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Review

Nanomaterial-Based Drilling Fluids for Exploitation of Unconventional Reservoirs: A Review

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Abstract: The world's energy demand is steadily increasing where it has now become difficult for conventional hydrocarbon reservoir to meet levels of demand. Therefore, oil and gas companies are seeking novel ways to exploit and unlock the potential of unconventional resources. These resources include tight gas reservoirs, tight sandstone oil, oil and gas shales reservoirs, and high pressure high temperature (HPHT) wells. Drilling of HPHT wells and shale reservoirs has become more widespread in the global petroleum and natural gas industry. There is a current need to extend robust techniques beyond costly drilling and completion jobs, with the potential for exponential expansion. Drilling fluids and their additives are being customized in order to cater for HPHT well drilling issues. Certain conventional additives, e.g., filtrate loss additives, viscosifier additives, shale inhibitor, and shale stabilizer additives are not suitable in the HPHT environment, where they are consequently inappropriate for shale drilling. A better understanding of the selection of drilling fluids and additives for hydrocarbon water-sensitive reservoirs within HPHT environments can be achieved by identifying the challenges in conventional drilling fluids technology and their replacement with eco-friendly, cheaper, and multi-functional valuable products. In this regard, several laboratory-scale literatures have reported that nanomaterial has improved the properties of drilling fluids in the HPHT environment. This review critically evaluates nanomaterial utilization for improvement of rheological properties, filtrate loss, viscosity, and clay- and shale-inhibition at increasing temperature and pressures during the exploitation of hydrocarbons. The performance and potential of nanomaterials, which influence the nature of drilling fluid and its multi-benefits, is rarely reviewed in technical literature of water-based drilling fluid systems. Moreover, this review presented case studies of two HPHT fields and one HPHT basin, and compared their drilling fluid program for optimum selection of drilling fluid in HPHT environment.

Keywords: unconventional reservoirs; shale; drilling technology; nanotechnology; rheology; shale inhibition

1. Introduction

Drilling fluids are essential consumables for drilling and exploration activities. Every drilling activity requires appropriate drilling fluids program, where they are used extensively across the globe. Different types of drilling fluids are available within the market with differing performances designed to fit selective purposes, in addition to varied costs of fluid and environmental impacts [1,2]. The consumption of drilling fluids and additives depends directly on drilling fluid activities that are carried out globally. The increasing demand for energy has encouraged oil and gas companies to drill unconventional reservoirs in order to fulfill energy supply. Energy demand can be compensated through unconventional resources include heavy oil [3,4], gas hydrates [5], coal bed methane [6–11], tight gas [12–16], gas and oil shale [16–18], and high pressure high temperature (HPHT) wells [19–21]. New explorations in HPHT environments has led to a rise in drilling activities globally. The HPHT environment (i.e., 422–589 K and pressure of 138 MPa to 276 MPa) requires suitable techniques and selection of particular technologies in order to conduct drilling into extreme environments [22]. Likewise, formulations of drilling fluids play an important role in drilling within HPHT environments. Therefore, oil-based drilling fluids (OBDF) have been repeatedly used in HPHT drilling fluid systems, where they have been shown to be effective in shale drilling in HPHT downhole environments [23]. However, OBDF is toxic for marine species [24] and involves a high cost [25] because it is mostly made up of diesel oil [26]. Therefore, investigators have been consistently working to improve the characteristics of water-based drilling fluid system (WBDF) for unconventional reservoirs and drilling operation, where WBDF is inexpensive [27] and environmental friendly [28]. Eighty percent of oil and gas wellbore drilling operation uses WBDF [29]; however, WBDF possesses several problems related to drag and torque, pipe sticking, formation damage, lost circulation, and wellbore instability within HPHT downhole environments. However, researchers are currently working on improvements to WBDF systems using polymers to enhance rheology, reduce filtrate loss and shale inhibition, and to increase salt resistance [30–32].

Recently, researchers have widely studied polymeric material in conjunction with bentonite to prepare drilling fluids for harsh condition, in particular HPHT [33,34]. Molecules of polymer have long carbon chains and yield viscosity in the solution form [32,35]; thus, influencing rheology filtrate loss and lubricity of drilling fluid systems [31,36]. Some natural polymers, in particular guar gum, starch, and cellulose, have been successfully used alongside bentonite to achieve adequate drilling fluid properties [37]. Naturally available polymers have been widely used due to their low cost [38], and environmentally friendly nature [39]. Nonetheless, natural polymers have low temperature stability [40–42]. High temperatures render the superior and thixotropic properties of polymers inactive, adversely affecting rheological characteristics and resulting in a loss of drilling fluid [43], inappropriate cutting, lifting barite sag problems [44,45], and increasing the cost of drilling. Recently, Jain et al. [46] found that grafted polymer showed better rheological properties and filtration performance compared to carboxymethyl cellulose (CMC) when considered as a drilling fluid additive for shale drilling. Ternary copolymer reduced the fluid loss in the presence of high salt content of drilling fluid additives and resulted in better salt tolerance. Moreover, the copolymer produced better thermal stability within the drilling fluid system [29]. Nonetheless, some cellulose polymers have been shown to degrade at 483 to 533 K [47], where polyacrylamide was substantially lost at around 378 K in the presence of oxygen. However, another study has reported this degradation between 388 to 723 K [48]. Drilling engineers currently require thermally stable, multifunctional, environmental, and inexpensive durable drilling fluid additives for the drilling of unconventional HPHT reservoirs [49].

Nanosize additives with enhanced characteristics are actively being investigated in regards to drilling of HPHT wells [33,50]. Several nanomaterial have been investigated such as nano silica [51], graphene oxide [52], graphene nanoplatelets [43,53], multi-walled carbon nanotube [51,54,55], single walled carbon nanotube [54,56], nano ZnO [57,58], TiO_2 [59], CuO [60], and Fe_2O_3, nano-cellulose, nano-silica polymer grafted polymer [61], ZnO polymer nanocomposite [43], TiO_2/polymer nanocomposite [62], TiO_2/clay nanocomposite [63], and several others [64].

Nanomaterials are widely used for different purposes, including enhanced oil recovery [65–68], wettability alteration [69–72], IFT reduction [73–75], surface adsorption [76], and CO_2 storage applications [77–81]. They have a potential to augment rheological properties and shale inhibition of unconventional HPHT wells, but this has not been reported in a review work to date. This paper is devised to present a review on unconventional resources, HPHT wells and drilling fluids additives used to drill HPHT and the superior role of nanomaterial additives in the drilling of HPHT wells.

2. Development of Unconventional Reservoirs

Unconventional reservoirs have different properties, behaviors, and flowing mechanisms [13,14]. The drilling mechanism of unconventional reservoirs varies according to type of lithology, downhole chemistry, and downhole environment. Recoverable unconventional hydrocarbon reservoirs are approximately 101.1 billion cubic meters; this estimation includes 27.5 billion cubic meters of sand oil (Canada), 42.9 billion cubic meters of heavy oil and bitumen (Venezuela), 5.2 billion cubic meters of oil shale in US, and 25.4 billion cubic meters shale oil around the world. Production of shale oil was measured 405,417 cubic meters and continued to increase by 680,465 cubic meters in 2020 [82] (Figure 1).

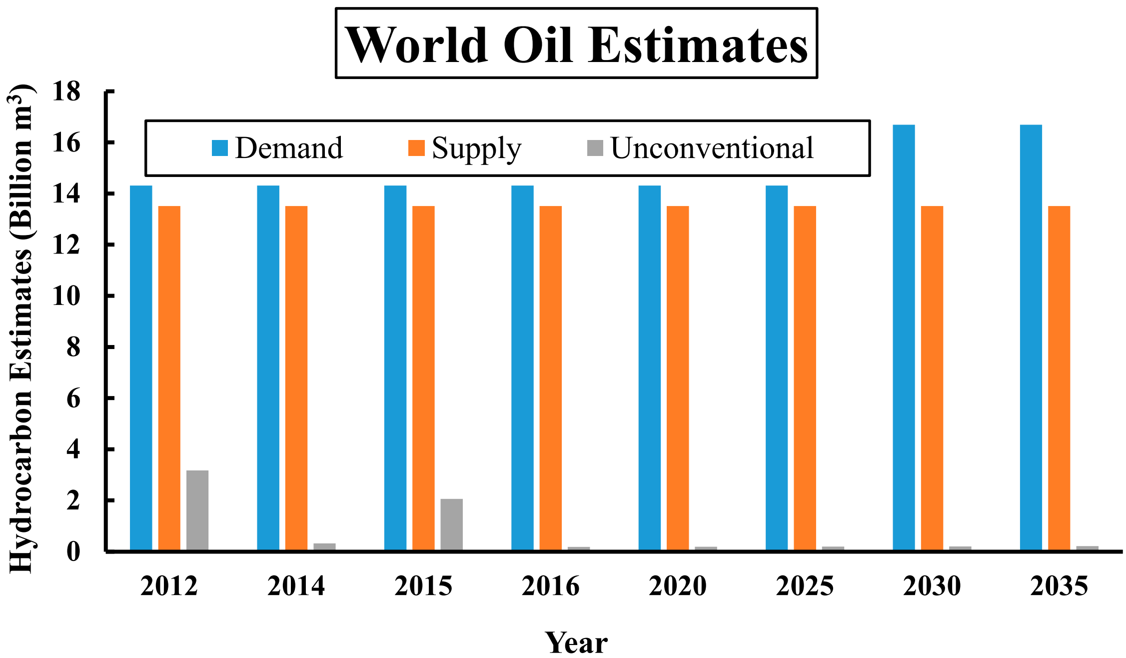

Figure 1. World oil demand, supply and contribution of unconventional oil, adapted from [82].

3. HPHT Drilling Fluid Challenges

Selection of drilling fluid for HPHT conditions requires the consideration of several factors, in particular geology, pore pressure, and downhole environment. Problems and issues associated with the progress of drilling fluids include inefficient hole cleaning, loss of circulation zones, high-pressure losses, and reservoir fluid invasions [83,84]. It is vital to develop fluid with a rheology profile of

minimum variation between surface and downhole properties [85]. Table 1 illustrates downhole temperature and pressure tier.

Table 1. Oil and gas well high temperature high pressure tiers [86].

Temperature Tiers	Static Reservoir Temperature (K)	Static Reservoir Pressure (MPa)
HPHT [a]	422–477	67–138
Ultra-HPHT	477–533	138–241
Extreme-HPHT	533–581	241–276

[a] HPHT = high pressure high temperature.

Thermal instability induces changes in fluid rheology, which affects drilling efficiency. Some other high temperature effects on drilling fluids [87–89] are:

I. High temperature gelation: WBDF develops gelation under stationary conditions for a long time at temperature through the flocculation of clay or bentonite. This is compounded by the thermal deterioration of thinners, a fall in pH, and an augmentation in filtrate loss. Contact of colloidal particles such as clays and fluid-loss additives and breakdown of emulsifiers may raise gelation in OBDF. Logging the pressure required for gel breaking is imperative to halt the surge pressure in HPHT wells, where if drilling fluid circulation is resumed quickly it may cause a loss of circulation [87].

II. High temperature fluid loss: The combination of high temperature, gelation effect and degradation of synthetic polymers due to thermal effects, influences static and dynamic fluid losses in drilling fluid. It is very important to keep these low to reduce potential damage from filtrate invasion [90].

III. Rheological property control: A drilling fluid with high density is required to develop control over hydrostatic pressure and well control [91]. The rheology properties of high-volume fraction of weight material in drilling fluid must be properly controlled. Inappropriate rheology of drilling fluid can raise problems, such as inappropriate pressure losses and dispersion of clay. Moreover, excessive surge pressure and swab can occur with little increases in colloidal-size drilled solids. Additionally, these solids improve the rheological properties of the fluid [92]. However, levels below the acceptable values of rheological properties can cause other problems such as inadequate hole cleaning, segregation of weighting material, and an inconsistent density profile in the annulus which leads to loss of drilling fluid or problems of well control. Moreover, recently Gul and Van Oot. [93] have used yield point, plastic viscosity mud weight, and initial sample information to predict API filtrate loss volume using a/the random forest regression model. Moreover, the predicted data was history matched with field scale API filtrate loss data. The regression fit showed a 0.56 mL/30 min with mean absolute error for API filtrate loss of WBDF. Moreover, a mean absolute error of 1.15 mL/30min/and 0.79 mL/min was determined for HPHT filtrate loss (FL) of WBDF, and HPHT FL of OBDF, respectively.

IV. Material degradation: Many drilling fluid products are prone to thermal degradation at high temperature. While some drilling fluids may survive initially, in a long trip time under HPHT static conditions the drilling fluid properties can also deteriorate, vary drilling fluid density and causing fluid loss [94].

V. Sagging of barite: Static and/or dynamic barite sag is a common problem encountered during drilling in HPHT wells. This problem results from loss circulation, torque and drag, equivalent circulation density (ECD) fluctuations, and also due to operation that requires drilling fluid to be static for long time. Downs et al. [95] have observed that high loading of barite in typical drilling fluids increase frictional pressure losses when circulating in long sections, leading to unacceptably high ECD in narrow operating drilling windows (where pore pressures and fracture pressures are very close to each other). The solids-carrying function of conventional

drilling fluid can be deteriorated, triggering dynamic and static barite sag, and intensifying the risk of losing well control in the case of high angle wells.

VI. Gas solubility: Conventional oil-based drilling fluids can take up large volumes of gas. Drilling fluids kept static for long periods in long horizontal sections create well control problems and deteriorate drilling fluid properties. Even when WBDF is used, the diffusion effect still exists, although to a much small extent [96]. The gas influx that dissolves in the oil phase of OBDF produces a new fluid mixture with unique phase equilibrium, and as this new mixture is in the liquid phase and has its own distinctive bubble point pressure, this makes the detection kick harder (Aberdeen Drilling School & Well Control Training Center, 2008). This new mixture (gas dissolved in the drilling fluid) will destabilize the formulation, and impair the carrying capacity of drilling fluid, raising weighting material (barite sag), precipitating cuttings, and affect viscosity agents, in particular, clays [96].

Drilling fluid engineers are required to resolve these challenges and provide solutions by finding adequate fluid formulations of good continuous performance in all adverse condition [39]. The drilling fluid system not only preserves favorable rheological properties at high temperature, but also balances drilling fluid weight to contain formation pressure with minimum invasion. It also achieves a satisfactory rate of penetration (ROP) in wells [97], managing to suspend weight material under a variety of conditions. The fluid must have an excellent thermal stability with extreme pressure consistency so that it poses little or no alteration to the formation to ensure hole integrity and wellbore stability [98].

4. Designing Drilling Fluid for HPHT Environment

High pressure and high temperature well drilling process is challenging and required robust drilling fluid program. Conventional drilling fluids additives in particular cellulosic polymer, and high concentration of KCl, may rise instable rheological properties. Bern et al. [99] stated that there are many interdependencies within the rheological and hydraulic area of drilling bit. However, they note the important criteria in selecting base drilling fluid for HPHT operations as being: (1) environmental impacts, (2) the stability at high pressure and temperature, and (3) minimum rheology to minimize ECD and reduce the frictional pressure loss [4].

Followings are several points-to-ponder when selecting drilling fluid system for the HPHT environment, which include:

(1) Narrow drilling operating window vs. high density of HPHT drilling fluid. The importance of balancing the need for thin, low incremental pressure fluid without creating problem of poor solids support (settling of conventional weighting materials). Moreover, high density drilling fluids may plug nano-pores in unconventional reservoirs in particular shale.
(2) Thermal stability of fluid products and system. Destabilization of products, and aggressive and rapid reactions towards any contaminants in the system will occur when products reach their operating condition limits.
(3) Technical performance of the fluid for HPHT environment should be placed as a main priority, not cost, as the margin for error in HPHT environment is very small, causing whole operation fail with underperformance of drilling fluid.
(4) The fluid and additives should not only be stable at high temperature but must also withstand the maximum expected time under the most extreme conditions anticipated.
(5) For HPHT operations, rigorous planning thorough laboratory work, detailed drilling, and well and drilling fluid programs becomes more critical, where it is important to prepare backup plans.
(6) Every HPHT well is unique; thus, a specific drilling fluid design may only work for a particular well.

More importantly, the drilling fluid weight window becomes more critical when drilling with a managed pressure drilling plan. The hydrostatic pressure of the drilling fluid is controlled with

the density of the drilling fluid. Thus, hydrostatic pressure could be lower compared to pore pressure according to the availability of equivalent circulation density [100].

5. Selection of HPHT Base Drilling Fluid

The three elements which usually determine the type of fluid selected for a specific well are cost, technical performance, and environmental impact. Some aspects of technical performance are measured based on drilling ability with certain formation type (e.g., shale formation, rock salt, etc.), operating pressure and temperature, and hole condition (e.g., hole inclination, hole stability, etc.).

Oil-based drilling fluid is normally chosen for HPHT drilling as a means of tackling high temperature conditions because it is stable to at least 450 °F in 16-h laboratory tests [101], it typically exhibits a lower coefficient of friction, and it provides a thinner and more lubricious filter cake [102]. Some drawbacks of OBDF are: (1) high cost, (2) influence on logging interpretation, (3) OBDF can absorb a large amount of gas, (4) environmental issues, and (5) the thermal expansion of OBDF is higher than WBDF, which can lead to pressurization of the annulus [95,101]. For example, invert emulsion system drilling fluid is environmental friendly and it has better thermal stability (up to 478 K); thus, it can be used to drill HPHT wells [103].

Synthetic-based drilling fluid for HPHT drilling operation is another option to replace OBDF since it is biodegradable and has low toxicity, i.e., environment acceptance of any waste generated including drilling cuttings. It exhibits thermal stability of up to 475 K [104], and eliminates gas solubility effects. The overall performance of synthetic based drilling fluid (SBDF) depends on the selection of the right combination of drilling fluid additives; for example, the selection of an emulsifier to give an overall emulsion stability [102]. Witthayapanyanon et al. [105] have developed a new flat rheology SBDF in which the formulation had been simplified to one emulsifier and one rheology modifier, where it can be combined with micronized barite technology that is suitable not only for HPHT application but also for narrow margin extended reach drilling. In Malaysia, a dual-weighted SBDF (barite and manganese tetraoxide) was formulated for the first ultra-HPHT, deep-gas well offshore with thermal stability of 508 K.

In water-sensitive rocks, the risk and costs of OBDF prompt operators to commonly choose WBDF [106]. However, WBDF are also likely to cause formation damage, hydration, and disintegration of cuttings, as well as possessing wellbore stability issues. These are all due to pore pressure elevation and thermal instability required for the drilling fluid system. Moreover, this can be adjusted with special additives to provide superior drilling hydraulics, rheology, thermal stability, lubricity, and shale stabilization [107]. However in some cases, WBDF has been shown to be needed for borehole logging due to its small resistivity, which reduces the amount of interference [108]. Extensive laboratory studies have shown multiple utilizations of WBDF for HPHT. For example, an experiment conducted by Tehrani et al. [107] developed a WBDF that can be used at temperature up to 453 K by using the right combination of weight material and selected polymers to produce a stable, controllable rheology, and good inhibitive and lubricating properties. Sun et al. [88] have emphasized the importance of clay in HT WBDF systems, where a water-based organosilicon drilling fluid system ODFS-III was developed with good thermal stability up to 493 K, inhibitive properties, and cutting–carrying capacity that caters to the need of Xushen 22 HT Deep Gas Well in China.

Gao et al. [4] have stated that base fluids with lowest viscosity, such as brine value, should be chosen, as viscosity of base fluids is considered detrimental. Examples of brines used in many HPHT wells are sodium formate, potassium formate, and cesium formate. These types of WBDF had been successfully applied in HPHT wells; for example, cesium formate has been used to drill 29 HPHT wells in the North Sea [95].

6. HPHT Drilling Fluid Formulation

Drilling fluid formulation is engineered to drill challenging HPHT zones [109]. OBDF has been used to drill HPHT wellbores due to its enhanced thermal stability [110]; nonetheless, toxicity and

the cost of OBDF have limited its usage [111]. Gao et al. [4] have suggested that HPHT drilling fluid formulation should be formulated for optimum rheology in expanded definition of minimizing ECD with no risk of barite sag. They also concluded that stable drilling fluids should be maximized by a viscosifier since the rheology built by viscosifier are more effective than viscosity developed by raising brine phase, while other factors (base fluid viscosity, concentration of weighting agent, wettability of solid (water wet solid), and poor quality of emulsion) are regarded as detrimental and should be minimized.

They also emphasized that there are four critical fluid properties for HPHT drilling operation:

(1) Drilling fluid weight—the standard temperature was defined by correlating the surface weight of drilling fluid with the equivalent downhole drilling fluid weight instead of maintaining steady drilling fluid weight at flow line without taking into the account the flow line temperature.
(2) Solid water (S/W) ratio—efficient S/W (which was at the least tendency of barite segregation) ratio must be maintained throughout the drilling phase.
(3) Rheology—the HPHT drilling fluid should be prepared and maintained with optimum 100-rpm reading ranges instead of aiming for the lowest plastic viscosity (PV), as PV and yield point (YP) are not relevant to the ECD; instead, they correlate to the shear rate range inside the drill string.
(4) HPHT Fluid Loss—several strategies applied to avoid operating problems considering the risk of differential sticking in the deeper section or at the different formation and/or at maximum geothermal temperature, by achieving lower than programmed HPHT fluid loss.

7. Selection of HPHT Additives

As discussed earlier, regardless of whether drilling fluid is water-based or oil-based, the properties of the fluid will always require adjustment with additives for each individual well. Several common additives which are applied in HPHT drilling fluids will be further discussed in this study these are weighting agents, emulsifiers, and viscosifier, and fluid loss additives.

7.1. Weighting Agents

The most common weighting agent for drilling fluid is barite and it is preferred because of its wide availability. Barite sag is an oilfield term used to describe significant density variations while circulating bottoms up after a trip, logging run, or other operation that requires the drilling fluid to remain static for an extended period of time. Sag of barite is a main issue to oil-based drilling fluid compared to water-based variants. It is very difficult to balance the need to minimize ECD with reducing sag stability in oil-based drilling fluid [112].

More considerations have to be taken into account when drilling fluids weighted with barite as utilized in HPHT conditions (with high-angle well). The rheological property of drilling fluid can deteriorate with high temperature and sagging of weight material will deteriorate, as it not only comes from the weighting material itself but also from other deteriorated additives. Several approaches to reduce or eliminate the sag of barite are:

(1) Using treated micronized barite (TMB), which is significantly smaller than regular API barite (2 micron as compared to <75 micron) to reduce the potential of sag of barite [112]. Benefits of TMB are: improvement of ECD management in narrow hydraulic operating margin (reducing the pump pressure for the same ECD and reducing the risk of ECD induced losses), improvement in pressure while drilling (PWD), logging while drilling (LWD) and measurement while drilling (MWD) signal, and reduced swab, surge, and circulating pressure [113].
(2) Replacing barite with a new weighting agent that is heavier than barite, more stable at high temperature, and can address the ECD challenges at reasonable cost [114]. However, the replacement of barite must be properly considered to avoid unnecessary drilling related problems such as abrasiveness (e.g., may be caused by hematite) or creating much higher tendency of sag [115].

(3) Using barite with other weighting agents in certain ratio that can optimize the packing arrangement such as ilmenite, hematite, and manganese tetra-oxide. Alabdullatif et al. [116] have demonstrated this option with the combination of barite and manganese tetraoxide, which proved to be effective in minimizing sag occurrence in high density WBDF.
(4) Utilizing solid-free drilling fluid, e.g., heavy brine-based systems. The density is given by the brines itself; thus, eliminating the need of weighting agent and prevents sag potential.
(5) Developing sag-resistant oil-based fluid under the weighting agent research project (WARP), which employs an ultra-fine particle of a weighting agent that has been treated with enhanced oil, produced stable high-solids, high density and low-viscous suspension, or slurries [112].
(6) Studying the effect of HPHT on the rheological properties of drilling fluids to reduce barite sag, e.g., Amighi and Shahbazi [45] studied effective ways to avoid barite sag in HPHT deviated wells, while Gao et al. [4] stated that optimum S/W ratio plays an important role in the indication of sagging of the weighting agent.

Conventional weighting agent (barite) will still be selected for HPHT operations; thus, it is important to try to mitigate the risk of sagging of barite, as has been practiced at Shearwater Project during the planning and the offshore operation itself [4]:

(1) Optimizing drilling fluid specifications (S/W ratio, rheology control, etc.). This practice can be planned ahead and even with lower pump rate; there is no tendency of barite sag to be accelerated.
(2) Conditioning drilling fluid to the maximum permissible rheology before pulling out of hole (POOH) to minimize sag.
(3) Breaking circulation while running in hole (RIH)—minimizing the barite sag by circulating while RIH only at the section where well is returned back to vertical.

Additionally, Basfar et al. [44] have shown that barite displays high sag factors such as 0.585 and 0.596 in vertical and inclined positions, respectively, compared to ilmenite. These values are greater than threshold range (i.e., 0.50–0.53) for sag factor; thus, barite could possess sag problems (Figure 2). In contrast, ilmenite showed better performance and less sag problem compared to barite; it was observed that ilmenite displayed no sag problem with its increasing concentration. Interestingly, it was found that barite sag was decreased after adding the 50 wt% of ilmenite in both the incline and vertical position (i.e., experimental set-up of well) with sag factor 0.51 (Figure 2).

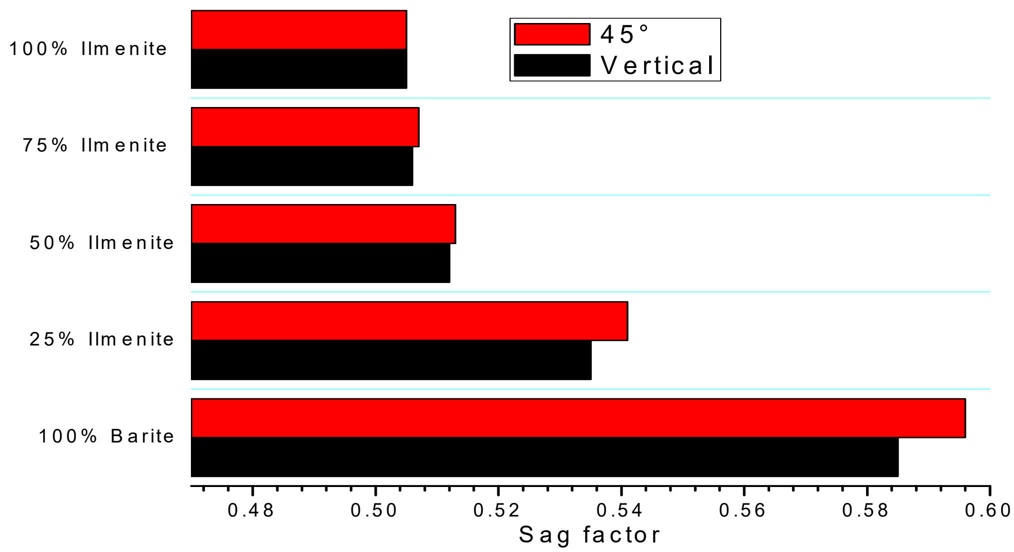

Figure 2. Influence of ilmenite (weighting agent) over sag behavior of the drilling fluid at 250 °F (static conditions). Reproduced with permission from [44].

7.2. Emulsifiers Selection for HPHT Application

The quality of emulsion has considerable influence on final drilling fluid viscosity. Gao et al. [4] have stated that an appropriate volume of emulsifier must be added into drilling fluid systems, where more emulsifier should be added during operation to adjust for depletion. Traces of water and electrical stability in HPHT filtration can be used to indicate the quality of emulsion.

Moreover, the quality of emulsifier enhances the emulsion's stability. The emulsifier concentration can be considered to achieve flat PV rheology. Moreover, enhancements in PV with the addition of emulsifier is critical to minimize barite sag, as it has been implemented in shear water projects [4].

Charnvit et al. [117] suggest the following criteria to be considered when applying emulsifiers to HPHT applications: (1) it must withstand high temperature, (2) must provide low viscosity, (3) has stable emulsion (low and flat gel structure), and (4) must contribute to HPHT filtration control and temperature stability of the system.

Stefano et al. [118] have stated that emulsifiers which have been used in HPHT application at up to 478 K are from a class of chemicals distinguished by functional groups with bipolarity such as fatty acids, fatty alcohols, and amine. Nicora et al. [119] focused on polyamides for synthesis of primary emulsifiers of the Kristin Development Project, as this chemical class shows the best stability at high temperature. Several new emulsifiers that can withstand HPHT environments have worked well, for example, polyamides and a novel amine-free emulsifier, which can sustain temperature more than 573 K [102].

7.3. Viscosifier Selection for HPHT Application

The need for high viscosity to achieve adequate hole cleaning, maintaining performance of drilling fluids, and gelling at high temperature remains as ongoing challenges and concern in HPHT drilling operations. Conventional viscosifiers are thermally unstable; when they degrade, they are unable to perform and hamper the drilling fluid system thus increase severity of sagging. Kelessidis et al. [120] noted that at above 393 K, colloidal systems composed of bentonite begin to thicken considerably, while Tehrani et al. [107] emphasized that biopolymer and organic mixture are only effective in controlling rheology up to a temperature of 403 K, beyond which stability problems will occur and synthetic polymers must be used. Another example, the usage of xanthan gum in WBDF, experiences thermal instability at temperature exceeding 394 K for extended hours due to oxidative and hydrolytic processes.

The rheology modifier for OBDF for HPHT wells is normally controlled by organophilic clay [121]. High-density thermally stable polymeric solutions have been developed and accepted by industry to meet these challenges. Another approach claimed by Shah et al. [97] developed organophilic clays composed of clay material and quaternary amine providing the drilling fluid ability to withstanding sagging of particle. Stefano et al. [121] have added that organo-clays could withstand the temperatures exceeding 533 K [121]. Organically modified clay (HT organoclays) is normally used in HPHT wells because of its good thermal stability, as has been used in Kristin Development Field [119].

Wang et al. [122] have suggested that an ideal viscosifier used for HPHT WBDF should possess similar rheological properties to xanthan gum, exhibiting high shear thinning properties with enhanced salt tolerance and thermal stability. For WBDF, a synthetic polymeric viscosifier has been developed which exhibits exceptional thickening efficiency, salt tolerance, and thermal stability at temperature ranges of 450–464 K in the presence of monovalent halide brines [123]. Further development of this synthetic polymeric viscosifier increased thermal stability in the range of 450–478 K. Tehrani et al. [107] have argued that a different approach is needed to generate viscosity by utilizing medium-molecular-weight polymers which adsorb over dispersed solids and contact with dissolve polymers to yield highly shear-thinning rheology. In addition, they claim that the appropriate mixing of polymers and weight material could create a fluid that is tolerant to various additives used in WBDF and provides better rheology and fluid control until 453 K. Moreover, Wang et al. [124] investigated viscous models of drilling fluid that improved with the addition of viscosifier, where viscosity reduced with temperature. Nonetheless, incorporation of manganese aluminum silicate nanoparticles and

sodium bentonite improved the viscous model of drilling fluid after hot rolling. This progress was attributed with heat resistant behavior of the nanoparticles [124] as shown in Figure 3.

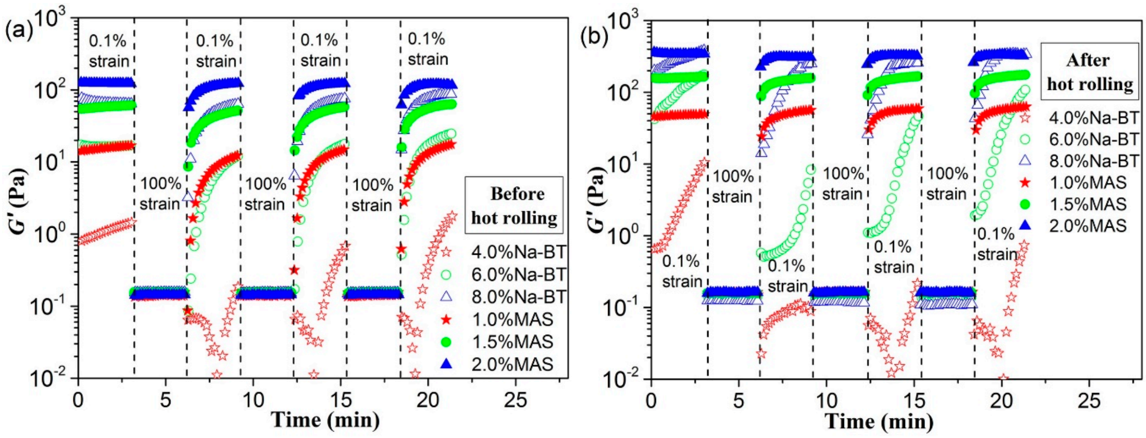

Figure 3. Changes in the viscous modulus (G′) due to strain of manganese aluminum silicate nanoparticles and sodium bentonite (**a**) before, and (**b**) after, hot rolling. The G′ of different suspension stabilized below 0.2 Pa at a high oscillatory strain (100%) and G′ increased at a low oscillatory strain (0.1%) resulting recovery of gel strength. The gel strength recovery performance increased before hot rolling; moreover, after hot rolling, the gel recovery performance of nanoparticles suspension was better compared to Na-BT suspension. Reproduced with permission from [124].

The viscosity of the polymer-based drilling fluid system was enhanced with the addition of SiC nanoparticles [125]. Degradation of polymer decompensate by SiC nanoparticles, polymer solution resulted in 36% degradation with the SiC nanoparticles displaying 15% degradation; therefore, the viscosity improved where it was measured using the Herschell–Buckley (HB) model fitting. The effect of shear stress on the viscosity of SCi nanoparticles added drilling fluids were predicted by using following equation,

$$Y_{sic} = A_1 \exp(-X/t_1) + Y_0 \tag{1}$$

Whereas, Y_{sci} is viscosity of the nanomaterial added drilling fluid and X is shear stress influencing the viscosity. Moreover, ($-1/t_1$) term in the Equation (1) described exponential decline in the viscosity with increase in shear stress. Thus, it could be explained that with an increase in stress (s-1) the viscosity of drilling fluid is reduced; however, viscosity was found greater compared to that of the viscosity of basic drilling fluid using similar shear stress inputs. Additionally, data plotted using the HB model displayed the same trend.

More recently, Medhi et al. [126] investigated the viscous behavior of zirconia nanoparticles into drilling fluid at different temperature and found that viscosity of drilling fluid improved after addition of the nanoparticles. However, viscosity of the drilling fluid generally reduced with temperature.

The degradation of the polymer was also caused by oxidation. Upon heating, the solution polymer broke apart and reduced molecular weight [125,127].The plastic viscosity and yield point of hydrophilic gilsonite nanoparticle (HGN) based drilling fluid were measured and it was observed that long chains of HGN increased the viscosity of drilling fluid [128]. Moreover, better dispersion of HGN increased the mechanical friction between the particles holding electric charges where there was an increase in the plastic viscosity of the drilling fluid system as displayed in Table 2. The yield point of HGN based drilling fluid in particular was improved after hot rolling. This progress was attributed to the polymeric characteristics of drilling fluid inhibited using the HGN material, which has high heat resistant properties. Therefore, the material sustained the gel and yield strength of the drilling fluid as provided in Table 2.

Table 2. Plastic viscosity and yield point of hydrophilic gilsonite nanoparticles (HGN) before and after hot rolling at 422 K [128].

Rheological Properties	Before Hot Rolling	After Hot Rolling
Plastic viscosity (mPa.s)	Basic mud: 23 Nano mud: 27	Basic mud: 21 Nano mud: 17
Yield point (Pa)	Basic mud: 15.3 Nano mud: 4.6	Basic mud: 14.8 Nano mud: 10.2

7.4. HPHT Fluid-Loss Additives

A filter cake formed from drilling fluid stabilizes the formation face but undergoes consolidation due to applied pressure and temperature. The applied pressure and temperature will expel the fluid from the cake and result in fluid loss into the geological formation [129,130]. This case is worsened within the HPHT environment, where, if using conventional fluid loss additives, either they can be too soluble and become detrimental to other fluid properties when their thermal limit is exceeded, or they can degrade at high temperature and lose their fluid control properties [31].

Stefano et al. [118] and Mettath et al. [131] have suggested several HPHT fluid loss additives for invert emulsion systems: (1) development of thermally-stable, organically-modified tanning and amine-treated lignite; and (2) development of low molecular weight polymeric materials that are thermally stable monomer (up to 533 K) and are heavily cross-linked up to 533 K as replacement for oil-soluble polymeric materials that degraded at high temperature [121]. An example of HPHT fluid loss additives from source of tannin is a non-asphaltic amine-treated quebracho-based for high temperature application which has been developed and field-tested; it exhibits thermal stability at up to 561 K, with minimal formation damage and acceptable environmental impact [131]. More recently, Sun et al. [132] have found that synthesized zwitterionic polymer brush (NS-DAD) based on modified nano-silica performed adequately; HPHT filtrate loss volume was reduced to 5.8 mL at high temperature (423 K), and high salinity environment compared an anionic polymer brush (NS-DA), a nonionic polymer brush (NS-D), and a cationic brush (NS-DD) additives. The morphology of the filter cake was smooth, and the size was thin. This progress was attributed to the anti-polyelectrolyte effect and nano-silica, both in water-based drilling fluid and high salt contained water-based drilling fluid. API filtrate loss volume data and certain types of polymer brushes at different wt% data were used to generate the equations as provided into Table 3.

Table 3. Regression analysis of API filtrate loss of water-based drilling fluid system (WBDF) after adding different types of polymer [132].

Polymer Brush Added WBDF	API Filtrate Loss Equation	Adjusted R2
Nonionic polymer (NS-D)	$Y_{\text{API filtrate loss}} = 1.38X_{\text{wt\%}} + 9.95$	0.89
Anionic polymer (NS-DA), cationic polymer (NS-DD),	$Y_{\text{API filtrate loss}} = 1.21X_{\text{wt\%}} + 9.29$ $Y_{\text{API filtrate loss}} = 1.07X_{\text{wt\%}} + 6.45$	0.89 0.91
Zwitterionic polymer (NS-DAD)	$Y_{\text{API filtrate loss}} = 0.17X_{\text{wt\%}} + 1.90$	0.91

Whereas, Y is API filtrate loss and dependent variable, and X is wt % of the primary additive and independent variable, the slope of equations reveals that API filtrate loss was high while using nonionic polymer brush (NS-D) in the drilling fluid; however, the loss linearly went down using NS-D, and NS-DD. The least slope or increment in the filtrate loss interval was found using NS-DAD in the drilling fluid.

7.5. HPHT Shale Inhibitor

A shale inhibitor with efficient performance at high temperature is required for shale reservoirs and intervals. High smectite content shale swelled rapidly upon contact with water vapor. Thus,

temperature resistant polymer and heat transfer materials could improve the performance of shale drilling.

More recently, the Woodford shale has 31% clay content (i.e., illite, chlorite, and kaolinite), but the shale lacked in the most swelling clay (i.e., smectite), where the median pore size of shale pores was 112.84 nm divided into: meso-pores (2–50 nm), macro-pores (>50 nm), nano-material such as SiO_2 (size 15 nm to 20 nm), and GNP (1.3–2.3 um and thickness 3 nm). The Woodford shale was used to bridge pores and aligned with the Abrams bridging rule which states that size of bridging material should be equal to one-third pore size or it may be slightly greater than the one-third of the pore to form efficient plugging (Table 4); thus, nanomaterials improved shale inhibition. SiO_2 and graphene nano-platelets improved the retention of mass into shale and decreased shale erosion by 35% in comparison to base fluid. Nanoparticles improved the coating on the shale and, therefore, reduced their dispersion into the fluid system [133].

Table 4. Dispersion (%) of Woodford shale in different fluids [133].

Fluids	Woodford Shale Dispersion (%)
Water	22.03
Base fluid	17.44
Base fluid+2 wt% graphite	15.76
NP-WBDF [a]	11.23

[a] NP-WBDF = nano-particle water based drilling fluid.

Shale recovery percent was investigated into deionized water, KCl, and Oligo (poly-L-lysine) solution. The shale recovery percent of KCl and deionized water were 7% and 13%, respectively, compared to 1 wt% of Oligo (poly-L-lysine), which displayed 59 wt%. The excellent progress was attributed to the synergetic effect of montmorillonite crystalline inhibition and reducing the diffuse double layer repulsion [134] (Table 5).

Table 5. Recovery percent of nanomaterial based drilling was found higher compared to water and KCl (different concentrations) at 393 K [134].

Fluids	Shale Recovery (%)
Deionized water	13.6
1% KCl [a]	17.8
3%KCl	19.4
5% KCl	21.5
7% KCl	22.6
1% Oligo (poly-L-lysine)	59.4
3% Oligo (poly-L-lysine)	66.8

[a] KCl = potassium chloride.

8. Field Cases

In this campaign, low toxicity oil-drilling fluid was chosen as the drilling fluid, considering the environment acceptance of any waste generated including drilling cuttings. Another advantage of selecting this type of drilling fluid was the elimination of gas solubility effects. Barite was selected as primary weighting agent in this drilling fluid. Due to deteriorating rheology and barite sag [135], hematite was chosen to replace it. Hematite, in the mineral form of ferric oxide, was abrasive and caused significant wear and tear in the surface and downhole equipment. In this case, the abrasiveness severely affected the poppet valve in MWD equipment to the extent that the manufacturing components had to be made of solid carbide rather than providing a carbine coating only. Geology, HPHT range, reservoir depth, and reservoir saturation of Kristin field, Raudhatain field, Qiongdongnan field, and Krishna Godavari Basin are provided in (Table 6).

Table 6. Geology and reservoir saturation of high pressure high temperature (HPHT) fields.

Parameters	Kristin Field (Norway) [136]	Raudhatain Field (Kuwait) [137]	Qiongdongnan Basin (China) [138]	Krishna Godavari Basin (India) [139]
Geology	Jurrasic Garn, Ile, and Tofte formations	Lower Mesozoic and Paleozoic horizons	fan-delta sandstones (Lingshui formation)	Lower cretaceous formation
HPHT [a] range	91 MPa bar and 443 K	69 MPa and 548 K	502–513 K, 103–137 MPa	483 K and 82 MPa
Reservoir depth	4600–4850 m	5792 m	4000 to 5000 m	5000 m
Reservoir saturation	Gas found in three variable formations	Jurassic sour gas	Gas	Gas

[a] HPHT = high pressure high temperature.

8.1. Kristin Field Development, 2006 (Norway)

The case study of Kristin field was under the scope of this study because this field has several HPHT wells. The drilling program required thermally and rheologically stable drilling fluids. Thus, there are three drilling fluid types which are used in the oil and gas wells reservoir drilling: (1) cesium/potassium formate clear brine system [140,141], (2) invert emulsion HPHT OBDF [142], and (3) invert emulsion HPHT OBDF with micronized barite slurries (MBS) [143].

Ten wells that were to be completed with liner and perforation in underbalanced drilling operations used HPHT OBDF as drilling fluid at 8 $\frac{1}{2}$″ section. Similarly, two other open hole and screen wells used carboxylic acids and the acidity of the OH bond (Cs/K-COOH) as drilling fluid. In brief, Cs/K-COOH was chosen as the drilling fluid to meet the objective of well completion strategy to screen all wells, as based on Statoil experience with this type of drilling fluid. This solids-free drilling fluid has many advantages including reduction of the risk of the formation damage. HPHT OBDF invert emulsion was chosen as drilling fluid to at 12 $\frac{1}{4}$″ sections to encounter washout that occurred in the shale section when drilling with Cs/K-COOH. The HPHT OBDF invert emulsion was chosen as the best option for high angle reservoir sections. The third type of drilling fluid, an invert emulsion OBDF with micronized barite slurries (MBS) as weighting agent, was selected as reservoir drilling fluid to counter the danger of plugging screens for open holes. The particle size distribution of MBS, which consists of micron size (D_{50} of 2 micrometer) and coatings (to prevent interaction between particles), helped to reduce the risk of plugging screens compared to the conventional barite observed in Kristin field, Norway HPHT wells. Figure 4 gives the location of Kristin field.

One of the wells, named 'Well I', was the first well to be drilled and completed (with screens) using the invert emulsion HPHT OBDF with MBS. A 290 m long section with approximately 35 degree inclination of 8 $\frac{1}{2}$″ was drilled using one bit run, where it was the fastest 8 $\frac{1}{2}$″ section drilled on Kristin field. Well J was drilled soon after Well I was completed. Well J with inclination of 60–70° through the reservoir and the total section length of 740 m was drilled with 7 bit runs. 6 bits were found plugged with barite (after analyses was done) on the nozzles and/or waterways, causing poor ROP throughout the section. The drilling fluid specification drifted out from the programmed specification due to water contamination. More time was needed to regain the drilling fluid specification, since the fluid is weighted up using concentrated slurry with MBS. Another advantage of using this drilling fluid is its stability. It was shown that after 12 days the reservoir remained in equilibrium against surface controlled subsurface safety valve (SCSSV) flapper and when the SCSSV was opened there was no indication of any slipped gas or signs that the drilling fluid was deteriorating.

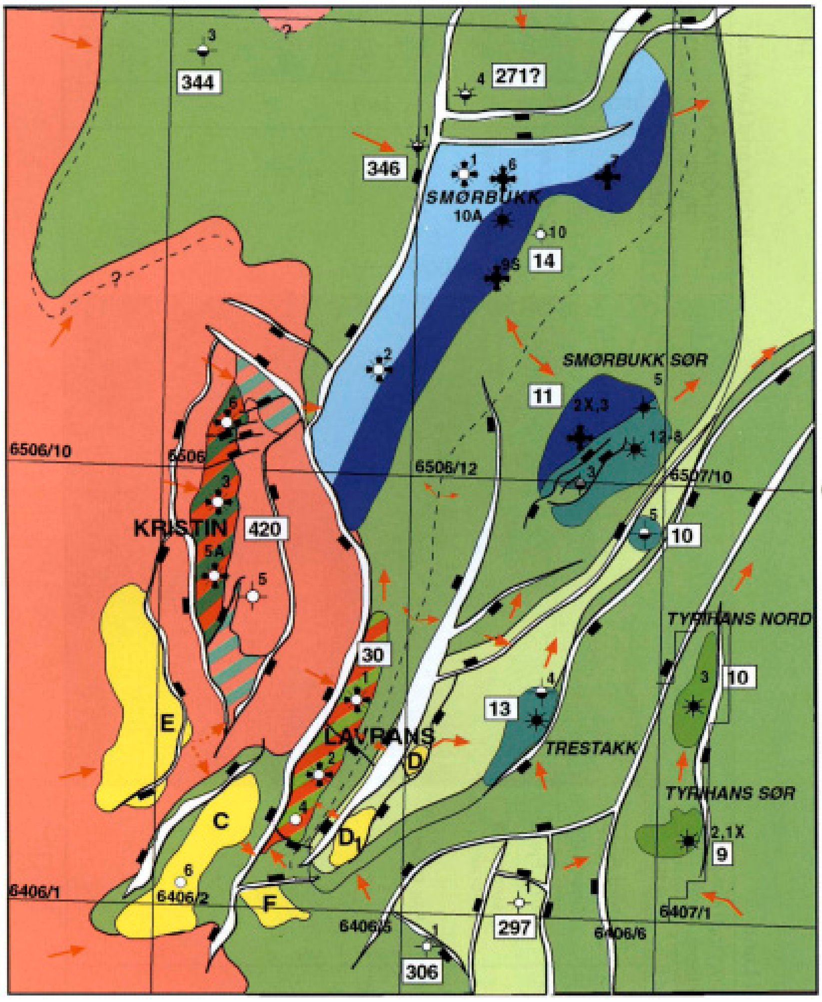

Figure 4. Geometry and position of the Kristin field. Reproduced with permission from [144].

8.2. Raudhatain Field Development, 2013 (Kuwait)

Drilling fluids selection was planned to control formation stability, pore pressure, and complicated geology in Raudhatian field. The OBDF was used to drill HPHT in the field and density of drilling fluid was controlled between 2228.8 kg/m^3 to 2348.6 kg/m^3. Moreover, plastic viscosity of the drilling was maintained between 40 to 60 pa [137]. Additionally, the main challenge was to obtain quality of log which failed (particularly for Image logs and Nuclear logs) as they were affected by underground downhole conditions produced from OBDF in the Raudhatain field.

Later, a WBDF prepared with saturated potassium formate brine along with manganese tetra-oxide was selected to replace OBDF. It was chosen based on the requirement of drilling fluid and criterion provided by saturated potassium formate brine weighted with manganese tetra-oxide (Table 7).

Table 7. Requirement of drilling fluid and weighting agent vs. criterion provided by saturated potassium-formate brine weighted with manganese tetra-oxide.

Requirements of Drilling Fluid System	Criterions of Saturated Potassium-Formate Brine Weighted with Manganese Tetra-Oxide
Fluid must perform well with acceptable rheology and fluid loss at temperature up to 422 K.	• Robust behavior in HPHT environment. • Water insoluble, partially acid soluble, dispersible weighting material with ideal properties for providing higher base-fluid density [108]. • Non-damaging nature—less solid-loaded fluids compared to barite. • Partial solubilization of barium sulphate can occur if the density of potassium formate solutions above 1.30 SG, reacting with barite. This soluble barium can reach 2 kg/m^3, which can be toxic [108,145] • Manganese tetra-oxide is harder than barite but less abrasive, reducing interaction between the particle-to-particle [108]
Must be capable of replacing OBDF [a] with the same (or better) drilling fluid weight, solid loading, fluid loss and rheology, stable as OBDF, and provide better quality logs.	
Must exhibit the best HPHT [b] filtrate with the lowest spurt (some fractured limestone zones were expected).	
Must aid in logging operation.	• Having the advantage of reduced resistivity, which creates borehole environmental condition for the possibility of better quality image logs. Manganese tetra-oxide will not interfere with log responses like hematite [108].

[a] OBDF = oil based drilling fluid. [b] HPHT = high pressure high temperature.

There were no signs of settling of weight material proven when the drilling fluid was left in static conditions for three days, where the drilling fluid losses were low and ROP was very high comparable to those from wells drilled with OBDF. Further, there was no hole-cleaning problems arising and plastic viscosity did not rise significantly, which contributed to low ECD and acceptable pump pressures. The logging data were improved when using potassium formate with manganese tetra-oxide fluid. The fluid system allowed better image logs to be obtained as compared to previous quality data log using OBDF.

Amongst all HPHT challenges (Table 8), some are directly related to drilling fluids and performance, where HPHT wells with poor cemented sand, and presence of unconsolidated formation, may cause loss of circulation problems.

Table 8. An overview of HPHT unconventional reservoir challenges and research gaps.

HPHT Challenges	Research Gaps Identified
Shale instability [146,147], geo-pressure detection [2,148], integrated team of operator, engineers and well technologist [100], new technologies adoption [149], well point and location [150], material selection and sustainability [151], HPHT [a] corrosion [12,152,153], HPHT instrumentation gauges [154,155], well completion and well control [135,154], and unconsolidated formation [156].	Drilling fluids • Areas: Tuned with heat transfer characteristics colloidal or nanoparticles. • Nano-polymer composite improved the properties and shale stability and coating). Casings • Enhanced metallurgy, composite material with anti-corrosion behavior. Well testing • Seals and safety measures. • Mature basin HPHT opportunities.

[a] HPHT = high pressure high temperature.

8.3. Qiongdongnan Basin

The selection criteria of drilling fluid systems in Qiongdongnan basin are given in Table 9, where the location of the basin is illustrated in Figure 5. The drilling operation at $14\frac{3}{4}''$ section was as per the drilling plan with only a few drilling fluid-related problems. The interval was completed with less than half of the programmed dilution rate using the solid removal equipment. The same drilling fluid system was used for $12\frac{1}{4}''$ section. The temperature at bottom hole was expected to reach 482 K.

Table 9. Drilling fluid and its applications in $14\frac{3}{4}''$ and $12\frac{1}{4}''$ sections.

Drilling Fluid Based $14\frac{3}{4}''$ and $12\frac{1}{4}''$ Sections	
Drilling Fluids	**Applications**
HT Glycol-Polymer WBDF [a]	To encounter high temperature that reached up to 458 °K
Selection of Additives at $14\frac{3}{4}''$and $12\frac{1}{4}''$Sections	
Drilling Fluids	**Applications**
Glycol	Shale stability and secondary lubrication properties.
Wyoming Bentonite	Provide initial viscosity, use with small concentrations together with deflocculant to prevent the gel strengths.
Polysulphonate, Sulphonated Asphalt, Synthetic Polymer Resin/Lignite Derivative Blends	Fluid-loss control and filter cake properties.
Calcium Sulphate (gypsum)	Soluble calcium source to minimize the result of carbonate/bicarbonate contamination over gelation, and use with small concentrations.
Potassium Chloride	Potassium ion source for shale inhibition.
Organic Amine	Stabiliser of polymer temperature (to expand the thermal stability of starch, cellulose, and biopolymers).

[a] WBDF = water based drilling fluid.

Figure 5. Location of Qiongdongnan basin. Reproduced with permission from [157].

The decision to use a high temperature glycol-polymer WBDF instead of the initially planned synthetic-based drilling fluid yielded significant advantages which included: (1) reduction of

consequences of loss circulation and brine flows; (2) effective cementation for 9″ liner; (3) no spacer and cement contamination of SBDF, if SBDF was used to drill 12 $\frac{1}{4}$″ hole interval; and (4) the SBDF to be used at 8 $\frac{1}{2}$″ section was in better condition containing less drill solids since it was only used in this section.

The drilling was continued at the critical section of 8 $\frac{1}{2}$″ section using clean SBDF. The drilling fluid and its additive information are provided into Table 10. Two weighting agents were used for this section—hematite and manganese tetraoxide in ratio of 90:10. This ratio optimized the packing arrangement between smaller particles and larger hematite particles. This packing arrangement not only led to a significant reduction in solids content but also provided significant rheological property improvements for use in HPHT conditions. Moreover, the formulation could help to reduce sagging and abrasion properties. Accounting for the abrasive nature of hematite, fine particle sized hematite was chosen, and abrasion testing was conducted in comparison to barite. The results proved that fine-grade hematite had a similar level of abrasion as API barite at the same drilling fluid weight. Later, further larger-scale confirmation testing was conducted with the result concluding that the abrasive characteristics of the fluid was not worse than the conventional API barite weighted fluid.

Table 10. Drilling fluids and its function for the drilling of 8 $\frac{1}{2}$″ wellbore section.

Drilling Fluid Based 8 $\frac{1}{2}$″Section	
Drilling Fluids	**Applications**
Synthetic Based Drilling Fluid (Linear alpha olefin system)	To encounter high temperature, and for stable fluid properties, and where environmental acceptability is demanded.
Selection of Additives at 8 $\frac{1}{2}$″Section	
Drilling Fluids	**Applications**
Fine particle size of hematite (D_{50} of 5 microns, SG 5.1 gm/cm^3) with Manganese Tetraoxide (D_{50} of 2 microns, SG 4.9 gm/cm^3)	Weighting agent.
Sodium Chloride	As internal brine phase that can reduce sag tendencies.
High temperature polyamide derivative emulsifier	Primary emulsifier, acting as secondary fluid loss.
Lignite derivative	Primary fluid loss control.
High temperature organophilic clay	Rheology control on viscosity.
Potassium Chloride	Potassium source ion for shale inhibition.
Other (as contingency)	Deflocculants and additives to manage the rheological properties and low shear rate.

HPHT testing was also conducted offshore to ensure that the fluid was stable under simulated downhole conditions. A five-day test was finished successfully, which took place after the initial synthetic–water ratio was adjusted from 93/7 to 70/30 due to operational and logistic limitations. The fluid was again tested in a portable drilling fluid laboratory (that installed on the rig) to ensure the ratio re-adjustment fluid properties were within specification and would not jeopardize the operation. With confirmation from the test, the high temperature WBDF was replaced successfully without a spacer and the drilling operation continued smoothly. However, due to a typhoon, the drilling fluid had to stay static in downhole for eight and a half days and when the drilling resumed there was no evident signs of too much gelation or weight material sag. A full suite of logs was run without incident, where the section was then smoothly drilled to the total depth with an estimated downhole temperature of 485 K. Drilling fluid cooler was used to minimize the bottom hole temperature.

8.4. Field Cases 2: Drilling Fluid System Selection for HPHT Krishna Godavari Basin

A 12 $\frac{1}{4}$″ section was drilled using WBDF with KCl and enhanced polyglycol system, except for in Well D. The selection of drilling fluid systems can be found in Table 11.

Table 11. Selection of Drilling Fluids and Additives at 12 $\frac{1}{4}$″.

Drilling Fluid Based at 12 $\frac{1}{4}$″ Section	
Drilling Fluids	**Applications**
Well A, B, and C: KCl [a]-polyglycol WBDF [b]	Counter clay swelling-promote shale stability.
Well D:Synthetic OBDF [c]	Biodegradable and less toxic than OBDF, base viscosity is higher than OBDF at normal condition, provide good hole gauge, and good environment for logging
Selection of Additives at 12 $\frac{1}{4}$″ Section	
Drilling Fluids	**Applications**
Enhanced polyglycol	Shale stability, and cloud out at high temperatures preventing hydration of shale.
Pre-gelatined starch	Fluid loss control (used below 240 °F).
Sulfonated organic resin	Aids in stabilizing shale sections, controlling solid dispersion and improving wall cake characteristic, plugs micro-fracture shale and sealing shale to avoid hydrostatic overbalance transmitted to the pore pressure network.
Polyanionic cellulose (PAC)	Fluid-loss control properties, shale inhibition, and salt tolerance.

[a] KCl = potassium chloride. [b] WBDF = water based drilling fluid. [c] OBDF = oil based drilling fluid.

Even though many additives were added to the WBDF in 12 $\frac{1}{4}$″, clay hydration and inhibition drilling in this section led to problems like low ROP, hole cleaning problems due to caving in the wellbore, wellbore fill, stuck pipe, bit balling, and high torque values damaging top drive systems; all of which were caused by the swelling of clay due to hydration. The same problems were encountered in the 8 $\frac{1}{2}$″ section using WBDF. The list of drilling fluids and additives used in drilling of 8 $\frac{1}{2}$″ section is provided in Table 12. However, in response to learnings from the previous drilled well, SBDF was chosen where the clay hydration in shale were alleviated at 8 $\frac{1}{2}$″ section for Well C. SBDF was also chosen in drilling the 12 $\frac{1}{4}$″ and 8 $\frac{1}{2}$″ sections in Well D. This resulted in no clay hydration problems, as SBDF did not react to the unstable clay.

As the bottom hole temperature reached 483 K, the effects of high temperature and pressure started to emerge, e.g., (1) damage on elastomeric property of drilling fluid motor, (2) a continuous circulation of drilling fluid required to cool LWD and MWD tools to enable them to function properly, and (3) gelation issue with WBDF. The low gravity solid that occurred which increased viscosity due to clays and drilling fluid, had to be diluted and sheared to reduce fluid loss at the shaker and flow line. A drilling fluid cooler was also required to cool the drilling fluid because of the very high temperatures.

Table 12. Selection of drilling fluids and additives at 8 $\frac{1}{2}$″ sections.

Drilling Fluid Based at 8 $\frac{1}{2}$″ Section	
Drilling Fluids	**Applications**
Well A, B: Low colloid, contaminant-resistant WBDF [a] for HPHT [b]	Providing good inhibition, minimize clay migration, swelling and formation damage, delivering high ROP [e], improve solids removal capability, and stable at temperature more than 394 K
Well C, D:Synthetic OBDF [c]	Biodegradable and less toxic than OBDF, base viscosity is higher than OBDF at normal condition, provides good hole gauge, and good environment for logging
Selection of Additives at 8 $\frac{1}{2}$″ Section	
Drilling Fluids	**Applications**
Oxidized and resinated lignite, synthetic polymer, pre-hydrated gel	Fluid loss control,
Modified tanning compounds, oxidized and resinated lignite	Curing high temperature gelation, and fluid loss control and stability.
Glycol and KCl [d]	Clay hydration inhibitor
Modified xanthan gum	Viscosifier (but burnt out at 422 K)
Barite	Weighting agent
Zinc Carbonate	Gas scavenger
Calcium Carbonate (Well B)	Reduce torque (lubrication)
Nut Plug	Reduce torque
Lime	To treat out effects of acid gases.

[a] WBDF = water based drilling fluid. [b] HPHT = high pressure high temperature. [c] OBDF = oil based drilling fluid. [d] KCl = potassium chloride. [e] ROP = rate of penetration.

9. Comparison between Case Studies

In the Brunei Drilling Campaign, the primary weighting agent of barite was replaced with hematite when the sagging of barite worsened during drilling operation. However, the aggressiveness of hematite caused damage on surface equipment and bottom hole assembly (BHA). Additional costs were incurred when the manufacturing components had to be made from solid carbide to withstand the abrasiveness of hematite. Thus, the usage of hematite was minimized. The problem emphasizes the importance of quality control with new hematite, where specifying spherical in shape should be considered.

Kristin field contains gas condensate in three sandstones (lower to Middle Jurassic paralic sandstones). The average depth of gas condensate reservoir was 4600 m and 4850 m [158]. For Kristin Development Field, it was decided earlier that the weighting agent would be micron-sized barite (MBS). This invert emulsion OBDF with MBS provides low ECD and was stable with acceptable formation damage. In addition, it met the objective to encounter the danger of plugging screens for open hole sand screens. However, the particles of MBS were found at the nozzles and/or waterways for Well J, which somehow affected the drilling progress and produced a tendency towards water contamination.

The Kuwait oil company was interested in exploiting the non-associated gas potential from two different horizons, in particular, the Lower Mesozoic and Paleozoic in Raudhatain field. In starting, there were four wells drilled until Pre-Khuff formations in developed field areas of Sabriyah, Burgan, and Umm Gudair. Following the outcomes, gas presence was identified in the Sudair formation and Unayzah formation. Additionally, free gas shows were strongly indicated while drilling the Mutriba 10 formations [137]. For Raudhatain Field Development, the decision to change the drilling system was made when the previous drilling fluid system (OBDF), weighted with barite, was unable to assist in providing high imaging log quality. It was replaced with potassium formate weighted with manganese

tetra-oxide fluid. The quality of logs (i.e., images) was improved using the manganese tetra-oxide fluid; however, manganese tetra-oxide fluid is an expensive material. It was also helpful in the evaluation of oil and gas shows in cutting samples, which added vital information about formation evaluation.

The obvious similarity between these cases was the objective of avoiding severity of sagging barite. However, the decision made to address this problem was different from case to case. From these three cases, it can be concluded that: (1) conventional weighting agents (for these cases, barite and hematite) are not a suitable weighting agent for HPHT environments; (2) using micron-sized barite as weighting agents can reduce the tendency of barite sagging and meet the completion strategy, but the sizing of barite must also consider the type of bit to be used to avoid particle plugging of weighting agents; and (3) changing the drilling fluid required changing the additives in order to meet the drilling objective. Overall, the selection of additives (in this case weighting agents) was important at the right time and the right place. This can affect the whole drilling operation and it might cause failure to other objectives such as logging. The cost of weighting agents may become a factor to be considered, but the bigger picture of the whole system has to be captured in the way that benefits may offset higher costs.

Moreover, from Case 1, it is clear that there was lack of crucial planning. Wells A, B and C encountered several problems during drilling and logging operations. With immediate lesson learned from previous wells, Well D was planned before operation.

From Case 2, the holistic approach taken to carefully plan for HPHT resulted in smooth drilling and logging operations. The planning and base/laboratory preparation not only produced innovative drilling fluid specific to the well's condition, but also led to modifications to rig design to suit the management of drilling fluid properties at high density with high flow line temperature. This included a portable drilling fluid laboratory that enabled drilling fluid sample to be continually tested so that the results could be obtained immediately (no need to send samples to town). Moreover, large abrasion and pressure tests were also conducted on shore prior to operation.

These two cases show that the drilling planning process involved crucial selection and decision, which included aspects of the materials, equipment, facilities, and personnel to be adjusted properly especially in unconventional drilling operation such as HPHT. Another important point is to have knowledge to predict the worst scenarios that might occur during the operation. Although it may incur higher initial cost, this whole planning and land/base preparations makes good contributions towards operations.

10. Conclusions

This review study presented case studies on use of drilling fluids in three different HPHT fields. Moreover, this study provided comprehensive information on use of drilling fluids additives to drill different wellbore sections, i.e., $8\frac{1}{2}''$ and $12\frac{1}{2}''$ in HPHT environments. However, conventional drilling fluid additives such as barite and cellulosic polymer raised thermal instability and raise high solid content problems. Relating to such problems, metal oxide nanomaterials have provided efficient drilling fluid progress in HPHT environments. During drilling of the $8\frac{1}{2}''$ section in a well in Qiongdongnan basin using clean SBDF, two weighting agents were used in the ratio of 90:10 (hematite and manganese tetroxide) in order to significantly reduce solids reduction and to improve the drilling process in the HPHT environment. Hence, this optimum ratio improved rheological properties and reduced solid content. For the techniques/methods, facilities/equipment that can withstand the HPHT drilling operation must be considered and rigorously planned. From the first case (Kristin field) of choosing suitable additives, the utilization of additives at the right time and place were important. The high initial cost of additives vs. their benefits, must be considered wisely. The conventional weighting agent (in this case barite and hematite) with the same size and packing arrangement should not be used at all for HPHT. The second case study (Radhatain field) on the overall selection of drilling fluid system showed that the drilling planning process involved crucial selection and decisions, and any matters that deviated from plan must be controlled to suit the drilling objective. Selected drilling fluid must not only be suitable for formation and other operations (testing or logging), but also the condition

of the drilling fluid (used or fresh/new) at critical sections (HPHT reservoir) can lead to different results. Raudhatain Field Development, the decision to change the drilling system was made when the previous drilling fluid system (OBDF), weighted with barite, was unable to assist in providing high imaging log quality. For Kristin Development Field, it was decided earlier that the weighting agent would be micron-sized barite (MBS). This invert emulsion OBDF with MBS provides low ECD and was stable with acceptable formation damage. Moreover, constructing suitable HPHT drilling fluid systems involves many aspects. Further, it is important that the whole team be knowledgeable and competent in drilling in HPHT conditions. This can save rig time, avoid cost overruns, avoid fatalities, and minimize the possibility of failure especially in drilling in HPHT condition.

11. Recommendations

Following recommendations can be drawn from present study:

(1) Tailoring of nanomaterials, chemical structure of polymers and investigation of degradation of polymer at HPHT conditions are important parameters to improve rheological properties of HPHT drilling fluids. There is need to examine the rheological and shale inhibition potential of nanomaterial-based drilling fluid in extreme HPHT environmental conditions i.e., 533 K and 241 MPa. Moreover, it is vital to improve the preparation of drilling fluids so that minimum deviation between surface and downhole properties could be obtained.

(2) The usage of HPHT drilling fluid additives varied from field to field. However, conventional drilling fluid additives are not appropriate choice for HPHT fields due to sag problems. Thus, it is recommended that micron size barite be used to meet operational requirements; moreover, further tuning of barite particle size can reduce particle plugging and formation damage in HPHT environments.

(3) OBDF drilling fluids are generally used for HPHT well drilling; however, OBDF may raise overall cost, logging disturbances, increase environmental issues, and pressurization in annulus. When compared to OBDF, invert emulsion drilling fluid system and water-based drilling fluid system are further choices and can modified with metal oxide nanoparticles to improve colloidal stability and heat transfer behavior.

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Nomenclature

HPHT	High pressure high temperature
API	American Petroleum Institute
BHA	Bottom hole assembly
CMC	Carboxymethyl cellulose
D_{50}	Cumulative 50% point of diameter
ECD	Equivalent circulation density
FIP	Formation integrity pressure
GNP	Graphene nano-platelets

HGN	Hydrophilic gilsonite nanoparticle
LWD	Logging while drilling
MBD	Million barrel per day
MPD	Managed pressure drilling
MW	Mud weight
MWD	Measurement while drilling
NS-D	Non-ionic polymer brush
NS-DA	Anionic polymer brush
NS-DAD	Polymer modified nanosilica
NS-DD	Cationic brush
OBDF	Oil-based drilling fluid
POOH	Pull out of hole
PP	Pore pressure
PV	Plastic viscosity
RIH	Run in hole
ROP	Rate of penetration
SBDF	Synthetic based drilling fluid
SCSSV	Surface-controlled subsurface safety valve
SG	Specific gravity
TMB	Treated micronized barite
WARP	Weighting agent research project
WBDF	Water-based drilling fluid
YP	Yield point
Kg/m^3	Kilogram per meter cube
K	Kelvin
MPa	Mega Pascal
m^3	Meter cube

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