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EFFECT OF SALINITY ON THE VISCOSITY OF WATER BASED DRILLING FLUIDS AT ELEVATED PRESSURES AND TEMPERATURES

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ABSTRACT

Due to the continued growth in hydrocarbon demand, operators in the oil and gas industry are always looking to drill deeper wells in order to access previously unattainable hydrocarbons. High-Pressure High-Temperature (HPHT) wells are now broadly present in places like the Gulf of Mexico, the North Sea, and the Middle East. At such conditions, the effect of salts on the properties and performance of water-based drilling fluids cannot be reliably extrapolated from moderate conditions.
As a result, this research aimed to test and investigate the rheological behavior of various water-based drilling fluids with a variety of different salinities at HPHT conditions using a state-of-the-art HPHT viscometer. The mud was found to start losing its intrinsic properties at 24,000 psi and the concentration of Calcium Chloride was found to have a more profound impact on the rheology than Sodium Chloride. Out of the used rheological models, Herschel-Bulkley had the best fit and could be used to predict the viscosity.

Keywords: ***Salinity, Rheology, Water Based Mud, High Pressure High Temperature, Drilling Offshore, Deepwells.***

1. INTRODUCTION

The upscale demand all throughout the world for oil and gas products provides a dynamic force to an inventive exploration and then venture to new resourceful means of production from deeper formations. Over half of the oil and gas reserves in the United States remain below 14,000 feet subsea according to the Minerals Management Service (MMS). In the Gulf of Mexico, wells were drilled at 27,000 feet below seabed with conditions of above 400°F and 24,500 psig in the reservoirs. As we drill into deeper formations, we will experience higher pressures and temperatures, at which every area of the field that has high levels of soluble salts (salinity) is believed to have an effect on the behavior and properties of water-based muds (WBM).

The integrity of the drilling fluid depends on its composition. The effect of temperature and pressure on the drilling fluid's viscosity is complicated to the extent that a wide variety of problems are encountered from its mechanical sector.

A similar issue is the negative impact on the rheological properties of the drilling fluid when it is exposed to high pressure high temperature (HPHT) conditions and/or contaminated with salts as it comes in contact with deep formations. Oil and gas wells are referred to as HPHT wells if their bottomhole conditions are greater than 300°F (150°C) or 10,000 psi (69 MPa).

Although oil-based muds are more effective in deep wells because of their thermal stability (Shadravan 2012), the demand for high-performance water-based drilling fluids and their improvement is necessary because "the drilling industry continues to go green due to stricter environmental constraints" (Donham and Young 2009). Many countries including the USA, Norway, Saudi Arabia, and Qatar have prohibited the use of oil-based drilling fluids because of the pollution they may cause to the soil and water aquifers (Amani et al. 2012). Water-based

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drilling fluids have a lower concentration of organics. This reduces the organic loading of the environment and favors biodiversity in the areas of discharge (Bland et al. 1995).

Several mud problems arise from the combined effects of high temperature and salts. Introducing salt into the mud increases the chemical treatments required to maintain acceptable mud properties. The incidence of salt further reduces the ability of active clays to hydrate. Bentonite, for example, is significantly affected in water of even moderate salinity and the amount of deflocculant required increases with the increasing salt concentration. Another important consideration is in the slurry design; at some point the salinity will speed up the thickening time.

In the Persian Gulf, drilling offshore wells also presents issues related to wellbore stability and increased downhole losses. The development of water-based muds that could minimize these operational problems has become a major objective (Donham and Young 2009).

Over-pressured formations, weak zones, unstable properties, highly deviated wells with slim boreholes and reactive shales are the most common problems in drilling High-Temperature and High-Pressure wells. The HPHT environment limits the range of available materials and technologies to exploit this reservoir. From another perspective, this research is very important to overcome well control issues under HPHT conditions. Therefore, controlling the drilling fluid's rheological properties is vital to maintain well control: the drilling fluid hydrostatic pressure must be high enough to resist the formation pore pressure, yet low enough to prevent formation fracturing and lost circulation. Under these extreme conditions, confining the drilling fluid's rheological properties becomes more complicated. A proper drilling fluids design is a necessary first step towards controlling the wells.

New testing equipment and laboratory techniques were needed for the evaluation of drilling fluids at high pressure and temperature conditions due the surge in the drilling of deeper wells and the resulting need for thermally-stable drilling fluids (Weintritt and Hughes 1965). Previously, most of the HPHT studies done were limited in maximum pressures and temperatures. However, systems that can measure the rheological properties of drilling fluids at conditions up to 600 F and 40,000 psi have recently become commercially available (Lee and Shadravan 2012).

2. SIGNIFICANCE

The issue at hand in this investigation is of increasingly great importance. With a daily oil demand of over 36 million bpd of oil, and the inevitable deterioration of oil wells over time due to continued production, it is very important to find enhanced recovery methods that can increase the production rate of present conventional oil wells. Many oil wells in developed nations suffer from aging effects and there is greater need to resort to deeper wells to recover crude oil. As a result, it is very important to be able to recover these deep well oils using innovative methods that do not entail new infrastructure, but instead make use of existing infrastructure. Therefore, the significance of this research is huge and affects the utilization of deep oil wells more than ever before.

The practice of extrapolation of fluid properties from some moderate to Ultra-HP/HT conditions (greater than 400°F BHT or 20,000 psi BHP) is not reliable and could result in significant inaccuracies in wellbore hydraulic calculations. From this experiment, we could add new laboratory results as supporting information to existing literature.

As drillers get into HPHT formations, a number of unique problems are introduced. Well control, for example, becomes more complicated due to narrow pressure margins and higher bottomhole pressures and temperatures (Shaughnessy et al. 2003).

Karstad and Aadnoy (1998) pointed out that recent MWD tools have measured temperatures and pressures with variations that are much greater than what was previously expected. They showed that dynamic changes in temperature have led to significant changes in the effective mud density of drilling fluids. The drilling fluid volume gains or losses are, therefore, more significant due to this strong dependency of mud density on temperature.

Bartlett (1967) also stated that mud properties at the surface are significantly different from those in downhole conditions. For example, he showed that the viscosity of a particular ligno-sulfate mud decreased two-fold when the temperature was increased from 80 F to 140 F and concluded that the flow characteristics rarely follow any one particular pattern throughout the entire range of temperatures encountered. He then recommended against the use of data obtained at surface temperatures to determine the flow conditions at the higher temperatures encountered downhole.

Oil-based mud systems are widely used in HP/HT applications because of their thermal stability, temperature tolerance, cost effectivity and ease of operation and production. However, they are not always feasible due to environmental regulations, cost logistics, difficult remedial treatments for lost circulation, or late gas kicks detection etc. In some countries, the use of oil-based muds is not allowed because of environmental concerns. All of these reasons suggest that the water-based muds should be considered for use in HPHT conditions like those present in Qatar.

3. OBJECTIVES

This research has the goal to test and investigate the rheological behavior of various water-based drilling fluids with a variety of different salinities at HPHT conditions using a state-of-the-art viscometer capable of accurately measuring drilling fluids properties up to 600°F and 40,000 psig.

The main equipment for these experiments is CHANDLER Model 7600 High Pressure High Temperature Viscometer. There are only 8 such equipment that exists in the whole world and our university in Qatar has one of them. Working on this experimental research will train the participating students to use one-of-a-kind high end viscometers in the world.

Today, scientists and engineers push the limits of materials science to meet the technical challenges posed by HPHT wells. This research will introduce and trigger the spirit of understanding the HPHT technology in the students. At the same time they will gain the knowledge of the effect of water based mud rheological behavior with different salinity and it promotes learning through research.

4. METHODOLOGY

The substance of this paper revolves around the investigation and modelling of deep oil well conditions. The main area of concern is with regards to the salinity and its rheological properties of deep wells and how they impact drilling operations. This paper studies certain effects of the inherent high pressure and temperature present in deep well's on the drilling fluid. The parameters that are gauged in this experiment are viscosity, yield point and gel strength of the drilling fluid when subjected to these conditions. To model this experiment, water based muds of varying salinity were experimented with two different types of salts – NaCl and CaCl2.

4.1 Experimental Matrix

For the purpose of this project, two types of salts, Sodium Chloride (NaCl) and Calcium Chloride ($CaCl_2$) were chosen for testing. These two salts are the most commonly used types in formulating drilling fluids for the Oil & Gas industry.

To compare the rheology of whole mud without salt versus a monovalent (NaCl) and a divalent (CaCl2) kind of brine having the exact amount of components and will undergo an increasing pressure and temperature, using the Chandler 7600 HTHP Viscometer.

Materials preparation and procedures are keen to establish dependable results. The formulation has to have compatible interaction between its recipes. Factors like, each polymer needs to come across its maximum yielding capacity (e.g. solubility etc) upon mixing, time interval and mixing speed are essentially considered.

Also, two percentages, 15 and 25, of each of these two salts are proposed to be used in formulating the water-based fluid samples which corresponds to approximately 9.3 and 10.0 ppg . 25% concentration of NaCl will result in full saturation of the water-based fluid system and thus this percentage represents a maximum value. 15% concentration, however, can represent a middle value between the maximum concentration (25%) and the minimum (0%).

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The weight of the water-based mud that will be used for all the experiments is 12.5 ppg which is a very suitable value for drilling fluids when dealing with HPHT conditions. A real experimental mud formulation will be use in this test, from viscosifier, fluid loss agent, starches, weighing materials, drill solids, pH control, hardness treating additive and etc.

The pressure, temperature range, and the number of experiments to be conducted in this project are illustrated in Table 1.

4.2 Water Based Mud Fluid Formulation

Commercial products known in drilling fluids sectors are highly qualified to restore its property in addition with other components even in HTHP conditions.

- Caustic and Soda Ash, use to control a pH and Ca++.
- NaCl and Calcium Chloride, initial weighing agent, viscosity, stability of shale and improving ROP (rate of penetration).
- Flowzan, act as a viscosifier
- Polysal HT, Filtration control and rheological stability at high temperature conditions.
- PAC-UL, polyanionic cellulose designed to control fluid loss
- Bentonite, aka Sodium Montmorillonite act as viscosifier and fluid loss control as well
- Calcium Carbonate and Barite , serve as a weighing additive

The need for a fluid that would deliver efficient performance while at the same time adhering to environmental limitations led to the development and use of low salinity high-performance water-based mud in the West Urdaneta field of Lake Maracaibo, Venezuela (Montilva et al. 2007). This mud helped improve operational performance even when salinity had to be decreased due to environmental constraints.

Thaemlitz et al. (1999) developed an environmentally safe water-based polymer system that can be used for drilling operations in high pressures as well as temperatures up to 450 F. The system has the advantage of consisting of only two basic polymers (for rheology and filtration control at high temperatures) instead of a large number of additives in order to control thermal degradation.

Another drilling fluid, known as WBHT (water-based high-temperature), was developed based on the hypothesis that the thermal degradation/ drilling fluid instability at high temperatures was mainly caused by the dispersion of clay solids (Berry and Darby 1997). The fluid showed a stable rheology vs. temperature profile at low shear rates and at temperatures up to 425 F. The fluid was also tested at Mobile Bay in the Gulf of Mexico and was not affected by salinity changes while drilling.

4.3 Model 7600, High-Pressure High-Temperature Viscometer

As Texas A&M at Qatar is equipped with the state of the art machine in measuring the rheology of a fluid at high-temperature and high-pressure conditions, the team made use of this. With its capacity of gauging the viscosity at approximately 40,000 psgi and 600 °F, this machine will give a remarkable output in our research. The shear stress (torque) produced using bob rotating rotor is determine by a precision torsion spring and high resolution encoder in accordance with ISO/API Specifications.

The rotational speeds from 0-900 rpm or 0 – 1533 sec-1, wherein suspended solids in the specimen are circulated outside of the face of the rotor. The sample viscosity is determined as the ratio of shear stress (dyne/cm2) to shear rate (sec-1) resulting in dyne-sec/cm2, otherwise expressed as Poise
The operation is controlled using a dedicated computer based program that delivers multi-axis data display options and automatic instrument control and calibration features.
Figures 2 and 3 show the Chandler 7600 HTHP Viscometer is assembled. The main sections used in this product are the vessel assembly and the rotor assembly. The vessel assembly is shown as the far right component in figure 3, followed immediately to the left by the rotor. All other parts mainly

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consist of supporting components such as shafts, bearings, seals and o-rings.

One of the main advantages of the Chandler 7600 HTHP Viscometer is that it is the highest pressure viscometer in the oil and gas industry currently available in the market. Furthermore the device can be used under demanding conditions with virtually any temperature and pressure that can be encountered during the drilling operations. Also this model produces a wide range of shear stress and viscosities.

5. RESULTS AND DISCUSSION

Overall, the results attained in this experiment were useful in coming to several conclusions regarding the effects of salinity on the rheological properties of water-based mud. As shown in figure 4, the average dial reading increases with the set pressure. It levels off at a maximum pressure of 18,000 psi and then decreases. This was the case for all the samples apart from the CaCl2 at 25%.

5.1 Graphical Results

In figure 5, it is evident that as the shear rate increases, so does the average dial reading and therefore viscosity. Also as the pressure increases, the slope of the curves becomes greater. However, the curve for 24,000 psi intersects that of the 18,000 psi. This is most likely due to the fact that at such as high pressure of 24,000 psi the fluid begins to lose its intrinsic properties. Similar results were seen in figures 6-9 for various salt concentrations.

In figure 10, as the pressure of the water based mud increases so does the gradient of the curve. Once again at 24,000 psi the curve intersects with the curve at 18,000 psi. This can also be attributed to the loss of certain fluid properties due to the fact that the fluid was subject to such a high pressure.

In figures 12-14 it is clear that the mud at 24,000 psi has a shallower slope of shear stress vs. shear rate at all salinity levels. This can be due to the modifications of some of the mud properties when subject to such a high pressure.

Most importantly it was seen in figures 11-12 that as the concentration of the sodium chloride increases, the measured stress also increases for the same pressure. This shows that the effect of increasing salinity is that it increases the mud viscosity. A similar trend was observed for the calcium chloride.

5.2 Salinity

Salinity is the total of all non- carbonate salts dissolve in water, unlike chloride concentration that represented only by its content. Therefore, the summation of all the salts in the mud can be expressed by salinity.

Amani and Hassiba (2012) performed HPHT tests on water-based drilling fluids containing different concentrations of Sodium and Potassium Chloride (NaCl and KCl). They showed that the fluids with these salts followed the Power Law model up to pressures of 20,000 psi. Above that pressure, the shear rate started to vary linearly with shear stress (best modeled by the Bingham Plastic equation).

5.3 Chloride to Salinity

5.4 Effect of Salinity in Viscosities:

In the presence of different kinds of salt additives to initially increase the weight of the mud, the junction to the point of separation between water and other solids creates and breaks the stable suspension and produces flocculation. Therefore, at the end it will decrease the viscosity of the mud. Up to some extent, modified starches become anionic and free in hydrated water.

According to the NOAA (National Oceanic and Atmospheric Administration), and as can be seen in figures 15-19, salinity decreases greatly from sea surface up to 18040 ft.

5.5 Mathematical Models

Rheology

The flow properties of the drilling fluid must be controlled so that the fluid can function properly. Properties of the fluid such as the plastic viscosity and the yield stress are very important for the success of the rotary-drilling operations and are therefore constantly measured.

Viscosity is the measure of a fluid's resistance to flow and is defined as the ratio of shear stress to shear rate.

Newtonian fluids are fluids where the proportionality between the shear stress and the shear rate is independent of the shear rate.

Newtonian fluids are usually water or fluids with low molecular weight material. However, most drilling fluids are non-Newtonian and experience shear thinning with increased shear rate as shown in Figure 20.

The Bingham plastic and the power law rheological models are non-Newtonian models that were used in the past and are still used today to approximate the behavior of drilling fluids and cement slurries. The majority of the behavioral models for drilling fluids and cement slurries used today include a yield stress. One of these rheological models that fits this kind of behavior at both high and low shear rates is the Herschel-Bulkley model.

Calculations

- Using the 2-point data at θ_{300} and θ_{600}, the plastic viscosity and the yield point were calculated using their respective equations.

$$PV = \theta_{600} - \theta_{300}$$
$$YP = \theta_{300} - PV$$

- Using the Bingham Plastic model, the plastic viscosity and the yield stress were calculated using linear regression on all data points by minimizing the residual sum of squares. An example of the predicted data and the real data can be seen in Figure 21.

$$\tau = \tau_y + \mu_p \dot{\gamma}$$
where $\tau > \tau_y$

- Using the Herschel-Bulkley model, the flow consistency index, the flow behavior index, and the yield stress were calculated using linear regression on all data points by minimizing the residual sum of squares. An example of the predicted data and the real data can be seen in Figure 22.

$$\tau = \tau_y + K\dot{\gamma}^n$$
where $\tau > \tau_y$

- Using the Power Law model, the flow consistency index and the flow behavior index were calculated using linear regression on all data points by minimizing the residual sum of squares. An example of the predicted data and the real data can be seen in Figure 23.

$$\tau = K\dot{\gamma}^n$$

All the calculated data can be seen in Table 6. The correlation coefficients show that the Herschel-Bulkley model is the best fit for the measured data as can be seen in Table 7.

6. CONCLUSIONS AND RECOMMENDATIONS:

- The mud used at all concentrations of salt lost its intrinsic properties when tested at 24,000 psi.
- All rheological data of the mud samples at different salinity levels can be best fitted using the Herschel-Bulkley model.
- The viscosity of the samples with salt had a more uniform trend of increase with increase in shear rate.
- The overall viscosity has decreased with increase in salinity.
- Calcium Chloride salt added to mud samples had a more profound effect on shear stress and rheological properties of the drilling fluid.

Although the cost of calcium chloride is more than sodium chloride per unit, it is still feasible to use this salt as it has a profound effect on the shear stress and other rheological properties of the fluids. In future iterations of this experiment it would perhaps be more useful to record more data points for the salinity level. Observing the results for more salt concentration levels will give a clearer picture of the effect of salinity on the rheological properties of the fluids.

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NOMENCLATURE

θ_{300}	Dial Reading at 300 rpm
θ_{600}	Dial Reading at 600 rpm
τ	Shear Stress *[Pa]*
τ_y	Yield Stress *[Pa]*
μ_p	Plastic Viscosity *[Pa s]*
$\dot{\gamma}$	Shear Rate *[1/s]*
K	Flow Consistency Index *[Pa s^n]*
n	Flow Behavior Index
PV	Plastic Viscosity *[cP]*
SG	Specific Gravity
YP	Yield Point *[cP]*

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APPENDIX 1: FIGURES

Figure 1: Chandler 7600 HTHP Viscometer (Actual Picture, Lab 169-F In TAMUQ)

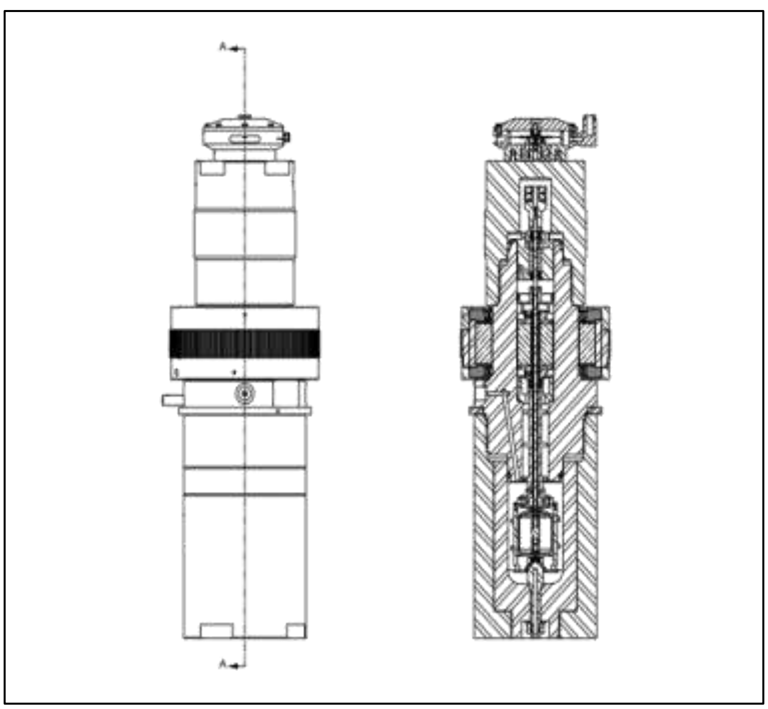

Figure 2: Schematic Of Chandler 7600 HTHP Viscometer (Left); Cross-Section Schematic (Right)

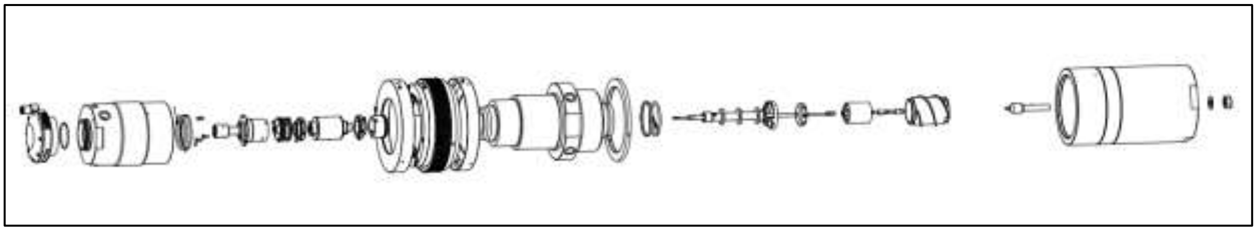

Figure 3: Exploder View of The Chandler 7600 HTHP Viscometer

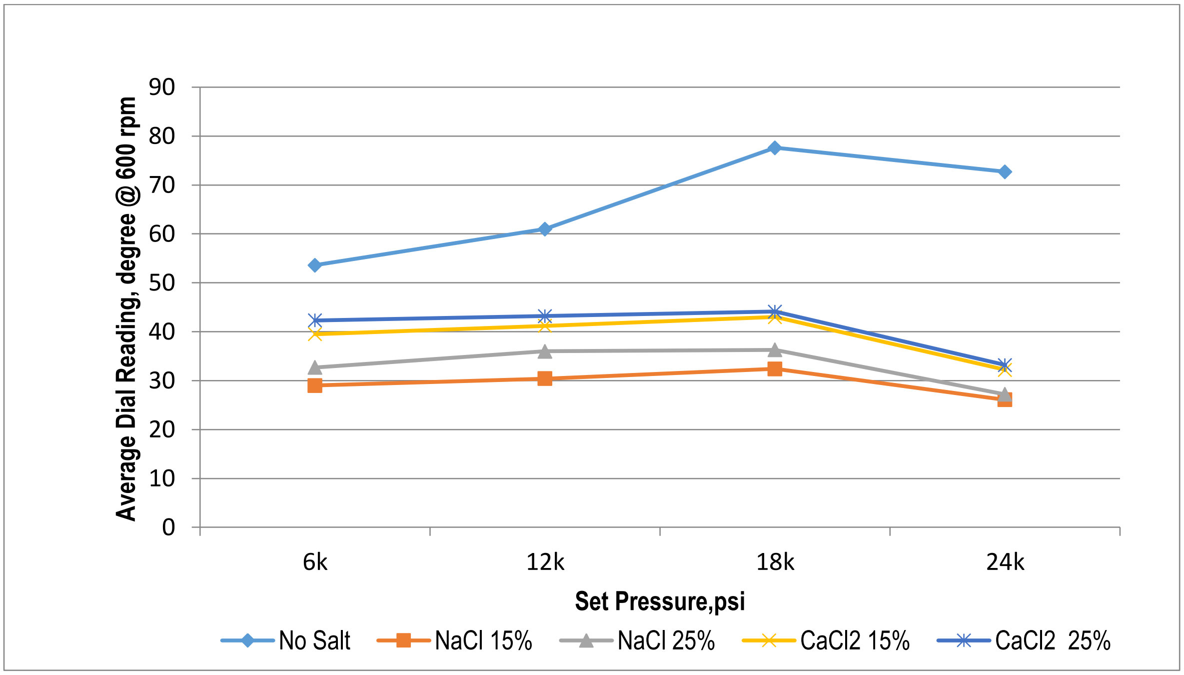

Figure 4: Plot of Average Dial Reading against Set Pressure at 600 Rpm

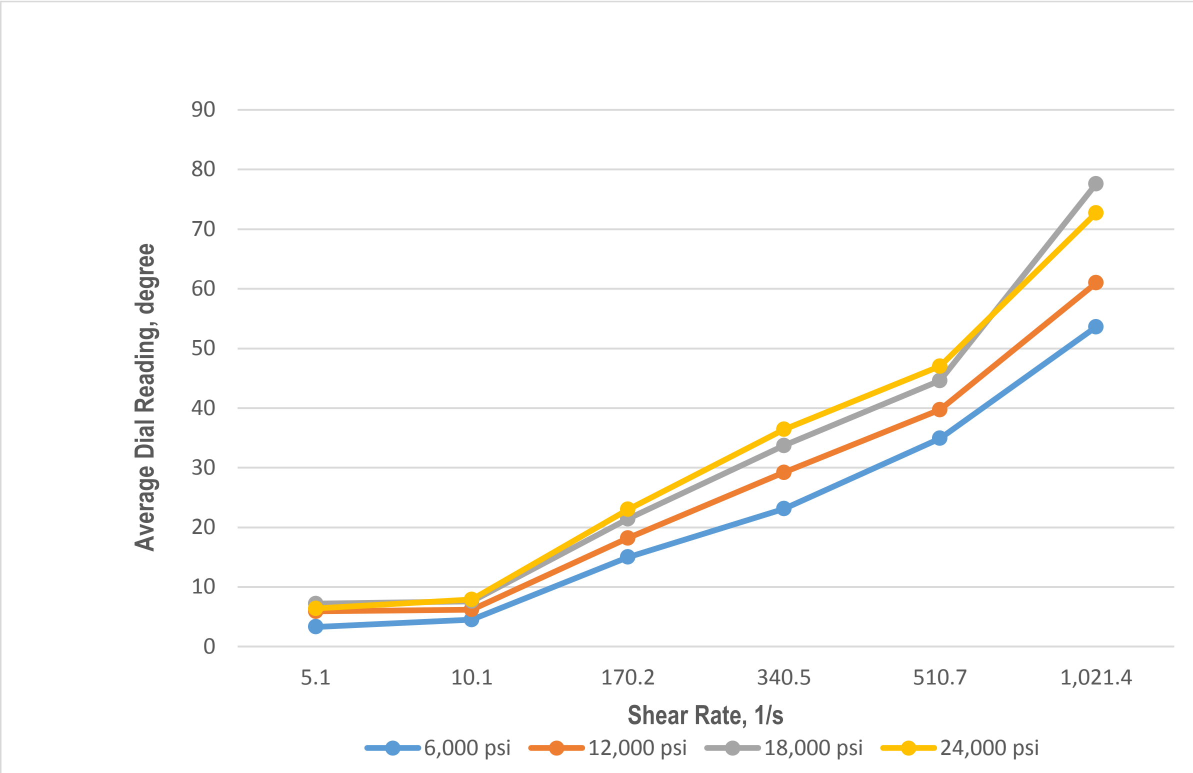

Figure 5: Plot of Average Dial Reading against Shear Rate for Zero Salt Concentration at 300°F

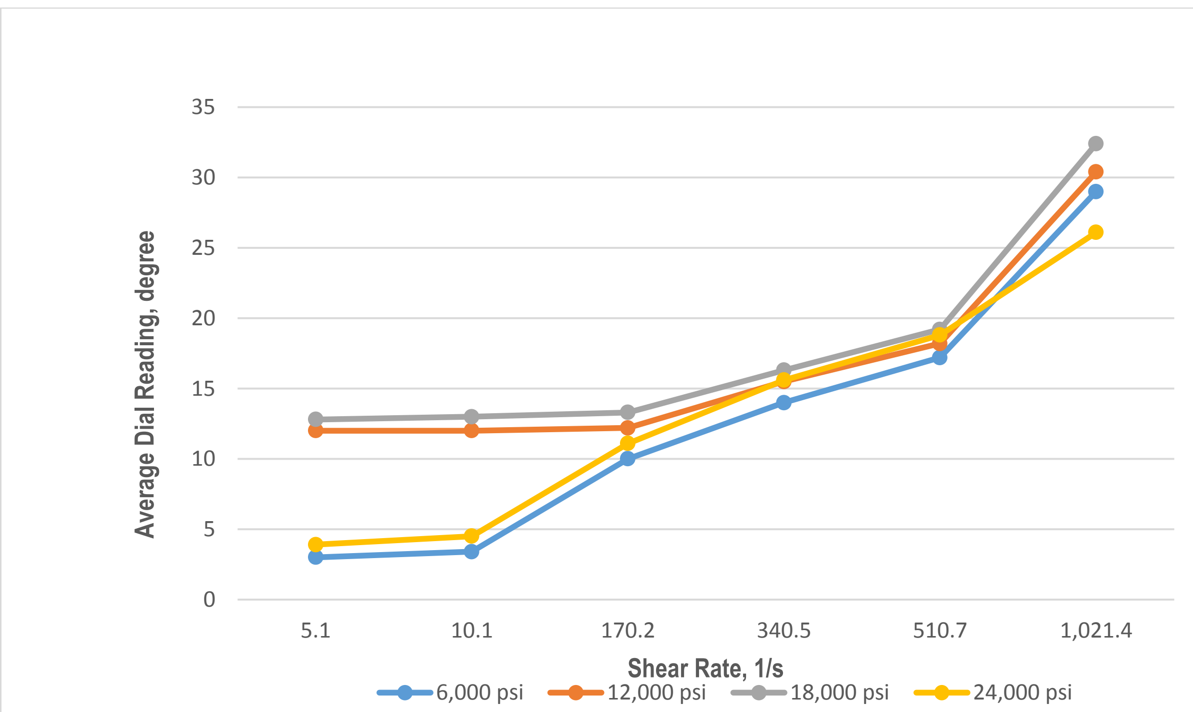

Figure 6: Plot of Average Dial Reading Against Shear Rate For 15% Sodium Chloride Concentration at 300°F

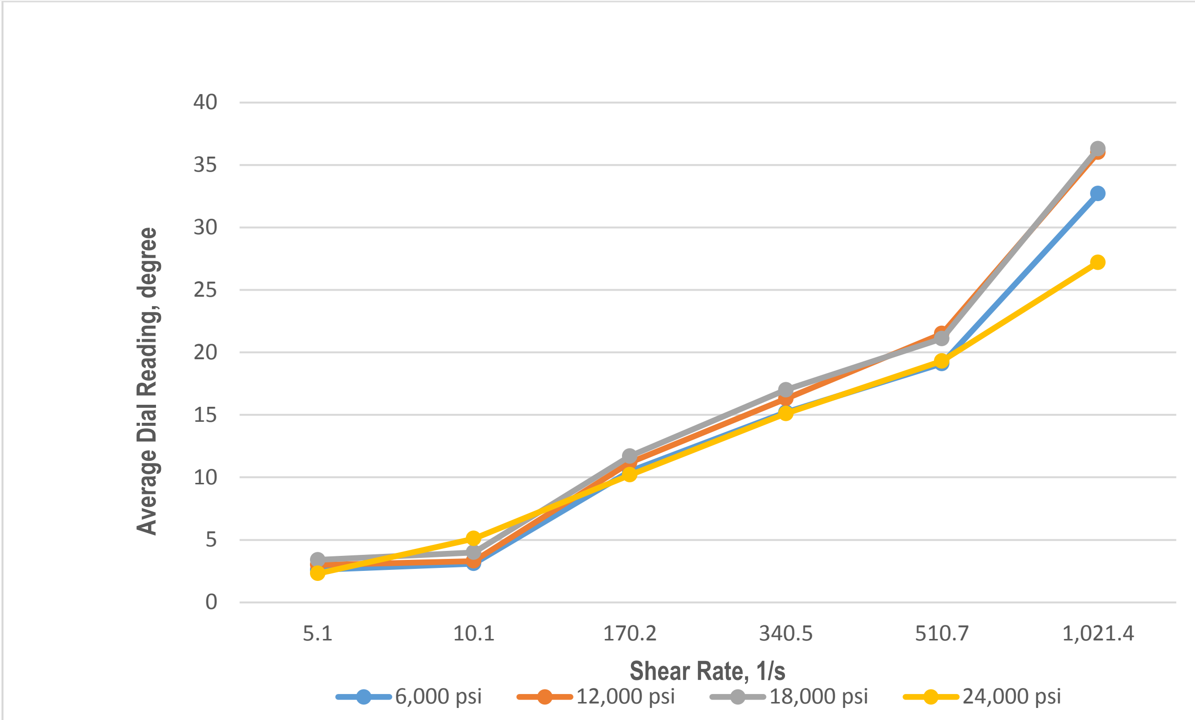

Figure 7: Plot of Average Dial Reading Against Shear Rate For 25% Sodium Chloride Concentration at 300°F

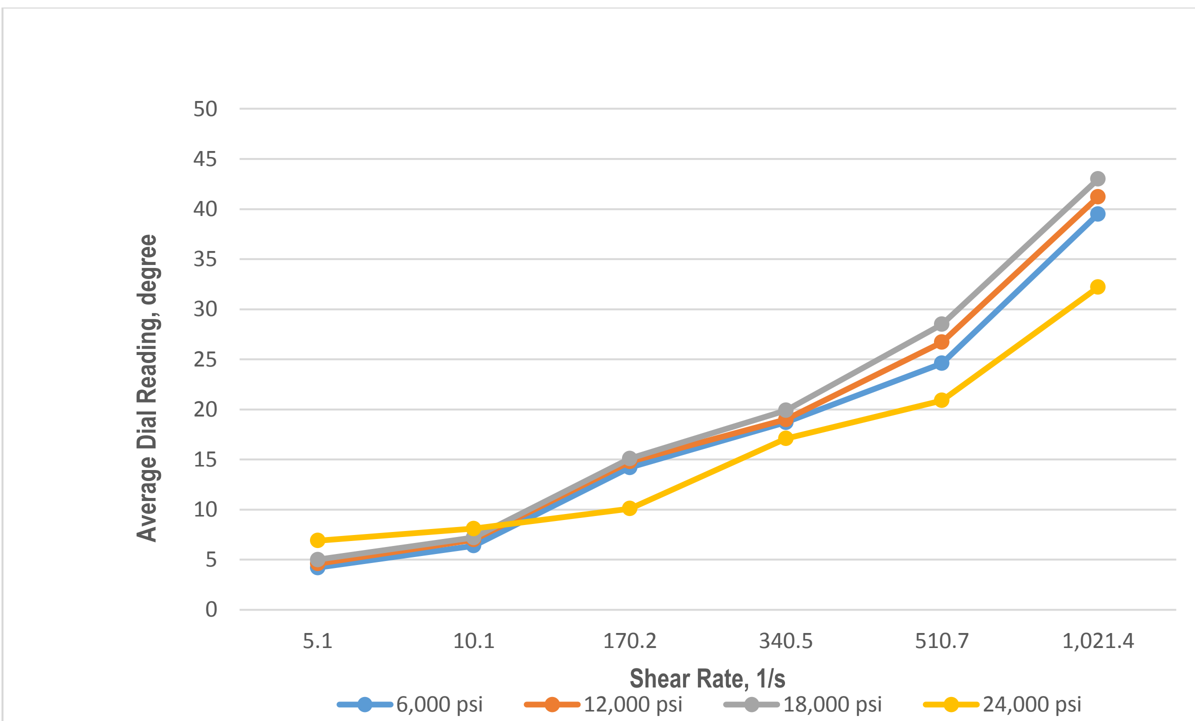

Figure 8: Plot of Average Dial Reading Against Shear Rate For 15% Calcium Chloride Concentration at 300°F

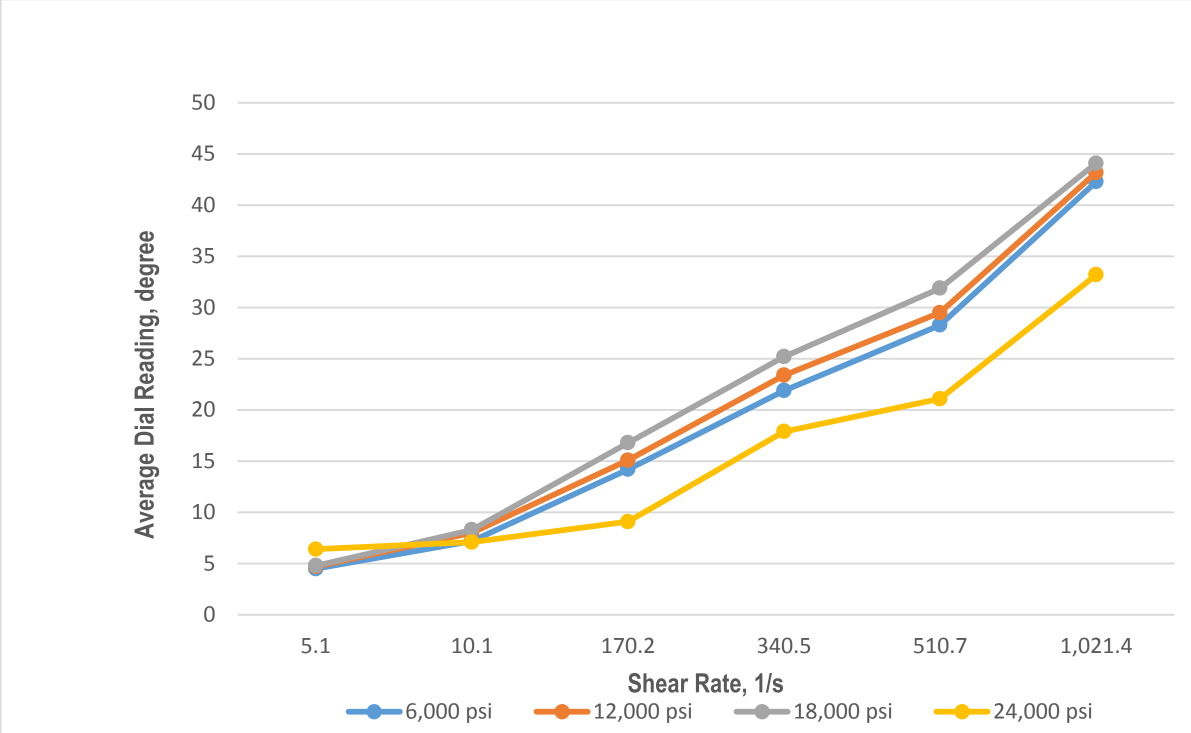

Figure 9: Plot of Average Dial Reading Against Shear Rate For 25% Calcium Chloride Concentration at 300°F

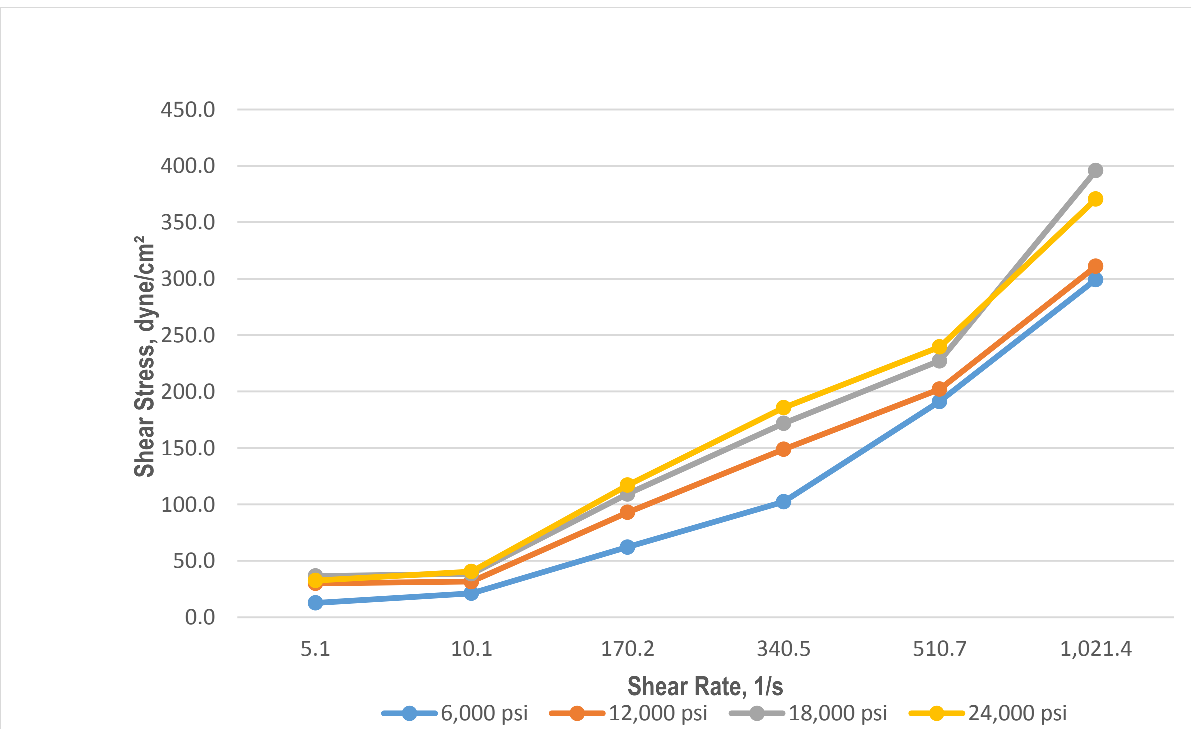

Figure 10: Plot of Shear Stress against Shear Rate for Zero Salt Concentration

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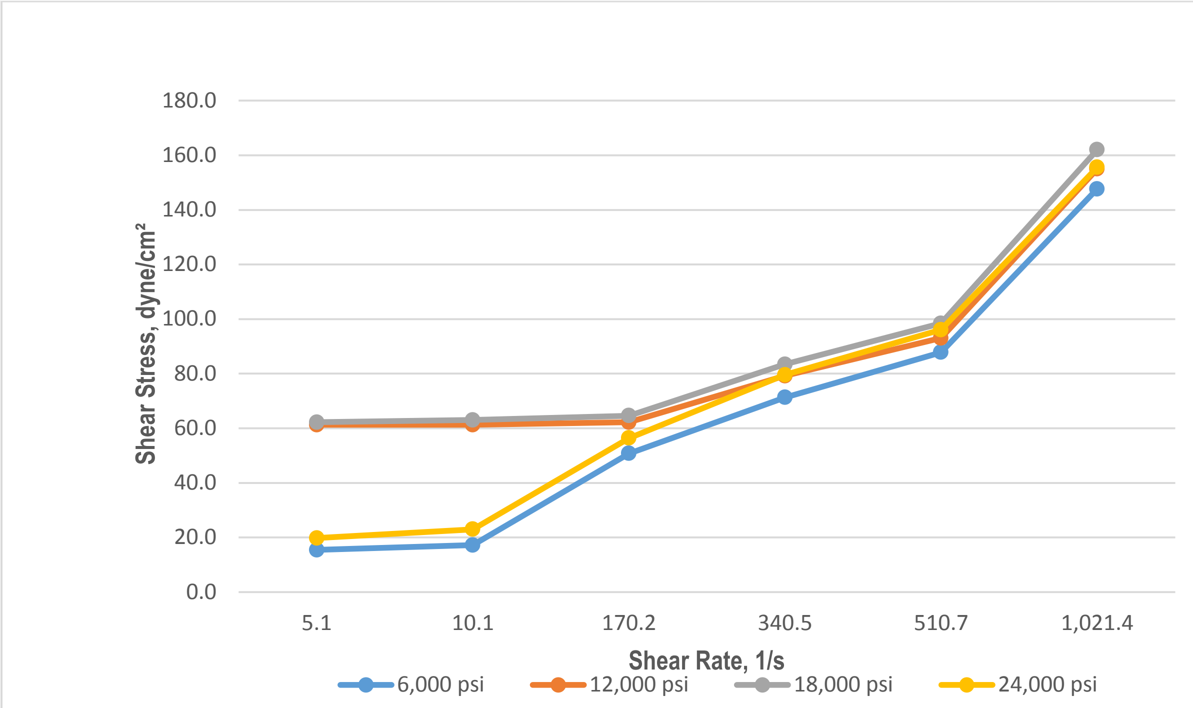

Figure 11: Plot of Shear Stress against Shear Rate For 15% Sodium Chloride Concentration

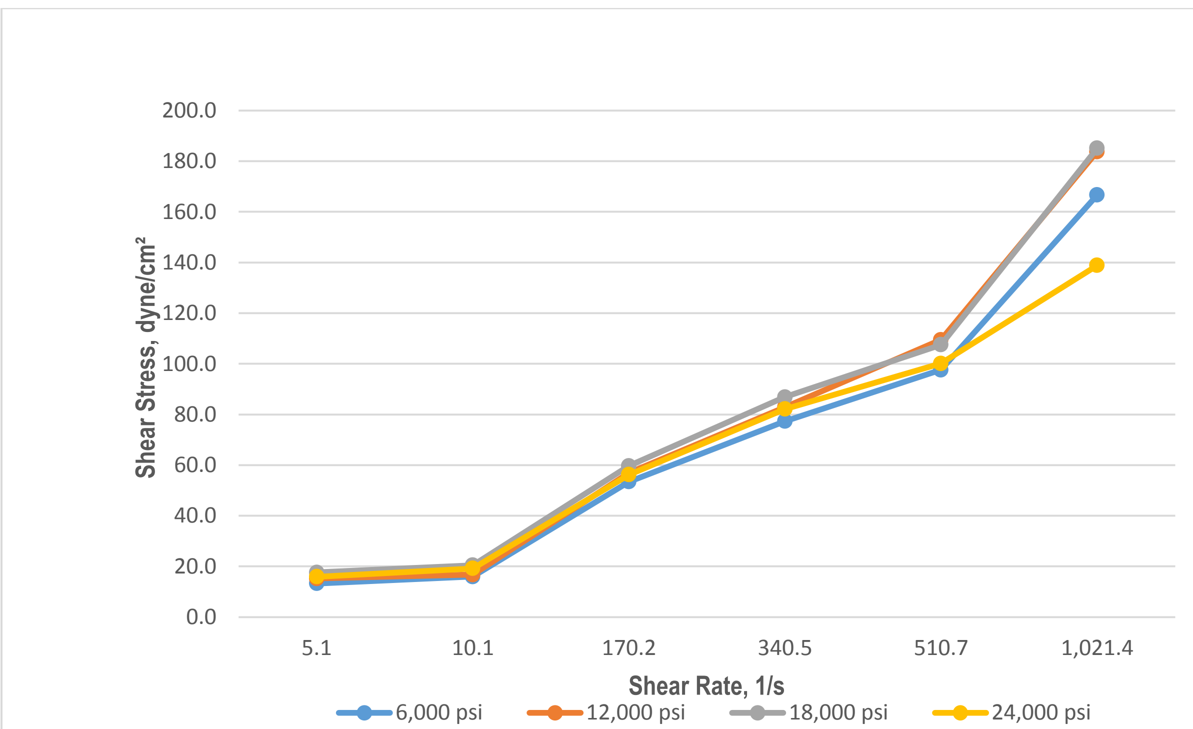

Figure 12: Plot of Shear Stress against Shear Rate For 25% Sodium Chloride Concentration

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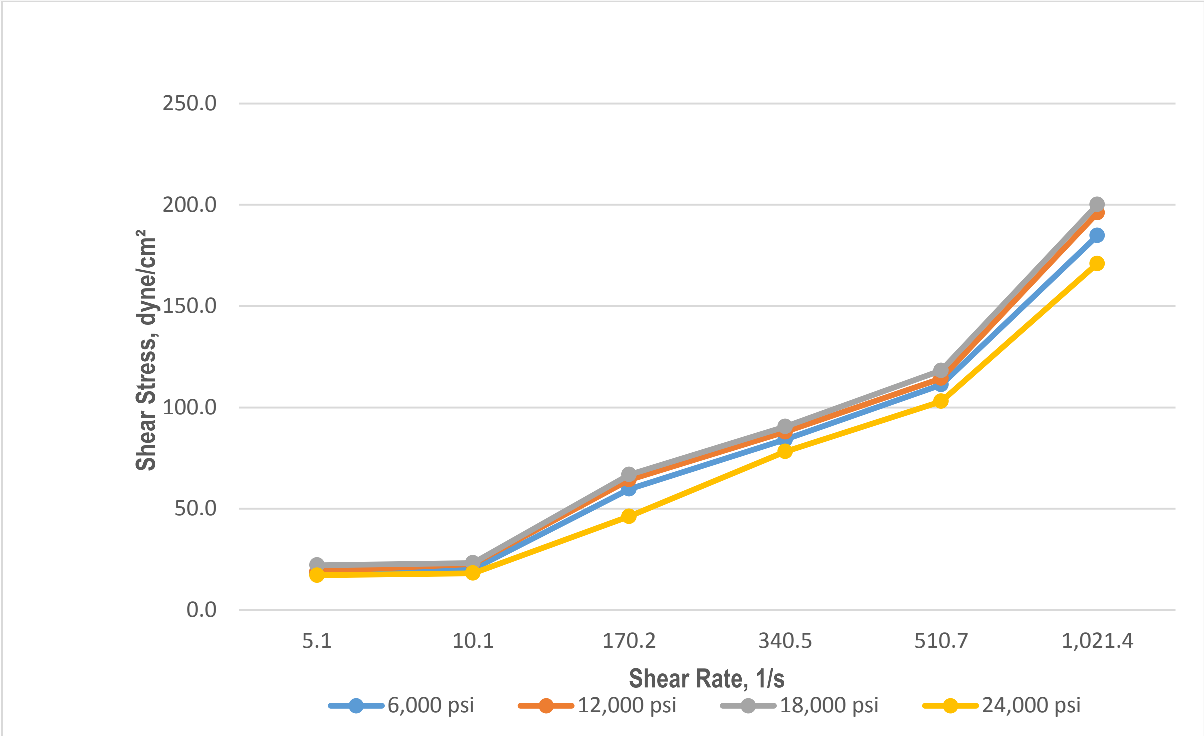

Figure 13: Plot of Shear Stress against Shear Rate For 15% Calcium Chloride Concentration

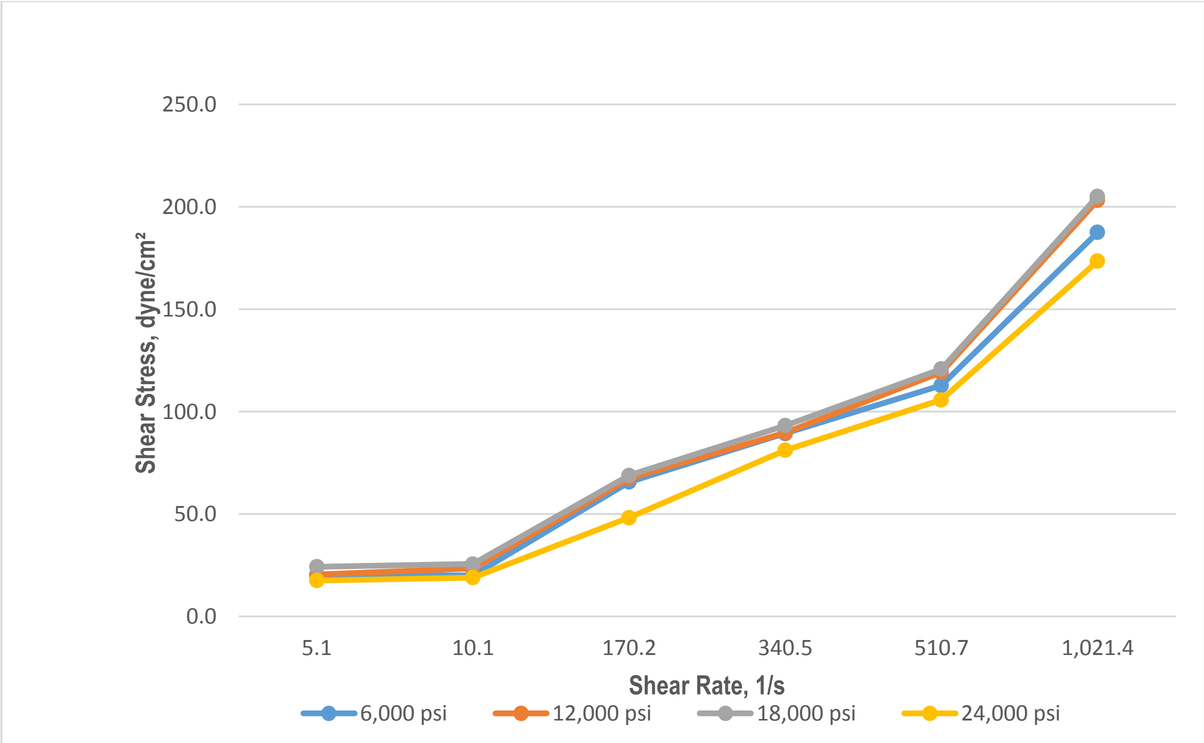

Figure 14: Plot of Shear Stress against Shear Rate For 25% Calcium Chloride Concentration

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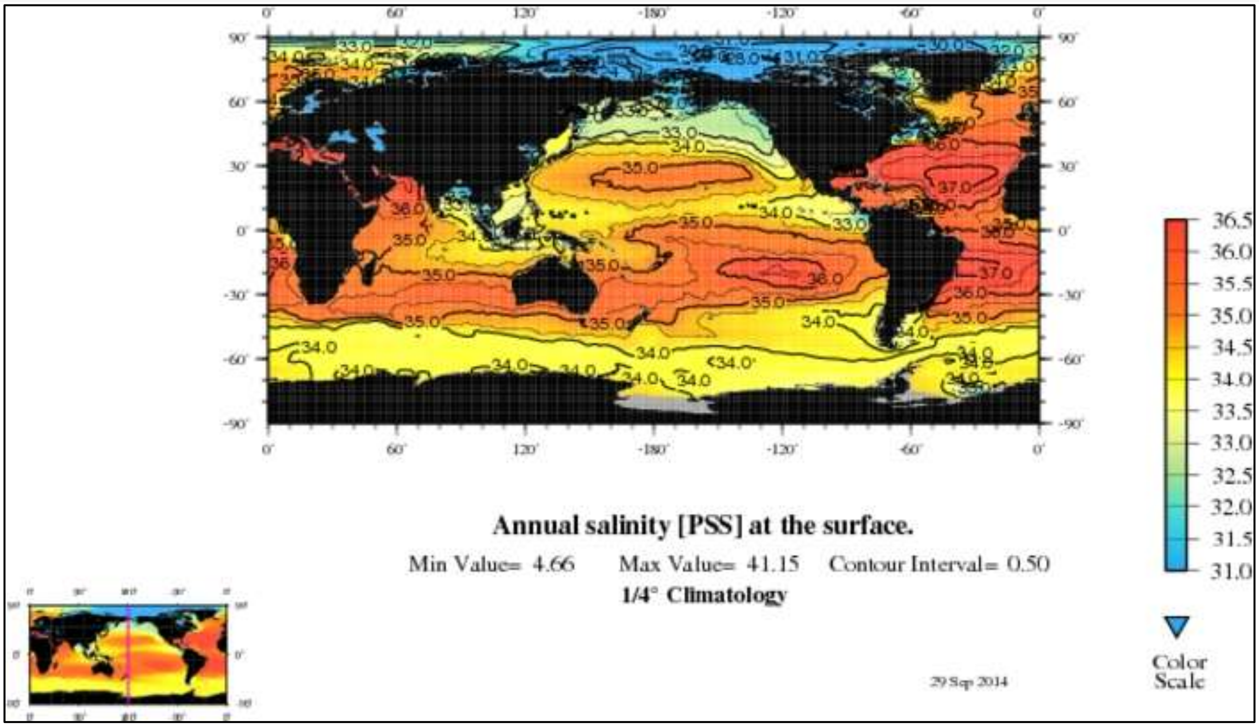

Figure 15: Annual Salinity at Surface

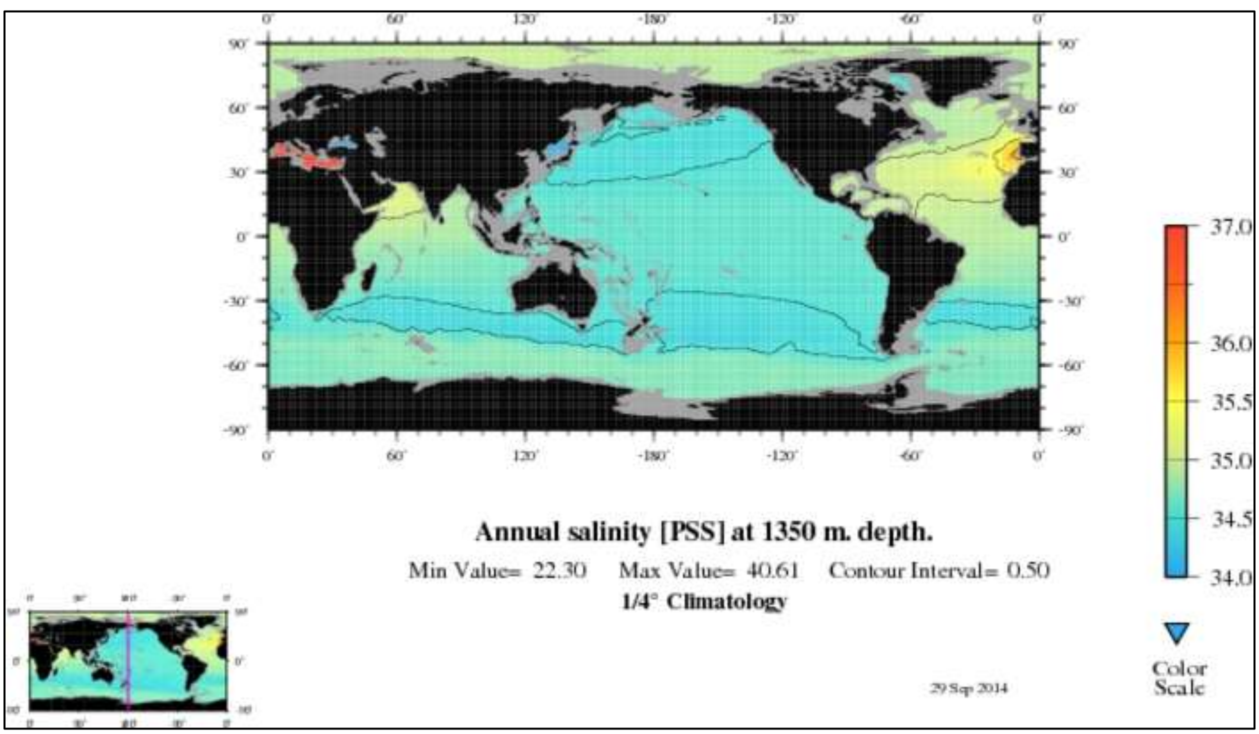

Figure 16: Annual Salinity at 4430 Feet

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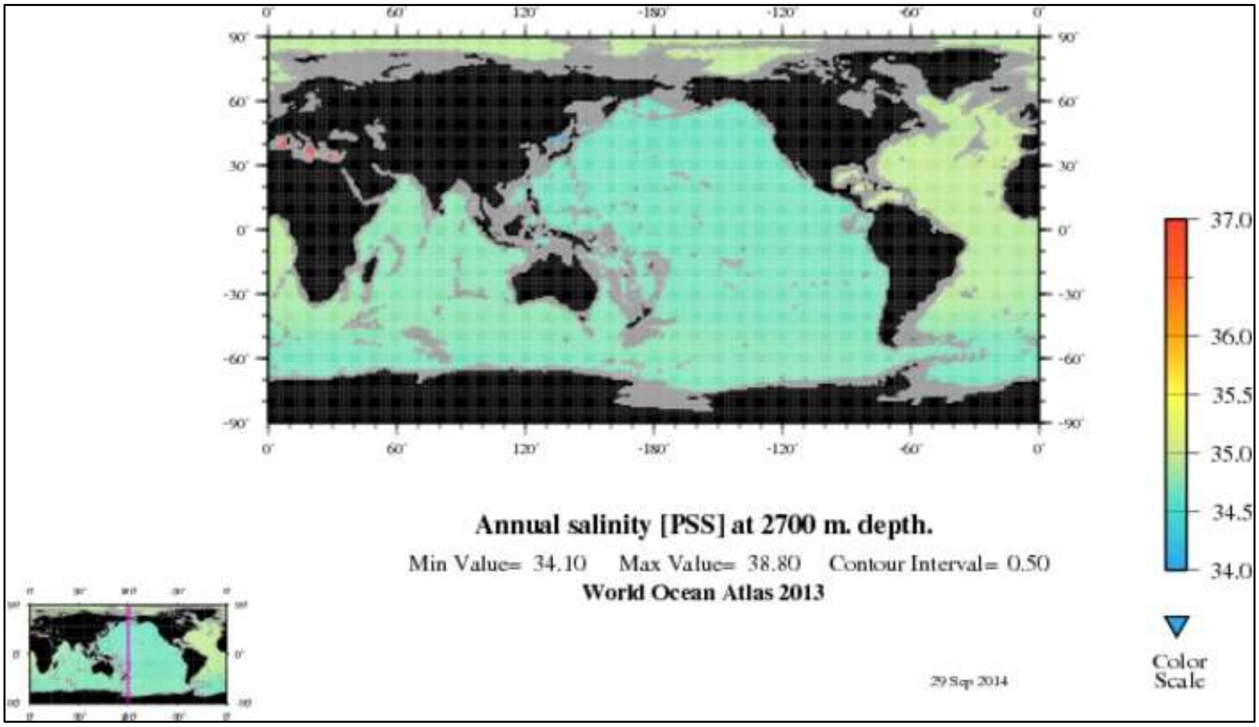

Figure 17: Annual Salinity at 8860 Feet

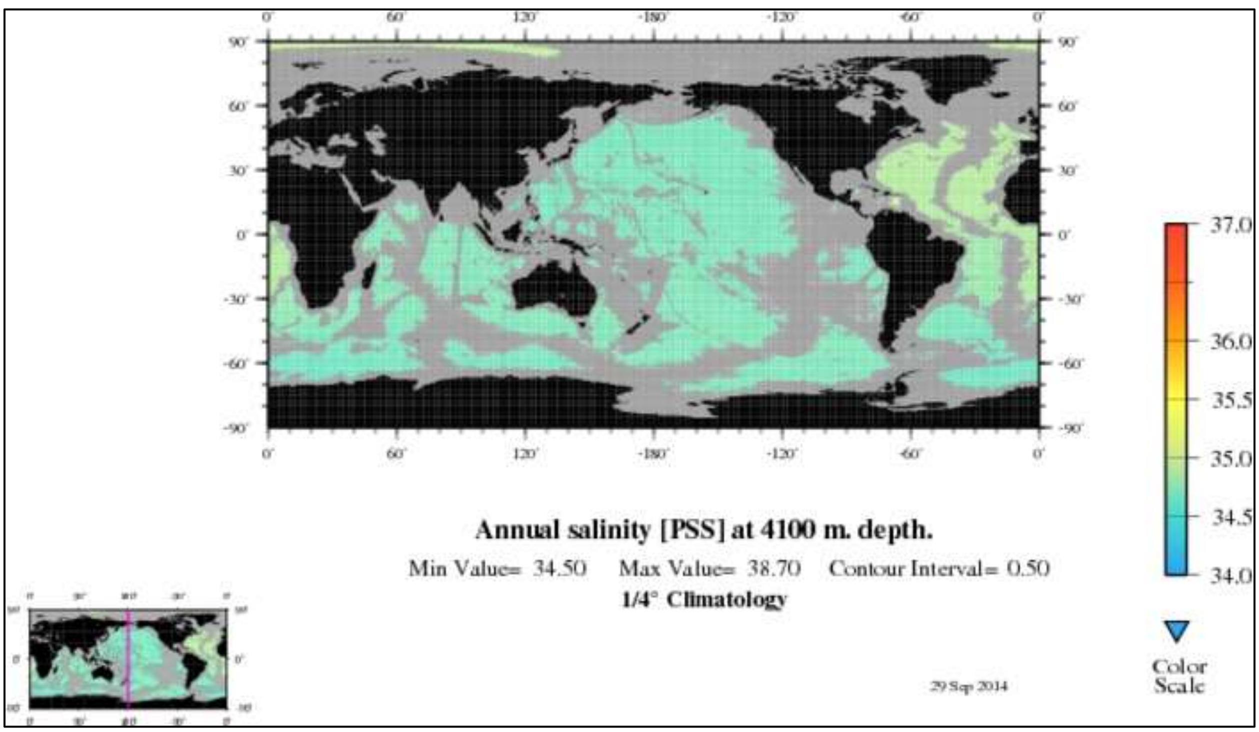

Figure 18: Annual Salinity at 13,450 Feet

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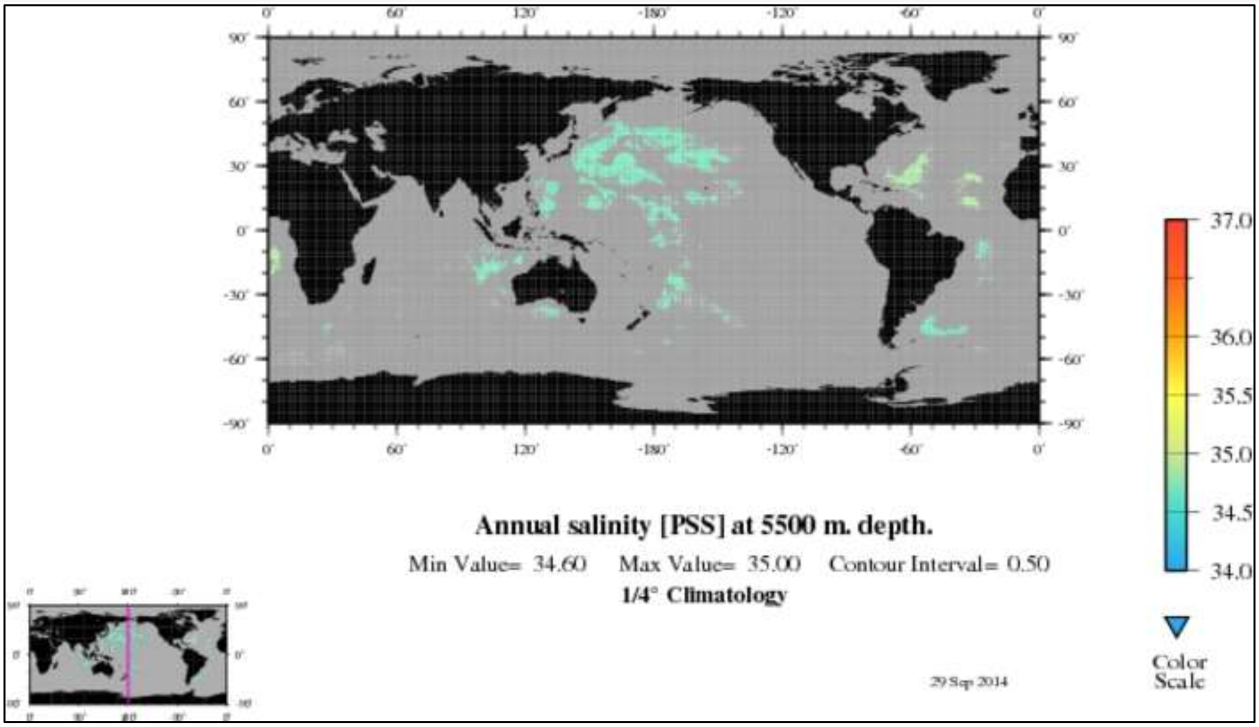

Figure 19: Annual Salinity at 18,040 Feet

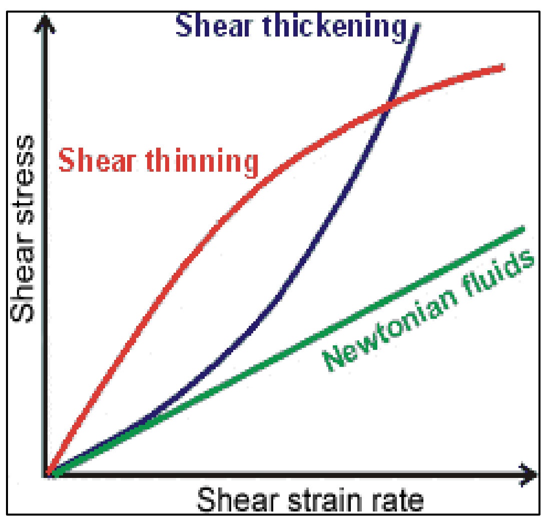

Figure 20: Comparison of The Behavior of Fluids With Shear Stress as A Function of Shear Rate

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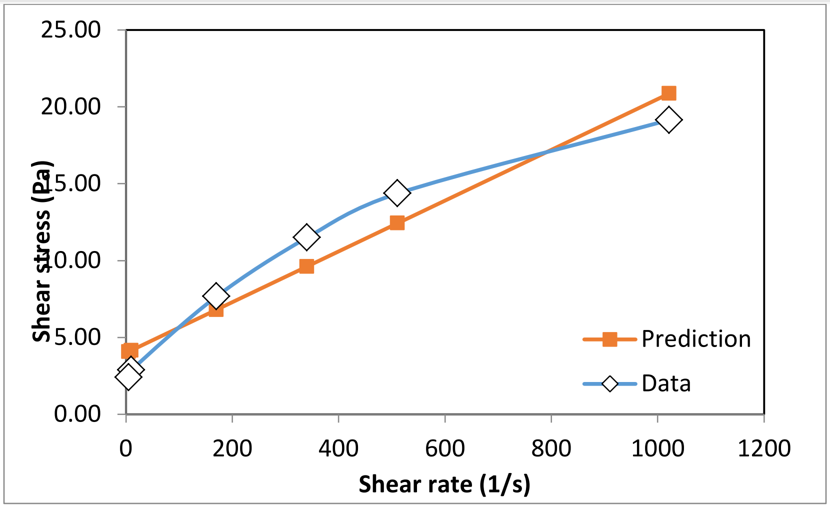

Figure 21: Bingham Plastic Model Fit for 15% NaCl at 6000 psi

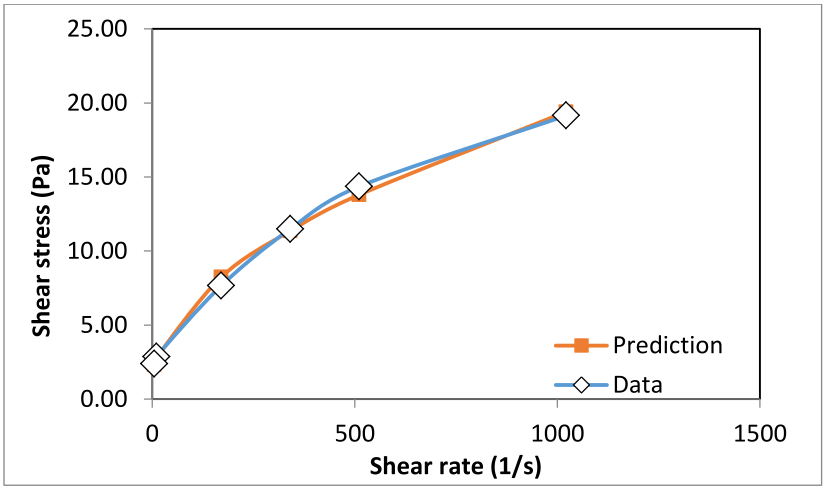

Figure 22: Herschel-Bulkley Model Fit for 15% NaCl at 6000 psi

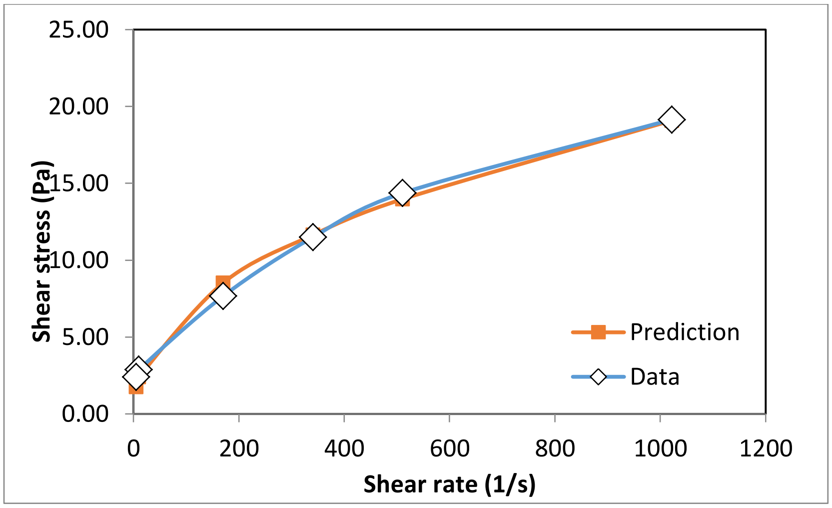

Figure 23: Power Law Model Fit for 15% Nacl at 6000 psi

APPENDIX 2: TABLES

Table 1: Experimental Matrix Showing Parameter Quantities for Each Experiment

EXPERIMENT #	TYPE OF SALT	SALT %	PRESSURE (psi)	TEMPERATURE RANGE (ºF)	MUD WEIGHT (ppg)
1	No Salt	0	6000	70-300	12.5
2			12000		
3			18000		
4			24000		
5	NaCl	15	6000		
6			12000		
7			18000		
8			24000		
9		25	6000		
10			12000		
11			18000		
12			24000		
13	$CaCl_2$	15	6000		
14			12000		
15			18000		
16			24000		
17		25	6000		
18			12000		
19			18000		
20			24000		

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Table 2: Concentration, Specific Gravity and Volume of Each Product Used In The Base Mud With No Salt

Products	Concentration.ppb	SG	Volume.ml
Drill Water	283.23	1	350
Soda Ash	0.25	2.13	
Caustic Soda	0.25	2.5	
Flowzan	1	1.5	
Polysal HT	4	1.5	
PAC UL	1	1.5	
Bentonite	8	2.6	
Calcium Carbonate	5	2.6	
Barite	241.3	4.2	

Table 3: Concentration, Specific Gravity and Volume of Each Product Used In The Base Mud With Sodium Chloride

Products	Concentration.ppb		SG	Volume.ml
	15%	25%		
Drill Water	287.88	272.53	1	350
Soda Ash	0.25	0.25	2.13	
Caustic Soda	0.25	0.25	2.5	
NaCl	53.64	95.38	2.3	
Flowzan	1	1	1.5	
Polysal HT	4	4	1.5	
PAC UL	1	1	1.5	
Bentonite	8	8	2.6	
Calcium Carbonate	5	5	2.6	
Barite	133.29	121.69	4.2	

Table 4: Concentration, Specific Gravity and Volume of Each Product Used In The Base Mud With Calcium Chloride

Products	Concentration.ppb		SG	Volume.ml
	15%	25%		
Drill Water	293.5	279.97	1	350
Soda Ash	0.25	0.25	2.13	
Caustic Soda	0.25	0.25	2.5	
$CaCl_2$	52.59	99.23	2.15	
Flowzan	1	1	1.5	
Polysal HT	4	4	1.5	
PAC UL	1	1	1.5	
Bentonite	8	8	2.6	

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Calcium Carbonate	5	5	2.6
Barite	133.29	121.69	4.2

Table 5: Chloride Content and Corresponding Salinity for Various Mud Samples

Mud Sample	Chloride Content, mg/L	Factor	Salinity, ppt
No Salt	42,300	0.001807	76.41918
NaCl 15%	143770	0.001807	259.7349
NaCl 25%	228761	0.001807	413.2796
$CaCl_2$ 15%	150944	0.001807	272.6954
$CaCl_2$ 25%	239300	0.001807	432.3194

Table 6: Calculated Parameters for Different Rheological Models at All Pressures and Salt Concentrations

	2-Point		Bingham Plastic		Power Law		Herschel-Bulkley		
Pressure (psig)	Yield Point (Pa)	Plastic Viscosity (Pa*s)	Yield stress (Pa)	Plastic Viscosity (Pa*s)	Flow Consistency Index K (Pa*s^n)	Flow Behavior Index n	Yield Stress (Pa)	Flow Consistency Index K (Pa*s^n)	Flow Behavior Index n
No Salt									
6000	7.76	0.0187	0.2185	0.69	0.2185	0.69	1.23	0.1167	0.77
12000	8.81	0.0213	0.3867	0.62	0.3867	0.62	2.13	0.1497	0.75
18000	5.55	0.033	0.2707	0.71	0.2707	0.71	3.12	0.0760	0.88
24000	10.20	0.0257	0.5529	0.60	0.5529	0.60	2.37	0.2341	0.71
NaCl 15%									
6000	2.59	0.0118	0.2281	0.59	0.2281	0.59	1.30	0.0615	0.77
12000	3.24	0.0106	0.4436	0.48	0.4436	0.48	1.27	0.1396	0.64
18000	2.73	0.0117	0.4951	0.47	0.4951	0.47	1.72	0.0954	0.70
24000	5.51	0.0073	0.6659	0.42	0.6659	0.42	1.26	0.2417	0.55
NaCl 25%									
6000	2.63	0.0136	0.1770	0.64	0.1770	0.64	1.10	0.0664	0.78
12000	3.35	0.0145	0.1792	0.66	0.1792	0.66	1.22	0.0668	0.79
18000	2.82	0.0152	0.2163	0.63	0.2163	0.63	1.52	0.0612	0.80
24000	5.46	0.0079	0.4585	0.48	0.4585	0.48	1.09	0.1813	0.61
CaCl2 15%									
6000	4.64	0.0149	0.4088	0.55	0.4088	0.55	2.21	0.0769	0.78
12000	5.84	0.0145	0.4450	0.54	0.4450	0.54	2.42	0.0778	0.78
18000	6.70	0.0145	0.4611	0.54	0.4611	0.54	2.50	0.0839	0.78
24000	4.60	0.0113	0.7304	0.43	0.7304	0.43	3.32	0.0204	0.92
CaCl2 25%									
6000	6.85	0.014	0.5077	0.53	0.5077	0.53	2.18	0.1257	0.72
12000	7.57	0.0137	0.6485	0.50	0.6485	0.50	2.29	0.1649	0.68
18000	9.43	0.0122	0.8607	0.46	0.8607	0.46	2.00	0.3092	0.60
24000	4.31	0.0121	0.4629	0.50	0.4629	0.50	2.90	0.0252	0.90

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Table 7: Correlation Coefficients for Different Rheological Models at All Salt Concentrations

	Correlation Coefficient (r)		
	Herschel-Bulkley	**Power Law**	**Bingham Plastic**
No Salt	0.9992	0.9965	0.9922
NaCl 15%	0.9959	0.9905	0.9800
NaCl 25%	0.9985	0.9951	0.9888
CaCl2 15%	0.9969	0.9793	0.9922
CaCl2 25%	0.9961	0.9848	0.9836