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Oil Viscosity Models for Greater Burgan Oilfield-Kuwait

Asrar AlShammari[1], Osamah Alomair[2], Adel Elsharkawy[2]

[1]*Kuwait Oil Company*
[2]*Kuwait University*

Corresponding Author:** ***Asrar AlShammari, *Kuwait Oil Company*

Abstract: *In the petroleum industry, the prediction of viscosity using correlations is commonly used for solving many reservoir engineering and surface production problems. In the last seven decades, several black oil viscosity models have been developed. However, these models may only be suitable for the geological regions for which they were developed and may not provide acceptable results for crude oils for other regions.*

The purpose of this paper is to create a comprehensive oil viscosity models for the Greater Burgan Oilfield-Kuwait which is the second-largest oil field in the world with estimated recoverable oil of nearly 6% of the world's proven conventional oil reserve. Therefore, 824 data points of oil viscosity measurements for the Greater Burgan Oil Field has been used to evaluate the accuracy of the published models and later used to develop a new oil viscosity models for estimating dead, saturated, bubble point, and under saturated oil viscosities. The validity and accuracy of the proposed models were confirmed by comparing their predictions with 166 measured data points from the field itself. These new models showed better accuracy in estimating oil viscosity in all pressure and temperatures ranges, compared to previously published viscosity ones. Additionally, the results show that using the newly developed black oil models, the viscosity of Greater Burgan Oil Field crudes can be predicted with AARE values of 5.86% for dead oil, 4.8% for saturated oil, 5.4% at bubble point, and 1.9% for undersaturated oil. The new models will improve our predications of oil flow rate, pressure drop in tubing and flow lines and hence the design of production equipment and surface facilities. These models can easily be integrated into reservoir simulation for planning primary, secondary and EOR studies.

Keywords: *Dead oil viscosity, saturated oil, undersaturated oil viscosity, Black oil models, live oil viscosity models.*

1. INTRODUCTION

The purpose of this work is to develop simple black oil models to predict oil viscosity (Dead, bubble point, saturated, and undersaturated) for Greater Burgan oil field under different conditions of pressure and temperature. using large data bank. This paper is structured as introduction and review to various published models and their range of applicability, data bank of Burgan oil field, assessment of the previously published models, development of new models, discussion of the accuracy and validity of the new models, finally limitation, and summary and conclusion.

Viscosity is one of the most important physical properties of crude oils. Crude oil viscosity, which is a measure of its fluidity, is a critical required parameter for many aspects of petroleum engineering calculations. Knowledge of crude oil viscosity helps in evaluating fluid flow in a reservoir, determining the most suitable method to recover oil from a specific reservoir, and defining the amounts of recoverable oil under primary, secondary, or enhanced methods. In reservoir studies, viscosity values are required for material balance calculations, estimates of oil initially in place, reserves, future reservoir performance, and ultimate hydrocarbon recovery. Viscosity is also very important for the design of production equipment and pipelines. Reservoir simulators require oil viscosity under different conditions of pressures and temperatures, and the accuracy of viscosity values can conclusively affect simulation results. Viscosity data are currently obtained through standard pressure-volume-temperature (PVT) laboratory analysis. Time and cost of oil viscosity measurements are the main disadvantages of such laboratory analysis. Even though experimental measurements of viscosity could be given as a function of pressure, they are typically measured at reservoir temperature. In some cases, the sample volume may be inadequate for running a complete fluid analysis. Another important consideration is the extent to which the collected sample is representative of reservoir fluid. Errors of lab analysis and measurement equipment also have an impact on accurate viscosity determination. For light oils, the typical uncertainty of oil viscosity is about 10%, with an effect of 10% on flow rates, fractional flow, and recovery factor. Accurate fluid viscosity determination is therefore key to minimizing technical risks and maximizing asset value (Honarpour, 2006). The previously mentioned highlights the necessity of developing a predictive model to estimate crude oil viscosity. Published models can be classified as follows:

I-Fundamental Models: these are mainly used to find viscosities of pure components and their mixtures. They are very accurate but applicable only to simple fluids.

II-Correlative Models: these are derived from experimental tests. The oil industry has depended mostly on these and practical experience. These models are simple and only require a few field-measured variables. There are two main types:

a) Generic Correlations: these are developed from random datasets.

b) Specific Correlations: these are used for specific oil types or geographical areas and have better performance than generic correlations for the areas which they were developed from (Dindoruk and Christman, 2001). This type is the focus of this work.

III-Semi-fundamental models: these are based on theoretical principles such as corresponding states and their extensions, and on some parameters that are experimentally determined. They combine fundamental and correlative models and are also made up of compositional models.

According to the definitions of the United Nations Institute for Training and Research, the crude oils from the Greater Burgan Oil field should be considered as light crude where the API gravity greater than 31°, density below 934 kg/m^3 and viscosity below100 cP, **Table 1**.

Table1. *UNITAR Definition of Light Oil, Heavy Oil, and Bitumen (Motahhari, 2013)*

Crude Oil type	Oil Viscosity (cP)	Oil Density (kg.m^{-3})	API Oil Gravity (°API)
Light Oil	< 100.0	< 934.0	> 20.0
Heavy Oil	100.0-100000.0	934.0-1000.0	10.0-20.0
Bitumen	> 100000.0	> 1000.0	< 10.0

This work focuses on the development of viscosity models capable of accurate prediction of the Greater Burgan Oil Field (GBOF), based on easily measured reservoir parameters, namely API gravity, bubble point pressure, reservoir temperature, solution gas-oil ratio (GOR), and reservoir pressure.

Due to variations and complexities of crude oil composition, there have been many efforts to model oil viscosity. Many correlating equations for estimating viscosity were published for several geographic locations. Viscosity correlations can be divided into compositional and black oil models. Compositional models predict crude oil viscosity as a function of temperature, pressure, and composition (Kamel et al. , 2019).

Conversely, black oil models are based on field measured data; stock-tank oil gravity, bubble point pressure, solution GOR, reservoir pressure, and temperature. All the published Models were developed from data obtained in specific parts of the world. This produces different errors in viscosity estimation, as the paraffinic and asphaltic crude oil composition vary from location to another. The widely used black oil models are summarized in **Appendix A**. **Tables A1 to A4** reports the ranges and limitations of all input parameter values used by various authors in developing the dead, saturated, bubble point and, undersaturated viscosity models are as shown in these tables. The tables also show reservoir parameters utilized in the published oil viscosity models.

Recently, there have been many models presented based on ANN or machine learning to predict crude oil viscosity. Hajirezaie et al. (2017) presented ANN model to predict the undersaturated oil viscosity. Zhang et al. (2019) presented ANN model to predict the apparent viscosity of waxy crudes. khanehchi et al. (2000) describe AAN model to predict the dead oil viscosity of light and medium crude oils. Sniha et al. (2000) also discussed the application of machine learning in predicting the dead oil viscosity. However, all these soft computing methods or machine learning do not present a model or an algorithm for the crude oil viscosity estimation. Additionally, Khemka et al. (2001) presented a model for viscosity prediction using one parameter friction theory.

2. GREATER BURGAN CRUDE OIL DATA BANK

The data bank used in this study to determine the viscosity of Greater Burgan oils was mainly obtained from PVT reports; either provided by the Kuwait Oil Company or experimentally conducted at Kuwait University. The utilized data were derived from 61 PVT laboratory analyses of bottom-hole samples, representing most of the entire producing reservoirs in the Burgan Oil Field (5 reservoirs); the remaining data were from 5 tested oil samples taken from the Burgan Oil Field. In total, 990 data points from PVT tests were used, divided into 332 data points for saturated reservoir oil, 526 data points for undersaturated reservoir oil, and 66 data points for both dead and bubble points. Bottom-hole samples had been differentially liberated to obtain solution GOR, and viscosity data had been measured using an EMV. Data points were divided into four databases for dead, saturated, bubble point, and under saturated oil viscosity, respectively. **Table 2** shows data ranges utilized in this study to develop the proposed models.

Table2. *Fluid Properties Information Summary (66 PVT Analysis/990 Data Points)*

Oil Properties	Minimum	Maximum
Pressure, (Psia)	15	10015
Bubble Point Pressure, (Psia)	615	4116
Reservoir Temperature, (°F)	112	232
Stock-Tank Oil Gravity, ($°\boldsymbol{API}$)	20.4	39.1
Gas Specific Gravity	0.704	0.95
Solution GOR, (SCF/STB)	36	1953
Dead Oil Viscosity, (cP)	1.28	86.20
Saturated Oil Viscosity, (cP)	0.24	46.00
Bubble Point Oil Viscosity, (cP)	0.179	26.5
Undersaturated Oil Viscosity, (cP)	0.19	27.60
Saturated Oil Density, (gm.cm-3)	0.63	0.91
Bubble Point Oil Density, ($\boldsymbol{\rho ob}$, gm.cm-3)	0.574	0.876
Undersaturated Oil Density, ($\boldsymbol{\rho ob}$, gm.cm-3)	0.59	0.90

To ensure a reliable and consistent PVT data set, data from the 61 PVT reports collected from the KOC and the 5 measured samples were analyzed before correlating oil viscosity equations. The database of Kuwaiti crude oils from the GBOF was divided randomly into two sets. The first set (training dataset), comprising 824 data points from 55 samples, was used to test published models and develop a new ones. The second set (testing dataset), containing 166 data points from 11 samples, was used to test the accuracy and validity of the developed models.

2.1. Sensitivity Analysis

The previously described viscosity data has been used, to evaluate effective of each parameters on viscosity, and to determine the relationships between independent and dependent variables. For this reason, a sensitivity analysis was carried out to determine influential parameters for dead, bubble point, saturated, and undersaturated oil viscosities. **Figure 1.** shows the relationship between oil viscosities and other parameters. Dead oil viscosity inversely proportional to API gravity and reservoir temperature. Although reservoir temperature is known to have a strong influence on dead oil viscosity, here it shows a small negative effect. This could be because of the limited temperature range. Bubble point oil viscosity is mostly affected by dead oil viscosity.

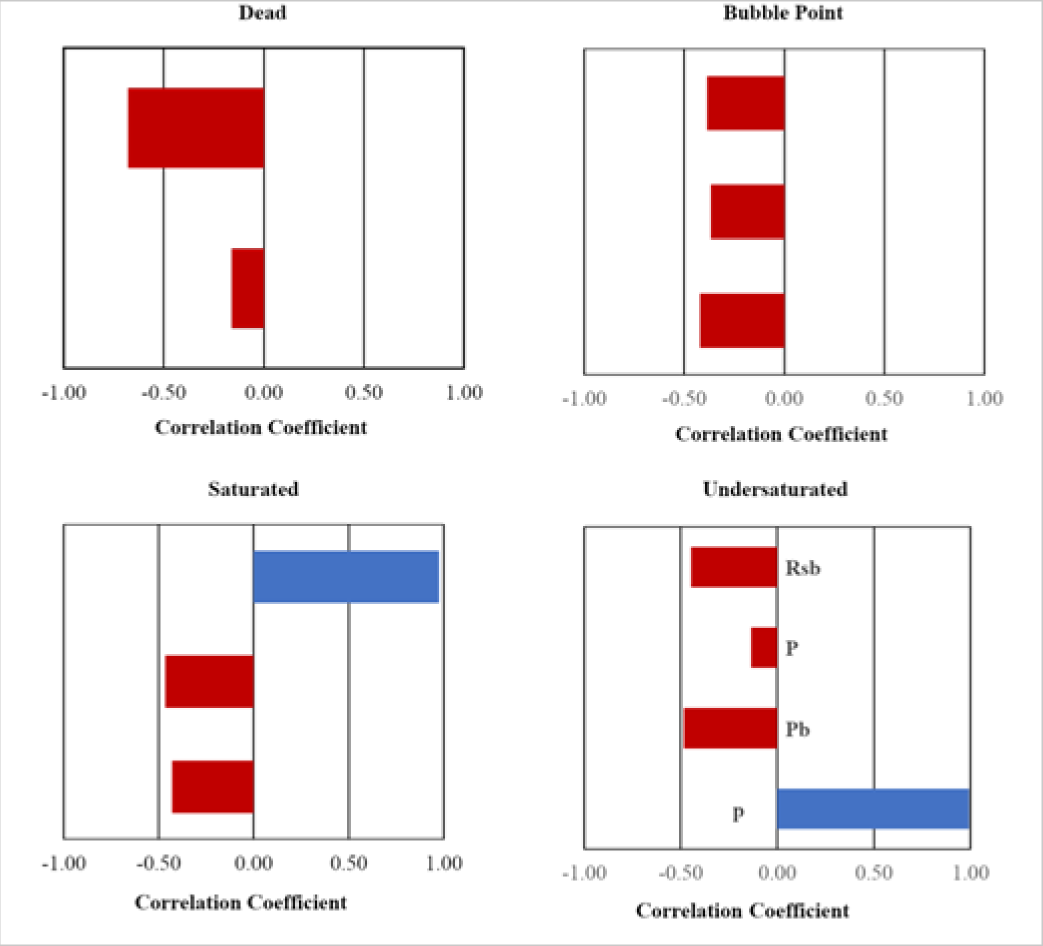


Figure1. *Model Coefficient between Oil Viscosity and Other Fluid Parameters*

Figure 1. clearly shows a strong direct proportional relationship between saturated oil viscosity and dead oil viscosity. Bubble point pressure, solution GOR, and reservoir pressure inversely affect saturated oil viscosity. Dead oil viscosity, solution GOR, bubble point pressure, and reservoir pressure were considered in developing a new saturated oil viscosity model. From the chart, it is easy to see that viscosity at the bubble point is directly proportional to undersaturated oil viscosity, while the remaining variables were inversely proportional. Conversely, parameters with which there is a negative correlation (inversely proportional) are bubble point pressure, solution GOR, and reservoir pressure. Bubble point pressure has the strongest inverse relationship with undersaturated oil viscosity, followed by solution GOR. The effect of reservoir pressure on undersaturated oil viscosity is relatively small. All these influential parameters are included in the developed undersaturated oil viscosity model.

3. ASSESSMENT OF PUBLISHED OIL VISCOSITY MODELS

The accuracy of the published black oil models was checked against the 824 observed data points (training data set). The performance of these published viscosity models was evaluated statistically and graphically through error analysis. Statistical error evaluation was based on different statistical functions, namely average relative error (ARE), average absolute relative error (AARE), and standard deviation.

3.1. Dead Oil Viscosity Models

The published dead oil viscosity models listed in **Table 2**. were tested using 55 points (training dataset). All these models are easy to use and depend only on API gravity and temperature as input parameters, except the Dindoruk and Christman (2001) model, which requires two more parameters, bubble point pressure, and the GOR at bubble point. **Figure 2a** shows that the best overall statistical error performance was obtained by the Labedi (1992) model, followed by Bergman (1992), Elsharkawy-Gharbi (2000), and Al-Khafaji et al. (1987). As expected, there was a high degree of error in estimated viscosity from models developed for heavy or extra-heavy oil, such as Bennison (1998), Hossain (2005), and Alomair et al. (2014) or a wide range of crudes such as Kartoatmodjo (1991), and Standing (1997). This confirms the importance of considering the type of fluid when chosen a model for viscosity estimation.

3.2. Bubble Point Oil Viscosity Models

Four published viscosity models for bubble point viscosity prediction are considered for evaluation. These models were tested against 55 points from the training database. **Figure 2b** shows that the lowest AARE was obtained from the Abu-Khamsin (1991) model. Labedi et al. (1992) model gave the highest AARE even though it is developed for light crude in API gravity range similar to Greater Burgan. These high levels of error when predicting the bubble point viscosity of Kuwaiti crude oils indicate that oils from a given region have some physio-chemical characteristics that are different from another region and confirm the need to develop a new model for Greater Burgan.

3.3. Undersaturated Oil Viscosity Models

All the published undersaturated oil viscosity models listed in **Table A-3** in the appendix**.** have been tested using 437 undersaturated viscosity data points (training dataset). **Figure 2c** shows that models are ranked based on AARE, from lowest to highest. This figure indicates that Almehaideb (1997) model has very good performance when tested against the training dataset. Comparatively, the Naseri et al. (2005) model exhibited the highest AARE.

3.4. Saturated Oil Viscosity Models

Accuracy of the published saturated oil viscosity models was tested using 277 viscosity points from the (training data set). **Figure 2d** shows that Kartoatmodjo (1991) model had the best accuracy, suggesting that the use of dead oil viscosity with solution GOR is very useful. Standing's (1977) model which is also the function of dead oil viscosity and solution GOR, showed the second-best performance. Conversely, Khan et.al. (1987) model, which is a function of pressure difference (between reservoir pressure and bubble point pressure) and bubble point viscosity showed a slightly higher error. The Labedi et al. (1992) model, which uses the same parameters in addition to API gravity, recorded even higher error than the Khan et al. model, suggesting that the inclusion of API gravity did not enhance the performance.

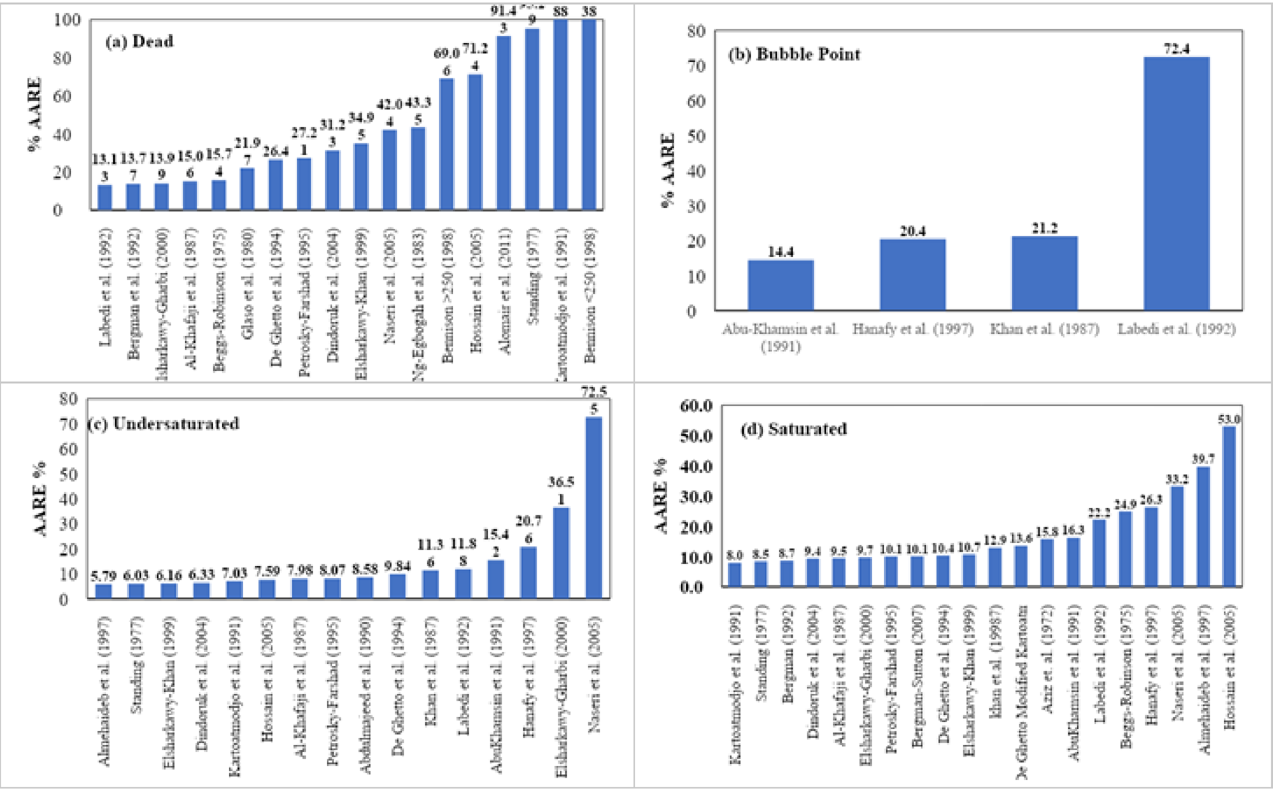


Figure2. *Average Absolute Relative Error of Published Oil Viscosity Models*

4. DEVELOPMENT OF NEW MODELS

It has been established in the literature that various viscosity models, dead (μ_{od}), satuarated (μ_{ob}) and undersaturated) (μ_{oa}) can be describe as functions of the most influential and easily measured parameters, as follows:

$$\mu_{od} = f\ (API, T) \qquad (1)$$

$$\mu_{obp} = f\ (\mu_{od}, P_b, R_{sb}) \qquad (2)$$

$$\mu_{ob} = f\ (\mu_{od}, P, P_b, R_s) \qquad (3)$$

$$\mu_{oa} = f\ (\mu_{obp}\ , P, P_b, R_{sb}) \qquad (4)$$

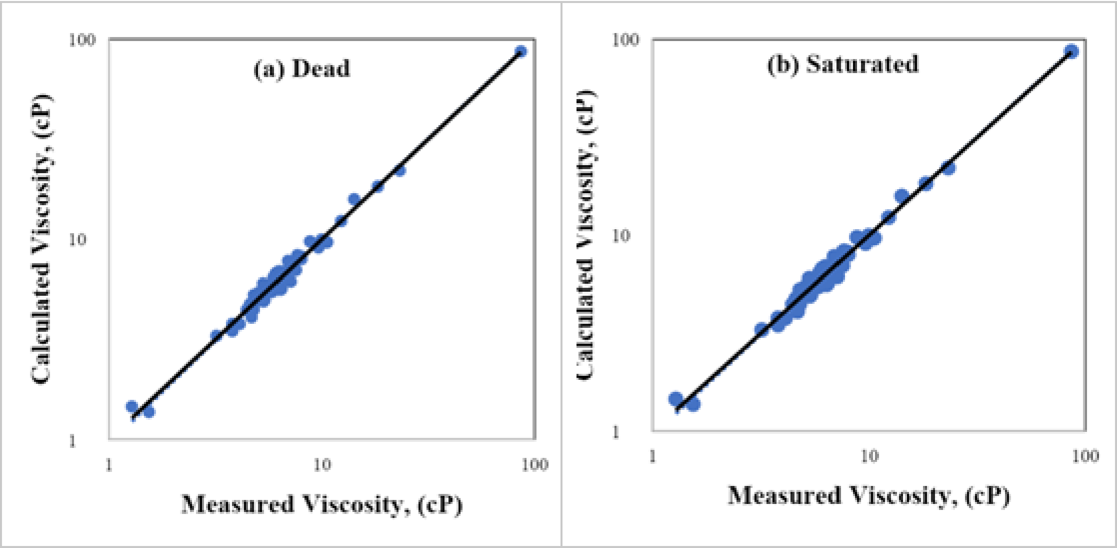
The relationship between the dependent variable (viscosity) and its independent variables was examined. Different functional forms of the independent variables were tested. This is very important to increase the model efficiency. Models were then developed using multiple non-linear regression techniques (based on the training data), taking the lowest AARE and highest Model coefficient as a target.

4.1. Dead Oil Viscosity Model

As mentioned earlier, the most easily measured and influential parameters affecting dead oil viscosity are reservoir temperature and API gravity, with these used in most published dead oil models. Using the 55 dead oil viscosity points of the training dataset, a new equation was developed. The proposed model has the form of a natural logarithm $ln(\mu_{od})$ as the dependent variable and two independent variables the API gravity and reservoir temperature, as follows:

$$ln\ ln\ (\mu_{od}) = a_0 + a_1\ API + a_2\ API^2 + a_3\ ln\ ln\ T \qquad (1)$$

The developed model is based on API gravity and reservoir temperature. Although reservoir temperature had only a small effect (as stated earlier, see Figure1), it was important to include it to improve model prediction and to account for potential model application to other temperatures. **Figure 3a.** shows the cross plot obtained when using the proposed dead oil viscosity model. The coefficient of determination is 99.8%. **Figure 4a.** shows that the histogram of residual data is bell-shaped, residuals are normally distributed, and most frequent in the range of 0.33 cP This means that, when using the proposed model, most predicted dead oil viscosity values deviate by 0.33 cp.



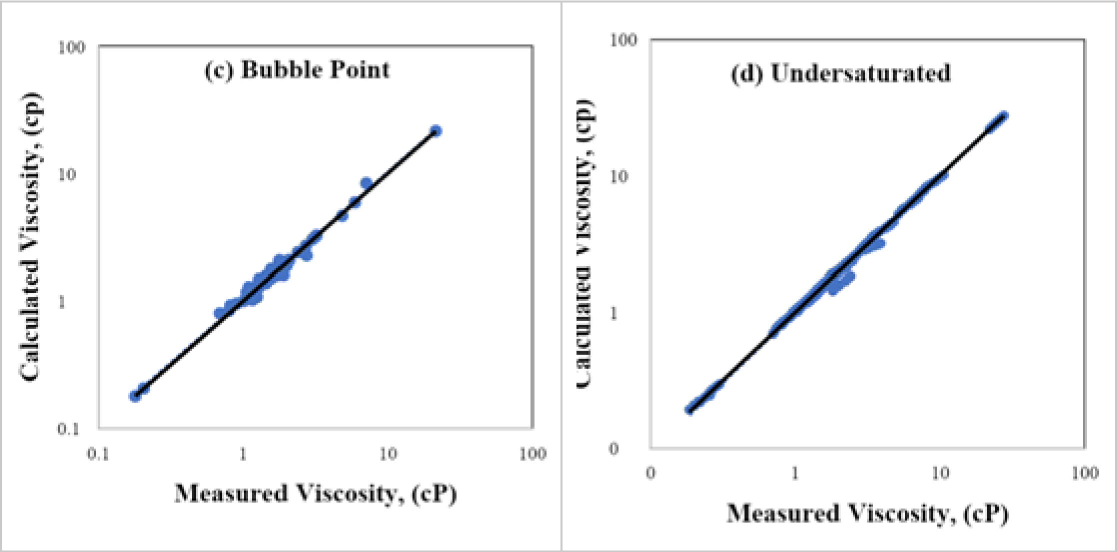


Figure3. *Calculated Viscosity using Proposed Models vs. Experimentally Measured Viscosity Data*

4.2. Saturated Oil Viscosity Model

As saturated oil viscosity has a strong direct proportional relationship with dead oil viscosity, and a strong inverse relationship with bubble point pressure, solution GOR, and reservoir pressure, these variables (R_s, P, P_b) were considered in developing the new saturated oil viscosity model. This is as follows:

$$ln\ ln\ \mu_{ob} = a_0 + a_1\ ln\ ln\ \mu_{od} + a_2 \frac{1}{\sqrt{R_s}} + a_3 \frac{1}{P} + a_4\ P_b \qquad (2)$$

Dead oil viscosity can be estimated from the developed dead oil viscosity model without the need for any viscosity measurements. **Figure 3b.** shows the cross plot obtained using the proposed saturated oil viscosity mode, with an excellent coefficient of determination of 99.51%. The frequency distribution of residual values when using the model is shown in **Figure 4b.** Most the predicted values deviate from 0.01 to 0.18 cp from actual measurements.

4.3. Bubble Point Oil Viscosity Model

Similar to the approach used for developing the dead oil viscosity model, the following bubble point oil viscosity model was developed using 55 data points:

$$ln\ ln\left(\mu_{obp}\right) = a_0 + a_1\ ln\ ln\ (P_b) + a_2\ {R_s}^{0.5} + a_3\ ln\ ln\ \mu_{od} \qquad (7)$$

This model relates bubble point viscosity to bubble point pressure, GOR, and dead oil viscosity. As shown in **Figure 3c**, the determination coefficient of this model is 99.5%. When using the proposed model, most predicted viscosity values deviate by 0.22 cp from actual measurements as shown in **Figure 4c**.

4.4. Undersaturated Oil Viscosity Model

The undersaturated oil viscosity model is a function of bubble point viscosity, GOR, bubble point pressure, and reservoir pressure, as follows:

$$ln\ ln\ \mu_{oa} = ln\ ln\ \mu_{obp} + A\frac{P}{P_b} \qquad (8)$$

$$\mu_{oa} = exp\ exp\ \left(ln\ ln\ \mu_{obp} + A\frac{P}{P_b}\right) \qquad (9)$$

Where:

$$A = f\ (R_{sb}) \tag{10}$$

$$A = a_0 + a_1\, R_{sb} + a_2\, R_{sb}^2 + a_3\, R_{sb}^3 \tag{11}$$

The cross plot of the proposed model is shown in **Figure 3d**. The model has an excellent coefficient of determination of 99.94%. **Figure 4d.** shows the frequency distribution of residual values. Most of the viscosity values deviated from actual measurements by 0.002–0.049 cp, which means that this model performs very well in estimating the undersaturated oil viscosity of Greater Burgan oils. The coefficients of regression $a_1$through a_4 for each model are given in **Table 3**.

Table3. *Proposed Oil Viscosity Models Coefficients*

Viscosity Model	a_0	a_1	a_2	a_3	a_4
Dead	23.3365	-0.7611	0.0099	-1.5439	-
Bubble Point	3.026686786	-0.473076903	-0.026238377	0.811198769	-
Saturated	1.7448	0.7958	-0.0292	0.252	-0.0001
Undersaturated	0.146270803	8.56853E-05	8.38227E-08	-3.10321E-11	-

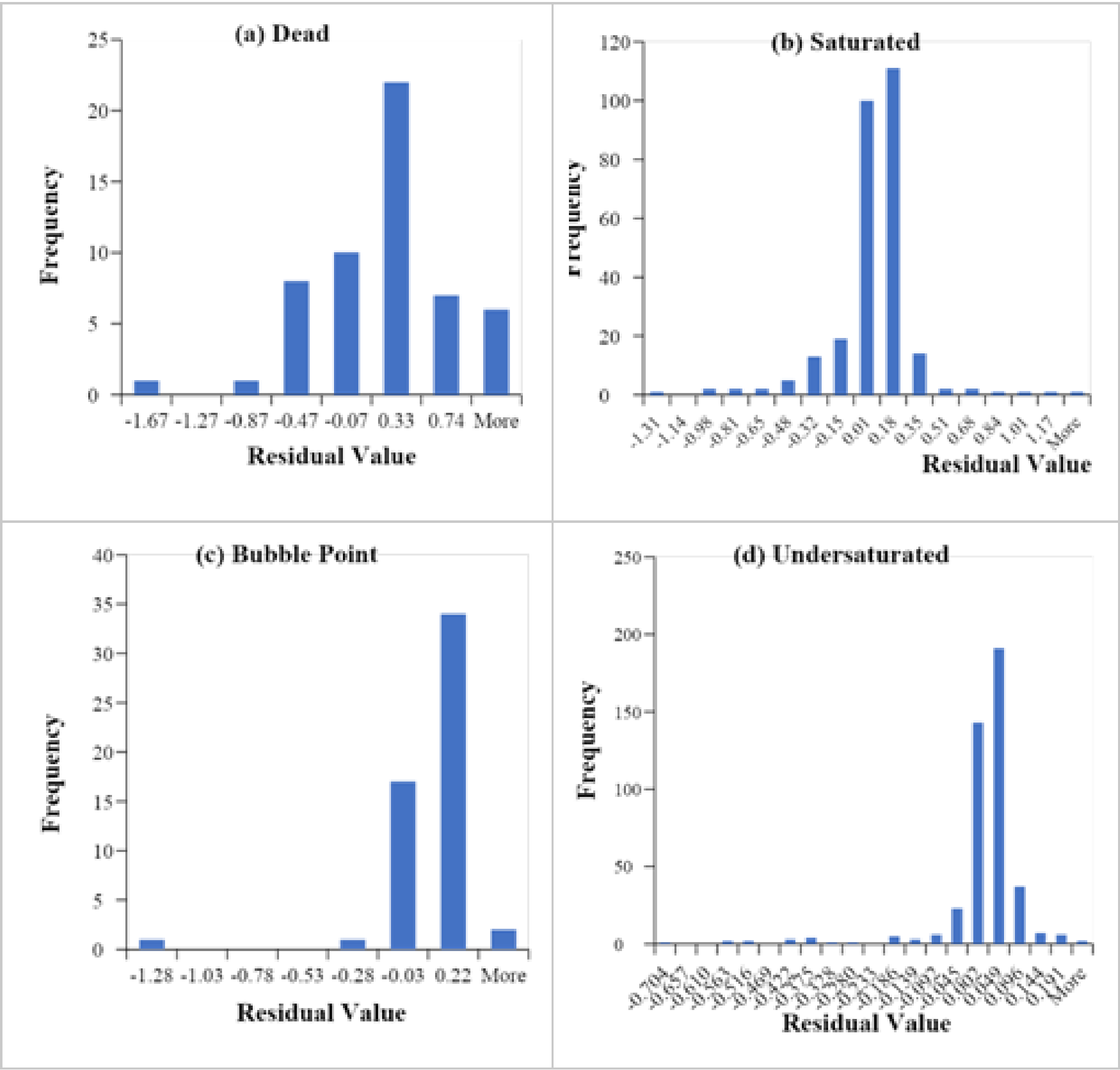


Figure4. *Residual Histogram for the Proposed Oil Viscosity Models*

5. RESULTS AND DISCUSSION

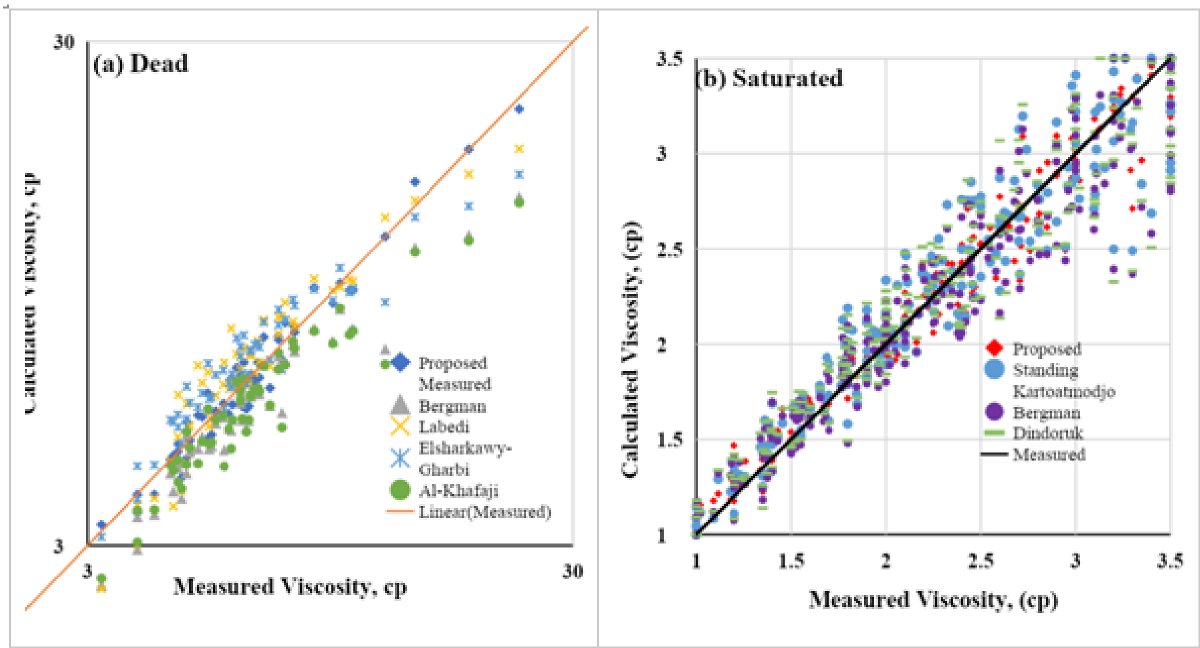
5.1. Accuracy of the Proposed Models

This section summarizes and discusses the accuracy of the newly proposed models in comparison with the best-published ones for estimating the viscosity of Greater Burgan oils (Training dataset) using graphical techniques as well as statistical error analysis.

5.1.1. Cross Plot

Cross plots are usually used as a mean of study the good of fitness of the predicted data to the measured ones. If the data falls on the unite slope line, it indicates a perfect fitness. Great scatter above, below or around the 45-degree line indicates poor fitness.

Cross plot in **Figure 5a** through **5d** shows measured versus predicted viscosity values from the proposed oil viscosity models and the best-performing published oil viscosity models. The plotted data points obtained by the new proposed models are close to the unit slope line (45° line). This indicates that the proposed models have a smaller scatter of values around the 45° line than other models. **Figure 5a** indicates that predicted dead oil viscosities from Labedi (1992) model are closest to those obtained using the newly proposed dead oil one, but the former exhibits more scattering around the unit-slop line. **Figure 5b** illustrates that Kartoatmodjo (1991) saturated oil viscosity model shows the least scattering of all published models, but the scatter is greater than the newly presented saturated oil viscosity model. The Bergman-Sutton (2007), Khan et al. (19987), De Ghetto Modified Kartoatmodjo (1994), Abu Khamsin (1991), Labedi (1992), Hanafy et al. (1997), Almehaideb (1997), and Hossain (2005) saturated oil viscosity models underestimate viscosity values. Conversely, the Naseri (2005) and Aziz et al. (1972) models overestimate saturated oil viscosity values. **Figure 5c** shows the performance of all bubble point oil viscosity models. Labedi et. al. (1992) model shows high overestimate as almost all data points fall above the unit slope line. Conversely, the Hanafy et al. (1997) model shows underestimate for Greater Burgan crudes. The Abu-Khamsin (1991) and Khan et al. (1987) show good predictive performance but more scattering around the 45° line than the proposed model. The performance of all undersaturated oil viscosity models is shown in **Figure 5d**. Almehaideb (1997) model shows some accuracy but exhibits more scattering around the 45° line. On the other hand, the viscosity predictions by Elsharkawy-Khan (1999), Dindoruk (2001) are above the 45º line (indicating overestimation). All published models showed some degree of scattering, except Abu Khamsin (1991), Hanafy (1997), Elsharkawy-Gharbi (2000), and Naseri (2005) models.



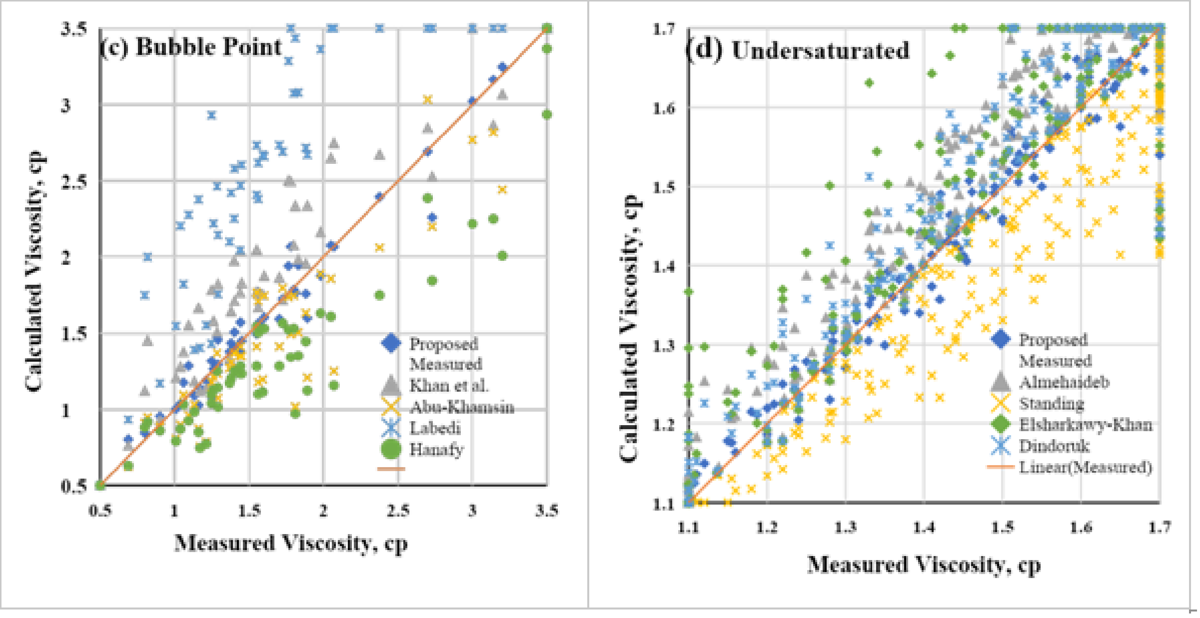


Figure5. *Calculated vs. Experimental Viscosity for Best-Performing Oil Models*

5.1.2. Error Analysis

The results of error analysis for dead oil viscosity models are summarized in **Table 4**. This table shows that the dead oil viscosity model developed in this study has the best results in predicting dead oil viscosity of Burgan oil crudes with the lowest AARE of 5.8%, followed by the Labedi (1992) model which has an AARE of 13%.

The reason that Labedi (1992) has the smallest error level is that it was developed for light oils. Some models shown in **Table 4** have high error level either because they were developed for wide ranges of crude oils (light, intermediate and heavy) such as Kartoatomodjo (1991) or for heavy crudes such as Alomair (2014) or extra heavy oils such as Benison (1998).

Table4. *Summary of Error Analysis for Dead Oil Viscosity Models*

Model	AARE (%)	SD % (AARE)	Sum of Absolute Residual	ARE (%)
Proposed	5.86	4.4	21.5	-0.36
Labedi (1992)	13.13	12.8	82.5	12.5
Bergman (1992)	13.77	10.6	101.3	-6.2
Elsharkawy-Gharbi (2000)	13.99	10.6	100.8	-6.9
Al-Khafaji et al. (1987)	15.06	13.5	106.0	13.6
Beggs-Robinson (1975)	15.74	12.6	118.3	-3.2
Glaso (1980)	21.97	10.2	137.6	21.3
De Ghetto (1994)	26.40	10.3	167.6	24.8
Petrosky (1995)	27.21	10.4	169.6	26.4
Dindoruk- Christman (2004)	31.23	9.2	178.5	30.6
Elsharkawy-Khan (1999)	34.95	31.8	175.4	-27.1
Naseri et al. (2005)	42.04	9.0	220.5	41.5
Ng-Egbogah (1983)	43.35	43.5	194.6	-36.1
Bennison > 250 (1998)	69.06	13.8	290.2	69.2
Hossain et al. (2005)	71.24	12.8	286.5	71.5
Alomair et al. (2011)	91.43	4.9	393.0	91.6
Standing (1977)	95.29	1.0	439.5	95.2
Kartoatmodjo (1991)	233.88	43.2	910.4	-236.8
Bennison < 250 (1998)	481.38	1524.0	1313.7	-507

Table 5 shows the error level for all the models considered in this study as well as the newly proposed one for saturated oil viscosity. The newly proposed exhibits the smallest AARE of 4.8%, ARE of -0.5%, and SD of 4.8%. The three best-performing models are those of Kartoamodjo (1991), Standing (1977), and Bergman (1992), with AARE values of 8%, 8.5%, and 8.7%, respectively. The accuracy of the published models has an AARE ranges from 8% to 53%.

Table5. *Summary of Error Analysis for Saturated Oil Viscosity Models*

Models	**AARE (%)**	**SD % (AARE)**	**Sum of Absolute Residual**	**ARE (%)**
Proposed	4.8	4.8	39.3	-0.5
Kartoatmodjo (1991)	8.0	6.1	81.7	-1.1
Standing (1977)	8.5	6.8	76.1	-1.7
Bergman (1992)	8.7	6.8	87.6	0.3
Dindoruk-Christman (2004)	9.4	6.9	87.9	-1.2
Al-Khafaji (1987)	9.5	7.4	91.5	-4.5
Elsharkawy-Gharbi (2000)	9.7	9.0	87.2	2.6
Petrosky-Farshad (1995)	10.1	8.0	96.0	6.0
Bergman-Sutton (2007)	10.1	7.5	94.3	7.1
De Ghetto (1994)	10.4	6.7	85.5	2.5
Elsharkawy-Khan (1999)	10.7	8.0	98.1	8.3
Khan et al. (19987)	12.9	9.9	126.8	11.8
De Ghetto/Kartoatmodjo (1994)	13.6	15.3	248.8	11.2
Aziz et al. (1972)	15.8	10.4	156.1	-14.5
AbuKhamsin (1991)	16.3	11.7	179.3	9.4
Labedi (1992)	22.2	14.3	223.6	22.1
Beggs-Robinson (1975)	24.9	7.7	207.4	24.2
Hanafy et al. (1997)	26.3	13.1	296.3	23.7
Naseri (2005)	33.2	17.4	386.1	-33.2
Almehaideb (1997)	39.7	13.9	415.1	38.8
Hossain (2005)	53.0	346.8	165.8	-40.7

Table 6. summarizes error analysis for proposed and published models for viscosity estimation at bubble point. The proposed model the best accuracy, compared to other models. The proposed one has AARE and SD of 5.4% and 5.8%, respectively. Surprisingly, Labedi et al. (1992) model, which was developed for Libyan light crude oils similar in API gravity range to Greater Burgan, was found to have the highest AARE. Abu-Khamsin (1991) has AARE of 14.4%, Khan et al. (1987), and Hanafy (1987) have AARE of 20.4 and 21.2% respectively.

Table6. *Summary of Error Analysis for Bubble Point Oil Viscosity Models*

Models	AARE (%)	SD % (AARE)	Sum of Absolute Residual	ARE (%)
Proposed	5.4	5.8	5.6	-1.4
Abu-Khamsin (1991)	14.4	11.7	26.3	8.4
Khan et al. (1987)	20.4	16.1	23.2	15.8
Hanafy (1997)	21.2	14.0	38.4	-14.0
Labedi (1992)	72.4	31.7	89.0	-60.3

Table 7. shows error analysis for the newly developed model as well as the published ones for estimating the undersaturated oil viscosity. The new model has the smallest AARE of 1.9%, ARE of -0.4%, and SD of 1.4%. The second-best model is Almehaideb (1997) model, with this having 5.8% AARE. Naseri (2005) Model showed the highest AARE, ARE, SD, and the sum of absolute errors.

Table7. *Summary of Error Analysis for All Undersaturated Oil Viscosity Models*

Models	AARE (%)	SD % (AARE)	Sum of Absolute Residual	ARE (%)
Proposed	1.95	3.3	20.0	0.19
Almehaideb (1997)	5.8	3.7	71.0	-4.84
Standing (1977)	6.0	5.1	1193.5	5.91
Elsharkawy-Khan (1999)	6.2	7.8	51.9	-4.45
Dindoruk- Christman (2004)	6.3	6.6	142.6	-5.25
Kartoatmodjo (1991)	7.0	5.7	73.1	6.88
Hossain (2005)	7.6	6.6	102.9	-6.58

Al-Khafaji (1987)	8.0	7.6	121.0	6.04
Petrosky (1995)	8.1	6.9	116.3	-4.87
Abdulmajeed (1990)	8.6	6.2	123.9	8.57
De Ghetto (1994)	9.8	9.9	107.9	-8.84
Khan (1987)	11.4	7.8	152.1	11.36
Labedi (1992)	11.9	11.5	151.2	-10.97
AbuKhamsin (1991)	15.4	12.4	273.8	4.97
Hanafy (1997)	20.8	15.0	412.4	17.75
Elsharkawy-Gharbi (2000)	36.5	103.1	1915.8	33.18
Naseri (2005)	72.5	112.9	2274.7	16.34

5.2. Validation of the Proposed Models

The proposed models were developed using a dataset of 824 data points from 55 samples. This section discusses the validation of the proposed models using independent data from 11 randomly selected samples (testing dataset). The testing dataset contained 166 viscosity measurements, divided into 89 data points for undersaturated oil viscosity, 55 for saturated oil viscosity, and 11 data points for dead and 11 data for bubble point viscosity. **Table 8.** describes data ranges for the testing samples.

Table8. *Data Description of Testing Dataset*

Reservoir Parameters	**Unit**	**Min**	**Max**
Pressure	**Psia**	15	6032
Bubble Point Pressure	**Psia**	650	2515
Reservoir Temperature	**°F**	117	163
Stock-Tank Oil Gravity	***°API***	22.3	32.2
Solution GOR	**scf/STB**	88	695
Dead Oil Viscosity	**cp**	4.63	45.58
Saturated Oil Viscosity	**cp**	1.14	27.74
Bubble Point Oil Viscosity	**cp**	1.043	13.5
Under saturated Oil Viscosity	**cp**	1.05	20.00

The proposed models were tested individually and evaluated through statistical and graphical error analysis. The performance and accuracy of the newly proposed models for the testing samples are summarized in **Table 9**. These show high accuracy in predicting crude oil viscosity of oils from the (GBOF).

Table9. *Summary of Error Analysis for the Proposed Models*

Models	**Dead Model**	**Bubble Point Model**	**Undersaturated Model**	**Saturated Model**
AARE (%)	6.10	6.30	2.20	5.20
ARE (%)	-0.889	3.721	0.773	-0.929
SD (for AARE)	4.06	5.67	2.39	5.05
Sum of Absolute Residual	7.20	2.30	11.1	19.70

Figures 6. presents cross plots of calculated and measured viscosity for the testing dataset using the proposed models. It is clear from the figure that the newly developed models perform very well as all the data points fall on the unite slope line. **Figure 7.** shows viscosity versus pressure for one of the testing samples. From this plot, it is clearly seen that the newly proposed models capture the physical trend of changing the viscosity as function of pressure. The figure also shows that the results of the developed models closely match experimentally measured viscosity points.

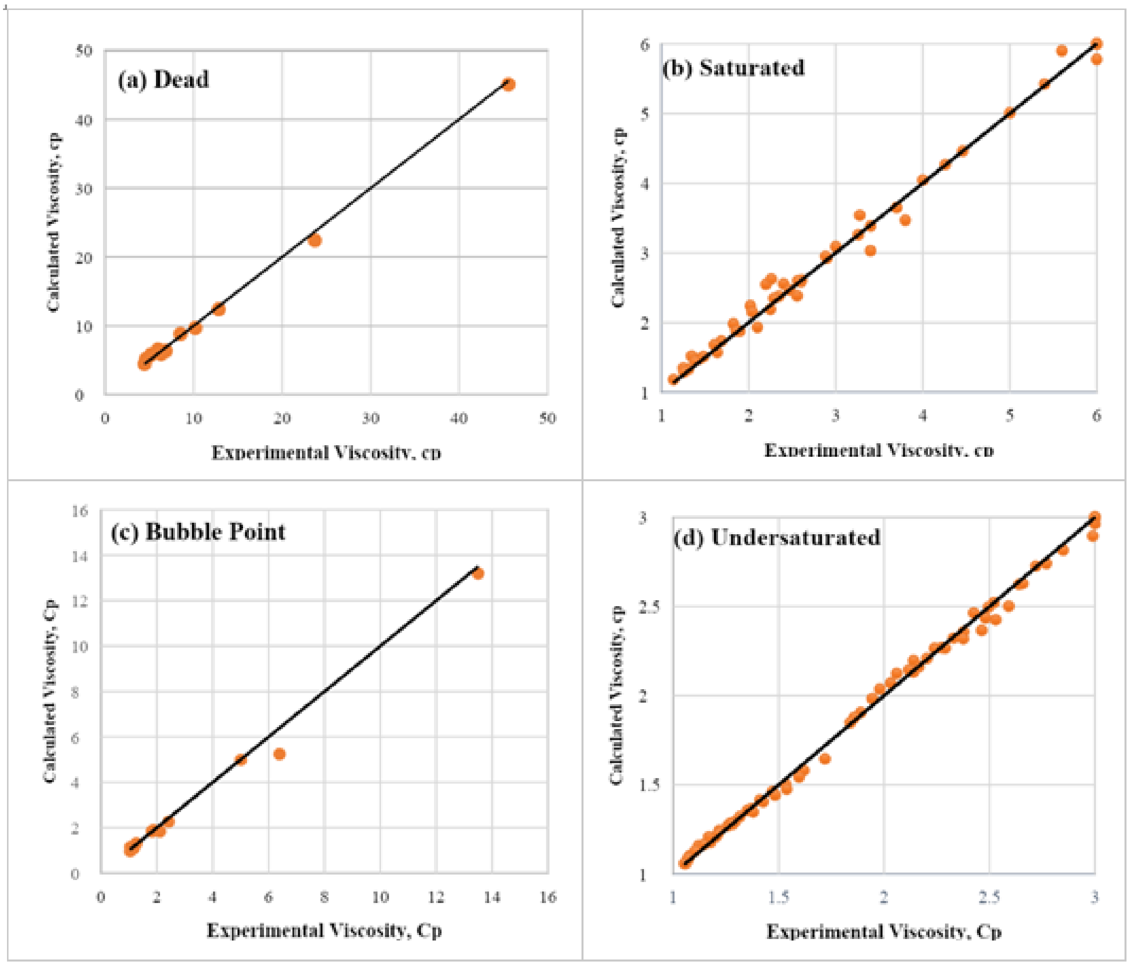


Figure6. *Cross Plots of the Proposed Oil Viscosity Model Using Testing Dataset*

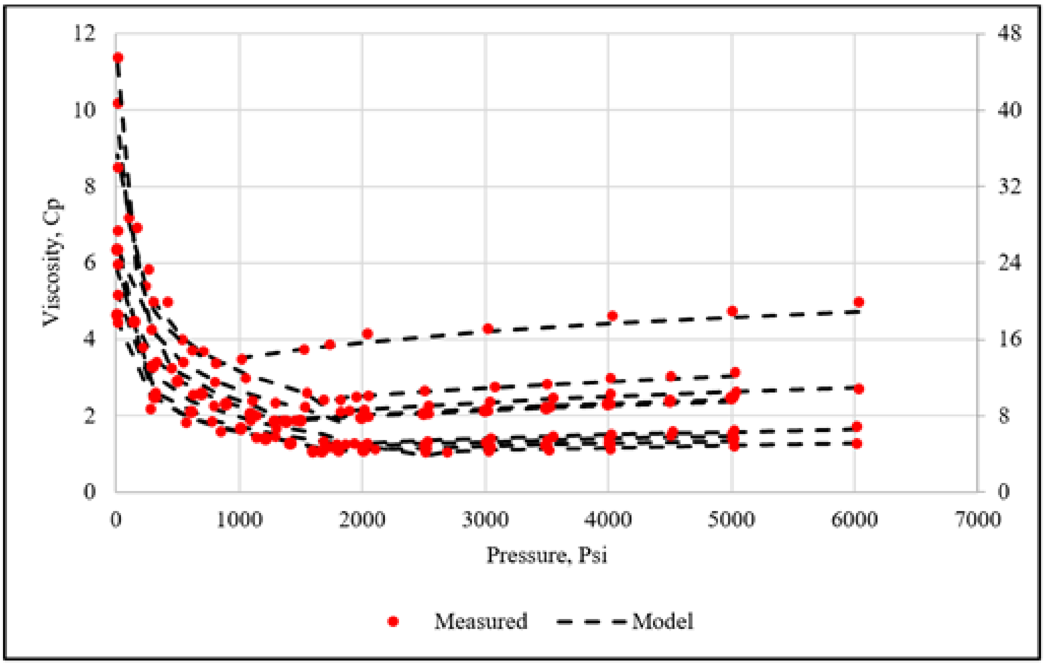


Figure7. *Viscosity vs. Pressure Plot Using Proposed Models for 11 Testing Dataset Samples*

5.3. Limitations

In this study, it was indicated that oil viscosity correlations that were developed for a given formation, local region or even from general data dank such as Kartoatmodjo (1991), cannot be extended to other formation or region because of the difference in the chemical composition; some oil are paraffinic while others are naphthenic or asphaltic which is not reflect in the API gravity. Therefore, having a universal correlations that can satisfactorily predict the dead, saturated, and undersaturated oil viscosity for all kind of crude oils; extra heavy, heavy, medium and light oils is almost impossible.

The correlations presented in this study is valid and recommended for estimating crude oil for GBOF when experimental data is unviable. Application of these models outside the data used in modeling or for crude oil with characteristics different from the GBOF should be taken with precautious.

6. SUMMARY AND CONCLUSIONS

A large database of measured viscosity data, as well as collected from PVT reports for Greater Burgan Oil Field was utilized in this study; this incorporates an extensive range of oil properties and was quality checked before being used to correlate the newly proposed oil viscosity models. The performance of published black-oil viscosity models was evaluated using 61 oil samples from the Burgan Oil Field of Kuwait.

Statistical error analysis of the published models showed that the acceptable error results were obtained using the model of Labedi (1992) for dead oil viscosity, Katoatmodjo (1991) for saturated oil viscosity, Abu-Khamsin (1991) for bubble point viscosity, and Almehaideb (1997) for undersaturated oil viscosity.

Most of the published dead and bubble point oil viscosity models were not able to accurately predict the viscosity of (GBOF) oils, as these were developed for crude oils from different regions.

A newly dead oil viscosity model is proposed to estimate dead oil viscosity for GBOF, which is a function of temperature and API gravity. The model performs better than published ones for dead oil viscosity prediction with an AARE of 5.86%. Another bubble point viscosity model was developed as a function of bubble point pressure, dead oil viscosity, and GOR at the bubble point. Compared with published bubble point models, this model reduced AARE by 9%. The newly proposed saturated oil viscosity model was also developed, based on reservoir pressure, dead oil viscosity, solution GOR, and bubble point pressure. It is more accurate than all published ones, where the new one has an AARE of 4.8%. Additionally, an undersaturated oil viscosity model for (GBOF) was developed based on solution GOR, bubble point pressure, bubble point viscosity, and reservoir pressure. This model showed a superior prediction of undersaturated oil viscosity than published ones, with an AARE of 1.95%.

Validation of the newly proposed models using some of the testing samples shows that the proposed models capture the physical changes in oil viscosity as a function of pressure.

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Nomenclature

Symbol	**Designation**	**Units**
API	Stock-tank oil gravity	^{o}API
P	Reservoir pressure	psia
R_S	Solution gas-oil ratio below bubble point pressure	scf/STB
R_{Sb}	Solution gas-oil ratio at bubble point pressure	scf/STB
T	Reservoir temperature	^{o}F
T_p	Pour point temperature	^{o}F
Greek		
γ_o	Oil specific gravity	
γ_g	Gas specific gravity	
μ_{oa}	Oil viscosity above bubble point pressure	cP
μ_{ob}	Oil viscosity below bubble point pressure	cP
μ_{obp}	Oil viscosity at bubble point pressure	cP
Abbreviation		
AARE%	Average absolute relative error	%
ARE%	Average relative error	%
PVT	Pressure-volume-temperature	
SD%	Standard deviation	%

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APPENDIX A

TableA1. *Limitations and Parameters of Published Dead Oil Viscosity Models*

Model	No. Data Points	T, °F	API, °*API*	Pb, Psi	Rsb, scf/STB	TP, °F	Function
Beal (1946)	786	60-300	10.1–52.5	-	-	-	f (T, API)
Beggs-Robinson (1975)	2533	70–295	16–58	-	-	-	f (T, API)
Standing (1977)	786	100–300	10.1–52.5	-	-	-	f (T, API)
Glaso et al. (1980)	26 oil samples	10–149	20.1–45.8	-	-	-	f (T, API)
Ng-Egbogah et al. (1983)	394 oil systems	59–176	5–58	-	-	(-58)–59	f (T, API,Tp)
Al-Khafaji et al. (1987)	300 samples	60–300	15–51	-	-	-	f (T, API)
Kartoatmodjo et al. (1991)	661 samples	100–300	14.4–59	-	-	-	f (T, API)
Labedi et al. (1992)	100 samples	100–306	32.2–48	-	-	-	f (T, API)
Bergman et al. (1992)	-	-	15–45	-	-	-	f (T, API)
De Ghetto et al. (1994)	195 samples	80.6–341.6	10–22.3	-	-	-	f (T, API)
Petrosky-Farshad (1995)	126 PVT report	114–288	25.4–46.1	-	-	-	f (T, API)
Bennison (1998)	16	< 121.1	< 20	-	-	-	f (T, API)
Elsharkawy-khan (1999)	254 samples	37.8–149	19.9–48	-	-	-	f (T, API)
Elsharkawy-Gharbi (2000)	59 oil systems	130–243	24.51–39.81	-	-	-	f (T, API)

Naseri et al. (2005)	472 PVT reports	105–295	17–44	-	-	-	f (T, API)
Hussain et al. (2005)	123	32–215	7.1–21.8	-	-	-	f (T, API)
Dindoruk et al. (2004)	90 PVT reports	121–276	17.4–40	201–10140	133–3050	-	f (T, API,Pb,Rsb)
Alomair et al. (2014)	360	20–160	10–20	-	-	-	f (T, API)

TableA2. *Limitations and Parameters of Published Saturated Oil Viscosity Models*

Model	No. Data Points	μod, cP	Rs, scf/STB	T, °F	API, $°API$	γ_g	P, Psia	Pb, Psi	μobp, cP	Function
Beal (1946)	351	-	12–1827	10–247	15.8–45.7	-	-	-	-	f $(\mu od, Rsb)$
Chew Connally (1959)	457 samples	0.377-50	51–3544	72–292	-	-	132–5645	-	-	f $(\mu od, Rsb)$
Aziz et al. (1972)	48 oil systems	-	-	-	-	-	-	-	-	f $(\mu od, Rsb)$
Beggs-Robinson (1975)	2073	-	20–2070	70–295	16–58	-	0–5250	-	-	f $(\mu od, Rsb)$
Standing (1977)	351	-	12–1827	10–247	15.8–45.7	-	-	-	-	f $(\mu od, Rsb)$
Khan et al. (1987)	1691	-	24–1901	75–240	14.3–44.6	-	14.7–5015	107–4315	0.13–17.9	f $(\mu obp, P, Pb)$
Al-Khafaji et al. (1987)	300 samples	-	0–2100	-	-	-	-	-	-	f $(\mu od, Rsb)$
Katoatmodjo et al. (1991)	5321	0.506–682	100–2000	-	-	-	-	-	-	f $(\mu od, Rsb)$
Labedi et al. (1992)	80	0.66–4.79	-	-	-	-	-	60–6358	0.115–3.72	f $(\mu obp, P, Pb, API)$
Bergman (1992)	-	-	-	-	-	-	-	-	-	f $(\mu od, Rsb)$
De Ghetto (1994)	195 samples	0.46–1386	8.33–2985	-	-	-	242–15304	107–6613	0.07–295	f $(\mu od, Rsb)$
Petrosky-Farshad (1995)	126 PVT report	0.725–11.69	21–18885	-	-	-	-	-	-	f $(\mu od, Rsb)$
Almehaideb (1997)	57	-	128–3871	190–306	30.9–48.6	0.746–1.116	-	-	-	f (Rsb, T, API, γ_g)
Elsharkawy-Khan (1999)	254 samples	-	10–3600	-	-	-	-	-	-	f $(\mu od, Rsb)$
Elsharkawy-Gharbi (2000)	59 oil systems	-	-	130–243	24.5–39.8	0.889–0.997	14.7–9900	-	-	f $(\mu od, P)$
Dindoruk et al. (2004)	90 PVT reports	0.896–62.6	133–3050	-	-	-	-	-	-	f $(\mu od, Rsb)$
Naseri et al. (2005)	472 PVT reports	1400–7000	255–4116	-	-	-	-	420–5900	-	f $(\mu od$, Pb)
Hussain et al. (2005)	415	-	62–345	-	-	-	-	-	-	f $(\mu od, Rsb)$
Bergman-Sutton (2007)	12,474	0.21–4277	3–6525	63–342	6–61.7	0.554–2.411	30–9649	66–10300	0.045–3285	f $(\mu od, Rsb)$

TableA3. *Limitations and Parameters of Published Undersaturated Oil Viscosity Models*

Model	No. Data Points	μod, cP	Rsb, scf/STB	T, °F	API, °API	γ_g	Pb, Psi	ρob, gm.cm^{-3}	Function
Khan et al. (1987)	150	-	24–1901	75–240	14.3–44.6	0.752–1.367	-	-	f (Rsb,T,API, σg)
Abu-Khamsin et al. (1991)	459	-	21–3001	74–240	21–49	0.525–1.588	-	0.493–0.897	f (ρob)
Labedi et al. (1992)	91	0.66–4.79	-	-	32.2–48	-	60–6358	-	f (μod,API, Pb)
Hanafy et al. (1997)	324 samples	0.236–106.6	6–4272	107–327	17.8–47.7	0.633–1.627	36–5003	0.428–0.939	f (ρob)

TableA4. *Limitations and Parameters of Published Bubble Point Oil Viscosity Models*

Model	No. Data Points	μobp, cP	P, Psia	Pb, Psi	μod, cp	API, °API	Rsb, SCF/STB	Function
Beal (1946)	78							f (μobp, P, Pb)
Standing (1977)	11	0.206–127	1500–4850	125–4070	-	-	12–1826	f (μobp,P,Pb)
Vasquez-Beggs (1980)	>6000	0.117–148	141–9515	-	-	15.3–59.5	9.3–2199	f (μobp,P, Pb)
Khan et al. (1987)	1503	0.13–17.9	14.7–5015	107–4315	-	-	-	f (μobp,P, Pb)
Alkafaji et al. (1990)	300 samples	-	-	-	-	-	-	f (μobp,P, Pb, API)
Abdulmajeed et al. (1991)	253	0.096–28.5	711–7112	498–4864	-	15–51	60–1334	f (μobp,P, Pb, API,Rsb)
Kartoatmodjo-Schmidt (1991)	3588	0.168–184.86	24.7–6014.7	24.7–4764.7	0.5062–682	14.4–58.95	1–2044	f (μobp,P,Pb)
Labedi et al. (1992)	100 samples	0.115–3.72	-	60–6358	0.66–4.79	5–58	-	f (μobp,P,Pb, $\mu od, API$)
De Ghetto (1994)	195 samples	-	242.22–15304.62	107.33–6613.82	0.46–1386.9	-	4.3–527.9	f (μobp,P,Pb, $\mu od, API$)
Petrosky-Farshad (1995)	126 PVT report	0.211–3.546	1600–10250	1574–9552	-	-	-	f (μobp,P,Pb)
Almehaideb et al. (1997)	328	-	-	501–4822	-	-	-	f (μobp,P,Pb, Rsb)
Elsharkawy-khan (1999)	254 samples	0.37–50	1287–10000	100–3700	0.6–33.7	-	10–3600	f (μobp,P,Pb, μod)
Elsharkawy-Gharbi (2000)	59 oil systems	-	14.7–9900	-	-	24.5–39.8	-	f (μobp,P,Pb, μod)
Dindoruk-Christman (2004)	90 PVT reports	0.161–8.7	202–10140	926–12230	-	-	-	f (μobp,P,Pb,Rsb)
Naseri et al. (2005)	472 PVT reports	-	1400–7000	255–4116	0.75–54	-	-	f (μobp,P,Pb, μod)
Hussain et al. (2005)	39	-	600–5015	-	-	-	-	f (μobp,P,Pb)

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