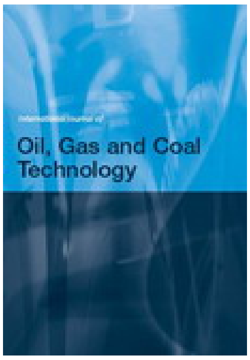

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A comprehensive review on the high-density clear completion fluids for applications in HPHT well completion

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Abstract: This paper will provide a broad high-level comprehensive review of various high-density completion fluids (HDCF) for the high pressure and high temperature (HPHT) reservoir. The goal is to explain the advantages and disadvantages of various high-density completion fluids over conventional completion fluids. Existing completion fluids solutions are low to mid-density range, expansive, limited availability, corrosion issues, and not suitable for all types of reservoir formations. Solids-free high-density completion fluids differ from conventional completion fluids in several key aspects such as high density, solids-free, low viscosity, alkaline pH, less corrosive, minimum formation damage, and thermal stability. The desired requirements from a high-density completion fluid system include insignificant solids, providing rheological stability, fulfilling environmental conditions, and reducing reservoir damage. A suitable completion fluid system can provide sufficient density for well control while eliminating solid weighting materials which are potentially formation damaging. [Received: January 13, 2022; Accepted: May 25, 2022]

Keywords: high-density completion fluids; HDCF; high pressure and high temperature; HPHT; solid-free; brine; formation damage; true crystallisation temperature; TCT.

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1 Introduction

Several definitions are used by the industry to describe the completion fluids based on either the composition or the properties of the completion fluids. Some of the available definitions, taken from different sources are mentioned below:

The American Petroleum Institute (API) defines the completion fluid (CF) as a solid-free liquid employed to complete oil and gas wells (Ezzat, 1990). According to the Schlumberger oilfield glossary, completion fluids are mostly brines (chlorides, bromides, and formates) or any appropriate fluid with suitable density and flow characteristics (Schlumberger Oil Field Glossary, 2022). Generally, high density solid free completion fluid is placed in the well to facilitate the final operations such as setting production liners, during gravel packing and well perforations process, installation of various screens, packers, subsurface down-hole safety valves, and during workover remedial works before initiation of production (Caenn et al., 2011). Baroid Fluids Handbook mentions that high-density completion and workover fluids are accustomed to modulating the formation pressure, and it also moderates formation damage to a certain extent (Baroid Drilling Fluids Inc., 1998). The Completion Fluids Manual, MI SWACO, mentions that a CF can be defined as any suitable fluid used during final operations after the initial drilling of a well, and workover fluids are those used during remedial operations after a well has been completed and produced oil and/or gas (MI SWACO, 2005). CF plays an important role during downhole hardware failure and is meant to regulate a well without damaging the producing formation or completion components. As shown in Figure 1, we can see that completion fluids are of considerable significance at the last stage of drilling operations to prepare the wellbore to initiate the production from it.

Figure 1 Completion fluid operations to prepare the wellbore to initiate the production from it at the last stage of drilling operations (see online version for colours)

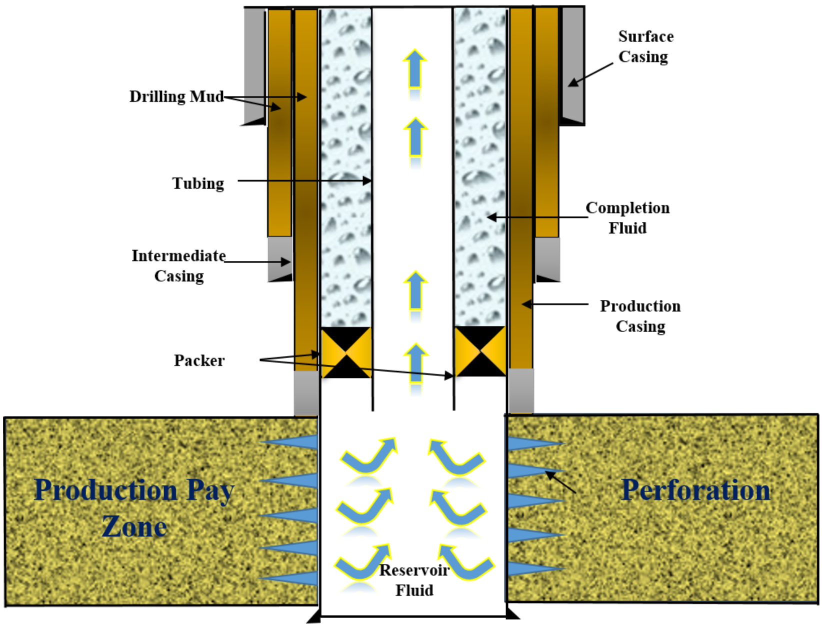
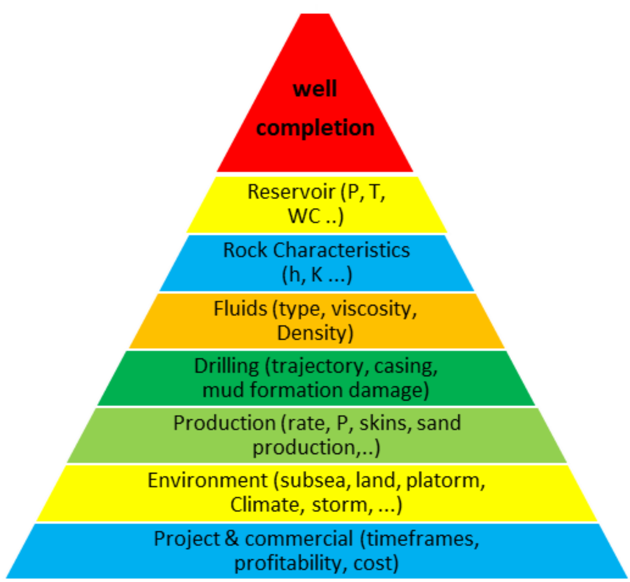
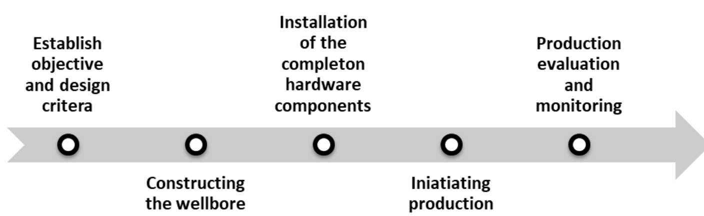


Figure 2 Factors affecting well-completion activities (see online version for colours)



Completion fluid design should be based on a detailed study of the reservoir characteristics at the downhole conditions (Caenn et al., 2011). To select the best suitable completion fluid design, we need a prior understanding of well completion requirements. CF is the interface between the reservoir and surface production. A well-completion development principally comprises preparing the bottom of the hole to the desired specifications, such as running a production tubing associated with downhole tools, perforation, and well stimulation (Hossain and Al-Majed, 2015). During the well completion process, a well engineer identifies the supreme approach in designing a well to optimise well productivity and oil recovery. A completed well consists of combined effects of overall various activities such as rock formation characteristics and fluid properties in reservoir condition, drilling and workover activities, the production optimisation, project and commercial viability for facilities development, and final consideration of environmental impact. If one of the parameters is affected or influenced by the resulting outcomes, the overall completion activities will be surely affected. Figure 2 shows factors affecting well-completion activities. Figure 3 demonstrates the sequential order the well completion requires. The role of CF design will play a vital role once the well completion objectives and the design conditions are fixed for wellbore construction and installation of the downhole completion components.

Figure 3 Different phases of well completion



2 Clear completion fluids systems

The basic types of completion and workover systems are clear-fluid systems. The clear brines used for completion and workover procedures are pure aqueous solutions of dissolved salt in water and must have sufficient stability at the surface and downhole conditions. Commonly used salts include: KCl, NaCl, NaBr, NH_4Cl, $CaCl_2$, $CaBr_2$ and $ZnBr_2$. These salts can be utilised alone or mixed to shape a CF with the required properties. Monovalent CF solutions such as Sodium chloride, Potassium chloride, and Ammonium chloride have a low specific gravity range of 1.008–1.2, hence not a good choice as HPHT completion fluids. Monovalent CF solutions such as caesium formate have a high specific gravity range of 1.56–2.4, which can be used in HPHT completion fluid. Divalent CF compositions such as calcium chloride, calcium bromide, and zinc bromide can give a specific gravity range of 1.008 to 2.5. Mixing two or more salts can alter the overall density of CF. such as NaCl/NaBr blend can give a specific gravity range of 1.008–1.5, sodium formate and potassium formate blend NaCOOH /KCOOH can give a specific gravity range of 1.008–1.57, $ZnBr_2/CaBr_2/CaCl_2$ blend can give specific gravity range of 1.44–2.29. The mixing of salts depends on compatibility and chemical composition. Changes in density and salt composition will cause and alter the brines stability and equilibrium curve. Increasing or maintaining the overall density of formulated CF can change the proportion of salts in a multi-salt blend. Generally, adding dry salt or saturated brine will alter the density. Similarly, adding water can reduce the overall density of the completion fluid and also will cause the hydrate equilibrium curve to shift and possibly increase the risk of forming hydrates (Jeu, 2002). Density control possibilities should be carried out in advance. Various salts solutions can be used for clear-fluid systems, these salts can be classified into two main categories: monovalent and divalent. Table 1 lists the comparative densities of clear-fluid completion systems (Caenn et al., 2011).

Table 1 Comparative densities of clear completion fluid systems

Brine type	*Brine formula*	*Density range (specific gravity)*	*Density range (lb/gallon)*
		Monovalent solutions	
Sodium chloride	$NaCl$	1.008–1.2	8.4–10
Potassium chloride	KCl	1.008–1.16	8.4–9.7
Ammonium chloride	NH_4Cl	1.008–1.06	8.4–8.9
Sodium bromide	$NaBr$	1.008–1.52	8.4–12.7
Mix	$NaCl/NaBr$	1.008–1.5	8.4–12.5
Sodium formate	$NaCOOH$	1.008–1.32	8.4–11.1
Potassium formate	$KCOOH$	1.008–1.59	8.4–13.3
Cesium formate	$CsCOOH$	1.56–2.4	13–20
Mix	$NaCOOH/KCOOH$	1.008–1.57	8.4–13.1
		Divalent solutions	
Calcium chloride	$CaCl_2$	1.008–1.35	8.4–11.3
Calcium bromide	$CaBr_2$	1.008–1.83	8.4–15.3
Zinc bromide	$ZnBr_2$	1.44–2.52	12–21
Mix	$ZnBr_2/CaBr_2/CaCl_2$	1.44–2.29	12–19.1

A clear CF fluid system is preferred because of the properties of clear-fluid systems to protect formations and minimise damage. Clear, solids-free CF brine can reduce the possibility of perpetual formation damage (permeability damage due to skin formation) ensuing from solids invasion or some form of incompatibility between the completion fluid and the in situ fluid matrix. In addition, clear fluid CF systems make excellent packer fluids during workover operations

3 Completion fluids properties and selection guide

High-density completion fluid (HDCF) systems have properties that must maintain rheological stability at downhole conditions, contain minimal solids, and minimise reservoir damage via satisfying environmental requirements (Dubberley and Magill, 2020). The primary factor influencing completion fluids selection for a specific well completion is the stable working density range. It is essential that the CF can provide sufficient density for well control and mechanical stabilisation of the wellbore. Secondary factors include commercial aspects such as cost/logistics, physical properties such as crystallisation temperature, and chemical properties such as corrosion/additive compatibility considerations. The selection of CF is related to the fulfilment of the following functions.

1. Available in a wide density range and adequate density, to control formation pressure (maintain overbalance) to avoid entrance of formation fluid into the wellbore during completion.
2. Thermal stability of brine at HPHT conditions.
3. Compatibility issues:
   a. compatibility with formation and formation fluids, to avoid or minimise formation damage
   b. compatibility with additives such as alkalinity control, and inhibitors to achieve desired properties to sustain at HPHT conditions
   c. compatibility with drilling mud, to avoid or minimise formation damage
   d. compatibility with coatings, elastomers, and material of wellbore.
4. Environmentally friendly and capable of being recovered for reuse.
5. Alkaline pH, corrosion control, less corrosive to reduce corrosion of wellbore equipment.
6. Economic, having optimum cost.
7. Solid tolerance, clean and uncontaminated, lesser settling in completion fluid to reduce formation damage.
8. Stable in presence of gas, brine, and cement contaminants.
9. CF should need gas solubility for accurate kick (abnormal formation pressure) detection and modelling.
10. Intermediate toxicity falls between water and hydrocarbon base fluids.
11. CF should have the stability to aging properties. Their rheological properties do not change over some time under either static or dynamic conditions but in reality, properties slightly, drop after dynamic aging and increase after static aging (Shadravan and Amani, 2012).
12. Optimum rheological property and low viscosity.
13. Crystallisation temperature.
14. Discern fractured intervals with optimal matrix porosity are crucial parts of the completion strategy. Commercially effective production relies upon the competence to drill through productive natural fractures and to complete the naturally fractured intervals with negligible damage (Ehlig-Economides et al., 2000). For naturally fractured reservoirs, it is vital to consider an integrative strategy. Careful attention to the completion fluid properties is crucial including compatibility with formation fluid. The role of natural fractures in the selection of completion fluids is an

important factor during final well completions. For example, over-balanced drilling can lead to the lost circulation of damaging drilling fluids and solids in the natural fractures. Similarly, cementing the fractured zones can promote plug natural fractures and cause productivity issues from the natural fractures.

15 The considerations of casing geometry and properties are essential regarding completion fluid selection. An open hole completion perhaps is suggested as an alternative to cementing and perforating. Upper intervals should be cemented above and below the productive interval so that an upper interval can finally be produced or integrated by perforating the casing (Ehlig-Economides et al., 2000). Understanding the casing specification such as burst and collapse ratings, the casing IDs needs from the beginning of the completion project. These specifications of casing must be optimised. There are some issues and limitations to take into consideration during the completion of equipment size selections. Examples are perforation burrs, debris in the well, restrictions to flow, swabbing, and flow velocity around the tools (Moreno et al., 2009).

16 Permeability consideration is important in designing a completion fluid pack. Dimensionless fracture conductivity (FCD), a ratio of formation permeability to fracture permeability is used to design fractures and net fracture conductivity. The permeability also plays a prominent role in completion fluid efficiency. The higher the permeability, the quicker the fluid will leak off into the formation (Moreno et al., 2009). This will play a role in fluid selection as well as the pump rate required to establish the optimal geometry.

17 Water depth plays a major role in determining the stresses in the formation. The overburden stress value of water is 0.45 psi/ft and the overburden value of rock formation is 1 psi/ft. These parameters are required in creating completion fluid design models.

4 Functions of completion fluids

Solids-free brine-based completion fluids (SFBCF) differ from conventional completion fluids in several key aspects such as solids-free, no fluid loss control additives, and low viscosity (Dubberley and Magill, 2020). Below are some of the required functions of completion fluid.

1 Completion and workover fluid:
   a density (well control) to control formation pressure during completion equipment installation such as screens, downhole packers, and different types of valves and equipment (gas lift valve, mandrel, etc.)
   b to control a well shutdown case during downhole hardware fail
   c casing and reservoir friendly
   d to clear out fine particles from the bottom of the wellbore after workover and stimulation operations.

2 Packer fluid:

  a sometimes used as packer fluid and workover fluid during well intervention operations
  b replace standard drilling muds in the reservoir section
  c minimise formation damage from filtrate loss.

3 To facilitate the operation of establishing communication between productive formation and the wellbore (perforation operation).

4 Drilling fluid:
  a brine-based completion fluids having widely density range and salt composition can be used as clay inhibition mud compatible with reservoirs fluids
  b water-based or inverted emulsion (water in oil)-based mud.

5 Role of true crystallisation temperature

High bottom hole temperature causes a reduction of CF density which can lead to well control-related problems (Spies et al., 1983). Well control is a particularly troublesome concern. The fluid density is typically chosen to surpass the formation pressure, in addition to an additional safety factor. CF should have the adequate density to control formation pressure (maintain overbalance) to inhibit the entry of formation fluid into the wellbore during completion. Regularly utilised overbalance levels are 200 psi for oil wells and 300 psi for gas wells (Hossain and Al-Majed, 2015).

Completion fluid density can also be affected due to crystallisation phenomena. The true crystallisation temperature or TCT is the temperature at which the brine becomes saturated and salt crystals begin to form (Davidson et al., 2017). The TCT is typically measured at atmospheric pressure and gives a measure of the lowest temperature that given brine can be used. Heavy completion fluid brines can crystallise if exposed to lower temperatures or higher pressures. Fluid crystallisation can cause blockage to tubular, pipelines to plug, and pumps to seize in a wellbore or the surface. To make certain crystallisation does not take place in a CF brine system, generally, a common practice is to first establish the required crystallisation point of the fluid and then analyse the existent crystallisation point of the fluid to calibrate the crystallisation point of the fluid for safe conditions (Baroid Drilling Fluids, Inc., 1998). For example, $CaCl_2/CaBr_2$ brine (14.8 lb/gal, 1.77 s.g.) will crystallise if the temperature of the brine falls below 63°F (Caenn et al., 2011). Generally, salt is dissolved in water, and it lowers the freezing point of the solution until the eutectic point is reached, and increasing the salt concentration beyond the eutectic raises the crystallisation point. The eutectic temperature signifies the lowest temperature on the saltwater phase diagram (MI SWACO, 2005). Similarly, salts will crystallise out of solution if the temperature decreases further down a certain critical value. This phenomenon depends on the composition of the brine as densities approach saturation (Adams, 1981; Hubbard, 1984; Milhone, 1983).

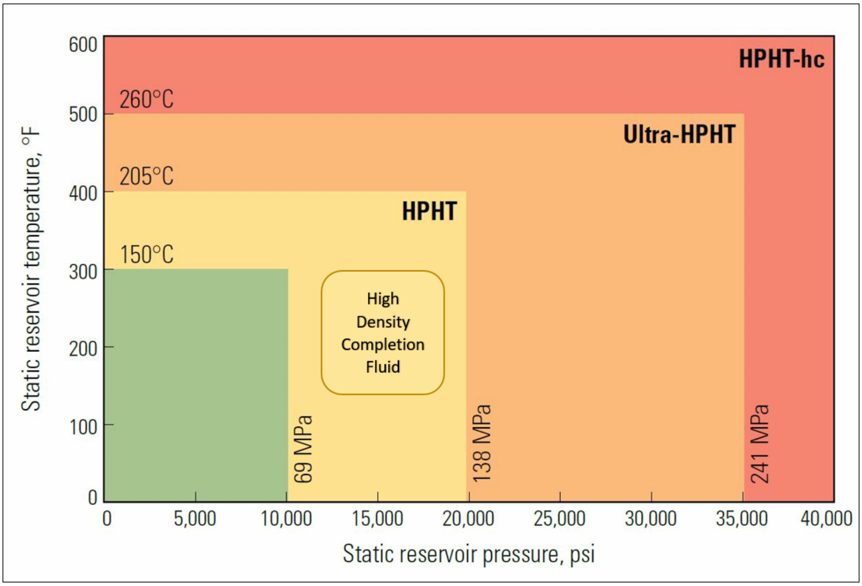
Crystallisation inhibitors such as methanol and ethylene glycol can be used to lower the TCT, but can also result in a reduction of the density of the brine. This will make it unsuitable for the original purpose of HDCF, which means that more solid divalent salt has to be added to bring the density of the brine back to the operational density. Zinc, such as in the form of zinc bromide ($ZnBr_2$), can be added to increase the density. However, zinc is a marine pollutant and can cause issues in the processing stage if residual zinc is in the oil sent to the refinery. Crystallisation of CF can be a major problem during working in winter as it can be solidified during winter. However, crystallisation was not a major problem during working in the summer. The use of electrically heated tanks during the winter allowed the minimisation (Spies et al., 1983). Sometimes surface facilities have a similar problem of getting brine crystallisation in handling brines. Using brine below its TCT can lead to serious consequences as the salt falls out of the solution and the fluid density is severely reduced. For example, in cold seawater offshore, the crystallisation temperature of brine is a crucial selection measure. Generally for deep-water applications, a TCT significantly less than 30°F is required but TCT in a range of about 20°F to about 60°F is useful for shallower water applications where the seabed temperature is not as low.

6 The desired rheological performance at HPHT

The worldwide progression in hydrocarbon exigency is directing the oil and gas industry to drill and complete a deeper reservoir under a challenging environment of high pressure and high temperature (HPHT) (Lee et al., 2012). During HPHT conditions for a well, they have an initial reservoir temperature >300°F and a reservoir pressure >10,000 psi or an initial reservoir overpressure >3,000 psi (Loth, 1998). Globally, most oil and gas industry players are involved in HPHT field assets in some capacity. Figure 4 shows the HPHT well classification system of Schlumberger (Smithson, 2016).

Temperature and pressure are significant factors when choosing a completion fluid at HPHT conditions. Generally, CF demonstrates the volumetric response to temperature and pressure (expanding and compressing with increasing temperature and pressure respectively) (MI SWACO, 2005). High bottom hole temperature causes a reduction of CF density which can lead to well control-related problems. The density of a CF diminishes as the temperature increments because of the liquid's warm volumetric extension (TETRA Technologies, Inc., 2021). Completion fluid should have the adequate density to control formation pressure (maintain overbalance) to avert the entry of formation fluid into the wellbore during completion (Hossain and Al-Majed, 2015). Temperature and pressure have a direct relationship with depth (directly increased with an increase in depth) (Ibeh et al., 2008). Generally, a completion fluid under HPHT conditions encounters two divergent properties of temperature and pressure in the wellbore. High reservoir pressure can cause the increase of completion fluid's viscosity because of its compressibility effect. On the other hand, a surge in temperature upsurges the random motion of the macromolecules dissolved in the completion fluid matrix and resulting in minimised molecular interaction and therefore reduced viscosity. However, these two opposing effects may cancel out for a particular pressure and temperature profile and further result in a uniform fluid viscosity/density equal to that at the surface (Ibeh et al., 2008). The effect of temperature on the volumetric expansion of a completion fluid is more predominant than the pressure in shallow water or onshore wellbore. However, in offshore deepwater environments, cold water depth will influence the expansion/compression correlation such that the combination of hydrostatic pressure and cold temperature can have appalling effects on CF property (MI SWACO, 2005). The impact of pressure is anticipated to be greater with oil-based systems having high oil phase compressibility as compared to a water-based system having less compressibility. Completion fluid needs to be properly formulated to account for deepwater environments.

Figure 4 HPHT well classification system (see online version for colours)



All well-servicing fluids rheology will be influenced by temperature and pressure. Completion fluid design should be based on a detailed study of the reservoir characteristics at the downhole conditions (Caenn et al., 2011). The general practice is to measure a completion fluid's flow characteristics under HPHT downhole conditions. Completion fluid rheology is influenced by many factors such as pressure, temperature, shear history, composition, and the electrochemical character of the components and the continuous fluid phase (Spies et al., 1983; Ibeh et al., 2008). This requires a reliable rheology model of how the rheology of the completion fluid changes in temperature, pressure, and shear stress during the completion process inside the wellbore. There are three well-known mathematical models used to describe fluid rheology; the power law model, Bingham plastic model, and Hershel-Buckley model (HB). Thermal degradation of chemical additives used in completion fluid formulations can lead to strong variations and loss of rheological properties (Ibeh et al., 2008). Generally, all viscosified brines behaved as near Newtonian fluids at high temperatures. That is probably related to the high salt concentration in the solution. The high salt concentration of viscosified brines has huge amounts of active ions to destroy water structure and breakwater or polymer bonding (Khatibi et al., 2016). Plastic viscosity measures the resistance to the flow of a fluid and represents the viscosity of fluid when extrapolated to an infinite shear rate based on the mathematics of the Bingham plastic (BP) model. PV is calculated by subtracting 300- and 600-rpm viscometer dial readings. PV should be as low as reasonably possible within the designed limits for efficient completion and minimise equivalent circulating density (ECD). High PV is caused by a viscous base fluid and by excess colloidal solids. A low value of viscosity is desired for completion fluid because, its low viscosity will offer less resistance to fluid flow which will result in good wellbore stability

(Masikewich and Bennion, 1999). Yield point (YP) is another important parameter of the Bingham plastic model and it is used to evaluate the ability of completion fluid to suspend and hold its solid particles. The yield point is calculated from 300 and 600 rpm viscometer dial readings by subtracting PV from the 300 rpm dial reading. A non-Newtonian fluid having high YP implies better cuttings carrying capacity than a lower YP of similar density fluid. An optimum value of YP is required to prevent sag problem, on the other hand, a high YP cause high surge and swabbing pressures related issues. The gel strength (GS) of the completion fluid is calculated at 10 seconds and 10 minutes. For a completion engineer, it is important to understand the rheological behaviour under prolonged exposure time, and temperature (aging process). There is equally important to investigate the changes in rheological properties such as viscosity, yield point, and density with changes in temperature and pressure under varying downhole subsurface conditions, particularly in deep oil and gas reservoirs.

7 Completion fluid related formation damage

Formation damage can occur due to the wrong implementation of the completion fluid. The conventional confrontational drawbacks embrace scale production from the reaction of divalent brine with dissolved carbon dioxide, the reaction of formation clays with the clear brine, and interaction with soluble iron in CF formation leads to precipitation of iron compounds (Baroid Drilling Fluids, Inc., 1998). The chemical compatibility of Completion fluid with the reservoir formation and fluids is a must. They should usually be filtered to a greater extent of clean to circumvent the entry of solids to the near-wellbore area. Fluid loss is a most important event, particularly when completing permeable formations. A very high density of CF can cause an increment in hydrostatic pressure over the formation pressure and results in borehole instability and further fluid loss. Fluid loss should be at a minimal level to minimise the risk of differential sticking and prevent formation damage. Completion fluid is meant to control a well, without damaging the producing formation or completion component. CF should be environment friendly and less corrosive to reduce corrosion of wellbore equipment. Most reservoirs are sensitive to any fluids aside from the ones contained in them certainly. Hence, any fluid brought which is chemically and/or physically one-of-a-kind from natural formation fluids may reason a few reservoir damages. All wells are prone to formation damage to some extent, from a moderate fall in the production rate to entirely plugging of pay zones. The concern is to apply a fluid that causes the least viable damage to the producing zone. Lesser settling in completion fluid will reduce the formation damage and solid-free clean CF will diminish formation damage and skin. Solids-free completion fluids extinguish the invasion of fine particulate which may otherwise result in drastic formation damage. In the case of compatibility with formation water, the main concern here is the development of scale because of synthetic responses between completion fluid and formation water (Hossain and Al-Majed, 2015). Calcium-based completion fluids are also susceptible to the precipitation of insoluble salts with solutions containing sulphate, sulphite, carbonate, bicarbonate, and fluoride. Therefore, if the application involves connate waters high in these ions, particularly sulphate, then the compatibility of the clear fluid with the connate water should be checked before use (Place et al., 1980). Incompatibility with formation waters is a potential cause of formation damage with high-density brine completion fluids. Special care should be taken to prevent the mixing of seawater (high in SO_4) with high-density brines. Calcium-based fluids tend gypsum formation at offshore water reactions. Scale is formed into tubular, casing due to gypsum ($CaSO_4$) formation which will lead to finally formation damage (Place et al., 1980; Frenier and Ziauddin, 2008).

$$\text{Such as: } CaCl_2 + Na_2SO_4 = CaSO_4 + 2NaCL \tag{1}$$

Study of compatibility of CF with reservoir formation, formation fluids such as formation water, formation crude, and natural gas, drilling mud, coatings, elastomers, and material of wellbore play vital role in avoiding or minimising formation damage (Caenn et al., 2011). Reservoir formation consists of clay rock, water, and hydrocarbons. In the case of clay formation, completion of saltwater will cause swelling, deflocculating as well as the relocation of formation clays, particularly in 'tight' high-earth sandstone. The pore-throat blockage brought about by dirt relocation is the most widely recognised formation damage instrument identified with CF. Investigational data recommended that the decline in permeability (permeability impairment) was caused by the swelling and dispersion of the montmorillonite clay (Caenn et al., 2011). This can subsequently block the pores by migrating particles such as loose fines of minerals. Formations that result in depleted permeability by aqueous fluids are called water-sensitive formations which are less with illite and least with kaolinite and chlorite. A laboratory-based evaluation of gas well deliverability damage affected by water blocking in carbonate and sandstone reservoirs (Kamath and Laroche, 2003) and the impact of completion fluids on gas/condensate reservoir productivity (Al-Anazi et al., 2005) shows the feasibility of using solvents such as alcohols which are compatible with completion brines can eradicate or lessen liquid-blocking effects. In the case of gas/condensate reservoir, water blocking problems arise due to keeping trapped water-based completion fluids for a longer period of time due to higher capillary forces and vapor pressure. Due to water blocking, gas wells in the low permeable reservoir have reduced deliverability after drilling and completion operations.

A fluid sensitivity study has been investigated to ensure fluid/fluid and fluid/rock minerals compatibility (Ezzat, 1990). Fluid sensitivity study consists of:

1 reservoir fluid properties such as water analysis, scaling tendencies, and filtrate compatibility

2 reservoir rock analysis such as clays, anhydrite, mica organic, grain and pore size distribution, and type of porosity and permeability.

A fluid sensitivity study on $CaCl_2$, $CaBr_2$, $ZnBr_2$, and NaBr brine completion fluids found that they have caused formation damage problems related to incompatibility with the reservoir water, and scale precipitation was also observed (Ezzat, 1990). The damage observed with highly concentrated (14.2 lb/gallon, ppg) brines formulated with $CaBr_2$ and/or $CaC1_2$ is caused by precipitation of acid-soluble calcium salt (Morgenthaler, 1986). These results suggest that incompatibility with formation waters is a potential cause of formation damage with high-density brine completion fluids. The formation of skin around the wellbore can be minimised by solid free clear CF. Poor completion practice contributes to skin formation due to contamination (solids) by CF particles or filtrates. Skin can reduce the near-wellbore permeability and cause pressure reduction during production time. A zone of reduced permeability is formed around the wellbore due to the formation of skin which results from contamination by mud particles or filtrate

(Caenn et al., 2011). Design application brines can be used in avoiding solid sag problems at high downhole temperature and providing minimal loss of circulating pressure and lesser chance of differential sticking and maintaining solid handling capacity at high downhole temperature (Place et al., 1980). Corrosion-related property plays an important role in the selection of CF. Monovalent fluids generally show low corrosivity, even at temperatures exceeding 400°F (Baroid Drilling Fluids, Inc., 1998). Dissolved oxygen is the essential destructive operator in a brine-based CF system. The dissolvability of oxygen in these saline solutions should be diminished by using an oxygen scavenger. For saline solutions recommended pH should be in the alkaline region. The corrosivity of divalent fluids depends on the density and chemical composition of the fluid. The corrosivity of a completion or workover fluid depends on its type. The corrosiveness of the zinc can cause extreme erosion. Most oilfield zinc bromide-based CF must contain a proper corrosion inhibitor. Laboratory data show that for divalent fluids $CaC1_2$ gives a slower rate of corrosion compared to that of $ZnBr_2$ which gives a faster rate of corrosion.

8 Survey of related reviews on completion fluid

There are few major reviews on completion fluid presented in the literature. The emphasis of each review and the chief outcomes of each review work are introduced in Tables 2 and 3 and it is clear that however, the reviews are inclusive, yet, they mainly focused on completion fluid high density, solid free, less corrosive, low cost, environmentally friendly, thermal stability at HPHT conditions, aging property, and rheology measurement in the laboratory.

Table 2 Summary of completion fluid challenges related review efforts at normal reservoir temperature

Author (year)	*Scope of study*		*Major findings and limitations*
Singh et al. (2022)	Aging effects on the rheology of completion fluids	1	Aging effects on the rheological properties of novel Magnesium bromide hexahydrate-based completion fluids for oil and gas reservoirs.
		2	The rheology temperature range is considered 85°F to 185 °F. Completion fluid formulated density is 12.91-lb/gal, specific gravity 1.55.
		3	Required further investigation of HPHT test conditions.
Tariq et al. (2020)	Completion fluid additive to moderate formation damage	1	To lessen the formation damage in unconventional reservoirs additives like polyoxyethylene quaternary ammonium Gemini surfactants were used as clay swelling agents in KCl and NaCl-based CF.
		2	Reported cationic Gemini surfactants are stable at temperature 212°F and pressure of 1,000 psi and no precipitation and degradation were observed.
		3	Low base density completion fluid, less or no applicability towards high-density CF and HP/HT reservoirs.

Table 2 Summary of completion fluid challenges related review efforts at normal reservoir temperature (continued)

Author (year)	*Scope of study*		*Major findings and limitations*
Dubberley and Magill (2020)	Scientific review on solids-free brine-based completion fluids	1	This paper provided a broad high-level scientific review of various solids-free brine-based completion fluids (SFBCF). The goal is to explain the advantages and disadvantages of SFBCF over conventional completion fluids. Solids-free, low viscosity brine-based completion fluids differ from conventional completion fluids.
		2	Low-density fluids only focus on lower ranges of HP/HT reservoir conditions.
Khatibi et al. (2016)	Influence of salts on non-Newtonian fluids and their rheological properties	1	The effects of salts on polymer solutions were studied at 67°F and 107 °F.
		2	All viscosified brines behaved as near Newtonian fluids. The high salt concentration results in enormous amounts of active ions, which may damage water structure and break polymer bonding.
Collins and Carl (2015)	Phosphate-based drilling and completion fluid	1	The fluid was prepared with phosphate brine ranging from about 10 lb/gal to about 20 lb/gal at 120°F.
		2	Deepwater completions are more challenging due to colder seafloor temperatures and greater hydrostatic pressures.
		3	Focus on lower ranges of reservoir conditions, no applicability towards HPHT reservoirs.
Kamath and Laroche (2003) and Al-Anazi et al. (2005)	The effect of completion fluids on gas/condensate reservoir productivity	1	They studied the effect of CF on gas/condensate reservoir productivity and found the gas well deliverability loss caused by water blocking at 1,500 psi and 230°F.
		2	They have investigated the water blocking effect of completion fluids on gas productivity in sandstone and carbonate reservoirs and, they also show the feasibility of using solvents such as alcohols which are compatible with completion brines can remove or minimise liquid-blocking effects.
Morgenthaler (1986)	Formation damage tests of high-density completion fluids	1	The damage observed with $CaBr_2$ and/or $CaC1_2$ (14.2 lb/gallon, ppg) brines and caused by the precipitation of acid-soluble calcium salt.
		2	These results suggest that incompatibility with formation waters is a potential cause of formation damage with high-density brine completion fluids.
		3	Tests were conducted at constant temperatures between room temperature and 150°F and pressure of between 800 psi to 1,200 psi.

Table 2 Summary of completion fluid challenges related review efforts at normal reservoir temperature (continued)

Author (year)	*Scope of study*		*Major findings and limitations*
Spies et al. (1983)	Field experience utilising high-density completion fluids	1	Heavy brines are quite hygroscopic. A heavier brine system is more dangerous in handling and the degree of affecting completion equipment and environment is much higher.
		2	Crystallisation of CF can be a major problem during working in winter as it can be solidified during winter. However, crystallisation was not a major problem during working in the summer. The use of electrically heated tanks during the winter allowed the minimisation.
		3	They found that brines with densities greater than 14 lb/gallon, ppg should be formulated with a minimum of 8% $ZnBr_2$ to lower pH and prevent precipitation. The heavy completion brines are being electrolyte solutions and they are quite corrosive.
		4	The test was conducted at a temperature of 160°F and a pressure of 200 psi.
Darlington et al. (1982)	Viscous heavy brine completion fluids	1	In order to avoid the problems associated with density reduction in completion fluids at a higher temperature, brines with additives such as viscosified polymers like Carboxyl Methyl Cellulose (CMC) and Hydroxyethylcellulose (HEC) can viscosities and increase density up to 19.2 1b/gallon containing calcium chloride, calcium bromide and/or zinc bromide at 150°F.
		2	Viscosified polymers-based brine completion fluids have thermal stability problems at HPHT conditions.
Ellis et al. (1981)	Clean fluids require during gravel packing	1	Gravel packing requires clean perforations with proper fluids. Consolidated sands can cause slumping and washouts can be prevented by the deposition of a filter cake on the walls of the hole so that the pressure overbalance is applied on the face of the formation.
Place et al. (1980)	High-density clear completions and workovers fluids	1	Zinc bromide-based completion fluid is toxic and corrosive. Completion fluid should be maintained on the alkaline side (pH 7–9) to keep corrosion rates acceptably low.
		2	Viscosifiers and other additives need to have adequate stability at bottom-hole temperatures. Thermal degradation products of viscosifiers may themselves be damaging to a productive formation. Additives such as CMC polymers utilised as viscosifiers and sodium formate additionally give brilliant thermal stability at ambient temperatures and formation pressure – approximately 5,439 psi.

Table 2 Summary of completion fluid challenges related review efforts at normal reservoir temperature (continued)

Author (year)	*Scope of study*		*Major findings and limitations*
Conners and Bruton (1979)	Use of clear brine CF as drill-in fluids	1	The high density brines such as calcium chloride/calcium bromide (1.62 s.g. to 1.63 s.g) or (13.5 lb/gal to 13.6 lb/gal) range have been used as drill-in fluids with significant benefits observed in terms of drilling rates at 60 0F.
		2	Focus on lower ranges of reservoir conditions, no applicability towards HPHT reservoirs.

Table 3 Summary of HPHT challenges related review efforts on completion fluid

Author (year)	*Scope of study*		*Major findings and limitations*
Jia et al. (2019)	Potassium-based phosphate brines high density solid free completion fluids in HPHT formations	1	Novel potassium-based phosphate CF with a maximum density of s.g. 1.815 was used, which makes headway on the density limit of normal potassium-based phosphate brine at 356°F.
		2	This work propounds that the phosphate brine can assist as a substitute to high density solid free well CF.
		3	Needs a detailed rheological and thermal aging study on its performance at the ultra HP/HT reservoir conditions.
Davidson et al. (2017)	High-density completion fluid	1	Water and alkaline earth metal salts such as calcium bromide (CaBr) with at least one rare earth nitrate salt such as lanthanum nitrate (La(NO)), cerium nitrate (Ce(NO)), Scandium nitrate, and/or yttrium nitrate used.
		2	They have a density in the range of about 8.5 lb/gal to about 21 lb/gal (s.g. 1.02 to s.g. 2.5).
		4	High cost because of the use of rare-earth metals, and no mention about its performance at the ultra HP/HT reservoir conditions.
Al-Bagoury and Steele (2016)	Liquid weight material for drilling and completion fluids	1	A stable slurry of manganese tetraoxide Mn_3O_4 in potassium formate with a high density of specific gravity 2.3 s.g. to 2.5 s.g. is used.
		2	The slurry is comprised of water and up to 92 wt% Mn_3O_4 particles, based on the weight of the slurry and testing at a temperature of 392°F for HPHT drilling. This heavy fluid has low plastic viscosity of 48cP.
Sangka and Budiman (2016)	Nitrate-based completion fluid	1	Nitrate-based completion fluid is an alternative option for bromide, chloride, and formate CF, with the advantages such as the possibility to increase the return permeability of the formation.
		2	Nitrate ion element is combined with monovalent cations (K, Li, Na), with a maximum density of specific gravity of 1.35 s.g.

Table 3 Summary of HPHT challenges related review efforts on completion fluid (continued)

Author (year)	*Scope of study*		*Major findings and limitations*
Sangka and Budiman (2016)	Nitrate-based completion fluid	3	Even it is combined with divalent ions such as calcium (Ca) or magnesium (Mg) to get a maximum density of specific gravity, s.g. 1.75. Since nitrate is an inorganic salt. Nitrate salt-based CF will remain stable at 350°F.
		4	Low base density and no rheological investigation at HPHT conditions.
Zhou et al. (2015)	Novel thermally stable high-density brine-based drill-in fluids for HP-HT applications	1	$CaBr_2$ brine (14.2 lb/gal) was used as a clay-free drill-in fluid and also investigated the aging properties by hot rolling (150°F/16 hours), followed by static aging (400°F /72 hours).
		2	Brine-based drill-in fluids are formulated in an aqueous-brine medium that typically contains little free water.
		3	A low base density $CaBr_2$ brine (14.2 lb/gal) was used. Not applicable at HPHT reservoirs.
Howard and Chrenowski (2014)	20 years of laboratory testing and field experience for corrosion in formate brines	1	Formate brines have been in virtually constant use in oil and gas wells since they were first introduced into the field in 1993.
		2	There has been a case of metal failure in formate brine, and that was caused by hydrogen embrittlement. The lower the pH value, the greater the tendency for corrosion.
		3	The temperature range was used from 356°F to 410°F. Cost is very high and availability is an issue.
Shadravan and Amani (2012)	What every engineer or geoscientist should know about HPHT wells	1	Plastic viscosity is an important property of completion fluid. PV should be as low as reasonably possible to minimise equivalent circulating density (ECD). High PV is caused by a viscous base fluid and by excess colloidal solids.
		2	Gel strength should have a low value due to clear completion fluid so it can minimise formation damage and minimise high surge and swab pressure losses.
		3	Zinc bromide and cesium formate-based completion fluids are stable at HPHT conditions, but they are having their limitations – expensive, corrosive, etc.
		4	Future HPHT wells will soon require the limitations of 30,000 psi and temperature up to 500°F.

Table 3 Summary of HPHT challenges related review efforts on completion fluid (continued)

Author (year)	*Scope of study*		*Major findings and limitations*
Amani and Hassiba (2012)	Salinity effect on the rheological properties of water-based mud for HPHT well	1	The effect of NaCl and KCl salt concentrations on the viscosity of water-based drilling fluids was investigated at different was tested at an elevated pressure of 35,000 psi and temperatures of 450°F.
		2	Water-based mud has no salt, resulting in lower shear stresses at higher shear rates at increasing the temperature and pressure. However, once pressure and temperature exceed 30,000 psi and 396°F respectively, shear stresses start to increase again.
		3	However, when exceeding 20,000 psi and 288°F, fluids started to follow the Bingham model.
		4	NaCl and KCl salt is low base density.
Benton and Turner (2000)	Application of cesium formate fluid in HPHT field	1	They studied the cesium formate fluid's success in North Sea HPHT field trials. High-density cesium formate can be blended with sodium and/or potassium formate to create a fluid of any density between 1.0 s.g. and 2.3 s.g.
		2	Formate fluids can be viscosified with conventional biopolymers for use as a drilling fluid, which is stable to 320°F.
		3	Cost is very high and worldwide availability is an issue.
Bungert et al. (2000)	Formate brines in high temperature and high-pressure operations	1	They concluded that formate-based completion fluid having specific gravity (s.g.) up to 1.55 has been applied as low solids reservoir completion fluids.
		2	Formate-based completion fluids have replaced high solids calcium carbonate-based fluids, which has resulted in a dramatic increase in completion performance and hydraulics at temperatures of 300°F.
		3	Formate-based completion fluid cost is very high and availability is an issue.
Loth (1998)	Field perspective on drilling and completion of HPHT wells	1	Globally, 87% of hydrocarbon players are involved in HPHT assets. HPHT operation for a well is defined as an initial reservoir temperature greater than 300°F and a reservoir pressure greater than 10,000 psi.
		2	The growth of HPHT wells has evolved as a consequence of the widening gap between demand and supply of oil and gas as conventional reserves diminish.

Table 3 Summary of HPHT challenges related review efforts on completion fluid (continued)

Author (year)	*Scope of study*	*Major findings and limitations*
Downs (1993)	Novel drilling and completion fluids	1 Formate-based CF has replaced high solids calcium carbonate-based fluids due to a dramatic increase in completion performance and hydraulics at 302°F. 2 Chloride and bromide brine can cause pitting corrosion and stress corrosion cracking (SCC) if O_2 or CO_2 are present in brine packer fluids. Zinc bromide-based completion fluid is toxic and corrosive.
Ezzat (1990)	Design criteria and current technology weaknesses for completion fluids	1 Completion fluid design should be based on a detailed study of the reservoir characteristics at the downhole conditions. 2 A fluid sensitivity study must be conducted to ensure fluid/fluid and fluid/rock minerals compatibility. Fluid sensitivity study consists of: a reservoir fluid properties such as water analysis, scaling tendencies, and filtrate compatibility b reservoir rock analysis such as clays, anhydrite, mica organic, grain and pore sise distribution and type of porosity and permeability. 3 Solids-free brines proved to be good packer fluids and well-service fluids. 4 Laboratory tests for $CaBr_2$, $ZnBr_2$ and calcium-free $NaBr/ZnBr_2$ blends were conducted at 300°F.

9 Conclusions

This review study on completion fluid has comprehensively identified and systematically focuses on various high-density completion fluid formulations, their desired rheological performance at HPHT conditions, and selection criteria development for estimating optimum suitable completion fluid rheological parameters. Currently, there is no particular completion fluid formulation that is suitable for all types of petroleum formations. A suitable completion fluid system has been illustrated to retain a distinctive combination that can be utilised for technical resolution. Their properties must contain minimal solids and maintain rheological stability, minimise reservoir damage and fulfil environmental concerns. We investigated the effects of temperature, and pressure on the rheology and analyse in detail the completion of fluid-related formation damage issues. The role of high density and true crystallisation temperature (TCT) is investigated for completion fluid, as density can also be affected due to crystallisation phenomena. Our in details survey of related reviews on completion fluid, clear fluid systems, and their properties, functions, and selection guide will help the users in the worldwide applicability of completion fluids systems. This review can provide remarkable advances in CF technology, especially in HPHT conditions. In numerous fields of completion, there is a considerable demand for in-depth assessment of existing CF as well as for comparisons between various conventional and HPHT completion fluids. CF design and formulation get complex due to restricted property in harsh environments and HPHT conditions. These reviews are expected to maximise the completion fluid program for HPHT oil and gas wells because the design of stable solid free completion fluid is essential for well completion to ensure an early and timely production start. Today available CF has shown some limitations such as low base density, corrosive, expensive, toxic, and availability. Generally, they are having lower to mid-density ranges, so they are mostly limited to use as completion fluid for conventional petroleum reservoirs. The petroleum industry is searching, for other alternative options that promise to come up with the above problems and that have high base density along with thermal stability, less corrosive nature, worldwide availability at a reasonable cost, and further applicability at different oil fields conditions also. Finally, some further research is needed on this topic. Breakthrough is still possible.

10 Recommendations for further studies

a Completion fluid is a complex fluid. Various aspects contribute to the complications. A detailed study on optimum rheology, thermal stability, the effect of corrosion, and pH analysis in the formulation of high-density clear brine-based completion fluid (HDCF) is a field of thorough investigation.

b The lacunae are relatively lesser research carried out or data available on the impact of suitable stable additives and nanoparticles on phase stability and rheology for the formation of clear HDCF.

c The two common choices of completion fluids are caesium formate-based completion fluid and $ZnBr_2$-based completion fluid. These two choices have the following critical limitations: caesium formate-based completion fluid is prohibitively expensive and $ZnBr_2$-based completion fluid is highly corrosive and toxic. Also, its performance at high pressure and temperature is not well known.

d Optimisation and prediction of completion fluid rheological properties or any other parameter depend largely on the availability of a varied range of data, hence to a greater extent the experiments with extensive parameter ranges must be carried out for high temperature and high-pressure applications.

Nomenclature

API	American Petroleum Institute.
HP/HT	High-pressure/high-temperature.
HDCF	High density completion fluid.
SFBCF	Solids-free brine-based completion fluids.
BP	Bingham plastic model.

HB	Hershel-Buckley model.
CF	Completion fluid.
TCT	True crystallisation temperature.
ECD	Equivalent circulating density.
PV	Plastic viscosity (cP).
YP	Yield point (lbf/100 ft^2).
GS	Gel strength (lbf/100 ft^2).
s.g.	Specific gravity.
ppg	Pounds per gallon (lb/gallon).

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