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MATRIX ACIDIZING WITH GELLED ACID

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Abstract. A laboratory investigation was conducted to compare the efficiency of gelled acid with conventional/plain mud acid in removing the formation damage induced by water-based mud. An acidizing system was developed to study the effect of flow/injection rate and gel viscosity on Berea sandstone. The main equi pments used in this research study were stainless steel core holder, mud cells, valves, and 3 mm tubing. The treatment fluids used were mud acid (3% HF–12% HCl), hydrochloric acid, and polymer gel (xanthan gum). The experimental results revealed that polymer gel with viscosity lower than 73 cP gave better performance as compared to polymer gel with viscosity greater than 73 cP. At gel viscosity of 73 cP, the permeability ratio was 3.5 compared to 1.5 only at viscosity of 126 cP. This was due to the permanent plugging by the high viscosity polymer gel in the core after the injection. Gelled acid has shown tremendous improvement in removing formation damage, where polymer gel with viscosity of 73 cP was found to give better treatment at flow rate of 0.28 ml/s as compared to lower flow rates.

Key words: Diversion technique, gelled acid, acidizing, polymer gel

Abstrak. Suatu uji kaji makmal telah dilakukan untuk membandingkan kecekapan asid gel dan asid lumpur konvensional dalam merawat kerosakan formasi yang disebabkan oleh lumpur dasar air. Suatu sistem pengasidan telah dibina untuk mengkaji kesan kadar alir dan kelikatan asid gel terhadap batu pasir Berea. Peralatan utama yang membentuk sistem pengasidan ialah pemegang teras, sel lumpur, injap, dan tiub 3 mm. Semua komponen ini diperbuat daripada keluli kalis karat. Bendalir perawat yang digunakan dalam uji kaji terdiri daripada asid lumpur (3% HF–12% HCl), asid hidroklorik, dan gel polimer (gam xanthan). Keputusan uji kaji menunjukkan bahawa polimer dengan kelikatan kurang daripada 73 cP memberikan kecekapan yang lebih baik berbanding kelikatan yang melebihi 73 cP. Ini terbukti apabila nisbah kebolehtelapan mencapai 3.5 pada kelikatan gel 73 cP berbanding 1.5 sahaja pada kelikatan 126 cP. Perbezaan nisbah kebolehtelapan yang ketara berlaku kerana polimer yang terlalu likat cenderung untuk memalam liang secara kekal. Asid gel berjaya merawat kerosakan formasi dengan lebih berkesan berbanding asid lumpur, terutama apabila gel polimer berkelikatan 73 cP dialirkan pada kadar alir 0.28 ml/saat, berbanding kadar alir yang lebih rendah.

Kata kunci: Teknik lencongan, asid gel, pengasidan, gel polimer

1.0 INTRODUCTION

Matrix acidizing has proven to be a cost-effective procedure for removing the causes of well impairment, thereby increasing the production potential of many new and

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existing wells. The efficient placement of acid in the impaired zones is critical because inefficient placement of acid tends to preferentially treat the high-injectivity zones, resulting in a poor response to the treatment [1].

The available choice of selective placement techniques are coiled tubing and diversion technique such as ball sealers, particulates, and viscosified fluids (gels or foams). The application of these techniques is depend on the types of completion and formation properties. Coiled tubing is used to spot treatment fluids in the required zone. By moving the coiled tubing during the treatment, it can be used to further improve coverage over the treatment interval. Alternatively, acidified fluids or inert fluids can be simultaneously bullheaded along the coiled tubing and coiled tubing /tubing annulus [2]. Coiled tubing can also be used in conjunction with most other diversion techniques. Both heavy and buoyant ball sealers have been widely used to shut off perforations. Conventional low-rate matrix treatments require buoyant ball sealers, that only work well in vertical wells and require ball catchers when back-producing the wel1. To overcome the limitations, high-rate matrix injection treatments have been promoted [3,4]. The theoretical background behind the encouraging results quoted for this method is unclear. Conventional theories of sandstone acidizing predict no improvement in required volumes for such high-rate treatments [5], although these theories neglect any physical effects, such as increased abrasion caused by the increased shear-rate in the formation or at the wellbore wall.

The use of chemical diversion systems has received serious attention. Initially, the industry concentrated on particulate systems, which have been widely used in the vertical perforated wells [2,6]. The success of particulate treatments, however, requires a detailed knowledge of the downhole configuration and the particle size distribution; the latter is not always simple [7]. Particulate (oil-soluble resin and benzoic acid) often exhibits less than ideal clean-up behavior, particularly in the presence of polymers that inhibit the dissolution of the particulate in oil or water. For those reasons, the industry has looked to foam technology and new polymers as a means for gelled acid.

Gelled acid is probably applicable to all completion types and it is particularly beneficial in horizontal, openhole, and gravel-packed wells, where many other diversion and selective placement techniques cannot be applied. The viscous fluid can be placed efficiently along the treatment interval because it can first limit fluid loss into the formation and then divert mud acid to the damaged zones. Gelled acid with a viscosity of about 70 cP at 100 sec^{-1} has been compared to conventional low-viscosity acids. The results showed that when there is a high permeable zone at the heel of the well, the use of gelled acids can significantly improve placement [3].

In this research study, an acidizing rig was developed in order to compare the efficiency of gelled acid with conventional mud acid. The same rig was also used to study the effects of gel viscosity and flow/injection rate of the gelled acid on permeability ratio of the Berea sandstone core samples.

2.0 EXPERIMENTAL

This section was discussed under two subtopics, namely materials and systems.

2.1 Materials

Hydrochloric acid and hydrofluoric acid were used in this research study to recover the damaged permeability. The mutual solvent, Ethylene Glycol MonoButyl Ether (EGMBE) was supplied by Halliburton Energy Services. The gelling agent, xanthan gum, and mud additives were supplied by Kota Mineral and Chemicals Sdn. Bhd. Solvent, gelling agent, and nonsolvent used were of reagent grade and used as received. The water-based mud used in this study was prepared as recommended by the API RP 13I [8].

The Berea sandstone cores with dimensions of 5.08 cm in diameter and 5.08 cm in length, were used to evaluate the damage induced by the water-based mud and improvement in permeability ratio after the matrix acidizing process.

2.2 Systems

This research study comprised two processes:

(1) induce damage to the core samples using water-based mud, and

(2) treatment of the damaged core samples using gelled acid.

2.2.1 *Process of Damaging the Core Samples*

Figure 1 shows the schematic diagram of the formation damage system. The system comprised a nitrogen gas line to displace the respective fluids, mud cell, valves, 3 mm stainless-steel tubing, core holder, and pressure gauges for measuring the pressure of various streams.

The flow system was operated in a counter-current flow mode. The injected fluid was introduced on shell side and the permeating stream (or filtrate) was collected at the bore side of the core holder. The ammonium chloride (NH_4Cl) was injected into the core and it was considered as production mode. The filtrate of NH_4Cl was collected using measuring cylinder 1, and was recorded against time. It was then used to calculate the initial permeability (ki) of the core sample using the Darcy equation [1].

$$Q = -\frac{kA}{m}\frac{dP}{dl} \tag{1}$$

When in production mode, valves C to F were opened and valves A and B were closed. C and D were 3-way valves and could be used to switch the flow direction to the production mode. 15 PV of water-based mud was injected into the core samples from opposite direction by switching the valves C and D to injection mode, with

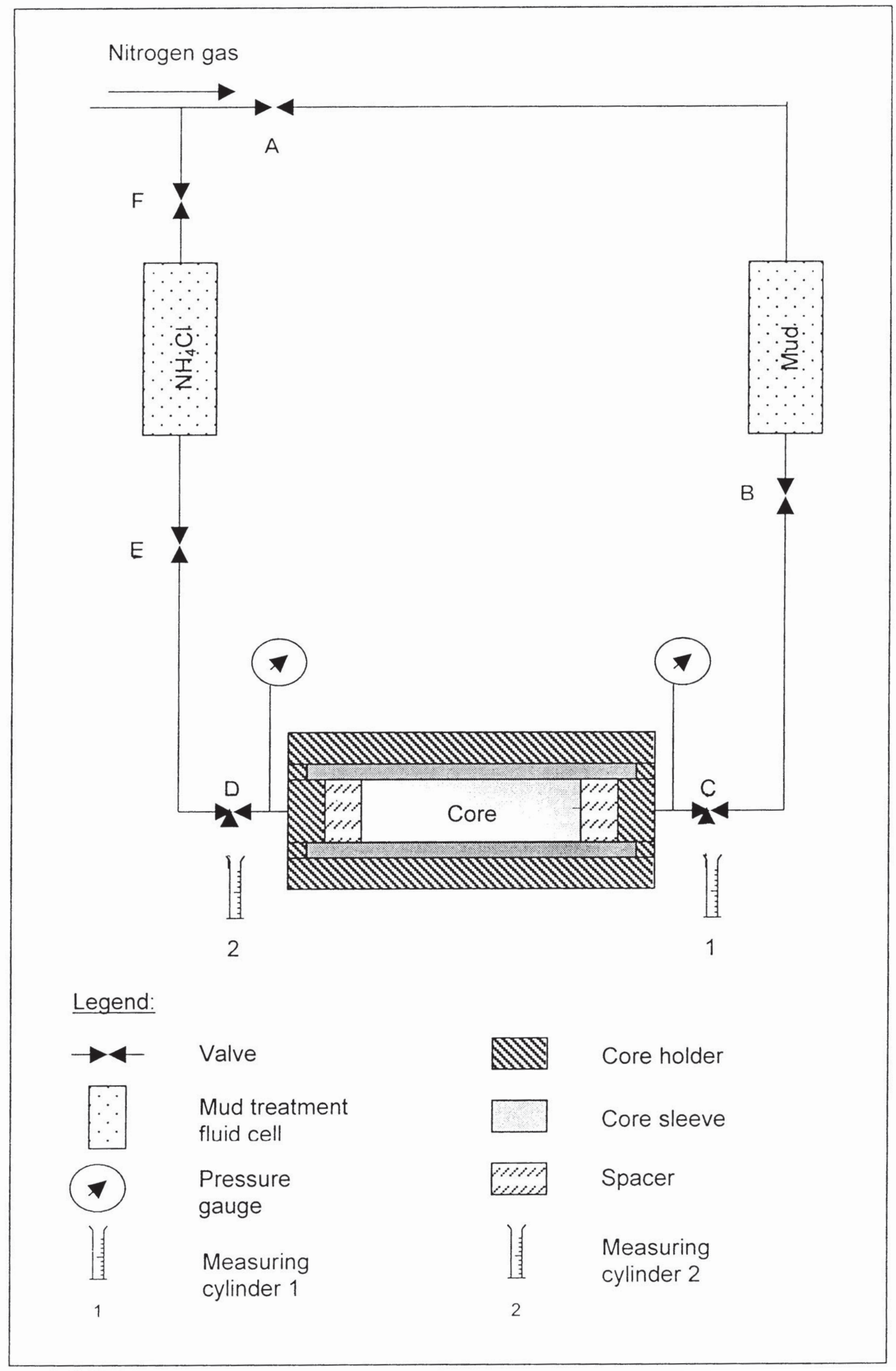

Figure 1 Schematic diagram of the formation damage system

valves *A* and *B* opened, while valves *E* and *F* closed. The mud filtrate was collected using the measuring cylinder 2 in order to measure the volume of injected mud.

In order to calculate the damaged permeability, the NH_4Cl was injected into the core sample until the flow rate stabilized. The filtrate of NH_4Cl was collected using the measuring cylinder 1 and was recorded against time. The damaged permeability (kd) was calculated using Equation (1).

2.3 Process of Acidizing

Figure 2 shows the schematic diagram of the acidizing system. The system comprised a nitrogen gas line to displace the respective fluids, mud cell, valves, 3 mm stainless-steel tubing, core holder, and pressure gauges for measuring the pressure of various streams.

The flow system was a counter-current flow mode. The injected fluid was introduced on the shell side and the permeating stream was collected at the bore side of the core holder. The flow direction of NH_4Cl was considered as production mode and the direction of treatment fluids such as hydrochloric acid, mud acid, and xanthan gum were considered as injection mode. When in production mode, valves *L* to *O* were opened, while valves *A* to *K* were closed. *N* and *O* were 3-way valves and they could be used to switch the flow directions. The valves *N* and *O* were switched to production direction when in production mode. When the process was in injection mode, valves *A* to *K* and valves *N* and *O* were opened, and the valves *L* and *M* were closed. At this moment, the valves *N* and *O* were switched to injection direction.

The gelled acidizing process was initiated by injecting the treatment fluids such as hydrochloric acid, mud acid, and xanthan gum into the core samples separately in the injection mode. The preflush fluid, hydrochloric acid, was injected into the core to displace NH_4Cl and also to remove traces of carbonate materials from the Berea sandstone. Then, polymer gel followed by mud acid were injected into the core to remove the damage. The hydrochloric acid was injected into the core again to displace some of the unused acid. The filtrate of every stream was collected using the measuring cylinder 2 to measure the volume of every fluid injected. In order to calculate the permeability after acidizing, the NH_4Cl was injected into the core again in production mode. The filtrate was collected using the measuring cylinder 1 and was recorded against time. This process continued until a constant flow rate was achieved. The recovered permeability (kr) was then calculated using Equation (1).

The conventional acidizing process was conducted the same way as the gelled acidizing process except there was no xanthan gum injected into the core samples.

3.0 RESULTS AND DISCUSSION

The experimental results were discussed under three subtopics, namely the effect of concentration of xanthan gum on viscosity of polymer gel, comparison between acid

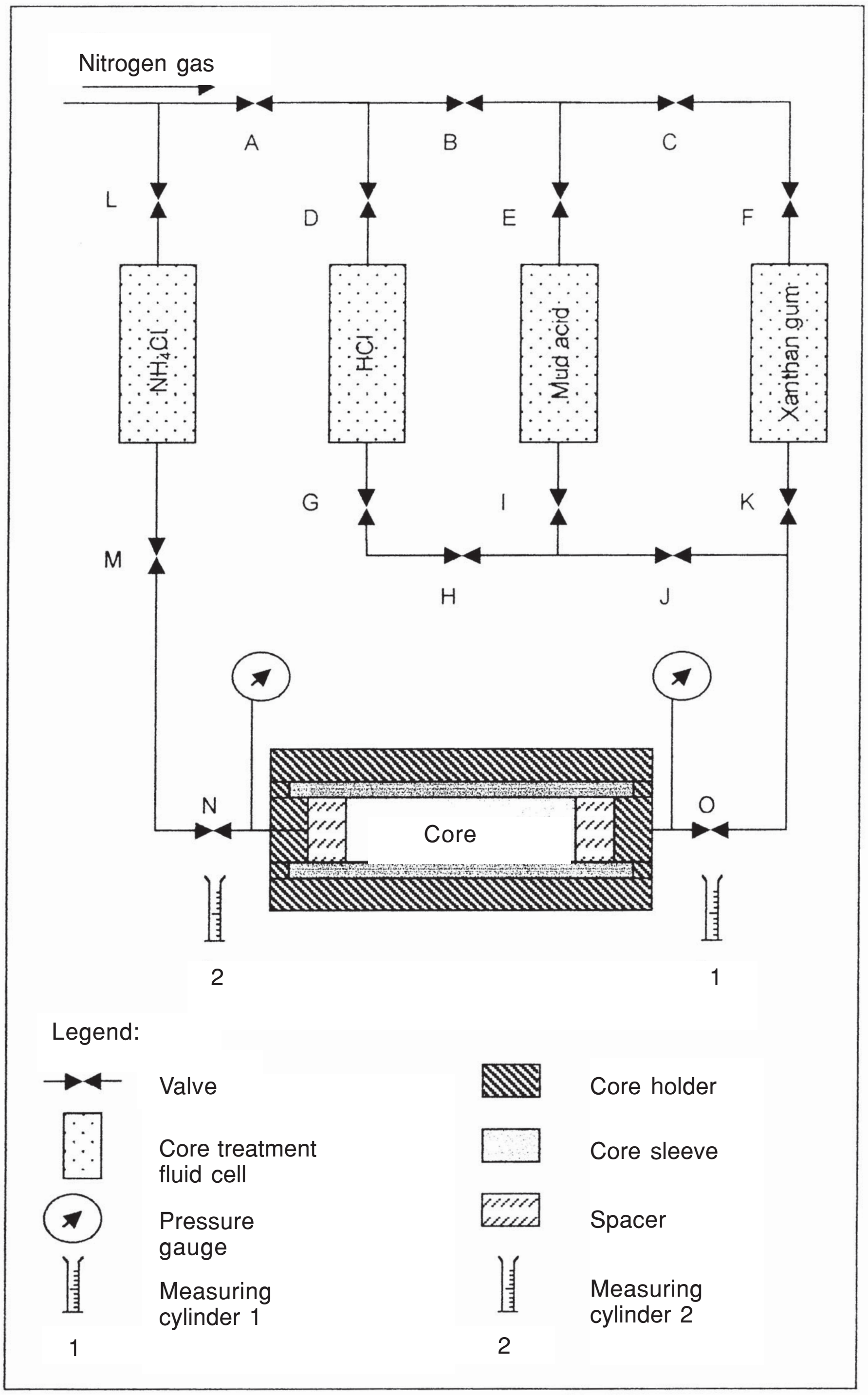

Figure 2 Schematic diagram of the acidizing system

systems, and the effect of flowrates on permeability ratio. All experimental data used to generate the results were collected at room temperature of 27°C.

3.1 Effect of Concentration of Xanthan Gum on Viscosity of Polymer Gel

Jones *et al*. had compared the polymer gel with viscosity of about 70 cP at shear rate of 100 sec^{-1} with the conventional mud acid, and they found that gelled acid improved the placement of the mud acid [9]. Thus, it was vital to determine the optimum concentration of the xanthan gum to be used in the research study before experimental works were carried out on the effects of flow rate and viscosity of the gel on the permeability ratio.

The experimental results for the effect of concentration of the xanthan gum on the viscosity of polymer gel was shown in Figure 3. The figure clearly shows that the viscosity of the polymer gel increased with the concentration of xanthan gum. The viscosity increased from 41 cP at 8000 ppm to 126 cP at 12 000 ppm. Generally, this relationship can be understood as the concentration of the xanthan gum increases, the percentage of the solid content in the gel increases as well [10]. Thus, the gel becomes more viscous and requires higher force to flow.

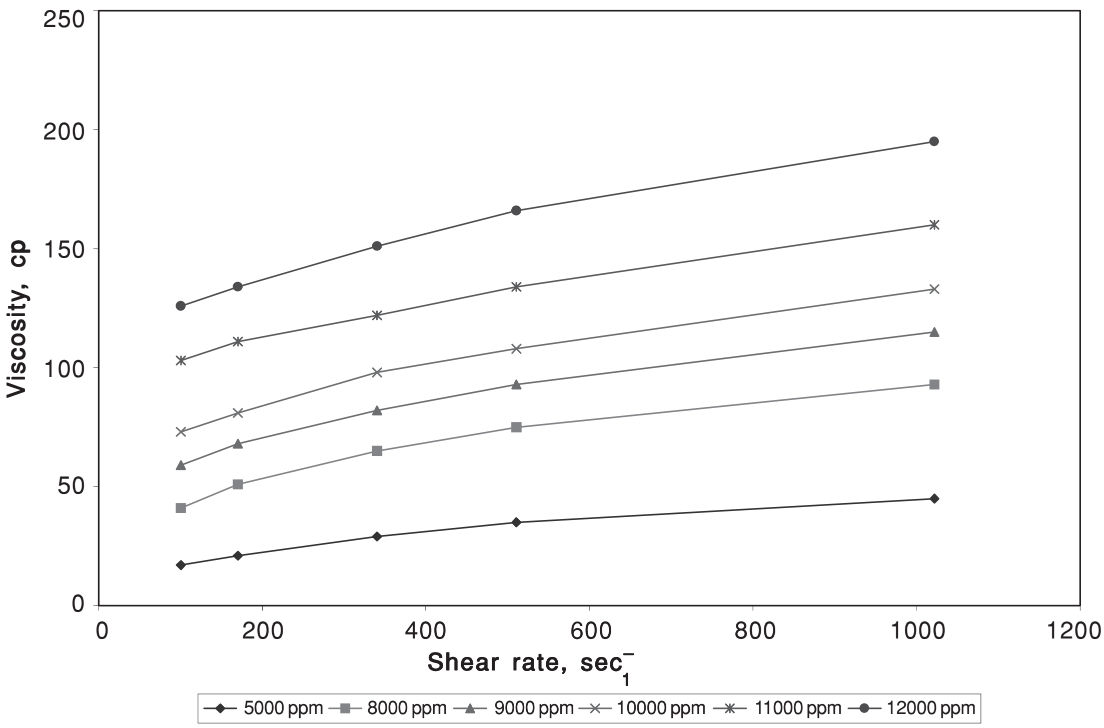

Figure 3 The effect of xanthan gum concentration on gel viscosity at various shear rates

Figure 3 shows that at 10 000 ppm, the viscosity of polymer gel was 73 cP at shear rate of 100 sec^{-1}. This result satisfied the value recommended by Jones *et al.* where the viscosity of the polymer gel should be about 70 cP at shear rate of 100 sec^{-1}. Therefore, polymer gel with 10 000 ppm of xanthan gum was used in order to study the effect of flow rate on the permeability ratio.

3.2 Comparison between Acid Systems

As highlighted earlier, the experimental works conducted were focused on the performance of the gelled acid as compared to conventional mud acid in removing formation damage induced by water-based mud. However, it would be a great disadvantage if the EGMBE was not taken into consideration, as it is widely used in the field to remove hydrocarbon from the surface of the formation [11]. Thus, EGMBE was added into the conventional/plain mud acid and gelled acid in order to evaluate its effectiveness when coupled with the respective acids in removing damage from the Berea sandstone.

With EGMBE, four types of acid systems were studied in order to evaluate their efficiencies in removing the damage caused by water-based mud. Those acid systems were:

- Conventional mud acid (3% HF – 12% HCl).
- Mud acid with 10% (v/v) of EGMBE.
- Gelled acid.
- Gelled acid with 10% (v/v) of EGMBE.

The experimental results were shown in Figure 4. When comparing the conventional mud acid and gelled acid, the gelled acid system was found to give higher permeability ratio than the conventional mud acid. The permeability ratios for the conventional mud acid and gelled acid were 1.81 and 2.94, respectively. In other words, the conventional mud acid was capable of recovering 181% of the damaged permeability but the gelled acid could recover up to 294% of the damaged permeability. This means that the gelled acid could improve the efficiency of matrix acidizing.

Generally, the injected polymer gel can partially block the highly permeable area and divert the subsequent injected mud acid to the damaged area. If only mud acid is injected, the mud acid tends to flow to area with high permeability and leaves the damaged area untreated.

The mutual solvent, EGMBE, was added in the preflush fluid. The mutual solvent is used to strip away hydrocarbon from the surface of the formation. The study conducted on the gelled acid and gelled acid with EGMBE revealed that the permeability ratios for both systems were 2.94 and 3.02, respectively. It showed that the EGMBE gave no relative effect on the gelled acid system. This was due to the fact that EGMBE was designed to change oil-wet system to water-wet system and thus, it

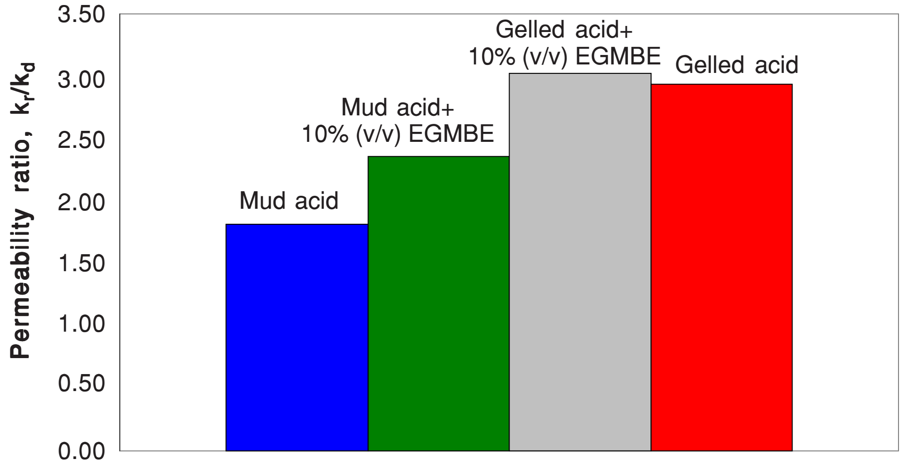

Figure 4 Permeability ratio for different acid systems

was redundant in this case as water-based mud was used in this study. Therefore, the recommended acid system to be used in this study was gelled acid system without EGMBE.

3.3 The Effect of Flow/Injection Rates on Permeability Ratio

In matrix acidizing, the placement of the acid is very important in order to minimize the volume of acid used in the operation. In other words, it can save the operating costs. The placement efficiency can be increased by decreasing the gelled acid degradation rate such as by pre-cooling the well or by tailoring the type and concentration of both polymer and acid. Alternatively, the treatment duration could be reduced by increasing the pump rate, thereby reducing the time during which gelled acid stability was required [9].

In this study, the polymer gel with viscosity of 73 cP was used. Figure 5 shows the experimental results where the permeability ratio increased significantly with flow/ injection rates from 1.5 at 0.16 ml/s to 3.5 at 0.28 ml/s. Generally, at low injection rate, the polymer tends to stay longer in the cores. Xanthan gum was the polymer gel used in this case, and it is a biopolymer that degrades with time.

At low rate of 0.16 ml/s, the polymer would stay longer in the core before the injection of mud acid. During this period, the polymer gel would degrade in the core and became less viscous. When the mud acid was injected into the core, the less viscous polymer gel would be displaced by the mud acid and was unable to divert the mud acid to the damaged area. For flow rate of 0.28 ml/s or higher, the permeability ratios were relatively unchanged. At this moment, the optimum flow rate was found to be 0.28 ml/s. This can be understood that the polymer degradation could be reduced due to the shorter period of placement. In practice, the determination of the optimum flow rate depends on the tubing size, depth, and length of the treatment interval [9].

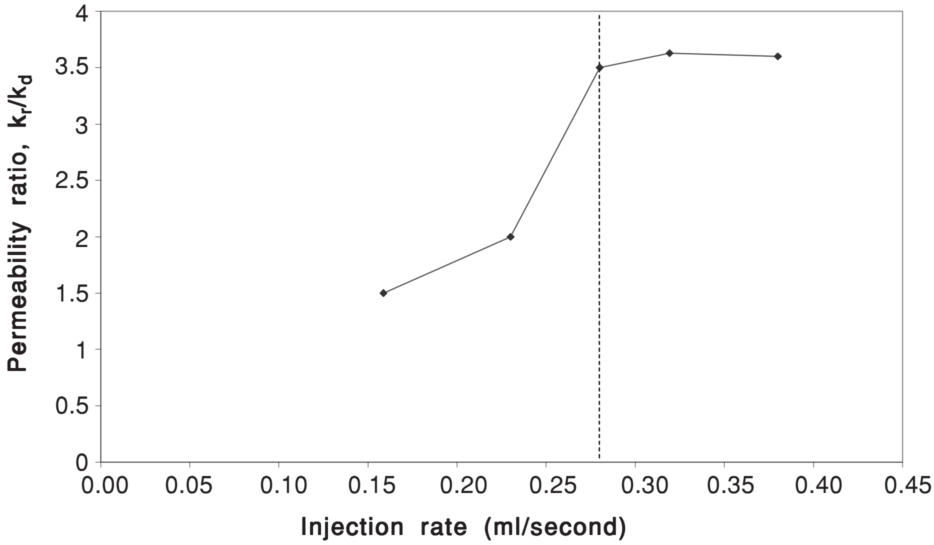

Figure 5 Effect of injection rate on the permeability ratio

3.4 The Effects of Viscosity on Permeability Ratio

The effect of viscosity on permeability ratio was studied in this experiment. The results are shown in Figure 6, where the permeability ratio increased significantly from 1.5 to 3.5 as the viscosity of the polymer gel increased sharply from 41 cP to 73 cP. The polymer gel used in this experiment was of optimum viscosity that capable of diverting the mud acid to the damaged area. Beyond the optimum viscosity of 73 cP, such as at

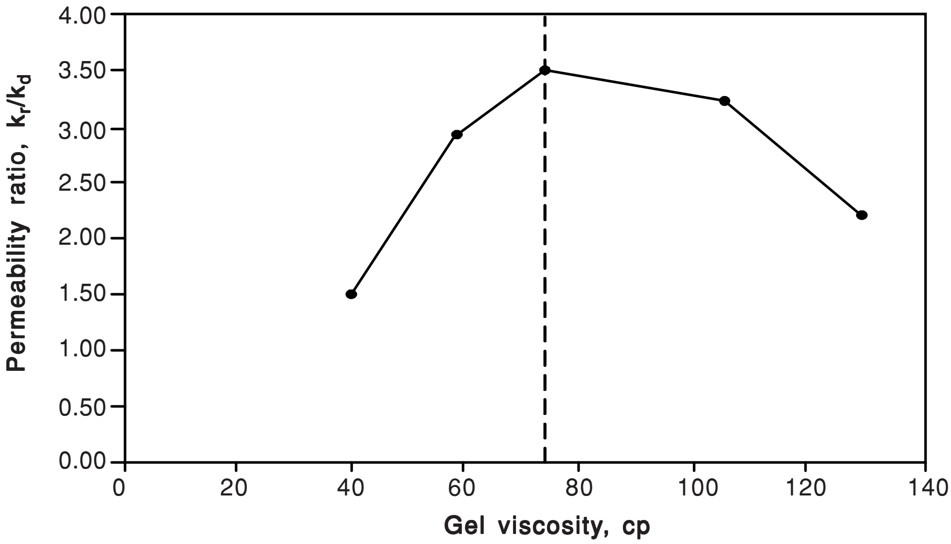

Figure 6 Effect of gel viscosity on the permeability ratio

103 cP and 126 cP, the permeability ratio dropped to 3.2 and 2.2, respectively. The results revealed that at viscosity higher than 73 cP, the polymer gel would permanently plug the formation and caused secondary formation damage. The subsequent injected mud acid would not be able to treat this formation damage caused by polymer plugging. Although the injected mud acid could treat the formation damage induced by the drilling fluid but the polymer plugging was still left behind. Therefore, gelled acid system with viscosity higher than 73 cP should be avoided as it could cause secondary formation damage by plugging the formation.

4.0 CONCLUSIONS

The following conclusions were derived from this research study:

(1) Gelled acid system was found to be effective for matrix acidization of heterogeneous formation as compared to the conventional mud acid. The optimum viscosity of the system could improve wellbore coverage and divert fluid to the low permeability and/or damaged sections of the well. In this study, the optimum viscosity was found to be 73 cP at shear rate of 100 sec^{-1}.

(2) The mutual solvent, EGMBE, was found to give no relative effect on the gelled acid system due to the absence of hydrocarbon in the Berea sandstone.

(3) It is recommended that the gel viscosity should be lower than 73 cP to avoid secondary formation damage and the effect of flow rate should be studied prior to conducting a field operation.

(4) The gelled acid system with viscosity of 73 cP was found to be capable of achieving maximum permeability ratio of 3.5, at an optimum flow rate of 0.28 ml/s.

NOMENCLATURE

EGMBE	– Ethylene Glycol MonoButyl Ether
NH_4Cl	– Ammonium chloride
PPM	– Parts per million
PV	– Pore volume
A	– Cross-sectional area of the core sample, cm^2
dP/dL	– Pressure gradient along the core sample, atm/cm
k	– Permeability, Darcy
k_i	– Initial permeability, Darcy
k_d	– Damaged permeability, Darcy
k_r	– Recovered permeability, Darcy
k_r/k_d	– Permeability ratio, dimensionless
μ	– Fluid viscosity, cP
Q	– Volume of flow, cm^3/s

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CONVERSION FACTOR

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(^{o}C $\times$ 1.8) + 32		= ^{o}F
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