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Integrated feasibility analysis of shale inhibition property by utilization of pore pressure transmission equipment

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ABSTRACT

Regarding the widespread utilization of formate-based drilling fluids in numerous operational circumstances, petroleum industries are in urgent need of decreasing wellbore inefficiencies by improving the procedures quality. Thereby, providing appropriate parameters such as safety, boosting the drilling speed and enrolling the proper procedure of optimizing performances of high activity water-sensitivity formation should be taken into consideration. The objective of this comprehensive study is to apply experimental evaluation tests on the shale inhibitor fluids by using prepared plug samples from the studied field due to the administration of pore pressure transmission (henceforth, PPT) equipment. Even though, PPT equipment is not able to simulate all the mechanisms which are applied to different drilling fluids on the shale layers' stability, it will control such parameters like the penetration of fluid filtration through the formation that subsequently reduce the wellbore problems. Consequently, the ubiquitous use formate fluid in drilling operations of exploratory oil wells in the studied field is successfully implemented to be addressed the current well inefficiencies adequately.

1. Introduction

The drilling fluid's primary functions include subsurface pressure control and wellbore stabilization, cuttings removal and transport, solids suspension, cooling and lubrication of bit and drill string, assistance in collection of formation data, assistance in supporting drill string and casing weights, transmission of hydraulic horsepower to the bit, prevention of formation damage (Lan and Polycarpou, 2017; Peng et al., 2018; Redburn and Heath, 2017; Rossi et al., 2017; Souza et al., 2017; Zhang et al., 2018).

Subsurface pressure control and wellbore stabilization: the formation pressure control is utterly depended upon maintaining sufficient drilling fluid density. It is nonetheless common to encounter abnormally pressured zones that require the addition of high-density material (usually barite, with a specific gravity of 4.2) to increase the fluid and the hydrostatic pressure of the column (Alimuddin et al., 2018; Betekhtin et al., 2017; Mehrabian et al., 2017; Rahmati et al., 2017).

Cuttings removal and transport: one of the substantial roles of drilling fluid is to transfer the cuttings in the wellbore because they might be plugged the drilling bit and subsequently decreased the production rate (Akhshik et al., 2015; Buttress et al., 2016; Ghassemi and Diek, 2003; Li and Luft, 2014).

Solids suspension: the solid suspension in the drilling fluid would be a significant parameter in the drilling operations due to unsettlement of solids in the wellbore and further sticking. Thereby, drilling fluids could be operated as a robust system to eliminate the problem of solid settlement.

Cooling and lubrication of bit and drill string: friction at the bit, and between the drill string-wellbore generates a considerable amount of heat; in respect of the way, the circulating drilling fluid transports the heat away from these frictional sites by absorbing it into the liquid phase of the fluid. For example, the bentonite is known for lowering frictional torque through its excellent cake-building and lubricity characteristics (Fink, 2011; Ghassemi and Diek, 2003; Karimi et al., 2015; McMillan et al., 2015; Peng et al., 2018; Santos et al., 2018b).

Assistance in collection of formation data: there are several factors that need to be considered in selecting a drilling fluid to ensure that subsurface geological information (cuttings, mud pulse data, and wire line logs) can be appropriately transported and evaluated (Caenn and Chillingar, 1996; Cayeux et al., 2014; Davarpanah et al., 2018; Davarpanah and Nassabeh, 2017a; De Lima and Niwas, 2000; Fink, 2011; Ghassemi and Diek, 2003; Li and Luft, 2014; Mahto and Sharma, 2004; Pifer and Fairey, 2014; Rabbani

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et al., 2018).

Assistance in supporting drill string and casing weights: due to increase of average well depth, the weight which is supported by the surface wellhead equipment becomes an increasingly crucial factor in drilling engineering performances. When the drilling fluid density is increased, the total weight supported by the surface equipment is reduced considerably (Caenn and Chillingar, 1996; Cayeux et al., 2014; De Lima and Niwas, 2000; Fink, 2011; Ghassemi and Diek, 2003; Li and Luft, 2014; Mahto and Sharma, 2004; Pifer and Fairey, 2014).

Transmission of hydraulic horsepower to the bit: during the fluid circulation, and the rate of fluid flow should be regulated, so that maximum hydraulic horsepower is available to clean the face of the hole ahead of the bit. The rheological properties of the drilling fluid (plastic viscosity and yield point) have a considerable influence upon hydraulics and should be monitored at all times (Davarpanah and Nassabeh, 2017b; McMillan et al., 2015; Njobuenwu and Wobo, 2007; Patel et al., 2007; Pifer and Fairey, 2014; Rabbani et al., 2018).

Prevention of formation damage: if a large volume of drilling-fluid filtrate invades a formation, it may damage the formation and hinder hydrocarbon production. There are several factors that should be taken into consideration when selecting a drilling fluid, such as fluid compatibility with the producing reservoir, presence of hydratable or swelling formation clays, fractured formations, and the possible reduction of permeability by invasion of nonacid soluble materials into the formation (Lowry et al., 2016; Salas et al., 2015; Wilson et al., 2014).

The choice of drilling fluid for a particular well is based on several factors, such as the characteristics and composition of the formations to be penetrated, formation temperatures and pressures, anticipated drilling problems, and even the source and quality of the fluid and materials used to build the drilling fluid. It complicates any attempt to classify drilling fluids by particular types. It is, however, possible to establish some broad categories or classifications based on the continuous phase of the fluid and the components used to build and maintain the fluid. Using these criteria, there are three basic categories of drilling fluids: water-base, oil-base, and air (Kakoli et al., 2016).

Drilling fluids are classified into two main groups such as water-based and oil-based fluids; these fluids consist of a base fluid which named, water or diesel, weighting agent materials and other supplementary additives that could help in removing the cuttings from the wellbore and maintaining the mud in the fluid state, for example, the water-based fluids are the most widely used drilling muds. They range from untreated native fluids to lightly treated fluids to highly processed inhibitive fluids that retard, or inhibit, the interaction between the fluid and the drilled formation. The oil-base fluids are naturally inhibitive. One of the chief aims of these fluids in comparison to conventional high-pressure, high temperature (henceforth, HPHT) and completion fluids is to minimize the damages which apply to the formation. Furthermore, they maintain the properties of these additives at high temperatures, lessen the resistance of hydraulic flow, utilize less potential energy for differential striking processes and reduce the rate of corrosion. Formate-based fluids can be administered among deep layers of drilled hole, shaly layers and formation which includes gas and salt (Caenn and Chillingar, 1996; Davarpanah et al., 2017; Davarpanah and Nassabeh, 2017c; Fink, 2011; Karimi et al., 2015; Lowry et al., 2016; Mehrabian et al., 2017; Salas et al., 2015; Santos et al., 2018b; Wilson et al., 2014; Zhang et al., 2018).

Although, there are a wide range of research and experimental evaluations are widely reported in literature, in this comprehensive study, we concentrate on the profound impact of formate fluids on the rheological properties and how these parameters will be changed in the operational performances such as plastic viscosity and yield point.

2. Materials and methods

2.1. Advantages of formate fluid

The principal benefits of drilling fluid are optimization of wellbore hydraulic, minimum damage to the formation, non compatibility of fluid to other fluid, non compatibility of fluid to rock, solid particle penetration, phase trapping/blocking, surficial absorption of chemical materials and wettability changes, good compatibility of formate fluids with environment, optimization of well control and risk reduction, anti-corrosion property of formate fluid, increase of drilling penetration rate (Lemasson et al., 2015; Santos et al., 2018a,b).

2.2. Thermal stability of formate fluid

The thermal stability of sodium formate fluids is examined in the presence of sodium formate brines at the proposed conditions in the laboratory tests as the plastic viscosity, apparent viscosity and yield point before and after applying the temperature of 250°F over 16 h period. As it evident in Table 1, the amount of these three principal parameters before and after applying the temperature are approximately the same value. Thereby, it indicates that, sodium formate based fluids has the best efficiency in maintaining the rheological properties of mud.

2.2. Working procedure of PPT equipment

As can be seen in Figs. 1 and 2, the PPT equipment is contained in these sections. Core holder for cores is 1.5 inch in diameter and 1–2 inch in length. Both sides of core are operated by using two pistons that are called borehole piston (this section has higher pressure, and the drilling fluid is in contact with the core) and formation piston (this section has lower pressure than the borehole piston). Pressure changes in the formation piston section are operated like a closed system that are measured by accurate barometers. The fluid that is used in the formation piston section is salty water that approximately simulated due to formation fluid. By investigating the rate of pressure differences in the formation piston section versus time, drilling fluid quality which is used to control the penetration of fluid filtration and as a result reduction of drilling problems in shaly layers will be evaluated (Piccolo and Leuchtenberg, 2015; Weems et al., 2016; Yihdego, 2017).

Properties of used plug for glycol drilling fluid are being statistically explained in Table 2,

Table 1
Amount of these three principal parameters before and after applying the temperature.

Mud Rheology	Apparent viscosity (cP)	Plastic viscosity (cP)	Yield point (Ib./100ft^2)
After applying temperature	21.45	15.4	17.1
Before applying temperature	19.62	14.7	16.5

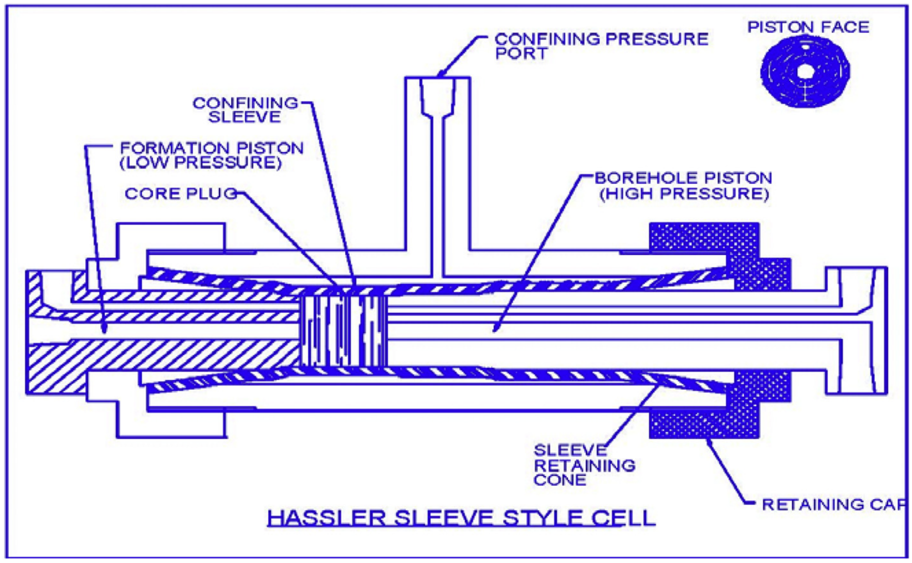

Fig. 1. Schematic of PPT cell equipment.

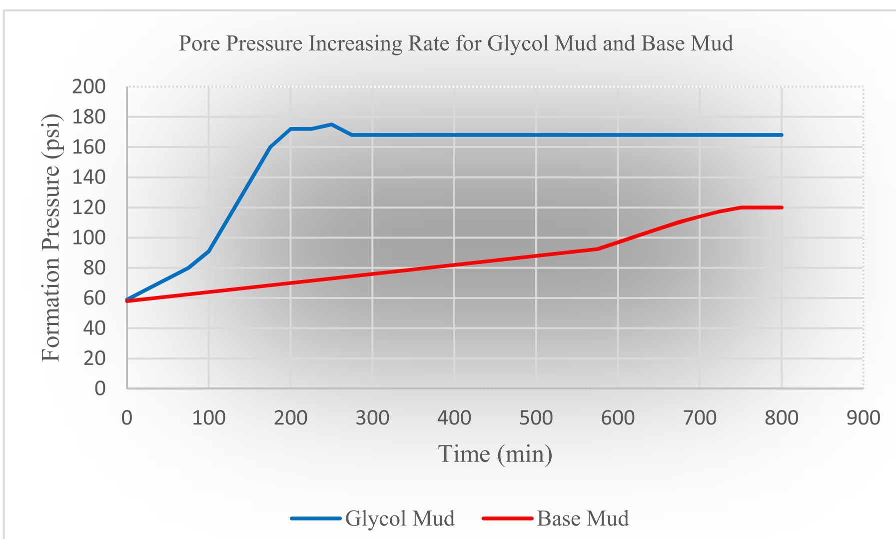

Fig. 2. Pore pressure increasing rate for glycol mud and base mud without glycol.

Table 2
Properties of used plug within PPT test.

Core ID	Sample depth (m)	Weight (g)	Length (McMillan et al., 2015)	Diameter (McMillan et al., 2015)	Porosity (%)	Permeability (mD)	Grain Density (g/cm^3)
5	4472.608	225.1916	8.122	3.889	13.417	1.048	2.697

Table 3
Formulation of base mud and glycol mud.

Mud additives	Unit	Base mud	Glycol mud
Salt Water[a] (300,000 ppm)	bbl.	1	1
Potassium chloride	lb.	21	21
Sodium carbonate	lb.	1	1
Sodium hydroxide	lb.	0.5	0.5
PAC-LV	lb.	4	4
XC-polymer	lb.	0.5	0.5
PHPA	lb.	1	1
Glycol	%v/v	–	3%
Barite	lb.	As need	As need

[a] Salt water includes NaCl which is used for this experiment.

Table 4
Properties of base mud and glycol mud.

Mud properties	Unit	Base mud	Glycol mud
$\theta 600$	–	87	86
$\theta 300$	–	50	47
Apparent viscosity	cP	43.5	43
Plastic viscosity	cP	37	39
Yield point	lb./100 ft^2	13	8
Gel 10sec/10min	lb./100 ft^2	1/2	1/2.5
pH	–	11.7	11.7
API fluid loss	ml	4.2	4
Mud weight	PCF	100	100

Table 5
Properties of used plug within PPT test.

Core ID	Sample depth (m)	Weight (g)	Length (McMillan et al., 2015)	Diameter (McMillan et al., 2015)	Porosity (%)	Permeability (mD)	Grain density (g/cm^3)
2	4472.16	217.6066	8.283	3.887	18.186	1.425	2.707

Table 6
Formulation of base mud and silicate mud.

Mud additives	Unit	Base mud	Silicate mud
Salt water (40,000 ppm)	bbl.	1	1
Potassium chloride	lb.	20	20
Sodium carbonate	lb.	1	1
Sodium hydroxide	lb.	0.5	0.5
PAC-LV	lb.	5	5
XC-polymer	lb.	1	1
Sodium silicate (R = 2.45)	%v/v	–	6%
Barite	lb.	As need	As need

Table 7
Properties of base mud and silicate mud.

Mud properties	Unit	Base mud	Silicate mud
θ600	–	139	128
θ300	–	95	88
Apparent viscosity	cP	69.5	64
Plastic viscosity	cP	44	40
Yield point	lb./100 ft^2	51	48
Gel 10sec/10min	lb./100 ft^2	6/10	11/13
pH	–	12.00	13.37
API fluid loss	ml	5.6	2.5
Mud weight	PCF	100	100

3. Results and discussion

3.1. Glycol drilling fluid design

Glycol mud and base mud (without glycol) according to the proposed formulation in Table 3 is made, and after measuring fluid properties (rheology, filtration loss, pH, and density), PPT test is done for both samples on the prepared plug through the well.

In Table 4 properties of base mud and glycol mud is described.

PPT test is done on each sample after the fluid properties of created mud is measured. According to the equipment limitations, the test is done on the temperature of 200°F. Core remaining pressure in all the experiment is 300 psi. Plug samples by using salty water of 4% are saturated. Then, specific fluid with a pressure difference of 100 psi (overbalance pressure) is in contact with the surface of plug sample and simultaneously pressure changes in the downstream part or formation piston versus time is measured and reordered. Fig. 2 demonstrates the pressure differences for the base mud and the glycol mud.

As can be seen in Fig. 2, the formation pressure is increased by passing the time; in respect of the way, both the base mud and the glycol mud has the same increasing pattern. The former, has the higher formation pressure, and after a time period, it reaches a constant value. However, the latter within the same period, is increased gradually.

3.2. Silicate drilling fluid design

Properties of used plug for silicate drilling fluid are shown in Table 5.

Silicate mud and base mud (without silicate) according to the proposed formulation in Tables 6 and 7 is made, and after measuring fluid properties (rheology, filtration loss, pH, and density), PPT test is done for both samples on the prepared plug through the well.

PPT test is done on each sample after the fluid properties of created mud is measured. According to the equipment limitations, the test is done on the temperature of 200°F. Core remaining pressure in all the experiment is 300 psi. Plug samples by using salty water of 4% (sodium chloride) are saturated. Then, specific fluid with a pressure difference of 100 psi (overbalance pressure) is in contact with the surface of plug sample and simultaneously pressure changes in the downstream part or formation piston versus time is measured and reordered. Fig. 3 demonstrates the pressure differences for the base mud and the silicate mud.

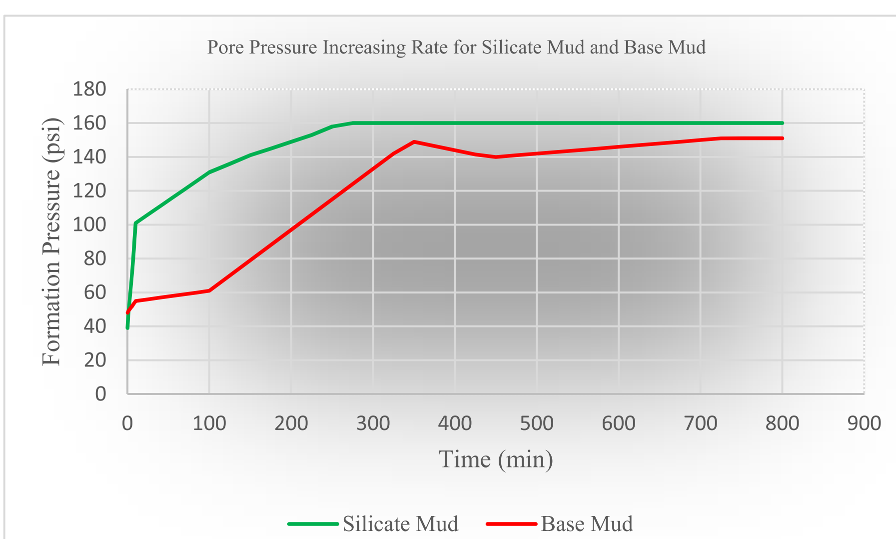

Fig. 3. Pore pressure increasing rate for silicate mud and base mud without silicate.

Table 8
Properties of used plug within PPT test.

Core ID	Sample depth (m)	Weight (g)	Length (McMillan et al., 2015)	Diameter (McMillan et al., 2015)	Porosity (%)	Permeability (mD)	Grain density (g/cm^3)
8	4472.818	212.3295	8.278	3.887	19.795	13.667	2.696

Table 9
Formulation of base mud and sodium formate mud.

Mud additives	Unit	Base mud	Sodium formate mud
Fresh water	bbl.	–	0.722
Salt saturated water	bbl.	1	–
Sodium formate	lb.	–	209.2
Sodium carbonate	lb.	0.5	0.5
PAC-LV	lb.	5	5
XC-polymer	lb.	1	1
Barite	lb.	As need	As need

Table 10
Properties of base mud and sodium formate mud.

Mud properties	Unit	Base mud	Sodium formate mud
θ600	–	108	91
θ300	–	64	56
Apparent viscosity	cP	54	45.5
Plastic viscosity	cP	44	35
Yield point	lb./100 ft^2	20	21
Gel 10sec/10min	lb./100 ft^2	2/3	5/7
pH	–	7.9	9.7
API fluid loss	ml	3.6	2.3
Mud weight	PCF	100	100

As can be seen in Fig. 3, the rate of pressure increase for the silicate mud in comparison to the base mud is less rather than downstream pressure (formation pressure). The most striking feature of this reduction is caused by forming silicate settling due to its contact with salty water through the core. Also, another aspect of this reduction is due to the penetration of fluid filtration into the downstream section.

3.3. Formate drilling fluid design

Properties of used plug for formate drilling fluid are being shown in Table 8.

Formate mud and base mud (saturated with sodium chloride) according to the proposed formulation in Table 9 is made, and after measuring fluid properties (rheology, filtration loss, pH, and density), PPT test is done for both samples on the prepared plug through the well. In this research, sodium formate salts are only used. Consequently, due to required weight of fluid for the specified field (100 PCF), high amount of potassium and sodium salts should be needed. Although, regarding the high cost of potassium formate salts, it only uses the sodium salts for this process.

The sodium formate mud has more solvent in comparison to the sodium chloride. Thereby, it could be made the fluid with higher density, and the percentage of solid weighting agents are far less. As a result, the required adding barite to increase the fluid weight to 100 PCF in the sodium formate mud is less than the base mud. In Table 10, properties of base mud and sodium formate mud are expressed.

As it is evident in Fig. 4, the sodium formate mud has more efficiency in comparison to the base mud (saturated with sodium chloride) because the sodium formate mud filtration viscosity is more than the base mud filtration viscosity. As a result, the filtration penetration to the matrix is reduced. Moreover, regarding the salt formate properties in increasing thermal stability of polymers, the efficiency of the fluid filtration control of polymers in formate mud are more than the base mud.

3.4. Evaluation and comparison of PPT experimental results of different shale inhibitors fluids together

Fig. 5 illustrates the PPT experimental results on the glycol, silicate and formate muds. As it is clarified in Fig. 5, the trend of increasing pressure for the sodium formate mud is less than the glycol mud. Besides, the pattern of pressure rising for the glycol formate mud is less than the silicate mud. As a result, the efficiency of the sodium formate mud to control fluid penetration through the

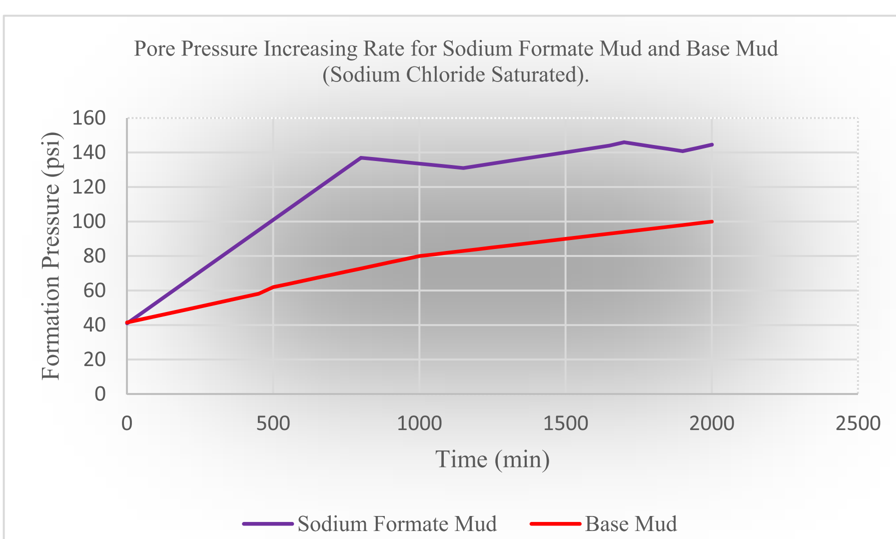

Fig. 4. Pore pressure increasing rate for sodium formate mud and base mud (sodium chloride saturated).

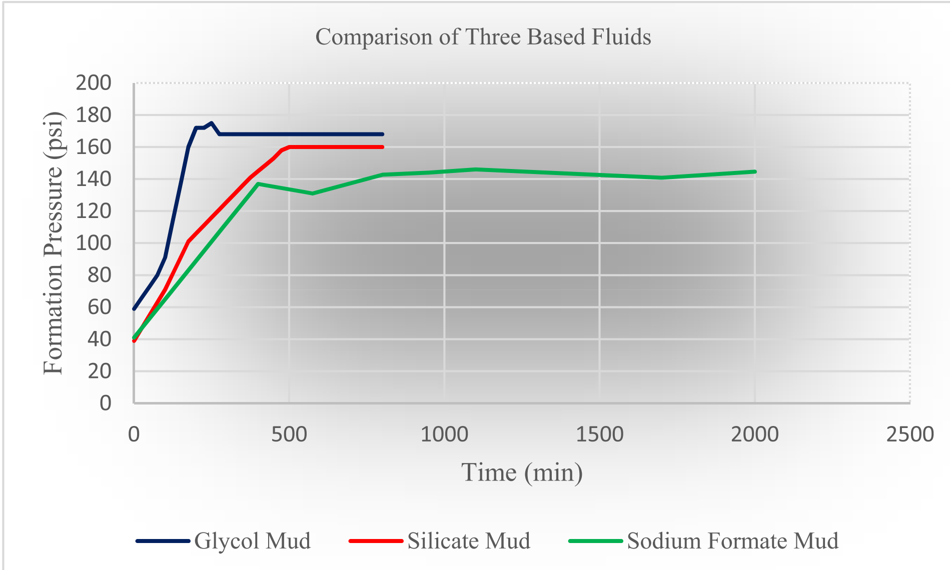

Fig. 5. Comparison of PPT experimental results of different shale inhibitors fluids together.

rock and increase the stability of shale layers, are better than the glycol and silicate muds respectively.

4. Conclusions

The format-based fluid is a kind of recent drilling fluid which can be made from inorganic salt brine drilling fluid system; in respect of the way, in comparison with conventional drilling fluid, the formate drilling fluid is characterized by no bentonite slurry. In this comprehensive laboratory experimental investigation, regarding the experimental evaluation tests with PPT equipment, it is determined that the formate fluids in comparison with the glycol and silicate fluids (due to their types and used concentration agents) have an appropriate operation when it are pumped to the well. Another reason for this phenomenon is related to the lower formation pressure drop which is occurred by the utilization of the formate fluids rather than the glycol and silicate based fluids. Besides, these fluids have more thermal stability up to a temperature of 250°F over 16 h period than the other fluids. Consequently, the formate fluids have more shale recovery percentage of the silicate, glycol, and potassium chloride fluids.

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