Velocity, Density and Modulus of Hydrocarbon Fluids --Data Measurement

De-hua Han, HARC; M. Batzle, CSM*

Summary

Density and ultrasonic velocity of numerous hydrocarbon fluids (oil, oil based mud filtrate, hydrocarbon gases and miscible CO2-oil) were measured at in situ conditions of pressure up to 50 Mpa and temperatures up to100 °C. Dynamic moduli are derived from velocities and densities. Newly measured data refine correlations of velocity and density to API gravity, Gas Oil ratio (GOR), Gas gravity and in situ pressure and temperature. Gas in solution is largely responsible for reducing the bulk modulus of the live oil. Phase changes, such as exsolving gas during production, can dramatically lower velocities and modulus, but is dependent on pressure conditions. Distinguish gas from liquid phase may not be possible at a high pressure. Fluids are often supercritical. With increasing pressure, a gas-like fluid can begin to behave like a liquid

Introduction

Hydrocarbon fluids are the primary targets of the seismic exploration. However, our understanding of seismic properties of hydrocarbon fluids is incomplete. Many measurements of Pressure-Volume-Temperature (PVT) relationships have been done to obtain static properties of hydrocarbon fluids for reservoir engineers. Relatively few measurements have been made on seismic properties of hydrocarbon fluids. Wang and Nur (1988) did an extensive study on pure hydrocarbons (Alkanes, Alkenes and Cycloparaffins). They found simple relationships among velocity, modulus, temperature, and carbon numbers. Wang et al (1988) published a series of velocity data measured on 8 'dead' oil (gas free oil at room condition) and one 'live' oil (gas dissolved into oil) samples. These data revealed that velocity properties of hydrocarbon oil are similar to pure hydrocarbons. Velocity has a simple relationship to API gravity, pressure and temperature. By combining hydrocarbon fluid property relations developed in petroleum engineering and a few velocity data measured on 'live' oil, Batzle and Wang (1992) derived an empirical model for velocity and density of 'dead' and 'live' oils. Their results clearly show that under normal in situ conditions, the fluid properties can differ so substantially that any wrong estimate of fluid velocity can cause expensive errors in seismic interpretation, DHI and AVO analysis. Therefore, a systematic investigation of fluid properties is a critical step to improve our understanding of hydrocarbon fluid signatures at reservoir conditions.

For this investigation, numerous hydrocarbon samples were donated by industrial sponsors. Velocity and density were measured with pressure up to 55.2 Mpa (8000 Psi) and temperature up to 100 °C.

Velocity of Dead Oil

Initial measurements were on the gas-free or 'dead' oils at pressure and temperature (see **Fig. 1)**. We used the following model to fit data:

$$Vp\ (m/s) = A - B * T + C * P + D * T * P \qquad (1)$$

Here A is a pseudo velocity at 0 °C and room pressure (0 Mpa, gauge), B is temperature gradient, C is pressure gradient and D is coefficient of coupled temperature and pressure effects.

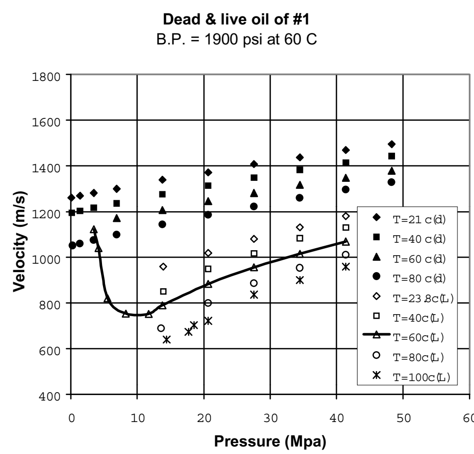

Fig. 1 Velocity of a gas-free 'dead' (solid symbols) and gas-charged 'live' (open symbols) oil as function of pressure and temperature

This regression relationship is the same as that used by Wang et al (1988) and Batzle and Wang (1992). Least square regression gives

$$Vp\ (m/s) = 1340 - 3.52 * T + 4.61 * P + 0.0137\ T * P \quad (2)$$

with a correlation coefficient of 0.998. Dead oil illustrates a predictable behavior: velocity increases with increasing pressure and decreases with increasing temperature. As a result, with increasing depth, pressure and temperature effects tend to cancel each other.

Property of Hydrocarbon Fluid

Velocity of Live Oil

Live oil samples were obtained directly or recombined from dead oil and gases based reported composition. A typical live oil velocity (Reinecke oil) as function of pressure and temperature is also shown in **Fig. 1**. The oil has an API gravity of 45.6, a gas/oil ratio (GOR) of 232 L/L (1300 scf/stb), and a 13.1 MPa (1900 Psi) Bubble Point at 60 °C. We use the same model to fit the live oil data:

Vp(m/s) = 936.7 – 4.688* T + 7.659* P + 0.0456* T* P (3)

Compared with dead oil, dissolved gas causes coefficient A to decrease, and B, C and D increase. Velocity of the live oil is significantly lower than that of the dead oil. At reservoir conditions (60 °C and 13.8 MPa), velocity (790 m/s) of the live oil is more than 35% lower than for the dead oil (790 m/s versus 1206 m/s). Similarly, the bulk modulus, K, of the live oil is less than one third for that of the dead oil (0.37GPa versus 1.16 GPa).

In contrast to the suggestion of Batzle and Wang (1992), coefficients B and C increase significantly for live oil.

Based on measured data, the velocity of oil with constant composition can be derived as a function of depth.

$V = A + B * Z * 30 + C * Z * 10.5 + D * Z^2 * 315$ (4)

Here using a pressure gradient of 10.5 MPa/km and a temperature gradient of 30 °C/km (with a surface temperature of 15.56 °C). Four oil sample velocity-depth lines are plotted in **Fig. 2**. Here we examine two temperature gradients: 20 °C/km and 30 °C/km. Two different velocity-depth trends are revealed: oil with low API and GOR has velocity that tends to decrease with depth; oil with high API and GOR has velocity that tends to

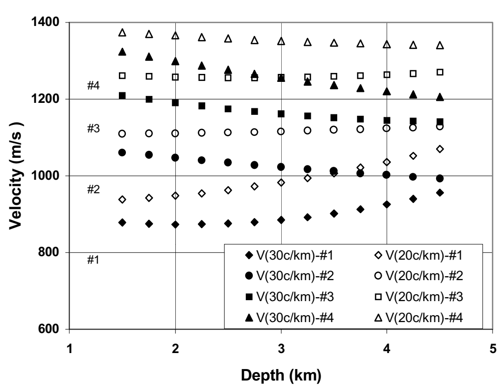

Fig. 2 Calculated oil velocity versus depth versus dept

increase with depth.

3. Bubble Point and GOR Effects on Oil Velocity

To investigate GOR effects on oil velocity, we began with the Reinecke oil with an initial bubble point pressure of 13.1 Mpa at 60 °C. To generate live oils with lower bubble points, we flashed gas out and pick 4 oil samples with bubble points of 10.34 Mpa (1500 Psi)), 6.90 Mpa (1000 Psi), 3.45 Mpa (500 Psi) and 1.24 Mpa (180 Psi) respectively. Based on the PVT data the GOR is correlated with bubble point:

B. P. (MPa)	13.1	10.34	6.90	3.45	1.24
Temp. (C)	60	23	24	60	23
GOR (scf/stb)	1300	1100	850	500	350

The major decrease of velocity with increasing GOR is shown in **Fig. 3**. For this sample, velocity decreases from 1206 m/s to 790 m/s with GOR increasing from zero to 1300 scf/stb (1 scf/stb =0.178 L/L) .

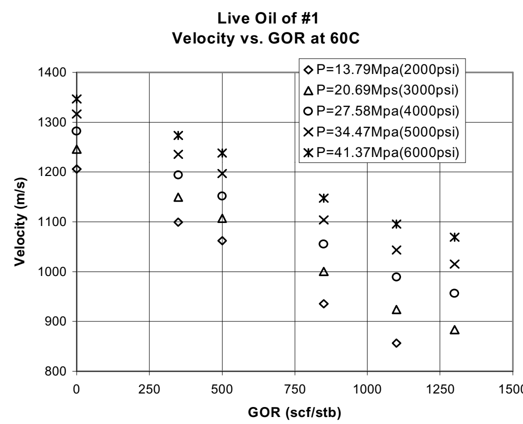

Fig 3. Oil velocity as a function of GOR

4. Gas Velocity

Gases are the other extreme phase of hydrocarbon fluids. **Fig. 4** shows measured velocity versus temperature at different pressures. As expected, velocity increases with increasing pressure. The temperature dependence changes dramatically with pressure. At pressures higher than 27.58 MPa (4000 Psi), gas behaves like an oil, and velocity decreases with increasing temperature. But at pressures lower than 16.52 MPa (2400 Psi), velocity increases with increasing temperature. This is similar to an ideal gas, velocity increasing with increasing temperature:

$$V = (R * T / M)^{1/2} \qquad (5)$$

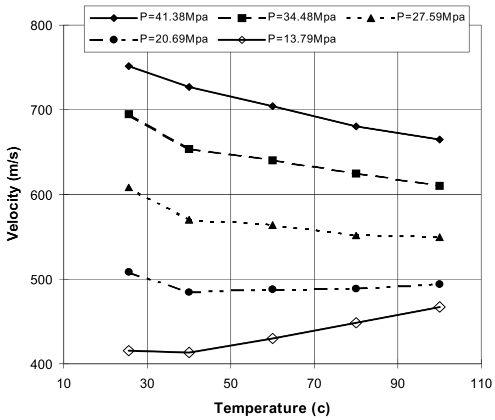

Figure 4. Gas velocity versus temperature

In the region between gas-like and liquid-like behavior, this fluid's velocity tends to be independent of temperature.

The properties of gas and oil will vary continuously over range of composition, pressure and temperature conditions. With increased depth (pressure), differences between saturated 'gas' and 'oil' tend to disappear, and a distinction between 'gas' and 'oil' is often not realistic.

Hydrocarbon Fluids Near and Below the Bubble Point

When seismic waves propagate through rocks, the elastic deformation will oscillate the pore fluid pressure. In a mixed gas-oil reservoir, at equilibrium we are forced to be at the phaseboundary or bubble point line. Seismic waves propagating through such reservoir may force mass transfer between the gas and oil phases. Potentially, seismic waves could be attenuated significantly. This effect has been proposed as a gas-oil indicator. We examined wave propagation near the bubble point and found that acoustic wave is not sensitive to the bubble point pressure. Thus, the acoustic wave does not generate any significant phase transition between gas and oil (liquid).

We also examined acoustic wave propagation as pressure dropped below the bubble pressure. We found that velocity is not sensitive to a small pressure drop (a tenth of MPa), especially at high pressures. This suggests that the tiny amounts of gas bubbles formed near the bubble point pressure do not change the mixture compressibility enough to alter the velocity. This is not surprising if we consider the physics of a small bubble. The pressure inside a bubble is higher and would make the gas behave more like the surrounding liquid. With greater pressure drops, more gas exsolves out of the oil as a separate phase (a slow process). Wave amplitude begins to be attenuated significantly and it may disappear completely.

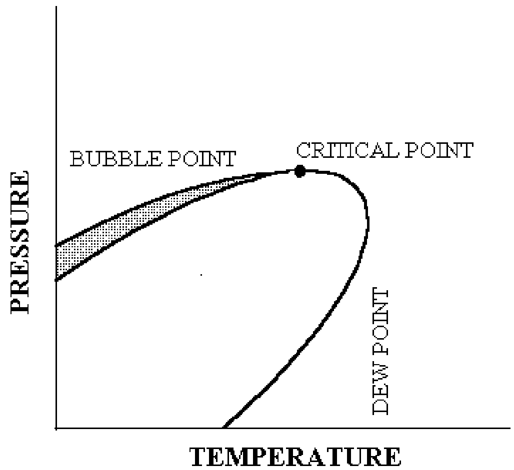

Fig. 5. Influence of phase transition for seismic detection

Figure 5 shows that sensitivity of phase transition of a gas-oil system to seismic data. At low bubble pressures, far from the critical point, we have the best conditions for detecting the gas effect. At conditions with increasing depth, the effect of gas phase near the bubble pressure (phase boundary) on velocity may become invisible.

Velocity of Mud Filtrate

During the drilling, mud filtrate may penetrate, or invade, into the formation, called invasion. In general, mud filtrate invasion is an inevitable and complicated process depending on the mud, formation and fluid properties as well as in situ conditions. Consequently, wireline logging data in an invaded zone will be complex and changing. Here, we examine measurements on velocity on oil-based mud.

In general, an oil-based filtrate is easy to separate from whole mud. Oil filtrate #1 is diesel-based mud. This filtrate has a density of 0.789 gm/cc (API gravity of 47.8). We recombined the filtrate with methane to make a live oil fixing the bubble pressure at 12.4 MPa). Data show (**Fig. 6**) that gas dissolved into the filtrate reduces velocity significantly. Note that the velocity of a live filtrate can vary widely dependeing on the condition in the encountered gas zones

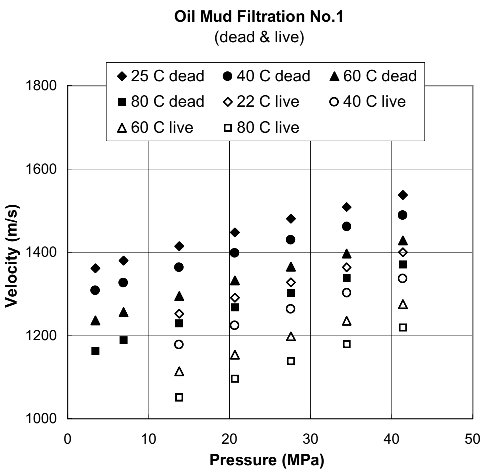

Fig. 6. Mud filtrate velocity

Measured Density of Hydrocarbon Fluids

Density of live oil was measured using a pressure vessel with a piston. Measured data **(Fig. 7)** show that density is almost linearly related to pressure up to 40 MPa and temperature up to 100 °C. Least-square linear regression correlates density to pressure and temperature as

$$\rho = \mathbf{D_0} + \mathbf{a} * T + \mathbf{b} * P \qquad (6)$$

(ρ in gm/cc, T in °C and P in MPa)

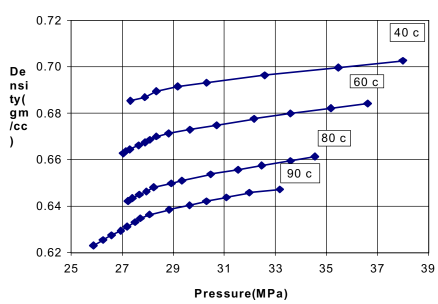

Fig. 7 Density vs. pressure of oil #5

The correlation coefficient is better than 0.999 for almost all the measured data. Sample #5 is recombined oil with API gravity of 50.6, GOR of 185.5 and gas gravity of 0.554. Systematic measurements were made on sample #5 with different bubble pressures. Figure 8 illustrates that the more gas dissolved in oil, the lower the density. It also shows that the pressure dependence of density slightly increases with increased bubble point.

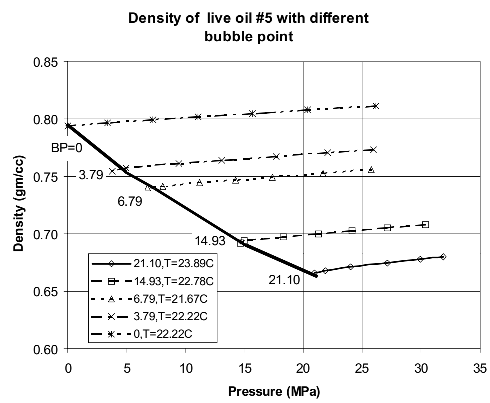

Fig. 8 Density of live oil #5 with different bubble point

We also found that density is not sensitive at high bubble pressure. Similar to velocity, with increasing depth, density contrast between light oil and bubbled gas tends to become insignificant.

Modulus of Hydrocarbon Fluids

Dynamic fluid modulus is the product of density and the square of velocity ($\rho * V^2$), is used in fluid substitution. Velocities and densities of hydrocarbon fluids are systematic in terms of their correlations to compositional parameters (API, GOR, and gas gravity) and in situ conditions (pressure and temperature). Therefore, effects of those parameters on fluid modulus are nearly tripled in magnitude over those effects on velocity and density.

Conclusion

1. 'Live' oils have a lower velocity, density and modulus when compared to 'dead' oil.on GOR. The more gas dissolved in oil, lower velocity, density and modulus.
2. Velocity, density and modulus of oils increase with increasing pressure and decreasing temperature. The pressure and temperature effects on velocity are enhanced with more dissolved gas.
3. With increasing depth, the pressure and temperature effects on velocity tend to cancel. Velocity, density

and modulus tend to decrease with depth if API and GOR are low and increase if API and GOR are higher.

4. With increasing pressure (depth), and increasing gas dissolved into oil, 'live' oil properties approach gas properties. Highly pressured gases or gas condensates behave like liquids.
5. Velocity density and modulus contrasts between saturated oil and exsolved gas at near the bubble pressure varies gradually: highly visible seismically at low pressure; invisible at high pressure.
6. Velocity, density and modulus are not sensitive to bubble-point, small pressure drops near the bubble point, or small amount of gas bubbles, especially at a high pressure.

Acknowledge

We appreciate the help from, Xiangyang Wu, Hongkui Ge and Weiping Wang to collect part of data. The results in this abstract are from the Fluid Project, a joint research consortium between Rock physics labs of CSM and HARC. Many thanks to our numerous industrial partners for their support and interest.

Reference

Batzle, M., and Wang, Z., 1992, Seismic properties of pore fluids; Geo. 57, 1396-1408.

Wang, Z., 1988, Wave velocities in hudrocarbons and hydrocarbon saturated rocks-with applications to EOR monitoring: Ph. D. Thesis, Stanford University.

Wang, Z., Nur, A., and Batzle, M. L., 1988, Acoutic velocity in petroleum oils: SPE paper 18163, Proc. 63 rd SPETC Formation Eval. Res. Geol. Section, 571-585.