

GREEN WELL TESTING

**A REPORT SUBMITTED TO THE DEPARTMENT OF
PETROLEUM ENGINEERING**

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**IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE
DEGREE OF MASTER OF SCIENCE**

**By
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I certify that I have read this report and that in my opinion it is fully adequate, in scope and in quality, as partial fulfillment of the degree of Master of Science in Petroleum Engineering.

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Abstract

Conventional well testing usually involves production of reservoir fluid at the surface. For newly completed wells, surface equipment to store reservoir fluid may not be present, so the fluid may be discharged and flared. Discharge of such fluids can be an environmental hazard.

In this study, testing of wells without surface production is investigated. Three possible testing methods are suggested and compared.

Three tests suggested are (1) closed chamber test, (2) controlled reinjection of reservoir fluid, and (3) modification of closed chamber test for longer duration. The radii of investigation for these tests were studied. The modified test and controlled reinjection tests are shown to have the large radius of investigation. A composite reservoir model was used to test the investigation radius.

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Chapter 1

Introduction

Transient well testing is used to determine physical properties that are required to evaluating reserves and to estimate dynamic flow properties that are used to forecast production behavior from the reservoir. In transient analysis, a disturbance is created in the reservoir and the response of the reservoir is recorded and then matched with a mathematical model to obtain the unknown parameters. An assumption inherent in this process is that the tested reservoir is represented by the selected model.

Disturbances in the reservoir can be created by changing wellbore conditions. Different ways of creating disturbances define different well tests. Common examples are the flow rate changes giving rise to drawdown and buildup tests.

Mathematical models used to match reservoir responses are usually solutions of the diffusivity equation under specific boundary conditions. Common examples are constant wellhead flow rate or constant pressure boundary conditions.

Conventional well testing methods usually involve surface production of fluid or changing rate at the surface. Sometimes surface facilities to store the reservoir fluid is not available and hence the fluid is discharged or flared. This is an environmental concern.

The present study, focuses on Green Well Test procedures that do not involve surface production of reservoir fluid. One example is a closed chamber test (CCT). Fluid is produced inside the wellbore until the wellbore pressure equates to the reservoir pressure. Rapid changes in rates give rise to inertial and frictional forces and hence there is a dynamic relationship between the rate and wellbore pressure. Saldana (1983) derived relationships between inertial, frictional, gravitational forces acting on the fluid and

wellbore pressure. These relationships were used for the wellbore pressure calculations in the present study.

1.1 Overview of Existing Work

Several methods have been proposed in order to achieve the objective of an emission free well test. All the proposed methods satisfy the condition that no fluid reach the wellhead and flow is confined within the wellbore. This has led to three possible methods:

1. Closed chamber test: Alexander (1977) proposed this method. This test was further studied in detail by Saldana (1983), who derived a wellbore equation and coupled that to reservoir equation for infinite acting reservoir model. Advantage of the test is that it is very simple. However the test has several limitations: I) a small radius of investigation, II) non repeatability of the test as it ends when the wellbore is filled with reservoir fluid and III) the well may not be 'clean' prior to the test and hence the results may be affected.
- 2 Harmonic testing: The principle of harmonic testing is to alternate periodically between production and injection sequences. Using the periodic input signal (rate) and subsequent periodic output (pressure), the data are interpreted with regard to frequency (Rosa, 1991). The test has a larger radius of investigation compared to the closed chamber test. The limitation of the test is that it is difficult to achieve control over rate with downhole equipment. The main issue with harmonic testing is its duration. Performing a harmonic test requires an impractical test time, longer than conventional tests by more than one order of magnitude (Hollaender et al.,2002).
- 3 Downhole production/reinjection: This test involves simultaneous production from a pay zone and reinjection into other. The test is almost like a conventional well test and can achieve a similar radius of investigation. The limitations of this test are the need of other zone to inject and the pump placed in wellbore causes noise in rate and pressure data.

1.2 Statement of the problem

In the present study, effort to maximize the radius of investigation with simple and practical mechanical configuration was considered. The closed chamber test was studied and the solution for any reservoir model was investigated. A controlled reinjection into the reservoir after the test was considered. The advantage of controlled reinjection is large radius of investigation. The closed chamber test was modified by adding a choke. The choke restricts the flow and hence prolongs the test resulting in greater radius of investigation.

These tests are simple and have relatively large radii of investigation.

1.3 Organization of Report

The present chapter introduces the topic. Chapter 2 introduces the three types of Green well test studied and describes the mathematical formulation for the tests. Chapter 3 shows the response of each of the Green well tests in different types of reservoir. Chapter 4 compares the applicability of each of the different types of tests. Chapter 5 summarizes the conclusions that are obtained from the present study and suggestions for future work.

Chapter 2

Types of Green Well Tests

The CCT was studied as the earliest form of the Green well test. This test format can be modified by adding a choke or by injecting at constant rate into the formation to create the other two kinds of tests. This chapter deals with the mathematical formulation of the three types of tests - CCT, controlled injection and choked closed chamber test.

2.1 Closed Chamber Test

The objective of a Green well test is to avoid production of reservoir fluid at the surface. The closed chamber test (CCT) fulfills this objective. CCT was suggested and tested by Alexander (1977). Figure 1 shows the mechanical configuration of a CCT.

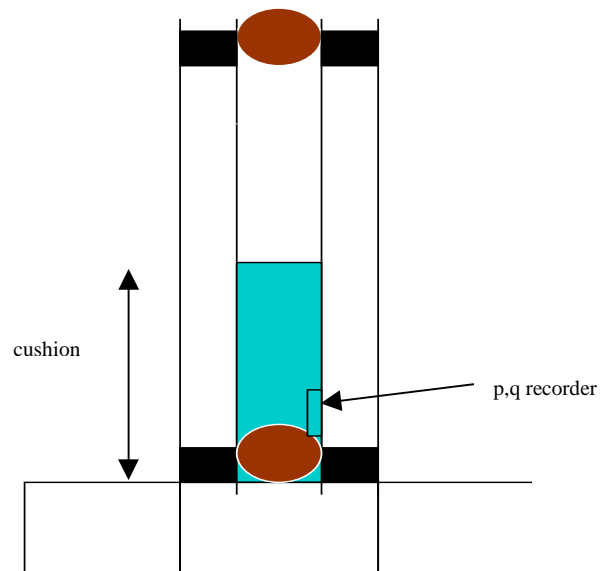


Figure 1. Mechanical configuration of Closed Chamber test.

The test starts as the bottom valve opens. Normally no backpressure is provided against the formation and hence a large initial drawdown occurs at the start of the test. This

causes large initial rate ($\sim 10^3$ - 10^6 STB/day, depending on permeability). Due to the large initial rate inertial and frictional forces are very significant in such tests.

Saldana (1983) studied drillstem test analysis considering inertial and frictional wellbore effects. Mathematical formulations of the flow phenomena during a slug test, a drillstem test, or a closed-chamber test were derived in his study. The formulation considered gravitational, inertial, and frictional effects on the fluid column changing in length inside the wellbore. This formulation is based on a transient momentum - balance equation for the wellbore fluid column coupled with the diffusivity equation for the reservoir through conditions including wellbore storage and skin effect. Saldana's solution of diffusivity equation was of infinite reservoir with instantaneous line source.

$$p_D = \frac{1}{2} \frac{C_D}{t_D} e^{-\frac{r_D^2}{4t_D}} \quad (2.1)$$

This reservoir equation was coupled with the wellbore equation and solved by finite differences. The Thomas algorithm was used to solve the resulting equations.

The wellbore equation in dimensional form is:

$$p_w(t) = A_w z'' + B_w z' + C_w z + D_w \quad (2.2)$$

Terms z , z' and z'' are level, velocity and acceleration of fluid respectively. These terms are functions of rate. Coefficients A_w , B_w , C_w and D_w are functions of levels and fluid velocity.

In the present study Equation (2.2) was used to describe the pressure in the wellbore due to movement of fluid. The pressure drop that fluid experiences as it moves from the reservoir to the wellbore is given by the multirate superposition equation (Equation 2.3). The advantage of this reservoir equation over Equation 2.1 to describe reservoir behavior is that any reservoir model can be used.

$$p_{wf}(t) = p_i - \frac{141.2B\mu}{kh} \left\{ q_1 [p_D(t_D) + s] + \sum_{j=2}^N (q_j - q_{j-1}) [p_D(t_D - t_{jD}) + s] \right\} \quad (2.3)$$

2.1.1 Solution Technique

Equation (2.2) and (2.3) were used in the study. Detailed technique is given in Appendix A.

2.1.1.1 Generation of Data, Forward Model

Equations 2.2 and 2.3 describe the wellbore pressure resulting from wellbore forces and the drop of pressure in the reservoir. Both pressures were equated to obtain rates which satisfy both equations and hence pressures were also found by substituting into either one of the equations.

One problem associated with equating the wellbore and reservoir equations is that we have a discontinuity at time $t=0$.

$$p_w |_{t=0} = \rho g z_o \quad (2.4)$$

$$p_{wf} |_{t=0} = p_i \quad (2.5)$$

At time $t=0$, the wellbore pressure according to Equation (2.4) is a hydrostatic head of cushion as opposed to initial reservoir pressure given by reservoir equation. Hence there is a strong singularity in pressure.

To remove the discontinuity a 'lag time' was introduced into the wellbore equation. The wellbore equation lags behind reservoir equation by time t_{lag} such that,

$$p_{wf} |_{t=t_{lag}} = p_w |_{t=0} \quad (2.6)$$

This implies we can equate the reservoir equation to the wellbore equation at later time t' as,

$$p_{wf} |_{t=t_{lag}+t'} = p_w |_{t=t'} \quad (2.7)$$

Mass is conserved in the problem, as the rate resulting from Equation (2.6) was used as first rate (rate at $t=0$) for the wellbore equation and the resulting level of fluid is added to the initial level (z_o) in the wellbore equation for all subsequent time intervals.

2.1.1.2 Inverse Model, Coupling of Equations

The reservoir and wellbore equations were coupled using the expression,

$$F(t') = (p_{wf} |_{t=t_{lag}+t'} - p_m)^2 + (p_w |_{t=t'} - p_m)^2 \quad (2.8)$$

where $F(t')$ represents the squares of the differences in the pressure in the wellbore equation and in the reservoir equation. The term p_m is the pressure generated from the forward model. The unknown parameters in the reservoir equation and the wellbore equation were obtained by nonlinear regression. The Gauss – Newton method was used.

The unknown parameters can be the permeability and other reservoir parameters, depending on the model selected (p_D), as well as the Moody friction coefficient in the wellbore equation.

2.2 Controlled reinjection

The second proposed Green well test is ‘controlled reinjection’. This test can follow a closed chamber test.

After a closed chamber test the well volume is filled with reservoir fluid. The reinjection method proposes injection of that fluid back into the reservoir at a constant rate. Depending on the rate of injection, the duration of this test can be prolonged and hence a larger radius of investigation can be achieved.

The configuration of the test is shown in Figure 2.

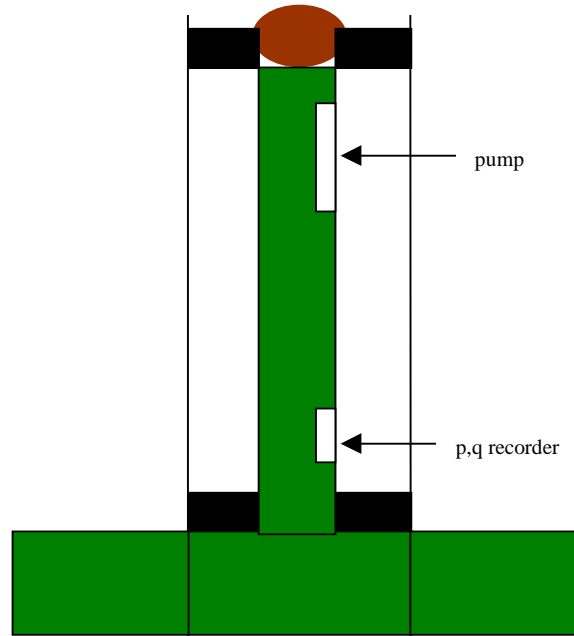


Figure 2. Mechanical configuration of controlled reinjection.

The advantages of such a test over injection from the surface is that injection of foreign fluid is avoided and moreover, the test will be more economical as no fluid treatment and surface facilities will be required.

One problem associated with this test is that it may be difficult to operate as pressure upstream of the pump will be decreasing all the time and hence the rate cannot be constant. Moreover, pumps inside the wellbore will produce noise in rate and pressure measurements. The latter problem can be avoided by placing pumps at some distance from the gauges inside the wellbore. (Figure 2).

2.3 Choked Closed Chamber test

The principle behind this Green well test is that the radius of investigation is independent of the rate or the magnitude of disturbance. The closed chamber test lasts until the wellbore pressure equals the reservoir pressure. With lower drawdown and hence lower rate, it takes longer for pressures to equate and hence we have a larger duration test which implies a greater radius of investigation.

The set up for this test is shown in Figure 3. Adding a choke to closed chamber test setup provides a backpressure to the formation and hence the rate is significantly reduced to order of 10^1 STB/day from 10^3 - 10^6 STB/day.

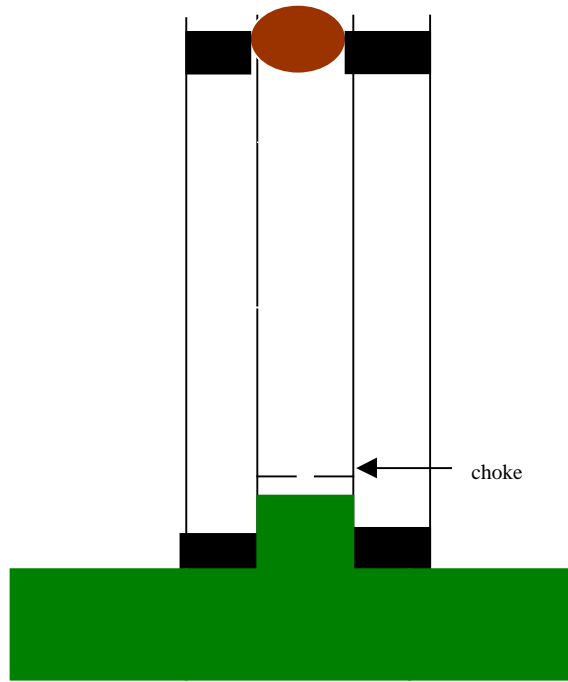


Figure 3. Mechanical configuration of chocked closed chamber test.

2.3.1 Solution Technique

The choke equation and reservoir equation were equated to obtain rate and pressure. An empirical correlation (Gilbert, 1954) was used for the choke calculation and the multirate superposition equation was used as the reservoir equation.

Choke equation:

$$p_c = \frac{AR_p^B Q}{S^C} \quad (2.9)$$

Reservoir Equation:

$$p_{wf}(t) = p_i - \frac{141.2B\mu}{kh} \left\{ q_1 [p_D(t_D) + s] + \sum_{j=2}^N (q_j - q_{j-1}) [p_D(t_D - t_{jD}) + s] \right\} \quad (2.10)$$

The wellbore equation is no longer required as critical flow in the choke is assumed. The advantages of using critical flow are:

- The choke causes an almost constant rate under critical flow. The rate depends on the size of choke used in the test.
- No backpressure is applied to the formation and hence the test is almost like drawdown test.

The rate and pressure are generated by equating Equations (2.9) and (2.10). The parameters in the reservoir equation can be obtained by 'straight line' analysis as used in conventional well test or by nonlinear regression.

Chapter 3

Results of Green Well Tests

The chapter shows responses of three tests in homogenous reservoirs of varying permeability. The infinite acting model was used for example reservoirs. Three permeability were considered—large permeability reservoir (1200md), moderate permeability (200md) and low permeability (20md) reservoir. The forward models described in chapter 2 were used to obtain rate and pressure for all tests in three different example reservoirs. Responses of tests with varying chamber radius, cushion length, and gas pressure were investigated. The inverse model was used to obtain parameters such as permeability, skin, initial reservoir pressure and Moody friction factor.

3.1 Data Used

The common data used for all the tests are listed in the table below:

Table 1: Properties of example reservoir.

Property	Symbol	Property of example reservoir	Comments
Permeability	k	20,200,1200	depending on reservoir type
Depth	D	5000'	
Chamber length	Lp	5000'	
Wellbore radius	rw	0.25'	
Radius of chamber	rp	0.125'	
Choke diameter	dc	2/64"	only applicable to choked CCT
Total compressibility	ct	1.2E-05 1/psi	
Pay thickness	h	20'	
Formation volume factor	Bo	1.25	
Porosity	ϕ	0.2	
Viscosity	μ	1.25 cp	
Moody friction factor	mf	0.02	

3.2 Closed Chamber Test

Rate and pressure were generated by the forward model in all three reservoirs. The effect of radius of chamber, and cushion fluid level in chamber on generated pressure and rate

were investigated. The inverse model was used to obtain parameters in reservoir and wellbore equation.

3.2.1 Forward Model results

Figures 4, 5, 6 show rate and pressure generated for high, medium and low permeability reservoirs using data in Table 1. The criterion for duration of test was until the wellbore pressure was 99% equal to the reservoir pressure. The duration of test for large, medium and low permeability reservoirs were 0.058, 0.72 and 7.2 hours respectively. Since the initial drawdown for all three reservoirs are same, the rate was higher in higher flow capacity reservoir than lower flow capacity reservoirs.

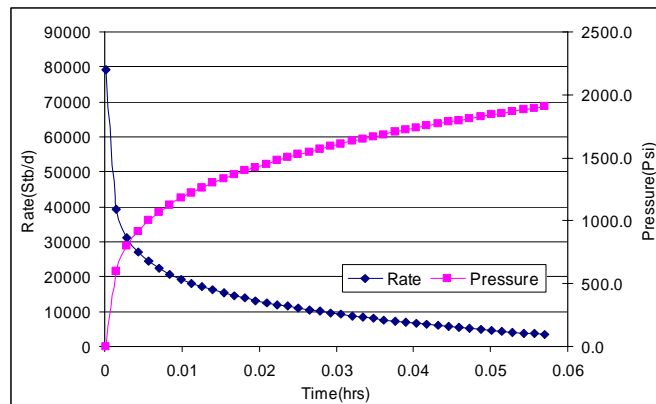


Figure 4. Rate and pressure in high permeability reservoir (CCT).

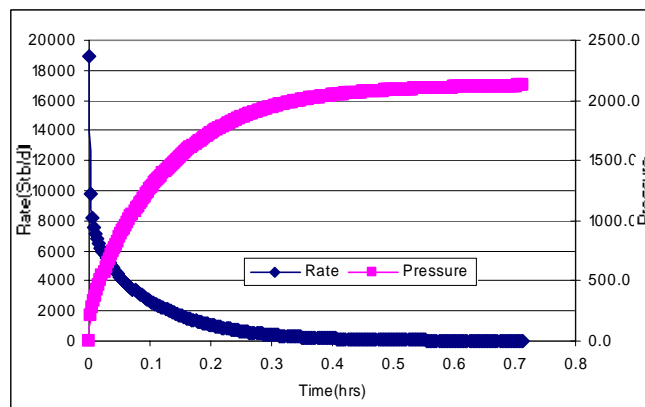


Figure 5. Rate and pressure in medium permeability reservoir (CCT).

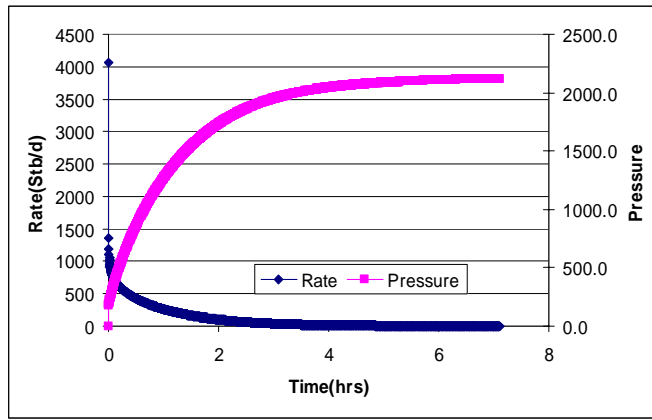


Figure 6. Rate and pressure in low permeability reservoir (CCT).

3.2.1.1 Effect of chamber radius

An increase in the radius of chamber results in an increase of the frictional and inertial forces acting on the fluid (Appendix A) but the hydrostatic force on the fluid decreases. The wellbore pressure is obtained as the resultant of these three forces. The decrease in the hydrostatic pressure is higher than the increase in the other two forces. Hence, the resulting wellbore pressure is decreased at any given time. Therefore, it takes a longer time for wellbore pressure to equate the reservoir pressure causing an increase in duration of the test.

Figures 7 show the increase in the duration of the test.

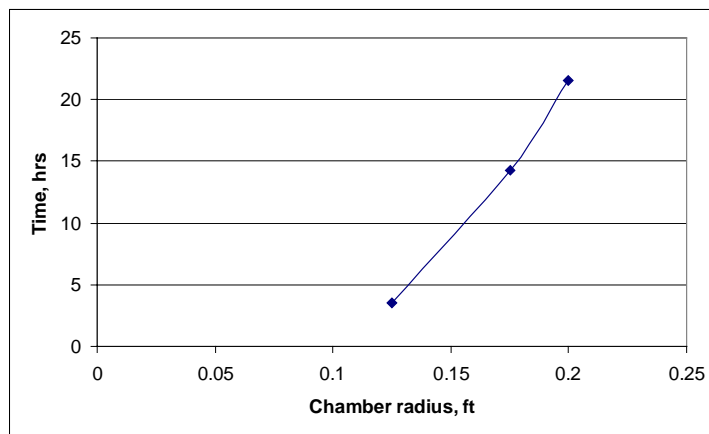


Figure 7. Change in duration of CCT with change in chamber radius.

3.2.1.2 Effect of cushion length

A cushion of fluid is added in chamber to avoid high initial drawdown. An increase in the size of the cushion decreases the duration of the test (Figure 8). A large cushion size decreases the effective volume of the chamber. Hence, less volume of reservoir fluid is required to fill the chamber until the wellbore pressure equates the reservoir pressure.

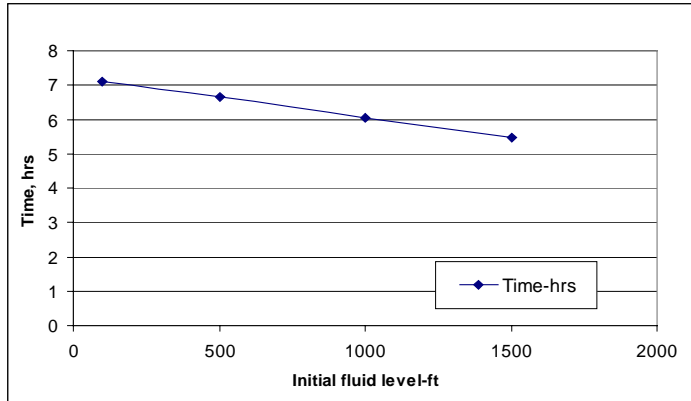


Figure 8. Change in duration of CCT with cushion

An increase in the cushion size increases the backpressure on the formation and thus the initial rate is reduced. Hence, the inertial force acting on the fluid reduces. Figure 9 shows the changes in the inertial pressure on fluid with cushion size.

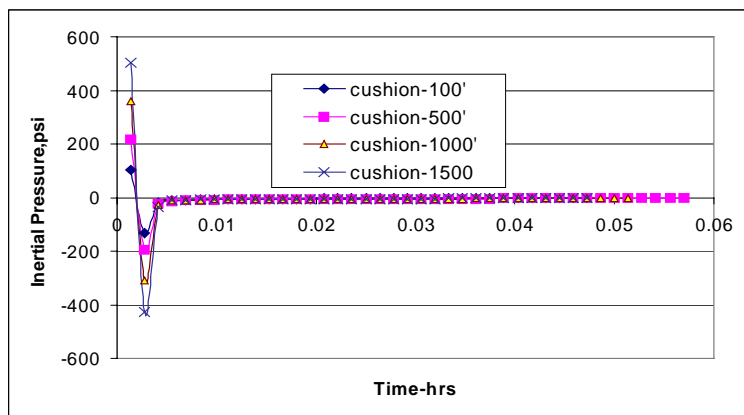


Figure 9. Inertial pressure varying with cushion level.

3.2.2 Inverse Model

The rate and pressure generated in the forward model were used to obtain parameters in the wellbore and the reservoir equation. Figures 10, 11, 12 show the match for the three reservoirs. Table 2 shows the parameters obtained in the inverse model and the parameters used in the forward model to generate data.

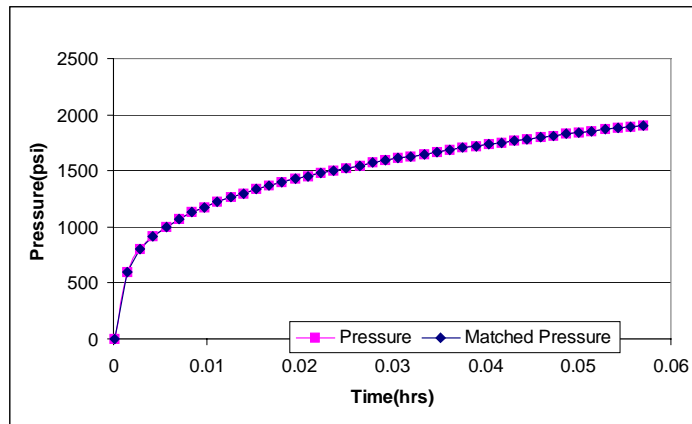


Figure 10. Inverse model CCT in high permeability.

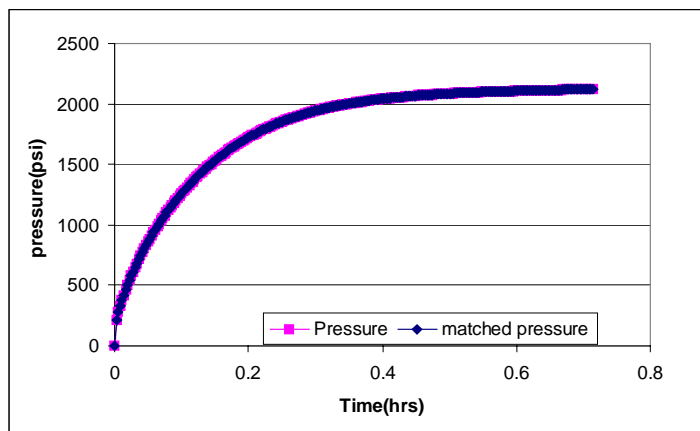


Figure 11. Inverse model CCT in medium permeability.

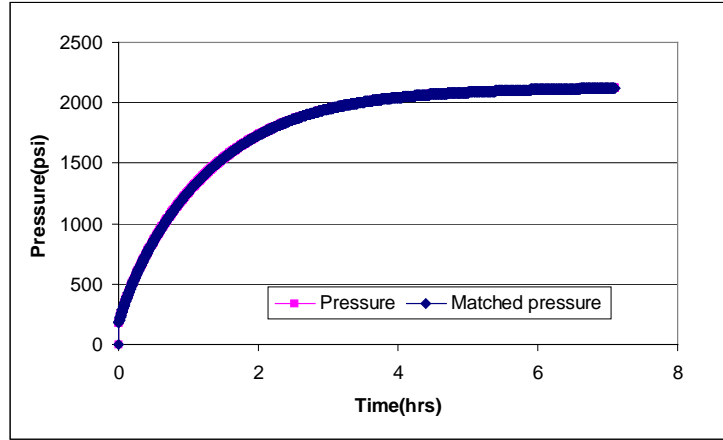


Figure 12. Inverse model CCT in low permeability.

Table 2: Properties obtained from the inverse model.

Parameters	Forward	Inverse
k	20,200,1200	19.9,198.9,1200.8
s	2	1.9,1.9,2.1
Pi	2165	2164.8,2165.1,2166
mf	0.02	0.0185

3.3 Controlled reinjection test

This test can be conducted after carrying out CCT. The chamber will be filled with reservoir fluid after CCT. The assumption in this test is that of injecting the fluid in the chamber at a constant rate into the reservoir. The test duration and hence the radius of investigation depends on the rate at which we inject into the reservoir. Figures 13, 14, 15 show the response of the test in all the three reservoirs.

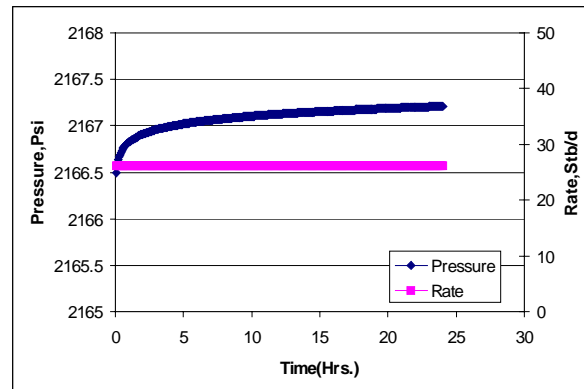


Figure 13. Rate and pressure in high permeability reservoir (controlled Reinjection).

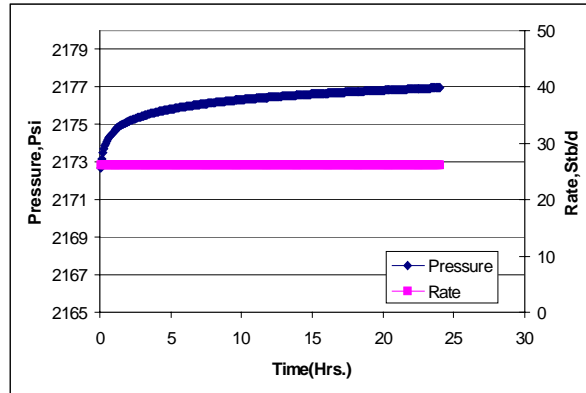


Figure 14. Rate and pressure in medium permeability reservoir (controlled reinjection).

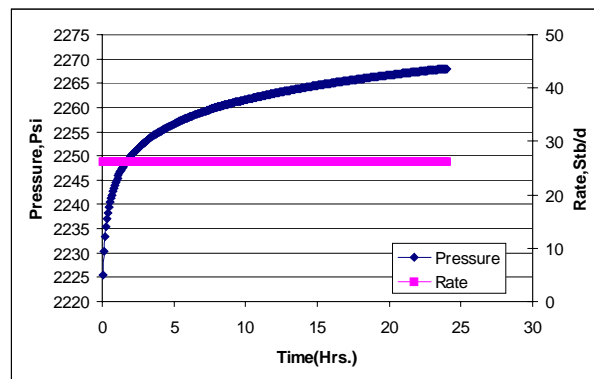


Figure 15. Rate and pressure in low permeability reservoir (controlled reinjection).

3.4 Choked closed chamber test

Rate and pressure were generated by the forward model in all the three reservoirs. The effect of the radius of chamber, and the choke size on the generated pressure and rate was investigated. The inverse model was used to obtain parameters in the reservoir and wellbore equations.

3.4.1 Forward Model results

Figures 16, 17, 18 show rate and pressure generated for high, medium and low permeability reservoirs using data in Table 1. The criterion for duration of the test was until wellbore pressure was 50% equal to pressure upstream of the choke. The duration of test for high, medium and low permeability reservoirs was 5.3 hours.

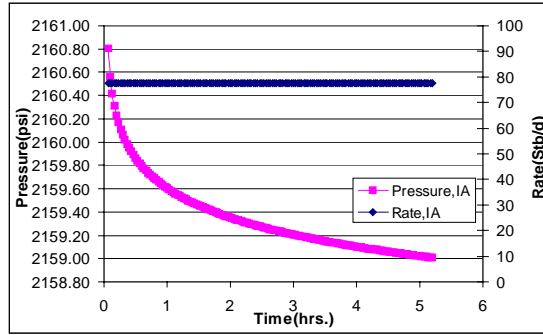


Figure 16. Rate and pressure in high permeability reservoir (choked CCT).

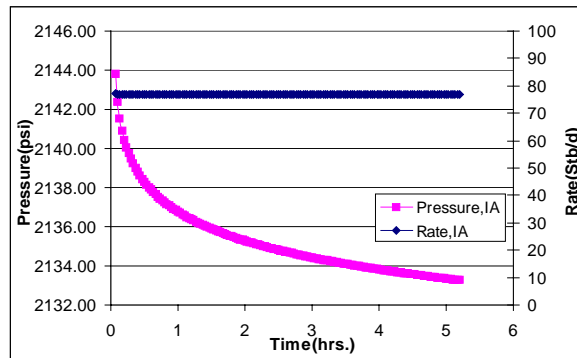


Figure 17. Rate and pressure in medium permeability reservoir (choked CCT).

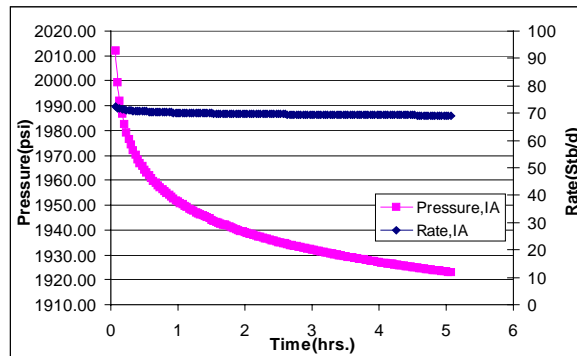


Figure 18. Rate and pressure in low permeability reservoir (choked CCT).

3.4.1.1 Effect of chamber radius

Figure 19 shows that the test duration increases with increase in size of chamber. Hence, the radius of investigation increases with increase in size of the chamber. The test lasts until the pressure downstream to the choke (wellbore equation) equates half the pressure upstream to the choke. As the size of chamber increases, the pressure downstream to the

choke decreases (refer.3.2.1.1). Hence it takes longer for the downstream pressure to equate half the upstream pressure which results in a longer test duration.

3.4.1.2 Effect of choke size

A decrease in the choke size causes increase in backpressure on the formation and hence it takes a longer duration to fill the chamber. Figure 20 shows increase in the duration of test with decrease in choke size.

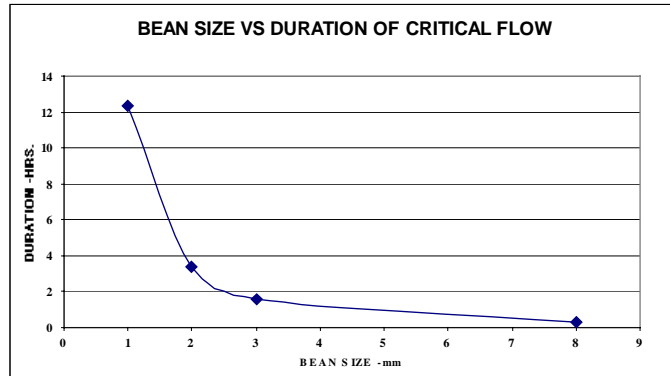


Figure 20. Change in duration of test with Choke size.

3.4.2 Inverse Model

Rates and pressure generated in the forward model were used to obtain parameters in the reservoir equation. Figures 21, 22, 23 show the match for the three reservoirs. Table 3 shows the parameters obtained in the inverse model and the parameters used in the forward model to generate data.

Table 3: Properties obtained from the inverse model.

Parameters	Forward	Inverse
k	20,200,1200	20.1,200.08,1999.8
s	0	0.3,0.2,-0.3
Pi	2165	2164.8,2165,2165.1

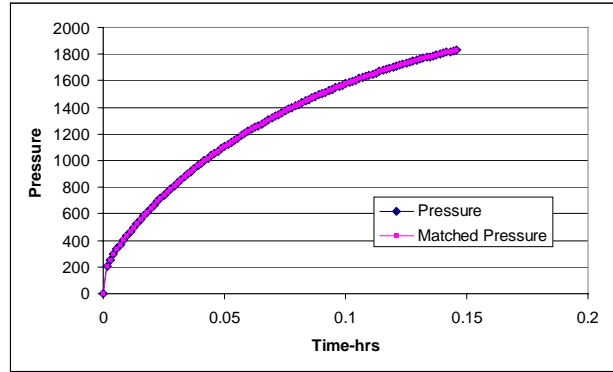


Figure 21. Inverse Model –Match for high permeability reservoir (Choked CCT).

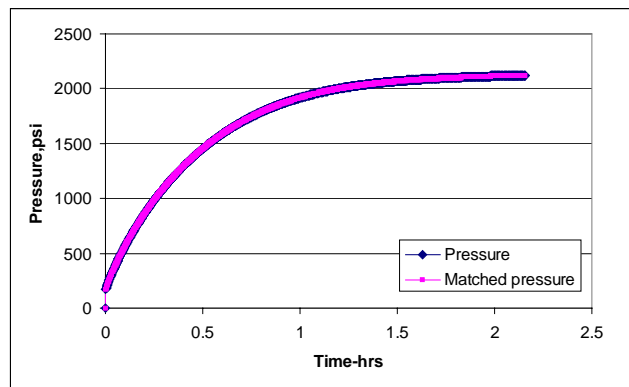


Figure 22. Inverse Model –Match for medium permeability reservoir (Choked CCT).

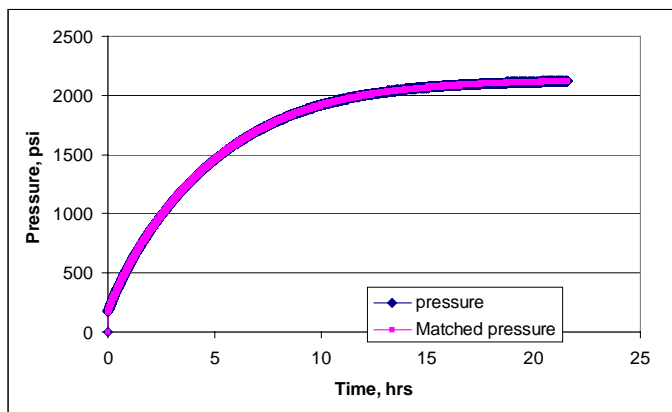


Figure 23. Inverse Model –Match for low permeability reservoir (Choked CCT).

Chapter 4

Applicability and Comparison of Green Well tests

The example reservoirs used in Chapter 3 were used to determine the radius of investigation for the three Green well tests. Two techniques were used for estimating radius of investigation:

1. Two ring composite model (Ross, 1991) – Rate and pressure for two ring composite model (Figure 24) were generated by the forward model. The generated rate and pressure were compared with the response of the infinite acting reservoir. The data was generated with different r_1 (Figure 24) until the response was different to that of the infinite acting reservoir. This implied the second ring permeability influenced the rate and pressure generated. Hence, the radius investigated by the test was that radius, r_1 , which had different response from infinite acting reservoir.

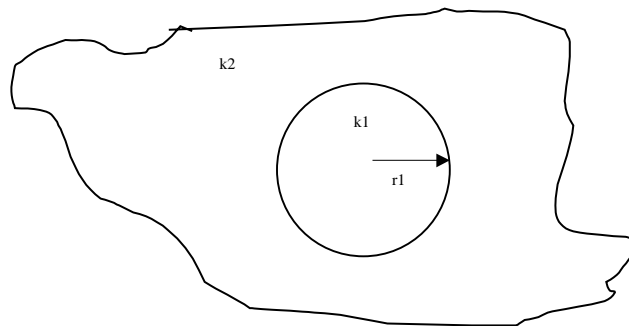


Figure 24. Two ring composite model.

2. Fault –To ascertain the estimated radius of investigation from two ring model, a fault was placed near to r_1 (Figure 24). The log derivative plots of deconvoluted pressure was seen for fault boundary (Bourgeois, M. 1992).

The data used for comparative study of the Green Well tests is given in Table 1.

4.1 High Permeability reservoir

The three Green Well tests were compared in high permeability reservoir of 1200 md.

CCT- The response for the test was different from that of the infinite acting reservoir when r_1 was equal to 125 ft. The data generated for various radius, r_1 , is shown in figure 25.

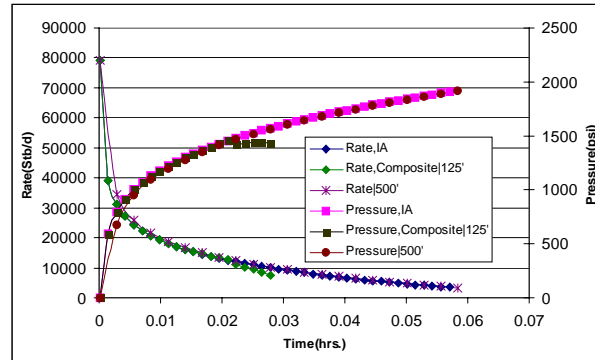


Figure 25. CCT response in high permeability reservoir.

A fault was placed at 100 feet to ascertain the radius of investigation. Figure 26 show the log derivative plot of the deconvoluted pressure in laplace space. A distinct rise in the derivative was seen for the fault placed at 100 ft. This can be inferred as a closed boundary response.

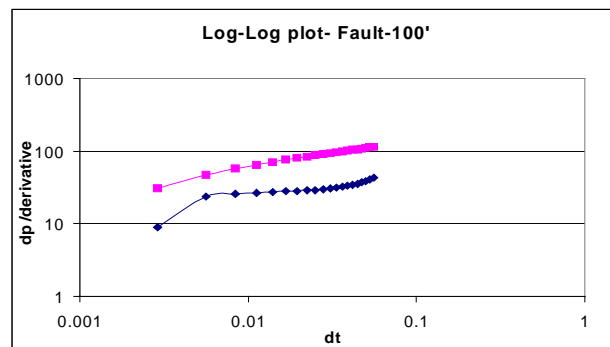


Figure 26. CCT response with fault at 100 ft (high permeability).

Choked CCT- To test radius of investigation for the choked CCT in high permeability reservoir, faults were placed at various distances from the well and the derivative plot was

seen for closed fault response. The fault was observed by the test at distance of 750 ft (Figure 27, 28).

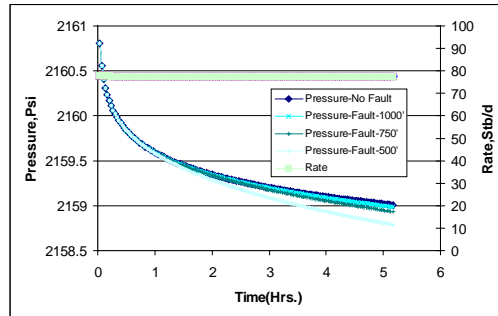


Figure 27. Choked CCT response in high permeability reservoir

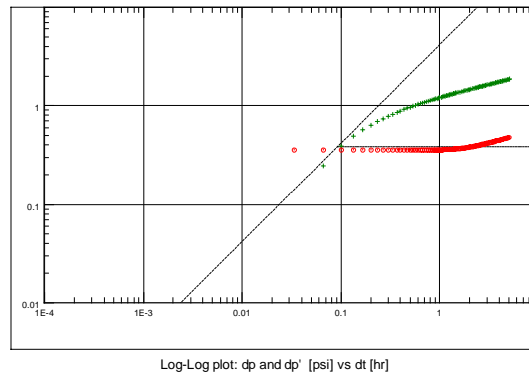


Figure 28. Choked CCT response in high permeability reservoir with fault placed at 750'.

Controlled reinjection- The procedure similar to choked chamber test was used to estimate the radius of investigation for this test. Figure 29 shows the response of tests for a fault placed at 1000 ft from the well. The fault at a distance of 1000 ft was observed in log derivative (Figure 30).

Comparison- For a high permeability reservoir the radius of investigation was least for CCT and large for controlled reinjection and choked CCT.

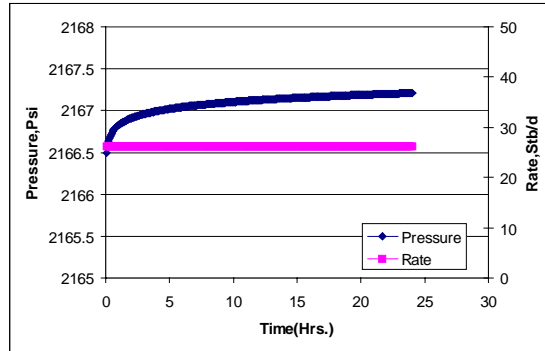


Figure 29. Controlled reinjection response with fault at 1000' (high permeability reservoir).

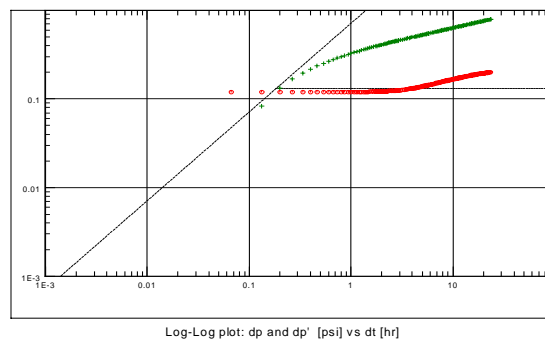


Figure 30. Derivative plot for controlled reinjection with fault at 1000' (high permeability reservoir).

4.2 Medium Permeability reservoir

A similar procedure was used for the medium permeability reservoir. The results for each test are discussed as below:

CCT - Figure 31 shows the response in two ring composite model with the inner ring of 200md and outer ring of 20 md. The response for the test was different from that of the infinite acting reservoir when r_1 (Figure 24) was equal to 250 ft.

A fault was placed at 150 ft to ascertain the estimated radius of investigation. Figure 32 show the log derivative plot of deconvoluted pressure in laplace space. The fault boundary in derivative was detected.

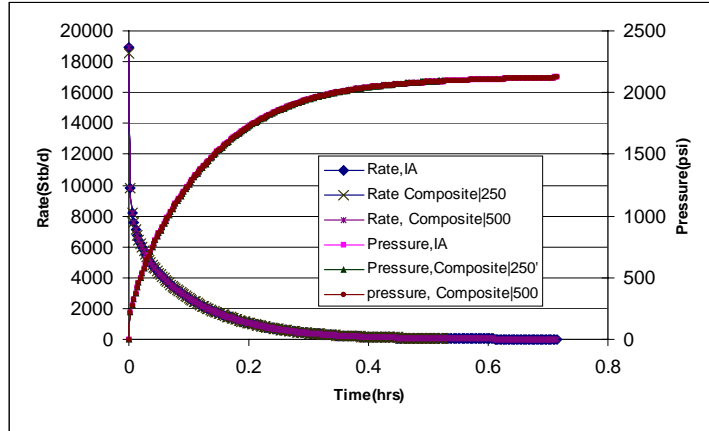


Figure 31. CCT response in medium permeability reservoir

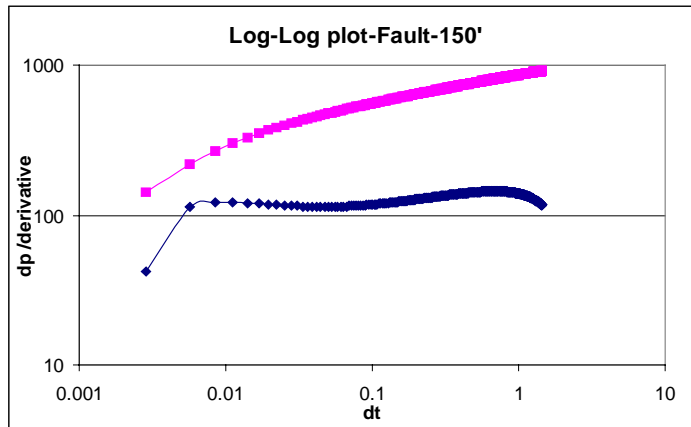


Figure 32. Derivative plot for choked CCT with fault at 150' in medium permeability reservoir

Choked CCT - Figure 33 shows the response of test in the reservoir with permeability of 200md with faults placed at various distances. The generated rate and pressure were different from the infinite acting reservoir of 200md for fault placed at 300 feet from well. The log derivative plot (Figure 34) shows the rise in derivative for a fault placed at 300 ft, indicating a closed fault boundary.

Controlled reinjection- Figure 35 show responses of the test in medium permeability reservoir with faults placed at 750 ft from wells. The log derivative plot (Figure 36) indicates the fault.

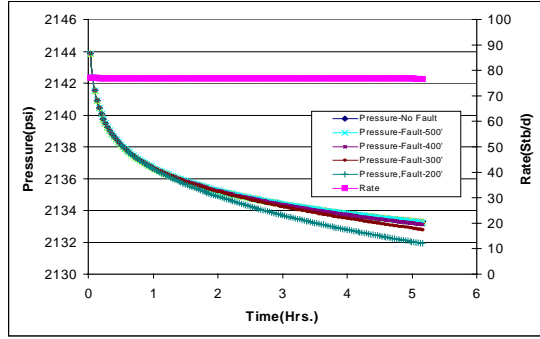


Figure 33. Choked CCT response in medium permeability reservoir.

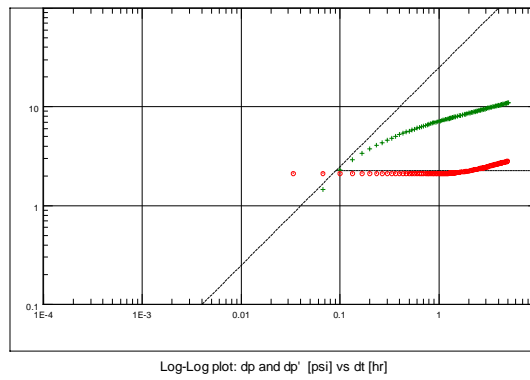


Figure 34. Derivative plot indicating fault at 300' in medium permeability reservoir (Choked CCT).

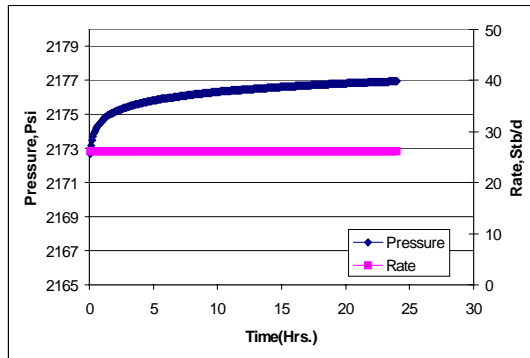


Figure 35. Controlled reinjection response in medium permeability reservoir.

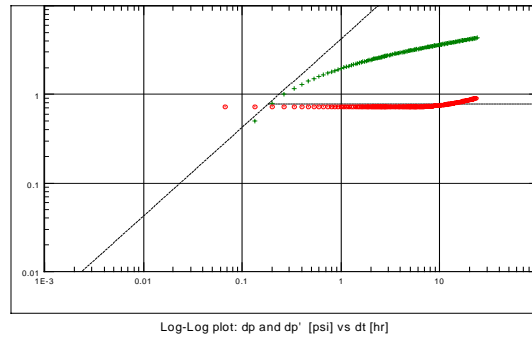


Figure 36. Derivative plot indicating fault at 150' in medium permeability reservoir, (controlled reinjection test).

Comparison – The radius of investigation for medium permeability reservoir was greater for CCT when compared to high permeability reservoir. The choked closed chamber test and controlled reinjection test has lower radius of investigation in medium permeability reservoir when compared to high permeability reservoir.

4.3 Low Permeability reservoir

CCT - Figure 37 shows the response in two ring composite model with inner ring of 20md and outer ring of 1200 md. The response for the test was different from that of the infinite acting reservoir when r_1 (Figure 24) was equal to 250 ft.

A fault placed at the distance 150 ft was detected by the test. The derivative plot of deconvoluted pressure in laplace space is shown in Figure 38. A distinct rise in the derivative can be inferred as a closed boundary response.

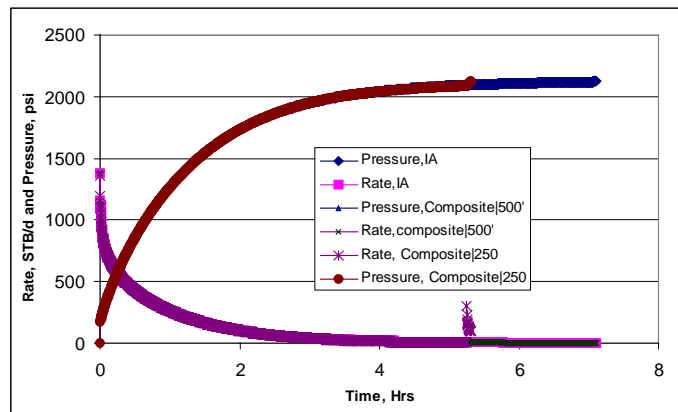


Figure 37. CCT response in low permeability reservoir.

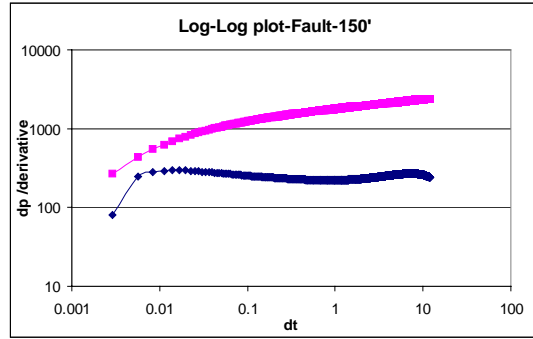


Figure 38. Derivative plot indicating fault at 150' in low permeability reservoir (CCT).

Choked Closed Chamber test- The faults at various distances from the well was placed. The test detected a fault at distance of 100 ft (Figure 39). The derivative plot for fault placed at 100 ft shows characteristic rise in derivative (Figure 40).

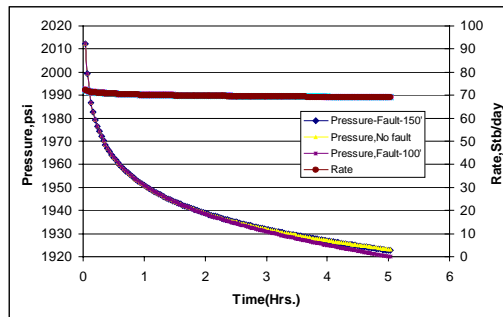


Figure 39. Choked CCT response in low permeability reservoir.

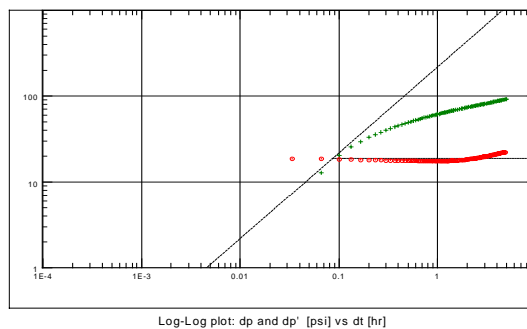


Figure 40. Derivative plot indicating fault at 100' in low permeability reservoir (Choked CCT).

Controlled Reinjection - Figure 41 show the responses of test in low permeability reservoir with faults placed at 250 ft from well. Log derivative plot indicates the fault at distance 250 ft (Figure 42).

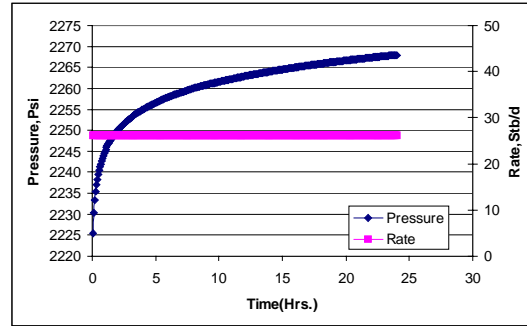


Figure 41. Controlled Reinjection response in low permeability reservoir

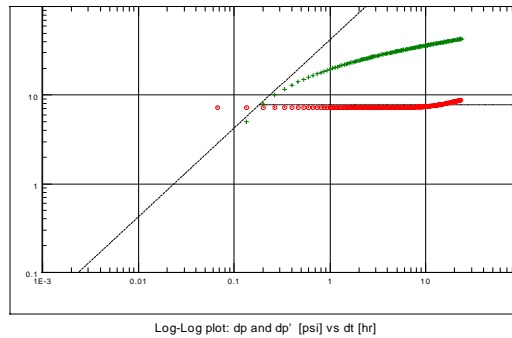


Figure 42. Derivative plot indicating fault at 250 ft (low permeability, controlled reinjection)

Comparison – The radius of investigation was the highest in low permeability reservoir for CCT. The controlled reinjection and choked closed chamber have reduced radius of investigation in low permeability reservoir than the high permeability reservoir.

4.4 Comparison of Green Well Tests

The three Green Well tests discussed in Chapter 2 differs in two broad category:

- Rates – Initial rates generated in CCT was in order of 10^3 - 10^6 STB/day and decreased with time as fluid was produced with increasing backpressure of the fluid column

inside wellbore. The choked closed chamber test and controlled reinjection has lower rate ($\sim 10^1$ STB/d), depending upon the choke size or pumping rate. The rates in these tests are also almost constant throughout the test.

- Forces acting on fluids – Due to high initial flowrate in CCT, inertial and frictional forces are dominant. Figure 43 shows the inertial force on fluid in the three tests. There is a negligible inertial force acting on fluid in choked closed chamber test and controlled reinjection test as compared to CCT. Figure 44 shows the frictional force on fluid in each test. Due to the large flowrate, the frictional head is greater in closed chamber test when compared to the other two tests.

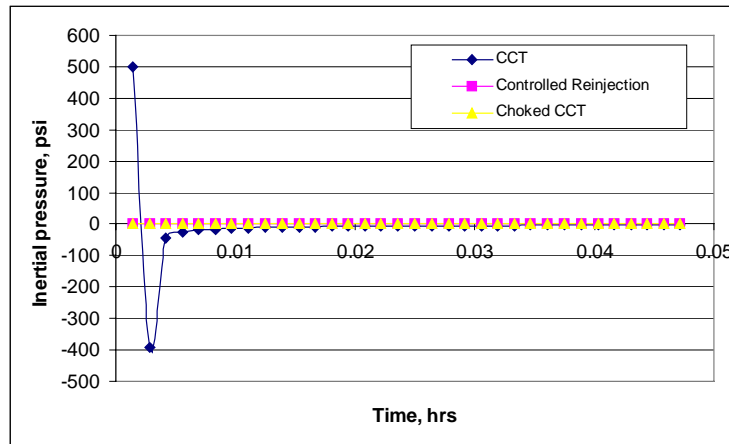


Figure 43. Inertial pressure in three tests

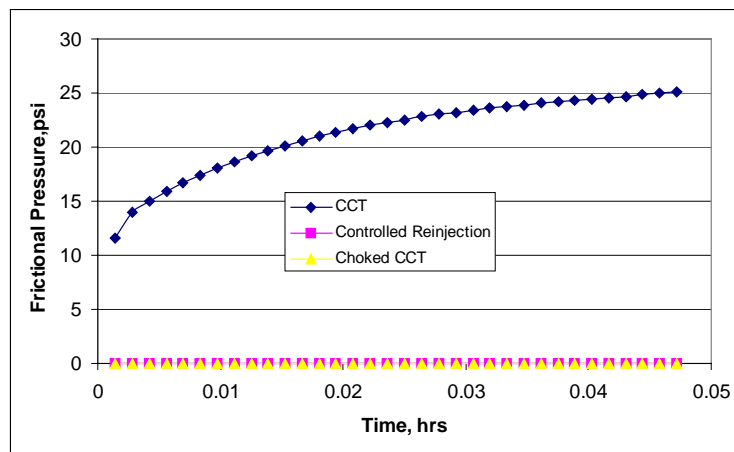


Figure 44. Frictional pressure in three tests

Chapter 5

Conclusions and Recommendations

Analysis of results presented in this study lead to following conclusions and recommendations:

- 1 CCT is of short duration and has less radius of investigation. CCT has least radius of investigation in high permeability reservoirs.
- 2 For high permeability reservoir choked CCT or controlled reinjection can be used. In medium or low permeability reservoirs CCT has a moderate radius of investigation and hence can be used.
- 3 High inertial forces act on fluid in CCT while choked CCT or controlled reinjection test has constant rate so almost no inertial force acts on fluid. Due to initial high rate in case of closed chamber test, inertial forces on fluid act not only in wellbore but in reservoir as well. Wave equation can be used as reservoir equation for CCT.
- 4 Each test discussed in this report has physical constraint. Transients can only be created by amount of fluid in wellbore. Hence, the duration of test is less resulting in reduced radius of investigation.
- 5 Injection tests has no physical constraints but has disadvantage of damaging formation.

Nomenclature

t_D = Dimensionless time

C_D = Dimensionless wellbore storage

r_D = Dimensionless radius

q = rate, STB/day

s = skin

p_i = initial reservoir pressure, psi

A = constant

R_p = Gas oil ratio, Scf/STB

S = diameter of choke, $1/64^{\text{th}}$ inch

μ = viscosity, cp

k = permeability, md

B = formation volume factor, rb/STB

r_p = radius of chamber, ft

ρ = density of fluid, lb/ft³

g = acceleration due to gravity, ft/s²

p_a = atmospheric pressure, psi

p_g = gas pressure in chamber, psi

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Appendix A

A. Generation of data for CCT

The reservoir equation was equated to the wellbore equation.

Reservoir equation:

$$p_{wf}(t) = p_i - \frac{141.2B\mu}{kh} \left\{ q_1 [p_D(t_D) + s] + \sum_{j=2}^N (q_j - q_{j-1}) [p_D(t_D - t_{jD}) + s] \right\} \quad (\text{A.1})$$

Wellbore equation:

$$p_w(t) = \underbrace{A_w z''(t)}_{(1)} + \underbrace{B_w z'(t)}_{(2)} + \underbrace{C_w z(t) + D_w}_{(3)} \quad (\text{A.2})$$

(1) Inertial force

(2) Frictional force

(3) Gravitational force

$$A_w = \left(z(t) + \frac{3}{8} \left[\frac{r_p}{r_w} \right]^2 \right) \rho \quad (\text{A.3})$$

$$B_w = \left(z(t) \frac{m_f}{4} \left| \frac{1}{r_p} z'(t) \right| + \frac{3}{4} \left[\frac{r_p}{r_w} \right]^4 \right) \rho \quad (\text{A.4})$$

$$C_w = \rho g \quad (\text{A.5})$$

$$D_w = \left(\frac{z_o - L_p}{z(t) - L_p} \frac{p_g(0)}{\rho} - \frac{p_a}{\rho} \right) \rho \quad (\text{A.6})$$

$$z''(t_n) = \frac{5.615}{24} \frac{1}{\pi r_p^2} \frac{1}{\Delta t} (q(t_n) - q(t_{n-1})) \quad (\text{A.7})$$

$$z'(t_n) = \frac{5.615}{24} \frac{1}{\pi r_p^2} q(t_n) \quad (\text{A.8})$$

$$z(t_n) = \frac{5.615}{24} \frac{1}{\pi r_p^2} \int_0^{t_n} q(t) dt \quad (\text{A.9})$$

Equations A.3 –A.9. was substituted in equation A.2 to obtain wellbore pressure.

First rate at time t_{lag} from the reservoir equation,

$$p_{wf}(t_{lag}) = p_i - \frac{141.2B\mu}{kh} \{q_1 [p_D(t_D) + s]\} = p_w(0) = \rho g z_o \quad (\text{A.10})$$

Therefore,

$$q_1 = (p_i - \rho g z_o) \frac{kh}{141.2B\mu [p_D(t_D) + s]} \quad (\text{A.11})$$

Subsequent rates can be obtained by equating the reservoir pressure to the wellbore pressure at time, t' ,

$$p_{wf} |_{t=t_{lag}+t'} = p_w |_{t=t'} \quad (\text{A.12})$$

The resulting nonlinear equation solved by Newton-Raphson method to obtain rates for all subsequent time intervals.