Is There A Better Way to Determine The Viscosity in Waxy Crudes?*

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Abstract

Accurate viscosity measurement is difficult even under the best of conditions and the lengthy time required to send and receive results from a lab prohibit basing important decisions on the viscosity of the reservoir fluid. Those challenges increase for reservoirs with complex fluids such as the highly viscous, waxy crudes found in many of oil fields in South East Asia. While correlations have been developed to determine the viscosity of waxy crudes, the accuracy can be limited under certain conditions. The objective of the paper is to review viscosity correlations for waxy crude and examine their applications to the actual field data. Limitations on the use and accuracy of these correlations will then be discussed. This paper also discusses the viscosity obtained in real-time from the suite of Downhole Fluid Analysis (DFA) measurements, and its result is then compared to standard PVT analysis over a wide range of viscosities, temperatures, and pressures. The technical contribution from this paper is that it presents the variation of the viscosity in waxy oil reservoirs and its impact on real time decision making, especially for purposes of pressure transient analysis. This paper covers the evolution of the DFA viscosity measurement including a description of the hardware, discusses the limitation of the DFA measurement for certain conditions, and summarizes the accuracy of the DFA viscosity measurement for different fluids and the ongoing development for covering more fluids in the lower end of the viscosity spectrum.

Introduction

Waxy oil reservoirs are found in a number of basins in the Gulf of Thailand and the viscosity in these reservoirs can significantly vary even in the same reservoir stratigraphically. Fluid samples are essential for these waxy oils in order to properly characterize the reservoir fluids. However, laboratory processing for viscosity measurements can take from three to six months after samples are acquired. Viscosity is a very important property in the oil industry and is required in many engineering calculations such as the determination of zone conductivity, permeability, and well productivity and the lengthy time causes a delay in applying correct viscosity values. An accurate estimation of waxy crude viscosity will result in more efficient exploration of new oil fields and production techniques. In complex reservoirs with waxy crude,

relying on the oil viscosity based on the correlations currently used in industry can lead to significant error. This paper will discuss the viscosity correlations currently being applied to waxy crude reservoirs and the limitation of each method is then discussed with their applications for different fluids. The evolution of the DFA measurement is then discussed with field examples from South East Asia.

Literature Review

In the literature, the most widely used viscosity correlation was developed by Lohrenz, Bray, and Clark (LBC) in 1964 (Lohrenz et. al., 1964). This viscosity predictive method is based on a fourth-degree polynomial and the reduced density. The correlation is dependent on the fluid composition including heptanes-plus, hydrogen sulfide, nitrogen, and carbon dioxide together with the molecular weight and specific gravity of the heptanes-plus fraction. The method was evaluated with 260 different reservoir oils ranging from black oil to highly volatile oil and was successfully applied with an average absolute deviation of 16 %. However, in this original paper, the method had a tendency for the deviation to increase near the critical point.

Xu and Khurana (1996) developed a new approach based on LBC to predict reservoir fluid viscosity utilizing the Peng Robinson Equation of State (EOS). This approach introduced an extra term into the LBC equation and the density was calculated using a cubic EOS. They explained that a disadvantage of the LBC method was that the predictive viscosity method was very sensitive to the density, which is normally predicted by a cubic EOS and can result in reduced accuracy for high viscosity fluids. The Xu and Khurana approach significantly improved the prediction of gas and liquid viscosities for hydrocarbon mixtures and particularly for high viscosity fluids.

Lindeloff and Pedersen (2004) discussed the pitfalls of current viscosity correlations with the main drawback being the use of methane as a fixed reference fluid. When using methane for these correlations applied to heavier oil systems, the viscosity value would not be representative. A corresponding state viscosity model was proposed where the reference fluid can be changed to a heavier hydrocarbon for a heavy oil system. This resulted in a major step forward compared to the other published viscosity models. However, this method is unsuitable for a waxy oil system since wax precipitation was not accounted for in the viscosity model.

For waxy oils, a reliable and accurate viscosity model, which is applicable over a wide range of temperature, pressure, solid wax content, composition, and thermal and shear history is required. In addition, the consideration of Newtonian and non-Newtonian conditions is essential (Oyekunle and Adeyanju, 2012). Viscosity determination in the non-Newtonian regime has always been a major problem in the oil industry. This is due to its dependence on precipitated wax, resin and asphaltene presence, shear, and the thermal and mechanical history of the crude oil, all of which can affect its rheological behavior. Above the Wax Appearance Temperature (WAT), waxy crudes behave as a simple Newtonian fluid. If the waxy crude cools below the WAT temperature, the wax will precipitate, agglomerate, and entrap the liquid oil into its structure. The flow property will gradually change from Newtonian to non-Newtonian behavior. As the temperature decreases further, the viscosity increases until the additional viscosity due to the crystallized wax no longer is negligible. The Viscosity WAT (Visco WAT) is defined as the temperature where the effect of crystallization changes the flow behavior. Above the Visco WAT, the viscosity is a function of temperature but is independent of the shear rate or the cooling rate and the oil exhibits Newtonian behavior. Below the Visco WAT, non-Newtonian flow behavior occurs and the viscosity depends on temperature, pressure, shear rate, and thermal history. Al-Fariss et. al. (1992)

suggested a modified form of the viscosity correlation, which related temperature and shear rate. The higher the shear rate, the lower the viscosity. This correlation is suitable for certain waxy crudes.

$$\mu = Ae^{\frac{B}{T}}\gamma^{c} \qquad \text{Equation 1}$$

The new terms that were added include the effect of shear rate developed from 180 experimental measurements for the viscosities of six types of waxy Saudi crudes with the samples measured with a rotational co-axial cylinder viscometer at six different temperatures. The coefficients A, B, and C in Equation 1 depend on wax concentration (in weight percentage) and the last term provides a correction factor for non-Newtonian behavior. The maximum absolute error obtained from all 180 experimental points was 37.3% and overall absolute error was 8.5%.

Pedersen and Ronningsen (2000) developed a shear rate dependent viscosity model by using parameters fitted to 713 measured viscosity data points with an absolute average deviation of 48%. However, the correlation was based on a specific cooling rate and therefore is not applicable to reservoir fluids. Oyekunle and Adeyanju (2012) proposed a new unified model for predicting non-Newtonian viscosity of waxy crudes based on the concentration of precipitated wax and temperature. Their correlation was developed by applying the theory of suspension rheology. This model could be used to predict the viscosity of virgin crudes with various shear and thermal histories. They stated that once the viscosity at two temperatures above the WAT and the apparent viscosity under the non-Newtonian regime are known, viscosities or apparent viscosities at any temperature above the gel point could be determined by using the model together with the concentration of precipitated wax at a specified temperature. Their model shown in Equation 2 was verified with two Nigerian crude oils with different shear and thermal histories, and two crudes from the literature. The results showed that the model predicted viscosities with an average absolute deviation of 4.9%.

$$\mu = \mu_0 \left(1 - k(\gamma)\left[\frac{2.5c - c^2}{(1-c)^2}\right]\right)^{-1} \qquad \text{Equation 2}$$

Where μ_0 is the viscosity of the continuous liquid phase and c is the effective mass concentration (the weight of precipitated wax particles accounted for in the total oil weight, %). $k(\gamma)$ may vary from crude to crude and it can be determined from experiments.

As shown in the literature, an effective waxy crude viscosity correlation is still under development and it requires testing with different reservoirs. All available waxy crude viscosity correlations require some parameters obtained from laboratory measurements such as shear rate, wax content, etc. As a result, viscosity can only be determined after samples are taken in the current well or with samples from previous wells. Quality of collected PVT samples, sample handing, transportation, and laboratory processes such as restoring live reservoir fluid back to reservoir conditions are potential sources of error for the lab measurement. Even if all processes are completed properly, it is not guaranteed that the viscosity from a previous well can represent fluid from the current well. Therefore, a better approach would be to obtain an accurate viscosity measured at reservoir conditions.

In-Situ Viscosity Evolution

The Downhole Fluid Analyzer (DFA) is part of the Wireline Formation Tester (FT) tool service and in situ viscosity is one of the measurements provided with the latest generation of DFA technology. DFA works by pumping fluid though the FT where a number of sensors utilizing Near-Infrared (NIR) Spectroscopy infer reservoir fluid properties downhole in real time. The technology was introduced in the early 1990's when the Optical Fluid Analyzer (OFA) was used to distinguish reservoir hydrocarbon from OBM or WBM filtrates (Smits et. al., 1993). Together with a gas detector, the 10-channel NIR spectroscopy approach could be used to differentiate gas, oil, or water flowing in the FT flowline. In the mid-90's, composition (C_1, C_2-C_5, C_6^+), CO_2, GOR, and condensate drop out detection were introduced as part of the Compositional Fluid Analyzer (CFA) (Fujisawa et. al., 2003). In 2008, the evolution of DFA took a major step forward when the In-Situ Fluid Analyzer (IFA) was placed into service (Dong et. al., 2008). The IFA consists of a 20 Channel Filter Array Spectrometer (FA) and a 16 Channel Grating Array Spectrometer (GR). This latest generation of DFA technology provides an accurate measure of fluid composition (C_1, C_2, C_2-C_5, C_6^+, CO_2), GOR from around 200 scf/bbl to gas condensate range, pH of live fluid, pressure, temperature, density, and viscosity. The FA and GR spectrometers were optimized for detection and analysis of hydrocarbon, color for relative asphaltene content, CO_2 measurement, as well as other applications. Wavelength and temperature stability of the spectrometers (Khalil et. al., 2008) were improved from the previous generation of DFA tool and a real time calibration was also enabled.

O'Keefe et al. (2007) introduced the first version of an in-situ fluid density and viscosity tool using a Density/Viscosity-Rod (DV-rod) sensor. The DV-rod sensor is an oscillating mechanical sensor providing downhole density and viscosity measurement in real time at reservoir conditions. Fluid density is determined by measuring corresponding changes in the vibration frequency of the oscillator while submerged in the flowline fluid and the viscosity is determined by monitoring the decay time of the resonance. As with any vibrating object in a fluid media, the resonance frequency and quality factors are related to the fluid characteristics. The resonance frequency is especially related to fluid density while the quality factor of the measurement is mainly related to the fluid viscosity. The more viscous the fluid, the more damping the sensing part will be subject to resulting in a lower quality factor (Khalil et. al., 2008). From both the resonance frequency and quality factor, density and viscosity are predicted using a complex physics modeling of the elastic properties of the sensing part, along with the Navier-Stokes equations describing fluid displacement around it. Since the sensor response is physically modeled, no empirical correlation or internal databases are required for the computation of density (or viscosity) (Khalil et. al., 2008).

The schematic of the DV-Rod sensor is shown in Figure 1. The geometrical element is carefully designed to minimize pressure and temperature effects on the resonator response (Fujisawa et. al., 2003). The resonator element has a shape defining a first and second resonance mode, which is characterized by different frequencies and quality factors.

The key benefit of using both resonances quasi-simultaneously is that the electronics frequency stability at high temperature and the drift of the mechanical resonator can be dramatically reduced. This is in contrast to a "Tuning Fork" design, which requires compensation factors to correct for pressure and temperature effects. Figure 2 is provided to show there is excellent agreement between the measured and reference viscosity values even when outside the specified range (gas condensate and high viscosity standard fluid) (O' Keefe et. al., 2007) as seen in

Table 1. Since 2007, a numbers of field examples are presented showing the DV-rod density measurements in different environments (i.e. gas in OBM (Khalil et. al., 2008), oil in OBM (Khalil et. al., 2008; O' Keefe et. al., 2007), water in WBM (Mas et. al., 2009), oil in WBM (Mas et. al., 2009; Daungkaew et. al., 2008; Daungkaew et. al., 2011), and gas in WBM (O' Keefe et. al., 2007; Daungkaew et. al., 2008; Daungkaew et. al., 2011). However, more field examples and laboratory analyses are required to increase confidence in the viscosity measurements using the DV-rod sensor, especially for two phase flow and immiscible fluid systems.

Al-Ajmi et al. (2010) introduced the second version of the viscosity sensor using a vibrating wire (VW) which presented the theory of the VW viscometer and provided three different field examples from Kuwait (i.e. oil in OBM, oil in WBM, and water in WBM). This paper showed a significant improvement in measuring the downhole viscosity of two immiscible fluids (sample oil in WBM) and emulsified fluids (sample oil in WBM).

Field Applications

Our paper concentrates on the waxy oil crudes with low GOR that are frequently found in the reservoirs of South East Asia (Daungkaew et. al., 2008; Daungkaew et. al., 2011; Duangprasert et. al., 2011; Houtzager et. al., 2011). For this type of reservoir, one of the main challenges for wireline FT is to identify reservoir oil from OBM filtrate (Duangprasert et. al., 2011). DFA tool are able to differentiate between reservoir oil and OBM filtrate by measuring fluid color, composition, GOR, and fluorescence. The GOR measurement is in general very useful indicator for differentiating reservoir oil and OBM filtrate, however, its uncertainty increases for low GOR fluid. Thus, all measurement results need to be utilized for low GOR fluid.

Another challenge for this type of reservoir is the thinly bedded reservoir geological characterization. Individual flow tests cannot be conducted in all sands; therefore, an Interval Pressure Transient Test (IPTT) can be implemented for this type of reservoir (Houtzager et. al., 2011). For Pressure Transient Analysis (PTA), one of the reservoir parameters to obtain for each zone is the viscosity value. The laboratory usually takes around three to six months to measure live oil viscosities using commercial viscometers. By having the real time viscosity, the reservoir parameters estimated from PTA can be used straight away after the IPTT build-up is completed. An operational decision can then be made in real time using representative formation properties. In addition, since the viscosity of pumping fluid (i.e. mixture of OBM filtrate and reservoir oil) can be measured simultaneously with rate data, the zone permeability can be determined even with the contaminated fluid pumping though the flowline. The actual example of this application will be presented later in this paper to illustrate this point.

Viscosity measurement compared to the PVT lab results

Table 2 shows a comparison of downhole in situ viscosity compared to the lab measurements from low GOR waxy oil reservoirs (Fields 1 and 2) in South East Asia (Duangprasert et. al., 2011; Houtzager et. al., 2011). Results from Field 1 show the direct comparison of the downhole viscosity measurement and the lab viscosity measurement for the collected FT sample. Results from Field 2 on the other hand, shows the comparison of the downhole measurement of flowing fluid though the FT during the pump-out period, and the lab analysis of the

Tubing Stem Test (TST) samples collected from separator and restored back to the reservoir condition. Three reservoirs for Field 2 are listed in Table 2.

Please note that all in situ viscosity values obtained in Table 2 were measured from flowing fluids via the dual packer FT. As a result, there is some degree of contamination in all cases compared to fluid that is pumped via a focused sampling probe. For a focused sampling probe, cleaner reservoir fluid can be controlled and the in situ fluid properties measurement will be more representative of the reservoir fluid (O' Keefe et. al., 2007). However, since there was no viscosity PVT data for samples collected with the focused sample probe, we want to illustrate the viscosity measurement application for the purposes of the IPTT applications and the results are presented in Table 2. If the typical non-waxy oil viscosity correlation available from commercial pressure transient analysis software was used for PTA, a ten times underestimation of the viscosity value would have resulted in a ten times underestimation of permeability-thickness, and subsequent well productivity. From Table 2, even with 5-20%wt OBM contamination, the downhole viscosity measurement is comparable to the lab measurements and the clean reservoir fluid viscosity obtained during the TST.

Applications to Pressure Transient Analysis

As mentioned previously, another advantage of using the downhole in-situ viscosity measurement is to be efficient in PTA. Table 3 shows the results of a case in which seventeen feet of sand that was expected to be oil bearing was tested. The objective of this test was to confirm hydrocarbon and to obtain reservoir parameters from the dual packer IPTT tests. The build-up pressure transient obtained from the dual packer IPTT was analyzed with the viscosity value obtained from in situ viscosity measurement. This was consistent with the TST pressure transient test, which was analyzed using the TST sample viscosity, as shown in Table 3.

To illustrate this point, the shape of the pressure derivative of the same reservoir should be the same. When we observe the pressure transient from the wireline formation tester, the pre-test build-up and final build up usually have the same shape of pressure derivative. However, there is some shift in the pressure derivative between two main build-ups due to a difference in flowing fluids (i.e. mostly mud during the first pump-out versus mainly reservoir fluid in the cleaning up period before the main build-up). Since the two main build-ups followed one another, the reservoir permeability-thickness for this particular tested zone should be the same. The ratio of the radial flow stabilization i.e. $\frac{kh}{\mu}$ is quite consistent to the ratio of the viscosity of fluid flowing before the two main build-up periods. In other words, the viscosity value of flowing fluid before conducting pressure build-up should be used to analyze pressure build-up transient in order to obtain the representative permeability-thickness for this particular zone. As a result, it is a benefit to have an accurate viscosity value obtained during the FT job. The IPTT test can be optimized if no PVT quality sampling is required.

Conclusions

This paper reviews waxy oil viscosity correlations that are available at this time. It should be noted that in order to obtain accurate viscosity of waxy oil, lab measurement parameters such as shear rate and wax content are necessary. The principal and concept of the downhole in

situ viscosity measurement was discussed with field examples from South East Asia. The application of using in situ fluid viscosity on pressure transient analysis was then introduced and examples of this application were provided. Conclusions that can be drawn from this paper include:

- Waxy oil viscosity requires proper correlations or directly measured values since the typical non-waxy oil correlation available from PTA software can cause significant error.
- Together with in-situ downhole measurement, the wireline formation tester IPTT is a powerful tool that can be used to characterize reservoir properties and enables real time decision making.

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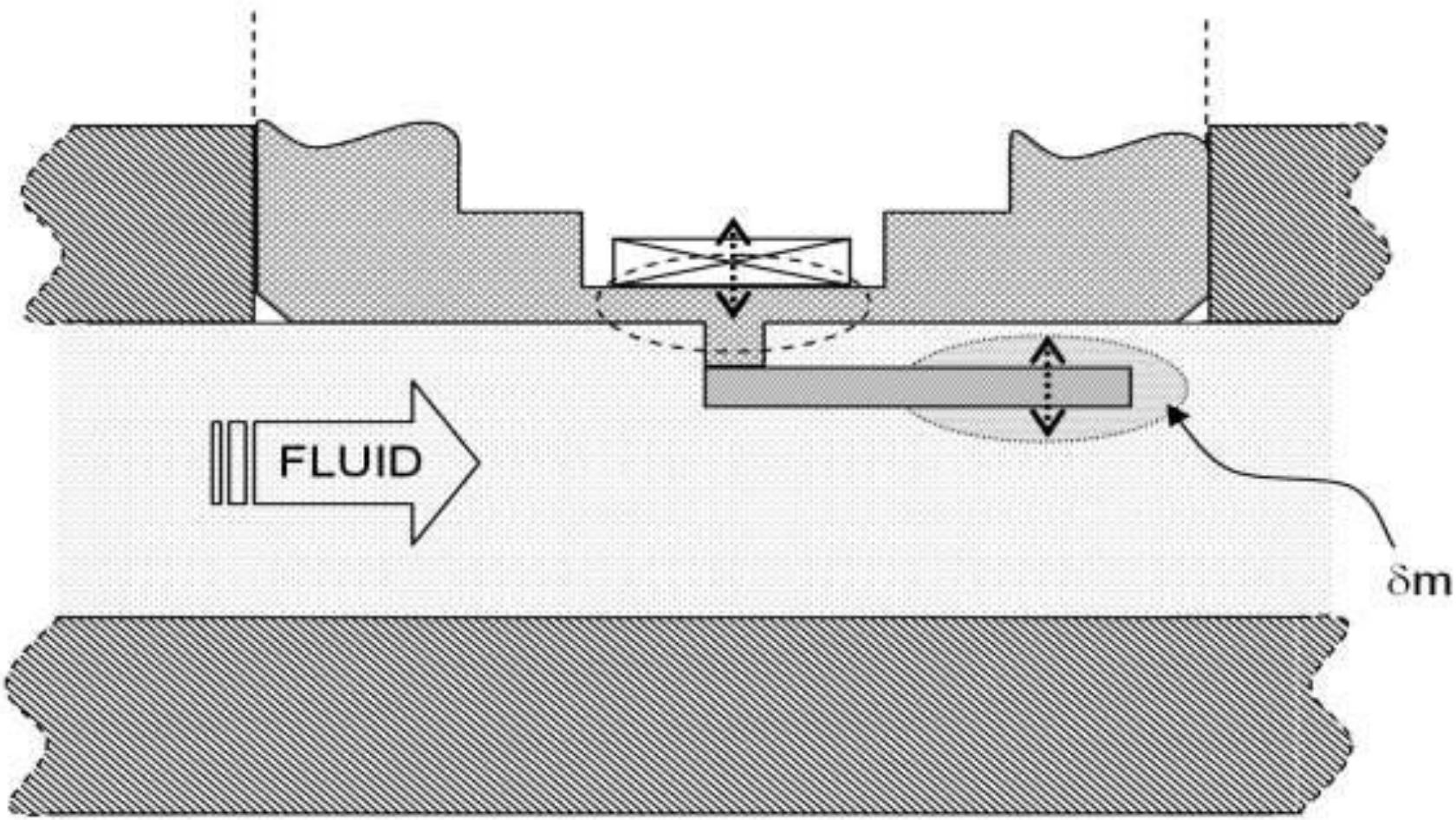

Figure 1. Vibrating D-V rod concept.

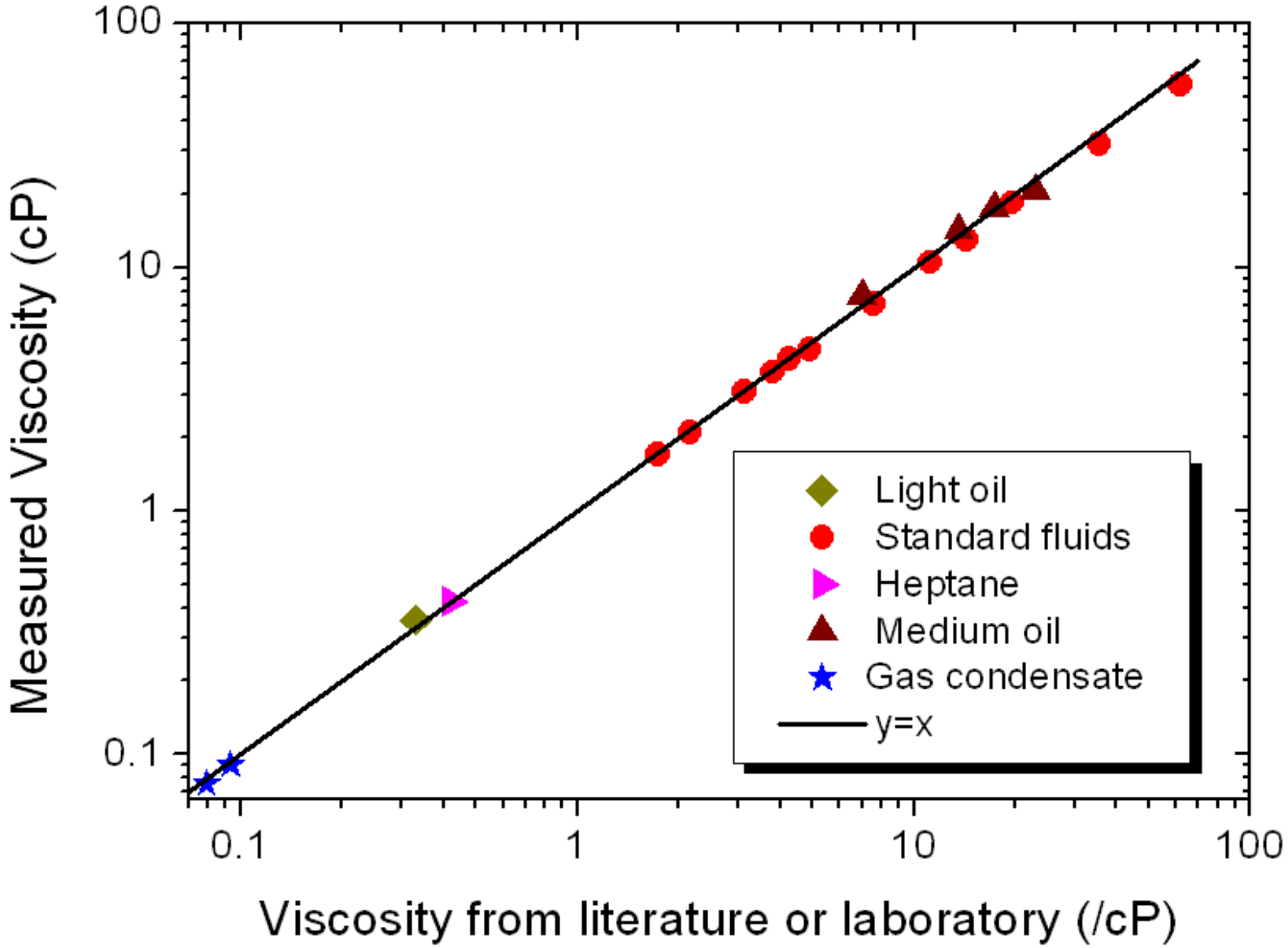

Figure 2. The measured viscosities were compared to reference viscosity values, for various fluid types such as alkane, viscosity standard live oils, and gas condensate (Fujisawa, et. al, 2003).

Density measurements	
Range	0.05 g/cm3 – 1.2 g/cm3 (for viscosity < 50 cP)
Accuracy	
Typical	+/- 0.010 g/cm3
Maximum	+/- 0.012 g/cm3
Resolution	
Typical	+/- 0.001 g/cm3
Viscosity measurements	
Range	0.25 cP to 50 cP
Accuracy	+/- 10% of measurement (for wells drilled with OBM and fluid density between 0.3 – 0.9 g/cm3)
Resolution	0.01 cP

Table 1. D-V sensor measurement specifications.

		Downhole	Lab measurement	Contamination
Field 1* **	**Viscosity (cp)**	14.6	11.2	15%wt
120 degC	**Density (g/cc)**	0.86 (at reservoir P,T)	0.795 (at Psat, Tres)	
	GOR (scf/bbl)	106	145	Dual Packer
Field 2	**Viscosity (cp)**	3.1*	2.2**	20%wt
Sand X	**Density (g/cc)**	0.769 (at res P,T)	0.773 (At Psat, Tres)	XPT gradient = 0.809
134 degC	**GOR (scf/bbl)**	73*	196**	Dual Packer
Field 2	**Viscosity (cp)**	2.6*	1.9**	5%wt
Sand Y	**Density (g/cc)**	0.785 (at res P,T)	0.779 (at Psat and Tres)	XPT gradient = 0.79
134degC	**GOR (scf/bbl)**	143*	157**	Dual Packer
Field 2	**Viscosity (cp)**	2.3*	7.9**	65%wt
Sand Y	**Density (g/cc)**	0.793 (at res P,T)	0.762 (at Psat and Tres)	
105 degC	**GOR (scf/bbl)**	45*	105**	Dual Packer

Table 2. Shows the comparison of downhole viscosity compared to the lab results from the low GOR waxy oil.

	Permeability-thickness (mD-ft)	Permeability (mD)	Time per Test	Radius of investigation
IPTT	28700	1688	3.4 hours	420 ft
TST	26520	1560	11.9	1240 ft
% different	7.6%	7.6%		

Table 3. Shows the comparison of PTA results obtained from dual packer IPTT and TST tests in the same zone.