

Top 5 Recent Learnings in Drilling Fluids Laboratory Testing – Building Upon the Guidelines of API RP 13 and Other Industry Recognized Procedures

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Abstract

With the multiplicity of tender submissions and the increasing challenges of global well operations, the complexity of Drilling Fluids testing protocols in Field Service Laboratories has seen a sizeable increase over the last few years. While a strong foundation, API testing protocols along with other procedures recognized by drilling fluids Subject Matter Experts (SMEs) as “standards”, are not completely addressing the more complex testing requirements of these new projects.

This paper will discuss well known testing procedures and, in some cases, put them under a magnifying glass to reveal observations which may or may not have been recorded in the past. Some of these observations can have direct impact on Drilling Fluids Engineering for all types of wells but most importantly could alter the drilling performance of complex wells such as Deepwater (DW), High-Temperature-High-Pressure (HTHP) and DW-HTHP projects.

The resulting observations and the impact they have on Drilling Fluids properties or whether a given formulation will pass/fail the specifications should result into a broader discussion within the Drilling Fluids SMEs community and ultimately may contribute in revising some of these procedures in the existing Recommended Practices or show the need for new ones.

The authors will discuss in detail the top 5 most recent learnings and corresponding impact on Cost/Performance ratios during Invitation To Tender processes for the following Field Service Laboratories tests: (1) Preparation and evaluation of invert-emulsion drilling fluids [Section 26 of API RP 13I], (2) Chemical Analysis of Oil-based Drilling Fluids [Section 10 of API RP 13B-2], (3) Electrical Stability Test [Section 11 of API RP 13B-2], (4) High-temperature/high-pressure filtration testing of drilling fluids using the permeability-plugging apparatus and cells with threaded end caps [Section 28 of API RP 13I].

Introduction

Repeatability and reproducibility of lab test results are key to fluids design, maintenance and ultimately performance benchmarking.

To make laboratory testing results more repeatable, reproducible and conducive to application-specific fluids design, Verification and Validation, a review of the existing API RP 13B-1, API RP 13B-2 and API RP 13I documentation was conducted, which culminated in the writing of the paper herein.

Static Sag

Although the API RP 13B-2 5th edition published in 2014 recognizes sag as a phenomenon occurring in both static and dynamic conditions (API 2014), the lab methods evaluated in such edition i.e. the Viscometer Sag Shoe Test (Zamora 2004), and the Sag Window, are intended to provide insight on the sag tendency of a drilling fluid under dynamic conditions only. In the case of the latter, that includes the behavior of the fluid’s viscosity in the ultra-low shear rate region (Dye 1999). Those methods have been part of a broader sag analysis approach that started in the 90s, when the focus shifted to the study of sag beds created during circulation and not merely under static conditions (Scott 2004), prompted by the finding that severe barite sag can occur dynamically even when the static sag is negligible (Saasen 1995). Lab equipment, such as the sag flow loop (SFL), was developed to help understand the impact of the drilling parameters in barite sag (Bern 1996). SLFs continue being part of the barite settlement evaluation of a fluid and have become more flexible with the ability to be used in the field (Troncoso 2018).

The importance of evaluating the dynamic sag potential of a fluid cannot be stress further. However, the straightforward static analysis should not be left out of the picture, even more when the drilling operation entails prolonged static periods under harsh downhole conditions in complex well geometries, and as it was concluded in a recent comparison of sag results on lab-built fluids and field mud samples, there is no a standalone evaluation method that can absolutely define the settling mechanisms in invert emulsion drilling fluids (IEDFs) (Zeng 2016). Thus, combining both static and dynamic assessments of a specific IEDF under specific stress conditions will provide more understanding on the propensity of such fluid to sag.

The assessment of the resistance of a fluid to sag under static conditions involves the calculation of a Sag factor (SF) which

is directly proportional to the sag tendency. A SF of 0.5 represents zero sag. Values greater than 0.53 are an indication of a fluid with high risk to settle (Gao 2000). Along with the SF, the MW variation is also reported.

The in-house static sag procedure consists in the ageing of 1 lab-barrel of IEDF in a 500-ml stainless-steel ageing cell at the desired testing temperature for a specific time period, which could vary from hours to even weeks. After the ageing of the sample, the cell is cooled down in front of a fan to room temperature. The cell is opened, and the MW measurements are taken by extracting 75% of the fluid volume, 262.5 ml +/- 5 ml, including the free oil on top of the cell, with a syringe or spoon. The 25% of the fluid volume on the bottom, 87.5 ml +/- 5 ml, is transferred to a beaker and homogenized. The MW is then measured using a 20-ml pycnometer. This procedure evaluates the static sag tendency under temperature but not pressure, which internal data has shown is the worst-case scenario, the pressure applied to the ageing cell is just to avoid evaporation of the internal phase of the fluid.

Before subjecting the IEDF to static heat ageing (SHA) at the temperature of interest: bottom hole static temperature, the mud sample can be hot rolled (HR) at the anticipated or actual bottom hole circulating temperature to simulate the field conditions. The dynamic aging of the sample would depend on whether it is a lab-built mud or if being a field sample, the fluid is considered not enough exposed to downhole conditions, or at the request of the customer. Though, doing it both ways would provide more insight to assess the emulsion stability, and in certain cases, such as for HTHP IEDFs, the dynamic ageing could help on the yielding of some of the fluid components.

In the testing of an IEDF built in the lab, the sag tendency evaluation of a fluid comprised the SHA for 3, 5, and 7 days. The procedure included the HR of the sample before the static time period. To evaluate the effect of homogenizing the fluid after HR fluid and before putting it to SHA, an API mix was built and two lab-barrel: Aliquot 1 and Aliquot 2, were HR for 16 h at the testing temperature. Pressure applied with nitrogen to avoid evaporation was same for both cells. Aliquot 1 and Aliquot 2 were pulled out of the oven after the 16 hours and cooled down to room temperature in front of a fan. The ageing cell containing Aliquot 1 was opened and the fluid was homogenized at 3000 rpm on a single spindle mixer for 5 min. The ageing cell was then pressurized and put to SHA. Aliquot 2 was put to SHA at the same time than Aliquot 1, but the fluid was not homogenized, the cell was never opened. Same than for the HR, the pressure applied to both cells was the same.

The results after the SHA period showed that for the non-homogenized sample, Aliquot 2, the Δ MW increased by 175% on the 3-day static sample. For the 5-, and 7-day samples, the increase in the Δ MW was lower but still more than double the values obtained for the homogenized sample, Aliquot 1. Figure 1. Effect of homogenization of mud sample on Δ MW before static ageing.

Vacuum Saturating Filter Media for PPA/MHTHP

As more projects move towards using Permeability Plugging Testing (PPT) and Modified High Temperature-High

Pressure Testing (MHTHP) for filtration, the techniques regarding the soaking of porous ceramic disc filtration media have become more important. API 13B-2 section K.3.2.1 states, "For oil-based drilling fluid, the disc should be soaked in base oil until saturated, so that the porous volume of the disk is filled with oil and filtration to the receiver begins immediately. When possible, vacuum saturate for at least 5 min to 30 min prior to use is preferred" (API 2019).

API 13I similarly recommends "For water-based drilling fluid samples, the disks shall be soaked in fresh water or brine until saturated, at least 5 min to 30 min prior to use. For oil-based drilling fluids, the disk shall be soaked for 5 min to 10 min in a sample of the base oil before use." And goes on to state, "Vacuum saturation shall be used for filter media with low porosity and permeability." (API 2009).

In comparison laboratory testing, there have been large deviations in test results when using ambient pressure saturation versus vacuum saturation when using low-permeability ceramic discs. In addition, when lab-tested, many low-permeability ceramics discs require more than 10 minutes to completely saturate at vacuum pressures. When saturating in a vacuum desiccator, air can be observed escaping from the ceramic disc up to 20+ minutes after applying vacuum.

Large testing differences in ambient-saturated versus vacuum-saturated ceramic discs were discovered when comparing field results with laboratory testing of the same fluid samples. To rule out all other variables, testing was completed on the same testing apparatuses in duplicate, only changing the soaking pressures and times as follows: ambient for 30 min, ambient for 3 days, vacuum for 30 mins, vacuum for 3 days. Going further, both ambient and vacuum saturated discs were soaked for 3 days to rule out time a variable. The laboratory vacuum unit used for this test employed a measured vacuum pressure of 28 inHg. In both time-cases, vacuum saturation was found to have consistently higher results, as seen below in Figure 2. Another important aspect to note is that the difference between 30-minute and 3-day saturation is not significant for the vacuum samples but can be significant for the ambient samples.

Based on current findings, a vacuum is necessary to completely saturate low permeability ceramic discs. In a field setting, electric vacuum pump sets have been tested and can be procured for a relatively low cost. Furthermore, although API 13I has the requirement for low porosity filter media to be vacuum saturated, there is no definition made for what is classified as "low permeability." In the interest of continuity, it is recommended that all ceramic discs be saturated for at least 30 minutes prior to completing a PPT or MHTHP.

Synthetic Cuttings for Solids Contamination

Solids Contamination Testing in the laboratory setting has long used standard evaluation clays such as OCMA Clay, Hymod Prima Clay, and API Standard Evaluation Base Clay (SEBC) to determine how a particular drilling fluid will react to solids loading during the drilling process. However, from region to region, geologies can vastly vary, and many times highly differ from these evaluation standards. In an effort to

make solids contamination testing more representative of the project at hand, the use of “synthetic cuttings” has been employed to perform Solids Contamination Testing.

As can be seen in the Mineralogy data below in Table 1, the API SEBC differs greatly from this random assortment reservoir mineralogy. The main difference can be observed in much higher clay concentrations in the API SEBC. In many field cases, it is rare to find a reservoir section that has these high clay concentrations. The higher clay content, when used to contaminate drilling fluid samples, can produce drilling fluid properties that are unrepresentative of field operations.

For the shallower sections, there tends to be higher clay concentrations in formation geology. For these intervals, there is much greater value in using the SEBC for solids contamination testing. However, when trying to replicate the fluids response to solids contamination in the lower intermediate and reservoir sections, SEBC may be excessive in areas where high clays are not present. Notably, test results such as rheology and gel strengths can be elevated far higher than what would be observed with the same solids loading in a field mud.

For fluid evaluation in certain areas, it has already been requested by operators to perform solids contamination testing using representative “synthetic cuttings”. The method for developing a synthetic formulation would involve obtaining mineralogy data from X-Ray Diffraction (XRD) testing or real-time petrophysical data collection such as Fourier Transform Infrared (FTIR) Spectroscopy tools (Poulin 2004). From the mineralogy data, a formulation can be mixed using products such as silica flour, calcium carbonate, and SEBC. These products are individually sieved to obtain a similar particle size as API SEBC, which is 88% less than 22 microns. Once sieved, the products are mixed in the average ratio of the offset well mineralogy for the target drilling interval.

In situations where these synthetic cuttings were used for solids contamination testing, drilling fluid response matched more closely with field data than using SEBC alone. It is recommended that this be used as a tool to better plan and anticipate fluid response while drilling critical intervals where lithologies significantly differ from the SEBC.

Multi-Temperature ES Testing

The measurement of Electrical Stability of an IEDF is an important measurement of a fluid’s emulsion stability and oil-wetting capability. API RP 13B-2 5th edition published in 2014 (Section 11) documents the advised standardized testing methodology at “120°F +/- 5°F”. This is perhaps a suitable procedure in the event of conventional drilling operations but as well designs become increasingly complex in their environmental and technical requirements there is scope to introduce a more robust testing methodology with regards to Electrical Stability. Furthermore, fluid formulations have a large bearing on the electrical stability of a fluid. It is observed that nearly all products of a formulation effect the Electrical stability of a Drilling Fluid. It has been observed that emulsifiers, barite & base oil increase the Electrical Stability values. Whereas increasing the concentration of water,

increasing the concentration of Calcium Chloride in the water phase decreased the Electrical Stability (Ali *et al.* 1987). This discussion will focus the current Electrical Stability testing methodology and indicate the key areas where the procedure can be brought in line with current drilling fluid testing requirements and operational environments.

During drilling operations, a drilling fluid system will undergo significant temperature cycles as it is pumped through the well. It is not uncommon to observe BHCT and flowline temperatures of >300°F & <60°F. This is further highlighted during periods when the well is static where the downhole fluid can reach the formation temperature and large riser volumes are cooled by the sea water temperature. As a result of the range of temperature conditions the drilling fluid is subjected to during operations it can be put forth that a more robust Electrical Stability testing procedure should be implemented.

Figure 3 illustrates the Electrical Stability of 10 different drilling fluid formulations at a temperature range of 40°F to 150°F. The specification for Electrical Stability is set in line with the fluid system implemented and the anticipated well conditions. It is observed in the Electrical Stability Comparison Graph that three fluids; Fluid 1, 5 & 10, are observed to have a >10% decrease in Electrical stability between 120°F and 40°F. This could indicate that the fluids are becoming less stable under cold conditions. Since the ES Procedure step 11.4.3 states that ES is to be conducted at “120°F +/- 5°F”, key areas in assessing the thermal stability of drilling fluid systems is being overlooked. It is also observed that within the ten-fluid data set the fluids increase in Electrical Stability measurement between 120°F and 150°F or fall within a <5% difference.

Whilst Electrical Stability is not an absolute value of stability it is a key factor (Van Zanten *et al.* 2012). If the testing procedure is updated to cover a wider range of temperatures, then drilling fluids could be better designed prior to their field deployment. In the field, the additional Electrical Stability data would also provide a wider data set which can be utilized to implement more robust and effective fluid treatments and mitigate the risk of thermal instability issues.

Alternate Alkalinity Measurement

When formulating IEDF systems, Lime is an important product which is added to conduct various functions including:

1. Activate fatty-acid IEDF products such as emulsifiers.
2. Control formation and other gases such as Hydrogen Sulfide & Carbon Dioxide.

As a result, it is important that fluid systems are designed with sufficient Excess Lime concentrations (Bleier 1990). The measurement of alkalinity is conducted by a titration method which measures the volume of acid required to react with the alkaline materials in an IEDF sample. The alkalinity value obtained from the titration is utilized to calculate the Excess Lime concentration present in the fluid. The Alkalinity & Excess Lime concentration is obtained utilizing the API RP 13B-2 5th edition methodology described in Section 10.

It is observed that whilst utilizing this procedure the titration color change to determine the alkalinity is not always easy to identify. The utilization of Fluid Loss additives which comprise of Asphaltites & Tannins are difficult to determine the titration end point. The difficulty arises from the nature of Asphaltites & Tannins which are dark brown to black in color. Due to the dark color of the fluid loss additives the pink color observed during the titration procedure is masked and can cause difficulty in clearly identifying the titration end point. This is also illustrated in systems which utilize specialized weighting material.

A solution to this issue can be to utilize a pH meter during the titration procedure to mitigate the issue of a difficult to identify titration end point. A proposed methodology is to implement a pH and record the volume of acid required to reduce the pH of the filtrate to 8.3, the phenolphthalein end point.

Conclusions

In an effort to replicate fluid response while drilling, a widespread practice is to hot roll the laboratory-built drilling fluid samples. If static ageing to evaluate sag is desired after hot rolling, IEDF samples showed at least twice as high ΔMW after 3, 5, and 7 days if the sample is not homogenized between the hot rolling and static ageing steps. It is recommended that after hot rolling, the sample be cooled down to room temperature and homogenized on a spindle mixer at 3000 rpm for 5 minutes before performing static ageing.

When performing PPTs and MHTHPs, there have been large variances in results between ambient and vacuum saturated discs. It has been observed that low porosity ceramic discs require vacuum and that ambient pressure soaking will not completely saturate the discs in less than 3 days. When using ceramic filter media, it is recommended to vacuum saturate the discs in base fluid at 28 inHg for a minimum of 30 minutes.

The testing of drilling fluid response to solids contamination is required for the technical evaluation of many drilling projects and tenders. Shale standards such as SEBC, OCMA Clay and Hymod Prima Clay are often used to contaminate drilling fluids, regardless of anticipated formation mineralogy. To make solids contamination more relevant to the target drilling interval, “synthetic cuttings” can be used to simulate a closer fluids response to what will be seen in the field. A basic methodology, which included identifying the mineralogy using offset well data, is outlined in the discussion section above.

The Electrical Stability reading, which is often only taken at 120°F, is a common benchmark property for IEDFs. However, during Deepwater drilling projects, the drilling fluid is subjected to a wide range of temperatures during circulation. In certain fluids, Electrical Stability has been observed to vary more than 10% between 40°F and 120°F. Just as rheologies are commonly measured at various temperatures, it is recommended that ES temperature also be measured at these points.

For IEDFs that contain fluid loss reducing agents and specialized weighting agents, performing the Phenolphthalein Alkalinity testing can be challenging. The issues arise when

these dark-colored products mask the visual endpoint. An alternate option is proposed using a pH probe, titrating to the phenolphthalein endpoint pH of 8.3.

These five learning and recommendations are all based on laboratory observations. The goal in sharing this information is to inform the industry of these observations and start a dialogue with other Drilling Fluid Subject Matter Experts. Since the basis of much of the drilling fluid testing performed is from the API Recommended Practices documents, a discussion with the API Sub Committee 13 for Drilling and Completion Fluids has already begun.

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Nomenclature

BHA = Bottomhole assembly

DW = Deepwater

FTIR = Fourier Transform Infrared

HR = Hot Rolled

IEDF = Invert Emulsion Drilling Fluid

PPT = Permeability Plugging Testing

MHTHP = Modified High Temperature-High Pressure

SF = Sag Factor

SFL = Sag Flow Loop

SHA = Static Heat Ageing

XRD = X-Ray Diffraction

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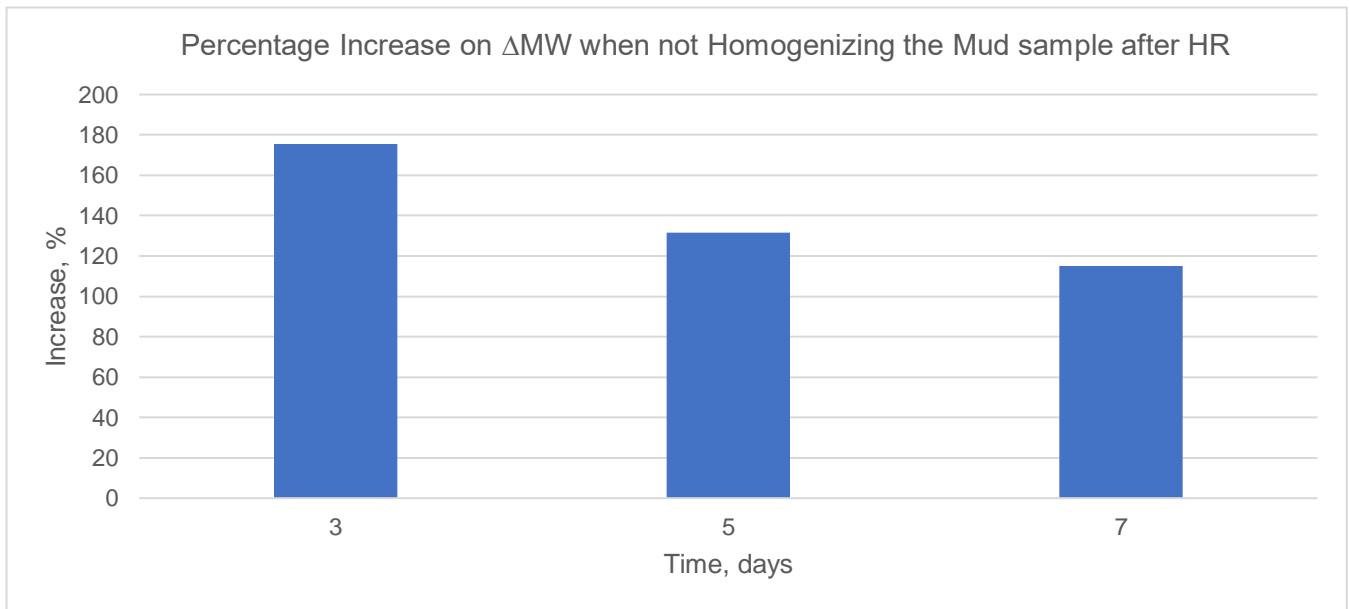


Figure 1. Effect of homogenization of mud sample on ΔMW before static ageing

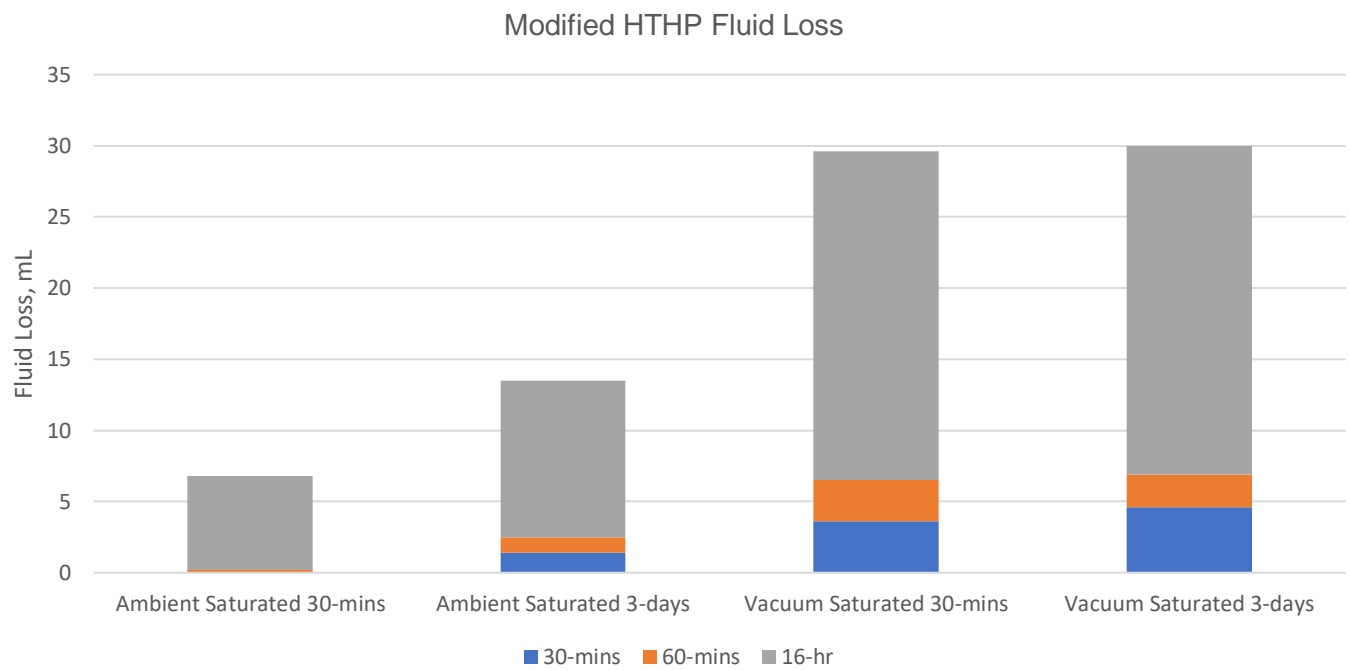


Figure 2. Modified HTHP testing using a 3-micron ceramic disc on SBM field mud sample.

Table 1. Average Mineralogy of North America Shale Formations vs API SEBC

Shale Sample	Marcellus	Woodford	Wolfcamp	Eagle Ford	API SEBC
Quartz	16	21	24	5	16.7
Calcite & Dolomite	24	2	4	64	
Illite	19	39	40	7	59.2
Kaolinite					10.5
Chlorite	5	2	2	6	
Pyrite	2	3	2	0	
Feldspars	2	11	8	1	Trace
Mixed Clays	20	6	5	3	13.8
Albite	6	9	8	3	
Siderite	4	6	5	6	
Others	2	1	2	5	Trace

1. Marcellus, Woodford, Wolfcamp, And Eagle Ford data from FTIR Mineralogy (Gupta 2019).
2. API SEBC data from X-ray Diffraction (API SPEC 13A 2019).

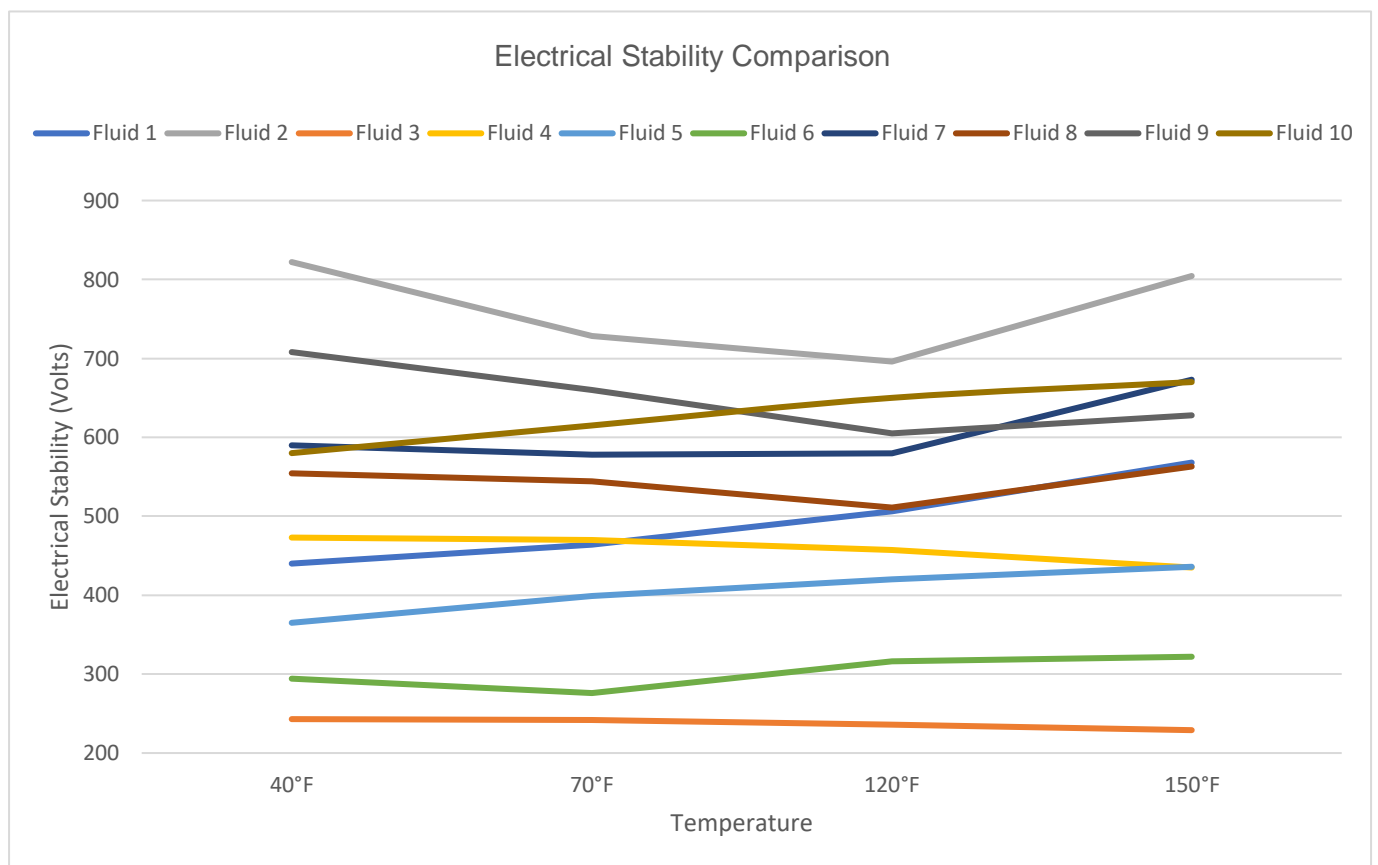


Figure 3. Electrical Stability trends in OBM/SBM Drilling Fluid Systems