



# Prevention of Barite Sag in Water-Based Drilling Fluids by A Urea-Based Additive for Drilling Deep Formations

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Received: 13 February 2020; Accepted: 26 March 2020; Published: 30 March 2020



Abstract: Barite sag is a challenging phenomenon encountered in deep drilling with barite-weighted fluids and associated with fluid stability. It can take place in vertical and directional wells, whether in dynamic or static conditions. In this study, an anti-sagging urea-based additive was evaluated to enhance fluid stability and prevent solids sag in water-based fluids to be used in drilling, completion, and workover operations. A barite-weighted drilling fluid, with a density of 15 ppg, was used with the main drilling fluid additives. The ratio of the urea-based additive was varied in the range 0.25–3.0 vol.% of the total base fluid. The impact of this anti-sagging agent on the sag tendency was evaluated at 250 °F using vertical and inclined sag tests. The optimum concentration of the anti-sagging agent was determined for both vertical and inclined wells. The effect of the urea-additive on the drilling fluid rheology was investigated at low and high temperatures (80 °F and 250 °F). Furthermore, the impact of the urea-additive on the filtration performance of the drilling fluid was studied at 250 °F. Adding the urea-additive to the drilling fluid improved the stability of the drilling fluid, as indicated by a reduction in the sag factor. The optimum concentration of this additive was found to be 0.5–1.0 vol.% of the base fluid. This concentration was enough to prevent barite sag in both vertical and inclined conditions at 250 °F, with a sag factor of around 0.5. For the optimum concentration, the yield point and gel strength (after 10 s) were improved by around 50% and 45%, respectively, while both the plastic viscosity and gel strength (after 10 min) were maintained at the desired levels. Moreover, the anti-sagging agent has no impact on drilling fluid density, pH, or filtration performance.

Keywords: barite sag; water-based drilling fluid; anti-sagging agent; urea-based additive

#### 1. Introduction

Drilling fluids are introduced to a formation to fulfill many functions, but mainly to control the formation pressure [1,2]. Overbalanced drilling is a common technique for well control, where the drilling fluid provides a hydrostatic pressure higher than the formation pressure. To achieve this function, the required fluid density is maintained by adding weighting materials to the drilling fluid. There are many weighting materials introduced to increase the drilling fluid density, such as barite, siderite, magnetite, iron oxides, ilmenite, hematite, and calcite [2–10]. Barite (BaSO<sub>4</sub>) is a common weighting material used to attain the desired density of drilling and completion fluids [2,11] because barite has a high density, low production cost, and less environmental impact [12,13]. However, the invasion of solid particles causes formation damage and reduces the permeability near the wellbore [14,15]. Another issue encountered with barite-weighted fluids is solids sag or barite sag.



Barite sag is a phenomenon that occurs when barite particles separate from the liquid phase and settle down, causing variations in fluid density. These variations may cause a loss of well control that could lead to severe kick [16,17]. Barite sag is a serious issue encountered in vertical and directional wells, but more commonly in directional wells. It can occur under either static conditions or dynamic conditions, particularly at low shear rates [16,18]. Several cases of barite sag have been encountered in drilling and completion operations [19]. For instance, a severe kick was detected during a well completion operation in the North Sea. In that operation, oil-based mud was used as a completion fluid. The kick resulted due to barite sag, with a significant contribution of well geometry to the solids sag issue [20]. However, the consequences of barite sag can be mitigated by maintaining the drilling fluid rheology, implementing sound strategies, and training rig personnel [19]. Using drilling fluid additives is the most effective solution to the problem of barite sag as it greatly enhances the drilling fluid rheology and stability, which are considered the main controlling factors of barite sag.

Many studies have been conducted to mitigate the solids sag phenomenon in both oil-based and water-based drilling fluids by adding drilling fluid additives and controlling the weighting material. Temple et al. [21] introduced a new method to enhance the stability of oil-based fluids without increasing the drilling fluid viscosity. Polyalkyl methacrylate, with low molecular weight, was added to the drilling fluid, while no copolymer such as vinylpyrrolidone was used. Davis et al. [22] introduced a new method to prevent solids sag in oil-based fluid by using a sag stability enhancer. The sag stability enhancer comprises polyethylene glycol (PEG) that has a molecular weight equal to or higher than 200 g/mol. Basfar et al. [23] and Elkatatny [24] evaluated a new copolymer to mitigate solids sag in oil-based mud at high temperatures, up to 350 °F. Just 1 lbm/bbl of the copolymer was enough to solve the barite sag issue in both vertical and inclined conditions. Boyou et al. [25] performed an experimental study on the use of nano-silica to improve the suspension capability of water-based fluids for directional well drilling applications. Different concentrations of nano-silica were used, and the experiments were conducted in a flow loop setup at different inclination angles. It was found that nano-silica increased the colloidal interaction with cuttings; therefore, the cuttings' transport efficiency was significantly improved in all inclination angles.

Another technique for reducing barite sag is to modify the weighting material without adding a stability enhancer to the drilling fluid. Alabdullatif et al. [26] proposed a combination of manganese tetra oxide ( $Mn_3O_4$ ) and barite as a weighting material in water-based kill fluid to mitigate the problem of barite sag. Adding  $Mn_3O_4$  to the fluid formulation effectively enhanced the fluid stability and minimized the possibility of solids sag, particularly over a long time under static conditions. Mohamed et al. [13] investigated the impact of barite particle size reduction on the stability of water-based mud using the sag test and zeta potential measurements. It was concluded that decreasing the barite particle size to micronized size slightly enhances the drilling fluid stability, but it does not eliminate the sag issue. Basfar et al. [27] and Mohamed et al. [28] studied the effect of using a barite-ilmenite combined weighting material on the properties of water-based and oil-based drilling fluids. It was found that the combined weighting material greatly enhanced the rheological properties and the stability of the drilling fluid and prevented solids sag in both vertical and inclined conditions. However, using a combined weighting agent would add more cost and introduce another challenge to the drilling fluid operation, that is, the removal of composite filter cake, as the weighting material contributes greatly to filter cake formation, at 70–80 wt.% [29].

For successful operations, the rheology of the drilling fluid should be monitored and maintained throughout drilling operations by adding the proper drilling fluid additives such as viscosifiers, thinners, and stability enhancers. Most of the previous studies related to barite sag were conducted on oil-based fluids, and barite sag in water-based drilling fluids has received little attention. The previous studies focused on measuring the sag tendency and tried to correlate the results with the rheological and viscoelastic properties (see Table 1).

In this study, an anti-sagging additive is introduced as another solution to enhance fluid stability and eliminate solids sag in water-based drilling, completion, and workover fluids, without introducing a combined weighting material to the drilling fluid that would lead to a complex solids system, or adding high cost to the drilling operation, because very low concentrations of this additive are required. This additive is a modified urea solution and was originally used in water-based applications for anti-sag in other industries, such as coatings, lubricants, foundries, and detergent industries [30,31]. The extension of the application of this additive to water-based drilling fluids for deep wells is investigated. First, the materials used are described, and the experimental procedure and conditions to conduct this work are explained. Then, the results of this study are discussed, and lastly, the findings of this work are summarized.

Study	Method	Drilling Fluid System	Findings
Temple et al., 2004	Adding polyalkyl methacrylate	Oil-based	The optimum concentration to prevent barite sag was 0.5–3 lb/bbl.
Davis et al., 2017	Adding polyethylene glycol (PEG)	Oil-based	A concentration of 0.5 lb/bbl was enough to eliminate barite sag.
Basfar et al., 2018 Elkatatny, 2019	Adding a copolymer	Oil-based	A concentration of 1 lbm/bbl of copolymer was enough to prevent barite sag up to 350°F.
Boyou et al., 2019	Adding nano-silica	Water-based	The cuttings' transport efficiency was significantly improved in different inclination angles.
	Adding a combination of		
Alabdullatif et al., 2015	Mn <sub>3</sub> O <sub>4</sub> and barite as a weighting material	Water-based	$Mn_{3}O_{4}$ effectively enhanced the fluid stability and minimized barite sag.
Mohamed et al., 2017	Using micronized barite	Water-based	Micronized barite improved the stability, but it did not eliminate barite sag.
Basfar et al., 2019	Using a barite-ilmenite	Water-based	A proportion of 50 wt.% ilmenite (of the total weighting material) was adequate to prevent barite sag.
Mohamed et al., 2019	material	Oil-based	A proportion of 40 wt.% ilmenite (of the total weighting material) was adequate to prevent barite sag.

Table 1. Summary of the methods used to prevent barite sag.

#### 2. Materials

The barite sample, obtained from a service company, was used as a weighting material for water-based drilling fluid. The elemental composition of the barite sample was obtained using the X-ray fluorescence technique, XRF. The barite sample mainly contains 82 wt.% barium, 12.6 wt.% sulfur, 1.99 wt.% silicon, and 1.33 wt.% iron, with small traces (<1 wt.%) of other elements, such as potassium, calcium, nickel, copper, and strontium (Table 2). The particle size distribution of this sample was measured using a particle size analyzer. The sample exhibited a normal distribution with a  $D_{10}$  of 4.5  $\mu$ m, average particle size (D<sub>50</sub>) of 30  $\mu$ m, D<sub>75</sub> of 52  $\mu$ m, and D<sub>90</sub> of 79  $\mu$ m (Figure 1). Defoamer (D-Air 4000L<sup>TM</sup>) was added to the water to prevent the formation of foam. The defoamer comprises an amide of carboxylic acid, a polypropylene glycol, an ethoxylated and propoxylated fatty alcohol, an ethoxylated alcohol comprising from 3 carbons to 6 carbons, and a hydrophobic silica in an amount of up to about 3% by weight of the defoaming composition. Soda ash was used to maintain the concentration of calcium in the water. Xanthan gum polymer and bentonite were used as viscosifiers to improve the drilling fluid rheology. Starch and Polyanionic Cellulose Regular Viscosity (PAC-R) were used to control fluid loss. Clay stabilization was maintained by adding potassium chloride to the drilling fluid. Calcium carbonate was used as a bridging agent, and potassium hydroxide was used to control the pH of the drilling fluid [7].

The anti-sagging additive was added in different concentrations, 0.25–3 vol.% of the total base fluid, to improve the stability of the drilling fluid and prevent solid settlement. It was added right before the weighting material, barite, and mixed for 10 min. This additive works as an anti-sagging agent, and it is a solution of modified urea that mainly contains pentanoic acid, 5-(dimethylamino)-2-methyl-5-oxo-, methyl ester, and lithium chloride (Table 3). It was obtained from a service company, and it was originally used in coatings, lubricants, foundries, and detergent industries as an anti-sagging agent. It has a density of 1.11 g/cc and dynamic viscosity of 700 mPa.s at ambient temperature, with complete solubility in water.

**Table 2.** The elemental composition of the barite sample measured by the X-ray fluorescence (XRF) technique.

Element	wt.%
Si	1.9916
S	12.6341
Κ	0.6331
Ca	0.1109
Fe	1.3338
Ni	0.0157
Cu	0.0354
Sr	0.5518
Мо	0.017
Ba	82.6171
Ta	0.023
Pb	0.0366



**Figure 1.** The particle size distribution of the barite sample ( $D_{50} = 30$  microns).

Parameter	Description					
Main components	<ul> <li>[Pentanoic acid, 5-(dimethylamino)-2-methyl-5-oxo-, methyl ester] 58–59%</li> <li>[Lithium chloride] 1–2%</li> </ul>					
Density	1.11 g/cc					
Dynamic viscosity	770 mPa.s					
Water solubility	Completely miscible					
Flash point	> 212 °F					

Table 3. The properties and main components of the anti-sagging additive.

# 3. Experimental Work

#### 3.1. Fluid Preparation

A barite-weighted drilling fluid, 15 ppg, was prepared using the main drilling fluid additives. Drilling fluid additives were added individually and mixed for a specific time initially by adding viscosifiers (xanthan gum polymer and bentonite). The mixing started with 10,000 rpm rotational speed, then increased to 14,000 rpm and then to 17,000 rpm as the viscosity built up. Afterward, other additives were added to the drilling fluid following the fluid formulation used (Table 4). Following the same procedure, many fluid samples were prepared by adding different concentrations of the urea-additive to the drilling fluid formulation (0.25, 0.5, 1.0, 1.5, 2.0, and 3.0 vol.% of the total base fluid). The urea-additive was added right before adding the weighting material and mixed for 10 min.

Component	Component Amount, g Mixing Time, m		Function
Water	245	-	Base
Defoamer (D-Air 4000L™)	0.08	1	Anti-foam agent
Soda ash	0.5	1	Maintains calcium concentration
Xanthan gum polymer	1.5	20	Viscosity control
Bentonite	4	10	Viscosity control
Potassium hydroxide	0.5	1	pH adjustment
Starch	6	10	Fluid loss control
PAC-R	1	10	Fluid loss control
Potassium chloride	20	10	Clay stabilization
Calcium carbonate	5	10	Bridging agent
Barite	350	10	Weighting material

Table 4. Drilling fluid formulation (lab scale).

### 3.2. Sag Tests

First, the sag test was conducted using the base drilling fluid at two different temperatures, 200 and 250 °F, to identify the temperature at which barite sag occurs. Then, the effect of the urea-additive on the sag tendency was evaluated at that temperature. The experimental setup consists of Teflon liner, aging cell, cell holder, and oven (Figure 2). First, the drilling fluid sample was agitated using the drilling fluid mixer for 10 min, and then poured in the cell. The fluid samples were pressurized with 500 psi using nitrogen and heated to 200/250 °F for 24 h under static conditions, vertical and inclined (45°). After 24 h, the cell was cooled and depressurized; then, a syringe was used to take a 10 cm<sup>3</sup> sample from the top and the bottom fluid, and the density of those samples was measured. Then, the sag factor was obtained using Equation (1). Sag tests were repeated three times to ensure the accuracy of the measurements, and the presented data are the average of the measurements.

$$Sag \ Factor = \frac{\rho_{Bottom}}{\rho_{Bottom} + \rho_{Top}} \tag{1}$$

where  $\rho_{Bottom}$  and  $\rho_{Top}$  are the density of the bottom and top fluid samples in ppg.



Figure 2. Experimental apparatus for the static sag test: (a) vertical and (b) inclined (45°) [24].

According to industry practices, the acceptable value of the sag factor is between 0.5 and 0.53, while a higher value indicates solids settlement [26,32].

#### 3.3. Rheology Measurement

After preparing the drilling fluid, the drilling fluid density was measured, and the rheology measurements were conducted at low temperature (80 °F) and high temperature with high pressure (250 °F and 2000 psi) to study the effect of the urea-additive on the drilling fluid rheology in those conditions. The measured properties are yield point (YP), plastic viscosity (PV), and gel strength after 10 s and 10 min. Plastic viscosity and yield point are calculated by Equations (2) and (3) using the dial readings at 300 RPM ( $\phi_{300}$ ) and 600 RPM ( $\phi_{600}$ ), while the gel strength data were obtained from the direct dial reading at 3 RPM after 10 s, 10 min, and 30 min of static gel time.

$$PV = \varnothing_{600} - \varnothing_{300} \tag{2}$$

$$YP = \emptyset_{300} - PV \tag{3}$$

#### 3.4. HPHT Filtration Experiments

The filtration performance of the drilling fluid and the filter cake properties were evaluated by conducting a series of filtration experiments. The test was conducted at 250 °F and 300 psi differential pressure, using a 50-micron ceramic filter disc as a filtration medium. The high-pressure high-temperature (HPHT) filtration cell was heated to 250 °F under a pressure of 300 psi (Table 5). Afterward, the experiment was started, and the filtrate volume was measured with time. After 30 min, the experiment was stopped, the filter cake was weighted, and the thickness of the filter cake was measured.

Parameter	Description
Fluid volume	350 cm <sup>3</sup>
Pressure	300 psi
Temperature	250 °F
Experiment duration	30 min
Ceramic filter disc	50-micron

#### 4. Results and Discussions

#### 4.1. Sag Tests

First, the drilling fluid density and the pH were measured for the drilling fluid samples. It was found that adding the anti-sagging additive at a concentration up to 3 vol.% of the total base fluid had no impact on drilling fluid density and pH. The density was around 15 ppg for all fluid samples, and the pH ranged between 9 and 10.

The sag performance of the base drilling fluid under vertical and inclined conditions was measured at two different temperatures, 200 and 250 °F. For the inclined sag test, the degree of inclination was set at 45° to simulate the worst scenario because the settling process is accelerated when the inclination is greater than 30° [33]. At 200 °F, the base drilling fluid exhibited a good sag performance in both cases, vertical and inclined, and the sag factor was within the safe range (0.5–0.53) with values of 0.51 and 0.52, respectively (Figure 3). In contrast, the base fluid showed a poor sag performance at 250 °F. The sag factor was higher than 0.53 for both inclined and vertical conditions; therefore, barite sag is highly anticipated.



Figure 3. Effect of temperature on sag for base fluid under vertical and inclined conditions.

Under vertical conditions, adding the anti-sagging additive to the drilling fluid formulation showed a significant improvement in the drilling fluid stability at 250 °F, the sag factor was within the acceptable range (0.5–0.53) for all the drilling fluid samples, and adding just 0.25 vol.% of the anti-sagging additive was adequate to prevent barite sag (Figure 4). Conversely, when the sag test was conducted under inclined conditions, 45°, Figure 5 shows that adding 0.25 vol.% of the anti-sagging additive reduced the sag factor from 0.63 to 0.54, and adding 0.5–1 vol.% was adequate to bring the sag factor into the safe zone (0.5–0.53); thus, barite sag is unlikely to occur under those conditions. The improvement in the sag tendency of the drilling fluid is because the urea-additive helped disperse the particles in the colloidal system and improved the suspension capability of the drilling fluid [34].



Figure 4. Effect of the urea-additive on sag under vertical conditions (250 °F).



Figure 5. Effect of the urea-additive on sag under inclined conditions,  $45^{\circ}$  (250 °F).

# 4.2. Rheological Analysis

The shear stress measured at room temperature (80 °F) was plotted versus the shear rate for all the drilling fluid samples (Figure 6). It was observed that the drilling fluid samples follow the Bingham plastic model. Increasing the concentration of the anti-sagging additive increased the shear stress values and shifted the consistency curve upward with almost a constant slope. This shift indicates a significant increase in yield point (intercept with the *y*-axis) without increasing the plastic viscosity (slope).



**Figure 6.** Effect of the urea-additive on the drilling fluid rheology (80 °F).

The effect of adding the urea-additive on the rheological properties was evaluated by measuring yield point, plastic viscosity, and gel strength at 10 s and 10 min. At room temperature, a significant

increase in the yield point and gel strength values after 10 s was observed as the concentration increased (around 40%–50% for 0.5–1.0 vol.%), reflecting an enhancement in the drilling fluid's ability to suspend solid particles (Figure 7). In contrast, the anti-sagging additive had no impact on plastic viscosity and gel strength values after 10 min. All the drilling fluid samples had a plastic viscosity of around 25 cP, and a gel strength (after 10 min) of around 45 lbf/100ft<sup>2</sup>. When YP/PV ratios were calculated for all drilling fluid samples (Figure 8), it was found that as the concentration of the anti-sagging agent increased, the YP/PV ratio increased, indicating a more stable drilling fluid, which confirms the sag test results.



Figure 7. Effect of the urea-additive on the rheological properties of the drilling fluid (80 °F).



Figure 8. Effect of the urea-additive on the yield point-plastic viscosity ratio (80 °F).

The yield-stress characteristics affect many drilling fluid issues such as hole cleaning, barite sag, surge and swab pressures, and equivalent circulating density [35]. YP/PV was proposed as a tool to evaluate drilling fluid stability [36]. From the rheology measurements, as the concentration of the anti-sagging additive was increased, the YP/PV ratio increased, which reflects an enhancement in

fluid stability and in the drilling fluid's capability to suspend solid particles. However, adding high concentrations of the anti-sagging additive will require higher pumping pressure to start the drilling fluid circulation because of the high yield point and gel strength values [37]. Moreover, very high YP/PV ratios indicate mud coagulation and flocculation [36]. Since adding just 0.5–1 vol.% of the anti-sagging additive prevented barite sag in both vertical and inclined conditions, 0.5–1 vol.% can be considered as the optimum concentration of the anti-sagging additive. Adding more than this concentration would cause additional pressure losses because the yield point affects the pressure losses for Bingham plastic fluids. Moreover, increasing the concentration of the urea-additive would also increase the total cost of the drilling operations.

Furthermore, the drilling fluid rheology for the base fluid and with 0.5–1.0 vol.% of the anti-sagging additive was measured at 250 °F and 2000 psi. The measurements were performed to evaluate the performance of the urea-additive at high pressure and temperature. All samples showed similar behavior to that at room temperature with lower values of yield point, plastic viscosity, and gel strength because of the high-temperature effect (Figure 9; Figure 10). A huge drop, 76%, in the plastic viscosity of the base fluid was observed, while the anti-sagging additive significantly reduced that drop to around 50% and improved the plastic viscosity at the elevated temperature. The YP/PV ratio was within the acceptable range for all the drilling fluid samples (1.5 to 3), according to drilling operation practices. However, the increase in the YP/PV ratio of the base drilling fluid at high temperature compared with that at low temperature, from 1.13 to 2.4, can be attributed solely to the huge drop in the plastic viscosity. No enhancement in the yield point was observed, while adding the anti-sagging additive maintained the YP/PV ratio of the drilling fluid at high temperature with acceptable plastic viscosity and yield point values.



Figure 9. Effect of the urea-additive on the drilling fluid rheology (250 °F).

#### 4.3. HPHT Filtration Experiments

Figure 11 compares the filtration performance curve of the base fluid, 0.5 vol.%, and 1 vol.% drilling fluid samples. It was found that the anti-sagging additive did not affect the filtration performance significantly, and the drilling fluid samples had similar filtration performances. The filtration experiments were conducted using a ceramic filter disc with uniform porosity and permeability to fairly compare the results and eliminate the effect of formation heterogeneity [38]. A difference of around 1.4

cm<sup>3</sup> in the total volume of the fluid filtrate was observed, and the filter cake weight and thickness were almost the same (Figure 12). The filtration experiment results are summarized in Table 6.





Figure 10. Effect of the urea-additive on the rheological properties of the drilling fluid (250 °F).

Figure 11. Effect of the urea-additive on the filtration performance (250 °F).



Figure 12. The formed filter cake: (a) base fluid, (b) 0.5 vol.%, and (c) 1.0 vol.%.

Parameter	Base Fluid	0.5 vol.%	1.0 vol.%
Filtrate volume, cm <sup>3</sup>	9.6	11	10.7
Filter cake weight, g	29.1	34.94	29.77
Filter cake thickness, mm	3.6	4.2	3.6

Table 6. Summary of filtration experiments.

The anti-sagging additive was proven to be effective in preventing barite sag in aqueous drilling fluids with the formulation used in this study. However, more research work is needed to determine the optimum concentration required for different drilling fluid formulations before use in field operations. Moreover, a lab study should be conducted to evaluate the performance of this additive at higher solids loading and salt concentrations and ultra-high temperatures.

#### 4.4. Molecular Investigation of Fluid Loss Control Agents

Molecular simulation can be employed to shed some light on the performance of fluid loss control additives. These polymeric substances tend to accumulate on the surfaces of the wellbore, creating an impermeable layer to avoid further drilling fluid invasion. In the experimental part, starch and polyanionic cellulose were used for this purpose. The two polymers were recreated on a molecular platform, as shown in Figure 13. Polymer Consistent Force Field (PCFF+), which has the capability of capturing the properties of all the atoms present in the system, is used to define the intermolecular atom types and charges. Detailed assignments of bonding are given in the first part of the Appendix A. The molecular simulation was then carried out with the objective of forming a thin polymeric layer in typical reservoir conditions and then characterizing its porosity. The latter serves as an indicator of how well sealed the formed layer is.



Figure 13. Starch (left) and Polyanionic Cellulose (PAC) (right) recreated for molecular simulation.

Two thin layers of starch and PAC were formed in reservoir conditions of 250 °F and 3000 psi, as shown in Figure 14. The molecular simulation protocol consisted of initialization with a 9.5 cutoff value, followed by an constant particle number, volume and temperature (NVT) stage run for 250 ps and then a series of four NPT stages of 200, 200, 400, and 400 ps, respectively, performed using LAMPPS open source software assisted by the MedeA interface.



Figure 14. Two thin layers of (a) starch and (b) PAC formed at 250 °F and 3000 psi.

Then, a porosity estimation was carried out using He-pycnometry simulations through the Gibbs isotherm module of MedeA. Helium adsorption calculations are given in the Appendix A. The estimated porosity values were around 3% for both cases, indicating that the drilling fluid invasion is minimized when those polymers are employed.

# 5. Summary and Conclusions

Extensive experimental work was conducted to assess an anti-sagging additive and study its impact on the properties of barite-weighted drilling fluid and the barite sag tendency. Based on the results of this study, the following conclusions are drawn:

- 1. Adding 0.5–1.0 vol.% of the urea-additive to the base drilling fluid increased the yield point and gel strength after 10 s at 80 °F by around 40–50%. Moreover, the plastic viscosity and gel strength after 10 min remained almost constant. At 250 °F, a 76% drop in the plastic viscosity was observed for the base drilling fluid, while the urea-additive reduced that drop to around 50% and maintained the YP/PV ratio at that temperature.
- 2. Adding just 0.5–1.0 vol.% of the urea-additive was adequate to enhance the drilling fluid stability and prevent barite sag at 250 °F. The sag factor was around 0.51 under both vertical and inclined conditions.
- 3. The urea-additive had no impact on the density and the pH of the drilling fluid, while it had minimal effect on the filtration performance of the drilling fluids and the properties of the formed filter cake. The total fluid filtrate increased by around 1.4 cm<sup>3</sup>, while the filter cake properties were almost the same. However, fluid loss control agents such as starch and polyanionic cellulose can help in minimizing drilling fluid invasions. Molecular simulation of polymeric accumulations showed that a thin layer of low porosity is formed under typical reservoir conditions.
- 4. The developed formulation can be used to drill deep formations efficiently without the barite sag issue at a temperature up to 250 °F. Furthermore, the concentration of the urea-additive should be optimized for different fluid formulations before using it in real field applications. More research work is needed to evaluate the performance of this urea-additive at higher solids loading, high salt concentrations, and ultra-high temperature and pressure. An experimental study is also needed to evaluate the interaction of this additive with formation rocks and fluids and how this may affect the formation damage.

**Author Contributions:** Conceptualization, S.E.; Methodology, A.M., S.A.-A., and S.E.; Formal Analysis, A.M., S.E., and I.H.; Investigation, A.M., S.A.-A., and S.E.; Resources, S.E. and I.H.; Data Curation, A.M. and S.E.; Writing—Original Draft Preparation, A.M. and S.A.-A.; Writing—Review and Editing, A.M., S.A.-A., S.E., and I.H.; Visualization, A.M.; Supervision, S.E. and I.H.; Project Administration, S.E. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

**Acknowledgments:** The authors wish to acknowledge King Fahd University of Petroleum and Minerals (KFUPM) for allowing them to utilize various facilities in carrying out this research. Many thanks are due to the anonymous referees for their detailed and helpful comments.

Conflicts of Interest: The authors declare no conflict of interest.

#### Appendix A

i- Forcefield assignments

Atom #	Name	Element	Atomic Number	Wycoff Position	Wycoff Equation	x	Ŷ	Z	FF Atom Type	Charge
1	C1	С	6	1a	x,y,z	0.172991	0.331875	0.762531	c3	-0.159
2	C2	С	6	1a	x,y,z	0.284569	0.331875	0.762531	c1oe	0.107
3	C3	С	6	1a	x,y,z	0.322175	0.240062	0.729939	c43o	0.107
4	C4	С	6	1a	x,y,z	0.290589	0.22067	0.623912	c43o	0.107
5	C5	С	6	1a	x,y,z	0.326374	0.281348	0.545539	c1oe	0.107
6	C6	С	6	1a	x,y,z	0.288937	0.374827	0.570667	c1oe	0.107
7	O1	0	8	1a	x,y,z	0.32222	0.401024	0.682899	ос	-0.32
8	C7	С	6	1a	x,y,z	0.33047	0.440172	0.490167	c4o	0.054
9	O2	0	8	1a	x,y,z	0.295668	0.526854	0.513608	oh	-0.57
10	O3	0	8	1a	x,y,z	0.430605	0.281129	0.546566	ос	-0.32
11	C8	С	6	1a	x,y,z	0.466156	0.341441	0.468663	coh	0.267
12	C9	С	6	1a	x,y,z	0.390106	0.375597	0.388848	c43o	0.107
13	C10	С	6	1a	x,y,z	0.317198	0.426105	0.443868	c43o	0.107
14	C11	С	6	1a	x,y,z	0.354739	0.502569	0.497479	c1oe	0.107
15	C12	С	6	1a	x,y,z	0.429364	0.473545	0.581691	c1oe	0.107
16	O4	0	8	1a	x,y,z	0.511396	0.420495	0.527721	ос	-0.32
17	C13	С	6	1a	x,y,z	0.472674	0.554988	0.635556	c2oe	0.054
18	O5	0	8	1a	x,y,z	0.541882	0.527929	0.713651	ос	-0.32
19	C14	С	6	1a	x,y,z	0.582344	0.604008	0.76398	coh	0.267
20	C15	С	6	1a	x,y,z	0.686053	0.565391	0.756915	c43o	0.107
21	C16	С	6	1a	x,y,z	0.71063	0.550135	0.647774	c43o	0.107
22	C17	С	6	1a	x,y,z	0.710806	0.628485	0.583634	c1oe	0.107
23	C18	С	6	1a	x,y,z	0.608095	0.669659	0.58369	c1oe	0.107
24	O6	0	8	1a	x,y,z	0.577683	0.689814	0.698637	ос	-0.32
25	C19	С	6	1a	x,y,z	0.60913	0.755165	0.519422	c4o	0.054
26	07	0	8	1a	x,y,z	0.513789	0.793264	0.519565	oh	-0.57
27	O8	0	8	1a	x,y,z	0.779177	0.690371	0.62576	ос	-0.32
28	C20	С	6	1a	x,y,z	0.779346	0.768236	0.562002	c3oe	0.001
29	O9	0	8	1a	x,y,z	0.805773	0.511777	0.643664	oh	-0.57
30	O10	0	8	1a	x,y,z	0.689893	0.483914	0.813656	oh	-0.57
31	O11	0	8	1a	x,y,z	0.401198	0.559376	0.422602	ос	-0.32
32	C21	С	6	1a	x,y,z	0.438511	0.63537	0.475895	coh	0.267
33	C22	С	6	1a	x,y,z	0.545024	0.603623	0.468663	c43o	0.107
34	C23	С	6	1a	x,y,z	0.572016	0.593898	0.359283	c43o	0.107
35	C24	С	6	1a	x,y,z	0.566907	0.674312	0.29918	c1oe	0.107
36	C25	С	6	1a	x,y,z	0.461274	0.708913	0.299555	c1oe	0.107
37	O12	0	8	1a	x,y,z	0.428021	0.722954	0.414885	oc	-0.32
38	C26	С	6	1a	x,y,z	0.456466	0.796524	0.239715	c4o	0.054
39	O13	0	8	1a	x,y,z	0.358424	0.828522	0.240146	oh	-0.57
40	O14	0	8	1a	x,y,z	0.629824	0.738754	0.345583	ос	-0.32
41	C27	С	6	1a	x,y,z	0.624737	0.818671	0.285847	c3oe	0.001

Table A1. Starch.

Table A1. Con
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Atom #	Name	Element	Atomic Number	Wycoff Position	Wycoff Equation	x	Y	Z	FF Atom Type	Charge
42	O15	0	8	1a	x,y,z	0.669933	0.561773	0.35487	oh	-0.57
43	O16	0	8	1a	x,y,z	0.554472	0.520613	0.521278	oh	-0.57
44	O17	0	8	1a	x,y,z	0.246009	0.454598	0.368657	oh	-0.57
45	O18	0	8	1a	x,y,z	0.344924	0.302505	0.33691	oh	-0.57
46	O19	0	8	1a	x,y,z	0.323739	0.134175	0.596919	oh	-0.57
47	O20	0	8	1a	x,y,z	0.284268	0.175102	0.800825	oh	-0.57
48	H1	Н	1	1a	x,y,z	0.146814	0.283559	0.818172	hc	0.053
49	H2	Н	1	1a	x,y,z	0.146814	0.315869	0.684508	hc	0.053
50	H3	Н	1	1a	x,y,z	0.146814	0.396197	0.784912	hc	0.053
51	H4	Н	1	1a	x,y,z	0.310467	0.347728	0.840705	hc	0.053
52	H5	Н	1	1a	x,y,z	0.400662	0.239352	0.733125	hc	0.053
53	H6	Н	1	1a	x,y,z	0.212278	0.226087	0.623553	hc	0.053
54	H7	Н	1	1a	x,y,z	0.300807	0.261604	0.468519	hc	0.053
55	H8	Н	1	1a	x,y,z	0.210494	0.37589	0.566526	hc	0.053
56	H9	Н	1	1a	x,y,z	0.307487	0.421597	0.411778	hc	0.053
57	H10	Н	1	1a	x,y,z	0.408928	0.439422	0.494222	hc	0.053
58	H11	Н	1	1a	x,y,z	0.224544	0.527531	0.509928	ho	0.41
59	H12	Н	1	1a	x,y,z	0.517959	0.3054	0.421392	hc	0.053
60	H13	Н	1	1a	x,y,z	0.425569	0.416737	0.331	hc	0.053
61	H14	Н	1	1a	x,y,z	0.287014	0.383617	0.503795	hc	0.053
62	H15	Н	1	1a	X.V.Z	0.29569	0.537323	0.53516	hc	0.053
63	H16	Н	1	1a	X.V.Z	0.393835	0.433089	0.640184	hc	0.053
64	H17	Н	1	1a	X.V.Z.	0.415248	0.592158	0.672863	hc	0.053
65	H18	н	1	1a	X,y,Z	0.508438	0.595531	0.577326	hc	0.053
66	H19	н	1	1a	X VZ	0.550038	0.624349	0.837726	hc	0.053
67	H20	н	1	1a 1a	X,y,Z	0.737255	0.611192	0.790925	hc	0.053
68	H21	н	1	1a	X,y,Z	0.655164	0.507369	0.616027	hc	0.053
69	H22	н	1	14	X,y,Z	0.731228	0.611743	0.503827	hc	0.053
70	H23	н	1	14	X,y,Z	0.556938	0.62429	0.548772	hc	0.053
70	H24	н	1	10	x,y,z	0.630756	0.741044	0.439265	hc	0.053
71	H25	н	1	10	x,y,Z	0.660089	0.800779	0.554228	hc	0.053
72	H26	и	1	10	x,y,Z	0.467595	0.300779	0.334228	ho	0.055
73	1120	п 	1	1a	x,y,Z	0.467393	0.731919	0.400001	ha	0.41
74	1127	п	1	1a	x,y,z	0.707547	0.707025	0.595741	he	0.053
73	1120	п	1	1a	x,y,Z	0.707347	0.797033	0.36201	he	0.053
70	H29	п	1	1a	x,y,z	0.799755	0.751467	0.462203	nc	0.055
	H30	п	1	la	x,y,z	0.653186	0.555005	0.673234	1	0.41
	H31	H	1	la	x,y,z	0.643477	0.442383	0.782833	no	0.41
	H32	H	1	la	x,y,z	0.405228	0.650971	0.550787	hc	0.053
80	H33	н	1	la	x,y,z	0.592159	0.651249	0.505842	hc	0.053
81	H34	H	1	la	x,y,z	0.520367	0.548947	0.324445	hc	0.053
82	H35	H	1	1a	x,y,z	0.589516	0.661778	0.218959	hc	0.053
83	H36	H	1	1a	x,y,z	0.414162	0.661758	0.261491	hc	0.053
84	H37	Н	1	1a	x,y,z	0.480081	0.786692	0.159295	hc	0.053
85	H38	Н	1	1a	x,y,z	0.503358	0.843918	0.277684	hc	0.053
86	H39	Н	1	1a	x,y,z	0.315914	0.785557	0.20573	ho	0.41
87	H40	Н	1	1a	x,y,z	0.67215	0.867226	0.320813	hc	0.053
88	H41	Н	1	1a	x,y,z	0.550897	0.842875	0.286086	hc	0.053
89	H42	Н	1	1a	x,y,z	0.647339	0.806117	0.205626	hc	0.053
90	H43	Н	1	1a	x,y,z	0.713691	0.604765	0.387334	ho	0.41
91	H44	Н	1	1a	x,y,z	0.511749	0.477428	0.487579	ho	0.41
92	H45	Н	1	1a	x,y,z	0.27695	0.492777	0.316273	ho	0.41
93	H46	Н	1	1a	x,y,z	0.312765	0.265203	0.389334	ho	0.41
94	H47	Н	1	1a	x,y,z	0.394914	0.132774	0.598385	ho	0.41
95	H48	Н	1	1a	x,y,z	0.213115	0.175733	0.797958	ho	0.41

Table	A2.	PAC.
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Atom #	Name	Element	Atomic number	Wycoff Position	Wycoff Equation	x	Ŷ	Z	FF Atom Type	Charge
1	C1	С	6	1a	x,y,z	0.513163	0.722667	0.454071	c2oe	0.054
2	C2	С	6	1a	x,y,z	0.478942	0.669498	0.605049	c1oe	0.107
3	C3	С	6	1a	x,y,z	0.373177	0.710624	0.663953	c43o	0.107
4	C4	С	6	1a	x,y,z	0.285433	0.686912	0.550835	c43o	0.107
5	C5	С	6	1a	x,y,z	0.283075	0.577245	0.523724	c43o	0.107
6	C6	С	6	1a	x,y,z	0.38819	0.547862	0.463682	coh	0.267
7	O1	0	8	1a	x,y,z	0.467066	0.56636	0.577042	ос	-0.32
8	O2	0	8	1a	x,y,z	0.392212	0.445572	0.43524	ос	-0.32
9	C7	С	6	1a	x,y,z	0.502271	0.422312	0.406015	c1oe	0.107
10	C8	С	6	1a	x,y,z	0.568449	0.421539	0.558158	c1oe	0.107
11	O3	0	8	1a	x,y,z	0.533879	0.340712	0.666164	ос	-0.32
12	C9	С	6	1a	x,y,z	0.521445	0.242076	0.587262	coh	0.267
13	C10	С	6	1a	x,y,z	0.455082	0.250801	0.441974	c43o	0.107
14	C11	С	6	1a	x,y,z	0.505278	0.322628	0.332261	c43o	0.107
15	O4	0	8	1a	x,y,z	0.613752	0.292302	0.295536	oh	-0.57
16	O5	0	8	1a	x,y,z	0.446687	0.152222	0.369569	oh	-0.57
17	O6	0	8	1a	x,y,z	0.625578	0.202517	0.54618	oh	-0.57
18	C12	С	6	1a	x,y,z	0.566382	0.523731	0.651178	c2oe	0.054
19	O7	0	8	1a	x,y,z	0.582028	0.613623	0.546866	ос	-0.32
20	O8	0	8	1a	x,y,z	0.26166	0.524457	0.670148	oh	-0.57
21	O9	0	8	1a	x,y,z	0.183688	0.720195	0.613857	oh	-0.57
22	O10	0	8	1a	x,y,z	0.380345	0.818516	0.687913	oh	-0.57
23	O11	0	8	1a	x,y,z	0.616691	0.682099	0.380761	ос	-0.32
24	H1	Н	1	1a	x,y,z	0.523351	0.799982	0.478606	hc	0.053
25	H2	Н	1	1a	x,y,z	0.451408	0.714894	0.370873	hc	0.053
26	H3	Н	1	1a	x,y,z	0.535598	0.678615	0.693189	hc	0.053
27	H4	Н	1	1a	x,y,z	0.355306	0.676198	0.772583	hc	0.053
28	H5	Н	1	1a	x,y,z	0.300047	0.723987	0.443468	hc	0.053
29	H6	Н	1	1a	x,y,z	0.223789	0.559367	0.440251	hc	0.053
30	H7	Н	1	1a	x,y,z	0.405584	0.587928	0.359924	hc	0.053
31	H8	Н	1	1a	x,y,z	0.534372	0.476054	0.327749	hc	0.053
32	H9	Н	1	1a	x,y,z	0.648517	0.40696	0.526661	hc	0.053
33	H10	Н	1	1a	x,y,z	0.483557	0.191738	0.665519	hc	0.053
34	H11	Н	1	1a	x,y,z	0.378091	0.276975	0.472049	hc	0.053
35	H12	Н	1	1a	x,y,z	0.460398	0.324803	0.227417	hc	0.053
36	H13	Н	1	1a	x,y,z	0.657829	0.291458	0.395134	ho	0.41
37	H14	Н	1	1a	x,y,z	0.502216	0.14579	0.283557	ho	0.41
38	H15	Н	1	1a	x,y,z	0.680625	0.257874	0.554148	ho	0.41
39	H16	Н	1	1a	x,y,z	0.629792	0.522485	0.732915	hc	0.053
40	H17	Н	1	1a	x,y,z	0.493954	0.529905	0.714596	hc	0.053
41	H19	Н	1	1a	x,y,z	0.300236	0.559503	0.759677	ho	0.41
42	H20	Н	1	1a	x,y,z	0.154476	0.666592	0.687862	ho	0.41
43	H21	Н	1	1a	x,y,z	0.372035	0.85421	0.58293	ho	0.41
44	C13	С	6	1a	x,y,z	0.638785	0.699253	0.631155	c2oe	0.054
45	C14	С	6	1a	x,y,z	0.721705	0.746325	0.527925	c_1	0.003
46	012	0	8	1a	x,y,z	0.693674	0.789124	0.393837	0-	0
47	O13	0	8	1a	x,y,z	0.833075	0.745494	0.575186	0	-0.003
48	C15	C	6	1a	x,y,z	0.683434	0.618188	0.484962	c2oe	0.054
49	C16	C	6	1a	x,y,z	0.767156	0.540745	0.453012	c_1	0.003
50	014	0	8	1a	x,y,z	0.7701	0.494722	0.315753	0-	0
51	015	0	8	1a	x,y,z	0.845524	0.516138	0.572953	0	-0.003
52	H22	Н	1	1a	x,y,z	0.744033	0.66319	0.435863	hc	0.053
53	H23	H	1	1a	x,y,z	0.636373	0.560931	0.432774	hc	0.053
54	H24	H	1	1a	x,y,z	0.675385	0.671506	0.733834	hc	0.053
55	H25	Н	1	1a	x,y,z	0.58324	0.756603	0.661779	hc	0.053

#### ii- He-Pycnometry Calculations

$$N^m = N^a - \rho_a V_P$$

where  $N^m$  and  $N^a$  are the number of excess and adsorbed molecules of helium, respectively.  $V_P$  is the pore volume, and  $\rho_a$  is the density of helium. Under the assumption of zero excess of molecules at such a degree of confinement, the above equation can be used to estimate the pore volume. Then, porosity can be calculated when  $V_P$  is divided by the bulk volume. A summary of the calculations is given below:

Pressure (bar)	Density (g/mL)	Molecular Volume (Å3/molecule)	Starch (molecule/box)	PAC (molecule/box)	V <sub>P</sub> starch (A <sup>3</sup> )	V <sub>P</sub> PAC (A <sup>3</sup> )	φ Starch	φ ΡΑϹ
0.1	$1.62\times10^{-5}$	411000.0	$4.87\times10^{-4}$	$3.49\times10^{-4}$	200.2	143.4	0.029	0.032
0.2	$3.23\times10^{-5}$	206000.0	$1.00  imes 10^{-3}$	$6.91  imes 10^{-4}$	206.0	142.3	0.030	0.032
0.3	$4.85\times10^{-5}$	137000.0	$1.58\times10^{-3}$	$1.09  imes 10^{-3}$	216.9	149.6	0.032	0.034
0.4	$6.46\times10^{-5}$	103000.0	$2.11\times 10^{-3}$	$1.44\times 10^{-3}$	216.9	148.4	0.032	0.033
0.5	$8.08\times10^{-5}$	82300.0	$2.54\times10^{-3}$	$1.78\times 10^{-3}$	209.0	146.5	0.031	0.033
0.6	$9.69\times10^{-5}$	68600.0	$3.02 \times 10^{-3}$	$2.17\times10^{-3}$	207.2	148.9	0.030	0.033
0.7	$1.13\times10^{-4}$	58800.0	$3.64\times10^{-3}$	$2.50\times 10^{-3}$	214.0	147.0	0.031	0.033
0.8	$1.29\times10^{-4}$	51400.0	$4.09 \times 10^{-3}$	$2.74\times10^{-3}$	210.2	140.8	0.031	0.032
0.9	$1.45\times10^{-4}$	45700.0	$4.52\times 10^{-3}$	$3.21 \times 10^{-3}$	206.6	146.7	0.030	0.033
1	$1.61\times 10^{-4}$	41200.0	$5.02  imes 10^{-3}$	$3.53  imes 10^{-3}$	206.8	145.4	0.030	0.033

Table A3. Summary of the calculations.

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