

## **An Experimental Study of Acid Diversion by Using Gelled Acid Systems Based on Viscoelastic Surfactants: A Case Study on One of Iran Southwest Oilfields**

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### **Abstract**

In matrix acidizing operations, the main goal is increasing permeability. For production engineers, it is desirable that acid could be injected into whole pay zone. Sometimes, this pay zone has a long height and various sub-layers which have different permeability values. To prevent acid from going completely into the most permeable sub-layer, one of the useful techniques is using diverters, and one of the major groups of diverters is gel diverters. Diverter viscosity changes by temperature and pH, and an increase in viscosity leads to a decrease in its permeability; thus, acid can permeate further through less permeable sub-layers. In this study, two kinds of different viscoelastic surfactants (VES) provided by two different companies were used to produce gel to divert acid into a core plug sample having lower permeability in a dual parallel acid injection set-up. The core plug samples were taken from the pay zone of Ahwaz oilfield, one of Iran southwest oilfields. Before performing the injection test, some viscosity measurement tests were carried out. Unfortunately, one of these two VES's did not have an acceptable quality and failed to pass the injection tests. However, the other one passed all the tests successfully and diverted the injection fluid. The water permeability values of the low-perm and high-perm core plug samples were 0.91 md and 6.4 md respectively, whereas, after injection, they rose to 1.5 and 18.5 md respectively.

**Keywords:** Carbonate Acidizing, Multi-layered Reservoirs, Diverters, Gels, Viscoelastic Surfactants

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### **1. Introduction**

The primary purpose of any acidizing treatment is to dissolve either the formation rock or the natural or induced materials within the pore spaces of the rock. There are three fundamental techniques used in acidizing treatments: wellbore clean-up, matrix acidizing, and acid fracturing. The technique selected depends on what the operation wishes to accomplish by using the treatment (Bradley, 1987). The common acids used to stimulate carbonate formations are hydrochloric (HCl), acetic (CH<sub>3</sub>COOH), and formic (HCOOH) (Kalfayan, 2008). Many factors such as pressure,

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temperature, flow velocity, and acid concentration govern the reaction rate of an acid (Mumallah, 1991). Many auxiliary chemicals have been developed to modify acid solution since the use of a corrosion inhibitor as an additive made the first commercially feasible acidizing treatments possible. Some other major additives are corrosion inhibitors, surfactants, silicate controlling agents, iron controlling agents, gelling agents, and fluid loss controlling agents (McLeod, 1984). While the use of temporary blocking agents as diverting agents in fracturing and acidizing operations was rather prevalent among well stimulation design engineers in 1958, White published an article in which he had classified those agents and had explained their chemical and physical properties. Based on the mechanism of blocking and diverting, he classified them into two major groups:

- 1- Materials which block the pores by bridging at or near the well bore and affect an impermeable seal such as naphthalene, walnut-shell resin mixture, ammonium-chloride pellets and fines in thickened kerosene, and rock salts.
- 2- Materials which are pumped relatively far back into formation as a fluid and develop a gel structure to block the permeability such as heavy-metal soap-kerosene gel.

White had also explained in detail the chemical and physical considerations for using each agent and investigated the effect of several factors on the performance of the agents and the factors affecting the choice of a blocking agent such as type of formation, type of completion, pressure, and temperature (White, 1958). In 1969, Smith et al. not only explained the previous methods of diverting, but also introduced a novel technique which used foams (Smith, et al., 1969). This novel technique was followed by other researchers and led to other kinds of foam such as CO<sub>2</sub> foam and researches on its properties until now (Farajzadeh et al., 2009); however, because of some limitations of this technique such as pressure, temperature, and permeability contrast, several researches have been conducted on other techniques of diversion, particularly on gel diverters.

Several researches have been conducted on the properties of polymers used for gelling acids. The first comprehensive detailed report was carried out by Norman et al. in 1984. They studied commercially available polymers to find out which one was stable at high temperatures. They identified a commercial copolymer suitable to be used in high temperature conditions and reported its behavior in solutions containing different weight percentages of polymer (Norman et al., 1984). In situ cross-linked acids (ICA) are the first generation of gelled acids designed for diverting acids at high temperatures, and their properties have completely been studied. ICA's contain a gelling agent, a cross-linker, a buffer, and a cross-link breaker. MaGee et al. were the first group technically used ICA's as a diverter system in a number of acid stimulation treatments in the ARAB-C and D formations in Idd-El-Shargi field, offshore Qatar. Alternating stages of 15% HCl and ICA were pumped, and good diversion was indicated by the bottom hole pressure response when the ICA reached the perforations (MaGee et al., 1997).

In ICA systems, any further increase in pH by completely spending the acid causes the cross-linker breaker to activate; then, the in situ gelled acid breaks down and its viscosity drops to values close to that of water to assist easy flow back. Since the system contains polymers, and the bulk fluid viscosity is dramatically reduced, there is still polymer residue, which can plug the face of the wormholes. To avoid this problem, the second generation of gelled acids was developed, named viscoelastic surfactants (VES). Viscoelastic surfactant (VES) technology uses a single component, which forms rod-like micelles in situ when pH increases due to acid spending, and the viscosity drops when hydrocarbons contact the fluid during flow back. The surfactant leaves no residue on the wormhole surfaces and requires very low cleanup pressures. Due to its ease of clean up, VES's-based in situ gelled acids can have a prolonged viscosity buildup without having to break back until the hydrocarbons flow back. This prolonged

viscosity buildup provides additional benefit over the polymer-based in situ gelled acid with sustained diversion. Chang et al. reported the first use of VES technology to divert acid solutions. They reported the viscosity profile of VES as a function of pH. VES-based gelled acid demonstrated superior diversion capability by its sustained viscosity when pH increases above 2. Furthermore, VES-based gelled acid showed superior cleanup capability even before it contacted hydrocarbons to reduce its viscosity (Chang et al., 2001). Naser-El-Din et al., utilizing laboratory data gathered from parallel flow testing, successfully used VES for diverting acid in a well in one of Saudi Arabia oilfields (Naser-El-Din et al., 2006).

Several works have been performed on various factors affecting the performance of gelled acid. Ahmed et al. studied the effect of cross-linker type and the presence of corrosion inhibitors. In general, there are two types of cross-linker, namely iron-based and aluminum-based. They showed that in situ gelled acids based on aluminum formed a gel at a pH value higher than the one noted with iron-based cross-linkers. Moreover, they showed that corrosion inhibitors reduced the pH of gelation for the iron-based cross-linker, whereas it increased the pH of gelation for the aluminum-based cross-linker (Ahmed et al., 2008). Gomaa and Naser-El-Din examined the effect of salinity and HCl concentration on the performance of gelled acids. Their results showed that polymer and other additives were separated out when gelled acids were prepared in high-salinity brines. In addition, preparing the in situ gelled acid using saline water decreased the viscosity of the live acid and gelled acid. Also, they recommended that HCl at an initial concentration of 3 to 5 wt.% should have the best performance (Gomaa and Naser-El-Din, 2010). Gomaa et al., using a parallel core flood setup, examined the impact of initial permeability contrast on the effectiveness of in situ gelled acid to divert regular acids into low permeability cores (Gomaa et al., 2010). Gomaa et al. conducted a core flood study using Indiana limestone cores and observed the effect of shear rate; they showed that diversion ability is higher at low shear rates (Gomaa et al., 2011). Van Zanten developed a method to stabilize different VES packages in high salinity brines such as high density completion brines (Van Zanten, 2011). Al-Sadat et al. studied the viscosity of different solutions containing different amounts of VES and showed that 7.5 wt.% of VES results in the highest viscosity (Al-Sadat et al., 2014). Carpenter reported a brilliant field success in using a self-diverting acid system based on a VES in more than 40 wells in an offshore carbonated reservoir in Brazil (Carpenter, 2014). Shu et al. studied interactions between VES and Fe(III) and showed that complexes containing iron and VES were produced because of the electrostatic interactions between negatively charged  $[\text{FeCl}_4]^-$  groups and positively charged amine groups in VES in live acids; they precipitated and caused a dramatic increase in the viscosity of live acid and prevented gel from being produced (Shu et al., 2015). Hull et al. published a detailed review article discussing the recent technical advances in VES's and their inherent limitations such as cost, applicable temperature range, and leak-off characteristics (Hull et al., 2015).

A summary of the cornerstones of researches from diverters to VES's is listed in Table 1. Because of high relationship between field characteristics (such as rock type and permeability) and operational features (such as HCl concentration, VES type, and injection rate), results may become different from a case to another case. Therefore, before any injection in wells, an experimental study on the performance of particular VES in the core plug samples of the field has to be performed. On the other hand, there is no experimental or field data on using VES's in Iran multi-layered carbonated reservoirs. In this study, two kinds of different VES's provided by two different companies are used to divert acid into a core plug sample having lower permeability in a dual acid injection set-up. The core plug samples are taken from the pay zone of Ahwaz oilfield, one of Iran southwest oilfields. Before performing the injection test, some viscosity measurements are carried out.

**Table 1**

Summary of the literature review.

<b>Year</b>	<b>Team</b>	<b>Research</b>
1958	White	Classification of blocking-diverting agents
1969	Smithe et al.	Use of foams as blocking-diverting agents
1984	Norman et al.	First comprehensive detailed use of polymers blocking-diverting agents
1997	MaGee et al.	First use of ICA
2001	Chang et al.	First use of VES
2006	Naser-El-Din et al.	Successful field use of VES for diverting acid in wells
2008	Ahmed et al.	A study on cross-linker type and corrosion inhibitor effect on the performance of gelled acids
2010	Gomaa and Naser-El-Din	A study into salinity and HCl concentration effect on the performance of gelled acids
2010	Gomaa et al.	An examination of the impact of initial permeability contrast on the effectiveness of gelled acids
2011	Gomaa et al.	An investigation of the effect of shear rate on the performance of gelled acids
2011	Van Zanten	Stabilization of VES in high-salinity brines
2014	Al-Sadat et al.	An examination of the effect of VES concentration on the performance of gelled acids
2014	Carpenter	Successful use of VES in more than 40 wells
2015	Shu et al.	A study of the interaction between VES and iron contamination
2015	Hull et al.	A detailed review on recent technical advances in VES's and their limitations

## 2. Materials and method

### 2.1. Materials

Two different industrial samples of VES were provided for carrying out our study. We named them as VES A and VES B. Their technical and chemical compositions are always kept confidential by manufacturers and providers due to their privacy policies. Each sample contained a full set of special additives which are necessary in industrial operations and injection into wells, but, because of controlled experimental conditions, most of them were ignored. For example, anti-sludge agent is used to avoid sludge formation when gelled acid encounters hydrocarbon. However, since core samples used in our study were completely washed and saturated by salt water (containing just KCl), this agent was ignored. Two kinds of additives could not be ignored: methanol and corrosion inhibitor agent. Methanol is one of the auxiliary substances used in the surfactant of some VES's for better performance; also, due to the volatile character of methanol, it is recommended by manufacturers that a specific amount of methanol should be added to the solution to compensate for the vaporized methanol. It is also stated in literature that corrosion inhibitor agents affect the gelation. Therefore, in each case, the specific amounts of methanol and special corrosion inhibitor (C.I.) agent were added to the solutions. 12 core plug samples were taken from one of Iran southwest oilfields (Ahwaz oilfield). The core plugs were cut by a cutter to have a perfect spherical shape with flat ends. It was desirable that all the samples after cutting

have the same maximum possible length. Unfortunately, 2 samples were broken during cutting because of their natural fractures and weak matrix; after cutting ends, 2 other samples also had a much smaller length than the other samples. The other 8 samples were cleaned with toluene and methanol to remove all the fluids in cores (oil and connate water). After washing, routine core analysis (R-cal) was performed on each core plug, and the gas permeability, porosity, and pore volume of each one were measured. The results of R-cal analysis of the core plugs are tabulated in Table 2. As pointed before, the gel created by VES systems breaks when it encounters hydrocarbons. In industrial operations, at the end of gelled acid injection process, gasoline is injected to break the gel down. Nevertheless, in laboratory tests, after the injection program, because measuring permeability is necessary and the plugs must be washed again if gasoline is used, a mutual solvent is injected instead of gasoline. A mutual solvent is capable of dissolving both polar materials (such as salts like  $\text{CaCl}_2$ ) and apolar materials (such as the polymer and surfactant of VES).

**Table 2**

Rock type and the R-cal analysis results of the core plugs.

Core plug number	Length (cm)	Diameter (in)	Rock type	Porosity (%)	Pore volume (cc)	Gas permeability (md)
1	8	1.5	Calcite	12.3	11.2	6.5
2	8	1.5	Calcite	16.5	15	1.5
3	8	1.5	Calcite	19.4	17.9	17.5
4	7.8	1.5	Calcite	16.5	14.7	1.17
5	7.8	1.5	Calcite	16.2	14.6	6.5
6	8	1.5	Calcite	16.5	15	2.2
7	10	1.5	Calcite	23	26	71
8	10	1.5	Calcite	13	15	12

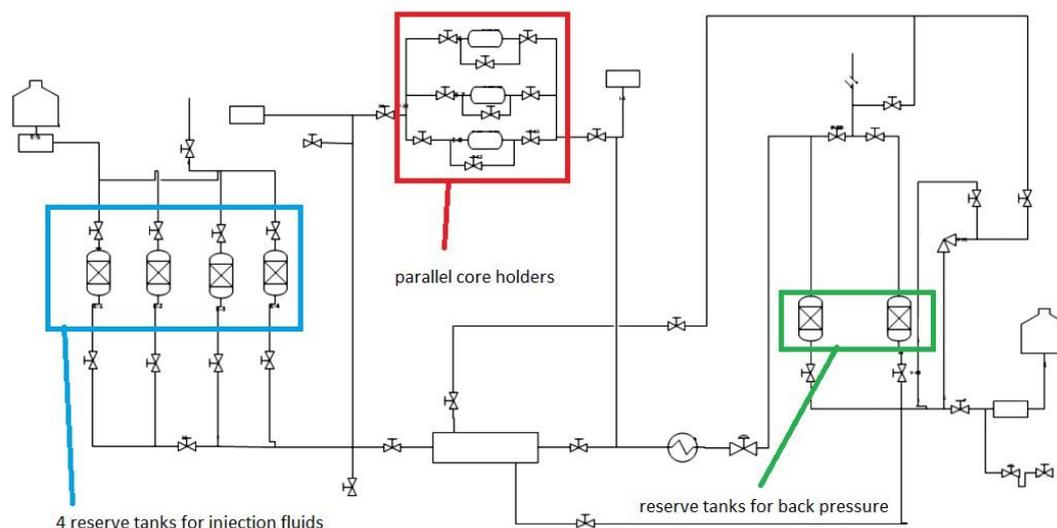
## 2.2. Methods

The effect of shear rate, pH, and temperature were examined during a number of experiments by using a rotational viscometer (Panhandler viscometer), which can directly exert heat to increase the temperature of the fluid. For each gel-acid injection program, a particular solution was designated. The first and second sets of injection program were carried out using the same solution, but different volumes of injection. Prior to each injection program, viscosity measurement test was run at room temperature and at 60 °C. Table 3 lists the components of the solution of each injection program. Parameters used in our fluids are based on the literature review. Before injection, the core plugs had to be saturated with salt water containing 2% KCl in order to prevent clay swelling. By using a saturating apparatus, the solution of salt water was injected into plugs at a high pressure, and they were then aged in the same solution at least for 2 weeks at room temperature.

**Table 3**  
Solution for each injection set

Injection set number	VES type	High-perm plug number	Low-perm plug number	HCl (%)	VES (%)	C.I. (%)	Methanol (%)
1	A	1	2	5	5	0.5	1
2	A	5	6	5	5	0.5	1
3	A	3	4	5	7.5	0.5	1
4	B	7	8	10	7.5	0.5	1

The injection tests were carried out by using a dual acid injection core flood set-up, a schematic of which is displayed in Figure 1. All the injection tests were performed at 100 °C at an injection rate of 0.5 cc/min and a back pressure of 55-60 bar; the overburden pressure was 80 bar. The first step for the injection is injecting salt water for controlling the leakage of the connections. After the leakage run, overburden pressure is applied and the connections are checked again. Then, temperature is increased up to the desire temperature, and overburden pressure is raised gradually. Owing to the injection and the increase in overburden pressure, the inlet pressure will increase until a steady flow in both core holders is established. The set-up must remain in this condition at least for 12 hours to reach a completely steady flow. Then by measuring the amount of the fluid gathered in each graduated cylinder and having viscosity, pressure drop, the length and cross section area of core plugs, and injection rate, water permeability of each core plug is calculated. In this work, the temperature was set at 100 °C in all the sets of injection programs. The injection was started by salt water having 2% KCl as a pre-flush, and the injection rate before injecting the main gel-acid fluid was 1 cc/min; however, the main fluid was injected at a rate of 0.5 cc/min, and after the main fluid, the post-flush fluid was injected at a rate of 0.5 cc/min; the post-flush fluid was salt water consisting of 2% KCl and 10% mutual solvent. All the flow rates were chosen by the laboratory experts of Research Institute of Petroleum Industry (RIPI) on the basis of the optimum flow rate of acid injection in National Iranian Southwest Oilfields Company (NISOC) standard procedure for the matrix acidizing operation. When a breakthrough occurred in both core plugs with the post-flush fluid, the water permeability of the core plugs was calculated again. The main gel-acid fluid for the injection sets 1 and 2 was the same. In the injection set 2, the main gel-acid fluid had to be injected until a breakthrough in both core plugs is achieved; injection sets 3 and 4 also followed this program; however, in injection set 1, the main gel-acid was first injected at a volume equal to one quarter of the total pore volume of the two core plugs; then, 15% HCl was injected at a volume equal to the previous step; Afterwards, the main gel-acid was again injected at a volume equal to one quarter of the total pore volume of the two core plugs; finally, 15% HCl was injected until a breakthrough occurred in both core plugs.



**Figure 1**

A schematic of the dual acid injection core flood set-up.

### 3. Results and discussion

#### 3.1. First set of the injection tests

In the first set of the injection tests, core plug samples 1 and 2 were chosen for high-perm and low-perm plugs. Their porosity, pore volume, and air permeability were already measured, and their water permeability values were calculated when they were placed in core holders in the dual acid injection set-up. Water permeability was 0.8 and 0.18 for sample 1 and sample 2 respectively. As mentioned above, the injection program of this set consists of injecting gel-acid and acid (15% HCl and 0.5% C.I.) periodically; the periodic program was instructed by the technical experts of NISOC. On an industrial scale, the purpose is the periodical injection of VES and acid in wells in at least 2 stages. The viscosity measurement test was also run using the corresponding spent acid at room temperature and at 60 °C (see Table 4). As illustrated in Table 4, increasing temperature reduces viscosity.

**Table 4**

Viscosity of the corresponding spent acid of the injection fluid of the first and second sets of the injection tests at room temperature and 60 °C.

Temperature (°C)	pH	Viscosity at different shear rates (cP)					
25	1.0	50.0	35.0	20.0	12.0	10.5	10.0
	1.5	50.0	35.0	20.0	12.0	10.5	10.0
	2.0	50.0	35.0	20.0	12.0	10.5	10.0
	2.5	50.0	35.0	20.0	12.0	10.5	10.0
	3.0	50.0	35.0	20.0	12.0	10.5	10.0
	3.5	50.0	35.0	20.0	12.0	10.5	10.0
	4.0	65.0	51.2	30.0	18.5	14.5	13.5
	4.5	76.9	60.3	37.0	23.5	18.0	16.0

Temperature (°C)	pH	Viscosity at different shear rates (cP)					
25	5.0	85.3	68.3	43.0	27.0	20.5	17.0
	5.5	90.6	74.5	48.0	30.0	22.5	18.0
	6.0	90.6	74.5	48.0	30.0	22.5	18.0
	6.5	90.6	74.5	48.0	30.0	22.5	18.0
	7.0	90.6	74.5	48.0	30.0	22.5	18.0
	1.0	48.0	33.6	19.2	11.5	10.0	9.6
	1.5	48.0	33.6	19.2	11.5	10.0	9.6
	2.0	48.0	33.6	19.2	11.5	10.0	9.6
	2.5	48.0	33.6	19.2	11.5	10.0	9.6
	3.0	48.0	33.6	19.2	11.5	10.0	9.6
60	3.5	48.0	33.6	19.2	11.5	10.0	9.6
	4.0	62.4	49.1	28.8	17.5	13.9	13.0
	4.5	73.8	57.9	35.5	22.5	17.2	15.3
	5.0	81.9	65.5	41.2	25.9	19.7	16.3
	5.5	87.0	71.5	46.0	28.7	21.5	17.2
	6.0	87.0	71.5	46.0	28.7	21.5	17.2
	6.5	87.0	71.5	46.0	28.7	21.5	17.2
	7.0	87.0	71.5	46.0	28.7	21.5	17.2

The relationship between the shear rate and viscosity of gelled-acid is described by a power-law model:

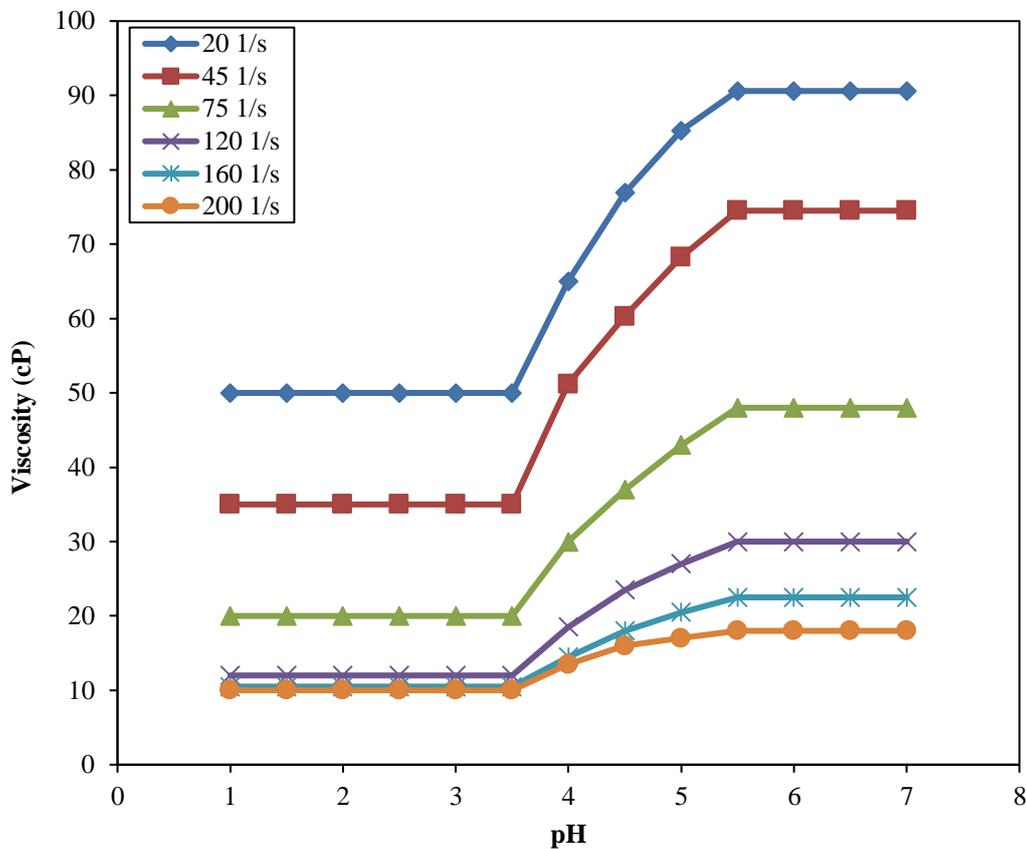
$$\mu = H\gamma^n \quad (1)$$

where,  $\mu$  is viscosity (cP), and  $H$  is the consistency coefficient ( $\text{cP}\cdot\text{s}^{n-1}$ );  $\gamma$  represents the shear rate ( $\text{s}^{-1}$ ), and  $n$  stands for the power index. Table 5 lists the  $H$  and  $n$  values of the model at room temperature and at 60 °C for all the sets. The parameter  $n$  is less than 1.0 at both temperatures, so the fluid is pseudo-plastic or shear-thinning. A drop in  $n$  and  $H$  values by increasing temperature represents a decrease in viscosity.

**Table 5**  
Parameters of viscosity-pH model.

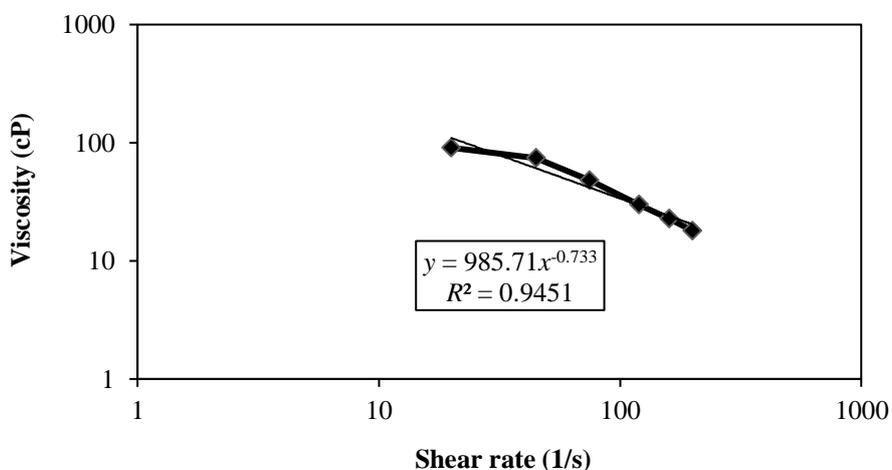
Injection set number	Temperature (°C)	$H$	$n$
1,2	25	985.71	0.267
	60	962.23	0.263
3	25	1491.30	0.265
	60	1443.30	0.263
4	25	1201.40	0.415
	60	1110.20	0.408

Figure 2 displays the variation of viscosity versus pH at different shear rates for the corresponding spent acid of the injection fluid of the first set of injection test at room temperature. Figure 3 also depicts the changes in viscosity versus the shear rate of the gelled-acid in the first set of injection test at room temperature.



**Figure 2**

Viscosity versus pH at different shear rates for the corresponding spent acid of the injection fluid of the first set of the injection tests at room temperature.



**Figure 3**

Viscosity versus the shear rate of the gelled-acid in the first set of the injection test at room temperature.

After injection, the water permeability values of the core plug samples were calculated again. The water permeability of core plug number 1 after injection was 85 md, while that of the core plug number 2 was 0.18 md. Unfortunately, diversion did not happen, and a volume of about 2 pore volumes was injected into core plug number 1, which caused such an increase in its permeability. Two rough guesses were made for the main reasons of this failure:

- 1- CO<sub>2</sub> gas is one of the productions of the reaction between acid and rock. When the solution containing acid and VES is mixed in laboratory, CO<sub>2</sub> escapes from the solution, and the reaction is completed. However, when the solution is injected in the core plug samples, CO<sub>2</sub> remains in the solution and causes the reaction to reach a reversible equilibrium.; hence, the reaction does not move forward completely. In this case, VES must have a brilliant quality to produce gel, otherwise gelation does not happen. The first guess was that the used VES was of poor quality.
- 2- The amount of gel-acid injected into the core plug samples must be enough to bear the pressure difference needed for diversion. Also, when acid is injected after gel-acid, acid will dissolve some of the gel. The second guess was that because of a small amount of gel-acid injected at each stage, the gel was weak, and the pressure difference destroyed it. In fact, the dissolution of the gel due to interaction with acid weakens it.

There is no way to confirm the first guess. Even using a high pressure high temperature (HPHT) viscometer, which simultaneously applies the effect of high pressure and high temperature, cannot be helpful because it does not consider the reversible reaction. For examining the second guess, a decision was made to inject just gel-acid solution and eliminate the acid stages. This led to the second set of the injection tests.

### 3.2. Second set of the injection tests

In the second set of the injection tests, the injection solution was the same as the injection solution of the first set of the injection tests, but the acid stages were eliminated. The experiment conditions were also the same as the previous tests. Core plug samples 3 and 4 were chosen for this set. Their water permeability values were respectively 2.5 md and 0.17 md. Unfortunately, this set of injection tests failed too. The water permeability values of the high-perm and low-perm samples after injection were 92 md and 0.19 md respectively. A small increase (0.02 md) in the water permeability of the low-perm sample confirms that a very little amount of the solution is diverted into the low-perm sample. Thus, we hypothesized that more permeability contrast compared to the previous set is needed to be compensated for by more VES. Therefore, the last test to evaluate whether VES A is of high quality or not is the injection of the gel-acid solution at a higher VES concentration. This generated the third set of the injection tests.

### 3.3. Third set of the injection tests

In the third set of the injection tests, core plug samples 5 and 6 were chosen for the high-perm and low-perm plugs. Their water permeability was 0.85 md and 0.25 md respectively. Table 6 summarizes the result of viscosity measurement test as well as parameters  $H$  and  $n$  of the power-law model at room temperature and at 60 °C. The parameter  $n$  is less than 1.0 at both temperatures, so the fluid is pseudo-plastic or shear-thinning. A drop in  $n$  and  $H$  at a higher temperature confirms viscosity reduction.

Unfortunately, this test also failed. The water permeability of the low-perm core plug sample after injection was 0.26 md, while the water permeability of the high-perm core plug sample after injection was 90 md. These 3 sets of the injection tests, which all failed, were persuasive enough that VES A is of poor quality; hence, VES B having different components was used in the next test.

**Table 6**

Viscosity of the corresponding spent acid of the injection fluid of the third and second sets of the injection tests at room temperature and 60 °C.

Temperature (°C)	pH	Viscosity at different shear rates (cP)					
25	1.0	75.00	52.50	30.00	18.00	15.75	15.00
	1.5	75.00	52.50	30.00	18.00	15.75	15.00
	2.0	75.00	52.50	30.00	18.00	15.75	15.00
	2.5	75.00	52.50	30.00	18.00	15.75	15.00
	3.0	75.00	52.50	30.00	18.00	15.75	15.00
	3.5	75.00	52.500	30.00	18.00	15.75	15.00
	4.0	97.50	76.8	45.00	27.75	21.75	20.25
	4.5	115.30	90.45	55.50	35.25	27.00	24.00
	5.0	127.90	102.45	64.50	40.25	30.75	25.50
	5.5	135.90	111.75	72.00	45.00	33.75	27.00
60	6.0	135.90	111.75	72.00	45.00	33.75	27.00
	6.5	135.90	111.75	72.00	45.00	33.75	27.00
	7.0	135.90	111.75	72.00	45.00	33.75	27.00
	1.0	72.00	50.40	28.80	17.25	15.00	14.40
	1.5	72.00	50.40	28.80	17.25	15.00	14.40
	2.0	72.00	50.40	28.80	17.25	15.00	14.40
	2.5	72.00	50.40	28.80	17.25	15.00	14.40
	3.0	72.00	50.40	28.80	17.25	15.00	14.40
	3.5	72.00	50.40	28.80	17.25	15.00	14.40
	4.0	93.60	73.65	43.20	26.25	20.85	19.50
	4.5	110.70	86.85	53.25	33.75	25.8	22.95
	5.0	122.85	98.25	61.80	38.85	29.55	24.45
	5.5	130.50	107.25	69.00	43.05	32.25	25.80
	6.0	130.50	107.25	69.00	43.05	32.25	25.80
6.5	130.50	107.25	69.00	43.05	32.25	25.80	
7.0	130.50	107.25	69.00	43.05	32.25	25.80	

### 3.4. Fourth set of the injection tests

VES B was used in the fourth set of the injection tests. In the fourth set of the injection tests, core plug sample 7 and 8 were chosen for the high-perm and low-perm plugs. Their water permeability was correspondingly 6.14 md and 0.91 md. Table 7 tabulates the result of viscosity measurement test and the parameters  $H$  and  $n$  of the power-law model at room temperature and 60 °C. The parameter  $n$

is less than 1.0 at both temperatures, so the fluid is considered to be pseudo-plastic or shear- thinning. A fall in  $n$  and  $H$  at elevated temperatures results in a reduced viscosity. The parameter  $n$  of this fluid is greater than that of the injection fluids of the injection tests 1, 2, and 3, which confirms that this fluid has a milder non-Newtonian behavior. Furthermore, this fluid has a lower viscosity value at a low pH (before gelation) and a higher viscosity value at a high pH (after gelation). These factors state that this injection fluid has better performance compared to the previous injection fluids. After injection, the water permeability of core plug samples was calculated again. The water permeability of core plug sample 7 after injection was 18.5 md, while that of core plug sample 8 was 12.5 md. This shows that the diversion has happened successfully.

Comparing VES A and VES B, the trends of viscosity curves are the same; they both show a low viscosity at pH values lower than about 3.5, and their viscosity values increase gradually until pH reaches nearly 5.5. As mentioned before, they differ at two points. One difference is that VES B shows a milder non-Newtonian behavior compared to VES A, and another point of difference lies in the fact that VES B has a lower viscosity at low pH values (before gelation) and higher viscosity at high pH values (after gelation). These two differences are the key factors affecting diversion. The non-Newtonian behavior leads to a more pressure drop due to fluid flow and to a non-homogenous flow in porous media. A milder non-Newtonian behavior leads to a less pressure drop and more homogenous flow of the injected fluid; therefore, further pores (smaller pores) are invaded by the injection fluid, and gelation takes place in the major portion of the porous media, thereby forming a stronger and more effective gel. Additionally, a lower viscosity before gelation, when the injection rate is constant, leads to more invaded pores. Also, higher viscosity after gelation is a remarkable symbol of a stronger gel. Thus, the milder non-Newtonian behavior of VES B, its lower viscosity before gelation, and its higher viscosity after gelation all lead to a stronger and more effective gel and successful diversion. The tests for VES A failed completely because its produced gel was not strong enough to divert the injection fluid from the core with higher permeability to the core with lower permeability; hence, all the injection fluid flowed into the core with higher initial permeability. The permeability of the high-perm cores enhanced, while the permeability of the low- perm cores remained intact.

As it was mentioned before, this is the first case study in Iranian carbonated reservoirs. So, there are not any experimental results or field data to compare our results with them.

**Table 7**

Viscosity of the corresponding spent acid of the injection fluid of the fourth and second sets of the injection tests at room temperature and 60 °C.

Temperature (°C)	pH	Viscosity at different shear rates (cP)					
25	1.0	47.0	33.0	19.0	11.5	10.0	9.5
	1.5	47.0	33.0	19.0	11.5	10.0	9.5
	2.0	47.0	33.0	19.0	11.5	10.0	9.5
	2.5	47.0	33.0	19.0	11.5	10.0	9.5
	3.0	47.0	33.0	19.0	11.5	10.0	9.5
	3.5	47.0	33.0	19.0	11.5	10.0	9.5
	4.0	102.0	80.2	47.0	29.0	22.5	21.0
	4.5	145.3	114.0	70.0	44.5	34.0	30.0

Temperature (°C)	pH	Viscosity at different shear rates (cP)					
	5.0	163.0	130.0	95.0	59.5	45.0	37.5
	5.5	173.0	142.8	117.5	73.5	55.0	44.0
	6.0	173.0	142.8	117.5	73.5	55.0	44.0
	6.5	173.0	142.8	117.5	73.5	55.0	44.0
	7.0	173.0	142.8	117.5	73.5	55.0	44.0
	1.0	44.65	31.35	18.05	11.90	9.50	9.00
	1.5	44.65	31.35	18.05	11.90	9.50	9.00
	2.0	44.65	31.35	18.05	11.90	9.50	9.00
	2.5	44.65	31.35	18.05	11.90	9.50	9.00
	3.0	44.65	31.35	18.05	11.90	9.50	9.00
	3.5	44.65	31.35	18.05	11.90	9.50	9.00
60	4.0	96.90	76.19	44.65	27.50	21.40	19.95
	4.5	138.03	108.30	66.50	42.30	32.30	28.50
	5.0	154.85	123.50	90.25	56.50	42.70	35.60
	5.5	164.35	135.66	111.63	69.80	52.20	41.80
	6.0	164.35	135.66	111.63	69.80	52.20	41.80
	6.5	164.35	135.66	111.63	69.80	52.20	41.80
	7.0	164.35	135.66	111.63	69.80	52.20	41.80

#### 4. Conclusions

Viscosity measurement tests must be run on solutions containing VES to specify its behavior and viscosity alteration at different shear rates, pH values, and temperatures. The stability of the gel must also be evaluated at higher temperatures. If the gel is not stable at high temperatures, injecting this fluid will fail without any doubt. However, even if a solution passed these tests successfully, without running the injection test, judgement about its quality and diversion behavior is not exact. The non-Newtonian behavior of the injection fluid and its viscosity before and after gelation are the key factors affecting its performance. A milder non-Newtonian behavior, lower viscosity before gelation, and higher viscosity after gelation will result in a more successful diversion.

VES A does not offer acceptable quality, and its surfactant is unable to make a strong gel capable of diverting the solution into low permeability core (layer). On the other hand, VES B can generate a strong gel and divert solution into low permeability core (layer).

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## Nomenclature

$H$	Consistency coefficient of power-law model
$n$	Power index of power-law model
$\gamma$	Shear rate
$\mu$	Viscosity

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