and make-up water should be collected for testing. When collecting oil and water it is essential to gather untreated samples. Often formation water must be synthesized – this is acceptable as extremely close replications are possible.

Most designs incorporate core analysis requiring small core plugs to be cut from full diameter cores. Typically, better quality rock is selected, since the majority of fluids will be produced from this rock. Careful selection and restoration of the plugs is a pre-requisite for effective special core analysis. Magnetic resonance imaging is a recommended technique for screening core plugs. This is because sandstone plugs with similar permeability and porosity may have markedly different internal characteristics including laminations and cross-bedding or they may even be impermeable on one side. MRI imaging of carbonate plugs clearly shows vugular heterogeneities as well as the nature and length of the fractures within the plug.

Since preserved cores are seldom available, it is usually necessary to restore extracted core plugs to their original wettability and water/oil saturations. This procedure is conducted at reservoir temperature, using real reservoir fluids. This may require 6–8 weeks for oil reservoir and somewhat less time for gas reservoirs. Project timeline should be constructed to account for this restoration time.

To validate and quantify the impairment mechanisms some tests described below should be performed.

**Emulsion Testing** should be performed wherever there is a possibility of filtrate mixing with oil. The simple procedure which can be used in the lab or the field to test for emulsions is described on API RP 42. This procedure is sometimes modified in that it is conducted at reservoir temperature and occasionally without the solids.

**Filtrate-Formation Water Compatibility Analysis** should be conducted, if the water analysis indicates dissolved solids. This involves combining the two samples in equal proportions and raising the temperature to reservoir temperature while stirring slowly. If precipitates are not observed, the test should be continued by raising the pH with sodium hydroxide.

**Oil-Oil Compatibility Testing** should be done if an oil continuous phase fluid is a candidate for drilling. This test measures the particulate population when varying ratios of crude oil and base oil are combined. The objective of the test is to ensure that the actual sum of the particulates in the combined fluid doesn't exceed the calculated sum.

**Clay Migration Testing**, sometimes called a critical velocity test uses a small core plug. The plug is mounted in a holder where reservoir conditions including stresses, temperatures and pressures may be simulated. In this test an inert fluid such as formation brine is passed through the core in a series of increasing velocities. The permeability to the fluid is measured at each flow rate. The critical velocity is that velocity where mobile fines such as bitumen or kaolinitic clays begin to dissociate or to shear off pore walls,

plugging the pore throats. A change in permeability will occur at the critical velocity. The relative impact of the velocity on well productivity may be extrapolated by comparing rates of fluid leak-off in regain permeability tests or by calculating interstitial velocities at expected production rates.

**Clay Swelling Testing** uses a similar procedure as for Clay Migration Testing. A baseline permeability to (usually saline) formation brine is established after several pore volumes have passed through the plug. Sensitivity to fresh water due to swelling clay is measured as a reduction in permeability when fresh or low salinity water is passed through the core. If the permeability hasn't been shut off completely, the base line permeability can usually be re-established by switching back to formation brine. This increase back to baseline permeability would indicate that dissolved salts are aggregating the hydrated clays – causing them to occupy less space in the pore throat system. Many clays can also deflocculate if electrostatic equilibrium which is holding the clays bound in place are disrupted by increases in pH or reduction in system salinity.

**Phase Trap Testing** can quantify the relative permeability effects associated with the retention of water or oil. To do the test, a core plug is restored to its in-situ wettability and fluid saturation's. In an aqueous phase trap test, the plug is restored to a sub-irreducible water saturation under reservoir conditions. Permeability to gas is measured. The plug is slowly injected with produced brine, establishing irreducible water saturation. Permeability to gas is then measured gain, at pressure resembling the available drawdown at reservoir conditions. If the second permeability is lower, damage due to phase trapping alone has been quantified.

**Wettability Testing** may also be conducted after API RP 42 to ensure that surfactant treatments leave the rock in their natural state. The procedure varies depending on whether the surfactant is water soluble or oil soluble. Since not all rocks will exhibit strongly water-wet or strongly oil-wet character, the results of this type of test may be difficult to interpret.

All impairment mechanisms identified during tests must be mitigated by optimization process. Starting points relative to concentrations or properties should be based on experience. When one method is shown to be the best, the next step is to optimize the concentration. For example, in the emulsion test previously described, if a stable emulsion is noted, the test should be repeated with different demulsifiers added to the filtrate before mixing. Once the most effective demulsifier is identified the concentration should be optimized to tell if more is better or if less is just as effective.

When dealing with precipitate problems the chemistry may be complex.

**Migrating Clays** can be controlled to a degree by controlling alkalinity, with the addition of certain polyvalent metal ions, and by controlling the rate at which fluids flow through the pore throat system – by enhancing fluid filtration control properties and by bridging the well on gradually during the production process.



**Swelling Clays** can be controlled with certain cations or polymers. A clay swelling test may be extended to include flooding the core with one or more possible candidate clay stabilizers and charting the results. Note how the cation improves permeability by dehydrating the swelling clays. Again, the object is to determine not only the best remedy, but also its most cost-effective concentration or application.

**Phase Trap** mitigation may require the proper application of a surface tension reducing additive such as a surfactant or alcohol. In some instances of aqueous phase trapping, a base oil may offer the best results.

**Wettability** – if API RP 42 wettability testing indicates an adverse reaction to any surfactant such as defoamer or torque reducer, testing should be conducted to determine a suitable replacement.

**Table 1**  
RDF basic reference table

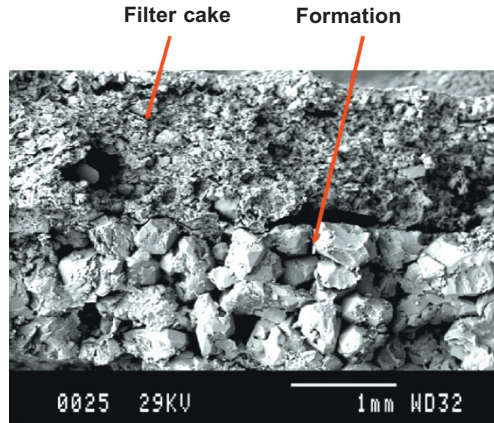
| Property   | DF                      | RDF                           |
|------------|-------------------------|-------------------------------|
| Density    | <del>Brine</del>        | Base Fluid/ Brine             |
| Viscosity  | <del>Oil</del>          | Bio-polymer/ Starch           |
| Fluid Loss | <del>Gel/ Polymer</del> | Starch                        |
| Bridging   | <del>Brine</del>        | Calcium Carbonate/ Sized Salt |

At the end of this process the components of the candidate fluid/ fluids should be selected (Tab. 1). In tight, complicated reservoirs the testing results may be less than what had been hoped for. This may lead to the selection of an alternate base fluid such as an oil or an alternate method such as underbalanced drilling.

#### 4.4. Bridging package

When fluid contacts the formation there is a spurt loss of whole fluid which continues until solid bridging particles block the pore throats. A properly designed filter cake has three basic layers. The primary bridge consists of large particles and is formed with

initial spurt loss. The secondary bridge is formed as smaller bridging solids mixed with colloidal particulates layer over the top of the primary bridge. The final seal is a polymer film. The construction of this thin, impermeable cake (less than 1.5 mm thick in properly designed fluids) proceeds rapidly as progressively smaller granular particles pack tightly into any remaining openings (Figs. 2 and 3).



**Fig. 2.** Image of filter cake



**Fig. 3.** Desirable filter cake

In 1977 Abrams concluded that: “Muds that contain bridging material that meets the 1/3 rule for bridging impairs rock to depths less than 1 inch. The rule requires that the mud must contain bridging material with diameters greater or equal to 1/3 the formation median pore size at concentrations levels of at least 5% by volume of the mud solids”. In 1980 Mahajan recognized that fluid loss polymers enhanced bridging efficiency and provided better return permeability in an HEC/sized carbonate fluid. He also pointed out that other work concluded that relative to HEC/calcium carbonate solutions the one third rule “might not hold”. The draw back to the rule is that it refers to median pore and particle sizes as opposed to distribution curves. In general, broader distribution curves are most efficient.

Bridging on fractures is a more difficult matter. Some studies suggests that a slot (fracture) size: particle size ratio of 0.8 to 1.0 at a concentration of 1.5–4.5% w/w was efficient for bridging fracture faces. This pertained to blocky materials – where particle size means that 95% of the particles were less than that size (Fig. 4).

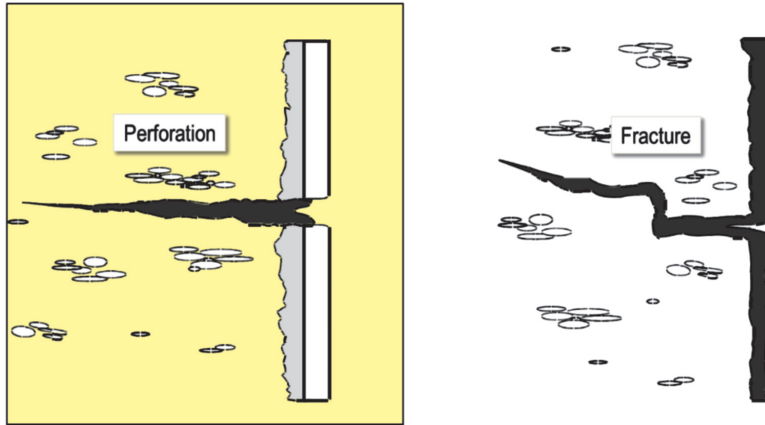


Fig. 4. Perforations and fractures plugged by thick filter cake

The nature of the reservoir and the planned completion technique are what drives bridging system design (Fig. 5). Sized carbonates are inexpensive and commonly used in both water and oil-based systems in all types of reservoirs where HCl treatments are possible to conduct. Close attention should be paid to the quality of the product. A disadvantage to using carbonates is that they are not soluble in formation fluids. Thus, if fine particles are lost too far back into the formation during high loss periods, they may be beyond the reach of acid. Calcium carbonate is thermally stable.

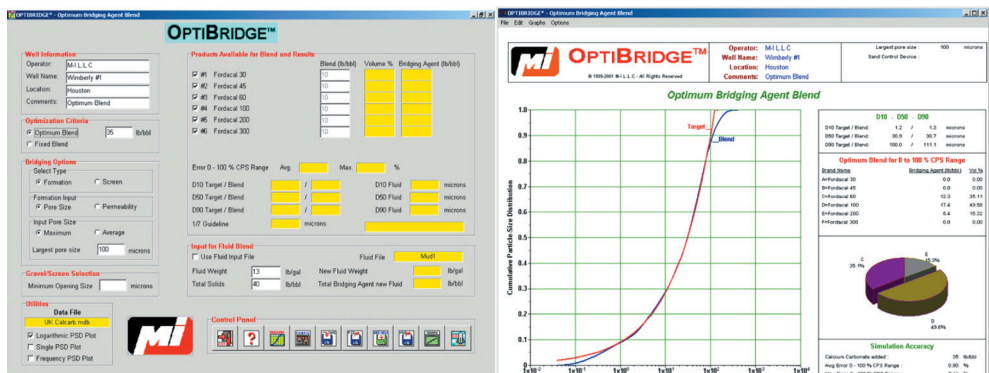






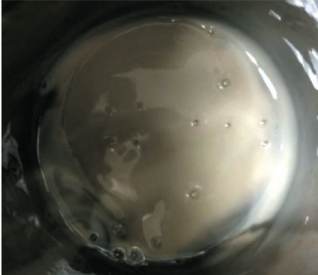



Fig. 5. Software for bridging optimization

|                                   |   |  |
|-----------------------------------|---|--|
| <p><b>Polymer mud<br/>RDF</b></p> |    |    |
|                                   | <p><b>Image 1 – Filter cake after 4-hours HTHP fluid loss</b></p>                   | <p><b>Image 2 – disk after flowback</b></p>  |
| <p><b>DIPRO RDF</b></p>           |    |    |
|                                   | <p><b>Image 3 – Filter cake after 4-hours HTHP fluid loss</b></p>                   | <p><b>Image 4 – disk after flowback</b></p>  |
| <p><b>FLOTHRU<br/>RDF</b></p>     |   |   |
|                                   | <p><b>Image 5 – Filter cake after 4-hours HTHP fluid loss</b></p>                   | <p><b>Image 6 – disk after flowback</b></p>  |
| <p><b>VERSAPRO<br/>RDF</b></p>    |  |  |
|                                   | <p><b>Image 7 – Filter cake after 4-hours HTHP fluid loss</b></p>                   | <p><b>Image 8 – disk after flowback</b></p>  |

**Fig. 6.** Typical flowback test results

Sized oil soluble resin particles are used in water-based systems for drilling both carbonate and sandstone oil reservoirs. Resin has an advantage in that it eventually dissolves even when carried back into reservoir. Typical resin has softening point of 162°C and as specific gravity of 1.02. The solubility of resin should always be testing using “live” live crude from close offset well.

Sized salt (NaCl) systems can be used in all reservoirs containing some formation water. They may be carried either in viscosified oil or in salt saturated water. Salt is thermally stable.

Cellulosic fibres make extremely effective sealants. However, fibres are only about 40% soluble in acid. Therefore, caution is advised prior to use in fractured reservoirs or where a slotted liner will be run. Fibre cakes rely mainly on drawdown, requiring a physical push from formation fluids for removal. Therefore, they may not be applicable in gas wells where drawdown is less than sufficient. Some experiments are in place with enzymes which “break” cellulose fibres (Fig. 6).

#### 4.5. Testing and optimization

Choosing of fluid is a matter of combining the one or two best bridging systems with one or two of the best base fluids. Regain permeability testing is conducted using core plugs that have similar characteristics. The test involves mounting a restored core plug in a holder and applying overburden stresses at reservoir temperature. A baseline permeability to the oil or gas is established by flowing it in direction  $D_1$ . Drilling fluid is then flowed across the face of the plug at overbalance pressure such that filtrate penetrates the plug in direction  $D_2$ . The volume of fluid lost versus time is recorded and plotted. Finally, the flow of formation fluid is again directed through the plug in direction  $D_1$ . The permeability is again calculated showing any reduction attributable to the mud. The results of these tests allow a quantifiable comparison of more than one drilling fluid system on the reservoir rock. There have been several important advancements in laboratory evaluation techniques recently. They include:

- Dynamic leak-off testing where fluids are able to flow across the face of the core.
- Full diameter and crossflow leak-off apparatus which provides up to 40 times the exposed cross-sectional area for work on highly heterogeneous rock.
- Techniques for artificially inducing fractures.
- Apparatus to simulate underbalanced drilling.
- Threshold pressure regain procedures – designed to determine both the point at which formation fluids initially penetrate the damaged rock and the permeability expected at the maximum expected drawdown gradient.
- Pressure tapped cores which allow for the evaluation of sectional permeabilities.
- Spontaneous imbibition tests – designed to measure counter current imbibition of drilling fluid into the reservoir while maintaining underbalanced conditions.

After the test has been conducted, a simulated stimulation can be conducted on the plug. This might include an underbalanced acid wash or an acid squeeze. Saving the core for petrographic analysis after the test may indicate the actual depth of invasion of particulates or the dislocation of reservoir fines.

Damage mechanisms which are difficult to simulate and test for include damage caused by:

- Bacterial growth (Long term testing required).
- Grinding and mashing of fines into near wellbore pore throats by drill string rotation.
- Glazing caused by inefficient heat removal.

#### **4.6. QHSE safe fluids handling**

Like all chemicals, oilfield completion fluids can be hazardous to your health if not handled properly. Brines have unique chemical properties and consequently must be handled differently from conventional drilling muds.

RDF's can weight from 1.01 to 2.40 SG depending on the amount and type of salt added. Generally, as brines get heavier they are more dangerous to handle and are more damaging to equipment and the environment.

Hazardous properties:

- acidity,
- absorption of water,
- chemical reactions,
- toxicity.

Mixing Salts:

- addition of dry calcium chloride or calcium bromide can boil the water.

Effect of exposure:

- skin contact,
- eye contact,
- inhalation,
- ingestion.

### **5. CONCLUSIONS**

1. A process has been presented which follows an analytical progression of information gathering, discussion, validation of theories and design optimization.

2. Technology is available to allow the process to focus on identification and design around discrete damage mechanisms.
3. Following the process will achieve the objective of assurance for all stakeholders that the best efforts has been expended to secure a zero skin well.

M-I SWACO provides a complete line of reservoir drill-in, completion and work-over fluids and additives that help make oil and gas wells more productive. The company also offers fluid reclamation and filtration service complemented by a complete line of wellbore cleanout tools.

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