FINAL YEAR PROJECT II
Dissertation

UNIVERSITI
TEKNOLOGI
PETRONAS

The Study of New Method of Modern Well Testing By Using Surface Control

BY

ALI AL-AMANI BIN AZLAN
9728 PETROLEUM ENGINEERING

Supervisor: Prof. Dr. Mehmet Raif Birol Demiral

January 2011

Universiti Teknologi PETRONAS
Bandar Seri Iskandar
31750 Tronoh,
Perak Darul Ridzuan

CERTIFICATION OF APPROVAL

The Study of New Method of Modern Well Testing By Using Surface Control

by

Ali Al-Amani bin Azlan

A project dissertation submitted to the
Geoscience & Petroleum Engineering Programme
Universiti Teknologi PETRONAS
In partial fulfilment of the requirement for the
BACHELOR OF ENGINERING (Hons)
(PETROLEUM ENGINEERING)

Approved by,

(Prof. Dr. Mehmet Raif Birol Demiral)
UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK
January 2011

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or person.

ALI AL-AMANI BIN AZLAN
(9728)

Acknowledgements

The authors gratefully acknowledge "Universiti Teknologi PETRONAS Graduate Program in Petroleum Engineering in Malaysia", especially Prof. Dr. Birol Demiral as the supervisor of this project and also Prof. Dr. Mariyamni Awang for her kindness to spend the time teaching "Advance Well Testing Analysis". Special thanks to Dr. Iain Paton, CPS Optimization Regional Manager of Weatherford Solution Sdn. Bhd. for inspiring the author to do advance study on well testing. The author also thank to Ms. Shri for providing the raw data to be used in the study. Last but not least, the appreciation to Mr. Hafiz and Ms. Diyana for their long lasting support in completing the study.

Award and Honor

This project has been chosen to be presented in **SHELL Student Paper Inter-Varsity Competition 2011 (SSPEC 2011)** at Universiti Teknologi Malaysia, Skudai Johor. The project won 1st place for the poster presentation category in undergraduate level.

ABSTRACT

The accurate information of the in-situ reservoir condition is very significant to every phase in petroleum engineering thus help the reservoir engineers to have better understanding on the reservoir and completion efficiency qualitatively and quantitatively. The analysis toward pressure data recorded during well test has been used for many years to evaluate the reservoir characteristic especially in determining the value of well damage (skin), effective permeability and heterogeneity behavior. However, well testing has become increasingly unpopular especially in exploration and appraisal wells due to the expensive costs, safety and environmental impact factors. For the production well, the potential revenue loss during buildup testing is one of the reason to decline well testing in their activity. For past 30 years, many methods have been published to improved the well testing technique but the problem of the cost either the expensive tools or the production loss is still occur. This paper presented the new technique of implementing well testing by using surface control which reduces the cost and eliminates the risk of running tools into well bores. This new technique also created to overcome the problem of the constant rate which in practical it is not achieved by allowing the varying rate test. Thus, it will increase better interpretation with lower the uncertainty ranges. The idea of this new technique will overcome all the weakness of conventional well testing and brings the significant impact to the industry. First, the general framework of the flowing surface-bottomhole pressure calculation will be presented which will be compared with the measured data from field and also with the calculation from the computer program using Modified Hagedorn and Brown Correlation. The pressure difference between the calculated flowing bottomhole pressure with measured depth averagely 3 to 6 psia. Next, the study of Tiab's Direct Synthesis method with the available multi rate test data taken from published source is analyzed and compared the result with the conventional analysis. The results obtained from the Tiab's Direct Synthesis method are very close with real data which the percentage difference of the absolute permeability estimate is about 0.36%. The specific procedure required in order to implement this new technique which focusing on choke control and test design will also be explained. The report also presents some case study of application of well testing toward estimating reservoir parameters for Malaysia fields.

CONTENTS

ABSTRACT i

CONTENTS ii

LIST OF FIGURES v

LIST OF TABLES vii

CHAPTER 1 - INTRODUCTION **1**

1.1 Background of Study 1

1.2 Problem Statement 1

1.2.1 Problem Identification 1

1.2.2 Significant of the Project 1

1.3 Objectives 1

1.4 Scope of Study 2

1.5 Relevancy of the Project 3

1.6 Feasibility of the Project within the Scope and Time Frame 3

CHAPTER 2 – LITERATURE REVIEW **4**

2.1 Fundamental of Correlations for Predictiong FBHP 4

2.1.1 Hagedorn and Brown Correlation 4

2.1.2 Modified Hagedorn and Brown Correlation 4

2.1.3 Simple Correlation for Predicting FBHP 5

2.2 Basic Mathematical Development of Well Testing 6

2.3 Pressure Derivatives 9

2.3.1 Fault and No Flow Boundaries 10

2.3.2 Partially Penetration Well 11

2.3.3 Radial Composite Reservoir 12

2.3.4 Varying Wellbore Storage 14
2.4 Well Test Design 14

CHAPTER 3 - PROJECT METHODOLOGY **16**
3.1 Research Methodology 16
3.2 Project Activities Flow 21
3.3 Key Milestone 22
3.4 Project Gantt Chart 22
3.5 Software 22
3.5.1 PanSystem™ 23
3.5.2 WellFlo™ 23

CHAPTER 4 - RESULTS AND DISCUSSIONS **24**
4.1 Prediction of FBHP Using Developed Mathematical Correlation 24
4.1.1 Field Case 1: Low Water Cut Well 24
4.1.1.1 Result and Discussion 24
4.1.2 Field Case 2: High Water Cut Well 26
4.1.2.1 Result and Discussion 26
4.2 Multi-rate Testing Analysis 27
4.2.1 Field Case 3: One pressure point for a given rate 27
4.2.1.1 Calculation and Analysis Procedure 28
4.2.1.2 Result and Discussion 30
4.3 The Conventional Well Testing Analysis Toward Malaysia Fields (Case Study) 30
4.3.1 Well 1 30
4.3.1.1 Data Input 30
4.3.1.2 Analysis Result 31
4.3.2 Well 2 33
4.3.2.1 Data Input 33
4.3.2.2 Analysis Result 33
4.3.3 Well 3 35

4.3.3.1 Data Input 35
4.3.3.2 Analysis Result 36
4.3.4 Well 4 38
4.3.4.1 Data Input 38
4.3.4.2 Analysis Result 38
4.3.5 Well 5 40
4.3.5.1 Data Input 40
4.3.5.2 Analysis Result 41
4.3.6 Well 6 43
4.3.6.1 Data Input 43
4.3.6.2 Analysis Result 43
4.3.7 Well 7 45
4.3.7.1 Data Input 45
4.3.7.2 Analysis Result 46

CHAPTER 5 - CONCLUSSION AND RECOMMENDATION 48
5.1 Conclusion 48
5.2 Recommendation 48

REFERENCES I

NOMENCLATURE II

LIST OF FIGURES

Figure 2.1 Pressure derivative calculation 10
Figure 2.2 Geometry of a partially penetrating well 11

Figure 3.1 Illustration of liquid inside the cylindrical glass 16
Figure 3.2 Project Activities for FYP II 21

Figure 4.1 The sensitivity done to find the best tune factor for well A 25
Figure 4.2 The comparison of calculated, modified Hagedorn and Brown and measured downhole pressure data for well A 25
Figure 4.3 Sensitivity to determine the best tune factor for well B 27
Figure 4.4 The comparison of calculated and measured downhole pressure data for well B 27
Figure 4.5 Delta Pq and t_{eq}*Delta Pq' vs t eq 29
Figure 4.6 Pressure Transient Analysis done using PanSystem™ 29
Figure 4.7 The identification region stage on pressure derivative plot for Well 1 31
Figure 4.8 The best fit match pressure and pressure derivative plot for Well 1 31
Figure 4.9 The best fit match pressure on semilog plot curve for Well 1 32
Figure 4.10 The identification region stage on pressure derivative plot for Well 2 33
Figure 4.11 The best fit match pressure and pressure derivative plot for Well 2 34
Figure 4.12 The best fit match pressure on semilog plot curve for Well 2 34
Figure 4.13 The identification region stage on pressure derivative plot for Well 3 36
Figure 4.14 The best fit match pressure and pressure derivative plot for Well 3 36
Figure 4.15 The best fit match pressure on semilog plot curve for Well 3 37
Figure 4.16 The identification region stage on pressure derivative plot for Well 4 38
Figure 4.17 The best fit match pressure and pressure derivative plot for Well 4 39
Figure 4.18 The best fit match pressure on semilog plot curve for Well 4 39

Figure 4.19 The identification region stage on pressure derivative plot for Well 5 41
Figure 4.20 The best fit match pressure and pressure derivative plot for Well 5 41
Figure 4.21 The best fit match pressure on semilog plot curve for Well 5 42
Figure 4.22 The identification region stage on pressure derivative plot for Well 6 43
Figure 4.23 The best fit match pressure and pressure derivative plot for Well 6 44
Figure 4.24 The best fit match pressure on semilog plot curve for Well 6 44
Figure 4.25 The identification region stage on pressure derivative plot for Well 7 46
Figure 4.26 The best fit match pressure and pressure derivative plot for Well 7 46
Figure 4.27 The best fit match pressure on semilog plot curve for Well 7 47

LIST OF TABLES

Table 2.1 Estimating Skin Factor- Rules of Thumb 15

Table 3.1 Suggested surface data taken for each choke size change 20

Table 3.2 Suggested surface data interval taken 21

Table 3.3 The Date's Submission for All Activities 22

Table 3.4 Gantt chart for Final Year Project II 22

Table 4.1 The summary of well A data taken in the study 24

Table 4.2 The summary of well B data taken in the study 26

Table 4.3 Time, pressure and oil rate data 28

Table 4.4 The summary of well testing analysis results 30

Table 4.5 Analysis result for Well 1 32

Table 4.6 Analysis result for Well 2 35

Table 4.7 Analysis result for Well 3 37

Table 4.8 Analysis result for Well 4 40

Table 4.9 Analysis result for Well 5 42

Table 4.10 Analysis result for Well 6 45

Table 4.11 Analysis result for Well 7 47

CHAPTER 1
INTRODUCTION

1.1 Background of Study

The existing practice well testing in industry required pressure gauge to be lowered inside the wellbore in order to collect the formation pressure when the rate is disturbed. In theory, the pressure collected should be in the sandface depth. However, in reality, the pressure gauge is lowered just above the sandface depth due to the tubing constraint. Thus, the idea of calculating pressure at sandface depth from surface can be done by using the mathematical correlation. This idea also has been supported by the availability of the advance technology of surface pressure transducer manufacture and calibration which will provide the accurate information of surface data.

In order to achieve constant rate assumption for conventional well testing, the well will be shut in for a certain time which brings to the potential revenue loss. In order to overcome it, the multi-rate testing is suggested to be done for the new method study. The combination of the predicting flowing bottomhole pressure and the multi-rate testing will have a potential to reduce the cost, minimize intervention while maintaining the reliability of the analysis result.

1.2 Problem Statement

The conventional well testing that normally be applied in industry have many disadvantages but still no suitable replacement of well testing in determining the value of well damage, effective permeability in large area of investigation and any heterogeneity behaviour.

The disadvantages of conventional well testing are:

1. High cost of tools required especially toward high pressure and temperature reservoir
2. Safety issue while dealing with the high contamination of H_2S and CO_2 wells
3. Environmental impacts
4. Production loss due to build up test
5. Difficulty in maintaining constant rate

1.3 Objectives

The main objective of the project is:

- To proposed a new method of well testing by using surface control

1.4 Scope of Study

This project covers three main activities that required in achieving the objective stated. There are:

1. *Calculate the flowing bottomhole pressure from wellhead pressure.*

   There have many correlations that able to calculate the flowing bottomhole pressure by using the surface pressure. The current used correlation for any production analysis on that well is Modified Hagedorn and Brown correlation. However, in this project, the author wish to do further study on the new correlation developed by S. O. Onyeizugbe et al. (2010) because the algorithm used is very easy and less of the data required compare with the correlation used now. The mathematical derived will be tested with the real data from field and the accuracy of the prediction of flowing bottomhole pressure will be compare with the measured data available.

2. *To analyze the multi rate test and the accuracy of the result.*

   The conventional well testing analysis limited to the assumption of constant rate testing which normally considered superposition method. However, in the practice, constant rate is very difficult to achieve. Thus, the real well behavior is not obtained due to the limitation of the assumption made. The idea of using Tiab's Direct Synthesis technique will try to overcome the problem of the assumption toward constant rate which allows the analysis on multi-rate testing. Each flow rate has its own pressure point and the time used will need to convert to equivalent time which also considered the flow rate.

3. *Determine the surface control technique to allow the well testing analysis method to be visible with the combination of the new correlation and the Tiab's Direct Synthesis.*

   The specific technique of surface control required to analyze the transient pressure data using the new method proposed. Basically, the study for this scope will just concentrate to the choke control and also the test design required before initiate the pressure disturbance testing.

1.5 The relevancy of the project

The new method proposed is relevant to today's high cost challenge that faced by the industry. There is no suitable replacement of well testing to get the skin value and permeability of the reservoir in large radius of investigation. But these two parameters are required in any reservoir analysis activities. Thus, the option available is just by overcome the conventional well testing problems which demonstrated by this new method. As part of the main subject in reservoir study, it suits very well to the petroleum engineering student which can be applied the knowledge gained during the project in the future career.

1.6 Feasibility of the Project within the scope and time frame

The project consists of three main stages which include the study of new correlation proposed by S. O. Onyeizugbe et al. (2010), the multirate Tiab's Direct Synthesis method and surface equipment focusing on choke control. As the time given is only 5 months, the well time planning has been proposed which allocated 2 months as the full literature review on interest subject related to the topic, 2 months on the analysis stage and 1 month for report preparation. This draft time planning will be explained in details in project Gantt Chart at section 3.

In completing this project, three software has been used. There are WellFlo™ version 4.1 software which used to calculate the formation pressure by using modified Hagedorn and Brown correlation, Microsoft Office Excel 2007 for calculating the formation pressure by using new correlation proposed for the study and also convert the raw data to process data by using Tiab's Direct Synthesis method and also PanSystem™ software for well testing analysis using the process data.

CHAPTER 2
LITERATURE REVIEW

2.1 Fundamental of Correlation for Predicting FBHP

2.1.1 Hagedorn and Brown Correlation

The correlation was developed from 475 tests in a 1500ft experimental well using viscosities up to 110cp. Tubing size used: 1", 1 1/4" 1 1/2". Hagedorn and Brown can be applied to the vertical well for the simultaneous flow of oil, water and gas. An average mixture density corrected for downhole conditions was used for calculating estimates of pressure losses caused by the friction and acceleration. The equation developed by Hagedorn and Brown is shown as below [4]:

$$144\frac{\Delta P}{\Delta h} = \rho_m + \frac{f Q_L^2 M^2}{2.9652 * 10^{11} d^5 \rho_m} + \frac{\rho_m \Delta[\frac{V_m^2}{2gc}]}{\Delta h} \quad (1)$$

or can be rearrange to become,

$$\frac{\Delta P}{\Delta h} = \frac{1}{144}\rho_m + \frac{1.294 * 10^{-3} f \rho_{ns}^2 v_m^2}{\rho_m d} + \frac{2.16 * 10^{-4} \rho_m v_m \Delta v_m}{\Delta h} \quad (2)$$

The extended study carried by Brill and Hagedorn recommended that pressure gradient should be calculated by the Griffith correlation for the bubble regime. And also compare the mixture calculated using the Hagedorn Brown holdup correlation should be compare with that calculated using no-slip holdup. Hagedorn and Brown did not consider the effects of flow patterns; hence they proposed a simplified calculation scheme independent of the prevailing flow pattern.

2.1.2 Modified Hagedorn and Brown Correlation

The revised study of the Hagedorn and Brown correlation from 51 pressure profile which mostly are vertical wells containing 540 pressure loss measurements. The revised correlation gave higher value of liquid holdup than the original for the same value of correlating function. The pressure drop for 157 well test data were calculated for different cases using the original and the revised liquid hold up correlation. As developed by Hagedorn and Brown[4],

$$144\frac{\Delta P}{\Delta h} = \rho_m + \frac{fQ_L^2 M^2}{2.9652*10^{11} d^5 \rho_m} + \frac{\rho_m \Delta[\frac{V_m^2}{2gc}]}{\Delta h} \tag{3}$$

which $\rho_m = H_L\rho_L + \rho_g(1 - H_L)$. f can be calculated from the two-phase Reynolds number using the standard Moody diagram. The two phases used was,

$$NRe_{tp} = 2.2 * 10^{-2} \frac{Q_L M}{d\mu_L^{HL}\mu_g^{(1-HL)}} \tag{4}$$

Using the value from the Reynolds number, the conventional relationship between f and NRe for single phase fluid, the liquid holdup is calculated from the equation developed by Hagedorn and Brown. The values of liquid holdup in terms of ψ were plotted vs the correlating function (Cf) suggested by Hagedorn and Brown [5],

$$Abscissa = Cf = \left(\frac{N_{LV}}{N_{gv}^{0.575}}\right)\left(\frac{\bar{P}}{14.7}\right)^{0.1}\left(\frac{C_{NL}}{N_d}\right) \tag{5}$$

The calculation procedure for the modified Hagedorn and Brown correlation carried by Ghassan H. Abdul Majeed et. al are[4],

1. The value of liquid holdup has been assumed.
2. The two phases Reynolds number is calculated by using the stated equation.
3. The value of f is calculated from Moody diagram by using the value of NRetp and ε/d.
4. By using equation developed by Hagedorn and Brown, the value of ρ_m is calculated.
5. The value of H_L also has been calculated by using the equation 2.
6. If the assumed value of H_L, and the calculated value from equation 2 agree within 1%, the H_L value will considered as the result. However, if the value of HL is more than 1%, the calculation needs to be repeated until agreed the condition given.

2.1.3 Simple Correlation for Predicting FBHP

This method establishes correlations that link all the important parameters that influence the flowing bottomhole pressure. Data required when using this method:

- Wellhead parameters (well head pressure and temperature)

- Well data (well depths)
- Fluid properties (oil, gas, water density, gas deviation factor)
- Produced Well Fluids Volumes (oil rate, BSW, GOR)

The approach applied is to relate the pressure drop in the tubing of a given length (in true vertical depth) to the well effluent mass flow rate. The mass flow rate was used in order to get common basis for evaluating the contribution of different fluids to the pressure loss in the tubing without being affected by their volumes. The flowing bottomhole pressure is estimated as the sum of the flowing well head pressure and the pressure loss in the tubing relative to the mass flow rate.

The main focus of this correlation is to establish relationship between the measured pressure loss in the tubing and calculated pressure drop in tubing.

For natural flow (in field unit) [8]:

$$FBHP = FTHP + \Delta P_{tubing\ corrected} \tag{6}$$

where,

$$\Delta P_{tubing\ corrected} = 91.34 * (\Delta P_{tubing\ calculated})^{x} \tag{7}$$

$$\Delta P_{tubing} = \frac{\rho_{eqivalent} * TVD}{144} \tag{8}$$

$\rho_{equivalent} =$

$$\frac{(\gamma_{oil}*\rho_{water}*Q_{oil}*5.615)+[(\gamma_{water}*\rho_{water}*Q_{oil}*5.615)*\left(\frac{\left(\frac{BSW}{100}\right)}{1-\left(\frac{BSW}{100}\right)}\right)+(\gamma_{gas}*\rho_{air}*Q_g)}{5.615\left(Q_{oil}+\left(Q_{oil}*\left(\frac{\left(\frac{BSW}{100}\right)}{(1-(\frac{BSW}{100}))}\right)\right)\right)+\frac{\left((Q_{oil}*GOR)\right)*P_{sc}*Z*(T_{ass}+460)}{T_{sc}*(\frac{P_{ass}+FTHP}{2})}} \tag{9}$$

$$FBHP_{assumed} = 0.732 * FTHP - (4 * 10^{-5}) * FTHP^2 + 2642 \tag{10}$$

$$SBHT_{assumed} = 0.049 * TVD - 87.34 - (2 * 10^{-6} * TVD^2) \tag{11}$$

2.2 Basic Mathematical Development of Well Testing

Mathematical model was developed based on the understanding toward reservoir response governed by parameters such as permeability, skin effect, storage coefficient, distance to boundary, fracture properties, dual porosity coefficients, etc. The equation also known as the general diffusivity equation [6]:

$$\frac{\partial^2 P}{\partial r^2} + \frac{1}{r}\frac{\partial P}{\partial r} + \frac{k_\theta}{k_r}\frac{1}{r^2}\frac{\partial^2 P}{\partial \theta^2} + \frac{k_z}{k_r}\frac{\partial^2 P}{\partial z^2} = \frac{\emptyset \mu c_t}{kr}\frac{\partial P}{\partial t} \tag{12}$$

Assumptions that made in developing this equation are:

- Darcy's Law applies
- Porosity, permeability, viscosity and compressibility are constant
- Fluid compressibility is small and single flow phase
- Pressure gradient in the reservoir are small
- Gravity and thermal effects are negligible

Normally, in most cases, isotropic condition is assumed and only radial and vertical flow is considered. The equation will be simplified to become:

$$\frac{\partial^2 P}{\partial r^2}+\frac{1}{r}\frac{\partial P}{\partial r}+\frac{\partial^2 P}{\partial z^2}=\frac{\emptyset\mu c_t}{kr}\frac{\partial P}{\partial t} \tag{13}$$

Matthews and Russell derived the equation in making assumption that horizontal flow occurred, negligible gravity effects, a homogeneous and isotropic porous medium, a single fluid of small and constant compressibility, applicability of Darcy's law and u, c_t,k and φ are independent of pressure. The derivation yields to [7];

$$\frac{\partial^2 P}{\partial r^2}+\frac{1}{r}\frac{\partial P}{\partial r}=\frac{1}{0.0002637}\frac{\emptyset\mu c_t}{k}\frac{\partial P}{\partial t} \tag{14}$$

When derive it using implicit finite difference, it reduce to steady state radial flow equation which is [2]:

$$q=0.007082\frac{kh(P_e-P_w)}{B\mu\ln\left({}^{r_e}/_{r_w}\right)} \tag{15}$$

2.2.1 Fundamental of Multi-rate Testing

The foundation of well test analysis is shown by Duhamel's principle [9]

$$\Delta P(t)=\int_0^\infty q(\tau)g(t-\tau)d\tau \tag{16}$$

Earlougher [2] presented the equation for multi-rate testing,

$$\Delta P_q=\frac{P_i-P_{wf}(t)}{q_n}=\frac{162.6\mu B}{kh}\left[X_n+log\frac{k}{\emptyset\mu c_t r_w^2}-3.23+0.87s\right] \tag{17}$$

where,

$$X_n = \sum_{i=1}^{n}\left(\frac{q_i-q_{i-1}}{q_n}\right)\log\left(t-t_{i-1}\right) \tag{18}$$

Further study has been done by Mongi and Tiab (2000) and Hachlaf et al. (2002) which used the equivalent time concept for the application of TDS technique. The equivalent time equation is presented as below [3],

$$t_{eq} = \prod_{i-1}^{n}\left(t_n - t_{i-1}\right)^{\left(\frac{q_i-q_{i-1}}{q_n}\right)} = 10^{X_n} \tag{19}$$

Early time region can be identified when the pressure derivative curve is shown by a unit slope line. Van Everdingen, Agarwal et al. and Wattenbarger studied a case of a constant wellbore storage and developed the equations for sandface flowrate. The pressure in the wellbore is directly proportional to the wellbore storage effect as proven by material balance concept [6],

$$P_D = \frac{t_D}{C_D} \tag{20}$$

As developed for type curve method, the dimensionless pressure, the dimensionless time and dimensionless wellbore storage are calculated by using the following equation [6],

$$P_D = \left(\frac{kh}{141.2\mu B}\right)\Delta P_q \tag{21}$$

$$t_D = \left(\frac{0.0002637k}{\emptyset\mu c_t r_w^2}\right)t \tag{22}$$

$$C_D = \left(\frac{0.8935}{\emptyset h c_t r_w^2}\right)C \tag{23}$$

Thus, Eqs. 20 can be expanded to Eqs. 24.

$$\frac{t_D}{C_D} = \left(2.95 * 10^{-4}\frac{kh}{\mu}\right)\frac{t}{C} \tag{24}$$

By substituting Eqs. 24 with Eqs. 22 and Eqs. 23, and solving for C, it reduces to Eqs. 25.

$$C = \left(\frac{B}{24}\right)\left(\frac{t}{\Delta P_q}\right) \tag{25}$$

The horizontal straight line for pressure derivative is identified as the infinite acting radial flow where the permeability value is obtained. For the pressure dimensionless in terms of the dimensionless time and dimensionless wellbore storage, it is written as [7],

$$P_D = \frac{1}{2}\left\{\ln\left(\frac{t_D}{C_D}\right) + 0.80907 + \ln(C_D e^{2s})\right\} \qquad (26)$$

As presented by Ramey, for infinite acting radial flow [11],

$$\frac{t_D}{C_D} P'_D = 0.5 \qquad (27)$$

$$k = \frac{70.6\mu B}{h(t*\Delta P'_q)} \qquad (28)$$

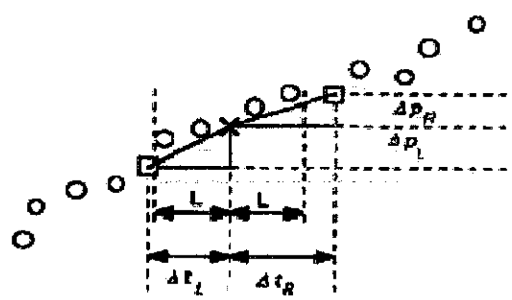
The most important parameter to be obtained using well testing is wellbore damage. As presented by Tiab (1993), skin factor can be calculated using [12],

$$s = 0.5\left[\frac{(\Delta P_q)_r}{(t_{eq}\Delta P_q)_r} - \ln\left(\frac{kt_r}{\phi\mu c_t r_w^2}\right) + 7.43\right] \qquad (29)$$

2.3 Pressure Derivatives

Modern well testing analysis always related with the usage of pressure derivative curve is log-log plot. Most of the cases, the curve for pressure build up test and drawdown test will yield to the same curve for their pressure derivative plot except for the closed system reservoir which will gives the opposite curve for both test. Because of this reason, it will helped engineers in knowing their reservoir accurately.

Compare to the straight line method (Horner's Plot) which gives a lot of uncertainties, pressure derivative is more convenient and give clear indication of the reservoir behavior. The derivative is measured by finding the weighted mean of the slopes to a preceding point and following point as showed in Figure 2.1. L can be defined as $\Delta(\ln t)$ for a drawdown test and $\Delta(\ln \Delta t)$ for a build up test [6].



O = Data points
X = Point to be derived

□ = Point used for the calculation
m_p = value of pressure derivative

$$m_p = \left(\frac{\frac{\Delta PL}{\Delta tL}\Delta tR + \frac{\Delta PR}{\Delta tR}\Delta tL}{(\Delta tL+\Delta tR)}\right) \quad (30)$$

Figure 2.1 Pressure derivative calculation

2.3.1 Fault and No Flow Boundaries

The faults or no flow boundaries effect in doubling in Horner's plot. In pressure derivatives, the upturn to the pressure plot indicates the faults behavior. The response is the same if there were an identical producer a distance 2L (if assume L is a distance from a producing well to sealing fault) away in an infinite reservoir. It is called mirror image effect. In mathematical approach, the Ei-function will be added due to "image well effect" onto the response of the test well. The equation is [1]:

$$p_D = -0.5*Ei\left(-(2\,L_D)^2/4t_D\right) \quad (31)$$

For a single fault, when the interference signal arrives, as the Ei-function becomes semi-logarithmic when $T_d/4L_d^2 > 25$. Thus, it means $p_{wf} \propto 2 \log t$. In pressure derivatives, it will double the pressure derivatives value to be 2m. This is still form of radial flow which known as hemi-radial flow.

For parallel fault, it showed by the positive linear slope that occurred after the radial flow .As the basic formula of the parallel fault which is $p_{wf} \propto \sqrt{t}$, so it will become:

$$p_{wf} = at^{0.5}$$

$$\therefore p' = \frac{dp}{d(\ln t)} = \frac{dp}{dt}\frac{dt}{d(\ln t)} \quad (32)$$

$$= 0.5at^{-0.5}t \quad (33)$$

$$\therefore p' = 0.5at^{0.5} \qquad (33)$$

In logarithm form,

$$\log p' = 0.5\log t + \log(0.5a) \qquad (34)$$

Thus, the 0.5 represent the half slope in the log-log plot. That is why in log-log plot, the parallel fault can be identified when there has positive half slope.

The different effect represented by the intersecting faults which created 3 image wells. If the degree of intersecting fault is 90°, it will produce a quadrupling of slope when the 3 interference signals are superposed on the test well response. Thus, $p_{wf} \propto 4 \log t$. In pressure derivatives plot, it will give the indication of 4m and the flow called hemi-demi radial flow.

2.3.2 Partially Penetration Well

Bourdet Dominic defined partially penetration well as the well communicates with only a fraction of the producing zone thickness. From Schlumberger glossary, it defined as an incomplete drilled portion of the productive interval.

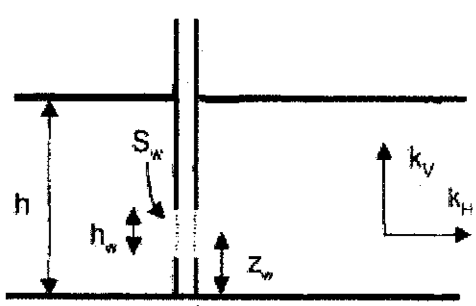


Figure 2.2 Geometry of a partially penetrating well

There have 3 main flow regions for partially penetration well which are radial flow, spherical flow and pseudoradial flow. For radial flow over vertical thickness of formation, (P_i - P_{wf}), Δp proportional to log (At) and a first derivative plateau in pressure derivative plot. Analysis of the initial radial flow regime yields the permeability thickness product for the open interval k_H h_w, and the infinitesimal skin of the well, S_w.

It follows with spherical flow with Δp proportional to $\Delta t^{-1/2}$ and a negative half unit slope straight line on the derivative log-log curve. The spherical flow regime lasts until the lower and upper boundaries are reached. Analysis yields the permeability anisotropy k_V/k_H.

The pseudoradial flow over the entire reservoir thickness with Δp proportional to log(At) and a second derivative stabilization. The reservoir permeability-thickness product $k_H h$, and the total skin S_T can be estimated from the second radial flow regime [2].

Modern well testing analysis used derivative curves for analysis. The ratio of k_v/k_h influence the period of first stabilization. If k_v/k_h decreases, the time to stabilize increases. If perforated segment is not centered – hemi-spherical flow geometry is developed

In partial penetration well, additional skin from completion effect contribute to add up the total skin. The equation for total skin is [1];

$$S_T = \frac{h}{h_w} S_w + S_{pp} \tag{35}$$

The calculation of S_{pp} (After Papatzacos), is using the penetration ratio hw/h. the dimensionless reservoir thickness-anisotropy group h_D, and the distance $z_w$from the center of the open interval to the lower or upper boundary. The equation is [1];

$$S_{pp} = \left[\frac{h}{h_w} - 1\right] \ln\left[\frac{\pi h_D}{2}\right] + \frac{h}{h_w} \ln\left[\frac{\frac{h_w}{h}}{2+\frac{h_w}{h}} \sqrt{\frac{\left(\frac{z_w + h_w}{4}\right)\left(h - z_w + h_w\frac{1}{4}\right)}{\left(\frac{z_w - h_w}{4}\right)\left(h - z_w - h_w\frac{1}{4}\right)}}\right] \tag{36}$$

where,

$$h_D = \frac{h}{r_w}\sqrt{\frac{k_H}{k_v}} \tag{37}$$

2.3.3 Radial Composite Reservoir

In a radial composite system a discontinuity in reservoir properties is specified at some radius, r_d , from a vertical well. Thus the system is divided into a cylindrical inner region - denoted 1 - with the well at the centre and an infinite outer region - denoted 2 - where both the diffusivity, $h=k/(\phi\mu c_t)$, and the capacity, fc_t , may be quite different. The contrast in properties is expressed by the ratios [1]:

1. *Mobility Ratio, M:*

When the mobility of the injected fluid, k_1/m_1, is less than that of the fluid ahead of the front, k_2/m_2, i.e. M as defined here is greater than unity, the displacement is termed favourable and the Buckley-Leverett theory indicates that a sharp displacement front will form. Under these conditions the radial composite model based on a step change in properties will be quite adequate in representing the physical situation. However when the mobility ratio is unfavourable, i.e. M is less than unity, an extended saturation transition zone will develop and the idealised step change in properties implicit in the radial composite model does not correspond to the actual situation in the reservoir. Thus, for water injection into heavy oil reservoirs and gas or steam injection wells field data may not correspond to the predictions of radial composite theory.

The situation in water injection wells is complicated by the cold ring effect which arises because the injection temperature T_i is less than the reservoir temperature T_r. When cold sea water is injected at high rate very little heating of the water will occur during its passage down the well and the injection temperature T_i will be close to the well-head (surface) temperature T_s. The equation used to measure the mobility ratio is;

$$M = \frac{\Delta p_{2nd\ stabilization}}{\Delta p_{1st\ stabilization}} \tag{38}$$

2. *Capacity Ratio, F:*

It is also known as the storativity ratio. It measures the ratio for the storage of the inner zone over outer zone. When F = 0.1, the storage of outer zone is 10 times larger than the storage of the inner zone. Thus, the response is said to be increasing in storativity. Conversely, when the F is greater than 1, the storage of outer boundary is reduced. Thus, the response shows a decrease of storativity. In pressure derivative curve in log-log plot, the transition on derivative curve shown a hump above the early zero slope line and also late zero slope line. Basically, capacity ratio is in general difficult to access. When the match generated by computer is performed a complete radial composite response, capacity ratio will be adjusted from the derivative transition.

2.3.4 Varying Wellbore Storage

Models are available for a gradual change of storage coefficient to represent the effects of wellbore gas phase redistribution, changing fluid compressibility. When the fluid is moving inside the well, the effect of density is effect the flow of the fluid. For the gas, it will tend to go upward, the oil in and water tends to move downward due to gravity and density effect. But of course, the effect is a bit low because of the pressure difference between the sandface and also well head.

The *Fair* and *Hegeman* models assume that any decrease (or increase) in the storage coefficient is exponential with time [12]:

1) Fair: $e^{-(t/\tau)}$ (39)

2) Hegemen: $e^{-(t/\tau)^2}$ (40)

C_{phi} is an amplitude term:

- positive for increasing wbs ('humping') caused by gas segregation and consequent wellbore overpressuring
- negative for decreasing wbs caused by wellbore fluid compression

The Fair and Hegeman models are analytical curve-fits to observed data. Basically, there is no physical factor on them.

2.4 Well Test Design

Well testing should be designed in order to achieve the well test objectives. The time taken for the test is the primary concern. The equations to calculate the test duration are shown by Eqs. 41, 42 and 43 [7].

Duration to prevent wellbore storage region :

$$\Delta t > \frac{(170000)Ce^{0.14s}}{(kh/\mu)} \tag{41}$$

For transient period of infinite acting:

$$\frac{3.79x10^5 * \emptyset\mu c_t r_e^2}{k} < t < \frac{948 * \emptyset\mu c_t r_e^2}{k} \tag{42}$$

Duration when the reservoir in pseudosteady state flow:

$$t_{pss} \approx \frac{\phi \mu c_t A}{0.0002637k}(t_{DA})_{pss} \quad (43)$$

However, several data should be estimated in order to determine the best duration of testing such as permeability (k), skin (s), area (A) and t_{DA}. John P. Spivey [7] presented the rules of thumb to estimate as shown in Table 2.1. Besides, permeability can also be estimated by using the one point method. The procedures of one point method are:

1. The equivalent producing time is calculated from,

$$t = \frac{24N_p}{q} \text{ or } t = \frac{24G_p}{q_g} \quad (44)$$

2. Initial guess for k need to be made. Normally, 10md for oil wells and 0.1md for gas wells.
3. Drainage radius is calculated by using the equation of,

$$r_d = [\frac{kt}{377\phi \mu c_t}]^{1/2} \quad (45)$$

4. By using the value of drainage radius, the new permeability is calculated,

$$k = \frac{141.2qB\mu}{h(P_i - P_{wf})}[\ln\left(\frac{r_d}{r_w}\right) - 0.75 + S'] \quad (46)$$

5. Step 3 and 4 is repeated until the value of permeability converges with percentage difference less than 0.1%.

Table 2.1 Estimating Skin Factor- Rules of Thumb

Type of completion	Skin
Openhole Completion	0
Small to Medium Acid Treatment	-1 to -2
Medium to Large Acid Treatment	-2 to -3
Small Hydraulic Fracture Treatment	-3 to -5
Large Hydraulic Fracture Treatment	-4 to -6
Cased Hole Gravelpack	+8 to +20
Open Hole Gravelpack	+2 to +10
Fracpack	0 to +8

CHAPTER 3

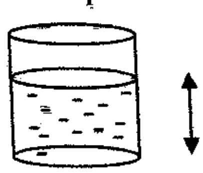
PROJECT METHODOLOGY

3.1 Research Methodology

The project involved three main stages which are the prediction of flowing bottomhole pressure from surface pressure, the analysis of multi-rate testing and the study of surface control. Because this is the new method suggested by the author and yet no data available to fully analyze using the new method, the indication of the successfulness of the project depending on every stages success. Thus, if the prediction of the flowing bottomhole pressure from well head pressure using simple correlation modified by the author succeed and the multi-rate test analyzed result gives the accepted accuracy compare with real data, the study is considered success.

1) Developed mathematical correlation for predicting flowing bottomhole pressure using surface data.

The basic idea of the pressure difference or measured pressure loss inside the natural flow well can be modeled by a static liquid inside the glass, as illustrated in Figure 1. The simple equation for static liquid pressure drop is shown in Eq. 47.



$$\Delta P = \rho * g * h \qquad (47)$$

Figure 3.1 Illustration of liquid inside the cylindrical glass

By converting the equation to field unit, the pressure drop along the tubing can be calculated using Eq. 48.

$$\Delta P_{tubing} = \frac{\rho_{eqivalent} * TVD}{144} \qquad (48)$$

The details derivation of correlation is shown as follows:

$$\rho_{equivalent} = \frac{M_{fluid}}{Q_{fluid}} = \frac{M_o+M_w+M_g}{Q_o+Q_w+Q_g} \qquad (49)$$

By considered the in situ condition, mass and volume of the fluids should be converted to reservoir condition. Thus,

$$M_{o\,res} = (\gamma_o * \rho_w * Q_o * B_o * 5.615) \qquad (50)$$

$$M_{w\,res} = (\gamma_w * \rho_w * Q_w * B_w * 5.615) \qquad (51)$$

$$M_{g\,res} = (\gamma_g * \rho_{air} * Q_{g\,reservoir}) \qquad (52)$$

$Q_{g\,reservoir}$ is calculated by converting the gas surface rate to the prevailing temperature and pressure condition in the interest depth. From real gas equation [10],

$$\frac{nP_1V_1}{z_1RT_1} = \frac{nP_2V_2}{z_2RT_2} \qquad (53)$$

By cancelling the same parameters in both terms (n and R) and setting 1 at standard condition and 2 at reservoir condition, thus,

$$V_{g\,res} = \frac{z_{res} * T_{res} * P_{sc} * V_{sc}}{z_{sc} * T_{sc} * P_{res}} \qquad (54)$$

Assumed P_{sc}=14.73 psia, T_{sc}=60°F=520°R, z_{sc}=1, the Eqs. 54 reduces to

$$V_{g\,res} = \frac{0.0283 * z_{res} * (T_{res} + 460) * V_{sc}}{P_{res}} \qquad (55)$$

If the data of P_{res} and T_{res} is not available, the assumed values calculated from the developed equation by Onyeizugbe S.O. et al. [8] are shown by Eqs. 56 and 57.

$$FBHP_{assumed} = 0.732 * FTHP - (4 * 10^{-5}) * FTHP^2 + 2642 \qquad (56)$$

$$SBHT_{assumed} = 0.049 * TVD - 87.34 - (2 * 10^{-6} * TVD^2) \qquad (57)$$

Because of $FBHP_{assumed}$ is determined as a function of FTHP, to get the average pressure for gas conversion, it is necessary to perform the calculation of,

$$P_{res} = (FBHP_{assumed} + FTHP)/2 \qquad (58)$$

For $T_{assumed}$, it is determined as a function of depth, thus the value calculated using Eq. 57 can be used for T_{res}. Thus, by substituting Eqs. 56 and 57 into Eq. 55, it becomes,

$$V_{g\,res} = \frac{0.0283 * z_{res} * ((0.049 * TVD - 87.34 - (2 * 10^{-6} * TVD^2)) + 460) * V_{g\,sc}}{((0.732 * FTHP - (4 * 10^{-5}) * FTHP^2 + 2642) + FTHP)/2}$$

$$= \frac{0.0566 * z_{res} * [(1.409 * TVD^{0.532}) + 460] * V_{SC}}{FTHP(0.732 - 4 * 10^{-5} * FTHP) + 2642} \tag{59}$$

Eq. 6 can be expanding to Eq. 14.

$$M_g = (\gamma_g * \rho_{air} * (\frac{0.0566 * z_{res} * [(1.409 * TVD^{0.532}) + 460] * Q_{g\,sc}}{FTHP(0.732 - 4 * 10^{-5} * FTHP) + 2642}) \tag{60}$$

For volume of the fluid, it can just be calculated by using Eqs. 15,16 and 17.

$$Q_{o\,res} = Q_o * B_o * 5.615 \tag{61}$$

$$Q_{W\,res} = Q_o * B_o * 5.615 \tag{62}$$

$$Q_{g\,res} = \frac{0.0566 * z_{res} * [(1.409 * TVD^{0.532}) + 460] * V_{SC}}{FTHP(0.732 - 4 * 10^{-5} * FTHP) + 2642} \tag{63}$$

By subtituting Eqs. 4, 5, 14, 15, 16 and 17 into Eq. 3, $\rho_{equivalent}$ can be calculated as,

$\rho_{\ equivalent} =$

$$\frac{(\gamma_o * \rho_w * Q_o * B_o * 5.615) + (\gamma_w * \rho_w * Q_w * B_w * 5.615) + (\gamma_g * \rho_{air} * (\frac{0.0566 * z_{res} * [(1.409 * TVD^{0.532}) + 460] * Q_{sc}}{FTHP(0.732 - 4 * 10^{-5} * FTHP) + 2642})}{(Q_o * B_o * 5.615) + (Q_o * B_o * 5.615) + \frac{0.0566 * z_{res} * [(1.409 * TVD^{0.532}) + 460] * V_{sc}}{FTHP(0.732 - 4 * 10^{-5} * FTHP) + 2642}}$$

(64)

The original equation for $\rho_{equivalent}$ which has been presented by Onyeizugbe S.O. et al. [8] is shown as,

$\rho_{equivalent} =$

$$\frac{(\gamma_{oil} * \rho_{water} * Q_{oil} * 5.615) + [(\gamma_{water} * \rho_{water} * Q_{oil} * 5.615) * \left(\frac{(\frac{BSW}{100})}{1 - (\frac{BSW}{100})}\right) + (\gamma_{gas} * \rho_{air} * Q_g)}{5.615\left(Q_{oil} + \left(Q_{oil} * \left(\frac{(\frac{BSW}{100})}{(1 - (\frac{BSW}{100})}\right)\right)\right) + \frac{((Q_{oil} * GOR)) * P_{sc} * Z * (T_{ass} + 460)}{T_{sc} * (\frac{P_{ass} + FTHP}{2})}} \tag{65}$$

The problem of the original equivalent density equation is the inconsistency of the parameters condition. The gas rate is calculated at reservoir condition but others parameters are calculated in surface condition.

In practice, many parameters affect to the pressure losses. Onyeizugbe S.O. et al. [8] developed the equation of corrected pressure drop along tubing which considers the deviation, inner tubing diameter and roughness, and the frictional force contributed by the moving fluid.

$$\Delta P_{tubing\ corrected} = 91.34 * (\Delta P_{tubing\ calculated})^x \qquad (66)$$

x is a tune factor obtained during history matching stage. The FBHP can be calculated by adding flowing bottomhole pressure with the corrected pressure drop calculated.

$$FBHP = FTHP + 91.34 * \left(\frac{\rho_{equivalent} * TVD}{144}\right)^x \qquad (67)$$

2) Analyze the mathematical correlation developed with real data

By using M.S. Excel, one calculation spreadsheet has been prepared to calculate the flowing bottomhole pressure by using the correlation developed. The raw data of two wells which consist of TVDss, fluid properties (γ_o, γ_w, γ_g, ρ_o, ρ_w, ρ_g, z, B_o and B_w) and surface data (wellhead pressure and temperature, oil, water and gas rate) is inserted into the prepared. Next, the measured data from field which available for the study has been compare with the calculated flowing bottomhole pressure and the history matching required to be done to get the best constant value of prediction. The calculated flowing bottomhole pressure for well A was compared with the current correlation used for the well and percentage error was measured. For well B, due to the available permanent downhole pressure gauge being installed for the well, the comparison is done between calculated downhole pressure using the study correlation and measured downhole data.

3) Establish the accuracy of multi-rate testing by focusing on Tiab's Direct Synthesis method

The multi-rate test data has been taken from book and the analysis using Tiab's Direct Synthesis method and computer assisted using well testing software has been done. The result of permeability and skin factor was compared and the percentage difference is taken into consideration.

4) Study of surface control and choke procedure to implement the method proposed

To implement the new method suggested by the author, specific test design has been proposed by the author by considering the limitation of Tiab's Direct Synthesis which required the sequences of flowrate in descending order. The main control will be on choke size control and data collection method. The detail explanation as below:

Since every well has difference choke size diameter, therefore the procedure should also be different. Let's say m is the maximum throat diameter of the choke, n is the minimum diameter of choke to obtain the minimum flow rate interest and t is the duration of total test designed. Thus, the number of choke size changing is defined in Eq. 68.

$$Number\ of\ choke\ size\ changing = \frac{(m-n)}{32} + 1 \tag{68}$$

The minimum data required as suggested in this new method is 18 data points for pressure, rate and time respectively which 5 to 10 data points for wellbore storage detection,10 to 15 data points for transient period of infinite acting and 3 to 5 data points for boundary detection region. Table 3.1 shows the suggested surface data taken for every choke size change according to the maximum choke size diameter.

Table 3.1 Suggested surface data taken for each choke size change

Maximum choke size diameter	Surface data taken during every choke size change
256	3
224	4
192	5
160	6
128	8
96	10
64	15
32	30

The details explanation is shown here. If the maximum and minimum choke size diameters are 256 and 32 respectively, thus the number of diameter choke sizes that involved during the well test are 8 (256 to 32). Let's say time required for wellbore storage is 30 minutes (0.5 hours) and initial time for reservoir in pseudosteady state flow is 10 hours, thus the recommended data taken is shown in Table 3.2.

Thus, for every diameter choke size and time taken designed, the surface data such as wellhead pressure and temperature and liquid rate (eg: oil, water and gas rate) need to be recorded which can then be analyzed by using this new method.

Table 3.2 Suggested surface data interval taken

Time (hours)	Diameter Choke Size	Time (hours)	Diameter Choke Size	Time (hours)	Diameter Choke Size
0.05	256	0.45	192	5	96
0.10	256	0.50	160	6	96
0.15	256	1	160	7	64
0.20	224	1.5	160	8	64
0.25	224	2	128	9	64
0.30	224	2.5	128	10	32
0.35	192	3	128	13	32
0.40	192	4	96	15	32

3.2 Project Activities Flow

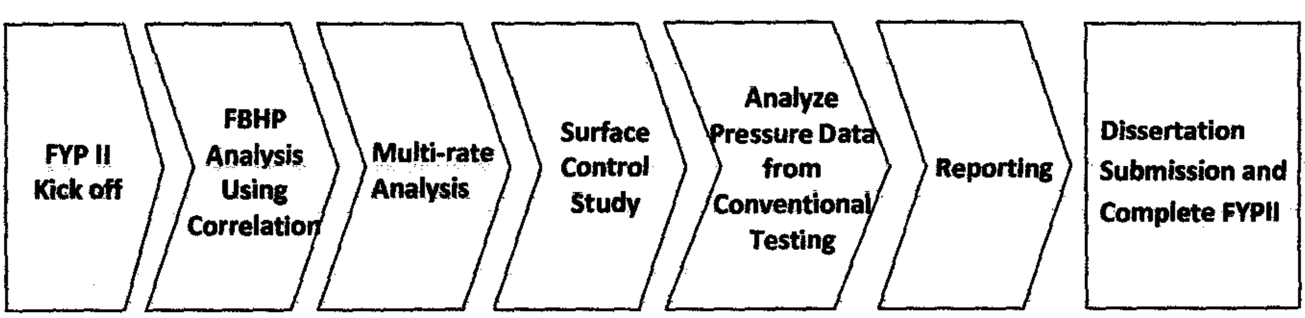


Figure 3.2 Project Activities for FYP II

3.3 Key Milestone

Table 3.3 The Date's Submission for All Activities

Dates	Activities
8th Feb 2010	Briefing and Update on Student Progress
16th March 2011	Submission of Progress Report
4th April 2011	PRE-EDX/ Poster Exhibition
11th April 2011	EDX
20th April 2011	Final Oral Presentation
20-27th April 2011	Delivery of Final Report to External Examiner
4th May 2011	Submission of Hardbound Copies

3.4 Project Gantt Chart

Table 3.4 Gantt chart for Final Year Project II

Time / Works	Week 2	Week 3	Week4	Week 5	Week 6	Week 7	Week8	Week9	Week 10	Week 11	Week 12	Week 13	Week 14
Briefing FYP II		X											
Data Acquisition	X	X	X										
Literature Review	X	X	X	X	X	X							
Development of FBHP Correlation		X	X										
Multirate Testing Analysis				X	X								
Surface Control Study						X							
SHELL Paper Contest						X	X	X	X	X			
Progress Report Submission							X						
PRE-EDX										X			
EDX											X		
Final Oral Presentation												X	
Dissertation Submission													X

3.5 Software

For this project, the student will used three types of software which are MS Excel 2007, PanSystem™ and WellFlo™ software. The first framework of the project will be focus on the spreadsheet development to predict FBHP from author's derived equation inside MS Excel 2007.

Then, the nodal analysis modeling of the well studied will be created using WellFlo™. The FBHP generated from WellFlo which is using the previous correlation will be analyzed and compared with the calculated FBHP using MS Excel 2007. Next, by using PanSystem, the multi-rate testing will be analyzed and the result is compared with manual calculation done using Tiab's Direct Synthesis.

3.5.1 PanSystem™

PanSystem™ software is an analytical well test analysis, simulation and reporting software. It is owned by e-Production Solution (EPS) which owned by Weatherford International under their production optimization business unit. By using this software, the user needs to have basic knowledge of well testing analysis because the identification of the flow regime needs to be done manually by the user. However, each pressure variation will be considered thus make the interpretation becomes more accurate and reliable. The software provides three types of analysis plot such as log-log plot (pressure derivative), type curve and special diagnostic plot (Horner's method) including semi-log plot.

3.5.2 WellFlo™

WellFlo is the software for designing, modeling, optimizing and troubleshooting naturally flowing or artificial lifted individual oil and gas wells. With this software, the author will be able to build well models, using a guided step-by-step well configuration interface. WellFlow software uses nodal analysis techniques to model reservoir inflow and well outflow performance. As in this project, the author used WellFlo to calculate the FBHP using the previous correlation used for the well studied.

CHAPTER 4
RESULTS AND DISCUSSION

4.1 Prediction of FBHP Using Developed Mathematical Correlation

4.1.1 Field Case 1: Low Water Cut Well

Well A data is taken from unpublished sources located in Indonesia field. It consists of TVDss, fluid properties (eg: γ_o, γ_w, γ_g, ρ_o, ρ_w, ρ_g, z, B_o and B_w) and surface data (eg: wellhead pressure and temperature, oil, water and gas rate). The summary of well A data used is presented in Table 4.1.

Table 4.1 The summary of well A data taken in the study

Well A	
Oil flow rate, STB/D	199-348
Water flow rate, STB/D	0-19
Gas flow rate, SCF/D	379000-666000
Tubing inner diameter, inch	2.992
Well depth, ft	7332.12
Wellhead pressure, Psia	72-95
Bottomhole pressure, Psia	436-497

4.1.1.1 Result and Discussion

The tune factor is chosen by conducting history matching with the measured downhole data. From the sensitivity analysis, the best tune factor, x is 0.286 as shown in Figure 4.1. The tune factor is constant for each well. Therefore, the value of 0.286 is valid to be used for the next analysis of the FBHP.

Previously, all nodal analysis modeling for well A is conducted by using modified Hagedorn and Brown correlation. However, it is identified to overpredict pressure drop at certain time. The comparison has been done which indicates that the calculated FBHP using modified correlation developed in this study is closer with the measured data, as illustrated by Figure 4.2. The result shows that the highest percentage difference between the modified correlation developed and measured data is 4 psia or 0.69% in percentage value. From the author's opinion, it is still acceptable due to the small value of error. Besides, in practice, the pressure gauge lowered to collect the data is also not at the sandface depth which means it has a possibility to underpredict pressure data.

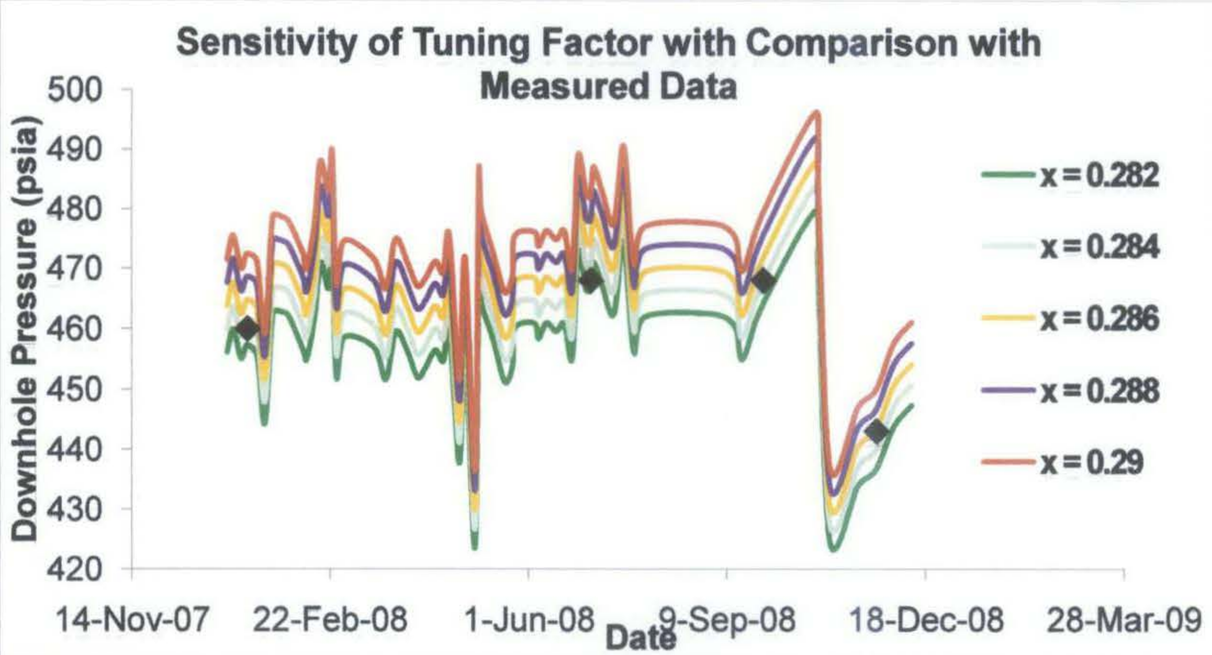


Figure 4.1 The sensitivity done to find the best tune factor for well A

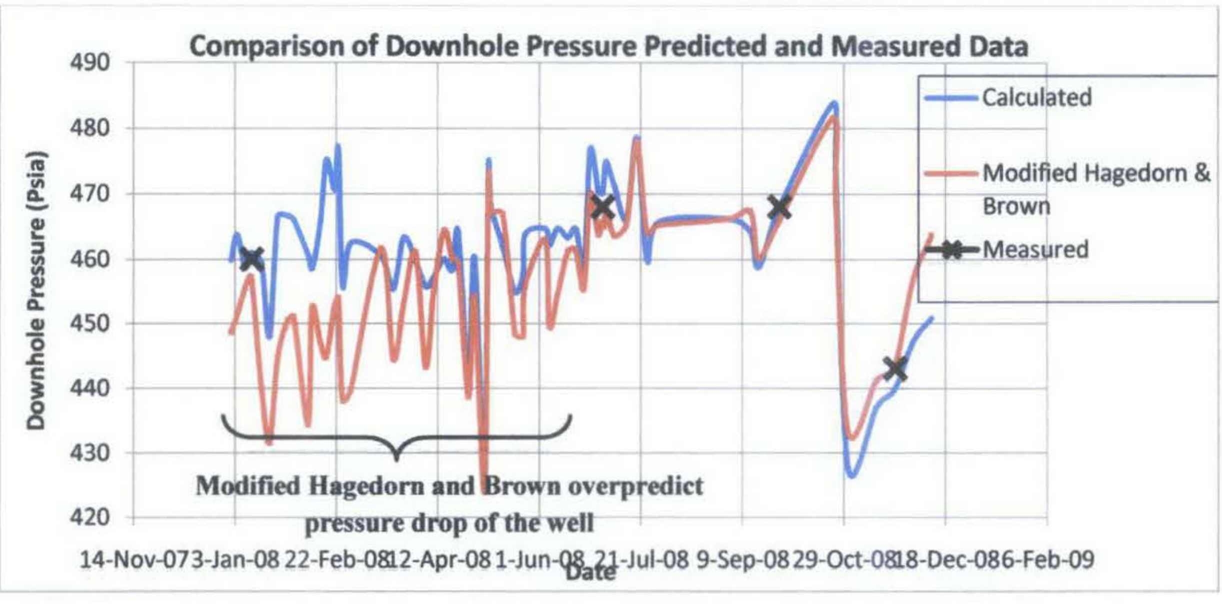


Figure 4.2 The comparison of calculated, modified Hagedorn and Brown and measured downhole pressure data for well A

4.1.2 Field Case 2: High Water Cut Well

Well B is located in Vietnam field. It is identified to produce high amount of water. The summary of well B data is presented by Table 4.2

Table 4.2 The summary of well B data taken in the study

Well B	
Oil flow rate, STB/D	294-1359
Water flow rate, STB/D	1882-5208
Gas flow rate, SCF/D	185000-410000
Tubing inner diameter, inch	3.958
Well depth, ft	15803.81
Wellhead pressure, Psia	226-297
Bottomhole pressure, Psia	1495-1745

4.1.2.1 Result and Discussion

The permanent pressure gauge is installed inside the well. Thus, the calculated FBHP can be directly compared with measured data available. The sensitivity has been done as shown in Figure 4.3. The best tune factor chosen is 0.35. Figure 4.4 shows the comparison between predicted FBHP and measured data. The average pressure difference obtained is 3 to 6 psia. However, there has one data point which violates the prediction of the downhole pressure by 22 psia pressure difference. The reason of the problem is expected due to the gas rate given. As overall, the prediction of the flowing bottomhole pressure is accepted for high producing water well.

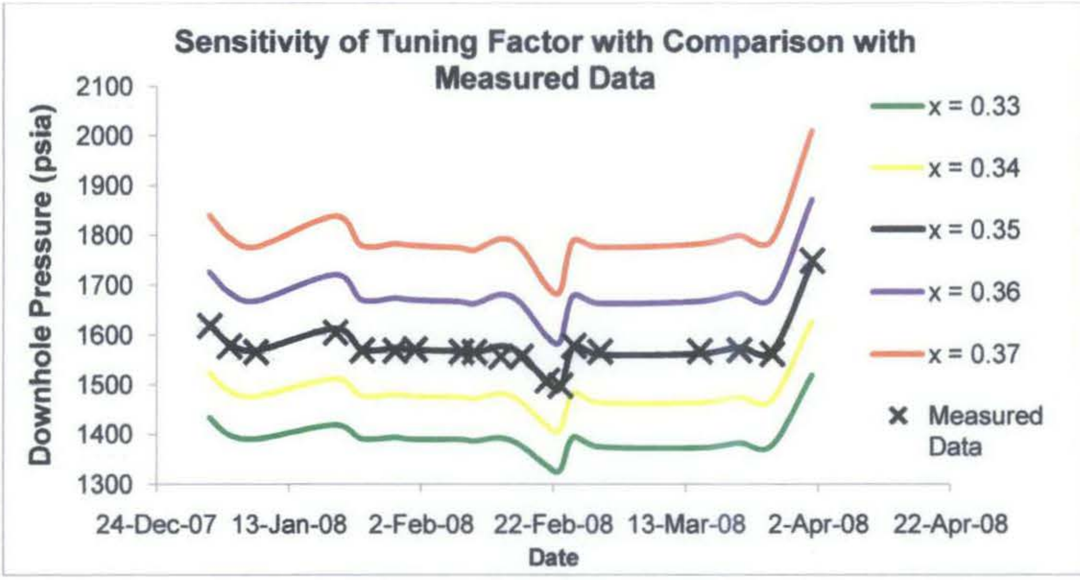


Figure 4.3 Sensitivity to determine the best tune factor for well B

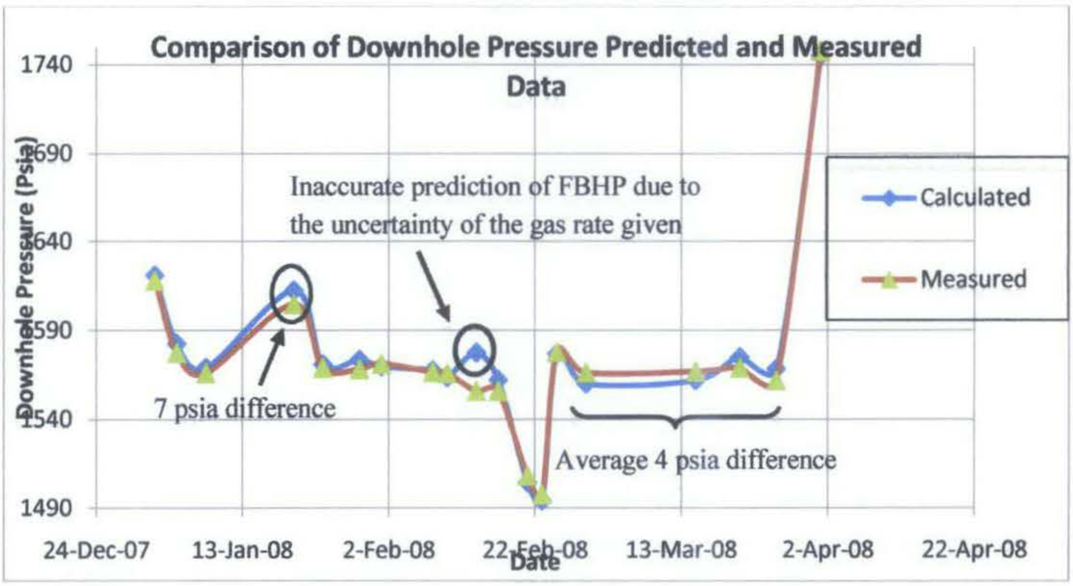


Figure 4.4 The comparison of calculated and measured downhole pressure data for well B

4.2 Multi-Rate Testing Analysis

4.2.1 Field Case 3: One pressure point for a given rate

The data is taken from published source [1]. The multi-rate testing has been done for 48 hours as shown in Table 4.3.

The data available for the analysis are:

P_i= 2906 psia, B_o= 1.27 RB/STB, μ_o= 0.6 cp , h= 40ft, Ø= 0.06,

r_w= 0.2 ft, c_t= 6 x 10^{-6} psi^{-1}

Table 4.3 Time, pressure and oil rate data

Time	Rate	Pwf	Time	Rate	Pwf
1.00	1580	2023	9.60	1370	-
1.50	1580	1968	10.00	1300	1815
1.89	1580	1941	12.00	1300	1797
2.40	1580	-	14.40	1260	-
3.00	1490	1892	15.00	1190	1775
3.45	1490	1882	18.00	1190	1771
3.98	1490	1873	19.20	1190	-
4.50	1490	1867	20.00	1160	1772
4.80	1490	-	21.60	1160	-
5.50	1440	1853	24.00	1137	1756
6.05	1440	1843	28.80	1106	-
6.55	1440	1834	30.00	1080	1751
7.00	1440	1830	33.60	1080	-
7.20	1440	-	36.00	1000	-
7.50	1370	1827	36.20	983	1756
8.95	1370	1821	48.00	983	1743

4.2.1.1 Calculation and Analysis Procedure

Firstly, a log-log plot of ΔP_q and $(t * \Delta P_q^{'})$ versus both t and t_{eq} is made as illustrated by Figure 4.5. The horizontal line drawn on pressure derivative plot is well developed, indicating infinite acting radial flow. The data obtained from plot are:

t_r = 18 hrs

(teq ΔP'q)$_r$ = 0.048

Thus, by using Eq. 28, formation permeability is calculated as below:

$$k = \frac{70.6(0.6)(1.27)}{40(0.048)} = 28md$$

The skin factor is estimated as:

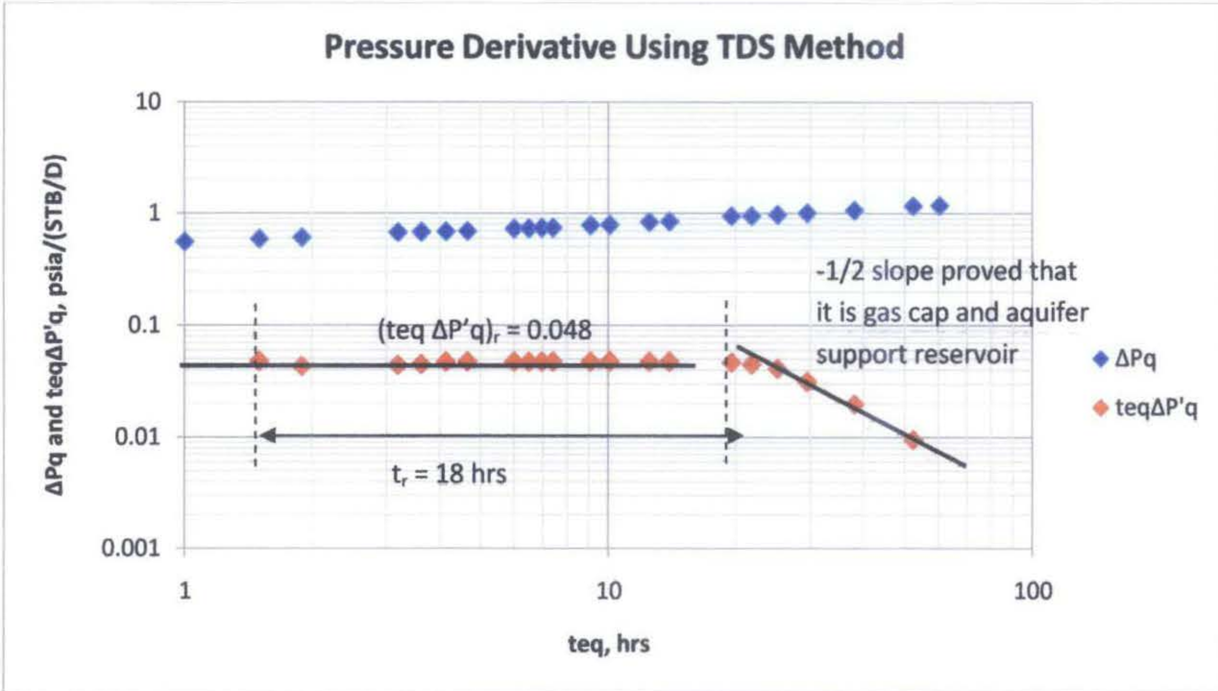


Figure 4.5 Delta Pq and t_{eq}*Delta Pq' vs t eq

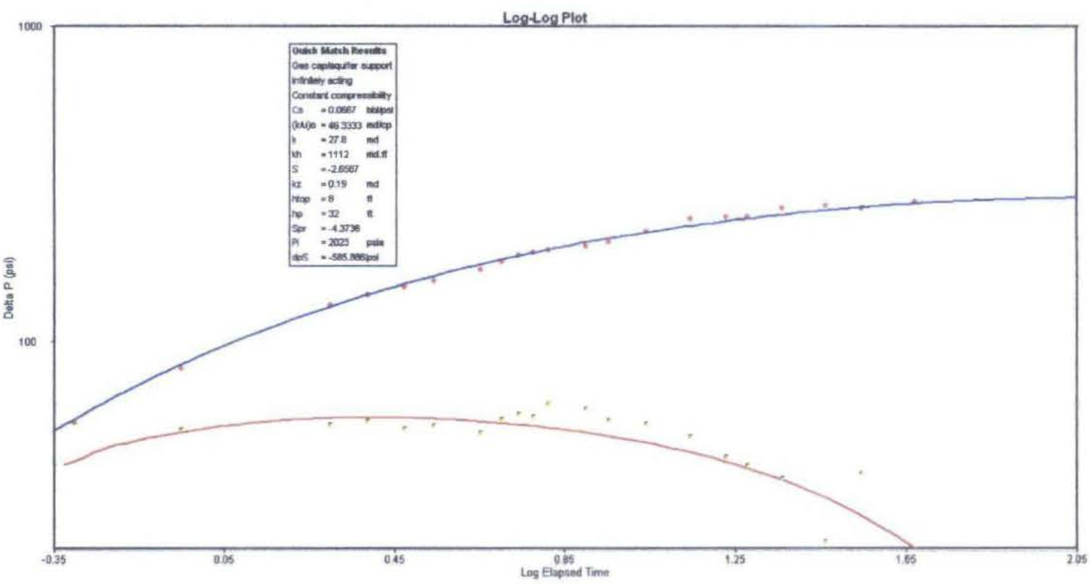


Figure 4.6 Pressure Transient Analysis done using PanSystem^{TM}

4.2.1.2 Result and Discussion

The analysis is done by using well testing software, PanSystem™ and the finalized matching pressure derivative plot is shown in Figure 4.6. Table 4.4 presents the comparison of the result of the study with the analysis result done by Earlougher [2]. Referring to the pressure derivative plot generated using TDS method and PanSystem™ (Figure 4.5 and Figure 4.6), the reservoir is identified as having aquifer and gas cap support due to the decreasing to negative half slope line at late time region. As a conclusion, Tiab's Direct Synthesis Method gives the acceptable result with less percentage difference with other method.

Table 4.4 The summary of well testing analysis results

Parameters	Book's result	TDS's result	Software result	Percentage Different (%)
Permeability	28.1 md	28 md	27.8 md	0.36
Permeability in z direction			0.19 md	-
Skin	-	-2.77611	-2.6587	4.2%

4.3 The Conventional Well Testing Analysis Toward Malaysia Fields (Case Study)

4.3.1 Well 1

4.3.1.1 Data Input

ID of casing: 0.35 ft

Porosity: 0.28

Thickness: 12.6 m = 41.33 ft

Total Compressibility: $9.20 \times 10\text{-}6\ psi^{-1}$

Formation Volume Factor: 1.24 rb/stb

Oil viscosity: 0.6 cp

4.3.1.2 Analysis Result

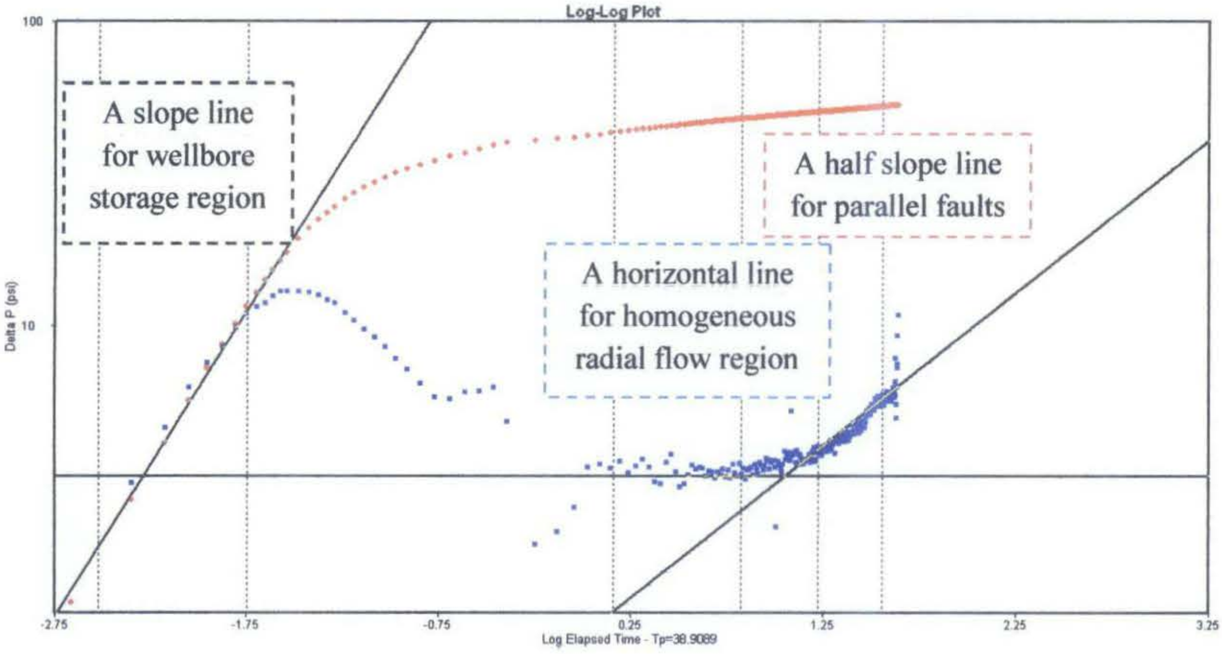


Figure 4.7 The identification region stage on pressure derivative plot for Well 1

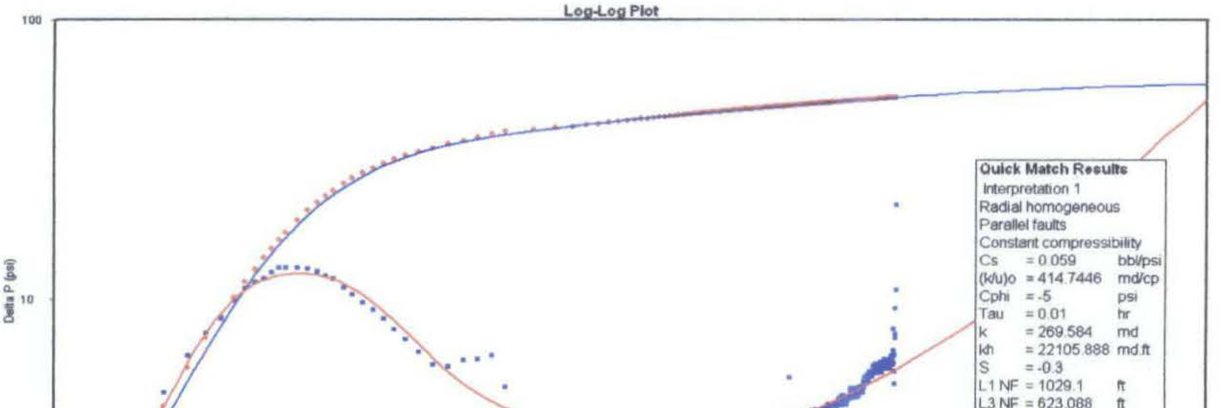


Figure 4.8 The best fit match pressure and pressure derivative plot for Well 1

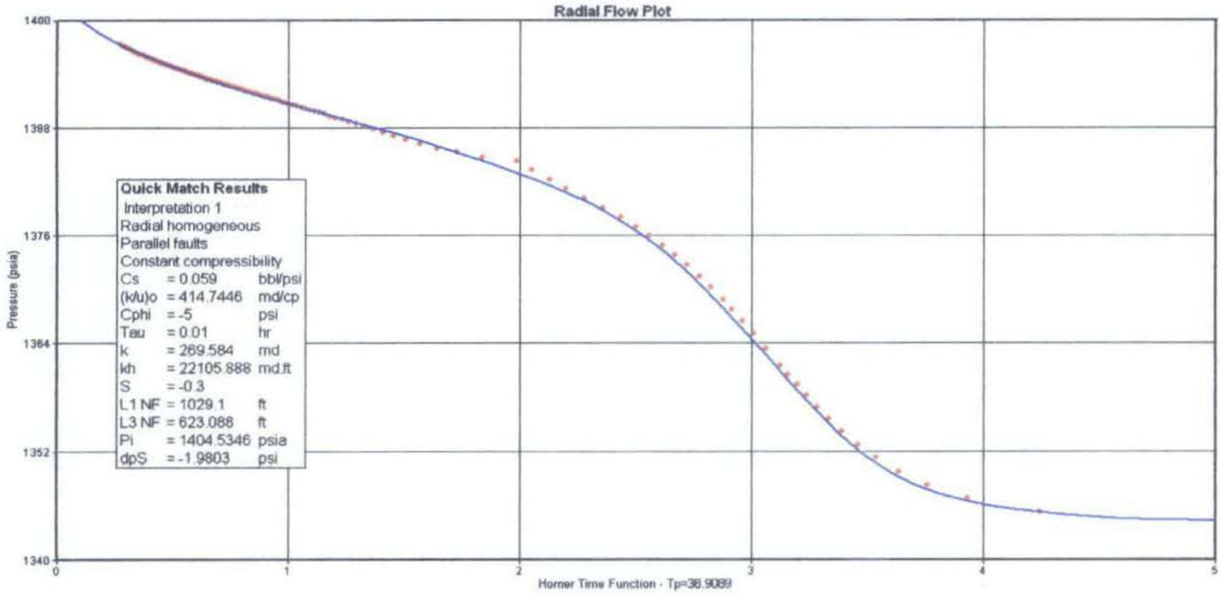


Figure 4.9 The best fit match pressure on semilog plot curve for Well 1

Table 4.5 Analysis result for Well 1

Parameters	Results
Characteristic of reservoir	Varying wellbore storage, Radial Homogeneous and Parallel Fault
Permeability (md)	269.584
Skin Factor	-0.3
Distance to Fault 1(ft)	1029.1
Distance to Fault 2 (ft)	623.088
Cphi (psia)	-5
Tau (hrs)	0.01
Cs (bbl/psia)	0.059
Initial Pressure	1404.5 psia

4.3.2 Well 2

4.3.2.1 Data Input

ID of casing: 0.4 ft

Porosity: 0.28

Thickness: 27.7 m = 91 ft

Total Compressibility: $5.9962 \times 10\text{-}4\ psi^{-1}$

Formation Volume Factor: 1.23 rb/stb

Oil viscosity: 0.4 cp

4.3.1.2 Analysis Result

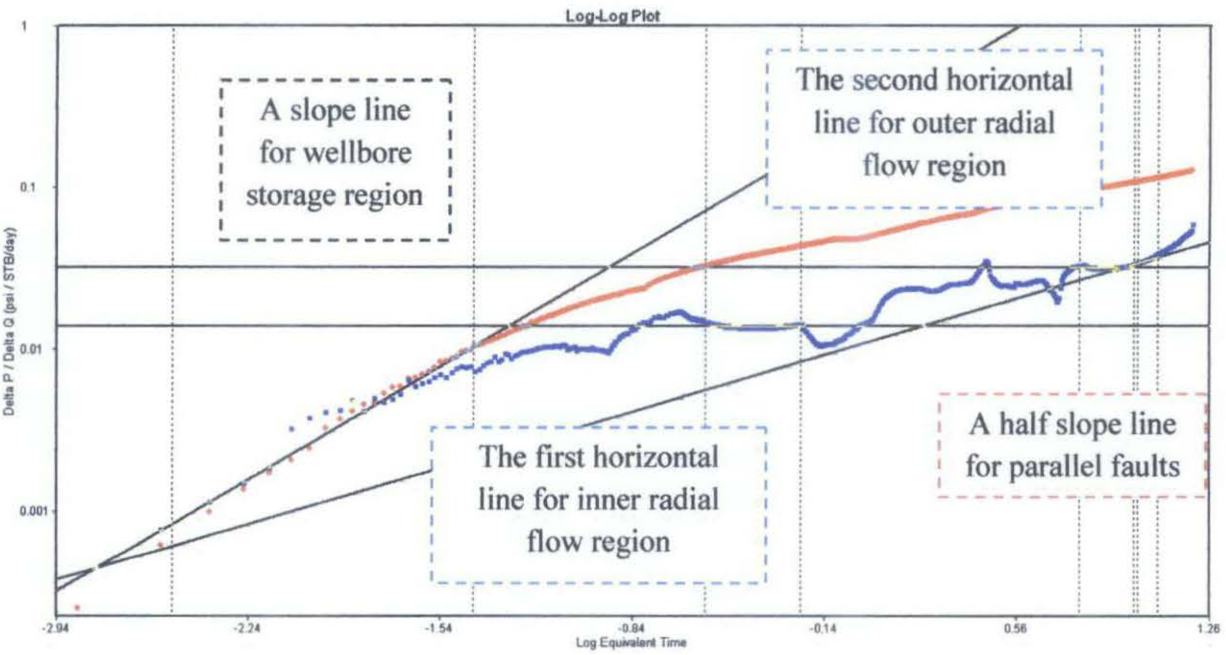


Figure 4.10 The identification region stage on pressure derivative plot for Well 2

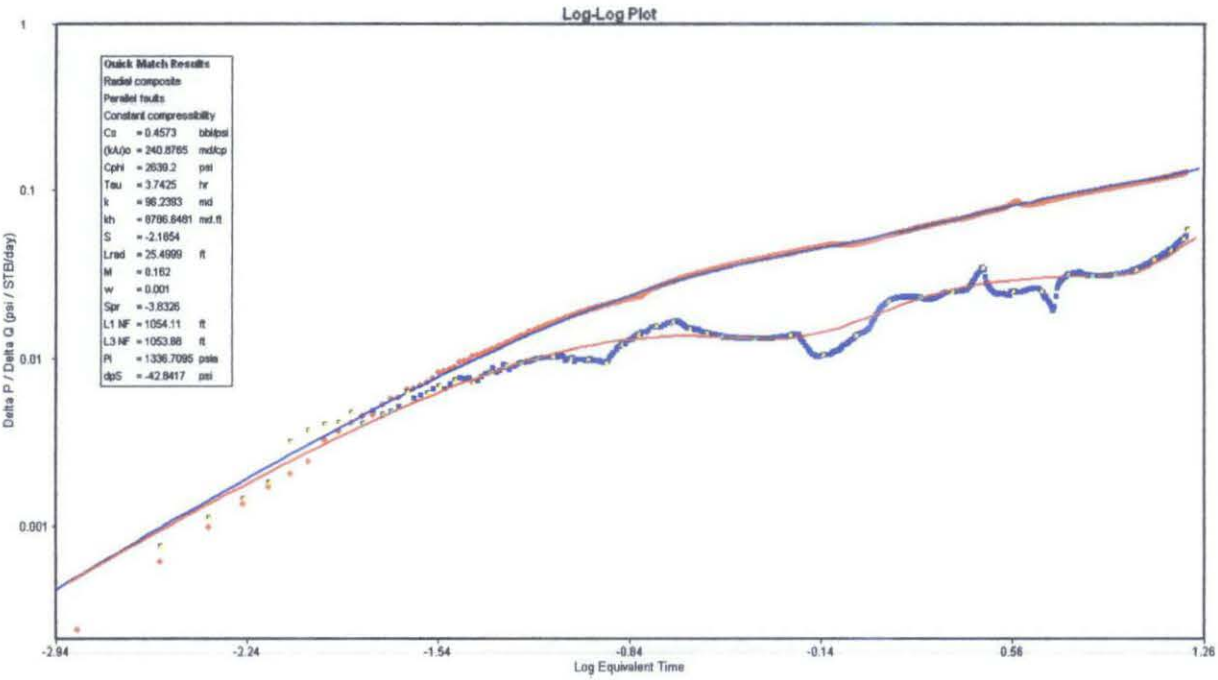


Figure 4.11 The best fit match pressure and pressure derivative plot for Well 2

Figure 4.12 The best fit match pressure on semilog plot curve for Well 2

Table 4.6 Analysis result for Well 2

Parameters	Results
Characteristic of reservoir	Varying wellbore storage, Radial Composite Reservoir and Parallel Fault
Permeability (md)	96.2393
Skin Factor	-2.1564
Distance to Fault 1(ft)	1054.11
Distance to Fault 2 (ft)	1053.68
Cphi (psia)	2639.2
Tau (hrs)	3.7425
Cs (bbl/psia)	0.4573
Initial Pressure	1336.7 psia

4.3.3 Well 3

4.3.3.1 Data Input

ID of casing: 0.4 ft

Porosity: 0.28

Thickness: 21.2 m = 69.88 ft

Total Compressibility: 7.4400×10-6 psi^{-1}

Formation Volume Factor: 1.28 rb/stb

Oil viscosity: 0.88 cp

4.3.3.2 Analysis Result

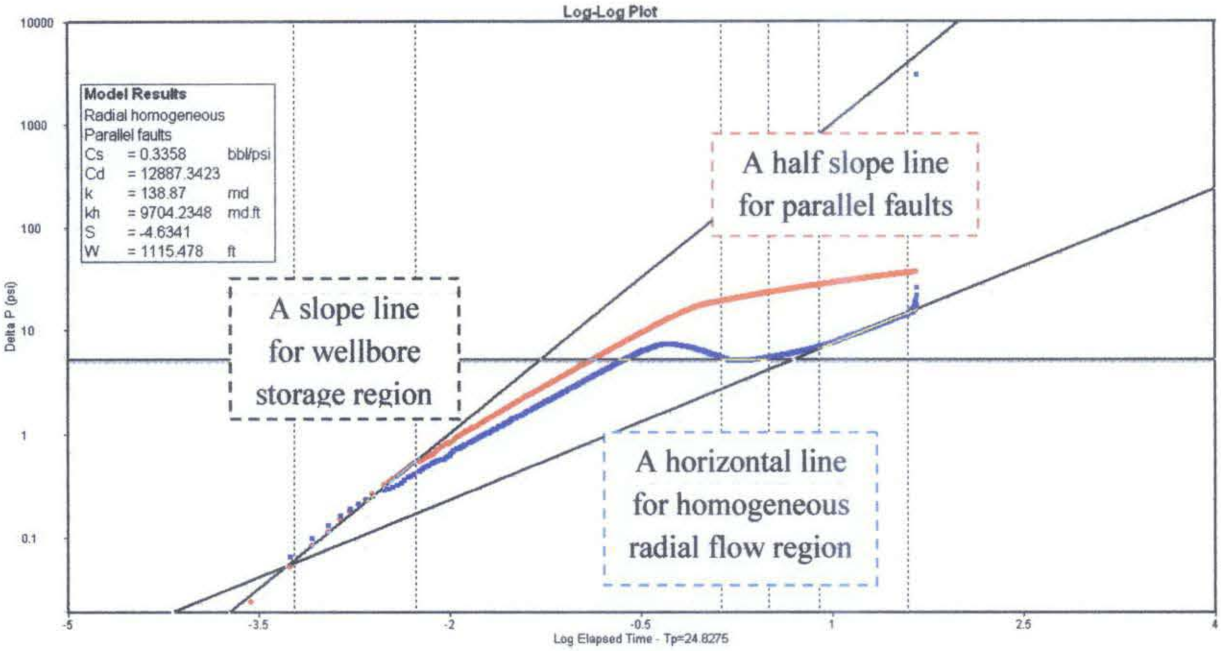


Figure 4.13 The identification region stage on pressure derivative plot for Well 3

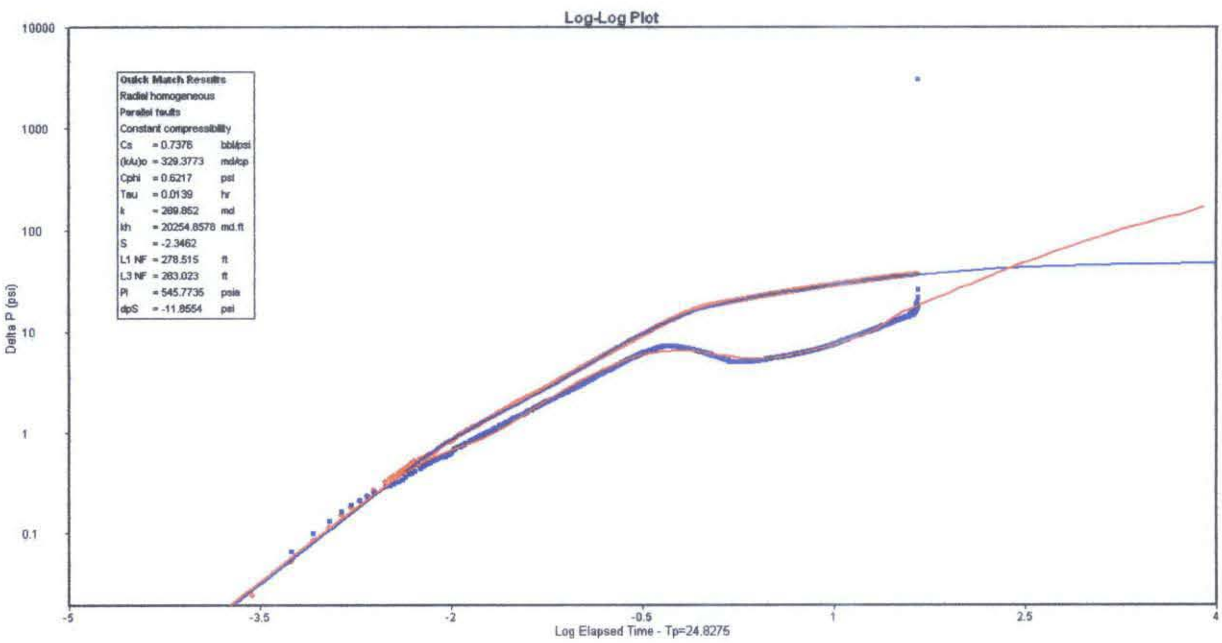


Figure 4.14 The best fit match pressure and pressure derivative plot for Well 3

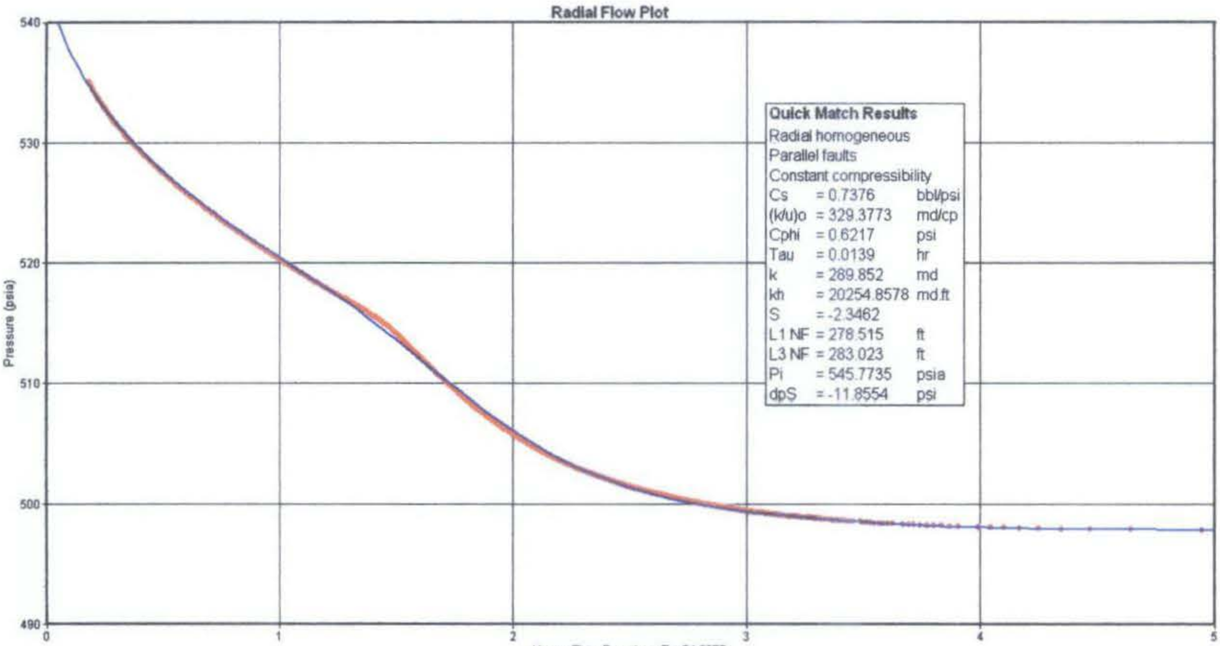


Figure 4.15 The best fit match pressure on semilog plot curve for Well 3

Table 4.7 Analysis result for Well 3

Parameters	Results
Characteristic of reservoir	Varying wellbore storage, Radial Homogeneous and Parallel Fault
Permeability (md)	289.852
Skin Factor	-2.3462
Distance to Fault 1(ft)	278.515
Distance to Fault 2 (ft)	283.023
Cphi (psia)	0.6217
Tau (hrs)	0.0139
Cs (bbl/psia)	0.7376
Initial Pressure	545.7735 psia

4.3.4 Well 4

4.3.4.1 Data Input

ID of casing: 0.4 ft

Porosity: 0.28

Thickness: 27.7 m = 91 ft

Total Compressibility: 5.9962×10-4 psi^{-1}

Formation Volume Factor: 1.23 rb/stb

Oil viscosity: 0.4 cp

4.3.4.2 Analysis Result

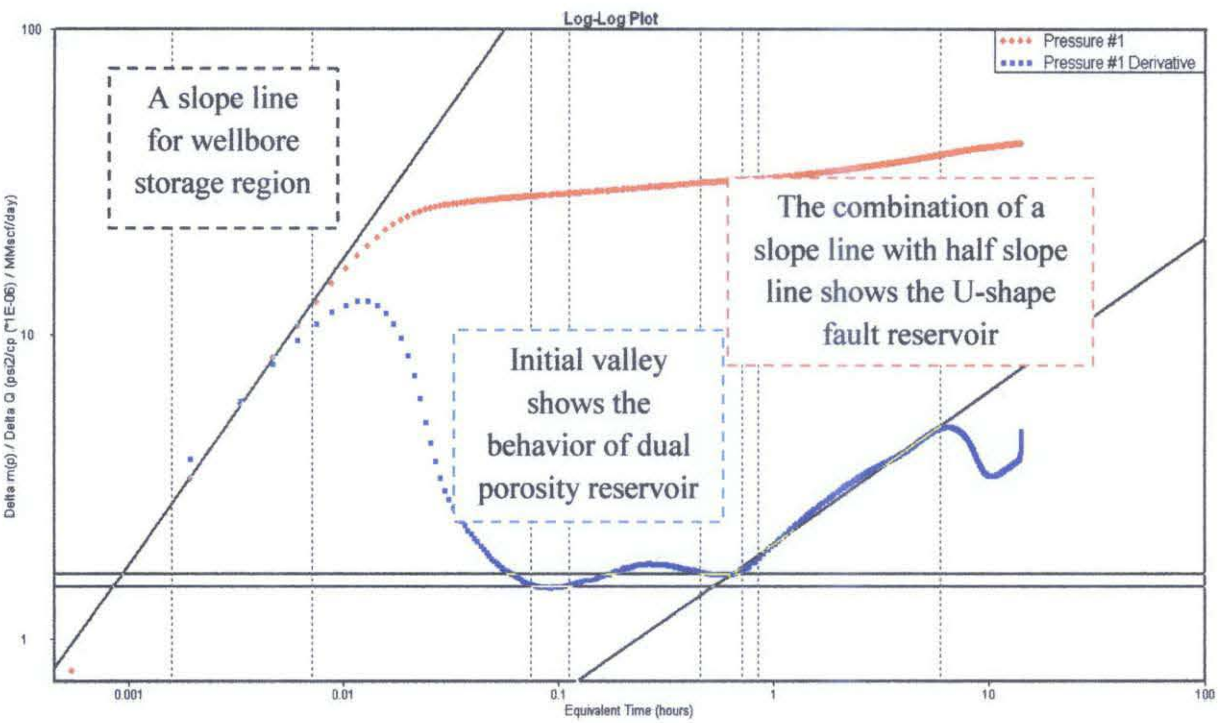


Figure 4.16 The identification region stage on pressure derivative plot for Well 4

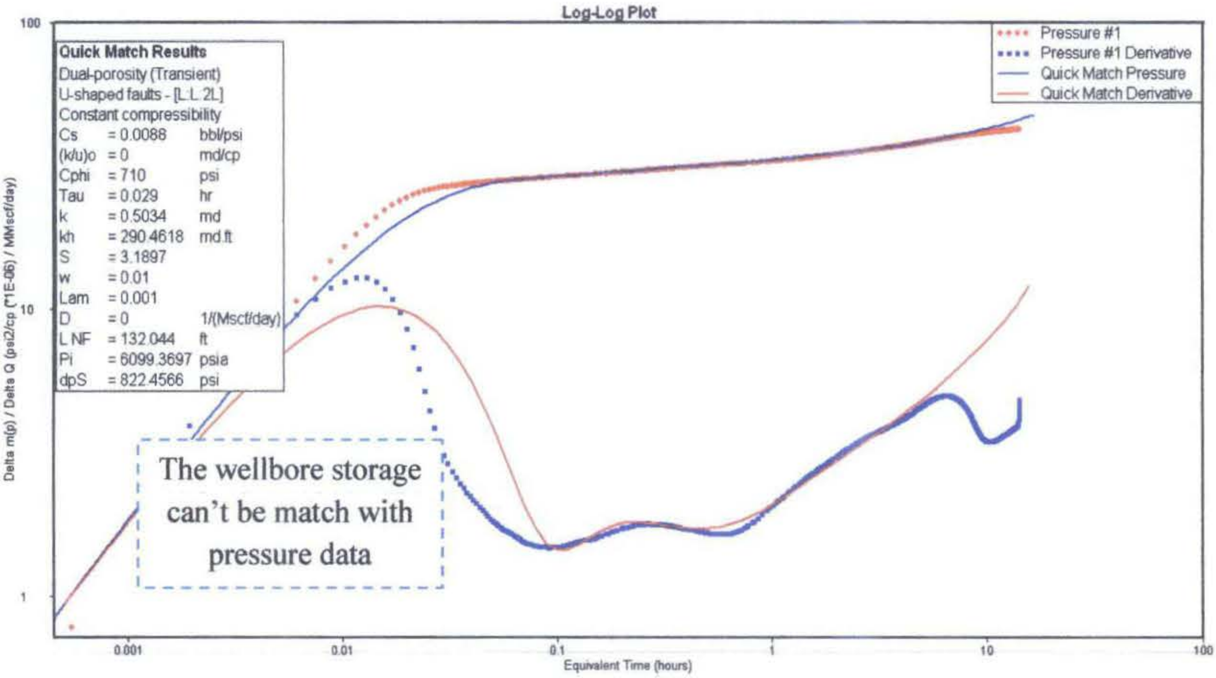


Figure 4.17 The best fit match pressure and pressure derivative plot for Well 4

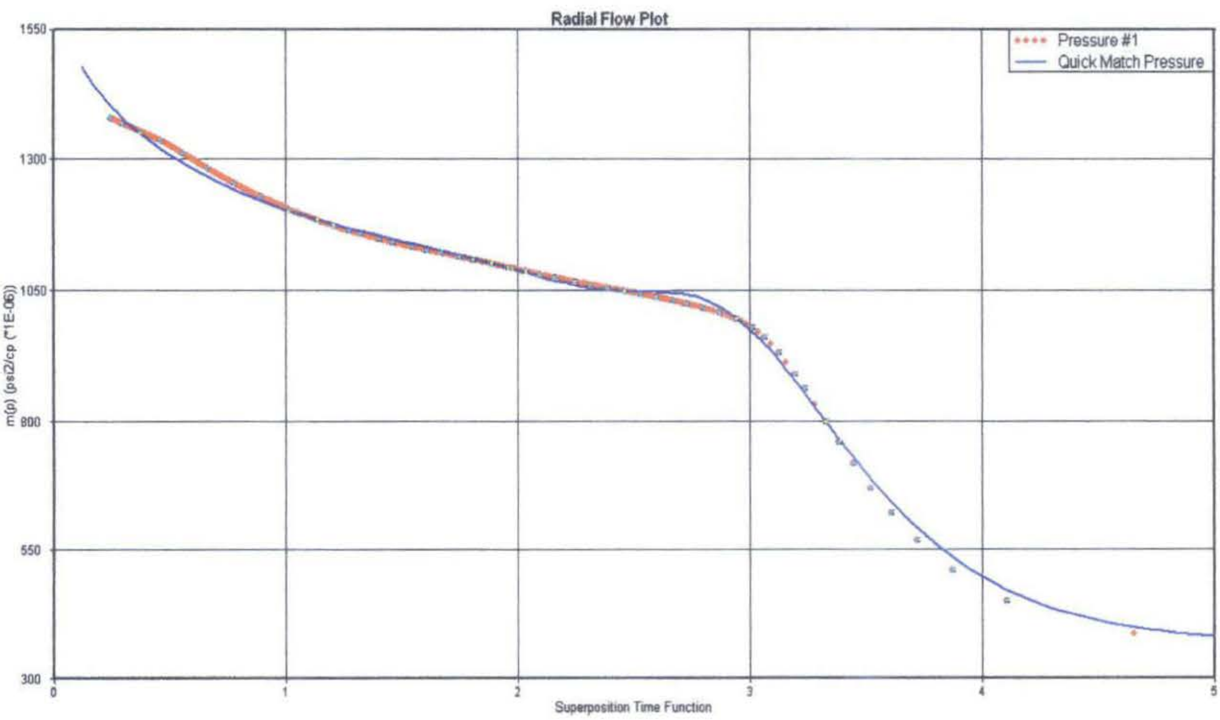


Figure 4.18 The best fit match pressure on semilog plot curve for Well 4

Table 4.8 Analysis result for Well 4

Parameters	Results
Characteristic of reservoir	Classic Wellbore Storage, Dual porosity model and U-shaped faults
Permeability (md)	0.5034
Skin Factor	3.1897
Distance to Fault 1(ft)	132.044
Distance to Fault 2 (ft)	132.044
Distance to Fault 3 (ft)	264.044
Omega	0.01
Lambda	0.001
Initial Pressure	6099.3697 psia

4.3.5 Well 5

4.3.5.1 Data Input

ID of casing: 0.4 ft

Porosity: 0.28

Thickness: 27.7 m = 91 ft

Total Compressibility: 5.9962×10-4 psi^{-1}

Formation Volume Factor: 1.23 rb/stb

Oil viscosity: 0.4 cp

4.3.1.2 Analysis Result

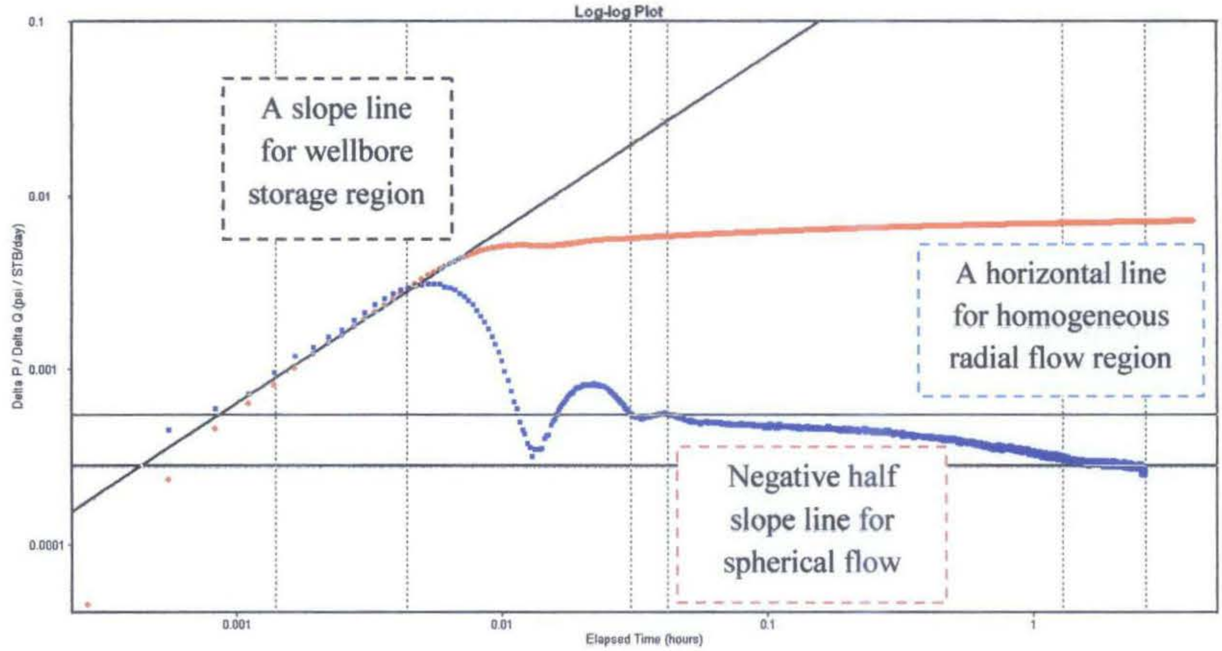


Figure 4.19 The identification region stage on pressure derivative plot for Well 5

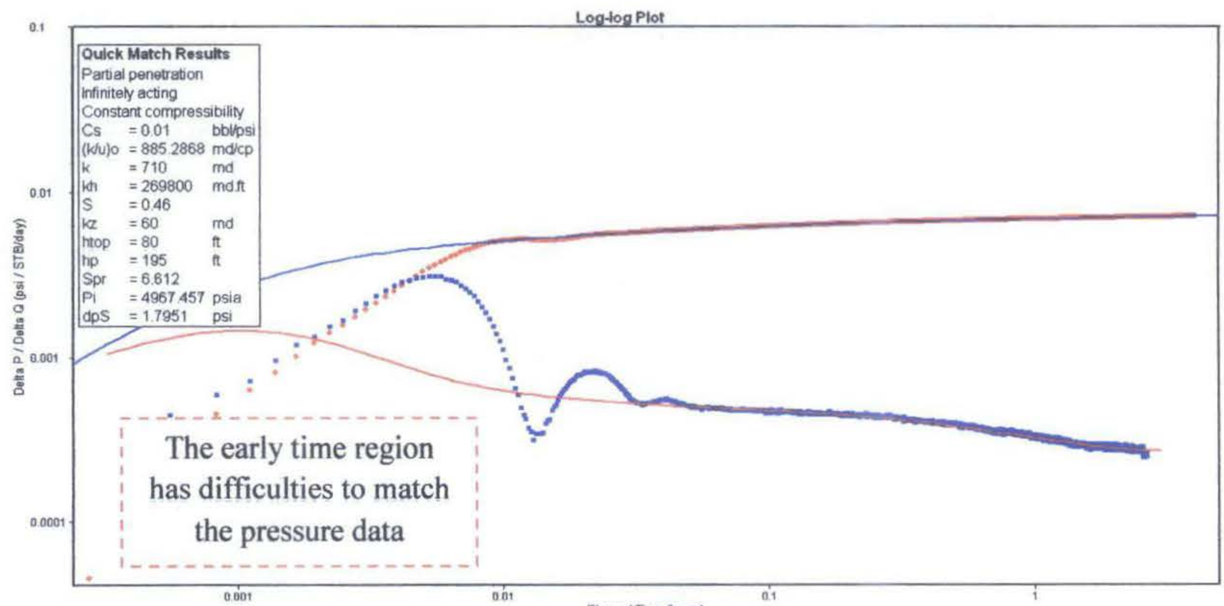


Figure 4.20 The best fit match pressure and pressure derivative plot for Well 5

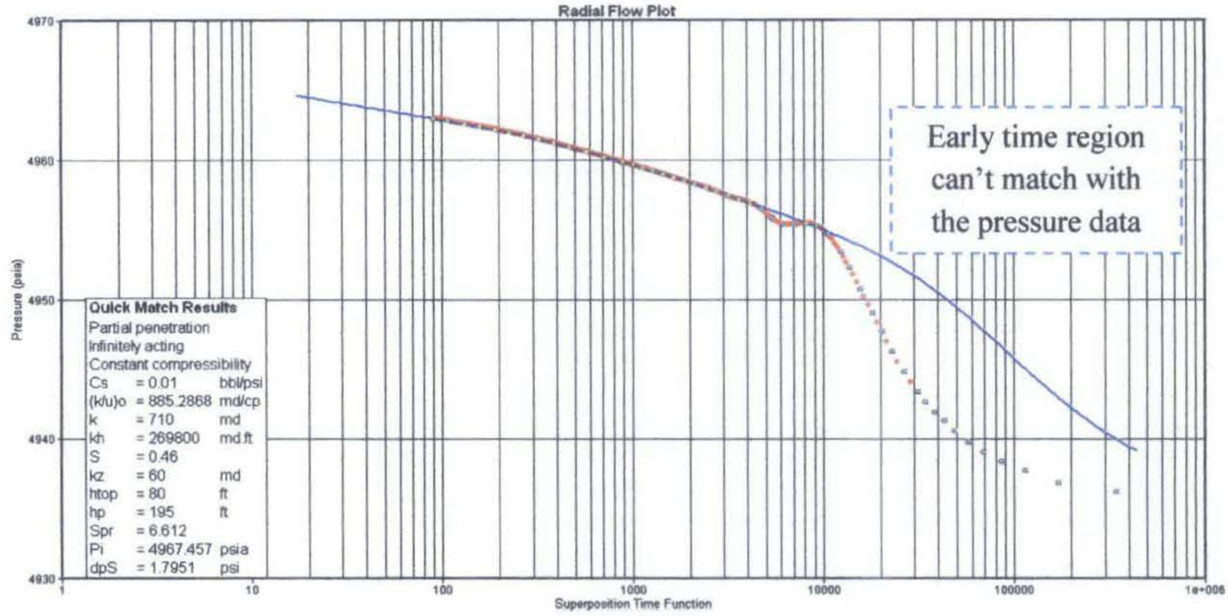


Figure 4.21 The best fit match pressure on semilog plot curve for Well 5

Table 4.9 Analysis result for Well 5

Parameters	Results
Characteristic of reservoir	Classic Wellbore Storage, Partial Penetration and Infinite Acting
Permeability (md)	710
Skin Factor	0.46
Vertical Permeability (md)	60
Thickness from top to mid perforation (ft)	80
Perforation thickness (ft)	195
Cs (bbl/psia)	0.01
Initial Pressure	4967 psia

4.3.6 Well 6

4.3.6.1 Data Input

ID of casing: 0.27 ft

Porosity: 0.28

Thickness: 12.6 m = 41.3 ft

Total Compressibility: 8.7100×10-6 psi^{-1}

Formation Volume Factor: 1.24 rb/stb

Oil viscosity: 0.6 cp

4.3.1.2 Analysis Result

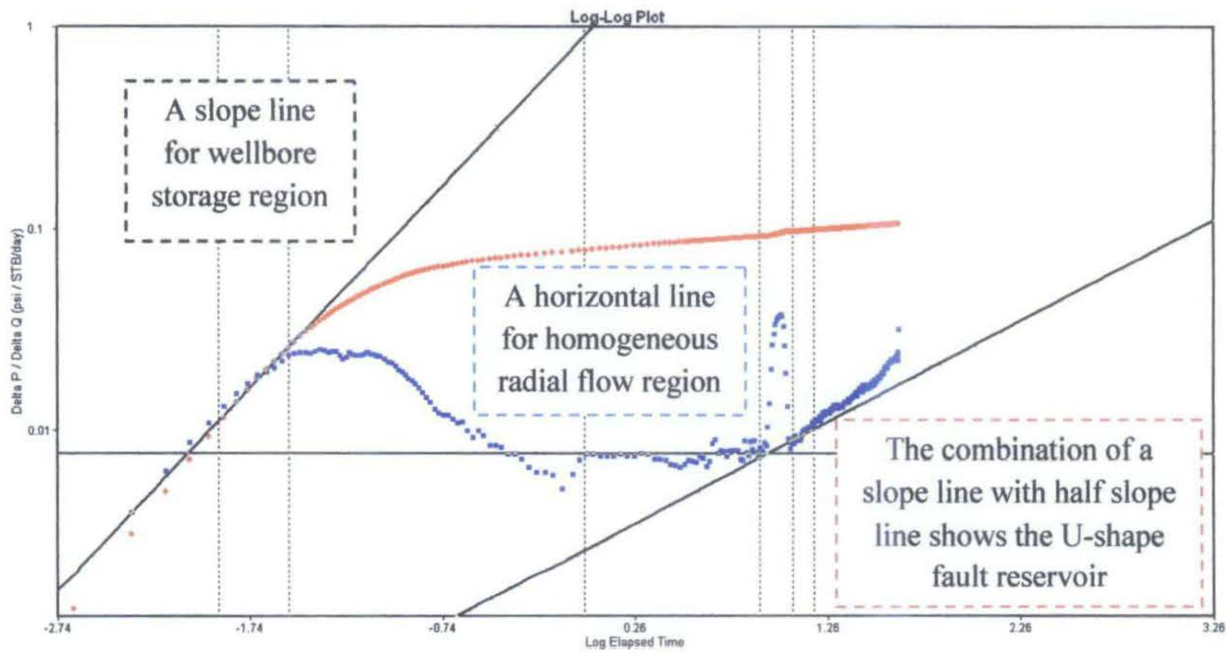


Figure 4.22 The identification region stage on pressure derivative plot for Well 6

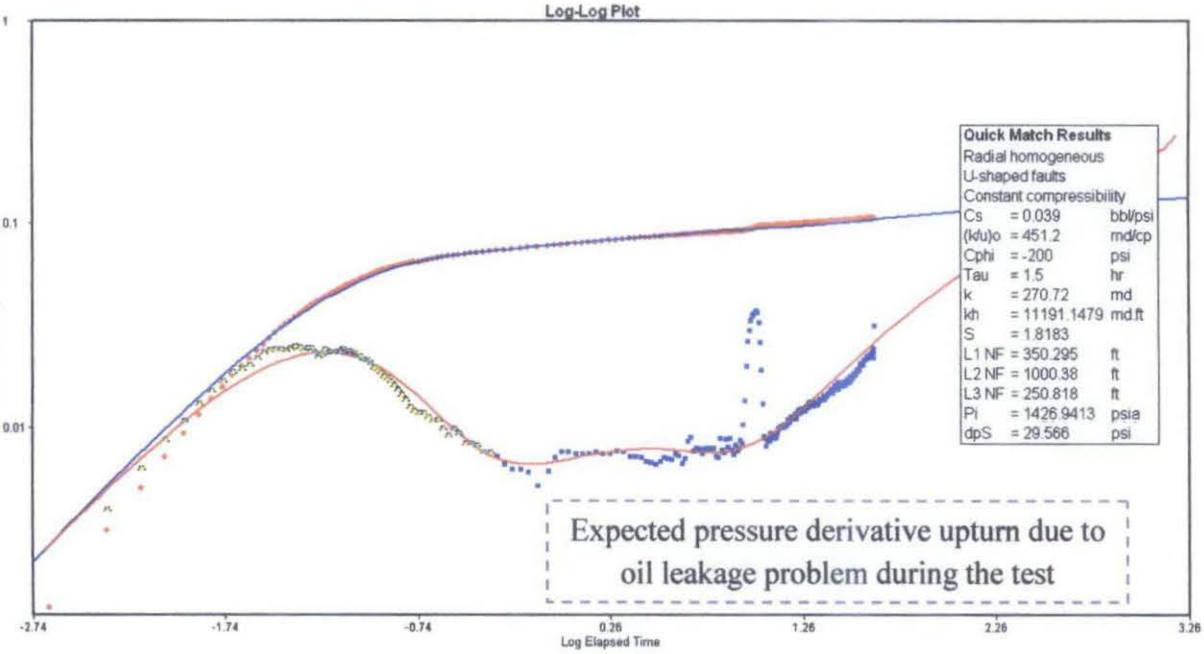


Figure 4.23 The best fit match pressure and pressure derivative plot for Well 6

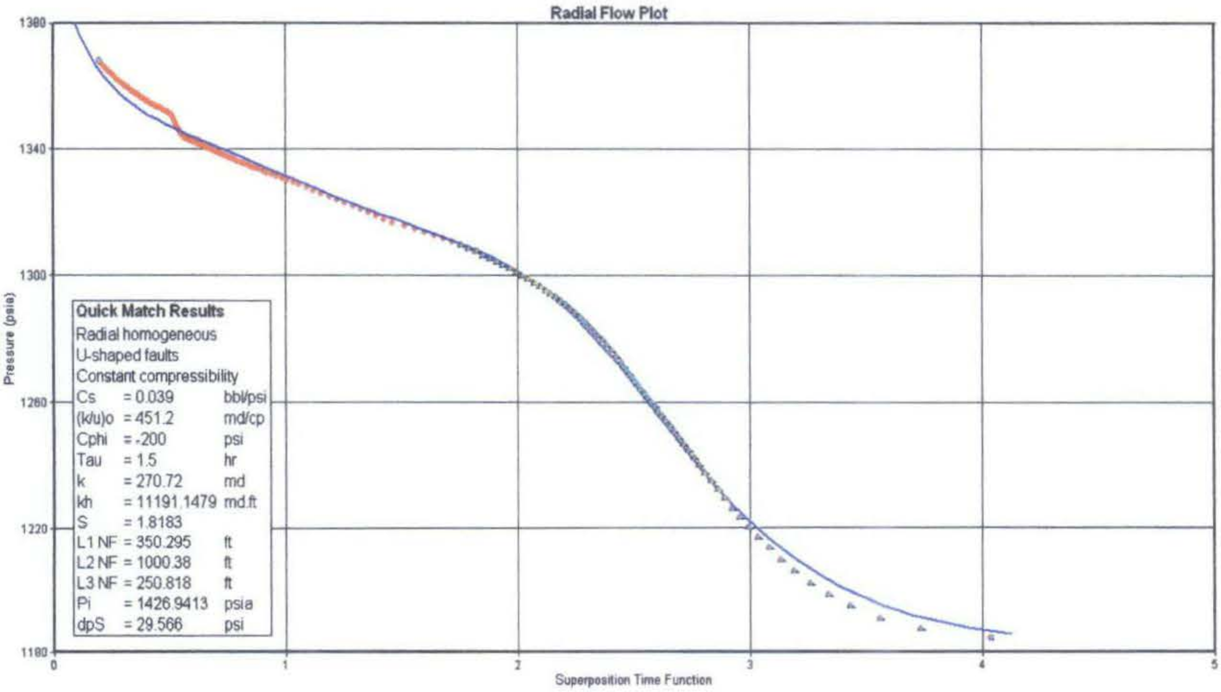


Figure 4.24 The best fit match pressure on semilog plot curve for Well 6

Table 4.10 Analysis result for Well 6

Parameters	Results
Characteristic of reservoir	Varying Wellbore Storage, Radial Homogeneous and U-shaped faults
Permeability (md)	270.72
Skin Factor	1.8183
Distance to Fault 1(ft)	350.295
Distance to Fault 2 (ft)	1000.38
Distance to Fault 3 (ft)	250.818
Cs (bbl/psia)	0.039
Initial Pressure	1426.94 psia

4.3.7 Well 7

4.3.7.1 Data Input

ID of casing: 0.35 ft

Porosity: 0.28

Thickness: 12.7 m = 41.54 ft

Total Compressibility: 8.5900×10-6 psi^{-1}

Formation Volume Factor: 1.24 rb/stb

Oil viscosity: 0.6 cp

4.3.1.2 Analysis Result

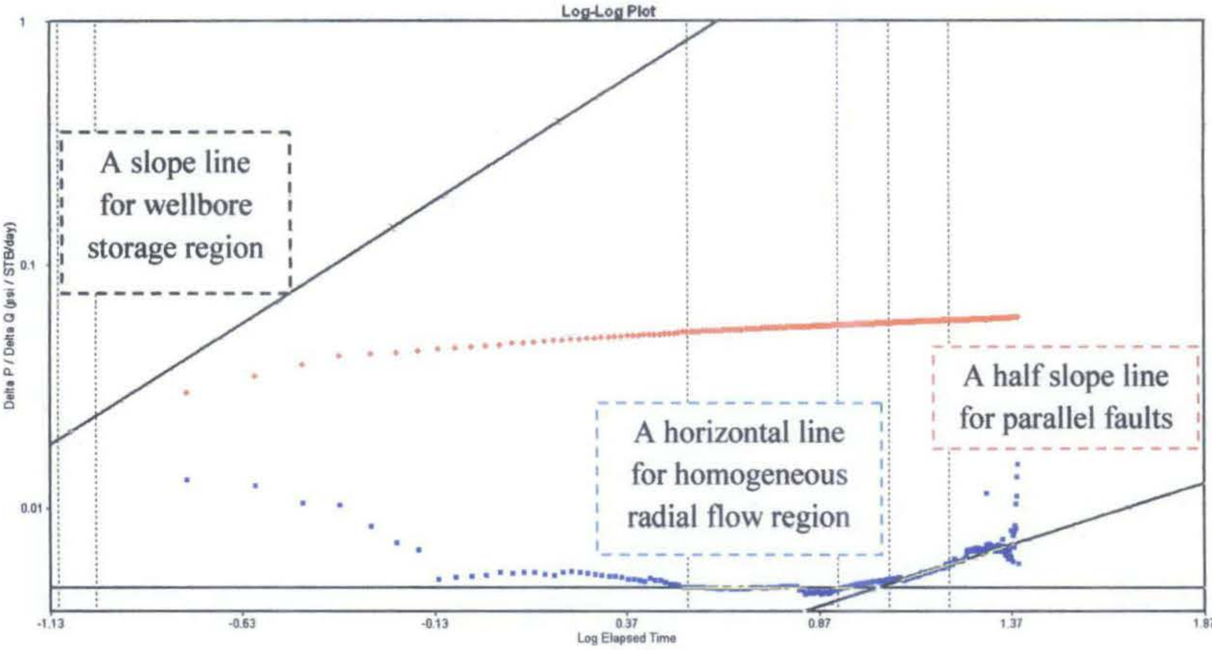


Figure 4.25 The identification region stage on pressure derivative plot for Well 7

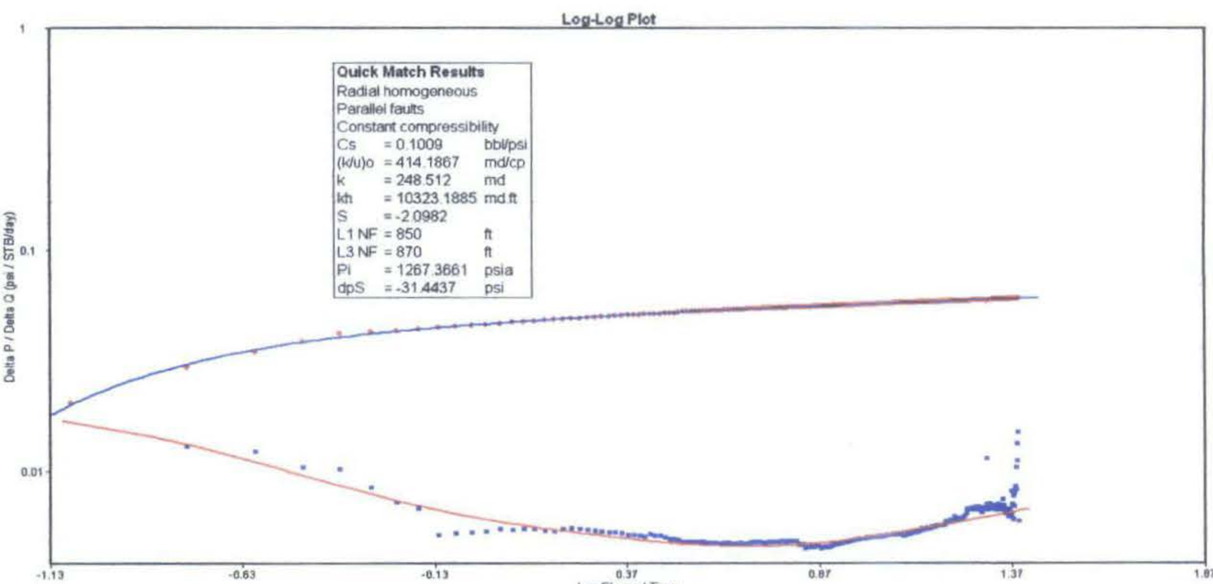


Figure 4.26 The best fit match pressure and pressure derivative plot for Well 7

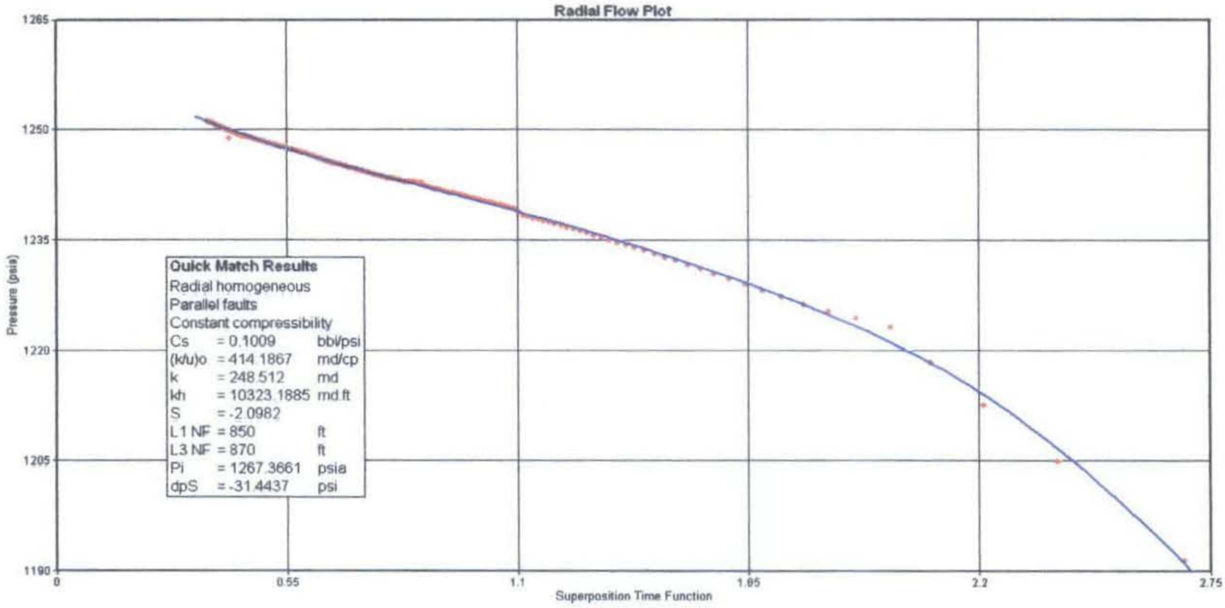


Figure 4.27 The best fit match pressure on semilog plot curve for Well 7

Table 4.11 Analysis result for Well 7

Parameters	Results
Characteristic of reservoir	Varying wellbore storage, Radial Homogeneous and Parallel Fault
Permeability (md)	248.512
Skin Factor	-2.0982
Distance to Fault 1(ft)	850
Distance to Fault 2 (ft)	870
Cs (bbl/psia)	0.1009
Initial Pressure	1267.36 psia

CHAPTER 5
CONCLUSION AND RECOMMENDATION

5.1 Conclusion

By using this new technique, it will not involve any expensive cost which normally occurred during conventional well testing work. The result of predicting FBHP by using modified equation shows that the accuracy of the prediction is less than 1% error or an average of 3 to 6 psia errors. The multi-rate testing analyzed using Tiab's Direct Synthesis technique is also proven to have accurate result. By using recommended surface control presented, it will allow the combination of these two methods (predicting FBHP from surface and TDS technique) which will have the potential to overcome almost all the disadvantages and problems faced by conventional well testing method. From the analysis of conventional well testing, many wells are identified to have varying wellbore storage effect. Sometimes, it will hide the infinite acting radial flow region which at the end will result in wrong permeability estimation.

5.2 Recommendation

The correlation used for this study is really sensitive with the rate data. Thus, the accurate measurement and the critical precaution should be done when implementing this new technique. It is recommended to compare the result of well testing analyzed by using this new method with the result obtained from previous testing to increase the level of confidence.

For a moment, the mathematical calculation developed is limited to the low Gas Liquid Ratio. Thus, the future improvement can be done toward the mathematical developed in this project. The focus might be on the compressibility behavior of gas.

REFERENCES

1. Bourdarot G. , "Well Testing: Interpretation Methods", Edition Technip, Paris(1998), page 97
2. Earlougher Jr., R.C., "Advance in Well Test Analysis", Monograph Series, vol. 5. SPE, pp. 284 (1977)
3. Escobar F.H., Ibagón O.E., Montealegre-M.M., "Average Reservoir Pressure Determination for Homogeneous and Naturally Fractured Formations from Multi-rate Testing with the TDS technique", Journal of Petroleum Science and Engineering 59, pp. 204-212 (2007)
4. Gábor T., "Gas Lift Manual," PennWell Corporation, Tulsa, Oklahama, pp. 73-78 (2005)
5. Ghassan H.A.M., Nikmat B., Jawad R.A., "An improved revision to the Hagedorn and Brown Liquid Holdup Correlation", JCPT Volume 28, No. 6 (1989)
6. Horne R.N., "Modern Well Test Analysis", Petroway Inc., Palo Alto, CA, Second Printing (1997)
7. Lee J., Rollins J.B., Spivey J.P., "Pressure Transient Testing SPE Textbook Series Vol. 9", Richardson, TX (2003)
8. Onyeizugbe S.O., Ajieka J.A., "Correlation for Real Time Prediction of Flowing Bottom Hole Pressure of Oil and Gas Wells", European Journal of Scientific Research, pp. 552-562 (2010)
9. Schroeter T. v., Hollaender F., Gringarten A. C., "Analysis of Well Test Data from Permanent Downhole Gauges by Deconvolution," SPE 77688 (2002)
10. Tarek A., "Reservoir Engineering Handbook Fourth Edition", Elsevier Inc., Oxford, UK, p. 37 (2010)
11. Tiab D., "Analysis of Pressure and Pressure Derivatives Without Type Curve Matching: 1-Skin and Wellbore Stirage", SPE 25426 (1993)
12. Weatherford Well Testing Training Notes

NOMENCLATURES

B_g: gas volume factor at p and T, ft3/scf

B_o: oil volume factor at p and T,bbl/STB

B_w: water volume factor at p and T,bbl/STB

$V\_m: average\ velocity\ of\ the\ mixture, ft/sec., (Q\_L\ M)/A$

q_{lsc}: liquid flow rate, STB/d

v_m: mixture velocity, ft/s

ρ_{all}: Equivalent density of oil, water and gas (lbm/ft^3)

$\rho_{all+lift\ gas}$: Equivalent density of oil, water, gas and lift gas (lbm/ft^3)

$\rho_{equivalent}$: Equivalent density of oil, water and gas (lbm/ft^3)

ρ_m: mixture density, lb/cu ft

ρ_{ns}: no-slip mixture density, lb/cu ft

$\emptyset$: porosity (fraction)

ΔP(t): wellbore pressure drop (psia)

ΔP_{tubing}: Pressure drawdown in tubing (psia)

Ap: pipe cross sectional area, ft2

BSW: basic sediment water (%)

C: choke size (inches)

C_D: dimensionless wellbore storage

c_t: total compressibility (psi^{-1})

d: internal diameter of tubing or casing, ft

FBHP: flowing bottomhole pressure (psia)

$FBHP_{assumed}$: assumed FBHP from correlation (psia)

gc: gravitational constant, lbm/sec.lbf

GLR: gas liquid ratio at std condition, scf/STB

h: formation thickness (ft)

k: formation permeability (md)

m: maximum size of choke (64th inch)

M_g: gas mass flowrate (lbm/d)

M_o: oil mass flowrate (lbm/d)

M_w: water mass flowrate (lbm/d)

n: minimum size of choke (64^{th} inch)

n: number of mole

P': derivative pressure (psi/h)

P_D: dimensionless pressure

P_i: initial pressure (psia)

P_{wf}: sand face pressure (psia)

$Q_{g\,res}$: gas volumetric rate (rcf/d)

Q_g: gas volumetric rate (scf/d)

$Q_{o\,res}$: oil volumetric rate (rb/d)

Q_o: oil volumetric rate (stb/d)

$Q_{w\,res}$: water volumetric rate (rb/d)

Q_w: water volumetric rate (stb/d)

R: gas constant, 10.73

r_d: drainage radius (ft)

Rs: solution GOR at p and T, scf/STB

r_w: wellbore radius (ft)

$SBHP_{assumed}$: assumed bottom hole temperature from correlation (°F)

t: time (hours)

T_D: dimensionless time

$t_{eq}*\Delta P'_q$: normalized pressure derivative (psi/(stb/d))

t_{eq}: equivalent time (hour)

T_{sc}: standard temperature (°F)

TVD: reference depth for the pressure (ftTVDMSL)

TVD_m: Mandrel depth (ftTVDMSL)

$V_{g\,res}$: volume of gas at standard condition (rcf)

$V_{g\,sc}$: volume of gas at standard condition (scf)

WOR: water oil ratio at std condition

x: tuning factor

z: gas deviation factor

γ_g: gas specific gravity (fraction)

γ_o: oil specific gravity (fraction)

γ_W: water specific gravity (fraction)

ρ_{air}: air density (lbs/ft^3) at standard condition

ρ_o: oil density (lbs/ft^3)

ρ_{water}: water density (lbs/ft^3) at standard condition

f: friction factor

$g(t-\tau)$: solution of the problem or reservoir response

$q(\tau)$: flowrate with time varying(stb/d)

α: Pipe inclination angle, measured from the horizontal, radians