IMPERIAL COLLEGE LONDON

Department of Earth Science and Engineering

Centre for Petroleum Studies

Reducing Fluid Type Uncertainty with Well Test Analysis

By

Hidayat Abd Hir

A report submitted in partial fulfilment of the requirements for the MSc and/or the DIC

September 2011

DECLARATION OF OWN WORK

I declare that this thesis *"Reducing fluid type uncertainty with well test analysis"* is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and /or with appropriate acknowledgements given.

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Reducing Fluid Type uncertainty with Well Test Analysis

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Abstract

A considerable amount of data is required to properly develop and produce oil or gas reservoirs. One of the important information that should be emphasized is the reservoir fluid type especially when the fluid is supercritical at reservoir conditions. This supercritical fluid could behave as gas condensate or volatile oil and will exhibit a complex behavior when the wells are produced below the saturation pressure. When the fluid type is not properly characterized, volatile oil reservoir is sometimes evaluated as gas condensate system when the pressure in the reservoir drops below the saturation pressure and vice versa for gas condensate reservoir. The determination of fluid type is therefore crucial for better understanding of the well and reservoir behavior in the future.

This paper evaluates PVT and pressure data to reduce reservoir fluid type uncertainty through well test analysis. The data was gathered from a low permeability chalk field where a reliable down-hole PVT sample was not available due to drop of the sampling pressure below the saturation pressure, as a result of the tight formation. Fluid from surface separator was sampled and recombined according to the different GORs observed during the DST. The down-hole and recombined surface samples were analyzed but the fluid type was still uncertain as the fluid is supercritical at reservoir conditions; thus it could be either gas condensate or volatile oil. DST data is available on a stimulated horizontal well.

The study to reduce the fluid type uncertainty focused mainly on the PVT data modeling to match an Equation of State (EOS), and analyzing DST pressure-rate data to assess the rate-dependent skin effect. From the PVT modeling, two possible fluid types – i.e. gas condensate and volatile oil were created and the skin effect was assessed in both cases. As the test pressure is below the fluid saturation pressure, the rate-dependent skin factor was assessed using two-phase pseudo-pressure and the results were compared with the trend that was previously studied using simulated and also confirmed with real field data. The wellbore skin effect was then used to reduce the uncertainty on fluid type which showed a trend behavior that was likely to associate with gas condensate reservoir.

Introduction

The determination of reservoir fluid type (Black Oil, Volatile Oil, Gas, etc) seems to be a straightforward task after initial production data are collected, provided that representative samples are available. General rules of thumb have been developed to accomplish this job (Moses, 1986; Mc Cain Jr. 1991). However, the task is complicated when there is no representative sample available. There are relatively few published papers dealing with reservoir fluid determination from a non-representative fluid sample. Cobenas *et al.* (1999) recommended a workflow to determine reservoir fluid composition from a non-representative fluid sample which led to the fundamental decision of volatile oil by qualitatively assessing the fluid data. His decision was based on the surface samples, PVT analysis and the GOR of recombined fluid samples that correspond to the static saturation pressure observed during the test. However for the case of present study, the GORs observed during well testing showed both gas condensate and volatile oil possibility. It is therefore required to integrate the workflow proposed by Cobenas *et al.* (1999) with the additional available DST pressure-rate data to determine the fluid type.

Well test analysis has been commonly used to identify and quantify near wellbore effect, reservoir behaviours and boundaries. The near wellbore effect that is of interest in this study is wellbore skin effects since it has been proven that wellbore skin effects show different behaviour in different fluid types (Gringarten *et al.* 2011). The skin effect receives contributions from many sources and the combined effects of the individual skin components are normally represented by a total skin factor. It is therefore very important to evaluate each skin component to identify which near wellbore flow restriction can be improved by remedial action. The total skin factor can be divided into rate-dependent and rate independent skin coefficients. The rate-independent skin components are caused by drilling damage (mechanical skin effect), completion (limited entry, hydraulic fracturing, gravel packing etc.) and geology (anisotropy or natural fractures). Rate-dependent skins on the other hand include rate and phase dependent effects that occur in dry gas wells or in oil or gas condensate wells producing under multi-phase flow conditions below the saturation pressure.

Above the saturation pressure, well test analysis of gas condensate reservoir is performed in the same way as a dry gas reservoirs are interpreted, using single-phase pseudo-pressure or real gas potential (Al-Hussainy *et al.* 1965) to account for pressure-dependent fluid properties:

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

p is the reservoir pressure, μ is the viscosity, Z is the gas compressibility factor and p_{ref} is a reference pressure, usually taken as the atmospheric pressure. This pressure linearization process into pseudo-pressure enables well test analysis of dry gas to be performed as in the case of single-phase oil, except that the wellbore skin effects must be treated differently. The wellbore skin effect for pseudo-pressure interpretation includes a rate-dependent term (Smith 1961), which is also known as non-Darcy, turbulence or inertia skin effect, in addition to the rate-independent mechanical skin effect.

$$S_w = S_m + DQ \quad (2)$$

S_w is the wellbore skin effect; S_m the rate-independent mechanical skin effect, Q is the gas flow rate, and D is the turbulence factor or non-Darcy coefficient. The skin effect due to completion and geology are handled explicitly in the interpretation models. S_w has a linear relationship with flowrate, thus when the wellbore skin effect is plotted against gas flowrate on a Cartesian graph, a straight line representing Eq.2 can be obtained. D and S_m are the slope and the intercept with the y-axis, respectively.

Below the dew point pressure in a gas condensate system, well test analysis becomes more complex as retrograde condensation occurs. The condensation of liquid introduces different regions in the reservoir due to the build up of condensate bank. Each of fluid regions in the reservoir has different mobile and immobile liquid saturations and gas relative permeability (Gringarten *et al.* 2000). There have been a number of published studies investigating the issue of estimating the skin effect in gas condensate and volatile oil reservoirs with bottom-hole pressure below the saturation pressure (Jones and Raghavan 1988; Saleh and Stewart 1992; Thompson *et at.* 1993; Raghavan *et al.* 1999; Xu and Lee 1999; Shandrygin and Rudenko 2005; Gringarten *et al.* 2000, 2006, 2011).

Jones and Raghavan (1988) proposed two-phase pseudo-pressure function to incorporate the influence of multiphase flow:

$$m_{2\phi}(p) = \int_{p_{ref}}^{p} (\frac{k_{rg}}{\mu_g B_g} + \frac{k_{ro}R_s}{\mu_o B_o})dp \quad (3)$$

with k_{rg}/k_{ro} estimated from:

$$\frac{k_{rg}}{k_{ro}} = \frac{R_p - R_s}{1 - R_v R_p}\left(\frac{B_{gd}\mu_{gd}}{B_o \mu_o}\right) \quad (4)$$

k_r is the relative permeability; μ is the viscosity; B is the formation volume factor; R_s is the solution gas oil ratio GOR. Subscript o, g and gd refer to condensate, gas and dry gas.

Gringarten *et al.* 2000 reported that analyzing pressure using single-phase pseudo pressure (Eq.1) considers gas as the dominant fluid and the condensate deposited around the wellbore as a fluid heterogeneity. The fluid-induced composite behaviour is created when the bottom-hole pressure falls below the saturation pressure, initially with three regions due to high capillary number effect as illustrated by curve (a) in Figure 1, with three corresponding radial stabilizations. As production continues and near-well oil saturation increases, the first stabilization line disappears and only a two-zone radial composite behaviour remains; resulting in two radial stabilizations as shown by curve (b) in Figure 1. The high condensate saturation stabilization (middle stabilization) yields the condensate bank mobility and the wellbore skin factor, $S_{w(1\phi)}$ which incorporates the rate-independent mechanical skin and the rate-dependent non-Darcy skin (Eq.2). Similarly, the final stabilization is related to the effective reservoir permeability and the total skin, which includes the wellbore skin effect plus a skin effect due to multiphase flow.

Alternatively, two-phase pseudo-pressure can be used to analyze well test of multiphase flow in the reservoir. Eq.3 converts the two-phase fluid into a single fluid equivalent in the two-phase flow regions (Figure 2). As a result, the fluid induced composite behaviour obtained with single-phase pseudo-pressure does no longer exist, and only a single derivative stabilization is obtained which corresponds to the absolute permeability (Gringarten *et al.* 2006). Consequently, there is only one skin effect – the wellbore skin factor $S_{w(2\phi)}$ which is equal to the wellbore skin effect from single-phase pseudo-pressure analysis $S_{w(1\phi)}$.

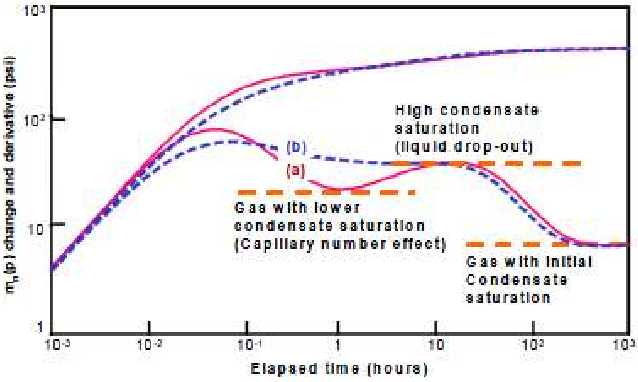

Figure 1: Schematic of single-phase pseudo-pressure and derivative three-region (a) and two-region (b) composite behavior (Gringarten et al., 2000)

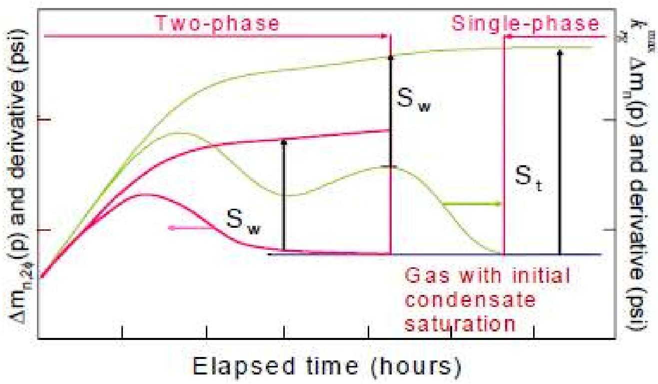

Figure 2: Single-phase versus two-phase pseudo-pressure formulation (Gringarten et al., 2006)

In a recent study, Gringarten *et al.* (2011) investigated the combined impact of capillary number and non-Darcy flow on the wellbore skin in lean and rich gas-condensate reservoirs, using single-phase and two-phase pseudo-pressure, and compared non-Darcy coefficients and zero-rate skin factors above and below the saturation pressure. The study included volatile oil reservoirs below the bubble point pressure, which also exhibit well test composite behaviours (Sanni and Gringarten, 2008). It was found that below saturation pressure, the wellbore skin behaviours in gas condensate and volatile oil reservoirs could be correctly estimated with 2-phase pseudo-pressure, provided that non-Darcy and capillary number effects are included in the two-phase pseudo-pressure calculations. The rate-independent mechanical skin effect obtained below the saturation pressure from the two-phase pseudo-pressure analysis are similar to the corresponding values obtained above the saturation pressure from the single-phase pseudo-pressure analysis for gas condensate, and the actual pressure analysis for volatile oil. The non-Darcy effect or turbulence factor calculated from this method showed a significant positive value for gas condensate but a very small value that could be taken as zero for volatile oil. The results have been validated with actual field data. This concept has been used in the present study in order to reduce the fluid type uncertainty.

The sections in this paper are organized as follows.

1. **Introduction to the Field:** An introduction to the field whose fluid is being studied and the issues faced during drilling of the horizontal appraisal well that lead to the uncertainty in fluid type.
2. **Available information:** A short description on the data that is available from the vertical exploration well and the horizontal appraisal well that are used in this study.
3. **Methodology and data analyses:** Step by step methods used to analyze each data including: PVT data modelling, Well Test Analysis and 2-Phase Pseudo-Pressure calculations from both uncertain volatile oil and gas condensate properties from PVT analysis.
4. **Results:** The discussion of the rate-dependent wellbore skin effect behaviours from the analysis of both gas condensate and volatile oil properties from each PVT model.

Introduction to the field

The main goal of this study is to reduce fluid type uncertainty for a reservoir fluid that exists as a supercritical fluid at reservoir conditions; which can be either volatile oil or gas condensate. The field is a low permeability chalk field with permeability estimated to be 0.03 – 0.04 mD from well test analysis. The hydrocarbon accumulation of this field was discovered by a vertical well and has been appraised recently by drilling a horizontal well which encountered some drilling and stimulation problems.

The hydrocarbon accumulation in this field can be best described as a frozen-in intra chalk accumulation. The reservoir interval is at a burial depth of about 8000 ft. Hydrocarbon was believed to have migrated through the chalk and to have only accumulated once the seal was in-place. The internal overpressure in the main reservoir formation developed concurrently with hydrocarbon charging. Hydrocarbon thus migrated vertically through the chalk in the vicinity of the vertical exploration well that had been drilled earlier, and migrated laterally along the more porous layers. Lateral migration terminated either due to facies pinch-out, or gradual porosity destruction of water-filled chalk by continuous burial.

The horizontal well was drilled to evaluate the potential for economic development of the field hydrocarbon accumulation present within porous layers of the main reservoir formation. Upon reaching the total depth (TD) at 14000 ft MDBRT , the well was stimulated using matrix stimulation with Controlled Acid Jet (CAJ) liner technique and tested post stimulation for the duration of 180 hours (including clean up and main flow). Three main pressure build ups are available to determine well deliverability and near wellbore reservoir parameters. Eight bottom-hole PVT samples were acquired from which only one sample was analyzed in laboratory, together with the other two recombined surface samples that represented the minimum and maximum gas oil ratios (GOR) observed during the testing.

The horizontal appraisal well established that the reservoir could flow after stimulation. The tested fluid was potentially much heavier than the gas-condensate that was expected from offset information, which increased the reservoir fluid type ambiguity. Moreover, no core was obtained over the formation and fluid sampling took place under non-ideal conditions as the low permeability chalk generated significant pressure drop during well testing. This study is therefore performed to reduce fluid type uncertainty due to the lack of representative PVT samples, based on the DST pressure data.

Available information

The following information, which is used as basic data in the study, contains the general characteristics of the case:

- **Reservoir**: A tight chalk field (well test permeability 0.03 – 0.04 mD and porosity 10-25 %) with a vertical exploration well and a horizontal appraisal wells completed in one productive layer. There were different initial pressures reported from different sources. At the same datum depth of 10000 ft TVDSS, the vertical exploration well that had been drilled earlier reported a higher value of initial pressure (11500 psia) compared to the value reported from the horizontal well test interpretation (10000-11000 psia) at the same datum. However from MDT the reservoir pressure was estimated as being 9500 psia but was still questionable with the very tight reservoir. The average formation temperature is around 298 °F.
- **DST Data**: The clean-up and main flow period was conducted for less than 50 hours during the DST with three build-up periods with durations of 5, 15 and 68 hours respectively. Flowing pressure was around 4050 psia, generating gas and oil to flow in the well.
- **Sampling**: Eight bottom-hole samples with volume of 300 ml each were acquired for PVT analyses. Surface separator gas and liquid were also iso-kineticly sampled for lab analyses.
- **PVT Analysis**: The composition of each bottom-hole sample was analyzed in the lab. One of the eight samples was further analyzed with Constant Composition Expansion (CCE) experiment at 298 °F. The gas and oil samples from test separator which had been recombined to represent the minimum and maximum GORs (2544 and 4136 SCF/STB) observed during well testing were also analyzed in the lab. The low GOR recombined sample was analyzed with CCE and Differential Vaporisation (DV) experiments and the high GOR recombined sample was analyzed with CCE and Constant Volume Depletion (CVD) experiments, both at 298 °F. Table 1 shows the summary of PVT analyses.

	Properties	Bottom Hole Sample	High GOR	Low GOR
CCE	Saturation Pressure (psig)	7200	5900	5200
	Gas Z Factor	1.243	1.128	-
	Density @ Sat. Pressure (g/cm3)	0.4059	0.4378	0.4792
	Viscosity @ Sat. Press (cP)	0.0607	0.0675	0.074
	Viscosity @ 11135 psig (cP)	0.0794	0.1048	0.122
Separator	GOR (scf/stb)	7325	4136	2544
	CGR (stb/MMscf)	137	242	393
	B_o (rbbl/stb)	5.232	3.466	2.626
	Tank Oil Density (API)	44.5	44.5	45.1

Table 1: PVT analyses summary

Methodology and data analyses

PVT modelling

Fluid PVT model is very important for fluid type determination. The fluid properties from PVT modelling would be used later in this study for the conversion of multiphase flow-rate to single phase flow-rate in Interpret 2010 (paradigm). This is because TLSD (Total Least Square Deconvolution) which is used for the pressure-rate deconvolution only takes single phase flow-rate as input. The PVT model would also be used for the 2-phase pseudo-pressure calculations.

Table 1 shows PVT data from three different fluid samples (bottom-hole, low GOR recombined and high GOR recombined) that are available for the fluid type analysis. All the values recorded and reported during the field and lab test were assumed to be valid. Prior to rejection of any information that presents an apparent inconsistency in the reported data; the origin of its inconsistency was carefully analyzed. The compositional analysis of each sample was imported into PVTi (Schlumberger) and the resulting phase envelope of each sample is shown in Figure 3. From the phase envelope, it can be seen that at the reservoir conditions, the fluid type of bottom-hole sample falls within the gas condensate region but both fluid types of the surface recombined samples fall within the volatile oil region. However from the laboratory PVT analysis, it was reported that both bottom-hole and high GOR recombined samples existed in gas phase at reservoir conditions whereas only the Low GOR recombined sample existed in volatile oil at the reservoir conditions. Therefore there is an inconsistency between the compositional and PVT analyses for the high GOR recombined sample. Due to this inconsistency, the PVT data could not be modelled in PVTi and would not be used further in this study.

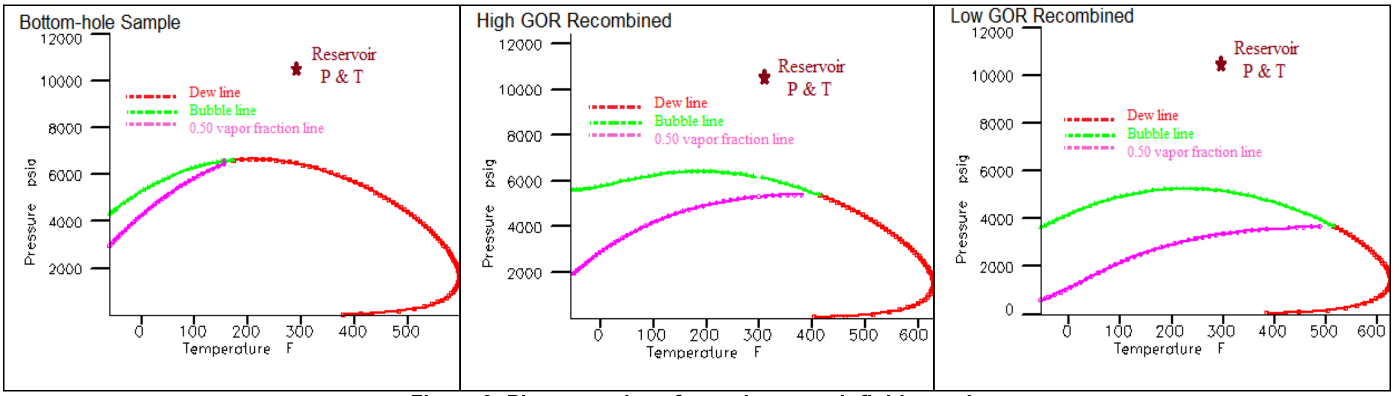

Figure 3: Phase envelope for each reservoir fluid sample

In modelling the PVT properties of the reservoir fluid samples, the corrected Peng-Robinson (PR) equation of state (EOS) with 3 parameters was used; together with Lorentz-Bray-Clark correlation for viscosity modelling. The PVT model for bottom-hole sample was validated against CCE, and low GOR recombined sample was validated against CCE and DV experiments. Regression was performed on molecular weight (MW), critical pressure (P_c) and critical temperature (T_c) of the C_7+ fraction pseudo-components; and binary interaction coefficients between light and heavy components. Figure 4 and 5 compare the observed and simulated CCE experiment for both bottom-hole and low GOR samples, respectively. Good matches were achieved with C_7+ components for both fluid samples with match error for each fluid property of less than 10% except liquid saturation was difficult to model. Emphasizing the regression on the liquid saturation would compromise the other PVT properties that would results in unrepresentative two-phase pseudo-pressure calculations.

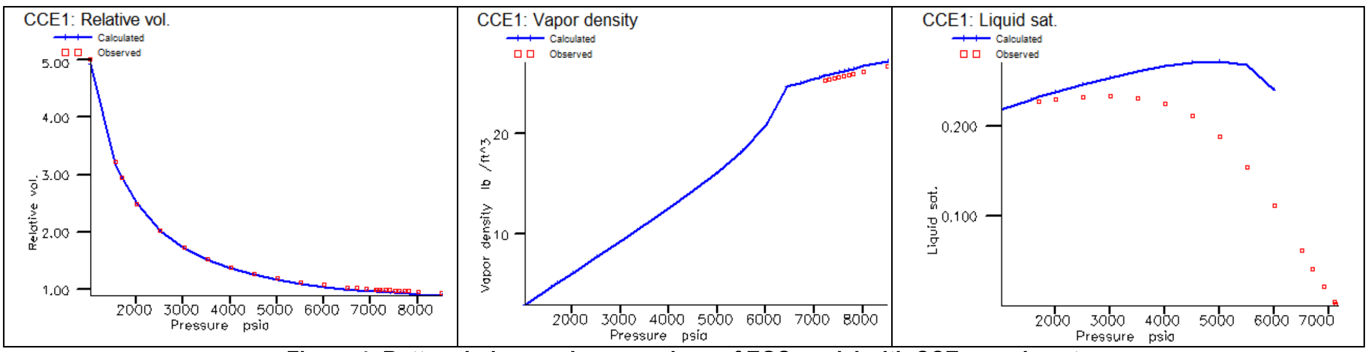

Figure 4: Bottom-hole sample comparison of EOS model with CCE experiment

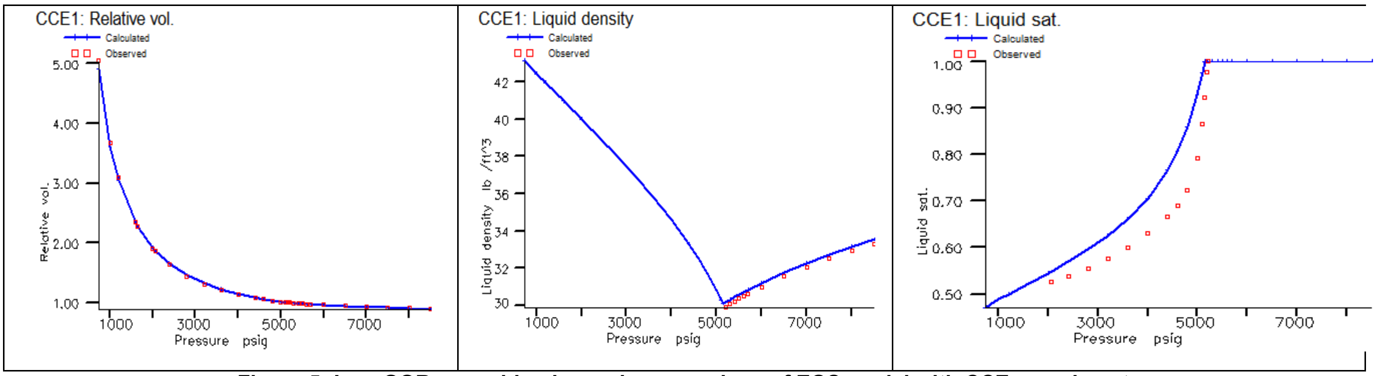

Figure 5: Low GOR recombined sample comparison of EOS model with CCE experiment

Both PVT models from bottom-hole and low GOR recombined samples would be used separately from this point onward to create two possible fluid types of gas condensate and volatile oil cases respectively. These fluids were analyzed independent from each other.

Well Test Analysis

Data preparations

Deconvolution was used in the interpretation of the well test data, as the basis for pressure transient analysis. The pressure and rate data (Figure 6) need to be properly prepared before applying deconvolution. Interpret 2010 and its functions were used for data preparation. The start of test time was selected to be the time when the well flow-line was connected to the acid injection line. The acid injection rates during well stimulation were retrieved from events sequence and synchronized with the pressure data to accurately estimate the initial reservoir pressure, and a correct derivation of pressure derivatives. For simplification purposes, the 15% HCl acid used during the stimulation was assumed to have similar properties as water. The entire rate history was then simplified by reducing the number of flow periods (FP) by merging flow periods that have about the same rate into one long flow period. There were initially 605 flow periods which later reduced to 76. Each flow period start and end times were also synchronized with the pressure data to have correct pressure build ups and drawdowns. By using the ‘winnow’ function in Interpret 2010, the number of data points was also reduced before importing the pressure and rate data into TLSD due to the limitation of data points. The reduction of data points also helped in enhancing the calculation speed. For the gas condensate case, the pressure data was linearized into normalized single-phase pseudo-pressure (Eq.1) with the gas condensate PVT properties from its PVT model. Figure 7 shows the rate validation where all of the three main build ups have the same derivative stabilization. These build up would later be used for the wellbore skin effect study.

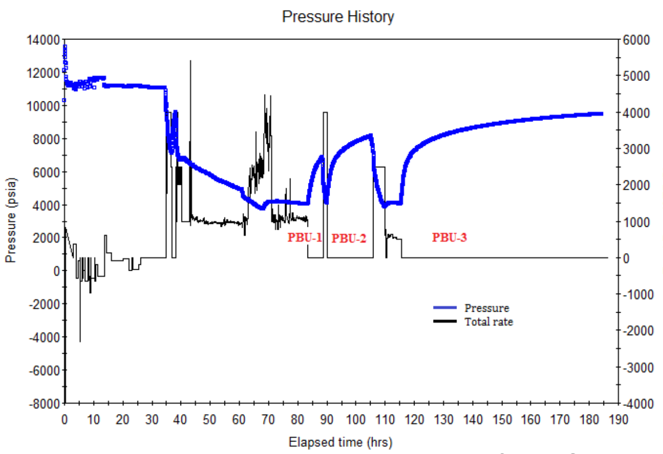

Figure 6: Pressure and rate data history from DST

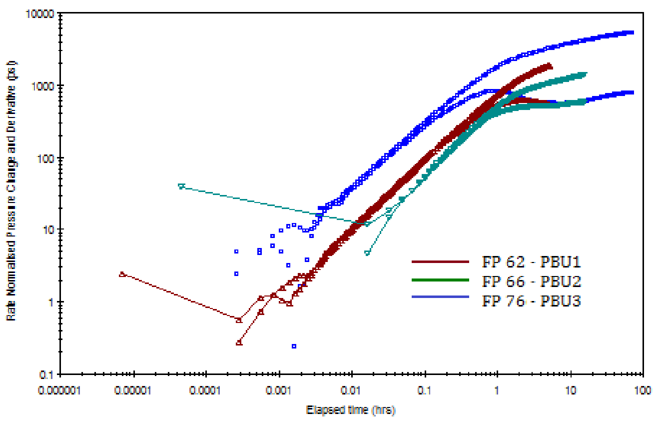

Figure 7: Rate validation of pressure build ups from DST

Deconvolution – initial reservoir pressure

Deconvolution is a new tool that processes pressure and rate data to obtain more pressure data for well test interpretation. It transforms variable-rate pressure data into a constant-rate initial drawdown with duration equal to the total duration of the test, and yields directly the corresponding pressure derivative, normalized to a unit rate (Gringarten 2006, 2010). Deconvolution removes the effects of rate variation from the pressure data measured during a well test sequence, thus the derivative is free from errors introduced by incomplete or truncated rate history and distortions caused by pressure-derivative calculation algorithms. As this process extracts more data available for interpretation than in the original data sets, it reveals underlying characteristic system behaviour that has been dominating throughout the test, and is not governed only by a specific flow period during the test (Levitan *et al.* 2004; Gringarten 2010).

Deconvolved pressure response is very sensitive to the value of initial reservoir pressure if the flow period being deconvolved is infinite acting (Gringarten 2010) thus making it as a very crucial parameter in deconvolution. The initial reservoir pressure entered by user affects the deconvolved pressure response at late time (Levitan *et al.* 2004). As there was inconsistency in the reported initial reservoir pressure of this field between the vertical well, horizontal well and MDT pressure, deconvolution was applied to correctly estimate the initial reservoir pressure by trial and error method. There are at least two infinite acting build ups available from the DST pressure data to meet this purpose. The correct P_i must yield the same deconvolved derivative (Levitan *et al.* 2004). For the gas condensate case, pressure data was converted to normalised pseudo-pressure in order to approximate a linear system before applying deconvolution. To make P_i estimation more accurate, the acidizing injection rates were included in deconvolving the pressure-rate data. Several initial pressures have been tested and the deconvolved pressures of different build ups were compared with the longest build up pressure derivative. Figure 8 shows an initial pressure of 10620 psia yields almost identical deconvolved derivative for several flow periods for both volatile and gas condensate cases. The deconvolved derivatives were also validated against the actual pressure history. Figures 9 and 10 show good matches were obtained between deconvolved derivatives and actual pressure data with maximum errors of less than 10% in the drawdowns (Gringarten 2010).

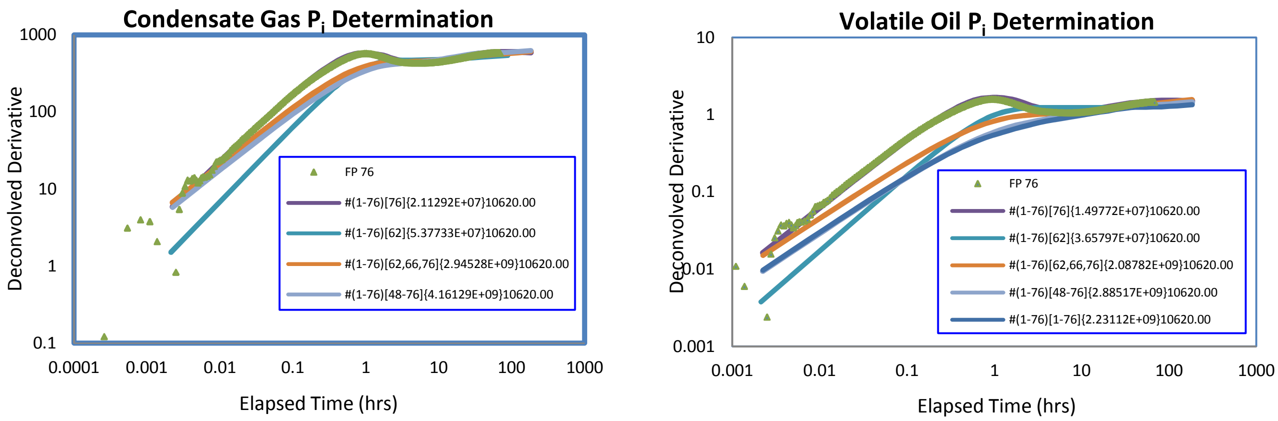

Figure 8: Initial pressure determination for both gas condensate and volatile oil cases

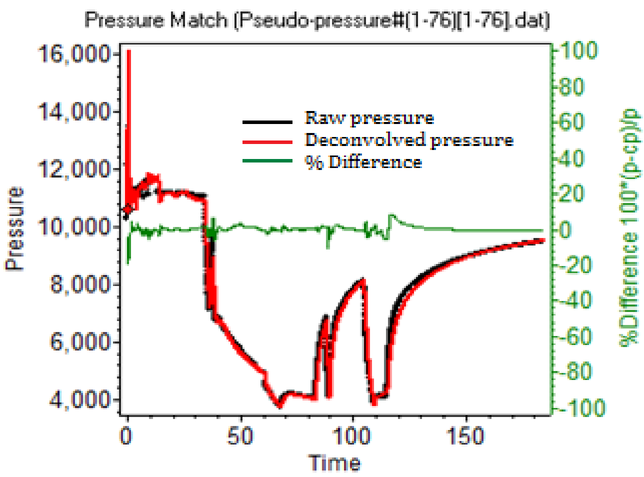

Figure 9: Entire pressure match for gas condensate

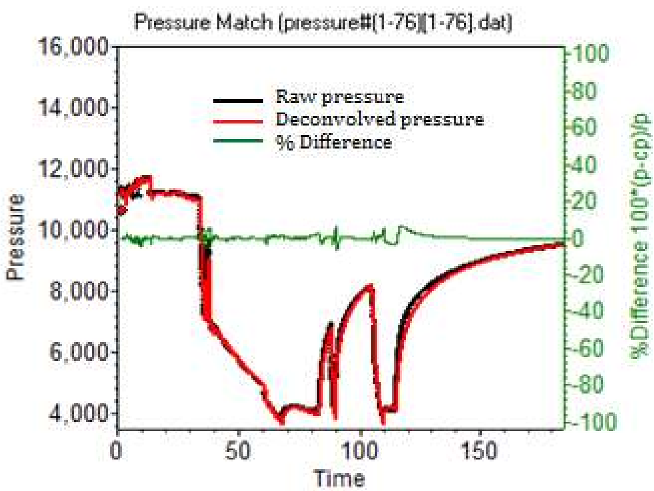

Figure 10: Entire pressure match for volatile oil

Principal of deconvolution – rate corrections

In this study, deconvolution was also used to correct erroneous and missing rates (Gringarten 2010). Some of the rates reported during the DST were only estimated values and it was important to correct the rates to correctly analyze the pressure-rate data. The rate correction was achieved by deconvolving the entire rate history and adapting the entire rate history with proper value of rate and curvature weighting parameters, ν and λ respectively. In this case, the initialized ν value was used but λ value was increased by a factor of 100 to smoothen the deconvolved pressure. Figure 11 and 12 show the adapted rate and the corresponding % error for both gas condensate and volatile oil cases.

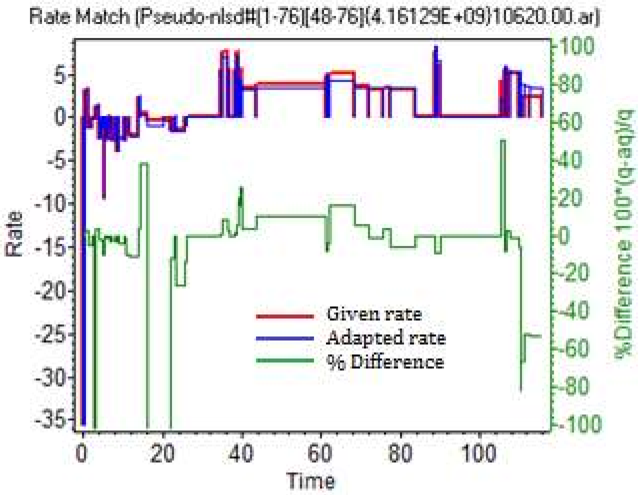

Figure 11: Rate corrections for gas condensate

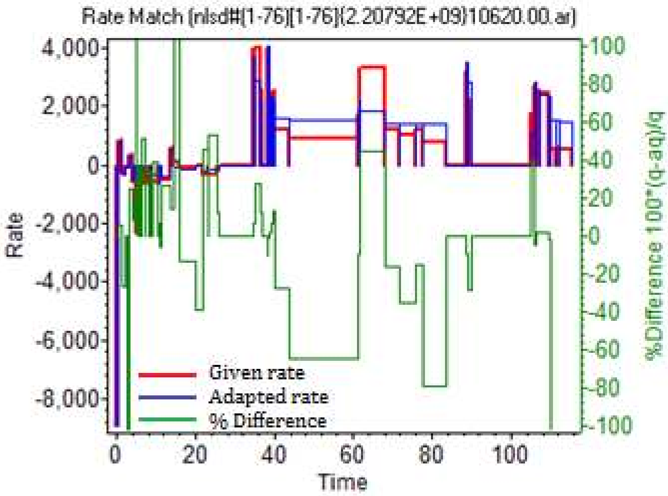

Figure 12: Rate corrections for volatile oil

Deconvolution – well test interpretation model

The methodology for well test analysis using deconvolution as proposed by Amudo *et al.* (2006) and Gringarten (2010) was used to interpret the DST pressure-rate data. After the initial pressure has been confirmed, rates have been corrected and a satisfactory derivative has been obtained, a convolved pressure is calculated and compared with the measure DST pressure. When the match was found acceptable, the unit-rate drawdown which has the same duration of the entire test was analyzed in the conventional way in Interpret 2010. The unit-rate drawdown response was calculated to match the initial reservoir pressure and the entire DST pressure while accounting for the flowing history of the well. Therefore, the resulting pressure response is a global representation of transient behavior associated with the whole test sequence (Levitan *et al*. 2004).

The pressure build up interpretation was done on both gas condensate and volatile oil cases. Both cases give the same interpretation model: uniform flux horizontal well with wellbore storage, C and skin, S; homogenous; and infinite lateral extent model, with about the same well test interpretation parameters. This makes sense as there is no reason the model should be different when the same reservoir is being tested. The slight difference in the parameters value could be due to the variation in the fluid PVT model between the two cases, which had affected the multiphase flowrate to single-phase flowrate conversion in interpret 2010. The interpretation model was then applied to interpret each build up using the adapted rates, and the model parameters were refined until an acceptable match was obtained. Table 2 shows the corresponding reservoir parameters for both cases and Figure 13 shows the resulting model of the unit-rate drawdown from the conventional well test analysis in Interpret 2010.

Parameter	Gas condensate	Volatile Oil	Unit
Initial Pressure, Pi	10620	10620	Psia
Horizontal permeability, k(xy)	0.1	0.4	mD
Vertical permeability, k(z)	0.008	0.01	mD
Effective horizontal length, L	580	610	ft
Wellbore skin, Sw	-1.5	-1.8	

Table 2: Well test interpretation parameters for gas condensate and volatile oil cases

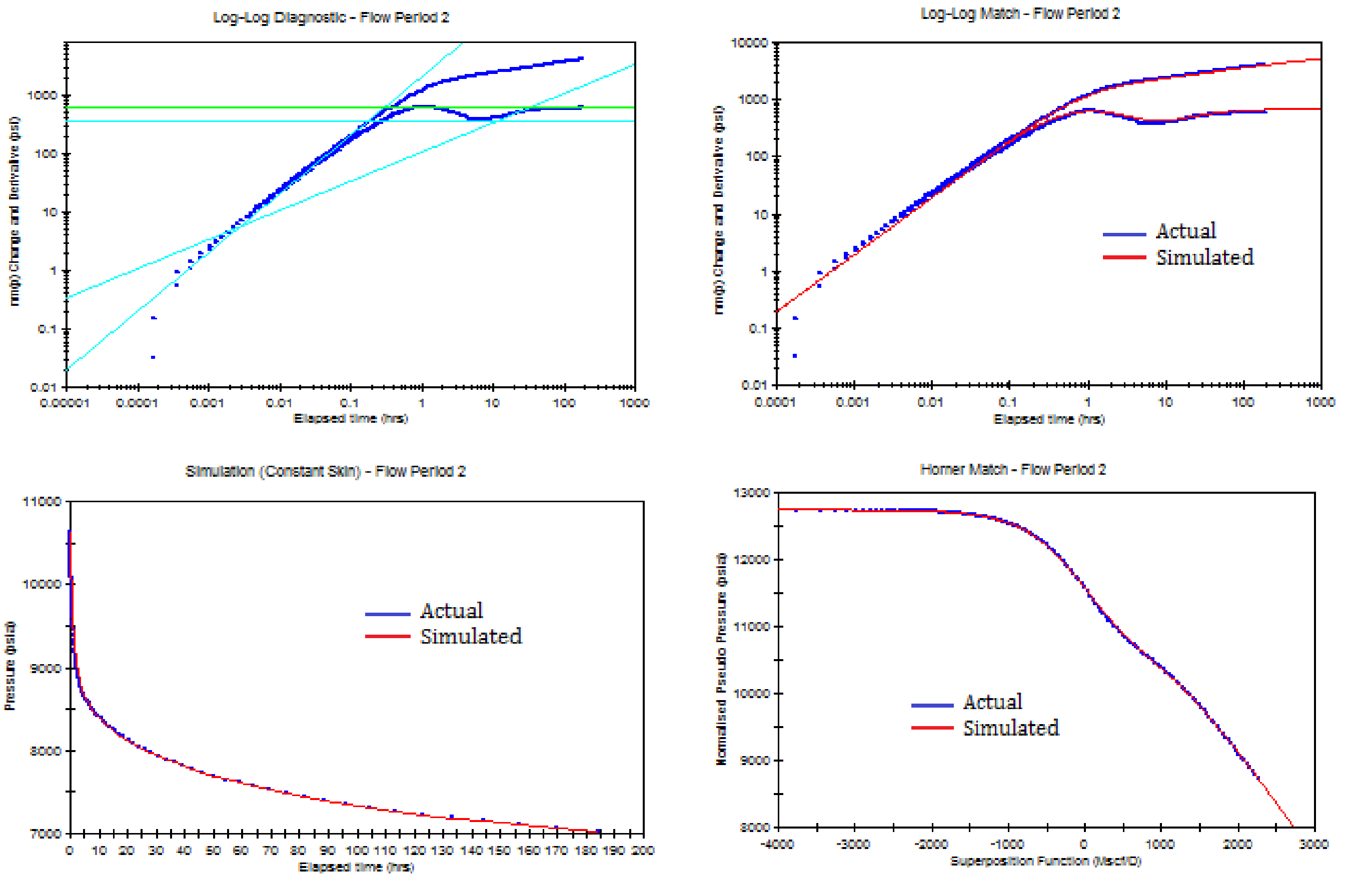

Figure 13: Interpretation model for unit pressure drawdown for gas condensate case

2-phase pseudo-pressure analysis

The wellbore skin effect of gas condensate case was analyzed with two-phase pseudo-pressure (Eq. 3) due to the development of region with different liquid saturations in the reservoir. For the case of volatile oil, the two-phase pseudo-pressure is transformed to:

$$m_{2\phi}(p) = \int_{p_{ref}}^{p} \left(\frac{k_{rg}R_v}{\mu_g B_g} + \frac{k_{ro}}{\mu_o B_o}\right)dp \qquad (5)$$

where R_v is the dissolve oil/gas ratio. The two-phase pseudo-pressure integral considers all the effects of two-phase fluid flow and transforms it into a single fluid equivalent flow. This transformation accounts for the pressure dependent fluid properties and relative permeability. There is no direct relationship between relative permeability k_{rg} and k_{ro} with pressure but it can be determined indirectly if a pressure-saturation relationship is defined for reservoir flowing conditions. Therefore the accuracy of the calculation is very much dependent on the fluid PVT modelling.

There were different methods proposed to calculate two-phase pseudo-pressure. For the purpose of this study, the method that was detailed by Bozorgzadeh (2006) in her PhD thesis is used. The correct radial flow stabilization which represents the reservoir absolute permeability can be achieved when the GOR at the well stream saturation pressure P_{bank} is used to calculate k_{rg}/k_{ro} (Bozorgzadeh and Gringarten, 2006). P_{bank} could be estimated from the single-phase pseudo-pressure derivative log-log plot for gas condensate and rate-normalized pressure log-log plot for volatile oil. The fluid PVT properties required for calculation were obtained from the simulated CVD experiment for the gas condensate case and Differential Vaporization experiment for the volatile oil case.

Figure 14 shows the gas condensate single and two-phase pseudo-pressure log-log plot for the third build up (FP 76) from the DST pressure-rate data. It can be seen that the 2-phase pseudo-pressure stabilizes at the same level the single-phase pseudo pressure derivative stabilizes. The stabilization takes place at the first stabilization of horizontal well behaviour since the bank only exists at the first stabilization. The calculated two-phase pseudo-pressure was then analyzed using the conventional well test analysis in Interpret 2010.

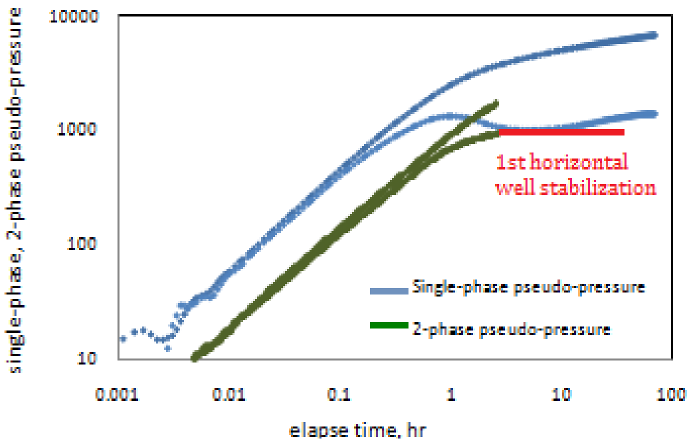

Figure 14: Single and two-phase pseudo-pressure log-log plot for gas condensate for FP 76 (PBU 3)

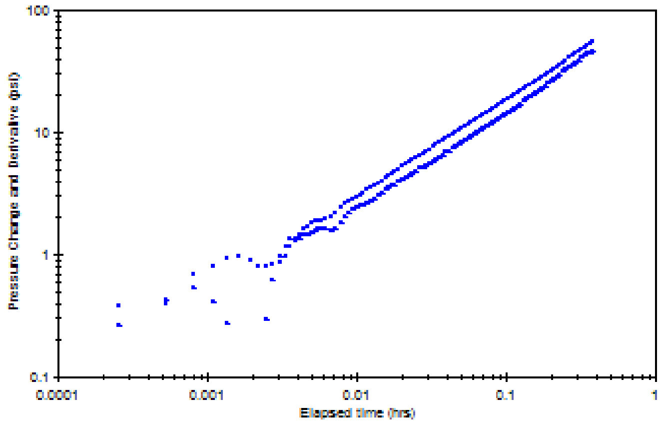

Figure 15: Two-phase pseudo-pressure log-log plot for volatile oil for FP 76 (PBU 3)

For the case of volatile oil fluid, since the bubble point pressure is considerably low (5200 psia) compared to the flowing pressure (around 4100 psia), the existence of multiphase-flow region near the wellbore did not last very long before the gas bank condensed back to the liquid phase during the pressure build-up. From the pressure-rate history and log-log plot illustrated in Figure 6 and 7, it can be seen that the pressure builds up very fast that it surpasses the bubble points in a very short time. Figure 15 shows the resulting two-phase pseudo-pressure log-log plot that was calculated for FP 76 and it was confirmed that the two-phase flow region only exist within the period where wellbore storage effect dominated. The same case applied for the other two pressure build ups FP 62 & FP 66. Due to this behaviour, the wellbore skin effect of volatile oil case was analyzed through the normal rate-normalized pressure, instead of two-phase pseudo-pressure. The conventional well test analysis was performed using Interpret 2010. Figure 16 shows the matches of well test analysis for the last build up of volatile oil case.

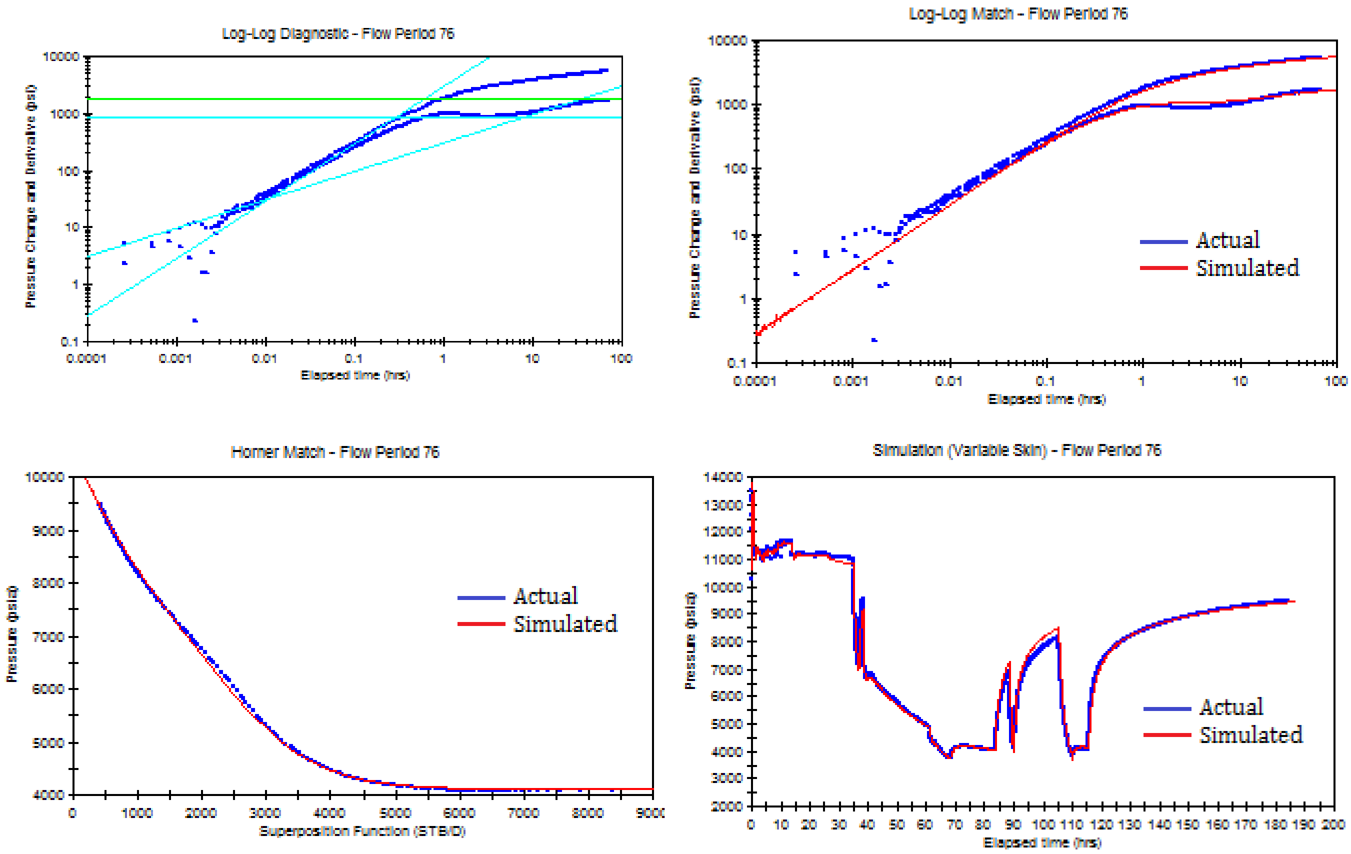

Figure 16: Well test analysis for FP 76 - PBU 3 (volatile oil case)

Results and discussion

Figure 17 and 18 show the skin effect for gas condensate and volatile oil cases, respectively. For the gas condensate case, the skin effect was analyzed using two-phase pseudo-pressure since the flowing pressure was below the dew point pressure. On the other hand, the volatile oil skin effect was only analyzed using the rate-normalized pressure as the bubble point pressure was considerably lower than the pressure build up data. Therefore the volatile oil case could be considered as single-phase flow.

Both cases show a positive trend of wellbore skin effect as rate increases but with different values of turbulence factor and rate-independent skin. The gas condensate case yields a significant positive turbulence factor of 0.18 Day/MMscf, and a rate-independent skin value of -1.7, while the volatile oil case yields a considerably small turbulence factor of 0.0013 Day/STB with a lower rate-independent skin value of -3.7. The difference in the mechanical skin values is difficult to justify since there was not enough pressure build ups above and below the saturation pressure to confirm the actual value.

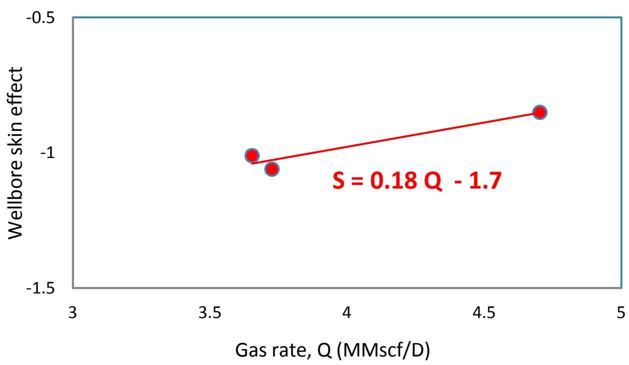

Figure 17: Wellbore skin vs. rate for gas condensate case

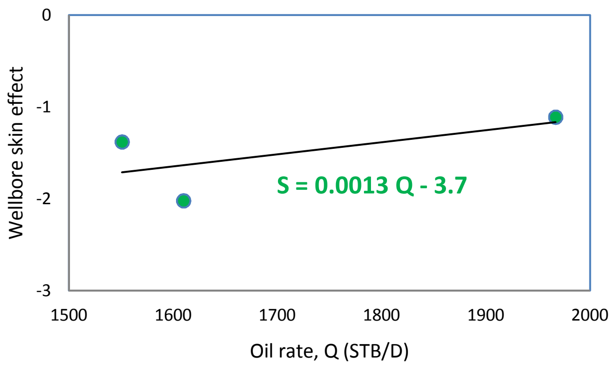

Figure 18: Wellbore skin vs. rate for volatile oil case

From a turbulence factor perspective, both cases yield the expected skin trend that corresponds to each fluid type as published in the literature; small value for volatile oil and a positive trend for gas condensate (Gringarten *et al.* 2011). However, for a fair comparison on the turbulence factor between the two cases, the comparison should be made using the similar turbulence factor unit. In this case, the gas flowrates were used for the comparison since wellbore skin effects are plotted against surface flowrates and both cases originated from the same surface flowrates. The wellbore skin effects from both cases were plotted against the gas flowrates as shown in Figure 19. From this plot it can be seen that the turbulence factor of volatile oil of 0.55 Day/MMscf is actually higher than the gas condensate itself and both cases still show an overall increasing trend of wellbore skin effect with rates.

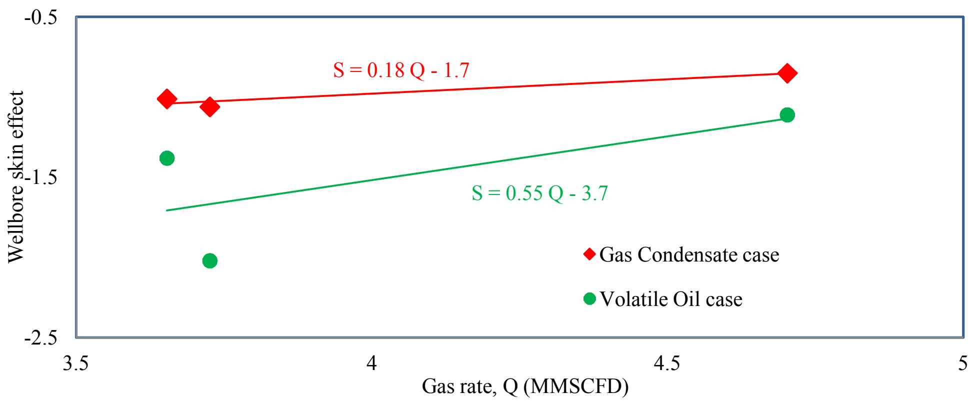

Figure 19: Wellbore skin vs. rate for both gas condensate and volatile oil cases

It is also important to emphasize that the analysis of the wellbore skin effect highly depends on the PVT model uncertainty. Although both cases show an overall positive trend in wellbore skin effect with rate, Figures 19 shows that either the first or second data point does not consistently follow the overall positive slope, and the flowrates for the first two data point are very close to each other. This inconsistency could be due to the random rate histories observed during the DST but this rate history-dependent skin effect is normally shown in the case of lean gas (Gringarten *et al.* 2011). However the molecular composition (C_1 between 60-70%) of the fluid that was tested did not show any possibility that the fluid could be a lean gas.

Regarding PVT model uncertainty, there was no CVD experiment performed on the bottom-hole sample for the gas condensate case. The required CVD data for two-phase pseudo-pressure calculation was simulated in PVTi based on regression against CCE experiment. The lack of experimental data could increase the uncertainty in PVT modeling. On the other hand, the interpretation of volatile oil case did not involve two-phase pseudo-pressure calculation although PVT model was used to convert multiphase flowrate to single-phase flowrate in the early stage of this study. The PVT modeling of volatile oil was also supported by Differential Vaporization experiment in addition to the CCE experiment that both cases have in common.

Conclusion

The results were derived from the information that was available from non-representative fluid samples and DST pressure-rate data from a horizontal well. Based on the behavior of the wellbore skin effect from both cases, the behavior of the skins is likely to associate with gas condensate system as both cases show a positive skin trend with rates.

Recommendations

The obtained results were derived base on fluid sample that was taken under non-ideal conditions and the recombined surface samples according to the observed GORs. The representativeness of the fluid sample is still questionable. The uncertainty in fluid properties could be reduced by having more lab-tested data from the bottom-hole samples that had been acquired during fluid sampling. If another appraisal well were to be drilled, it is recommended to run downhole fluid analyzer that currently available in the market to have better idea of the fluid at reservoir conditions, and to reduce uncertainty associated with fluid handling methods.

The quality of well test analysis could also be enhanced if the flowrates were properly reported. Some of the reported flowrates were just estimated values when the fluid was not flowed into test separator during the DST. Although deconvolution could be used to correct the estimated rates, the resulting difference between the adapted and reported rates was very significant. This difference could also contribute to the uncertainty in well test analysis.

The results of wellbore skin effect trend were only based on the three build up points. The wellbore skin effect study could have been more representative if more pressure build ups data were available, above and below the saturation pressure with broader range of flow-rates.

For future work, it is also a good idea to incorporate the DST data from the vertical well if it could help to reduce the fluid type uncertainty. The vertical well DST was not used in this study due to unknown well stimulation history during the DST which might have affected the wellbore skin effect differently.

Nomenclature

B = formation volume factor
CCE = constant composition expansion
CVD = constant volume depletion
D = non-Darcy coefficient
DV = differential vaporization
k = permeability
MMscf/D = million standard cubic feet per day
m(p) = pseudo-pressure
p = pressure
p_{bank} = well stream saturation point pressure
PBU = pressure build up
PVT = pressure-volume-temperature
Q = production rate
R_p = producing gas/ oil ratio
R_s = solution gas /oil ratio
R_v = dissolved oil/gas ratio
s =skin
S = saturation
STB/D = standard barrel per day
TLSD = total least square deconvolution
Z = real gas compressibility
L = distance

Subscripts

a = absolute
b = bubble
d = dew
eff = effective
g = gas
i = initial
m = mechanical
o = oil
r = relative
ref = reference
t = total
w = wellbore
1 ϕ = one phase
2 ϕ = two-phase

Greek

λ = curvature weighting parameter
μ= viscosity
ρ = density
υ = velocity
ν = rate weighting parameter

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APPENDIX A

Critical Literature Review

MILESTONES IN GAS CONDENSATE & VOLATILE OIL STUDY

TABLE OF CONTENT

SPE Paper n°	Year	Title	Authors	Contribution
JPT	1965	"Two Phase Flow of Volatile Hydrocarbons"	V.J. Kniazeff S.A. Naville	- First to numerically model radial gas condensate well deliverability. - First to describe three different zones around the well.
13185	1984	"Interpretation of Results From Well Testing Gas-Condensate Reservoirs: Comparison of Theory and Field Cases"	P. Behrenbruch G. Kozma	First to discuss wellbore dynamics effect in gas condensate wells.
14204	1985	"Interpretation of Flowing Well Response in Gas Condensate Wells"	J. R. Jones, R. Raghavan	First to propose a methodology for analysing well tests in gas condensate wells.
62920	2000	"Well Test Analysis in Gas Condensate Reservoir"	A.C. Gringarten A. Al-Lamki S. Daungkaew R. Mott T. M. Whittle	First to use 3-region composite model to analyse gas condensate well tests
100993	2006	Well Test Analysis in Lean Gas Condensate Reservoirs: Theory and Practice"	A.C. Gringarten M. Bozorgzadeh S. Daungkaew A. Hashemi	First to report the increasing, decreasing or remaining constant of wellbore skin factor at high rates Developing methodology to obtain gas end point relative permeability, base capillary number and critical oil saturation
116239	2008	"Well Test Analysis in Volatile Oil Reservoirs"	M. Sanni, A.C. Gringarten	Discuss typical well test behaviours in volatile oil reservoirs below the bubble point pressure.
JCPT	2009	"Two-Phase Flow in Volatile Oil Reservoirs Using Two-Phase Pseudo-Pressure Well Test Method"	M. Sharifi, M. Ahmadi	Describe two-phase pseudo-pressure method for well test interpretation of volatile oil reservoirs which includes predicting true permeability and mechanical skin with good accuracy.
134534-MS	2010	"Practical Use of Well-Test Deconvolution"	A.C. Gringarten	Variety of practical applications of deconvolution is presented such as correction of erroneous rates from DST's, initial reservoir pressure determination, identification of recharge from reservoir layers and compartmentalization - features which conventional well test analysis could not provide
143592	2011	"Assessment of Rate-Dependent Skin Factors in Gas Condensate and Volatile Oil Wells"	A.C. Gringarten O. Ogunrewo G. Uxukbayev	First paper to describe relationship of rate-dependent skin below saturation pressure calculated with two-phase pseudo-pressure are identical to the corresponding values calculated above dew point pressure with single-phase pseudo-pressure for condensate oil, and pressure above bubble point pressure in volatile oil reservoirs.

1. SPE 143592 (2011)

Assessment of Rate-Dependent Skin Factors in Gas Condensate and Volatile Oil

Authors: Gringarten, A.C., Ogunrewo, O., Uxukbayev, G.

Contribution to the understanding of wellbore skin effect in well test analysis:
First to show below saturation pressure in gas condensate reservoir, single-phase pseudo-pressure well test analysis does not correctly estimate the wellbore skin effect whereas analyses with two-phase pseudo-pressure do. Same goes for volatile oil, below bubble point pressure, well test analysis with normal pressure do not correctly estimate the wellbore skin effect, but 2-phase pseudo-pressure well test analysis can be used instead.

Objective of the paper:
To investigate the combined impact of capillary number and non-Darcy flow on the wellbore skin in lean and rich gas-condensate reservoirs , using single-phase and two-phase pseudo-pressures, and to compare non-Darcy coefficients and zero-rate skin factors above and below the saturation point pressure. Volatile oil reservoir was also included in the study.

Methodology used:
Compositional reservoir model was simulated with three different fluid types together with capillary number and non-Darcy effects to evaluate their impact on the skin evaluation. In order to study the impact of the rate sequence on wellbore skin, pressures for different rate histories (random, increasing and decreasing rates), were generated and analyzed for each type of fluid.

Conclusion reached:
Verified that well test analysis with 2-phase pseudo-pressure does correctly estimate the rate-independent wellbore skin effect and the non-Darcy flow coefficient in gas condensate and volatile oil wells below the saturation point pressure. The rate independent skin factor and the non-Darcy flow coefficient calculated with two-phase pseudo-pressure are identical to the corresponding values calculated above the saturation point pressure with single-phase pseudo-pressure for gas condensate and pressure for volatile oil.

Comments:
The results were verified and confirmed with actual data from lean and rich gas condensates as well as volatile oil reservoir.

2. SPE 116239 (2008)

Well Test Analysis in Volatile Oil Reservoirs

Authors: Sanni, M., Gringarten, A.C.

Contribution to the understanding of the volatile oil reservoirs:
Understanding the behavior of volatile oil reservoir when the bottomhole pressure falls below the bubble point pressure followed up subsequent build up

Objective of the paper:
To indentify typical well test behaviors in volatile oil reservoirs above and below the bubble point pressure

Methodology used:
Compositional numerical simulation was used to verify the effect of capillary number on well test data

Conclusion reached:
Existence of two-zone radial composite behavior when the bottomhole pressure falls below the bubble point pressure
During the buildup, the gas created around the well bore during the preceding drawdown condenses into the oil and initial gas saturation is created.

3. SPE 116239 (2004)

Well Test Analysis of Horizontal well in Gas-Condensate Reservoirs

Authors: Hashemi, A., Gringarten, A.C

Contribution to the understanding of the horizontal well gas condensate reservoirs:
The first to detail the near wellbore effects in well tests of horizontal wells in as condensate reservoir below the dew point

Objective of the paper:
To establish an understanding of the near-wellbore well test behavior in horizontal wells in gas condensate reservoirs, with a focus on the existence of different mobility zones due to condensate dropout

Methodology used:
3D Compositional model was used to develop derivative shapes to be expected from horizontal well test data and actual field data that exhibit the same characteristics was analyzed. Compositional model was used to verify the results from conventional well test analysis

Conclusion reached:
In horizontal well test, condensate deposition creates a composite well test behavior similar to what is obtained in vertical wells, but superimposed on a horizontal well behavior

Comments:
Actual well test behaviors were consistent with behaviors predicted from compositional simulations.
Only the derivative stabilization corresponding to the reduced mobility zones due to condensate deposit could be identified on the log-log plot at early times. Derivative stabilization due to capillary number effects could not be identified due to the dominating wellbore storage effect.
Due to complex PVT behavior in gas-condensate systems, both analytical well test analysis and compositional simulation are required to analyze well test in horizontal well.

4. SPE 62920 (2000)

Well Test Analysis in Gas Condensate Reservoir

Authors: Gringarten, A.C., Al-Lamki, A., Daungkaew, S., Mott, R., Whittle, T.M.

Contribution to the understanding of the gas condensate reservoirs:
First to use three-zone radial composite model to analyze gas condensate well test data

Objective of the paper:
To investigate the existence of increased mobility zone in the near vicinity of the wellbore in well test data

Methodology used:
Compositional numerical simulations to verify existence of different mobility zones (Capillary number effects)
Analyzing well test data from numerous gas condensate fields

Conclusion reached:
Negative impact of phase distribution in analyzing well test data
Verification of the existence of three mobility zones on well test data

5. SPE 134534-MS (2010)

Practical Use of Well-Test Deconvolution

Authors: A.C. Gringarten

Contribution to the understanding of a deconvolution method in well testing:
Proved that deconvolution is as a powerful tool in well test analysis and showed examples where decovolution was used in identification of boundaries, connectivities and multilayer behavior in a gas condensate

Objective of the paper:
To recommendations on how to perform deconvolution and how to verify deconvolution results
To illustrate various applications of deconvolution well test interpretation

Methodology used:
Deconvolution of well test data from a gas condensate reservoir is applied on individual DST build-ups, build-ups during production phase, groups of build-ups and continuous multi-flow periods & final unit-rate pressure drawdown analysis.
Deconvolution of DST data in an oil well. Comparison of pressure histories calculated from the deconvolved derivatives, with and without rate adaptation, with actual pressure history.

Conclusion reached:
Deconvolution increases the radius of investigation, which allows seeing boundaries and connectivities not visible in individual flow periods
Deconvolution corrects erroneous rates and determines missing rates.
Deconvolution can be applied to pseudo-linear systems such as with gas and multiphase flow.

APPENDIX B

Geology illustration of the field

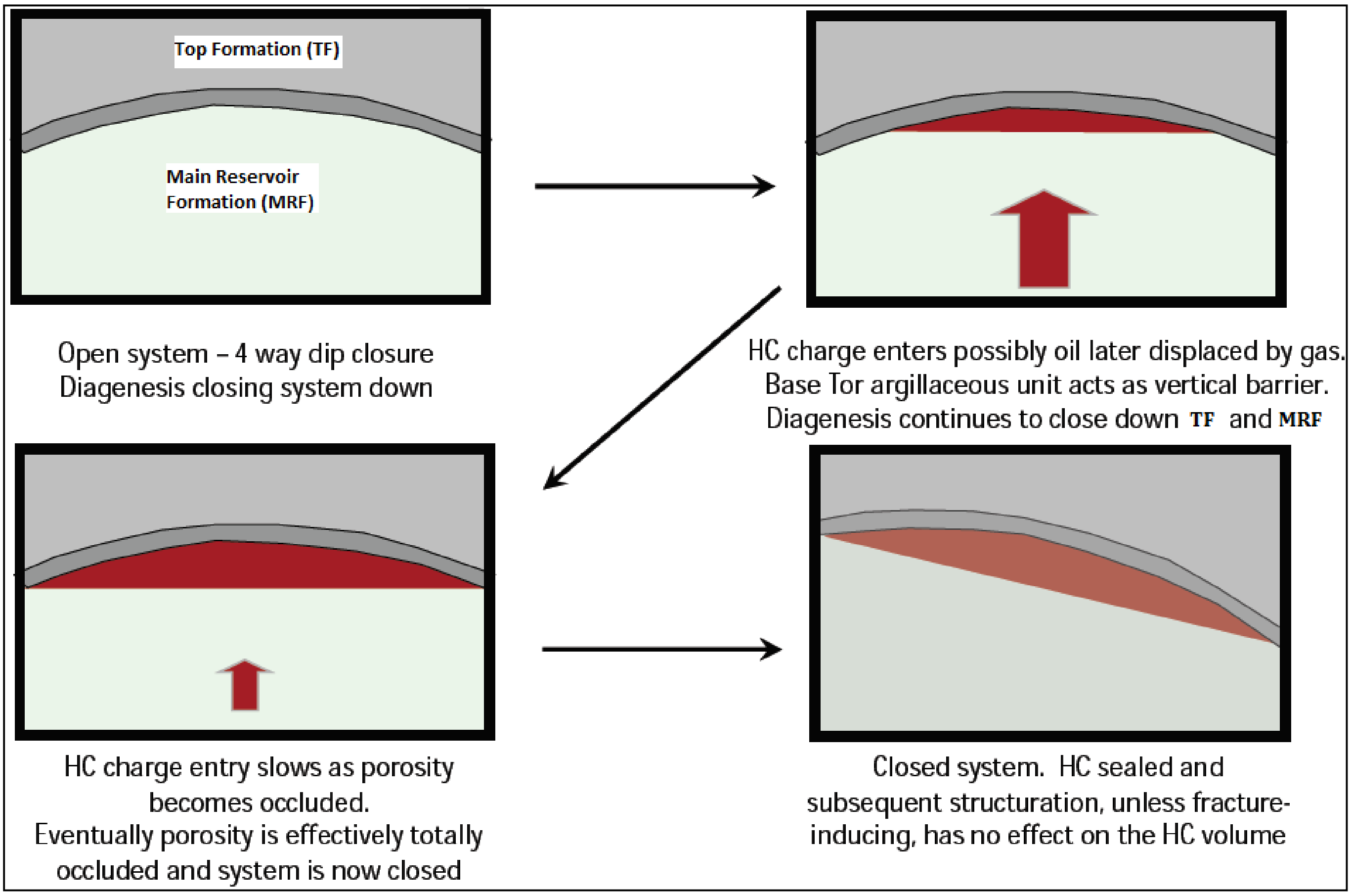

Figure B 1: Hydrocarbon accumulation system in the field under study

APPENDIX C

The comparison of EOS model results and experimental data for both bottom-hole and low GOR recombined samples are shown in below presented figures.

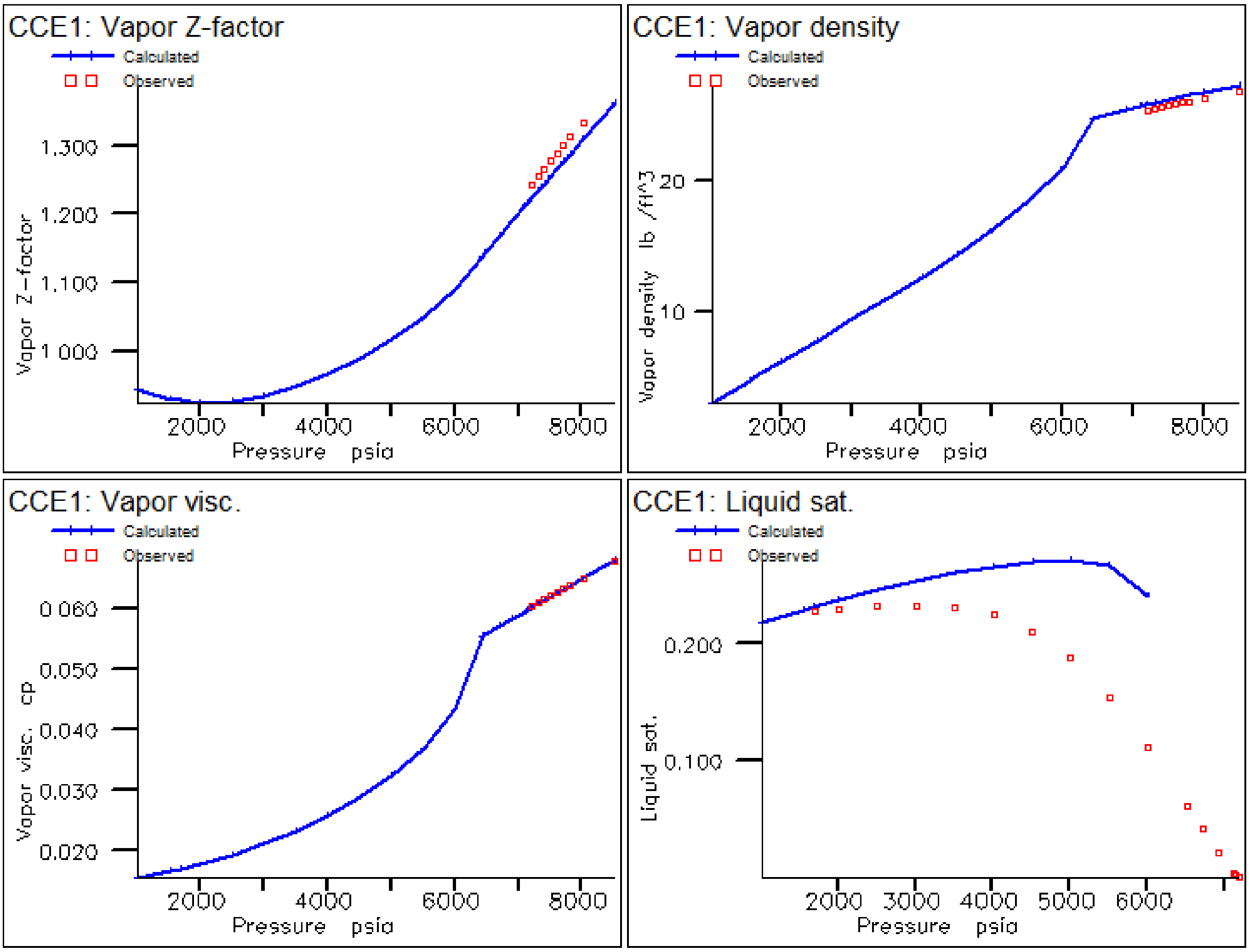

Figure C 1: Comparison of EOS predicted and observed values from CCE experiment for bottom-hole sample

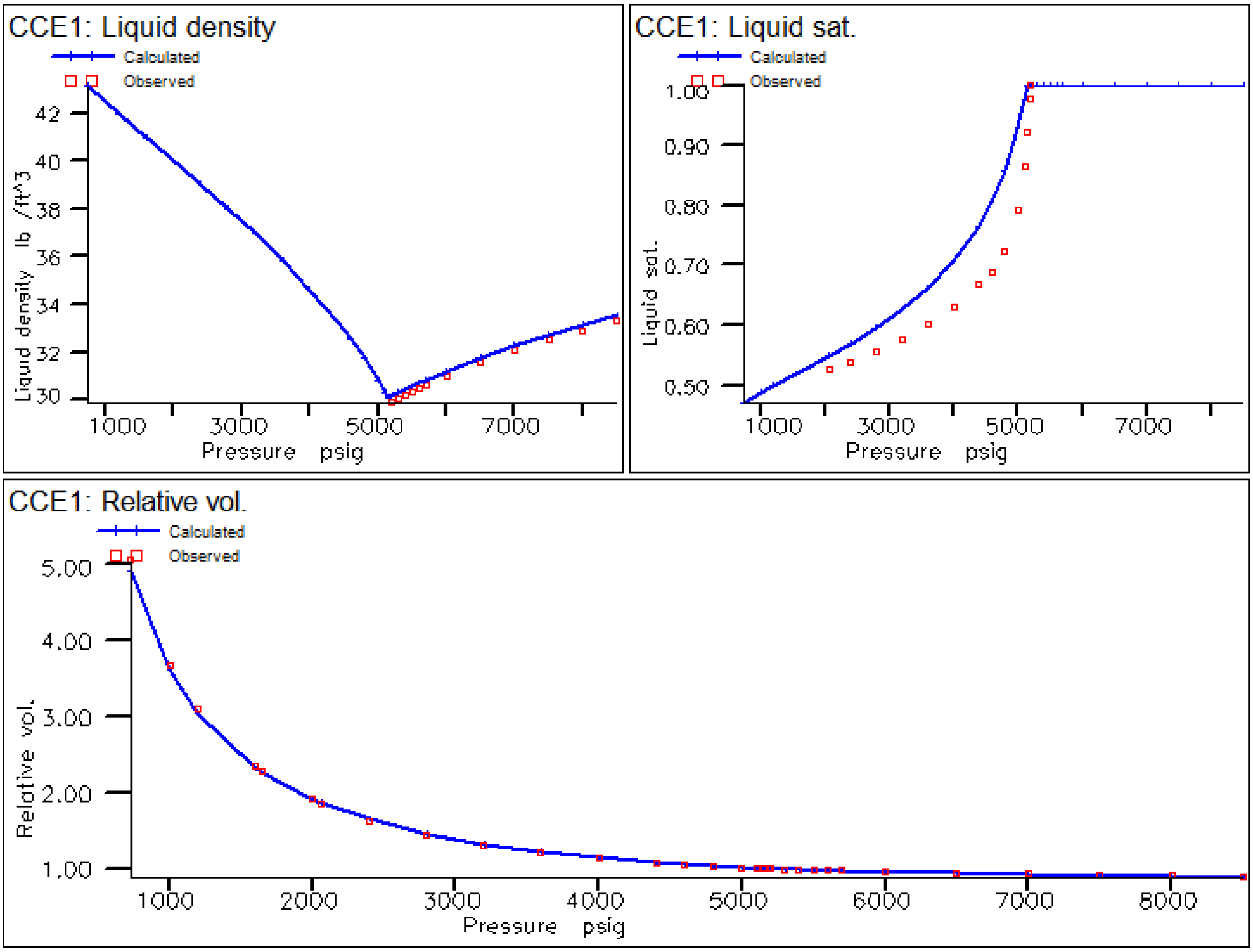

Figure C 2: Comparison of EOS predicted and observed values from CCE experiment for low GOR recombined sample

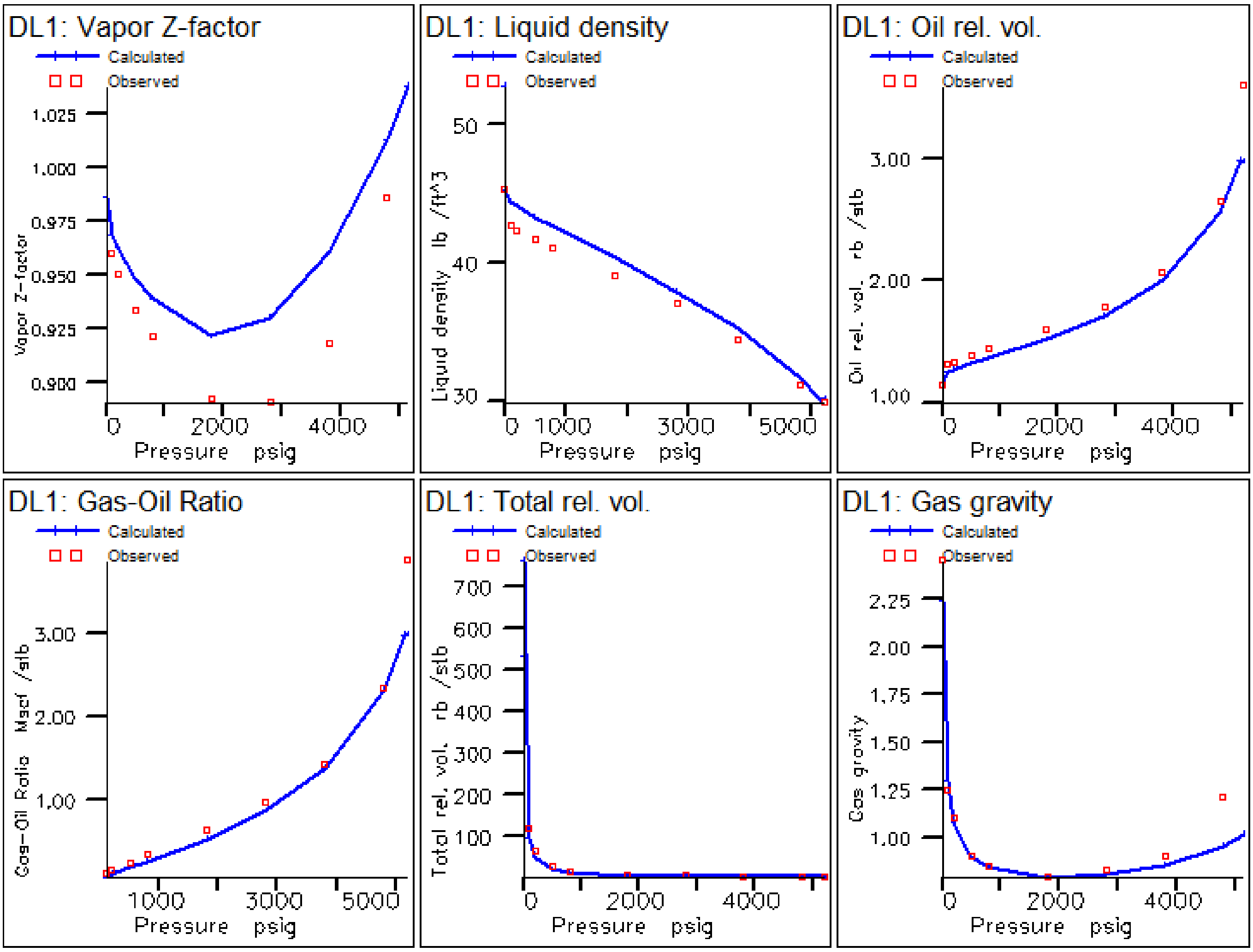

Figure C 3: Comparison of EOS predicted and observed values from DV experiment for low GOR recombined sample

APPENDIX D

Well test interpretation model

The well test interpretation model from unit-rate pressure drawdown for volatile oil is shown below:

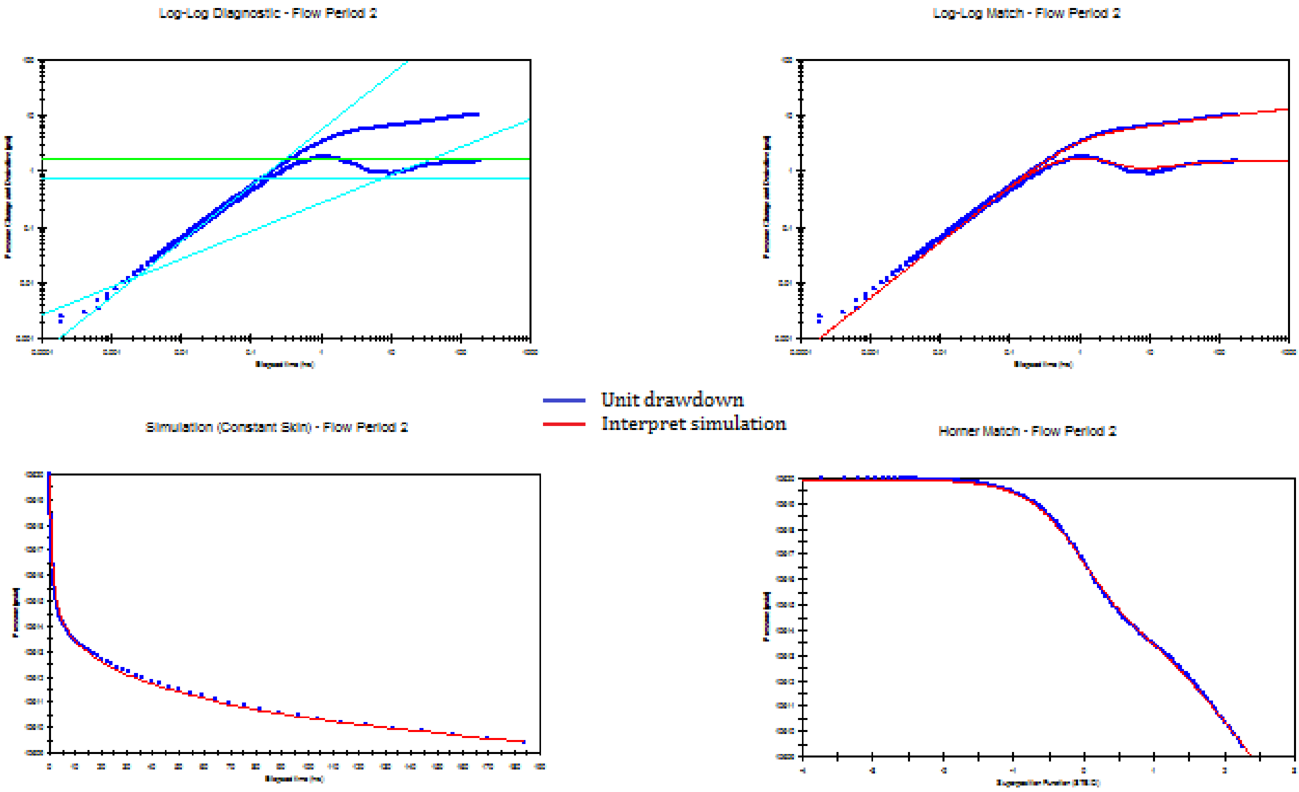

Figure D 1: Interpretation model from unit-rate drawdown for volatile oil case

APPENDIX E

Well test interpretation for volatile oil case

Below are the pressure matched for volatile oil case, analyzed with normal pressure for the first two build up data:

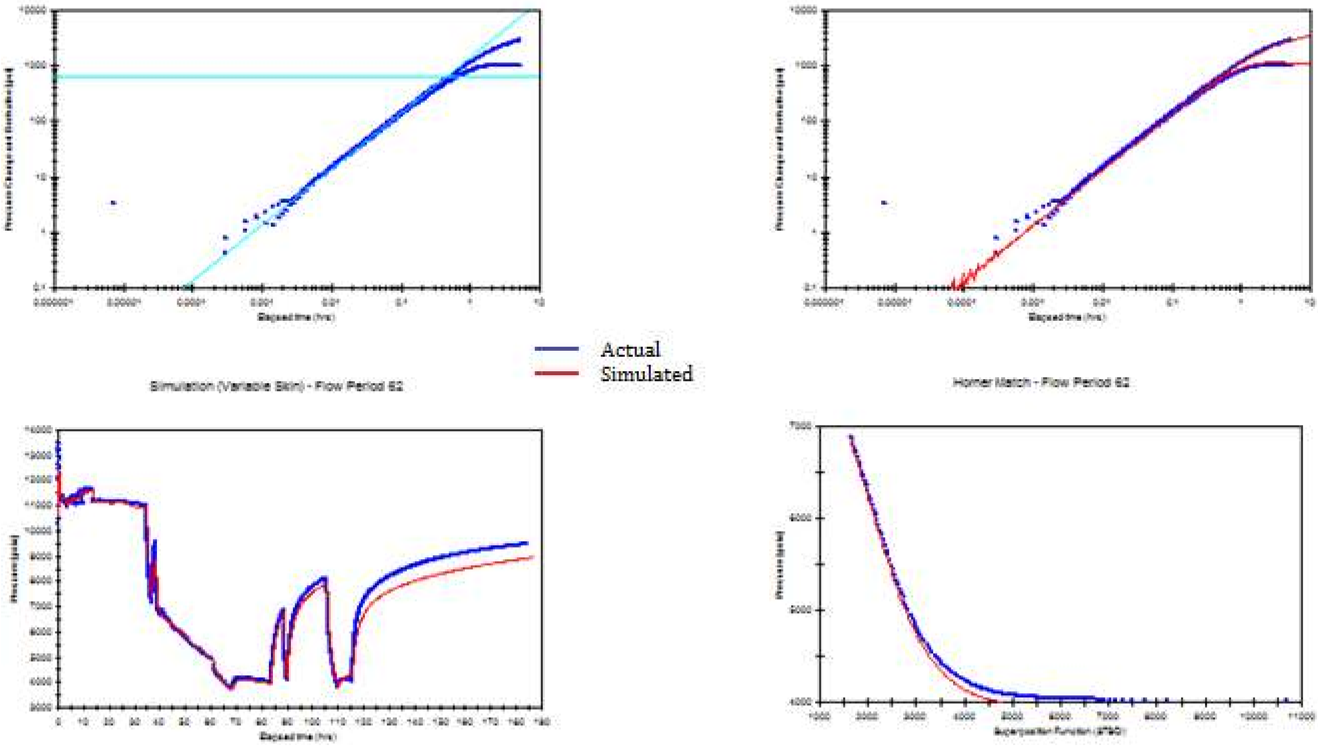

Figure E 1: Well test interpretation for PBU 1 (volatile oil case)

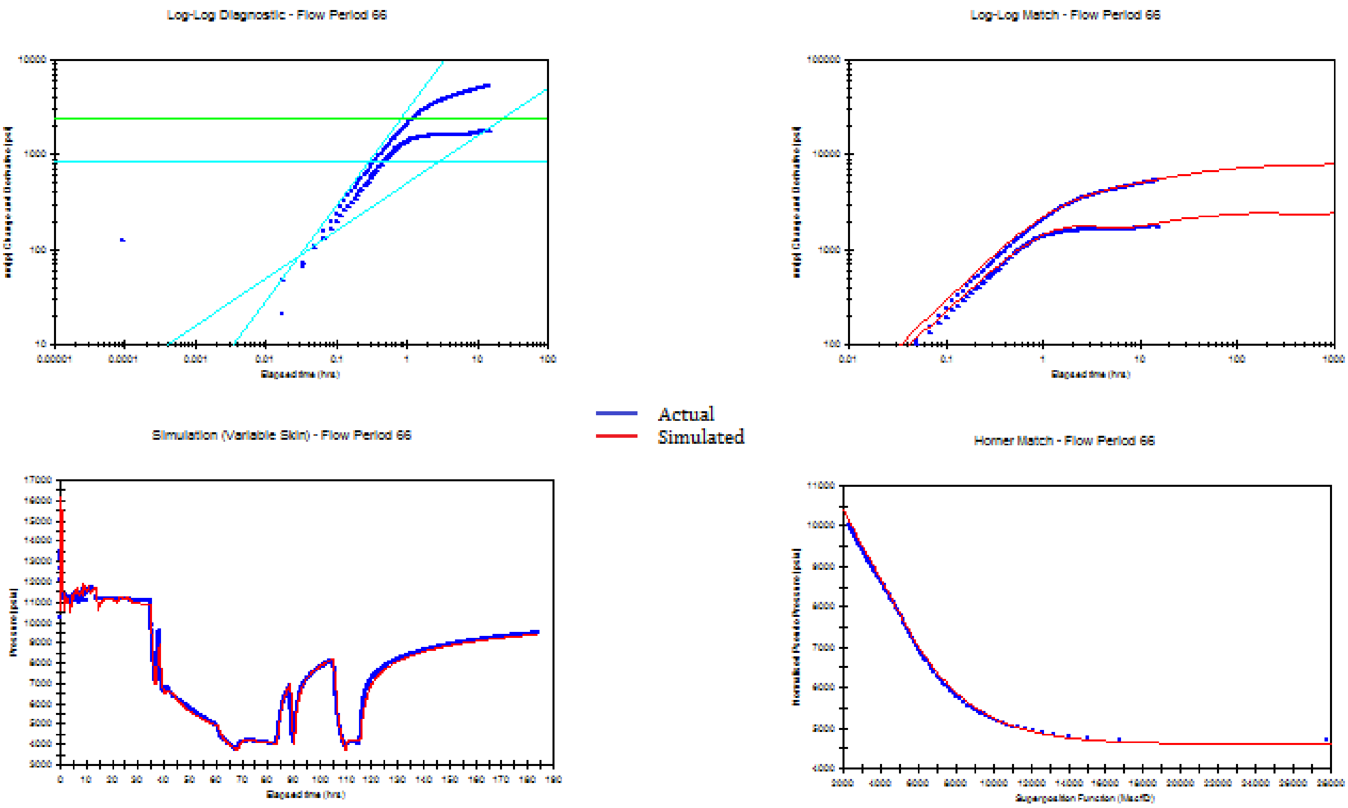

Figure E 2: Well test interpretation for PBU 2 (volatile oil case)

APPENDIX F

Well test interpretation for gas condensate case

Below are the pressure matched for gas condensate case, analyzed with 2-phase pseudo-pressure:

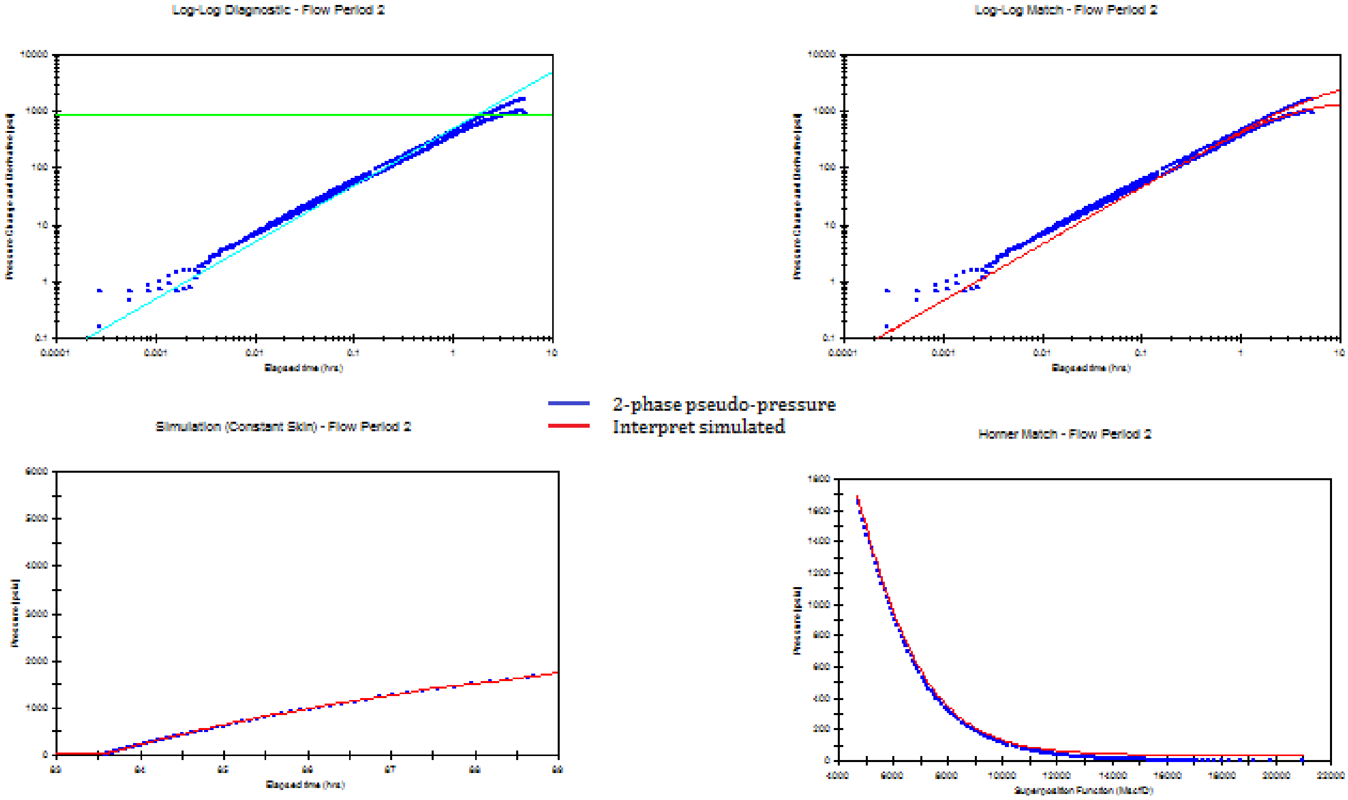

Figure F 1: Well test interpretation for PBU 1 (gas condensate case)

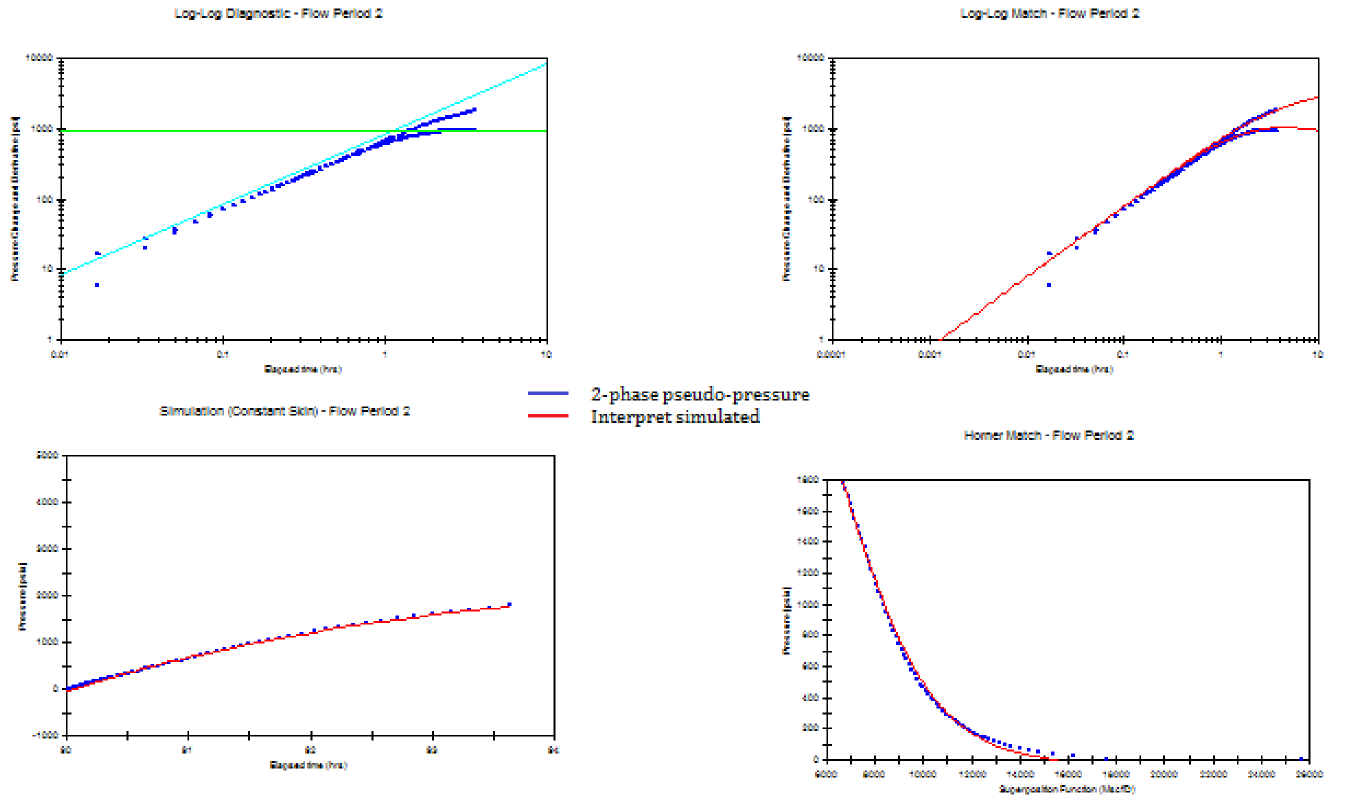

Figure F 2: Well test interpretation for PBU 2 (gas condensate case)

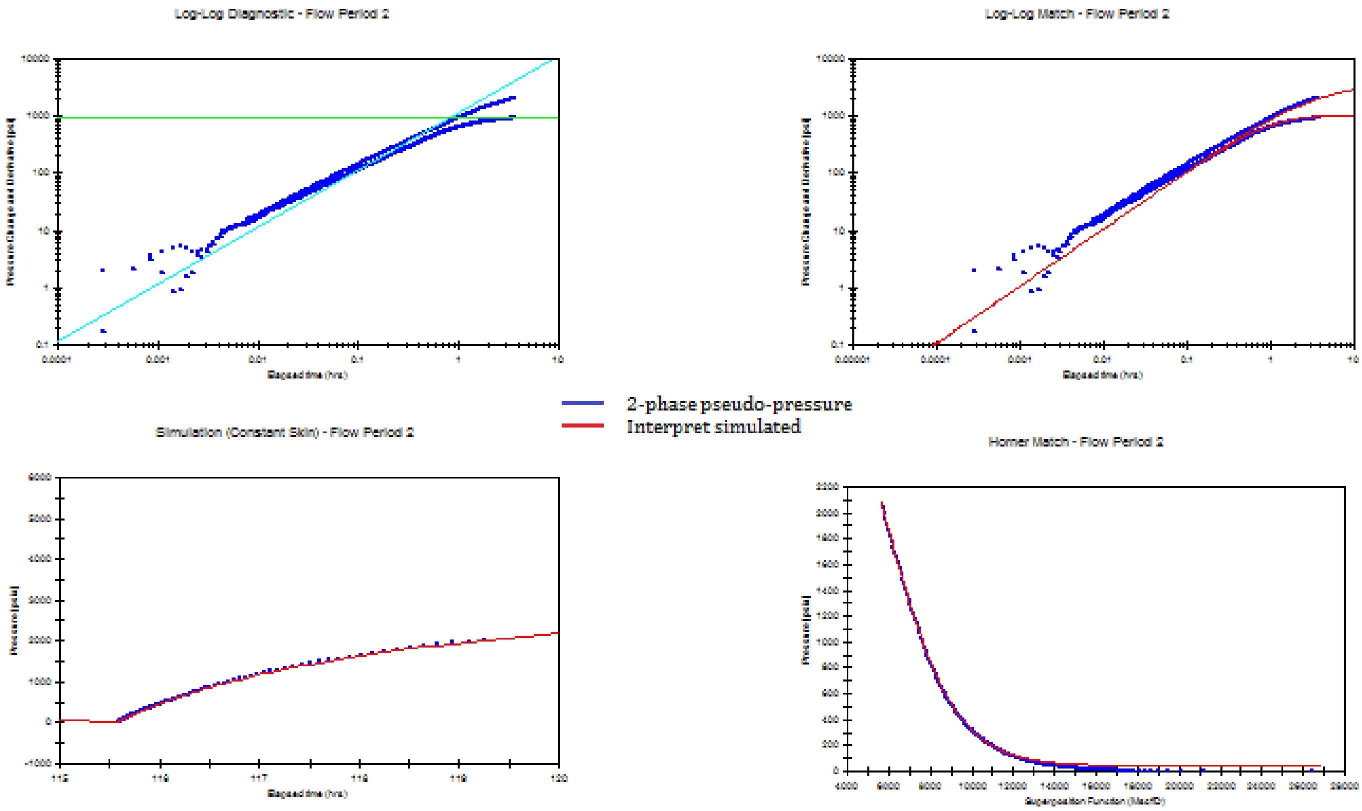

Figure F 3: Well test interpretation for PBU 3 (gas condensate case)