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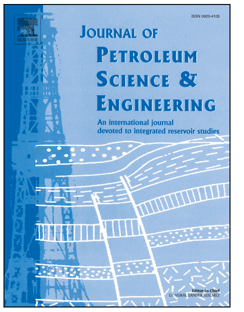

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Development of Inflow Performance Model in High Temperature Gas-Condensate Reservoirs

Abstract

Inflow Performance Relationships (IPRs) are important element for reservoir engineers in the design of new wells and also for monitoring and optimizing existing wells. IPRs are used to determine optimum production of gas rate and condensate rate in a well for any specified value of average reservoir pressure and predict the performance.

Jokhio and Tiab proposed a simple method of establishing IPR for gas condensate wells. The method uses transient pressure test data to estimate effective permeability as a function of pressure. Effective permeability data used to convert production bottomhole flow pressure into pseudopressure to establish well performance. Despite the effectiveness of the method, single phase correlations were used in PVT calculations of each phase, which over simplified the fluid flow in gas condensate wells. Single phase dry gas equations do not reflect the multiphase flow behaviour of gas condensate wells below the dew point. Due to this limitation Jokhio and Tiab method modified by this study and new analytical IPRs for gas condensate well proposed.

The major improvement of the above method is incorporating new viscosity correlation developed by this study and using two-phase compressibility factor as key parameters for predicting gas condensate inflow performance. Therefore, the main contribution of this study is development of viscosity correlation which is a critical issue in predicting gas condensate inflow performance both above and below the dew point. Optimization techniques and nonlinear regression used to develop a new viscosity correlation for high temperature heavy gas condensate reservoirs under depletion.

The application of the new model is illustrated with field example for current IPR curves. Compositional simulation study of the well performed in PIPSIM simulator. The proposal approach provides reasonable estimates of simulator input reservoir properties (e.g. IPRs). Accuracy of the new method compared with compositional simulation study. The proposed method presents average absolute relative deviation (AARD) of 5.8% for gas IPR and 7.5% for condensate IPR compare to compositional simulation results. New method provides a tool for quick estimation of gas condensate wells without need of relative permeability curves and expensive and time consuming compositional simulation.

Keywords

Inflow Performance Relationship (IPR); Gas Condensate Reservoirs; Viscosity, two phase Compressibility Factor, analytical condensate well IPR, pressure build up test.

Nomenclature

Bc	Condensate formation volume factor
Bg	Gas formation volume factor
Bgd	Dry gas formation volume factor
BHFP	Bottom-hole flow pressure
C	Productivity index
h	Net thickness
K	Absolute permeability, md
Krg	Gas phase relative permeability
Kro	Oil phase relative permeability
Keg	Gas phase effective permeability
Keo	Oil phase effective permeability
Mg	Gas molecular weight
Mo	Oil molecular weight
mP	Pseudo-pressure function
Pdew	Dew point pressure
Pinitial	Initial pressure of the reservoir
Pwf	Well flowing bottom-hole pressure
P*	Pressure at outer boundary of Region 1
Pavg	Average reservoir pressure (psia)
Ppr	Pseudo reduced pressure (psia)
Ppc	Pseudo-critical pressure
q	Surface flow rate
R	Universal gas constant
Rp	Producing gas to oil ratio (scf/STB)
Ro	Oil to gas ratio (STB/scf)
Rs	Solution gas to oil ratio (scf/STB)
r	Radial distance
re	External drainage radius
rw	Wellbore radius
Rs	Solution gas to oil ratio
Ro	Oil to gas ratio

Rp Producing gas to oil ratio

S Skin factor

T Reservoir temperature

Tsc Standard condition temperature

Tpr Pseudo reduced temperature

Tpc Pseudo-critical temperature

V Volume at reservoir condition

dew Dew point

Y Constant term in viscosity correlation

Z Compressibility factor single phase

Z_{2p} Two-phase compressibility factor

Greek Letters

φ Porosity

μ Viscosity

μ_{od} Dead oil viscosity

ρ Density

σ Gas/oil interfacial tension

γ_g Gas specific gravity

Subscripts

c Condensate

g Gas

gt Total gas

n Exponent of gas rate equation

o Oil phase

ot Total oil

V vertical

SP Single phase

2p Two-phase

1. Introduction

Gas condensate well behaviour is unique as it is characterized by a rapid loss of well productivity. When the bottom-hole flowing pressure (Pwf) drops below the dew point, a region of high condensate saturation builds up near the wellbore, resulting in reduced gas permeability and lower gas deliverability (Fevang and Whitson, 1996; Jokhio et al., 2002; Kniazeff and Naville, 1965; Mott, 2003). It is essential to consider effect of condensate blockage in calculating well deliverability. Pseudopressure function is used in gas rate equation to describe the effect of condensate blockage on well deliverability through establishing Inflow Performance Relationship (IPR) curve. (Fevang and Whitson, 1996; Jokhio and Tiab, 2002; Mott, 2003; Stewart, 2012).

Gilbert, (1954) introduced Inflow Performance Relationship (IPR) for a well. O'Dell and Miller, (1955) presented the first gas rate equation using pseudopressure function (mP) to describe the effect of condensate blockage. In later study Kniazeff and Naville, (1965) were the first to numerically model radial gas condensate well deliverability. Gondouin et al., (1967) extended the work of Kaniazeff and Naville by performing black oil simulations, showing the importance of condensate blockage and non-Darcy flow effects on backpressure performance. Effect of liquid drop out on non-Darcy flow described by Yu et al., (1996) using modification of condensate saturation function.

IPR is an important tool in understanding the reservoir/well behaviour and quantifying production rate and evaluate reservoir deliverability (Fattah et al., 2014; Guo et al., 2008; Mott, 2003; Stewart, 2012). Fevang and Whitson, (1996) proposed a method to model deliverability of gas condensate well based on pseudopressure integral (Al-Hussainy et al., 1966; Fevang and Whitson, 1996). They identified the existence of three flow regions before wellbore in gas condensate reservoirs. Following Fevang and Whitson, (1996), Jokhio and Tiab, (2002) utilized two-phase pseudopressure integral to study effect of condensate blockage in well deliverability and establish gas condensate well IPR. In their study transient pressure test data used to convert production (BHFP) data into pseudopressure and establish well IPR. Despite simple and effective approach of Jokhio and Tiab, (2002), fluid Pressure-Volume-Temperature (PVT) properties calculated using single dry gas equations. Fluid flow near well bore region in depleted gas condensate reservoir below the dew point is in the form of two phases "gas and condensate (light oil)" (Fevang and Whitson, 1996; Jokhio and Tiab, 2002; Mott, 2003; Qasem et al., 2014; Rahimzadeh et al., 2016; Thomas and Bennion, 2009; Whitson et al., 1999). Furthermore, gas condensate PVT properties are different from natural gas and crude oil due to the compositional changes that occurs below the dew point (Elsharkawy, 2006; Rayes et al., 1992; Whitson et al., 2000; Yang et al., 2007). Therefor using single dry gas equations for modelling gas condensate pseudopressure function (mP) is oversimplifying the calculation.

The objective of this study is to develop new IPR curves for better performance prediction of high temperature rich gas condensate reservoirs. Therefore, for better reflection of aforementioned changes below the dew point a new viscosity correlation developed, using nonlinear regression analysis and optimization techniques. Two sets of experimental data of Yang et al., (2007) and Al-Meshari et al., (2007) was used for developing new viscosity correlation. New correlation was incorporated with two-phase compressibility factor of Rayes et al., (1992) in generating PVT tables and determining pseudopressure integral. Pseudo critical temperature (Tpc) and pressure (Ppc) proposed by Elsharkawy et al., (2000), which developed for gas condensate reservoirs were also used to model two phase compressibility factor. Transient pressure test data from high temperature heavy gas condensate well was obtained from Economides et al., (1989) and utilized to generate the IPR curves. New IPRs covers effect of condensate blockage near wellbore region as an important factor in reducing well productivity (Behmanesh et al., 2017; Chen et al., 1995; Fevang and Whitson, 1996; Gondouin et al., 1967; Jokhio and Tiab, 2002; Rahimzadeh et al., 2016).

The remaining section of the paper is organized as follow. Section 2 is a detail description of new viscosity correlation and PVT calculation. Section 3 is explaining how the new IPR model developed with new viscosity correlation and two-phase compressibility factor. Section 4 shows validation of the new developed model by compositional simulation and analysing the results. Section 5 is presenting the results of this study and analysing the finding. Section 6 concluding overall achievement of this study.

2. Construction of Pressure – Volume – Temperature (PVT) relationship

The knowledge of PVT data such as formation volume factor, viscosity, compressibility factor and solution gas to oil ratio is essential to form pseudopressure integral and construct inflow performance relationship (IPR). Viscosity and compressibility factor are governing parameters to model gas condensate pseudopressure integral and determine the performance (Arukhe and Mason, 2012; Hernandez; et al., 2002; Whitson et al., 1999; Yang et al., 2007). To emphasis the important of viscosity the research shows 1% error in calculating reservoir fluid viscosity resulted in 1% error in cumulative production (Al-Meshari et al., 2007; Fevang and Whitson, 1996; Hernandez; et al., 2002; Sutton, 2005; Whitson et al., 1999).

Behmanesh et al., (2017) found that using single dry gas viscosity and compressibility factor effect the performance prediction of gas condensate reservoirs. Well known method of Lee-Gonzalez-Eakin, (1966), which originally developed from natural dry gas, is used in most of PVT software due to its simplicity. Londono et al., (2002) and Sutton, (2005) examined applicability of the LGE correlation to predict gas viscosity in low to high gas specific gravities. Londono et al., reported average absolute error of 3.34% and Sutton, (2005) reported average absolute error of 22.6% for their entire database. Another study by Al-

Nasser and Al-Marhoun, (2012) shows that LGE predicts gas viscosity with maximum error of 16.81 within $0.55 < \gamma_g < 1.55$. Elsharkawy, (2006) also reported 13.8 average absolute error using LGE method over the range of $0.566 < \gamma_g < 1.895$. All aforementioned studies were confirming that LGE method is not suitable for modelling gas condensate viscosity below the dew point. Hence in this study an attempt was made to optimize the existing well known viscosity correlations, for better modelling of gas condensate reservoirs through establishing new Inflow Performance Relationship (IPR). For this purpose two sets of experimental data by Al-Meshari et al., (2007) and Yang et al., (2007) selected. These studies carried out in elevated pressure and temperature in laboratory condition similar to the reservoir temperature and pressure condition. The fluids used in these experimental studies are from gas condensate reservoirs in Saudi Arabia and North Sea. The collected fluids (gas and liquid) recombined in laboratory and viscosity measurement were made (Al-Meshari et al., 2007; Yang et al., 2007).

Prediction performance of Lee et al., 1966, (LGE) , Lohrenz et al., 1964, (LBC), Londono et al., (2002), Sutton, (2005) and Elsharkawy, (2006) are tested against the experimental data. These correlations are typically used for predicting viscosity in PVT software. Average Absolute Relative Deviation (AARD%) of each model performed using Eq. (1). The performance of each method is presented in Fig. 1.

$$AARD\% = \frac{1}{Np}\sum_{i=1}^{N}\left|\frac{{\mu_i}^{experiment} - {\mu_i}^{calculated}}{{\mu_i}^{experiment}}\right| \times 100 \quad (1)$$

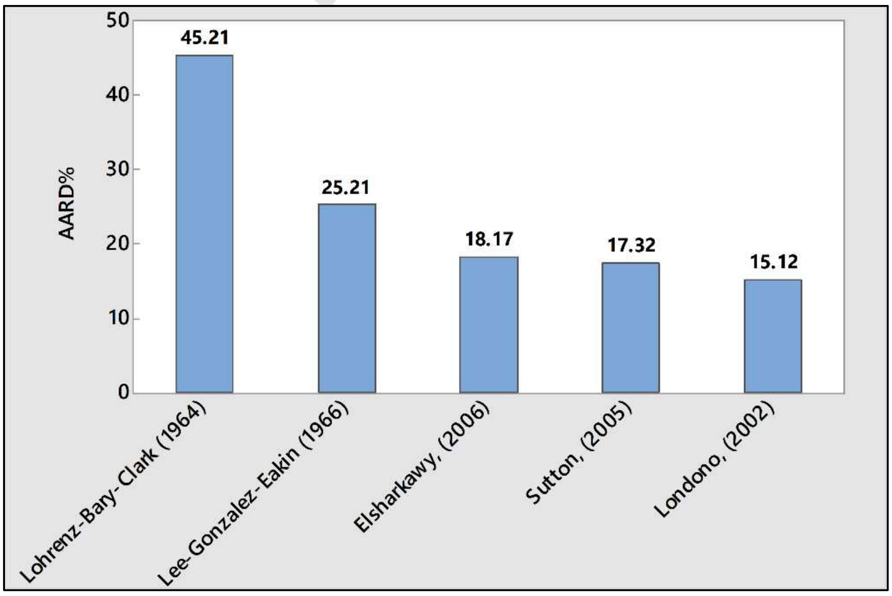

Fig. 1. Average absolute relative deviation percentage (AARD %) of each method in predicting gas condensate viscosity.

The correlation proposed by Londono et al., (2002) provides best performance in predicting experimental viscosity data, hence it has been selected for further modification. Londono et al., (2002) used an extensive data bank (4909 data sets) to modify Lee-Gonzalez-Eakin, (1966) for predicting viscosity of hydrocarbon mixture. The original form of Londono et al, (2002) given in equation 2 to 5.

$$\mu_g = 10^{-4} K exp\left[X {\rho_g}^{Y}\right] \quad (2)$$

Where:

$$K = \frac{(16.7175 + 0.0419188 Mg) T^{1.40256}}{212.209 + 18.1349 Mg + T} \quad (3)$$

#

$$Y = 1.09809 - 0.0392581 X \quad (4)$$

$$X = 2.12575 + \frac{2063.71}{T} + 0.011926 Mg \quad (5)$$

$$\rho_g = 1.601846 \times 10^{-2} \frac{Mg.P}{RT} \quad (6)$$

Where T is temperature in Rankine (Ꞧ), ρ_g is gas density in g/cc, P is pressure in psia; Mg is gas molecular weight and R is universal gas constant (10.732) psia cuft/[lb-mole-Ꞧ].

In an attempt to minimize the error between experimental data and the Londono correlation a non-linear regression model on MATLAB was used. Londono et al., (2002) model was cast in the following form:

$$\mu_g = aK exp\left[X\left(\frac{\rho_g}{b}\right)^{Y}\right] \quad (7)$$

Where *"a"* and "*b"* are the optimized coefficient for the model as follow:

$$\begin{Bmatrix} a = 0.000246933 \\ b = 27.6718 \end{Bmatrix}$$

As a result of this analysis new gas condensate viscosity model is proposed in Eq. (8).

$$\mu_{gc} = 0.000246933 K exp\left[X\left(\frac{\rho_g}{27.6718}\right)^{Y}\right] \quad (8)$$

The parameters of K,Y and X are same as the original Lee et al., (1966) equation. 50% of the experimental data were used for developing regression model in Eq. (8). The remaining 50% of the data used to test the performance of the model. The performance of the model plotted against the experimental data and shown in Fig. (2). New developed model is predicting experimental data with 5.2% AARD %. Eq. (8) will be used in modelling PVT properties of gas condensate reservoir later in this study.

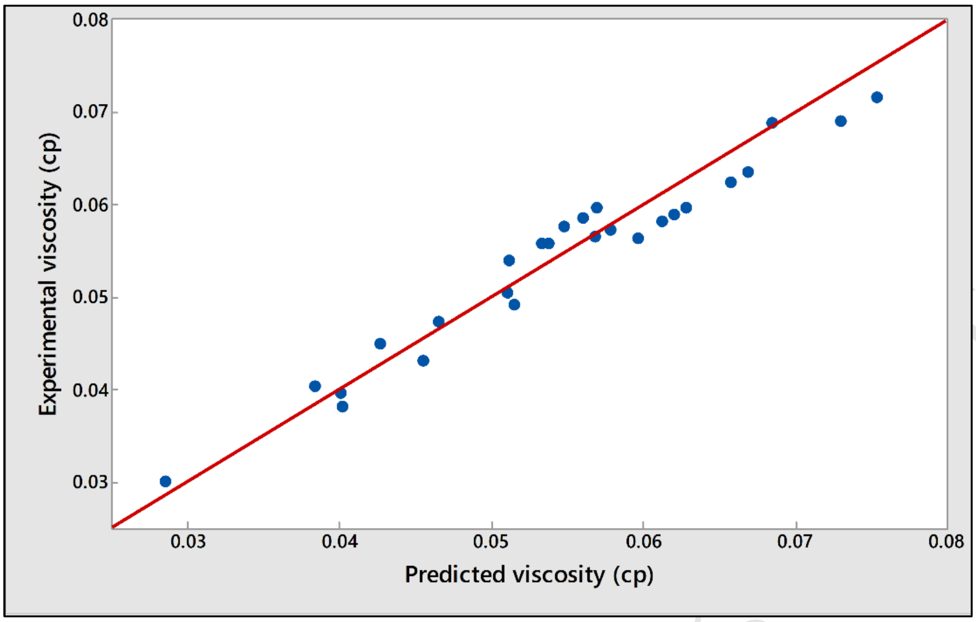

Fig 2. Plot of calculated vs. the measured viscosity data.

Accurate prediction of gas condensate reservoirs require using more accurate compressibility factor (Elsharkawy et al., 2000; Whitson et al., 1999). In fact compressibility factor dictates gas and condensate recoveries in gas condensate reservoirs (Whitson et al., 2000, 1999). Studies by Behmanesh et al., (2017) Arukhe and Mason, (2012) elucidate that use of single phase compressibility factor underestimate the production in gas condensate reservoirs. Hence for better prediction of performance, two-phase compressibility factor correlation, developed by Rayes et al., (1992), shown in Eq. (9) utilized to model PVT. Their method is applicable to rich gas condensate reservoirs with pseudo-reduced pressure range of 0.7 ≤ Pr ≤ 20 and temperature range of 1.1 ≤ Tr ≤ 2.1.

$$Z_{2p} = A_0 + A_1(P_{pr}) + A_2\left(\frac{1}{T_{pr}}\right) + A_3(P_{pr})^2 + A_4\left(\frac{1}{T_{pr}}\right)^2 + A_5\left(\frac{P_{pr}}{T_{pr}}\right) \quad (9)$$

Where $A0 = 2.2435$, $A1 = -0.03752$, $A2 = -3.5653$, $A3 = 0.0008292$, $A4 = 1.5342$, and $A5 = 0.131987$.

Accurate prediction of compressibility factor is function of accurate pseudo-critical properties of pressure (Ppc) and temperature (Tpc). To determine more accurate pseudocritical properties Eq. (10) and Eq. (11) proposed by Sutton, (2005) were also employed in this study. According to Sutton, (2005) these two equations outperform other well-known pseudo critical properties in the literature such as Elsharkawy et al., (2000), Sutton, (1985) and Piper et al.,(1993).

$$P_{pc} = 744 - 125.4\gamma_g + 5.9{\gamma_g}^2$$

(10)

$$T_{pc} = 164.3 + 357.7\gamma_g - 67.7{\gamma_g}^2 \quad (11)$$

New viscosity correlation Eq. (8), two-phase compressibility factor in Eq. (9) and pseudo-critical properties Eq. (10) and Eq. (11) are used to complete material balance calculation and generate gas phase PVT properties. An algorithm flowchart in Fig. 3 shows the calculation steps to complete PVT calculation.

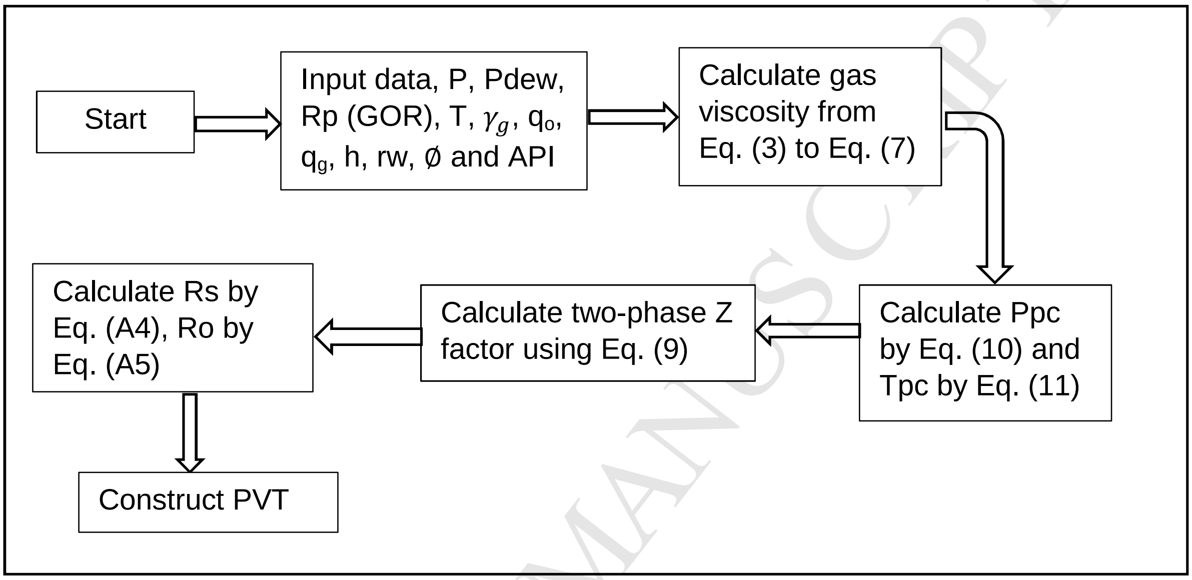

Fig. 3. Flow chart for computing PVT properties of gas phase.

There are many models in the literature for performance modelling of gas condensate through establishing Inflow Performance Relationship (IPR) curves. This include (Fevang and Whitson, 1996; Guehria, 2000; Jokhio et al., 2002; Jokhio and Tiab, 2002; Mott, 2003; Qasem et al., 2014; Shahamat et al., 2015; Sousa et al., 2017). However, PVT calculation in aforementioned methods completed with the assumption of single phase flow. In Jokhio and Tiab, (2002) single phase correlations were applied to model PVT, then tabulated PVT used in calculating of pseudopressure integrals. In this study the performance of high temperature heavy gas condensate reservoir is determined by implementation of two new gas condensate viscosity and two phase compressibility factor.

3. Two phase pseudopressure approach

Pseudopressure approach is a simple and convenient method of handling the nonlinearity in gas condensate reservoirs and establishing IPR (Bonyadi et al., 2012; Fevang and Whitson, 1996; Kniazeff and Naville, 1965; Mott, 2003). The fundamental gas flow rate equation is proposed by Rawlins and Schellhardt, (1936), shown in Eq. (12) This back pressure equation, which developed as a results of several hundred wells studies is relating gas rate to bottom-hole flowing pressure (Pwf).

$$q_{gt} = C\left({P_{avg}}^2 - {P_{wf}}^2\right)^n \tag{12}$$

In terms of pseudopressure Eq. (12) can be written as follow:

$$q_{gt} = C_g\left(\Delta mP_{gt}\right)^n \tag{13}$$

Where C is productivity index, ΔmP_{gt} is total gas pseudopressure function, n is exponent and q_{gt} is total gas flow rate. Productivity index C depends on well and reservoir geometry, that can be estimated mathematically from Eq. (14) for gas phase and Eq. (15) for oil phase. During pressure build up test the values of gas and condensate flow rates are measured at the surface. Semi log-log plot of pseudopressure ΔmP against measured flow rates form a straight line. The intercept of this straight line is the value of *C* and the slope is *n* (Ahmed, 2010; Guo et al., 2008; Roussennac, 2001; Stewart, 2011). In this study similar concept has been applied, utilizing pressure test data to determine productivity index and coefficient n.

$$C_g = \frac{0.00708.kh}{ln\left(\frac{r_e}{r_w}\right) - 0.75 + s} \tag{14}$$

$$C_O = \frac{0.00708.kh}{ln\left(\frac{r_e}{r_w}\right) - 0.75 + s} \tag{15}$$

The constant C includes basic reservoir properties such as permeability, thickness h, drainage radius, r_e; well bore radius, r_w; skin factor, s; and other constants (Bonyadi and Rostami, 2017; Jokhio and Tiab, 2002; Lyons et al., 2016; Mott, 2003).

ΔmP_{gt} in Eq. (13) is a two-phase pseudopressure function that can be calculated from two phase pseudopressure integral proposed by Fevang and Whitson, (1996). Their integral in terms of effective permeability ($k.\mathrm{k_{rg}}$) is shown in Eq. (16).

$$\Delta mP_{gt} = \left\{\int_{P_{dew}}^{P_{avg}} \left(\frac{k.k_{rg}(S_{wi})}{\mathrm{B_{gd}\mu_g}}\right)\mathrm{dp} + \int_{P^*}^{P_{dew}} \left(\frac{k.\mathrm{k_{rg}}}{\mathrm{B_{gd}\mu_g}}\right)\mathrm{dp} + \int_{P_{wf}}^{P^*} \left(\frac{k.\mathrm{k_{rg}}}{\mathrm{B}_{gd}\mathrm{\mu_g}} + \frac{k.\mathrm{k_{ro}}}{\mathrm{B}_c\mathrm{\mu}_o}R_s\right)\mathrm{dp}\right\} \tag{16}$$

Where: P_{avg} is average reservoir pressure, P_{dew} is dew point pressure, S_{wi} is the initial water saturation, k is absolute permeability, kr: phase relative permeability, P^* is the pressure in the interface between Region 1 and Region 2, P_{wf} is bottom hole flowing pressure, Bgd is dry gas formation volume factor, Bo is oil formation volume factor, μ is viscosity and Rs is solution gas to oil ratio (GOR).

In Eq. (16) the first integral, with integral limits $Pdew$ to P_{avg}, relates to Region 3, in which only gas phase is present. The second integral, with the integral limits P^* to $Pdew$, relates to

Region 2, in which condensate drop-out, but its saturation is less than critical condensate saturation. Hence, it is immobile and only the gas phase is flowing. The third integral, with the integral limits Pwf to P^*, relates to Region 1, near wellbore region, in which both gas and condensate phases are flowing simultaneously at different velocities. The flow in this region is steady state flow, meaning what comes into Region 1 through its outer boundary, will flow at and will be produced at the surface with no net accumulation of fluid. Region 1 is the main source of deliverability loss due to condensate build up, which decreases relative permeability to gas in gas condensate reservoirs (Behmanesh et al., 2017; Bonyadi et al., 2012; Bonyadi and Rostami, 2017; Fevang and Whitson, 1996; Hekmatzadeh and Gerami, 2018; Mott, 2003; O'Dell and Miller, 1967).

Existence of the aforementioned regions in gas condensate reservoirs is a function of pressure. If bottom-hole flowing pressure is less than the dew point pressure ($Pwf < Pdew$), Region 1 will always exist; and if bottom hole flowing pressure is higher than the dew point pressure ($Pwf > Pdew$), Region 1 will not exist (Fevang and Whitson, 1996; Wheaton and Zhang, 2007). If pressure interface between Region 1 and 2 (P*) is bigger than average reservoir pressure [$P^* > P_{avg}$], then integration of Region 1 pressure function should be only from Pwf to P_{avg}. In this case Region 2 and 3 don't exist (Fevang, 1995; Fevang and Whitson, 1996), then the first two integral terms can be ignored in the calculation. This is happening in highly saturated gas condensate reservoirs (Fevang, 1995; Fevang and Whitson, 1996; Jokhio and Tiab, 2002). In this case ($P^* > P_{avg}$), only third part of the pseudopressure integral in Eq. (16), which devoted for Region 1, is used with pressure limits from Pwf to P_{avg}.

Similar concept is used in this study and Eq. (17) has been used to calculate pseudopressure function. This is because the well that was selected for this study is producing heavy condensate and is very high in temperature (Economides et al., 1989). Region 2 and 3 did not develop in such reservoirs and condensation start from the beginning of the production.

$$\Delta m P_{gt} = \int_{\mathrm{P_{wf}}}^{P_{avg}} \left(\frac{k.\mathrm{k_{rg}}}{\mathrm{B}_{gd}\mu_{\mathrm{g}}} + \frac{k.\mathrm{k_{ro}}}{\mathrm{B}_{o}\mu_{o}} R_s \right) \mathrm{dp} \tag{17}$$

The PVT properties, producing gas/oil ratio (GOR) Rp and gas/oil effective permeabilities are needed to evaluate pseudopressure integral in Eq. (17) (Bonyadi et al., 2012; Fevang and Whitson, 1996; Guehria, 2000; Mott, 2003). Pwf and P_{avg}, are known based on well pressure build up test.

Producing gas to oil ratio, Rp is a ratio of total gas production to total oil production on the surface. Eq. (18) (Ahmed, 2010; Fetkovich et al., 1986; Fevang and Whitson, 1996; Guehria, 2000; Jokhio and Tiab, 2002).

$$R_p = \frac{q_{gt}}{q_{ot}} = \frac{C_g\left[\left(\frac{k_{rg}}{B_{gd}\mu_g}\right) + \left(\frac{k_{ro}}{B_o\mu_o}\right)R_s\right]}{C_o\left[\left(\frac{k_{rg}}{B_{gd}\mu_g}\right)R_O + \left(\frac{k_{ro}}{B_o\mu_o}\right)\right]} \quad (18)$$

Where, Ro is oil to gas ratio (STB/scf), q_{gt} and q_{ot} are total gas flow rate and total oil flow rate respectively. On simplification of Eq. (18), Rp can be presented in Eq. (19) (Fetkovich et al., 1986; Fevang, 1995).

$$R_p = R_s + \left(\frac{k_{rg}}{k_{ro}}\right)\left(\frac{B_o\mu_o}{B_{gd}\mu_g}\right)\left(1 - R_oR_p\right) \quad (19)$$

Fetkovich et al., (1986), rearranged and solved Eq. (19) for krg/kro as it is shown in Eq. (20). This expression gives the ratio of $(krg/kro\ )$ as a function of pressure.

$$\frac{k_{rg}}{k_{ro}}(P) = \frac{\left(R_p - R_s\right)}{\left(1 - R_oR_p\right)}\left(\frac{B_{gd}\mu_g}{B_o\mu_o}\right) \quad (20)$$

One of the primary objectives of this study was to determine effective permeabilities of gas and oil using well pressure test data. Hence, Evinger and Muskat, (1942), which indicates relative permeabilities Krg and Kro can be expressed directly as a function of ratio (Krg/Kro), when both phases are mobile, is used. Therefore Eq. (20) in terms of effective permeability rewritten and yields Eq. (21) for gas phase and Eq. (22) for oil phase. These two equations are showing that the effective permeability of one phase can be calculated from the other phase.

$$k_{eg} = k\mathrm{k_{rg}} = \frac{\left(R_p - R_s\right)}{\left(1 - R_oR_p\right)}\left(\frac{B_{gd}\mu_g\{kk_{ro}\}}{B_o\mu_o}\right) \quad (21)$$

$$k_{eo} = k\mathrm{k_{ro}} = \frac{\left(1 - R_oR_p\right)}{\left(R_p - R_s\right)}\left(\frac{B_o\mu_o\{kk_{rg}\}}{B_{gd}\mu_g}\right) \quad (22)$$

Where, Keg and Keo are gas and oil effective permeabilities respectively. Substituting Eq. (21) in Eq. (16) and simplifying yields gas pseudopressure integral in terms of effective permeability (Fetkovich et al., 1986; Fevang and Whitson, 1996; Guehria, 2000).

$$\Delta mP_{gt} = \int_{p_{wf}}^{P_{avg}} \left(\frac{k.krg}{B_{gd}\mu_g}\right)\frac{R_p\left(1 - R_oR_s\right)}{\left(R_p - R_s\right)}(P)dp$$

(23)

Pseudopressure integrals in Eq. (23) can be computed through the reformulation by Jokhio and Tiab, (2002) in Eq. (24).

$$\Delta mP_{gt} = \left[\int_{p_{wf}}^{P_{avg}} \left(\frac{1}{\mathrm{B}_{gd}\mu_{\mathrm{g}}}\right)\frac{R_p(1-R_oR_s)}{(R_p-R_s)}(P)dp\right] \times \int_{P_{wf}}^{P_{avg}} k.\,\mathrm{k_{rg}}(P)\,dp \quad (24)$$

Based on conventional assumption of transient fluid flow and fluid superposition principle, the pseudopressure integral can be obtained as shown in Eq. (25) (Earlougher, 1977; Horner, 1951; Serra et al., 2007; Stewart, 2012).

$$\int_{p_{wf}}^{P_{avg}} \left(\frac{k.\,\mathrm{k_{rg}}}{\mathrm{B}_{gd}\mu_{\mathrm{g}}}\right)\frac{R_p(1-R_oR_s)}{(R_p-R_s)}(P)dp = 162.6\left(\frac{q_{g,meas}}{h}\right)\left(log(t)+log\left(\frac{keg(p)}{\emptyset\mu_g c_t {r_w}^2}\right)-3.23+0.87s\right) \quad (25)$$

$$\int_{P_{wf}}^{P_{avg}} k.\,\mathrm{k_{rg}}(P)\,dp = 162.6\frac{q_{g,meas}}{h\left(\frac{d\Delta mP_g}{dln(t)}\right)} \quad (26)$$

This allows the integral in Eq. (24) to be solved without the need of relative permeability curve, which is plotted as a function of saturation.

In Eq. (25), $q_{g,meas}$ is measured gas flow rate at surface during the test; t is recorded pressure test time; h is reservoir thickness; keg is effective permeability of gas phase; $\emptyset$ is porosity of the media; μ_g is gas viscosity; c_t is total compressibility factor; r_w is wellbore radius; and *s* is skin factor. Right hand side of Eq. (25) is pressure build up equation originally proposed by Horner, (1951) and modified by Earlougher, (1977). This equation is based on conventional assumption of transient fluid flow and superposition principles. The assumption indicates semi log plot of recorded time against well flow bottom-hole pressure (Pwf), provides straight line with a slope of $162.6\left(\frac{q_{g,meas}}{h}\right)$ and intercept of $\left[log(t)+log\left(\frac{keg(p)}{\emptyset\mu_g c_t {r_w}^2}\right)-3.23+0.87s\right]$ (Ahmed, 2010; Dake, 2001; Earlougher, 1977; Roussennac, 2001; Serra et al., 1990). Fig. 4 shows this relation graphically where recorded time of the pressure build up test is plotted against (Pwf) in a heavy gas condensate well (KAL05). The plot in Fig 4 commonly referred as Horner plot. An early time deviation from the graph can be caused by wellbore storage effect and skin factor (Ahmed, 2010; Roussennac, 2001). This deviation is large if permeability is low and compressibility is high. This is the case in heavy gas condensate reservoir, where the liquid evolves from the gas in early stages, as it shown in Fig. (4).

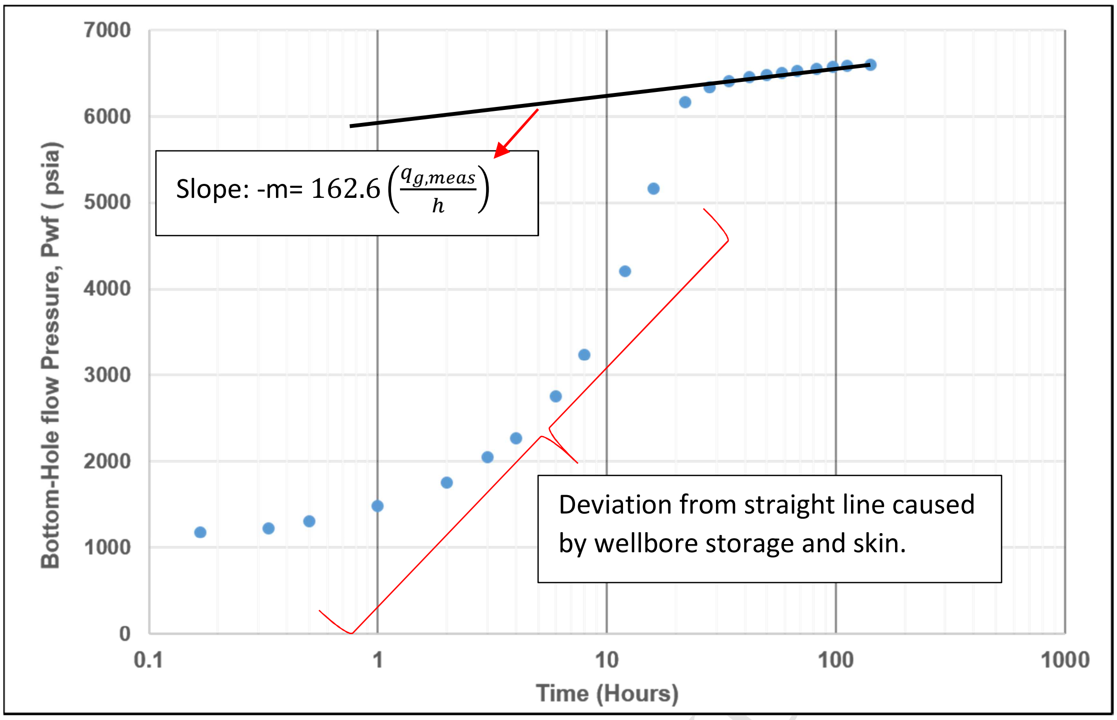

Fig. 4. Horner plot for KAL-5 gas condensate well (data after Economides, 1989).

Gas phase effective permeability integral as a function of pressure can be estimated by Eq. (26) (Jokhio et al., 2002), where $d\Delta mPg/dln(t)$ is the derivative function of gas phase. Eq. (26) specifies that the effective permeability integral is inversely proportional to the derivative of the pressure with natural logarithmic of time. On semi log plot of time against pseudopressure, the rate of change of pseudopressure is the slope of a straight line (Jokhio and Tiab, 2002; Serra et al., 2007). This will provide an equation for straight portion of the graph in Fig. 4. To evaluate effective permeability integral in Eq. (26), pseudopressure derivative group $d\Delta mPg/dln(t)$ is needed, which can be estimated using Eq. (27) after Jokhio and Tiab, (2002).

$$\left(\frac{d\Delta mP}{dln(t)}\right)_i = \frac{\left(\frac{d\Delta mP_{i-1}}{dln(t)_{i-1}}\right)\Delta ln(t)_{i+1} + \left(\frac{d\Delta mP_{i+1}}{dln(t)_{i+1}}\right)\Delta ln(t)_{i-1}}{[\Delta ln(t)_{i+1} + \Delta dln(t)_{i-1}]} \tag{27}$$

Where, the point i is the point, where the derivative is calculated and point $(i-1)$ is the point before it and $(i+1)$ is the point after it. Pseudopressure difference is calculated from $(\Delta mP = mP - mP_{(t=0)})$, which is the difference in pseudopressure of any given pressure and pseudopressure at the beginning of the pressure build up test.

For condensate (oil) phase the two-phase pseudopressure function can be written as Eq. (28) (Fevang, 1995, 1995; Jokhio et al., 2002; Penula, 2003). Substituting Eq. (21) and Eq. (22) in Eq. (28) and simplifying yields Eq. (29), which represents condensate (oil) phase pseudopressure function in terms of effective permeability (Fetkovich et al., 1986; Fevang and Whitson, 1996; Guehria, 2000; Penula, 2003)

$$\Delta mP_{ot} = \int_{\mathrm{P_{wf}}}^{P_{avg}} \left(\frac{k.\mathrm{k_{ro}}}{\mathrm{B}_o \mu_\mathrm{o}} + \frac{k.\mathrm{k_{ro}}}{\mathrm{B}_g \mu_g} R_o \right) \mathrm{dp} \tag{28}$$

$$\Delta mP_{ot} = \left[\int_{p_{wf}}^{P_{avg}} \left(\frac{K.Kro}{\mathrm{B}_o \mu_\mathrm{o}} \right) \frac{(1 - R_o R_s)}{(1 - R_o R_p)} (P) dp \right] \tag{29}$$

Jokhio and Tiab, (2002) reformulate and present the oil phase pseudopressure integral in form of Eq. (30), using generalized superposition equation to model the effective permeability directly by well pressure build up data. Oil phase effective permeability integral can be calculated using Eq. (31).

$$\Delta mP_{ot} = \left[\int_{p_{wf}}^{P_{avg}} \left(\frac{1}{\mathrm{B}_o \mu_\mathrm{o}} \right) \frac{(1 - R_o R_s)}{(1 - R_o R_p)} (P) dp \right] \times \int_{P_{wf}}^{P_{avg}} k.\mathrm{k_{ro}}(P)\, dp \tag{30}$$

$$\int_{P_{wf}}^{P_{avg}} k.\mathrm{k_{ro}}(P)\, dp = 162.6 \frac{q_{o,meas}}{h \left(\frac{d\Delta mP_o}{dln(t)} \right)} \tag{31}$$

Pseudopressure and its derivative $(d\Delta mPo)/dln(t)$ in Eq. (31) can be computed using Eq. (27). Similar to gas phase back pressure equation of Rawlins and Schellhardt, (1936), Eq. (32) can be used to estimate the total oil flow rate.

$$q_{ot} = C_o(\Delta mP_{ot})^n \tag{32}$$

Having calculated pseudopressure function in any given pressure logarithmic plot of mP against measured flow rates (gas, oil) at the surface, provides a straight line. The slope of this straight line is coefficient 'n' and intercept is 'C' in Eq. (13) and Eq. (32) for gas and oil phase respectively. Hence gas flow rate in each pressure step can be calculated using Eq. (13); and Inflow Performance Relationship (IPR) curve can be established. To determine condensate phase IPR similar procedure were also used.

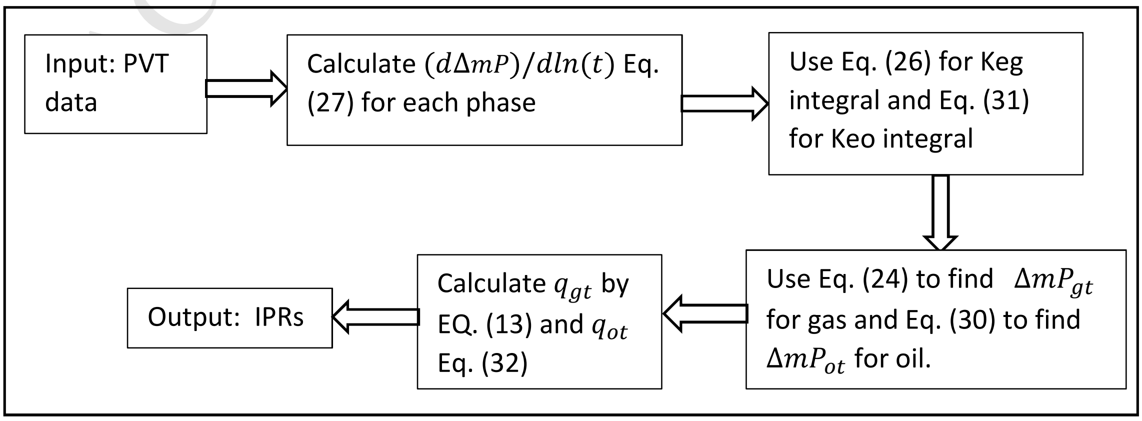

Fig. 5. Flowchart for computing pseudopressure integrals and construct IPRs.

3.1 Methodology to use the new IPR model

To establish gas phase IPR, for given bottom-hole flowing pressure (Pwf), the calculation procedure can be summarized as follow:

1. Calculate PVT properties for gas phase, using new viscosity correlation Eq. (7) and two-phase compressibility factor Eq. (9). Detail calculation of PVT are provided in Appendix A for gas phase and Appendix C for condensate phase.
2. Calculate pseudopressure derivative group $(d\Delta mP)/dln(t)$ using Eq. (27) for each phase. Use recorded time (t) and bottom-hole flowing pressure (Pwf) from pressure build up test data.
3. Calculate effective permeability integral for any given pressure using Eq. (26) for gas phase and use Eq. (31) for condensate phase.
4. Calculate pseudopressure function using Eq. (24) for gas phase and Eq. (30) for condensate phase. Evaluate the integral by trapezoidal rule of integration. A sample of numerical evaluation of pseudopressure integral is presented in Appendix B.
5. Evaluate productivity index (C) and coefficient (n) using plot of pseudopressure function against flow rate on a log-log scale to form a straight line. Slope of this straight line is *n* and intercept is *C*. Gas and condensate flow rates can be obtained from pressure build up test.
6. Having calculated C and n for gas and condensate phase evaluate gas flow rate by Eq. (13) and condensate flow rate by Eq. (32).
7. Plot the bottom-hole flow pressure (Pwf) against the flow rates to establish Inflow Performance Relationship (IPR) curve.

4. Validation of New IPR model

The validity of the new IPR model is verified by compositional simulation of a high temperature rich gas condensate well, using Schlumberger (PIPSIM) simulator. Results of transient pressure test data is obtained from Economides et al., (1989) and used to validate the developed IPR model. This vertical well named (KAL-5) located in a Permian basin in a very high temperature formation (365 ℉ at 11,500 f t [180℃ at 3500m], which produces gas and heavy condensate. The physical properties of the reservoir and well is presented in Table 1. Reservoir and well geometry is obtained from Economides et al., (1989) and Jokhio and Tiab, (2002). The flow rate during the well test was 75.4 Mscf/day [2135 std m^3/day] of gas and 2.8 STB/day [0.45 m3/day] of condensate. API gravity is assumed to be 50 to match the gas condensate gravity which is typically in the range of 40 to 60 API (McCain and Cawley, 1991; Whitson et al., 2000). Table 2 includes fluid molar composition of the reservoir (Economides et al., 1989). During the test, well flowed for 103 hours and then was subjected to 141 hours pressure buildup. The initial reservoir pressure is 6750psia and it is almost identical to retrograde condensation point. Condensation of the gas started from the beginning of the production and entire reservoir is in two-phase flow condition. This condition is same as near well-bore region, Region 1, where combination of oil and gas are simultaneously flow.

Table 1

Well and reservoir data (Economides, et al., 1989).

Pinitial	6750 psia	q_o	2.8 STB/day = 0.45m^3/day
Pdew	6750 psia	H	216.5ft = 65.98m
GOR	9470 scf/STB=1686.67 m^3/m^3	∅	0.062
T	356℉=180℃	r_w	0.54ft = 0.16459m
Gas γ_g	0.94 [MW=27.17]	API	50 [Assumed]
q_g	75.4 Mscf/day=2135 m^3/day	ΔT	2.85 ℉/100FT

Table 2

Reservoir Fluid molar composition information for well KAL-5.

Components	**% mole fraction**
H_2S	0.006
N_2	1.452
CO_2	10.931
C_1	72.613
C_2	6.24
C_3	1.63
i-C_4	0.553
n-C_4	0.693
i-C_5	0.442
n-C_5	0.379
C_6	0.516
C_7	0.644
C_8	0.541
C_9	0.388
C_{10+}	2.979

Multi flash compositional simulation of the condensate fluid performed on PIPSIM simulator. A vertical well is created using physical properties of the well shown in Table 1 and fluid properties in Table 2.

Fig. 6 shows the phase diagram of the heavy gas condensate well as a results of multi flash compositional simulation of the fluid sample in a standard condition (temperature of 60℉ and pressure of 14.696psia). The dew point line in phase diagram indicates that the initial conditions coincide with the retrograde condensation, hence condensation begins from the begging of the production. This highlights the fact that using single phase correlation to model this type of reservoir fluid is oversimplify the modelling. As pressure declines to around 3000psia the water phase enters the hydrocarbon region and fluid become three phase (gas, condensate and water). Water cut of 30% is used in PVT calculation of the fluid. Three parameters Peng-Robinson, (1976) equation of state was used to complete the PVT calculation in the simulation study. Calculation include gas viscosity (μg), compressibility factor (Z), gas formation volume factor (Bg) and solution gas to oil ratio (Rs).

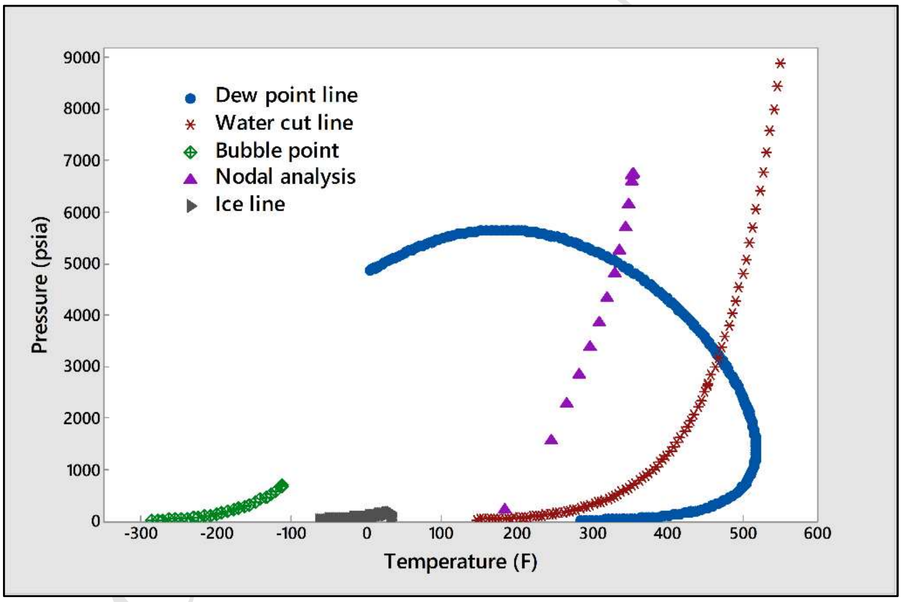

Fig. 6. Pressure-Temperature diagram for KAL-5 gas condensate well.

5. Results and discussion

Fig. 7 shows the variation of gas and condensate viscosity as a function of pressure for very high temperature rich gas condensate well (KAL-5). New gas viscosity correlation proposed by this study presented in Eq. (8), used to predict gas phase viscosity. Fig. 8 shows the different in gas viscosity using new gas viscosity correlation and LGE, (1964) correlation. New viscosity correlation provides gas condensate viscosity in lower range in compare to the LGE method. The experimental gas condensate viscosity data is used in developing new correlation to predict the gas viscosity in high temperature condition. The range of gas viscosity is in agreement with the study of gas viscosity in high temperature and high pressure reservoirs by Davani et al., (2013) and Ling et al., (2009). They show that in the pressure range of $2000 < P < 7000psia$ and temperature range of $104 < T < 212℃$ variation in gas viscosity is very low. These studies also confirming increasing temperature and pressure in the reservoirs, result in decreasing the viscosity.

Explain more Graphical representation of compressibility factor as a function of pseudo reduced pressure presented in Fig 9. The two phase compressibility factor accounts for formation of liquid in reservoir formation. The result confirms using single phase compressibility factor for predicting two-phase system, underestimate productivity. As the pressure declines due to the production, single phase z-factor provide lower range of gas compressibility factor, whereas two phase compressibility factor predicts Z factor with a linear relationship to the pseudo-reduced pressure.

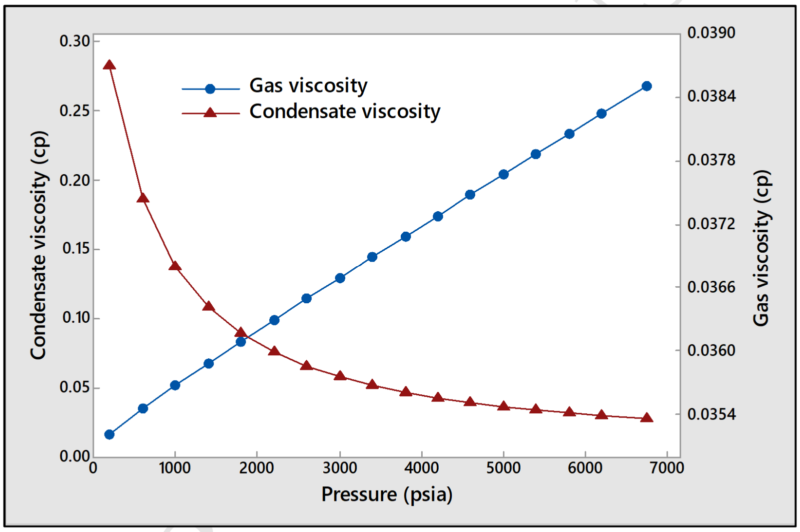

Fig. 7. Variation of gas and condensate viscosity with pressure.

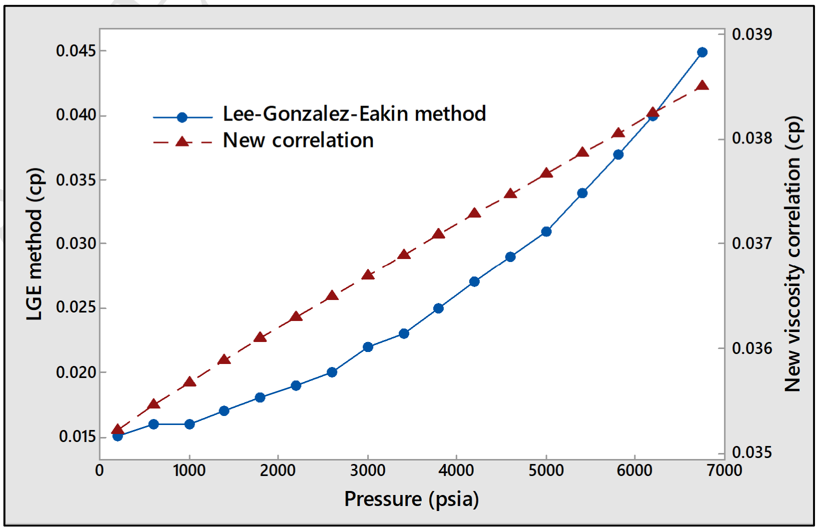

Fig. 8. Comparison of gas phase viscosity using new developed correlation and LGE (1964) correlation.

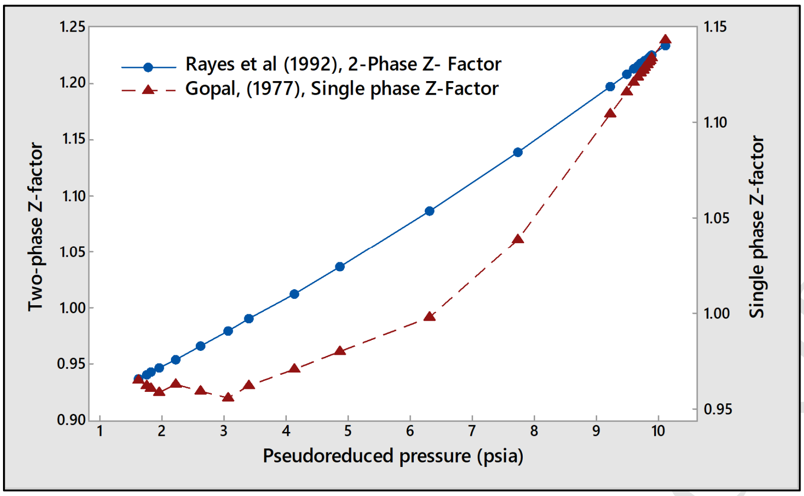

Fig. 9. Plot of z-factor vs pseudo reduced pressure.

Gas and condensate effective permeability integral is calculated using pseudopressure derivative function. The detail description of the calculation is given in Appendix B. The results of effective permeability integrals are illustrated in Fig. 10. The graph in Fig. 10 shows that the effective permeability is dropped sharply when pressure declined, due to the condensate drop out and increasing liquid saturation. The results of effective permeabilities reconfirm the finding of Behmanesh et al., (2017); Fevang, (1995); Fevang and Whitson, (1996) and Mott, (2003), such that condensate drop out in gas condensate reservoirs leads to reduction in gas effective permeabilities. Relative permeability ratio of gas to oil (krg/kro) also determined using Eq. (20) and presented in Fig. 11. The graph shows that the condensation build up, which starts in early stage of production leads to significant reduction in relative permeability to gas.

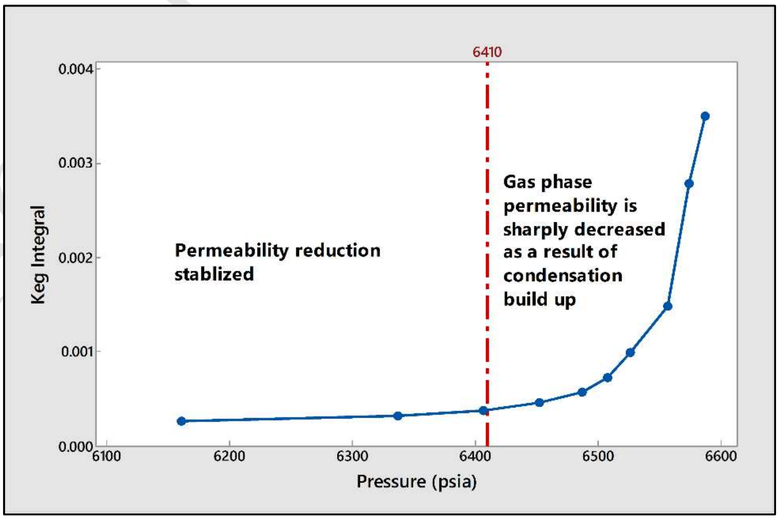

Fig. 10. Gas phase effective permeability integrals.

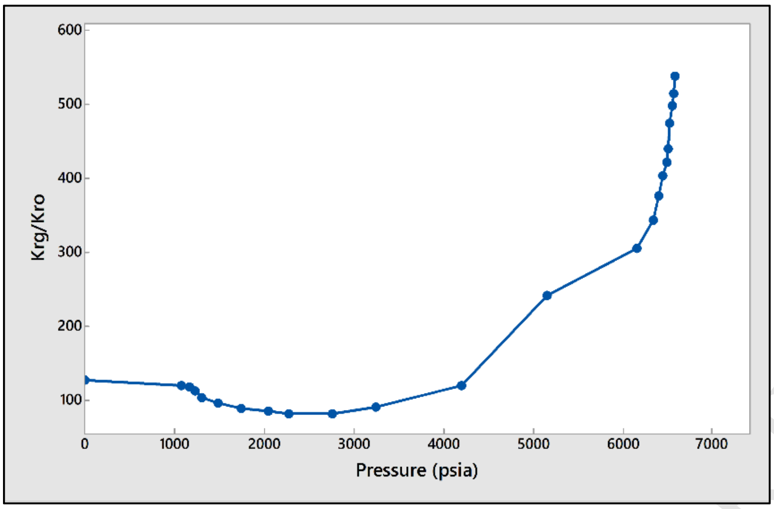

Fig. 11. Relative permeability ratio (gas to oil) as a function of pressure.

During well pressure build up test gas flow rate (q_g) and oil flow rate (q_o) were measured as previously shown in Table 1. Having calculated pseudopressure function ΔmP, allow to build a plot of flow rate against ΔmP. Fig. 12 shows the log-log plot of ΔmPg against gas flow rate, the intercept of the graph is productivity index C and gradient of the graph is value of coefficient n, in Eq. (13). Once these two aforementioned values are determined from the graph, Eq. (13), is applied to determine the gas rate for various bottom-hole flowing pressure (Pwf). Plotting the gas flow rate against Pwf establish the gas phase IPR, shown in Fig. (13). Condensate IPR is also established and presented in Fig. (14).

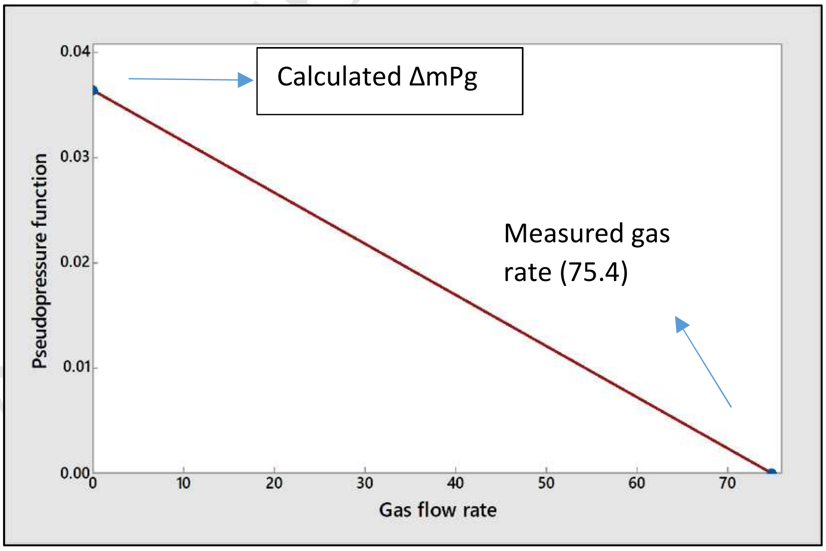

Fig. 12. Plot of gas flow rate against pseudopressure. [n=0.8] and C=0.0948].

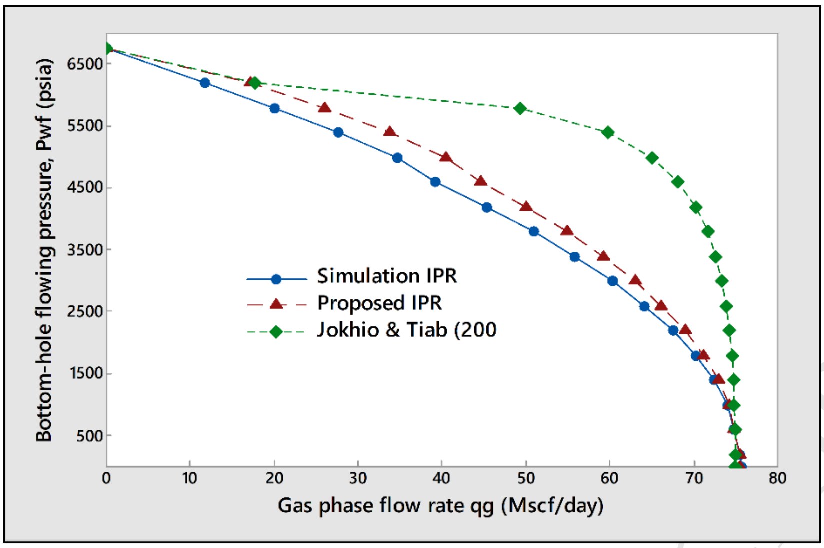

Fig. 13. Gas phase IPR.

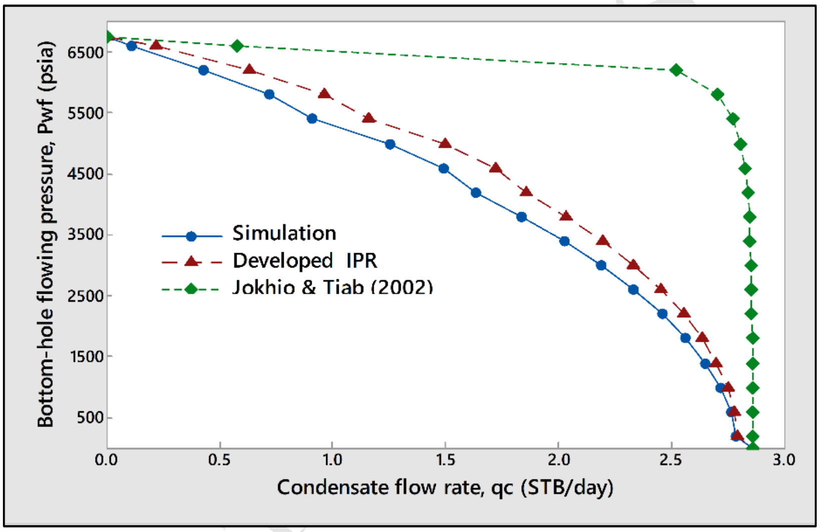

Fig. 14. Condensate phase IPR.

The average absolute relative deviation percent (AARD%) between the new developed IPR, Jokhio and Tiab, (2002) and simulation study of the well are estimated. The results of this error analysis is shown in Fig. (15) for gas phase and Fig. (16) for condensate phase. It is clear from the results that the new developed IPRs are in better agreement with simulation study with lower AARD%.

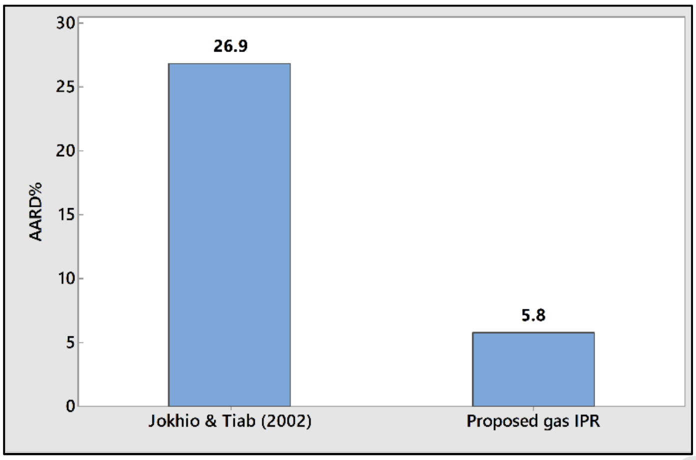

Fig. 15. The average absolute error deviation percent for gas phase IPR.

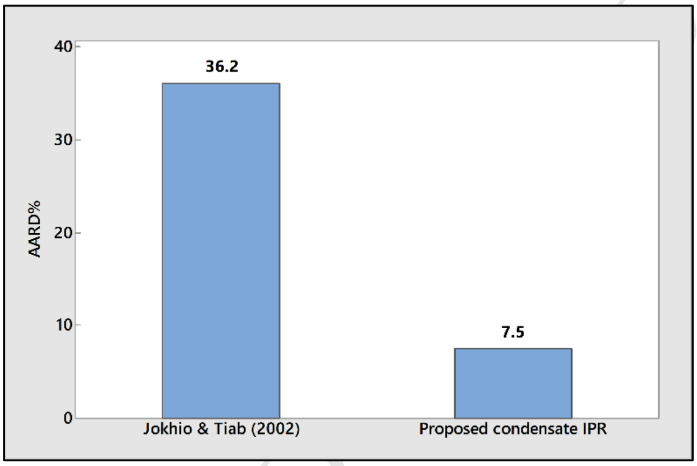

Fig. 16. The average absolute error deviation percent for condensate phase IPR.

The results of this study show that performance of high temperature heavy gas condensate well is a strong function of PVT properties include viscosity and compressibility. The characteristics of two-phase flow in gas condensate reservoirs are significantly different from conventional gas system. Single dry gas correlations cannot represent multiphase fluid behaviour of gas condensate reservoirs below the dew point.

6. Conclusions

In this study we generate IPR curves to predict the performance of depleting high temperature heavy gas condensate well. New developed gas condensate viscosity correlation and tow-phase compressibility factor is used in PVT calculation of pseudopressure function. The new IPR is compared to Jokhio and Tiab, (2002) and validated via compositional simulation study. Based on this work, the following can be concluded:

(1) A general correlation for viscosity "μ" of high temperature heavy gas condensate reservoirs as a function of pressure was developed using published experimental

studies. Jokhio and Tiab, (2002) method to construct and predict the IPR curves for gas condensate reservoirs was modified by using developed general viscosity correlation incorporated with two phase compressibility factor.

(2) The new IPR model developed based on assumption of transient fluid flow theory and superposition principle in calculating effective permeability integrals from pressure transient teste data.

(3) The validity of new IPR model was tested through compositional simulation on a field case (KAL-05) high temperature gas condensate well. The results of new IPR model compared with compositional simulation study and Jokhio and Tiab, (2002).The results showed that the new model outperform Jokhio and Tiab, (2002).

(4) The results of this study show that using single dry gas equation is not applicable for modelling gas condensate reservoir under depletion, where two phase flow exist.

(5) The new analytical approach in this study provides an appropriate engineering tool for uncertainty studies and decision making for choosing the best heavy gas condensate reservoir strategy.

(6) This simple analytical method can predict performance of gas condensate reservoirs, without requirement for expensive and time consuming computational simulation.

Appendix A

Procedure to calculate gas phase PVT Table 4

To calculate pseudocritical properties (pressure and temperature) equation of Sutton, (2005) Eq. (10) and Eq. (11) developed for gas condensate reservoir is used as follow:

$$T_{pc} = 164.3 + 357.7\gamma_g - 67.7{\gamma_g}^2$$

$$T_{pc} = 164.3 + 357.7(0.94) - 67.7(0.94)^2 = 440.72°R$$

$$P_{pc} = 744 - 125.4\gamma_g + 5.9{\gamma_g}^2$$

$$P_{pc} = 744 - 125.4(0.94) + 5.9(0.94)^2 = 631.34\,psia$$

At 2600 psia

$$T_{pr} = \frac{T}{T_{pc}} = \frac{(354 + 460)}{440.72} = 1.846 \quad \text{(A1)}$$

$$P_{pr} = \frac{P}{Ppc} = \frac{2600}{631.34} = 4.1182 \quad \text{(A2)}$$

Using Eq. (9) to calculate two-phase compressibility factor.

$$Z_{2p} = A_0 + A_1(P_r) + A_2\left(\frac{1}{T_r}\right) + A_3(P_r)^2 + A_4\left(\frac{1}{T_r}\right)^2 + A_5\left(\frac{P_r}{T_r}\right)$$

$$Z_{2p} = 2.24353 + (0.0375281)(4.12) + (3.56539)\left(\frac{1}{1.846}\right) + 0.000829231(4.12)^2 + 1.53428\left(\frac{1}{1.846}\right)^2 + 0.131987\left(\frac{4.12}{1.846}\right) = 0.91$$

$$Z_{2p} = 0.91$$

$$B_g = 0.00504\frac{Z_{2P}T}{P} = 0.00504\frac{(0.91)(354+460)}{2600} = 0.00144\ bbl/SCF \quad \text{(A3)}$$

Use Eq. (6) to calculate gas density

$$\rho_g = 1.601846 \times 10^{-2}\frac{Mw.P}{RT}$$

$$\rho_g = 1.601846 \times 10^{-2}\frac{(27.17)\times(2600)}{(10.73)(354+460)} = 0.1296\ g/cc$$

Calculate gas viscosity at 2600psia use developed correlation, Eq. (8).

$$\mu_{gc} = 0.000246933Kexp\left[X\left(\frac{\rho_g}{27.6718}\right)^Y\right]$$

Where:

$$K = \frac{(16.7175 + 0.0419188M)T^{1.40256}}{212.209 + 18.1349M + T} = \frac{(16.7175 + 0.0419188 \times 27.17)(814)^{1.40256}}{212.209 + 18.1349(27.17) + 814} = 142.95$$

$$X = 2.12575 + \frac{2063.71}{T} + 0.011926M = 2.12575 + \frac{2063.71}{814} + 0.011926 \times 27.17 = 4.99$$

$$Y = 1.09809 - 0.0392581X = 1.09809 - 0.0392581 \times 4.99 = 0.902$$

$$\mu_{gc} = 0.000246933Kexp\left[X\left(\frac{\rho_g}{27.6718}\right)^Y\right] = 0.000246933(142.95) \times exp\left[4.99\left(\frac{0.1296}{27.6718}\right)^{0.902}\right] = 0.03649\ cp$$

To calculate solution gas to oil ratio Rs, modified form of Kartoatmodjo and Schmidt, (1991) is used.

$$R_s = (P^{1.1535})\left(\frac{\gamma_g}{37.966}\right) \times 10^{\left(\frac{9.441API}{T}\right)} \quad \text{(A4)}$$

Where T is in ℉R

$$R_s = (2600^{1.1535})\left(\frac{0.94}{37.966}\right) \times 10^{\left(9.441\times\frac{50}{354+460}\right)} = 818.1233$$

Calculate oil to gas ratio, Ro [STB/MMscf], as follow:

$$R_o = -11.66 + 4.706 \times 10^{-9}(R_s)^3 + 1.623\sqrt{R_s} - \frac{42.3815}{\sqrt{R_s}}$$

$$R_o = -11.66 + 4.706 \times 10^{-9}(818.123)^3 + 1.623\sqrt{818.1233} - \frac{42.3815}{\sqrt{818.1233}} = 35.8576\frac{STB}{MMscf} = 3.58 \times 10^{-5} STB/scf$$

Producing gas to oil ratio, Rp was measured at the surface of the well during pressure transient test: Rp=9470 scf/STB. Table 3, is include PVT properties of gas phase for entire pressure range.

Table 3

PVT Properties for gas-phase in region 1.

P (psia)	Ppr (psi)	Z (Two-phase)	Bg (B/scf)	New Vis model, µg (cp)	Rs (scf/STB)
200	0.31	0.872	0.0179	0.0352	42.45
600	0.95	0.879	0.0060	0.0354	150.74
1000	1.58	0.885	0.0036	0.0356	271.73
1400	2.21	0.891	0.0026	0.0358	400.59
1800	2.85	0.898	0.0020	0.0360	535.30
2200	3.48	0.904	0.0016	0.0362	674.73
2600	4.11	0.910	0.0014	0.0364	818.12
3000	4.75	0.917	0.0012	0.0366	964.95
3400	5.38	0.923	0.0011	0.0368	1114.82
3800	6.01	0.930	0.0010	0.0370	1267.43
4200	6.65	0.936	0.0009	0.0372	1422.54
4600	7.28	0.942	0.0008	0.0374	1579.93
5000	7.91	0.9491	0.0007	0.0376	1739.43
5400	8.55	0.955	0.0007	0.0378	1900.91
5800	9.18	0.961	0.0006	0.0380	2064.24
6200	9.82	0.968	0.0006	0.0382	2229.31
6750	10.69	0.976	0.0005	0.0385	2458.94

Appendix B

Calculation of pseudopressure integral

In this section calculation step of two phase pseudopressure integral for gas phase is demonstrated, trapezoidal rule of integration was used to evaluate the integral. Eq. (24)

$$\Delta mP_{gt} = \left[\int_{p_{wf}}^{P_{avg}} \left(\frac{1}{\mathrm{B}_{gd}\mu_{\mathrm{g}}}\right)\frac{R_p(1-R_oR_s)}{(R_p-R_s)}(P)dp\right] \times \int_{P_{wf}}^{P_{avg}} k.\,\mathrm{k_{rg}}(P)\,dp$$

First part of the integral is calculated as follow:

if, $X = \left(\frac{1}{\mathrm{B}_g\mu_{\mathrm{g}}}\right)\frac{R_p(1-R_oR_s)}{(R_p-R_s)}$, the pseudopressure integral can be written as follow:

$$\Delta mP_g = \int_{p_{wf}}^{P_{avg}} X\,(P)dp$$

Having calculated the PVT properties, at pressure of 200psia, (X_{200}) can be calculated as follow:

$$X_{200} = \left(\frac{1}{\mathrm{B}_g \mu_g}\right) \frac{R_p(1 - R_o R_s)}{(R_p - R_s)} = \frac{9470 \times (1 - (-7.58E - 06 \times 42.45)}{(0.0179 \times 0.035) \times (9470 - 42.45)} = 1797.3$$

$$X_0 = 0$$

Hence:

$$\Delta m P_{gt} = \int_0^{200} X\,(P) dp$$

$$\int_0^{200} X\,(P) dp = \frac{0 + 1797.3}{2}(200 - 0) = 179730\, psi^{\wedge}2/cp$$

Second part of Eq. (24), is effective permeability integral that can be calculated as follow at pressure 6574.3psia. Having calculated pseudopressure derivative group$(d\Delta mPg)/dln(t)$, effective permeability integral at 6574.3psia is

$$\int_{P_{wf}}^{Pavg} k.\,\mathrm{k_{rg}}(6574.3)\, dp = 162.6 \frac{q_{g,meas}}{h\left(\frac{d\Delta m P_g}{dln(t)}\right)} = \frac{162.6}{44080.16} \frac{75.4 \times 100}{216.5} = 0.1283\, cp$$

Calculating several values of the effective permeability integral at various pressure, results in constructing Fig. (10). The other pressure range of permeability integral can be estimated from extrapolation of this graph. For pressure of 200psia the effective permeability integral is 0.000074.

Hence pseudopressure integral at 200psia, Eq. (24) is:

$$\Delta m P_g = 179730 \times 0.000074 = 13.3 \frac{psi^2}{cp} = 0.00001338\, MM \frac{psi^2}{cp}$$

And continue the above procedure for given bottom-hole flowing pressures.

The result of pseudopressure, pseudopressure derivative group and effective permeability integral is presented in Table 4.

Table 4

Pressure, pseudopressure and pseudopressure derivative results, for gas-phase.

Time(hours)	P(psia)	m(p),region gas	Δmp, MMpsi^2/cp	t.ΔmP/d(ln(t)	Integral (Keg)
0	1083.1	24674.74			
0.167	1174.5	26844.29	3647.32		
0.333	1226.7	30147.45	5816.87		
0.5	1303.6	38660.77	9120.02	7916.19	
1	1490.6	51522.34	17633.34	12347.16	
2	1751.6	67104.64	30494.91	29919.68	
3	2046	80061.04	46077.22	39009.35	

4	2279.4	107613.27	59033.61	56001.64	
6	2759.4	136008.52	86585.84	76609.43	
8	3246.5	189821.83	114981.09	108816.41	
12	4210	236758.29	168794.41	145354.52	
16	5162	276446.10	215730.86	145893.57	
22	6161	282294.79	255418.67	100093.52	
28	6336.5	284516.45	261267.37	63915.29	0.0088
34	6406.1	285966.50	263489.02	18041.50	0.0313
42	6452.5	287037.70	264939.07	10466.39	0.0541
50	6487.3	287665.09	266010.27	6400.52	0.0884
58	6507.6	288227.53	266628.66	5838.47	0.0969
68	6526.5	289137.98	267200.10	5438.58	0.1041
82	6556.9	289654.26	268110.55	4062.96	0.1393
97	6574.3	290037.67	268626.83	4408.16	0.1284
112	6587.3	29.463.04	269010.26	3114.06	0.1818
141	6601.8	21027.43	269435.62		

Appendix C

Procedure to calculate condensate (oil) PVT

Calculate the PVT for condensate part, estimate Ppc by Eq. (10) and Tpc by Eq. (11) as follow:

$$P_{pc} = 744 - 125.4\gamma_{condensate} + 5.9{\gamma_{condensate}}^2$$

$$T_{pc} = 164.3 + 357.7\gamma_{condensate} - 67.7{\gamma_{condensate}}^2$$

Where specific gravity of condensate $\gamma_{condensate}$ is calculated from the following equation:

$$\gamma_o = \frac{141.5}{131.5 + API} = \frac{141.5}{131.5 + 50} = 0.779 \quad \text{(C1)}$$

Hence:

$$P_{pc} = 744 - 125.4(0.779) + 5.9(0.779)^2 = 649.9$$

$$T_{pc} = 164.3 + 357.7(0.779) - 67.7(0.779)^2 = 402.02$$

Ppr and Tpr at pressure of 2200 psia are as follow:

$$P_{pr} = \frac{P}{Ppc} = \frac{2200}{649.9} = 3.385$$

$$T_{pr} = \frac{T}{402.02} = \frac{(354 + 460)}{402.02} = 2.025$$

To evaluate compressibility factor of condensate phase, Eq. (9) is used. Having calculated Ppr and Tpr at pressure of 2200psia, compressibility is calculated as follow:

$$Z_{2p} = A_0 + A_1(P_{pr}) + A_2\left(\frac{1}{T_{pr}}\right) + A_3(P_{pr})^2 + A_4\left(\frac{1}{T_{pr}}\right)^2 + A_5\left(\frac{P_{pr}}{T_{pr}}\right)$$

$$Z_{2p} = 2.2435 - (0.03752)(3.385) + 3.5653\left(\frac{1}{2.025}\right) + 0.000829(3.385)^2 + 1.5342\left(\frac{1}{2.025}\right)^2 + 0.131987\left(\frac{3.385}{2.025}\right) = 0.96$$

Standing and Katz, (1942) correlation is used to calculate condensate (oil) formation volume factor. At pressure of 2600psia.

$$B_O = 0.972 + 0.000147F^{1.175} \quad \text{(C2)}$$

Where:

$$F = R_s\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + 1.25T, \qquad T = \ ^\circ\mathrm{F} \quad \text{(C3)}$$

In equation C3, Rs is determined by modified correlation of Kartoatmodjo and Schmidt, (1991) as follow:

$$R_s = (P^{1.1535})\left(\frac{\gamma_g}{37.966}\right) \times 10^{\left(\frac{9.441API}{T}\right)} \quad \text{(C4)}$$

Where T is ℉R

$$R_s = (2600^{1.1535})\left(\frac{0.94}{37.966}\right) \times 10^{\left(\frac{9.441\times 50}{354+460}\right)} = 678.53$$

Therefore:

$$F = 678.63 \times \left(\frac{0.94}{0.779614}\right)^{0.5} + 1.25 \times (354) = 1187.7$$

$$B_O = \ 0.972 + 0.000147(1187.7)^{1.175} = 1.5746$$

To estimate the oil to gas ratio the following equation is used:

$$R_O = -11.66 + 4.706 \times 10^{-9}(Rs)^3 + 16.623\sqrt{Rs} - \frac{42.3815}{\sqrt{Rs}} \quad \text{(C5)}$$

At 2600psia:

$$R_O = -11.66 + 4.706 \times 10^{-9}(678.53)^3 + 16.623\sqrt{678.53} - \frac{42.3815}{\sqrt{678.53}} = 3.046 \times 10^{-5} STB/scf$$

To estimate the viscosity of condensate phase, modified form of Beggs and Robinson, (1975), Eq. (C5) is used. For dead oil viscosity modified Egbogah and Jack, (1990) correlation shown in Eq. (C10) is used.

$$\mu_c = (25.1921(R_s + 100)^{-0.6487})\mu_{od}[2.7516\,(R_s + 150)^{-0.2135}] \quad \text{(C6)}$$

$$log.\log(\mu_{od} + 1) = 1.8513 - 0.0255484API - 0.56238\log(Tg) \quad \text{(C7)}$$

API assumed to be 50 in this study. Damaged skin factor is taken as -4.1235 after Jokhio and Tiab (2002).

Table 5 depicts the PVT results of condensate phase.

Table 5

PVT properties of condensate (oil) phase.

P	Ppr (psi)	$Z_{(Two\text{-}phase)}$	Bo (B/scf)	Vis ,μ_o (cp)	Rs (scf/STB)	Ro(STB/scf)
200	0.3077	0.8654	1.1804	0.2825	35.2076	-9.1722E-06
600	0.9233	0.8831	1.2315	0.1866	125.0248	2.7064E-06
1000	1.5388	0.9014	1.2903	0.1374	225.3714	9.9359E-06
1400	2.1544	0.9203	1.3549	0.1083	332.2443	1.5771E-05
1800	2.7699	0.9398	1.4241	0.0893	443.9722	2.0938E-05
2200	3.3855	0.9600	1.4975	0.0758	559.6075	2.5767E-05
2600	4.0010	0.9808	1.5746	0.0659	678.5326	3.046E-05
3000	4.6166	1.0022	1.6551	0.0582	800.3101	3.5168E-05
3400	5.2321	1.0243	1.7387	0.0521	924.6128	4.0017E-05
3800	5.8477	1.0469	1.8253	0.0472	1051.1854	4.512E-05
4200	6.4633	1.07029	1.9147	0.0431	1179.8234	5.0582E-05
4600	7.0788	1.0942	2.0067	0.0397	1310.3585	5.6508E-05
5000	7.6944	1.1187	2.1012	0.0367	1442.6496	6.2999E-05
5400	8.3099	1.1439	2.1980	0.0342	1576.5769	7.0157E-05
5800	8.9255	1.1698	2.2972	0.0320	1712.037	7.8085E-05
6200	9.5410	1.1962	2.3985	0.0301	1848.9398	8.6888E-05
6750	10.38	1.2336	2.5413	0.0278	2039.3927	0.00010061

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- New gas condensate viscosity correlation developed
- Inflow Performance Relationship curves are established for high temperature gas condensate reservoirs
- Multi-flash compositional simulation of a high temperature gas condensate well performed
- Pressure transient test data utilized to evaluate effective permeability integral
- Pseudopressure function is used to model gas condensate reservoir performance