Well Test Analysis on Well-head Pressure Build-up to Identify Well Behaviour/Under Performance

By

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

September 2012
DECLARATION OF OWN WORK

I declare that this thesis

Well Test Analysis on Well-head PBU to Identify Well Behaviour/Under-Performance

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 acknowledgement given.

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This work is dedicated to my brother Stavros and my sister Demetra.
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To my brother and my sister,
Stavros and Demetra
Abstract

Well Test Analysis (WTA) on bottom-hole (BH) pressure data is the most reliable method to estimate the reservoir parameters and identify well behaviour. However recording bottom-hole data is not always operationally possible, whereas most wells are equipped with gauges at well-head (WH) and pressure data are recorded continuously at this point. In this project the ability of WH data to be used in identifying Well Behaviour is studied.

Three different cases have been tested according to the fluid behaviour in the wellbore: a water injector case where there is a single phase fluid in the wellbore and the density is fairly constant; a dry gas case, still single phase but with density varying in the wellbore; and a gas/condensate case where multiphase fluid is present in the tubing and the density is varying.

Several WH data along with their corresponding BH data were gathered for each case. The same methodology was used to study all of the cases. It involved initially the comparison of the log-log plots of the corresponding datasets to observe the differences and the similarities between them. WTA was then performed to confirm the observations and lastly an attempt was made for an analytical approach.

Several methodologies are presented to estimate or correct permeability and skin values derived from well-head data for different fluid type cases. It is demonstrated how to convert WH to BH data for water injector and dry gas cases based on the techniques suggested in the literature and further confirmed in this work using real field data. Finally for the gas/condensate case, two conversion methods were developed and illustrated. At this stage, due to the limited time and scope of this project, the study was only focused on estimating permeability and skin, as two main characteristic parameters of reservoir and well behaviour.

In the case of the water injector it is shown that analysis of WH data can estimate permeability but overestimates skin whereas in the dry gas and gas condensate cases WH analysis overestimates both permeability and skin factor. For the first case a conversion from WH to BH pressures is considered and a way to evaluate the skin is also provided. In the case of the dry gas a method to correct the WH derived permeability and skin is presented along with an equation that converts WH to BH pressures. Finally in the gas/condensate case two methods were developed to estimate BH from the WH pressures which are illustrated in the next sections.

It is important to note that this work does not recommend replacing conventional BH WTA with WH analysis. The intention is to provide some tools for engineers to derive important well and reservoir parameters from WH data in the cases where BH data are unavailable and especially for wells where down-hole pressure measurement is not possible.

Introduction

Identifying well and reservoir behaviour is a key task for reservoir engineers during the appraisal phase of a field development. BH Pressure Transient Analysis (PTA) is currently the dominant method of estimating the reservoir parameters and well behaviour. Since WH gauges are present on all wells, WH pressures are often continuously recorded by the operating companies. The amount of WH data available raises the question of whether this data can be used to identify well and reservoir behaviour. The aim of this work is to investigate the ability of WH data to provide useful estimations on key reservoir parameters such as permeability and skin.

Being able to withdraw useful information from the WH data provides several advantages for the companies. The cost of a down-hole survey to begin with is much greater in comparison with a WH survey where the data are gathered anyway and the risk of running tools in the wellbore is eliminated. For High-Pressure/High-Temperature (HP/HT) wells this is most significant because of the harsh down-hole conditions and especially for wells that due to completion or other restrictions cannot be tested at all.

Despite its significance this area is not yet fully explored. Smith, R.V. (1950) was the first to propose a WH to BH conversion algorithm for flowing dry gas wells. Cullender and Smith (1956) developed a procedure to calculate pressures in gas wells that
makes no assumptions for temperature and compressibility and their formula is widely used to calculate bottom-hole pressures. Several methods were also developed to account for the presence of liquid in the wellbore such as Govier and Fogarasi (1975) and the modified Cullender and Smith equation by Peffer et al. (1988). All the above methods provide satisfactory results but are strictly limited to flowing conditions.

Dall’Olio and Vignati (1998) were the first to develop a methodology which allows the use of WH pressure data for test interpretation purposes, correcting the obtained results to reservoir conditions. In their paper Fair et al. (2002) present a complete methodology of categorizing wells based on the type and the behaviour of fluid in the reservoir and in the wellbore as well as a procedure of testing wells from the surface.

This project studies the ability of WTA on WH Pressure Build-Up (PBU) to identify well behaviour. Three different cases have been investigated according to the fluid behaviour in the wellbore: a water injector case where there is a single phase fluid in the wellbore and the density is constant; a dry gas case, still single phase but with density varying in the wellbore; and a gas/condensate case where a two-phase fluid is present in the tubing and the density is varying. At this stage, due to the project’s time restrictions, the study is only focused on determining the impact on permeability and skin. The analysis of the three cases will be presented individually for each one. The method used to approach this project was to study datasets of WH with their corresponding BH pressures at the same time. In this way the results of the investigation could be validated against the actual results derived from the BH data.

Initially the comparison of the pressure change and derivative on a log-log plot along with qualitative results of the observations will be presented as well as the results of WTA that was performed to confirm the observations and allow for quantitative comparison. Finally the outcome of the analytical investigation that was attempted will be illustrated.

**Methodology, Analysis and Discussion**

The same methodology was followed for all of the three cases. Initially the log-log plots of the BH along with the corresponding WH pressures were observed, subsequently WTA was performed and finally an analytical attempt was made to convert WH to BH pressures and yield the correct values for the parameters. Each case will be presented individually and as a whole.

**Case 1: Water Injector**

*Log-log plot comparison*

The case of the water injector well was first studied (Figure 1). Only single-phase fluid with a fairly constant density is present in the wellbore. Comparing the log-log plots of BH with the corresponding WH pressures (Figure 2) shows that the derivative curves are very similar between the two data sets. This is an indication that WH data can be used to estimate permeability. The difference in the Δp curve suggests that WH data tend to significantly overestimate the skin.
WTA

WTA on the data (Figure 3) confirms the observations as it is shown in Table 1. Unfortunately only fall-off 6 was long enough to reach radial flow stabilization. BH and WH analysis returned the same permeability which was then used to analyse the remaining WH data. As it was expected from the log-log plots, WH data significantly overestimate skin. The skin is decreasing between the fall-offs which suggests that the well gets stimulated. A fracture of the formation created by the water injection could explain this observation.

Figure 2: Comparison between the log-log plots of BH with WH data (E.ON E&P UK Field Development Well Test Report (2012)).

Table 1: Permeability and skin estimations from BH and WH data

<table>
<thead>
<tr>
<th></th>
<th>BH</th>
<th>WH</th>
</tr>
</thead>
<tbody>
<tr>
<td>FO1</td>
<td>27</td>
<td>27</td>
</tr>
<tr>
<td>Skin</td>
<td>37.5</td>
<td>93.5</td>
</tr>
<tr>
<td>FO2</td>
<td>27</td>
<td>27</td>
</tr>
<tr>
<td>Skin</td>
<td>26.7</td>
<td>70</td>
</tr>
<tr>
<td>FO3</td>
<td>27</td>
<td>27</td>
</tr>
<tr>
<td>Skin</td>
<td>25</td>
<td>28.7</td>
</tr>
<tr>
<td>FO4</td>
<td>27</td>
<td>27</td>
</tr>
<tr>
<td>Skin</td>
<td>22.7</td>
<td>52.9</td>
</tr>
<tr>
<td>FO5</td>
<td>27</td>
<td>27</td>
</tr>
<tr>
<td>Skin</td>
<td>20.8</td>
<td>92</td>
</tr>
<tr>
<td>FO6</td>
<td>27</td>
<td>27</td>
</tr>
<tr>
<td>Skin</td>
<td>20.4</td>
<td>65.2</td>
</tr>
</tbody>
</table>

Analytical Approach

Under the assumption that the water is incompressible and that the BH pressure is the WH plus the weight of the water column the above observations can be proved analytically. The bottom-hole pressure during build-up is given by Equation 1.

\[ p_t - p_{wf} = \frac{162.6 \mu B}{k h} \left( log t + log \left( \frac{k}{\phi \mu C_r w} \right)/3.23 + 0.87 s \right) \]
Well Test Analysis on Well-head PBU to Identify Well Behaviour/Under Performance

Assumption 1: \( p_{wf} = p_{wh} + \Delta p \)

Assumption 2: \( \frac{dp}{dt} = 0 \)

Then Equation 1 can take the form of Equation 2.

\[
p_i - p_{wh} = \Delta p + \frac{162.6 q u B}{k h} \left( \log t + \log \frac{k}{\phi \mu c_t r_w^2} \right)
\]

It is now obvious that the derivatives of Equations 1 and 2 with respect to \( \ln t \) are the same. Therefore the analysis of WH data yields the same permeability as with BH data. BH pressures were estimated by adding the weight of the water column to the WH pressures. The plot of the converted BH data is shown in Error! Reference source not found.4 and the log-log plot of the actual and estimated BH data in Figure 5. The estimated BH pressures offer a very good match with the actual pressures except at early times due to the fact that the initial WH pressure is high because of the water injection. The high initial estimated BH pressures is the reason why the estimated data result in a higher \( \Delta p \) curve. The matching derivative curve is due to the fact that the conversion method provides a constant error between the estimated and the actual BH data. These two observations indicate that analysis on the estimated data yields the correct permeability but higher skin.

Each point of Error! Reference source not found. represents the difference between the BH and the WH pressures at each time step. The difference increases for the first few seconds which means that the WH pressure is falling off faster than the BH. The stabilization after that confirms assumption 1 that the difference between the two pressures is constant. This profile confirms that a higher \( \Delta p \) curve should be expected from the WH data as well as a higher skin estimation.

It is possible to use the permeability derived from the WH analysis to calculate the skin. Converted BH pressures can be used and the skin is estimated by rearranging the semi-log radial flow approximation equation (Equation 4). This correction method can yield satisfactory results as it can be seen in

\[
p_D(t_D) = \frac{1}{2} (\ln t_D + 2s) + 0.80907
\]

\[
s = \frac{2p_D - \ln t_D - 0.80907}{2}
\]

where \( p_D = \frac{k h \Delta p}{141.2 q u B_w} \) and \( t_D = \frac{0.009264 k \phi c_t r_w^2}{\mu c_t r_w^2} \)

![Figure 4: Plot of the estimated along with the actual and the WH data.](Image)
It is shown in Figure 7 that the correction provides satisfactory results of the skin. The WH Vs BH curve however displays an inconsistency between FO3 and FO4. After FO3 the injection rate was increased from 1440 bbl/d to 2880 bbl/d. Since the WH pressure is affected by the injection of the water it can be assumed that increased injection rate will result to a higher WH pressure at the beginning of the fall-off. Consequently a higher Δp curve of the WH data is expected and therefore an increased skin estimation.

### Table 2: Comparison of the corrected skin against WH and BH estimations.

<table>
<thead>
<tr>
<th>Case</th>
<th>WH</th>
<th>Corrected</th>
</tr>
</thead>
<tbody>
<tr>
<td>FO1</td>
<td>93.7</td>
<td>36.3</td>
</tr>
<tr>
<td>FO2</td>
<td>70</td>
<td>25.3</td>
</tr>
<tr>
<td>FO3</td>
<td>52.9</td>
<td>22.6</td>
</tr>
<tr>
<td>FO4</td>
<td>92</td>
<td>22.4</td>
</tr>
<tr>
<td>FO5</td>
<td>65.2</td>
<td>21.8</td>
</tr>
<tr>
<td>FO6</td>
<td>13.9</td>
<td>1.8</td>
</tr>
</tbody>
</table>

**Figure 5:** Comparison between estimated and actual BH pressures.

**Figure 7:** WH and corrected skin factor Vs BH.

**Figure 6:** Subtraction of WH from BH pressures.

**Case 2: Dry Gas**

For the purpose of this study and as a limit to the methods described, a dry gas well is considered. This is a well with an oil production of less than 10bbl/MMcf (Fair et al. (2002)).

The complexity of this case is greater than the water injection case. In the wellbore there is still single-phase but now the density varies along the wellbore due to the compressibility of gas.

**Log-log plot comparison and WTA**

For this case only two datasets of BH with their corresponding WH pressure were available. The majority of the WH pressures at each time step were interpolated and only a few values of pressure were measured. For this reason the data were deconvolved to generate drawdown responses and compare the log-log plots. As shown in Figure 9 the Δp and derivative curves have very similar shapes and the WH curves seem to be slightly shifted downwards. Consequently we expect the WH data to predict higher permeabilities and skin factors. This is confirmed by WTA (Figure 10) which is consistent with the observations. WH data slightly overestimated permeability and skin for both cases (Table 3).

**Figure 6:** Rate and pressure history.
Well Test Analysis on Well-head PBU to Identify Well Behaviour/Under Performance

Analytical Approach

Smith, R.V. (1950) was the first one to find a relation between well head \( p_{wh} \) and bottom-hole \( p_{wf} \) pressures by integrating the energy balance equation along a straight line assuming a constant tubing internal diameter and negligible variation of \( zT \).

Neglecting acceleration losses the correlation between WH and BH pressure should be represented in the form (Equation 5):

\[
p_{wh}^2 = p_{wf}^2 K_s - K_f \]

\[
K_s = e^{-S} \]

\[
S = \frac{0.0683 y g L}{(zT)_{avg}} \]

where \( K_s \) and \( K_f \) represent the gravity forces and the friction losses respectively. Since this project focuses on Pressure Build-ups where there is no flow in the wellbore it is safe to assume that friction losses are minimum and therefore neglect \( K_f \). Equation 5 is then used to calculate BH pressures in the form of Equation 8. The results of the converted BH pressure are shown in Figure 11. The error in each timestep is less than 1.7%.

Table 3: WTA results.

<table>
<thead>
<tr>
<th></th>
<th>BH</th>
<th>WH</th>
</tr>
</thead>
<tbody>
<tr>
<td>BU1</td>
<td>22</td>
<td>32</td>
</tr>
<tr>
<td>BU2</td>
<td>21</td>
<td>28</td>
</tr>
<tr>
<td>Skin</td>
<td>0.9</td>
<td>2.8</td>
</tr>
<tr>
<td>Skin</td>
<td>-1.1</td>
<td>-0.7</td>
</tr>
</tbody>
</table>
As it can be seen in the log-log plots (Figure 12) the estimated BH derivative overlays the derivative of the actual BH data suggesting that the converted data can estimate the same permeability as the actual. The Δp curve though is shifted upwards which indicates that the skin estimation would be greater than the actual. This is likely to be because in both examples Equation 6 at early times tends to underestimate the BH pressures with an error that is greater than middle and late times where the error stabilises at a lower value. The error stabilisation explains why the derivatives are the same and the higher error at the beginning explains the higher Δp curve.

\[
p_{wf} = p_{wh} \sqrt{\frac{1}{K_s}} \tag{8}
\]

Dall’Olio and Vignati (1998) in their paper suggest that the value of the permeability derived by the interpretation of the WH data can be corrected to match the value that a proper BH interpretation would yield. Using Darcy’s law for single phase gas (Equation 9) and Smith’s formula (Equation 5) they found a correlation between the correct permeability and the one estimated by WH data (Equation 10).

\[
q_g = 7.03 \times \frac{10^{-4} k_g h (p_r^2 - p_{wf}^2)}{\mu z \left( \ln \left( \frac{r_e}{r_w} \right) - 0.75 + \sigma + d q_g \right)} \tag{9}
\]

\[
k = \frac{\mu z}{(\mu z)_{ref}} k_{ref} K_s \tag{10}
\]

where the subscript ref is referring to the values that were used for the WH interpretation and \(K_s\) refers to the gravity losses of Equation 5. For viscosity, \(z\) factor and Temperature without subscript values that represent reservoir condition should be used. Similar to what was done for the water injector case, by knowing the corrected permeability and with an estimation of the BH pressures the skin can be estimated using Equation 4. The results are in a very good agreement with the actual as it can be seen in Table 4 as well as Figure 14 and Figure 15.
Case 3: Gas/Condensate

When a gas/condensate reservoir pressure drops below the dew point pressure, liquid condensate is formed. This leads to the presence of a two-phase fluid in the wellbore during production. Due to the compressibility of the gas and condensate, the density varies along the wellbore. In addition to that the hold-up depth is not constant and during the shut-in, liquid reinjection in the reservoir may take place. The exhibition of this complex behaviour makes the study of this case more difficult than the previous two.

For this rich gas condensate reservoir (CGR: 192 bbl/MMscf) two examples of built-ups have been studied (Figure 16). For the first one the reservoir pressure is above the dew point pressure (P: 5630psia, T: 195 °C) whereas for the second the pressure is below and a condensate bank is formed.
**Log-log plot Comparison and WTA**

In contrast to what it was observed in the water injector and dry gas case, the study of the log-log plots is not helpful as the plots seem not to display any specific trends (Figure 17). Despite that, it is expected that the WH interpretation would overestimated permeability. It is not clear what the estimation of the skin would be because in Figure 17 LHS, WH interpretation is likely to overestimate it while in Figure 17 RHS, WH curves are shifted downwards and the WH skin estimation would be the same as the BH skin estimation. The WTA on the two datasets (Figure 18) confirms the observations and the results are shown in .

WTA on the BH pressures returned different permeabilities for the two build-ups. Reservoir pressure dropped below the dew point pressure at some time between the two build-up. A condensate bank therefore should exist around the well at the time of the second build-up. Consequently the BU1 permeability represents the permeability of the condensate bank. If the shut-in period were longer an increased in mobility would have been seen as a second stabilization of the derivative at the BU2 permeability, which represents the reservoir permeability (Figure 19). The BU1 skin values in Table 5 represent the wellbore skin effect, whereas the BU2 skin values corresponds to the total skin factor which is the sum of wellbore and condensate bank skins.

<table>
<thead>
<tr>
<th></th>
<th>BH</th>
<th>WH</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>BU1</strong> k(mD)</td>
<td>7.46</td>
<td>13.7</td>
</tr>
<tr>
<td>Skin</td>
<td>-1.49</td>
<td>3.79</td>
</tr>
<tr>
<td><strong>BU2</strong> k(mD)</td>
<td>1.71</td>
<td>3.59</td>
</tr>
<tr>
<td>Skin</td>
<td>31.7</td>
<td>34.6</td>
</tr>
</tbody>
</table>

**Table 5: WTA results for the Gas/Condensate case.**
Analytical Approach

As a first step an attempt was made to correct the WH estimations of permeability and skin as was done for the water injector and dry gas cases. Results were less representative of the actual values and even of the WH derived parameters. When flow is multi-phase in the wellbore and the reservoir is shut-in, liquid falls back and reinjection may occur. Due to the difference in the density between the two phases Wellbore Phase Redistribution (WPR) takes place (Ali et al. 2005). The denser phase moves to the bottom of the well whereas the lighter phase rises to the surface. Because of compressibility effects, WPR results to an increase in the wellbore pressure which is dissipated through the formation until equilibrium is reached between the reservoir and the wellbore (Ali et al. 2005).

After WPR is over, the well exhibits a segregated phase distribution (Nurafza et al. 2009) where the gas column lies above the oil column. As a result there is no direct pressure communication between the WH and the reservoir (Fair 2001, Fair et al. 2002). The pressure communication can only be established when all of the liquid is reinjected in the reservoir and there is only single-phase gas present in the wellbore (Fair et al. 2002).

Since there is no pressure communication between the WH and the reservoir WH derived parameters cannot be corrected to match the actual. The only way forward is to convert WH to BH pressures. In the following sections two conversion methods will be presented and discussed.

**WH to BH Conversion**

For a well that is shut-in the governing equation for a WH to BH conversion is Equation 11 (Fair et al. 2002). Since WTA studies the pressure change Equation 11 can be modified to Equation 12 (in the equation acceleration losses are considered to be negligible and the friction losses to be zero because of the shut-in).

\[
WHP = BHP - \rho gh \tag{11}
\]

\[
\Delta WHP = \Delta BHP - \Delta \rho gh \tag{12}
\]

An operational WH to BH pressure algorithm should be able to take into account the temperature profile in the wellbore through time (Fair et al. 2002, Hasan et al. 2005). In HP/HT fields the WH temperature can go up to 300°F due to the flow of the fluids from the reservoir. During the shut-in the flow stops allowing for the WH to cool down. As the temperature drops the fluid density in the wellbore increases. The reservoir pressure stabilizes very quickly and therefore \( \Delta BHP \) in Equation 10 becomes small. Because of the increase in fluid density as the WH cools down \( \Delta \rho gh \) is high resulting in a negative \( \Delta WHP \) (Redman 2012). This means that the WH pressure decreases in middle and late times (Figure 21).

In addition to the wellbore-temperature profile, a conversion algorithm is necessary to account for the change in fluid properties for different pressures and temperatures. Consequently a PVT model should be created and used.

![Figure 18: Rate-normalized plot of the two built-ups.](image)

![Figure 19: Example of WH pressure decreasing during a shut-in in a Gas/Condensate well.](image)
**1st Method: Modified Peffer et al. (1988) Equation**

In their paper Peffer et al. (1988) developed a method to calculate BH pressures with a modification of Cullender and Smith (1956) equation (Equation 13) to account for the presence of liquid in the gas to obtain satisfactory results for flowing conditions.

\[
\int_{P_{RF}}^{P_{WF}} \frac{P_d dp}{667(M_g+z^2)} = \frac{y_D D}{53.34} \tag{13}
\]

The above form of the equation is only applicable to dry-gas wells. The adjustment that Peffer et al. (1988) proposed to account for the presence of liquid was to change the surface gas gravity in Equation 13 with a wet-gas specific gravity that can be estimated by Equation 15.

\[
\gamma_w g = \gamma_g + 4.584 \gamma_o R_g \frac{1}{132.800 \gamma_o M_o R_g} \tag{14}
\]

\[
M_o = \frac{44.2 \gamma_o}{1.03 - \gamma_o} \tag{15}
\]

The methodology used in this study was to consider friction losses equal to zero since a shut-in is investigated and therefore neglect the friction term from the Equation 13 and apply the Peffer et al. (1988) modification. The conversion equation for a shut-in then takes the following form:

\[
\int_{P_{RF}}^{P_{WF}} \frac{P dP}{P_d} = \frac{y_w g D}{53.34} \tag{16}
\]

The equation was tested and validated with two datasets where both the WH and the corresponding BH pressures were known. To implement the equation a Visual Basic Application (VBA) Macro was developed and an existing PVT model was used. The Macro was designed to run an algorithm that divides the wellbore in 100ft segments and take the WH pressure and temperature as initial inputs. It then calls for the PVT model to calculate \(z, \rho_g, \rho_o\) and \(M_o\) for that pressure and temperature. These parameters are used to estimate wet gas specific gravity with Equation 12. The next segment’s pressure is then calculated by Equation 16 which is implemented with the trapezoidal rule. The procedure is repeated until the depth of the bottom-hole gauge is reached.

The algorithm was found to be very sensitive to temperature and produced erroneous results when temperature was changing with time. For this reason in the simulations the temperature profile was varied versus the well depth but not versus time. The results of the conversion can be seen in Figure 22 where the estimated BH pressures are plotted against the actual. The error in each time step is less 1.6%. The log-log plots of the two datasets were then compared (Figure 23). The estimated derivative is similar to the actual and in the case of BU2 seems to overlay it. The \(\Delta p\) curve though is much higher for the estimated pressures. This is because the method under predicts the pressure at early times whereas at middle and late times it over predicts it. The derivative seems to be the same because the error between estimated and actual values is stabilizing after early times. Results indicate that the converted BH pressures might estimate the permeability correctly but overestimate skin. This is confirmed by the WTA and the results are displayed in Table 6 as well as in Figure 24 and Figure 25.

![Figure 20: Estimated BH pressures against the actual (modified Peffer method).](image-url)
Well Test Analysis on Wellhead PBU to Identify Well Behaviour/Under Performance

Table 6: Results of the WTA on estimated BH, actual and WH pressures.

<table>
<thead>
<tr>
<th></th>
<th>BH</th>
<th>WH</th>
<th>Estimation</th>
</tr>
</thead>
<tbody>
<tr>
<td>BU1</td>
<td>7.46</td>
<td>13.7</td>
<td>6.75</td>
</tr>
<tr>
<td>k(mD)</td>
<td>-1.49</td>
<td>3.79</td>
<td>0.312</td>
</tr>
<tr>
<td>Skin</td>
<td>1.71</td>
<td>3.59</td>
<td>1.71</td>
</tr>
<tr>
<td>BU2</td>
<td>31.7</td>
<td>34.6</td>
<td>43.3</td>
</tr>
</tbody>
</table>

Figure 21: Log-log plot comparison. Estimated BH pressures against actual and WH (modified Peffer method).

Figure 22: WH and corrected permeability Vs BH.

Figure 23: WH and corrected skin factor Vs BH.

2nd Method: Adding Column Weight

A simplified method was also tested. The idea was to use the PVT model to find an average density of the fluid for each 100ft segment since an equation that gives wet gas specific gravity is known (Equation 14). The density was used to find the weight of the fluid column and add it to the WH pressure. The procedure is repeated until the bottom-hole gauge depth is reached. Temperature was varied versus time in agreement with a WH temperature profile that was recorded during a shut-in performed on another well in the same field.

The results of the estimations obtained by the adding column weights are plotted in Figure 26. Although the method provides very good results for the calculation of pressure at each timestep, where the error although high in the first few seconds is less the 2% for the rest of the built-up, the log-log plots of the estimated data (Figure 27) are different from the actual BH pressure log-log plots. This is because the error is changing at each timestep and is not reaching a stabilization point as happened in the 1st method. Therefore the results are not suitable for a WTA as they yield incorrect results. Nevertheless the method can provide a good estimation of the pressures. The increasing error between estimated and actual data though is an indication that as the build-up progress results will be less representative.
Well Test Analysis on Well-head PBU to Identify Well Behaviour/Under Performance

Conclusions

Water Injector

- It is shown that analysis of WH data can yield the same derivative with the BH data, by integrating log-log observations, WTA results and the analytical approach.
- The BH pressure during built-up can be reasonably estimated by adding the weight of the water column to the WH. The derivative curve generated by the estimated pressures matches the derivative generated by the actual data indicating that the permeability can be predicted correctly.
- Skin can be corrected using the permeability derived from the WH interpretation, the estimated BH pressures and the semi-log radial flow approximation, to satisfactorily match the results from BH data.

Dry Gas

- WH data can be converted to BH using Equation 4, with an error of less than 1.7%. The converted BH data yield the same pressure derivative as the actual BH data, indicating that the WH data can predict permeability quite accurately in the cases of a dry gas fluid in the wellbore.
- WH derived permeability can be corrected to the actual value using Dall’Olio and Vignati (1988) correlation.
- Skin can be adjusted to match the estimation of BH data, using the corrected permeability, the estimated BH pressures and the semi-log radial flow approximation (Equation 4).

Gas/Condensate

- Two methods were developed to calculate BH pressures providing reasonable results. The error between estimated and actual pressures in the modified Peffer et al. (1988) method is stabilizing at middle and late times and consequently leads to a derivative that is very similar with the one from BH data. WTA indicates that permeability can be estimated using the converted pressures. Skin factor though is overestimated.
- A good estimation of the pressures can be provided by using the Adding Column Weight method, but the results are not suitable for WTA.

Figure 24: Comparison of the estimated with the actual BH pressures (adding column weights method).

Figure 25: Converted data against actual and WH log-log plot comparison.
Recommendations for Further Study

The methods discussed in this project should be applied to more datasets. This study suggests that WH data can yield higher skin than BH data and can be recommended as an interesting subject for future work to be investigated further.

It is well known that for the gas/condensate case during build-up liquid may be re-injected in the reservoir. In the case it does, it means that as the build-up progresses the fluid loses the heavier components and therefore the PVT model is changing due to change in fluid composition. This can be taken into account when converting WH to BH pressures.

Although the computational time required will be much higher, discretizing the wellbore in smaller segments might lead to better results of the estimated pressures. It will also definitely provide a smoother density profile and eliminated some discontinuities that can be seen in the estimations.

Newer methods and tools like Computational Flow Dynamics (CFD) and Neutral Networks may prove to be useful in converting WH to BH pressures.

Nomenclature

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
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<tbody>
<tr>
<td>$B$</td>
<td>Formation volume factor</td>
</tr>
<tr>
<td>$c$</td>
<td>Compressibility (psi$^{-1}$)</td>
</tr>
<tr>
<td>$\gamma_g$</td>
<td>Gas specific gravity</td>
</tr>
<tr>
<td>$\gamma_o$</td>
<td>Oil specific gravity</td>
</tr>
<tr>
<td>$\gamma_{wg}$</td>
<td>Wet gas specific gravity</td>
</tr>
<tr>
<td>$D$</td>
<td>Turbulence factor</td>
</tr>
<tr>
<td>$D_v$</td>
<td>Vertical Depth (ft)</td>
</tr>
<tr>
<td>$\Delta$</td>
<td>Change in a given parameter</td>
</tr>
<tr>
<td>$f_M$</td>
<td>Moody friction factor</td>
</tr>
<tr>
<td>$g$</td>
<td>Gravity acceleration (m/s$^2$)</td>
</tr>
<tr>
<td>$h$</td>
<td>Reservoir thickness (ft)</td>
</tr>
<tr>
<td>$k$</td>
<td>Permeability (mD)</td>
</tr>
<tr>
<td>$k_g$</td>
<td>Gas relative permeability (mD)</td>
</tr>
<tr>
<td>$K_f$</td>
<td>Friction losses</td>
</tr>
<tr>
<td>$K_s$</td>
<td>Gravity Forces</td>
</tr>
<tr>
<td>$L$</td>
<td>Well length (ft)</td>
</tr>
<tr>
<td>$M_o$</td>
<td>Oil molecular weight</td>
</tr>
<tr>
<td>$\mu$</td>
<td>Viscosity (cp)</td>
</tr>
<tr>
<td>$p_D$</td>
<td>Dimensionless pressure</td>
</tr>
<tr>
<td>$p_i$</td>
<td>Initial pressure (psi)</td>
</tr>
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<td>$p_r$</td>
<td>Reservoir pressure (psi)</td>
</tr>
<tr>
<td>$p_{rf}$</td>
<td>Reference pressure (psi)</td>
</tr>
<tr>
<td>$p_{wf}$</td>
<td>Bottom-hole pressure (psi)</td>
</tr>
<tr>
<td>$p_{wh}$</td>
<td>Well head pressure (psi)</td>
</tr>
<tr>
<td>$q$</td>
<td>Flow rate</td>
</tr>
<tr>
<td>$q_g$</td>
<td>Gas flow rate (Mscf/d)</td>
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<td>$r_e$</td>
<td>Reservoir radius (ft)</td>
</tr>
<tr>
<td>$r_w$</td>
<td>Well radius (ft)</td>
</tr>
<tr>
<td>$\phi$</td>
<td>Porosity</td>
</tr>
<tr>
<td>$R_g$</td>
<td>Gas Condensate Ratio (scf/bbl)</td>
</tr>
<tr>
<td>$\rho$</td>
<td>Density (kg/m$^3$)</td>
</tr>
<tr>
<td>$s$</td>
<td>Skin</td>
</tr>
<tr>
<td>$t$</td>
<td>Time (h)</td>
</tr>
<tr>
<td>$t_d$</td>
<td>Dimensionless time</td>
</tr>
<tr>
<td>$T$</td>
<td>Temperature (°F)</td>
</tr>
<tr>
<td>$z$</td>
<td>Compressibility (dimensionless)</td>
</tr>
</tbody>
</table>

References


Faire, C., 2001: “Is it a Wellbore of a Reservoir Effect?”, Hart’s E&P.


Nurazifa, P.R., and Fernagu, J., 2009: “Estimation of Static Bottom Hole Pressure from Well-Head Shut-in Pressure for a Supercritical Fluid in a Depleted HP/HT Reservoir”, SPE 124578, paper presented at the SPE Offshore Europe Oil & Gas Conference & Exhibition held in Aberdeen, UK, 8-11 September.


<table>
<thead>
<tr>
<th>SPE Paper #</th>
<th>Year</th>
<th>Title</th>
<th>Authors</th>
<th>Contribution</th>
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<tbody>
<tr>
<td></td>
<td>1929</td>
<td>Thermodynamic Properties of Petroleum Products</td>
<td>Cragoe C.S.</td>
<td>First to develop a formula to calculate oil molecular weight using oil specific gravity.</td>
</tr>
<tr>
<td>AIME 160</td>
<td>1945</td>
<td>Calculation of Static Pressure Gradients in Gas Wells</td>
<td>Rzasa M.J. Katz, D.L.</td>
<td>First to develop an equation to calculate wet gas specific gravity.</td>
</tr>
<tr>
<td>AIME 73</td>
<td>1950</td>
<td>Determining Friction Factors for Measuring Productivity of Gas Wells</td>
<td>Smith R.V</td>
<td>First to create an equation to calculate BH from WH pressures.</td>
</tr>
<tr>
<td>AIME 207</td>
<td>1956</td>
<td>Practical Solutions of Gas-Flow Equation for Wells and Pipelines with Large Temperature Gradients</td>
<td>Cullender M.H. Smith R.V</td>
<td>Introduce an equation to convert WH to BH pressure that makes no assumption regarding temperature and compressibility.</td>
</tr>
<tr>
<td>962</td>
<td>1965</td>
<td>Two Phase Flow of Volatile Hydrocarbons</td>
<td>V.J.Kniazeff S.A.Nvaille</td>
<td>First to numerically model radial gas condensate well deliverability and to describe three different zones around the well.</td>
</tr>
<tr>
<td>14204</td>
<td>1985</td>
<td>Interpretation of Flowing Well Response in Gas Condensate Wells</td>
<td>J. R. Jones R. Raghavan</td>
<td>First to propose a methodology for analysing well tests in gas condensate wells.</td>
</tr>
<tr>
<td>SPE Production Engineering</td>
<td>1988</td>
<td>An Improved Method for Calculating Bottomhole Pressures in Flowing Gas Wells with Liquid Present</td>
<td>Peffer J.W. Miller M.A. Hill A.D.,</td>
<td>First to modify Cullender and Smith Equation to account for liquid production in the wellbore.</td>
</tr>
<tr>
<td>39971</td>
<td>1998</td>
<td>Well Head Test Analysis: Save and Safe</td>
<td>D. Dall’Olio L. Vignati</td>
<td>First use Well Head pressure data for test interpretation purposes.</td>
</tr>
<tr>
<td>ID</td>
<td>Year</td>
<td>Title</td>
<td>Authors</td>
<td>Notes</td>
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<td>62930</td>
<td>2000</td>
<td>Condensate Banking dynamics in Gas/Condensate Fields: Compositional Changes and Condensate Accumulation Around Production Wells</td>
<td>R. J. Wheaton, H. R. Zhang</td>
<td>First to develop a theoretical treatment of condensate banking dynamics to show how the compositions of heavy components of a gas condensate change with time around production wells during depletion.</td>
</tr>
<tr>
<td>77701</td>
<td>2002</td>
<td>Gas/Condensate and Oil Well Testing – From the Surface</td>
<td>C. Fair, B. Cook, T. Brighton, M. Redman, S. Newman</td>
<td>Provided guidelines and examples where well head data are used to test multiphase wells.</td>
</tr>
<tr>
<td>94018</td>
<td>2005</td>
<td>Application of Build-Up Transient Pressure Analysis to Well Deliverability Forecasting in Gas Condensate Reservoirs Using Single-Phase and Two-Phase Pseudo-Pressures</td>
<td>M. Bozorgzadeh, A. C. Gringarter</td>
<td>First to show that well deliverability mainly depends on the gas relative permeabilities at both the end point and the near wellbore saturations, and on the reservoir permeability.</td>
</tr>
<tr>
<td>97027</td>
<td>2005</td>
<td>Condensate Skin Evaluation of Gas/Condensate Wells by Pressure-Transient Analysis</td>
<td>A. Shandrygin, D. Rudenko</td>
<td>First to propose a procedure for evaluating skin in gas/condensate wells, using a simplified numerical model.</td>
</tr>
<tr>
<td>124578</td>
<td>2009</td>
<td>Estimation of Static Bottom Hole Pressure From Well-Head Shut-in Pressure for a Supercritical Fluid in a Depleted HP/HT Reservoir</td>
<td>P. R. Nurafza, J. Fernagu</td>
<td>First that used the fluid phase distribution along the well in their correlations to estimate bottom-hole pressure.</td>
</tr>
<tr>
<td>143592</td>
<td>2011</td>
<td>Assessment of Individual Skin Factors in Gas Condensate and Volatile Oil Wells</td>
<td>A.C. Gringarten, O. Ogunrewo, G. Uxukbayev</td>
<td>First to show that WTA with two-phase pseudo pressures can estimate the rate-independent wellbore skin effect and the non-Darcy coefficient in gas/condensate wells below the dew point pressure.</td>
</tr>
</tbody>
</table>
Appendix A - Literature Review

SPE 39971 (1998)

Title: Well Head Test Analysis: Save and Safe

Author: D. Dall’Olio, L. Vignati

Contribution:
First to use well Head pressure data for test interpretation purposes.

Paper objective:
To develop a methodology that allows Well Head pressure data for Well Test Analysis

Methodology:
Performs Well Test Analysis directly on Well Head data and corrects the results

Conclusions:
Well Head Analysis is reliable only if a single phase liquid is present in the tubing

SPE 77701 (2002)

Title: Gas/Condensate and Oil Well Testing – From the Surface

Authors: C. Fair, B. Cook, T. Brighton, M. Redman, S. Newman

Contribution:
Provided guidelines and examples where well head data are used to test multiphase wells.

Paper objective:
To propose guidelines for testing multiphase wells from surface.

Methodology:
Presentation of surface-to-bottomhole pressure calculation and assumptions
Separation of wells in three categories and discussion of testing options for each one
Wellbore phase and temperature modelling
Field examples to compare calculated bottomhole pressures from surface to measured bottomhole pressures

Conclusions:
In order to be test a multiphase well must be categorized, screened and tested properly.
AIME 73 (1950)

**Title:** Determining Friction Factors for Measuring Productivity of Gas Wells

**Authors:** Smith R.V

**Contribution:**
First to develop an equation to calculate BH from WH pressures

**Paper objective:**
To calculate friction factors for flow in gas wells

**Methodology:**
Presented two methods to calculate friction factors:
By integrating energy balance equation on a vertical well.
By deriving an equation under the assumption that both the temperature and the compressibility are fixed throughout the flowing column of the gas.

**Conclusions:**
Method one is particularly applicable in calculating friction factors for deep high-pressure and high-temperature gas wells. The second method can address the problem of calculating subsurface pressure for a flowing gas well.

SPE 124578 (2009)

**Title:** Estimation of Static Bottom Hole Pressure from Well-Head Shut-in Pressure for a Supercritical Fluid in a Depleted HP/HT Reservoir

**Authors:** P. R. Nurafza, J. Fernagu

**Contribution:**
First that used the fluid phase distribution along the well in their correlations to estimate bottom-hole pressure.

**Paper objective:**
To develop a correlation methodology to derive the static bottom-hole pressure from the well-head shut-in using thermodynamic modelling.

**Methodology:**
Used field observations to understand the fluid phase distribution along the well and developed a correlation methodology to estimate bottom hole shut-in pressure from the recorded well head shut-in pressure for depleted wells.

**Conclusions:**
The pressure estimated using the proposed methodology match reasonably (less than 2% difference) the bottom-hole shut-in pressure observed during static surveys.
SPE 62920 (2000)

Title: Well Test Analysis in Gas-Condensate Reservoirs

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

Contribution:
First to identify the existence of three zones in gas-condensate reservoirs using Well Test Analysis.

Paper objective:
To investigate the existence of a third zone in well test data for gas-condensate reservoirs and overall to develop new methods that predict well productivity in reservoirs.

Methodology:
Initially compositional simulations were performed to verify the conditions of the existence of the three mobility zones. After that the existence of “velocity stripping” in gas-condensate wells was confirmed from well test data.

Conclusions:
Phase redistribution is a major problem in analysing the data
The authors presented examples to exhibit three stabilizations on the derivative, corresponding to three mobility zones

SPE 62930 (2000)

Title: Condensate Banking dynamics in Gas/Condensate Fields: Compositional Changes and Condensate Accumulation Around Production Wells

Authors: R. J. Wheaton, H. R. Zhang

Contribution:
First to develop a theoretical treatment of condensate banking dynamics to show how the compositions of heavy components of a gas condensate change with time around production wells during depletion.

Paper objective:
To introduce a new theoretical treatment of condensate bank formation and to use this as a basis to increased conceptual understanding of the processes involved.

Methodology:
How the fluid mixture composition will change with time in the near wellbore region is considered during condensate dropout or potential ‘revaporisation’.
A general component mobility term is defined, and a novel analytical model is developed to make general theoretical analysis possible for the compositional changes during condensate banking process without complicated full compositional flow modelling.

Conclusions:
A general theoretical treatment of condensate banking dynamics is developed to show how the compositions of heavy components of a gas condensate change with time around production wells during depletion
A new component relative mobility ‘Chi’ function has been defined and analytical study has been presented.
Reservoir permeability and production rate have significant effects on condensate banking behaviour.
Once a well is produced with flowing bottom hole pressure below the dewpoint, it may not be possible to remove the liquid bank by shutting the well and letting the pressure to rise above the initial dewpoint pressure.
For a well producing at a constant bottom hole flowing pressure, a pseudosteady state can be reached at some stage of condensate banking.
Title: An Improved Method for Calculating Bottomhole Pressures in Flowing Gas Wells with Liquid Present

Authors: Peffer J.W., Miller M.A., Hill A.D.

Contribution:
Modified Cullender and Simth equation to account for liquid production in the wellbore.

Paper objective:
To introduce a new method for calculating bottomhole pressures and to evaluate the effective roughness factor.

Methodology:
Modified Cullender and Simth equation by adjusting the gas specific gravity to account for condensate production. The gas specific gravity was replaced by a wet gas specific gravity developed by Rzasa and Katz. The proposed method was tested against the two-phase model developed by Govier and Fogarasi for 144 flowing wells.

Conclusions:
The proposed method was proved to outperform any other applied method for a wide range of gas-condensate well conditions.

Title: Practical Solutions of Gas-Flow Equation for Wells and Pipelines with Large Temperature Gradients

Authors: Cullender M.H., Smith R.V

Contribution:
Introduce an equation to convert WH to BH pressure that makes no assumption regarding temperature and compressibility.

Methodology:
Integrate the mechanical-energy balance equation for vertical inclined and horizontal flow.

Conclusions:
The method result in more accurate calculation of flowing pressures in gas wells and pipe lines.
SPE 962 (1965)

Title: Two-Phase Flow of Volatile Hydrocarbons.

Authors: Kniazeff, V. J. and Naville, S. A.

Contribution:
Authors were first to numerically model radial gas condensate well deliverability and be first to describe three different zones around the well.

Paper objective:
To numerically solve second order non-linear partial differential equation for radial two phase flow around the gas condensate well taking into account thermodynamic fluid properties and physical properties of the reservoir.

Methodology used:
Developed a computer program to numerically solve partial differential equations for prediction of the pressure and phase saturation as a function of the radial distance in the vicinity of the wellbore and time.

Conclusions:
Solution of partial differential equation showed that condensate saturation increases when Bottom-hole pressure drops below the dew point which tends to reduce well deliverability.

SPE 1243 (1966)

Title: Application of Real Gas Flow Theory to Well Testing and Deliverability Forecasting

Authors: R. Al-Hussainy, H.J. Ramey Jr

Contribution:
First to define a single-phase real gas pseudo-pressure.

Objectives of the paper:
To provide necessary engineering forms for use of the real gas flow results, and to illustrate applications. fundamental considerations which can be used successfully to analyze the flow of real gases.

Methodology:
Real gas flow equations were applied to cases of gas well flowing testing(drawdown, build-up and back pressure testing).

Conclusions:
Approximate solution was found for the production of real gas by changing real gas pseudo-pressure. Implemented real gas pseudo-pressure in well test analysis.
SPE 2033 (1968)

**Title:** The Compositional Reservoir Simulator: Case 1- The Linear Model

**Authors:** I.F. Roebuck, G.E.Henderson, J.Douglas, W.T. Ford

**Contribution:**
First to develop compositional model to study gas condensate reservoirs. The linear model forms the basis for radial and 3-D Cartesian models developed later.

**Objective of the paper:**
To describe the results of the linear, compositional, mathematical model.

**Methodology used:**
Numerical simulation of differential and algebraic relations governing one-dimensional three-phase flow in porous media is used. And it is based upon compositional representation of the hydrocarbon system.

**Conclusions:**
A numerical solution for multiphase flow of reservoir fluids has been formulated and applied to studies of actual well and field performance.

SPE 14204 (1985)

**Title:** Interpretation of Flowing Well Response in Gas Condensate Wells

**Authors:** J. R. Jones, R. Raghavan

**Contribution:**
First to propose a methodology for analysing well tests in gas condensate wells.

**Paper objective:**
To examine the flowing well response and effect of liquid condensation on the well response as the pressure drops below the dew point in a gas condensate reservoir.

**Methodology used:**
A one-dimensional radial compositional model was used to gain the results. The interpretation method assumes pressures or rate constant productions.

**Conclusions:**
This paper examined pressure transient test in gas condensate wells.
SPE 94018 (2005)

**Title:** Application of Build-Up Transient Pressure Analysis to Well Deliverability Forecasting in Gas Condensate Reservoirs Using Sing-Phase and Two-Phase Pseudo-Pressures

**Authors:** M. Bozorgzadeh, A.C. Gringarten

**Contribution to understanding of Gas Condensate Reservoirs:**
First method for generating the pseudo-relative permeabilities and the absolute permeability in lieu of experimental data using single-phase and two-phase pseudo-pressures

**Objective:**
To generate relative permeability curves from well test analysis

**Methodology used:**
Simulation study to determine factors controlling productivity of gas condensate reservoirs.

**Conclusions reached:**
This paper showed that well deliverability is controlled by gas relative permeability at near wellbore saturation and at the initial liquid saturation, and the absolute permeability.

---

SPE 143592 (2011)

**Title:** Assessment of Individual Skin Factors in Gas Condensate and Volatile Oil Wells

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

**Contribution to understanding of Gas Condensate Reservoirs:**
First to use compositional simulation for wellbore skin effect calculation using single-phase and two-phase pseudo-pressures in lean gas condensate reservoirs.

**Objective(s) of the paper:**
To investigate the combined impact of capillary number and non-Darcy flow on the wellbore skin in gas condensate reservoirs by using single-phase and two-phase pseudo-pressures, and to compare non-Darcy coefficients and zero-rate skin factors above and below saturation pressures.

**Methodology used:**
Numerical compositional simulation is performed to investigate wellbore skin behaviour in lean, rich gas condensate reservoirs and volatile oil reservoirs.

**Conclusions reached:**
Well test analysis with single-phase pseudo-pressure do not correctly estimate the rate-independent wellbore skin effect, whereas analyses with two-phase pseudo-pressure do.
SPE 97027 (2005)

Title: Condensate Skin Evaluation of Gas/Condensate Wells by Pressure-Transient Analysis

Authors: A. Shandrygin, D. Rudenko

Contribution:
First to propose a procedure for evaluating skin in gas/condensate wells, using a simplified numerical model.

Paper objective:
To develop a numerical model for the evaluation of skin in gas/condensate wells.

Methodology:
The authors based their procedure on a single-phase approach, treading condensate as immobile. Radial condensate distribution is described using condensate-bank radius as regression parameters for fitting modelled built-up pressure curves with well test data. The procedure was validated for a radial reservoir.

Conclusions:
Condensate skin can be evaluated with an error on the order of 10 to 20%. This approach does not account for phase transitions between gas and condensate.
Appendix B – Smith Method
By expanding Equation 5 we get the following formula:

\[ p^2_{wh} = p^2_{wf} e^{-S} - \frac{9.6168 e^{-18g/\rho} q^2 (ct)_{avg} (1-e^{-S})}{Sd^2} \]  \hspace{1cm} \text{(B-1)}

from which \( K_s \) and \( K_f \) can be derived as follow:

\[ K_s = e^{-S} \]  \hspace{1cm} \text{(B-2)}

\[ S = \frac{0.0683 Y_p l}{(ct)_{avg}} \]  \hspace{1cm} \text{(B-3)}

\[ K_f = \frac{C_2 Y_p a^2 (ct)_{avg} M D (1-e^{-S})}{Sd^2} \]  \hspace{1cm} \text{(B-4)}

Appendix C - Dall’Olio and Vignati Method
\( K_s \) and \( K_f \) depend on flow rate. Under the hypothesis of small cooling effect and fully turbulent flow the impact of rate changes on \( K_s \) is negligible compared to that on \( K_f \). Therefore:

\[ p^2_{wh} = p^2_{wf} K_s - K_f, q - K_f, q^2 \]  \hspace{1cm} \text{(C-1)}

Darcy’s law for single phase gas (Equation C-2) can take the form of Equation C-3.

\[ q_B = 7.03 \times 10^{-4} g_h \frac{v_p - v_{wf}}{\mu T [\ln \left( \frac{v_p}{v_{wf}} \right) - 0.75 + s + C_d]} \]  \hspace{1cm} \text{(C-2)}

\[ p^2 - p^2_{wf} = A q + B q^2 \]  \hspace{1cm} \text{(C-3)}

where \( A \) and \( B \) are given by the following expressions:

\[ A = \frac{\pi^2 T}{7.03 \times 10^{-4} g_h} \left[ \ln \left( \frac{v_p}{v_{wf}} \right) - 0.75 + s \right] \]  \hspace{1cm} \text{(C-4)}

\[ B = \frac{\pi^2 T}{7.03 \times 10^{-4} g_h} D \]  \hspace{1cm} \text{(C-5)}

therefore

\[ A, B \propto \frac{\pi^2 T}{kh} \]  \hspace{1cm} \text{(C-6)}

where \( \mu, z \) and \( T \) are evaluated at the bottom-hole conditions. By combining Equations C-1 and C-3 it is possible to obtain the well head flow equation:

\[ \Delta p^2_{wh} = (AK_s + K_f, q + (BK_s + K_f, q^2) = A_t q + B_t q^2 \]  \hspace{1cm} \text{(C-7)}

Equation C-7 shows that it is possible to interpret well head pressure data in the same way as bottom-hole: the friction dependent terms \( K_f, q \) and \( K_f, q^2 \) should be interpreted as increases of the global skin. It is possible now to point that:

\[ A_t, B_t \propto \frac{\pi^2 T}{kh} K_s \]  \hspace{1cm} \text{(C-8)}

which means that if PVT properties are evaluated at reservoir condition during a well head interpretation, the calculated \( k \) will not be correct for the presence of \( K_s \). It is correct to say that \( A_t \) and \( B_t \) depend on the reference conditions that the test was made, in this case the well head conditions:

\[ A_t, B_t \propto \frac{\pi^2 T}{kh} \text{ref} \]  \hspace{1cm} \text{(C-9)}
Combining Equation C-8 and C-9 a formula that gives the correct permeability is derived:

\[ k = \frac{\mu z T}{(\mu z T)_{ref}} k_{ref} K_s \]  

\[(C-10)\]

**Appendix D - VBA Macro Code**

**Modified Peffer et al. Algorithm**

Sub Convert()
Sheet_ = "Sheet1"
iLin = 14
kCol = 45
For k = 56 To 152
'set time
Worksheets(Sheet_).Cells(37, 10) = Worksheets(Sheet_).Cells(10, kCol + k)
For m = 0 To 1
'input T
Worksheets("CCE").Cells(23, 1) = Worksheets(Sheet_).Cells(iLin + m - 1, 37)
'input Pressure
Worksheets("CCE").Cells(23, 2) = Worksheets(Sheet_).Cells(iLin + m - 1, kCol + k)
DoCCE
'set z
Worksheets(Sheet_).Cells(iLin + m - 1, 38) = Worksheets("CCE").Cells(45, 5)
'set gamma g
Worksheets(Sheet_).Cells(iLin + m - 1, 39) = Worksheets("CCE").Cells(45, 3) / 1225
'set gamma o
Worksheets(Sheet_).Cells(iLin + m - 1, 40) = Worksheets("CCE").Cells(45, 4) / 1000
'calculate Mo
Worksheets(Sheet_).Cells(iLin + m - 1, 41) = (44.29 * Worksheets(Sheet_).Cells(iLin + m - 1, 39)) / (1.03 - Worksheets(Sheet_).Cells(iLin + m - 1, 39))
'calculate gamma wg
Worksheets(Sheet_).Cells(iLin + m - 1, 42) = (Worksheets(Sheet_).Cells(iLin + m - 1, 39) + Worksheets(Sheet_).Cells(iLin + m - 1, 40) * 4584 / 4813.267)
Worksheets(Sheet_).Cells(iLin + m - 1, 43) = 1 + (132800 * Worksheets(Sheet_).Cells(iLin + m - 1, 40)) / (Worksheets(Sheet_).Cells(iLin + m - 1, 41) * 4813.267)
Worksheets(Sheet_).Cells(iLin + m - 1, 44) = Worksheets(Sheet_).Cells(iLin + m - 1, 42) / Worksheets(Sheet_).Cells(iLin + m - 1, 43)
Next
For i = 0 To 172
'input T
Worksheets("CCE").Cells(23, 1) = Worksheets(Sheet_).Cells(iLin + i, 37)
'input Pressure
Worksheets("CCE").Cells(23, 2) = Worksheets(Sheet_).Cells(iLin + i, kCol + k)
DoCCE
'set z
Worksheets(Sheet_).Cells(iLin + i, 38) = Worksheets("CCE").Cells(45, 5)
'set gamma g
Worksheets(Sheet_).Cells(iLin + i, 39) = Worksheets("CCE").Cells(45, 3) / 1225
'set gamma o
Worksheets(Sheet_).Cells(iLin + i, 40) = Worksheets("CCE").Cells(45, 4) / 1000
'calculate Mo
Worksheets(Sheet_).Cells(iLin + i, 41) = (44.29 * Worksheets(Sheet_).Cells(iLin + i, 39)) / (1.03 - Worksheets(Sheet_).Cells(iLin + i, 39))
'calculate gamma wg
Worksheets(Sheet_).Cells(iLin + i, 42) = (Worksheets(Sheet_).Cells(iLin + i, 39) + Worksheets(Sheet_).Cells(iLin + i, 40) * 4584 / 4813.267)
Worksheets(Sheet_).Cells(iLin + i, 43) = 1 + (132800 * Worksheets(Sheet_).Cells(iLin + i, 40)) / (Worksheets(Sheet_).Cells(iLin + i, 41) * 4813.267)
Worksheets(Sheet_).Cells(iLin + i, 44) = Worksheets(Sheet_).Cells(iLin + i, 42) / Worksheets(Sheet_).Cells(iLin + i, 43)
'calculate p
Worksheets(Sheet_).Cells(45, 19) = Worksheets(Sheet_).Cells(iLin + i, 37) * Worksheets(Sheet_).Cells(iLin + i, 38)
B1 = (Worksheets(Sheet_).Cells(iLin + i + 1, 44) * Worksheets(Sheet_).Cells(iLin + i + 36) - Worksheets(Sheet_).Cells(iLin + i - 1, 44) * Worksheets(Sheet_).Cells(iLin + i, 36)) / 53.34
B2 = (Worksheets(Sheet_).Cells(iLin + i + 1, 37) * Worksheets(Sheet_).Cells(iLin + i, 38) - Worksheets(Sheet_).Cells(iLin + i + 1, 37) * Worksheets(Sheet_).Cells(iLin + i, 38) * (Worksheets(Sheet_).Cells(iLin + i, kCol + k))^2)
Worksheets(Sheet_).Cells(46, 19) = -(B1 + B2) * 2 * Worksheets(Sheet_).Cells(iLin + i, kCol + k)
Worksheets(Sheet_).Cells(47, 19) = Worksheets(Sheet_).Cells(iLin + i + 1, 37) * Worksheets(Sheet_).Cells(iLin + i, 38) * (Worksheets(Sheet_).Cells(iLin + i + 1, kCol + k))
Next
Next
End Sub

Adding Weights Algorithm
Sub BH_Conversion()
Sheet_ = "Sheet1"
ilein = 7
kCol = 10
For k = 91 To 152
Worksheets(Sheet_).Cells(6, 2) = Worksheets(Sheet_).Cells(1, kCol + k)
For i = 0 To 174
'input T
Worksheets("Calc").Cells(14, 1) = Worksheets(Sheet_).Cells(iLin + i, 2)
'input Pressure
Worksheets("Calc").Cells(14, 3) = Worksheets(Sheet_).Cells(iLin + i, kCol + k)
DoCVD
'set z
Worksheets(Sheet_).Cells(iLin + i, 3) = Worksheets("Calc").Cells(38, 17)
'set gamma g
Worksheets(Sheet_).Cells(iLin + i, 4) = Worksheets("Calc").Cells(38, 3) / 1225
'set gamma o
Worksheets(Sheet_).Cells(iLin + i, 5) = Worksheets("Calc").Cells(38, 4) / 1000
'calculate Mo
Worksheets(Sheet_).Cells(iLin + i, 6) = (44.29 * Worksheets(Sheet_).Cells(iLin + i, 4)) / (1.03 - Worksheets(Sheet_).Cells(iLin + i, 4))
If Worksheets(Sheet_).Cells(iLin + i, 6) = 0 Then
Worksheets(Sheet_).Cells(iLin + i, 9) = Worksheets(Sheet_).Cells(iLin + i, 4)
Else
'calculate gamma wg
Worksheets(Sheet_).Cells(iLin + i, 7) = (Worksheets(Sheet_).Cells(iLin + i, 4) + Worksheets(Sheet_).Cells(iLin + i, 5) * 4584 / 4813.267
Worksheets(Sheet_).Cells(iLin + i, 8) = 1 + (132800 * Worksheets(Sheet_).Cells(iLin + i, 5)) / (Worksheets(Sheet_).Cells(iLin + i, 6) * 4813.267)
Worksheets(Sheet_).Cells(iLin + i, 9) = Worksheets(Sheet_).Cells(iLin + i, 7) / Worksheets(Sheet_).Cells(iLin + i, 8)
End If
'calculate p
Worksheets(Sheet_).Cells(iLin + i + 1, kCol + k) = Worksheets(Sheet_).Cells(iLin + i, kCol + k) * (Worksheets(Sheet_).Cells(iLin + i, 9) * 1225 * 9.81 * 100 / 3.28) * 0.000145
Worksheets(Sheet_).Cells(2, 3) = Worksheets(Sheet_).Cells(iLin + i + 1, kCol + k)
Worksheets(Sheet_).Cells(2, 4) = i
Worksheets(Sheet_).Cells(2, 5) = k
Next
Next
End Sub

Type Set – Constant Volume Depletion
Sub DoCVD()
CalcType = "CVD"
DoCalc
End Sub

**Type Set - Constant Composition Expansion**

Sub DoCCE()
  Dim iCalc As Integer
  Dim iErr As Integer
  Dim iCol As Integer
  Dim iRes As Integer
  Dim iNumCols As Integer
  SetUpServer
  Sheet = "CCE"
  iStream = Worksheets(Sheet).Cells(3, 2)
  iNumStream = DoGet("PVT.NUMSTREAMS")
  If (iStream > iNumStream - 1) Then
    MsgBox "Stream selected does not exist num streams = " + CStr(iNumStream)
    Exit Sub
  End If
  iLine = 8
  SendCellData "PVT.OPTIONS.CALC_TYPE"
  iLine = 10
  ' Identify the mode to be used in the calculation USER or AUTO
  SendCellData "PVT.CALCUL[" + CStr(iStream) + "]CALC_CCE_MODE"
  If (Worksheets(Sheet).Cells(10, 2) = "AUTO") Then
    iLine = 13
    'AUTO Mode
    'send calculation ranges
    SendCellData "PVT.CALCUL[" + CStr(iStream) + "]CALC_CCE_MIN_TEMP"
    SendCellData "PVT.CALCUL[" + CStr(iStream) + "]CALC_CCE_MAX_TEMP"
    SendCellData "PVT.CALCUL[" + CStr(iStream) + "]CALC_CCETEMPVALUES"
    SendCellData "PVT.CALCUL[" + CStr(iStream) + "]CALC_CCE_MIN_PRESS"
    SendCellData "PVT.CALCUL[" + CStr(iStream) + "]CALC_CCE_MAX_PRESS"
    SendCellData "PVT.CALCUL[" + CStr(iStream) + "]CALC_CCEPRESSVALUES"
  Else
    iLine = 23
    ' USER Mode
    ' send individual temperatures and pressures
    For iCalc = 0 To 9
      DoSetStr iLine, 1, "PVT.CALCUL[" + CStr(iStream) + "]CALC_USER_CCE_TEMPS[" + CStr(iCalc) + "]", False
      For iCol = 0 To 4
        DoSetStr iLine, 2 + iCol, "PVT.CALCUL[" + CStr(iStream) + "]CALC_USER_CCE_PRESSURES[" + CStr(iCalc + (10 * iCol)) + "]", False
      Next
      iLine = iLine + 1
    Next
    ' Clear the stream calculation flags
    DoCmd "PVT.RESET_STREAM_IN_CALC_FLAGS"
    ' Tell the program to do a CCE Calculation on stream identified by index iStream
    DoCmd "PVT.CCE[" + CStr(iStream) + "]"
    iLine = 42
    Worksheets(Sheet).Range("A45:AM200").ClearContents
    iErr = DisplayCellData("Number of Results", DoGetCheck("PVT.CALCUL[" + CStr(iStream) + "]CALC_NUM_RESULTS"))
    'Find the number of results produced during the calculation
    iNumRes = DoGetCheck("PVT.CALCUL[" + CStr(iStream) + "]CALC_NUM_RESULTS")
    'Find the number of columns calculated for CCE
    iNumCols = DoGetCheck("PVT.CALC_COLUMN_TOTAL")
    'Get column names
Worksheets(Sheet).Cells(iLine, 1) = DoGet("PVT.CALC_COLUMN_NAME[" + CStr(0) + "]")
'Get column names
Worksheets(Sheet).Cells(iLine + 1, 1) = DoGet("PVT.CALC_COLUMN_UNIT[" + CStr(0) + "]")
'Get column units
Worksheets(Sheet).Cells(iLine + 2, 1) = DoGet("PVT.CALCUL[" + CStr(iStream) + "].CALC_COLUMN_VALUE[" + CStr(0) + "]" + CStr(0) + "]" + CStr(0) + "]")
'Get all column values
Worksheets(Sheet).Cells(iLine, 2) = DoGet("PVT.CALC_COLUMN_NAME[" + CStr(1) + "]")
'Get column names
Worksheets(Sheet).Cells(iLine + 1, 2) = DoGet("PVT.CALC_COLUMN_UNIT[" + CStr(1) + "]")
'Get column units
Worksheets(Sheet).Cells(iLine + 2, 2) = DoGet("PVT.CALCUL[" + CStr(iStream) + "].CALC_COLUMN_VALUE[" + CStr(0) + "]" + CStr(0) + "]" + CStr(1) + "]")
'Get all column values
Worksheets(Sheet).Cells(iLine, 3) = DoGet("PVT.CALC_COLUMN_NAME[" + CStr(3) + "]")
'Get column names
Worksheets(Sheet).Cells(iLine + 1, 3) = DoGet("PVT.CALC_COLUMN_UNIT[" + CStr(3) + "]")
'Get column units
Worksheets(Sheet).Cells(iLine + 2, 3) = DoGet("PVT.CALCUL[" + CStr(iStream) + "].CALC_COLUMN_VALUE[" + CStr(0) + "]" + CStr(0) + "]" + CStr(3) + "]")
'Get all column values
Worksheets(Sheet).Cells(iLine, 4) = DoGet("PVT.CALC_COLUMN_NAME[" + CStr(4) + "]")
'Get column names
Worksheets(Sheet).Cells(iLine + 1, 4) = DoGet("PVT.CALC_COLUMN_UNIT[" + CStr(4) + "]")
'Get column units
Worksheets(Sheet).Cells(iLine + 2, 4) = DoGet("PVT.CALCUL[" + CStr(iStream) + "].CALC_COLUMN_VALUE[" + CStr(0) + "]" + CStr(0) + "]" + CStr(4) + "]")
'Get all column values
Worksheets(Sheet).Cells(iLine, 5) = DoGet("PVT.CALC_COLUMN_NAME[" + CStr(24) + "]")
'Get column names
Worksheets(Sheet).Cells(iLine + 1, 5) = DoGet("PVT.CALC_COLUMN_UNIT[" + CStr(24) + "]")
'Get column units
Worksheets(Sheet).Cells(iLine + 2, 5) = DoGet("PVT.CALCUL[" + CStr(iStream) + "].CALC_COLUMN_VALUE[" + CStr(0) + "]" + CStr(0) + "]" + CStr(24) + "]")
'Get all column values
DoGetCCEAnalysis
Set Server = Nothing
End Sub

Calculator - Calls PVT-P to Calculate Parameters

Sub DoCalc()
    Dim iCalc As Integer
    Dim iErr As Integer
    Dim iCol As Integer
    Dim iRes As Integer
    Dim iNumCols As Integer
    SetUpServer
    Sheet = "Calc"
    iStream = Worksheets(Sheet).Cells(3, 2)
    iNumStream = DoGet("PVT.NUMSTREAMS")
    If (iStream > iNumStream - 1) Then
        MsgBox "Stream selected does not exist num streams = " + CStr(iNumStream)
        Exit Sub
    End If
    iLine = 8
    Worksheets(Sheet).Cells(iLine, 2) = CalcType
    SendCellData "PVT.OPTIONS.CALC_TYPE"
    iLine = 14
    DoSetStr iLine, 1, "PVT.CALCUL[" + CStr(iStream) + "]" + CalcType + "]" + ".CALC_TEMP[0]", False
    If (CalcType = "DEPL") Then
        DoSetStr 17, 1, "PVT.CALCUL[" + CStr(iStream) + "]" + CalcType + "]" + ".CALC_DEPL_GASINPLACE", False
    End If
End Sub
End If
For iCalc = 0 To 9
DoSetStr iLine, 3, "PVT.CALCUL[" + CStr(iStream) + "]\CALC_" + CalcType + "\_PRESSURES[" + CStr(iCalc) + "]", False
DoSetStr iLine, 4, "PVT.CALCUL[" + CStr(iStream) + "]\CALC_" + CalcType + "\_PRESSURES[" + CStr(iCalc + 10) + "]", False
iLine = iLine + 1
Next
iLine = iLine + 1
DoCmd "PVT.RESET_STREAM_IN_CALC_FLAGS"
DoCmd "PVT." + CalcType + "] + CStr(iStream) + "]"
iLine = 35
Worksheets(Sheet).Range("A38:AZ200").ClearContents
iErr = DisplayCellData("Number of Results", DoGetCheck("PVT.CALCUL[" + CStr(iStream) + "].CALC_NUM_RESULTS")
iNumRes = DoGetCheck("PVT.CALCUL[" + CStr(iStream) + "].CALC_NUM_RESULTS")
iNumCols = DoGetCheck("PVT.CALCULATION_TOTAL")
For iCol = 0 To iNumCols - 1
Worksheets(Sheet).Cells(iLine, iCol + 1) = DoGet("PVT.CALCULATION_NAME[" + CStr(iCol) + "]")
Worksheets(Sheet).Cells(iLine + 1, iCol + 1) = DoGet("PVT.CALCULATION_UNIT[" + CStr(iCol) + "]")
For iRes = 0 To iNumRes - 1
Worksheets(Sheet).Cells(iLine + iRes + 2, iCol + 1) = DoGet("PVT.CALCUL[" + CStr(iStream) + "].CALCULATION_VALUE[" + CStr(iRes) + "]")
Next
Next
DoGetAnalysis
Set Server = Nothing
Appendix E - WTA
Dry Gas

Figure 27: BH WTA of BU1.

Figure 26: Superposition plot BU1.

Figure 28: Pressure and rate history plot (BU1).

Figure 30: WH WTA (BU1).

Figure 29: Superposition plot of BU1 (WH).
Well Test Analysis on Well-head PBU to Identify Well Behaviour/Under Performance

Figure 31: WH pressure and rate history plot (BU1).

Figure 32: BH WTA (BU2).

Figure 33: BH Superposition plot (BU2).

Figure 34: BH History plot (BU2).
Well Test Analysis on Well-head PBU to Identify Well Behaviour/Under Performance

Figure 36: WH WTA (BU2).

Figure 35: WH superposition plot (BU2).

Figure 37: WH History plot (BU2).

Gas/Condensate

Figure 39: BH WTA (BU1).

Figure 38: Superposition plot (BU1).
Well Test Analysis on Well-head PBU to Identify Well Behaviour/Under Performance

Figure 40: BH history plot (BU1).

Figure 41: WH history plot (BU1).

Figure 42: WH superposition plot (BU1).

Figure 43: WH WTA (BU1).
Well Test Analysis on Well-head PBU to Identify Well Behaviour/Under Performance

Figure 48: BH WTA (BU2).

Figure 47: BH superposition plot (BU2).

Figure 46: BH history plot (BU2).

Figure 45: WH WTA (BU2).

Figure 44: WH superposition plot (BU2).
Well Test Analysis on Well-head PBU to Identify Well Behaviour/Under Performance

Figure 49: WH history plot (BU2).

Figure 50: WTA of the estimated BH pressures using modified Peffer method (April 09).

Figure 51: Superposition plot (April 09).

Figure 52: History plot (Estimation April 09).
Figure 54: WTA of the estimated BH pressures using modified Pefer method (July 05).

Figure 53: Superposition plot (July 05)