

Centre for Petroleum Studies
Department of Earth Science and Engineering

USE OF TWO-PHASE PSEUDO-PRESSURE FOR WELL
TEST ANALYSIS OF GAS CONDENSATE AND VOLATILE
OIL BELOW SATURATION PRESSURE

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DECLARATION OF ORIGINALITY

I, Olakunle Ogunrewo declare that I am the sole author of this thesis and it has not been submitted in any other form for another degree in any other institution or university. The work or any proprietary rights of other authors included in my thesis were acknowledged, cited and referenced in the text and list of references.

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ABSTRACT

This study examines the benefits of using two-phase pseudo-pressure in three areas: (1) rate dependent skin analysis; (2) bottomhole backpressure deliverability forecasting; and (3) deconvolution of the pressure transient response of wells producing from gas condensate and volatile oil reservoirs flowing below saturation pressure. The study was carried out with compositional simulations whose results were compared with field data.

It was shown that below saturation pressure, single-phase pseudo-pressure analysis of gas condensate and pressure analysis of volatile oil does not correctly estimate the mechanical skin and non-Darcy factor, whereas two-phase pseudo-pressure analysis does, provided that the gas or oil relative permeability which incorporates high capillary number and non-Darcy effects is used for the two-phase pseudo-pressure calculation. High capillary number reduces the effect of condensate or gas blockage at the wellbore due to enhanced mobility below saturation pressure.

It was established that stabilised backpressure deliverability line can be quantified with two-phase pseudo-pressure backpressure plot calculated with the relative permeability curves which incorporate high capillary number and non-Darcy effects instead of single-phase pseudo-pressure or pressure backpressure plots.

Furthermore, deconvolution of pressure, single-phase and two-phase pseudo-pressure in gas condensate and volatile oil data below saturation pressure were studied to identify and mitigate non-linearities. The deconvolved derivatives obtained from two-phase pseudo-pressure, pressure (for volatile oil) and single-phase pseudo-pressure (for gas condensate) exhibit similar late time behaviours, thus, justifying the simpler pressure and single-phase pseudo-pressure approach.

Whilst it is shown that in theory the use of two-phase pseudo-pressure calculated with relative permeability curves which incorporate high capillary number and non-Darcy effects linearizes the pressure transient response of wells producing from gas condensate and volatile oil reservoirs flowing below saturation pressure, in practice, the uncertainty in the input data required to generate two-phase pseudo pressure is likely to be too great to achieve a reliable analysis.

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NOMENCLATURE AND ABBREVIATIONS

AOFP	absolute open flow potential	MTG	a rich gas condensate reservoir
B	formation volume factor(vol/norm vol)	$m(p)$	pseudo-pressure
BU	build-up.	$m_n(p)$	normalized pseudo-pressure
C	wellbore storage coefficient (bbl/psi)	N_c	capillary number
CCE	constant composition expansion	nD	non-Darcy coefficient
CDFi	a lean gas condensate reservoir	OGR	oil gas ratio
CVD	constant volume depletion	p	pressure
d_1	distance to first boundary (ft)	p_{bank}	the pressure of the well stream where the condensate or gas bank becomes mobile
d_2	distance to second boundary (ft)	PP	pseudo pressure
d_3	distance to third boundary (ft)	PR EOS	Peng Robinson Equation of State
d_4	distance to fourth boundary (ft)	Q	gas/oil production rate
DD	drawdown.	R_p	producing gas/ oil ratio
Decr.	Decreasing	R_s	solution gas /oil ratio
DL	differential liberation	R_v	dissolved oil/gas ratio
DST	drill stem test	RG	rich gas
FP	flow period	s	skin
GOR	gas oil ratio	S	saturation
GWC	Top Upper Shallow Marine gas water contact	VO	volatile oil
Incr.	Increasing	z	real gas compressibility
k	permeability	$1\phi m(p)$	one-phase pseudo-pressure
kh	permeability-thickness product (md.ft)	$2\phi m(p)$	two-phase pseudo-pressure
LG	lean gas	$1At1$	cretaceous synrift unconformity identified in the E-M-Field structure TUSM
		m (Depth)	BUSM
		L	horizontal well length (ft)

$(p_{av})_i$ initial average reservoir
 pressure (psia)
 $(p_{av})_f$ final average
 reservoir pressure
 p_{wf} flowing pressure at the
 start of flow period (psia)
 h layer thickness (ft)
 P/Z corr. c_t correction to c_t to
 honour material balance
 c_t total compressibility
 (1/psi)
 Z_w distance to lower
 boundary (ft)

g gas
 h horizontal
 m mechanical
 n normalized
 o oil
 r relative
 ref reference
 t total
 w well
 w well
 z vertical
 1ϕ one phase
 2ϕ two-phase

Subscripts

a absolute
 bub bubble
 $corr$ correction
 c capillary
 c completion
 d dry
 eff effective

Greek

v velocity
 μ viscosity
 ϕ phase
 ρ density
 λ Corey exponent
 Ω Mobility (i.e. k/μ)

CHAPTER 1

INTRODUCTION

1.1 Background

Reservoir fluids are commonly defined by the initial reservoir pressure and temperature of the gas and liquid region on the pressure-temperature phase envelope. The phase envelope defines conditions at which thermodynamically distinct phases can occur at equilibrium, it is the locus of bubble and dew point line joining at the critical point. Gas condensate fluids can be classified based on the condensate gas ratio (CGR). The CGR cover wide range of fluid composition from 10-50 STB/MMscf for lean gas, 50-125 STB/MMscf for medium rich gas to 125-250 STB/MMscf for rich gas (Yisheng *et al.* 1998). The API gravity of produced condensate is usually in the range of 45 to 65° API. Oil gas ratio (OGR) for volatile oils varies from 600 to 1200 STB/MMscf while the OGR for black oil is greater than 1200 STB/MMscf.

Gas condensate fluids show a retrograde behaviour as a result of liquid condensation due to isothermal depletion during production below dew point pressure. These condensate fluids fall between wet gases and volatile oils on the phase envelope. Volatile oils contain few heavy and more intermediate hydrocarbon molecules compared to black oil. The quality lines in volatile crude oils are more widely spaced at lower pressures than black oil but are closer to one another near bubble point pressure. The phase envelope for gas condensate and volatile oil are shown in Figs. 1.1 and 1.2 respectively.

Kniazeff and Naville (1965) established that three different mobility zones exist for lean gas condensate reservoirs, when the near-wellbore pressure drops below the dew point pressure: (a) an outer zone away from the well with zero condensate saturation; (b) a zone nearer to the well with lower gas mobility and increased condensate saturation and; (c) a zone in the immediate vicinity of the well with high capillary number.

The formation of condensate or gas bank at the wellbore reduces the deliverability of the well (Fussel, 1973; Bardon and Longeron, 1979; Hinchman and Baree, 1985; Economides *et al.* 1987; Afidick *et al.* 1994; Barnum *et al.* 1995; Yu *et al.* 1996; Blom and Hagoort, 1998; Gringarten *et al.* 2000; El-Banbi, 2000) through a reduction in the effective permeability around the wellbore when the pressure around a well drops below the saturation pressure.

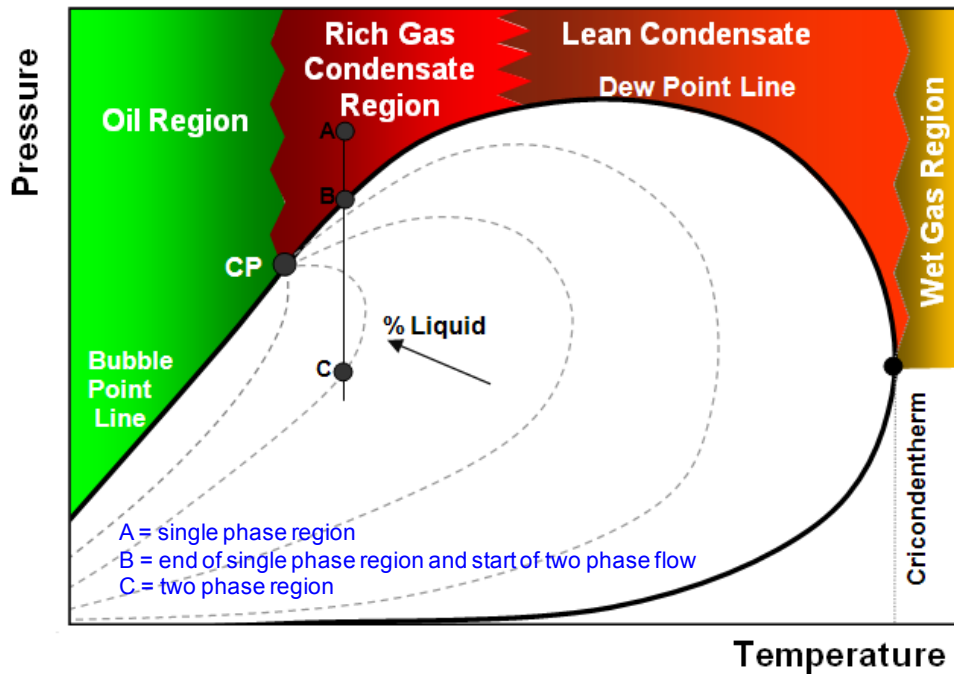


Figure 1.1: Schematic phase diagram of lean and rich condensate fluids (modified from Danesh, 1998)

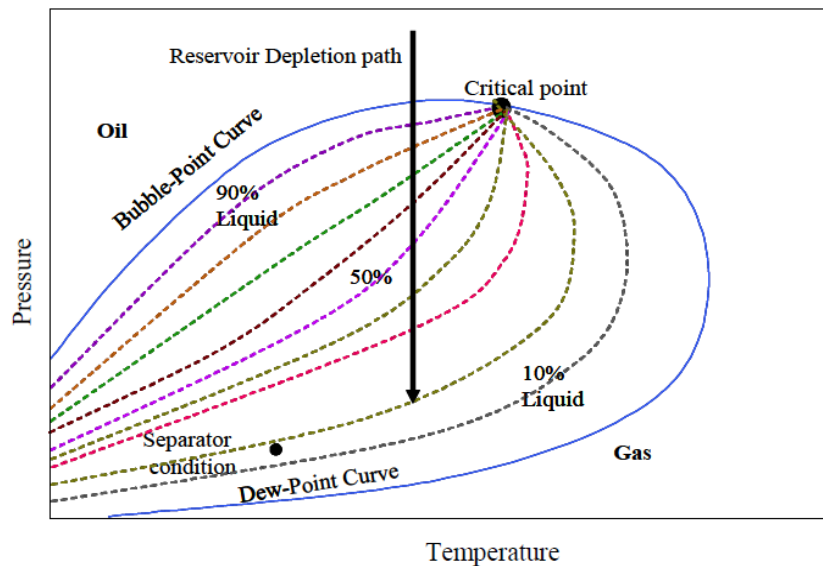


Figure 1.2: A typical P-T diagram for volatile crude oil (Danesh, 1998)

Sanni and Gringarten (2008) showed a high gas saturation zone is created around the wellbore with two-phase (oil and gas) flow in volatile oil wells producing below the bubble point pressure, while single-phase (oil) with the initial gas saturation remains away from the wellbore. The gas bank region around the wellbore during the preceding drawdown re-dissolves into the oil with the wellbore region returning to zero gas saturation.

Aluko and Gringarten (2009) showed that condensate drop out in rich gas from the preceding drawdown re-vaporizes completely during build-up above the dew point pressure and it is a mirror image of the preceding drawdown in high permeable rich gas condensate reservoirs with re-pressurization. The condensate bank region around the wellbore is seen as a mobility contrast in well test analysis data for rich gas condensate.

Several publications have focused on understanding and characterisation of lean gas, rich gas and volatile oil reservoirs using single-phase pseudo-pressure analysis for gas condensate and pressure analysis for volatile oil. Nonetheless, the limitations of the current methodology have not been fully resolved before now.

1.2 Research Motivation and Objectives

Several studies have been carried out on the well test interpretation of gas condensate and volatile oil in the last decade. However, none of the published studies has estimated the rate-dependent skin for gas condensate and volatile oil wells producing below saturation pressure using two-phase pseudo-pressure calculated with relative permeability curves that incorporates high capillary number and non-Darcy effects.

It had been suggested and verified with field data (Gringarten *et al.* 2000 and 2006) that the wellbore skin effect from single-phase pseudo-pressure for lean gas condensate, instead of always increasing with gas rate as expected above the dew point pressure, could increase, decrease or remain constant below the dew point pressure, reflecting the balance between the positive impact on productivity of high capillary number and the negative impact of non-Darcy factor. However, in-depth studies on the assessment of rate-dependent skin factor for wells producing below saturation pressure in lean gas condensate, rich gas condensate and volatile oil reservoir are still outstanding.

Thrasher *et al.* (1994), Thrasher *et al.* (1995) and Göktas *et al.* (2010) are some of the previous authors who studied the concept of bottomhole pressure backpressure analysis for gas and oil wells but none of these authors have considered the use of two-phase pseudo-pressure calculated with relative permeability curves which integrate high capillary number and non-Darcy effects to predict stabilized backpressure deliverability line for lean gas, rich gas and volatile oil wells below saturation pressure.

Deconvolution of single-phase pseudo-pressure can be applied to pseudo-linear system such as gas condensate wells flowing below dew point pressure (Gringarten, 2010).

Although, it has been suggested in literature that deconvolution can be applied to pseudo-linear system there are still concerns on the consistency and reliability of deconvolution results of pseudo-linear system such as gas condensate and volatile oil wells flowing below saturation pressure.

The objectives of this study are:

- a. To investigate the impact of high capillary number and non-Darcy effects on the rate-dependent skin calculation and stabilised backpressure deliverability prediction for wells flowing below saturation pressure in lean gas condensate, rich gas condensate and volatile oil reservoir using compositional simulation, pressure, single-phase pseudo-pressure, and two-phase pseudo-pressure.
- b. To develop a methodology for calculating well and reservoir parameters needed for predicting and improving well productivity in gas condensate and volatile oil reservoir below saturation pressure.
- c. To study the deconvolution of gas condensate and volatile oil wells flowing below saturation pressure.

1.3 Methodology

Reservoir simulation was performed using a one dimensional single well compositional model with and without high capillary number (N_c) and non-Darcy (nD) effects to generate well test data in lean gas condensate, rich gas condensate as well as volatile oil reservoirs. Fluid properties were modelled using the modified Peng-Robinson equation of state (EOS) to represent the thermodynamic properties of fluids and viscosity modelling was carried out with the Lorentz-Bray-Clark correlation.

Well test interpretations of simulated pressure data were performed to estimate wellbore skin and backpressure plots using pressure, single-phase pseudo-pressure and two-phase pseudo-pressure techniques. Total compressibility and two-phase pseudo-pressure were estimated using the methods proposed by Bozorgzadeh and Gringarten (2004 and (2005) respectively.

Deconvolution was applied to well test data from wells flowing below saturation pressure in lean gas condensate, rich gas condensate and volatile oil reservoir using pressure, single-phase pseudo-pressure and two-phase pseudo-pressure. This is to investigate the applicability of deconvolution to linear (after two-phase pseudo-pressure transformation is applied) and pseudo-linear system (pressure and single-phase pseudo-pressure

systems). Application of deconvolution with and without material balance correction to gas condensate data under severe depletion was also considered in this study.

The list of synthetic and field data used in this study are:

1. Synthetic data
 - a) Lean gas from North Sea (Fluid A).
 - b) Rich Gas from North Africa (Fluid B).
 - c) Volatile oil (Fluid C) from Coats and Smart (1982).
2. Field Data
 - a) Lean Gas from North Sea (CDFi)
 - b) Lean Gas from South Africa (EM02P)
 - c) Rich Gas from North Africa (MTG)
 - d) Volatile Oil from Russia (VO)

1.4 Publications

The lists of published paper at Society of Petroleum Engineers (SPE) conferences as a result of this thesis include:

1. A.C. Gringarten, O. Ogunrewo, and G. Uxukbayev. 2011.: “Assessment of Rate-Dependent Skin Factors in Gas Condensate and Volatile Oil Wells”, Paper SPE 143592, presented at SPE EUROPEC 2011 Conference Vienna, Austria, 23-26 May.
2. O. Ogunrewo, T. Herens, and A. C. Gringarten. 2013.: “Well Deliverability Forecasting Of Gas Condensate and Volatile Oil Wells below Saturation Pressure: Paper SPE 164869-MS, presented at SPE EUROPEC 2013 Conference London, United Kingdom, 10-13 June.
3. O. Ogunrewo and A. C. Gringarten. 2013.: Deconvolution of Lean and Rich Gas Condensate, and Volatile Oil Wells below Saturation Pressure, Paper SPE 166340-MS, presented at SPE ATCE 2013 Conference, New Orleans, Louisiana, USA, 30 September – 2 October.

1.5 Thesis Outline

This thesis comprises of seven chapters:

Chapter 1 summarises the introduction to the gas condensate and volatile oil, motivation and objectives of the research, methodology and publications.

Chapter 2 explains the relevant theory, literature review and methodology of well test analysis of gas condensate and volatile oil.

Chapter 3 outlines the fluid composition, characterisation and relative permeability modelling.

Chapter 4 investigates wellbore skin versus rate relationship in lean gas and rich gas condensate as well as volatile oil wells by using compositional simulation with high capillary number and non-Darcy effects. The rate-dependent skin factor above and below saturation pressure was estimated using pressure, single-phase pseudo-pressure and two-phase pseudo-pressure calculated with relative permeability which integrates high capillary number and the non-Darcy effects. The well deliverability forecasting of gas condensate and volatile oil field data using compositional simulation was also discussed in this chapter.

Chapter 5 describes the bottomhole backpressure plots of single-phase pseudo-pressure, pressure and two-phase pseudo-pressure as an effective tool for capturing productivity and mobility reduction due to the condensate or gas bank accumulation in simulated and field data.

Chapter 6 illustrates the application of deconvolution to simulated and field data of lean gas, rich gas and volatile oil below saturation pressure using pressure, single-phase pseudo pressure and two-phase pseudo pressure. The application of deconvolution to linear and pseudo-linear system such as reservoirs with a slightly compressible fluid and the material balance correction to gas condensate data under severe depletion was also considered.

Chapter 7 presents the conclusions and recommendations of this thesis.

1.6 Summary of Chapter 1

1. Gas condensate and volatile oil fluids can be classified based on the condensate gas ratio (CGR) and oil gas ratio (OGR) respectively. CGR varies from 10-50 STB/MMscf for lean fluid, 50-125 STB/MMscf for medium rich gas to 125-250 STB/MMscf for rich gas. OGR for volatile oils varies from 600 to 1200 STB/MMscf while it is greater than 1200 STB/MMscf for black oil.
2. The objective of this thesis is to investigate: (a) the impact of high capillary number and non-Darcy effects on the rate-dependent skin calculation; (b) stabilised backpressure deliverability prediction and (c) the deconvolution of gas condensate and volatile oil data below saturation pressure, using compositional simulation, pressure (for volatile oil), single-phase pseudo-pressure (for gas condensate) and two-phase pseudo-pressure.
3. One dimensional single well compositional model will be used to generate well test data in lean gas condensate, rich gas condensate as well as volatile oil reservoirs.
4. Fluid properties will be modelled using the modified Peng-Robinson equation of state (EOS) to represent the thermodynamic properties of fluids and viscosity modelling will be carried out with the Lorentz-Bray-Clark correlation.
5. The synthetic data used for this study as well as the published papers are listed in this chapter.

CHAPTER 2

LITERATURE REVIEW AND TWO-PHASE PSEUDO-PRESSURE FORMULATION

2.1 Introduction to Well Test Analysis

Well test analysis is a means of obtaining the well and reservoir properties such as average permeability (k), well drainage area, wellbore skin which varies from being damaged to stimulated, initial reservoir pressure (p_i), reservoir heterogeneities and boundaries. The interpretation model is assumed to represent the characteristics of the actual reservoir. Hence, if a wrong model is selected the estimated parameters calculated for the actual reservoir will be incorrect.

In well test analysis, a known signal (withdrawal of reservoir fluid) is applied to an unknown system (the well and reservoir) and the response of the unknown system (pressure change) (Gringarten *et al.* 1979, 2006a). In signal theory, signal processing is schematically described as:

$$I \rightarrow S \rightarrow O$$

where S represents an operator; I , an input signal applied to S ; and O , an output signal resulting from the application of I into S . O represents the dynamic response of the system S to the input signal I (Gringarten *et al.* 2006a).

The solution involves a search for a well-defined theoretical reservoir model whose input and output are very close to that of the actual reservoir. The response of the theoretical reservoir is computed for specific initial and boundary conditions (direct problem) that must correspond to the actual ones, when they are known. However, this is an inverse problem with a non-unique solution; it is possible to find several reservoir configurations that would yield similar responses to a given input signal (Gringarten *et al.* 1979). The non-uniqueness can be reduced by analysing more well test data and checking consistency of result with other reservoir characterisation methodology (geophysics, geology, petrophysics).

A well test interpretation model is obtained by solving the diffusivity equation (Eqs. 2.1) which governs the fluid flow in a porous media. It is derived from the principle of conservation of mass combined with Darcy's flow equation and equation of state. It can

be expressed in another form (Eq. 2.2) if the right hand side and the left hand side is divided by $\frac{k\rho}{\mu}$.

$$\frac{1}{r} \frac{\partial}{\partial r} \left[\frac{k}{\mu} \rho r \frac{\partial p}{\partial r} \right] = \rho \phi c_i \frac{\partial p}{\partial t} \quad 2.1$$

$$\frac{1}{r} \frac{\partial}{\partial r} \left[r \frac{\partial p}{\partial r} \right] = \frac{\mu \phi c_i}{k} \frac{\partial p}{\partial t} \quad 2.2$$

where μ , ρ and r are the fluid viscosity, fluid density and the radial distance to the well respectively. Eqs. 2.1 and 2.2 are non-linear partial differential equations because the rock and fluid properties are functions of pressure.

Well test interpretation models can be expressed in terms of dimensionless variables; this reduces the total number of unknowns and provides a model solution independent of any unit system. The dimensionless pressure (p_D), time (t_D), radius (r_D) and dimensionless diffusivity equations are defined in Eqs. 2.3 to 2.6.

$$p_D = \frac{kh}{141.2qB\mu} (p_i - p_{wf}) \quad 2.3$$

$$t_D = \frac{0.000264kt}{\phi \mu c_i r_w^2} \quad 2.4$$

$$r_D = \frac{r}{r_w} \quad 2.5$$

$$\frac{1}{r_D} \frac{\partial}{\partial r_D} \left[r_D \frac{\partial p_D}{\partial r_D} \right] = \frac{\partial p_D}{\partial t_D} \quad 2.6$$

The solution to Eq. 2.6 can be achieved with one initial condition and two boundary conditions, one at the wellbore (constant rate or constant pressure) and the other at the external radius (no-flow or constant-pressure).

Solution to the diffusivity equation can be obtained using Laplace transform (van Everdingen and Hurst, 1949); Green's functions (Gringarten and Ramey, 1973); Boltzman transformation (for radial flow); Hankel transforms and Numerical techniques (finite difference, finite element).

Well test interpretation results can be obtained using different type curves published in literature [Agarwal *et al.* (1970); Wattenbarger and Ramey (1970); McKinley (1971); Gringarten *et al.* (1974); Earlougher and Kersch (1974); Gringarten *et al.* (1979); Bourdet and Gringarten (1980); Bourdet *et al.* (1983)]. However, Bourdet *et al.* (1983)

derivative plot methodology is currently the most widely used. The derivative amplifies the difference in shapes between the various flow regimes that can be present during a given flow period, thus improving the diagnostic effectiveness of well test interpretation.

Interpretation of well test analysis process comprises model identification defined by flow regimes on the log-log pressure and derivative plots. The main flow regimes are near wellbore (wellbore storage, skin, fractures, partial penetration, horizontal well), reservoir behaviour (homogenous and heterogeneous: 2-porosity, 2-permeability and composite) and boundaries response (infinite extent, specified rates, specified pressure and leaky boundary) (Gringarten, 2006a). Well test interpretation process can be summarised with flow chart in Fig. 2.1. The model confirmation involves matching simulated data with actual data using log-log pressure and derivative plot; Horner plot and simulated pressure history.

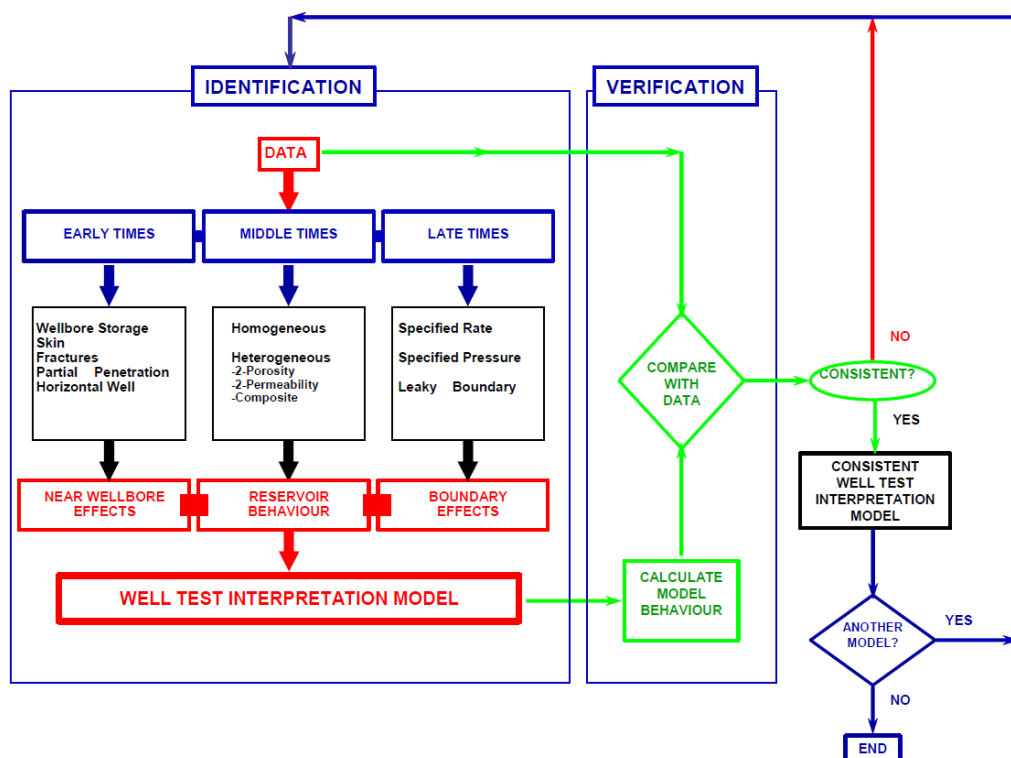


Figure 2. 1: Well test interpretation model identification process (Gringarten, 2006a)

Well test analysis of gas condensate and volatile oil below saturation pressure is more complex than the analysis of oil or dry gas well tests because of two-phase flow and changing oil and gas properties with pressure. Hence, the diffusivity equation for gas or oil is non-linear. In practice, pressure, single-phase pseudo-pressure and two-phase pseudo-pressure are used in the well test interpretation of volatile oil and gas condensate below the saturation pressure.

2.2 Single-phase Pseudo-pressure

The pressure transients governing equation is given by:

$$\nabla^2 P - \frac{\phi \mu c_t}{k} \frac{\partial P}{\partial t} = 0 \quad 2.7$$

In deriving the equation it was assumed that porosity, permeability are constant, pressure gradients, gravity and thermal effects are assumed to be negligible, a single phase, slightly compressible fluid (constant viscosity and compressibility) and that Darcy's law applies. Thus, it is applicable essentially to oil or gas wells above bubble or dew point pressure respectively.

Van Everdingen and Hurst (1949, 1953) showed that the pressure drop for damaged or stimulated well per unit rate is controlled by the conductivity of the formation, the viscosity of the fluid and the potential existence of an impediment to flow concentrated around the wellbore known as the skin factor, s (Eq. 2.8).

$$s = \left(\frac{kh(\Delta p)_{skin}}{141.2qB\mu} \right) \quad 2.8$$

where $(\Delta p)_{skin}$ is the pressure drop due to well damage, k is the reservoir permeability, B is the formation volume factor, q is the fluid rate, h is the reservoir thickness and μ is the fluid viscosity.

In order to linearize the diffusivity equation for real gas flow, Al-Hussainy *et al.* (1965)¹ introduced the real gas potential function or single-phase pseudo-pressure by accounting for the variation of fluid properties (viscosity and compressibility) with pressure (Eq. 2.9), so well test analysis is performed as in the case of single-phase oil:

$$m_{1\phi}(p) = 2 \int_{p_{ref}}^p \left(\frac{p}{\mu(p)Z(p)} \right) dp \quad 2.9$$

The limits of integration are between a reference pressure p_{ref} usually taken as the atmospheric pressure, and the pressure of interest. The gas single-phase pseudo-pressure (Eq. 2.9) can be estimated using molar density and viscosity from correlations or

¹ In this study, we use a normalized single-phase pseudo-pressure (Meunier *et al.* 1987):

$$m_n(p) = \left(\frac{\mu Z}{p} \right)_{p_{ref}} \int_{p_{ref}}^p \frac{p}{\mu(p)Z(p)} dp$$

because of its convenience: units are the same as for pressure, and equations for well test analysis are the same as for single-phase oil.

laboratory experiments. Single-phase pseudo-pressure analysis for gas condensate or pressure analysis for volatile oil reservoirs below saturation pressure considers gas or oil as the dominant fluid. Two-phase flow creates a fluid-induced composite behaviour at the wellbore characterised by mobility and storativity changes.

Gringarten *et al.* (2006) showed that a fluid induced three-region radial composite behaviour is created at the wellbore when the bottomhole pressure falls below the saturation pressure with the second, third and fourth region appearing as three different mobility zones (Figs. 2.2 and 2.3).

Four regions (Figs. 2.3 and 2.4) developed around the wellbore is shown in the condensate saturation profile for gas condensate wells (Fig. 2.4):

Region 1: Characterized by a decrease of the liquid saturation and an increase in gas relative permeability (velocity stripping).

Region 2: The liquid saturation reaches a critical value, and the effluent travels as a two-phase fluid with constant composition.

Region 3: Characterised by rapid increase in liquid saturation and a corresponding decrease in gas relative permeability.

Region 4: Contains gas with zero liquid saturation.

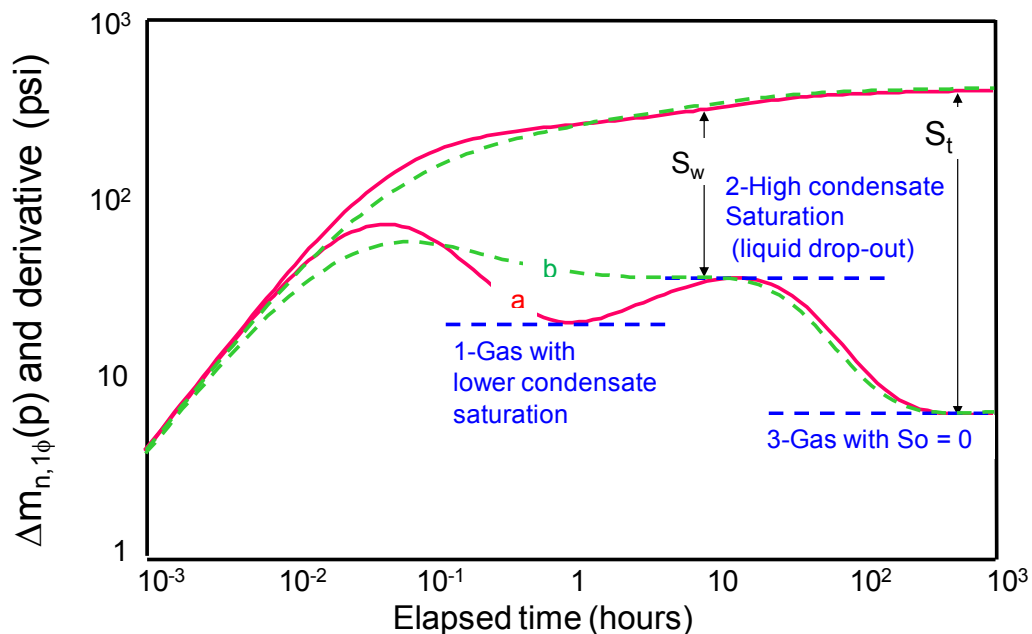


Figure 2.2: Schematic of pressure and derivative composite behaviour: (a) three-region composite; (b) two-region composite (Gringarten *et al.* 2006)

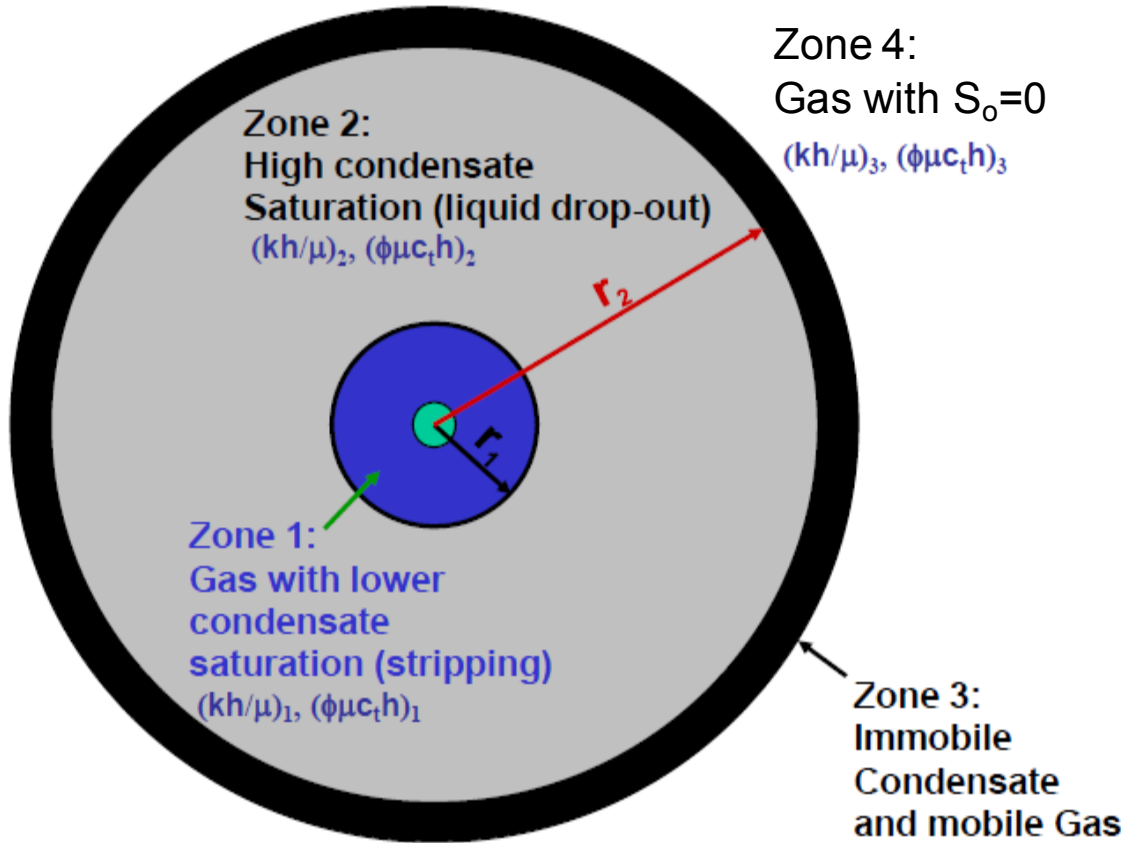


Figure 2.3: The four-radial composite model in a gas condensate reservoir (Gringarten, 2000)

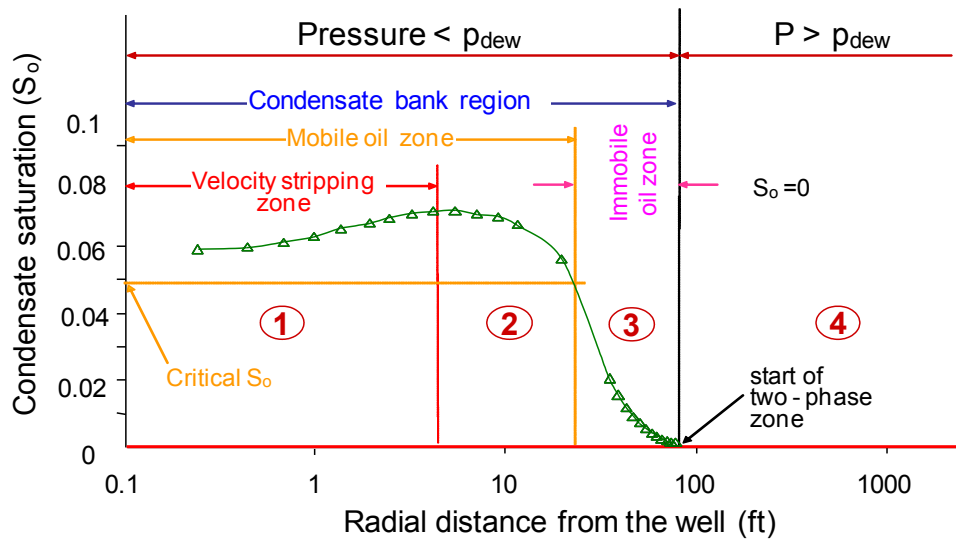


Figure 2.4: Condensate saturation profile with condensate drop-out and velocity stripping (Gringarten *et al.* 2006)

2.3 Two-phase Pseudo-pressure

Two-phase pseudo-pressure linearizes the well test data of wells flowing below saturation pressure by transforming pressure data under multiphase flow into a single phase flow equivalent. Hence, the fluid-induced composite behaviour from single-phase pseudo-pressure analysis no longer exists (Fig. 2.5). The derivative from two-phase pseudo-pressure analysis which incorporates the effects of both fluid properties and relative permeability should be flat and correspond to the absolute permeability of the formation if the gas saturation was estimated correctly.

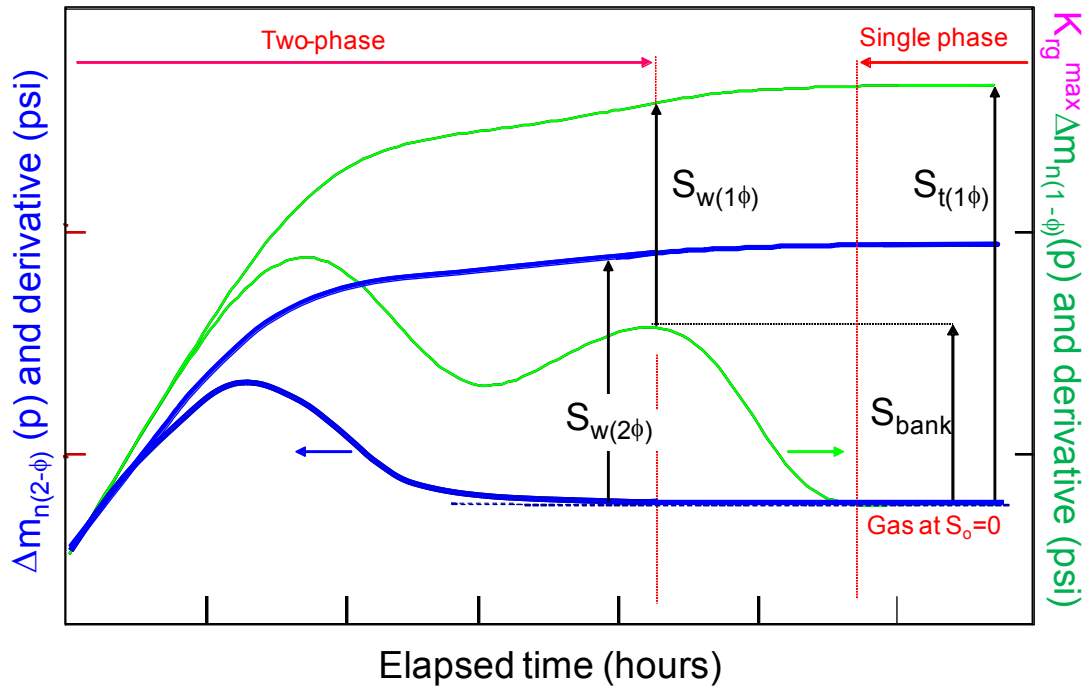


Figure 2.5: Single-phase versus two-phase pseudo-pressure (modified from Gringarten *et al.* 2006)

Jones and Raghavan (1989) showed that gas condensate well test data below saturation pressure can be analysed using O'Dell and Miller (1973) and Fussel (1973) two-phase pseudo-pressure integral (Eq. 2.10). They established that two-phase formulation can be used to estimate formation flow capacity and skin factor when the bottomhole pressure is below dew or bubble point pressure for gas condensate and volatile oil respectively.

$$m_{2\phi}(p) = \int_{p_{ref}}^p \left(\frac{k_{rg}}{\mu_g B_g} + \frac{k_{ro}}{\mu_o B_o} \right) dp \quad 2.10$$

where B , k_r and μ in Eq. 2.10 represent the formation volume factor, relative permeability, and viscosity. The subscripts o and g denote oil and gas respectively.

The two-phase pseudo-pressure integral can be estimated using three mobility zones (1, 2 and 3) shown in the condensate saturation profile (Fig 2.6) and log-log plot of single-phase pseudo-pressure (Fig 2.7). The three mobility zones 1, 2 and 3 are analysed using Eqs. 2.11, 2.13 and 2.15 for gas condensate and Eqs. 2.12, 2.14 and 2.16 for volatile oil.

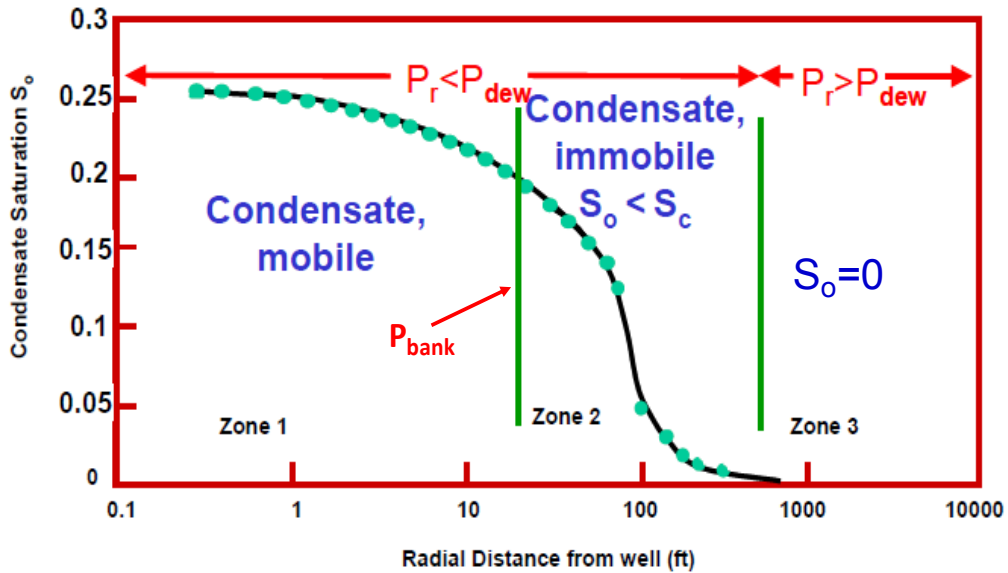


Figure 2.6: Condensate saturation profile in the reservoir (Gringarten *et al.* 2000)

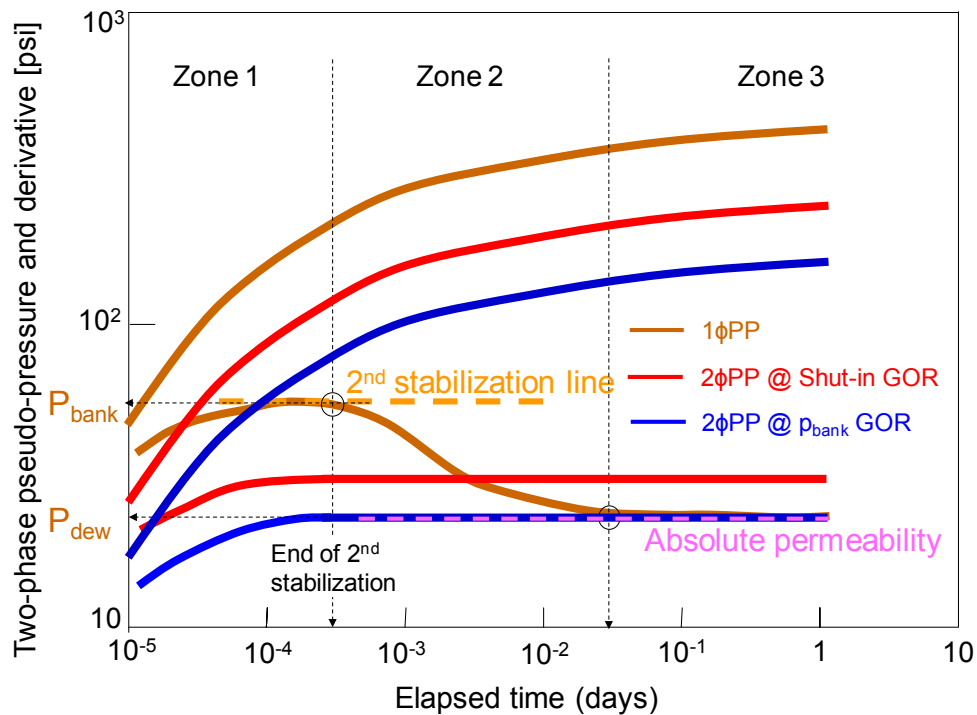


Figure 2.7: Log-log plot of single-phase and two-phase pseudo-pressure derivative stabilisation levels for zone 1-3 (modified from Bozorgzadeh and Gringarten, 2005)

Zone 1: $p_{wf} \leq p \leq p_{bank}$ (between wellbore and p_{bank})

Gas Condensate:

$$m_{2\phi 1}(p) = \int_{p_{wf}}^{p_{bank}} \left(\frac{k_{rg}}{\mu_g B_g} + \frac{k_{ro} R_s}{\mu_o B_o} \right) dp \quad 2.11$$

Volatile Oil:

$$m_{2\phi 1}(p) = \int_{p_{wf}}^{p_{bank}} \left(\frac{k_{rg} R_v}{\mu_g B_g} + \frac{k_{ro}}{\mu_o B_o} \right) dp \quad 2.12$$

Zone 2: $p_{bank} \leq p \leq p_{sat}$ (between p_{bank} and p_{sat})

Gas Condensate:

$$m_{2\phi 2}(p) = \int_{p_{bank}}^{p_{dew}} \left(\frac{k_{rg}}{\mu_g B_g} \right) dp \quad 2.13$$

$p_{bank} \leq p \leq p_{bubble}$

Volatile Oil:

$$m_{2\phi 2}(p) = \int_{p_{bank}}^{p_{bubble}} \left(\frac{k_{ro}}{\mu_o B_o} \right) dp \quad 2.14$$

Zone 3: $p_{sat} \leq p$ (between p_{sat} and maximum pressure)

Gas Condensate:

$$m_{2\phi 3}(p) = k_{rg}(S_{wc}) \int_{p_{dew}}^p \left(\frac{1}{\mu_g B_g} \right) dp \quad 2.15$$

$p_{bubble} \leq p$

Volatile Oil:

$$m_{2\phi 3}(p) = k_{ro}(S_{wc}) \int_{p_{bubble}}^p \left(\frac{1}{\mu_o B_o} \right) dp \quad 2.16$$

p_{wf} is the well flowing pressure; p_{bank} (Fig. 2.6 and 2.7) is the pressure of the well stream where the condensate or gas bank becomes mobile; R_s is the solution gas oil ratio (GOR); R_v is dissolved oil gas ratio (OGR), p_{bubble} is bubble point pressure and p_{dew} is the dew point pressure. The procedure for converting pressure data to two-phase pseudo-pressure is discussed in section 2.4.

2.4 Two-phase Pseudo-pressure Calculation Procedure

In this study, the pressure transient data obtained from the field and compositional simulation were converted to two-phase pseudo-pressures using the Bozorgzadeh and Gringarten (2004) approach which considers high capillary number and non-Darcy effect on the relative permeability curves. The flow chart of two-phase pseudo-pressure calculation is shown in Fig. 2.8.

The computation steps for the two-phase pseudo-pressure calculated with high capillary number and non-Darcy effects on the relative permeability curves are specified below:

- 1) Establish p_{bank} from single-phase pseudo-pressure or pressure derivative (Fig. 2.7); p_{bank} is selected at the end of the 2nd stabilisation line or via trial and error if the 2nd stabilisation is not visible on the derivative.

- 2) Estimate solution GOR at p_{bank} from CVD and DL test and $\frac{k_{rg}}{k_{ro}}$ ratio using:

$$\frac{k_{rg}}{k_{ro}} = \frac{R_p - R_s}{1 - R_v R_p} \left(\frac{B_g d\mu_{gd}}{B_o \mu_o} \right)$$

- 3) Compute k_{rg1} using $\frac{k_{rg}}{k_{ro}}$ from step 2 and measured relative permeability data.

- 4) Calculate S_g using $\frac{k_{rg}}{k_{ro}}$ from step 2 and measured relative permeability data

- 5) Calculate total compressibility (c_t):

$$c_t = (1 - S_w) \left[\frac{S_g}{B_g} \left\{ \frac{-dB_g}{dP} + \frac{dR_v}{dP} \left(\frac{B_o - R_s B_g}{1 - R_s R_v} \right) \right\} + \frac{S_o}{B_o} \left\{ \frac{-dB_o}{dP} + \frac{dR_s}{dP} \left(\frac{B_g - R_v B_o}{1 - R_s R_v} \right) \right\} \right] + S_w C_w + C_f$$

- 6) Calculate the radius of investigation at elapsed time using $R_i = 0.032 \sqrt{\frac{k_{rg1} \Delta t}{\mu_g \phi c_t}}$

with k_{rg1} from step 3, c_t from step 5 and gas viscosity from fluid data.

- 7) Multiply the radius of investigation from step 6 by $2\pi h$ (reservoir net thickness) to obtain equivalent area A.

- 8) Calculate Darcy gas velocity, $u_g = \frac{Q_g B_g}{A}$. Q_g is the production rate, B_g is the formation volume factor and A is the area from step 7.

- 9) Calculate the non-Darcy flow multiplier (F_{ND}) which allows for the effects of non-Darcy flow to be imposed on the relative permeability data:

$$F_{ND} = \frac{1}{\left(1 + \frac{\beta k \rho_g u_g}{\mu_g}\right)} \quad (\text{Mott } et al. 2000a). \quad \text{where } \beta \text{ is given by } \beta = \frac{3.3 \times 10^{-9}}{\phi^{\frac{3}{4}} k^{\frac{5}{4}}} \quad (\text{Blom } et al. 1998).$$

u_g is from step 8, ρ_g gas density, and μ_g gas viscosity.

F_{ND} factor is a dimensionless term that gives a quantitative indication of the deviation of the flow behaviour from Darcy's law. It models non-Darcy effect on the relative permeability as a function of the Darcy gas velocity u_g calculated in step 8.

10) Compute the superficial gas velocity:

$$v = \frac{u_g}{\phi(1 - S_w)} ; \phi = \text{porosity, } u_g \text{ is from step 8 and } S_w \text{ is connate water saturation.}$$

11) Estimate capillary number using gas/oil interfacial tension (σ) from fluid data:

$$N_c = \frac{v\mu}{\sigma} ; v \text{ is from step 10, and } \mu \text{ is fluid viscosity.}$$

12) Calculate interpolation function for high capillary number on relative permeability: $f = \left(1 - \frac{1}{(\alpha N_c)^n + 1}\right)$; the value of f varies between 1 (at low capillary number) and 0 (at high capillary number), $\alpha = 3000$, and $n = -0.6$ (Mott *et al.* 2000).

13) Calculate the miscible straight line gas relative permeability k_{rgM} (Whitson *et al.* 2003) using $\frac{k_{rg}}{k_{ro}}$ from step 2:

$$k_{rgM} = k_{rg}^{\max} \left(\frac{1}{1 + \left(\frac{k_{rg}}{k_{ro}}\right)^{-1}} \right). \quad k_{rgM} \text{ is the 'miscible' gas}$$

relative permeability at the same value of saturation.

14) Calculate the gas relative permeability (k_{rg}) which incorporates the high capillary number and non-Darcy effects in velocity stripping zone using k_{rg1} , F_{ND} , f and k_{rgM} from steps 3, 9, 12 and 13: $k_{rg} = F_{ND}(fk_{rg1} + (1 - f)k_{rgM})$.

15) Calculate k_{ro} for velocity stripping zone using k_{rg} from step 14 and $\frac{k_{rg}}{k_{ro}}$ from step 2:

$$k_{ro} = \left[\frac{k_{rg}}{\left(\frac{k_{rg}}{k_{ro}}\right)} \right]$$

16) Calculate the S_g at the immobile condensate region (beyond p_{bank}) and region with original oil saturation using S_g equation derived in Appendix A:

$$S_g = \left[\frac{e^{\left(\frac{B_g'}{B_g}\right)(P-P_{sat})} \left[c_t + \left(\frac{B_g'}{B_g}\right) \right] - c_t}{\left(\frac{B_g'}{B_g}\right)} \right] \quad c_t \text{ is the total compressibility, } B_g \text{ is the}$$

formation volume factor, P_{sat} is the saturation pressure.

17) Calculate k_{rg} at the immobile condensate region and region with zero oil saturation using the S_g from step 16.

18) Calculate the pseudo-pressure integral for Zones 1-3 using Eqs. 2.11, 2.13 and 2.15 for gas condensate and Eqs. 2.12, 2.14 and 2.16 for volatile oil using trapezoidal rule.

19) Normalise the two-phase pseudo pressure by multiplying with $\left(\frac{\mu_i Z_i}{p_i}\right)$
 p_i , z_i and μ_i are initial pressure, z-factor and viscosity respectively.

20) Analyse the two-phase pseudo-pressure as pressure in well test analysis software by matching with the type curve to calculate skin or applying deconvolution to estimate boundaries.

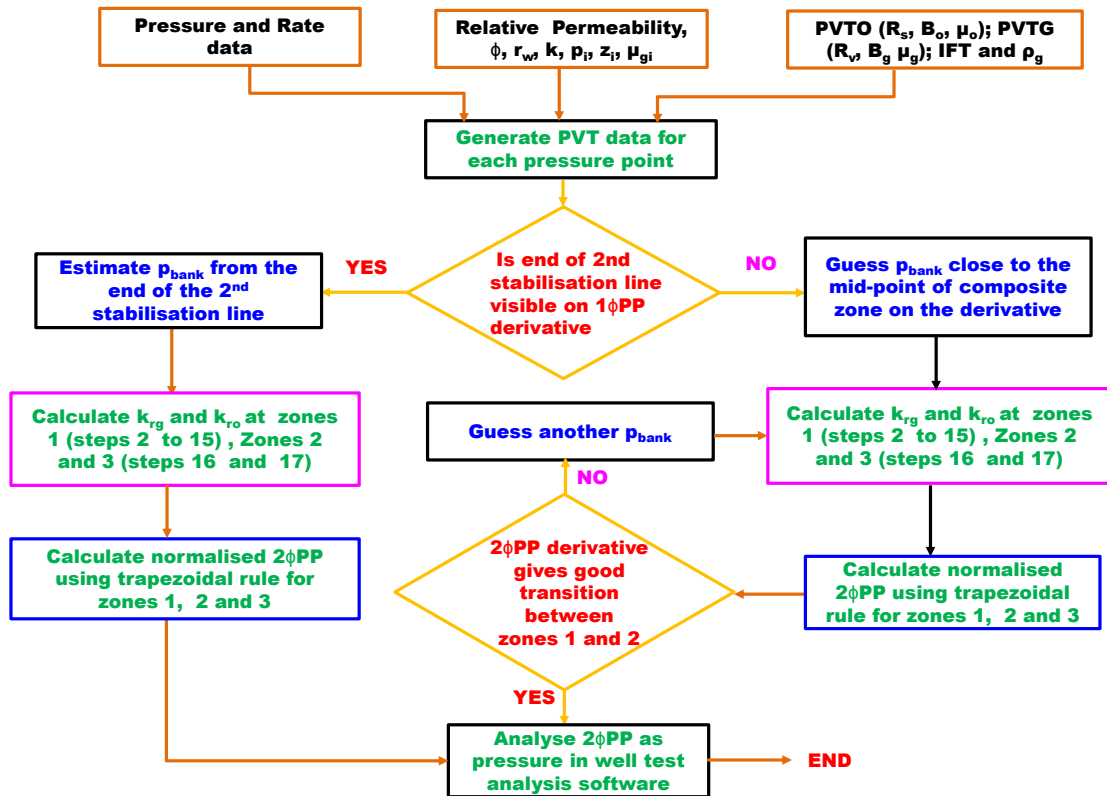


Figure 2.8: Flow Chart of Two-phase Pseudo-pressure Calculation

2.5 Non-Darcy Flow Model

At low flow rates, the behaviour of a single-phase dry gas flowing through a porous medium is expressed by Darcy's law, which states that there is a linear relationship between pressure drop and rate (Darcy, 1856). However, at high flowing velocities, the pressure drop is no longer proportional to flow rate. Thus, Darcy's law is no longer valid and a quadratic velocity term must be added to calculate the pressure drop (Forchheimer, 1901). The modification to Darcy's law is given by:

$$-\frac{dp}{dL} = \frac{\mu}{k}v + \beta\rho v^2 \quad 2.17$$

where $\frac{dp}{dL}$ is the pressure drop along the porous medium of length, L ; μ is viscosity; v , the velocity; k , the absolute permeability; ρ , the density and β the non-Darcy coefficient. β can be treated as a rate-dependent skin term, called non-Darcy, turbulence or inertia skin effect (Smith, 1960). The relationship between rate-dependence skin (DQ) and wellbore skin above saturation pressure in the near-wellbore region can be described with a straight line equation (Eq. 2.18):

$$s_w = s_m + DQ \quad 2.18$$

where s_w is wellbore skin, s_m mechanical skin, Q is the flow rate and D is the turbulence factor (Eq. 2.22).

Pressure drop at the wellbore due to non-Darcy factor can have dramatic effects on the flowing bottomhole pressure required to maintain production rates, especially in gas condensate systems flowing at high rate. Neglecting or underestimating this effect will cause optimistic predictions of the maintenance of gas rate plateau (Coles and Hartman, 1998).

Narayanaswamy *et al.* (1998) presented an analytical method for calculating an effective non-Darcy flow coefficient for heterogeneous grid blocks in reservoir simulation. They showed that non-Darcy effect of a heterogeneous formation is larger than the non-Darcy flow coefficient of an equivalent homogeneous formation. Hence, the non-Darcy effect must be taking into account when determining the productivity index of a well.

For single-phase flow, the non-Darcy factor is constant and can be determined from multi-rate well test analysis or from the characteristic relationship between non-Darcy flow coefficient, porosity and permeability for single-phase flow is given by Li and Engler (2001):

$$\beta = \frac{c}{\phi^a k^b} \quad 2.19$$

where k and ϕ are the permeability and the porosity and the constants a , b and c must be experimentally determined. The non-Darcy factor determined from correlations is usually not reliable because different types of parameters were considered in developing the correlations; thus, it varies from one correlation to another.

For multiphase flow, the non-Darcy effect can be estimated with the equations developed by Geertsma (1974) and Henderson *et al.* (2000). In Eclipse 300, two models are available for estimating the non-Darcy flow parameter β (Eqs 2.20 and 2.21):

$$\beta_p = \frac{a}{\phi^b S_p^c (kk_r)^d} \quad 2.20$$

$$\beta_p = \beta_d S_p^c (kk_r)^d \quad 2.21$$

where k_r is the relative permeability, k is the absolute permeability and S_p the phase saturation. The set of parameters (a, b, c, d) or (β_d, c, d) are constant, and must be experimentally determined. In this study, model 1, which is very similar to Geertsma (1974) model, was selected for calculating the non-Darcy flow parameter β .

The turbulence factor (D-factor) for each production well connection in Eclipse 300 was calculated with Eqs. 2.20 and 2.22. The Forchheimer parameter β was determined from the values listed in Table 2.1.

$$D = \alpha \beta_p \frac{k_e}{h} \frac{1}{r_w} \frac{\gamma_p}{\mu_p} \quad 2.22$$

where:

α is a constant, the value of which depends on the units system (6.83352×10^{-8} Day/Mscf). This constant was multiplied with oil GOR to convert the unit to Day/STB in the case of volatile oil.

β_p is the Forchheimer parameter for each phase (in Forchheimer units, F)

k_e is the effective permeability of the connected grid block.

h is the length of the connection (in this case, h is the reservoir thickness)

r_w is the wellbore radius

γ_p is the relative density of produced or injected fluid at surface conditions with respect to air or water at standard temperature and pressure for gas and liquid respectively.

μ_p is the viscosity of the fluid.

Table 2.1: Forchheimer Model Parameters

	Lean Gas	Rich Gas	Volatile Oil
Parameter	Values		
a	1.57×10^{-3}	5×10^{-4}	5×10^{-4}
b	5.5	5.5	5
c	5.5	5.5	5.5
d	0.5	1	1
γ	0.441	0.436	0.798
μ	0.0336	0.0599	0.148

2.6 Capillary Number Effect

Below saturation pressure interfacial tension and superficial velocity has an impact on the flow of gas condensate and volatile oil at the wellbore. Under such conditions, multiple transfers occur between the liquid and vapour phases so that a complete miscibility may be reached because the relative permeability curves (Fig. 2.9) straighten out (become miscible) as a result of decrease in the residual fluid saturations and the interfacial tension between the two phases (Bardon and Longeron, 1980).

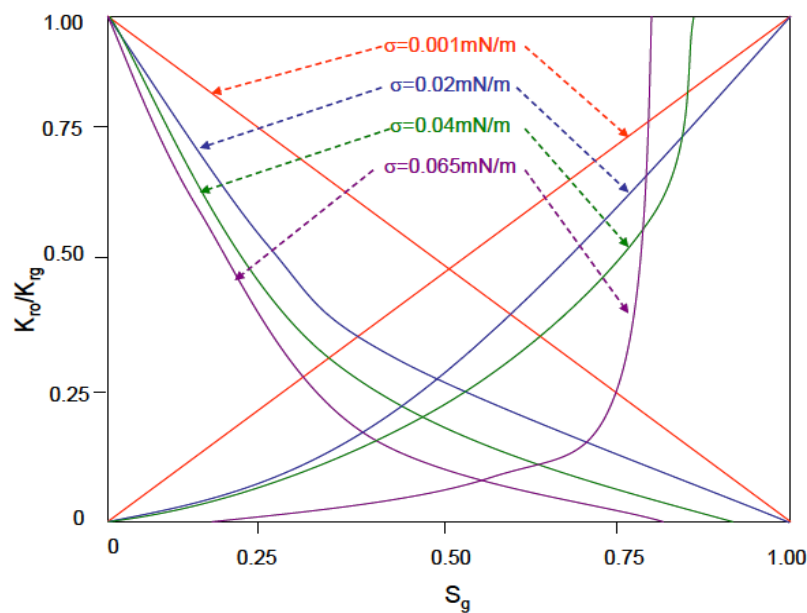


Figure 2.9 Vapour Liquid relative permeability for low interfacial tension values (Bardon and Longeron, 1980)

The change of relative permeability curve from immiscibility towards miscibility in gas condensate at high flow rates and decreasing interfacial tension has been studied widely in the literature. Gondouin *et al.* (1967); Asar and Handy (1983); Fulcher *et al.* 1985; Haniff *et al.* 1990; Boom *et al.* 1995; Kalaydjian *et al.* 1996; Nikraves and Soroush

(1996); and Blom *et al.* (2000) concluded that productivity losses due to the creation of condensate bank around the wellbore is overcompensated for by high capillary number obtained from high flow rate or low interfacial tension.

Capillary number (N_c) is a dimensionless number which accounts for the relative effect of viscous forces against surface tension across the interface of two immiscible fluids such as gas or liquid. It increases with increasing velocity and decreasing interfacial tension (Eq. 2.23). High capillary number increases the fluid mobility around the wellbore; this phenomenon is known as ‘velocity stripping’. N_c is a dimensionless number which measures the relative strength of viscous and capillary forces. Saffman and Taylor (1958) defined N_c as:

$$N_c = \frac{v\mu}{\sigma} \quad 2.23$$

where μ is the fluid viscosity, v is the superficial velocity of the fluid and σ is the surface or interfacial tension between the two fluids phases i.e. gas and liquid phases.

The superficial gas velocity is given by:

$$v = \frac{u_g}{\phi(1 - S_w)} \quad 2.24$$

u_g is Darcy’s velocity (Eq. 2.25); ϕ , the rock porosity; and S_w , the irreducible water saturation.

$$u_g = \frac{Q_g \beta_g}{A} \quad 2.25$$

Blom and Haggot (1998a) analysed different methods for incorporating high capillary number (N_c) in the gas condensate relative permeability curves and established that well impairment by condensate drop-out may be grossly overestimated if the dependence of relative permeability on the high capillary number is ignored. They showed that an increase in capillary number result in decrease of critical or residual saturations. Hence, the relative permeabilities changes from immiscible saturation curves to miscible straight-lines (Henderson *et al.* 1995).

Relative permeability at low interfacial tension and high flow rate can be modified by high capillary number during compositional simulation. High capillary number converts the immiscible relative permeability to internally-generated miscible curves and reduces the residual saturations during simulation. The three alternate models (Eqs. 2.26, 2.27 and 2.28) are available for calculating capillary number effect in Eclipse 300:

$$N_{cp}^{(1)} = \frac{v_p \mu_p}{\sigma} \quad 2.26$$

$$N_{cp}^{(2)} = \frac{Kk_{rvp} \Delta P_p}{\sigma L} \quad 2.27$$

$$N_{cp}^{(3)} = (2\phi S_p Kk_{rvp})^{\frac{1}{2}} \frac{\Delta P_p}{\sigma} \quad 2.28$$

where:

S_p is the normalized phase saturation

ΔP_p is the pressure drop of the p^{th} phase in the direction of flow

μ_p is the fluid viscosity and σ is the gas-oil surface tension

v_p is the fluid velocity in the direction of flow and k_{rvp} is the capillary number modified relative permeability of the p^{th} phase calculated at the previous time step.

Whitson *et al.* (1999) showed that the simulation results from using any of Eqs. 2.26, 2.27 and 2.28 are the same; hence, capillary number model 1 in Eclipse 300 was selected to model velocity-dependent relative permeability. The parameters ($N_{cbg/o}$, $m_{g/o}$, $n_{1g/o}$, $n_{2g/o}$) in the capillary model are listed in Table 2.2.

Table 2. 2:Capillary Number Model Parameters

	Lean Gas	Rich Gas	Volatile Oil
Parameter	Values		
$N_{CBg/o}$	$1 \times 10^{-3}/1 \times 10^{-6}$	1.3×10^{-5}	1×10^{-6}
m_o	79.62	0	50
m_g	23.89	0	20
n_{1o}	24.2	10	20
n_{1g}	6.23	10	5
n_{2o}	0	-1	0
n_{2g}	0	-1	0

where:

$N_{cbg/o}$: Base capillary number for gas/oil (the threshold value of capillary number above which the velocity dependent relative permeability is active)

$m_{g/o}$: This parameter controls the variability of the critical gas/oil saturation with normalized capillary number.

$n_{1g/o}$: This parameter along with n_{2g} parameter controls the weighting between the miscible and immiscible relative permeability curves.

$n_{2g/o}$: This parameter along with n_{1g} parameter controls the weighting between the miscible and immiscible relative permeability curves.

2.7 Total Compressibility Calculation

Total compressibility for oil and gas reservoir is the combined compressibilities of oil, gas, water and reservoir rock. The total compressibility (c_t) for single-phase flow is given by:

$$c_t = c_f + S_o c_o + S_g c_g + S_w c_w \quad 2.29$$

$c_{t/f/w}$ represent the total/formation/water compressibilities, $S_{g/w/o}$ are the gas/water/oil saturations.

Continuous dissolution of gas into oil for gas condensate and vaporisation of oil into gas for volatile oil occur in multiphase flow of gas condensate and volatile oil below saturation pressure. In order to account for the dissolution of the gas into the oil (R_s) and the vaporisation of the oil into the gas (R_v), the total compressibility of the multiphase flow zone was calculated with Eq. 2.30 (Bozorgzadeh and Gringarten, 2004):

$$c_t = (1 - S_w) \left[\frac{S_g}{B_g} \left\{ \frac{-dB_g}{dP} + \frac{dR_v}{dP} \left(\frac{B_o - R_s B_g}{1 - R_s R_v} \right) \right\} + \frac{S_o}{B_o} \left\{ \frac{-dB_o}{dP} + \frac{dR_s}{dP} \left(\frac{B_g - R_v B_o}{1 - R_s R_v} \right) \right\} \right] + S_w c_w + C_f \quad 2.30$$

where $C_{t/f/w}$ represent the total/ rock /water compressibilities; $B_{g/o}$, gas/oil formation volume factors; $S_{g/o}$, gas/oil saturations.

The total compressibility of the multiphase flow method uses live oil and wet gas fluid properties as a function of pressure for total compressibility calculation. The live oil and wet gas fluid properties were calculated with Whitson and Torp's method.

2.8 Summary of Chapter 2

1. Well test analysis can be used to obtain well and reservoir properties by representation of the behaviour of actual reservoir with theoretical reservoir model whose input and output are very close to that of the actual reservoir for specific initial and boundary conditions.
2. Gas condensate and volatile oil wells exhibit composite behaviour due to condensate or gas bank formation around the wells when the bottomhole pressure drops below the saturation pressure.
3. Single-phase pseudo-pressure shows composite effect characterized by mobility and storativity change when the bottomhole pressure drops below saturation pressure.
4. The two-phase pseudo-pressure linearizes the well test data of wells flowing below saturation pressure by transforming pressure data under multiphase flow into a single phase flow equivalent.

CHAPTER 3

FLUID CHARACTERISATION AND RELATIVE PERMEABILITY MODELLING

3.1 Fluid Characterisation

Fluid phase behaviour and fluid properties provide necessary information for proper characterisation of reservoir fluids for reservoir simulation. The fluid composition of gas condensate and volatile oil below saturation pressure can vary continuously during production due to pressure depletion. The equilibrium between oil and gas phases can be estimated by thermodynamic flash calculation using an equation-of-state (EOS) or correlations derived empirically from their equilibrium ratios.

An equation-of-state (EOS) is a thermodynamic equation which describes the relationship between pressure, temperature and volume or internal energy of gas or liquid. EOS is extensively used for predicting fluid behaviour in well test interpretation. Several authors (Redlich *et al.* 1944; Zudkevitch *et al.* 1970; Soave 1972; Peng *et al.* 1976; Martin 1979; Peneloux *et al.* 1982, Wang and Pope, 2001) have investigated the use of equations of state for modelling reservoir fluid behaviour.

The Peng-Robinson (1975) equation of state is well-accepted and widely used because it gives very good agreement with laboratory fluid properties (Whitson 1983). In this study, the modified Peng-Robinson equation of state (EOS) with 3 parameters was used for modelling reservoir fluid properties and the viscosity modelling was carried out with Lorentz-Bray-Clark correlation. Peng-Robinson (1975) EOS is given by:

$$P = \frac{RT}{(V-b)} - \frac{a}{V(V+b)+b(V-b)} \quad 3.1$$

where P is the pressure, R the universal gas constant, T is the absolute temperature; V is the molar volume. The parameters a and b are given by Eq. 3.2 and 3.3.

$$a = \Omega_a \frac{R^2 T_c^2}{P_c} \alpha \quad 3.2$$

$$b = \Omega_b \frac{RT_c}{P_c} \quad 3.3$$

$\alpha^{0.5}$ is a linear function of $T_r^{0.5}$ given by Eq. 3.4:

$$\alpha^{0.5} = 1 + m(1 - T_r^{0.5})\Omega_a \quad 3.4$$

Ω_a and Ω_b are constants. The relationship between m and ω (the acentric factor) is given by:

$$m = 0.37464 + 1.54226\omega - 0.26992\omega^2 \quad 3.5$$

These equations are applied to multi-component mixtures with the aid of mixing rules even though they were developed for single component fluids. The parameters a and b are calculated using mixing rules (Eqs. 3.6, 3.7 and 3.8):

$$a = \sum_i \sum_j x_i x_j a_{ij} \quad 3.6$$

$$b = \sum_i x_i b_i \quad 3.7$$

$$a_{ij} = \sqrt{a_i a_j} (1 - k_{ij}) \quad 3.8$$

The subscripts i and j in Eqs. 3.6, 3.7 and 3.8 specify the component numbers and k_{ij} is the binary interaction coefficient (BIC) which accounts for the intermolecular forces between unique components i and j .

Molar volume correction (volume shift) adds a third parameter to the Peng Robinson EOS and gives improved liquid property estimation (Peneloux *et al.* 1982):

$$V_c = V_f^{EOS} - \sum_i z_i c_i \quad 3.9$$

where:

f = represents the phase of the system

V_f^{EOS} = phase molar volume predicted by the traditional 2-parameter Peng Robinson EOS

z_i = liquid and vapour mole compositions

c_i = constitute a set of volume corrections.

It is essential for compositional modelling that the fluid model behaves like the actual reservoir fluid in the applicable pressure range. A fluid properties model should describe accurately the key phase, volumetric, and viscosity dictating key processes affecting rate-time performance (Whitson *et al.* 1999). Accurate compositional fluid modelling influences recovery and can be used to optimize reservoir production, maximize final recovery, optimize production economics and understand phase behaviour. The three fundamental experiments performed on gas-condensate and volatile oil fluids are: the constant volume depletion (CVD) experiment, the constant composition expansion (CCE) experiment, and the Differential Liberation (DL) experiment.

3.1.1 Constant Volume Depletion Test

Constant Volume Depletion (CVD) test is a laboratory experiment performed on gas condensate and volatile oil to simulate reservoir depletion performance and compositional variation when the reservoir pressure drops below saturation pressure. It provides volumetric and compositional data for gas-condensate and volatile-oil reservoirs producing under pressure depletion (Whitson and Brule, 2000; Moses, 1986). CVD experiment on the reservoir fluid starts from dew point pressure and ends at the likely abandonment pressure.

CVD test involves expanding fluid to a new volume and pressure via stepwise reduction of pressure below the saturation point. The volume of gas withdrawn, its composition and single-phase and two-phase z-factor, and the remaining oil volume in the cell are measured and recorded. Accurate measurement of the removed gas composition is very important to the prediction of condensate recovery and liquid yield variation (Whitson *et al.* 1999).

3.1.2 Constant Composition Expansion Test

Constant Composition Experiments (CCE) is used to measure the dew point pressure, oil relative volume below the dew point and single-phase gas z-factors (Whitson and Brule, 2000). CCE measures the pressure-volume relationship of the reservoir fluid at reservoir temperature. The pressure is reduced slowly by increasing cell volume until a liquid phase is visually noticed. Total cell volume and liquid volume are monitored from the initial reservoir pressure down to a low pressure (Whitson *et al.* 1999).

3.1.3 Differential Liberation (DL) Test

In Differential Liberation (DL) test, the pressure is dropped below the bubble point pressure, then after each flash all the solution gas liberated is removed and the liquid composition from the flash becomes a feed for the next pressure depletion before establishing equilibrium with the liquid phase. DL is used to determine oil and gas formation volume factors, gas oil ratio and density of oil and depletion process in oil reservoir (Whitson and Brule, 2000). The liquid is discharged and its density is obtained. The density of the liquid at pressure and temperature stages can be calculated from mass balance knowing the volumes and molecular weight of the removed gas streams.

In order to match the laboratory fluid properties, regression was performed on the molecular weight (MW) of heavy components, critical pressure (P_c), critical temperature (T_c), omega A and B (Ω_A , Ω_B), volume shift, acentric factor of the pseudo-components; and binary interaction coefficient between light and heavy components. Tuning of the plus fraction pseudo-components in the EOS was carried out using nonlinear regression (Coats 1985; Coats *et al.* 1986; Agarwal *et al.* 1990; Liu, 2001; Wang and Pope, 2001) in order to improve the accuracy of prediction. Emphasis was placed on matching the CCE and CVD liquid dropout for the lean and rich gas condensate and gas oil ratio for the DL experiments (Fig. 3.1 and Appendix B).

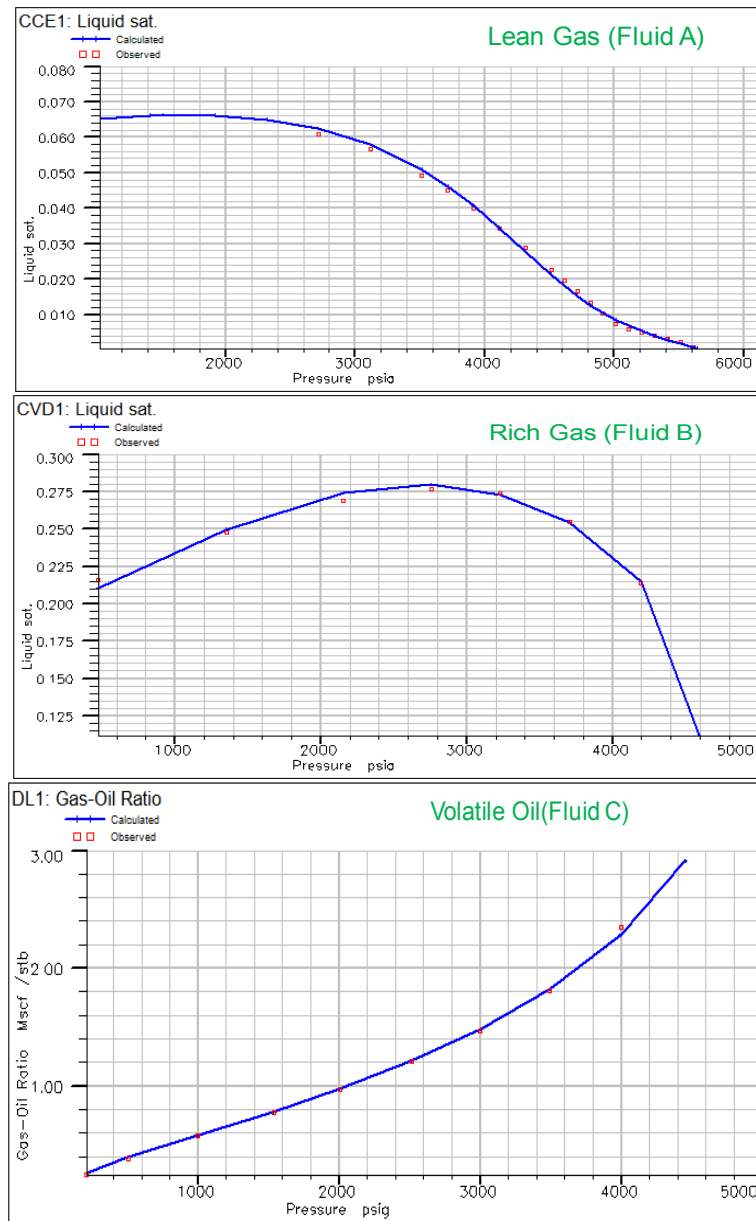


Figure 3.1: Liquid saturation match for lean gas and rich gas as well as GOR match for volatile oil

3.2 Fluid Properties and data

Three different fluids, A (lean gas, Bozorgzadeh and Gringarten 2005), B (rich gas, Aluko 2009) and C (volatile oil, Coats and Smart 1982; Sanni and Gringarten, 2008) were used in the simulation studies. The corrected Peng-Robinson (PR) equation of state (EOS) was used for modelling fluid properties of the reservoir fluids and viscosity modelling was used with the Lorentz-Bray-Clark correlation. The fluid model for fluids A, B and C (listed in section 1.3) were validated against Constant Volume Depletion (CVD), Differential Liberation (DL) and Constant Composition Experiments (CCE) in each of the paper above. Good matches were achieved with 11 components for fluid A, 19 components for fluid B and 9 components for fluid C. The plus fraction pseudo-components in the EOS were tuned using nonlinear regression (Coats and Smart, 1982 and 1985). The characteristics of each fluid are given in Table 3.1.

Table 3.1: Fluid Characteristics

Fluid	A	B	C
Type	Lean Gas	Rich Gas	Volatile Oil
Saturation Pressure	5679 psia at 275° F	4835 psia at 228° F	4474 psia at 176 F
Condensate Gas Ratio CGR (stb/MMscf)	42	237	
Gas Oil Ratio GOR (scf/bbl)			3377

Number of components in Peng-Robinson EOS	11	19	9
CO2	1.65%	0.96%	0.90%
N2	0.57	0.35	0.3
C1	81.35	63.73	53.47
C2	6.86	12.4	11.46
C3	2.8	6.24	8.79
C4	1.49	3.4	4.56
C5	0.77	1.95	2.09
C6	0.54	1.38	1.51
GRP1	2.63		
GRP2	1.16		
GRP3	0.18		
C7 or C7+		1.71	16.92
C8-C11		4.56	
C12-C14		1.26	
C15-C18		0.96	
C19+		1.1	

3.3 Relative Permeability Model

Corey relative permeability correlations (Eq. 3.10 and 3.11) by Liu *et al.*(2001) were used to generate gas/oil relative permeability curves (Fig. 3.2), with a gas relative permeability end point ($k_{rg}^{\max}$) of 1, an oil relative permeability end point ($k_{rog}^{\max}$) of 1, a connate water saturation (S_{wc}) of 40%, gas saturation of 60%, a Corey exponent (λ) of 2.5, a critical gas saturation (S_{gc}) of 5% and a critical condensate (S_{oc}) of 20%.

$$k_{rog} = k_{rog}^{\max} \left(\frac{1 - S_g - S_{oc} - S_{wc}}{1 - S_{oc} - S_{wc}} \right)^{\lambda} \quad 3.10$$

$$k_{rg} = k_{rg}^{\max} \left(\frac{S_g - S_{gc}}{1 - S_{gc} - S_{wc}} \right)^{\lambda} \quad 3.11$$

The water and oil/condensate relative permeability curves (Fig. 3.3) were generated using Eq. 3.12 and 3.13 respectively.

$$k_{ro} = k_{row}^{\max} \left(\frac{1 - S_w - S_{orw}}{1 - S_{orw} - S_{wc}} \right)^2 \quad 3.12$$

$$k_{rw} = k_{rw}^{\max} \left(\frac{S_w - S_{wc}}{1 - S_{wc}} \right)^2 \quad 3.13$$

where S_w is the water saturation, $k_{row}^{\max}$ and $k_{rw}^{\max}$ are end point oil and water relative permeability given by 1 and 0.3 respectively, a connate water saturation (S_{wc}) of 40%, gas saturation of 60%, a Corey exponent (λ) of 2.0 and the residual oil saturation in water S_{orw} of 20%.

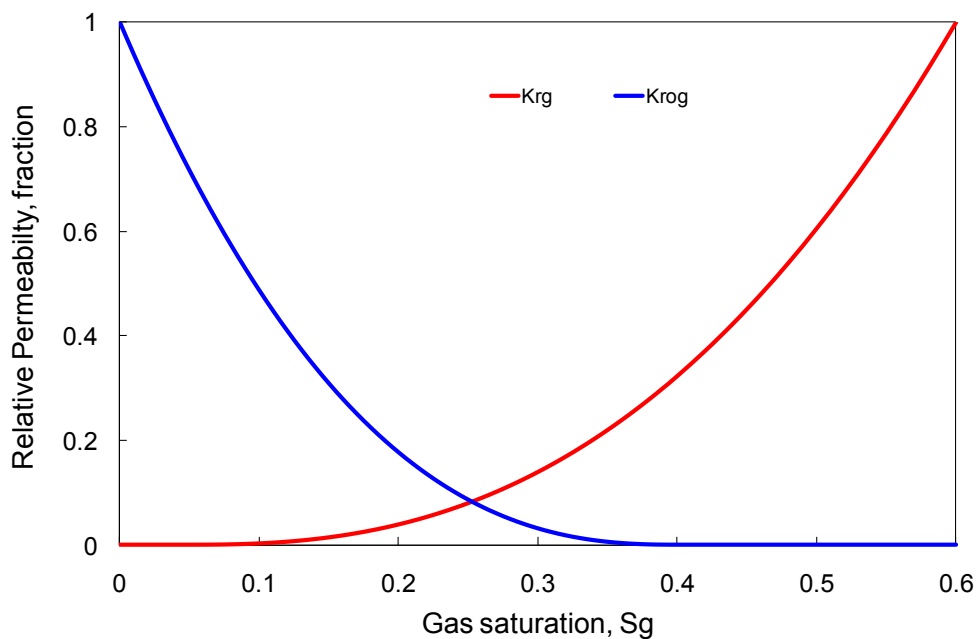


Figure 3.2: Gas-Oil relative permeability curve

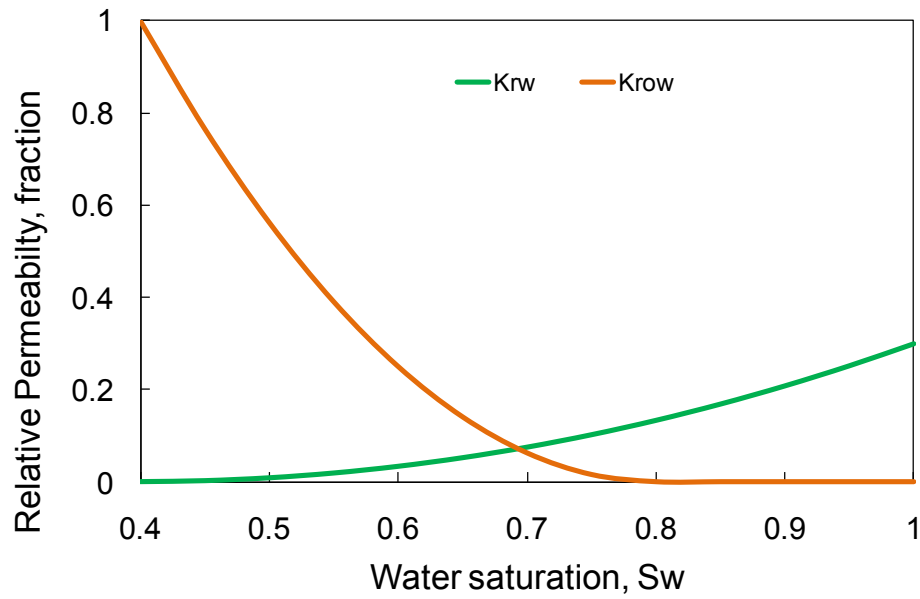


Figure 3.3: Water-Oil relative permeability curve

3.4 Summary of Chapter 3

1. The corrected Peng-Robinson equation of state was used for modelling fluid properties of the reservoir fluids whilst the viscosity modelling was done with Lorentz-Bray-Clark correlation.
2. Three different fluids, A (lean gas), B (rich gas) and C (volatile oil) were used for the simulation studies.
3. Gas/oil relative permeability curves were generated using Corey's relative permeability correlation.

CHAPTER 4

EVALUATION OF RATE-DEPENDENT SKIN FACTORS IN GAS CONDENSATE AND VOLATILE OIL WELLS

This chapter examines wellbore skin factor in lean and rich gas condensate as well as volatile oil wells using pressure, single-phase and two-phase pseudo-pressure.

4.1 Introduction

The pressure drop in a well due to restriction to flow around the wellbore was defined by Van Everdingen and Hurst (1949, 1953) as the skin effect, s . Hawkins (1956) related the skin factor to a zone of changed permeability, k_s , which extends to a distance r_s in the formation (Eq. 4.1).

$$s = \left(\frac{k}{k_s} - 1 \right) \ln \left(\frac{r_s}{r_w} \right) \quad 4.1$$

Multiphase flow causes an additional pressure drop in the wellbore because of reduction of gas or oil relative permeability as a result of fluid induced skin factor. Using simplified assumptions and interpretation models allow the derivation of analytical solutions which reduces the amount of information that can be obtained from well test analysis during multiphase flow. This often yields results that are difficult to relate to reality.

A Cartesian plot of wellbore skin versus rate for dry gas or gas condensate above dew point pressure exhibits a straight line above the saturation pressure (Fig. 4.1). The intercept and slope of the straight line correspond to the mechanical skin and non-Darcy flow coefficient respectively.

Gringarten *et al.* (2000) and (2006) showed that the wellbore skin estimate from single-phase pseudo-pressure could increase, decrease or remain constant below dew point pressure instead of always increasing with gas rate when the pressure is above dew point pressure, as it can be seen in a North Sea gas condensate well in Fig. 4.2.

Additionally, the wellbore skin in rich gas condensate wells was found to increase linearly with increasing rate, but the turbulence factor often changes with time and the corresponding rate-independent skin effect sometimes takes values that are totally unrealistic (-13.4 in Fig. 4.3). This could be due to balance between the positive impact

on productivity of high capillary number effect, the negative impact of inertia or possibly other wellbore conditions different from high capillary number or turbulent factor (Gringarten, 2004c). Hence, the importance of studying the impact of high capillary number and non-Darcy factor on the calculation of wellbore skin.

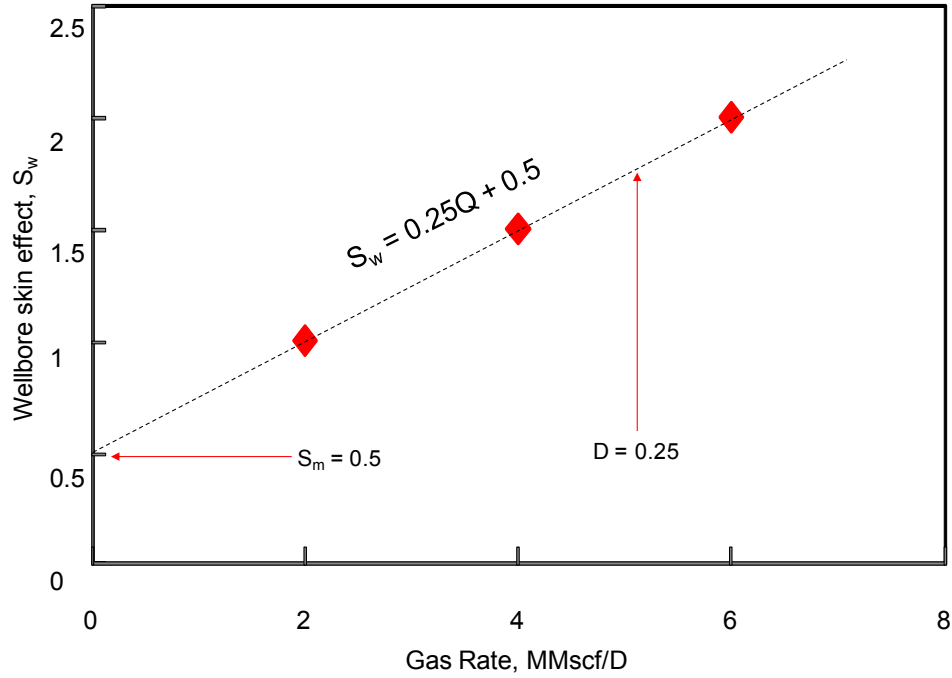


Figure 4.1: Non-Darcy effect in the near-wellbore region

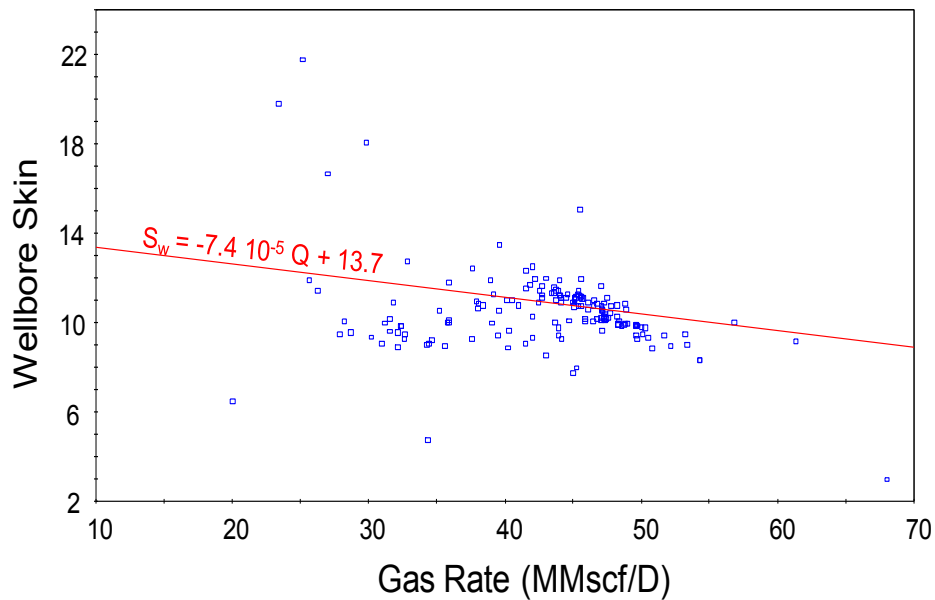


Figure 4.2: Wellbore skin vs. rate for a lean gas well (North Sea)

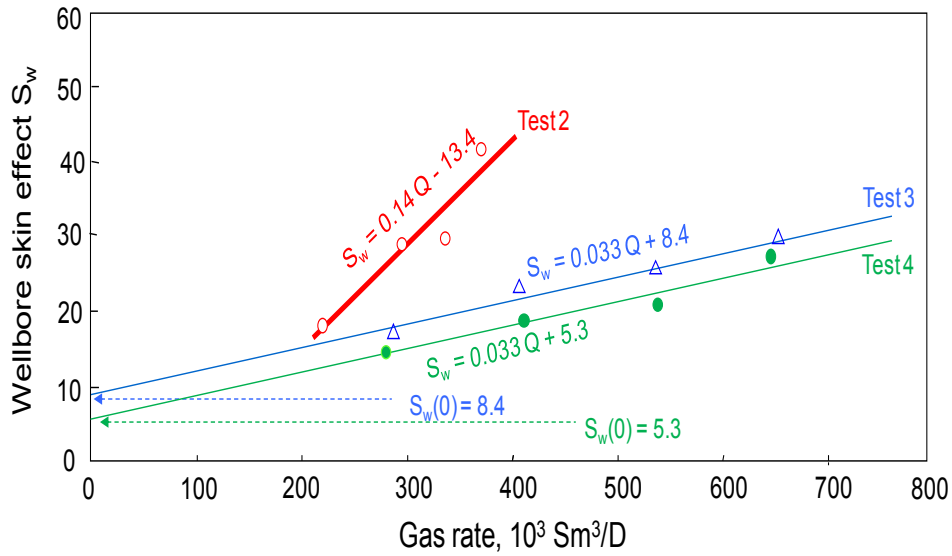


Figure 4.3: Wellbore skin versus gas rate for a North African rich gas condensate well

The wellbore skin versus rate relationship is not linear below saturation pressure because the non-Darcy flow coefficient ($D_{2\phi}$) for two-phase system (Eq. 4.2) is inversely proportional to the effective permeability (Gewers and Nichols, 1969; Wong, 1970):

$$D_{2\phi} = \frac{\text{constant}}{\left(\frac{k_a}{k_{rg}} \right)^\alpha} \quad 4.2$$

where α is a constant, k_a and k_{rg} are absolute and relative permeability respectively.

The non-Darcy flow coefficient for two-phase system and the corresponding skin depend on the near-wellbore condensate saturation, which depends on the rate history as well as the capillary number parameters. Since the turbulence factor increases rapidly as liquid saturation increases and gas relative permeability decreases (Ali *et al.* 1997), non-Darcy flow is expected to be more pronounced in gas condensate reservoirs than in dry gas reservoirs (Blom and Hagoort, 1998). Hence, the mechanical skin cannot be predicted below dew point pressure with the single-phase turbulence factor.

Experimental study by Lombard *et al.* (1999) to investigate the impact of condensate accumulation on turbulence factor showed significant increase of turbulence factor below the dew point pressure for lean gas and rich gas (Figs. 4.4 and 4.5). However, a consistent and a linear correlation could not be obtained for lean gas (Fig. 4.4). The turbulence factor is represented in Fig. 4.4 by the Forchheimer parameter β (Forchheimer, 1901) calculated using the square of the pressure, which is a simplified form of the single-phase pseudo-pressure below 2000 psi. These experimental findings are in agreement with the results of this study.

The relationship between the turbulence factor D and β is given by Eq. 4.3 (Ramey, 1965):

$$D = \frac{2.715 \times 10^{-15} \beta M P_{sc} k}{\mu h r_w T_{sc}} \quad 4.3$$

where M is the molecular weight of gas in lb/lb-mole; k , the effective permeability in mD; μ , the viscosity in cp; h , the net formation thickness in ft; r_w , the well radius in ft; P_{sc} (in psia) and T_{sc} (in °R), the base pressure and temperature, respectively, for standard gas volume measurement.

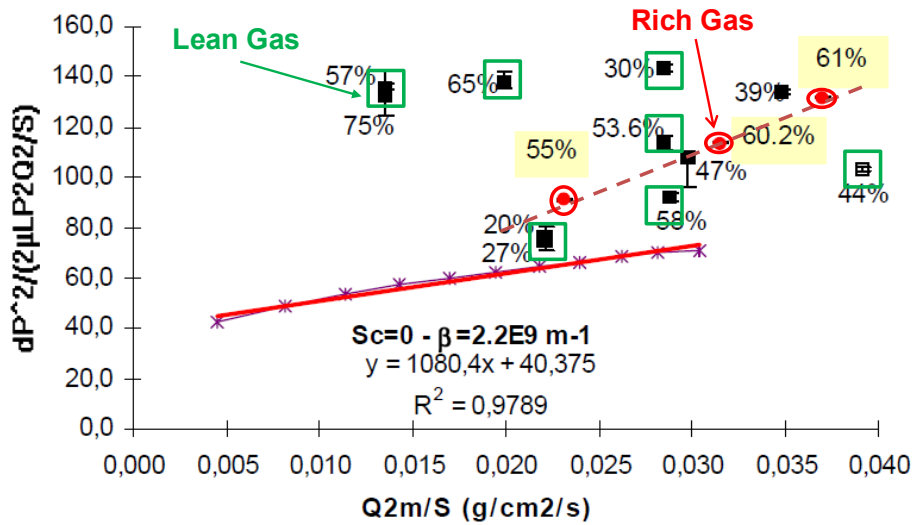


Figure 4.4: Experimental determination of Forchheimer parameter (Lombard *et al.* 1999)

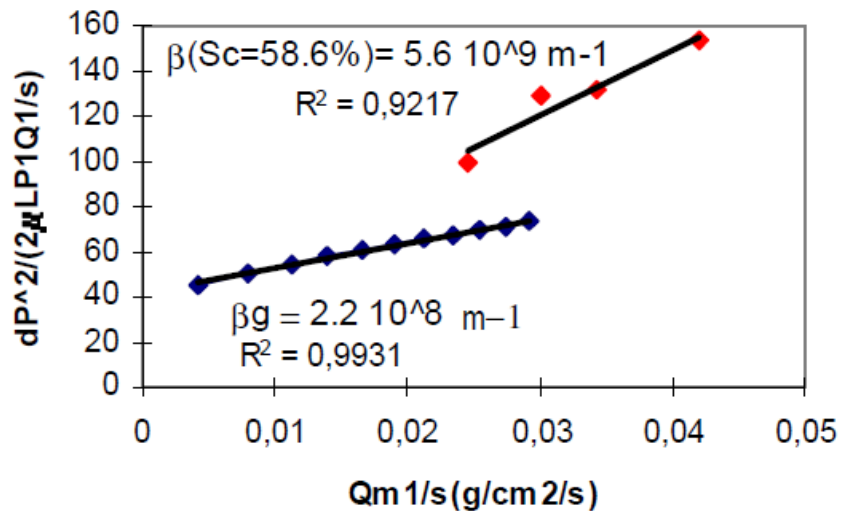


Figure 4.5: Forchheimer parameter above and below dew point pressure (Lombard *et al.* 1999)

Several studies have been done on the calculation and the meaning of the skin effect in gas condensate wells when the bottomhole pressure falls below the dew point pressure.

Saleh and Stewart (1992) analysed field data using single-phase and two-phase pseudo-pressure with pseudo time (Agarwal, 1979) but without high capillary number and non-Darcy effects on the relative permeability curves to obtain the absolute permeability, k , and total skin that includes rate independent skin and the non-Darcy skin. Single-phase pseudo-pressure yielded a two-region composite behaviour with a total skin factor that incorporates mechanical skin and fluid induced skin. The fluid induced skin factor was estimated as a difference of total skin factors of single-phase and two-phase pseudo pressure but the results were not confirmed with numerical simulation.

Thompson and Reynolds (1993) derived a theoretical equation for calculating total skin factor (wellbore and two-phase skin) and determined the effective gas permeability in the liquid drop out zone from drawdown and build-up semi-log analysis based on single-phase real gas pseudo pressure. They showed that skin due to the multiphase flow could be determined by combining drawdown and build-up analyses.

Xu and Lee (1999) used the two-phase, three-region pseudo-pressure formulation developed by Fevang and Whitson (1996) for gas condensate well test analysis and concluded that it provided more accurate, although slightly overestimated, skin values.

Raghavan *et al.* 1999 concluded that the skin factor increases with rate if the single-phase analog is used and decrease with rate when the two-phase analog is used. The increase in skin factor for single-phase analog reflects the increase in liquid accumulation that takes place as a result of an increasing rate and may not simply be attributed to non-Darcy flow. Barrios *et al.* 2003 estimated both absolute permeability and mechanical skin factor using two-phase pseudo-pressure but concluded that two-phase pseudo-pressure skin estimate has an error of two units. However, the two-phase pseudo-pressure estimate from Raghavan *et al.* (1999) and Barrios *et al.* (2003) was performed with single-phase compressibility factor, without high capillary number and non-Darcy effects on the relative permeability curves.

Shandrygin and Rudenko (2005) proposed a procedure for estimating the skin due to the condensate bank in gas-condensate wells by using a simple numerical model. Their method was based on a single-phase pseudo-pressure approach which gives composite behaviour below dew point pressure.

None of the studies above did significant work on skin versus rate relationship in volatile oil reservoirs or accounted for the impact of non-Darcy effect and high capillary number on relative permeability used for two-phase pseudo-pressure calculation.

This chapter is an excerpt from SPE paper 143592 and contributions from this thesis include: compositional simulation, rate dependent skin estimation of simulated and field data of various rate histories, as well as history matching of field data.

4.2 Compositional Simulation

The reservoir simulations and fluid modelling were performed using a commercial compositional simulator (Eclipse 300 and PVTi from Schlumberger) to generate synthetic well test data for lean gas, rich gas and volatile oil wells (see Appendix C for sample Eclipse code). The wellbore skin was calculated by matching the pressure (for volatile oil), normalised single-phase pseudo pressure (Eq. 2.9, for gas condensate) and two-phase pseudo-pressure (calculated with procedure in section 2.4) with type curves using well test analysis software (Interpret, from Paradigm).

4.2.1 Simulation Model

A one dimensional radial geometry simulation model was constructed with vertical well located at the centre of the reservoir (Fig. 4.6). The block length increases logarithmically in radial direction, with smaller grids placed closed to the wellbore and larger grids further away from the well. Noise due to numerical precision of the simulator was minimised by taking very small time steps during the simulation. The fluid properties (for fluids A, B and C) and relative permeability used for this study are specified in section 3.2 and 3.3 respectively. All runs were made with capillary number and non-Darcy models provided by the flow simulator. Basic reservoir data are shown in Table 4.1.

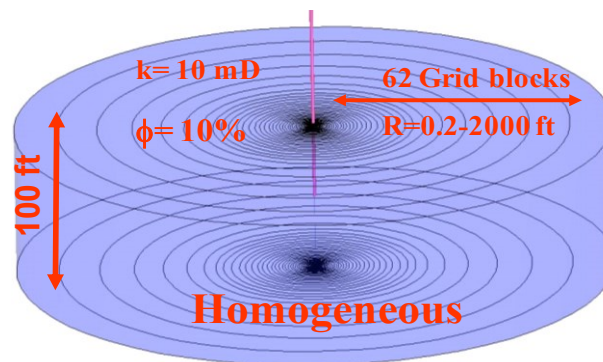


Figure 4.6: Single well compositional simulation model

Table 4.1: Parameters for simulation

Parameter	Value
Formation Thickness (ft)	100
Average Porosity (%)	10
Absolute Permeability (mD)	10
Mechanical (rate-independent) skin effect	0
Net-to-Gross Ratio, N/G	1
Connate Water saturation (%)	40
Well Radius (ft)	0.25
Water Compressibility (1/psi)	3.00E-6
Rock Compressibility (1/psi)	4.00E-6

4.3 Compositional Simulation Results for Lean Gas Condensate

4.3.1 Single-phase pseudo-pressure analysis

4.3.1.1 Random Rate History

Fig. 4.7 presents the pressure and random rate history for lean gas. It has 18 flow periods, with one day duration for each drawdown (DD) alternating with build-up (BU). The flowing pressure during the first three drawdowns is above the dew point pressure, whilst it dropped below dew point pressure for all subsequent drawdowns. The pressure at the end of all the build-ups is above the dew point pressure as there is no depletion in the reservoir. The single-phase pseudo-pressure rate-normalized log-log plot, corresponding condensate profile and turbulence factor at the wellbore are shown in Figs. 4.8, 4.9 and 4.10 respectively.

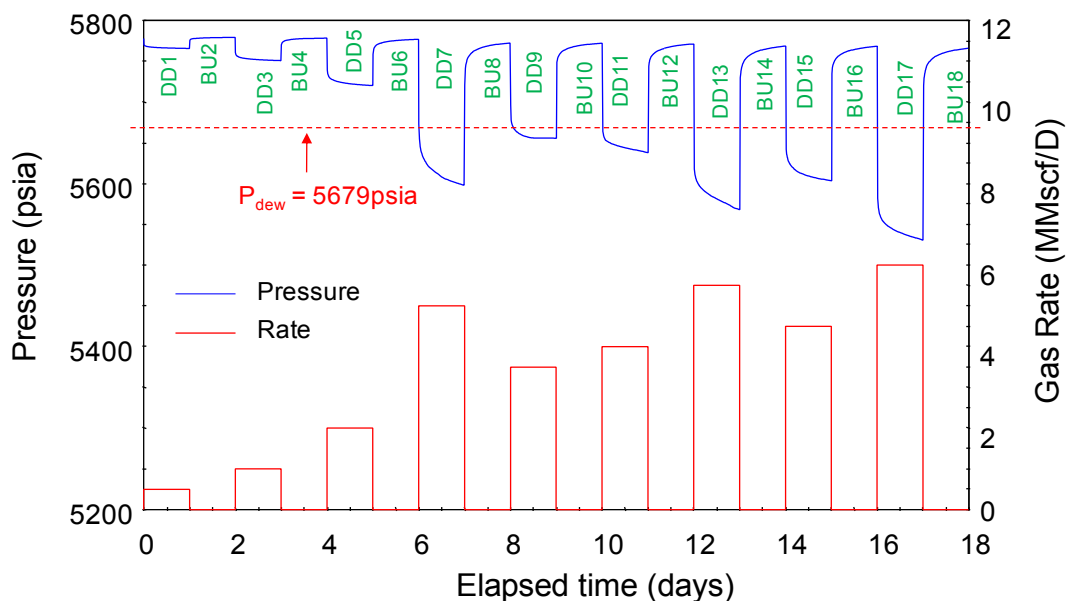


Figure 4.7: Pressure and random rate history for lean gas

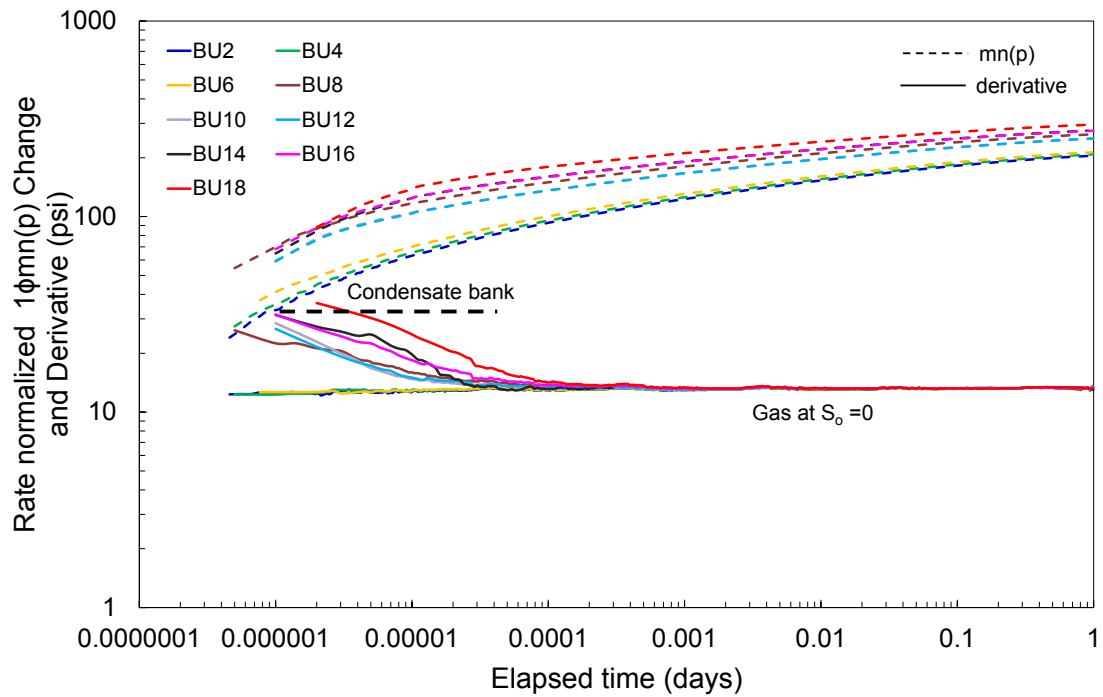


Figure 4.8: Rate-normalized 1ϕ PP log-log plot for lean gas (random rate history)

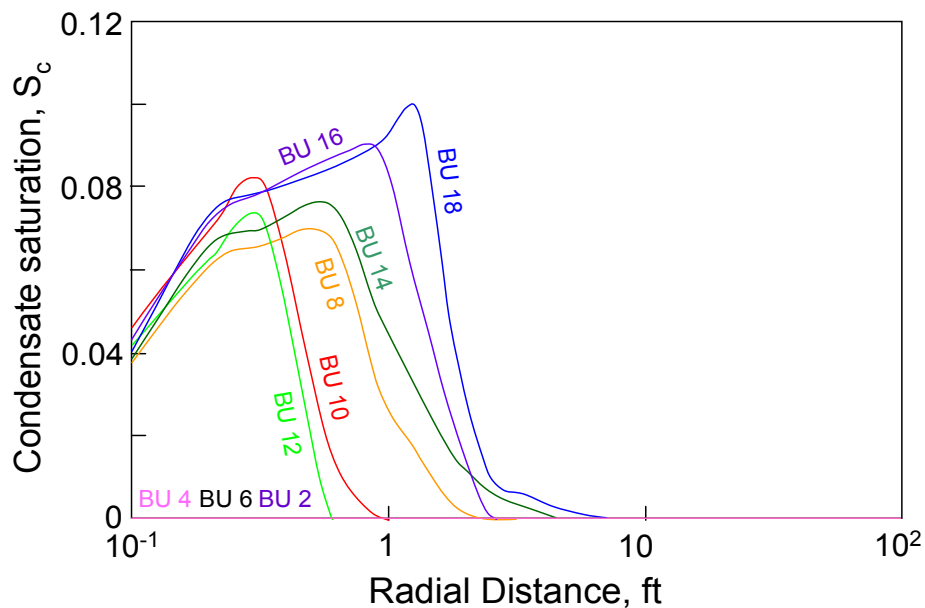


Figure 4.9: Condensate saturation profiles for lean gas (random rate history)

Above the dew point pressure, build-up data (BU2, BU4, BU6) exhibit a homogeneous behaviour as there is no condensate dropout. The corresponding wellbore skin effect versus rate relationship in the left hand side (LHS) of Fig. 4.11 is linear, as expected of dry gas. The rate-independent (mechanical) skin (0.11) and the turbulence factor (0.095 D/MMscf) are consistent with value from the simulator (0 and 0.095 D/MMscf respectively).

Below the dew point pressure (BU 8 and later), the derivatives in Fig. 4.8 exhibit a radial composite behaviour due to the development of the condensate bank (Fig. 4.9) and the total skin increases with increasing rate, as evidenced by the upward shift of the pressure curves (Fig. 4.8) and an increase in the turbulence factor at the wellbore (Fig. 4.10).

Fig. 4.10 shows that of the turbulence factor for lean gas condensate reservoir above dew point pressure does not change with rate but increases dramatically below dew point pressure as the condensate saturation at the wellbore changes with gas rate. The behaviour of the turbulence factor for lean gas condensate reservoir below dew point pressure is highly dependent on rate history. It is very unpredictable when rate increases or decreases because the condensate bank from preceding drawdown before a build-up did not fully re-vaporised in the build-up for lean gas (Kgogo and Gringarten, 2010).

Similar to Fig. 4.4 (Lombard *et al.* 1999), the right hand side (RHS) of Fig. 4.11 does not show a linear relationship, and suggests that wellbore skin values are function of the rate history. The wellbore skins provided in Table 4.2 were calculated with well test analysis software by matching the build-up of single-phase pseudo-pressure with multirate type curve.

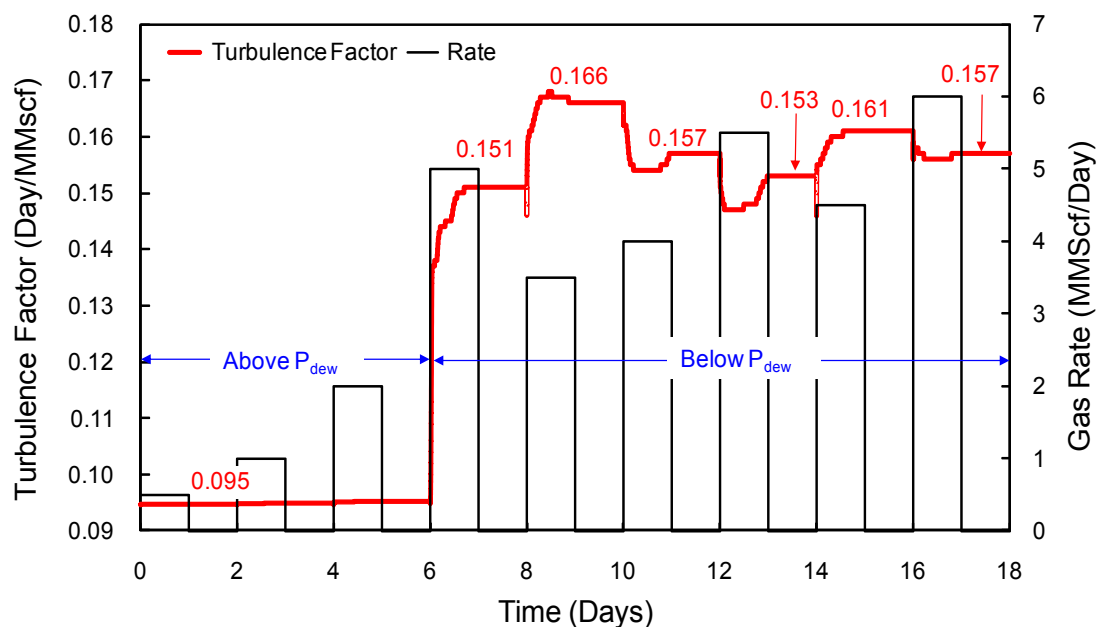


Figure 4.10: Simulated Turbulence Factor vs. Time and Rate for Lean Gas (random rate)

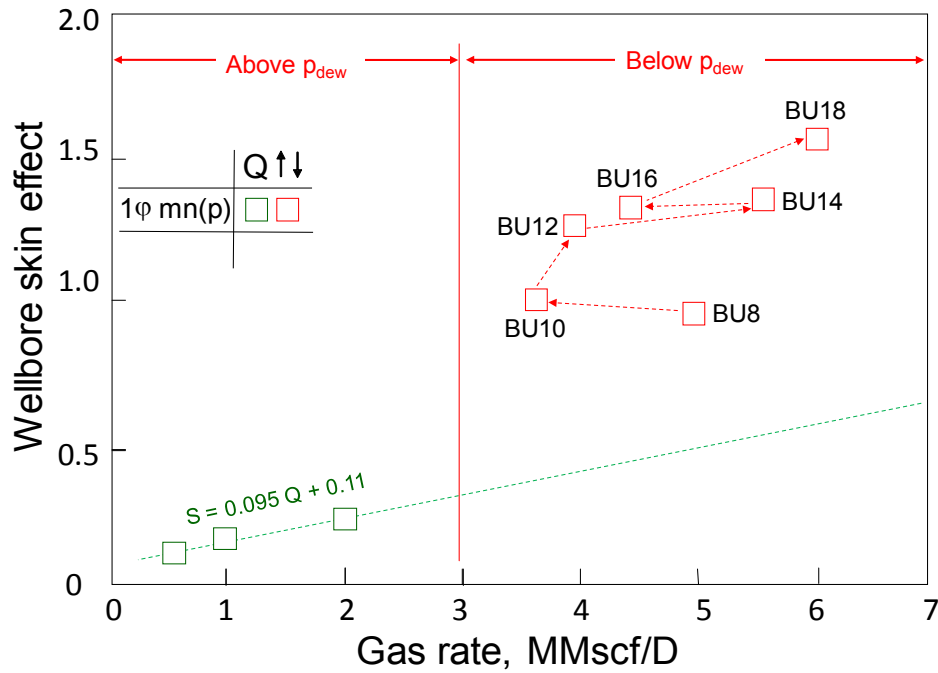


Figure 4.11: Wellbore skin vs. random rate history for lean gas (1 ϕ PP) ($s_m=0$)

Table 4.2: Interpretation results for the data from Fig. 4.7 (1 ϕ PP)

Q, LG MMscf/D	Skin
0.5	0.16
1.0	0.20
2.0	0.30
5.0	0.98
3.5	1.00
4.0	1.25
5.5	1.35
4.5	1.32
6.0	1.60

4.3.1.2 Increasing and Decreasing Rate History

The simulation runs with increasing and decreasing rate sequence (Figs. 4.12 and 4.13) were carried out to examine the impact of rate history on skin versus rate relationship for lean gas condensate below dew point pressure. Figs. 4.12 and 4.13 have 16 flow periods with 1-day duration for each drawdown (DD) and build-up (BU). The flowing pressure during the first four drawdowns for increasing rate history is above the dew point pressure, whilst during all successive drawdown, it is below dew point pressure. However, the pressure of first four drawdown dropped below the dew point pressure while the last four are above dew point pressure for decreasing rate history. The wellbore skins (Table 4.3) were calculated by matching the build-up data from single-phase pseudo-pressure with multirate type curve.

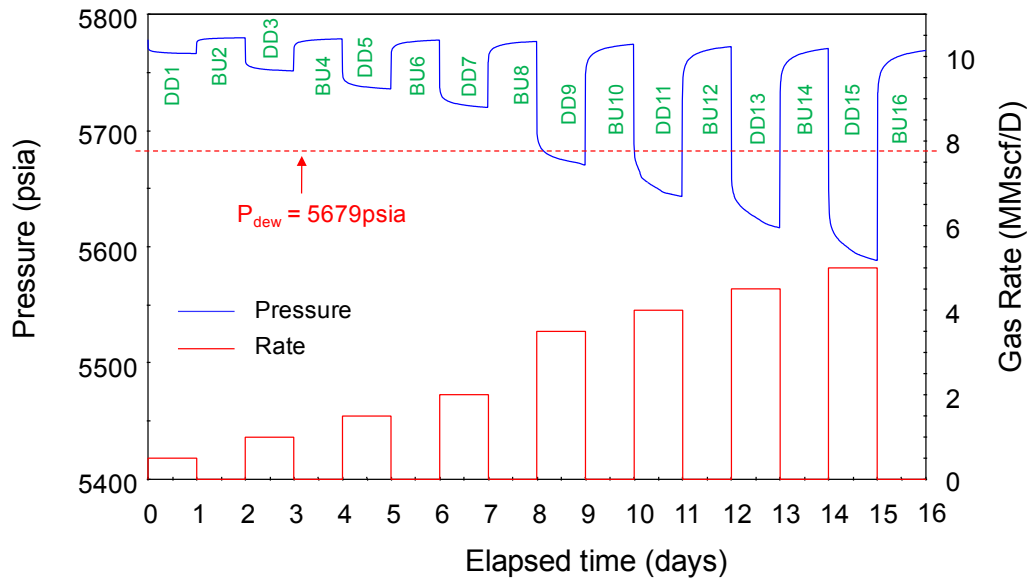


Figure 4.12: Pressure and increasing rate history for lean gas

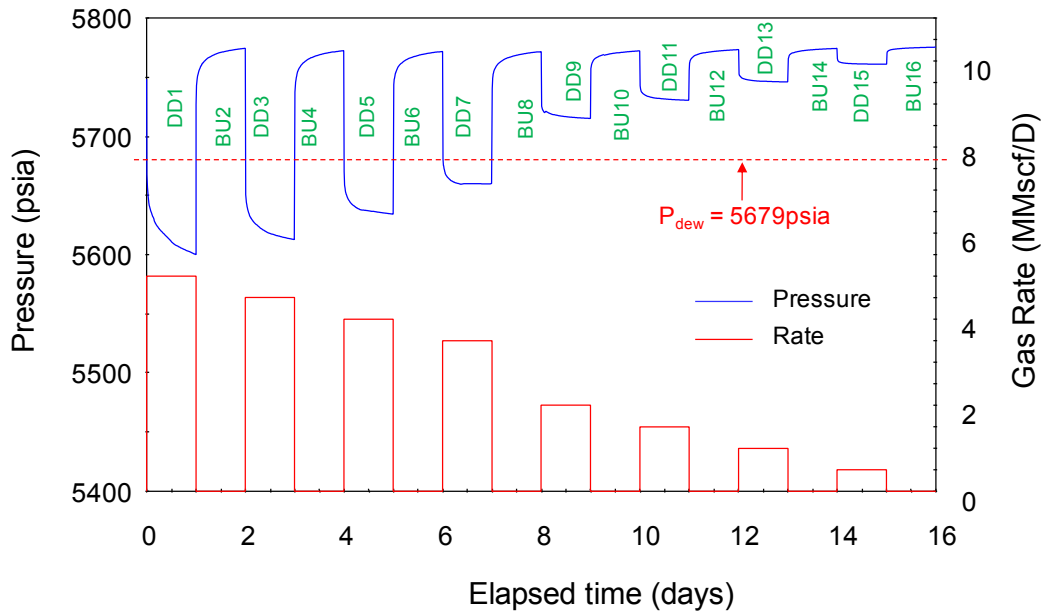


Figure 4.13: Pressure and decreasing rate history for lean gas

The single-phase pseudo-pressure rate-normalized log-log plot for increasing and decreasing rate histories (Figs. 4.14 and 4.15), the corresponding condensate profiles (Figs. 4.16 and 4.17) and turbulence factor (Figs. 4.18 and 4.19) show the evidence of composite effect due to condensate dropout at the wellbore. The derivatives (Fig. 4.14 and 4.15) exhibit a radial composite behaviour and an upward shift of the pressure curves due to the development of the condensate bank below the dew point pressure for increasing rate history (BU10, BU12, BU14, BU16) and decreasing rate history (BU2, BU4, BU6, BU8). The wellbore skin versus rate for increasing rate history (Fig. 4.12) and decreasing rate history (Fig. 4.13) is shown in Fig 4.20.

The condensate saturation (Figs. 4.16 and 4.17) and turbulence factor (Figs. 4.18 and 4.19) below dew point pressure increases with increasing and decreasing rate histories because the condensate drop out from preceding drawdown before a build-up for lean gas did not totally re-vaporised in the build-up (Kgogo and Gringarten, 2010). Hence, the rate dependent skin for decreasing rate history increases with decreasing rate (Figs. 4.17, 4.19 and 4.20).

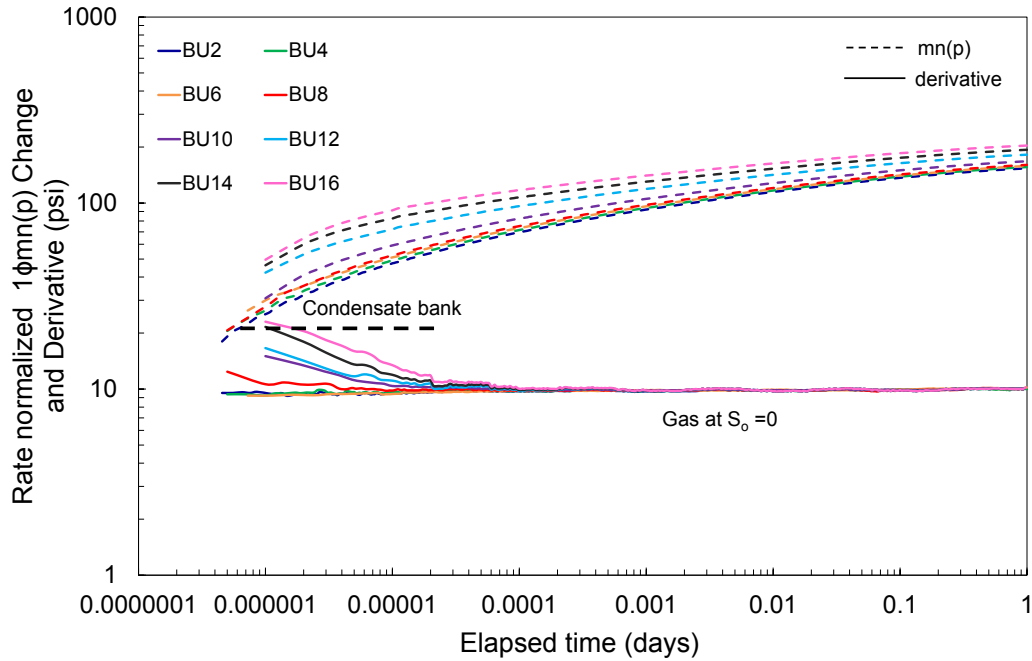


Figure 4.14: Rate-normalized $1\phi PP$ log-log plot for lean gas (increasing rate history)

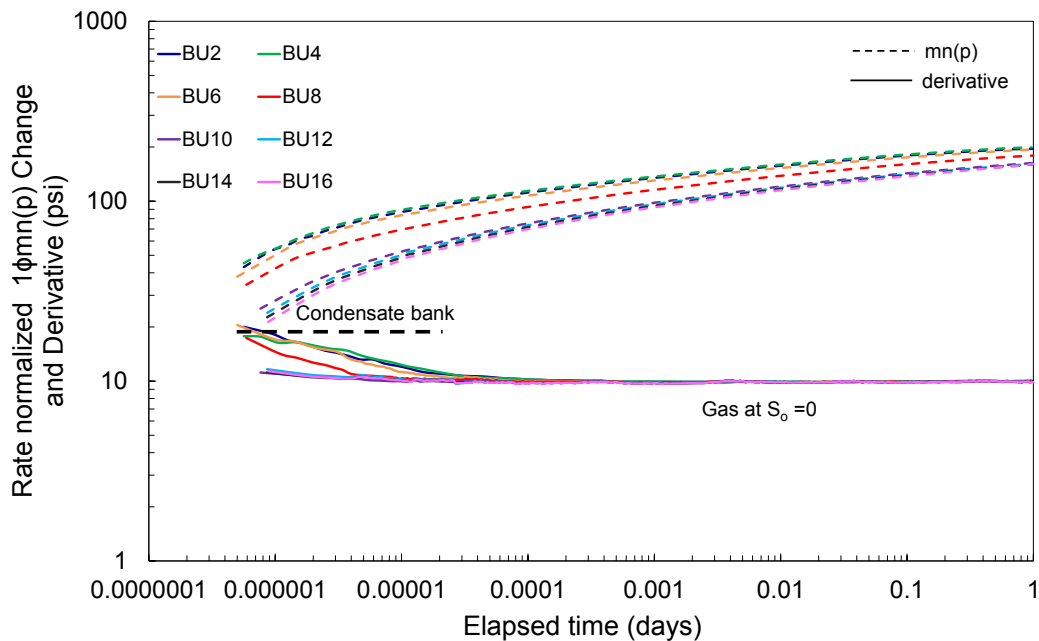


Figure 4.15: Rate-normalized $1\phi PP$ log-log plot for lean gas (decreasing rate history)

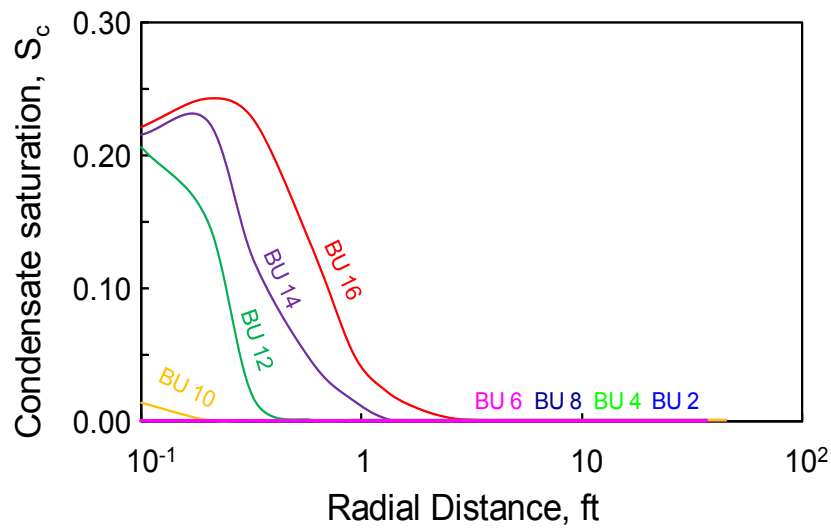


Figure 4.16: Condensate saturation profiles for lean gas (increasing rate history)

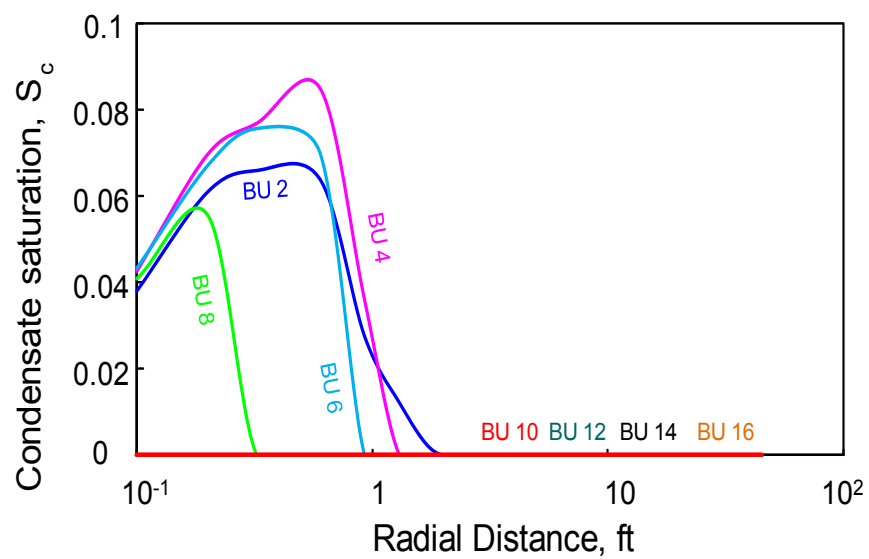


Figure 4.17: Condensate saturation profiles for lean gas (decreasing rate history)

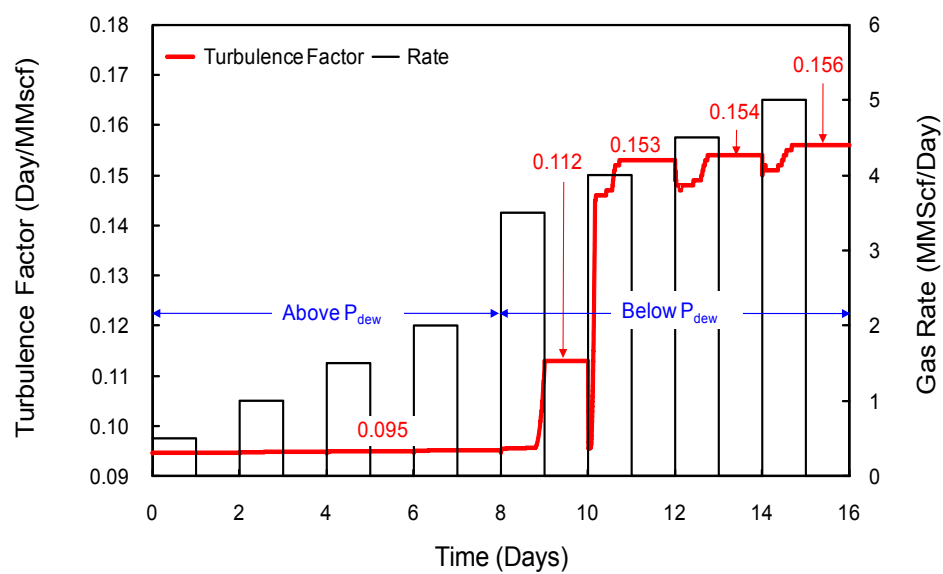


Figure 4.18: Simulated Turbulence Factor vs. Time and Rate for Lean Gas (Increasing rate)

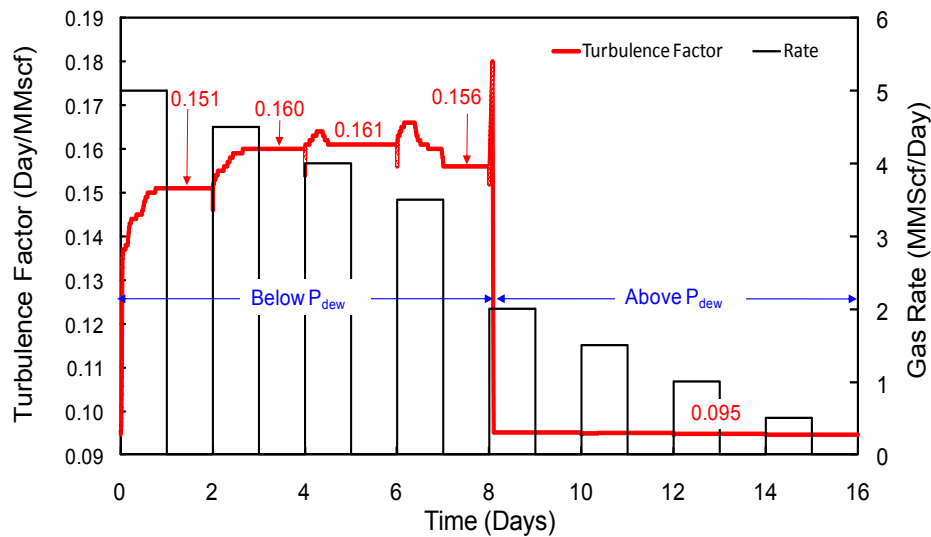


Figure 4.19: Simulated Turbulence Factor vs. Time and Rate for Lean Gas (Decreasing rates)

The build-up data (BU2, BU4, BU6, BU8) for increasing rate history and decreasing rate history, (BU10, BU12, BU14, BU16) exhibit a homogeneous behaviour above the dew point pressure. The corresponding wellbore skin vs. rate relationship in the left hand side (LHS) of Fig. 4.20 is linear, comparable to dry gas behaviour. The mechanical skin (0.1) and turbulence factor (0.095 D/MMscf) are similar to the values from the simulator (0 and 0.095 D/MMscf respectively).

Below dew point pressure, the mechanical skin increases when the rate increases or decreases (Fig. 4.20 and Table 4.3). Decreasing rates yield a negative turbulence factor (-0.2 D/MMscf), and a mechanical skin of +1.8. Both values are difficult to justify because they are inconsistent with the values above dew point pressure from the simulator (0 and 0.095 D/MMscf respectively). The values provided in Table 4.2 were calculated with well test analysis software by matching the build-up of single-phase pseudo-pressure with multirate type curve.

Table 4.3: Interpretation results for the data from Figs. 4.12 and 4.13 (1 ϕ PP)

Q, LG MMscf/d	Wellbore Skin	
	↑ Q	↓ Q
0.5	0.16	0.16
1.0	0.20	0.20
1.5	0.25	0.25
2.0	0.3	0.30
3.5	0.93	1.23
4.0	1.03	1.20
4.5	1.06	1.10
5.0	1.15	1.00

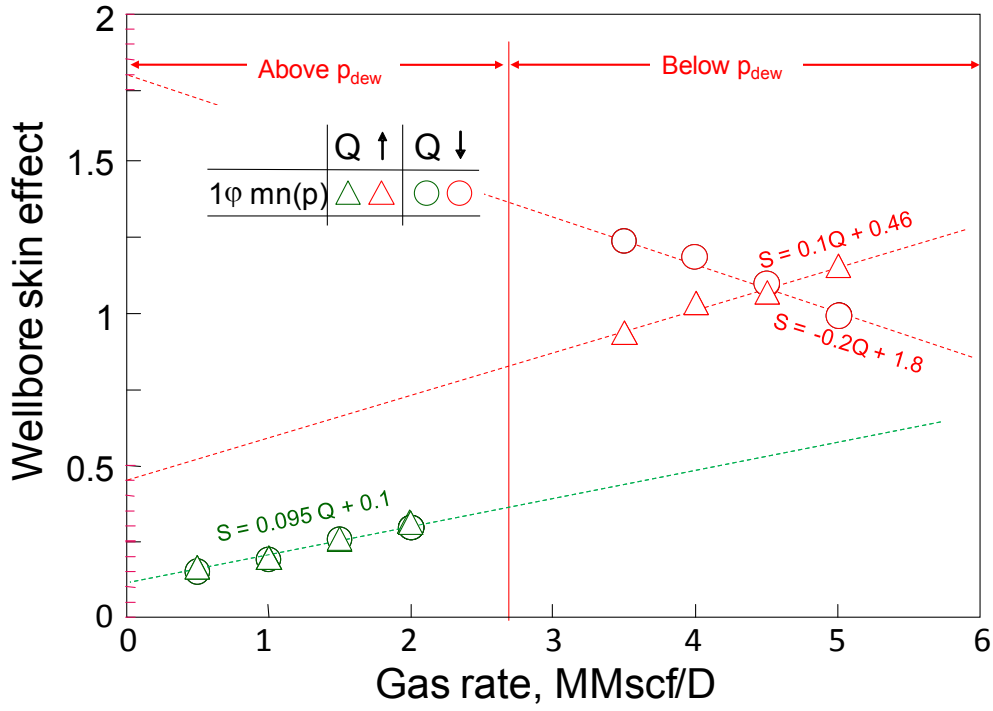


Figure 4.20: Wellbore skin vs. increasing and decreasing rate history for lean gas (1φPP) (sm=0)

4.3.2 Two-phase pseudo-pressure analysis

Two-phase pseudo-pressure (Figs. 4.21, 4.22 and 4.23) was calculated with relative permeability curves which integrate high capillary number and non-Darcy effects using procedure in section 2.4. Figs. 4.24 and 4.25 show wellbore skin versus rate relationships from single-phase (Figs. 4.11 and 4.20) and two-phase pseudo-pressure analyses, for pressure and rate histories in Figs. 4.7, 4.12 and 4.13. The two-phase pseudo-pressure for lean gas was calculated using the relative permeability curve in Fig. 3.2.

The two-phase pseudo-pressure corrected the composite behaviour from single-phase pseudo-pressure and yielded a final derivative stabilization that corresponds to the absolute permeability at $k_{rg} = k_{rg}^{\max}$ (Figs. 4.21, 4.22 and 4.23).

The plot of wellbore skin versus rate for two-phase pseudo-pressure analyses in the right hand side (RHS) of Figs. 4.24 and 4.25 show a linear relationship. The mechanical skin and turbulence factor obtained with two-phase pseudo-pressure calculated with relative permeability which incorporates the non-Darcy effect and high capillary number are similar to the values obtained above the dew point pressure from single-phase pseudo-pressure analysis.

The negative slope of wellbore skin versus rate relationship for decreasing rate history (Fig. 4.20) was corrected by two-phase pseudo-pressure (Fig. 4.25) because it accounts

for the oil saturation due to the condensate bank by integrating the influence of multiphase flow (i.e. gas and condensate saturation) at the wellbore into the analysis. Thus, high capillary number does not overcompensate for non-Darcy effect due to the very high production rates. The estimated values of wellbore skin and rate are provided in Tables 4.4 and 4.5. The two-phase pseudo-pressure skin values in Tables 4.4 and 4.5 were calculated by matching the build-up data from the two-phase pseudo-pressure analysis with multirate type curve in well test analysis software.

The sensitivity on the fluid properties and relative permeability parameters (Corey exponent (λ), k_{rg}^{max} , k_{ro}^{max}) used for the two-phase pseudo-pressure skin estimate for lean gas (Fig. 4.59) is discussed in section 4.6.

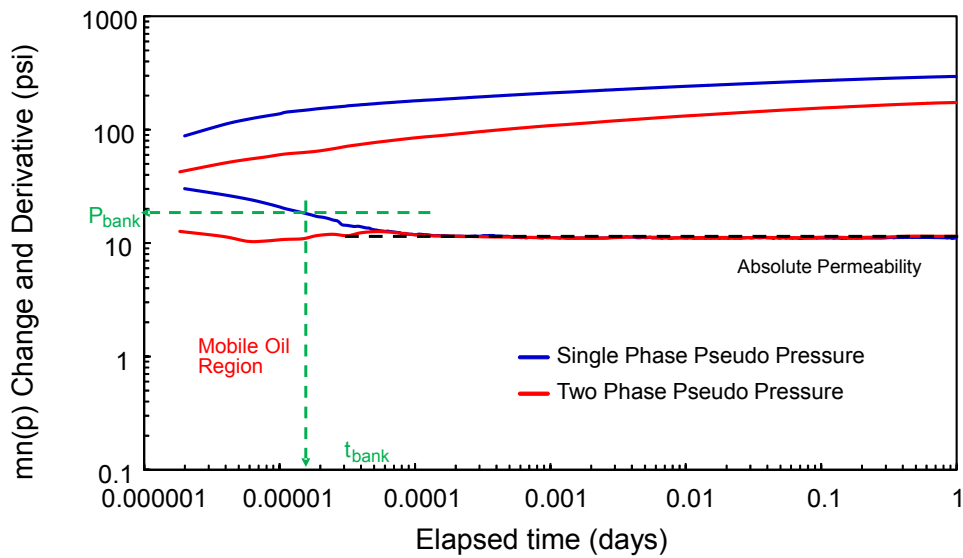


Figure 4.21: 1 ϕ PP and 2 ϕ PP log-log plot for lean gas (BU18) (random rate history at $k_{rg}^{max}=1$)

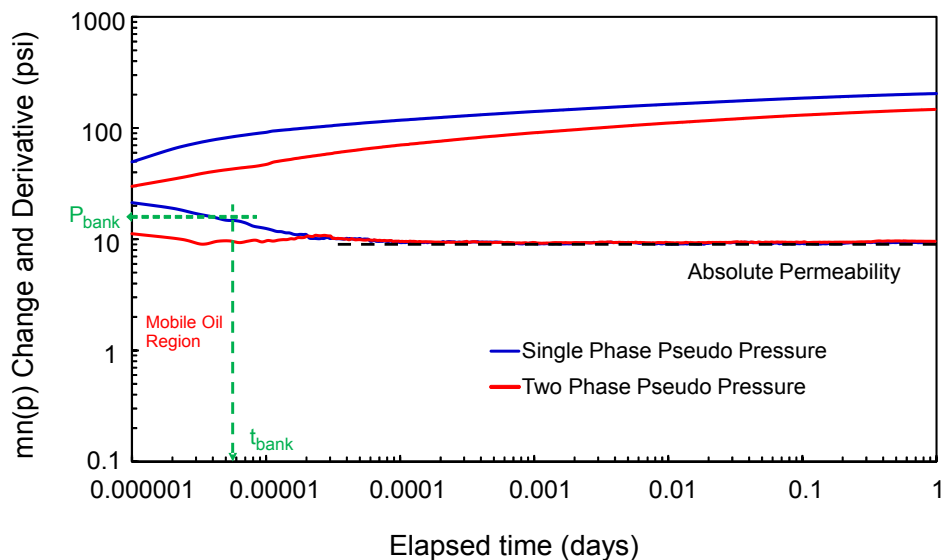


Figure 4.22: 1 ϕ PP and 2 ϕ PP log-log plot for lean gas (BU16) (increasing rate history at $k_{rg}^{max}=1$)

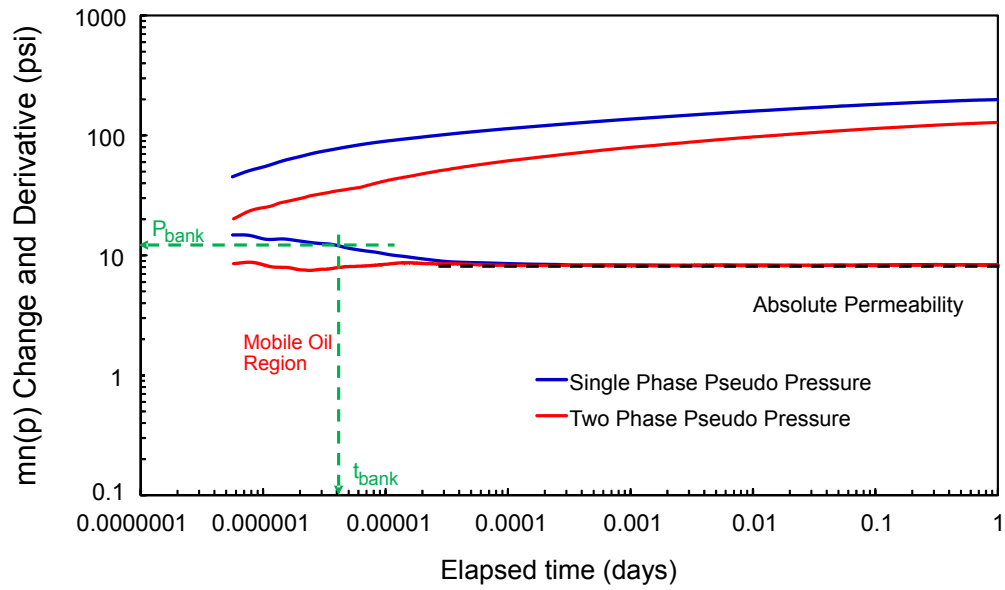


Figure 4.23: 1 ϕ PP and 2 ϕ PP log-log plot for lean gas(BU4) (decreasing rate history at $k_{rg}^{max}=1$)

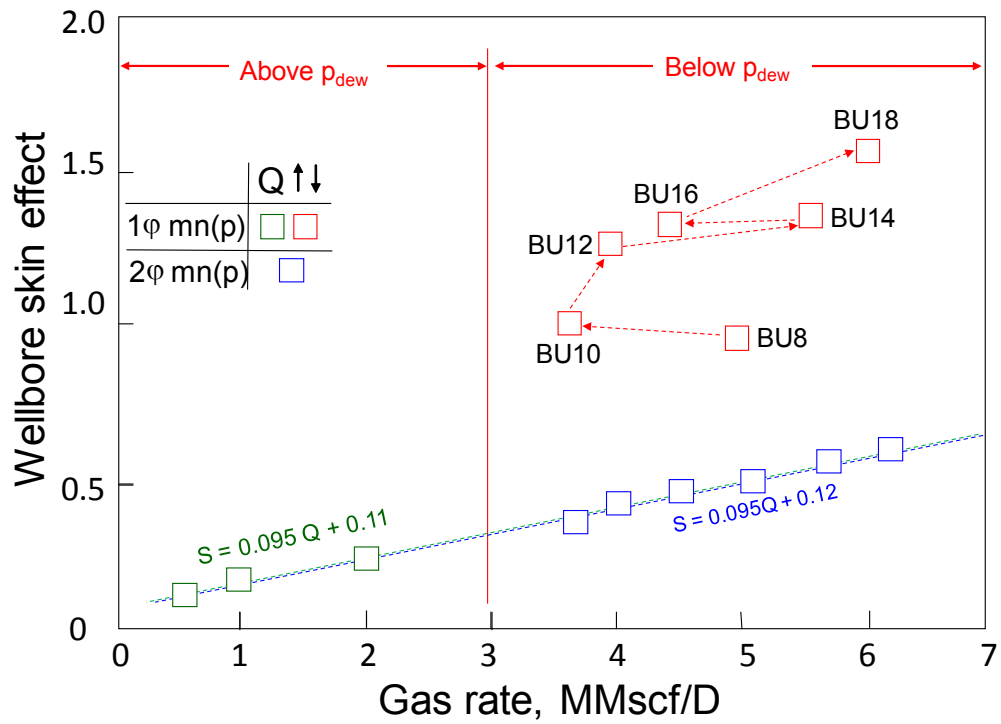


Figure 4.24: Wellbore skin vs. random rate for lean gas (2 ϕ $m_n(p)$) ($s_m=0$)

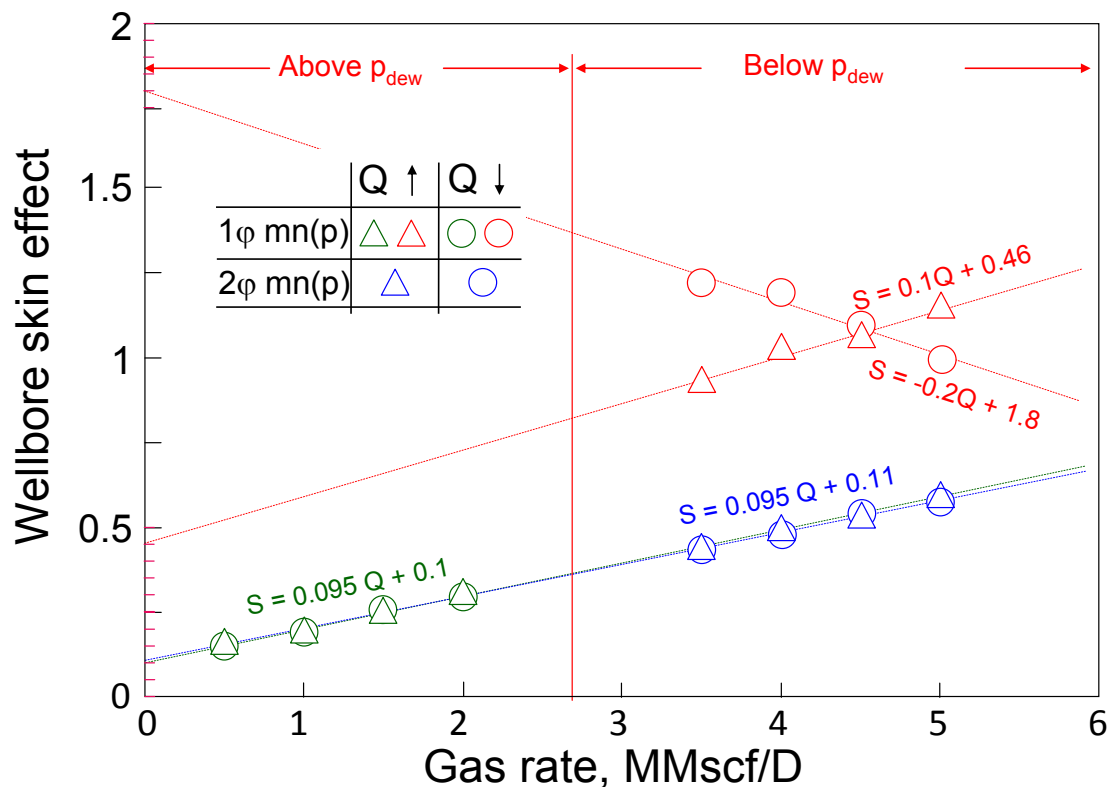


Figure 4.25: Wellbore skin vs. increasing and decreasing rate for lean gas ($2\phi m_n(p)$) ($s_m=0$)

Table 4.4: Interpretation results for the data from Fig. 4.7 ($2\phi m_n(p)$)

Q, LG MMscf/d	Skin 1Ø PP	Skin 2Ø PP
5.0	0.98	0.60
3.5	1.00	0.45
4.0	1.25	0.50
5.5	1.35	0.64
4.5	1.32	0.55
6.0	1.60	0.69

Table 4.5: Interpretation results for the data from Figs. 4.12 and 4.13 ($2\phi m_n(p)$)

Q, LG	Skin Q ↑	Skin Q ↓	Skin Q ↑	Skin Q ↓
MMscf/d	1φPP	1φPP	2φPP	2φPP
3.5	0.93	1.23	0.43	0.43
4.0	1.03	1.20	0.48	0.48
4.5	1.06	1.10	0.53	0.55
5.0	1.15	1.00	0.59	0.58

4.3.3 Summary of Single-phase and Two-phase pseudo-pressure analysis for lean gas condensate

1. Above dew point pressure, single-phase pseudo-pressure derivatives exhibit homogeneous behaviour as there is no condensate drop out. The corresponding wellbore skin versus rate relationship is linear, as expected of dry gas.
2. Below dew point pressure, single-phase pseudo-pressure derivatives show radial composite effect due to the development of the condensate bank at the wellbore and the total skin increases with increasing and decreasing rate history. The wellbore skin versus rate estimate from the single-phase pseudo-pressure show a negative slope for decreasing rate history.
3. The wellbore skin versus rate relationship for two-phase pseudo-pressure analyses below dew point pressure show a linear relationship and give a mechanical skin and non-Darcy factor similar to the values obtained above dew point pressure from single-phase pseudo-pressure.

4.4 Compositional Simulation Results for Rich Gas Condensate

4.4.1 Single-phase pseudo-pressure analysis

The same approach for lean gas was used for rich gas. The pressure and rate histories (random, increasing and decreasing rates) from the simulations are shown in Figs 4.26, 4.31 and 4.32.

4.4.1.1 Random Rate History

Fig. 4.26 comprises 16 flow periods with 1-day duration for each drawdown (DD) and build-up (BU). It shows that the pressures of first three drawdowns are above the dew point pressure, while all successive drawdowns dropped below dew point pressure. Presented in Figs. 4.27, 4.28 and 4.29 are the rate-normalized single-phase pseudo-pressure log-log plot, saturation profile and turbulence factor from the simulator. The wellbore skins provided in Table 4.6 were calculated with well test analysis software by matching the build-up data of single-phase pseudo-pressure with multirate type curve.

Fig. 4.27 shows an upward shift of the pressure curves and radial composite behaviour of the derivatives (BU8, BU10, BU12, BU14, and BU16) below the dew point pressure due to condensate dropout (Fig. 4.28). The total skin and condensate bank decrease as the rate decreases because the condensate formed from the preceding drawdown re-vaporises completely during shut-in (Aluko and Gringarten, 2009).

As expected of dry gas, the single-phase pseudo-pressure derivative of BU2, BU4 and BU6 exhibit a homogeneous behaviour above the dew point pressure. The left hand side (LHS) of wellbore skin versus rate plot (Fig. 4.30) shows a linear relationship. The turbulence factor (0.005 D/MMscf) and mechanical skin (0.1) are comparable to the values from the simulator (0.005 D/MMscf and 0 respectively).

Similar to Fig. 4.4 (Lombard *et al.* 1999), Fig. 4.30 shows a linear relationship on the right hand side (RHS) below dew point pressure. The wellbore skin value is less dependent on rate history because the turbulence factor (Fig. 4.29) increases and decreases with rate contrary to the lean gas case. Nonetheless, the mechanical skin (-0.14) and turbulence factor (0.18 D/MMscf) from the single-phase pseudo-pressure analysis are dissimilar to values from the simulator (0 and 0.005 D/MMscf respectively).

The turbulence factor from the simulator (Figs. 4.29, 4.37 and 4.38) for rich gas condensate reservoir above dew point pressure does not change with rate but increases below dew point pressure as the condensate saturation at the wellbore increases with increasing gas rate. The turbulence effect decreases as the rate decreases because the condensate drop-out from the preceding drawdown re-vaporises completely during build-up (Aluko and Gringarten, 2009).

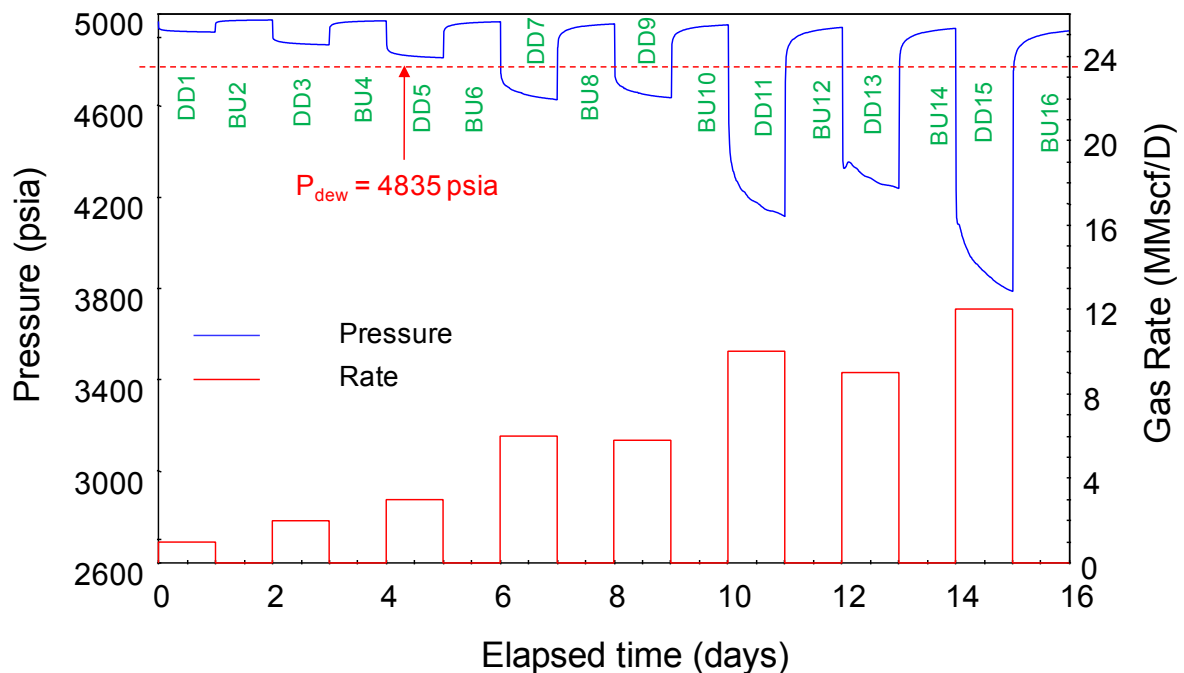


Figure 4.26: Pressure and random rate history for Rich Gas

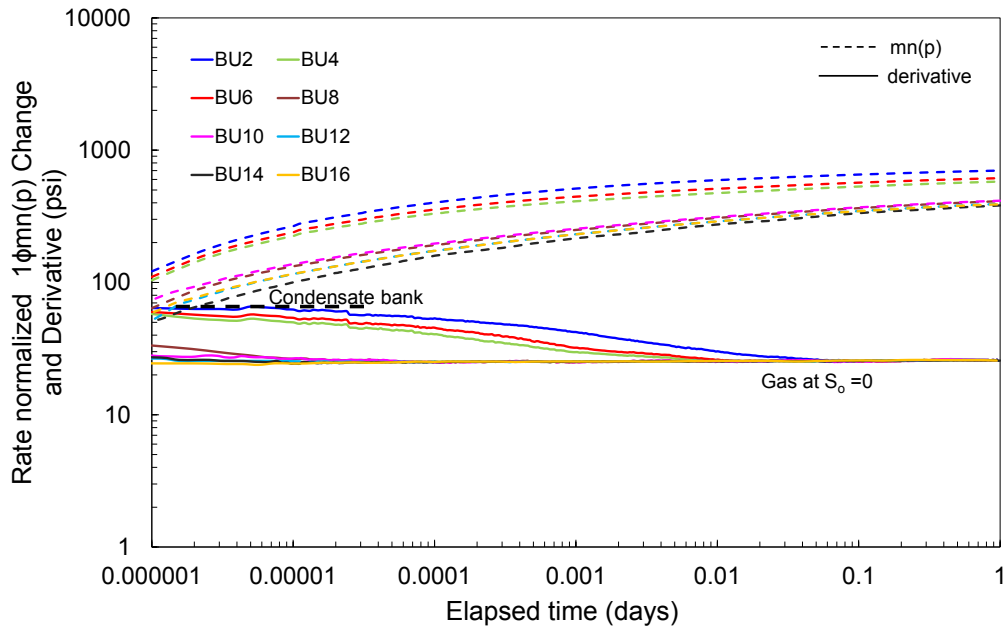


Figure 4.27: Rate-normalized 1ϕ PP log-log plot for Rich Gas (random rate, Fig. 4.26)

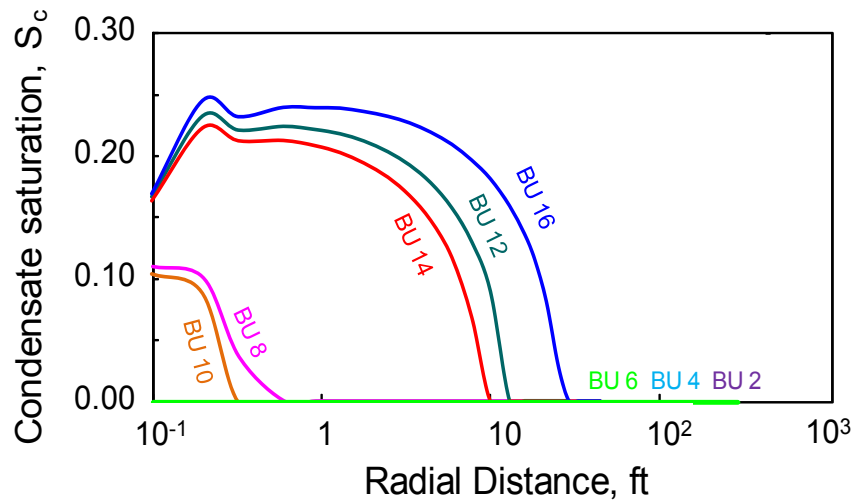


Figure 4.28: Condensate saturation profiles for rich gas (random rate, Fig. 4.26)

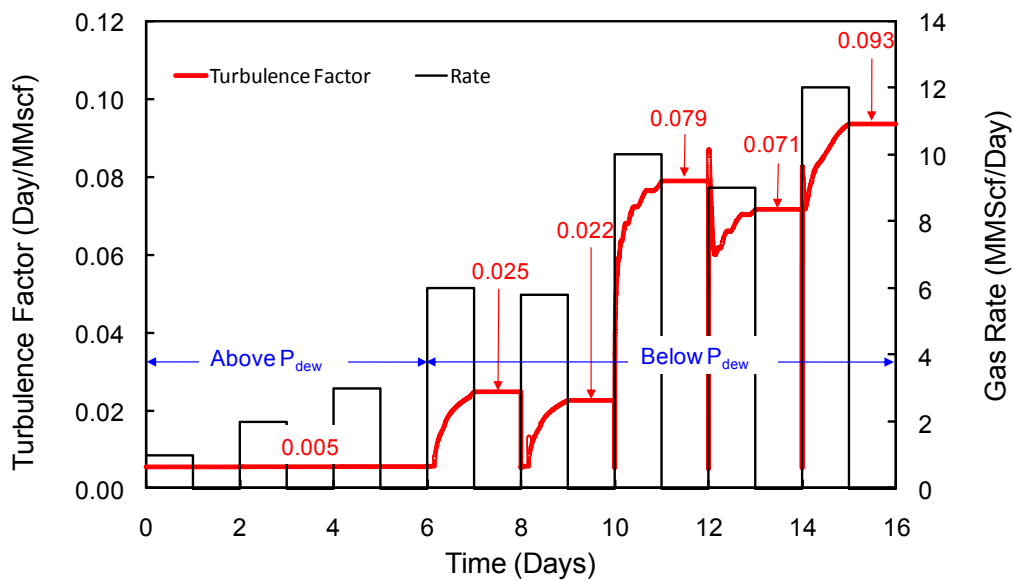


Figure 4.29: Simulated Turbulence Factor vs. Time and Rate for Rich Gas (random rate, Fig. 4.26)

Table 4.6: Interpretation results for the data from Fig. 36 ($1\phi m_n(p)$)

Q, RG (MMscf/d)	Skin
1.0	0.13
2.0	0.13
3.0	0.14
6.0	0.95
5.8	0.93
10.0	1.65
9.0	1.45
12.0	2.06

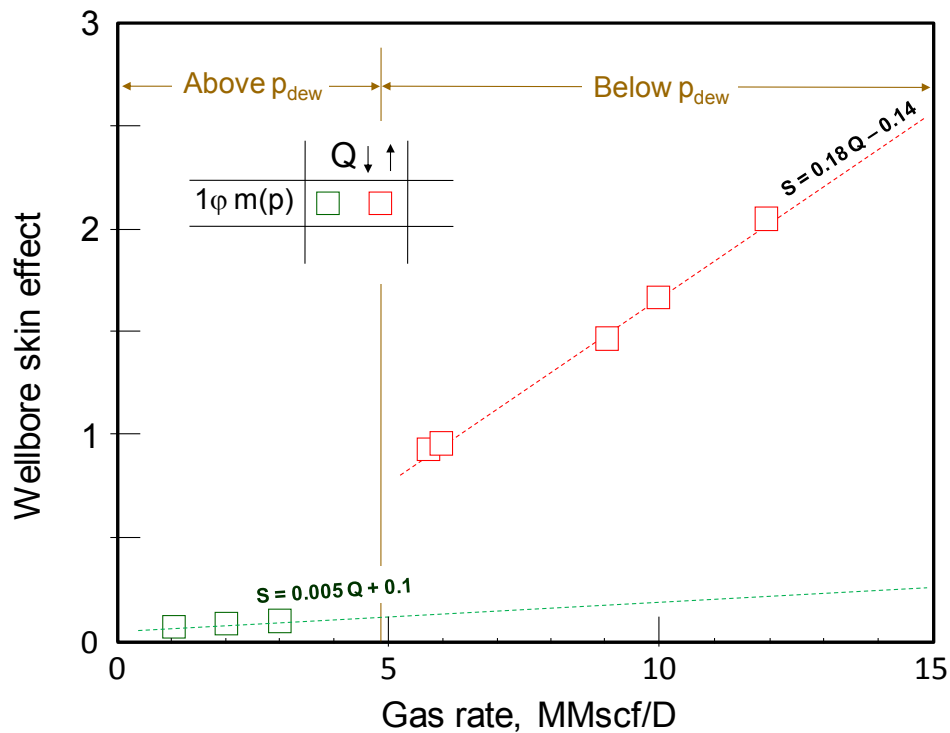


Figure 4.30: Wellbore skin vs. random rate history for rich gas ($1\phi m_n(p)$) ($s_m=0$)

4.4.1.2 Increasing and Decreasing Rate History

Figs. 4.31 and 4.32 show the pressure, increasing and decreasing rate histories for rich gas. They have 12 flow periods with duration of 1-day for each drawdown (DD) alternating with build-up (BU). The pressure in the first three drawdowns (Fig. 4.31) is above the dew point pressure, while all successive drawdowns dropped below dew point pressure for increasing rate history and vice versa for decreasing rate history. The rate-normalized single-phase pseudo-pressure log-log plots for increasing and decreasing rate histories are shown in Figs. 4.33 and 4.34. The single-phase pseudo-pressure skin values provided in Table 4.7 were estimated by matching the build-up of single-phase pseudo-pressure with multirate type curve.

The build-up derivatives for increasing rate history (BU2, BU4, and BU6) and decreasing rate history (BU8, BU10 and BU12) show a homogeneous behaviour above dew point pressure (Figs. 4.33 and 4.34). Similar to dry gas behaviour, the left hand side (LHS) of wellbore skin versus rate plot (Fig. 4.39) is linear and the estimated mechanical skin (0.1) and the turbulence factor (0.005 D/MMscf) are comparable to the values from the simulator (0 and 0.005 D/MMscf).

Figs. 4.33 and 4.34 show a radial composite behaviour and an upward shift of the pressure curves below the dew point pressure for increasing rate history (BU8, BU10, BU12) and decreasing rate history (BU2, BU4, BU6) due to the formation of condensate bank (Figs. 4.35 and 4.36) at the wellbore. The condensate bank and turbulence factor (Figs. 4.37 and 4.38) decreases with decreasing rate and increases as the rate increases because the condensate formed from the preceding drawdown re-vaporises completely during shut-in (Aluko and Gringarten, 2009).

The right hand side (RHS) of Fig. 4.39 shows the wellbore skin versus rate calculated with single-phase pseudo-pressure is linear below dew point pressure but yielded a mechanical skin of 0.5 and turbulence factor (0.075 D/MMscf) which are different to the values from the simulator (0 and 0.005 D/MMscf respectively).

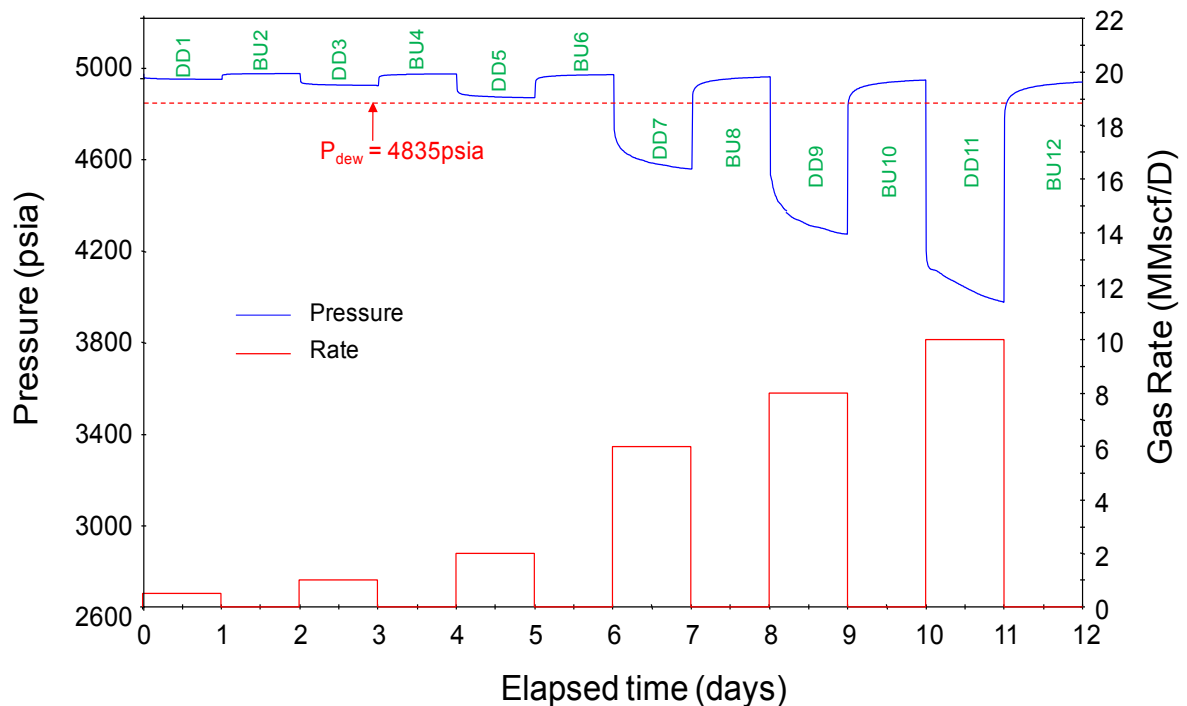


Figure 4.31: Pressure and increasing rate history for Rich Gas

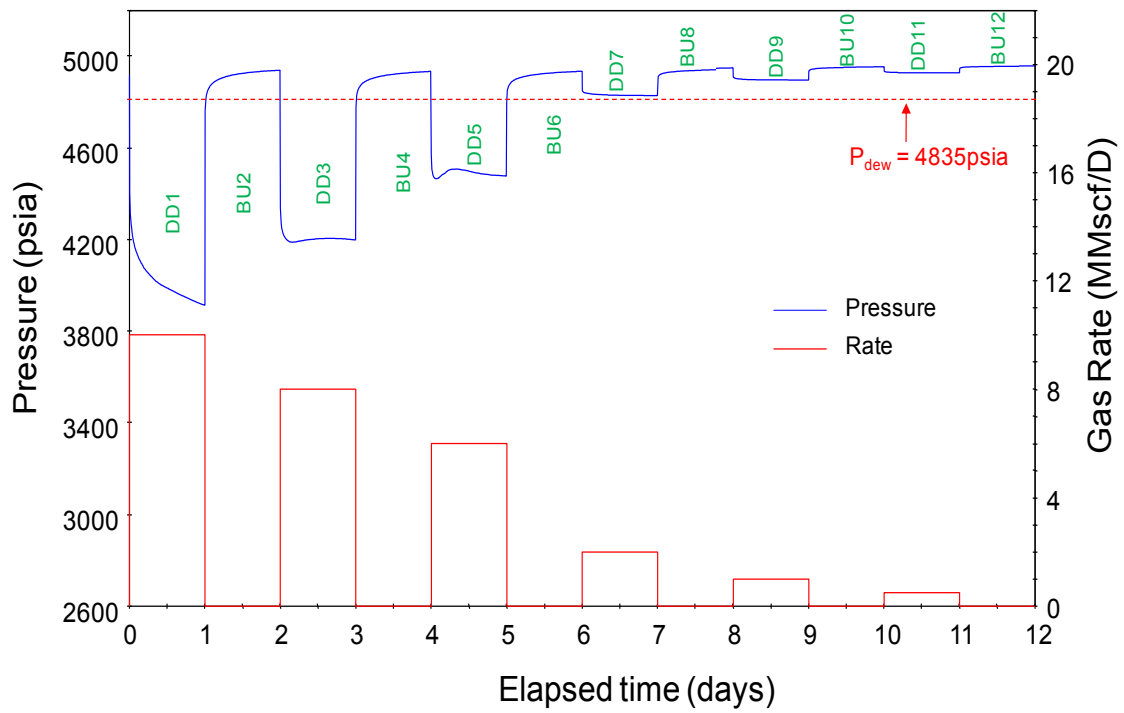


Figure 4.32: Pressure and decreasing rate history for Rich Gas

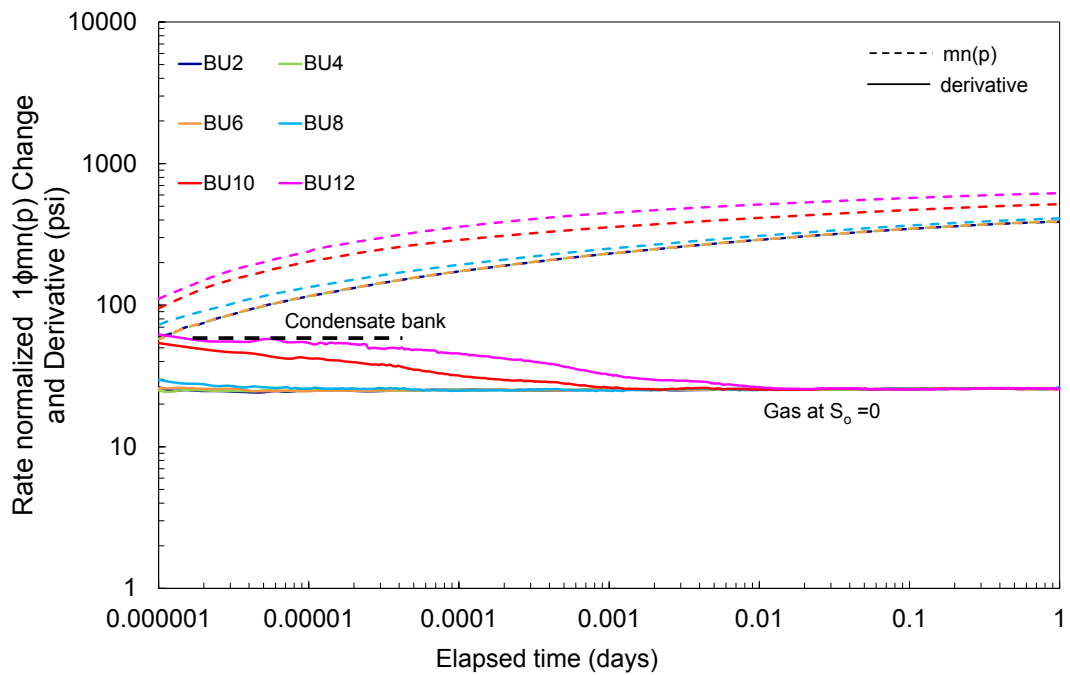


Figure 4.33: Rate-normalized 1ϕ PP log-log plot for Rich Gas (increasing rate, Fig. 4.31)

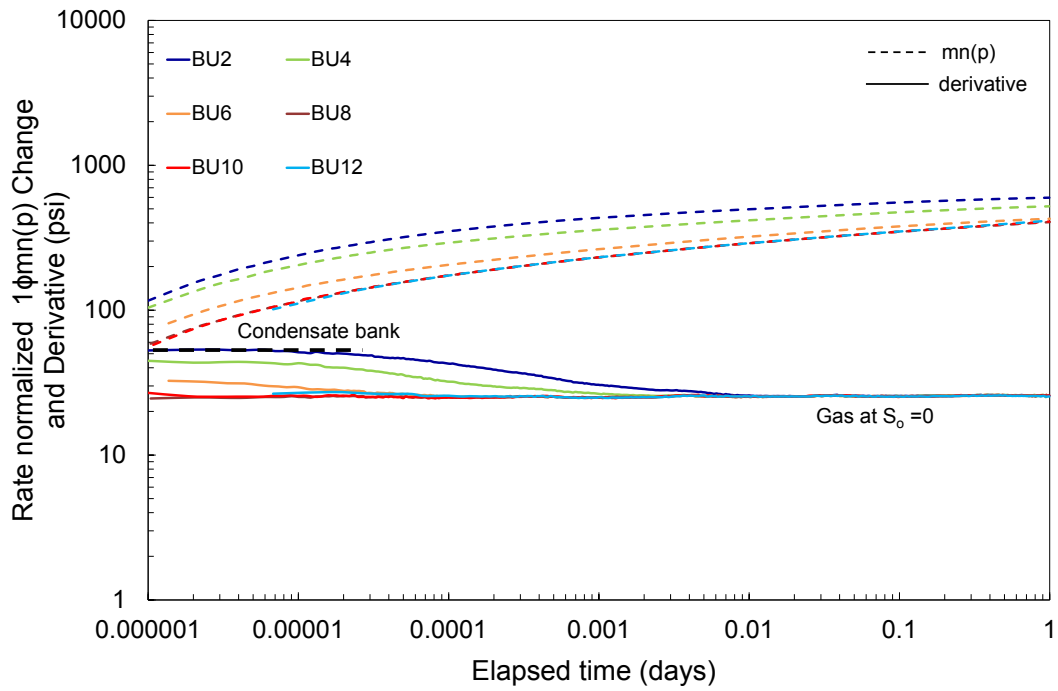


Figure 4.34: Rate-normalized 1ϕ PP log-log plot for Rich Gas (decreasing rate, Fig. 4.26)

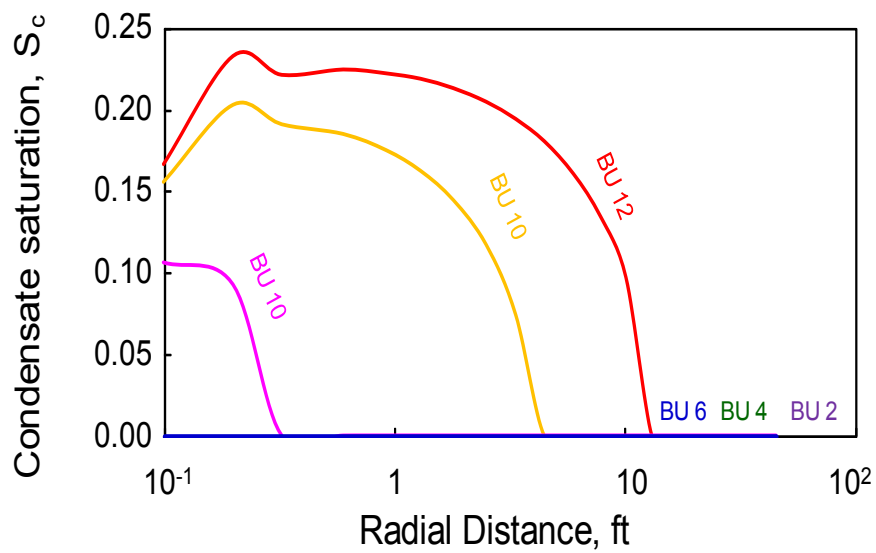


Figure 4.35: Condensate saturation profile for rich gas (increasing rate history)

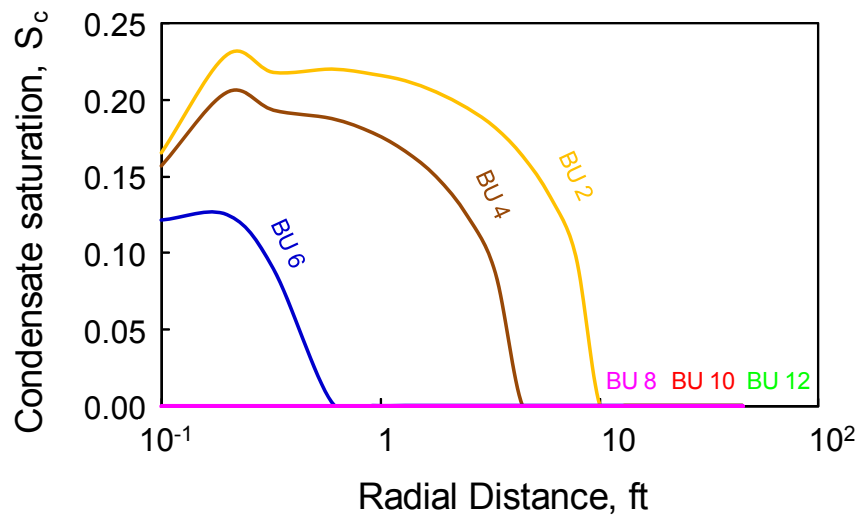


Figure 4.36: Condensate saturation profile for rich gas (decreasing rate history)

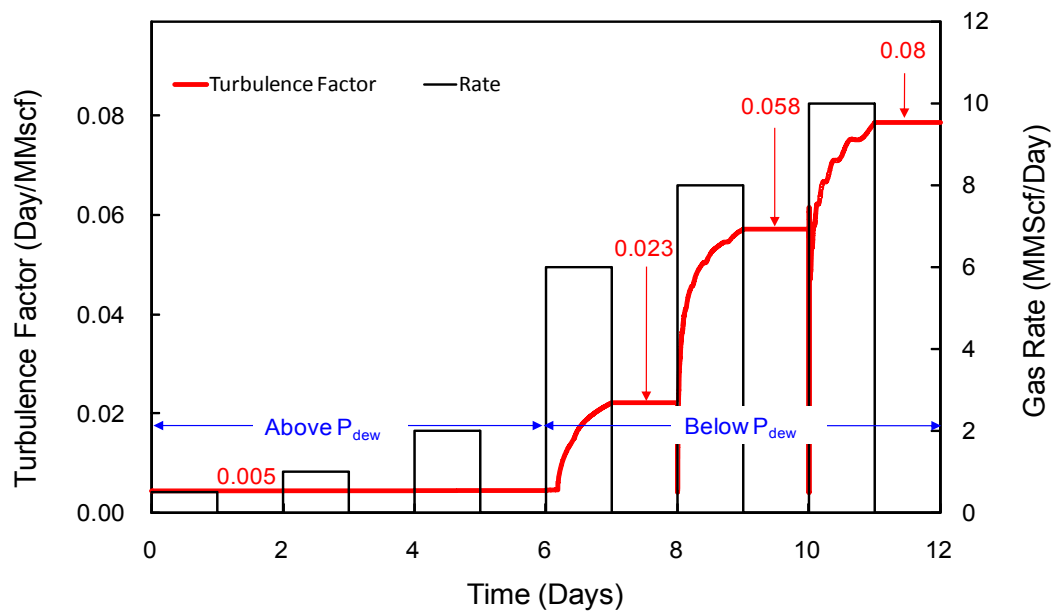


Figure 4.37: Simulated Turbulence Factor vs. Time and Rate for Rich Gas (increasing rate)

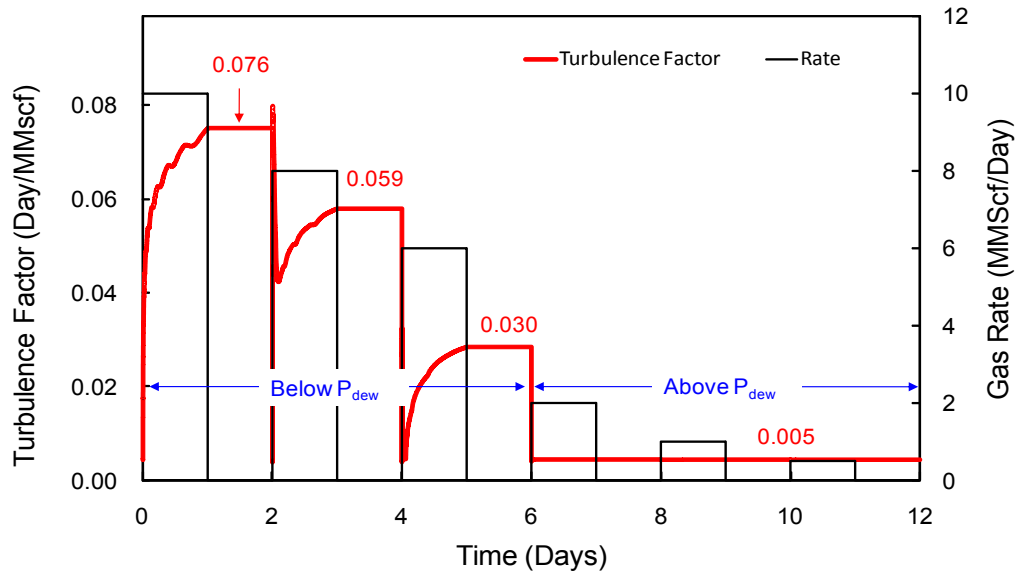


Figure 4.38: Simulated Turbulence Factor vs. Time and Rate for Rich Gas (decreasing rate)

Table 4.7: Interpretation results for the data from Figs. 4.31 and 4.32 ($2\phi m_n(p)$)

Q, RG MMscf/d	Wellbore Skin	
	↑ Q	↓ Q
0.5	0.13	0.13
1.0	0.14	0.14
2.0	0.14	0.14
6.0	0.95	0.95
8.0	1.05	1.10
10.0	1.24	1.25

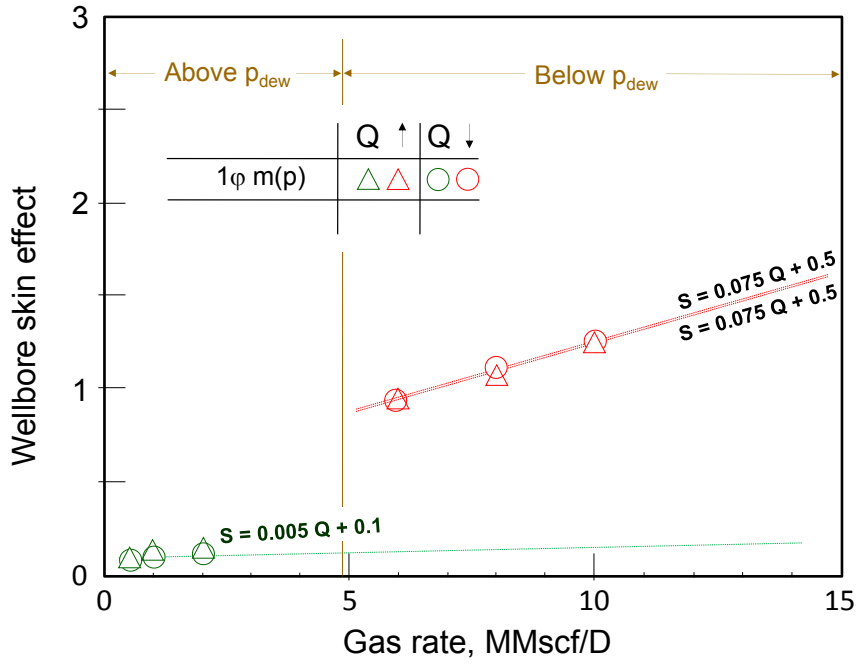


Figure 4.39: Wellbore skin vs. increasing and decreasing rate history for rich gas ($1\phi m_n(p)$) ($s_m=0$)

4.4.2 Two-phase pseudo-pressure analysis

The build-up data below saturation pressure were converted to two-phase pseudo-pressure (Figs. 4.40, 4.41 and 4.42) using relative permeability curve that integrates high capillary number and non-Darcy effects and the procedure in section 2.4. The two-phase pseudo-pressure corrected the composite effect from the single-phase pseudo-pressure derivatives and give a derivative stabilization (Figs. 4.40, 4.41 and 4.42) which corresponds to the absolute permeability at $k_{rg} = k_{rg}^{max}$. The skin versus rate relationship for two-phase pseudo-pressure analyses are shown in Fig. 4.43.

The two-phase pseudo-pressure skin versus rate relationship at right hand side (RHS) of Fig. 4.43 shows a linear relationship. The mechanical skin and turbulence factor obtained from two-phase pseudo-pressure calculated with relative permeability which integrates non-Darcy effect and high capillary number give a linear trend similar to that obtained with single-phase pseudo-pressure analysis above the dew point pressure. The two-phase pseudo-pressure accounts for the multiphase flow (i.e. gas and condensate saturation) at the wellbore. The wellbore skin calculated by matching the build-up data from the two-phase pseudo-pressure analysis with multirate type curve using well test analysis software are provided in Tables 4.8 and 4.9.

The sensitivity on the relative permeability parameters (Corey exponent (λ), k_{rg}^{max} , k_{ro}^{max}) and fluid properties used for the two-phase pseudo-pressure skin estimate for rich gas (Fig. 4.60) is summarised in section 4.6.

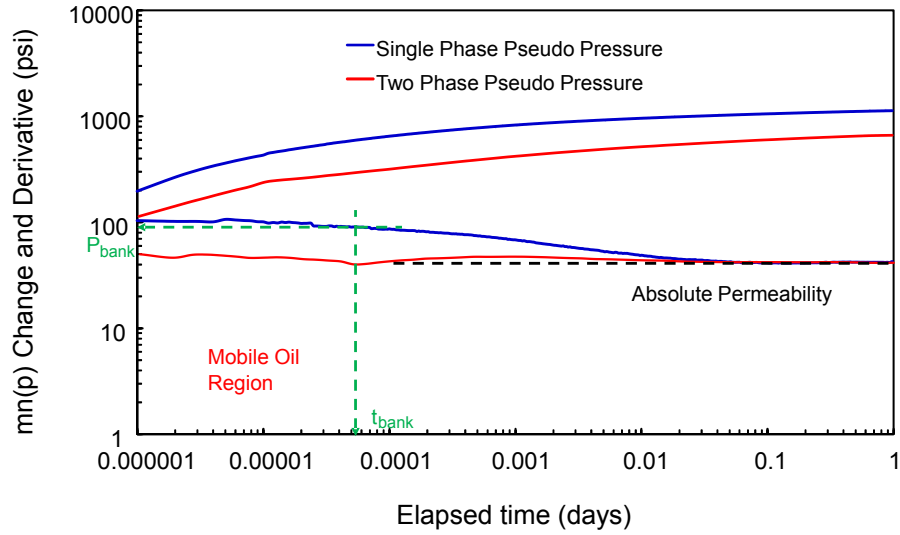


Figure 4.40: 1 ϕ PP and 2 ϕ PP log-log plot for rich gas (BU 16) (random rate at $k_{rg}^{max}=1$)

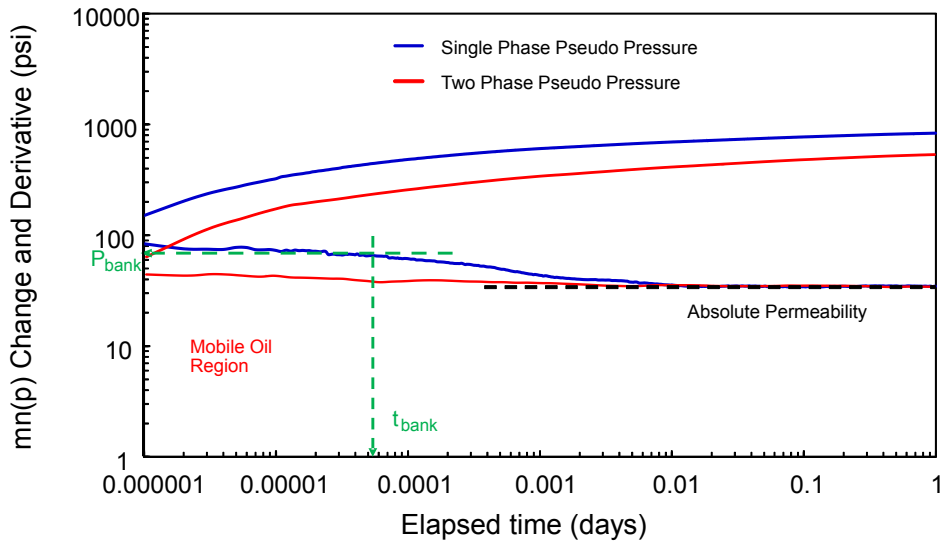


Figure 4.41: 1 ϕ PP and 2 ϕ PP log-log plot for rich gas (BU 12) (increasing rate at $k_{rg}^{max}=1$)

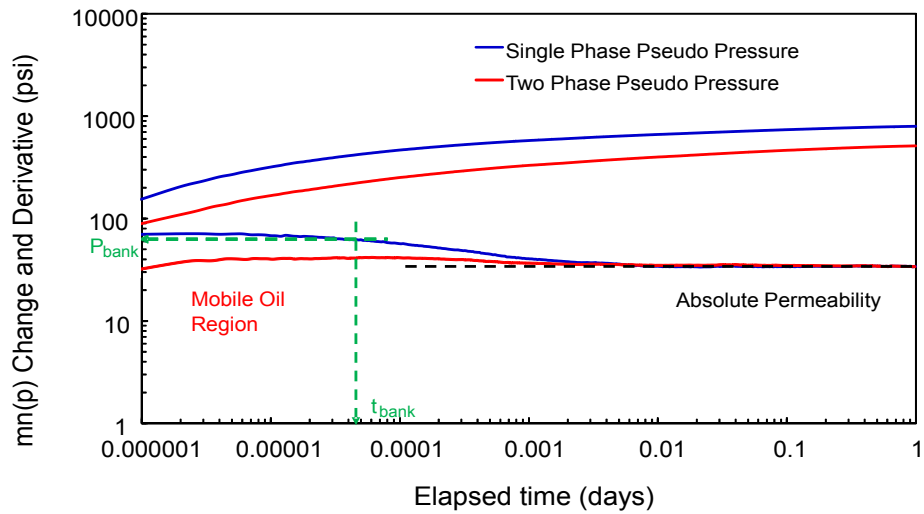


Figure 4.42: 1 ϕ PP and 2 ϕ PP log-log plot for rich gas (BU 4) (decreasing rate at $k_{rg}^{max}=1$)

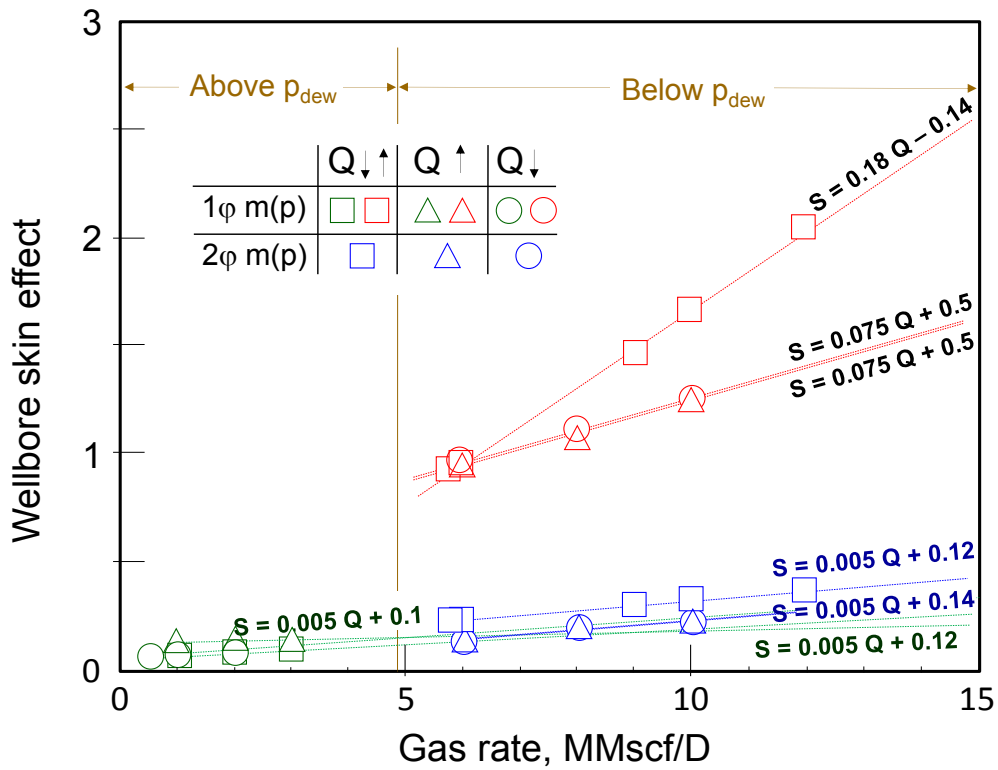


Figure 4.43: Wellbore skin vs. rate for rich gas (random, increasing and decreasing rate)

Table 4.8: Interpretation results for the data from Fig. 4.26 (1 and 2φ $m_n(p)$)

Q, RG MMscf/d	Skin 1Ø PP	Skin 2Ø PP
6.0	0.95	0.15
5.8	0.93	0.15
10.0	1.65	0.17
9.0	1.45	0.17
12.0	2.06	0.18

Table 4.9: Interpretation results for the data from Figs. 4.31 and 4.32 (1φ and 2φ $m_n(p)$)

Q, RG MMscf/d	Skin Q ↑ 1φPP	Skin Q ↓ 1φPP	Skin Q ↑ 2φPP	Skin Q ↓ 2φPP
6	0.95	0.95	0.17	0.17
8	1.05	1.1	0.18	0.18
10	1.24	1.25	0.19	0.19

4.4.3 Summary of Single-phase and Two-phase pseudo-pressure analysis for rich gas condensate

1. The estimated mechanical skin and the turbulence factor from single-phase pseudo-pressure analysis above dew point pressure are comparable to values from the simulator.

2. The turbulence factor and wellbore skin estimate from single-phase pseudo-pressure in rich gas condensate are less dependent on rate history compared to lean gas below dew point pressure.
3. The wellbore skin versus rate relationship for two-phase pseudo-pressure analyses below dew point pressure show a linear relationship and give a mechanical skin and non-Darcy factor similar to the values obtained from single-phase pseudo-pressure analysis above dew point pressure.

4.5 Compositional Simulation Results for Volatile Oil

Pressure, random, increasing and decreasing rate histories (Figs. 4.44, 4.48 and 4.49) data were generated from compositional simulation of volatile oil in order to evaluate the wellbore skin versus rate relationship using pressure and two-phase pseudo-pressure techniques. The pressure at the end of each build-up is above the bubble point pressure, as there is no depletion in the reservoir.

4.5.1 Pressure analysis

4.5.1.1 Random Rate History

The pressure in the first three drawdowns (Fig. 4.44) for pressure and random rate history are above the bubble point pressure while all subsequent drawdowns dropped below bubble point pressure. Fig. 4.44 has 16 flow periods with 1-day duration for each drawdown (DD) and build-up (BU). The rate-normalized log-log plot of pressure change and derivative as well as the corresponding gas saturation profile in the reservoir are shown in Figs. 4.45 and 4.46 respectively.

The build-up (BU2, BU4, and BU6) pressure change and derivatives show a homogeneous behaviour above bubble point pressure as expected of black oil. The wellbore skin versus rate relationship in the left hand side (LHS) of Fig. 4.47 does not change with rate above bubble point pressure. The mechanical skin (0.05) is similar to the value from the simulator (0).

The derivatives (Fig. 4.45) of BU 8, BU10, BU12, BU14 and BU16 exhibit composite behaviour due to the development of the gas bank at the wellbore. The composite behaviour is associated with the high total skin effect seen on the pressure curves below bubble point pressure (Sanni and Gringarten, 2008). The skin versus rate plot shows a linear trend in the right hand side (RHS) of Fig. 4.47. However, the pressure analysis for

random rates history yield a turbulence factor of 0.2 D/Mstb which is conflicting with the simulator value (0.004 D/Mstb). The skin values calculated by matching the build-up data with type curve are given in Table 4.10.

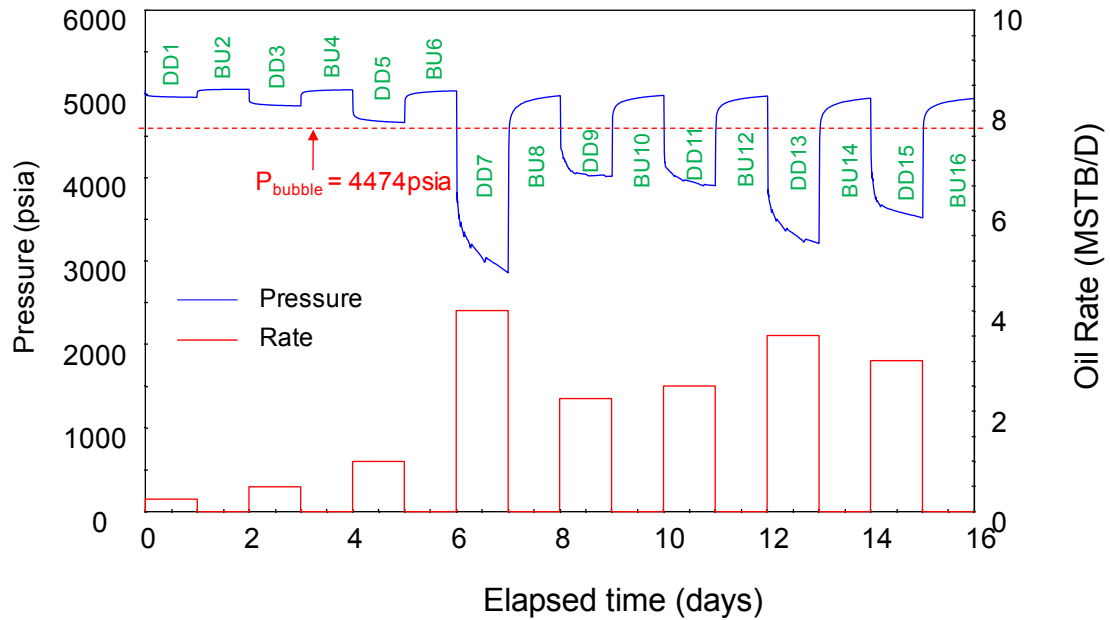


Figure 4.44: Pressure and random rate history for volatile oil

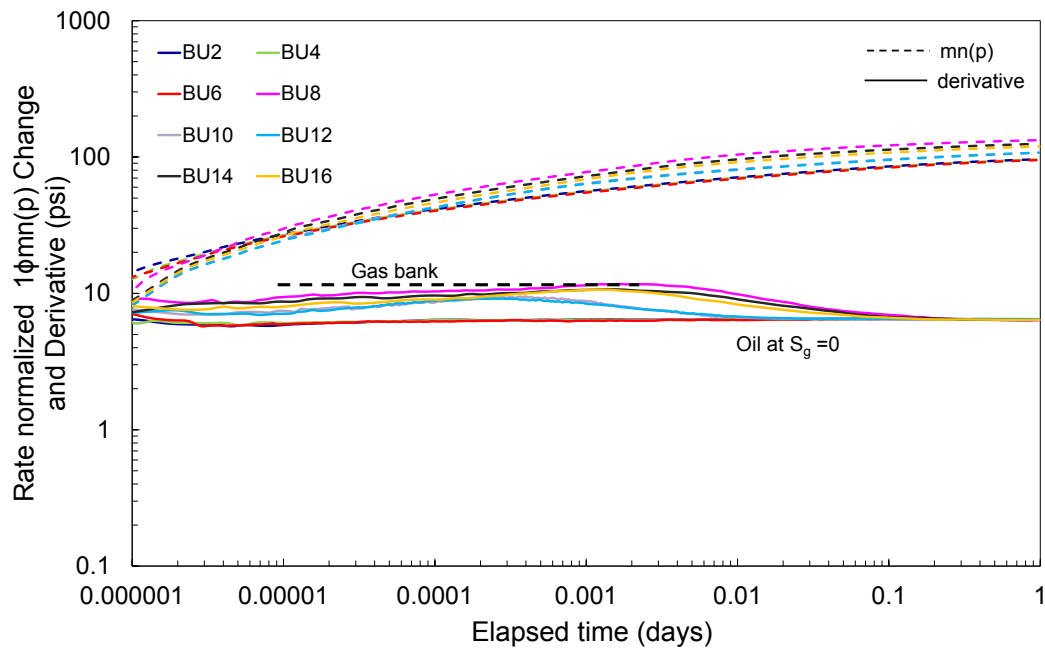


Figure 4.45: Rate-normalized pressure log-log plot for volatile oil (random rate, Fig. 4.44)

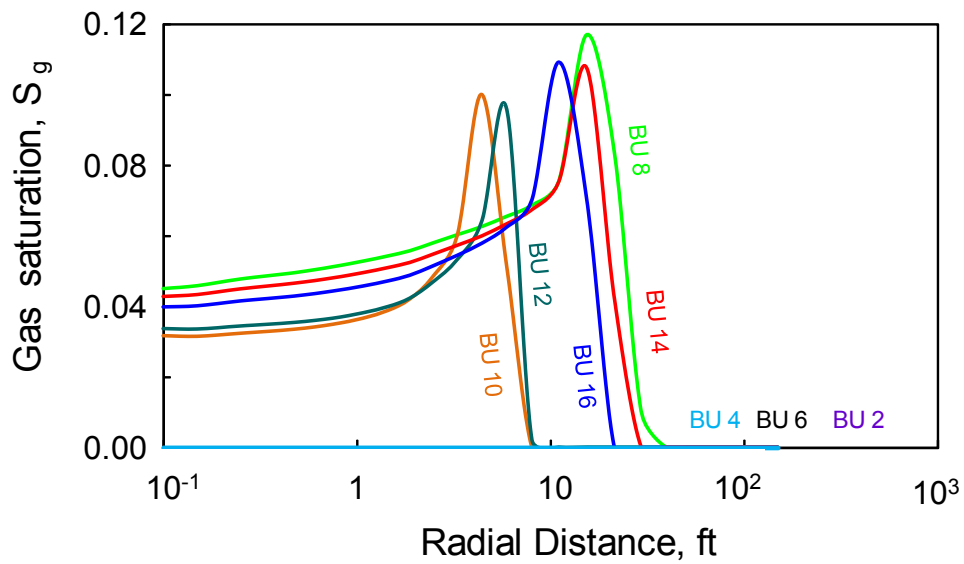


Figure 4.46: Gas saturation profile for volatile oil (random rate history)

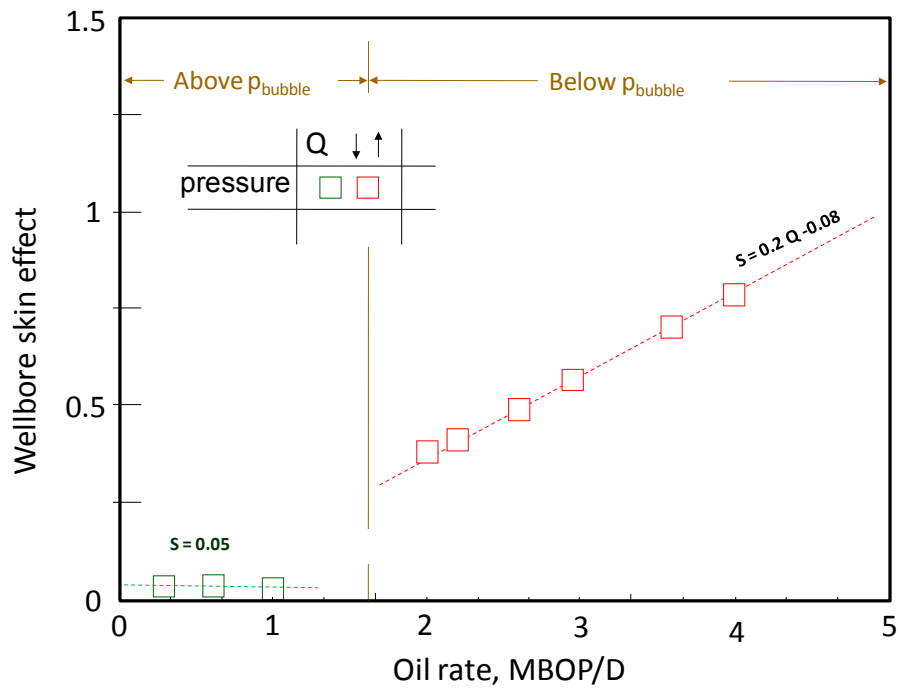


Figure 4.47: Wellbore skin vs. random rate history for volatile oil (pressure analysis) ($s_m=0$)

Table 4.10: Interpretation results for the data from Fig. 4.44 (pressure analysis)

Q, VO (MBOPD)	Skin
0.25	0.05
0.50	0.05
1.00	0.05
4.00	0.7
2.25	0.35
2.50	0.42
3.50	0.6
3.00	0.5

4.5.1.2 Increasing and Decreasing Rate History

Increasing and decreasing rate sequence (Figs. 4.48 and 4.49) were simulated to evaluate the dependence of wellbore skin versus rate relationship for volatile oil below bubble point pressure on rate history. Figs. 4.48 and 4.49 have 12 flow periods with 1-day duration for each of drawdown (DD) alternating with build-up (BU). Pressure in the first three drawdowns is above the bubble point pressure, while all other drawdowns dropped below bubble point pressure for increasing rate history and vice versa for decreasing rate history.

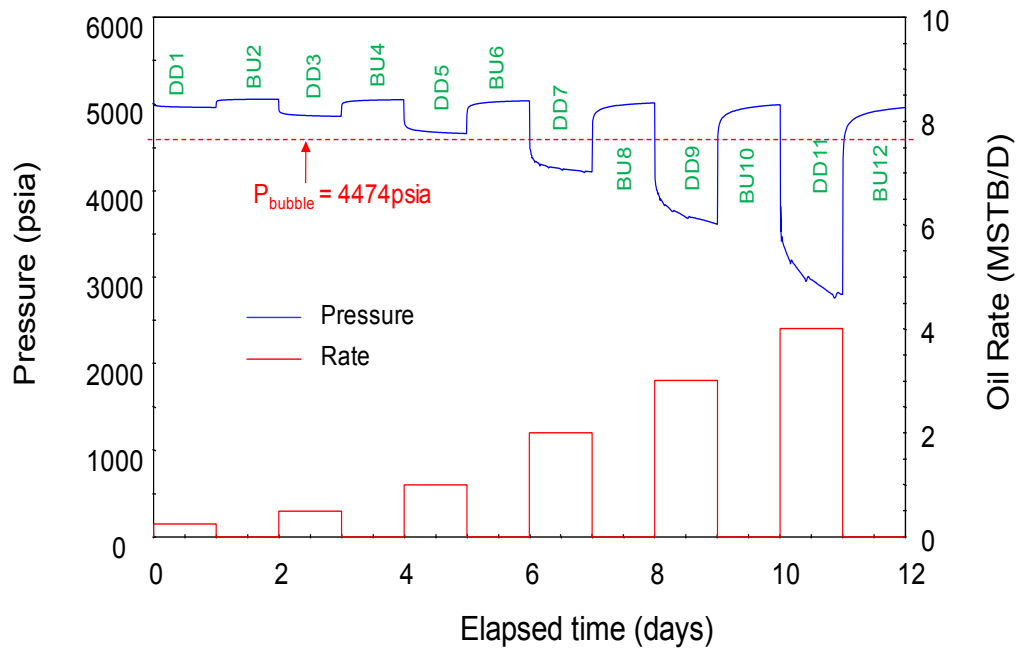


Figure 4.48: Pressure and increasing rate history for Volatile Oil

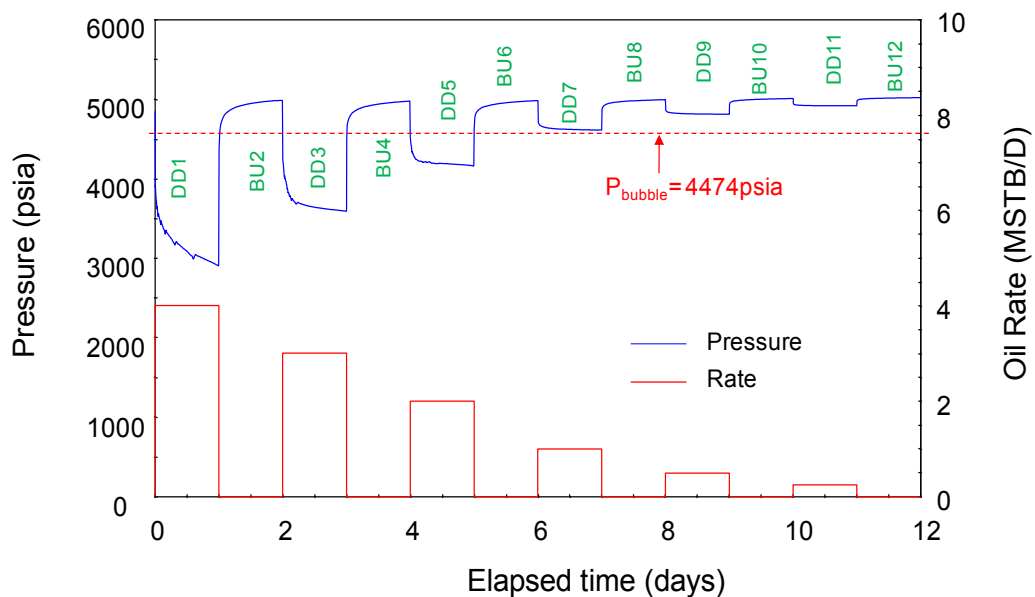


Figure 4.49: Pressure and decreasing rate history for Volatile Oil

The rate-normalized log-log plots of pressure change and derivative for increasing and decreasing rate histories are shown in Figs. 4.50 and 4.51. The corresponding gas saturation profiles at the wellbore are shown in Figs. 4.52 and 4.53 respectively. The pressure change and the derivatives (Figs. 4.50 and 4.51) above bubble point pressure for increasing rate (BU2, BU4, BU6) and decreasing rate (BU8, BU10, BU12) histories exhibit a homogeneous behaviour. The wellbore skin versus rate relationship in the left hand side (LHS) of Fig. 4.54 does not change with rate as expected of black oil. The mechanical skin and the turbulence factor are 0.05 and 0 respectively.

However, below the bubble point pressure the derivatives in Figs. 4.50 and 4.51 exhibit composite behaviour due to gas bank (Figs. 4.52 and 4.53) formation at the wellbore. This behaviour is connected to the high total skin effect seen on the pressure curves (Sanni and Gringarten, 2008). The plot of wellbore skin versus rate in the right hand side (RHS) of Fig. 4.54 for increasing and decreasing rate histories show a linear relationship. The gas bank and the total skin decreases and increases as rate decreases and increases, hence, rate history does not have any impact on wellbore skin estimate for volatile oil.

The pressure analysis for increasing and decreasing rate histories below bubble point pressure yield similar turbulence factor of 0.2 D/Mstb which is inconsistent with value from the simulator (0.004 D/Mstb). Wellbore skins listed in Table 4.11 were estimated with well test analysis software by matching the build-up data with multirate type curve.

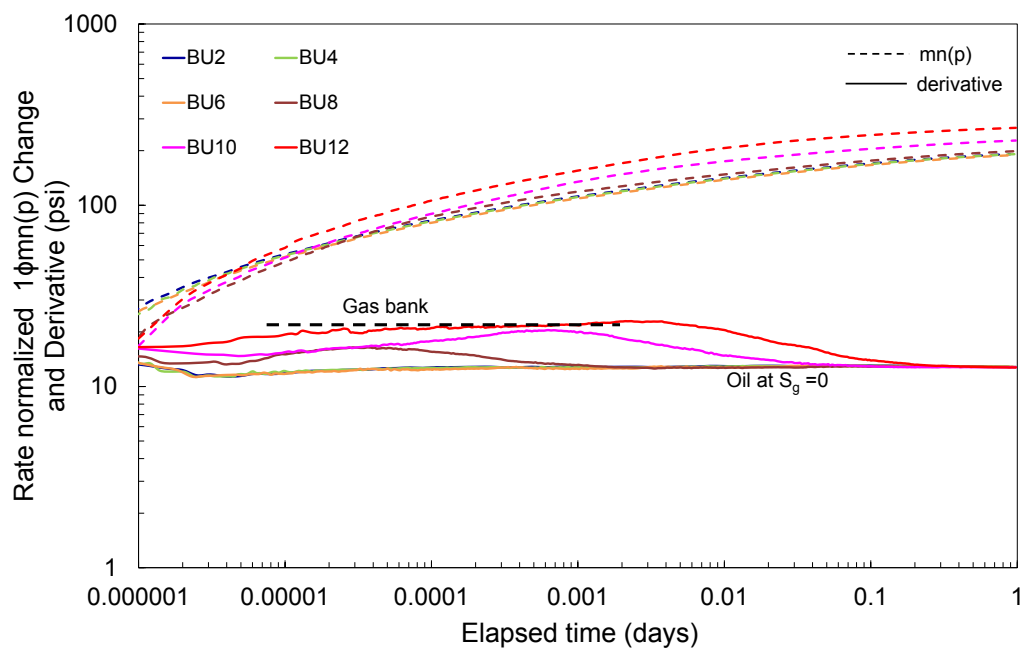


Figure 4.50: Rate-normalized pressure log-log plot for volatile oil (increasing rate, Fig. 4.48)

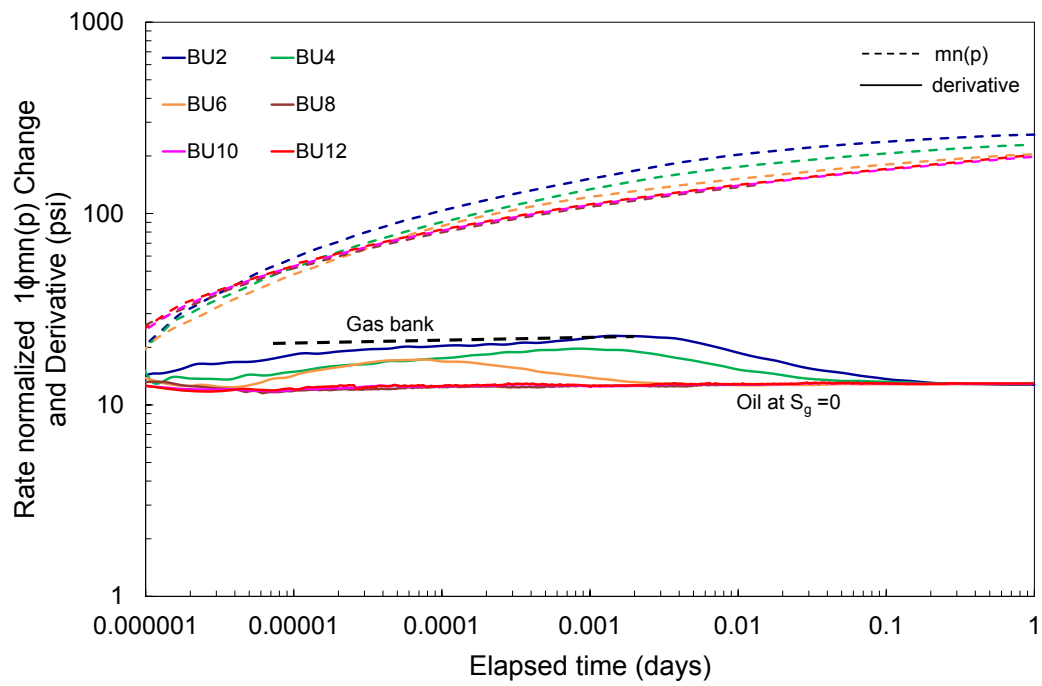


Figure 4.51: Rate-normalized pressure log-log plot for volatile oil (decreasing rate, Fig. 4.49)

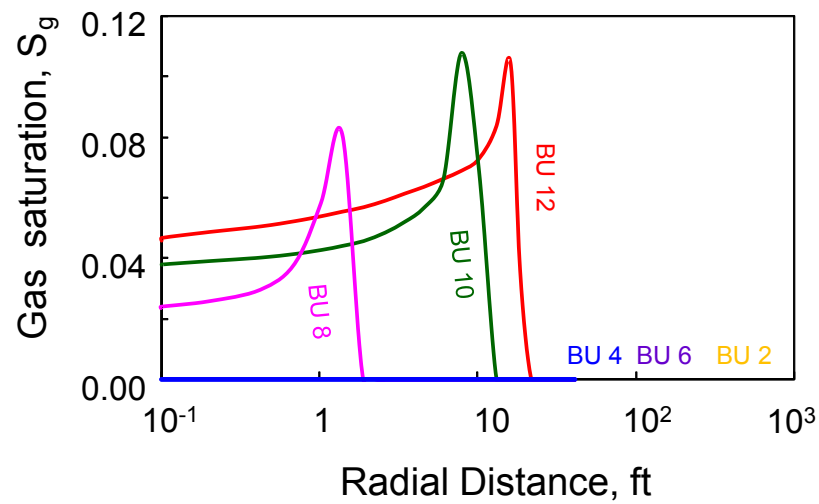


Figure 4.52: Gas saturation profile for volatile oil (increasing rate history)

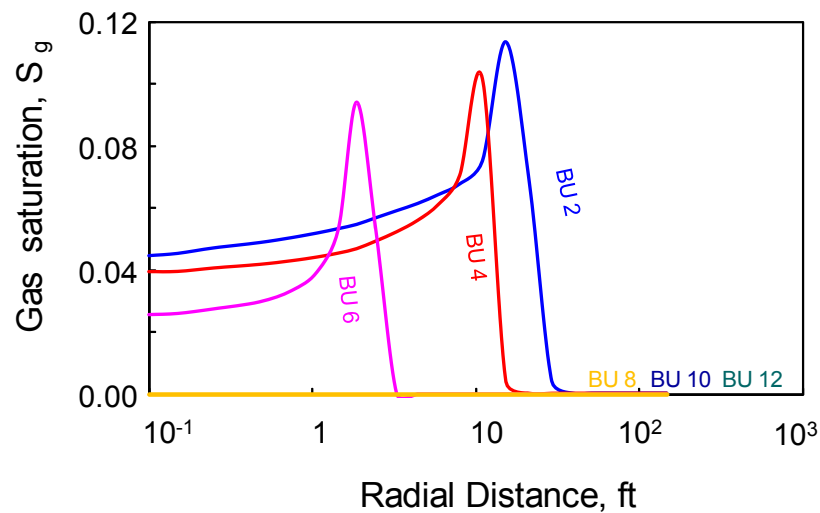


Figure 4.53: Gas saturation profile for volatile oil (decreasing rate history)

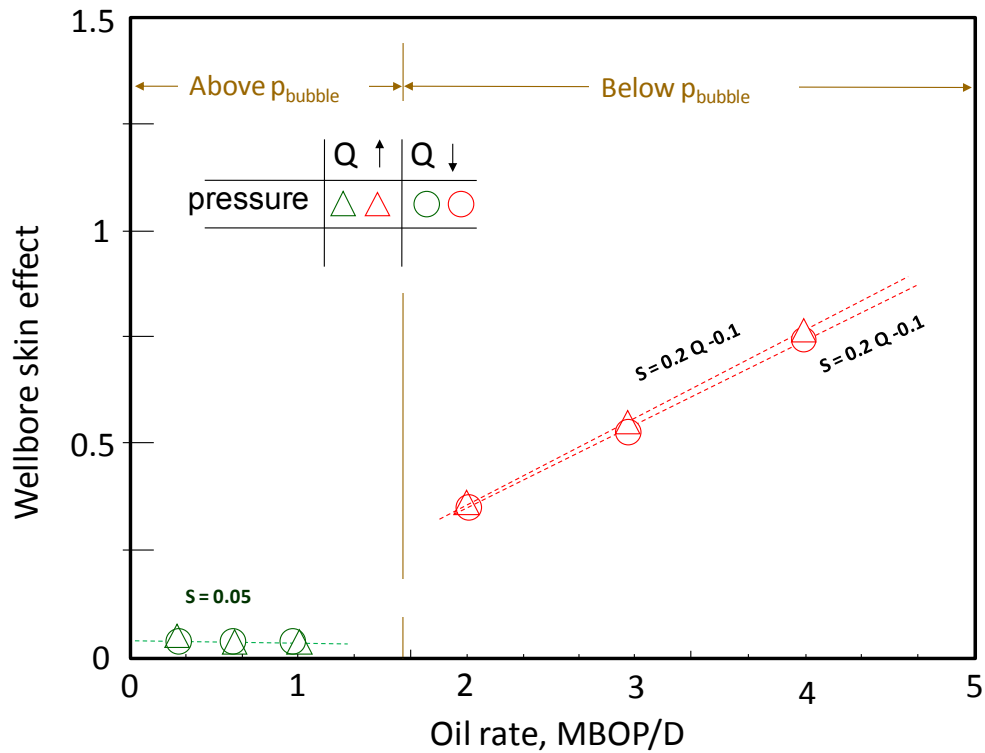


Figure 4.54: Wellbore skin vs. increasing and decreasing rate history for volatile oil (pressure analysis) ($s_m=0$)

Table 4.11: Interpretation results for the data from Figs. 4.48 and 4.49 (pressure analysis)

Q, VO MBOPD	Wellbore Skin	
	↑ Q	↓ Q
0.25	0.05	0.05
0.50	0.05	0.05
1.00	0.05	0.05
2.00	0.3	0.3
3.00	0.5	0.5
4.00	0.7	0.7

4.5.2 Two-phase pseudo-pressure analysis

The build-up data below bubble point pressure in Fig 4.44, 4.48 and 4.49 were converted to two-phase pseudo-pressure (Figs. 4.55, 4.56 and 4.57) calculated with the effect of high capillary number and non-Darcy factor on the relative permeability curves using steps shown in section 2.4. The log-log plots (Figs. 4.55, 4.56 and 4.57) of pressure and two-phase pseudo-pressure derivatives in the mobile gas region show that the two-phase pseudo-pressure derivatives stabilise at the absolute permeability at $k_{ro}=k_{ro}^{\max}$.

Fig. 4.58 shows wellbore skin versus rate relationships from pressure (Figs. 4.57 and 4.54) and two-phase pseudo-pressure analyses. The plot of wellbore skin versus rate for two-phase pseudo-pressure analyses on the right hand side (RHS) of Fig. 4.58 shows a

linear relationship. The mechanical skin of 0.1 is consistent with simulator values of 0. However, the turbulence factor obtained with two-phase pseudo-pressures calculated with capillary number is small and could be taken as zero (Fig. 4.58). The wellbore skin obtained from matching the two-phase pseudo-pressure build-up data with multirate type curve are provided in Table 4.12 and 4.13.

The sensitivity on the relative permeability parameters (Corey exponent (λ), $k_{rg}^{\max}$, $k_{ro}^{\max}$) and fluid properties used for the two-phase pseudo-pressure skin calculation for volatile oil (Fig 4.61) is presented in section 4.6

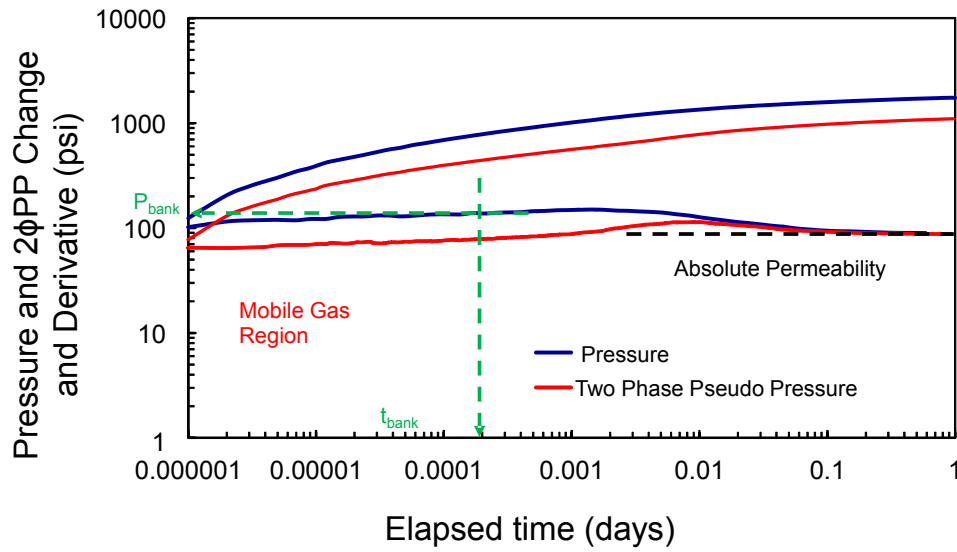


Figure 4.55: Pressure and two-phase pseudo-pressure log-log plot (BU 14) for volatile oil (random rate history)

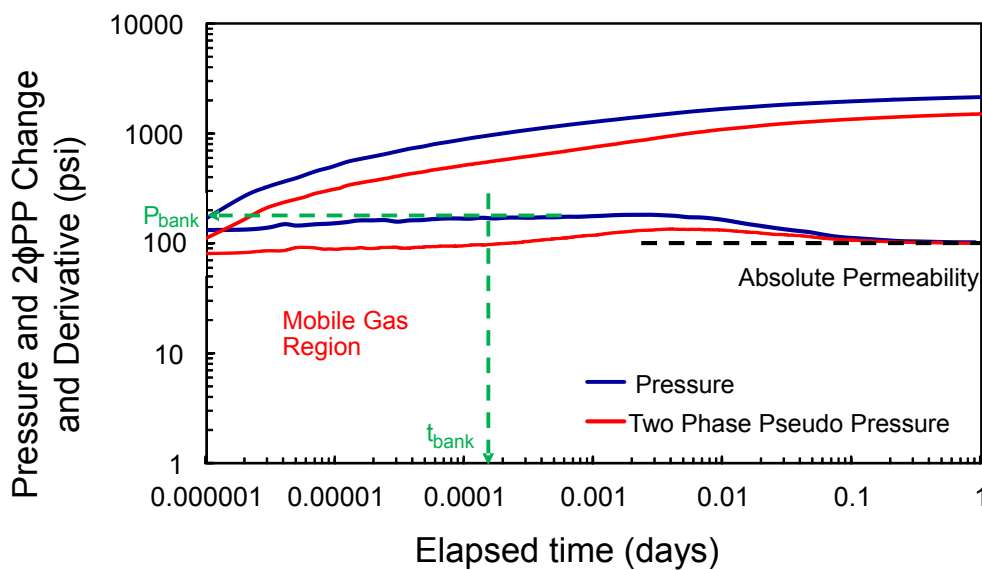


Figure 4.56: Pressure and two-phase pseudo-pressure log-log plot (BU 12) for volatile oil (increasing rate history)

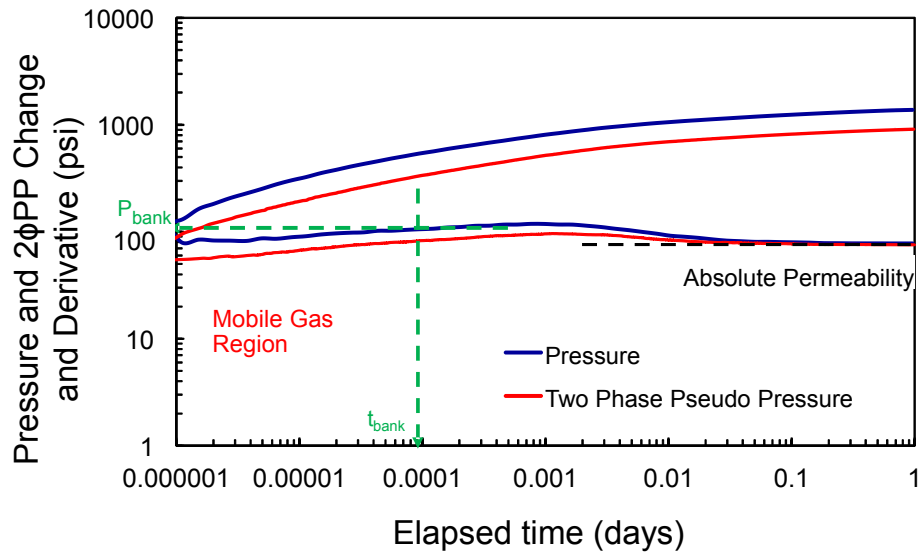


Figure 4.57: Pressure and $2\Phi_{pp}$ log-log plot (BU 4) for volatile oil (decreasing rate history)

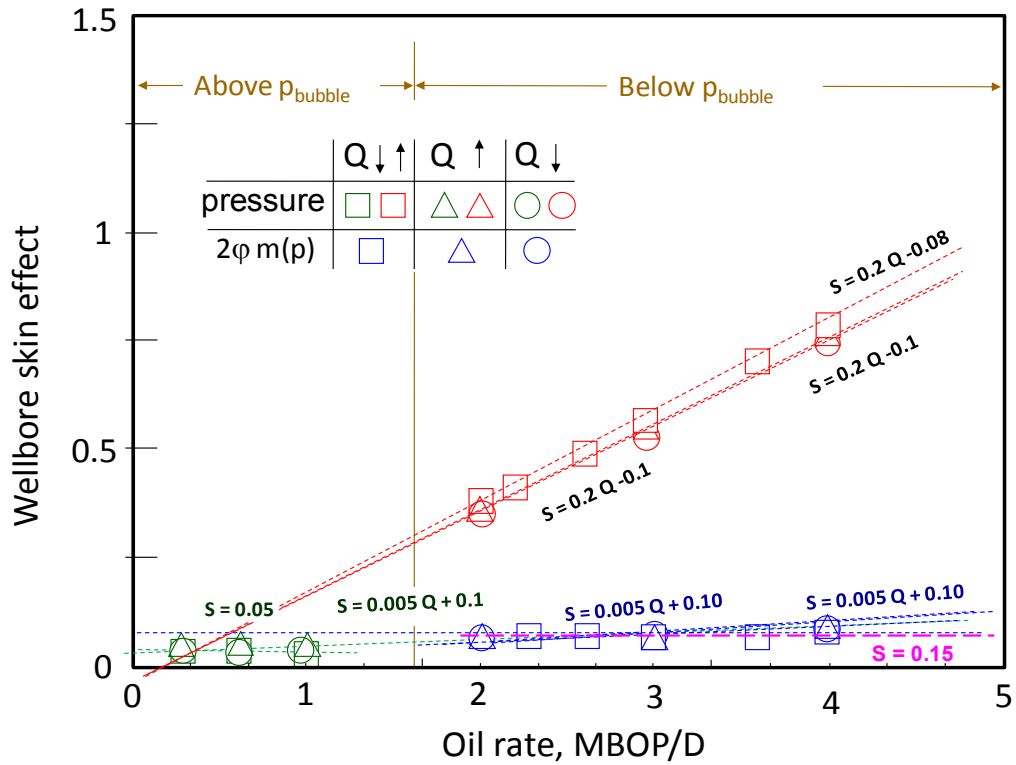


Figure 4.58: Wellbore skin vs. rate for volatile oil

Table 4.12: Interpretation results for the data from Fig. 4.44 ($2\phi_{PP}$)

Q, VO MBOPD	Skin $1\phi_{PP}$	Skin $2\phi_{PP}$
4.00	0.7	0.12
2.25	0.35	0.11
2.50	0.42	0.11
3.50	0.6	0.11
3.00	0.5	0.11

Table 4.13: Interpretation results for the data from Figs. 4.48 and 4.49 (2 ϕ PP)

Q, VO	Skin Q $\uparrow$	Skin Q $\downarrow$	Skin Q $\uparrow$	Skin Q $\downarrow$
MBOPD	1 ϕ PP	1 ϕ PP	2 ϕ PP	2 ϕ PP
2	0.3	0.3	0.11	0.11
3	0.5	0.5	0.11	0.11
4	0.7	0.7	0.12	0.12

4.5.2 Summary of Pressure and Two-phase pseudo-pressure analysis for volatile oil

1. The wellbore skin versus rate relationship above bubble point pressure does not change with rate as expected of black oil.
2. Wellbore skin estimates of volatile oil are less dependent on rate history compared to lean gas condensate below saturation pressure.
3. The pressure analysis yields incorrect values of wellbore skin and non-Darcy factor in volatile oil below bubble point pressure. However, the turbulence factor and wellbore skin obtained from two-phase pseudo-pressure analysis give a value similar to the pressure analysis above bubble point pressure.

4.6 Sensitivity Analysis on Two-phase Pseudo-pressure Calculation

Sensitivity analysis was carried out on relative permeability parameters (Corey exponent (λ), $k_{rg}^{\max}$, $k_{ro}^{\max}$) and fluid properties to investigate the robustness of two-phase pseudo-pressure skin estimates. The impact of Corey exponent (λ) on wellbore skin vs. rate was quantified by changing the base value by $\pm 8\%$ and $\pm 32\%$ while $k_{rg}^{\max}$ and $k_{ro}^{\max}$ were decreased from initial value of 1 to 0.6.

However, for fluid properties, the percentage (%) error was assumed in the liquid drop out and gas oil ratio of the experimental data for the CCE, CVD and DL experiments for the lean gas, rich gas and volatile oil. This is to estimate the deviation of our experimental value to the approximate value during fluid modelling or laboratory analysis since experimental and fluid modelling processes are subject to systematic error and random error because no measurement can be made with infinite precision and due to non-linear regression technique used in matching the experimental data. The

percentage error limits considered in this study are ± 5 and ± 10 . The percentage error was calculated using equation:

$$\text{Percentage Error} = \frac{\text{Experiment Value} - \text{Approximate Value}}{\text{Approximate Value}} 100\%$$

The tornado chart comparing the relative impact of the uncertainties associated with Corey exponent (λ), $k_{rg}^{\max}$, $k_{ro}^{\max}$ and fluid properties on the two-phase pseudo-pressure skin estimate for lean gas, rich gas and volatile oil are shown in Figs. 4.59, 4.60 and 4.61. They were generated for the worst case scenario for the deviation of wellbore skin estimate from base case [(lean gas (0.11), rich gas (0.12), volatile oil (0.1)] shown in Figs. 4.25, 4.43 and 4.58. The plots were produced from $\pm 32\%$ change in Corey exponent, $k_{rg}^{\max} = 0.6$, $k_{ro}^{\max} = 0.6$ and $\pm 10\%$ error on liquid drop out and gas oil ratio of the fluid properties.

The spread from base case (Figs. 4.25, 4.43 and 4.58) is within an acceptable the error limit of ± 0.5 . Hence, the impact of all relative permeability key parameters (Corey exponent (λ), $k_{rg}^{\max}$, $k_{ro}^{\max}$) and fluid properties on the two-phase pseudo-pressure calculation is not severe for all the three fluids considered in the theoretical study. Sensitivity analysis on the input parameters for estimating two-phase pseudo pressure for field data is not considered in this study.

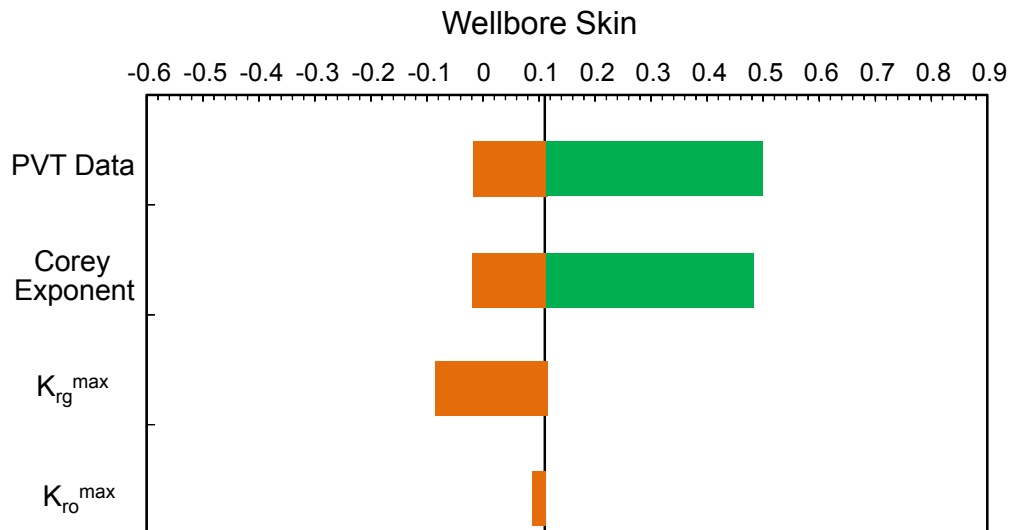


Figure 4.59: Tornado chart for lean gas sensitivity (2 ϕ PP)

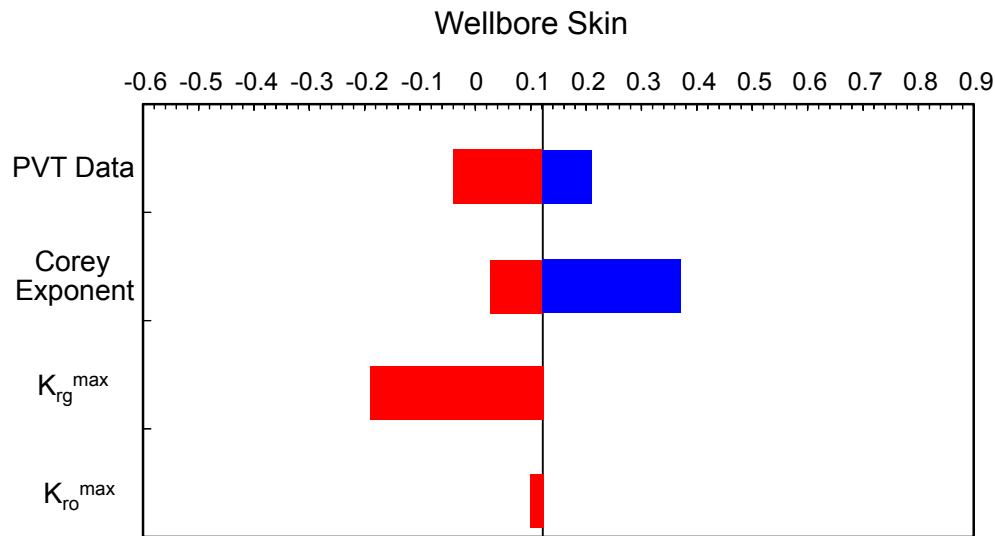


Figure 4.60: Tornado chart for rich gas sensitivity (2φPP)

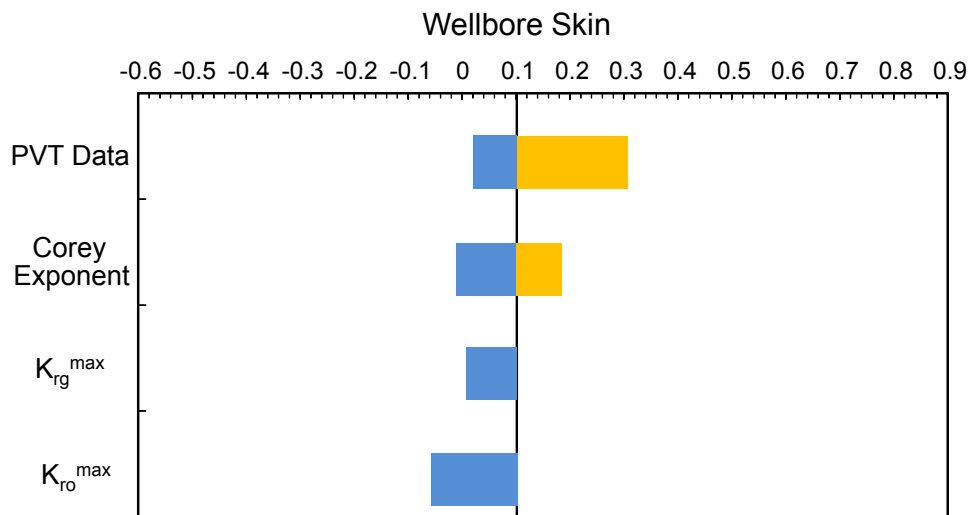


Figure 4.61: Tornado chart for volatile oil sensitivity (2φPP)

4.7 Comparison of estimated Single-phase D-Factor below saturation pressure for gas condensate and volatile oil

The lean gas single-phase turbulence factor below dew point pressure for increasing and decreasing rate histories are different (Figs. 4.18 and 4.19); it increases with both increasing and decreasing rate histories. Conversely, it decreases and increases with decreasing and increasing rate histories for the rich gas (Figs. 4.37 and 4.38). This is because for rich gas, the condensate re-vaporizes entirely when the pressure increases above the dew point pressure during build-up, whereas it does not with lean gas (Kgogo and Gringarten, 2010). Equally, for volatile oil the gas bank re-dissolves totally when the pressure increases above the bubble point pressure (Sanni and Gringarten, 2008). Hence, the wellbore skin versus rate in lean gas rate is dependent on rate history.

As indicated by Eq. 4.2, the non-Darcy factor below the saturation pressure in gas condensate or volatile oil wells is inversely proportional to the gas or oil effective permeability and increases as the condensate or gas bank at the wellbore increases. Hence, non-Darcy factor is usually higher in gas condensate or volatile oil wells below saturation pressure compared to dry gas or black oil reservoir. This is illustrated in Figs. 4.11 and 4.20 for lean gas; Figs. 4.30 and 4.39 for rich gas and in Fig. 4.47 and 4.54 for volatile oil.

4.8 Skin vs. rate relationship with two-phase pseudo-pressure calculated without high capillary number and non-Darcy effects

Figs. 4.62 and 4.63 show the wellbore skin vs. rate relationship obtained with two-phase pseudo-pressure calculated without high capillary number and non-Darcy effects on relative permeability curve for lean gas and rich gas, respectively. The relationship is still linear, but the slopes are different from the slopes above the dew point pressure and are less than the slopes with two-phase pseudo-pressure calculated with high capillary number and non-Darcy effects on the relative permeability curves. Although, the corresponding mechanical skins differ by a small amount for these examples, the difference may be larger. Authors have reported errors of up two units of the mechanical skin used in the simulation (Raghavan *et al.* 1999; Barrios *et al.* 2003).

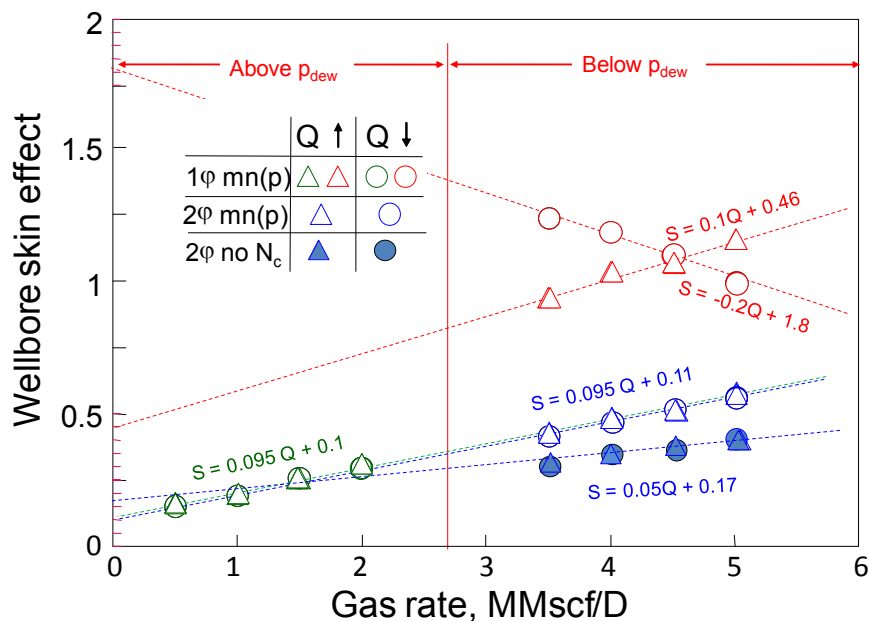


Figure 4.62: Wellbore skin vs. increasing and decreasing rate for lean gas ($2\phi m_n(p)$ without N_c and nD) ($s_m=0$)

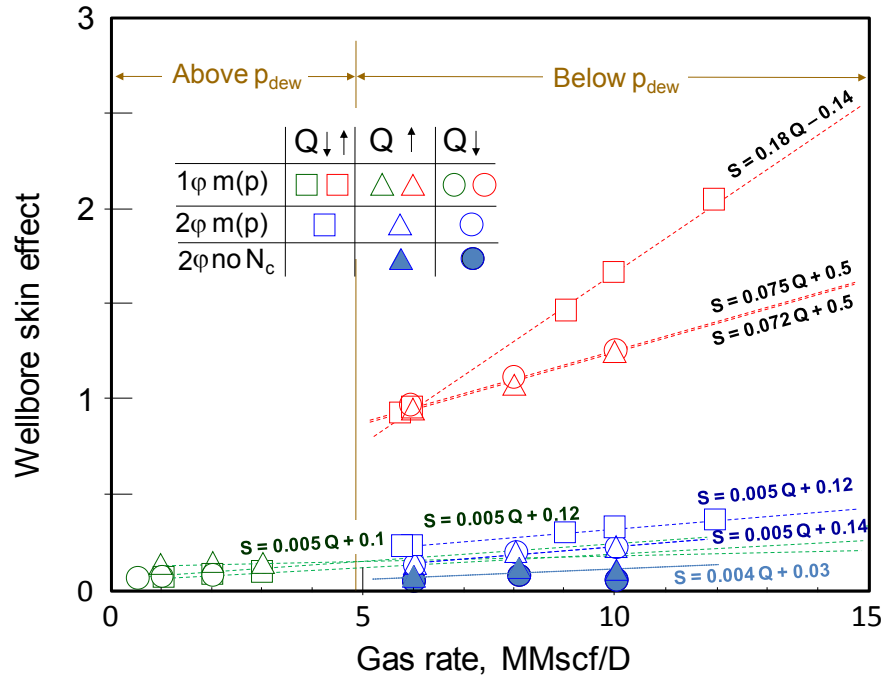


Figure 4.63: Wellbore skin vs. increasing and decreasing rate for rich gas(2φ $m_n(p)$ without N_c and nD) ($s_m=0$)

4.9 Skin versus Rate Relationship for Two-Phase Pseudo-Pressure for different values of Simulated Mechanical Skin

Additional compositional simulation runs were carried out to study the impact of different values of mechanical skin (i.e. $s_m = 2, 5, 10$ and 15 for lean and rich gases, $s_m = 2, 5, 8$ and 10 for volatile oil) on single-phase and two-phase wellbore skin versus rate analyses. The rates were set in a descending and ascending order (similar to Figs. 4.12 and 4.13 for lean gas, Figs. 4.31 and 4.32 for rich gas, Figs. 4.48 and 4.49 for volatile oil). The build-up data of single-phase pseudo-pressure (for lean and rich gas), pressure (for volatile oil) and two-phase pseudo-pressure were matched with multirate type curve to estimate the wellbore skin.

4.9.1 Results of Lean and Rich Gas Condensate

Above the dew point, the single-phase pseudo-pressure estimate of wellbore skin versus rate relationship in the left hand side (LHS) of Figs. 4.64 and 4.65 for mechanical skin, $s = 2$ is linear. The mechanical skin (2.05 for lean gas; 2.12 for rich gas) is consistent with the corresponding value from simulator. The turbulence factors (0.095 D/MMscf for lean gas, 0.005 D/MMscf for rich gas) are similar to the simulator values of 0.095 D/MMscf and 0.005 D/MMscf.

Below the dew point pressure, the single-phase pseudo-pressure estimate of mechanical skin is inconsistent with the simulator value of 2. The plot of wellbore skin versus rate for two-phase pseudo-pressure analyses in the right hand side (RHS) of Figs. 4.64 and 4.64 show a linear relationship. The turbulence factor obtained from two-phase pseudo-pressure (Figs. 4.64 and 4.65) calculated with relative permeability which integrates non-Darcy effect and high capillary number are similar to the values obtained above the dew point pressure for lean and rich gas condensate. The negative slope of wellbore skin versus rate relationship for decreasing rate history for lean gas was corrected by two-phase pseudo-pressure. This also confirms that the high capillary number do not overcompensate for non-Darcy effect due to the very high production rates.

The plot of two-phase mechanical skin estimate versus actual mechanical skin (Figs. 4.66 and 4.67) for lean and rich gases give a linear relationship. However, Figs. 4.66 and 4.67 show that the error in the mechanical skin estimated with two-phase pseudo-pressure (2.05, 4.80 and 9.5 for lean gas; 2.13, 4.6 and 9 for rich gas) increases with increasing actual mechanical skin. Even though, the error in the estimated rate independent skin increases with increase in the actual mechanical skin (Figs 4.66 and 4.67), better predictions of mechanical skin were obtained when high capillary number and turbulence effect are incorporated on the relative permeability curves used for the two-phase pseudo-pressure calculation compared to the values reported by Raghavan *et al.* 1999 and Barrios *et al.* 2003.

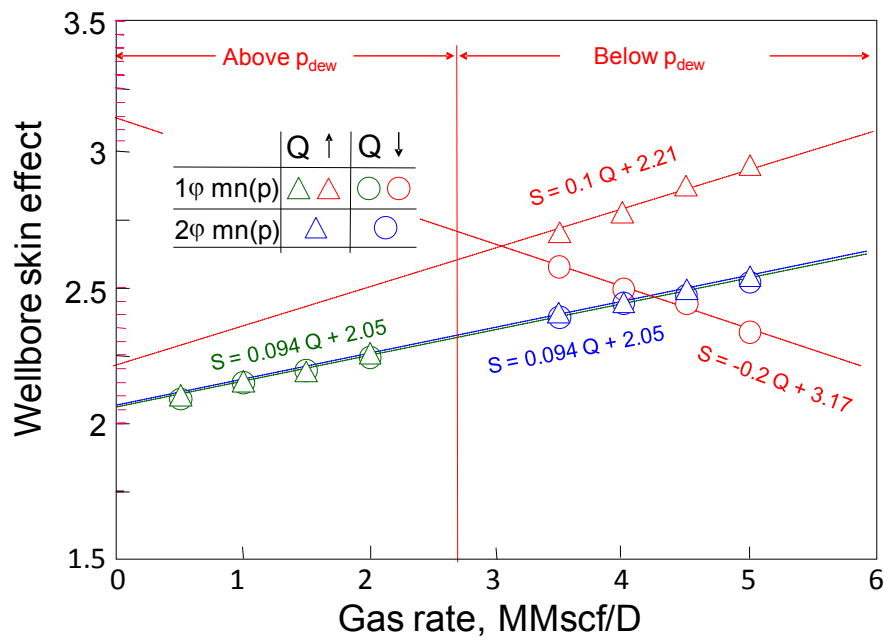


Figure 4.64: Wellbore skin vs. increasing and decreasing rate for lean gas (2φ mn(p)) ($s_m=2$)

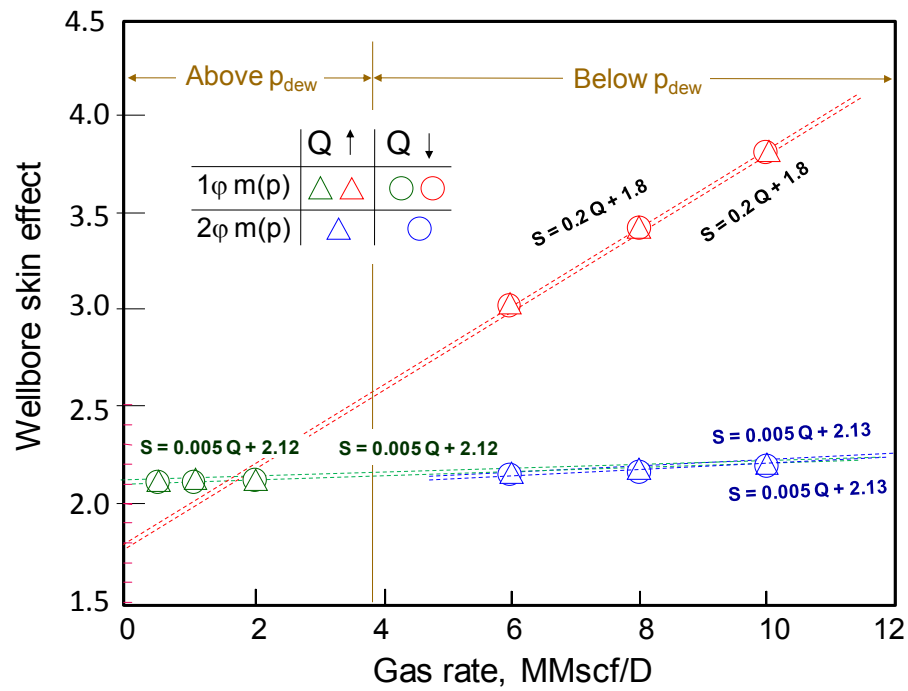


Figure 4.65: Wellbore skin vs. increasing and decreasing rate for rich gas (2φ m_n(p)) (s_m=2)

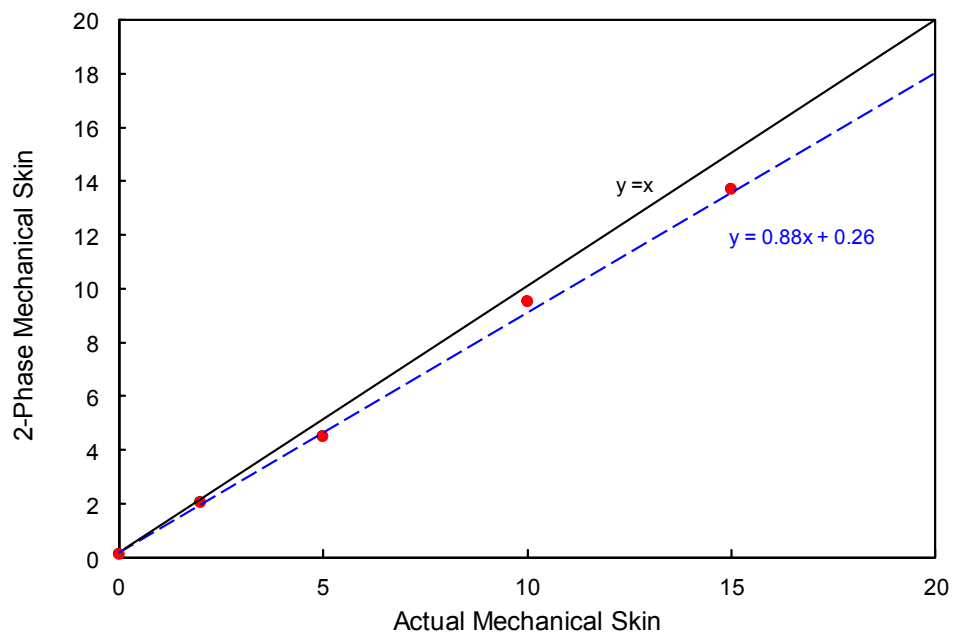


Figure 4.66: Calculated 2-Phase Mechanical Skin vs. Actual Mechanical Skin for Lean Gas

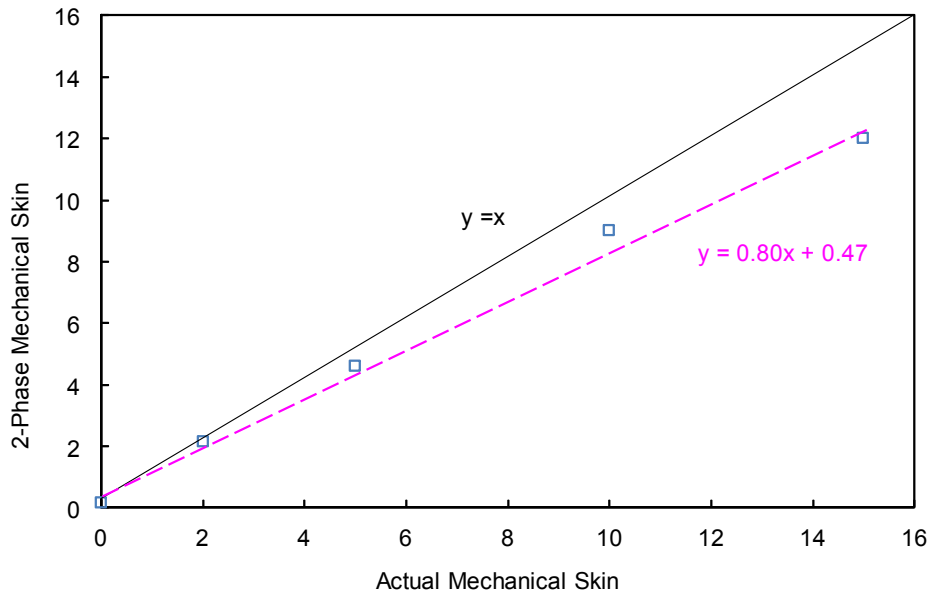


Figure 4.67: Calculated 2-Phase Mechanical Skin vs. Actual Mechanical Skin for Rich Gas

4.9.2 Results of Volatile Oil

Above bubble point pressure, the wellbore skin effect versus rate relationship in the left hand side (LHS) of Figs. 4.68 is constant as expected of black oil for mechanical skin =2. The plot of wellbore skin versus rate in the right hand side (RHS) of Figs. 4.68 shows a linear relationship below the bubble point pressure. The pressure analysis for increasing and decreasing rates history yield a similar turbulence factor of 0.2 D/Mstb and a rate independent skin effect of 1.9. These values are inconsistent with the simulation input values for mechanical skin (2) and turbulence factor (0.004D/Mstb).

Similar to lean and rich gases, the plot of two-phase mechanical skin versus actual mechanical skin (Figs. 4.69) for volatile oil shows a linear relationship. The error in the rate-independent (mechanical) skin estimated with two-phase pseudo-pressure (2.1, 4.48, 6.88 and 7.94) increases with increase in actual mechanical skin (2, 5, 8 and 10). The two-phase pseudo-pressure underestimated the wellbore skin with error more than two units for higher value of mechanical skin (Fig. 4.69) for the volatile oil case.

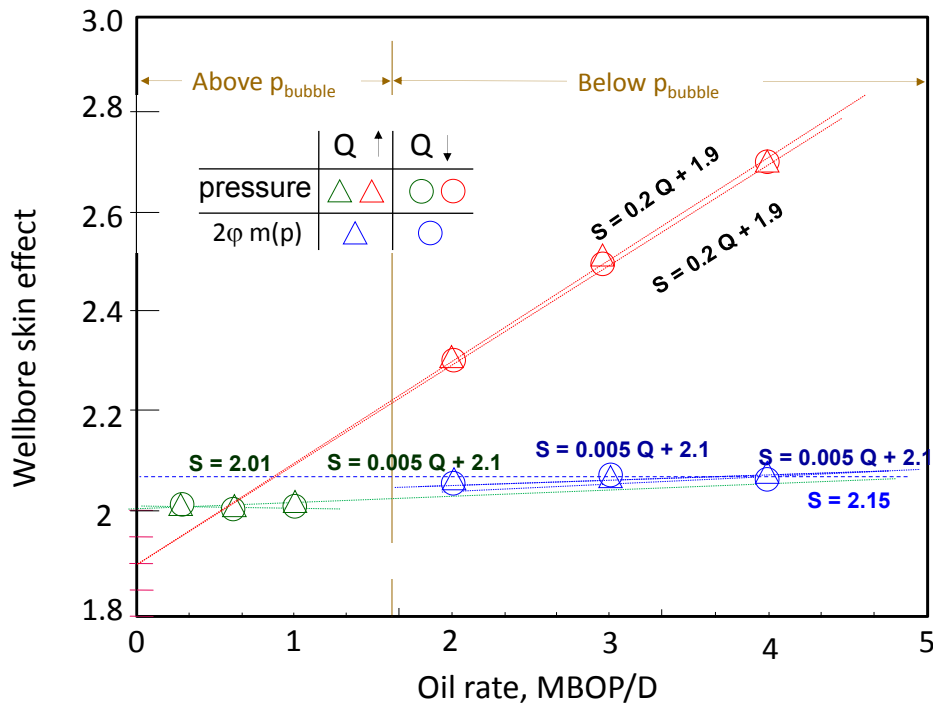


Figure 4.68: Wellbore skin vs. increasing and decreasing rate for volatile oil ($2\phi m_n(p)$) ($s_m=2$)

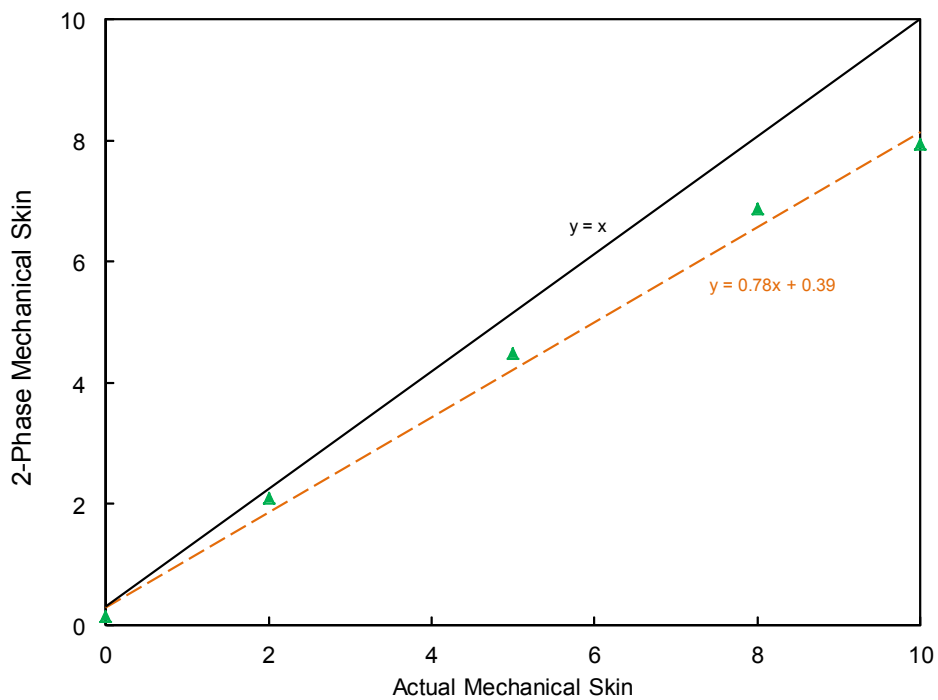


Figure 4.69: Calculated 2-Phase Mechanical Skin vs. Actual Mechanical Skin for Volatile Oil

4.9.3 Summary of Two-phase Pseudo-pressure for higher values of mechanical skins

1. The plot of two-phase mechanical skin versus actual mechanical skin for all the three fluids shows a linear relationship.

2. The error in the mechanical skin effect estimated with two-phase pseudo-pressure for lean gas, rich gas and volatile oil increases with increasing actual mechanical skin. However, the error in the volatile case is much higher compared to lean and rich gas condensate.

4.10 Rate-Dependent Skin Calculation of Field Data

The wellbore skin versus rate relationship from compositional simulations above were checked against field data for lean gas and rich gas condensate as well as volatile oil using single-phase pseudo-pressure, pressure analysis (for volatile oil) and two-phase pseudo-pressure. All build-up data were converted to two-phase pseudo-pressure using the procedure specified in section 2.4. Sensitivity analysis on the input parameters for estimating two-phase pseudo pressure for field data is not considered in this study.

4.10.1 Lean gas condensate example (CDFi)

This example is from a horizontal well in a North Sea lean gas reservoir (CDFi) described in Hashemi *et al.* (2004). The condensate gas ratio (CGR) is between 24-33 STB/MMscf. Pressure and production rate data from one drill stem test (Fig. 4.70) and two production tests (Figs. 4.71 - 4.72). The first and second production test comprised two main build-up each (BU18 and BU20) and (BU30 and BU36) respectively. All drawdowns in the DST are above the dew point pressure (except the last one), and all drawdowns and build up's in the production tests are below the dew point pressure.

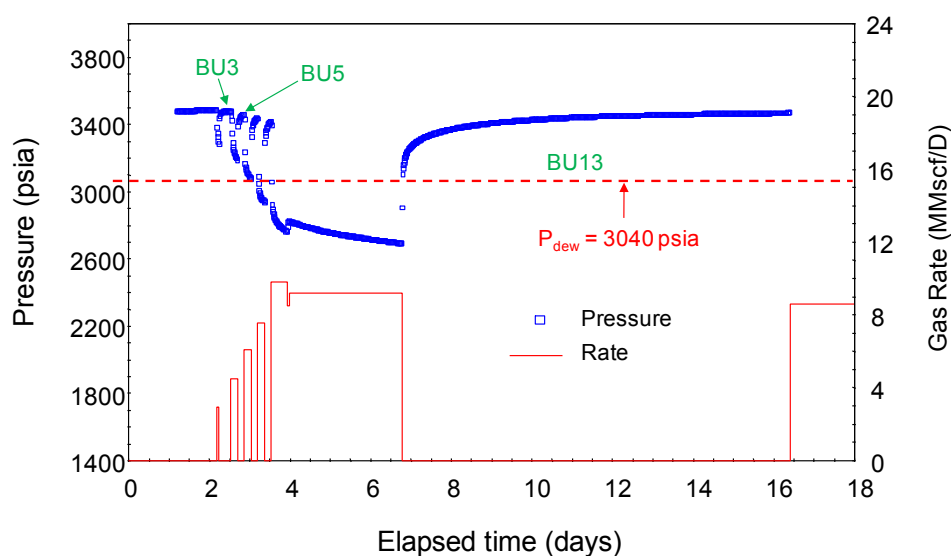


Figure 4.70: Pressure and rate histories for lean gas well CDFi (1)

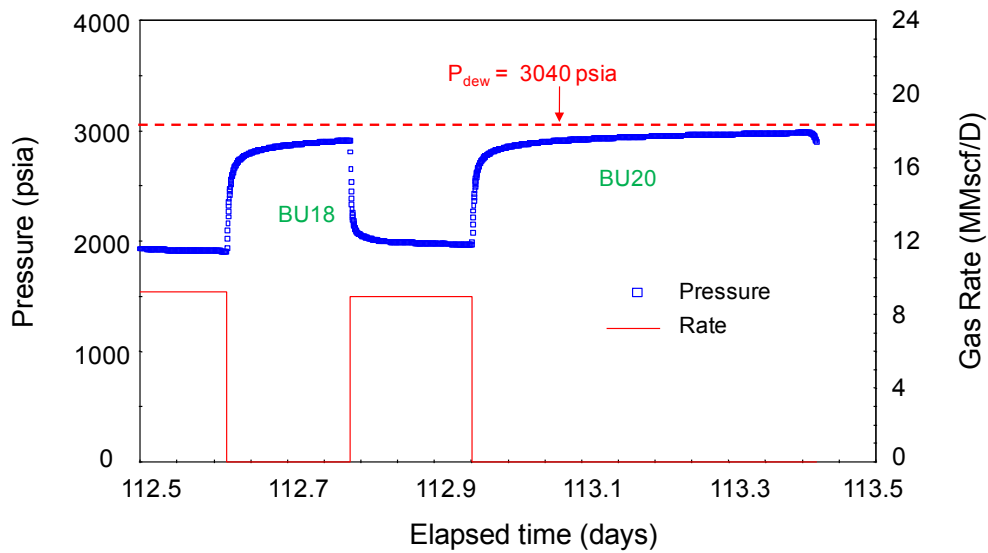


Figure 4.71: Pressure and rate histories for lean gas well CDFi (2)

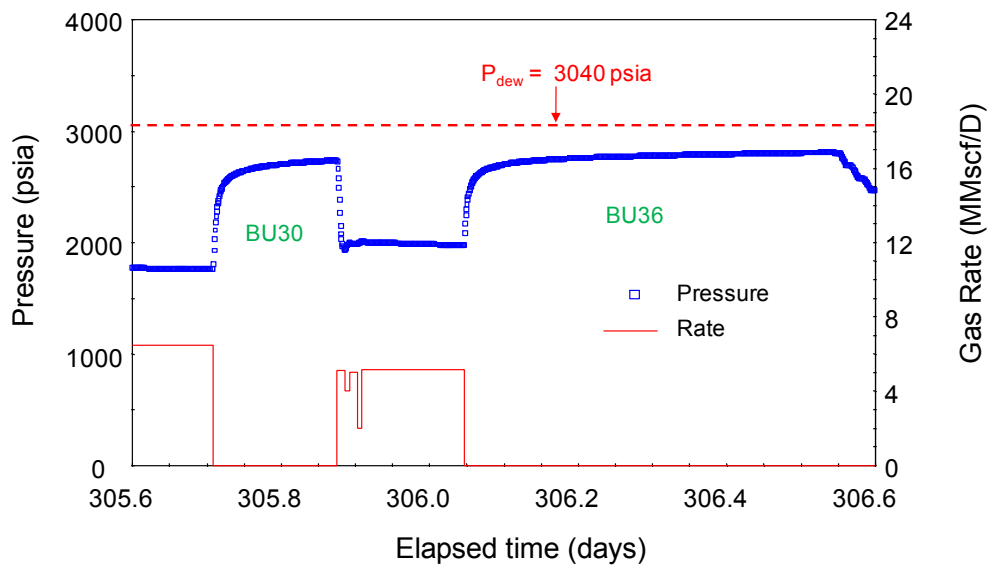


Figure 4.72: Pressure and rate histories for lean gas well CDFi (3)

4.10.1.1 Single-phase Pseudo-pressure results for CDFi

Build-up data from Figs. 4.70, 4.71 and 4.72 were analysed with single-phase pseudo-pressure to obtain the main reservoir parameters, identify the existence of a decreased mobility zone due to condensate bank and evaluate the skin versus rate relationship. The interpretation model for the well is a uniform flux horizontal well with wellbore storage and skin in a homogeneous reservoir with open rectangular boundaries.

Fig. 4.74 shows the wellbore skin versus gas rate relationship. When the analysis is performed with single-phase pseudo-pressure, a straight line with a positive slope is obtained with DST data above the dew point pressure. This line includes build-up BU13 which follows the DST drawdown below the dew point pressure. On the other hand, a

negative slope is obtained with production data which are all below dew point pressure. This is similar to the simulation results shown in Fig. 4.20.

4.10.1.2 Two-phase Pseudo-pressure results for CDFi

The build-up data (BU18, BU20, BU30 and BU36) in Figs. 4.71 and 4.72 were converted to two-phase pseudo pressure using the procedure specified in section 2.4. The relative permeability curve (Fig. 4.73) was taken from the CDFi full field simulation model (simulation model update, June 2000). It was generated with connate water saturation (S_{wc}) of 15.7%, end point gas and oil relative permeability (k_{rg}^{max} and k_{ro}^{max}) of 1, gas saturation (S_g) of 84.3%, a Corey exponent (λ) of 3.5, critical gas saturation (S_{gc}) of 10% and a critical condensate (S_{oc}) of 20%.

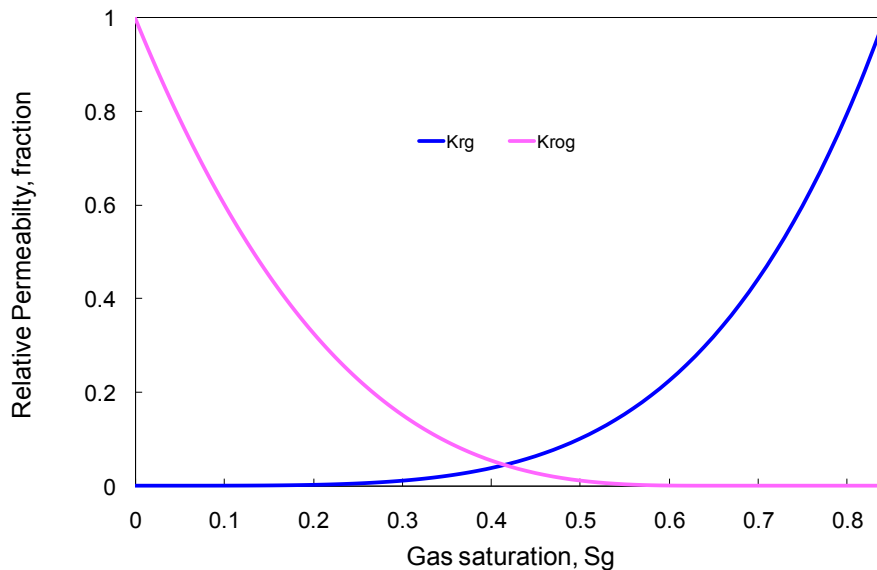


Figure 4.73: Gas-Oil relative permeability curve for CDFi

The wellbore skin versus rate plot (Fig. 4.74) for flow periods below the dew point pressure fall on the DST straight line (similar to Fig. 4.25) when two-phase pseudo-pressure was applied. Listed in Table 4.14 are the single-phase and two-phase pseudo-pressure analyses results which were obtained by matching the build-up data with multirate type curve.

Fig. 4.75 shows the rate normalized log-log pressure change and derivative plot for single-phase and two-phase pseudo-pressure showing the mobile oil region, p_{bank} , t_{bank} , and k_{abs} for CDFi. Two-phase pseudo-pressure can be used to estimate the effective permeability for a lean gas condensate reservoir below dew point pressure provided correct end point gas relative permeability (k_{rg}^{max}) is used for the two-phase pseudo-pressure calculation.

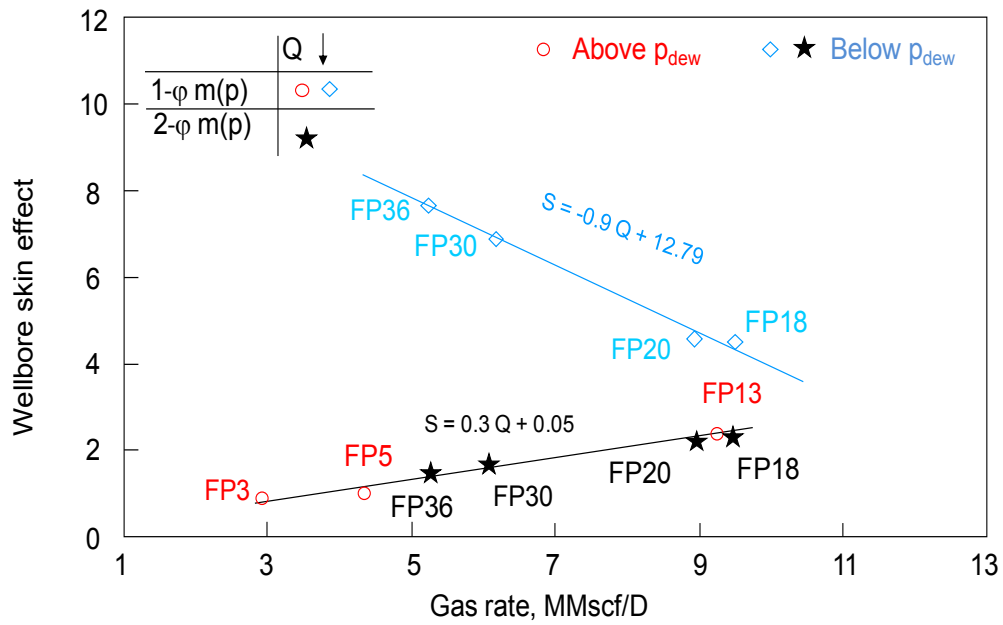


Figure 4.74: Wellbore skin vs. rate for lean gas (1φPP and 2φPP) for lean gas well CDFi

Table 4.14: 1φPP and 2φPP analysis results for CDFi

Flow Period	Rate MMscf/day)	1φSkin	2φSkin
BU3	2.95	0.95	
BU5	4.50	1	
BU13	9.20	2.6	
BU18	9.25	4.2	2.51
BU20	9.00	4.5	2.44
BU30	6.45	7.08	1.8
BU36	5.13	7.8	1.44

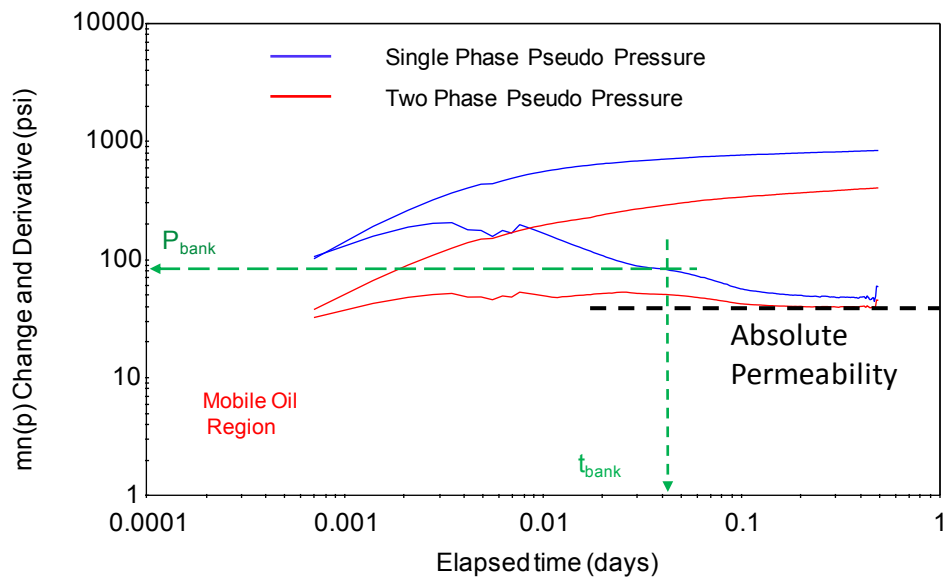


Figure 4.75: Single-phase vs. two-phase pseudo-pressure for lean gas well (CDFi)

4.10.2 Rich gas condensate example (MTG)

This example is from a vertical well (Well W-7) in a North Africa very rich gas reservoir (MTG) described in Aluko and Gringarten (2009). The pressure and rate history from Well W-7 are shown in Fig. 4.76. This includes an initial extended well test (IEWT) from FP8 to FP11 followed by a series of flow and shut-in periods over approximately 3 years. The IEWT consisted of three relatively short drawdowns (4hrs, 4hrs and 4days) of progressively increasing rates followed by an extended build up lasting 105 days. MTG has a dew point pressure of 4835psi and initial reservoir pressure of 5164psi. The condensate gas ratio (CGR) varies from 175stb/MMscf at the top interval to 320stb/MMscf in the oil rim. The reservoir has an effective porosity of 13% and average permeability of 131mD.

4.10.2.1 Single-phase Pseudo-pressure results for MTG

The well test behaviour of the build-up data (Fig. 4.76) was matched with wellbore storage and skin in a channel reservoir with a three-region radial composite behaviour. The drawdowns were affected by well unloading and phase redistribution, hence; were not considered in this study. Fig. 4.78 shows the wellbore skin versus gas rate relationship. Straight lines with positive slopes were obtained when the analysis is performed with single-phase pseudo-pressure for both IEWT above the dew point pressure and production data below the dew point pressure (Fig. 4.78).

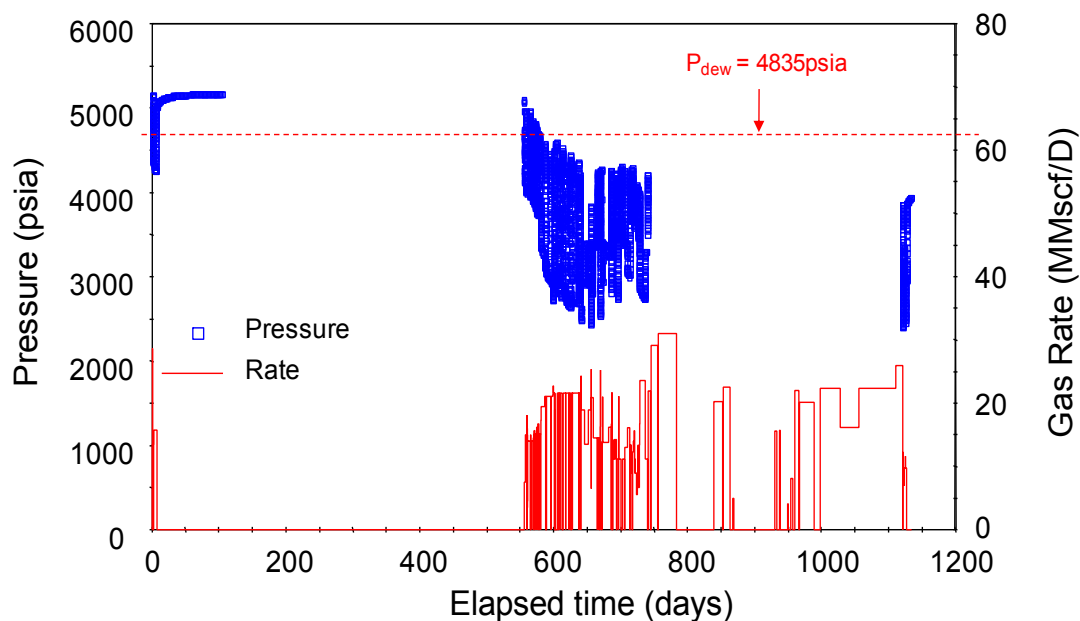


Figure 4.76: Pressure and rate histories for rich gas well MTG

4.10.2.2 Two-phase Pseudo-pressure results for MTG

The build-up in Fig. 4.76 was converted to two-phase pseudo pressure using the procedure specified in section 2.4. The Corey relative permeability curves selected for the two-phase pseudo-pressure calculation was derived from a set of normalised laboratory-measured curves of the MTG gas condensate reservoir, it was de-normalised with average gas saturation end point of 60% (Aluko, 2009). The match was obtained with end point gas relative permeability (k_{rg}^{max}) of 1, an end point oil relative permeability (k_{ro}^{max}) of 1, connate water saturation (S_{wc}) of 40%, gas saturation of 60%, a critical gas saturation (S_{gc}) of 0%, a critical condensate (S_{oc}) of 10% and a Corey exponent (λ) of 2.0 and 3.0 for k_{rg} and k_{ro} respectively (Fig. 4.77).

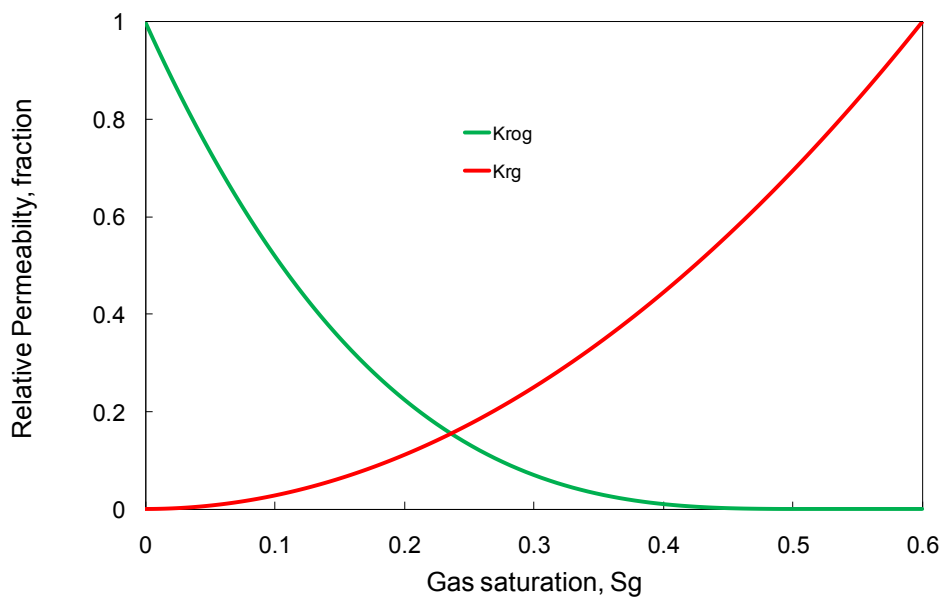


Figure 4.77: Gas-Oil relative permeability curves for MTG

The wellbore skin versus rate plot for two-phase pseudo-pressure (Fig. 4.78) gives a straight line relationship, a turbulence factor (0.8 Days/MMscf) and mechanical skin of -3.8. Similar values were obtained for the single-phase pseudo-pressure analysis above the dew point pressure. The negative skin value from the wellbore skin versus rate for both single-phase pseudo-pressure above dew point and two-phase pseudo-pressure below dew point could be due to regular acid and water wash to clean salt precipitation at the perforations because of extremely high chloride content (300,000 ppm) of the formation water (Aluko, 2009), this causes a variation in wellbore skin. The single-phase and two-phase pseudo-pressure analyses results obtained from matching the build-up data with multirate type curve are listed in Table 4.15.

Fig. 4.79 shows that the rate normalized log-log pressure and derivative plot for single-phase versus two-phase pseudo-pressure showing the mobile oil region, p_{bank} , t_{bank} , and k_{abs} for MTG. The two-phase pseudo-pressure transforms the fluid induced radial composite below dew point to homogeneous behaviour with the derivative stabilising at absolute permeability.

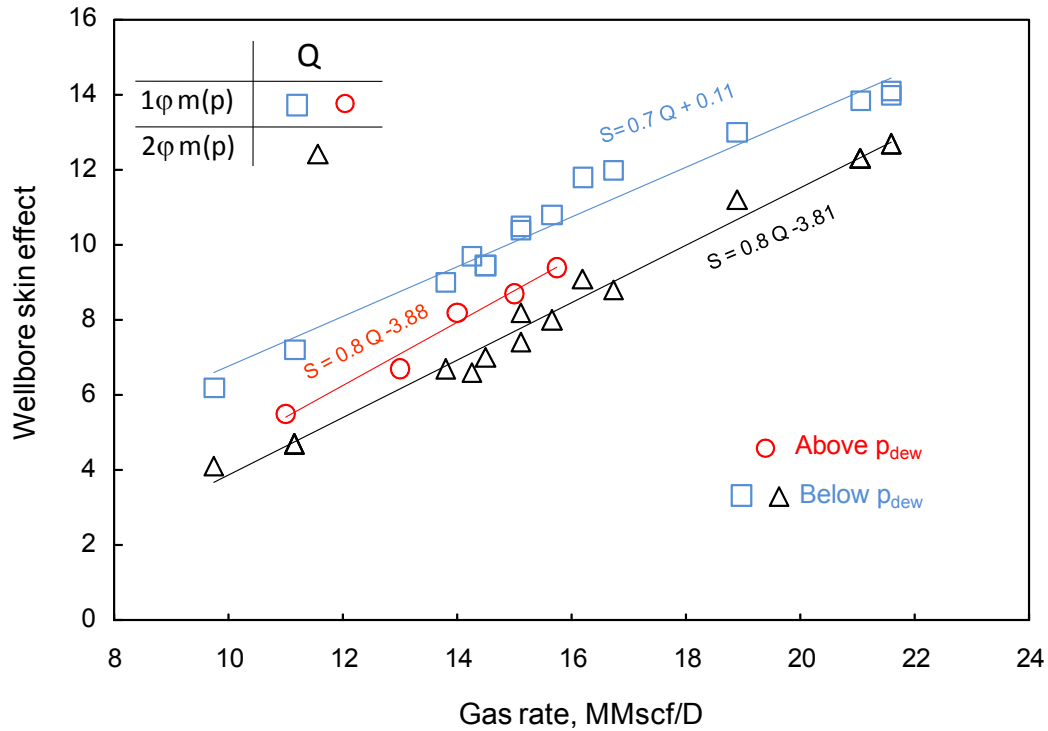


Figure 4.78: Wellbore skin vs. rate for lean gas (1φPP and 2φPP) for rich gas well MTG

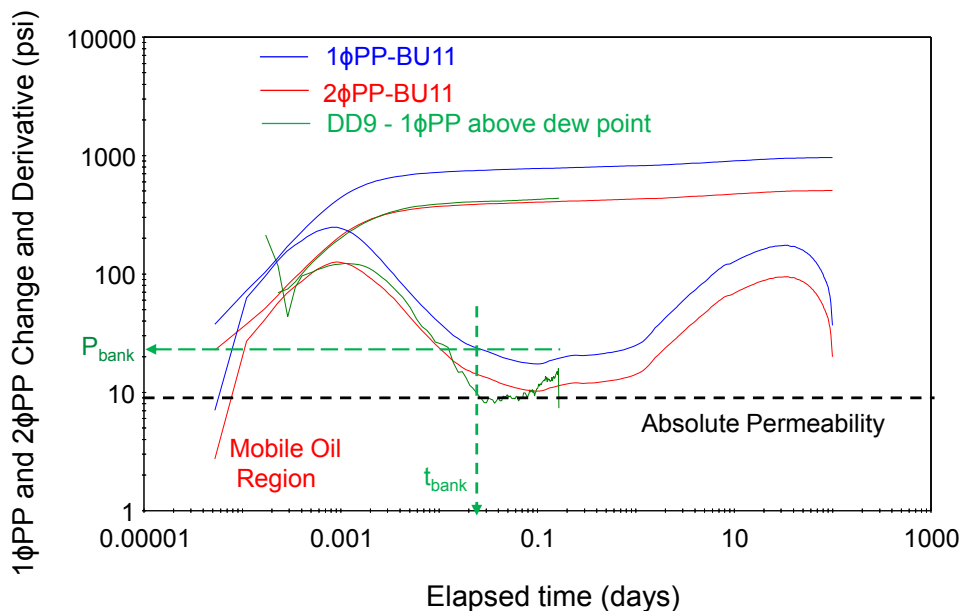


Figure 4.79: 1φPP and 2φPP for MTG

Table 4.15: 1 ϕ pp and 2 ϕ PP analysis results for MTG

Start of BU (days)	FP	Rate(MMscf/Day)	1 ϕ Skin	2 ϕ Skin
571.38	BU38	15.66	10.8	8
573.76	BU43	15.12	10.5	8.2
576.32	BU49	16.2	11.8	9.09
578.46	BU55	16.74	12	8.8
580.67	BU57	15.12	10.4	7.4
588.46	BU65	21.06	13.85	12.3
589.52	BU67	21.06	13.85	12.3
596.27	BU69	21.06	13.85	12.3
601.68	BU77	18.9	13	11.2
602.04	BU79	21.6	14.1	12.7
613.00	BU85	21.6	14	12.7
668.73	BU118	14.5	9.45	7
671.85	BU134	13.8	9	6.7
694.43	BU152	14.26	9.7	6.6
700.96	BU161	11.16	7.2	4.7
706.35	BU164	11.16	7.2	4.7
740.66	BU189	11.16	7.2	4.7
1128.01	BU232	9.75	6.2	4.1

4.10.3 Volatile oil example (VO)

This example is from a vertical well (Well W-15) in a Western Siberia volatile oil reservoir described in Sanni and Gringarten (2008). The pressure and rate history of DST-Well-15 (Fig. 4.80) show that the reservoir is below bubble point pressure. There is an initial drawdown of 41.8 days; a build-up of 6.4 days (2BU); a drawdown of 26 hours at 3 different rates (4 to 6DD); a build-up of 2.7days (7BU); a drawdown of 26 hours at 7 different rates (8 to 15DD); and a final build-up of 6.2 days (16BU). All pressure data are below the bubble point pressure. The volatile oil has a bubble point pressure of 4076psia and GOR of 1.786Mscf/bbl at 189⁰F reservoir temperature.

4.10.3.1 Pressure Analysis results for VO

The build-up data were matched with wellbore storage and skin in an open rectangular reservoir with a two-region radial composite behaviour. Fig. 4.82 shows the wellbore skin versus gas rate relationship for pressure and two-phase pseudo-pressure. The wellbore skin effect calculated from pressure analysis increases linearly with rate (Fig. 4.82) for all analysed build-up (BU2, BU7 and BU16).

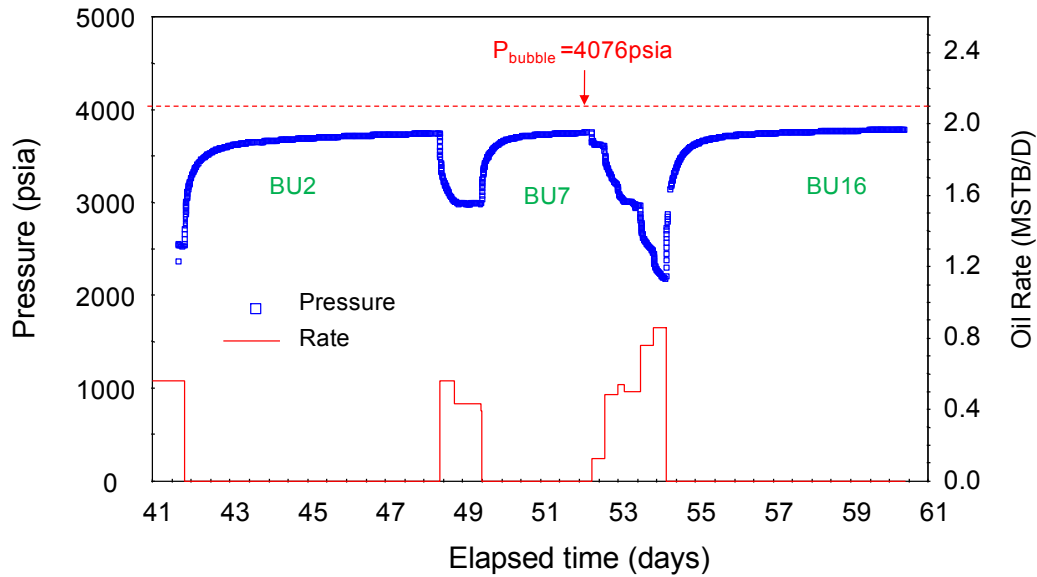


Figure 4.80: Pressure and rate history for volatile oil well

4.10.3.2 Two-phase Pseudo-pressure results for VO

The build-up data (BU2, BU7 and BU16) of DST-Well-15 (Fig. 4.80) were converted to two-phase pseudo-pressure with relative permeability curves (Fig. 4.81) which integrate the non-Darcy effect and high capillary number using the procedure specified in section 2.4. The relative permeability curves (Fig. 4.81) was derived from critical gas saturation (S_{gc}) of 0.0, critical oil saturation of 0.2, gas saturation of 0.6, Corey exponent of 2.5, end point gas and oil relative permeability (k_{rg}^{max} and k_{ro}^{max}) of 1, and connate water saturation (S_{wc}) of 0.4.

The plot of wellbore skin versus rate for two-phase pseudo-pressure analysis is shown in Fig. 4.82. The negative value of mechanical skin (-4.67 and -4.58) given by the intercept from pressure and two-phase pseudo-pressure analysis indicates that the well might have been acidized in the past, although; there is no enough information to justify this. The turbulence factor (2×10^{-3} Day/STB) calculated with two-phase pseudo-pressure generated with high capillary number and non-Darcy effects on relative permeability curves is small (similar to Fig. 4.58). The pressure and two-phase pseudo-pressure skins estimated by matching the build-up data with multirate type curve are listed in Table 4.16

Fig. 4.83 shows the rate normalized log-log pressure and derivative plot for single-phase versus two-phase pseudo-pressure showing the mobile gas region, p_{bank} , t_{bank} , and k_{abs} for the volatile oil. The two-phase pseudo-pressure derivative stabilises at the absolute permeability at $k_{ro} = k_{ro}^{max}$.

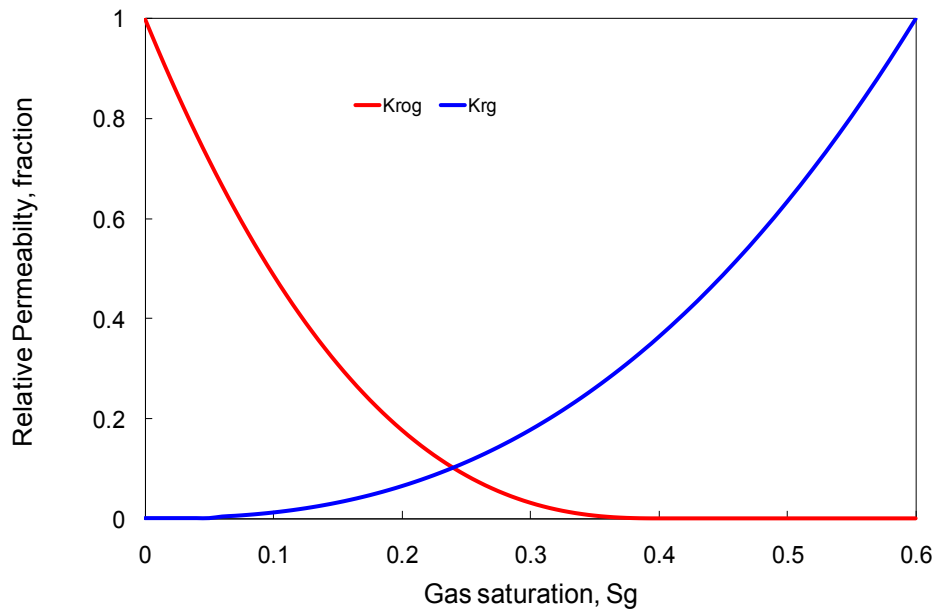


Figure 4.81: Gas-Oil relative permeability curves for Well W-15

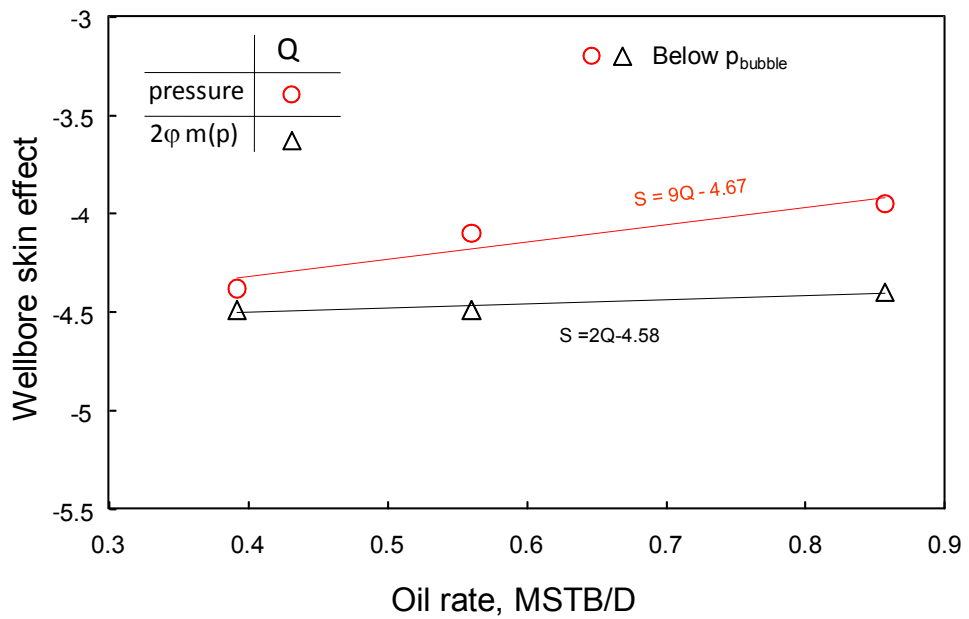


Figure 4.82: Wellbore skin vs. rate for lean gas (pressure and $2\phi PP$) for Well W-15

Table 4.16: Interpretation results for the data from Figs. 4.83 (pressure and $2\phi PP$)

FP	Oil Rate (STB/D)	Skin	$2\phi Skin$
BU2	560	-4.1	-4.49
BU7	392	-4.38	-4.49
BU16	857	-3.95	-4.4

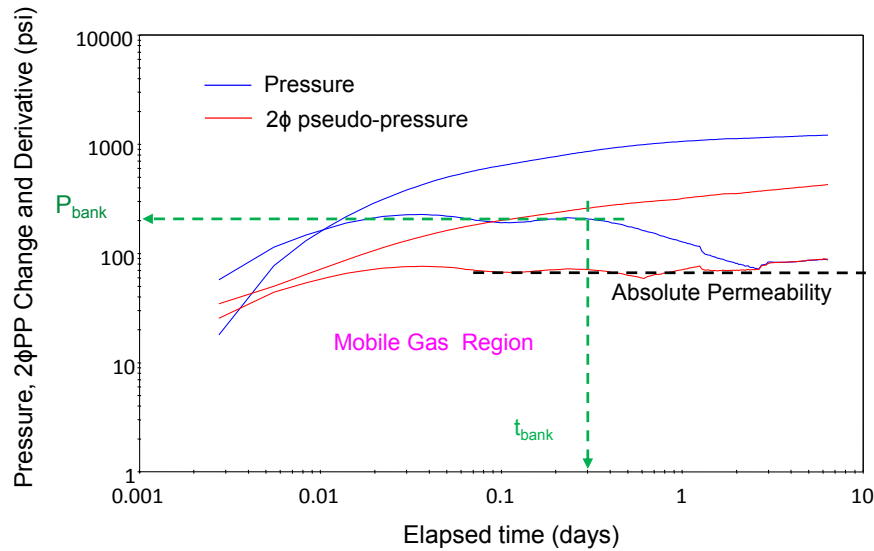


Figure 4.83: Single-phase vs. two-phase pseudo-pressures for Well W-15

4.10.4 Summary of Rate-Dependent Skin Calculation for Field Data

1. The wellbore skin versus gas rate obtained from single-phase pseudo-pressure for CDFi above dew point pressure shows a linear relationship with a positive slope while below dew point pressure show a negative slope. The wellbore skin versus gas rate from two-phase pseudo-pressure analysis for CDFi shows a linear relationship with a positive slope below dew point pressure.
2. The wellbore skin versus gas rate obtained from single-phase and two-phase pseudo-pressure for MTG above and below dew point pressure shows a linear relationship with positive slope.
3. The wellbore skin versus oil rate shows a linear relationship for pressure and two-phase pseudo-pressure below bubble point pressure. However, the non-Darcy factor from two-phase pseudo-pressure is smaller compared to value obtained from pressure analysis for VO.

4.11 Well Deliverability Forecasting Using Compositional Simulation

Compositional simulation is used to study gas condensate or volatile oil because of the compositional changes in reservoir below saturation pressure. It accounts for the effects of composition on the phase behaviour; miscibility or near-miscible displacement behaviour in compositionally dependent mechanisms such as vaporisation, condensation, and oil swelling. It can also be used to confirm the reliability and usefulness of the turbulence factor and the mechanical skin (calculated with two-phase pseudo-pressure) in

the deliverability forecasting for gas condensate and volatile oil reservoir below saturation pressure.

Capillary number and non-Darcy effect were included in the compositional simulation model to avoid overestimating the well pressure drop below the dew or bubble point pressure for gas condensate and volatile oil respectively. The turbulence factor and mechanical skin used for the compositional simulation study were taken from the two-phase pseudo-pressure analysis for CDFi, MTG and VO.

4.11.1 CDFi

A 3D horizontal well model with 15120 ($42 \times 30 \times 12$) Cartesian grid blocks was used for the compositional simulation of CDFi. The well is fully penetrating in the x-direction (Fig. 4.84). The distances to the no-flow boundaries, initial reservoir pressure and the basic reservoir parameters (Table 4.17) were developed based on the analytical well test results of well CDFi. A model consisting of an open rectangle with the mid-point of the horizontal well was positioned 1200ft and 1200ft from the parallel sides of the rectangle in the x-direction, and 1700 ft from the parallel sides in y-direction, the fourth boundary was set far enough (at 6000 ft). The estimated capillary number parameters are listed in Table 4.18.

The turbulence factor (0.3 D/MMscf) and mechanical skin (0.05) were taken from two-phase pseudo-pressure analysis in section 4.10.1.2. Relative permeability curves (Fig. 4.73) were used for the simulation model. A good match was obtained between the actual and simulated pressure history for CDFi (Figs. 4.85, 4.86 and 4.87). The match of the actual and simulated log-log pressure and derivative plot for BU13 is shown in Fig 4.88.

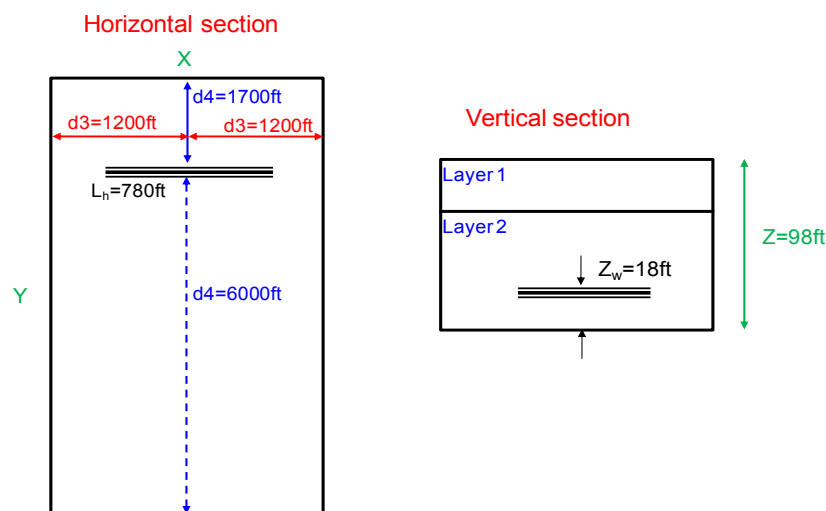


Figure 4.84: Model configuration for simulating well CDFi (Hashemi, 2006)

Table 4.17: Parameters for simulation of CDFi

Parameter	Value
Top of Reservoir (ft)	7453
Wellbore Radius (ft)	0.178
Reservoir Thickness (ft)	27
Reservoir Porosity (%)	12%
Mechanical Skin	0.05
D Factor (Day/Mscf)	3×10^{-4}
Initial Reservoir Pressure at gauge	3485
Average Horizontal Permeability	2.2
K_v/K_h Ratio	0.05
Initial water Saturation (S_{wi})	15.7%
Well Length (ft)	780
Dew Point Pressure (psia)	3040
d1 (ft)	1200
d2 (ft)	1700
d3 (ft)	1200

Table 4.18: Capillary Number Parameters for CDFi

Parameter	Values
$N_{CBG/o}$	5.2×10^{-8}
m_o	79.62
m_g	23.89
n_{1o}	24.2
n_{1g}	30
n_{2o}	-3
n_{2g}	-3

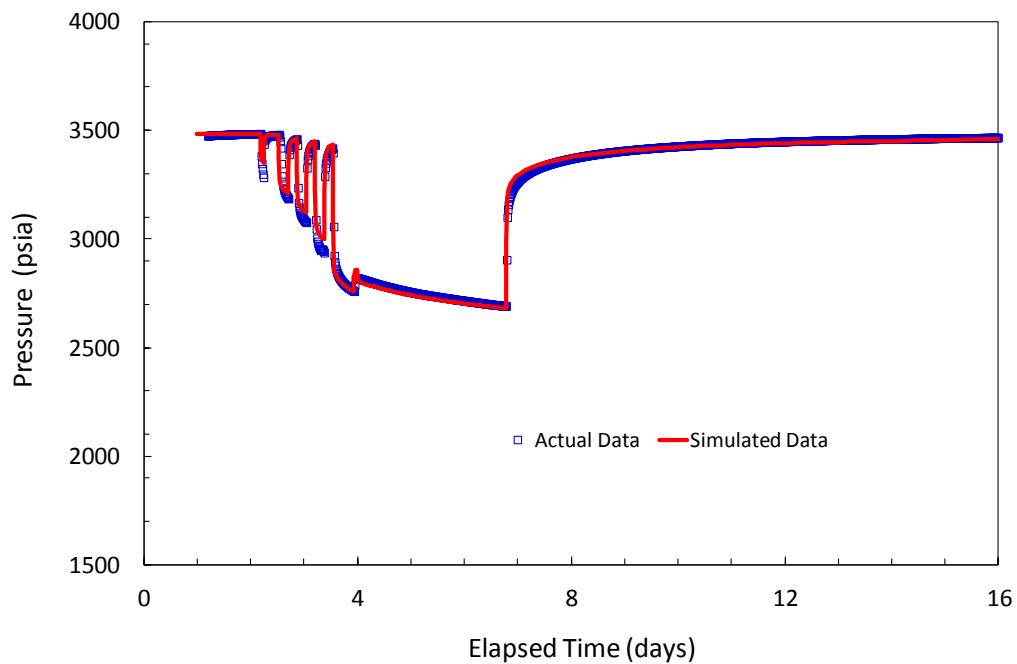


Figure 4.85: Comparison of actual and simulated data for CDFi (BU3, BU5 and BU13)

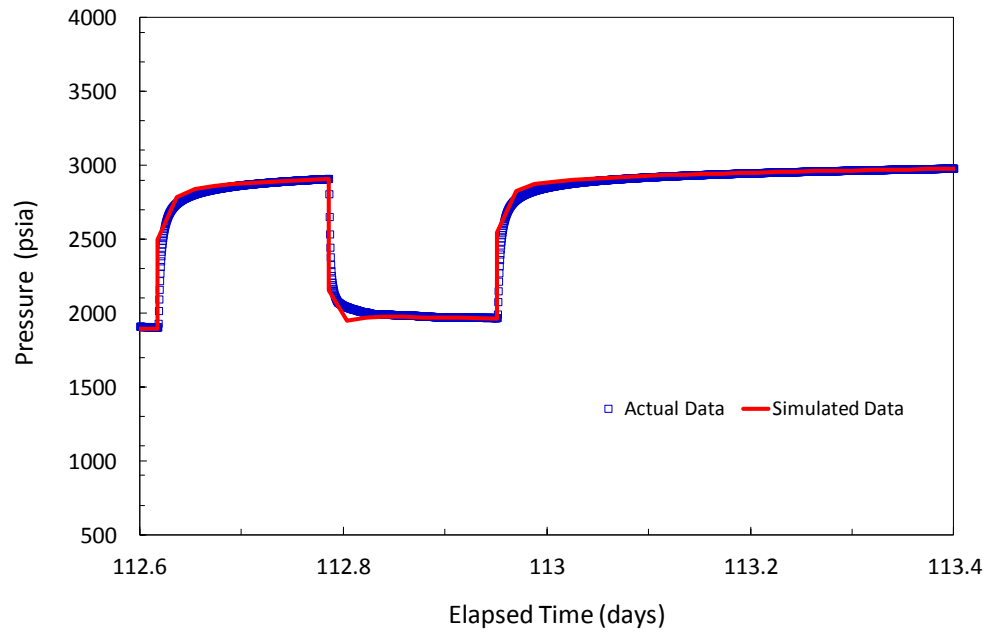


Figure 4.86: Comparison of actual and simulated data for CDFi (BU18 and BU20)

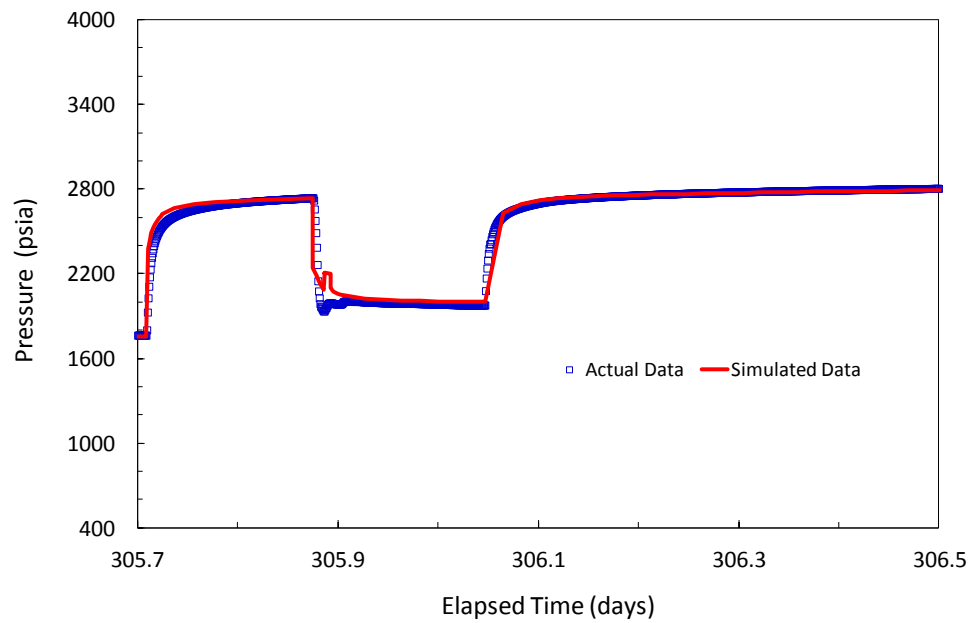


Figure 4.87: Comparison of actual and simulated data for CDFi (BU30 and BU36)

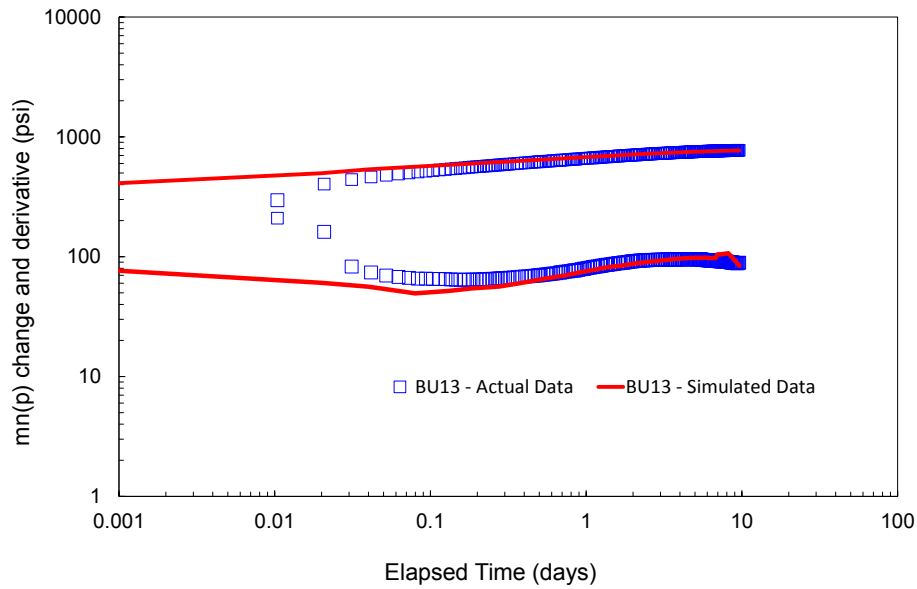


Figure 4.88: Log-log comparison between actual data and simulated data for CDFi (BU13)

4.11.2 MTG

A multi well two dimensional (6 x 18 x 1) Cartesian homogeneous reservoir model was set up with the pressure set at the MTG reservoir initial pressure of 5164psi. The basic reservoir and well parameters were obtained from the well test interpretations and core analysis of well W-7. Additional, 2 producers and 3 injectors present in the MTG reservoir when the well test data for well W-7 was obtained were included in the history matching model. Fig. 4.89 shows the MTG top structure schematic showing faults, and additional 2 producer wells and 3 injectors at relative distance to the vertical well W-7.

Local grid refinements (LGR) were included in the simulation model close to the wellbore of well W-7 so as to capture near wellbore effect. The production rates from other 2 producers were adjusted to match the depletion observed in well W-7 since well W-7 is of primary interest and no information was available on the other production wells. The relative permeability curve (Fig. 4.77), non-Darcy factor and mechanical skin taken from the two-phase pseudo-pressure analysis (Fig. 4.78) were used for the compositional simulation. The basic reservoir data and estimated capillary number parameters from the history matched model are presented in Tables 4.19 and 4.20.

A good match was obtained between the actual and simulated pressure history (Fig. 4.90). The match of the actual and simulated log-log pressure and derivative plots for BU11, BU65 and BU79 is shown in Figs 4.91.

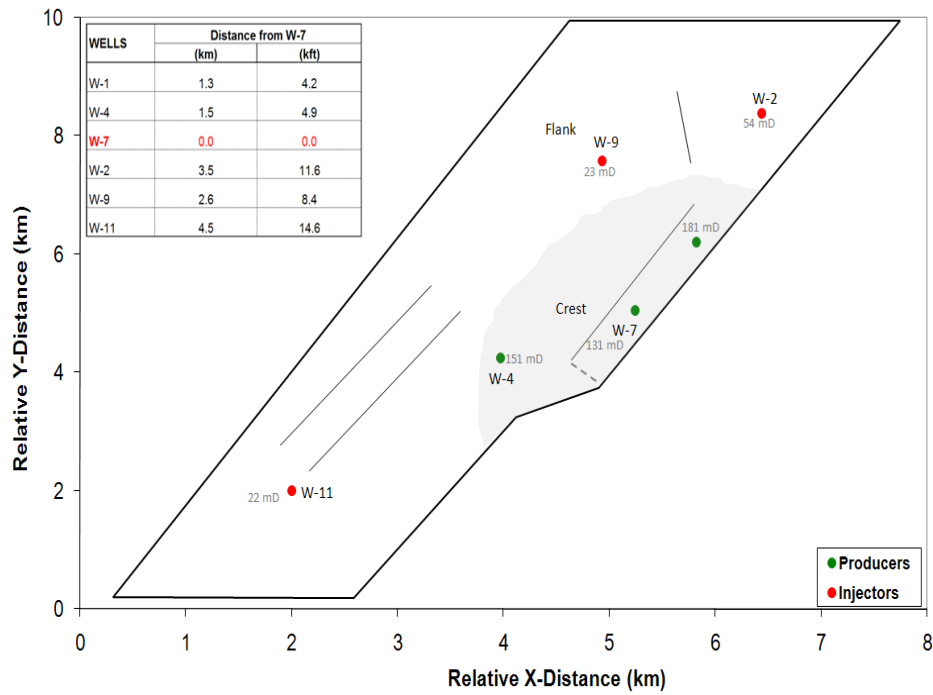


Figure 4.89: MTG top structure schematic showing faults, wells, well utility and distances (Aluko, 2009)

Table 4.19: Parameters for simulation of MTG Well W-7

Parameter	Value
Top of Reservoir (ft)	10014
Wellbore Radius (ft)	0.25
Reservoir Thickness (ft)	27
Reservoir Porosity (%)	13%
Mechanical Skin	-1
D Factor (Day/Mscf)	8×10^{-4}
Initial Reservoir Pressure at gauge Depth	5164
Average Reservoir Permeability (mD)	131
K_v/K_h Ratio	0.1
Initial water Saturation (S_{wi})	40%
Dew Point Pressure (psia)	4835

Table 4.20: Capillary Number Parameters for MTG

Parameter	Values
$N_{CBg/o}$	1.3×10^{-4}
m_o	0
m_g	0
n_{1o}	30
n_{1g}	30
n_{2o}	-1
n_{2g}	-1

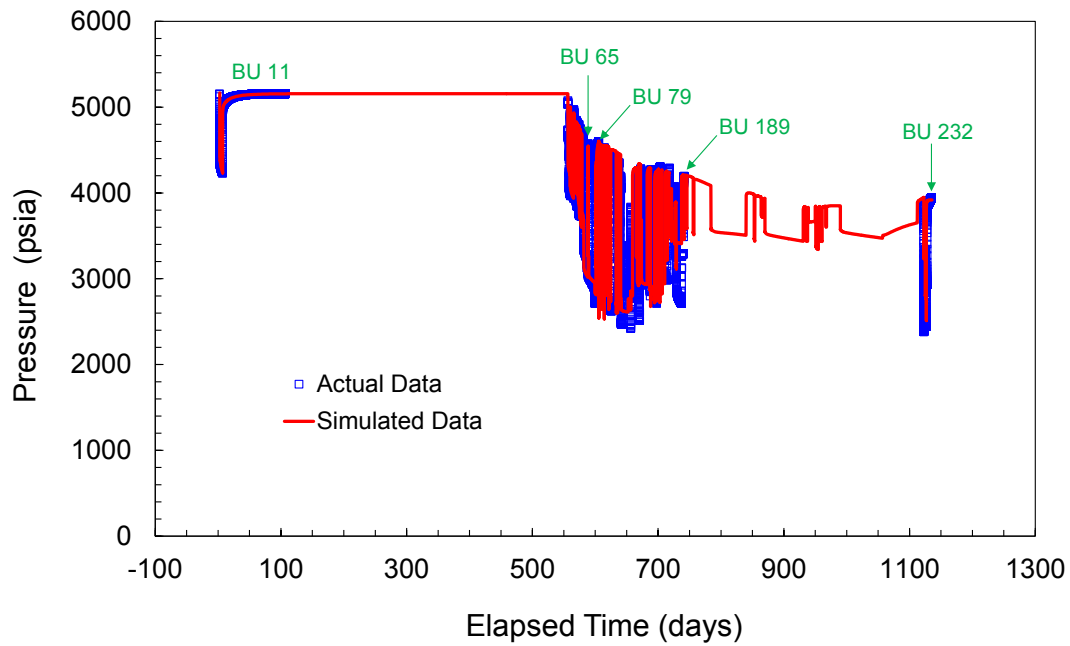


Figure 4.90: Comparison of actual and simulated pressure history for MTG

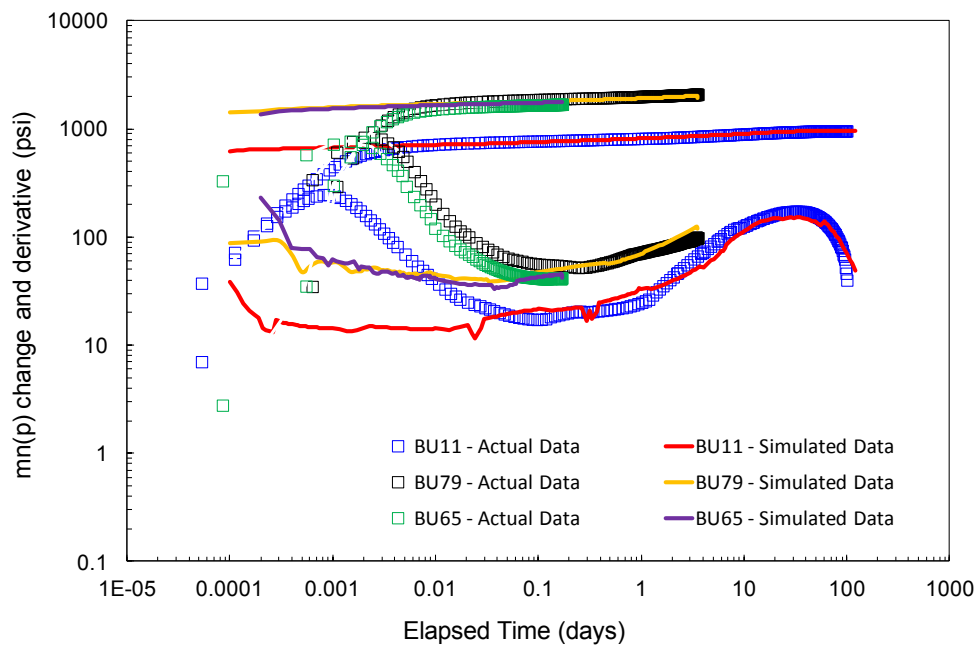


Figure 4.91: Comparison of simulated and actual pressure change and derivatives (BU11, BU65 and BU 79)

4.11.3 Volatile Oil

A 2D Cartesian grid (52 x 10 x 1) homogeneous reservoir with local grid refinement was constructed. The refined radial grid around the well vertical and fully perforated was located in cell (12, 4, 1), it consist of 20 cells with radii increasing logarithmically away from the well to capture the near-wellbore behaviour. Distances from well to the three sealing faults were set at the values obtained from the conventional well test analysis (Fig. 4.92). Simulation parameters and capillary number parameters are listed in Tables

4.21 and 4.22. The turbulence factor and mechanical skin were taken from the two-phase pseudo-pressure analysis in section 4.10.3.2. Relative permeability curve (Fig. 4.81) was used for the compositional simulation. A good match was achieved between the actual well test data pressure history and the simulated pressure history (Fig. 4.93).

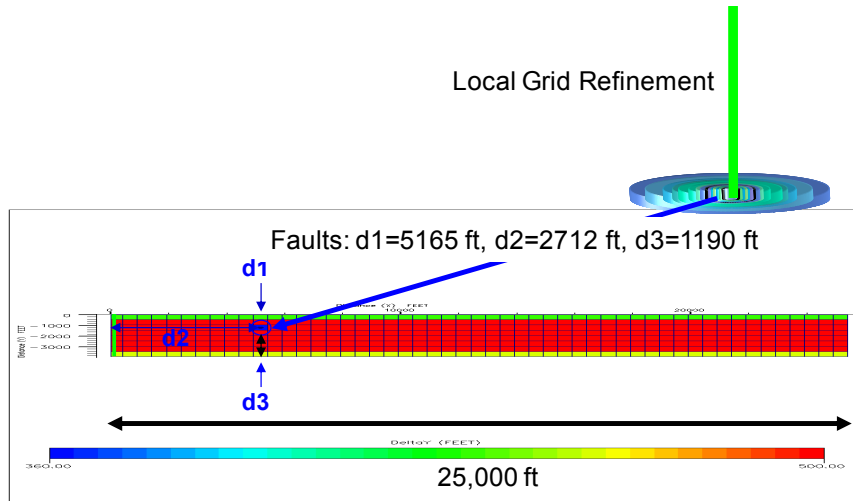


Figure 4.92: Grid model for simulation of well test for volatile oil well W-15 (Sanni, 2008)

Table 4.21: Parameters for simulation of Volatile Oil Well W-15

Parameter	Value
Top of Reservoir (ft)	10000
Wellbore Radius (ft)	0.31
Reservoir Thickness (ft)	20
Reservoir Porosity (%)	20%
Mechanical Skin	-3
D Factor (Day/STB)	2×10^{-3}
Initial Reservoir Pressure at gauge	4067
Gauge Depth (190 ft above top)	9810
Average Reservoir Permeability	19
K_v/K_h Ratio	0.1
Initial water Saturation (S_{wi})	0.4
Bubble Point Pressure (psia)	4067
d1 (ft)	5165
d2 (ft)	2712
d3 (ft)	1190

Table 4.22: Capillary Number Parameters for Volatile Oil

Parameter	Values
$N_{CBg/o}$	1×10^{-4}
m_o	80
m_g	79.62
n_{1o}	6.23
n_{1g}	6.23
n_{2o}	0
n_{2g}	-2

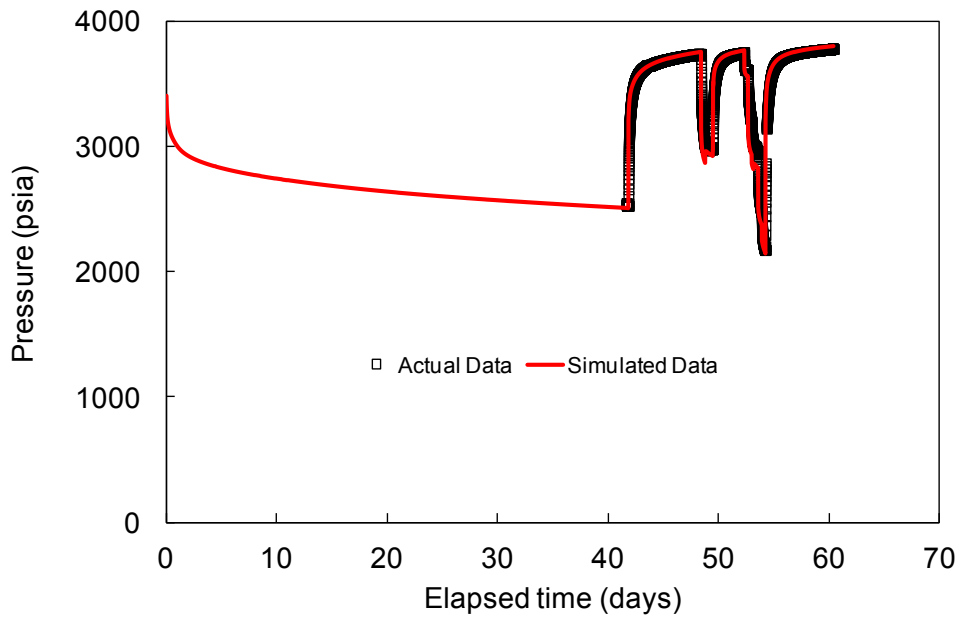


Figure 4.93: Comparison of actual and simulated pressure history for VO

4.12 Summary of Chapter 4

1. Single-phase pseudo-pressure and pressure analysis give good estimate of wellbore skin, non-Darcy factor and effective permeability above saturation pressure but yield incorrect values of wellbore skin and non-Darcy factor below saturation pressure.
2. Below saturation pressure, the wellbore skin and turbulence factor estimate from single-phase pseudo-pressure for lean gas is highly dependent on rate history compared to rich gas and volatile oil.
3. The correct value of mechanical skin, non-Darcy flow coefficient can be obtained by analysing well test data using single-phase pseudo-pressure above saturation pressure and two-phase pseudo-pressure below saturation pressure.
4. Sensitivity on the key parameters used for the two-phase pseudo-pressure calculation give an acceptable error limit of ± 0.5 on the wellbore skin estimate.
5. The match of actual and simulated well test data can provide the capillary number parameters when the turbulence factor and mechanical skin obtained from two-phase pseudo pressure below saturation pressure are used in the compositional simulation model.

CHAPTER 5

BACKPRESSURE WELL DELIVERABILITY FORECASTING OF GAS CONDENSATE AND VOLATILE OIL

5.1 Introduction

Bottom-hole backpressure plots can be used to determine the absolute open flow potential, well performance and reservoir deliverability (Fetkovich, 1973). Well deliverability testing of natural gas wells for the estimation of stabilized absolute open flow (AOF) potential is usually performed using backpressure deliverability plot [Rawlins and Schellhardt (1935); Poe and Jennings (1988)].

Rawlins and Schellhardt (1935) developed the flow-after-flow backpressure deliverability equation which gives linear relationship on log-log plot of the difference in the squares of the average reservoir pressure and flowing gas rate under stabilized conditions in terms of pressure squared. Their equation can be written in terms of normalised pseudo-pressure (Eq. 5.1) in order to account for variation gas properties. C is the stabilized performance coefficient and n is an indication of turbulence effect given by the reciprocal of slope of the straight line.

$$q_g = C \left[m_n \left(\frac{-}{p} \right) - m_n(p_{wf}) \right]^n \quad 5.1$$

Evinger and Muskat (1942) developed a method for calculating the productivity factors of producing formations for heterogeneous gas-oil flow system at reservoir conditions. They concluded that the fluid system productivity factor depend not only upon the detailed characteristics of the fluid and sand, but also upon the gross and overall parameters such as the gas-oil ratio, pressure changes and average reservoir pressure. Moreover, the limitations of their method are the assumption of steady state system, an ideal gas phase, unconsolidated sandstone and constant oil viscosity.

Cullender (1955) proposed the isochronal test method of determining the flow characteristics of gas well backpressure test, this method requires stabilized extended flow point for transient isochronal deliverability and stabilised prevailing average reservoir pressure for build-up after drawdown. The characteristic deliverability performance of a well is determined from data obtained at short-time intervals at the start of the drawdown.

Katz et. al (1959) showed good and reliable results for stabilized AOF potentials by modification of the isochronal test method. They proposed drawdown of same duration followed by extended build-up to allow wellbore pressures to stabilise at the average reservoir pressure. In this case, the build-up pressure at bottom-hole was used for the deliverability analysis.

Houpeurt (1959) presented analytical deliverability equation which accounts for turbulence factor and mechanical skin for stabilised flow in terms of p-squared. His equation can be rewritten in terms of real gas pseudo-pressure (Eq. 5.2):

$$q = \frac{kh[m_n(\bar{p}) - m_n(p_{wf})]}{1422T \left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S + D|q_g| \right]} \quad 5.2$$

Odeh and Jones (1965) developed a transient generalized variable-rate procedure for obtaining formation flow capacities from backpressure surveys without resorting to further well tests; the test analysis equation was formulated in terms p-squared. Essis and Thomas (1971) modified Odeh and Jones (1965) transient flow equation by the use of real gas pseudo-pressure (Eq. 5.3).

$$q = \frac{k_{abs}k_{rgi}h[m_n(\bar{p}) - m_n(p_{wf})]}{1422T \left[\frac{1}{2} \ln\left(\frac{k_{abs}k_{rgi}t}{1688\phi\mu_i c_{it} r_w^2}\right) + S + D|q_g| \right]} \quad 5.3$$

Winestock and Colpitts (1965) presented a drawdown analysis technique with varying gas rate for analysing the early time data from a backpressure test when the rate has not yet stabilized to a constant value. Their method used the turbulent flow in gas well systems as a condition to calculating a gas well current and potential deliverability using two or more drawdown tests. Lee *et al.* (1972) confirmed the validity of Winestock and Colpitts (1965) technique for analysing variable rate drawdown data using numerical simulation of the pressure history of a gas well for drawdown data obtained with smoothly varying production rates.

Condensate bank builds up in a well producing below saturation pressure; this reduces the productivity (Fussel, 1973) and effective permeability around the wellbore (Kniazeff and Naville, 1965). Goudouin *et al.* (1967) showed the turbulence effects and condensate bank on backpressure well deliverability performance using modified Kniazeff and Naville (1965) numerical equations with simplification of non-Darcy effect around the

wellbore. The simplification of non-Darcy effect around the wellbore allows for detailed description of the flow restriction due to condensate dropout at the wellbore.

Fussell (1973) presented the implicit one-dimensional radial model developed by Roebuck *et al.* (1969) to study long-term single well performance of a gas condensate reservoir. He showed that the relative permeability characteristics of the formation affect the magnitude of condensate saturations around the wellbore and the productivity of the well can be reduced by a factor of three due to condensate bank at the wellbore.

Brar and Aziz (1978) presented a technique for estimating the stabilized AOF potential of build-up data in stabilizing gas wells using only isochronal data from modified isochronal tests to obtain values of permeability thickness, skin and turbulence factor. The duration of the test is dependent on the number of flow periods of the isochronal and modified isochronal tests.

Poettmann (1986) introduced a method to rapidly estimate the stabilised deliverability behaviour of a gas well from isochronal test data using the concept of a time to pseudo steady state transient deliverability equation. The method does not depend on the calculation turbulence factor (D), skin (s) and reduces the use of other well and reservoir parameters such as wellbore radius (r_w) to predict stabilised gas flow behaviour. However, his definition of transient flow is correct if the initial pressure is used in his analysis instead of the average reservoir pressure. His transition from transient to pseudo steady state occurs at time to pseudo stabilisation (Eq. 5.4) rather than time to stabilisation (Eq. 5.5). Brar and Mattar (1987) extended Poettmann (1986) method to non-circular drainage geometry by modification of the pseudo stabilisation time.

$$t_{ps} = \frac{376 \phi \mu c_i r_e^2}{k} \quad 5.4$$

$$t_{stab} = \frac{948 \phi \mu c_i r_e^2}{k} \quad 5.5$$

Camacho-V and Raghavan (1989) examined the influence of the pressure and skin factor on the inflow performance relationship (IPR) for well producing under solution gas drive using numerical simulation. They confirmed the validity of Standing (1971) and Fetkovich (1973) empirical observations via numerical simulation for a wide range of conditions for a well under production. In contrast, the effect of non-Darcy flow on wells producing under solution gas drive mechanism was not considered.

Johnson *et al.* (1991) presented comparisons between Houpeurt (1959) and Rawlins and Schellhardt (1935) analyses by showing the correlation between the two methods. The more rigorous Houpeurt (1959) gas well deliverability forecasting method can be written in terms of Rawlins and Schellhardt (1935) equation, this includes the stabilized performance coefficient (C) and turbulence factor (n). He showed that the relationship between Rawlins and Schellhardt (1935) and Houpeurt (1959) developed by Brigham (1988), Duong (1988), and Poettmann and Kazemi (1988) is valid and should yield accurate backpressure deliverability forecasting.

Thrasher *et al.* (1994) applied the backpressure deliverability plot to monitor wellhead-deliverability performance for flowing oil wells in a manner similar to gas wells. However, the study did not include the effects of high capillary number and turbulence factor on the backpressure deliverability curve.

Thrasher *et al.* (1995) used bottom-hole backpressure curve to monitor and analyse the performance of flowing oil-well in layered reservoirs without crossflow. They gave a framework for monitoring individual well performance in multilayer no crossflow layered reservoir. Using field data, the paper described total depletion performance as a function of layer depletion performance.

Göktas *et al.* (2010) concluded that backpressure well deliverability plots can be used; to monitor performances of gas condensate wells, to quantify productivity losses due to condensate bank and as a diagnostic tool in routine reservoir engineering management. However, application to volatile oil was not considered and the single-phase pseudo-pressure which does not fully account for the effect of the multiphase flow below dew point pressure was used in their backpressure analysis.

Herens (2010) applied single-phase and two-phase pseudo-pressure to backpressure plot analysis to quantify the effect of multi-layering and condensate dropout on the deliverability of lean gas condensate field data. His analysis was not confirmed with compositional simulation and did not include high capillary number and turbulence effects on the two-phase pseudo-pressure calculation. Therefore, the match of analytical deliverability line was impossible without changing the initial relative permeability parameters such as Corey exponents, k_{rg}^{max} and k_{ro}^{max} ; this makes the solution non-unique. The test points of from his single-phase pseudo-pressure do not line up on the analytical pseudo steady state well deliverability line (Fig. 5.1).

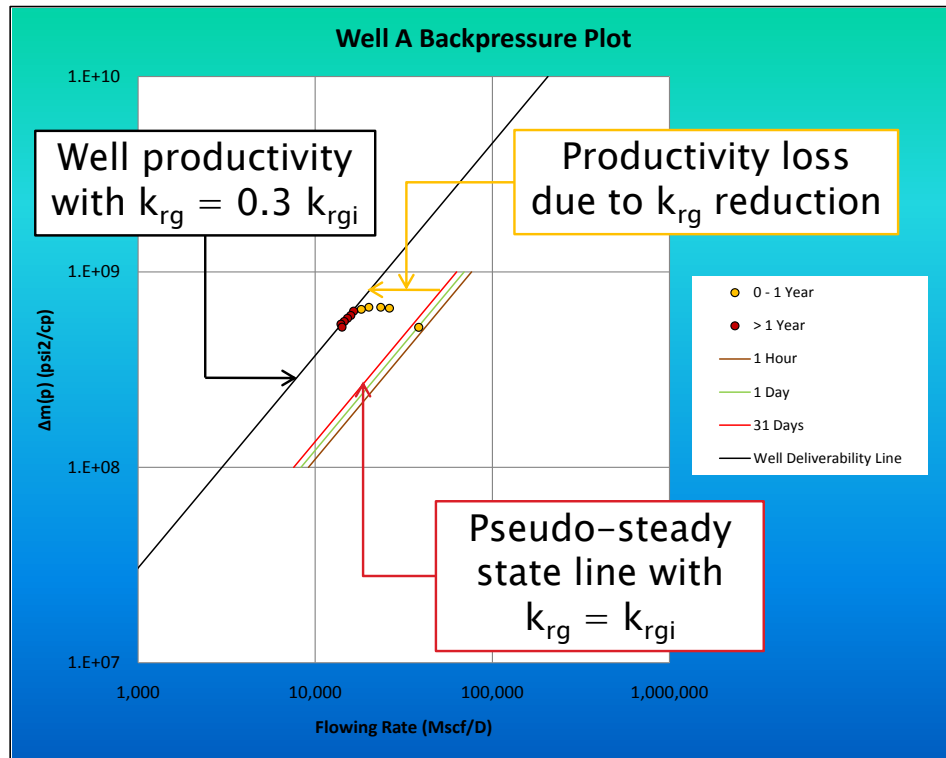


Figure 5.1: Well productivity losses due to condensate bank formation (Herens, 2010)

None of the studies above applied two-phase pseudo-pressure calculated with relative permeability which integrates the high capillary number non-Darcy effects to simulated or field data of lean gas condensate, rich gas condensate as well as volatile oil well producing below saturation pressure.

The objective of this study is to investigate the impact of high capillary number and non-Darcy effects on backpressure plot of wells producing below dew point pressure using single-phase pseudo-pressure and two-phase pseudo-pressure backpressure plot for lean gas condensate and rich gas condensate as well as pressure and two-phase pseudo-pressure backpressure plot for volatile oil wells producing below bubble point pressure.

5.2 Simulation and Fluid Model

The reservoir simulations and fluid modelling were performed using a compositional simulator (Eclipse 300 and PVTi from Schlumberger) to generate synthetic well test data for lean gas, rich gas and volatile oil wells. The simulation model, capillary number, non-Darcy parameters, fluid data and relative permeability curves used for the compositional simulation are described in section 4.2. However, the initial pressure for volatile oil reservoir model was set at 5400psia in this case.

Impact of rate sequence on backpressure deliverability line was quantified by simulating and analysing backpressure data of different rate histories (decreasing, increasing and random rates) for lean gas, rich gas, and volatile oil. The pressures of all the drawdowns dropped below the saturation pressure during the simulation. Results from compositional simulation were compared with backpressure plot for the field data.

5.3 Backpressure Plot for Lean and Rich Gas Condensate

Bottomhole backpressure plots were constructed to compute the well deliverability for the simulated well test response from the compositional model. The plot of $\Delta m_n(p)$ versus gas rate was constructed on a log-log scale with a slope of $(1/n)$ and intercept C. The estimated values of n for lean gas and rich gas condensate from the simulation model are 0.82 and 0.85 respectively. The computational steps for backpressure plots for lean and rich gases are given below:

- a. Calculate single-phase pseudo-pressure (Eq. 2.9).
- b. Construct backpressure plot $\Delta m_n(p)$ vs. q and fit deliverability line (Eq. 5.1).
- c. Calculate the wellbore skin and non-Darcy factor using multi rate test.
- d. Calculate two-phase pseudo-pressure ($\Delta m_{2\phi}(p)$), using procedure in section 2.4) and match the stabilised deliverability line with $\Delta m_{2\phi}(p)$ calculated with relative permeability curves which incorporate the high capillary number and non-Darcy effects.

5.4 Backpressure Plot for Lean Gas Condensate

5.4.1 Single-phase pseudo-pressure analysis

5.4.1.1 Decreasing Rate History

The pressure and decreasing rate history for lean gas is shown in Fig. 5.2. It has 20 flow periods with 1-year duration for each drawdown (DD) alternating with build-up (BU). The single-phase pseudo-pressure rate-normalized log-log and backpressure plots are shown in Figs. 5.3 and 5.4 respectively. The derivatives in Fig. 5.3 exhibit radial composite behaviour due to the condensate bank development as shown by the upward shift of the pressure curves.

The difference between single-phase pseudo-pressure of bottomhole pressure at the end of each build-up and that of preceding drawdown versus well rate (Fig. 5.4) aligned on a

deliverability line which is parallel to the stabilized gas flow deliverability line (Eq. 5.2) at k_{rg} less than k_{rgi} .

Single-phase pseudo-pressure backpressure plot (Fig. 5.4) line up on deliverability line lower than the stabilized deliverability line (Eq. 5.2) because it did not capture the productivity losses due to reduction in relative permeability and condensate dropout below dew point pressure at the wellbore.

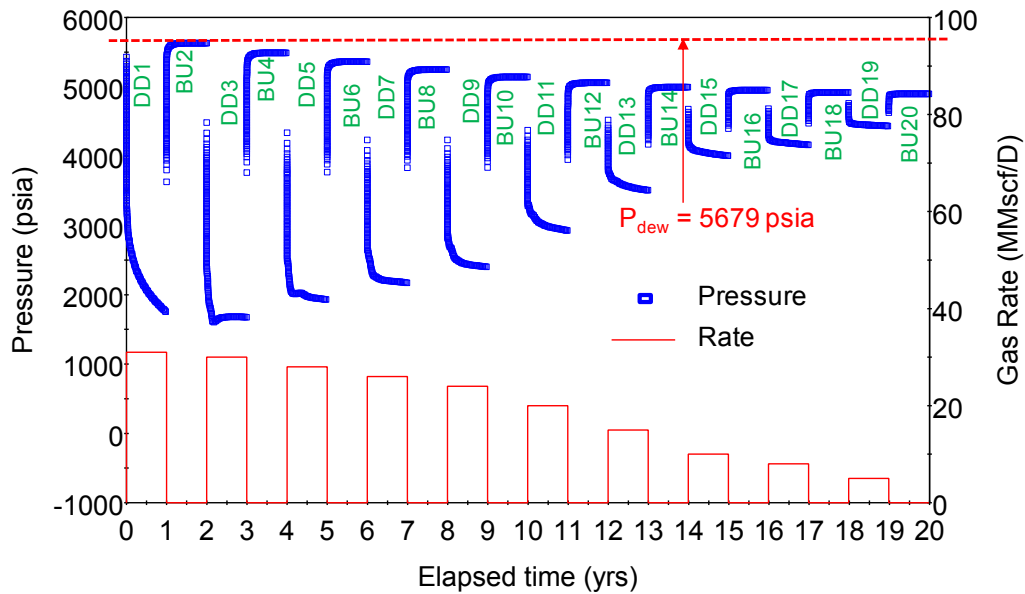


Figure 5.2: Pressure and decreasing rate histories for lean gas

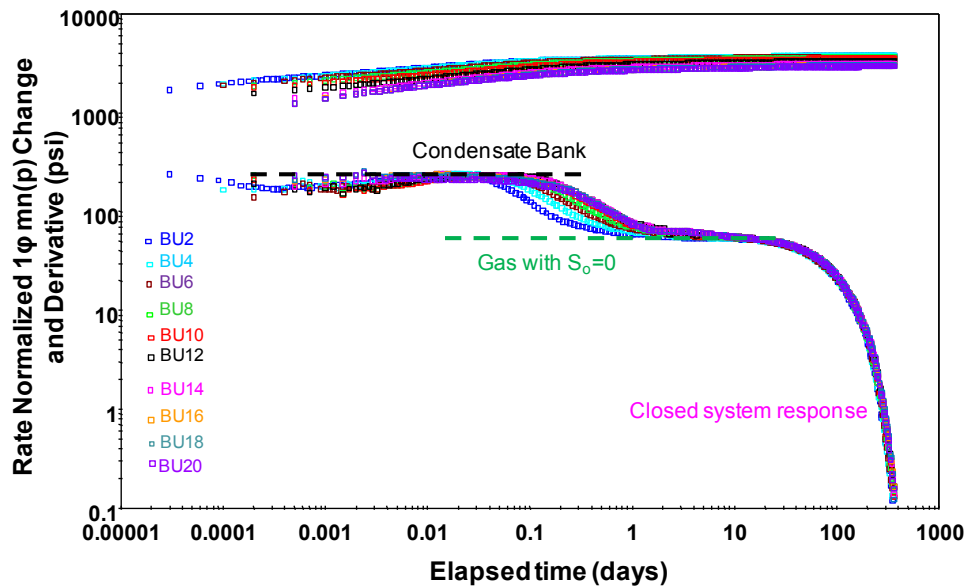


Figure 5.3: Rate-normalized 1ϕ PP log-log plot for lean gas (decreasing rate history)

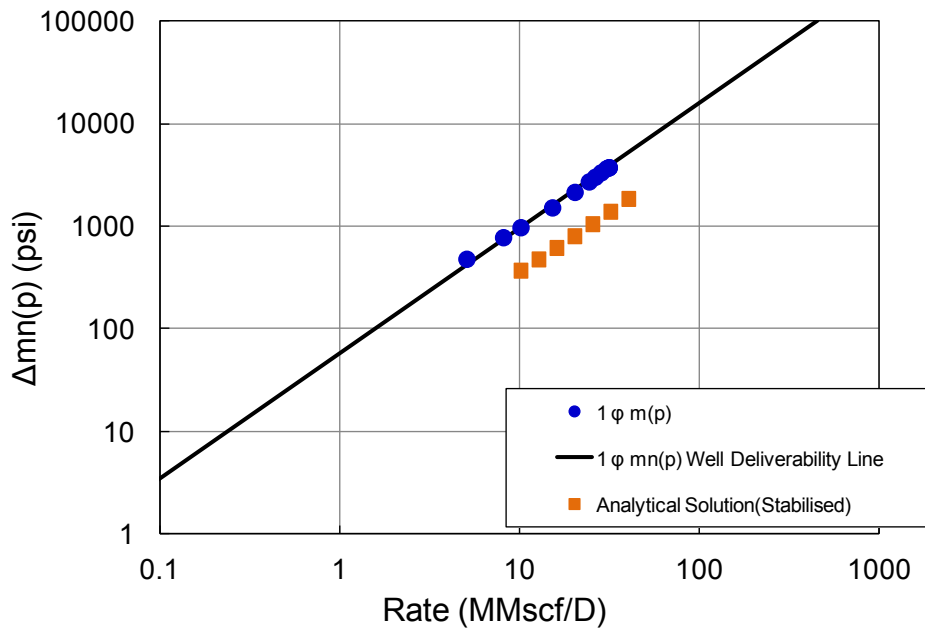


Figure 5.4: Single-phase backpressure plots for lean gas (decreasing rate history)

5.4.1.2 Increasing and Random Rate History

Figs. 5.5 and 5.6 show the pressure and increasing and random rate histories for lean gas, it consists of 20 flow periods with 1 year duration for drawdowns (DD) and build-ups (BU) in a closed system. The rate normalised single-phase pseudo-pressure log-log plot for increasing and random rate histories are shown in Figs. 5.7 and 5.8 respectively. They show an upward shift of the pressure curves and exhibit radial composite effect on the derivatives because of the condensate dropout at the wellbore.

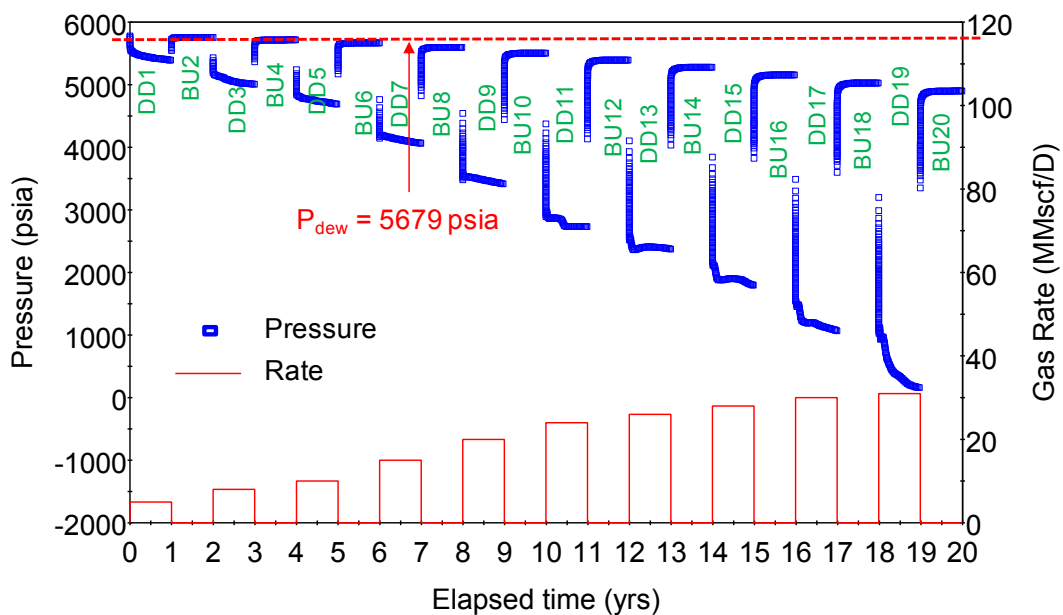


Figure 5.5: Pressure and increasing rate history for lean gas

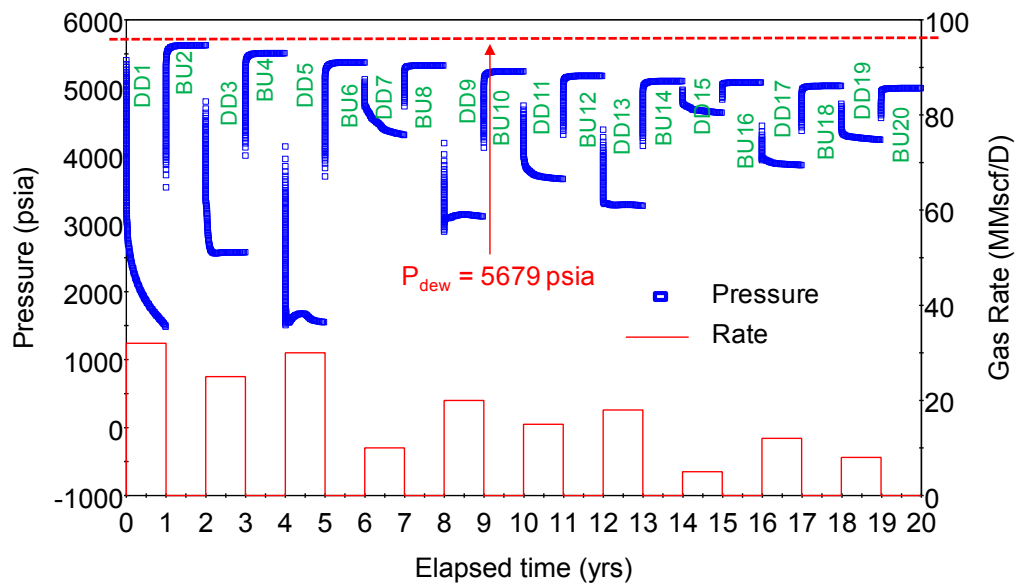


Figure 5.6: Pressure and random rate history for lean gas

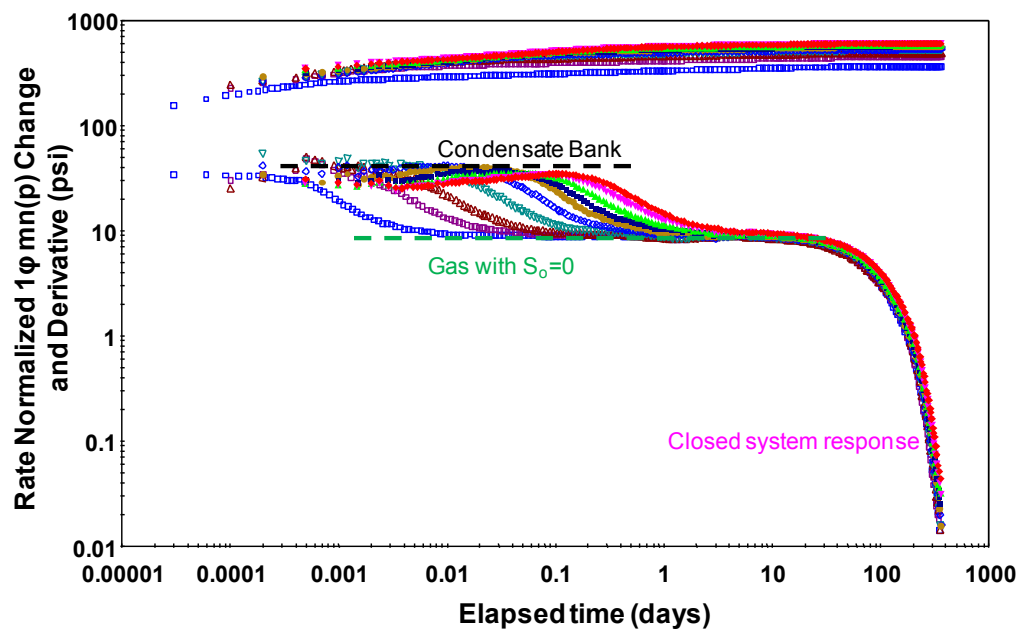


Figure 5.7: Rate-normalized 1ϕ PP log-log plot for lean gas (increasing rate history)

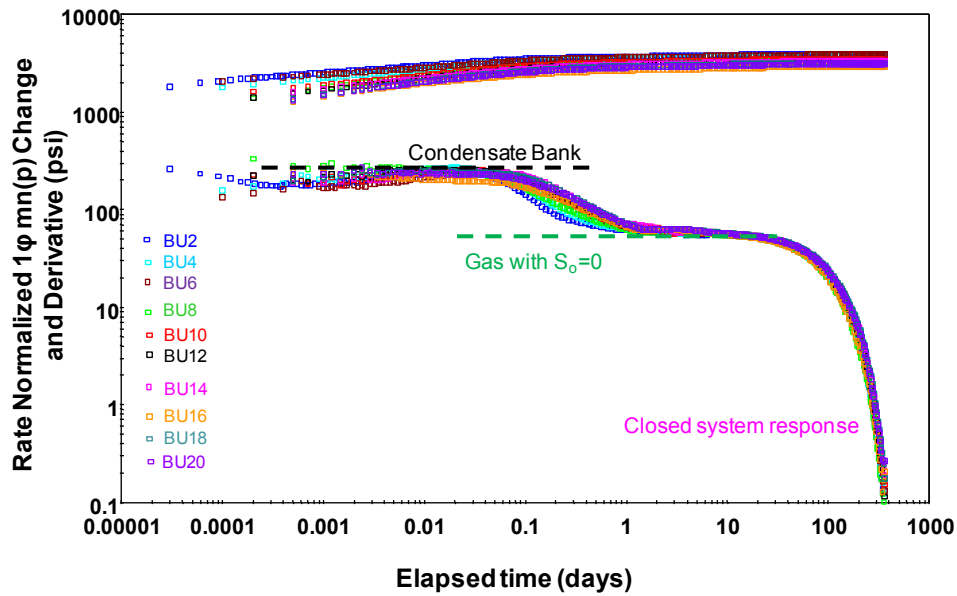


Figure 5.8: Rate-normalized 1φPP log-log plot for lean gas (random rate history)

Similar to Fig. 5.4, the single-phase pseudo-pressure backpressure plots (Figs. 5.8 and 5.9) for increasing and random rate histories aligned parallel to stabilized deliverability line (Eq. 5.2) at k_{rg} less than k_{rgi} because it did not capture deliverability losses due to reduction in relative permeability and condensate dropout at the wellbore.

Fig. 5.11 shows deliverability capacity for the lean gas condensate single-phase pseudo-pressure backpressure plot is the same for all different rate sequence i.e. decreasing, increasing and random rate.

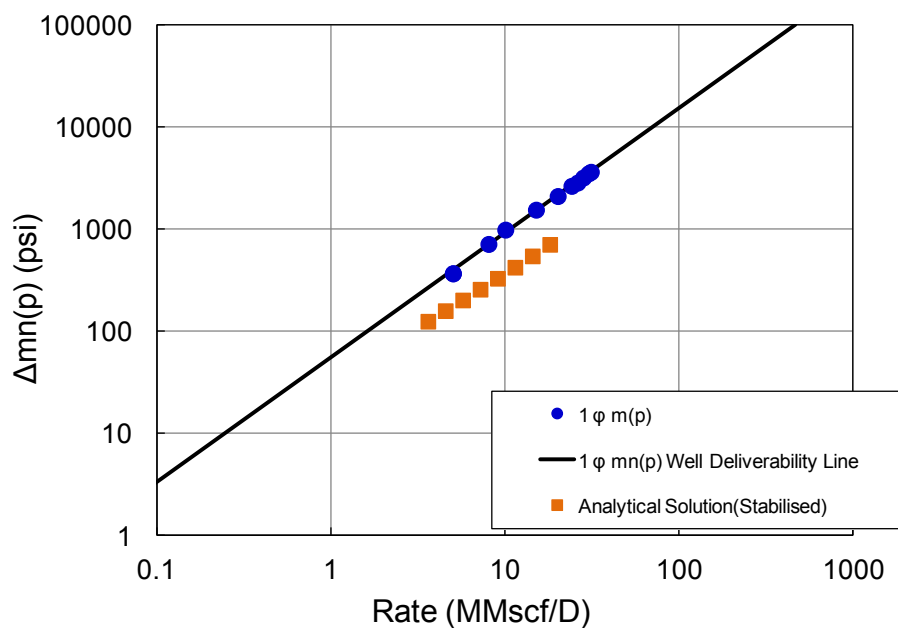


Figure 5.9: 1φPP backpressure plot for lean gas (increasing rate history)

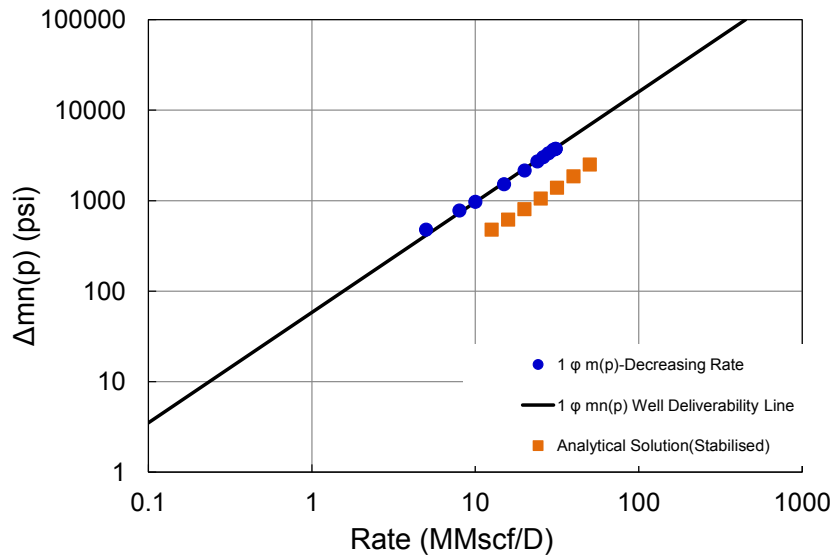


Figure 5.10: 1φPP backpressure plot for lean gas (random rate history)

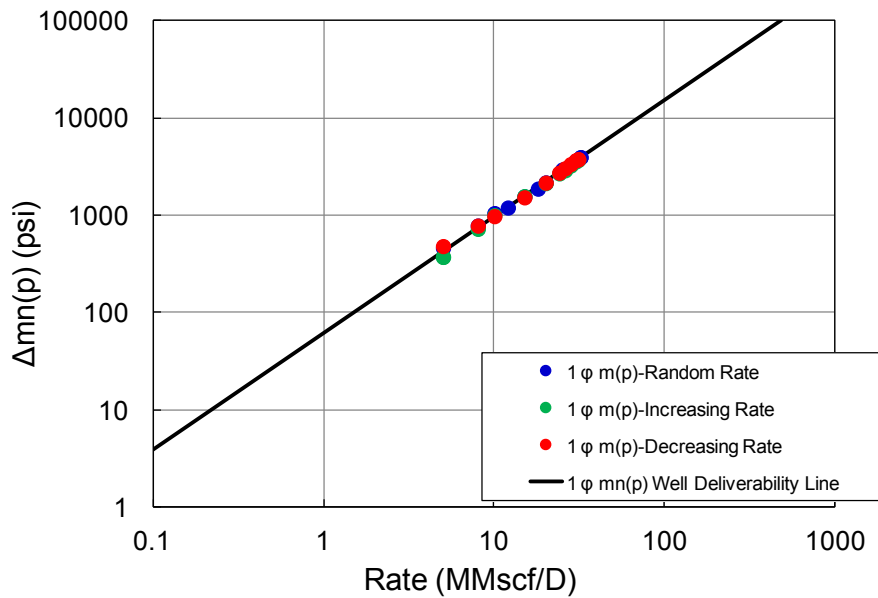


Figure 5.11: 1φPP backpressure plot for lean gas (decreasing, increasing, and random rate history)

5.4.2 Two-phase pseudo-pressure analysis

Two-phase pseudo-pressure backpressure plots for lean gas were calculated with and without high capillary number and non-Darcy effects on the relative permeability using steps specified in section 2.4. The log-log plot for single-phase and two-phase pseudo-pressure for decreasing, increasing and random rate histories are shown in Figs. 5.12, 5.13 and 5.14. The two-phase pseudo-pressure transformed the radial composite effect to homogeneous behaviour (Figs. 5.12, 5.13 and 5.14) and gives a radial flow stabilisation at zero condensate saturation.

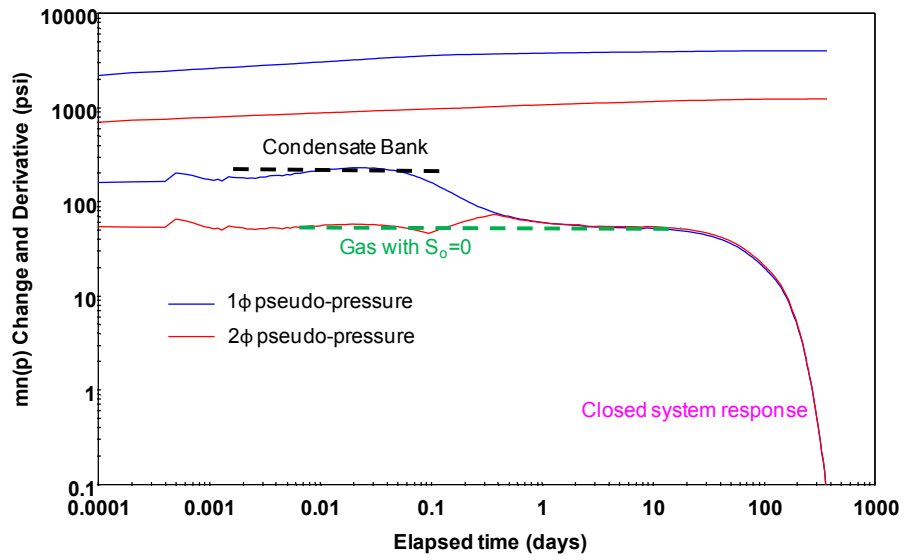


Figure 5.12: 1φPP and 2φPP log-log plot for lean gas (BU 4) (decreasing rate at $k_{rg}^{max}=1$)

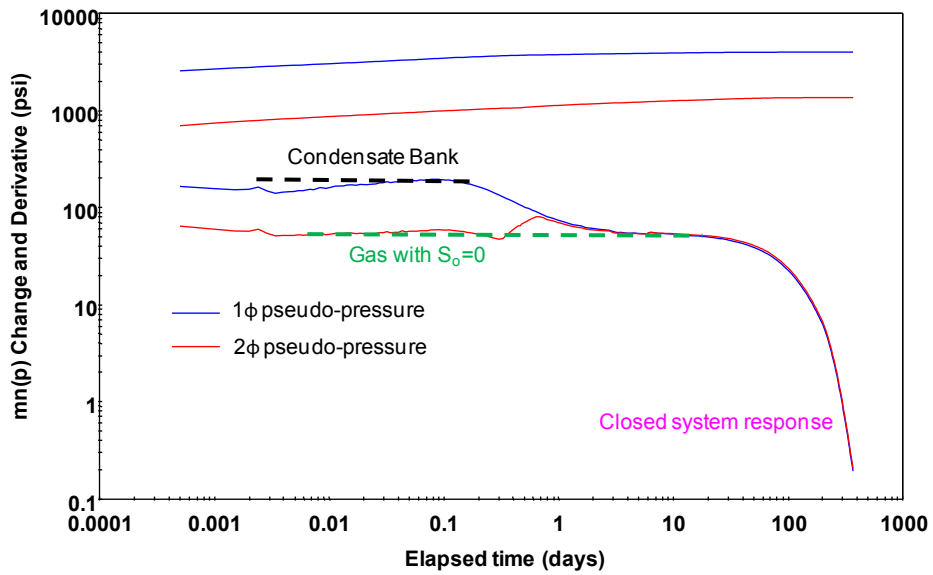


Figure 5.13: 1φPP and 2φPP log-log plot for lean gas (BU 4) (increasing rate at $k_{rg}^{max}=1$)

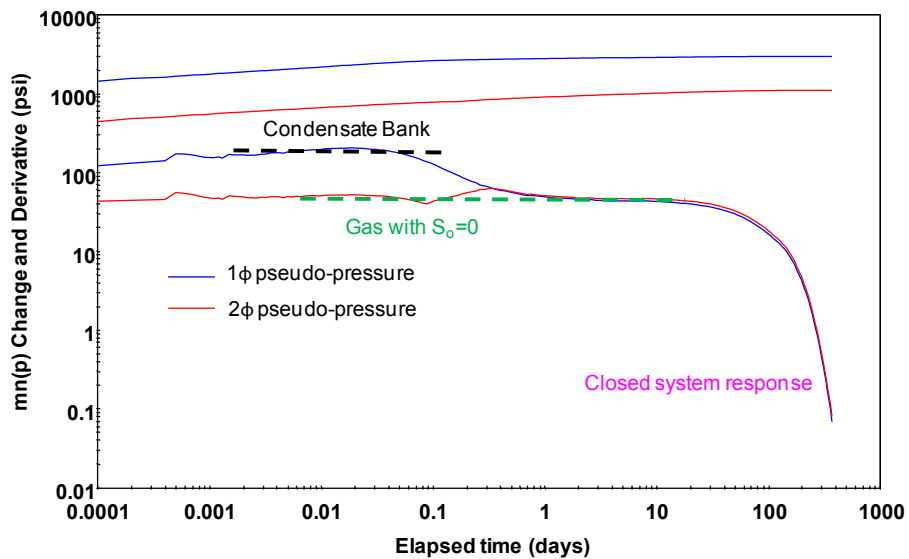


Figure 5.14: 1φPP and 2φPP log-log plot for lean gas (BU 4) (random rate at $k_{rg}^{max}=1$)

Figs. 5.15, 5.16 and 5.17 show the backpressure plots for two-phase pseudo-pressure calculated with and without high capillary number and turbulence effects on relative permeability for decreasing, increasing and random rate histories respectively.

Similar to single-phase pseudo-pressure backpressure plots, the two-phase pseudo-pressure backpressure plots (Figs. 5.15, 5.16 and 5.17) calculated without high capillary number and turbulence effects on the relative permeability did not align on the stabilised analytical solution (Eq. 5.2). It overestimated the deliverability of the well because it did not account for velocity stripping and turbulence effects of the condensate bank at the wellbore.

Conversely, the two-phase pseudo-pressure backpressure plot (Figs. 5.15, 5.16 and 5.17) calculated with high capillary number and turbulence effect on relative permeability line up on the stabilised analytical solution because it captures the deliverability losses due to k_{rg} reduction, condensate bank formation, high capillary number and non-Darcy effects at the wellbore.

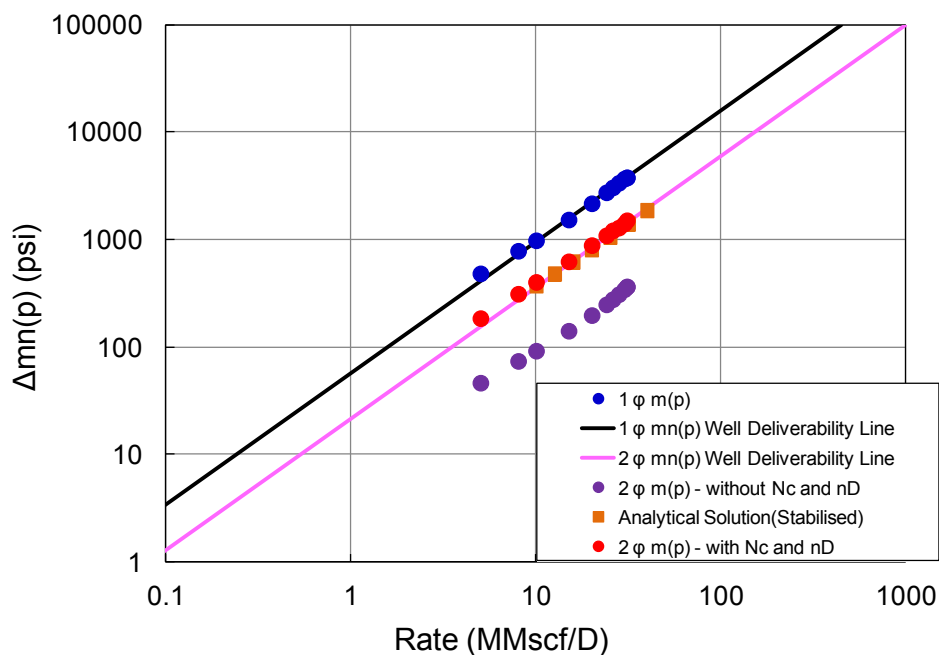


Figure 5.15: 1φPP and 2φPP backpressure plot for lean gas (decreasing rate history)

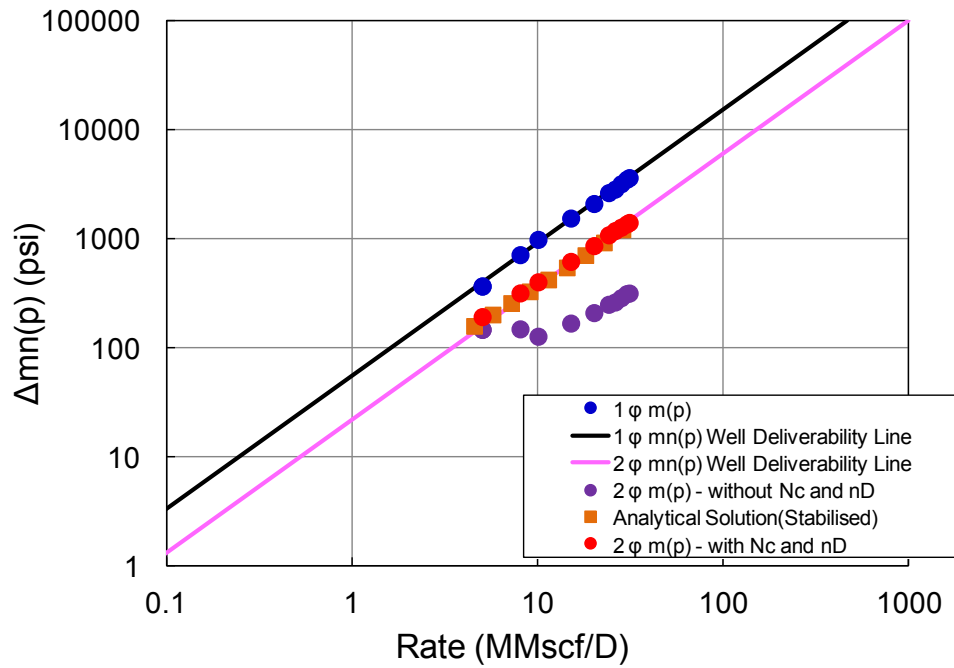


Figure 5.16: 1 ϕ PP and 2 ϕ PP backpressure plot for lean gas (increasing rate history)

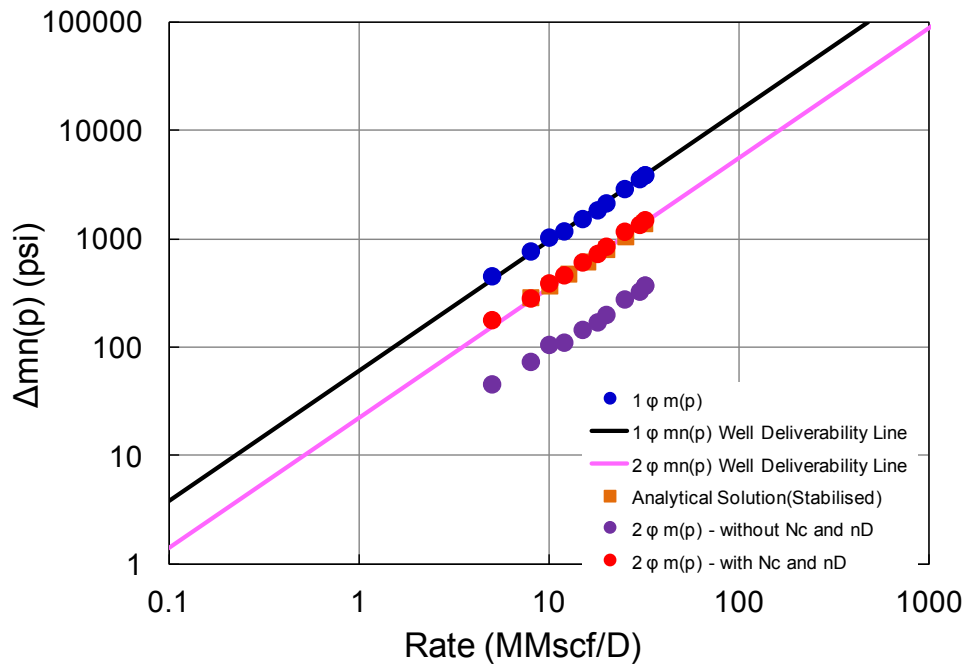


Figure 5.17: 1 ϕ PP and 2 ϕ PP backpressure plot for lean gas (random rate history)

5.4.3 Summary of Backpressure Plot for Lean Gas Condensate

1. Single-phase pseudo-pressure backpressure plot does not align on the stabilised analytical solution.
2. Stabilised analytical solution was matched with two-phase pseudo-pressure backpressure plot calculated with relative permeability which incorporates high capillary number and non-Darcy effects.

5.5 Backpressure Plot for Rich Gas Condensate

5.5.1 Single-phase pseudo-pressure analysis

5.5.1.1 Decreasing Rate History

Fig. 5.18 shows the pressure and decreasing rate history for rich gas condensate, it comprise 16 flow periods with 1-year duration for each drawdown (DD) and build-up (BU). The rate-normalized single-phase pseudo-pressure log-log and backpressure plots are shown in Figs. 5.19 and 5.20 respectively.

The effect of condensate dropout at the wellbore in Fig. 5.19 is designated by the upward shift of the pressure curves and a radial composite behaviour of the derivatives. The shift in the boundary response (Fig. 5.19, 5.23 and 5.24) is due to the impact of condensate on the reservoir boundary for long production time (Aluko, 2009); the condensate bank response was superimposed on boundary response for long production time. This is discussed in details in section 5.8.

The single-phase pseudo-pressure backpressure plot (Fig. 5.20) for decreasing rate history did not line up on the stabilized flow deliverability line (Eq. 5.2) at $k_{rg} = k_{rgi}$ because it did not capture the relative permeability reduction and condensate bank at the wellbore. It aligned on a deliverability line which is parallel to stabilized deliverability line (Eq. 5.2) at k_{rg} less than k_{rgi} .

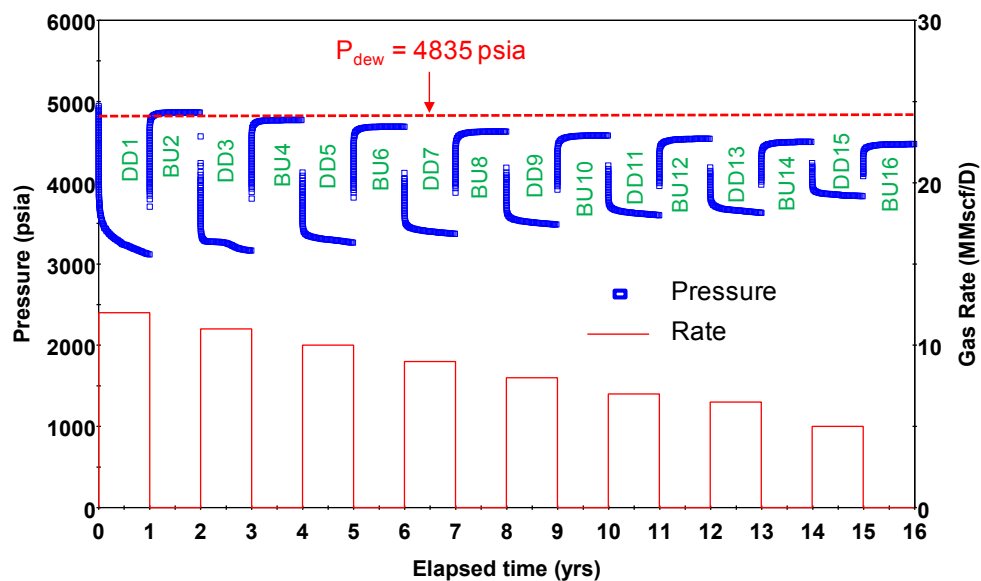


Figure 5. 18: Pressure and decreasing rate histories for rich gas

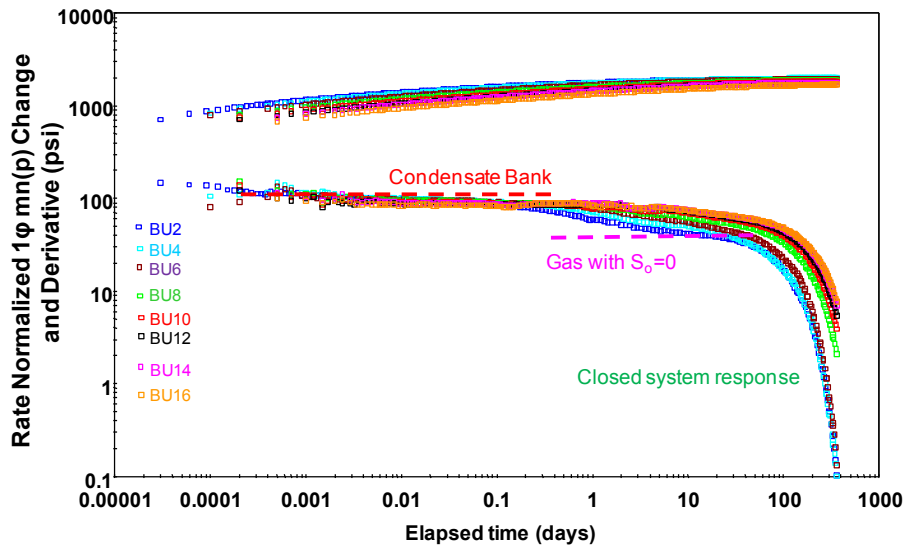


Figure 5.19: Rate-normalized 1φPP log-log plot for rich gas (decreasing rate history)

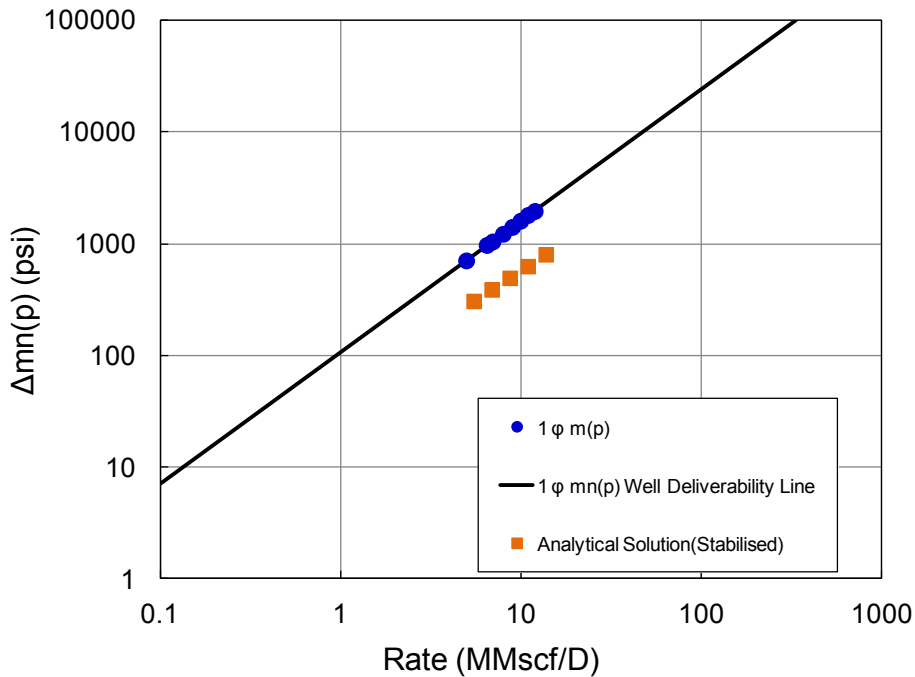


Figure 5.20: : 1φpp backpressure plots for rich gas (decreasing rate history)

5.5.1.2 Increasing and Random Rate History

The pressures, increasing and random rate histories for rich gas are shown Figs. 5.21 and 5.22; they consist of 1-year duration for each drawdown (DD) and build-up (BU) with 16 and 18 flow periods respectively. Single-phase pseudo-pressure rate-normalized log-log plots for increasing and random rate histories are shown in Figs. 5.23 and 5.24 respectively. The derivatives show a radial composite behaviour and an upward shift of the pressure curves due to the development of the condensate bank at the wellbore.

The single-phase pseudo-pressure backpressure plots (Figs. 5.25 and 5.26) for increasing and random rate histories line up on a deliverability line parallel to stabilized deliverability line (Eq. 5.2) at k_{rg} less than k_{rgi} . It did not capture the relative permeability reduction due to multiphase flow at the wellbore. Hence, single-phase backpressure plots cannot quantify the deliverability losses of rich gas condensate below dew point pressure. The deliverability line for the rich gas single-phase backpressure plot is similar for decreasing, increasing and random rate histories (Fig. 5.27).

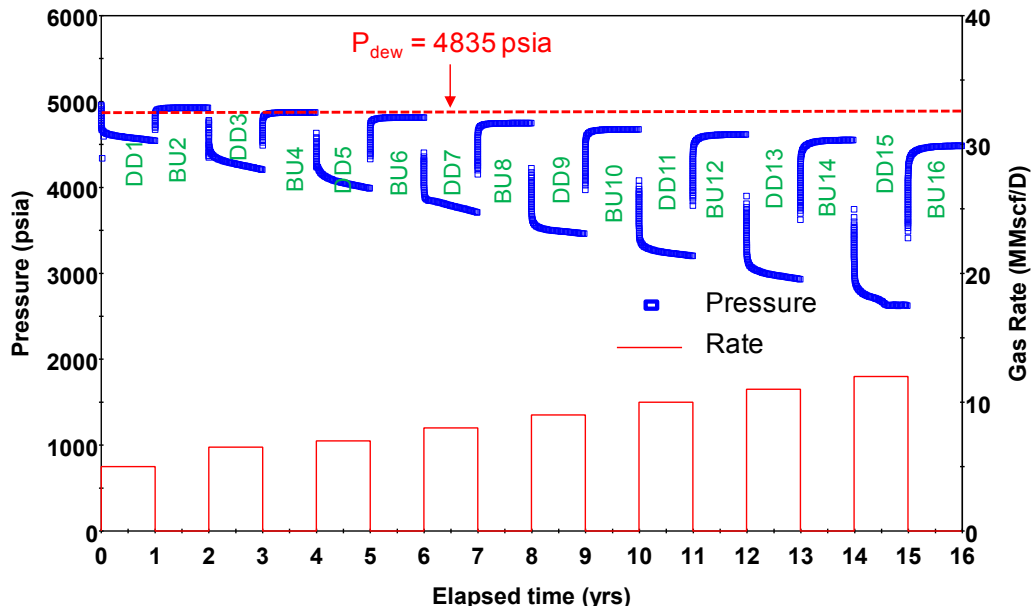


Figure 5.21: Pressure and increasing rate history for rich gas

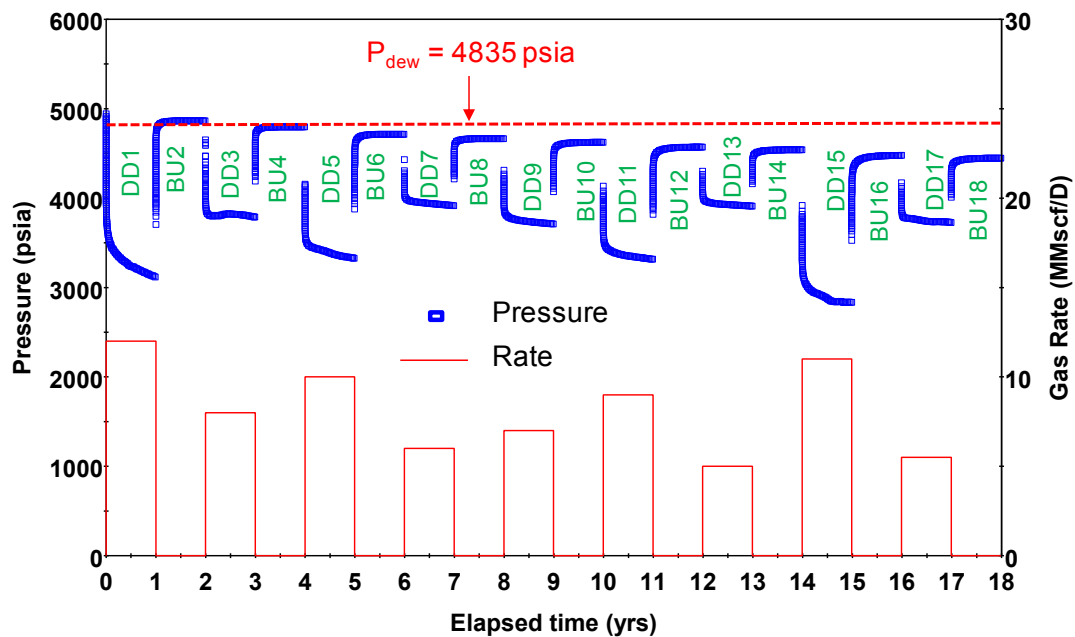


Figure 5.22: Pressure and random rate history for rich gas

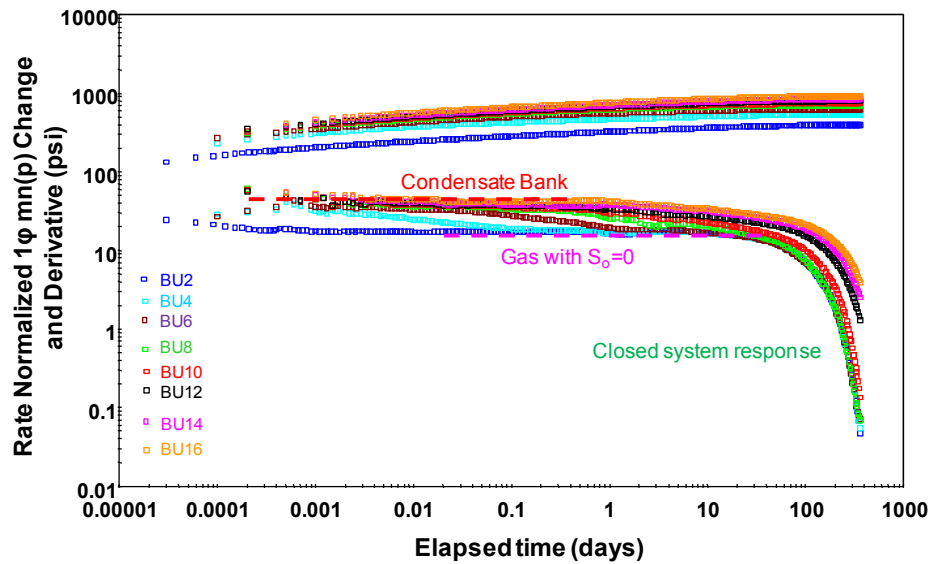


Figure 5.23: Rate-normalized 1ϕ PP log-log plot for rich gas (increasing rate history)

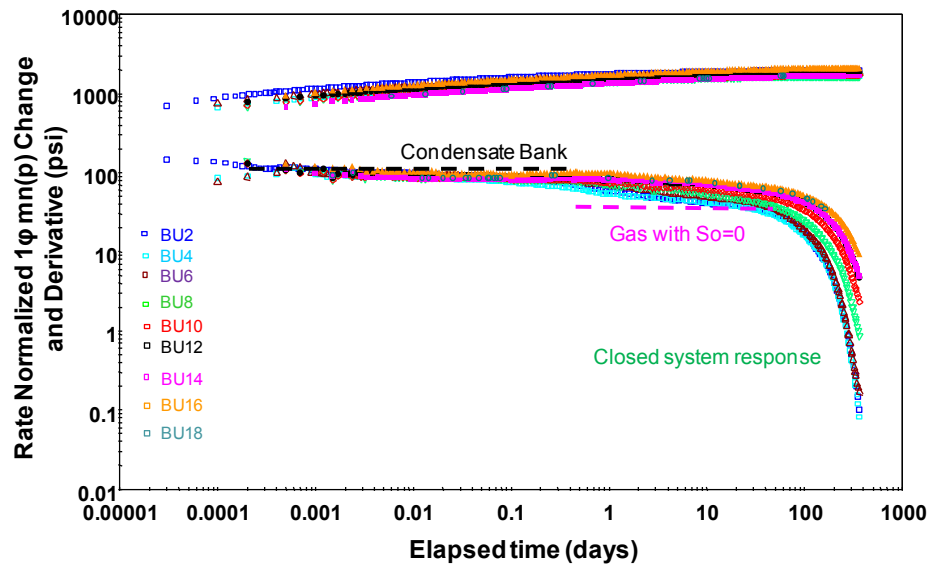


Figure 5.24: Rate-normalized 1ϕ PP log-log plot for rich gas (random rate history)

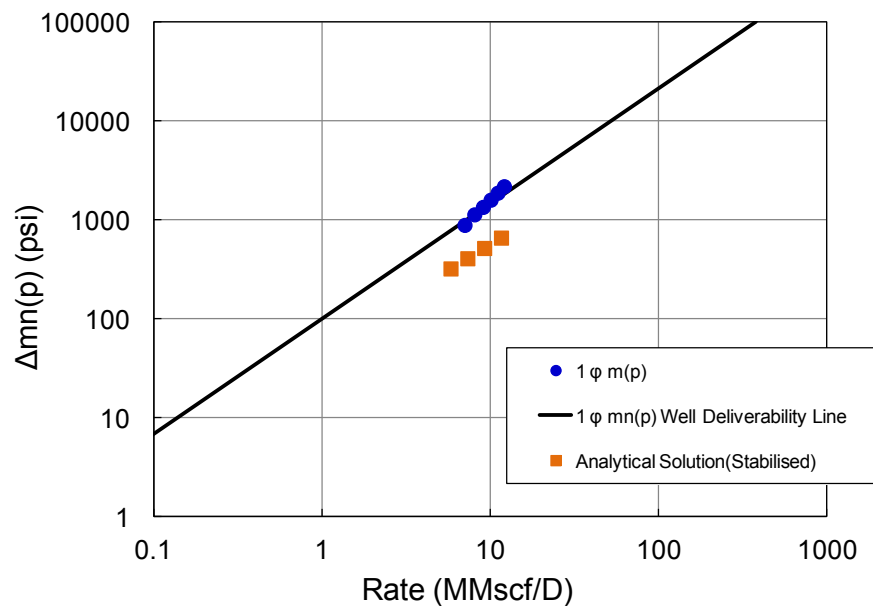


Figure 5.25: 1ϕ pp backpressure plot for rich gas (increasing rate history)

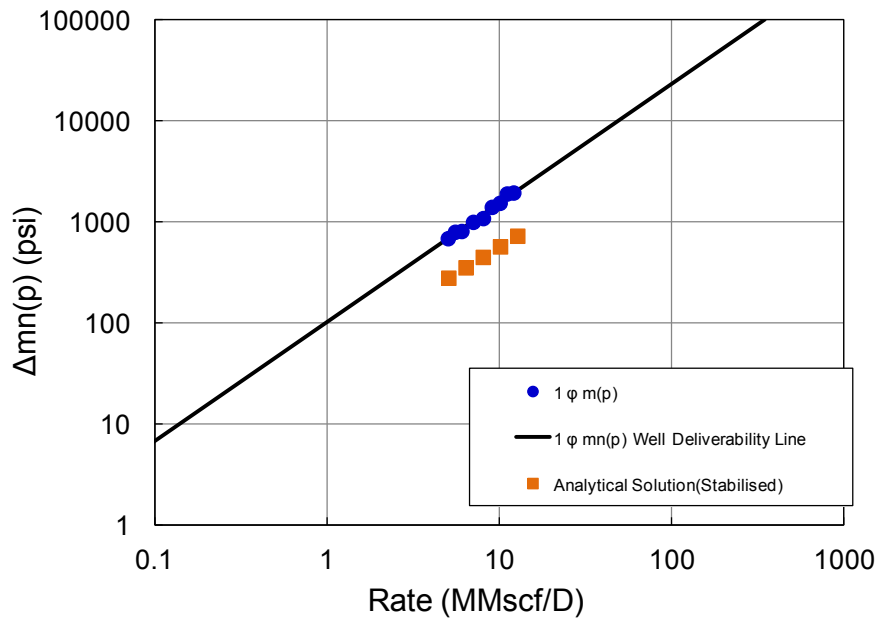


Figure 5.26: 1φPP backpressure plot for rich gas (random rate history)

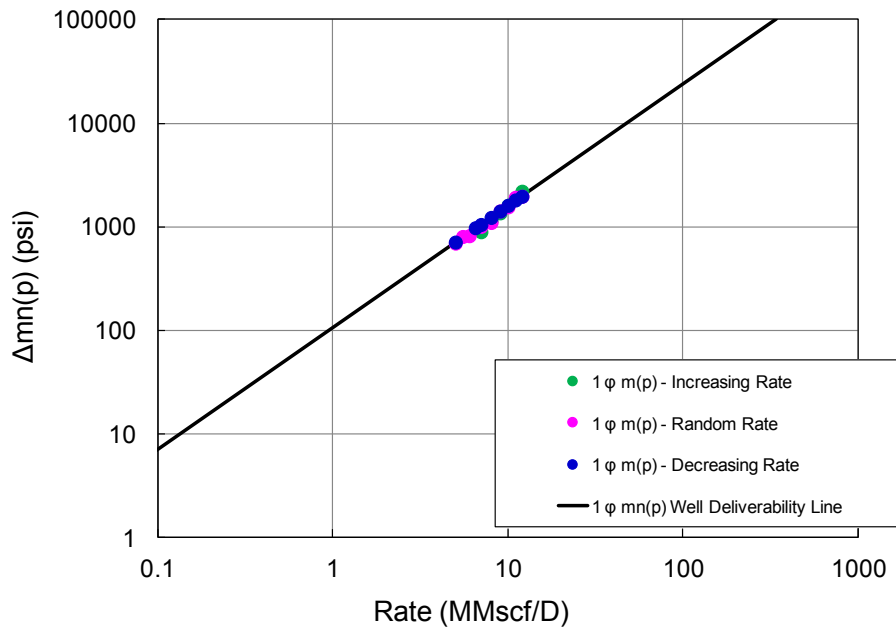


Figure 5.27: 1φPP backpressure plot for rich gas (decreasing, increasing and random rate)

5.5.2 Two-phase pseudo-pressure analysis

Two-phase backpressure plot for rich gas was calculated with and without high capillary number and non-Darcy effects on the relative permeability using steps specified in section 2.4. The log-log plots for single-phase pseudo-pressure and two-phase pseudo-pressure (Figs. 5.28, 5.29 and 5.30) for decreasing, increasing and random rate histories show that two-phase pseudo-pressure give correct radial flow stabilisation by transforming the radial composite effect to homogeneous behaviour with the derivative stabilising at zero condensate saturation.

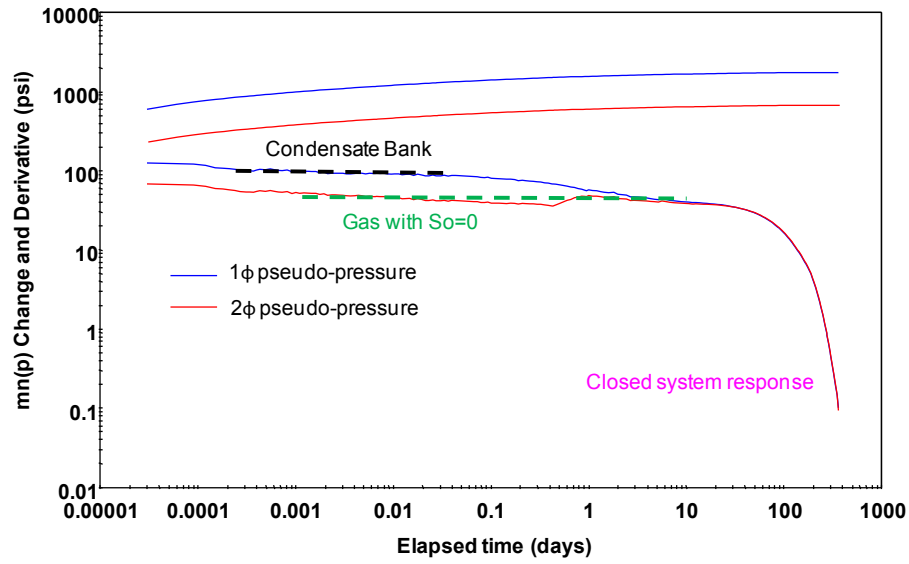


Figure 5.28: 1φPP and 2φPP log-log plot for rich gas (BU 2) (decreasing rate at $k_{rg}^{max}=1$)

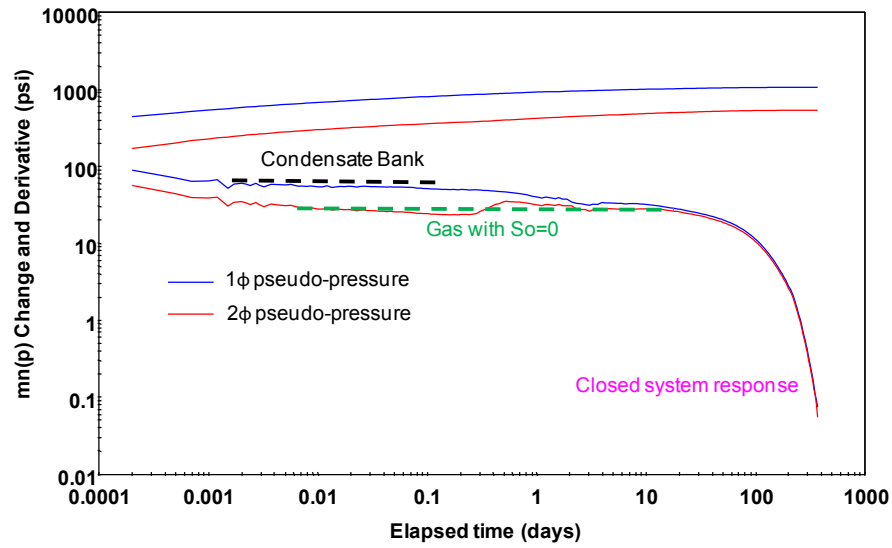


Figure 5.29: 1φPP and 2φPP log-log plot for rich gas (BU 2) (increasing rate at $k_{rg}^{max}=1$)

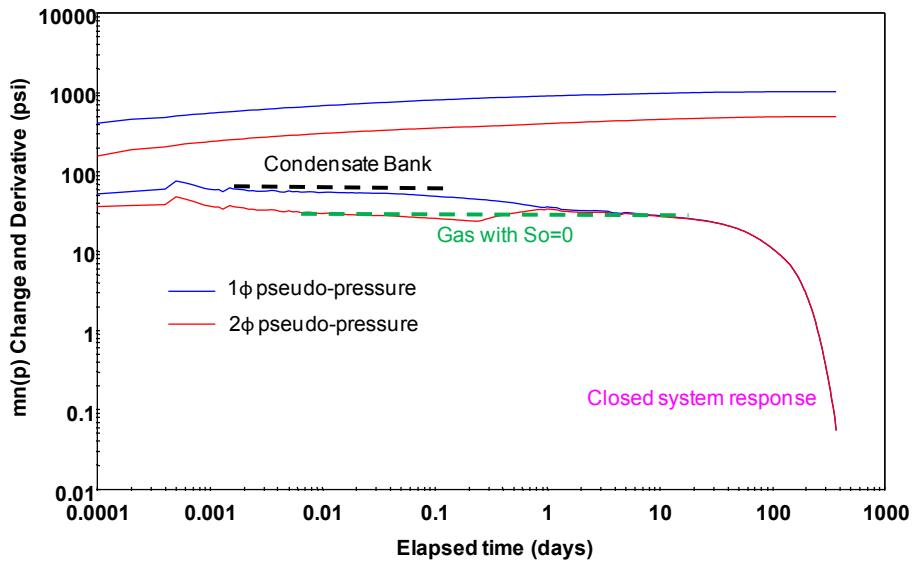


Figure 5.30: 1φPP and 2φPP log-log plot for rich gas (BU 2) (random rate at $k_{rg}^{max}=1$)

Figs. 5.31, 5.32 and 5.33 show the backpressure plots for single-phase pseudo-pressure (Figs. 5.20, 5.25 and 5.26) and two-phase pseudo-pressure analyses calculated with and without high capillary number and turbulence factor on the relative permeability curve for decreasing, increasing and random rate histories.

The two-phase pseudo-pressure backpressure plot (Figs. 5.31, 5.32 and 5.33) calculated without capillary number and turbulence factor overestimates the deliverability of the well because it did not account for the velocity stripping and turbulence effect at the wellbore. It aligned on a deliverability line with slope 0.85 greater than but parallel to the stabilised analytical deliverability line (Eq. 5.2).

Nonetheless, the two-phase pseudo-pressure backpressure plots (Figs. 5.31, 5.32 and 5.33) calculated with the relative permeability curves which integrate high capillary number and non-Darcy effects line up on the stabilised analytical solution (Eq. 5.2) at $k_{rg} = k_{rgi}$ because they capture the deliverability losses due to the influence of multiphase flow (i.e. condensate saturation), k_{rg} reduction, high capillary number and non-Darcy effects at the wellbore. This behaviour is similar to that of lean gas.

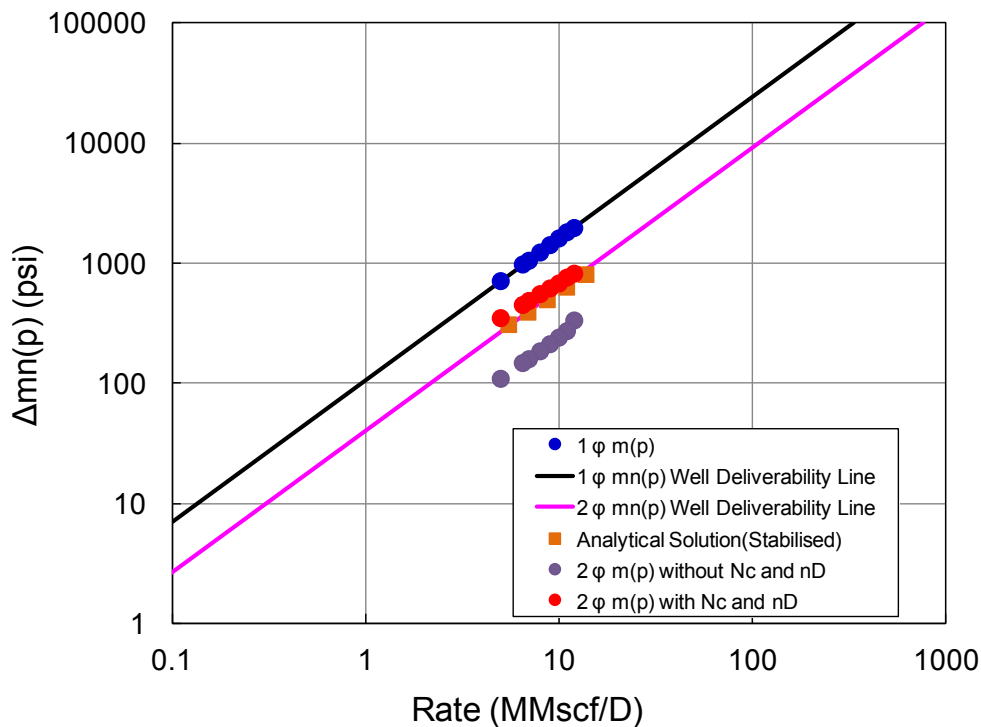


Figure 5.31: 1φPP and 2φPP backpressure plot for rich gas (decreasing rate history)

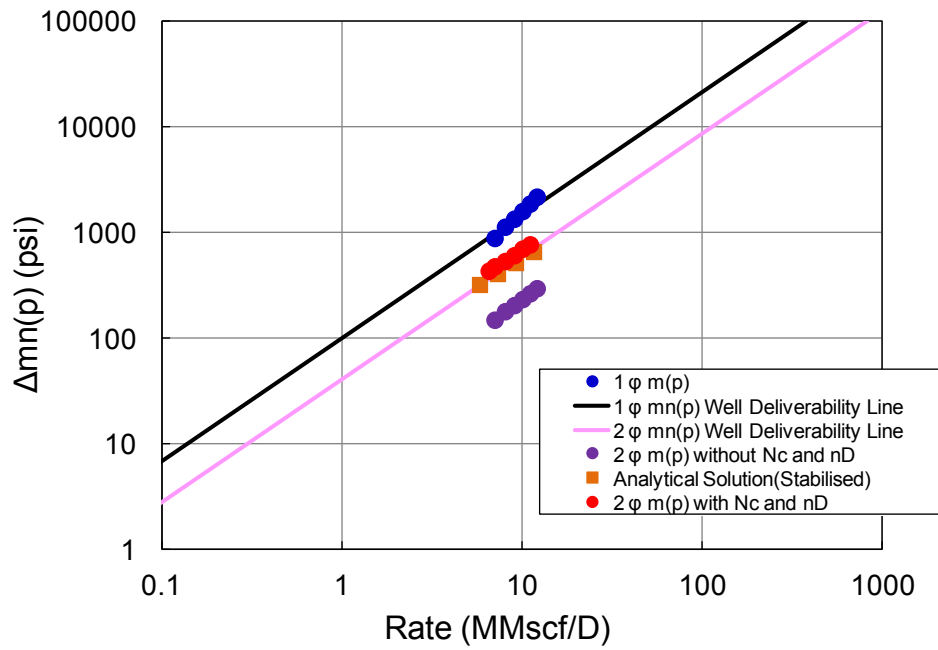


Figure 5.32: 1φPP and 2φPP backpressure plot for rich gas (increasing rate history)

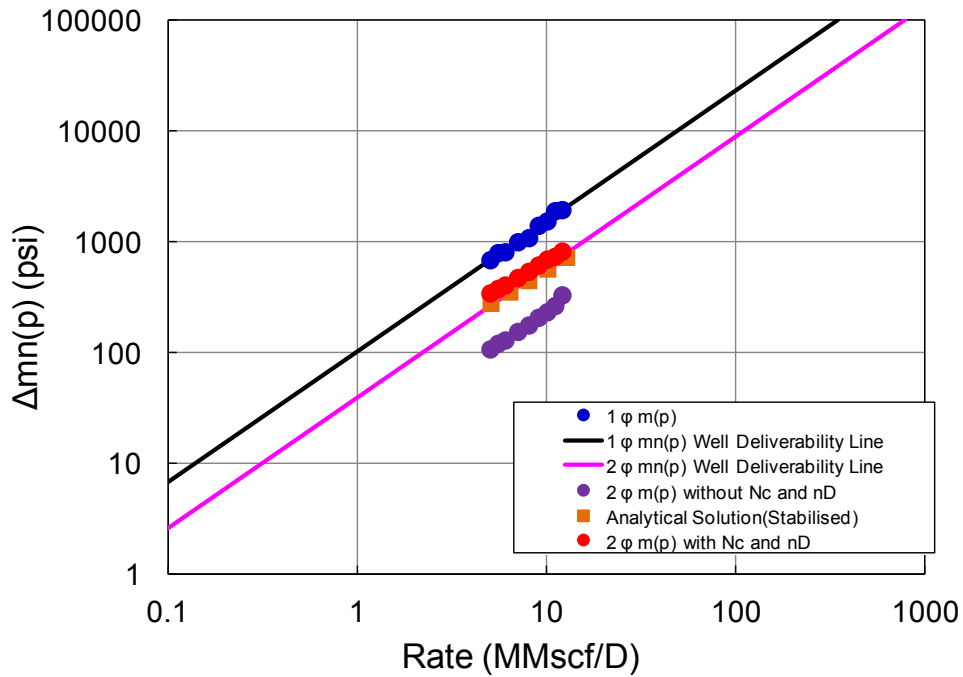


Figure 5.33: 1φPP and 2φPP backpressure plot for rich gas (random rate history)

5.5.3 Summary of Backpressure Plot for Rich Gas Condensate

1. The single-phase pseudo-pressure backpressure plot underestimates the stabilised deliverability line below dew point pressure for rich gas condensate.
2. The two-phase pseudo-pressure backpressure plot calculated without high capillary number and turbulence effects on the relative permeability curves overestimates well

deliverability because it does not account for the velocity stripping and turbulence effects at the wellbore.

3. The two-phase pseudo-pressure backpressure plots calculated with high capillary number and turbulence effects on the relative permeability curve line up on the stabilised analytical solution.

5.6 Backpressure Plot for Volatile Oil

Haider (1936) presented the productivity index as a more reliable method for determination of deliverability or productivity of an oil well. Kantzer and Trostel (1937) provided empirical relationship for productivity index for producing sub-surface pressures and production rates. The bottomhole pressure backpressure equation based on the concept of productivity index is given by:

$$q_o = C[\Delta p]^n \quad 5.6$$

The equation for pressure change (Δp) above and below bubble point pressure is given by Eqs. 5.7 and 5.8 respectively. Eq. 5.9 shows the expression of Eqs. 5.7 and 5.8 in terms of normalized two-phase pseudo-pressure.

$$\Delta p = \left(\bar{p}_R - p_{wf} \right) \quad 5.7$$

$$\left[\Delta p = \left(\bar{p}_R - p_b \right) + \left(\frac{p_b^2 - p_{wf}^2}{2p_b} \right) \right] \quad 5.8$$

$$\Delta p = \left[m_n \left(\bar{p}_R \right) - m_n \left(p_{wf} \right) \right] \quad 5.9$$

Expressing Eq. 5.6 in terms of well and reservoir parameters we have Eq. 5.10 and 5.11 for transient and stabilised oil well deliverability respectively.

$$q_o = \frac{k h \Delta p}{162.6 \mu_o B_o \left(\log \left(\frac{kt}{\phi \mu_o c_i r_w^2} \right) - 3.23 + 0.87s \right)} \quad 5.10$$

$$q_o = \frac{k h \Delta p}{141.2 \mu_o B_o \left(\ln \left(\frac{r_e}{r_w} \right) - 0.75 + s \right)} \quad 5.11$$

The two-phase pseudo-pressure can be applied to volatile oil backpressure plot to account for multiphase flow below bubble point pressure. The computation steps for backpressure plot for volatile oil are shown below:

- Construct a backpressure plot Δp vs. q ; (Eq. 5.7; above p_{bubble}) and (Eq. 5.8; below p_{bubble})
- Fit a deliverability line using Eq. 5.6.
- Calculate the wellbore skin and non-Darcy factor using multi rate test.
- Calculate two-phase pseudo-pressure ($\Delta m_{2\phi}(p)$) and match the stabilised deliverability line (Eq. 5.11) with $\Delta m_{2\phi}(p)$ calculated with and without high capillary number and non-Darcy effect on the relative permeability curves.

5.6.1 Pressure Backpressure Plot for Volatile Oil

5.6.1.1 Decreasing Rate History

The pressure and decreasing rate history for volatile oil (Fig. 5.34) has 16 flow periods of 1-year duration for each drawdown (DD) alternating with build-up (BU). The rate-normalized pressure log-log and the backpressure plot are shown in Figs. 5.35 and 5.36 respectively. The upward shift of the pressure curves and radial composite behaviour of the derivatives (Fig. 5.35) are due to the development of gas bank at the wellbore.

The pressure backpressure plot (Fig. 5.36) for decreasing rate history did not line up on the stabilized deliverability line (Eq. 5.11) at $k_{ro} = k_{roi}$, the points align on a deliverability line parallel to the deliverability line at k_{ro} less than k_{roi} because it did not capture the effect of gas bank at the wellbore. Therefore, deliverability losses for volatile oil due to reduction in k_{ro} or gas bank cannot be quantified using pressure backpressure plots.

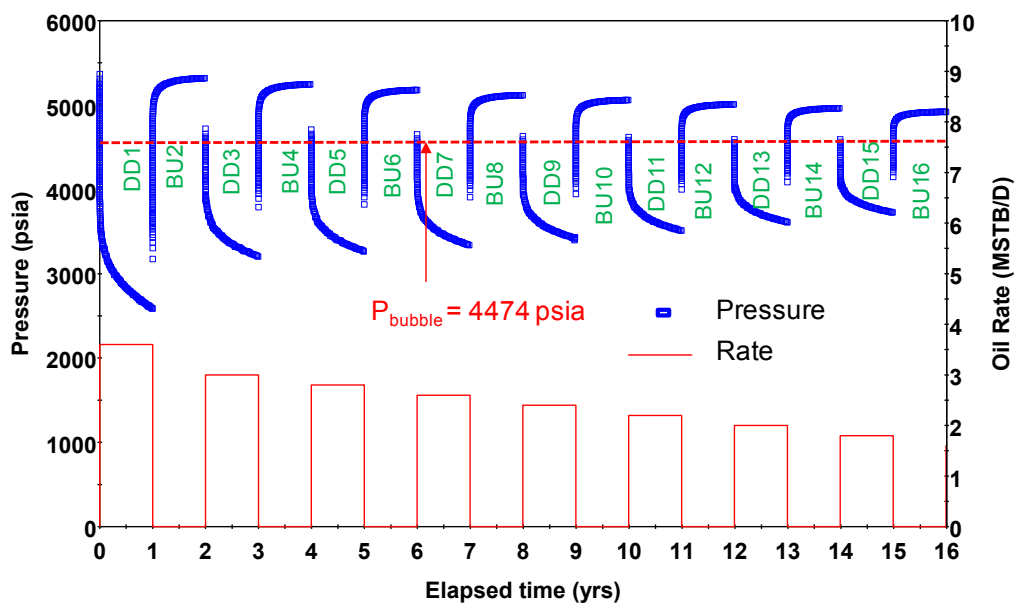


Figure 5.34: Pressure and decreasing rate histories for volatile oil

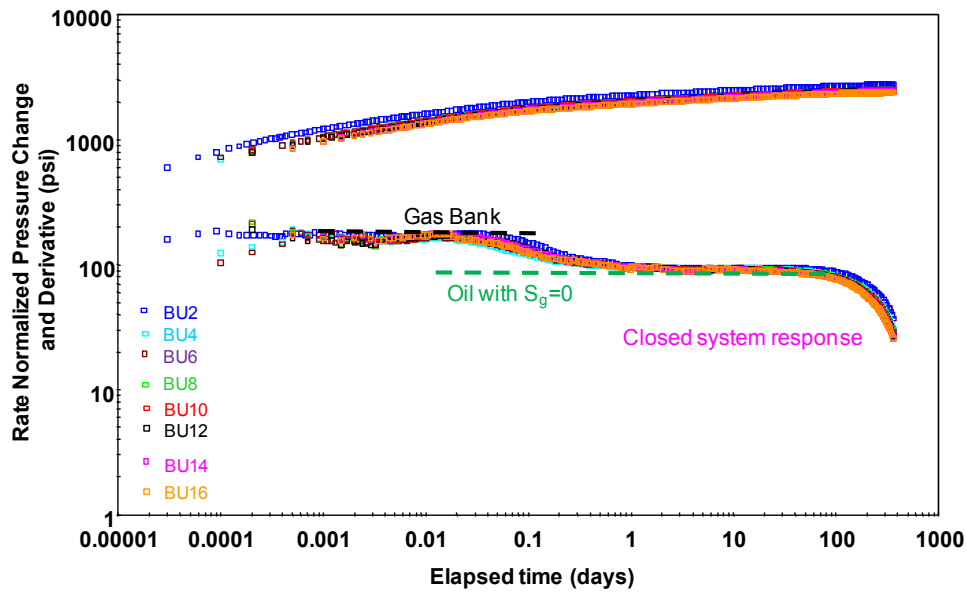


Figure 5.35: Rate-normalized pressure log-log plot for volatile oil (decreasing rate history)

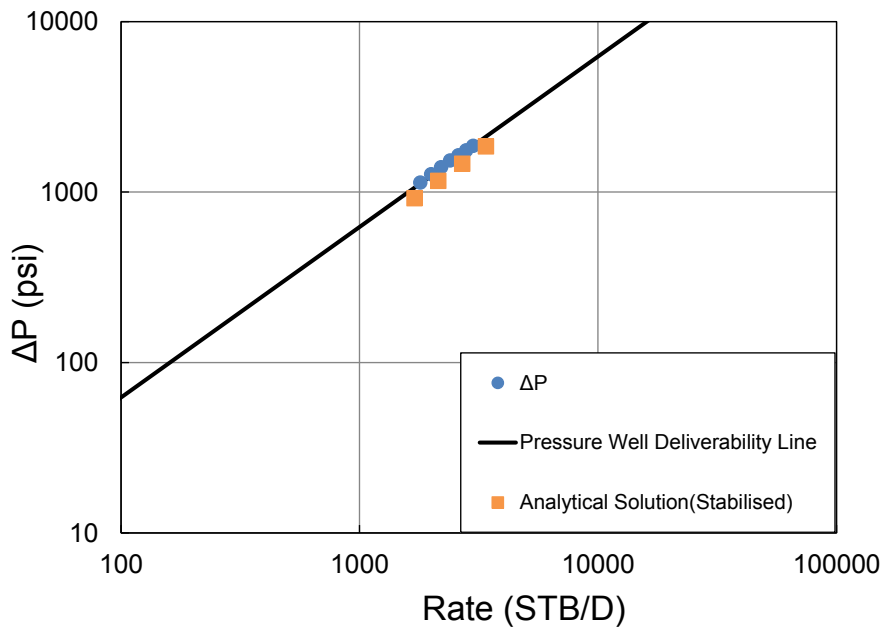


Figure 5.36: Pressure backpressure plots for volatile oil (decreasing rate)

5.6.1.2 Increasing and Random Rate History

The pressure, increasing and random rate histories for volatile oil are shown in Figs. 5.37 and 5.38, they consist of 1-year duration for each drawdowns (DD) and build-up (BU). The rate-normalized log-log and the backpressure plots are shown in Figs. 5.39 and 5.40 respectively. The derivatives exhibit a radial composite behaviour due to the development of the gas bank at the wellbore as confirmed by the upward shift of the pressure curves.

Similar to Fig. 5.36, the pressure backpressure plots (Figs. 5.41 and 5.42) for increasing and random rate histories line up at a deliverability line at k_{ro} less than k_{roi} because they did not capture the effect of multiphase flow below bubble point pressure at the wellbore. Thus, productivity losses due to reduction of effective permeability because of formation of gas bank at the wellbore cannot be quantified using pressure backpressure plots.

The deliverability line for the volatile oil for pressure backpressure plot (Fig. 5.43) is similar for decreasing, increasing and random rate histories. The multiphase flow have more visible impact on lean and rich gas condensate backpressure plot compared to volatile oil for decreasing (Figs. 5.4, 5.20 and 5.36), increasing (Figs. 5.9, 5.25 and 5.41) and random (Figs. 5.10, 5.26 and 5.42) rate histories.

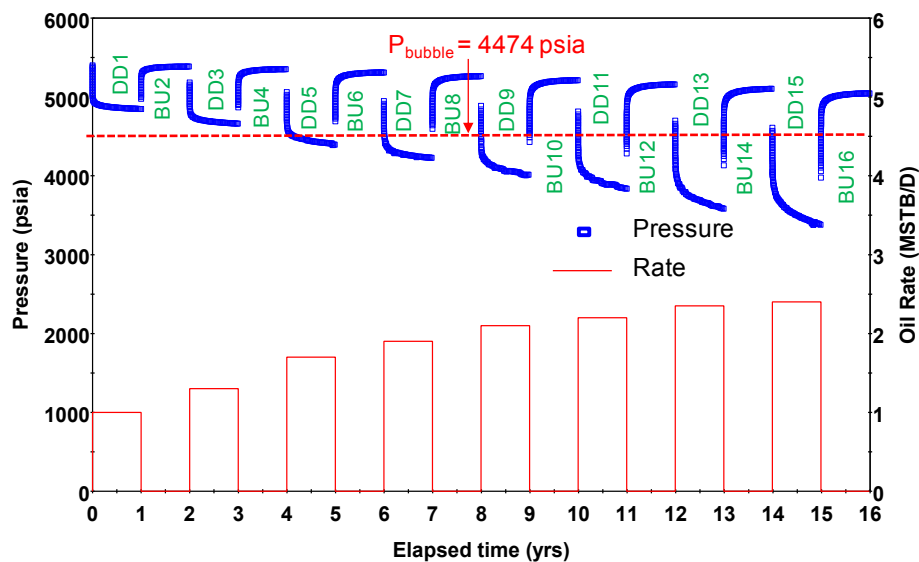


Figure 5.37: Pressure and increasing rate history for volatile oil

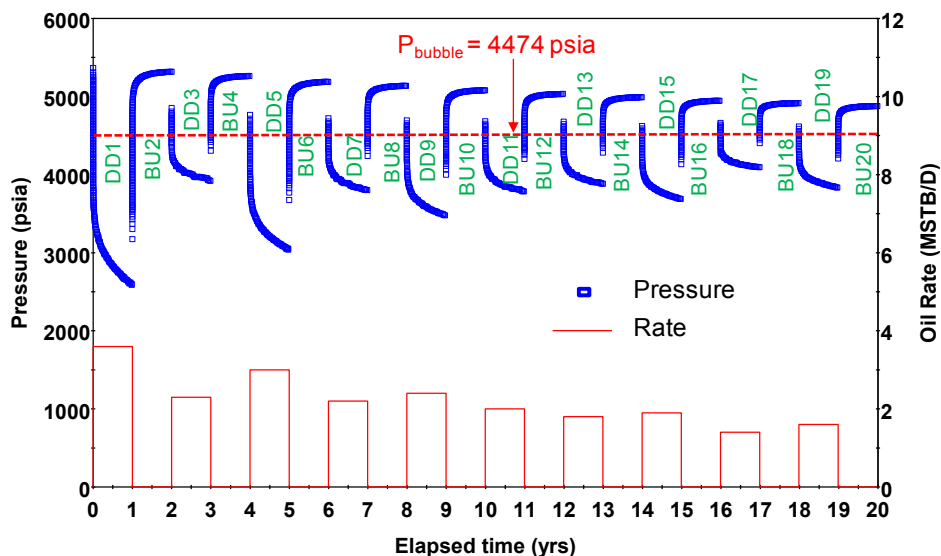


Figure 5.38: Pressure and random rate history for volatile oil

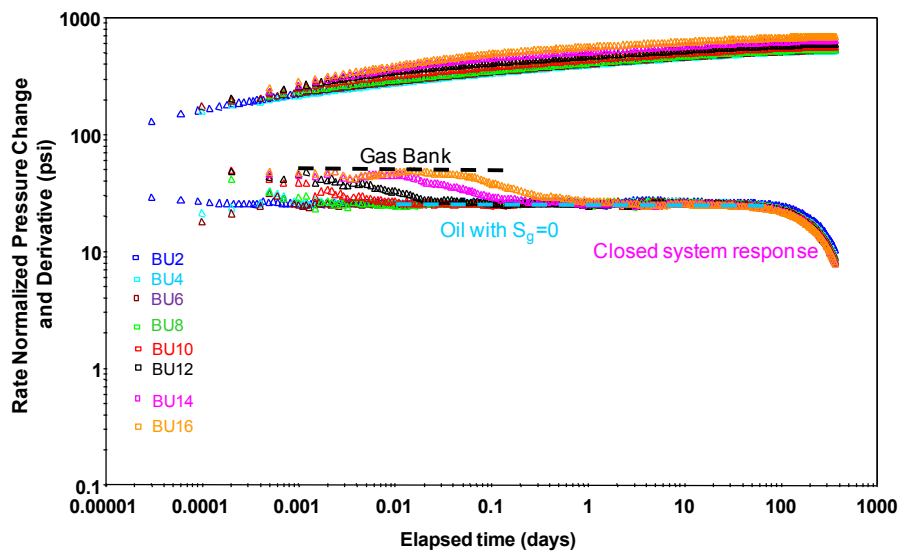


Figure 5.39: Rate-normalized pressure log-log plot for volatile oil (increasing rate history)

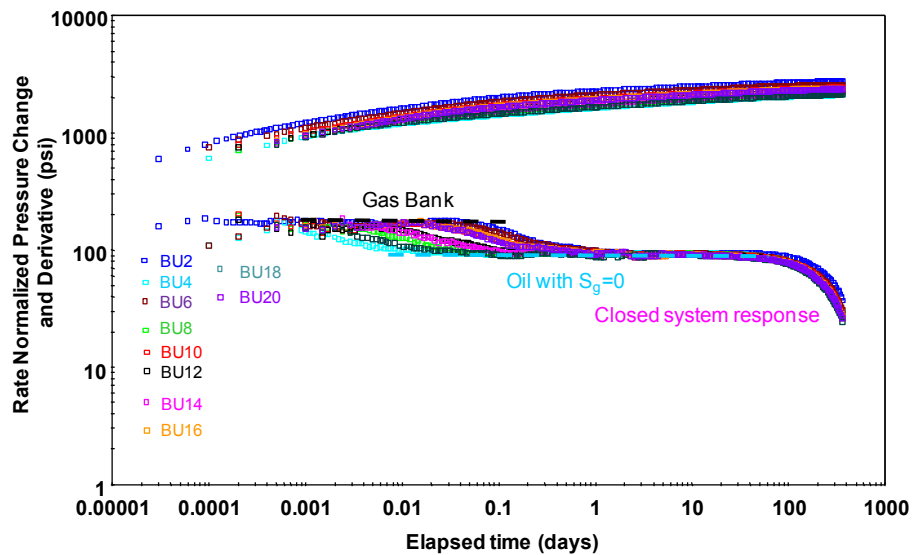


Figure 5.40: Rate-normalized pressure log-log plot for volatile oil (random rate history)

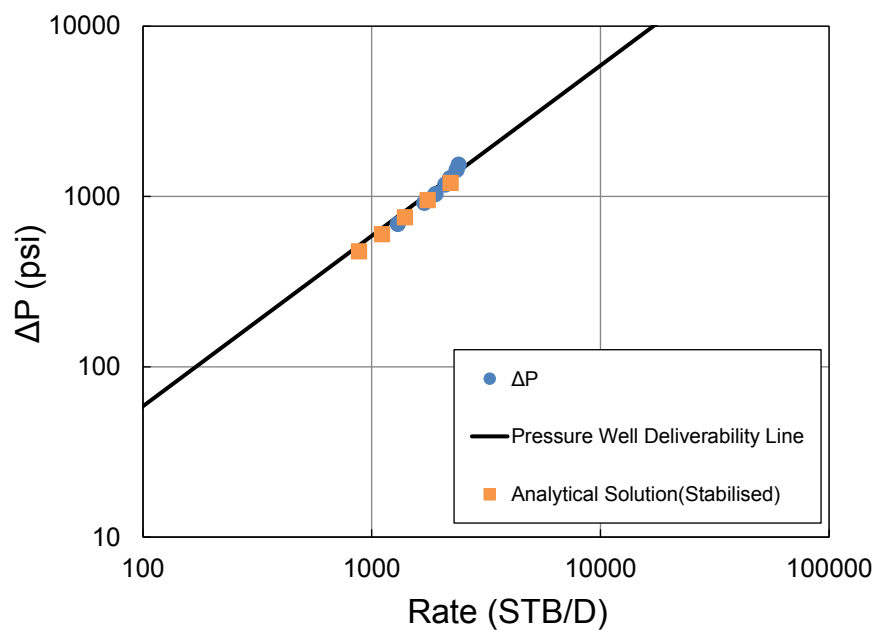


Figure 5.41: Pressure Backpressure plot for volatile oil (increasing rate history)

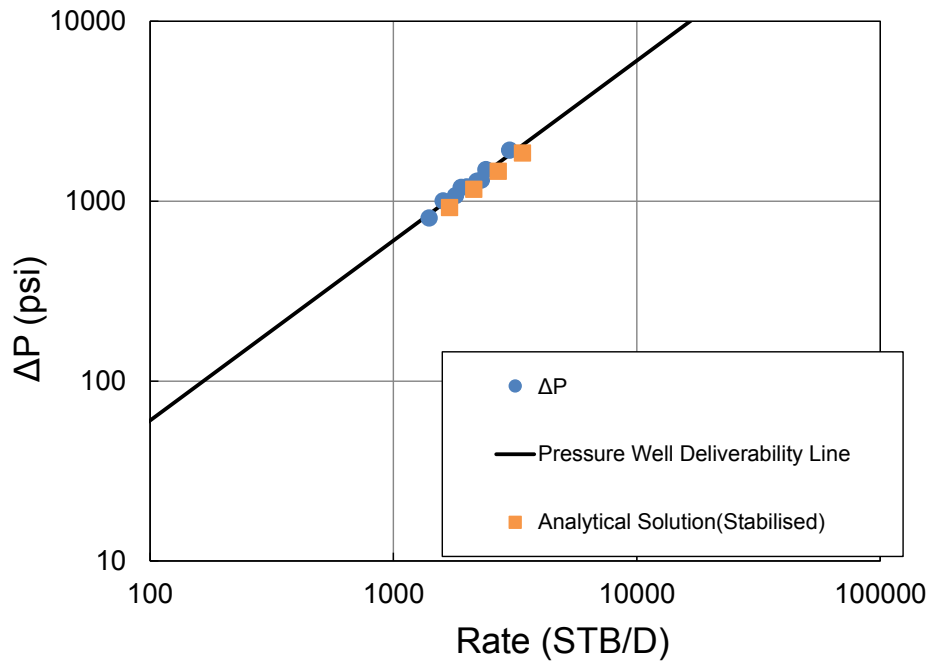


Figure 5.42: Pressure Backpressure plot for volatile oil (random rate history)

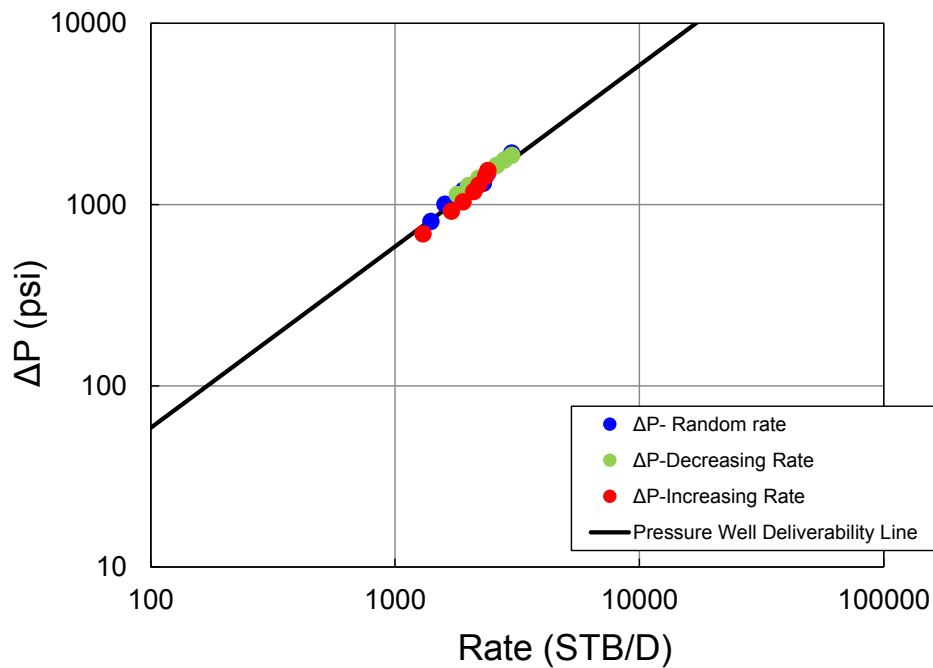


Figure 5.43: Pressure backpressure plot for volatile oil (decreasing, increasing and random rate)

5.6.2 Two-phase pseudo-pressure Backpressure Plot for Volatile Oil

Two-phase pseudo-pressure backpressure plot for volatile oil was calculated with and without high capillary number and non-Darcy effect on the relative permeability curves using the steps in section 2.4. The pressure and two-phase pseudo-pressure log-log plots for decreasing, increasing and random rate histories are shown in Figs. 5.44, 5.45 and 5.46. The two-phase pseudo-pressure derivatives stabilises at zero gas saturation.

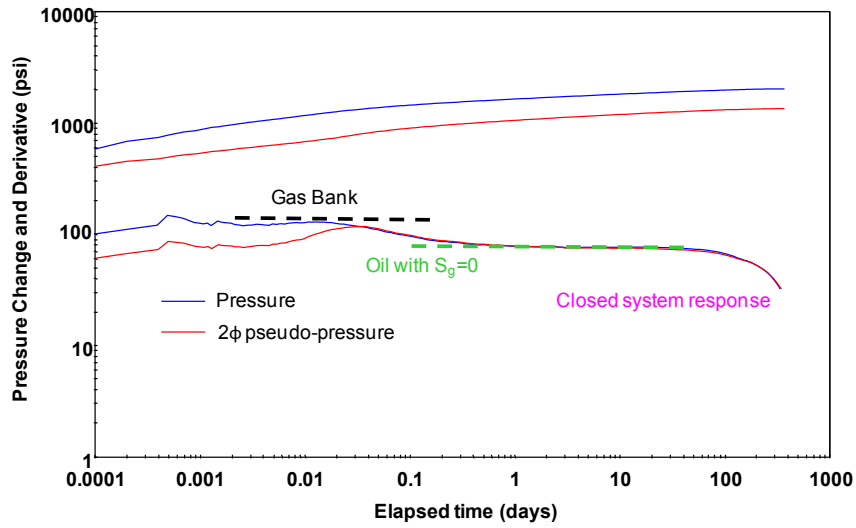


Figure 5.44: Pressure and 2φPP log-log plot for volatile oil (BU 4) (decreasing rate at $k_{rg}^{\max}=1$)

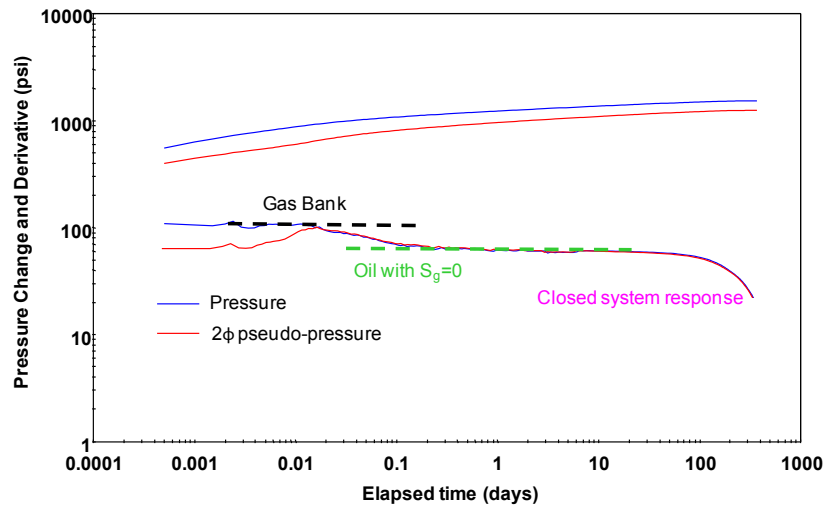


Figure 5.45 Pressure and 2φPP log-log plot for volatile oil (BU 14) (increasing rate at $k_{rg}^{\max}=1$)

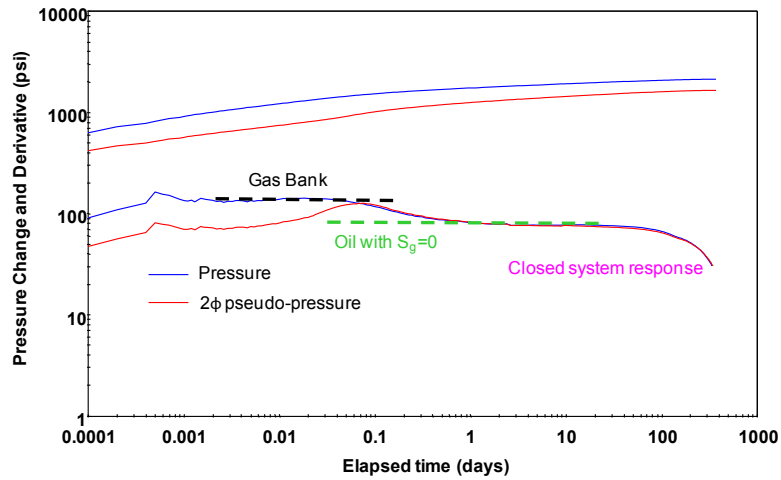


Figure 5.46: Pressure and 2φPP log-log plot for volatile oil (BU 4) (random rate at $k_{rg}^{\max}=1$)

Figs. 5.47, 5.48 and 5.49 show the backpressure plots for pressure (Figs. 5.39, 5.40 and 5.41) and two-phase pseudo-pressure calculated with and without capillary number and turbulence factor for decreasing, increasing and random rate histories.

The two-phase pseudo-pressure backpressure plot (Figs. 5.46, 5.47 and 5.48) calculated without capillary number and turbulence factor line up almost completely on the stabilised analytical solution (Eq. 5.11). Hence, high capillary number and non-Darcy effects at the wellbore have less impact on the backpressure plot of volatile oil compared to lean and rich gases used in this study.

However, the backpressure plots calculated with high capillary number and turbulence factor on the relative permeability curves line up on the stabilised analytical solution (Eq. 5.11). It incorporates the influence of multiphase flow (i.e. gas saturation) and relative permeability reduction at the wellbore into the backpressure analysis.

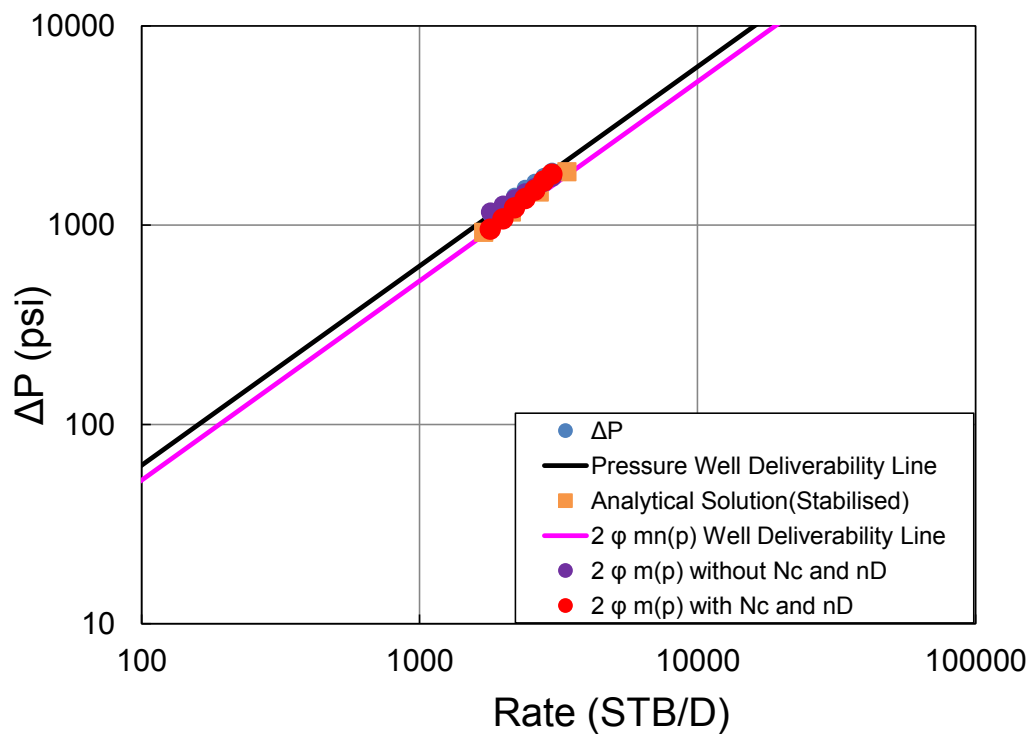


Figure 5.47: Pressure and 2φPP backpressure plot for volatile oil (decreasing rate history)

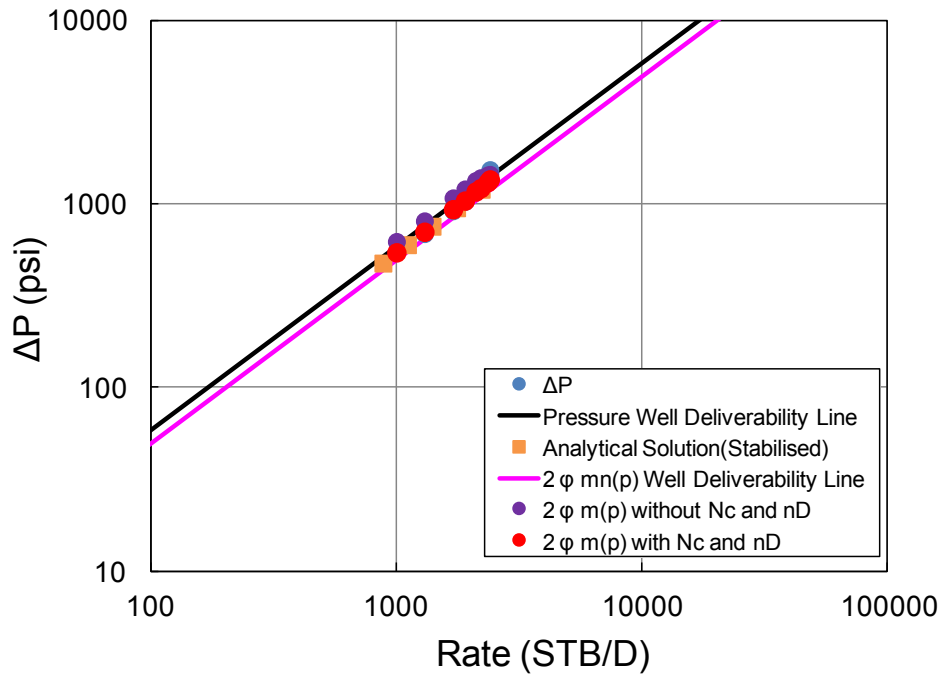


Figure 5.48: Pressure and 2 ϕ PP backpressure plot for volatile oil (increasing rate history)

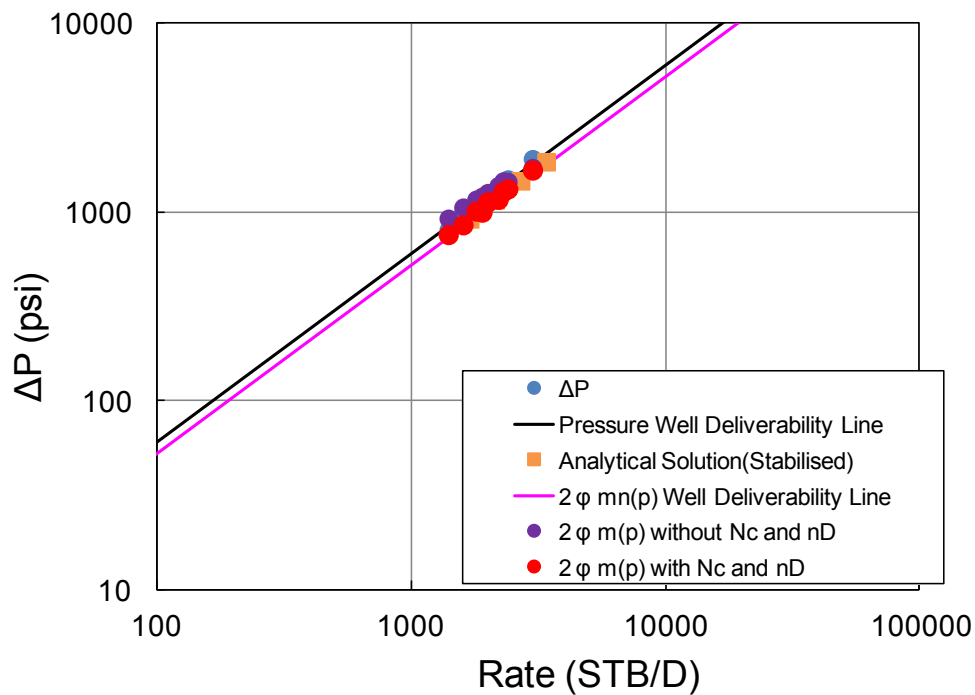


Figure 5.49: Pressure and 2 ϕ PP backpressure plot for volatile oil (random rate history)

5.6.3 Summary Backpressure Plot for Volatile Oil

1. The pressure backpressure plot predicted a deliverability line less than the stabilized deliverability line below bubble point pressure for volatile oil.
2. The high capillary number and non-Darcy effects at the wellbore have less impact on the backpressure plot of volatile oil compared to lean gas and rich gas.

3. The backpressure plots calculated with high capillary number and turbulence effects on the relative permeability curves line up on the stabilised deliverability line.

5.7 Backpressure Plot Calculated for different values of Simulated Mechanical Skin and Permeability Thickness

Additional simulation runs with different mechanical skin ($s_m = 2$ and 5) and reservoir permeability thickness ($kh=300\text{mDft}$ and 100mDft) were carried out to study the effect of different values of mechanical skin and reservoir permeability thickness on single-phase and two-phase pseudo-pressure backpressure plots for lean gas, rich gas and volatile oil wells. The rate histories were set in a descending order (similar to Fig. 5.2 for lean gas, Fig. 5.18 for rich gas, Fig. 5.34 for volatile oil).

5.7.1 Lean Gas Condensate

5.7.1.1 Single-phase pseudo-pressure analysis

The single-phase backpressure plot for different values of mechanical skin (Fig. 5.50) and reservoir permeability thickness (Fig. 5.51) show similar backpressure deliverability slope. The deliverability lines are parallel but shifted sideways based on the value of mechanical skin or reservoir permeability thickness.

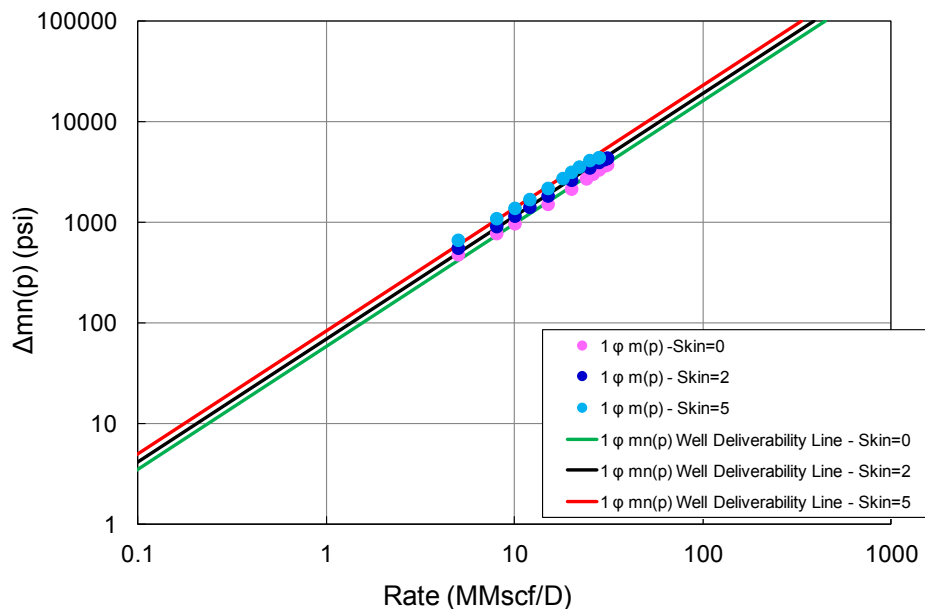


Figure 5.50: 1 ϕ pp backpressure plots for lean gas (skin =0, 2 and 5)

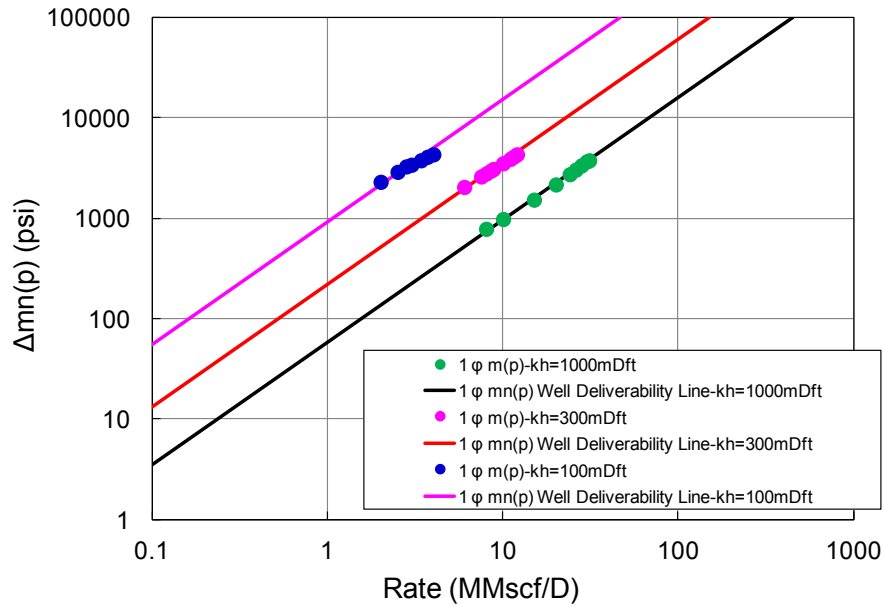


Figure 5.51: 1 ϕ pp backpressure plots for lean gas ($kh = 1000, 300$ and 100mDft)

5.7.1.2 Two-phase pseudo-pressure analysis

Similar to two-phase backpressure plot (Fig. 5.15) calculated without high capillary number and non-Darcy effects on the relative permeability curves for $s_m = 0$ and $kh=1000\text{mDft}$; the two-phase backpressure plots (Figs. 5.52, 5.53, 5.54 and 5.55) for different mechanical skin ($s_m = 2$ and 5) and permeability thickness ($kh = 100\text{mDft}$ and 300mDft) did not align with the stabilised analytical deliverability line (Eq. 5.2).

Nonetheless, the two-phase backpressure plot (Figs. 5.52, 5.53, 5.54 and 5.55) calculated with high capillary number and turbulence factor on the relative permeability curve for different mechanical skin ($s_m = 2$ and 5) and permeability thickness ($kh = 100\text{mDft}$ and 300mDft) line up on the stabilised analytical solution because it captures the deliverability loss due to relative permeability reduction, condensate bank, high capillary number and non-Darcy effects at the wellbore.

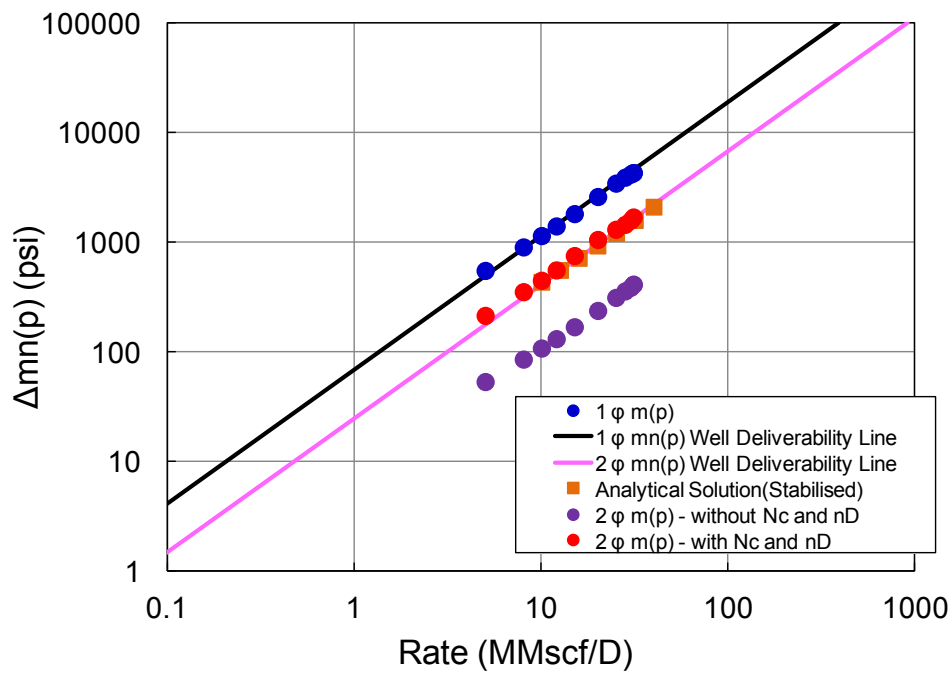


Figure 5.52: 1 ϕ PP and 2 ϕ PP backpressure plots for lean gas (skin =2)

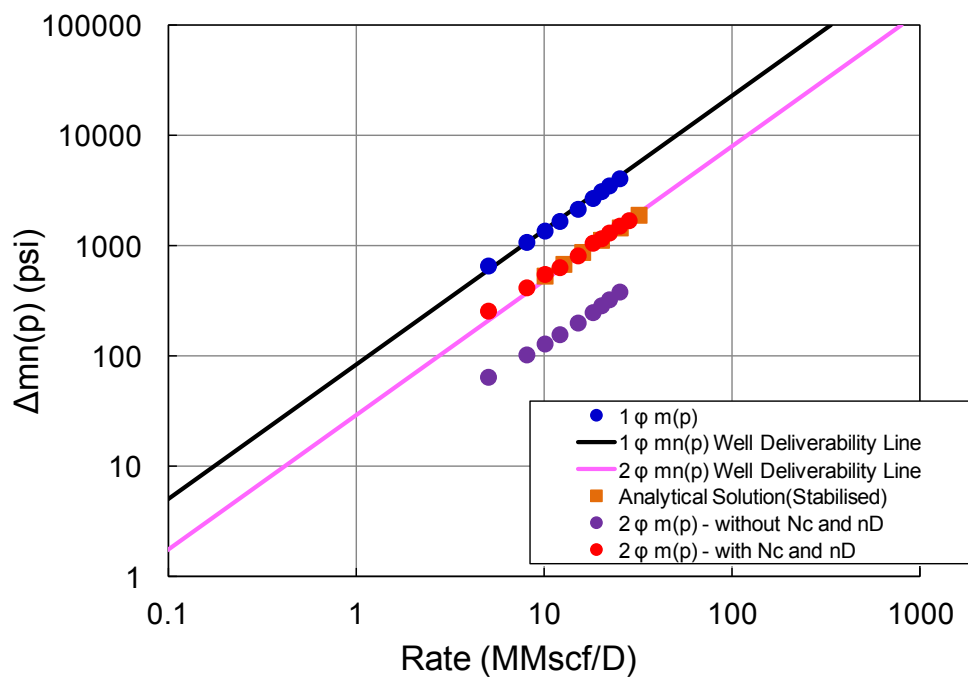


Figure 5.53: 1 ϕ PP and 2 ϕ PP backpressure plots for lean gas (skin =5)

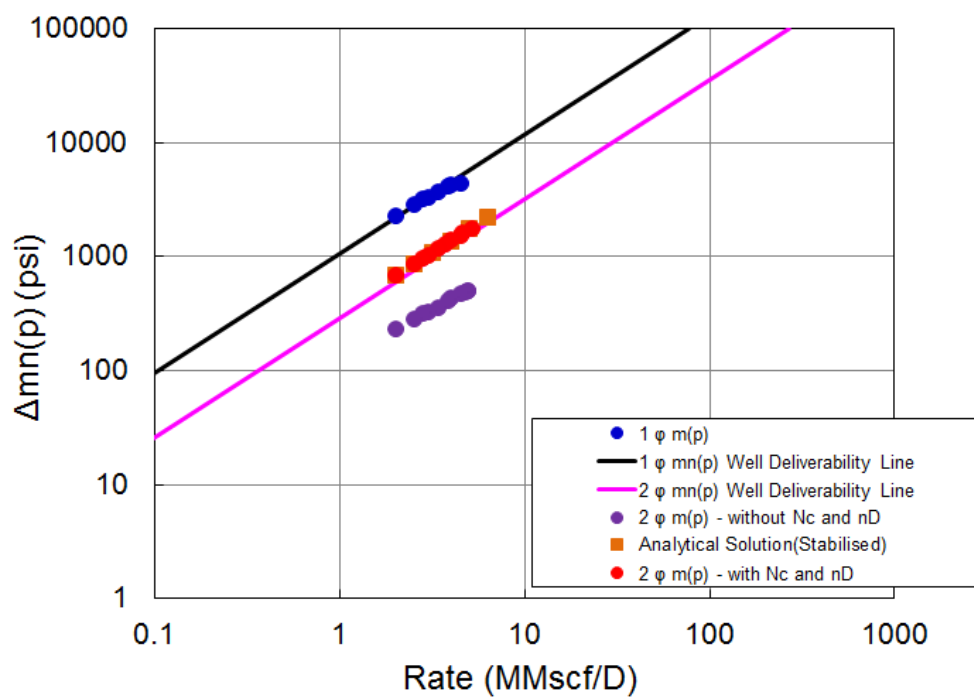


Figure 5.54: 1φPP and 2φPP backpressure plots for lean gas (kh =100mDft)

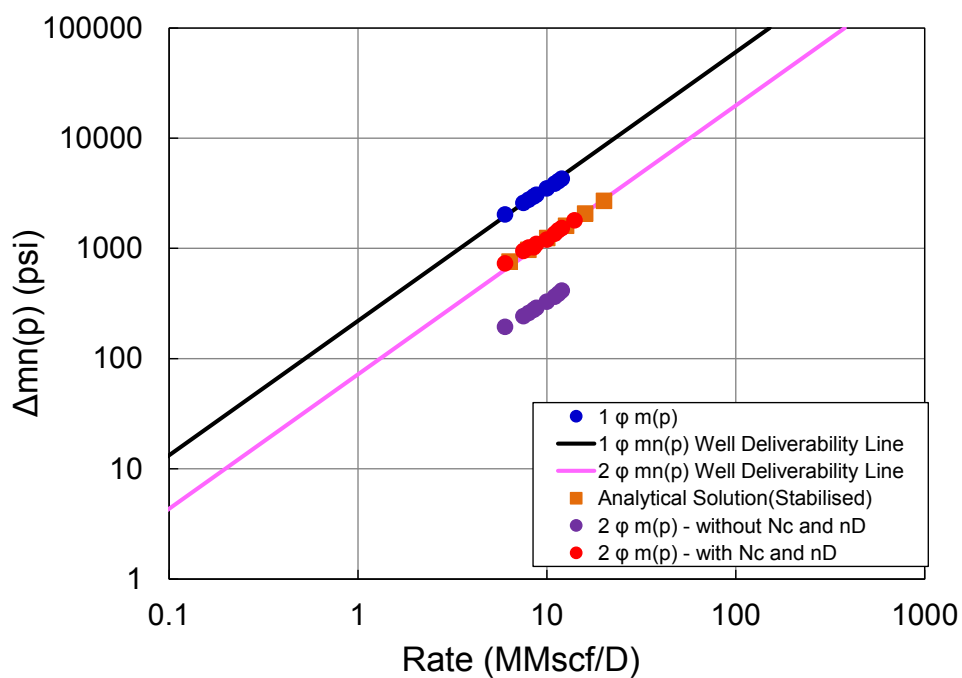


Figure 5.55: 1φPP and 2φPP backpressure plots for lean gas (kh =300mDft)

5.7.2 Rich Gas Condensate

5.7.2.1 Single-phase pseudo-pressure analysis

The rich gas single-phase backpressure deliverability plots (Figs. 5.56 and 5.57) for different values of mechanical skin ($s_m = 2$ and 5) and reservoir permeability thickness ($kh = 100\text{mDft}$ and 300mDft) show the similar backpressure deliverability slope.

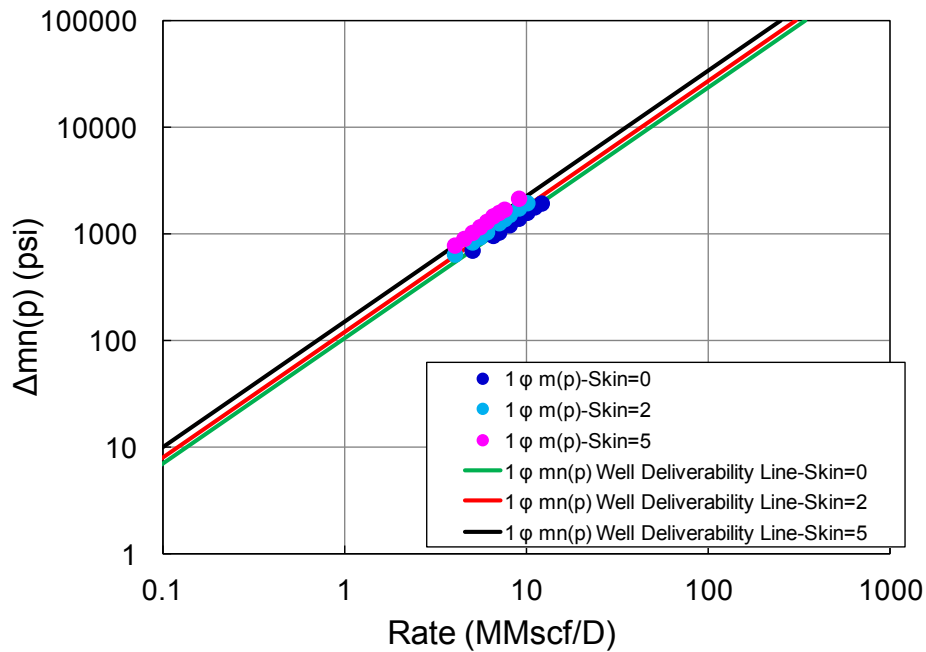


Figure 5.56: 1ϕ PP and 2ϕ PP backpressure plots for rich gas (skin = 0, 2 and 5)

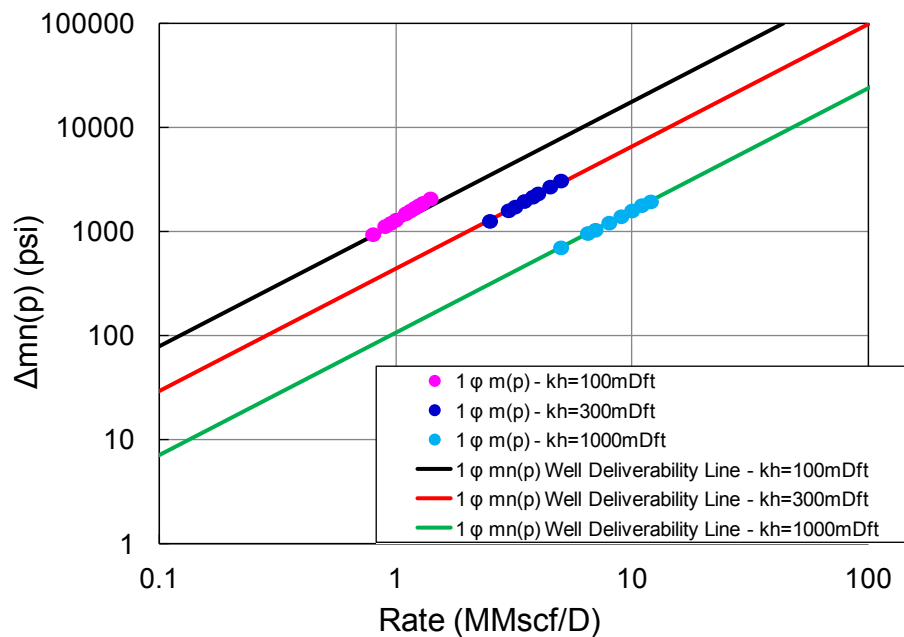


Figure 5.57: 1ϕ PP and 2ϕ PP backpressure plots for rich gas ($kh = 1000\text{mDft}$, 300mDft and 100mDft)

5.7.2.2 Two-phase pseudo-pressure analysis

The two-phase backpressure plots (Figs. 5.58, 5.59, 5.60 and 5.61) calculated without high capillary number and turbulence factor on the relative permeability curve for different values of mechanical skin ($s_m = 2$ and 5) and reservoir permeability thickness ($kh = 100\text{mDft}$ and 300mDft) did not align with the stabilised analytical solution. The well deliverability was exaggerated in all cases.

However, the two-phase backpressure plots (Figs. 5.58, 5.59, 5.60 and 5.61) calculated with relative permeability that integrates high capillary number and turbulence effects align with the stabilised analytical line because it captures the deliverability loss due to decrease in the relative permeability, condensate drop out, high capillary number and non-Darcy effects at the wellbore.

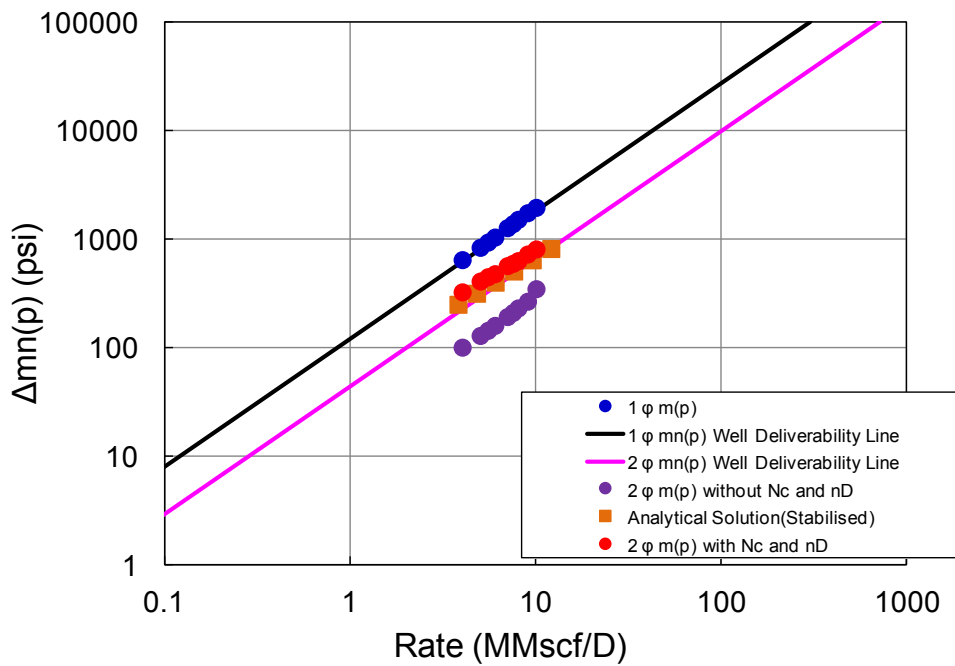


Figure 5.58: 1ϕ PP and 2ϕ PP backpressure plots for rich gas (skin = 2)

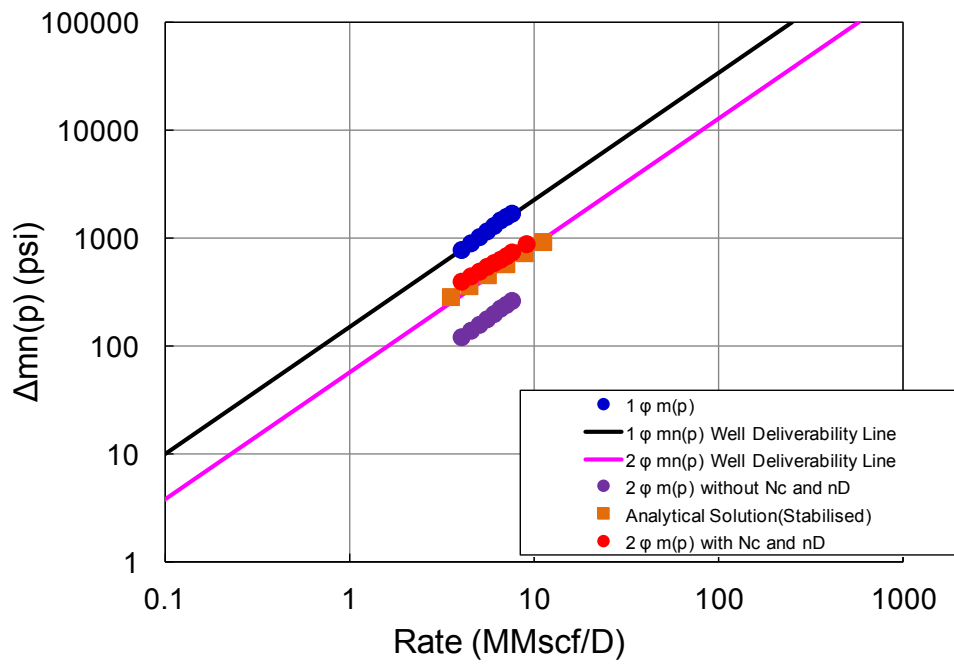


Figure 5.59: 1 ϕ PP and 2 ϕ PP backpressure plots for rich gas (skin =5)

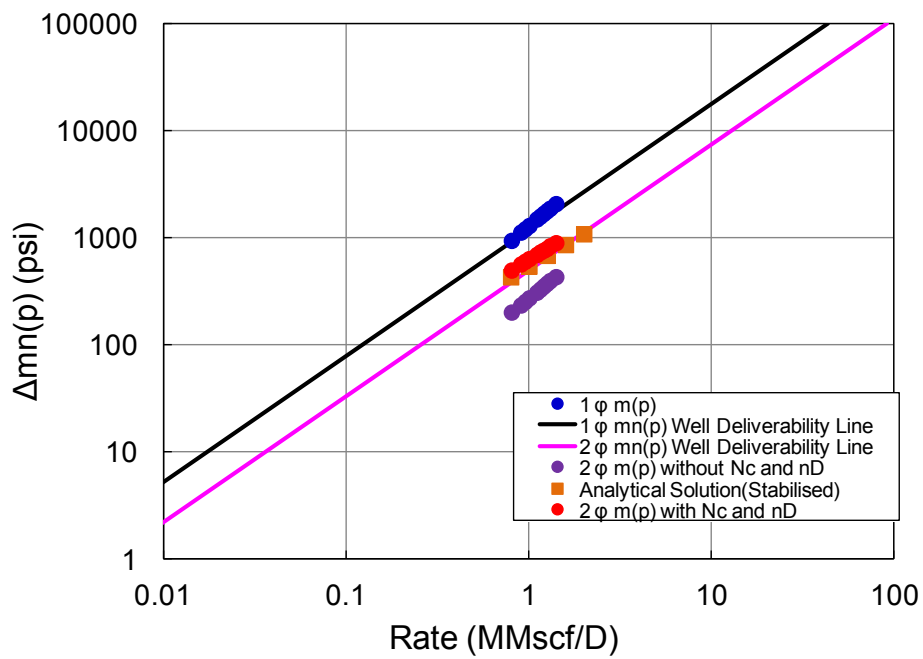


Figure 5.60: 1 ϕ PP and 2 ϕ PP backpressure plots for rich gas (kh = 100mDft)

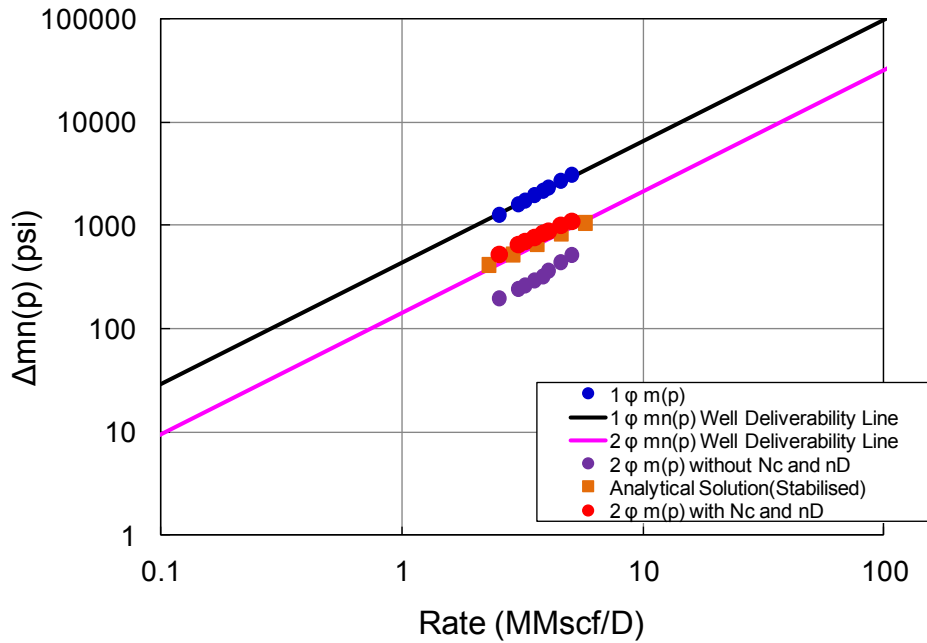


Figure 5.61: 1φPP and 2φPP backpressure plots for rich gas ($kh = 300\text{mDft}$)

5.7.3 Volatile Oil

5.7.3.1 Pressure analysis

The pressure backpressure plot (Fig. 5.62) for on different mechanical skin shows similar backpressure deliverability slope. In contrast, the pressure backpressure plot (Fig. 5.63) for different reservoir permeability thickness show different backpressure deliverability slope, this is more pronounced in the case of $kh = 100\text{mDft}$ where the slope of the deliverability line is completely different when compared to $kh=300\text{mDft}$ and 1000mDft .

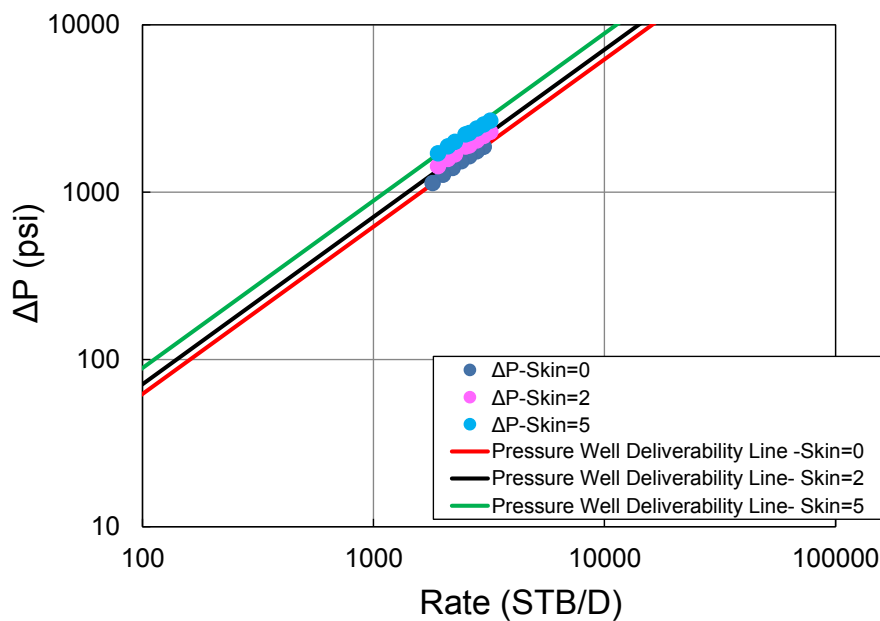


Figure 5.62: Pressure backpressure plots for volatile oil (skin= 0, 2 and 5)

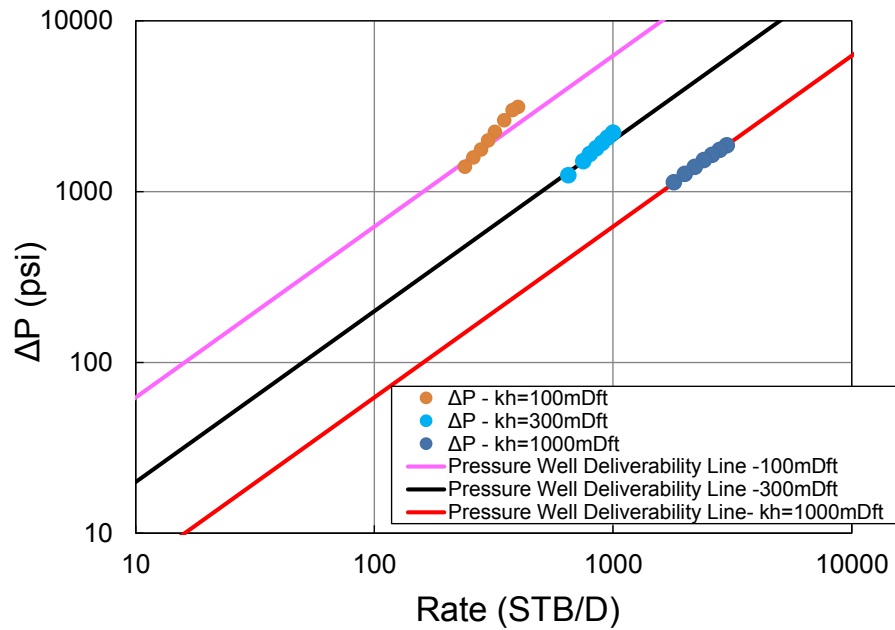


Figure 5.63: Pressure backpressure plots for volatile oil ($kh = 1000, 300$ and 100mDft)

5.7.3.2 Two-phase pseudo-pressure analysis

The two-phase backpressure plots (Figs. 5.64, 5.65, 5.66 and 5.67) calculated without high capillary number and turbulence factor on the relative permeability curve for different values of mechanical skin ($s_m = 2$ and 5) and reservoir permeability thickness ($kh=100\text{mDft}$ and 300mDft) line up nearly completely on the stabilised analytical deliverability line (Eq. 5.11). Thus, high capillary number and non-Darcy effects at the wellbore have less impact on the backpressure plot of volatile oil compared to lean and rich gas condensate.

Conversely, the backpressure plots calculated with high capillary number and turbulence factor on relative permeability curve align completely with the stabilised analytical solution (Eq. 5.11). The slope of pressure backpressure deliverability line for $kh = 100\text{mDft}$ was corrected in two-phase backpressure plot calculated with high capillary number and turbulence factor on the relative permeability curve as shown Fig. 5.66.

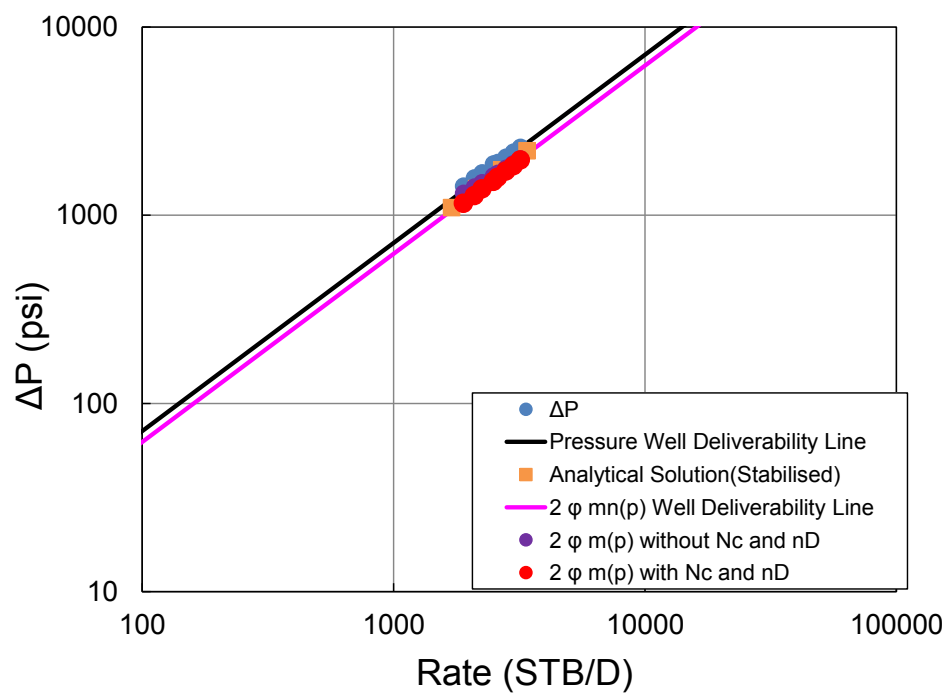


Figure 5.64: Pressure and 2 ϕ PP backpressure plots for volatile oil (skin= 2)

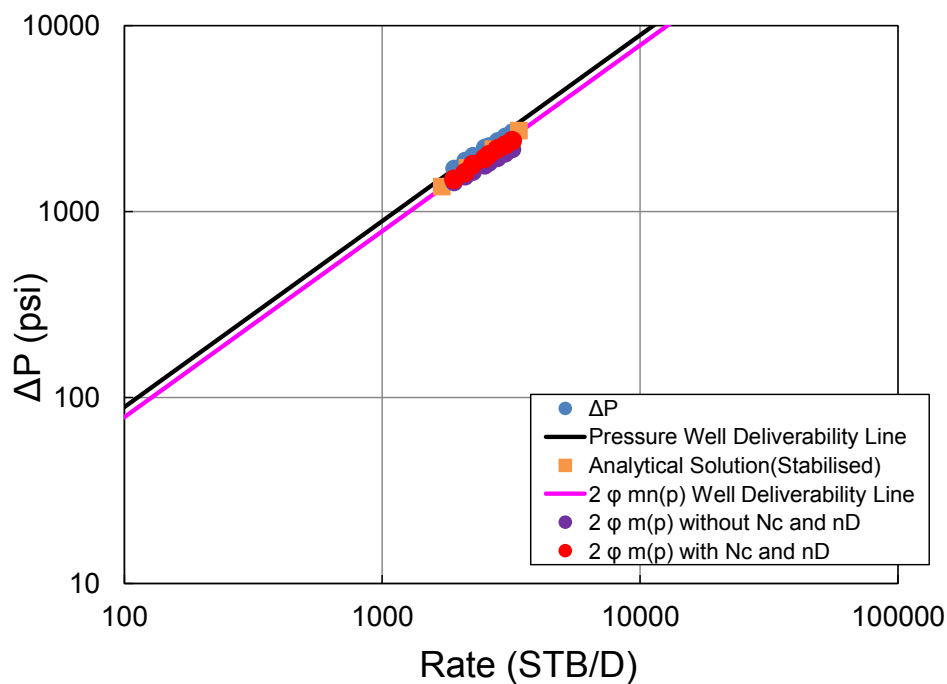


Figure 5.65: Pressure and 2 ϕ PP backpressure plots for volatile oil (skin= 5)

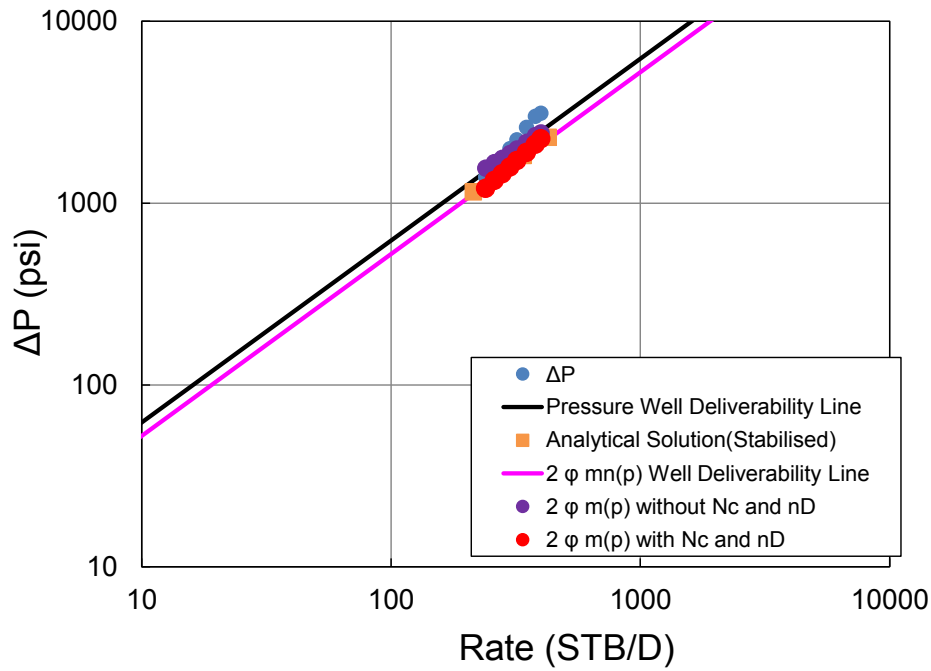


Figure 5.66: Pressure and Two-phase Backpressure plots for volatile oil ($kh = 100\text{mDft}$)

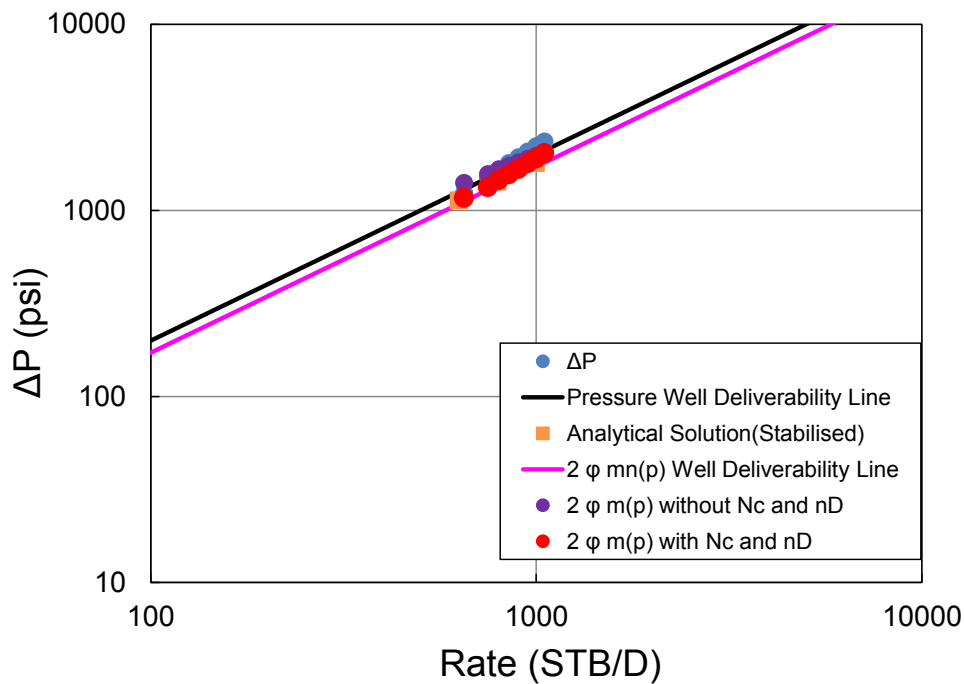


Figure 5.67: Pressure and Two-phase Backpressure plots for volatile oil ($kh = 300\text{mDft}$)

5.7.4 Summary of Backpressure Plot for different Mechanical Skin and Permeability Thickness (KH)

Changes to the value of mechanical skin and permeability thickness has no impact on the prediction of stabilised deliverability line for two-phase pseudo-pressure backpressure plot calculated with high capillary number and non-Darcy factor on the relative permeability curve for lean gas, rich gas and volatile oil.

5.8 Effects of Fluid Richness on Reservoir Boundary Response

5.8.1 Lean and Rich Gas Condensate

Aluko (2009) showed that condensate bank response can be superimposed on boundary response for long production time if the reservoir pressure at the boundary goes below the dew point pressure; i.e. there is liquid drop-out everywhere in the reservoir. This was confirmed by the shift in the boundary response for late time behavior as we move from one flow period to another. However, he did not show the comparative impact of fluid richness on the boundary response for lean and rich gas condensate. This case was simulated with initial pressure set at 135psi higher than the dew point pressure for lean gas and rich gas. The flow periods are 1-year in duration, with drawdown alternating with build-up.

Fig. 5.69 show that the impact of condensate saturation on the boundary response is more severe and were shifted with increase in condensate drop for long production time in rich gas compared to lean gas (Fig. 5.68) whose boundary response was not affected by condensate bank for long production time because less condensate drop out of the lean gas compared to rich gas. Thus, below dew point pressure higher mobility reduction will occur quicker at the boundary of rich gas compared to lean gas for long production time.

The condensate saturation profile at the end of each drawdown for lean gas (Fig. 5.70) and rich gas (Fig. 5.71) show that the condensate bank at the boundary is zero for lean gas but there was a significant increase for rich gas from the beginning to the end of the production history. This was confirmed by the obvious shift in boundary response for rich gas compared to lean gas at late time (Figs. 5.68 and 5.69).

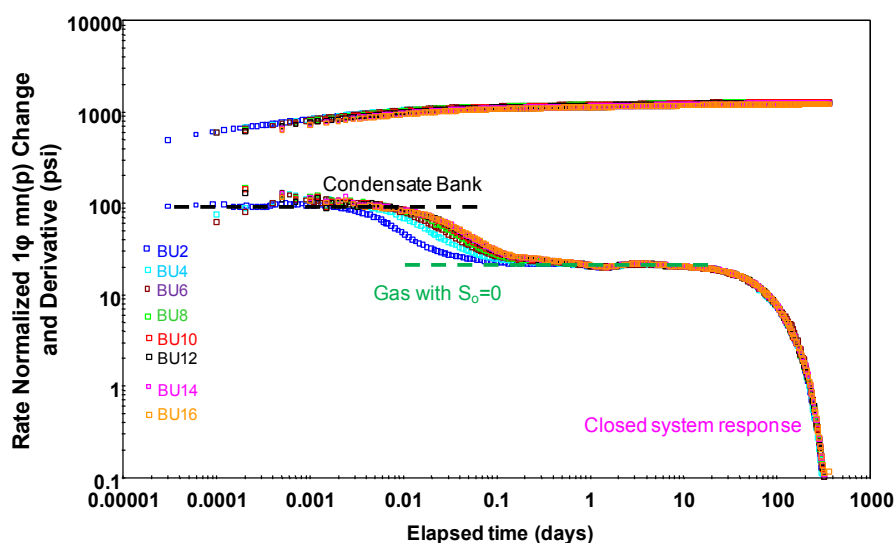


Figure 5.68: Rate-normalized build-up response below p_{dew} for lean gas (decreasing rate)

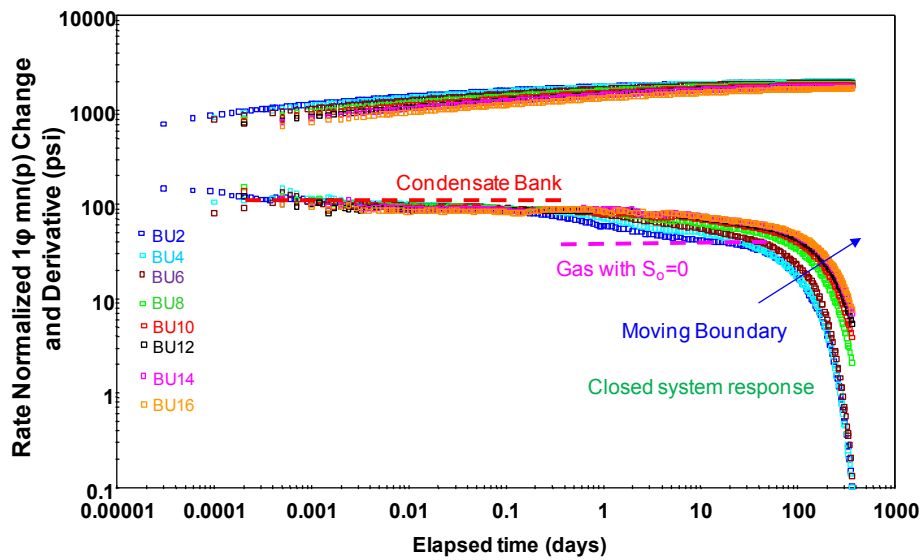


Figure 5.69: Rate-normalized build-up response below p_{dew} for rich gas (decreasing rate)

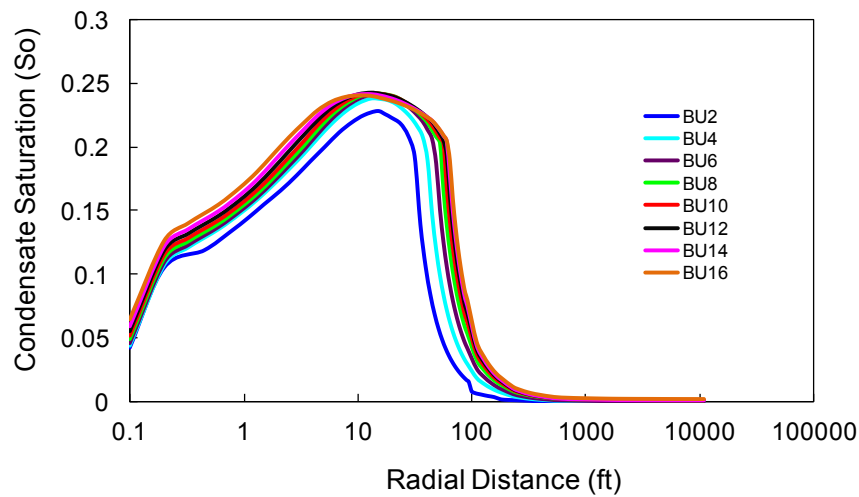


Figure 5.70: Condensate saturation profiles for lean gas (decreasing rate history)

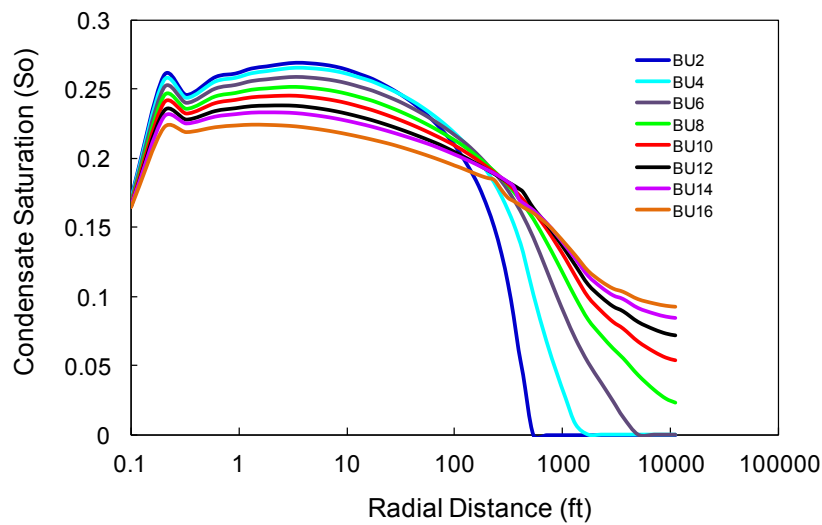


Figure 5.71: Condensate saturation profiles for rich gas (decreasing rate history)

5.8.2 Volatile Oil

Similar to lean gas, the impact of the fluid richness on boundary response of volatile oil used in this study is not severe compared to the rich gas behaviour (Fig. 5.69). The mobility reduction from the wellbore to the boundary is small for long production time. The saturation profile shows that the gas bank at the end of each drawdown for volatile oil (Fig. 5.73) is zero at the boundary. Hence, there was no visible shift in the boundary response at late time (Figs. 5.72).

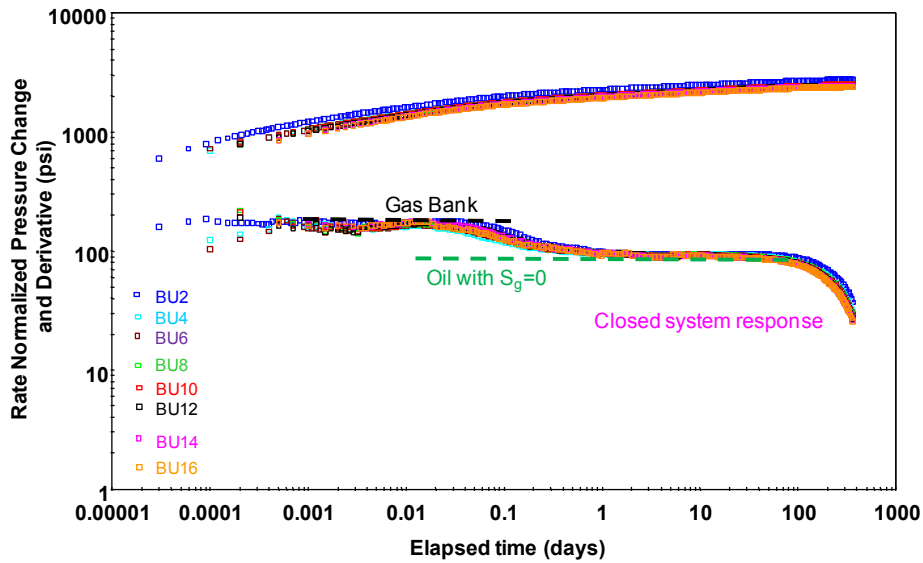


Figure 5.72: Rate-normalized build-up response in a closed system below p_{bubble} for decreasing rate history (volatile oil)

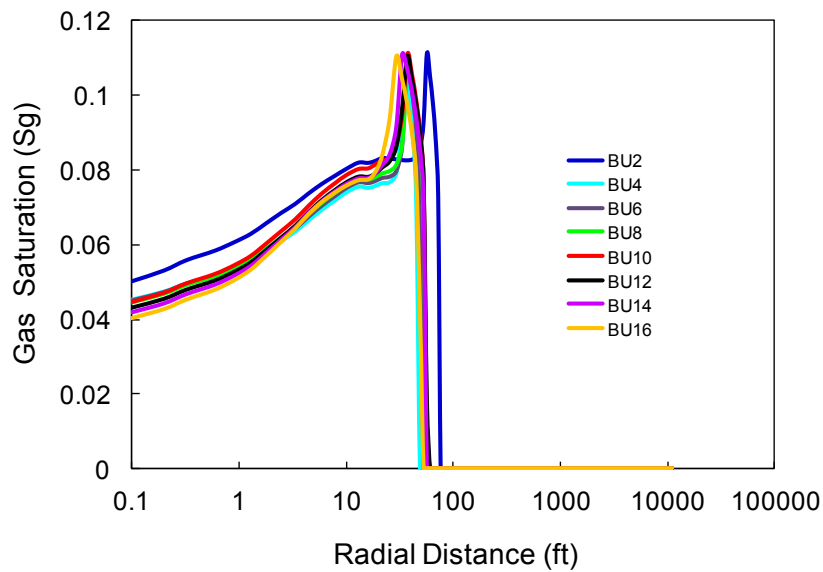


Figure 5.73: Condensate saturation profiles for volatile oil (decreasing rate history)

5.8.3 Summary of Effects of Fluid Richness on Reservoir Boundary Response

1. Higher reduction in mobility will occur quicker at the boundary of rich gas compared to lean gas for long production time below dew point pressure.
2. Impact of condensate saturation on the boundary response of rich gas condensate is more severe compared to lean gas and volatile oil for long production time

5.9 Backpressure Plot of Field Data

5.9.1 Lean gas condensate example (CDFi)

This example is from a horizontal well in a lean gas reservoir (CDFi) described in section 4.10.1. The stabilized deliverability line for horizontal well was calculated using Eqs. 5.12 to 5.18 (Badu and Odeh, 1989; Billiter *et al.* 2001; Kamkom and Zhu, 2006).

$$q_g = \frac{b\sqrt{k_y k_z} \left(m\left(\frac{p}{p}\right) - m(p_{wf}) \right)}{1424T \left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H - 0.75 + s_R + \frac{b}{L}(s + Dq) \right]} \quad 5.12$$

where C_H is the shape factor and s_R is the partial penetration skin factor given by Eqs. 5.13 and 5.14:

$$\ln C_H = 6.28 \frac{a}{I_{ant} h} \left[\frac{1}{3} - \frac{y_o}{a} + \left(\frac{y_o}{a} \right)^2 \right] - \ln \left(\sin \frac{\pi z_o}{h} \right) - 0.5 \left[\frac{a}{I_{ant} h} \right] - 1.088 \quad 5.13$$

$$s_R = P_{xyz} + P'_{xy} \quad 5.14$$

P_{xyz} and P'_{xy} is given by Eqs. 19 and 20:

$$p_{xyz} = \left(\frac{b}{L} - 1 \right) \left[\ln \frac{h}{r_w} + 0.25 \ln \frac{k_y}{k_z} - \ln \left(\sin \frac{\pi z}{h} \right) - 1.84 \right] \quad 5.15$$

$$P'_{xy} = \frac{2b^2}{I_{ant} L h} \left[F \left(\frac{L}{2b} \right) + 0.5 \left[F \left(\frac{4x_{mid} + L}{2b} \right) \right] - F \left(\frac{4x_{mid} - L}{2b} \right) \right] \quad 5.16$$

x_{mid} and F are defined in Eqs. 21 and 22:

$$x_{mid} = 0.5(x_1 + x_2) \quad 5.17$$

$$F(x) = \begin{cases} -(x) \left[0.145 + \ln(x) - 0.137(x)^2 \right] \text{ for } x = \frac{L}{2b}, x = \frac{4x_{mid} \pm L}{2b} \leq 1 \\ (2-x) \left[0.145 + \ln(2-x) - 0.137(2-x)^2 \right] \text{ for } x = \frac{4x_{mid} + L}{2b} > 1 \end{cases} \quad 5.18$$

As shown in the theoretical study, single-phase pseudo-pressure backpressure plot and the two-phase pseudo-pressure backpressure plot calculated without high capillary

number and turbulence factor on the relative permeability curve did not line up on the stabilized flow deliverability line (Eq. 5.12), whereas two-phase pseudo-pressure backpressure data calculated with the relative permeability curves that incorporates high capillary number and turbulence effects give a better prediction of the stabilized deliverability be (Fig. 5.74).

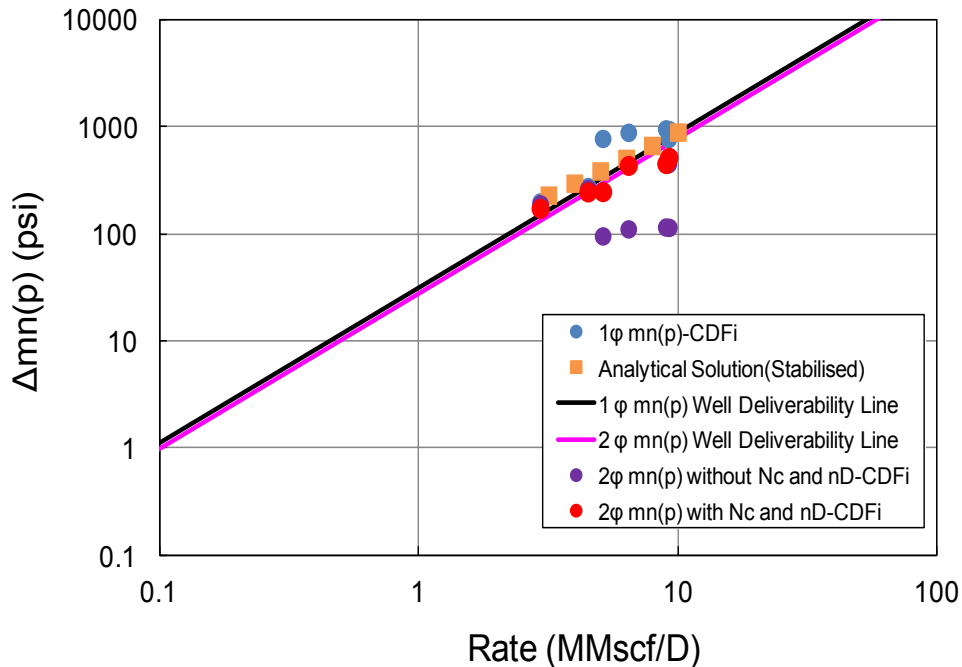


Figure 5.74: Single and 2φPP backpressure plot for CDFi

5.9.2 Rich gas condensate example (MTG)

This example is from a vertical well (Well W-7) in a rich gas reservoir (MTG) described in section 4.10.2.

5.9.2.1 Single-phase and Two-phase Pseudo-pressure Backpressure Plot

The single-phase pseudo-pressure backpressure plots (Fig. 5.75) for MTG do not line up on the stabilized flow deliverability line (Eq. 5.2) at $k_{rg}=k_{rgi}$ because it did not capture the effect of condensate bank formed at the wellbore. Therefore, deliverability losses due to reduction in k_{rg} or condensate bank cannot be quantified using single-phase backpressure plots.

The pressure data of MTG (Fig. 5.8) was converted to two-phase pseudo-pressure using methodology in section 2.4. The backpressure plots for single-phase (Figs. 5.75) and two-phase pseudo-pressure analyses were calculated with and without high capillary number and turbulence factor on the relative permeability curves (Fig. 5.75).

The two-phase backpressure plot (Figs. 5.75) calculated without high capillary number and turbulence factor on the relative permeability curve did not line up on the stabilised analytical solution (Eq. 5.2). On the contrary, the backpressure plot calculated with high capillary number and turbulence factor on the relative permeability curve line up on the stabilised analytical solution because it captures the deliverability loss due to k_{rg} reduction, condensate bank formation, high capillary number and non-Darcy effects at the wellbore. It incorporates the influence of multiphase flow (i.e. gas and condensate saturation) at the wellbore into the backpressure calculation.

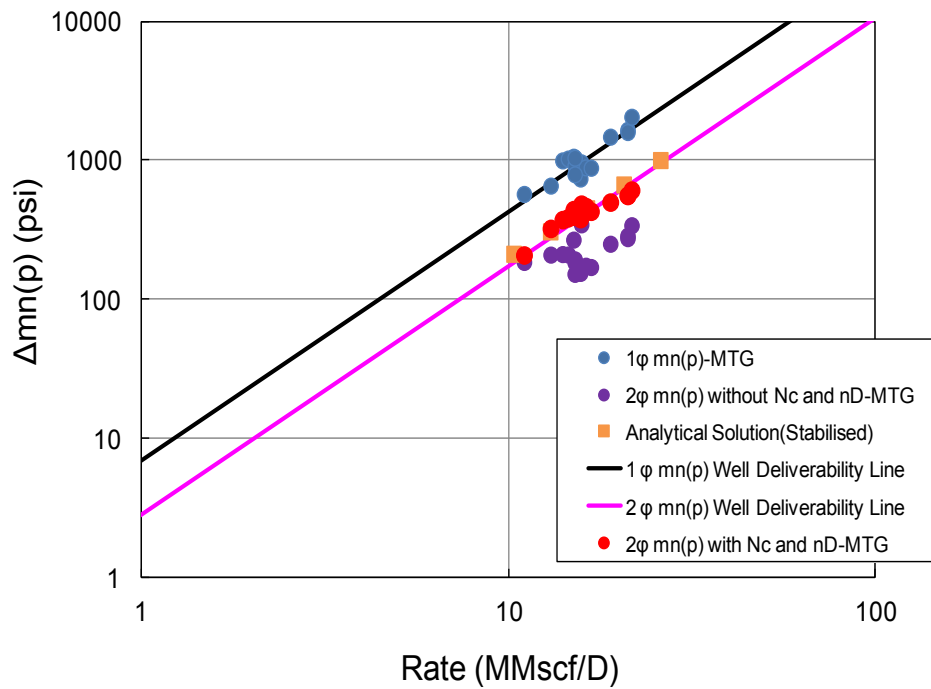


Figure 5.75: 1φPP and 2φPP backpressure plot for MTG

5.9.3 Volatile Oil example

This example is from a vertical well (Well W-15) in a volatile oil reservoir described in section 4.10.3.

5.9.3.1 Pressure and Two-phase Pseudo-pressure Backpressure Plot

The pressure backpressure plot (Fig. 5.76) did not line up on the stabilized flow deliverability line (Eq. 5.11) at $k_{ro} = k_{roi}$ because it did not capture the effect of gas bank formed at the wellbore. Therefore, deliverability losses due to reduction in k_{ro} or gas bank formation cannot be quantified using pressure backpressure plots for volatile oil. As shown in the theoretical study, the impact of multiphase flow on lean and rich gas condensate backpressure plot is more pronounced compared to the volatile oil (Figs. 5.53, 5.57 and 5.62).

The pressure data of DST-Well-15 (Fig. 5.13) was converted to two-phase pseudo-pressures using steps in section 2.4. Fig. 5.76 shows the pressure backpressure plot (Figs. 5.71) and two-phase pseudo-pressure backpressure plot calculated with and without high capillary number and turbulence factor on the relative permeability curves.

The two-phase pseudo-pressure backpressure plot (Figs. 5.76) calculated without high capillary number and turbulence effects on the relative permeability curve did not line up on the analytical deliverability line (Eq. 5.11) but gave a better prediction of the stabilised analytical solution when compared to lean and rich gases. However, the two-phase pseudo-pressure backpressure plot (Figs. 5.76) calculated with relative permeability curves that integrates high capillary number and turbulence effects line up very close to the stabilized flow deliverability line (Eq. 5.11). Hence, the capillary number and non-Darcy effect at the wellbore do not have any major impact on the backpressure plot of volatile oil. This behaviour is similar to the results from theoretical study (Fig. 5.47, 5.48 and 5.49)

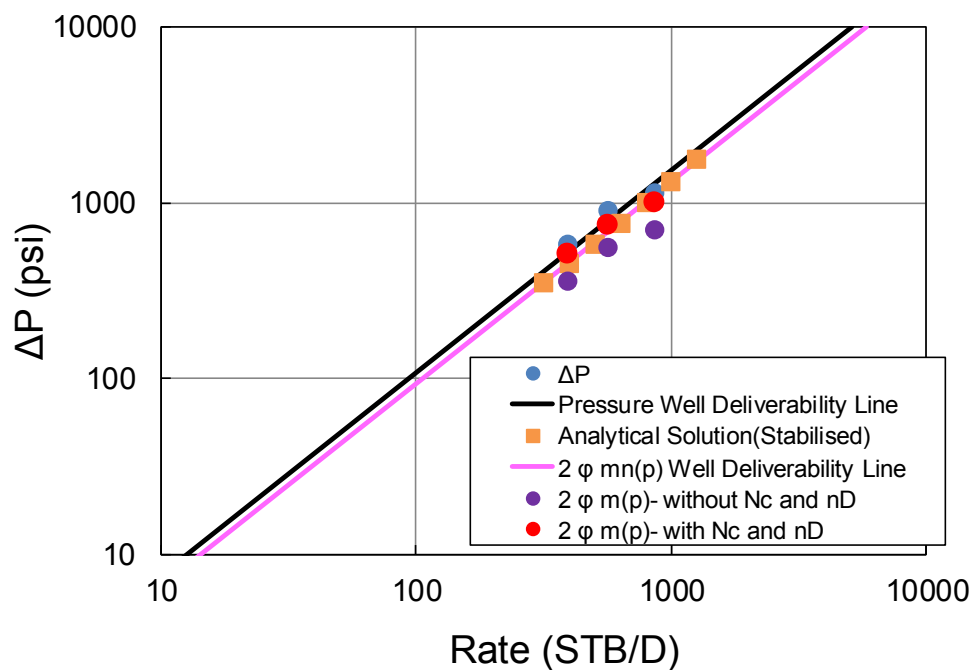


Figure 5.76: Pressure and 2φPP backpressure plot for volatile oil

5.9.4 Summary of Examples from Field Data

1. Pressure and single-phase pseudo-pressure backpressure plot did not capture the deliverability losses due to formation of gas or condensate bank at the wellbore below saturation pressure for field data.
2. The two-phase pseudo-pressure backpressure plot calculated without high capillary number and turbulence factor on the relative permeability curves did not line up with the stabilised analytical solution
3. The two-phase pseudo-pressure backpressure plot calculated with the relative permeability which integrates the non-Darcy effect and high capillary number line up on the stabilised analytical solution below saturation pressure.

5.10 Chapter 5 Summary

1. The correct theoretical stabilised backpressure deliverability line below saturation pressure can be quantified using two-phase pseudo-pressure calculated with relative permeability curves that incorporate high capillary number and non-Darcy effects.
2. Productivity losses due to reduction relative permeability end point and gas or oil mobility cannot be quantified using single-phase pseudo-pressure and pressure backpressure plots.
3. Well deliverability losses due to condensate or gas bank cannot be captured with two-phase pseudo-pressure backpressure plots calculated with the relative permeability curves which does not integrate high capillary number and non-Darcy effects.
4. Higher reduction in mobility will occur quicker at the boundary of rich gas compared to lean gas for long production time below dew point pressure.

CHAPTER 6

DECONVOLUTION OF LEAN AND RICH GAS CONDENSATE, AND VOLATILE OIL WELLS BELOW SATURATION PRESSURE

6.1 Introduction

Deconvolution transforms measured multi-rate pressure data into a constant-rate initial drawdown with duration equal to the total duration of the test and gives a corresponding pressure derivative, normalized to a unit rate. This derivative is free from oscillations caused by pressure-derivative calculation algorithms, and from errors introduced by incomplete or truncated rate histories (Gringarten, 2006). It also exhibits all the flow regimes that have been dominating throughout the test and provides additional information on the pressure transient, which cannot be obtained from conventional analysis.

Theoretically, deconvolution is only valid for linear systems, but can be applied to pseudo linear system such as reservoirs with a slightly compressible fluid. In practice, deconvolution can be used with pseudo-pressure in the case of gas condensate and volatile oil below saturation pressure (Gringarten, 2010).

Deconvolution is based on Duhamel's principle (Eq. 6.1). Duhamel's principle states that the pressure drop at the wellbore is the convolution of flow rate and reservoir impulse function. It was derived with the assumption that the convolution integral (Eq 6.1) is linear:

$$\Delta p(t) = p_i - p(t) = \int_0^t q(\tau) \frac{dp_u(t-\tau)}{dt} d\tau \quad 6.1$$

where $q(\tau)$ is the production rate, $p(t)$ is the bottomhole pressure, p_i is the initial reservoir pressure, $\Delta p(t)$ is the pressure drop over time and $p_u(t)$ is the pressure response at constant unit rate. Deconvolution extracts the impulse response function $\frac{dp_u(t-\tau)}{dt}$ from

Eq. 6.1

Several authors have proposed different spectral and time-domain techniques to the convolution integral (Eq. 6.1) in the literature. Nonetheless, these algorithms proved to be unstable and could not tolerate errors normally present in actual well test data (Kuchuck *et al.* 1990).

Jargon and van Poolen (1965) outlined the use of the principle of superposition to convert variable rate data to a constant-rate pressure response, called the unit response function. This method gave erratic and oscillating results for drastic pressure and/or rate changes.

Thompson and Reynolds (1986) used of Duhamel's principle to analyse pressure drawdown and build-up data of bottomhole pressure (BHP's) and sandface flow rates. The method converts pressure data for variable rate to the equivalent pressure data for a constant rate. Moreover, the calculation involves three different complex methods which are time consuming and have severe numerical convergence difficulties.

Roumboutsos and Stewart (1988) developed numerical Laplace transformation of variable rate and pressure measurements in time domain into Laplace space. They inverted the Laplace transforms using Stehfest algorithm to estimate the constant-rate pressure response but results were characterised by instability and are sensitive to measurement errors in the rate data.

Mendes *et al.* (1989) established a deconvolution procedure based on the approximation of pressure and rate measurements by combinations of cubic spline functions and the use of Laplace transforms for these approximations. The inversion from Laplace space to real space was done with standard numerical algorithms. This method showed a serious problem of error accumulation and instability.

Kuchuk (1990) presented deconvolution techniques that are numerical solutions of the convolution integral to compute the constant-rate or -pressure solution of a system from the measured wellbore pressure and flow rate. However, his techniques have stability problems and failed in the presence of noisy flow rate.

Gilly and Horne (1999) established a technique that extends the deconvolution principle to the entire rate history by recovering the missing parts of the pressure history of wells with constant skin and wellbore storage coefficient. The recovery of the missing pressure is built on nonlinear regression procedures in which the unknown parameters are representative of pressure points in the missing periods. Their algorithms are unstable and could not tolerate errors normally present in actual well test data (Kuchuck *et al.* 1990). Hence, they technically avoided the introduction of errors from measured data which are always intrinsic.

von Schroeter *et al.* (2001, 2002, 2004) developed a novel deconvolution algorithm based a nonlinear Total Least Square method (Eq. 6.2) which gave stable results. The algorithm estimates the rates (adapted rates) and normalised derivative by minimising an error measure, E , which is a weighted combination of pressure match, rate match, and a penalty term based on the overall curvature of the graphed derivative and whose purpose is to enforce smoothness of the resulting deconvolved derivative.

$$E = \underbrace{\|(p_i - y * g) - p\|_2^2}_{\text{pressure match}} + \underbrace{v\|(y - q)\|_2^2}_{\text{rate match}} + \underbrace{\lambda\|(Dz - k)\|_2^2}_{\text{curvature}} \quad 6.2$$

where p and q are input data, matrix D and vector k are curvature operators. v is the relative weight for rate match, λ is the regularization or roughness penalty, y is the adapted rate, and g is the instantaneous source function (Gringarten and Ramey, 1973), both y and g are outputs of deconvolution. Eq. 6.2 is minimised over p_i , y and z .

Essentially, $t.g(t)$, the derivative of the pressure with respect to the natural log of time, is calculated instead of $g(t)$: an arbitrary shape of $t.g(t)$ is input as an initial guess into Eq. 6.2, and it is modified in successive iterations until the error measure E is minimized as shown in Fig. 6.1 (Gringarten, 2010).

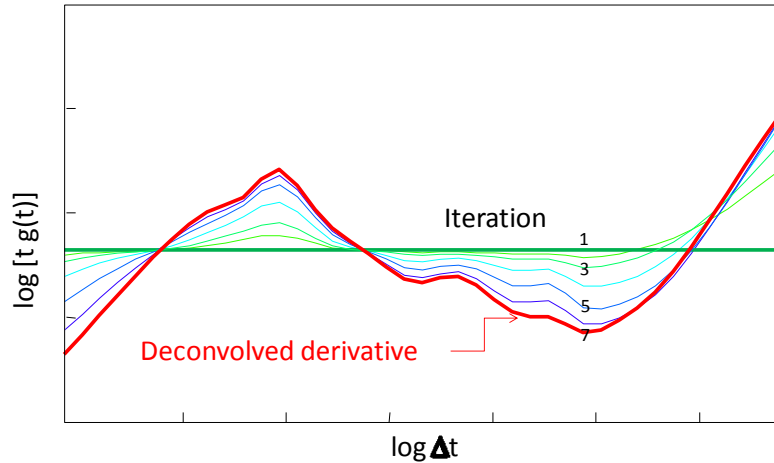


Figure 6.1: Iterative calculation of deconvolved derivative (Gringarten, 2010)

Levitan (2003) showed that the deconvolution algorithm proposed by von Schroeter *et al.* (2001) works well on consistent sets of pressure and rate data but was unpredictable or even failed when applied to inconsistent data set. These inconsistencies occurred with early time behaviour such as skin or changing wellbore storage. However, since the

crucial aim of deconvolution is to predict the reservoir model most importantly the reservoir geometry, this shortcoming is considered insignificant.

Levitan *et al.* (2004) discussed specific issues to be aware of when deconvolving pressure and rate data. They provided practical considerations and recommendations on how to produce correct deconvolution results. The reliability of deconvolution was underlined by applying deconvolution to several simulated and real pressure and rate data. Levitan *et al.* (2004) concluded that deconvolution as a very useful tool for well test analysis but should not be a replacement of conventional well test techniques.

Gringarten (2010) presented various uses of deconvolution in tests of short and long durations. He showed examples of DST's with erroneous rates, which was corrected by deconvolution; as well as data from permanent downhole pressure gauges in a horizontal well where deconvolution shows compartmentalization and recharge from other layers, which could not be seen in the original data. The paper showed that deconvolution can be applied to systems that are pseudo-linear, such as gas condensate below dew point pressure and gave recommendations on how to perform deconvolution as well as verify deconvolution results.

Deconvolved derivatives from the simulated and real well test data should give a very similar derivative shapes when compared with derivatives obtained from conventional well test analysis. However, caution should be exercised when the well behaviour undergoes major changes over the duration of the test e.g. changing wellbore storage due to phase redistribution in the well or changing skin due to transport of solid particles into or out of the well. The methodology for well test analysis using deconvolution is shown in Fig. 6.2.

The objective of deconvolving well test data for wells flowing below saturation pressure in gas condensate and volatile oil reservoir is to investigate the optimum way of obtaining the best deconvolved derivatives below saturation by removing non-linearity using pressure, single-phase pseudo-pressure with and without material balance correction as well as two-phase pseudo pressure. Material balance correction linearizes well test data of gas condensate under severe depletion while two-phase pseudo-pressure linearizes the well test data of wells flowing below saturation pressure by transforming pressure data under multiphase flow into a single phase flow equivalent.

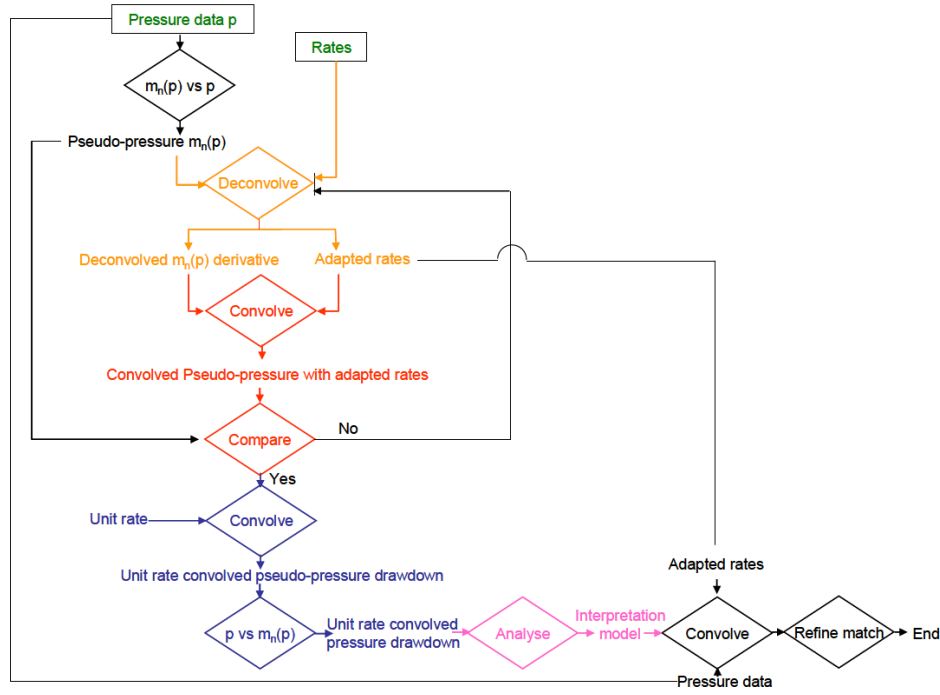


Figure 6.2: Deconvolution interpretation methodology (Amudo *et al.* 2006)

6.1.1 Material Balance Correction

Single-phase pseudo-pressure computation departs from the actual reservoir behaviour if used on longer time scales, especially during severe depletion of a gas reservoir (Bourgeois and Wilson, 1996). The average reservoir pressure estimate from single-phase pseudo-pressure for a gas reservoir under severe depletion is different from that of the material balance.

Bourgeois and Wilson (1996) used single-phase pseudo-pressure to account for changes in volume factor and viscosity, and a material balance correction to account for changes in compressibility due to reservoir depletion. They showed that material balance correction (Eq. 6.3) produces sufficiently accurate prediction of average reservoir pressure of gas reservoir under severe depletion.

$$\Delta m(p)_{corr} = m(p)_{true} - m(p_{init}) + \frac{P_{sc}}{\pi T_{sc}} \frac{T}{\mu_{ref}} \frac{G_p}{(\phi c_t A h)_{ref}} \quad 6.3$$

The gas flow in a reservoir under significant pressure depletion is non-linear even when pressure data has been converted to single-phase pseudo-pressure because the pressure and rate data are inconsistent with superposition (Levitan and Wilson, 2010).

Levitan and Wilson (2010) presented an enhancement of the deconvolution algorithm for gas wells that allows it to be used with the pressure data affected by pressure-dependent compressibility by applying the material balance correction to gas data in order to ensure that gas flow is governed by a linear set of equations most especially for gas well with significant depletion where total compressibility and viscosity are pressure dependent. They used material balance correction (Bourgeois and Wilson, 1996) which depends on cumulative production and shows decline of average reservoir pressure.

Conversely, the application of material balance correction to linearize gas data under severe depletion does not yield the true solution of the non-linear gas data but allows the linearized problem to be a better approximation of the true solution (Levitan and Wilson, 2010). Similarly, the constant-rate drawdown response of their deconvolved derivative represents the pressure behaviour of a different reservoir or the same reservoir but filled with different gas that has constant compressibility and viscosity with respect to pressure change.

6.2 Deconvolution of Gas Condensate and Volatile Oil

Deconvolution provides additional information on the pressure history and enables us to analyse reservoir geometries and forecast well performance. The simulated pressure data for lean and rich gas condensate were transformed to single-phase pseudo-pressure and two-phase pseudo-pressure. The pressure, single-phase pseudo-pressure and two-phase pseudo-pressure were then deconvolved using “TLSD” deconvolution software from joint industry project on well test analysis at Imperial College London. The software is a pre-processor that converts a variable rate and pressure history into a unit rate drawdown with duration equal to the total duration of the pressure history. TLSD uses an algorithm based on the Total Least Square method (von Schroeter et. al, 2004) which provides stable results.

6.3 Simulation and Fluid Model

The reservoir simulations and fluid property modelling were performed using a commercial compositional simulator (Eclipse 300 and PVTi from Schlumberger) to generate synthetic well test data for lean gas, rich gas and volatile oil. The description of simulation model, capillary number and non-Darcy parameters, PVT data and relative permeability can be found in sections 4.2 and 5.2.

In order to study the impact of the rate sequence on deconvolution of lean gas, rich gas and volatile oil, pressures for different rate histories (random, decreasing and increasing rates) were generated and analysed for lean gas, rich gas and volatile oil. The initial pressure used for the deconvolution is the same as the simulation input. The pressure of all drawdown dropped below saturation pressure during simulation to ensure that condensate and gas bank were formed at the wellbore. The simulated results were checked with field data.

6.4 Deconvolution of Lean Gas Condensate

6.4.1 Deconvolution of Single-phase Pseudo-pressure

6.4.1.1 Random Rate History

The pressure and random rate history for lean gas is shown in Fig. 6.3. There are 10 flow periods, with 110-days duration for each drawdown (DD) alternating with build-up (BU) of 30-days duration in a closed system (Fig. 6.4). The single-phase pseudo-pressure rate-normalized log-log plot for random rate history is shown in Fig. 6.4. The derivatives in Fig. 6.4 show radial composite behaviour due to reduced effective permeability as a result of condensate dropout at the wellbore.

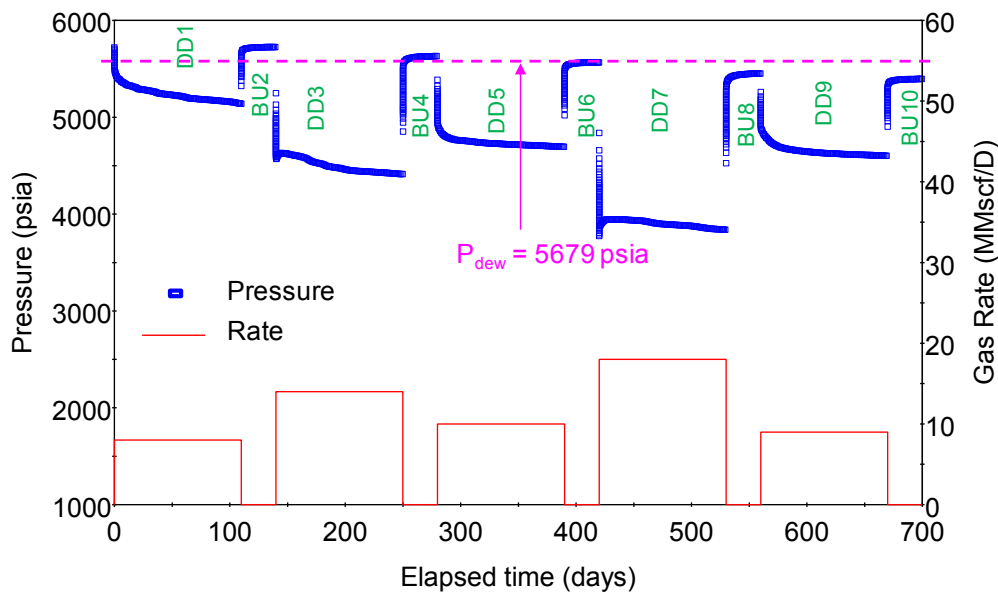


Figure 6.3: Pressure and random rate history for lean gas

Deconvolution was applied to BU2, BU4, BU6, BU8 and BU10 of the single-phase pseudo-pressure from Fig. 6.4 in order to ensure that the deconvolved derivative gives a reduced mobility and pseudo-steady state response indicated by a unit slope at late time

(closed system response). Deconvolution transformed the variable rate pressure data into a constant rate initial drawdown with duration equal to the total duration of 700 days.

Fig. 6.5 shows a very good agreement with a closed system response from the simulation. The radial composite behaviour of the derivative is the dominating flow regime at early to middle time (similar to the actual derivatives in Fig 6.4) and a closed system at late time indicated by a unit slope.

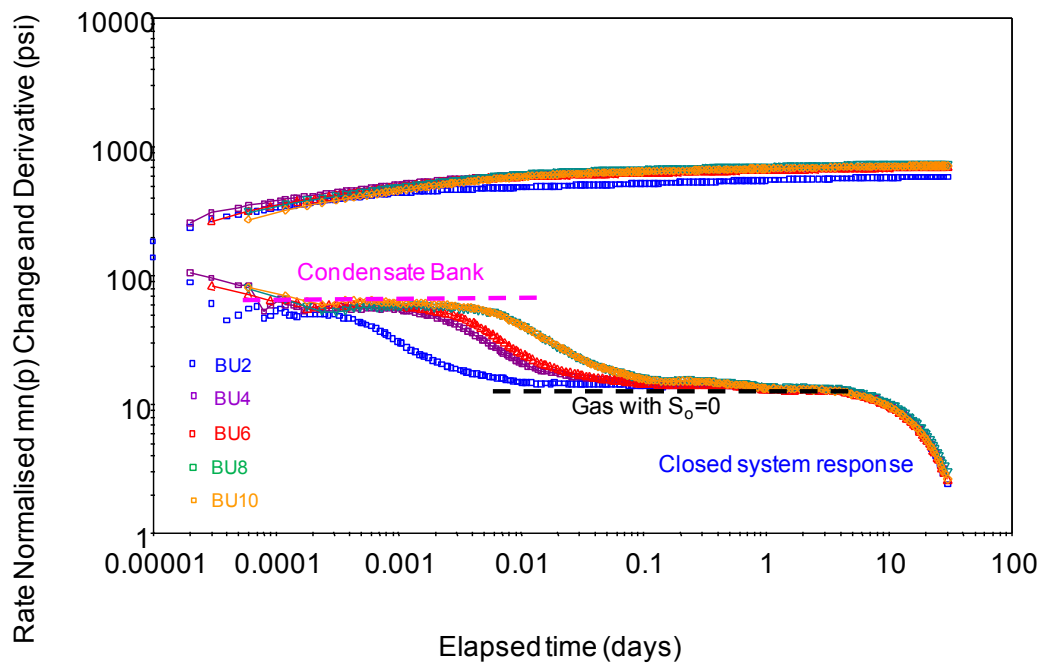


Figure 6.4: Rate-normalized 1φPP log-log plot for lean gas (random rate history)

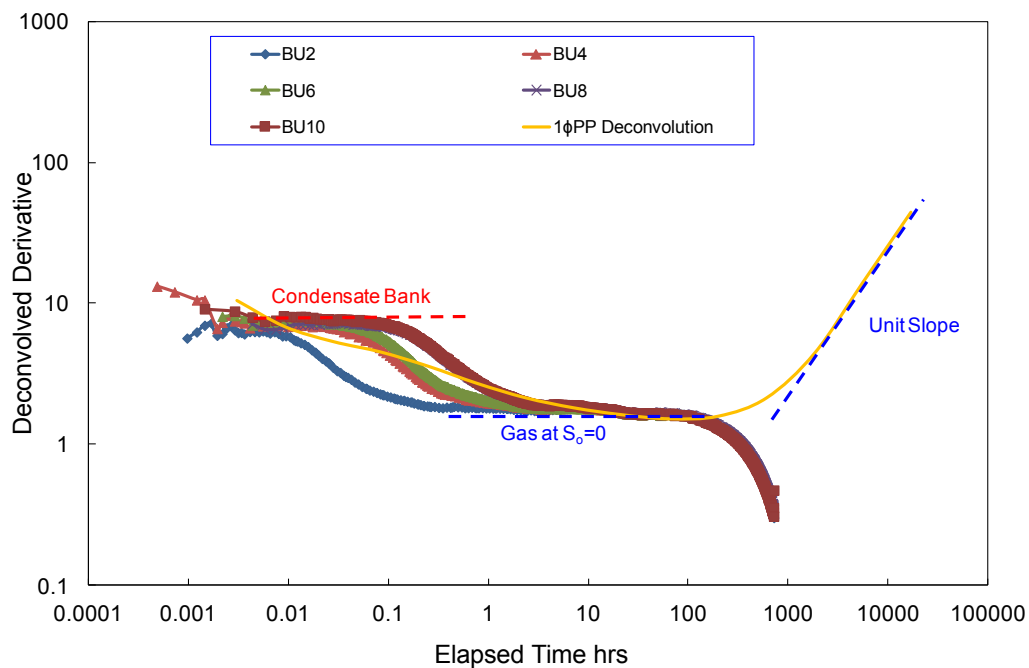


Figure 6.5: Deconvolution of 1φPP for lean gas (random rate)

6.4.1.2 Increasing and Decreasing Rate History

Figs. 6.6 and 6.7 show the pressure, increasing and decreasing rate histories for lean gas with 110-days duration for every drawdown (DD) alternating with build-up (BU) of 30-days duration. The single-phase pseudo-pressure rate-normalized log-log plots for increasing and decreasing rate histories are shown in Figs. 6.8 and 6.9. Similar to random rate history, Figs. 6.8 and 6.9 show an upward shift of the pressure curves and radial composite behaviour of the derivatives due to condensate bank formation at the wellbore and a closed system response at late time.

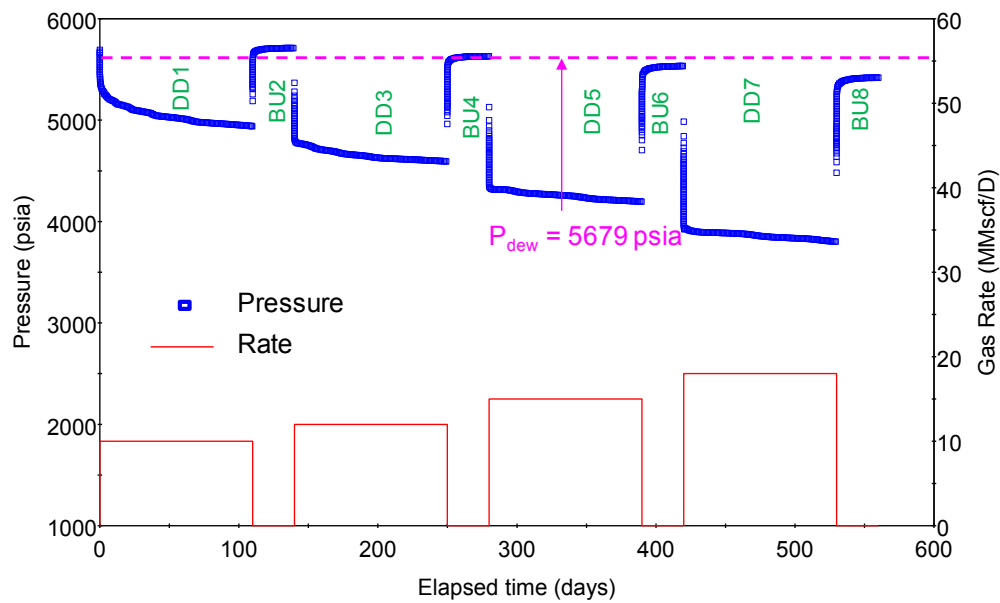


Figure 6.6: Pressure and increasing rate history for lean gas

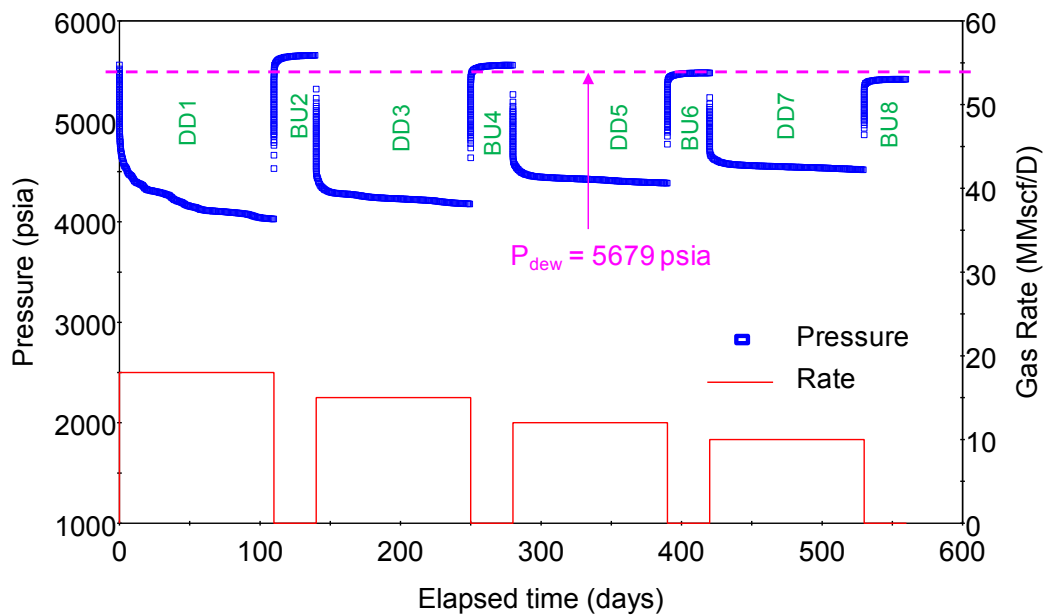


Figure 6.7: Pressure and decreasing rate history for lean gas

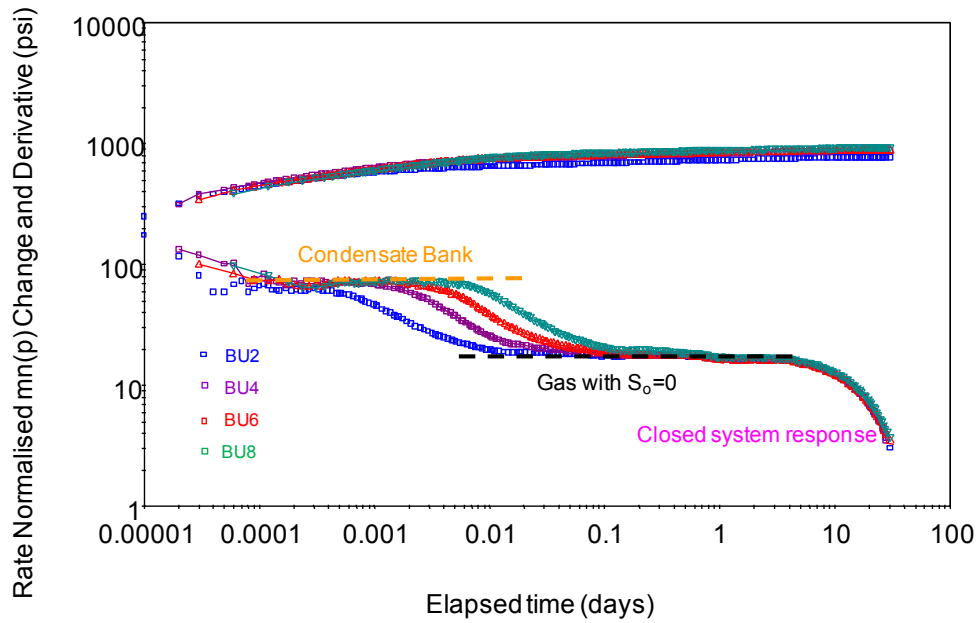


Figure 6.8: Rate-normalized 1ϕ PP log-log plot for lean gas (increasing rate)

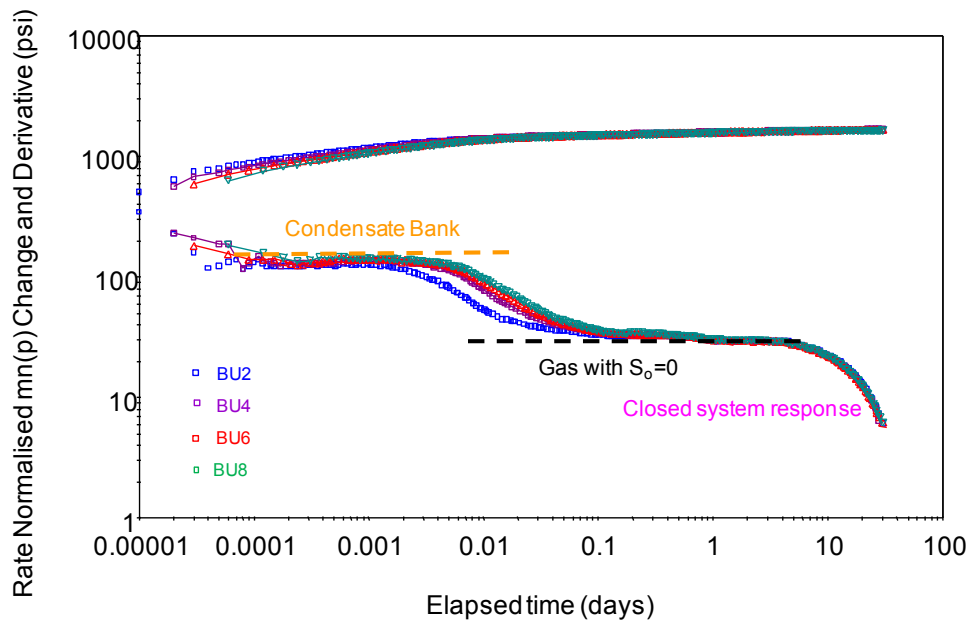


Figure 6.9: Rate-normalized 1ϕ PP log-log plot for lean gas (decreasing rate)

BU2, BU4, BU6 and BU8 of the single-phase pseudo-pressure from Figs. 6.6 and 6.7 in were deconvolved in order to ensure that the deconvolved derivative reproduce the simulated reservoir behaviour and gives a unit slope at the late time. The deconvolved derivative (Figs. 6.10 and 6.11) showed a radial composite behaviour at early to middle time, homogeneous behaviour at middle time (similar to the actual derivatives in Figs. 6.8 and 6.9) and a unit slope which represent a closed system at late time. An initial pressure of 5780psia was used for the deconvolution.

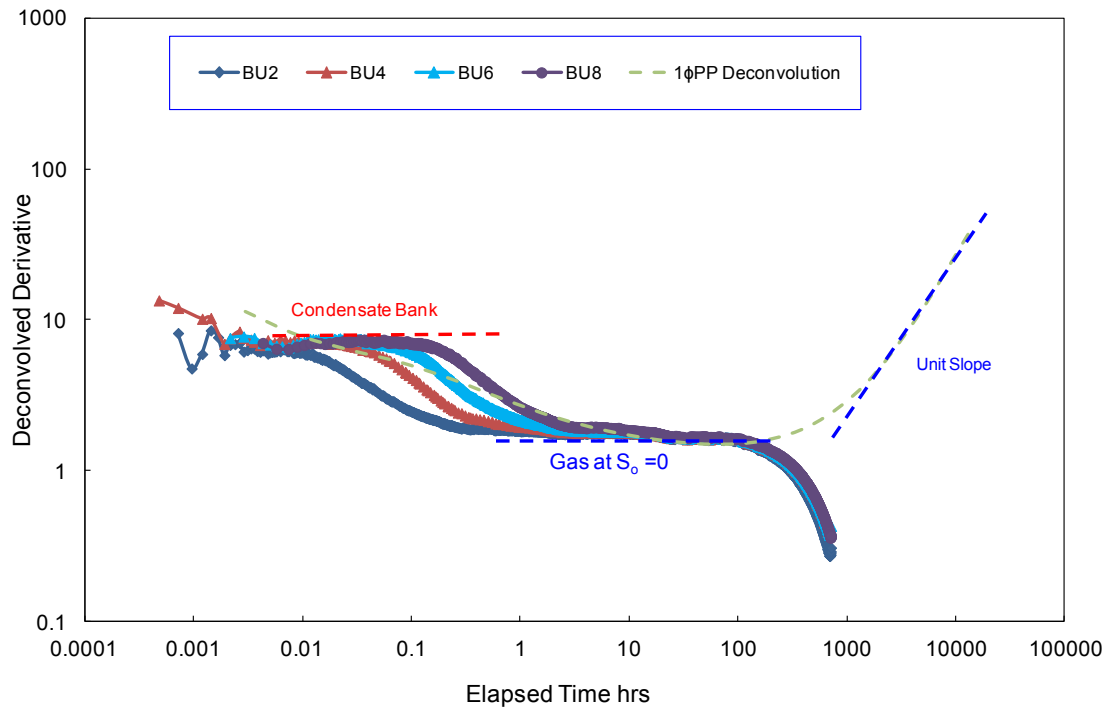


Figure 6.10: Deconvolution of $1\phi PP$ for lean gas (increasing rate)

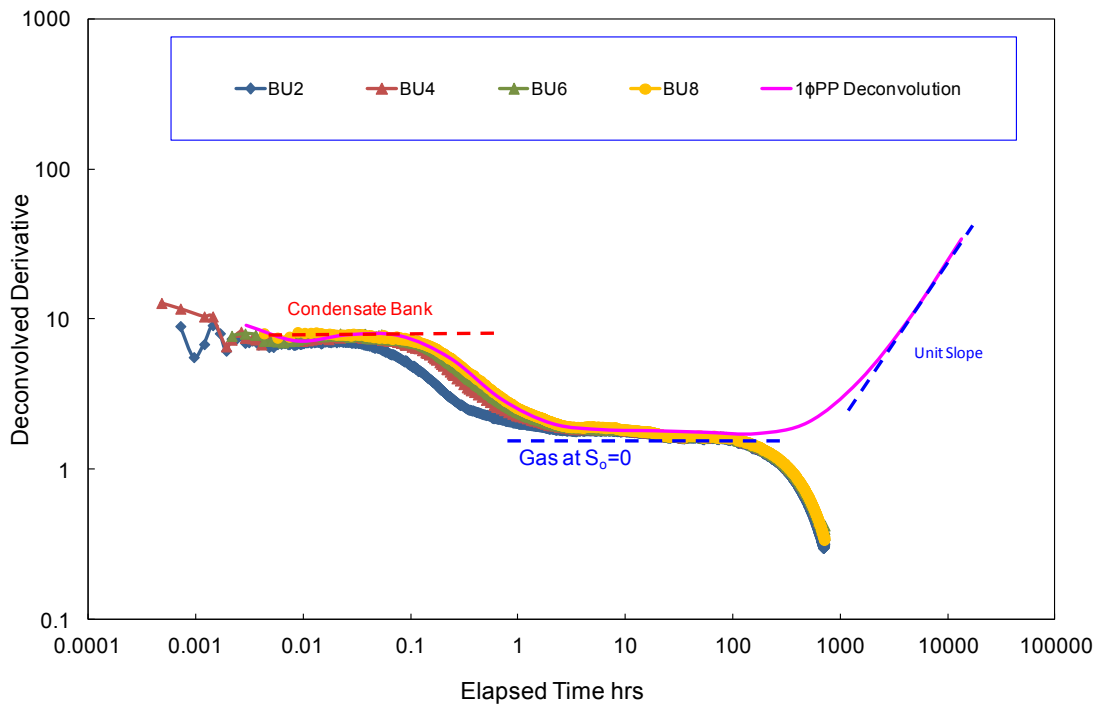


Figure 6.11: Deconvolution of $1\phi PP$ for lean gas (decreasing rate)

6.4.2 Deconvolution of Two-phase pseudo-pressure

Two-phase pseudo-pressure was calculated with relative permeability curves which incorporate high capillary number and non-Darcy effects using steps in section 2.4. The pressure and two-phase pseudo-pressure for random, decreasing and increasing rate histories for lean gas are shown in Figs. 6.12, 6.13 and 6.14.

The rate normalised log-log plot for two-phase pseudo-pressure for random, decreasing and increasing rate histories are shown in Figs. 6.15, 6.16 and 6.17. They show that the radial composite behaviour in Figs. 6.4, 6.8 and 6.9 was corrected. The single-phase and two-phase pseudo-pressure log-log plots for random, decreasing and increasing rate histories (Figs. 6.18, 6.19 and 6.20) show that the two-phase pseudo-pressure stabilises at effective permeability with zero condensate saturation.

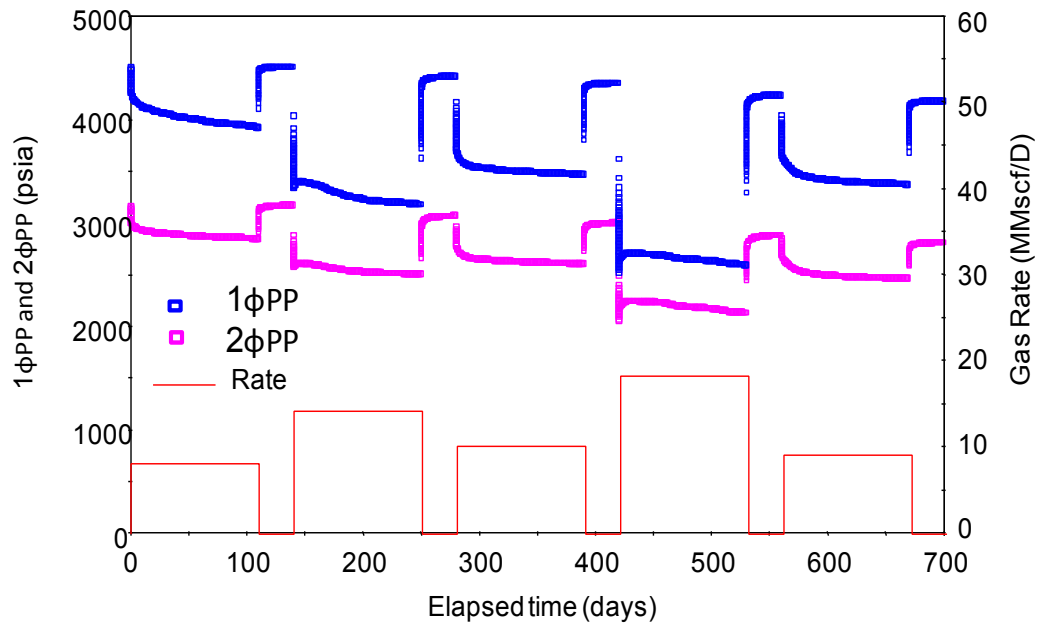


Figure 6.12: Pressure, 2 ϕ PP and random rate history for lean gas

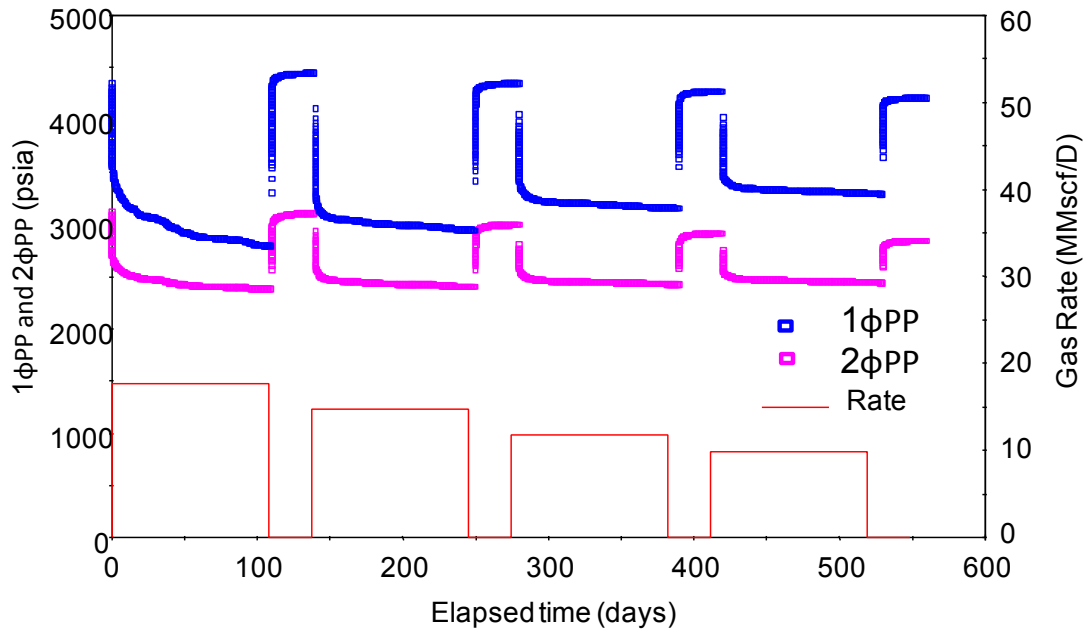


Figure 6.13: Pressure, 2 ϕ PP and decreasing rate history for lean gas

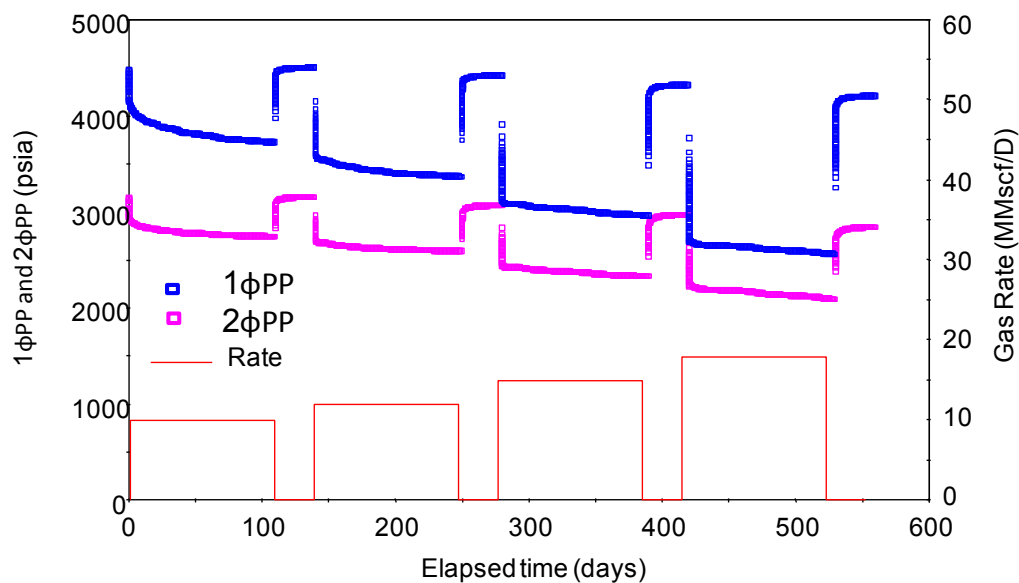


Figure 6.14: Pressure, 2 ϕ PP and increasing rate history for lean gas

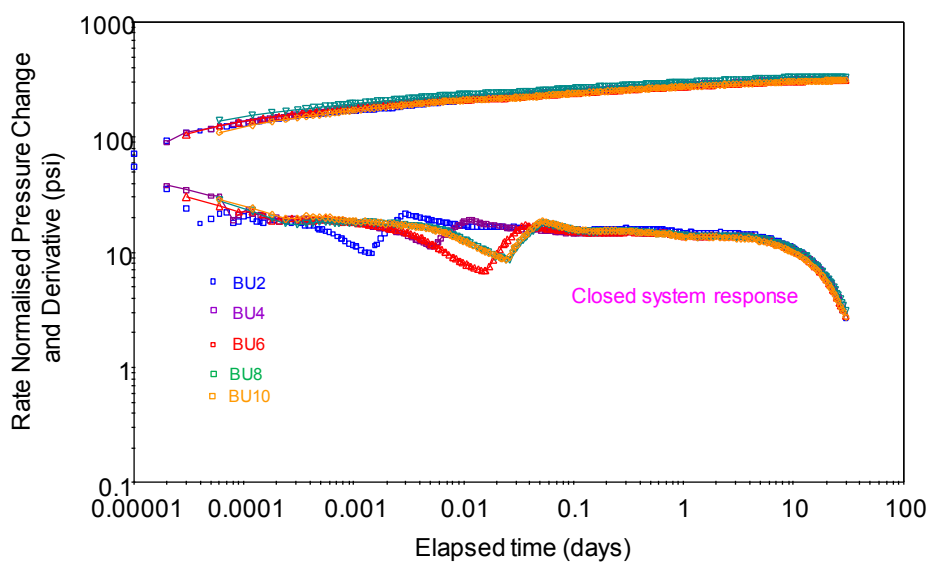


Figure 6.15: Rate-normalized 2 ϕ PP log-log plot for lean gas (random rate)

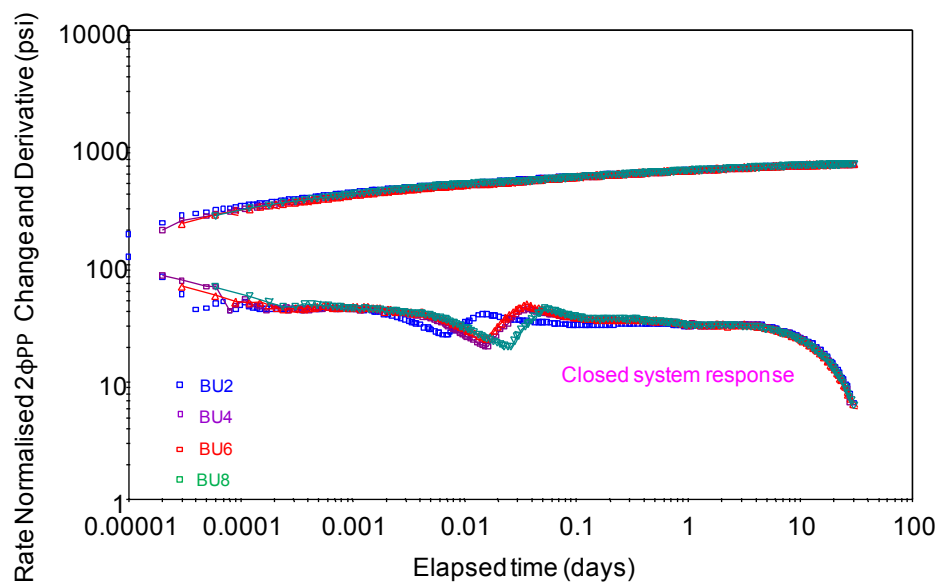


Figure 6.16: Rate-normalized 2 ϕ PP log-log plot for lean gas (decreasing rate)

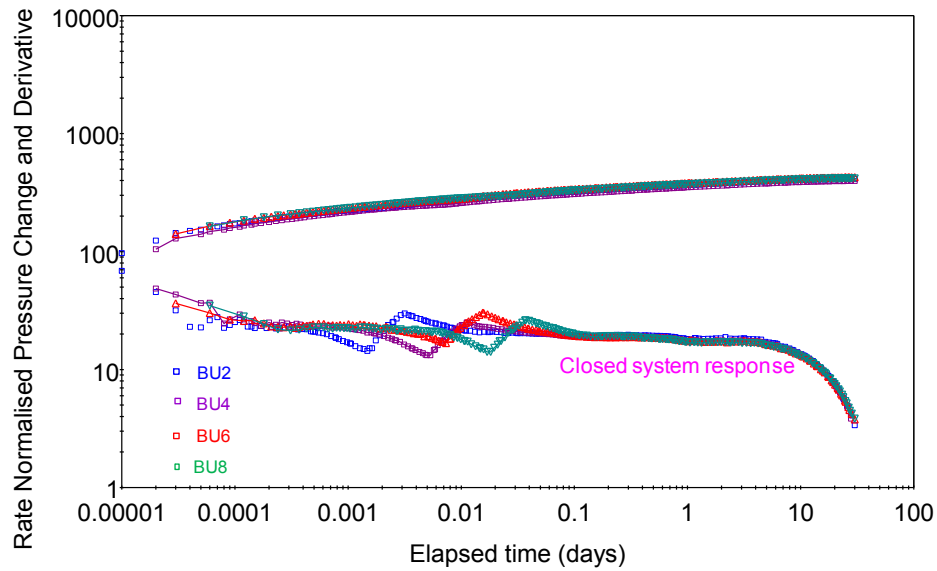


Figure 6.17: Rate-normalized 2 ϕ PP log-log plot for lean gas (increasing rate)

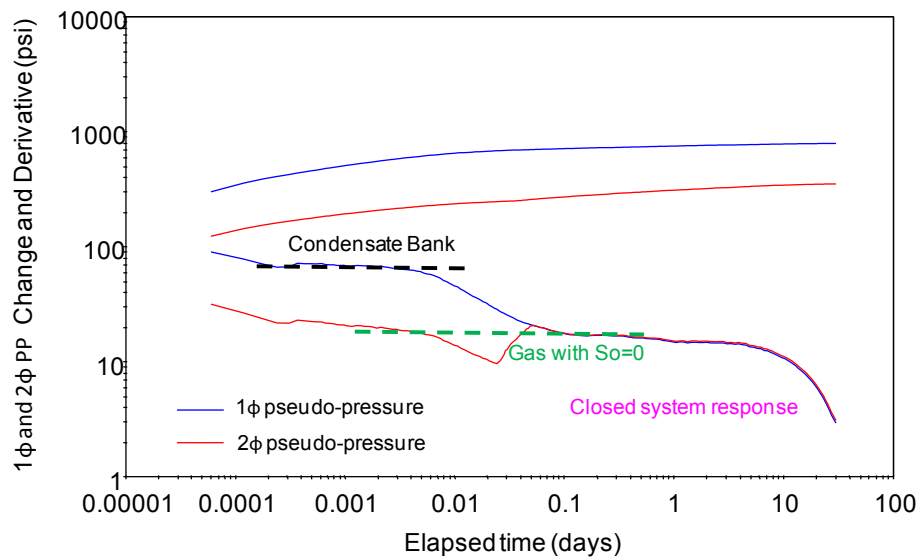


Figure 6.18: 1 ϕ PP and 2 ϕ PP log-log plot for lean gas (BU 6) (random rate at $k_{rg}^{\max}=1$)

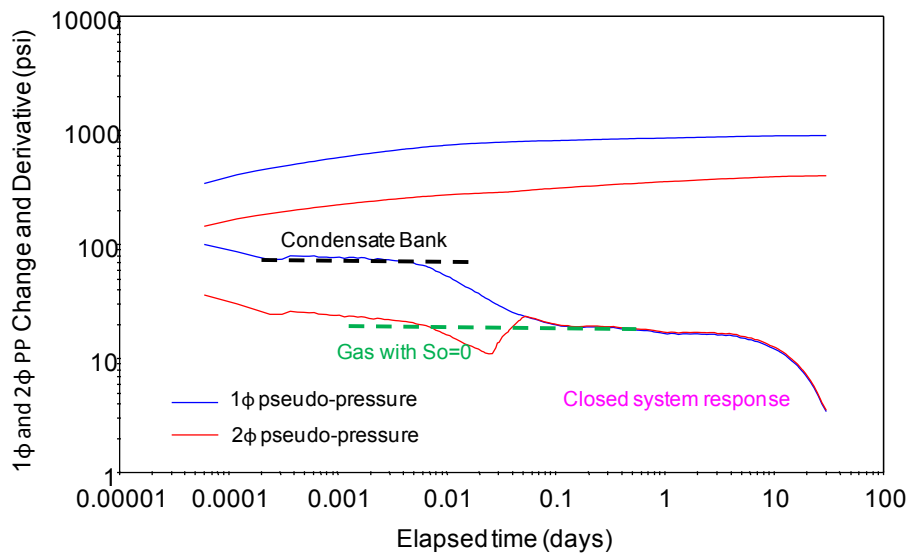


Figure 6.19: 1 ϕ PP and 2 ϕ PP log-log plot for lean gas (BU 8) (decreasing rate at $k_{rg}^{\max}=1$)

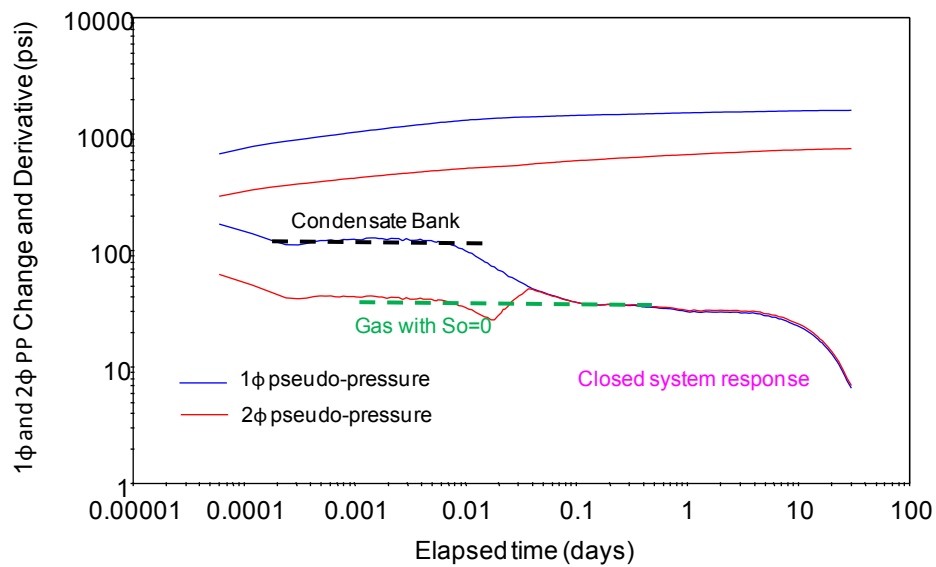


Figure 6.20: 1φPP and 2φPP log-log plot for lean gas (BU 8) (increasing rate at $k_{rg}^{max}=1$)

The deconvolved derivative (Figs. 6.21, 6.22 and 6.23) show that the radial composite behaviour from single-phase pseudo-pressure was transformed into a homogeneous behaviour at early time, middle time, and give a unit slope which represent a closed system at late time.

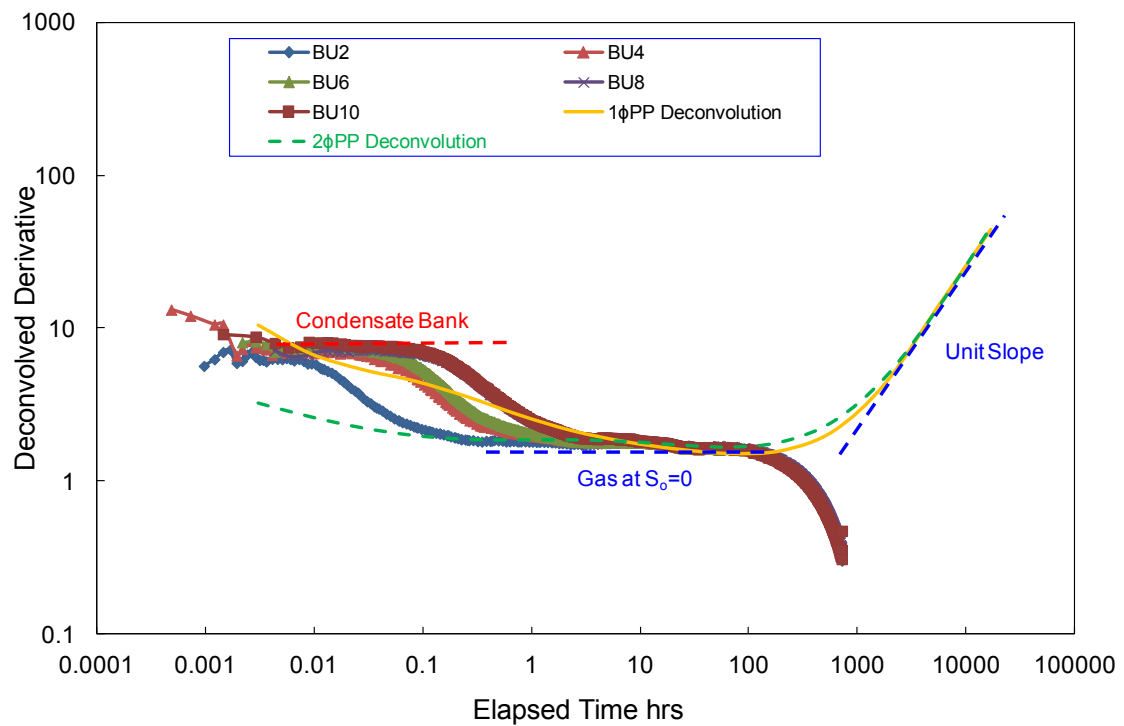


Figure 6.21: Deconvolution of 1φPP and 2φPP for lean gas (random rate)

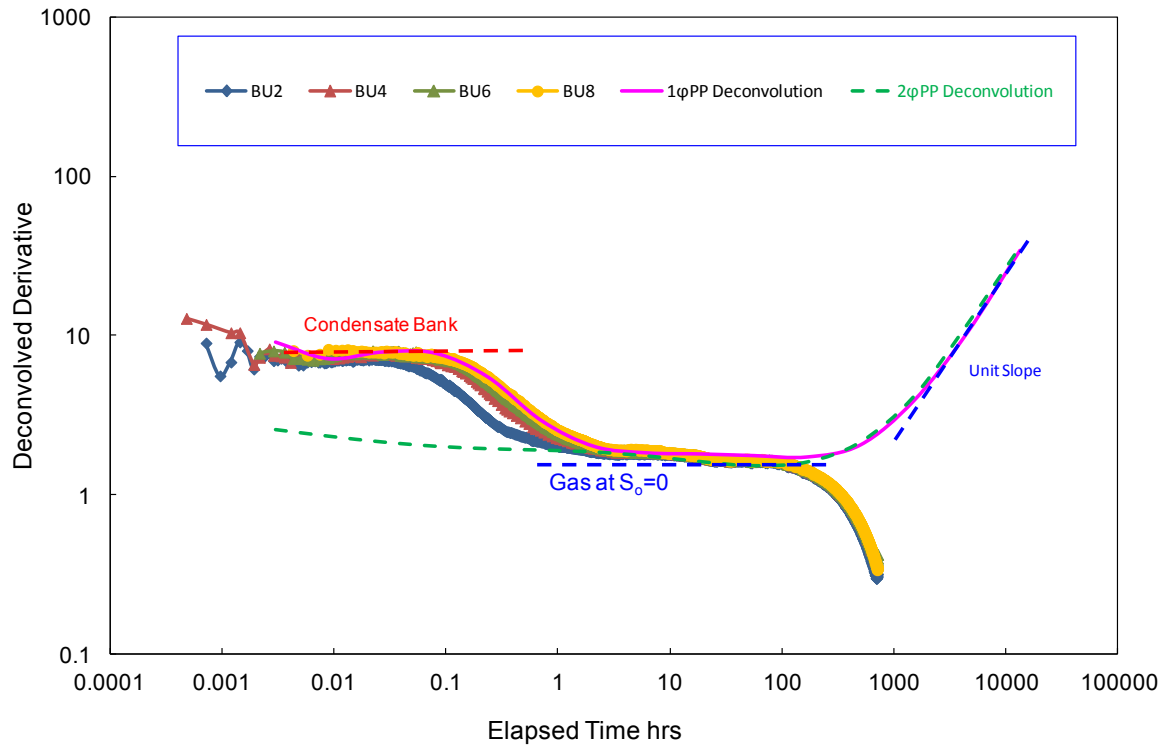


Figure 6.22: Deconvolution of 1 ϕ PP and 2 ϕ PP for lean gas (decreasing rate)

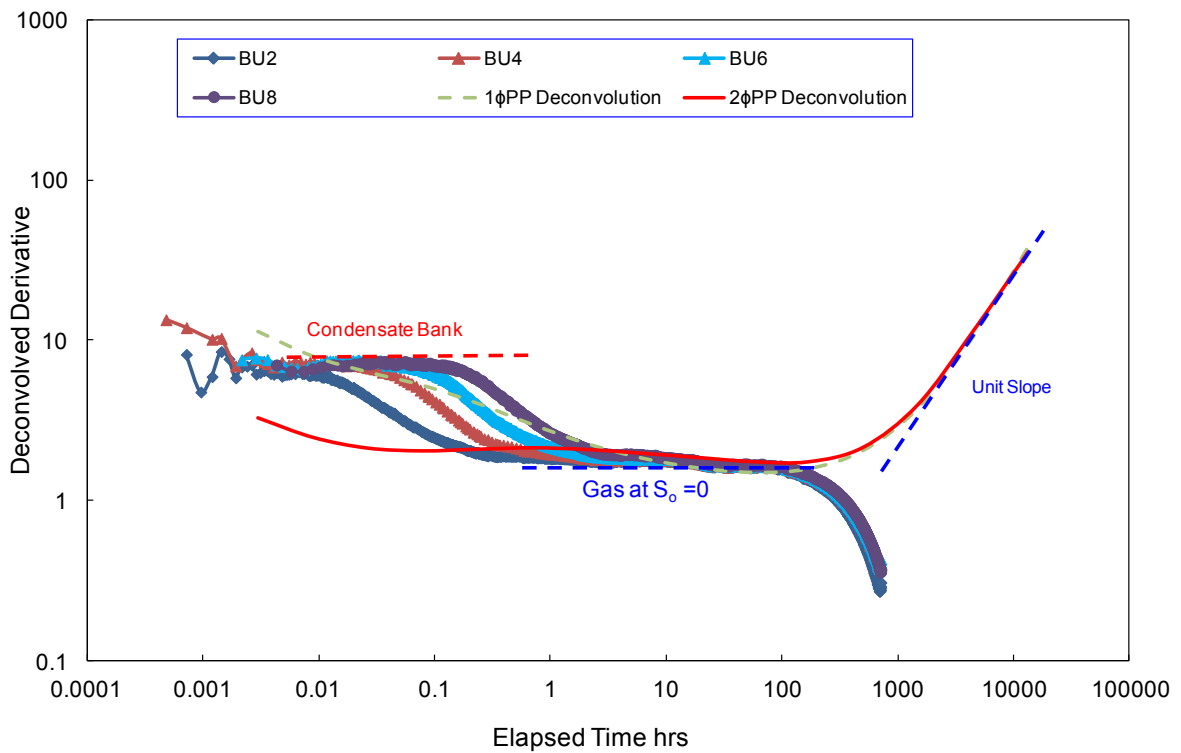


Figure 6.23: Deconvolution of 1 ϕ PP and 2 ϕ PP for lean gas (increasing rate)

6.4.3 Summary of Deconvolution of Lean Gas Condensate

1. Single-phase pseudo-pressure deconvolved derivative for lean gas below dew point pressure shows radial composite behaviour at early to middle time while two-phase pseudo pressure show homogeneous behaviour.
2. The deconvolved derivatives from single-phase and two-phase pseudo-pressure show similar behaviour at late time i.e. a closed system designated by a unit slope.

6.5 Deconvolution of Rich Gas Condensate

6.5.1 Deconvolution of Single-phase Pseudo-pressure

6.5.1.1 Random Rate History

Fig. 6.24 shows the simulated pressure and random rate history for rich gas condensate, it has 10 flow periods, with duration of 30-days for each build-up (BU) and 110-days for every drawdown (DD). The rate-normalized log-log derivative from single-phase pseudo-pressure (Fig. 6.25) shows an upward shift of the pressure curves due to condensate drop-out at the wellbore. The deconvolved derivative (Fig. 6.26) gives a radial composite behaviour at early to middle time and closed system (unit slope) at late time (similar to the actual derivatives in Fig 6.25).

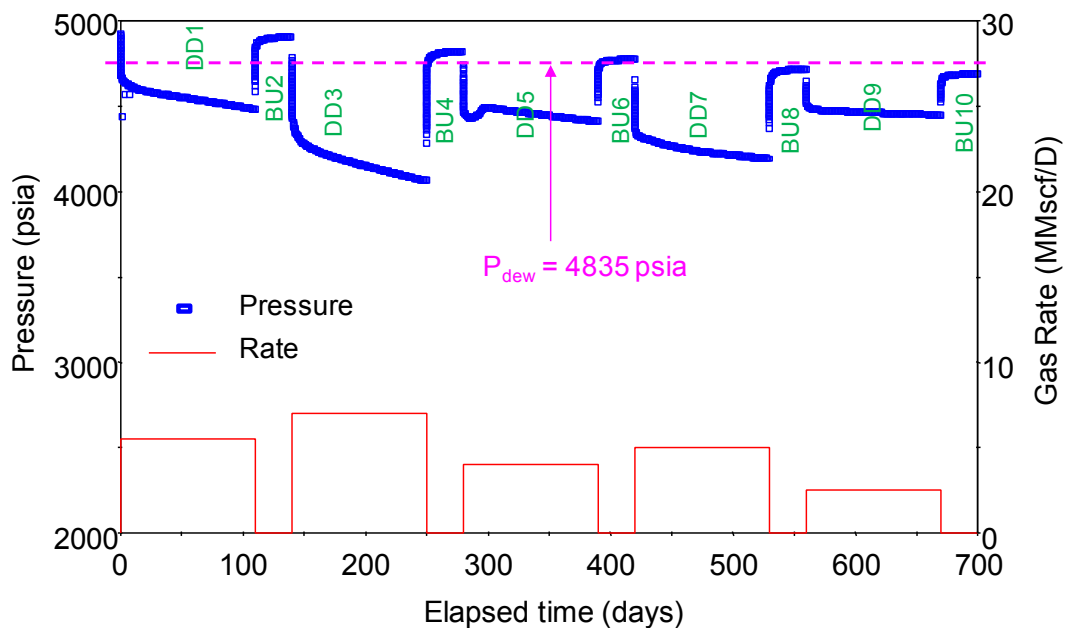


Figure 6.24: Pressure and random rate history for rich gas

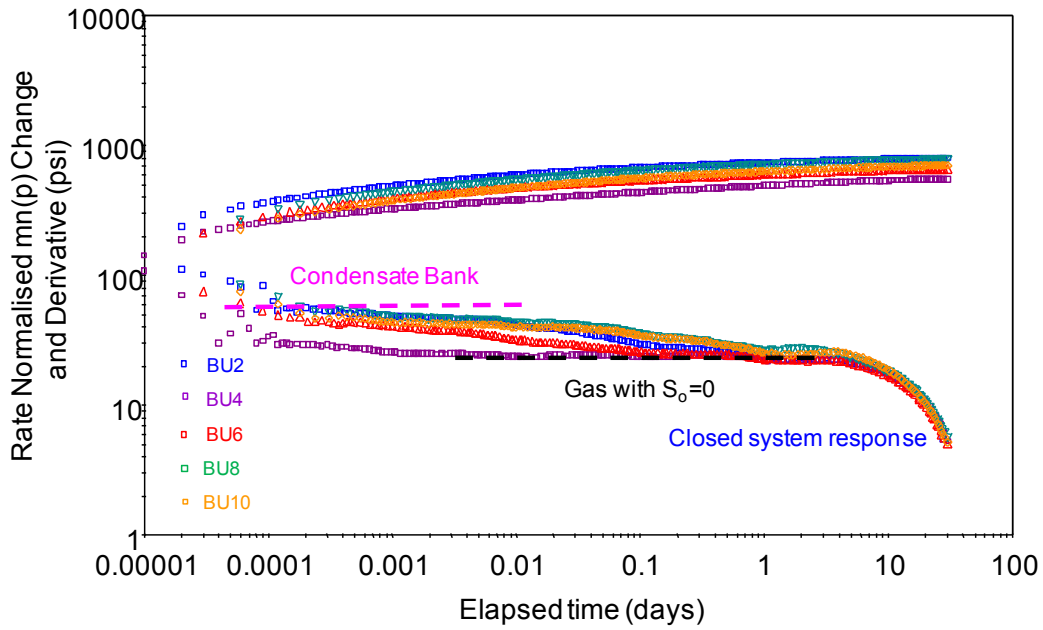


Figure 6.25: Rate-normalized $1\phi PP$ log-log plot for rich gas (random rate)

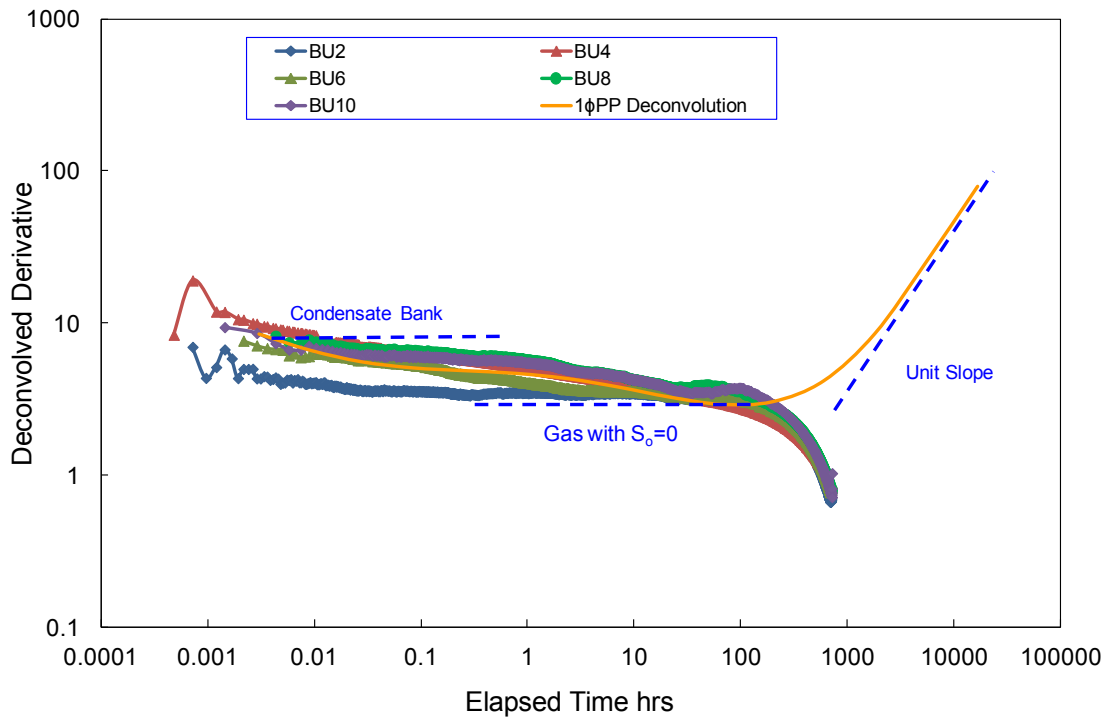


Figure 6.26: Deconvolution of $1\phi PP$ Pressure for rich gas (random rate)

6.5.1.2 Increasing and Decreasing Rate History

The pressure, increasing and decreasing rate histories for rich gas are shown Figs. 6.27 and 6.28. Each has a total of 8 flow periods with duration of 110-days and 30-days for every drawdown (DD) and build-up (BU) respectively. The rate-normalized log-log plots for increasing and decreasing rate histories are shown in Figs. 6.29 and 6.30 respectively. The formation of condensate bank at the wellbore is confirmed by an upward shift in

pressure curves (Figs. 6.29 and 6.30) and the radial composite behaviour of the derivatives.

The deconvolved derivatives (Figs. 6.31 and 6.32) of single-phase pseudo-pressure of Figs. 6.27 and 6.28 show a radial composite behaviour at early to middle time and a closed system at late time.

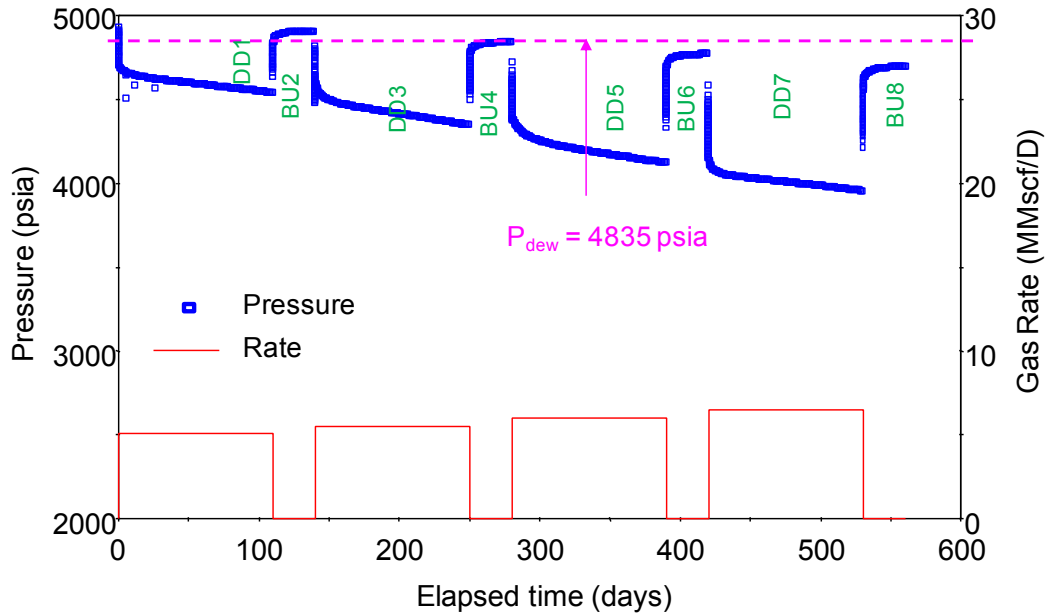


Figure 6.27: Pressure and increasing rate history for rich gas

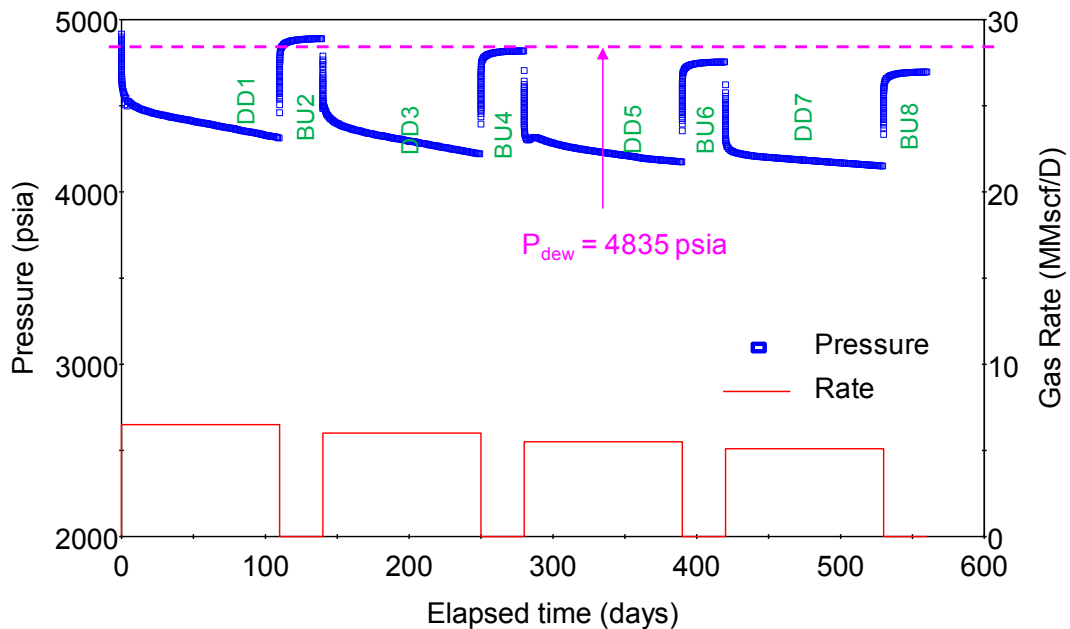


Figure 6.28: Pressure and decreasing rate history for rich gas

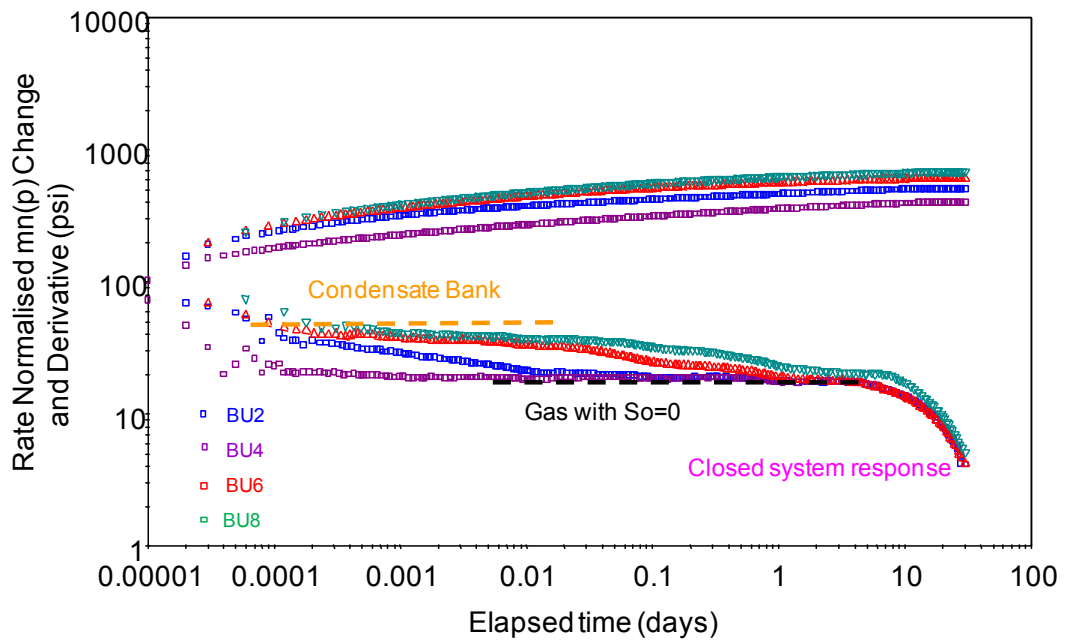


Figure 6.29: Rate-normalized 1φPP log-log plot for rich gas (increasing rate)

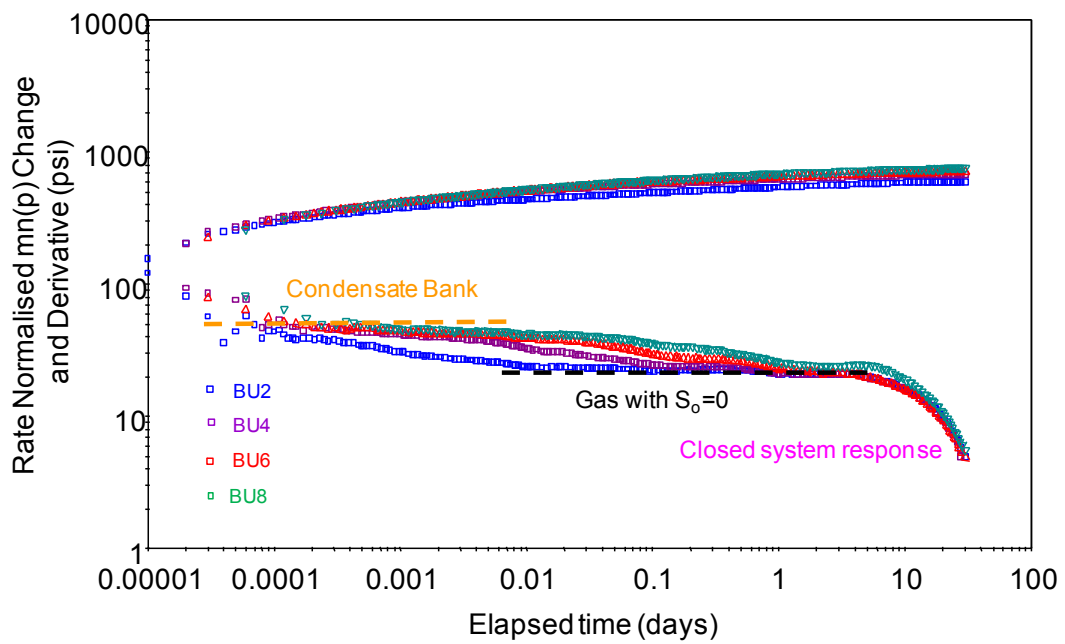


Figure 6.30: Rate-normalized 1φPP log-log plot for rich gas (decreasing rate)

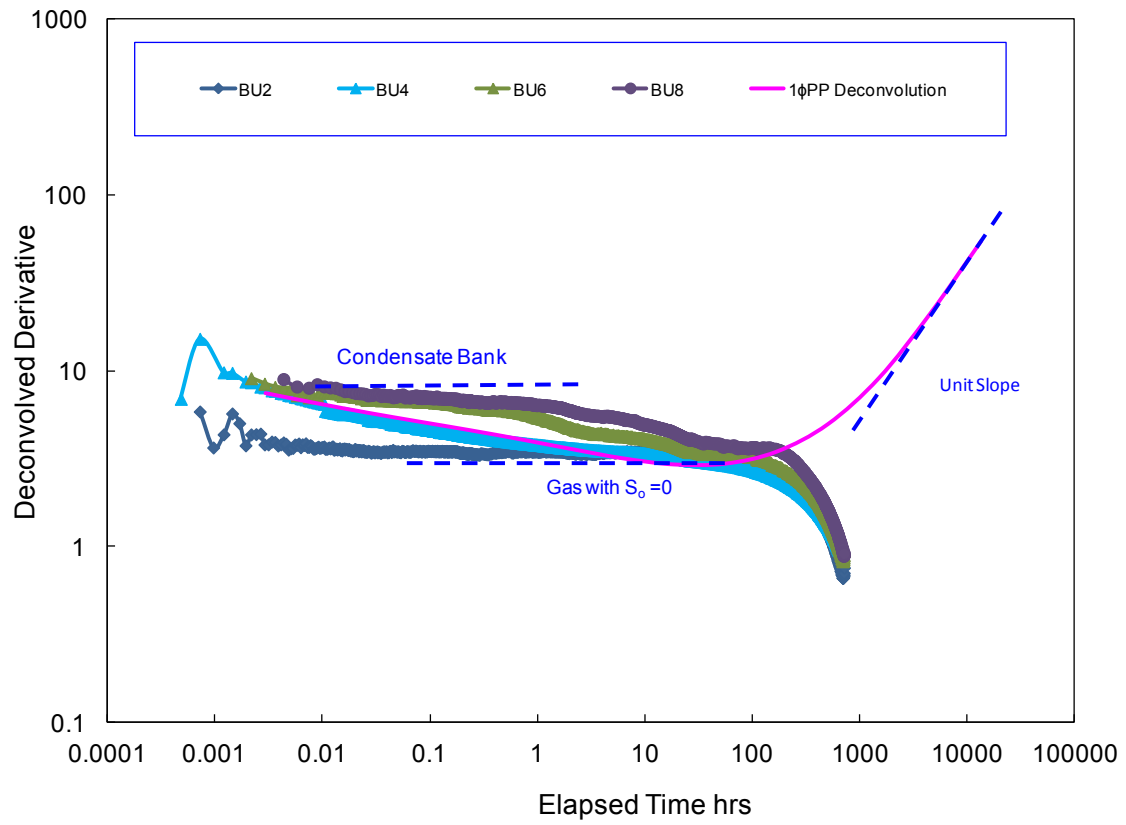


Figure 6.31: Deconvolution of 1φPP for rich gas (increasing rate)

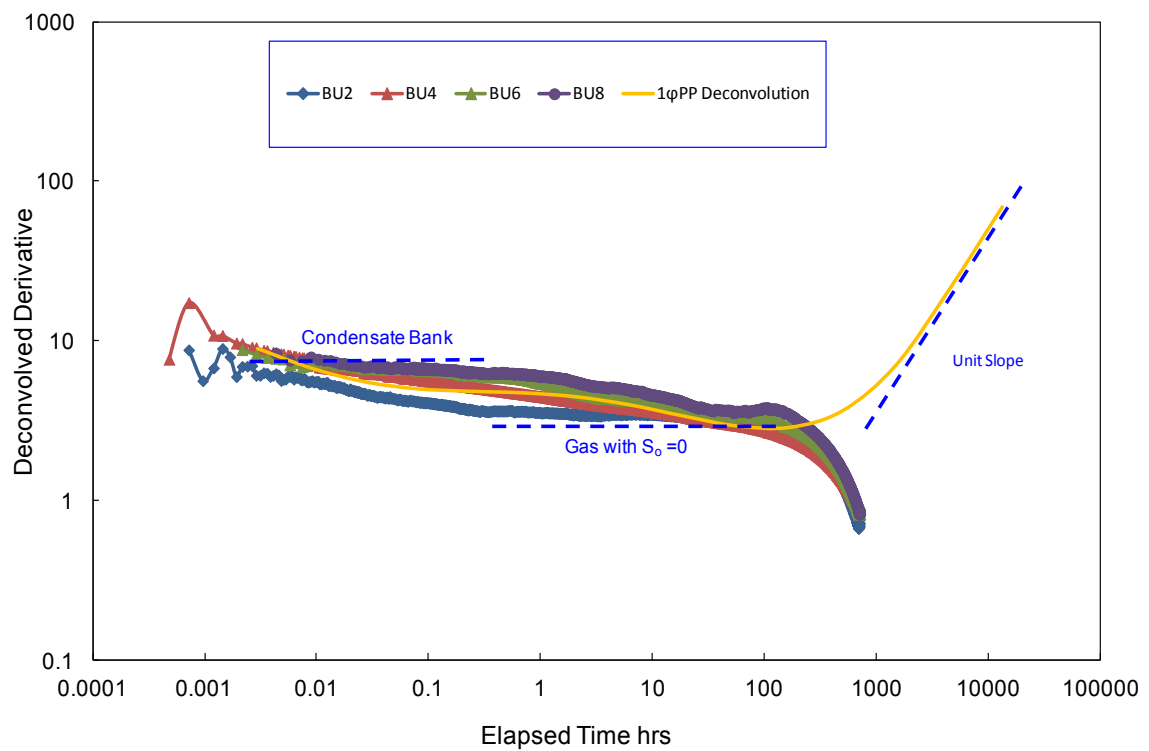


Figure 6.32: Deconvolution of 1φPP for rich gas (decreasing rate)

6.5.2 Deconvolution of Two-phase Pseudo-pressure

The pressure data from Figs 6.24, 6.27 and 6.28 were converted to two-phase pseudo-pressure calculated with relative permeability curves which integrate high capillary number and non-Darcy effects using procedure in section 2.4. Figs. 6.33, 6.34 and 6.35 show the plot of single-phase and two-phase pseudo-pressure for random, decreasing and increasing rate histories for rich gas.

The two-phase pseudo-pressure rate normalised log-log plots for random, decreasing and increasing rate histories are shown in Figs. 6.36, 6.37 and 6.38. The radial composite effect in Figs. 6.25, 6.29 and 6.30 was corrected in Figs. 6.36, 6.37 and 6.38 by two-phase pseudo-pressure. The single-phase and two-phase pseudo-pressure log-log plots for random, decreasing and increasing rate histories (Figs. 6.39, 6.40 and 6.41) show that the two-phase pseudo-pressure stabilises at effective permeability with zero condensate saturation.

The deconvolved derivatives (Figs. 6.42, 6.43 and 6.44) of two-phase pseudo-pressure for random, decreasing and increasing rate histories show a homogeneous behaviour at early time, middle time, and a closed system designated by unit slope at late time. Single-phase pseudo-pressure and two-phase pressure deconvolution (Figs. 6.42, 6.43 and 6.44) give exactly same result at the late time (closed system).

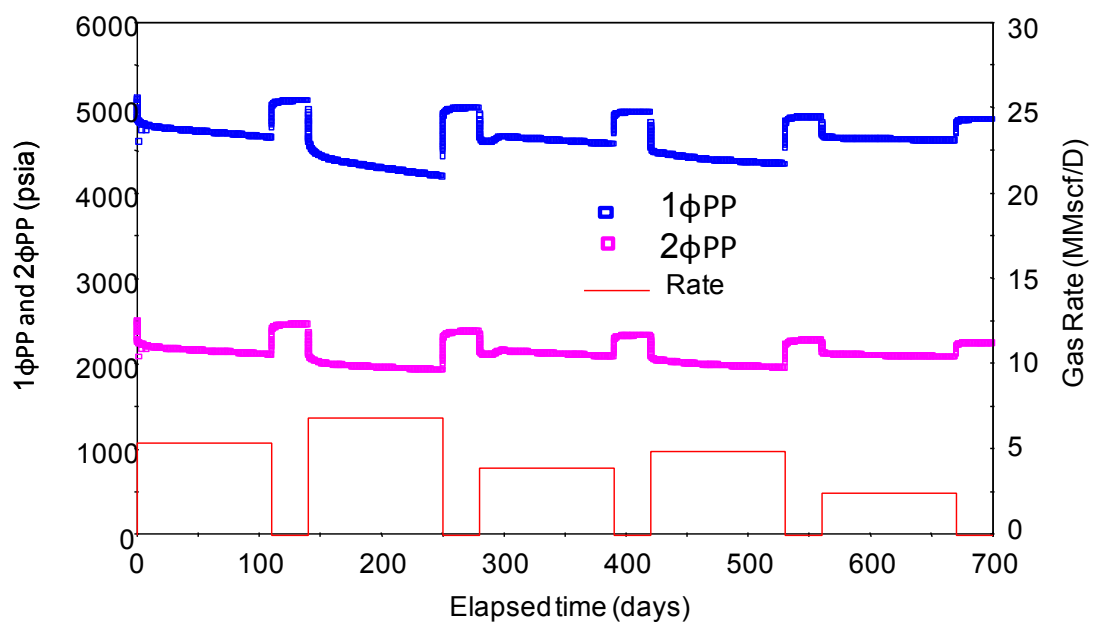


Figure 6.33: Pressure, 2 ϕ PP and random rate history for rich gas

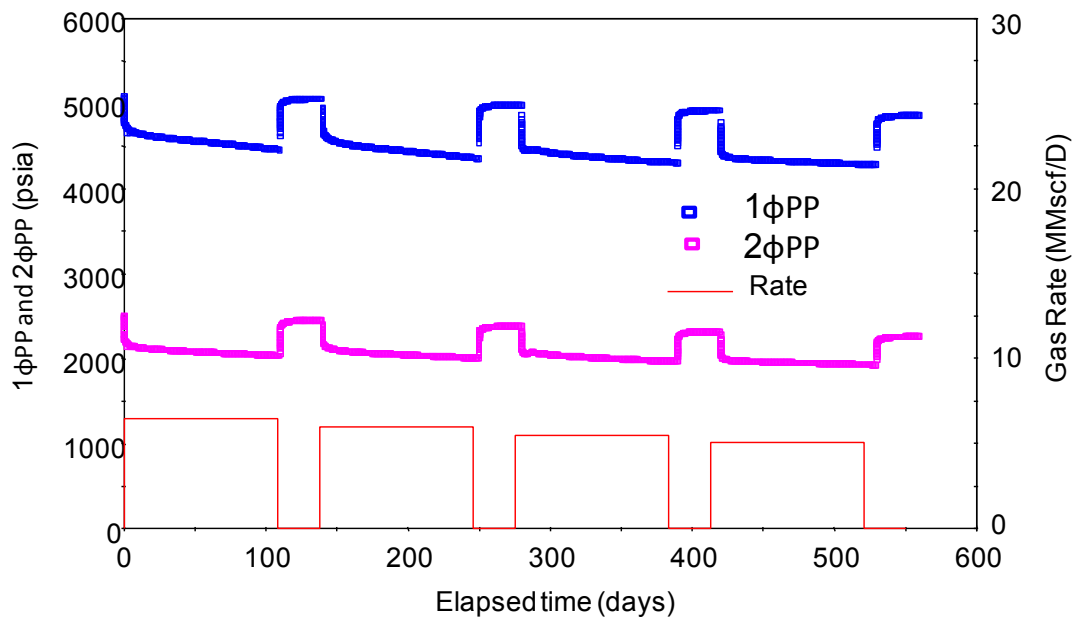


Figure 6.34: Pressure, $2\phi_{PP}$ and decreasing rate history for rich gas

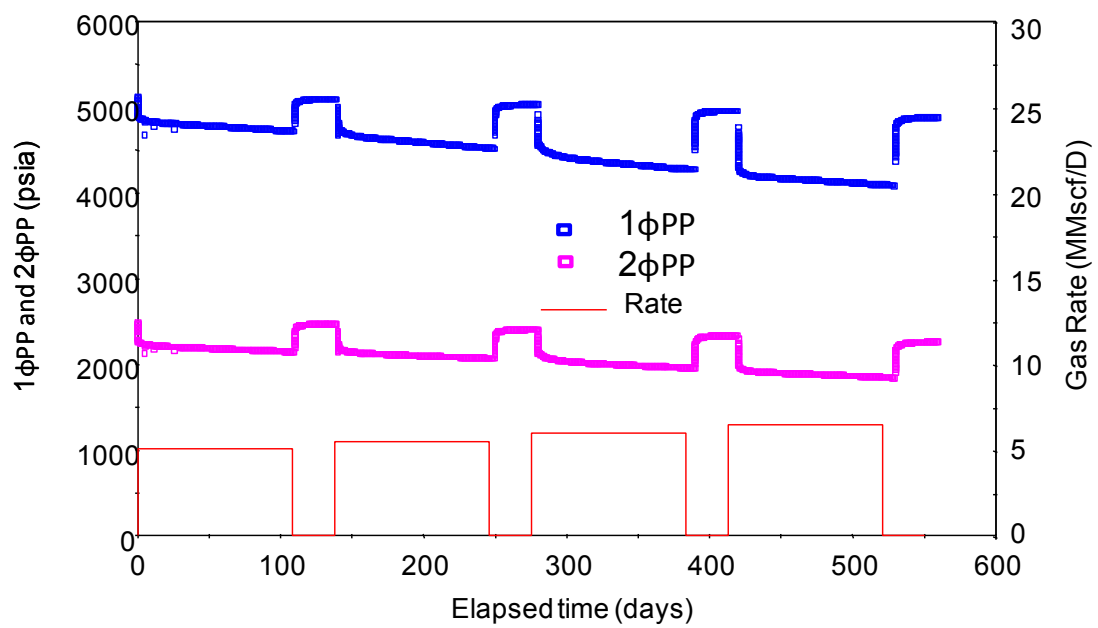


Figure 6.35: Pressure, $2\phi_{PP}$ and increasing rate history for rich gas

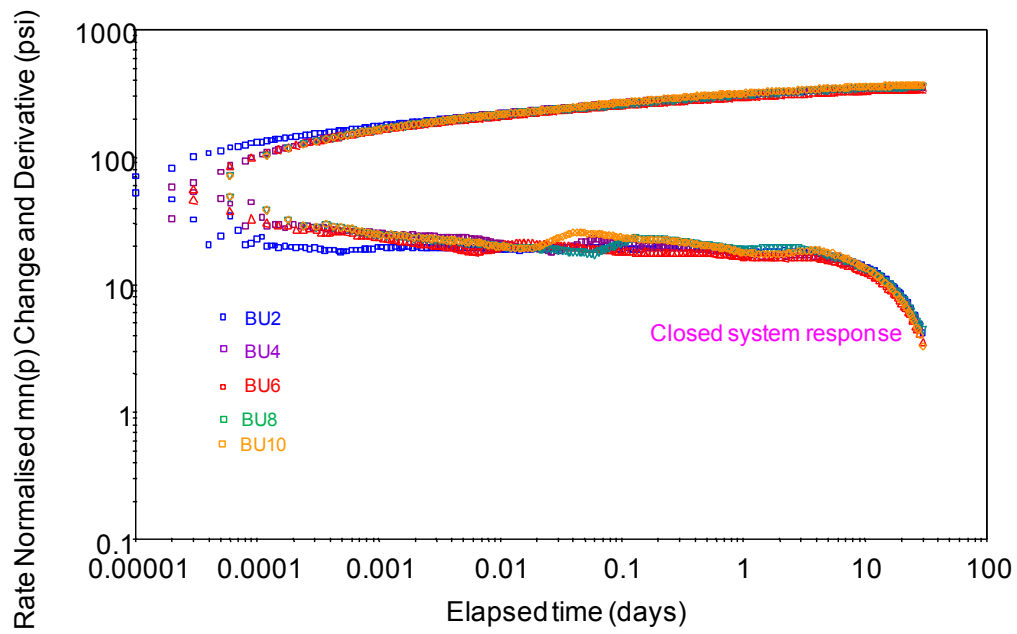


Figure 6.36: Rate-normalized 2φPP log-log plot for rich gas (random rate)

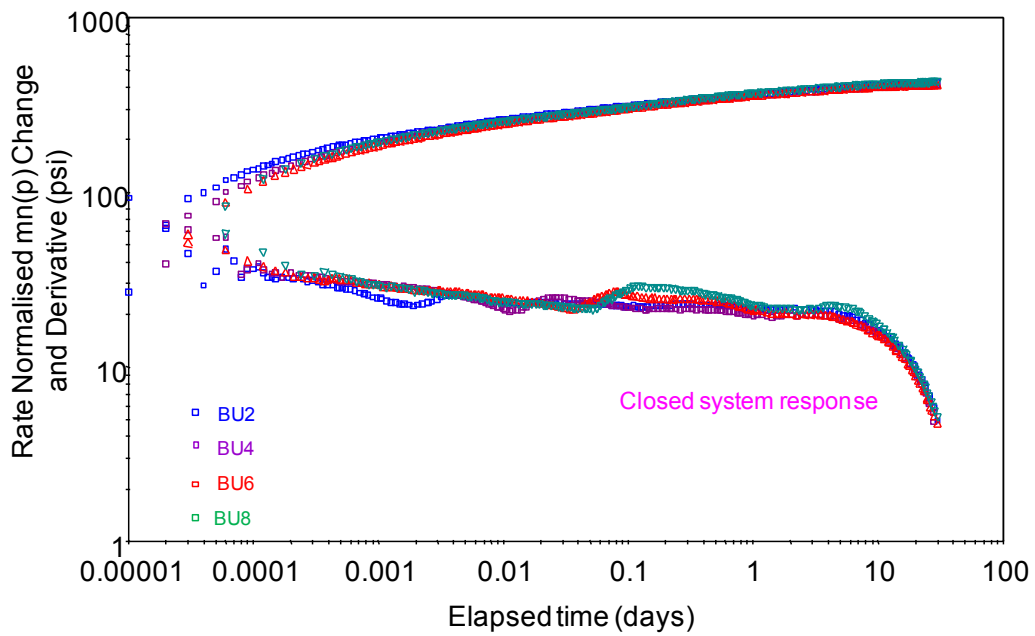


Figure 6.37: Rate-normalized 2φPP log-log plot for rich gas (decreasing rate)

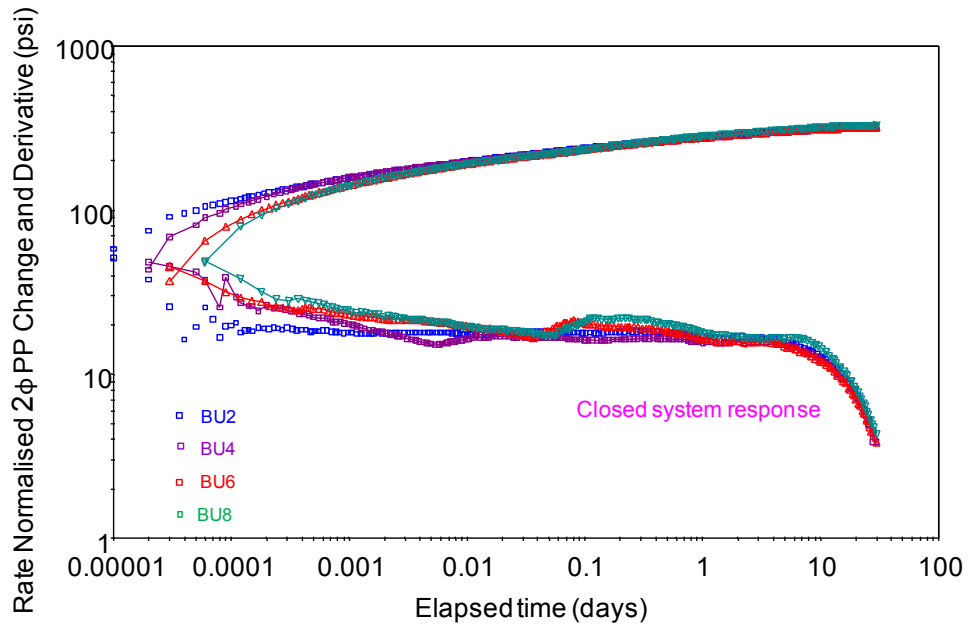


Figure 6.38: Rate-normalized 2φPP log-log plot for rich gas (increasing rate)

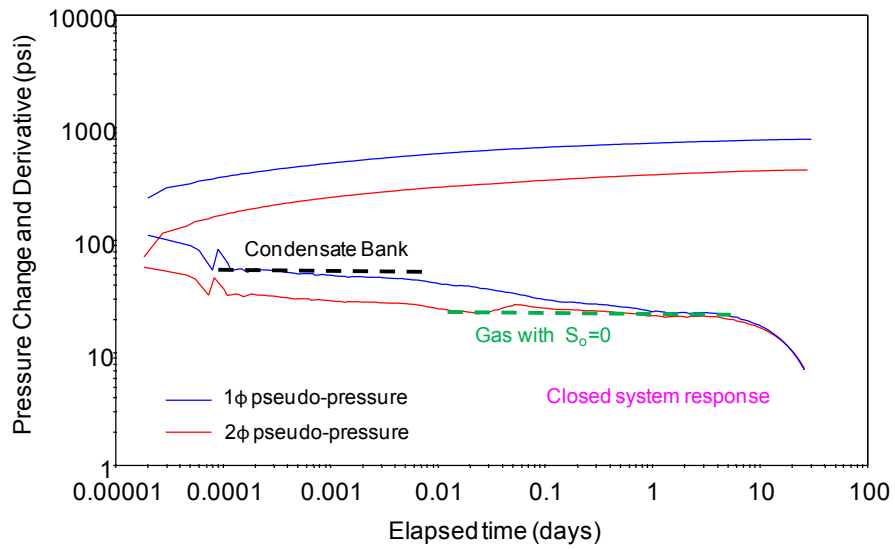


Figure 6.39: 1φPP and 2φPP log-log plot for rich gas (BU 6) (random rate at $k_{rg}^{\max}=1$)

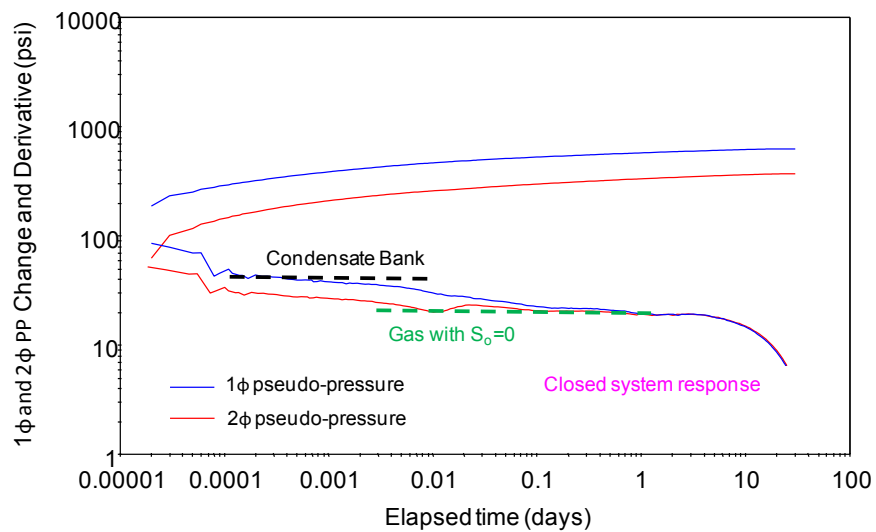


Figure 6.40: 1φPP and 2φPP log-log plot for rich gas (BU 4) (decreasing rate at $k_{rg}^{\max}=1$)

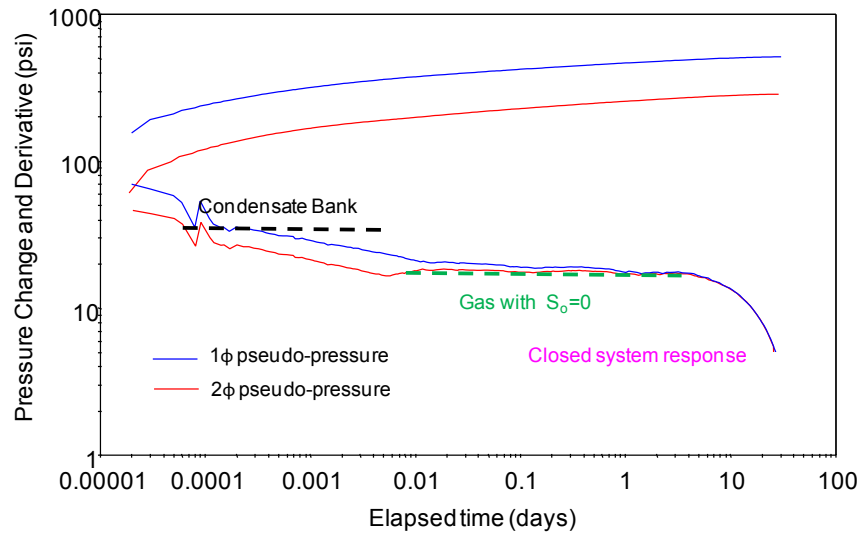


Figure 6.41: 1 ϕ PP and 2 ϕ PP log-log plot for rich gas (BU 4) (increasing rate at $k_{rg}^{\max}=1$)

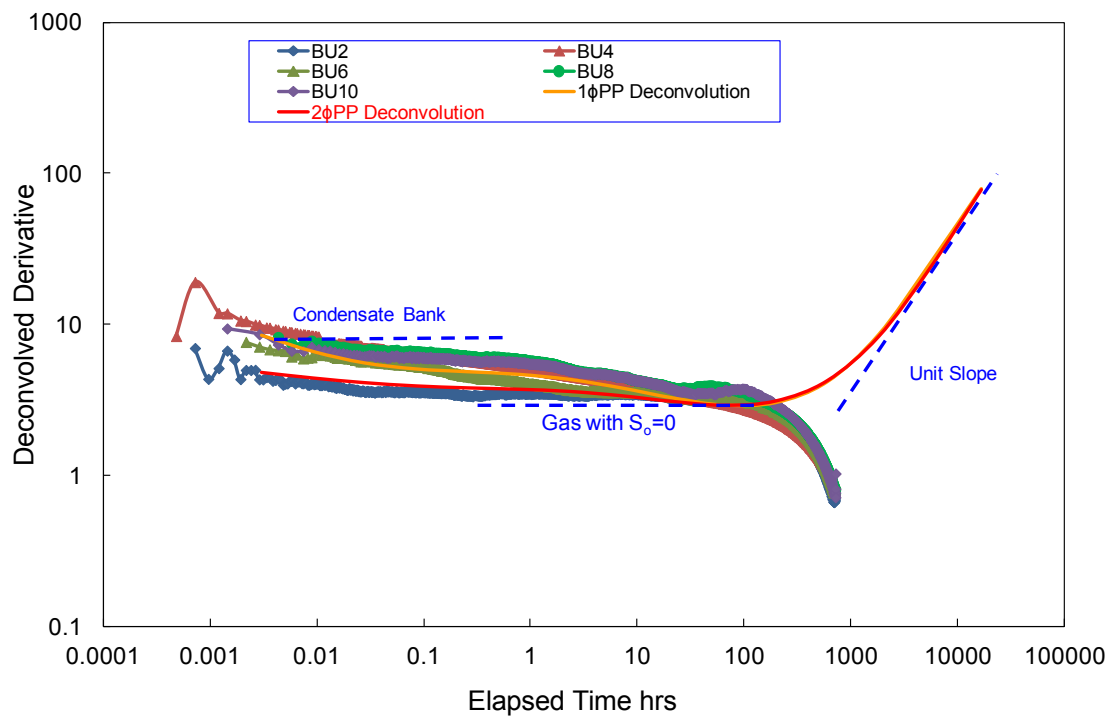


Figure 6.42: Deconvolution of 1 ϕ PP and 2 ϕ PP pressure for rich gas (random rate)

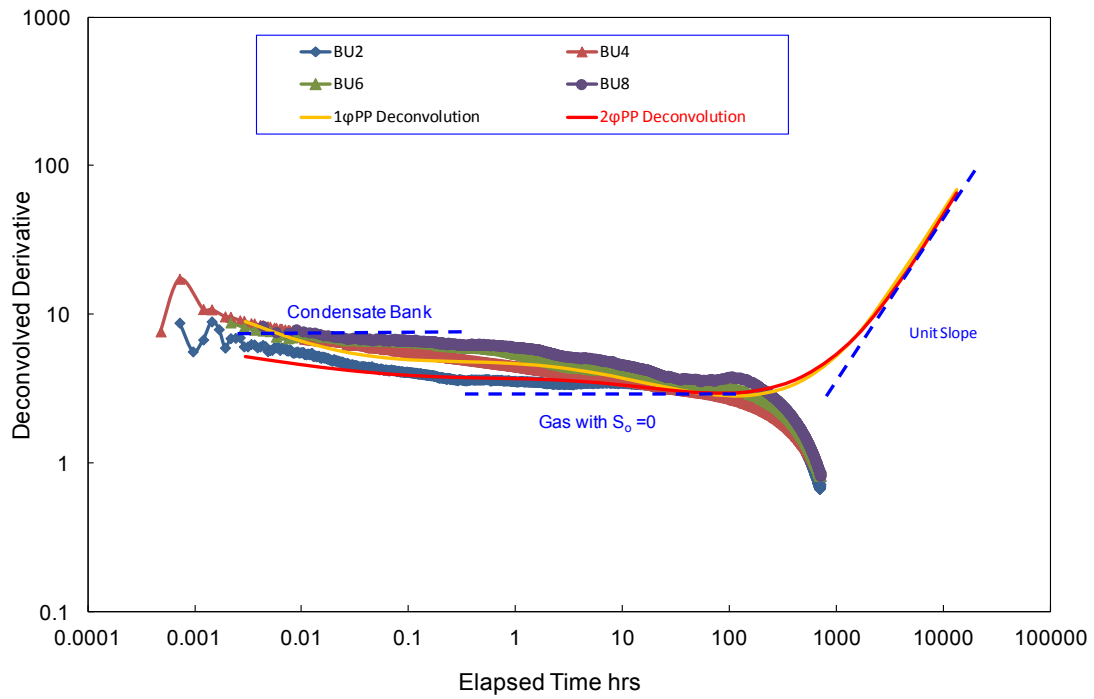


Figure 6.43: Deconvolution of 1 ϕ PP and 2 ϕ PP for rich gas (decreasing rate)

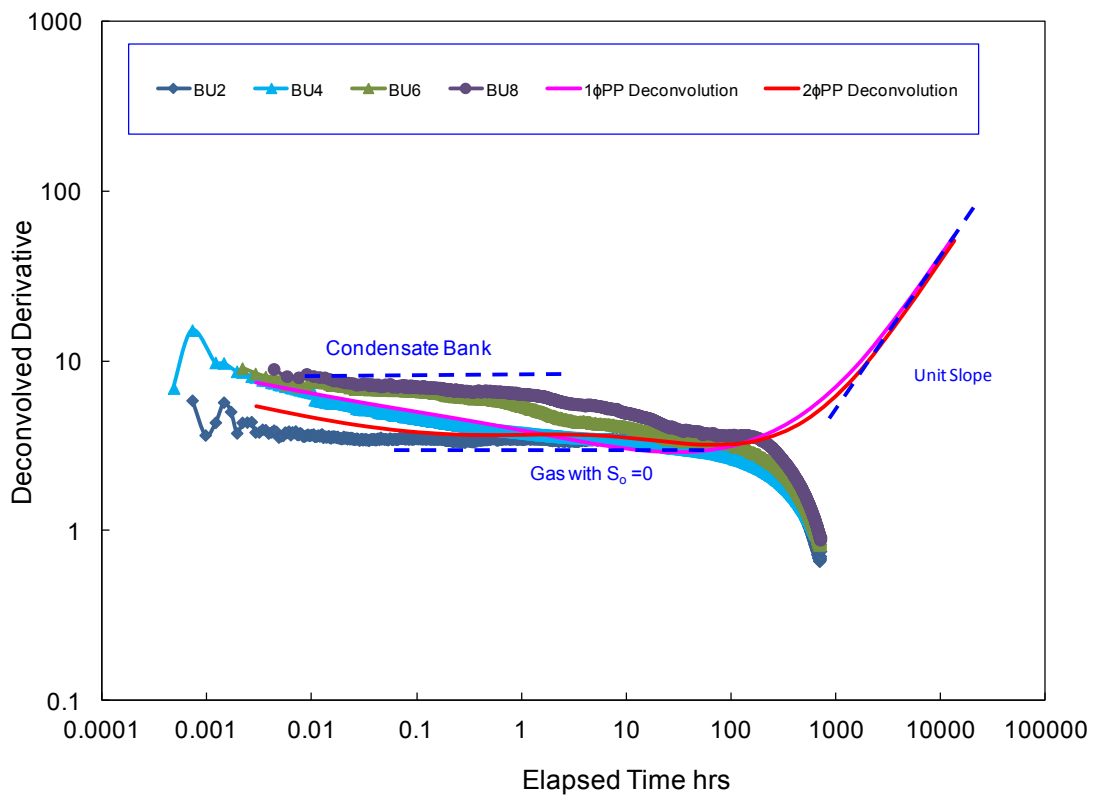


Figure 6.44: Deconvolution of 1 ϕ PP and 2 ϕ PP for rich gas (increasing rate)

6.5.3 Summary of Deconvolution of Rich Gas Condensate

1. Below dew point pressure, the single-phase pseudo-pressure deconvolved derivative shows a radial composite behaviour at early time, middle time, and gives closed system response at late time.

2. The two-phase pseudo-pressure deconvolved derivative shows a homogeneous behaviour at early, middle time, and gives closed system at late time.
3. The deconvolved derivatives from single-phase and two-phase pseudo-pressure show a similar late time response for rich gas.

6.6 Deconvolution of Volatile Oil

6.6.1 Deconvolution of Pressure Data

6.6.1.1 Random Rate History

The simulated pressure and random rate history (Fig. 6.45) for volatile oil was generated with a duration of 110-days for each drawdown (DD) and 30-days for every build-up (BU) for a total of 10 flow periods. The plot of rate normalised log-log derivatives (Fig. 6.46) shows radial composite effect with an upward shift of the pressure curves as a result of gas bank formation at the wellbore and a closed system response at late time.

The deconvolved derivative (Fig. 6.47) shows a radial composite behaviour at early time to middle time, homogeneous behaviour at middle time (similar to Fig 6.46) and a closed system at late time.

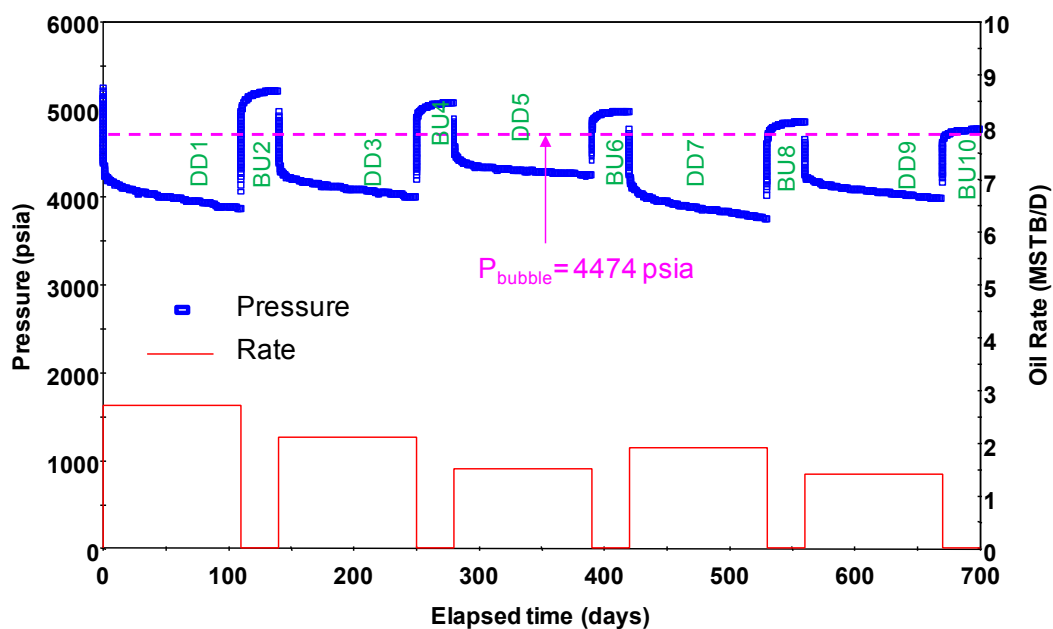


Figure 6.45: Pressure and random rate history for volatile oil

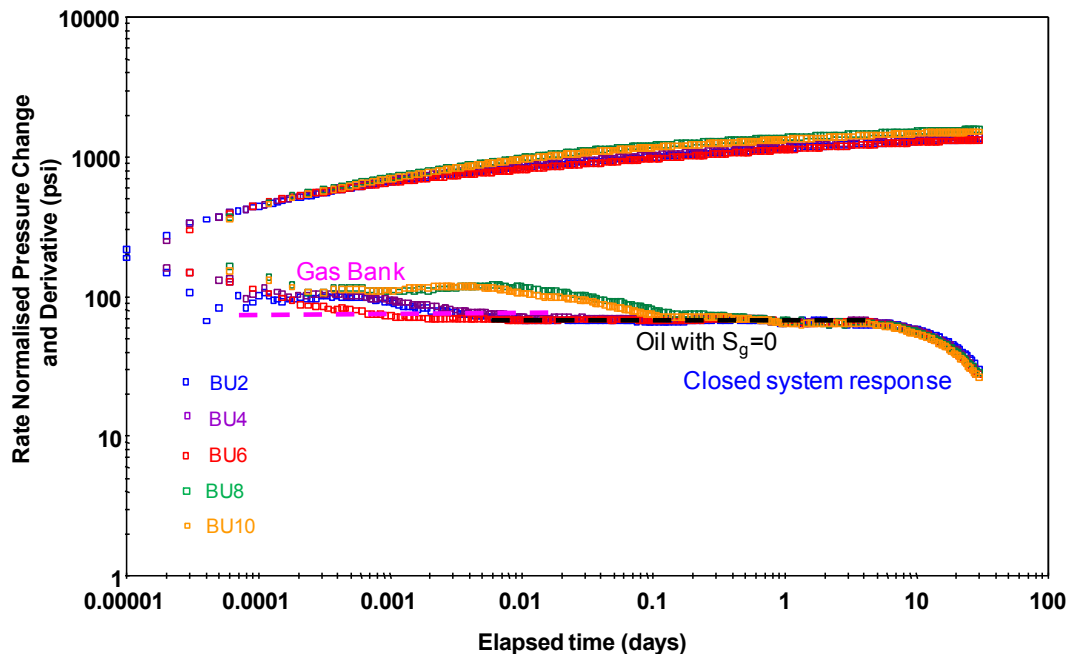


Figure 6.46: Rate-normalized pressure log-log plot for volatile oil (random rate)

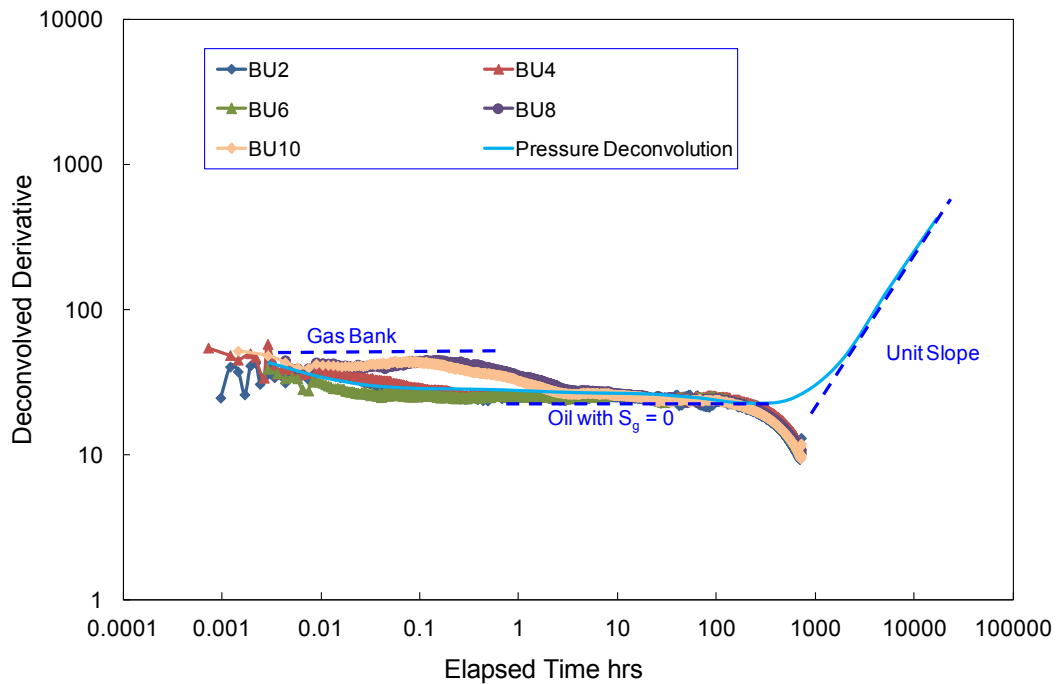


Figure 6.47: Deconvolution of pressure for volatile oil (random rate history)

6.6.1.2 Increasing and Decreasing Rate History

The pressure, increasing and decreasing rate histories for volatile oil are shown in Figs. 6.48 and 6.49. They have 8 flow periods with 110-days and 30-days duration for each drawdown (DD) and build-up (BU) respectively. Figs. 6.50 and 6.51 show the rate-normalized log-log plot for increasing and decreasing rate histories. The pressure

derivatives (Figs. 6.50 and 6.51) show radial composite effect resulting in a reduced effective permeability because of the production of gas bank at the wellbore.

The deconvolved derivatives (Figs. 6.52 and 6.53) from pressure data (Figs. 6.48 and 6.51) show a radial composite behaviour at early time to middle time (similar to the actual derivatives in Figs. 6.50 and 6.51) and a closed system at late time.

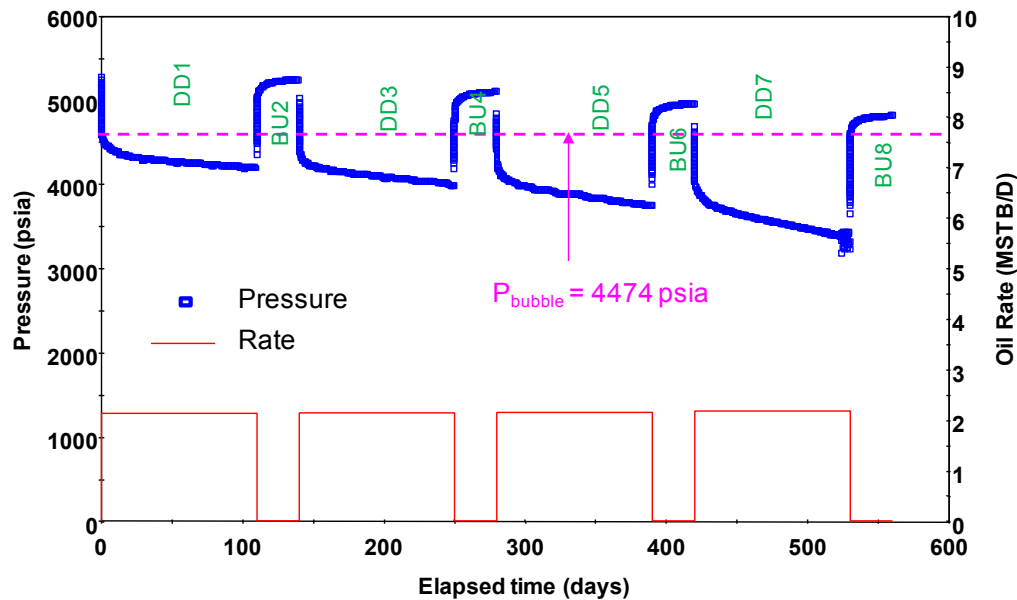


Figure 6.48: Pressure and increasing rate history for volatile oil

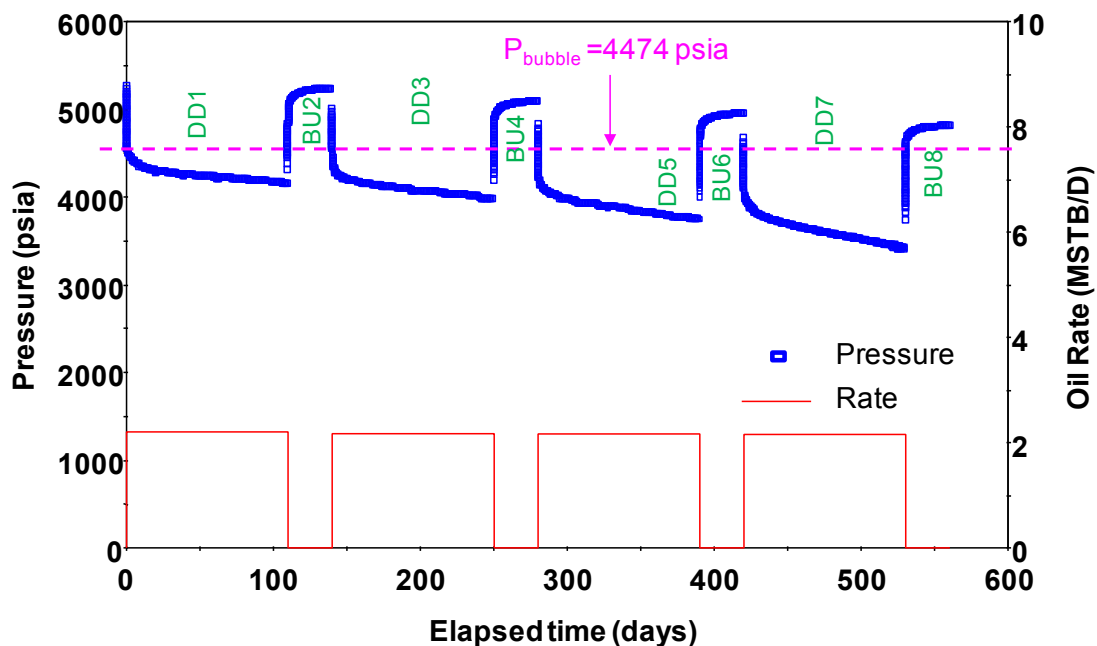


Figure 6.49: Pressure and decreasing rate history for volatile oil

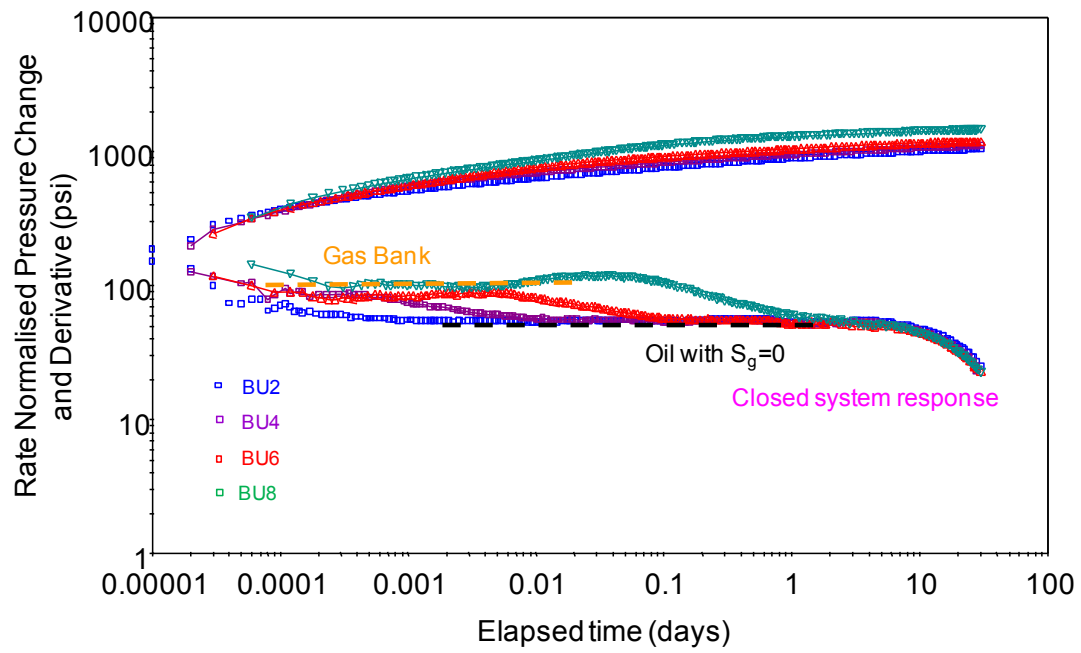


Figure 6.50: Rate-normalized pressure log-log plot for volatile oil (increasing rate)

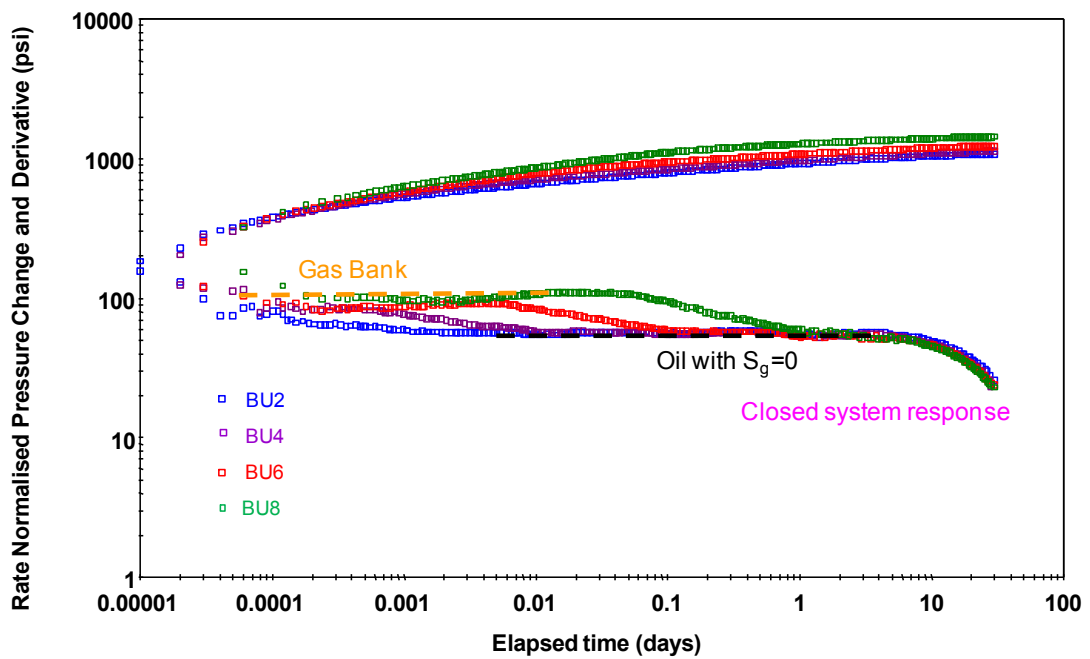


Figure 6.51: Rate-normalized pressure log-log plot for volatile oil (decreasing rate)

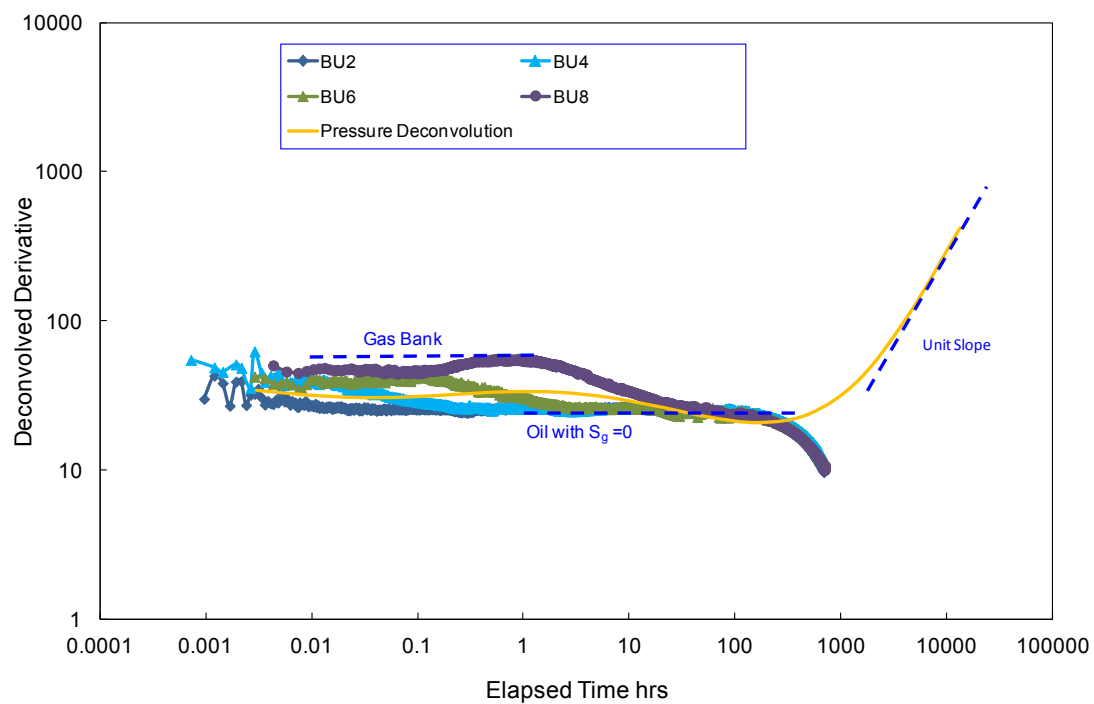


Figure 6.52: Deconvolution of Pressure for volatile oil (increasing rate)

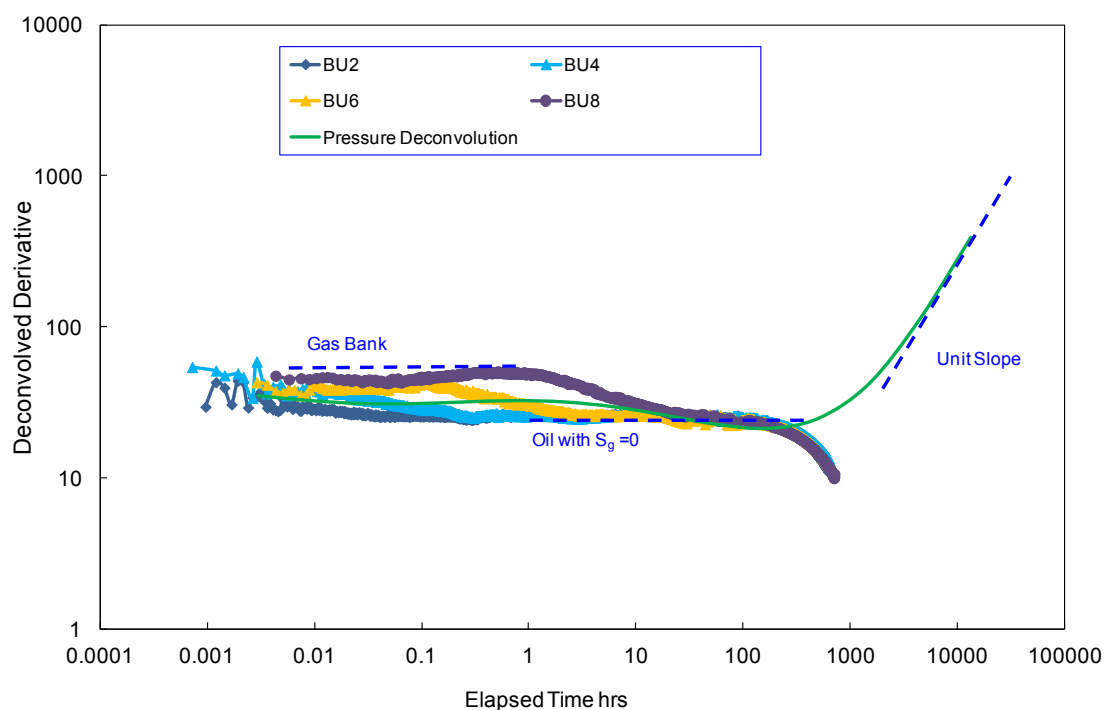


Figure 6.53: Deconvolution of pressure for volatile oil (decreasing rate)

6.6.2 Deconvolution of two-phase pseudo-pressure

The pressure data (Figs. 6.45, 6.48 and 6.49) were transformed into two-phase pseudo-pressure calculated with relative permeability curves which incorporate high capillary number and non-Darcy effects using procedure specified in section 2.4. The plot of pressure and two-phase pseudo-pressure for random, decreasing and increasing rate histories for volatile oil are shown in Figs. 6.54, 6.55 and 6.56.

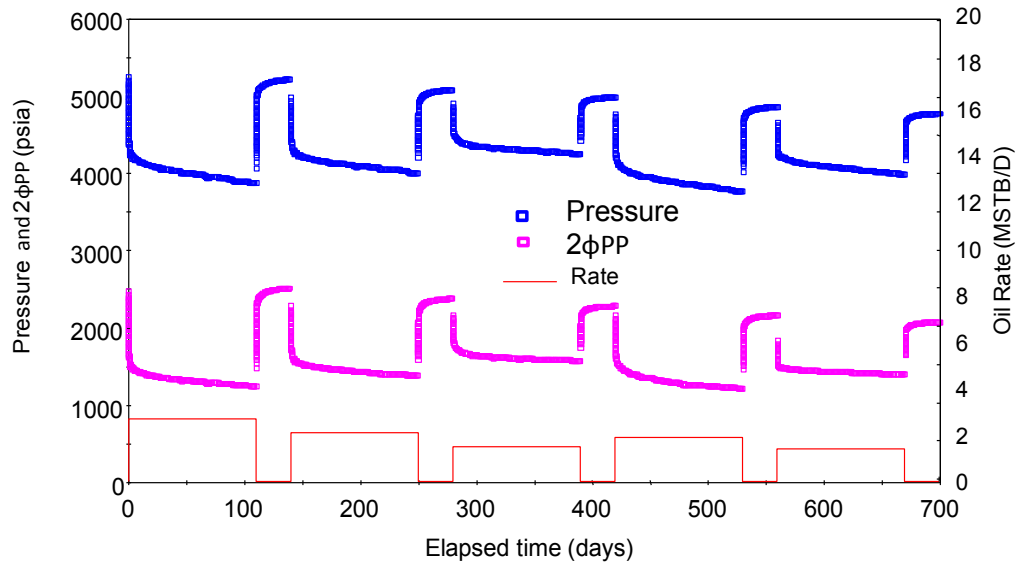


Figure 6.54: Pressure, 2 ϕ PP and random rate history for volatile oil

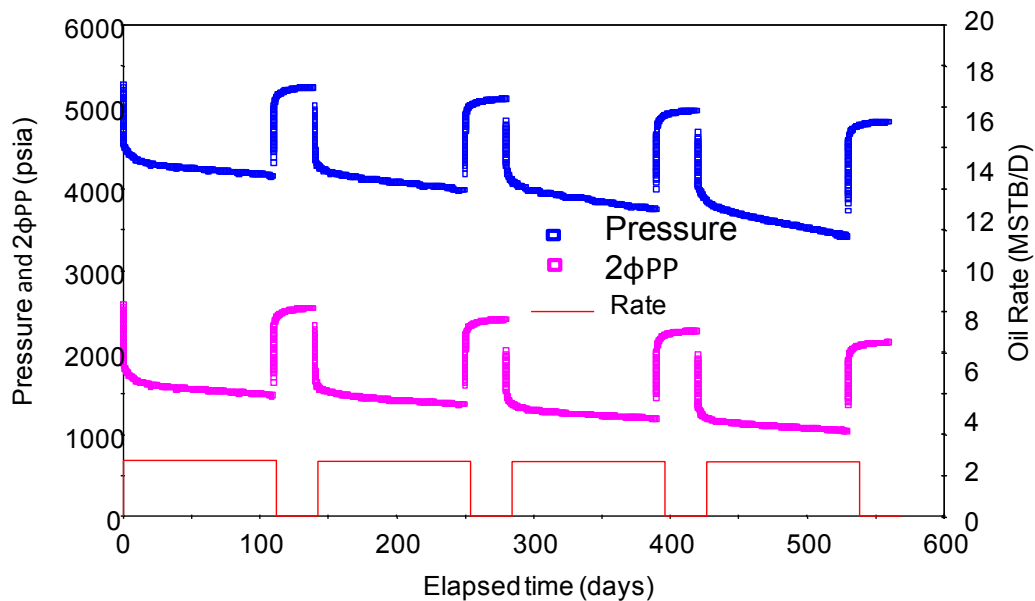


Figure 6.55: Pressure, 2 ϕ PP and decreasing rate history for volatile oil

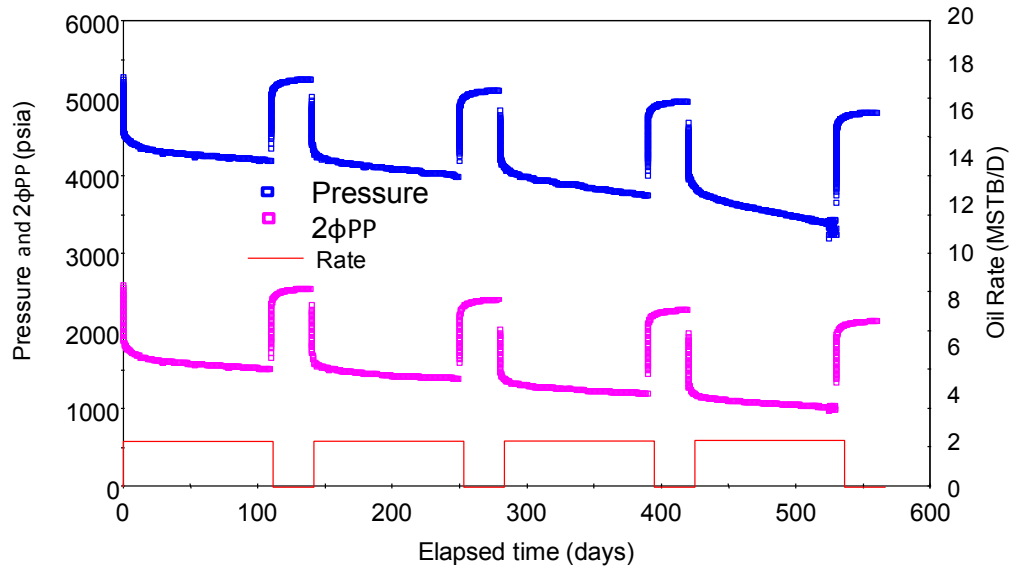


Figure 6.56: Pressure, $2\phi PP$ and increasing rate history for volatile oil

The rate normalised log-log plots for two-phase pseudo-pressure for random, decreasing and increasing rate histories are shown in Figs. 6.57, 6.58 and 6.59. They show reasonable corrections of the radial composite behaviour in Figs. 6.46, 6.50 and 6.51.

The log-log plots for pressure and two-phase pseudo-pressure for random, decreasing and increasing rate histories (Figs. 6.60, 6.61 and 6.62) shows that the two-phase pseudo-pressure derivatives stabilise at effective permeability of zero gas saturation.

Figs. 6.63, 6.64 and 6.65 show that the pressure and two-phase pseudo-pressure deconvolution are the same at late time.

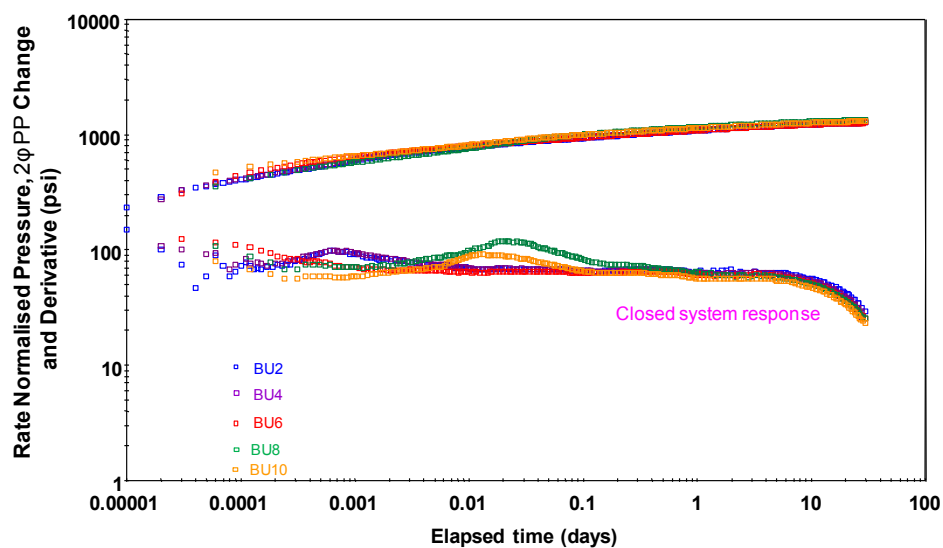


Figure 6.57: Rate-normalized $2\phi PP$ log-log plot for volatile oil (random rate)

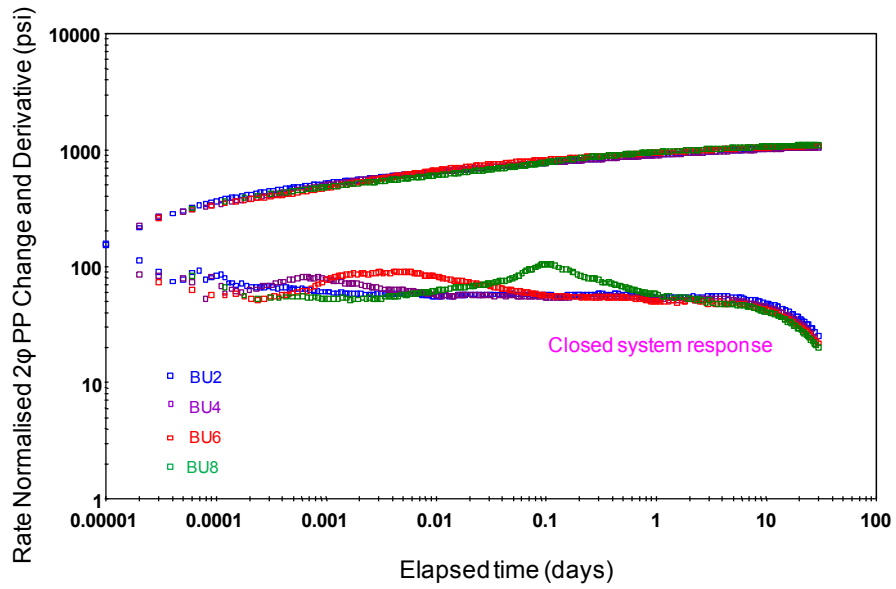


Figure 6.58: Rate-normalized 2φPP log-log plot for volatile oil (decreasing rate)

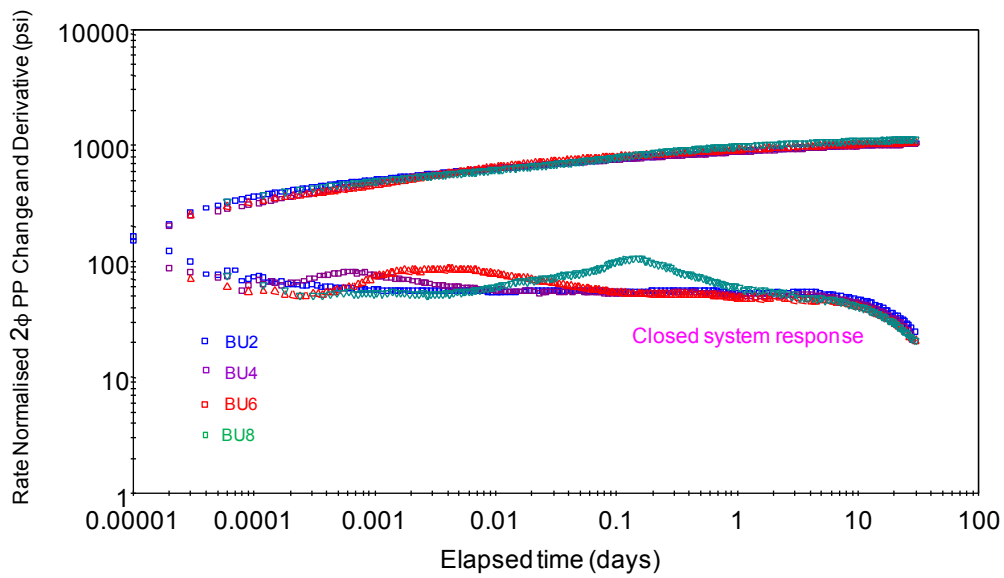


Figure 6.59: Rate-normalized 2φPP log-log plot for volatile oil (increasing rate)

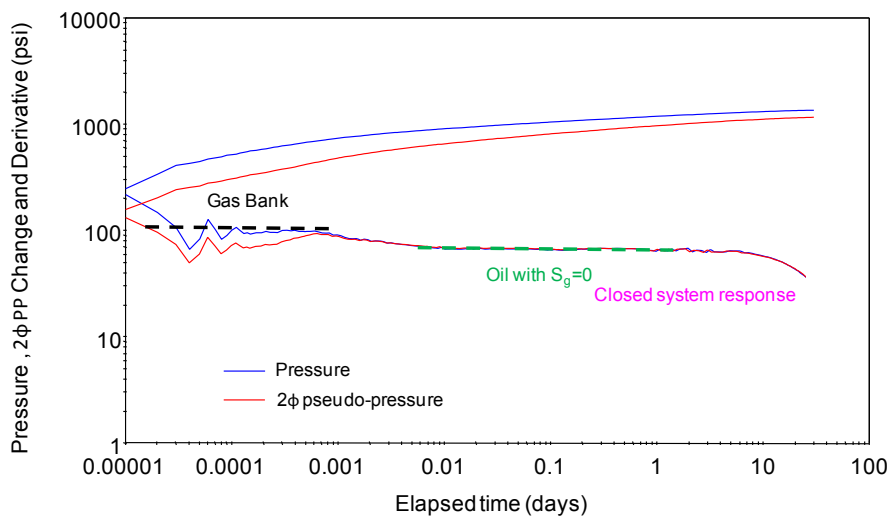


Figure 6.60: Pressure and 2φPP log-log plot for volatile oil (BU 2) (random rate at $k_{rg}^{\max}=1$)

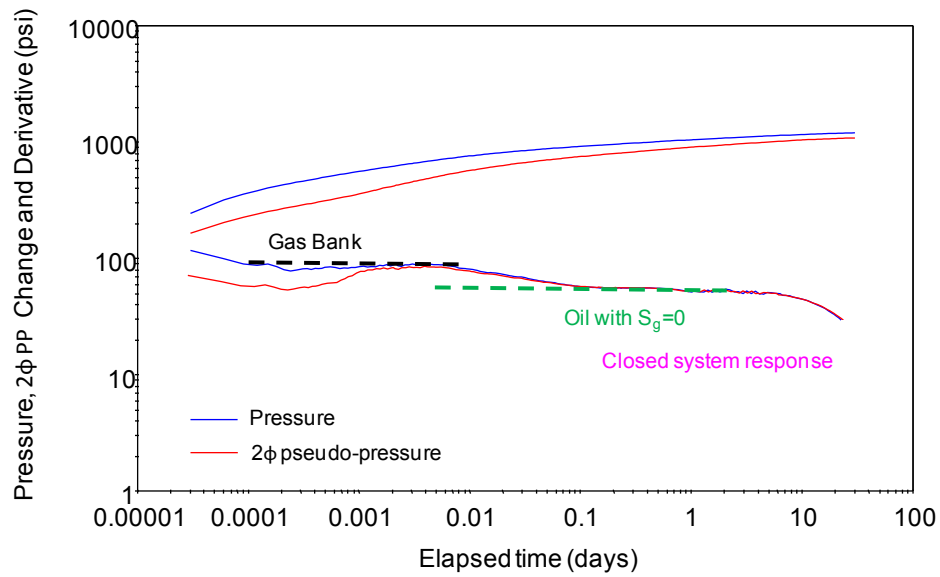


Figure 6.61: Pressure and 2φPP log-log plot for volatile oil (BU 6) (decreasing rate at $k_{rg}^{max}=1$)

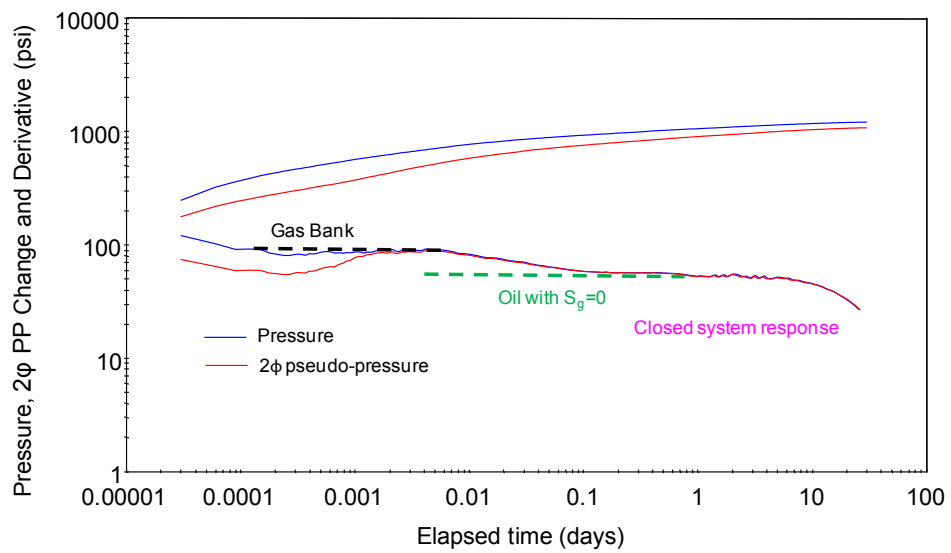


Figure 6.62: Pressure and 2φPP log-log plot for volatile oil (BU 6) (increasing rate at $k_{rg}^{max}=1$)

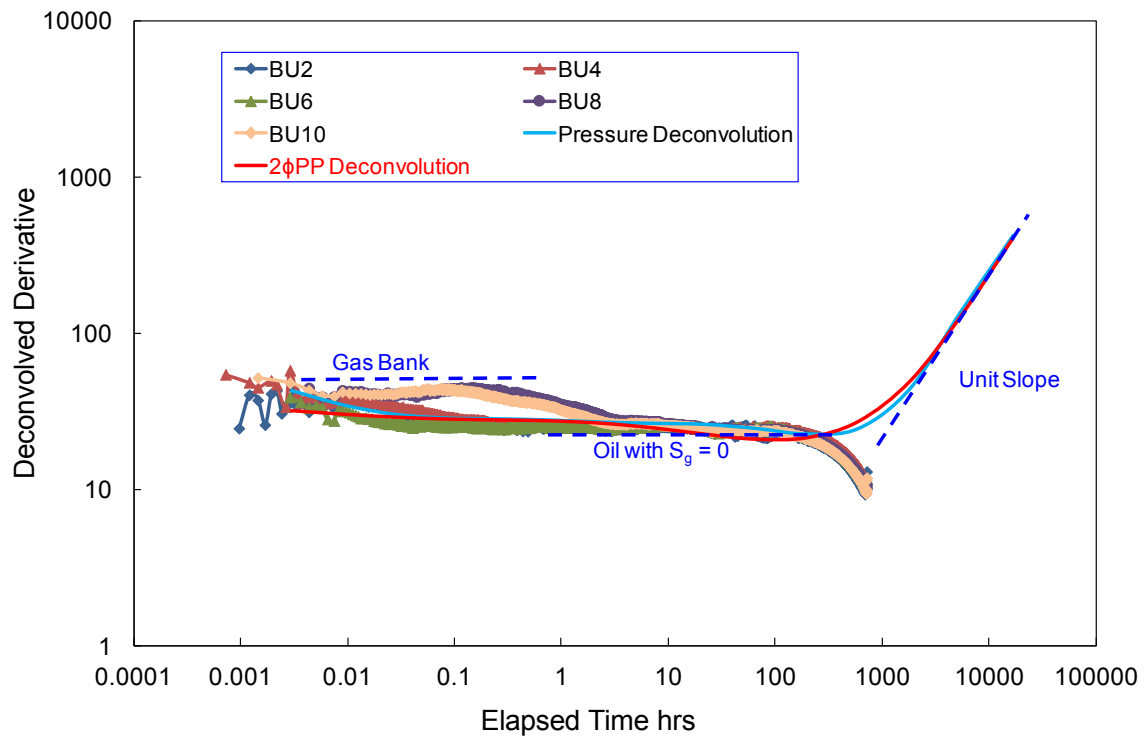


Figure 6.63: Deconvolution of pressure and 2φPP for volatile oil (random rate)

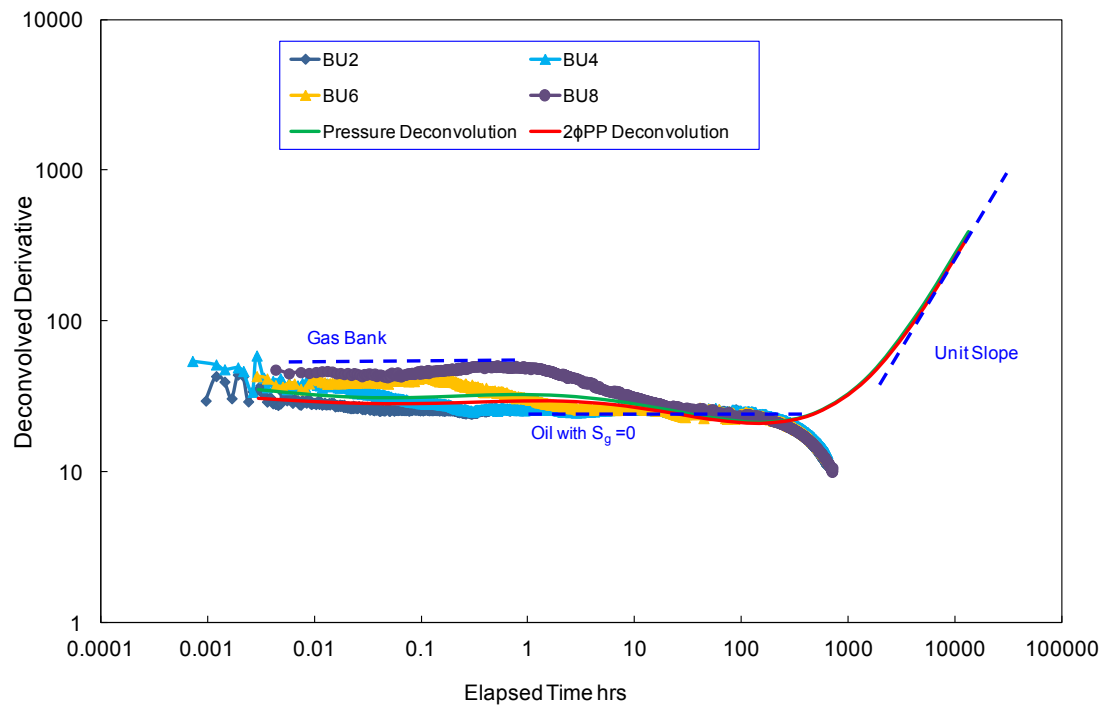


Figure 6.64: Deconvolution of pressure and 2φPP for volatile oil (decreasing rate)

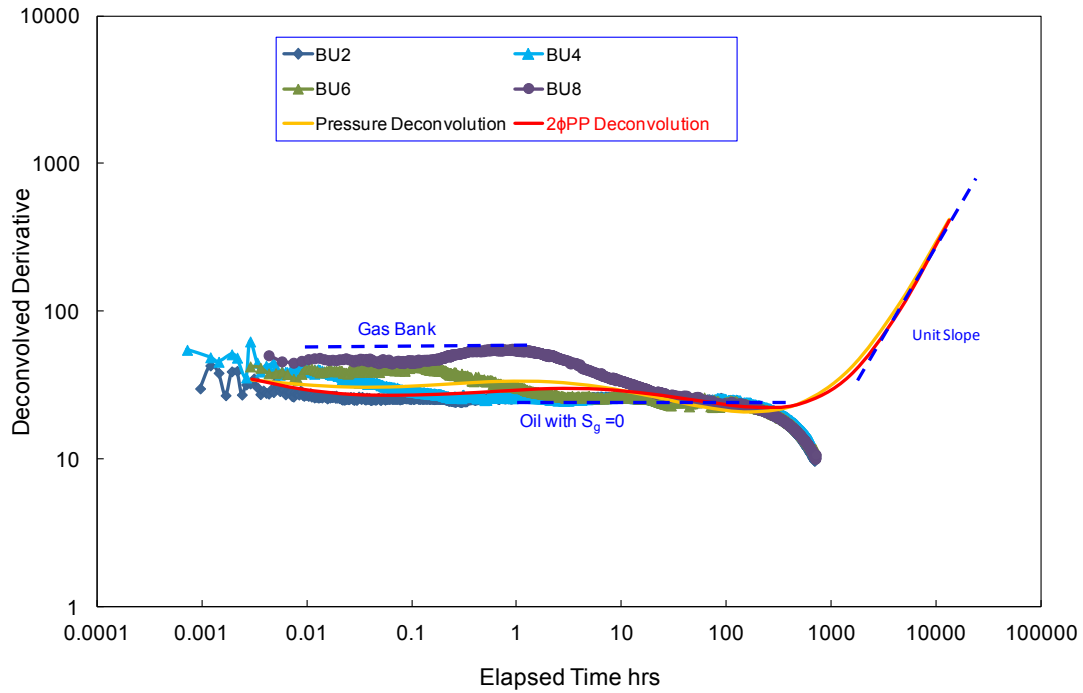


Figure 6.65: Deconvolution of pressure and $2\phi PP$ for volatile oil (increasing rate)

6.6.3 Summary of Deconvolution of Volatile Oil

1. The deconvolved derivative of pressure data below bubble point pressure shows a radial composite behaviour at early to middle time, homogeneous behaviour at middle time and a closed system at late time.
2. Both pressure and two-phase pseudo pressure deconvolution give a closed system at late time.

6.7 Deconvolution of Lean Gas, Rich Gas and Volatile for different values of Mechanical Skin and Permeability Thickness

Additional simulation runs were done in order to study the impact of different values of mechanical skin ($s_m = 2$ and 5) and reservoir permeability thickness ($kh = 1500\text{mDft}$ and 2000mDft) on deconvolution of pressure, single-phase pseudo-pressure and two-phase pseudo-pressure for lean gas, rich gas and volatile oil. The rate histories were set in a descending order similar to Fig. 6.7 for lean gas, Fig. 6.28 for rich gas, Fig. 6.49 for volatile oil.

6.7.1 Deconvolution of Single-phase and Two-phase pseudo-pressure for Lean Gas Condensate

Similar, to lean gas with $s_m = 0$ and $kh = 1000\text{mDft}$ (Fig. 6.11); the deconvolved derivatives of single-phase pseudo-pressure for different values of mechanical skin ($s_m = 2$ and 5) and reservoir permeability thickness ($kh = 1500\text{mDft}$ and 2000mDft) show a radial composite behaviour at early to middle time and a closed system at late time (Figs. 6.66, 6.67, 6.68 and 6.69).

The deconvolved derivative (Figs. 6.66, 6.67, 6.68 and 6.69) of two-phase pseudo-pressure for different values of mechanical skin ($s_m = 2$ and 5) and reservoir permeability thickness ($kh = 1500\text{mDft}$ and 2000mDft) show a homogeneous behaviour at early time, middle time, and give a unit slope at late time signifying a closed system. Hence, deconvolution of single-phase and two-phase pseudo-pressure of lean gas wells flowing below dew point pressure is not sensitive to changes in mechanical skin and permeability thickness.

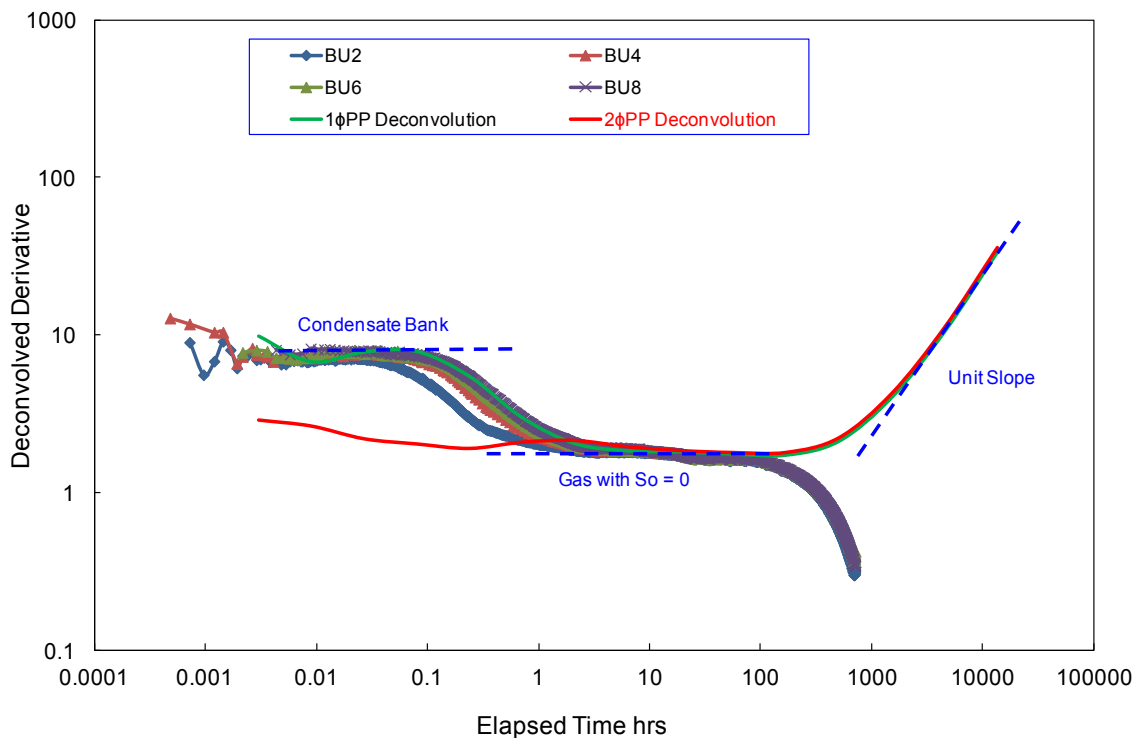


Figure 6.66: Deconvolution of 2φPP for lean gas (skin=2)

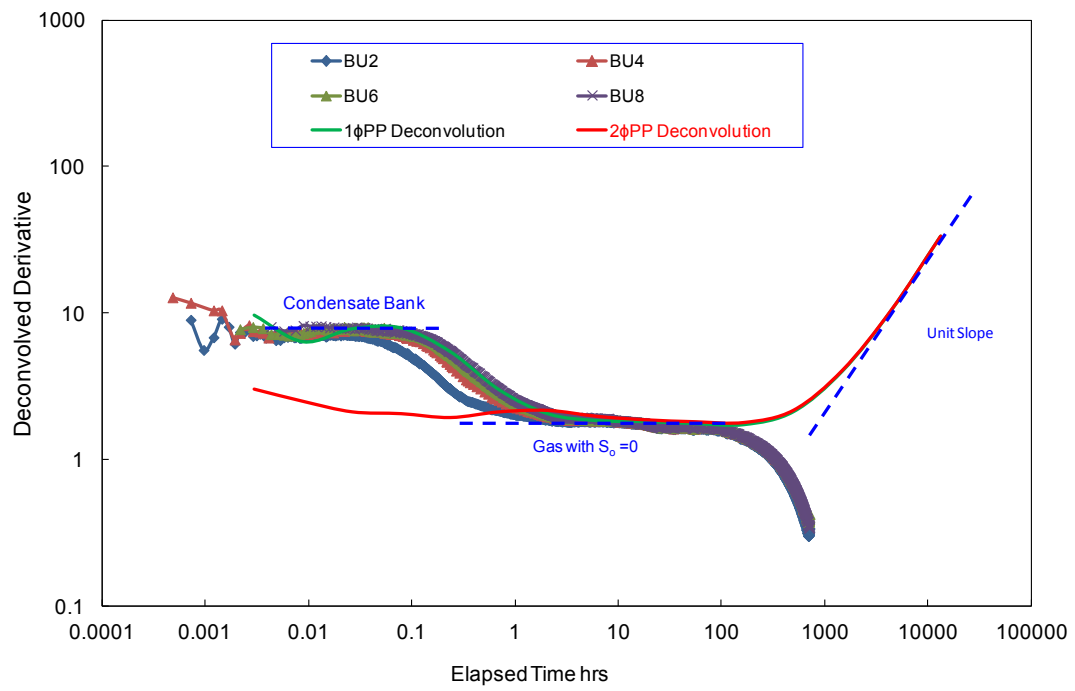


Figure 6.67: Deconvolution of 2 ϕ PP for lean gas (skin=5)

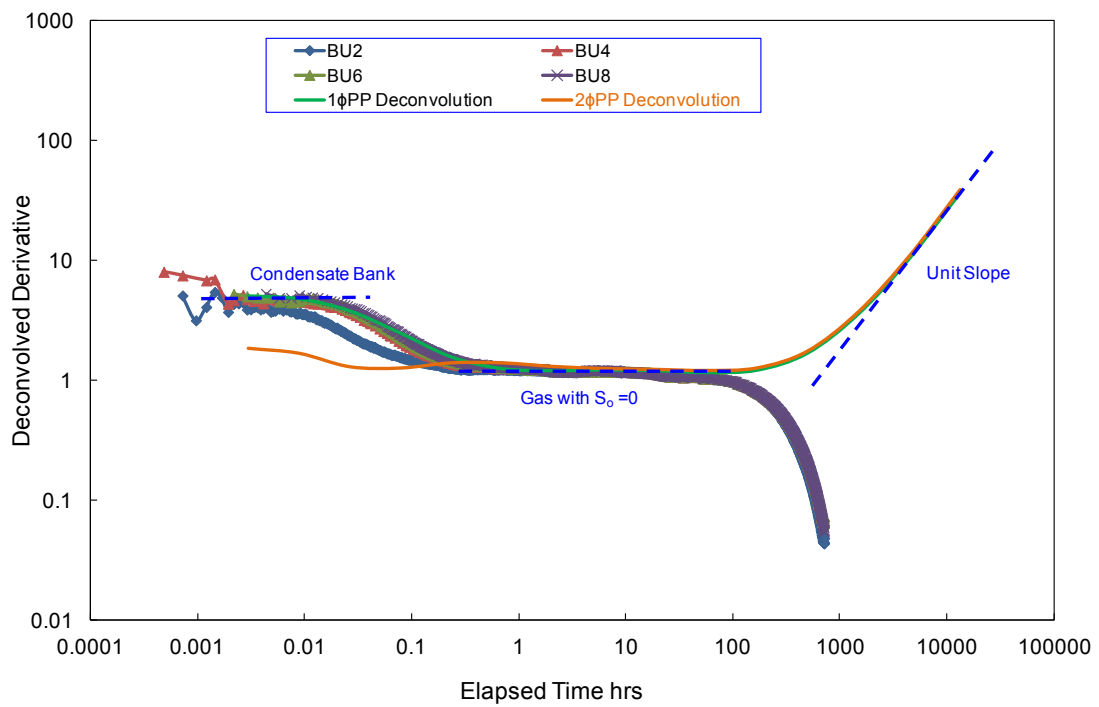


Figure 6.68: Deconvolution of 2 ϕ PP for lean gas (kh=1500mDft)

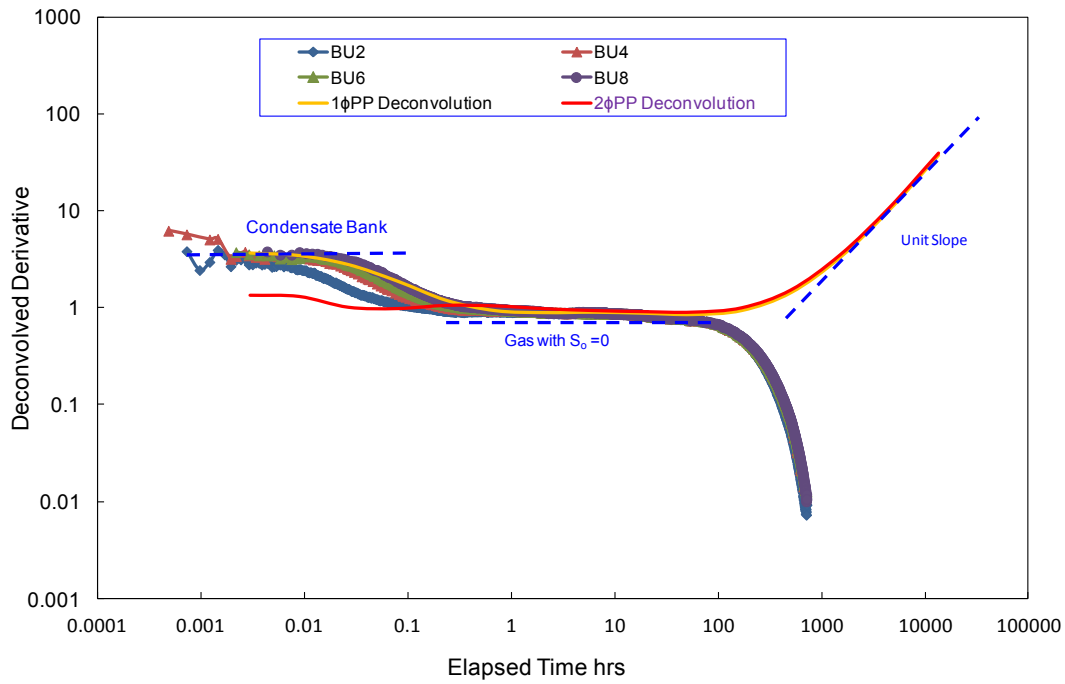


Figure 6.69: Deconvolution of 2φPP for lean gas (kh=2000mDft)

6.7.2 Deconvolution of Single-phase and Two-phase pseudo-pressure for Rich Gas Condensate

The deconvolved derivatives of single-phase pseudo-pressure for different values of mechanical skin ($s_m = 2$ and 5) and reservoir permeability thickness ($kh = 1500\text{mDft}$ and 2000mDft) for rich gas show a radial composite behaviour at early to middle time and a closed system at late time (Figs. 6.70, 6.71, 6.72 and 6.73).

The two-phase pseudo-pressure deconvolved derivative (Figs. 6.70, 6.71, 6.72 and 6.73) for different values of mechanical skin ($s_m = 2$ and 5) and reservoir permeability thickness ($kh = 1500\text{mDft}$ and 2000mDft) show a homogeneous behaviour at early time, middle time, and give a unit slope at late time. Hence, deconvolution of single-phase and two-phase pseudo-pressure for rich gas is insensitive to changes in mechanical skin and permeability thickness.

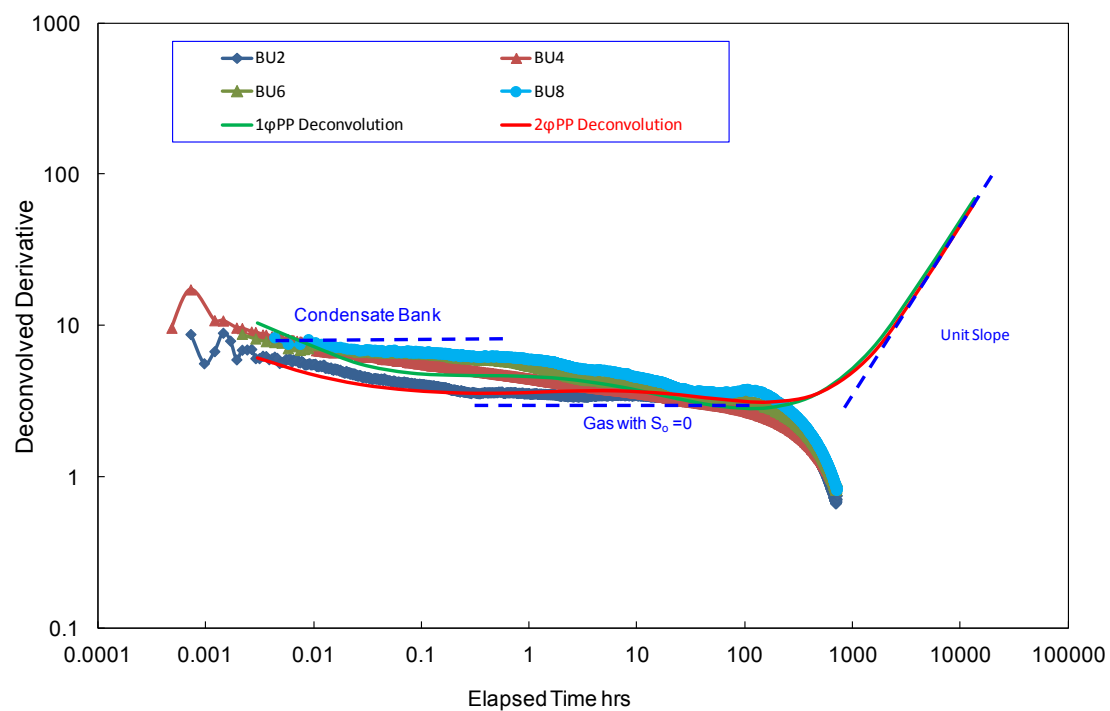


Figure 6.70: Deconvolution of 2φPP for rich gas (skin=2)

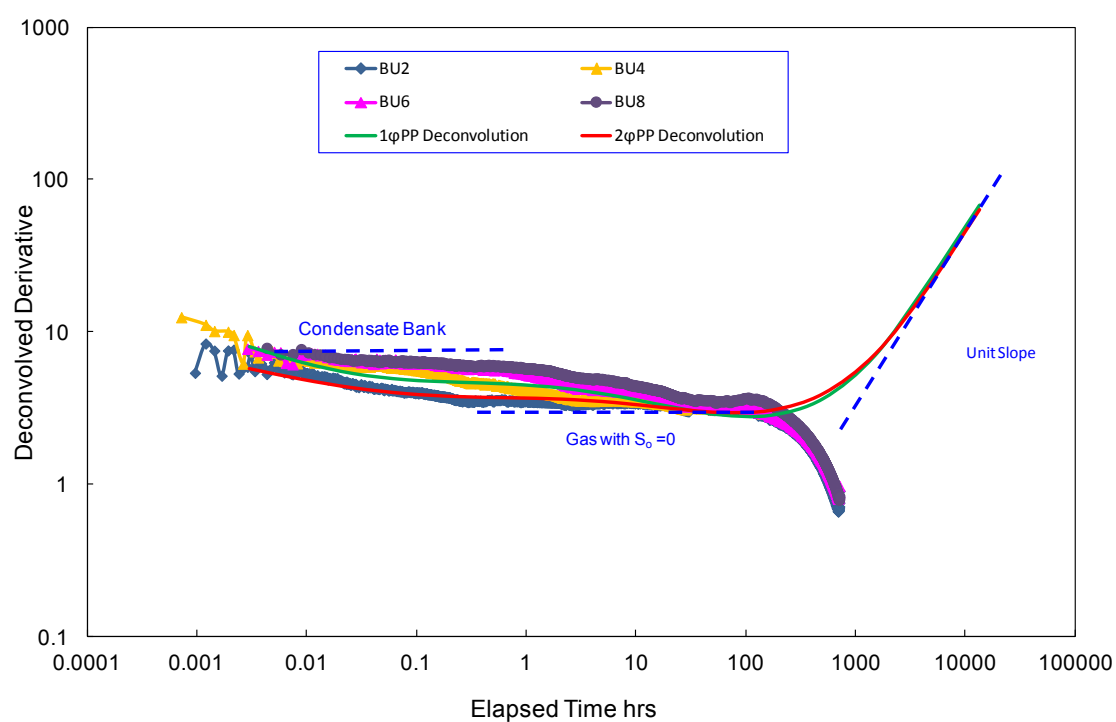


Figure 6.71: Deconvolution of 2φPP for rich gas (skin=5)

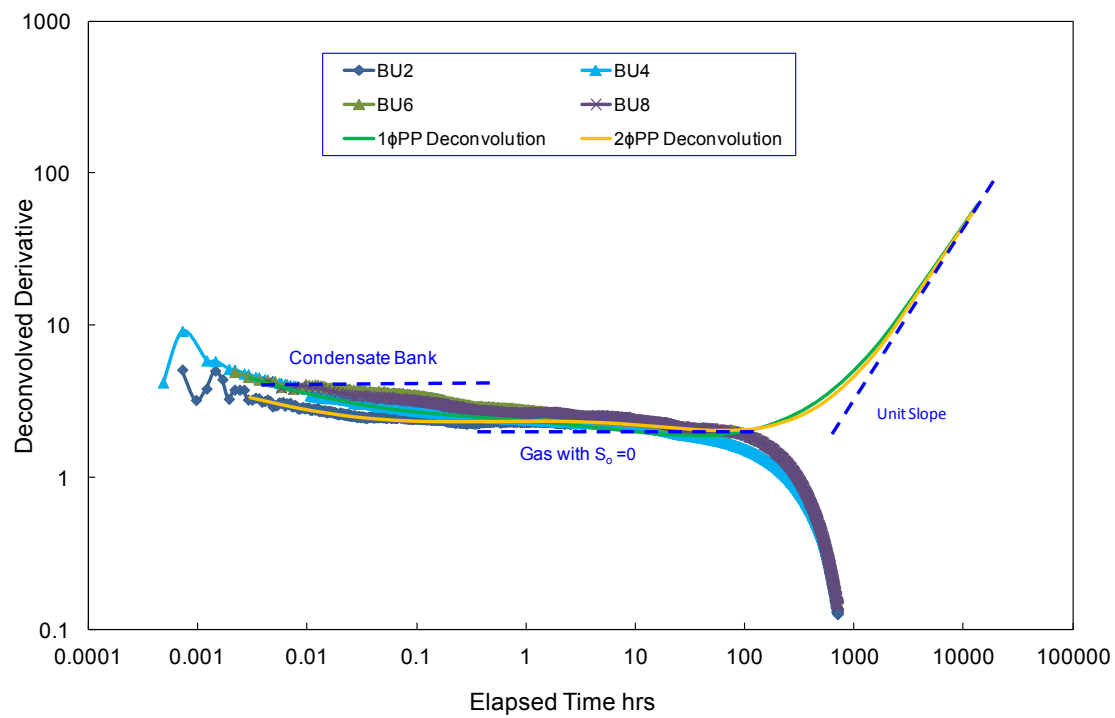


Figure 6.72: Deconvolution of 2φPP for rich gas ($kh=1500\text{mDft}$)

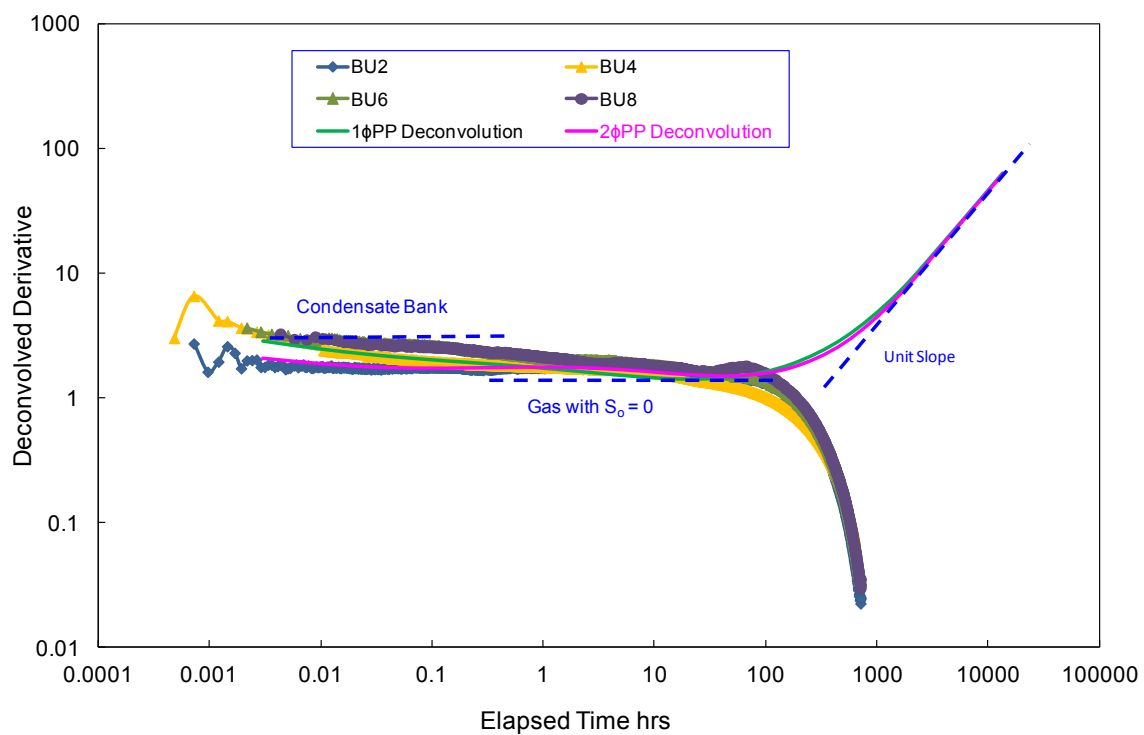


Figure 6.73: Deconvolution of 2φPP for rich gas ($kh=2000\text{mDft}$)

6.7.3 Deconvolution of Pressure and Two-phase pseudo-pressure for Volatile Oil

The deconvolved derivative (Figs. 6.74, 6.75, 6.76 and 6.77) of simulated pressure data for different values of mechanical skin ($s_m = 2$ and 5) and reservoir permeability thickness ($kh = 1500\text{mDft}$ and 2000mDft) show a reduced mobility and pseudo-steady state response at late time indicated by a unit slope even though the data is pseudo-linear because all the drawdown were below bubble point pressure.

The two-phase pseudo-pressure deconvolved derivative (Figs. 6.74, 6.75, 6.76 and 6.77) show a homogeneous behaviour at early time, middle time, and give a unit slope which represents a closed system at late time.

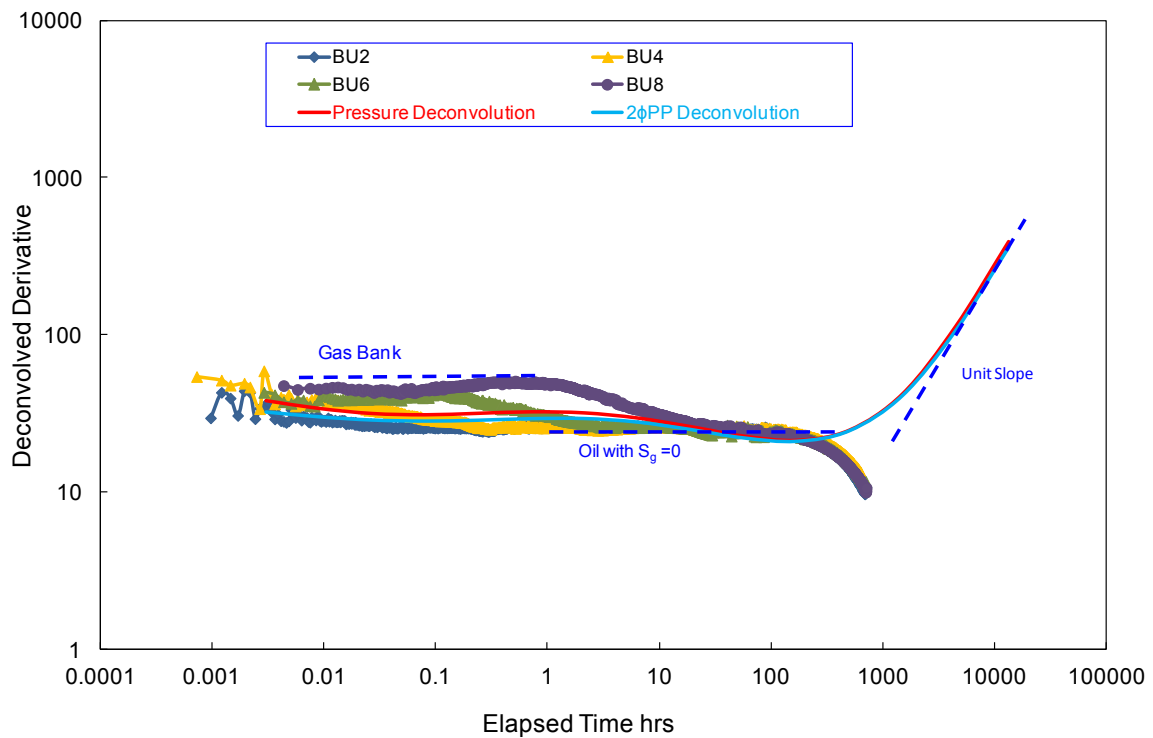


Figure 6.74: Deconvolution of 2φPP for volatile oil (skin=2)

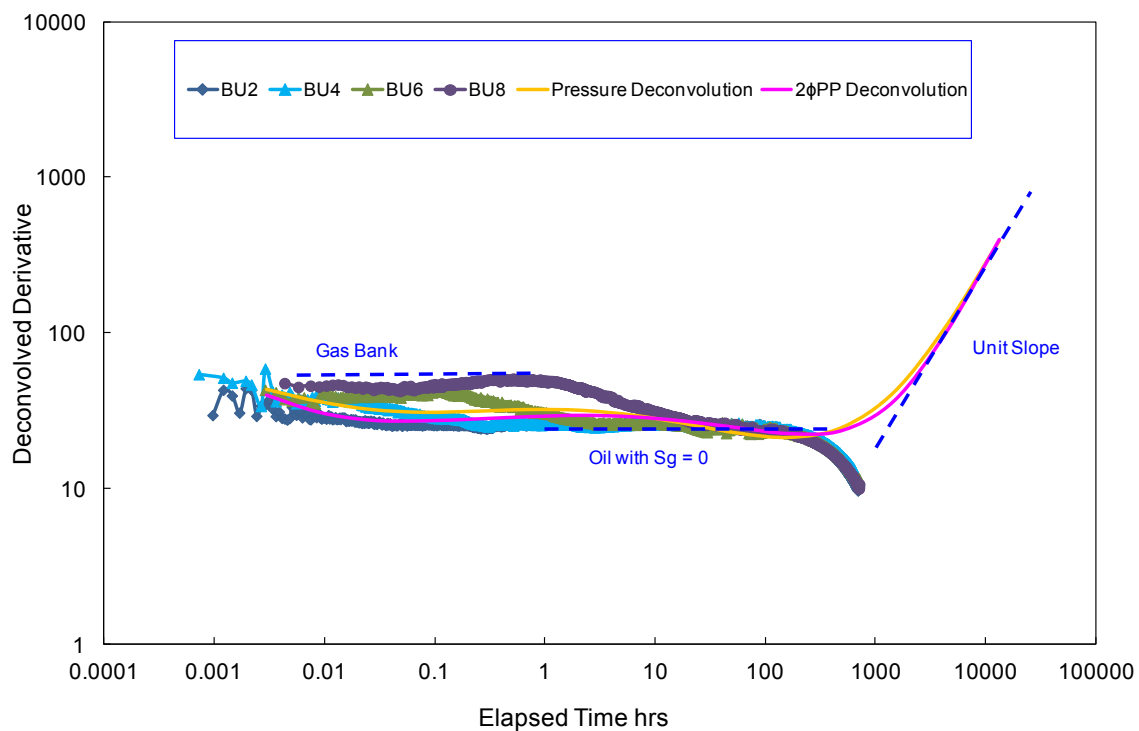


Figure 6.75: Deconvolution of 2 ϕ PP for volatile oil (skin=5)

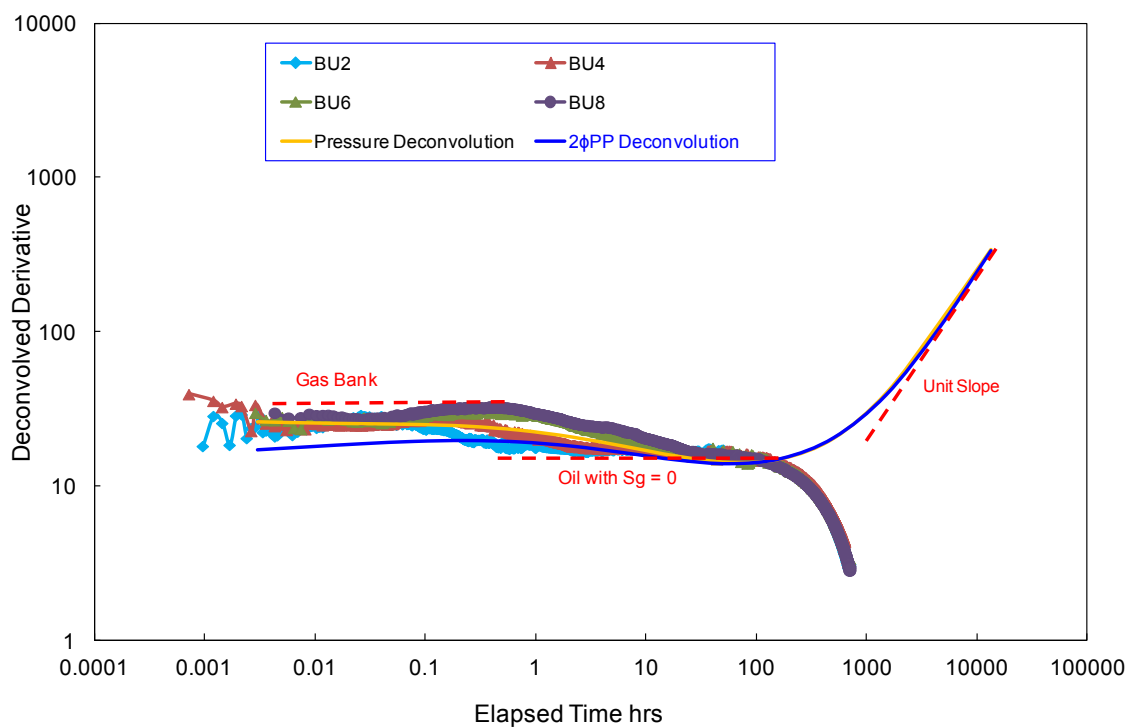


Figure 6.76: Deconvolution of 2 ϕ PP for volatile oil (kh=1500mDft)

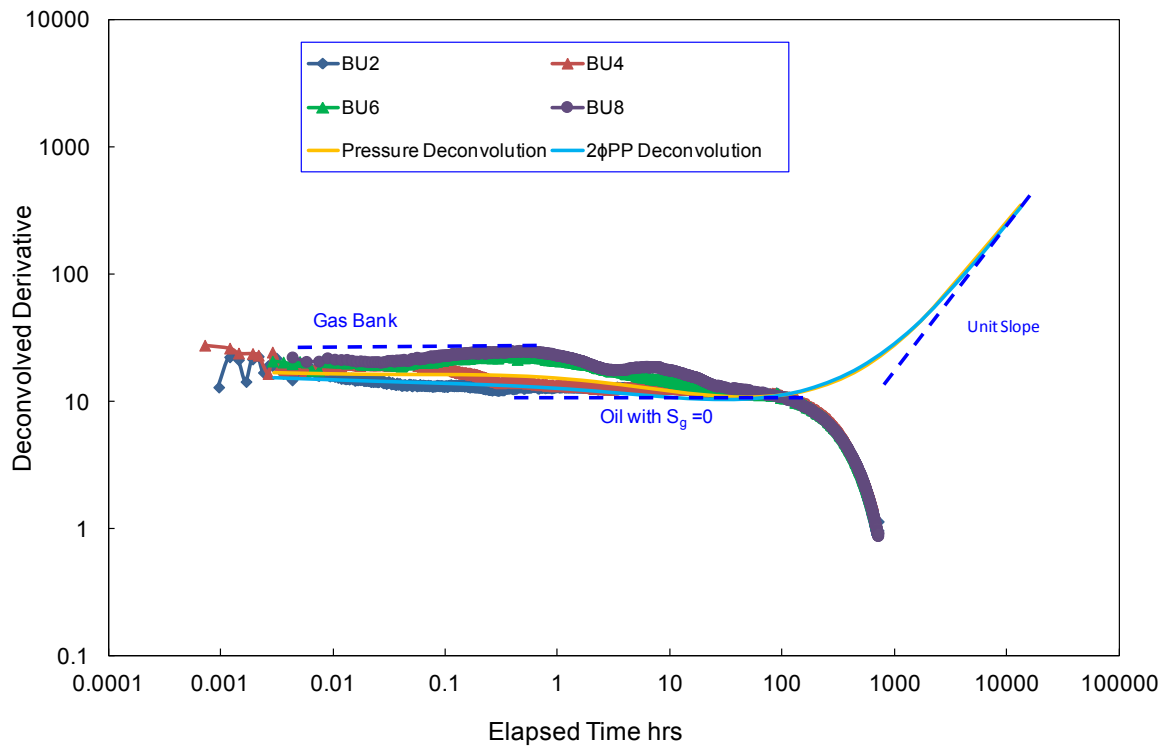


Figure 6.77: Deconvolution of 2φPP for volatile oil (kh=2000mDft)

6.7.4 Summary of Deconvolution of Lean Gas, Rich Gas and Volatile oil data with different Mechanical Skin and Permeability Thickness

1. Deconvolution of lean gas, rich gas and volatile for different values of mechanical skin and permeability thickness give a closed system at late time.
2. Deconvolution of two-phase pseudo-pressure of below saturation pressure is not sensitive to changes in mechanical skin and permeability thickness.

6.8 Deconvolution of Field Data

6.8.1 E-M02 Pa

E-M field is a lean gas condensate field located offshore South Africa. It was discovered in 1984 in water depths of around 328ft. About 6 exploration, appraisal and production wells (E-M1, E-M2, E-M3, E-M4, E-M5 and E-M6) have been drilled on the field till date. E-M field is a shallow marine and fluvio-deltaic sandstone reservoir with complex geology due to extensive faulting, thus, the field is suggested to be vertically and horizontally compartmentalized. Fig. 6.78 shows subdivision of the field in 10 fault bound segments (polygons) and field stratigraphy respectively. Two wide, laterally continuous shale layers within the Zone 3 were identified (Figs. 6.79 and 6.80): Upper

Shale Layer (USL) and Lower Shale Layer (LSL). The USL is 2m thick and separates Zone 2 and Zone 3. The LSL is 6-13m thick and is located within the Zone 3.

Well E-M02Pa is a horizontal well was drilled as a replacement well for the E-M02PZ1 well which was lost in July 2001. It was designed with sub-horizontal producing section, drilled in the central part of the field, parallel to the E-M02PZ1 with the aim of draining hydrocarbons in polygons 5 and 6 (Fig. 6.78). E-M02Pa was drilled in the upper shale layer (Zone 2) of the two-layer lean gas condensate reservoir with 2m thick shale separating Zone 2 and Zone 3 (Fig. 6.80).

The pressure and rate history (Fig. 6.81) for Well EM02Pa includes the DST and production data with series of both drawdown and shut-in over a period of about 8.3 years. E-M02Pa has a dew point pressure of 3465psi, initial reservoir pressure of 3696.75psi and condensate gas ratio of 23stb/MMscf. The reservoir has effective porosity of 0.17 and average permeability of 23mD. The rate normalised log-log plot of pressure change and derivatives (Fig. 6.82) below dew point pressure show an upward shift of the pressure curves and radial composite behaviour of the derivatives due to reduced effective permeability as a result of condensate dropout at the wellbore.

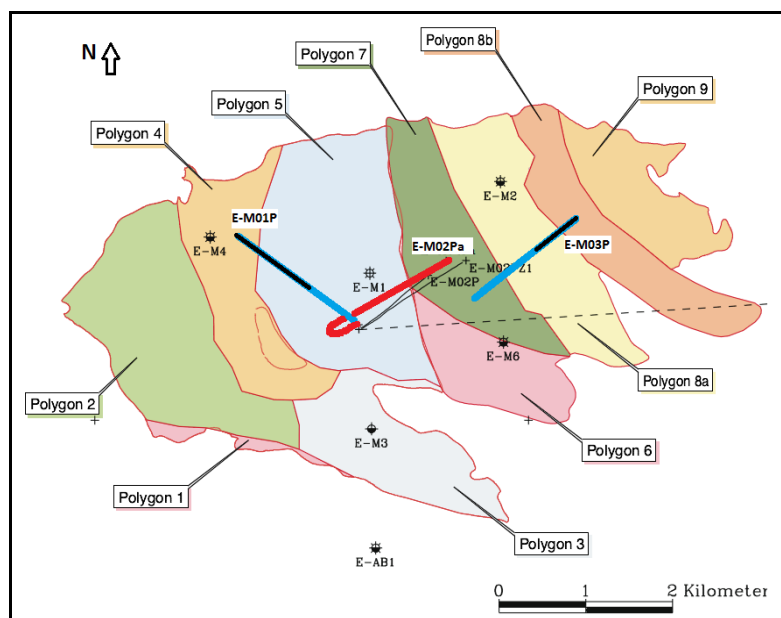


Figure 6.78: E-M field polygon map and three located wells

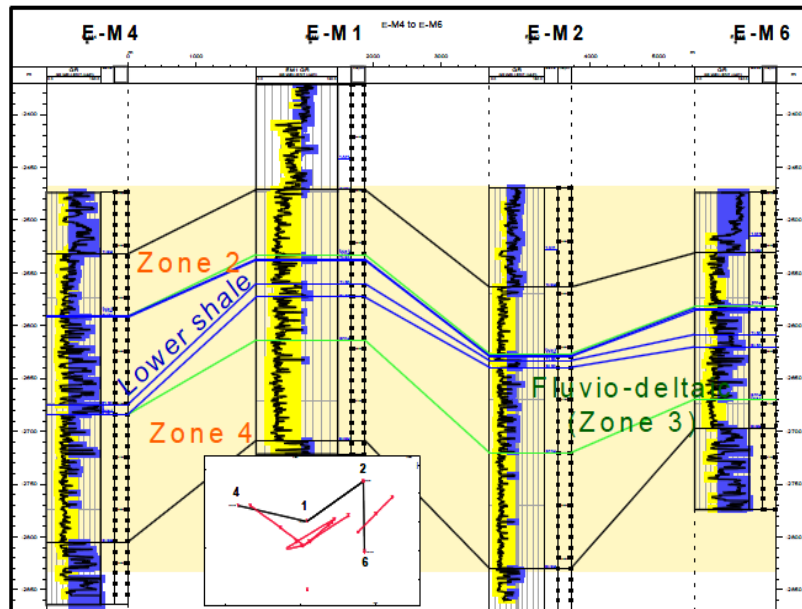


Figure 6.79: Cross section E-M4 to E-M6

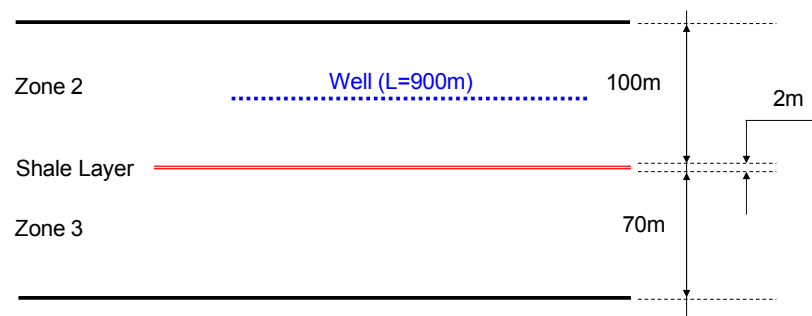


Figure 6.80: Well E-M02Pa schematic (Gringarten, 2010)

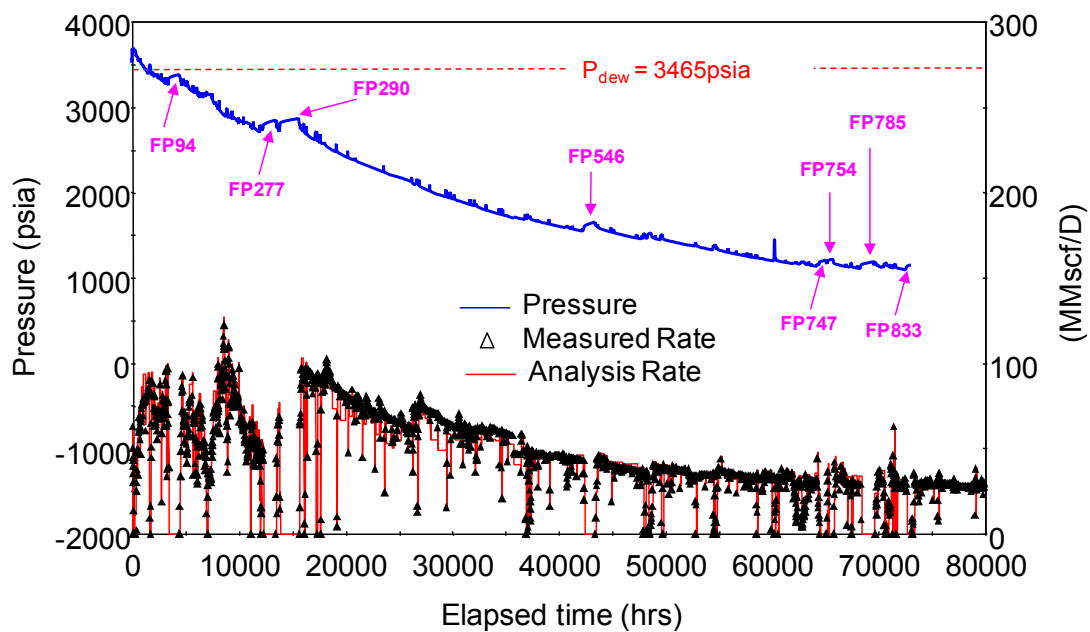


Figure 6.81: Well EM02Pa Pressure and Rate History

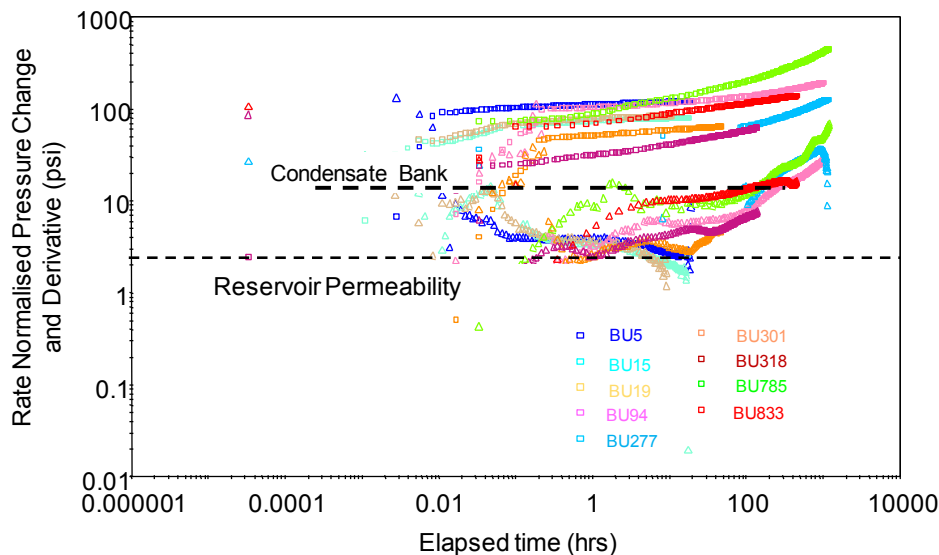


Figure 6.82: Rate-normalized 1ϕ PP log-log plot for E-M02Pa

Deconvolution was carried out by Gringarten (2008; 2010) and Rinas (2011) to identify potential communication between Zone 2 and Zone 3 separated from each other by continuous, laterally extended upper shale layer and established the drainage area of the reservoir. They were able to establish communication between Zone 2 and Zone 3 through upper shale layer. Rinas (2011) incorporates the analysis of data already analysed by Gringarten (2008; 2010) between August, 2005 and November, 2008 and newly acquired data between November, 2008 and May, 2011. Ascertaining communication between Zone 2 and Zone 3 through upper shale layer is very crucial in reservoir management decision on whether to drill a new infill well in Zone 3.

6.8.2 Deconvolution of Single-phase Pseudo-pressure

The initial reservoir pressure 3696.75psia was determined by deconvolving FP 15 and FP 19, the deconvolution of these flow periods give identical deconvolved derivatives (Fig. 6.83) by converging at late times (Gringarten, 2010). Deconvolution was applied to single-phase pseudo-pressure and entire production rate history of Fig. 6.81 in order to estimate the reservoir parameters and understand the geological complexity of Well E-M02Pa most importantly to ascertain whether there is communication between Zone 2 and Zone 3 of the reservoir through the upper shale barrier.

Deconvolution of pressure build-ups (FP5, 15 and 19, and 301) in the early stage of production between 100 and 21200 hours (FP5-301) shows a pseudo-steady state response (unit slope) at late-late times which is an indication that the reservoir boundaries have been reached (Fig. 6.84). However, the deconvolution of production period between 21200 and 73100 hours (FP318-833) merge into a single unit slope straight line which is

shifted to the right when compared to the deconvolved derivatives of early flow period (FP5-301), signifying a recharge from Zone 3 through upper shale layer or increase in reservoir volume. The deviation from the first unit slope occurs between 16100 - 17350 hrs (FP301-318), this was not seen on deconvolved derivatives of individual build-ups but on the deconvolved derivatives combined flow period (Fig. 6.84). Nonetheless, it must be noted that the unit slope from the deconvolution of single-phase pseudo-pressure is not exactly 1 because of the non-linearity of gas flow under severe depletion (Levitan and Wilson, 2010). Thus, a material balance correction suggested by Bourgeois and Wilson (1996) and Levitan and Wilson (2010) was applied to the well test data in section 6.84.

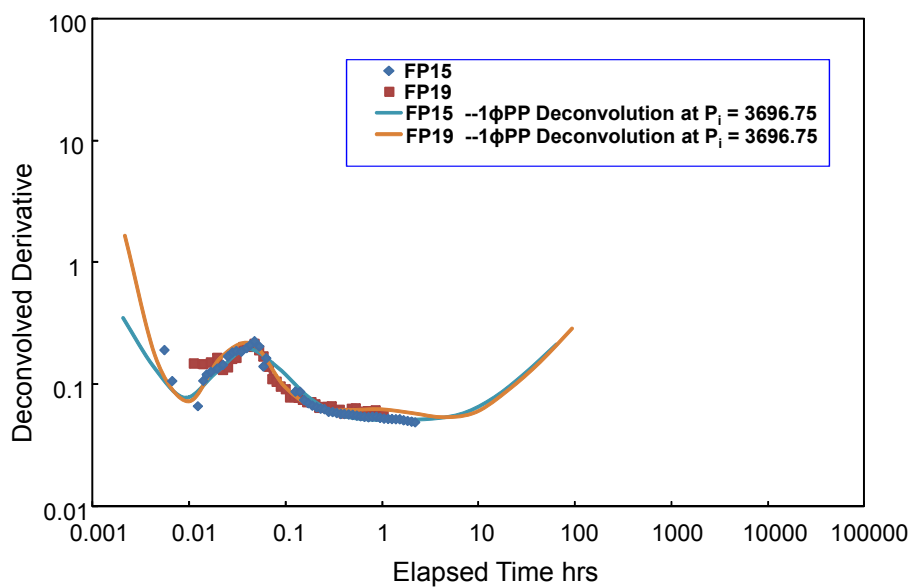


Figure 6.83: Determination of Initial Pressure for Well E-M02Pa (Gringarten, 2010)

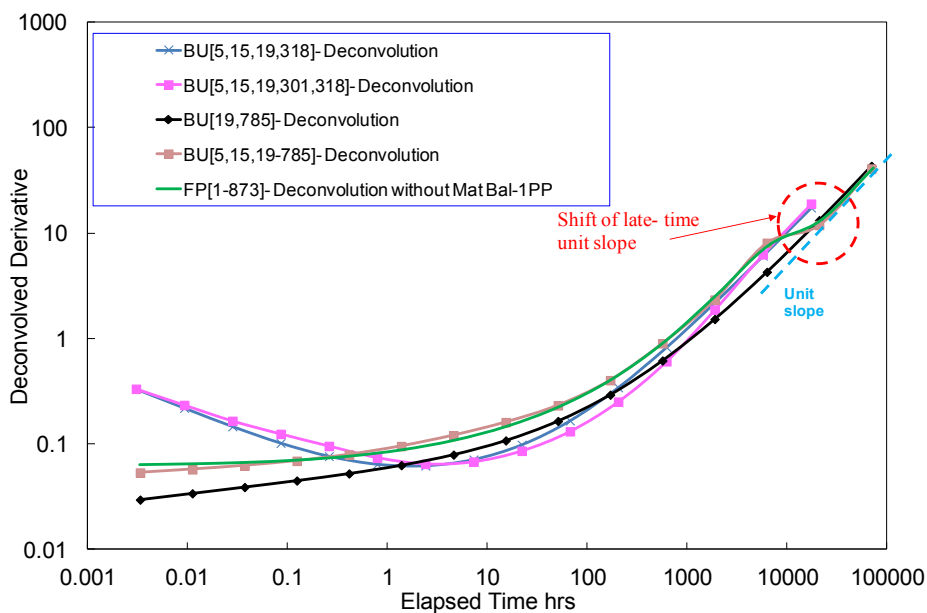


Figure 6.84: Deconvolution of 1φPP Well EM02Pa

6.8.3 Single and Multi-Layer Analysis

Single layer closed reservoir model match (Fig. 6.85) shows that a good match can only be obtained on the entire pressure and rate history until FP290, indicating that the upper shale layer was not permeable before this flow period and there was no communication between Zones 2 and 3. Similarly, a good match could not be obtained for unit rate drawdown with single layer closed reservoir model match (Fig. 6.86), indicating that the upper shale layer became permeable during production. Thus, allowing communication between Zones 2 and 3.

However, a good match was obtained with multi-layer analysis for flow periods after FP290 (Figs. 6.87 and 6.88). The pressure match was obtained with shale layer vertical permeability of around 10^{-4} mD.

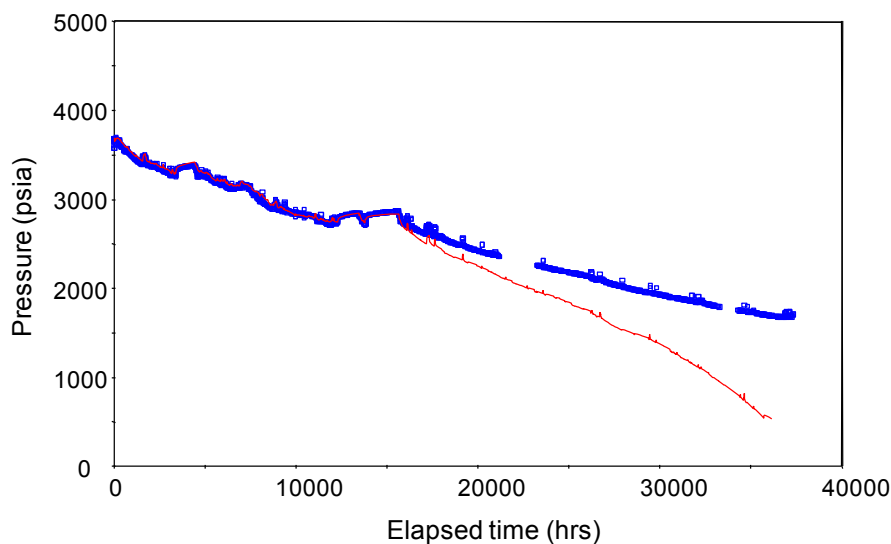


Figure 6.85: Single layer Analysis of entire pressure history of Well E-M02Pa

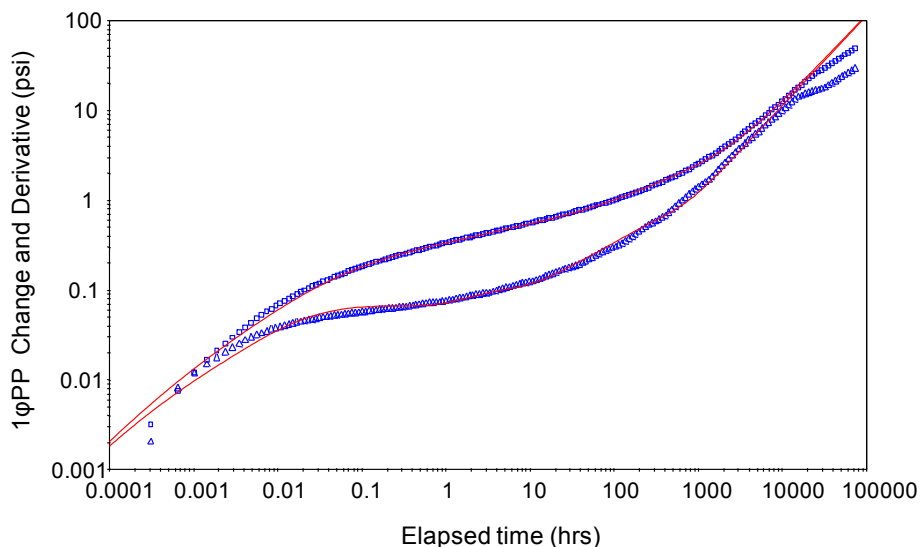


Figure 6.86: Single layer Analysis of Unit Rate Drawdown of Well E-M02Pa

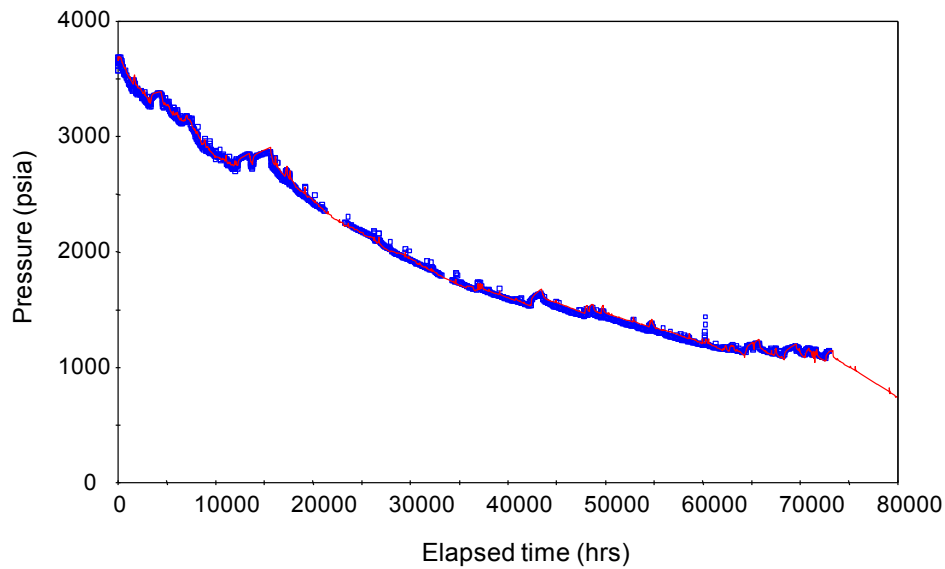


Figure 6.87: Multilayer Analysis of entire pressure history of Well E-M02Pa

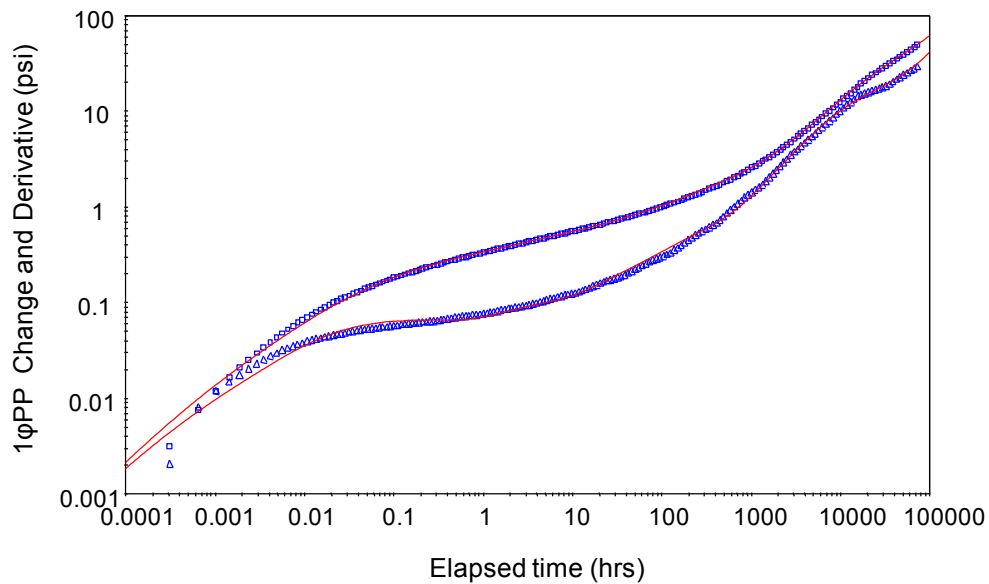


Figure 6.88: Multilayer Analysis of Unit Rate Drawdown of Well E-M02Pa

6.8.4 Deconvolution of Single-phase Pseudo-pressure with Material Balance Correction

Material balance correction (Eq. 6.3) was applied to the pressure and rate data of Well E-M02Pa to correct non-linearity due to changes in gas properties (c_t and μ_g) because of reservoir depletion. Fig. 6.89 shows the plot of pressure and rate history for Well E-M02Pa with and without material balance correction. The material balance correction (Fig. 6.89) was calculated with a single layer (layer 2) thickness at the beginning of production history. However, the layer thickness was changed to the

thickness of layers 2 and 3 (Fig. 6.80) when the recharge from lower layer was noticed as shown in Figs. 6.85, 6.87 and 6.89.

The deconvolved derivative (Fig. 6.90) of pressure build-ups of single-phase pseudo-pressure with material balance correction give exactly a unit slope at late time, which is an indication of closed reservoir. The unit slope is shifted to the right for FP318-833 when compared to the deconvolved derivatives of early flow period (FP5-301), indicating a recharge from Zone 3 through upper shale layer or increase in reservoir volume.

The deconvolution of two-phase pseudo-pressure with material balance correction is not considered under material balance correction because the constant-rate drawdown response from the deconvolved derivative of material balance correction (Fig. 6.90) represents the pressure behaviour of a different reservoir or the same reservoir but filled with different gas which has constant compressibility and viscosity. The fluid data available is completely different to what the fluid data of the reservoir will be after material balance correction.

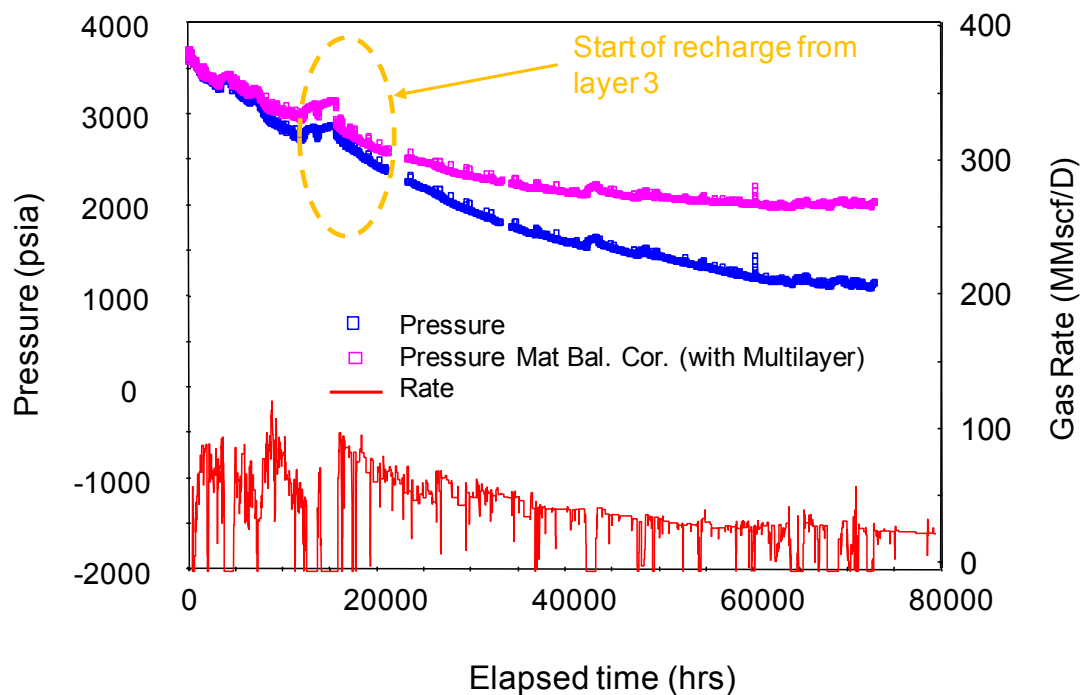


Figure 6.89: Pressure and rate history for rich gas well E-M02Pa with and without material balance correction

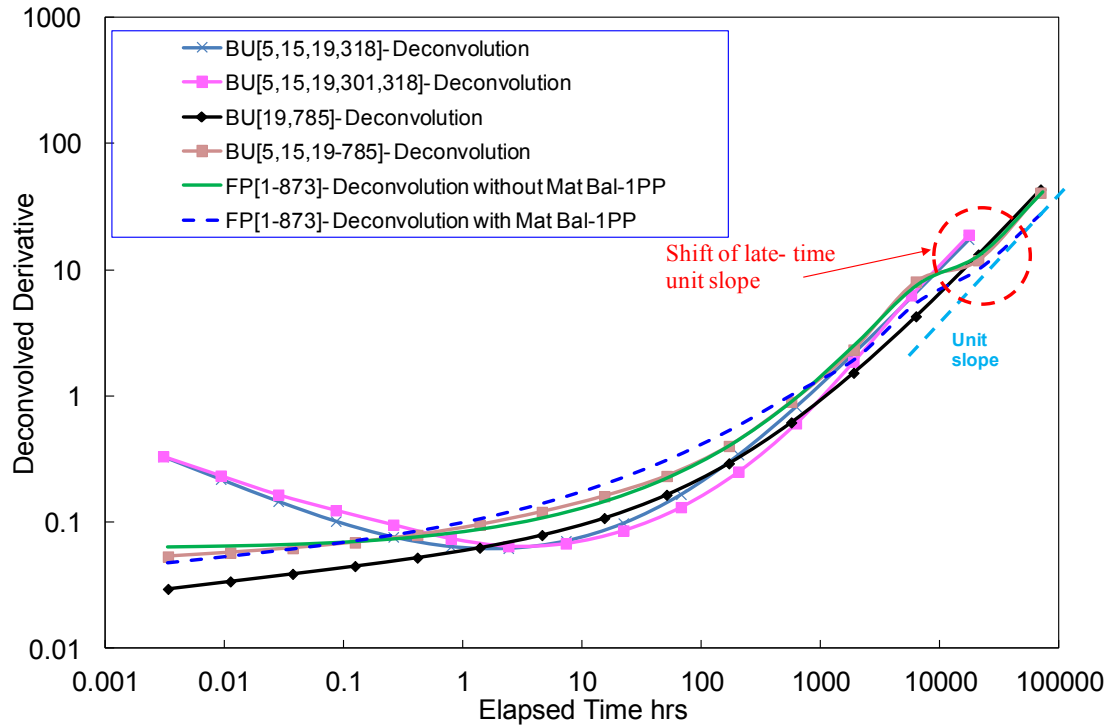


Figure 6.90: Deconvolution of 1 ϕ PP of E-M02Pa with and without material balance correction

6.8.5 Deconvolution of Two-phase Pseudo-pressure

The E-M02Pa data was converted to two-phase pseudo-pressure (Fig. 6.91) using steps in section 2.4 so as to linearize the diffusivity equation by removing the fluid induced composite behaviour in Well E-M02Pa data. Fig. 6.91 shows the plot of pressure, two-phase pseudo-pressure and rate history of Well E-M02Pa. The gas-oil relative permeability curves (Fig. 6.92) were selected from the one that provided the best match of full field compositional simulation model of Well E-M02Pa. The relative permeability curves (Fig. 6.92) have critical gas saturation (S_{gc}) of 0.0, critical oil saturation of 0.2, gas saturation of 0.6, end point gas relative permeability (k_{rg}^{max}) of 0.935, end point oil relative permeability (k_{ro}^{max}) of 0.75, and connate water saturation (S_{wc}) of 0.4.

The rate normalised log-log plot (Fig. 6.93) of two-phase pseudo-pressure shows that the two-phase pseudo-pressure transformed the fluid induced radial composite behaviour below dew point pressure to homogeneous behaviour with the derivatives stabilising at almost same level as the derivatives above dew point pressure.

Deconvolution was applied to two-phase pseudo-pressure data in Fig. 6.93 in order to ascertain the shift in unit slope close boundary response is due to communication between Zone 2 and Zone 3 of the reservoir through the upper shale barrier (Fig. 6.80) not as result of formation of condensate bank at the wellbore and in the reservoir.

The two-phase pseudo pressure deconvolved derivative (Fig. 6.94) shows a response similar to that of single phase pseudo pressure at late time. It gives a unit slope (closed system) at the early stage of production from FP5-301 which is shifted to another unit slope on the right from FP318-833. This confirms that there is a recharge from Zone 3 to 2 through upper shale layer or increase in reservoir volume. The pressure data has been linearized by the two phase pseudo pressure; thus, the shift in the boundary response cannot be due to non-linearity of the pressure data as result of condensate bank formation at the wellbore.

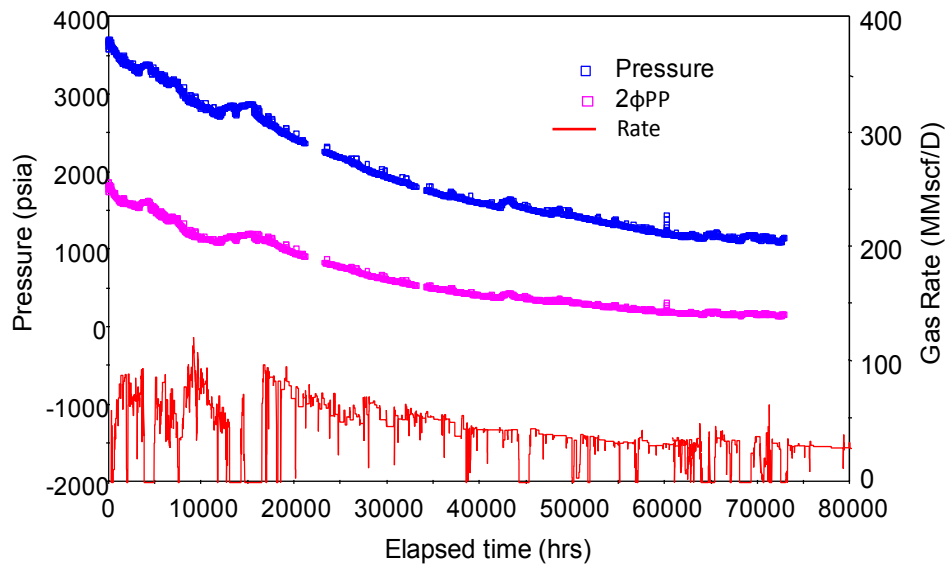


Figure 6.91: Pressure, 2 ϕ PP and rate history for E-M02Pa

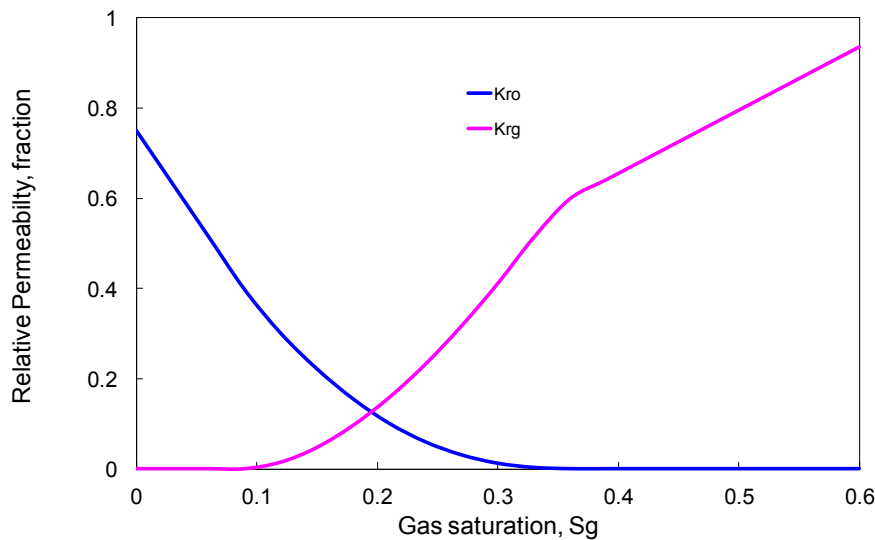


Figure 6.92: Gas-Oil relative permeability curves for E-M02Pa

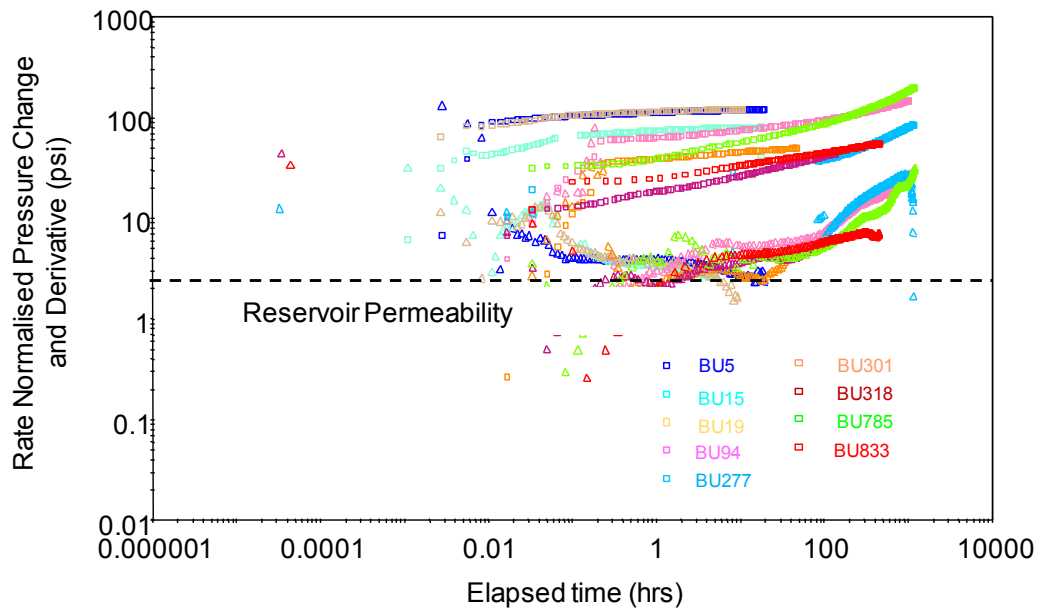


Figure 6.93: Rate-normalized 2φPP log-log plot for EM2

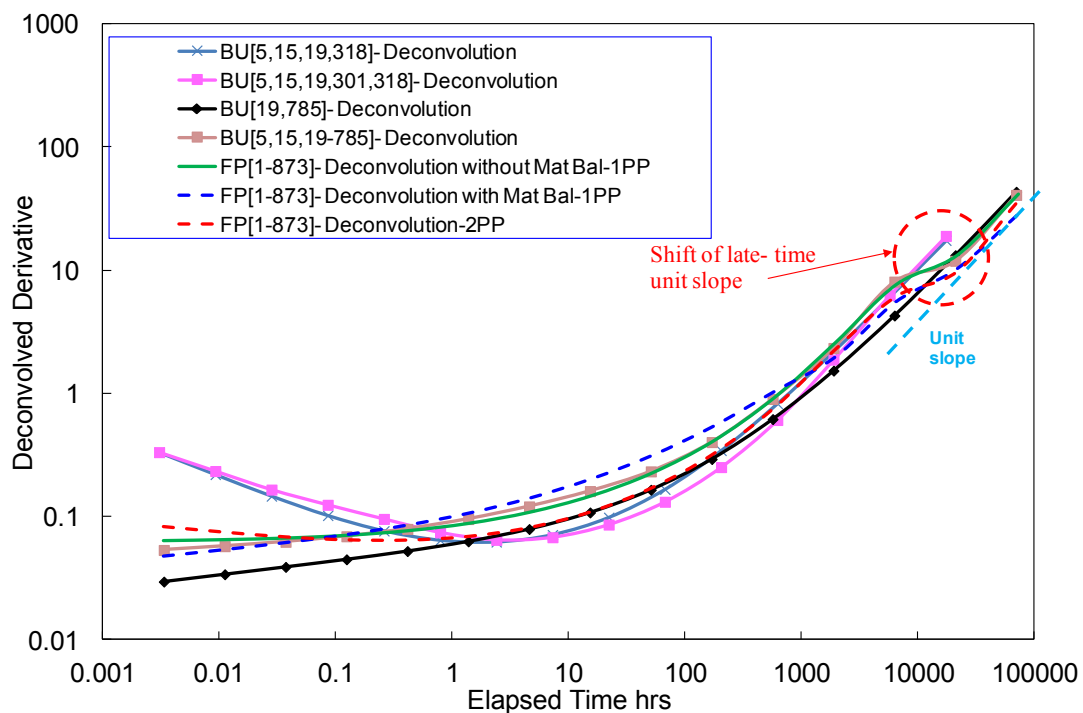


Figure 6.94: Deconvolution of 1φPP (with and without material balance correction) and 2φPP pressure for E-M02Pa

6.8.6 Verification of deconvolution of Well E-M02Pa

The reproduction of actual pressure history from the deconvolved derivatives is a vital means of verifying deconvolution results. The plots of measured pressure, material balance corrected pressure and two-phase pseudo press with convolved pressure for well E-M02Pa are shown in Figs. 6.95, 6.96 and 6.97. A satisfactory match was obtained with maximum error of less than 5% in build-up and drawdowns (Figs. 6.95, 6.96 and 6.97),

indicating that different flow periods give a converging derivatives and there was a negligible late time oscillations on the deconvolved derivatives.

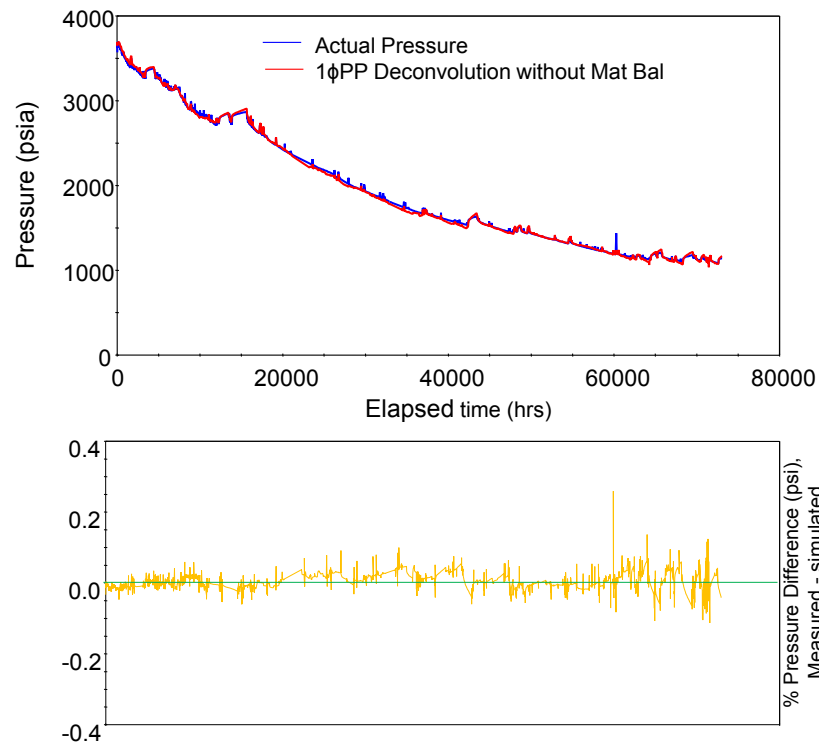


Figure 6.95: Pressure history match and difference between measured and convolved pressure data for Well EM02Pa (without material balance correction)

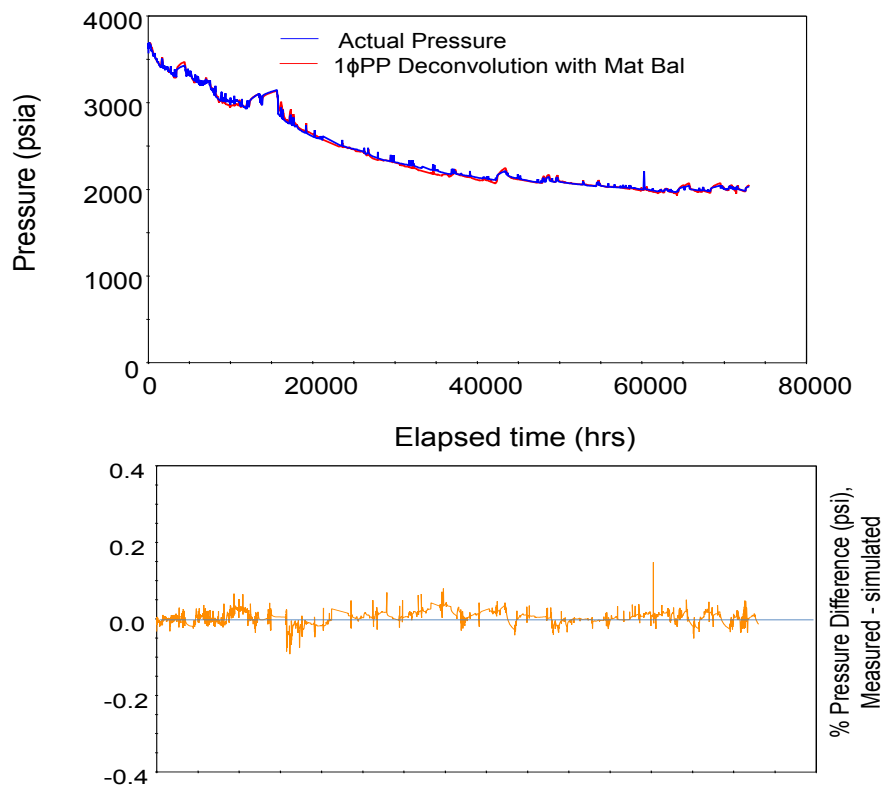


Figure 6.96: Pressure history match and difference between measured and convolved pressure data for Well EM02Pa (with material balance correction)

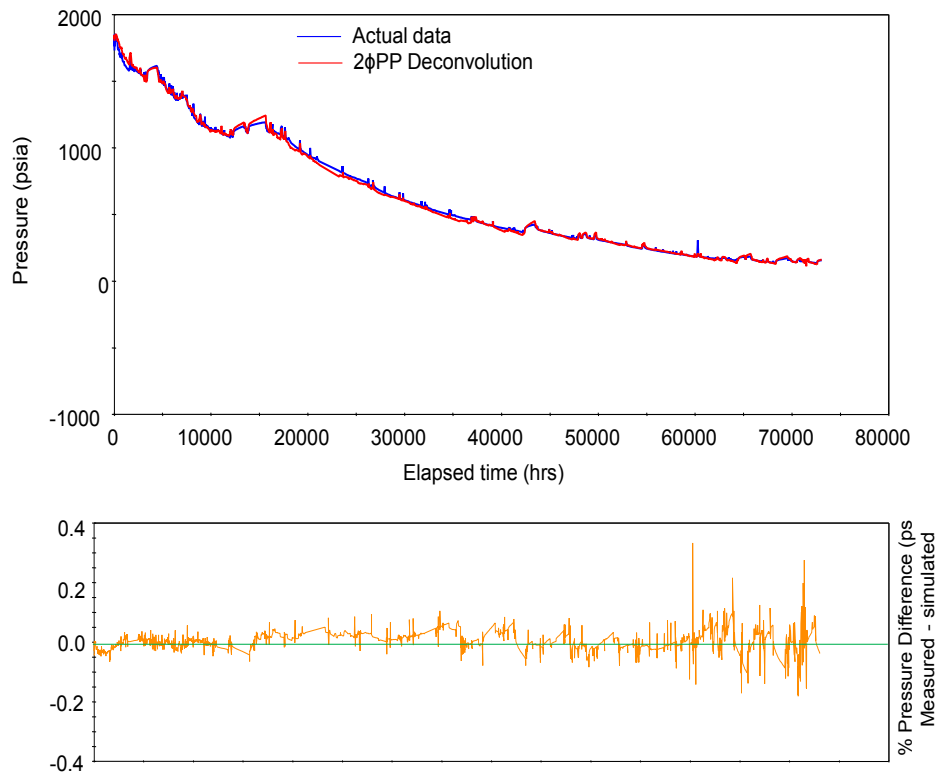


Figure 6.97: 2 ϕ PP history match and difference between measured and convolved pressure data for Well EM02Pa

6.8.7 Summary of Deconvolution of Well E-M02Pa

1. The unit slope from the deconvolution of single-phase pseudo-pressure without material balance is not exactly 1 because of the non-linearity of gas flow under severe depletion but it is close enough to 1 to indicate that reservoir boundaries have been reached.
2. The deconvolved derivative of single-phase pseudo-pressure with material balance correction gives exactly a unit slope at late time for E-M02Pa lean gas condensate.
3. Deconvolution of single-phase pseudo-pressure and two-phase pseudo-pressure give similar late time response
4. Deconvolved derivative of single-phase pseudo-pressure and two-phase pseudo-pressure, single and multilayer analyses were used successfully to detect and confirm recharge between layers of a multi-layered reservoir.

6.9 MTG

This is a rich gas condensate reservoir described in section 4.10.2.

6.9.1 Deconvolution of Single-phase Pseudo-pressure without Material Balance Correction

Fig. 6.98 shows an upward shift of the pressure curves and radial composite behaviour of the derivatives due to reduced effective permeability as a result of condensate dropout at the wellbore.

Deconvolution was applied to the single-phase pseudo-pressure of the pressure and rate histories (Fig. 6.99) in order to estimate reservoir parameters and understand the geological complexity of the reservoir. Deconvolution transformed variable rate pressure data into a constant rate initial drawdown with duration equal to the total duration of 3.3 years. The late time derivative response (Fig. 6.99) shows a region of reduced mobility followed by pseudo-steady state response (unit slope) at late-late time, when the reservoir limits were reached.

The deconvolved derivative (Fig. 6.99) may not be theoretically correct because it did not give exactly a unit slope at late-late time. This could be due to non-linear effects such as interference as a result of production from other wells and changes in gas compressibility and viscosity. 5164psia determined from wireline formation tester measurement was used as the initial pressure for the single-phase pseudo pressure deconvolution.

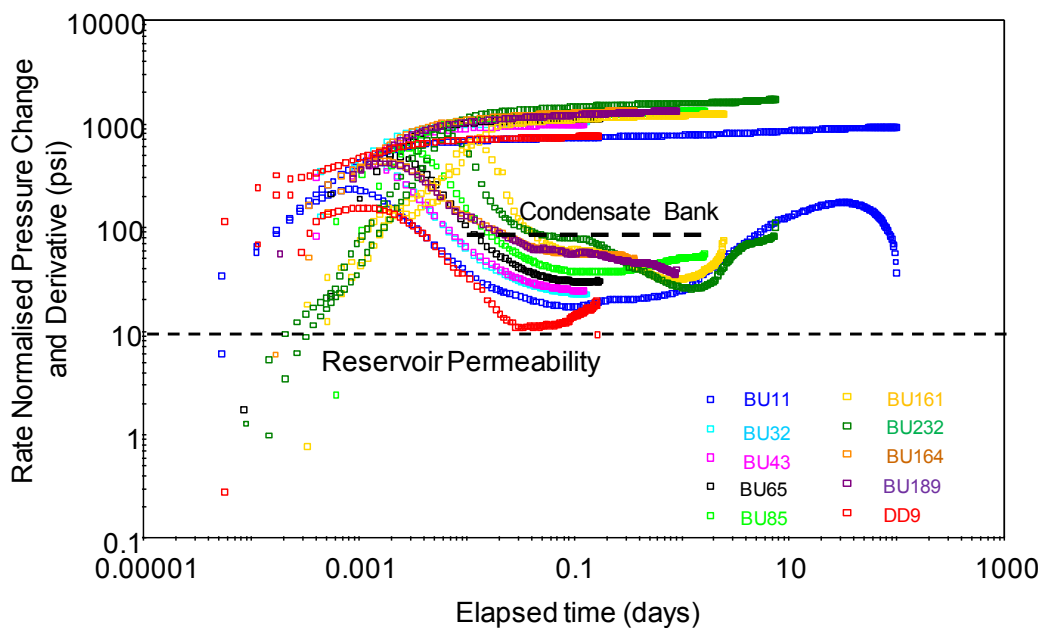


Figure 6.98: Rate-normalized 1 ϕ PP log-log plot for MTG

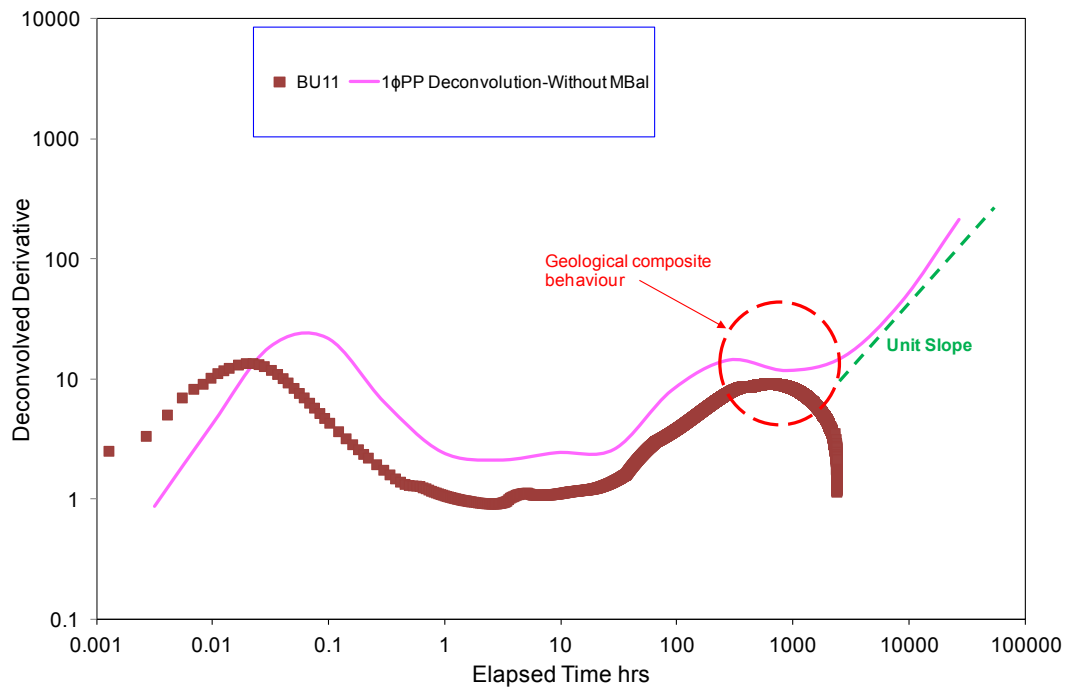


Figure 6.99: Deconvolution of 1 ϕ PP for MTG without material balance correction

6.9.2 Deconvolution of Single-phase Pseudo-pressure with Material Balance Correction

Material balance correction (Eq. 6.3) was applied to the pressure and rate data of MTG shown in Fig. 4.76 to correct non-linear effects due to severe depletion of the well and changes in gas properties such as total compressibility and viscosity. Fig. 6.100 shows the plot of pressure history for MTG well with and without material balance correction.

Fig. 6.101 shows the deconvolved derivative for pressure and rate data of MTG with and without material balance correction. The deconvolved derivative for with material balance correction gives exactly a unit-slope at late-late time. Deconvolution of two-phase pseudo-pressure with material balance correction is not considered for MTG since the deconvolved derivative from material balance correction (Fig. 6.101) describes the pressure behaviour of a different reservoir or the same reservoir but filled with different gas that has constant compressibility and viscosity with respect to pressure change.

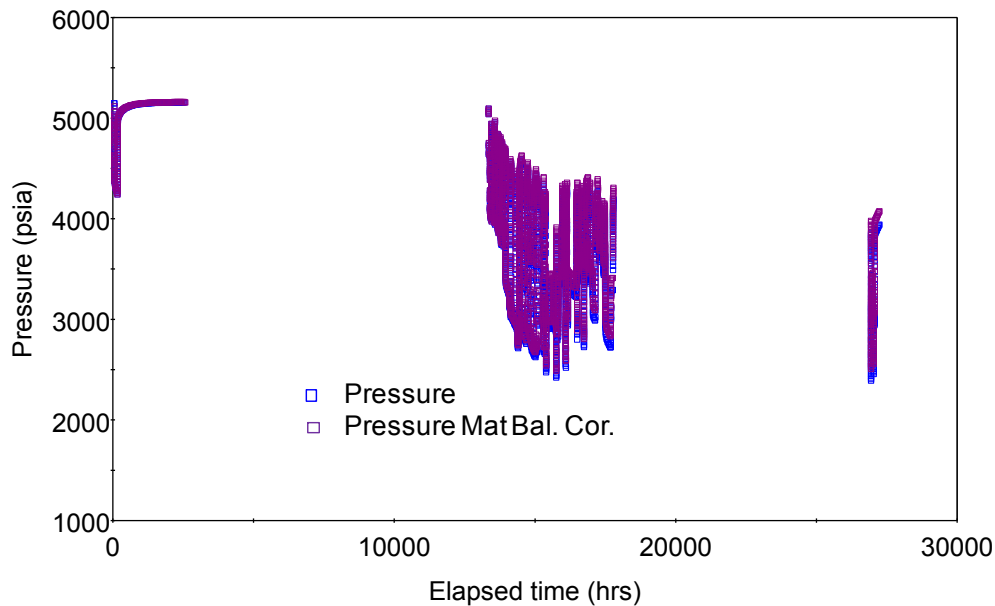


Figure 6.100: Pressure and rate history for rich gas well MTG with and without material balance correction

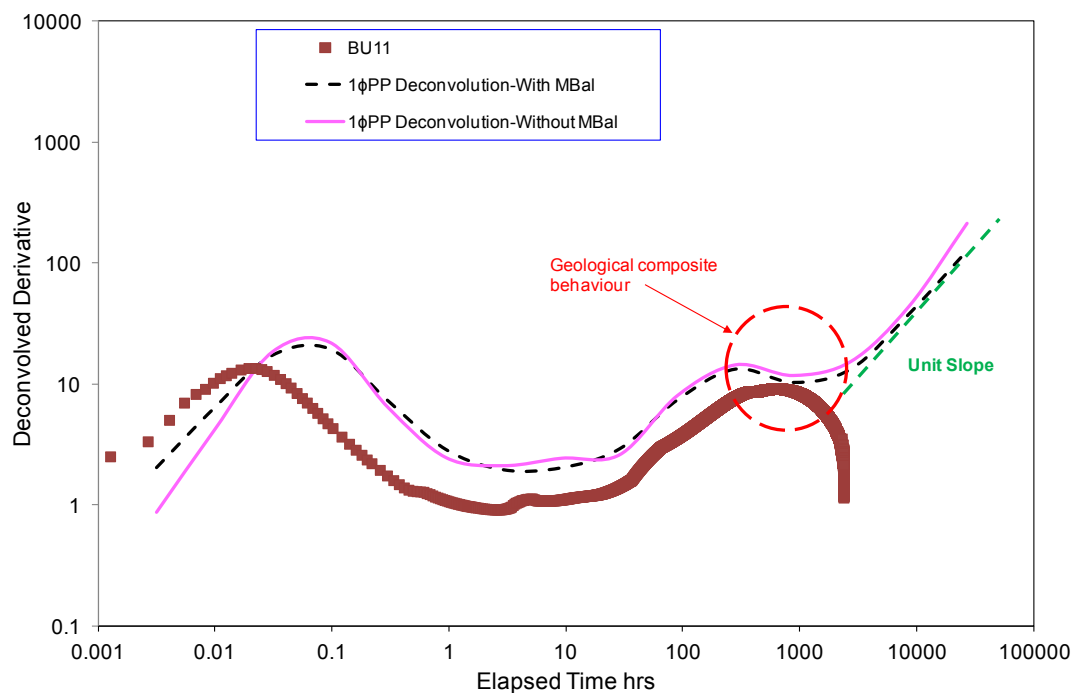


Figure 6.101: Deconvolution of 1 ϕ PP for MTG with and without material balance correction

6.9.3 Deconvolution of Two-phase Pseudo-pressure

The MTG data was converted to two-phase pseudo-pressures using procedure in section 2.4. The plot of pressure history, two-phase pseudo-pressure for MTG is shown in Fig. 6.102. The relative permeability curves (Fig. 4.77) were used for the two-phase pseudo-pressure calculation. The rate normalised log-log plot of two-phase pseudo-pressure derivatives is shown in Fig. 6.103.

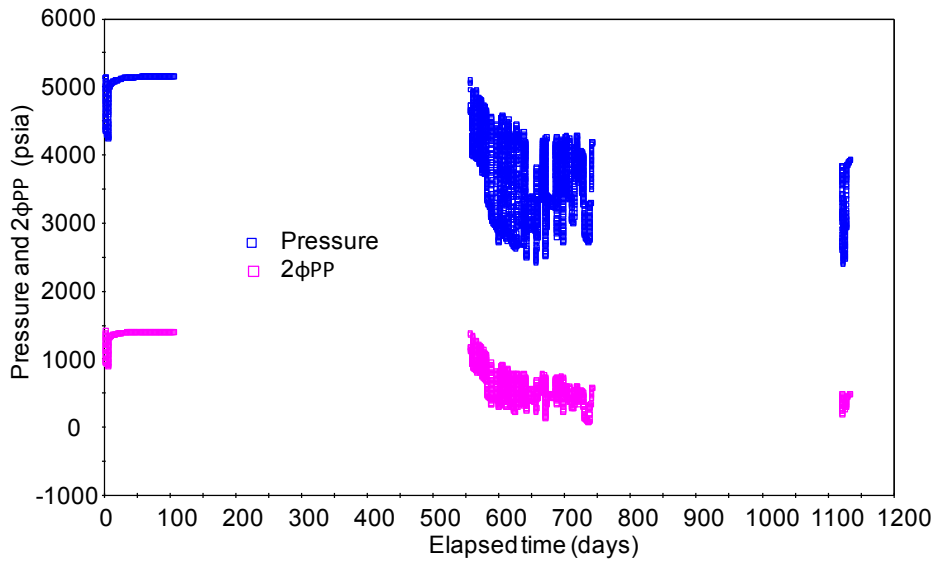


Figure 6.102: Pressure and $2\phi_{PP}$ History for MTG

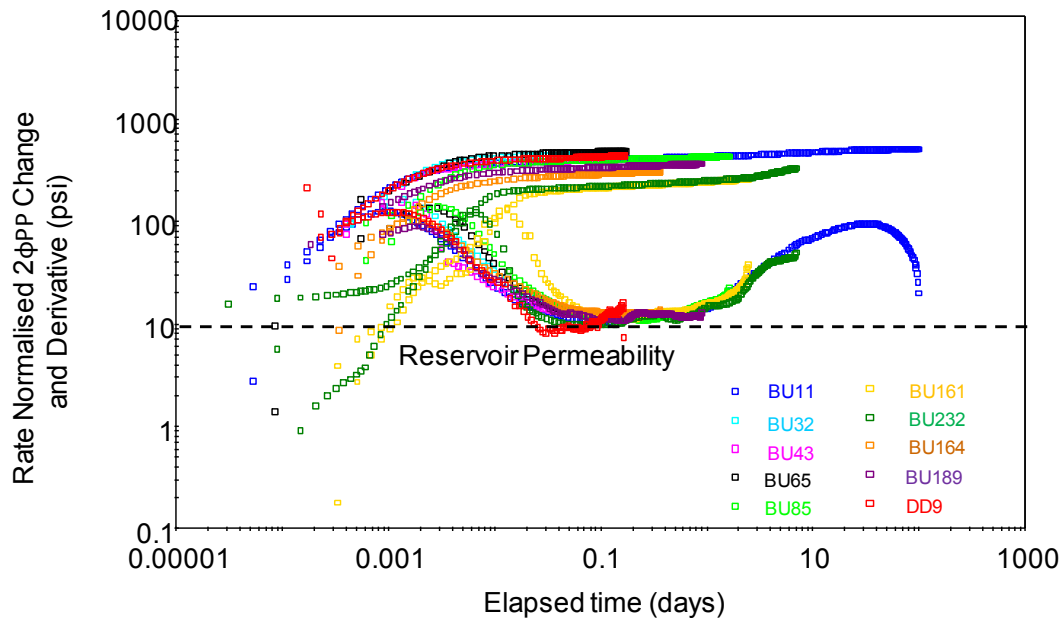


Figure 6.103: Rate-normalized $2\phi_{PP}$ log-log plot for MTG

The deconvolved derivative (Fig. 6.104) shows a homogeneous behaviour at early time, middle time, and gives a unit slope which represents a closed system at late time. However, the geological composite behaviour which is due to changes in storativity and mobility of geological features at the middle time to late time before late-late time is less visible.

Although, the MTG data is non-linear as result of condensate bank formation; the deconvolved derivative of single-phase pseudo-pressure with and without material balance correction as well as two-phase pseudo-pressure (Fig. 6.104) give a similar deconvolved derivatives. Hence, the deconvolved derivative of pseudo-linear single-

phase pseudo-pressure without material balance correction is a good method of estimating the reservoir behaviour and geometry because it gives a unit slope that is very close to 1.

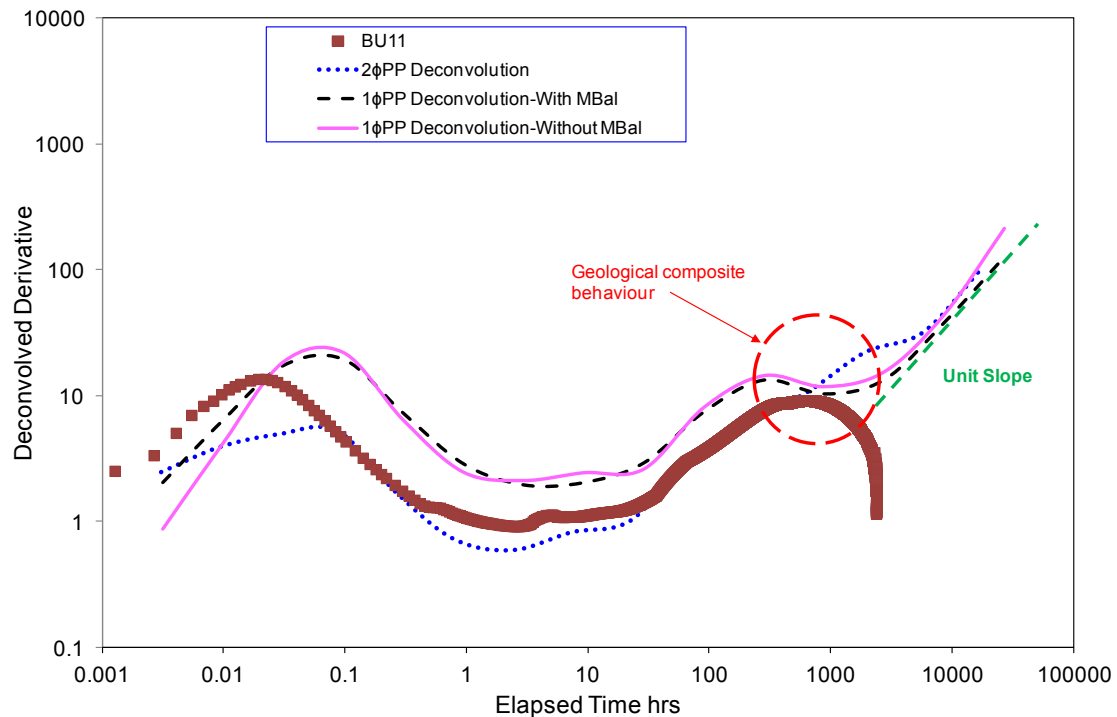


Figure 6.104: Deconvolution of 1 ϕ PP (with and without material balance correction) and 2 ϕ PP for MTG

6.9.4 Summary of Deconvolution of MTG

The deconvolved derivatives of single-phase pseudo-pressure with and without material balance correction as well as two-phase pseudo-pressure give a similar late time response. However, deconvolved derivative with material balance correction give exactly a unit slope at late time.

6.10 Volatile oil example (VO)

This is a volatile oil reservoir described in section 4.10.3. The rate-normalized log-log plot for well W-15 is shown in Fig. 6.105, it shows an upward shift of the pressure curves and radial composite behaviour of the derivatives due to reduced effective permeability as a result of formation of gas bank at the wellbore.

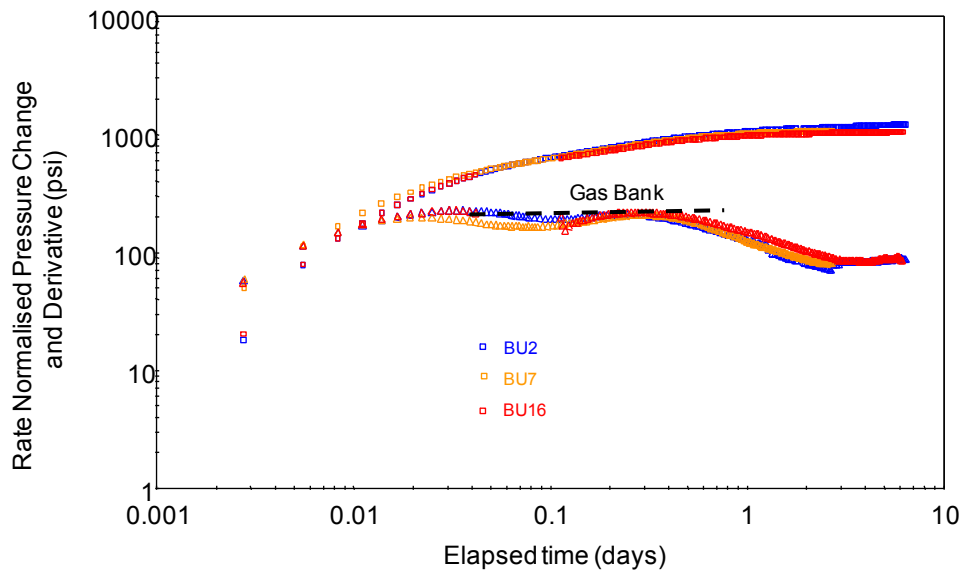


Figure 6.105: Rate-normalized Pressure log-log plot for Volatile Oil

6.10.1 Deconvolution of Pressure Data

The build-up data of Well-15 was deconvolved in order to evaluate the reservoir geometry and diagnose the late time response on the deconvolved derivatives. The deconvolved derivative (Fig. 6.106) gives a radial composite behaviour and a half-unit slope at late time indicating a channel boundary. The well test interpretation model is a well with wellbore storage and skin, radial composite behaviour in an open rectangular reservoir (i.e. a channel bounded on one side; Sanni, 2008). The deconvolution was constrained by an initial pressure of 4076psia.

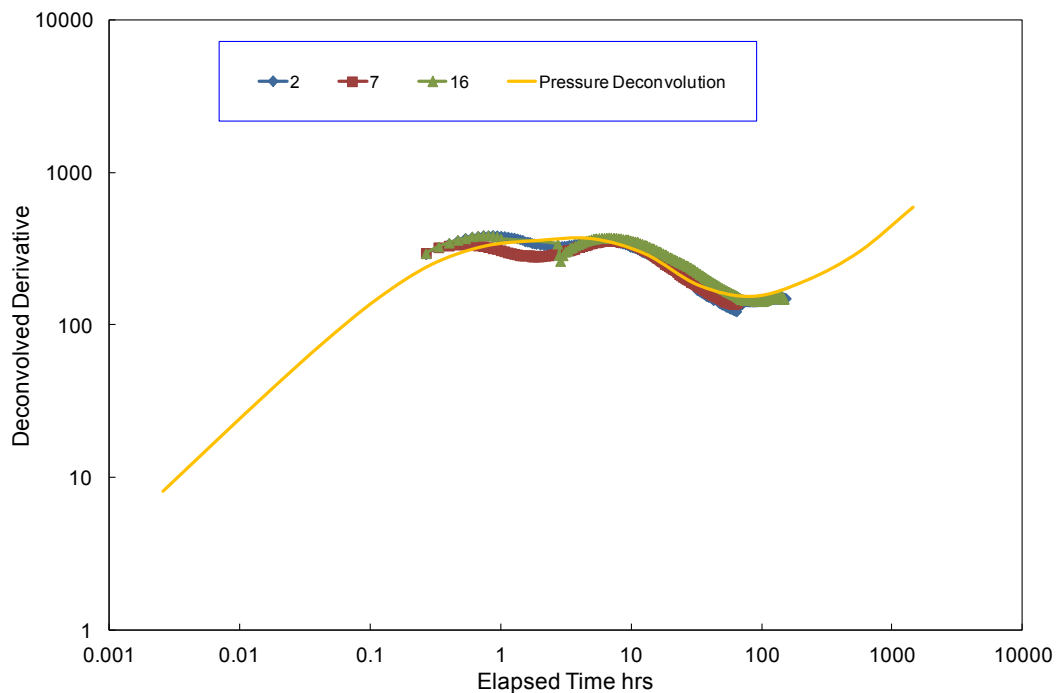


Figure 6.106: Deconvolution of pressure data for volatile oil

6.10.2 Deconvolution Two-phase Pseudo-pressure

Two-phase pseudo-pressure of DST-Well-15 (Fig. 6.107) was calculated with high capillary number and non-Darcy effects using the methodology specified in section 2.4. The relative permeability curves (Fig. 4.81) were used for the two-phase pseudo-pressure calculation. The rate normalised log-log plots for two-phase pseudo-pressure for Well-15 is shown in Fig. 6.108.

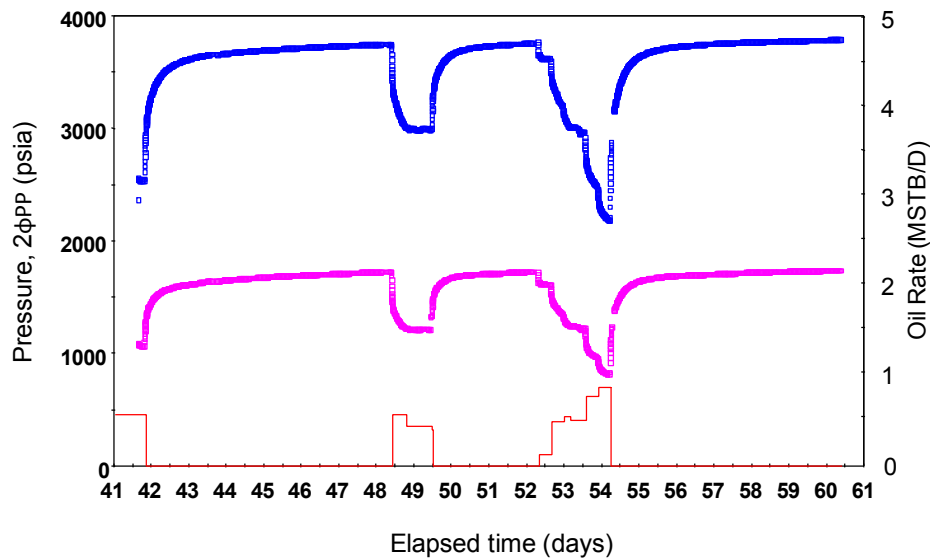


Figure 6.107: Pressure, 2φPP and rate history for Volatile Oil

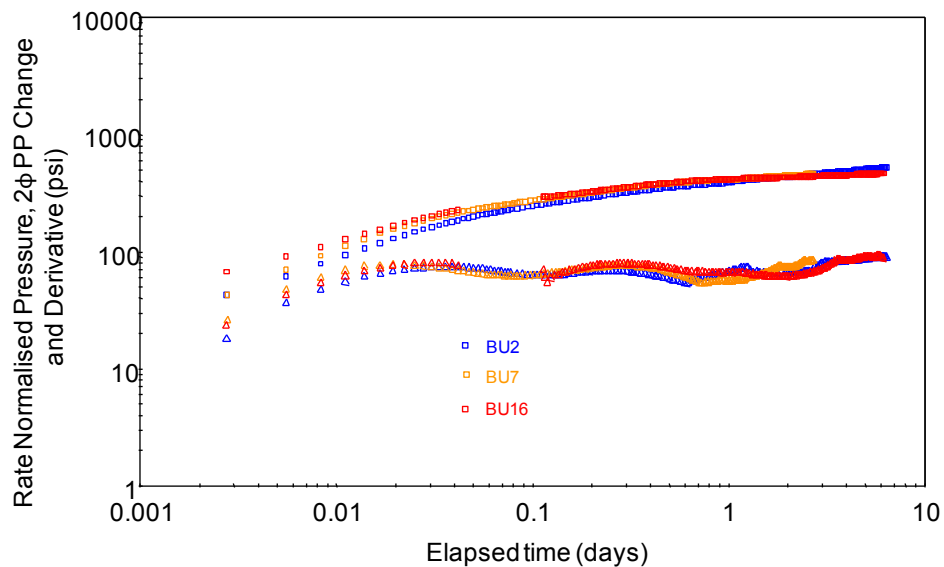


Figure 6.108: Rate-normalized 2φPP log-log plot for Volatile Oil

The deconvolved derivative (Fig. 6.109) exhibit homogeneous behaviour and a half-unit slope at late time which represents a channel boundary. Fig. 6.109 shows that the pressure and two-phase pseudo-pressure deconvolved derivatives are the same at late time (open rectangle). This validates the use of the deconvolution of pressure data below the bubble point pressure for extraction the reservoir geometry.

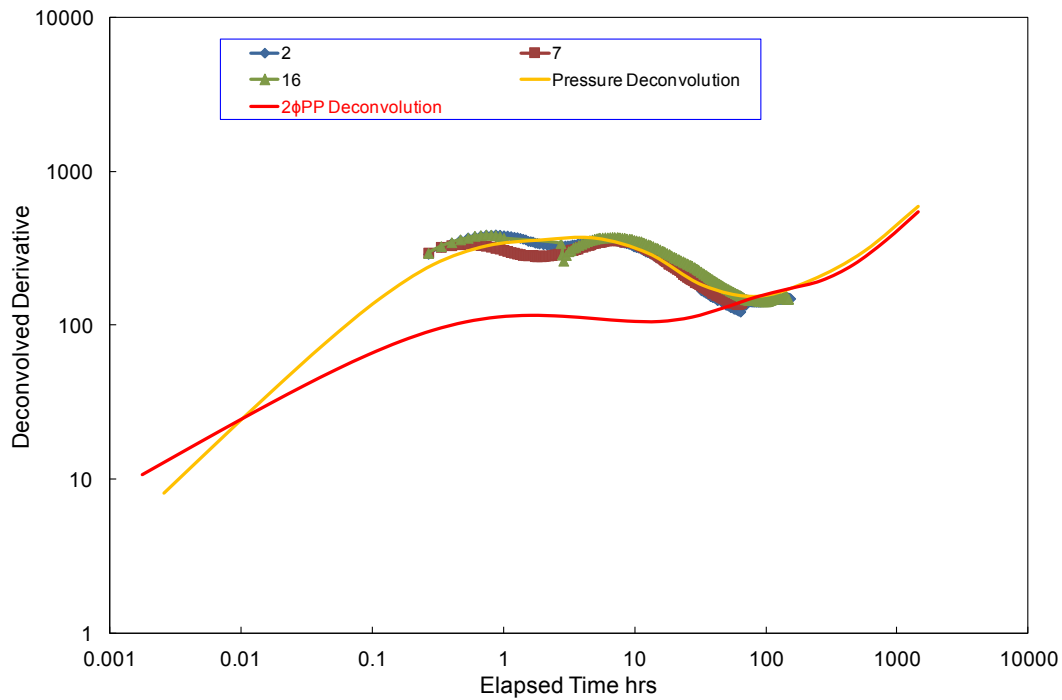


Figure 6.109: Deconvolution of pressure and 2 ϕ PP for Volatile Oil

6.10.3 Verification of deconvolution

Generating the pressure history that match the actual data from the deconvolved derivatives is a vital check of deconvolution process. The plots of actual pressure and two-phase pseudo-pressure with convolved pressure for well 15 are shown in Figs. 6.110 and 6.111. A very good match was obtained with less than 5% error in build-ups and drawdowns (Figs. 6.110 and 6.111) indicating a negligible late time oscillations on the deconvolved derivatives.

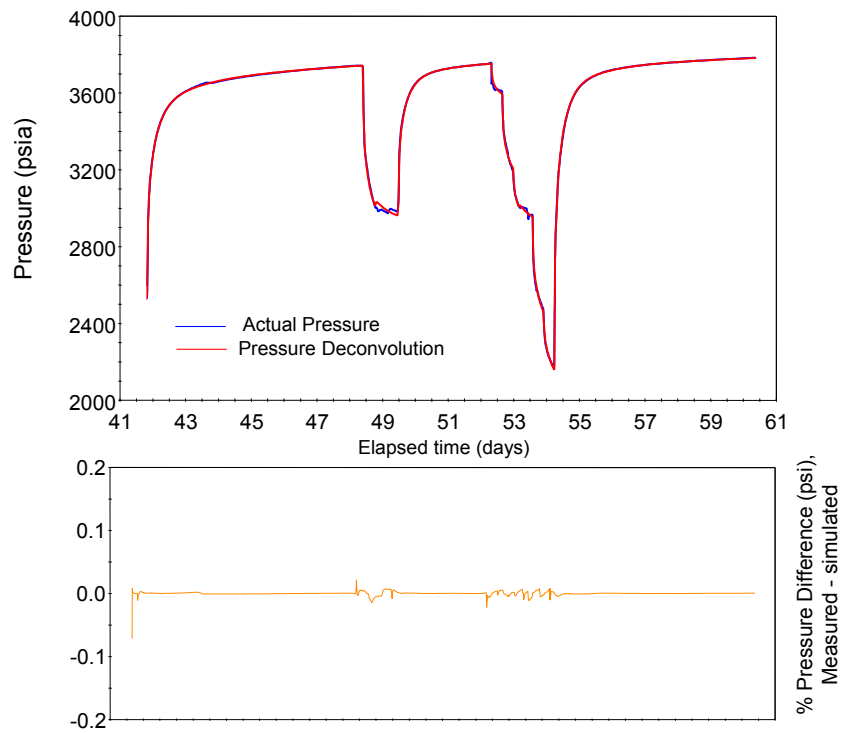


Figure 6.110: Pressure history match and difference between measured and convolved pressure data for Well 15

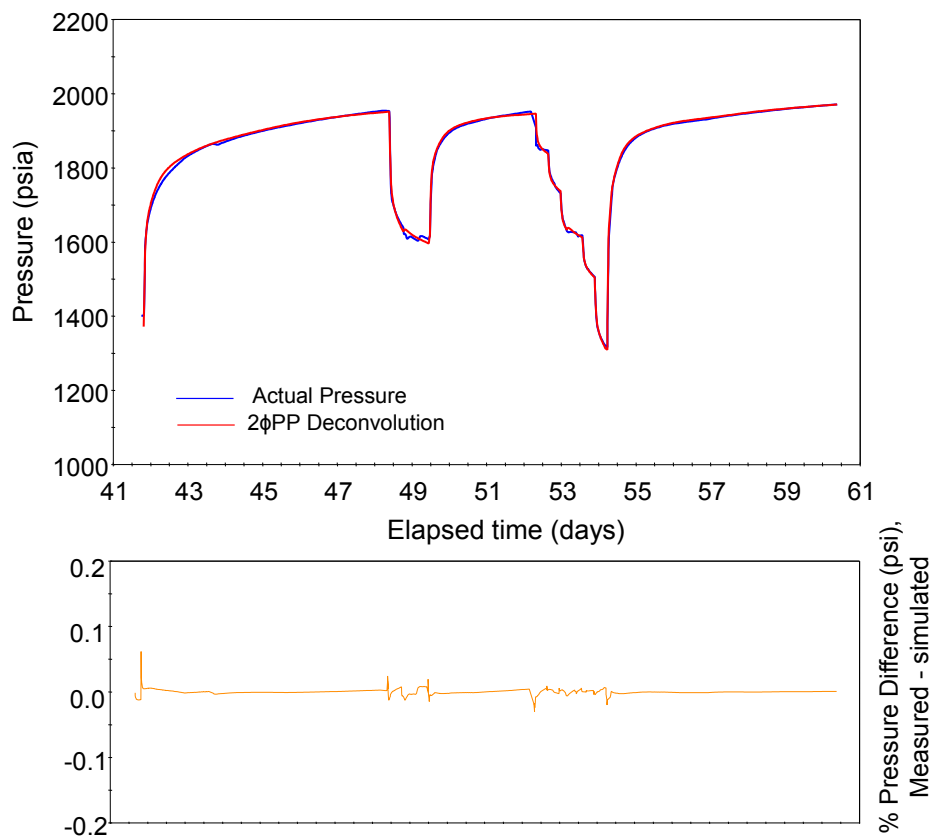


Figure 6.111: 2φPP history match and difference between measured and convolved pressure data for Well 15

6.10.4 Summary of deconvolution of VO

1. The deconvolved derivative of pressure data gives a radial composite behaviour and a half-unit slope at late time indicating a channel boundary.
2. The deconvolved derivative of two-phase pseudo-pressure exhibit homogeneous behaviour and a half-unit log-log straight line at late time which represents a channel boundary
3. The pressure and two-phase pseudo-pressure deconvolved derivatives are the same at late time.

6.11 Summary of Chapter 6

1. Deconvolution of gas condensate or volatile oil below saturation using pressure and single-phase pseudo-pressure without material balance correction (pseudo-linear data) as well as two-phase pseudo-pressure (linearized data) give the same reservoir geometry at late time.
2. The deconvolved derivatives of two-phase pseudo-pressure show a homogeneous behaviour at middle time for gas condensate and volatile oil below saturation pressure.
3. Deconvolution of single-phase pseudo-pressure with material balance correction gives a closed system at late time.
4. Pressure and single-phase pseudo-pressure deconvolved derivatives are useful tool for extracting vital reservoir behaviour and geometry despite the non-linearity of the data below saturation pressure.
5. Deconvolved derivative, two-phase pseudo-pressure, single and multilayer analyses of single-phase pseudo were used successfully to detect and confirm recharge between layers of a multi-layered reservoir.

CHAPTER 7

CONCLUSIONS AND RECOMMENDATIONS

7.1 Conclusions

Accumulation of condensate or gas bank in gas condensate and volatile oil wells flowing below the saturation pressure causes productivity losses through reduction of gas or oil mobility and relative permeability. Capturing productivity and mobility reduction in gas condensate and volatile oil wells is critical to well and reservoir deliverability forecasting. The objective of this study is to investigate well test interpretation techniques for lean gas and rich gas condensate as well as volatile oil wells producing below saturation using pressure, single-phase pseudo-pressure and two-phase pseudo-pressure.

This thesis is divided into three parts:

- a) The first part examines the impact of high capillary number and non-Darcy effects on the various components of wellbore skin for lean gas, rich gas and volatile oil wells flowing below the saturation pressure.
- b) The second part studies the use of backpressure plots for calculating well and reservoir parameters, predicting and improving well productivity in gas condensate and volatile oil wells flowing below saturation pressure.
- c) The third part investigates early time, middle time and late time behaviours of deconvolved derivatives of pressure, single-phase pseudo-pressure and two-phase pseudo-pressure (linearizes well test data below saturation pressure).

Using compositional simulation and analysis of field data; the conclusions of this study are summarised below:

7.1.1 Rate Dependent Skin Analysis

7.1.1.1 Lean Gas Condensate

1. Single-phase pseudo-pressure gives a good estimate of wellbore skin, non-Darcy factor and effective permeability above dew point pressure but yields incorrect values of wellbore skin and non-Darcy factor below dew point pressure.
2. The wellbore skin and turbulence factor estimate for single-phase pseudo-pressure is highly dependent on rate history in lean gas condensate. It gives a negative turbulence factor (negative slope) below dew point pressure for decreasing rate history.

3. Below dew point pressure, two-phase pseudo-pressure converts the negative slope (negative turbulence factor) of single-phase pseudo-pressure to positive slope, yields correct value of effective permeability, non-Darcy factor and wellbore skin if the relative permeability curves which integrate high capillary number and non-Darcy effects are used for the two-phase pseudo-pressure calculation.
4. The positive slope of the wellbore skin versus rate relationship for two-phase pseudo-pressure analysis indicates that high capillary number does not overcompensate for non-Darcy effect at high production rates contrary to what has been published in the literature.
5. The capillary number parameters which should be experimentally determined can be obtained from matching the actual and the simulated well test data provided correct non-Darcy factor and mechanical skin are used in the compositional simulation of lean gas condensate.

7.1.1.2 Rich Gas Condensate

1. Turbulence factor and wellbore skin estimate from single-phase pseudo-pressure in rich gas condensate are less dependent on rate history compared to lean gas condensate.
2. The single-phase pseudo-pressure analysis yields incorrect values of wellbore skin, non-Darcy factor and effective permeability below dew point pressure.
3. The correct value of mechanical skin, non-Darcy factor and effective permeability can be obtained by analysing well test data using single-phase pseudo-pressure above dew point pressure and two-phase pseudo-pressure calculated with relative permeability curves which incorporate high capillary number and non-Darcy effects below dew point pressure.
4. The match of actual and simulated well test data can provide the capillary number parameters when the turbulence factor and mechanical skin are used in the compositional simulation of rich gas condensate.

7.1.1.3 Volatile Oil

1. The pressure analysis yields incorrect values of wellbore skin and non-Darcy factor in volatile oil below bubble point pressure.
2. Wellbore skin estimates of volatile oil are less dependent on rate history compared to lean gas condensate.

3. The correct value of mechanical skin, non-Darcy factor and effective permeability can be estimated by analysing pressure transient test using pressure analysis above bubble point pressure and two-phase pseudo-pressure calculated with relative permeability curves which integrate the high capillary number and non-Darcy effects below bubble pressure.
4. The match of simulated and measured well test data can provide the capillary number parameters when the wellbore skin and non-Darcy factor are used in the compositional simulation of volatile oil.

7.1.2 Backpressure Plot Analysis

1. Productivity losses due to reduction in gas or oil mobility and relative permeability cannot be quantified using single-phase pseudo-pressure and pressure backpressure plots.
2. Well deliverability losses due to condensate or gas bank cannot be captured with two-phase pseudo-pressure backpressure plots calculated with relative permeability curves that does not incorporates the effects of high capillary number and non-Darcy factor.
3. Below saturation pressure, the stabilised backpressure plot can be quantified using two-phase pseudo-pressure backpressure plots calculated with relative permeability curves which incorporate high capillary number and non-Darcy effects.
4. The impact of multiphase flow, high capillary number and non-Darcy effects is more pronounced in lean and rich gas condensate backpressure plot compared to volatile oil.
5. The effect of condensate bank on the reservoir boundary response increases as the fluid richness increases for gas condensate .i.e. it has more impact on the boundary response of rich gas compared to lean gas condensate.

7.1.3 Deconvolution of gas condensate and volatile oil below saturation pressure

1. Below saturation pressure, deconvolved derivatives of pressure and single-phase pseudo-pressure without material balance correction (pseudo linear data) as well as two-phase pseudo-pressure (linearized data) give the same reservoir geometry at late time.

2. The deconvolved derivatives of two-phase pseudo-pressure show a homogeneous behaviour at middle time for gas condensate and volatile oil below saturation pressure.
3. Deconvolution of single-phase pseudo-pressure with material balance correction in gas condensate well gives exactly a unit slope (closed system) at late time.
4. Pressure and single-phase pseudo-pressure deconvolved derivatives are useful tools for extracting vital reservoir behaviour and geometry despite the non-linearity of the data below saturation pressure for gas condensate and volatile oil.
5. Deconvolved derivative, two-phase pseudo-pressure, single and multilayer analyses of single-phase pseudo were used successfully to detect and confirm recharge between layers of a multi-layered reservoir.

Whilst it is shown that in theory the use of two-phase pseudo-pressure calculated with relative permeability curves that incorporate high capillary number and non-Darcy effects linearizes the pressure transient response of wells producing from gas condensate and volatile oil reservoirs flowing below saturation pressure, in practice, the uncertainty in the input data required to generate two-phase pseudo pressure is likely to be too great to achieve a reliable analysis.

7.2 Recommendation for Future Work

Based on the results and conclusions of this study, a further investigation is recommended for the following areas:

1. Application of the methodology in this study to well test data of medium rich and near critical gas condensate wells flowing below saturation pressure.
2. Application of two-phase pseudo-pressure to gas condensate and volatile oil wells flowing below saturation pressure in reservoir with complex heterogeneity and geometry.
3. Application of two-phase pseudo-pressure to gas condensate and volatile oil wells flowing below saturation pressure in very low permeability system such as shale formation.
4. Investigation of the relationship between the turbulence factors calculated with single-phase pseudo-pressure and two-phase pseudo-pressure below saturation pressure.
5. Application of the methodology in this study to multi-layered gas condensate and volatile oil wells producing below saturation pressure.

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APPENDIX A

Gas Saturation at Immobile Condensate Zone

$$\frac{dS_g}{dP} - S_g \left(\frac{B'_g}{B_g} \right) = C_t \quad (\text{Martin, 1959}) \quad \text{Eq A 1}$$

$$\text{Let } A(P) = \left(\frac{B'_g}{B_g} \right)$$

$$S'_g - A(P)S_g = C_t \quad \text{Eq A 2}$$

$$\text{Let } I = e^{\int -AdP} = e^{-AP}$$

$$e^{-AP} (S'_g - AS_g) = e^{-AP} C_t \quad \text{Eq A 3}$$

$$\int (e^{-AP} S'_g - AS_g e^{-AP}) dP = \int e^{-AP} C_t dP \quad \text{Eq A 4}$$

$$e^{-AP} S_g = \int e^{-AP} C_t dP \quad \text{Eq A 5}$$

$$\text{Let } u = -AP; \quad du = -AdP;$$

$$\text{Hence; } dP = -\frac{du}{A}$$

$$e^{-AP} S_g = \int e^{-AP} C_t dP = -\frac{C_t}{A} \int e^u du \quad \text{Eq A 6}$$

$$e^{-AP} S_g = -\frac{C_t}{A} (e^u + \text{Cont}) \quad \text{Eq A 7}$$

Where Cont = Constant

$$e^{-AP} S_g = -\frac{C_t}{A} (e^{-AP} + \text{Cont}) \quad \text{Eq A 8}$$

$$Ae^{-AP} S_g = -C_t (e^{-AP} + \text{Cont}) \quad \text{Eq A 9}$$

Boundary Condition: at $P \geq P_{\text{dew}}$, $S_g = 1$ (for gas only system)

$$Ae^{-AP_{dew}}S_g = -C_t(e^{-AP_{dew}} + Cont) \quad \text{Eq A 10}$$

$$-\frac{A}{C_t}e^{-AP_{dew}} = (e^{-AP_{dew}} + Cont) \quad \text{Eq A 11}$$

$$Cont = -e^{-AP_{dew}} - \frac{A}{C_t}e^{-AP_{dew}} \quad \text{Eq A 12}$$

$$Cont = -e^{-AP_{dew}}\left(1 + \frac{A}{C_t}\right) \quad \text{Eq A 13}$$

Substitute Eq A 13 to Eq A 9

$$Ae^{-AP}S_g = -C_t\left(e^{-AP} - e^{-AP_{dew}}\left(1 + \frac{A}{C_t}\right)\right) \quad \text{Eq A 14}$$

$$Ae^{-AP}S_g = -C_te^{-AP} + e^{-AP_{dew}}(C_t + A)$$

$$Ae^{-AP}S_g + C_te^{-AP} = e^{-AP_{dew}}(C_t + A)$$

$$e^{-AP}(AS_g + C_t) = e^{-AP_{dew}}(C_t + A)$$

$$AS_g + C_t = \frac{e^{-AP_{dew}}}{e^{-AP}}(C_t + A)$$

$$AS_g = e^{-AP_{dew}+AP}(C_t + A) - C_t$$

$$S_g = \frac{e^{A(P-P_{dew})}}{A}(C_t + A) - C_t \quad \text{Eq A 15}$$

$$S_g = \frac{e^{\left(\frac{B'_g}{B_g}\right)(P-P_{dew})}}{\left(\frac{B'_g}{B_g}\right)}\left[C_t + \left(\frac{B'_g}{B_g}\right)\right] - C_t$$

$$S_g = \left[\frac{e^{\left(\frac{B'_g}{B_g}\right)(P-P_{dew})}\left[C_t + \left(\frac{B'_g}{B_g}\right)\right] - C_t}{\left(\frac{B'_g}{B_g}\right)} \right] \quad \text{Eq A 16}$$

APPENDIX B

Shown below are the EOS model matches to experimental data for all the fluid samples:

Lean Gas Condensate

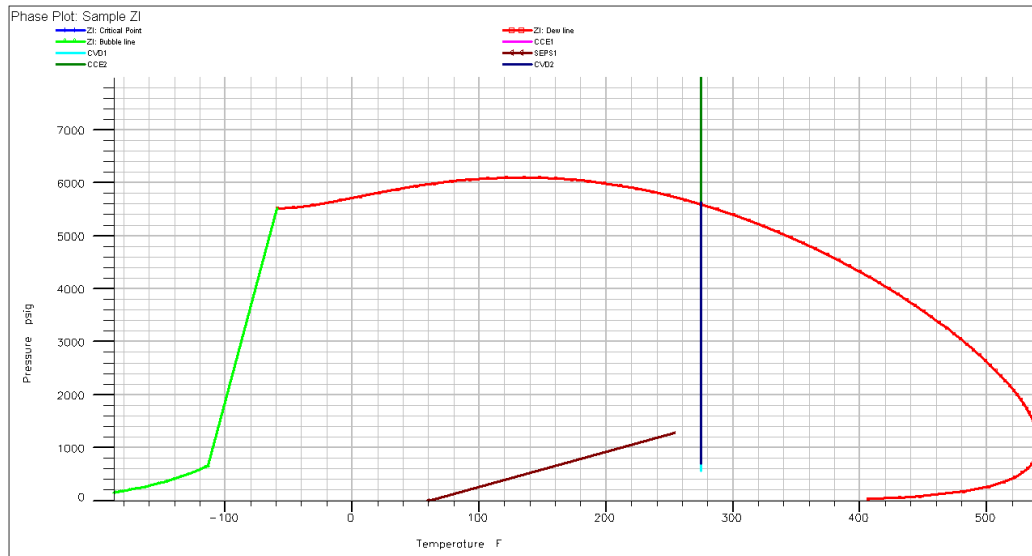


Figure B1: Phase diagram of Lean gas

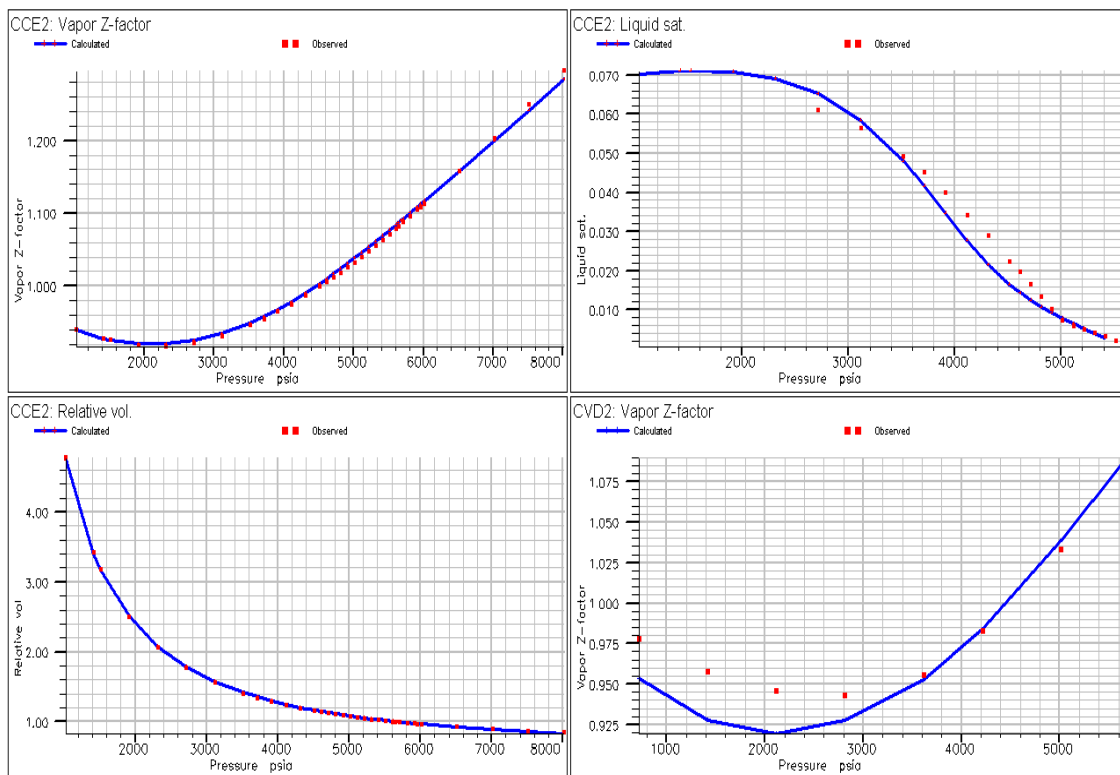


Figure B2: Comparisons of liquid saturation and vapour z-factor between EOS predicted and CCE/CVD measured data for lean gas condensate fluid

Rich Gas Condensate (North Africa)

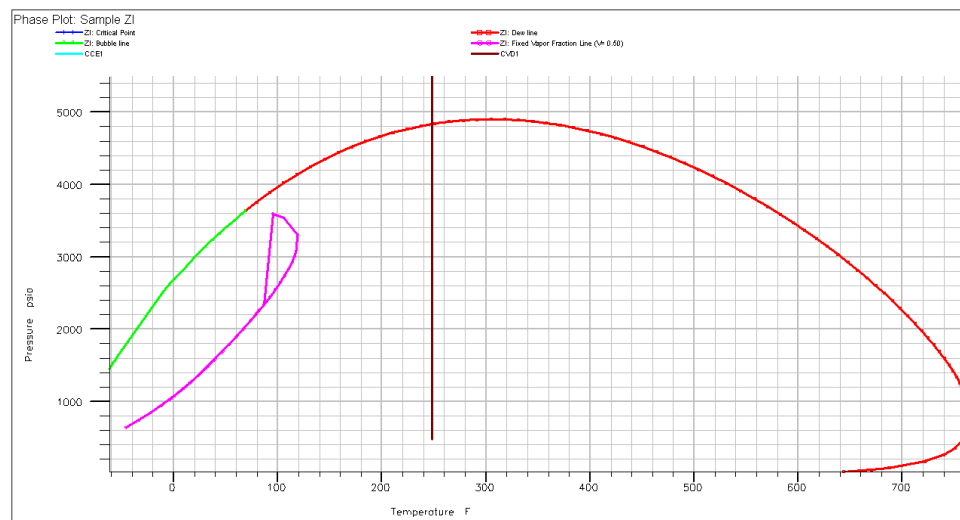


Figure B3: Phase diagram of Rich Gas condensate fluid

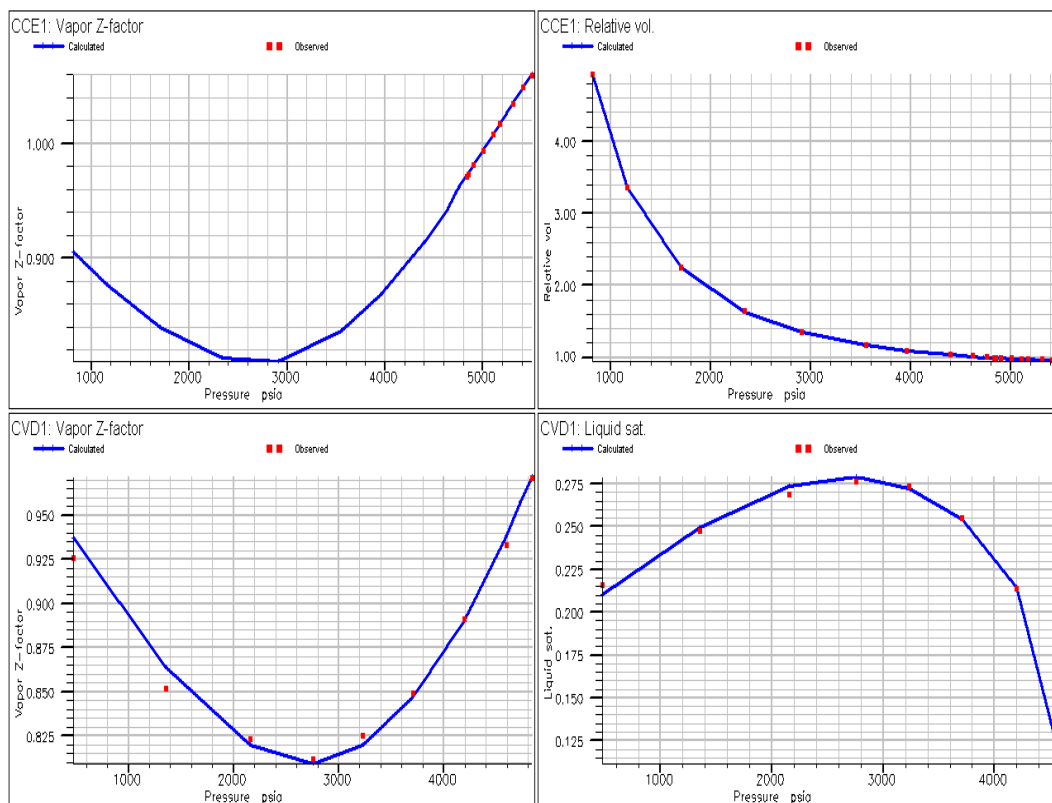


Figure B4: Comparisons of liquid saturation and vapour z-factor between EOS predicted and CCE/CVD measured data for the rich gas condensate fluid

Volatile Oil

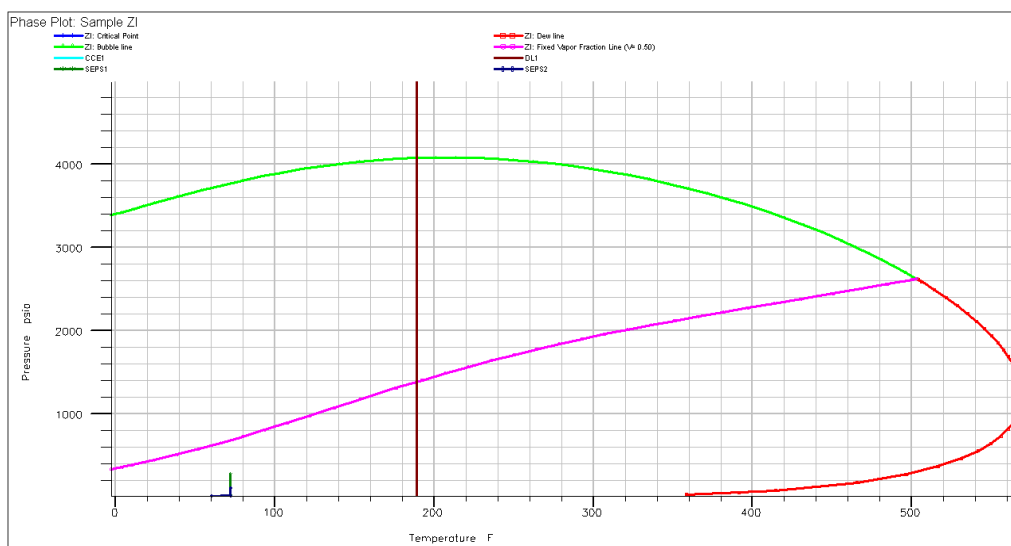


Figure B5: Phase diagram of Volatile Oil fluid

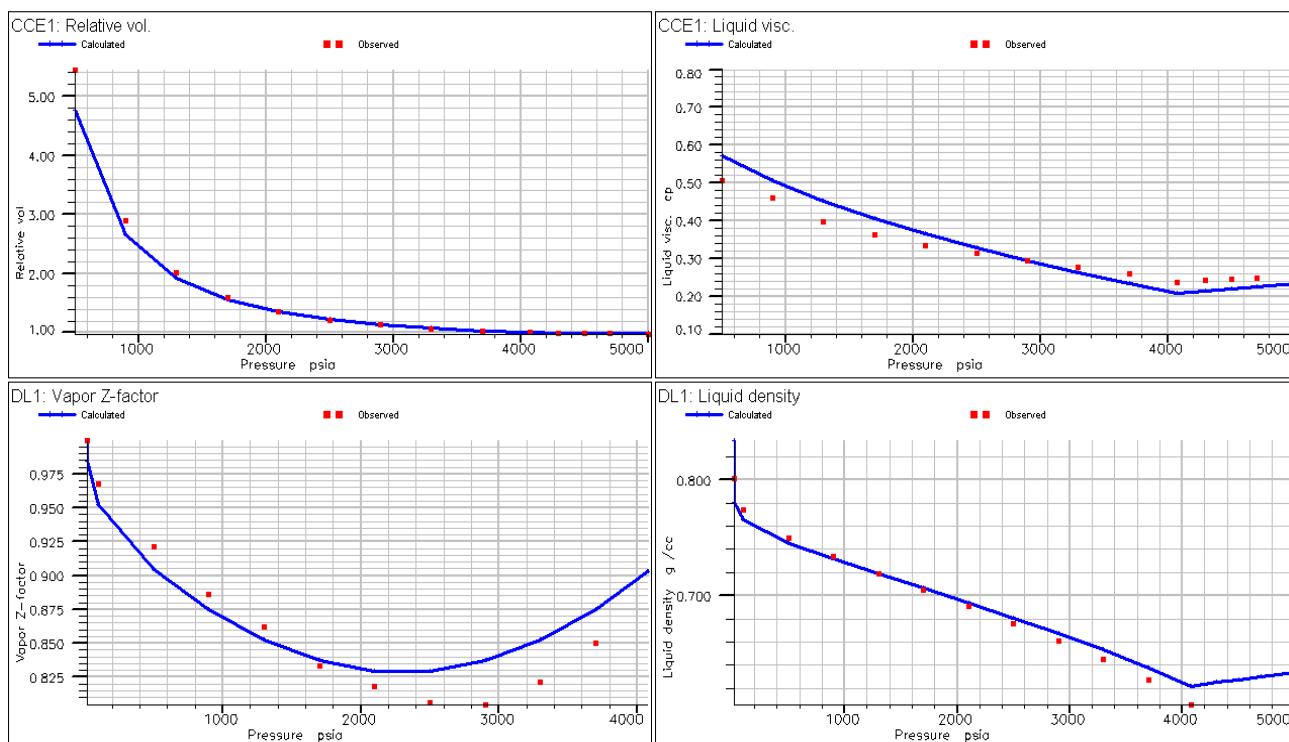


Figure B6: Comparisons of liquid density, liquid viscosity, relative volume and vapour z-factor between EOS predicted and CCE/DL measured data for Volatile Oil fluid

Lean Gas Condensate (CDFi)

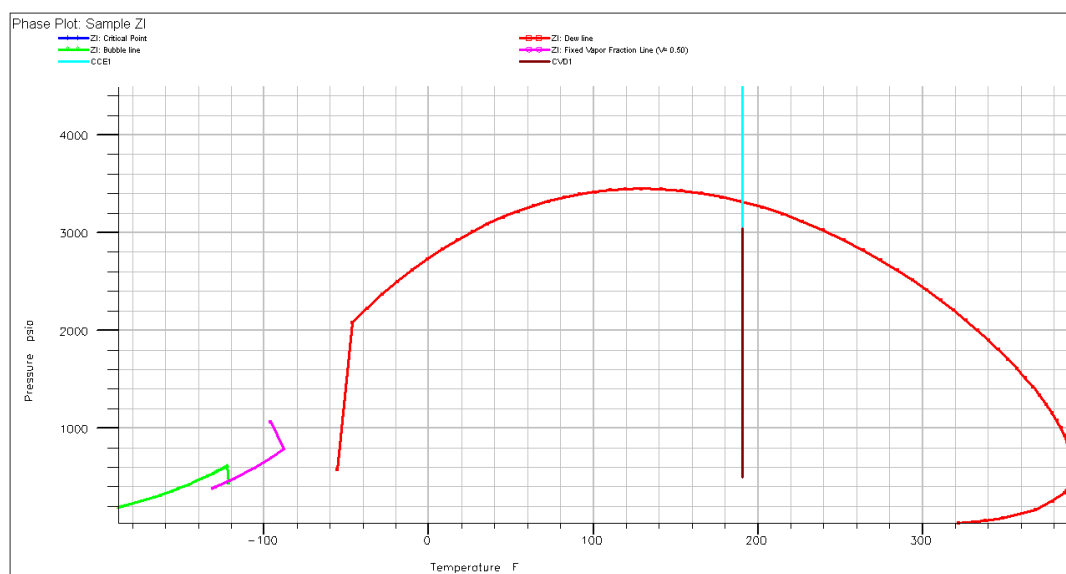


Figure B7: Phase diagram of CDFi fluid

Table B1: Composition of CDFi PVT Sample

S/N	Component	Mole Fraction %	S/N	Component	Mole Fraction %
1	CO ₂	1.606	13	C ₉	0.273
2	N ₂	4.881	14	C ₁₀	0.162
3	C ₁	77.082	15	C ₁₁	0.094
4	C ₂	8.105	16	C ₁₂	0.065
5	C ₃	3.614	17	C ₁₃	0.056
6	IC ₄	0.575	18	C ₁₄	0.039
7	NC ₄	1.087	19	C ₁₅	0.026
8	IC ₅	0.366	20	C ₁₆	0.016
9	NC ₅	0.36	21	C ₁₇	0.011
10	C ₆	0.421	22	C ₁₈	0.007
11	C ₇	0.569	23	C ₁₉	0.004
12	C ₈	0.572	24	C ₂₀₊	0.009

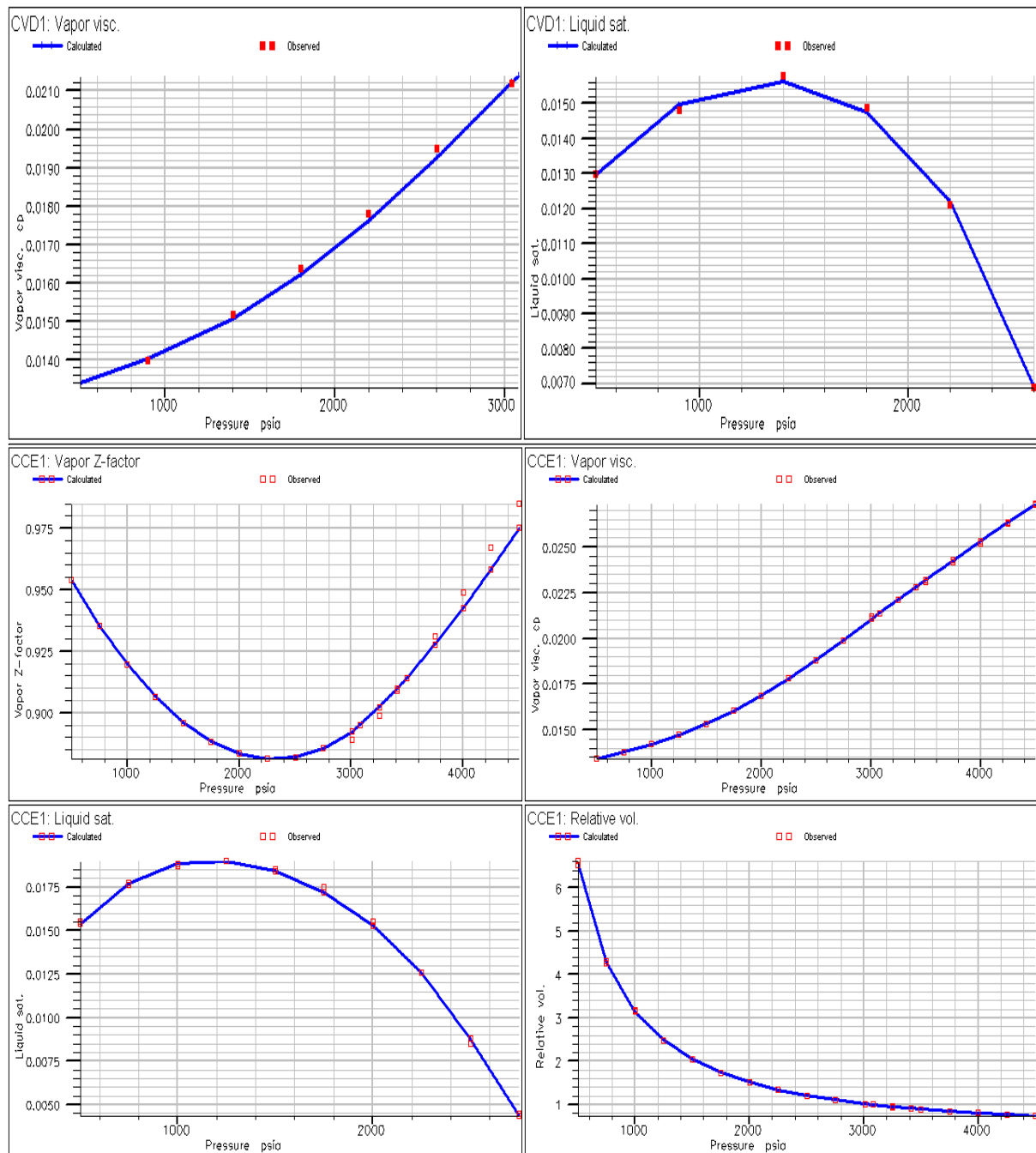


Figure B8: Comparisons of liquid saturation, vapour viscosity, vapour z-factor and relative volume between EOS predicted and CCE/CVD measured data for fluid CDFi

APPENDIX C

Sample E300 simulation code

```
-----  
-- Fluid Sample source:           Gas Condensate  
-- Permeability of 10mD, Porosity of 10%  
-- Eclipse 300 Simulation using Corrected Peng Robison Equation of State  
-----
```

```
RUNSPEC--*****  
FORMOPTS  
HCSCAL /  
DIMENS  
  62 1 1 /  
OIL  
WATER  
GAS  
RADIAL  
VELDEP  
1 1 0 1 /  
FIELD  
EOS  
PR3 /  
PRCORR  
COMPS  
13 /  
TABDIMS  
1 1 55 55 1 /  
EQLDIMS  
1 55 55 1 55 /  
WELLDIMS  
1 1* 1 5 /  
UNIFIN  
UNIFOUT  
UNIFSAVE  
START  
01 JAN 2011 /  
--*****  
GRID  
--*****  
INIT  
ECHO  
INRAD  
0.25 /  
DRV  
0.1 0.2 0.25 0.3 0.35 0.4 0.6 0.8 0.92 1.3 1.7 2.01 2.5 3.5 2.42 2.42 3.9 3.9 3.9 3.9 3.9 3.9  
3.9 3.9 3.9 3.9 3.9 3.9 3.9 3.9 3.9 3.9 3.9 3.9 3.9 3.9 18.2 18.2 18.2 18.2 18.2 18.2  
39.3 39.3 39.3 39.3 39.3 39.3 169.89 169.89 169.89 200 300 500 600 700 700 2000 2000  
2000 2000  
/  
DTHETAV  
360 /  
DZV
```

```

100 /
EQUALS
TOPS 14000 /
PERMR 10 /
PORO 0.1 /
/
RPTGRID
/
--*****
PROPS
--*****
INCLUDE
MLN_DST1-1B(new).PVO /
VDKRO
0 10 -1 1.3E-5 0 0 0 0 1* /
VDKRG
0 10 -1 1.3E-5 5e-4 5.5 5.5 1 1* /
ROCK
14.7 3.402e-6 /
SWOF
0.4 0.000 1 0.0
0.5 0.008333 0.5625 0.0
0.6 0.033333 0.25 0.0
0.7 0.075 0.0625 0.0
0.8 0.133333 1.92e-32 0.0
1 0.3 0 0.0
/
SGOF
00 1 0
0.01 0 0.938666977 0
0.05 0 0.716176609 0
0.06 4.45752E-05 0.666112087 0
0.08 0.000694859 0.572433402 0
0.12 0.005778809 0.409963413 0
0.14 0.010831773 0.34063039 0
0.16 0.017888544 0.278854801 0
0.2 0.038843774 0.176776695 0
0.24 0.07014186 0.101192885 0
0.28 0.113087048 0.04929503 0
0.3 0.139297492 0.03125 0
0.38 0.278854801 0.000559017 0
0.4 0.32304527 0 0
0.46 0.479791907 0 0
0.5 0.605514518 0 0
0.54 0.749175345 0 0
0.58 0.911555153 0 0
0.6 1 0 0
/
--*****
REGIONS
--*****
SOLUTION
--*****

```

```

EQUIL
14050 5780 14050 0.0 14050 0 3* 1 /
FIELDSEP
  1 60.0 14.7 3* 1 /
  1 60.0 14.7 3* 0 /
/
--*****
SUMMARY
--*****
INCLUDE
Summary-Output.txt /
--*****
SCHEDULE
--*****
RUNSUM
SEPCOND
SEP1 G1 1 72 114.7 2 0 /
SEP1 G1 2 72 59.7 3 0 /
SEP1 G1 3 72 24.7 4 0 /
SEP1 G1 4 72 14.7 0 0 /
/
WELSPECS
Prod1 G1 1 1 14050 GAS /
/
COMPDAT
Penetration
Prod1 1 1 1 1 OPEN 2* 0.5 1* 0/
/
WSEPCOND
Prod1 SEP1 /
/
WELLPROD
Prod1 GAS 2* 500.0 1* 20.0 /
/
INCLUDE
TIMESTEP10DAYS.txt /
WELLPROD
Prod1 GAS 2* 0.0 1* 20.0 /
/
INCLUDE
TIMESTEP10DAYS.txt /
WELLPROD
Prod1 GAS 2* 1000.0 1* 20.0 /
/
INCLUDE
TIMESTEP10DAYS.txt /
WELLPROD
Prod1 GAS 2* 0.0 1* 20.0 /
/
INCLUDE

```

```

TIMESTEP10DAYS.txt /
WELLPROD
Prod1 GAS 2* 2000.0 1* 20.0 /
/
INCLUDE
TIMESTEP10DAYS.txt /
WELLPROD
Prod1 GAS 2* 0.0 1* 20.0 /
/
INCLUDE
TIMESTEP10DAYS.txt /
WELLPROD
Prod1 GAS 2* 6000.0 1* 20.0 /
/
INCLUDE
TIMESTEP10DAYS.txt /
WELLPROD
Prod1 GAS 2* 0.0 1* 20.0 /
/
INCLUDE
TIMESTEP10DAYS.txt /
WELLPROD
Prod1 GAS 2* 8000.0 1* 20.0 /
/
INCLUDE
TIMESTEP10DAYS.txt /
WELLPROD
Prod1 GAS 2* 0.0 1* 20.0 /
/
INCLUDE
TIMESTEP10DAYS.txt /
-- 9DD
WELLPROD
Prod1 GAS 2* 10000.0 1* 20.0 /
/
INCLUDE
TIMESTEP10DAYS.txt /
WELLPROD
Prod1 GAS 2* 0.0 1* 20.0 /
/
INCLUDE
TIMESTEP10DAYS.txt /
END
/

```