International Journal of Engineering Research & Technology (IJERT)
ISSN: 2278-0181
Vol. 15 Issue 10 , October - 2026

Accurate Natural Gas Viscosity Correlations for High and Ultra High Pressure and Temperature Gas Systems.

[1,2]Julie Bemigho Mamukuyomi, [2]Victor Joseph Aimikhe, [2]Ijeoma Irene Mbachu and [1]Adewale Dosunmu
[1]Department of Petroleum Engineering, Federal University, Otuoke, Nigeria
[2]Department of Petroleum and Gas Engineering, University of Port Harcourt, Nigeria.

Abstract
Accurate modeling of natural gas viscosity under high and ultra-high pressure temperature reservoir conditions is crucial for efficient reservoir simulation, flow assurance and production optimization. Conventional viscosity correlations often fail in such ultra-high conditions due to nonlinear gas behavior. Its behaviour under ultra-high reservoir conditions is still uncertain despite being thoroughly investigated at low to moderate temperatures and pressures. As exploration moves deeper into ultra-high pressure high temperature (UHPHT) reservoirs, where accurate viscosity predictions are essential for accurate simulation, reserve estimation and field planning, this limitation becomes more significant. Most existing correlations are calibrated on dataset below 10,000 psia and 300 °F, raising concerns when applied to ultra-high reservoir conditions. This study developed two new empirical correlations capable of accurately predicting natural gas viscosity in ultra-high reservoir environments, based on extensive 460 laboratory measurements with temperature and pressure range of 212–392 °F and 5,000–20,000 psi, respectively. Model validation confirmed the superior predictive performance of the proposed empirical correlations PLM and POLM compared with existing correlations, yielding average absolute relative errors of 1.25% and 1.38% and high coefficients of determination (R^2) of 0.98 and 0.97, respectively. These results indicate the reliability and accuracy of the developed correlations for prediction under the investigated conditions. These correlations provide reliable tools for gas viscosity prediction in high and ultra- high pressure and temperature gas systems.

Keywords: Natural gas, Viscosity, Correlation, High pressure high temperature, Ultra high pressure high temperature.

1. Introduction

Natural gas viscosity is a fundamental thermophysical property that influences the design, analysis and operation of reservoir, production, processing and transportation systems. It represents the internal resistance of a gas to flow and is strongly affected by pressure, temperature and gas composition. Accurate estimation of viscosity is therefore important in reservoir simulation, well performance prediction, flow assurance, reserve estimation, pressure drop calculations and surface facility design. The challenge becomes more pronounced in deep gas reservoirs, where fluids are subjected to high pressure and high temperature conditions that differ considerably from those encountered in conventional reservoirs.

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International Journal of Engineering Research & Technology (IJERT)
ISSN: 2278-0181
Vol. 15 Issue 10 , October - 2026

The industry has no universally accepted classification of high-pressure, high-temperature environments. For the purpose of this study, the classification presented by Amanullah and Ramasamy (2018) was adopted. They classified HPHT conditions as pressures of 10,000–15,000 psi and temperatures of 300–350°F**,** Ultra-HPHT conditions as pressures of 15,000–20,000 psi and temperatures of 350–400°F and Extreme HPHT (XHPHT) conditions as pressures exceeding 20,000 psi and temperatures above 400°F (Amanullah & Ramasamy, 2018). This classification provides a suitable pressure temperature basis for evaluating natural gas viscosity across progressively more severe reservoir conditions. Under HPHT, Ultra HPHT and XHPHT conditions, natural gas exhibits increasingly complex thermophysical behaviour as pressure, temperature and fluid density change. At elevated pressures, stronger intermolecular interactions and increased gas density can result in significant departures from ideal-gas behaviour, making viscosity prediction more difficult. Consequently, correlations developed primarily from conventional reservoir data may become less reliable when extrapolated beyond their original calibration ranges. Accurate representation of gas viscosity under such conditions therefore requires predictive models that adequately account for the wider pressure, temperature and compositional ranges encountered in deep and complex gas reservoirs. Direct laboratory measurement remains the most reliable method for determining natural-gas viscosity. However, obtaining experimental viscosity measurements under HPHT, Ultra-HPHT and XHPHT conditions is technically demanding, expensive and time-consuming. Experimental data also become increasingly scarce toward the upper limits of pressure and temperature because specialised equipment and strict operating procedures are required (Jarrahian & Heidaryan, 2014; Rezaei et al., 2021). These practical limitations have encouraged the development of predictive correlations that can estimate viscosity from readily available fluid and reservoir properties.

Over the past several decades, numerous viscosity correlations have been proposed, ranging from theoretical and semi theoretical formulations to corresponding states methods and empirical correlations (Coming et al., 1944; Carr et al., 1954; Jossi et al., 1962; Lee et al., 1966; Londono et al., 2002; NIST, 2008; Bahadori et al., 2009; Ohirhian & Abu, 2009; Heidaryan et al., 2010; Anyiador et al., 2015). Among the most widely applied are the correlations of Carr et al. (1954) and Lee et al. (1966), largely because of their simplicity and ease of implementation in routine petroleum-engineering calculations. However, these classical correlations were developed using datasets that predominantly represent conventional pressure and temperature conditions. Their application outside their original calibration ranges, particularly under Ultra-HPHT and XHPHT conditions, may therefore introduce substantial prediction uncertainty (Ling et al., 2009; Chapoy et al., 2011; Sanjari et al., 2011; Rostami et al., 2018). More recent studies have attempted to overcome these limitations by developing correlations from larger and more diverse experimental datasets. Sanjari et al. (2011), for example, developed an empirical natural gas viscosity correlation using experimental data points and reported an average absolute relative deviation of approximately 2.17%. Kashefi et al. (2013) reported experimental

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International Journal of Engineering Research & Technology (IJERT)
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viscosity measurements for binary and multicomponent hydrocarbon fluids under HPHT conditions, covering pressures from approximately 34.5 to 138 MPa and temperatures up to 473.15 K. The experimental data were subsequently used to evaluate the performance of the Lohrenz–Bray–Clark, Pedersen and modified LBC viscosity models. These studies demonstrated that the predictive performance of viscosity correlations can be improved by expanding the range and quality of the experimental database used during model development.

Recent studies have focused on improving empirical natural gas viscosity correlations to extend their applicability across wider ranges of pressure, temperature and gas composition. Izadmehr et al. (2016) developed new correlations based on an extensive database comprising 6,484 experimental measurements. Their correlations incorporated key parameters, including pseudo-reduced pressure, pseudo-reduced temperature and gas specific gravity, resulting in improved viscosity prediction accuracy over the ranges considered in their study. More recently, Akinsete et al. (2026) evaluated and calibrated existing empirical correlations, including the Lee et al. (1966) and Carr et al. (1954) models, using gas data from the Niger Delta. Their findings demonstrated that regional calibration can improve the predictive performance of established correlations under specific reservoir conditions. The following functional relationship can represent natural gas viscosity. Equation 1 shows that gas viscosity depends on pressure, temperature and molecular weight. Gas viscosity can be estimated using generalized mathematical formulas.

$$\mu_g = f(P, T, M) \tag{1}$$

The Lee-Gonzalez Eakin correlation

Lee at al, (1966) developed a semi-empirical correlation for estimating natural gas viscosity. The viscosity was expressed as a function of reservoir temperature, gas gravity and molecular weight. The proposed equation is given as follows:

$$\mu_{\boldsymbol{g}} = 10^{-4} K\, exp(\mathrm{X}\rho_g^{\gamma}) \tag{2}$$

$$K = \frac{(9.379+0.01607M_W)T^{1.5}}{209.2+19.26M_wT} \tag{3}$$

Where,

$$X = 3.448 + \left[\frac{986.4}{T}\right] + 0.01009M_w \tag{4}$$

$$Y = 2.447 - 0.2224\mathrm{X} \tag{5}$$

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The proposed correlation predicts gas viscosity with a standard deviation of 2.7% and a maximum deviation of 8.99%. Its range of applicability is 10–8000 psia and temperatures above 100 °F.< T < 340 ^{O}F and 0.9 < CO_2 < 3.2 mol.%

Dempsey Correlation

Dempsey (1965) developed an empirical correlation for estimating natural gas viscosity at reservoir conditions. The input variables required for this correlation are reduced pressure (P_r) and reduced temperature (T_r).

$$\ln\left[T_{pr}\left(\frac{\mu_g}{\mu_{1atm}}\right)\right] = a_0 + a_1P_{pr} + a_2P_{pr}^2 + a_3P_{pr}^3 \quad (6)$$

$$+T_{pr}(a_4 + a_5P_{pr} + a_6P_{pr}^2 + a_7P_{pr}^3) \quad (7)$$

$$+T_{pr}^2(a_8 + a_9P_{pr} + a_{10}P_{pr}^2 + a_{11}P_{pr}^3) \quad (8)$$

$$+T_{pr}^3(a_{12} + a_{13}P_{pr} + a_{14}P_{pr}^2 + a_{15}P_{pr}^3 \quad (9)$$

This correlation was developed for pressures between 100 and 8000 psia and temperatures from 100 to 340 °F. It predicts gas viscosity with a standard deviation of 2.7% and a maximum deviation of 8.99%. However, its accuracy decreases for gases with higher specific gravities and for sour gases.

Dean and Stiel Correlation

Dean and Stiel (1965) proposed a mathematical expression for estimating the viscosity of natural gases at atmospheric pressure and reservoir temperature.

$$\mu_{gsc} = 34(10^{-5})\frac{(T_{pr})^{8/9}}{\varepsilon} \quad \text{for } T_{pr} \le 1.50 \quad (10)$$

$$\mu_{gsc} = 166.8(10^{-5})\frac{(0.1338T_{pr} - 0.0932)^{5/9}}{\xi} \quad \text{for } T_{pr} > 1.50 \quad (11)$$

$$\varepsilon = 5.4398\left(\frac{T_{pc}}{M^3P_{pc}^4}\right)^{\frac{1}{6}} \quad (13)$$

$$P = \frac{0.27P_{pr}}{Z\,T_{pr}} \quad (14)$$

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$$\mu_g = \mu_{gsc} + \frac{(10.8(10^{-5}))\left[e^{(1.439_{pr})} - e^{(-1.111_{pr}^{1.858})}\right]}{\xi} \quad (15)$$

Correlation is recommended for gases at pressures up to 8,000–10,000 psia and temperatures between 100 °F and 300 °F.

Ohirhian Correlation

Ohirhian and Abu (2009) developed a viscosity correlation for gases for both surface and reservoir conditions, derived from experimental measurements of gas samples.

$$\mu_g = \frac{0.0109388 - 0.0088234X - 0.0075720X^2}{1.0 - 1.3633077X + 0.0461989X^2} \quad (16)$$

Where,

$\mu_g =$ Viscosity of gas at elevated pressure, (cp)

$$X = \text{Rg}/(100\text{Bg}) \quad (17)$$

$$B_g = \frac{0.0283zT}{P} \quad (18)$$

$$R_g = \frac{0.001031PT}{P - 0.061T} \quad (19)$$

The proposed correlation is recommended for application within a pressure range of 144–4100 psia and a temperature range of 130–220 °F. The proposed correlation can predict gas viscosity with an average absolute error of 1.55%, a maximum absolute error of 4.878% and a standard deviation of 1.29%

Azubuike, Ikiensikimama and Orudo Correlation

Azubuike et al, (2019) developed a new mathematical equation for predicting natural gas viscosity under high-pressure and high-temperature (HPHT) conditions.

$$\mu_g = \left[\frac{a_1}{10^4}\right] + \left[\frac{a_2}{10^4}\right]\gamma_g - \left[\frac{a_3}{10^7}\right]T \quad (20)$$

Where,

$$a_1 = 140.9 + 17.78T_r + 9.5726P_r + 4.1025P_rT_r \quad (21)$$

$$a_2 = 70.549 + 8.9042T_r + 4.7946P_r + 2.058P_rT_r \quad (22)$$

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$$a_3 = 129.06 + 16.289T_r + 8.771P_r + 3.759P_rT_r \quad (23)$$

The proposed correlation can predict gas viscosity with a standard deviation of 2.7% and a maximum deviation of 8.99%. The correlation is valid for 6,000 < P < 14,000 psia and a temperature range of 270 < T < 370 °F.

Heidaryan Correlation

In this study, an extensive dataset of natural gas properties was utilized to develop a new viscosity correlation, drawing on earlier measurements reported by Heidaryan et al. (2010). A multiple rational regression equation was then formulated using gas density (ρ), molecular weight (Mwa) and the reciprocal of temperature (1/T) as the correlating parameters. This proposed model can estimate gas viscosity with an average absolute error of 2.083%.

$$\mu_g = \frac{B_1+(B_2+B_3)\frac{M}{T}+B_4\rho_g+B_5\rho_g^2+B_6\rho_g^3}{1+B_7\frac{M}{T}+B_8\left(\frac{M}{T}\right)^2+B_9\left(\frac{M}{T}\right)^3+B_{10}\rho_g} \quad (24)$$

Recommended for calculating natural gas viscosity at reservoir conditions, applicable up to 10,000 psia and 400 °F, particularly for natural gas mixtures where classical methods.

Viswanathan Correlation

Viswanathan (2007) modified the Lee et al. (1965) gas viscosity correlation to improve prediction accuracy under high-pressure and high-temperature conditions. The modified correlation was assessed against NIST pure methane viscosity values over a pressure range of 5,000–30,000 psia and temperatures of 100–400 °F. The model performance was evaluated using relative deviation statistics, achieving an average relative error (ARE) and average absolute relative error (AARE) of −0.707% and 0.707%, respectively. These results demonstrated a close agreement between the predicted and reference viscosity values and represented an improvement over the original Lee et al. correlation. However, the correlation was primarily validated using pure methane data.

$$\mu_g = 10^{-4}Ke^{(X\rho^y)} \quad (25)$$

$$\mathrm{K} = \frac{(5.0512-0.2888M_W)T^{1.832}}{-443.8+12.9+T} \quad (26)$$

$$X = -6.1166 + \left(\frac{3084.9437}{T}\right) + 0.3938M_w \quad (27)$$

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$$Y = 0.5893 - 0.1563X \quad (28)$$

However, the applicability of conventional correlations under extreme reservoir conditions remains a concern. Mamukuyomi et al. (2026) investigated natural gas viscosity under ultra-high-pressure and high-temperature (UHPHT) conditions using gas samples from the Niger Delta and Edinburgh regions. Experimental viscosity measurements were obtained using a capillary viscometer at pressures ranging from 5,000 to 20,000 psi and temperatures between 212 and 392 °F. The study further evaluated several widely used gas viscosity correlations and found that the Dempsey (1965) correlation exhibited the best performance among those considered under UHPHT conditions, although its predictive accuracy remained limited, with an average absolute relative error (AARE) and correlation coefficient (R^2) of 8.575% and 0.873. Cross-plot analyses also revealed considerable deviations between measured and predicted viscosities under HPHT and UHPHT conditions. The authors therefore concluded that existing gas viscosity correlations may not provide sufficiently reliable predictions under UHPHT reservoir conditions.

Empirical correlations, derived from experimental data, offer a practical and efficient alternative due to their simplicity and ease of implementation. This gap highlights the need for improved models capable of accurately predicting gas viscosity over a wide range of pressures and temperatures. Therefore, the objective of this study is to develop robust empirical correlations for accurately predicting natural gas viscosity under ultra-high pressure and high temperature (UHPHT) reservoir conditions.

2. Materials and Methods

The materials used in this study were carefully selected to facilitate the development of robust empirical correlations for predicting natural gas viscosity under ultra-high reservoir conditions. The materials include:

i. Experimental data
ii. Computational software (MATLAB 2024 version)
iii. Data processing tools (Microsoft Excel)

Two sets of gas viscosity data were used for the development of the models: (i) PVT analyzes of 120 reservoir gas samples obtained under low to moderate conditions and (ii) 340 laboratory measurements obtained from high to ultra-high pressures and temperatures. Tables A1 and A2 in Appendix A present the experimental viscosity data for natural gas samples A and B for all considered components. The dataset were combined, normalized to pseudoreduced pressure and temperature and used to develop new viscosity correlations. Table 1 shows the descriptive statistics of the database used in this study. The experimental data serve as the primary input for developing and evaluating the proposed empirical correlations.

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2.1 Model Formulation Rationale

The formulation of empirical correlations for natural gas viscosity under HPHT and UHPHT reservoir conditions requires a mathematical structure capable of representing highly nonlinear thermophysical behaviour. Gas viscosity in such environments is strongly influenced by molecular interactions, density effects and deviations from ideal gas laws, particularly near or beyond the pseudo critical region. Accordingly, the second order exponential and polynomial laws were adopted to capture the combined nonlinear pressure temperature dependence of viscosity with high predictive fidelity and physical interpretability.

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
Pseudoreduced 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

Model Development Procedure

Step 1: Problem formulation and key variable identification

The regression analysis was initiated by defining the problem and identifying the variables influencing natural gas viscosity. Reservoir pressure (P), temperature (T) and molecular weight (M) were selected as independent variables while viscosity served as the dependent variable. As highlighted by Al-Mutairi and Ali (2011), proper problem formulation and variable selection are critical to developing empirical correlations that are

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both accurate and applicable. The general functional relationship describing gas viscosity as a function of the selected independent variables can be expressed as:

$$\mu_g = f\ (P_r, T_r, M) + \varepsilon \qquad (25)$$

This expression indicates that gas viscosity is a function of pseudoreduced pressure, pseudoreduced temperature and molecular weight. It therefore provides the theoretical basis for developing empirical correlations through regression analysis, with the objective of identifying a functional relationship that most accurately represents the observed data.

Step 2: Data Preprocessing

Statistical methods were used to pick out outliers and missing values, with imputation or removal as needed. Independent variables (pressure, temperature and molecular weight) were standardized with z-scores to maintain consistent scaling and enhance model convergence.

Step 3: Model selection

Model selection was guided by software that evaluated various regression approaches to identify the equation best representing the relationship between input parameters and gas viscosity. Both multilinear and non-linear regression models were developed using MATLAB functions. Empirical formulations incorporating power law and polynomial terms were tested as part of this evaluation.

Step 4: Filtration

This stage employed several statistical metrics including average absolute relative error (AARE) root mean square error (RMSE) and the correlation coefficient (R^2) to evaluate model performance using Equations (26), (27) and (28)

$$AAPE(\%) = \frac{100}{N}\sum_{i=0}^{n}\left|\frac{|\ \mu_{exp} - \mu_{pred}}{\mu_{exp}}\right| \qquad (26)$$

$$\text{RMSE} = \sqrt{\frac{1}{N}\sum_{i=0}^{n}\ (\mu_{exp} - \mu_{pred})^2} \qquad (27)$$

$$R^2 = 1 - \frac{\sum_{i=0}^{n}\ (\mu_{exp} - \mu_{pred})^2}{\sum_{i=0}^{n}\ (\mu_{mean} - \mu_{pred})^2} \qquad (28)$$

The correlation that demonstrated the best overall performance across these criteria was selected as the most robust and generalizable for predicting gas viscosity under ultra-high reservoir conditions. In addition, both mathematical and graphical validation were performed to ensure the suitability of the final correlation. The flowchart for the correlation development process is shown in Figure 1.

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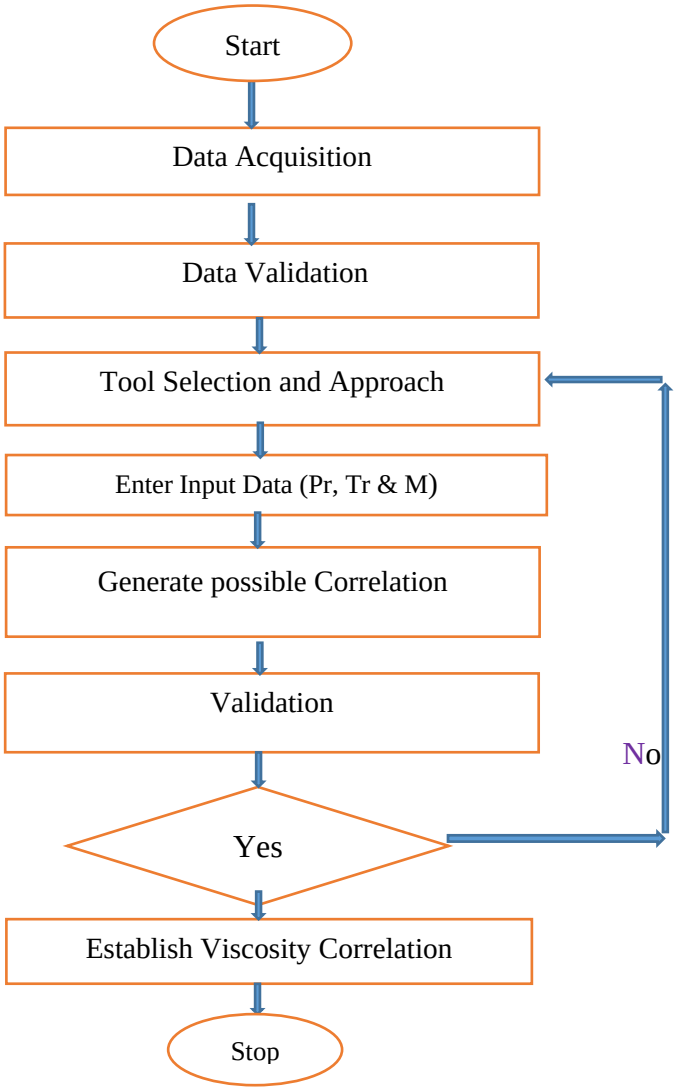


Figure 1: Flow chart for the Development of the Viscosity Correlations

3. RESULTS AND DISCUSSION

3.1 Developed Natural Gas Viscosity Correlations

In this study, novel empirical correlations were established using 460 experimental dataset obtained under LPLT, HPHT and UHPHT conditions. The derived correlations are presented in Equations 26 and 27 and their tuned coefficients are presented in Table 2 and Table 3, explicitly relate gas viscosity to molecular weight, pseudoreduced pressure and pseudoreduced temperature, thus offering reliable predictive tools for reservoir engineering applications.

3.1.1 Power Law Model (PLM)

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The first model developed in this study is Model I, known as the Power Law Model. It is motivated by the physical observation that gas viscosity at elevated pressures exhibits an approximately power law dependence on pseudo reduced temperature (Tpr) modified by a correction for pseudo reduced pressure (Ppr) and molecular weight. The general functional form used in this study is expressed in Equation (29)

$$\mu_g = B_1 * T_r^{B2} * P_r^{B3} * M^{B4} \quad (29)$$

where μ_g is the predicted gas viscosity in centipoise (cp), P_r is the pseudo reduced pressure, T_r is the pseudo reduced temperature and B_1, B_2, B_3 and B_4 are empirical regression coefficients. The coefficients of the developed power law model were estimated in MATLAB R2023a using least squares fitting techniques. The estimated coefficients yielded B_1 =10.4760, B_2 = −0.68380, B_3 = 0.62670 and B_4 = -2.36280. The negative value of B_2 and B_4 correctly capture the viscosity reducing effect of increasing pseudo reduced temperature at constant pressure, while the positive B_1 and fractional B_3 describe the accelerating viscosity increase with pressure as the gas transitions from the high pressure to ultra pressure regimes.

Table 2. Tuned Coefficients of Eq. (29)

Coefficient	Tuned Coefficient
B_1	10.4760
B_2	-0.6838
B_3	0.62670
B_4	-2.3628

3.1.2 Polynomial Model Prediction (POLM)

The second model developed in this study is the Polynomial Law Model. It is a second-degree polynomial. It is formulated to represent the relationship between the variables using polynomial terms is illustrated in Equation (30)

$$\mu_g = C_0 + C_1T_r + C_2P_r + C_3M + C_4T_r^2 + C_5P_r^2 + C_6T_rP_r + C_7T_rM + C_8P_rM \quad (30)$$

where μ_g is the predicted gas viscosity in centipoise (cp), P_r is the pseudoreduced pressure, T_r is the pseudoreduced temperature and C_0, C_1, C_2, C_3, C_4, C_5, C_6, C_7 and C_8 are empirical regression coefficients. The coefficients of the developed polynomial law models were estimated in MATLAB

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R2023a and fitted using polynomial regression. The negative value of C_5, C_6 and C_7 correctly captures the viscosity reducing effect of increasing pseudo-reduced temperature at constant pressure, while the positive C_0, C_1, C_2, C_3, C_4 and C_8 describe the accelerating viscosity increase with pressure as the gas transitions from the high pressure to ultra non ideal regimes.

3.2

Table 3. Tuned Coefficients of Eq. (30)

Coefficient	Tuned Coefficient
C_0	0.00E-00
C_1	0.00E-00
C_2	0.00E-00
C_3	2.06E-03
C_4	2.59E-03
C_5	-2.11E-05
C_6	-1.45E-04
C_7	-1.09E-03
C_8	1.31E-04

.

Performance Comparison of Developed Correlations with Conventional Models.

The developed empirical equations were tested against experimental data and seven published correlations to assess their ability to predict gas viscosity over a wide range of reservoir pressure and temperature conditions. The correlations considered for comparison include: Dean and Stiel (1958); Dempsey (1965); Lee et al. (1966); Viswanathan (2007); Ohirhian and Abu (2009); Heidaryan et al. (2010); Azubuike et al. (2016). The accuracy of these seven empirical correlations was evaluated for estimating gas viscosity for gas samples 1 and 2. Figure 2 compares the selected gas viscosity models with the measured data at 212° F for the entire pressure range studied; similarly, Figures 3 and 4 show model comparisons at 302 ° F and 392 ° F. As pressure increases into the intermediate range (8, 000–12, 500 psi), differences among the correlations become more noticeable. Significant deviation was observed in traditional correlations calibrated at lower pressures and temperatures; for instance, Dean and Stiel (1965) predict a viscosity nearly twice as high as the experimental value. Similarly, Lee et al. (1986) and Viswanathan (2007) strongly overpredict. Conversely, Heidaryan et al. (2010) and Azubuike et al. (2016) continue to underestimate viscosities at high pressures, falling about 15% below the experimental value. Among the published correlations, Dempsey (1965) and Ohirhian and Abu (2009) provide the closest match, though they underpredict by 5-10% in this region. The predictions from Studies 1 and 2 align closely with experimental data, keeping deviations below ±2 %. Overall, the results confirm that traditional correlations calibrated at lower to moderate pressures are not suitable for HPHT and UHPHT conditions. Where accurate viscosity prediction is a key factor for ultra-high reservoir conditions modeling and production forecasting, the newly developed correlations offer more reliable estimates, especially in the 10, 000–20, 000 psi range

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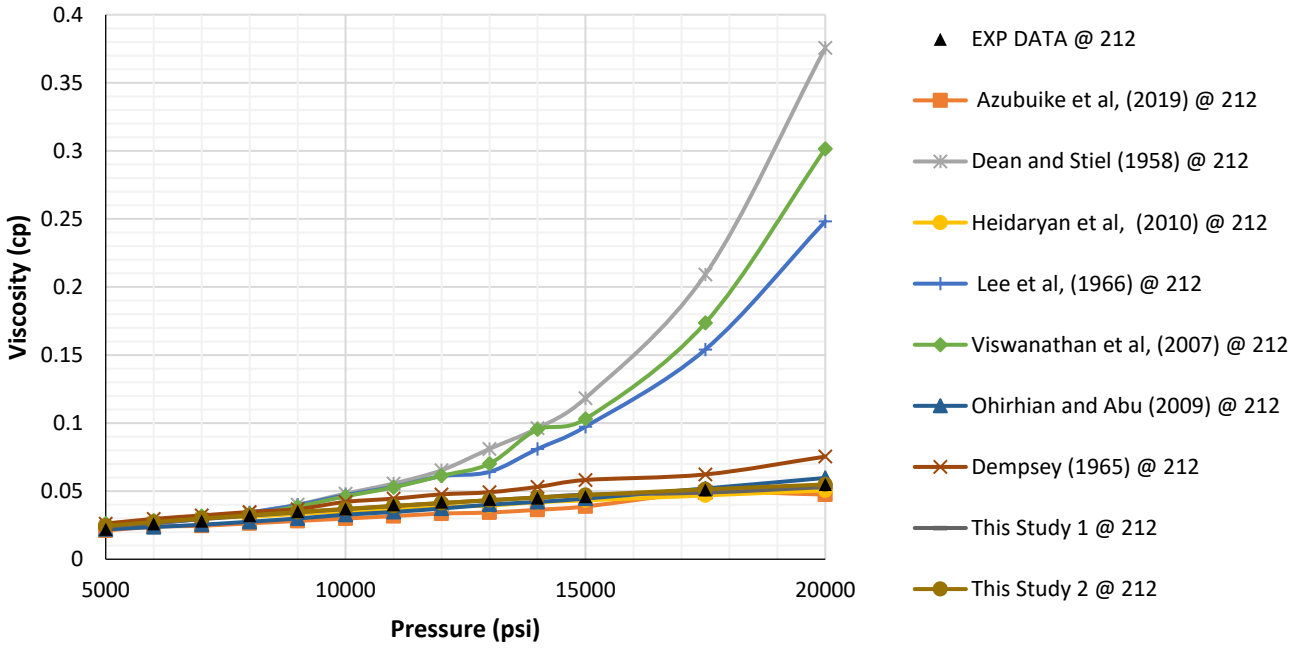


Figure 2: Gas Viscosity against Pressure at 212°F

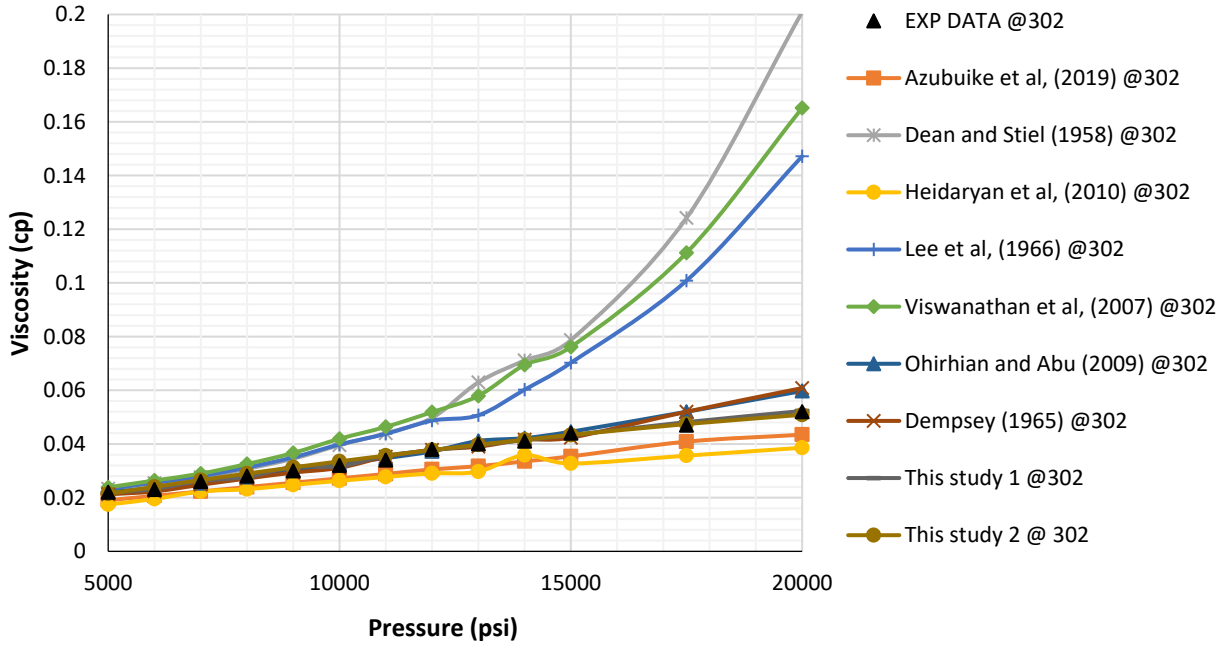


Figure 3: Gas Viscosity against Pressure at 302^{O}F

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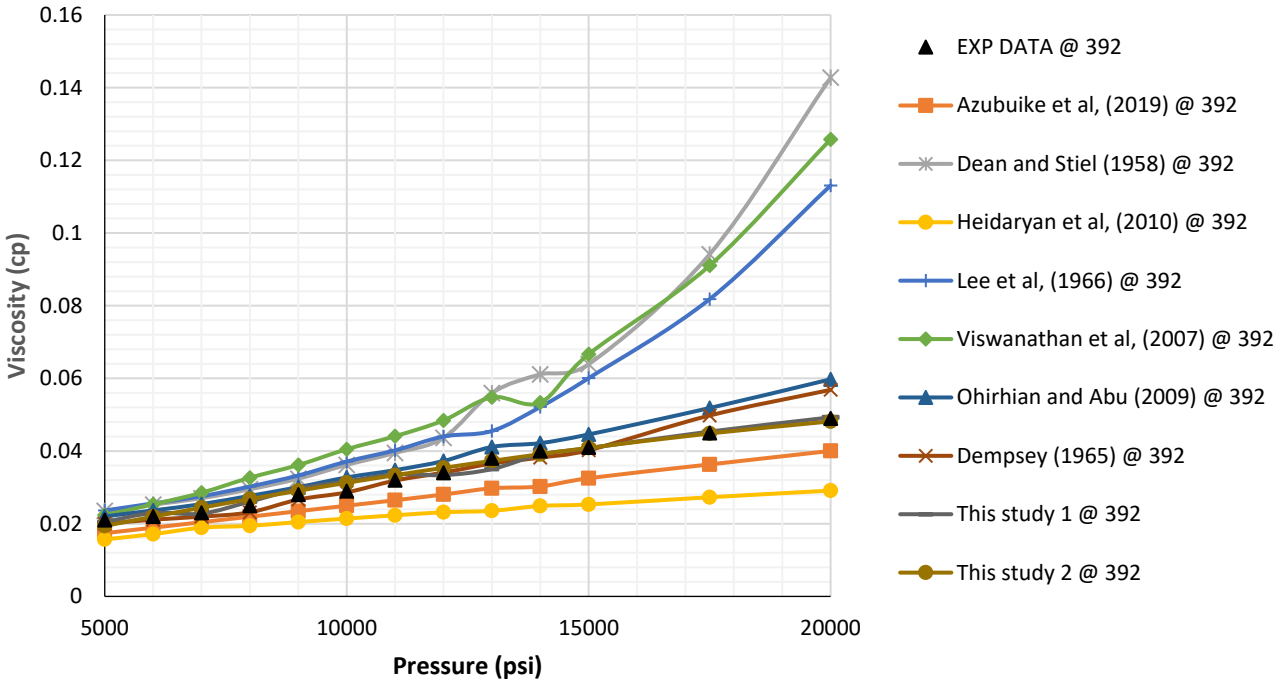


Figure 4: Gas Viscosity against Pressure at 392^{O}F

3.3 Comparative Statistical Evaluation of Existing and Proposed Natural Gas Viscosity Correlations

Tables 4, 5 and 6 present the comparative statistical performance of seven existing natural gas viscosity correlations and the two correlations developed in the present study under low pressure and low temperature (LPLT), high-pressure and high-temperature (HPHT) and ultra-high pressure and high temperature (UHPHT) regimes. The existing correlations evaluated were those proposed by Azubuike et al. (2019), Dean and Stiel (1958), Heidaryan et al. (2010), Lee et al. (1966), Viswanathan et al. (2007), Ohirian and Abu (2009) and Dempsey (1965). The predictive performances of the correlations were assessed using the average absolute relative error (AARE), root mean squared error (RMSE) and coefficient of determination (R^2). These statistical indices provide complementary measures of model accuracy and goodness of fit.

3.3.1 Performance of the Correlations under the LPLT Regime

Table 4 shows the statistical models predictions under the LPLT regime. Study 2 recorded the lowest AARE of 2.84873%, followed by Study 1 with an AARE of 3.81026%. Among the existing correlations, Heidaryan et al. (2010) produced the lowest AARE of 4.13805%, followed by Dempsey (1965), Ohirian and Abu (2009), Viswanathan et al. (2007), Azubuike et al. (2019), Lee et al. (1966) and Dean and Stiel (1958), with values of 4.33020%, 5.11449%, 6.96369%, 9.20010%, 10.0149% and 10.1118%, respectively. Relative to Heidaryan et al. (2010), which was the best performing existing correlation based on AARE, Study 1 reduced the average

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absolute relative error by approximately 7.92%. Study 2 achieved a substantially greater reduction of approximately 31.16%. This result indicates that both proposed correlations improved the average percentage agreement between predicted and experimental viscosity values under LPLT conditions. The particularly low AARE obtained from Study 2 shows that it reproduced the relative magnitude of the experimental viscosity values more accurately than the other correlations. An AARE below 3% indicates that, on average, the predictions from Study 2 deviated from the experimental values by less than approximately three percent. The RMSE values follow the same general order. Dempsey (1965) recorded the lowest RMSE of 0.00066, followed by Ohirian and Abu (2009) with 0.00073. Study 2 produced an RMSE of 0.00092, while Study 1 recorded 0.00118. Heidaryan et al. (2010), Viswanathan et al. (2007), Azubuike et al. (2019), Lee et al. (1966) and Dean and Stiel (1958) recorded RMSE values of 0.00134, 0.00361, 0.00424, 0.00436 and 0.00469 respectively. Dempsey (1965) and Ohirian and Abu (2009) produced smaller absolute residuals under LPLT conditions. The (R^2) results also favour some of the existing correlations under LPLT conditions. Dempsey (1965) recorded the highest (R^2) of 0.97798, indicating that the model explained approximately 97.80% of the variation in the experimental viscosity values. Ohirian and Abu (2009) followed with an (R^2) of 0.96165. Study 2 recorded an (R^2) of 0.94503, while Study 1 produced 0.90696. Heidaryan et al. (2010), Viswanathan et al. (2007), Azubuike et al. (2019), Lee et al. (1966) and Dean and Stiel (1958) recorded values of 0.85011, 0.78022, 0.72891, 0.70768 and 0.69023 respectively. The LPLT results therefore show that model selection depends on the performance criterion considered. Study 2 was the most accurate model based on AARE and was the stronger of the two proposed correlations based on RMSE and (R^2). However, Dempsey remained the strongest correlation based on AARE, RMSE and (R^2). Overall, Dempsey and Ohirian and Abu remained highly competitive under this regime.

Table 4. Statistical Models Predictions at LPLT

Pressure (Psi)	Experiment	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)	This Study 1	This Study 2
5000	0.022	0.02106	0.02329	0.02414	0.0234	0.02228	0.02201	0.02341	0.02243	0.02366
5500	0.024	0.02194	0.02460	0.02544	0.02464	0.02352	0.02564	0.02468	0.02546	0.02501
6000	0.026	0.02149	0.02636	0.02668	0.02652	0.02540	0.02665	0.02637	0.02689	0.02632
6500	0.027	0.02382	0.02789	0.02788	0.02812	0.02700	0.02751	0.02728	0.02828	0.02762
7000	0.028	0.02459	0.02952	0.02903	0.02978	0.02866	0.02939	0.02913	0.02963	0.02889
7500	0.030	0.02547	0.03190	0.03015	0.03214	0.03102	0.03059	0.03014	0.03093	0.03014
8000	0.032	0.02635	0.03421	0.03122	0.03439	0.03327	0.03166	0.03188	0.03097	0.03137
8500	0.033	0.02724	0.03722	0.03225	0.03722	0.03610	0.03394	0.03392	0.03221	0.03257
9000	0.035	0.02812	0.04009	0.03324	0.03985	0.03873	0.03404	0.03486	0.03345	0.03376
9500	0.036	0.02900	0.04388	0.03421	0.04324	0.04212	0.03537	0.03597	0.03467	0.03491
10000	0.037	0.02822	0.04821	0.03514	0.04709	0.04597	0.03673	0.03698	0.03587	0.03605
AARE		**9.20010**	**10.1118**	**4.13805**	**10.0149**	**6.96369**	**5.11449**	**4.33020**	**3.81026**	**2.84873**

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RMSE	**0.00065**	**0.00472**	**0.00134**	**0.00062**	**0.00069**	**0.00068**	**0.00066**	**0.00118**	**0.00092**
R^2	**0.72891**	**0.69023**	**0.85011**	**0.70768**	**0.78022**	**0.96165**	**0.97798**	**0.90696**	**0.94503**

3.3.2 Performance of the Correlations under the HPHT Regime

Table 5 shows the statistical models predictions under the HPHT regime. The superiority of the proposed correlations became more evident under HPHT conditions. Study 2 recorded the lowest AARE of 1.93042%, followed closely by Study 1 with 1.99917%. Among the existing models, Dempsey (1965) produced the lowest AARE of 3.33134%, followed by Ohirian and Abu (2009), with 3.55387%. The remaining existing correlations produced substantially higher AARE values. Azubuike et al. (2019), Heidaryan et al. (2010), Viswanathan et al. (2007), Lee et al. (1966) and Dean and Stiel (1958) recorded values of 17.8890%, 22.2285%, 32.6149%, 37.3602%, and 43.7360% respectively. This small difference indicates that their percentage performances were broadly comparable. Nevertheless, Study 2 was marginally more accurate in terms of average absolute relative deviation. The AARE results also reveal the limited applicability of several conventional correlations under HPHT conditions. Dean and Stiel (1958), Lee et al. (1966), and Viswanathan et al. (2007) produced errors exceeding 30%. Heidaryan et al. (2010), which performed relatively well under LPLT conditions, produced an HPHT AARE of 22.2285%. The RMSE values were 0.00084 for Study 1 and 0.00090 for Study 2. Dempsey and Ohirian and Abu produced values of 0.00134 and 0.00141, respectively. The other existing correlations recorded considerably higher RMSE values. Azubuike et al. (2019), Heidaryan et al. (2010), Viswanathan et al. (2007), Lee et al. (1966) and Dean and Stiel (1958) produced values of 0.00663, 0.00872, 0.01378, 0.01601 and 0.01947 respectively. The (R^2) results similarly favoured the proposed models. Study 1 recorded the highest (R^2) of 0.92523, indicating that it explained approximately 92.52% of the variation in the HPHT experimental viscosity data. Study 2 recorded the second-highest value of 0.91837. Dempsey and Ohirian and Abu produced (R^2) values of 0.89074 and 0.87795, respectively. The remaining models recorded values below 0.86. When all three statistical measures are considered, Study 1 provided the strongest overall HPHT performance. The differences between the two proposed models were small, but the consistency of Study 1 across two of the three metrics supports its selection as the preferred model for HPHT applications.

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Table 5. 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)	This Study 1	This Study 2
10000	0.032	0.02723	0.03954	0.02628	0.03983	0.03870	0.03273	0.03291	0.03357	0.03260
10500	0.034	0.02805	0.04144	0.02700	0.04149	0.04037	0.03362	0.03363	0.03462	0.03368
11000	0.034	0.02887	0.04400	0.02770	0.04377	0.04265	0.03475	0.03524	0.03564	0.03475
11500	0.037	0.02968	0.04674	0.02838	0.04617	0.04505	0.03524	0.03768	0.03665	0.03578
12000	0.038	0.03057	0.04970	0.02904	0.04870	0.04758	0.03586	0.03919	0.03764	0.03680
12500	0.039	0.03132	0.05294	0.02970	0.05068	0.04956	0.03811	0.03942	0.03861	0.03779
13000	0.039	0.03209	0.05723	0.03032	0.05378	0.05102	0.04111	0.04100	0.03957	0.03876
13500	0.040	0.03293	0.06208	0.03094	0.05706	0.05494	0.04178	0.04189	0.04052	0.03971
14000	0.041	0.03372	0.06622	0.03155	0.06222	0.05781	0.04216	0.04201	0.04146	0.04064
14500	0.043	0.03453	0.07205	0.03214	0.06748	0.06452	0.04485	0.04424	0.04238	0.04154
15000	0.044	0.03541	0.07867	0.03274	0.07022	0.06910	0.04656	0.04627	0.04329	0.04242
AARE		**17.8890**	**43.7360**	**22.2285**	**37.3602**	**32.6149**	**3.55387**	**3.33134**	**1.99917**	**1.93042**
RMSE		**0.00697**	**0.01947**	**0.00872**	**0.01601**	**0.01423**	**0.01417**	**0.00136**	**0.00085**	**0.00090**
R^2		**0.85723**	**0.73618**	**0.81720**	**0.75154**	**0.76897**	**0.87795**	**0.89074**	**0.92523**	**0.91837**

3.3.3 Performance of the Correlations under the UHPHT Regime

Table 6 shows the statistical models predictions under the UHPHT regime. The proposed correlations produced their greatest relative improvement under UHPHT conditions. Study 1 recorded the lowest AARE of 1.25249%, followed by Study 2 with 1.38144%. The best performing existing correlation was Dempsey (1965), which recorded an AARE of 8.57541%. Ohirian and Abu (2009), Azubuike et al. (2019), Viswanathan et al. (2007), Lee et al. (1966), Heidaryan et al. (2010) and Dean and Stiel (1958) recorded AARE values of 12.6794%, 18.9259%, 32.5341%, 37.4692%, 39.0198% and 45.5279% respectively. The AARE of Study 1 indicates that its predictions deviated from the experimental values by only about 1.25% on average. Similarly, the average absolute deviation associated with Study 2 was approximately 1.38%. The difference between the AARE values of the proposed models was only 0.12895 percentage points. Although both models performed very well, Study 1 provided the better percentage accuracy under the UHPHT regime. Dempsey recorded an RMSE of 0.00469 while Ohirian and Abu recorded 0.00693. The small RMSE values show that the predicted viscosity values from the proposed models were closely distributed around the experimental values. The (R^2) results also identify Study 1 as the strongest model. It recorded an (R^2) of 0.93178, indicating that approximately

93.18% of the variation in the UHPHT experimental data was explained by the correlation. Study 2 recorded an (R^2) of 0.91158. Dempsey and Ohirian and Abu produced values of 0.87253 and 0.81521 respectively. Study 1 ranked first across all five UHPHT statistical measures. It produced the lowest AARE and RMSE and

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the highest (R^2). This consistency provides strong evidence that Study 1 was the preferred proposed correlation under ultra high pressure and high temperature UHPHT conditions.

Table 6. 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)	Viswanathan et al, (2007)	Ohirhian and Abu (2009)	Dempsey (1965)	This Study 1	This Study 2
15000	0.041	0.03259	0.06389	0.02531	0.06007	0.05894	0.04458	0.04023	0.04061	0.04089
15500	0.042	0.03398	0.07324	0.02601	0.07154	0.06453	0.04591	0.04268	0.04145	0.04156
16000	0.042	0.03489	0.07811	0.02655	0.07342	0.06978	0.04738	0.04438	0.04228	0.04252
16500	0.043	0.03505	0.08409	0.02698	0.07962	0.07245	0.04818	0.04579	0.04311	0.04331
17000	0.045	0.03589	0.08768	0.02701	0.08908	0.07785	0.04978	0.04768	0.04392	0.04408
17500	0.045	0.03638	0.09415	0.02728	0.08179	0.08067	0.05185	0.04902	0.04473	0.04482
18000	0.046	0.03712	0.09529	0.02801	0.08876	0.08369	0.05281	0.05041	0.04552	0.04555
18500	0.047	0.03867	0.09678	0.02857	0.09111	0.08732	0.05402	0.05234	0.04631	0.04625
19000	0.048	0.03923	0.09836	0.02895	0.09567	0.09102	0.05665	0.05497	0.04709	0.04692
19500	0.048	0.03909	0.12392	0.02900	0.10123	0.09765	0.05808	0.05504	0.04787	0.04758
20000	0.049	0.04011	0.14274	0.02912	0.11307	0.11195	0.05975	0.05685	0.04863	0.04821
AARE		**18.9259**	**45.5279**	**39.0198**	**37.4692**	**32.5341**	**12.6794**	**8.57541**	**1.25249**	**1.38144**
RMSE		**0.00857**	**0.05277**	**0.01772**	**0.03822**	**0.02914**	**0.00693**	**0.00466**	**0.00068**	**0.00070**
R^2		**0.78128**	**0.63567**	**0.71396**	**0.67321**	**0.68921**	**0.81521**	**0.87253**	**0.93178**	**0.91158**

3.3.4 Overall Performance across the Three Regimes

The comparative evaluation across the three pressure temperature regimes shows that model performance varied with operating conditions. Under the LPLT regime, Dempsey and Ohirian models demonstrated the strongest and most consistent performance among the evaluated correlations, producing comparatively low prediction errors and strong agreement with the experimental viscosity data. Their results indicate that both models are reliable for natural gas viscosity estimation under low pressure and low temperature conditions. Under the more demanding HPHT and UHPHT regimes, however, study 1 exhibited the strongest and most consistent overall performance. It maintained low prediction errors and high coefficients of determination despite the increasing severity of the pressure and temperature conditions. Its stability across both regimes demonstrates greater robustness and improved applicability under ultra-high operating environments. Overall, the findings indicate that Dempsey and Ohirian are the most dependable existing correlations for the LPLT regime, while study 1 provides the most reliable and consistent predictions for the HPHT and UHPHT regimes. This confirms that the suitability of a viscosity correlation depends strongly on the pressure temperature range for which it is applied.

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3.3.5 Comparative Statistical Evaluation of Existing and Proposed Natural Gas Viscosity Correlations

Figure 5 shows the comparative performance of seven published natural gas viscosity correlations with the two correlations developed in this study across the LPLT, HPHT and UHPHT regimes. The performance indicators were evaluated using AARE, RMSE and R^2, where lower error values indicate better predictive accuracy, while an R^2 value closer to unity indicates stronger agreement between the predicted and experimental viscosity data. Because the metrics differ considerably in magnitude, the logarithmic scale allows the small RMSE values to be displayed alongside the percentage errors and R^2 values in a single plot. Under the LPLT regime, the published correlations generally produced lower errors than they did under the more severe pressure–temperature conditions. Among the published models, Dempsey (1965) recorded the lowest RMSE values of 0.00066, respectively, together with the highest R^2 value of 0.97798. Ohirian and Abu (2009) also performed strongly, with an R^2 of 0.96165. However, the correlations developed in this study produced the lowest percentage-error values. These results indicate that the proposed correlations provide highly competitive predictions at low-pressure and low-temperature conditions, although Dempsey's correlation retained a slight advantage in terms of RMSE and R^2. The superiority of the newly developed correlations became more pronounced under the HPHT regime. Study 2 produced the lowest AARE of 1.93042%, while Study 1 recorded the lowest RMSE values of 0.00085. Study 1 also achieved the highest R^2 value of 0.92523. In contrast, several published correlations showed substantial increases in error under HPHT conditions. Dean and Stiel (1958), for example, produced AARE values of 43.736%, an RMSE of 0.01947 and an R^2 of 0.73618. Among the published models, Dempsey (1965) and Ohirian and Abu (2009) remained the most reliable, but their error values were still higher than those of the correlations developed in this study. A similar trend was observed under the UHPHT regime, where the performance differences became even more distinct. Study 1 provided the best overall results, with an AARE of 1.25249%, RMSE of 0.00068 and R^2 of 0.93178. Study 2 also maintained strong predictive performance, recording an AARE of 1.38144%, RMSE of 0.00070 and R^2 of 0.91158. By comparison, the published correlations displayed considerably higher errors. Dean and Stiel (1958) recorded the highest AARE values of 45.5279%, while Lee et al. (1966) and Viswanathan et al. (2007) also produced relatively high errors. Dempsey (1965) remained the best-performing published correlation under UHPHT conditions, but its AARE of 8.57541% and RMSE of 0.00469 were substantially higher than those obtained from the correlations developed in this study.

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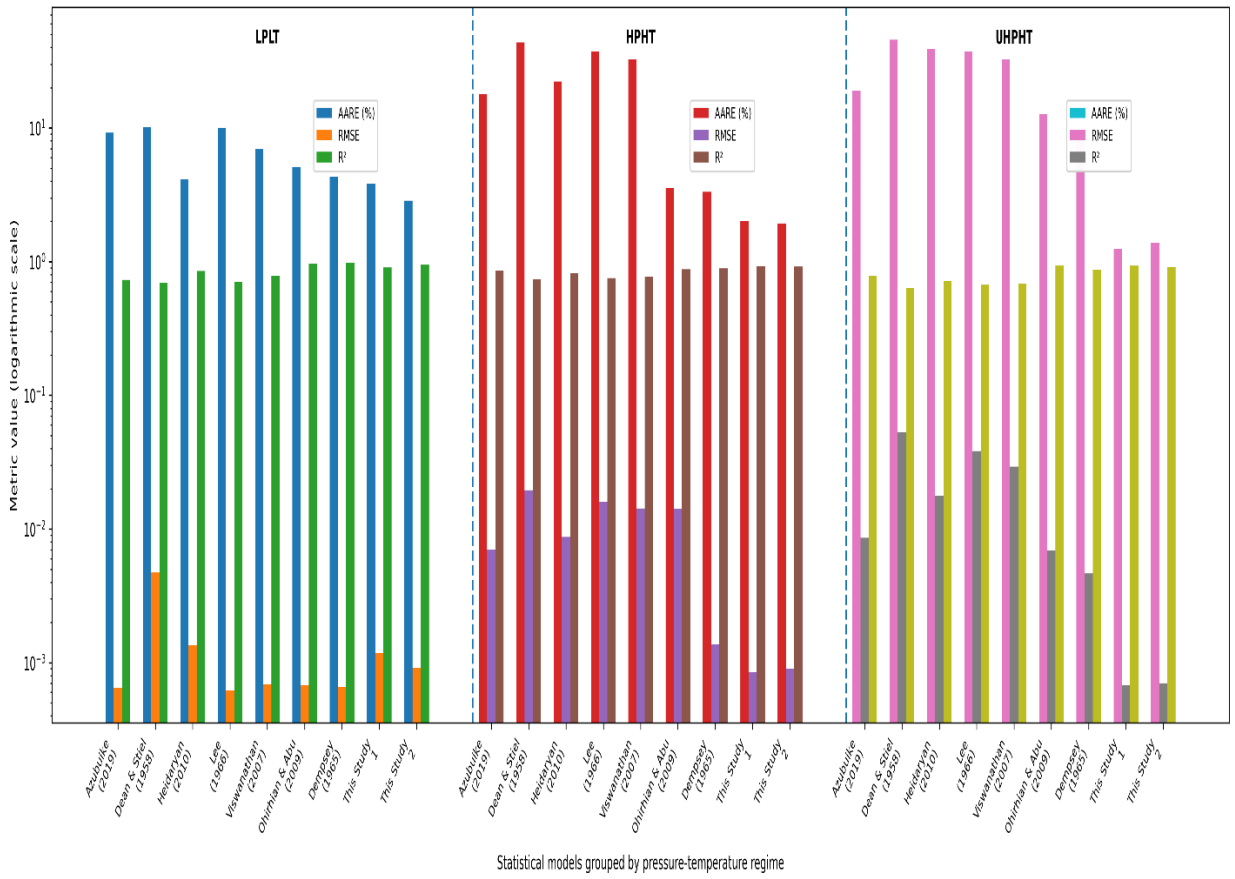


Figure 5: Gas Viscosity Correlation Performance at LPLT, HPHT and UHPHT Conditions

3.4 Cross Plot Analysis

Figures 6 to 14 present an assessment of seven published gas viscosity correlation models. The cross plot for Ohirhian and Abu (2009) (Figure 9) shows a reasonably good distribution of points along the 45° line, particularly in the mid viscosity region. Azubuike et al. (2019) and Heidaryan et al. (2010) correlations, presented in Figures 6 and 8 respectively, show that most of the predicted data points fall below the 45° line, indicating that both correlations generally underpredicted the experimental natural gas viscosity values. However, moderate scattering is evident at higher viscosities, suggesting that while the correlation captures the overall trend, deviations become more significant under elevated conditions. The performance of Lee et al. (1966) and Viswanathan (2007), Figures 11 and 12, is comparatively weaker. The cross plot exhibits wider scattering across the entire viscosity range, with noticeable divergence from the 45° line. This behavior reflects the limited predictive accuracy of the correlation under HPHT and UHPHT conditions, where its assumptions are less valid. The results of Dempsey (1965) Figure 10, show improved clustering of data points, with much of the distribution lying away from the 45° line. Although some dispersion remains at higher viscosities, the correlation performs consistently better than others, demonstrating moderate reliability for viscosity estimation. The proposed correlations (Figure 13 and Figure 14) outperform all others, as evidenced by the closest and most compact

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clustering of points along the 45° line. The agreement persists across both low and high viscosity regions, confirming its ability to capture the viscosity behavior of natural gases with higher precision. The results obtained confirm the consistency and reliability of the correlations that were developed, which surpass the performance of previously published models. The superior predictive performance highlights the enhanced adaptability of the present correlations to HPHT and UHPHT reservoir conditions

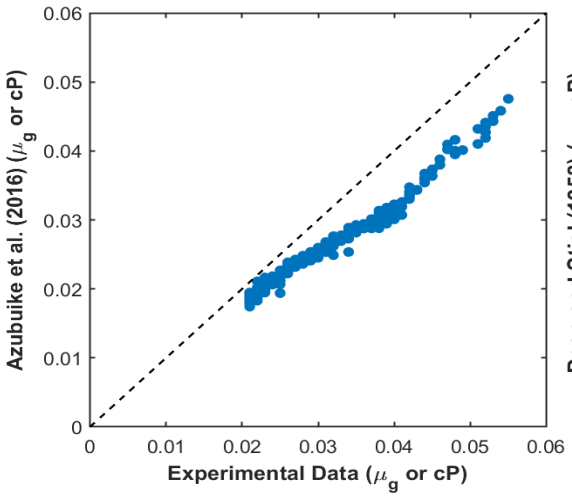


Figure 6: Predicted against measured gas viscosity

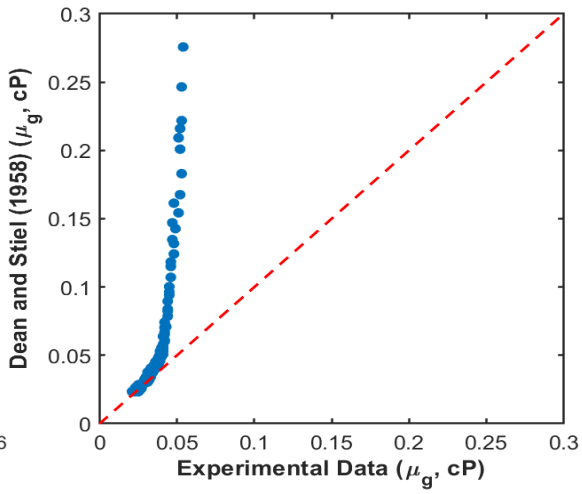


Figure 7: Predicted against measured gas viscosity

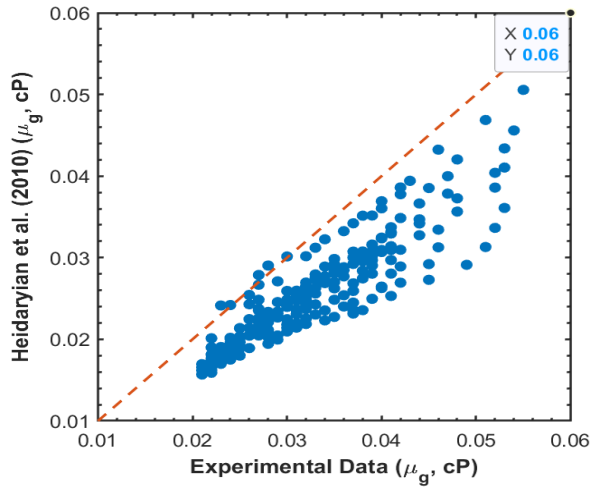


Figure 8: Predicted against measured gas viscosity

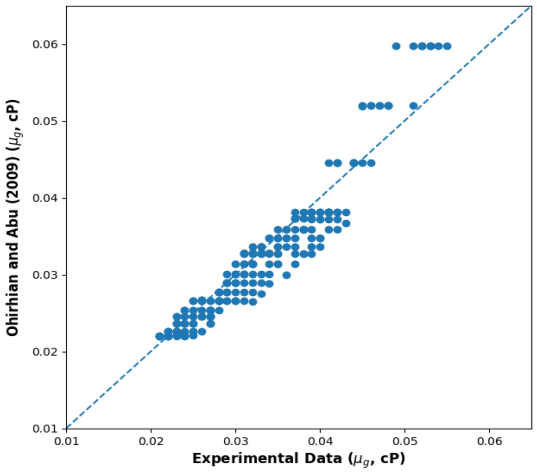


Figure 9: Predicted against measured gas viscosity

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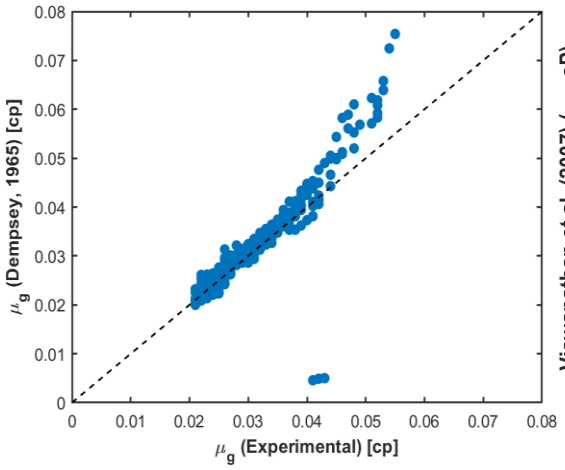


Figure 10: Predicted against measured gas viscosity

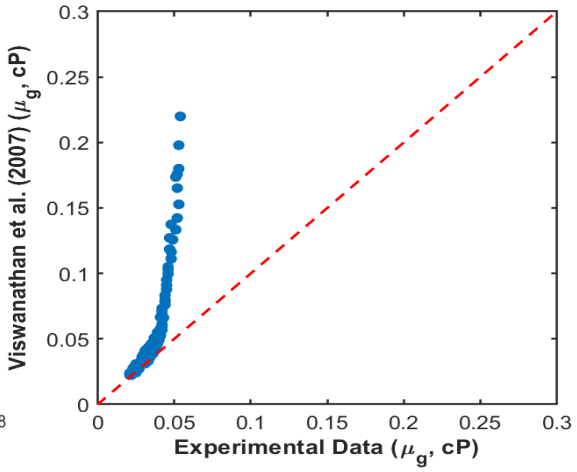


Figure 11: Predicted against measured gas viscosity

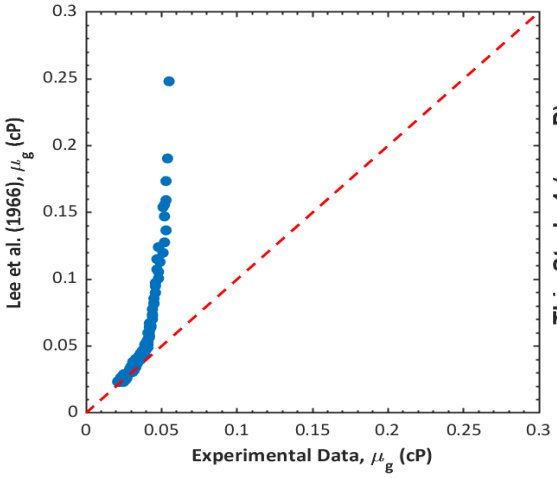


Figure 12: Predicted against measured gas viscosity

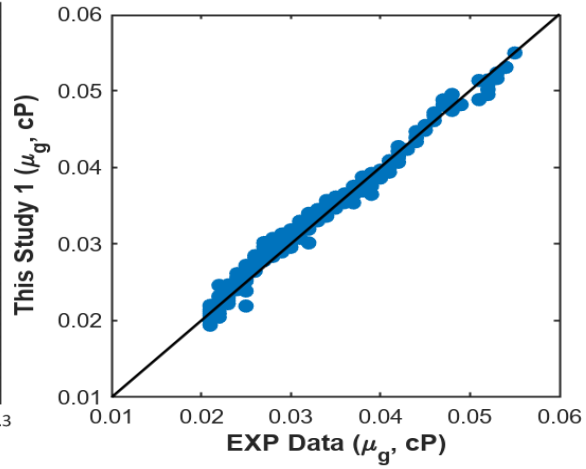


Figure 13: Predicted against measured gas viscosity

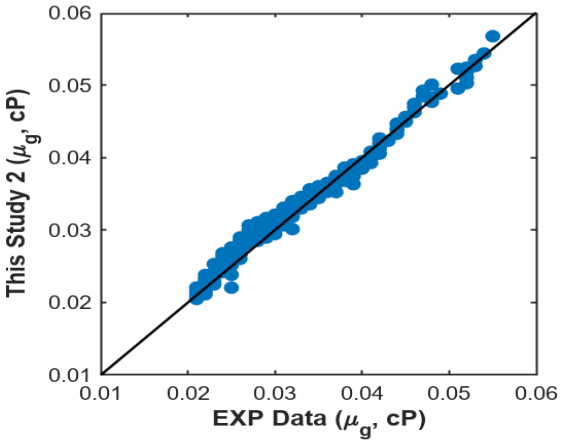


Figure 14: Predicted against measured gas viscosity

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International Journal of Engineering Research & Technology (IJERT)
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4. CONCLUSION

This study developed and validated new gas viscosity models capable of predicting viscosity behaviour across a broad range of reservoir conditions, including LPLT (5,000–10,000 psi), HPHT (10,000–15,000 psi and 300–350°F) and UHPHT (15,000–20,000 psi and 350–400°F) regimes. The proposed models provide improved viscosity prediction capability across progressively more challenging pressure temperature environments relevant to deep and ultra deep gas reservoirs.

The findings support the following conclusions:

1. This study compared experimental measurements with some commonly used correlations and the recently developed correlations to present a thorough evaluation of natural gas viscosity at 212°F, 254°F, 278°F, 297°F, 302°F, 316°F, 335°F, 354°F, 373°F and 392°F across a wide pressure range (5,000–20,000 psi). The results of the analysis demonstrated that although traditional correlations like Dean and Stiel (1965), Lee et al. (1966) and Viswanathan (2007) offer accurate approximations at low pressures, they show notable variations at ultra-high pressures and temperatures. In contrast, Heidaran and Jarrahian (2010) and Azubuike et al. (2019) consistently underestimate viscosity, whereas Ohirhian and Abu (2009) and Dempsey (1965) perform better but still diverge at elevated pressures.
2. The developed Power Law model provided an accurate and practical tool for quick viscosity estimation within the data range.
3. Originally calibrated at low to moderate pressure, traditional models are insufficient for HPHT and UHPHT applications. To support improved reservoir simulation, production forecasting and engineering design in ultra deep and high pressure environments, the proposed correlations offer a more reliable way to estimate viscosity under ultra-high reservoir conditions.

5. RECOMMENDATIONS

Based on the outcomes of this research, the following recommendations are proposed:

1. Future studies should explore model generalization across different gas fields with varying compositions, including sour and wet gases.
2. Additional experimental data at pressures beyond 20,000 psi and wider temperature ranges should be collected to extend the model applicability to extreme HPHT reservoirs.
3. Comparative studies with molecular simulation techniques (e.g., Monte Carlo or Molecular Dynamics) could provide deeper insights into the microscale causes of viscosity behaviour.

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NOMENCLATURE

μ	Viscosity (cp)
AARE	Average absolute relative error, %
RMSE	Root mean square error
SD	Standard deviation
R	Correlation coefficient
EOS	Equation of state
PLM	Power Law Model
POLM	Polynomial Law Model
N	Number of data points
Ppr	Pseudo-reduced pressure, dimensionless
Tpr	Pseudo-reduced temperature, dimensionless
P	System pressure, Psi
T	System temperature, ^{o}F
LPLT	Low high pressure high temperature
HPHT	High pressure high temperature
UHPHT	Ultra high pressure high temperature

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Appendix A.

T**able A1**. 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

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International Journal of Engineering Research & Technology (IJERT)
ISSN: 2278-0181
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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

T**able A2.** 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

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International Journal of Engineering Research & Technology (IJERT)
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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

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