

Hydraulic Fracturing Fluid Modified with Nanosilica Proppant and Salt Water for Clay Shale Rocks

Cumaraswamy Vipulanandan and Ahmed Mohammed CIGMAT- University of Houston

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Abstract

Combining technologies such as hydraulic fracturing along with horizontal drilling has revolutionized the production of hydrocarbons worldwide. Because of lower production rate and negative environmental impact still restrains the development of unconventional reservoirs. Nanotechnology, applied from consumer electronics to healthcare with very limited use in hydraulic fracturing, offers the promise of bringing the hydrocarbon industry into a new era. The benefits are expected to impact the entire process from replacing, proppant, polymer based fracturing fluids, gel breakers, stimulation methods, flowback fluids and downhole sensors.

The composition of the fracturing fluid is important to not only fracture the rocks but also provide for efficient transport and placement of proppant into fractured rocks to keep it opened to extract the oil and gas. In this study, the effect of salt water and 1% nanosilica proppant on the rheological properties, fluid loss and electrical resistivity of the fracturing fluids and transport characteristics in the pre-cracked shale was investigated at various temperatures up to 85°C and up to a pressure of 700 psi (splitting tensile strength of rock) respectively. Five different mixes of the fracturing fluids were developed and used in this study to investigate the effects of nano silica proppant and salt water. The amount of water in the fracturing fluid varied from 87% to 93% (by the total weight of the fracturing fluid) and the percentage of the fine sand used varied from 5% to 9% (by the weight of fluid) with different percentages of guar gum up to 2%. With increasing the temperature from 25°C to 85°C, the electrical resistivity of fracturing fluid with and without nano silica decreased from 4.56 Ω -m to 3.11 Ω -m and from 3.75 Ω -m to 2.78 Ω -m respectively. The electrical resistivity of fracturing fluid using 3% of salt (KCl) with and without nanosilica decreased from 4.56 Ω -m to 0.089 Ω -m and from 3.75 Ω -m to 0.065 Ω -m respectively at room temperature.

The nanosilica modification increased the yield stress (τ_0) from 87.3 Pa to 110.4 Pa at 25°C. Additional of 3% of salt decreased the yield stress (τ_0) for the fracturing fluid without and with nano silica from 87.3 Pa to 44.4 Pa and from 110.4 Pa to 54.4 Pa respectively at 25°C. The viscosity of fracturing fluid at a shearing strain rate of 170 s^{-1} increased by 10% with the addition of 1% of the nanosilica at room temperature. The viscosity of fracturing fluid with and without nanosilica

decreased by 77% and 59% respectively using 3% KCl at 25°C. Addition of guar gum substantially increased the viscosity of the salt water fracturing fluid. A new test protocol was developed using pre-cracked shale to evaluate the performance of the fracturing fluids. In the range of 690 to 700 psi the permeability of the clay shale increased by 23% using fracturing fluid modified with nanosilica. The apparent permeability of the clay shale rock increased by 33% when the fracturing fluid modified with 1% nanosilica at temperature of 85°C and pressure of 700 psi. Additional of 3% salt to the fracturing fluid decreased the permeability of the shale rock by over 50%. The apparent permeability of the clay shale rock doubled when 1% nanosilica was added to the salty fracturing fluid. The performance of salty fracturing fluid was further enhanced with the addition of 2% guar gum and 1% nanosilica.

Analyzing the results showed that the hyperbolic model predicated the fluid loss with the time, temperature and pressure and the shear thinning relationship between the shear stress with shear strain rate of fracturing fluids very well. The results also showed strong influence of the nano silica and temperature on fracturing fluid rheology, fluid loss and the fracturing behavior of the shale rock.

Introduction

In order to crack the formations hydraulic fracturing which started in the US in late 1940s the extract oil and natural gas trapped underground in low permeability rock formations by injecting a fluid under high pressure. The composition of a fracturing fluid varies with the nature of the formation, but typically contains 99% of water and proppant sand to keep the fractures open and a small percentage of chemical additives (Murrill and Vann 2012). The quality of fracturing fluid can be effectively maintained by continuously measuring fluid characteristics in the field and controlling its viscous properties by modifying fluid additives and injection rate. Minimizing formation damage and fracture damage is regarded as a unique goal in hydraulic fracture design (Bouts et al. 1997).

In the United States shale gas and oil production has grown rapidly in the past years with continuous technological developments in hydraulic fracturing. Hydraulically fracturing rocks increases the permeability by opening, connecting and keeping open pre-existing or new fractures in the formation.

The design of the fracturing fluid is therefore critical for the success of the operation. Its main function is to open the fractures and to transport and keep the proppant along the length of the cracked rocks. The rheological properties of the fluid are usually considered the most important parameters (Economides and Nolte 1989). However, the fracturing fluid must exhibit other important properties such as minimizing fluid loss and demonstrate low friction pressure during pumping (API RP39 1998). Also enhancing the sensing properties will help in monitoring the changes and contamination in the fracturing fluids (Vipulanandan et al. 2014a).

Nanomaterials are excellent tools for the development of sensors and imaging contrast agents due to the significant alterations in their optical, magnetic and electrical properties (in comparison to their bulk analogues) along with their ability to form (electrically and/or geometrically) percolated structures at low volume fractions Krishnamoorti (2006). Such nanomaterials, when combined with smart fluids, can be used as extremely sensitive downhole sensors for temperature, pressure and stress even under extreme conditions.

Nanotechnology is increasingly being deployed in hydraulic fracturing of conventional and unconventional wells (Vipulanandan et al. 2014a). Some of the best known areas where it has demonstrated success have been in fracturing fluids as viscosity control agents, time- delayed breakers, proppant, chemical tracers, chemical carriers for acid stimulation, and as agents for magnetic and thermal stimulation. Nanotechnologies are also being developed to enable and enhance down-hole sensors and actuators that can operate in chemically harsh environmental at high pressures and temperatures. Moreover, nanotechnologies are also being developed and are at the early stage of demonstration for the cleanup of flow back and produced waters in cost effective and high throughput applications.

The well –developed example of nanotechnology in hydraulic fracturing is nanoparticle modified fracturing fluids (Vipulanandan et al. 2014a). Conventional fracturing fluids, viscoelastic surfactant system and polymer based fluids have individual drawbacks that nanoparticles could mitigate. Studies on the micro scale transport have suggested that nanoparticles can often move unimpeded in most porous materials and therefore don not pose a significant additional challenge in improved fracturing technologies, (He et al. 2012-2014).

Huang et al. (2008) introduced the use of nanoparticle treated proppant as a mechanism to fix the migration of formation fines. The nanoparticles employed in this method had significantly high surface forces including van der Waals and electrostatic forces and readily attracted to the surface of proppant particles during the fracturing treatment. During production when formation fines moved through the nanoparticle treated proppant bed, surface forces of the nanoparticle captured and prevented the fines from moving to the near wellbore region. Laboratory testing of the proppant bed and sand packs treated with low concentration of nanoparticles demonstrated that nanoparticles were capable of

fixating formation fines such as colloidal silica, charged and nano-charged particles, expandable and nonexpandable clays. Nanosilica has been used or considered for use in many applications and it has received increasing attention also in building materials, with potential advantages and drawbacks being underlined (Berra et al. 2012). The addition of nano silica to cementitious mixes produces a remarkable reduction of the mix workability, due to instantaneous interactions between the nanosilica and the liquid phase of the cementitious mixes, with formation of gels characterized by high water retention capacities. The delayed addition of mixing water aliquots proves to be an effective way of reducing the adverse effect of nano silica on mix workability, without changing the water/binder ratio and/or adding super plasticizer. In contrast, no workability improvement associated with delayed water addition was observed for Portland cement mixes (Berra et al. 2012). The development of nano silica based high performance concrete will possibly help to the global community for reducing the cement consumption for specific grade of concrete. The reduction in cement usage will help in protecting the environment to a great extent (Berra et al. 2012).

A typical hydraulic fracturing treatment can consume, on average, 3 to 5 million gal of water (usually fresh water). This is particularly problematic for offshore jobs, where fresh water must be transported to the well site; whereas, seawater is readily available. Very few conventional polymers perform well in brine; however, even fewer perform well in hard brines, such as seawater, which typically includes high concentrations of divalent metal ions, such as magnesium and calcium. The presence of divalent metal ions in seawater inhibit the full hydration of the polymer, which results in a lower base gel viscosity and ultimately affects the final properties of the cross-linked fluid system. Several sea water tolerant fracturing fluids are currently available, but none of these fluids meet the current requirements to reduce formation damage caused by a relatively high percentage ($\geq 5\%$) of insoluble residues in the polymer system (Loan et al. 2014).

Rock Characterization

(a) Strength Correlation

Based on the experimental study and literature data, a correlation between compressive strength (σ_c psi) and tensile strength (σ_t psi) was developed (Eqn. 1) using total of 77 data. The relationship for the data collected can be represented as follows:

$$\sigma_t = \frac{\sigma_c}{8.2 + 0.0003 * \sigma_c} \quad (1)$$

The σ_c for collected data on shale rock varied from 2991 psi to 14707 psi. The σ_t for shale rock samples varied from 310 psi to 1030 psi. The coefficient of determination (R^2) was 0.82.

(b) Permeability (k) of the Rock

Based on the experimental study and literature data, the correlation between compressive strength (σ_c MPa) and permeability (k mD) was developed (Eqn. 2). Total of 21 data on σ_c and κ for different type of rocks were collected from various research studies as shown in Fig. 2. Based on the experimental and literature data, the correlation between compressive strength (σ_c) and the permeability (k) was developed as shown in Fig. 2. The relationship for the data collected can be represented as follows:

$$\sigma_c = (7100 + \frac{10^{12} * k}{0.06 + 10^7 * k}) \quad (2)$$

The k values for shale rock varied from 0.14×10^{-9} mD to 0.2×10^{-8} mD as shown in Fig. 2. Constant head permeability test was conducted on the 2.3"D *3.3" H shale rock sample according to CIGMAT Testing Standard 2011 using double ring permeameter mold. The water was allowed to seep through the rock under the pressure of 100 psi. Total data used for the analyses was 21 and the coefficient of determination (R^2) was 0.92.

Objectives

The overall objective was to investigate the effect of nanosilica proppant and salt content on the performance of the hydraulic fracturing fluid. The specific objectives are as follows:

- i. Evaluate the effect of nanosilica and salt on the rheological properties and fluid loss of the fracturing fluid at different temperatures.
- ii. Evaluate the effect of nanosilica and salt on the fracturing fluid transport through pre-fractured clay shale rock.

Materials and Methods

Material

(i) Sand

Uniformly graded sand was used in this study. It had a coefficient of uniformity (C_u) of 2.53, the coefficient of gradation (C_c) of 0.90 and 50% of the particles were passing 0.46 mm sieve ($d_{50} = 0.46$ mm) and surface area of $0.05 \text{ m}^2/\text{g}$. Specific gravity of the sand was 2.65.

(ii) Clay Shale Rock Sample

Field rock samples were used for hydraulic fracturing test. Permeability, water absorption, unconfined compressive strength and spilt tension tests were performed according to ASTM Standards. These results are summarized in Table 1.

(iii) Nanosilica

Nanosilica with the grain size of about 20 nm and surface area of $600 \text{ m}^2/\text{g}$ was selected for this study.

(iv) Guar Gum

Biopolymer Guar gum (PHGG) with the surface area of $22 \text{ m}^2/\text{g}$ and the density of 0.55 gm/cm^3 was used.

Methods

Rheological Properties

The rheological properties such as shear stress - shear strain rate, gel strength and viscosity (μ) for fracturing fluids were measured using a viscometer. Five different mixes with and without salt and nanosilica were used as summarized in Table 2. The fracturing fluids were tested in the temperature range from 25°C to 85°C using a viscometer with the speed range of 0.3 to 600 rpm.

HTHP Filtrate

Measuring the HTHP fluid loss of a fracture fluid involves heating the fluid in a controlled environment to a temperature that is expected in the well. When test temperature was reached, long term filtrate volume was determined at a temperature differential to simulate downhole conditions. The equipment designed for this purpose includes a heating jacket (with a bimetallic thermostat) a cell to contain the fluid, a means to pressurize the cell and a means of collecting filtrate. Gauging the effect of temperature on the fracturing fluid filtrate volume is the main purpose of the HTHP test and accurate temperature measurements are required. Thermocouple device was used to monitor the fluid temperature the fluid in the cell. Test results indicated the fluid temperature met the targeted test temperature within the API recommended one hour heat up period for the 500 mL HTHP cell. The filtrate volume was measured according to API specification 13A.

Electrical Resistivity

Two different resistivity devices were used to measure the electrical resistivity of fracturing fluid. API resistivity meter measured the resistivity of fluids, slurries and semi-solids with resistivities in the range of 0.01 to $400 \Omega\text{-m}$. Conductivity meter was used to compare the results with resistivity in the range of 0 to $199.9 \mu\text{S/cm}$. Both of the devices were calibrated using standard solution of sodium chloride (NaCl). The electrical resistivity of the fracturing fluid with and without nanosilica was measured for each 10oC temperature interval.

Hydraulic Fracturing Test

The saturated rock sample was pre-micro cracked; double ring steel mold 2.3" D* 7" H was used for fracturing the shale rock. Annular space between the rock and the wall of the mold was sealed using polymer grout. The mold provided two valves stem, one of the valve to collect side volume leakage and the other valve to collect the water coming from the rock sample as shown in Fig. 7. To study the effect of the salt and nanosilica on the permeability of the rock; five different mixes of fracturing fluid were used. The fracturing fluid on the top of the rock sample was subjected to various pressures up to 700 psi. The hydrofracturing test study was performed using two different temperature 25°C and 85°C . For each environmental condition the permeability of the shale sample was measuring with time as shown in Fig. 8.

Hyperbolic Model

It is important to quantify the changes in the hydraulic fracturing fluid properties due to the additives and environment (temperature, pressure). The hyperbolic model has been used for different applications under different conditions. Mohammed and Vipulanandan (2014) used the hyperbolic relationship to predicate the relation between compressive and tensile strength of sulfate contaminated CL soils with and without polymer treatment. Vipulanandan and Mohammed (2014b) used the hyperbolic model to predicate shear stress with shear strain rate of bentonite drilling mud modified with polymer.

Based on the inspection of the test data following relationship is proposed:

$$Y = Y_o + \frac{X}{A + B * X} \quad (3)$$

where:

X: time or shear strain rate or temperature (independent variable).

Y: is the fracture fluid property with varying X value.

Y_o (yield stress), A and B: model parameters.

Relationship proposed in Eqn. (3) can be used to represent various linear and nonlinear trends based on the values of the parameters A and B.

Results and Analysis

Rheological Properties

Mix 1 (9% sand)

This hydraulic fracturing fluid composition is what is currently used in the field where 9% sand, 1% guar gum and 90% water are used. The viscosity of the fracturing fluid at shear strain rate of 170 s⁻¹ reduced from 478 cP to 192 cP, a 60% reduction when the temperature was increased from 25°C to 85°C as summarized in Table 3. The electrical resistivity of the mix reduced from 3.75 Ω-m to 2.78 Ω-m, a 26% reduction when the temperature was increased from 25°C to 85°C as summarized in Table 3. The yield stress (τ_o) of the mix also reduced from 87.3 Pa to 48 Pa, a 45% reduction when the temperature was increased from 25°C to 85°C as summarized in Table 3. The gel strength at 10 sec and at 10 min decreased from 73.6 Ib/100 ft² to 58.2 Ib/100 ft² and from 86.9 Ib/100 ft² to 66.2 Ib/100 ft², a 21% and 23% reduction respectively when the temperature was increased from 25°C to 85°C as summarized in Table 3.

Mix 2 (1% Nanosilica)

The viscosity of the fracturing fluid at shear strain rate of 170 s⁻¹ reduced from 525 cP to 225 cP, a 57% reduction when the temperature was increased from 25°C to 85°C as summarized in Table 3. The electrical resistivity of the Mix 2 reduced from 4.56 Ω-m to 3.11 Ω-m, a 32% reduction when the temperature was increased from 25°C to 85°C as

summarized in Table 3. The electrical resistivity of the mix 2 at temperature of 25°C was higher than the electrical resistivity of the Mix 1 by 18% as summarized in Table 3. Also Mix 2 had the highest resistivity of all the mixtures investigated. The yield stress (τ_o) of the Mix 2 also reduced from 110.4 Pa to 70.7 Pa, a 36% reduction when the temperature was increased from 25°C to 85°C. The yield stress (τ_o) of the Mix 2 at temperature of 25°C was higher than the yield stress of Mix 1 by 21% as summarized in Table 3. The gel strength at 10 sec and at 10 min for the Mix 2 decreased from 90.5 Ib/100 ft² to 73.1 Ib/100 ft² and from 105.2 Ib/100 ft² to 82.2 Ib/100 ft², a 19% and 22% reduction respectively when the temperature was increased from 25°C to 85°C as summarized in Table 3. The gel strength of the Mix 2 at 10 sec and at 10 min at temperature of 25°C was higher than the gel strength at 10 sec and at 10 min of Mix 1 by 19% and 17% respectively as summarized in Table 3.

Mix 3 (9% Sand +3% salt water)

Additional of 3% salt to the Mix 1 reduced the viscosity at shear strain rate of 170 s⁻¹ from 478 cP to 108 cP, a 77% reduction at temperature of 25°C as summarized in Table 3. Additional of 3% salt to the Mix 1 reduced the electrical resistivity from 3.75 Ω-m to 0.065 Ω-m, a 98% reduction at temperature of 25°C as summarized in Table 3. The electrical resistivity of the Mix 3 reduced from 0.065 Ω-m to 0.036 Ω-m, a 45% reduction when the temperature was increased from 25°C to 85°C as summarized in Table 3. Mix 3 had the lowest resistivity of all the mixtures studied. Additional of 3% salt to the Mix 1 reduced the yield stress (τ_o) from 87.3 Pa to 44.4 Pa, a 49% reduction at temperature of 25°C as summarized in Table 3. The yield stress (τ_o) of the Mix 3 reduced from 44.4 Pa to 17 Pa, a 62% reduction when the temperature was increased from 25°C to 85°C. The gel strength at 10 sec and at 10 min for the Mix 3 decreased from 45.2 Ib/100 ft² to 24.3 Ib/100 ft² and from 38.6 Ib/100 ft² to 31.5 Ib/100 ft², a 46% and 20% reduction respectively when the temperature was increased from 25°C to 85°C as summarized in Table 3. The gel strength of the Mix 3 at 10 sec and at 10 min at temperature of 25°C was lower than the gel strength at 10 sec and at 10 min of Mix 1 by 38% and 55% respectively as summarized in Table 3. The shear stress –shear strain rate relationship was quantified using Eqn. 3 and the model parameters A and B with coefficient of determination (R²) are summarized in Table 4.

Mix 4 (3% salt water +5% sand + 1% nano silica)

Additional of 3% salt to the Mix 2 reduced the viscosity at shear strain rate of 170 s⁻¹ from 525 cP to 215 cP, a 59% reduction at temperature of 25°C as summarized in Table 3. Additional of 3% salt to the Mix 2 reduced the electrical

resistivity from 4.56 Ω -m to 0.089 Ω -m, a 98% reduction at temperature of 25°C as summarized in Table 3. The electrical resistivity of the Mix 4 reduced from 0.089 Ω -m to 0.045 Ω -m, a 49% reduction when the temperature was increased from 25°C to 85°C as summarized in Table 3. Additional of 3% salt to the Mix 2 reduced the yield stress (τ_o) from 110.4 Pa to 54.4 Pa, a 51% reduction at temperature of 25°C as summarized in Table 3. The yield stress (τ_o) of the Mix 4 reduced from 54.4 Pa to 25.7 Pa, a 53% reduction when the temperature was increased from 25°C to 85°C. The gel strength at 10 sec and at 10 min for the Mix 4 decreased from 73.1 Ib/100 ft² to 55.3 Ib/100 ft² and from 81.6 Ib/100 ft² to 68.3 Ib/100 ft², a 24% and 17% reduction respectively when the temperature was increased from 25°C to 85°C as summarized in Table 3. The shear stress –shear strain rate relationship was quantified using Eqn. 3 and the model parameters A and B with coefficient of determination (R^2) are summarized in Table 4.

Mix 5 (2% Guar Gum+3% salt water +5% sand + 1% nano silica)

Additional of 2% guar gum to the Mix 4 increased the viscosity at shear strain rate of 170 s⁻¹ from 215 cP to 333 cP, a 55% increasing at temperature of 25°C as summarized in Table 3. Additional of 2% guar gum to the Mix 4 increased the electrical resistivity from 0.089 Ω -m to 1.36 Ω -m at temperature of 25°C as summarized in Table 3. The electrical resistivity of the Mix 5 reduced from 1.36 Ω -m to 0.99 Ω -m, a 27% reduction when the temperature was increased from 25°C to 85°C as summarized in Table 3. Additional of 2% guar gum to the Mix 4 increased the yield stress (τ_o) from 54.4 Pa to 96.9 Pa, a 78% reduction at temperature of 25°C as summarized in Table 3. The yield stress (τ_o) of the Mix 5 reduced from 96.9 Pa to 64.3 Pa, a 34% reduction when the temperature was increased from 25°C to 85°C. The gel strength at 10 sec and at 10 min for the Mix 5 decreased from 76.2 Ib/100 ft² to 59.3 Ib/100 ft² and from 89.3 Ib/100 ft² to 71.2 Ib/100 ft², a 23% and 20% reduction respectively when the temperature was increased from 25°C to 85°C as summarized in Table 3. The shear stress –shear strain rate relationship was quantified using Eqn. 3 and the model parameters A and B with coefficient of determination (R^2) are summarized in Table 4.

Model parameters A and B with coefficient of determination (R^2) are summarized in Table 4. Parameter A varied from 1.28 to 3.77 and from 2.25 to 7.60 at temperature of 25°C and 85°C respectively as summarized in Table 4. Parameter B varied from 0.013 to 0.022 and from 0.019 to 0.021 at temperature of 25°C and 85°C respectively as summarized in Table 4.

Filtration Loss

Long term fluid loss test on the fracturing fluids was performed and the results are shown in Fig. 5. Based on the Eqn. 3, the volume of fluid loss at 30 minutes was measured as shown in Fig. 6. Additional of the 1% nanosilica (Mix 2), the filter volume of the fracturing fluid decreased by 74% at room temperature. The volume of fluid loss of the fracturing fluid using 9% sand (Mix 1) increased by 268% when the temperature increased from 25°C to 85°C. Additional of 3% salt to the fracturing fluid using Mix 1 and Mix 2 increased fluid loss of the fracturing fluid by 122% and 285% at temperature of 25°C as shown in Fig. 6. Model parameters with coefficient of determination (R^2) are summarized in Table 5.

Electrical Resistivity

Addition of 1% nanosilica to the fracturing fluid increased the electrical resistivity by 22% as summarized in Table 3. Also increasing the temperature the electrical resistivity of fluids nonlinearly decreased as shown in Fig. 3. Adding 3% salt sharply decreased the electrical resistivity of the fluid with and without nanosilica from 3.75 Ω -m to 0.065 Ω -m and from 4.56 Ω -m to 0.089 Ω -m at room temperature, a decreasing in resistivity of 98% as summarized in Table 3. The electrical resistivity of the fracturing fluids decreased when the temperature increased from 25°C to 85°C by 26% to 49% based on the nanosilica and salt content as summarized in Table 3.

Electrical Resistivity – Rheological Properties Relationship

Electrical resistivity and rheological properties of the hydraulic fracturing fluid increased gradually. Using the electrical resistivity of the hydraulic fracturing fluid as a tool to predicate the rheological properties of the hydraulic fracturing fluid in the field. The correlations between electrical resistivity and rheological properties of the fracturing fluid for ($25 \leq T$ (°C) ≤ 85) were:

$$\tau_o = 15 \times \rho + 30 \quad R^2=0.80 \quad \text{No. of Data}=8 \quad (4)$$

$$\mu_p = 106 \times \rho + 62 \quad R^2=0.81 \quad \text{No. of Data}=8 \quad (5)$$

$$Gel10' = 12.3 \times \rho + 33 \quad R^2=0.83 \quad \text{No. of Data}=8 \quad (6)$$

where:

τ_o , ρ , μ_p and $Gel10'$ are yield stress, electrical resistivity, plastic viscosity and gel strength at 10 min respectively. Effect of Nanosilica on the Rock Fracturing Test. In this study, ten different fracturing tests setup were tested. The shale rock pre-cracked using the splitting tensile test.

Flow Test

Test # 1

(a) Temperature =25°C

The fracturing fluid used in this test was 9% sand (Mix 1); the fracturing fluid was subjected to different pressures up to 700 psi. The amount of the fluid collected from the pre-cracked shale rock was zero mL at 100 psi for 26 hours, by increasing the pressure to 500 psi and 700 psi the permeability of the shale rock increased from 1.8×10^{-9} mD to 0.29 mD and 0.33 mD under pressure of 500 psi and 700 psi respectively as shown in Fig. 8.

(b) Temperature =85°C

The fracturing fluid used in this test was 9% sand (Mix 1) at temperature of 85°C. The amount of the fluid collected from the sample was zero mL at 100 psi for 22 hours, by increasing the pressure to 500 psi and 700 psi the permeability of the shale rock increased by 37% and 74% compared with the permeability of the shale rock tested at T=25°C under pressure of 500 psi and 700 psi respectively as shown in Fig. 8.

Test # 2

(a) Temperature =25°C

The fracturing fluid used in this test was 1% nano silica (Mix 2). The fracturing fluid was subjected to different pressures up to 700 psi. Addition of 1% nano silica increased the permeability of the shale rock by 29% and 32% compared with fracturing fluid using Mix 1 under pressure of 500 psi and 700 psi respectively as shown in Fig. 8.

(b) Temperature =85°C

The fracturing fluid used in this test was 1% nano silica (Mix 2). The fracturing fluid was subjected to different pressures up to 700 psi. Using of 1% nano silica increased the permeability of the shale rock by 36% and 37% compared with fracturing fluid using mix 1 under pressure of 500 psi and 700 psi respectively as shown in Fig. 8.

Test # 3

(a) Temperature =25°C

The fracturing fluid used in this test was 3% salt (Mix 3). The fracturing fluid was subjected to different pressures up to 700 psi. Addition of 3% salt reduced the permeability of the shale rock by 72% and 57% compared with fracturing fluid using Mix 1 under pressure of 500 psi and 700 psi respectively as shown in Fig. 8.

(b) Temperature =85°C

The fracturing fluid used in this test was 3% salt (Mix 3); the fracturing fluid was subjected to different pressures up to 700 psi. Addition of 3% salt reduced the permeability of the clay shale rock by over 50% compared with fracturing fluid using Mix 1 under testing pressures of 500 psi and 700 psi as shown in Fig. 8.

Test # 4

(a) Temperature =25°C

The fracturing fluid used in this test was 3% salt with 1% nanosilica (Mix 4). The fracturing fluid was subjected to different pressures up to 700 psi. Addition of 1% nanosilica to the 3% salt solution doubled the permeability of the clay shale rock compared to the salty fracturing fluid (Mix 3) under testing pressures of 500 psi and 700 psi as shown in Fig. 8.

(b) Temperature =85°C

The fracturing fluid used in this test was 3% salt with 1% nanosilica (Mix 4). The fracturing fluid was subjected to different pressures up to 700 psi. Addition of 1% of nanosilica to the 3% salt solution doubled the permeability of the clay shale rocks compared to the salty fracturing fluid (Mix 3) under testing pressures of 500 psi and 700 psi as shown in Fig. 8.

Test # 5

(a) Temperature =25°C

The fracturing fluid used in this test had 2% guar gum with 1% nanosilica and 3% salt (Mix 5). Increasing the polymer content to 2% increased the permeability of the shale rock by 48% and 32% compared with fracturing fluid using Mix 4 under pressure of 500 psi and 700 psi respectively as shown in Fig. 8.

(b) Temperature =85°C

The fracturing fluid used in this test was 2% guar gum (Mix 5); the fracturing fluid was subjected to different pressures up to 700 psi. Increasing the polymer content to 2% increased the permeability of the shale rock by 15% and 50% compared with fracturing fluid using Mix 4 under pressure of 500 psi and 700 psi respectively as shown in Fig. 8.

Conclusions

In this study, rheological properties, electrical resistivity and fluid loss of nanosilica and salt modified fracturing fluids were investigated. Based on the experimental study and modeling following conclusions are advanced:

1. Yield stress (τ_0) of fracturing fluid increased with increasing of nanosilica content. Adding 1% nanosilica to the fracturing fluid to increased the yield stress by 10% at room temperature. Additional of 3% salt decreased the yield stress of the fracturing fluid modified with nanosilica by 51% at room temperature.
2. Additional of 1% nanosilica decreased the fluid loss by 16% and 18% at room temperature of 25°C and 85°C respectively. Additional of 3% salt increased the fluid loss of the fracturing fluid with and without nanosilica by 122% and 285% at room temperature.
3. The hyperbolic model was effective in predicting the rheological properties – temperature, shear stress – shear strain rate and fluid loss- time relationships.
4. Addition of 1% nanosilica to the fracturing fluid increased the permeability of the rock under different pressures, also

the permeability of the rock increased with increase in the temperature.

5. Addition of 3% KCl salt (simulating sea water) to the conventional fracturing fluid decreased the permeability of the clay shale rock.
6. Increasing amount of the biopolymer to 2% with 1% nanosilica increased the viscosity of the salt fracturing fluid using by 78% and 150% at temperature of 25°C and 85°C respectively.
7. Electrical resistivity was a good indicator for different mixtures investigated in this study. Mix 2 (1% nano silica) with highest electrical resistivity had the best performance of the all the mixtures investigated. Mix 3 (3% salt water) with lowest electrical resistivity had the worst best performance based on the viscosity and increasing the permeability of the rock.

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Table 1. Test Methods and Mechanical Properties of Shale Rock

Mechanical Property	Test Method	Shale
Density, γ (gm/cm ³)	ASTM D 5195	2.4
Permeability, k (mD)	ASTM D 2434 & CIGMAT Testing Standard 2011	0.18×10^{-9}
Porosity, n (%)	ASTM D 7263	12.4
Compressive Strength, σ_c (psi)	ASTM D7012	7005
Splitting Tensile Strength, σ_t (psi)	ASTM D3967	711
Modulus of Elasticity, E (psi)	ASTM D3148	485000

Table 2. Fracturing Fluid Mixes

Mix #	Water (%)	Salt (%)	Sand (%)	Guar Gum (%)	Nano Silica (%)	Remark
1	90	0	9	1	0	Base Fluid
2	93	0	5	1	1	Effect of Nano silica
3	87	3	9	1	0	Effect of Salt
4	90	3	5	1	1	
5	89	3	5	2	1	Effect of Polymer

Table 3. Electrical Resistivity and Rheological Properties of Fracturing Fluid Mixes

Temperature=25°C					
Mix #	Resistivity ($\Omega \cdot m$)	Yield Stress, τ_0 (Pa)	Viscosity (cP at 170 s ⁻¹)	Gel Strength (10 s) (lb/100ft ²)	Gel Strength (10 min) (lb/100ft ²)
1	3.75	87.3	478	73.6	86.9
2	4.56	110.4	525	90.5	105.2
3	0.065	44.4	108	45.2	38.6
4	0.089	54.4	215	73.1	81.6
5	1.36	96.9	333	76.2	89.3
Temperature=85°C					
1	2.78	48.0	192	58.2	66.2
2	3.11	70.7	225	73.1	82.2
3	0.036	17.0	44	24.3	31.5
4	0.045	25.7	164	55.3	68.3
5	0.99	64.3	206	59.3	71.2

Table 4. Model Parameters for Relationship between Shear Stress – Shear Strain Rate for Fracturing Fluids

Mix #	Temperature=25°C				Temperature=85°C			
	Yield Stress τ_0 (Pa)	A	B	R ²	Yield Stress τ_0 (Pa)	A	B	R ²
1	87.3	1.28	0.019	0.96	48.0	4.92	0.019	0.99
2	110.4	1.43	0.013	0.98	70.7	2.25	0.020	0.97
3	44.4	3.77	0.021	0.99	17.0	7.60	0.021	0.99
4	54.4	2.64	0.022	0.98	25.7	4.42	0.019	0.98
5	96.9	1.55	0.014	0.96	64.3	4.10	0.021	0.96

Table 5. Model Parameters for Relationship between Fluid Loss – Time for Fracturing Fluids

Mix #	Temperature=25°C			Temperature=85°C		
	A	B	R ²	A	B	R ²
1	2.317	0.039	0.99	1.015	0.025	0.99
2	3.085	0.042	0.99	1.268	0.029	0.99
3	1.614	0.031	0.99	0.566	0.019	0.97
4	1.449	0.024	0.99	0.487	0.016	0.99
5	0.793	0.020	0.99	0.349	0.012	0.99

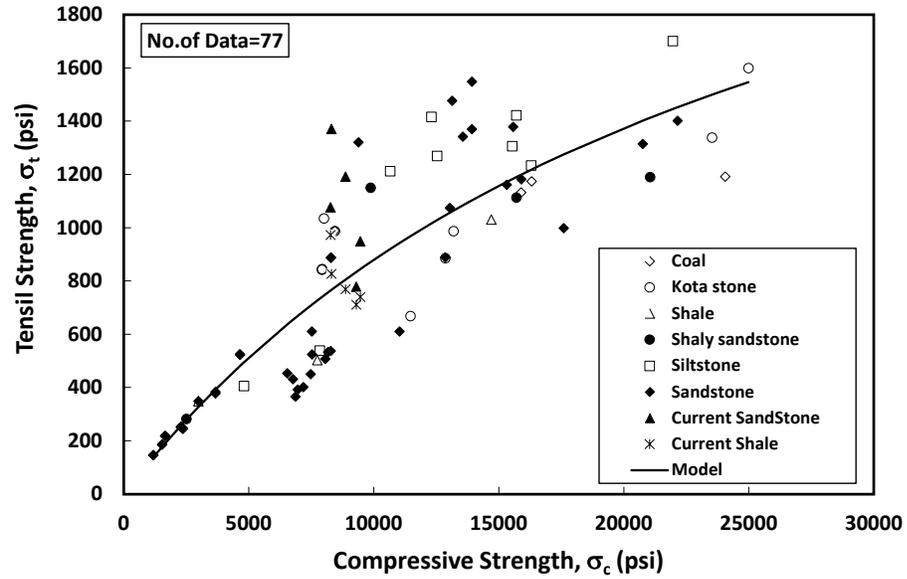


Figure 1. Relationship between Tensile Strength and Compressive Strength of the Rocks

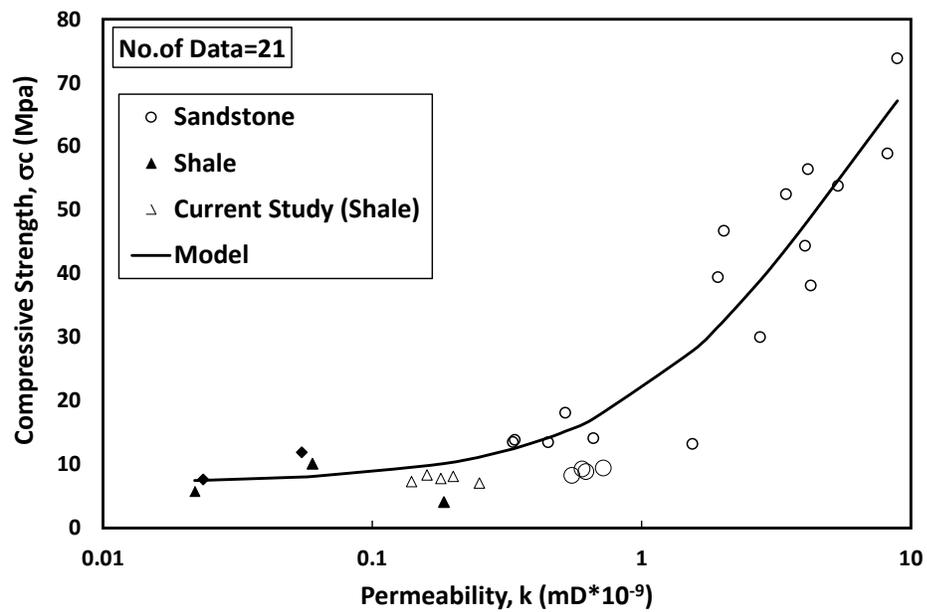


Figure 2. Relationship between Compressive Strength and Permeability of the Rocks

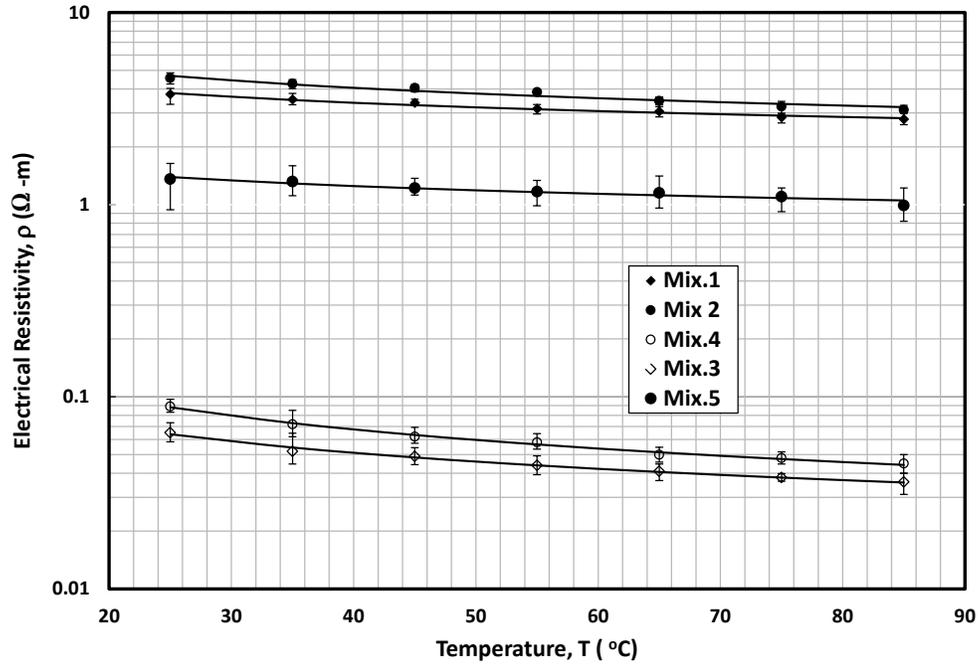


Figure 3. Electrical Resistivity of Fracturing Fluid with Temperature

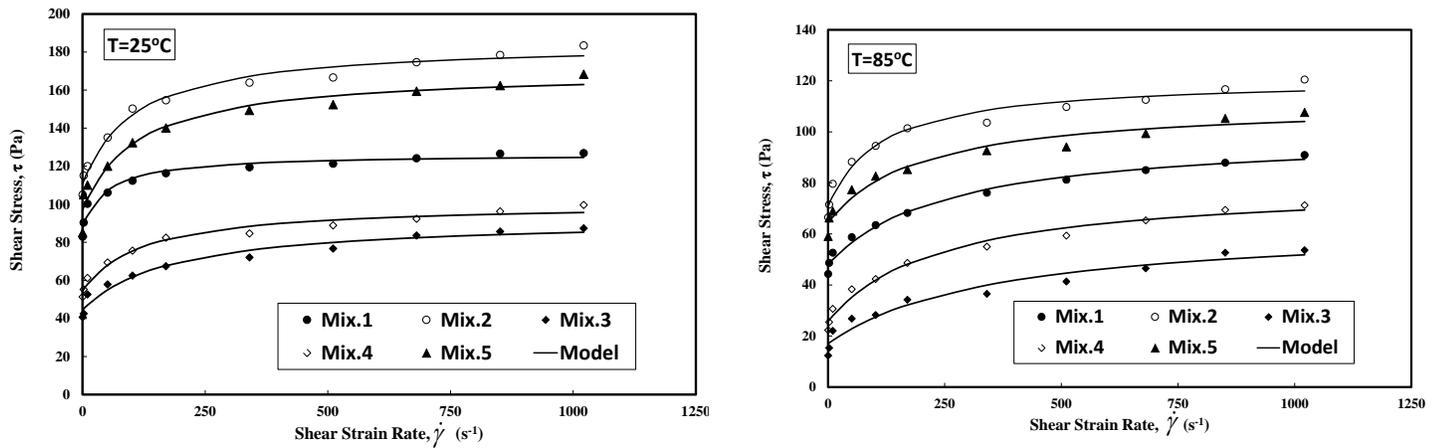


Figure 4. Predicted and Measured Shear Stress - Shear Strain Rate Relationship for Fracturing Fluids at Various Temperatures: (a) T=25°C (b) T=85°C

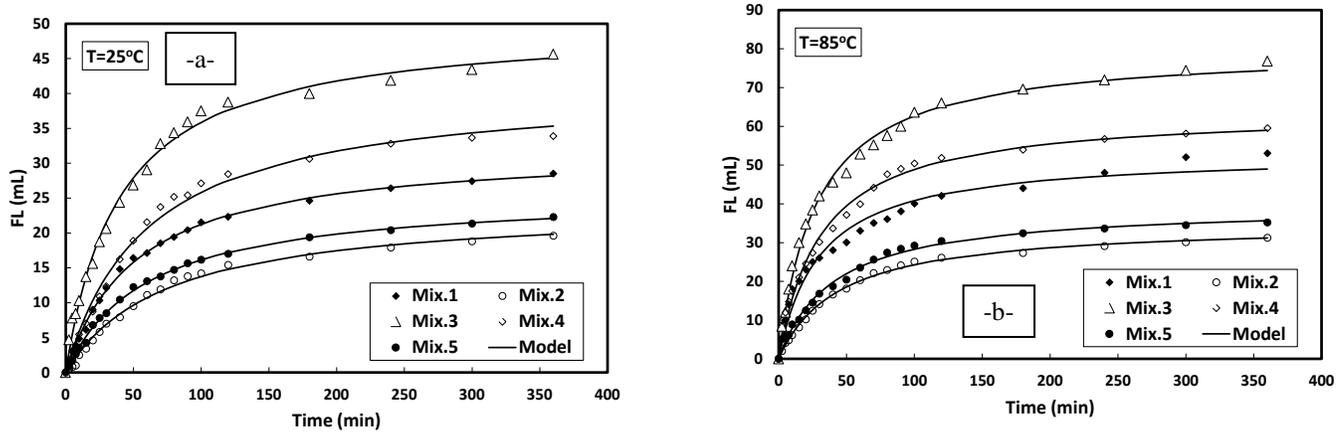


Figure 5. Effect of Temperature on the Fluid Loss in Fracturing Fluids (a) T=25°C (b) T=85°C

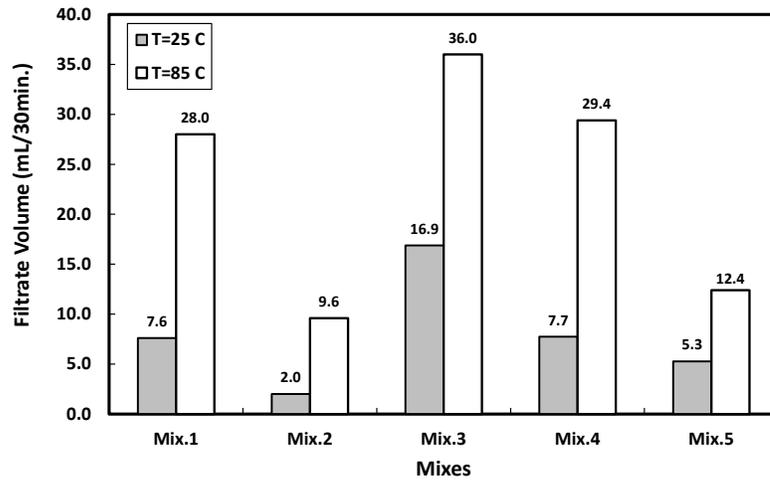


Figure 6. Variation of Fluid Loss Volume after 30 mints for Fracturing Fluids with Temperature

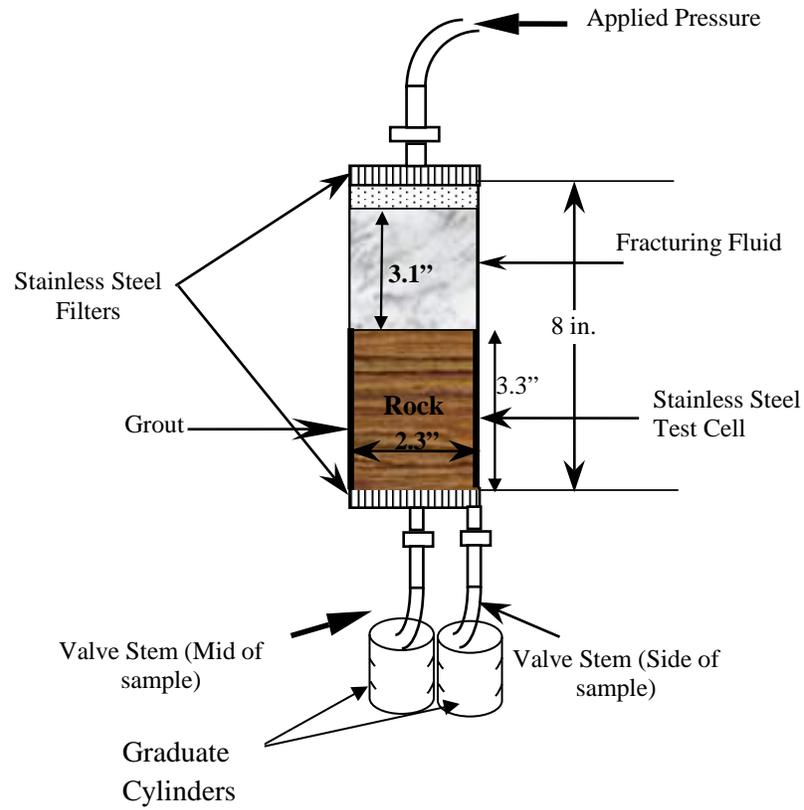


Figure 7. Schematic Diagram for Rock Fracturing System

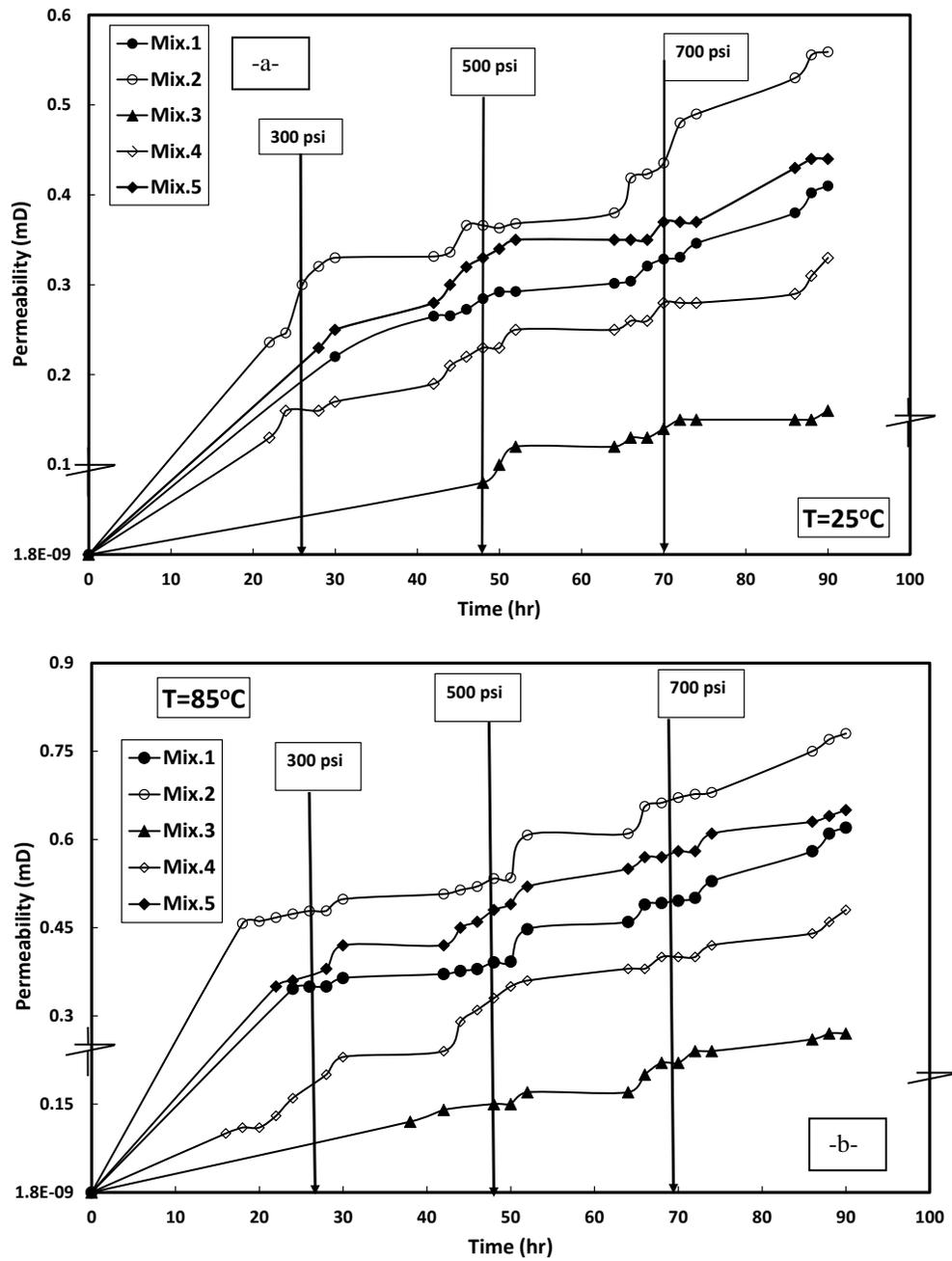


Figure 8. Permeability of the Shale Rock versus Time for Fracturing Fluids: (a) Temperature=25°C, (b) Temperature=85°C