GLOBAL JOURNAL OF PURE AND APPLIED SCIENCES VOL 14, NO. 3, 2008: 331 - 337

REVIEW OF PVT CORRELATIONS FOR CRUDE OILS

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(Received, August 2007; Revision Accepted 13, September 2007)

ABSTRACT

Reservoir fluid physical property values constitute an integral part of the data required for comprehensive study of the reservoir and for optimal design of oil recovery and production schemes. More specifically, Pressure-Volume-Temperature (PVT) data corresponding to the reservoir fluid are needed to validate the well test property and to provide meaningful interpretation. In the absence of laboratory measured PVT data, property correlations are used for property estimation.

Various PVT correlations have been published over the years, which used data from limited geographical areas, sometimes assumed to be global and differing fluid characteristics. Because of variation in the crude compositions, geographical, and petrophysical conditions of the operating environments, these correlations cannot acclaim universal applicability. This paper attempts to give comprehensive review of existing PVT correlations and models in the literature, indicating geographical region, accuracies as well as the nature of these correlations. Using these correlations from other regions would have implications such as poor fluid property estimations, poor reservoir performance studies, as well as uncertainty in reserve estimations in the Niger Delta.

KEYWORDS: PVT Correlations, PVT Data, Reservoir Fluid Properties, Fluid Property Estimation

1.0 INTRODUCTION

Reservoir fluid physical property values constitute an integral part of the data required for comprehensive study of the reservoir and for optimal design of oil recovery and production schemes. More specifically, PVT data corresponding to the reservoir fluid are needed to validate the well test property and to provide meaningful interpretation. The optimum design of the well completion and surface facilities is possible only when the type and volume of the fluids flowing through the wellbore and produced through the separator are known. In addition, estimation of reservoir reserves and the design of the best depletion strategy are feasible only when realistic and reasonably accurate values of the reservoir fluid properties are available.

Analysis of a representative fluid sample performed in a specialized PVT laboratory offers solutions. In most cases, however, because of backlogs and transportation problems, the laboratory report becomes available to the operating companies several months after the well test. Meanwhile, crucial decisions concerning planning and management of the reservoir have to be made on the basis of physical property values. These values are currently derived from empirical correlations, and the accuracy of the predictions depends on how closely the chemical composition of the fluid being tested approaches that of the fluids used.

During the last 50 years, several correlations have been proposed for determining PVT properties. The most widely used treat oil and gas as a two-component system with each component having a fixed composition. Only the specific gravity and relative amount of each component, the pressure, and the temperature are used to characterize the oil's PVT properties. Crude oil systems from various oil-producing regions are used in the development of correlations. These crude oils exhibit regional trends in chemical composition that categorize them as paraffinic, naphthenic, or aromatic. Because of the differences in composition, correlations developed from regional samples that are predominantly of one chemical base may not provide satisfactory results when applied to crude oils from other regions (Sutton and Farshad, 1990).

PVT properties are a function of temperature, pressure, composition of the hydrocarbon mixture and the presence of paraffins and impurities. The performance of empirical models depends mainly on how much a correlation model represents this mixture under specific conditions (Al-Shammasi, 1999). This paper attempts to give comprehensive review of existing PVT correlations and models in the literature and the implications of applying these models to the Niger Delta crude.

2.0 LITERATURE REVIEW

Studies on PVT properties are done in the following areas: development of empirical correlations, evaluation of existing correlations for their applicability to different regions of the world and neural network models.

2.1 EMPIRICAL CORRELATIONS/ MODELS

Since the 1940's, engineers in the United States have realized the importance of developing empirical correlations for PVT properties. Studies carried out in this field resulted in the development of new correlations. Several studies of this kind were published by Katz (1942), Standing (1947), Lasater (1958) and Cronquist (1973). For several years, these correlations were the only source available for estimating PVT properties when experimental data were unavailable. In the last twenty five years, there has been an increasing interest in developing new correlations for crude oils obtained from the various regions in the world. Some of the recent studies have been carried out by Vazquez and Beggs (1980), Al-Marhoun (1985), Abdul-Majeed and Salman (1988), Dokla and Osman (1992), Almehaideb (1997) and Dindoruk and Christman (2004). The Dindoruk and Christman (2004) correlations of the Gulf of Mexico are presented below as an example:

Bubble-point Pressure correlation, P_b

$$P_b = 1.869979257\left(\frac{R_s^{1.221486524}}{\gamma_g^{1.370508349}}10^{A} + 0.011688308\right) \qquad 2.1$$

where,

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$$A = \frac{1.42828x10^{-10}\,T^{\,2.844591797} - 6.74898x10^{-04}\,\mathrm{API}^{1.225226436}}{\left(0.033383304 + \dfrac{2R_s^{\;-0.272945957}}{\gamma_{\mathrm{g}}^{\;-0.084226069}}\right)^2} \qquad 2.2$$

T=reservoir temperature, ^{0}F, API=stock-tank oil gravity, ^{0}API, and
γ_g = total gas specific gravity

Solution Gas-Oil Ratio Correlation, R_s

$$R_s = \left[\left(\frac{p_b}{3.359754970} + 28.10133245\right)\gamma_{\mathrm{g}}^{\;1.579050160}\,.\,10^{\mathrm{A}}\right]^{0.928131344} \qquad 2.3$$

where,

$$A = \frac{4.86996\,\mathrm{x}10^{-6}\,\mathrm{API}^{5.730982539} + 9.92510\,x10-3T^{\,1.776179364}}{\left(44.25002680 + \dfrac{2\mathrm{API}^{2.702889206}}{\mathrm{P_b}^{\;0.744335673}}\right)^2} \qquad 2.4$$

Oil FVF at the bubble-point, B_{ob}

$$B_{ob} = 9.871766\,\mathrm{x}10^{-1} + 7.865146\,\mathrm{x}10^{-4}\,\mathrm{A} + 2.689173\,\mathrm{x}10^{-6}\,\mathrm{A}^2 + 1.100001\,\mathrm{x}10^{-5}\,(\mathrm{T} - 60)\frac{\mathrm{API}}{\gamma_{\mathrm{g}}} \qquad 2.5$$

where,

$$A = \frac{\left[\dfrac{R_s^{\;2.510755}\gamma_g^{\;-4.852538}}{\gamma_o^{\;11.83500}} + 1.365428\,\mathrm{x}10^5\,(\mathrm{T} - 60)^{2.252880} + 10.07190R_s\right]^{0.4450849}}{\left[5.352624 + \dfrac{2\mathrm{R_s}^{\;-0.6309052}}{\gamma_g^{\;0.9000749}}(\mathrm{T} - 60)\right]^2} \qquad 2.6$$

where γ_o= specific gravity (water = 1) of tank oil at 60°F

Undersaturated Oil Compressibility Correlation, C_o

$$C_o = \left(4.487462368 + 0.00519704A + 0.000012580A^2\right)x10^{-6} \qquad 2.7$$

where,

$$A = \frac{\left[\dfrac{R_s^{\;0.980922372}\gamma_g^{\;0.021003077}}{\gamma_o^{\;0.338486128}} + 20.00006358\,(\mathrm{T} - 60)^{0.300001059} - 8.76813622x10^{-1}R_s\right]^{1.759732076}}{\left[2.749114986 + \dfrac{2\mathrm{R_s}^{\;-1.71357145}}{\gamma_g^{\;9.999932841}}(\mathrm{T} - 60)\right]^2} \qquad 2.8$$

Dead-Oil-Viscosity correlation, μ_{od}

$$\mu_{od} = \frac{9.36579\,\mathrm{x}10^9\,\mathrm{T}^{-4.194017808}(\log \mathrm{API})^{\mathrm{A}}}{-3.1461171x10^{-9}\,p_b^{\;1.517652716} + 0.010433654R_s^{\;-0.000776880}} \qquad 2.9$$

where,

$$A = 14.505357625\log T - 44.86865416 \qquad 2.10$$

Saturated-Oil-Viscosity Correlation, μ_{ob}

$$\mu_{ob} = \mathrm{A}\,(\mu_{\mathrm{od}})^B \qquad 2.11$$

where,

$$A = \frac{1.000000}{\exp(4.740729x10^{-4} R_s)} - \frac{1.023451\,x10^{-2} R_s^{0.6600358}}{\exp\left(1.075080\,x10^{-3} R_s\right)} \quad 2.12$$

and

$$B = \frac{1.000000}{\exp(-2.191172x10^{-5} R_s)} - \frac{1.660981\,x10^{-2} R_s\, 4.233179x10^{-1}}{\exp\left(-2.273945\,x10^{-4} R_s\right)} \quad 2.13$$

Undersaturated-Oil-Viscosity Correlation, μ_o

$$\mu_o = \mu_{ob} + 6.3340x10^{-5}\left(p - p_b\right)10^A \quad 2.14$$

where,

$$A = 0.776644115 + 0.987658646\log\mu_{ob} - 0.190564677\log R_s + 9.147711\,x10^{-3}\mu_{ob}\log R_s - 1.9111\,x10^{-5}\left(P - P_b\right) \quad 2.15$$

and P = reservoir pressure, psia

Tables 1-3, shows that not much work have been done in the area of correlation development for the Niger Delta crudes. From the host of correlations listed on the tables ranging from bubblepoint pressure (P_b) to undersaturated-oil-viscosity (μ_o) only formation volume factor (B_o) and solution gas-oil ratio (R_s) are developed for the region just for black oil. Nothing has been done for the entire range of black-volatile oil for these properties (B_o and R_s) and the others such as P_b, undersaturated oil compressibility (C_o), dead-oil-viscosity (μ_{od}), saturated-oil-viscosity (μ_{ob}), and undersaturated-oil-viscosity (μ_o). It should be noted that those other parameters not defined for the Niger

Table 1: Authors, Regions and Accuracies of $\mu_{od,}$ μ_{ob} and μ_o Correlations

Authors	Sample Origin	Property	Author average error %	Author absolute average error %	Author standard deviation %	Nature of Correlation using R_s as basis
Beal (1946)	U. S	μ_{od} μ_{ob} μ_o	24.5 2.7			Black Oil
Beggs and Robinson (1975)		μ_{od} μ_{ob} μ_o	-0.64 -1.83		13.53 27.25	Black Oil
Vasquez and Beggs (1980)	Global	μ_{od} μ_{ob} μ_o	 -7.54			Black-Volatile Oil*
Kartoatmodjo & Schmidt (1994)	Global	μ_b μ_{ob} μ_o			18.84 3.98	Black-Volatile Oil
Petrosky & Farshad (1995)	Gulf of Mexico	μ_{od} μ_{ob} μ_o	-3.48 -3.12 -0.19	12.38 14.47 2.91	16.40 19.66 4.22	Black Oil
Almehaideb (1997)	UAE	μ_{ob} μ_o	13.00 2.885		16.26 4.07	Black-Volatile Oil
Dindoruk & Christman (2004)	Gulf of Mexico	μ_{od} μ_{ob} μ_o	-2.86 -3.05 -0.83	12.62 13.20 5.99	16.74 17.29 8.42	Black-Volatile Oil

***** exceptional case, ref McCain (1991)

Delta region are important in reservoir performance. For instance, the bubblepoint pressure gives an indication of the best depletion strategy to apply to a particular reservoir and viscosity must be determined for calculations involving the flow of oil through porous media.

Table 2: Authors, Regions and Accuracies of C_o Correlations

Authors	Sample Origin	Property	Author average error %	Author absolute average error %	Author standard deviation %	Nature of Correlation using R_s as basis
Kartoatmodjo & Schmidt (1994)	Global	C_o	23.67			Black-Volatile Oil
Almehaideb (1997)	UAE	C_o	9.88		13.33	Black-Volatile Oil
Petrosky & Farshad (1998)	Gulf of Mexico	C_o	-0.17	6.66	11.32	Black Oil
Dindoruk & Christman(2004)	Gulf of Mexico	C_o	-0.85	6.21	8.95	Black-Volatile Oil

2.2 EVALUATION STUDIES OF CORRELATIONS

As more correlations are developed, researchers evaluate the previously published correlations with the new ones. Others carry out studies to select the most accurate correlation for a particular reservoir or geographical region. Some of these are discussed below:

Ostermann et al., (1983) evaluated published correlations based on eight Alaskan fluid samples. They indicated that Glaso (1980) correlation for bubble point pressure and Standing (1947) correlation for oil formation volume factor showed least error for Alaskan crudes. The samples they used were characterized by high nitrogen (N_2) and carbon dioxide (CO_2) content. The study pointed out the significant effect of non-hydrocarbons on the bubble point pressure; Jacobson's (1967) nitrogen correction was found to be of better performance over Glaso's (1980) correction.

Table3: Authors, Regions and Accuracies of P_b, B_o and R_s Correlation

Authors	Sample Origin	Property	Author average error %	Author absolute average error %	Author standard deviation %	Nature of Correlation using R_s as basis
Standing (1947)	California	P_b B_o	4.8 1.17			Black-Volatile Oil*
Lasater (1958)	Canada, USA	P_b	3.8			Black-Volatile Oil
Vasquez & Beggs (1980)	Global	P_b B_o R_s	 4.7 -0.7			Black-Volatile Oil
Glaso (1980)	North Sea	P_b B_o	1.28 -0.43		6.98 2.18	Black-Volatile Oil
Obomanu &Okpobiri(1987)	Nigeria	B_o R_s				Black Oil
Al-Mahoun (1988)	Middle East	P_b B_o	0.03 -0.01	3.66 0.88	4.536 1.18	Black Oil
Abdul-Majeed & Salman (1988)		B_o	-0.24	1.4	1.91	Black Oil
Dokla & Osman (1992)	UAE	P_b B_o	0.45 0.023	7.61 1.225	10.376 1.681	Black Oil
Petrosky & Farshad (1993)	Gulf of Mexico	P_b B_o R_s	-0.17 -0.01 -0.05	3.28 0.64 3.80	4.18 0.68 4.79	Black Oil
Farshad et al (1992)	Colombia	P_b B_o	-3.49 13.32		14.61 37.02	Black Oil
Al-Mahoun (1992)	Global	B_o	0.00	0.57	0.687	Black-Volatile Oil
Omar & Todd (1993)	Malaysia	P_b B_o		7.17 1.44	9.54 1.88	Black Oil
Almehaideb (1997)	UAE	P_b B_o		4.997 1.35	6.56 1.70	Black-Volatile Oil
Macary & El-Batanony (1992)	Gulf of Suez	P_b B_o	0.52 0.521	7.04 7.05		Black Oil
Kartoatmodjo & Schmidt (1994)	Global	P_b B_o	3.34 -0.104	20.17 2.025		Black-Volatile Oil
Al-Shammasi (1999)	Global	P_b B_o		17.849 3.033	17.16 2.66	Black-Volatile Oil
Dindoruk & Christman(2004)	Gulf of Mexico	P_b B_o R_s	-0.27 -0.11 -1.28	5.70 2.00 7.66	7.51 3.17 9.89	Black-Volatile Oil

***** exceptional case, ref McCain (1991)

Abdul-Majeed (1985) evaluated the PVT correlations of Standing (1947), Lasater (1958) and Vasquez and Beggs (1980) for their region of applicability to oil reservoirs. He tested the correlations against laboratory measured solution gas-oil ratios from 630 PVT tests. The performance of each of the correlations was evaluated within pre-determined ranges of three selected variables, which are oil API gravity, gas specific gravity, and temperature. Recommended areas of application are given for each correlation, which would assist the practising engineer in selecting the most accurate correlation for his problem.

Sutton and Farshad (1990) in 1990 published an evaluation of Gulf of Mexico crude oils. They used 285 data sets for gas-saturated oil and 134 data sets for undersaturated oil representing different crude oils and natural gas systems. The result shows that Glaso (1980) correlations for bubble point pressure, solution gas oil ratio and oil formation volume factor perform the best for most of the data of the study. It was pointed out that Vazquez and Beggs (1980) performed better than Glaso (1980) correlation at high solution gas oil ratios above 1400 scf/STB and bubble point pressures greater than 7000 psia. The overall average absolute error for bubble point pressure and solution gas oil ratio reported for Glaso (1980) correlation models are 25.34% and 27.05% respectively. These values are relatively high when compared to what is reported in the literature.

McCain (1991) published an evaluation of all reservoir properties correlations based on a large global database at Texas A&M University. McCain (1991) recommended Standing (1947) correlations for bubble point pressure and solution gas oil ratio with estimation accuracy of 15% when used with separator gas gravity and total solution gas oil ratio. For oil formation volume factor at and below bubble point pressure McCain (1991) recommended Standing (1947) correlation also with estimation accuracy of 5.0% when used with total solution gas oil ratio. He also pointed out the dependence of estimation accuracy on the source of the data. For example, the accuracy of formation volume factor estimation is less if an estimated solution gas oil ratio is used.

Elsharkawy et al (1994) published a study for evaluating PVT correlations for Kuwaiti crude oils. The study used 44 sample analyses for the evaluation. Standing (1947) correlation for bubble point pressure gave the best results with average absolute error of 10.85%. Al-Marhoun (1988) oil formation volume factor correlation model performed the best with an average absolute error of 2.72%.

Mahmood and Al-Marhoun (1996) presented an evaluation of PVT correlations for Pakistani crude oils. They used 166 data sets from 22 different crude samples for the evaluation. High errors were obtained for bubble point pressure. Al-Marhoun (1988) correlation gave the least error with average absolute error of 31.5%. Al-Marhoun (1992) oil formation volume factor correlation gave the best results with an average absolute error of 1.23%. The bubble point pressure errors reported in this study, for all correlations, are among the highest reported in the literature.

Hanafy et al (1997) published a study for evaluating the most accurate correlation to apply to Egyptian crude oils. Although the reported average absolute error for Macary and El-Batanoney (1992) correlations were not the minimum, the study did recommend these correlations for bubble point pressure and oil formation volume factor. Macary and El-Batanoney (1992) correlation for bubble point pressure showed an average absolute error of 16.6% while Standing's (1947), Lasater's (1958), and Labedi's (1990) models showed 14.1, 14.8% and 14.9% respectively. For formation volume factor Macary and El-Batanoney (1992) correlation showed an average absolute error of 4.9% while Dokla and Osman (1992) showed 3.9%. The study strongly supports the approach of developing a local correlation against a global correlation.

Al -Shammasi (1999) also evaluated published correlations for bubble point pressure and oil formation volume factor for accuracy and flexibility to represent hydrocarbon mixtures from different geographical locations worldwide using geographical and gravity grouping as bases. He pointed out that the concept of having one global model for all types of data is more likely possible for oil formation volume factor property. Petrosky and Farshad (1993) correlation, with original coefficients exhibited almost complete geographical and API grouping superior performance consistency for bubble point pressure with an average absolute error range of 1.728 – 1.760. The study concluded that calculating new coefficients for correlation models based on limited data sets might result in coefficients that invalidate the physical behavior of petroleum fluids. The practice of calculating new set of coefficients for a specific data set was found to be not always better than the published coefficients. The process of developing new coefficients for an existing correlation model or developing a new correlation should be always followed with a check for the trend of the correlation model against the physical laws.

2.3 NEURAL NETWORK MODELS

Neural network uses in petroleum applications have been increasing in recent years. Artificial neural networks (ANN) are parallel-distributed information processing models that can recognize highly complex patterns within available data. Many authors: Kumoluyi and Daltaban (1994), Ali (1994), Mohaghegh and Amari (1994), Mohaghegh (1995) and Mohaghegh (2000) discussed the applications of neural network in petroleum engineering. The area of PVT properties modeling using neural networks is relatively new. Some studies were carried out during the last few years on this subject. Some of them are discussed below.

Gharbi and Elsharkawy (1996) published neural network models for estimating bubble point pressure and oil formation volume factor for Middle East crude oils. Separate models were used for each property, and the models architectures were of two hidden layers. The bubble point pressure model had eight neurons in the first layer and four neurons in the second. The formation volume factor model had six neurons in both layers. 498 data sets collected from the literature and unpublished sources were used for training the models. Another set of 22 data points from the Middle East, not included in the training, were used to verify the resulting network. The results showed improvement over the conventional correlation methods with at least 50% reduction in the average error for the bubble point pressure and 30% reduction for oil formation volume factor.

Al- Shammasi (1999) published a neural network model for oil formation volume factor consisting of two hidden layers, five nodes in the first layer and three in the second layer. The model used 1165 data sets for training and 180 data sets for testing. The best model exhibited an average absolute error of 11.68%, which is much higher than the conventional numerical correlations. He, however, pointed out that the newly developed model performed better when compared with empirical correlations, but suffered from stability and had some set backs with trend analysis. The author stated that the major problem in comparing published neural network models is the unavailability of the missing parameters of the network architecture in the publications.

Varotsis et al., (1999) presented a novel approach for predicting the complete PVT behavior of reservoir oils and gas condensates using Artificial Neural Network (ANN). The method uses key measurements that can be performed rapidly either in the laboratory or at the well site as input to an ANN. The ANN was trained by a PVT studies database of over 650 reservoir fluids originating from all parts of the world. Tests of the trained ANN architecture utilizing a validation set of PVT studies indicate that, for all fluid types, most PVT property estimates can be obtained with a very low mean relative error of 0.5-2.5%, with no data set having a relative error in excess of 5%. This level of error is considered better than that provided by tuned Equation of State (EOS) models, which are currently in common use for the estimation of reservoir fluid properties. In addition to improved accuracy, the proposed ANN architecture avoided the ambiguity and numerical difficulties inherent in EOS models and provide for continuous improvements by the enrichment of the ANN training database with additional data.

Finally, Osman et al., (2001) presented an Artificial Neural Network (ANN) model that used a new algorithm for training feed forward neural networks to predict formation volume factor at the bubble point pressure. The model was developed using 803 published data from the Middle East, Malaysia, Colombia, and Gulf of Mexico fields. Of the 803 data points, 402 were used to train the ANN models, 201 to cross-validate the relationships established during the training process and the remaining 200 to test the model for accuracy and trend stability. The results showed that the developed model provided better predictions and higher accuracy than the published empirical correlations. The present model provided predictions of the formation volume factor at the bubble point pressure with an average absolute percent error of 1.789%, a standard deviation of 2.2053% and correlation coefficient of 0.988. Trend tests were performed to check the behavior of the predicted values of B_{ob} for any change in reservoir temperature, gas oil ratio (GOR), gas gravity and oil gravity. The trends were found to obey the physical laws.

3.0 GENERAL CHARACTERISTICS OF THE NIGER DELTA (NIGERIAN) CRUDE

Most of the petroleum production activities in Nigeria occur from the Niger Delta Basin and both crudes from offshore and the Niger delta are characterized by very low non-hydrocarbon content. Sulphur content hardly exceeds 0.5%, if at all present, and the nitrogen/carbon dioxide content is usually below 1%. Hence, the Nigerian crude is termed sweet because of the low sulphur content.

Nigerian crudes are light, that is, they have low densities and contain much of the light ends of crude oil assay. Depending on their API gravity, crude species have been classified as light, blend, medium or heavy. The light crude has API gravity above 35^o, the blend is between 26^o and 35^o, medium is between 21^o and 26^o while the heavy has API gravity less than 21. Generally, the Nigerian crude API gravity has never been below 20^o.

4.0 LIMITING FACTORS OF PVT CORRELATIONS APPLICABILITY

Though fluid properties can be estimated from the empirical correlations, the accuracy of each correlating equation depends on the region from which the crudes (whose properties are being estimated) are obtained. This is because

- The data used in the correlations are from specific geographical areas.
- The paraffinicity (which affects properties of crude oil) differs from region to region.
- Surface gases from some reservoirs, contain relatively large amounts of non-hydrocarbons such as CO_2, N_2, and H_2S (see Table 4.0)

Looking at Table 4.0, it is clear that correlations developed for these various regions were concerned with crudes of different characteristics and that such correlations would not provide best approximation of PVT properties elsewhere. Studies performed by Glaso (1980), Al-Marhoun (1988), Labedi (1990), Dokla and Osman (1992), and Macary and Botanoney (1992) support this observation. Also no one particular crude from the regions match the crude from the Niger Delta. From the foregoing, using any of the correlations from these regions would have implications such as poor fluid property estimations, poor reservoir performance studies, as well as uncertainty in reserve estimations.

5.0 CONCLUSIONS

Though fluid properties can be estimated from the empirical correlations, the accuracy of each correlating equation depends on the region from which the crude (whose properties are being estimated) comes from. The PVT behavior of crude oil is a strong function of composition; therefore, the direct application of correlations that do not take compositional effects into account should be undertaken with caution.

Table 4.0: The Regions and the Nature of Crude

Geological Region/ Countries	Grade of Oil (^{o}API)	Paraffinicity	Non-Hydrocarbon
Californian Crude	Heavy and Medium		
Canada, Western & Mid-Continental U. S and North America	light	High	-
North sea	Medium and Light	High	High
Middle East	Medium and Light		High
Egypt	Medium and Light		Low
Malaysia	Medium and Light		High
Gulf of Mexico	Medium	Low (medium)	Low
United Arab Emirate (UAE)	Heavy and Medium		High
Alaskan Cook Inlet Basin	Heavy and Medium	High	High
Eastern Venezuela	Heavy and Medium	High	High
Niger Delta	Medium and Light	High	Very Low or None

The characteristics of the Nigerian (Niger Delta) crude are high API gravity, very low sulphur content, low nitrogen and low carbon dioxide content. It differs from the crudes of other regions. Therefore, applying the most acclaimed PVT correlations to Niger Delta crude would have implications such as poor fluid property estimations, poor reservoir performance studies, as well as uncertainty in reserve estimations since there are clear variation in the crude compositions, geographical, and petrophysical conditions of the operating environments.

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