Petroleum and Coal

WELL TEST ANALYSIS IN EGYPTIAN NATURALLY FRACTURED OIL RESERVOIRS

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Abstract

In this paper, well test data from three naturally fractured oil reservoirs were analyzed based on conventional semi – log plots, type curve matching, and Tiab's direct synthesis techniques. A computer program using C# was developed based on the direct synthesis method to be used in analyzing well test data in naturally fractured reservoirs.

The developed program gives accurate results compared with pan-system (one of the commercial softwares) which characterizes the naturally fractured reservoir using conventional semi-log and type curve matching techniques. The developed program characterizes the fractured reservoir in case of the infinite reservoir without wellbore storage effect whether all flow regimes are present, the early time infinite acting radial flow regime is absent, the late time infinite acting radial flow regime is absent or both infinite acting radial flow periods cannot be observed.

Keywords: *Well Test; Fracture Reservoir; Tiab's Method; Conventional Analysis, Dual Porosity*.

1. Introduction

More than 50% of oil and gas reservoirs all over the world are naturally fractured [1]. Some naturally fractured reservoirs are called dual porosity reservoirs as they consist of two porous media of different characteristics; which are the matrix and the fractures. The matrix has high porosity and low permeability. However, the fractures medium has high permeability and low porosity. The flow in the dual porosity system comes from the matrix towards the fractures, then from the fracture directly towards the wellbore.

A number of authors have developed different models for interpreting the pressure response in fractured reservoirs considering, among others, the characteristics of flow from the matrix to fractures, fracture orientation, and block-size distribution. In general, pressure-transient tests in NFR show a behavior consistent with the Amanat U. Chaudhry [2] model. The characteristic behavior of pressure response can be described with two dimensionless parameters; namely storativity ratio (ω) and interporosity flow coefficient (λ). Several models were developed to describe the pressure behavior of wells in dual porosity reservoirs. These models assume that the flow from the matrix to fractures is under transient or pseudosteady state flow conditions. The flow rate in pseudosteady state model is proportional to the pressure difference between the matrix and the adjacent fracture. In addition, the pseudosteady state conditions are assumed at initial flow conditions. On the other side, the flow rate in case of transient matrix flow model is proportional to the pressure gradient as the pressure drawdown starts at the interface between the matrix and fracture, and then propagates into the matrix. Finally, the pseudosteady state is achieved.

The presence of skin region of low permeability at the interface between matrix and fracture causes the pressure behavior to be predicted by pseudosteady state matrix flow model, although the flow in the matrix is under transient flow conditions. Therefore, most of the field

cases follow the pseudosteady state flow model. Fractures have been defined in different terms depending on the specific purpose or context of the definition. From reservoir point of view, Nelson [3] has defined fracture as a naturally macroscopic planar discontinuity in rock due to deformation or physical digenesis. Fractures can be produced by brittle or ductile failure. The characteristic of fractures will also be different depending on the generation process. Fractures can have a positive or negative effect on fluid flow. NFR are those reservoirs where fractures have or could have, any influence on reservoir performance. Nelson [3] has stressed the importance to collect information that allows identifying a reservoir as fractured in the early stage of development.

2. Naturally fractured reservoir

2.1. Fracture properties

The two major factors that govern permeability and porosity of fracture are fracture width and spacing. Fracture width (e) is the distance between two parallel surfaces that represent the fracture. Fracture spacing (D) is the average distance between parallel regularly spaced fractures. According to Nelson [3], the four most relevant properties of fractured reservoirs, in order of increasing difficulty to determine, are:

Fracture porosity.
Fracture permeability.
Fluid saturation within fractures.
Expected recovery factor.
Fracture porosity

2.1.1. Fracture porosity

Fracture porosity is the percentage of void space in fractures compared to the total volume of the system. Fracture porosity is estimated using the following expression:

$$\emptyset_f = \left(\frac{e}{D+e}\right) \tag{1}$$

As can be noticed from the expression, the fracture porosity is very scale-dependent. The value of $\emptyset_f$ can be 100 % in a particular location of the reservoir, but the value for the whole reservoir porosity is generally less than 1 %. According to Nelson [3], fracture porosity is always less than 2 %; in most reservoirs is less than 1 % with a general value of less than 0.5 %. An exception to this rules-of-thumb is vuggy fractures where porosity can vary from 0 to a very large value.

The importance of fracture porosity in reservoir performance depends on the type of fractured reservoir. If the fracture system provides an essential porosity and permeability to the reservoir, then fracture porosity is a critical parameter to be determined in the early stages of development. As the contribution of the matrix porosity to the whole system increases, the relevance of the fracture porosity decreases. Therefore, the estimation of the fracture porosity in the early stages is not so crucial in reservoirs where the matrix porosity is several orders of magnitude greater than the fracture porosity.

The Fracture porosity is one of the fracture properties that are difficult to be determined. The common sources of the fracture porosity estimation are:

Core analysis.
Porosity-Permeability relationship.
Field/Lab Determination.
Multiple–Well tests.

2.1.2. Fractured permeability

Permeability defines the ability of a porous medium to transmit fluids. The presence of open fractures has a great impact on reservoir flow capacity. Therefore, the fracture permeability is an important factor that determines reservoir quality and productivity.

Nelson [3] cited the work of Parsons [4], who combined the model for the fracture and matrix fluid flow and obtained the following equation for the fracture permeability:

$$k_f = \frac{e^2}{12} x \frac{\rho g}{\mu} \tag{2}$$

This equation assumes laminar flow between smooth, non-moving, parallel plates and homogenous fractures with respect to orientation, width, and spacing. Parson´s relationship is simple but is applicable to fluid flow through fractured reservoirs. Fractures do not always improve fluid flow in a reservoir. In some cases, partially or total filled fractures can act as flow barriers. The effect of the fractures on the permeability depends on several factors such as morphology, orientation, and others.

Fracture width and permeability are difficult to determine from direct sources such as core data or laboratory test. Well test analysis is the most common source of the fracture permeability information.

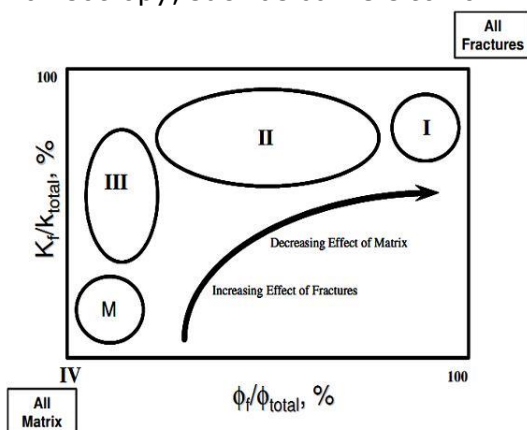## 2.2. Classification of fractured reservoirs

Fractured reservoirs can be classified into:
Fractures provide the essential reservoir porosity and permeability.
Fractures provide the essential reservoir permeability.
Fractures assist permeability in an already producible reservoir.
Fractures provide no additional porosity or permeability but create significant reservoir anisotropy, such as barriers to flow.

As shown in Figure 1, the effect of fractures is of paramount importance for type I reservoir, decreases for type II and so on. In the same way, the importance of the proper characterization of porosity and permeability changes with the reservoir type.

Figure 1. Schematic plot of fracture porosity and permeability percentage for four fractured reservoir types, (after Nelson [3])

3. Models of Well test analysis in a naturally fractured reservoir

In naturally fractured reservoirs, several sophisticated models were developed to describe the pressure response in dual porosity system. This section reviews the analytical and numerical models concerning well test analysis in this type of reservoirs.

The discovery of the first fractured reservoir was in 1880, according to Hubbert and Willis [5]. At this time, the well test methods were not used yet; they were first applied to homogenous reservoirs in 1950. One of the most useful methods to analyze well test data is presented by Horner [6]. His method is based on plotting bottom hole shut-in pressure versus $(t_0 + \Delta t)/\Delta t$ on a semi-log plot. Where t_p is the flowing is time prior to shut-in and Δt is the shut-in period. The slope calculated from the semi-log plot can be used to calculate the permeability thickness product of the formation.

3.1 Baker model

Baker [7] used the limestone formation in the Middle East. He assumed that the reservoir consists of parallel plates where the fluid can flow through them. This assumption was based on the model given by Lamb [8], Muskat [9], and Huitt [10]. The equation used was:

$$q = -\frac{g_c \, b \, W_f{}^2 \, dp}{12\mu} \frac{dp}{dL} \ldots \ldots \tag{3}$$

The equation is valid only for steady state flow.

3.2. Warren and Root model

Warren and Root Model [11] presented a modified model for naturally fractured reservoirs. They considered that the reservoir has both primary and secondary porosity. In addition, they defined the fissured reservoir by two new parameters: (1) the relative storativity ω, which is defined as the ratio of pthe orosity-compressibility product of the fractures to the total system porosity-compressibility product, given as follows:

$$\omega = \frac{(QC_t)_f}{(QC_t)_m + (QC_t)_f} \ldots \tag{4}$$

and (2) the interporosity flow parameter, λ *which*, is defined by the dimensionless matrix/fracture permeability ratio:

$$\lambda = \alpha\, r_w{}^2 \frac{K_m}{K_f} \ldots \tag{5}$$

where the shape factor α, ft^{-2}, depends on the type of geometry of the matrix block (horizontal slap, rectangular cylinders, or spherical matrix block).

In the case of $\omega=1$ and $\lambda=\infty$, Warren and Root model can represent homogenous reservoir which is considered as a limiting case in their model.

Warren and Root model [11] is based on the following assumptions:
1. The rock matrix is homogeneous and isotropic and is contained within a systematic array of identical, rectangular parallelepipeds.
2. An orthogonal system of continuous, uniform fractures surrounding the matrix blocks contains the secondary porosity
3. Flow occurs between the matrix blocks (primary porosity) and the fractures (secondary porosity), then from the fracture network to the wellbore.

3.3. Sugar cube model

The Sugar cube model is based on the first two assumptions of Warren and Root model. This model considered the idealized representation of the fractured formation as shown in Figure (2).
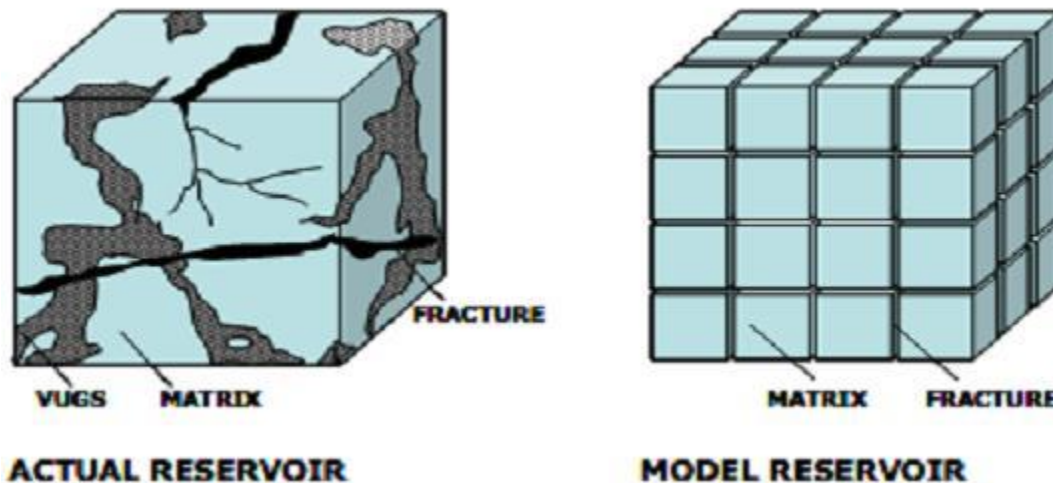

ACTUAL RESERVOIR   **MODEL RESERVOIR**

Figure 2. Ideal model for a naturally fractured reservoir *(after Warren and Root model [11])*

The slightly compressible radial flow equation that describes the flow in fractures can be expressed as:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial P_f}{\partial r}\right) = \frac{\phi_2 C_f \mu}{K_2}\frac{\partial P_f}{\partial t} + \frac{\phi_1 C_m \mu}{K_2}\frac{\partial P_m}{\partial t} \ldots \tag{6}$$

The pseudosteady flow in matrix block can be written as:

$$\phi_1 C_m \frac{\partial P_m}{\partial t} = \frac{\alpha K_1}{\mu}\left(P_f - P_m\right)... \tag{7}$$

The porosity and permeability values are calculated with respect to bulk properties. The reservoir is infinite acting and producing at a constant rate.

Equations (6) and (7) can be expressed in dimensionless form as:

$$\frac{1}{r_D}\frac{\partial}{\partial r_D}\left(r_D \frac{\partial P_D f}{\partial r_D}\right) = \omega \frac{\partial P_D f}{\partial t_{Dw}} + (1-\omega)\frac{\partial P_{Dm}}{\partial t_{Dw}}... \tag{8}$$

$$(1-\omega)\frac{\partial P_{Dm}}{\partial t_{Dw}} = \lambda\left(P_{Df} - P_{Dm}\right)... \tag{9}$$

The solution is obtained by transforming the governing equations to Laplace space and approximating the modified Bessel function:

$$P_{Df} = \frac{1}{2}\left(ln t_{Dw} + 0.80908 + Ei\left(-\frac{\lambda t_{Dw}}{\omega(1-\omega)}\right) - Ei\left(-\frac{\lambda t_{Dw}}{(1-\omega)}\right)\right) + S... \tag{10}$$

Warren and Root model [11] found that the buildup pressure response exhibits two semi log straight lines, Figure 3.

The first straight line corresponds to the transient flow in the fracture media, and the second to the transient flow in the total system. The slopes of those lines are related to the flow capacity of the formation. The vertical separation of the two lines is related to the relative storage capacity of the fracture. They also defined two parameters describing the pressure behavior in a fractured system. The first parameter is the storativity ratio which is the ratio of fractured storage capacity to the total storage capacity of the system. The second parameter is the interporosity flow coefficient which governs the flow form the matrix to the fracture and is related to the heterogeneity of the system.

Figure 4 shows the effect of different values of ω. As ω decreases, the fracture depletes faster and that results in a shorter early straight line.
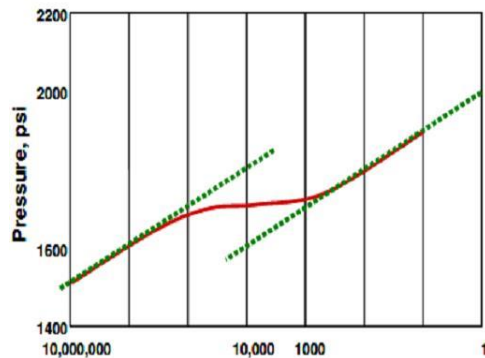

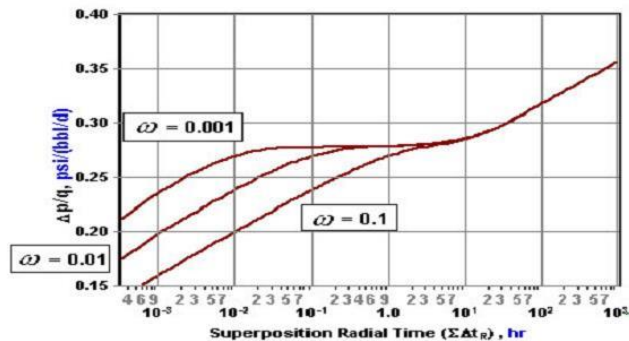Figure 3. Semi log plot for pressure response in NFR

Figure 4. Effect of storativity ratio on the pressure response with pseudosteady state interporosity flow. $\lambda = 10^{-7}$

The effect of various values of λ is shown in Figure 5. As λ decreases, the transfer of fluid from the matrix to the fracture becomes limited and consequently a delay in the pressure plateau. Small λ values are resulted from: (1) a large contrast between fracture and matrix permeability's with a constant α (shape factor), or (2) increasing matrix block sizes with a constant permeability ratio.

During early times, the pressure response is dominated totally by the fracture system behavior; Equation (10) is reduced to:

$$P_{Df} = \frac{1}{2}\left(ln t_{Dw} + 0.80908 + ln\left(\frac{1}{\omega}\right)\right) \tag{11}$$

When the reservoir behaves as homogeneous system $(\omega = 1)$, Equation (11) can be approximated as:

$$P_{Df} = \frac{1}{2}(ln t_{Dw} + 0.80908) \tag{12}$$

A plot of ΔP versus log of the flowing time can give the fracture permeability K_f by calculating the slope of either straight lines, m:

$$m = \frac{162.6 q \mu B_0}{K_f h} \tag{13}$$

Skin can be calculated from the first time straight line by:

$$S = 1.151 \left(\frac{P_i - P_{wf(\Delta t=0)}}{m} - log \left(\frac{K_f}{(\phi_1 C_m + \phi_2 C_f) \mu r_w^2} \right) + 3.23 + log \left(\frac{1}{\omega} \right) \right) \tag{14}$$

Or from the second straight line by removing $log(1/\omega)$ term in Equation (14). In case of the two parallel straight lines are present, the relative storativity ratio can be calculated as follows:

$$\omega = e^{-2.3025 \frac{\Delta P}{m}} \tag{15}$$

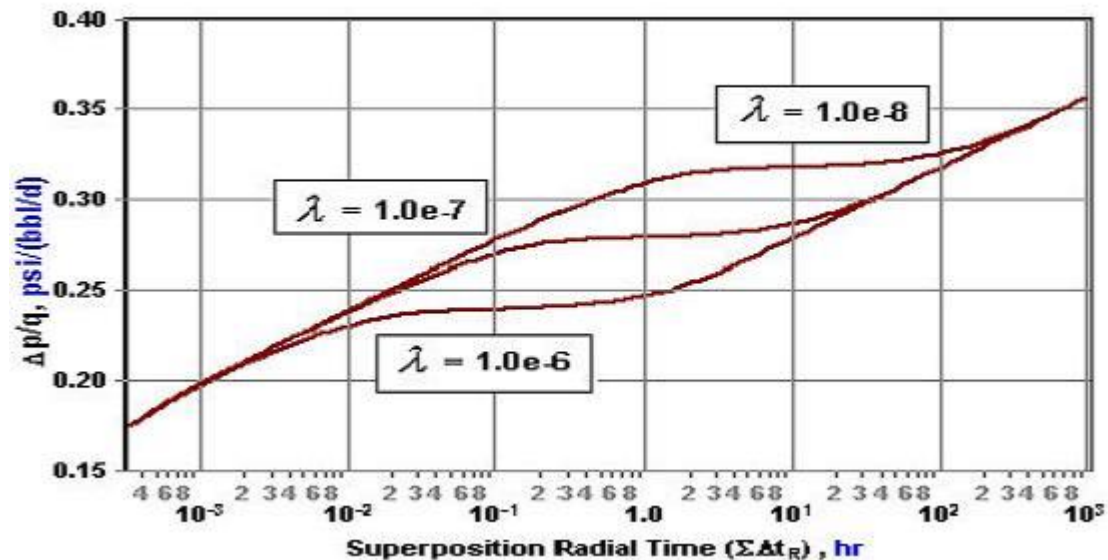where ΔP is the vertical displacement separating the two parallel lines and m is the slope of them.

Figure 5. Effect of interporosity on the pressure response with pseudosteady state interporosity flow ω = 0.01
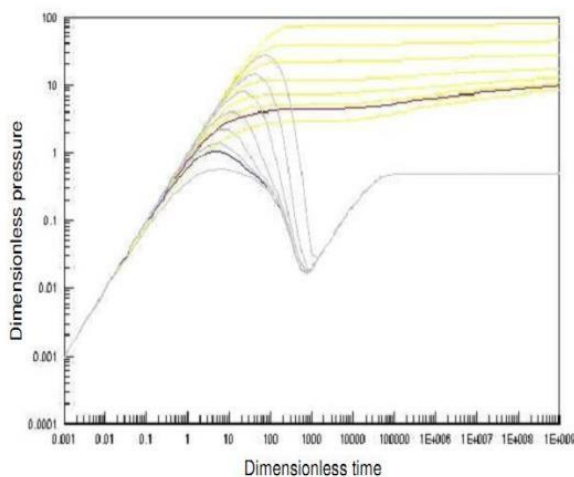
3.4. Odeh model

Figure 6. Derivative type curve for double-porosity reservoir, pseudo-steady state flow

Odeh [12] presented a model to analyze pressure transient tests in dual porosity reservoirs. By analyzing various pressure buildup and drawdown data, he concluded that there is no distinction between the behavior of fractured and homogeneous reservoir. Odeh [12] observed that no parallel straight lines ever appeared on the semi-log plot. This led him to conclude that there is no difference between the equations used to describe the fractured reservoir behavior and these used to describe the unsteady state behavior of homogeneous reservoir. Warren and Root [13] showed in a later publication that Odeh's presentation is a special case in Warren and Root model. The pseudosteady state matrix flow by Warren and

Root [13] has been used to analyze a large number of naturally fractured reservoirs. However, the duration of the transition period in some cases was longer and has less pressure drop. Therefore, transient matrix flow models were developed for this pressure behavior. Bourdet *et al.* [14] developed a set of type curves that is used to analyze well test data from fractured reservoirs. Bourdet *et al.* [15] developed another set of type curves that can be used in analyzing buildup and drawdown tests.

3.5. Direct synthesis technique

Direct synthesis method uses a log-log plot of pressure and pressure derivative data versus time to calculate various reservoirs and well parameters. It uses the pressure derivative technique to identify reservoir heterogeneities. In this method, the values of intersection points, the slopes, and the beginning and ending times of various flow regimes from the log-log plot can be used in analytical equations to calculate the different parameters. High accuracy pressure gauges are needed to make this method reliable. Engler and Tiab [16] developed direct synthesis method to analyze pressure transient tests in dual porosity formation without using type curve matching. They used analytical and empirical correlations to calculate the naturally fractured reservoir parameters.

Advantages of using the direct synthesis technique are:
- Accurate results of reservoir and well parameters.
- Independent verification is frequently possible from a third unique point.
- Very useful when not all flow regimes are observed.

The direct synthesis was applied to different models such as; homogeneous reservoir with skin and wellbore storage [17] and to fractured reservoir in closed systems [18].

4. Field description

This study is conducted on an X field which extends over 7500 acre. The reservoir is a naturally fractured reservoir (carbonate rock) and is characterized by a heterogeneous distribution of porosity and permeability.

The reservoir has low porosity and low permeability matrix blocks surrounded by a tortuous, highly permeable fracture network. As a result, the overall fluid flow in the reservoir strongly depends on the flow properties of the fracture network.

The reservoir has variable thicknesses generally between 60 to 250 ft and it consists of dolomite, and some silt. the reservoir boundary is a closed system, constant compressibility.

This reservoir has a crude oil of 34.8° API gravity and average GOR of 332 SCF/STB. The initial reservoir pressure was 4840 psi and the bubble point pressure is 1536.943 psi. The other reservoir and fluid properties are shown in Table 1. Table 1 presents the main reservoir characteristics.

Table 1. Main reservoir characteristics

Well	Vertical well	Well	Vertical well
Wellbore radius, ft	0.35	Formation temperature, °F	218
Gauge depth,ft	11 099	Reservoir pressure, psi	4 840
Net pay thickness, ft	60	GOR, SCF/STB	332
Porosity, %	10	API	34.8
Water saturation, %	10.3	Sp.gr	0.88
Compressibility, psi^{-1}	5×10^{-6}		

Pressure and temperature profiles and the rate schedule are shown in Figures 7 and 8.

Before the buildup test, the well is allowed to produce at a rate of 4052 BOPD for 11 hrs. After that, the well was shut in for a 24 hrs to allow the pressure to build-up.

Then the well was open to flow at a rate of 9010 BOPD for 3 hrs. Then, the flow rate was reduced to 8333 BOPD for 3 hrs.

Then, the flow rate was reduced to 990 BOPD for 5.5 hrs, for PVT sampling. The second draw-down was at a rate of 3809 BOPD on a choke size 32/64" for 19.5 hrs.
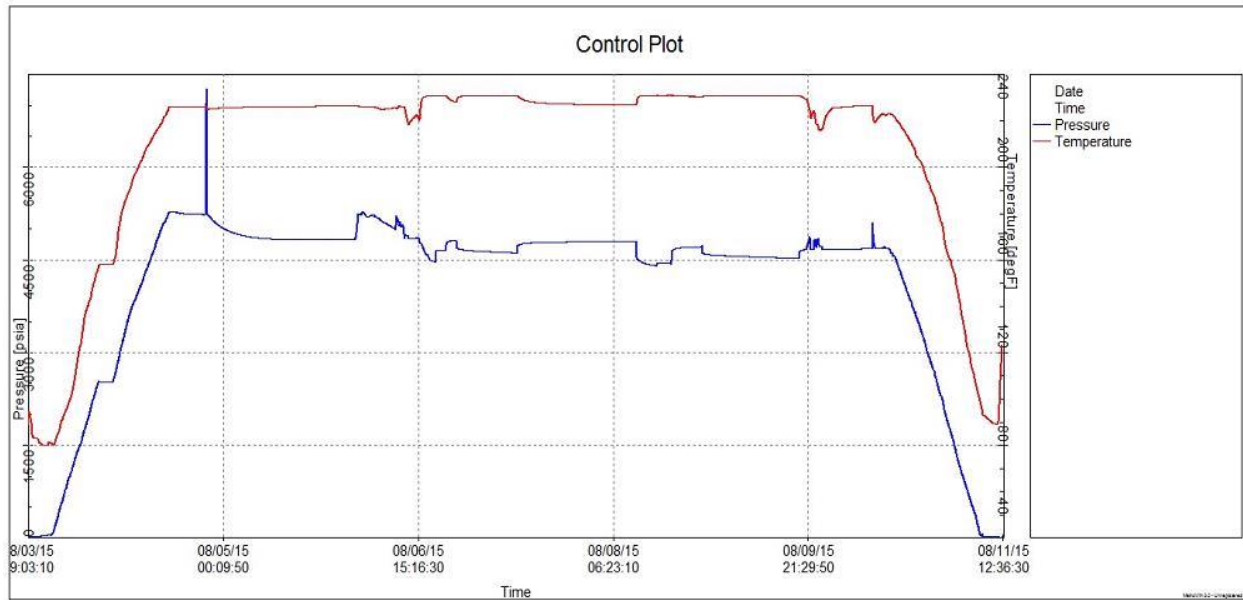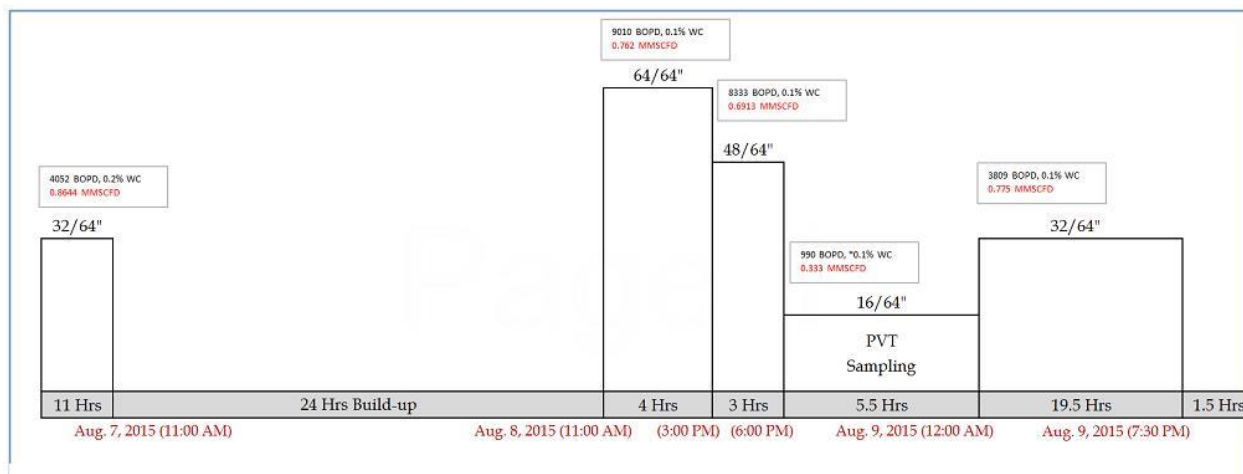
Figure 7. Pressure and temperature profiles

Figure 8. Rate schedule history used in test

5. Results and discussions

This section illustrates the results of applying the three techniques on different cases to analyze the naturally fractured reservoirs. First, the conventional semi-log analysis is applied, if it is possible. Then, the direct synthesis technique results are presented using the developed computer program. Finally, Type curve matching and automatic matching were used to analysis the performance of the subject reservoirs.

5.1. First draw-down period

After running the software, the first step is to import data by entering the pressure data and rate schedule of the test to plot pressure and rate versus time as shown in Figure 9. The second step is the data preparation by entering the well, reservoir and fluid properties mentioned above.
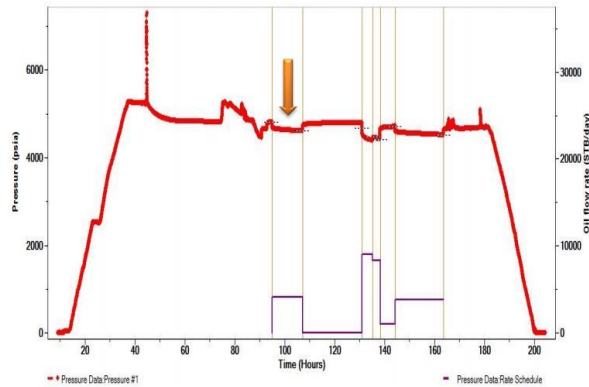
Figure 9. The first draw-down period

The third step is to analyze the data as shown in Figure 10. This figure shows the combined log-log plot of pressure difference and its derivative versus time for a dual – porosity system.

The derivative plot shows a "minimum" or a "dip" on the pressure-derivative curve caused by the interporosity flow during the transition period. The "minimum" is between two horizontal lines; the first represents the radial flow Controlled by the fissures, and the second describes the combined behavior of the double porosity system.
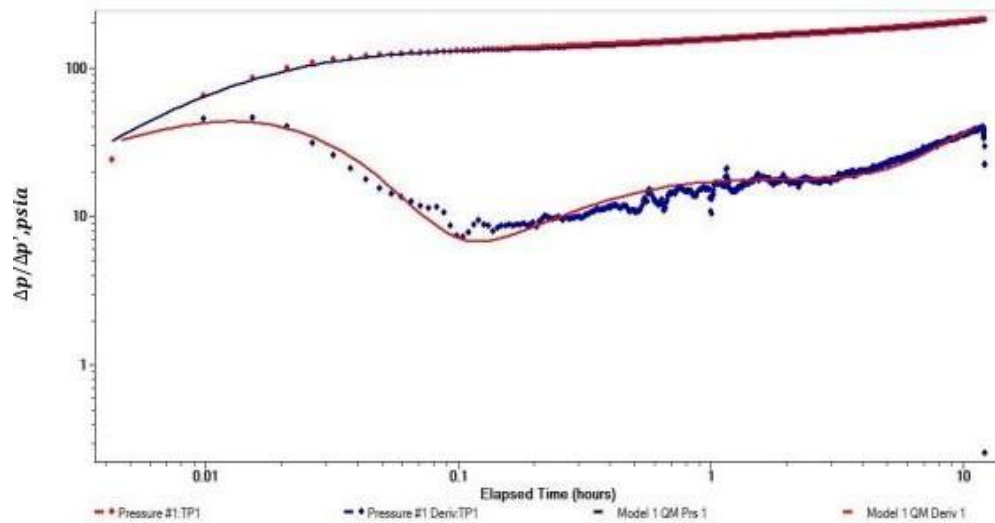

Figure 10. Log-log plot of pressure difference and its derivative versus time

At early time, the typical behavior of wellbore storage effects with the deviation from the 45° straight line to a maximum depects wellbore damage.

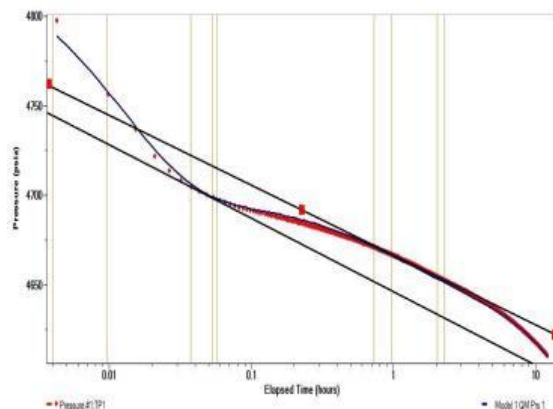## 5.2. Conventional semi-log analysis

Figure 11. Conventional semi log plot

The semi log plot yields an S–shape curve with two parallel straight lines as shown in Figure 11. The two separate straight lines indicate that the double porosity nature of the reservoir. Secondary porosity (fissures), having greater transmissivity and being connected to the wellbore, respond first as described by the first semi log straight line which reflects the tran-sient radial flow through the fractures, and thus its slope is used to determine the system permeability-thickness product.

However, because the fracture storage is small, the fluid in the fracture is quickly deplet-ed with a combined pressure decline in the fractures due to production. This pressure drop in the fracture allows more fluid to flow from the matrix into the fractures, which causes a slowdown in the pressure decline rate.

The matrix starts to discharge the fluid into the fracture throught the "minimum" or the transition zone, until the pressure is stabilized in the two systems and yield the second semi-log straight line.

As for the drawdown, wellbore storage effects may obscure the first semilog straight line. If both semi log straight lines are developed, the permeability –thickness product and the other reservoir parameters can be determined.

Storativity ratio and interporosity flow coefficient are estimated from the slope m of ei-ther straight line. Table 2 represents the results obtained from the conventional semi-log analysis.

Table 2. Semi-log analysis results

k_f,md	272.078
ω	0.07532
λ	3.59×10^{-6}
S	-2.4496

5.3. Direct synthesis technique

The pressure difference and its derivative curves are shown on Figure 12 with the charac-teristic points and line labelled.

From the plot:

$(\Delta p'w)_{r1} = 17.97 psi$ $(t^*\Delta p'w)_{min} = 7.13 psi$

$t_{min} = 0.13 hrs$ $t_{e1} = 0.051 hrs$

$t_{b2} = 0.97$ $t_{r1} = 0.037 hrs$

$t_{r2} = 1.3 hrs$ $(\Delta pw)_{r1=} 116.13\ psi$

$(\Delta pw)_{r2} = 160.2 psi$ $(t^*\Delta p'w)_{r2} = 17.97 psi$

$(t^*\Delta p'w)_{r1} = 17.97\ psi$

where r_1 and r_2 stand for the early (fracture) and late (total system) radial flow; te_1 is the end time of the early radial flow line, and tb_2 is the beginning time of the late radial flow line.

The log-log plot shows a unique behavior of a naturally fractured reservoir. Different res-ervoir parameters can be calculated by direct synthesis technique.

The fracture permeability can be calculated from the early and late radial flow lines:

$$k_f = \frac{70.6q\mu\beta_o}{h(\Delta p'w)_{r1}} = \frac{70.6x4052x0.817x1.18}{60x17.97} = 256.2\ md$$

Two methods were applied to calculate the storativity coefficient (ω):

➤ From minimum to radial pressure derivative ratio:

$$\omega = 0.15866\left(\frac{(\Delta p'wfxt)_{min}}{(\Delta p'wfxt)_r}\right)0.54653\left(\frac{(\Delta p'wfxt)_{min}}{(\Delta p'wfxt)_r}\right)^2 = 0.15866\left(\frac{7.13}{17.97}\right) + 0.54653\left(\frac{7.13}{17.97}\right)^2 = 0.148$$

➤ From minimum, early radial, or radial time ratio:

$$\omega = 0.19211\left(\frac{5t_{min}}{tb_2}\right) + 0.80678\left(\frac{5t_{min}}{tb_2}\right)^2 = 0.19211\left(\frac{5*0.13}{0.97}\right) + 0.80678\left(\frac{5*0.13}{0.97}\right)^2 = 0.4909$$

Four methods were employed to determine the interporosity flow coefficient parameter (λ):

➤ From the characteristic times:

$$\lambda = \frac{s_t\mu r_w^2}{0.0002637k_f}\frac{\omega ln\ ^1/_\omega}{t_{min}} = \frac{0.1x4.8623x10^{-6}x0.817x0.35^2}{0.0002637x256.2}\ x\ \frac{0.148xln\left(\frac{1}{0.148}\right)}{0.13} = 2.2\times10^{-6}$$

$$\lambda = \frac{s_t\mu r_w^2}{0.0002637k_f}\frac{\omega(1-\omega)}{50t_{e1}} = \frac{0.1x4.8623x10^{-6}x0.817x0.35^2}{0.0002637x256.2}x\frac{0.148(1-0.148)}{50x0.051} = 3.6x10^{-8}$$

$$\lambda = \frac{s_t \mu r_w^2}{0.0002637 k_f} \frac{5(1-\omega)}{t_{b2}} = \frac{0.1x4.8623x10^{-6}x0.817x0.35^2}{0.0002637x256.2} \; x \; \frac{5x(1-0.148)}{0.97} = 3.15x10^{-6}$$
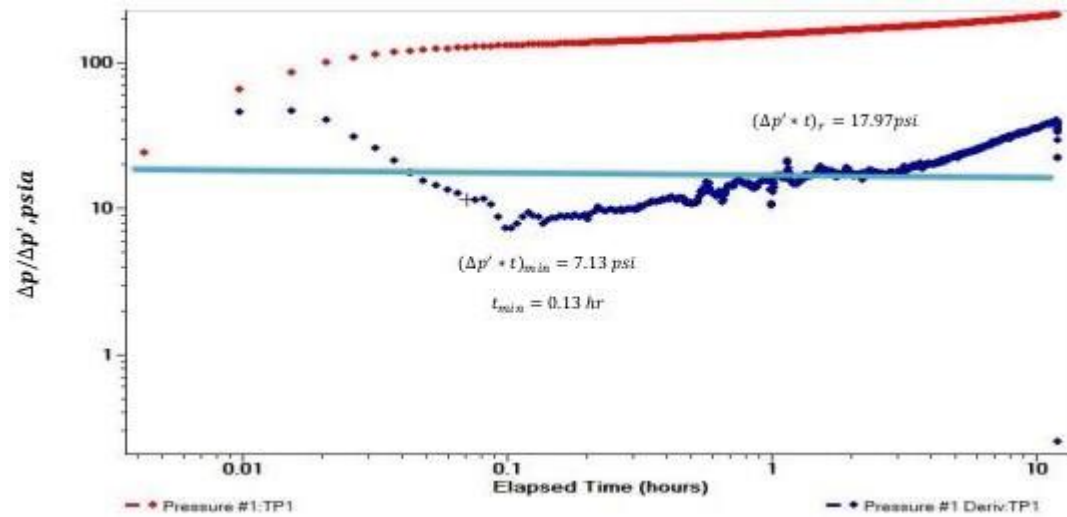

Figure 12. Pressure difference and its derivative plot

➢ From the minimum coordinates:

$$\lambda = \frac{42.5hs_t r_w^2}{q\beta_o}\left(\frac{\Delta p_{wf'*t}}{t}\right)_{min} = \frac{42.5x60x0.1x4.8623x10^{-6}x0.35^2}{4052*1.18} \; x \; \left(\frac{7.13}{0.13}\right) = 2.33x10^{-6}$$

The skin factor is calculated from a convenient point during early or late radial flow period:

➢ From the early time pressure and pressure derivative data:

$$s_m = \frac{1}{2}\left[-ln\left(\frac{k_f t_{r1}}{s_t \mu r_w^2}\frac{1}{\omega}\right)7.43\right] = \frac{1}{2}\left[\frac{116.13}{17.97} - ln\left(\frac{256.2x0.037}{0.1x4.8623x10^{-6}x0.817x0.35^2} \; x \; \frac{1}{0.15}\right) + 7.43\right] - 3.21$$

➢ From the late time pressure and pressure derivative data:

$$s_m = \frac{1}{2}\left[\left(\frac{\Delta p_{wf}}{\Delta p'wf*t}\right)_{r2} - ln\left(\frac{k_f t_{r2}}{s_t \mu r_w^2}\right) + 7.43\right] = \frac{1}{2}\left[\frac{160.2}{17.97} - ln\left(\frac{256.2x1.3}{0.1x4.8623x10^{-6}x0.817x0.35^2}\right)7.43\right] = -2.8$$

Table 3 presents the results of analyzing well test data from naturally fracture reservoir by the developed program based on direct synthesis technique. Table 4. presents the results which are obtained from the type curve matching analysis.

Table 3. Direct synthesis technique results

$K_{f,md}$	256.2
ω	0.148
λ	$3.15.10^{-6}$
S	-2.8

Table 4. Type curve matching analysis result

$K_{f,md}$	279.9
ω	0.001
λ	$4.37.10^{-6}$
S	-2.665

5.4. Commercial software matching

A commercial software (Pan-System) was used for analyzing well test data from naturally fractured reservoir. Figure 14 depects that the response of pressure build-up and its derivative for the well is divided into six periods.

Period (1) is a unit-slope region which indicates the wellbore storage (WBS) impact. It should be noted that the WBS effect lasts for only 0.01 hour assuming negligible (or controlled) WBS period due to the low compressibility of the crude. This should be confirmed and assured by utilizing down-hole shut-in tool (DHST) to mitigate the WBS impact. In this case, a slight change in the pressure derivative trend would be expected.
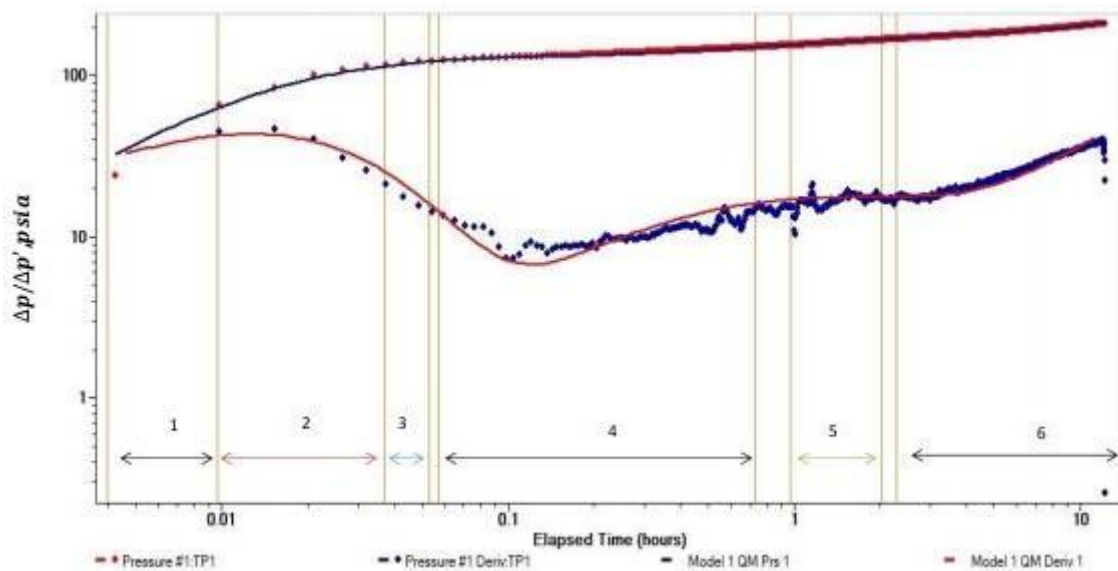
Figure 14. Typical pressure derivative and its periods

DHST is very important to avoid masking of later periods.

Period (2) is the skin hump period. It will be analyzed to estimate the skin factor (S) (which is related to damaged zone or stimulated zone).

Period (3) period refers to zero slope line which reflects the radial flow in the fracture. From this period, permeability and reservoir pressure can be estimate.

Period (4) period can be considered as an extension of IAFR period. The presence of the dual-porosity system (Φsec) can be detected from this period. This period may (or may not) exist based on the nature of rock petrography and pores-system of the formation.

This period is called the minimum and at which the interflow occurs between the fracture and the matrix. From this period, the main important two factors which describe the fluid flow and behavior of dual porosity system can be estimated.

The first parameter is the storativity ratio (ω) which describes the fracture porosity as a percentage of the matrix porosity. The duration and depth of the depression are linked by the value of ω; a small value produces a long and therefore deep transition. The second parameter is the interporosity flow coefficient (λ) which describes the fluid transfer between the matrix and fractures, and defines the position of the time axis of the transition regime.

Period (5) represents the homogenous behavior of both media when recharge from the least permeable medium (matrix) is fully established and pressure is equalized.

Period (6) represents the effect of boundary condition which is a closed system (unit slope on the pressure derivative). From this period, the distance to boundary and drainage area can be calculated.

Table 5 presents the model selected from the commercial software. Table 6 presents the main model parameters. Table 7 presents the reservoir and boundary parameters.

Table 5. The model selected from the software

Model option	Standard model
Well	Vertical
Flow regime	PSS
Reservoir	Dual porosity
Boundary	Closed system

Table 6. Main model parameter

$C_s, bll/psi$	0.018
V, bll	2596.79
$k/_\mu, md/cp$	322.813
$k_{f,md}$	263.869
$kh, md.ft$	15832.14
S	-2.5973

559

Table 7. Reservoir and boundary parameters

ω	0.083
λ	$4.89 \cdot 10^{-6}$
$A, acre$	104.171
$OOIP, MMSTB$	3.689
$p_i psi$	4 821.56
dp_s, psi	-90.573
R_{inv}, ft	1 715.814
$F.E$	1.4002
Ca	30.8815
L, ft	1 065.09

The standard model is selected as a dual porosity pseudo steady state to the reservoir due to a transformation between the least permeable media (matrix) and the high permeable media (fissures), and it is mathematically equivalent to the pseudo steady-state solution, i.e., the Warren and Root model, and selected as closed system for the reservoir boundary.

After setting the model, the main model parameters can be obtained. These are wellbore storage coefficient, skin factor, storativity ratio, interporosity flow coefficient and permeability thickness product.

Wellbore storage coefficient (C) which is very small value due to using down-hole shut-in tool ($DHST$) which is necessary to mitigate wellbore storage (WBS) effect and hence obtaining valuable pressure curve.

Skin factor has a value of -2.5973 which indicates that there is no damage around the wellbore (i.e., stimulation process is successful).

Permeability - thickness product ($K.h$) has a value of 15832.14 $md.ft$. This is very high value due to the higher permeability of the fracture.

One of the well test analysis results is the initial reservoir pressure (Pi), which has a value of 4821 psi, Pi is necessary for estimating the productivity index ($P.I$) and inflow performance relationship (IPR).

Pressure drop due to skin (dps), which equal to -90.573 psi, is a small value caused by lower value of skin effect (S). This means that there is no additional pressure drop due to damage of the formation around the wellbore which will give a higher production rate and higher productivity index.

Storativity ratio (ω) is related to the fracture porosity. A typical range of ω is from 0.1 to 0.001. In this work the value of ω is 0.0832 which means that the value of ω in this reservoir is a small value as compared to the typical one, i.e., large and deep transition period. This is because the fracture porosity is low as compared to the matrix porosity which takes small time to deplete the fracture due to lower porosity.

The pressure drop in the fracture which permits the matrix to discharge flow in to the fracture and the pressure stabilization occurs slowly (the duration and depth of the depression are linked by the value of ω).

By assuming that the fracture compressibility is equal to the matrix compressibility, the fracture porosity can easily be obtained from storativity ratio using the following equation:

$$\emptyset f = \left(\frac{\omega}{1-\omega}\right)\emptyset \qquad (15)$$

$$\emptyset f = \left(\frac{0.0832}{1-0.0832}\right)0.1 = 0.009$$

So, the storativity ratio is very important in understanding the performance of the dual porosity system and in finding the fracture porosity.

Interporosity flow coefficient (λ); is related to the fracture permeability. In this case the value of λ is 4.89×10^{-6}. This means that higher value of interporosity flow coefficient moves the dipression to the left side of the plot. This is clearly shown in Figure 14.

This occurs because the lower the value of λ, the lower the value of matrix permeability as compared to the fracture permeability which leads to delay the minimum from disappears and moves to the right of the plot.

The Interporosity flow coefficient λ value defining the position of the time axis of the transition regime. As shown on Figure 14, the shape of the "minimum" takes a "U – shape"

and this is due to a non-restricted interporosity flow coefficient (i.e., there is a low skin between the matrix face and the fracture). The fluid flows from the matrix system into the fractures under pseudo –steady-state conditions with the fracture acting like conduits to the wellbore (i.e., Warrenn and Root model).

Distance to boundary (L) which has a value of 1065.09 *ft.*, effects on the pressure derivative curve. For the case under steady, the OOIP has a value of 3.684MMSTB, and the drainage area has a value of 104.171 acre c. It should be noted that the test time should be long enough to reach the boundary of the reservoir.

Table 8 shows a comparison among the three techniques used in analyzing well test data in naturally fractured reservoirs.

The results show that, conventional semi-log technique gives an accurate permeability only, and type curve matching gives inaccurate matching during the transition period and leads to erroneous values of ω and λ. The direct synthesis gives accurate results of nearly all the reservoir parameters except permeability.

Table 8. Comparison of results

Parameter	Conventional semi-log	Direct synthesis technique	Type curve matching
k_f, md	272.078	256.2	279.9
ω	0.075	0.148	0.001
λ	$3.59.10^{-6}$	$3.15.10^{-6}$	$4.37.10^{-6}$
s	-2.449	-2.8	-2.66

The results of direct synthesis were used as inputs into a model to generate pressure vs. time data as shown on Figure 15. A comparison between the direct synthesis results and the software matching results with the actual field data are shown on Figure 16.

The direct synthesis technique gives a good match during the early time and the transition flow period.

However, the software match shows poor fit during the early and the transition flow period and a good match during the late time period.

The difference between the fracture permeability values obtained from the two techniques is directly related to the matching quality during the radial total system period.
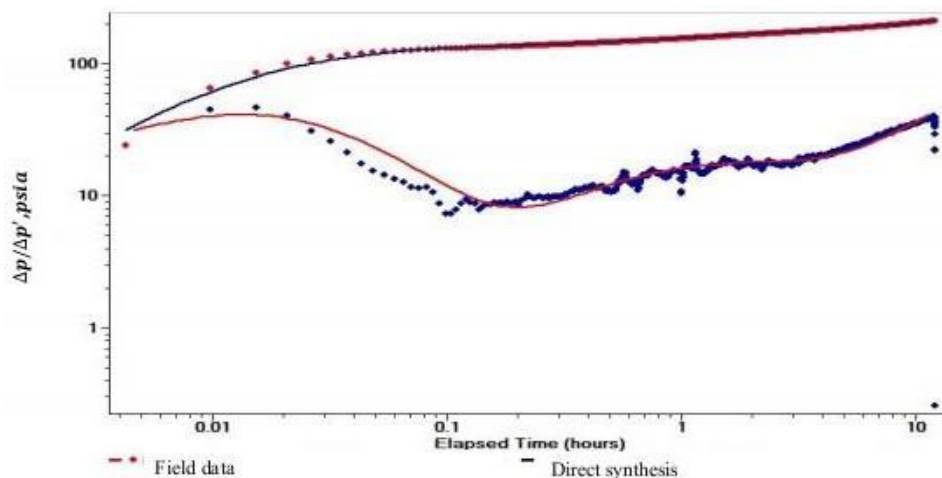

Figure 15. Direct synthesis model

The difference in the matching of the two techniques during the transition period gives different values of the dimensionless storage coefficient.
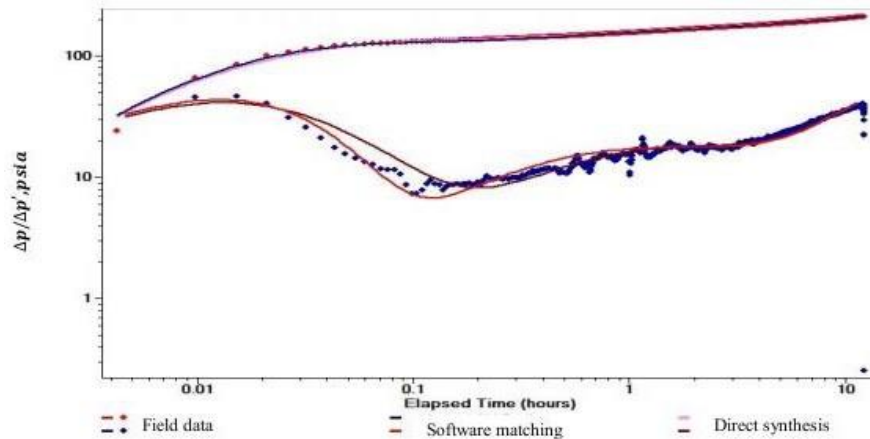
Figure 16. Comparison between direct synthesis results and software matching

6. Conclusions

From this work, can conclude that well test pressure response should exhibit a complete flow regimes (fracture radial flow, transition flow, and system radial flow) in order to obtain reliable estimates of storativity ratio and interporosity flow coefficient. The use of pressure derivatives plots improved the analysis of well test data. Different flow regimes can be identified on the derivative log-log plots. Type curve matching can give good results in case of all of the flow regimes are identified.

Tiab direct synthesis technique gives direct estimates of all reservoir parameters and fracture characteristics by using a log-log plot of pressure difference and its derivative data without type curve matching. In case of high wellbore storage, the conventional semi-log analysis gives inaccurate results and not all naturally fractured reservoir parameters can be estimated.

The developed computer program gives accurate results as compared to commercial software matching, conventional semi-log analysis, and the type curve matching. Interporosity flow coefficient obtained from well test analysis can also be used to estimate the fracture permeability provided that the shape factor and the matrix permeability values are known.

When all flow regimes are not identified, type curve matching gives incorrect reservoir and fracture parameters. However, the direct synthesis technique gives an accurate result of the naturally fractured reservoir parameters and fracture properties.

Nomenclature

A	Area, ft^2
AOFP	Absolute open flowing potential, STB
B	Formation volume factor, res bbl/STB
C	Wellbore storage coefficient, bbl/psi
C_A	Shape factor
C_t	Total compressibility, psi^{-1}
C_{dw}	Dimensionless wellbore storage
DHST	Down-Hole Shutting Tool
d_{p_s}	Pressure drop due to skin, Psi
F.E	Flow efficiency
GOR	Gas Oil Ratio, SCF/STB
h	Total formation thickness, ft
IPR	Inflow performance relationship
J	Productivity index, $STB/D/psi$
k_f	Fracture permeability, md
$k.h$	Permeability-thickness product, $md.ft$
k_m	Matrix permeability, md
L	Distant to boundary, ft
l_{ma}	Fracture spacing, ft

N_P	Cumulative oil production, STB
OOIP	Original oil in place, STB
p	Pressure, psi
P_D	Dimensionless pressure
P_{wD}	Dimensionless bottom-hole pressure
P_{int}	Initial pressure, psi
P_{wf}	Bottom-hole flowing pressure, psi
P_D'	Dimensionless pressure derivative
P_{wD}'	Dimensionless bottom-hole pressure derivative
Δp	Pressure difference, psi
$\Delta p'$	Pressure difference derivative, psi
q_t	Total flow rate, STB/D
r_e	Reservoir outer radius, ft
r_w	Wellbore radius, ft
S	Skin factor
t	Test time, hr
t^D	Dimensionless time
WOR	Water oil ratio
w_f	Fracture width, ft
ω	Dimensionless storage coefficient
λ	Interporosity flow coefficient
ρ_f	Natural fracture density, $frac/ft$
μ	Viscosity, Cp
$\emptyset$	Porosity

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