14(B)-11

BTL

Malaysian Science & Technology Congress '98
Johor Bahru, 30 - 31 Octo. 1998

Optimum Acid System for Trengganu Offshore Gas Well Acidizing Process

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ABSTRACT

Key Words: **Acidizing, mud acid, permeability, acid reaction coefficient**

Formation damage usually occurs during drilling operation, chemical treatment and etc. Drilling fluids causes the most common formation damage. In order to repair this damage, a laboratory experiment using matrix acidizing technique were carried out. The successful of this technique depends upon several parameters, such as the reservoir temperature, acid concentration, mineral composition and acid type. These papers present the results of the laboratory study on optimum acid system for acidizing operation at Offshore Trengganu gas field. In this study, a work used combination of hydrochloric acid (HCl) and hydrofluoric acid (HF) or mud acid has been carried out using core samples from Offshore Trengganu gas field. The damaged in the cores, which was caused by water base mud, could be removed by acid with certain concentration.The results show that by using the correct type of acid with optimum concentration, permeability increased has been observed. Therefore, the reservoir productivity can be increase significantly. In addition, acid reaction coefficient (ARC) has been calculated for each type of acid. From ARC results, it can be concluded that mud acid consists of 6 % HCl and 1 % HF is the most suitable acid system recipe for gas field "A" acidizing job.

BACKGROUND

Acidizing is a process to treat productive formation with acid for the purpose of increasing production. Therefore, the objective of an acidizing process is to react with formation rock and/or pore plugging materials to form soluble salts that can be produced to the surface, or displaced into the pore system some distance away from the wellbore, thus providing enlarged or more open flow channels. In this process, acid is injected into the formation under pressure. This acid etches the rock, enlarging the pore spaces and passages through which the reservoir fluids flow. The acid is held under pressure for a period of time and then pumped out, after which the well is swabbed and put back into production. Chemical inhibitors combined with the acid prevent corrosion of the pipe. Acid may be used to reduce damage near the wellbore in all types of formation. Inorganic, organic, and combination of these acids, along with surfactants, is used in a variety of well stimulation treatments.

The two basic types of acidizing are characterized through injection rates and pressures. Injection rates below formation fracture pressure are termed as matrix acidizing, while those above the formation fracture pressure are termed as fracture acidizing. A third treatment, called wash acidizing may be used to remove some inorganic scales from tubular and perforations, often used as a prelude to a matrix or fracture treatment.

Matrix acidizing is applied primarily to remove near-wellbore damage caused by drilling, completion, workover or well-killings, or injection fluids, and by precipitation of scale deposits from produced or injected water. Due to the extremely large surface area contacted by acid in a matrix acidizing process, acid-spending time is very short. It is difficult to affect formation more than a few feet from the wellbore. With sandstone reservoirs, live HF acid penetration is usually less than 30 cm.

Removal of severe plugging in formation can result in a very large increase in well productivity. The important factors in acidizing process design are to assess the degree of productivity impairment and the nature of the damage. To effectively remove pore system damage near the wellbore only small volume of acid is needed, but uniform acid placement into a high percentage of the near-wellbore system is the key. Matrix acidizing must be carried out below formation fracture pressure to avoid bypassing plugged pores. Below formation fracture acidizing tend to leave zone barriers, and perhaps mud plugged primary cement channels, intact to provide zonal isolation.

Basic acids used are hydrochloric, hydrofluoric, acetic, formic and a lesser extent, fluoboric and sulfamic acid. Various combinations are used in specific applications. Acids that form insoluble precipitants should not be used under the conditions where precipitants occur. For sandstone formation, acidizing process is used to increase permeability by dissolving clays and other pore plugging materials near the wellbore. Clays may be naturally occurring formation clays or those introduced from drilling, completion, or workover fluids.

Knowledge of the factors affecting the reaction rate of acids is important for several reasons. First, these factors, correlated with reservoir and formation characteristics, form a guide for the selection of acid type and volume for a given acidizing process. Next, a study of these factors can furnish an understanding of what parameters govern spending time, which will determine how far a given acid formulation can penetrate into the formation before spending. Many factors govern the reaction rate of an acid, such as pressure, temperature, flow velocity, acid concentration, reaction products, viscosity, acid type, area/volume ratio, and formation composition (physical and chemical).

EXPERIMENTAL WORK

Twenty-four formation core samples from a gas field "A" had been tested for permeability, porosity, petrophysics, solubility and acidizing flow tests. The depth of coring ranging from 2415 - 2416 m. The permeability, porosity and petrophysic tests had been carried out by using standardized core-analysis procedures. In addition, acid solubility and flow tests were run to determine to what extent the formation will respond to an acidizing treatment. Using 1-gram sample grain, 200-ml acid at the temperature of 65 °C for the period of 30 minutes ran the solubility tests. The solubility was then calculated by weight different between original and final weight of the sample.

Figure 1 shows the set-up used in the acidizing flow test work. The 5.08 cm length with 3.81 cm diameter core must be cleaned and saturated with the brine before was put in the core holder. For the core cleaning process, the methanol solution was used for the period of 24 hours, after which the core was dried in the oven at 80 °C for another 24 hours. 20000 ppm natrium chloride solution was used to represent the formation water in the saturation process as shown in Fig. 2. The flow test consists of initial permeability (Ki) determination, damage the core with water base mud filtrate, damage permeability (Kd) measurement, acidizing and final permeability (Kf) measurement, as shown in Fig. 3. Table 1 and Table 2 show the water base mud rheology and mud acid formulation used in the experiment, respectively. From the damaged and final permeability data, the acid reaction coefficient (ARC) can be calculated by equation (1).

$$ARC = Kf / Kd \quad (1)$$

Darcy equation was used to determine the formation permeability, as in equation (2):

$$K = q\mu L / A(P1 - P2) \quad (2)$$

Where;

K	=	permeability, darcy
Q	=	flow rate, ml/sec.
μ	=	viscosity, cp
L	=	core sample length, cm
A	=	cross-section area, cm. sq.
P1	=	inlet pressure, atms
P2	=	outlet pressure, atms

RESULTS AND DISCUSSION

Physical and Chemical Properties

The results from petrophysic tests on the 24 core samples show that the tested sandstone sample is very tight with very fine sand particle and very compact. The sandstone cores have porosity ranging from 6.8 % to 18.9 %, with an average of 15 %, and permeability ranging from 0.755 mD to 1.029 mD. From petrography analysis, it was found that the core sample contains quartz (monocrystalline and polycrystalline), feldspar (k-feldspar and plagioclase), chert, volcanic, schistose, mica. kaolinite authigenic, as shown in Table 3. Particles size ranging from 50 to 700 micron meter and very well sorted. Since those minerals are very reactive and have very high reaction rate with acid, therefore the core sample will be sensitive to hydrochloric and hydrofluoric acids, or the mud acid.

The hydrofluoric acid will react with sand and clay in the formation to produced fluosilicic and fluoaluminic acid which will, in turn, react with sodium or potassium ions in the formation water to produce gelatinous precipitates in the pore, as shown in eq. 3-8. This gelatinous precipitate will plugged the pore and reduced the formation productivity that can be avoided by using HCl together with the HF. The HCl acid will react with gelatinous precipitate and maintenance the pH low to prevent precipitation resulting from the reaction of HF acid with formation rock.

$$\underset{\text{(Sand)}}{SiO_2} + 6HF \text{ --------- } \underset{\text{(Fluosilicic acid)}}{H_2SiF_6} + 2H_2O \quad (3)$$

$$\underset{\text{(Clay)}}{Al_2Si_4O_{10}(OH)_2} + 36HF \text{ ----- } \underset{\text{(Fluosilicic acid)}}{4H_2SiF_6} + 12H_2O + \underset{\text{(Fluoaluminic acid)}}{2H_3AlF_6} \quad (4)$$

$$H_2SiF_6 + 2Na^+ \text{ ------ } Na_2SiF_6 \downarrow + 2H^+ \quad (5)$$

$$H_3AlF_6 + 3Na^+ \text{ ------ } Na_3AlF_6 \downarrow + 3H^+ \quad (6)$$

$$H_2SiF_6 + 2K^+ \text{ ------ } K_2SiF_6 \downarrow + 2H^+ \quad (7)$$

$$H_3AlF_6 + 3K^+ \text{ ------ } K_3AlF_6 \downarrow + 3H^+ \quad (8)$$

Sandstone Formation Solubility

The result for the solubility of sandstone formation in the various mud acid systems is shown in Table 4. It can be seen from Table 4 and Fig. 4, that all tested mud acid systems (HCl and HF) are suitable to be used in acidizing process of the sandstone sample, since the solubility values are less than 20 %. If the solubility is higher than 20 %, the acid will damaged the core sample and not suitable for acidizing process.

Acidizing Performance

The results of acidizing flow test for various mud acid systems is shown in Table 5. It can be seen from Table 5 and Fig. 5 that acid reaction coefficient (ARC) for all tested mud acid system are higher than 1.0. Therefore all tested mud acid systems are capable to completely react with carbonate and sandstone minerals in the formation core sample. However, the mud acid system that consists of 6 % HCl and 1 % HF gives the highest ARC value, that is 1.593. Therefore the combination of 6 % HCl with 1 % HF is the best mud acid combination for the tested formation.

The above result was then confirmed by the effect of injected mud acid volume to the ARC value results, as shown in Fig.6. From this figure, it can be seen that the 6 % HCl and 1 % HF acid system gives ARC values above 1.0, even though the acid volume used per cm. sq. is relatively low than others. This further suggests that the 6 % HCl and 1 % HF combination is the optimum mud acid system for the tested formation.

Table 5 also shows that all tested mud acid systems give better permeability after acidizing process, ranging from 0.804 mD to 1.142 mD. But, mud acid system consist of 6 % HCl and 1 % HF gives better permeability improvement, from 0.882 mD to 1.142 mD. Even though the permability improvement is relatively small, but for the gas reservoir, small permeability improvement will significantly increase the reservoir productivity.

CONCLUSION

The study has shown that mud acid that comprises of 6 % HCl and 1 % HF is the optimum acid system for the gas field "A", Trengganu Offshore. By using this acid system, permeability of damaged sandstone formation can be improved by 29.48 %.

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Table 1
Water Base Mud Rheology

Mud Rheology	
Density, ppg	10.0
Reading at 600 RPM	65.0
Reading at 300 RPM	52.0
App. Viscosity, cp	33.0
Plastic Viscosity, cp	16.0
Yield Point, lb/100 ft	15.5
Gel Strength at 10 sec.	8.0
Gel Strength at 10 minutes	12.0
pH	8.5
Cake Thickness, mm	2.9

Table 2
Mud Acid Formulation (For 100 ml mud acid)

HCl %	HF %	Distilled water ml	Ammonium Bioflouride (NH_4HF_2) gram	Hydrochloric Acid (HCl-37%) ml
10.0	1.0	68.2	1.6	31.8
10.0	2.0	68.2	3.2	31.8
12.0	3.0	61.9	4.8	38.1
6.0	1.0	81.0	1.6	19.0
8.0	1.0	74.6	1.6	25.4
4.0	0.5	87.3	0.8	12.7
6.0	0.5	81.0	0.8	19.0
8.0	0.5	74.6	0.8	25.4
6.0	1.5	81.0	2.4	19.0

Table 3
Petrography Test Results

Mineralogy	Composition, %	Texture	Range
Monocrystalline quartz	43.7 - 51.7	Particle size, μm	50 - 700
Polycrystalline quartz	7.7 - 13.7	Order	Medium - Good
Feldspar	1.0 - 1.4	Roundness	Subangular - subrounded
Chert	6.0 - 9.5	Permeability	0.755 – 1.029 mD
Clay clasts, volcanic & schistose	3.4 - 9.5	Porosity	6.8 – 18.9 %
Muscovite	[illegible]		
Zircon, tourmaline	0.5		
Quartz overgrowth	4.4 - 7.5		
Matrix	8.0 - [illegible]		

Table 4
Solubility Test Results

HCl (%)	HF (%)	Initial Weight (gram)	Final Weight (gram)	Solubility (%)
4.0	0.5	1	0.91	9
6.0	0.5	1	0.90	10
8.0	0.5	1	0.88	12
6.0	1.5	1	0.90	10
10.0	2.0	1	0.86	14
8.0	1.0	1	0.88	12
10.0	1.0	1	0.87	13
6.0	1.0	1	0.89	11

Table 5
Acidizing Flow Test Results

HCl Acid %	HF Acid %	Porosity %	Initial Permeability (Ki) mD	Damaged Permeability (Kd) mD	Final Permeability (Kf) mD	ARC
6.0	0.5	12.6	0.899	0.731	0.987	1.350
10.0	2.0	12.7	0.755	0.635	0.804	1.266
10.0	1.0	16.8	0.924	0.807	1.004	1.244
8.0	0.5	13.4	1.029	0.852	1.112	1.305
4.0	0.5	15.5	0.874	0.731	0.931	1.274
6.0	1.5	16.1	0.851	0.704	0.912	1.296
8.0	1.0	18.9	0.923	0.773	1.075	1.391
6.0	1.0	17.0	0.882	0.717	1.142	1.593

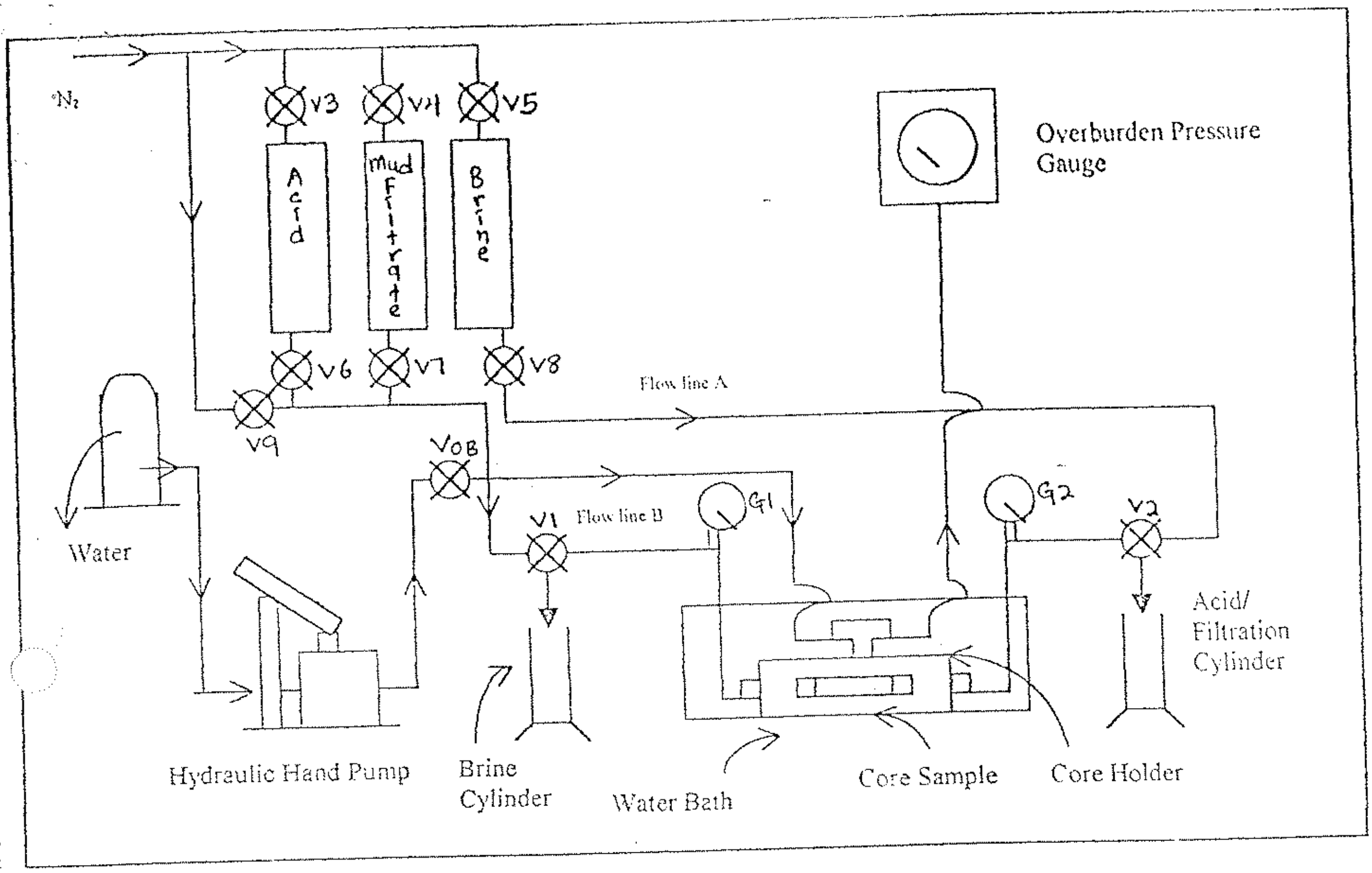

Figure 1 : Acidizing process schematic diagram.

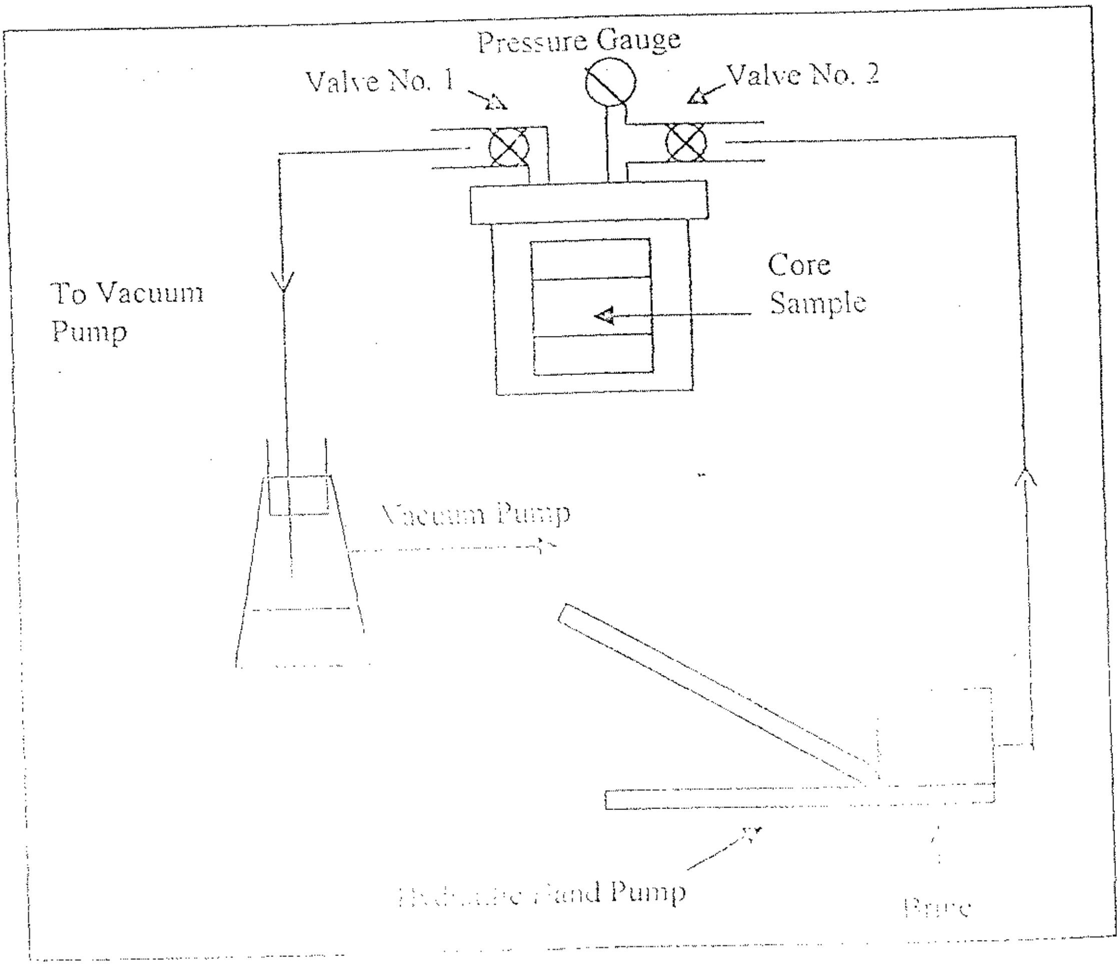

Figure 2 : Schematic diagram of core sample saturation process.

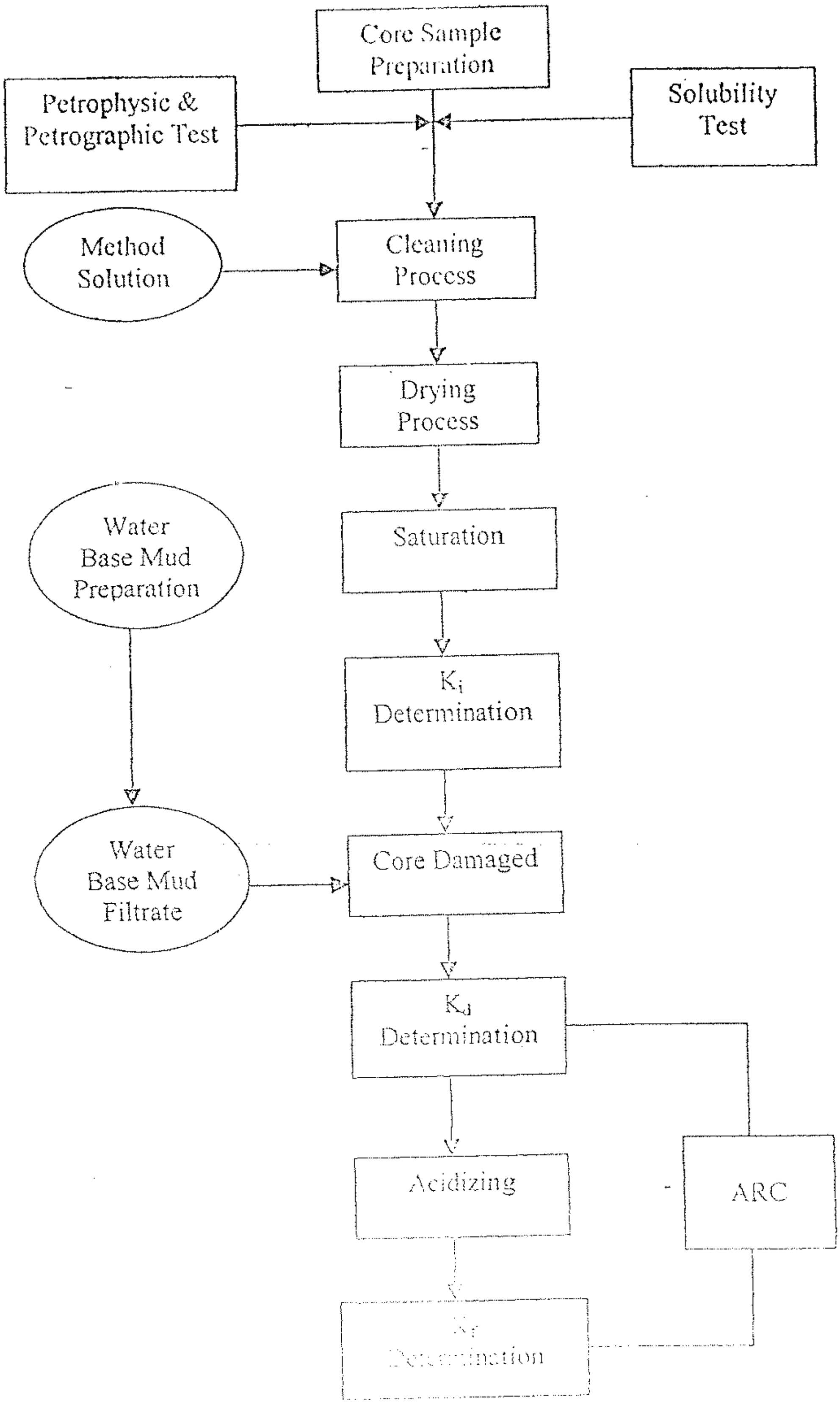

Fig. 3 : Experimental Flow Chart

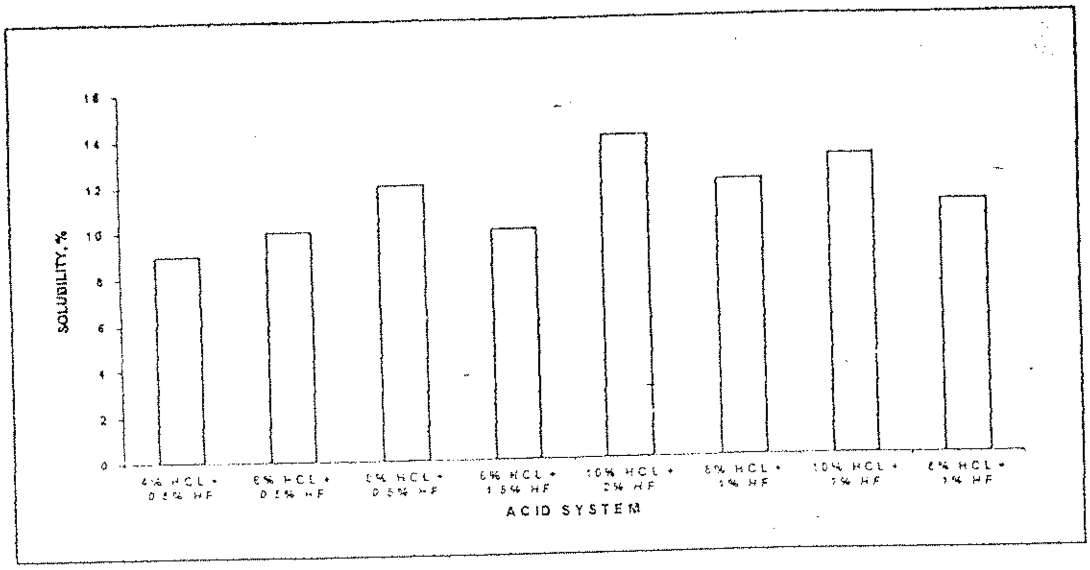

Figure 4 : Solubility test for various mud acid system.

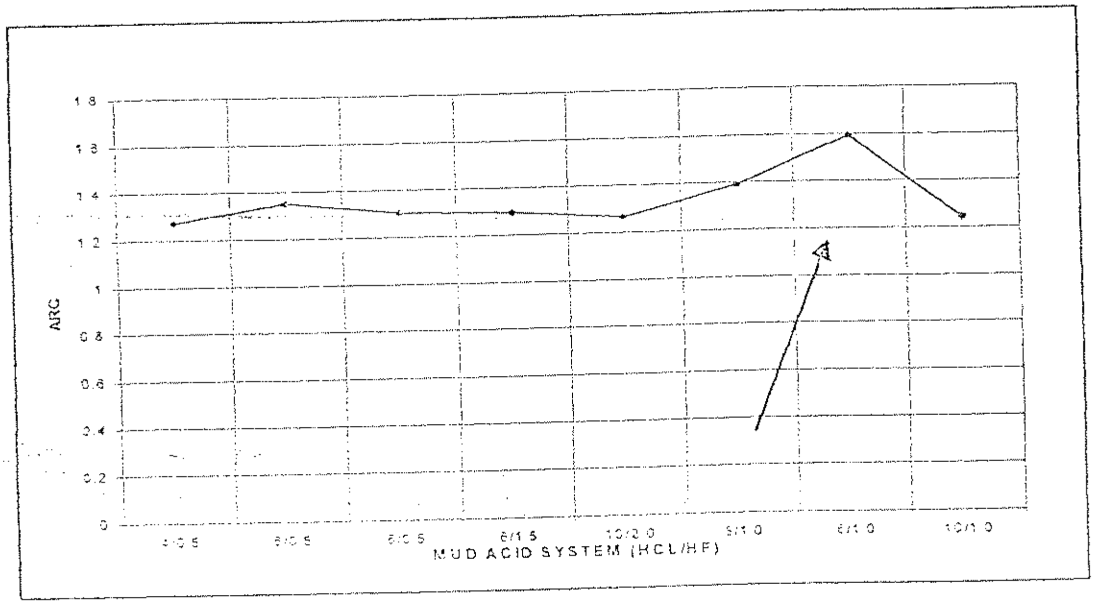

Figure 5 : ARC change for various mud acid system.

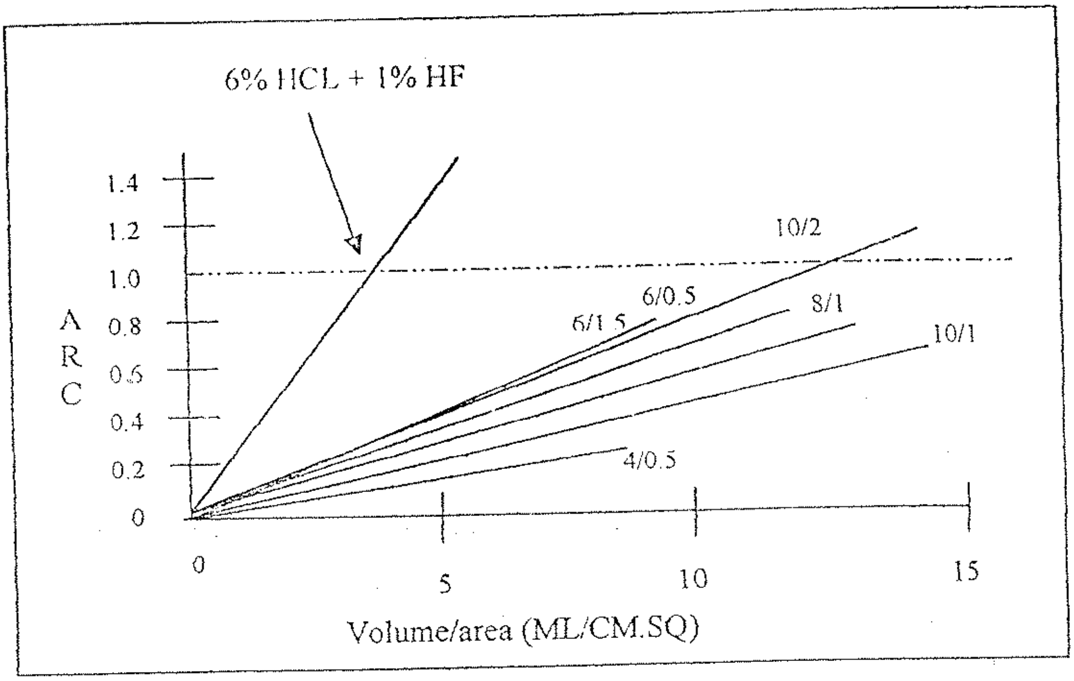

Figure 6 : ARC for various volume/area ratio.

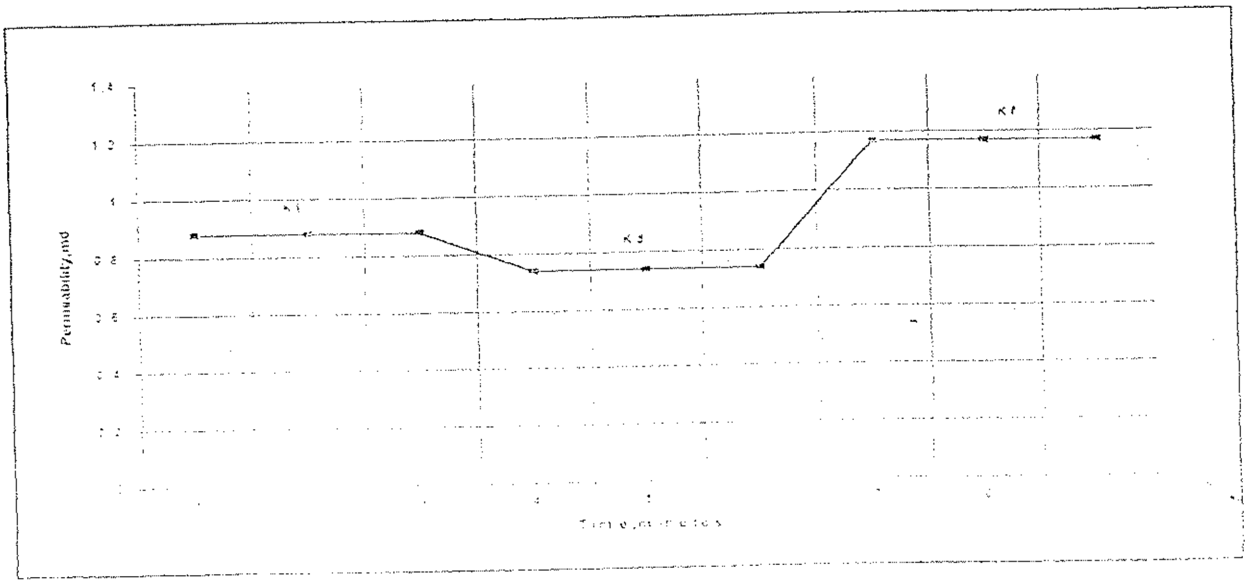

Figure 7 : Permeability change with time (6% HCL + 1.0% HF).