A SEMI-EMPIRICAL APPROACH TO MODELLING WELL DELIVERABILITY IN GAS CONDENSATE RESERVOIRS

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Declaration

I hereby declare that the research work reported in this Thesis is an original piece of work undertaken by myself (Johnson Obunwa Ugwu), under the supervision of Professor John A. Steel and Dr W. E. Mason. That the work or any portion of it referred to in this PhD thesis has not been submitted in support of an application for another degree or qualification of another university or institution of learning. All results and work other than my own cited are clearly credited.

Johnson Obunwa Ugwu

Abstract

A critical issue in the development of gas condensate reservoirs is accurate prediction of well deliverability. In this investigation a procedure has been developed for accurate prediction of well production rates using semi-empirical approach. The use of state of the art fine grid numerical simulation is time consuming and computationally demanding, therefore not suitable for real time rapid production management decisions required on site. Development of accurate fit-for-purpose correlations for fluid property prediction below the saturation pressure was a major consideration to properly allow for retrograde condensation, complications of multiphase flow and mobility issues. Previous works are limited to use of experimentally measured pressure, volume, temperature (PVT) property data, together with static relative permeability correlations for simulation of well deliverability.

To overcome the above limitations appropriate fluid property correlations required for prediction of well deliverability and dynamic three phase relative permeability correlation have been developed to enable forecasting of these properties at all the desired reservoir conditions The developed correlations include; condensate hybrid compressibility factor, viscosity, density, compositional pseudo-pressure, and dynamic three phase relative permeability. The study made use of published data bases of experimentally measured gas condensate PVT properties and three phase relative permeability data. The developed correlations have been implemented in both vertical and horizontal well models and parametric studies have been performed to determine the critical parameters that control productivity in gas condensate reservoirs, using specific case studies. The improved correlations showed superior performance over existing correlations on validation. The investigation has built on relevant literature to present an approach that modifies the black oil model for accurate well deliverability prediction for condensate reservoirs at conditions normally ignored by the conventional approach.

The original contribution to knowledge and practice includes (i) the improved property correlations equations, (4.44, 4.47, 4.66, 4.69, 4.75, 5.21) and (ii) extension of gas rate equations, for condensate rate prediction in both vertical and horizontal wells. Standard industry software, the Eclipse compositional model, E-300 has been used to validate the procedure. The results show higher well performance compared with the industry standard. The new procedure is able to model well deliverability with limited PVT and rock property data which is not possible with most available methods. It also makes possible evaluation of various enhanced hydrocarbon recovery techniques and optimisation of gas condensate recovery.

Keywords; *Well Deliverability, Gas Condensate, Reservoirs, Semi-empirical, Modelling and Simulation*

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Thank you all for being part of this success story more is thy due than words can say.

To God the glory be forever.

Dedicated to Almighty God for His infinite mercies and goodness to me

To my Parents for their monumental role in shaping my life

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NOMENCLATURE

A, B, C, D	Beggs-Brill correlation parameters
$A_1 - A_{11}$	DAK and DPR correlations constants
Aij	Binary interaction coefficient
a	Length of reservoir in x direction, ft
AOF	Absolute Open flow potential
b	Width of reservoir in y direction, ft
B_c	Condensate formation volume factor, RB/STB
B_g	Gas formation volume factor (FVF), RB/scf
BHFP	Bottom hole flowing pressure, psi
B_o	Oil formation volume factor, RB/STB
Bw	Water formation volume factor, RB/STB
CCE	Constant composition expansion
CGR	Condensate-gas ratio, stb/MCF
C_H	Geometric factor
C_K	Kozeny constant
C_m	Morris constant; Oil = 250; Gas = 80
CVD	Constant volume depletion
D	Inside diameter of pipe, in
DAK	Dranchuk-Abu-Kassem
d_m	Median grain size (microns)
DPR	Dranchuk-Purvis-Robinson
E_j , E_k,	SSBV mixing rule parameters
EOS	Equation of State
F_i, Fj	Sutton adjustment parameters
f	Fanning friction factor
f_n	No-slip friction factor (unitless)

Fr_m	Froude mixture number (unitless)
f_{tp}	Two phase friction factor
g	Acceleration of gravity (32.2ft/s^2)
g_c	Conversion factor $\left(32.2 lb_m . ft / lb_f .s^2\right)$
GOR	Gas-oil ratio, MCF / stb
h	Reservoir thickness, ft
$H_L(0)$	Horizontal liquid holdup (unitless)
h_p	Perforated interval, ft
$H_L(\theta)$	Inclined liquid holdup (unitless)
J	Steward Burkhardt and Voo (SBV) Parameter, ^{o}R/psia
J'	Sutton parameter, ^{o}R/psia
J_h	Horizontal well productivity index, bbl/day/psi
$J_{\inf}$	Inferred value of J parameter, ^{o}R/psia
K	Absolute permeability,
K'	Sutton parameter, ^{o}R/psia$^{0.5}$
k_a	Absolute roughness, in
k_c, k_g, k_w	Effective permeability of condensate, gas, and water
$K_{\inf}$	Inferred value of K parameter, ^{o}R/psia$^{0.5}$
k_{rc}	Condensate relative permeability
k_{rccw}	Condensate relative permeability in the presence of connate water
k_{rcw},	Relative permeability to water in water condensate system
k_{rgc}	Relative permeability to gas in gas-condensate system
k_{rl}	Relative permeability of phase 1
k_{rl}^o	Endpoint relative permeability of phase 1

k_{rg}	Gas relative permeability
k_{ro}	Oil relative permeability
$K_r(S_{wi})$	Relative permeability at interstitial water saturation
K_s	SBV parameter, $^oR/psia^{0.5}$
L	Well length = $y_2 - y_1$, ft
L_p	Length of pipe section, ft
M	Molar mass, lb-mole
M_a	Apparent molecular weight (lb/lb-mole)
M_i	Molecular weight of the 'i' component (lb/lb-mole)
M_{C7+}	Molar mass of heptanes plus fraction, lb-mole
N_B	Bond number
N_c	Capillary number
n_g	Corey exponent for gas phase
n_p	Numbers of phases
N_T	Trapping number
N_{vi}	Liquid velocity number (unitless)
P	Pressure, psi
P_c	Critical pressure, psi
P_{ci}	Critical pressure of the 'i' component, psi
P_d	Dew point pressure, psi
P_{pc}	Pseudo-critical pressure, psi
P_{pr}	Pseudo-reduced pressure, psi
P_r	Reduced pressure, psi
P_R	Reservoir pressure, psi
P_{sc}	Pressure at standard conditions, psi

Pwf	Well flowing pressure, psi
q_g	Gas flow rate, MMscf/Day
q_h	Production rate, STB/D
r	Radius, ft
R	Universal gas constant = 10.73 psia ft^3/lb-mole °R
r_{dew}	Radius at which the pressure equals the dew point pressure
r_e	Drainage radius (ft)
R_{eh}	Horizontal well equivalent drainage radius, ft.
Re_N	No-slip Reynold's Number (unitless)
r_{ev}	Vertical well equivalent drainage radius, ft.
R_N	Reynold's number (unitless)
r_w	Well radius, ft
R_s	Solution gas-oil ratio, MCF/stb
s	Skin
s_{cc}	Critical condensate saturation
S_c^*	Effective Condensate saturation
S_b	Beggs and Brill coefficient (unitless)
S_g	Gas saturation
S_{gc}	Critical gas saturation
S_{gr}	Residual gas saturation
S_j	Saturation of phase j
S_{jr}	Residual saturation of phase j
S_L	Total liquid saturation
s_m	Mechanical skin

S_o	Oil saturation
S_{or}	Residual oil saturation
S_{wr}	Residual water saturation
s_R	Pseudo skin factor due to fractional penetration, s_R=0 if $L = b$
s_t	Total skin
S_{wi}	Irreducible water saturation
T	Reservoir temperature, ^oR or ^oF
T_l	Trapping parameter for phase l
V	Volume , ft^3
V_m	Mixture velocity, ft/s
V_{si}	Superficial liquid velocity, ft/s
WC	Water cut
X , Y	Viscosity correlation parameter
X_{da}	(2a/L) for ellipsoidal drainage area, dimensionless.
X_e	Reservoir width, ft
x_{mid}	$0.5(x_1 + x_2)$ With reference to reservoir geometry
x_o	Position of well, ft
y_{C7+}	Mole fraction of heptanes plus fraction
y_i	Mole fraction of the i-th component (i=N_2, CO_2, C_1... nC_6)
y_o	Position of well, ft
Z	Condensate compressibility factor
z_g	Gas Compressibility factor
z_o	Position of well, ft

Greek letters

α_{i-n}	Coefficients of new correlations for J (i=0,1,...,7)
β	Turbulence factor
β_{i-n}	Coefficients of new correlation for K (i=0,1,...,7)
γC_{7+}	Specific gravity of the C_{7+} plus fraction
γ_g	Specific gravity of gas
Δ	Difference
Δ P	Pressure drop through horizontal well, psi
ΔP_f	Pressure loss due to friction effects, psi
ΔP_{HH}	Pressure change due to hydrostatic head, psi
ΔZ	Elevation change , ft
ε	Witchert and Aziz pseudo critical temperature adjustment parameter, ^oR
ε_J	Sutton SBV parameter, ^oR/psia
ε_K	Sutton SBV parameter, $^oR/psia^{0.5}$
ζ	Viscosity parameter for viscosity correlations
θ	Angle of inclination from the horizontal, degree
λ	Pore size distribution parameter
$\lambda_c, \lambda_g, \lambda_w$	Exponents for condensate, gas and water saturations
λ_L	Liquid input volume fraction
μ	Viscosity , cp
μ_1	Viscosity of the gas at 1 atm , cp
μ_g	Gas Viscosity' cp
$\mu_{g\,sc}$	Low-pressure gas viscosity, cp
μ_n	No-slip viscosity, cp

μ_o	Oil Viscosity, cp
ρ	Density (lb/ft^3)
ρ_{air}	Density of air = 1, lb/ft^3
ρ_G	Gas density, Ib/ft^3
ρ_L	Liquid density, lb/ft^3
ρ_M	Mixture density, lb/ft^3
ρ_n	No-slip density, lb/ft^3
ρ_o	Oil molar density, lb –M/ft^3
ρ_r	Reduced density, lb/ft^3
Ω	Equation of state constant
ω	Acentric factor
σ	Gas /liquid surface tension, dynes/cm
ϕ	Porosity
$\psi(P)$	Pseudo pressure function
$\psi(\theta)$	Inclination factor (unitless)

Subscripts

c	Condensate phase
d	Dimensionless
e	at the drainage radius
f	Future time
g	Gas
i, j	Component identification
m	Mixture definition
pc	Pseudo critical property
pr	Pseudo reduced property
l	Liquid

l	Displaced phase
l'	Displacing phase
m	Molar
o	Oil phase
p	Present time
r	Residual
Sc	Standard condition
t	Total
v	Vertical
w	Water phase
1, 2	Index for components 1 and 2

Superscripts

$high$	High trapping number
low	Low trapping number
i	Initial value
o	Endpoint value

CHAPTER ONE

1.0 INTRODUCTION

1.1 Background

Gas Condensate reservoir is a class of hydrocarbon reservoir that could be referred to as reservoir intermediate between oil and gas reservoirs. Condensate is a petroleum liquid consisting mostly of pentanes and heavier hydrocarbon usually in the gas vapor) phase above the dew point pressure and condenses to liquid phase below the saturation pressure. The effects of the complex phase behaviour encountered in gas-condensate reservoirs on phase compositions and fluid PVT (Pressure, volume and temperature) properties cannot be calculated accurately with simple approaches using black oil models and constant composition assumptions (Miller and Holstein 2007). A method of accounting for variable composition in the black oil model to make it adequate for accurate well deliverability prediction in gas condensate reservoirs is an important aspect of this investigation.

A major goal of modern gas condensate reservoir management is to optimise the production system for optimum well deliverability. This is not possible without an accurate well deliverability model for production and field development plans to achieve the set goal. Though the goal can be achieved by fine-grid numerical simulation, the data requirement is huge coupled with the problem of the tuning equation of state (EOS) to the available experimental data. The experimental data for this kind of reservoir is usually not available at desired reservoir conditions and the cost of obtaining it is prohibitive. Lack of such data and other associated problems of numerical simulation prompted this work.

Unconventional reservoirs especially gas condensate reservoirs have received much attention in recent years partly due to concerns about the global depletion of hydrocarbon resources, scarcity of new reserves and increasing demand for energy resources. In today’s petroleum industry, the central issue is on how to bridge the gap between supply and demand for hydrocarbon at minimum cost of production and optimum output. The need for development of optimisation tools for production of gas condensate reservoirs prompted this work, as the tools available were developed for Oil and Gas systems, are not valid for Condensate at most reservoir conditions (Bourbiaux 1994; Bozorgzadeh and Gringarten 2007, Fevang and Whitson 1996, Jokhio and Tiab 2002, Mott 1999).

Global warming, the greenhouse effect, and clean technology concerns favour the development of gas-condensate fields. This is because condensate has advantage over other hydrocarbon products in terms of being a composite fluid that can be used in liquid or in gas form. A well managed gas-condensate reservoir produces less gas than gas condensate reservoir produced with limited knowledge of phase behaviour. Producing less gas is important in reducing the chances of flaring that may lead to greenhouse effects and global warming with all the associated undesirable consequences. Condensate has a higher market value then oil and gas as it is a cleaner energy source, and could be used in gas or liquid form. The ease of transporting it is an additional advantage.

Time has been spent in this study developing accurate models for prediction of well deliverability in gas-condensate reservoir. This will help in optimizing production strategy. The demand and supply gap for hydrocarbon could be reduced if the improved prediction methods are applied appropriately in determining optimum production conditions.

However, challenges are high in the development of this kind of reservoir (Condensate). Gas Condensate reservoirs are characterised by production of condensate, gas and water and have long been recognised as a class of reservoir that has the most intricate flow pattern and complex thermodynamic behaviour (Shi 2009). Gas-condensate may be thought of as an intermediate between oil and gas reservoirs (Craft, Hawkins and Terry 1959).

At this juncture, it may be of interest to have a brief look at the world's major gas condensate fields where the PVT correlations developed in this work may be applied. Gas condensate fields in the North Sea are shown in figure 1.1 and the global natural gas (non-associated gas) that are the major source of gas condensate are shown in figures 1.2a to 1.2c. These locations served as a guide for sourcing of data sample sets used in this study.

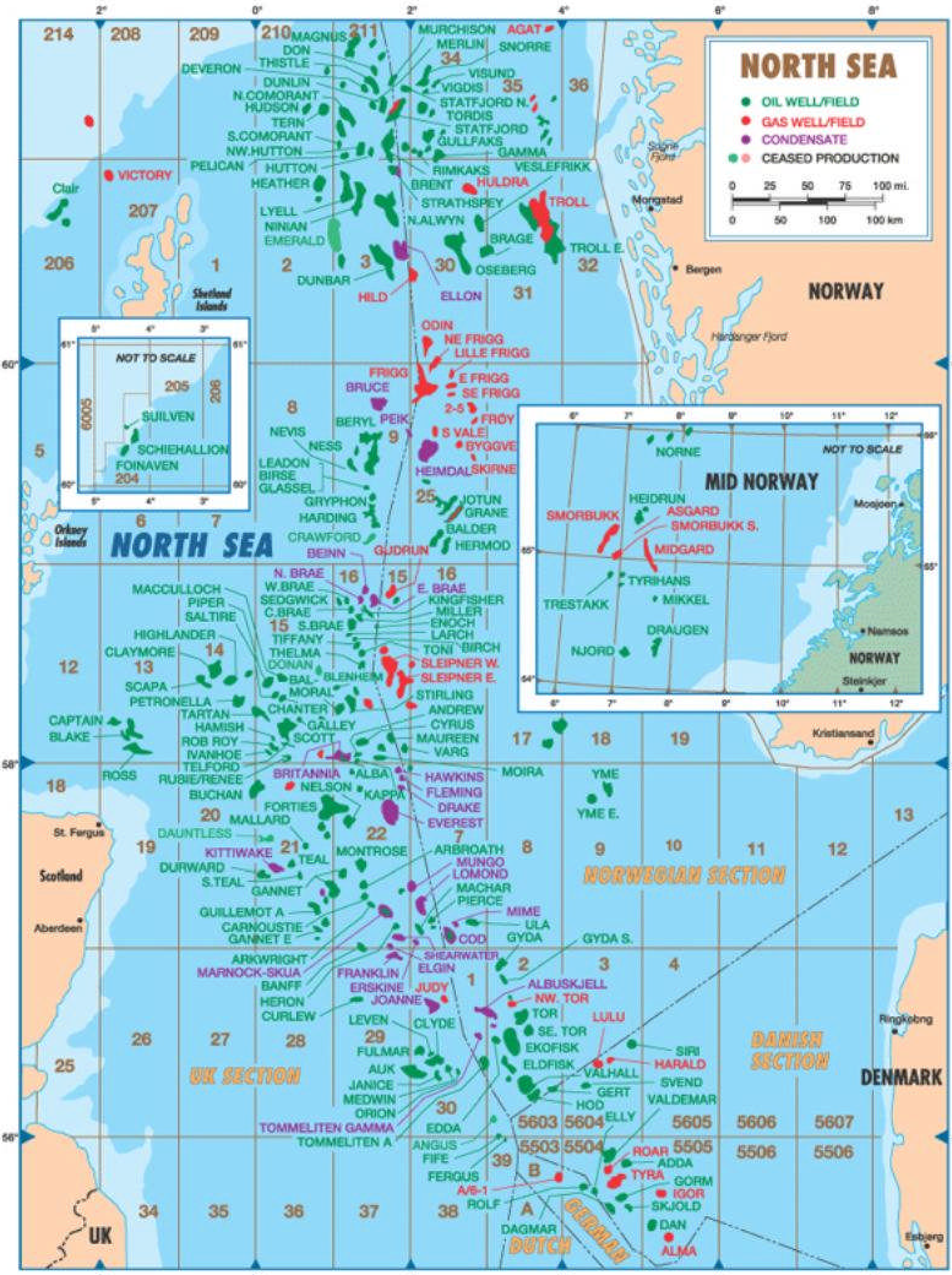


Figure 1.1 Condensate fields in the North Sea (APS 2011)

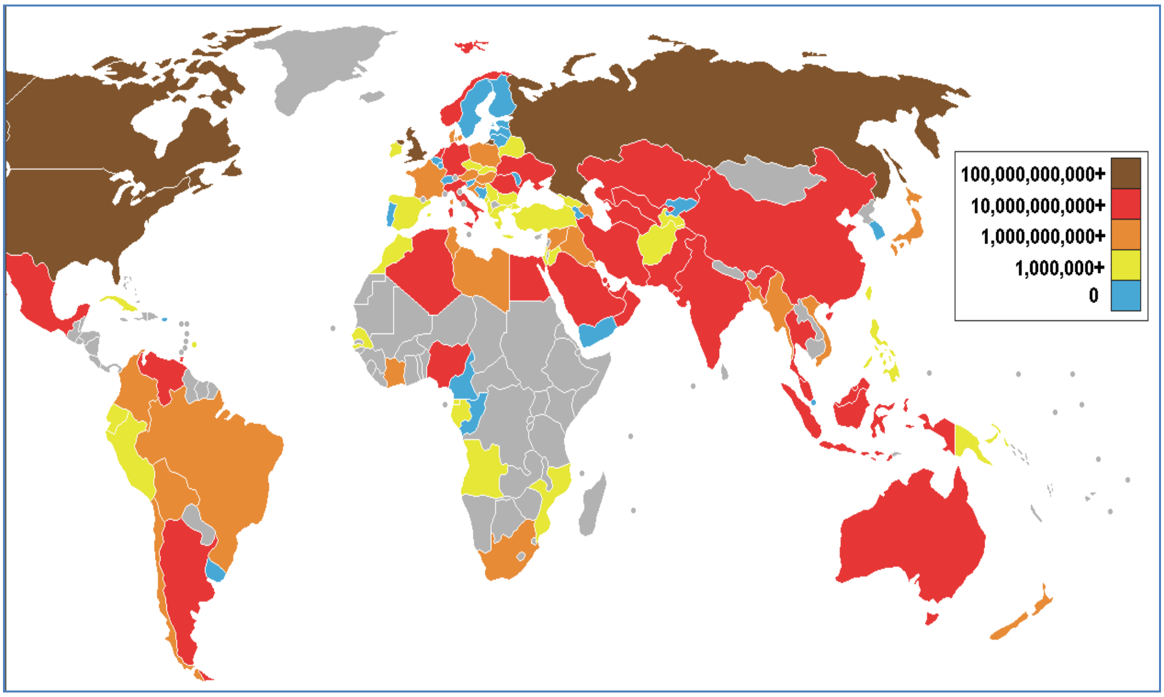


Figure 1.2a Major world natural gas fields (gas condensate sources) measured in cubic meters (BAF 2011)

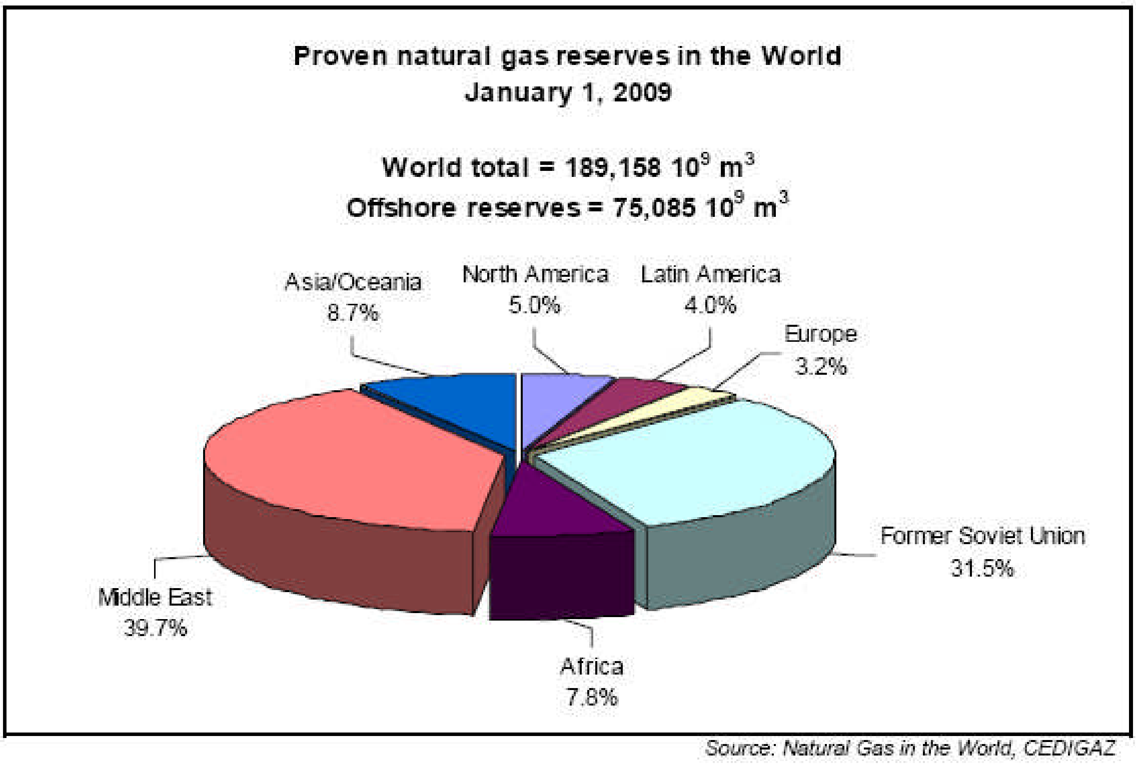


Figure 1.2b Proven Natural gas reserves in the world as at January 1, 2009 (CEDIGAZ 2009)

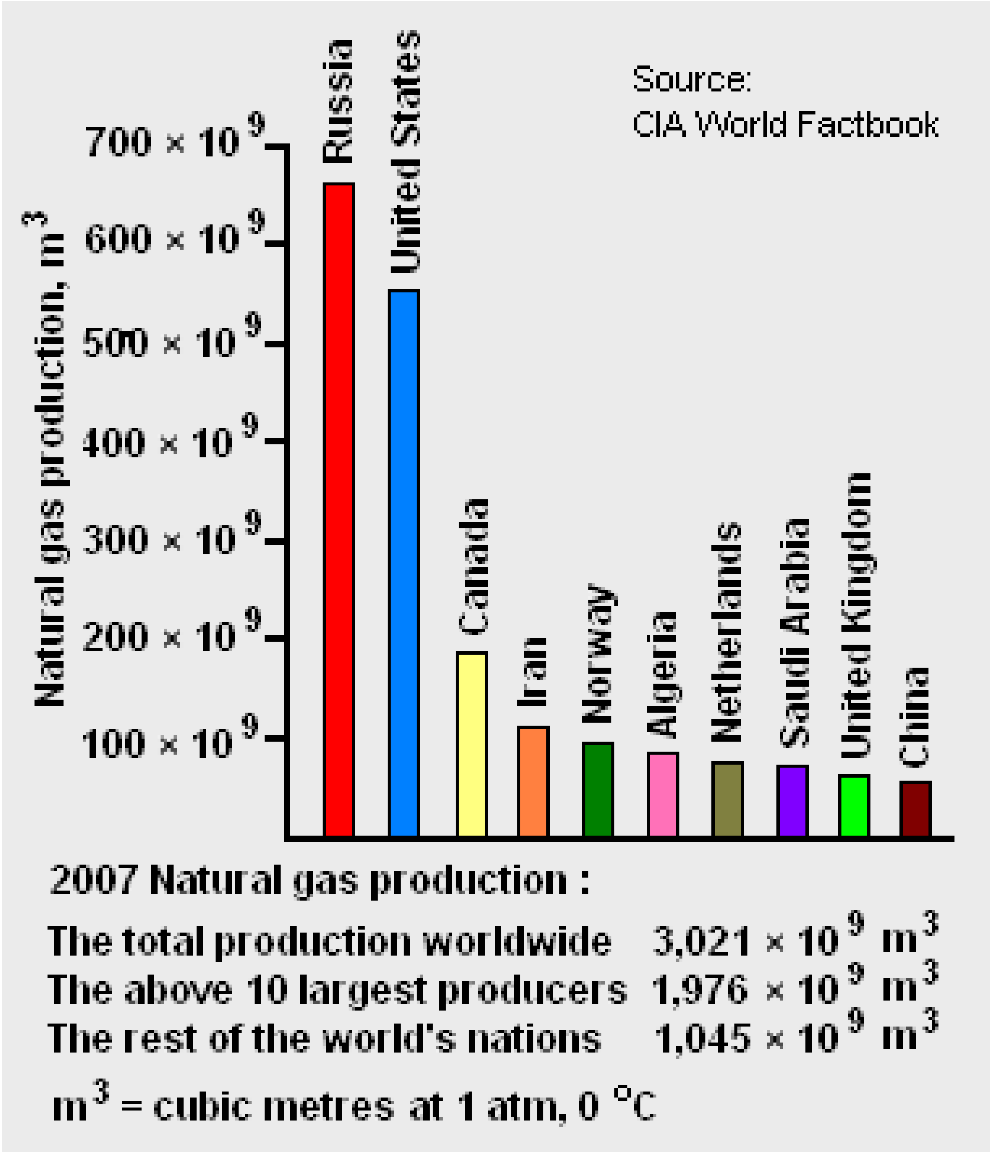


Figure 1.2c Global natural gas production as at 2007, Central intelligence agency (CIA 2011)

Prediction of well deliverability in gas condensate reservoirs is one of the first steps in effective reservoir management and the overall field development plan. This revolves around reservoir/well pressure changes and relative permeability as the key controlling variables in the deliverability models with temperature and compositional variations playing a key role also.

Classification of a reservoir fluid as oil, volatile oil, condensate, wet gas, or dry gas is important because application of appropriate engineering practices to predict reserve and rates traditionally require this knowledge (Amyx et al.

1960, McCain 1990, Raghavan and Jones 1996). A typical Phase diagram of a gas condensate reservoir is illustrated in figure 1.3 below.

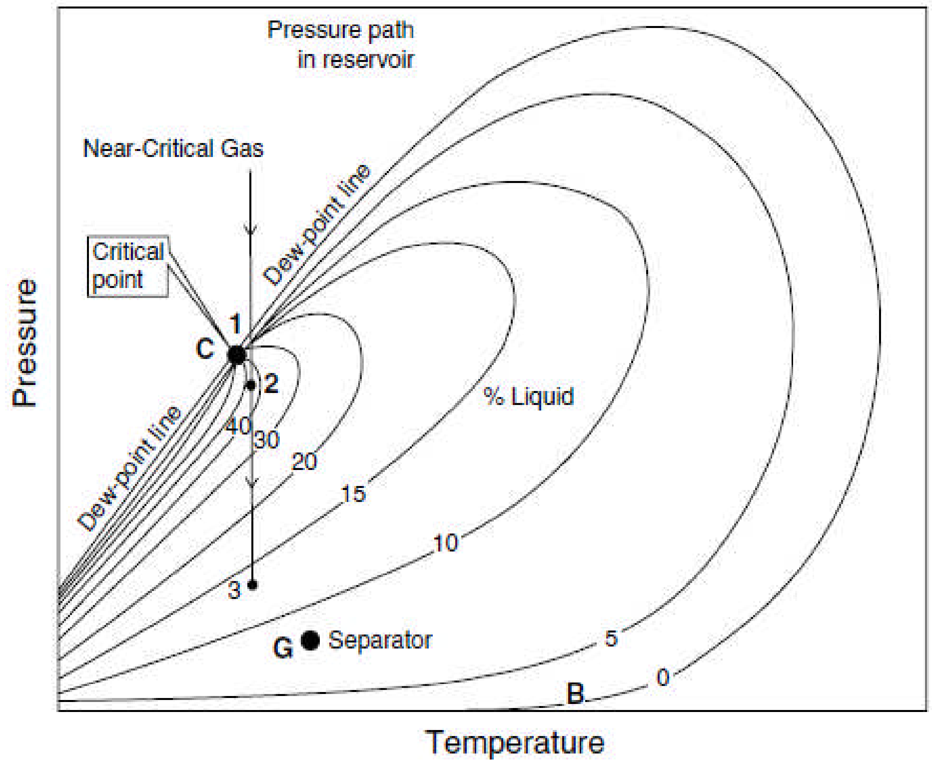


Figure 1.3 A typical phase diagram of a gas condensate system, (Ahmed 2006)

The dew-point curve is the line separating the vapor-phase region from the two-phase region. Reservoirs are conveniently classified on the basis of the location of the point representing the initial reservoir pressure pi and temperature T with respect to the pressure-temperature diagram of the reservoir fluid. The critical point for a multi-component mixture is the state of pressure and temperature at which all intensive properties of the gas and liquid phases are equal. The Cricondentherm is the maximum temperature above which liquid cannot be formed regardless of pressure.

The reservoir temperature lies between the critical temperature and the cricondentherm with the initial pressure above the dew point. The dew point pressure, a unique condition of condensate reservoir has critical implications to modelling well deliverability which informed the approach taken in the study. The uniqueness of conditions of the reservoir below the dew point comes from the retrograde condensation which invalidates most of the well deliverability modelling attempts. The phase diagram, figure 1.3 is a summary of gas condensate phase behaviour.

Further illustration of the flow of condensate near the wellbore and condensate banking can be seen in figure 1.4.

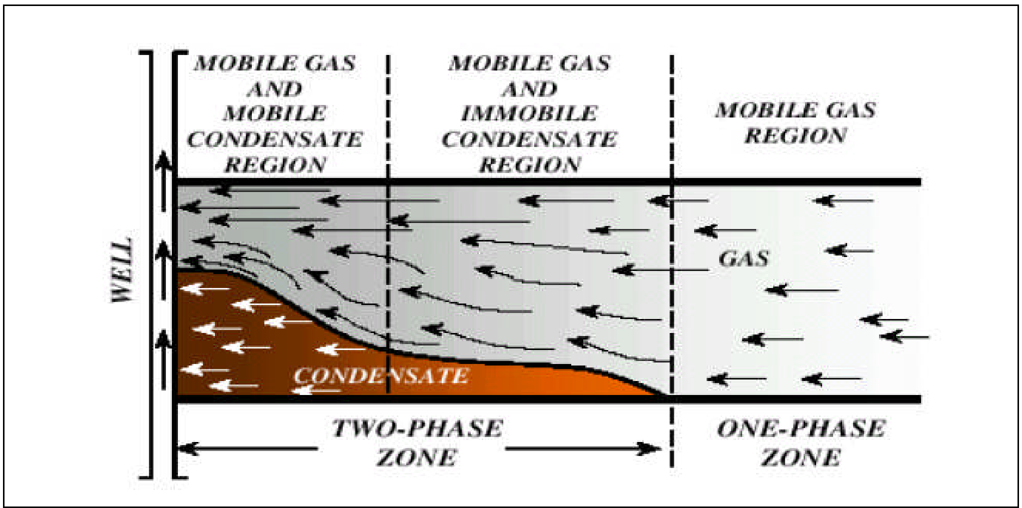


Figure 1.4 Condensate flow near the wellbore, (Penuela and Civan 2000)

Reservoir fluid PVT properties are sometimes used to classify reservoir types though with some limitations (Walsh and Lake 2003) as illustrated in table 1.1 below.

Table 1.1 Classes of reservoir fluid based on SG, API, GOR (Walsh, 2003)

Type	SG	API Gravity	GOR (scf/stb)
Heavy oil	0.93	12 – 25	< 100
Black oil	0.85	25 – 40	100 – 2500
Volatile oil	0.81	40 – 50	2500 – 4500
Gas condensate	0.75	50 – 70	4500 – 50000
Wet gas	< 0.1	50 – 70	50000 – 100000
Dry gas	-	N/A	< 10 stb/MMscf

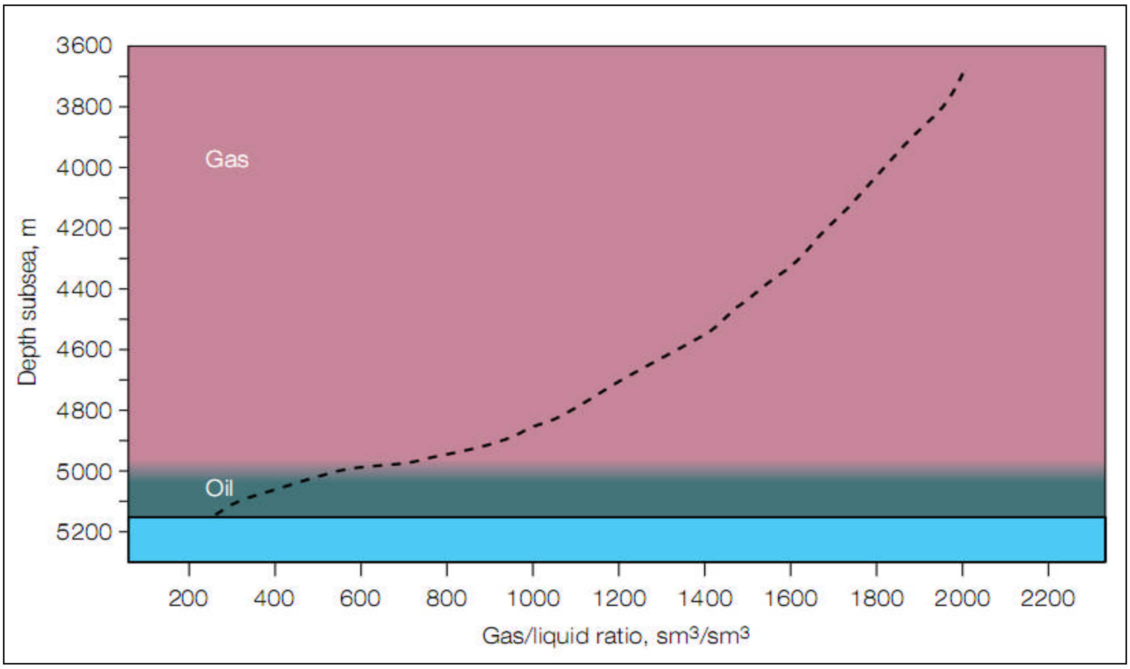


Figure 1.5 Variation of gas/liquid ratio with depth for the giant Karachaganak gas condensate field (Elliot et al. 1998)

1.1.1 The production system and process description

The production system is made up of the reservoir, the wellbore and the surface production facility. The subject of this research is modelling well deliverability in gas condensate reservoirs. The use of a single well in developing accurate models for prediction of well deliverability in gas condensate reservoir is being examined in this study. The depletion of gas condensate reservoirs below the dew point pressure in deeper and higher temperature hydrocarbon reservoirs results in condensation which may cause a build up of high liquid saturation around the wellbore (Dawe, and Grattoni 2007a, Bang et al. 2006, Barnum et al. 1995, Castelijns 1981, Castelijns and Hagoort 1984). The resulting multiphase flow reduces the productivity of such reservoirs. All productivity calculations must allow for this effect (Kalaydjian, Bourbiaux et al. 1996, Kamath 2007, Mott 2003).

The phase change resulting from compositional variations impacts on reservoir and wellbore parameters involved in gas condensate flow modelling. The parameters mainly affected are the fluid and rock properties which govern the productivity of such fluids from the reservoir to the wellbore. The study of gas condensate depletion by many researchers (Fevang 1996, Mott 2002, Jokohio and Tiab 2002, Shi et al. 2006) over many years has shown that analytical models are inadequate in modelling productivity of gas condensate. The most successful attempts have resulted from the use of semi-analytical models as the physical phenomena controlling multiphase flow lack a complete mechanistic mathematical description, making the use of complete analytical models impossible (Niemstschik, Poettmann and Thompson 1993, Panfilov 2003, Penuela and Civan 2000b). This is why most older and recent publications still refer to condensate as a complex reservoir fluid. Another reason why condensate is referred to as complex reservoir fluid is because of the retrograde behaviour phenomena. The depletion process in which at pressures below the dew point, condensate instead of vaporising condenses into liquid and if the pressure is further reduced re-vaporises is known as retrograde behaviour. For the fact that in the 21st century, condensate is still being referred to as a complex reservoir fluid by the leading Investigators in the field indicate a huge gap in knowledge, and provides a motivation for this work.

The decision to develop a gas condensate field is usually based on the productivity of condensate not gas recovery because of condensate's higher market value which brings additional income to the investor. In this regard, for field development every investor would like to know how much he will be able to recover from such fields. Complexity of flow, compositional and phase changes associated with production of gas condensate systems do not permit a quick answer to such a question because of lack of accurate semi-empirical models that could give quick and accurate well deliverability figures.

One way to answer such question is the use of a state-of-the-art method for predicting well productivity in gas condensate reservoirs by operators who can afford it. This is accomplished by fine grid numerical simulation, whether for a single well or for full field models with local grid refinement. Though numerical simulation is suitable for detailed modelling of reservoir behaviour, it is not feasible in many applications. Data requirements for setting up the simulation models are not only huge but also expensive and tedious in sourcing and sometimes are not available at certain required reservoir condition of interest. The associated sampling error in deep offshore water and the in-experience of the laboratory analyst have been widely reported (Schebetov, Rimoldi and Piana 2010, Minhas et al 2009, Shokir 2008, Kabir and Pop 2007). Some of the available commercial simulators are still using reservoir fluid (PVT) property correlations that have been proven prone to error by current research. This is one area that was looked into seriously in this research as most of the oil industries are now totally software driven. As a result focused effort was put into developing condensate PVT and rock property correlations needed for gas condensate reservoir simulations.

1.1.2 Challenges of gas condensate reservoir management

Black oil model is a modelling method in which oil and gas phases are represented by a single component. The basic assumption of this model is that the compositions of oil and gas components are constant with pressure and time. The concept of black oil models have been applied to modelling condensate productivity but have been found to be inadequate (Izgec 2003).

Gas condensate modelling moved on to a modified black oil (MBO) approach. It is important to recall that the black oil modelling concept works back from PVT parameters, density, gas oil ratio (GOR), viscosity measured at the surface conditions to predict down-hole properties to account for process changes. The above concept is the basis for semi-empirical modelling. The limitations as to the range of data used in developing the models notwithstanding, the advantages are many. The attraction towards the use of semi-empirical models is that it gives quick and accurate solutions to well deliverability modelling to allow for quick decision on production strategies even at well site. These models are easily adaptable to spread sheet calculations using Excel and other software.

The works of Fevang and Whitson (1996), Mott (1999), Mott (2003), Jokhio, Tiab, and Escobar (2002), Mott (2002) and others have made major contribution to the use of semi-analytical models in modelling well deliverability in gas condensate reservoirs.

However Fevang’s and other models cannot be easily used for real time monitoring of well performance as most of them require measured PVT and rock properties to be used. The problems of use of measured data have been earlier highlighted. Apart from being tedious and not available at certain reservoir condition of interest for optimization purposes, are not affordable for private investors. The need for accurate correlations for critical fluid and rock properties, PVT and relative permeabilities required for well deliverability prediction are highlighted by the above problem.

Some available productivity models for wells use static relative permeability models to predict inflow performance by assuming irreducible water saturation in the reservoir and applying two phase relative permeabilities for multiphase condensate deliverability prediction. This assumption may not be correct for condensate reservoirs as water production may start even from day one. This suggests that the use of dynamic three phase relative permeability correlations may be more appropriate for condensate well deliverability prediction below the saturation pressure.

There is an increasing need for the development of an efficient and reliable method for estimation of gas condensate well deliverability for research and production development studies, production optimization and for improved well deliverability prediction in gas condensate reservoirs.

The productivity of enhanced oil recovery techniques needs to be rapidly evaluated to ease decision making in the application of such methods to production strategy and overall production planning. The available well deliverability models do not have the capability of predicting condensate liquid flow below the dew point as they were developed for flow in the gas phase. They cannot characterise condensate flow below the dew point as they are developed for gas flow prediction. It becomes imperative to critically examine the key issues in modelling well deliverability to be able to propose reliable solutions for specific problems as it is not possible to solve all the problems in a single investigation.

1.2 Key issues and technology gaps

The critical issues in well deliverability modelling in gas-condensate reservoirs could be summarized under the following headings

(i) Sampling and PVT property measurement issues.

(ii) Mobility issues arising from reservoir thermodynamics

(iii) Retrograde influences on relative permeability

(iv) Choice of horizontal well equation for multiphase flow modelling

(v) Characterization and optimization of reservoir productivity

1.2.1 Sampling and PVT measurement issues

The difficulties associated with obtaining representative samples for determination of PVT properties in gas-condensate reservoirs from deep offshore fields are well known challenges in the industry (Sutton 1985, Sutton 2005, Sutton and Bergman 2006). The cost of PVT tests for this type of reservoir is only affordable for giant operators. The short-coming of use of laboratory approach in sourcing for PVT and rock properties favours the use of correlations, and informed the methodology adopted in this work. The cost effectiveness is a major attraction. Accurate correlations for key PVT properties for gas condensate well deliverability modelling are not available, and use of correlations developed for oil and gas is not reliable.

1.2.2 Retrograde influences on relative permeability

Relative permeability is the ratio of the effective permeability to a given fluid at a definite saturation to the permeability at 100% saturation (Ahmed 2006)

A key parameter that governs well deliverability in gas-condensate reservoirs is the relative permeability (Pope et al. 2000, Whitson, Fevang and Sævareid 2003). In single phase flow above the dew point pressure the use of absolute permeabilities is adequate as there are no relative permeability issues on well deliverability. The accumulation of condensate (condensate banking) in the reservoir as a result of depletion or production below the dew point pressure makes modelling of relative permeability prediction difficult (Maravi 2003). In spite of several publications on modelling well deliverability of condensate reservoirs there are still no valid relative permeability correlations for all the thermodynamic process conditions obtainable in gas condensate reservoirs. Most of the available models that have been applied to modelling performance prediction are static two phase models that have limited validity arising from the assumption of irreducible water saturation throughout the production life cycle of the reservoir. There is a need for a dynamic three phase model to accurately model condensate well deliverability below the dew point pressure where the retrograde condensation has the greatest impact on relative permeability

1.2.3 Choice of horizontal well equation for multiphase flow modelling

There are over 24 horizontal well equations available in the public domain for modelling reservoir inflow performance. Our approach to developing a fit for purpose model for effective reservoir inflow performance prediction was first to test the available horizontal equations. For this purpose twelve (12) horizontal well models were tested and it was observed that they closely agreed with measured production rates for a given reservoir under the same production conditions. This gave confidence not to develop a new horizontal well equation from the basic fundamental physics, but to focus on selecting the best fit-for-purpose horizontal well equation that can be modified to fit our purpose. The challenge here was that the entire 12 horizontal wells tested for condensate gave different production rate forecast for the same reservoir conditions and predicted rates different from the measured rates, suggesting that none of the equations or models was adequate, and selection of which model to use for modification became a major issue that were resolved in chapter six.

1.2.4 Optimization and characterisation of reservoir productivity

Operators and private investors are sceptical in investing in gas condensate reservoirs for lack of information on how to ensure optimum recovery (Thomas, Andersen and Bennion 2006, Thomas et al. 1996). The level of risk involved in investing in deep water offshore exploration with the attendant harsh environment coupled with retrograde characteristics that are difficult to model, does not encourage investors in this area. A model that can be used to reduce levels of uncertainty and define an optimum recovery production process is the challenge of this study.

The optimization and mobility issues are all related and tied to phase behaviour. The phase changes result in higher viscosity that reduces relative permeability and requires higher reservoir energy to produce the reservoir. As adequate correlations to predict the effect of these phase changes on the viscosity, compressibility factor for condensate are not available, appropriate production optimisation strategies are difficult to determine currently.

1.3 Research questions

The ultimate question that could be path of the future work which the study has given some solution insight is captured by Goktaps et al. (2010). They reported that in the Britannia field gas condensate reservoir located in the central North Sea, condensate accumulation near the wellbore as wellbore pressure dropped below the dew point could account for productivity loss of up to 60% within the first year before production stabilized. How much of such losses can be recovered is an aspect which this work provides a unique solution insight. Several studies confirm production of condensate below the dew point pressure (Jokhio and Tiab, 2002, Dawe and Grattoni 2007a, Jokhio, Tiab and Escobar 2002, Jokhio and Tiab 2002, Almarry and Al-Saadoon 1985, Dawe and Wilson 2005, Penuela and Civan 2000a, Jokhio et al. 2002). The challenge is how accurately well productivity can be predicted at these pressure conditions. Knowledge of the recovery which can be achieved by natural depletion is important, not only for fields that are actually produced by pressure depletion, but also for also for evaluation of probable pressure maintenance that could be used in the future (Curtis and Brinkley 1949)

The present study focused on modification of existing horizontal well gas rate equations for gas condensate well deliverability prediction and validation of the modified model. The approach prompts the following research questions;

(i) Whether models of adequate validity for efficient and effective well deliverability prediction could be developed from this approach?

(ii) How to make simple gas rate equations adequate for prediction of condensate production rate?

(iii) What other simpler approaches can be used to achieve accuracy in the prediction of well deliverability in gas-condensate reservoirs without the use of fine-grid numerical compositional simulators?

The problems posed by limited measurements of the PVT and the rock property data required for modelling well deliverability as indicated in the research questions have been addressed in this work through the following research aim and objectives:-

1.4 Research aim and objectives

1.4.1 Research aim

The overall aim of the research work is to accurately model well deliverability in gas condensate reservoirs using simple robust semi-empirical correlations.

1.4.2 Specific objectives

The following research objectives were outlined and addressed accordingly to achieve the defined research aim:-

(i) Development of required PVT property correlations, condensate compressibility factor, density, viscosity and formation volume factor for improved well deliverability prediction.

(ii) Sourcing and adapting a dynamic three phase relative permeability model for condensate.

(iii) Updating single phase gas vertical and horizontal well inflow performance models for well deliverability modelling in gas condensate reservoirs.

(iv) Carrying out parametric studies to determine the critical parameters that govern productivity of gas condensate reservoirs.

(v) Validation and comparison of improved model performance with a standard industry reservoir simulator.

1.5 Study scope

The study was limited to primary recovery through natural depletion. Any form of pressure maintenance, gas lift or water injection was not covered. The study did not cover the entire surface production facility network also. However it covered flow up to the wellbore as the last node. Emphasis was on optimizing production and conserving natural drive mechanisms within the reservoir.

1.6 Approach

The methodology adopted in the study included the following steps;

(i) The relevant literature was critically reviewed and evaluated to identify the key issues and technology gaps in modelling well deliverability in gas condensate reservoirs. This helped in shaping the aim and objectives of the research to keep abreast with the state-of-the-art technology in research and development of well performance in gas condensate reservoirs.

(ii) Sourced laboratory measured and field data bases were sourced for development of required PVT and rock properties correlations for improved well deliverability prediction. The PVT property correlations were developed calibrated and validated using the database.

(iii) A dynamic three phase relative permeability model was developed for flow in gas condensate reservoirs.

(iv) An extended single phase gas inflow performance model for well deliverability in gas condensate reservoirs.

(v) Parametric studies were carried out to determine the critical parameters in gas condensate reservoir modelling for vertical and horizontal single well models.

(vi) Validated and Compared modified model performance from the above integrated steps of the objectives with standard industry reservoir simulator.

1.7 Rationale and technical relevance

Huge investment is required in development of gas condensate reservoirs. Security of these investments is the immediate concern of every operator. A step towards guaranteeing these investments could be achieved with accurate forecasting tool to ensure feasible field development plan for optimum production and sustainable cash flow.

The justification for this research could be summarised as follows;

(i) For rapid forecasts of well deliverability and for sensitivity studies to determine impact of some reservoir parameters on reservoir performance, semi-empirical models are more attractive than fine-grid numerical simulation.

(ii) Where accurate fluid and rock property data are not available, semi-empirical modelling appears to be the most feasible option.

(iii) Well productivity modelling as a first step in effective reservoir management are required to select best field development plan and production management strategy through accurate production figure forecast which are useful in determining the asset and market value of fields. This is not possible without accurate well deliverability model.

(iv) The study is in line with the current industry real-time reservoir production management strategy and software driven trend.

(v) It will serve as a tool for assessment of the performance of the various enhanced condensate recovery techniques currently embarked on in the industry and a general research tool for production optimisation

(vi) To correct for general inaccuracy in prediction of well deliverability due retrograde condensation below the dew point pressure.

1.8 Order of presentation

Chapter 1 Gives the research background of the study, highlighting the critical issues, technology gaps, challenges, aim and objectives, scope, technical relevance and order of presentation.

Chapter 2 Critical review and evaluation of previous published work and summary of different points of view on the subject matter as found in the available literature. General conclusions on the state of the art technology on gas condensate reservoirs as at the time of this writing, and core concepts in predicting well deliverability were defined.

Chapter 3 Approach and the conceptual frame work. Overview of all the methodologies used in the study.

Chapter 4 Review and development of key PVT property correlations, including compressibility factor, molecular weight, density, viscosity, compositional pseudo-pressure and formation volume factor.

Chapter 5 Modelling rock properties and dynamic three phase relative permeability for condensate and absolute permeability

Chapter 6 Developed fluid property correlations were implemented in the horizontal well models and parametric studies under taken to determine the critical parameters in condensate well productivity.

Chapter 7 Comparison of the developed correlation performance with standard industry simulators, for validation of the semi-empirical modelling approach

Chapter 8 Conclusion and recommendation for future studies were made in this section. These were followed by references and finished with appendix that show computer codes, experimental databases and sample calculations performed in the research work.

CHAPTER TWO

2.0 LITERATURE REVIEW

2.1 Introduction

A critical literature review was carried out to identify and summarize the different points of view on the subject matter as found in available literature, and to critically evaluate these views and make general conclusions on the state-of-the-art technology of well deliverability modelling

Optimizing the development of a gas-condensate field presents complex challenges, when depletion leaves behind valuable condensate fluids in the reservoir (Fan et al. 2006) and condensate blockage can cause a loss of well productivity from 30- 60% (report from a recent workshop in Moscow), causing the reservoir to choke on its most valuable component, condensate liquid. The understanding of the fluids and how they flow in the reservoir is critical for solving these problems and for modelling well deliverability in gas condensate reservoirs. The sensitivity of gas condensate to changes in pressure is a key factor in prediction of well delivery because of its role in the compositional and phase changes involved in production.

The importance of the liquid product, condensate, and the need for accurate prediction of delivery to ensure adequate field development planning has become the subject of concern of several researchers and field developers, and led to many good papers being published on the subject (Fevang and Whitson 1996, Barnum et al. 1995, Kamath 2007, Mott 2003, Jokhio, Tiab and Escobar 2002, Singh et al. 2000, Aziz 1985, Bengherbia and Tiab 2002, Coskuner 1999, Dehane and Tiab 2000, Eaton and Jacoby 1965, El-Banbi et al. 2000, Kabir and Hasan 2006).

Gas condensate wells producing at a flowing bottom-hole pressure below the dew point suffer a more rapid decline in productivity than that predicted in theory for dry gas wells. The loss in productivity is caused by a liquid hydrocarbon accumulation near the well bore, known as condensate banking due to reduction in bottom-hole pressure as production progresses. This poses a challenge to accurate well deliverability prediction which is a key business activity in the Oil and Gas-industry. Prediction of well deliverability in gas condensate reservoirs is one of the first steps in effective reservoir management and the overall field development plan (Craft, Hawkins and Terry 1959).

2.2 Scope of research problem

The complications of modelling phase, behaviour and flow patterns of hydrocarbons near to the well bore and close to the critical region operating conditions has provoked a lot of research resulting in many published gas-condensate deliverability models which require much fine-tuning of the Equations of state (EOS) used. These models continue to undergo further development in an effort to improve precision the precision of equations of state deteriorates near the critical region (Ahmed 2006, McCain 1990, McCain 1991, Elsharkawy 2006) and this is why EOS has to be tuned to match the actual laboratory measured PVT properties. The result of these modifications and derivations are usually long and complex models, especially when dealing with condensate saturations in the reservoir and its effect on flow patterns. Apart from deterioration near the critical region EOS involves numerous computations.

At best the existing models are generally not simple. Their application requires many parameters that cannot be directly measured or easily predicted such as instantaneous gas condensate ratio, multiphase pseudo-pressure and condensate relative permeability thereby limiting the use of such models. In some cases the models are radical solutions rather than practical solution involving complex mathematics with imaginary solution which may be of no immediate practical importance to the industry.

In the first instance, a gas condensate rate equation was developed through extension of the standard gas rate equation. Since the focus of study was developing the well deliverability model for gas condensate reservoirs assuming multiphase flow under pseudo-steady state flow conditions using the modified gas rate equation, the PVT properties were identified as the critical variables that make the modelling of gas flow different from condensate flow. This is because the gas rate equation is a black oil model and condensate reservoir below the dew point pressure is a multiphase system where black oil model is not valid as the composition varies with changes in reservoir pressure. Appropriate PVT property correlations were developed for condensate and implemented in the gas rate equation to correct for inadequacies of the gas models which assumes no compositional variations during pressure changes in the reservoir. This assumption is not valid for condensate reservoirs and the major modification effort was on taking this into account.

Whether condensate flow rate models/correlations of adequate validity and accuracy could be developed by use of modified gas PVT property correlations was a major research consideration. This was followed by consideration of the implementation of the improved PVT and relative permeability correlations for modification of gas inflow performance relation as a step for accurate prediction of well deliverability in gas condensate reservoir. The hypothesis of the study is that the use accurate PVT property and relative permeability correlations capable of accounting for large variability in gas-condensate reservoir fluid properties at different reservoir conditions may contribute to improved accuracy in prediction of well deliverability in gas-condensate reservoirs.

The following critical review of previous work on the subject informed the above research direction;

2.3 Well deliverability modelling methods

Recognizing that classical analytical methods for dry gas wells do not apply for the multiphase conditions of a gas condensate well, several semi-analytical methods have been proposed. The approaches used by most of their models ranged from semi-analytical, to two phase pseudo-pressure methods.

The traditional dry-gas methods have commonly been used for modelling and data interpretation in gas-condensate reservoirs up to the point where multiphase flow effects become important (Ali, McGauley and Wilson 1997b, Ursin 2007, Yu et al. 1996).

However, methodologies and technologies based on numerical and analytical models have been employed to define, simplify and overcome the complexities of compositional dependence of fluid flow, though analytical solutions have limited success in accurately quantifying the impact of the retrograde condensation. The principal advantage of a compositional numerical method over analytical methods is in determining and understanding relative effects of variable and parameters controlling /governing well deliverability. The compositional model has the capability to monitor the saturations of each component at all reservoir depletion stages. This is not possible with the analytical model.

The most accurate way of calculating gas-condensate well productivity is by fine grid numerical simulation either in single well models with a fine grid near to the well, or in a full field models using local grid refinement. However, while numerical simulation using Eclipse compositional is suitable for detailed forecasting of reservoir behaviour, there are many applications where this level of modelling is not justified, and simpler engineering calculations are more appropriate (Mott 1999). Simple engineering calculation approaches may also be very useful where accurate data on reservoir, fluid or rock properties for full scale compositional simulation are not available. The advantage of the current approach proposed in this work is that the algorithms for prediction of the non available PVT and rock property data required for modelling and simulation of well deliverability is implementable in Excel spread sheet.

In spite of the complexity of the retrograde condensate reservoir behaviour, the subject has attracted several publications, including (Dehane and Tiab 2000, Dawe and Grattoni 2007b, McCain et al. 2000, Shi et al. 2010, Silpngarmlers, Ayyalasomayajula and Kamath 2005, Whitson and Kuntadi 2005, Zeidouni et al. 2006, Zoghbi, Fahes and Nasrabadi 2010). The first numerical modelling of radial gas-condensate well deliverability were done by Kniazeff and Naville (1965). The ability to predict well deliverability is a key issue for the development of gas-condensate reservoirs (Bozorgzadeh and Gringarten 2007)

The early historical development efforts for inflow performance relation can be traced back from Gilbert to Vogel (black oil, solution gas-drive mechanism) and up to the present stage.

The first gas rate equation based on pseudo pressure function to account for condensate banking was introduced by O’Dell and Miller (1967) in which they demonstrated the severity of deliverability reduction as a result of condensate banking.

It was noted that O'Dell and Miller's model was unable to predict the saturation profile in the two phase region correctly (Fussell 1973). They went further to show that the productivity of the condensate well predicted by O'Dell and Miller was much smaller than the productivity of gas-condensate reservoirs. Fussell used a compositional simulation to conclude that O'Dell and Miller's work could be used to predict sand face saturation only when the gas saturation in the multiphase-phase region is the same with the initial fluid composition. This is not possible for depletion of the condensate reservoir below the saturation pressure.

Jones and Raghavan (1996) showed that with the transformation of pressures to pseudo-pressures, the drawdown pressure responses from retrograde condensate system could be correlated with classical liquid solution. In spite of this development, the reservoir integral is just a theoretical tool and cannot be used for analysis since it requires advanced knowledge of the reservoir pressure and saturation profiles. Also they showed how two phase steady state pseudo-pressures can be used to estimate reservoir flow capacity (kh).

The work of Raghavan et al (1995) which involved the simulation and analysis of many fields concluded that their method was suitable for reservoir pressures much higher than the dew point pressures.

The following equation;

$$q_g = \frac{1}{141.2} \frac{kh}{\left[\ln(r_e / r_w) - 3/4 + s\right]} \int_{p_{wf}}^{p} \left[\frac{k_{rg}}{\mu_g B_g} + R_s \frac{k_{ro}}{\mu_o B_o} \right] dp \qquad (2.1)$$

was proposed by Fevang and Whitson (1995) as a gas flow rate equation employing pseudo-pressure function for gas-condensate flow. This equation is complex in terms of requiring many input parameters for application and the method of evaluation of the pseudo-pressure integral. The equation is also more of an analysis tool than a predictive tool since the pressure integral and the saturation dependent function cannot be known in advance. Fevang's contribution has been significant for introducing the transition zone, where both condensate and gas are present but only the gas flows. Fevang and Whitson also introduced the two phase pseudo-pressure, which does a separate calculation for each of the three regions defined and using pressure saturation relationships. The initial value of producing gas-condensate ratio (GCR) was assumed for the three zones in his approach. The short comings of the assumptions and requirements for GCR prompted for development of a modified approach by Robert Mott (2000)

The simulation work of Coats (1985) for gas-condensate gave a ground breaking but controversial result. It showed the result of a full compositional equation of state (EOS) model pressure, volume and temperature formulation for natural depletion above and below dew point giving the same result as Black-Oil PVT formulation. However, cycling below the dew point using two-components simulation gave inaccurate results, meaning that the two component approach was incapable of modelling the resulting large compositional gradients.

Fevang and Whitson (1995) hinted that Coat's result should be taken with caution as EOS characterisation uses seven components with one C_{7+} fraction (hydrocarbon mixture group components with carbon numbers higher than 6 eg. C7, C8, C9). This is because condensate viscosity difference between black-oil and compositional formulations often yield noticeable difference in well delivery in more detailed C_{7+} split. This informed the need for the developed procedure for condensate viscosity in this study, as errors in viscosity prediction could mean corresponding errors in condensate productivity prediction.

The result obtained by Fevang et al (2000) gave support to Coat's findings, but significant differences in condensate recovery predicted by compositional and modified black oil (MBO) models were found for downstream cases of increasing permeability and very rich gas-condensate.

In a full field simulation study of rich gas-condensate reservoir, El-Banbi and McCain (2000) compared the performance of modified black oil (MBO) model with that of a compositional model in the presence of water influx and also conducted a field wide history match study. They suggested the use of MBO irrespective of the reservoir fluid complexity. The study is in line with the above suggestion and went further to validate the numerical model with semi-empirical models developed in this work.

A number of publications are available for vertical well test in gas-condensate reservoir but not in horizontal wells where there is yet to be any publication on analytical modelling (Hashemi, Nicolas and Gringarten 2004).

The use of large grids for field studies by most commercial compositional simulators omit local detailed descriptions necessary for the explanation of flow behaviour around well-bores which may result in less accurate predictions. Other problems of some simulators include restrictive assumptions like steady state flow, and negligible capillary-number dependency of relative permeability. The models in use include semi-implicit, equation of state (EOS) based compositional, one dimensional radial simulator, and Peng-Robinson equation of state (PR-EOS).

A recent study by Kamath (2007) outlined five steps in predicting deliverability loss caused by condensate banking to include appropriate laboratory measurements, fitting laboratory data to relative permeability models, use of spreadsheet tools, single well models, and full field models (FFMs).

In the absence of adequate experimental data, spreadsheet tools should be used as the first step in understanding whether condensate banking will affect well deliverability significantly and whether detailed compositional simulation is warranted (Kamath 2007). The suggested methods though are improvements on earlier methods, partly rely to an extent on experimental data, and are still expensive, so simple and accurate methods that do not rely heavily on experimental data, are still needed. Simulation studies have shown no significant difference between extended black oil and compositional simulator results for gas condensate reservoirs under depletion (Mott and Cable (2002) for condensate reservoirs above dew point pressure. Therefore the use of black oil model as the basic frame work for development of an improved predictive model for well delivery in gas-condensate reservoir below the dew point pressure is justifiable.

The effect of gas-condensate blockage region on deliverability depends on pressure, volume, temperature (PVT), absolute and relative permeabilities, and how the well is being produced.

Well-bore effects often reduce considerably the productivity of wells in gas-condensate reservoirs, and are impractical to model analytically because of the complicated and highly coupled phase and flow behaviour (Penuela and Civan 2000). In this case, numerical simulation and semi-analytical models are the most likely candidates to be used to forecast reservoir performance under different conditions.

2.4 Parameters affecting flow in gas condensate reservoirs

Productivity above the dew point pressure depends on the reservoir mobility ratio, represented as Mobility Ratio= $\frac{Permeability(K) \times thickness(h)}{Vis\cos ity(\mu)}$ for normal dry gas reservoir, but below the dew point, it is controlled by the critical condensate saturation, the shape of the gas and condensate relative permeability curves and non-Darcy flow effects (Hashemi et al 2004).

2.4.1 Relative permeability correlations

The most important variable that governs the productivity of gas-condensate reservoir below the dew point pressure is the relative permeability (Pope et al. 1998, Mott 2000, Mott 1999, Mulyadi et al. 2002). Condensate banking and associated productivity reduction complicates relative permeability prediction. The complexity of determination of this important variable required in modelling well deliverability is the major attraction of research in this area of study.

The fundamental works of Darcy is still the major theoretical frame work for evaluation of relative permeability of flow in a porous media. However several researchers have proposed correlations for relative permeabilities of oil, and gas in gas-condensate reservoirs. The works of Muskat (1981), Fussell (1973) App and Mohanty (2002) and other related work formed part of the theoretical frame work for this study. Others were the works of Bourbiaux (1994), Henderson et al. (2000), Nikravesh and Soroush 91996) . Most of the work highlights the problems of the use of conventional method, which the use of core flood experiment in estimating relative permeability apart from being difficult is expensive, yet the accuracy questionable.

Multiphase flow in the well bore poses major challenges to production engineers because of difficulty in characterising of the prevailing flow regime which determines the appropriate pressure drop calculation type to be used (Sadeghi, Gerami and Masihi 2010). This is related to the relative permeability issues in the reservoir.

Field experience shows that operating conditions and rock fluid property changes, can lead to major productivity losses in gas-condensate reservoirs. These effects have been extensively studied in the last three decades (Fussel, 1973, Hagoort 1988, Penuela and Civan 2000) and some practical solutions have been proposed. However, analysis of well test results have shown that simulation with conventional relative permeability models tends to under estimate well productivity (Mott et al. 1999, Afidick et al. 1994) implying that there is still need for further research in gas-condensate well modelling to accurately predict the near well bore fluid behaviour and its effect on well productivity.

Available correlations, Mott (2000), Fevang (1995) and Pope (2002) for gas-condensate relative permeability are mostly for 2-phases, as most of the models have assumed irreducible water saturations resulting in a static relative permeability models. This assumption is made to simplify gas-condensate modelling and may not be completely valid for gas condensate reservoirs, as in majority of cases water production during depletion of gas condensate reservoirs starts from day one to abandonment pressure. To correct for the above assumption, three phase relative permeability has been sourced for and developed in this work.

Bourbaiux et al (1994) and (Kalaydjian et al. 1996) measured the critical condensate saturation (Scc), gas (Krg) and condensate (Krc) relative permeabilities using laboratory methods. For the case they studied they observed that the critical liquid saturation remained constant at 26% of pore volume and noted the relationship between the Scc and Swi, the initial water saturation.

Other methods tested for applications to the study include Mott et al (2000), Pope (2000), and Corey correlations. None of the correlations tested were adequate. Alternative fit for purpose model was sourced for and upgraded for the study for prediction of three phase relative permeability in gas condensate system.

2.4.2 Condensate phase behaviour concepts

A typical phase diagram for multi-component and for different classes of reservoir fluid is illustrated as in figure 2.1.

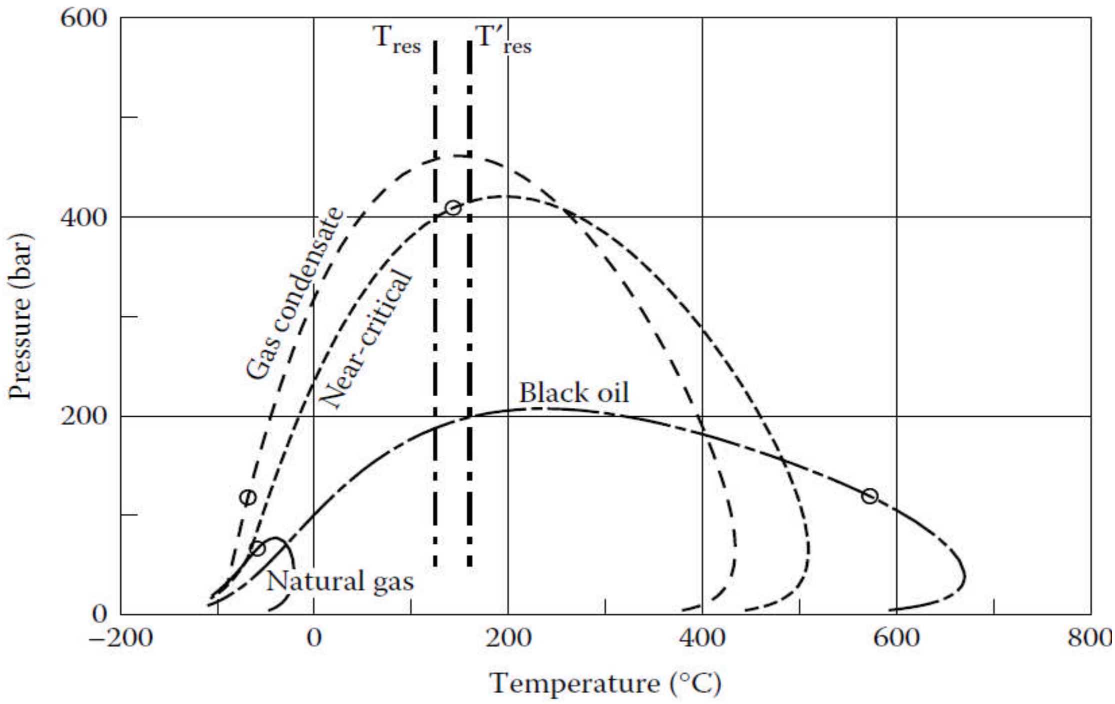


Figure 2.1 Phase envelopes of different classes of hydrocarbons (Pedersen and Christensen 2007)

The shape of the phase envelopes varies widely with the composition of the class of the reservoir fluid. The reservoir temperature and pressure in relation to critical and saturation pressures and temperatures are part of the basic parameters in defining the reservoir fluid class.

The abnormal or retrograde behaviour of gas-condensate are usually located in a region between the critical point and cricondentherm, bounded by the dew point curve above and curve below connected from the maximum temperature for each percentage volume of the liquid (Ahmed 2006).

The knowledge of phase behaviour is essential for the reservoir engineer to be able to plan the optimum production strategy for condensate field development. The conditions that govern these phases or state are of considerable practical importance (Ahmed 1988, Ahmed 1989). The fluid properties shape the exploitation strategy for evaluation of the entire production system (Ali, McGauley and Wilson 1997a). The phase diagram determines quantitatively the likely fluid phases in the reservoir at various conditions of temperature and pressure. However the temperature is usually constant in the reservoir because the reservoir is large and acts as a sink.

Approaches that are widely used to simulate mass transfer between phases within the envelope as temperature and pressure changes within the reservoir include; the black oil or constant composition model and the compositional model (variable composition model). A link model between these two concepts is a principal objective of the present work. Figure 2.2 gives a good illustration of phase conditions in the reservoir where black oil modelling approaches are not adequate for prediction of volumetric phase behaviour in gas-condensate reservoirs.

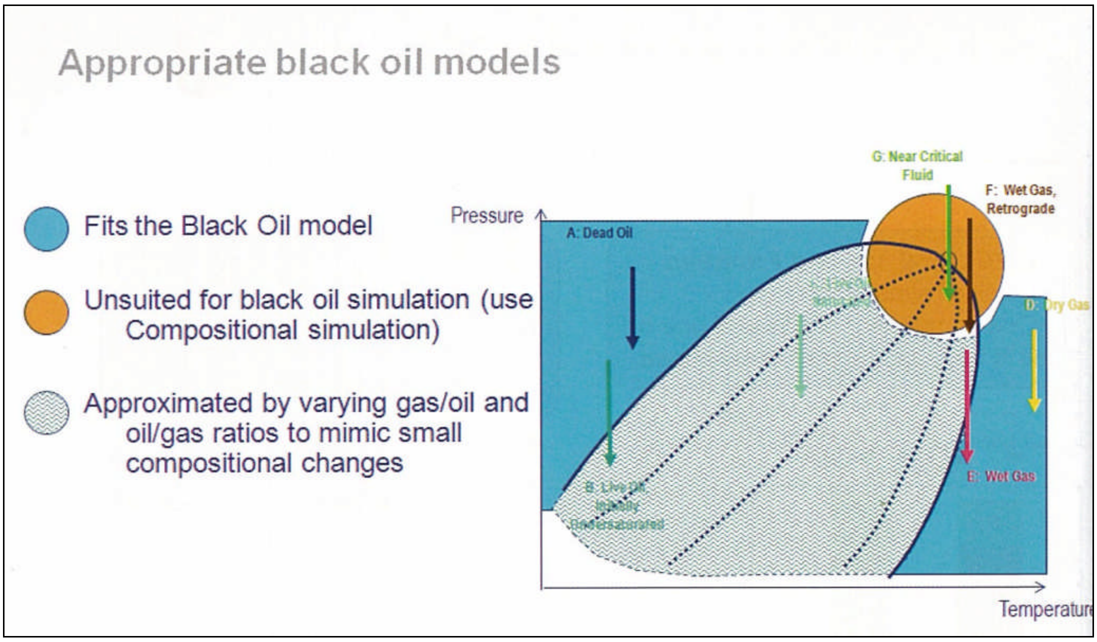


Figure 2.2 Regions where black oil models are not adequate for gas-condensate reservoirs (Schlumberger Petrel, 2009)

The phase diagram can be determined experimentally; by use of correlations or use of Equation of state (EOS) methods. However any of the methods has its own limitations. All the methods can be used to determine other relevant PVT properties of the reservoir fluid that dictate its phase behaviour. For a complete picture, there is need to recall that reservoir fluids are complex mixtures of hydrocarbons. The components determine the mixture PVT properties which controls the phase behaviour. Equations of state and experimental methods were not applied for prediction of our PVT properties in this study for reasons that will be detailed in relevant sections of this work. On cost considerations, correlations were applied to predict most of the PVT property data used in this study.

Reservoir performance in gas-condensate reservoirs are strictly governed by phase behaviour of the reservoir fluid (Ikoku 1984). Therefore a good understanding of the phase behaviour is a minimum knowledge requirement for effective and efficient recovery of gas-condensate reservoir. The critical areas that need be studied for optimum management of gas condensate reservoir include;

(i) Prediction of PVT properties of gas condensate using equation of state and validated correlations

(ii) Laboratory phase behaviour studies.

The information gathered from the two sources above are important in all aspects of modelling and simulation of gas-condensate reservoirs, optimization and design of new wells.

2.4.3 Prediction of phase behaviour with Equation of State (EOS)

Usually in practice, liquid and vapour phase behaviour in the reservoir are modelled by EOS methods (Lake and Fanchi 2007). The commonly used equations of state in the industry are the Peng-Robinson (Stryjek and Vera 1986), and the Soave-Redlickh-kwong EOS.

EOS has been found to generally require tuning of its parameters to match experimental data as a result of uncertainties arising from the plus fraction of reservoir fluids in its molecular weight and critical properties (Al-Meshari

2004). Tuning EOS helps in improving the predictions of compositional reservoir simulators. EOSs have been developed for different reasons, however most of the reason could be summarised as below;

The objectives of search for EOS include:

To find a single EOS;

(i) whose form is appropriate for all gases

(ii) that has relatively few parameters

(iii) that can be readily extrapolated

(iv) that can be adapted for mixtures

This objective is yet to be fulfilled even with the development of hundreds of EOSs after Van der Waals (Uidaho 2008).

Notwithstanding these limitations, EOSs have been extensively applied for phase behaviour studies in the industry. The detailed review of all the applications are actually beyond the scope of this study. However an attempt has been made to cover those applications that are of immediate relevance The modified EOS was used to study gas-condensate phase behaviour (Sarkar et al. 1991). They found a better prediction of the dew point and condensate volumes for the studied cases without using any binary interaction parameters.

Ahmed (1989) and Ahmed (1991) modelled gas-condensate systems with eight EOSs. He compared the predicted PVT properties from the eight EOSs with experimental data of four gas-condensate hydrocarbon systems. A reliable compressibility prediction was got from Patel-Teja (1982), Valderrama (1990) and Schmidt-Wenzel EOS (1980), and part of the conclusion was that the Schmidt-Wenzel EOS was better for prediction of volumetric properties than other EOSs and recommended them including Peng and Robinson (1976) for predictions of vapour liquid equilibrium studies.

Wang and Mohanty (2000) recommended a better method of tuning EOS for matching experimental phase behaviour of gas condensate systems to ensure accurate well deliverability prediction from reservoir simulations.

A new method of predicting pseudo critical properties of gas condensate fluid and input properties for calculation of gas-condensate compressibility factor was introduced by Elsharkawy et al (2000) from a study that used 1200 gas-condensate compositions for investigation of several methods of modelling two phase compressibility factor for gas-condensate systems. Part of the above approach was modified for prediction of compressibility factor in this study. Other relevant applications of EOS to gas condensate systems include but not limited to Lindeloff et al. (2010), Pederson et al. (1996), and Arcia et al. (2004), Pedersen, Michelsen and Fredheim (1996), Pedersen and Milter (2004), Lindeloff and Michelsen (2003), Sunil, et al. 2000, Arcia, Rodriguez, et al. 2004)

2.5 Gas condensate PVT property modelling approaches.

2.5.1 Introduction

Petroleum reservoir fluids are multi-component mixtures of hydrocarbon and non hydrocarbon compounds. They can be classified as gases, gas-condensate, volatile oils and black oils. Condensate is petroleum liquid at normal temperatures that mostly consists of pentanes and heavier hydrocarbons. However, definition of condensate has been controversial among OPEC countries (Lake and Fanchi 2007). Our mission here is not to go into that controversy but to get a picture of how condensate acquires its properties. The component mixtures that make up this class of hydrocarbon or the compositions determine the properties of the mixture which in turn determine the phase behaviour. A unique behaviour of gas-condensate reservoirs is retrograde condensation. The condensate PVT properties of interest that dictates the phase behaviour here include; the compressibility factor, viscosity, density, apparent molecular weight, and other pseudo critical and reduced properties. The key PVT properties of gas condensate control the recovery and well performance of the reservoir (Wheaton and Zhang 2000). Knowledge of these PVT properties values is indispensable in reservoir modelling and simulation, material and energy balances, process optimization and design of new wells. Predictions of PVT properties are usually targeted for modelling the volumetric phase behaviour for evaluation of recovery factor for investment decisions. The various approaches to modelling gas condensate PVT properties could be summarised under the following subheadings;

2.5.2 Compositional and gas gravity correlations

The compositions of gas-condensate reservoir are determined from PVT tests, which in gas-condensate reservoirs involve constant composition expansion (CCE) for conditions above the saturation pressure (the dew point); this is also known as Constant Mass Expansion (CME) test. It is used to measure single phase compressibility factor, Z, dew point pressure, and condensate relative volume. The constant volume depletion (CVD) at reservoir conditions below the dew point (the saturation pressure) PVT test is also used in determining gas condensate compositions. These processes are expected to replicate the reservoir processes but CVD is valid only when the liquid drop out in the reservoir is never produced to the surface. But at condensate liquid saturations above the critical in the reservoir, the liquid condensate is producible at the surface and invalidates the CVD assumption of zero liquid production at the surface. The test is also used to study the phase changes and volumetric behaviour of the reservoir fluid sample at the reservoir temperature as pressure varies. The test is supposed to simulate the actual behaviour of the gas condensate reservoir produced by natural pressure depletion (Ahmed 2007). The results of the CVD test can be directly used to calculate gas and condensate recoveries in relation to changes in reservoir pressures. The single phase z-factor obtained from the CCE test, and the two phase compressibility factors obtained from CVD are used to accurately model the depletion behaviour or profile of the reservoir from initial pressure to abandonment.

Several researchers Elsharkawy (2000), Sutton (1998), Sutton (2005) have applied the compositions from CVD approach successfully in predicting PVT properties. It has been pointed out that the use of gas gravity is more prone to errors than use of hydrocarbon mixture compositions but on cost consideration, is attractive as determination of condensate composition is not only tedious, time consuming but also expensive. The correlations developed in this research though based on PVT data from world-wide sources could have some geographical limitations but could be tuned to experimental data to increase the range of application. In reservoir engineering it is always recommended to validate any correlation before use. Most of these correlations including compressibility factor, density, viscosity, formation volume factor and compositional pseudo-pressure for condensate have been tested and improved upon in this study.

2.5.3 Applications of Equation of State (EOS) to hydrocarbons.

We have earlier discussed the applications of EOS but at this juncture it is important to add that EOSs have the advantage of using a single equation to calculate k-values, compressibility, density, and viscosity unlike some correlations, and viscosity prediction does not depend on density in EOS. Dependence of viscosity correlation on density correlation could introduce error into viscosity calculation as density calculation errors are automatically transferred to viscosity correlations. EOS had more mathematical consideration than hydrocarbon phase behavior physics in the development which is evident in several fudge factors in EOS for purposes of matching experimental data. These make the use of EOS in determining fluid properties difficult and time consuming and requiring a lot of input data for prediction. Tuning EOS requires skills and experience. EOS require correction factors to be valid for complex hydrocarbon mixtures as they were originally developed for pure components and extension to mixtures became crucial to make EOS valid for evaluation of hydrocarbon fluid properties (Danesh 1998, Firoozabadi 1999). Such correction factors incorporated into EOS to make it valid for hydrocarbon mixtures include; acentric factors, binary interaction coefficient, and mixing rules.

2.5.4 Laboratory experimental approach

Under normal circumstances, PVT properties are supposed to be sourced from Laboratory tests, but because of sample collection difficulties and sensitivity to pressure problems typical of gas-condensate reservoirs, this approach is un-attractive. Some measurements are not possible at certain reservoir conditions. The cost of measuring viscosities of complex hydrocarbon mixtures in the laboratory can be prohibitive (Ali 1991). Splitting of C7+ heavy fractions are also required for proper characterization, requiring additional expertise, time and money, making it unaffordable for private investors except for big operators.

2.6 Production of condensate liquid below the dew point

It was commonly believed that production of liquid condensate reservoirs below the dew point pressure could significantly limit reservoir performance in producing gas and liquid condensate (Elliot et al 1998). Strong technical arguments and field analogies that support production strategies that yield efficient recoveries at pressures below the dew point have been reported. by Elliot as well. Also reported was the confirmation of mobility of condensate that dropped out of the gas phase below the dew point pressure by BG Technologies. In 1995, Agip and BG Oil producing companies have produced six condensate wells at Karachaganak Field below the dew point pressure and no reduction of condensate gas ratio has been reported (Elliot et al.1998). In addition several researchers have reported extensively on modelling liquid condensate flow and productivity (Jokhio and Tiab 2002, Dawe and Grattoni 2007a, Almarry and Al-Saadoon 1985, Dawe and Wilson 2005, Penuela and Civan 2000a, Jokhio et al. 2002).

CHAPTER THREE

3.0 METHODOLOGY AND CONCEPTUAL FRAME WORK

3.1 Introduction

The chapter highlights problems addressed in this work and the short-falls of existing methodology. An approach to modelling well deliverability in condensate reservoirs and the conceptual frame work to this approach is described in brief and will be detailed in relevant chapters. Consistent and systematic technical approaches followed in the selection of suitable methods for each of the major work steps are detailed in relevant sections of the following chapters.

Case studies have been used to demonstrate practical applications of developed and adopted methodologies. Data requirements and sources for this work were briefly discussed.

3.2 Approaches to modelling well deliverability

The reservoir temperature in a gas-condensate reservoir lies between the critical temperature and the cricondentherm temperature (temperature beyond which liquid cannot exist) for the reservoir fluid. Production /depletion of the reservoir below the dew point pressure results in the phase behaviour known as retrograde condensation in which condensation occurs on pressure reduction rather than vaporisation as for a pure fluid. The retrograde behaviour occurs in a region between the critical point and cricondentherm, bounded by the dew point curve above and below by a curve defined by connecting the maximum temperature for each liquid volume percent or fraction (Brill and Murkherjee 1999). The retrograde condensation complicates the hydrocarbon mixture thermodynamics. The engineering of well deliverability in gas-condensate reservoirs becomes difficult as well. An attempt to accurately model the mass transfer between the liquid and gas arising from reservoir pressure changes has been a reservoir engineering challenge over the years.

The two popular conventional approaches normally used to simulate mass transfer of hydrocarbon system are the black oil, (constant composition) and compositional (variable composition) models.

3.3 Black oil model (Constant composition)

The black oil model assumes that the reservoir fluid has only two Pseudo-components, oil and gas. The only component of the gas phase is gas, while the oil phase includes oil and gas dissolved in the oil. Black oil model also assumes that the oil component cannot be dissolved in the gas phase and no compositional changes of gas or oil occurs as a result of pressure changes. These assumptions are not valid for condensates and volatile oils thereby limiting the application of this model (Izgec 2003).

The concept works back from measured values of density and gas oil ratio at the known surface conditions to simulate properties at other conditions occurring down-hole. Conventional black-oil models are known not to accurately model volatile oil and gas condensate reservoirs. As a result modified black oil (MBO) that allows the use of a simple and less expensive computational algorithm that results in significant timesaving is usually preferred to a fully compositional model. The attraction of this method is that it is fast and accurate when applicable. The above reasons informed decision to employ a modified black oil model in the investigation.

3.4 Compositional model

This concept assumes that, reservoir fluid properties are functions not only of the reservoir temperature and pressure but also of the composition of the reservoir fluid. Unlike the black oil model, the oil and gas phases are multi-component mixtures, of variable composition.

This method uses the EOS to calculate k-values, compressibility, density, and viscosity just in one equation. The treatment of the PVT properties is the major difference between black oil and compositional model.

However, the equation of state is not predictive without being matched to measured data. Iterative EOS solution and flash computations make this approach difficult and expensive.

3.5 Modified black oil model (MBO)

One way of exploiting the benefits and reducing the short comings of the two approaches described above is the use of an MBO. It is a variation of the black oil model that treats gas-condensate as a reservoir fluid that is composed of gas component and vaporized oil in gas. The retrograde phase behavior of condensate requires the assumption for proper characterization. The MBO concept allows the use of a simple and less expensive procedure for modeling well productivity in condensate reservoirs. The adequacy of this approach for modeling gas-condensate has been an issue of extensive controversy among several investigators (Izgec 2003, El-Banbi et al. 2000, Coats 1985)

3.6 Current study approach and selection of modeling strategy

The critical issues given in the introduction chapter one have not been adequately addressed by any of the previous work reviewed in the last chapter. The current investigation has a similar approach with the MBO but differs in procedure of incorporating in the black oil model those features that are present in compositional model but lacking in black oil model. The method of modeling PVT in black oil model was identified as a major difference in the approaches between the black oil model and the compositional. Thus time was spent on incorporating compositional variation in modeling the black oil PVT property correlations in the current investigation to upscale to compositional correlations required for multiphase flow modeling in gas condensate reservoirs.

The study approach here is similar to several well deliverability models (Xiao et al 2004, Kabir 2006, Fevang and Whitson 1995, Mott 200 and others) (Kabir and Hasan 2006) published recently. However the advantage of the current study approach using semi-empirical models is the flexibility of use with limited measured PVT and rock property data. The claim for a simplified approach is common to all the methods mentioned above, yet none is simplified as majority of them require gas oil (condensate) ratio (CGR) as an input and assume three flow regions, which in practice has more complicated flow boundary regions than those usually assumed. The CGR is required for the determination of two phase pseudo-pressure adopted by the existing methods. Prediction of two phase pseudo-pressure requires numerical simulation to forecast all the necessary input parameters which makes the calculation cumbersome and is not justified for certain levels of reservoir forecast required, in this case well deliverability. The current study approach does not suffer the limitations highlighted above and uses improved PVT property and relative permeability correlations to account for the impact of condensate banking phenomena below the dew point pressure in predicting gas-condensate well deliverability. Unlike the majority of the available correlations, it does not use a two phase relative permeability models and does not assume irreducible water saturation throughout the reservoir production cycle. This assumption may not be practically correct as water production may occur from day one up to abandonment in most gas condensate reservoirs.

To account for water cut in production of this reservoir, a dynamic three phase relative permeability model has been developed and has been successfully applied to the well deliverability prediction.

The current study approach is described in the major work steps given below; these are informed by some procedural difficulties in previous published works

The justification for this approach can be seen in the rational and technical relevance of the study given in chapter 1.

However, other justifications include:-

(i) Spreadsheet adaptability,

(ii) Accurate rapid forecast of well productivity

(iii) A versatile tool for real time production management strategy and

(iv) A production system optimization tool for field development planning

The above merits are the major attractions of the current approach.

3.7 Major work steps

The conceptual frame work for this investigation could be summarized under the following major work steps to be detailed in relevant chapters.

The methodology adopted in the study included the following steps;

(i) The relevant literature was critically reviewed and evaluated to identify the key issues and technology gaps in modelling well deliverability in gas-condensate reservoir. This helped in shaping the aim and objectives of the research to keep abreast with the state of the art trend of research and development in well performance in gas condensate reservoirs.

(ii) Data bases of laboratory measured PVT properties for development of required PVT properties were compiled for improved well deliverability prediction. The PVT property models were developed calibrated and validated using these databases.

(iii) A dynamic three phase relative permeability model for gas condensate was sourced and adapted through using published relative permeability data.

(iv) An extended single phase gas inflow for multiphase flow (3-phase) in gas condensate reservoir was developed.

(v) Parametric studies were carried out to determine critical parameters that control productivity in gas condensate reservoirs and performed nodal analysis.

(vi) Horizontal well equations were up scaled for productivity forecast for multiphase flow in gas condensate reservoirs. Also a stochastic study was done on the modified horizontal well equations to define parameters that control productivity.

(vi) Verification and validation of the study approach was done by comparison of simulation results with standard industry reservoir simulator, Eclipse compositional (E300).

The details of each of the work steps are described in their respective chapters that follow.

3.8 Data requirement and acquisition

Case studies were used to demonstrate practical applications of the proposed semi-empirical method. Data sets for major world condensate fields were sourced from published works.

Data sourcing was one of the major considerations in adopting the semi-empirical approach used in most of the concept applied in this study.

Gathering of relevant data required for model development and simulation proved to be more time consuming than simulation and interpretation of result.

The use of semi-empirical models in spite of their limitations seems to be the most feasible option. However, it was validated with measured data. The data used had a wide coverage of reservoir conditions as shown in the data bases in appendix A compiled from published data and used in different sections of the study.

3.9 Quality control and pre-processing of acquired data

The due diligence steps taken to ensure that the published experimental data used in the study were accurately measured include;

(i) Checking the consistency of well test data with verified and standard physical trends.

(ii) Consistency of production test data with current well performance

(i) Consistency of PVT and well completion data were checked using physical law trends and some statistical techniques

3.10 Summary

The methodologies outlined above have been implemented as described in various chapters to ensure that accurate well deliverability correlations are available for prediction of well productivity of condensate reservoirs below the dew point pressure. Detailed methodologies for each will be presented in the respective chapters. The compiled databases sourced from published data were partly used for the semi-empirical model testing and development. However, care was taken not to use the development database for validation to eliminate the likely errors associated with use of same database for development and validation. The current chapter gives a road map of how the research work progressed to completion with the specifics given in later chapters.

CHAPTER FOUR

4.0 DEVELOPMENT OF CONDENSATE PVT PROPERTY CORRELATIONS

4.1 Introduction

Development of an accurate well deliverability model in gas-condensate reservoirs requires accurate PVT property correlations for the generation of down-hole fluid properties required for simulation using either the compositional or black oil model approach.).

Prediction of well deliverability in gas-condensate reservoirs is complicated by retrograde condensation and requires accurate estimation of condensate pressure/volume/temperature, (PVT) properties. The normal source for these hydrocarbon properties is usually from laboratory PVT tests of recombined or preserved samples of reservoir fluid. The limitations of laboratory facilities, the huge cost of experimentation and sometimes impossibility of measuring certain fluid properties, (Viscosity for instance) at elevated reservoir pressure and temperature makes the use of correlations indispensable. Even when laboratory facilities are available, the final values for such properties need to be calculated by skilled professionals using valid correlations. This underscores the importance of correlations generally. Present involvement in a study to improve the accuracy of well deliverability prediction in gas condensate reservoirs was the main motivation for this work. The major parameter input to well delivery models that impact on the accuracy include the down-hole PVT properties of the reservoir fluids. These properties include the compressibility factor, density and viscosity to mention just the few of the correlations developed in this work. The near wellbore region is particularly an important aspect of this study as phase, compositional changes and effect of turbulence are significant. The large pressure gradient, and low interfacial tensions between the phases observed in this region, as well as resultant retrograde condensation effects impact on the PVT properties. Also, the non hydrocarbon contents of the fluid have to be properly accounted for in any empirical correlation to adequately predict the PVT properties.

In this investigation, published correlations for compressibility factor, density and viscosity have been evaluated, and modified, to correct the deficiencies found in existing correlations.

4.2 Milestone in prediction of condensate PVT properties

Numerous studies on prediction of Natural gas condensate PVT properties exist in the literature. A major milestone in prediction of natural gas PVT properties includes the Katz and Standing Charts for determination of compressibility factors of reservoir fluid. The chart is still the basis for the prediction of compressibility factor by many correlations presently in the Oil and Gas industry though in digital forms. The digital forms of the Katz Chart were facilitated by several scholars, (Hall and Yarborough 1974, Dranchuk Abou Kassem (DAK) 1975, Gopal 1977, Brill and Beggs 1974). These were followed by evaluation work to determine the accuracy of the developed digital correlation for Katz Chart (Abd-el Fattah, 1995). The magnitude of errors associated with the use of correlations for prediction compressibility factor were highlighted in Abd-el Fattah's work in which he provide guidelines for range of applicability of the correlations for prediction of compressibility factors. Most of the correlations involved the use of some form of equation of state (EOS) involving trial and error method of solution and the accuracy of these methods is within 0.5%, but for region where reduced temperature, Tr=1 and reduced pressure, Pr>1 very large errors have been reported (Kumar 1987).

The inaccurate prediction of PVT properties of reservoir fluids arising from non-hydrocarbon components stimulated further investigation into ways of improving the performance prediction of down-hole PVT properties (Sutton 1985, 2005, 2007, Elsharkawy 2000, 2002, 2005 and 2006).

The problems with most of the available correlations applied for natural gas-condensate PVT properties prediction were developed for sweet and dry gases. The applications of these correlations to natural gas-condensate reservoir fluid property predictions are not only limited by mixture compositions and geographical locations of the reservoir as a general problem with empirical correlations but also to a range of reservoir temperatures and pressures. Therefore most of the available correlations for natural gases need to be modified for natural gas-condensate to improve on the prediction accuracy.

Further developments on improving the performance of compressibility factor correlations followed. Wichert and Aziz (1972) proposed a correction factor to extend the applicability of the Standing and Katz compressibility factor chart to sour gases. The correction factor is given by equation 4.31 in page 52.

Most of the available specific correlations for condensate have limited prediction accuracy (Sutton 1985, 2005), Elsharkawy (2000, 2002, 2003)

The compressibility factor correlations developed by Standing and Katz up to the digitized versions by Dranchuk and Abou Kassem and others have all been specific to sweet and dry gases. This led Londono (2005) to suggest that the attempts for prediction of compressibility factors should be extended to gas-condensate systems.

The major focus of numerous works has been on the improvement of the prediction of the pseudo critical properties of gas mixtures including heptanes plus fractions using different mixing rules and accounting for the non-hydrocarbon contents as critical input parameters in forecasting the compressibility factors. For a soft ware driven Oil and Gas industry, there is no better time for reviewing and updating outdated correlations in most of our widely used simulators than now.

4.3 Applied theoretical concepts

The search for efficient methods for predicting PVT properties for gas-condensates when measured data are not available have been the subject of extensive research. These efforts are justified considering the importance of PVT properties in governing reservoir production performance. At various stages of reservoir production cycle, solution to reservoir performance problems requires accurate knowledge of the physical properties of reservoir fluid at high temperature and pressure obtainable in gas-condensate reservoirs (Al-Shammasi 2001). Accurate knowledge of these properties are indispensable in energy and material balance calculations required in design of new wells and production optimisation to aid decision making in production management strategy and overall field development plans.

Critical performance evaluation of existing correlations based on comparison with published experimental data and development of improved correlations were carried out in this investigation. Theoretical principles governing the existing correlations were reviewed and updated as follows;

4.3.1 Evaluation of available compressibility factor correlations

The compressibility factor (Z) is a measure of how much the real gas deviates from ideal gas at a given temperature and pressure. It is a dimensionless quantity and a ratio of the volume actually occupied by gas at a given pressure and temperature to the volume it would occupy if it behaved ideally. Where, a value of z = 1 would represent an ideal gas condition. The ratio is given as;

$$Z = \frac{V_a}{V_i} \tag{4.1a}$$

Where;

V_a Actual volume of n moles of gas at a given reservoir T and P

V_i Ideal volume of n moles at same reservoir Temperature and Pressure

The development of gas compressibility factor for condensate compressibility prediction was considered because condensate is a compressible liquid that is relatively sensitive to pressure. As a result, improvement of corresponding gas PVT properties to allow for compositional variations usually ignored by gas correlations was a major consideration for development of condensate PVT properties below the dew point. In order to develop a suitable correlation for prediction of condensate compressibility factor in this investigation, the following correlations were reviewed, and evaluated;

(i) The Hall - Yarborough Method
(ii) The Dranchuk-Abu Kassem Method
(iii) The Brill and Beggs Method

The first two methods are forms of Equations of state (EOS) method and involve trial and error in evaluation of the (ρ_r) reduced density, the accuracy of these methods is generally within 0.5%, but for the region where T_r =1.0, $\rho_r > 1.0$, very large errors have been reported (Kumar 1987).The third method does not involve trial and error and is more convenient for engineering computations with good accuracy depending on the reduced temperature and pressure ranges.

The work recognized the popularity of the Dranchuk-Abu Kassem (DAK) method and went further to evaluate the contributions of Sutton, Piper (1993) and Elsharkawy (2003) to the improvement of DAK'S prediction by determining accurate Pseudo-critical properties to be used as input to any of the three methods above. The modifications were focused on proper accounting for impurities in the gas-condensate mixture and for correction of the heptanes plus fraction to extend the capability and use of the Standing and Kartz charts digitized by DAK, Yarborough, Beggs and Brill and others.

4.3.2 The Hall-Yarborough method (Yarborough 1973)

The compressibility factor, Z was defined as follows:-

$$Z = \left[\frac{0.06125 P_{pr} t}{Y}\right] \exp\left[-1.2\left(1-t^2\right)\right] \tag{4.1b}$$

$$F(Y) = -0.06125 P_{pr} T\left[-1.2\left(1-t^2\right)\right] + \frac{Y + Y^2 + Y^3 - Y^4}{\left(1-Y\right)^3} - \left(14.76t - 9.76t^2 + 4.58t^3\right)Y^2$$
$$+\left(90.7t - 242.2t^2 + 4.248t^3\right)Y^{(2.18+2.82t)} = 0 \tag{4.2}$$

$$t = \frac{1}{T_{pr}} = \frac{T_{pc}}{T} \tag{4.3}$$

4.3.3 **The Dranchuk-Abu Kassem method** (Dranchuk 1975)

The mathematical model expression for Dranchuk model is:-

$$Z = \left[A_1 + \frac{A_2}{T_{pr}} + \frac{A_3}{T_{pr}^3} + \frac{A_4}{T_{pr}^4} + \frac{A_5}{T_{pr}^5}\right]\rho r + \left[A_6 + \frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}^2}\right]\rho_r^2 - A_9\left[\frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}^2}\right]\rho_{pr}^5$$

$$+A_{10}\left(1 + A_{11}\rho_r^2\right)\frac{\rho_r^2}{T_{pr}^3} 3\exp\left[-A_{11}\rho_r^2\right] + 1 \tag{4.4}$$

Where;

$$\rho_r = \frac{0.27P_{pr}}{ZT_{pr}} \tag{4.5}$$

$\boldsymbol{A}_1 = 0.3265,\quad \boldsymbol{A}_2 = -1.0700,\quad \boldsymbol{A}_3 = -0.5339,\quad \boldsymbol{A}_4 = 0.01569,\quad \boldsymbol{A}_5 = -0.05165,$

$\boldsymbol{A}_6 = 0.5475,\ \boldsymbol{A}_7 = -0.7361,\ \boldsymbol{A}_8 = 0.1844,\ \boldsymbol{A}_9 = 0.1056,\ \boldsymbol{A}_{10} = 0.6134,\ \boldsymbol{A}_{11} = 0.7210.$

4.3.4 Beggs-Brill correlation (Beggs, and Brill 1974)

The following procedures were given for prediction of the Z factor;

$$Z = A + \frac{(1-A)}{e^B} + CP_{pr}{}^D \tag{4.7}$$

Where :- $A = 1.39(T_{pr} - 0.92)^{0.5} - 0.36T_{pr} - 0.101$ (4.8)

$$B = (0.62 - 0.23T_{pr})P_{pr} + \left[\frac{0.066}{(T_{pr} - 0.86)} - 0.037\right]P_{pr}{}^2 - \left[\frac{0.32}{10^{9(T_{pr}-1)}}\right]P_{pr}{}^6 \tag{4.9}$$

$$C = (0.132 - 0.32\log(T_{pr})) \tag{4.10}$$

$$D = 10^{\left(0.3106 - 0.49T_{pr} + 0.1824T_{pr}{}^2\right)} \tag{4.11}$$

4.4 Definition of other PVT correlation concepts

For a comprehensive development of key PVT properties, definitions of several concepts are necessary as they form important calculation steps in the evaluation of existing models and development of new ones. These concepts or principles include:-

4.4.1 Apparent molecular weight

Condensate is not a pure component but a mixture of hydrocarbon and non hydrocarbon compounds and is a compressible liquid. This compressibility property is the basis of the use of the gas analogy in the correlations quoted above definitions involved in the investigation. The apparent molecular weight of the mixture is defined by:-

$$M_a = \sum_{i=1}^{n} y_i M_i \tag{4.12}$$

It is a basic property of a hydrocarbon mixture which is necessary for the calculation of PVT properties required for the prediction of phase the behaviour and engineering of gas-condensate reservoirs.

4.4.2 Specific gravity correlations

Calculation of the apparent molecular weight requires compositions of hydrocarbon mixtures determined from constant composition expansion (CCE) or constant volume depletion (CVD) from laboratory experiment to represent the physical process of production of fluid from the reservoir assuming that the liquid dropped out in the reservoir is never produced to the surface. If these compositions are not available, gas gravity is usually the immediate available alternative, though not as precise as compositions in the calculation of other PVT properties (Guo and Ghalambor 2005, Guo, Lyons and Ghalambor 2007).

It is defined as the ratio of the gas density to air density, both measured at the same temperature and pressure, usually at standard temperature and pressure conditions, expressed as;

$$\gamma_g = \frac{\rho_g}{\rho_{air}} \tag{4.13}$$

It can also be given as;

$$\gamma_g = \frac{\dfrac{P_{sc} M_a}{RT_{sc}}}{\dfrac{P_{sc} M_{air}}{RT_{sc}}} \tag{4.14}$$

Then $\gamma_g = \dfrac{M_a}{M_{air}} = \dfrac{M_a}{28.96}$ (4.15)

Assuming ideal gas behaviour where, apparent molecular weight of air, M_{air} = 28.96

4.5 Classification of existing PVT prediction methods

The available methods for prediction of gas condensate and other heavy gas PVT properties can be put in three groups (Elsharkawy 2003). These are:-

(i) Use of gas composition or gas gravity for the determination of pseudo-critical properties for prediction of properties at all desired reservoir temperatures and pressures.

(ii) Application of corresponding states method to predict gas properties using composition data.

(iii) Prediction of properties using equation of state (EOS) methods

The disadvantage of the use of first group is that prediction of viscosity depends on the method used in forecasting density as gas density is used to predict viscosity carrying over the errors in density prediction to viscosity. The EOS method has the advantage of using one equation to predict compressibility factor, density, viscosity and k-values (Lawal 1968, Guo et al. 1977). Prediction of sour gases properties is not accurate with EOS and modification attempts on EOS to correct for accurate prediction of sour gases adds to numerical computations making the application not suitable for reservoir modelling and simulation (Li and Guo 1991).

However all the approaches are limited in predicting properties of sour heavy natural gases including gas condensate.

The performance of existing correlations was evaluated for a representation of gas condensates. It was found that Elsharkawy's approach addressed the problem areas better than other correlations and had a lower margin of error on comparison with measured two phase compressibilities of gas condensate. Elsharkawy's model was modified in this study and further comparison demonstrated performance improvement over existing models.

4.5.1 Critical property correlations using mixing rules

The basic step in calculating the pseudo-critical properties for prediction of compressibility factors is the determination of an approximate mixing rule. Mixing rules are used to extend the validity of equation of state to mixtures as EOS methods were originally developed for pure components. Critical properties of pure components used for property prediction are available in literature but pseudo-critical properties for hydrocarbon mixtures are not and have to be determined using appropriate mixing rules based on the pure component critical properties. Usually hydrocarbon mixture with carbon number higher than C_6, eg C_7, C_8, C_9…etc is grouped as C_{7+} fractions to ease the characterisation of the hydrocarbon mixture properties.

The critical properties of the C_{7+} plus fraction are usually not available in the literature and have to be calculated using certain correlations. The popular correlations used include;

(i) Kesler Lee (KL) (Kesler 1976)
(ii) Riazi Daubert (Riazi, and Daubert 1987)
(iii) Cavett's Correlations (Cavett 1962)

For brevity these correlations are not given here but the details are available elsewhere (Riazi and Daubert 1987). Elsharkawy's (2006) mixing rule excludes this step in the calculation of pseudo-critical properties, and thus is one of the major attractions of Elsharkawy's approach. Mixing rules correlations investigated include;

4.5.2 Kay's mixing rule (Kay 1936)

Kay's mixing rule developed for sweet dry gases for prediction of pseudo-critical properties is defined as;

$$P_{pc} = \sum y_i P_{ci} \qquad (4.16)$$

$$T_{pc} = \sum y_i T_{ci} \qquad (4.17)$$

The high error values resulting from use of this basic mixing rule for reservoir gases with high molecular weight, and condensates with significant amount of

C_{7+} content attracted the attention of several researchers resulting in development of improved correlations. Other relevant mixing rules whose performance were studied in this work include:-

4.5.3 Stewart- Burkhardt -Voo (SBV) mixing rule (Stewart 1959)

The mixing rule gives acceptable results for gases of high molecular weight and is defined by the following expression:-

$$J = \frac{1}{3}\sum y_i\left(\frac{T_{ci}}{P_{ci}}\right) + \frac{2}{3}\left[\sum y_i\left(\frac{T_{ci}}{P_{ci}}\right)^{0.5}\right]^2 \qquad (4.18)$$

$$K = \sum\left[y_i\left(\frac{T_{ci}}{P_{ci}^{\ 0.5}}\right)\right] \qquad (4.19)$$

$$T_{pc} = \frac{K^2}{J} \qquad (4.20)$$

$$P_{pc} = \frac{T_{pc}}{J} \qquad (4.21)$$

4.5.4 Piper mixing rule (Piper 1993)

The mixing rule was developed to take account of both the C_{7+} content and the non-hydrocarbons present in the gas simultaneously to eliminate the need for a correction factor. Mathematically the rule is defined as follows;

$$J = \alpha_0 + \sum_{i=1}^{3}\alpha_i y_i\left(\frac{T_{ci}}{P_{ci}}\right) + \alpha_4\sum_j y_j\left(\frac{T_{cj}}{P_{cj}}\right) + \alpha_5\sum_j y_j\left(\frac{T_{cj}}{P_{cj}}\right)^2$$

$$+\alpha_6 y_{C7+}M_{C7+} + \alpha_7\left(y_{C7+}M_{C7+}\right)^2 \qquad (4.22)$$

$$K = \beta_0 + \sum_{i=1}^{3}\beta_i y_i\left(\frac{T_{ci}}{P_{ci}^{\ 0.5}}\right) + \beta_4\sum_j y_j\left(\frac{T_{cj}}{P_{cj}^{\ 0.5}}\right) + \beta_5\sum_j y_j\left(\frac{T_{cj}}{P_{cj}^{\ 0.5}}\right)^2$$

$$+\beta_6 y_{C7+} M_{C7+} + \beta_7 \left(y_{C7+} M_{C7+} \right)^2 \quad (4.23)$$

Where, y_i = (y_{H2S} , y_{CO2} , y_{N2}) and y_i = ($y_1, y_2 .... y_6$)

α_0 = 5.27E-02	α_1 = 1.016	α_2 = 8.70E-01	α_3 = 7.26E-01
α_4 = 8.51E-01	α_5 = 0	α_6 = 2.08E-02	α_7 = -1.51E-04
β_0 = -3.97E-01	β_1 = 1.0503	β_2 = 9.66E-01	β_3 = 7.86E-01
β_4 = 9.82E-01	β_4 = 0	β_5 = 4.55E-01	β_6 = -3.77E-03

4.5.5 Sutton's modified (SSBV) mixing rule (Sutton 1985)

The (SBV) rule was modified by Sutton by introducing empirical adjustment factors $F_j, E_{j,} E_k$ to account for C_{7+} content of natural gases. The rule is given by the following equations;

$$F_j = \frac{1}{3}\left[y_i \left(\frac{T_{ci}}{P_{ci}} \right) \right]_{C7+} + \frac{2}{3}\left[y_i \left(\frac{T_{ci}}{P_{ci}} \right)^{0.5} \right]^2_{C7+} \quad (4.24)$$

$$E_j = 0.6081 F_j + 1.1325 F_j^2 - 14.004 F_j y_{C7+} + 64.434 F_j y_{C7+}{}^2 \quad (4.25)$$

$$E_k = \left(\frac{T_{ci}}{P_{ci}{}^{0.5}} \right)_{C7+} \left[0.3129 y_{C7+} - 4.8156 y_{C7+}{}^2 + 27.3751 y_{C7+}{}^3 \right] \quad (4.26)$$

$$J' = J - E_j \quad (4.27)$$

$$K' = K - E_k \quad (4.28)$$

$$T_{pc} = \frac{K'^2}{J'} \quad (4.29)$$

$$P_{pc} = \frac{T_{pc}}{J'} \quad (4.30)$$

4.5.6 Wichert- Aziz correction factor (Wichert, and Aziz 1972)

Wichert and Aziz introduced a correction term to account for the affect of the non-hydrocarbons, CO_2, or H_2S present in the fluid mixture. The expression for the correction factor could be summarised as follows;

$$\varepsilon = 120\left(A^{0.9} - A^{1.6}\right) + 1.5\left(B^{0.5} - B^{4}\right) \quad (4.31)$$

Where,

$$A = y_{H2S} + y_{CO2}$$

$$B = y_{CO2}$$

The pseudo-critical properties are then corrected as below;

$$T_{pc}' = T_{pc} - \varepsilon \quad (4.32)$$

$$P_{pc}' = \frac{P_{pc} T_{pc}'}{\left[T_{pc} + B(1-B)\varepsilon\right]} \quad (4.33)$$

4.5.7 Elsharkawy mixing rule (Elsharkawy et al 2000)

The mixing rule was developed to correct for both the C_{7+} and the non-hydrocarbons contents of gas-condensate. The calculation steps are summarised by the following equations;

$$J = \left[\sum y_i\left(\frac{T_{ci}}{P_{ci}}\right)\right]_{C1-C6} + \left\{\alpha_0 + \left[\alpha_1\left(y_i\frac{T_{ci}}{P_{ci}}\right)_{C7+}\right] + \left[\alpha_2\left(y_i\frac{T_{ci}}{P_{ci}}\right)_{N2} \alpha_3\left(y_i\frac{T_{ci}}{P_{ci}}\right)_{CO2} \alpha_4\left(y_i\frac{T_{ci}}{P_{ci}}\right)_{H2S}\right]\right\} \quad (4.34)$$

$$K = \left[\sum y_i\left(\frac{T_{ci}}{\sqrt{P_{ci}}}\right)\right]_{C1-C6} + \left\{\beta_0 + \left[\beta_1\left(y_i\frac{T_{ci}}{\sqrt{P_{ci}}}\right)_{C7+}\right] + \left[\beta_2\left(y_i\frac{T_{ci}}{\sqrt{P_{ci}}}\right)_{N2} + \beta_3\left(y_i\frac{T_{ci}}{\sqrt{P_{ci}}}\right)_{CO2} + \beta_4\left(y_i\frac{T_{ci}}{\sqrt{P_{ci}}}\right)_{H2S}\right]\right\} \quad (4.35)$$

Where;

α_0	α_1	α_2	α_3	α_4
-0.040279933	0.881709332	0.800591625	1.037850321	1.059063178
β_0	β_1	β_2	β_3	β_4
-0.776423332	1.030721752	0.734009058	0.909963446	*0.888959152*

4.5.8 Elsharkawy mixing rule (Elsharkawy 2006)

The model is an improvement on earlier version of Elsharkawy et al (2000) mixing rule, as the need for correlation for critical properties of C_{7+} plus fraction is not required, rather the molecular weight of the C_{7+} plus fraction is applied. The first part of the equation for the mixing rule corrects for the non-hydrocarbons, the second corrects for the pure hydrocarbons, whose critical properties are widely published; and the last part accounts for the C_{7+} content.

The governing equations for the mixing rule include;

$$J_{\inf} = \alpha_0 + \left[\alpha_1\left(y_i \frac{T_{ci}}{P_{ci}}\right)_{H2S}\right] + \left[\alpha_2\left(y_i \frac{T_{ci}}{P_{ci}}\right)_{CO2}\right] +$$

$$\left[\alpha_3\left(y_i \frac{T_{ci}}{P_{ci}}\right)_{N2}\right] + \left[\alpha_4 \sum\left(y_i \frac{T_{ci}}{P_{ci}}\right)_{C1-C6}\right] + \alpha_5\left(y_i M\right)_{C7+} \qquad (4.36)$$

$$K_{\inf} = \beta_0 + \left[\beta_1\left(y_i \frac{T_{ci}}{\sqrt{P_{ci}}}\right)_{H2S}\right] + \left[\beta_2\left(y_i \frac{T_{ci}}{\sqrt{P_{ci}}}\right)_{CO2}\right] + \left[\beta_3\left(y_i \frac{T_{ci}}{\sqrt{P_{ci}}}\right)_{N2}\right]$$

$$+ \left[\beta_4 \sum\left(y_i \frac{T_{ci}}{\sqrt{P_{ci}}}\right)_{C1-C6}\right] + \beta_5\left(y_i M\right)_{C7+} \qquad (4.37)$$

Where;

α_0	α_1	α_2	α_3	α_4	α_5
0.036983	1.043902	0.894942	0.792231	0.882295	0.018637
β_0	β_1	β_2	β_3	β_4	β_5

-0.7765003 1.0695317 0.9850308 0.8617653 1.0127054 0.4014645

To properly define all the parameters required in calculating the pseudo-critical properties, the mixing rule of Stewart-Burkhardt-Voo was adopted, defining Parameter J as follows;

$$J = \left(\frac{1}{3}\right)\left[\sum yi\left(\frac{T_c}{P_c}\right)_i\right] + \left(\frac{2}{3}\right)\left[\sum yi\left(\frac{T_c}{P_c}\right)_i^{0.5}\right]^2 \tag{4.38}$$

$$K = \sum\left[yi\left(\frac{T_c}{P_c^{0.5}}\right)_i\right] \tag{4.39}$$

For a given composition, the parameters $J_{\inf}, K_{\inf}$ can be calculated from equations 4.36 and 4.37 and the pseudo-critical properties then calculated using the correlations below;

$$\boldsymbol{T_{pc}} = \frac{\boldsymbol{K_{\inf}^2}}{\boldsymbol{J}} \tag{4.40}$$

$$\boldsymbol{P_{pc}} = \frac{\boldsymbol{T_{pc}}}{\boldsymbol{J_{\inf}}} \tag{4.41}$$

The pseudo-reduced properties are calculated from the two relations below and applied to calculation of the compressibility factor from the DAK correlations, equation 4.4 for use with Standing and Katz compressibility chart.

$$\boldsymbol{P_{pr}} = \frac{\boldsymbol{P}}{\boldsymbol{P_{pc}}} \tag{4.42}$$

$$\boldsymbol{T_{pr}} = \frac{\boldsymbol{T}}{\boldsymbol{T_{pc}}} \tag{4.43}$$

4.6 Modifications made by current study for compressibility factor

The effort to develop efficient methods for predicting the compressibility factor, Z for gas-condensates, when laboratory data are not available, has been the subject of extensive research. The major differences in approach by scholars have been in the area of correcting the pseudo critical properties for heptanes plus and non hydrocarbon contents of the reservoir gas. Prediction inaccuracies have been as a result of lack of proper account for the impurities in the modelling equation.

Presentation of efficient methods for predicting compressibility factor, density and viscosity for natural gases have been extensively treated by the previous works reviewed above. However most of the work reviewed including Elsharkawy had limited condensate data samples, and may not be efficient for prediction of condensate PVT properties.

Considering that our aim was to develop an efficient method for prediction of compressibility factor, density and viscosity for condensate, it became important that the existing models first be tested for prediction of condensate PVT properties.

On the above basis, the following procedure was followed for this study;

(i) Review and identification of relevant PVT property correlations for gas-condensate

(ii) Compilation of correlations for predicting condensate compressibility factor, density and viscosity

(iii) Sourcing and compilation of measured data bases for development of required PVT properties for improved well deliverability prediction from available publications. The database for each of the PVT properties was divided into development and test data, to ensure that any error of using development data for test data was eliminated.

(iv) The correlations were tested by comparing predicted results against the measured PVT database in each case.

(v) Performance results showed that none of the tested correlations showed good agreement with the measured compressibility factor database and the least average absolute error (AAE) was used as criterion for selection model that was modified using multiple regression analysis with the aid of Minitab statistical package software.

(vi) The modified model was tested and the performance was compared with the selected best available model and validated with the measured database.

(vii) Similar steps were taken for all the three PVT correlations for development, calibration and validation against measured and published database samples in appendix A.1 to A5.

Subsequently, Elsharkawy (2006) proposed modifications, which by our evaluation supports his claim for a simpler and more efficient model compared to various equations of state, corresponding state, and other correlations. The evaluation results showed that the latest of the Elsharkawy's proposals had the best fit among the correlations tested; however it had an error margin that may be regarded as unacceptable for condensate deliverability modelling. As a result a database that had a better representation of CVD measured condensate compressibility factor was created for the purpose of extending the Elsharkawy's (2006) correlation.

4.6.1 Modified correlation for condensate compressibility factor (study)

The mixing rule correlations reviewed above represents the various efforts by different investigators to extend the validity of the Standing-Katz chart, developed for sweet dry gas, to heavier natural gas-mixtures including gas-condensate. To get a better fit of digitised standing-Katz chart to measured condensate compressibility factor using the modified Elsharkawy mixing rule, a multiple non-linear regression of Elsharkawy-DAK parameter was done to fit the correlation to our database of laboratory measured condensate compressibility factors which resulted in the following modified expressions for condensate compressibility factor;

$$Z = \frac{Z_{DAK}}{2} + 0.36015 \qquad (4.44)$$

$$Z_{DAK} = \left[A_1 + \frac{A_2}{T_{pr}} + \frac{A_3}{T_{pr}^3} + \frac{A_4}{T_{pr}^4} + \frac{A_5}{T_{pr}^5}\right]\rho r + \left[A_6 + \frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}^2}\right]\rho_r^2$$
$$-A_9\left[\frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}^2}\right]\rho_{pr}^5 + A_{10}\left(1 + A_{11}\rho_r^2\right)\frac{\rho_r^2}{T_{pr}^3} 3\exp\left[-A_{11}\rho_r^2\right] + 1 \qquad (4.45)$$

$$\rho_r = \frac{0.27 P_{pr}}{Z T_{pr}} \qquad (4.46)$$

Where $\boldsymbol{A_1 = 0.3265, A_2 = -1.0700, A_3 = -0.5339, A_4 = 0.01569, A_5 = -0.05165,}$ $\boldsymbol{A_6 = 0.5475, A_7 = -0.7361, A_8 = 0.1844, A_9 = 0.1056, A_{10} = 0.6134, A_{11} = 0.7210.}$

4.7 New modification for gas condensate density (ρ_c) correlation

An estimate of gas density is required for all density based viscosity correlation. Although there are many equations of state (EOS) for gas density (or more specifically, for the gas Z-factor), EOS models generally do not reproduce the measured gas densities in our data base (Londono 2005). The problem of reproducibility of measured volumetric properties, Z-factor and density is worse in gas-condensate reservoirs because of the uncertainties of the molecular weight and the critical properties of the plus fraction. The EOSs are generally not predictive without tuning their parameters to match experimental data. The Z-factor and density are usually solved as roots of the EOS. The need to correlate PVT variables for real gas mixture and condensates with experimental data reliably has led to development of several EOSs, yet none has completely and singularly achieved the objective as no gas really behaves like an ideal gas. In petroleum engineering the effort is on extending EOS method to mixtures (instead of the pure component systems for which they were developed) by using several correction methods including the use of binary interaction number (BIN) or coefficients, parachor and omega etc. All these cumbersome steps make the use of EOSs unattractive.

The Dranchuk Abou Kassem (DAK) provides an equation of state (EOS) representation form of real gas compressibility factor, Z which is considered as the current industry standard for prediction of gas density.

The modified Z- factor, Zm was used to predict condensate density from the equation;

$$\rho_c = \frac{PM_a}{Z_m RT}$$ (4.47) (Ugwu, Mason and Gobina 2011).The equation was developed from equation 4.44 where $Z=Z_m$. The Z_m is the ideal gas compressibility factor corrected for condensate.

The equation 4.47was derived using the improved compressibility factor for condensate equation 4.44 developed in this work. The new condensate density correlation was validated with laboratory measured condensate density values sourced from several publications. A sample data base for the validation is shown in appendix A2. The correlation gave superior performance on comparison with several correlations widely used in the industry. Other correlations assumed constant composition at various reservoir pressures. The assumption is not valid for production of condensate below the dew point pressure. The modified correlation equation 4.47 made provision for compositional variation of density with changes in reservoir pressure. This may the reason for the observed improved performance.

4.8 Condensate viscosity (μ_c) correlation

Predicting petroleum reservoir well performance and hydrocarbon recovery requires reliable viscosity estimation especially when dealing with processes such as miscible gas-injection and gas-condensate systems, where major compositional changes occur, and employment of a single model that can accurately predict the viscosity of both gas and liquid phases using phase composition is needed. Simulation of liquid dropout issues and fluid flow in gas-condensate reservoirs requires accurate viscosity correlations capable of predicting viscosity of reservoir fluid at high temperatures and pressures.

The problem of capture and the measurement difficulties involved in measuring the viscosity of condensate at elevated temperatures and pressures favours the use of correlations since routine measurements may be impossible at the desired reservoir conditions (Al-Meshari 2007 Ali, 1991)

The fluid resistance to flow is a measure of its dynamic viscosity. For given viscosities of a gas mixture components at known compositions, pressure and temperature, a mixing rule can be used to obtain the viscosity of the gas mixture as;

$$\mu_g = \frac{\sum\left(\mu_{gi} y_{i\sqrt{MW_i}}\right)}{\sum\left(y_i \sqrt{MW_i}\right)} \qquad (4.48)$$

Usually viscosity is estimated by charts or correlations. Most of the approaches in this study prefer use of correlations because of ease of programming.

Many researchers have proposed different methods for predicting viscosity but the accuracy of such prediction is critical in well deliverability prediction of gas-condensates because of its sensitivity to pressure and composition.

The most popular methods of predicting viscosity in engineering calculations with reservoir fluids includes Lohrenz-Bray-Clark (LBC), (which relates the residual viscosity to the reduced density), (Al-Syabi et al 2001, Elsharkawy 2002, Al-Meshari 2006) and others.

The problems with most of the available correlations include;

(i) They were developed for oil and gas and have limited application in condensate management

(ii) Validity near the critical region and with complex hydrocarbon is limited because of the difficulty of phase characterisation within the region.

(iii) Limited range of application to single component fluids and low pressures and not for multiphase flow from production of condensate below the saturation pressure.

(iv) The effects of temperature, pressure and composition were separately and singly taken into account in developing some of the correlation, instead of considering viscosity as a function of all the variables simultaneously.

(v) Accuracy of Viscosity correlation is dependent on density correlation and this could increase the prediction error margin.

Previous works (Elsharkawy 2006, Guo et al 1977) have shown that EOS is capable of satisfactory prediction of pure component hydrocarbon viscosity but is unsatisfactory for hydrocarbon mixture viscosity. As a result, instead of adopting the use of EOS, other prediction correlations were reviewed and their performance evaluated for probable adoption for further development in this study.

4.8.1 Evaluation of available viscosity correlations

The most widely used correlations for viscosity prediction of mixtures were reviewed in order to evaluate performance as a first step to developing more accurate methods for condensate viscosity prediction for modelling well deliverability in gas-condensate reservoirs. The correlations evaluated in the study include;

(i) Lee-Gonzalez-Eakin (LGE) (1966)

(ii) Sutton (2007)

(iii) Elsharkawy (2006)

(iv) Carr-Kobayashi-Burrows (1959) as modified by Dempsey (CKB-D) (1965)

4.8.2 Lee-Gonzalez-Eakin (1966) (LGE) viscosity correlation

The theoretical concept of this model can be mathematically expressed as follows;

$$\mu_g = 10^{-4} K \times \exp\left[X \left(\frac{\rho_g}{62.4} \right)^Y \right] \tag{4.49}$$

Where,

$$K = \frac{(9.379 + 0.016 M_a) T^{1.5}}{209.2 + 19.26 M_a + T} \tag{4.50}$$

$$X = 3.448 + \frac{986.4}{T} + 0.01009 M_a \tag{4.51}$$

$$Y = 2.4 - 0.2X \tag{4.52}$$

This model is important as the basis of many viscosity correlations in petroleum reservoir engineering.

4.8.3 Sutton (2007) viscosity correlation

A modified LGE correlation expressed as follows;

$$\mu_{gsc}\xi = 10^{-4}\left[0.807T_{pr}^{\;0.618} - 0.357\exp\left(-0.449T_{pr}\right) + 0.34\exp\left(-4.058T_{pr}\right) + 0.018\right] \quad (4.53)$$

Where, viscosity parameter $\xi = 0.9490\left(\dfrac{T_{pc}}{M^3 P_{pc}^{\;4}}\right)^{1/6}$ (4.54)

$$\mu_g = \mu_{gsc} \times \exp\left[X\left(\frac{\rho_g}{62.4}\right)^Y\right] \quad (4.55)$$

Where,

$$X = 3.47 + \frac{1588}{T} + 0.0009M_a \quad (4.56)$$

$$Y = 1.66378 - 0.04679X \quad (4.57)$$

4.8.4 Elsharkawy (2006) viscosity correlation

This is an extension of the LGE viscosity correlation to correct for the presence of non-hydrocarbons and the C_{7+} content present in heavy reservoir gases and condensates.

The original form of Elsharkawy model is

$$\mu_g = 10^{-4}K \times \exp\left[X\left(\frac{\rho_g}{62.4}\right)^Y\right] \quad (4.58)$$

Where,

$$K = \frac{\left(9.379 + 0.016M_a\right)T^{1.5}}{209.2 + 19.26M_a + T} \quad (4.59)$$

$$X = 3.448 + \frac{986.4}{T} + 0.01009M_a \quad (4.60)$$

$$Y = 2.4 - 0.2X \tag{4.61}$$

And corrections for non-hydrocarbon content and the plus fraction are as follows:-

$$\Delta\mu_{H2S} = y_{H2S}\left(-3.2268\times10^{-3}\log\gamma_g + 2.1479\times10^{-3}\right) \tag{4.62}$$

$$\Delta\mu_{CO2} = y_{CO2}\left(6.4366\times10^{-3}\log\gamma_g + 6.7255\times10^{-3}\right) \tag{4.63}$$

$$\Delta\mu_{C7+} = y_{C7+}\left(-3.2875\times10^{-1}\log\gamma_g + 1.2885\times10^{-1}\right) \tag{4.64}$$

Giving the corrected viscosity as;

$$\left(\mu_g\right)_{corrected} = \mu_g + \Delta\mu_{H2S} + \Delta\mu_{CO2} + \Delta\mu_{C7+} \tag{4.65}$$

Where $\mu_g = \mu_c$ = Condensate Viscosity derived from gas viscosity.

4.8.5 New modification for Elsharkawy (2006) viscosity correlation

The error margins associated with the use of existing gas-condensate viscosity correlations were found to be high on performance evaluation and needed upgrading for meaningful engineering calculations

Elsharkawy (2006) Viscosity correlation gave the least average absolute error compared to other widely used viscosity correlations and had a better versatility of application to non-hydrocarbon impurities and heptanes plus fraction. Based on the above criteria it was selected for further modification to improve on the accuracy of prediction of gas-condensate viscosity which was the main objective of this part of the study.

The method applied for developing the new prediction procedure for the condensate viscosity included the following steps;

(i) Creation of compositional database for published measured condensate viscosity for different reservoir pressures and temperatures of world-wide sample representation shown in appendix A3.

(ii) Compilation and evaluation of the performance of different available viscosity correlations against the created database.

(iii) Use of average absolute error criteria for model selection for further development for lack of good match to measured values in the database.

(iv) Modification of the Elsharkawy (2006) viscosity model that gave the least absolute average error margin on evaluation using part of the database as development and validation data, equation (4.66)

(v) Validation of the modified model and comparison with the best available correlation based on the evaluated performance of the existing models.

Measured condensate viscosity database in appendix A3 from a CVD test was used to derive new coefficients for the original Elsharkawy viscosity model using non-linear regression statistical techniques. The above technique resulted in the following modified Elsharkawy viscosity correlation;

$$\mu_c = K^{-2.5}\exp(176 + 0.062\rho Y - 15.5X) \qquad (4.66)$$

Where K, X and Y are same as in equations (4.59, 4.60 and 4.61respectively) and the corrections for the non hydrocarbon contents and heptanes plus fraction remain the same as defined in equations (4.62 to 4.65).

4.9.0 Comparison of correlations with measured data

4.9.1 Comparison of compressibility factor correlation with published data

The available measured data for compressibility factor was first checked for consistency and validity by checking whether the measured data captured the physical trend of changing compressibility factor as a function of composition, temperature and pressure by use of published data from Elsharkawy (2006) as shown in figure 4.1 below;

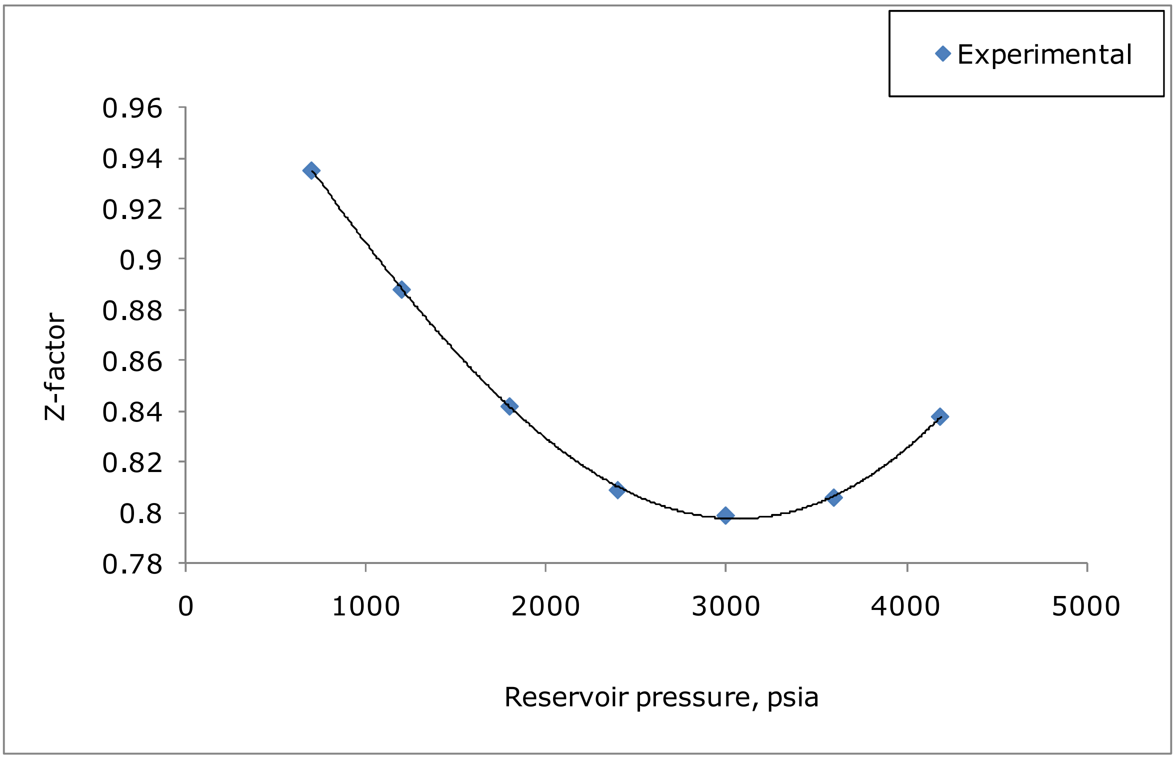


Figure 4.1 Consistency check of measured experimental database of gas condensate compressibility factor used in the study

The quality of the gas condensate compressibility factor data used in the study was checked by making a plot of the measured compressibility factor data against the reservoir pressure as shown in figure 4.1. The trend shown by the curve is consistent with practically observed compressibility factor curve and in agreement with physical laws controlling this property. On this basis the data was used for validation of existing correlations for application in this work. To select a better compressibility factor correlation for development for application to predicting down-hole condensate compressibility factor, the available correlation performances were compared to our database.

The results of comparison of prediction of compressibility factor using Piper, Sutton and Elsharkawy with measured (experimental) values of compressibility factors are shown in tables 4.1, 4.2, 4.3, 4.4, 4.5 below.

Table 4.1 Experimental (measured) and Calculated Compressibility factor Z

Pressure(psia)	Measured Z	Piper Z,1993	SuttonZ,1985	Elsharkawy,2003
4050	0.914	0.886	0.93	0.914
4255	0.968	0.963	0.975	0.967
4825	0.851	0.857	1.058	0.854
3500	0.916	0.9	0.9	0.91
2347	0.823	0.842	0.795	0.795
1000	0.802	0.797	0.804	0.8
1594	0.452	0.489	0.67	0.396
1364	0.606	0.615	0.732	0.589
	(Elsharkawy, 2002)			

Table 4.2 Comparison of the Piper's predicted Z with laboratory measured Z

Resrvoir Pressure (psia)	Piper's predicted Z	Measured Compressibility Z	% Error
4050	0.886	0.914	-3.16
4255	0.963	0.968	-0.52
4825	0.857	0.851	0.70
3500	0.9	0.916	-1.78
2347	0.842	0.823	2.26
1000	0.797	0.802	-0.63
1594	0.489	0.452	7.57
1364	0.615	0.606	1.46
	Average Absolute Error AAE =		0.74

Table 4.3 Comparison of Sutton's predicted Z with the measured Z

Reservoir Pressure (Psia)	Sutton's predicted Z	Measured Compressibility Z	% Error
4050	0.93	0.914	-1.75
4255	0.975	0.968	-0.72
4825	1.058	0.851	-24.32
3500	0.9	0.916	1.75
2347	0.795	0.823	3.40
1000	0.804	0.802	-0.24
1594	0.67	0.452	-48.23
1364	0.732	0.606	-20.63
	Average Absolute Error =		11.33

Table 4.4 Comparison of Elsharkawy's predicted Z with the measured Z

Reservoir Pressure (Psia)	Elsharkawy,s Predicted Z	**Measured Compressibility Z**	**% Error**
4050	0.914	0.914	0.00
4255	0.97	0.968	0.20
4825	0.86	0.851	-1.07
3500	0.913	0.916	0.33
2347	0.82	0.823	0.36
1000	0.8	0.802	0.25
1594	0.45	0.452	0.44
1364	0.589	0.606	0.00
Average Absolute Error =			0.52

The results of analysis of correlation methods for prediction of compressibility factor Z for gas-condensate and comparison of different correlations are also shown figure 4.2 below.

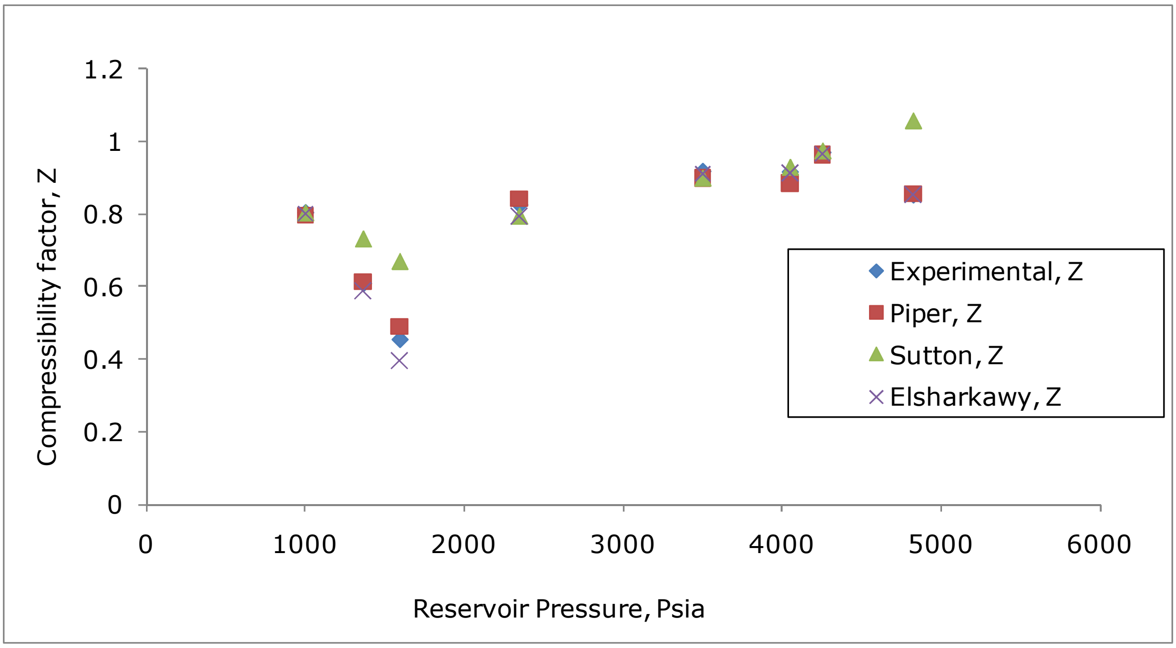


Figure 4.2 Comparison of compressibility factor, Z prediction correlation performance with measured CVD test database

Further validation of selected compressibility factor correlations with lower average absolute error (AAE) with measured compressibility factor gave the following results shown in tables 4.5, 4.6 and figures 4.3 and 4.4.

Table 4.5 Further comparison of selected compressibility factor, Z with laboratory measured condensate data.

Reservior pressure(psia)	Experimental	Predicted Z factors for different models		
		Elshark	Sutton	Modified
4190	0.838	1.000	0.933	0.860
3600	0.806	0.763	0.966	0.742
3000	0.799	0.859	0.978	0.789
2400	0.809	0.941	0.994	0.831
1800	0.842	0.996	1.014	0.858
1200	0.888	1.052	1.041	0.886
700	0.935	1.114	1.069	0.917

Table 4.6 Percentage average absolute error margins for various Z factor correlations

Reservior pressure(psia)	Sutton % Error	Elshark % Error	modified model % error
4190	-11.30	-19.33	-2.64
3600	-19.80	5.29	7.96
3000	-22.44	-7.47	1.19
2400	-22.83	-16.37	-2.70
1800	-20.43	-18.28	-1.91
1200	-17.20	-18.44	0.22
700	-14.36	-19.11	1.93
AAE	**18.34**	**14.90**	**2.65**
AAE - Average Absolute Error			

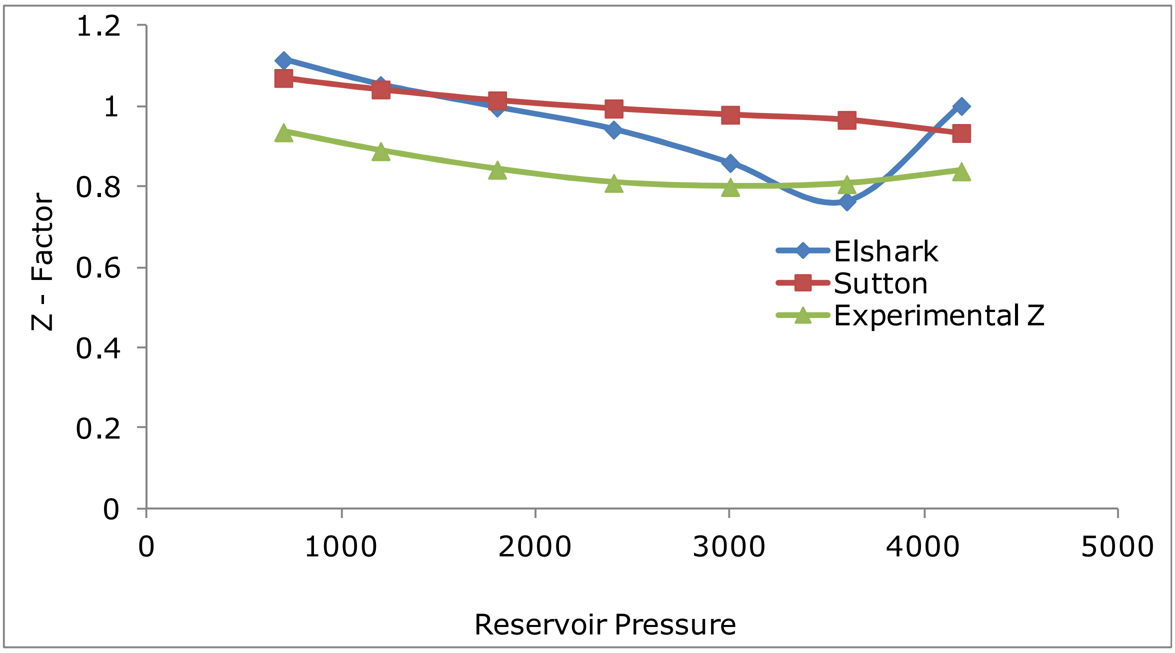


Figure 4.3 Further comparison of predicted condensate compressibility factor for selected correlations with published experimental compressibility factor data base

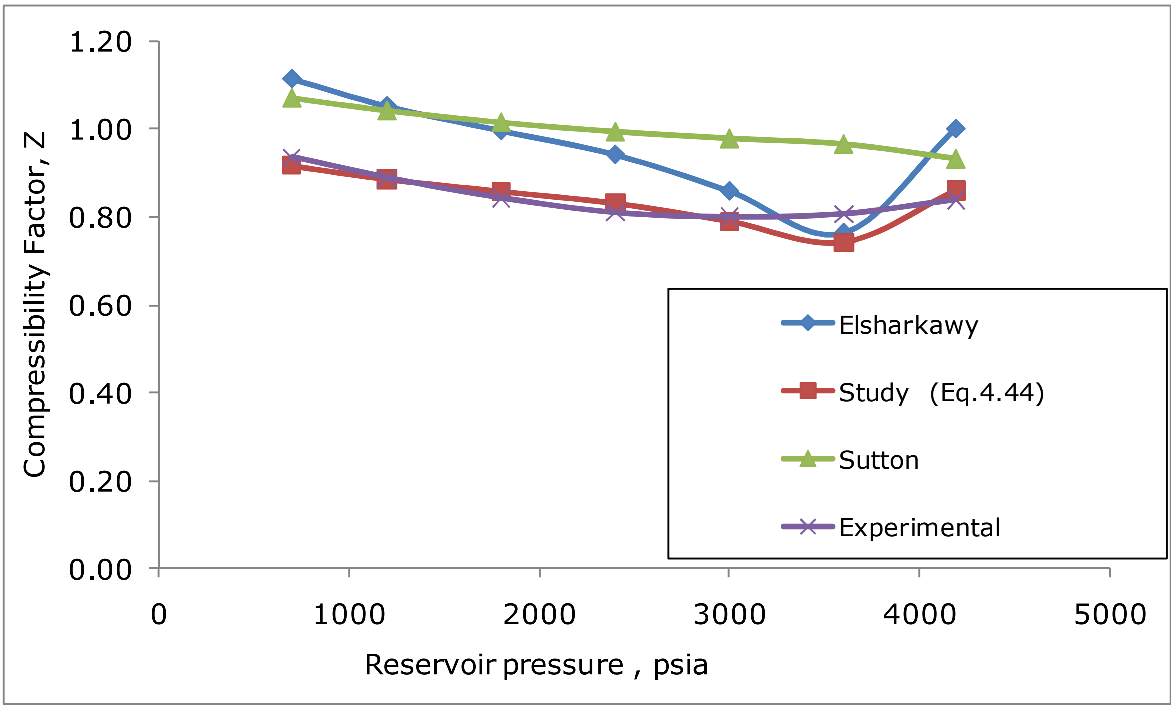


Figure 4.4 Validation of modified compressibility factor correlation with measured data and further comparison with existing models.

Figure 4.1 is a quality check for measured compressibility factor which showed that the change of compressibility factor with pressure is in agreement with theoretical expectation. The decrease in compressibility factor with increase in pressure up to a point where compressibility increases with pressure is illustrated. The trend is an indication of consistency and accurately measured compressibility factor database that is reliable for engineering analysis. Figure 4.3 showed that Elsharkawy's compressibility factor correlation had a better agreement with the measured data, with AAE of 14.90% shown in table 4.6 than Sutton correlation with AAE of 18.34%. The modified model by this study (Eq. 4.44) showed a superior performance with AAE of 2.65% as shown in table 4.6. Table 4.5 shows the performance of selected correlations compared with measured data at same reservoir conditions.

4.9.2 Verification of modified density correlation results

Experimental data were obtained from Elsharkawy (2002) to validate the above density correlation equation (4.47) derived from the modified Elsharkawy compressibility factor. The result of the calculation methods are shown as sample calculations at certain conditions of reservoir pressure in tables 4.7 and comparison of experimental data with the predicted results also shown in table 4.8 and figure 4.5.

Table 4.7 Predicting gas-condensate density using modified Z factor approach

Reservoir system pressure,P ,psia				1800	
Reservoir system Temperature,T,^{0}F,^{0}R				250	710
Univeral gas-constant R, psia ft^3/Ib-mol ^{o}R				10.732	
Experimental compressibility factor, Z				0.842	
Compone	**Mole %, Yi**	**Mi**	**YiMi**		
H_2S	0.273	34.08	9.30		
CO_2	0.0694	44.01	3.05		
N_2	0.0461	28.01	1.29		
C_1	0.4844	16.04	7.77		
C_2	0.0493	30.07	1.48		
C_3	0.0239	44.10	1.05		
IC4	0.0049	58.12	0.28		
NC4	0.0106	58.12	0.62		
IC5	0.0053	72.15	0.38		
NC5	0.0052	72.15	0.38		
C6	0.006	86.18	0.52		
C_{7+}	0.0217	128.25	2.78		
Apparent Molecular weight,Ma			28.92		
Predicted Density,ρ, lb/ft^3			8.11		
Experimental Density,ρ			7.95		
% Error			-2.04		

A sample calculation of condensate density using the modified study (Eq.4.47) is illustrated in table 4.7 and applied in calculation of condensate density variation for different reservoir pressures shown in figure 4.5.

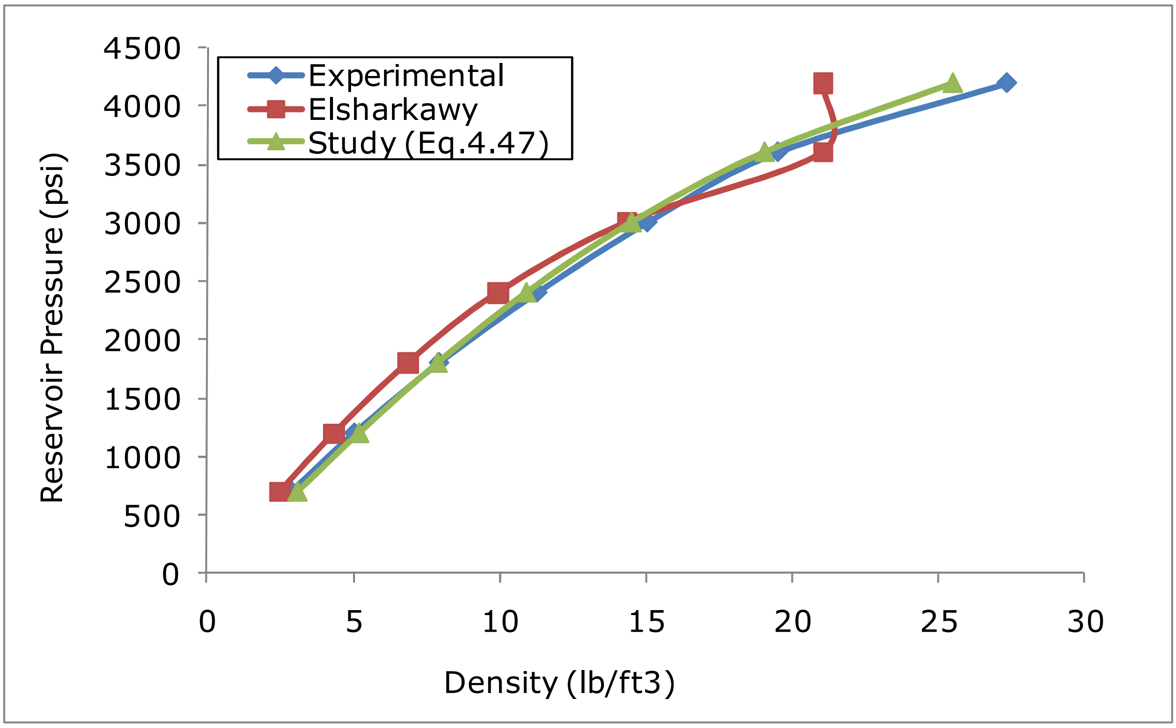


Figure 4.5 Validation of modified density correlation with experimental data

Table 4.8 Predicted gas-condensate density using modified Elsharkawy's compressibility factor correlation approach and AAE

Reservoir Pressures (psi)	Experimental Density(lb/ft^3)	Elsharkawy's Density(lb/ft^3)	Modified Mod Density(lb/ft^3)	Elsharkawy's % Error	Modified mod. % Error
4190	27.34	21.06	25.46	22.99	6.88
3600	19.52	21.03	19.04	-7.76	2.47
3000	15.06	14.33	14.5	4.86	3.74
2400	11.3	9.94	10.91	12.05	3.43
1800	7.95	6.86	7.88	13.72	0.88
1200	5.06	4.35	5.2	13.97	-2.85
700	2.91	2.49	3.1	14.3	-6.67
		Average Absolute Errors (AAE)		12.81	3.85

4.9.3 Test results for condensate viscosity correlations

Preliminary and final test results on the performance of existing correlations and the validation of new viscosity correlation is presented in this section.

The most popular methods of predicting viscosity in engineering calculation of reservoir fluid includes Lohrenz-Bray-Clark (LBC), which relates the residual viscosity to the reduced density (Al-Syabi et al 2001, Elsharkawy 2002, Al-Meshari 2007).

However, Al-Syabi's work at Heriot-Watt (HW) University has made modifications to the Lohrenz correlation.

The reliability of the modified method for calculating viscosity of mixtures and in particular of high pressure high temperature fluids can be graphically expressed as shown in figure 4.5 below.

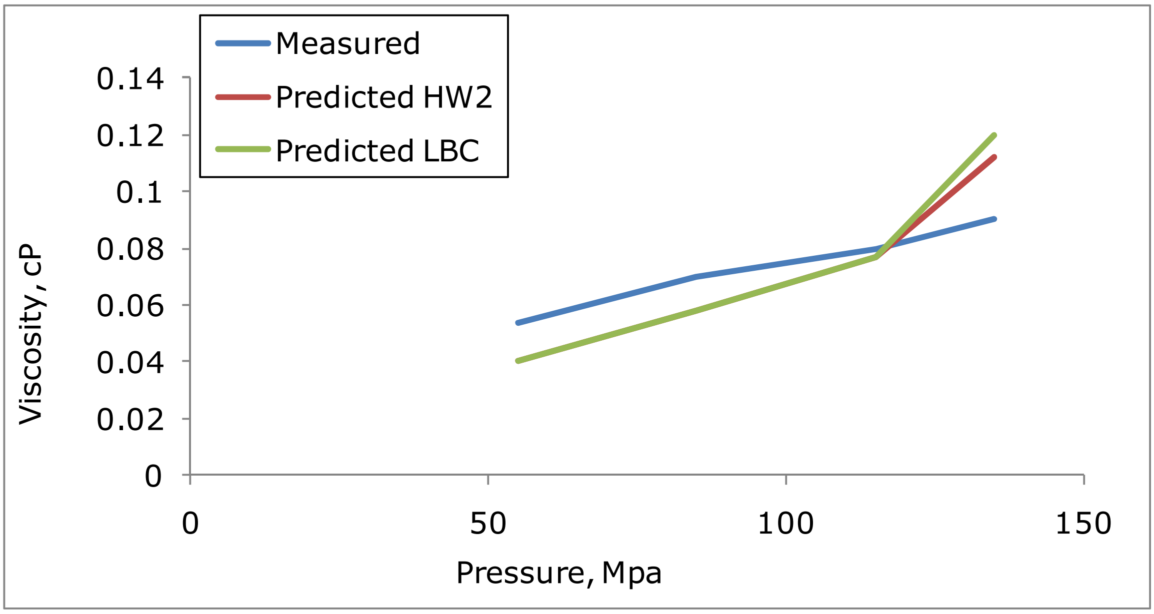


Figure 4.6 Comparison of Al-Syabi, (2001) HW2 and LBC viscosity correlations with measured condensate viscosity data

This was further subjected to statistical analysis, apart from the above graphical comparison, and the average absolute error (AAE) of the prediction methods, LBC and the Herriot Watt University's second modification (HW2) model were computed and compared as on tables 4.9 and 4.10 below.

This comparison was based on digitized Viscosity curve data from Al-Syabi et al. (2001)

Table 4.9 Comparison of LBC predicted viscosity with the measured.

Reservoir Pressures(MPa)	LBC predicted Viscosity(cP)	Measured Viscosity(cP)	% Error
55	0.045	0.055	18.18
80	0.055	0.060	8.33
110	0.077	0.080	3.75
135	0.125	0.100	25.00
			AAE =13.82

Table 4.10 Comparison of HW2 predicted viscosity with the measured

Reservoir Pressures(MPa)	HW2 predicted Viscosity(cP)	Measured Viscosity(cP)	% Error
55	0.045	0.055	18.18
80	0.057	0.060	5.00
110	0.077	0.080	3.75
135	0.105	0.100	5.00
			AAE =7.98

The above figure 4.6 shows that at lower pressure, the two models have same predictions but at higher pressures HW2 is superior. Also the absolute error analysis from the two tables 4.9 and 4.10 above favoured HW2.

In spite of the choice of HW2 by the above comparison, the correlation was still not a close fit to the experimental data. On this basis, an attempt was made to scale up HW2 which still resulted in a long correlation. Further literature search gave other correlations, Lee-Gonzalez-Eakin (1966) (LGE), Sutton (2007), Elsharkawy (2006), Carr-Kobayashi-Burrows (1959) as modified by Dempsey (CKB-D) (1965)

The correlations were tested and compared with experimental data as shown in tables 4.9, 4.10 and figure 4.6. The results were similar to those of Elsharkawy (2002) on evaluation of several gas-condensate correlations. The general conclusion here was that most of the viscosity models had a poor fit to experimental data which motivated the modification of Elsharkawy's correlation. The Elsharkawy correlation gave the least average absolute error margin of 35.31% which on modification gave reduced absolute error of 25.45%. The error margin was still high with the modified model but it gave better performance when compared with widely used correlations as shown on the tables and figures below;

Table 4.11 Predicted condensate viscosity at different reservoir pressures using different correlations

			Predicted Viscosity Values using different models			
Reservoir Pressure (Psia)	Temperature (^{0}F)	Experimental Viscosity(cp)	LGE (cP)	Sutton 2005 (cP)	Elsharkawy (cP)	Study (Eq.4.66) (cP)
5367	244	0.035	0.025	0.027	0.031	0.043
4931	262	0.048	0.032	0.036	0.040	0.063
4415	217	0.07	0.038	0.044	0.053	0.074
8590	282	0.11	0.228	0.334	0.255	0.124
5361	251	0.096	0.084	0.109	0.107	0.127
6010	313	0.099	0.043	0.053	0.066	0.127
5030	290	0.091	0.033	0.039	0.054	0.095
4669	296	0.042	0.044	0.055	0.057	0.125
4190	250	0.1	0.042	0.057	0.061	0.145
4825	219	0.09	0.062	0.105	0.079	0.173

LGE= Lee Gonzalez-Ekin

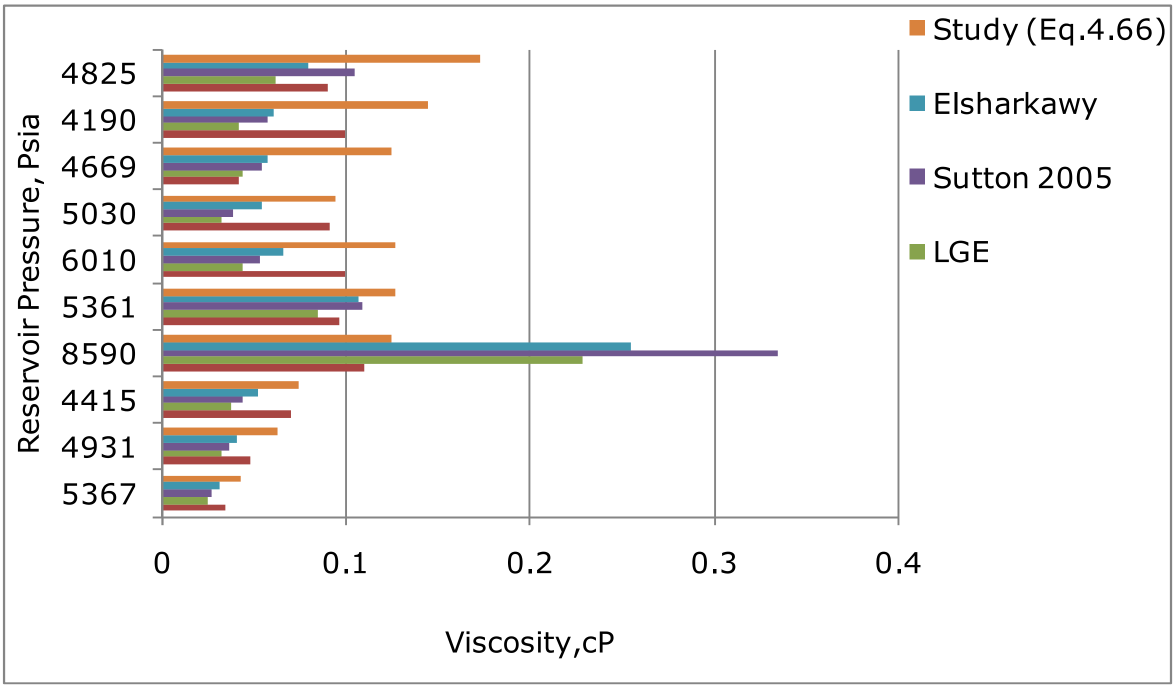


Figure 4.7 Validation of existing and developed(study) condensate viscosity correlation with published experimental data

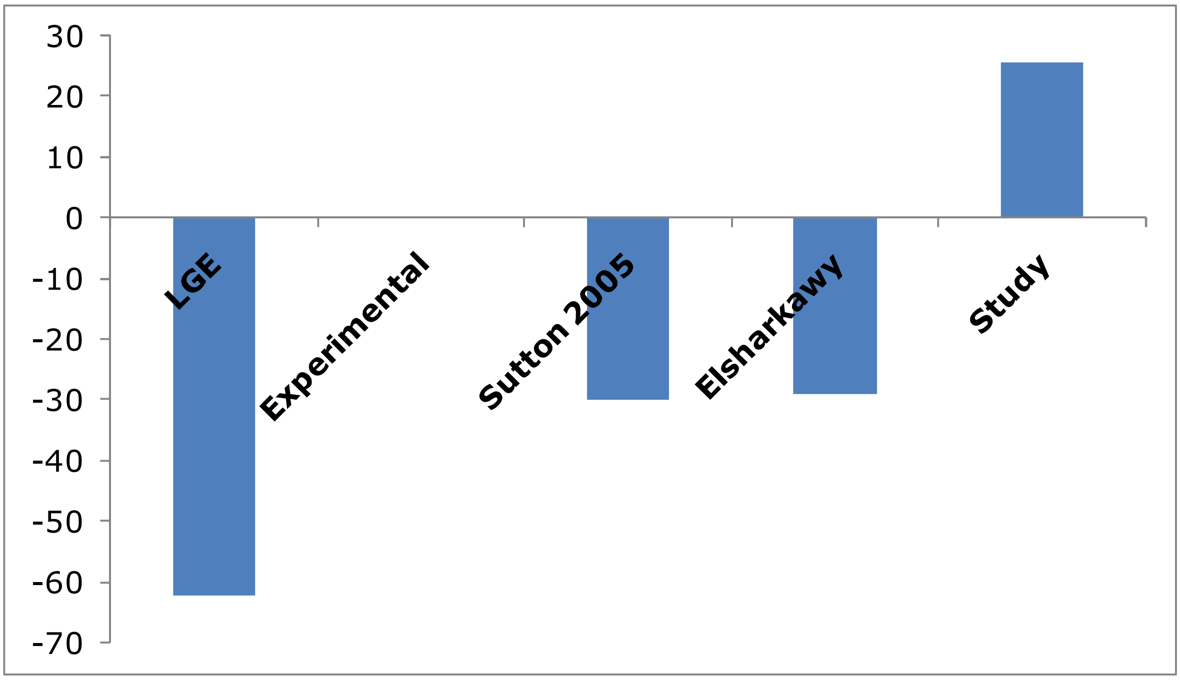


Figure 4.8 Average error comparison for gas condensate viscosity correlation

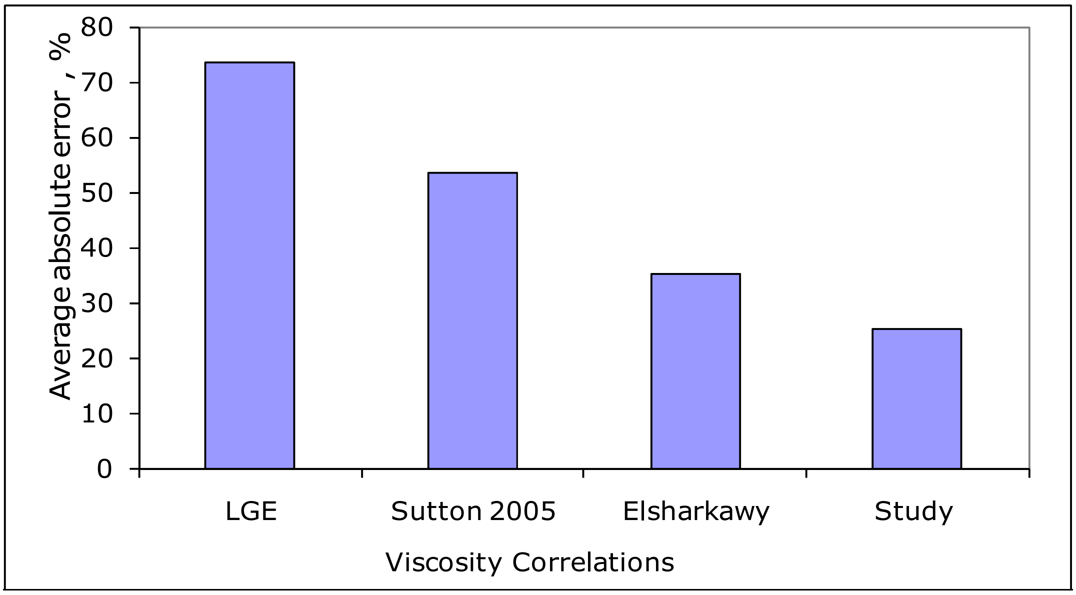


Figure 4.9 Absolute average error comparison for gas condensate viscosity correlations

4.9.4 Hybrid correlation for condensate compressibility factor

The Compressibility factor (Z) for condensate is a critical parameter in modelling well deliverability. The phase behaviour is accurately modelled by this parameter if it is well correlated or measured. Condensate sensitivity to pressure, compositional variation, phase changes and cost of experimentation make empirical correlation more cost effective. Compositions of condensate mixture obtained from constant composition expansion (CCE) and constant volume depletion are used to correlate for pseudo-critical and pseudo reduced properties that are used in modelling Z. But if compositions are not available condensate gravity correlations can be used. However, Sutton (2007), Elsharkawy (2006) and Guo (2005) have noted that the Z factor correlated using specific gravity has less accuracy.

In this investigation the possibility of using upgraded condensate gravity using composition, resulted in developing a correlation known as hybrid Z factor correlation. This approach was suggested to serve as an alternative to calculation of compressibility factor for gas condensate reservoir fluids when compositions are not available as is usually the case in industry. Alternative methods of estimating compressibility factor for prediction of well deliverability in gas condensate reservoir are highly desirable for as the cost of laboratory determination is rising. The Laboratory process is tedious and some times unreliable.

4.9.5 Modification steps for the new hybrid correlation, Z.

This approach is called hybrid model or correlation because it involves the use of composition and specific gravity in developing it but only needs specific gravity values at various reservoir pressures as input parameter. The routes used in deriving the hybrid correlation include;

Recalling equation (4.13) Specific gravity, $\gamma_g = \frac{\rho_g}{\rho_{air}}$

And assuming ideal gas law for the air and gas, equation (4.15) is

$$\gamma_g = \frac{M_g}{M_a} = \frac{M_g}{29}$$

Applying Elsharkawy’s correlation (2006) for condensates, heavier gases;

$$P_{pc} = 787.06 - 147.34\gamma_g - 7.916\gamma_g^2 \qquad (4.67)$$

$$T_{pc} = 149.18 + 358.14\gamma_g - 66.976\gamma_g^2 \qquad (4.68)$$

The pseudo critical properties were used to determine the pseudo reduced properties which were then applied to the Dranchuk Abou Kassem (DAK) correlation to calculate the compressibility factor Zm .

Also, the compositions were used as well to determine the pseudo critical properties and the pseudo reduced properties. The Anschutz rich gas condensate composition reported by Walsh 2003 was used as base case for compositional based compressibility factor. The gas gravity approach is referred to in this study as the molecular mass basis gave compressibility factor (Z_m), and the compositional approach gave the compressibility factor (Zc). The predicted Zc and Zm were plotted in figures 4.10 against reservoir pressures corresponding to each of the corresponding composition and condensate gravity as shown below.

4.9.6 Results and discussions

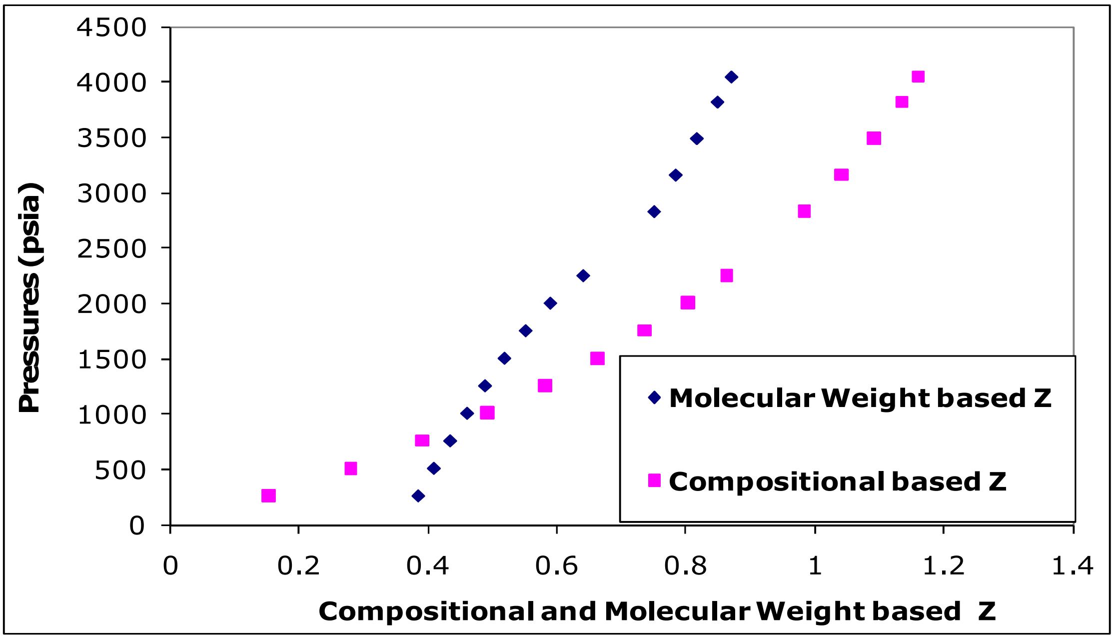


Figure 4.10 Compositional based condensate compressibility factor (Zc) compared with molecular weight

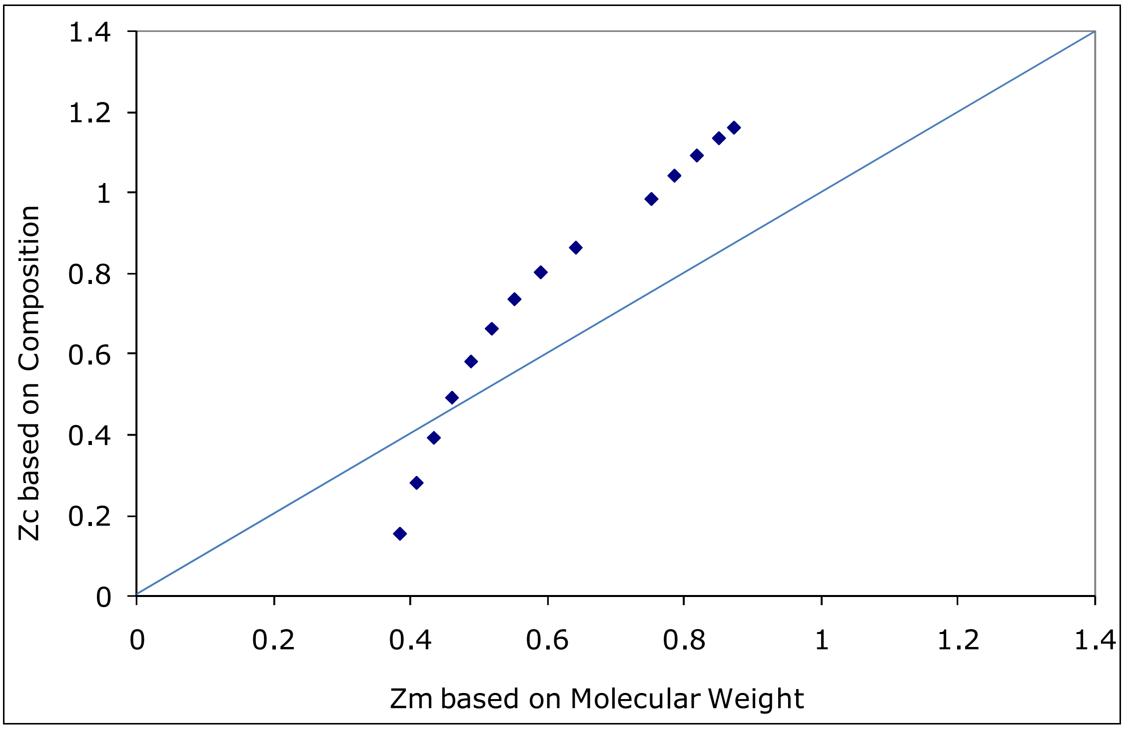


Figure 4.11 Cross plot of compressibility factor (Zc) based on composition versus molecular weight based (Zm)

Preliminary investigations using specific gravity and molecular weight relation as a basis for correlation have shown that molecular weight as a basis did not agree closely with the gas condensate compressibility factor determined from composition as shown in figures 4.10 and 4.11. For other reservoir fluids it is a good basis but for gas condensate, the compositional variations with temperature and pressure may be the reason for lack of agreement between the compositional and the molecular weight based predicted compressibility factor.

However figures 4.10 and 4.11 suggest a relation between the compositional based Zc and the molecular weight calculated Zm. Different curve fits were applied to the figures 4.12, 4.13 and 4.14 to derive the best curve fit that relates compositional compressibility factor Z to Z_m.

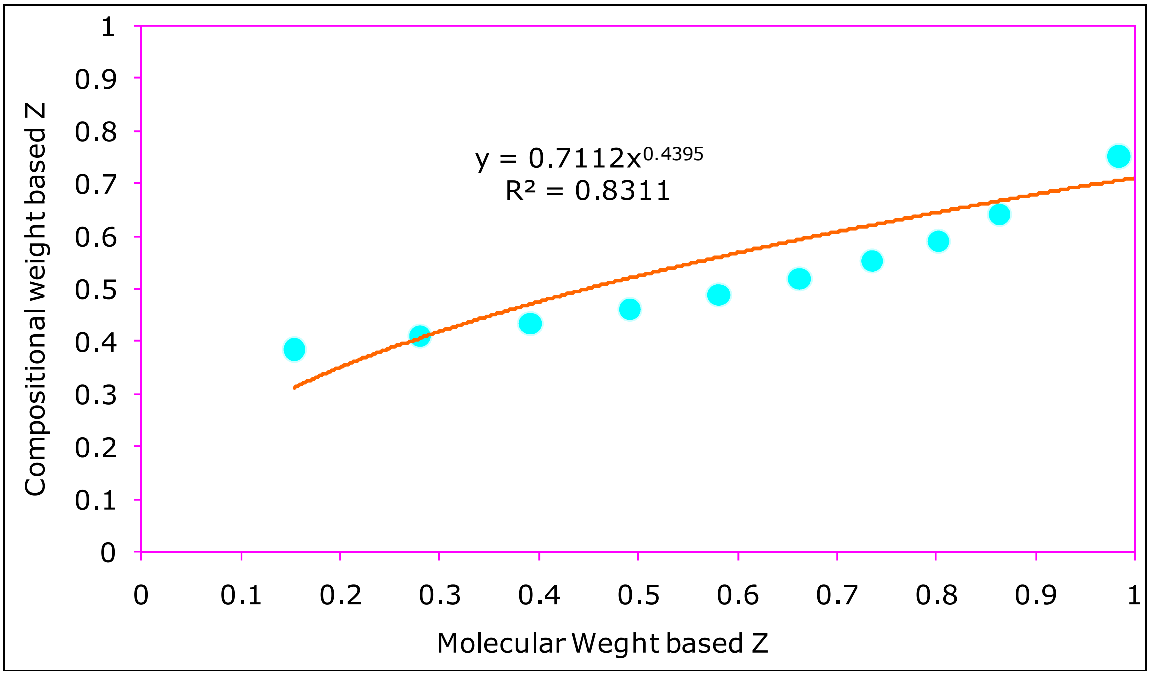


Figure 4.12 Compositional based Zc as a power function of molecular weght based Zm for condensate

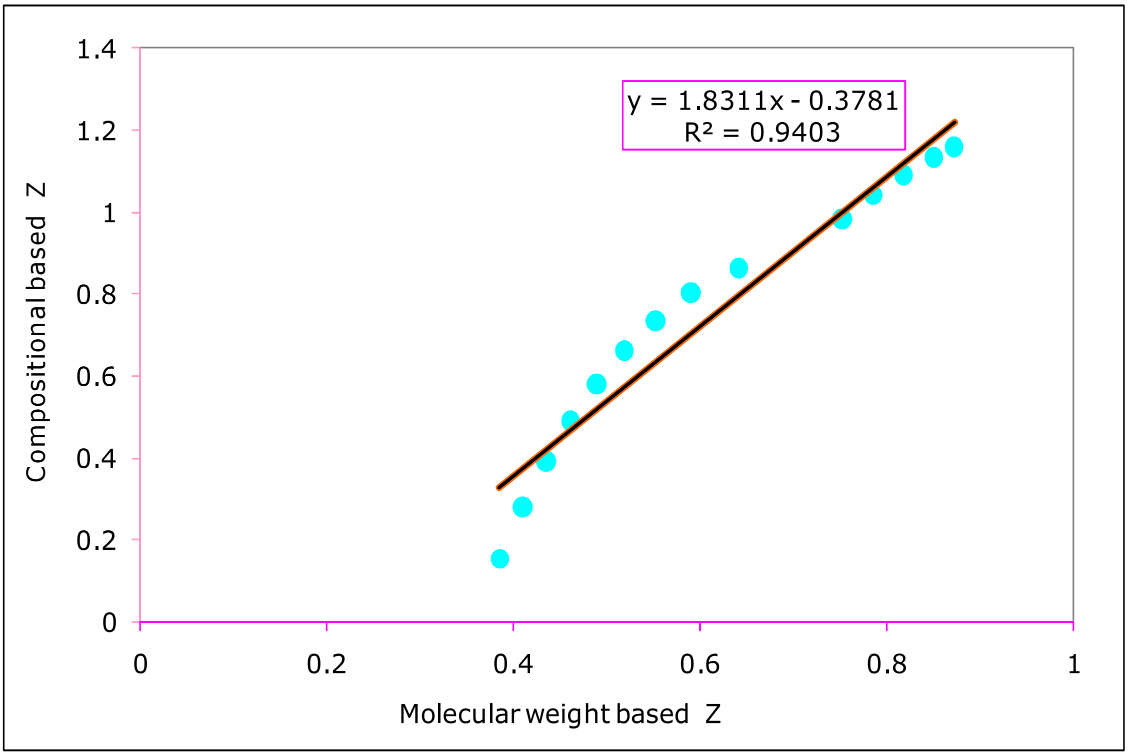


Figure 4.13 Compositional based compressibility factor (Zc) as a Linear function of molecular weght based compressibility factor

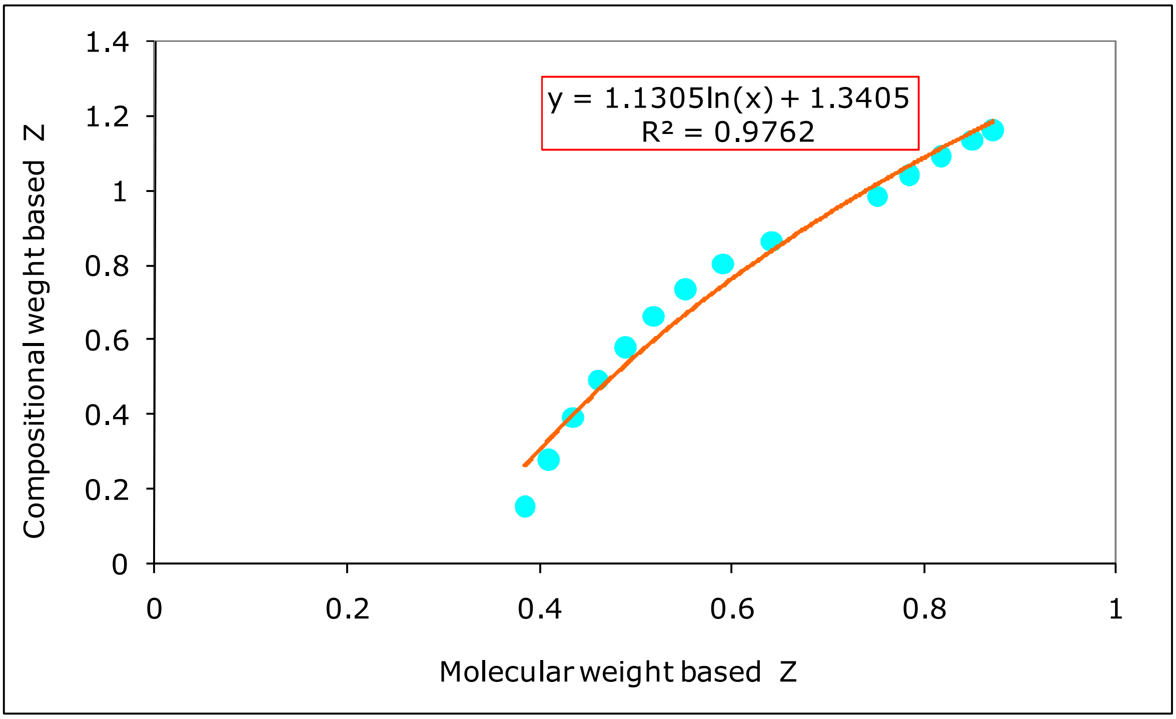


Figure 4.14 Compositional based compressibility factor (Zc) as a Logarithmic function of molecular weght based compressibility factor

This approach gave hybrid correlation for prediction of compressibility factor that combines compositional and specific gravity effects as;

$$Z = 1.1305 \ln Z_m + 1.3405 \qquad (4.69)$$

Where Z = Condensate compressibility factor

Z_m = Compressibility factor based on molecular weight.

The curve fit in figure 4.14 had the best regression coefficient of 97.6%. This represents a better correlation compared with the relationship between the compositional based and the molecular weight based compressibility factor.
The correlation was tested by comparison of the predicted compressibility factor with Eq. 4.69 to the measured compressibility factor. The average absolute error in the use of equation (4.69) in calculating the compressibility factor of gas condensate was 5.72% as shown in table 4.12 below.

Table 4.12 Absolute average error in condensate compressibility factor, Z , based on molecular weight.

Molecular weight based Zm	Compositional based Zc	Z Correlated based on mol. Wt.	% Error	Absolute % Error
0.409183579	0.2799	0.33029495	-18.00	18.00
0.434383672	0.3915	0.397858466	-1.62	1.62
0.460780068	0.4913	0.464549681	5.44	5.44
0.488716207	0.581	0.531092172	8.59	8.59
0.518743031	0.662	0.598500122	9.59	9.59
0.551850058	0.7355	0.668441599	9.12	9.12
0.590198737	0.8023	0.744391922	7.22	7.22
0.641158686	0.8631	0.83801729	2.91	2.91
0.751417065	0.9839	1.017409392	-3.41	3.41
0.784788501	1.0414	1.066533474	-2.41	2.41
0.817554208	1.0915	1.112774263	-1.95	1.95
0.849777497	1.1347	1.156476383	-1.92	1.92
0.871593082	1.1606	1.18513243	-2.11	2.11
		Absolute Average Error (AAE)		**5.72**

The calculation illustrates that compressibility factor; Z can be evaluated from molecular weight using gas gravity when compositions are not known. The gas gravity has been correlated to pseudo critical properties even for gas condensate mixtures by many researchers, (Sutton 2007, Standing 1981 and Elsharkawy 2000) and has been tested to yield similar results with marginal difference.

Our figures 4.10 and 4.11 as shown above support the literature references Sutton (2005), Galumbo (2007) that the use of gas gravity does not yield accurate match of compressibility factor as demonstrated. We have been able to correlate molecular weight based compressibility factor Zm to compositional based compressibility factor.

4.10 Prediction of condensate formation volume factor (FVF)

The equation of state is mainly used to correlate reservoir volumes to surface hydrocarbon volumes. The gas formation volume factor and gas expansion factor are used to convert reservoir volumes to equivalent surface volumes. The formation volume factor is an important parameter in reservoir performance evaluation and design of different stages of oil and gas field operations (Marhoun 1992). . For this study the formation volume factor was one of the parameters needed in modelling well deliverability as measured values may not be available all the time. As a result correlations for gas formation volume factor and oil formation volume factor were sourced for gas-condensate systems Published measured data were collected from condensate fields and were used in testing the available correlations for oil and gas phases of gas condensate reservoirs.

The available formation volume factors shortlisted for investigation to facilitate the selection of the best model for gas and condensate formation volume factor for this study include:-

(i) Gas formation volume factor correlation (Craft and Hawkins 1991)

(ii) Petroleum Expert default model (1998)

(iii) Khuzhayorov (1996)

Khuzhayorov (1996) gave the following correlations for modelling both oil and gas formation volume factors as;

$$B_o = 0.338 + 2.10^{-2} p, \tag{4.70}$$

$$B_c = 1.15 + 0.145.10^{-2} p, \tag{4.71}$$

$$B_g = 1/p, \tag{4.72}$$

The gas formation volume factor correlations given by Craft and Hawkins (1991) are of the following forms;

$$B_g = 0.02829\frac{zT}{P}, cuft/SCF \tag{4.73}$$

$$B_g = 0.00504\frac{zT}{P}, bbI/SCF \tag{4.74}$$

$$B_c = 1.29 + 182ZT/P \tag{4.75}$$

The correlations were validated with measured field data. The gas formation volume factor prediction using equation (4.74) agreed closely with measured data as shown in figure 4.15 and was adopted for implementation in the well deliverability performance equation without modification. The oil and the condensate formation volume factor correlations were validated using measured data and the results were shown in figure 4.16. The tested correlations did not agree with the measured correlation especially at lower pressure and the gas correlation was modified using a Minitab statistical package to give the correlation coefficients. The new correlation for condensate formation volume proposed by this study is defined by equation (4.75). The new correlation was validated and the result is shown in figure 4.17. The predicted condensate formation volume factor agreed with the measured data over the whole pressure range and was adopted as part of the model input correlation to the well deliverability.

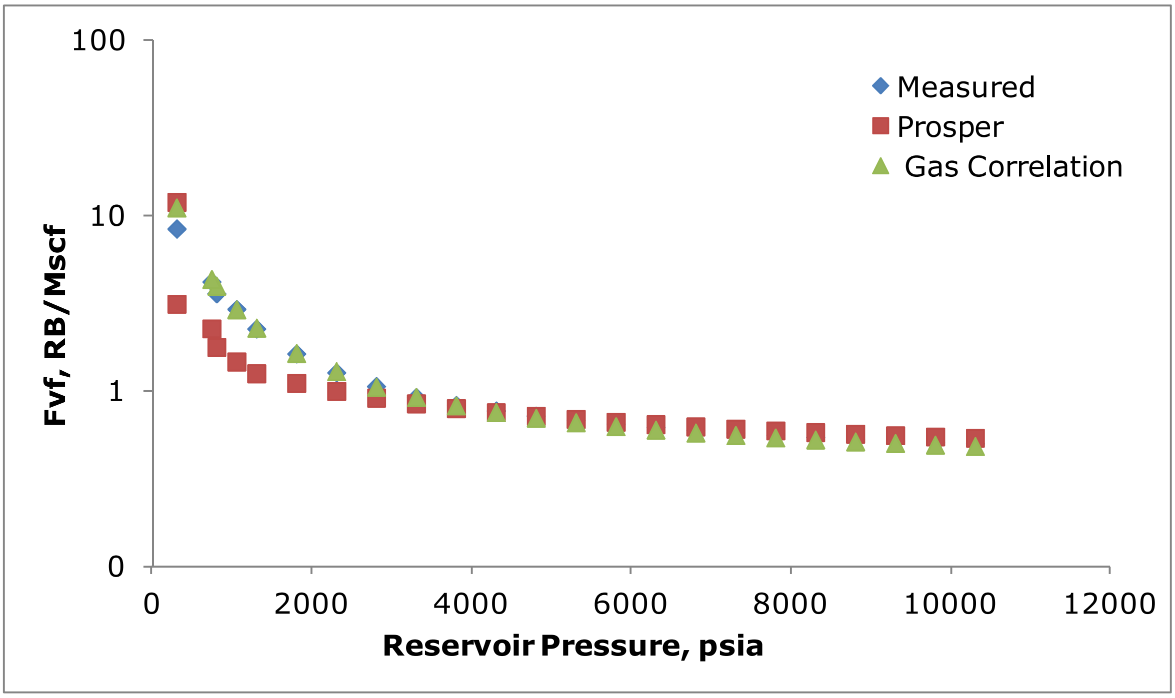


Figure 4.15 Tested gas formation volume factor (FVF) correlations with gas condensate field data.

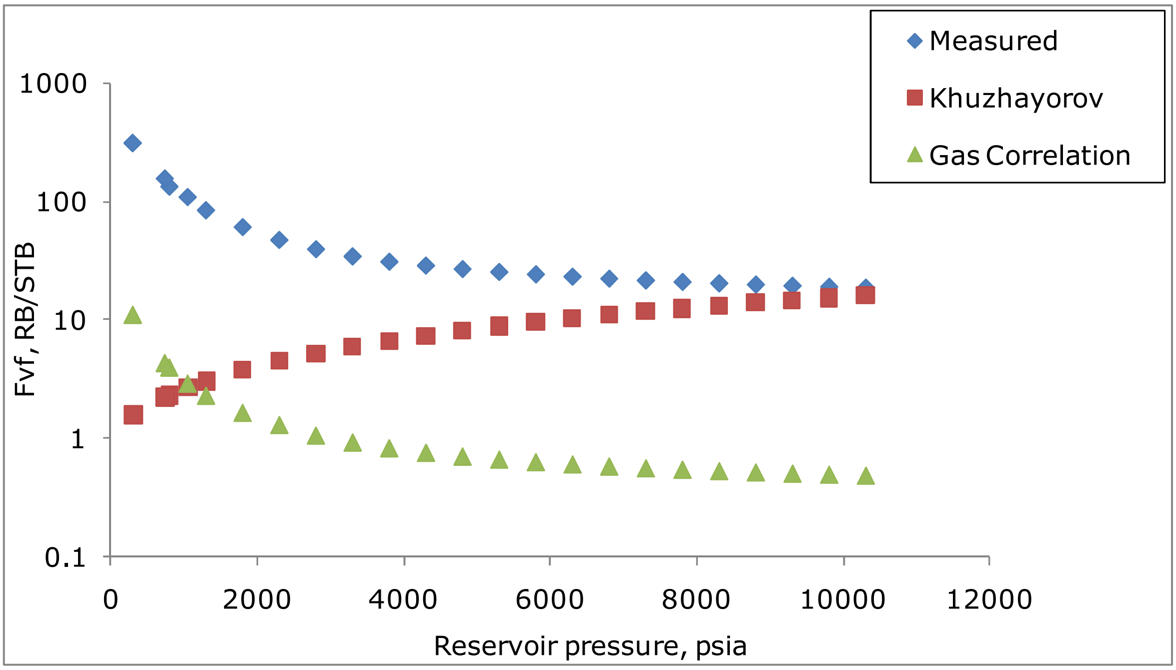


Figure 4.16 Tested gas formation volume factor (FVF) correlations with condensate field data.

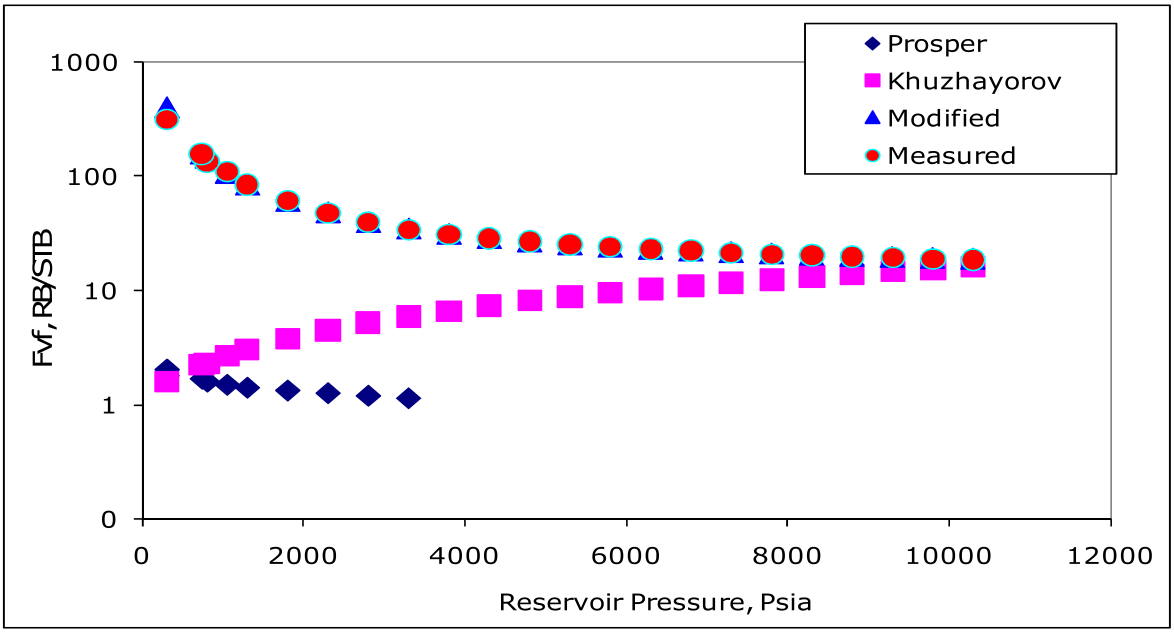


Figure 4.17 Validation and comparison of modified gas condensate formation volume factor (FVF) correlation with existing correlations and gas condensate field data

4.11 Result summary

This reduced the error in calculation of compressibility factor for rich gas condensate reservoir from over 18% to a maximum error of 5.7%, in addition to saving time and money, laboratory cost of experimentation to determine composition, therefore represents a good contribution to knowledge. With the above correlation, equation (4.69), condensate compressibility factor could be predicted with confidence, when composition is not available.

The newly developed correlation based on improved specific gravity or molecular based correlation compare favourably with results obtained from compositional based correlation. This is demonstrated by the high correlation coefficient and low average absolute error values shown by the application of the new correlation. The validated results show that prediction of condensate PVT property data has been improved by the new correlation. These properties are required for well deliverability prediction. The development of a correlation that matches experimental results satisfactorily is an indication of additional understanding of gas condensate reservoir phase behaviour.

The new correlations developed and validated in this study include equations, 4.44, 4.47, 4.66, 4.69, and 4.75.

CHAPTER FIVE

5.0 DEVELOPMENT OF ROCK PROPERTY CORRELATIONS.

5.1 Introduction

Probably one of the most important properties of a gas condensate reservoir system is its relative permeability to condensate, gas and water. Yet relative permeability is perhaps the least understood and the least precisely known property (Trujillo 1982). A good illustration of the poor understanding of relative permeability is given by standing, (1990), Standing (1975) where he explained how engineers source relative permeability data in the industry. He summarised the approaches as;

(i) Guess and take a piece of paper and draw curved lines simulating the shapes seen in the text books, or technical articles and the result will be poor indeed.

(ii) By analogy, select a relative permeability saturation curves from any core and assume same characteristics with your candidate reservoir and your result will be as good as guess work and unreliable for any meaningful engineering judgement.

(iii) The use of empirical relationships between measured capillary-saturation data to characterise the pore structure of the reservoir rock and extrapolating and averaging in a consistent manner an experimentally determined data. The approach may yield good result in some cases but not always.

(iv) He further stated that laboratory measured values are generally believed to be the most accurate, yet they can be inaccurate for so many reasons ranging from inexperience to use of inconsistent procedures.

The problem lies in obtaining data for a good representative core and extrapolating this reservoir boundary. However because of the scarcity of measured relative permeability data empirical relations are widely used but the understanding of theory behind the relationships is crucial for accurate relative permeability prediction. These problems are further complicated in three phase flow where most of the time measurements are impossible and This problem is worse in gas-condensate reservoirs where retrograde condensation and re-vaporisation are present. These problems informed the use of semi-empirical procedure adopted in the current investigation.

A reservoir engineer is often expected to make decisions with little or no data about a reservoir. Among the more important decisions that he must make is the selection of a relative permeability correlation. This is one of the critical input parameters in analytical, black oil or compositional modelling of well deliverability in gas-condensate reservoir below the dew point pressure. There is no definitive relative permeability correlation (Maravi 2003) for modelling gas-condensate relative permeability both in two, three or four multiphase systems. Relative permeability is conventionally sourced from special core analysis (SCOA) data for reservoir simulation but this data is rarely available. Three phase relative permeability is rarely measured but can be derived from two phase relative permeability measurement. Non-availability of experimental relative permeability data has made the use of correlations for predicting relative permeability popular.

Relative permeability modelling is a critical issue in well deliverability modelling where applicable. It is important to note that high percentage of the errors in prediction of well deliverability comes from relative permeability issues. Some oil companies have special policy on relative permeability values for well performance evaluation reports

Our approach is not modelling relative permeability from the first principle rather published experimental relative permeability databases were used to validate some of the popular relative permeability correlations used to generate data for relative permeability input in modelling well deliverability in gas-condensate reservoirs.

5.2 Approaches to modelling relative permeability.

Relative permeability is an important parameter in modelling well deliverability in multiphase systems. Production of retrograde gas-condensate system below the dew point pressure is such a system. Study has been on the various concepts for relative permeability determination in the near-well region which is the dominant factor in prediction of well deliverability in gas condensate reservoirs where condensate banking is implicated. The available experimental data is not of the form that could be fitted into some of the reviewed correlations in the study. That limited their applicability in the study. The work has matched available correlations to sourced database of measured relative permeability to fully evaluate the validity of the widely used relative permeability correlations to enable decision on which correlation to adapt for this study or propose an alternative correlation.

The models reviewed and validate with measured data in the study include the following;

5.2.1 Testing Brooks-Corey relative permeability correlations (Fevang 1995)

Corey correlations for oil and water have been widely applied to condensate systems (Fevang 1994, Rossenac 2001, Yanil 2003). On this basis, data obtained from Fevang was used to test the following Corey correlations;

$$k_{rg} = k_r(S_{wi})\left(S_g^*\right)^2\left[1-\left(1-S_g^*\right)^{(2+\lambda)/\lambda}\right] \tag{5.1}$$

$$k_{rc} = k_r(S_{wi})\left(S_c^*\right)^2\left(\frac{S_c}{1-S_{wi}}\right)^{(2+\lambda)/\lambda} \tag{5.2}$$

Where;

$$S_g^* = \frac{S_g}{1-S_{wi}} \tag{5.3}$$

$$S_c^* = \frac{S_c - S_{cc}}{1-S_{wi}-S_{cc}} \tag{5.4}$$

The following data values used are fixed for Fevang's relative permeability data set sample

$K_r(S_{wi})$	Relative permeability at interstitial water saturation = 0.8
λ	Pore size distribution parameter = 2
S_{cc}	Critical Condensate Saturation = 0.1
S_{wi}	Irreducible water saturation = 0.25

The approach accounted for the transient values of the relative permeabilities which are dependent on the residual condensate and gas saturations, and the irreducible water saturation as indicated in the above models.

The relative permeability of Fevang's gas condensate data have been fitted into Corey correlation and compared with measured values as shown in figure 5.1. The method assumed uniform irreducible water saturation.

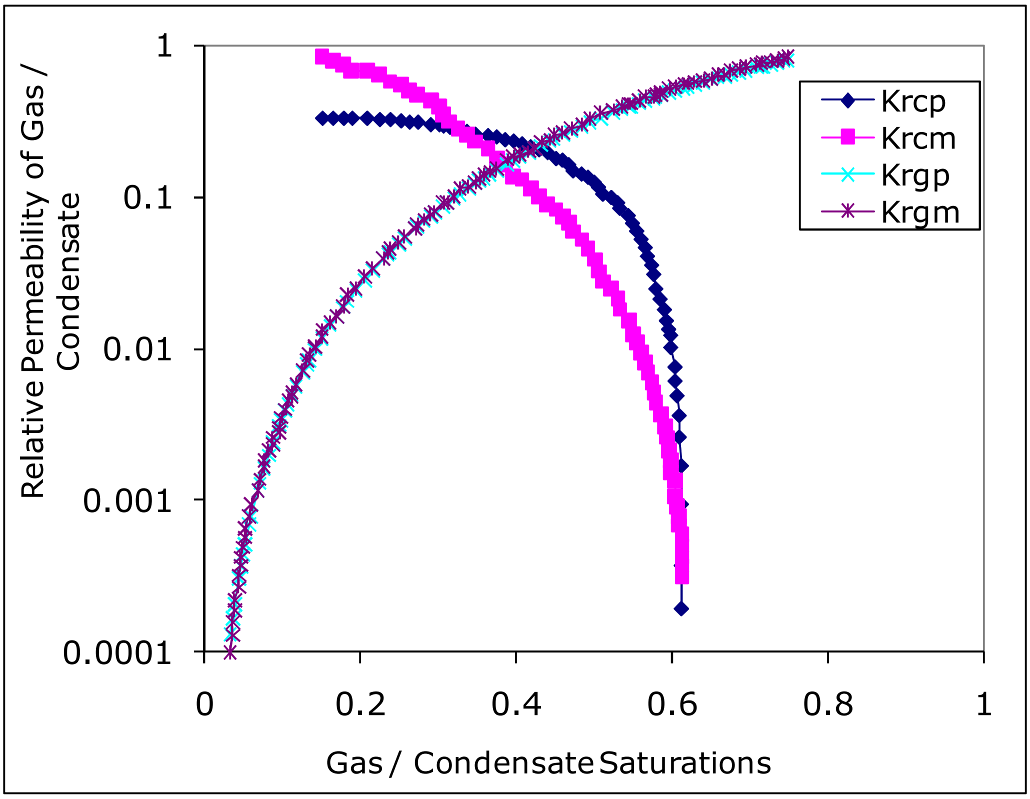


Figure 5.1 Corey fit for gas condensate relative permeability curve compared with measured relative permeability data.

The predicted relative permeability of gas (Krgp) is in agreement with the measured relative permeability of gas (Krgm). The relative permeability of condensate predicted by Corey (Krcp) deviates from the measured relative permeability of condensate (Krcm) as can be seen from the above curve. Subjecting the data to error analysis over the condensate relative permeability range from 0.001 to 0.2 gave an average absolute error of 5.7% and maximum percentage error of 10.2%. However the irreducible water saturation assumption and the deviation of the predicted condensate relative permeability from the measured made the above correlations inadequate for application in this study. Other approaches for prediction of condensate relative permeability were explored.

5.2.2 Modifications of Corey oil-gas systems for condensate-water-gas system

Corey condensate – water (Ahmed 2006)**;**

$$k_{rcw} = \left(\frac{1 - s_w - s_{cr}}{1 - s_{wi} - s_{cr}} \right)^{\lambda c} \quad (5.6)$$

$$k_{rw} = k_{rwend} \left(\frac{s_w - s_{wi}}{1 - s_{wi} - s_{cr}} \right)^{\lambda w} \quad (5.7)$$

Corey condensate – gas;

$$k_{rcg} = \left(\frac{1 - s_g - s_{wi} - s_{cr}}{1 - s_{wi} - s_{cr}} \right)^{\lambda c} \quad (5.8)$$

$$k_{rg} = \left(\frac{s_g - s_{gc}}{1 - s_{wi} - s_{cr} - s_{gc}} \right)^{\lambda g} \quad (5.9)$$

$$S_g = S_{org} + \left(\frac{[1 - WC] \times B_g}{[1 - WC] B_g + WC \times B_w} \right) \times [1 - S_{wi} - S_{orw}] \quad (5.10)$$

$$S_w = S_{wi} + \left(\frac{WCB_w}{[1 - WC] B_o + WC \times B_w} \times [1 - S_{wi} - S_{orw}] \right) \quad (5.11)$$

Where at $s_g = 0$

$k_{rg} = 0$, and $k_{rcg} = 1$

5.2.3 Application of Stone 2 modified model for condensate

$$k_{rc} = k_{rccw}\left[\left(\frac{k_{rcw}}{k_{rccw}} + k_{rw}\right)\left(\frac{k_{rcg}}{k_{rccw}} + k_{rg}\right) - k_{rw} - k_{rg}\right] \qquad (5.12)$$

The value of k_{rc} from the above function may be negative; usually the negative values are regarded as zero values. (Ahmed, 2006)

For three phases, the block average saturations sums up to one,

$$s_c + s_w + s_g = 1 \qquad (5.13)$$

The effective Permeability equations used include;

$$k_c = kk_{rc}, k_w = kk_{rw}, k_g = kk_{rg} \qquad (5.14)$$

The correlations were originally developed for oil-water and oil-gas systems, but modifications introduced into the original correlations by this study were meant to investigate the adequacy of the correlations for condensate-gas-water systems. The earlier test of the original Corey correlations for the condensate system was not in agreement with the measured data, as shown in figure 5.1 and that was the reason for the modification of the 2-phase for 3-phase system.

The following results as shown in figures 5.2 to 5.5 were obtained from the above modifications of Corey correlations with (Eq. 5.10) to (Eq.5.14).

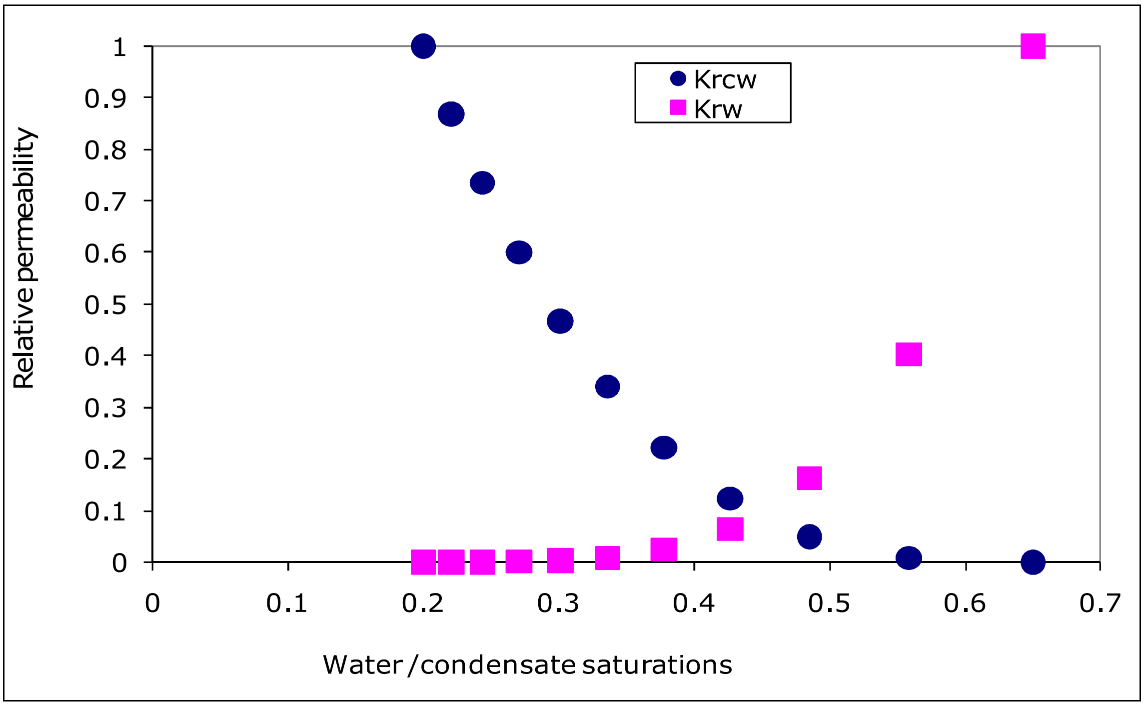


Figure 5.2 Condensate-water relative permeability as a function of water saturation

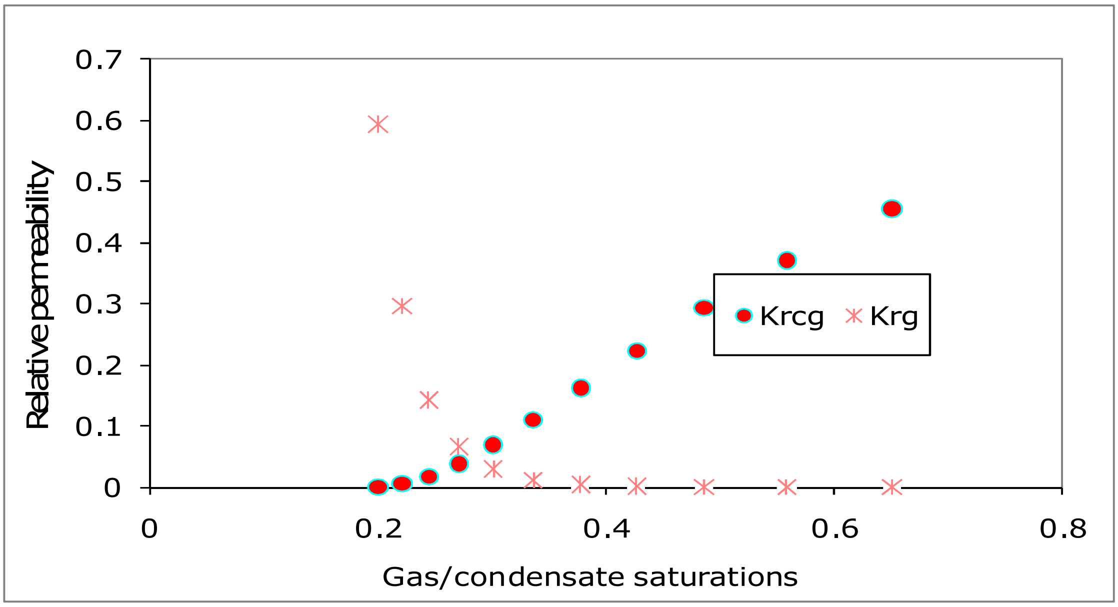


Figure 5.3 Condensate-gas relative permeability

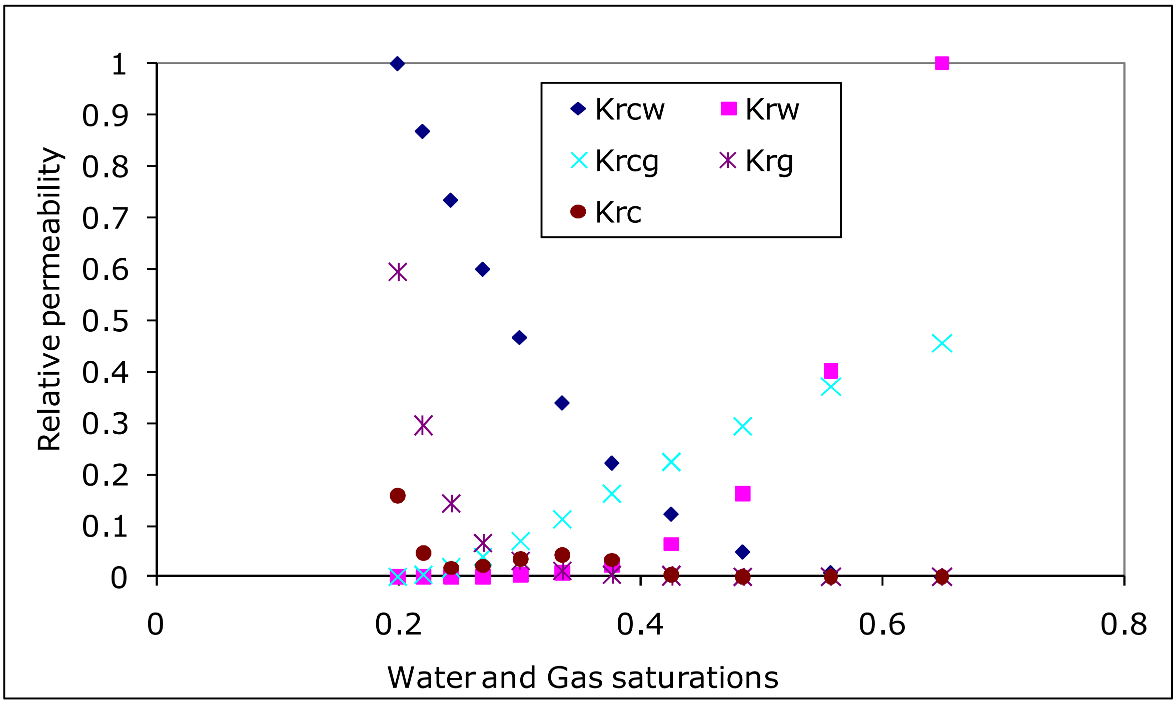


Figure 5.4 Relative permability for the three phase system (Condensate-gas-water)

The plots of figures 5.2 to 5.5 represent results of modified Corey correlations of Eq.5.6 to 5.14.

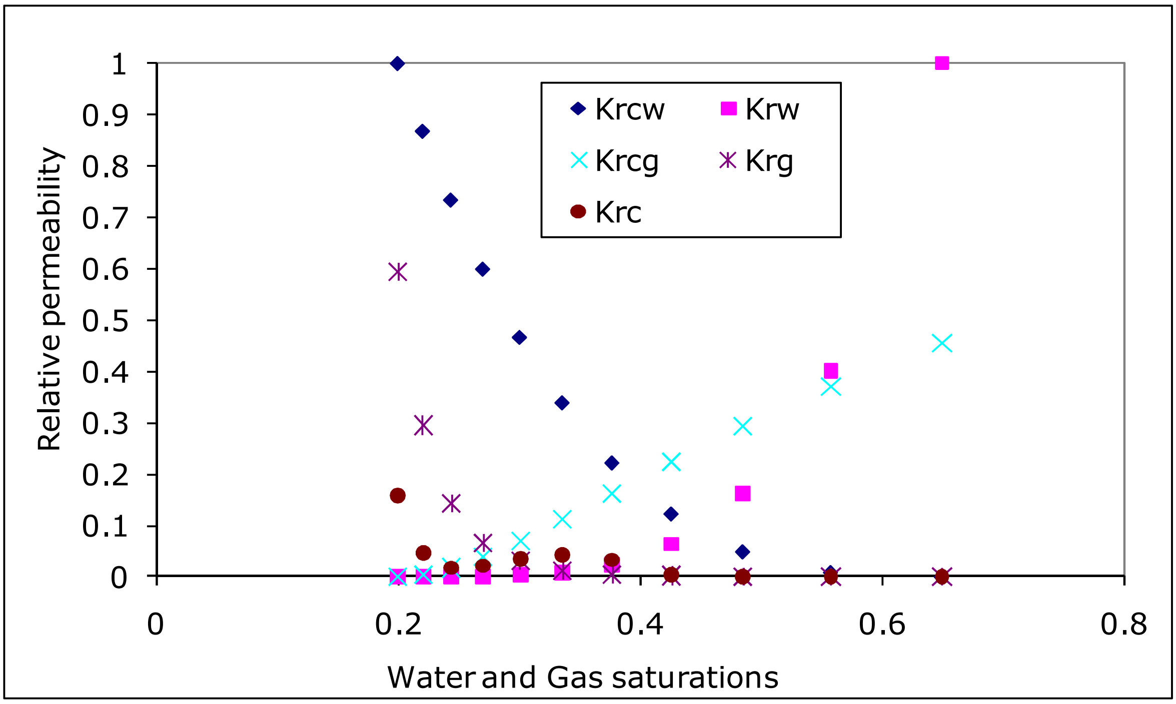


Figure 5.5 Impact of water cut levels on relative permeabilities of condensate and gas

5.3 New trapping model approach (Pope et al 2000)

A build up of condensate in the near the wellbore region results from production in many gas condensate reservoirs below the dew point pressure. The decrease in relative permeability of gas phase arising from the build up of condensate below the dew point causes decrease in the productivity index. The build up around the well bore (also known as condensate banking) makes prediction of condensate relative permeability complex. Accurate relative permeability is required for well inflow performance and for well test interpretation and reservoir simulations. As part of solution to the above problems, a new trapping model was developed by Pope et al, (2000), which is being tested by this study to validate its use for prediction of well deliverability in gas-condensate reservoirs. The model captures the effects of porosity, Capillary number, Bond numbers and interfacial tensions which are critical factors in predicting gas condensate relative permeability near the wellbore. Pope's trapping model is a modification of representation of gas condensate relative permeability model as a function of the Bond numbers to account for buoyancy and capillary numbers for viscous and interfacial forces. The ratio of the gravitational forces to capillary forces on the pore scale is the Bond number, expressed as $N_B = \frac{k\Delta\rho\|g\|}{\phi\sigma}$ (5.15a)

The relative permeability models are given as,

$$\log k_{rl} = \log k_{rl}^0 + \log\overline{S_l} + \frac{\log\left(\frac{k_{rl}}{k_{rl}^0}\right)^{low} + \log\overline{S_l}}{1 + T_l\left(N_{Tl}\right)^{\tau l}} \tag{5.15b}$$

Where

$$\overline{S_l} = \frac{S_l - S_{lr}}{1 - \sum_{l=1}^{nP} S_{lr}} \tag{5.16}$$

$$S_{lr} = \min\left(S_l, S_{lr}^{high} + \frac{S_{lr}^{low} - S_{lr}^{high}}{1 + T_l\left(N_{Tl}\right)^{\tau l}}\right) \tag{5.17}$$

$$N_c = \frac{k\Delta P}{\sigma L} \tag{5.18}$$

$$k_{rl}^{o} = k_{rl}^{olow} + \frac{S_{l'r}^{low} - S_{l'r}}{S_{l'r}^{low} - S_{l'r}^{high}} \left(k_{rl}^{ohigh} - k_{rl}^{olow} \right) \quad (5.19)$$

The relative permeability curves were calculated using the following parameters using Popes' data.

T_l =52335, t_l =1.0

S_{lc}^{low} =0.2, S_{lc}^{high} =0.0

k_{rc}^{olow} =0.25, k_{rc}^{ohigh} =1.0

The basis for the above relative permeability concept is the two flow regime assumption of gas-condensate reservoirs, where one regime corresponds to conditions away from critical point with high interfacial tension (IFT), the other with low IFT belonging to conditions near the critical point (99) for the two regimes. The capillary number, Nc which is the ratio of viscous forces to capillary forces on a pore scale is the controlling parameter for relative permeability. The approach is more appropriate for two phase flow in gas-condensate system assuming water at connate water saturation.

One of our objectives in this study is development of a dynamic relative permeability correlation that does not assume irreducible water saturation for gas-condensate-water system. Therefore as Pope's approach is not valid for three phase systems, further discussion on the pope's approach will be left for other studies (Pope et al. 1998, Afamefule and Handy 1982, Henderson et al. 1997, Boom et al. 1995, Morel, Nectoux and Danquigny 1997, Chen, Wilson and Monger-McClure 1995, Calisgan, Demiral and Akin 2006, Blom and Hagoort 1998, Narayanaswamy et al. 1999, Ayyalasomayajula et al. 2005). Other approaches considered for development of three phase relative permeability for gas condensate system were investigated.

5.4 Three phase relative permeability using MBAL (PETEX suite, 2008)

This correlation is known to be valid for oil-water-gas system, but as a way of sourcing for accurate relative permeability for condensate in three phase system, Stone 2 correlations was tested for condensate relative permeability in three phase systems. The Stone 2 correlation is given by equation 5.12. For lack appropriate test or validation data for condensate relative permeability in three phase systems, a case study was taken from Petroleum Expert, MBAL, and three phases relative permeability data for gas-condensate system were modelled in MBAL to generate relative permeability data that was used for testing Stone 2 correlation. The relative permeability curves generated are shown in figures 5.6 to 5.12.

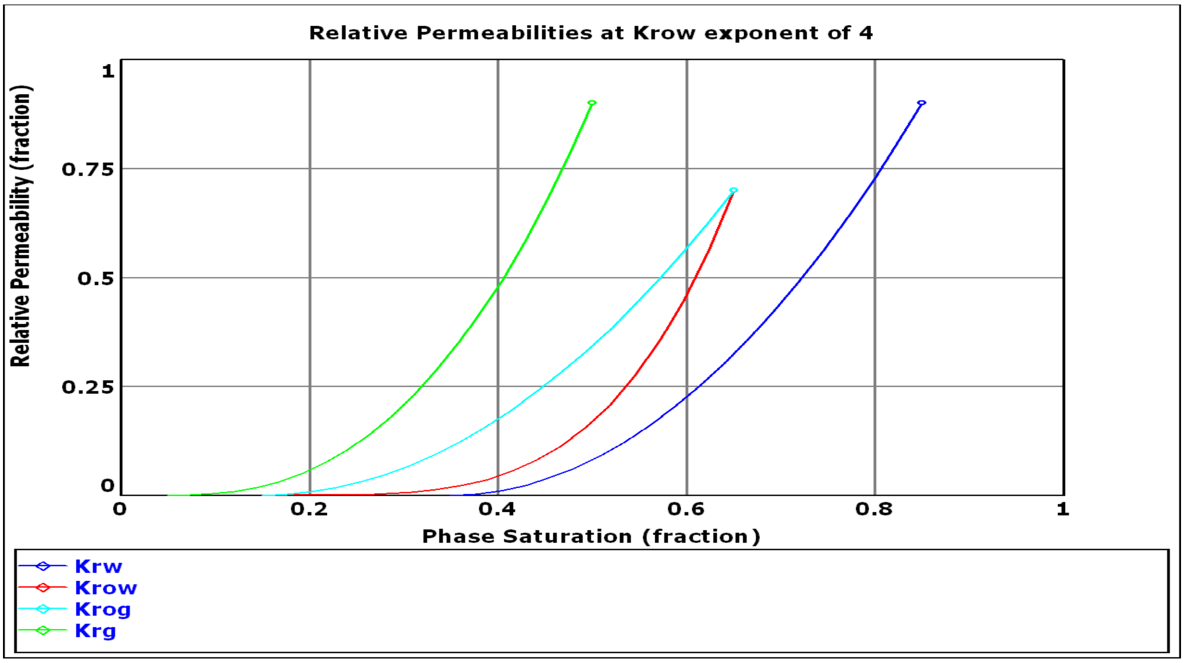


Figure 5.6 Relative permeability model for Anchutz gas-condensate reservoir

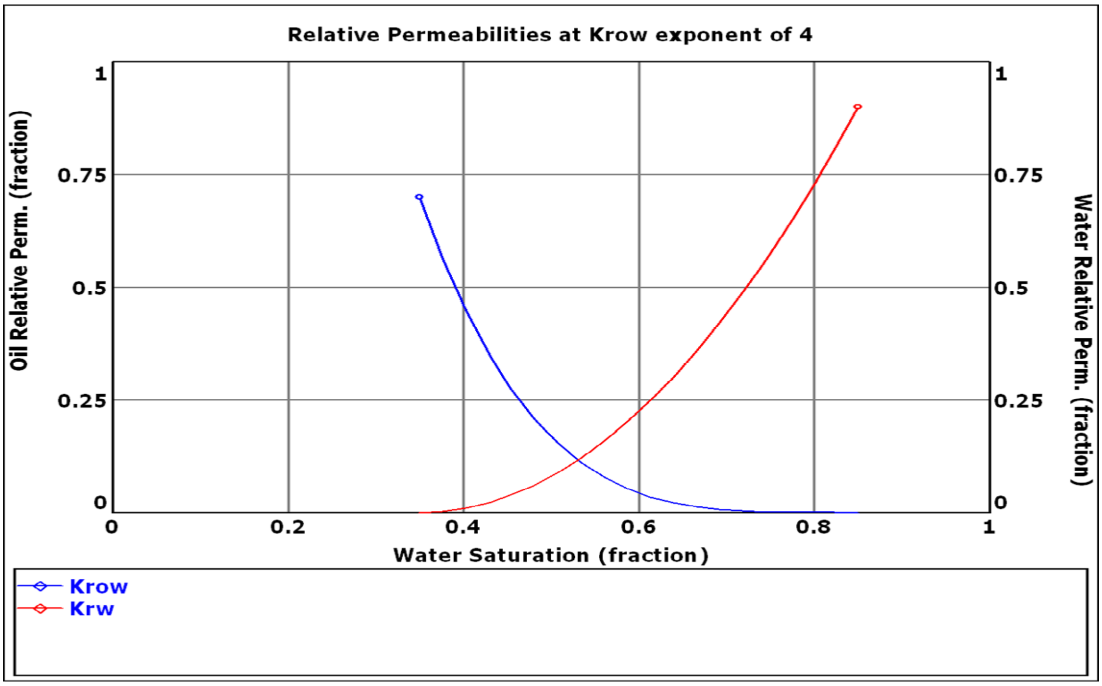


Figure 5.7 Relative permeability model at exponent of 4

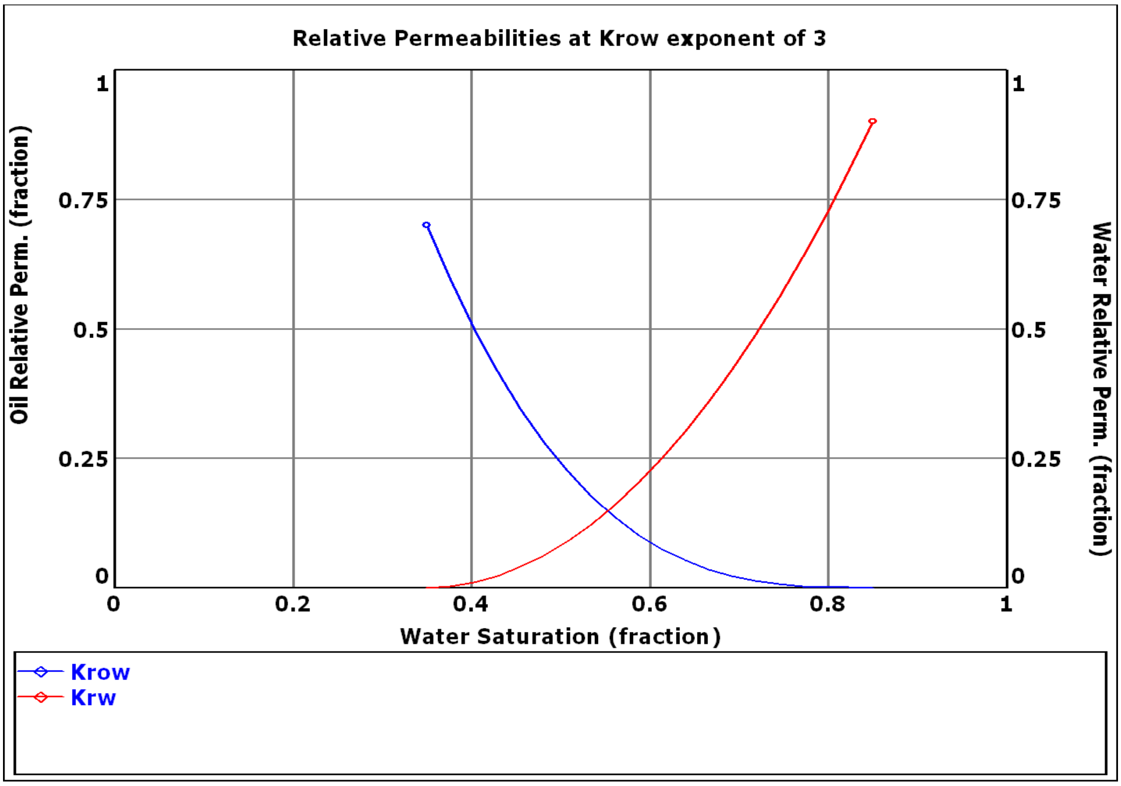


Figure 5.8 Relative permeability model at exponent of 3

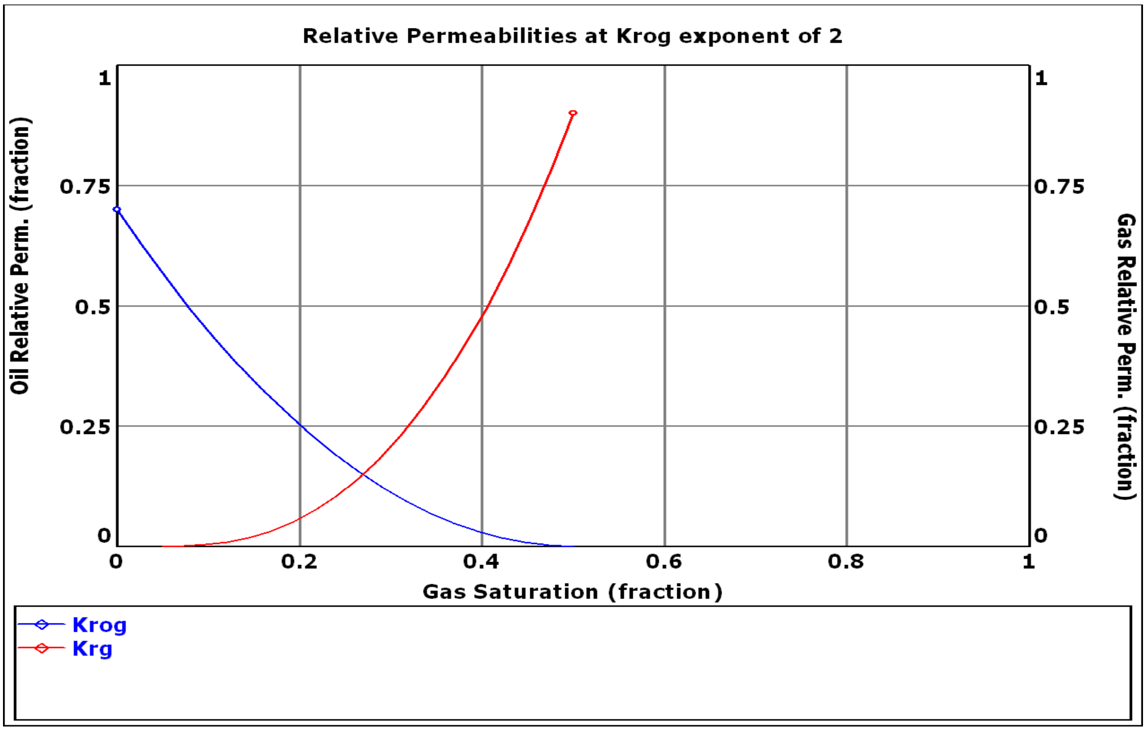


Figure 5.9 Relative permeability at Krog exponent of 2

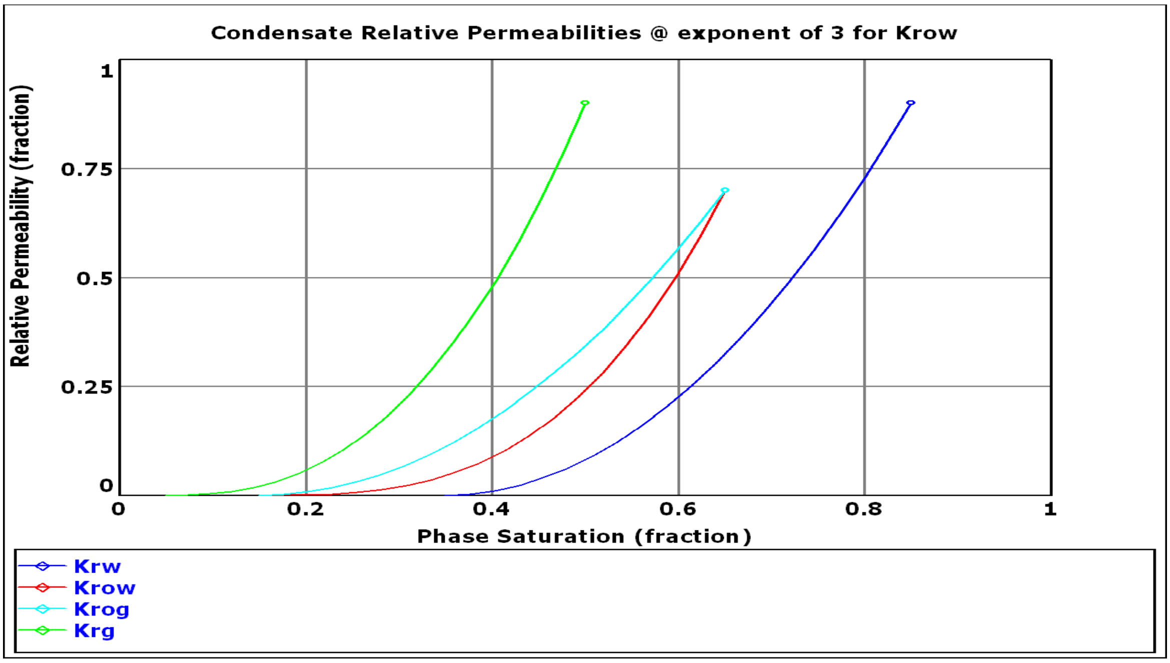


Figure 5.10 Relative permeability of gas with respect to condensate and Water and with respect to condensate at Krow exponent of 3

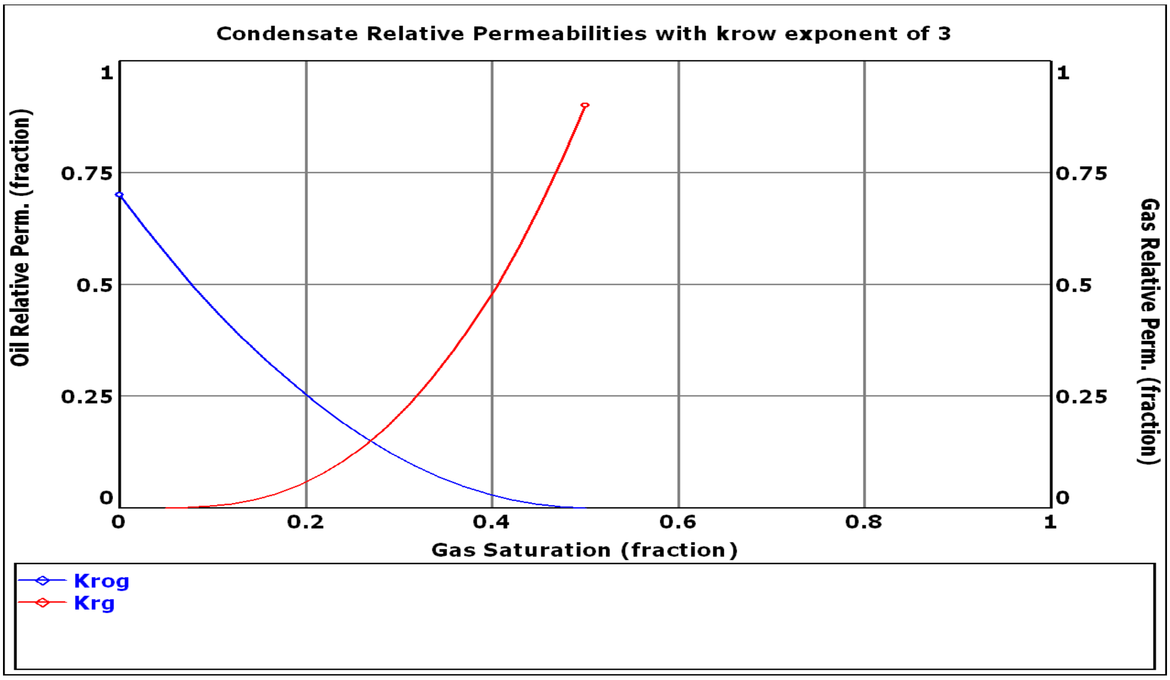


Figure 5.11 Relative permeability of gas with respect to condensate at Krow exponent of 3

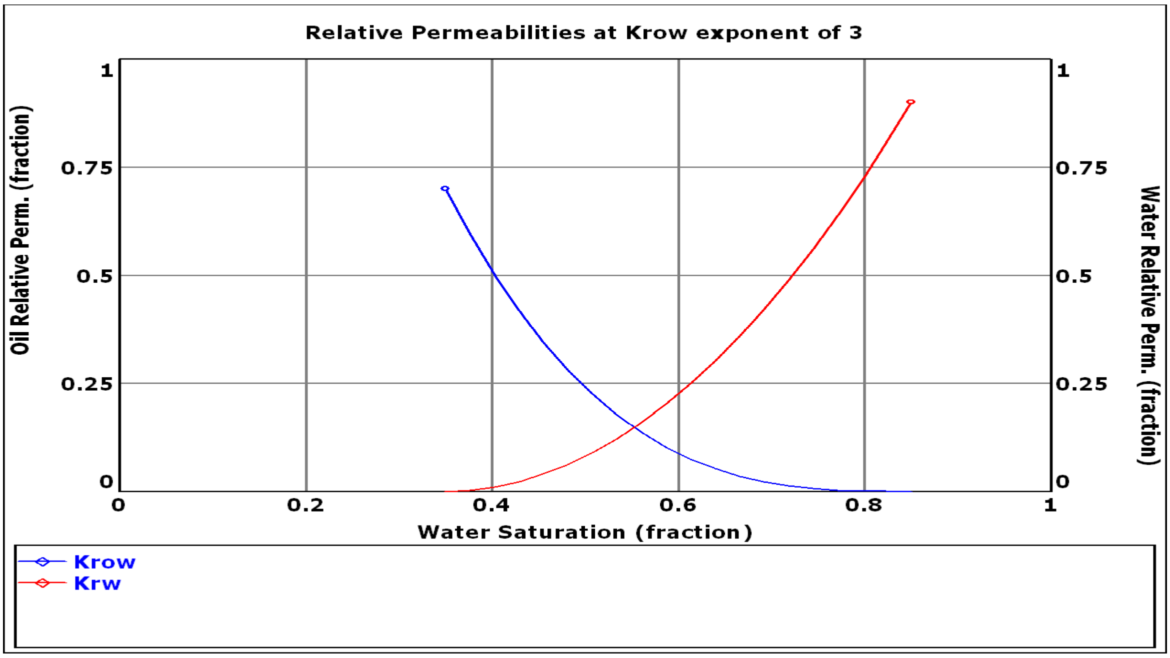


Figure 5.12 Relative permeability of water with respect to condensate at Krow exponent of 3

The generated relative permeability data were used to match Corey correlation as shown in the figures 5.13 to 5.16 below.

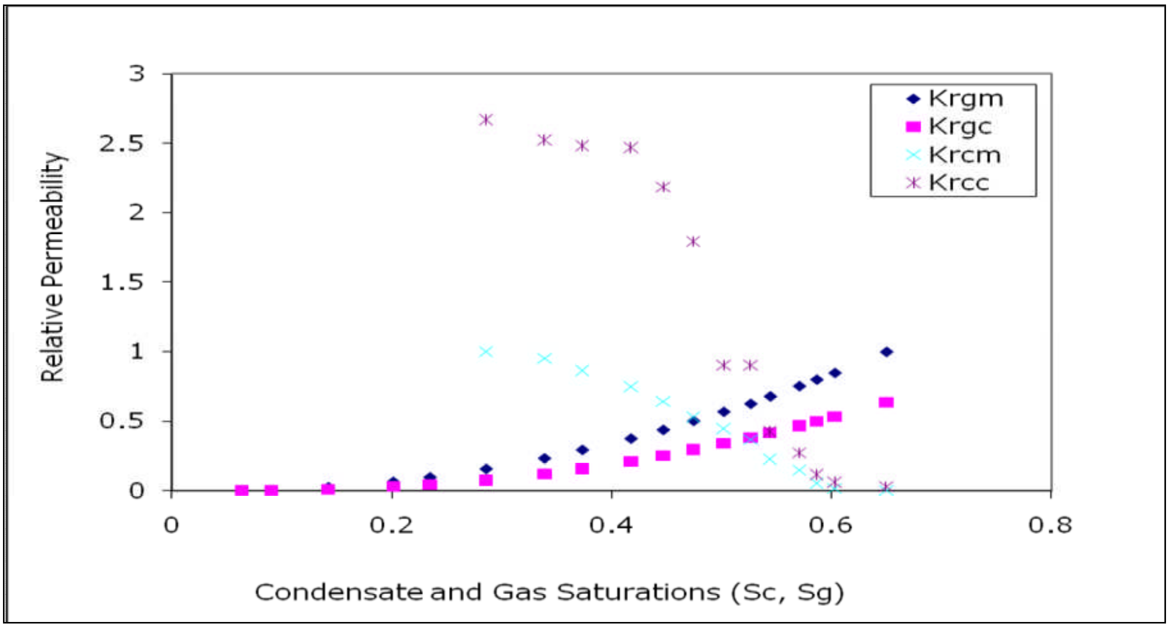


Figure 5.13 Testing Corey relative permeability correlations for condensate reservoirs

As the correlations did not match the MBAL generated relative permeability curve as shown in figure 5.13, attempts were made to tune the correlations to match relative permeability curves by varying the Corey relative permeability exponents as shown in figures 5.14 to 5.16.

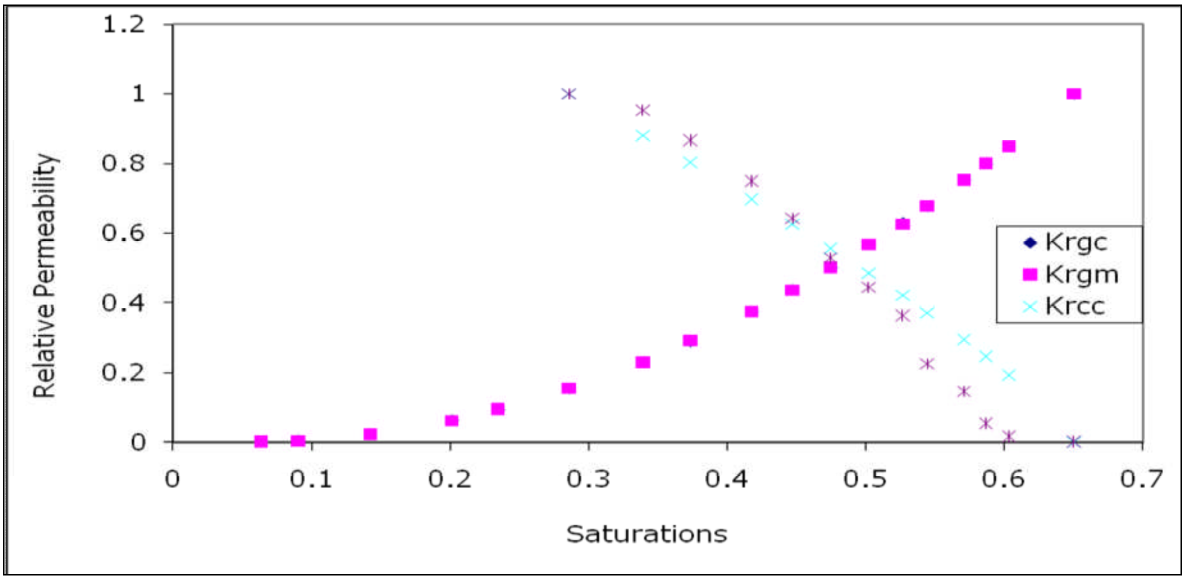


Figure 5.14 Testing Corey's relative permeability correlation for condensate reservoirs for exponent (n=2 for condensate, and n=2 for gas)

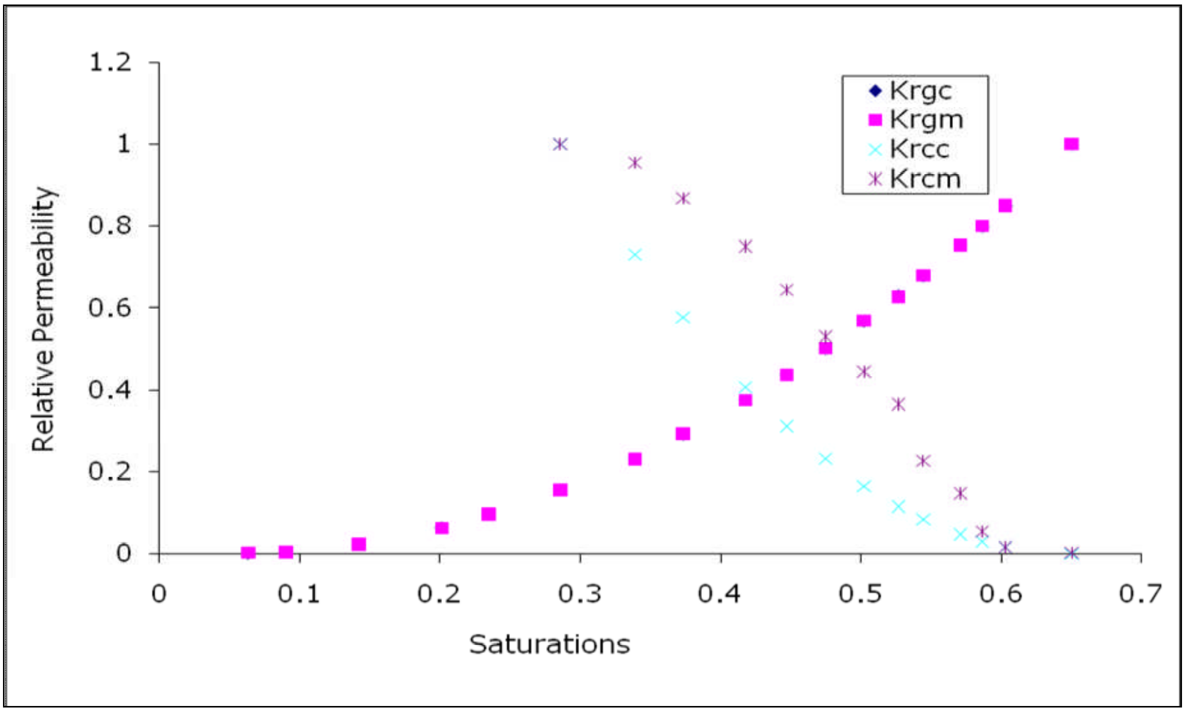


Figure 5.15 **Testing Corey's relative permeability correlation for condensate reservoirs for exponent (n=1 for condensate, and n=2 for gas)**

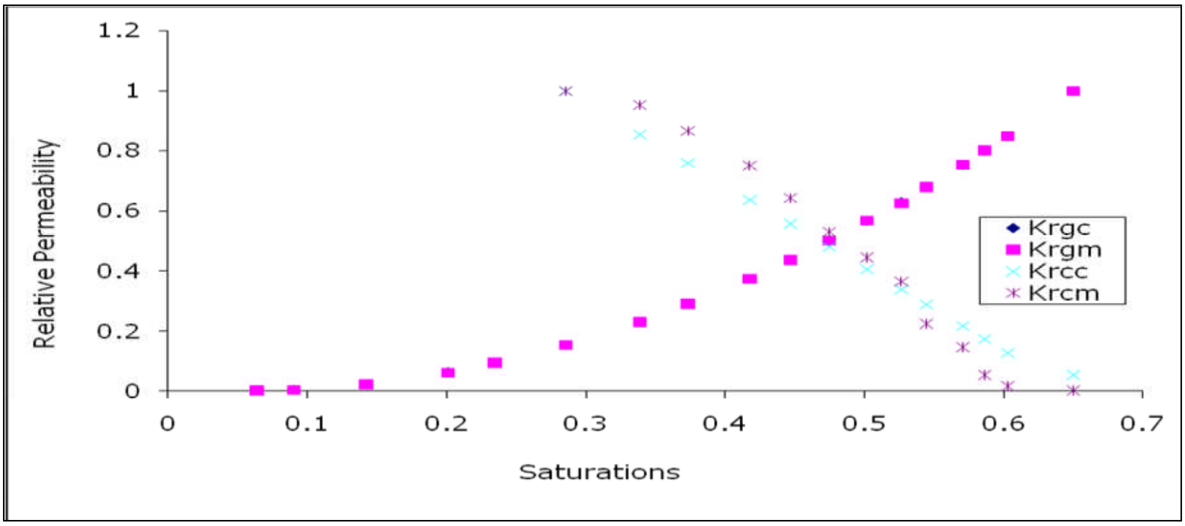


Figure 5.16 **Testing Corey's relative permeability correlation for condensate reservoirs for exponent (n=0.8 for condensate, and n=2 for gas)**

5.5 Modification of two phase oil relative permeability for three phases in gas condensate reservoirs.

The following modifications were made on two phase oil relative permeability for correlating condensate relative permeability (Krc) in 3 phase The new condensate saturation correlation equation 5.20 was derived from old condensate saturation analogous to equation 5.10, and the new condensate relative permeability in three phase equation 5.21 is also a derivative of the old oil relative permeability correlation in two phase equation 5.21a. The correlations were derived used statistical software package MINTAB to define new coefficient for the new correlations using regression analysis. The details of this derivation are shown in appendix B3.The two old correlations equations 5.10 and 5.21 were validated using measured condensate saturation and relative permeability data and results are as shown in the figures 5.17 to 5.19. The results were unsatisfactory, and a regression analysis was done to upgrade the old correlations to new correlations equations 5.20 and 5.21 using a statistical package, MINITAB.

$$S_c = S_{crw} + \left(\frac{\left[1 - WC - GCR\right] * B_c}{\left[1 - WC - GCR\right] B_c + WC * B_w} \right) * \left[1 - S_{wi} - S_{crw} - S_{crg}\right] \tag{5.20}$$

$$K_{ro} = 0.76067 * \left[\frac{\frac{S_o}{1 - S_{wi}} - S_{orw}}{1 - S_{orw}} \right]^{1.8} * \left[\frac{S_o - S_{orw}}{1 - S_{wi} - S_{orw}} \right]^2 * 2.6318\phi\left[1 - S_{orw}\right]\left[S_o - S_{orw}\right] \tag{5.21a}$$

$$K_{rc} = A * \left[\frac{\frac{S_c}{1 - S_{wi}} - S_{crw}}{1 - S_{crw}} \right] * B * \left[\frac{S_c - S_{crw}}{1 - S_{wi} - S_{crw}} \right] * C\phi\left[1 - S_{crw}\right]\left[S_c - S_{crw} - S_{crg}\right] \tag{5.21}$$

Where A=0.168, B=7.57, C=0.97 are regression coefficient for new relative permeability correlation derived from MINTAB as shown in appendix B.3 session window.

The original equations were validated with measured condensate saturations and relative permeability before and after modification and the results were shown in the figures 5:17 to 5.21;

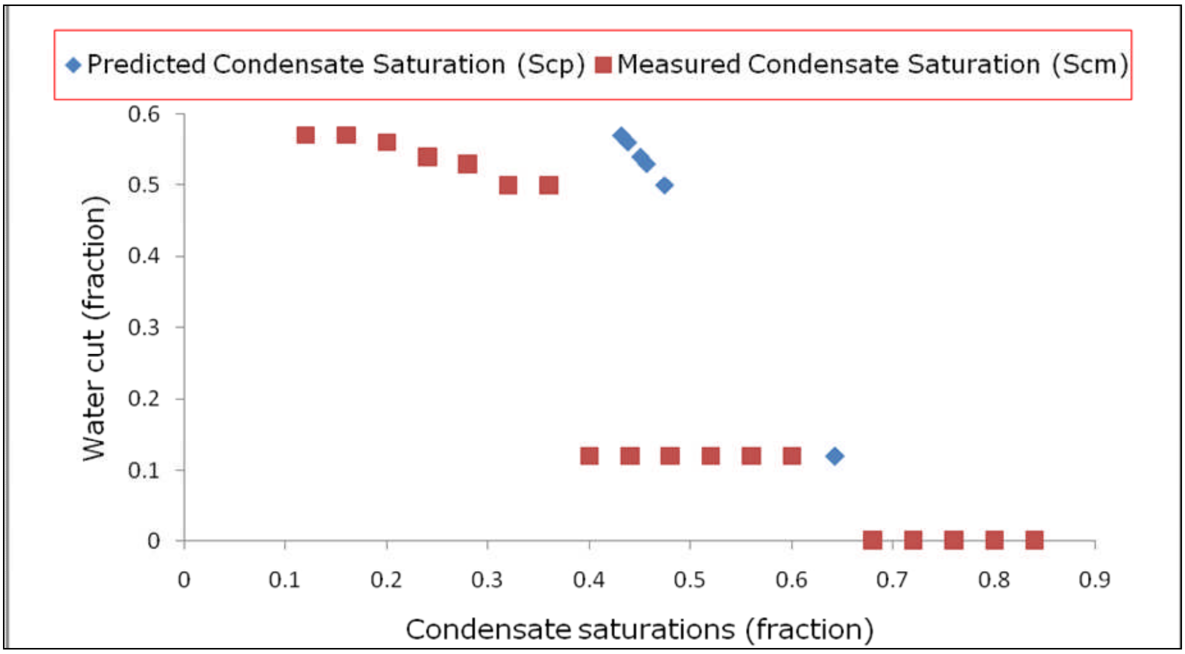


Figure 5.17 Testing old condensate saturation correlation equation 5.20 at different levels of water cut

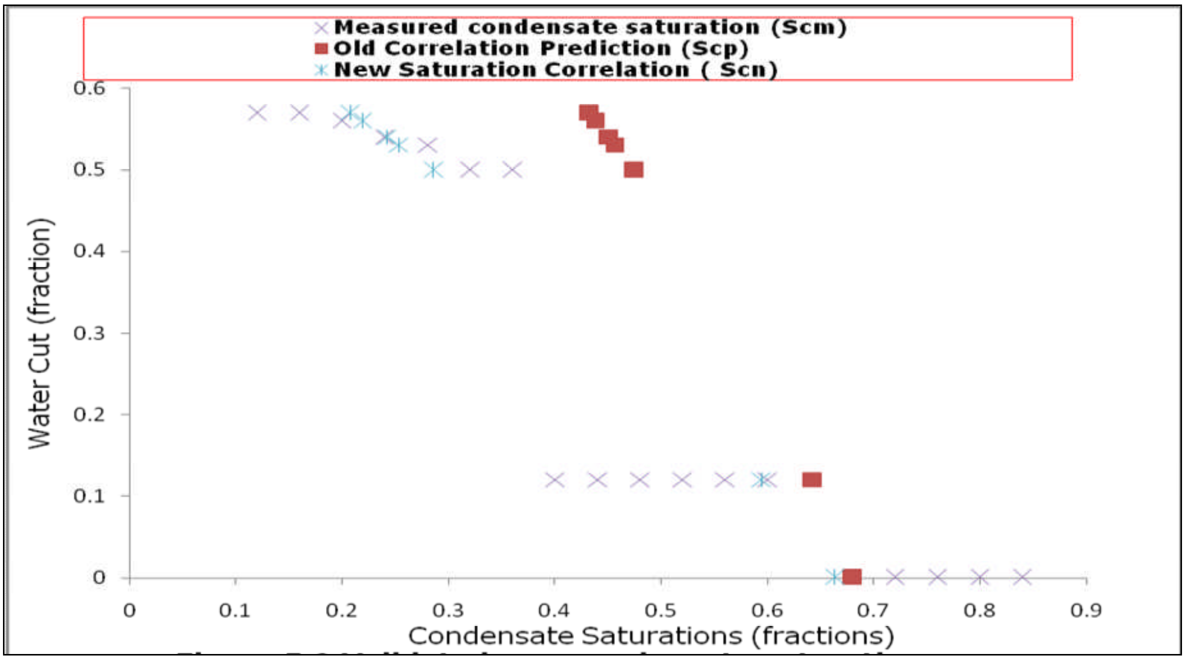


Figure 5.18 Validated new condensate saturation correlation (Scn) with measured database

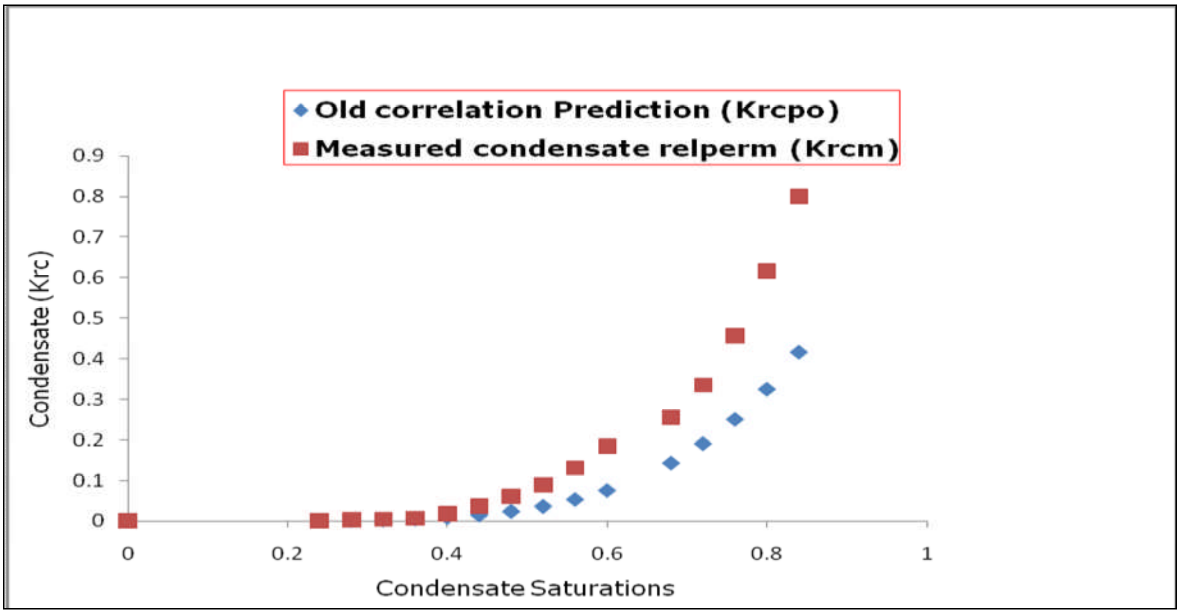


Figure 5.19 Tested adapted correlation equation 5.21 for condensate relative permeability

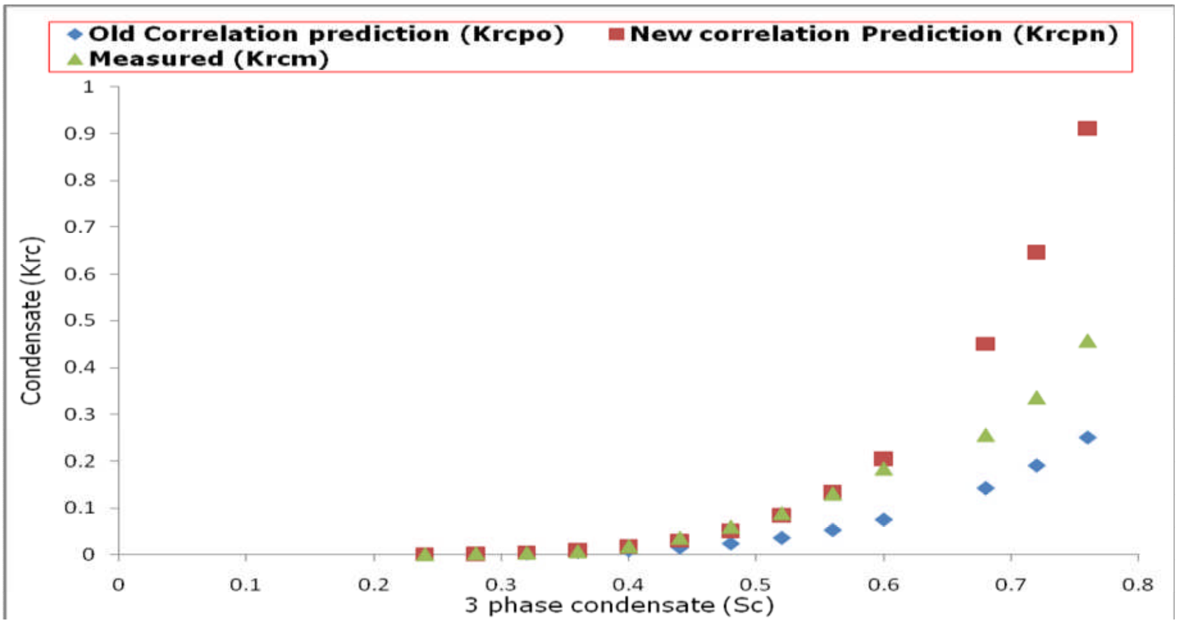


Figure 5.20 Comparison of modified (new) 3-phase condensate relative permeability (Krcpn) with old correlation and measured data.

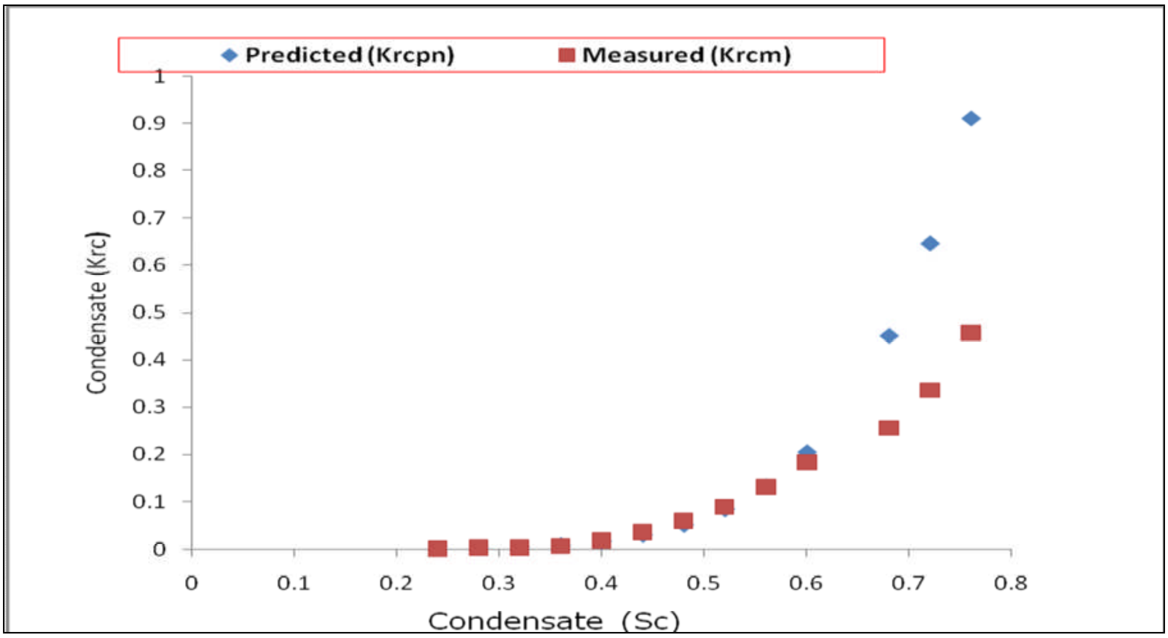


Figure 5.21 Modified relative permeability correlation for condensate in 3-phase system compared with measured data.

The oil saturation correlation equation 5.10 was first tested for prediction of condensate saturations; it gave an absolute average error of 45.72%.The comparison of the predicted result using the existing oil saturation correlation was compared with measured condensate saturation data as shown in figure 5.7. As a result of high error margin of 45.72%, there was need for modification of the existing saturation correlation for accurate condensate saturation prediction. Then the condensate saturation data were put into a Minitab statistical package to tune the oil saturation correlations for prediction of condensate saturations using measured condensate data base. The saturation database was divided into development and validation data. On regression in Minitab it gave a new saturation correlation, equation 5.20. The new condensate saturation correlation was used to predict condensate saturation and the results were compared to measured data and an existing correlation as shown in figure 5.8

With the new saturation correlation the error margin reduced to 8.10%. On this basis the new saturation correlation equation 5.20 was used for prediction of condensate saturations for calculation of condensate relative permeability.

The same steps were applied to oil relative permeability correlation equation 5.21(referred to as old condensate relative permeability correlation) to scale it for modelling condensate relative permeability at varying condensate saturation and water cut. The existing relative permeability correlations were first validated using measured relative permeability data as shown in figure 5.9. At higher condensate saturations, figure 5.19 shows that the existing correlation is not in agreement with measured data. This was the basis for the modification of the relative permeability for modelling condensate relative permeability prediction in three phase system. The modified condensate relative permeability equation 5.21 were validated with measured condensate relative permeability data and compared with the existing model as shown in fgures 5.10 and 5.11. The correlation prediction matches the measured relative permeability data over the practical range of condensate saturation values but does not match at very high condensate saturations. The modified correlation equation 5.21 was however selected and used for condensate relative permeability prediction, the lack of agreement at high measured saturation value notwithstanding as retrograde revaporisation may not allow condensate saturations in the reservoir to go beyond 60%. The correlation was considered to be adequate as the saturations were not expected to go higher than 60%.

5.6 Absolute permeability (K) modelling

For accurate flow prediction of each phase in a three phase system, effective permeability is needed. Having defined relative permeability correlation for each of the phases the absolute permeability correlation needs to be defined as effective permeability is given by the product of relative permeability and absolute permeability.Reservoir compaction can be high when carbonate reservoirs whose porosity are high are depleted (Prins, Smits and Schutjens 1995a, Dudley, Linden and Mah 2007). The impact of reservoir compaction caused by depletion can be predicted with geomechanical correlation and calibrated to field measred data (Hettema et al. 2000, Hettema et al. 1998, Hilbert et al. 2011, Hilbert et al. 2009, Hindriks et al. 2008, Holt et al. 1998, Prins, Smits and Schutjens 1995b, Schutjens et al. 1998, Schutjens et al.

1996, Schutjens et al. 2001, Schutjens et al. 2004, Schutjens, Hindriks and Myers 2008, Tura et al. 2006). The purpose of this analysis is to track changes in absolute permeability of condensate reservoirs due to depletion with corresponding compaction and porosity change. The following correlations were tested against a given field data from Chiligarian et al. (1992), and the correlation that gave the closest prediction to the measured data was selected and upgraded to accurately reproduced measured data using simple regression analysis.

The models tested include;

(i) Wyllie and Rose 1, (Wyllie and Rose 1950)

$$K = \left(\frac{100\phi^{2.25}}{S_{wi}} \right)^2 \qquad (5.22)$$

(ii) Wyllie and Rose II

$$K = \left(\frac{100\phi^2 [1 - S_{wi}]}{S_{wi}} \right)^2 \qquad (5.23)$$

(iii) Kozeny Carman

$$K = \frac{C_k d^2 \phi^3}{(1-\phi)^2} \qquad (5.24)$$

(iv) Chilingarian, (Chilingarian et al. 1992)

$$LogK = 0.9532 - 2.7880 \times 10^{-2} S_{wr} - 5.5597 \times 10^{-4} S_s + 1.3309 \times 10^{-1} \phi + 1.1707 \times 10^{-5} S_{wr} \times S_s \qquad (5.25)$$

(v) Timur Equation (Timur 1968)

$$K = \frac{0.136\phi^{4.4}}{S_{wi}^2} \qquad (5.26)$$

(vi) Berg Equation

$$K = 8.4 \times 10^{-2} \times d^2 \phi^{5.1} \tag{5.27}$$

(vii) Morris and Biggs Equation

$$K = \left(\frac{C_m \phi^3}{S_{wi}^2} \right) \tag{5.28}$$

5.6.1 Absolute permeability changes in carbonate gas-condensate reservoirs

Table 5.1 Measured absolute permeability data used in testing the seven correlations

Swr	Swr, %	Ss,cm2/cm3	Ss,microns	Median d (mirons)	φ	ϕ %	Measured K, mD
0.16	16	2156	0.2156	27.829	0.07	7	3.6
0.28	28	7070	0.707	8.487	0.08	8	0.4
0.19	19	3878	0.3878	15.472	0.08	8	1.6
0.25	25	2058	0.2058	29.155	0.1	10	11.5
0.12	12	1827	0.1827	32.841	0.12	12	26
0.12	12	1113	0.1113	53.908	0.12	12	76
0.09	9	1421	0.1421	42.224	0.13	13	58
0.09	9	1428	0.1428	42.017	0.13	13	63
0.28	28	2030	0.203	29.557	0.13	13	28
0.05	5	945	0.0945	63.492	0.14	14	138
0.09	9	3668	0.3668	16.358	0.14	14	9.5
0.07	7	644	0.0644	93.168	0.14	14	294
0.03	3	854	0.0854	70.258	0.15	15	208
0.16	16	2142	0.2142	28.011	0.15	15	36
0.08	8	1001	0.1001	59.940	0.15	15	167
0.04	4	532	0.0532	112.782	0.18	18	1011
0.04	4	441	0.0441	136.054	0.2	20	1910

Table 5.2 Absolute permeability correlation validation with laboratory measured data, K, mD

Wyllie and Rose1	Wyllie Rose2	Timur Eqn	Morris and Biggs	Morris % Error	Kozeny	Berg Equation	Chilingarian	Morris and Biggs	Measured
2.48	6.62	0.000	3.35	6.96	1.54	0.00008	4.4	3.3	3.6
1.48	2.71	0.000	1.63	-308.16	0.22	0.00002	0.4	1.6	0.4
3.21	7.44	0.000	3.55	-121.61	0.72	0.00005	1.6	3.5	1.6
5.06	9.00	0.000	4.00	65.22	5.25	0.00057	11.1	4.0	11.5
49.88	111.51	0.001	30.00	-15.38	12.03	0.00182	28.6	30.0	26
49.88	111.51	0.001	30.00	60.53	32.42	0.00491	56.7	30.0	76
127.13	291.99	0.002	67.81	-16.91	25.87	0.00453	62.0	67.8	58
127.13	291.99	0.002	67.81	-7.63	25.62	0.00449	61.5	67.8	63
13.13	18.89	0.000	7.01	74.98	12.68	0.00222	27.5	7.0	28
574.96	1386.82	0.010	274.40	-98.84	74.78	0.01496	161.1	274.4	138
177.46	392.74	0.003	84.69	-791.49	4.96	0.00099	8.2	84.7	9.5
293.35	678.08	0.005	140.00	52.38	161.02	0.03222	207.0	140.0	294
2178.55	5292.56	0.036	937.50	-350.72	115.29	0.02605	263.7	937.5	208
76.59	139.54	0.001	32.96	8.45	18.33	0.00414	51.7	33.0	36
306.36	669.52	0.005	131.84	21.06	83.92	0.01896	183.5	131.8	167
2783.60	6046.62	0.045	911.25	9.87	551.62	0.17008	925.6	911.3	1011
4472.14	9216.00	0.071	1250.00	34.55	1156.93	0.42360	1900.9	1250.0	1910

The results from table 5.2 show that out of the seven correlations tested for prediction of absolute permeability change as a function of porosity, the Chilingarian (1995) performed best followed by Morris and Biggs as their prediction were closest to the measured data. They gave regression coefficient of 99% and 74% respectively as shown in figures 5.12 and 5.13 respectively. On this basis, Chilingarian correlation was applied for this study.

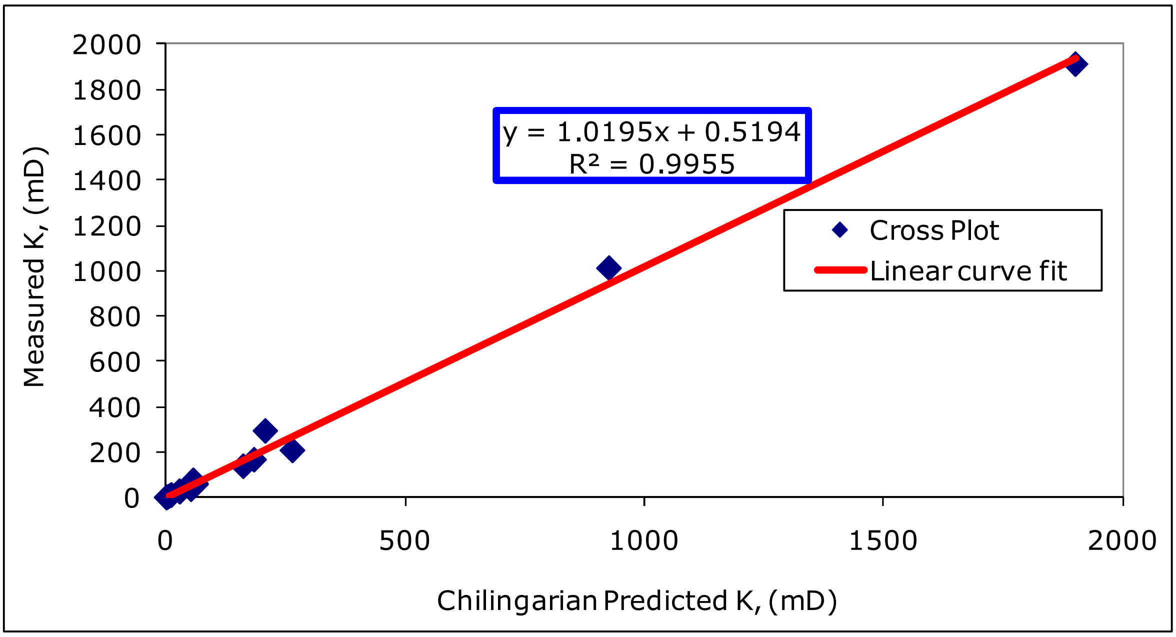


Figure 5.22 Comparison of laboratory measured absolute permeability change with Chilingarian prediction for condensate reservoirs

The results show that most of the methods used in predicting the absolute permeability changes deviated significantly compared to the laboratory measured values. Chilingarian correlation ranked closer to the laboratory measured data was considered more adequate for prediction of absolute permeability changes for carbonate condensate reservoirs

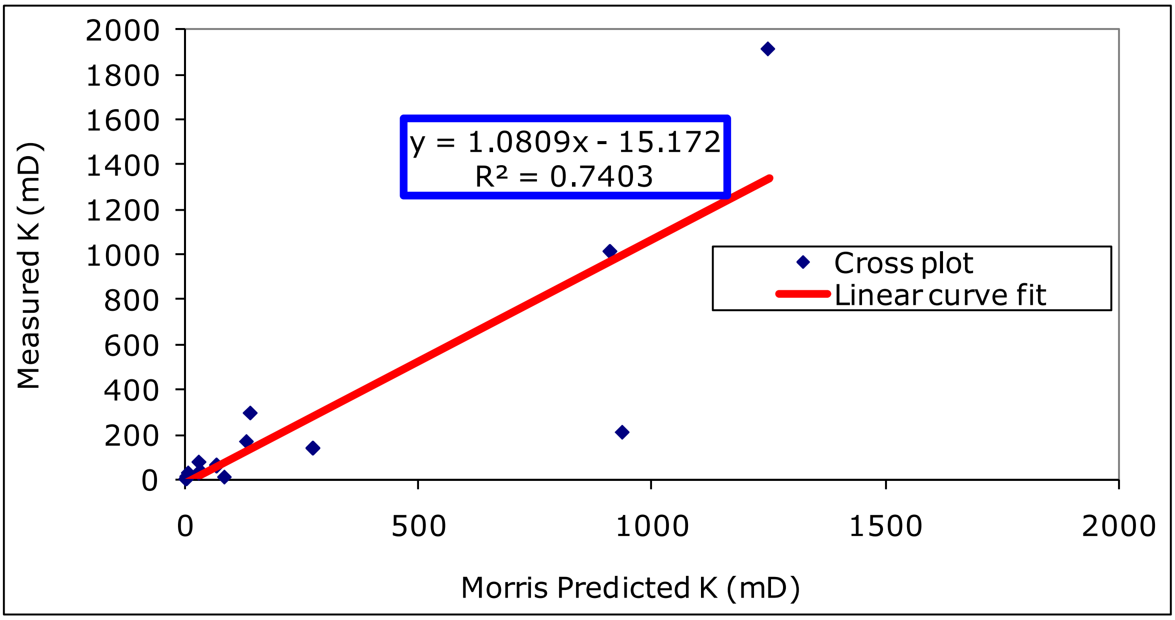


Figure 5.23 Comparison of laboratory measured absolute permeability change with Morris and Biggs prediction for condensate reservoirs

5.7 Absolute permeability changes in unconsolidated sandstone reservoirs

To properly account for absolute permeability changes in predicting the productivity performance of gas-condensate reservoirs similar correlation performance test for prediction of absolute permeability changes as a function of porosity was carried out using same correlation earlier used for carbonate reservoirs. The data used for the performance test for the correlations is shown in table 5.3

.

Table 5.3 Absolute permeability change with porosity based on surface area and Interstitial Water Saturation for Arkansas Unconsolidated Sandstone Reservoir

Swr	Swr, %	Ss,cm2/cm3	Ss,microns	Median d, microns	φ	ϕ,%
0.32	32	2156	0.2156	2000	0.324	32.4
0.35	35	7070	0.707	2000	0.203	20.3
0.38	38	3878	0.3878	2000	0.234	23.4
0.3	30	2058	0.2058	2000	0.349	34.9
0.27	27	1827	0.1827	2000	0.309	30.9
0.43	43	1113	0.1113	2000	0.318	31.8
0.54	54	1421	0.1421	2000	0.305	30.5
0.35	35	1428	0.1428	2000	0.269	26.9
0.3	30	2030	0.203	2000	0.154	15.4
0.31	31	945	0.0945	2000	0.165	16.5
0.31	31	3668	0.3668	2000	0.142	14.2
0.27	27	644	0.0644	2000	0.321	32.1
0.36	36	854	0.0854	2000	0.243	24.3
0.45	45	2142	0.2142	2000	0.273	27.3

Table 5.4 Performance of different models in predicting absolute permeability changes as a function of porosity for Arkansas unconsolidated sandstone reservoirs

Porosity (φ)	Wallie and Rose1	Wallie Rose2	Timur Eqn	Morris and Biggs	Kozeny	Berg Equation	Meassured K, mD
0.324	612.6	497.6	0.009	83.04	1488578.13	1071.81	1685
0.203	62.5	58.6	0.001	17.07	263391.32	98.76	333
0.234	100.4	79.8	0.002	22.18	436737.04	203.86	732
0.349	973.8	807.7	0.015	118.08	2006061.76	1565.85	1380
0.309	695.2	666.4	0.011	101.18	1235803.27	841.64	1975
0.318	311.9	179.7	0.005	43.48	1382746.62	974.36	1150
0.305	163.9	62.8	0.003	24.32	1174789.09	787.53	142
0.269	221.7	180.6	0.003	39.72	728537.79	415.03	1213
0.154	24.5	30.6	0.000	10.15	102059.03	24.14	61
0.165	31.3	36.7	0.001	11.69	128857.26	34.32	135
0.142	15.9	20.1	0.000	7.45	77789.41	15.96	850
0.321	825.2	776.1	0.013	113.43	1434846.84	1022.15	2100
0.243	132.6	110.2	0.002	27.68	500791.63	247.13	460
0.273	143.3	83.0	0.002	25.12	769926.23	447.48	506

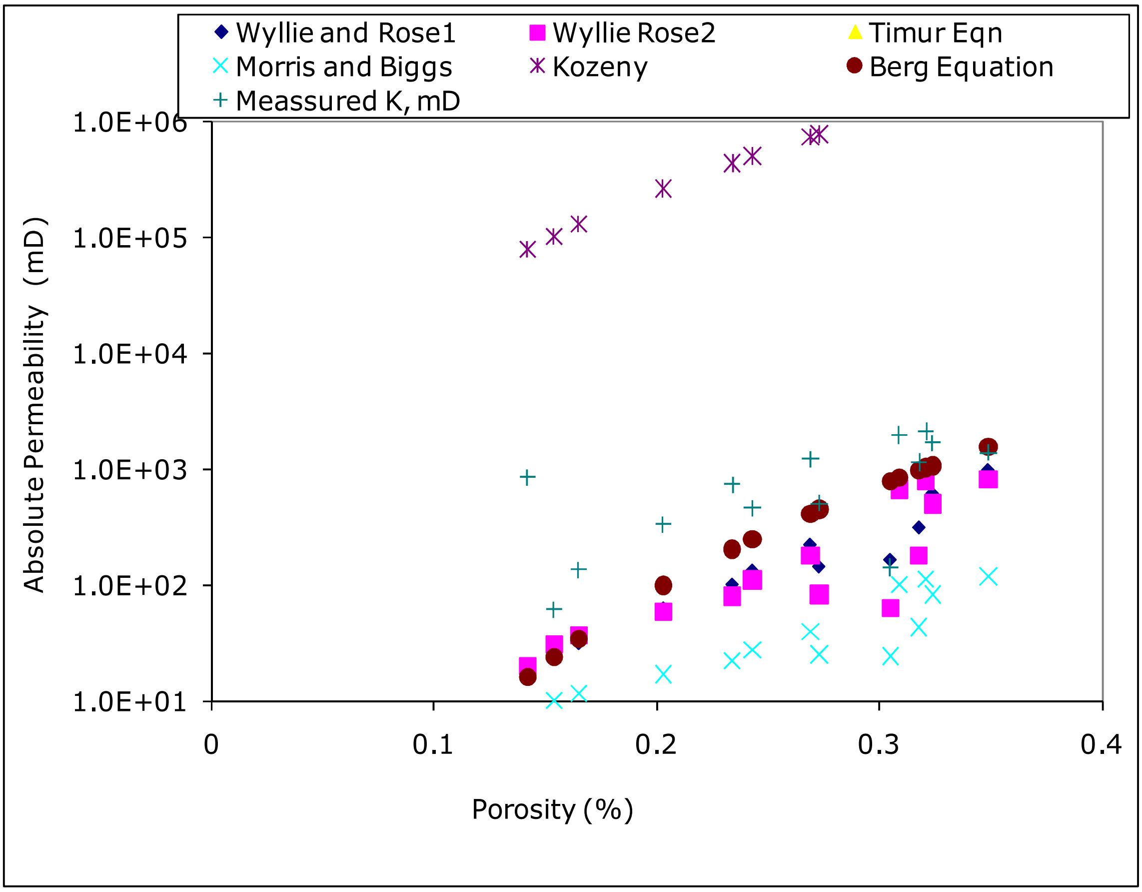


Figure 5.24 Changes in absolute permeability of unconsolidated sandstone condensate reservoirs with porosity

5.8 Summary and conclusions

The modified correlation equation 5.21 was selected and used for condensate relative permeability prediction, the lack of agreement at high measured saturation value notwithstanding as retrograde revaporisation may not allow condensate saturations in the reservoir to go beyond 60%, below which the correlation is adequate. The three phase relative permeability correlation proposed by this investigation has some advantages over some of the available models as irreducilbe water saturation is not asumed.

The validation test results from table 5.4 and figures 5.14 show that Morris-Biggs, and Bergs' Equation predictions ranked closest to the measured field data. Therefore Morris or Bergs is adequate for prediction of absolute permeability changes as a function of porosity in unconsolidated sandstone reservoirs. However it is recommended that the model be validated for any field of world-wide origin as geographical variations could affect the accuracy of semi-empirical models used.

CHAPTER SIX

6.0 MODELLING CONDENSATE INFLOW PERFORMANCE RELATIONS (IPR)

6.1 Introduction

A worldwide interest in production of gas-condensate reservoirs is currently observed partly as result of scarcity of reserves and search for hydrocarbons at greater depths where many rich gas condensate and volatile oils are situated (Eaton and Jacoby 1965). Accurate recovery prediction is a huge challenge for optimisation of gas-condensate reservoirs. A reasonable estimate of the ability of the reservoir to produce hydrocarbons, (the inflow performance) is required for determination of optimum production strategy, production forecasts and field development planning. Other important applications of IPR include the design of production systems, artificial lift and surface treatment facilities.

No meaningful well deliverability prediction is possible without an accurate IPR model. In order to develop adequate inflow performance relationships for Gas Condensate wells, different well trajectories (vertical and horizontal) were considered both in the single and multiphase flow scenarios. However, emphasis was placed on modelling the multiphase flow below the dew point pressure where the main challenge of predicting well deliverability in gas condensate reservoirs lies.

6.2 Comparative IPR analysis methods for vertical wells

In order to select appropriate inflow performance curves for application of the modified fluid property and relative permeability correlations proposed in chapters four and five, they were applied to widely-used correlations for gas inflow performance relationship (IPR) to test the performance of these correlations. By this test also the performance of the available vertical well equations in various forms. were evaluated Updating available gas well inflow performance correlations with accurate fluid PVT property correlations for gas-condensate reservoirs was first attempted approach for this research. Development of fluid PVT property correlations was crucial for modification of

any gas inflow performance model as the constant composition assumption of the dry gas IPR model is not valid for condensate reservoirs.
On this basis, natural gas IPR models were reviewed and tested. An approach that has potential to predict well delivery of gas-condensate with better accuracy, when modified with fluid property correlations earlier proposed was selected for preliminary development for the comparative analysis, though for single phase analysis.

The reviewed IPR correlations included;

a. Simplified back –pressure equation
b. Laminar-inertial-turbulent (LIT) methods:
    i. Pressure-squared approach.
    ii. Pressure approximation approach.
    iii. Pseudo pressure approach

Three-point conventional deliverability test data as recorded in table 6.1 below taken from Ahmed, (2000) were used for the comparative inflow performance analysis for selection of a vertical well for development of condensate inflow performance.

Table 6.1 Well deliverability test data

p_{wf}, psia	ψ_{wf}, psi^2/cp	$Q_g\,Mscf/day$
$\overline{Pr}$ =1952	316×10^6	0.00
1700	245×10^6	2624.6
1500	191×10^6	4154.7
1300	141×10^6	5425.1

The inflow performances were generated using each of the four methods given above as and the results were compared in table 6.2 and figure 6.1 below.

Table 6.2 Performance comparison of the different IPR methods using the well deliverability test data given.

Computed flow Rates for different Methods in Mscf/Day

Pressure , (psia)	Back-Pressure	P^2-Approach	P-Approach	Pseudo-Pres-Approach
1952.00	0.00	0.00	0.00	0.00
1700.00	2608.45	2623.93	2474.33	2448.03
1600.00	3405.64	3450.90	3296.52	3378.85
1200.00	5941.80	5963.25	6087.76	6276.90
1000.00	6890.67	6854.92	7283.73	6559.50
500.00	8465.41	8281.04	9912.82	8037.16
0.00	8980.31	8733.77	12189.54	8969.42

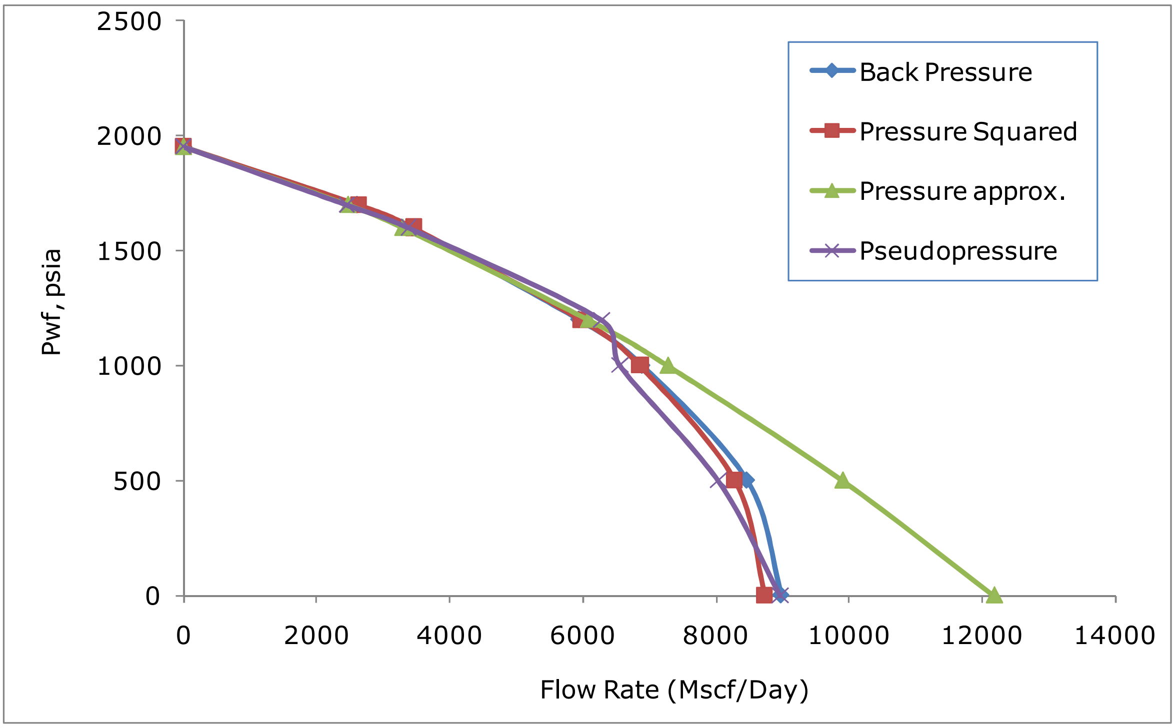


Figure 6.1 Comparison of different inflow performance approaches

The figure 6.1 above shows that back pressure and pressure squared approach compared favourably well with the pseudo-pressure method except the pressure approximation approach which deviated significantly from the other three methods. The backpressure or pressure squared approximation approach were therefore considered as good candidates for the investigation as they were in good agreement with the pseudo-pressure model which is widely accepted in the industry because of its capability to account for effect of pressure on fluid properties. The back pressure was selected at this stage of the investigation as it was simpler to compute than pseudo-pressure but gave the same results for the above case.

6.2.1 Vertical lift performance and nodal analysis

The back pressure equation selected for modification for prediction of well IPR for condensate was of the form;

$$q_g = C(\overline{P_R^2} - P_{wf}^2)^n \tag{6.1}$$

The initial fluid property correlations for condensate compressibility factor, density and viscosity correlations were applied to the above IPR model and the Beggs and Brill tubing performance relation (TPR) was used for vertical lift performance prediction. The nodal analysis for the prediction of the operating point for the semi-empirical model was determined as the intersection of the vertical lift performance (VLP) and the IPR as shown in figure 6.2. The multiphase correlation was used for calculation of pressure drop as the bottom-hole flowing pressure was below the dew point pressure implying multiphase flow at wellbore conditions. The calculation detail for the TPR is given in appendix C1 to C4. The results are summarised in table 6.3 and figure 6.2.

Table 6.3 Tubing performance relation (TPR) generated using Beggs and Brill method for pressure drop calculation for vertical well in Gas Condensate reservoir

	q_g (Mscf/D)	p_{wf} (psia) IPR	TPR
	0	3600	
	338	2999	2309
	524	2497	1945
	666	1995	1782
	772	1493	1696
	846	989	1648
	890	473	1624
AOF	**903**	0	

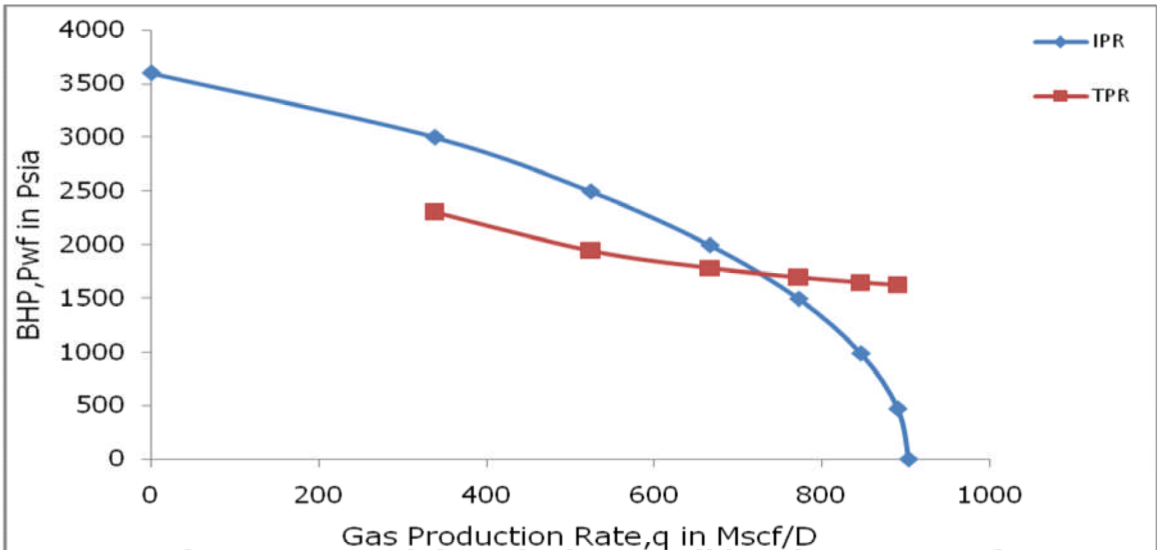


Figure 6.2 Nodal Analysis at well head pressure of 500psia

In order to validate the preliminary results from the semi empirical models The equation (6.1) were modified with the developed PVT property correlations and referred to as semi-empirical models These correlations in combination with the vertical lift performance correlation were applied to generate the semi-empirical nodal analysis curve shown in figure 6.2. The same problem was solved using standard industry software, (Petroleum expert software (PETEX), Prosper) in order to validate the performance of the semi-empirical models in vertical well and the results are as summarised in figure 6.3:-

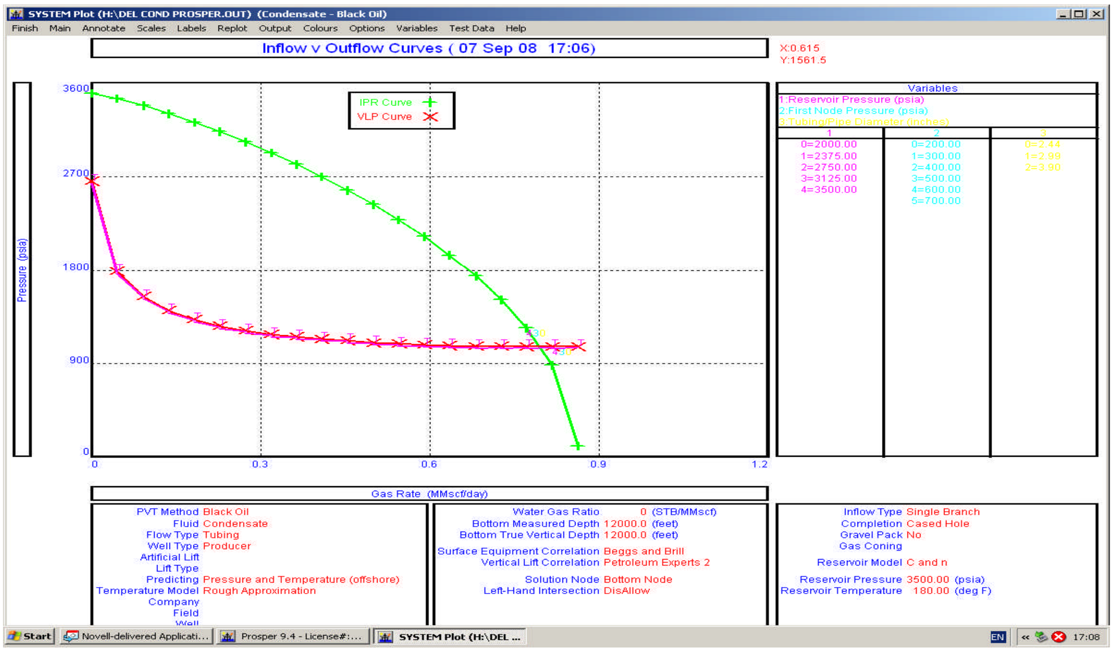


Figure 6.3 Nodal analyses at wellhead pressure of 500psia

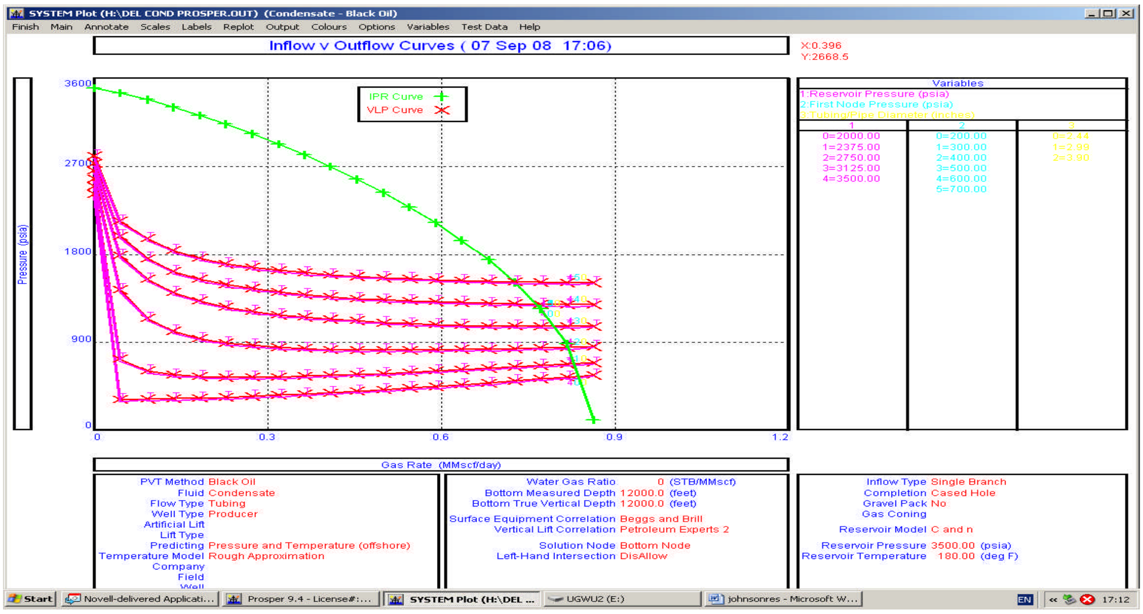


Figure 6.4 Nodal analyses at for various well head pressures with Prosper

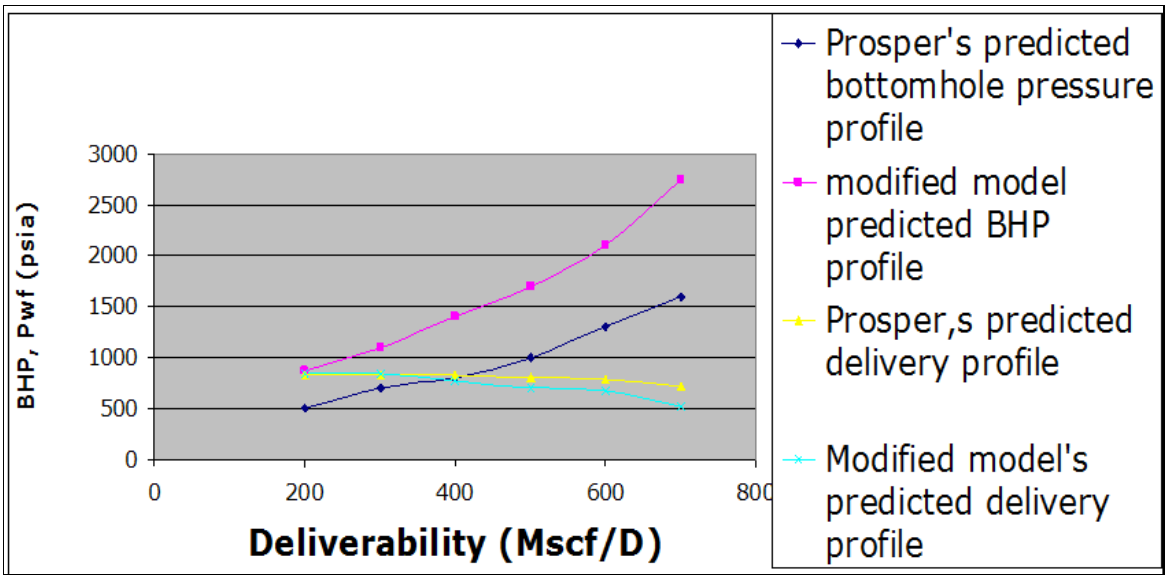


Figure 6.5 Comparison of modified semi-empirical model performance using Prosper at different bottom-hole pressures

6.2.2 Result Summary

The prediction comparison with Prosper in figures 6.2 and 6.3 gave operating bottom hole pressure of 1,782psia and1,555psia for our modified approach and Prosper respectively, but both gave a deliverability of 666Mscf/Day The semi empirical models compared well with Prosper but the results are limited to single phase flow at reservoir conditions. More rigorous fluid property correlations valid for multiphase scenarios at reservoir conditions were sourced and further developed in chapter four of this thesis using the Anschutz rich gas-condensate data published by Walsh and Lake (2003). In addition to fluid properties the three phase relative permeability correlation as modified in chapter five and applied to vertical well IPR. The modified pseudo-pressure approach was applied as it has the capacity to correct for black oil model assumption which is not valid for condensate. For the first time compositional pseudo-pressure approach was initiated, developed and applied in this study to cater for compositional variation and associated phase changes in gas-condensate reservoirs produced below the dew point pressure. A part of the novelty of this investigation is the introduction of the compositional pseudo-pressure approach to account for phase changes and compositional variations in pseudo-pressure arising from depletion of pressure below the dew point value.

6.3 Well deliverability modelling considerations for gas condensate reservoirs

Development of gas-condensate production is limited by technology as either black oil or gas deliverability models that have been perfected for oil and gas are inadequate for prediction of multiphase flow in gas-condensate reservoirs (Fussell 1973). Well deliverability loss due to condensate dropout is frequently observed when producing below the dew point pressure (condensate banking). Well deliverability gain due to condensate mobility may be observed when condensate saturation around the wellbore is above the critical value (Jokhio and Tiab 2002). The low interfacial tension and non-Darcy flow near the wellbore favour condensate mobility under these conditions resulting in additional condensate recovery. This additional recovery is usually ignored in modelling well deliverability in gas-condensate reservoirs. Modelling the level of recovery at this stage of production has not received adequate attention; rather the emphasis in existing models has been on how much gas production is impaired by condensate banking. Modelling of liquid condensate flow below the dew point is a focus of this investigation, as it has given us the opportunity to source and develop appropriate condensate PVT correlations and condensate relative permeability correlations below the dew point. This is a better alternative than modelling condensate flow using the condensate gas ratio (CGR) as other relevant condensate flow parameters are not defined using CGR. Lasting solutions to condensate modelling problems arising from inadequate characterisation of condensate transport properties below the dew point pressure have been addressed in this investigation. Appropriate artificial lift and pressure maintenance facilities for condensate recovery optimisation or production impairment remediation could better be handled through accurate condensate fluid PVT and relative permeability modelling as they govern fluid flow in gas-condensate reservoirs (Ikoku 1984)

6.3.1 Modification of gas well IPR for gas condensate

Various modifications of Darcy's law are used for several types of fluid flow in porous media especially the flow of hydrocarbons in the reservoir.

For fluid flow through porous media, Darcy's law can be represented, (Chaudhry 2003) as,

$$dp/dr = av \qquad (6.2)$$

This is valid for laminar flow. For turbulent flow the equation has been modified by Forchheimer as,

$$dp/dr = av + bv^2 \qquad (6.3)$$

For pseudo-steady state flow for gas wells, equation (6.3) can be rewritten in terms of Pseudo- pressure as,

$$\psi\left(\overline{P}_R\right) - \psi\left(p_w\right) = Bq_{sc} + Cq_{sc}^2 \qquad (6.4)$$

Where; ψ = Pseudo-pressure

$$B = \frac{1.422 \times 10^3 T}{kh}\left[\ln\left(\frac{0.472 r_e}{r_w}\right) + s\right] \qquad (6.5)$$

$$C = \frac{1.422 \times 10^3 T}{kh} D \qquad (6.6)$$

Equation (6.4) can be written in a form that indicates the degree of turbulence in the gas reservoir through a relationship between the two parameters D, and β, the turbulence coefficient and the velocity coefficient respectively as;

$$\psi(\overline{P_R})-\psi(p_w)=1.422\times10^3 T\left(\ln\frac{0.472 r_e}{r_w}+s\right)q_{sc}+\frac{3.161\times10^{-12}\gamma_g T\beta}{r_w h^2}q_{sc}^2 \qquad (6.7)$$

The form of the equation above includes the assumption that $r_e >> r_w$. Equating the terms multiplying q_{sc}^2 in Equations (6.4) and (6.7) gives,

$$\frac{1.422\times10^3\bar{\mu}_g \bar{z}T}{kh}D=\frac{3.161\times10^{-12}\gamma_g \bar{z}T}{r_w h^2}\beta \qquad (6.8)$$

From Eq (6.8), $$D=\frac{2.22\times10^{-15}\gamma_g k}{\bar{\mu}_g h r_w}\beta \qquad (6.9)$$

And $$\beta=\frac{2.33\times10^{10}}{K^{1.2}} \qquad (6.10)$$

$$D=\frac{5.18\times10^{-5}\gamma_g}{\bar{\mu}_g h r_w k^{0.2}} \qquad (6.11)$$

Considering reservoir fluid saturations and relative permeabilities for multiphase flow, the effective permeabilites for condensate, water and gas can be written as follows;

$$k_c = kk_{rc}, k_w = kk_{rw}, k_g = kk_{rg} \qquad (6.12)$$

The inflow equations can be written as;

For condensate, $$\left(P_e-P_{wf}\right)_c=\frac{141.2B_c q_c \mu_c}{hkk_{rc}}\left(\ln\frac{r_e}{r_w}+S\right) \qquad (6.13)$$

For gas flow,

$$\left(P_e-P_{wf}\right)_g=\frac{141.2B_g q_g \mu_g}{hkk_{rg}}\left(\ln\frac{r_e}{r_w}+S\right) \qquad (6.14)$$

For water,

$$\left(P_e - P_{wf}\right)_{ww} = \frac{141.2 B_w q_w \mu_w}{hk k_{rw}} \left(\ln \frac{r_e}{r_w} + S\right) \tag{6.15}$$

In terms of Pseudo-pressures for condensate (vertical) well, the inflow performance equation was adapted as,

$$q_{sc} = \frac{k k_{rc} h T_{sc} \left[\psi(P_R) - \psi(P_{wf})\right]}{50.337 \times 10^3 T P_{sc} \left[\ln(r_e / r_w) - 0.75 + S + S_m + S_{CA} - C' - D q_c\right]} \tag{6.16}$$

The above equation (6.16) is a quadratic equation of the form:-

$$\psi\left(\overline{P}_R\right) - \psi\left(p_{wf}\right) = B q_c + C q_c^2 \tag{6.17}$$

Where;

$$B = \frac{50.337 \times 10^3 \overline{\mu}\overline{z} T P_{sc}}{k k_{rc} h T_{sc}} \left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s + s_{CA} - c'\right] \tag{6.18}$$

$$C = \frac{50.337 \times 10^3 \overline{\mu}\overline{z} T P_{sc}}{k k_{rc} h T_{sc}} D \tag{6.19}$$

$$q_C = \frac{C}{B + D q_C} \tag{6.20}$$

$$q_C = \frac{-B + \sqrt{(B)^2 + 4 \times D \times C}}{2D} \tag{6.21}$$

The quadratic form of equation 6.16 was important so as to permit a quadratic method of solution for prediction of flow rate as the equation cannot be solved directly for non-Darcy flow.

The above expressions for condensate derived from natural gas can be written for any fluid including water provided the effective permeability to the corresponding fluid is used.

The pseudo pressures in equations (6.17) were calculated from,

$$\psi(p) = 2 \int_{p_{ref}}^{\bar{p}} \frac{p}{\mu z} dp \tag{6.22}$$

$$\psi(\bar{P}_R) - \psi(P_{wf}) = 2\int_{\Pr ef}^{P_R} \frac{PdP}{\mu_g Z} - 2\int_{pref}^{P_{wf}} \frac{PdP}{\mu_g Z} \qquad (6.23)$$

6.3.2 Modified parameters in existing IPR models

Procedures for calculating fluid PVT property parameters in the above IPR models have been defined by appropriate correlation in chapter four to make such correlation valid for gas condensate modelling. Use of correlations to predict fluid properties results in huge savings, and are also very useful in forecasting the properties at conditions where experimentation are not possible. However, the correlations are not without limitations for worldwide application, no matter how large the data size and range may be. The practice is always to validate before applying any correlation.

Accurate relative permeability definition is a critical issue in gas-condensate modelling, as slight errors in estimation could result in unacceptable error margins in deliverability prediction. A new correlation was also introduced in chapter five for prediction of condensate relative permeability in three phase flow.

A compositional pseudo-pressure (pseudo-pressure derived from mixture composition) has also been introduced into this study to correct for constant composition assumption of black oil model. The procedure and the new method of compressibility factor determination are very critical to accurate phase behaviour prediction for reliable performance prediction.

6.3.3 Evaluation and comparison of the modified IPR

To evaluate the performance of the modified dry gas IPR for prediction of condensate inflow, a case study was taken from Petroleum Expert (2008) with specifications shown in appendix D1. The Prosper IPR model is presented as shown in figure 6.6 below. The improved PVT correlations introduced in chapter four were used to generate the PVT properties shown in table 6.4 which are required for calculation of the condensate IPR for the Prosper case study defined in appendix D1 and the modified IPR curve for condensate is shown in figure 6.7.

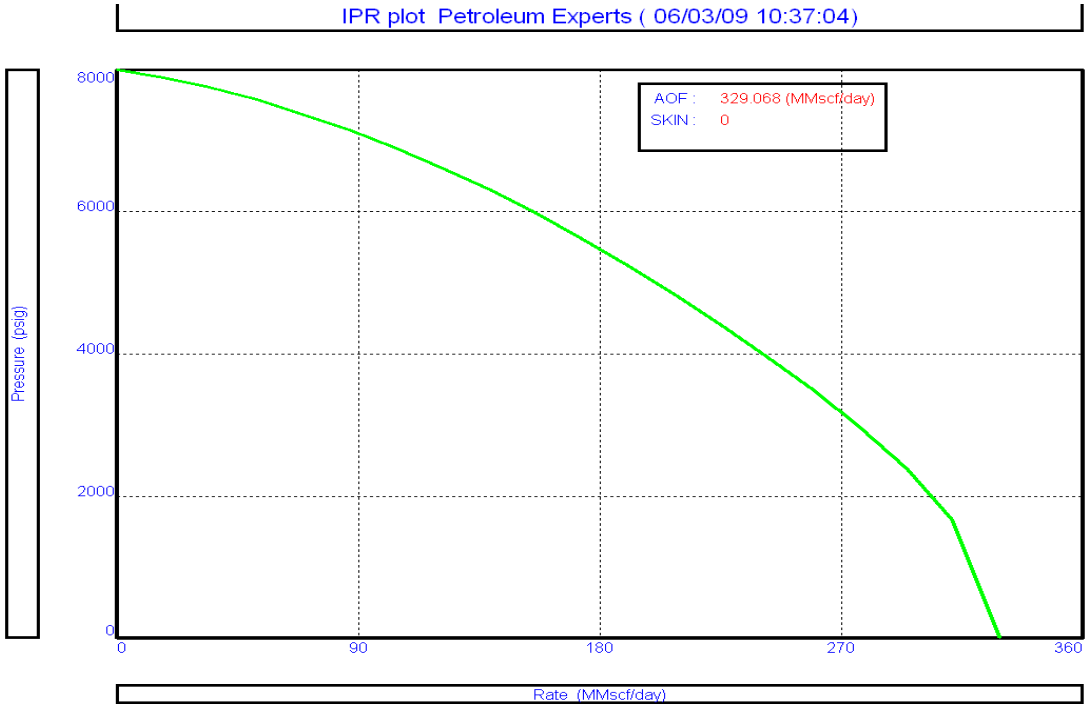


Figure 6.6 IPR case study using Prosper condensate data.

Table 6.4 Generated Condensate PVT properties using developed PVT correlations in chapter four and implemented in generating condensate IPR model in fgure 6.7

Pressure, P_{wf} (Psia)	μ_c (cP)	Z Compress. fact.	$P_{wf} / \mu_C Z$ (Psia/cP)	$\psi(P_{wf})$ (Psia^2)	$\psi(\bar{\mathrm{Pr}}) - \psi(P_{wf})$ Drawdown
1.48	0.08094	0.9388	1.68	2.4854E+00	5.2992E+07
1484.68	0.08148	0.8732	1947.28	2.8911E+06	5.0101E+07
2133.01	0.08491	0.8486	2962.07	6.3181E+06	4.6674E+07
2663.45	0.08545	0.8302	3864.70	1.0293E+07	4.2698E+07
3141.43	0.08354	0.8137	4744.62	1.4905E+07	3.8087E+07
3591.96	0.14962	0.8058	5532.00	1.9871E+07	3.3121E+07
4028.95	0.13319	0.7911	6436.98	2.5934E+07	2.7058E+07
4463.86	0.09213	0.6957	9222.58	4.1168E+07	1.1824E+07
4899.18	0.12484	0.8215	7259.68	3.5566E+07	1.7425E+07
5312.31	0.10513	0.8450	7440.17	3.9525E+07	1.3467E+07
5701.25	0.11452	0.8331	8214.96	4.6836E+07	6.1564E+06
6065.44	0.08380	0.8688	8034.80	4.8735E+07	4.2573E+06
6404.26	0.06832	0.8883	8116.17	5.1978E+07	1.0138E+06
6716.93	0.06281	0.9332	7712.29	5.1803E+07	1.1890E+06
7002.65	0.09447	0.9180	8310.03	5.8192E+07	-5.2003E+06
7260.63	0.09059	0.8466	10130.96	7.3557E+07	-2.0565E+07
7490.06	0.09765	0.8737	9812.44	7.3496E+07	-2.0504E+07
7690.25	0.097772	0.9191	9103.90	7.0011E+07	-1.7019E+07
7860.43	0.106155	0.9909	8005.55	6.2927E+07	-9.9352E+06
8000	0.126884	1.0990	6623.98	5.2992E+07	0.0000E+00

Table 6.5 Comparison of modified model generated IPR and Petroleum Expert (Prosper)

Pressure, P_{wf} (Psig)	Modified Model, MSTB/D	Petroleum Expert Model, MSTB/D
1.48	218.65	294.45
1484.68	207.11	278.95
2133.01	196.04	263.46
2663.45	185.05	247.96
3141.43	174.02	232.46
3591.96	162.94	216.97
4028.95	151.77	201.47
4463.86	140.17	185.97
4899.18	128.11	170.47
5312.31	116.12	154.98
5701.25	104.22	139.48
6065.44	92.43	123.98
6404.26	80.64	108.48
6716.93	68.97	92.99
7002.65	57.20	77.49
7260.63	45.56	61.99
7490.06	34.06	46.49
7690.25	22.46	31.00
7860.43	11.12	15.50
8000.00	0.00	0.00

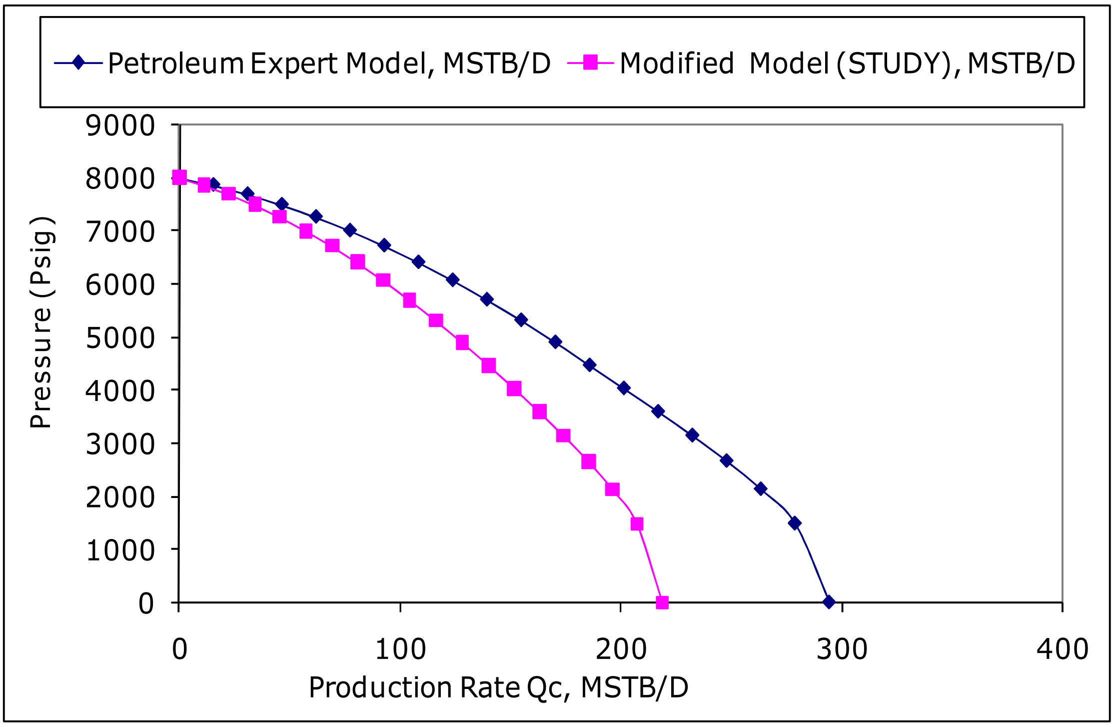


Figure 6.7 Petroleum Expert's (Prosper) gas condensate IPR compared to modified model (STUDY)

In figure 6.7, the modified model has same trend with Prosper but the predicted rates differ at all bottom-hole pressures used in forecasting. This difference could arises from prosper assumptions that (1) No condensate banking occurs, and (2) All the condensate dropped out is produced (Prosper manual, 2008). These assumptions are not valid in the present investigation. Prosper was producing liquid condensate even above the dew point from our calculations, which in our modified model calculation gave liquid condensate prediction above the dew point pressure to be zero as expected from practical point of view, suggesting an agreement with the physics of condensate production. Prosper predicts liquid drop out only in the tubing and the process is best described by constant composition expansion (CCE) as against the study that considers the case of constant volume depletion (CVD) with recovery of condensate liquid, not the conventional CVD that assume that all the liquid produced in the reservoir below the dew point is lost to the formation as considered in CVD PVT cell experiment.

6.3.4 Performance analysis of the modified vertical well IPR

A modified inflow performance relation for primary depletion drive in gas condensate reservoir is presented. To determine the critical parameters that control the productivity of such reservoirs and analyse the performance of the modified inflow performance for gas-condensate reservoirs, a parametric study was carried out. The impacts of certain key parameters that have been shown affect the productivity of other hydrocarbon reservoirs investigated for gas-condensate reservoirs using the modified condensate IPR. The reservoir parameters concerned: - Condensate Saturation, Permeability, pay thickness, and drainage radius.

6.3.5 Results and discussions

The highlight of results are summarised in the figures 6.8 through 6.13.

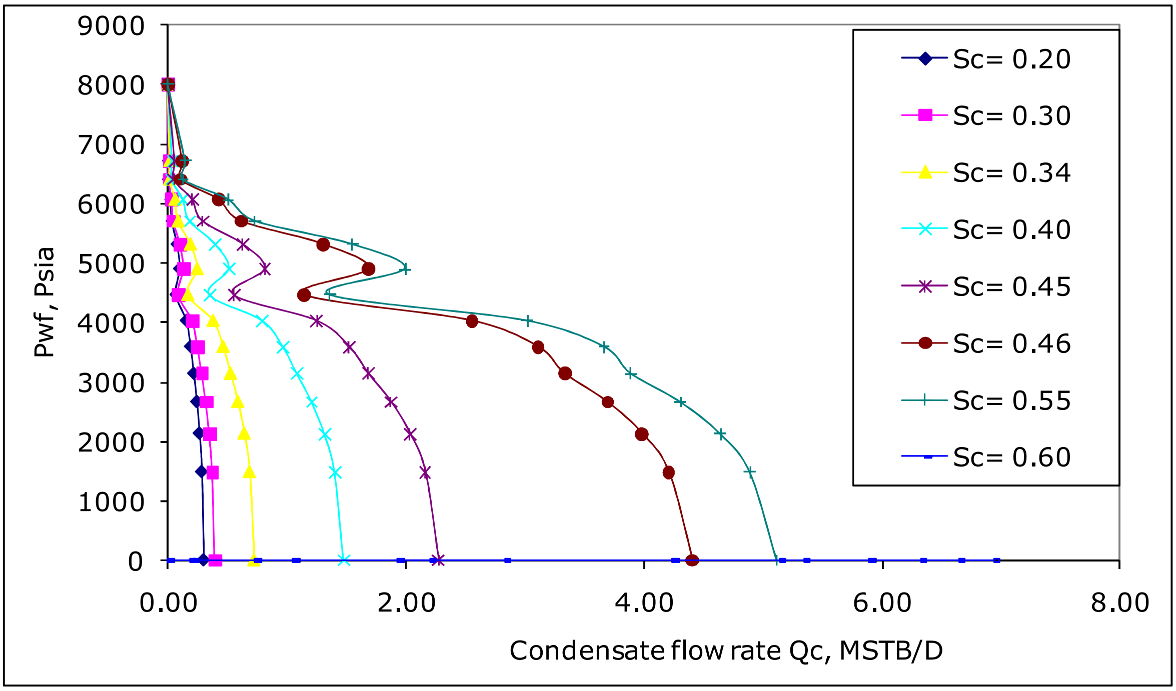


Figure 6.8 Effect of condensate saturations on inflow performance Curve (IPR)

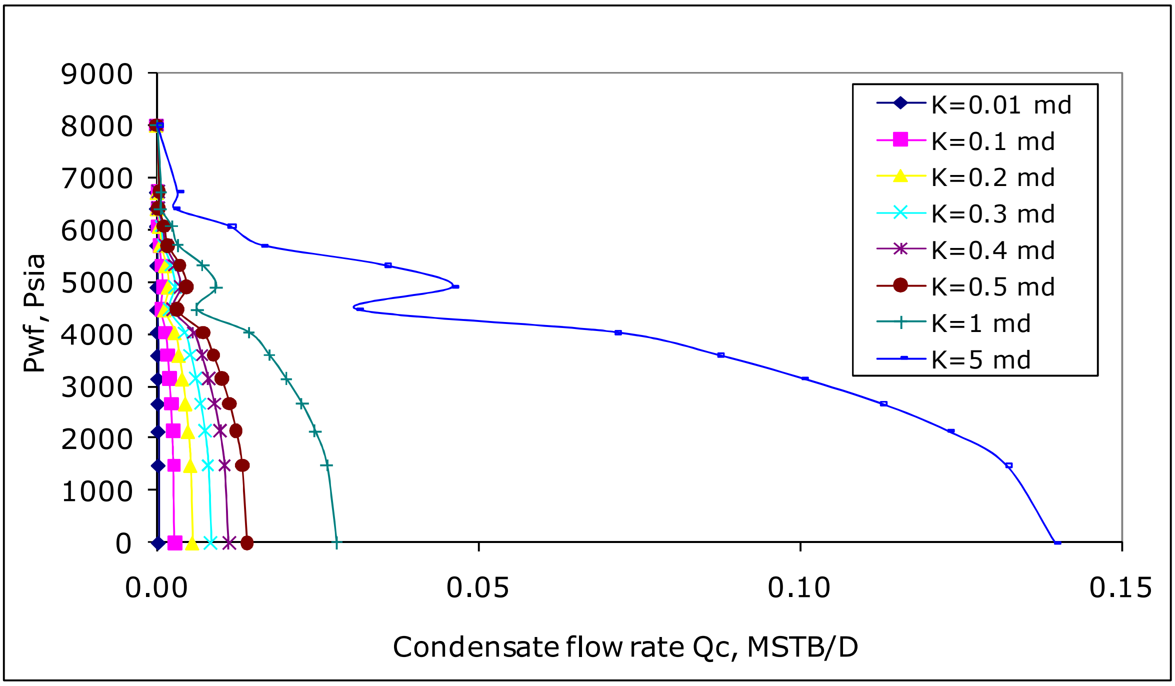


Figure 6.9 Effect of low permeability sand on condensate inflow performance curve (IPR)

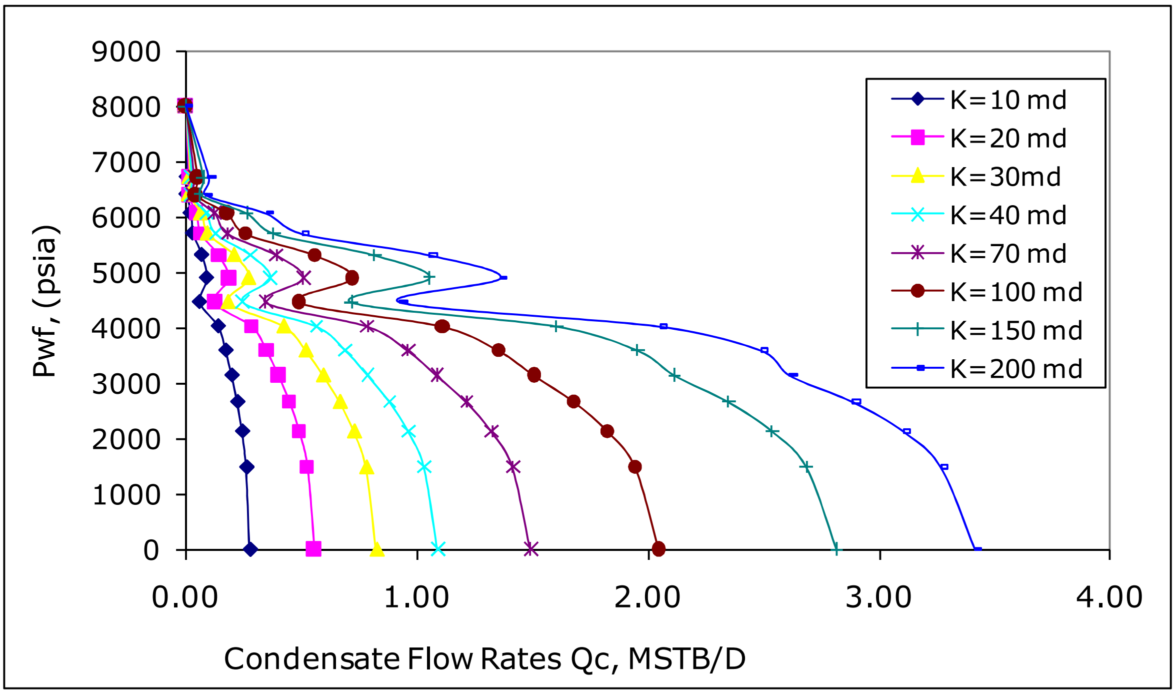


Figure 6.10 Effect of high permeability sand on condensate inflow performance curve (IPR)

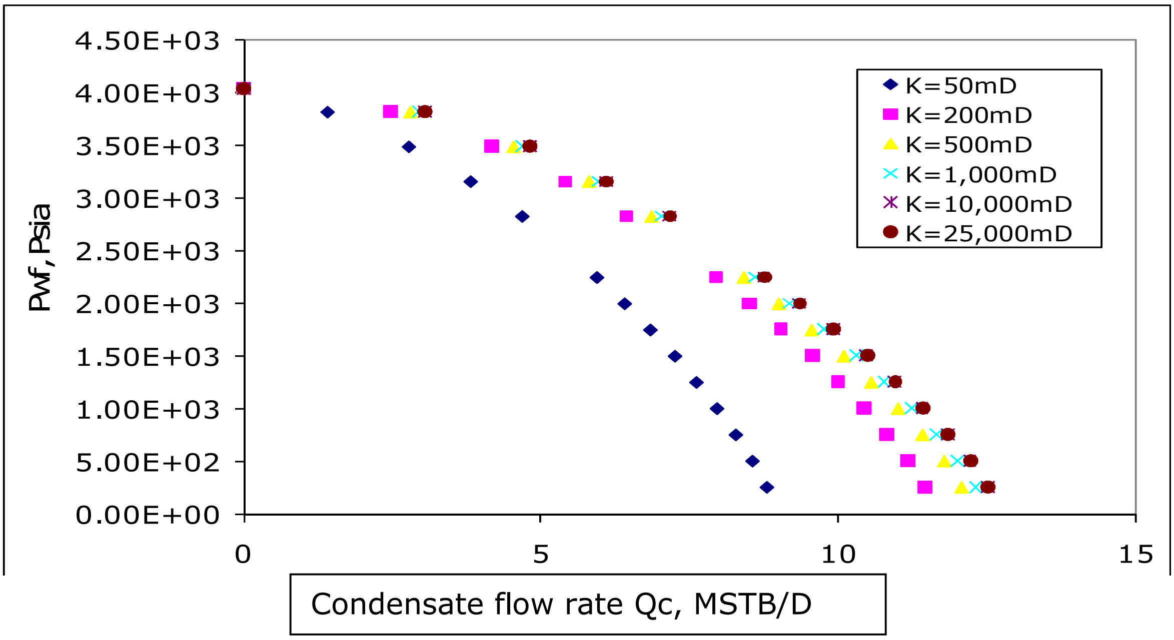


Figure 6.11 Effect of high absolute permeability sand on condensate inflow performance curve (IPR)

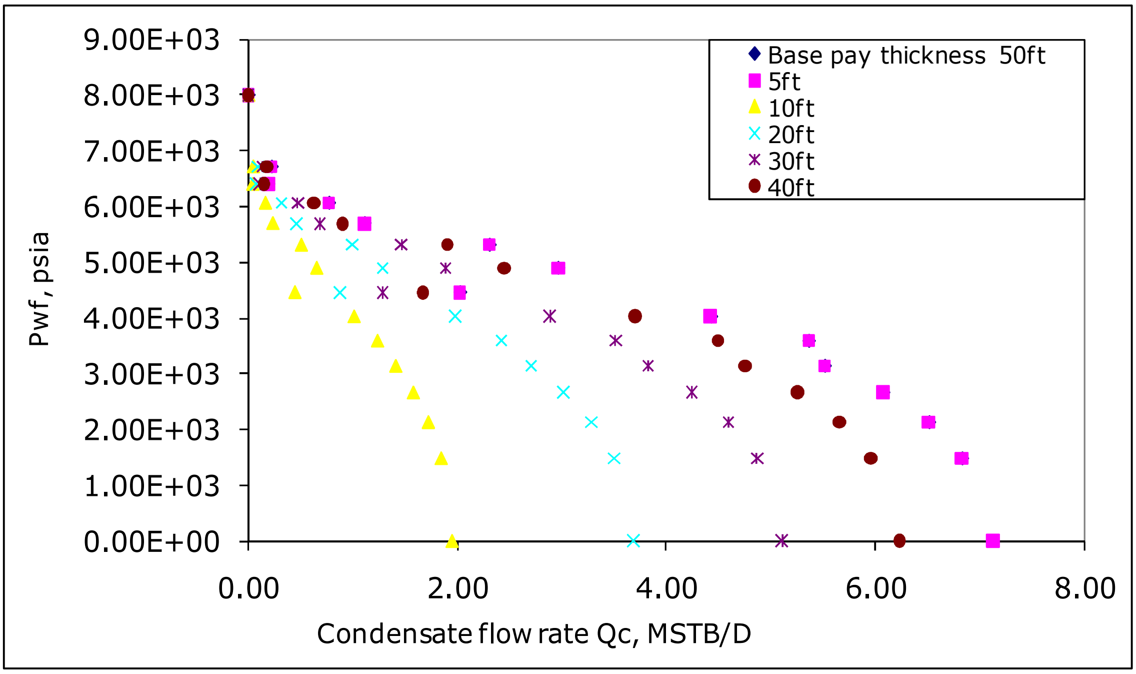


Figure 6.12 Effect of pay thickness on condensate inflow performance curve (IPR)

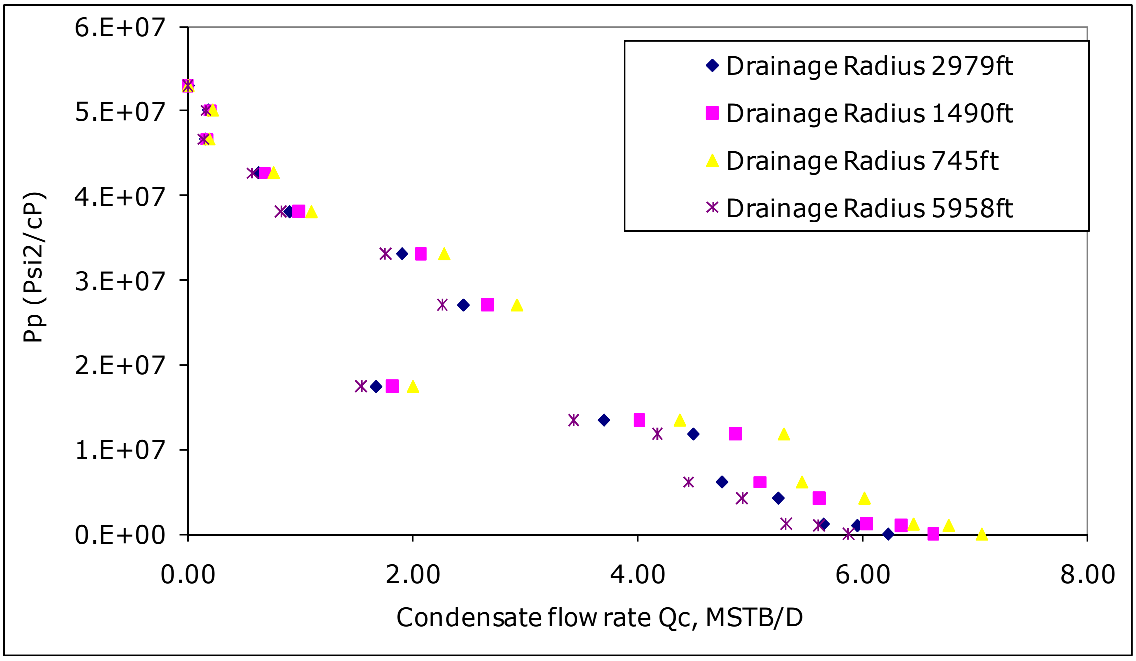


Figure 6.13 Effect of drainage radius on condensate inflow performance curve (IPR)

6.3.6 Sensitivity of IPR to condensate saturations

Six saturation values were used for the sensitivity test as shown in figure 6.8. Saturation parameters do not have explicit impact on the inflow performance (IPR) as it is not represented directly in the modified IPR equation, but are implicitly represented through the corresponding relative permeability. The effect of saturation is significant at the present condition which IPR represents.

6.3.7 Sensitivity of IPR to tight sand

The low absolute permeability values represent typical characteristics of low permeability sand. The IPR showed significant sensitivity to the eight low absolute permeability values used for the test as shown in figure 6.9. The implication of this result is that recovery of condensate in tight sands which are low permeability sands may be difficult due to its effect in addition to condensate banking

6.3.8 Sensitivity of IPR to absolute permeability

Figure 6.10 shows direct impact of absolute permeability on the IPR for all the absolute permeability used in the investigation. This behaviour is in agreement with most published reports. It has been reported that with high values of relative permeability the effect of condensate blockage may not be apparent in gas condensate reservoirs. The higher absolute permeability values used in figure 6.11 show that absolute permeability is directly proportional to IPR, the reservoir productivity.

6.3.9 Sensitivity of IPR to reservoir pay thickness

The higher the pay thickness the higher the recovery from the reservoir is demonstrated in figure 6.12, but this may not always be the case, as this need to be considered along with the permeability of the reservoir.

6.3.10 Sensitivity of IPR drainage radius

The inflow performance is expected to increase with drainage radius. The recovery from the reservoir is expected to increase with higher drainage radius, but this is not the case with the result shown in figure 6.13. The IPR seems to be insensitive to drainage radius in this case. Many factors could be responsible for the static IPR displayed. Then factors could range from relative permeability to other issues beyond the scope of this study. The base case assumes that the only varying parameter for each of the sensitivity test is the variable of interest that is being tested.

6.4 Horizontal well (HW) productivity models.

6.4.1 Introduction

Selection of horizontal well models for specific application is no less difficult for any class of hydrocarbon and even more challenging especially for modelling well deliverability in gas-condensate reservoirs. Special consideration is important in this case because of complicated fluid property behaviour in gas condensate reservoirs. Earlier research, (Wang and Economides 2009) has indicated how the popular Joshi model overestimated flow resistances of a horizontal well resulting in under prediction, and predicts increasing productivity index (PI) when the horizontal wellbore is not located at the midpoint of the reservoir. More accurate productivity index and IPR estimation have been an emerging critical issue in the petroleum industry since 1980s, (Choi and Shah 2008, Economides and Frick 1994). For complex geometry the

IPR model is getting more rigorous and complex in a bid for accurate prediction of IPR, but definitely at higher cost and more computationally demanding approach.

There are over 24 published horizontal well (HW) models, each with its associated limitations. These models even for the same reservoir conditions predict different production rates thereby making selection for certain applications difficult, since you need to validate for specific applications. The observed different production rates predicted supports the accuracy issues raised by (Shedid and Zekri 2001)

The primary objective of this parametric study is to source a suitable horizontal well model that needs little or no modification for modelling well deliverability in gas-condensate reservoirs. Fluid properties and relative permeability correlations developed in chapter four were used to generate data needed for the horizontal well models as modification for multiphase prediction of well deliverability in gas-condensate reservoir. The impact of these modifications were analysed by this parametric investigation.

6.4.2 Horizontal well modelling considerations

The major difference between black oil modelling and compositional modelling in reservoir simulation lies in the fluid PVT properties. These informed the approach to source and develop fluid properties correlation that accounts for compositional variation in production of condensate below the dew point for application in black oil models for prediction of well performance in gas-condensate reservoir. The black oil models are simpler, yield rapid solutions, and can easily be implemented on a spread sheet for real-time prediction at well site to aid production decision making. Prediction of well deliverability using fine grid numerical simulation, when detailed reservoir description is not needed is not recommended as the data requirement to set up the model is huge, time consuming and computationally demanding (Mott 200). The associated problems have made research into alternative approaches to modelling well deliverability popular, and motivated the present research.

Present study has shown that the different available horizontal well models applied to same reservoir conditions gave different production rates, as shown in figures 6.8 and 6.9, thus highlighting the need for selection and the inaccuracy of the available horizontal well (hw) models. The above considerations informed decision to carry out parametric studies using various horizontal well models to determine the dominant controlling parameter in modelling well deliverability in this kind of reservoir. The determined dominant parameters that govern the productivity of condensate reservoir helped to focus the study on the modification of the appropriate parameter to improve on the performance prediction of the well deliverability. The selection of the HW model to forecast the well inflow performance was based on performance validation using production data from the Anschutz gas condensate field, (Walsh 2003)

6.4.3 Modelling below the dew point pressure considerations

Many gas condensate reservoirs are found to have initial pressures only slightly above the dew point pressure (Marhaendrajan, and Kartawidjaya 2007). This closeness of dew point pressure to initial reservoir pressure is one of the reasons why production below the dew point is imperative in most gas condensate reservoir to achieve any reasonable primary recovery. Majority of earlier studies have modelled gas production, and predicted condensate production rate using the condensate gas ratio. This approach does not properly characterise condensate PVT properties and relative permeability for conditions below the dew point pressure. It therefore cannot provide an effective analysis of gas condensate recovery as proper characterisation of condensate transport properties is needed to predict how much of the condensate dropped out in the reservoir is producible. This will help to determine where appropriate artificial lift and gas cycling support feasibility and facility sizing could be recommended if required. These considerations directed the focus of the investigation to modelling condensate production below the dew point. This is because the complications of condensate modelling are usually below the dew point pressure where condensate banking and other complex fluid behaviour are dominant. Modelling well deliverability of gas-condensate reservoir using condensate fluid properties below the dew point are very important and should be the way forward. The approach here is focused on characterising the condensate dropout through the development of appropriate correlation to determine condensate pressure, volume, temperature (PVT) fluid properties at those conditions. Accurate knowledge of reservoir fluid properties at these conditions is important as they govern the mobility of condensate that dropped out. Since up to 50% of condensate that has dropped out is mostly lost to the formation, (Shadrin et al. 2009) it is very important that we determine how much of this condensate that could be produced to the surface, as it is mobile when above the critical condensate saturation, (Jokhio and Tiab 2002, Elliott et al 1998). If condensate recovery can be predicted with precision, further planning and the feasibility of using pressure maintenance, other artificial lift methods and optimisation of condensate production could be done using the adapted horizontal well model from this study. At the moment no existing horizontal well model has addressed the issue of producing condensate dropped out in the reservoir except through gas cycling which expensive and very risky. The modified horizontal well model using the developed PVT fluid flow parameters recommended by this study has an important role in addressing remediation of relative permeability reduction occurring in gas condensate reservoirs. It also has the capability of addressing the issue of recovery of the most important components of condensate that gives it higher market value than black oil and gas.

6.4.4 Study assumptions

The study of gas-condensate reservoir behaviour below the dew point pressure, which is the area with the greatest challenges in modelling well deliverability, is major attraction in this work. This is largely the modelling of multiphase flow problems arising from thermodynamics of change of phase associated with reservoir pressure changes and isothermal production. The great variability in composition associated with the reservoir depletion must be properly accounted for in meaningful well productivity modelling. The study assumed a bounded reservoir.

Darcy's law was extended to multiphase conditions and no gas or condensate solubility in the water phase was considered.

6.4.5 Fluid flow model basis

Multiphase fluid flow models in porous media were all developed from fundamental principles by combining physical principles of conservation of mass, Darcy's, Law and an equation of state (EOS). The form of this equation for reservoir fluids generally can be represented as follows; (Wiggins et al. 1992, Wiggins 1993, Wiggins, Russell and Jennings 1996):-

For oil (condensate);

$$\nabla.\left\{\frac{kk_{ro}}{\mu_o\beta_o}\nabla P\right\} = \frac{\partial}{\partial t}\left(\frac{\phi S_o}{B_o}\right) \qquad (6.30)$$

For gas

$$\nabla.\left\{\frac{kk_{rg}}{\mu_g\beta_g} + \frac{kk_{ro}R_s}{\mu_o\beta_o}\right\}\nabla P = \frac{\partial}{\partial t}\left(\frac{\phi S_g}{B_g} + \frac{\phi S_o R_o}{B_o}\right) \qquad (6.31)$$

And for water,

$$\nabla.\left\{\frac{kk_{rw}}{\mu_w\beta_w}\nabla P\right\} = \frac{\partial}{\partial t}\left(\frac{\phi S_w}{B_w}\right) \qquad (6.32)$$

The above models assume no solubility of gas in water, also that gravity and capillary effects are absent.

These are the basic models from which several researchers have provided different solutions to the above partial differential equations assuming different reservoir boundary conditions and resulting in different well models. These models are solved using numerical simulators for prediction of different reservoir production profiles including but not limited to fluid flow profiles. One of the excellent features of these models is that they can be easily extended to multiphase flow even when they were originally derived for single phase flow. The derivation of the basic solution are similar for different reservoir conditions; as details of such derivations are available in the public domain (Izgec 2003, and Chaudhry 2003), there is no need to repeat such details here.

However, modifications of the different horizontal well models available were carried out to make them suitable for the purpose of our investigation.

6.4.6 Approach: Review of horizontal well (HW) models

The available well, reservoir and fluid property information and parametric studies planned for this work dictated the choice of HW models used.

The following widely used horizontal well models were reviewed for sensitivity analysis as summarised below;

(1) Giger Equation (Giger, Reiss and Jourdan 1984, Giger 1987)

$$J_h = \frac{0.007078 k_h L\left(\mu_o B_o\right)}{\left(L/h\right)\ln\left[\frac{1+\sqrt{1-\left[L/\left(2r_{eh}\right)\right]^2}}{L/\left(2r_{eh}\right)}\right]+\ln\left[h/\left(2\pi r_w\right)\right]} \tag{6.33}$$

(2) Joshi (Joshi 1988b, Joshi 1988a, Joshi 1991)

$$a = \left(l/2\right)\left[0.5+\sqrt{0.25+\left(2r_{eh}/L\right)^4}\right]^{0.5} \tag{6.34}$$

$$J_h = \frac{0.007078 k_h h/\left(\mu_o B_o\right)}{\ln\left[\frac{a+\sqrt{a^2-\left[\left(L/2\right)^2\right]}}{L/2}\right]+\left(h/L\right)\ln\left[h/\left(2r_w\right)\right]} \tag{6.35}$$

(3) Giger, Reiss and Jourdan (1984)

$$J_h/J_v = \frac{\ln\left(r_e/r_w\right)}{\ln\left[\frac{1+\sqrt{1-\left[L/\left(2r_{eh}\right)\right]^2}}{L/\left(2r_{eh}\right)}\right]+\left(h/L\right)\ln\left[h/\left(2\pi r_w\right)\right]} \tag{6.36}$$

(4) Renard and Dupuy (Renard and Dupuy 1991)

X = 2a/L for ellipsoidal drainage area

a= half the major axis of drainage ellipse

$$q_h = \frac{2\pi k_h h \Delta p / \left(\mu_o B_o\right)}{\ln\left[\dfrac{a\sqrt{a^2-\left(L/2\right)^2}}{l/2}\right]+\left(h/L\right)\ln\left[h/\left(2r_w\right)\right]} \quad (6.37)$$

$$a = \left(L/2\right)\left[0.5+\sqrt{0.25}+\left(2r_{eh}/L\right)\right]^{0.5} \quad (6.38)$$

(5) Joshi and Economides (Joshi 1991)

$$q = \frac{7.08\times10^3 k_H h\left(p_e - p_{wf}\right)}{\mu_o B_o\left(\ln\left(\dfrac{a+\sqrt{a^2-\left(L/2\right)^2}}{\left(L/2\right)^2}\right)+\dfrac{I_{ani}h}{L}\ln\left(\dfrac{I_{ani}h}{r_w\left(I_{ani}+1\right)}\right)+s\right)} \quad (6.39)$$

Where

$$I_{ani} = \sqrt{\frac{k_H}{k_V}} \quad (6.40)$$

And

$$a = \frac{L}{2}\left\{0.5+\left[0.25+\left(\frac{r_{eH}}{L/2}\right)^4\right]^{0.5}\right\}^{0.5} \quad (6.44)$$

(6) Borisov (Borisov 1984)

$$J_h = qh/\Delta p = \frac{0.007078 k_h h}{\mu_o B_o\left[\ln\left(4r_e/L\right)+\left(h/L\right)\ln\left(h/\left(2\pi r_w\right)\right)\right]} \quad (6.45)$$

(7) Butler (Butler 1989, Butler 1978)

$$q_o = \frac{7.08\times10^3 k_H L\left(p_e - p_{wf}\right)}{\mu_o B_o\left(I_{ani}\ln\left[\dfrac{hI_{ani}}{r_w\left(I_{ani}+1\right)}\right]+\dfrac{\pi y_b}{h}-1.14 I_{ani}\right)} \quad (6.46)$$

(8) Furui (Furui, Zhu and Hill 2002)

$$q_o = \frac{7.08\times10^3 kL\left(p_e - p_{wf}\right)}{\mu_o B_o\left(\ln\left[\frac{hI_{ani}}{r_w\left(I_{ani}+1\right)}\right]+\frac{\pi y_b}{hI_{ani}}-1.224+s\right)} \tag{6.47}$$

Where k is defined as $\sqrt{k_H k_V}$, and eq.6.47 could be rearranged as (Kamkom 2006)

$$q_o = \frac{7.08\times10^3 k_H L\left(p_e - p_{wf}\right)}{\mu_o B_o\left(I_{ani}\ln\left[\frac{hI_{ani}}{r_w\left(I_{ani}+1\right)}\right]+\frac{\pi y_b}{h}-I_{ani}\left(1.224-s\right)\right)} \tag{6.48}$$

(9) Modified Furui's model turbulent form;

$$q_g = \frac{kL\left(m\left(\overline{p}\right)-m\left(p_{wf}\right)\right)}{1424T\left(\ln\left[\frac{hI_{ani}}{r_w\left(I_{ani}+1\right)}\right]+\frac{\pi y_b}{hI_{ani}}-1.224+s+Dq_g\right)} \tag{6.49}$$

Where non Darcy coefficient is calculated from equation

$$D = 2.2\times10^{-15}\frac{L\gamma_g\sqrt{k_x k_z}}{\mu_g\left(p_{wf}\right)}\times\left[\left(\frac{\beta_d}{L^2}\right)\left(\frac{1}{r_w}-\frac{1}{r_d}\right)+\left(\frac{\beta}{L^2}\right)\left(\frac{1}{r_d}-\frac{1}{r_e}\right)\right] \tag{6.50}$$

(10) Babu and Odeh (Babu and Odeh 1989)

$$q_g = \frac{b\sqrt{k_y k_z}\left(m\left(\overline{p}\right)-m\left(p_{wf}\right)\right)}{1424T\left[\ln\left(\frac{A^{0.5}}{r_w}\right)+\ln C_H-0.75+s_R+\frac{b}{L}\left(s+Dq_g\right)\right]} \tag{6.51}$$

The calculation steps include;

$$\ln C_H = 6.28\frac{a}{I_{ani}h}\left[\frac{1}{3}-\frac{y_0}{a}+\left(\frac{y_0}{a}\right)^2\right]-\ln\left(\sin\frac{\pi z_0}{h}\right)-0.5\ln\left[\frac{a}{I_{ani}h}\right]-1.088 \tag{6.52}$$

For $\frac{a}{\sqrt{k_x}}\geq\frac{0.75b}{\sqrt{k_y}}>\frac{0.75h}{\sqrt{k_z}}$ (6.53)

$$s_R = P_{xyz}+P'_{xy} \tag{6.54}$$

And if $b/\sqrt{k_x} > 1.33a/\sqrt{k_y} >> h/\sqrt{k_z}$ then s_R is

$$s_R = P_{xyz} + P_y + P_{xy} \tag{6.55}$$

For eqns. 6.54 and 6.55

$$P_{xyz} = \left(\frac{b}{L} - 1\right)\left[\ln\frac{h}{r_w} + 0.25\ln\frac{k_y}{k_z} - \ln\left(\sin\frac{\pi z}{h}\right) - 1.84\right] \tag{6.56}$$

$$P'_{xy} = \frac{2b^2}{I_{ani}Lh}\left[F\left(\frac{L}{2b}\right) + 0.5\left[F\left(\frac{4x_{mid}+L}{2b}\right) - F\left(\frac{4x_{mid}-L}{2b}\right)\right]\right] \tag{6.57}$$

$$p_y = \frac{6.28b^2}{ah}\frac{\sqrt{k_y k_z}}{k_x}\left[\left(\frac{1}{3} - \frac{x_{mid}}{b} + \frac{x_{mid}^2}{b^2}\right) + \frac{L}{24b}\left(\frac{L}{b} - 3\right)\right] \tag{6.58}$$

and

$$P_{xy} = \left(\frac{b}{L} - 1\right)\left(\frac{6.28a}{h}\sqrt{k_z/k_y}\right)\left(\frac{1}{3} - \frac{y_0}{a} + \frac{y_0^2}{a^2}\right) \tag{6.59}$$

The functions in equation 6.57, $F\left(L/2b\right)$, $F\left(\left(4x_{mid}+L\right)/2b\right)$ and $F\left(\left(4x_{mid}-L\right)/2b\right)$, are defined as

$$F(x) = \begin{cases} -(x)\left[0.145 + \ln(x) - 0.137(x)^2\right] for, x = \dfrac{L}{2b}, x = \dfrac{4x_{mid} \pm L}{2b} \le 1 \\ (2-x)\left[0.145 + \ln(2-x) - 0.137(2-x)^2\right] for, x = \dfrac{4x_{mid}+L}{2b} > 1 \end{cases} \tag{6.66}$$

Figure 6.14 is important to understand the concepts and symbols used in most of the horizontal well equations described above and the MATLAB codes used in the study.

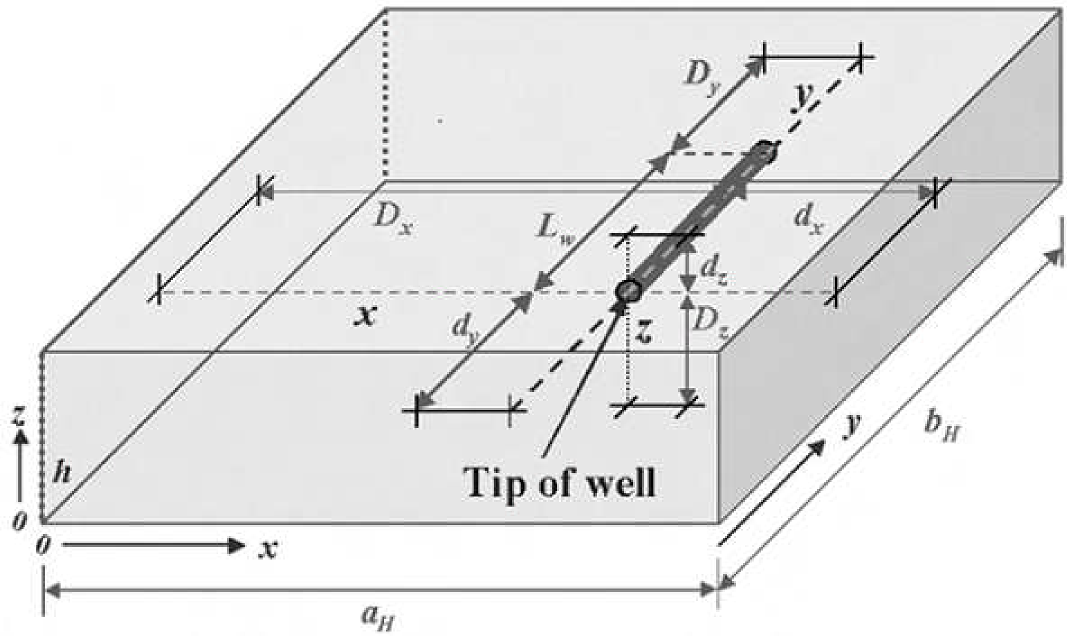


Figure 6.14 Reservoir and horizontal well geometry (Lake and Fanchi 2007)

6.4.7 Modification steps

Gas condensate recovery optimisation is one the greatest challenges of modern condensate reservoir management (Thomas et al. 1996). Part of our strategy for solving to the above problem is the extension of the black oil model to account for compositional changes. This is to ensure accurate well deliverability prediction as the constant composition assumption of the black oil model is not valid for reservoir conditions below the dew point pressure.

The search to apply modified black oil models for the prediction of well productivity in gas-condensate reservoirs have become very popular as use of fine grid numerical simulation, when detailed reservoir description is not needed. For rapid on site decision-making black oil models are preferable as they do not require huge data bases and long time intervals to complete simulation runs for specific projects. The steps taken to modify the model for prediction of well deliverability in gas-condensate reservoirs include;

(i) Development of a compositional pseudo-pressure model for multiphase modelling.

(ii) Development of compositional correlations for compressibility factor, density, viscosity and relative permeability for condensate.

(iii) Use of correlations developed in each of the above steps to generate fluid properties and relative permeability for the horizontal well models reviewed above to make them adequate for multiphase modelling of condensate.

Production rates were predicted using the modified models to compare performance.

6.4.8 Anschutz gas condensate case study (Walsh 2003)

Further development of 12 horizontal well correlations have been carried out by implementing modified reservoir fluid PVT and petro-physical property correlations in the equations. The available horizontal well correlations are for single phase and to modify them for multiphase modelling of condensate inflow performance, relative permeabilities for the flowing phases are needed to convert absolute permeability to effective permeability for accurate prediction of IPR for each phase. The relative permeability needed for condensate flow below the dew point as well as condensate fluid properties are usually not available at the desired reservoir conditions. Correlations for these parameters for condensate were developed earlier and have been used to predict the properties used in each of the horizontal well models in this investigation.

Specific input parameters have been used in this case study to determine the limitations, effective range and trends of these correlations in the first instance. This was followed by selection of horizontal well correlation for prediction of condensate IPR based on performance. The understanding of the sensitivity of any of the correlations used for prediction of horizontal well productivity is important for selection and validation purposes.

The input parameters for all the horizontal well models were derived from Anschutz gas condensate reservoir well test and PVT test data. The required PVT properties and the relative permeabilities calculated from Anschutz for the base case in this sensitivity study are shown in table 6.6

6.4.9 Results and discussions

The following figures are the result highlights:-

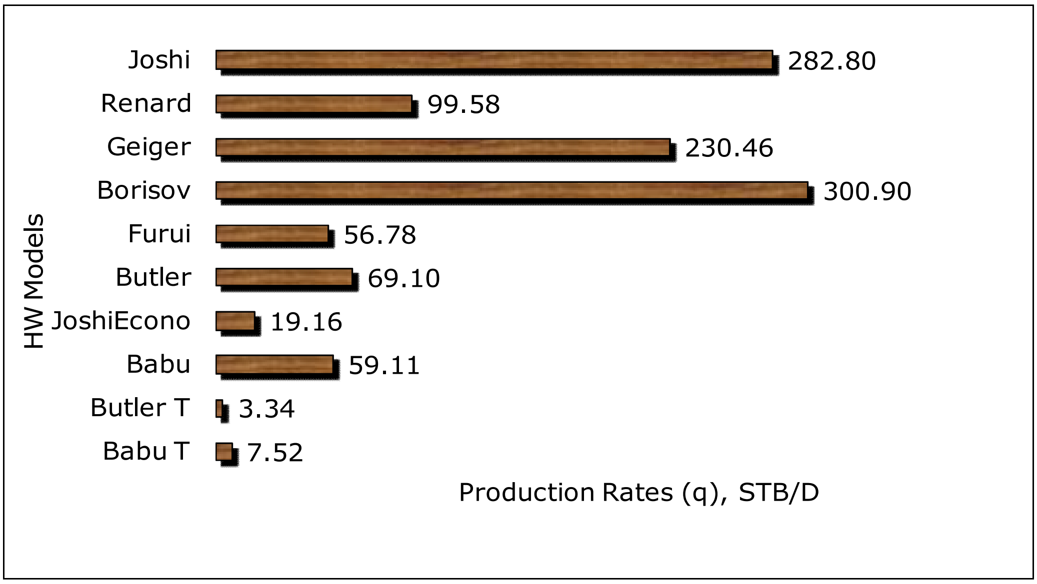


Figure 6.15 Production rate forecast for modified horizontal well models (HW) for isotropic gas condensate reservoir

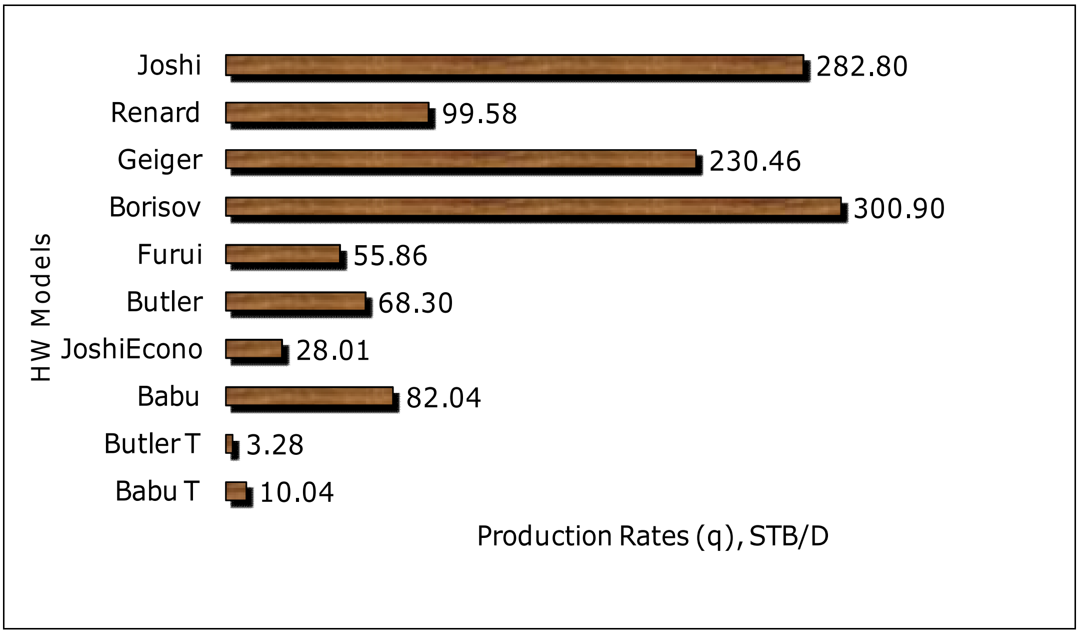


Figure 6.16 Production rate forecast for modified horizontal well models (HW) for anisotropic gas condensate reservoir

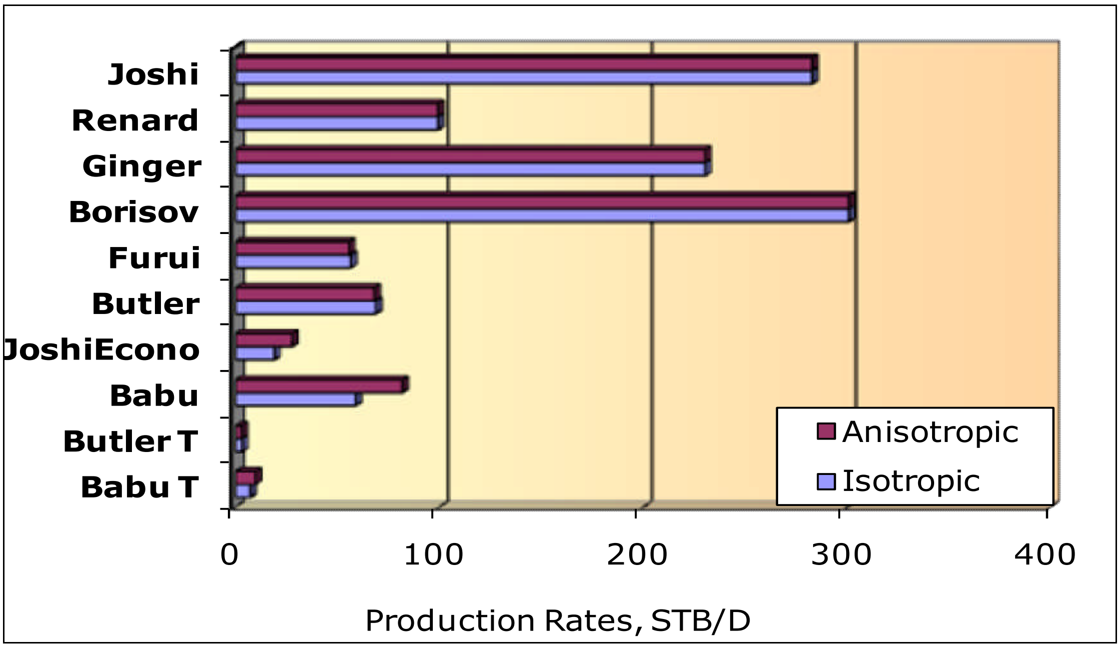


Figure 6.17 Anisotropic and isotropic gas condensate production rate forecast for modified horizontal well models

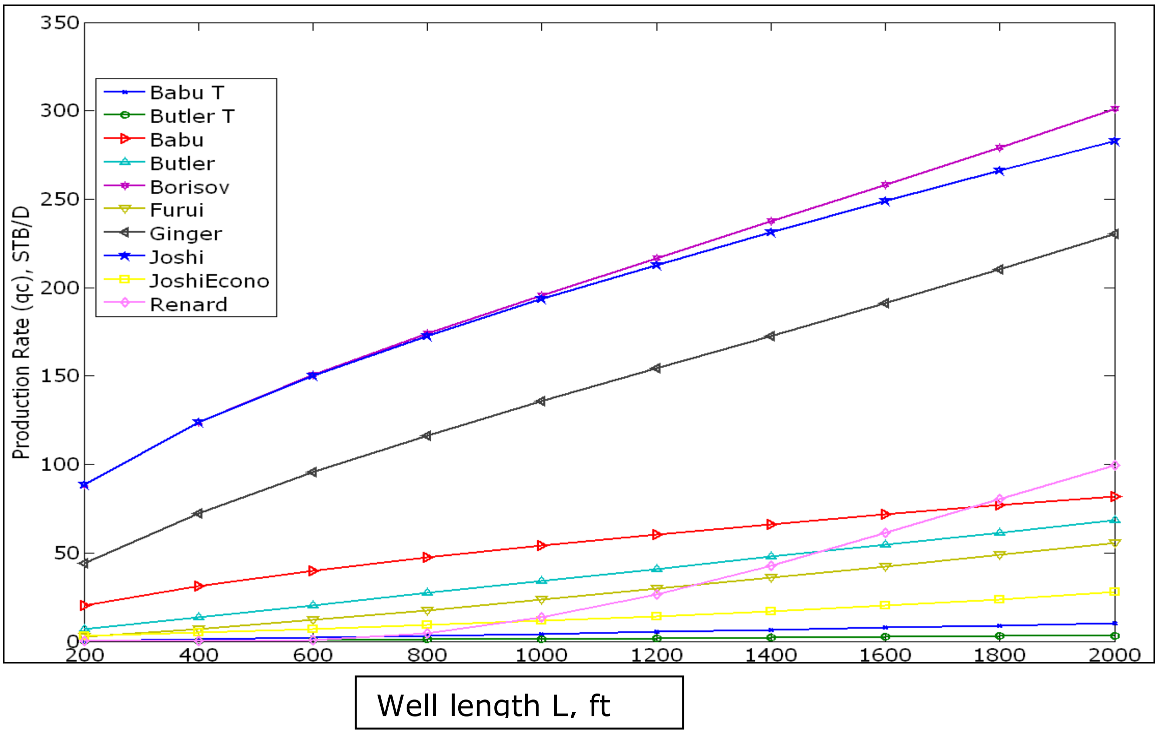


Figure 6.18 Effect of well length on production rate of anisotropic gas-condensate reservoir using various modified horizontal well model

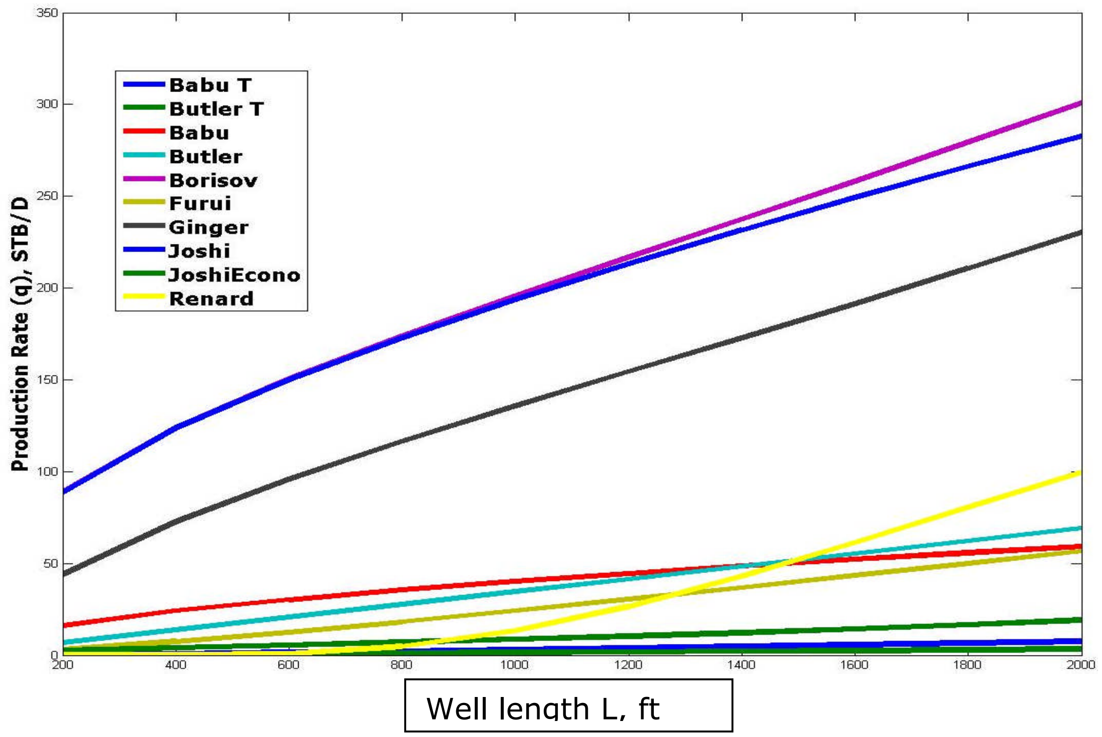


Figure 6.19 Effect of well length on productivity of isotropic condensate reservoir using various modified horizontal well models

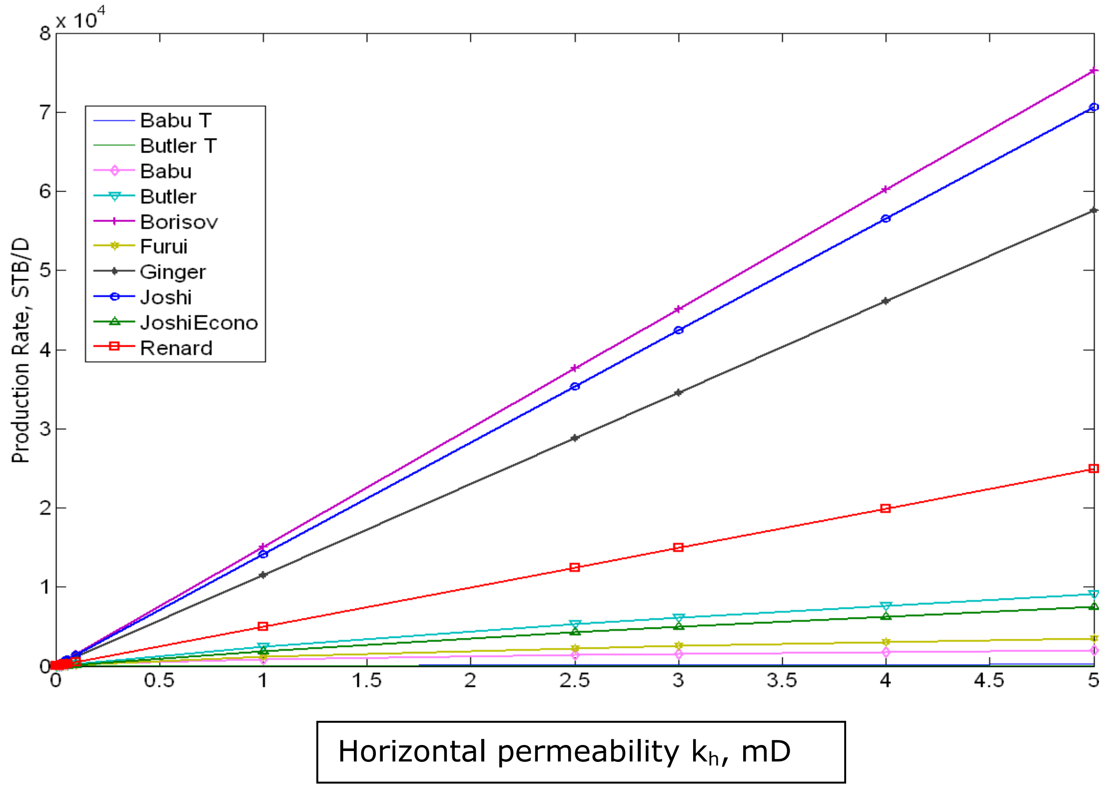


Figure 6.20 Effect of horizontal permeability on productivity on anisotropic gas-condensate reservoir using various horizontal well models

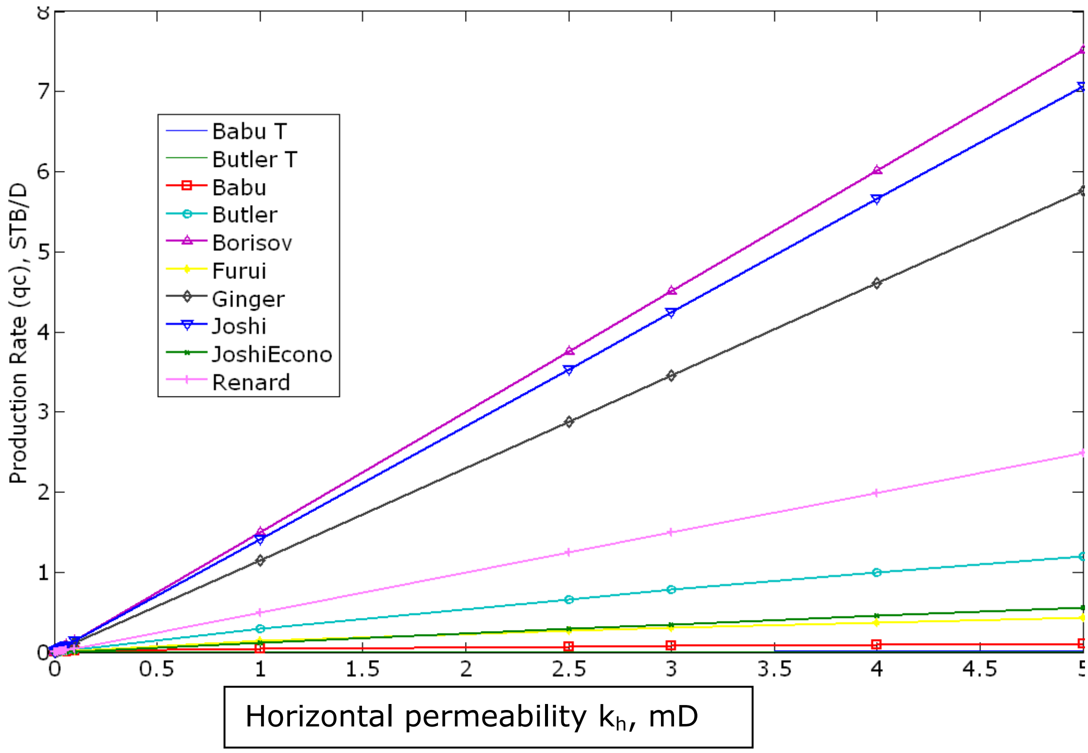


Figure 6.21 Effect of horizontal permeability on isotropic gas condensate reservoir using various modified HW models

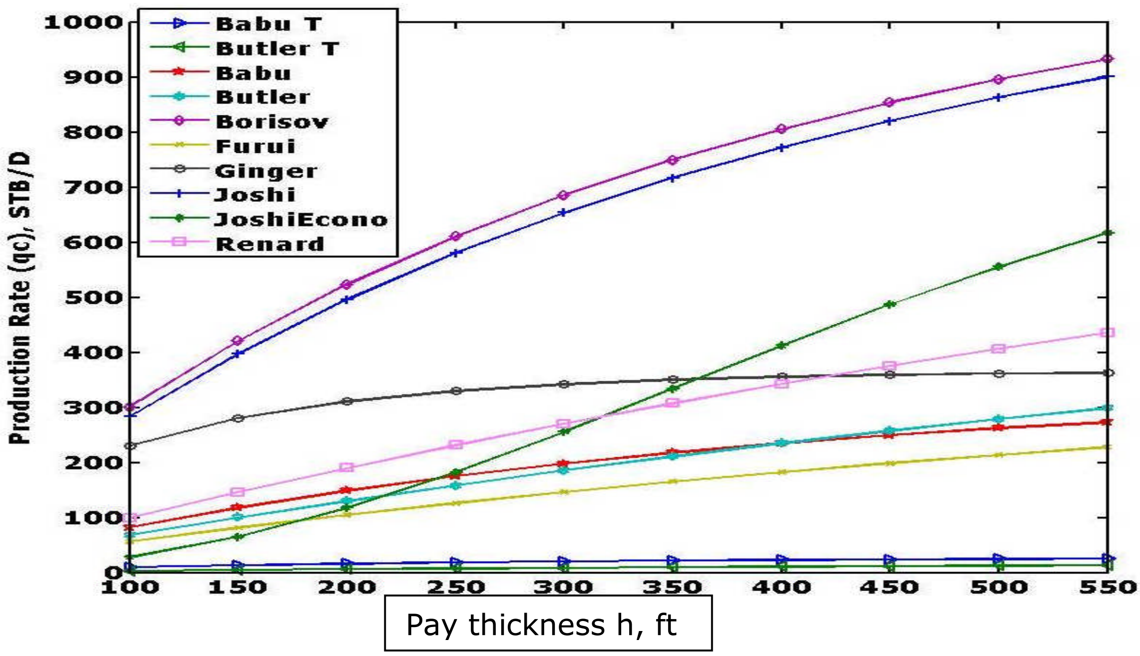


Figure 6.22 Effect of pay thickness on productivity of anisotropic gas condensate reservoir using various horizontal well models

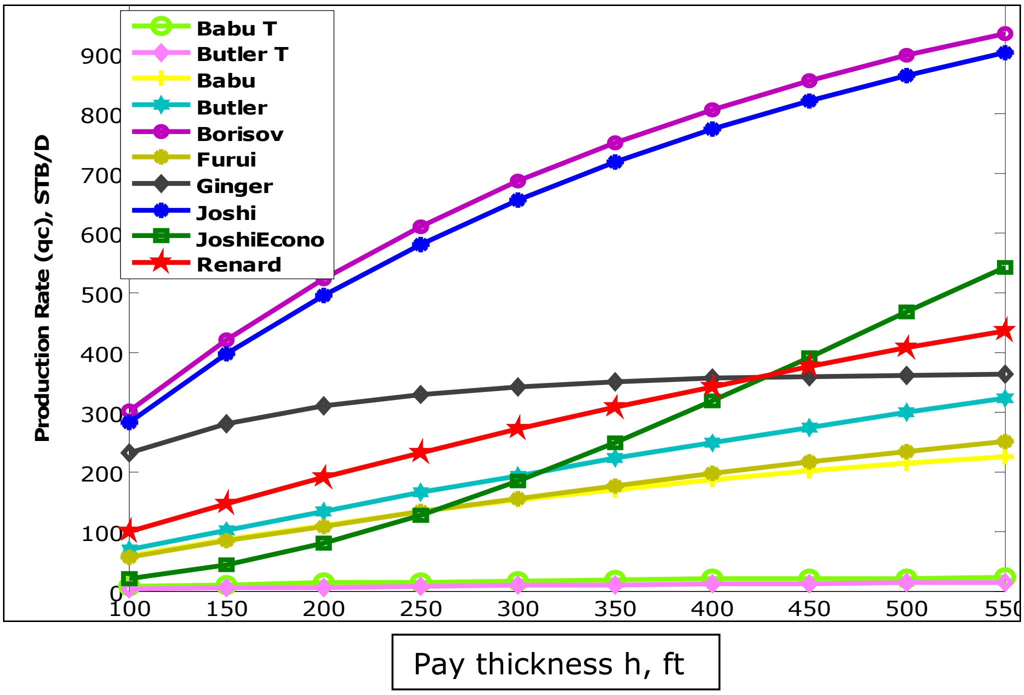


Figure 6.23 Effect of pay thickness on the productivity of isotropic gas-condensate reservoir using various horizontal well models

6.4.10 Discussion of results

The horizontal well equations are more complex in predicting well performance than the vertical wells. However, horizontal wells have more access to larger reservoir surface area and are preferable where the reservoir thickness is limited and are currently more attractive than vertical wells (Menouar et al. 2000). The various production rates predicted by the different horizontal well models for given reservoir conditions shown in figures 6.15 through 6.17 is an indication of model validity for different reservoir boundary conditions. Some are relevant for ideal isotropic reservoir conditions assuming no friction and formation damage, Borisov is a good example. Others are valid for anisotropic reservoirs only and other boundary condition limitations. All these are reflected in the differences recorded in the sensitivity test. Parametric studies have been carried out covering a range of conditions from isotropic to anisotropic condensate reservoirs to determine the impact of well length, permeability and pay thickness on production rates predicted by different modified horizontal well models.

The production rates showed some sensitivity to parameters studied predicted by the different horizontal well models. However at some ranges of parameter variation, there was some insensitivity to production rates. The different Horizontal well models rate predictions were different for several cases of same reservoir conditions investigated. This suggested the need to subject the models to comparison with a benchmark so as to assess the performance of each of the models for selection best fit for purpose model for prediction of well deliverability in gas condensate reservoirs.

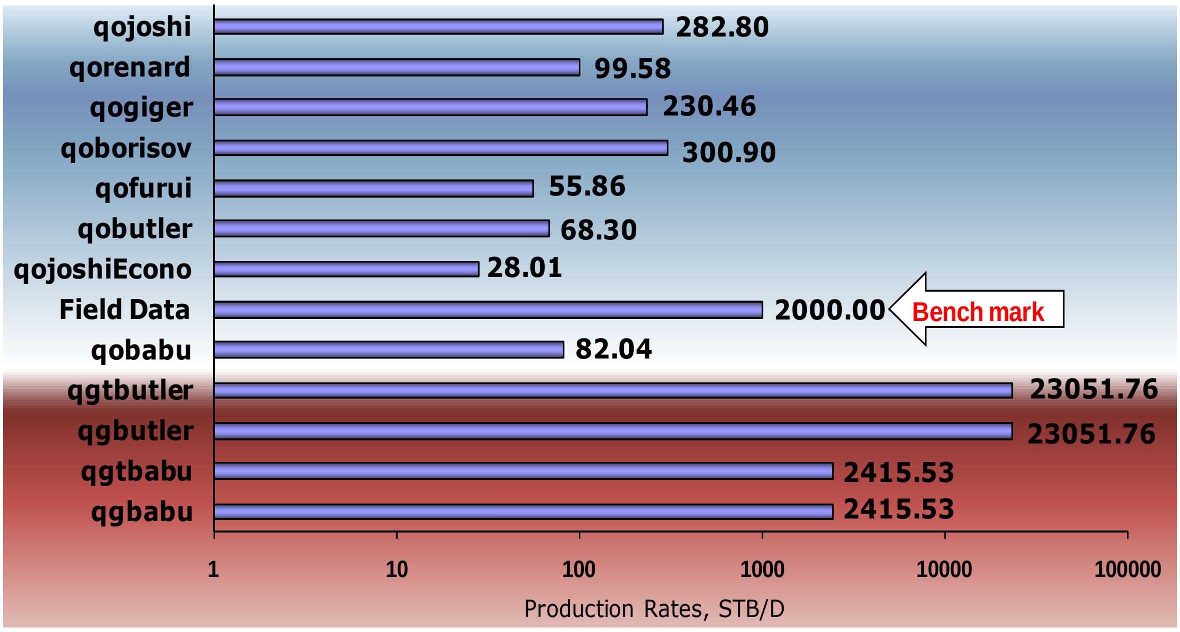


Figure 6.24 Benchmarking production rate performance of the modified HW models with field data

Where;	
qojoshi	Oil flow rate for Joshi horizontal well equation
qorenard	Renard's equation Oil flow rate
qogiger	Geiger horizontal well Oil flow rate
qoborisov	Borisov Oil well flow rate
qobutler	Butler Oil well flow rate
qjoshiEcono	Joshi-Economides Oil well flow rate
qobabu	Babu and Odeh Oil well flow rate
qgbutler	Butler Gas well flow rate
qgtbutler	Butler Gas well flow rate for turbulent flow
qgtbabu	Babu and Odeh Gas well flow rate for turbulent flow
qgbabu	Babu and Odeh Gas well flow rate for laminar flow

Figure 6.24 shows under and over prediction of production rate performance compared to the field data benchmark of 2000STB/D from the Anschutz gas condensate reservoir. However, Babu and Ode (qgbabu and qgtbabu) had the closest production rate predictions to the bench mark, and the Babu modified gas rate model (qgbabu) was selected for further verification and application in the investigation.

The use of the twelve Horizontal well models for parametric studies to determine the dominating parameters for productivity of gas condensate reservoirs has shown sensitivity to some important well and reservoir parameters as shown in figures 6.18 through 6.23. All the Horizontal well models used showed some sensitivity of production rates to parameters investigated.

However these results do not actually conclude on the dominating parameters as the result have not shown which parameter has higher impact than the other on the production rate. As a result further sensitivity studies was carried out on the parameters using Babu's model which was considered more fit for purpose as it gave the closest prediction to field data. It is also more flexible for well placement as against other models' restrictions. Butler and Furui's models gave good agreement but they are for full well penetration only and give no consideration to partial penetration. Babu's model is rigorous and gave a good representation for both isotropic and anisotropic reservoirs.

Results for further sensitivity tests using with Babu's model are presented in figure 6.25.

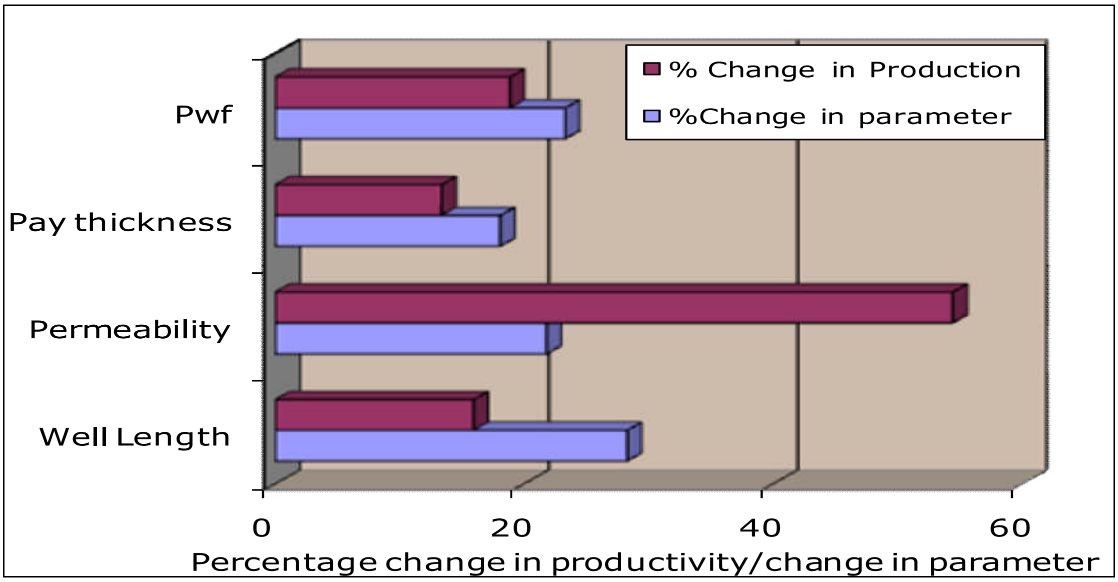


Figure 6.25 Dominating/controlling parameters in productivity of gas condensate reservoirs

The controlling parameters in productivity of condensate reservoirs were summarised in figure 6.25 which showed permeability as the most sensitive parameter. This is in agreement with most sensitivity test literature reports on the productivity of gas-condensate reservoirs. The above result in figure 6.25 is in close agreement with practical experiences and concepts that demonstrate that the prediction accuracy of well deliverability model is as only as good as the relative permeability and fluid property correlations used in the model.

The gas and condensate production profile is a good profitability parameter for determination of development feasibility of gas condensate field, (Bourbiaux 1994). To establish a good field development plan, reliable prediction of well deliverability is the minimum requirement as modelling well deliverability is the first step in an effective and efficient field development plan. The above statements underscore the importance of this investigation aimed at developing accurate well deliverability model for gas condensate reservoir under multiphase conditions.

6.4.11 Result highlights

(i) Permeability (absolute or relative) has a dominant influence on the productivity of gas condensate reservoirs, and must be determined accurately.

(ii) All the HW equations have shown remarkable sensitivity to all the parameters analysed under the same drainage area and identical reservoir flow conditions.

Specific input parameters have been used in this case study to determine the limitations, effective range and trends of these correlations in the first instance. This was followed by selection of horizontal well correlation for prediction of condensate IPR based on performance comparison with field data from case study. The understanding of the sensitivity of any correlation used for prediction of horizontal well productivity is important for accurate model selection, production process control and model validation purposes. These conclusions are limited to this case study but can be extended to other cases with caution, and will serve very well as reference material for further studies.

6.4.12 Key conclusions

Twelve horizontal well equations were sourced and modified. A fit-for-purpose horizontal well model for accurate well productivity was selected. The selected modified model was applied for prediction of multiphase flow in a gas condensate reservoir below the saturation pressure.

The twelve modified open-hole horizontal well models under identical reservoir geometry and fluid properties were subjected to a wide range of horizontal well lengths (200 to 2,000 ft), Permeability (0.5 to $5x10^4$mD), pay zone thickness (100 to 550 ft), sensitivity test and other performance verifications.

The results are in close agreement with practical experience which demonstrates that the prediction accuracy of the well deliverability model is dependent on the accuracy of the relative permeability and fluid property correlations upon which the model is based.

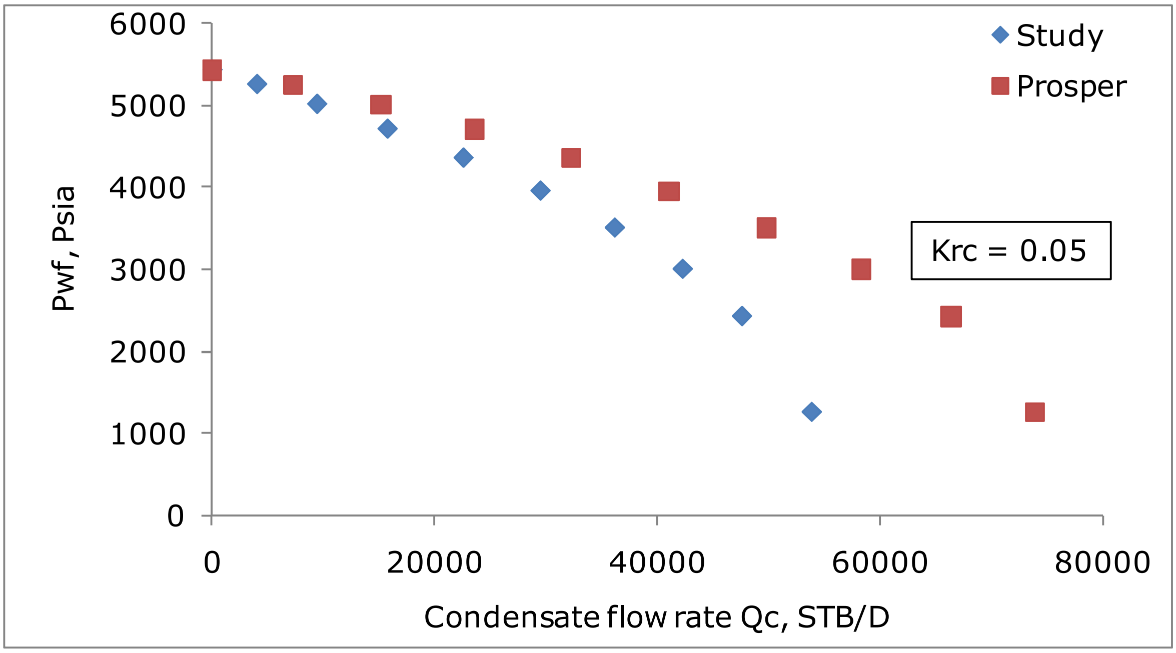
6.5 Comparison of selected horizontal well IPR with Prosper

One way of validating the performance of the modified horizontal well correlation based on Babu and Odeh for well deliverability prediction is by comparison of the predicted IPR with that given by standard industry software, Prosper IPR. The comparison was done as shown in figures 6.26 through 6.28. At very low condensate relative permeability, the IPRs were different especially at lower reservoir pressures,(figure 6.26) where the Prosper model predicted a higher productivity than the modified model. The Prosper model does not assume any condensate loss to the formation, but the modified model accounts for this loss, which could be the reason for the disparity of the results. Figure 6.27 shows that at higher condensate relative permeability, the IPR curves for the two horizontal well models are the same. For these conditions, condensate loss to the formation is reduced and the productivity of condensate will be closer to the Prosper value which assumes no loss to the formation.

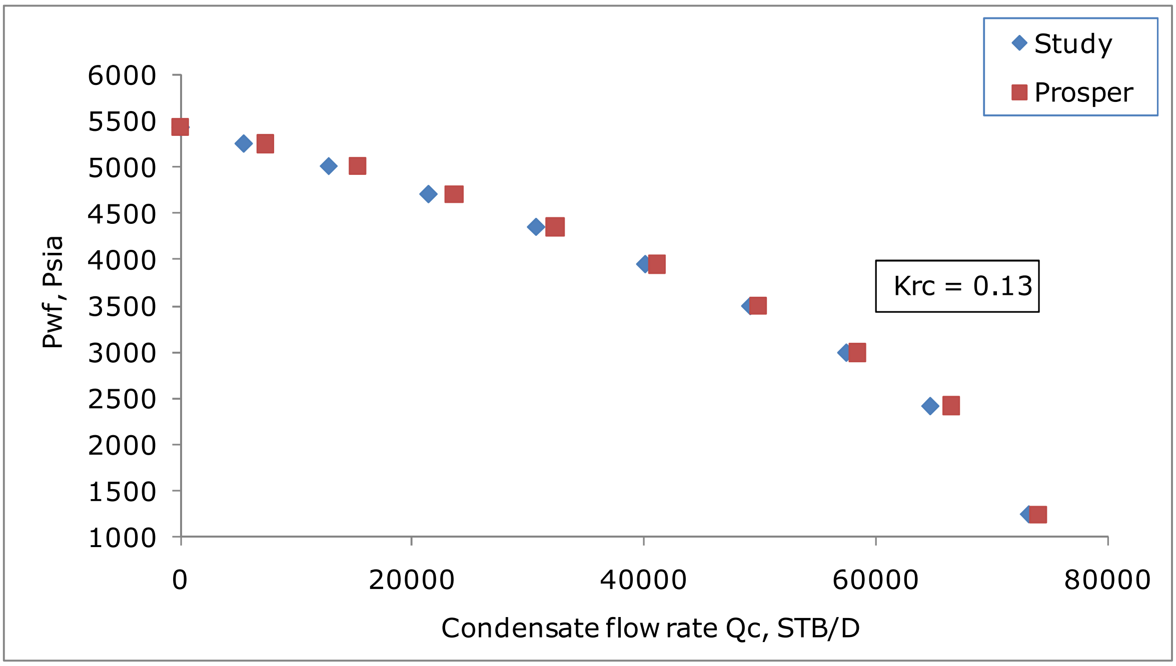
Figure 6.28 shows the sensitivity of the modified IPR to condensate relative permeability, which is in close agreement with the physics of condensate production, which predicts higher average open flow potential (AOFP) of the well at higher condensate relative permeability.

6.6 Summary

The modified horizontal well algorithms and codes were realised in MATLAB, a high performance language for technical computing. It has the capability of integrating computation, visualisation and programming in an easy-to –use environment and expressing problems and solutions in a conventional mathematical form (MATLAB, 2002). The processing and the post-processing of solution of the problem were performed in a unified MATLAB M-file (Appendix E). For verification and validation of the code, it has been compared with commercial simulator results using the Anschutz gas condensate field data (figure 6.24).



Figures 6.26 Validation of modified condensate IPR with Prosper at low condensate relative permeability



Figures 6.27 Validation of modified condensate IPR with prosper at higher condensate relative permeability.

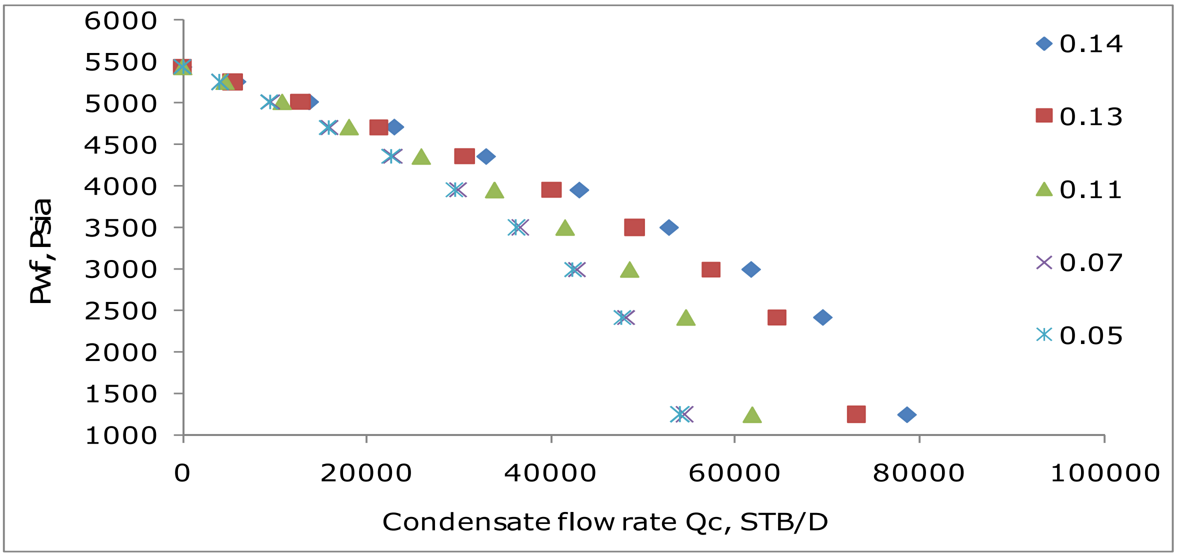


Figure 6.28 Study IPR sensitivity to condensate relative permeability

Table 6.6 Anschutz base case input parameters for the horizontal well parametric studies.

S/ No	Parameter	Symbol	Unit /Field	Base Case values
1	Drainage Area	A	Acres	320
2	Average reservoir pressure	p_r	psi	5800
3	Average Permeability	k	md	200
4	Vertical Permeability	k_v	md	100
5	Horizontal Permeability	k_h	md	200
6	Permeability in the x-direction	k_x	md	200
7	Permeability in the y-direction	k_y	md	200
8	Pay thickness	h	ft	175
9	Open hole	h_p	ft	1800
10	External boundary radius	r_e	ft	2.1064e+03
11	Reservoir half length in the direction	x_e	ft	3200

	parallel to the wellbore			
12	Reservoir half length in the direction perpendicular to the wellbore	y_e	ft	100
13	Shape factor	C_A	-	1.4
14	Formation volume factor	B_c	bbl/ STB	4.382
15	Condensate Viscosity	μ_c	cp	0.2135
16	Initial dew point pressure	P_d	psi	5430
17	Bottom hole flowing pressure (BHFP)	P_{wf}	Psi	1.247e+03
18	Condensate viscosity	μ_g	cp	0.0244
19	Condensate compressibility factor	Z_c	-	0.945
20	Temperature	T	^oR	675
21	Gas specific gravity	γ_g	-	0.71
22	Average Reservoir Pseudo-Pressure	$\psi(P_r)$		1.337e+08
23	Wellbore radius	r_w	ft	0.50
24	Horizontal well length	L	ft	2000
25	Distance from the side wall boundary perpendicular to the wellbore to the midpoint of wellbore	x_w	ft	3000
26	Distance from the side of wall boundary parallel to the wellbore to the center of wellbore	y_w	ft	750
27	Distance from bottom or top boundary to the center of wellbore	z_w	ft	50
28	Bottom-hole Pseudo-pressure	$\psi(P_{wf})$		1.805e+07
29	Skin	s	-	22.4
30	Non-Darcy factor	β	1/ft	7.0776e-5

CHAPTER SEVEN

7.0 NUMERICAL SIMULATION

7.1 Verification and validation of the semi-empirical correlations developed

A single well compositional simulation was run for the Anschutz gas condensate reservoir to compare the depletion behaviour of the reservoir below the dew point with the predictions of the semi-empirical models developed in the investigation for performance verification. The validation and verification was done using Schlumberger Eclipse E3-00 reservoir simulator. The numerical simulation step was important in validating the performance of the semi-empirical modelling approach proposed in this investigation. Data from the Anschutz gas condensate reservoir under natural depletion as published by Walsh in (2003) was a special case study used for the investigation. Simulation for natural depletion was done with the full compositional model in Eclipse E3-00. Reveal simulator; Part of Petroleum Expert's integrated production modelling (IPM) suite software for reservoir simulation and surface network modelling and integration was used to implement the fluid PVT properties generated using the semi-empirical correlations developed in the study. The results were compared with the full compositional simulation for the proposed Semi-empirical correlation approach. The approach assumes condensate phase saturation in the reservoir to be above critical. The assumption ensures the mobility of condensate and a modification of the original CVD assumption which is only valid when condensate is below the critical saturation in the reservoir.

The compositional model in Eclipse 300 was built using the Peng Robinson EOS with CVD data for the Anschutz gas condensate reservoir fluid sample to generate all the PVT data required for the simulation. The performance of the developed semi-empirical model was compared to that of the compositional model for various reservoir conditions. The result of earlier work for comparison of performance of Eclipse and Reveal reservoir simulator by PETEX showed an excellent agreement between Reveal and Eclipse as shown in figure 7.1

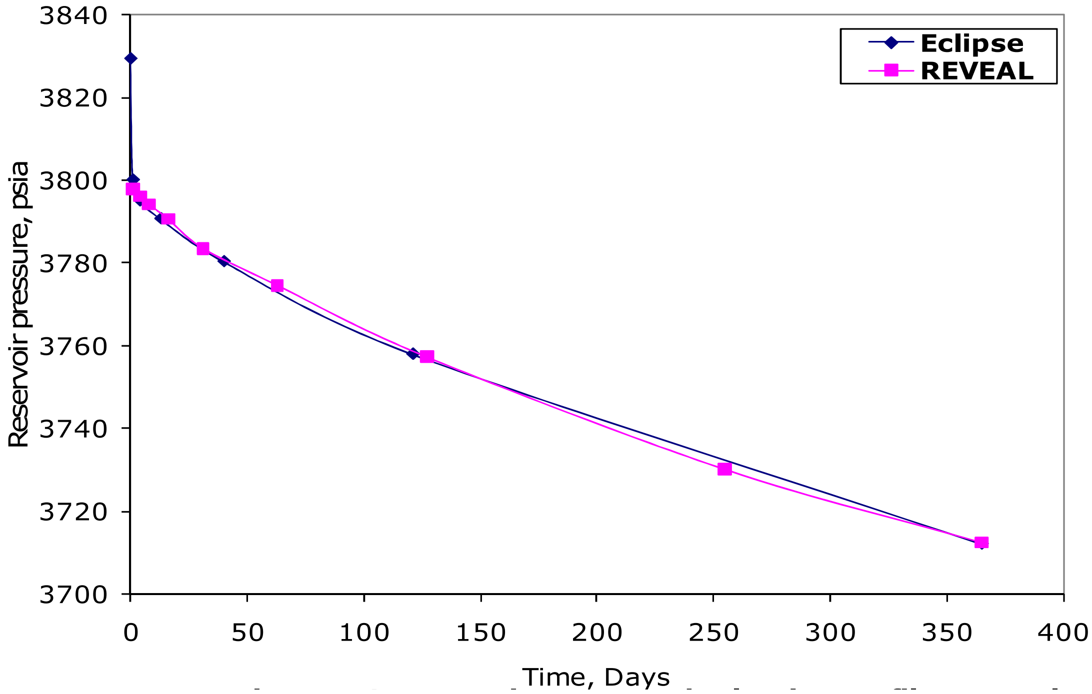


Figure 7.1 Comparison of E300 and Reveal reservoir pressure depletion profile (Reveal, 2008)

The implication of the above result is to show that any differences in the result between the E300 and the study proposed semi-empirical approach implemented in Reveal do not result from software platform differences. (Reveal Simulator data file used is shown in appendix F).

The reservoir parameter values used for simulation for the two approaches, the validation model and the verified method used in the study, is identical and as shown in the table 7.1. Also the same initial reservoir composition is used for both as shown in table 7.2.

Table 7.1 Reservoir and fluid property parameters for rich gas condensate reservoir used for simulations (Walsh (2003)

Property	value
Simulation area, acres	320
Number of wells	1
Reservoir depth, ft	12,800
Horizontal permeability, md	1.5
Pay thickness, ft	175
Average porosity, %	10
Connate water saturation,% PV	20
Temperature, ^{o}F	215
Initial pressure, Psia	5800
Initial dew point, Psia	5430
Initial fluid molecular weight	35.52
Initial oil FVF, RB/STB	4.382
Initial $R_{s,}$ scf/STB	6042
Initial oil-leg gas saturation, % PV	80
Buttonhole producing well pressure, psia	601
Residual oil saturation to gas, % PV	15
Residual oil saturation to water,% PV	35
Critical gas saturation, % PV	5
Separator pressure, psia	500
Stock-tank –oil density, lbm/ft^3	52.58
Stock-tank-oil molecular weight	141.65
Stock-tank-oil gravity, API	36
Separator-gas molecular weight	21.7
Initial gas-oil equivalency factor, $R_{go,}$ scf/STB	789.20
Pore volume, MMRB	43.45
OOIP, MMSTB	7.93
OGIP, Bscf	47.93
Reservoir Radius, ft	0.50

Table 7.2 Reservoir fluid compositions used (Walsh,2003)

	Composition, mole fraction Rich-gas condensate
N_2	0.0223
C_1	0.6568
CO_2	0.0045
C_2	0.1170
C_3	0.0587
$i\text{-}C_4$	0.0127
$n\text{-}C_4$	0.0168
$i\text{-}C_5$	0.0071
$n\text{-}C_5$	0.0071
C_6	0.0098
C_{7+}	0.0872
Total	1.0000
Mol.wt.	35.52

These parameters were chosen to be same for the two cases to form a sound base case for comparison of the modified black oil model approach by the study and the compositional model used for verification.

One question that drove the objective of the investigation was whether the complex thermodynamic phenomena for a gas condensate reservoir below the saturation pressure can be represented by simple semi-empirical correlations of pressure, temperature and compositional dependent relationships as illustrated in the modified procedures or whether further adjustment would be required to adequately represent depletion behaviour of gas condensate reservoir. The scenario below the dew point was specifically chosen for the study because this is the main challenge of gas condensate modelling

7.1.1 Reservoir description

The Anschutz gas-condensate reservoir was selected for the case study in this investigation is reported to be the largest hydrocarbon accumulation in the western Over thrust Belt in USA. (Kleinsteiber et al. 1983) The sample analysis test from the discovery well showed the field to be a rich gas condensate field with a liquid dropout as high as 40% of the hydrocarbon pore volume. The dew point was also very close to the initial reservoir pressure, justifying the need for early reservoir depletion plan to ensure efficient condensate recovery.

The above reservoir characteristics made it an ideal case for this investigation as a reservoir with typical condensate behaviour was necessary to model condensate delivery below the saturation pressure. Rich gas condensate reservoirs give maximum condensate dropout, and serve as good bases for developing and testing the condensate correlations developed for modelling well deliverability. The reservoir dimensions are specified in E300 data file in appendix G and other important reservoir parameters were earlier given in table 7.1 and the hydrocarbon fluid mixture compositions were also given in table 7.2. Further description of the reservoir is given in a conceptual 3-D compositional simulation model built for this case as shown in figure 7.2. The grid was made to be transparent so that the horizontal well location can be seen from the surface as the well is placed at depth specified in the data file (in Appendix G) far below the surface.

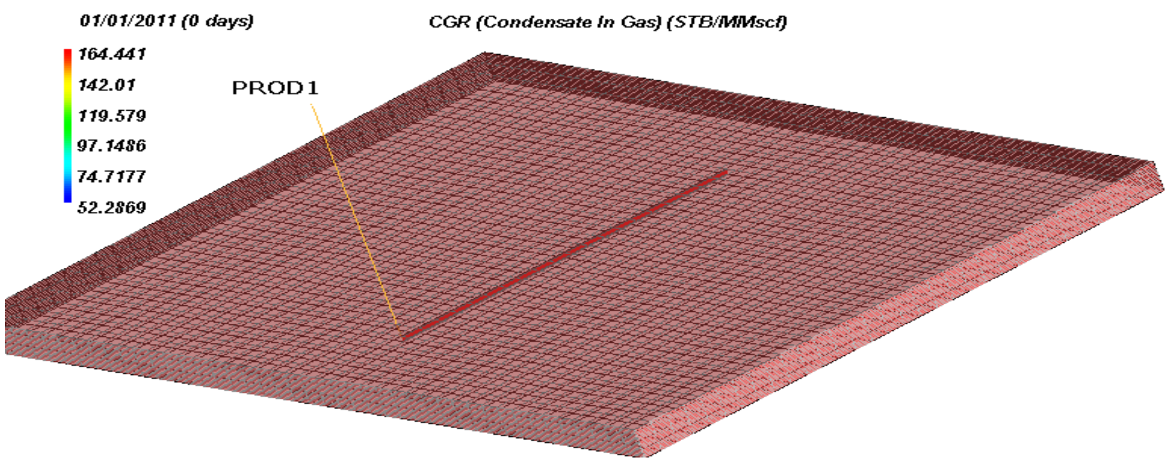


Figure 7.2 Schematic of 3-D reservoir simulation model for horizontal well

The horizontal well model was used to predict production performance, analyse phase behaviour and compared well deliverability for the semi-empirical modelling approach developed in the study and the numerical compositional model using E-300 for three phase fluid model in both cases.

7.1.2 Simulation model set up

The reservoir description and the compositions earlier given form the major components of the model. A single horizontal well model was built in 3-D in Cartesian coordinates as shown in figure 7.2 using E-300. The single layer homogenous reservoir was represented by 253, 44 grid cells. The well was located parallel to the X-direction and perforated over its entire length. The model top is at 12800ft with an initial reservoir pressure of 5800Psia and dew point pressure of 5430Psia. Details of other specifications are given in the data file in appendix G.

7.1.3 Fluid property model

The major difference between the compositional and black oil model has been earlier stated to be fluid property behaviour that is why quality time was spent in chapter four to develop critical PVT correlations that accounted for compositional variations in the black oil model (which conventionally is handled by assuming the gas and the oil to have fixed compositions for all reservoir conditions). To accurately model well deliverability in gas condensate reservoirs, fine grid numerical simulation to model condensate bank formation, account for high velocity phenomena, non-Darcy flow and change in relative permeability at high capillary number is required (Mott 200). Simpler approaches that are more adaptable to application of the modified black oil model on a spreadsheet were developed in chapter four and is verified with compositional simulation in the current chapter. Research into the use of the modified black oil model to model well deliverability in gas condensate reservoir has become very popular as fine grid numerical compositional modelling is time consuming, and has cumbersome data requirements.

The fluid properties used in the study approach (semi-empirical models) were calculated from the modified black oil correlations that were described in chapter four. To track the PVT properties changes against reservoir pressure depletion so that future well performance can be predicted with good precision, the properties were developed as a function of pressure.

The phase diagram for the 11-components condensate system used in the study was generated using PVTi version 2009 and the Peng Robinson Equation of State (PREOS) as shown in figure 7.3.

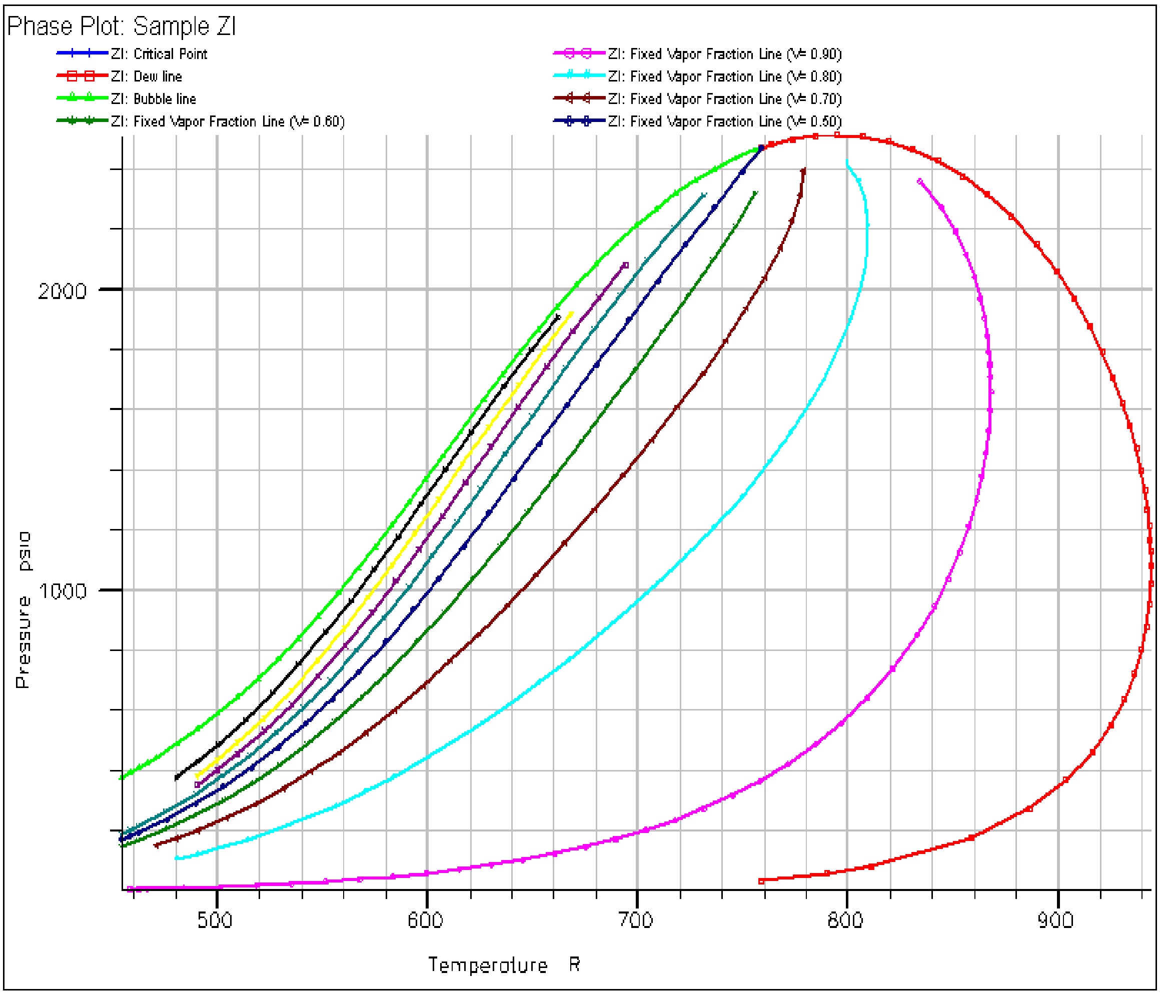


Figure 7.3 Anschutz gas condensate phase diagram for the 11-component gas condensate system

The fluid properties needed for the full compositional simulation that was used for the verification of the study approach for well deliverability prediction were generated using PREOS in PVTp package from the Petroleum Expert (PETEX) software suite. The generated PVT properties using Anschutz gas condensate reservoir Constant volume depletion data are shown from figures 7.4 through figure 7.6 for the 11-component fluid model.

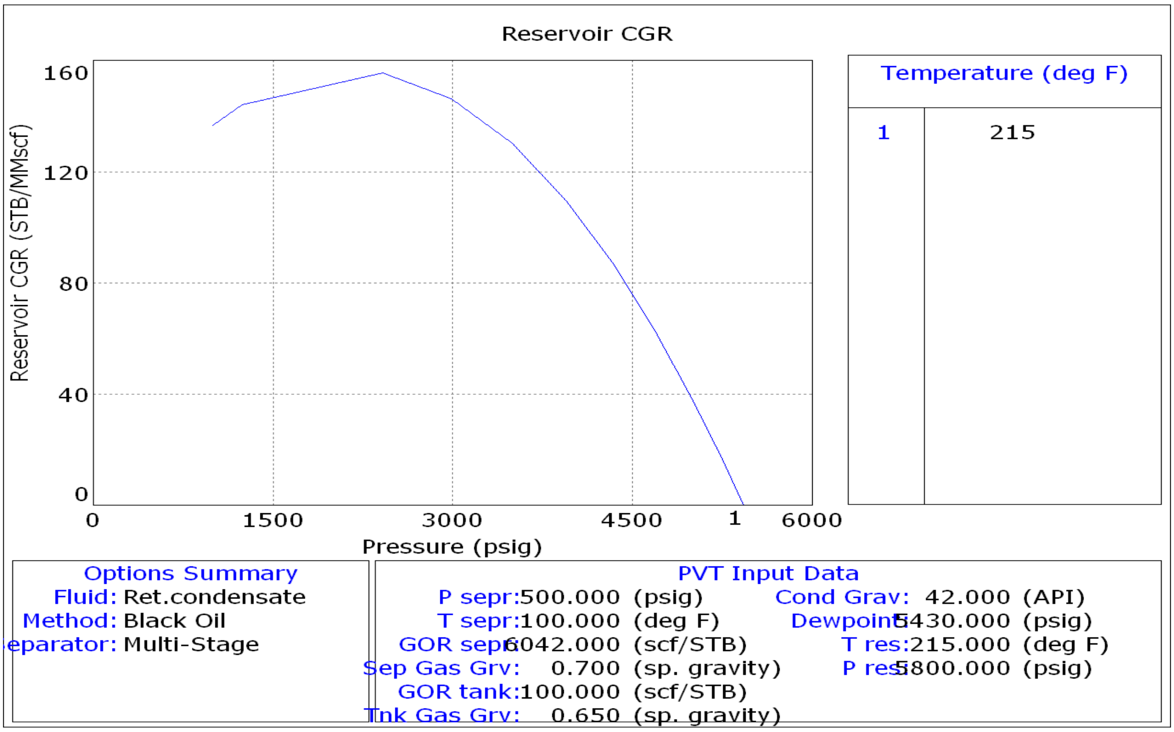


Figure 7.4 Retrograde condensations during depletion of Anschutz gas condensate reservoir, condensate yield

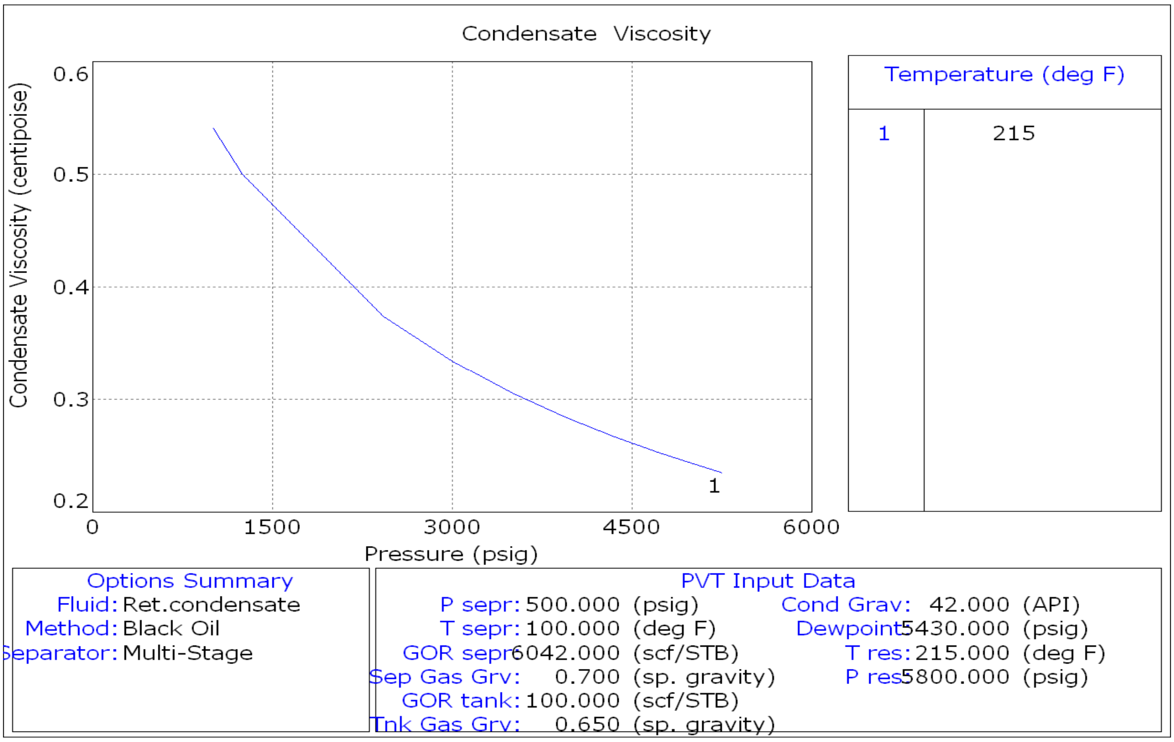
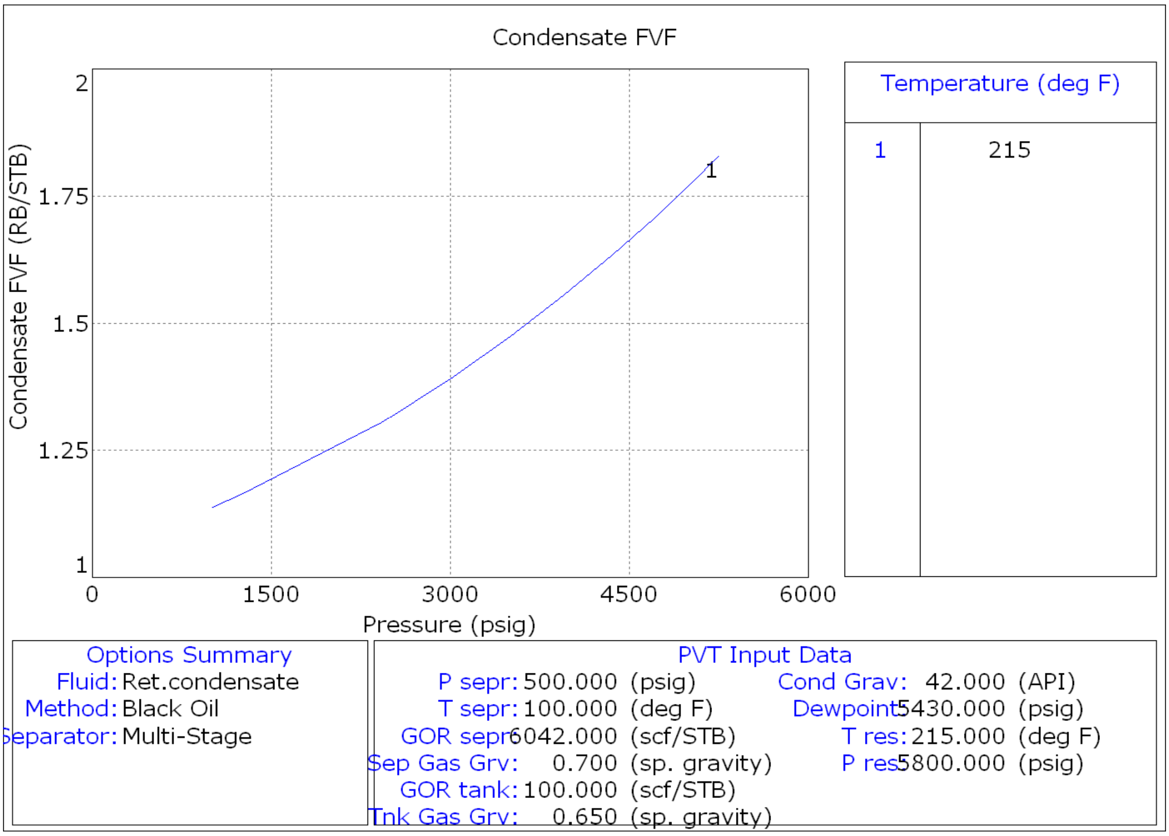


Figure 7.5 Condensate viscosity changes as a function of reservoir pressure



7.6 Condensate formation volume factor (FVF) as function of reservoir pressure

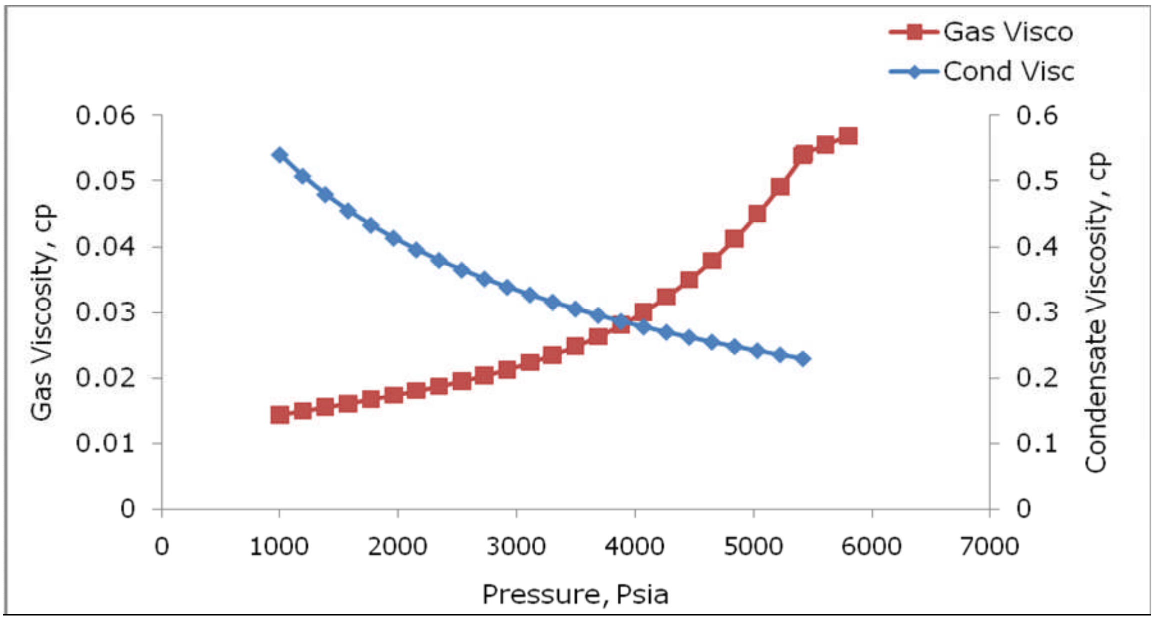


Figure 7.7 Condensate and gas viscosity as a function of reservoir pressure

The fluid PVT properties for the numerical simulation are shown as input parameters in the user defined code (E300 data file) in Appendix G. These include acentric factor, parachor and pure component critical parameters (critical pressures and temperatures).

7.1.4 Condensate relative permeability model

There is no definitive relative permeability model for three phase flow in gas condensate reservoirs. The dependence on flow rates, capillary forces, interfacial tensions (IFT) and the complexity of laboratory measurements required, make definition of relative permeability difficult (Sharifi, and Ahmadi 2009). Rather several modifications of Corey and Stone's relative permeability correlations assuming two phase flow where the water is at its irreducible saturation have been used extensively (Fevang 1996, Mott 2002). These static correlations as a result of assuming water at irreducible saturation do not actually represent the condensate recovery process in gas condensate reservoirs. The irreducible water saturation is assumed for simplification, but these assumptions are not valid for some condensate reservoirs that start water production from the first day of production of the reservoir. In other words dynamic relative permeability correlations are needed to allow for continuous water production in the three phase gas condensate system. As a result several approaches were applied in sourcing and tuning available two phase models to three phase model in this study as detailed in chapter 5. Laboratory measurement of three phase relative permeability is not common in the industry, rather a correlation is usually developed to tune measured two phase relative permeability for three phase relative permeability prediction. A good example is the use of Stone 2 correlations. Experience has shown that relative permeability prediction could introduce up to 200% error in modelling well deliverability in gas condensate reservoirs if appropriate correlations tuned to measured experimental data are not used.

In chapter five, a tuned relative permeability correlation was developed for condensate in three phase systems and was applied to generate the relative permeability table that was used in the modified semi-empirical correlations for simulation of well deliverability that was validated with E300 (Eclipse compositional) model. The relative permeability curves are shown in chapter five, figures 5.8 to 5.11. The correlations were also validated and adopted for modelling absolute permeability for the calculation of effective permeability for the well productivity prediction of each phase. The model was also converted to a pressure function using Fevangs' correlation to be able to predict the reservoir future performance.

The relative permeability table for E300 verification model were generated using standard Corey correlations for water, and gas and the Stone 2 correlation for condensate relative permeability. Experimentally measured Anschutz condensate relative permeability parameters were used to tune the relative permeability correlations generating for the compositional simulation. The relative permeability tables generated are shown in the E300 data file in appendix G. The generated relative permeability curves for the three phases are shown in figures 7.8 to 7.10

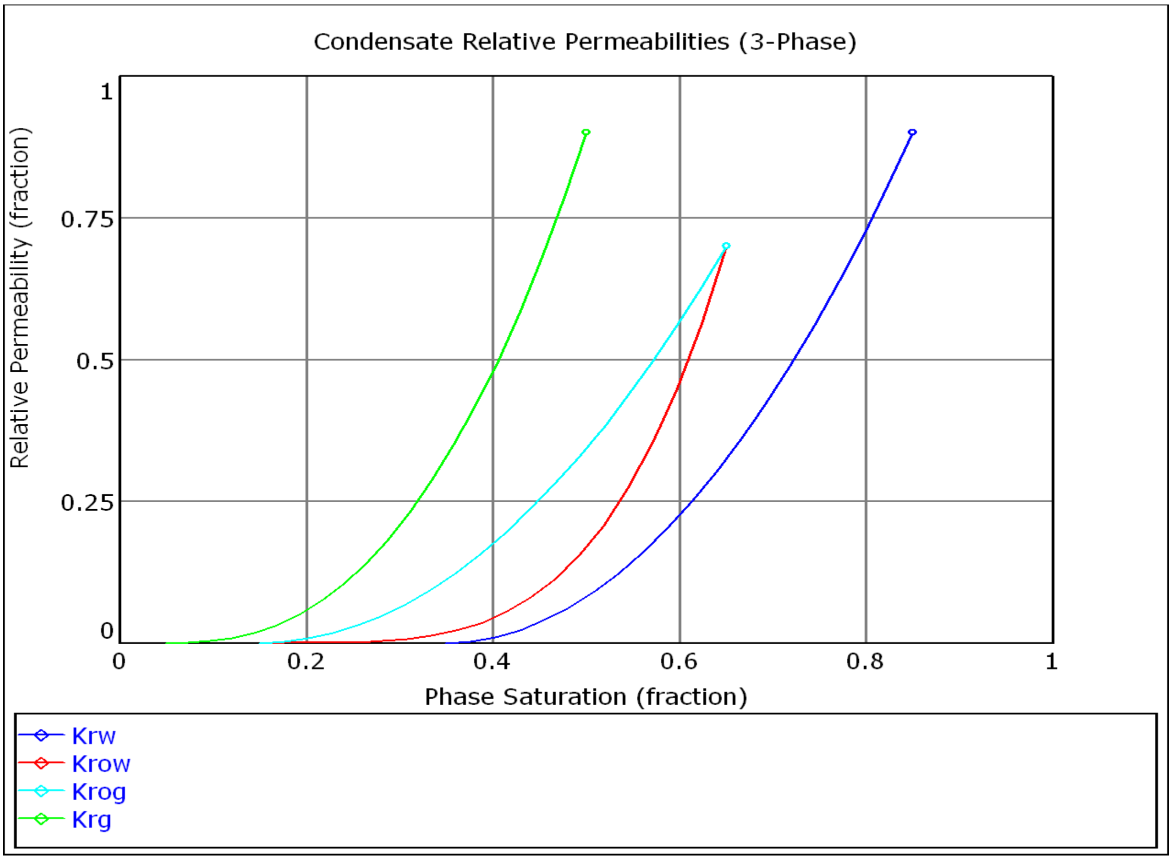


Figure 7.8 Condensate-water –gas relative permeability curves used in the E-300 simulation

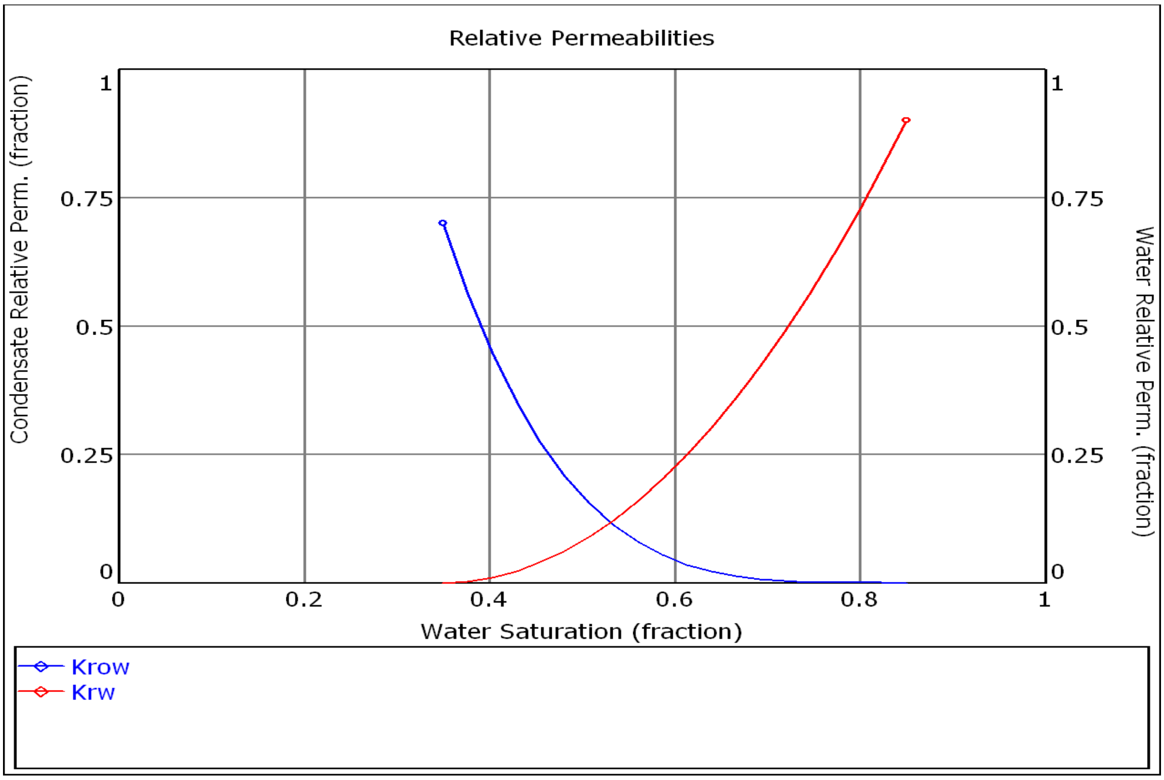


Figure 7.9 Condensate-water relative permeability used in the E-300, verification model simulation

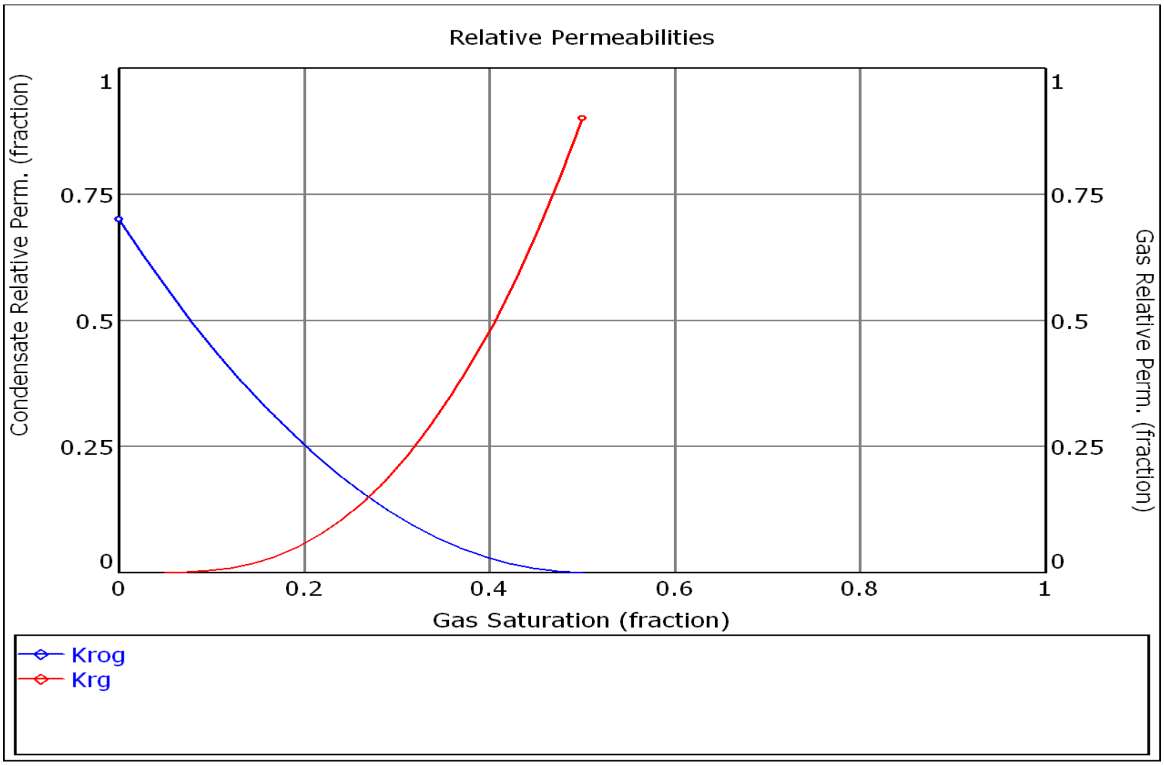


Figure 7.10 Condensate-gas relative permeability used in the E-300, verification model simulation

A representative relative permeability model is critical to accurate modelling of mobility in gas-condensate system. Interfacial tension plays an important role in the prediction of relative permeability when the gas condensate fluid is far away from the critical point. At such points the interfacial tension will be very high and could cancel all the positive effects of the capillary number effect. The modelling of relative permeability model with interfacial tension (IFT) or capillary number dependent functions was not considered in this study. The relative permeability model applied is valid for a specific capillary number as the high capillary number is assumed to remain constant from saturation to abandonment pressure.

7.1.5 Simulation results and discussion

The simulation runs were designed to generate results capable of verifying the performance of the modified approaches, the study semi-empirical correlations in comparison with Eclipse Compositional, E300, which is the standard in the industry. The well was controlled with gas production rate of 25MMscf/Day and was run for 3 years equivalent to 1050 days approximately in each case, starting from January, 2011. Both the E300 and the semi empirical cases were run in the forecast mode for performance verification. In both the E300 and the semi-empirical method approach (study), the initial reservoir pressure was set below the dew point pressure as characterisation of gas condensate reservoir behaviour below the dew point/saturation pressure is crucial for accurate well deliverability prediction. This is to be able to critically validate the approach which was developed for these conditions. The compositional simulation results are summarised in figures 7.11 to figure 7.27 followed by comparison with the study semi-empirical results, figures 7.28 to 7.30. The basic assumption of the work is that if the only requirements from reservoir simulation are; (1) prediction of well deliverability and (2) sensitivity analysis of production controlling parameters for production optimisation for field development planning, the semi empirical modelling approach should be adequate. The use of fine grid numerical simulation models where detailed reservoir analysis is not required is expensive and not economically viable, therefore not recommended. That is why our comparison is limited to production profiles that are relevant to condensate well deliverability, as the semi-empirical model is not capable of generating detailed reservoir behaviour results like the full compositional model E-300. The semi-empirical models implemented on excel spreadsheet cannot generate the contour blocks shown in figure 7.16 through to figure 7.27. These reservoir details are not needed in every case, therefore simple semi-empirical models may be adequate However the production, average reservoir and bottom hole flowing pressure profiles shown in figures 7.11 to figure 7.15 could be generated from the semi-empirical model approaches. The result comparisons are limited to profiles that both approaches are capable of generating in common. However the correlations we are verifying is for condensate production below the dew point and this limits the compared results to condensate as shown in figure 7.28 to figure 7.30.

The closest works available in the literature to the present study include Fevang (1996) and Mott (2002). However their argument is slightly different from this investigation. They present a gas rate pseudo pressure approach which they have developed to match the results of compositional simulators. A major difference between their approach and the present study is their EOS to calculate the PVT properties for the extended black oil model used in the spreadsheet, while the present study used the improved correlations developed from this study. The argument of the present study is that with an improved prediction of condensate PVT properties and relative permeability correlations implemented on dry gas rate equation at bottom-hole pressure and average reservoir pressure lower than the dew point pressure, better accuracy of prediction of liquid condensate production can be achieved. So while the earlier efforts Fevang and Mott were mostly matching their results with compositional model results, our approach go further to predict condensate production performance below the dew point pressure which earlier work ignored. The comparison of the bottom-hole pressure, average reservoir pressure and condensate yield profile results for the compositional model and the semi empirical model in figures 7.23, 7.24 and 7.25 show major differences between the two models. Results show a higher production profile for the present study approach suggesting higher recovery. The contours shown in figures 7.16 to 7.22 were to highlight the sensitivity of the compositional model to changes in reservoir parameters as result of changes in the condensate production process over time. The simulation started in 2011, and from this day to any point in time the extent of depletion can be visualised. The ethane C2 fluid in place captured in the contour shown in figure 7.27 is an indication of the special capability of the E-300 compositional fluid model to predict the productivity of the entire component range in the gas condensate system with precision. The black oil model does not have this capability.

Figure 7.11 gives a good trend of the bottom hole flowing pressure profile over the next 3 years starting from time equal to zero to time equal to 1050days when compared with the average reservoir depletion profile in figure 7.15. The gas production rate which was set as a well control parameter is shown in figure 7.12 with a constant profile indicating the performance of the model as expected. The condensate production was at plateau for up to 780days, indicating good reservoir production performance after which the condensate production continued to fall irreversibly beyond 1000th day of production. The rising cumulative condensate production profile through to abandonment pressure and the increasing productivity index up to 620days of depletion as shown in figure 7.15 were expected. However the decline in the average reservoir pressure was responsible for the falls in the productivity index and in condensate production.

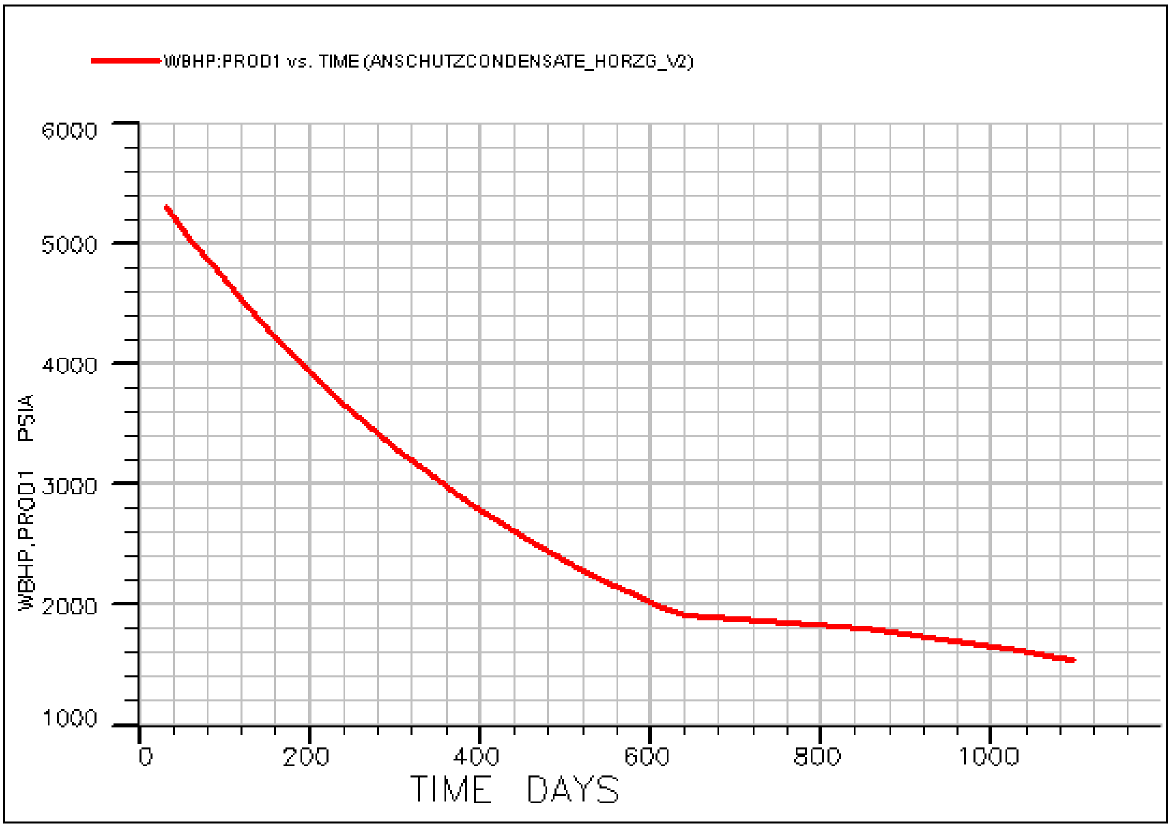


Figure 7.11 Well bottomhole flowing pressure profile forecast

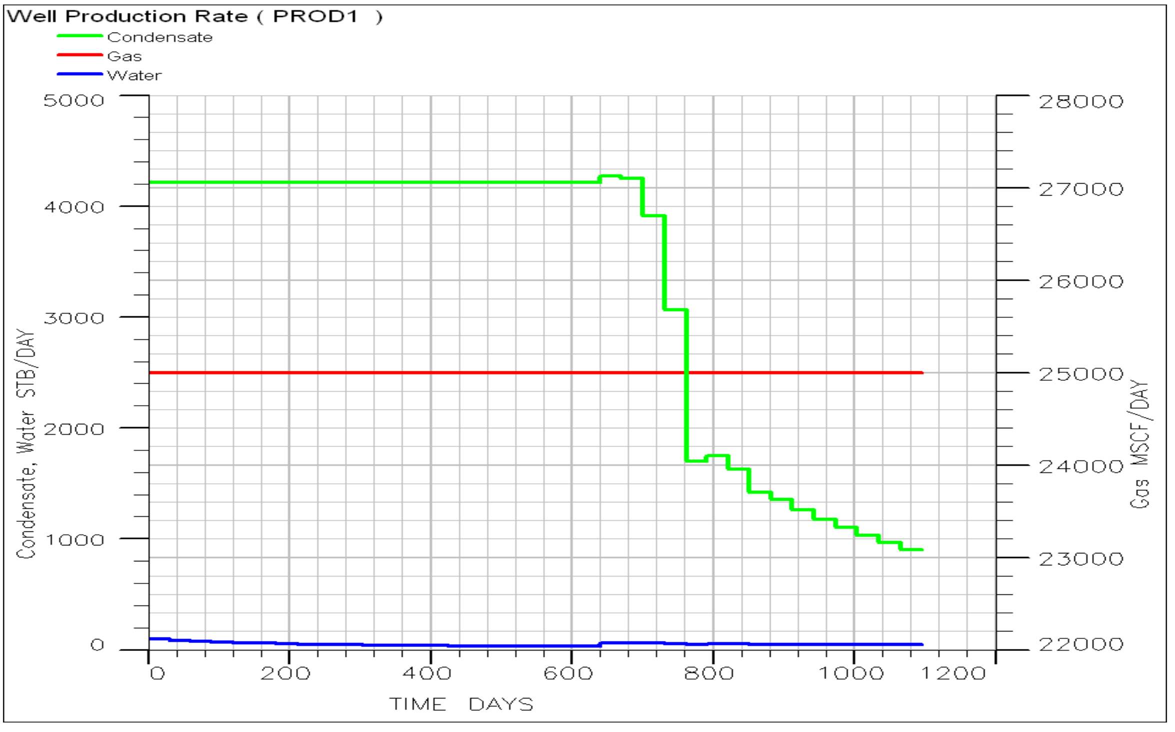


Figure 7.12 Well production rate profile for condensate, gas, and water

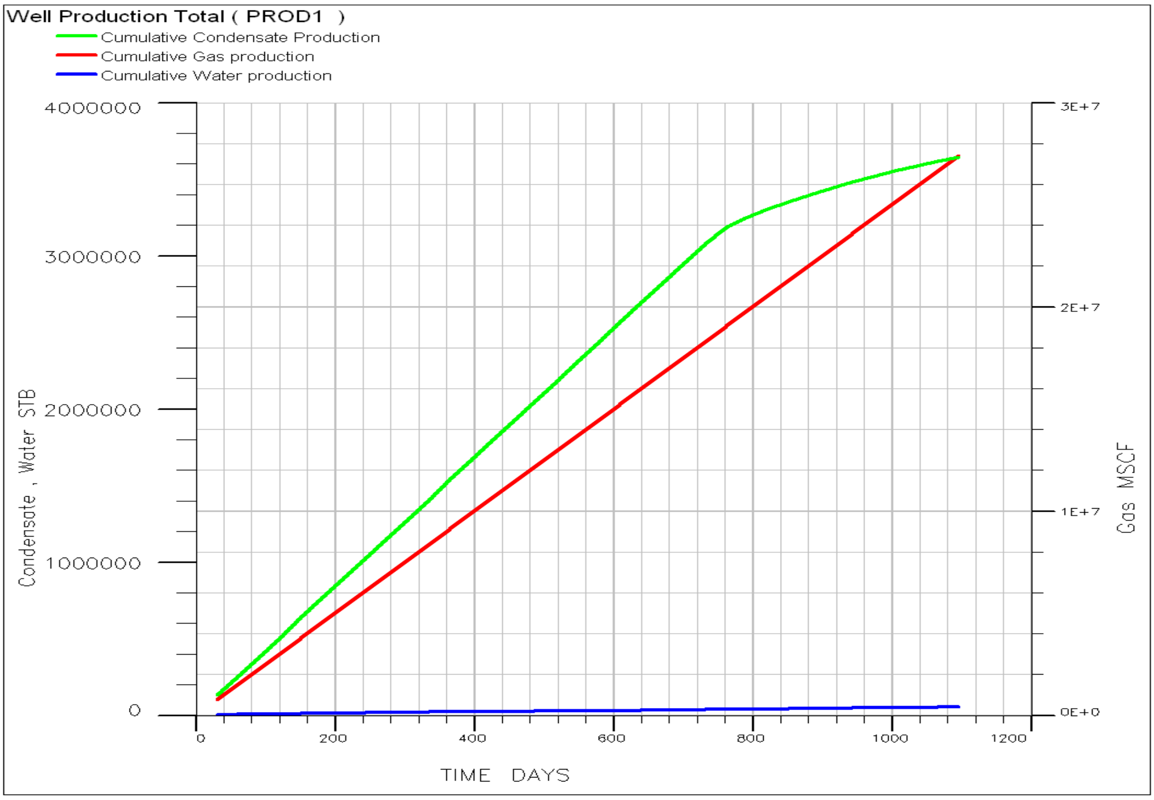


Figure 7.13 Well cumulative production forecast profile for the 3-phases

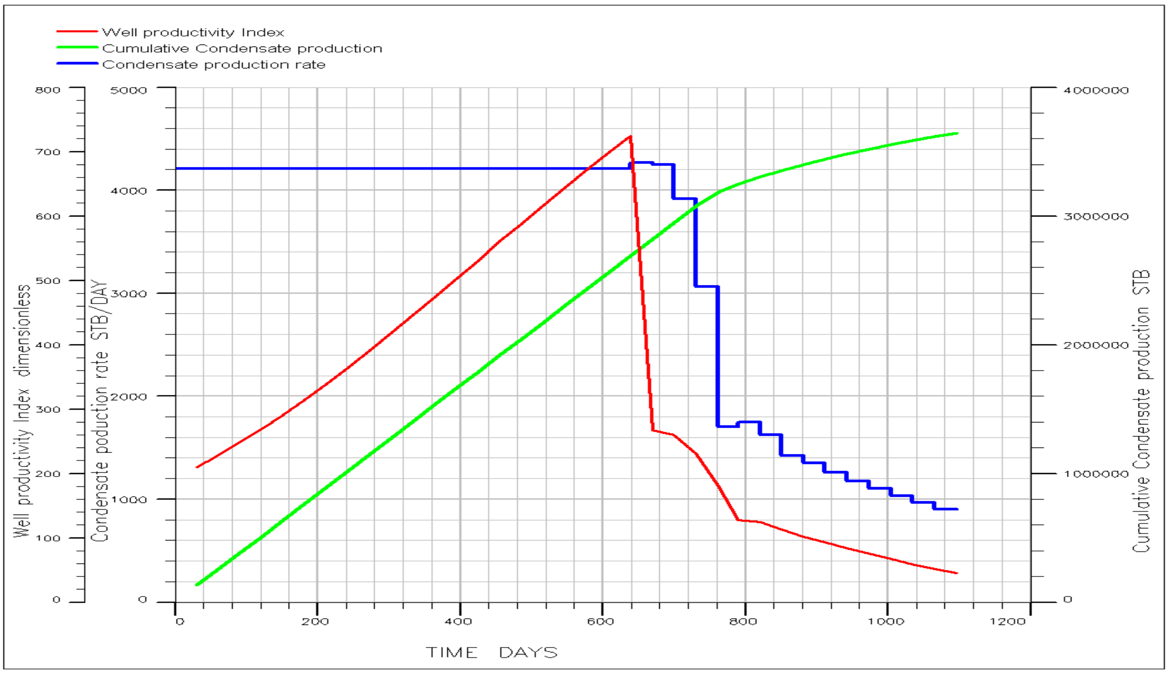


Figure 7.14 Well productivity index, condensate production rate and cumulative production profile

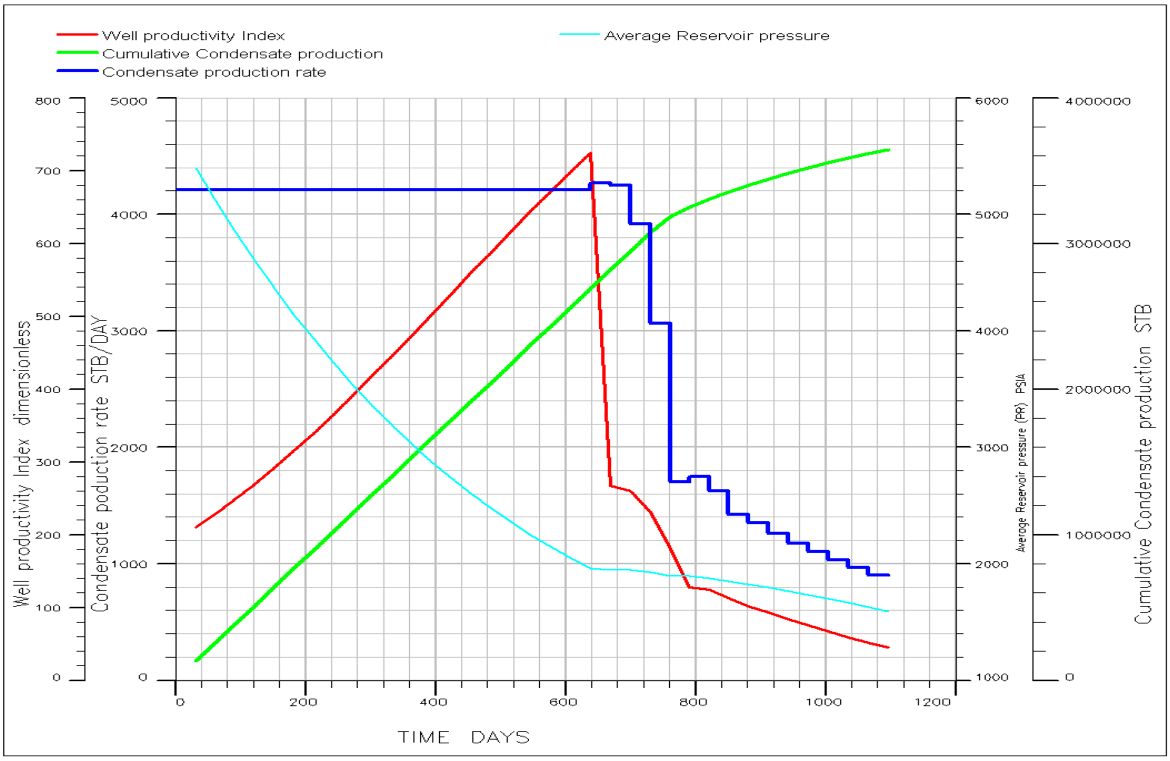


Figure 7.15 Average reservoir pressure, condensate production rate and cumulative production profile.

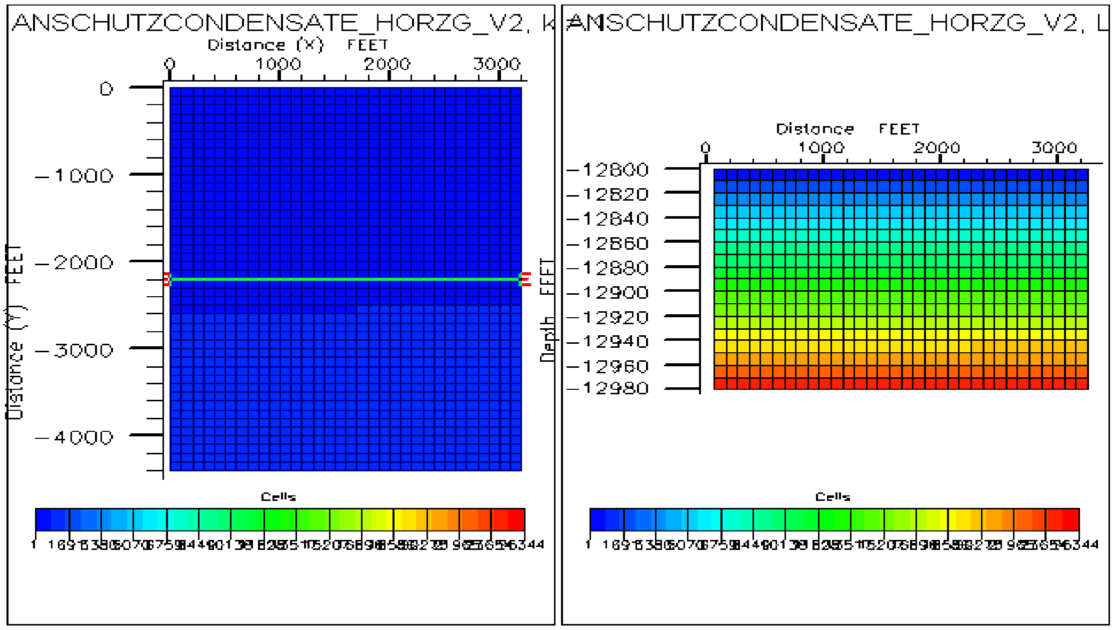


Figure 7.16 2-D Cross section showing the reservoir depth

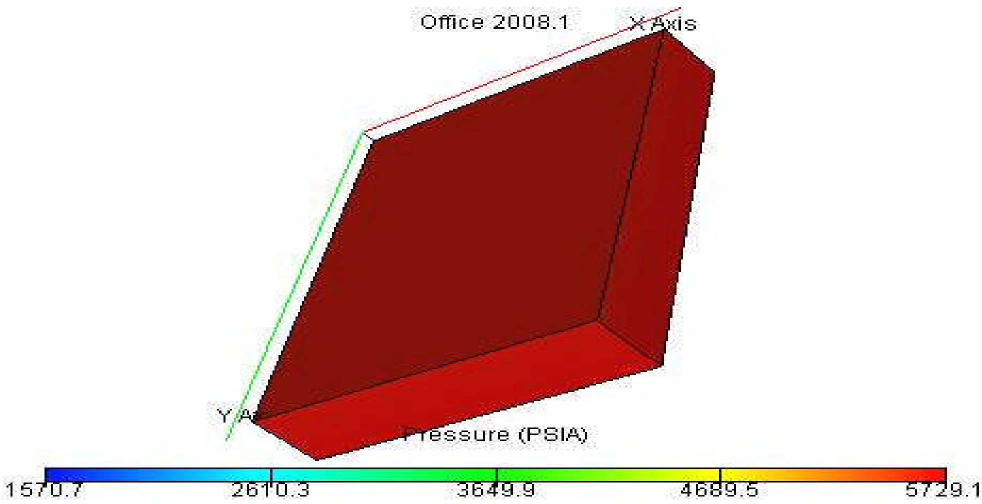


Figure 7.17 Initial reservoir pressure distributions in January, 2011

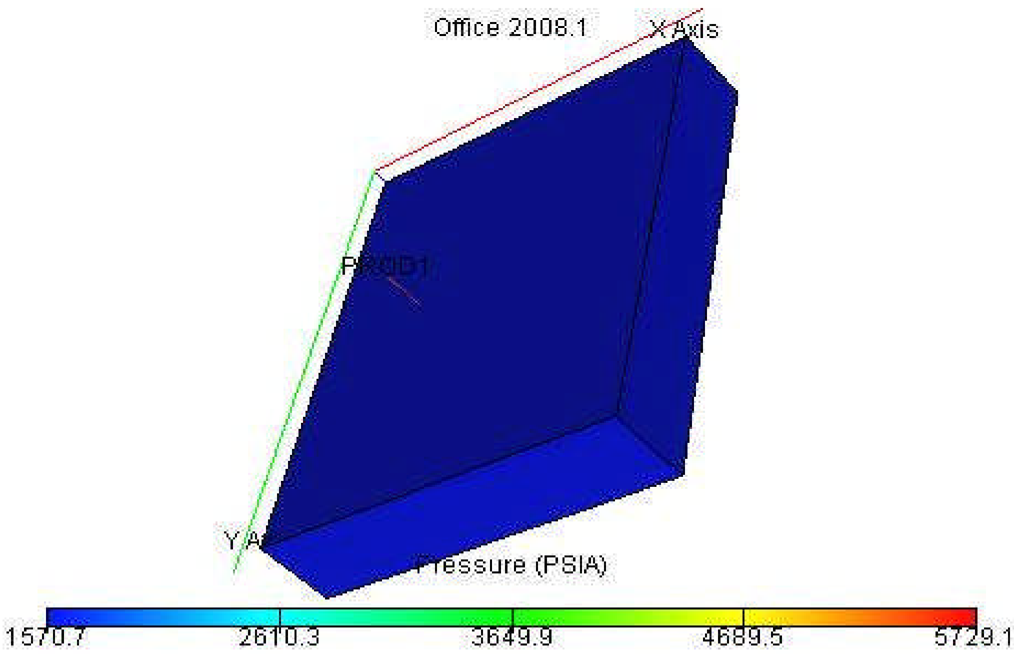


Figure 7.18 Reservoir pressure distribution January, 2013 to January, 2014

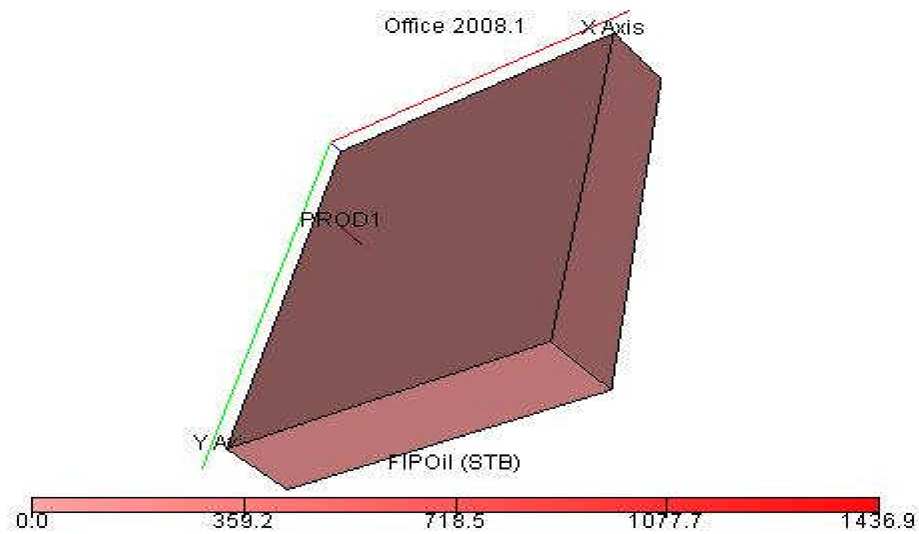


Figure 7.19 Condensate fluid in place as at January, 2011

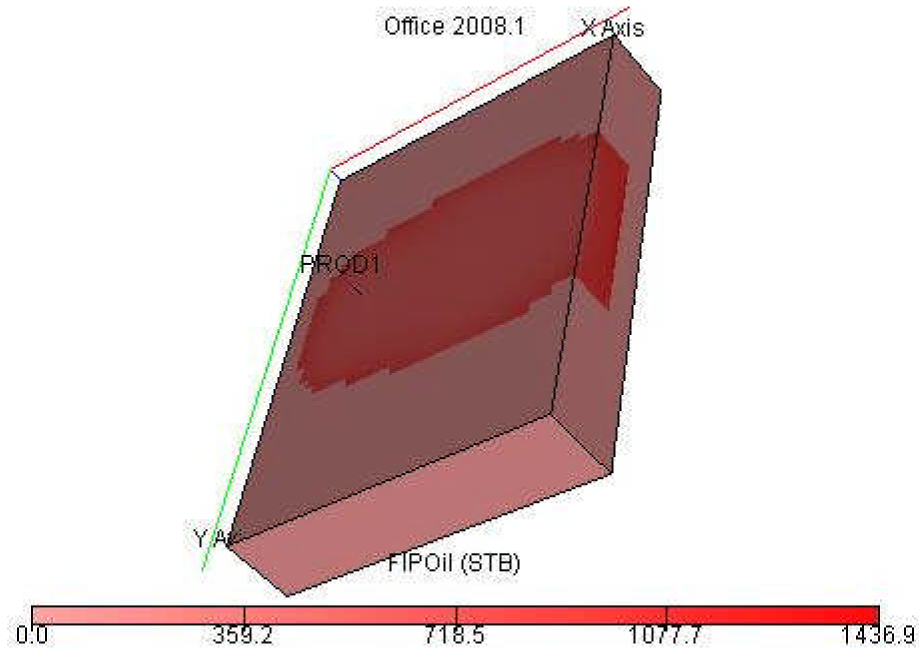


Figure 7.20 Condensate fluid in place as at November, 2012

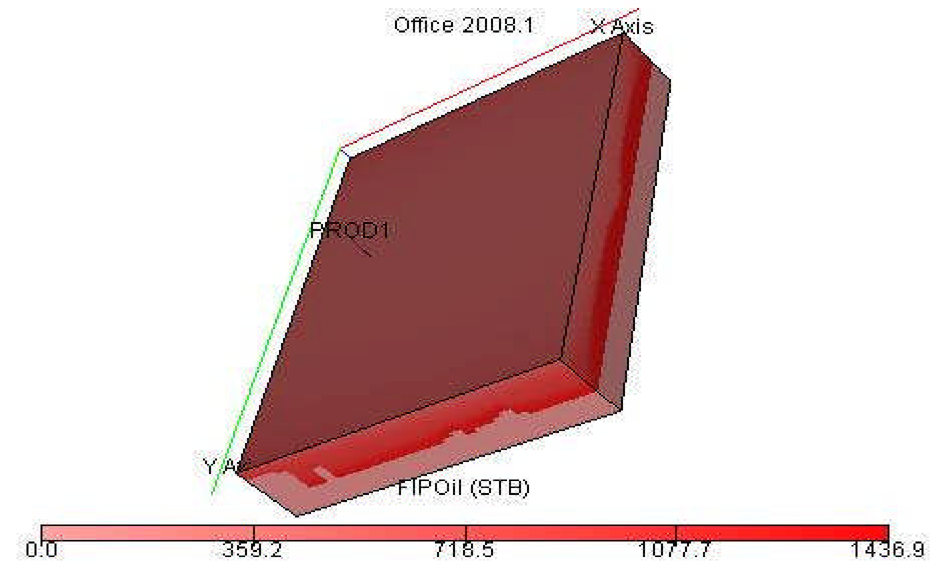


Figure 7.21 Condensate fluid in place as at November, 2013

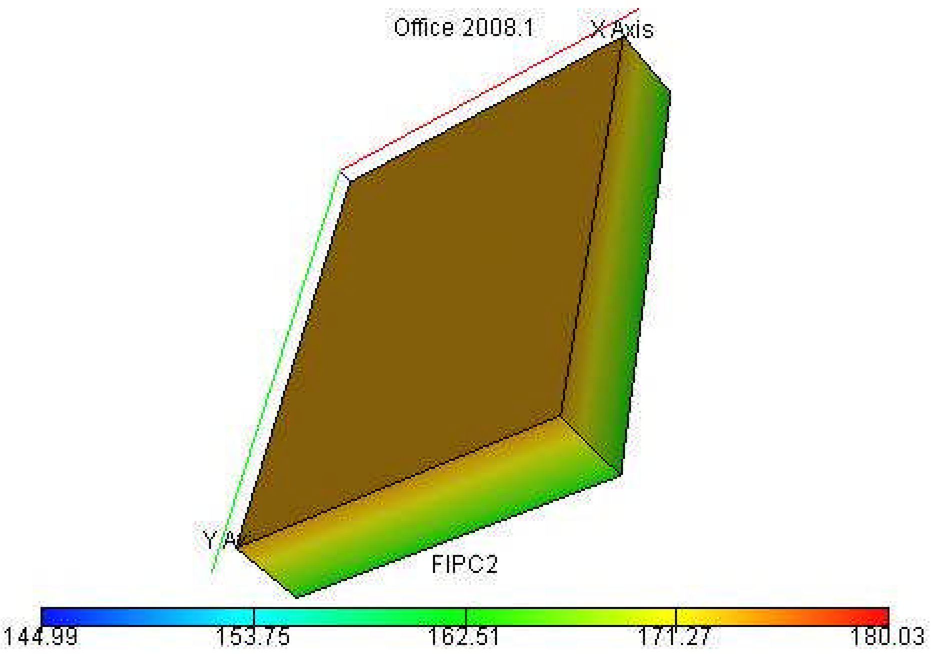


Figure 7.22 Ethane fluid in place as at January, 2011

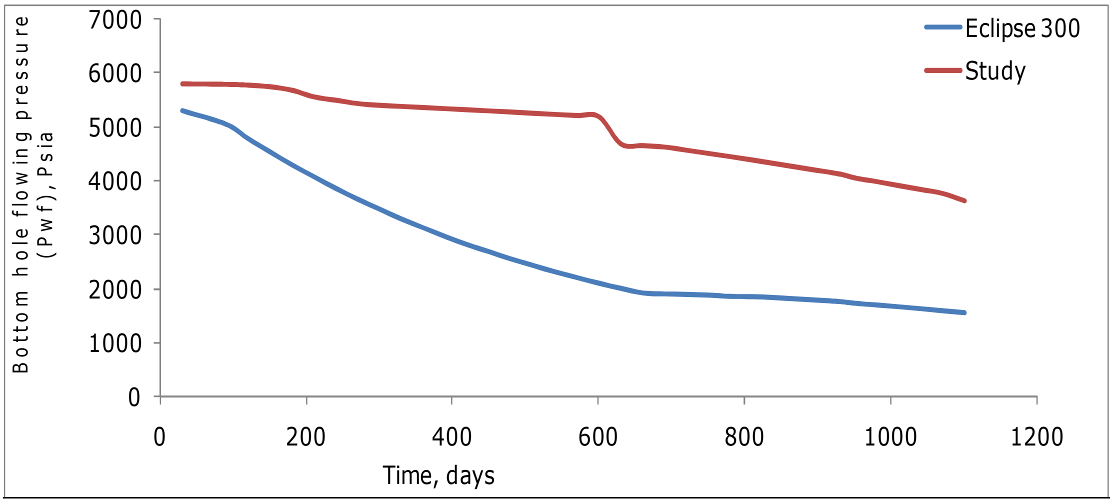


Figure 7.23 Comparison of E300 BHFP, Pwf profile with study empirical model

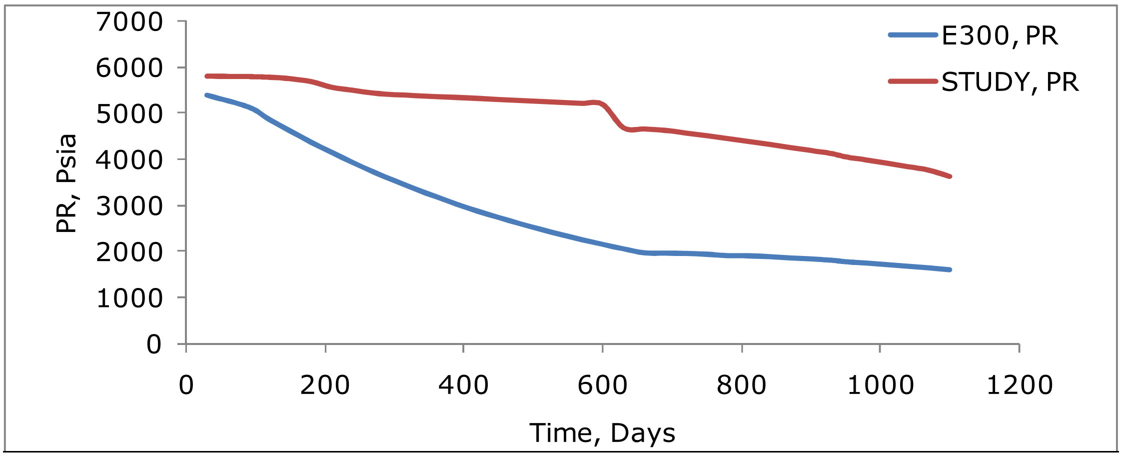


Figure 7.24 Comparison of E300 reservoir pressure depletion profile with study

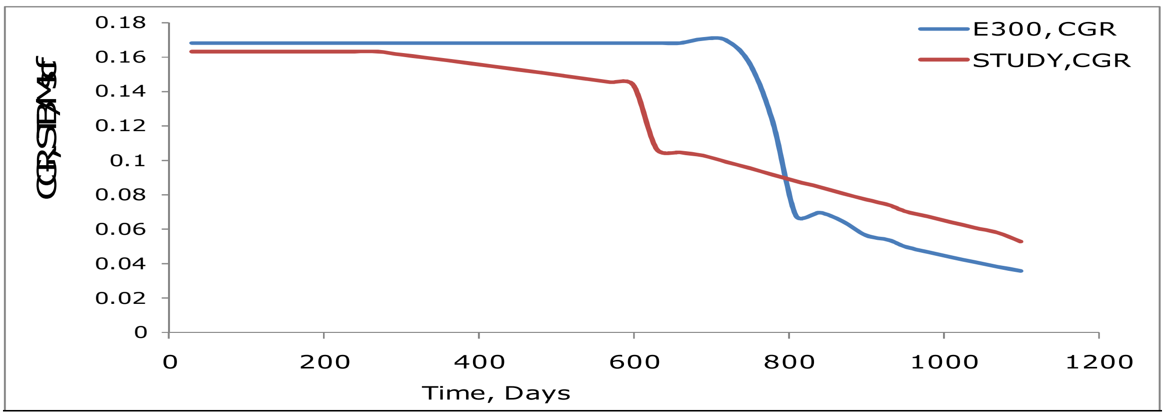


Figure 7.25 Comparison of E300 condensate gas ratio (CGR), condensate yield profile with study

7.1.6 Result Summary

The results suggest improved well performance for the semi-empirical correlation used. However further validation with field data is necessary for confirmation of the results. At various reservoir pressures, the compositional model prediction was lower than the study semi empirical model approach, which may be due to the effect of higher condensate relative permeability in the latter case, which would cancel the effect of higher condensate viscosity predicted in chapter four.

A simpler semi-empirical modelling approach for prediction of well deliverability in gas-condensate reservoir has been developed and validated.

The Anschutz case study was chosen for illustration because of lack of the complete published test data, well test, production and PVT test data required for evaluation of existing correlations and validation of the study developed correlations from other data sources. However the PVT property correlations were developed from world wide sourced data, but it is recommended that the correlations be validated for specific applications where applicable. The results are in close agreement with previous studies that the use of the gas rate equation for prediction of gas condensate rate results in over prediction. This is because the gas rate equation does not account for multiphase flow in the reservoir. The study illustrated this with the comparison of prediction of inflow performance with the extended model and the Prosper model, which gave higher inflow performance as Prosper assumptions are closer to the dry gas single phase model.

The improvements observed from the study results could be partly due to the improved down-hole PVT property correlations developed in this investigation Initial validation of the correlations used in the available commercial reservoir simulators show that they were not accurate. Also the accuracy of condensate relative permeability issues is critical to productivity of gas condensate reservoirs below the dew point pressure. The three phase relative permeability could largely account for the improved condensate production profile, as the two phase relative permeability usually assumed does not properly represent condensate systems.

CHAPTER EIGHT

8.0 SUMMARY, CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE WORK

The summary of developed concepts, correlations and sound engineering judgements applied in achieving the research aim and objectives are given in this chapter. The highlight of major findings, brief discussions and general conclusions on all aspect of the work and recommendations for future work are also given here.

8.1 Overview

A key consideration in the development of gas condensate reservoirs is condensate recovery because of the relatively high added market value of the condensate liquid produced. Condensate is a composite fluid which can be used in gaseous or liquid form and is much more environmentally friendly than the higher hydrocarbons because of the clean technology associated with its use.

However, the enormity of the challenges of condensate reservoir management is captured by Panfilov (2003) as follows; "*Fortunately for science, the thermodynamic and hydrodynamic behaviour of retrograde mixtures is so complex that it will long be the object of scientific research*" He further stated that since the eighties to nineties, numerical modelling has become a standard tool for the testing of various scenarios of reservoir exploitation, and it became obvious that improvements in numerical models could yield significant enhancement of condensate recovery. As a result the need to refine hydrodynamic flow laws and thermodynamic description prompted research in physics and mathematics in order to improve the modelling accuracy.

Critical review of production from gas condensate reservoirs shows that a major goal of modern gas-condensate reservoir management is a production system for optimum well deliverability. This is not possible without accurate well deliverability prediction models for production and field development plans to achieve the desired goal. Though this goal can be achieved by fine-grid numerical simulation, the data requirement is huge coupled with the problem of tuning equations of state (EOS) to experimental data if available.

The experimental data required for modelling this kind of reservoir is usually limited or not available at desired reservoir conditions and the cost of its acquisition may be prohibitive. Lack of such data and other associated problems of available commercial numerical reservoir simulators was part of motivation for this research. These challenges informed the definition of the overall aim of the research as the development of a semi-empirical approach for accurate modelling and simulation of well deliverability in gas condensate reservoirs.

8.1.1 Summary of achieved research objectives.

Based on critical reviews of previous work, and the identified technology gap, the following key research areas were identified and followed up to achieve the set aim and objectives of this research.

These include;

(i) Development of PVT property correlations required to modify the gas rate equations for multiphase flow prediction in gas condensate reservoirs.

(ii) Development of dynamic condensate relative permeability correlation for three phase flow in gas condensate reservoirs

(iii) Proposition of a new correlation for forecasting the pseudo-pressure integral to allow for compositional variation in predicting inflow performance.

(iv) Application of the new approach, to improve flow correlations in both vertical and horizontal well case studies for demonstration of practical application and verification of new method.

(v) Carrying out parametric studies on the modified well productivity equations to define the critical parameters that govern productivity in gas condensate reservoirs.

(vi) Validation of the new procedure using a compositional reservoir simulator.

The research involves improving the fluid property correlations that constitute gas production rate equation to improve on the prediction accuracy of the rates in order to determine well deliverability. A major modelling consideration and assumption for the modification of the gas rate equation for modelling well deliverability in condensate reservoirs is the compressibility of condensate (whether in liquid or gaseous phase). In this approach, the gas phase behaviour is considered to be closer to condensate. This informed our modelling approach to start with modification of natural gas flow rate equations to derive condensate flow rate equation for accurate well deliverability in gas condensate reservoirs.

Accurate physical property correlations of reservoir fluid are required in, semi-empirical, modified black oil modelling and compositional simulations. These properties govern the productivity of any class of hydrocarbon. Generation of accurate PVT properties for material balance, energy balance, design and optimization of existing wells, and production facilities require the availability of representative fluid samples and special skills in modelling fluid PVT properties with EOS. The requirement for representative fluid samples at all reservoir conditions is usually not met as it is difficult to obtain such samples. Also sourcing and developing precise correlations for prediction of the fluid properties at all desired reservoir conditions are critical issues in modelling productivity of gas condensate reservoir below the dew point pressure. The new experimental and field PVT data obtained as a result of changing reservoir pressure with respect to thermodynamic behaviour of condensate mixture at high temperature and pressures invalidates existing correlations for prediction of these fluid properties. As a result, in this investigation widely used correlations have been tested, modified, validated and implemented in both vertical and horizontal well models for prediction of condensate well deliverability The summary of the achieved objectives of this research include;

8.1.2 Developed PVT and relative permeability correlations

The major highlight of results and findings of this work derived from implementation of the above research objectives include;

- Initial investigation to accurate correlations revealed that the existing correlations had error margins higher than the range acceptable for technical consideration.
- Two correlations for prediction of the condensate compressibility factor required for simulation of well deliverability have been developed.

The correlations are Equations (4.44) and the hybrid correlation Equation (4.69). Both are capable of predicting condensate compressibility behaviour at reservoir pressures below the dew point where retrograde condensation complicates prediction. The hybrid correlation is capable of predicting condensate compressibility factor without mixture composition data with a regression coefficient of 97% and an absolute average error of 6%. This is not possible with most of the available correlations, which without a given mixture composition cannot give accurate prediction. Compositions data however is usually not available or very expensive to source. These hybrid correlations have been validated with laboratory database of published gas condensate measured compressibility factors. A sample database that was used is shown in appendix A5. The correlations showed an improved fit to the measured database compared to existing correlations that are widely used .The new correlation Equation (4.44) had the least absolute average error of 2.65%

Another outcome of the research was the derivation of a correlation giving the relationship between condensate density and its compressibility factor (Equation 4.47) On comparison with existing correlation and experimental measured database, the new correlation gave a closer agreement with the experimental measured database than the existing correlations, giving an absolute average error of 3.85%. On comparison with an independent experimental measured database it showed a good performance improvement over existing condensate density correlations.

The new condensate viscosity correlation, Equation (4.66) developed was also validated and on comparison with available and widely used correlations in the industry gave better performance. The determinant of what parameter correlations to be improved or developed to achieve accurate well deliverability prediction is the components of gas rate equation in the vertical and horizontal well models. Based on these criteria other correlations developed include;

- Condensate formation Volume factor, Equation (4.75)
- Condensate saturation correlation, Equation (5.20) and

- Correlation for prediction of condensate relative permeability in three phase flow of the condensate-gas-water system, Equation (5.21),
- The compositional pseudo-pressure correlation, Equation (6.22) adapted from the compressibility factor , density and viscosity correlations modified in this study is capable of predicting the multiphase pseudo pressure integral without requiring fine grid numerical simulation for determination of production Gas Oil Ratio needed by Fevang and other conventional methods for prediction of two-phase pseudo-pressure parameter.

The compressibility factor correlations predicted from compositions of condensate fluid are more accurate than those predicted from gas gravity correlations. Yet compositions are usually not available and more expensive to acquire than the gas gravity. The correction factor developed in this work is capable of making the gas gravity correlation as accurate as that derived from composition data with a regression coefficient of 99% and absolute average error of 5%.The above sets of correlations were used in generating the PVT properties for the semi-empirical modelling without any need for representative samples or the application of EOS with elaborate procedures for generation of PVT properties for different reservoir pressures required in reservoir simulation.

8.1.3 Development of new compositional pseudo pressure integral method

A part of the novelty of this investigation is the introduction of a compositional pseudo-pressure integral approach to account for phase changes and compositional variation in pseudo-pressure arising from depletion of reservoirs below the dew point pressure.

Conventional modelling of well deliverability with single or 2-phase pseudo-pressure integral was not used; rather a compositional pseudo-pressure was derived from the developed correlations for multiphase density and viscosity and implemented in the production rate and the condensate inflow performance model. This approach entirely developed in this study has cutting edge over the conventional methods in accounting for multiphase flow and not involving numerical simulation required in predicting multiphase pseudo-pressures integral as by Fevang, Jokhios and other researchers in this area.

8.1.4 Developed 3 phase condensate relative permeability

Existing relative permeability correlations for condensate are mostly two phase assuming a constant residual water saturation. These static relative permeability models are not always valid for gas condensate reservoirs.

A dynamic three phase condensate relative permeability has been developed and validated with measured relative permeability data. The agreement of the new correlation with measured data gives more confidence in application than the existing static two-phase relative permeability correlations. This correlation was used in this study for predicting the effective permeability for deliverability forecast of the condensate phase.

8.1.5 Modified absolute permeability correlation. In multiphase flow, effective permeability is critical for prediction of fluid flow for each phase. The product of relative permeability and absolute permeability gives the effective permeability, therefore accurate absolute permeability correlation are required for precise forecasting of the flow of each phase. Absolute permeability is known to vary with reservoir pressure, changes in porosity from compaction and irreducible water saturation both for clastic and carbonate reservoirs. Correlation for absolute permeability for gas condensate reservoirs in the above two rock types have been developed, validated and used in this report.

Part of the ultimate goal of modern gas-condensate reservoir management is to optimise the production system for optimum well deliverability. This is not possible without accurate well deliverability models for production and field development plans to achieve the set goal. Though the goal can be achieved by fine-grid numerical simulation, the data requirement is huge coupled with the problem of tuning equations of state (EOS) to experimental data if available. The experimental data for this kind of reservoir is usually not available at desired reservoir conditions and the cost of such data is prohibitive if facilities are available. Lack of such data and other associated problems of numerical simulation has encouraged research into semi-empirical modelling for PVT properties and well deliverability. Other findings of this study are summarised in the following sections;

8.2 Application of the improved correlations

8.2.1 Application of the developed correlation to vertical wells

The inflow performance curves for the modified correlations were compared with standard industry software, Prosper for the same reservoir conditions, and Prosper gave higher reservoir productivity than the study modified correlations. This result is expected as prosper assumes no condensate drop out in the reservoir. However both models show same trend for the IPR curve indicating an additional understanding of condensate flow behaviour from the new correlation. The parametric studies performed for the vertical well showed that the most critical parameter for condensate productivity in vertical wells is the relative permeability. This is in agreement with the most of the consulted literature in this subject.

8.2.2 Horizontal well application of the improved correlations.

On validation of the modified horizontal well (HW) model with field data, Babu and Odeh HW modified by this study was selected for prediction of well deliverability as it had a closer performance prediction compared to the field data for the case studied. The twelve horizontal well models available for use in this investigation were for single phase fluids. With the three phase condensate relative permeability correlation developed and applied to the horizontal well equations, the extension of the single phase models for multiphase prediction was possible.

To decide on the dominant parameters that govern the productivity of condensate reservoirs, and the parameters to be used for optimization, The sensitivity studies performed show permeability and relative permeability as the most critical parameter.

- The developed correlations have been applied to specific case studies to demonstrate practical applications and for further verification in addition to initial validation of individual correlations.
- Comparison of the vertical well application result with the inflow performance of standard industry software, PROSPER, it gave a higher performance than the study approach.

- Vertical lift performance and nodal analysis for the vertical well gave a close operating production rate forecast and close operating bottom hole flowing pressure on comparison with Prosper as shown in figure 6.5.
- Parametric studies for modified vertical well productivity model show that all the parameters studied are sensitivity to condensate productivity, however further analysis was not performed to define the most sensitive parameter for vertical well.
- Similar studies were carried out on modified horizontal well correlations and on further analysis to define critical parameters that control productivity revealed relative permeability to be the most critical.
- Babu and Odeh's model on testing prediction performance of twelve horizontal well equations gave closest prediction performance compared to published measured data (figure 6.24) and was selected for use for most of the verification analysis for the modified horizontal well model.

8.3 Validation of the new method with Eclipse compositional reservoir simulator, E-300.

The results for the new procedure have been compared with the Eclipse compositional model E300. The new procedure generally gave a higher production profile than the E300, Eclipse Compositional model .This could be because of the improved PVT and relative permeability correlations used. The developed PVT correlations maximizes the value of PVT tests as the number of test required for reservoir simulation are reduced because the correlations can forecast the PVT properties required for other desired reservoir conditions.

8.4 Original contributions to knowledge and practice, and conclusions

The contributions to knowledge made in this study can be seen from the following key conclusions of this work;

- The PVT correlations developed that fit a database of measured condensate PVT properties below the dew point pressure suggests an improved understanding of condensate phase behaviour, which is critical to accurate well deliverability modelling.
- A dynamic three phase condensate relative permeability correlation has been developed, Equation (5.21) and validated with measured relative

permeability database. The agreement of the new correlation with the measured database gives more confidence in application than the existing static two phase relative permeability correlations which assume irreducible water saturation. The correlation was used in this study for predicting the effective permeability for the deliverability forecast of the condensate phase. According to current understanding of the flow behaviour in gas condensate systems, it is better described by three phase relative permeability than by the conventional assumption of two phase system.

- In a recent workshop in Moscow on gas condensate recovery, condensate recovery optimisation was highlighted as one of the greatest challenges. In this research, a semi empirical modelling approach capable of accurate prediction and optimisation of well deliverability below the saturation pressure has been developed.

- Optimisation of condensate production is not possible without such correlations except with the use of fine grid numerical simulation which time and cost does not favour.
- A major research question as to whether the modified gas rate equation is capable of accurate well deliverability prediction when PVT and rock property data are limited or not available, has been satisfactorily answered by the new method developed in this investigation, using modified Equations (6.16) and (6.51) for vertical and horizontal well trajectories respectively. Having developed semi-empirical models that accurately model condensate PVT properties and well deliverability suggests an additional understanding of gas condensate phase behaviour which is usually the reason why condensate is referred to as complex reservoir fluid. This understanding indicates the level of knowledge gap partly addressed by this work.
- A correlation capable of accurate prediction of condensate compressibility factor with limited measured laboratory mixture compositions or when mixture compositions are not available with an absolute average error of 6% have been developed, Eq. (4.69)
- The following correlation modifications developed in this research, Equations (4.44, 4.47, 4.66, 4.69, and 4.75) have been applied to extend the gas rate equation in vertical and horizontal well models for

accurate prediction of inflow performance and productivity of condensate reservoirs.

- The new approach on validation has shown a superior performance to conventional method. This is shown by a 3 years reservoir simulation production profile results validated by a standard industry reservoir simulator, Eclipse E-300 (Compositional).

The technique presented is a way forward for accurate well deliverability optimisation using the improved correlations. The cost savings by use of the modified correlations could run in millions of pounds as the cost of PVT data acquisition is rising. Therefore apart from contributions to knowledge and practice, the new approach has financial contributions as well. The huge investment required in development of gas condensate fields is another important justification of this study. Security of investment is the concern of every operator, and this can only be guaranteed with accurate forecasting tools, the main subject of this investigation. Accurate prediction models will ensure feasible field development plan for optimum production and sustainable income. Award and Publication abstracts from this work are in appendix H.

8.5 Recommendations for future work.

Suggestions that could add value to the approach developed in this study or recommendations for possible improvement can be summarised as follows;

8.5.1 Data acquisition difficulties

The recommendations are focused on major limitations of this work in spite of all the strategic design to ensure that all the correlations proposed are accurate. Field and experimental data requirement for the research was huge. There were no facilities for generation of these data and some cannot actually be generated within the School laboratory facility; rather, published field data including well test, PVT, production test data and special core analysis data were used in the study.

Quality research time was wasted making contacts for data acquisition from oil and gas industry operators and service providers around the world, yet only limited data were obtained from such attempts with the excuse that confidentiality issues do not allow release of such data. As a result, the use of published data became the only option as data and knowledge acquisition from the oil and gas industry are highly confidential.

Availability of a larger database for model development, testing and validation of correlations would have added further value to this study.

- Future studies should consider the application of developed approach on mature wells to ensure enough production data for history matching , as the present study could run validation on prediction mode as the available data were from exploratory well with no past production data for history matching.
- For further validation of the semi-empirical method of this study, the parametric studies for the semi-empirical model should be compared with numerical simulation. This could help to identify further areas for improvement.

8.5.2 Provision of in-house reservoir simulator

A good basis for establishing in house reservoir simulator for the university has been started by this investigation. However further validation of the models as more data become available and completions of other correlations that are required for reservoir simulation are recommended. Experience of the Imperial College Joint Industry project (JIP) on well test analysis in gas condensate reservoirs shows that more team work and research in this area are needed before a reliable complete in house reservoir simulator can be established. Six PhD and over twenty M.Sc. theses have gone into this project for the past ten years, yet the in-house software is yet to be completed, (jipimperial 2011).

Development of software to implement the developed algorithms will provide Oil and Gas industry Operators with an optimization tool for real time condensate production management. The tool could be used for field development planning and could serve as an audit or optimization bench mark for production optimization of existing condensate fields. The in-house simulator when completed will help in making the new approach developed in this research work more robust and flexible to suit specific applications.

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APPENDIX A Published PVT database

Table A.1 A sample of published experimental database of down-hole PVT properties used in development of condensate compressibility factor (Z) correlation (Elsharkawy, 2003)

Serial No.	39	Rich gas Condensate				
IND	281	282	283	284	285	286	287
H_2S	0	0	0	0	0	0	0
CO_2	0.0231	0.0242	0.0248	0.0253	0.0258	0.0262	0.0266
N_2	0.0137	0.0155	0.0161	0.0166	0.0163	0.0155	0.0143
C_1	0.6583	0.7074	0.738	0.7559	0.7583	0.7485	0.7292
C_2	0.0803	0.0817	0.0821	0.0839	0.0863	0.0905	0.0944
C_3	0.0417	0.0411	0.0404	0.0402	0.0415	0.0447	0.0495
iC_4	0.0078	0.0073	0.007	0.0069	0.0073	0.0082	0.0091
nC_4	0.0184	0.017	0.0162	0.0159	0.0167	0.0186	0.0208
iC_5	0.0075	0.0067	0.0062	0.006	0.0062	0.007	0.008
nC_5	0.0108	0.0097	0.0089	0.0084	0.0086	0.0096	0.0107
nC_6	0.0116	0.011	0.0103	0.0086	0.0078	0.0082	0.0092
C_7+	0.1268	0.0784	0.05	0.0323	0.0252	0.023	0.0282
M_w+	191	154	139	128	120	115	113
Sg+	0.831	0.804	0.789	0.778	0.77	0.765	0.763
P_c C_7+, (psia)	324.6	378.4	404.3	427.5	447.2	461.0	466.9
T_c C_7+, (°R)	1264.0	1177.7	1136.4	1105.1	1081.6	1066.6	1060.5
T(°F)	313	313	313	313	313	313	313
P (psia)	6010	5100	4100	3000	2000	1200	700
Z (Expt.)	1.212	1.054	0.967	0.927	0.93	0.952	0.97
ρ(lb/cu.ft.)	26.3	18.97	14.17	9.79	6.27	3.68	2.19

Table A.2 Published condensate compressibility factor database used in development of condensate compressibility factor correlation for this study continued.

Serial No.	57	Highly sour gas condensate				
IND	439	440	441	442	443	444	445
H_2S	0.282	0.277	0.272	0.27	0.273	0.289	0.318
CO_2	0.0608	0.0644	0.0669	0.0685	0.0694	0.0699	0.0679
N_2	0.0383	0.0455	0.0476	0.0473	0.0461	0.0434	0.0394
C_1	0.4033	0.4382	0.4641	0.4807	0.4844	0.4688	0.4331
C_2	0.0448	0.0471	0.0481	0.0487	0.0493	0.0496	0.0494
C_3	0.0248	0.0243	0.0239	0.0237	0.0239	0.0252	0.0277
iC_4	0.006	0.0055	0.0051	0.0049	0.0049	0.0055	0.0067
nC_4	0.0132	0.012	0.0111	0.0106	0.0106	0.0114	0.014
iC_5	0.0079	0.0068	0.006	0.0055	0.0053	0.0058	0.0074
nC_5	0.0081	0.0069	0.006	0.0054	0.0052	0.0057	0.0071
nC_6	0.0121	0.0096	0.0078	0.0066	0.006	0.0063	0.0077
C_7+	0.0991	0.063	0.0412	0.0286	0.0217	0.0192	0.0214
M_w+	165	121	116	112	109	107	107
Sg+	0.818	0.778	0.773	0.768	0.764	0.762	0.762
P_c C_7+, psia	365.4	453.2	467.1	477.8	486.0	492.7	492.7
T_c C_7+, °R	1209.7	1090.7	1075.7	1062.7	1052.5	1046.3	1046.3
T(°F)	250	250	250	250	250	250	250
P (psia)	4190	3600	3000	2400	1800	1200	700
Z (Expt.)	0.838	0.806	0.799	0.809	0.842	0.888	0.935
ρ(lb/cu.ft.)	27.34	19.52	15.06	11.3	7.95	5.06	2.91

Table A.3 Condensate viscosity correlation development database sample (Elsharkawy)

Component Mol Fraction/Samp	1	2	3	4	5	6	7	8
H2S	0	0	0.0708	0	0.2816	0	0	0
CO2	0	0	0.0096	0.0088	0.0608	0.0081	0.0508	0.0231
N2	0.0135	0.0211	0.0064	0.0053	0.0383	0.0098	0.0058	0.0137
C1	0.874	0.7758	0.6771	0.6796	0.4033	0.6514	0.6449	0.6583
C2	0.0391	0.0762	0.0871	0.0621	0.0448	0.0975	0.0731	0.0803
C3	0.0172	0.0342	0.0384	0.0237	0.0248	0.0517	0.0406	0.0417
i-C4	0.0045	0.0112	0.005	0.0056	0.006	0.0135	0.0084	0.0078
n-C4	0.0058	0.0128	0.0156	0.0151	0.0132	0.023	0.0183	0.0184
i-C5	0.0035	0.0083	0.0056	0.0067	0.0079	0.012	0.0071	0.0075
n-C5	0.0037	0.006	0.0082	0.0054	0.0081	0.0102	0.0098	0.0108
C6	0.0071	0.0116	0.0083	0.0147	0.0121	0.0152	0.0153	0.0116
C7+	0.0316	0.0428	0.0656	0.0788	0.0991	0.1076	0.1259	0.1268
C7+ MW	155	157	154	135	165	187	164	191
C7+ SG	0.7927	0.7818	0.776	0.7999	0.818	0.808	0.823	0.831
Reservoir Temp (R)	704	722	756	677	710	711	750	773
Reservoir Pressure (psi)	5367	4931	4669	4415	4190	5361	5030	6010
Experimental Viscosity (cp)	0.035	0.046	0.042	0.07	0.1	0.096	0.091	0.099

Table A.4 Published condensate compressibility factor database used in correlation testing

Component Mol Fraction/ Psi	5713	4000	3500	2900	2100	1300	605
H2S	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2	0.0018	0.0018	0.0018	0.0018	0.0018	0.0019	0.0021
N2	0.0013	0.0013	0.0013	0.0014	0.0015	0.0015	0.0014
C1	0.6172	0.6172	0.631	0.6521	0.6979	0.7077	0.6659
C2	0.141	0.141	0.1427	0.141	0.1412	0.1463	0.1606
C3	0.0837	0.0837	0.0826	0.081	0.0757	0.0773	0.0911
i-C4	0.0098	0.0098	0.0091	0.0095	0.0081	0.0079	0.0101
n-C4	0.0345	0.0345	0.034	0.0316	0.0271	0.0259	0.0331
i-C5	0.0091	0.0091	0.0086	0.0086	0.0067	0.0055	0.0068
n-C5	0.0152	0.0152	0.014	0.0139	0.0097	0.0081	0.0102
C6	0.0179	0.0179	0.016	0.0152	0.0103	0.0073	0.008
C7+	0.0685	0.0685	0.059	0.0441	0.02	0.0106	0.0107
C7+ MW	143	143	138	128	116	111	110
C7+ SG	0.795	0.795	0.79	0.78	0.767	0.762	0.761
Reservoir Temp (R)	646	646	646	646	646	646	646
Pressure (psi)	5713	4000	3500	2900	2100	1300	605
Experimental z-factor	1.107	0.867	0.799	0.748	0.762	0.819	0.902

Table A.5 Published condensate compressibility factor database sample used in developed correlation validation (Ahmed, 1991)

Component Mol Fraction/Pres, Psig	6750	5500	4300	3100	2100	1200	700
H2S	0.00	0.0	0.0	0.0	0.0	0.0	0.0
CO2	0.0237	0.024	0.0245	0.025	0.0253	0.0257	0.026
N2	0.0031	0.0032	0.0033	0.0034	0.0034	0.0034	0.0033
C1	0.7319	0.7556	0.7789	0.7933	0.7962	0.789	0.778
C2	0.078	0.0783	0.0787	0.0792	0.0804	0.084	0.087
C3	0.0355	0.0347	0.034	0.0341	0.0353	0.0374	0.0391
i-C4	0.0071	0.0067	0.0065	0.0064	0.0066	0.0072	0.0078
n-C4	0.0145	0.0137	0.0131	0.013	0.0133	0.0144	0.0156
i-C5	0.0064	0.0059	0.0055	0.0053	0.0054	0.0059	0.0064
n-C5	0.0068	0.0062	0.0058	0.0056	0.0057	0.0061	0.0066
C6	0.0109	0.0097	0.0088	0.0083	0.0082	0.0085	0.009
C7+	0.0821	0.062	0.0409	0.0264	0.0202	0.0184	0.0212
C7+ MW	184	143	138	128	116	111	110
C7+ SG	0.816	0.795	0.79	0.78	0.767	0.762	0.761
Reservoir Temp (R)	740	740	740	740	740	740	740
Pressure (psi)	6764.7	5514.7	4314.7	3114.7	2114.7	1214.7	714.7
Pseudo-Reduced Pressure	11.445	8.935	6.780	4.776	3.204	1.833	1.082
Experimental z-factor	1.238	1.089	0.972	0.913	0.914	0.937	0.96

B.1 Modified Elsharkawy viscosity correlation (STUDY)

————— 14/01/2009 22:30:47 Session Window—————————————

Welcome to Minitab, press F1 for help.

Regression Analysis: LN(Exp.Vis.) versus LN (K), DY, X

The regression equation is

LN(Exp.Vis.) = 176 - 2.5 LN (K) + 0.062 DY - 15.5 X

Predictor Coef SE Coef T P VIF

Constant 176.23 54.11 3.26 0.047

LN (K) -20.531 6.067 -3.38 0.043 16.034

DY 0.0621 0.6284 0.10 0.928 2.484

X -15.518 4.943 -3.14 0.052 11.782

S = 0.191247 R-Sq = 90.0% R-Sq(adj) = 80.1%

PRESS = 1.63741 R-Sq (pred) = 0.00%

Analysis of Variance

Source DF SS MS F P

Regression 3 0.99270 0.33090 9.05 0.052

Residual Error 3 0.10973 0.03658

Total 6 1.10243

Durbin-Watson statistic = 1.87051

Normplot of Residuals for LN(Exp.Vis.)

Residuals vs Fits for LN(Exp.Vis.)

Residual Histogram for LN(Exp.Vis.)

Residuals vs Order for LN(Exp.Vis.)

————— 04/06/2011 20:45:50 ————————————————————

B.2 Condensate formation volume factor correlation (STUDY)

————— 18/03/2010 12:16:33 Session Window ———————————————

Welcome to Minitab, press F1 for help.

Regression Analysis: Bc versus ZT/P

The regression equation is

Bc = 1.29 + 182 ZT/P

Predictor	Coef	SE Coef	T	P	VIF
Constant	1.2915	0.1613	8.00	0.000	
ZT/P	182.258	1.222	149.14	0.000	1.000

S = 0.156197 R-Sq = 99.9% R-Sq(adj) = 99.9%

PRESS = 0.493723 R-Sq(pred) = 99.91%

Analysis of Variance

Source	DF	SS	MS	F	P
Regression	1	542.70	542.70	22243.85	0.000
Residual Error	14	0.34	0.02		
Total	15	543.04			

Durbin-Watson statistic = 0.924692

Normplot of Residuals for Bc

Residuals vs Fits for Bc

Residual Histogram for Bc

B.3 Condensate relative permeability in 3-phase system session window Correlating condensate relative permeability in 3-phase system

15/11/2010 11:14:36

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Welcome to Minitab, press F1 for help.
* NOTE * All values in column are identical.
* NOTE * All values in column are identical.
* NOTE * All values in column are identical.
```

Regression Analysis: C1 versus C2, C3, C4, C5, C6, C7, C8

```
* C2 is (essentially) constant
* C2 has been removed from the equation.

* NOTE * All values in column are identical.
* NOTE * All values in column are identical.

* C4 is highly correlated with other X variables
* C4 has been removed from the equation.

* NOTE * All values in column are identical.
* NOTE * All values in column are identical.

* C5 is (essentially) constant
* C5 has been removed from the equation.

* NOTE * All values in column are identical.

* C6 is (essentially) constant
* C6 has been removed from the equation.

* NOTE * All values in column are identical.

* C7 has all values = 0
* C7 has been removed from the equation.

The regression equation is
C1 = 0.168 + 7.57 C3 - 0.97 C8

Predictor    Coef  SE Coef      T      P     VIF
Constant   0.1682   0.2216   0.76  0.472
C3          7.567    1.899   3.98  0.005  84.011
C8         -0.974    1.045  -0.93  0.382  84.011

S = 0.189589   R-Sq = 99.1%   R-Sq(adj) = 98.9%

PRESS = 0.584602   R-Sq(pred) = 97.95%

Analysis of Variance

Source          DF      SS      MS       F      P
Regression       2  28.249  14.125  392.96  0.000
Residual Error   7   0.252   0.036
Total            9  28.501
Durbin-Watson statistic = 1.82459
```

Residuals vs Fits for C1

```
Residual Histogram for C1
```

06/08/2011 22:19:26

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Welcome to Minitab, press F1 for help.
Retrieving project from file: 'C:\JBUILD\RELATI~1\MINITAB.MPJKRC.MPJ'
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C.1 Tubing performance relation (TPR) calculation steps using Beggs and Brill pressure drop correlations

The following Gas condensate well data taken from Lea et al, (2008) were partly taken and modified to illustrate the IPR and TPR calculations to determine deliverability;

The reservoir pressure was 3500psia,

$2.7/8$ inch tubing	2.441-inch ID
Depth (vertical well)	12000 ft
Condensate production	60bbls/MMscf
Gas gravity	0.65
Surface Temperature (T_{surf})	120^0F
Bottom hole Temperature (BHT)	180^0F
Surface pressure (P_{surf})	500 psia
Dew Point pressure	2,500 psia

The values of C and n for Backpressure equation were calculated from flow after flow test as 0.00113 (Mscf/D)/psia^2 and 0.83 respectively.

The details of theory and calculations using Beggs and Brills method are

illustrated by the following steps:-

1. Estimate $\Delta \boldsymbol{p}^*$ and calculated the average pressure $\bar{\boldsymbol{p}}$
2. From fluid property correlations, at the average temperature and pressure calculate;

   $R_s scf/STB$, $\sigma_0, dyne/cm$

   $B_0,\ Z,\ \mu_0, cp$, μ_g, cp
3. Calculate flow rates and densities

   $$\rho_0 = \frac{350\gamma_0 + 0.0764\boldsymbol{R}_s\gamma_g}{5.615\boldsymbol{B}_0}, \boldsymbol{Ibm}/\ \boldsymbol{ft}^3$$

$$\rho_g = \frac{2.7 p\gamma_g}{ZT}, Ibm / ft^3$$

$$q_o = 6.49 \times 10^{-5} q_o^{'} B_o, ft^3 / \sec$$

$$q_g = \frac{3.27 \times 10^{-7} Z\left(q_g^{'} - q_o^{'} R_s\right)T}{p}, ft^3 / \sec$$

4. Calculate the in-situ superficial velocities

$$V_{sL} = q_L / A, ft / \sec$$

$$V_{sg} = q_g / A, ft / \sec$$

$$V_m = V_{sL} + V_{sg}, ft / \sec$$

5. Determine the flow pattern

$$\lambda_L = \frac{V_{sL}}{V_m}; \qquad N_{FR} = V_m^2 / gd$$

$$N_{Lv} = 1.938 v_{sL} \left[\frac{\rho_L}{\sigma_L}\right]^{2.5}$$

$$L_1 = 316 \lambda_L^{0.302}$$

$$L_2 = 0.009252 \lambda_L^{-2.4684}$$

$$L_3 = 0.10 \lambda_L^{-1.4516}, \quad L_4 = 0.5 \lambda_L^{-6.738}$$

and applying the flow limit as above to determine the flow pattern to know the correlation to use for liquid holdup, $H_{L(0)}$ calculation.

6. Calculate liquid holdup

   a. Segregated

$$H_{L(0)} = \frac{0.98(\lambda_L)^{0.4846}}{\left(N_{FR}\right)^{0.0868}}$$

$$C = (1 - \lambda_L) \ln\left[0.011(\lambda_L)^{-3.768} \left(N_{LV}\right)^{3.539} \left(N_{FR}\right)^{-1.614}\right]$$

$$\psi = 1 + C\left[\sin(1.8\phi) - \sin^3(1.8\phi / 3)\right]$$

$$H_{L(\phi)}(segregated) = H_{L(0)} \psi$$

   b. Intermittent

$$H_{L(0)} = \frac{0.845(\lambda_L)^{0.5351}}{N_{FR}^{0.0173}}$$

$$C = (1 - \lambda_L) \ln\left[2.96(\lambda_L)^{0.305} \left(N_{LV}\right)^{-0.4437} \left(N_{FR}\right)^{0.0978}\right]$$

$$\psi = 1 + C(0.1015)$$

$H_{L(\phi)}$(intermittent)= $H_{L(\phi)}\psi$

$$A = \frac{L_3 - N_{FR}}{L_3 - L_2}, \quad B = 1 - A$$

$$H_L(transition) = A \times H_L(seg.) + B \times H_L(\text{int.})$$

7. Calculate the actual and no-slip densities

$$\rho_s = \rho_L H_L + \rho_g H_g, lbm/ft^3$$

$$\rho_n = \rho_L \lambda_L + \rho_g \lambda_g, lbm/cuft$$

8. Calculate the friction factor

$$N_{\text{Re}n} = \frac{1488 \rho_n V_m d}{\mu_L \lambda_L + \mu_g \lambda_g}, \quad fn = 0.0126, \; y = \frac{\lambda_L}{[H_L(\phi)]^2}, \; X = \ln y$$

$$S = X / \left[-0.0523 + 3.182X - 0.8725X^2 + 0.01853X^4\right]$$

$$f_{tp} = fn \;\; EXP(S)$$

9. Calculate the pressure gradient

$$\frac{dp}{dL} = \frac{\frac{g}{g_c}\rho_s \sin\phi + \frac{f_{tp}\rho_n V_m^2}{2g_c d}}{1 - \frac{\rho_s V_m V_{sg}}{g_c p}}$$

10. Calculate the pressure drop

$$\Delta p = \left(\frac{dp}{dL}\right)\Delta L$$

C.2 Tubing performance relation (TPR) curve calculations using Beggs and Brill method

Input Data

				a_0	-2.462	Surface tension, σ_l	22.8453 dynes/cm
				a_1	2.97		
				a_2	-0.286		
				a_3	0.0081		
				a_4	2.808		
Reservoir Pressure, P_e	3500 Psia	Tubing wall relative Roughness, e =	0.0125	a_5	-3.498		
Tubing inner Diameter ,d	2.441 inch ID	Area of tubing, A_t	0.032481997 ft2	a_6	0.3603		
Depth, (Vertical well)	12000 ft			a_7	-0.01		
Condensate production	60 bbls/MMscf	Mass Flow Rate	31190.93091 lbm/D	a_8	-0.7933		
Condensate Gravity	57 ^{o}API	Condensate, λ_{API} Sp.Gr.=	0.75066313	a_9	1.396		
Gas Grav.	1	Condensate Density, ρ_L =	45.41179566	a_{10}	-0.1491		
Flowing Tubing Temperature	120 ^{o}C			a_{11}	0.00441		
BHT	180 ^{o}C	Liquid Flow rate,	20.28 bbls/D	a_{12}	0.0839		
Flowing Tubing Head Pressur	500 psia	Liquid Superficial Velocity,Vsl =	0.040611385 ft/s	a_{13}	-0.186		
Condensate Viscosity	1.5 Cp	Tpc =187+33(γ_g -71.5 γ_g^2 =	516 ^{o}R	a_{14}	0.0203		
		Ppc =706 -51.7 γ_g -11.1 γ_g^2 =	653.3 psia	a_{15}	-6E-04		

C.3 Tubing performance relation (TPR) curve calculations using Beggs and Brill method (contd.)

Depth,ft	Pressure, Psi	Temperature,°F	Ppr	Tpr	ln(μ_g/μ_1*Tpr)	Surface Viscosity,cP	Gas Viscosity cP	A	B	C	D	Compressiblity Factor Z	Gas Solubility R_s scf/STB	Formation Volume,B_o bbl/STB	Gas formation Volume,B_g ft^3/scf	Gas Density ρ_g lbm/ft^3	superficial gas Velocity,V_{sg} ft/sec
0	500	120	0.765345171	1.124031008	0.365011984	0.010006388	0.01282395	0.1222	0.4063	0.1158	0.9779	0.796018206	39.43504	1.04329	0.026132	2.924036	3.1438022
1200	600	126	0.917736227	1.135658915	0.370234149	0.010096556	0.01300725	0.1357	0.5113	0.1143	0.9758	0.759170585	49.11678	1.05109	0.020999	3.638793	2.5262753
2400	713	132	1.09137601	1.147286822	0.375446247	0.010186724	0.013192	0.1487	0.6438	0.1129	0.9739	0.718807537	60.55929	1.05989	0.01689	4.523936	2.0319897
3600	842	138	1.28908097	1.158914729	0.380648289	0.010186724	0.0132608	0.1612	0.8156	0.1115	0.9721	0.674999114	74.05157	1.06989	0.013564	5.633162	1.6318707
4800	989	144	1.514152302	1.170542636	0.385840283	0.010186724	0.01332983	0.1734	1.0461	0.1101	0.9704	0.628461675	89.93792	1.08129	0.01086	7.036072	1.306495
6000	1157	150	1.770332509	1.182170543	0.391022239	0.010186724	0.01339908	0.1851	1.3683	0.1087	0.9688	0.581671598	108.62	1.09437	0.008682	8.800829	1.0445144
7200	1347	156	2.061286574	1.19379845	0.396194168	0.010186724	0.01346856	0.1966	1.8373	0.1074	0.9674	0.540685591	130.5217	1.10942	0.006999	10.91665	0.842071
8400	1561	162	2.388899144	1.205426357	0.401356078	0.010186724	0.01353826	0.2077	2.5404	0.106	0.966	0.516039261	155.9542	1.12668	0.00582	13.12808	0.7002238
9600	1797	168	2.750140657	1.217054264	0.40650798	0.010186724	0.01360819	0.2184	3.5944	0.1047	0.9648	0.517778999	184.8395	1.1462	0.005122	14.91857	0.6161845
10800	2049	174	3.135701669	1.228682171	0.411649883	0.010186724	0.01367834	0.2289	5.1152	0.1034	0.9636	0.544543535	216.5412	1.1677	0.004769	16.02099	0.5737843
12000	**2309**	180	3.53510602	1.240310078	0.416781796	0.010186724	0.01374872	0.2392	7.1828	0.1021	0.9626	0.58393532	250.2363	1.19076	0.004579	16.6853	0.5509394

C.4 Tubing performance relation (TPR) curve calculations using Beggs and Brill method

											Inclination		Slip	No							
Mixture	Flow Pattern							Liquid Holdup			Correction factor	Liquid holdup	Mixture Density	Slip Densi	Slip Visco	Reynolds No	Friction factor				
Velocity,Vm	λ_L	F_{rm}	σ_L	L_1	L_2	L_3	L_4	$H_L(o)$	N_{vl}	β	φ	$H_L(90)$	ρ_s	ρ_n	μ_s	Re_N	f	y	S	f_φ	dp/dz
ft/sec													lbm/ft³	lbm/ft³	cP						(psi/ft)
3.18441	0.012753	1.548162	13.86	84.642	43.886	56.219	2.91E+12	0.113955	0.0935	2.796044	1.838813309	0.2095416	11.82699	3.4659	0.0318	105085.06	0.010356	-1.236	0.2344	0.0131	0.083
2.56689	0.015821	1.005937	13.095	90.335	25.777	41.113	6.8E+11	0.131327	0.0935	2.672787	1.801835989	0.2366303	13.5235521	4.2997	0.0365	91441.679	0.010375	-1.264	0.2333	0.0131	0.0945
2.0726	0.019594	0.655827	12.304	96.363	15.203	30.14	1.61E+11	0.151181	0.0935	2.549303	1.764790774	0.2668021	15.4329027	5.3251	0.0423	78928.819	0.010398	-1.29	0.2323	0.0131	0.1076
1.67248	0.024282	0.427052	11.484	102.81	8.9535	22.076	3.79E+10	0.174105	0.0935	2.424098	1.727229498	0.3007185	17.5953333	6.5991	0.0494	67677.045	0.010425	-1.315	0.2313	0.0131	0.1225
1.34711	0.030147	0.277052	10.631	109.75	5.2489	16.126	8.83E+09	0.200749	0.0935	2.29622	1.688866057	0.3390389	20.0469347	8.193	0.0581	57450.528	0.010459	-1.338	0.2303	0.0132	0.1395
1.08513	0.037426	0.17977	9.7404	117.16	3.0777	11.781	2.06E+09	0.231459	0.0935	2.166577	1.649972959	0.3819007	22.7825837	10.171	0.069	48390.362	0.010501	-1.36	0.2295	0.0132	0.1584
0.88268	0.046009	0.118951	8.8116	124.7	1.8487	8.73	5.11E+08	0.265154	0.0935	2.040884	1.612265312	0.4274986	25.6632739	12.504	0.0819	40808.335	0.01055	-1.379	0.2287	0.0133	0.1784
0.74084	0.054818	0.083792	7.8485	131.47	1.1997	6.7698	1.57E+08	0.297561	0.0935	1.932623	1.579786982	0.4700828	28.3040993	14.898	0.095	35156.195	0.010599	-1.394	0.2282	0.0133	0.1967
0.6568	0.061833	0.065859	6.8674	136.34	0.8912	5.6842	69782593	0.322102	0.0935	1.857283	1.557184848	0.501573	30.2131488	16.804	0.1055	31660.437	0.010638	-1.403	0.2278	0.0134	0.2099
0.6144	0.0661	0.057631	5.8957	139.12	0.7559	5.1594	44510761	0.336566	0.0935	1.815181	1.544554257	0.5198442	31.2996292	17.964	0.1119	29847.732	0.010662	-1.408	0.2276	0.0134	0.2174
0.59155	0.068652	0.053425	4.9561	140.72	0.6884	4.8833	34481292	0.345065	0.0935	1.791163	1.537348763	0.5304859	31.9243044	18.657	0.1158	28852.754	0.010676	-1.411	0.2275	0.0134	0.2218

Appendix D

Condensate reservoir production forecast for single phase in vertical well completion.

The reservoir properties of the base case used for the parametric studies for two gas condensate reservoirs are shown in the two tables below.

Appendix D.1 Gas condensate reservoir model data (Petroleum Experts, 2008) **case study**

Reservoir Pressure	8000.00 (psia)
Reservoir Temperature	300.00 (deg F)
Water-Gas Ratio	0 (STB/MMscf)
Total GOR	7432.13 (scf/STB)
Absolute Open Flow (AOF)	329.069 (MMscf/day)
Reservoir Permeability	100.00 (md)
Reservoir Thickness	50.0 (feet)
Drainage Area	640.0 (acres)
Dietz Shape Factor	31.00
Wellbore Radius	0.41667 (feet)
Perforation Interval	40.00 (feet)
Reservoir Porosity	0.2 (fraction)
Connate Water Saturation	0.2 (fraction)
Non-Darcy Flow Factor (D)	7.0776e-5 (1/(Mscf/day)
Non-Darcy Flow Factor (D)	Entered
Permeability Entered	Total Permeability

Appendix D.2 Reservoir and fluid properties for rich-gas condensate simulations (Walsh, 2003), Anschutz case Study

Property	value
Simulation area, acres	320
Number of wells	1
Reservoir depth, ft	12,800
Horizontal permeability, md	1.5
Pay thickness, ft	175
Average porosity, %	10
Connate water saturation,% PV	20
Temperature, ^{o}F	215
Initial pressure, psia	5800
Initial dewpoint,psia	5430
Initial fluid molecular weight	35.52
Initial oil FVF, RB/STB	4.382
Initial $R_{s,}$ scf/STB	6042
Initial oil-leg gas saturation, % PV	80
Buttonhole producing well pressure, psia	601
Residual oil saturation to gas, %Pv	15
Residual oil saturation to water,% PV	35
Critical gas saturation, % PV	5
Separator pressure, psia	500
Stock-tank –oil density, lbm/ft^3	52.58
Stock-tank-oil molecular weight	141.65
Stock-tank-oil gravity, API	36
Separator-gas molecular weight	21.7
Initial gas-oil equivalency factor, $R_{go,}$ scf/STB	789.20
Pore volume, MMRB	43.45

Appendix E MATLAB code for calculation of IPR for Anschutz gas condensate case using modified horizontal well equations

```
clc
A=320.*43560;
reh=sqrt(A./pi);
rw=.5;
L=2000;
a=(L./2).*(0.5+sqrt(0.25+(2.*reh./L).^4)).^0.5;
aa=a;
X=2.*aa./L;
u=0.213514;
hp=L;
Kh=200;
h=100;
Pr=5430;
Pwf=[1246.97 2417.28 2994.48 3498.92 3950.34 4353.43 4707.97 5010.2
5253.22 5430];
m_PR=1.337e+8;
m_Pwf=[18053539 31495764 42941249 56048093 70375122 8.525E+07
9.991E+07 1.135E+08 1.251E+08 1.337E+08]
Sm=0;
Gg=0.685;
B0=1.279;
B_dash=2.73e+10.*Kh.^1.201
D_q=(2.222e-15.*Gg.*Kh.*h.*B_dash)./(u.*rw.*(hp).^2)
Krc=0.014
Tsc=520;
T=675;
Psc=14.65;
sCA=1.4;
b1=3200;
```

```
a1=A./b1;
Xe=b1;
Ye=h;
x0=3000;
y0=750;
z0=50;
Kx=200;
Kz=100;
Ky=Kh;
LnCh=6.28.*(a1./h).*sqrt(Kz./Kx).*(1/3-(x0./a1)+(x0./a1).^2)-
log(sin((pi.*z0)./h))-0.5.*log((a1./h).*sqrt(Kz./Kx))-1.088;
LnCh1=3/4-log(2.*pi)-0.5.*log(a1./h)+(2.*pi./(3.*h.*a1.^3)).*(x0.^3+(a1-
x0).^3)-log(sin(pi.*z0./h));
a11=a1./sqrt(Kx);
b11=0.75.*b1./sqrt(Ky);
h11=0.75.*h./sqrt(Kz);
y1=(4.*y0-L)./(2.*b1);
y2=(4.*y0+L)./(2.*b1);
l1=L./(2.*b1);
fl1=-(l1).*(0.145+log(l1)-0.137.*(l1).^2);
if y1<=1
   fy1=-(y1).*(0.145+log(y1)-0.137.*(y1).^2);
else
   fy1=(2-yl).*(0.145+log(2-yl)-0.137.*(2-yl).^2);
end
fy2=(2-y2).*(0.145+log(2-y2)-0.137.*(2-y2).^2);
Pxyz=((b1./L)-1).*(log(h./rw)+0.25.*log(Kx./Kz)-1.05);
Pxy1=((2.*b1.^2)./(L.*h)).*(sqrt(Kz./Ky)).*(fl1+0.5.*(fy2-fy1));
Realpxy1=real(Pxy1);
Py=(6.28.*(b1.^2)./(a1.*h)).*((sqrt(Kx.*Ky))./Ky).*((1./3-
y0./b1+y0.^2./b1.^2)+(L./(24.*b1)).*(L./b1-3));
```

```
Pxy=(b1./L-1).*((6.28.*a1./h).*(sqrt(Kz/Kx))).*(1./3-x0./a1+x0.^2./a1.^2);

if ((a11>=b11)&(b11>h11))

   sr=Pxyz+Realpxy1;

else

   sr=Pxyz+Py+Pxy;

end

Kv=Kz;

Iani=sqrt(Kh./Kv);

s=sr;

yb=a1;

rd=0;

re=reh;

Bbd_dash=0;

Bb_dash=((2.6e+10)./((Kx.*Kz).^0.5).^1.2);

Dqb=((2.22e-
15).*(L.*Gg.*(Kx.*Kz).^0.5)./((u.*Pwf))).*(Bb_dash./(L).^2).*((1./rw)-
(1./re))

c_dash=1.386;

C=(Kh.*Krc.*h).*(m_PR-m_Pwf)./(1422.*T);

Cb=b1.*(Kx.*Ky).*Krc.*(m_PR-m_Pwf)./(1422.*T);

B=log(reh./rw)-0.75+s+Sm+sCA-c_dash

Bb=(log((a1.*h).^0.5)./rw)+LnCh-0.75+sr+(b1.*s./L)

q1= (Cb./(Bb))/178.09439;

q2= ((-Bb+sqrt((Bb).^2+4.*Cb.*Dqb))./(2.*Dqb))/178.09439;

Bfu=(Iani.*log((h.*Iani)./(rw.*(Iani+1)))+((pi.*yb)./h)-Iani.*(1.224-s));

Cfu=(Kx.*Ky).*Krc.*L.*(m_PR-m_Pwf)./(1422.*T);

qgbabu=(b1.*sqrt(Kx.*Ky).*Krc.*(m_PR-
m_Pwf)./(1422.*T).*(log((a1.*h).^0.5)./rw)+LnCh-
0.75+sr+(b1./L).*(s)).178.094;

%newgbabu=real(qgtbabu);
```

```
qgtbabu=(b1.*sqrt(Kx.*Ky).*Krc.*(m_PR-
m_Pwf)./(1422.*T).*(log((a1.*h).^0.5)./rw)+LnCh-
0.75+sr+(b1./L).*(s+Dqb))./178.094;

qgbutler=(sqrt(Kx.*Ky).*Krc.*L.*(m_PR-
m_Pwf)./(1422.*T).*(log((h.*Iani)./(rw.*(Iani+1)))+(pi.*yb)./h.*Iani)-
1.224+s)./178.094;

qgtbutler=(sqrt(Kx.*Ky).*Krc.*L.*(m_PR-
m_Pwf)./(1422.*T).*(log((h.*Iani)./(rw.*(Iani+1)))+(pi.*yb)./h.*Iani)-
1.224+s+Dqb)./178.094;

%qobabu=7.08.*10.^-3.*b1.*sqrt(Kx.*Ky).*Krc.*(Pr-
Pwf)./(B0.*u.*(log((a1.*h).^0.5)./rw)+LnCh-.75+sr);

%newbabu=real(qobabu);

%qojoshiEcono=7.08.*10.^-3.*Kh.*h.*Krc.*(Pr-
Pwf)./(B0.*u.*(log((a+sqrt(a.^2-
(L./2).^2))./(L./2).^2)+((Iani.*h)./L).*log((Iani.*h)./(rw.*(Iani+1)))+s));

%qobutler=7.08.*10.^-3.*Kh.*L.*Krc.*(Pr-
Pwf)./(B0.*u.*(Iani.*log((h.*Iani)./(rw.*(Iani+1)))+((pi.*yb)./h)-
1.14.*Iani));

%qofurui=7.08.*10.^-3.*Kh.*L.*Krc.*(Pr-
Pwf)./(B0.*u.*(Iani.*log((h.*Iani)./(rw.*(Iani+1)))+((pi.*yb)./h)-
Iani.*(1.224-s)));

%qoborisov=(7.08.*10.^-3.*Kh.*h.*Krc.*(Pr-
Pwf))./(B0.*u.*((log((4.*reh)./L))+(h./L).*log(h./(2.*pi.*rw))));

%qogiger=(7.08.*10.^-3.*Kh.*L.*Krc.*(Pr-
Pwf))./(B0.*u.*(L./h).*((log((1+sqrt(1-
(L./(2.*reh)).^2))./(L./(2.*reh)))))+log(h./(2.*pi.*rw)));

%qorenard=(7.08.*10.^-3.*Kh.*h.*Krc.*(Pr-
Pwf))./(B0.*u.*(cosh(X)+(h./L).*log(h./(2.*pi.*rw))));

%qojoshi=7.08.*10.^-3.*Kh.*h.*Krc.*(Pr-
Pwf)./(B0.*u.*(log((a+sqrt(a.^2+(L./2).^2))./(L./2))+(h./L).*log(h./(2.*pi.*r
w))));

%qopermadi=7.08.*10.^-3.*Kh.*h.*Krc.*(Pr-Pwf)./(B0.*u.*log(Xe-
Ye.*sqrt(h./L)+(log((Ye./(2.*rw)).*sqrt(h./L)))));

%qoshedid=7.08.*10.^-3.*Kh.*h.*Krc.*(Pr-
Pwf)./(B0.*u.*(((log(h./(2.*rw)))./(L./h))+(.25+C./L).*(1./rw-2./h)));

%newgiger=real(qogiger);

plot(qgtbabu,Pwf,qgbutler,Pwf)

legend('Babu T','Butler')

output= [qgtbabu, qgbutler]
```

Appendix F Code for implementation of the improved semi empirical models in Reveal reservoir simulator

```
!------------------------------------------
!
! control section
!
!------------------------------------------

section control

  import_case_type none
  phases 3
  components total 3
  startdate 01/01/2011
  comp_model simple
  ! components 1-3 are hydrocarbon
  fracture off
  aquifer off
  well_microwave_heating off
  well_heater off
  directional_relperms up_down_horizontal
  well_connection_relperms horizontal
  ref_temperature 215    ! deg F
  ref_depth 12800    ! feet
  min_porosity 1e-005    ! fraction
  min_gridvol 1e-006    ! ft3
  wettability off
  miscibility off
  solve full_implicit
  solve implicit_temperature on
  solve rs_solve on
  solve dead_oil off

  ! solver options
  implicit maxdp_iter 500    ! psi
  implicit maxds_iter 0.5    ! fraction
  implicit maxdt_iter 100    ! deg F
  implicit maxdp_conv 1    ! psi
  implicit maxdsw_conv 0.01    ! fraction
  implicit maxdso_conv 0.01    ! fraction
  implicit maxdsg_conv 0.01    ! fraction
  implicit maxdt_conv 1    ! deg F
  implicit maxdqq_conv 0.01    ! fraction
  implicit rowcol_order xyz colour 0
  implicit point_scheme 9
  implicit newt_miniter 1
  implicit newt_maxiter 10
  implicit newt_redoiter 8
  implicit newt_holditer 6
  implicit diverge_crit 1000    !
  implicit max_newt_step 1    !
  implicit min_dp 0.001    ! psi
```

```
  implicit preconditioner ILUTP
  implicit prec_fill 33
  implicit prec_droptol 0.001    !
  implicit prec_permtol 0.0001    !
  implicit gmres_subs 10
  implicit sol_residreduc 0.0001    !
  implicit sol_residmax 0    !
  implicit scale_matrix 0
  implicit adaptive_parameter 0.01    !

end

!------------------------------------------
!
! reservoir section
!
!------------------------------------------

section reservoir

  grid coordinates cartesian
  grid blocks 32 44 18
  grid dx range 1 32   100    ! feet
  grid dy range 1 44   100    ! feet
  grid dz range 1 18   10    ! feet
  grid mapaxis origin 0 0    ! feet feet
  grid mapaxis xax 1 0    ! feet feet
  grid mapaxis yax 0 1    ! feet feet
  porosity  range x 1 32 y 1 44 z 1 18   0.1    ! fraction
  x_permeability  range x 1 32 y 1 44 z 1 18   0.2    ! darcy
  y_permeability multiple_of_x_perm 1
  z_permeability multiple_of_x_perm 0.5
  depth  range x 1 32 y 1 44   12800    ! feet
  extern transmissibility off
  rock_types total 1
  rock_types range x 1 32 y 1 44 z 1 18  1
  pvt_regions total 1
  pvt_regions range x 1 32 y 1 44 z 1 18  1
  eql_regions total 1
  eql_regions range x 1 32 y 1 44 z 1 18  1
  fip_regions total 1
  fip_regions range x 1 32 y 1 44 z 1 18  1
  nonneighbour_connections pinch 0.001    ! feet
  nonneighbour_connections minpv on
  nonneighbour_connections mintz off

end

!------------------------------------------
!
! physical section
!
```

```
!-----------------------------------------

section physical

  heat_capacity component 1 1    ! BTU/lb/F
  JT_coef component 1 0    ! degrees F/psi
  heat_capacity component 2 0.5    ! BTU/lb/F
  JT_coef component 2 0    ! degrees F/psi
  heat_capacity component 3 0.1    ! BTU/lb/F
  JT_coef component 3 0    ! degrees F/psi
  diffusivity off
  density rock_type 1 160    ! lb/ft3
  porethroat_mult rock_type 1 1    !
  porethroat_dev rock_type 1 2    !
  heat_capacity rock_type 1 0.2    ! BTU/lb/F
  compressibility rock_type 1 value 4e-005 pressure 5800 pore_volume    !
1/psi psig
  density overburden 160    ! lb/ft3
  density underburden 160    ! lb/ft3
  heat_capacity underburden 0.2    ! BTU/lb/F
  heat_capacity overburden 0.2    ! BTU/lb/F
  conductivity off
  dispersivity off
  IFT_calculation off
  water_viscosity default
  petex_pvt file phases_cond

end

!-----------------------------------------
!
! relperm section
!
!-----------------------------------------

     0.16      0    ! fraction psi
     0.2      0    ! fraction psi
     0.24      0    ! fraction psi
     0.28      0    ! fraction psi
     0.32      0    ! fraction psi
     0.36      0    ! fraction psi
     0.4      0    ! fraction psi
     0.44      0    ! fraction psi
     0.48      0    ! fraction psi
     0.52      0    ! fraction psi
     0.56      0    ! fraction psi
     0.6      0    ! fraction psi
     0.64      0    ! fraction psi
     0.68      0    ! fraction psi
     0.72      0    ! fraction psi
     0.76      0    ! fraction psi
     0.8      0    ! fraction psi
```

```
   0.84      0    ! fraction psi

 capillary_pressure table 22
!    Sw      Pc
   0.18      40    ! fraction psi
   0.2      32    ! fraction psi
   0.24      21    ! fraction psi
   0.28      15.5    ! fraction psi
   0.32      12    ! fraction psi
   0.36      9.2    ! fraction psi
   0.4      7    ! fraction psi
   0.44      5.3    ! fraction psi
   0.48      4.2    ! fraction psi
   0.52      3.4    ! fraction psi
   0.56      2.7    ! fraction psi
   0.6      2.1    ! fraction psi
   0.64      1.7    ! fraction psi
   0.68      1.3    ! fraction psi
   0.72      1    ! fraction psi
   0.76      0.7    ! fraction psi
   0.8      0.5    ! fraction psi
   0.84      0.4    ! fraction psi
   0.88      0.3    ! fraction psi
   0.92      0.2    ! fraction psi
   0.96      0.1    ! fraction psi
   1      0    ! fraction psi

 data for faces all
 relperm HT water table 22
!    Sw      krw
   0.18      0    ! fraction
   0.2      0.002    ! fraction
   0.24      0.01    ! fraction
   0.28      0.02    ! fraction
   0.32      0.033    ! fraction
   0.36      0.049    ! fraction
   0.4      0.066    ! fraction
   0.44      0.09    ! fraction
   0.48      0.119    ! fraction
   0.52      0.15    ! fraction
   0.56      0.186    ! fraction
   0.6      0.227    ! fraction
   0.64      0.277    ! fraction
   0.68      0.33    ! fraction
   0.72      0.39    ! fraction
   0.76      0.462    ! fraction
   0.8      0.54    ! fraction
   0.84      0.62    ! fraction
   0.88      0.71    ! fraction
   0.92      0.8    ! fraction
   0.96      0.9    ! fraction
   1      1    ! fraction
```

```
 relperm HT oil_water table 15
!    So      krow
    0.24       0    ! fraction
    0.28       0.005    ! fraction
    0.32       0.012    ! fraction
    0.36       0.024    ! fraction
    0.4       0.04    ! fraction
    0.44       0.06    ! fraction
    0.48       0.082    ! fraction
    0.52       0.112    ! fraction
    0.56       0.15    ! fraction
    0.6       0.196    ! fraction
    0.68       0.315    ! fraction
    0.72       0.4    ! fraction
    0.76       0.513    ! fraction
    0.8       0.65    ! fraction
    0.84       0.8    ! fraction
 relperm HT oil_gas table 17
!    So      krog
    0.08       0    ! fraction
    0.2       0    ! fraction
    0.24       0.004    ! fraction
    0.28       0.005    ! fraction
    0.32       0.012    ! fraction
    0.36       0.024    ! fraction
    0.4       0.04    ! fraction
    0.44       0.06    ! fraction
    0.48       0.082    ! fraction
    0.52       0.112    ! fraction
    0.56       0.15    ! fraction
    0.6       0.196    ! fraction
    0.68       0.315    ! fraction
    0.72       0.4    ! fraction
    0.76       0.513    ! fraction
    0.8       0.65    ! fraction
    0.84       0.8    ! fraction
 relperm HT gas table 18
!    Sg      krg
    0.16       0    ! fraction
    0.2       0.058    ! fraction
    0.24       0.078    ! fraction
    0.28       0.1    ! fraction
    0.32       0.126    ! fraction
    0.36       0.156    ! fraction
    0.4       0.187    ! fraction
    0.44       0.222    ! fraction
    0.48       0.26    ! fraction
    0.52       0.3    ! fraction
    0.56       0.349    ! fraction
    0.6       0.4    ! fraction
    0.64       0.45    ! fraction
    0.68       0.505    ! fraction
```

```
    0.72       0.562    ! fraction
    0.76       0.62    ! fraction
    0.8       0.68    ! fraction
    0.84       0.74    ! fraction
end
!-----------------------------------------
! aquifer section
!-----------------------------------------
section aquifer
end
!-----------------------------------------
! phase section
!-----------------------------------------
section phase
end
!-----------------------------------------
! adsorption section
!-----------------------------------------
section adsorption
end
!-----------------------------------------
! mobility section
!-----------------------------------------
section mobility
end
!-----------------------------------------
! water chemistry section
!-----------------------------------------
section wchemistry
end
section solids
end
!-----------------------------------------
! well section
!-----------------------------------------
section well
  well model block shear off
  well Well1 at multilateral Horiz
  well Well1 drainage_model streamline
  well Well1 fully_implicit on
  well Well1 allow_unstable_flow on
  well Well1 friction off
  well Well1 crossflow off
  well Well1 bhpmode top
end
!-----------------------------------------
! voltage section
!-----------------------------------------
section wellbore_heating
end
!-----------------------------------------
! initialisation section
```

```
!------------------------------------------
section initialisation
  data_for pvt_region 1
  petex_pvt file phases_cond
  data_for eql_region 1
  initial_pressure 5800 at depth 12800    ! psig feet
  initial_temperature reference 215 gradient 0 depth 12800    ! deg F deg F/ft
feet
  equilibration
end
!------------------------------------------
! injection/schedule section
!------------------------------------------
section schedule
  timestep initial 1    ! days
  restart_file off
  produce well Well1 grate 25 pmin 1000     ! MMscf/day psig
  until time 01/01/2014
end
```

Appendix G E-300, compositional simulation code for validation of study approach (Semi-empirical) for well deliverability prediction

```
-----------------------------------------------------------------

--STUDY      ANSCHUTZ GAS CONDENSATE RESERVOIR PRODUCTION
             PROFILE

             FOR VALIDATION OF THE SEMI EMPIRICAL MODELLING (STUDY)

             APPROACH

--AUTHOR         JOHNSON O. UGWU

--SIMULATOR      ECLIPSE-300

--DATE           APRIL12, 2011

-----------------------------------------------------------------

--Problem dimensions and phases-----------------------------------

RUNSPEC

NSTACK

50 /

TITLE

HORIZONTAL SNGLE WELL WITH OIL, GAS AND WATER FLOW

ISGAS

MULTSAVE
```

```
0/
FIELD
OIL
WATER
GAS
FULLIMP
COMPS
11 /
TABDIMS
1 1 40 40 /
EOS
PR  /
DIMENS
32 44 18 /
EQLDIMS
1 1* /
WELLDIMS
1 42 1 /
HWELLS
FMTOUT
UNIFOUT
START
1 JAN 2011/
VECTABLE
2500/
--Grid section-------------------------------------------------------
GRID
INIT
GRIDFILE
2 1/
```

```
RPTGRID
TRANX  ALLNNC /
-- EQUALS
-- DX   100.0  1 32 1 44 1 18/
-- DY   100.0/
-- DZ    10.0/
-- TOPS 12800/
-- PERMX 200/
-- PERMY 200/
-- PERMZ 100/
-- PORO  0.1/
-- /
--Basic grid block sizes
DX
25344*100 /
DY
25344*100 /
DZ
25344*10 /
--Cell top depths - only for first layer specified
TOPS
1408*12800 /
PORO
25344*0.1 /
PERMX
25344*200 /
PERMY
25344*200 /
PERMZ
25344*100 /
```

```
/
=====================================================================
EDIT
=====================================================================
PROPS
NCOMPS
     11 /
EOS
 PR /
-- Peng Robinson correction
 PRCORR
-- Standard temperature and pressure in Deg F and PSIA
STCOND
   60.0206      14.6960 /
-- Component names
CNAMES
 N2
 CO2
 C1
 C2
 C3
 IC4
 NC4
 IC5
 NC5
 C6
 PS-1
/
-- Critical temperatures Deg R
```

```
TCRIT
  2.26565996e+002  5.47362001e+002  3.43152002e+002
5.49467997e+002
  6.65675997e+002  7.34364000e+002  7.64964006e+002
8.29476000e+002
  8.45262010e+002  9.13770006e+002  1.21349825e+003
/
-- Critical pressures PSIA
PCRIT
  4.92022080e+002  1.07295491e+003  6.73076798e+002
7.08347184e+002
  6.17378983e+002  5.29055985e+002  5.50659135e+002
4.83057511e+002
  4.89523759e+002  4.39704331e+002  3.16384416e+002
/
-- Critical volumes FT3/LBMOLE
VCRIT
  1.43841791e+000  1.50409186e+000  1.58898735e+000
2.37547183e+000
  3.25165749e+000  4.21273851e+000  4.08459425e+000
4.90151310e+000
  4.86947727e+000  5.92666626e+000  2.06723003e+001
/
-- Critical volumes for LBC Viscosities FT3/LBMOLE
VCRITVIS
  1.43841791e+000  1.50409186e+000  1.58898735e+000
2.37547183e+000
  3.25165749e+000  4.21273851e+000  4.08459425e+000
4.90151310e+000
  4.86947727e+000  5.92666626e+000  2.06723003e+001
/
-- Acentric factors
ACF
```

```
  3.90000008e-002  2.38999993e-001  1.09999999e-002  9.89999995e-002
  1.52999997e-001  1.82999998e-001  1.99000001e-001  2.26999998e-001
  2.50999987e-001  2.98999995e-001  4.59895045e-001
/
-- Molecular Weights
MW
  2.80100002e+001  4.40099983e+001  1.60400009e+001
3.01000004e+001
  4.40999985e+001  5.80999985e+001  5.80999985e+001
7.21999969e+001
  7.21999969e+001  8.61999969e+001  1.76000000e+002
/
-- fluid sample composition
ZI
  2.23000000e-002
  6.56800000e-001  4.50000000e-003  1.17000000e-001  5.87000000e-002
  1.27000000e-002  1.68000000e-002  7.10000000e-003  7.10000000e-003
  9.80000000e-003  8.72000000e-002
/
-- Boiling point temperatures Deg R
TBOIL
  1.39319994e+002  3.50460001e+002  2.00879991e+002
3.32280001e+002
  4.15980001e+002  4.70520000e+002  4.90860001e+002
5.41799997e+002
  5.56559999e+002  6.15420000e+002  8.72185991e+002
/
-- Reference temperatures Deg R
TREF
  5.19690600e+002  5.19690600e+002  5.19690600e+002
5.19690600e+002
```

5.19690600e+002 5.19690600e+002 5.19690600e+002
5.19690600e+002

5.19690600e+002 5.19690600e+002 5.19690600e+002

/

-- Reference densities LB/FT3

DREF

7.68883182e+001 6.72772779e+001 4.00460000e+001
6.40736010e+001

8.13734746e+001 9.01835957e+001 9.35474546e+001
1.00115000e+002

1.01076101e+002 1.09726040e+002 1.29749040e+002

/

-- Parachors (Dynes/cm)

PARACHOR

6.04000015e+001 7.80000000e+001 7.00000000e+001
1.15000000e+002

1.55000000e+002 1.81500000e+002 2.00000000e+002
2.25000000e+002

2.45000000e+002 2.82500000e+002 4.98904297e+002

/

BIC

-- Binary Interaction Coefficients

0.00000000e+000

0.00000000e+000 0.12000000e+000

0.00000000e+000 0.00000000e+000 0.10000000e+000

0.00000000e+000 0.00000000e+000 0.10000000e+000
0.10000000e+000

0.00000000e+000 0.00000000e+000 0.00000000e+000
0.10000000e+000

0.00000000e+000

0.00000000e+000 0.00000000e+000 0.00000000e+000
0.06100000e+000

0.00000000e+000 0.00000000e+000

```
  0.00000000e+000  0.00000000e+000  0.00000000e+000
0.04900000e+000

  0.00000000e+000  0.00000000e+000  0.00000000e+000

  0.00000000e+000  0.00000000e+000  0.00000000e+000
0.03900000e+000

  0.00000000e+000  0.00000000e+000  0.00000000e+000
0.03100000e+000

  0.00000000e+000  0.00000000e+000  0.00000000e+000
0.02500000e+000

  0.00000000e+000  0.00000000e+000  0.00000000e+000
0.02000000e+000

  0.00000000e+000

  0.00000000e+000  0.00000000e+000  0.00000000e+000
0.01600000e+000

  0.00000000e+000  0.00000000e+000  0.00000000e+000
0.01300000e+000

  0.00000000e+000  0.00000000e+000

/

-- Reservoir temperature in Deg F

RTEMP

 215 /

--Water saturation functions

SWFN

    0.16  0      50

    0.18  0      40

    0.20  0.002  32

    0.24  0.010  21

    0.28  0.020  15.5

    0.32  0.033  12.0

    0.36  0.049  9.2

    0.40  0.066  7.0

    0.44  0.090  5.3

    0.48  0.119  4.2
```

```
   0.52  0.150  3.4
   0.56  0.186  2.7
   0.60  0.227  2.1
   0.64  0.277  1.7
   0.68  0.330  1.3
   0.72  0.390  1.0
   0.76  0.462  0.7
   0.8   0.540  0.5
   0.84  0.620  0.4
   0.88  0.710  0.3
   0.92  0.800  0.2
   0.96  0.900  0.1
   1.00  1.000  0.0
/
   0.2 0 0
   1.0 1 0
/
--Gas saturation functions
SGFN
   0.00  0.000  0.0
   0.04  0.005  0.0
   0.08  0.013  0.0
   0.12  0.026  0.0
   0.16  0.040  0.0
   0.20  0.058  0.0
   0.24  0.078  0.0
   0.28  0.100  0.0
   0.32  0.126  0.0
   0.36  0.156  0.0
   0.40  0.187  0.0
```

```
   0.44  0.222  0.0
   0.48  0.260  0.0
   0.52  0.300  0.0
   0.56  0.349  0.0
   0.60  0.400  0.0
   0.64  0.450  0.0
   0.68  0.505  0.0
   0.72  0.562  0.0
   0.76  0.620  0.0
   0.80  0.680  0.0
   0.84  0.740  0.0//
--Oil saturation functions
SOF3
   0.00  0.000  0.000
   0.04  0.000  0.000
   0.08  0.000  0.000
   0.12  0.000  0.001
   0.16  0.000  0.002
   0.20  0.000  0.003
   0.24  0.000  0.004
   0.28  0.005  0.005
   0.32  0.012  0.012
   0.36  0.024  0.024
   0.40  0.040  0.040
   0.44  0.060  0.060
   0.48  0.082  0.082
   0.52  0.112  0.112
   0.56  0.150  0.150
   0.60  0.196  0.196
   0.68  0.315  0.315
```

```
   0.72  0.400  0.400
   0.76  0.513  0.513
   0.80  0.650  0.650
   0.84  0.800  0.800/
/
--Rock and water pressure data
ROCK
5800 0.000004 /
PVTW
5800 1.0 0.000003 0.31 0.0 /
--Surface density of water
DENSITY
1* 63.0 1* /
--Solution section-----------------------------------------------------
SOLUTION
--Equilibration data - initial pressure 3500 psi at 7500, which is
--the oil-water and the oil-gas contact depth
EQUIL
--Dep Pref Dow Pcow Dgo  Pcog
 13200  5800 13200 0 7000  0 /
--   1 1 0  /
RPTRST
BASIC=2 PRESSURE SOIL SWAT SGAS /
SUMMARY
===========================================================
RUNSUM
RPTONLY
SEPARATE
DATE
FGIP
```

FWIP

FOIP

FGSAT

FWSAT

FGPR

FWPR

FOPR

FGPT

FWPT

FOPT

FWGR

FPR

FPPG

WGPR

/

WWPR

/

WOPR

/

WGPT

/

WWPT

/

WOPT

/

WWGR

/

WBHP

/

```
WTHP
/
WPI
/
--Schedule section------------------------------------------------------
SCHEDULE
--TUNINGDP
--/
TUNING
1 30 0.1 1* 3 0.3 2* 0.75 /
4* 10 /
12 1 900 1 3* 1E6 /
-- WELSPECS
--P FIELD 32 44 12800 OIL  /
--/
RPTSCHED
  FIP WELLS /
RPTRST
  BASIC=3 FIP /
WELSPECS
 PROD1  'GROUP1' 10 22 12800 'OIL'  /
/
COMPDAT
 PROD1  10 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  11 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  12 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  13 22  15 15 OPEN  2*  0.708 1*  0  1*  X /
 PROD1  14 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  15 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  16 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
```

```
 PROD1  17 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  18 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  19 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  20 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  21 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  22 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  23 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  24 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  25 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  26 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  27 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  28 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  29 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
 PROD1  30 22  15 15  OPEN  2*  0.708 1*  0  1*  X /
/
GRUPTREE
  'GROUP1' FIELD /
  /
WCONPROD
 PROD1 OPEN GRAT 1* 1* 25000 2* 1000 /
/
DATES
  1 FEB 2011 /
  /
DATES
  1 MAR 2011 /
  /
DATES
  1 APR 2011 /
  /
```

```
DATES
 1 MAY 2011 /
 /
DATES
 1 JUN 2011 /
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DATES
 1 JUL 2011 /
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DATES
 1 AUG 2011 /
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DATES
 1 SEP 2011 /
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DATES
 1 OCT 2011 /
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DATES
 1 NOV 2011 /
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DATES
 1 DEC 2011 /
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 1 JAN 2012 /
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DATES
 1 MAR 2012 /
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DATES
 1 DEC 2013 /
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DATES
 1 JAN 2014 /
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END
```

Appendix H: Award and Publication Abstracts:-

Awards;

(1) Petroleum Technology Development Fund (PTDF) PhD Overseas Scholarship (2008 – 2010)

(2) Won third place price, SPE European Student paper contest, PhD division, Offshore Europe 2009, Price presentation available at http://www.offshoreeurope.co.uk/page.cfm/link=264

Appendix H.1 Publications

OE 2009 Offshore Europe

Oil and Gas Conference and Exhibition
8th–11th September 2009 | Aberdeen

PhD Division of European Student Paper Contest, at the SPE's Offshore Europe 10 September 2009, Aberdeen, United Kingdom

<u>Third position, Presented paper Award</u>

Modified Correlations for the Estimation of Compressibility Factor, Density and Viscosity of Condensate Reservoir Fluid

Johnson O. Ugwu

PhD Student, School of Engineering, The Robert Gordon University,

Schoolhill, Aberdeen, AB10 1FR

Abstract

Accurate well deliverability prediction in gas-condensate reservoirs depends largely on relative permeability and accurate estimation of the fluid pressure-volume-temperature (PVT) properties used. However these PVT properties at desired reservoir conditions are not available most of the time. To estimate these important properties, the oil and gas industry has relied on laboratory experimental approach, use of

correlations and equations of state (EOS). However, laboratory method is tedious, expensive, time consuming and sometimes it is impossible to recreate exact reservoir conditions in the laboratory. The use of correlations as an option is much easier, faster and produces comparably good results. Equation of state also gives comparably good results but it is computationally more intensive than other correlations. This has led to the development of many correlations for natural gas and gas-condensate PVT properties as an alternative approach. However natural gas-condensate compressibility factor, density and viscosity estimated at reservoir conditions using some widely-used correlations have been reported to be fraught with errors when compared with experimental data.

In this work, some of the existing correlations for these key PVT properties were shortlisted for accuracy investigation based on popularity of application and analysis of errors. The error analysis results showed that all the shortlisted correlations exhibited large error margins in comparison with measured data. As a result these correlations were modified using regression analysis to tune the correlations to better match the measured values. The modified correlations were tested and validated against measured data and compared with the existing correlations. The results showed better agreement with the measured data than the existing correlations. The major contributions of this study include application to accurate production forecasting and cost reduction through elimination of unnecessary PVT tests.

Appendix H2

Sand Production forecasts for unconsolidated gas and condensate reservoirs

Gbenga Oluyemi, Johnson Ugwu and Babs Oyeneyin, *Robert Gordon University;* ***Tunde Moriwawon,*** *Shell*

Development of appropriate strategy for the management of reservoirs with sanding problems is rather complex and requires integrated approach to finding the optimum solution to solving the problem. Mitigation of sanding requires reliable sanding prediction, precise well design, accurate technology selection as well as optimum completion strategy. This requires integration of key aspects of reservoir characterisation, drilling, completion and production technologies including sand tolerances (seabed wellhead/flow lines, topside facilities). Providing an accurate forecast of the tolerance depends on accurate prediction of sand failure and the corresponding volume of produced sand. This is a transient phenomena further complicated by gas and condensate reservoir fluid flow. In this paper the results of a comprehensive Thick Wall Cylinder (TWC) experimental sand production studies carried out on synthetic sandstones are presented. The sand production prediction models for liquid flow are further calibrated and upscale with field data for gas and condensate reservoirs. The prediction model developed is further validated with independent field data with good results. The results represent a first for sand production forecast for gas reservoirs. Specific case studies are presented to demonstrate the essence of integrated sand management for effective unconsolidated reservoir management especially in deep water environment.

H.3

Modified Gas Condensate Down-hole PVT Property Correlations

Johnson UGWU, Edward MASON and Edward GOBINA

Robert Gordon University, AB10 1FR,

Aberdeen, UK

Proceeding of International symposium on Models and modelling Methodologies in Science and Engineering (MMMse 2011) 19-22 July 2011, Orlando, Florida, USA

ABSTRACT

In this investigation some widely used correlations for gas-condensate PVT properties were subjected to validation test, and were found to be inadequate for prediction of condensate down-hole PVT properties below the saturation pressure. The error margins associated with the use of some of these correlations for predicting condensate compressibility factor, density and viscosity were at levels unacceptable for engineering calculations. The developed new correlations include Eqs. (1), (4) and (22) for condensate compressibility factor, density and viscosity respectively. The modified correlations were tested and validated against large experimental measured database. The results showed a superior performance of the modified to the existing correlations in comparison with measured database.

The novelty of this investigation is the demystification of the perplexing fluid PVT properties phase behaviour which is a barrier to accurate well deliverability modelling in gas condensate reservoirs.

H.4

Parametric study of gas-condensate reservoir using different modified horizontal well productivity models

Johnson Ugwu, John Steel, Edward Mason, Edward Gobina

Robert Gordon University,

Aberdeen, UK

Abstract

Investigation of the effect of various horizontal well modelling parameters on productivity of gas-condensate reservoirs is presented. The study is important for determination of best optimization methods for production and field development planning for gas condensate reservoirs.

Productivity of twelve modified horizontal well models was evaluated. The models on evaluation gave different production rate forecasts for the same reservoir conditions; thus highlighting the problem of selection of horizontal well model to use for productivity prediction as a critical issue. One way of solving the selection problem is the comparison of prediction accuracy of each of the models with measured field or simulated production rates using standard industry software as bench mark. The models were first used for parametric studies to determine the dominant parameters that control the horizontal well productivity. Later, published field Production rate data from Anschutz field case study was used as a bench mark which was compared with the predicted rates of the modified horizontal well models. On this basis, Babu and Ode had the closest production rate prediction compared to the bench mark and was selected for modelling well deliverability (condensate production rate) in gas-condensate reservoir.

The contribution to knowledge and practice is the extension of gas rate equation for modelling condensate production rate and validation of 12 horizontal well models.