Velocity, Density and Modulus of Hydrocarbon Fluids -- Empirical Modeling

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Summary

Improved velocity and density models were developed based on an extensive suite of new data. Nearly 70 gas-free (dead) and gas-charged (live) oil samples provided by industry sponsors were measured at pressures up to 55.2 Mpa (8000 Psi) and temperatures up to 100 C. This new data suggest that the velocity model developed by Batzle and Wang, (1992) overestimates the gas-oil ratio (GOR) effect on velocity of hydrocarbon liquids. Two techniques are employed to fit the data: a model based on engineering concepts of ideal liquids, and on purely empirical forms. These results have been generalized and incorporated in a program (FLAG) to calculate and plot fluid properties as functions of composition, pressure, and temperature.

Introduction

We need to accurately predict hydrocarbon fluid properties for a broad range of geophysical applications such as seismic interpretation, reservoir delineation and monitoring and direct hydrocarbon indicators (DHI) including amplitude versus offset (AVO) analysis. Batzle and Wang (1992) made an initial effort in applying engineering properties to develop the geophysical properties of hydrocarbon fluids. They suggest that specific fluid properties were responsible for observed seismic anomalies, such as gas/brine and oil/brine interfaces and bright spots (Hwang and Lellis, 1988 and Clark, 1992). They produced general trends showing how the oil properties are affected by compositional parameters and in situ conditions. Unfortunately, only a very few live oils were measured at in situ conditions. To extend this analysis, we measured a suite of oil samples provided by industrial sponsors. This extensive data suite allows us to examine the published models and develop more accurate relationships.

B-W model

Batzle and Wang (1992) and Wang et al. (1988) developed an empirical relation for velocity of dead oil

$$V = A - B * T + C * T + D * T * P \qquad (1)$$

Where $A=2090*(\rho_0 / (2.6 - \rho_0)^{1/2}$; $B = 3.7$; $C = 4.64$ and

$$D = 0.0115 * [4.12 / (1.08 * \rho_0^{-1} - 1)] * T * P. \qquad (2)$$

where velocity V is in m/s, ρ_0 is oil reference density, temperature T in °C and pressure P in MPa. The coefficient A is the velocity at 0 °C and 0.1 MPa pressure. The equation shows that oil velocity decreases with decreasing oil density, decreasing pressure, and increases temperature. This B-W model did a reasonable job of predicting 'dead' oil velocity.

For live oil, velocity can still be calculated using equation (1) by employing a pseudodensity $\rho`$ defined as

$$\rho` = \rho_0 * [B_0 * (1 + 0.001 * R_s)]^{-1} \qquad (3)$$

where R_s is GOR (Gas-Oil volume Ratio at 15.6 °C and 0.1 MPa), B_0 is a volume factor. This model applies the following equation (Standing, 1962) for B_0

$$B_0=0.972+0.00038*[2.4R_s*(G / \rho_0)^{0.5} +T+17.8]^{1.175} \qquad (4)$$

where G is specific gas gravity. Using pseudodensity, to replace oil density in the equation (1), the B-W model estimates 'live' oil velocity. In their approach, pseudodensity is largely empirical. Using this pseudodensity technique is an effective way to unify the calculation of both dead and live oils.

However, several problems arose from Batzle and Wang's scheme:

1. The model was developed on a small live oil data set.
2. Constant coefficients B and C are not consistence with the newly acquired data.
3. Procedure to calculate density is confused and inconsistent with engineering concepts.

Density Model 1 (H-C model 1) Using 'Pseudodensities'

We developed the density model based on the pseudoliquid density concept often used by petroleum engineers. A pseudoliquid at standard conditions (15.6°C and ATM. Pressure) has the same composition as the 'live' oil at reservoir conditions (although such a liquid could not exist in equilibrium). Based on the ideal solution principle (McCain, 1990) a pseudoliquid is assumed as a idea mixture of dead oil and gas (apparent liquid). First, we calculate apparent liquid density ρ_a for natural gas at 'standard conditions' (Katz, 1942).

$$\rho_a=0.61731*(10^{-0.00326API})+(1.5177–0.54349*\log API)*\log G \qquad (5)$$

where G is the gas gravity and API is the gravity for oil. Pseudoliquid density ρ_{p0} at 'standard conditions' can be calculated as.

$$\rho_{p0} = (W_o + W_g) / (\underline{V}_o + \underline{V}_g) \qquad (6)$$

where W_o and W_g is weight of oil and gas dissolved in oil, $\underline{V}_o$ and $\underline{V}_g$ are oil volume and apparent liquid gas volume. ρ_{p0} can be written as

$$\rho_{P0} = \rho_0 * (1 - v_g) + \rho_a * v_g \qquad (7)$$

where v_g is volume fraction of apparent liquid gas.

This pseudoliquid density at 'standard conditions' needs to be adjusted to reservoir pressure and temperature. We follow an engineering approach using the coefficient of isothermal compressibility for pressure correction (Standing, 1952), and the coefficient of isobaric thermal expansion for the temperature correction (Witte, 1987).

Density Model 2 Based on Experimental Data

We also developed an empirical model based on measured density data. A linear fit is appropriate for the dead oil data (pressure up to 55 Mpa (8000 Psi) and temperature up to 100 °C).

$$\rho = \mathbf{D_0} + \mathbf{a} * T + \mathbf{b} * P \qquad (8)$$

Equation (8) can be used to calculate density of undersaturated oils (above the bubble pressure).

Additional adjustments must be made to calculate 'live' oil density. The following general form was used to fit each of the coefficients $\mathbf{D_0}$, **a** and **b** in equation (8)

$$\mathbf{Y} = a_i + b_i * R_s^2 + c_i * R_s + d_i * API + e_i * G \qquad (9)$$

where R_s is GOR, API is oil gravity and G is specific gas gravity.

New Velocity Model (H-C 1) for Hydrocarbon Fluids

We use a two-step method to analyze our data. First, Batzle and Wang's model (1992) was in the form

$$V = A - B * T + C * T + D * T * P \qquad (10)$$

The results of least square regression on 74 'dead' and 'live' oil datasets (including 9 dataset from Wang et al.,1988) show that equation (10) fits quite well. Correlation coefficient for most datasets is better than 0.99. Second, we assume the model is a valid representation for each fluid. Instead of all data (over 2000 data points) we use the regression results on each oil (4 coefficients for each sample).

For the form in equation (10), the coefficient A, the pseudoliquid velocity (V_{P0}) is a function of pseudodensity ρ` and is compared with measured data in **Fig. 1**. The data falls in a narrow range and the B-W model fits dead oil almost perfectly. However, there is significant deviation for live oil data. Coefficient A is underestimated .

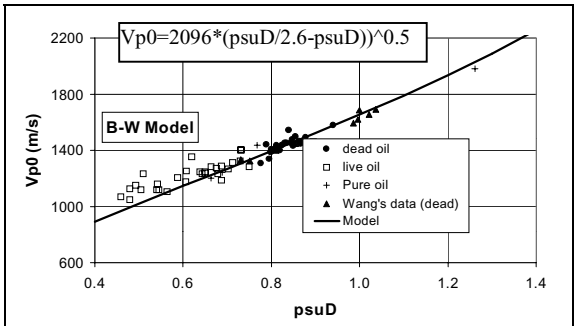

Fig.1 Pseudoliquid velocity vs. pseudodensity for B-W Model

We can modify the B-W model to redefine the velocity pseudodensity ρ_{PV}. A pseudoliquid density was given in equation (7). This is similar to the equation for porous rock if we substitute oil as the rock frame and gas as the fluid filling the pores. In this analog, oil molecules make a major contribution to velocity, just as rock frame does. Therefore, we define the velocity pseudodensity ρ_{PV} at 0 °C and 0.1 MPa pressure as

$$\rho_{PV} = \rho_0 * (1 - v_g) + \varepsilon * \rho_a * v_g \qquad (11)$$

where ε is the effective gas parameter to represents the gas contribution to pseudoliquid velocity. We apply the velocity pseudodensity ρ_{PV} to fit data and search for the best value for an effective gas parameter ε:

$$\varepsilon = 0.113 \qquad (12)$$

Fig. 2 shows coefficient A (the pseudoliquid velocity V_{P0}) as a function of velocity pseudodensity.

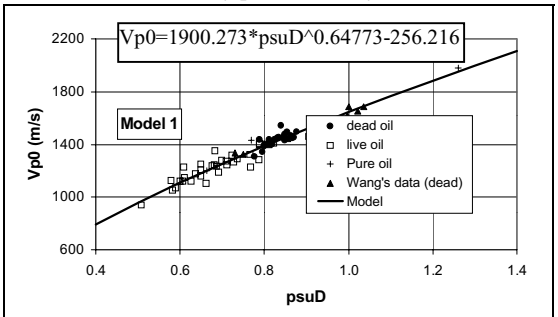

Fig. 2 Pseudoliquid velocity vs. pseudodensity for model 1

$$V_{P0} = 1900.3 * \rho_{PV}^{0.6477} - 256.2. \qquad (13)$$

The correlation coefficient for the least square regression is 0.986. **Fig. 2** shows clearly that the new model can fit both 'dead' and 'live' oil data well. In the restricted range of GOR less than 250 L/L, ε is small and can be assumed as a constant.

A few data points were not included in the regression analysis because the data was well off the general trend. Those include CO2-oil mixture, gas condensate with high GOR, oil mud filtrates, and diesel: all are not natural crude oils.

In the B-W model, temperature coefficient B and pressure coefficient C are constant. The new data demonstrate that an increase of GOR has a significant effect on coefficients B and C (**Fig. 3**). The trend is that B increases with decreasing velocity pseudodensity ρ_{PV}.

$$B = 3.044 + 0.012 * (141.5 / \rho_{PV} - 131.5) \qquad (14)$$

If the fluid is more gas-like, the temperature effect on velocity disappears. This B model fails to predict the transition from gas-rich oil to gas condensate. Similarly this model cannot predict the velocity of heavy oil at low temperatures through the glass point (transition between liquid and semi-solid phases).

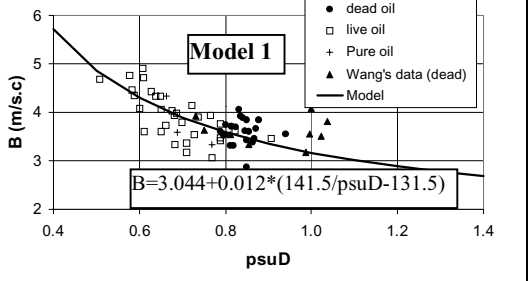

Fig. 3 Coefficient B vs. pseudodensity for model 1

Fig. **4** shows coefficient C versus pseudodensity ρ_{PV}. With decreasing pseudodensity, $\rho_{PV,}$ C clearly increases.

$$C = 3 + 0.031 * (141.5 / \rho_{PV} - 131.5) \qquad (15)$$

Coefficient D is for the cross-dependence T * P term. In this data range, the effect of D is relatively small (**Fig. 5**). Although small, this nonlinearity term increases with decreasing ρ_{PV}.

$$D = 0.3356 * \exp(-4.036 * \rho_{PV}) \qquad (16)$$

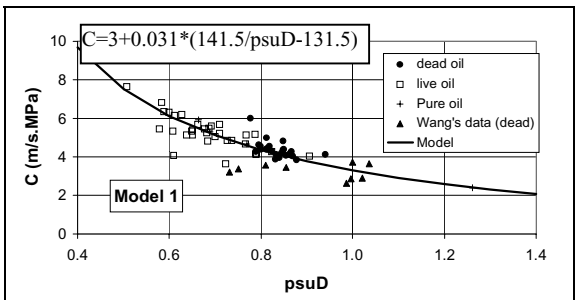

Fig. 4 Coefficient C vs. pseudodensity of model 1

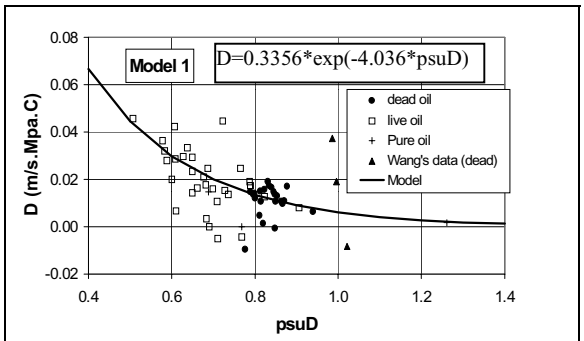

Fig. 5 Coefficient D vs. pseudodensity for model 1

In this model all parameters, V_{P0}, B, C, and D correlate to ρ_{PV}. This means that for 'live' oil, the velocity will change significantly with different GOR. For most samples, the velocity of 'live' oil can be estimated within 5% (**Fig. 6**) under the following conditions:

1. API gravity of 15 to 55 and GOR up to 250 L/L
2. Pressure up to 55.2 MPa.
3. Temperature up to 100 °C

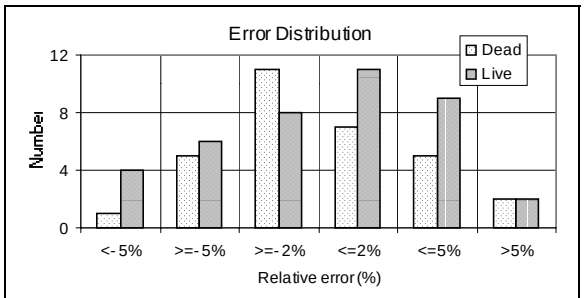

Fig. 6: Relative error distribution for model 1

However, our characterization of velocity and density of hydrocarbon fluids should be expanded to include gas, gas

condensate, and heavy oil to higher pressure and temperature.

Modulus of Hydrocarbon Fluids

Dynamic fluid modulus is the product of density and the square of velocity ($\rho * V^2$). This is the term directly used in fluid substitution. The modulus is easily calculated based the velocities and densities models developed above. As mentioned previously, velocity and density 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 these controlling parameters on fluid modulus are nearly tripled in magnitude over those effects on velocity and density.

Computer Program "FLAG"

A computer program, FLAG, was written using Microsoft Visual Basic for PC Windows. This program provides different kinds of calculations based on newly developed model:

A. Hydrocarbon fluid properties with plot capability,
B. Formation water properties,
C. Rock properties based on Gassmann's equations.

This version of the program is free and available to the public and can be down loaded from our web site: "www.mines.edu/research/fluids".

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