Brines and Other Workover Fluids

- Purposes
- Selection
- Filtration needs
- Placement
- Fluid Loss Control
- Cleanup and Displacement of Muds
- Limitations
- Alternatives
Purposes of Brines

1. Mud displacement prior to cementing,
2. Debris removal,
3. Controlling formation pressures during completion and intervention operations,
4. Enabling repair operations as a circulating or kill fluid medium,
5. As packer fluids,
Purposes of Brines (cont.)

6. In some stimulations as base fluids;
7. Enable cleanup of the zone prior to running screens;
8. Reduce friction while running screens & equipment;
9. Avoid damaging the well after completion, stimulation, or repair;
10. Allow other well operations to be conducted.
Will Circulating a Well Really Clean It Out?

• Not necessarily.

• Clean-out efficiency depends on:
  – Ability to remove the solids from returning fluids,
  – Fluid hydraulics - the flow rates in every section,
  – Ability to disperse, then lift solids out of the well,
  – Ability to effectively remove the dope, mud cake, residues, etc., from the pipe walls.
Returns from a cleanout scraper run – dope, wireline grease, rust, mud, etc., are common components.
Selection of the Brine

• Must Satisfy:
  1. Well control at every phase of the operation.
  2. Must be able to filter the brine to 5 to 10 microns with beta of 1000.
  3. Compatibility with the formation, well equipment and all operations and fluids.
  4. Corrosion and scale dropout must be controllable.
  5. Cleanup requirements from the formation
  6. Cleanup and disposal requirements at the surface
  7. Cost and availability to fit the well.
<table>
<thead>
<tr>
<th>Brine Type</th>
<th>Brine Formula</th>
<th>Density Range (ppg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chloride Salt</td>
<td>NaCl</td>
<td>8.4 - 10.0</td>
</tr>
<tr>
<td>Chloride Salt</td>
<td>KCl</td>
<td>8.4 - 9.7</td>
</tr>
<tr>
<td>Chloride Salt</td>
<td>NH4Cl</td>
<td>8.4 - 8.9</td>
</tr>
<tr>
<td>Bromide Salt</td>
<td>NaBr</td>
<td>8.4 - 12.7</td>
</tr>
<tr>
<td>Mix</td>
<td>NaCl/NaBr</td>
<td>8.4 - 12.5</td>
</tr>
<tr>
<td>Formate Salt</td>
<td>NaHCO2</td>
<td>8.4 - 11.1</td>
</tr>
<tr>
<td>Formate Salt</td>
<td>KHCO2</td>
<td>8.4 - 13.3</td>
</tr>
<tr>
<td>Formate Salt</td>
<td>CsHCO2</td>
<td>13.0 - 20.0</td>
</tr>
<tr>
<td>Formate Salt</td>
<td>KHCO2/CsHCO2</td>
<td>13.0 - 20.0</td>
</tr>
<tr>
<td>Formate Salt</td>
<td>NaHCO2/KHCO2</td>
<td>8.4 - 13.1</td>
</tr>
<tr>
<td>Chloride Salt</td>
<td>CaCl2</td>
<td>8.4 - 11.3</td>
</tr>
<tr>
<td>Bromide Salt</td>
<td>CaBr2</td>
<td>8.4 - 15.3</td>
</tr>
<tr>
<td>Mix</td>
<td>CaCl2/CaBr2</td>
<td>8.4 - 15.1</td>
</tr>
<tr>
<td>Bromide Salt</td>
<td>ZnBr2</td>
<td>12.0 - 21.0</td>
</tr>
<tr>
<td>Mix</td>
<td>ZnBr2/CaBr2</td>
<td>12.0 - 19.2</td>
</tr>
<tr>
<td>Mix</td>
<td>ZnBr2/CaBr2/CaCl2</td>
<td>12.0 - 19.1</td>
</tr>
</tbody>
</table>
## Lower Density Fluids

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Density Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nitrogen gas</td>
<td>0.1 to 2.6 lb/gal</td>
</tr>
<tr>
<td>Water foam</td>
<td>3.5 to 8.3 lb/gal</td>
</tr>
<tr>
<td>Kerosene and diesel</td>
<td>6.7 to 7.1 lb/gal</td>
</tr>
<tr>
<td>20º crude</td>
<td>7.8 lb/gal</td>
</tr>
<tr>
<td>30º crude</td>
<td>7.3 lb/gal</td>
</tr>
</tbody>
</table>

Most low density fluids are not be usable because of migration, flash point, or stability issues.
Displacement and Pill Design

• The displacement must be designed to obtain effective mud removal (dispersement and lift) & water wetting of casing.

• Keys:
  – disperse and thin the drilling fluid
  – compatibility with the following fluids (brine, acid, cement, etc.
  – lift out debris and junk
  – water wet pipe
  – remove pipe dope effectively
  – displace the mud
Brines for Displacement

1. A thinning base fluid flush.
2. An effective brine transition system must further thin and strip the mud and create wellbore displacement.
3. A carrier spacer must sweep out the solids and clean any coating from the pipe or rock that could cause damage problems.
4. A separation spacer must do the final cleaning and separate the residual mud from the brine.
5. The brine must sweep the spacer out. At this point the well should be clean.
# Cleaning and Transition Spacers

<table>
<thead>
<tr>
<th>Spacer Type</th>
<th>Function</th>
<th>Minimum Annulus Coverage</th>
<th>WBM</th>
<th>OBM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Fluid</td>
<td>Thin &amp; mud condition – start dispersement</td>
<td>250 to 500 ft</td>
<td>Water, and some brines</td>
<td>Base oil (composition varies)</td>
</tr>
<tr>
<td>Transition</td>
<td>Mud to spacer, cuttings removal</td>
<td>500 to 1000’</td>
<td>Viscous pill</td>
<td>Viscous Pill</td>
</tr>
<tr>
<td>Wash</td>
<td>Clean pipe</td>
<td>500 to 1500’</td>
<td>Water+ WBM surfactant</td>
<td>Oil + OBM surfactant</td>
</tr>
<tr>
<td>Separation</td>
<td>Separate wash from completion brine</td>
<td>500 to 1000’</td>
<td>Viscous pill</td>
<td>Surfactant gel? Some water gels if compat.</td>
</tr>
<tr>
<td>Completion Fluid</td>
<td>Completion fluid</td>
<td>Fill</td>
<td>Completion Fluid</td>
<td>Completion Fluid</td>
</tr>
</tbody>
</table>
# Brine Flush Contact Times

9-5/8” casing in 12-1/4” hole, annular area = 0.3 ft²

<table>
<thead>
<tr>
<th>Pump Rate, bpm</th>
<th>Annular Velocity, ft/min</th>
<th>Barrels Pumped</th>
<th>Column Length, ft</th>
<th>Contact Time, minutes on one foot.</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>150</td>
<td>200</td>
<td>3743</td>
<td>25</td>
</tr>
<tr>
<td>10</td>
<td>187</td>
<td>400</td>
<td>7486</td>
<td>40</td>
</tr>
<tr>
<td>12</td>
<td>225</td>
<td>400</td>
<td>7486</td>
<td>33</td>
</tr>
</tbody>
</table>
Flow profile in a well with decentralized pipe. Note that most of the flow comes along the top of the pipe. This affects cleanup and residence time of the fluid on the wellbore. The lower section of the wellbore may remain buried in cuttings and never have contact with any of the circulated fluids.
Displacement of the annulus to displace fluids and mud cake depends partly on velocity. The annulus changes as casing replaces the drill string. As the annular space decreases – velocity for any rate increases in the smaller area and the back pressure on the bottom hole may also increase.

Circulating down the casing and up the small annulus can produce very high friction pressure and raised BHP.
Displacement Considerations

- Well control is key consideration in selection of the pill sequence.
- In many cases, it is only possible to get thin, light fluids into turbulence.
- Pumping fluids to displace oil based fluids without suitable surfactant/solvent packages to disperse the mud can result in sludges that are insoluble except in aggressive solvents.
- For deepwater wells, low temperatures can impact surfactant effectiveness.
Carrying Capacity

• Pills in turbulence lose carrying capacity if the annular velocity drops below that required for turbulence (e.g. entering larger diameter pipe such as a riser)

• In high mud weight, the risk of inducing barite sag needs to be considered if mud is thinned (displacement pills thin the mud to the point it can no longer support barite)
LEARNING

• As depth and hole angle increase, the minimum pill volume (based on largest annular hole length) should **increase** to allow for contamination, e.g.:
  – If MD < twice TVD, annular fill length > 80 m (260 ft),
  – If MD > twice TVD, annular fill length > 125 m (410 ft),
• **Contact time** (the time that critical points in the well are exposed to the pill) depends on reaction of surfactant/solvent to mud. For surfactant pills, plan for contact times of greater than 4 minutes for best results.
BEST PRACTICES AND DESIGN CRITERIA

• Good mud thinning fluid is continuous phase of the mud:
  – for water based mud pumping 50 bbl (8 m$^3$) of water as the first displacement pill will effectively thin mud,
  – 50 bbl (8 m$^3$) of the mud base fluid can be pumped in the case of oil based muds. (check oil compatibility)

• Before any displacement, the compatibility of the spacers with the mud and the ability to water wet steel surfaces should be checked at ambient and bottom hole temp to confirm compatibility.

• In deep water, tests at lower temperature will be needed
BEST PRACTICES AND DESIGN CRITERIA

• All tests should be done on field mud samples to ensure mud is effectively sheared and has representative particles/cuttings.
• Water wetting surfactants are generally effective >3% vol/vol concentration, little additional benefit is obtained above 10%.
• Solvents and mechanical or hydraulic agitation are required to remove sludges and pipe dope.
Displacement

• Displacement of mud from an annulus is complex. The main driving forces:
  – time of contact
  – flow rate and frictional forces
  – density
  – mechanical agitation
  – pipe centralization
RISKS AND ISSUES

• Fluid Interface area increases w/ hole angle
• In deviated wells the eccentricity of the displacement string may reduce displacement. Pipe rotation and/or reciprocation is needed.
• At low temperature (<40°C/104°F), OBM is very viscous ( synthetic based muds are worst), circulating to warm the annular contents reduces the problem.
RISKS AND ISSUES

• High circulation rates may be better (even in laminar flow), they reduce the boundary layer thickness on the casing wall. (Watch wash-out potential of soft sands)
• Turbulence is best, flow rate must be calculated allowing for pipe eccentricity. A complete wellbore hydraulics check is necessary.
• High rates (300 ft/min?) may reduce the fluff (80% of the outer layer of the filter cake that does not contribute to fluid loss control); sharply reducing the amount of solids in the well without reducing fluid loss control.
BEST PRACTICES AND DESIGN CRITERIA

- High flow rates will always be better even if turbulence cannot be achieved.
- Pipe movement will improve displacement efficiency.
- Multi-function circulating subs should be used, currently the best tools open by setting weight down, incorporating a clutch mechanism to allow rotation.
- Do not stop displacement once pills enter the annulus.
- Circulate to warm mud and fine up shakers (increase screen mesh number) to reduce particles in the fluid when possible, condition mud (reduce rheology).
- Use reverse circulation if possible when displacing with lighter fluids.
Muds, Cakes, Breakers and Particles

• Drilling mud is the best known particulate based fluid loss control system.
• Particles are sized to bridge on the face of the formation. Carbonate and salt are most common.
• Breakers are acid, oxidizers and enzymes.
• Filter cakes very effective in preventing losses as long as over-balance pressure is maintained.
• Cakes are very sensitive to swabbing, but are never completely removed.
• Tool systems sensitive to plugging by particulates.
Particles – Damage?

• “Dirty” particles, unsized particles, debris and pipe dope are severe formation damage problems.
• Protecting the perforations with the right particles during a workover improves chances of well improvement afterwards.
• The type of carrier fluid and the gels are v. important

Clear (no particles) brines are not always best solution
Particulate Pill Displacement

• A spacer or displacement pill for displacing a polymer system carrying sized particulates should be 0.2 to 0.25 ppg heavier and about three times the low shear rate viscosity (at 0.06 sec$^{-1}$) of the fluid being displaced.
Data from a set of Alaska wells where the perforations were not protected during a workover. No protection shows significant long term damage.
When perfs were protected, that was little risk of long term damage.
Sized particulates, particularly those that can be removed, are much less damaging than most polymers.
Formation Damage by Gels

• Gels
  – Linear gels not recommended for high overbalance or high permeability formations – too much depth of damage.
  – HEC is not always clean breaking.
  – Breaker selection is critical to removing the damage from a linear gel.
Linear HEC Pill needed per ft of zone, 80 lb/1000 gal or 3.36 ppb
Fluid Loss Rate vs. Pressure Differential for Various Permeabilities

1 cp fluid, $s = +5$

Modified from World Oil, Modern Sandface Completion Practices, 2003
Breaker

• Breaker must stay with the part of the gel that causes the damage
  – penetrate to the distance that gel penetrates, or
  – stop at the wall – with the gel wall cake.

• Breakers:
  – Acid, internal breaker, or enzyme
  – Many breakers adsorb or spend in the formation, before they work.
Brine Stability

• The stability of the brines at high salt loadings can be very “touchy” with temperature drops causing salt precipitation.
• Increases in temperature decreases brine density and may leave the brine under-saturated to salt.
• Additions of gas, alcohol, some surfactants, shear and reduction in temperature can lead to salt precipitation.
• Salt may affect the way polymers hydrate or disperse.
The reduction of brine density as it comes to equilibrium in the well may explain why a well can go from a no-flow condition to flow within a few hours after being killed.
Temperature Changes

GOM Seafloor Temperature

Sea Floor Temperature, F

Water Depth, ft

Composite data from DTC
Temperatures in the Well?
Circulating or High Rate Injection?

Circulation pump rate = 8-BPM
BHST = 122°F
BHCT = 98°F

Frac job pump rate = 35-BPM
BHST = 125°F
BHTT = 86°F
Adding salt lowers freezing point of water until the point at which additional salt precipitates.

Salt-Out or “Freezing” Temperature of a Brine

Crystallization Temp

Salt Content

Eutectic Point
## Composition Determines TCT (true crystallization temperature)

<table>
<thead>
<tr>
<th>Density (ppg)*</th>
<th>CaCl$_2$ (wt %)</th>
<th>CaBr$_2$ (wt %)</th>
<th>TCT (°F / °C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>12.5</td>
<td>34.40</td>
<td>10.80</td>
<td>60/ 15.5</td>
</tr>
<tr>
<td>12.5</td>
<td>32.20</td>
<td>13.13</td>
<td>44/ 6.7</td>
</tr>
<tr>
<td>12.5</td>
<td>22.84</td>
<td>20.55</td>
<td>15/ - 2.8</td>
</tr>
<tr>
<td>12.5</td>
<td>00.00</td>
<td>41.55</td>
<td>- 33/ - 36</td>
</tr>
</tbody>
</table>

*1.50 SG
Density Change with Temp Change

\[ D_{DH} = D_S (1 + 0.000252 (T_S - T_{DH})) \]

What is downhole density \( D_{DH} \) of a 16.4 lb/gal surface density \( D_S \) brine (60\(^\circ\)F) when downhole temperature increases to 230\(^\circ\)F?

\[ D_{DH} = (16.4) (1 + 0.000252 (60-230)) \]

\[ D_{DH} = 15.7 \text{ lb/gal} \]
There is a slight increase in density with applied pressure, usually about 0.1 ppg.
### Temperature and Pressure Effects on Completion Fluids

<table>
<thead>
<tr>
<th>Fluid System</th>
<th>Density, ppg</th>
<th>Temp Expansion of Fluids</th>
<th>Pressure Effect on Fluids</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Expansion Coef.</td>
<td>Compression Coef.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>vol/vol(^{\circ})Fx10^4</td>
<td>lb/gal/100(^{\circ})F</td>
</tr>
<tr>
<td>Diesel</td>
<td>7</td>
<td>3.8</td>
<td></td>
</tr>
<tr>
<td>NaCl</td>
<td>9.49</td>
<td>2.54</td>
<td>0.24</td>
</tr>
<tr>
<td>CaCl(_2)</td>
<td>11.45</td>
<td>2.39</td>
<td>0.27</td>
</tr>
<tr>
<td>NaBr</td>
<td>12.48</td>
<td>2.67</td>
<td>0.33</td>
</tr>
<tr>
<td>CaBr(_2)</td>
<td>14.3</td>
<td>2.33</td>
<td>0.33</td>
</tr>
<tr>
<td>ZnBr(_2)/CaBr(_2)/CaCl(_2)</td>
<td>16.01</td>
<td>2.27</td>
<td>0.36</td>
</tr>
<tr>
<td>ZnBr(_2)/CaBr(_2)</td>
<td>19.27</td>
<td>2.54</td>
<td>0.48</td>
</tr>
</tbody>
</table>

At 12,000 psi from 76F to 345F

At 198F from 2,000 to 12,000 psi
Brine Selection – Circulating Density

• Match density needs on both static (ESD) needs, and circulating density (ECD) needs. Consider friction effects on BH press while circulating.

• Remember – brine must exert pressures in a window between controlling pore pressure or shale heaving and fracturing the formation.

• Brine density changes with temperature (can drop by >1 lb/gal) and a small increase with pressure (0.1 lb/gal).

• Carried solids add density to the brine – easily by 0.5 to 2+ lb/gal.
Brines have small density changes due to temperature, pressure, and contamination; and larger density changes due to suspended solids.

**CaCl₂ Brine in a 14,000 ft Wellbore in 8,000 ft Water**

**Hydrostatic Pressure at TVD**

*Note: Fluid Density is Greater at the Mud line than at the Surface*
Adding solids to any fluid, either at the surface or downhole increases its density. 0.5 to 2+ lb of solids are common in cleanout with circulated fluids.
Completion Fluid - Checklist

- Is the formation liquid sensitive to liquid relative permeability effects?
- Compatibility with formation? (clay and minerals)
- Compatibility with formation fluid? (emulsion, sludge, foam, froth)
- Tanks and surface equipment clean? (pumps, lines, hoses, blenders)
- Are polymers breakable? How is breaker added?
- Polymers, hydrated, sheared and filtered? Filter level? Beta rating?
- Minimize the pipe dope?
- Corrosion reactions understood?
- Erosion potential understood?
Special Case - Horizontal Wells

- Hole circulated to a large volume of fluid to stop losses.
- Minimum amount of solids can be used where internal tool sticking is a possibility.
- Suspension of solids beyond 60° deviation is difficult.
- Penetration to furthest reaches of the well is required – buckling considerations?
- Very sensitive to swabbing.
Filtration and Cleaning

• Brine and ? (tanks, lines, pumps, etc.)
• Pickle the tubulars?
• NTU or particle count as a measure? How clean is clean? = Avg pore throat x 0.2?
• Beta rating and micron rating important
• Tank arrangement when filtering (from dirty tank to clean, not in a loop)
• Filter type
  – DE or Cartridge (no resin coated cartridges)
Filtration Ratings

• NTU - a turbidity indicator - can be mislead by natural color of water. An NTU of 20 to 30 is generally clean.
• Nominal filter rating - estimate of the size of particle removed - don’t trust it. Filtration efficiency improves with bed build-up
• Absolute filter rating - size of the holes in the filter. Filtration efficiency improves with bed build-up
• Beta rating - a ratio of particles before filtration to after. A good measure of filter efficiency.
• Suggestion – use a 5 to 10 micron rating with a beta rating of 1000 for most clear brine applications.
Beta Rating

• Beta = number of filter rating and larger size particles in dirty fluid divided by number of those particles in clean fluid.

• Beta = 1000/1 = 1000 or 99.99% clean
Filtration Considerations

• Very clean fluids have high leakoff rates
• Fluids with properly blended fluid loss control materials added after filtration have a better chance of cleanup than with the initial particles in the fluid. Particles must be sized to stop at the face of the formation.
• All gelled fluids should be sheared and filtered – even the liquid polymer fluids.
These are the small fisheyes that flowed out of the shear device. These pills were made using liquid HEC.
Microgels or “fisheyes” after straining a liquid HEC dispersion through a 200 mesh screen in a shear and filter operation for gravel pack fluid preparation.
Scrapers and Brushes – Physically Cleaning the Well

- Available tools
- Damage potential
One very detrimental action was running a scraper prior to packer setting. The scraping and surging drives debris into unprotected perfs.
Casing Scraper – Designed to knock off perforation burrs, lips in tubing pins, cement and mud sheaths, scale, etc.

It cleans the pipe before setting a packer or plug.

The debris it turns loose from the pipe may damage the formation unless the pay is protected by a LCM or plug.
Placement Methods

• Circulating – preferred – watch effective circulation density (friction pressures)
• Spotting – watch density induced drift – 0.05 lb/gal difference can start density migration.
• Bullheading - next to last resort.
• Lubricating - last resort.
• Consider coiled tubing for most accurate spotting and ability to circulate fluids into place with minimum contamination.
• Remember that fluid density differences of even 0.05 lb/gal will start density segregation.
Fluid Loss Control

• Methods: viscosity, particulates, mechanical
• Best method? – depends on application and options afterward.
  – Viscosity based methods often leave polymer debris
  – Particulates must be sized with small, medium and large particles to build a tight cake at the surface. Don’t use them in cased and perforated completions???
  – Mechanical methods preferred, but not always practical.
Fluid Loss Control Systems

- Fluid (pumped)
  - Gels (linear and x-link)
  - Bridging particulates
- Mechanical
  - Downhole valves
  - Plugs
  - Flappers (watch the throat size)
  - Ball checks

Removal methods?
In the Formation / At the Formation Face (Not in Perf)

- **Gels** – high vis. limits the fluid loss by pressure drop.
  - May not work in high perm (>0.5 darcy).
  - Temperature greatly affects performance.
  - Cleanup is a problem.

- **Particulates** bridge at the formation face.

Particulates are very effective in controlling fluid loss, but are also very sensitive to swabbing, dissolving in carrier fluids and must be sized for the formation pores and natural fractures.
Particulate Systems

• Sized carbonates and salts are most common. Penetration depth = 0.125” (3mm)
• Do not use in most perforated completions unless the perforations have been packed with gravel.
• Gravel pack tools and tools with close clearances should not be exposed to particulate laden fluids.
• Gel carriers for particulates still require breakers.
## Considerations for Fluid loss Control Selection

<table>
<thead>
<tr>
<th>BHT</th>
<th>Formation sensitivity to treatment fluids</th>
<th>Onshore / Offshore / Deepwater</th>
</tr>
</thead>
<tbody>
<tr>
<td>BHP</td>
<td>Treatment/completion fluid types</td>
<td>Rig cost per day</td>
</tr>
<tr>
<td>Overbalance or underbalance</td>
<td>Frequency and amount of surge/swab loads</td>
<td>Rig equip available - pumps, tanks, lines,</td>
</tr>
<tr>
<td>Vertical and horizontal permeability variations</td>
<td>Formation sand strength</td>
<td>All tubular sizes in the flow path</td>
</tr>
<tr>
<td>Formation sand size and pore throat size</td>
<td>Sand production and presence of cavity</td>
<td>Mobilization time available</td>
</tr>
<tr>
<td>Production rate</td>
<td>Producer or injector</td>
<td>Regulations on use and disposal</td>
</tr>
<tr>
<td>Produced fluid types</td>
<td>Wellbore deviation through the pay</td>
<td>Natural or hydraulic fractures present</td>
</tr>
</tbody>
</table>
Areas for Fluid Loss Control

• In formation matrix
• At the formation face
• Inside the perf tunnel
• On the fracture pack
• Inside the casing (on the perforation)
• On a sand-back plug
• In the gravel

• Inside the screen
• Above the screen or in the BHA
• Inside the tubing
• At the surface

Each location requires different plug construction methods and removal considerations.
Cleanup

• Gel break and damage issues
• Fluid imbibition effects
• Other fluid unloading issues
Cleanup

• How to remove from the reservoir (through the fractures or the matrix). Is a surface/interfacial reduction surfactant needed? Is gas needed? Is the formation initially undersaturated to water (yes, it can and does happen).

• From the wellbore – effective unloading is plagued by well deviation and low flow rates from small coiled tubing and other non rotating strings.
Problems - unwanted foams during backflow

• Foam is an emulsion where gas is the internal phase (mist is an emulsion with gas as external phase). Foams are used to unload brines – BUT the forms may cause a problem at the surface.

• Foaming conditions
  – some oils (ppm conc. of C6-C9 organic acids and alcohols)
  – diesel - (particularly bad and varies from lot to lot)
  – some acid additives (emulsifiers, salts, inhibitors)
  – XCD polymers (and others)

• Look for and destroy the stabilizer to break the foam.
Brine Tankage Required

1. Volume of prod. Casing – annulus & below packer?
2. Displacement volume of work string
3. Displacement volume of producing string including packers
4. Volume of manifolds, lines, hoses and pumps
5. Volume of transport tankage (usable)
6. Volume of filtering system (all tanks, lines and pods)
7. Volume of pill tank
8. Pickle flush volume
9. Spare volume for safe operation
Special Topics

- Alternatives to a clear brine
- Gravel pack brines
- Brine handling and preparation
- Solids free gels
- Corrosion
- Hydrates
- Best Practice Learnings
- Toxicity
Alternatives to a Clear Brine

• Emulsions, Foams, Muds
  – Will it be stable?
  – What will stop fluid loss?
  – What will clean up or degrade?
  – What will damage least?
  – Can an oil be ever be used in a gas zone??
Is mud a viable kill fluid for high temp and high pressure wells?

• How much perm damage does it cause?
  – Against the formation?
  – In the perforations?
  – In a naturally fractured formation?
  – Against a gravel pack or screen?

• Is the damage reversible?
  – If you have high wellbore pressures, some of the mud damage is reversible - SOME!
Fluids for Gravel/Frac Pack

- Water - low viscosity brines, low molecular weight salts
- HEC - high molecular weight, water soluble polymer, straight chain
- Xanvis - high molecular wt bio polymer, water soluble. Branched chain, lower damage than HEC?
Water

• Advantages - no mixing, no breakers, high leakoff, easier to get turbulence

• Disadvantages - low gravel carrying capacity (+/- 2 ppg), more fluid lost, compatibility problems?
HEC

• Advantages: mixes easily?? (still must shear and filter), easy to break?? (we’ve had problems here), commonly available

• Disadvantages: lower leakoff rates, lower sand carrying capacity than bio-polymers
XC

- Advantages: shear thinning, higher leakoff, good carrying capacity

- Disadvantages: said to wet some formations (anionic), x-links with calcium and iron (water composition more critical), harder to mix, breaks rapidly above 125°F
# Brine Handling and Preparation

<table>
<thead>
<tr>
<th></th>
<th>Brines</th>
<th>HEC</th>
<th>XC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Min Filter Req</td>
<td>5 to 10 mu</td>
<td>10 mu</td>
<td>10mu</td>
</tr>
<tr>
<td>Beta rating</td>
<td>B=1000</td>
<td>B=10-100</td>
<td>B=10-100</td>
</tr>
<tr>
<td>Shear Req?</td>
<td>N/A</td>
<td>2 bpm/1200 psi</td>
<td>2 bpm/600</td>
</tr>
<tr>
<td>Gravel Conc.</td>
<td>1-5 ppg</td>
<td>1-15 ppg</td>
<td>1-15 ppg</td>
</tr>
<tr>
<td>Breaker</td>
<td>N/A</td>
<td>acid, enz, ox</td>
<td>oxidizers</td>
</tr>
<tr>
<td>Brine Compat?</td>
<td>N/A</td>
<td>&lt;15.5 ppg</td>
<td>KCl &amp; NH4Cl</td>
</tr>
<tr>
<td>Leakoff</td>
<td>excellent</td>
<td>fair</td>
<td>good</td>
</tr>
</tbody>
</table>
Solids Free Gels

- Surfactant gel
- Requires clay control (early problems)
- Breaks with oil
- Not perfect, but generally better than gels.
# Breakers for HEC-Gelled Brines

<table>
<thead>
<tr>
<th>Breaker</th>
<th>BHT</th>
</tr>
</thead>
<tbody>
<tr>
<td>HCl</td>
<td>130 to 200°F</td>
</tr>
<tr>
<td>Ammonium hypochlorite</td>
<td>130 to 200°F</td>
</tr>
<tr>
<td>Enzymes</td>
<td>below 130°F</td>
</tr>
</tbody>
</table>

**No Breaker Required? Above 200°F?**
Corrosivity

• In oxygen free environment, CaCl$_2$/CaBr brines exhibit very low corrosion rates if the pH is kept between 7 and 10.
• Lime and magnesium oxide are used to increase the pH of the brines.
• Use of sulfite oxygen scavengers in large concentrations can potentially cause CaSO$_4$ precip. Use other methods.
• Biocide may not be needed in more concentrated brines.
### Corrosion From Brines

- Example from Materials, Corrosion and Inspection: [http://upstream.bpweb.bp.com/mci/default.asp](http://upstream.bpweb.bp.com/mci/default.asp)

<table>
<thead>
<tr>
<th>Material</th>
<th>General Corrosion</th>
<th>Pitting/Crevice Corrosion</th>
<th>SSC</th>
<th>CL SCC</th>
<th>Relative Failure Risk</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Alloy Steel</td>
<td>Y</td>
<td></td>
<td>Y</td>
<td></td>
<td>Low</td>
</tr>
<tr>
<td>13 Chrome</td>
<td>Y</td>
<td></td>
<td>Y</td>
<td></td>
<td>Low/Med</td>
</tr>
<tr>
<td>Super Cr 13, etc.</td>
<td>Y</td>
<td></td>
<td>Y</td>
<td>Y</td>
<td>High</td>
</tr>
<tr>
<td>Alloy 450</td>
<td></td>
<td></td>
<td>Y</td>
<td>Y</td>
<td>Med</td>
</tr>
<tr>
<td>17-4PH</td>
<td></td>
<td></td>
<td>Y</td>
<td>Y</td>
<td>High</td>
</tr>
<tr>
<td>Duplex Stainless</td>
<td></td>
<td></td>
<td>Y</td>
<td>Y</td>
<td>High</td>
</tr>
<tr>
<td>Austenitic</td>
<td></td>
<td></td>
<td>Y</td>
<td></td>
<td>High</td>
</tr>
<tr>
<td>Super Austenitic</td>
<td></td>
<td></td>
<td>Y</td>
<td></td>
<td>Low</td>
</tr>
<tr>
<td>Ni Alloys</td>
<td></td>
<td></td>
<td>Y</td>
<td></td>
<td>Low</td>
</tr>
</tbody>
</table>
Hydrates and “Freezing”

- Sea floor temperatures
- Gas expansion cooling

- Is the brine naturally hydrate formation resistant?
- Is it tolerant of antifreeze?
Dense Brines Inhibit Hydrates

Hydrate inhibition by CaCl2 Brine

Hydrate equilibrium pressure for pure water calculated using CSMHYD, VK 917 gas

Solvent Needed  Maybe  Safe
LEARNINGS

• Proper disposal required for all chemicals.
• Mixed displacement pills and mud have to be separated from the mud and packer fluid for disposal (zero discharge issues)
• Brine/Water/Acid pumped without surfactants/solvents to displace oil muds (e.g. for an inflow test) prior to clean up can form sludges, these will not be broken down by subsequent clean up pills
• Clean up pills containing surfactants can foam during mixing (particularly when put through a hopper) and during flowback.
Viscosifier Learnings

- XCD/biozan are preferred for mixing viscous pills but do not work in calcium brines,
- HEC will not support solids.
- Polymers should be checked for suitability at the anticipated temperature (thermal thinning an issue particularly >135°C/275°F).
The use of a circulating sub to allow high flow rates is recommended.

As steel surfaces water wet, pipe rotation may not be possible due to friction and displacement of solids becomes much more difficult.

Displacement must exceed solids settling rate and (e.g. 0.18 ft/sec for 40/60 mesh sand in water) not stop once pills are in the annulus.

Displacement optimized for smallest production casing ID can leave bypassed mud in larger OD’s for tapered casing strings.

Reverse circulation is most effective if packer fluid is lighter than mud (watch bridging potential)
Many Brines are Sensitive to Temperature When Viscosified

- Brine type sensitive – NaCl to ZnCl
- Temperature sensitivity is also affected by concentration
- Liquid vs. dry polymer makes a difference.
Stability of Dry HEC in Sodium Chloride

Temperature, F

Precipitation, Separation or Lost Viscosity

Transition Zone

HEC Active and Soluble

Sodium Chloride Density, ppg

3/14/2009

George E. King Engineering
GEKEngineering.com
Liquid HEC in Zinc Based Brines

Zinc Brine Density, ppg

Temperature, F

Transition Zone

HEC Active and Soluble

3/14/2009

SPE 58728
## Brief toxicity data for standard test organisms

<table>
<thead>
<tr>
<th>Species</th>
<th>Acute Toxic Threshold Concentration (mg/l)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Zinc bromide</td>
</tr>
<tr>
<td>Algae</td>
<td>0.32</td>
</tr>
<tr>
<td>Invertibrates</td>
<td>1.6</td>
</tr>
<tr>
<td>Fish</td>
<td>?</td>
</tr>
</tbody>
</table>