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Viscosity Measurements and Data Correlation for Two Synthetic Natural Gas Mixtures

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Viscosity is among the most relevant properties required for the reliable and economic design of natural gas processing and transport units. However, the available viscosity data covering wide pressure and temperature ranges are scarce. This worldwide research project has a goal of producing accurate thermophysical properties for synthetic natural gas mixtures in a systematic manner using state-of-the-art techniques. The main purpose of the work is to analyze the effect of different compounds on mixture thermophysical properties and the validity of available predictive models. In this work, the viscosity measurements for the first two studied samples, QNG-S1 and QNG-S2, cover the temperature range (250 to 450) K and pressure range (10 to 65) MPa. Experimental measurements utilized an electromagnetic piston viscometer with a comparison to available reference data for pure methane. Using the reported results to probe the predictive ability of several theoretical models leads to unsatisfactory results. This work is one of the first available studies for the systematic analysis on the effects of natural gas components on mixture viscosity.

Introduction

The world demand for natural gas has increased dramatically recently. The total natural gas consumption has increased from the 1.42 billion cubic meter (BCM) in 1980 to 2.84 BCM in 2006, leading to an expected 4.32 BCM in 2030.[1] Natural gas is the fuel of choice for electricity and heat generation because it is the most environmentally friendly fossil fuel.[1,2] Proven world natural gas reserves were 176.8 BCM on January 1, 2009, having increased remarkably from 73.6 BCF in 1980, and undiscovered natural gas reserves may be 117 BCM.[1] Moreover, current technologies allow the exploration and production from nonconventional reservoirs whose compositions and pressure−temperature characteristics are unusual.[3] Therefore, world reserves can last 63 years.[1]

Accurate knowledge of natural gas thermophysical properties has technological as well as economic impact. The most reliable and accurate way to obtain thermophysical properties is from accurate experimental measurements. However, it is impossible to measure properties for all possible compositions of natural gases.[4] Moreover, many nonconventional reservoirs contain increased amounts of heavy hydrocarbons that affect mixture thermophysical properties.[5] Thus, the industry seeks predictive models to calculate the properties. Accurate and reliable experimental data provide validation for these models. Unfortunately, many of the models fail when applied to extended pressure−temperature-composition ranges such as those encountered in nonconventional reservoirs.

Viscosity is an important property for calculating the dynamic or flow behavior. Flow is predominantly laminar in reservoirs, so the influence of viscosity is especially important, but studies in the open literature are scarce[6−16] especially for accurate data in high-pressure and high-temperature regions.[8,10,11] Because current models lack accuracy, accurate viscosity data on natural gas mixtures is an immediate need. Currently, it is possible to reduce significantly the errors in viscosity data. A small uncertainty in gas viscosity data may affect inflow performance relationship curves,[17] and change reserve estimates under high-pressure and high-temperature regions conditions influencing production forecasting.[18] A 1 % uncertainty in gas viscosity data results in a 1 % uncertainty in the gas flow rate.[18]

This work presents experimental viscosity data, measured with an electromagnetic viscometer from (10 to 65) MPa and (250 to 450) K, for two synthetic natural gas mixtures, QNG-S1 and QNG-S2. These two synthetic mixtures are typical of the Qatari North Field reservoir gas after sweetening. The North Field is the largest nonassociated natural gas reservoir in the world.[19,20] The objective of this work is to obtain accurate and reliable experimental viscosity data for natural gases, to improve their production and processing, and to provide an experimental viscosity database covering multiple compositions. Results reported in this work are among the first data of an international, multilaboratory, research effort to study the thermophysical properties of natural gas mixtures. The results of this work are applicable universally for production, processing, and transmission of natural gases.

Experimental Section

Materials. Synthetic natural gas sample compositions resemble those of typical sweetened Qatar North Field gas. Linde Inc. gravimetrically prepared and certified the samples in Spain according to ISO 6142. Sample compositions were confirmed

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Table 1. Composition of Mixtures Studied in This Work[a]

	QNG-S1[b]	QNG-S2[c]
component	x	x
methane	0.84990	0.90260
ethane	0.05529	0.05828
propane	0.02008	0.02106
isobutane	0.00401	0.00412
n-butane	0.00585	0.00641
isopentane	0.00169	0.00214
n-pentane	0.00147	0.00162
n-octane	0.00152	0.00161
toluene	0.00090	0.00110
methylcyclopentane	0.00102	0.00111
nitrogen	0.03496	
carbon dioxide	0.02331	

[a] x, mole fraction. Relative uncertainty: methane 0.2 %, C2 to C4 2.0 %, C5 plus higher 5 %, nitrogen and carbon dioxide 2 %. [b] x (C_{6+}) = 0.00344. [c] x (C_{6+}) = 0.00382.

by gas chromatography in our laboratory as well. Sample 1 (QNG-S1) and sample 2 (QNG-S2) compositions appear in Table 1. The principal difference between samples is the presence of CO_2 and N_2 in QNG-S1 (5.83 %), whereas these compounds are absent in QNG-S2. QNG-S1 contains a slightly lower quantity of methane, and the C_2-C_5 fractions are almost the same for both mixtures. Hence, the results reported in this work probe the effects of CO_2 and N_2 on natural gas viscosity.

Measurement and Calibration Methodology. An electromagnetic viscometer developed by Cambridge Viscosity Inc. and commercialized by Vinci Technologies (electromagnetic viscometer EV1000) provides the experimental viscosity data reported in this work. Figure 1 is a schematic of the apparatus. The system contains a sample chamber connected top and bottom to lines that enable inflow or outflow of the sample. An electromagnetically driven stainless steel piston inside a sensor moves at constant force between two magnetic coils. The viscosity of the fluid impedes the motion of the piston, allowing the observation of viscosity as a function of travel time after calibration. An external Julabo LH50 circulating bath controls the temperature of the sample measured within ± 0.01 K by a built-in platinum resistance probe. A VINCI BSP65 syringe pump controls the sample pressure measured within ± 0.01 MPa by a pressure transducer. The temperature and pressure sensor calibrations are traceable to ENAC (Spanish National Accreditation Agency) according to UNE-EN ISO/IEC 17025:2000 quality regulation. The viscosity range dictates the size of piston used as a pursuant, thus improving the uncertainty. This work uses the piston suitable for (20 to 200) μPa·s. Measurements cover (250 to 450) K (in 10 K steps) and (10 to 65) MPa (in 5 MPa steps).

Because they contain unusual quantities of heavy components, QNG-S1 and QNG-S2 may condense in the measurement chamber during experiments. To avoid condensation conditions, establishing the experimental procedure uses the Peng−Robinson equation of state to estimate the cricondentherm of the mixtures 304.15 K and 3.88 MPa and 305.79 K and 4.04 MPa for QNG-S1 and QNG-S2, respectively, and the cricondenbar of the mixtures 255.84 K and 10.88 MPa and 256.14 K and 10.79 MPa for QNG-S1 and QNG-S2, respectively. The experimental conditions were well beyond these troublesome conditions; all lines were above 350 K during the experiments. The syringe pump was also above 350 K through use of a Polyscience circulating bath with the temperature measured using thermocouples. Cylinders containing gas samples were kept above 350 K for at least two weeks before measurements.

The use of similar viscometers for such mixtures is rare in open literature. Thomas et al.[21] and Viswanathan[22] report several problems for gas viscosity measurements using electromagnetic viscometers, mainly at temperatures far from that of calibration, deriving from the poorly defined pressure−temperature dependence of the measurement chamber. Therefore, obtaining reliable results for gas measurements and ensuring full scale accuracy require special attention to calibration. This work uses (i) a special calibration procedure to account for pressure−temperature dependence of cell properties and (ii) a performance test of the apparatus using reliable viscosity data for pure methane (the principal component of natural gases).

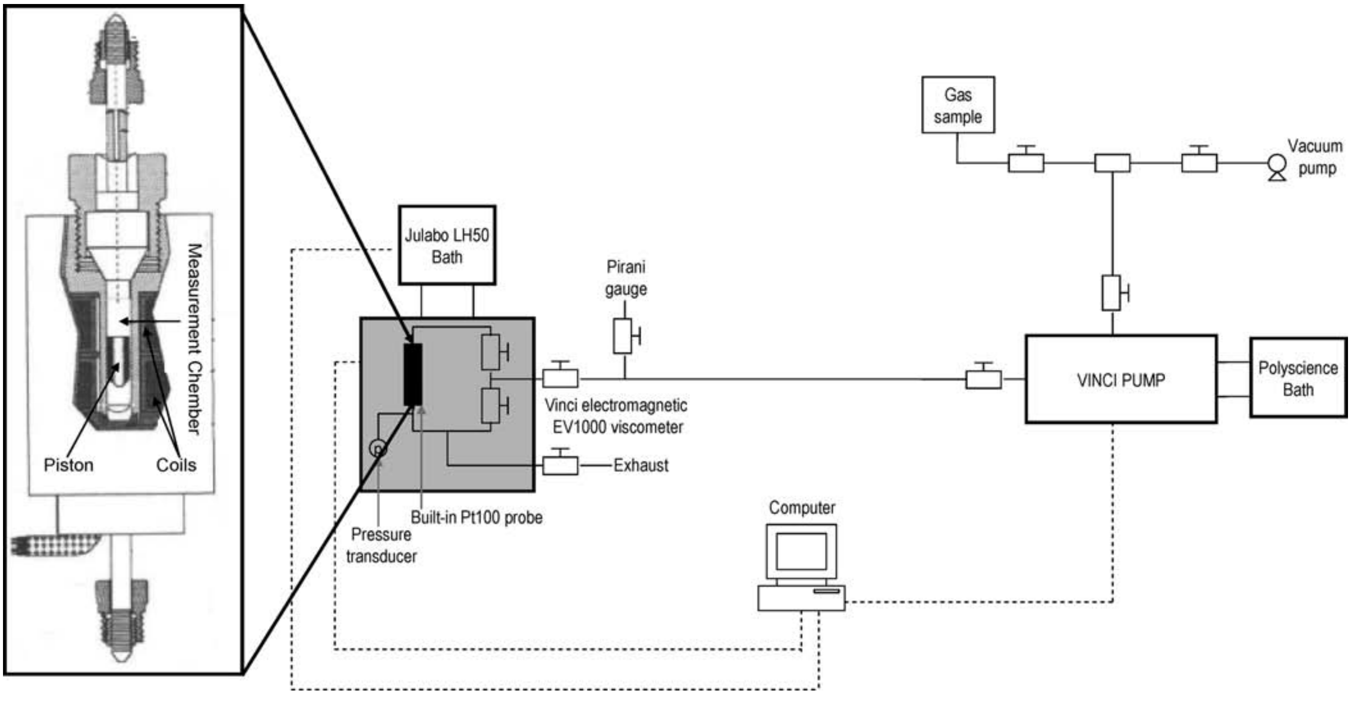

Figure 1. Schematic of the apparatus for viscosity measurements used in this work. Continuous lines are tubing, and dashed lines are electrical connections. The left panel with an extended view of the measuring chamber is adapted from ref 22.

Table 2. Experimental Dynamic Viscosity of Pure Methane, as a Function of Pressure, *P*, and Temperature, *T*

P/MPa	η/μPa·s										
	T/K										
	250.00	270.00	290.00	310.00	330.00	350.00	370.00	390.00	410.00	430.00	450.00
10.0	14.13	13.65	13.79	14.09	14.47	14.85	15.26	15.76	16.21	16.40	16.76
20.0	25.06	21.78	19.50	18.67	18.37	18.03	18.25	18.38	18.49	18.66	19.00
30.0	32.46	28.82	25.51	23.65	22.57	21.78	21.65	21.32	21.27	21.06	21.14
40.0	37.99	34.14	30.33	28.26	26.93	25.55	25.13	24.49	24.02	23.66	23.41
50.0	42.20	38.12	34.73	32.10	30.61	29.13	28.13	27.24	26.28	26.20	25.40
60.0	45.82	41.53	38.15	35.82	33.83	32.10	30.93	29.79	28.47	28.47	27.60
70.0	49.04	44.53	41.12	39.13	36.30	34.73	33.47	32.02	30.86	30.63	29.40

The viscometer is a linear device, and therefore only two different standard gas samples are necessary for calibration, corresponding to fluids in the high and low ends of the measurement range. A propane gas sample is obtained from Linde Inc. as ultra high purity with a mole fraction of 0.9995. The nitrogen gas sample is obtained from Linde Inc. as ultra high purity with a mole fraction of 0.999999. Viscosity data for both fluids come from the literature,[23,24] as given in the National Institute of Standards and Technology (NIST) Chemistry Webbook.[25] Viscosity data for propane have a relative uncertainty of ± 2.5 % (below 30 MPa) and a relative uncertainty of ± 4 % (above 30 MPa) for the entire temperature range.[23] Moreover, the relative uncertainty of the viscosity data for nitrogen from the NIST Chemistry Webbook[25] is ± 2 % over the entire temperature and pressure ranges.[24] Measuring chamber expansion with increasing pressure and temperature is an effect considered during calibration. The most reliable way to perform calibrations is to perform measurements both for propane and nitrogen at the same temperatures and pressures as the gas samples. Hence, converting raw piston traveling times, t, into dynamic viscosity, η, data uses eq 1:

$$\eta = T_1 t^2 - T_2 \tag{1}$$

where the instrument constants, T_1 and T_2, depend upon temperature, T, and pressure, P, according to:

$$T_1 = \sum_i A_i T^i + \sum_j B_j P^j + CTP \tag{2}$$

$$T_2 = \sum_i D_i T^i + \sum_j E_j P^j + FTP \tag{3}$$

where $i = 0, 1, 2, 3$ and $j = 1, 2$. The 14 fitting parameters come from propane and nitrogen measurements, as a function of pressure and temperature, and viscosity reference data from the literature.[23−25] The proposed calibration equation is similar to those previously reported for high-pressure and high-temperature calibration of vibrating-tube densimeters.[26] The reproducibility of the measurements is better than ± 0.1 %; nevertheless, calculated uncertainties are ± 2.5 % for pressures less than 30 MPa and ± 4.0 % for larger pressures. These large uncertainties rise from the uncertainties in the propane reference viscosity values obtained from the correlation equation reported in the literature.[23]

Results

Apparatus Performance. Pure methane is purchased from Linde Inc. as ultra high purity with a mole fraction of 0.999995. Measurements for ultrapure methane show fair agreement between current values in Table 2 and those from reliable literature sources, in Figure 2. The methane reference viscosity data reported by Friend et al.[27] are obtained from the correlation reported by the authors with an accuracy of ± 2 %. Data from Schley et al.[16] come from their correlation, with a reported accuracy of ± 0.5 %. The relative deviations between experimental viscosity data reported in this work and literature reference values are within the range of ± 2 %. The proposed method for calibrating electromagnetic viscometers leads to accurate, reproducible, and reliable results, and this method accounts for pressure and temperature effects on cell properties. This calibration method is a clear improvement over other methods available in the literature for the same apparatus, which lead to deviations as high as 20 %.[22] In spite of the uncertainties rising from the use of propane as a high-end calibration fluid, methane viscosity is measured within a ± 2 % uncertainty range, which is greater to the ± 1 % uncertainty value reported by the manufacturer (in our opinion, it is not possible to achieve this level of accuracy for gas viscosity measurements, in the pressure−temperature ranges studied, using this apparatus).

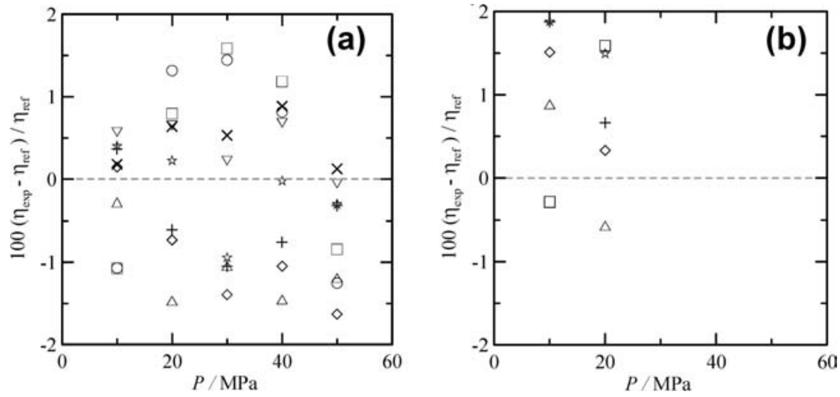

Figure 2. Measurements of dynamic viscosity, η_{exp}, of pure methane as a function of pressure, P, and temperature, T, in comparison with the correlation equations, η_{ref}, of (panel a) Friend at al.[27] (± 2 %) and (panel b) Schley et al.[16] (± 0.5 %). Symbols: ○, 250 K; □, 270 K; △, 290 K; ◇, 310 K; ∗, 330 K; +, 350 K; ×, 370 K; and ▽, 390 K.

Table 3. Experimental Dynamic Viscosity of Pure QNG-S1 Synthetic Natural Gas-Like Mixture, as a Function of Pressure, P, and Temperature, T

P/MPa	η/μPa·s									
	T/K									
	250.00	260.00	270.00	280.00	290.00	300.00	310.00	320.00	330.00	340.00
10.0					14.52	14.40	14.19	14.32	14.48	14.65
15.0	26.14	23.53	21.57	20.14	19.11	18.39	17.34	17.14	17.03	17.00
20.0	32.39	29.59	27.28	25.40	23.90	22.71	21.14	20.56	20.14	19.84
25.0	37.25	34.37	31.92	29.85	28.12	26.69	25.00	24.13	23.43	22.89
30.0	41.40	38.43	35.87	33.68	31.81	30.21	28.64	27.56	26.67	25.94
35.0	45.13	42.07	39.40	37.10	35.10	33.39	32.01	30.78	29.75	28.87
40.0	48.62	45.44	42.66	40.24	38.14	36.31	35.12	33.79	32.64	31.66
45.0	51.94	48.63	45.74	43.20	40.99	39.06	38.03	36.61	35.37	34.29
50.0	55.17	51.72	48.69	46.04	43.71	41.68	40.76	39.26	37.95	36.80
55.0	58.34	54.73	51.57	48.79	46.35	44.20	43.34	41.78	40.40	39.18
60.0	61.48	57.71	54.39	51.48	48.92	46.66	45.81	44.19	42.75	41.46
65.0	64.61	60.67	57.19	54.14	51.45	49.08	48.17	46.49	44.99	43.66

	T/K										
	350.00	360.00	370.00	380.00	390.00	400.00	410.00	420.00	430.00	440.00	450.00
10.0	14.85	15.06	15.27	15.49	15.72	15.95	16.18	16.42	16.66	16.89	17.13
15.0	17.02	17.08	17.17	17.28	17.42	17.57	17.73	17.90	18.08	18.26	18.46
20.0	19.63	19.51	19.43	19.41	19.42	19.47	19.53	19.62	19.73	19.85	19.98
25.0	22.47	22.15	21.91	21.74	21.62	21.55	21.52	21.51	21.53	21.58	21.64
30.0	25.34	24.85	24.46	24.15	23.91	23.73	23.59	23.49	23.43	23.40	23.39
35.0	28.13	27.51	26.99	26.57	26.21	25.92	25.69	25.51	25.36	25.25	25.18
40.0	30.81	30.08	29.46	28.93	28.48	28.10	27.78	27.52	27.30	27.12	26.98
45.0	33.36	32.54	31.83	31.22	30.69	30.23	29.84	29.50	29.22	28.98	28.78
50.0	35.78	34.89	34.11	33.43	32.83	32.30	31.84	31.45	31.10	30.80	30.55
55.0	38.10	37.15	36.30	35.55	34.89	34.31	33.80	33.34	32.94	32.59	32.29
60.0	40.33	39.31	38.41	37.61	36.89	36.26	35.69	35.19	34.74	34.35	34.00
65.0	42.46	41.40	40.44	39.59	38.83	38.14	37.53	36.98	36.49	36.06	35.67

Table 4. Experimental Dynamic Viscosity of Pure QNG-S2 Synthetic Natural Gas-Like Mixture, as a Function of Pressure, P, and Temperature, T

P/MPa	η/μPa·s									
	T/K									
	250.00	260.00	270.00	280.00	290.00	300.00	310.00	320.00	330.00	340.00
10.0					14.37	14.23	14.19	14.32	14.48	14.67
15.0	26.41	23.75	21.71	20.20	19.10	18.32	17.18	17.00	16.91	16.89
20.0	32.41	29.65	27.35	25.45	23.92	22.70	20.73	20.20	19.82	19.55
25.0	37.04	34.24	31.84	29.80	28.08	26.64	24.24	23.47	22.85	22.37
30.0	40.97	38.11	35.63	33.49	31.66	30.09	27.49	26.55	25.78	25.14
35.0	44.50	41.57	39.01	36.78	34.84	33.17	30.44	29.41	28.52	27.77
40.0	47.80	44.77	42.11	39.79	37.76	35.99	33.15	32.04	31.07	30.24
45.0	50.95	47.80	45.04	42.61	40.49	38.63	35.65	34.48	33.45	32.55
50.0	54.00	50.73	47.85	45.31	43.09	41.13	37.99	36.77	35.69	34.74
55.0	57.00	53.58	50.58	47.93	45.60	43.54	40.19	38.93	37.80	36.80
60.0	59.97	56.40	53.26	50.49	48.05	45.89	42.28	40.97	39.81	38.77
65.0	62.93	59.21	55.92	53.02	50.46	48.19	44.27	42.93	41.72	40.64

	T/K										
	350.00	360.00	370.00	380.00	390.00	400.00	410.00	420.00	430.00	440.00	450.00
10.0	14.87	15.08	15.30	15.52	15.75	15.99	16.22	16.46	16.70	16.94	14.87
15.0	16.92	16.99	17.09	17.22	17.36	17.51	17.68	17.86	18.05	18.24	16.92
20.0	19.38	19.27	19.22	19.22	19.24	19.30	19.38	19.48	19.60	19.72	19.38
25.0	22.01	21.73	21.53	21.39	21.29	21.25	21.23	21.24	21.28	21.34	22.01
30.0	24.62	24.20	23.87	23.61	23.41	23.26	23.15	23.08	23.04	23.03	24.62
35.0	27.14	26.61	26.17	25.80	25.51	25.27	25.08	24.93	24.82	24.74	27.14
40.0	29.52	28.91	28.38	27.93	27.56	27.24	26.98	26.77	26.59	26.45	29.52
45.0	31.77	31.09	30.50	29.98	29.54	29.16	28.84	28.56	28.33	28.14	31.77
50.0	33.90	33.16	32.51	31.94	31.45	31.01	30.64	30.31	30.03	29.79	33.90
55.0	35.92	35.13	34.44	33.82	33.28	32.80	32.38	32.01	31.68	31.40	35.92
60.0	37.84	37.01	36.28	35.62	35.04	34.52	34.05	33.65	33.28	32.97	37.84
65.0	39.68	38.82	38.04	37.35	36.73	36.17	35.68	35.23	34.84	34.49	39.68

Nevertheless, the reported results are only slightly less accurate than the common range of literature accuracy (~ ± 1 %) for recent gas viscosity measurements using different state-of-the-art experimental approaches in wide pressure−temperature ranges.[10,15,16,28−30]

Viscosity Measurements for Gas Mixtures. Experimental viscosity results for the two synthetic natural gas samples appear in Tables 3 and 4. The large number of experimental points reported in this work for these two mixtures (252 points for each mixture) is considerably larger than the number of data values commonly reported in the literature using the other apparatus.[7,10,15]

As the pressure increases, the viscosity increases remarkably for both mixtures for all experimental temperatures as expected. However, this effect is more remarkable at lower temperatures. The pressure effect on viscosity is more remarkable for QNG-

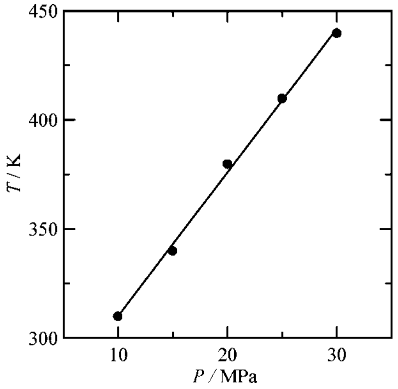

Figure 3. Temperature at which viscosity minima appear for isobaric conditions, for QNG-S2; analogous results exist for QNG-S1. The line is a linear fit of experimental values.

S1 than for QNG-S2, so natural gas samples containing CO_2 and N_2 would appear to have a slightly higher rate of change of viscosity with pressure.

The temperature effect upon viscosity is different for low and high pressures. For pressures lower than 25 MPa, viscosity decreases with increasing temperature, and then it increases again, thus showing minima. The minima appear at higher temperatures as the pressure increases and for pressures larger than 30 MPa appear to be above the 450 K as seen in Figure 3. It is also observed that the rate of viscosity change with temperature is much lower than with pressure.

The viscosity for QNG-S1 is slightly larger than for QNG-S2 ((0.1 to 9) % larger in the studied pressure−temperature ranges), with the difference between both samples increasing with increasing pressure. Thus, the presence of CO_2 and N_2 in natural gas leads to an increase in viscosity that is more important at higher pressures. However, the effect of CO_2 and N_2 on natural gas viscosity is almost null for the typical operating pressures of gas pipelines (usually < 20 MPa). The differences between QNG-S1 and QNG-S2 samples for these pressures are less than 0.4 %. The viscosity values for these samples at pressures lower than 20 MPa would lead to very high Reynolds numbers ($\sim 1 \cdot 10^7$), and according to the Colebrook−White friction factor correlation,[31] small irregularities on the pipe wall would lead to significant effects upon the friction factor. The flow of QNG-S1 and QNG-S2 would be almost the same under the same pressure−temperature conditions. Temperature changes along pipelines should not affect the rate of flow because of viscosity changes; however, pressure effects could be significant. The reported viscosity results for QNG-S1 and QNG-S2 also allow a better characterization and simulations of reservoirs.

Analysis of Predictive Ability for Selected Viscosity Models. This work includes a comparison of the experimental viscosity data to several models commonly used in natural gas industry. Four models are selected to compare the experimented viscosity data. These models are: the Nilpotent−Bazhanov−Stroganov (NBS) model developed by Ely and Hanley[32] at NIST, also known as TRAPP; the CLS (Chung, Lee, and Starling) model developed by Chung et al.;[33,34] the LBC (Lohrenz, Bray, and Clark) model developed by Lohrenz et al.;[35] the PFTC (Pedersen, Fredenslund, Thomassen, and Christensen) model developed by Pedersen et al.[36,37] The NBS model is based on an extended corresponding states principle and requires only critical constants and Pitzer's acentric factor for each component as input.[32] The CLS model is used for predictions of viscosity, critical temperature, and critical pressure for homologous hydrocarbon series via the carbon number information data in the empirical equation.[33,34] The PFTC model is based on the

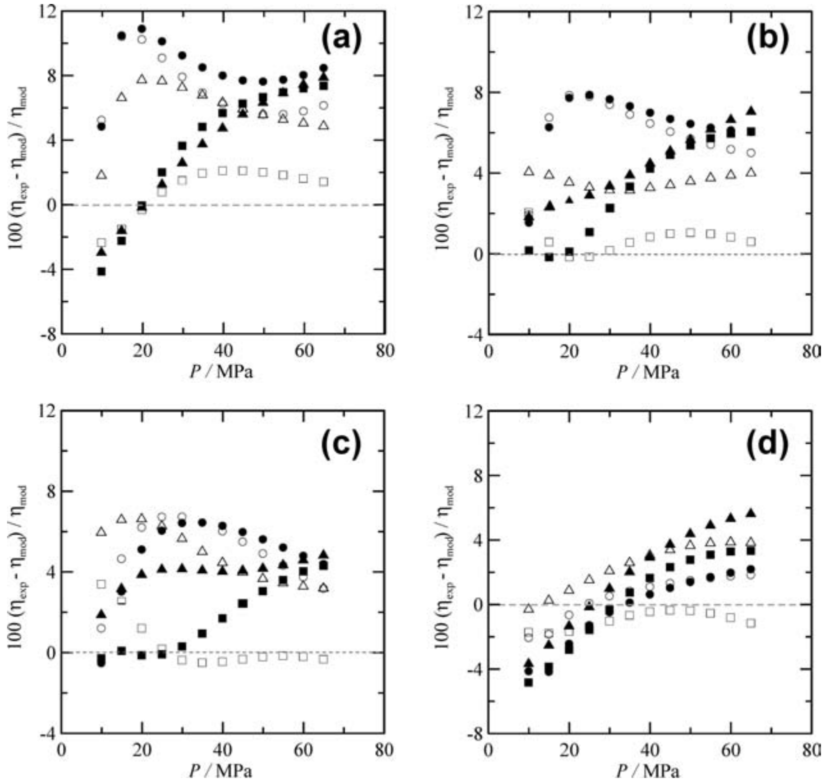

Figure 4. Percentage deviations between experimental, η_{exp}, and predicted, η_{mod}, viscosity values. Symbols: circles, values for 250 K; squares, values for 350 K; and triangles, values for 450 K; filled symbols, values for QNG-S1; empty symbols, values for QNG-S2. Panels: (a) NBS, (b) CLS, (c) LBC, and (d) PFT models. (Uncertainties of experimental values reported in this work are ± 2.5 % for $P < 30$ MPa and ± 4.0 % for $P > 30$ MPa.)

Table 5. Percentage Absolute Average Deviations between Experimental and Predicted Viscosity Data Obtained Using the Reported Models

sample	NBS	CLS	LBC	PFCT
QNG-S1	5.86	4.68	3.60	2.50
QNG-S2	3.92	3.46	3.58	1.59

principle of corresponding states with methane and decane as reference components. In the PFTC model, the viscosity of a given component or mixture is determined from the reduced viscosities of the reference components using the molecular weight as an interpolation parameter.[36,37] LBC model is a 16th degree polynomial in the reduced density, and due to this the viscosity estimations are highly dependent on the accuracy of the estimated reduced density. The viscosity correlation based on the residual viscosity concept is derived from Jossi et al.[38] and generally referred to as the LBC correlation,[35] since Lohrenz et al.[35] introduced a procedure for calculating the viscosity of hydrocarbon mixtures and reservoir fluids using the same equation and coefficients originally derived by Jossi et al.[38] for pure fluids.

A comparison between experimental and predicted results at (250, 350, and 450) K and (10 to 65) MPa appears in Figure 4 and in Table 5 (along with the average error). The deviations between experimental and predicted results of the models are: NBS > CLS > LBC > PFCT. Deviations are larger for QNG-S1 than for QNG-S2 for all of the studied models, so the models apparently cannot describe the effect of N_2 and CO_2 on natural gas viscosity. The PFCT model has lower deviations for both mixtures (−4 to 5.7 % and −2 to 4 % for QNG-S1 and QNG-S2, respectively) leading to viscosity predictions that are reasonably accurate over the whole pressure−temperature range analyzed. This analysis agrees with available literature studies.[12]

Conclusions

This paper reports new, accurate viscosity data for two synthetic natural gas-like mixtures, resembling gases from the Qatari North Field, covering the (250 to 450) K and (10 to 65) MPa temperature and pressure ranges, using an electromagnetic viscometer. The comparison between experimental viscosity data for pure methane, obtained using the electromagnetic viscometer with a new calibration procedure, and highly accurate literature data indicates good performance of the apparatus leading to deviations lower than 2 %. Electromagnetic viscometers allow rapid and accurate measurements of gas viscosity, leading to a reasonably accurate characterization of the $P\eta T$ behavior of natural gas mixtures. An analysis of several viscosity models indicates the PFCT model does better for natural gas viscosity prediction. The presence of N_2 and CO_2 leads to a loss of accuracy for all of the studied models, and this may be important when working with gases rich in these compounds.

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