Mathematical Models for predicting CO_2 Density and Viscosity for Enhanced Gas Recovery and Carbon Sequestration

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Abstract
There is limited work on mathematical correlations in place for predicting density and viscosity of supercritical carbon-dioxide (CO_2), necessary for Enhanced Gas Recovery - Carbon Sequestration (EGR-CS) operations. In this work, three categories of mathematical correlations were developed by Split Regression Analytical method and validated using Equation of State (EOS) models for predicting density and viscosity of carbon-dioxide under supercritical conditions as expected in EGR-CS operation. The models range for application is for reservoir depths of 1000-1500m, 1600-5000m and beyond 5000m for both CO_2 density and viscosity, which are ideal for carbon sequestration and covers depths of most gas reservoirs in Niger-Delta. The new "UDA-Model" matched with Peng Robinson and Soave-Redlich-Kwong (EOS) models at the tested reservoir conditions, with low Absolute Average Deviation. Application of these mathematical correlations on four depleted gas reservoirs in Niger Delta formations shows Relative Density Difference (RDD) and Relative Viscosity Difference (RVD) on CO_2 and natural gas. CO_2 densities at those depths range from 0.5-0.6g/cm^3, 0.6-0.7g/cm^3, and 0.7-0.8g/cm^3 respectively while the viscosities range from 0.05-0.06cP, 0.06-0.07cP, and 0.07-0.08cP respectively. The results promise smoother displacement of natural gas by CO_2 during EGR-CS operations.

Keywords: Mathematical correlations, CO_2 density and viscosity, Enhanced Gas Recovery, Carbon Sequestration, Equation of State, Niger Delta formations

1.0 INTRODUCTION

Oil exploration activity has gained prominence in Niger-Delta, Nigeria for over 60 years. This has enabled the accumulation of thousands of informative reservoir data including temperature and pressure from well logs and other sources. Long time production over these years has led to depletion and abandonment of most reservoirs in Niger-Delta and on that context, many are today termed marginal fields.

CO_2 sequestration is a sure tool for reducing the concentration of emitted CO_2 in the environment. The technology in a depleted gas reservoir is a win-win venture because the revenue accruing from produced gas could contribute to defray the cost of a CO_2 sequestration (CS) project (Abba et al., 2018; Leeuwenburgh et al., 2014; Mohammed et al., 2020).

Before embarking on any capital-intensive project such as CO_2 sequestration – Enhanced Gas Recovery (CS – EGR) projects, it is necessary to evaluate the potential benefits or setbacks from the project using the reservoir property data to conduct preliminary simulation or experimental test. Enhanced Gas Recovery and Sequestration projects need adequate knowledge and estimates of formation pressures and temperatures to determine the expected in-situ fluid density and viscosity which would enable proper design for injection. The efficiency of gas-gas displacement dynamics is not only affected by injection rate, rock and fluids properties but also by the density and viscosity of the fluids (Hamza et al., 2021).

In petroleum engineering, enhancement recovery from gas or oil reservoirs requires accurate PVT data gathered at the reservoir conditions (Ghanbari et al., 2017). Also, experimental data are not only expensive but time consuming and, in some cases, the validity of the reported experimental results are doubtful (Polishuk et al., 2001), hence the need for simulation and mathematical models.

Geological storage for CO_2 is mainly in saline aquifers, but its injection into depleted oil or gas reservoirs are advantageous due to its ability to produce the residual oil or gas that was not producible during the primary production stage. Also, the presence of basic infrastructures already in place for injection makes it easier to develop, operate and maintain (Adebayo, 2013; Gou et al., 2014; Anene & Odumodu, 2021).

Additionally, Depleted Gas Reservoirs (DGR) have the potential to, securely sequester CO_2 with a storage capacity between 390 and 750 Giga-tons based on the replacement ratio. (Hamza et al., 2021; Hoteit et al., 2019; Regan, 2010; Vega & Kovscek, 2010), concluded that residual gas saturation varies from 15% to 50%, depending on the type of reservoir, indicating substantial amount of natural gas remaining in the reservoir after depletion.

Carbon-Dioxide Property Prediction

To appropriately design and operate on Enhanced Gas Recovery - Carbon Sequestration (EGR-CS) projects, the accurate representation of carbon-dioxide properties, mainly density and viscosity is a must (Ouyang, 2011). These are the two critical properties required for well injectivity for carbon-capture projects as well as stable displacement and sweep efficiency for EGR projects.

Carbon-dioxide density and viscosity can be calculated using black oil PVT Model, Equation of States (EOS) Model or Empirical Mathematical Model (EMM) (Ghanbari et al., 2017; Ouyang, 2011; Perez et al., 2017). Black oil PVT model is a simplified fluid model used for surface gas and oil. This model cannot be applied to pure carbon-dioxide but for oil and gas where CO_2 component is less than three percent (3%) and where the CO_2 component can reach 10-20% as in the case of sour gas (Ouyang, 2011). An EOS is a function that relates the thermodynamic properties of CO_2, such as pressure, temperature, and volume while the mathematical model in this context is the representation of density and viscosity of CO_2 using mathematical correlations, equations or algorithms.

EOS are important tools in PVT calculations designed for predicting phase equilibria, thermo-physical properties, and volumetric behavior of fluid system, both in subcritical and supercritical domain, which gives foundation for other calculations like reservoir simulation, fluid mapping, surface processing etc. (Ghanbari et al., 2017). Models by Peng-Robinson (PR-EOS) (Robinson, 1978) and that of Soave-Redlich-Kwong (SRK-EOS) (Soave, 1972) are the two common and primary Equation of State (EOS) for two-phase modeling in different areas of petroleum and chemical engineering.

Geothermal and Pressure Gradient of Niger-Delta Formation

Geothermal gradient is a measure of the rate of change of temperature with depth (Emujakporue & Ekine, 2014; Godec, 2013). The geothermal gradients of subsurface formations are computed using a linear relationship as shown in equation (1)

$$T = G * D + T_o \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots. (1)$$

Where: T = Wellbore temperature (^oC); G = Geothermal Gradient ($^oC/Km$)
D = Depth of reference (Km); T_o = Mean Surface Temperature (^oC)

Formation pressure is the pressure acting on the fluids (gas, oil, water) in the pore spaces of the rock (Rabia, 2002.). It is affected by the density of the in-situ fluid and the weight of the overlying rock materials, with respect to the depth of reference. Mathematically,

$$Fp = 0.052\ x\ \rho(f, r)xD \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2)$$

where Fp= Formation pressure (Psi); D = True vertical depth (ft);
ρ(f,r) = formation fluid/rock matrix density

Accumulated reservoir data in Niger-Delta over the years led to the development of the following mathematical correlation. (Lawal, 2011; Lawal & Adenuga, 2010)

$$P_r = 0.434D + 14.7 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (3)$$

$$T_r = 0.0105D + 71.4 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (4)$$

Where, Pr = Reservoir pressure (Psia); Tr = Reservoir temperature (°F);
D = Reservoir depth (ft).

2.0 MATERIALS AND METHOD

This study is divided into two parts: First is focussed on model development for CO_2 density and viscosity and second part is the application of the predicted results from the models for EGR-CS project in Niger-Delta formation. Niger-Delta Formation data and PVTsim software were the basic tools employed in this research.

2.1 Model development

The study adopted extensive literature review and analytical framework to validate the Niger-Delta formation gradients as reported in equation (3 & 4) of this work.

2.1.1 Validation of the Adopted Niger-Delta Formation Gradient using Absolute Average Deviation (AAD) Approach

Below is a sensitivity analysis on reservoir gradients formulated a few years after the models (equation 3 & 4) were developed. These were carried out using percentage Absolute Average Deviation (ADD%) approach stated in equation (5)

$$AAD\ (\%) = \frac{|Xi^A - Xi^B|}{Xi^A} * 100 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (5)$$

AAD (%) = Percentage Absolute Average Deviation
Xi^A=Niger-Delta Formation gradient (Pressure/Temperature) adopted for this work
Xi^B= Other Reported Formation gradient (Pressure/Temperature) in Niger-Delta

Table 1: Comparative Analysis of the adopted Pressure Gradient Correlation with other Gradient Correlations.

	MODEL (Equation.3)	**(Nwozor & Onuorah, 2014)**		**(Ogbamikhumi et al., 2017)**		**(JE & DO, 2018)**		**(Agbasi et al., 2013)**		**Remark**
Depth (m)	Pressure @ Model (Psi)	Pressure (Psi)	AAD (%)	Pressure (Psi)	AAD (%)	Pressure (Psi)	AAD (%)	Pressure (Psi)	AAD (%)	MFFP
1000	1,438.58	1,407.46	2.16	1,420.59	1.25	1,459.96	1.49	1,427.15	0.79	MFFP
1200	1,723.36	1,688.96	1.99	1,704.70	1.08	1,751.95	1.66	1,712.58	0.63	MFFP
1400	2,008.14	1,970.45	1.88	1,988.82	0.96	2,043.94	1.78	1998.01	0.51	MFFP

MFFP: Model Fit For Purpose; MNFFP: Not Fit For Purpose

In the same vein the AAD's for the adopted Thermal Gradient (Equation 4) are less than 3% for those reported by (Akpabio et al., 2013.; Emujakporue & Ekine, 2014; Mosto Onuoha & Ekine, 1999).

2.1.2 "UDA" Mathematical Model Development Approach

Carbon-dioxide properties, specifically density and viscosity were generated from PVT simulation software known as (PVTsim) using Niger-Delta pressure and temperature gradients data generated from equations (3 & 4) of this work at reservoir depths ideal for sequestration and EGR.

Upon launching the software a new project was set, CO_2 was selected as the fluid component, subsurface conditions (i.e. the pressure and temperature) for the formation depths were inputted. Density and viscosity of CO_2 at the varying depths generated from simulation was extracted, followed by data regression, training and testing to develop the models.

Below is a flow diagram for the UDA model development.

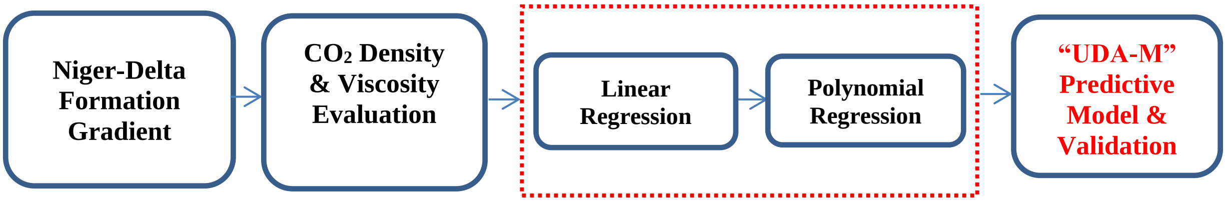

Figure 1: Model Development Algorithm

In other to ensure that the outputs "CO_2 density and viscosity correlations" are robust and reliable, the correlation data were trained by running series of regressions and the regression coefficients optimised so get the final correlation equations. The proposed correlations were tested, and the results falls within acceptable error margins i.e. ±5% for both density and viscosity. Finally, the developed correlations and the associated constants met two significant criteria proposed by (Ouyang, 2011) as defined below.

Criteria One: Least Square Curve:

$$Sum = \sum_{1=1}^{n}\left[\rho(UDA)_{PiTi} - \rho(EOS)_{piTi}\right]^2 = Minimum \ldots\ldots (6)$$

$$Sum = \sum_{1=1}^{n}\left[\mu(UDA)_{PiTi} - \mu(EOS)_{piTi}\right]^2 = Minimum \ldots\ldots (7)$$

Criteria Two: Absolute deviation from standard:

$$Sum = \sum_{i=1}^{n}\left[\frac{\rho(UDA)_{P_iT_i} - \rho(EOS)_{P_iT_i}}{\rho(EOS)_{P_iT_i}}\right] = Minimum \ldots\ldots (8)$$

$$Sum = \sum_{i=1}^{n}\left[\frac{\mu(UDA)_{P_iT_i} - \mu(EOS)_{P,T_i}}{\mu(EOS)_{P_iT_i}}\right] = Minimum \ldots\ldots (9)$$

Where: $(UDA)_{Pi,Ti}$= Density and Viscosity Predictive Model as a function of Pressure and Temperature

$(EOS)_{Pi,Ti}$ = Equation of State Model as function of Pressure and Temperature

μ = Viscosity (cP); ρ = Density (g/cm^3)

2.1.3 NDF Model Validation

Peng Robinson (PR-EOS) and Soave-Redlich-Kwong (SRK-EOS) are the most successful equation of states which have been modified repeatedly to improve their accuracy in different ranges of pressure and temperatures, alongside their extrapolative ability to condition reservoir parameters outside their correlation ranges. These PVT models (PR-SRK-EOS) have attracted a lot of attentions for predicting the properties of pure and mixed components both in subcritical and supercritical states, hence considered for validating the newly developed UDA Mathematical Models.

Sensitivity analysis was used to examine the responses of the newly developed correlations (UDA-Model) vis-à-vis that of Peng Robinson (PR-EOS) and Soave-Redlich-Kwong (SRK-EOS) under defined boundaries. The predicted results from the models were assessed and validated by comparing percentage Absolute Average Deviation (ADD%) between UDA model and PR-SRK-EOS using the relationship below:

$$AAD\ (\%) = \frac{|Xi^{UDA} - Xi^{EOS}|}{Xi^{NDF}} * 100 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (10)$$

Where;
X = Evaluated CO_2 property (Density and Viscosity)
EOS= Equation of state (PR-EOS and SRK-EOS)
UDA= New Mathematical Model.
n = Number of data.

2.2 The Generalised Equation for formulation of the Models

The general equation for model formulation is as shown in equation (11)

$$Ř_{(P,T)} = \delta_0 + \delta_1 P + \delta_2 T + \delta_3 P^2 + \delta_4 T^2 + \delta_5 P.T \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (11)$$

Where: Ř= Estimator of the mean response of density and viscosity at test conditions.
$\boldsymbol{\delta}_{j=}$ Estimator of the Model constants; P = Reservoir Pressure; T = Reservoir Temperature

2.2.1 Split Regression Approach (SRA)

Split 1: From generalized equation (11).

$$Ř_{(P,T)} = \delta_0 + \delta_1 P + \delta_2 T \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (12)$$

The normal equations from Split 1:

$$\sum_{i=1}^{n}(Ř) = \delta_0 N + \delta_1 \sum_{i=1}^{n} P + \delta_2 \sum_{i=1}^{n} T$$

$$\sum_{i=1}^{n}(Ř.P) = \delta_0 \sum_{i=1}^{n} P + \delta_1 \sum_{i=1}^{n}(P^2) + \delta_2 \sum_{i=1}^{n}(P.T)$$

$$\sum_{i=1}^{n}(Ř.T) = \delta_0 \sum_{i=1}^{n}(T) + \delta_1 \sum_{i=1}^{n}(P.T) + \delta_2 \sum_{i=1}^{n}(T^2)$$

Split 2: From generalised equation (11)

$$Ř_{(P,T)} = \delta_0 + \delta_1 P^2 + \delta_2 T^2 + \delta_3 P.T \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (13)$$

The normal equations from Split 2:

$$\sum_{i=1}^{n}(\check{R}) = \delta_0 N + \delta_1\sum_{i=1}^{n}(P^2) + \delta_2\sum_{i=1}^{n}(T^2) + \delta_3\sum_{i=1}^{n}(P.T)$$
$$\sum_{i=1}^{n}(\check{R}.P^2) = \delta_0\sum_{i=1}^{n}(P^2) + \delta_1\sum_{i=1}^{n}(P^4) + \delta_2\sum_{i=1}^{n}(P^2T^2) + \delta_3\sum_{i=1}^{n}(P^3.T)$$
$$\sum_{i=1}^{n}(\check{R}.T^2) = \delta_0\sum_{i=1}^{n}(T^2) + \delta_1\sum_{i=1}^{n}(P^2T^2) + \delta_2\sum_{i=1}^{n}T^4 + \delta_3\sum_{i=1}^{n}(P.T^3)$$
$$\sum_{i=1}^{n}(\check{R}.P.T) = \delta_0\sum_{i=1}^{n}(P.T) + \delta_1\sum_{i=1}^{n}(P^3.T) + \delta_2\sum_{i=1}^{n}(P.T^3) + \delta_3\sum_{i=1}^{n}(T^2P^2)$$

The split functions below at varying validity

$$\left\{\begin{array}{l} \sum_{i=1}^{n}(\check{R}) = \delta_0 N + \delta_1\sum_{i=1}^{n}P + \delta_2\sum_{i=1}^{n}T \\ \sum_{i=1}^{n}(\check{R}.P) = \delta_0\sum_{i=1}^{n}P + \delta_1\sum_{i=1}^{n}(P^2) + \delta_2\sum_{i=1}^{n}(P.T) \\ \sum_{i=1}^{n}(\check{R}.T) = \delta_0\sum_{i=1}^{n}(T) + \delta_1\sum_{i=1}^{n}(P.T) + \delta_2\sum_{i=1}^{n}(T^2) \end{array}\right\}$$

$$\left\{\begin{array}{l} \sum_{i=1}^{n}(\check{R}) = \delta_0 N + \delta_1\sum_{i=1}^{n}(P^2) + \delta_2\sum_{i=1}^{n}(T^2) + \delta_3\sum_{i=1}^{n}(P.T) \\ \sum_{i=1}^{n}(\check{R}.P^2) = \delta_0\sum_{i=1}^{n}(P^2) + \delta_1\sum_{i=1}^{n}(P^4) + \delta_2\sum_{i=1}^{n}(P^2T^2) + \delta_3\sum_{i=1}^{n}(P^3.T) \\ \sum_{i=1}^{n}(\check{R}.T^2) = \delta_0\sum_{i=1}^{n}(T^2) + \delta_1\sum_{i=1}^{n}(P^2T^2) + \delta_2\sum_{i=1}^{n}T^4 + \delta_3\sum_{i=1}^{n}(P.T^3) \\ \sum_{i=1}^{n}(\check{R}.P.T) = \delta_0\sum_{i=1}^{n}(P.T) + \delta_1\sum_{i=1}^{n}(P^3.T) + \delta_2\sum_{i=1}^{n}(P.T^3) + \delta_3\sum_{i=1}^{n}(T^2P^2) \end{array}\right\}$$

Validity: Reservoir depth (1000-5000m) Validity: Reservoir depth: (>5000m)

2.3 Viability of EGR-CS Project in Niger-Delta Gas Reservoirs

The second part of this research is to test the viability of EGR-CS project in Depleted Gas reservoirs in the Niger Delta. The efficiency of displacing Natural Gas (Gas-in-Place) by CO_2 (Injected Gas) during Enhanced Gas Recovery (EGR) operation is affected by the operating conditions i.e. (reservoir pressure, temperature and injection rate), the fluids properties i.e. (reservoir petrophysical property, connate water saturation, pore geometry and fractures) (Hamza et al., 2021).

Table 2: Data for four Depleted Gas Reservoirs (DGR) in Niger-Delta

Parameter	Res.1	Res.2	Res.3	Res.4
Sampling Depth (ft)	8501	9755	5525	11237
Pressure (Psi)	3561	2291	2412	4906
Temperature (°C)	88.00	79.44	54.44	88.33
Swc	N/A	N/A	N/A	N/A
Sgr	0.135	0.153	0.141	0.092
Elements	**Composition**			
C1	79.48	82.72	82.05	72.53
C2	7.62	7.25	7.42	8.58
C3	7.06	4.47	4.55	5.42
n-C_4	3.39	1.34	1.4	3.39
n-C_5	0.7	0.38	0.43	0.7
C_6	0.21	0.42	0.47	0.21
C_{7+}	0.2	0.66	0.73	0.2
N_2	0.17	0.78	0.9	0.17
CO_2	1.17	0.5	0.45	1.17

Howbeit, the displacement efficiency here was tested based on the influence of density and viscosity at the stated reservoir conditions. Samples from four depleted gas reservoirs (Table 2) from Niger-Delta region were evaluated to examine the applicability of EGR with regards to displacement efficiency using the predicted CO_2 density and viscosity as yardsticks.

3.0 RESULTS AND DISCUSSION

Studies have shown that Niger-Delta formations have unique reservoir characteristics i.e. pressure, temperature and geochemistry. Below are mathematical correlations developed for predicting densities and viscosities of supercritical CO_2 suitable for Niger-Delta formation under temperature and pressure conditions corresponding to depth of reference.

3.1 CO_2 Density Correlation for Formations at varying reservoir depths

$$\boldsymbol{CO_2(\rho) = 0.104 + 5.300\ x\ 10^{-5}P + 8.400\ x\ 10^{-3}T} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (\mathbf{14})$$

Validity Depth (1000-1500m).

$$\boldsymbol{CO_2(\rho) = 11.2631 + 6.630\ 10^{-3}P - 4.916\ x\ 10^{-1}T} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (\mathbf{15})$$

Validity Depth (1600-5000m)

$$\boldsymbol{CO_2(\rho) = 500.53\ x\ 10^{-3} - 1.64\ x\ 10^{-8}\ P^2 + 7.431\ x\ 10^{-3}T^2 + 7.644\ x\ 10^{-8}P * T} \ldots (\mathbf{16})$$

Validity Depth (>5000m)

Where:
T= Temperature (^oC);
P= Pressure (Psi),
ρ= Density (g/cm^3);
μ=Viscosity (cP**).**

3.2 CO_2 Viscosity Correlation for Formation at varying reservoir depths

$$\boldsymbol{CO_2(\mu) = 5.960\ x\ 10^{-2} + 1.971\ x\ 10^{-5}P - 6.806\ x\ 10^{-4}T} \ldots\ldots\ldots\ldots\ldots\ldots\ldots (\mathbf{17})$$

Validity Depth (1000-1500m).

$$\boldsymbol{CO_2(\mu) = 3.350\ x\ 10^{-3}T - 8.568\ x\ 10^{-3} - 4.285\ x\ 10^{-5}P} \ldots\ldots\ldots\ldots\ldots\ldots\ldots (\mathbf{18})$$

Validity Depth (1600-5000m)

$$\boldsymbol{CO_2(\mu) = 56.290\ x\ 10^{-3} - 1.373\ x\ 10^{-9}P^2 + 6.262\ x\ 10^{-6}T^2 + 7.073\ x\ 10^{-9}\ P * T} \ldots (\mathbf{19})$$

Validity Depth (>5000m)
Where:
T= Temperature (^oC);
P= Pressure (Psi),
ρ= Density (g/cm^3);
μ=Viscosity (cP**).**

3.3 Determination of Absolute Average Deviation (AAD)

The Percentage AAD as evaluated for the newly developed "UDA-Model" vis-à-vis "PR-EOS" and "SRK-EOS" are shown in tables (3, 4 & 5)

Table 3: Category 1: Reservoir depths between (1000 -1500m)

Depth (m)	CO_2 Density, ρ (g/cm^3) PR-EOS	SRK-EOS	UDA Model	AAD (%) for ρ PR-EOS	SRK-EOS	CO_2 Viscosity, μ (cP) PR-EOS	SRK-EOS	UDA Model	AAD (%) for μ PR-EOS	APD SRK
1000	0.5347	0.5213	0.5249	**-1.86**	**0.69**	0.0603	0.0603	0.0600	**-0.45**	**-0.45**
1050	0.5531	0.5392	0.5367	**-3.05**	**-0.46**	0.0615	0.0615	0.0608	**-1.18**	**-1.18**
1100	0.5679	0.5537	0.5486	**-3.53**	**-0.94**	0.0625	0.0625	0.0615	**-1.57**	**-1.57**
1150	0.5801	0.5658	0.5604	**-3.52**	**-0.97**	0.0633	0.0633	0.0623	**-1.63**	**-1.63**
1200	0.5905	0.5761	0.5722	**-3.20**	**-0.68**	0.0640	0.0640	0.0630	**-1.52**	**-1.52**
1250	0.5997	0.5853	0.5840	**-2.69**	**-0.22**	0.0647	0.0647	0.0638	**-1.43**	**-1.43**
1300	0.6079	0.5935	0.5958	**-2.03**	**0.39**	0.0653	0.0653	0.0645	**-1.17**	**-1.17**
1350	0.6152	0.6009	0.6076	**-1.25**	**1.11**	0.0658	0.0658	0.0653	**-0.77**	**-0.77**
1400	0.6218	0.6076	0.6194	**-0.38**	**1.91**	0.0663	0.0663	0.0660	**-0.38**	**-0.38**
1450	0.6278	0.6137	0.6312	**0.54**	**2.78**	0.0668	0.0668	0.0668	**0.00**	**0.00**
1500	0.6333	0.6193	0.6431	**1.52**	**3.69**	0.0672	0.0672	0.0676	**0.52**	**0.52**

Table 4: Category 2: Reservoir depths between (1600-5000m)

Depth (m)	CO_2 Density, ρ (g/cm^3) PR-EOS	SRK-EOS	UDA Model	AAD (%) for ρ PR-EOS	SRK-EOS	CO_2 Viscosity, μ (cP) PR-EOS	SRK-EOS	UDA Model	AAD (%) for μ PR-EOS	APD SRK
1600	0.6433	0.6295	0.6545	**1.72**	**3.82**	0.0680	0.0680	0.0691	**1.60**	**1.60**
1800	0.6595	0.6464	0.6613	**0.27**	**2.25**	0.0694	0.0694	0.0697	**0.47**	**0.47**
2000	0.6725	0.6600	0.6680	**-0.67**	**1.20**	0.0705	0.0705	0.0703	**-0.21**	**-0.21**
2200	0.6833	0.6714	0.6748	**-1.26**	**0.51**	0.0715	0.0715	0.0710	**-0.75**	**-0.75**
2400	0.6925	0.6812	0.6816	**-1.60**	**0.05**	0.0724	0.0724	0.0716	**-1.13**	**-1.13**
2600	0.7004	0.6897	0.6883	**-1.75**	**-0.20**	0.0731	0.0731	0.0722	**-1.23**	**-1.23**
2800	0.7074	0.6973	0.6951	**-1.77**	**-0.32**	0.0738	0.0738	0.0728	**-1.33**	**-1.33**
3000	0.7137	0.7041	0.7019	**-1.69**	**-0.32**	0.0744	0.0744	0.0735	**-1.29**	**-1.29**
3200	0.7193	0.7102	0.7086	**-1.51**	**-0.22**	0.0750	0.0750	0.0741	**-1.25**	**-1.25**
3400	0.7244	0.7159	0.7154	**-1.26**	**-0.07**	0.0755	0.0755	0.0747	**-1.07**	**-1.07**
3600	0.7291	0.7210	0.7221	**-0.96**	**0.16**	0.0760	0.0760	0.0753	**-0.90**	**-0.90**
3800	0.7334	0.7258	0.7289	**-0.62**	**0.43**	0.0765	0.0765	0.0759	**-0.74**	**-0.74**
4000	0.7374	0.7302	0.7357	**-0.24**	**0.74**	0.0769	0.0769	0.0766	**-0.44**	**-0.44**
4200	0.7411	0.7344	0.7424	**0.18**	**1.08**	0.0773	0.0773	0.0772	**-0.15**	**-0.15**
4400	0.7445	0.7383	0.7492	**0.63**	**1.45**	0.0777	0.0777	0.0778	**0.13**	**0.13**
4600	0.7477	0.7419	0.7559	**1.09**	**1.86**	0.0780	0.0780	0.0784	**0.54**	**0.54**
4800	0.7508	0.7454	0.7627	**1.56**	**2.27**	0.0784	0.0784	0.0790	**0.82**	**0.82**
5000	0.7537	0.7487	0.7695	**2.05**	**2.70**	0.0787	0.0787	0.0797	**1.21**	**1.21**

Table 5: Category 3: Reservoir depths between (>5000m)

Depth (m)	CO_2 Density, ρ (g/cm^3) PR-EOS	SRK-EOS	UDA Model	AAD (%) for ρ PR-EOS	SRK-EOS	CO_2 Viscosity, μ (cP) PR-EOS	SRK-EOS	UDA Model	AAD (%) for μ PR-EOS	APD SRK
5000	0.7537	0.7487	0.7568	**0.41**	**1.07**	0.0787	0.0787	0.0789	**0.29**	**0.29**
5100	0.7551	0.7503	0.7592	**0.54**	**1.18**	0.0789	0.0789	0.0792	**0.35**	**0.35**
5200	0.7564	0.7518	0.7615	**0.67**	**1.28**	0.0791	0.0791	0.0794	**0.39**	**0.39**
5300	0.7577	0.7533	0.7638	**0.79**	**1.37**	0.0792	0.0792	0.0796	**0.55**	**0.55**
5400	0.7590	0.7547	0.7659	**0.90**	**1.46**	0.0794	0.0794	0.0799	**0.58**	**0.58**
5500	0.7602	0.7562	0.7680	**1.01**	**1.54**	0.0795	0.0795	0.0801	**0.72**	**0.72**
5600	0.7615	0.7576	0.7700	**1.10**	**1.61**	0.0797	0.0797	0.0803	**0.74**	**0.74**
5700	0.7626	0.7589	0.7719	**1.20**	**1.68**	0.0798	0.0798	0.0805	**0.87**	**0.87**
5800	0.7638	0.7603	0.7737	**1.28**	**1.74**	0.0800	0.0800	0.0807	**0.86**	**0.86**
5900	0.7649	0.7616	0.7755	**1.36**	**1.79**	0.0801	0.0801	0.0809	**0.98**	**0.98**
6000	0.7661	0.7629	0.7772	**1.42**	**1.83**	0.0803	0.0803	0.0811	**0.96**	**0.96**
6100	0.7672	0.7642	0.7788	**1.48**	**1.87**	0.0804	0.0804	0.0813	**1.06**	**1.06**
6200	0.7682	0.7654	0.7803	**1.55**	**1.91**	0.0806	0.0806	0.0814	**1.03**	**1.03**
6300	0.7693	0.7666	0.7817	**1.59**	**1.93**	0.0807	0.0807	0.0816	**1.11**	**1.11**
6400	0.7703	0.7678	0.7831	**1.63**	**1.95**	0.0808	0.0808	0.0818	**1.19**	**1.19**
6500	0.7713	0.7690	0.7843	**1.66**	**1.96**	0.0810	0.0810	0.0819	**1.14**	**1.14**
6600	0.7723	0.7701	0.7855	**1.69**	**1.97**	0.0811	0.0811	0.0821	**1.20**	**1.20**
6700	0.7732	0.7712	0.7867	**1.71**	**1.97**	0.0812	0.0812	0.0822	**1.25**	**1.25**
6800	0.7742	0.7723	0.7877	**1.71**	**1.96**	0.0814	0.0814	0.0824	**1.18**	**1.18**
6900	0.7751	0.7734	0.7887	**1.72**	**1.94**	0.0815	0.0815	0.0825	**1.22**	**1.22**
7000	0.7760	0.7745	0.7895	**1.72**	**1.91**	0.0816	0.0816	0.0826	**1.25**	**1.25**
7100	0.7769	0.7755	0.7903	**1.70**	**1.88**	0.0818	0.0818	0.0828	**1.16**	**1.16**
7200	0.7778	0.7766	0.7911	**1.68**	**1.83**	0.0819	0.0819	0.0829	**1.18**	**1.18**
7300	0.7787	0.7776	0.7917	**1.64**	**1.78**	0.0820	0.0820	0.0830	**1.19**	**1.19**
7400	0.7795	0.7786	0.7923	**1.61**	**1.73**	0.0821	0.0821	0.0831	**1.19**	**1.19**
7500	0.7804	0.7796	0.7928	**1.56**	**1.66**	0.0823	0.0823	0.0832	**1.07**	**1.07**
7600	0.7812	0.7806	0.7932	**1.51**	**1.58**	0.0824	0.0824	0.0833	**1.06**	**1.06**
7700	0.7820	0.7815	0.7935	**1.45**	**1.51**	0.0825	0.0825	0.0834	**1.04**	**1.04**
7800	0.7828	0.7825	0.7937	**1.38**	**1.42**	0.0826	0.0826	0.0835	**1.02**	**1.02**
7900	0.7836	0.7834	0.7939	**1.30**	**1.32**	0.0828	0.0828	0.0835	**0.87**	**0.87**
8000	0.7844	0.7843	0.7940	**1.21**	**1.22**	0.0829	0.0829	0.0836	**0.83**	**0.83**
8100	0.7851	0.7852	0.7940	**1.12**	**1.11**	0.0830	0.0830	0.0837	**0.79**	**0.79**
8200	0.7859	0.7861	0.7939	**1.01**	**0.99**	0.0831	0.0831	0.0837	**0.74**	**0.74**
8300	0.7866	0.7870	0.7938	**0.90**	**0.85**	0.0832	0.0832	0.0838	**0.68**	**0.68**
8400	0.7873	0.7879	0.7936	**0.79**	**0.71**	0.0833	0.0833	0.0838	**0.61**	**0.61**
8500	0.7881	0.7887	0.7932	**0.65**	**0.57**	0.0835	0.0835	0.0839	**0.42**	**0.42**

Table 6: Relative density and viscosity comparison of CO_2 and Natural Gas at varying reservoirs

Reservoir I.D & Depth			Reservoir condition		CO_2 Property		N. G Property		Relative Difference	
	Depth (ft)	(m)	Temp. (°C)	Pres. (Psi)	Density (g/cm^3)	Viscosity (cP)	Density (g/cm^3)	Viscosity (cP)	RDD (%)	RVD (%)
Res.1	8501	2591.11	88.00	3561	0.6689	0.0784	0.1989	0.0250	70.26	68.11
Res.2	9755	2973.32	79.44	2291	0.6471	0.0798	0.1280	0.0185	80.22	76.82
Res.3	5525	1684.02	54.44	2412	0.6605	0.0698	0.1569	0.0200	76.25	71.35
Res.4	11237	3425.04	88.33	4906	0.6959	0.0737	0.2416	0.0302	65.28	59.02

$CO_2(\rho) > N.G\ (\rho)\ \&\ CO_2\mu > \ N.G\ (\mu)$

Where**,** RDD = Relative Density difference (RDD); RVD= Relative Viscosity difference
N.G = Natural Gas

3.4 Discussion on the developed Models

In this work, the adopted correlation for pressure and temperature gradients of Niger-Delta formation was validated using reported gradients in literature by Absolute Average Deviation (AAD) method as shown in table (1).

Stepwise reservoir depth was used to compute the pressures and temperatures by utilizing the adopted Niger-Delta formation gradients equations (3 & 4) respectively. The generated densities and viscosities at those reservoir depths were generated with PVTsim software and used to develop three Novel Models (NM) using Regression Split Approach (RSA). This was after the data were rigorously trained and tested at those conditions to meet criteria (1) and (2) of this report. The developed models were transversed from Linear - Second degree - Interactive (LSI) terms of (P;T),(P^2;T^2) and (P*T) respectively. This was necessitated due to the non-linearity relationships between density, viscosity (dependent variables) and pressure, temperature (independent variables) at some depths in the formation.

The insitu density (ρ) and viscosity (μ) relationship with the independent variables appears to have presents of interactions and curvilinear relationships, hence the need for two algorithms (Linear- quadratic split models) at varying depths. For significant improvement in the fit, three types of models were generated independently at different reservoir depths that formed correlations.

3.5 Sectoral (activity-based) waste temporal distribution

Res1, Res2, Res3 and Res 4 are typical reservoir data in Niger-Delta which falls within reservoir depth ranging from 1600m – 5000m as shown in Table (6). The results revealed that CO_2 at those simulated depths possess higher density and viscosity than in-situ natural gas at same reservoir conditions.

The calculated Relative Density difference (RDD) of "CO_2 on Natural Gas" ranges from 65.28 - 80.22% and Relative Viscosity difference (RVD) ranges from 59.02 - 76.82% for the four gas reservoirs under study. These indicates smooth displacement potentials and promising less dispersion coefficients of CO_2 on the displaced natural gas under optimum injection rate.

Therefore, under optimum injection rate, using CO_2 as the displacement fluid would encourage infinitesimal gas mixing and stable displacement due to expected low mobility ratio between the displacing and the displaced fluid. The results are in agreement with (Al-Hashami, 2005; Clemens & Wit, 2002; Hamza et al., 2021; Hoteit et al., 2019; Oldenburg & Benson, 2002)

4. CONCLUSION

Niger-Delta formation screening and ranking for CO_2 sequestration are rated "Very Good" and "Excellent" in all assessed scenarios for carbon sequestration as reported by researchers like (Davies et al., 2020; Umar et al., 2020). However, field deployment of EGR-CS project in Niger-Delta is dependent on reliable experimental assessment or reservoir simulation.

Over the last decade, geological sequestrations of CO_2 have been an area of active research to mitigate greenhouse gas emission in our environment. Understanding phase behaviors of CO_2 at varying subsurface associated PVT conditions are essential for knowing the flow dynamics as a displacing fluid for enhanced recovery and sequestration. On that basis, comprehensive reservoir characterization data of formations to be injected are required for numerical simulations and laboratory investigation. Density and viscosity are the two critical parameters for pure CO_2 in supercritical conditions needed for EGR-CS projects in depleted gas reservoirs.

In this work, three categories of mathematical models within reservoir depths of 1000-1500m, 1600-5000m and beyond 5000m were developed for CO_2 density (ρCO_2) and viscosity (μCO_2) necessary for EGR-CS projects in Niger-Delta formation. CO_2 densities at those depths range from 0.5-0.6g/cm^3, 0.6-0.7g/cm^3 and 0.7-0.8g/cm^3 respectively while the viscosities range from 0.05-0.06cP, 0.06-0.07cP and 0.07-0.08cP respectively.

The new correlations were validated using Peng Robinson and Soave-Redlich-Kwong Equation of States Model (EOS-M) by Absolute Average Deviation (AAD) method as shown in Tables 3, 4 & 5 of this work. The results are in agreement with Peng Robinson and Soave-Redlich-Kwong Equation of States (EOS) at the tested reservoir conditions, with AAD of ±3.82%. This has also supported the reliability of the new models.

The model was consequently applied to four depleted gas reservoirs (Res.1, Res.2, Res.3 and Res.4) in Niger-Delta for recovery potential, which revealed promising relative density and viscosity differences as shown in Table 6. As EGR-CS continues to gain global interest, these mathematical correlations provide alternatives to complex equations of state and are therefore recommended for engineers and researchers to use.

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