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On the viscosity of natural gas

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ABSTRACT

This study reports new experimental viscosity measurements at high pressure and high temperature for a sour natural gas mixture. The measurements were conducted with a capillary tube viscometer at pressures ranging from 10.3 to 138 MPa and temperatures up to 444 K. The study develops a comprehensive model to predict natural gas viscosity in a wide range of pressures, temperatures and compositions. The arithmetic average of the model's absolute error was found to be 2.4% compared with experimental data from the literature (containing the experimental data of the current study), which is acceptable for accurate engineering calculations; the absolute error demonstrates that this model is superior to other methods.

1. Introduction

Increasing numbers of deep hydrocarbon reservoirs are being discovered worldwide [1,2]. Knowledge of thermophysical properties such as viscosity of reservoir fluids at high-pressure and high-temperature (HPHT) conditions are required to determine the optimum number of wells and to design surface facilities [3,4]. To investigate the flow behavior of mixtures where transport of momentum occurs in fluid motion, such as in pipelines, wellbore and porous media, knowledge of the viscosity of hydrocarbons is needed [5]. Such information also plays a key role in natural gas management and development planning [6]. Therefore, laboratories must make experimental measurements of natural gas. As most laboratories do not have the equipment required to measure gas viscosities, prediction using models is particularly important.

This study consists of two main parts. First, the experimental viscosity data for a sour natural gas at HPHT conditions are determined with a capillary tube at pressures ranging from 10.3 to 138 MPa and temperatures up to 444 K. In the second part, the forms of the Benedict-Webb-Rubin equation of state (BWR-EOS) [7] and low-the pressure viscosity correlation of Lucas [8] conjugated with the reduced inverse viscosity of Stiel and Thodos [9] were incorporated into a model to investigate natural gas viscosity.

2. Experimental

A capillary viscometer was installed into an HPHT apparatus configured to examine the phase properties of fluids at desired pressures and temperatures. The apparatus could measure from ambient conditions to a maximum pressure of 145 MPa and temperature of 460 K. The capillary tube had a calibrated internal diameter of 0.27375 mm. Schematic of the apparatus is illustrated in Fig. 1.

The two ends of the capillary tube were connected to two small-volume (10 cm^3) cells, which were mounted inside a temperature-controlled air bath that could be thermostatically regulated. Sight-glasses were installed at the top of both cells.

Pressure was generated and maintained by a 15 cm^3 mercury hand pump that was also used to load samples into the HPHT apparatus. All pipe work and fittings were made from 316 grade stainless steel (all rated to 206 MPa). A Quartzdyne DXB015-20-200 high-pressure transducer was used to monitor the pressure to estimate the differential pressure generated across the capillary-tube viscometer. The pressure transducer was monitored and recorded via a computer.

After purging the system with test fluid, it was brought to the desired system pressure using the pump. The oven was heated to the desired temperature and sufficient time was allowed for the system to attain thermal equilibrium. Downstream valves were opened to allow the test fluid to flow through the capillary tube.

The composition of the natural gas used in the experiments is presented in Table 1.

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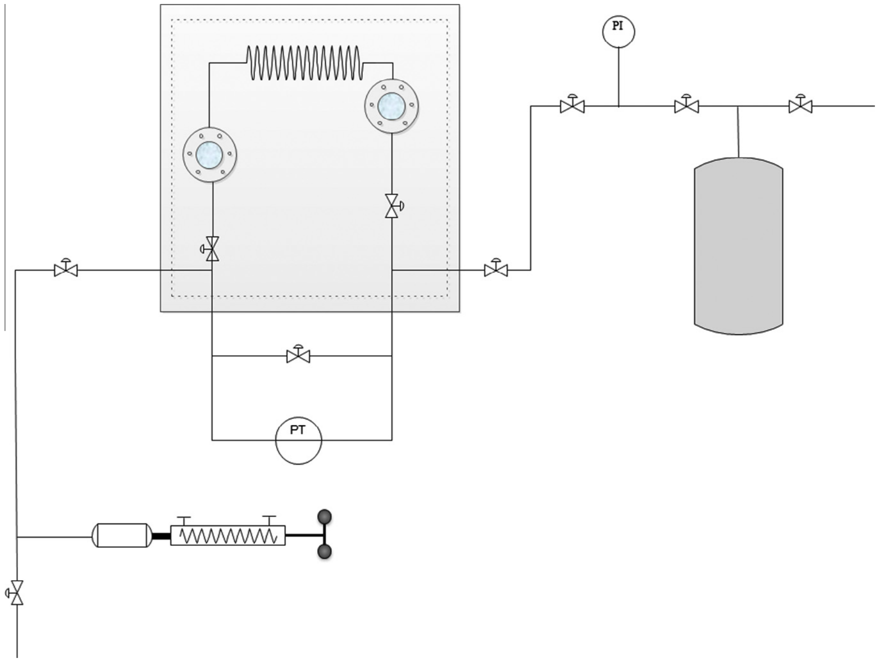

Fig. 1. Schematic of the apparatus.

Table 1
Composition of the natural gas mixture used in this study.

Component	Mole %
Methane	71.5
Ethane	11.0
Propane	6.5
n-Butane	1.9
iso-Butane	0.9
n-Pentane	0.4
iso-Pentane	0.4
Carbon Dioxide	4.0
Nitrogen	1.8
Hydrogen Sulfide	1.6
Total	100

Apparatus calibration results for pure methane and nitrogen are given in Figs. 2 and 3.

Deviations between calibration results and those from REFPROP 9.0 [10] were within ±0.5% and ±1% ranges for methane and nitrogen respectively in the full pressure–temperature ranges. Results reported in Figs. 2 and 3 show no pressure or temperature trends in the deviations obtained with the calibration procedure; thus systemic deviations could be eliminated.

The phase envelope of the sour natural gas mixture [11] and the experimental domain are illustrated in Fig. 4.

The experimental viscosity data for the sour natural gas mixture measured in this work is reported in Table 2.

The viscosity data for natural gas reported in Table 2 show that the viscosity increases with increasing pressure and/or decreasing

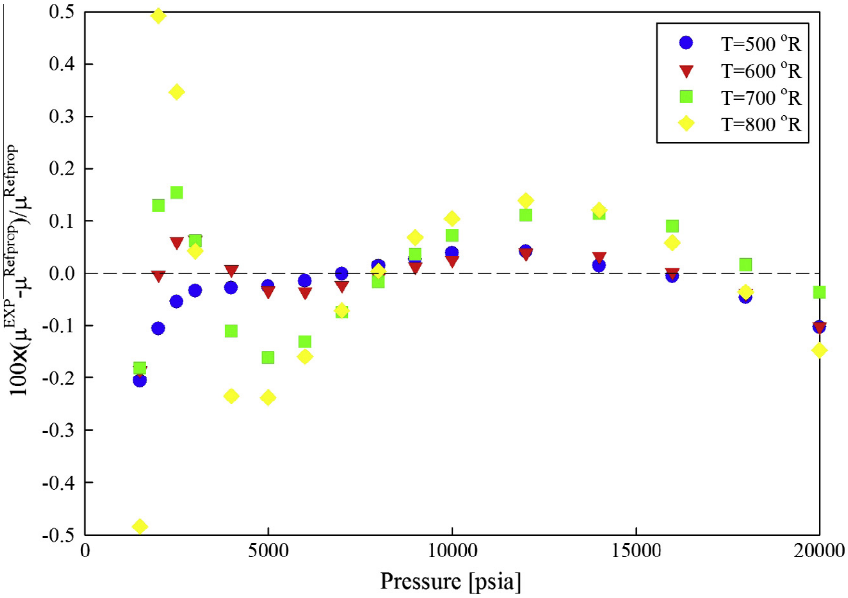

Fig. 2. Relative deviation plots between the data obtained for calibration purposes and that from REFPROP 9.0 [10] for methane.