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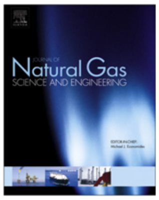

HPHT viscosities measurements of mixtures of methane/nitrogen and methane/carbon dioxide

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ABSTRACT

Gas production worldwide has been steadily increasing over the past 15 years. This growing demand for natural gas is driving the E&P industry to look for new resources in previously unexplored and deeper areas, where High Pressure High Temperature (HPHT) reservoirs may be encountered. These are reservoirs that exhibit pressures greater than 10,000 psia and temperatures over 300 °F. Thus, more attention must be paid to gas properties at HPHT conditions.

Among all gas properties, viscosity is seldom measured in the laboratory and typically estimated through correlations. At HPHT conditions, the reservoir fluids will typically be very lean gases (e.g. methane with some degree of impurity) and therefore the gas properties may differ from those at lower pressures and temperatures. Consequently, the accuracy of gas viscosity correlations that are not experimentally validated at HPHT conditions may be doubtful.

A review of a large database of published viscosity data for pure methane and mixed hydrocarbons revealed that they are limited in terms of both experimental conditions and quantity, and in some cases their accuracy is unknown.

New HPHT gas viscosity correlations were derived using a set of viscosities of pure methane (CH_4), mixtures of methane/nitrogen (CH_4/N_2) and mixtures of methane/carbon dioxide (CH_4/CO_2) measured using an oscillating piston viscometer at HPHT conditions.

1. Introduction

To meet the increasing energy demand worldwide, the industry has turned to unconventional gas resources, which has helped increase the world's natural gas reserves-to-production ratio to 63.6 years in 2011, and the reserves to 208.4 trillion m^3 (BP, 2012).

This growing demand for natural gas is driving the E&P industry toward new resources in previously unexplored and deeper areas, where HPHT reservoirs may be encountered. These are reservoirs that exhibit pressures greater than 10,000 psia and temperatures over 300 °F. Table 1 provides a summary of HPHT definitions according to Halliburton (2012). Fig. 1 shows a map of HPHT plays across the world.

Evaluating and modeling the performance of these HPHT reservoirs requires an understanding of gas behavior at high pressures and high temperatures. Thus, more attention must be paid to gas properties at HPHT conditions. One of the most important gas properties is viscosity. Gas viscosity dictates the fluid mobility in the reservoir and subsequently has a significant impact on cumulative production forecasting during field development planning.

At HPHT conditions, the reservoir fluids will typically be very lean gases (e.g. CH_4 with some degree of impurity), although there are reported gas condensate fields with reservoir pressure in excess of 14,500 psi (Sun et al., 2012). Accurate measurements of gas viscosities at HPHT conditions are generally difficult and expensive. Thus, they are usually predicted from published correlations based upon laboratory data.

Davani et al. (2009a) first indicated the sensitivity of Inflow Performance Relationship (IPR) curves to gas viscosity uncertainty, which may result in unrealistic well-flow models and therefore mislead the well-performance investigation.

Later, Davani et al. (2009b) reviewed a large database of published viscosity data for pure CH_4 and mixed hydrocarbons and showed that they are limited in terms of both experimental conditions and quantity, and in some cases their accuracy is unknown. Davani et al. (2009b) also performed a review of available gas

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Table 1
HPHT definition (Halliburton, 2012).

	Borehole temperature	Borehole pressure
HPHT	>300 °F (150 °C) – 350 °F (175 °C)	>10,000 psi (69 MPa) – 15,000 psi (103 MPa)
Extreme HPHT	>350 °F (175 °C) – 400 °F (200 °C)	>15,000 psi (103 MPa) – 20,000 psi (138 MPa)
Ultra HPHT	>400 °F (200 °C) and above	>20,000 psi (138 MPa) and above

viscosity correlations and indicated that they were developed from experimental data obtained at low to moderate pressures and temperatures, and their applicability at HPHT conditions could therefore be doubtful.

Generally, the problem can be overcome in two ways: by improving the available gas viscosities measurement equipment and the procedures for use at HPHT conditions, and by developing new correlations for HPHT supported by accurately measured data.

2. Main laboratory techniques for measuring gas viscosity

Several techniques are available to measure gas viscosity. However, just a few of them are applicable to HPHT conditions. The following viscometers have been used to measure gas viscosity:

- Vibrating wire viscometer
- Capillary tube viscometer
- Falling (or rolling) ball viscometer
- Oscillating-piston viscometer

All of them are also used to measure liquid viscosities, but because of the low density and very low viscosity of gas, they need to be modified to be applicable to gas.

2.1. Vibrating wire viscometer

The vibrating wire viscometer works based upon damping of transverse vibrations of a rigid wire in the fluid in order to reduce the effect of a hydrodynamic correction term. The vibrations' decay time relates to the viscosity of the fluid.

The motion of an oscillating wire in a dense fluid was first used by Bessel (1828) when he indicated the need for an added mass adjustment to the motion of pendulum in air. Du Buat (1786) described this added mass effect. Stokes (1901) developed the added mass dependency on the surrounding fluid viscosity. Tough et al. (1964) used vibrating wire to measure the viscosities of fluid for the first time. Since then, vibrating wire viscometers were developed widely with different wire materials, diameters, lengths, clamping devices, and with forced or transient modes of oscillation.

The vibrating wires have been made from tungsten, stainless steel, chrome, and NbZr alloy. Tungsten is the ideal material because of its high Young's modulus and density compared to those of other materials providing a stable resonance and sensitivity to the surrounding fluid.

Different wire diameters have been used based on the fluid viscosities range. Smaller diameters are usually used for gases and low viscosity liquids, and larger diameters are used for more viscous fluids.

Because of ease of operation, continuous readings, wide range and optional internal reference, the vibrating wire viscometer has been used widely to measure different types of fluids.

Tough et al. (1964) measured the viscosities of liquid helium at very low temperatures using the vibrating wire viscometer. Wilhelm et al. (1998) used a modified vibrating wire viscometer to measure the viscosities of dilute and dense gases for pressures up to 5,800 psia and temperatures as high as 480 °F. Bruschi and Santini (1975) measured the viscosities of argon from atmospheric pressure to 440 psi and temperature of 70 °F using the vibrating wire viscometer.

2.2. Capillary viscometer

The main feature of all capillary viscometers is a long straight tube of small diameter. By measuring the volumetric flow rate and pressure drop through the capillary tube, the viscosity of a fluid flowing within the tube can be calculated. However, the initial viscosity should be corrected to account for end effect (Van Wazer et al., 1963; Walters, 1975). Operation of the capillary viscometer consists of pumping the test fluid through a tube with a known length and diameter, and measuring the pressure drop at a known

Fig. 1. HPHT plays distribution across the world (Halliburton, 2012).