

## Fluid Loss as a Function of Position around the Wellbore

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### Abstract

Overbalanced drilling and workover operations invariably cause invasion of the drilling and workover fluids into formation. With increasing horizontal drilling to exploit reservoirs exhibiting thin pay zones, more and more of the lateral section of the well is exposed to drilling fluid. In a horizontal wellbore, a difference in filtration rate between the upward and downward section of drill pipe along with of settling of barite can cause variation in filter cake thickness. This can lead to differential sticking of the drill pipe, increased torque on the drill pipe while pulling out of the hole, and wellbore stability problems. An experimental study was undertaken to address the aforementioned issues.

Experiments were performed using high temperature high pressure (HPHT) fluid loss equipment and permeability plugging apparatus (PPA) to measure the fluid loss from downward and upward section of a drill pipe in a horizontal wellbore respectively. Aloxite discs of different permeabilities were used for experiments. Oil-based mud (OBM), water-based mud (WBM), drill-in fluid and drilling fluid procured from the field were used for experiments. Experiment results indicate a strong correlation between difference in fluid loss from different directions and fluid rheology. Difference in the fluid loss from upward and downward directions was observed to decrease with increasing concentration of viscosifier. Drilling fluids having lower low shear rate yield point (LSRYP) exhibit a higher tendency toward barite sag, and it was observed to affect the filtration rate. Increase in pore pressure due to difference in filtration rate was estimated and wellbore stability analysis was performed

### Introduction

Horizontal wells are being utilized throughout the world in an ever increasing fashion to attempt to increase production rates by maximizing reservoir exposure and targeting multiple zones to exploit thin pay zones. Overbalanced drilling and workover operations invariably cause invasion of the drilling and workover fluids into the formation. Invasion of mud filtrate into the formation leaves behind a mud cake (deposition of solids) on the formation rock which behaves like a membrane. It is generally acknowledged that static filtration governs the initial growth of mud cake and that the fundamental role of dynamic filtration is to limit this growth. At the initial exposure of a permeable formation to a drilling fluid, when the mud solids are building a low permeability

filter cake on the wellbore, a high rate of filtration occurs and fine mud solids invade the formation. This high rate of initial filtration is called the spurt loss. The three stages in filter-cake buildup are: spurt loss during initiation of the filter cake, buildup of filter cake thickness during which time leak off is proportional to the square root of time, and limitation of filter-cake growth by erosion.<sup>1</sup> For a static filtration, flow of the filtrate through the filter cake is governed by Darcy's law.

$$V_f = \sqrt{2k\Delta p \left( \frac{f_{sc}}{f_{sm} - 1} \right)} A \frac{\sqrt{t}}{\sqrt{\mu}} \quad \text{..... Equation 1}$$

Equation 1 indicates that for static filtration, fluid loss is proportional to square root of  $t$  (time).

In-situ rock formation properties such as porosity, absolute permeability, relative permeability, pore pressure, shale chemistry, capillary pressure, and residual fluid saturations, also play important roles in controlling both the dynamic formation of mudcake and the time evolution of the invasion process. Particle size distribution, cake compressibility, cake lubricity, state of flocculation and cake thickness are cited as the most important properties of the filter cake.

The rate of fluid filtration into the reservoir rock (leak off rate) is one of the most critical parameters that need to be controlled carefully during drilling and completion operations. With increasing open hole completion operations, the problem gets exacerbated because the fluid remains in the well for a longer time.

Excessive fluid invasion can give rise to a number of problems:

- Differential sticking of the drill string is in many cases caused when a high permeability formation permits large volumes of drilling fluid filtrate to move into the formation leaving behind a thick wall cake on the wellbore. If a thick filter cake forms, the risk of differential pressure sticking of the drill pipe increases.
- Invasion of whole mud or filtrate into producing formations increases the probability of the formation damage.
- Mud filtrate invasion changes the properties of the formation surrounding the borehole and thus, the measurements of various types of borehole logging tools.

Since, most borehole logging tool responses will be affected by the flushed zone, it is important to know the volume and shape of the mud filtrate invaded region.

Invasion of the fluid into a rock matrix during overbalance operation will elevate the pore pressure. If this increased pore pressure is unable to bleed away quickly (if the permeability is very low as in shale), the effective in situ stress decreases, as indicated by Equation 2.

$$\sigma'_i = \sigma_i - p_p \quad \dots\dots \text{Equation 2}$$

Compressive rock failure around the borehole is a function of effective stresses, in situ rock strength, pore pressure in the formation and pressure in the wellbore. Mohr Circle shifts towards left with increasing pore pressure, due to this the failure envelope decreases and the formation becomes more prone to compression failure. This type of issue is prominent in shales.

Several numerical models and software tools have been developed in the industry to determine the depth of filtrate invasion. Tien compared the conventional filtration theory results with numerical models and concluded that results from conventional theory do not match with numerical analysis.<sup>2</sup> Waldmann modeled the linear filtration formulation and a radial single phase formulation to predict fluid invasion depth of the drilling fluid filtrate.<sup>3</sup> Suryanarayana developed a radially adaptive 3D micro simulator for determining impact of filtrate invasion on near wellbore saturation and reservoir pressure.<sup>4</sup> Wu developed a 3D reservoir simulator to simulate the filtrate invasion during the drilling of a horizontal well.<sup>5</sup> Simulation result indicates that depth of filtrate invasion is very sensitive to permeability anisotropy. Distribution of damage zone along a horizontal well is elliptically shaped and depends on the degree of permeability anisotropy.

### Scope of Work

Maintaining a hydrostatic overbalance is necessary to impede the premature flowing of formation fluids into the wellbore and prevent a “blow out.” This pressure overbalance forces the liquid portion of the mud into the rock formation and concurrently filters the solids from the mud to form a low permeability layer at the borehole wall termed the “mud cake.” For permeable formations, the mud cake controls the rate of invasion of the liquid “mud filtrate.” The invasion geometry around the wellbore is important because the properties of the invaded zone will be different from the undisturbed formation properties.

Filtration rate can vary as the function of radial position in the horizontal wellbore (angle from 0 to 360 as described in **Figure 1**). Several factors that can affect the difference in the filtration rate could be settling of particles blocking the formation pores and leaving a clear fluid at the top, viscosity of the drilling fluid, drill pipe eccentricity, and erosion of filter cake from one location because of drill pipe movement. Inappropriate size of plugging particles in drilling fluid will

also form a thick and permeable filter cake leading to continuous filtration. In case of shales, difference in filtration rate can lead to more swelling of shales on one side of well, causing issues of stuck pipe which will require higher torque and drag on the drill pipe while tripping, which can cause wellbore stability issues. To address the aforementioned issues, a methodical study was undertaken to understand this phenomenon and filtration rate was determined from three different radial positions: upward, horizontal and downward. As invasion of filtrate in the formation increases the pore pressure and effectively decreases the collapse pressure of the formation. Early radial flow well testing equation was used to estimate the increase in the pore pressure due to filtrate invasion and wellbore stability analysis was performed using PoroMechanics Institute PBORE-3D™ software.

### Experimental Technique

To simulate the fluid loss from different directions in the wellbore, for each fluid formulation three experiments were performed by varying the direction from which fluid loss was collected (**Figure 2**). PPA and HPHT cells were used for the experiments. The PPA is a high pressure, high temperature filtration device designed to evaluate fluid loss and “spurt loss” of drilling fluids under filtration conditions that more closely approximate those encountered downhole, using a ceramic disc rather than the filter paper normally used. The main feature of the PPA is the use of porous ceramic disks as the filtration medium.<sup>6</sup> These are available in a wide range of porosities and permeabilities to match those properties of the formation much better than filter paper can. Different orientations of the cells and how they actually simulate the wellbore conditions is described in the following section:

1. **Downward direction:** In HPHT cells filtrate is collected from the bottom as shown in **Figure 3**. Particles in the drilling fluid will settle in the direction of the filtration. This condition simulates the fluid loss from the bottom of the horizontal well.
2. **Upward direction:** In PPA with a floating piston, filtrate is collected from the top of the cell as shown in **Figure 4**. Particles in drilling fluid will settle in the direction opposite to the filtration. This condition simulates the fluid loss from the top of the well.
3. **Horizontal direction:** PPA was oriented into horizontal direction and filtrate was collected as shown in **Figure 5**. Certain modifications were done in the PPA filtrate collection assembly. In this case, particles in drilling fluid will settle in the direction perpendicular to the filtration. This condition is equivalent to the fluid loss from the side walls in the well.

A constant pressure technique was used for filtration experiments. Inert gas was used for pressurizing the cells. This ensured in the maintaining of constant pressure drop across the cell, especially when filtrate is being collected (with a hydraulic pump, pressure drops to zero when valve is opened

to collect filtrate). Drilling fluid was prepared using a Silverson mixer. After performing the basic mud check, the fluid was hot rolled for 16 hrs at 250 °F in a roller oven after which mud check was performed (rheology, mud weight, pH for water-based fluid and electrical stability for oil-based fluid).

Equal volumes of fluid were measured and poured in three different cells for static aging. Static aging of the drilling fluid simulated the downhole condition (when drilling operations halt for a period of time) and created an environment where barite will settle in the direction of gravity (only if fluid rheology degrades to the extent that it will allow barite sag). It is worth mentioning that cell orientation while static aging was similar to the orientation under which fluid loss experiment will be conducted. For example, for filtration from horizontal direction, the cell was placed horizontally in the static oven.

After 16 hours of static aging at 250 °F, a fluid loss test was done at differential pressure of 500 psi and temperature of 250 °F. Filtrate was collected at regular intervals and a test was performed for 30 minutes. Equations 7, 8 and 9 in Table 1 were used to calculate the total filtrate collected spurt loss and static filtration rate respectively.

Different types of fluid system such as non damaging reservoir fluid (drill-in fluid), water base drilling fluid and a fluid procured from the field were used for experiments. Details of specific type of drilling fluid formulations will be discussed in next section. Aloxite discs of different pore size (permeability) were used as filtration medium, the details of which have been tabulated in

**Table 2.** Drilling fluid designed to plug a specific pore size will form a thick and permeable filter cake on other pore sizes, consequently showing higher fluid loss values. Experiments performed using different pore/permeability ceramic disc simulate this condition.

## Results and Discussion

Spurt loss is the term used to describe the earliest stages of filtration and formation invasion. As a drill bit mechanically exposes new rock to the mud column, whole mud invades the formation. Solids concentration in the fluid, particle size and viscosity determine how easily fluid will pass through the formation. Once the pore spaces have been bridged, implying formation of the filter cake, the process of mud filtration begins.

Of more particular interest is the static filtration volume (ml/min). This value does not include spurt loss and indicates the continuous fluid loss after formation of the filter cake. After spurt loss, the filter cake will control the invasion rate meaning that the invasion rate will be independent of formation permeability. Highly compacted filter cake will have significantly less permeability and static filtration rate. In the following section major emphasis will be given to static filtration rate as this determines the total amount of fluid that will invade the formation.

### a) Drill-in fluids

Drill-in fluids are designed to be essentially non-damaging to the producing formation, provide superior hole cleaning, allow easy clean-up and be cost effective. These fluids address the wide range of problems encountered in horizontal drilling, completion, and workover operations. These systems are designed to provide the lowest filtration rate possible in order to minimize or prevent formation damage. When bridging production zones, the correct sizing of particles becomes important. The pore diameter of the formation must be known to help ensure effective bridging. An industry rule of thumb for estimating an unknown pore diameter (microns) is to take the square root of the permeability in millidarcies as per Equation 3. To effectively bridge off the production zone, 20-30 percent by weight of the bridging material should be one-third of the pore size in microns as per Equation 4.

$$\text{Pore Diameter (microns)} = \sqrt{\text{Permeability (millidarcy)}} \quad \dots\dots \text{Equation 3}$$

$$D(50) = \frac{\lambda}{3} = \frac{\text{Pore Diameter}}{3} \quad \dots\dots \text{Equation 4}$$

Filtration tests on drill-in fluids were conducted using a ceramic disc which simulates as closely as possible the pore size of the formation. These tests can be utilized in the field to determine proper application of the drill-in fluid system.

A 9.8 ppg sodium chloride brine solution weighted up to 10.5 ppg using different grades of calcium carbonate was used for testing. The concentration of polymeric viscosifier was varied from 0.25 lb/bbl to 1 lb/bbl whereas the concentration of polymeric filtration control agent was kept constant at 8 lb/bbl. A constant amount of 50 lb/bbl of calcium carbonate was used for weighting as well as plugging purposes. Experiments were performed on two different sizes of aloxite disc: 10 and 35  $\mu\text{m}$ . The mean particle size required to effectively plug the 35  $\mu\text{m}$  aloxite disc, according to Equation 4 should be around 12  $\mu\text{m}$ . Hydraulics and pore size modelling software was used to determine the optimum ratio of different calcium carbonate grades that will be required to achieve a mean particle size of 12  $\mu\text{m}$ . Based on the modelling results as reported in

**Figure 6**, two different size grades of calcium carbonate having mean particle size of 5 and 25  $\mu\text{m}$  were mixed together in 40/60 (wt %). Particle size determined using the Malvern Particle Size Analyzer for one of the drill-in fluids (Test 7.1) confirms that fluid has a mean particle size of 12  $\mu\text{m}$  (**Figure 7**). Rheology data for various concentration of viscosifier have been tabulated in **Table 4**. With increasing concentration of viscosifier, the plastic viscosity (cP) and yield point (lb/100  $\text{ft}^2$ ) of the drill-in fluid increase, as expected. Experimental results indicate that static filtration rate reaches its maximum from the upward direction and its minimum from the downward direction. Fluid loss test results for drill-in fluid are tabulated in **Table 5**.

Testing performed on 35  $\mu\text{m}$  indicates that with increasing concentration of polymeric viscosifier static filtration rate decreases from all upward and downward direction whereas the static filtration rate increases from the horizontal direction as shown in **Figure 8**. The above observation could be attributed to the return flow phenomena. The solids suspension capacity of drilling fluid decreases with decreasing viscosity. Particles begin settling and there is a clear liquid at the top, which passes through the disc very easily. As particles settle due to body forces (caused by higher specific gravity), settling particles displace liquid in the upward direction known as *return flow*. This return flow adds to the total fluid loss from the upward direction in the ceramic disc. Due to additional flux of displaced fluid, fluid loss from the upward direction will be greater, compared to fluid loss from downward direction. Fluid designed for a 35  $\mu\text{m}$  aloxite disc gives higher static filtration rate on a 10  $\mu\text{m}$ . This is because of the inability of the drilling fluid to effectively plug the pores of the aloxite disc.

### b) Water-based drilling fluid

A recent theoretical approach has indicated that the maximum rate of barite sag for a drilling fluid occurs at approximately 13.0 lb/gal.<sup>7</sup> Several other factors like oil water ratio, viscosity, solids suspension capability, surfactant concentration, and hole angle also affect settling of barite, but the effects of these factors were out of the scope for this work.<sup>8</sup>

A 13.0 lb/gal KCl/polymer water-based fluid was prepared for the experiments. In initial formulations, a significant reduction in fluid properties (low shear viscosity, gel strength) consequently reflected in settled barite of 16/32 inch and very high total filtrate (approximately 150-180 ml). Several tests were done to optimize the concentration of additives and plugging material. Once a satisfactory fluid was formulated, tests were performed to determine the filtration rate from different radial directions. Static filtration rates for few tests performed with water based mud have been reported in **Table 6**. Appropriate size ceramic disc was used after determining the mean particle size. As barite was only added to the fluid, mean particle size of the fluid will be somewhere near to the mean particle size of barite. On a 35  $\mu\text{m}$  aloxite disc, the static filtration rate from upward and downward direction was observed to be similar (**Figure 9**). However comparing the filtration rate from downward direction performed on two different size aloxite disc, 10 and 35  $\mu\text{m}$ , a lower rate was observed with 10  $\mu\text{m}$  aloxite disc (**Figure 10**).

### c) Drilling fluid procured from field

Fluids prepared under laboratory conditions have different physical properties as compared to fluid prepared at a field location with the same formulation. This is primarily due to difference in shear rate observed by the fluid in lab and field and the extent of exposure to high pressure and high temperature conditions. Certain additives used in drilling fluids yield more at higher shear rates. To validate the applicability of the above results, test was done on fluid

procured from field location. Testing was performed with a 14.6 ppg KCl/polymer fluid used to drill to a TVD of 5514 m with a bottomhole temperature of 220 °F. Xanthan gum was used to provide the necessary viscosity, and a combination of starch and cellulose was used as the filtration control agent. Glycol was added to inhibit shale swelling. Optimised particle size distribution of calcium carbonate to assist in plugging high permeability formations was kept for contingency. As the fluid was already exposed to high temperature, no hot rolling of fluid was done. Equal volumes of fluid were used for static aging at 250 °F and 16 hrs. Particle size of the fluid was determined using the Malvern Particle Size Analyzer. Bimodal distribution of the particles is evident from **Figure 11**, and the fluid had a mean particle size of 7  $\mu\text{m}$ . Fluid loss testing was done on a 10  $\mu\text{m}$  aloxite disc and different fluid loss values have been tabulated in **Table 7**. The fluid loss profile and static filtration rate for upward and downward direction has been plotted in **Figure 12**. As observed with other fluid systems, static filtration rate for the field mud from the upward direction is again greater than fluid loss from downward direction.

### d) Increase in pore pressure because of the drilling fluid invasion

Wellbore pressure response during the pressure drawdown test is given by Equation 5.<sup>9</sup> Pressure variation during production for different flow rates is analyzed by this equation. The same equation can be applied for injection with negative value of  $Q_o$ .

$$p_i - p_{wf} = \frac{162.6q_o\beta_o\mu_o}{\sqrt{k_v k_y} L} \left[ \log \left( \frac{\sqrt{k_v k_y} t}{\phi\mu_o c_i r_w^2} \right) - 3.23 + 0.868s \right]$$

.....Equation 5

For injection into formation (negative  $Q_o$ ):

$$p_{wf} - p_i = \frac{162.6q_o\beta_o\mu_o}{\sqrt{k_v k_y} L} \left[ \log \left( \frac{\sqrt{k_v k_y} t}{\phi\mu_o c_i r_w^2} \right) - 3.23 + 0.868s \right]$$

.....Equation 6

Anisotropy in permeability was ignored (same permeability in horizontal and vertical direction) for calculations. Values used for various variables in the Equation 6 have been tabulated in **Table 8**. Increase in pore pressure for different static filtration rate was calculated and results have been tabulated in **Table 9**. From the theoretical calculations it seems, for the static filtration rate observed during experiments, no significant increase in pore pressure will occur. As pore pressure does not changes significantly, no issue of wellbore stability will occur, which was confirmed by performing calculations using PBORE-3D software.<sup>10</sup>

## Conclusions

Several experiments were performed to determine the filtration rate from different radial positions. Increase in pore pressure due to filtrate invasion was estimated by using well testing equations and for increased pore pressure, wellbore stability analysis was performed using PBORE-3D software. The following conclusions can be drawn from the above work:

1. In a horizontal well while drilling overbalanced, fluid loss varies for different radial positions.
2. Static filtration rate is always observed to be at its maximum from the upward direction because of settling of particles in the direction opposite to filtration, whereas the minimum rate is observed from downward direction.
3. Improper selection of the particle size for plugging the pores of the formation can lead to more fluid invasion causing higher formation damage and potential instability issues. Numerical models should be used for accurately determining the ratio of different products to achieve the particle size.
4. Increases in wellbore pore pressure due to invasion of filtrate were estimated using well testing correlations. For the experimental static filtration rate observed, no significant increase in wellbore pore pressure occurs.
5. Although fluid loss from different radial positions in a wellbore does not cause any wellbore stability issues, it can alleviate the issues of differential sticking, stuck pipe, shale swelling etc.
6. Filter cake is desired while drilling as it helps prevent the sloughing of the formation. In case of tight filtrate, uniform filtration occurs from different radial positions,
7. Numerical models developed across the industry should incorporate this difference in fluid loss to accurately predict the invasion depth. This will help in proper determination of skin factor and also in accurate analysis of the logging data.

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## Nomenclature

$V_{7.5}$	- filtrate volume after 7,5 min, in millilitres
$V_{30}$	- filtrate volume after 30 min, in millilitres
$V_{PPT}$	- PPT volume, in millilitres
$V_1$	- spurt loss, in millilitres
$V_f$	- static filtration rate (velocity of flow), in millilitres per minute
$t_1$	- time at initial reading, in minutes
$t_2$	- time at final reading, in minutes
PPA	- Permeability plugging apparatus
HPHT	- High pressure high temperature
AHR	- After hot roll

BHR	- Before hot roll
$p_i$	- Pressure (Psi)
$p_{wf}$	- Wellbore pressure (psi)
$q_o$	- Volumetric flow rate (bbl/hr/ft)
$\beta_o$	- Formation Volume Factor (bbl/STB)
$k_v, k_y$	- Vertical and horizontal permeability (mD)
$\mu_o$	- Viscosity (cP)
$t$	- Time (min)
$c_t$	- Compressibility (1/psi)
$r_w$	- Wellbore radius (feet)
$s$	- Skin factor (-)
$L$	- Length (feet)
$\sigma(x,y,z)$	- In situ stress (Psi)

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**Table 1: Equations used to determine filtration rate**

Total Filtrate Collected	=	$V_{PPT} = 2V_{30}$	... Equation 7
Spurt Loss	=	$V_1 = 2[V_{7.5} - (V_{30} - V_{7.5})] = 2(2V_{7.5} - V_{30})$	... Equation 8
Static Filtration Rate	=	$V_f = \frac{2(V_{30} - V_{7.5})}{\sqrt{t_2} - \sqrt{t_1}} = \frac{2(V_{30} - V_{7.5})}{2.739}$	... Equation 9

**Table 2: Porosity and permeability relationship for ceramic disc using in the experiments**

Mean Pore Diameter	Permeability (mD) (Air)
3 micron	500
5 micron	750
10 micron	950
20 micron	2.8
35 micron	5.5
60 micron	6.7
90 micron	13.5
150 micron	26.5

**Table 3: Formulation of drill-in fluid (10.5 PPG)**

Product	Concentration (lb/bbl)
Water	As required
NaCl	91.09
Viscosifier	Varied from 0.25 to 1
Filtration Control	8
Plugging and weighing material	As required
Alkalinity	0.25

**Table 4: Rheology data for different drill-in fluid formulation**

	D2.1		D3.2		D4.1		D5.1		D7.1		D8.1	
	BHR	AHR	BHR	AHR	BHR	AHR	BHR	AHR	BHR	AHR	BHR	AHR
MW	10.5	10.5	10.4	10.4	10.4	10.4	10.5	10.5	10.5	10.5	10.5	10.5
Temp	120	120	120	120	120	120	120	120	120	120	120	120
600 RPM	78	40	66	52	55	43	40	26	78	56	70	45
300 RPM	57	28	48	38	39	33	26	19	57	40	50	31
200 RPM	48	23	40	31	31	29	21	15	48	28	42	26
100 RPM	36	17	29	24	22	16	15	11	36	23	30	19
6 RPM	12	6	9	7	6	9	4	4	12	7	9	7
3 RPM	10	5	7	5	5	6	3	3	10	6	7	6
10 Sec Gel	10	5	7	5	4	5	3	3	10	6	7	6
10 Min Gel	14	6	8	6	6	7	4	4	14	7	9	7
pH	10.5	8.5	10.13	8.9	10.34	9.1	10.1	9.1	10.5	8.5	---	---
PV	21	12	18	14	16	10	14	7	21	16	20	14
YP	36	16	30	24	23	23	12	12	36	24	30	17
LSRYP	8	4	5	3	4	3	2	2	8	5	5	5
n	0.52	0.56	0.48	0.46	0.53	0.47	0.63	0.49	0.47	0.61	0.49	0.58
k	2.03	1.09	2.42	2.23	1.39	2.04	0.50	0.97	2.93	0.82	2.27	0.75
Tau	4.57	4.21	1.88	0.67	1.48	2.51	2.88	2.05	3.70	3.87	2.07	4.29

Table 5 :Filtration rate for drill-in fluids (10.5 ppg)

Test no	Amount of viscosifier	Disc size Used	Filtration property	Downward	Upward	Horizontal
	lb/bbl	( $\mu\text{m}$ )				
D2.1	1	35	$V_{ppt}(ml)$	17.2	25.2	21.6
			$V_f(ml)$	10.8	9.2	8.0
			$V_f(ml/min)$	1.2	2.9	2.5
D3.2	0.75	35	$V_{ppt}(ml)$	11.2	24.8	24.8
			$V_f(ml)$	3.2	9.6	10.4
			$V_f(ml/min)$	1.5	2.8	2.2
D4.1	0.5	35	$V_{ppt}(ml)$	10.0	22.4	18.8
			$V_f(ml)$	1.2	8.0	8.4
			$V_f(ml/min)$	1.6	2.6	1.9
D5.2	0.25	35	$V_{ppt}(ml)$	14.4	60.0	--
			$V_f(ml)$	1.6	28.0	--
			$V_f(ml/min)$	2.3	5.8	--
D7.1	1	10	$V_{ppt}(ml)$	14.0	32.0	--
			$V_f(ml)$	2.8	3.2	--
			$V_f(ml/min)$	2.0	5.3	--
D8.1	0.75	10	$V_{ppt}(ml)$	15.6	34.8	30.8
			$V_f(ml)$	3.6	14.0	14.0
			$V_f(ml/min)$	2.2	3.8	3.1

Table 6 : Static filtration rate for WBM (13 ppg)

Test no	Static Filtration Rate $V_f$ (ml/min)			Disc size Used
	Downward	Upward	Horizontal	( $\mu\text{m}$ )
W4.1	5.48	5.48	--	35
W4.2	2.19	--	--	10

Table 7 : Static filtration rate for FIELD MUD (14.6 ppg)

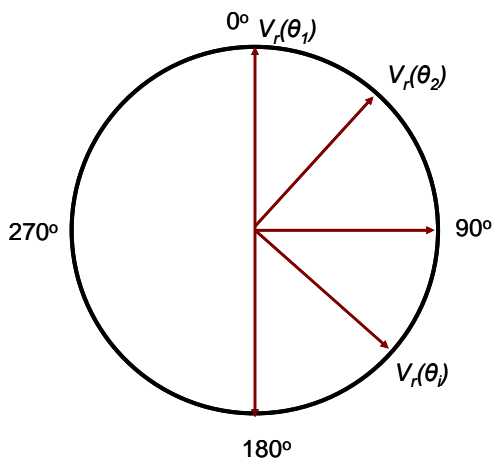
Test no	Static Filtration Rate $V_f$ (ml/min)			Disc size Used
	Downward	Upward	Horizontal	( $\mu\text{m}$ )
F1	4.38	6.21	6.57	10
	Total filtrate in 30 min ( $V_{ppt}, ml$ )			
	28	51	74	
	Spurt Loss ( $V_1, ml$ )			
	2	8.5	19	

**Table 8: Input values for parameters of Equation 5**

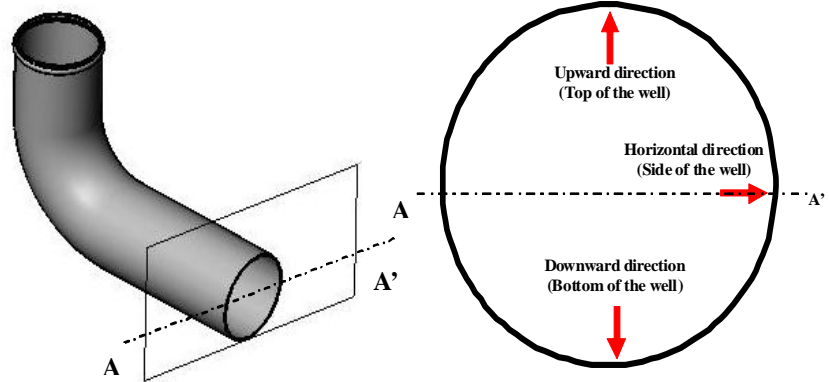
Parameters	Unit	Value
Wellbore Radius ( $r_w$ )	feet	<b>0.365</b>
Permeability ( $k$ )	mD	<b>0.01 – 0.0001 0.02 mD for Shales</b>
Viscosity ( $\mu_o$ )	cP	<b>1</b>
Length (L)	feet	<b>1</b>
Formation Volume Factor ( $\beta_o$ )	bbl/STB	<b>1.2</b>
Compressibility ( $C_t$ )	1/psi	<b>1.3E-05</b>
Porosity ( $\phi$ )	---	<b>0.3 for shales 0.15 for sandstones</b>
Skin Factor (s)	---	<b>1</b>
Flow rate ( $q_o$ -ve for injection)	bbl/hr/ft	<b>varied</b>
Vertical Depth (TVD)	Feet	<b>10000</b>
Initial Pore Pressure ( $p_m$ )	Psi/ft	<b>0.48</b>

**Table 9: Increase in pore pressure**

Static filtration rate (experimental, ml/min)	Initial Pore Pressure Gradient (Psi/ft)	Changed Pore Pressure gradient (Psi/ft)
5	0.48	0.48
50	0.48	0.48
100	0.48	0.48
5000	0.48	0.486
50000	0.48	0.54
100000	0.48	0.598



**Figure 1: Different direction of fluid loss in a horizontal wellbore**



**Figure 2: Description of directions from which fluid loss was collected and its relevance to a horizontal well.**





Figure 3: Downward Direction



Figure 4: Upward direction

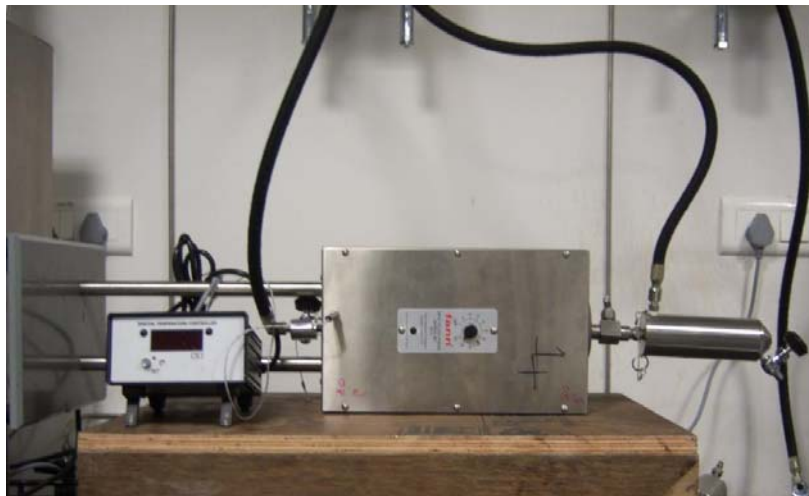


Figure 5: Horizontal direction

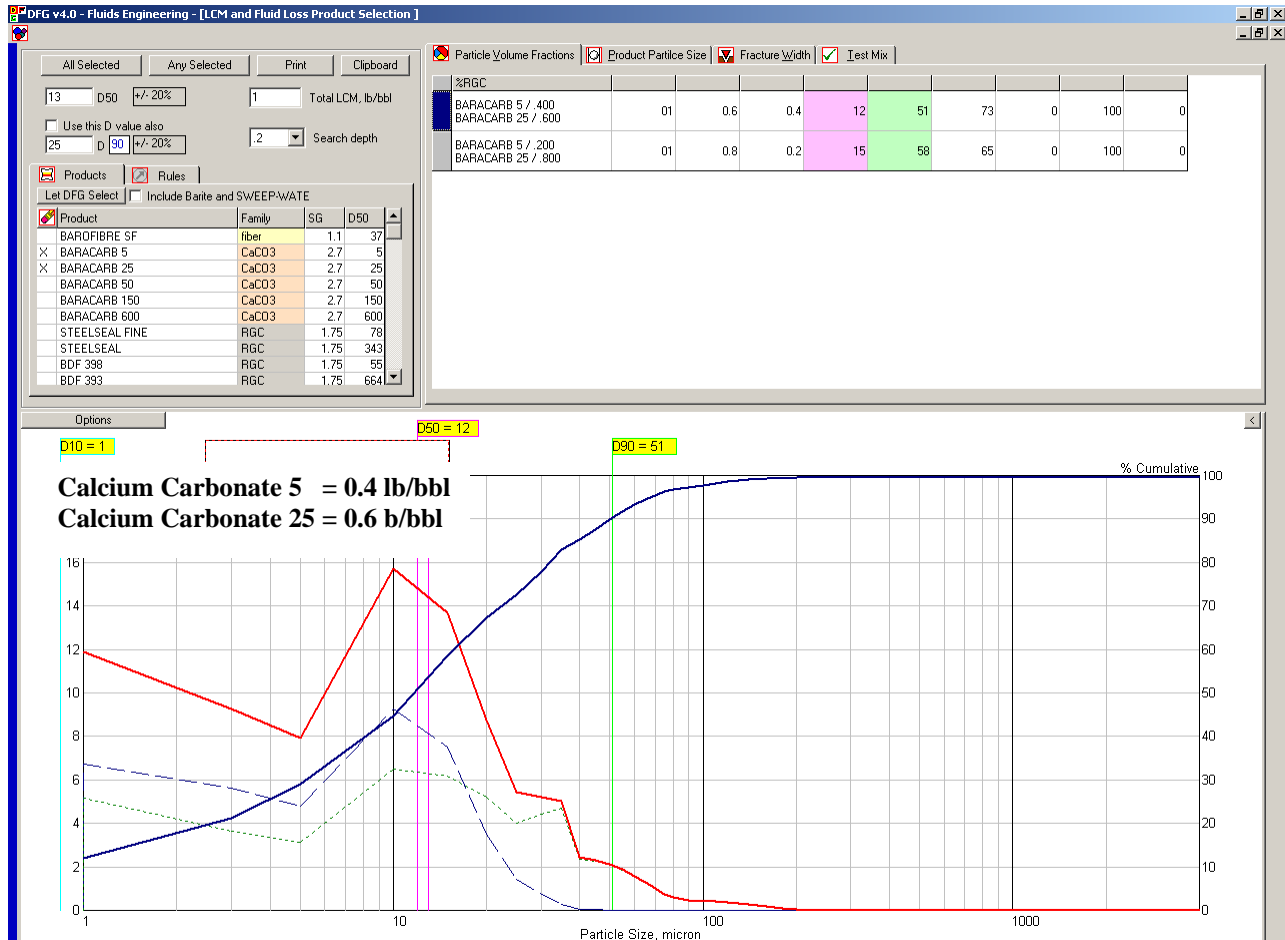


Figure 6: Determination of optimum size of calcium carbonate using solids modelling for plugging the ceramic disc for drill-in fluid (Test D2.1)

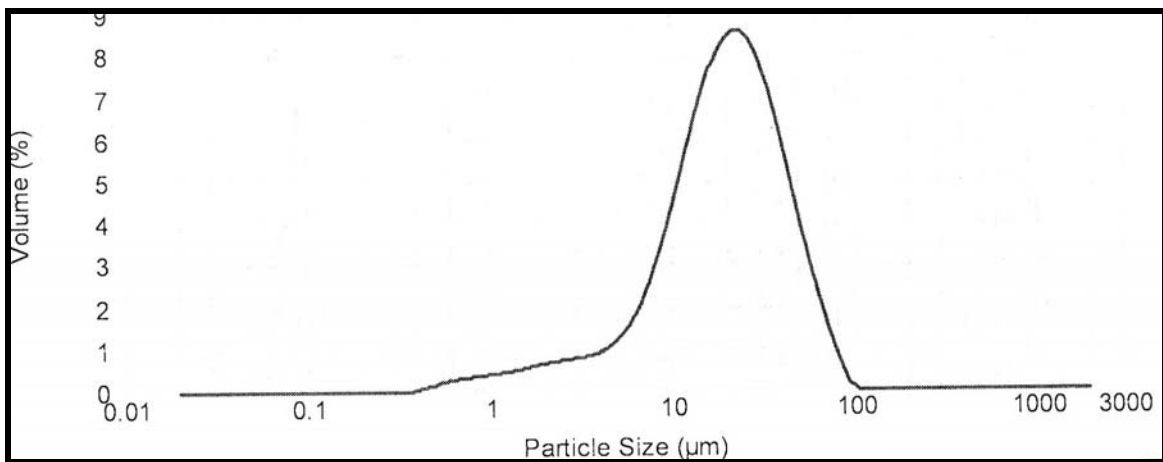


Figure 7: Particle size distribution determined using Malvern Particle Size analyzer for D7.1

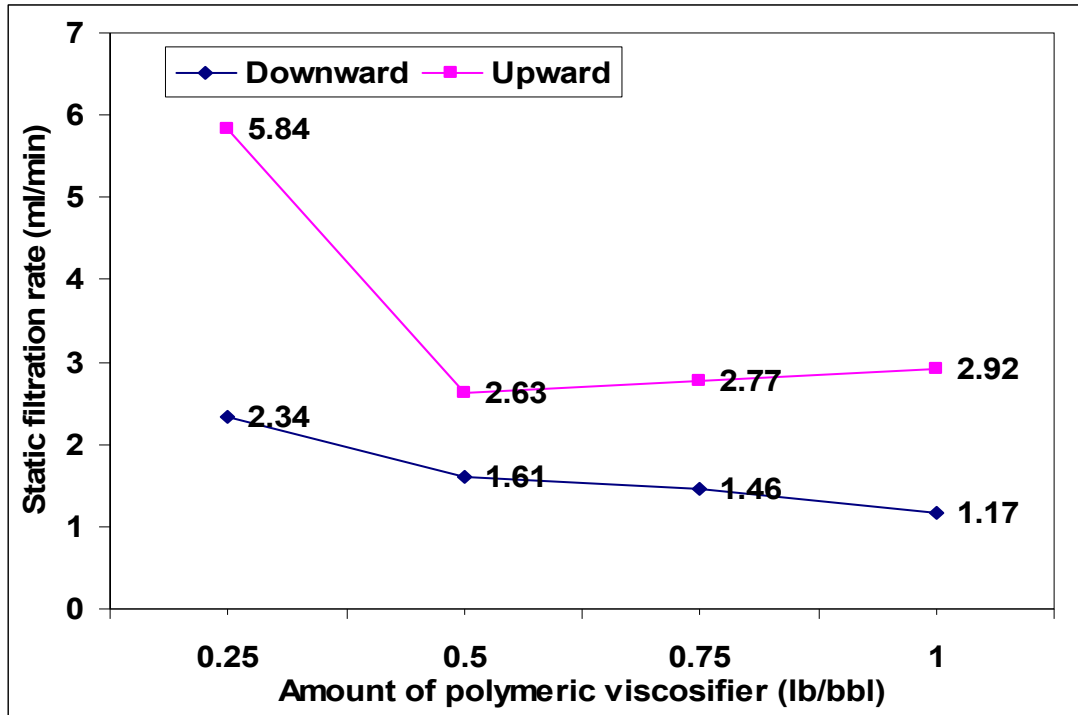


Figure 8: Effect of varying concentration of polymeric viscosifier on static filtration rate (experiments performed on 35  $\mu\text{m}$  ceramic discs).

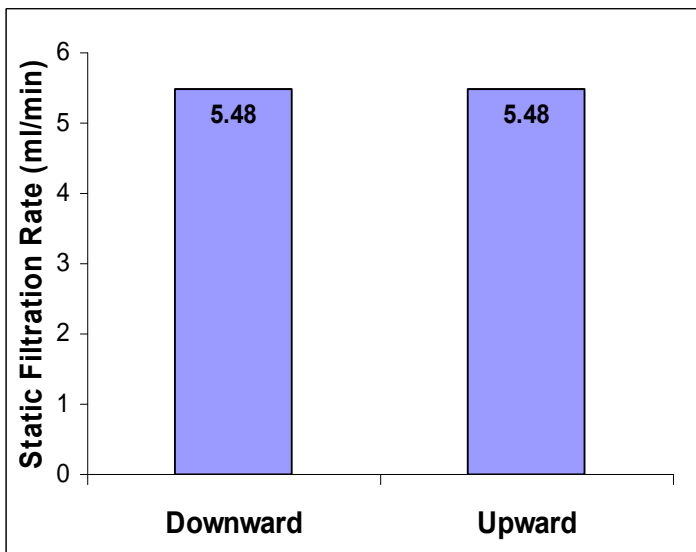


Figure 9: Variation of static filtration rate for WBM. Test was done on 35  $\mu\text{m}$  aloxite disc.

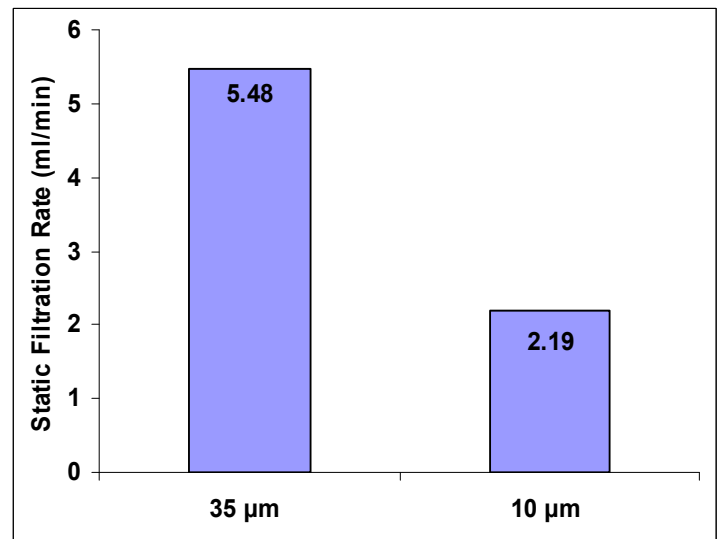


Figure 10: Variation of static filtration rate from downward direction with varying aloxite pore size for WBM.

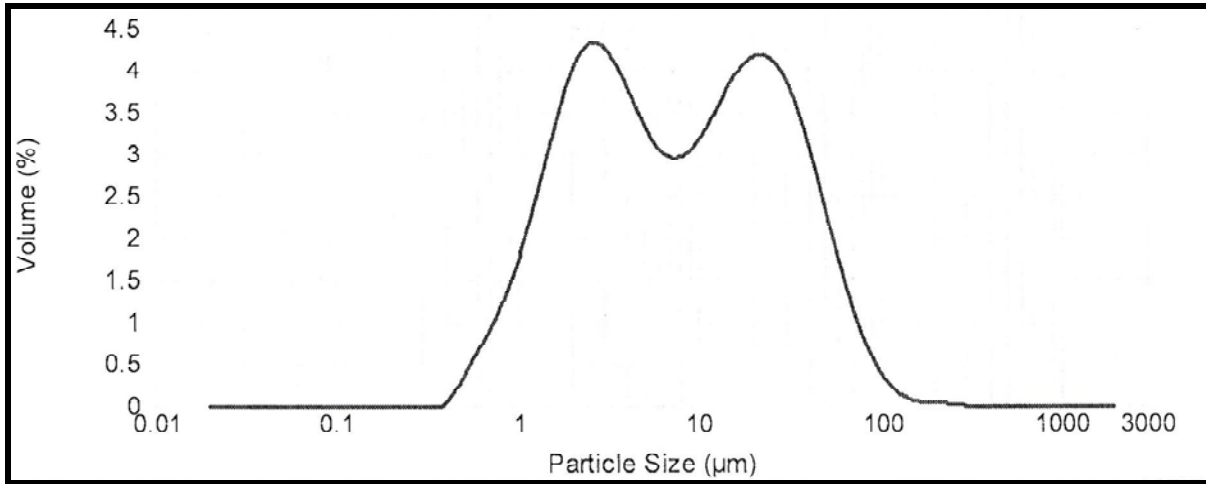


Figure 11: Particle size distribution determined using Malvern Particle Size analyzer for Field Mud

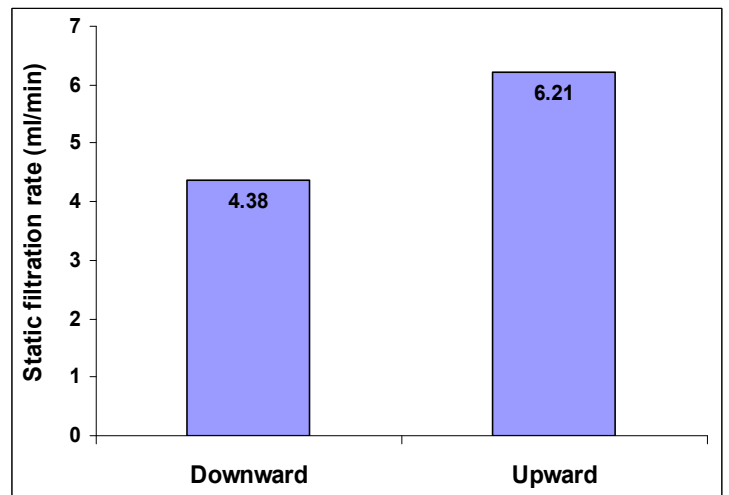
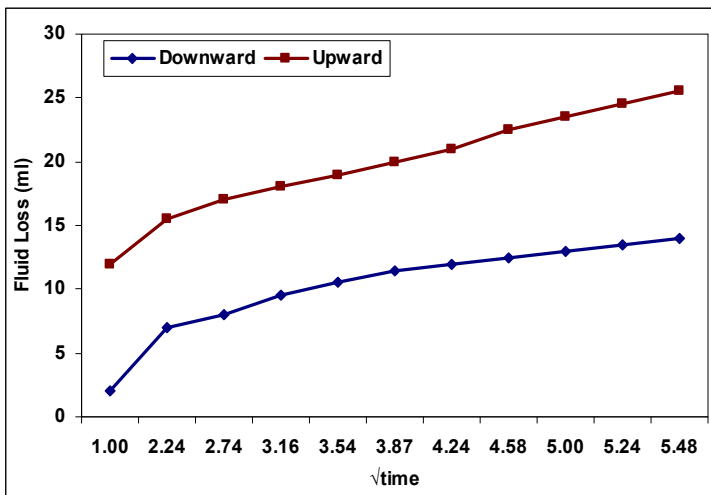


Figure 12: Fluid loss profile with time and static filtration rate from upward and downward direction for drilling fluid procured from field.