

# **A COMPARISON STUDY OF THE OF THE CO<sub>2</sub>-OIL PHYSICAL PROPERTIES LITERATURE CORRELATIONS ACCURACY USING VISUAL BASIC MODELLING TECHNIQUE**

Mohsin Al-Jarba

*Drilling Supervisor Assistant LUKOIL Saudi Arabia Energy*  
[mjrbaa@luksar.com.sa](mailto:mjrbaa@luksar.com.sa)

Bandar Duraya Al-Anazi

*Research Assistant, King Abdulaziz City for Science & Technology*  
[bandar.alanazi@gmail.com](mailto:bandar.alanazi@gmail.com)

*A key parameter in a CO<sub>2</sub> flooding process is the gas solubility as it contributes to oil viscosity reduction and oil swelling, which together, in turn, enhance the oil mobility and oil relative permeability. Often injected gas-oil mixture physical properties parameters are established through time-consuming experimental means or using correlations available in the literature. However, one must recognise that such correlations for predicting the injected CO<sub>2</sub>-oil physical properties are valid usually for certain data ranges or site-specific conditions.*

*In this paper , a comparison has been presented between the literature correlations for CO<sub>2</sub>-oil physical properties using excel spreadsheet and also using Visual Basic soft ware. Emera and Sarma (2006) correlations have yielded more accurate predictions with lower errors than the other tested models for all the tested physical properties (CO<sub>2</sub> solubility, oil swelling due to CO<sub>2</sub>, CO<sub>2</sub>-oil density, and CO<sub>2</sub>-oil viscosity). Furthermore, unlike the literature models, which were applicable to only limited data ranges and conditions, Emera and Sarma models could be applied over a wider range and conditions.*

*The developed Visual Basic software can be used to test which correlation presents the best accuracy between a list of different literature correlations for CO<sub>2</sub>-oil physical properties and then once the best correlation has been selected, the user can go to this correlation and use it in predicting the property (CO<sub>2</sub> solubility, oil swelling due to CO<sub>2</sub>, CO<sub>2</sub>-oil density, and CO<sub>2</sub>-oil viscosity) when no experimental data are not available.*

## **INTRODUCTION**

Crude oil development and production from oil reservoirs can include up to three distinct phases: primary, secondary, and tertiary (or enhanced) recovery. During primary recovery, the oil is recovered by the natural pressure of the reservoir or gravity drive oil into the wellbore, combined with artificial lift techniques (such as pumps)

which bring the oil to the surface. But only about 10 percent of a reservoir's original oil in place is typically produced during primary recovery. Secondary recovery techniques to the field's productive life are generally include injecting water or gas to displace oil and drive it to a production wellbore, resulting in the recovery of 20 to 40 percent of the original oil in place. However, with much of the easy-to-produce oil already recovered from oil fields, producers have attempted several tertiary, or enhanced oil recovery (EOR), techniques that offer prospects for ultimately producing 30 to 60 percent, or more, of the reservoir's original oil in place. Three major categories of Enhanced Oil Recovery have been found to be commercially successful to varying degrees:

1. Thermal recovery, which involves the introduction of heat such as the injection of steam to lower the viscosity of the heavy viscous oil, and improve its ability to flow through the reservoir.

2. Gas injection, which uses gases such as natural gas, nitrogen, or carbon dioxide that expand in a reservoir to push additional oil to a production wellbore, or other gases that dissolve in the oil to lower its viscosity and improves its flow rate. Gas injection accounts for nearly 50 percent of EOR production.

3. Chemical injection, which can involve the use of long-chained molecules called polymers to increase the effectiveness of waterfloods, or the use of detergent-like surfactants to help lower the surface tension that often prevents oil droplets from moving through a reservoir (Gozalpour, 2005).

CO<sub>2</sub> flooding is an effective enhanced oil recovery process. It appeared in 1930's and had a great development in 1970's. Over 30 years' production practice, CO<sub>2</sub> flooding has become the leading enhanced oil recovery technique for light and medium oils. It can prolong the production lives of light or medium oil fields nearing depletion under waterflood by 15 to 20 years, and may recover 15 % to 25 % of the original oil in place (Hao, 2004).

## **CO<sub>2</sub> FLOODING**

The phase behavior of CO<sub>2</sub>/crude-oil systems has been investigated extensively since the 1960's. This attention was at its peak in the late 70's and early 80's, at the onset of many CO<sub>2</sub> miscible flooding projects and higher oil prices. Interest continues as new projects come on stream and earlier projects mature. Studies to understanding the

development, and prediction of the MMP for both pure and impure CO<sub>2</sub> injection have been ongoing for over thirty years (Quinones et al, 1991).

Various attempts with the target of developing methods for measuring and calculating the MMP exist in the literature. Many of these are based on simplifications such as the ternary representation of the compositional space. This has later proven not to honor the existence of a combined mechanism controlling the development of miscibility in real reservoir fluids. Zick (1986) and subsequently Stalkup (1987) described the existence of a vaporizing/condensing mechanism. They showed that the development of miscibility (MMP) in multicomponent gas displacement processes could, independent of the mechanism controlling the development of miscibility, be predicted correctly by 1 dimensional (1D) compositional simulations. A semi-analytical method for predicting the MMP was later presented by Wang and Orr (1997) who played an important role in the development and application of the analytical theory of gas injection processes (Jessen et al, 2005).

## **CO<sub>2</sub> FLOODING PROCESS**

Carbon dioxide injected into depleted oil reservoir with suitable characteristics can attain enhanced oil recovery through two processes, miscible or immiscible displacement. Miscible process is more efficient and most common in active enhanced oil recovery projects (Amarnath, 1999).

The following subsections explain the two processes, as follows:

### **Immiscible Displacement**

In immiscible flooding, there exists an interface between the two fluids and thus, there also exists a capillary pressure caused by the interfacial tension between the oil and CO<sub>2</sub>. The benefits of the flood are primarily due to reservoir pressure maintenance and by displacing the fluid. Since the two fluids are immiscible, higher residual oil saturations can be expected than with a miscible flood. Hence the immiscible flood achieves lower oil recoveries than the miscible flood. Whether a miscible or immiscible flood is to be implemented is dictated by the injection pressure and the MMP of the gas with the oil (Dake, 1978).

### Miscible displacement

The CO<sub>2</sub> miscible process (First-Contact Miscible Process or Multiple-contact Miscibility process) shown in one such process (Fig. 1). A volume of relatively pure CO<sub>2</sub> is injected to mobilize and displace residual oil. Through multiple contacts between the CO<sub>2</sub> and oil phase, intermediate and higher-molecular-weight hydrocarbons are extracted into the CO<sub>2</sub>-rich phase. Under proper conditions which shown in (Table 1 and Table 2), this CO<sub>2</sub>-rich phase will reach a composition that is miscible with the original reservoir oil. From that point, miscible or near-miscible conditions exist at the displacing front interface (Green, et al. 1998). There are two types of miscibility, first contact and multiple contact, as follows:

Table 1  
Critical temperature of CO<sub>2</sub> and identified miscibility conditions (Ahmad, 1997)

Criteria	Condition	Comments
$T_{res} < 86^{\circ} F$	Immiscible	
$86^{\circ} F < T_{res} < 90^{\circ} F$	Miscible/Immiscible	Either Possible $T_{CO_2} = 87.8^{\circ} F$
$T_{res} > 90^{\circ} F$	Miscible possible	

Table 2  
Critical pressure of CO<sub>2</sub> and identified miscibility conditions. (Ahmad, 1997)

Criteria	Condition	Comments
$P_{res} < 1000 \text{ psia}$	Immiscible	
$1000 \text{ psia} < P_{res} < 1200 \text{ psia}$	Miscible/Immiscible	Either Possible $P_{CO_2} = 1073 \text{ psia}$
$P_{res} > 1200 \text{ psia}$	Miscible possible	

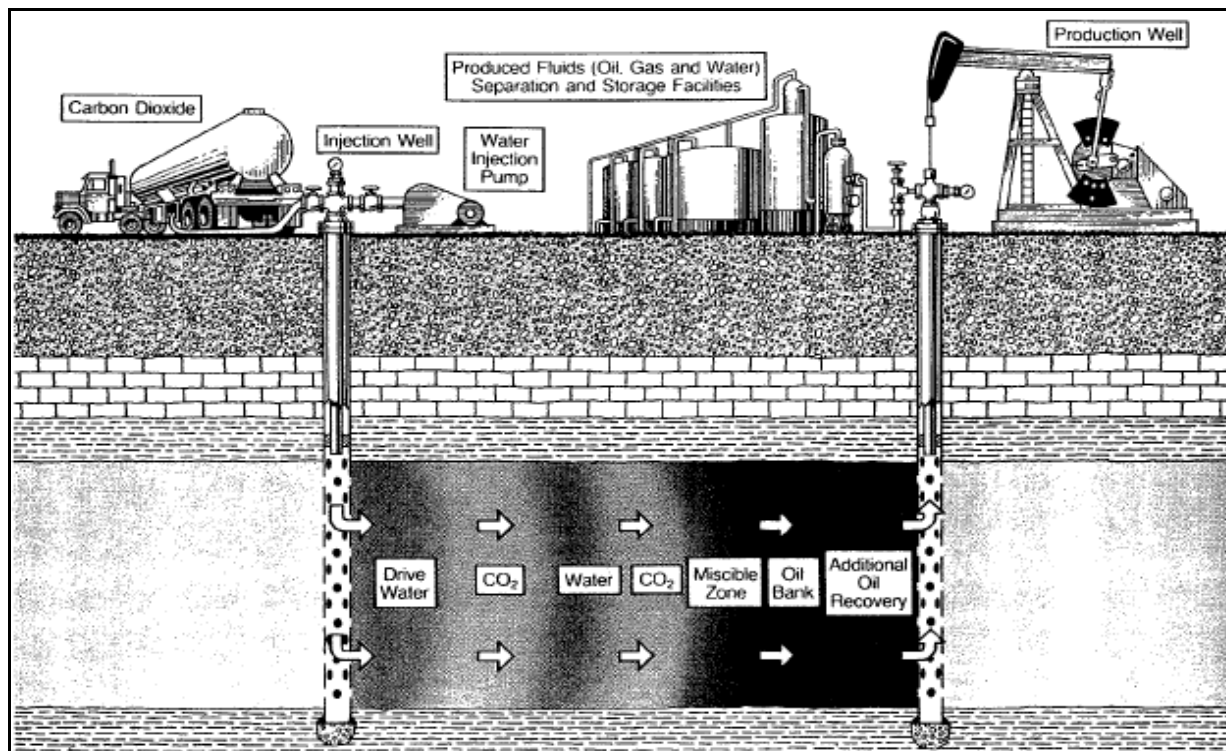


Figure 1. CO<sub>2</sub> miscible process (Green and Willhite,1998)

### THE CO<sub>2</sub>-OIL PHYSICAL PROPERTIES CORRELATIONS

Knowledge of the physical and chemical interactions between CO<sub>2</sub> and reservoir oil in addition to their effect on oil recovery are very important for any gas flooding project. The major parameter that affects gas flooding is gas solubility in oil because it results in oil viscosity reduction and an increase in oil swelling, which in turn, enhances the oil mobility and increases the oil recovery efficiency. Therefore, a better understanding of this parameter and its effects on oil physical properties is vital to any successful CO<sub>2</sub> flooding project.

Physical properties such as oil swelling due to CO<sub>2</sub>, viscosity, density, and CO<sub>2</sub> solubility in oil are required to design and simulate oil recovery process. The effects of CO<sub>2</sub> on the physical properties of crude oils must be determined to design an effective immiscible displacement process. A predictive method of properties of heavy oil/CO<sub>2</sub> mixtures is useful for process design and screening. CO<sub>2</sub>-oil Physical properties can be determined by two methods, experimental method and by correlations prediction (Chung et al, 1988).

In this work, correlations were developed to predict the solubility of CO<sub>2</sub>, Swelling factor, viscosity of the CO<sub>2</sub>/heavy-oil mixture, and density for Emera and Sarma (2006), Simon and Graue (1965), Mehrotra and Svrcek (1982) and Chung *et al* (1986). The property-prediction package requires only the temperature, pressure, specific gravity of oil, and oil viscosity at any temperature and pressure condition to be entered.

## CO<sub>2</sub> SOLUBILITY

As shown in Table 3 and Fig. 2, the Emera and Sarma (2006) offered a better accuracy compared to correlations of Simon and Graue (1965), Mehrotra and Svrcek (1982), and Chung *et al.* (1986). In addition to the higher accuracy and compared to the other available correlations, the Emera and Sarma (2006) could be applied over a wider range of data conditions. Table 4 presents a summary of the experimental data range used in this study for testing of the CO<sub>2</sub> solubility in oil correlations.

### Simon and Graue (1965)

Simon and Graue presented graphical correlation the CO<sub>2</sub> is expressed as a function of saturation pressure and temperature. The solubility developed for the UOP characterization factor that is equal to 11.7, the solubility correction factor for the oil whose UOP characterization factors differ than 11.7. (Simon and Graue, 1965)

### Mehrotra and Svrcek (1982)

$$\text{Sol } (m^3/m^3) = C_1 + C_2 P_s + C_3 \left( \frac{P_s}{T + 273.16} \right) + C_4 \left( \frac{P_s}{T + 273.16} \right)^2,$$

where :  $C_1 = -0.0073508$ ,  $C_2 = -14.794$ ,  $C_3 = 6428.5$ ,  $C_4 = 4971.39$ .

### Chung et al (1986)

$$\text{Sol } (m^3/m^3) = \frac{1}{C_1 \gamma^{C_2} (1.8T + 32)^{C_7} + C_3 (1.8T + 32)^{C_4} \exp \left[ -C_5 P_s - \frac{C_6}{P_s} \right]},$$

where  $C_1 = 0.02770441$ ,  $C_2 = 4.0928$ ,  $C_3 = 3.20617 \times 10^{-6}$ ,  $C_4 = 1.6428$ ,  $C_5 = 0.098057$ ,  $C_6 = 5.38888$ ,  $C_7 = 0.2499$ .

Limited to pressures up to 20.684 MPa and oil gravity from 10 to 20° API (for dead oils).

### **Emera and Sarma (2006)**

1. When CO<sub>2</sub> is in the gaseous state for temperature greater than T<sub>c</sub>, CO<sub>2</sub> (for all pressure) and temperatures less than T<sub>c</sub>, CO<sub>2</sub> (for pressure less than the CO<sub>2</sub> liquefaction pressure):

$$\text{Sol (mole fraction)} = 2.238 - 0.33y + 3.235y^{0.6474} - 4.8y^{0.25656},$$

$$y = \gamma (0.006897 \times (1.8T + 32)^{0.8} / P_s)^{\exp(1/MW)}.$$

2. When CO<sub>2</sub> is in the liquid state for temperature less than T<sub>c</sub>, CO<sub>2</sub> and pressure greater than the CO<sub>2</sub> liquefaction pressure:

$$\text{Sol (mole fraction)} = 0.033 + 1.14y^2 - 0.7716y^3 + 0.2176y^4 - 0.02183y^{\exp((1.8T+32)/MW)},$$

$$y = \gamma (P_s / P_{\text{liq}}).$$

## **OIL SWELLING FACTOR**

For the oil swelling factor, Table 5 and Fig. 3 present a comparison between the oil swelling factor correlations accuracy. As shown, the Emera and Sarma (2006) model offered a better accuracy than that of Simon and Graue model. Also, it could be applied over a wider range of conditions. Table 6 presents a summary of the experimental data range used in this study for testing of the oil swelling factor (due to CO<sub>2</sub> injection) correlations.

### **Simon and Graue (1965)**

The relationship between swelling factor, mole fraction of CO<sub>2</sub> dissolved and molecular size correlated which presented by Simon and Graue (1965).

### **Emera and Sarma (2006)**

Emera and Sarma oil swelling factor (SF) correlation is proposed as a function of the CO<sub>2</sub> solubility and oil molecular size (equal to the ratio between oil MW and oil

density at 15.56° C (oil specific gravity)). The oil is classified, based on its molecular weight, into two groups: heavier oil (for  $MW \geq 300$ ) and lighter oil (for  $MW < 300$ ).

For heavier oil (for  $MW \geq 300$ ):

$$SF = 1 + 0.3302Y - 0.8417Y^2 + 1.5804Y^3 - 1.074Y^4 - 0.0318Y^5 + 0.21755Y^6,$$

$$Y = 1000.0 \times ((\gamma / MW) \times \text{Sol}(\text{mole fraction}))^2 \exp(\gamma / MW / MW).$$

For lighter oil (for  $MW < 300$ ):

$$SF = 1 + 0.048411Y - 0.9928Y^2 + 1.6019Y^3 - 1.2773Y^4 - 0.48267Y^5 + 0.06671Y^6.$$

### CO<sub>2</sub>-OIL DENSITY

For the CO<sub>2</sub>-oil density, as evident from Table 7 and Fig 4, Emera and Sarma (2006) model yielded a much lower error than the Quail *et al.* (1988) model. In addition, this model could be applied over a wider range of conditions. Table 8 presents a summary of the experimental data range used in this study for testing of the CO<sub>2</sub>-oil density correlations.

#### Quail et al (1988)

$$\rho = (C_1 - C_2(T + 273.16) + C_3 P_s) \frac{\exp(-C_4 \text{Sol}(\text{mole fraction}))}{(1 + C_5(\text{CH}_4, \text{mole fraction}))}$$

Where the coefficients used for Senlac region heavy oil were found to be:  $C_1 = 1.1571$ ,  $C_2 = 0.6534\text{E-}03$ ,  $C_3 = 0.7989\text{E-}03$ ,  $C_4 = 35.8\text{E-}04$ ,  $C_5 = 50.86\text{E-}0$ .

#### Emera and Sarma (2006)

Emera and Sarma CO<sub>2</sub>-oil density correlation accounts for the saturation pressure, temperature, oil specific gravity and initial oil density at the specific temperature

$$\rho = \rho_i - 0.10276y^{0.608} + 0.1407y^{0.6133},$$

$$\text{where } y = (\gamma * P_i (P_s - P_b)^{1.25}) / (1.8T + 32)$$

## CO<sub>2</sub>-OIL VISCOSITY

For CO<sub>2</sub>-oil viscosity, compared to other correlations (Beggs and Robinson (1975) and Mehrotra and Svrcek (1982)), Emera and Sarma (2006) CO<sub>2</sub>-oil viscosity correlation appeared to yield more accurate results (see Table 9 and Fig. 5). Also, it could be used successfully for a wider range of conditions (e.g., has been applied for up to 12086 mPa.s). Table 10 presents a summary of the experimental data range used in this study for testing of the CO<sub>2</sub>- oil viscosity correlations.

### Beggs and Robinson (1975)

Beggs and Robinson correlation neglects the dependence of oil viscosity on the composition since oils of widely varying compositions have the same gravity. Also, this correlation neglects the dependence of the viscosity on the pressure. The correlation is presented as follows:

For dissolved gas (e.q. CO<sub>2</sub>):

$$\mu = A(10^X - 1)^B,$$

where:

$$X = 10^{(3.0324 - 0.02023 \gamma_o)} (1.8T + 32)^{-1.163}$$

$$A = 10.715 \left( \frac{\text{Sol} (m^3/m^3)}{5.615} + 100 \right)^{-0.515}$$

$$B = 5.44 \left( \frac{\text{Sol} (m^3/m^3)}{5.615} + 150 \right)^{-0.338}$$

### Mehrotra and Svrcek (1982)

$$\log \log (\mu) = a_1 + a_2 T + a_3 P_s + \frac{a_4}{(T + 273.16)} P_s,$$

where  $a_1 = 0.815991$ ,  $a_2 = -0.0044495$ ,  $a_3 = 0.076639$ ,  $a_4 = -34.5133$ .

This correlation was developed for CO<sub>2</sub>-saturated bitumen, based on the pressure and temperature.

Limitations:

1. Temperatures range from 23.89° C to 97.22° C;
2. Pressures up to 6.38 Mpa.

### Quail et al (1988)

Quail et al correlation is a function of: saturation pressure, temperature, CH<sub>4</sub> mole fraction, and CO<sub>2</sub> this correlation was developed based on heavy oil data from Senlac region, is presented as follows:

$$\mu = \left( 10^{C_1(T+273.16)^{C_2}} + C_3 P_S - 1 \right) \frac{\exp(-C_4 \text{Sol (mole fraction)})}{(C_5(\text{CH}_4, \text{mole fraction}) + 1)},$$

where, for Senlac region of Saskatchewan, Canada:

C<sub>1</sub> ("defines the original dead oil viscosity") = 5.1942E08, C<sub>2</sub> = - 3.3163, C<sub>3</sub> = 62.612, C<sub>4</sub> = 6.374, C<sub>5</sub> = 10.309.

This correlation modified Beggs-Robinson (1975) to account for CO<sub>2</sub> dissolved in oils.

Limitations :

1. Viscosity range from 7.1 to 2600 mPa.s;
2. Pressures upto 17.0 MPa;
3. Temperatures up to 140° C.

### Emera and Sarma (2006)

Emera and Sarma CO<sub>2</sub>-oil viscosity correlation is developed based on the CO<sub>2</sub> solubility, initial oil viscosity, saturation pressure, temperature, oil specific gravity.

The effect of CO<sub>2</sub> liquefaction pressure is included in this correlation through the CO<sub>2</sub> Solubility variable.

$$\mu = y * \mu_i + A (\text{Sol (mole fraction)} / \mu_i),$$

where

$$y = x^B,$$

$$x = (C * \mu_i (Ps / (1.8T + 32)) D)^{(y * \text{Sol (mole fraction)})},$$

$$A = - 9.5, B = - 0.732, C = 3.14129, D = 0.23.$$

## RECOMMENDATION AND CONCLUSIONS

Visual Basic software was developed in this study and was successfully used as a comparison and predictive tool for CO<sub>2</sub>-oil physical properties. This software has been tested and validated the comparison and property prediction using literature data sets.

Experimental data available in the public domain were used in testing of different CO<sub>2</sub>-oil physical properties correlations. Based on the data used in this study and keeping in mind the limitations of this data, the following conclusions are made.

- The Visual Basic software that has been developed in this study proved to be an efficient method in testing of the different literature models (CO<sub>2</sub> solubility, oil swelling factor, CO<sub>2</sub>-oil density, and CO<sub>2</sub>-oil viscosity). It can be used as a predictive tool to use certain literature correlation to predict the CO<sub>2</sub>-oil physical properties.

- Emera and Sarma (2006) CO<sub>2</sub>-oil mixture physical properties models prediction presented a more reliable prediction with higher accuracy than the other models tested in this study.

- Besides the higher prediction results with better accuracy, Emera and Sarma (2006) models were capable of covering a wider range of oil properties, with regard to oil gravities, pressures up to 34.5 MPa, oil MW > 490, oil viscosities up to 12000 mPa.s, and temperatures up to 140° C.

- In the absence of any measured site-specific interactions data and when the project financial situation is a concern, Emera and Sarma (2006) correlations could be used as an effective predictive tool to guesstimate CO<sub>2</sub>-oil physical properties for initial design calculations. They can be used as a fast track gas flooding project screening guide. In addition, they could contribute towards designing a more efficient and economical experimental programs.

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Table 3

Comparison between the CO<sub>2</sub> solubility literature correlations.

Correlations	No. of data	Average Error, %	STDEV, %
Emera and sarma, (2006)	06	0	5.6
Simon and Graue (1965)	49	5.72	10.8
Mehrotra and Svrcek (1982)	106	32.6	36.6
Chung <i>et al.</i> (1986)	106	83.7	150.3

Table 4

Experimental data range used in this project for testing oil correlation

Variable	Minimum value	Maximum value
Saturation pressure ,Ps(MPa)	0.5	27.4
Temperature(ec)	18.33	140
MW	196	490
Oil gravity,(API)	12	37.3

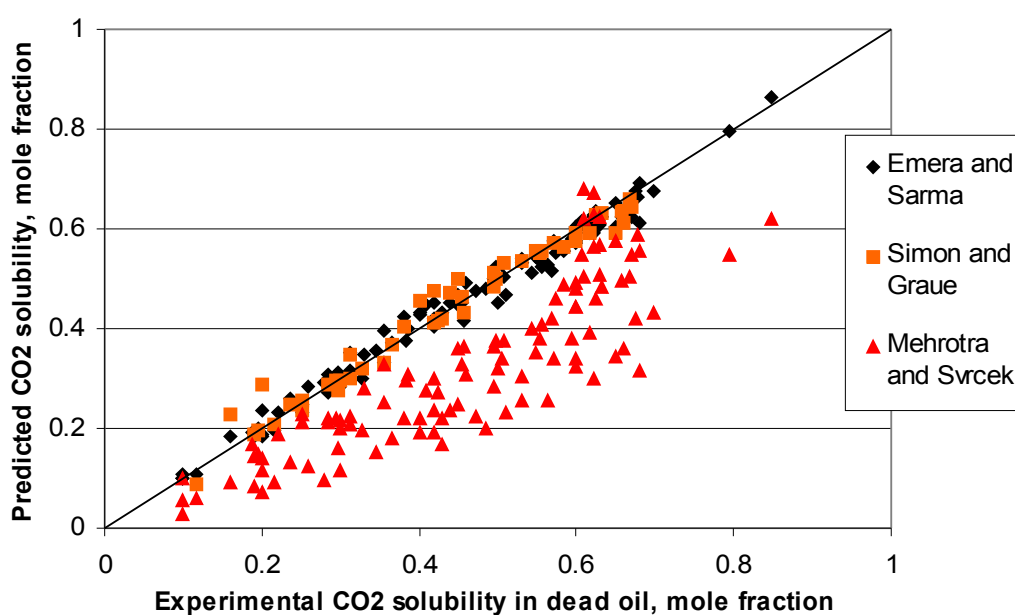


Figure 2. Comparison results between Emera and Sarma (2006) CO<sub>2</sub> solubility, Simon and Graue (1965), and Mehrotra and Svrcek (1982) correlations

Table 5

Comparison between different swelling factor correlations

Correlations	No. of data	Average Error, %	STDEV, %
Emera and sarma (2006)	85	0.61	0.94
Simon and Graue (1965)	83	1.0	1.7

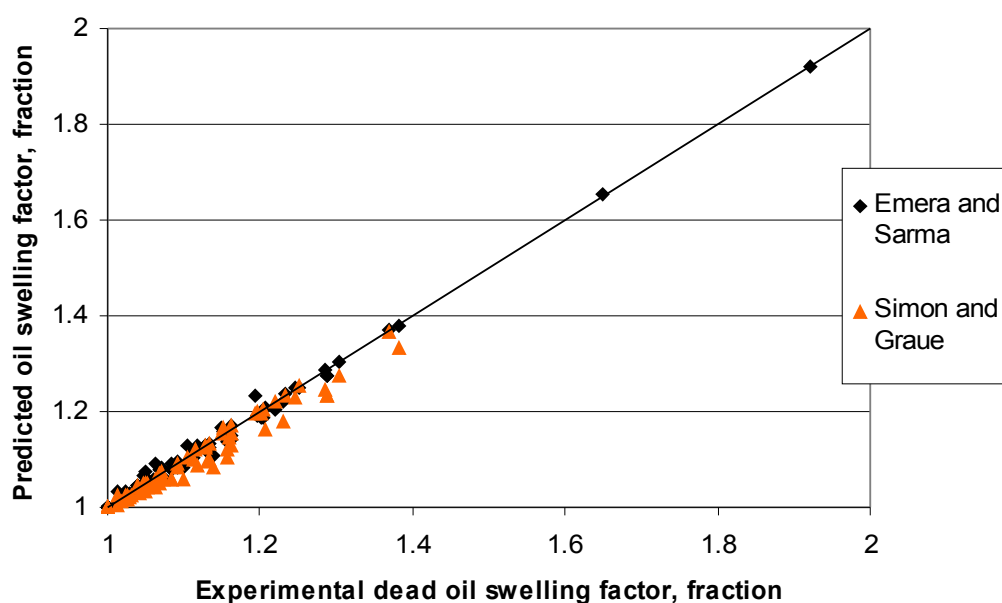


Figure 3. Comparison results between Emera and Sarma (2006) and Simon and Graue (1965) oil swelling factor (due to CO<sub>2</sub>) correlations prediction results.

Table 6

Experimental data range used in this study for testing of oil swelling factor (due to CO<sub>2</sub>) correlations

Parameters	Minimum value	Maximum Value
Saturation pressure, Ps(MPa)	0.1	27.4
Temperature (°C)	23	121.1
MW	205	463
Oil gravity, (API)	11.9	37.3

Table 7

Comparison between Emera and Sarma (2006) and Quail *et al.* (1988) correlations results for the CO<sub>2</sub>- oil density prediction

Correlations	No. of data	Average Error, %	STDEV, %
Emera and sarma (2006)	136	0.29	0.43
Quail et al (1988)	129	3.0	4.8

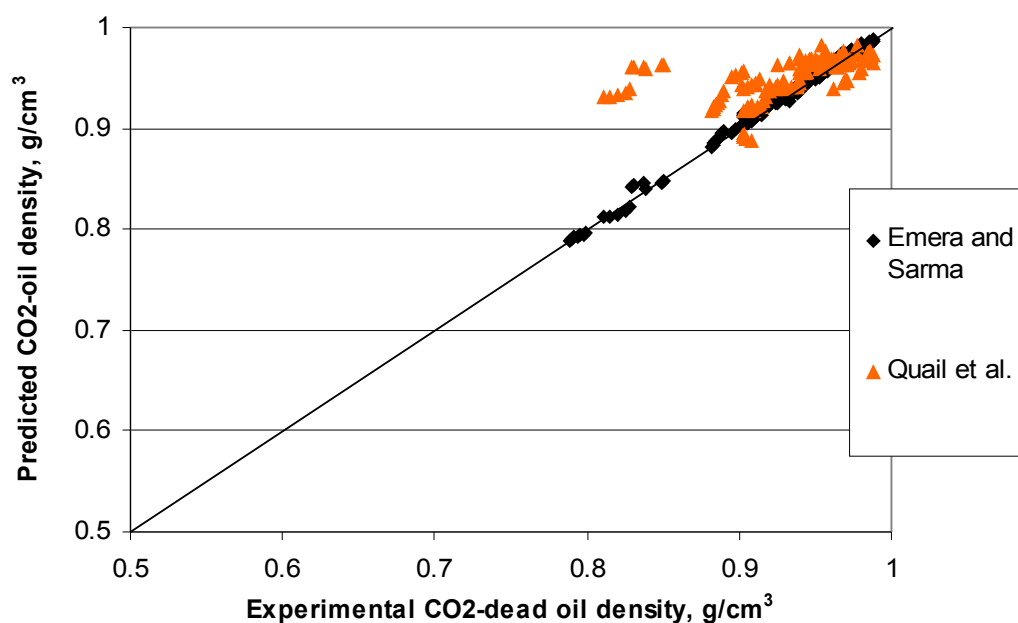


Figure 4. Comparison results between Emera and Sarma (2006) and Quail *et al.* (1988) CO<sub>2</sub>-oil density correlations prediction results.

Table 8

Experimental data range used in this study for testing of the CO<sub>2</sub>- oil density correlations

Parameters	Minimum value	Maximum Value
Saturation pressure, Ps (MPa)	0.1	34.5
Temperature (°C)	18.33	121.4
MW	246	490
Oil gravity, (API)	11.9	37.3
Initial density, (gm/cc)	0.789	0.9678

Table 9

Comparison between CO<sub>2</sub>- oil viscosity literature correlations

Correlations	No. of data	Average Error, %	STDEV, %
Emera and Sarma (2006)	130	6.0	8.8
Beggs and Robinson (1975)	130	56.8	62.7
Mehrotra and svrcek (1982)	130	94.3	95.2
Quail et al. (1988)	130	208.9	376.43

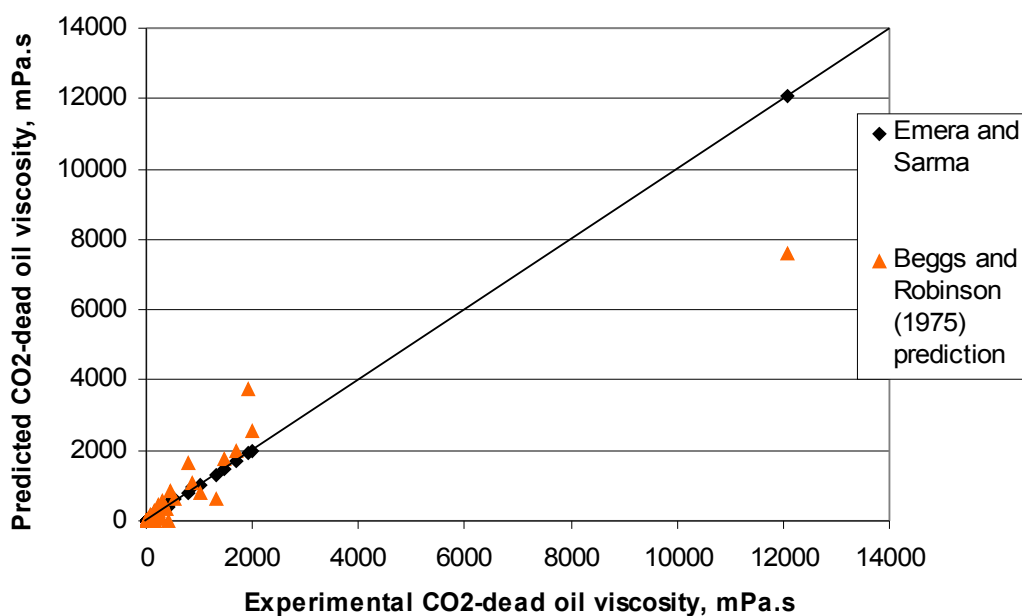
Figure 5. Comparison results between Emera and Sarma (2006) and Beggs and Robinson (1975) CO<sub>2</sub>- oil viscosity correlations

Table 10

Experimental data range used in this study for testing of the CO<sub>2</sub>- oil viscosity correlations

Parameters	Minimum valu	Maximum Value
Saturation pressure, Ps(Mpa)	0.1	34.48
Temperature(°C)	21	140
MW, (Ib/mol)	205	530
Oil gravity, (API)	10	37.3
Solubility, mole fraction	0.0	0.768