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LBC Viscosity Modeling of Gas Condensate to Heavy Oil

Tao Yang, SPE, Statoil ASA; Øivind Fevang, SPE, E.ON Ruhrgas; and Kjell Christoffersen, SPE, and Endre Ivarrud, SPE, Statoil

Abstract

Due to simplicity, consistency and flexibility, the Lohrenz-Bray-Clark (LBC) correlation is the most widely used viscosity model in reservoir engineering. Unfortunately the LBC viscosity model does not accurately predict liquid viscosity. Consequently it is necessary to tune the calculated viscosities. Tuning of the LBC viscosity model is normally performed by modifying the critical volumes of the C_{7+} components and/or the LBC coefficients. The tuning procedure is not straight forward. Special attention is required for three challenging fluid systems: viscosity of the condensed oil from gas condensates, viscosity changes in connection with gas injection and viscosity of heavy oils.

This paper describes guidelines for proper tuning and consistency checking of the LBC viscosity model. Instead of using various correlation-estimated critical volumes for the C_{7+} components as in most PVT software, the initial critical volumes of the C_{7+} components are calculated based on component viscosities estimated from a dead-oil empirical correlation. Global regression to the measured viscosity data is then made with modifiers to the initial critical volumes. This procedure guarantees monotonically increasing component viscosities for the C_{7+} components. In the case of any regression on LBC coefficients, it is very important to maintain a monotonic relation of viscosity vs. reduced density.

Viscosity data from three Norwegian offshore reservoirs, from gas condensate to heavy oil, are used as examples. The guidelines for tuning the LBC viscosity model presented in this paper provide practical insight and understanding of how to apply the LBC viscosity model to various fluid systems.

Introduction

Viscosity is an important physical property for fluid flow calculations in reservoirs, tubing and pipelines. Empirical correlations and corresponding-states models have been developed for modeling viscosity under various pressure and temperature conditions.

The Lohrenz-Bray-Clark (LBC) correlation for dense gas mixtures was published in 1964 by Lohrenz et al.[1] based on the original work by Jossi et al.[2] for pure substances. The detailed formula is given in the next section.

The prediction capability of gas viscosity with the LBC correlation is reasonable, while the prediction of oil viscosity is usually poor. Other more recent corresponding-states viscosity models show better prediction capability for oil viscosity, for example, the Corresponding States Principle (CSP) method proposed by Pederson et al.[3] Due to the simplicity and flexibility, the LBC correlation is the most widely used viscosity model, especially in most commercial compositional simulators.

The LBC correlation is very sensitive to mixture density and to the critical volumes of the heavy components. Adjustment of critical volumes of the heavy components and/or the LBC coefficients to match the experimental oil viscosity is usually necessary. However, the tuning procedure is not straight forward, especially for three challenging fluid systems: viscosity of the condensed oil from gas condensates, viscosity changes in connection with gas injection and viscosity for heavy oils.

Conventional tuning methods usually start with the initial critical volumes which are estimated based on various empirical correlations. The resulting component viscosity of the C_{7+} components is often non-monotonically increasing with molecular weight. This can potentially cause problems in compositionally sensitive processes, for example, viscosity of the condensed oil from gas condensates, and viscosity changes during gas injection.

Another challenge is viscosity in heavy oil systems. It is generally difficult to calculate accurately the viscosity behavior with pressure of heavy oils with the original LBC model. Heavy tuning of the LBC coefficients can easily cause a non-monotonic relation of viscosity vs. reduced density. In

such a case the LBC viscosity model will result in unreliable predictions of viscosity transition from gas to oil.

Viscosity data from three Norwegian offshore reservoirs, from gas condensate to heavy oil, are used as examples to demonstrate limitations with the conventional tuning approach and application of the new approach proposed in this paper.

LBC Viscosity Correlation
The LBC correlation expresses gas and oil viscosities as a fourth-degree polynomial in reduced density:

$$\left[\left(\mu-\mu^0\right)\xi_T+10^{-4}\right]^{1/4}=a_0+a_1\rho_{pr}+a_2\rho_{pr}^2+a_3\rho_{pr}^3+a_4\rho_{pr}^4 \quad (1)$$

where a_0 to a_4 are the coefficients in the correlation and equal to 0.l023, 0.023364, 0.058533, -0.040758 and 0.0093324 respectively.

Other definitions are listed below:

$$\xi_T=5.35\left(\frac{T_{pc}}{M^3 p_{pc}^4}\right) \quad (2)$$

$$\rho_{pr}=\frac{\rho}{\rho_{pc}}=\frac{\rho}{M}v_{pc} \quad (3)$$

$$\mu^0=\frac{\sum_{i=1}^{N}z_i\mu_i\sqrt{M_i}}{\sum_{i=1}^{N}z_i\sqrt{M_i}} \quad (4)$$

Pseudocritical properties T_{pc}, p_{pc}, and v_{pc} are calculated using Kay's mixing rule.

Component viscosities, μ_i, can be calculated from the Stiel and Thodos correlation[4].

$$\mu_i\xi_{Ti}=\left(34\times10^{-5}\right)T_{ri}^{0.94} \quad (5)$$
for $T_{ri}\leq1.5$ and

$$\mu_i\xi_{Ti}=\left(17.78\times10^{-5}\right)\left(4.58T_{ri}-1.67\right)^{5/8} \quad (6)$$
for $T_{ri}>1.5$, where $\xi_{Ti}=5.35\left(T_{ci}M_i^3/p_{ci}^4\right)^{1/6}$

Lohrenz et al.[1] suggested a special relation for v_c for the C_{7+} fraction(s).

$$v_{cC_{7+}}=21.573+0.015122\,M_{C_{7+}}-27.65\gamma_{C_{7+}}+0.070615\,M_{C_{7+}}\gamma_{C_{7+}} \quad (7)$$

with μ in cp, ξ in cp^{-1}, ρ in $lbm/ft3$, v in ft3/lbm mol, T in ^{o}R, p in psia, and M in lbm/lbm mol.

There are various modified versions of the original LBC viscosity correlation. Dandekar et al.[5] introduced molecular weight into the original LBC correlation for fluids with reduced density higher than 2.5 and carbon number higher than 8. The molecular weight is used to account for structure effects. Further work was published in 2001 by Al-Syabi et al.[6] by introducing reduced temperature to account for thermal effects.

For improving the viscosity description of heavy oil systems, different methods have been proposed. Xu et al.[7] published a simple approach by introducing an additional term in the original LBC correlation for high viscosity fluids. The proposed additional term has an exponential multiplier, which is a function of reduced density. Instead of using the exponential function only for the last term like in the paper by Xu et al., a different exponential term has been made available in a widely used commercial reservoir simulator[8]. The exponential term is used as a multiplier to the polynomial summation of reduced densities, and only starts to function when the reduced molar density approaches the specified maximum value for very viscous fluids.

In this paper, we focus on the original formulation of the LBC correlation since it is widely available and used in most commercial software. However, the guidelines we propose are readily applicable to any modified version of the LBC viscosity correlation.

Field Examples
Three samples from different Norwegian offshore reservoirs are selected in this paper. To cover a wide range of fluids, we have selected one rich gas condensate sample, one black oil sample, and one heavy oil sample. We use *Gas Condensate*, *Black Oil*, and *Heavy Oil* to refer to the three samples in this paper.

Gas Condensate
The composition and the EOS parameters are listed in Table 1 for the *Gas Condensate* sample. The SRK[9] EOS with Peneloux volume translation[10] is used for modeling the PVT behavior of this sample. The viscosity model parameters are listed in Table 2 for the default LBC, tuned LBC, and CSP models.

The most typical viscosity measurement (if any) for rich gas condensates is only single phase gas viscosity as listed in Table 3. It is not common to perform any viscosity measurements on the condensed oil below the dew point pressure. It is well known that the predictive capability of oil viscosities for the LBC correlation is low, especially for the condensed oil below the dew point pressure. In this study, we have measured the single phase viscosity of a separator oil sample at reservoir temperature (listed in Table 3) to reduce the uncertainty in the calculated viscosity of the condensed oil. The reservoir temperature is at 170 ^{o}C.

Black Oil
The composition and the EOS parameters are listed in Table 4 for the *Black Oil* sample. The PR79[11,12] EOS with Peneloux

volume translation is used for modeling the PVT behavior of this sample. The estimated critical volumes from different correlations are listed in Table 5.

The API gravity of the *Black Oil* sample is about 30. The reservoir temperature is at 85 °C. The viscosity data during a differential liberation experiment (DLE) are listed in Table 6.

Heavy Oil
The composition and the pseudoized EOS parameters are listed in Table 7 for the *Heavy Oil* sample. The PR79 EOS with Peneloux volume translation is used for modeling the PVT behavior of this sample. The viscosity model parameters are listed in Table 8.

The *Heavy Oil* sample is highly biodegraded and the API gravity is about 18. The reservoir temperature is at 57 °C. Only depletion viscosity data have been measured. The measured viscosity data are listed in Table 9.

Gas Condensate Viscosity Modeling
It is straight forward to get a reasonable viscosity description of the single phase gas, but not for the oil phase (condensate) below the dew point pressure. As described by Whitson et al.[13], condensate oil viscosity is important for proper modeling of condensate blockage, i.e. the two-phase gas/oil flow effect on gas relative permeability in the region around the wellbore. In addition, for very rich gas condensate, the condensed oil will flow in the reservoir when the oil saturation is higher than the critical oil saturation. Therefore, condensate oil viscosity might also be important for modeling of two-phase gas/oil flow in the reservoir.

As shown in Fig. 1, both the LBC and CSP viscosity models give reasonable predictions of the single phase gas viscosity, with the default LBC model without tuning. However, the calculated separator oil viscosity is not calculated accurately (at reservoir temperature) especially at high pressures. It is obvious that the LBC correlation needs to be tuned to the measured separator oil viscosity data. As shown in Fig. 2, both the tuned LBC and the CSP viscosity models calculate the measured separator oil viscosity with reasonable accuracy.

When the LBC correlation has been tuned to the measured separator oil viscosity data, the prediction of the condensate viscosity is reasonable. As shown in Fig. 3, the calculated condensate viscosity with the tuned LBC correlation is lower than the viscosity from the default LBC model.

Due to a lack of measured viscosity data, we predict the condensate oil viscosities using two other methods: the CSP model and the Standing correlation[14]. The two methods usually give more reasonable predictions of the oil viscosities. The Standing correlation for live oil viscosity is estimated as a function of dead-oil viscosity and solution gas/oil ratio. As shown in Fig. 3, the viscosity predictions from the tuned LBC model, the CSP model, and the Standing correlation are quite close. Therefore, we recommend to measure the viscosity of the separator oil (at reservoir temperature) and to use this data

to tune the LBC viscosity model to improve the prediction of condensate oil viscosity. When measured data is not available we recommend tuning the LBC correlation to calculated data from other viscosity correlations (e.g. CSP or Standing).

Black Oil Viscosity Modeling
As described in the previous LBC correlation section, Lohrenz suggested a critical volume correlation for the C_{7+} fraction in equation (7). Although the critical volume correlation was described initially for the bulk C_{7+} fraction, it has been used widely for the C_{7+} pseudocomponents in the industry. There are other correlations for C_{7+} critical volume estimation as summarized by Whitson et al.[15] The correlations for estimation of C_{7+} critical volumes provide only initial values as tuning is necessary in most of the fluids (oils).

There has not been any review regarding how well these correlations work or if there is any advantage in using one or the other. In this paper, we use viscosity regression for the *Black Oil* sample to test the two most widely used correlations: Lohrenz and Twu[16].

As shown in Fig. 4, the default LBC correlations using Lohrenz and Twu estimated critical volumes do not give reasonable viscosity prediction of the measured *Black Oil* viscosity data. The difference between these two correlations is very large. The Lohrenz correlation gives too high viscosity prediction, while the Twu correlation predicts too low viscosity. After regression, both the LBC calculated viscosities fit the experimental data very well independent of the correlation used to calculate the initial critical volumes as shown in Fig. 5.

Although the calculated oil viscosities are the same, the individual C_{7+} component viscosities at reservoir temperature (as shown in Figs 6 and 7) are very different. We found that the component viscosity for the C_{7+} components based on critical volumes from Lohrenz and Twu correlations is not monotonically increasing with molecular weight. The Lohrenz correlation gives reasonable results except in the range of C_7 to C_{10}-C_{13}. The component viscosities calculated from the tuned Twu correlation are not monotonically increasing with molecular weight. In fact, C_{36+} (the heaviest) component has the lowest viscosity as shown in Figs 6 and 7.

For depletion and water injection strategies, the impact of the non-monotonically increasing C_{7+} component viscosities on the overall viscosity description is low. This is due to small changes in the relative amount of the C_{7+} components during production. However, the non-monotonically increasing C_{7+} component viscosities can cause potential problems for a compositionally sensitive process, e.g. a gas injection process. Fig. 8 shows oil viscosity changes during a vaporization process (e.g. close to gas injector) with CO_2 injection at 300 bara. Due to the severe non-monotonically C_{7+} component viscosities with the Twu correlation, the resulting residual oil viscosity appears to be too low at higher amount of CO_2 injection.

Instead of using the Lohrenz or Twu correlations to estimate critical volumes for C_{7+} components, we propose a new approach in this paper to avoid the non-monotonically increasing C_{7+} component viscosities. The initial critical volumes of C_{7+} components are calculated based on component viscosities estimated from dead oil empirical viscosity correlations.

There are many dead oil viscosity correlations we can select from. Zick[17] recently suggested more rigorous viscosity correlation (group contribution method based) for component viscosity estimation. We have used the Beggs correlation[18] in this paper. Beggs correlation only requires component density and reservoir temperatures as input parameters to estimate component viscosity at low pressure and reservoir temperature. The critical volume for each C_{7+} pseudo component can be derived from component viscosity directly. Global regression to the measured viscosity data is then made with common modifier(s) to the initial critical volumes estimated based on component viscosity. This new approach always results in monotonically increasing component viscosities for the C_{7+} components after tuning.

As shown in Fig. 4, the default LBC correlation with the critical volumes estimated by the new approach predicts the measured data reasonably well. After the regression, the match to the measured viscosity data is very good as shown in Fig.5. As shown in Figs 6 and 7, the new approach is the only method giving monotonically increasing component viscosities for the C_{7+} components.

Heavy Oil Viscosity Modeling
The LBC correlation and its various modified versions have a basic assumption of the relation between viscosity and reduced density. The polynomial formula has to be consistent with fundamental physics: viscosity increases monotonically with reduced density. However, due to the negative coefficient in the LBC correlation, the monotonic relation between viscosity and reduced density is not always maintained when the coefficients are used as regression parameters.

As shown in Fig. 9, tuning of the LBC correlation to measured viscosity from a *Heavy Oil* viscosity can be difficult. The heavily tuned LBC model has a good description of the undersaturated oil viscosity, but with a non-monotonic relation of viscosity and reduced density. The less tuned LBC model does not match the data well.

As shown in Fig. 10, the consequence of the non-monotonic polynomial is a non-physical viscosity transition from gas to oil. When the reduced density is at the artificial local minimum between the typical gas and oil, the fluid viscosity is lower than the viscosity of a light gas. The viscosity transition can be found in practical recovery processes, e.g. gases at higher pressures, diluted oils from gas injection or solvent injection.

Fig. 11 shows swollen oil viscosity behavior during CO_2 injection. As more and more CO_2 is injected into the *Heavy Oil* sample, the reduced density of swollen oil decreases and the calculated viscosities of the swollen oil drop to zero for the non-monotonic polynomial LBC model (which is obviously not physically correct). Fig. 12 shows the strange behavior of the calculated gas viscosities at elevated pressures. For a gas consisted of only C_1N_2 pseudo component (original from methane and nitrogen with pseudo component properties listed in Table 7), the viscosity should increase with pressure because the gas is denser as the pressure increases. However, when the reduced density of compressed gas approaches the artificial local minimum region for the non-monotonic polynomial LBC model, the gas viscosities start to decrease instead of increasing with pressure.

As shown by the *Heavy Oil* sample, the LBC original viscosity correlation has limitations when it is applied to heavy oil systems. Tuning of the LBC coefficients often causes a non-monotonic relation of viscosity vs. reduced density. In such cases, it is recommended to avoid heavy tuning (especially on the LBC coefficients) in order to retain the physical meaning of the tuned LBC model.

Some modified LBC correlations have been proposed for heavy oils as discussed in the LBC model section. The extra exponential terms in the two modified LBC models can increase viscosity sharply with small changes in reduced density. These modifications have made it easier to match the viscosity of heavy oils. The principle discussed above regarding the monotonic relation of viscosity and reduced density is still applicable to the modified LBC correlations.

Conclusions
1. The critical volume estimations of the C_{7+} fraction by Lohrenz and Twu correlations do not provide good initial values for LBC viscosity tuning. The correlations (especially the Twu correlation) can easily cause non-monotonic component viscosity vs. molecular weight.

2. The recommended critical volume estimation can be derived from component viscosities estimated by an empirical correlation. Starting with the estimated critical volumes, global regression is recommended to match the measured reservoir fluid viscosity data, potentially combined with LBC coefficients.

3. The monotonic relation of viscosity and reduced density should always be maintained during the tuning of LBC coefficients. Violation of the monotonic relation will result in unrealistic predictions of the viscosity transition from gas to oil systems.

4. For gas condensates, it is recommended to tune the LBC correlation to measured separator oil viscosity data or to more reliable viscosity models (e.g. CSP) to improve the condensate oil viscosity description.

5. For heavy oils, it is recommended to avoid heavy tuning on LBC coefficients for improving the viscosity data match. Such regression has to be performed with great caution in order to maintain sensible physics for the LBC correlation. If the LBC coefficients are used as tuning

parameters, we strongly recommend checking LBC polynomial monotonicity.

Acknowledgements

Nomenclature

a	=	Lohrenz-Bray-Clark correlation coefficient
M	=	molecular weight
p	=	pressure, m/Lt^2, psia
T	=	temperature, T, ^{o}R
v	=	volume, L^3, bbl
z	=	mole fraction in overall mixture
μ	=	dynamic viscosity, m/Lt^2, cp
ξ_T	=	Thodos (Lohrenz-Bray-Clark) gas viscosity correlation parameter, cp^{-1}
ρ	=	density, m/L^3, lbm/ft^3

Subscripts

C	=	critical
C_{7+}	=	C_{7+} fractions
i	=	component i
pc	=	pseudocritical
pr	=	pseudoredcued
r	=	reduced

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SI Metric Conversion Factors

^{o}API 141.5/(131.5+^{o}API)		= g/cm^3
bar × 1.0*	E+05	= Pa
bbl × 1.589 873	E-01	= m^3
cp × 1.0*	E-03	= Pa.s
ft^3 × 2.831 685	E-02	= m^3
ft^3/lbm mol × 6.242 796	E-02	= m^3/kmol
lbm × 4.535 924	E-01	= kg
lbm mol × 4.535 924	E-01	= kmol
psi × 6.894 757	E+00	= kpa
^{o}R × 5/9		= K

* Conversion factor is exact.

Table 1 EOS parameters for *Gas Condensate* (SRK EOS with Peneloux volume translation)

Comp.	Gas Cond. Mole-%	Sep. Oil Mole-%	Mol. Weight	Crit. Temp. K	Crit. Pres. bara	Acentric Factor	Volume Trans. s	Non-Zero Binary Interaction Coefficients N2	CO2
N2	0.290	0.030	28.014	126.20	33.940	0.0400	0.0344	0.0000	0.0000
CO2	3.650	2.010	44.010	304.20	73.760	0.2250	0.1019	-0.0315	0.0000
C1	73.550	20.090	16.043	190.60	46.000	0.0080	0.0211	0.0278	0.1200
C2	8.510	9.060	30.070	305.40	48.840	0.0980	0.0584	0.0407	0.1200
C3	3.750	8.280	44.097	369.80	42.460	0.1520	0.0806	0.0763	0.1200
iC4	0.750	2.350	58.124	408.10	36.480	0.1760	0.0905	0.0944	0.1200
nC4	1.260	4.800	58.124	425.20	38.000	0.1930	0.0975	0.0700	0.1200
iC5	0.530	2.440	72.151	460.40	33.840	0.2270	0.1115	0.0867	0.1200
nC5	0.550	2.870	72.151	469.60	33.740	0.2510	0.1215	0.0878	0.1200
C6	0.740	4.310	86.178	507.40	29.690	0.2960	0.1460	0.0800	0.1200
C7	1.190	7.310	94.630	522.48	36.200	0.4638	-0.0776	0.0800	0.1000
C8	1.230	7.910	106.088	545.56	31.490	0.4971	0.0131	0.0800	0.1000
C9	0.770	5.220	120.305	567.28	27.010	0.5378	0.0868	0.0800	0.1000
C10-C11	0.857	5.858	140.021	596.17	22.930	0.5938	0.1525	0.0800	0.1000
C12	0.339	2.351	161.000	623.61	19.990	0.6504	0.1957	0.0800	0.1000
C13-C14	0.540	3.796	181.947	649.34	17.970	0.7067	0.2207	0.0800	0.1000
C15-C16	0.396	2.842	213.411	684.19	15.860	0.7869	0.2396	0.0800	0.1000
C17-C18	0.291	2.128	243.485	715.92	14.530	0.8597	0.2455	0.0800	0.1000
C19-C21	0.299	2.234	274.967	749.10	13.610	0.9323	0.2444	0.0800	0.1000
C22-C24	0.188	1.447	316.728	789.78	12.730	1.0208	0.2361	0.0800	0.1000
C25-C30	0.193	1.546	374.633	844.44	11.930	1.1301	0.2186	0.0800	0.1000
C31-C80	0.127	1.118	518.152	979.70	11.210	1.2928	0.1749	0.0800	0.1000

Table 2 LBC and CSP viscosity model parameters for *Gas Condensate*

Component	LBC Default Crit. Vol. m3/kmol	LBC Tuned Crit. Vol. m3/kmol	CSP Wt. Avg. MW
N2	0.090	0.090	28.014
CO2	0.087	0.087	44.010
C1	0.101	0.101	16.043
C2	0.147	0.147	30.070
C3	0.201	0.201	44.097
iC4	0.255	0.255	58.124
nC4	0.254	0.254	58.124
iC5	0.306	0.306	72.151
nC5	0.310	0.310	72.151
C6	0.534	0.534	86.178
C7	0.482	0.538	94.630
C8	0.504	0.562	106.088
C9	0.547	0.610	120.305
C10-C11	0.610	0.680	140.321
C12	0.684	0.763	161.000
C13-C14	0.764	0.852	182.255
C15-C16	0.893	0.996	213.709
C17-C18	1.022	1.140	243.685
C19-C21	1.161	1.295	275.434
C22-C24	1.354	1.510	317.080
C25-C30	1.632	1.821	376.153
C31-C80	2.364	2.638	535.119
LBC Coefficients			
a0	0.1023	0.1023	
a1	0.023364	0.023364	
a2	0.058533	0.058533	
a3	-0.0407580	-0.0402702	
a4	0.0093324	0.0091236	

Table 3 *Gas Condensate* viscosity data

Gas Condensate		Separator Oil	
Pressure bara	Gas Visc. cp	Pressure bara	Oil Visc. cp
931.8	0.0739	552.6	0.271
912.0	0.0729	483.6	0.255
897.3	0.0722	414.7	0.239
828.4	0.0688	345.8	0.224
759.4	0.0651	276.8	0.209
690.5	0.0613	207.9	0.195
621.5	0.0573	145.8	0.184
552.6	0.0529	138.9	0.183
518.1	0.0506	132.0	0.182
483.6	0.0482	125.1	0.181
456.1	0.0463	118.2	0.179
449.2	0.0457	112.4	0.178
442.3	0.0452		
435.4	0.0447		
428.5	0.0442		
422.6	0.0437		

Table 4 Composition and EOS parameters for *Black Oil* (PR79 EOS with Peneloux volume translation)

Comp.	Comp. Mole-%	Mol. Weight	Crit. Temp. K	Crit. Pres. bara	Acentric Factor	Volume Trans. s	Non-Zero Binary Interaction Coefficients N2	CO2	C1
N2	0.248	28.014	126.20	33.980	0.0370	-0.1676	0.0000	0.0000	0.0250
CO2	1.028	44.010	304.12	73.740	0.2250	0.0019	0.0000	0.0000	0.1050
C1	43.813	16.043	190.56	45.990	0.0110	-0.1500	0.0250	0.1050	0.0000
C2	6.172	30.070	305.32	48.720	0.0990	-0.0628	0.0100	0.0057	0.0022
C3	3.761	44.097	369.83	42.480	0.1520	-0.0638	0.0900	0.0166	0.0073
I-C4	0.858	58.123	407.85	36.400	0.1860	-0.0620	0.0950	0.0302	0.0137
N-C4	1.816	58.123	425.12	37.960	0.2000	-0.0539	0.0950	0.0285	0.0129
I-C5	0.772	72.150	460.39	33.810	0.2290	-0.0565	0.1000	0.0396	0.0183
N-C5	0.949	72.150	469.70	33.700	0.2520	-0.0293	0.1100	0.0402	0.0185
C6	1.402	83.569	515.79	35.235	0.2269	-0.0408	0.1100	0.0443	0.0205
C7	2.658	97.314	552.01	32.810	0.2610	-0.0305	0.1100	0.0525	0.0245
C8	2.920	111.233	583.48	30.332	0.2986	-0.0163	0.1100	0.0607	0.0285
C9	2.261	125.199	611.43	28.107	0.3369	-0.0016	0.1100	0.0687	0.0324
C10-C13	4.612	158.680	667.80	23.839	0.4285	0.0306	0.1100	0.0859	0.0408
C14-C19	11.387	226.732	752.60	18.323	0.5981	0.0768	0.1100	0.1131	0.0542
C20-C24	7.048	304.475	821.23	14.788	0.7711	0.1001	0.1100	0.1341	0.0647
C25-C29	4.201	374.231	853.24	14.050	0.8415	0.0004	0.1100	0.1400	0.0676
C30-C35	2.530	449.986	893.37	12.602	0.9599	-0.0169	0.1100	0.1499	0.0725
C36+	1.566	676.256	979.92	10.264	1.2344	-0.1020	0.1100	0.0195	0.0256

Table 5 LBC viscosity model parameters for *Black Oil*

Component	Crit. Vol. - LBC m3/kmol Initial	Final	Crit. Vol. - Twu m3/kmol Initial	Final	Crit. Vol. - This Work m3/kmol Initial	Final
N2	0.090	0.090	0.090	0.090	0.090	0.090
CO2	0.093	0.093	0.094	0.094	0.094	0.094
C1	0.101	0.101	0.099	0.099	0.099	0.099
C2	0.148	0.148	0.146	0.146	0.146	0.146
C3	0.201	0.201	0.200	0.200	0.200	0.200
I-C4	0.256	0.256	0.263	0.263	0.263	0.263
N-C4	0.254	0.254	0.255	0.255	0.255	0.255
I-C5	0.529	0.529	0.308	0.308	0.308	0.308
N-C5	0.520	0.520	0.311	0.311	0.311	0.311
C6	0.453	0.453	0.332	0.332	0.332	0.332
C7	0.466	0.418	0.374	0.456	0.416	0.398
C8	0.497	0.446	0.420	0.512	0.471	0.451
C9	0.537	0.482	0.467	0.569	0.527	0.504
C10-C13	0.655	0.587	0.582	0.709	0.661	0.632
C14-C19	0.936	0.840	0.807	0.983	0.934	0.894
C20-C24	1.292	1.159	1.032	1.257	1.248	1.194
C25-C29	1.630	1.462	1.106	1.347	1.522	1.457
C30-C35	2.010	1.803	1.241	1.512	1.828	1.750
C36+	3.200	2.871	1.524	1.856	2.751	2.633

Table 6 *Black Oil* viscosity data

Pressure bara	Oil Visc. cp
414.7	0.860
380.2	0.830
345.7	0.801
311.3	0.772
276.8	0.744
269.9	0.739
263.0	0.734
256.1	0.729
249.2	0.724
248.0	0.723
242.3	0.720
238.7	0.718
207.9	0.813
173.4	0.927
138.9	1.052
104.4	1.191
76.9	1.318
49.3	1.468
28.6	1.610
14.8	1.735
8.7	1.809
1.0	2.923

Table 7 Composition and EOS parameters for *Heavy Oil* (PR79 EOS with Peneloux volume translation)

Comp.	Comp. Mole-%	Mol. Weight	Crit. Temp. K	Crit. Pres. bara	Acentric Factor	Volume Trans. s	Non-Zero Binary Interaction Coefficients	
							CO2	C1N2
CO2	0.524	44.010	304.12	73.740	0.2250	0.0019	0.0000	0.1050
C1N2	18.150	16.518	187.81	45.514	0.0120	-0.1506	0.1050	0.0000
C2C9	0.204	70.820	467.41	38.454	0.1973	-0.0582	0.1300	0.0045
C10C18	17.256	219.857	756.14	21.144	0.5504	0.0030	0.1250	0.0153
C19C22	18.943	284.120	818.35	17.839	0.6884	0.0122	0.1200	0.0179
C23C27	17.832	344.515	863.74	15.823	0.8039	0.0064	0.1150	0.0196
C28C35	16.301	426.731	912.89	14.017	0.9400	-0.0162	0.1150	0.0213
C36+	10.791	576.000	979.83	12.094	1.1372	-0.0788	0.1150	0.0232

Table 8 LBC viscosity model parameters for *Heavy Oil*

	Non-monotonic Polynomial	Monotonic Polynomial
	Critical Volume	Critical Volume
Component	m3/kmol	m3/kmol
CO2	0.094	0.094
C1N2	0.098	0.098
C2C9	0.261	0.272
C10C18	1.206	1.120
C19C22	1.566	1.454
C23C27	1.910	1.774
C28C35	2.388	2.218
C36+	3.281	3.047
LBC Coefficients		
a0	0.1023	0.1023
a1	0.023364	0.023364
a2	0.05853	0.058533
a3	-0.1029160	-0.0407580
a4	0.0189638	0.0074659

Table 9 *Heavy Oil* viscosity data

Pressure bara	Oil Visc. cp
276.8	58.79
242.3	54.45
207.9	50.20
173.4	46.03
167.7	45.36
138.9	42.00
104.4	38.15
97.5	37.42
90.6	36.69
83.8	35.99
76.9	35.31
70.0	34.66
63.4	34.13
56.2	35.81
38.9	39.99
21.7	44.52
11.4	47.53
1.0	51.22

Fig. 1 Comparison of single phase gas viscosity – *Gas Condensate*

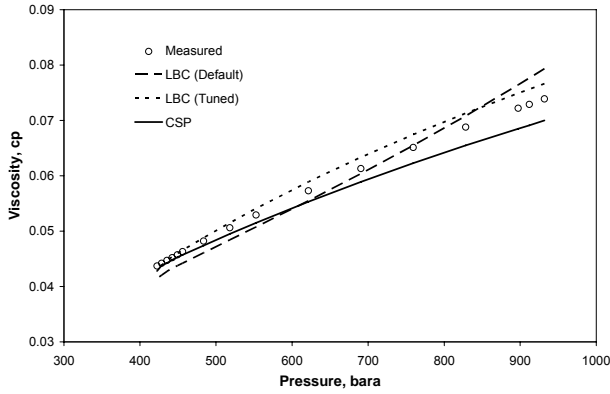Fig. 2 Comparison of separator oil viscosity – *Gas Condensate*

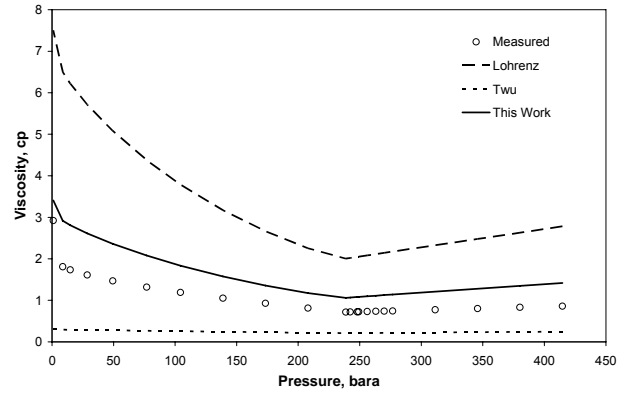Fig. 3 Comparison of condensate oil viscosity – *Gas condensate*

Fig. 4 Comparison of LBC predictions with different critical volume estimation methods (before regression) – *Black Oil*
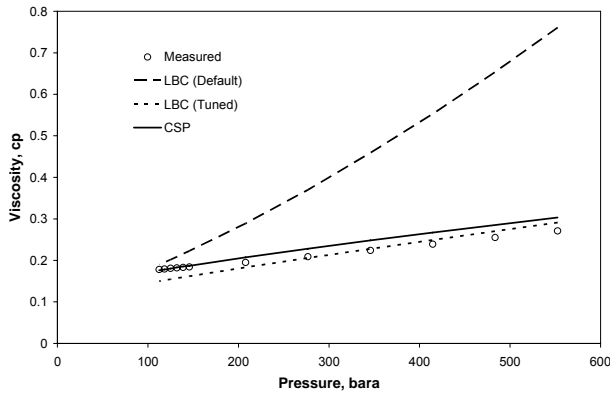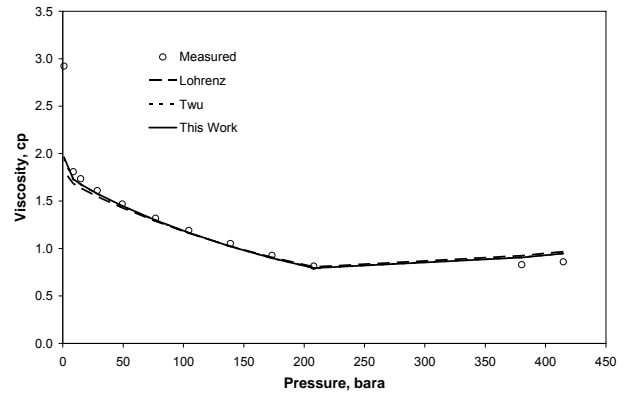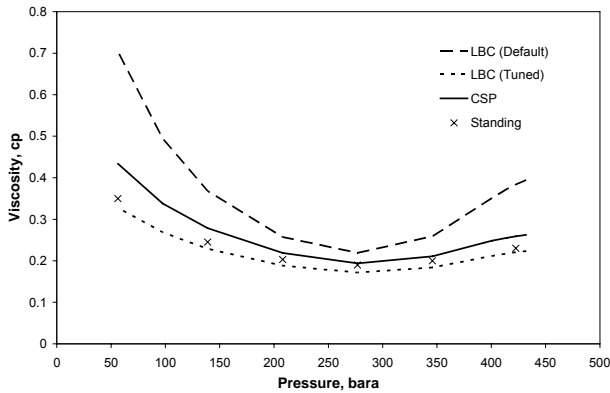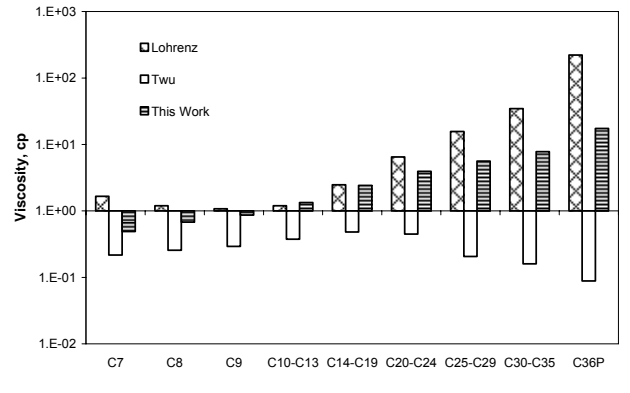

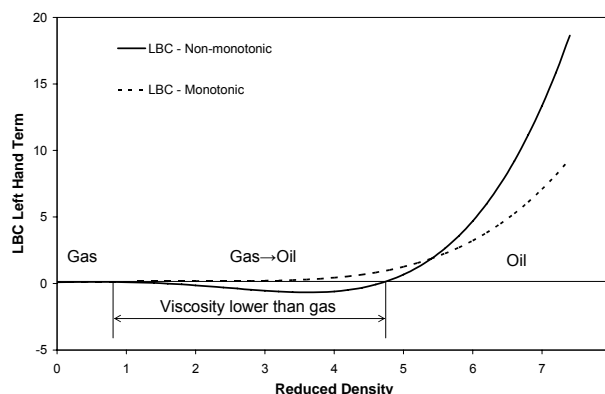Fig. 5 Comparison of LBC predictions with different critical volume estimation methods (after regression) – *Black Oil*

Fig. 6 Comparison of component viscosities with different critical volume estimation methods (before regression) – *Black Oil*

Fig. 7 Comparison of component viscosities with different critical volume estimation methods (after regression) – *Black Oil*

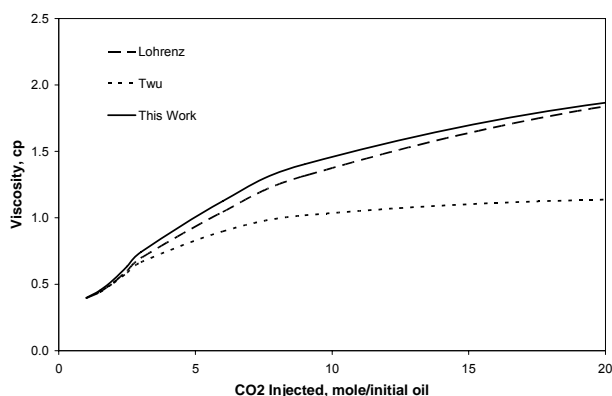**Fig. 10 Comparison of LBC monotonic and non-monotonic polynomials**

Fig. 8 Comparison of viscosities in vaporization process with different critical volume estimation methods – *Black Oil*
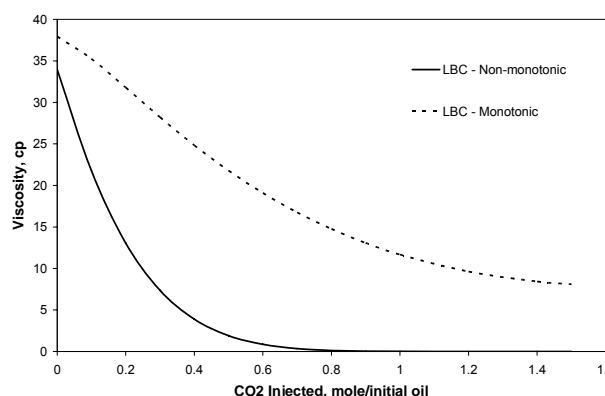

Fig. 11 Comparison of LBC predictions for swelling test (after regression) – *Heavy Oil*
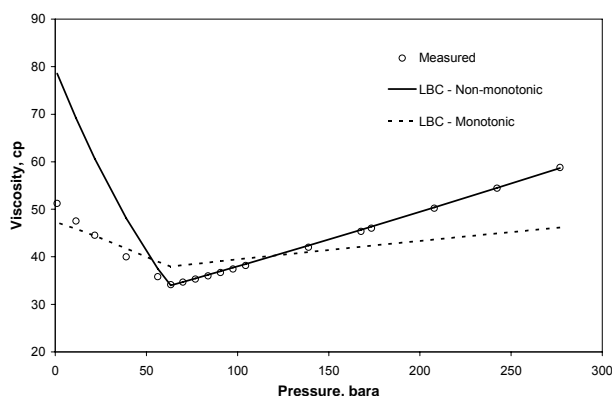

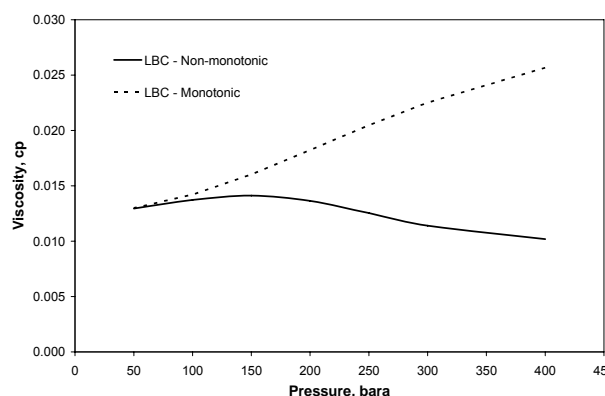**Fig. 9 Comparison of LBC predictions for depletion (after regression) – *Heavy Oil***

Fig. 12 Comparison of LBC predictions of C_1N_2 gas viscosity (after regression) – *Heavy Oil*