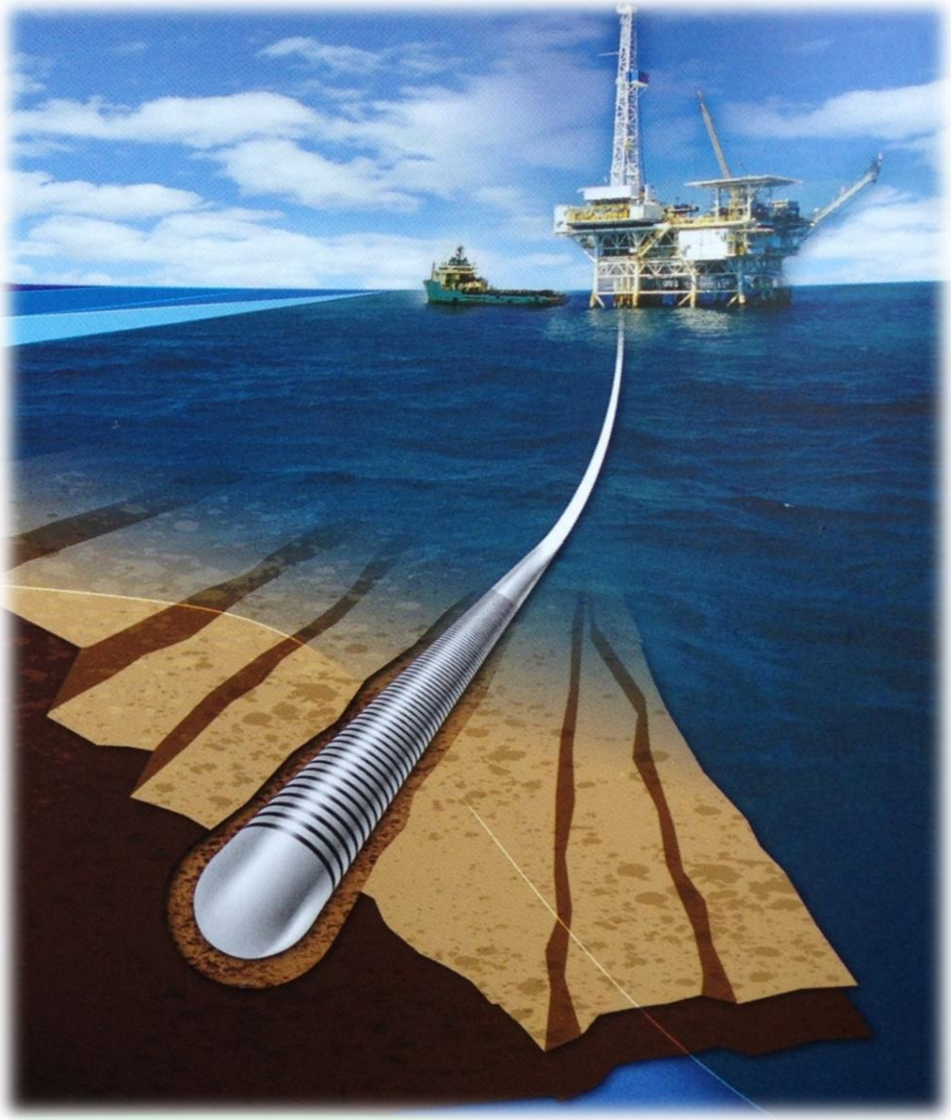
Reservoir Drill-in Fluids, Completion and Workover Fluids



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Abstract

Conventional Drilling Fluids can cause different problems if used in the final stages of the well operations, to avoid dealing with reservoir skin damage, fluid and solids invasion, clay/shale swelling, new fluid systems such as Reservoir Drill-in Fluids and Completion and Workover Fluids were developed to protect the reservoir and prevent damage.

The aim of this Master Thesis Project was to present the difference between Conventional Fluids Systems and Reservoir Drill-in Fluids and Completion and Workover Fluids. The project incorporates different types of fluids used for the above mentioned operation, properties and functions that these Special Fluids develop under the surface of the Earth in either drilling the reservoir section or completing it.

The data and experience that aided the writer in finishing this project was acquired from rig laboratory testing on Conventional Oil Base Mud System (VersaClean), Oil Base Reservoir Drill-in Fluid (VersaPRO) and two types of Completion Fluids (NaCl brine with densities of 9.4 lb/gal and 10 lb/gal). The results of these tests reflect a real life drilling and completion operations, and can be mentioned that several fluid treatments were performed in order to bring the fluids back in Drilling Program specifications. From the comparison of the four fluids, with a 9 day average for the drilling systems, and one test performed on each of the NaCl Brine systems, the most important results were: Solids: 25% Conventional OBM, 14% RDF; Plastic Viscosity: 29 cP Conventional OBM, 19 cP RDF, 5 cP NaCl Brines; Yield Point: 22 lb/100ft^2 Conventional OBM, 14 lb/100ft^2 RDF, 2 lb/100ft^2 NaCl Brines; Fluid Loss: 2.1 ml/30 min Conventional OBM, 2.4 ml/30 min RDF. Backed by these results, Reservoir Drill-in Fluids and Completion and Workover Fluids are more effective than the Conventional Fluid System when the reservoir section is drilled and completed, and if used can decrease the final cost of the project.

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Preface

This section will describe the focus and objectives of this project as well as the methodology and limitations that need to be followed to achieve a good understanding of this Master Thesis in Oil and Gas Technology.

Project

The focus of this project is to present why Reservoir Drill-in Fluids (RDF) and Completion and Workover Fluids are preferred over the Conventional WBM – OBM systems in drilling the reservoir section, and in the completion section; how to safely and economically displace a conventional fluid with an RDF or Completion Fluid; relative wellbore calculations and tests performed on conventional systems and RDF and Completion Fluids.

Relevant rig laboratory data will support, and will be used in the comparison of Conventional Systems with RDF and Completion Fluids for a better understanding of this project.

Objectives

The objectives of this project are to study and understand the behavior of RDF's and Completion Fluids down hole, and a few steps need to be passed in order to have a better perception of these fluids:

- Oil and Gas Reservoirs and Occurrence;
- Conventional Drilling Fluids;
- RDF's, Completion and Workover Fluids;
- Laboratory data comparison between Conventional, RDF and Completion systems;
- Volumetric calculations / displacement method.

Methodology

In the beginning it is important to understand the economic value of Oil and Gas, how to drill for them and how to extract it as cheaply as possible; then to understand the difference between Conventional Fluids and RDF's and Completion Fluids, to compare measurement data from both systems and examine the results; after that, wellbore volumes and calculations will be presented for a better understanding of the drilling process; and how to displace a Conventional System with an RDF or Completion Fluid.

Limitations

It is difficult to present in detail the chemical composition of all kinds of fluids (Conventional, RDF's, Completion, etc.) simply because the chemicals used to build these systems bring important sums of money to each individual company; each fluid company developed its own chemical additives with chemical formulas that are kept secret and classified as New Technology.

Project content

It is important to mention that the data used in this Project is backed up by laboratory data, and all charts can be found as well on the CD that comes along with the project; a list of symbols is provided on page 65 for a better understanding of the acronyms used in this Thesis, and more; Appendix 1 to 4 aid the reader in understanding the tests performed on Fluids, volumetric calculations, and also different facts about RDF's, Completion and Workover fluids.

Introduction

The focus of this project is to present and make the reader understand why Reservoir Drill-in Fluids and Completion and Workover Fluids are preferred over the Conventional Fluid Systems when drilling and/or completing the reservoir section of a well; also it is important to know the down hole behavior of these fluids, in the reservoir section, to maximize production by reducing reservoir damage. Therefore, this project is briefly introduced with an overview on Oil and Gas, Reservoirs, and Drilling Fluids, for a better understanding of the drilling process.

Oil and Gas: Characteristics and Reservoirs

In current days, the Oil and Gas Industry alongside green energy, power the modern world by supplying materials that are used for fuel, heat and in production of many everyday items (ex: plastic, pharmaceuticals, wood processing, heat our homes, etc.). Through its worldwide extent it also employs hundreds of thousands of people and makes a large contribution to the world's technology and economy. [2]

Oil and gas are naturally occurring hydrocarbons composed of Hydrogen (H) and Carbon (C); because these chemical components have a strong attraction to each other, and they will form many hydrocarbon compounds (ex: CH_4, C_4H_{10}, etc.). These hydrocarbons occur in buried rocks thousands of meters below the Earth's surface, and were formed under high pressures and high temperatures, over a long period of time, from organic matter (especially marine or swamp plants and animals that lived millions of years ago), (see Figure 1). [3]

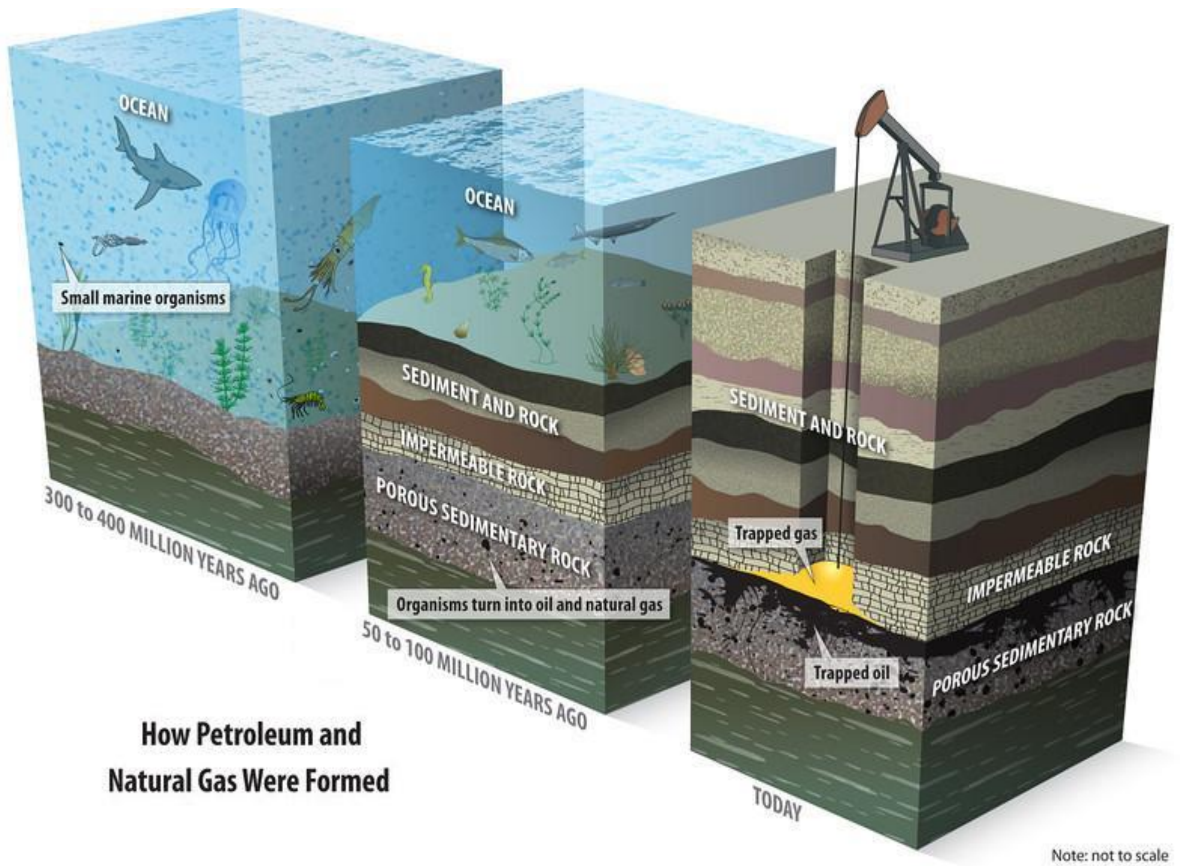


Figure 1 – How Petroleum and Natural Gas were formed [4]

Rock associations that hold these hydrocarbons in the depths of Earth are called reservoirs.

All natural occurring reservoirs must contain:

1. One or more formations of organic-rich sediments that has been buried to a certain depth and exposed to enough pressure and temperature such that hydrocarbons are generated and expelled;
2. Pathways (permeable strata and faults) that allow the oil and gas to migrate;
3. Reservoir rocks with sufficient porosity and permeability to accommodate a large quantity of hydrocarbons (ex: sandstone);
4. Cap rock / Sealing rock / Trap (low to none permeability) structures that restrict the migration of petroleum and keep it within the reservoir rock (ex: limestone, dolomite, chalk). (see Figure 2). [5]

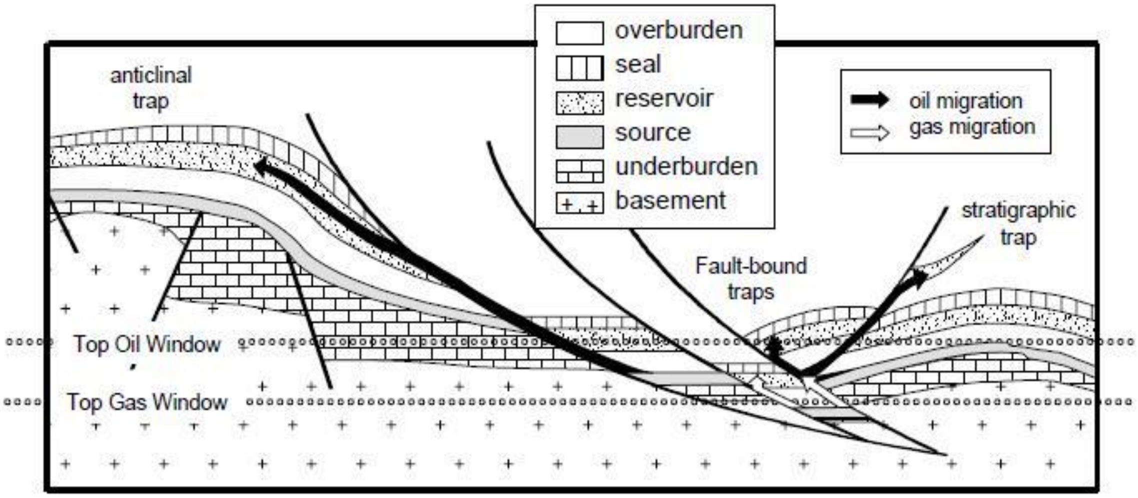


Figure 2 – Elements of a Hydrocarbon Reservoir [5]

For a reservoir to occur, as it was presented earlier on, the reservoir rock must be porous and permeable. Why porous and permeable? Because a rock with pores (with open spaces) can accommodate hydrocarbons inside the pores, presented in Figure 3, the usual porosity found in nature is around 30% for sandstone, that means that 30% of the rock mass can be occupied by hydrocarbons and/or other fluids/liquids.[3]

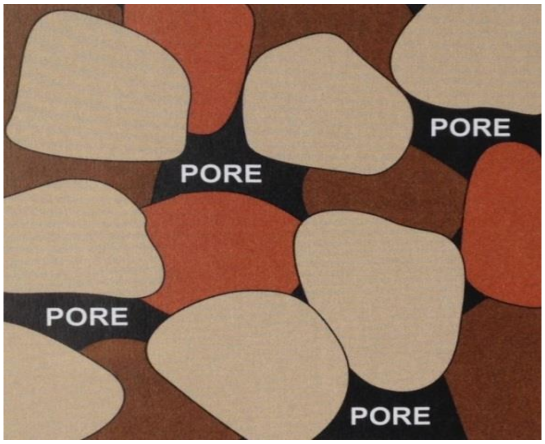


Figure 3 – Rock porosity [3]

Permeable means that the pores are interconnected, so that hydrocarbons or other fluids (ex: sea water) or gas can pass from a pore to another, and flow through the reservoir rock, see Figure 4. That means a good reservoir rock must be porous, permeable but also to accommodate a large quantity of hydrocarbons to make it economical enough to be exploited. [3]

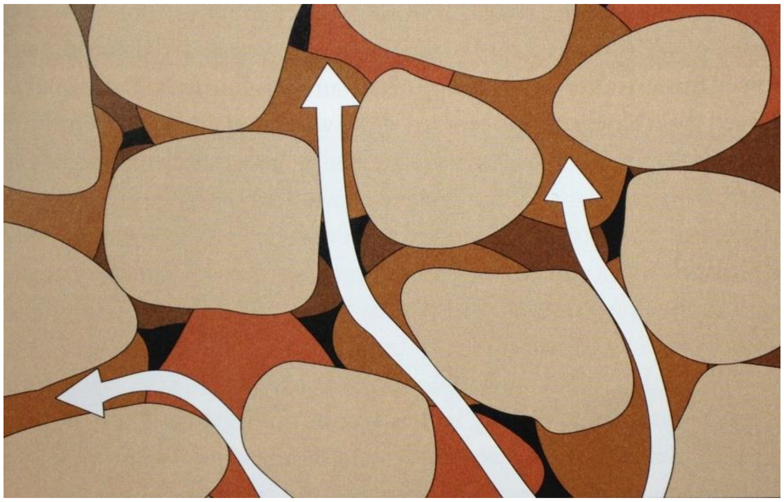


Figure 4 – Connected pores, which give rocks permeability [3]

The porosity and permeability of the reservoir were presented because they will be also mentioned in the next chapters when the Conventional Fluid systems and RDF systems will be presented; these reservoir characteristics play an important role in the drilling fluid selection for drilling the reservoir section.

There are many oil and gas reservoirs on the globe, some of them easier to find than others, special seismic surveys are performed and analyzed by reservoir engineers to establish their existence; after these preliminary steps are performed, the next move is to investigate by drilling a well and tap the reservoir (if applicable). [6]

It has been presented the economic value of Oil and Gas, and the way they naturally occur deep underground, but the purpose is to reach these reservoirs in order to extract these compounds; this operation is done with the help of drilling rigs (onshore, or offshore), and their sole purpose is to dig a hole in the ground and tap an oil and/or gas reservoir as economical as it can. As years pass these rigs evolved to reach the reservoir in fewer days and more economical, thus a considerable increase in profit. [3]

Drilling Fluids

One of the technologies used in drilling are Drilling Fluids, which evolved from a composition of water and clay to Water-based, Oil-Based, Synthetic- Based fluids with added chemicals (called additives) that perform differently under many circumstances. [6]

Conventional Drilling Fluids are Water-based, Oil-based or Synthetic-based fluid systems (built depending on their external (base fluid) and internal phase liquids) used in drilling, to give an increased performance under certain temperatures and pressures experienced down hole. [7]

Drilling the section from the seabed/land to the top of the reservoir is different regarding the economic value of the final project, compared to the reservoir section (see Figure 5); while in the top section the concerns are to seal the permeable formations and maintain the well from caving in; the drilling fluid must perform a multitude of functions to help sustain the wellbore. [6]

The most common conventional Drilling fluid functions:

1. Remove cuttings from the well;
2. Control formation pressures;
3. Suspend and release cuttings;
4. Seal permeable formations;
5. Maintain wellbore stability;
6. Minimize reservoir damage;
7. Cool, lubricate, and support the bit and drilling assembly;
8. Transmit hydraulic energy to tools and bit;
9. Ensure adequate formation evaluation;
10. Control corrosion;
11. Facilitate cementing and completion;
12. Minimize impact on the environment. [7]

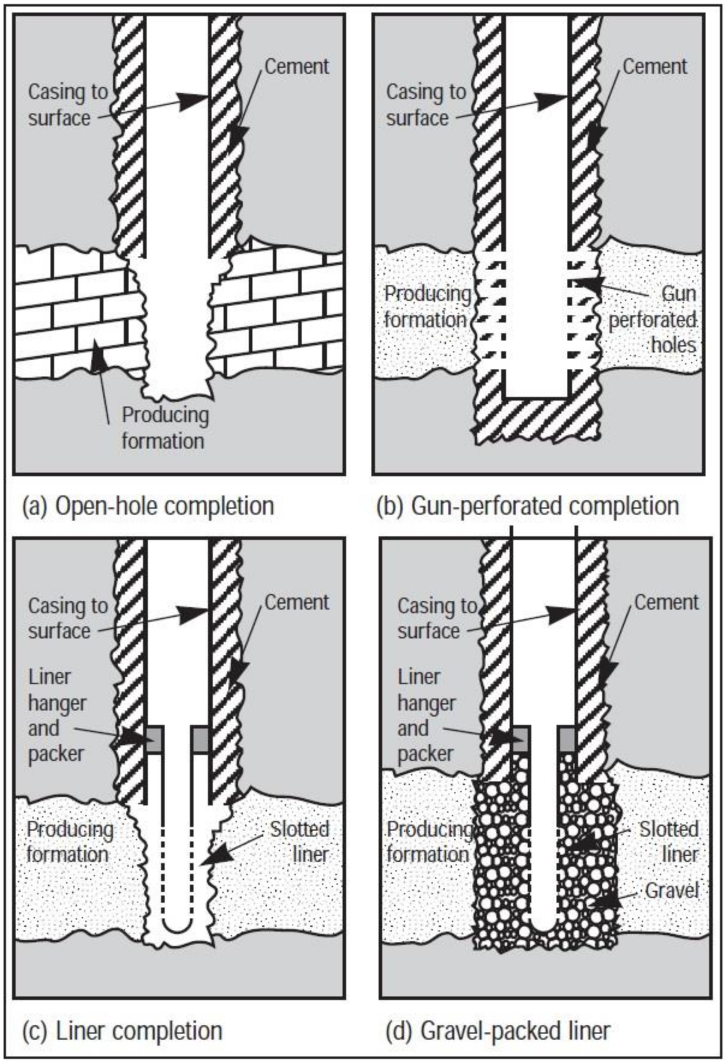


Figure 5 – Types of bottom-hole completions [6]

When drilling reaches the reservoir section, and after the well is cased and cemented; then the reservoir section will be drilled and special measures will be put in place not to damage the reservoir skin and/or plug the reservoir pores; special drilling fluids are used, called Reservoir Drill-in Fluids, or simply RDF, which are specially formulated to maximize drilling experience and to protect the reservoir. The next step is the completion phase of the well, that means making the well able to produce oil and gas, in Figure 5 are shown four types of bottom-hole completions; the completion phase is helped by special fluids called Completion Fluids which aid in controlling subsurface pressures and minimize formation damage to increase production.[6]

In the next chapters, the RDF's, Completion and Workover fluids will be presented in detail, and the difference between these and Conventional Fluids will be better understood.

Conventional fluid systems, properties, tests and contaminants were explained in depth in the 9th Semester Project, "Drilling Fluids Types, Testing and related problems".

In Appendix 1 are explained, in detail, API recommended testing procedures performed on WBM's and OBM's/SBM's, which are the same for RDF's, Completion and Workover fluids; the information presented in Appendix 1, helps in a better understanding of the Tables and Charts presented in Chapter 1, Chapter 2 and Chapter 3.

1. Reservoir Drill-in Fluids

Reservoir Drill-in Fluid, Completion and Workover Fluids are classified under Special Fluids, and they make an important economical difference in the drilling process, as if they are used in the final well stages, will bring a higher profit to all the companies involved in the drilling process.[6], [7]

When drilling into a reservoir zone with a conventional fluid system, it can arise a series of risks and/or problems, that can affect direct the reservoir by plugging the reservoir pores and/or fluid invasion into the productive formation, as presented in Figure 6, a horizontal well subjected to a conventional fluid; it can be observed the Gravel-packed slotted liner, and the fluid invasion into the reservoir rock, damaging it. [6], [8]

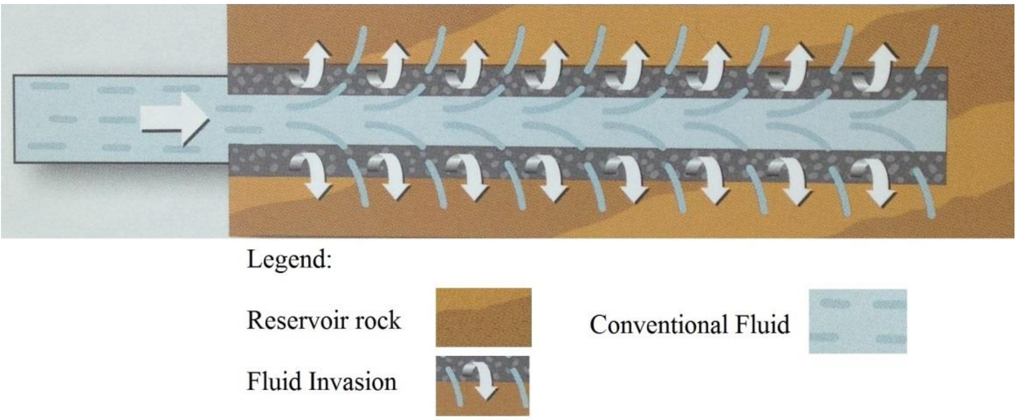


Figure 6 – Fluid invasion in reservoir [1]

In horizontal wells, where the production zone will be exposed to the drilling fluid over a long interval, a precise understanding of the reservoir is needed, to be able to select the proper drill-in fluid; this selection is based on laboratory data gathered from core samples (see Figure 7) extracted from the reservoir, also the natural fluids from the reservoir core sample is analyzed to create a RDF with the same or similar chemical composition, to prevent damage in case of a fluid invasion, and to effective anticipate problems that may occur. [8]

Figure 7 – Reservoir core sample [7]

Reservoir Drill-in Fluids are specially created fluids for the reservoir needs; their sole purpose is to minimize reservoir damage and maximize drilling performance, thereby conserving the productive potential of the reservoir. [6], [7] The composition of these fluids depends on the formation being drilled; a multitude of fluids can be used ranging from water, brine, oil and synthetic base fluids, plus additional chemicals that help in performing different functions, and should have special features, as followed:

1. Formation damage control:
   a. RDF's should not contain inert solids (ex: Barite, sand) or clays that may have the power to settle into the reservoir pores and plug the formation;
   b. It should be built with acid-soluble clays, and properly selected fluid loss control agents, that limit the fluid invasion into the reservoir rock and make possible a thorough clean-up;
   c. The fluid should be formulated to inhibit clays from the production zone to swell, migrate and/or plug the reservoir rock; also it needs to be compatible with the reservoir fluid not to change the natural chemistry of the reservoir, or form emulsions with it, and block the reservoir pores. [6], [7], [8]

A good example of how an RDF should perform can be seen in Figure 8; in a horizontal well with a Gravel-packed slotted liner; the RDF seals the permeable gravel by constructing a thin, impermeable filter cake, and minimizing the fluid filtrate lost to the formation.

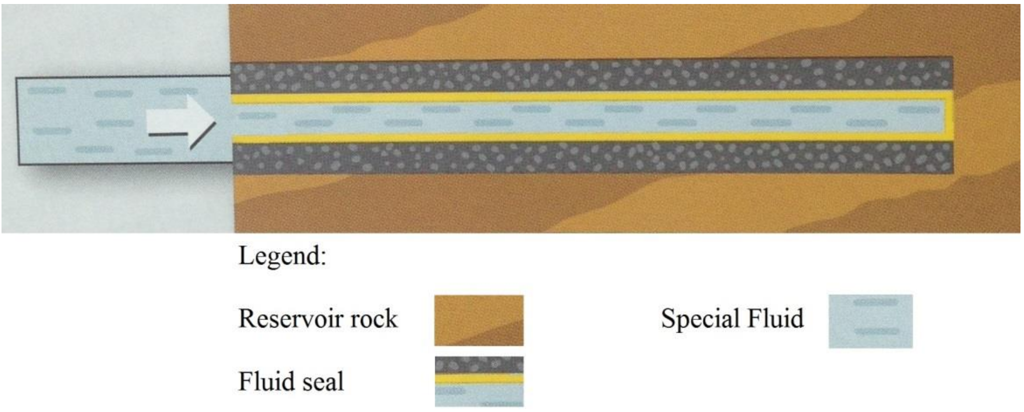


Figure 8 – Reservoir sealed by RDF [1]

2. Drilling performances:
   a. RDF's, as Conventional fluids, should provide wellbore stability and minimize hole enlargement when drilling in open hole;
   b. RDF's should aid in the transport of cuttings (hole-cleaning), minimize shale inhibition and lubricate and sustain the drilling assembly. [6], [7]
3. Completion compatibility:
   a. RDF's should be compatible with completion fluids and reservoir fluids;
   b. Fluid components should be composed of water soluble, acid soluble or solvent soluble material, for a better clean-up. [6], [7]

The main factors in deciding the Reservoir Drill-in Fluid Type are the reservoir rock and well conditions; in Appendix 2 it can be observed the procedure that needs to be followed in order to select the proper RDF compatible with the current conditions.

If the permeability of the reservoir is damaged in any way it is not possible to restore it to the initial state. [8]

Formation damage mechanisms

A group of several factors that can damage the productive formation and reduce the amount of hydrocarbons that can be extracted will be presented in the next paragraphs, accompanied by possible prevention techniques:

1. Solids plugging – a large range of solid materials contained by the drilling fluid can end up plugging the reservoir pores; these materials can range from drill solids, fluid chemicals, clay viscosifiers. Prevention techniques: added fluid chemicals (solids) should be sized to form a bridging filter cake between the formation and the drill-in fluid (see Figure 9); also these chemicals should be acid-soluble. [6], [7]

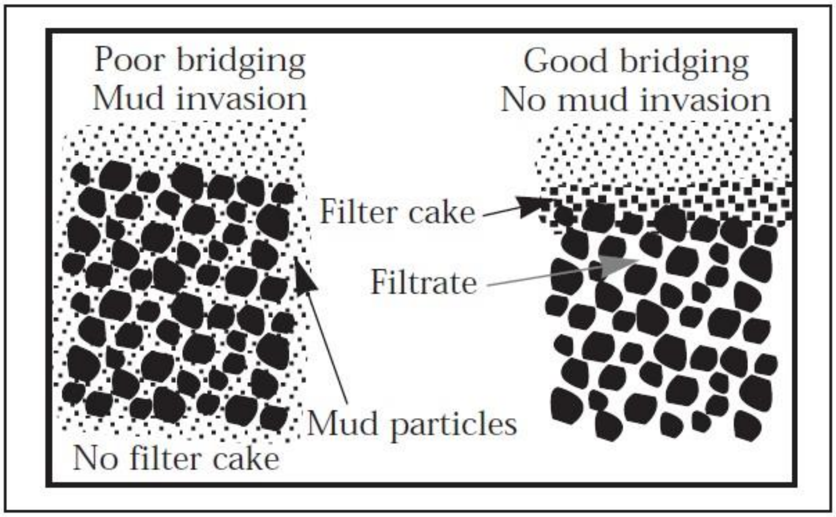


Figure 9 – Bridging comparison [6]

A well designed solids control program should be put in place to remove drill solids from the first circulation, a major problem will arise if they are allowed to be recirculated, because as they are pumped multiple times through the bit nozzles they will get smaller and smaller and scatter in the fluid creating a mass of fine solids that will damage the reservoir skin. [6]

2. Clay inhibition and migration – these clays are attributed to some sandstone formations, and when subjected to drilling fluid filtrate, cement, spacers, can swell, change size and/or migrate which can interfere with the natural flow of the reservoir in the completion stage. Prevention techniques: the reservoir drill-in fluid used should have the property to inhibit swelling; several fluids have been developed in this matter: oil-base, synthetic-base, and also fluids that mimic the chemical properties of the reservoir fluid. [6]

3. Emulsions and scaling – these two mechanisms depend on the contact between the improper RDF fluid composition and the reservoir fluid; if the RDF system is not chemical engineered to mimic the reservoir fluid chemistry, emulsions may appear and block or restrict the natural flow of the reservoir; Scaling, chemical reaction between the fluid filtrate and the reservoir fluid that will form a precipitate, thus will result in formation damage (blocked pores), some examples can be calcium (Ca^{2+}) from the fluid filtrate react with soluble carbonate formation (CO_3^{2-}) to form calcium carbonate ($CaCO_3$) scale. Prevention techniques: designing a chemical compatible RDF System. [6]

Reservoir drill-in fluids are designed to produce a thin, slick, impermeable filter cake that blocks/limits the contact between the reservoir fluids and the wellbore fluids; in many cases of reservoir completed with gravel-packed liner or in open hole, the deposit of filter cake is recommended to prevent the drill-in fluid and drill solids from invading the pay zone, also the filter cake should be designed to be easily removed with a breaker solution (acid) to begin the completion process. [9]

In Figure 10 is presented a special filter cake developed by a FloThru RDF system (will be presented later on this chapter) that limits the fluid invasion in the producing formation while allowing the hydrocarbons to flow at a low flow-initiation pressures. [10]

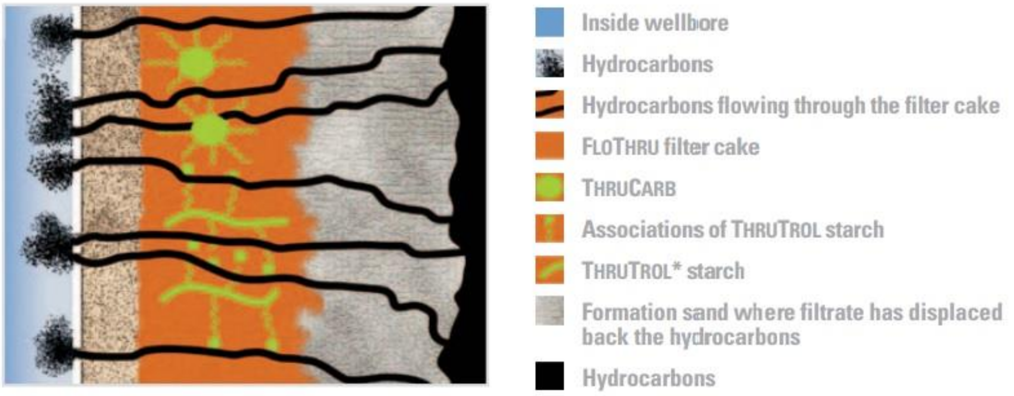


Figure 10 – The FloThru filter cake [10]

RDF's, Types and Uses

In the next paragraphs the most important M-I SWACO Reservoir Drill-in Fluid Systems will be presented, note that some chemicals and/or systems are classified under New Technology (NT); they are confidential and cannot be disclosed in the current project, therefore they will be marked with the symbol: NT, and chemicals that are Mark of M-I SWACO with: *.

DiPro System – it is characterized by being the single water-based reservoir drill-in fluid, that is biopolymer-free, in the Oil and Gas Industry. [12]

Applications: can be used offshore and onshore in wells that will use divalent brines for the completion phase, and where the need for a high-density, low-solids content RDF is required. [1]

Strong points:

- Has stable rheology;
- Low fluid loss;
- Pre-hydration of polymers is not required;
- Can be formulated from more mixed-salt brines;
- Shale stability;

Benefits:

- Minimize formation damage;
- Cost effective;
- High performance in deep water wells;

- Enhance drilling experience;
- Good filter cake removal;
- Designed to be compatible with completion method. [11]

DiPro system is formulated to give a high density and low solids content, besides the minimal formation damage, and its formulation can be seen in Table 1.

Being a water-base fluid, it uses brines and/or brine blends as a fluid phase; these brines aid in shale inhibition and also provide density that can range from 11.5 to 17.5 lb/gal (1.38 to 2.1 SG).

Table 1 – DiPro System components [11], [12]

Product	Functions	Description
$CaCl_2$, $CaBr_2$, $CaCl_2/CaBr_2$, $CaBr_2/ZnBr_2$, $CaCl_2/CaBr_2/ZnBr_2$	Shale inhibition; Density	Brine
DI-Trol*	FLC agent; Viscosifier	Starch derivative
DI-Balance*	pH balance; Viscosifier	Inorganic compound
Safe-Carb* (all grades) ($CaCO_3$)	Bridging, plugging and weighting agent	Calcium Carbonate ($CaCO_3$)
DI-Boost* (optional)	Viscosity stabilization	Glycol blend

In Table 2 are presented the typical properties of a DiPro system.

Table 2 – Typical DiPro properties. [11]

Typical DiPro properties	
Fluid density (MW)	11.6 – 17.0 lb/gal
Plastic viscosity (PV)	15 – 35 cP
Yield point (YP)	15 – 35 lb/100 ft^2
3 RPM	2 – 7 cP
HTHP Fluid Loss	< 5.0 ml/60 min @ 150^{o}F (66^o C)

FazePro System – was invented to perform as well as a Conventional OBM system, plus the proper cleanup efficiency of a Conventional WBM system. [12]

A very complex system, which possesses the ability to interchange its properties, while being efficient in drilling with oil-external phase, controls reactive shale, increase ROP and provides borehole stability; and water-external phase for an enhanced clean-up and a minimal impact on the completion state. [13]

The reversible change from oil-wet to water-wet (see Figure 11) is performed by changing the pH in the FazePro System; the purpose is to keep a high pH during drilling, that maintains the filter cake and separates the reservoir from the wellbore; after drilling operations are completed the pH is lowered below 7 (<6) for the complete removal of the filter cake, that gives connectivity between the reservoir and the wellbore. [14]

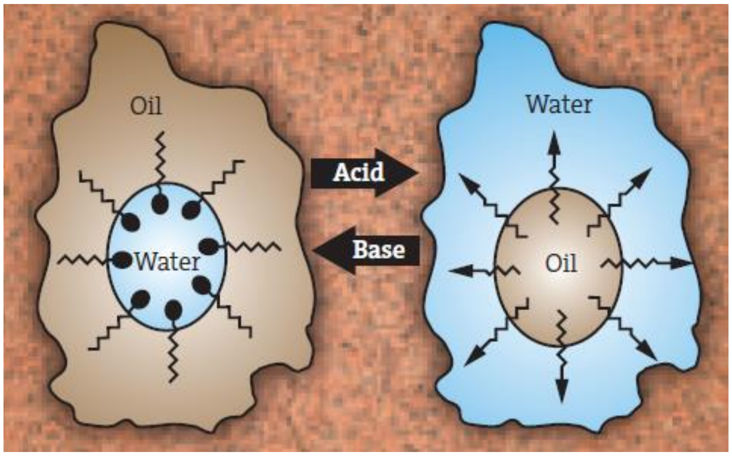


Figure 11 – FazePro reverse emulsion [1]

In Figure 12 can be observed the way the fluid performs while:

- Oil-wet – in the left jar it can be observed the fluid behavior as an oil-wet substance, the white substance from the plastic pipette does not dissipate in the fluid's mass, it will drop at the bottom of the jar without mixing with the surrounding oil-wet fluid;
- Water-wet – in the right jar it can be observed the fluid behavior as a water-wet substance, the pH was dropped under 7 and can be seen that the white substance from the plastic pipette is dissipating in the fluid's mass.

Figure 12 – FazePro invert emulsion change [15]

Applications: mostly used in wells with open hole completion, gravel-packed liner or cased hole injector wells that need a comprehensive filter cake destruction and removal, for an unimpeded injection or production. [1]

Strong points:

- Maximized drilling performance while oil-wet;
- Good clean-up while water-wet;
- Easy reversed with pH changes;
- Good shale inhibition.

Benefits:

- Reduces waste generation;
- Easy removal of filter cake;
- Enhanced drilling experience;
- Stable wellbore;
- No remedial treatments needed. [14]

In Table 3 are presented the FazePro system components and functions.

Table 3 – FazePro System components [11], [14]

Product	Functions
Synthetic, mineral oil, olefin, paraffin	Provides continuous phase for system
$CaCl_2$, $CaBr_2$, NaCl, NaBr (Brines)	Internal phase inhibition
VG-69*, VG-Plus*	Viscosifiers
Faze-Mul*	Primary emulsifier
Faze-Wet*	Wetting agent / HTHP FLC agent
Lime ($Ca(OH)_2$)	Control alkalinity
EcoTrol*	FLC agent
Safe-Carb* (all grades) ($CaCO_3$)	Acid-soluble bridging agent

In Table 4 are presented the typical properties of a FazePro system.

Table 4 – Typical FazePro properties. [11]

Typical FazePro properties	
Fluid density (MW)	9.0 – 12.0 lb/gal
Plastic viscosity (PV)	25 – 35 cP
Yield point (YP)	20 – 25 lb/100 ft^2
10 sec. Gel	6 – 10 lb/100 ft^2
10 min. Gel	10 – 20 lb/100 ft^2
3 RPM	5 – 7 cP
P_{om} – Alkalinity of whole mud	< 3.0 ml
Electric stability (ES)	500 – 800 volts
HTHP Fluid Loss	< 5.0 ml/30 min @ 200^{o}F (95^o C)
Oil/brine ratio	80/20 – 60/40 %

FloPro NT System – water-base system which has a non-damaging formulation, it is environmentally friendly, very efficient with cuttings transport and develops a high Rate of Penetration (ROP). [12]

This system is used for open hole completions and is specifically built for each individual application. [11]

Applications: a multi-purpose new developed system for use in onshore and offshore wells, that require a non-damaging RDF for variations of completion methods, such as open-hole gravel-pack or non-gravel-pack, barefoot, slotted or perforated liner, cased-hole, expanded sand-screen, or high-temperature applications. [17]

Strong points:

- Individual formulations;
- Ultra-low permeability filter cake;
- Minimize formation damage;
- Rheological engineered;
- Environmental friendly.

Benefits:

- Maximizes production;
- Reduces final cost;
- Minimizes fluid and solids invasion in the reservoir;
- Maximizes ROP;
- Reduces pump pressure. [11]

FloPro NT can be composed from a wide range of Brines ($CaCl_2$, $CaBr_2$, $CaCl_2/CaBr_2$, etc.) that can provide a density range from 8.4 lb/gal to 14.7 lb/gal (1 to 1.8 SG) without any other addition of weighing agents. [6]

The products that compose FloPro NT are all soluble in acid, oxidizers or water, for an easier way of removing the filter cake; an indicated procedure prior to the completion phase is to spot a solid free (SF) pill to break and remove the filter cake. [6]

In Table 5 are presented the FloPro NT system components, functions and description.

Table 5 – FloPro NT System components [11]

Product	Functions	Description
Base fluid (brine) – halide or formates	Density and shale inhibition	Base Brine
Flo-Vis Plus*, Flo-Vis NT*	Viscosifiers	Premium grade xanthan gum
Dual-Flo*, Flo-Trol*	FLC	Modified starch
Greencide 25G	Bactericide	Glutaraldehyde
Caustic Soda (NaOH), MgO, KOH	Control pH	Alkalinity
Safe-Carb* (all grades)	Bridging, plugging and weighting agent	Calcium Carbonate ($CaCO_3$)
Kla-Guard*, Kla-Stop*	Shale inhibition	Amine type of shale inhibitors

In Table 6 are presented the typical properties of a FloPro NT system.

Table 6 – Typical FloPro NT properties. [11]

Typical FloPro NT properties	
Fluid density (MW)	8.8 – 18.0 lb/gal
Plastic viscosity (PV)	12 – 20 cP
Yield point (YP)	20 – 35 lb/100 ft^2
3 RPM	10 – 15 cP
pH	8.5 – 10.0
HTHP Fluid Loss	< 5.0 ml/30 min @ 150^{o}F (66^o C)

NovaPro System – synthetic-base reservoir drill-in fluid invert-emulsion, designed to minimize formation damage for all types of completions. [12]

This system is built to be compatible with the reservoir, drilling conditions, and comply with the environmental protocol. [11]

Applications: this Synthetic-base system provides similar advantages to oil-base systems, it is more expensive than competitive oil-base systems, but as a plus it presents an approved offshore discharge of cuttings in many locations all over the world. [6] Can be used onshore and offshore for all kinds of development wells that are planned for either cased or an open-hole completion. [1]

Strong points:

- Designed to be compatible with the completion method;
- Synthetic-base fluid for external phase;
- Invert-emulsion drilling fluid properties;
- Enhanced drilling performance.

Benefits:

- Reduces fluid loss;
- High ROP, lubricity and wellbore stability, plus environmental friendly;
- Minimizes formation damage and maximizes reservoir production. [1], [11]

In Table 7 are presented the NovaPro system components and functions.

Table 7 – NovaPro System components [11]

Product	Functions
Base synthetic	Provides the continuous phase
Brine	Provides the internal phase; shale inhibition
VG-Plus*	Viscosity
NovaMul*, SureMul*	Primary emulsifier
NovaWet*, SureWet*	Wetting agent
Lime ($Ca(OH)_2$)	Control alkalinity
Safe-Carb* (all grades)	Acid-soluble bridging material

In Table 8 are presented the typical properties of a NovaPro system.

Table 8 – Typical NovaPro properties. [11]

Typical NovaPro properties	
Fluid density (MW)	9.0 – 16.0 lb/gal
Plastic viscosity (PV)	10 – 40 cP
Yield point (YP)	10 – 25 lb/100 ft^2
3 RPM	5 – 15 cP
P_{om} – Alkalinity of whole mud	< 3.0 ml
Electric stability (ES)	>500 volts
HTHP Fluid Loss	< 5.0 ml/30 min @ 250°F (121° C)

FloThru System – water-based system formulated in such way that creates organophilic connected pores in the filter cake that aid hydrocarbons to flow inside the wellbore and denies any water/fluid in the reservoir; which result in lower water production. [12]

Strong points:

- No chemical breakers needed in clean-up;
- Channels through filter cake for hydrocarbon flow;
- High tolerance to drill solids contamination.

Benefits:

- Improves completion time and costs;
- Provides uniform clean-up;
- Increase production rates;
- Eliminates clean-up risks and costs.[10]

In Table 9 are presented the FloThru system components and functions.

Table 9 – FloThru System components [11]

Product	Functions	Description
Base fluid (brine)	Density and shale inhibition	Base brine
Flo-Vis Plus*, Flo-Vis NT*	Viscosifiers	Premium-grade xanthan gum
ThruTrol*	FLC and viscosity	Organophilic starch
Thrucarb*	FLC and bridging agent	Organophilic Calcium Carbonate
Greencide 25G	Bactericide	Gluteraldehyde
Caustic Soda, MgO, KOH	Control pH	Alkalinity
Safe-Carb* (all grades)	Bridging, plugging and weighting agent	Calcium Carbonate ($CaCO_3$)
Kla-Guard*, Kla-Stop*, Kla-Cure*	Shale inhibition	Amine type of shale inhibition

Applications: system developed for all types of hydrocarbon producing wells; used in any open-hole application where a chemical breaker is usually applied. [10]

In Table 10 are presented the typical properties of a FloThru system.

Table 10 – Typical FloThru properties. [10], [11]

Typical FloThru properties	
Fluid density (MW)	8.8 – 18.0 lb/gal
Plastic viscosity (PV)	15 – 20 cP
Yield point (YP)	25 – 35 lb/100 ft^2
10 sec. Gel	10 – 12 lb/100 ft^2
10 min. Gel	13 – 18 lb/100 ft^2
3 RPM	10 – 15 cP
pH	8.5 – 9.5
API Fluid Loss	< 5.0 ml/30 min @ ambient temp.
HTHP Fluid Loss	< 10.0 ml/30 min @ 150^{o}F (66^o C)

VersaPro System – oil-base reservoir drill-in fluid; can be used in all types of completions, and is based on the formulation for VersaClean Conventional OBM. [12]

This system is commonly used in the reservoir drilling section in the North Sea; rig laboratory tests were performed on this RDF System and will be compared with rig laboratory tests performed on VersaClean Conventional OBM System.

The density of the VersaPro system is maximized through the internal phase (brine), and may include a wide range of clear brine fluids (shown in Table 11) that can provide densities from 7.0 to 14.2 lb/gal;

Table 11 – VersaPro system Density ranges [16]

Brine internal phase	**Maximum density (lb/gal)**
Calcium Chloride ($CaCl_2$)	9.4 lb/gal
Potassium Formate ($KHCO_2$)	10.6 lb/gal
Calcium Bromide ($CaBr_2$)	11.2 lb.gal
Cesium Formate ($CsHCO_2$)	14.2 lb/gal

Applications: for reservoir sections that need an oil-base reservoir drill-in fluid for cased-hole or open-hole completions, which has to be solids free, or have a low solids content, and also a low fluid loss to the formation. [16]

Strong points:

- Low solids content;
- High-density brine as internal phase;
- Oil for continuous phase;
- Stable under high-temperature.

Benefits:

- Low fluid loss;
- Reduced screen plugging;
- Maximized production rates;
- Reduced gelation, sag and settling potential.[1]

In Table 12 are presented the VersaPro System components and functions.

Table 12 – VersaPro System components [11]

Product	Functions
Base oil	Continuous phase
Brine	Internal phase
VG-Plus*	Viscosifiers
VersaPro P/S, VersaCoat*, VersaWet*	Primary emulsifier
EcoTrol*	FLC agent
Lime	Alkalinity
Safe-Carb* (all grades)	Acid-soluble bridging material

In Table 13 are presented the typical properties of a VersaPro system.

Table 13 – Typical VersaPro properties. [16]

Typical VersaPro properties	
Fluid density (MW)	9.0 – 16.0 lb/gal
Plastic viscosity (PV)	10 – 40 cP
Yield point (YP)	10 – 25 lb/100 ft^2
3 rpm	5 – 15 cP
P_{om} – Alkalinity if whole mud	< 3.0 ml
Electric stability	>300 volts
HTHP Fluid Loss	< 5.0 ml/30 min @ 250^{o}F (121^o C)

It has been mentioned in the current chapter what is an RDF System, what are its functions and also the types of Reservoir Drill-in Fluids that can be used in different environments, plus their composition and typical properties. A comparison between a Conventional OBM VersaClean and an RDF System VersaPro will be presented in Chapter 3 to acknowledge the difference between them and also to recognize the pluses that an RDF can bring when drilling the reservoir section.

Health, Safety and Environmental Concerns

Health and safety issues relate to work protection, and Environmental concerns relate to the impact on the environment exposed to drilling and completion operations. Protecting the environment and people is one of the most substantial concerns that drilling operation face today; fluid companies are on a race to develop and produce environmental friendly products to aid the drilling operations by minimizing, measuring and managing pollution. [6]

Appropriate PPE must be used when handling all kind of fluids, because they can cause all kind of irritations to eyes, skin and internal organs, also Material Safety Data Sheets must be consulted to learn the safe way of handling these fluids, and how to act if come in direct contact with them. [6]

Environmental impact is managed by a series of techniques:

1. Pollution prevention;
2. Recycling;
3. Volume minimization;

4. Treatment and disposal. [6]

These techniques constrain the fluid company to develop new environmental friendly chemicals, and properly treat and reuse or dispose of waste material. [6]

Under North Sea regulation Water Base and Synthetic Base Systems have an advantage over Oil Base Systems, the majority of Water Base and Synthetic base systems can be discharged overboard if they do not present any traces of oil or heavy metals. Oil Base systems have a Zero discharge policy. [6]

In the next chapter (Chapter 2) Completion and Workover fluid will be presented in the same manner as the RDF's were presented in this chapter.

2. Completion and Workover Fluids

Once the drilling reaches TD, a formation evaluation is done in order to estimate if the well is able to produce enough hydrocarbons to give back profit; the completion phase will commence, if not, the well will be plugged and abandoned. [3]

Completion and Workover Fluids are specially designed to aid in Completion and remedial Workover operations. The main functions that these fluids need to exert are:

- Control formation pressure – with density;
- Minimize formation damage. [6]

The difference between Completion and Workover operations is:

- Completion operation: will commence once drilling of a well has ended, and it will be prepared to produce for the first time;
- Workover operation: remedial operations performed on a well that has been produced before.

The fluids for Completion and Workover operations will mostly be the same. [7]

There are several types of Completion and Workover fluids that are selected depending on the application, which range from:

- Clear, solids-free brines;
- Polymer-viscosified brines;
- Other fluids such as oil-based, water-based or converted muds. [6]

The most commonly used Completion and Workover fluids are Clear brines, and they will be the focus of the current chapter as they are used for both operations that are discussed.

Clear brines are true solutions that incorporate dissolved salts in a mass of water, meaning that they don't incorporate any solids; they need to be stable and have an enhanced performance for a wide range of operations like: perforating, gravel-packing, well kills, fishing and also drilling. [11]

These brines can be composed from one type of dissolved salt (single salt), or an intermixture of two or three types of salt compounds that are compatible with one another. In order for these Clear brines to perform at a high level they need to be:

- Solids-free;
- To inhibit shale;
- Able to be reused;
- To be available in a wide range of densities. [6]

Applied in the field, these clear brines should be formulated to guarantee a stable wellbore with a minimal reduction in permeability. In the selection of clear brines some factors should be taken in consideration:

1. Density and Turbidity;

Density and Turbidity (Clarity) are representative properties for clear brines, while density is necessary to control wellbore pressures, and can range from 8.33 lb/gal to 21 lb/gal depending on the Brine type (see Table 14) [11]; turbidity is a function of fluid cleanliness, it is measured in Nephelometer Turbidity Units (NTUs) by a Turbidity Meter , see Figure 13 – Nephelometry is the technique of beaming light on a sample, and measuring the amount of light scattered at a certain angle, the industry standard is <30 NTUs per sample – ; if a fluid contains drill solids, undissolved salts, etc., the turbidity will be high, the NTU value will drop by cleaning the fluid, thus a brine with a low NTU will be preferred in Completion and Workover operations. [7]

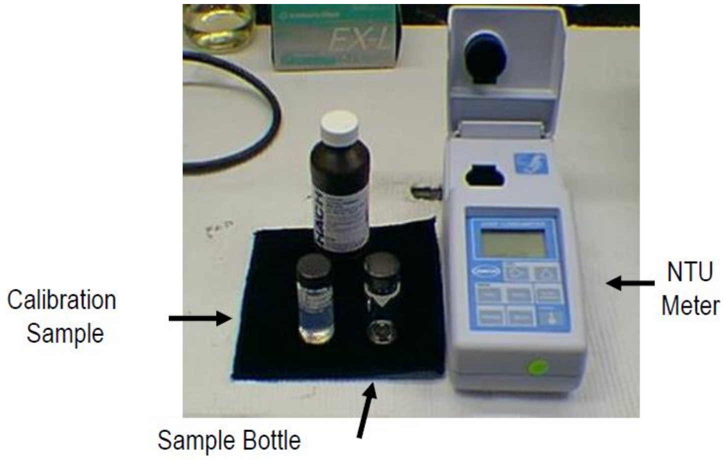


Figure 13 – NTU Meter [7]

Table 14 – Clear Brine Types and Density ranges: [11]

Brine Type	Density Range (lb/gal)	Typical Density (lb/gal)
NaCl	8.33 – 10.0	8.4 – 10.0
KCl	8.33 – 9.7	8.4 – 9.0
NH_4Cl	8.33 – 8.9	8.4 – 8.7
NaBr	8.33 – 12.7	10.0 – 12.5
NaCl / NaBr	8.33 – 12.5	10.0 – 12.5
$NaHCO_2$	8.33 – 11.1	9.0 – 10.5
$KHCO_2$	8.33 – 13.3	10.8 – 13.1
$NaHCO_2$ / $KHCO_2$	8.33 – 13.1	8.4 – 12.7
$KHCO_2$ / $CsHCO_2$	8.33 – 20.0	13.1 – 18.3
$CaCl_2$	8.33 – 11.8	+/- 9.0 – 11.6
$CaBr_2$	8.33 – 15.3	+/- 12.0 – 14.2
$CaCl_2$ / $CaBr_2$	8.33 – 15.1	11.7 – 15.1
$ZnBr_2$	+/- 12 – 21.0	19.2 – 21.0
$ZnBr_2$ / $CaBr_2$	+/- 12 – 19.2	+/- 14.0 – 19.2
$ZnBr_2$ / $CaBr_2$ / $CaCl_2$	+/- 12 – 19.1	+/- 14.2 – 19.2
$CsHCO_2$	+/- 8.33 – 20.0	13.2 – 19.2

Density is obtained by dissolving salt in water, thus the obtained density will be directly proportional to the quantity of added salt in solution.

The solubility of salts in water is very high, fit to give densities up to 21 lb/gal, also as the solubility increases, the salt-water ratio will become smaller, as it will be presented in Table 15, some clear brine systems can have more salt than water in their composition. [11]

In Table 15 it can be observed the maximum solubility of completion fluid brine in water, one barrel (bbl), at room temperature:

Table 15 – Maximum solubility of salt in water one bbl at room temperature: [11]

Salt	Sol wt%	Density lb/gal	Specific Gravity	Lb Salt	Lb Water
NaCl	26	10.0	1.200	109	311
KCl	24	9.7	1.164	98	309
NaBr	46	12.7	1.525	245	288
$CaCl_2$	40	11.8	1.416	198	298
$CaBr_2$	57	15.3	1.837	366	194
$ZnBr_2$	78	21.0	2.521	688	194
$NaHCO_2$	50	11.1	1.329	231	235
$KHCO_2$	78	13.3	1.595	434	125
$CsHCO_2$	84	19.17	2.30	676.3	128.8

2. Wellbore temperature;

Temperature is a factor that must be taken in consideration when selecting a completion fluid, due to the change in volume that brine will suffer at temperature change; the density of brine will decrease as the temperature increases due to thermal expansion, and thus the well stability may suffer if the brine can't handle the formation pressure. Temperature can also influence additives and corrosion rate. [6]

In Figure 14 it can be observed the density reduction of a $CaCl_2$ Brine due to thermal expansion.

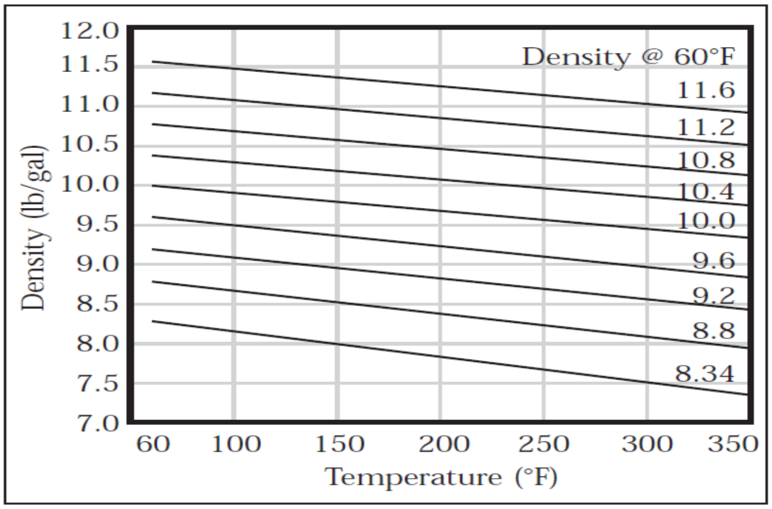


Figure 14 – Density reduction due to thermal expansion ($CaCl_2$). [6]

3. Crystallization temperature;

Brines are, as it was presented earlier on, salts dissolved in water, this leads to lowering the freezing / crystallizing temperature of the mixture until the eutectic point is achieved (see Figure 15); each individual brine, has its own crystallization / freezing temperature, under this temperature the fluid will freeze. [6]

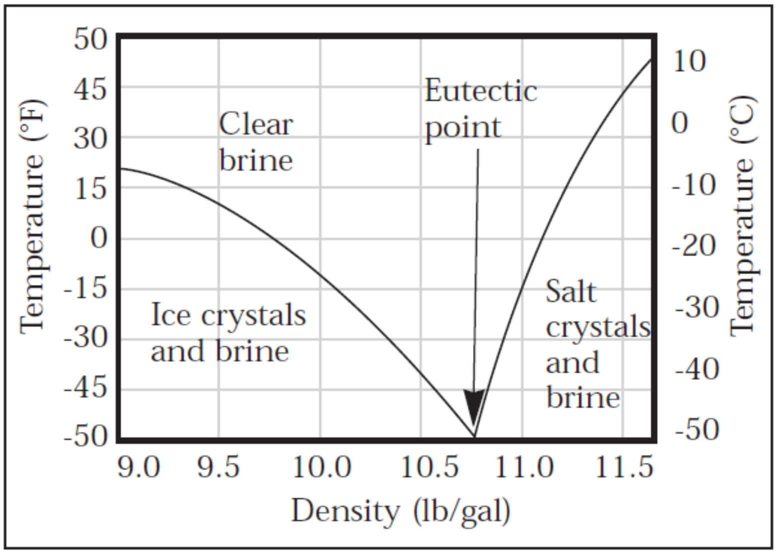


Figure 15 – Density effect on the crystallization temperature of a $CaCl_2$ Brine [6]

There are three crystallization points measurements used to determine when freezing occurs (see Figure 16):

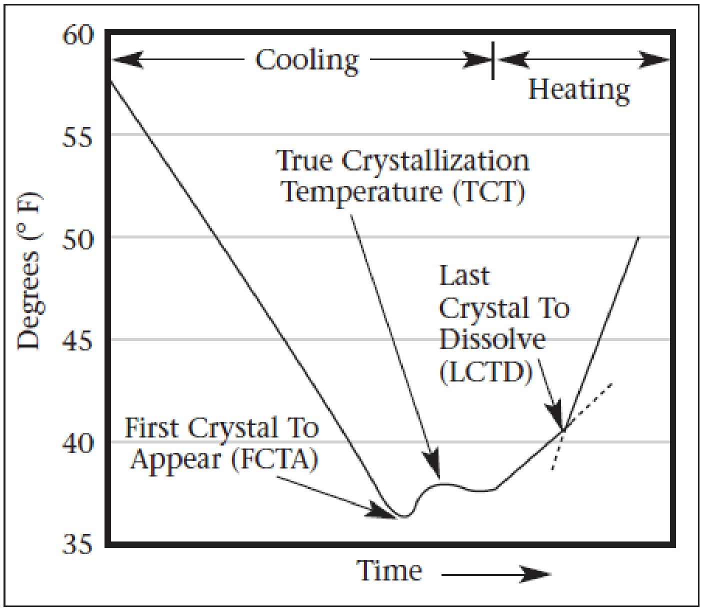


Figure 16 – Crystallization points [6]

a. First Crystal To Appear (FCTA): represents (as seen in Figure 16) the appearance of the first visible salt crystal as the temperature of the solution drops. It represents the lowest point on the Crystallization curve and includes the cooling under the True Crystallization Temperature (TCT) referred as the super-cooling effect.

b. True Crystallization Temperature (TCT): can be explained as an increase in the temperature of the solution after the super-cooling minimum (allowing more salts to be dissolved in the solution), before continuing to cool, it is represented in Figure 16 as the slope in the Crystallization curve.

c. Last Crystal to Dissolve (LCTD): it is represented on the Crystallization curve as the point where the last salt crystal disappears if the solution is exposed to an increase in temperature. The LCTD point is influenced by the contamination percent in the solution. [6]

The salt concentration in a brine at which the solution is saturated is a function of temperature; as it was presented in Table 15, for example $CaCl_2$, has up to 40-wt% percentage of $CaCl_2$ soluble salt, dissolved in water at room temperature; this mixture is known as to be saturated at room temperature. If the temperature decreases (ex: cold climates, offshore environments) the brine will cool, and under a certain temperature salt will precipitate from the solution; it must be taken into consideration that pressure increases the crystallization temperature of a brine which will lead to salt crystals forming (see Figure 17). [11]

Figure 17 – Salt crystals [7]

In the opposite instance, if the brine is heated (ex: hot climates) extra salt can be dissolved in the solution. The temperature at which a certain salt will saturate the water is referred as True Crystallization Temperature (TCT), and it's one of the selection criteria for Completion and Workover operations. [11]

When used in different environments, brines, will be chosen with a TCT much lower than the actual temperature at which it will be exposed; usually operators request a brines that has a minimum TCT in the range of 15^o to 20^o F (-9^oC to -7^o C); salt crystals (solid) have a smaller specific volume than the volume of the brine, thus brines do not increase their volume during freezing, leading to pumps, fluid lines and other equipment not being affected as they will be if water freezes. [6], [7] In Figures 18 and 19 are shown crystallization curves for different types of brines.

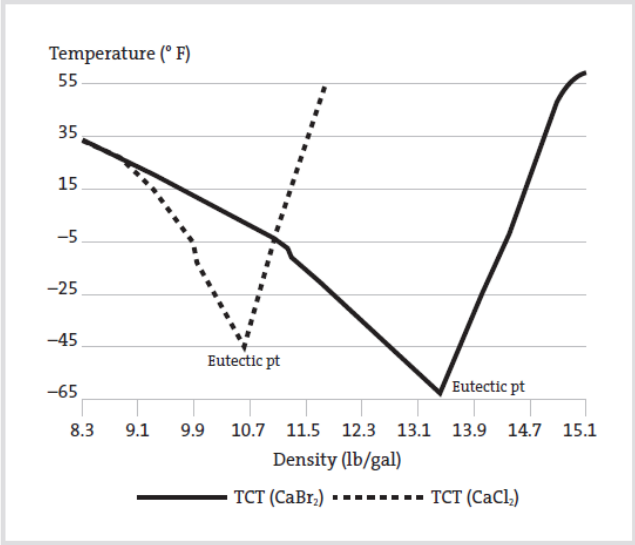


Figure 18 – Crystallization curves for $CaCl_2$ and $CaBr_2$ [11]

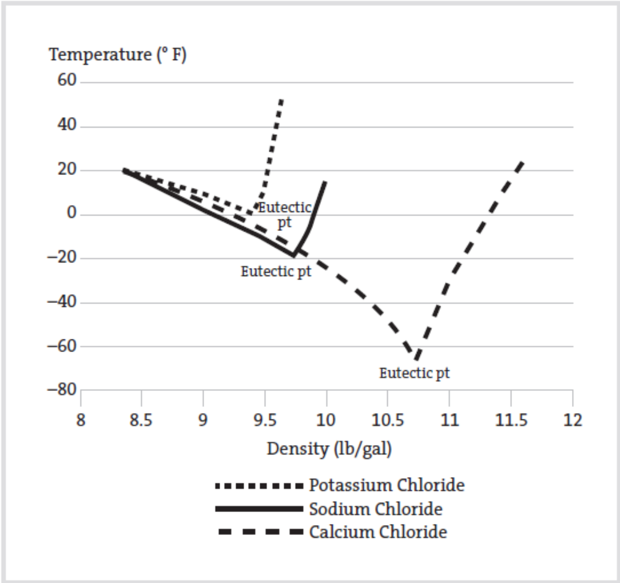


Figure 19 – Crystallization curves for KCl, NaCl and $CaCl_2$ [11]

4. Compatibility with the formation fluids;

Another important factor that needs to be taken in consideration when selecting a brine system should be the chemical compatibility between the brine system and the formation, and not only the formation rock, but also the formation water and hydrocarbon compositions; because chemical incompatibility between these two parts can lead to formation damage. [6]

The main concern is that a completion and workover brine can cause swelling and migration of the formation clay that can block the reservoir pores, thus the brine system should be compatible with the formation by having more or the same amount of salt % dissolved in it as the formation fluid. Other concerns are the formation of scale (deposits of inorganic materials) that can produce a chemical reaction between the brine system and the formation fluid that can block the formation pores; the contact between brines and formation hydrocarbons can lead to the formation of emulsions, which also lead to formation plugging. [7]

As a precaution, samples from the formation must be examined in detail, in the laboratory, to precisely build up compatible brine, which will save in final cost and rig time.

5. Corrosion control;

Corrosion affects and deteriorates the Oil and Gas Industry metal, from the start of the well till the abandonment stage; pipes, casing, tools, containers, etc.; [20] and can appear anywhere in the system from the surface equipment (ex: lines, pumps, pits, pipes, etc.) to bottom hole equipment. [21]

Oxygen, introduced through contaminated fluids, alongside formation gases (CO_2, H_2S) plays an important role in the corrosion of metal; also water-base drilling mud and brines have a corrosive effect on all kinds of metal drilling equipment and casing strings. [20]

In Figure 20 is presented the impact that corrosion has on the well casing and completion tubing.

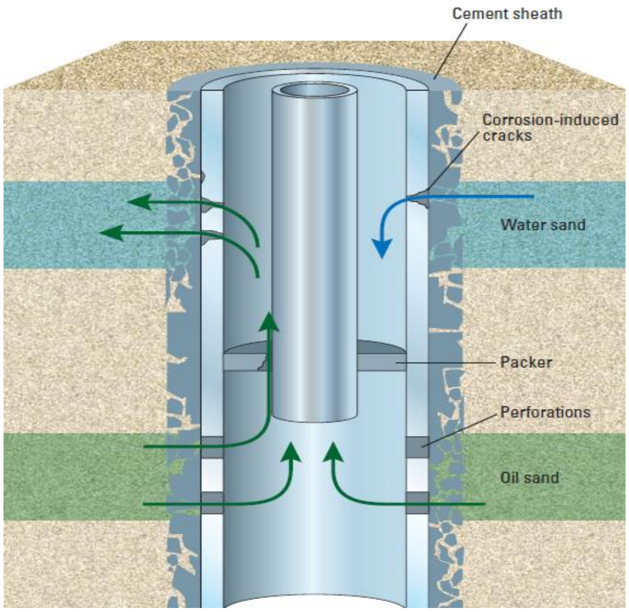


Figure 20 – Corrosion impact on the integrity of Casing [22]

The rate of corrosion will depend on the present condition of the oil field, temperature, pressure, bottom hole temperature, the amount of produced water, etc. [21] Special tools have been developed for monitoring down hole corrosion, to aid engineers in the understanding of the physical state of the down hole casing and tubing strings, and come up with the right decision to conduct changes and repairs. [22]

A large amount of money is invested yearly in combating corrosion at the rig site, by adequate planning and prevention techniques to maintain corrosion rates at a minimum [20]; thus corrosion control is an important factor not only in choosing a brine system but knowing the adverse effects that the system could imply on the rig metal parts.

6. Environmental impact;

Salts and brines possess chemical properties that can harm the persons who will handle them; some of them are extremely hygroscopic – the ability to absorb water from al kind of sources (ex. leather boots, skin, air, etc.) – in contact with skin will cause burns; also dry calcium salts are highly exothermic – they release heat when added to water, around 180-200°F – special measures should be put in place when handling these brines, starting with Personal Protective Equipment (PPE) like slicker suits, rubber gloves, rubber boots, goggles plus a face shield; if in contact with skin and eyes must rinse with fresh water immediately and seek medical attention. If in the event of spills, they must be contained and diluted before removal. [7]

7. Economics.

The economical aspect is also important not only for Brine but also for RDF systems, all data collected from the well is imputed in a computer program – Virtual Completion Solutions (VCS)) that will plan and design simulations of multiple operations and scenarios, establish pump rates, flow regimes and chemical clean-up efficiency and displacements; also planes and designs RDF and/or Brine systems formulations that needs to be used for the well with minimal impact, it will also give cheaper alternatives that can be more damaging. [6], [7], [11]

Damage Mechanisms

These mechanisms can be separated into two categories, depending on the type of damage related to the completion style, Completion damage and Formation damage (see figure 21).

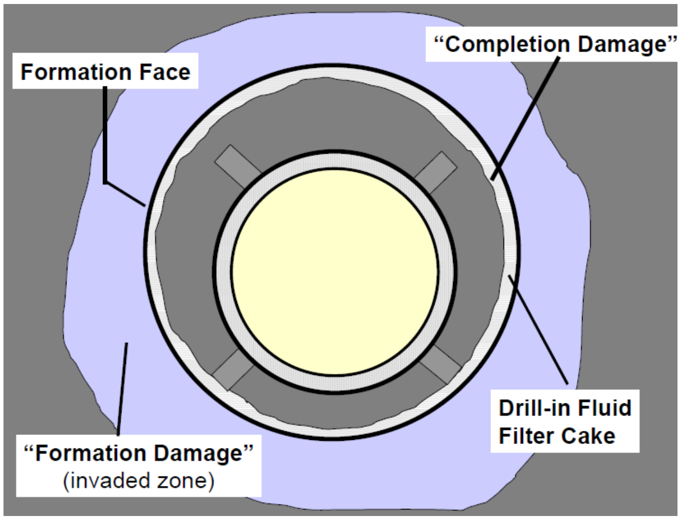


Figure 21 – Well damage mechanisms [19]

a. Completion damage – refers to all sorts of materials, contaminants, junk or residue that can make its way into the open-hole and cause damage to the reservoir formation.

Shale inhibition is one of the greatest completion damage mechanisms that can result from the improper selection of the Completion fluid; this can cause the fluid to become contaminated with reactive clays that can lead to aggressive chemical treatment which will damage the reservoir. Another cause of completion damage is the residue left behind by the drilling operation, if improper clean-up, can lead to solids plugging. [19]

b. Formation damage – refers to the deterioration of the reservoir rock permeability.

From the formation damage types, fluid invasion can be mentioned. To prevent formation damage, fluid invasion into the formation should/must be minimized, also the selection of a completion fluid that has similar chemistry as the formation fluid will aid in minimizing the formation damage. [19]

Clear Brine Systems

In the next paragraphs the most important clear brine systems will be presented, they are grouped into two categories, and will be presented as will follow:

A. Monovalent Brine systems:

Sodium Chloride NaCl – a worldwide available product, with the common name of table salt; is an economical chemical used to build clear brine for completion and workover operations, with a density range between 8.4 lb/gal to 10 lb/gal. The liquid NaCl brine is characterized by a density of 10 lb/gal and a TCT of 23^oF (-5^oC); in the areas where the liquid NaCl brine is not available, clear brine can be built with dry NaCl salt mixed with drill water. The fluid applications for this type of brine are characterized by increase in density, prevention of shale inhibition by reducing the water activity (Aw), reduced crystallization point, and low potential of gas hydrate formation. [6], [11] NaCl brine has a clarity of under 3 NTU, and a pH range between 6.5 and 7.0. [23]

NaCl brine can be mixed with NaBr brine to achieve a composite fluid density up to a maximum 12.5 lg/gal. [11] NaCl brine system can also be used in the build-up of FloPro RDF System. [23]

Applications: mostly used in completion and workover operations that require a low-density, clear brine, such as shallow wells with low-pressure; also used to adjust the density of other brines. [23] In Appendix 3.1 can be found the Blending Table of NaCl dry salt to obtain the appropriate density and TCT.

Potassium Chloride KCl – single-salt clear fluid brine, mostly used for its capability to inhibit shale; it is available worldwide with an elevated purity, as a dry inorganic salt. It has a density range between 8.4 lb/gal and 9.7 lb/gal; can also be used in clear-water completion solutions, with a KCl concentration between 2 and 7 %, such as seawater and NaCl fluids to aid in stabilizing clay and shale formations. [6], [11] KCl Brines have a clarity of under 3 NTU, and a TCT of 59^oF (14.9^o), and can also be used in the build-up of FloPro RDF Systems. [24]

Applications: are used for completion and workover operations which require enhanced shale stabilization in clay and shale formations or clay-sandstone formations; it also can be used to improve shale inhibition in other brine systems. [24] In Appendix 3.2 can be found the Blending Table of KCl dry salt to obtain the appropriate density and TCT.

Sodium Bromide NaBr – system used for completion and workover operations that require a density range between 8.4 lb/gal and 12.8 lb/gal, it can be mixed with NaCl to obtain fluid density up to 12.5 lb/gal. [6]

This system is used as an alternative to Calcium brine systems where the formation water has a high concentration in bicarbonate and sulfate ions; it presents a clarity of less than 3 NTU, a pH of 7.0, a TCT of 33^oF (0^oC) and it is compatible with water and a wide range of formation fluids, but is more expensive in comparison with previous presented brine systems. [25]

Applications: used in wells where a low TCT and/or chlorides-free brine is required; it eliminates the potential of formation damage by the precipitation of carbonate, bicarbonate and sulfate compounds that form in contact with a calcium base brine. [25] In Appendix 3.3 can be found the Blending Table of NaBr dry salt to obtain the appropriate density and TCT.

Sodium Formate $NaHCO_2$ – brine system that can be built using dry sack material mixed with drill water or as a stock liquid, with a density range between 8.4 lb/gal and 11.0 lb/gal; it can be used in completion and workover operations as an alternative to calcium base and chloride base brines, and also can be used in the build-up of RDF systems. [6], [11]

From the typical properties of Sodium Formate brine can be mentioned a clarity of under 3 NTU, pH of 8.6, and PV (40 wt% solution) of 29 cP. [26]

Applications: in operations that require a solid-free brine system; it has the ability to reduce the effect of clay and shale inhibition and migration, also does not react with carbonates, bicarbonates or sulfate ions, thus it dismisses the precipitate formation and blocking / damaging the reservoir skin. It can be mixed with Potassium Formate brine to lower the cost. [26] In Appendix 3.4 can be found the Blending Table of $NaHCO_2$ dry salt to obtain the appropriate density and TCT.

Potassium Formate $KHCO_2$ – a limited-available system used as an alternative to bromide and chloride brines, can be built using dry sack material or liquid stock; it is more expensive than alternative single-salt brines presented so far, but it presents better health, safety and environmental characteristics. Density range from 8.4 lb/gal to 13.1 lb/gal, it presents increased thermal stability and enhanced clay stabilization. [6], [11] In Appendix 3.5 can be found the Blending Table of $KHCO_2$ dry salt to obtain the appropriate density and TCT.

B. Divalent Brine systems:

Calcium Chloride $CaCl_2$ – divalent brine solution prepared from dry stock or liquid stock, it is characterized by being one of the most economic brine system, with densities that range from 9.0 lb/gal to 11.6 lb.gal, it presents a TCT of 34^{o}F (1.1^{o}C), and can also be blended with a heavier brine system for higher-density operations. [6]

Must be carefully built because it is highly hygroscopic and exothermic, when mixed with water temperatures can reach as high as 200^{o}F (93.3^{o}C), special measures must be put in place, adequate PPE and a lot of attention. [11] In Appendix 3.6 can be found the Blending Table of $CaCl_2$ dry salt to obtain the appropriate density and TCT.

Calcium Bromide $CaBr_2$ – single-salt system that can present densities up to 15.5 lb/gal, it is available as a stock liquid with a density of 14.2 lb/gal, and also as a dry stock material; it has a low TCT, 0^{o}F (-18^{o}C), it is mostly used in cold climates. [6]

Applications: provides a good inhibition and prevents clay from hydrating and migrating; can be used as a packer fluid, or to be mixed with other brine systems to adjust the density. They present the same handling issues as $CaCl_2$, and must be handled carefully. [11] In Appendix 3.7 can be found the Blending Table of $CaBr_2$ dry salt to obtain the appropriate density and TCT.

Calcium Chloride / Calcium Bromide / Zinc Bromide $CaCl_2$ / $CaBr_2$ / $ZnBr_2$ – heavy density solution, produced my blending Zinc Bromide brine with less dense Calcium Bromide and/or Calcium Chloride, to lower the cost and to reach a desired density and TCT; it presents a density range between 14.0 lb/gal to 19.2 lb/gal. [11]

Typical properties for this sort of mixture: pH between 1.8 – 6.0, clarity under 5 NTU, and a good compatibility with water and other Calcium/Zinc Brines. [27]
Applications: used for completion and workover operations that require an elevated density; prevent swelling and migrations of formation clay, can be mixed with a wide range of TCTs, and used for packer fluids, especially used in cold climates. [27] In Appendix 3.8 can be found the Blending Table of $CaCl_2$ / $CaBr_2$ / $ZnBr_2$ liquid stock to obtain the appropriate density and TCT.

Health, Safety and Environmental Concerns

Brine fluids as all chemicals can be hazardous to a certain degree if not used properly. As it was presented, brines are salts dissolved in water, and provide weight by the amount of salt dissolved, thus depending and how heavy a brine is it arises certain concerns, the heavier the brine system the more dangerous is to handle, and the degree of affecting equipment and environment is higher. [11]

Brines must be handled with care no matter the weight, because from the hazardous properties of brines can be mentioned: acidity (pH), grade of toxicity, absorption of water and chemical reactions. PPE must be worn all time when brine is mixed and used, because it will have effects on exposure (eye irritation, skin burns, respiratory inflammation, etc.). [11] Material Safety Data Sheet must be consulted every time brine is used; brine systems are regulated differently compare to Conventional fluids regarding Environmental Concerns. [6] Under the North Sea Environmental regulation all Brine systems, with the exception of Zinc Bromide, are accepted for discharge, only if they do not present any trace of oil residue. [11]

3. Comparing Results of Conventional OBM, RDF and NaCl Brine Systems

In the next pages, it will be presented relevant rig laboratory results based on the tests performed on a 13 lb/gal Conventional OBM System, VersaClean, 10 lb/gal OBM RDF System, VersaPRO, and a 10 lb/gal NaCl Brine System, at the rig site; followed by comparison charts between them.

OBM vs. RDF

In Table 18 and Table 19, Tests results, performed on the Conventional OBM System (Table 18), and RDF System (Table 19), over a nine days period, and a nine days average, are presented; test results will be compared to show the difference and similarities between these two systems, and to make the reader understand why it is better to use a Reservoir Drill-in Fluid to drill through the pay zone.

In Tables 16 and 17, it will be presented the Drilling Program Properties and Formulations for these two Systems.

Table 16 – Drilling Fluid Properties and Formulation Conventional VersaClean OBM System

Drilling Fluid Properties		Formulation for one bbl of fluid	
Mud weight	13.0 lb/gal	Base fluid (Continuous Phase)	0.549 bbl
PV (120^{o}F)	< 35 cP	Water (Discontinuous Phase)	0.178 bbl
YP	15 – 25 lb/100ft^2	$CaCl_2$ Powder (water Phase Salinity)	22.03 ppb
Fann 6 (120^{o}F)	8 -16 cP	TruVis* (viscosifier)	8.0 ppb
Gels (10s) (120^{o}F)	10 – 15 lb/100ft^2	VersaClean CBE* (emulsifier)	10.0 ppb
Gels (10m) (120^{o}F)	20 – 30 lb/100ft^2	VersaTrol M* (FLC agent)	4.0 ppb
HTHP Fluid Loss	<5.0 ml (250^{o}F)	Lime (Alkalinity)	8.0 ppb
ES	>400 volts	Barite (Weighting Agent)	277.86 ppb
Cl^-	80k – 120k mg/l		
OWR	75/25 – 80/20		

Table 17 – Drilling Fluid Properties and Formulation VersaPRO RDF System

Drilling Fluid Properties		Formulation for one bbl of fluid	
Mud weight	10.0 lb/gal	Base fluid (Continuous Phase)	0.546 bbl
PV (120^{o}F)	< 20 cP	Water (Discontinuous Phase)	0.228 bbl
YP	15 – 25 lb/100ft^2	$CaCl_2$ Powder (water Phase Salinity)	28.21 ppb
Fann 6 (120^{o}F)	6 – 16 cP	TruVis* (viscosifier)	5.75 ppb
Gels (10s) (120^{o}F)	8 – 15 lb/100ft^2	VersaClean CBE* (emulsifier)	9.5 ppb
Gels (10m) (120^{o}F)	19 – 28 lb/100ft^2	VersaTrol M* (FLC agent)	3.0 ppb
HTHP Fluid Loss	<3.0 ml (250^{o}F)	Lime (Alkalinity)	8.0 ppb
ES	>500 volts	Safe-Carb Blend (Bridging & Weighting Agent) ($CaCO_3$)	132.54 ppb
Cl^-	50k – 100k mg/l		
OWR	70/30 %		

Table 18 – Conventional OBM System Tests and Results

13 ppg Conventional VersaClean OBM											
Property	unit	1	2	3	4	5	6	7	8	9	10
Date		22/11/13	23/11/13	23/11/13	24/11/13	24/11/13	25/11/13	26/11/13	27/11/13	27/11/13	9 day avg.
Time	h	20:30	02:30	20:30	03:30	21:00	20:30	20:30	03:00	19:30	
Depth	ft.	9000	9089	9305	9390	9462	9462	9572	9671	10042	
MW	ppg	12.9	12.9	13	13	12.8	12.9	13	13	13.1	13
FV	sec/ quart	54	51	51	51	53	53	53	51	49	52
Fann 600	RPM	82	85	90	85	70	70	77	80	77	80
Fann 300	RPM	52	54	58	54	44	44	49	51	49	51
Fann 200	RPM	41	42	44	42	34	35	39	40	38	39
Fann 100	RPM	29	30	31	29	24	24	27	28	26	28
Fann 6	RPM	14	13	13	12	10	10	11	12	11	12
Fann 3	RPM	11	12	12	11	9	9	10	11	10	11
Gel 10sec	lb/ $100ft^2$	16	16	17	15	13	13	14	15	14	15
Gel 10min	lb/ $100ft^2$	25	26	30	27	23	22	24	24	23	25
PV	cP	30	31	32	31	26	26	28	29	28	29
YP	lb/ $100ft^2$	22	23	26	23	18	18	21	22	21	22
%S	%	25	24	26	26	25	26	25	24	26	25
%O	%	57.5	58	58	58	59	59	58	59	58	58
%W	%	17.5	18	16	16	16	15	17	17	16	17
OWR	%	77/23	77/23	78/22	78/22	79/21	80/20	77/23	78/22	78/22	
FL	ml/30 min	2.2	2.2	2	2	2.4	2.2	2	2.2	2	2.1
ES	volts	655	665	880	700	648	600	730	634	753	696
Alk	ml	1.5	1.5	1.7	1.5	1.4	1.5	1.4	1.6	1.6	2
Cl^-	mg/l	49998	49998	49998	49998	49998	49998	49998	49998	49998	49998

Comparing Table 16 with Table 18, and Table 17 with Table 19, it can be observed that most of the values match the Drilling program; the only problem was with the Chloride concentration, it was lower than the program specifications (50k for the Conventional System, and 60k for the RDF system), more $CaCl_2$ powder needed to be added to bring back the fluid in program specifications.

Table 19 – RDF System Tests and Results

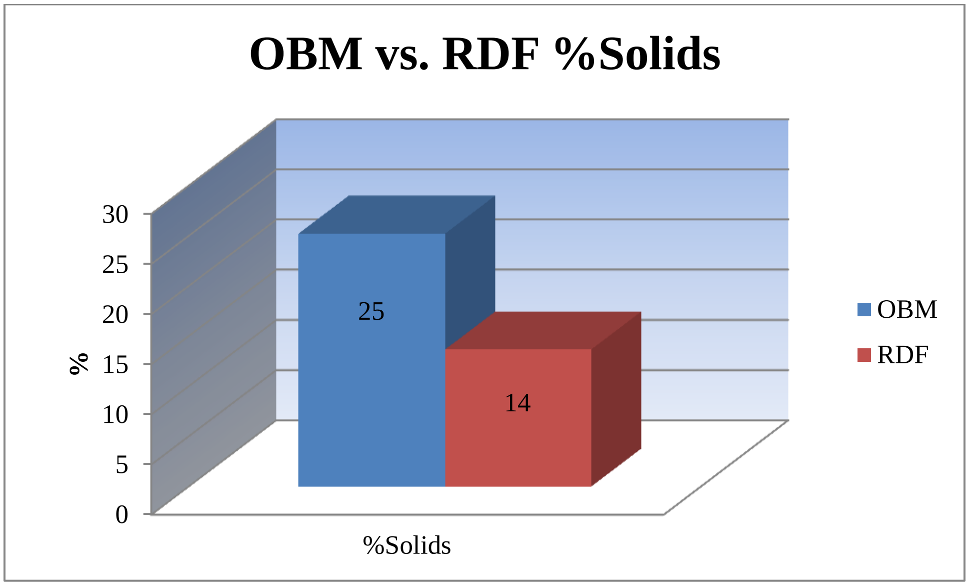
10 ppg VersaPro RDF											
Property	unit	1	2	3	4	5	6	7	8	9	10
Date		03/12/13	03/12/13	04/12/13	04/12/13	05/12/13	06/12/13	07/12/13	07/12/13	08/12/13	9 day avg.
Time	h	04:00	19:00	03:30	20:30	21:15	03:15	03:45	19:45	20:00	
Depth	ft.	10245	10245	10295	10674	10886	10966	11869	12559	12604	
MW	ppg	10	10	10.05	10.05	10	10.05	10.05	10.05	10	10
FV	sec/ quart	55	53	51	54	51	51	49	49	53	52
Fann 600	RPM	46	52	52	56	52	51	55	56	55	53
Fann 300	RPM	27	33	33	35	33	32	35	36	36	33
Fann 200	RPM	21	25	26	28	26	26	28	29	29	26
Fann 100	RPM	13	18	18	20	18	18	19	21	21	18
Fann 6	RPM	5	7	7	8	8	8	8	9	9	8
Fann 3	RPM	4	6	6	7	7	7	7	8	8	7
Gel 10sec	lb/ $100ft^2$	5	7	8	9	9	9	9	11	11	9
Gel 10min	lb/ $100ft^2$	6	6	10	11	11	11	11	13	13	10
PV	cP	19	19	19	21	19	19	20	20	19	19
YP	lb/ $100ft^2$	8	14	14	14	14	13	15	16	17	14
%Solids	%	12	14	13	14	14	14	14	14	14	14
%O	%	64	62	63	63	63	63	64	63	64	63
%W	%	24	24	24	23	23	23	22	23	22	23
OWR	%	73 / 27	72 / 28	72 / 28	73 / 27	73 / 27	73 / 23	74 / 26	73 / 27	74 / 26	
FL	ml/30 min	2	2.2	2.2	2.2	2.6	3.2	2.3	2.6	2.6	2.4
ES	volts	542	675	720	830	952	1027	1027	972	987	859
Alk	ml	1	0.7	1.3	1.9	2.3	2.3	2.2	2.1	2.1	2
Cl^-	mg/l	60000	62485	60000	62485	59985	57486	57486	56237	57486	59294

Comparing the results in Tables 18 and 19, it can observed several differences between these two systems, mainly because they do not have the same chemical composition; the Conventional OBM System is mainly designed to drill through formations that can make an impact on the well stability, and they need to be blocked (porosity point of view), with all means necessary, regardless the fact that the formation porosity and permeability will be damaged (it is not a pay zone formation). The Conventional OBM is weighted up to 13 lb/gal with Barite, one of the chemicals that will damage the formation skin if used in a Reservoir Drilling operation. The RDF System is mostly designed to compose a thin filter cake on the walls of the reservoir, which can be easily removed with a Breaker solution (acid-soluble) in the Completion phase. From the density point of view, the RDF system is weighted up with 8.9 lb/gal $CaCl_2$ Brine, and $CaCO_3$; the $CaCl_2$ Brine also helps in shale and clay stabilization.

In the next pages, the tests results from these two Systems will be compared, and represented in Charts.

One of the most important properties of an RDF System is the Solids content, this result is taken from a Retort test; in Chart 1 it can be observed the % Solids comparison between the two systems from a nine day average.

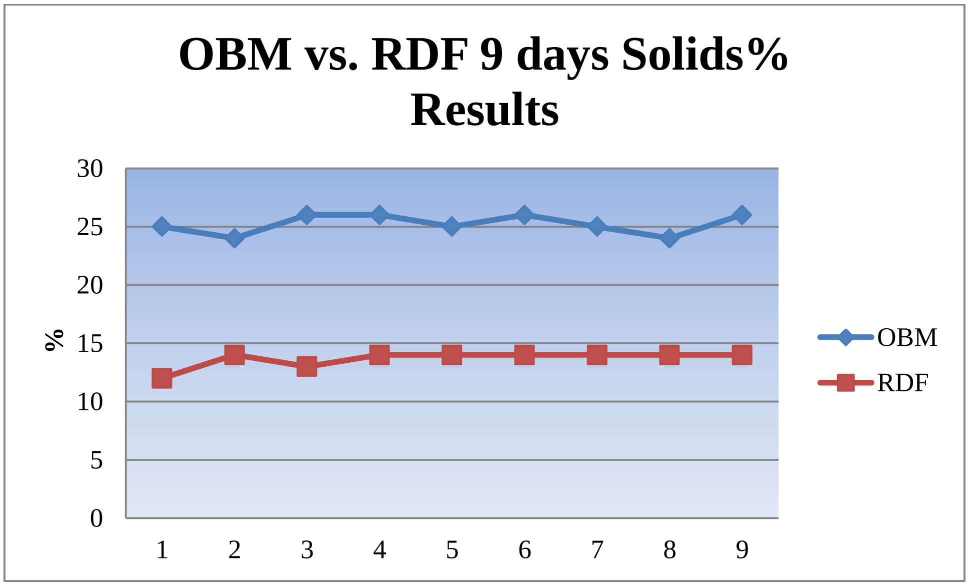
Chart 1 – %Solids Results OBM vs. RDF



Clearly it can be observed that solid % present in the RDF is with 11% lower than the Conventional drilling fluid, mainly because the lb/gal $CaCO_3$ (132.54 lb/gal) added to RDF System is almost half of the lb/gal Barite added to the Conventional System (277.86 lb/gal).

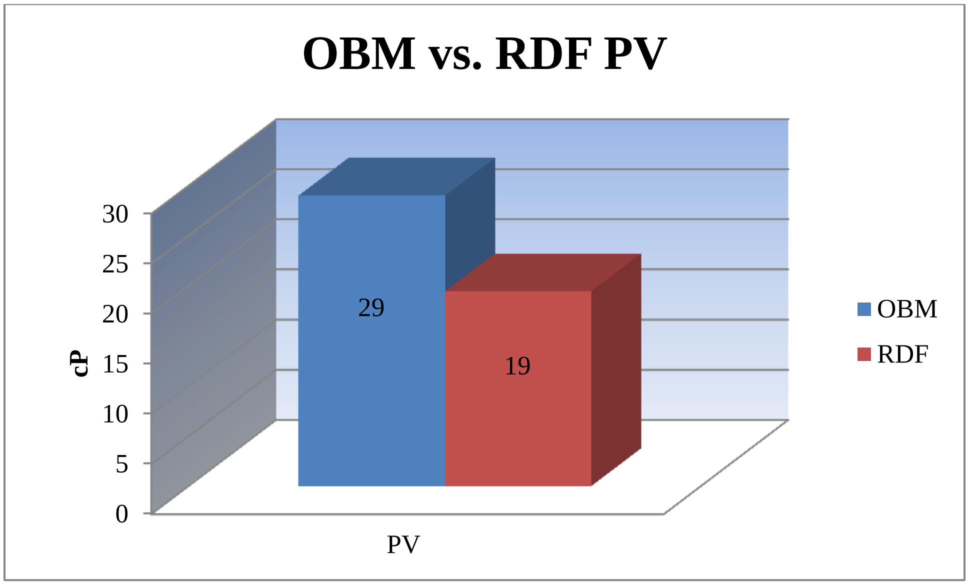
In Chart 2, it can be observed the test results over a period of nine days, performed on the two fluids.

Chart 2 – 9 Days Results for %Solids OBM vs. RDF



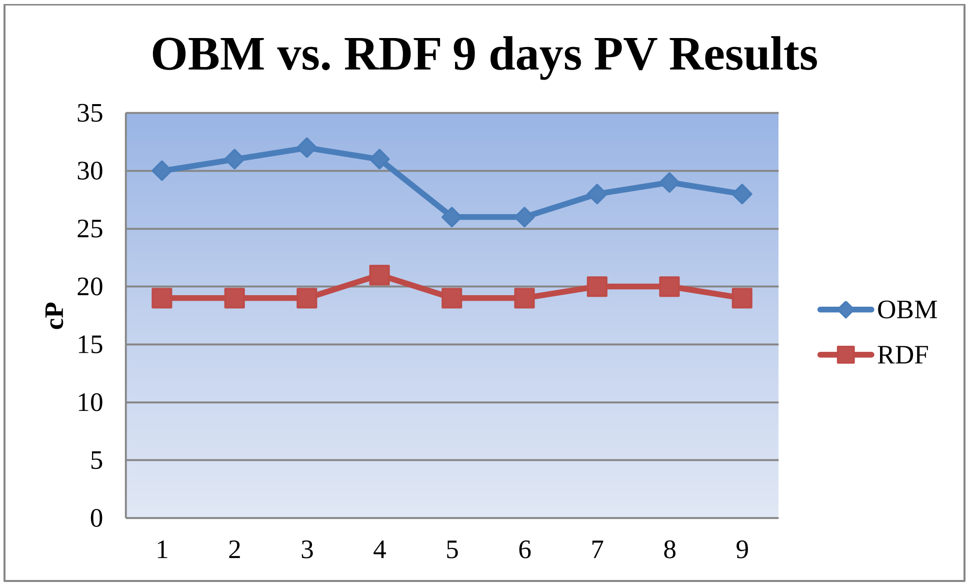
In Chart 3, test results for Plastic Viscosity, from a nine days average are presented.

Chart 3 – Plastic Viscosity Results OBM vs. RDF



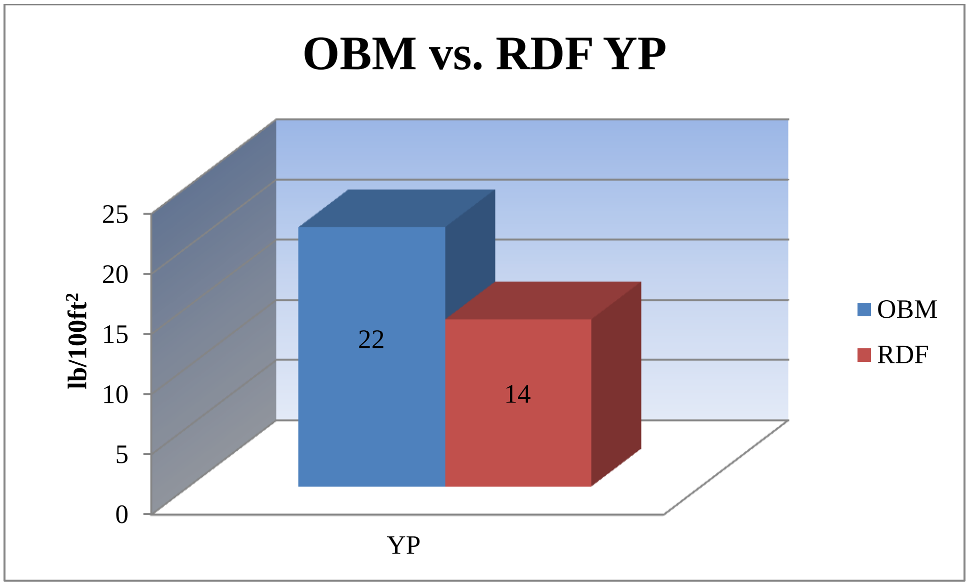
Plastic Viscosity shows the resistance to flow due to mechanical friction [7], thus the more solids are present in the fluid system, the higher the PV; can be observed in Chart 3 and Chart 4, that the PV in the Conventional System is higher than the RDF Systems, mainly because it has in its composition inert solids (Barite), on the other hand the RDF System has $CaCO_3$ in the fluid mass and it will a smaller effect on the PV, it will show up also in the Retort test. Drill solids also increase the PV if they are present in the fluid system, and they need to be removed with adequate solids control equipment.

Chart 4 – 9 Days Results for Plastic Viscosity OBM vs. RDF



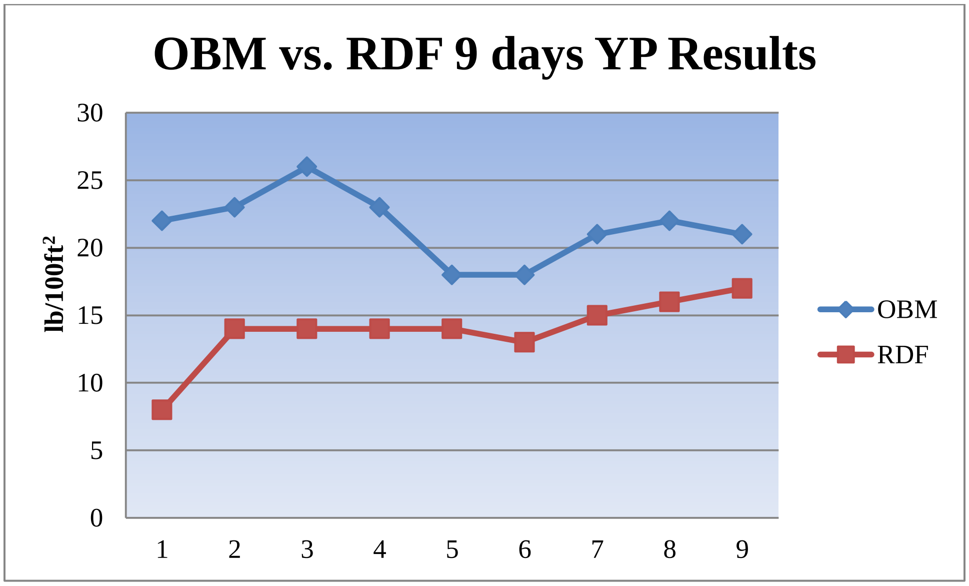
Yield Point is the resistance to flow due to chemical attractions and repulsions of particles [7]; in Chart 5 it can be observed that the YP of the RDF System is 8 lb/100ft^2 lower than the Conventional System. The factors that can cause changes in the YP are formation contaminants; the fluids are formulated with specific quantities of chemicals additives to give the correct fluid properties.

Chart 5 – Yield Point Results OBM vs. RDF



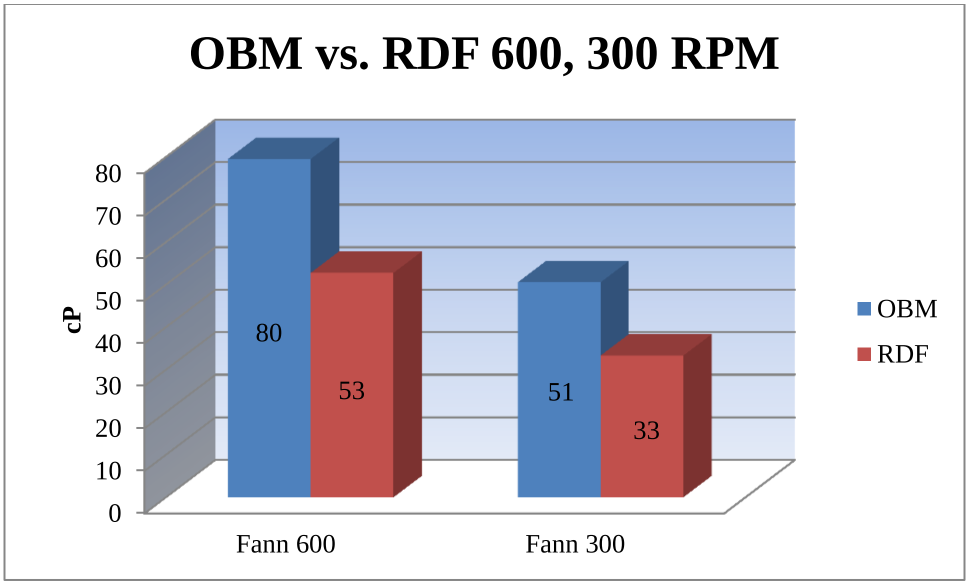
In Chart 6 can be observed the Yield Point results over a nine day period; in the Conventional OBM System, a gradually increase in YP, is shown, from day 1 to day 3, then a decrease; a Calcium contamination from a Dolomite formation disrupted the fluid properties, it was brought back in specification with Soda Ash (Na_2CO_3) treatment, to precipitate the excess Calcium.

Chart 6 – 9 Days Results for Yield Point OBM vs. RDF



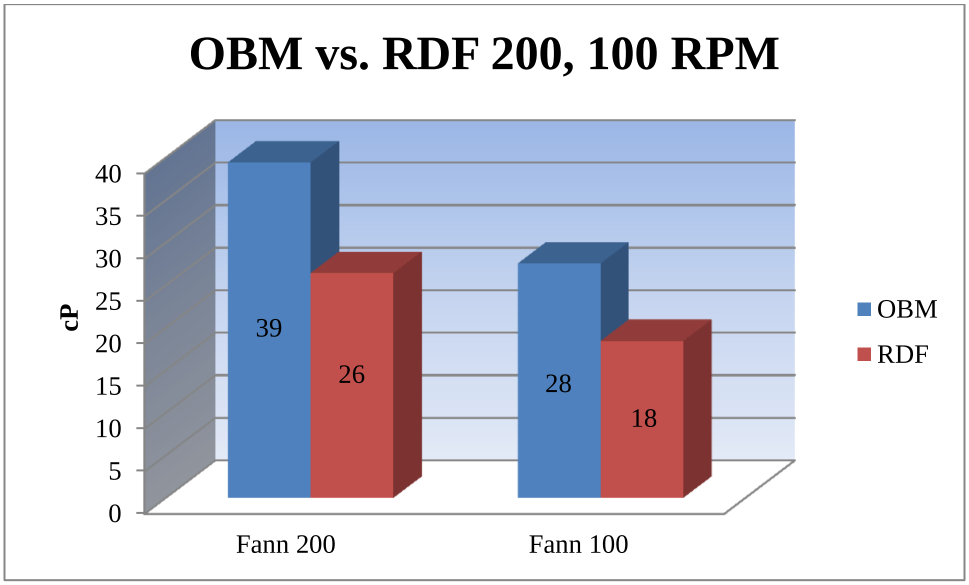
In Charts 7, 8 and 9 are presented the comparison between the dial readings of a VG-meter at 600 and 300 RPM (Chart 7), 200 and 100 RPM (Chart 8), 6 and 3 RPM (Chart 9). It can be observed that the Conventional system has higher results compared with the RDF system, mainly because the inert solids and drill solids in the Conventional fluid restrict the fluid flow.

Chart 7 – 600, 300 RPM Results OBM vs. RDF



The 600 RPM and 300 RPM readings aid in determining the PV value (PV = 600 RPM reading – 300 RPM reading), and YP value (YP = 300 RPM reading – PV). These high end values (600, 300, 200 and 100) show the power of solids suspension in the fluid.

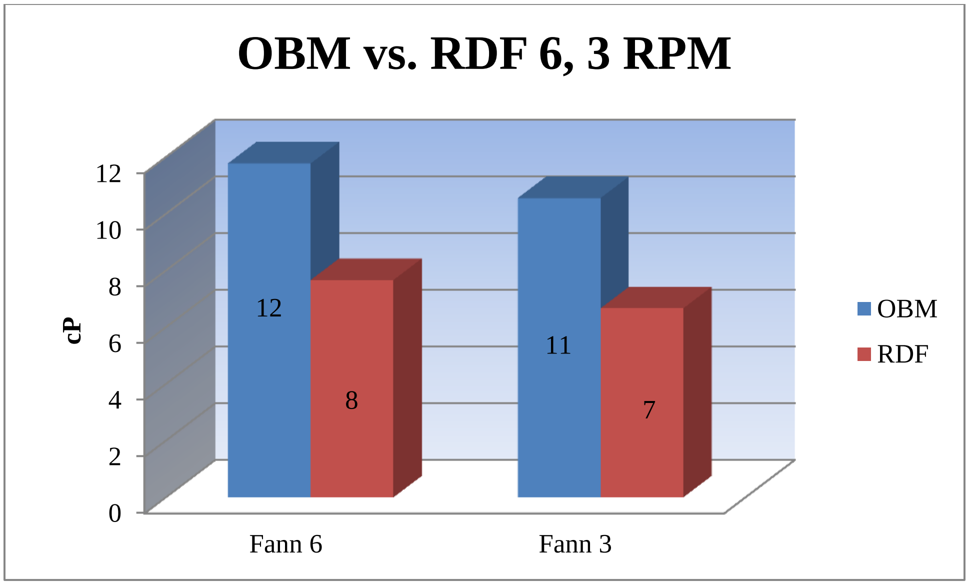
Chart 8 – 200, 100 RPM Results OBM vs. RDF



In Chart 9 is presented the 6 and 3 RPM readings for both systems tested, these values represent the hole cleaning properties in a high reach extended well. As expected the Conventional OBM

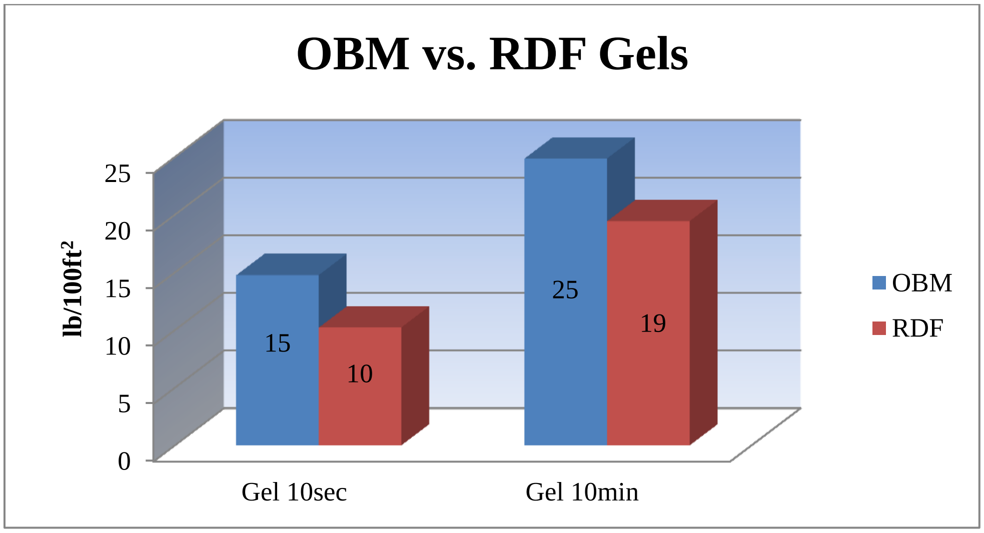
System will perform better at cleaning the hole from cuttings compared to the RDF system, because the weighting agent (Barite) in the Conventional System forms a dense, viscous fluid mass with the viscosifing agents and has a more efficient contribution in hole cleaning, than the $CaCO_3$ in the RDF System.

Chart 9 – 6, 3 RPM Results OBM vs. RDF



In Chart 10 are presented the Gel strength of the two compared systems, and can be observed that the Conventional system presents higher values than the RDF System, for the 10 seconds gel 15 lb/100ft^2 vs. 10 lb/100ft^2, and for the 10 minute Gel 25 lb/100ft^2 vs. 19 lb/100ft^2. These Gels need to have a linear progression, so the gels can easily be broke, when circulation is reinstated, not to over-pressure the fluid pumps.

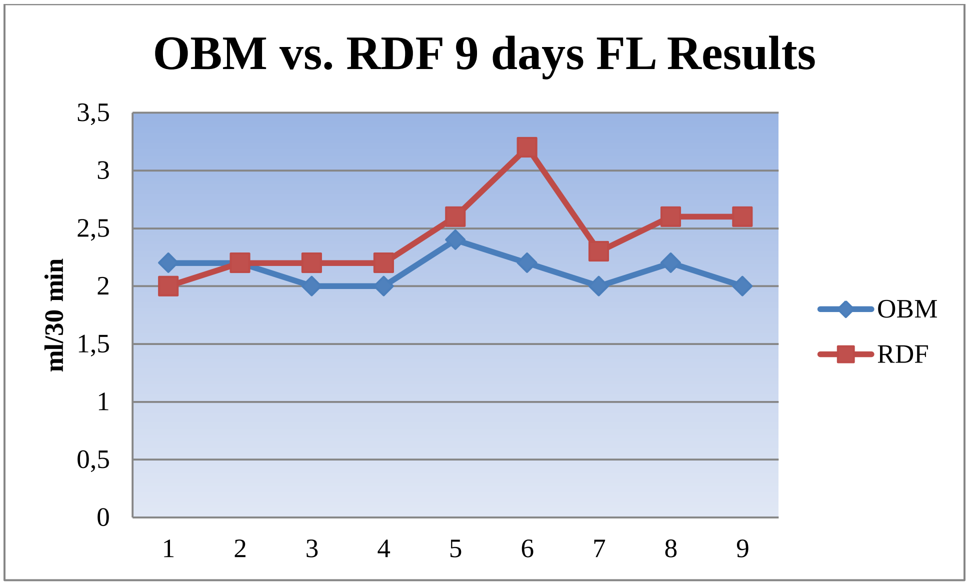
Chart 10 – Gels Results OBM vs. RDF



In Chart 11 Fluid Loss results are presented. It can be observed that both of the systems have a fluid loss as per the Drilling Program specifications. For the RDF, it can be observed a graduated increase from day 4 to day 6, FLC agent was added to bring the fluid in specifications. Both

Systems performed well over this 9 day period, with an average of 2.1 ml/30 minutes for the Conventional System, and a 2.4 ml/30 minutes for the RDF System, despite the fact that they were used in drilling of different formations.

Chart 11 – 9 Days Results for Fluids Loss OBM vs. RDF



OBM vs. NaCl Brine

In the second part of the chapter, a comparison between the Conventional OBM system and a 10.0 lb/gal NaCl Brine system will be presented.

In Table 20, are presented test and results performed on two NaCl Brine systems.

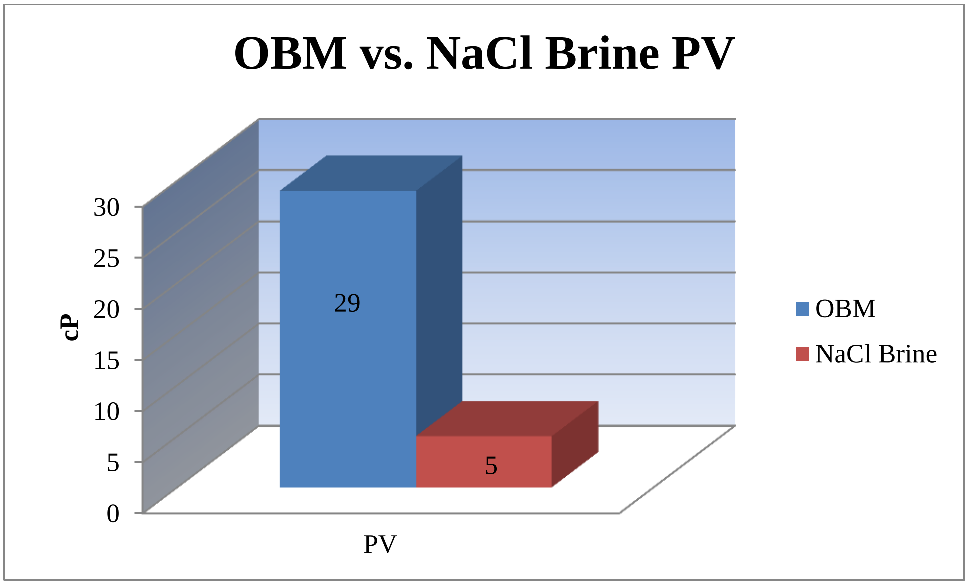
Table 20 – NaCl Brine Systems Tests and Results

		9.4 lb/gal NaCl Brine	10.0 lb/gal NaCl Brine
Property	**Unit**		
Date		29/01/2014	31/01/2014
Density	lb/gal	9.4	10
PV	cP	5	5
YP	$lb/100ft^2$	2	2
Fann 6	cP	2	2
Gel 10sec	$lb/100ft^2$	2	2
pH		9	9
Cl^-	mg/l	95000	187000

The results that will be presented in the next paragraphs origin from the comparison of the tests results of the nine day average of the Conventional OBM system (Table 18) and the 10.0 lb/gal NaCl Brine results presented in Table 20.

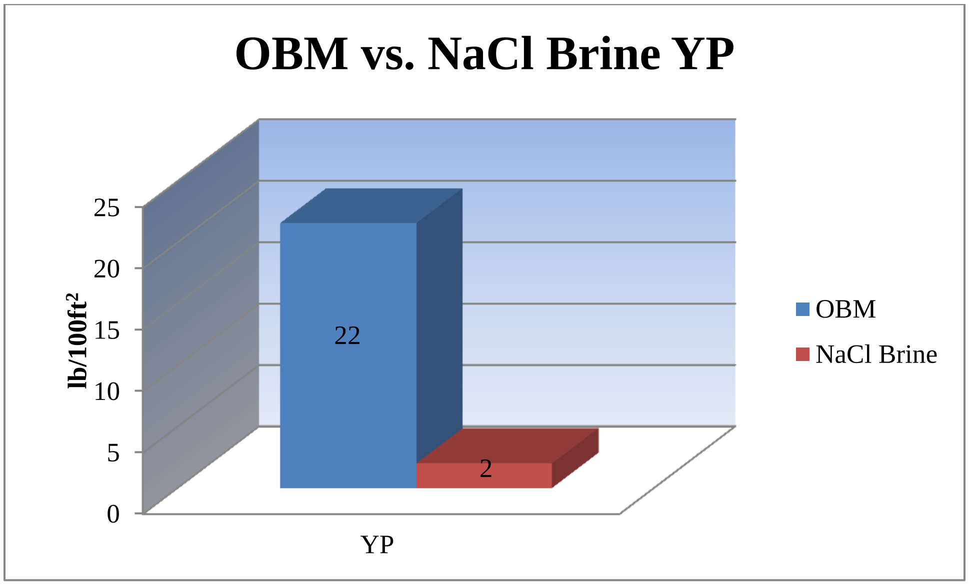
In Chart 12 is presented the Plastic Viscosity results of the two systems. It can clearly be observed that the Brine system has a much lower result (5 cP) compared with the OBM system results (29 cP), because the Brine system does not have any solids in its composition, it has only dissolved NaCl salt, which gives it its density of 10 lb/gal, and it is not used in drilling (no drill solids), on the other hand the Conventional systems is weighted up with Barite and also drill solids could be present in its composition, thus the larger PV.

Chart 12 – Plastic Viscosity Results OBM vs. 10 lb/gal NaCl Brine



In Chart 13 can be observed the Yield Point results of the two compared systems.

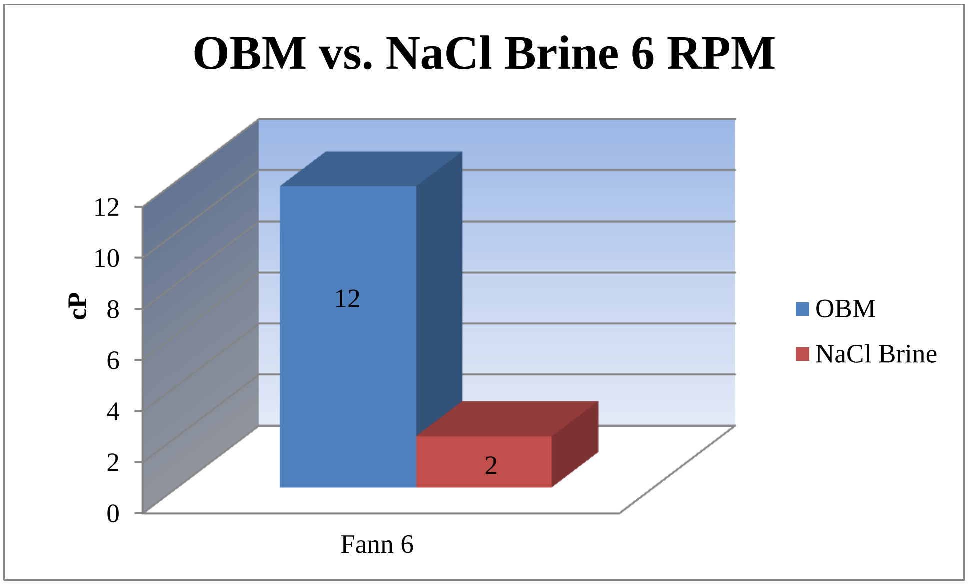
Chart 13 – Yield Point Results OBM vs. 10 lb/gal NaCl Brine



Yield point, shows, if it deviates from the Program specifications, a possible chemical contamination occurred, in this case, the NaCl Brine has no viscosifiers in its composition, thus the YP is very low (2 lb/100ft^2) compared with the OBM Systems (22 lb/100ft^2), which has added chemical viscosifiers to lift/suspend the drill solids, and support the weighting agent.

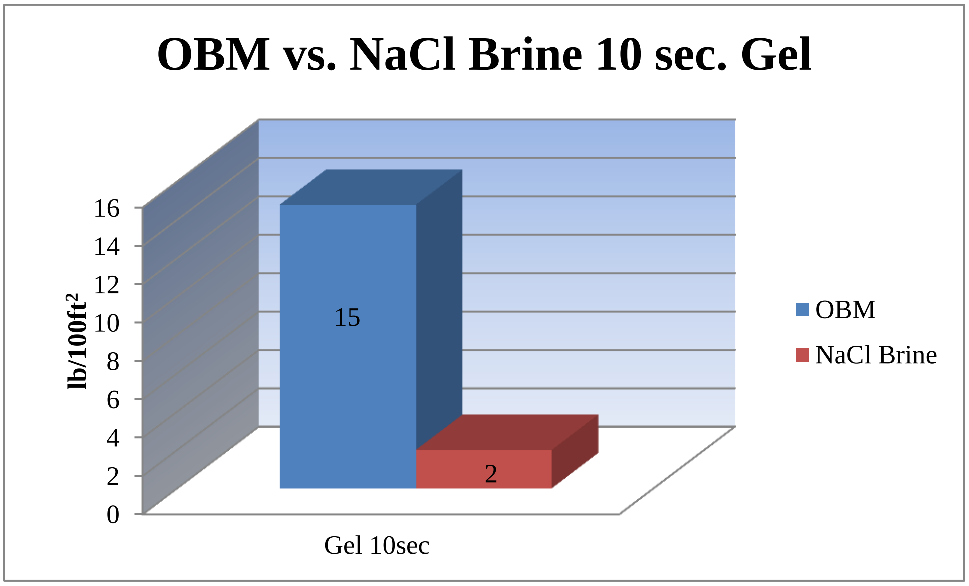
In Chart 14 can be observed the compared results of the 6 RPM readings; although the Brine System is not designed for hole cleaning, with a low result of 2 cP compared with the 12 cP of the OBM System, these results are presented to make the reader understand the importance of viscosifying agents in a drilling operation.

Chart 14 – 6 RPM Results OBM vs. 10 lb/gal NaCl Brine



In Chart 15 are presented the results of the 10 seconds Gel; like previous results, these readings are based on the viscosifiers in each system.

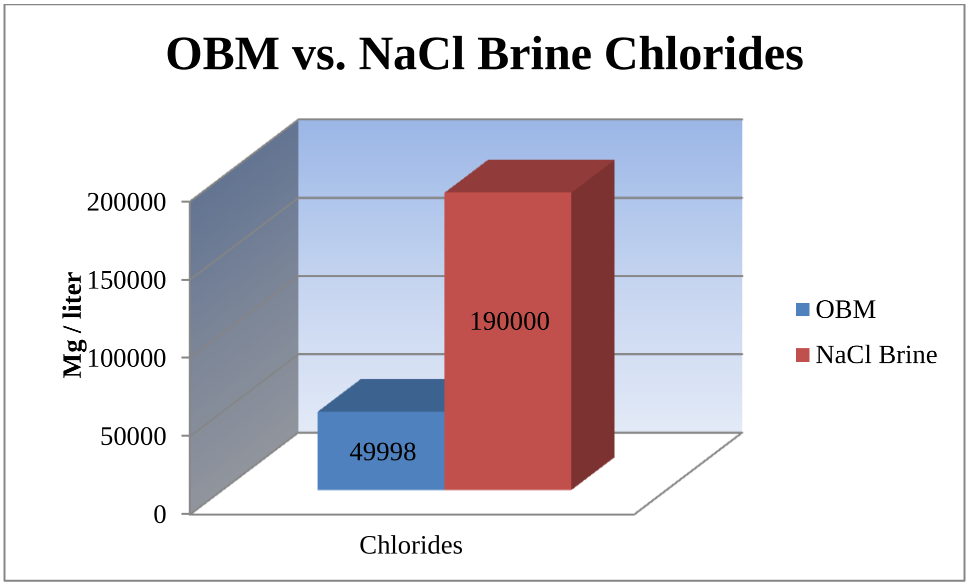
Chart 15 – 10 sec. Gel Results OBM vs. 10 lb/gal NaCl Brine



With a low result, of 2 lb/100ft^2, the Brine system does not gel under static conditions, compared with the OBM system, with a reading of 15 lb/100ft^2, it is designed to gel under static conditions to suspend the drill solids, otherwise they will settle to the bottom of the well and can cause serious problems like stuck pipe.

In Chart 16 are presented the Chloride concentration results in mg/liter, to point out the superior inhibitive property of the Brine system, with a result of 187000 mg/liter compared with the 49998 mg/liter of the OBM System.

Chart 16 – Chlorides Results OBM vs. 10 lb/gal NaCl Brine



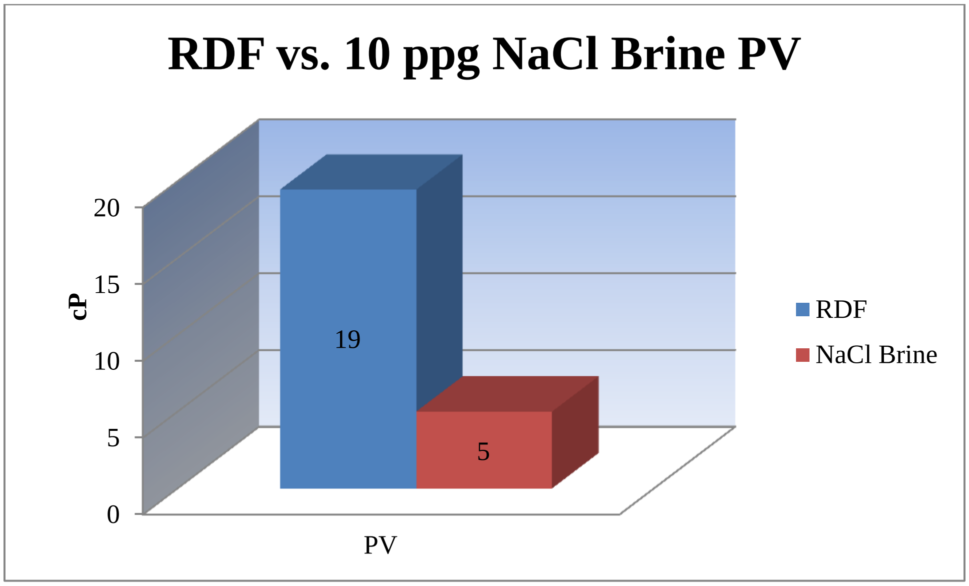
RDF vs. NaCl Brine

In the third and final part of this chapter, a comparison between the RDF and the 10 lb/gal NaCl Brine System will be presented using Table 19 and Table 20.

In Chart 17 are presented the results based on the Plastic Viscosity of the two systems, and can be observed that the RDF System has a higher PV (19 cP) compared with the one of the Brine System (5 cP), because the RDF System incorporates bridging and weighting agents ($CaCO_3$) and other chemical additives that aid in Fluid Loss Control, viscosity and bridging, while the Brine System lacks these additives.

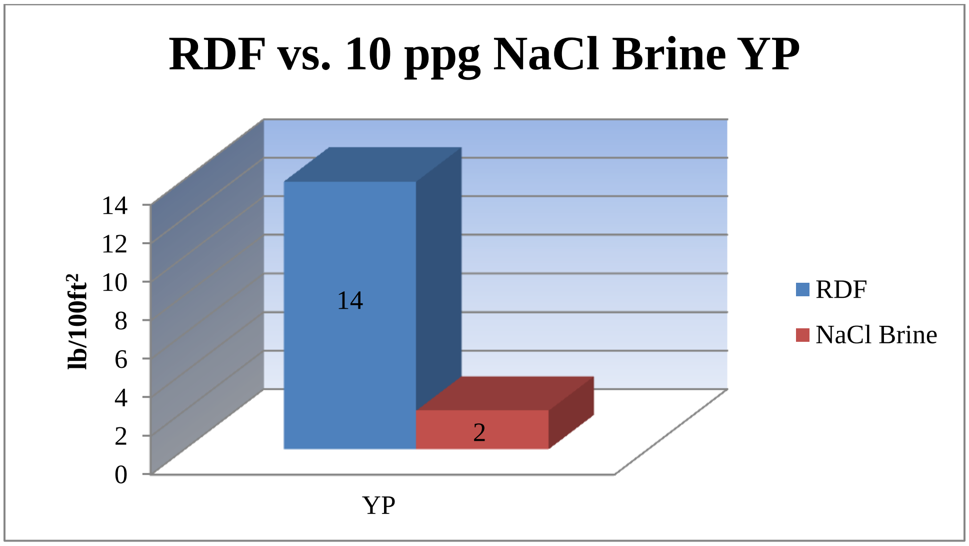
Although, these systems (Conventional, RDF, Brine) are not built to perform the same, sometimes a RDF system can be used in a Completion operation (with the $CaCO_3$ removed), but a Brine system can’t be used in a Reservoir Drilling operation in this state, mainly because it will cause wellbore instability and cuttings build-up, it will need several chemical additives in its composition which will transform it in a RDF System.

Chart 17 – Plastic Viscosity Results RDF vs. 10 lb/gal NaCl Brine



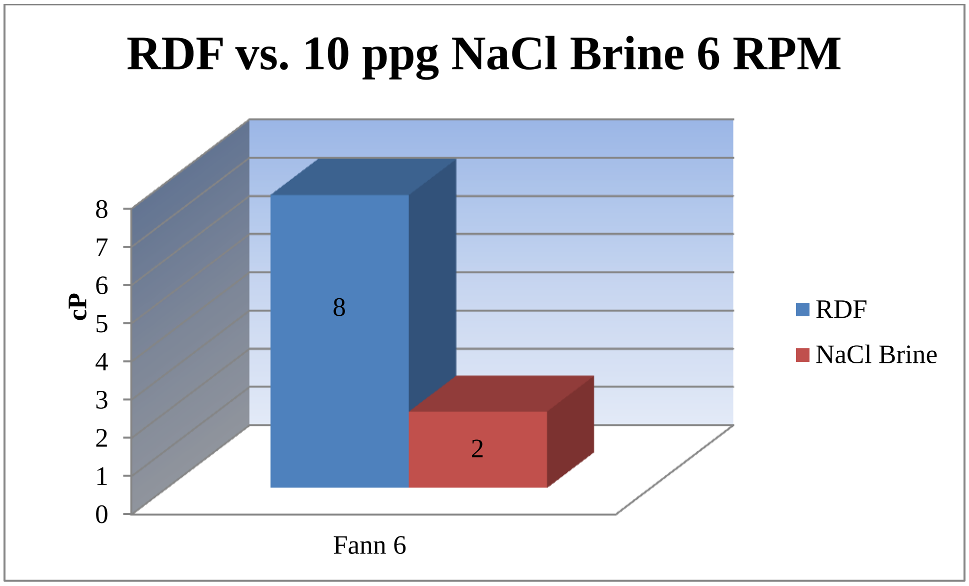
Yield Point results are presented in Chart 18, and show a notable difference of 12 lb/100ft^2 between these two systems (14 lb/100ft^2 for the RDF System and 2 lb/100ft^2 for the Brine System), these prove yet again that the viscosifying agents in a drilling fluid decrease flow in the wellbore when compared to clear non-viscosified Brine System.

Chart 18 – Yield Point Results RDF vs. 10 lb/gal NaCl Brine



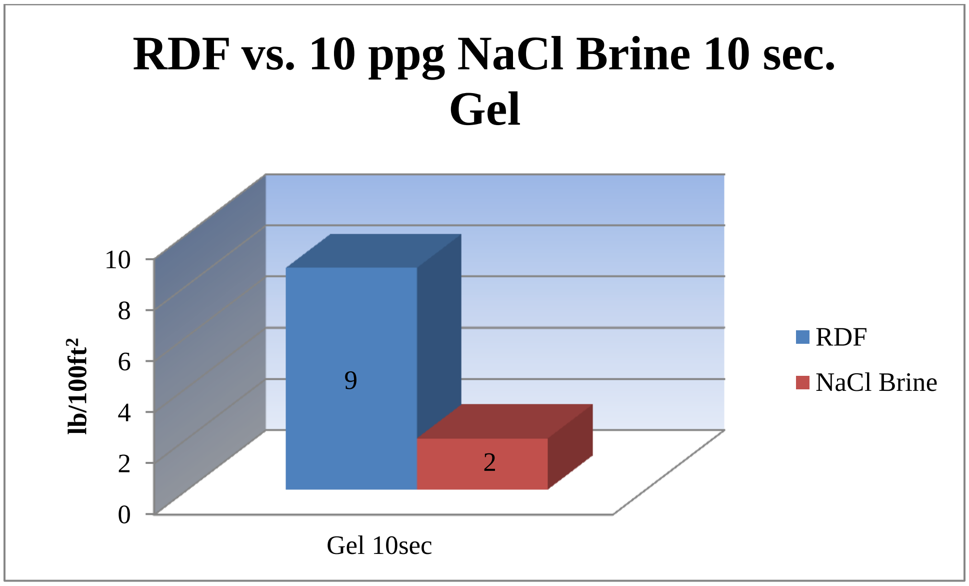
In Chart 19 is presented the comparison between the 6 RPM dial reading results; as presented earlier on, it represents the hole cleaning power in high extended, horizontal wells. A 6 cP difference is observed (8 cP for the RDF System, and 2 cP for the NaCl Brine System). It must be noted that the Completion Brine is not used in drilling and it does not require a higher value, compared with the RDF System, which must perform exceptional in cleaning the wellbore to prevent any Reservoir contamination.

Chart 19 – 6 RPM Results RDF vs. 10 lb/gal NaCl Brine



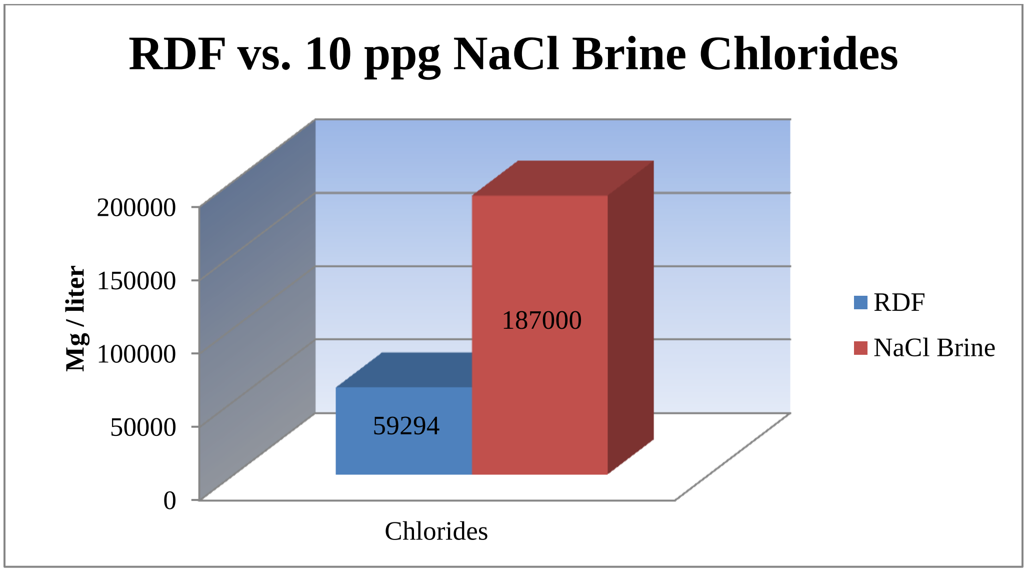
In Chart 20, results from the 10 Seconds Gel are presented. A difference of 7 lb/100ft^2 can be acknowledged (9 lb/100ft^2 for the RDF System and 2 lb/100ft^2 for the NaCl Brine System). Gel strength aids in suspending drill solids under static operations, which will prevent stuck pipe probability, while the Brine System does not require such property in this formulation.

Chart 20 – 10 sec. Gel Results RDF vs. 10 lb/gal NaCl Brine



In Chart 21, are presented the results based on the Chlorides tests (mg/liter) for the two compared Systems. Can be observed that the Chlorides in the Brine System reach the maximum possible mg/liter that can be present in a NaCl System (187000 mg/liter) compared with the 59294 mg/liter Chlorides present in the RDF System.

Chart 21 – Chloride Results RDF vs. 10 lb/gal NaCl Brine



4. Fluid Systems Related Calculations and Displacement Plan

Fluid Engineers must be competent to solve different types of fluid calculations, ranging from Pit volumes, Well volumes, Pipe volumes, Circulation time, Pump output, and other fluid calculations. These calculations are put in practice in the office and at the Wellsite, for building up fluid volumes, estimating circulation times, putting in practice efficient plans for Displacements and Cement jobs.

In the next pages, project relevant calculations will be shown and explained, and after, they will be put in practice in a Displacement plan.

Fluid Systems Related Calculations

Usually in the Oil and Gas Industry, the units used are U.S. Oilfield (barrels, foot, inch, etc.), however, every Oil industry company can choose to use any kind of units (Metric, Imperial, Combined). In the current project U.S. Oilfield units will be used.

Pit volume refers to how much fluid is in the surface pits, it is measured in barrels, and can be calculated using Equation 1:

Equation 1 – Pit Volume Rectangular tank (bbl) [6]

$$V_{pit}(bbl) = \frac{\text{Lenght (ft) x Width (ft) x Fluid Depth (ft) x No. of Pits}}{\text{5.6 cubic foot per bbl}}$$

Pipe volumes refers to how much fluid can be stored inside a Drill Pipe, Heavy Weight Drill Pipe, Drill Collar, in barrels, or other pieces of equipment used in drilling and the fluid can pass through it; can be calculated using Equation 2:

Equation 2 – Volume of Drill Pipe, HWDP and Drill Collar (bbl) [6]

$$V_{pipe}\,(bbl) = \left(\frac{\text{Pipe Inside Diameter (in)}^2}{1029}\right) \text{x PipeLenght (ft)}$$

Drill Pipe, Heavy Weight Drill Pipe and Drill Collar Outside Diameter (O.D.), Inside Diameter (I.D.), Weight, Capacity and Displacement are shown in Appendix 4 (4.1, 4.2, 4.3)

Annular Volume refers to how much fluid can be accommodated in the wellbore, in barrels, can be calculated the same for each individual section of Casing Strings, Liners and Open Hole, with or without the String inside (removing Pipe O.D.^{2} from the Equation), by using Equation 3:

Equation 3 – Annular Volume Drill Pipe/HWDP/Drill Collar inside the Well (bbl) [6]

$$V_{Annulus}(bbl) = \left(\frac{\text{Well I.D. (in)}^2 - \text{Pipe O.D. (in)}^2}{1029}\right) \text{x Lenght (ft)}$$

Casing Outside Diameter (O.D.), Inside Diameter (I.D.), Weight, Capacity and Displacement are shown in Appendix 4.4.

System Volume relates to the fluid in the surface pits, in the Annulus and in the Drill String that are directly connected and circulated; can be calculated using Equation 4:

Equation 4 – Active System Volume (bbl) [6]

$$V_{System}\,(bbl) = V_{Pit}(bbl) + V_{pipe}\,(bbl) + \text{Annular Volume (bbl)}$$

Pump Output for a Triplex Mud Pump can be calculated in barrel/minute from the pump details (Liner I.D. and stk/min), and it relates to the volume of fluid that a certain Pump can transfer in one minute, by using Equation 5:

Equation 5 – Pump Output Triplex Mud Pump (Output) (bbl/stk) [6]

$$V_{\text{pump output}}\ (\text{bbls/min}) = \text{pump}_{\text{stk/min}}\ \text{x bbl/stk x Efficiency (decimal)}$$

Barrels/Stroke of a Triplex mud pump can be chosen from Appendix 4.5 depending on the Liner I.D. (in) and stroke length of each individual pump.

Annular Velocity refers to the average rate that the fluid is flowing in the Annulus, this aids as theoretical value needed for an efficient hole cleaning; can be calculated with Equation 6:

Equation 6 – Annular Velocity (ft/min) [6]

$$\text{AV (ft/min)} = \frac{\text{Pump output (bbl/min)}}{\text{Annular Volume (bbl/ft)}}$$

Total Circulating Time refers to the time it takes the fluid to circulate from the fluid pit, down the Drill String, out the Bit, up the Annulus and back in the fluid pit. It is calculated in barrels/minute, it is a very important calculation in a Displacement plan, and all the prior results must be correct in order to have a good Displacement result. Can be calculated with Equation 7:

Equation 7 – Total Circulating Time (min) [6]

$$T_{\text{circ. time}}(\text{min}) = \frac{V_{\text{System}}\ (\text{bbl})}{V_{\text{pump output}}(\text{bbl/min})}$$

Bottom-up time refers to the time it takes the fluid to circulate from the bit (down-hole), up the Annulus and back to the surface system. Can be calculated with Equation 8:

Equation 8 – Bottoms-up time (min) [6]

$$\text{Bottoms} - \text{up}(\text{min}) = \frac{V_{\text{Annulus}}\ (\text{bbl})}{V_{\text{pump output}}(\text{bbl/min})}$$

In the next stage of the Chapter, some of the discussed Equations will be used accompanied by Wellsite data to engineer an efficient Displacement plan.

Displacement Plan

Displacement plans are usually put in place a couple of days in advance of the actual event, as per work instructions discussed with the Wellsite leader; the fluid engineer will need to calculate pit volumes, well volumes, pump output, and circulation time.

The displacement plan will be explained based on calculations on well data, and for a better interpretation consult Figure 22, Table 21 and Table 22.

Well bore data (see Figure 22):
Surface Casing: 1900 ft. of 13 $^5/_8$ –in. O.D., 48 lb/ft
Intermediate Casing: 9000 ft. of 9 $^5/_8$-in. O.D., 40 lb/ft
Liner: from 9000 ft. to 15000 ft. of 7-in. O.D., 26 lb/ft
Bit Diameter: 6 $^1/_8$-in.
Total Depth (TD): 17000 ft.
Drill String: DP 5-in O.D., 19.50 lb/ft to 8000 ft.
DP 3 $^1/_2$-in. O.D., 13.3 lb/ft to 16000 ft.
DC 4 $^3/_4$-in. OD x 2 $^1/_4$-in I.D. 1000 ft.
Surface system: can be observed in Table 19 and Table 20.
Pit 1 – 820 bbl capacity
Pit 2 – 410 bbl capacity
Pit 3 – 820 bbl capacity
Pit 4 – 420 bbl capacity
Pit 5 – 420 bbl capacity
Pit 6 – 420 bbl capacity
Pit 7 – 420 bbl capacity
Pit 8 – 420 bbl capacity
Mud Weight: 13 lb/gal VersaClean OBM System
10 lb/gal VersaPRO RDF System
Mud pump: Triplex 6-in. x 11-in., 50 stk/min, at 96% efficiency.

The problem is to efficiently displace the VersaClean OBM System from the wellbore with the VersaPRO RDF System from the Fluid pits, which will be used to drill the reservoir section.

First of all it will be mentioned that the surface system has a total capacity of 4150 barrels, the Drill String and Annulus are filled with VersaClean OBM, and the first step is to calculate these volumes, to know how much RDF fluid is needed to fully displace the wellbore.

Using Equation 2 and Appendix 4.1 and 4.3, Drill String Volume will be calculated for each individual type of pipe used, and the sum of fluid in the DP and DC will be the Drill String Volume.

From Appendix 4.1 it will be selected, based on the DP O.D. and weight, the I.D. of the DP (5-in O.D., 19.50 lb/ft), DP (3 $^1/_2$-in. O.D., 13.3 lb/ft); the DC I.D. is already known from the Well data as 2 $^1/_4$-in I.D.; in Equation 2 the know values will be substituted to calculate the final Drill String volume.

Drill String Volume:

$$V_{\text{drill pipe 5-in.O.D.}}(\text{bbl}) = \left(\frac{4.276^2}{1029}\right) \text{x } 8000 \text{ (ft)} = 0.01777 \text{ x } 8000 = 142.15 \text{ bbl}$$

$$V_{\text{drill pipe } 3^1/_2\text{-in.O.D.}}(\text{bbl}) = \left(\frac{2.764^2}{1029}\right) \text{x } 8000 \text{ (ft)} = 0.00742 \text{ x } 8000 = 59.4 \text{ bbl}$$

$$V_{\text{drill collar } 4^3/_4-\text{in.OD.}}(\text{bbl}) = \left(\frac{2.250^2}{1029}\right) \text{x } 1000 \text{ (ft)} = 0.00492 \text{ x } 1000 = 4.92 \text{ bbl}$$

Thus, summing the Pipe Volumes, the Final Drill String Volume is equal to 206.47 bbl. This volume will be used in calculating the Total Well Volume.

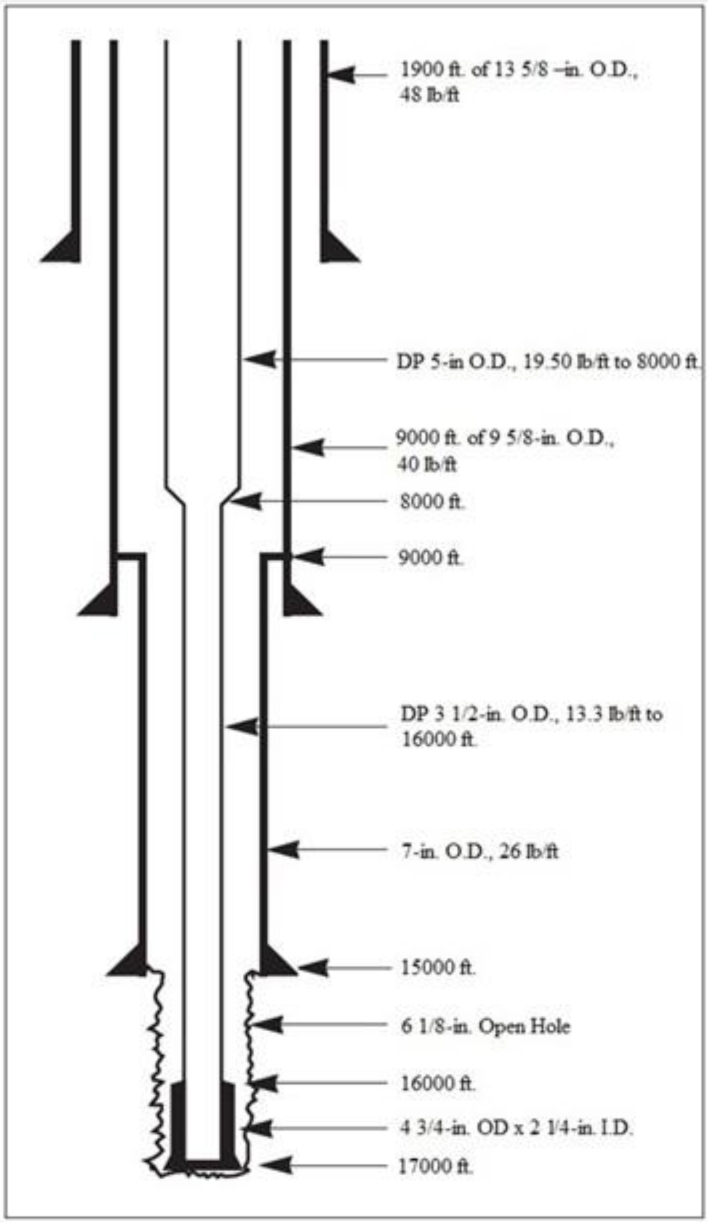


Figure 22 – Wellbore data [6]

The next step is to calculate the Annular Volume. Using Appendix 4.4, the Casing I.D. and Liner I.D. will be selected based on the Casing O.D. and weight, 9 $^5/_8$-in. O.D., 40 lb/ft, and Liner O.D. and weight 7-in. O.D., 26 lb/ft. in Equation 3 the know values will be substituted to calculate the Annular Volume.

$$V_{Casing-5-in.O.D.DP}(bbl) = \left(\frac{8.835^2 - 5^2}{1029}\right) x\, 8000\ (ft) = 0.05156\ x\ 8000 = 412.495\ bbl$$

$$V_{Casing-3^1/_2-in.O.D.DP}(bbl) = \left(\frac{8.835^2 - 3.5^2}{1029}\right) x\, 1000\ (ft) = 0.06395\ x\ 1000 = 63.95\ bbl$$

$$V_{Liner-3^1/_2-in.O.D.DP}(bbl) = \left(\frac{6.276^2 - 3.5^2}{1029}\right) x\, 6000\ (ft) = 0.02637\ x\ 6000 = 158.22\ bbl$$

$$V_{Open\ Hole-3^1/_2-in.O.D.DP}(bbl) = \left(\frac{6.125^2 - 3.5^2}{1029}\right) x\, 1000\ (ft) = 0.02455\ x\ 1000 = 24.55\ bbl$$

$$V_{Open\ Hole-4^3/_4-in.OD.DC}(bbl) = \left(\frac{6.125^2 - 4.75^2}{1029}\right) x\, 1000\ (ft) = 0.01453\ x\ 1000 = 14.53\ bbl$$

Summing the calculated volumes, will result in an Annular Volume of 673.745 bbl, thus summing the Annular Volume with the Drill String Volume, the Total Well Volume is 880.215 bbl.

The next step is to calculate the Triplex Mud Pump output in bbl/min using Equation 5 and Appendix 4.5, this result, and the Total Well Volume, will aid in calculating the time it takes the fluid to circulate the Well.

$$V_{pump\ output}\ (bbl/min) = 50_{stk/min}\ x\ 0.096_{bbl/stk}\ x\ 0.96 = 4.608\ bbl/min$$

Dividing the Total Well Volume by the pump output will result the time it takes the fluid to circulate the well, 191 minutes.

Knowing the Total Well Volume and the Well circulation time; the volume of fluid can be seen in Table 21, a total of 850 bbl of OBM in the Surface System, a total of 880.215 bbl in the Well, and a total of 1800 bbl of RDF in the Surface System, the Displacement Plan can be put in place.

Table 21 – Pit Room plan Start volumes– capacities, fluid volume and fluid type.

<table>
<tr><th colspan="2">Pit 3 (820)</th><th>Pit 2 (410)</th><th colspan="2">Pit 1 (820)</th></tr>
<tr><td colspan="2">13 ppg OBM
500 bbl

Reserve Pit</td><td>50 bbl Hi-Vis

Spacer</td><td colspan="2">10 ppg RDF
600 bbl

Reserve Pit</td></tr>
<tr><th>Pit 8 (420)</th><th>Active Pit 7 (420)</th><th>Pit 6 (420)</th><th>Pit 5 (420)</th><th>Pit 4 (420)</th></tr>
<tr><td>Empty</td><td>13 ppg OBM
350 bbl</td><td>10 ppg RDF
400 bbl</td><td>10 ppg RDF
400 bbl</td><td>10 ppg RDF
400 bbl</td></tr>
</table>

The main idea in a Displacement Plan is to fully change one well fluid with another. In this Displacement Plan a 50 bbl High-Viscosity Spacer, from Pit 2, will be used to separate the two fluids.

As seen in Table 21, the Active pit for the OBM is Pit 7, as the displacement will start, the first pit to be emptied will be Pit 2, the Hi-Vis Spacer, to place a limit on the 2 fluids, the returns from the well (OBM) will be received in Pit 8 (until +/- 400 bbl), Pit 2 (until +/- 400 bbl) and the rest in Pit 3. After the spacer is pumped, the Active Pit will change to Pit 6 (RDF), and RDF will be pumped down hole maintaining a fluid level in Pit 6 of +/- 300 bbl, by transferring RDF fluid from Pit 5 (until empty), and Pit 4 (until empty).

The well circulation time was calculated earlier on, and a total of 191 minutes will take until the Hi-Vis spacer will reach the surface, usually the spacer is water based, and has a different color and smell, to differentiate it from the other systems involved in the displacement. The Fluid Engineer must be present at the return line and spot the spacer, once the spacer reaches the surface, mud weights must be taken frequently to see the transition from 13 lb/gal to 10 lb/gal, once 3 consecutive mud weights of 10 lb/gal are taken the pumps are stopped and returns are diverted to the Active Pit, Pit 6, and the displacement is complete.

As it was calculated previously a total of 880.215 bbl of RDF need to be pumped into the well for a complete displacement, as the initial RDF volume was 1800 bbl, a reserve RDF fluid of 600 bbl is left in Pit 1 for further fluid transfer into the active pit; the Active Pit, Pit 6, will remain with 319.78 bbl of fluid. (See Table 22)

A total of 1730.21 bbl of OBM fluid, and 50 bbl Hi-Vis spacer were displaced from the well. The OBM fluid will be sent onshore for recycle or disposal.

Note that the end volumes from Table 22 are calculated values, in an actual displacement some barrels of RDF may end up in OBM pits due to the fluid interference with the spacer, in order to minimize any solids contamination.

Table 22 – Pit Room plan End volumes – capacities, fluid volume and fluid type

<table>
<tr><th colspan="2">Pit 3 (820)</th><th>Pit 2 (410)</th><th colspan="2">Pit 1 (820)</th></tr>
<tr><td colspan="2">13 ppg OBM
630.215 bbl</td><td>13 ppg OBM
400 bbl</td><td colspan="2">10 ppg RDF
600 bbl

Reserve Pit</td></tr>
<tr><th>Pit 8 (420)</th><th>Pit 7 (420)</th><th>Active Pit 6 (420)</th><th>Pit 5 (420)</th><th>Pit 4 (420)</th></tr>
<tr><td>13 ppg OBM
400 bbl</td><td>13 ppg OBM
350 bbl</td><td>10 ppg RDF
319.78 bbl</td><td>Empty</td><td>Empty</td></tr>
</table>

Results and Discussion

Oil and gas reservoir present a well-known challenge in the design of Reservoir Drill-in Fluids and Completion and Workover fluids. In this paper are presented these Special Fluids that aid in suppressing these challenges, by minimizing fluid loss to the formation, clay and shale migration and swelling, mud solids invasion into the reservoir formation. Fluid loss control is essential in the design of RDFs and Completion and Workover fluids by optimizing bridging agents to minimize and control fluid and solids invasion into fractures and pores which are most likely to guide in damaging the reservoir.

The fluids presented and the fluids tested in the current engineering paper present a maximum fluid invasion of under 5 ml/30 min at different temperatures. Fluid additives that aid in swell inhibition, are mixed not only in Conventional Drilling fluids but also in RDF systems; Completion and Workover fluids, in their essence, are designed to prevent shale inhibition without extra fluid additives. Inert solids, such as Barite and Hematite, that are usually used in weighting up Conventional Fluids are replaced in RDF systems by two essential components: Calcium Carbonate (Safe-Carb) that can be easily dissolved with an acid solution, and also provide bridging properties, and Brine which is added to serve as an internal phase, and can be built with a density range between 8.4 lb/gal to 21 lb/gal.

Rheology is one of the key properties for RDF's, and from the tests performed on a VersaPRO system shows a Plastic Viscosity in the range of 19 cP, a Yield Point of 14 lb/100ft^2, also a good hole cleaning of 8 cP (Fann 6), which provide the necessary information on the amount of solids in the fluids (PV), and the probability of chemical contaminants and reactive solids present in the fluids (YP); Gel strength provides information on how fast the fluid is gelling during static operations, and with an average of 9 lb/100ft^2 (10 seconds Gel), and 10 lb/100ft^2 (10 minutes Gel) shows a fragile gel type, which is fundamental for a RDF system. Last but not least, the percentage of Solids in the mud, shown after a Retort Test, an average of 14% Solids, in comparison with 25% that a normal Conventional fluid presents.

Brine systems that are used in Completion and Workover operations have a density range between 8.4 lb/gal and 21 lb/gal, present good shale stabilization (high salt content over 90000 mg/l), a clarity of under 5 NTU, True Crystallization Temperatures between -75^{o}F (-59.5^{o}C) and 70^{o}F (21^{o}C) depending on the fluid system and its density. Rheology on brine systems is usually low (under 5 cp for PV, 5 lb/100ft^2 for YP, and under 2-3 lb/100ft^2 for gels) because they do not use viscosifiers in their mixture; some brine systems designed for difficult wells can be formulated with viscosity agents, but are more expensive, more difficult and time consuming to build. The most important fluid systems used in the North Sea were presented in this project, but it does not mean that any other systems are not used or developed; the purpose of this Master Thesis was not to point out chemicals and fluid systems, was to present accurate rig laboratory data, how the fluid behaves in a drilling/completion operation, what are the differences between Conventional Fluids and Special Fluids, and how calculations and planning are performed to ensure the correct volume and time management for every operation.

Environmental concerns enforce drilling engineers to develop new types of fluids, to make the work place and the surrounding environment safer; they are oriented to non-toxic components, and with their use in these operations to give a positive feedback on Health, Safety and Environmental Concerns. A multitude of fluids are developed during the past years, but still they are classified as New Technology and need more tests to be performed on them before they will be used in drilling and completion operations.

An important note that needs to be pointed out is that everything in the Oil and Gas Industry is related to cost, when talking about initial planning, drilling, completion, workover or abandonment operations; the most important decision is either if the reservoir will produce enough hydrocarbons to overcome operation costs, and also give an essential profit.

Conclusions

Planning is the first step in achieving a good profit after a well is drilled, completed and produced. Engineers come up with new ideas to create a fluid that combines the drilling efficiency with a reliable completion process. A multiple selection of Brine based fluids are currently used to drill and complete a well that implicate drilling through several non-productive formations and also be able to protect the exposed reservoir formation.

Reservoir Drill-in fluids are designed especially for drilling the productive section; they are particularly designed to minimize formation damage by the removal of inert weighing agents (ex: barite, sand) from its composition and eliminating drill solids from the well in order for a slick, slim, removable filter cake to be constructed on the open hole walls. Filter cake is built with the help of bridging agent (Safe-Carb* $CaCO_3$) in such way that it will seal the reservoir rock to effectively prevent filtrate and solids from invading the productive formation.

A multitude of RDF's were evolved and currently developed to satisfy different drilling needs, ranging from the reservoir type, porosity and permeability; they use water, brine, oil or synthetic fluids as a fluid faze, plus chemical additives to aid in different function for the requirement of every operation, these fluids are developed especially for each individual operation (the amount of each additive for each fluid is not the same) to perform at their best each time.

From the laboratory tests, was confirmed that RDF Systems are performing better than Conventional Systems when drilling the Reservoir section; it was shown that RDF can overcome possible chemical and physical interactions down hole from the interaction between drill-in fluid and reservoir rock/fluid, it is very important in selecting the proper fluid to prevent formation damage and improve wellbore productivity.

The RDF filter cake effectively seals the reservoir pores, by achieving and maintaining a careful selection of the optimal bridging agents concentration, size and distribution; this selection should be based on the reservoir rock morphology, pore size and permeability. The filter cake should be easy to remove with an acid-soluble solution.

Brine Systems are designed to aid in shale stabilization, and to provide wellbore stability through density. Many types of Brine are also used as a continuous or discontinuous phase in many Drilling Fluids. They present a health hazard, if handled improperly.

It was presented, from the laboratory tests, that Brine system had the lower rheological results when compared with the OBM System and RDF System, but had a large content in dissolved salt compared with the two drilling systems.

When a Displacement operation needs to be performed at the rig site, a plan must be put in place prior to this event; volumes and circulation time need to be calculated and also have a good vision over the Pit Room and Wellbore, to know exactly how much fluid is available and how much will be displaced.

List of Symbols

3 RPM – V-G meter speed - relates how well the wellbore is cleaned from drill solids
10 sec. – 10 Seconds Gel
10 min. – 10 Minutes Gel
API – American Petroleum Institute
BBL – Barrel
BBL/FT – Barrel per Foot
BBL/MIN – Barrel per Minute
BHA – Bottom Hole Assembly
BOP – Blowout preventer
COF – Coefficient of Friction
DC – Drill Collar
DP – Drill Pipe
ECD – Equivalent Circulating Density
ES – Emulsion Stability or Electric Stability Testing
FLC – Fluid Loss Control
FT – Foot
FV – Funnel Viscosity
GGT – Garrett Gas Train
HGS – High Gravity Solids
HP – High Pressure
HT – High Temperature
HWDP – Heavy Weight Drill Pipe
I.D. – Inside Diameter
IN - Inch
Lb/gal – Pounds per Gallon
LCM – Lost Circulation Materials
LGS – Low Gravity Solids
LWD – Logging While Drilling
OBM – Oil Base Mud
O.D. – Outside Diameter
OH – Open Hole
OWR – Oil/Water Ratio
MBT – Methylene Blue Test
Mg/Liter – Milligram per liter
MIN – Minute
MW – Mud Weight
MWD – Measurement While Drilling
NAF – Non-Aqueous Emulsions
NTUs – Nephelometer Turbidity Units
PHPA – Partially Hydrolyzed Polyacrylamide
PPB – Pounds per Barrel
PPG – Pounds per Gallon
PPE – Personal Protective Equipment
PRO – Production Reservoir Optimization
PV – Plastic Viscosity
RDF – Reservoir Drill-in Fluid
ROP – Rate of Penetration
SF – Solids Free
SBM – Synthetic Base Mud
STK – Stroke
STK/MIN – Stroke per Minute
TD – Total Depth
TCT – True Crystallization Temperature
TTTM – Too Thick To Measure
HI-VIS – High Viscosity
VIS – Viscosity
WBM – Water Base Mud
YP – Yield Point

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Appendix

Appendix 1 – Drilling fluids testing and Contaminants [18]

*note that the references correspond to the initial 9th semester Project

A. <u>Water base mud testing and contaminants</u>

A series of laboratory test need to be performed on WBMs, to ensure that the fluid is in good shape, and it is not affected by formation contaminants, these test will be presented in the next paragraphs. [2]

First of all an 1 liter sample cup of fresh mud need to be collected from the flow line or the pit room, to have the required testing material.

1. Mud Weight (MW)

The density (mud weight) of the fluid needs to be checked constantly, performed with a mud balance (Fig. 8), to make sure that drill solid (contaminants) are properly removed by the solid control equipment, and the mud weight should match the one in the mud program (can be measured in lb/gal, lb/ft^3, psi/1000 ft or SG). [3]

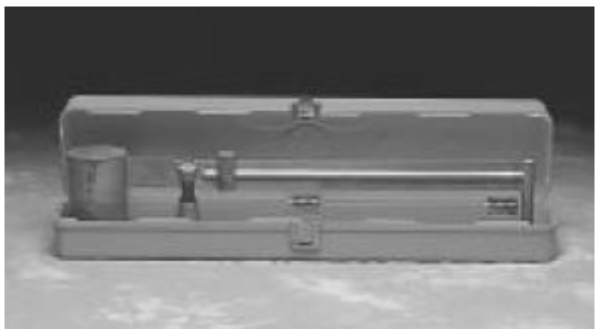


Fig. 8 – M-I Mud Balance [2]

2. Viscosity

Viscosity shows the resistance to flow of a fluid. Two tests are done to check viscosity:

<u>Funnel Viscosity (FV)</u>, tested with the Marsh Funnel (see Fig. 9), it is used as an indicator of change. The time it takes the drilling fluid to pass through the funnel and fill one quart (946 ml); note the time in seconds/quart for future comparison. This test is the simplest viscosity measurement. [3]

Fig. 9 Marsh Funnel [2]

Viscometer (Fig. 10), with this instrument the fluid can be tested to know the plastic viscosity (PV), yield point (YP), and gel strength. The test is done at 120°F (after API standards) by taking the dial readings on the V-G meter for all the six RPM speeds (600, 300, 200, 100, 6 and 3), PV = 600 RPM – 300 RPM, YP = 300 RPM – PV. These series of test are referred as Rheology. [3]

Fig. 10– V-G meter laboratory model [2]

Plastic viscosity (PV) – is the resistance to flow due to mechanical friction, and it is affected by solids concentration, size and shape and viscosity of the fluid phase. Should be maintained under control with solids control equipment and dilution. [3]

Yield point (YP) – is the resistance to flow due to dispersion or electrochemical attraction between solid particles, it is affected by chemical contaminants, inert solids, hydratable clay and shale, and over-treatment with some mud additives (ex: Soda Ash); can be maintained under control by chemically treating out the contaminants. [3]

Gel strength – there are 2 types of gel strength, fragile and progressive, and it's the structure that develops when the mud system is static (ex: during pipe connections). It is a function of time, temperature, ions in solution and solids concentration. The test is done for 10 seconds, 10 minutes and 30 minutes, and the fragile type of gel strength is suitable. [2]

3. Filtration

Through this test is determined the wall cake building property of a mud. The procedure is to determine the rate at which the fluid passes through the filter paper and forms a filter mud cake. These testes are done under specific temperature, pressure and time conditions, to result in the final measurement; if the resulted fluid loss is over the desired content FLC agent should be added to the mud. [2]

a. API Fluid loss (Fig. 11)

This test is performed at room temperature with a top pressure of 100 psi for 30 minutes, and the resulted filter cake is inspected and measured, the resulted filtrate is measured and will be further used in the Alkalinity and Chlorides testing. [3]

Fig. 11– API filter press [2]

b. HTHP filter press (Fig. 12)

Uses the same principle as the API filter press, but the test is performed for 30 minutes at 300^{o}F, a top pressure of 600 psi and a bottom pressure of 100 psi, the resulted filtrate is recorded as double. [3]

Fig. 12 – HTHP filter press [2]

4. Sand Content (Fig. 13)

This test estimates the % of sand in the mud; it is easy to use and is performed widely in the field. [2]

Fig. 13 – Sand content kit [2]

5. Retort – Liquid and Solid Content (Fig. 14)

The test is used to identify the % of liquid and % of solids in the mud, the Retort works like an oven heating up the mud until the liquid from the mud is vaporized, then condensed and collected in a graduated cylinder. (% liquid + % solids = 100%)

Fig. 14 – Retort [2]

6. Methylene Blue Test (MBT)

This test is performed to establish the amount of reactive solids in the mud. (Bentonite equivalent)

7. pH Test – Hydrogen Ion Concentration

The pH is measured on drilling fluids to be able to maintain it in spec; pH and pH adjustments are essential in mud testing, because it can affect the solubility and effectiveness of different chemical additives; pH can be modified by chemical contaminants and treated with Caustic Soda, Caustic Potash, Lime and Magnesium Oxide.

8. Chemical Analysis of Water-Base Drilling Fluids
   a. Alkalinity (Pf, Mf, Pm and Lime content)

These titrations are performed to establish the amount of Hydroxyl OH^-, Carbonate ion HCO_3^- and Bicarbonate ion CO_3^{-2} concentrations ions present in the mud filtrate obtained with the Filter press test. Based on Pf and Mf determination, Lime content in the mud can be calculated. [13]

b. Chlorides (Cl^-)

This test in conducted to determine the salt content in the mud; this test is performed on the filtrate collected in the Fluid loss test. It is a very effective test in determining the salt contamination; salt contamination may come from makeup water, chemical sacks, salt domes and salt beds. [2]

c. Total Hardness (Ca^{2+} and Mg^{2+}) and Ca^{2+} testing

These tests are performed to determine the amount of Calcium and Magnesium in the mud filtrate. Large amounts of Ca^{2+} and Mg^{2+} present in water is referred as hard water, and has to be treated because it affects the mixing quality of added chemicals in the drilling fluid system. [2]

Presented so far are the main test performed on WBMs with normal equipment that is found on every land or offshore rig, other more complex tests exists that are more accurate, but they are done in special laboratories with high tech equipment.

B. Oil / Synthetic base mud testing and contaminants

When talking about OBM/SBM testing fewer test are required to establish if the drilling fluid is in the right shape, compared with the WBM. The tests performed on OBM/SBM will be further explained with a key accent on the test not performed on WBMs.

1. Mud Weight (MW) – is performed exactly the same as for WBM.
2. Funnel Viscosity (FV) – is performed exactly the same as for WBM.
3. Rheology – (PV, YP, Gels) – the same principle as for WBM, except the mud must be heated up to 150^{o}F.
4. Fluid Loss – on OBMs/SMBs only he HTHP Fluid Loss is performed at 300^{o}F, with a 500 psi differential pressure for 30 minutes, the collected filtrate will be used further in the Alkalinity and Cl^- testing, when noted the filtrate must be multiplied by 2.

5. Retort (%Solids, %Oil/%Synthetic, %Water) – the procedure is the same as for WBMs, but the resulting fluid will be %water, which will be settling at the bottom of the graduated cylinder, %oil or %synthetic which will occupy the section on top of the water, and the % solids will be calculated (%solids = 100% -(%W+%O)); also the Oil/Water Ratio (OWR) will be calculated to see the oil and water fractions in the drilling fluid.

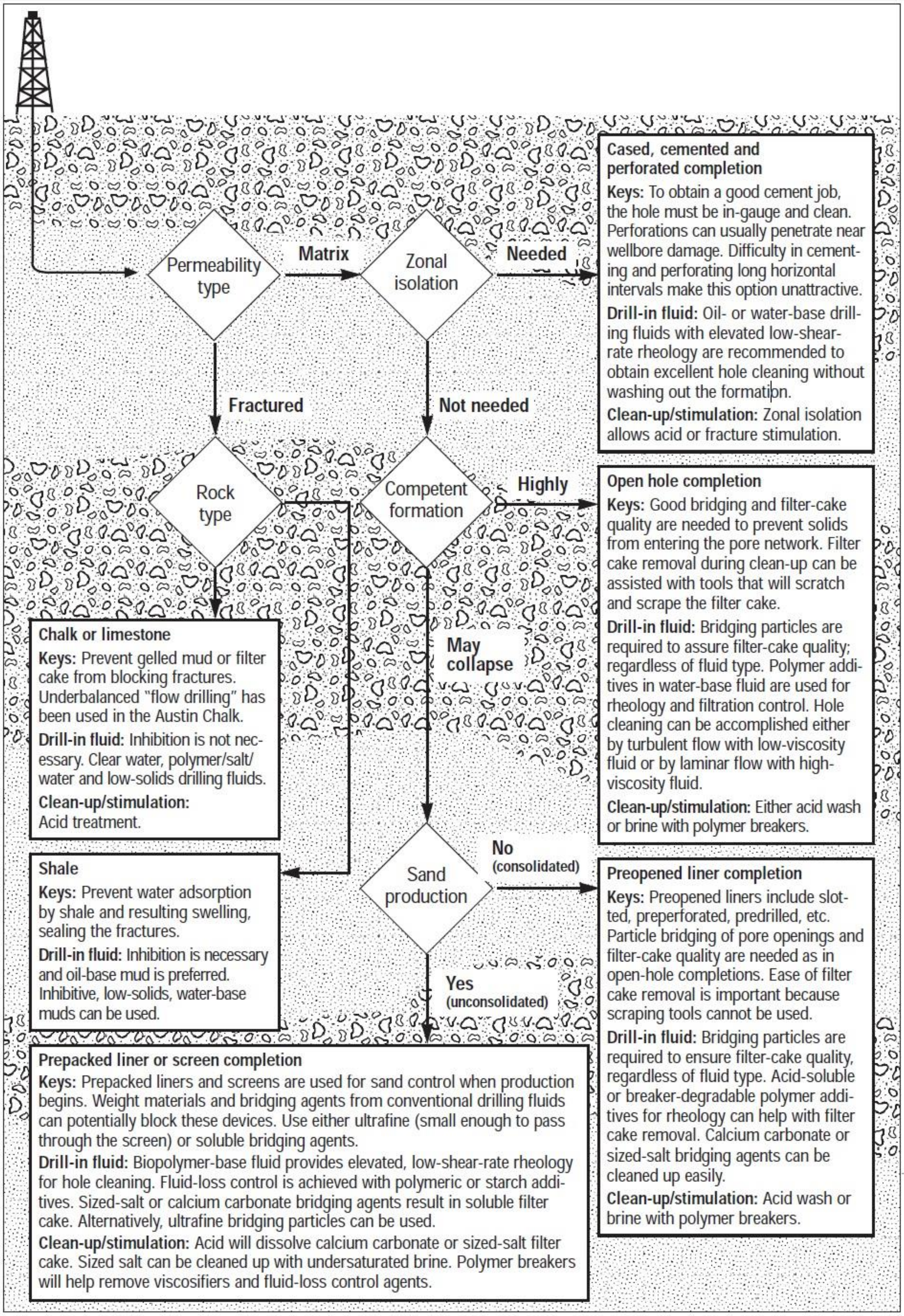
6. Chemical Analysis

- Pom/Psm titrations are the same as Pm for WBMs, multiplying the Pom/Psm result with 1.3 will equal the excess Lime (ppb lime) in the system.
- Chlorides – the same titration as per WBMs [3]

7. Emulsion Stability or Electric Stability Testing (ES) – the check is performed at 150^{o}F and will show the relative stability of the water in oil emulsion. [2]

8. Sand content – the same principle as for WBMs is applied.

Appendix 2 – Procedure for selecting proper reservoir drill-in fluids [6]



Appendix 3 – Brine Composition

Appendix 3.1 – NaCl Composition [11]

Sodium Chloride NaCl (U.S.)
Mixing dry NaCl (99%) and water
Composition for one barrel of fluid

Density lb/gal @70° F	NaCl lb/bbl	Water bbl/bbl	NaCl wt %	Na^+ mg/L	Cl^- mg/L	TCT ° F
8.33	0.0	1.000	0.0	0	0	32
8.40	3.7	0.998	1.0	4,133	6,350	31
8.50	9.6	0.993	2.7	10,710	16,524	29
8.60	16.2	0.986	4.4	18,060	27,761	27
8.70	22.2	0.981	6.0	24,638	38,106	25
8.80	28.1	0.976	7.5	31,258	48,259	23
8.90	34.8	0.969	9.2	38,662	59,701	21
9.00	41.0	0.962	10.7	45,576	70,200	19
9.10	47.7	0.955	12.4	53,071	81,900	16
9.20	54.3	0.948	13.9	60,389	93,178	14
9.30	61.3	0.940	15.5	68,188	105,239	11
9.40	68.0	0.933	17.1	75,576	116,748	8
9.50	74.6	0.926	18.5	82,992	128,022	5
9.60	81.3	0.919	20.0	90,432	139,507	1
9.70	88.6	0.910	21.5	98,474	152,135	–2
9.80	95.6	0.902	23.0	106,310	164,052	–6
9.90	102.3	0.895	24.4	113,810	175,586	12
10.00	109.0	0.890	25.7	121,200	187,080	25

To calculate parts per million, divide mg/L by the specific gravity.

Appendix 3.2 – KCl Composition [11]

Potassium Chloride KCl (U.S.)
Mixing dry KCl (99%) and water
Composition for one barrel of fluid

Density lb/gal @70° F	KCl lb/bbl	Water bbl/bbl	KCl wt %	K mg/L	Cl^- mg/L	TCT °F
8.33	0.0	1.000	0.00	0	0	32
8.40	4.3	0.995	1.21	6,350	5,745	31
8.50	11.6	0.986	3.22	17,237	15,605	29
8.60	19.0	0.977	5.21	28,171	25,592	28
8.70	26.0	0.970	7.04	38,521	34,971	26
8.80	33.4	0.960	8.95	49,522	44,876	24
8.90	41.0	0.950	10.86	60,871	55,104	22
9.00	47.7	0.943	12.49	70,734	64,147	20
9.10	55.7	0.932	14.43	82,658	74,905	18
9.20	62.7	0.924	16.06	93,060	84,339	16
9.30	69.4	0.917	17.59	102,999	93,290	14
9.40	76.8	0.908	19.26	113,919	103,317	12
9.50	84.1	0.898	20.87	124,706	113,079	23
9.60	91.5	0.890	22.47	135,695	123,024	38
9.70	98.6	0.882	23.96	146,303	132,569	54

To calculate parts per million, divide mg/L by the specific gravity.

Appendix 3.3 – NaBr Composition [11]

Sodium Bromide NaBr (U.S.)
Mixing dry NaBr (97%) and water
Composition for one barrel of fluid

Density lb/gal @70° F	Water bbl/bbl	NaBr 97% dry lb/bbl	NaBr wt %	Na mg/L	Br mg/L	TCT °F
9.0	0.973	37.9	9.73	23,434	81,533	24
9.1	0.969	43.4	11.01	26,861	93,359	23
9.2	0.965	48.9	12.28	30,247	105,203	0
9.3	0.961	54.5	13.53	33,701	117,282	21
9.4	0.957	60.2	14.79	37,334	129,597	19
9.5	0.953	65.8	16.00	40,809	141,577	17
9.6	0.948	71.5	17.20	44,233	153,895	16
9.7	0.944	77.2	18.38	47,837	166,090	14
9.8	0.940	83.0	19.56	51,387	178,620	12
9.9	0.935	88.7	20.69	54,881	190,896	11
10.0	0.931	94.5	21.83	58,555	203,384	9
10.1	0.926	100.3	22.94	62,171	215,840	7
10.2	0.922	106.1	24.02	65,724	228,258	5
10.3	0.917	111.9	25.09	69,334	240,754	4
10.4	0.912	117.8	26.16	73,002	253,449	2
10.5	0.907	123.6	27.19	76,602	265,965	0
10.6	0.903	129.5	28.22	80,257	278,673	–2
10.7	0.898	135.3	29.20	83,838	291,188	–4
10.8	0.893	141.2	30.19	87,473	303,888	–6
10.9	0.888	147.1	31.17	91,160	316,511	–7
11.0	0.884	153.0	32.12	94,768	329,182	–9
11.1	0.879	158.9	33.06	98,427	341,897	–11
11.2	0.874	164.7	33.96	102,001	354,384	–13
11.3	0.869	174.6	35.69	108,200	375,718	–14
11.4	0.864	176.5	35.76	109,294	379,863	–16
11.5	0.859	182.4	36.63	113,013	392,441	–18
11.6	0.855	188.3	37.49	116,640	405,179	–19

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Sodium Bromide NaBr (U.S.)
Mixing dry NaBr (97%) and water
Composition for one barrel of fluid

Density lb/gal @70° F	Water bbl/bbl	NaBr 97% dry lb/bbl	NaBr wt %	Na mg/L	Br mg/L	TCT °F
11.7	0.850	194.2	38.33	120,313	417,937	–19
11.8	0.845	200.1	39.16	123,890	430,571	–16
11.9	0.840	206.0	39.98	127,653	443,216	–11
12.0	0.835	211.9	40.78	131,174	456,012	–5
12.1	0.830	217.8	41.57	134,880	468,668	2
12.2	0.826	223.6	42.33	138,483	481,178	10
12.3	0.821	229.5	43.09	142,127	493,830	19
12.4	0.816	235.4	43.84	145,812	506,475	28
12.5	0.811	241.2	44.56	149,388	518,958	37
12.6	0.807	247.2	45.31	153,153	531,879	46
12.7	0.804	252.5	45.92	156,350	543,415	54

To calculate parts per million, divide mg/L by the specific gravity.

Appendix 3.4 – $NaHCO_2$ Composition [11]

Sodium Formate $NaHCO_2$ (U.S.)
Mixing dry $NaHCO_2$ (96%) and water
Composition for one barrel of fluid

Density lb/gal @70° F	96% $NaHCO_2$ lb/bbl	Water bbl/bbl	TCT ° F
8.4	5.86	0.9929	31
8.5	12.23	0.9867	29
8.6	18.71	0.9801	27
8.7	25.31	0.9733	25
8.8	32.02	0.9661	23
8.9	38.86	0.9585	20
9.0	45.83	0.9506	18
9.1	52.92	0.9423	16
9.2	60.14	0.9337	13
9.3	67.49	0.9247	11
9.4	74.98	0.9153	8
9.5	82.60	0.9055	6
9.6	90.36	0.8953	3
9.7	98.26	0.8847	6
9.8	106.30	0.8737	9
9.9	114.50	0.8623	12
10.0	122.80	0.8504	15
10.1	131.30	0.8382	18
10.2	140.00	0.8254	22
10.3	148.80	0.8123	27
10.4	157.70	0.7986	32
10.5	166.90	0.7845	38
10.6	176.10	0.7700	44
10.7	185.60	0.7549	49
10.8	195.20	0.7394	54
10.9	205.00	0.7233	59
11.0	215.00	0.7068	70

Appendix 3.5 – $KHCO_2$ Composition [11]

Potassium Formate $KHCO_2$ (U.S.)
Mixing dry $KHCO_2$ and water
Composition for one barrel

Density lb/gal @60° F	Water bbl/bbl	$KHCO_2$ dry lb/bbl	$KHCO_2$ wt %	TCT ° F
8.5	0.9896	7.2	2.0	30
8.6	0.9696	21.2	5.8	29
8.7	0.9593	28.1	7.6	28
8.8	0.9504	34.9	9.4	26
8.9	0.9410	41.7	11.1	25
9.0	0.9318	48.4	12.8	23
9.1	0.9135	61.9	16.0	20
9.2	0.9044	68.6	17.6	18
9.3	0.8953	75.3	19.1	15
9.4	0.8862	81.9	20.6	12
9.5	0.8771	88.6	22.1	10
9.6	0.8680	95.3	23.6	6
9.7	0.8496	108.8	26.4	3
9.8	0.8402	115.6	27.8	0
9.9	0.8308	122.4	29.2	–4
10.0	0.8213	129.2	30.6	–8
10.1	0.8116	136.1	32.0	–12
10.2	0.7920	150.0	34.7	–16
10.3	0.7820	157.0	36.0	–20
10.4	0.7719	164.0	37.3	–24
10.5	0.7617	171.2	38.6	–28
10.6	0.7514	178.3	39.9	–32
10.7	0.7303	192.7	42.4	–37
10.8	0.7196	199.9	43.7	–41
10.9	0.7087	207.2	44.9	–46
11.0	0.6978	214.6	46.2	–50
11.1	0.6868	221.9	47.4	–55

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Potassium Formate $KHCO_2$ (U.S.)
Mixing dry $KHCO_2$ and water
Composition for one barrel

Density lb/gal @60° F	Water bbl/bbl	$KHCO_2$ dry lb/bbl	$KHCO_2$ wt %	TCT °F
11.2	0.6644	236.8	49.8	–59
11.3	0.6530	244.3	51.0	–64
11.4	0.6416	251.8	52.2	–69
11.5	0.6301	259.3	53.4	–73
11.6	0.6185	266.9	54.5	–75
11.7	0.5951	282.1	56.8	–69
11.8	0.5833	289.7	57.9	–63
11.9	0.5715	297.4	59.0	–57
12.0	0.5596	305.1	60.1	–51
12.1	0.5475	312.8	61.2	–45
12.2	0.5233	328.3	63.4	–39
12.3	0.5110	336.1	64.5	–33
12.4	0.4986	344.0	65.5	–28
12.5	0.4861	351.8	66.6	–21
12.6	0.4735	359.8	67.6	–15
12.7	0.4478	375.8	69.7	–9
12.8	0.4347	383.9	70.7	–3
12.9	0.4213	392.1	71.8	3
13.0	0.4077	400.4	72.8	9
13.1	0.3938	408.8	73.9	16
13.2	0.3795	417.3	74.9	22

Appendix 3.6 – $CaCl_2$ Composition [11]

Calcium Chloride $CaCl_2$ (U.S.)
Mixing dry $CaCl_2$ (94 to 97%) and water
Composition for one barrel fluid

Density @70° F	$CaCl_2$ lb/bbl	Water bbl/bbl	$CaCl_2$ wt %	Ca^{+2} mg/L	Cl^- mg/L	TCT °F
8.3	0.0	0.0000	0.00%	0	0	32
8.4	3.8	0.9989	1.00%	3,641	6,443	32
8.5	9.4	0.9951	2.50%	9,212	16,298	30
8.6	14.9	0.9914	3.90%	14,540	25,724	29
8.7	20.4	0.9875	5.30%	19,989	35,365	27
8.8	26.0	0.9836	6.70%	25,560	45,221	25
8.9	31.6	0.9796	8.00%	30,866	54,608	24
9.0	37.2	0.9755	9.40%	36,675	64,886	22
9.1	42.9	0.9714	10.70%	42,211	74,680	20
9.2	48.6	0.9671	11.90%	47,461	83,968	18
9.3	54.3	0.9627	13.20%	53,218	94,153	15
9.4	60.1	0.9583	14.50%	59,087	104,538	13
9.5	65.9	0.9537	15.70%	64,658	114,394	10
9.6	71.7	0.9491	16.90%	70,333	124,433	7
9.7	77.5	0.9443	18.10%	76,111	134,657	4
9.8	83.4	0.9395	19.30%	81,994	145,065	1
9.9	89.4	0.9346	20.40%	87,552	154,897	–3
10.0	95.3	0.9296	21.60%	93,638	165,666	–7
10.1	101.3	0.9245	22.70%	99,391	175,843	–12
10.2	107.3	0.9193	23.80%	105,239	186,190	–16
10.3	113.4	0.9140	24.90%	111,182	196,705	–22
10.4	119.4	0.9086	26.00%	117,221	207,389	–27
10.5	125.6	0.9031	27.00%	122,900	217,436	–33
10.6	131.7	0.8975	28.10%	129,125	228,450	–39
10.7	137.9	0.8918	29.10%	134,982	238,812	–46
10.8	144.1	0.8860	30.20%	141,394	250,155	–51
10.9	150.4	0.8801	31.20%	147,428	260,831	–36

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Calcium Chloride $CaCl_2$ (U.S.)
Mixing dry $CaCl_2$ (94 to 97%) and water
Composition for one barrel fluid

Density @70° F	$CaCl_2$ lb/bbl	Water bbl/bbl	$CaCl_2$ wt %	Ca^{+2} mg/L	Cl^- mg/L	TCT °F
11.0	156.7	0.8741	32.20%	153,549	271,661	–22
11.1	163.0	0.8680	33.20%	159,757	282,644	–10
11.2	169.4	0.8618	34.20%	166,052	293,780	13
11.3	175.8	0.8555	35.20%	172,433	305,070	17
11.4	182.2	0.8491	36.10%	178,407	315,639	30
11.5	188.7	0.8426	37.10%	184,957	327,228	40
11.6	195.2	0.8360	38.10%	191,594	338,970	48
11.7	201.7	0.8293	39.00%	197,810	349,969	56
11.8	208.1	0.8227	39.90%	204,105	361,105	66

To calculate parts per million, divide mg/L by the specific gravity.

Appendix 3.7 – $CaBr_2$ Composition [11]

Calcium Bromide $CaBr_2$ (U.S.)
Mixing dry $CaBr_2$ (95%) and water
Composition for one barrel of fluid

Density @70° F	$CaBr_2$ lb/bbl	Water bbl/bbl	$CaBr_2$ wt %	Ca^{+2} mg/L	Br^- mg/L	TCT °F
8.33	0.0	1.0000	0.00%	0	0	32
8.4	3.6	0.9992	1.00%	2,022	8,062	30
8.5	9.0	0.9958	2.40%	4,910	19,580	30
8.6	14.4	0.9923	3.80%	7,866	31,366	29
8.7	19.9	0.9889	5.20%	10,889	43,421	28
8.8	25.3	0.9854	6.50%	13,768	54,900	27
8.9	30.7	0.9819	7.80%	16,709	66,628	27
9.0	36.1	0.9784	9.10%	19,713	78,606	26
9.1	41.6	0.9749	10.30%	22,560	89,961	25
9.2	47.0	0.9713	11.60%	25,687	102,428	24
9.3	52.4	0.9678	12.80%	28,653	114,253	23
9.4	57.9	0.9642	13.90%	31,449	125,405	22
9.5	63.3	0.9606	15.10%	34,528	137,681	21
9.6	68.8	0.9570	16.20%	37,433	149,266	19
9.7	74.3	0.9534	17.30%	40,391	161,061	18
9.8	79.7	0.9498	18.40%	43,402	173,068	17
9.9	85.2	0.9461	19.50%	46,466	185,286	16
10.0	90.7	0.9425	20.50%	49,343	196,756	14
10.1	96.2	0.9388	21.50%	52,267	208,417	13
10.2	102.0	0.9351	22.50%	55,240	220,270	11
10.3	107.0	0.9314	23.50%	58,261	232,316	10
10.4	113.0	0.9277	24.50%	61,329	244,553	8
10.5	118.0	0.9239	25.50%	64,447	256,982	7
10.6	124.0	0.9202	26.40%	67,357	268,586	5
10.7	129.0	0.9164	27.30%	70,310	280,362	3
10.8	135.0	0.9126	28.20%	73,307	292,312	2
10.9	140.0	0.9088	29.10%	76,347	304,434	0
11.0	146.0	0.9050	30.00%	79,430	316,729	–2

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Calcium Bromide $CaBr_2$ (U.S.)
Mixing dry $CaBr_2$ (95%) and water
Composition for one barrel of fluid

Density @70° F	$CaBr_2$ lb/bbl	Water bbl/bbl	$CaBr_2$ wt %	Ca^{+2} mg/L	Br^- mg/L	TCT °F
11.1	151.0	0.9012	30.80%	82,289	328,131	–4
11.2	157.0	0.8973	31.70%	85,457	340,762	–6
11.3	162.0	0.8935	32.50%	88,396	352,481	–8
11.4	168.0	0.8896	33.30%	91,373	364,353	–10
11.5	174.0	0.8857	34.10%	94,389	376,379	–12
11.6	179.0	0.8818	34.90%	97,444	388,559	–14
11.7	185.0	0.8779	35.70%	100,537	400,892	–16
11.8	190.0	0.8740	36.50%	103,668	413,379	–18
11.9	196.0	0.8700	37.20%	106,552	424,877	–21
12.0	201.0	0.8660	38.00%	109,758	437,661	–23
12.1	207.0	0.8621	38.70%	112,711	449,438	–25
12.2	213.0	0.8581	39.40%	115,698	461,349	–28
12.3	218.0	0.8540	40.10%	118,719	473,394	–30
12.4	224.0	0.8500	40.80%	121,773	485,574	≤–30
12.5	229.0	0.8460	41.50%	124,861	497,888	≤–30
12.6	235.0	0.8419	42.20%	127,983	510,336	≤–30
12.7	241.0	0.8378	42.90%	131,139	522,919	≤–30
12.8	246.0	0.8338	43.50%	134,020	534,408	≤–30
12.9	252.0	0.8296	44.20%	137,240	547,249	≤–30
13.0	258.0	0.8255	44.80%	140,182	558,978	≤–30
13.1	263.0	0.8214	45.40%	143,152	570,822	≤–30
13.2	269.0	0.8172	46.10%	146,469	584,048	≤–30
13.3	274.0	0.8131	46.70%	149,499	596,131	≤–30
13.4	280.0	0.8089	47.30%	152,558	608,330	≤–30
13.5	286.0	0.8047	47.90%	155,646	620,644	≤–30
13.6	291.0	0.8005	48.50%	158,763	633,073	≤–30
13.7	297.0	0.7962	49.10%	161,909	645,618	≤–30
13.8	303.0	0.7920	49.60%	164,752	656,953	≤–30

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Calcium Bromide $CaBr_2$ (U.S.)
Mixing dry $CaBr_2$ (95%) and water
Composition for one barrel of fluid

Density @70° F	$CaBr_2$ lb/bbl	Water bbl/bbl	$CaBr_2$ wt %	Ca^{+2} mg/L	Br^- mg/L	TCT °F
13.9	309.0	0.7877	50.20%	167,953	669,718	–29
14.0	314.0	0.7835	50.80%	171,183	682,598	–19
14.1	320.0	0.7792	51.30%	174,103	694,240	–10
14.2	326.0	0.7749	51.90%	177,389	707,341	–1
14.3	331.0	0.7705	52.40%	180,359	719,185	7
14.4	337.0	0.7662	52.90%	183,353	731,125	15
14.5	343.0	0.7618	53.50%	186,720	744,552	23
14.6	349.0	0.7575	54.00%	189,765	756,693	30
14.7	354.0	0.7531	54.50%	192,834	768,931	36
14.8	360.0	0.7487	55.00%	195,927	781,264	43
14.9	366.0	0.7443	55.50%	199,044	793,693	48
15.0	371.0	0.7398	56.00%	202,185	806,218	54
15.1	377.0	0.7354	56.50%	205,350	818,839	59
15.2	383.0	0.7309	57.00%	208,540	831,557	63
15.3	389.0	0.7264	57.50%	211,753	844,370	68

To calculate parts per million, divide mg/L by the specific gravity.

Appendix 3.8 – $CaCl_2/CaBr_2/ZnBr_2$ Composition [11]

Calcium Chloride/Calcium Bromide/ Zinc Bromide $CaCl_2/CaBr_2/ZnBr_2$ (U.S.) Blending 15.1 $CaCl_2/CaBr_2$ (liquid) with 19.2 $ZnCaBr_2$ (liquid)
Composition for one barrel of fluid

Density lb/gal @70° F	$CaCl_2/CaBr_2$ 15.1 lb/gal bbl/bbl	$CaBr_2/ZnCaBr_2$ 19.2 lb/gal bbl/bbl	TCT °F
15.1	1.000	0.000	62
15.2	0.976	0.024	60
15.3	0.951	0.049	59
15.4	0.927	0.073	58
15.5	0.903	0.098	56
15.6	0.878	0.122	55
15.7	0.854	0.146	54
15.8	0.829	0.171	53
15.9	0.805	0.195	51
16.0	0.780	0.220	51
16.1	0.756	0.244	49
16.2	0.732	0.268	48
16.3	0.707	0.293	47
16.4	0.683	0.317	46
16.5	0.658	0.342	44
16.6	0.634	0.366	42
16.7	0.610	0.390	39
16.8	0.585	0.415	34
16.9	0.561	0.439	28
17.0	0.537	0.463	25
17.1	0.512	0.488	26
17.2	0.488	0.512	28
17.3	0.463	0.537	28
17.4	0.439	0.561	30
17.5	0.415	0.585	32

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Calcium Chloride/Calcium Bromide/ Zinc Bromide $CaCl_2/CaBr_2/ZnBr_2$ (U.S.) Blending 15.1 $CaCl_2/CaBr_2$ (liquid) with 19.2 $ZnCaBr_2$ (liquid)
Composition for one barrel of fluid

Density lb/gal @70° F	$CaCl_2/CaBr_2$ 15.1 lb/gal bbl/bbl	$CaBr_2/ZnCaBr_2$ 19.2 lb/gal bbl/bbl	TCT °F
17.6	0.390	0.610	34
17.7	0.366	0.634	36
17.8	0.341	0.659	38
17.9	0.317	0.683	40
18.0	0.293	0.707	35
18.1	0.268	0.732	32
18.2	0.244	0.756	29
18.3	0.220	0.780	27
18.4	0.195	0.805	25
18.5	0.171	0.829	23
18.6	0.146	0.854	21
18.7	0.122	0.878	20
18.8	0.097	0.903	19
18.9	0.073	0.927	17
19.0	0.049	0.951	16
19.1	0.024	0.976	12
19.2	0.000	1.000	10

To make 1 bbl 15.1 lb/gal = .851 (14.2 lb/gal $CaBr_2$) + 127 ppb dry $CaCl_2$.

Appendix 4 – Wellbore data Capacity and Displacement [6]

Appendix 4.1 – Drill Pipe Capacity and Displacement

OD		Weight		ID		Capacity		Displacement	
in.	mm	lb/ft	kg/m	in.	mm	bbl/ft	m³/m	bbl/ft	m³/m
2⅜	60	4.85	7.23	1.995	51	0.0039	0.0020	0.0016	0.0008
2⅞	73	6.85	10.21	2.441	62	0.0058	0.0030	0.0022	0.0012
2⅞	73	10.40	15.50	2.150	55	0.0045	0.0023	0.0035	0.0018
3½	89	13.30	19.82	2.764	70	0.0074	0.0039	0.0045	0.0023
3½	89	15.50	23.10	2.602	66	0.0066	0.0034	0.0053	0.0028
4	102	14.00	20.86	3.340	85	0.0108	0.0057	0.0047	0.0025
4½	114	16.60	24.73	3.826	97	0.0142	0.0074	0.0055	0.0029
4½	114	20.00	29.80	3.640	92	0.0129	0.0067	0.0068	0.0035
5	127	19.50	29.06	4.276	109	0.0178	0.0093	0.0065	0.0034
5	127	20.50	30.55	4.214	107	0.0173	0.0090	0.0070	0.0037
5½	140	21.90	32.63	4.778	121	0.0222	0.0116	0.0072	0.0038
5½	140	24.70	36.80	4.670	119	0.0212	0.0111	0.0082	0.0043
5 9/16	141	22.20	33.08	4.859	123	0.0229	0.0120	0.0071	0.0037
5 9/16	141	25.25	37.62	4.733	120	0.0218	0.0114	0.0083	0.0043
6⅝	168	31.90	47.53	5.761	146	0.0322	0.0168	0.0104	0.0054
7⅝	194	29.25	43.58	6.969	177	0.0472	0.0246	0.0093	0.0049

Appendix 4.2 – Heavy Weight Drill Pipe Capacity and Displacement

OD		ID		Weight		Capacity		Displacement	
in.	mm	in.	mm	lb/ft	kg/m	bbl/ft	m³/m	bbl/ft	m³/m
3½	89	2.063	52	25.30	37.70	0.0042	0.0022	0.0092	0.0048
3½	89	2.250	57	23.20	34.57	0.0050	0.0026	0.0084	0.0044
4	102	2.563	65	27.20	40.53	0.0064	0.0033	0.0108	0.0056
4½	114	2.750	70	41.00	61.09	0.0074	0.0039	0.0149	0.0078
5	127	3.000	76	49.30	73.46	0.0088	0.0046	0.0180	0.0094
5½	140	3.375	86	57.00	84.93	0.0112	0.0058	0.0210	0.0110
6⅝	168	4.500	114	70.80	105.49	0.0197	0.0103	0.0260	0.0136

Appendix 4.3 – Drill Collar Capacity and Displacement

OD		ID		Weight		Capacity		Displacement	
in.	mm	in.	mm	lb/ft	kg/m	bbl/ft	m³/m	bbl/ft	m³/m
3½	89	1.500	38	26.64	39.69	0.00219	0.0011	0.0097	0.0051
4⅛	105	2.000	51	34.68	51.67	0.00389	0.0020	0.0126	0.0066
4¾	121	2.250	57	46.70	69.58	0.00492	0.0026	0.0170	0.0089
6	152	2.250	57	82.50	122.93	0.00492	0.0026	0.0301	0.0157
6¼	159	2.250	57	90.60	134.99	0.00492	0.0026	0.0330	0.0172
6½	165	2.813	71	91.56	136.42	0.00768	0.0040	0.0334	0.0174
6¾	171	2.250	57	108.00	160.92	0.00492	0.0026	0.0393	0.0205
7¾	197	2.813	71	138.48	206.34	0.00768	0.0040	0.0507	0.0264
8	203	2.813	71	150.48	224.22	0.00768	0.0040	0.0545	0.0284
9½	241	3.000	76	217.02	323.36	0.00874	0.0046	0.0789	0.0412
10	254	3.000	76	242.98	362.04	0.00874	0.0046	0.0884	0.0461
11¼	286	3.000	76	314.20	468.16	0.00874	0.0046	0.1142	0.0596

Appendix 4.4 – Casing and Liner Capacity and Displacement

OD		Weight		ID		Capacity		Displacement	
in.	mm	lb/ft	kg/m	in.	mm	bbl/ft	m^3/m	bbl/ft	m^3/m
4½	114	13.50	20.12	3.920	100	0.0149	0.0078	0.0047	0.0025
4½	114	15.10	22.50	3.826	97	0.0142	0.0074	0.0055	0.0029
4¾	121	16.00	23.84	4.082	104	0.0162	0.0084	0.0057	0.0030
5	127	15.00	22.35	4.408	112	0.0189	0.0099	0.0054	0.0028
5	127	18.00	26.82	4.276	109	0.0178	0.0093	0.0065	0.0034
5½	140	20.00	29.80	4.778	121	0.0222	0.0116	0.0072	0.0038
5½	140	23.00	34.27	4.670	119	0.0212	0.0111	0.0082	0.0043
5¾	146	22.50	33.53	4.990	127	0.0242	0.0126	0.0079	0.0041
6	152	26.00	38.74	5.140	131	0.0257	0.0134	0.0093	0.0049
6⅝	168	32.00	47.68	5.675	144	0.0313	0.0163	0.0114	0.0059
7	178	26.00	38.74	6.276	159	0.0383	0.0200	0.0093	0.0049
7	178	38.00	56.62	5.920	150	0.0340	0.0177	0.0136	0.0071
7⅝	194	26.40	39.34	6.969	177	0.0472	0.0246	0.0093	0.0049
7⅝	194	33.70	50.21	6.765	172	0.0445	0.0232	0.0120	0.0063
7⅝	194	39.00	58.11	6.625	168	0.0426	0.0222	0.0138	0.0072
8⅝	219	38.00	56.62	7.775	197	0.0587	0.0306	0.0135	0.0070
9⅝	244	40.00	59.60	8.835	224	0.0758	0.0395	0.0142	0.0074
9⅝	244	47.00	70.03	8.681	220	0.0732	0.0382	0.0168	0.0088
9⅝	244	53.50	79.72	8.535	217	0.0708	0.0369	0.0192	0.0100
10¾	273	40.50	60.35	10.050	255	0.0981	0.0512	0.0141	0.0074
10¾	273	45.50	67.80	9.950	253	0.0962	0.0502	0.0161	0.0084
10¾	273	51.00	75.99	9.850	250	0.0942	0.0491	0.0180	0.0094
11¾	298	60.00	89.40	10.772	274	0.1127	0.0588	0.0214	0.0112
13⅜	340	54.50	81.21	12.615	320	0.1546	0.0806	0.0192	0.0100
13⅜	340	68.00	101.32	12.415	315	0.1497	0.0781	0.0241	0.0126
16	406	65.00	96.85	15.250	387	0.2259	0.1178	0.0228	0.0119
16	406	75.00	111.75	15.124	384	0.2222	0.1159	0.0265	0.0138
18⅝	473	87.50	130.38	17.755	451	0.3062	0.1597	0.0307	0.0160
20	508	94.00	140.06	19.124	486	0.3553	0.1853	0.0333	0.0174

Appendix 4.5 – Triplex Pump Output (100% Efficiency) (bbl/stk)

Liner ID (in.)	Stroke Length (in.)									
	7	7½	8	8½	9	9½	10	11	12	14
3	0.015	0.016	0.017	0.019	0.020	0.020	0.022	0.024	0.026	—
3¼	0.018	0.019	0.021	0.022	0.023	0.024	0.026	0.028	0.031	—
3½	0.021	0.022	0.024	0.025	0.027	0.028	0.030	0.033	0.036	—
3¾	0.024	0.026	0.027	0.029	0.031	0.032	0.034	0.038	0.041	—
4	0.027	0.029	0.031	0.033	0.035	0.036	0.039	0.043	0.047	—
4¼	0.031	0.033	0.035	0.037	0.039	0.041	0.044	0.048	0.053	—
4½	0.034	0.037	0.039	0.042	0.044	0.045	0.049	0.054	0.059	—
4¾	0.038	0.041	0.044	0.047	0.049	0.051	0.055	0.060	0.066	—
5	0.043	0.045	0.049	0.052	0.055	0.056	0.061	0.067	0.073	0.085
5¼	0.047	0.050	0.054	0.057	0.060	0.062	0.067	0.074	0.080	0.094
5½	0.051	0.055	0.059	0.062	0.066	0.068	0.073	0.081	0.088	0.103
5¾	0.056	0.060	0.064	0.068	0.072	0.074	0.080	0.088	0.096	0.112
6	0.061	0.065	0.070	0.074	0.079	0.081	0.087	0.096	0.105	0.122
6¼	0.066	0.071	0.076	0.081	0.085	0.088	0.095	0.104	0.114	0.133
6½	0.072	0.077	0.082	0.087	0.092	0.095	0.103	0.113	0.123	0.144
6¾	0.077	0.083	0.088	0.094	0.100	0.102	0.111	0.122	0.133	0.155
7	0.083	0.089	0.095	0.101	0.107	0.110	0.119	0.131	0.143	0.167
7½	—	—	—	—	—	—	0.137	0.150	0.164	0.191
8	—	—	—	—	—	—	0.155	0.171	0.187	0.218

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