Sensitivity Analysis of the Gas Compressibility Factor

Walid Mohamed Mahmud
Department of Petroleum Engineering
University of Tripoli, Tripoli-Libya
walidt@hotmail.com

Saber Elmabrouk
School of Applied Science and Engineering
The Libyan Academy, Tripoli-Libya
saber.elmabrouk@academy.edu.ly

Hassan M. Sbiga
Libyan Petroleum Institute (L.P.I)
Tripoli-Libya
hasanespiga@yahoo.com

Abstract
Compressibility factor, *z*, values of natural gases are necessary in most petroleum gas engineering calculations. Most common sources of the compressibility factor values are experimental measurements, equations of state method and empirical correlations. If laboratory measured data were unavailable, empirical correlations can be used to determine the compressibility factors. However, there might be discrepancies between laboratory-measured values with those obtained by correlations which, in turn, might affect the outcome of a study. Sensitivity analysis is a technique used to determine how different values of the compressibility factor would affect well testing and material balance equation calculations. Under a given set of data, this technique is used within specific boundaries that will depend on one or more methods, such as the effect that changes in reservoir's parameters obtained from build-up test and calculations of gas initial in place by using material balance equation. This study highlights how changes in the compressibility factor affect well testing results and volume of gas initially in reservoir calculated using material balance equation. Three wells producing under partial water drive mechanism were considered for this study. Dranchuk and Abu-Kassem's method was found to have the lowest error.

Keywords
Gas compressibility factor, gas flow, sensitivity analysis, well testing, z-factor

1. Introduction
A sensitivity analysis is conducted in order to determine the effect of measurement uncertainties on performance calculations. A detailed review of various sensitivity analysis techniques has been provided by Gevrey et al (2003). In this study the sensitivity of gas compressibility (z-factor) in gas well testing and material balance equation calculations was conducted. However, the importance of gas condensate reservoirs has grown continuously since the late 1930's. Development and operation of these reservoirs, for maximum recovery, require engineering and operating methods significantly different from crude oil or dry gas reservoirs. Properties of reservoir fluids determine best program in each case. A thorough understanding of fluid properties together with good understanding of economics involved is therefore required for optimum engineering of gas condensate reservoirs. Other important aspects include geologic conditions, rock properties, well deliverability, well costs and spacing, well-pattern geometry and plant costs.

1.1 Gas Condensate Characterization
Hydrocarbon reservoir fluids range continuously from dry gases containing almost no condensable liquid to solid tars and bitumen. These hydrocarbons are classified in arbitrary divisions based on their color, density and gas-oil ratio. Although some gases have their source in carbonaceous rocks, most hydrocarbon accumulations originate from organic rich shales. The degree of degradation of complex organic molecules increases with temperature and pressure to which the organic matter has been subjected. Therefore, the deeper the source rock the more likely the resulting hydrocarbon mixture is to be gas or gas condensate that is usually found in deep reservoirs. The classical categories of hydrocarbons are in decreasing order of volatility.

A gas condensate will generally yield from 30 to 300 barrels of liquid per million standard cubic feet of gas. Most known retrograde gas condensate reservoirs are in the range of 5000 to 10000 ft deep at 3000 to 8000 psi and temperature from 200 to 400 ^oF.

Reservoir behavior of gas condensate system depends on both the fluid phase envelope and reservoir conditions. Phase envelope consists of bubble point line (under which the first bubble of gas vaporizes from the liquid) and dew point line (under which the first droplet of liquid condenses from the vapor) meeting at a critical point. The highest pressure at which two phases can coexist is called cricondenbar pressure, thus, two phases cannot co-exist above the cricondenbar pressure or temperature. At the critical point, properties of liquid and vapor phases can no longer be distinguished.

1.2 Gas Condensate Well Test and Sampling

Proper testing of gas condensate wells is essential to ascertain the hydrocarbon system state at reservoir conditions and to plan best production and recovery program for the reservoir. It is not possible to accurately determine phase conditions of a reservoir contents at reservoir temperature and pressure and to estimate the amount of hydrocarbon materials in place without proper well tests and samples.

Tests are made on gas condensate wells to obtain representative samples for laboratory analysis in order to identify composition and properties of reservoir fluids. And to also make field determinations on gas and liquid properties to determine formation and well characteristics including productivity, producibility, and injectivity. The first consideration for selecting wells for gas condensate fluid samples is that they are far enough from the "black-oil ring" (if present) to minimize any chance that the liquid oil phase will enter the well during the test period. The second consideration is the selection of wells with as high productivities as possible so that minimum pressure drawdown would occur as reservoir fluid samples are acquired.

Gas and condensate considered for the present study are produced from fifteen platform wells and eleven subsea wells divided in two clusters located twenty and twenty-five km away from Sabratha Platform. Production from the subsea and platform wells is treated on Sabratha Platform for separation and dehydration. The condensate is pumped through a 10-inch pipeline to Mellitah for further treatment and then export. The gas is transported through a 36-inch pipeline to Mellitah plant for final treatment and onward transmission to the local market and export to Italy through the Green Stream compression station and then through a 540 km long and 32-inch sea line.

2. Gas Compressibility Factor

Gas compressibility factor is required for gas reservoir engineering calculations which include estimation of gas reserves, design of oil and gas separators and design of pipelines for the transmission of produced gas, among others. Laboratory analysis is the most accurate way to determine gas compressibility factor; however, in the absence of laboratory data, correlations are viable alternatives for estimating the compressibility factor.
In this present study, the compressibility factor was calculated by using five methods:

2.1 Papay's Method

Papay (1968) proposed the following simplified equation for calculating the compressibility factor:

$$Z = 1 - \frac{3.52 p_{pr}}{10^{0.9813 T_{pr}}} + \frac{0.274 p_{pr}^{2}}{10^{0.8157 T_{pr}}} \quad (1)$$

where, Ppr = pseudo-reduced pressure, and Tpr = pseudo-reduced temperature. However, Correlation (1) is convenient for hand calculations, however, it produces an average error of -4.8% (Takacs,1989).

2.2 Hall & Yarborough's Method

Hall and Yarborough (1973) presented an equation-of-state that accurately represents the Standing and Katz Z-factor chart. The proposed expression is based on the Starling-Carnahan equation-of-state. The coefficients of the correlation were determined by fitting them to data taken from the Standing and Katz Z-factor chart. Hall and Yarborough proposed the following mathematical form:

$$Z = \frac{X_1 P_{pr}}{Y} \quad (2)$$

where, T = reciprocal of the pseudo-reduced temperature, i.e., Tpc/T, and Y = the reduced density which can be obtained as the solution of the correlation (3):

$$y = [(-x_1 + x_2 y^2 - x_3 y^4) * (1 - y)^3] - y^2 - y^3 - y^4 \quad (3)$$

This non-linear equation can be conveniently solved for the reduced density Y by using the Newton-Raphson iteration technique. Hall and Yarborough pointed out that the method is not recommended for application if the pseudo-reduced temperature is less than one.

2.3 Dranchuk & Abu-Kassem's Method

Dranchuk and Abu-Kassem (1975) proposed an eleven-constant equation of state for calculating the gas compressibility factors. The authors proposed the correlation (4):

$$Z = 1 + \left(A_1 + \frac{A_2}{Tpr} + \frac{A_3}{Tpr^3} + \frac{A_4}{Tpr^4} + \frac{A_5}{Tpr^5}\right)\rho_r + \left(A_6 + \frac{A_7}{Tpr} + \frac{A_8}{Tpr^2}\right)\rho_r^2 - A_9\left|\frac{A_7}{Tpr} + \frac{A_8}{Tpr^2}\right|\rho_r^5 . A_{10}(1 + A_{11}\rho_r^2)\frac{\rho_r^2}{Tpr^3} . e^{-A^{11}\rho_r^2}$$

(4)

where, ρr = reduced gas density and is defined as the correlation (5):

$$\rho_r = \frac{0.27P_r}{zT_r} \quad (5)$$

The constants A1 through A11 were determined by fitting the equation, using non-linear regression models to 1,500 data points from the Standing and Katz Z-factor chart.
The coefficients have the following values:

Table 1: Coefficients of Dranchuk & Abu-Kassem Method

A	Values	A	Values
A1	0.3265	A7	-0.7361
A2	-1.0700	A8	0.1844
A3	-0.5339	A9	0.1056
A4	0.0157	A10	0.6134
A5	-0.0517	A11	0.7210
A6	0.5475		

The above correlation was reported to duplicate compressibility factors from the Standing and Katz chart with an average absolute error of 0.585 percent, and is applicable over the following ranges:

0.2 $\leq$ Ppr < 30
1.0< Tpr $\leq$ 3.0

2.4 Dranchuk, Purvis and Robinson's Method

Dranchuk, Purvis and Robinson (1974) developed a correlation based the Benedict-Webb-Rubin type of equation of state. The eight coefficients of the proposed equations were optimized by fitting the equation to 1,500 data points from the Standing and Katz Z-Factor chart. The equation has the following form:

$$Z = 1 + \left(A_1 + \frac{A_2}{T_r} + \frac{A_3}{T_r^3}\right)\rho_r + \left(A_4 + \frac{A_5}{T_r}\right)\rho_r^2 + \left(A_5 . \frac{A_6}{T_r}\right)\rho_r^5 + A_7\frac{\rho_r^2}{T_r^3}(1 + A_8\rho_r^2)exp(-A_8 . \rho_r^2)$$

(6)

where, ρr = reduced gas density and is defined by the equation (5). The coefficients A1 through A8 have the following values:

Table 2: The Coefficients of Dranchuk Purvis & Robenson Method

A	A value	A	A value
A1	0.31506237	A5	-0.61232032
A2	-1.0467099	A6	-0.10488813
A3	-0.57832729	A7	0.68157001
A4	0.53530771	A8	0.68446549

The method is valid within the following ranges of pseudo-reduced temperature and pressure:

$1.05 \leq Tpr < 3.0$

$0.2 \leq Ppr \leq 3.0$

2.5 Brill & Beggs's Method

This method involves 21 iterative steps wherein a pressure drop is obtained at the end of each iteration. The compressibility factor is determined as follows:

$$A = 1.39(Tpr - 0.92)^{0.5} - 0.36Tpr - 0.101 \tag{7}$$

$$B = (0.62 - 0.23Tpr)Ppr + \left(\frac{0.066}{Tpr - 0.86} - 0.037\right)P_r^2 + \frac{0.32P_r^6}{10^{(9Tr-9)}} \tag{8}$$

$$C = (0.132 - 0.32logTr) \tag{9}$$

$$D = AntiLog(0.3106 - 0.49Tr + 0.1824T_r^2) \tag{10}$$

$$Z = A + \frac{1-A}{e^B} + CP_r^D \tag{11}$$

3. Results and Discussion

Table 3 shows the gas compositions and specific gravity by using equations 8, 9, 12 and 13 for known composition and equations 18 and 19 for unknown composition. The critical properties for C7+ were calculated and shown in Table 4 and the critical properties for each method is shown in Table 5.

By substituting the values above in the previous equations for each method to calculate the compressibility factor, results of some selected compressibility factor values at different pressures compared with compressibility factor measured in the lab are shown in Tables 6 to 10.

Table 3: Gas Compositions and Gas Specific Gravity

γ_g = 0.8870775			
Component	Mole %	Component	Mole %
N_2	3.095	i-C_5	0.205
CO_2	11.770	n-C_5	0.185
H_2S	1.445	C_6	0.360
C_1	73.355	Mcyclo-C_5	0.060
C_2	3.850	Benzene	0.115
C_3	1.590	Cyclo-C_6	0.060
i-C_4	0.320	C_{7+}	3.040
n-C_4	0.530		

Table 4: Critical Properties for C_{7+}

Component	**Mole %**	**M_i**	γ_g
C_{7+}	3.04	100.202	0.66127

Table 5: Gas Critical Properties for Each Method

	Known Composition		Unknown Composition	
Critical Properties	McCain's method	Stewart's method	McCain's method	Sutton's method
Tpc	488.52291	421.53812	397.87107	396.60391
Ppc	685.78315	666.27337	683.50284	677.47989

Table 6: Compressibility Factor Calculated by Papay's Method

Papay's Method					
Pressure Psia	Z Lab	Known Gas Composition		Unknown Gas composition	
		Stewart's method	McCain's method	Sutton's method	McCain's method
716.48	0.8611784	0.9407273	0.8984269	0.9548356	0.9545254
2123.3	0.8790415	0.8919023	0.7993349	0.9192317	0.9179679
3021.1	0.8939306	0.9075390	0.8056055	0.9332753	0.9311644
3500.0	0.9057105	0.9307910	0.8310988	0.9524813	0.9498426
3600.0	0.9083421	0.9369556	0.8383668	0.9575204	0.9547648
3700.0	0.9124307	0.9435725	0.8463068	0.9629148	0.9600401
3800.0	0.9190000	0.9506417	0.8549186	0.9686647	0.9656684
3900.0	0.9240000	0.9581633	0.8642023	0.9747699	0.9716498
4000.0	0.9290000	0.9661372	0.8741579	0.9812305	0.9779843

Table 7: Compressibility Factor Calculated by Hall and Yarborough's Method

Hall and Yarborough's Method					
Pressure Psia	Z Lab	Known Gas Composition		Unknown Gas Composition	
		Stewart's method	McCain's method	Sutton's method	McCain's method
716.48	0.8611784	0.9437007	0.9025942	0.9571000	0.9568345
2123.3	0.8790415	0.8853872	0.7922019	0.9144754	0.9132099
3021.1	0.8939306	0.8979244	0.8146527	0.9246921	0.9225720
3500.0	0.9057105	0.9187337	0.8476432	0.9413264	0.9387644
3600.0	0.9083421	0.9240507	0.8556736	0.9456242	0.9429740
3700.0	0.9124307	0.9296592	0.8640142	0.9501778	0.9474410
3800.0	0.9190000	0.9355405	0.8726342	0.9549745	0.9521527
3900.0	0.9240000	0.9416769	0.8815061	0.9600017	0.9570967
4000.0	0.9290000	0.9480515	0.8906049	0.9652472	0.9622606

Table 8: Compressibility Factor Calculated by Dranchuk and Abu-Kassem's Method

Dranchuk and Abu-Kassem's Method					
Pressure Psia	Z Lab	Known Gas Composition		Unknown Gas Composition	
		Stewart's method	McCain's method	Sutton's method	McCain's method
716.48	0.8611784	0.9426450	0.9037914	0.9553044	0.9550868
2123.3	0.8790415	0.8829015	0.7850740	0.9120737	0.9108199
3021.1	0.8939306	0.8923746	0.7957820	0.9213237	0.9192063
3500.0	0.9057105	0.9100752	0.8215229	0.9363404	0.9337837
3600.0	0.9083421	0.9146417	0.8280646	0.9402038	0.9375592
3700.0	0.9124307	0.9194724	0.8349365	0.9442933	0.9415621
3800.0	0.9190000	0.9245525	0.8421112	0.9485980	0.9457818
3900.0	0.9240000	0.9298677	0.8495635	0.9531076	0.9502078
4000.0	0.9290000	0.9354045	0.8572702	0.9578121	0.9548301

Table 9: Compressibility Factor Calculated by Dranchuk, Purvis and Robinson's Method

Dranchuk, Purvis and Robinson's Method					
Pressure Psia	Z Lab	Known Gas Composition		Unknown Gas Composition	
		Stewart's method	McCain's method	Sutton's method	McCain's method
716.48	0.8611784	0.9380247	0.8937480	0.9520360	0.9518202
2123.3	0.8790415	0.8447392	0.7041976	0.8865842	0.8851890
3021.1	0.8939306	0.8514279	0.8001684	0.8856693	0.8831020
3500.0	0.9057105	0.8848553	0.8351126	0.9048846	0.9017633
3600.0	0.9083421	0.8936878	0.8441391	0.9105492	0.9073273
3700.0	0.9124307	0.9030131	0.8535574	0.9167228	0.9134056
3800.0	0.9190000	0.9127754	0.8632905	0.9233731	0.9199657
3900.0	0.9240000	0.9229245	0.8732829	0.9304670	0.9269741
4000.0	0.9290000	0.9334155	0.8835047	0.9379714	0.9343973

Compressibility factor varies with each method implemented. Calculating the error percent between calculated and laboratory measured compressibilities, thus, the closest results to lab measurements can be obtained.

The smallest value of Absolute Relative Error (ARE), as shown in Table 11, was obtained for Dranchuk and Abu-Kassem's Method for known compositions which is 17.82% and also shown in Figure 1. Thus, Dranchuk and Abu-Kassem's Method can be considered as the most accurate method for calculating the compressibility factor.

Table 10: Compressibility Factor Calculated by Brill and Biggs's Method

Brill and Beggs's Method					
Pressure Psia	Z Lab	Known Gas Composition		Unknown Gas Composition	
		Stewart's method	McCain's method	Sutton's method	McCain's method
716.48	0.8611784	0.9474514	0.9075188	0.9609070	0.9606311
2123.3	0.8790415	0.8764195	0.7836656	0.9099957	0.9086936
3021.1	0.8939306	0.8755963	0.7882738	0.9084153	0.9063250
3500.0	0.9057105	0.8894603	0.8122403	0.9184949	0.9159696
3600.0	0.9083421	0.8934402	0.8186378	0.9214955	0.9188791
3700.0	0.9124307	0.8977609	0.8254392	0.9247890	0.9220815
3800.0	0.9190000	0.9024064	0.8326117	0.9283670	0.9255686
3900.0	0.9240000	0.9073611	0.8401240	0.9322209	0.9293318
4000.0	0.9290000	0.9126090	0.8479458	0.9363418	0.9333621

Table 11: Error of Calculating the Compressibility Factor

Pseudo critical Gas Properties Correlations	Factor Correlations	RE%	ARE%	SSE
Stewart correlation Known gas composition	Papay	-68.594	46.194	380.260
	Hall and Yarborough	-29.046	29.046	126.310
	Dranchuk & Abu-Kassem	-17.111	17.824	100.860
	Dranchuk, Purvis & Robinson	22.825	43.050	200.100
	Brill and Beggs	9.209	35.235	149.730
McCain's correlation Known gas composition	Papay	108.217	116.868	953.130
	Hall and Yarborough	90.330	99.949	714.700
	Dranchuk & Abu-Kassem	124.773	134.669	1255.160
	Dranchuk, Purvis & Robinson	127.839	135.403	1479.380
	Brill and Beggs	135.886	146.648	1487.130
Sutton correlation unknown gas composition	Papay	-82.092	82.092	483.822
	Hall and Yarborough	-66.718	66.718	349.144
	Dranchuk & Abu-Kassem	-59.316	59.316	292.001
	Dranchuk, Purvis & Robinson	-14.743	22.054	133.416
	Brill and Beggs	-68.594	46.194	380.260
McCain's correlation unknown gas composition	Papay	-29.046	29.046	126.310
	Hall and Yarborough	-17.111	17.824	100.860
	Dranchuk & Abu-Kassem	22.825	43.050	200.100
	Dranchuk, Purvis & Robinson	9.209	35.235	149.730
	Brill and Beggs	108.217	116.868	953.130

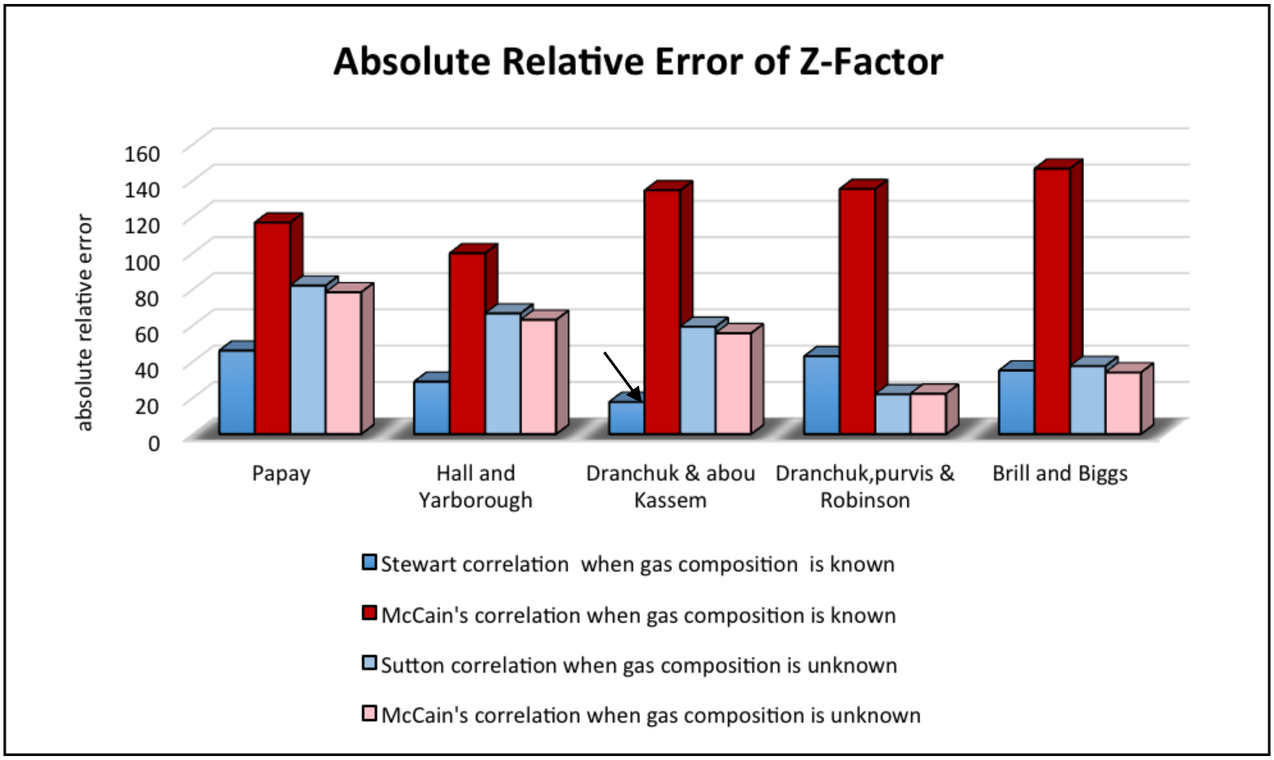

Figure 1: Absolute Relative Error of the Compressibility Factor.

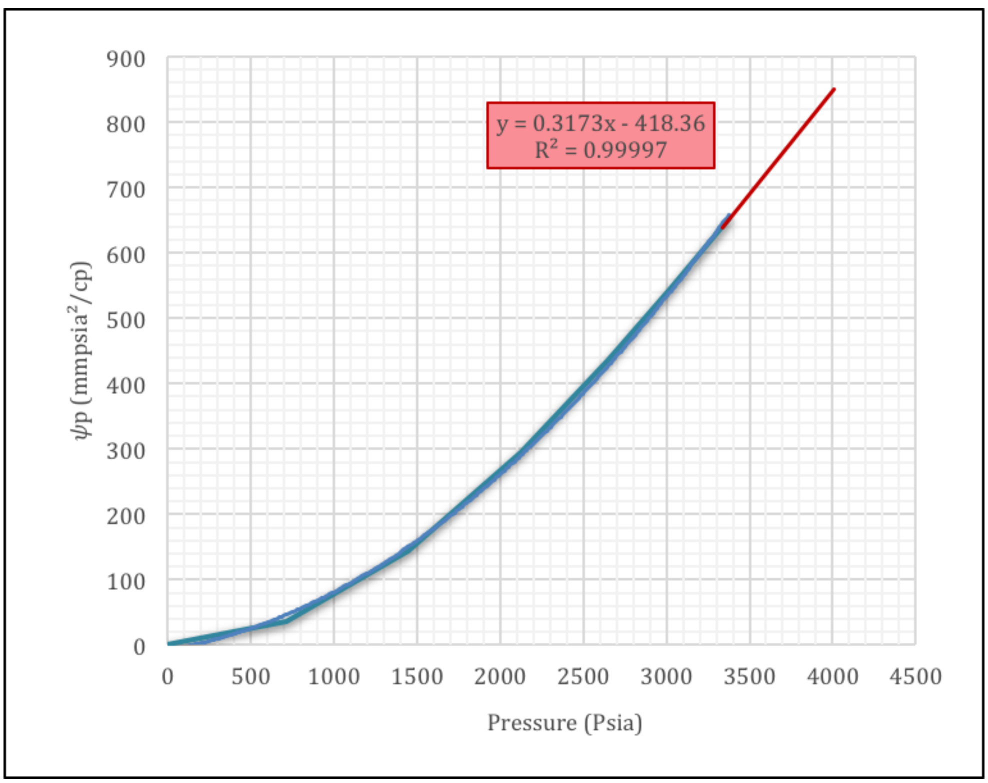

Figure 2: Real gas pseudo-pressure, ψ-P, curve versus reservoir pressure

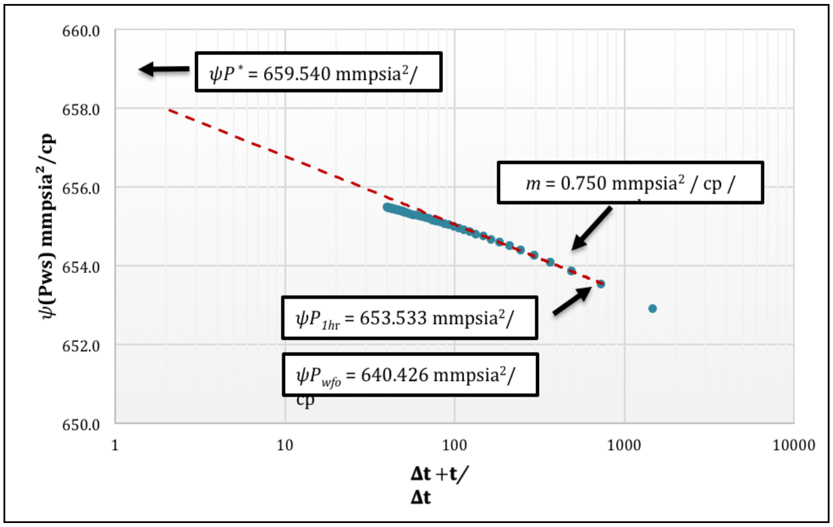

Figure 3: Horner buildup data plot for CC06 Well.

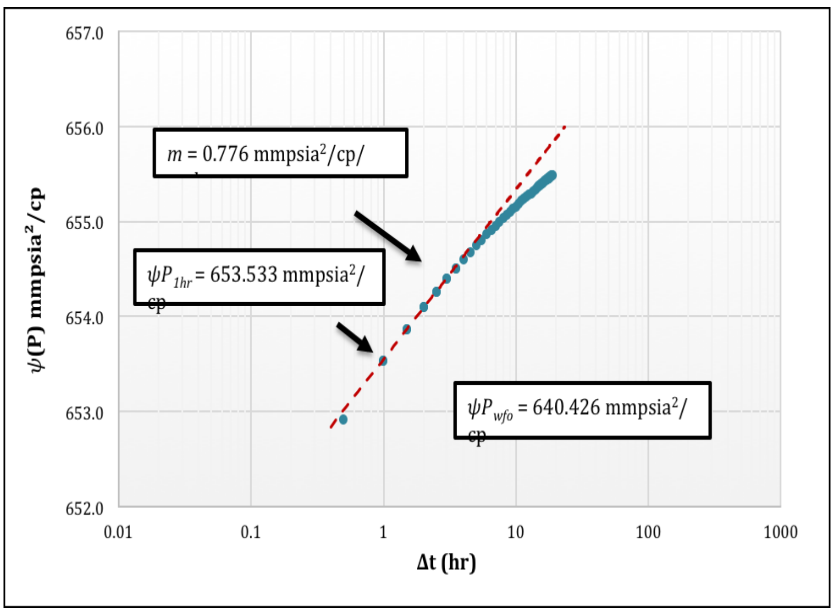

Figure 4: Horner buildup data plot for CC11 Well

Gas well test analysis is a branch of reservoir engineering; information derived from flow and pressure transient tests is important in many phases of petroleum engineering. Pressures are most valuable and useful data in reservoir engineering, directly or indirectly, they enter into all phases of reservoir engineering calculations. Therefore, accurate determination of reservoir parameters is very important. During a well test, a transient pressure response is created by a temporary change in production rate. The well response is usually monitored during a relatively short period compared to the life of the reservoir, depending upon the test objectives. For well evaluation, tests are frequently achieved in less than two days, in the case of reservoir limit testing; several months of pressure data may be needed, in most cases, the flow rate is measured at surface while the pressure is recorded down-hole. Before opening, the initial pressure p_i is constant and uniform in the reservoir during flow time.

Some of the objectives of gas well test analysis is to provide information on the reservoir parameters such permeability and initial and average reservoir pressures, to determine whether all the drilled length of gas well is

also a producing zone and to estimate skin factor or drilling and completion related damage. Well test results are then used to build a reservoir model for predicting field behavior and fluid recovery at different operating scenarios. Input data required for well test analysis are flow rate and bottom hole pressure as a function of time. Other well and reservoir data are also required such as porosity, wellbore radius, formation depths and thickness.
There are two types of pressure testing in gas wells: pressure transient and deliverability.

Figure 2 is a plot of the real gas pseudo-pressure (ψ-P) versus reservoir pressure (psi) for each flow rate. From this plot, a straight-line equation can be used to estimate the pseudo pressure for the reservoir that then can be used to calculate the reservoir parameters in a build-up test of gas condensate. Figures 3, 5 and 7 show the build-up test analysis of wells CC06, CC11 and CC13, respectively by using Horner method. Tables 12, 13 and 14 show the results (permeability, skin, etc.) obtained by the two methods, Horner and Miller, Dyes and Hutchinson (MDH), for wells CC06, CC11 and CC13, respectively. Figure 15, 16 and 17 show Miller, Dyes and Hutchinson (MDH) buildup data plots for wells CC06, CC11 and CC13, respectively. FE of 1.26, in Table 12 for example, indicates that the well produces About 54% as much gas as simulated well in a completed perforated interval would produce. The physical interpretation of this result is that the tested well is producing 75.86 MMMscf gas at a drainage radius of 587.48 ft and permeability unaltered up to the sand face.

Permeability was calculated and found to be 456.69 md by Horner method and 441.39 md by MDH method.
Comparing between Tables 12 and 13, it can be noticed that there is a little mismatch between results obtained by Horner plot and those estimated from MDH plot. Therefore, both plots can be used for calculating reservoir parameters in the three wells. From the skin value; we note that the well is damaged; the completion would probably benefit from stimulation.

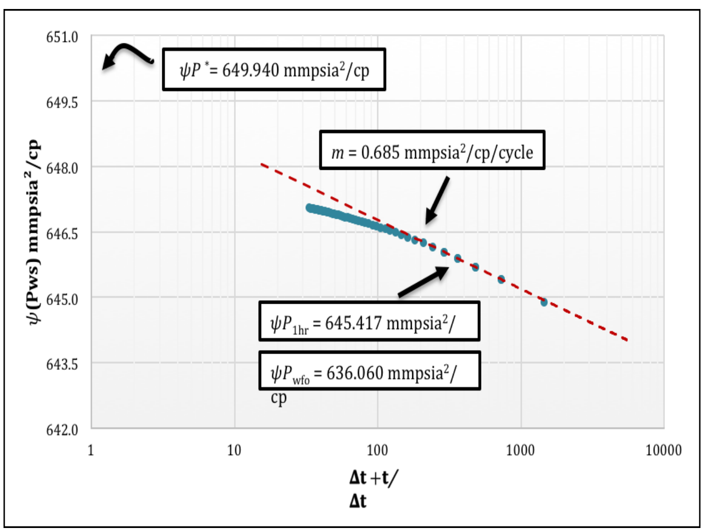

Figure 5: MDH buildup data plot for CC11 Well

-

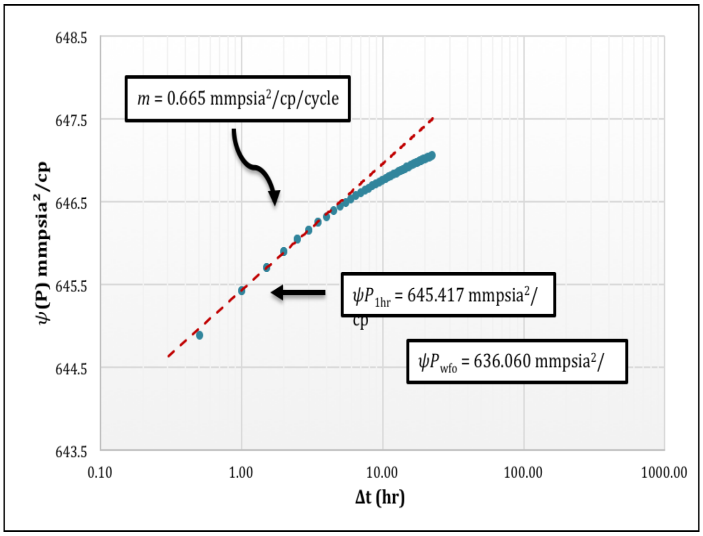

Figure 6: MDH buildup data plot for CC11 Well.

.

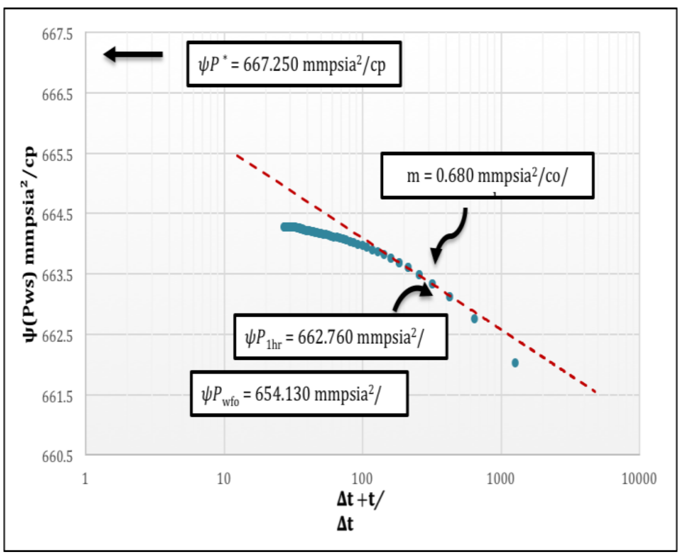

Figure 7: Horner buildup data plot for CC13 Well

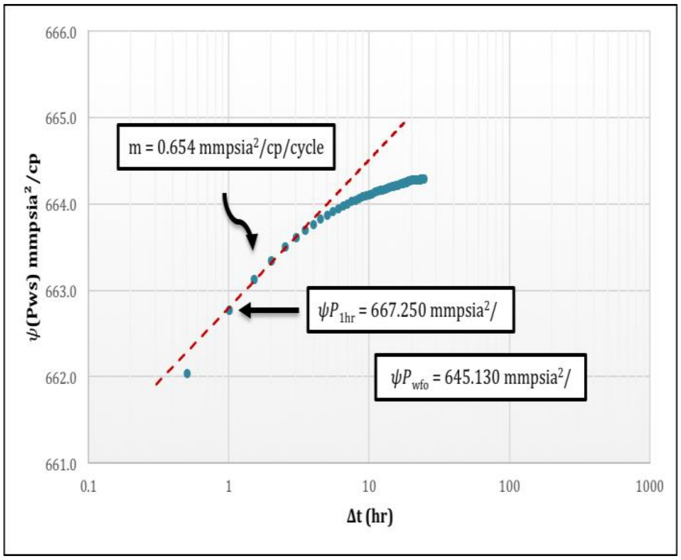

Figure 8: MDH buildup data plot for CC13 Well

Table 12: Reservoir Parameters for CC06 Well

Method	K (md)	S	ψ(ΔP) skin (mmpsia²/cp)	FE %	rwa (ft)	$\bar{P}_R$ (Psia)	GIIP (MMMscf)
Horner	456.69	-7.41	-4.82760	126.68	583.56	3390.701	75.86063
MDH	441.39	-7.39	-4.98347	132.389	573.70	3385.35	75.86063

Table 13: Reservoir Parameters for CC11 Well

Method	K (md)	S	ψ(ΔP) skin (mmpsia²/cp)	FE %	rwa (ft)	$\bar{P}_R$ (Psia)	GIIP (MMMscf)
Horner	355.08	8.44	5.02490	63.798	7.64E-05	3364.172	103.08121
MDH	366.09	8.91	5.14644	54.125	4.76E-05	3358.456	103.08121

Table 14: Reservoir Parameters for CC13 Well

Method	K (md)	S	$\psi(\Delta P)$ skin (mmpsia^2/cp)	FE %	rwa (ft)	$\bar{P}_R$ (Psia)	GIIP (MMMscf)
Horner	357.77	7.32	4.32753	67.016	2.34E-04	3418.857	104.30836
MDH	371.936	7.882	4.48047	59.970	1.34E-04	3415.325	104.30836

4. Conclusions

A sensitivity analysis is conducted in order to determine the effect of measurement uncertainties on performance calculations. The following are the main conclusions that can be withdrawn from this study:

- Different methods, temperatures, pressures, and gas compositions covering a wide range of naturally occurring petroleum gases and non-hydrocarbon impurities have been used to calculate the compressibility factor by empirical equations then compared with the equivalent compressibility factor determined in PVT laboratory.
- Determination of accurate critical parameters of mixtures is an essential step in order to obtain accurate compressibility factor value.
- Using two methods to determine critical properties with known composition yield an average absolute error of 17% and a maximum error over 100%. On the other hand, two other methods used to calculate the critical properties with unknown composition have an average absolute relative error of 22 to 82%.
- Dranchuk and Abu-Kassem’s method yields lower errors than the other methods; compressibility factors at an average absolute error of 17% and a maximum error of 46%.
- Well testing is the only method through which information on the dynamic behavior of a well/reservoir can be obtained.
- Derivative (diagnostic) analysis plot must be used to better interpret transient pressure tests.
- Wells CC11 and CC13 considered in this study can be recognized as damaged wells because their skin factors are positive.
- Two build-up test methods were used to estimate reservoir parameters; Horner method and MDH method which both yielded close results.
- Upon comparing reservoir parameters determined by utilizing the compressibility factor obtained by fives methods with those obtained by utilizing the compressibility factor obtained experimentally, Dranchuk and Abu-Kassem’s method yielded the lowest absolute error ranging from 0 to 10%. While Brill and Biggs’s method yielded an absolute error of 0.8 to 20%.

References

Brill, J. P., and Beggs, H. D., “Two-Phase flow in pipes,” INTERCOMP Course, The Huge (1974).

Dranchuk, P. M., Purvis, R. A., and Robinson, D. B., “Computer Calculation of Natural Gas Compressibility Factors Using the Standing and Katz Correlations,” Inst. of Petroleum Technical Institute Series, No. IP74-008, 1-13 (1974).

Dranchuk, P. M., and Abou-Kassem, J. H., “Calculation of Z-Factors for Natural Gases Using Equations of State,” J. Cdn. Pet. Tech., 14, 34 (1975).

Gevrey, M., I. Dimopoulos and S. Lek, 2003. Review and Comparison of Methods to Study the Contribution of Variables in Artificial Neural Network Models. Ecol. Model, pp: 249-264.Appendix A - Correlation for Undersaturated OFVF

Papay, J., "A terrnelestechnologiai pararneterek valtozasa a gaztelepek muvelese soran." OGIL Musz. Tud. kozl., Budapest, 1968, pp. 267-73.

Takacs, G., "Comparing methods for calculating Z-factor/' OGJ, May 15, 1989, p. 43.

Yarborough, L., and Hall, K. R., “A New EOS for Z-Factor Calculations,” Oil & Gas J., 82 (1973).

Biography

Walid Mohamed Mahmud is currently an Assistant Professor at the Department of Petroleum Engineering, University of Tripoli, Libya. In addition to teaching several undergraduate and postgraduate petroleum engineering courses, Dr. Mahmud has supervised numerous undergraduate and postgraduate graduation projects. Dr. Mahmud is the Department Quality Control and Assurance Coordinator. Dr. Mahmud’s main research interests include, but not limited to, multiphase flow in porous media, network modeling and relative permeability laboratory measurements.

Saber Kh. Elmabrouk received his Ph.D. degree in reservoir and oilfield management from the University of Regina, Saskatchewan, Canada. He earned his Master’s and Bachelor’s degrees in Petroleum Engineering from the University of Tripoli, Libya. Dr. Saber is currently a faculty member at the School of Applied Science and Engineering, The Libyan Academy, Tripoli, Libya. He teaches graduate courses in both Petroleum Engineering department and Engineering Management department. His research interests include uncertainty analysis and risk management, modeling, optimization, big data analysis, artificial intelligence, and oilfield management. His research experience and teaching career spans twenty-five years.

Hassan Sbiga received his B.SC in petroleum engineering from Tripoli University - Libya in spring1992; and Master degree in petroleum engineering from Heriot-Watt University, Edinburgh-UK in 2005; and Doctor of Philosophy (PhD) in Petroleum Engineering from Heriot Watt University, Edinburg UK in 2013. Mr. Sbiga has 20 years experience in oil field and he is a member of SPE. His experience covered Routine and special core analysis and participated in several joint venture studies concerning Libyan oil Reservoirs. He joined recently to reservoir simulation studies section at LPI and worked a Lecturer as a co-operator in different Universities and institutes in Libya giving Reservoir Rock Properties Course, Introduction to petroleum engineering, and others. He was selected by HWU as a staff to teach Formation Evaluation course in HWU School Branch in Libya in 2008. Mr. Sbiga also participated, presented, and published papers in national and international conference and journals in petroleum industry.