International Journal of Engineering Research and Development
e- ISSN: 2278-067X, p-ISSN: 2278-800X, www.ijerd.com
Volume 22, Issue 9 (September 2026), PP 154-170

Natural Gas Viscosity Determination for Ultra High Pressure and Temperature Gas Reservoirs: Experimental Measurement, Evaluation and Implications for Reservoir Performance.

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Abstract
Natural gas viscosity is an important fluid property that affects reservoir performance, hydrocarbon recovery, pipeline transportation and flow assurance calculations in petroleum engineering. Consequently, accurate viscosity data are needed for PVT modeling, reservoir performance forecasting, reserves assessment, production design and enhanced gas recovery project design. Despite numerous studies concerning natural gas viscosity at low to moderate pressures and temperatures, the availability of reliable experimental viscosity data under the extreme conditions prevailing in deep and ultra-deep gas reservoirs has been limited. As a result, several popular gas viscosity correlations often require extrapolation beyond the pressure temperature (P-T) region for which they were developed and the validity of such extrapolations is not guaranteed. This study presents the results of experimental measurements for two natural gas samples that differ in composition for extreme reservoir conditions (5,000 to 20,000 psia, 212 to 392F) and comparison with measurements of selected gas viscosity correlations. The comparison reveals that while the correlations examined typically give satisfactory predictions at lower and intermediate P-T conditions, they increasingly deviate from measurements with increasing pressure under ultra-high-pressure temperature conditions. This work shows that correlations developed primarily from data at low to moderate P-T conditions may yield inaccurate viscosity predictions when extrapolated to conditions encountered in deep and ultra- high pressure high temperature gas reservoirs and provides valuable data to test existing correlations and the development of new correlations applicable to such conditions.
Keywords *Natural gas, Viscosity, High pressure high temperature, ultra-high pressure and high temperature.*

Date of Submission: 10-09-2026 Date of acceptance: 20-09-2026

I. Introduction

A clear understanding of hydrocarbon fluid viscosity is essential for analyzing the flow behaviour of fluids through pipelines, porous reservoir formations and other systems involving momentum transfer. In gas reservoir engineering, reliable viscosity data are particularly important for estimating reserves, predicting reservoir performance at different stages of production and evaluating the movement of fluids under varying pressure and temperature conditions. Gas viscosity measures the internal resistance of gas molecules to flow and is generally much lower than the viscosity of oil or water, making gas considerably more mobile within reservoir formations. Although laboratory measurement provides the most accurate means of determining natural gas viscosity, such measurements are often technically difficult, time consuming and expensive, especially under elevated pressure and temperature conditions (Davani et al (2009). Consequently, empirical correlations are widely employed to estimate gas viscosity with relatively low deviations from experimental measurements (Davani et al., 2009).

Accurate prediction of natural gas viscosity is critical in reservoir engineering because viscosity directly affects gas mobility through porous media, pressure losses during transportation through wells and pipelines, production performance and the reliability of reservoir simulation studies. Under high-pressure and high-temperature (HPHT) conditions, particularly in deep and ultra-deep gas reservoirs, natural gas can exhibit complex non ideal behaviour that may not be adequately captured by conventional viscosity correlations developed under less severe conditions. The increasing exploration and production of HPHT reservoirs have therefore intensified the need for reliable experimental measurements and robust predictive models capable of accurately representing natural gas properties under extreme pressure and temperature environments. These reservoirs are generally associated with pressures above 10,000 psi and temperatures exceeding 300°F (Bahadori et al., 2009). However, despite the increasing application of HPHT concepts in the petroleum industry, there is no universally accepted classification standard for these reservoir conditions. Several pressure–temperature classification schemes have consequently been proposed in the literature. In this study, the classification proposed

by Amanullah and Ramasamy (2018) was adopted, where HPHT conditions are defined as pressures between 10,000 and 15,000 psi and temperatures of 300–350°F. Ultra-HPHT conditions correspond to pressures of 15,000–20,000 psi and temperatures of 350–400°F, while Extreme HPHT (XHPHT) conditions refer to environments with pressures exceeding 20,000 psi and temperatures above 400°F (Amanullah & Ramasamy, 2018). This classification provides a structured pressure temperature basis for evaluating natural gas viscosity behaviour across progressively more severe reservoir conditions.

Traditionally, gas viscosity has been estimated using correlations such as those proposed by Carr et al. (1954), Dean and Stiel (1958) and Lee et al. (1966). While these correlations perform reasonably well under moderate pressure and temperature conditions, their accuracy deteriorates when extrapolated to UHPHT environments. This limitation arises from the nonlinear interactions among gas molecules and the increasing influence of real gas effects at elevated pressures. Consequently, predictions based solely on existing correlations can lead to significant errors in reservoir modeling, flow assurance and production optimization.

The precise calculation of natural gas viscosity is essential for maximizing production systems when operating at high and ultra high pressure and temperature reservoir conditions (Chapoy et al., 2011). The modeling of viscosity under extreme conditions proves difficult because it directly impacts reservoir simulation and gas transport and well completion and EOR efficiency. The predictive models developed by Viswanathan (2007), Chapoy et al. (2011) and Azubuike et al. (2019) expanded their range of applicability to broad pressure and temperature domains. Yet, these models demonstrate substantial inaccuracies when operating at UHPHT conditions because small prediction errors can significantly affect IPR curves and reserve calculations. The initial work of Carr et al. (1954) and Lohrenz et al. (1964) and Lee et al. (1966) established fundamental principles for low to intermediate reservoir conditions, but detailed knowledge at UHPHT remains limited in petroleum research.

Natural gas viscosity has been extensively investigated at low to moderate pressures and temperatures (Coming et al., 1944; Carr et al., 1954; Jossi et al., 1962; Lee et al., 1966; Londono et al., 2002; Ohirhian and Abu, 2009; NIST, 2008; Heidaryan et al, 2010; Bahadori et al., 2009; Anyiador et al., 2015); however, detailed understanding under ultra high pressure, high temperature (UHPHT) conditions remain limited within the petroleum and gas industry. Carr et al. (1954) developed one of the earliest and most influential graphical correlations for natural gas viscosity, presenting a comprehensive chart set that included atmospheric pressure, viscosity ratio and correction charts for non hydrocarbons. Derived experimentally, the correlation expresses viscosity as a function of pseudo-reduced pressure, pseudo-reduced temperature and viscosity ratio and is recommended for gases with specific gravities between 0.55 and 1.22. Despite its widespread application in the petroleum industry, the graphical nature of the method limits accuracy and subsequent studies have reported significant deviations when applied beyond the recommended ranges, particularly under high pressure, high temperature conditions or for sour gases.

Dempsey (1965) refined the work of Carr et al. (1954) by regressing their dataset to develop a mathematical expression incorporating the combined effects of temperature, pressure and gas compressibility for gas viscosity estimation. This work represented a shift toward models that account for real gas behaviour and demonstrated improved accuracy for moderately high-pressure systems compared to earlier correlations. By explicitly integrating pressure, temperature and compressibility, the model offered enhanced predictive capability. However, its applicability is limited, as it fails to adequately capture non-linear behaviour at extreme reservoir conditions.

Lee et al. (1966) presented a semi empirical relationship for calculating the viscosity of natural gases. The authors expressed gas viscosity in terms of the reservoir temperature, gas density and molecular weight of the gas. The proposed correlation could predict the viscosity value with a standard deviation of 2.7% and a maximum deviation of 8.99%. The correlation was less accurate for gases with higher specific gravities. The authors pointed out that this method could not be used for sour gases. Their correlation was developed for pressure ranges between 100 and 8000 psi and temperature ranges between 100 and 340°F.

Viswanathan (2007) employed a Cambridge viscosity SPL440 system to measure the viscosity of pure methane at pressures ranging from 5,000 to 30,000 psi and temperatures between 100 and 400 °F. Using these measurements, the author modified the correlation originally proposed by Lee et al. (1966) and validated the revised model against NIST (2008) data for pure gases. The modified correlation demonstrated a closer agreement with NIST values than the original Lee et al. formulation. However, the study's applicability is limited, as the findings cannot be directly extended to gas systems containing impurities.

Ling et al. (2009) conducted a systematic review of methane gas viscosity correlations available in the open literature, critically assessing their validity within specified ranges of applicability. To complement this evaluation, experimental measurements were carried out using a falling body viscometer over pressures from 3,000 to 24,500 psi and temperatures between 100 and 415 °F. Nitrogen was employed for instrument calibration, reflecting its increasing concentration in HPHT reservoirs, while the viscosity measurements were designed to

represent lean methane-dominated systems with minor impurities. The study demonstrated that the correlation by Lee et al. (1966) provided satisfactory predictions under low to moderate pressure temperature conditions but showed significant deviations when applied to HPHT reservoir conditions.

Kashefi et al. (2013) conducted one of the most extensive studies on hydrocarbon viscosity under HPHT conditions, providing experimental data for binary and multicomponent mixtures at pressures up to 138 MPa and temperatures up to 473.15 K. Their results showed that conventional correlations lose accuracy at extreme conditions, while molecular based models offer better predictions but still face challenges with complex mixtures.

Given the limitations of existing models and the scarcity of high quality experimental data at extreme conditions, experimental evaluation of gas viscosity under UHPHT reservoir conditions is imperative. Laboratory data provide the most reliable foundation for understanding viscosity behaviour and serve as benchmarks for validating and improving predictive models. Furthermore, combining such experimental data with modern predictive modeling techniques can significantly enhance the reliability of viscosity estimation across a broad range of reservoir conditions.

Consequently, there is a pressing need for improved predictive models that incorporate the physics of gas behaviour under extreme conditions, leveraging both empirical correlations and advanced computational methods. In this study, an integrated experimental and predictive evaluation of gas viscosity in ultra high pressure and high temperature reservoirs is conducted and also the review of widely used correlations (e.g., Dempsey, 1965; Dean and Stiel, 1958; Lee et al., 1966; Viswanathan, 2007; Ohirhian and Abu, 2009; Heidaryan et al., 2010; Azubuike et al., 2019) is also conducted, evaluating their theoretical basis, operating ranges and limitations. The review aims to identify the most reliable approaches while outlining future directions for improving UHPHT viscosity prediction.

II. MATERIAL AND METHODS

2.1 Material

2.1.1 Gas Samples

Natural gas samples were obtained from a high pressure high temperature reservoir in the Kolo field, located in the Niger Delta region and Edinburgh gas field located in Scotland, United Kingdom. Samples were transported to the laboratory under controlled conditions to prevent contamination and phase change. The analyzed gas samples in this study consisted primarily of hydrocarbon and non-hydrocarbon components. Each gas was of research grade purity and sourced from certified suppliers. Prior to testing, the gases were subjected to standard dehydration to remove moisture that could affect viscosity measurements.

2.1.2 Gas Storage and Supply System

A high pressure gas source cylinder served as the reservoir for the gas samples. The supply system comprised high pressure stainless steel lines, safety rated valves and fittings rated for operation up to 25,000 psi to ensure safe handling and integrity under test conditions. A RIX Industries high pressure piston compressor compressed and delivered the gas into the HPHT vessel at 2000 psi and it was connected to the gas supply system. The experimental setup is illustrated in Figure 1.

2.2 Experimental Apparatus

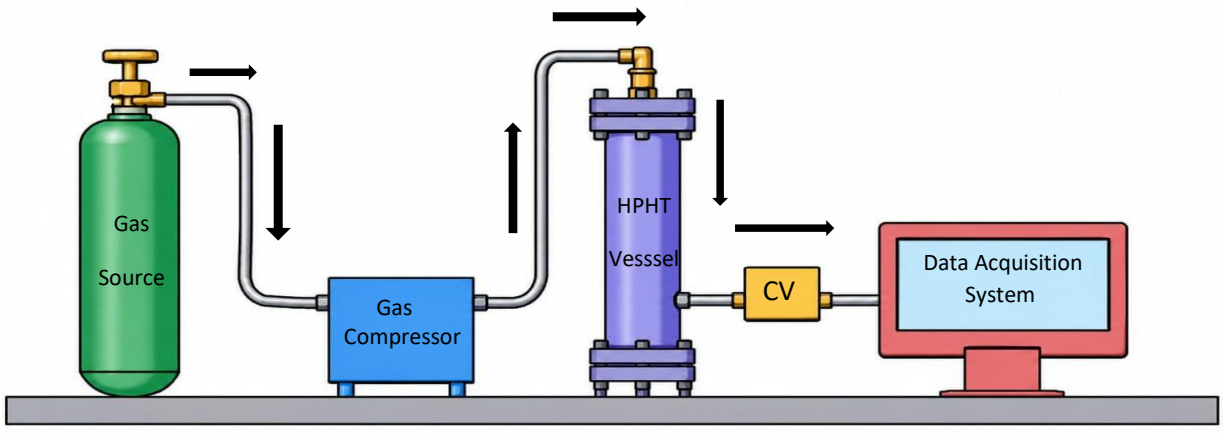

Figure 1: Schematic diagram of experimental setup

The experimental arrangement was designed to accurately measure natural gas viscosity under high pressure and high temperature (HPHT) conditions. The system comprised five major components: the gas source, gas compressors, a high pressure high temperature (HPHT) vessel, a measuring system and a data acquisition system. The configuration ensured precise control of pressure, temperature and sample integrity throughout the experimental process.

2.2.1 Gas Compressor

A RIX Industries high pressure piston compressor was used to reach and sustain the required test pressures. It delivered continuous, pulsation free gas compression up to 2,000 psi, ensuring stable and consistent operating conditions. This system allowed for precise pressurization of the gas sample and compensated for minor pressure fluctuations resulting from thermal expansion or system compliance during the experiment. The compressor system also ensured stable gas flow and uniform distribution within the HPHT chamber.

2.2.2 High Pressure and High Temperature (HPHT) Vessel

The HPHT vessel constituted the primary experimental chamber in which pressure and temperature conditions were precisely regulated to simulate reservoir environments. The vessel, constructed from high strength stainless steel, was rated for pressures up to 25,000 psi and temperatures up to 400°F. The vessel capacity was approximately 1–5L, allowing sufficient gas volume for measurement stability while maintaining thermal and pressure uniformity. A combination of electrical resistance heating elements and a PID based temperature control system ensured stable temperature regulation within ±0.5°F of the setpoint. Pressure was controlled through the piston compressor and monitored using high accuracy digital transducers (accuracy ±0.05% full scale). The vessel was equipped with instrumentation ports to facilitate integration with the viscometer and data acquisition systems.

2.2.3 Measuring System

Special instrumentation is required for gas viscosity measurements under HPHT conditions where the thermodynamic stability of the gas sample must be maintained. Such measurements are often conducted under high pressure (20,000 psi) and temperature (up to 392°F). In this study, gas viscosity was measured using a high pressure Cambridge SPL440 viscometer, which is suitable for accurate viscosity determination under HPHT conditions. The Cambridge SPL440 viscometer The Cambridge SPL-440 measures gas viscosity using an electromagnetically driven oscillating piston. The viscosity is determined from the fluid resistance to piston motion during oscillation. This principle enables the instrument to evaluate the dynamic viscosity of the gas while maintaining stable pressure and temperature conditions. The instrument was considered suitable for HPHT gas viscosity measurements because its oscillating piston sensor has a mechanically simple design, avoids dynamic seals within the sensing mechanism and requires only a small sample volume. This is particularly important where reservoir fluid samples are limited. In addition, the instrument is capable of operating across a wide range of viscometric conditions with a measurement uncertainty of approximately ±1–2% (Chapoy et al., 2011). The viscometer was directly connected to the HPHT vessel through a pressure balanced interface to ensure that the gas sample remained under uniform and representative measurement conditions throughout the experiment. Before each test sequence, the instrument was calibrated using reference gas, particularly nitrogen, at known thermodynamic conditions. The measured nitrogen viscosities were compared with reference values calculated at the corresponding thermodynamic states using NIST REFPROP. The instrument was considered suitable for testing when the measured values fell within the predefined acceptance tolerance. This calibration procedure was carried out to improve measurement reliability and ensure that the viscosity readings obtained during the experiment were accurate and reproducible. The Cambridge SPL440 viscometer has an accuracy of approximately ±1.5% of the measured value, making it suitable for high-pressure gas viscosity measurements in reservoir fluid studies.

2.2.4 Data Acquisition and Monitoring System

A computerized data acquisition system (DAMS) was integrated with the experimental setup to continuously monitor and record pressure, temperature and viscosity data throughout each experimental run. Pressure and temperature sensors were connected to the DAMS via high precision signal conditioners. All data were logged at one second intervals to ensure temporal resolution adequate for capturing steady state conditions. The data acquisition interface also facilitated real time visualization of system stability and test progression.

2.3 Experimental Procedure

Every experimental run followed a structured and controlled procedure designed to ensure high data accuracy, repeatability and reproducibility of results under High Pressure High Temperature (HPHT) conditions. The HPHT vessel was initially evacuated and thoroughly purged with nitrogen gas to eliminate any residual gases,

moisture, or contaminants that could affect measurement integrity or alter gas composition. The samples were carefully transferred from high pressure storage cylinders through stainless steel tubing into the compressor system under sealed conditions to prevent atmospheric contamination and preserve fluid composition. The gas was then pressurized using a RIX high pressure compressor to approximately 2,000 psi above the original reservoir pressure in order to ensure system stability and allow controlled experimental evaluation under HPHT conditions. Following pressurization, the HPHT vessel was conditioned to a target pressure of 20,000 psi and a temperature of 392°F, with a stabilization period of approximately 15–30 minutes to ensure thermal and pressure equilibrium within the system. Subsequently, the system temperature was increased in controlled increments to achieve the required experimental temperature conditions, including 392°F and 212°F. Once the desired pressure temperature equilibrium was established, gas viscosity measurements were taken using the SPL440 viscometer. For each pressure temperature condition, readings were recorded over a 10 minute stabilization period to ensure steady state flow behaviour, after which average values were computed to improve measurement reliability and reduce random error effects. The pressure was then systematically reduced in stages from 20,000 psi to 19,500 psi, 19,000 psi, 18,500 psi, 18,000 psi, 17,500 psi, 17,000 psi and subsequently down to 5,000 psi, allowing for comprehensive evaluation across a wide pressure range. To determine the temperature dependence of natural gas viscosity, the entire procedure was repeated at multiple temperature levels, including 373°F, 354°F, 316°F, 302°F, 297°F, 278°F, 259°F and 212°F. This ensured complete data capturing both pressure and temperature effects on gas viscosity behaviour. All experimental tests were conducted under strictly controlled isothermal and isobaric conditions. Data consistency was verified at each stage and all measurements were validated within the precision limits and calibration accuracy of the SPL440 viscometer to ensure reliability of the final dataset used for modelling and analysis

2.4 Data Quality Control and Uncertainty Analysis

Experimental uncertainties were carefully assessed. Pressure and temperature sensors contributed errors of less than ±0.3% and ±0.2°F, respectively, while flow measurements carried an uncertainty of ±0.3%. Propagation of these errors yielded an overall uncertainty in viscosity determination of approximately ±3%. To evaluate repeatability, each experiment was conducted at least thrice under identical conditions. The variation between repeated measurements was consistently below 2%, confirming both the accuracy and reliability of the data.

Table 1. Descriptive Statistics of Database used in this study

Parameter	Descriptive Statistics		Variability		
	Min. Value	**Max.Value**	**Mean**	**SD**	**Variance**
Reservoir Temperature (°F)	212	392	302	127	16200
Reservoir Pressure (psia)	5015	20015	12716	6125	3.8E+07
Molecular Weight	18.61	18.67	18.64	0.030	0.001
Pseudoreduced Temperature	1.825	2.313	2.069	0.345	0.119
Reduced Pressure	7.325	29.26	18.29	15.51	240.6
Experimental Gas Viscosity	0.022	0.056	0.039	0.024	0.001
C_1	88.83	90.50	89.67	0.682	0.465
C_2	4.080	5.180	4.630	0.449	0.202
C_3	1.320	1.640	1.480	0.131	0.017
i-C_4	0.160	0.280	0.220	0.049	0.002
n-C_4	0.270	0.350	0.310	0.033	0.001
i-C_5	0.040	0.410	0.225	0.151	0.023
n-C_6	0.040	0.090	0.065	0.020	0.001
C_{7+}	0.200	0.250	0.225	0.061	0.004
CO_2	2.240	3.210	2.725	0.396	0.157
N_2	0.120	1.600	0.685	0.461	0.213

2.5 Viscosity Correlations

The experimental data were evaluated against the predictive performance of seven established gas viscosity correlations, namely those proposed by Dean and Stiel (1958), Dempsey (1965), Lee et al. (1966), Ohirhain and Abu (2009), Viswanathan (2007), Heidaryan et al. (2010) and Azubuike et al. (2019). Each correlation was implemented and computed using an Excel spreadsheet to ensure consistency in unit handling, parameter evaluation and numerical accuracy across all models.

Statistical Evaluation

$$AAPE(\%) = \frac{100}{N}\sum_{i=0}^{n}\left|\frac{|\mu_{exp} - \mu_{pred}}{\mu_{exp}}\right| \quad (1)$$

$$\text{RMSE}=\sqrt{\frac{1}{N}\sum_{i=0}^{n}(\mu_{exp}-\mu_{pred})^2} \quad (2)$$

$$R^2=1-\frac{\sum_{i=0}^{n}(\mu_{exp}-\mu_{pred})^2}{\sum_{i=0}^{n}(\mu_{mean}-\mu_{pred})^2} \quad (3)$$

III. RESULTS AND DISCUSSION

3.1 Experimental Viscosity Results

The experimental viscosity data for natural gas samples A and B for all considered components are presented in Tables 6 and 7. A sensitivity analysis was conducted to examine the relative influence of pressure and temperature on viscosity behaviour and the analyzed samples are illustrated in Figures 2 and 3. The viscosity increases with pressure, consistent with theoretical expectations due to increased molecular interactions under compression. However, due to enhanced molecular kinetic energy, viscosity decreases with increasing temperature. For sample A at 5000 psi and 212°F, the viscosity is 0.022 cp and at 20,000 psi, it increases to 0.055 cp; a similar trend was also observed in sample B, with slight deviations due to compositional variations (e.g., higher C_2 and N_2 content). Viscosity measurements for the natural gas samples were successfully obtained across the pressure range of 5,000–20,000 psi and temperature range of 212–392 °F. At constant temperature, viscosity increased with pressure, consistent with the expected densification of the gas phase. Conversely, viscosity decreased with increasing temperature at constant pressure. These results confirm the strong dependence of gas viscosity on both pressure and temperature, especially in the HPHT and UHPHT regime where non-ideal gas behaviour becomes significant.

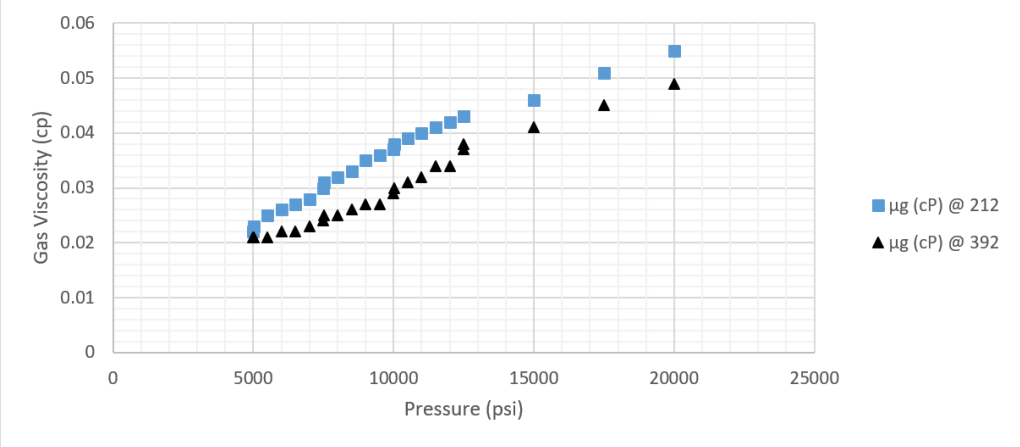

Figure 2: Pressure against Gas Viscosity for Sample A

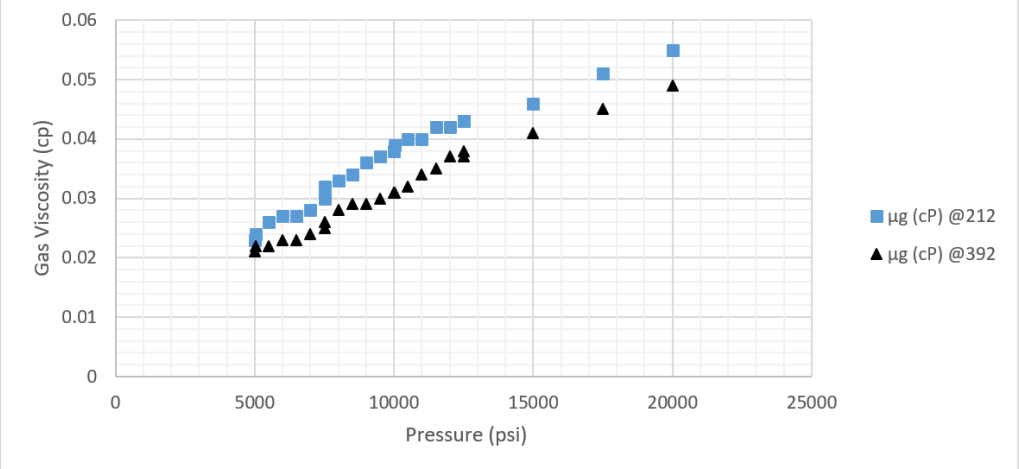

Figure 3: Pressure against Gas Viscosity for Sample B

3.2 Performance Comparison of Conventional Model.

The experimental data sets for this study were compared against seven established empirical and semi empirical correlations as applied to natural gas. These correlations were carefully selected, having been models specifically for the prediction of natural gas viscosity. The accuracy of the seven empirical correlations was evaluated for estimating gas viscosity for gas samples 1 and 2. Considering the entire pressure range under study, Figure 4 compares the chosen gas viscosity models with the measured data at 212°F; similarly, Figures 5 and 6 compare the models at 302°F and 392°F. The experimental data demonstrate the anticipated pattern of increased viscosity with increasing pressure, particularly above 12,000 psi, when the slope becomes significantly steeper. This behaviour indicates strong molecular interactions under ultra high pressure conditions. Among the tested correlations, the model of Dean and Stiel (1958) aligns reasonably well with the experimental data at lower pressures but diverges significantly beyond 12,000 psi, where it greatly overestimates viscosity. Likewise, the correlation by Lee et al. (1966) and Viswanathan et al. (2007) follows the overall pressure trend but consistently overpredicts viscosity at higher pressures.

On the other hand, Heidaryan et al. (2010) tend to underpredict viscosity across the entire pressure range, showing a relatively flat trend compared to the experimental data. It produces the lowest viscosity values, deviating markedly from measured data, indicating its limited applicability under the present temperature and high pressure conditions. The Azubuike et al. (2019) correlation demonstrates closer alignment with the experimental measurements across a wide range of pressures, though slight underestimation is observed at the highest pressures. Dempsey's (1965) correlation provides a moderate agreement but fails to capture the steep trend. Overall, Dempsey (1965) and Ohirhian and Abu (2009) show relatively better predictive capability compared to other correlations, though both exhibit limitations in the UHPHT regime. Both models showed the best alignment with experimental.

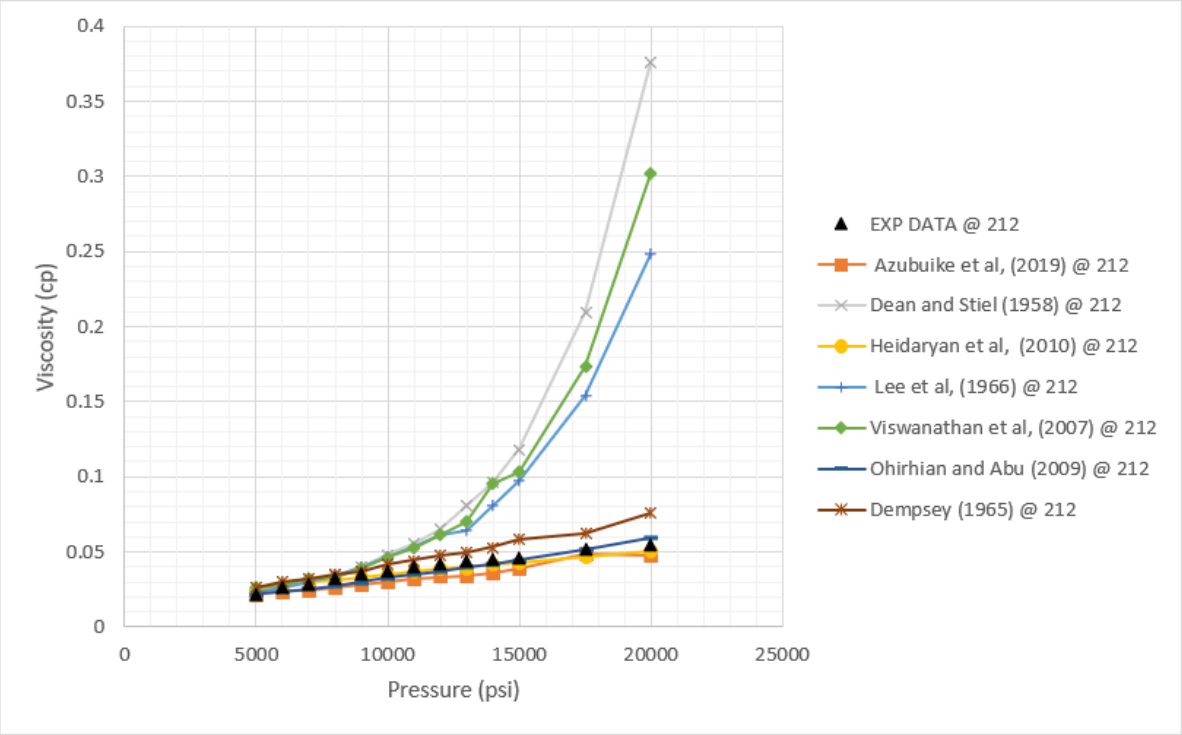

Figure 4: Gas Viscosity against Pressure at 212°F

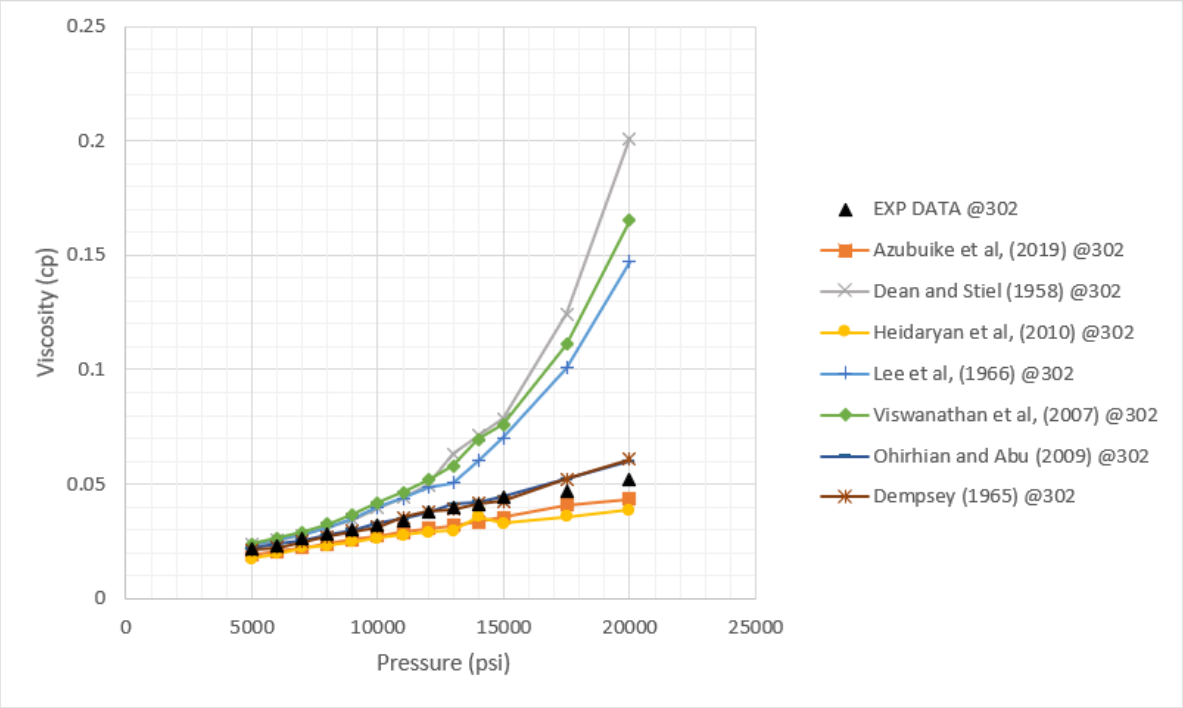

Figure 5: Gas Viscosity against Pressure at 302^{O}F

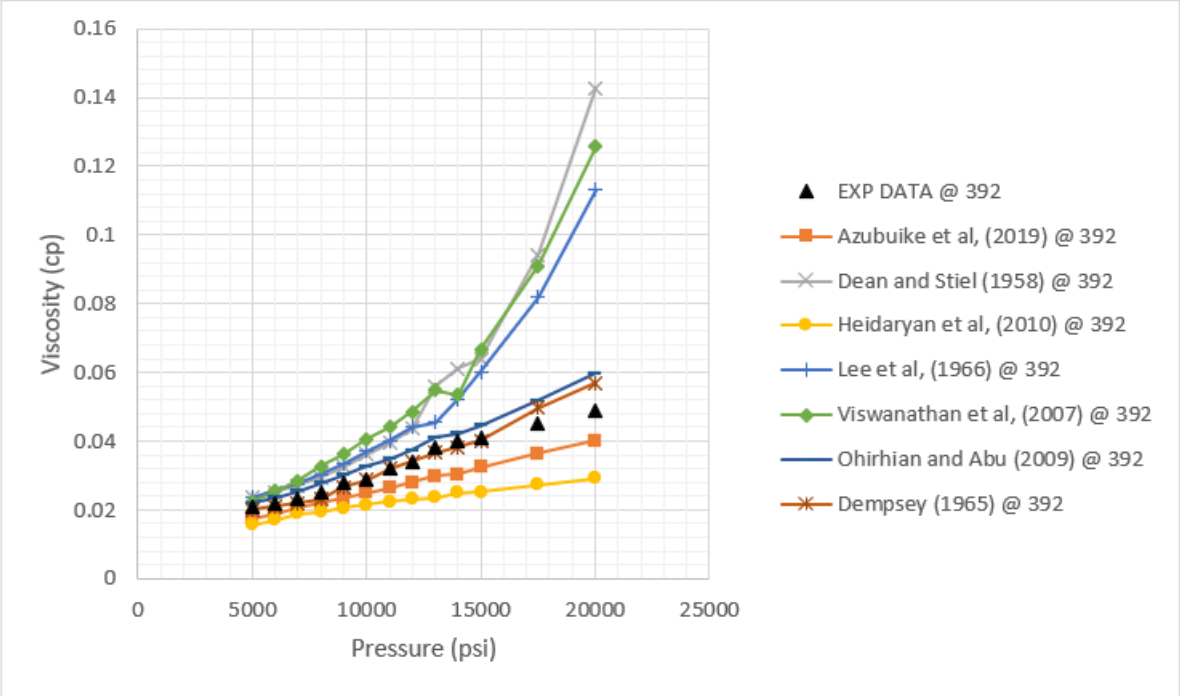

Figure 6: Gas Viscosity against Pressure at 392^{O}f

3.3 Comparative Statistical Evaluation of Existing Natural Gas Viscosity Correlations

Tables 2-4 present the statistical evaluation of seven existing natural gas viscosity correlations under low pressure and low temperature (LPLT), high pressure and high temperature (HPHT) and ultra-high pressure and high temperature (UHPHT) conditions. The correlations evaluated were those developed by Azubuike et al. (2019), Dean and Stiel (1958), Heidaryan et al. (2010), Lee et al. (1966), Viswanathan et al. (2007), Ohirhian and Abu (2009) and Dempsey (1965).

3.3.1 Performance under the LPLT Regime

The LPLT results show that the predictive performances of the existing correlations differed considerably. Based on AARE, Heidaryan et al. (2010) produced the lowest error of 4.13805%, indicating the best average percentage accuracy within the LPLT regime. This was followed closely by Dempsey (1965), with an AARE of 4.33020% and Ohirhian and Abu (2009), with an AARE of 5.11449%. Viswanathan et al. (2007) recorded an AARE of 6.96369%, while Azubuike et al. (2019), Lee et al. (1966) and Dean and Stiel (1958) produced comparatively higher values of 9.20010%, 10.0149% and 10.1118%, respectively. This difference is relatively small and indicates that both correlations achieved comparable average percentage accuracy under LPLT conditions. The result suggests that the Heidaryan et al. correlation described the relative changes in the LPLT experimental viscosity values more effectively than most of the other correlations. Heidaryan et al. (2010) provided the strongest LPLT performance. Its AARE value is lower than those of the remaining correlations. This finding indicates that the correlation produced relatively small average deviations when the prediction errors were normalised by the experimental viscosity values. Dempsey (1965) produced the lowest RMSE of 0.00066, followed by Ohirhian and Abu (2009) with 0.00073 and Heidaryan et al. (2010) with 0.00134. Viswanathan et al. (2007), Azubuike et al. (2019), Lee et al. (1966) and Dean and Stiel (1958) produced RMSE values of 0.00361, 0.00424, 0.00436 and 0.00469, respectively. This result confirms that Dempsey produced the smallest typical absolute deviation from the experimental viscosity data. The (R^2) values further support the strong performance of Dempsey (1965). Dempsey recorded the highest (R^2) value of 0.97798, indicating that the correlation explained approximately 97.80% of the variation in the LPLT experimental viscosity data. Ohirhian and Abu (2009) followed with an (R^2) of 0.96165, corresponding to approximately 96.17% of the observed variation. Heidaryan et al. (2010) recorded an (R^2) of 0.85011, while Viswanathan et al. (2007), Azubuike et al. (2019), Lee et al. (1966) and Dean and Stiel (1958) recorded values of 0.78022, 0.72891, 0.70768 and 0.69023, respectively. The (R^2) results demonstrate that Dempsey (1965) and Ohirhian and Abu (2009) reproduced the trend and variability of the experimental LPLT data more effectively than the other correlations. Although Heidaryan et al. (2010) produced the lowest AARE, its (R^2) value was approximately 0.128 lower than that of Dempsey. This indicates that Heidaryan et al. provided good average percentage accuracy but were less effective than Dempsey in reproducing the complete variation in the experimental data. Overall, Dempsey (1965) has the strongest existing correlation under LPLT conditions.

Table 2: Statistical Models Predictions at LPLT

Pressure (Psi)	Experimental Data	Azubuike et al, (2019)	Dean and Stiel (1958)	Heidaryan et al, (2010)	Lee et al, (1966)	Viswanathan et al, (2007)	Ohirhian and Abu (2009)	Dempsey (1965)
5000	0.022	0.02106	0.02329	0.02414	0.02340	0.02228	0.02201	0.02341
5500	0.024	0.02194	0.02460	0.02544	0.02464	0.02352	0.02564	0.02468
6000	0.026	0.02149	0.02636	0.02668	0.02652	0.02540	0.02665	0.02637
6500	0.027	0.02382	0.02789	0.02788	0.02812	0.02700	0.02751	0.02728
7000	0.028	0.02459	0.02952	0.02903	0.02978	0.02866	0.02939	0.02913
7500	0.030	0.02547	0.03190	0.03015	0.03214	0.03102	0.03059	0.03014
8000	0.032	0.02635	0.03421	0.03122	0.03439	0.03327	0.03166	0.03188
8500	0.033	0.02724	0.03722	0.03225	0.03722	0.03610	0.03394	0.03392
9000	0.035	0.02812	0.04009	0.03324	0.03985	0.03873	0.03404	0.03486
9500	0.036	0.02900	0.04388	0.03421	0.04324	0.04212	0.03537	0.03597
10000	0.037	0.02822	0.04821	0.03514	0.04709	0.04597	0.03673	0.03698
AARE (%)		**9.20010**	**10.1118**	**4.13805**	**10.0149**	**6.96369**	**5.11449**	**4.33020**
RMSE		**0.00424**	**0.00469**	**0.00134**	**0.00436**	**0.00361**	**0.00073**	**0.00066**
R^2		**0.72891**	**0.69023**	**0.85011**	**0.70768**	**0.78022**	**0.96165**	**0.97798**

3.3.2 Performance under the HPHT Regime

The HPHT results show a clearer separation between the best performing and least performing correlations. Dempsey (1965) produced the lowest AARE of 3.33134%, followed closely by Ohirhian and Abu (2009), with an AARE of 3.55387%. Azubuike et al. (2019) ranked third with an AARE of 17.8890%. The remaining correlations produced substantially higher errors. Heidaryan et al. (2010), Viswanathan et al. (2007), Lee et al. (1966) and Dean and Stiel (1958) recorded AARE values of 22.2285%, 32.6149%, 37.3602% and

43.7360%, respectively. Although the numerical difference between the two correlations was only 0.22253 percentage points, both correlations substantially outperformed the other five models. These substantial differences demonstrate that Dempsey (1965) and Ohirhian and Abu (2009) were considerably more capable of representing the HPHT viscosity data. The low AARE values of approximately 3.3–3.6% obtained from the two correlations indicate close average percentage agreement with the experimental results. The RMSE values provide the same general ranking. Dempsey (1965) recorded the lowest RMSE of 0.00134, while Ohirhian and Abu (2009) produced a closely comparable value of 0.00141. Azubuike et al. (2019) ranked third with an RMSE of 0.00663. Heidaryan et al. (2010), Viswanathan et al. (2007), Lee et al. (1966) and Dean and Stiel (1958) recorded RMSE values of 0.00872, 0.01378, 0.01601 and 0.01947 respectively. The (R^2) values further confirmed the superiority of Dempsey (1965). Dempsey recorded the highest (R^2) of 0.89074 indicating that it explained approximately 89.07% of the variation in the HPHT experimental viscosity data. Ohirhian and Abu (2009) produced the second highest (R^2) of 0.87795. Azubuike et al. (2019) recorded an (R^2) of 0.85723, while Heidaryan et al. (2010), Viswanathan et al. (2007), Lee et al. (1966) and Dean and Stiel (1958) recorded values of 0.81720, 0.76897, 0.75154 and 0.73618 respectively. Although the difference between the (R^2) values of Dempsey and Ohirhian and Abu was relatively small, Dempsey consistently ranked first for all five statistical parameters. This consistency provides strong evidence that Dempsey offered the best overall representation of the HPHT viscosity data.

The favourable performance of Dempsey (1965) and Ohirhian and Abu (2009) under HPHT conditions suggests that their empirical structures were more compatible with the pressure, temperature and compositional ranges of the gas samples used in this study. Their performance remains dependent on the degree of similarity between the present data and the data used in developing the correlations. The poor performance of Dean and Stiel (1958), Lee et al. (1966) and Viswanathan et al. (2007) is evident from their AARE values of 43.7360%, 37.3602% and 32.6149%, respectively. Errors of this magnitude indicate that the predicted values deviated substantially from the experimental viscosity data. Overall, Dempsey (1965) was the best performing existing correlation under the HPHT regime because it produced the lowest AARE and RMSE and the highest (R^2). Ohirhian and Abu (2009) provided a close second best performance, while Azubuike et al. (2019) ranked third. The remaining correlations showed limited reliability for the HPHT dataset considered.

Table 3: Statistical Models Predictions at HPHT

Pressure (Psi)	Experimental Data	Azubuike et al, (2019)	Dean and Stiel (1958)	Heidaryan et al, (2010)	Lee et al, (1966)	Viswanathan et al, (2007)	Ohirhian and Abu (2009)	Dempsey (1965)
10000	0.032	0.02723	0.03954	0.02628	0.03983	0.03870	0.03273	0.03291
10500	0.034	0.02805	0.04144	0.02700	0.04149	0.04037	0.03362	0.03363
11000	0.034	0.02887	0.04400	0.02770	0.04377	0.04265	0.03475	0.03524
11500	0.037	0.02968	0.04674	0.02838	0.04617	0.04505	0.03524	0.03768
12000	0.038	0.03057	0.04970	0.02904	0.04870	0.04758	0.03586	0.03919
12500	0.039	0.03132	0.05294	0.02970	0.05068	0.04956	0.03811	0.03942
13000	0.039	0.03209	0.05723	0.03032	0.05378	0.05102	0.04111	0.04100
13500	0.040	0.03293	0.06208	0.03094	0.05706	0.05494	0.04178	0.04189
14000	0.041	0.03372	0.06622	0.03155	0.06222	0.05781	0.04216	0.04201
14500	0.043	0.03453	0.07205	0.03214	0.06748	0.06452	0.04485	0.04424
15000	0.044	0.03541	0.07867	0.03274	0.07022	0.06910	0.04656	0.04627
AARE (%)		**17.8890**	**43.7360**	**22.2285**	**37.3602**	**32.6149**	**3.55387**	**3.33134**
RMSE		**0.00663**	**0.01947**	**0.00872**	**0.01601**	**0.01378**	**0.00141**	**0.00134**
R^2		**0.85723**	**0.73618**	**0.81720**	**0.75154**	**0.76897**	**0.87795**	**0.89074**

3.3.3 Performance under the UHPHT Regime

Under the UHPHT regime, the prediction errors increased for all the correlations, although the magnitude of the deterioration differed considerably among the models. Dempsey (1965) remained the strongest correlation, producing the lowest AARE of 8.57541%. Ohirhian and Abu (2009) ranked second with an AARE of 12.6794%, while Azubuike et al. (2019) ranked third with an AARE of 18.9259%. Viswanathan et al. (2007), Lee et al. (1966), Heidaryan et al. (2010) and Dean and Stiel (1958) produced substantially higher AARE values of

32.5341%, 37.4692%, 39.0198% and 45.5279%, respectively. The difference between Dempsey and Ohirhian and Abu became considerably greater under UHPHT conditions. This indicates that Dempsey retained its predictive accuracy more effectively as the pressure and temperature conditions became more severe. Dempsey (1965) produced the lowest RMSE of 0.00469 followed by Ohirhian and Abu (2009) with 0.00693 and Azubuike et al. (2019) with 0.00854. Heidaryan et al. (2010), Viswanathan et al. (2007), Lee et al. (1966) and Dean and Stiel (1958) recorded RMSE values of 0.01761, 0.03873, 0.04243 and 0.05196 respectively. These results demonstrate that Dempsey produced the smallest typical absolute prediction error within the UHPHT dataset. The (R^2) results also identified Dempsey (1965) as the best performing correlation. Dempsey produced the highest (R^2) value of 0.87253, indicating that approximately 87.25% of the variation in the UHPHT experimental viscosity data was explained by

Table 4: Statistical Models Predictions at UHPHT

Pressure (Psi)	Experimental Data	Azubuike et al, (2019)	Dean and Stiel (1958)	Heidaryan et al, (2010)	Lee et al, (1966)	Viswan athan et al, (2007)	Ohirhian and Abu (2009)	Dempsey (1965)
15000	0.041	0.03259	0.06389	0.02531	0.06007	0.05894	0.04458	0.04023
15500	0.042	0.03398	0.07324	0.02601	0.07154	0.06453	0.04591	0.04268
16000	0.042	0.03489	0.07811	0.02655	0.07342	0.06978	0.04738	0.04438
16500	0.043	0.03505	0.08409	0.02698	0.07962	0.07245	0.04818	0.04579
17000	0.045	0.03589	0.08768	0.02701	0.08908	0.07785	0.04978	0.04768
17500	0.045	0.03638	0.09415	0.02728	0.08179	0.08067	0.05185	0.04902
18000	0.046	0.03712	0.09529	0.02801	0.08876	0.08369	0.05281	0.05041
18500	0.047	0.03867	0.09678	0.02857	0.09111	0.08732	0.05402	0.05234
19000	0.048	0.03923	0.09836	0.02895	0.09567	0.09102	0.05665	0.05497
19500	0.048	0.03909	0.12392	0.02900	0.10123	0.09765	0.05808	0.05504
20000	0.049	0.04011	0.14274	0.02912	0.11307	0.11195	0.05975	0.05685
AARE (%)		**18.9259**	**45.5279**	**39.0198**	**37.4692**	**32.5341**	**12.6794**	**8.57541**
RMSE		**0.00854**	**0.05196**	**0.01761**	**0.04243**	**0.03873**	**0.00693**	**0.00469**
R^2		**0.78128**	**0.63567**	**0.71396**	**0.67321**	**0.68921**	**0.81521**	**0.87253**

the model. Ohirhian and Abu (2009) ranked second with an R^2 of 0.81521, followed by Azubuike et al. (2019) with 0.78128. Heidaryan et al. (2010), Viswanathan et al. (2007), Lee et al. (1966) and Dean and Stiel (1958) produced values of 0.71396, 0.68921, 0.67321 and 0.63567 respectively. The UHPHT findings demonstrate that model reliability generally deteriorated as the correlations were applied to more extreme operating conditions. Overall, Dempsey (1965) was unequivocally the strongest existing correlation under UHPHT conditions. It ranked first for all five statistical measures under the most extreme conditions. The overall statistical evaluation demonstrates that Dempsey (1965) was the most reliable existing natural gas viscosity correlation across the three pressure and temperature regimes investigated.

3.4 Comparison of Group Error Metrics for Correlation Models

Figure 7 represents the group metrics of seven published correlations. It shows the sensitivity of the existing models to changes in pressure and temperature. In the LPLT regime, most of the published correlations showed acceptable performance, particularly Dempsey (1965), Ohirian and Abu (2009) and Heidaryan et al. (2010). Heidaryan et al. recorded the lowest AARE among the published models at 4.13805%, while Dempsey achieved the strongest RMSE and R^2 results. However, as conditions changed from LPLT to HPHT and UHPHT, the performance of many correlations deteriorated markedly, as shown by increasing AARE and RMSE values and in several cases, declining R^2 values. Dempsey (1965) displayed the greatest consistency among the published correlations across all three regimes. Its AARE values were 4.33020%, 3.33134% and 8.57541% for LPLT, HPHT and UHPHT, respectively, while its R^2 values remained relatively high at 0.97798, 0.89074 and 0.87253. Ohirian and Abu (2009) also performed comparatively well, especially under LPLT and HPHT conditions. In contrast, Dean and Stiel (1958) showed the weakest overall performance under severe conditions, with AARE values increasing from 10.1118% in LPLT to 43.7360% in HPHT and 45.5279% in UHPHT. The Lee et al. (1966) and Viswanathan et al. (2007) correlations also exhibited large prediction errors under HPHT and UHPHT conditions.

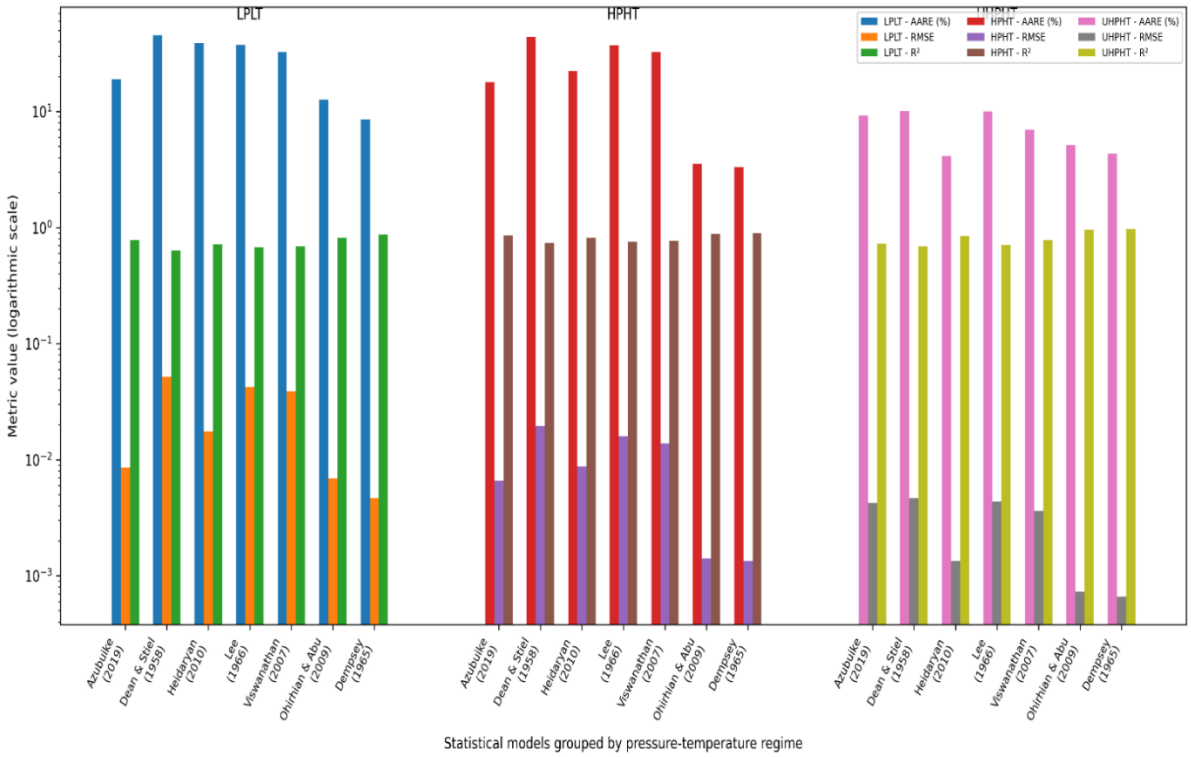

Figure 7: Comparison of Group Error Metrics for Correlation Models

3.5 Cross Plot Analysis

Cross plots were constructed to compare the experimentally measured viscosities of natural gas with the corresponding predicted values obtained from the seven published correlations. In an ideal situation, the experimental data and the predicted data points should align along a 45° line, representing perfect agreement between experimental and predicted viscosities. As illustrated in Figures 8 to 14, none of the evaluated correlations achieved an ideal 45° slope, indicating the presence of systematic deviations between the predicted and experimental values. However, the correlations proposed by Dempsey (1965) and Ohirhian and Abu (2009) demonstrated the closest agreement with the experimental data, showing the least scatter and highest degree of linearity along the line of equality. This suggests that these two models provide improved predictive capability for gas viscosity within the investigated pressure temperature range. The Ohirhian and Abu (2009) model exhibited superior performance at higher pressures (above 10,000 psi), indicating its robustness under high pressure conditions. Similarly, Dempsey (1965) correlation performed particularly well at moderate pressures (5,000–10,000 psi), where its empirical formulation aligns closely with real gas viscosity trends. These results are consistent with previous findings in the literature, where both models were recognized for their adaptability to dense phase and HPHT gas systems. A closer examination of the cross plots reveals that models lying below the 45° line tend to underpredict viscosity, whereas those above the line overpredict it. Most traditional correlations, including those of Heidaryan et al. (2010) and Azubuike et al. (2019) exhibited underprediction at high pressures, reflecting their limited calibration ranges. In contrast, density dependent correlations such as Dean and Stiel (1958), Viswanathan (2007) and Lee et al. (1966), overpredicted viscosity at elevated temperatures. Quantitatively, the statistical evaluation validates the visual interpretation of the cross plots. The Dempsey (1965) and Ohirhian and Abu (2009) models achieved the lowest Average Absolute Relative Error (AARE) values of 5.32% and 5.52%, Average Relative Error value of 3.82% and 4.00% and the highest correlation coefficients of 0.87 and 0.82 at XHPHT reservoir conditions representing strong agreement with experimental data. The remaining models displayed higher scatter and larger error metrics, confirming their reduced reliability under UHPHT conditions. Overall, the cross plots analysis confirms that while no existing correlation perfectly reproduces experimental viscosities across the entire tested range, the Dempsey (1965) correlation performed better than others which also agreed with the previous evaluation.

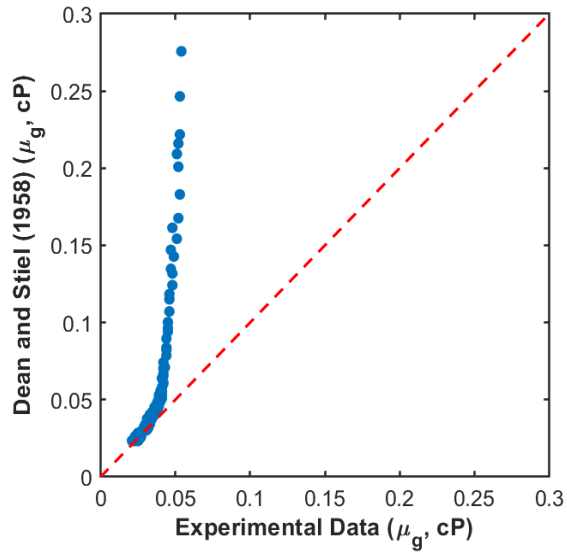

Figure 8: Plot of predicted against measured gas viscosity

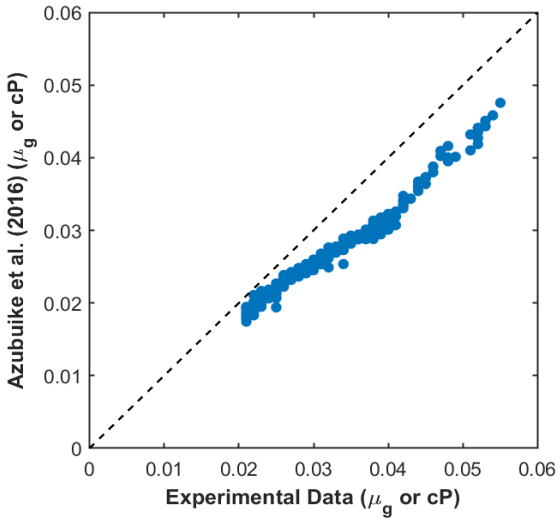

Figure 9: Plot of predicted against measured gas viscosity

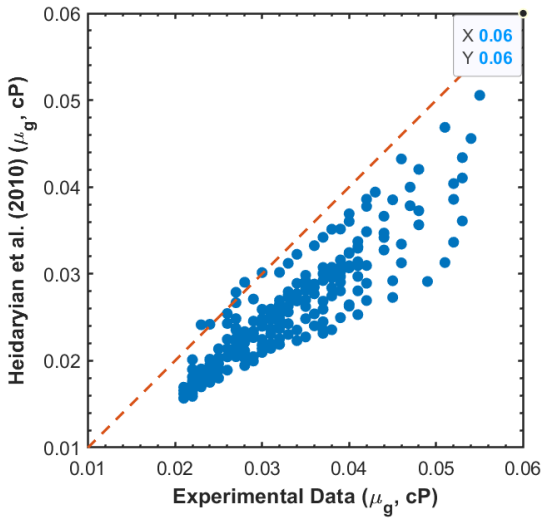

Figure 10: Plot of predicted against measured gas viscosity

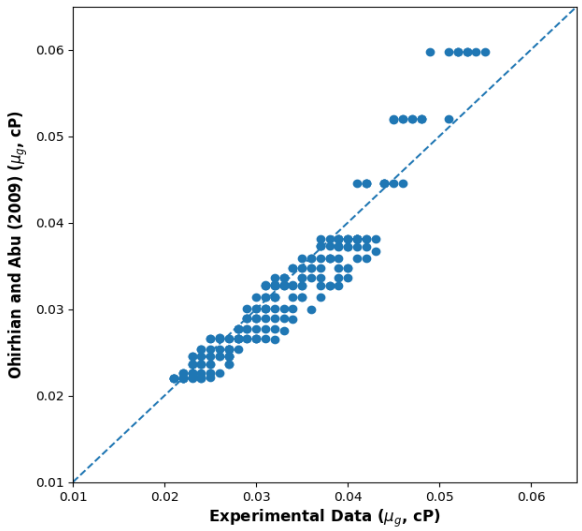

Figure 11: Plot of predicted against measured gas viscosity

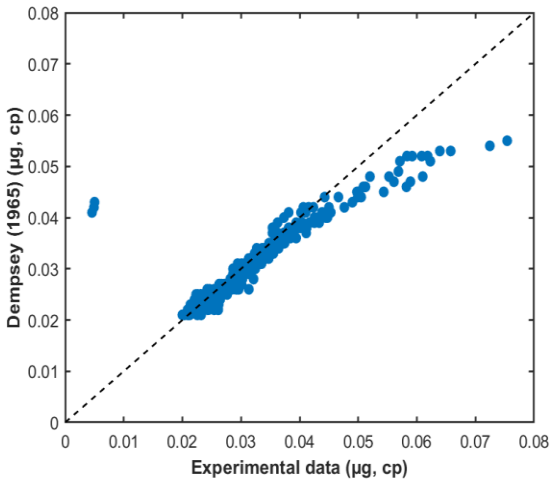

Figure 12: Plot of predicted against measured gas viscosity

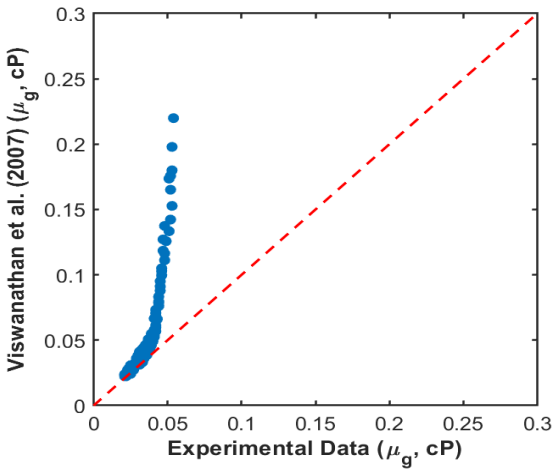

Figure 13: Plot of predicted against measured gas viscosity

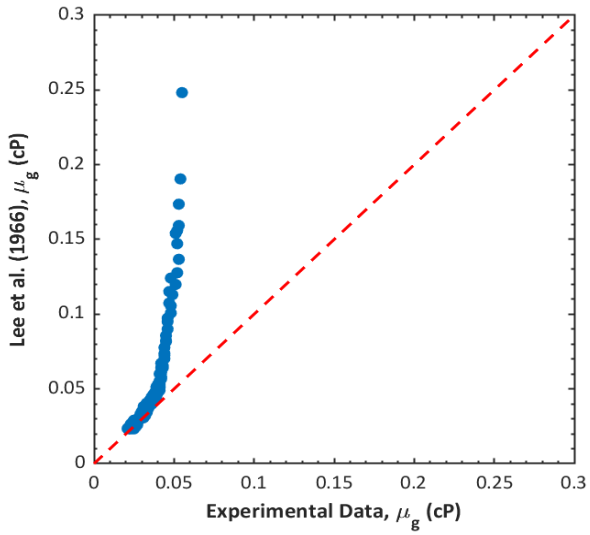

Figure 14: Plot of predicted against measured gas viscosity

IV.Conclusion

This study presents an experimental investigation of natural gas viscosity behaviour under a wide range of pressure and temperature conditions relevant to conventional, high-pressure high-temperature (HPHT) and ultra-deep gas reservoir applications. Experimental viscosity measurements were obtained across a broad pressure range of 5,000–20,000 psi and temperatures of 212°F, 254°F, 278°F, 297°F, 302°F, 316°F, 335°F, 354°F, 373°F, and 392°F, providing a comprehensive dataset for evaluating gas viscosity behaviour under increasingly severe reservoir conditions. The experimental results demonstrated that natural gas viscosity increases with increasing pressure at constant temperature, while increasing temperature generally reduces viscosity due to enhanced molecular mobility. However, at high pressure conditions, the relationship between viscosity and thermodynamic variables becomes increasingly nonlinear. These observations confirm that viscosity prediction under extreme reservoir environments requires models capable of accurately representing non ideal gas behaviour. A comparative assessment of existing empirical correlations revealed significant variations in prediction performance across the investigated pressure temperature range. Correlations such as Dean and Stiel (1965), Lee et al. (1966) and Viswanathan (2007) provided acceptable predictions at lower pressure conditions but exhibited increasing deviations at elevated pressures. Similarly, Heidaryan and Jarrahian (2010) and Azubuike et al. (2019) showed a tendency to underestimate viscosity, whereas Ohirhian and Abu (2009) and Dempsey (1965) demonstrated relatively improved performance but still experienced deviations under severe pressure conditions. These findings indicate that many existing correlations may have limited applicability when extrapolated to HPHT and UHPHT reservoir environments. The experimental dataset generated in this study provides valuable information for improving natural gas viscosity prediction under challenging reservoir conditions. The findings highlight the need for developing and validating viscosity correlations specifically designed for high pressure and high temperature applications. The results can support more reliable fluid characterization, reservoir simulation, production forecasting, and engineering design for deep and ultra-deep natural gas reservoirs.

Contribution to Knowledge

The study creates a high-quality dataset by producing a detailed experimental dataset covering a wide range of pressures, temperatures and compositions, contributing valuable reference data for future research and model development, with practical application for industry offering robust and field-applicable viscosity prediction tools that can be integrated into reservoir simulators and digital oilfield platforms for improved forecasting and decision-making.

Nomenclature

μ	Viscosity (cp)
AARE	Average absolute relative error, %
RMSE	Root mean square error
SD	Standard deviation
DAMS	Data Acquisition and Monitoring System
R	Correlation coefficient
EOS	Equation of state
N	Number of data points

Ppr Pseudo-reduced pressure, dimensionless
Tpr Pseudo-reduced temperature, dimensionless
P System pressure, Psi
T System temperature, ^{0}F
CV Cambridge Viscometer
LPLT Low high pressure high temperature
HPHT High pressure high temperature
UHPHT Ultra high pressure high temperature
XHPHT Extreme high pressure high temperature

Reference

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Table 5. Experimental Viscosity Data of Natural Gas (Sample A) and Kashefi et al. (2013) data

Pressure (psi)	**212**°F µg (cp)	**257**°F µg (cp)	**278**°F µg (cp)	**297**°F µg (cp)	**302**°F µg (cp)	**316**°F µg (cp)	**335**°F µg (cp)	**354**°F µg (cp)	**373**°F µg (cp)	**392**°F µg (cp)
5000	0.022	0.022	0.022	0.021	0.021	0.021	0.021	0.021	0.021	0.021
5020	0.026	0.023	0.023	0.022	0.025	0.022	0.022	0.022	0.021	0.024
5500	0.024	0.024	0.025	0.023	0.022	0.022	0.023	0.022	0.021	0.021
6000	0.026	0.025	0.025	0.024	0.024	0.024	0.023	0.023	0.022	0.022
6500	0.027	0.026	0.026	0.025	0.024	0.025	0.024	0.024	0.023	0.022

7000	0.028	0.026	0.026	0.026	0.026	0.026	0.025	0.024	0.024	0.023
7500	0.030	0.029	0.028	0.027	0.027	0.026	0.025	0.025	0.024	0.024
7518	0.032	0.030	0.029	0.028	0.029	0.027	0.026	0.026	0.025	0.028
8000	0.032	0.031	0.032	0.029	0.028	0.028	0.027	0.026	0.026	0.025
8500	0.033	0.032	0.031	0.030	0.029	0.029	0.028	0.027	0.026	0.026
9000	0.035	0.033	0.032	0.031	0.030	0.030	0.029	0.028	0.027	0.027
9500	0.036	0.034	0.034	0.033	0.031	0.031	0.030	0.029	0.028	0.027
10000	0.037	0.036	0.035	0.033	0.032	0.032	0.031	0.031	0.030	0.029
10013	0.038	0.037	0.035	0.034	0.035	0.032	0.031	0.031	0.030	0.033
10500	0.039	0.039	0.036	0.035	0.034	0.034	0.033	0.032	0.031	0.031
11000	0.040	0.039	0.038	0.036	0.035	0.034	0.034	0.033	0.033	0.032
11500	0.041	0.040	0.039	0.038	0.037	0.037	0.036	0.035	0.034	0.034
12000	0.042	0.040	0.040	0.039	0.038	0.038	0.037	0.036	0.035	0.034
12500	0.043	0.042	0.041	0.041	0.039	0.038	0.038	0.037	0.037	0.037
12510	0.042	0.042	0.041	0.041	0.039	0.039	0.041	0.040	0.039	0.037
15000	0.048	0.045	0.044	0.044	0.044	0.044	0.042	0.042	0.042	0.041
17500	0.053	0.048	0.047	0.047	0.048	0.048	0.046	0.046	0.045	0.045
20000	0.057	0.054	0.053	0.053	0.052	0.052	0.052	0.052	0.051	0.049

Table 6. Experimental Viscosity Data of Natural Gas (Sample B) and Kashefi et al. (2013) data

Pressure (psi)	**212°F µg (cp)**	**257°F µg (cp)**	**278°F µg (cp)**	**297°F µg (cp)**	**302°F µg (cp)**	**316°F µg (cp)**	**335°F µg (cp)**	**354°F µg (cp)**	**373°F µg (cp)**	**392°F µg (cp)**
5000	0.023	0.022	0.022	0.022	0.022	0.022	0.021	0.021	0.021	0.021
5020	0.026	0.024	0.024	0.023	0.025	0.024	0.023	0.022	0.022	0.024
5500	0.026	0.025	0.025	0.024	0.023	0.023	0.023	0.022	0.022	0.022
6000	0.027	0.027	0.025	0.025	0.024	0.024	0.024	0.023	0.023	0.023
6500	0.027	0.027	0.026	0.026	0.027	0.027	0.025	0.024	0.023	0.023
7000	0.028	0.027	0.027	0.027	0.027	0.027	0.026	0.025	0.024	0.024
7500	0.030	0.030	0.029	0.028	0.028	0.028	0.027	0.026	0.025	0.025
7518	0.032	0.031	0.030	0.029	0.029	0.028	0.027	0.026	0.026	0.028
8000	0.033	0.032	0.031	0.030	0.029	0.029	0.028	0.028	0.028	0.028
8500	0.034	0.033	0.032	0.031	0.030	0.030	0.029	0.030	0.029	0.029
9000	0.036	0.034	0.033	0.032	0.031	0.031	0.031	0.030	0.030	0.029
9500	0.037	0.035	0.035	0.034	0.032	0.032	0.032	0.031	0.031	0.030
10000	0.038	0.037	0.035	0.034	0.033	0.033	0.032	0.031	0.032	0.031
10013	0.038	0.038	0.035	0.034	0.035	0.033	0.032	0.032	0.032	0.033
10500	0.040	0.039	0.037	0.036	0.035	0.035	0.033	0.033	0.033	0.032
11000	0.040	0.040	0.039	0.037	0.036	0.036	0.035	0.035	0.034	0.034
11500	0.042	0.041	0.039	0.038	0.038	0.038	0.037	0.036	0.036	0.035
12000	0.042	0.041	0.040	0.040	0.039	0.039	0.038	0.037	0.037	0.037
12500	0.043	0.042	0.041	0.041	0.040	0.039	0.039	0.040	0.039	0.037
12510	0.042	0.042	0.041	0.041	0.039	0.039	0.041	0.040	0.039	0.037
15000	0.048	0.045	0.044	0.044	0.044	0.044	0.042	0.042	0.042	0.041
17500	0.053	0.048	0.047	0.047	0.048	0.048	0.046	0.046	0.045	0.045
20000	0.057	0.054	0.053	0.053	0.052	0.052	0.052	0.052	0.051	0.049

Table 7. Kashefi et al. (2013) data

T **(K)**[a]	***P*** **(MPa)**[b]	**η (cP)**
323.15	34.61	0.028
323.15	51.88	0.036
323.15	69.08	0.043
323.15	86.25	0.049
323.15	103.52	0.055
323.15	120.7	0.06
323.15	137.79	0.064
373.15	34.6	0.026
373.15	51.9	0.032
373.15	69.00	0.038
373.15	86.23	0.042
373.15	103.56	0.048
373.15	120.78	0.053
373.15	137.79	0.057
423.15	34.6	0.025
423.15	51.79	0.029
423.15	69.06	0.035
423.15	86.27	0.039
423.15	103.51	0.044
423.15	120.72	0.048
423.15	137.78	0.052
473.15	34.63	0.024
473.15	51.83	0.028
473.15	69.05	0.033
473.15	86.27	0.037
473.15	103.5	0.041
473.15	120.75	0.045
473.15	137.75	0.049