Well Testing Data Interpretation for Oil Wells

Nasir Atallah Houady
College of Petroleum Engineering, Al-Ayen University,
Thi-Qar, Iraq

Muhammad Ali Najm
College of Petroleum Engineering, Al-Ayen University,
Thi-Qar, Iraq

Ali Abdul Hussein
College of Petroleum Engineering, Al-Ayen University,
Thi-Qar, Iraq

Baqer Jaafar Wasil
College of Petroleum Engineering, Al-Ayen University,
Thi-Qar, Iraq

Saif Majed Odeh
College of Petroleum Engineering, Al-Ayen University,
Thi-Qar, Iraq

Mortada Jabbar Dighem
College of Petroleum Engineering, Al-Ayen University,
Thi-Qar, Iraq

Ahmed Giad Abd
College of Petroleum Engineering, Al-Ayen University,
Thi-Qar, Iraq

Adel Ameer Abdel Hussein
College of Petroleum Engineering, Al-Ayen University,
Thi-Qar, Iraq

2021-2022

Abstract— The objective of this project, as the title suggests, is to develop a basic understanding of well testing methodology and the associated interpretation techniques. To achieve this, a review of some of the fundamental basics of petroleum engineering is necessary in order to develop the essential principles required later on. The project will cover the necessary requirements for different test scenarios and the objectives of testing with an emphasis on data acquisition. In this research, we will learn the different types of well testing, Productivity index (J), Skin factor, and the type of Flow Regimes. Then the research will concentrate on the interpretation models; Early, middle, and late time models. The last section includes a case study and shows the calculations and steps of interpretation.

The introduction to well test interpretation will be kept in a simple form, avoiding complicated mathematical analysis where possible. Well Testing is different from most techniques as it requires the reservoir to be in a dynamic state as opposed to a static state in order to trigger the responses needed for mathematical modeling.

Well testing is a costly operation involving significant resources and logistics. As such, management require detailed justification before giving approval to any testing budget and it is often critical to highlight a return on the investment. Accurate well testing data can reveal extremely valuable information which in turn leads to efficient reservoir management.

Keywords—Well testing type, well testing interpretation, pressure derivative.

I. INTRODUCTION

During a well test, the response of a reservoir to changing production (or injection) conditions is monitored. Since the response is characteristic of the properties of the reservoir, it is possible in many cases to infer reservoir properties from the response. Well test interpretation is therefore an inverse problem in that model parameters are inferred by analyzing model response to a given input. In most cases of well testing, the reservoir response that is measured is the pressure response. Hence in many cases well test analysis is synonymous with pressure transient analysis. The pressure transient is due to changes in production or injection of fluids; hence we treat the flow rate transient as input and the pressure transient as output.

Thus, in most cases, the design and the interpretation of a well test is dependent on its objectives. The objectives of a well test usually fall into three major categories [1]:

Reservoir Evaluation:

To reach a decision as to how best to produce a given reservoir, we need to know its deliverability, properties, and size. Thus, we will attempt to determine the reservoir conductivity (kh, or permeability-thickness product), initial reservoir pressure, and the reservoir limits (or boundaries). At the same time, we will sample the fluids so that their physical properties can be measured in the laboratory. Also, we will examine the near wellbore condition in order to evaluate whether the well productivity is governed by wellbore effects (such as skin and storage) or by the reservoir at large. The conductivity (kh) governs how fast fluids can flow to the well. Hence it is a parameter that we need to know to design well spacing and number of wells. If conductivity is low, we may need to evaluate the cost-effectiveness of stimulation. Reservoir pressure tells us how much potential energy the reservoir contains (or has left) and enables us to forecast how long the reservoir production can be sustained. Pressures in the vicinity of the wellbore are affected by drilling and production processes, and may be quite different from the pressure and the reservoir at large.

Reservoir Management:

During the life of a reservoir, we wish to monitor performance and well condition. It is useful to monitor changes in average reservoir pressure so that we can refine our forecasts of future reservoir performance. By monitoring the condition of the wells, it is possible to identify candidates for workover or stimulation. In special circumstances, it may also be possible to track the movement of fluid fronts within the reservoir.

Reservoir Description:

Geological formations hosting oil, gas, water and geothermal reservoirs are complex, and may contain different rock types, stratigraphic interfaces, faults, barriers and fluid fronts. Some of these features may influence the pressure transient behavior to a measurable extent, and most will affect the reservoir performance. To the extent that it is possible, the use of well test analysis for the purpose of reservoir description will be an aid to the forecasting of reservoir performance. In addition, characterization of the reservoir can be useful in developing the production plan.

II. TYPES OF WELL TESTING [2]

A. Drill Stem Test (DST)

A drill stem test is a test which uses a special tool mounted on the end of the drill string. It is a test commonly used to test a newly drilled well, since it can only be carried out while a rig is over the hole. In a DST, the well is opened to flow by a valve at the base of the test tool, and reservoir fluid flows up the drill string (which is usually empty to start with). A common test sequence is to produce, shut in, pro- duce again and shut in again. Drill stem tests can be quite short, since the positive closure of the downhole valve avoids wellbore storage effects (described later). Analysis of the DST requires special techniques, since the flow rate is not constant as the fluid level rises in the drill string. Complications may also arise due to momentum and friction effects, and the fact that the well condition is affected by recent drilling and completion operations may influence the results.

B. MDT - Mini DST

It is possible to test the fluids in an open hole or cased hole (perforations h=30 cm) by setting packers above and below the interval of interest. This way a well interval is isolated and the formation fluids are allowed to flow into the well by using a downhole pump. The tools can be run in hole by wireline or drill pipes. The formation pressure and fluid mobility (thus permeability) can be measured and the formation fluids sampled.

A mini – DST can have a single probe or a dual packer configuration. The use of straddle packers enables a one - meter interval to be isolated both in open or cased hole. A downhole pump allows withdrawal of the fluid into the wellbore. The drawdown and buildup pressure measurements are acquired with high - resolution quartz gauges devices. They can be used to collect PVT samples. When combined with downhole fluid analyzers, they can also provide information about in - situ fluid characteristics

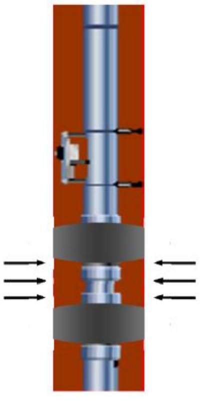

Figure II. Mini DST

C. Standard production test

DRAWDOWN PERIOD

In a drawdown test, the well is static, stable and opened to flow. For the purposes of traditional analysis, the flow rate is supposed to be constant.

Many of the traditional analysis techniques are derived using the drawdown test as a basis. However, in practice, a drawdown test may be rather difficult to achieve under the intended conditions. In particular: (a) it is difficult to make the well flow at constant rate, even after it has (more-or-less) stabilized, and (b) the well condition may not initially be either static or stable, especially if it was recently drilled or had been flowed previously. On the other hand, drawdown testing is a good method of reservoir limit testing, since the time required to observe a boundary response is long, and operating fluctuations in flow rate become less significant over such long times.

BUILDUP PERIOD

A well which is already flowing (ideally at constant rate) is shut in, and the downhole pressure measured as the pressure builds up. Analysis of a buildup test often requires only slight modification of the techniques used to interpret drawdown test. In a buildup test, a well which is already flowing (ideally at constant rate) is shut in, and the downhole pressure measured as the pressure builds up (Fig. 1-3). Analysis of a buildup test often requires only slight modification of the techniques used to interpret constant rate drawdown test. The practical advantage of a buildup test is that the constant flow rate condition is more easily achieved (since the flow rate is zero)

Buildup tests also have disadvantages

- It may be difficult to achieve the constant rate production prior to the shut in. In particular, it may be necessary to close the well briefly to run the pressure tool into the hole.
- Production is lost while the well is shut in.

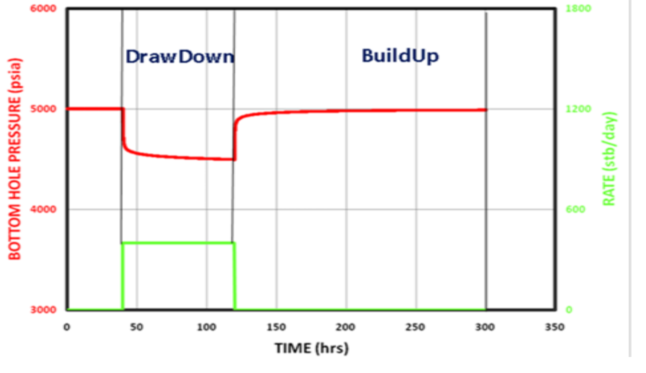

Figure 2. Drawdown and build up periods

D. Interference Test

In an interference test, one well is produced and pressure is observed in a different well (or wells). An interference test monitors pressure changes out in the reservoir, at a distance from the original producing well. Thus, an interference test may be useful to characterize reservoir properties over a greater length scale than single-well tests. Pressure changes at a distance from the producer are very much smaller than in the producing well itself, so interference tests require sensitive pressure recorders and may take a long time to carry out. Interference tests can be used regardless of the type of pressure change induced at the active well (drawdown, buildup, injection or falloff). [3]

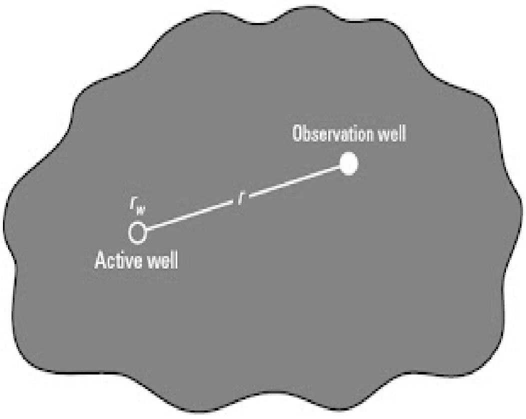

Figure 3. interference test

III. Chapter Two: Interpretation Review

A. Skin factor

Skin factor is a constant that is used to adjust the flow equation derived from the ideal condition (homogeneous and isotropic porous media) to suit the applications in nonideal conditions. It is an empirical factor employed to consider the lumped effects of several aspects that are not considered in the theoretical basis when the flow equations were derived.

What is skin effect?

It is not unusual for materials such as mud filtrate, cement slurry, or clay particles to enter the formation during drilling, completion, or workover operations and reduce the permeability around the wellbore. This effect is commonly referred to as a wellbore damage and the region of altered permeability is called the skin zone. This zone can extend from a few inches to several feet from the wellbore. Many other wells are stimulated by acidizing or fracturing, which in effect increase the permeability near the wellbore. Thus, the permeability near the wellbore is always different from the permeability away from the well where the formation has not been affected by drilling or stimulation.

Those factors that cause damage to the formation can produce additional localized pressure drop during flow. This additional pressure drop is commonly referred to as Δpskin. On the other hand, well stimulation techniques will normally enhance the properties of the formation and increase the permeability around the wellbore, so that a decrease in pressure drop is observed. The resulting effect of altering the permeability around the well bore is called the skin effect.

$$S = \left(\frac{k}{k_s} - 1\right) ln \frac{r_s}{r_w}. \qquad \text{……………………..(1)}$$

$$\Delta p_{skin} = \frac{q \mu B}{2 \pi h k} s \qquad \text{……………………....(2)}$$

where s is called the skin factor and defined as:

Positive Skin Factor, s > 0

When a damaged zone near the wellbore exists, kskin is less than k and hence s is a positive number. The magnitude of the skin factor increases as kskin decreases and as the depth of the damage rskin increases.

Negative Skin Factor, s < 0

When the permeability around the well kskin is higher than that of the formation k, a negative skin factor exists. This negative factor indicates an improved wellbore condition.

Zero Skin Factor, s = 0

Zero skin factor occurs when no alternation in the permeability around the wellbore is observed, i.e., kskin = k.

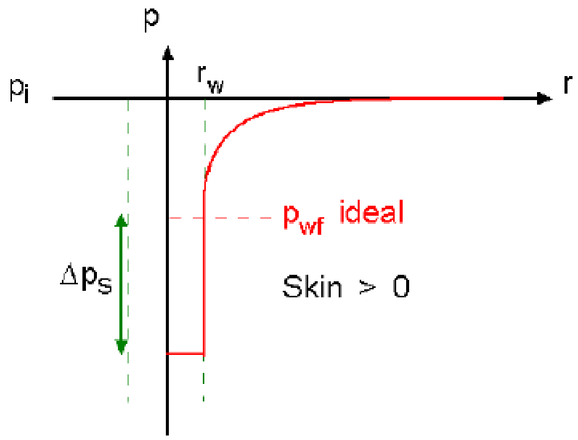

Figure 3. Positive skin

B. Productivity index (J)

The productivity index is a measure of the well potential or ability to produce and is a commonly measured well property1.

The productivity index can be mathematically expressed as the ratio of volumetric flow produced by a well (bbl/day) to the pressure loss between reservoir and bottomhole (psi).

Productivity Index = J = Q/(Pe-Pwf) ………………..(3)

J = Productivity Index, STB/day/psi

Q = Surface flowrate at standard conditions, STB/D

Pe = External boundary radius pressure, psi

Pwf = Well sand-face mid-perf pressure, psi

Over a longer timescale as the oil and gas reservoirs are depleted, the reservoir pressure drops down. Hence flow and pressure loss also change. But this depletion can only be considered over a timescale of a few years. For shorter time scales, the hydrocarbon fluid flow as well as the reservoir pressure can be considered to be constant. This is known as pseudo steady state for the producing well.

C. Radius of investigation

Radius of investigation represents the distance that transient effects have traveled into the reservoir.

A pressure transient is created when a disturbance such as a change in rate occurs at a well. As time progresses, the pressure transient advances further and further into the reservoir. This concept is not theoretically rigorous, but is adequate for practical purposes. Theoretically, when a pressure disturbance is initiated at the well, it will have an immediate effect, however minimal, at all points in the reservoir. At a certain distance from the well, however, the effect of the disturbance will be so small as to be unmeasurable. The furthest distance at which the effect is detectable is called the radius of investigation, rinv.

The figure below illustrates the basic concept of radius of investigation using a plot of pressure versus distance into the reservoir.

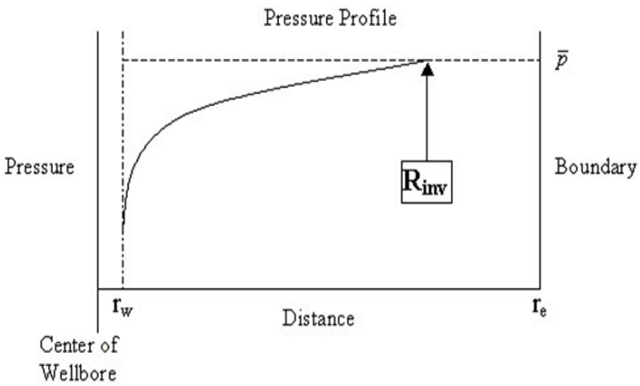

Figure 4. *Radius of investigation*

The radius of investigation is calculated using the following equation:

$$r_d = 1.5\sqrt{\frac{k}{\mu c_t \phi}t} \qquad \textbf{.............(4)}$$

D. Time to reach pseudo- steady state

A situation that is changing slowly enough that it can be considered to be constant. For example, atmospheric turbulence has a fast response time, while the atmospheric boundary layer depth that controls the turbulence grows with a slower timescale.

In all of our discussions on well performance, we assumed that *Steady-State Conditions* (time-invariant conditions) were occurring in the reservoir. Steady-state implies that nothing changes in the drainage volume with time or production. This simplification is not appropriate for most real production situations. the more common *Transient Flow Conditions* (time-dependent conditions) that occurs in the reservoir. [4]

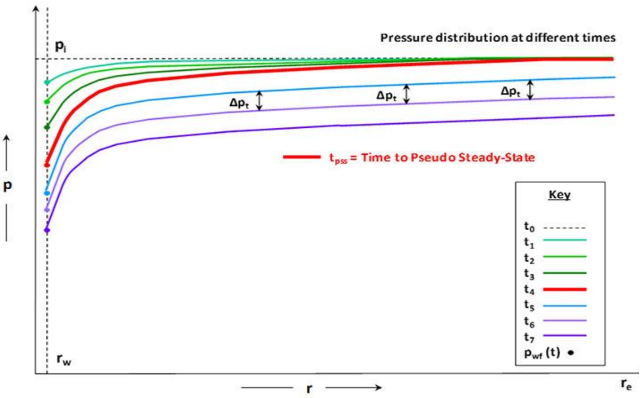

Figure 5. Time to reach pseudo- steady state

In this figure, the early-time pressures (green curves) form a pressure disturbance that over time propagates outward toward the external radius of the drainage volume, re. At some point in time, this pressure disturbance reaches the external boundary (bold red curve). This time is referred to as the time to pseudo steady-state, tpss . Pseudo steady-state is a flow regime which is defined by a uniform pressure drop from one time to the next, ΔPt , that is equal everywhere in the drainage volume.

Estimating the time, it would take to reach the boundaries of the drainage area by rearranging the radius of investigation equation as follows:

$$t_s = \frac{1}{2.25}\frac{\mu c_t \phi r_e^2}{k} \qquad \textbf{...............(5)}$$

E. Flow Regimes

Flow in a reservoir is often characterized as being one of two types: transient or boundary-dominated.

Transient flow takes place during the early life of a well, when the reservoir boundaries have not been felt, and the reservoir is said to be infinite-acting. During this period, the size of the reservoir has no effect on the well performance, and reservoir size cannot be determined except to deduce minimum contacted volume. Since the boundary of the reservoir has not been contacted during the transient flow period, static pressure at the boundary remains constant.

Pressure transient analysis/well testing theory relies heavily on the assumption that the well flows at a constant rate. Several terms are often used when describing flow from a well at constant rate:

- Transient Flow — Pressure transient migrates outward from the well without encountering any boundaries.
- Steady State Flow — Pressure transient has reached all of the boundaries but the static pressure at the boundary does not decline. This is often called “constant pressure boundary”.
- Pseudo-Steady State Flow — Pressure transient has reached all of the boundaries and the static pressure is declining at the boundary and uniformly throughout the reservoir.
- Boundary-Dominated Flow — Pressure transient has reached all of the boundaries and the static pressure is declining at the boundary, but not uniformly because the flow rate is not constant. This is also often called “tank-type flow”.

The following schematic chart presents the pressure distribution in the reservoir for a constant flow rate. The red lines present the transient portion and the blue lines the pseudo-steady state portion. The yellow line indicates the transition from transient to pseudo-steady state. Note that the vertical distance between each line is uniform from the near wellbore to the boundary.

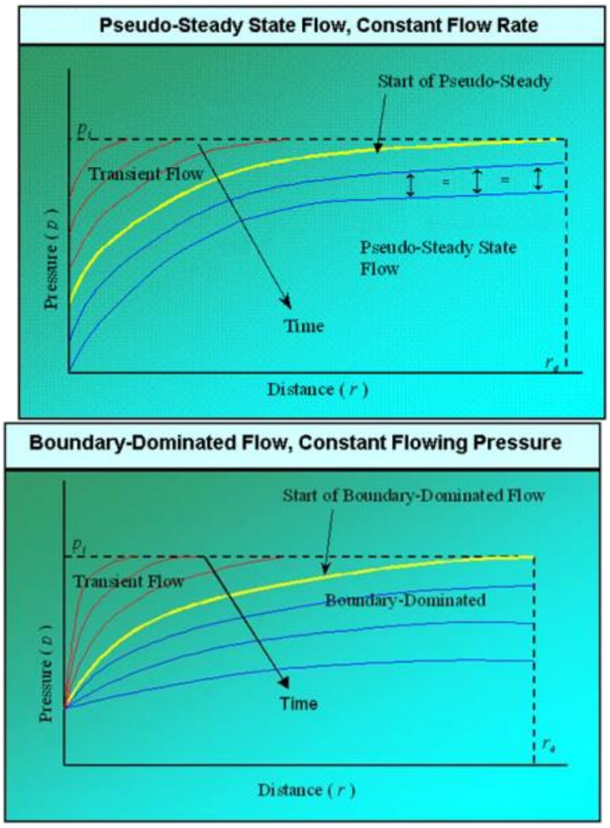

Figure 6. Reservoir Flow

F. Productivity Test for oil well

During well tests, reservoir fluids are produced to the separator at varying rates according to a predetermined schedule. These tests may take less than two days to evaluate a single well or months to evaluate reservoir extent. Test types include buildup, drawdown, falloff, injection and interference.
Well testing is a valuable and economical formation evaluation tool used in the hydrocarbon industry. It has been supported by mathematical modeling, computing, and the precision of measurement devices. The data acquired during a well test is used for reservoir characterization and description. However, the biggest drawback is that the system dealt with is neither designed nor seen by well test interpreters, and the only way to make contact with the reservoir is through the well by making indirect measurements.

Wellbore storage coefficient

It is the continuous flow of the formation to the well after the well has been shut-in for stabilization. It is also called after-flow, postproduction, post injection, loading, or unloading (for flow tests). The flow occurs by the expansion of fluids in the wellbore. In pressure buildup tests, after-flow occurs. illustrates the above

Traditional pressure tests had to be long enough to cope with both wellbore storage and skin effects so that a straight line could be obtained indicating the radial flow behavior. Even this approach has disadvantages since more than one apparent line can appear and analysts have problems deciding which line to use. In addition, the scale of the graph may show certain pressure responses as straight lines when in fact they are curves. To overcome these issues, analysts developed the method the type-curve matching method. There is flow in the wellbore face after shutting-in the well in surface. Wellbore storage affects the behavior of the pressure transient at early times. Mathematically, the storage coefficient is defined as the total volume of well fluids per unit change in bottom-hole pressure, or as the capacity of the well to discharge or load fluids per unit change in background pressure:

$$C=\Delta V \Delta PE \qquad \ldots\ldots\ldots\ldots.(6)$$

The wellbore storage causes the flow rate at the face of the well to change more slowly than the surface flow rate.

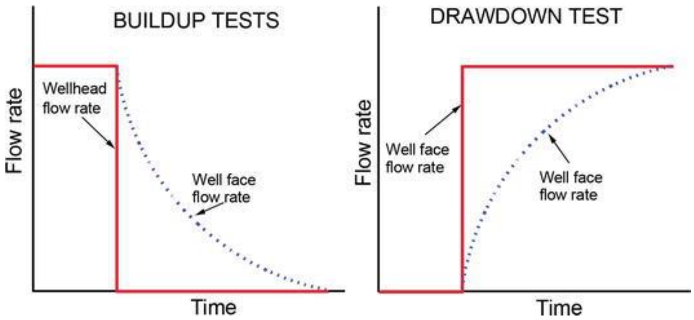

Figure 7. flow rate & time (build up & drawdown test)

Drawdown and Build-up

The two main pressure tests are (a) pressure drawdown and (b) buildup. While the first one involves only one flow rate, the second one involves two flow rates, one of which is zero. Then, a pressure buildup test can be considered as a multi-rate test.

Pressure tests run in producer wells

Drawdown pressure test It is also referred as a flow test. After the well has been shut-in for a long enough time to achieve stabilization, the well is placed in production, at a constant rate, while recording the bottom pressure against time. Its main disadvantage is that it is difficult to maintain the constant flow rate. [5]

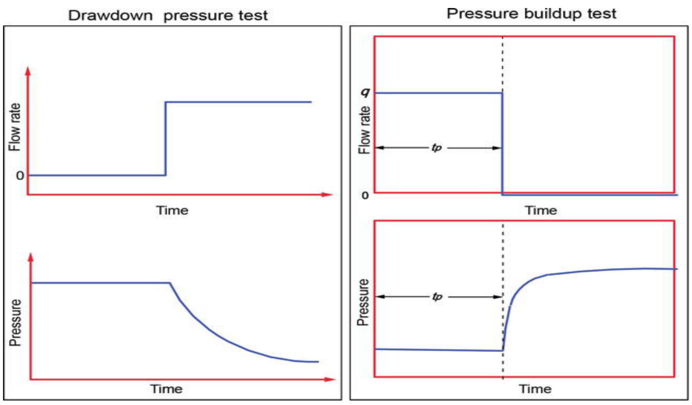

Figure 8. Pressure of drawdown test buildup test

MDH plot

The most simple semi-log plot, in which the time axis is log(Δt), is called the Miller-DyesHutchinson or MDH plot. It is strictly valid only for the first ever drawdown on a well, but can in exceptional circumstances be used for analysis of a later drawdown or even a build-up. In 1998, with computers that can handle superposition rigorously, it should only be used for ‘Drawdown #1’

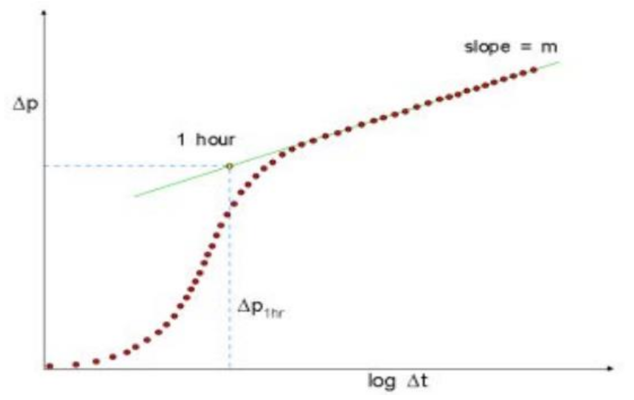

Figure 9. MDH plot for ΔP

All of the semi-log plots are more conveniently plotted with pressure on the y-axis, as this makes no difference to the analysis. So for the MDH, a drawdown plot.

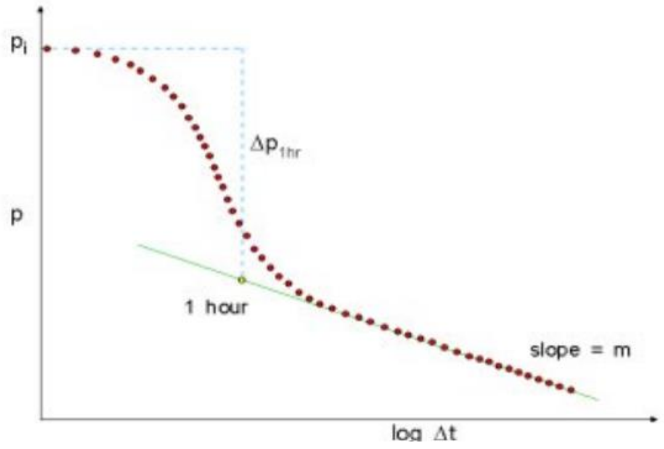

Figure 10. MDH plot for p

As already mentioned the slope of the straight line is:

$$m = 162.6\frac{q\mu B}{kh} \quad \text{………………….(7)}$$

This gives the permeability-thickness product as:

$$kh = 162.6\frac{q\mu B}{m} \quad \text{…………………….(8)}$$

The value of the pressure on the line at Δt = 1 hour is used to evaluate the skin. Cross-multiplying the expression on the previous page:

$$S = 1.151\left[\frac{\Delta p_{1hr}}{m} - \log\left(\frac{k}{\phi\mu C_t r_w^2}\right) + 3.23\right] \quad \text{…(9)}$$

Horner Plot

In the simplest superposition case of a build-up following a single drawdown, in which an elementary drawdown solution' of rate -q (i.e. an injection) overlays a drawdown of rate +q, and assuming that both solutions reach IARF, we get the approximate build-up solution:

$$p = p_i - 162.6\frac{q\mu B}{kh}\log\left(\frac{t_p + \Delta t}{\Delta t}\right) \quad \text{….(10)}$$

So infinite-acting radial flow will be characterized by a linearity between the pressure response and the Horner time function, log (tp+Δt)/Δt, which depends upon tp, the duration of the production period preceding the shut-in.

The coefficient in front of the log term is the same as for the MDH plot, so the straight line slope will again be 'm',

$$kh = 162.6\frac{q\mu B}{m} \quad \text{……………..(8)}$$

Taking the pressure on the line again at 1 hour, the skin equation becomes:

$$S = 1.151\left[\frac{\Delta p_{1hr}}{m} - \log\left(\frac{k}{\phi\mu C_t r_w^2}\right) + \log\left(\frac{t_p + 1}{t_p}\right) + 3.23\right] \quad \text{…(11)}$$

Note that the time function is such that the data plots 'backwards', as when Δt is small, at the start of the build-up, Horner time (log (tp +Δt)/Δt) will be large, and when Δt tends to infinite shut-in time the Horner time tends to 1, the log of which is 0:

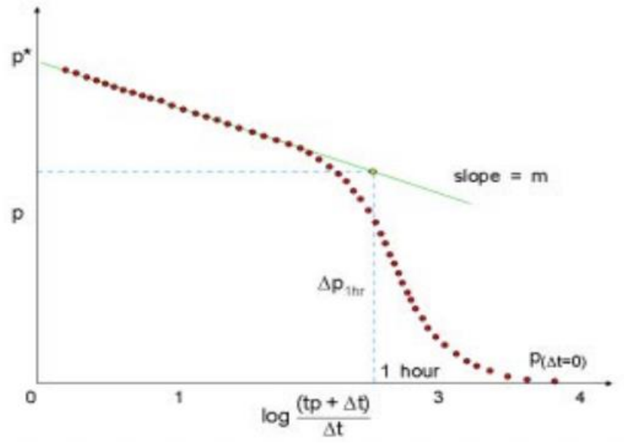

Figure 11. Horner Plot

If the reservoir were truly infinite, the pressure would continue to build-up in infinite-acting radial flow and eventually intercept the y-axis at pi, the initial pressure. However, as no reservoir is infinite, the extrapolation of the radial flow line at infinite shut-in time is called p*, which is simply an extrapolated pressure. It may give a value very close to the eventual shut-in pressure, but to call this value the present reservoir pressure would be a mistake, as the only thing that is certain about the real data is that it would NOT follow the infinite-acting radial flow line forever. As the effects of boundaries are seen, as they eventually must be, the data will deviate from the 'm' line. [6-7]

IV. INTERPRETATION MODELS

A. Early time models (Well models)

1. Wellbore Storage and Skin

When a well is opened at surface, the first flow at the wellhead is due to the expansion of wellbore fluid alone. This expansion continues after the reservoir fluid starts to contribute to the production, until the sandface flowrate equals the surface flowrate. This effect is called wellbore storage, as is the reverse effect, also known as after flow, observed during a shut-in. Wellbore storage is quantified by the constant C, defined as $^{\Delta V}/_{\Delta P}$, and expressed in STB/psi.

The immediate vicinity close to the wellbore usually does not have the same characteristics as the surrounding formation, typically being less permeable due to the invasion of mud filtrate during drilling, but possibly due to other causes. This causes an additional pressure drop close to the wellbore, Δp_s, and is represented by the skin factor, S, also as discussed in section 2. The skin factor is a dimensionless variable:

$$r_D = \frac{kh}{141.2\, q\mu B}\Delta p_s \qquad \text{............(12)}$$

A positive skin corresponds to a damaged well, and a negative skin corresponds to a stimulated well.

CD, the dimensionless wellbore storage constant, any dimensionless solution for a well with wellbore storage and skin in a homogeneous reservoir is completely determined by the value of C_De^{2S}, and for this reason is usually called a C_De^{2S} curve.

is given by:

$$C_D = \frac{0.8937C}{\phi C_t h r_w^2}\Delta t \qquad \text{............(13)}$$

$$\frac{t_D}{C_D} = \frac{0.000295\, kh\, \Delta t}{\mu C}\Delta t \qquad \text{............(14)}$$

and the dimensionless time is defined as:

As seen later, an increase in the C_De^{2S} value has the effect of increasing the separation of the log-log and derivative curves. As the C_De^{2S} function is dominated by the skin value in the exponent, it follows that an increasing skin causes the curves to move apart. A useful rule of thumb is that when radial flow is first seen in the derivative, a separation between the 2 curves of one log cycle is approximately equivalent to a zero skin - less than a log cycle is a negative skin, more is skin damage. [8]

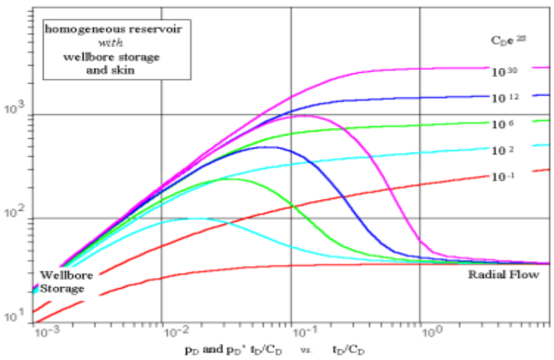

Figure 12. Wellbore storage and skin

2. Infinite-Conductivity or Uniform Flux Vertical Fracture

To improve the productivity of a well, there are 2 basic choices; acidizing or fracturing. There are many factors to consider when selecting a stimulation treatment, but the general rule is 'high permeability, acidize, low permeability, fracture'.

For acidizing, injectivity is needed, so that the fluid will enter the formation without too much difficulty. To fracture a well, the opposite is true; you need to pump fluid against a high resistance, so that the bottomhole pressure rises above the formation breakdown pressure and the rock cracks. Once the fracture is initiated, the key is to maintain a high bottomhole pressure by pumping rapidly, so that the fracture propagates away from the wellbore. During the treatment a 'proppant' is included in the injection fluid, so that when pumping stops the fracture faces cannot close back together.

Rock mechanics suggests that the fracture is always a 'bi-wing' symmetrical geometry, although our assumption in well testing that the fracture wings are 2 perfect rectangles is an oversimplification:

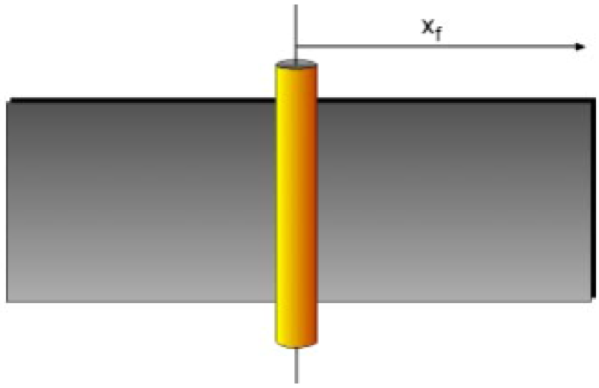

Figure 13. infinite-Conductivity Vertical Fracture

It is also assumed in the analysis of the fracture behavior that it is internally propped to a constant dimension, i.e. that there is no variation in fracture width with height or length. At present there is no way to know if this is true or not, but like all mathematical models, the fracture models are as good as can be handled analytically, and they typically reproduce the pressure response due to the fracture quite accurately.

There are 2 basic fracture models, of which one assumes 'high conductivity', in which the pressure drop along the inside of the fracture is negligible, and the other is 'low conductivity', in which the pressure drop along the fracture is significant.

The high conductivity fracture model can be divided into 2 sub-categories:

Infinite-Conductivity Fracture

Assumes that there is no pressure drop along the fracture.

Uniform Flux Fracture

Assumes a uniform production per unit length of fracture.

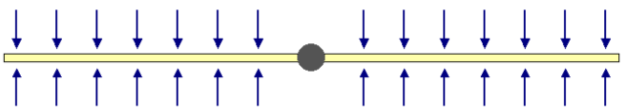

Figure 14. Linear Flow into Fracture

The 2 models were derived with different starting points with 2 different boundary conditions, so they have slightly different solutions. The differences are indeed very slight, which is not surprising if you consider the physical meaning of the 2 definitions: In order to have uniform production per unit length of fracture, you would need the same linear p between the reservoir and the fracture at all points along its length – which means no pressure drop inside the fracture. The same argument can be used in reverse, and the conclusion is that the 2 models are in fact equivalent. The mathematical model is different to the non-fractured models, as skin drops out of the equation. Any localized formation damage close to the wellbore becomes irrelevant if the flow is linear into a fracture plane hundreds of feet long, so skin simply isn't considered.

Similarly, the wellbore radius is now an irrelevance, and in the dimensionless variables all 'r_w' terms are replaced by another length term, 'x_f', the fracture-half length.

More surprisingly, wellbore storage tends to be absent in the solution. This is not because there is no wellbore storage, and in fact there should be additional 'fracture storage' due to the volume of fluid contained in the fracture itself, but the productivity of fractured wells is so high that wellbore storage just isn't seen in most cases. The first flow regime seen in the pressure response is linear flow into the fracture, which is characterized by $^1/2$-unit slope lines in both the pressure and derivative curves. [9]

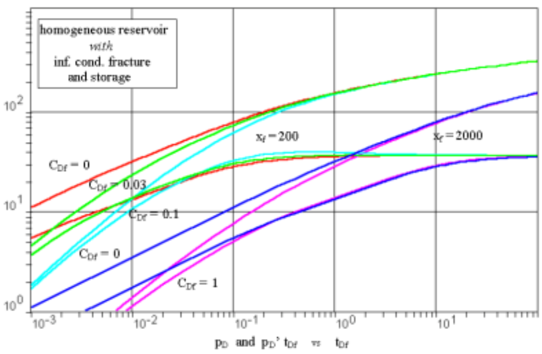

Figure 15. **Homogeneous Reservoir, with fracture and storage**

3. Finite-Conductivity Fracture

The fracture geometry is the same as for the 'high-conductivity' models, but the assumption is now that there is a significant pressure gradient along the fracture:

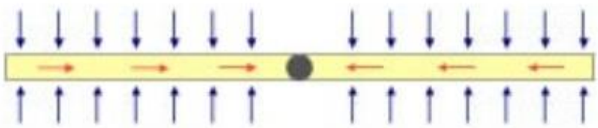

Figure 16. Infinite-Conductivity Fracture

In the absence of storage, the first flow regime is a linear flow along the fracture axis (red arrows), which simultaneously induces a linear flow orthogonal to the fracture (blue arrows), the amplitude of which changes along the fracture length – i.e., there is a non-uniform flux into the fracture, in contrast to the high-conductivity models.

This bi-linear flow regime, with linear flow along 2 axes, gives a pressure response proportional to the fourth root of time. Both the log-log and derivative plots exhibit a quarter slope during bi-linear flow. Bi-linear flow is followed by the usual linear flow, characterized by a $^1/2$-unit slope on log-log.

The bi-linear flow regime is a very early time feature, and is almost never seen. It represents the time at which the pressure drop along the fracture is significant, and in reality, this time is very short indeed. Even when there is no storage the data does not exhibit a $^1/4$-unit slope, and can be matched on a high-conductivity fracture type-curve with an immediate $^1/2$-unit slope. The general model for a fractured well must surely be the finite-conductivity fracture, as there must always be a pressure drop along the fracture, however small; but it just isn't significant compared to the linear pressure drop in the reservoir, into the fracture.

Note that for a very high fracture conductivity, FCD, the model approaches an infinite-conductivity response, with a $^1/2$-unit slope developed instantaneously. Conversely, with a very low FCD the pressure drop along the fracture is significant almost to the onset of radial flow. [10]

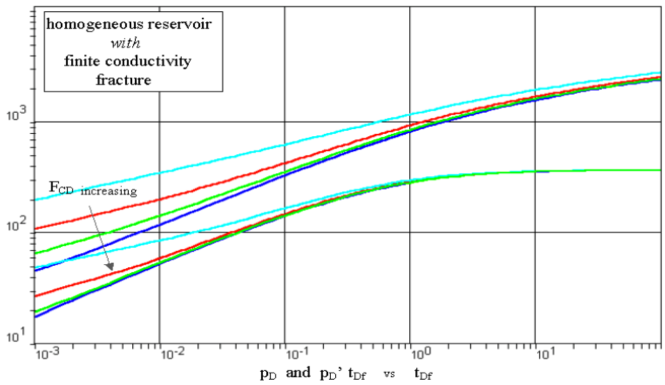

Figure 17. Finite-Conductivity Fracture Model

4. Limited-Entry Well

This model assumes that the well produces from a perforated interval smaller than the interval thickness:

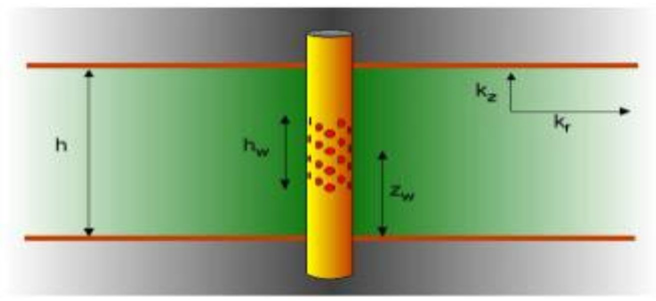

Figure 18. Limited-Entry Well

In theory, after wellbore storage, the response can be initially radial in the perforated interval thickness hw, shown as '1' below. This will give a derivative match equivalent to the small mobility k hw, and it can be imagined that if there were no vertical permeability this would be the only flow regime. In practice this flow regime is often masked by storage.

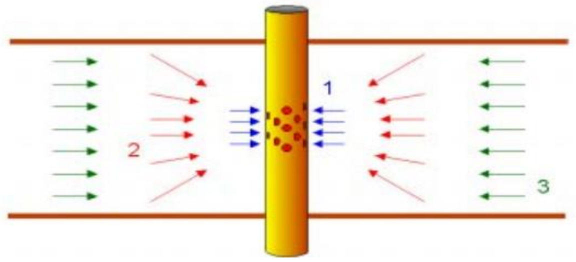

Figure 19. Limited Entry Flow Regimes

In flow regime ‘2’ there is a vertical contribution to flow, and if the perforated interval is small enough a straight line of slope -1/2 may be established in the pressure derivative, corresponding to spherical or hemi-spherical flow. (As with radial flow, there is no special log-log shape corresponding to spherical flow.

Finally, when the upper and lower bed boundaries have been seen, the flow regime becomes radial again, and the mobility now corresponds to the normal kh.

In any model where there is a vertical contribution to flow, there must also be a pressure drop in the vertical direction, and vertical permeability has to be considered along with the radial permeability. The pressure drop due to the flow convergence (flow regime 2) is a ‘near-wellbore’ effect, so typically looks like an additional skin. If the spherical flow is seen in the data, it may be possible to separate the ‘true’ and ‘geometric’ components of the apparent skin, but sometimes the first flow regime seen after storage is the final radial flow.

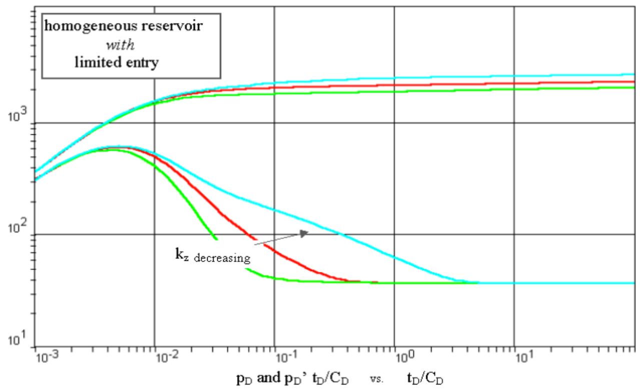

Figure 20. Limited Entry Response

With a high enough vertical permeability the spherical flow may not be seen at all, as shown by the green curve, but this also depends on hw/h, the fraction of the producing interval that is perforated, and of course the storage. As kz decreases the -1/2 spherical flow derivative becomes evident, as the duration of the spherical flow regime increases, and does the overall pressure drop increases, shown by the log-log curve moving up the page. The apparent skin also increases, as shown by the separation of the log-log and derivative curves.

5. Horizontal Well

The well is assumed to be strictly horizontal, and is defined with the same parameters as a limited entry well [11]:

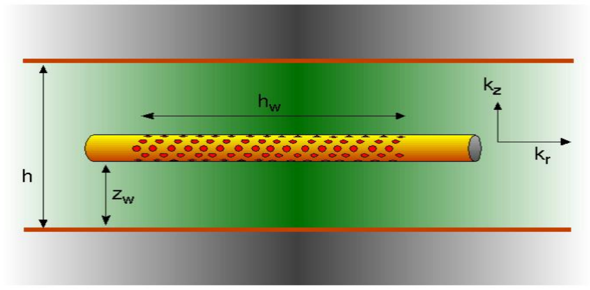

Figure 21. Horizontal Well

The first flow regime, often obscured by wellbore storage, is pseudo-radial flow in the vertical sense, analogous to radial flow in a vertical well. The average permeability combines a vertical and a radial (horizontal) component, and the ‘thicknesses correspond to the producing well length. The horizontal derivative therefore represents a high mobility:

$$(kh)_{early} = h_w \sqrt{k_r k_z} \qquad \ldots\ldots\ldots\ldots(15)$$

The second flow regime is linear flow, corresponding to horizontal flow between the upper and lower bed boundaries. Both log-log and derivative curves will follow a $^1/2$ -unit slope.

The final flow regime is radial flow equivalent to that in a vertical well, with the derivative representing the usual kh, where in this case:

$$kh_{late} = k_r h \qquad \ldots\ldots\ldots(16)$$

The flow regimes are summarized next:

Horizontal Well Flow Regimes:

Looking end-on into a horizontal well is equivalent to looking down on a vertical well. The first flow regime after storage in a vertical well is radial flow, and in a horizontal well the same applies. However due to permeability anisotropy the flow around the wellbore is not circular, but elliptical, as the pressure front will typically propagate more slowly in the vertical direction:

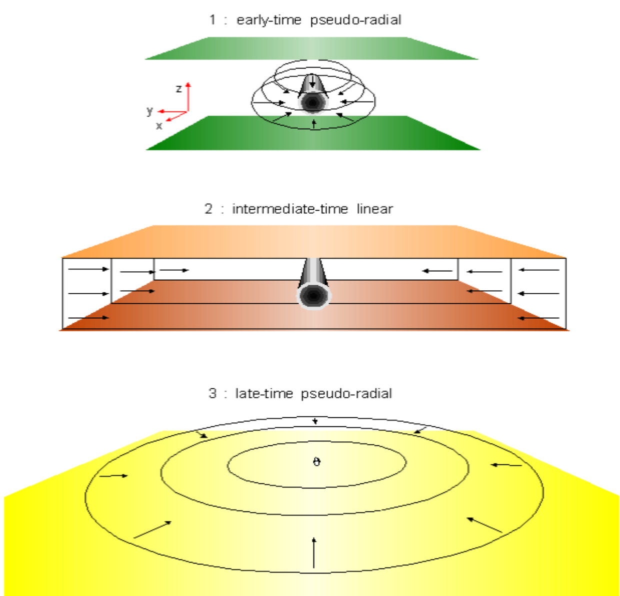

Figure 22. Horizontal Well Flow Regimes

Once the pressure front has reached the upper and lower bed boundaries the flow becomes linear, equivalent to the parallel faults' geometry in a vertical well, but because of the finite length of the horizontal wellbore it cannot stay linear. Eventually the pressure front is sufficiently far from the wellbore that the dimensions of the horizontal section become irrelevant, and the flow again becomes radial, equivalent to normal radial flow in a vertical well.

Horizontal Well Log-Log Responses:

In a reservoir with no gas cap or aquifer, the well would typically be positioned as centrally as possible between the upper and lower bed boundaries, in which case the boundaries would be seen simultaneously and there would be a clean transition from radial to linear flow:

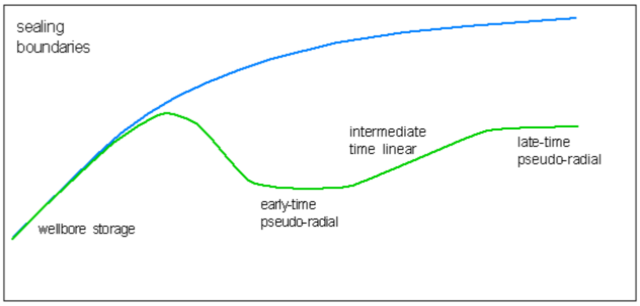

Figure 23. Horizontal Well Log-Log Responses

E. Middle time models (Reservoir Models)

1. Dual Porosity Response

The double-porosity (2Φ) models assume that the reservoir is not homogeneous, but made up of rock matrix blocks, with high storativity and low permeability, connecting to the well by natural fissures of low storativity and high permeability. The matrix blocks cannot flow to the well directly, so even though most of the hydrocarbon is stored in the matrix blocks it has to enter the fissure system in order to be produced.

and characterizes the ability of the matrix blocks to flow into the fissure system; it is dominated by the matrix/fissures permeability contrast, km/kf.

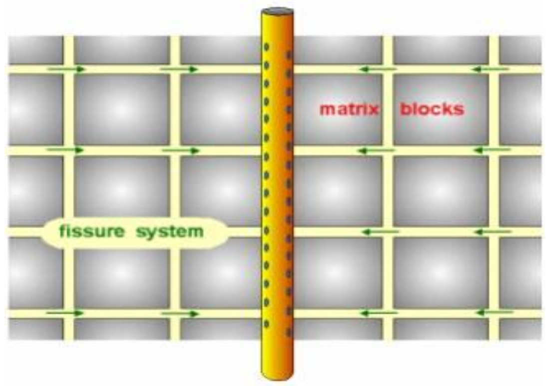

Figure 24. Reservoir Models Dual Porosity

When the well is first put on production, the first flow regime will be fissure system radial flow – i.e., the fissure system is producing, and there is no change in pressure inside the matrix blocks. This first flow regime is typically over very quickly, and is frequently masked by wellbore storage. If not, it will be manifested by an IARF response on the pressure derivative.

Once the fissure system has started to produce, a pressure differential is established between the matrix blocks, still at initial pressure pi, and the fissure system, which at the wellbore has a pressure pwf. The matrix blocks then start to produce into the fissure system, effectively providing pressure support, and the drawdown briefly slows down, creating a transitional 'dip' in the derivative [12].

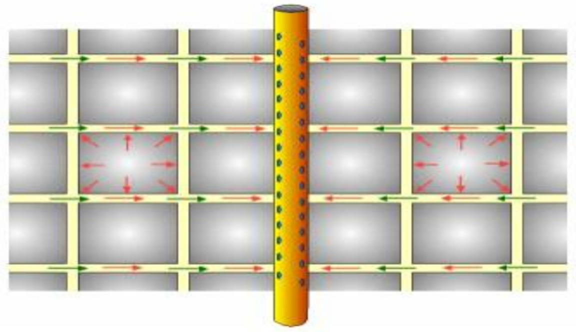

Figure 25. Reservoir Models Dual Porosity Response

Dual Porosity PSS (pseudo-steady state interporosity flow):

In this case it is assumed that the pressure distribution in the matrix blocks is uniform, i.e. there is no pressure drop inside the matrix blocks. (A physical explanation for this might be that the matrix blocks are small, so that any pressure drop inside them is insignificant compared to the pressure diffusion in the reservoir away from the wellbore.)

All of the pressure drop takes place at the surface of the blocks, as a 'discontinuity', and the resulting pressure response gives a sharp 'dip' during the transition:

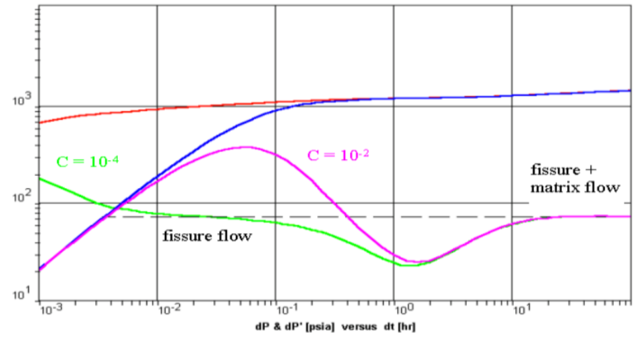

Figure 26. Dual Porosity Transient Interporosity Flow

As seen in this example, if the wellbore storage constant (C) is very low, it may be possible to see the fissure system radial flow in early time. However, with a storage value of only 0.01 bbl/psi the first flow regime has already been obscured, and the purple curve is typical of what would be seen in a real test. The data picks up the dual-porosity transition immediately after storage effects are over, and this creates a potential uniqueness problem with the data set.

Dual Porosity (transient interporosity flow):

This model assumes that there is a pressure gradient, and therefore diffusivity, within the matrix blocks. If the pressure profile inside the blocks is important, then the shape of the blocks has to be taken into consideration, and for this reason there are 2 solution models available, each corresponding to different matrix block geometries. The 2 responses are very similar:

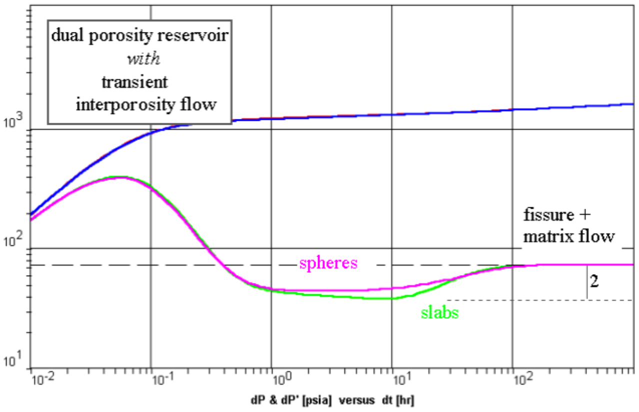

Figure 27. Dual Porosity Transient Interporosity Flow

2. Double Permeability

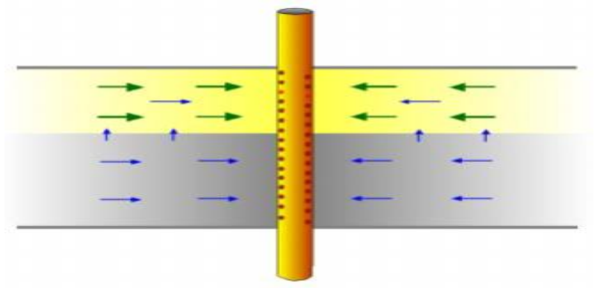

Figure 28. Double Permeability

In the double-permeability (2K) model the reservoir consists of 2 layers of different permeabilities, each of which may be perforated. Crossflow between the layers is proportional to the pressure difference between them.

In addition to the storativity ratio ω and the interporosity flow coefficient λ, another coefficient is introduced: κ is the ratio of the permeability-thickness product of the first layer to the total for both layers:

$$\kappa = k1\ h1 / (k1\ h1 + k2\ h2)$$

Usually, the high permeability layer is considered as layer 1, so κ will be close to 1. At early time there is no pressure difference between the layers and the system behaves as 2 homogeneous layers without crossflow, in infinite-acting radial flow, with the total kh of the 2 layers. As the most permeable layer produces more rapidly than the less permeable layer, a Δp develops between the layers and crossflow begins to occur. Eventually the system behaves again as a homogeneous reservoir, with the total kh and storativity of the 2 layers [13].

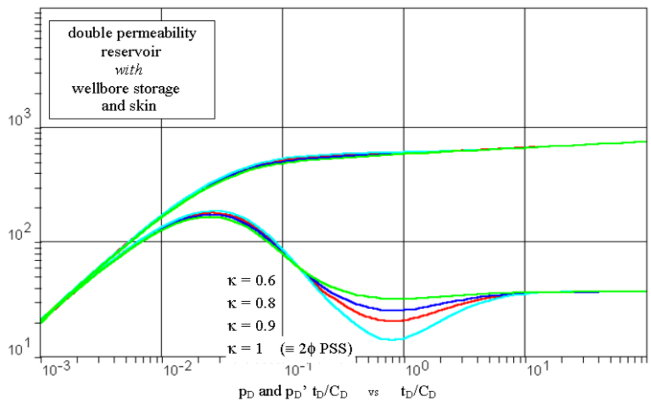

Figure 29. Double Permeability Type-Curve

3. Radial Composite

With composite models, the reservoir is divided into 2 regions of different mobilities and/or storativities:

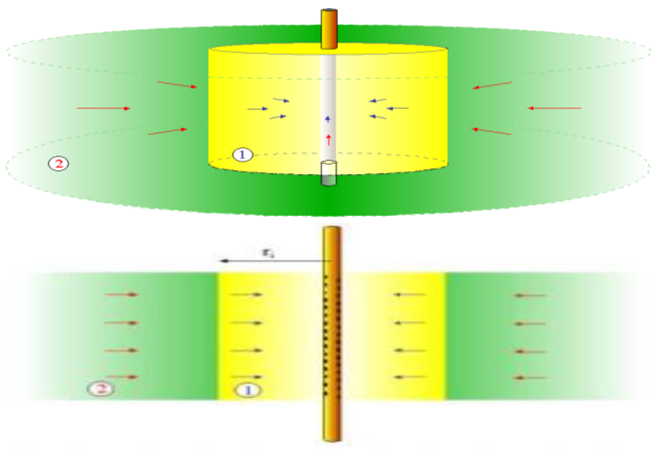

Figure 30. Radial Composite

In the case of the radial composite model, there is a circular inner zone, with the well located at the center, and an infinite outer zone.

Each zone has the characteristics of a homogeneous reservoir. The parameters defining the change in properties from one zone to the other are the mobility and diffusivity ratios, M and D above. There is no pressure loss at the interface, which is at a distance r_i from the wellbore.

$$M = (k/\mu)1 / (k/\mu)2 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots(17)$$

$$D = (k/\varphi\mu Ct)1 / (k/\varphi\mu Ct)2 \quad \ldots\ldots\ldots\ldots\ldots(18)$$

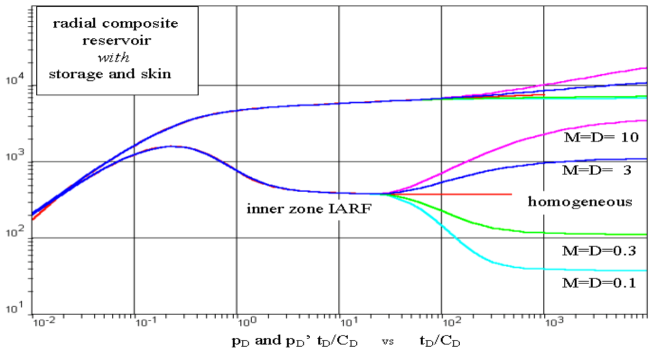

Figure 31. Radial Composite Reservoir response

This model has a practical use in injection wells, where the injection fluid has a different viscosity to the reservoir fluid.

With any model, the direction of movement of the derivative can be remembered as 'down = good', as a downward movement means a slowing down of the drawdown due to some kind of improvement to the flow mechanism, whether a support boundary, an increase in kh, or in this case an increase in mobility. (With one exception, the build-up derivative always moves in the same direction as the drawdown derivative.)

For example, with water injecting into oil, the mobility of the oil will typically be greater than the water mobility, and the derivative will move down at the interface. Interestingly, water injected into an aquifer will do the same thing, as the cool injection water is more viscous than the reservoir water.

4. Linear Composite

The producing well is in a homogeneous reservoir, infinite in all directions but one, where the reservoir and/or fluid characteristics change across a linear front. Again, there is no pressure loss at the interface. On the other side of the interface the reservoir is again homogeneous and infinite, with different properties:

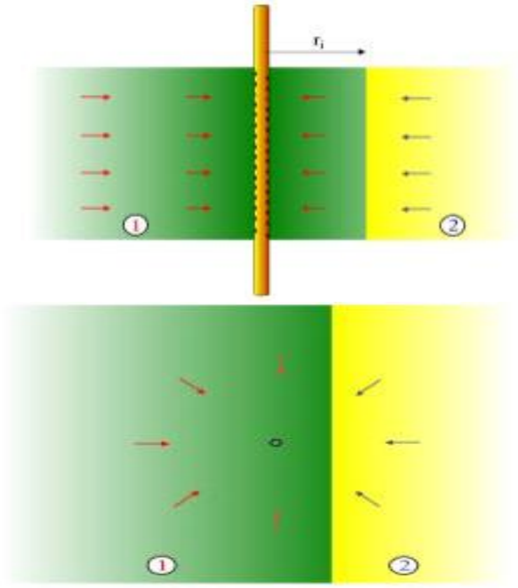

Figure 32. Linear Composite

– After wellbore storage effects, the derivative will correspond to homogeneous radial flow in the first zone.
– After the transition, the second homogeneous response is semi-radial flow in the 2 parts of the reservoir.

Assuming a constant bed thickness, h, the first derivative stabilization will correspond to k1/µ1. The second will be the average mobility of the 2 zones: ((kl/mu1) + (k2/mu2)) /2 [14]

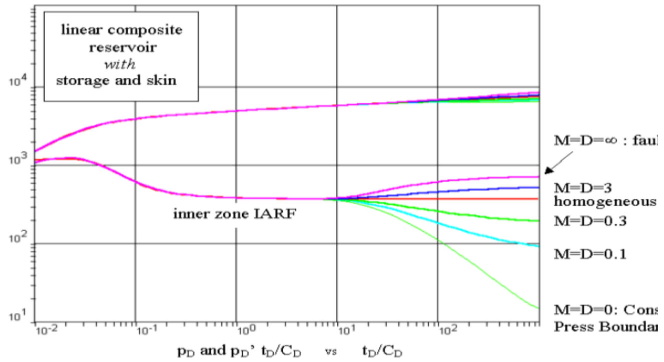

Figure 33. Linear Composite Response

In the case of decreasing mobility, the second stabilization can never be more than double that of the first, in which case the linear discontinuity represents a sealing fault – i.e. M = ∞, because k2mu2=0.

In the case of increasing mobility, there is no lower limit for the second stabilization which tends to zero (constant pressure) when M = 0, meaning that k2 mu2= ∞.

V. Boundary Models

1. Linear Boundaries

Sealing Fault:

In reality, the nature of the reservoir beyond the fault is irrelevant, but in the model the reservoir is replaced by an infinite virtual reservoir, which extends beyond the fault. The virtual image well has the same production history as the active well, so that the Δp each side of the boundary is symmetrical, and nothing will flow across it [15]:

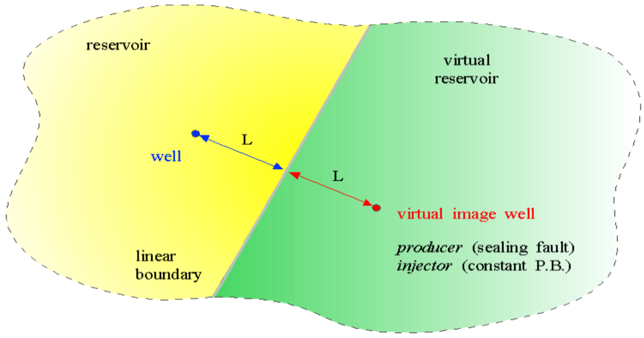

Figure 34. Linear Boundaries

Constant Pressure Boundary:

The configuration is exactly as above, except the production history at the image well is the inverse of the active well; i.e., if the active well is a producer the image well is an injector, and vice versa. Any point on the boundary is equidistant from the 2 wells, so the Δp from one is balanced by the -Δp from the other, and the pressure along the boundary is constant.

Note that for the image well approach to be rigorous, the image well(s) should have the same wellbore storage, skin, etc. as the active well. However, the image wells are typically represented by straightforward line sources, which is technically incorrect. Fortunately, the pressure regime around any well, outside the skin-damaged zone, will be almost identical to that around a line source well, with no storage and no skin, as the inner boundary conditions affect only the pressure internal to the wellbore. The deliverability of the reservoir is not changed by the presence of a well, and the only distortion will be the effect on the early-time flowrate in the reservoir, which will not change instantaneously.

Pressure Response:

When the semi-log approximation holds for both active and image wells, the overall derivative, which is the sum of the individual derivatives, becomes:

In the sealing fault case, the late-time response is identical to the response of an infinite system with a permeability of half the actual reservoir permeability.

In the constant pressure response, the derivative is tending to zero, as the pressure stabilizes.

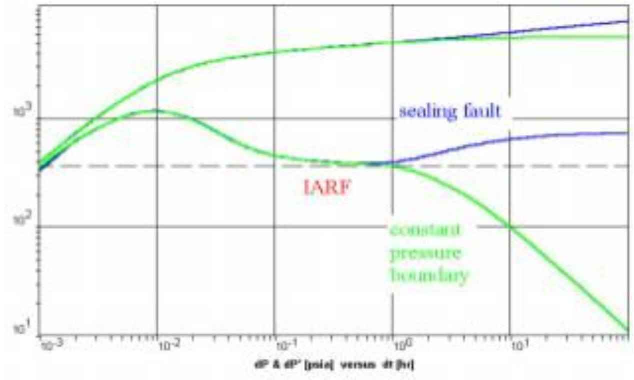

Figure 35. Pressure Response

2. Circular Boundaries (Closed Circle)

The well is at the center of a reservoir limited by a sealing circular boundary, radius re. Unlike linear faults, this model has a radial symmetry and can be solved without the need for image wells [16,17]:

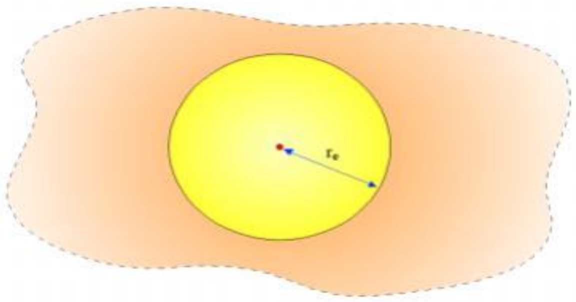

Figure 36. Circular Boundaries

When the boundary is seen during a drawdown, the pressure response will be transition from radial flow to pseudo-steady state flow, corresponding to depletion and approximated in dimensionless terms by:

The build-up response is actually the difference between 2 drawdown responses, at the same point in space but shifted in time. When the pseudo-steady state approximation holds for both responses the pressure becomes constant, equal to the average reservoir pressure, and the derivative tends to zero. This is precisely the response of a reservoir with a constant pressure boundary: The drawdown response in a closed circle (or any closed reservoir) is unmistakable, a unit-slope straight line in late time, on both the log-log and the derivative. The build-up response is the same as for a constant pressure circular boundary, as seen below. (It is too steep to be a linear constant pressure).

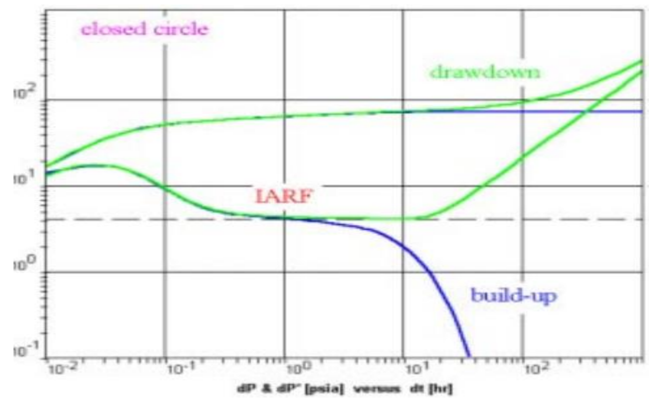

Figure 37. Closed Circular Boundary

3. Intersecting Faults

If the first fault is far enough away, infinite-acting radial flow is established after wellbore storage. Until a fault is seen, it will have no effect on the pressure curve. Similarly, the first fault will always cause the derivative to double, as until it is seen the second fault will have no effect. The final stabilization level is determined by the angle between the faults

If the well is centered (1), there will be a single jump to the final stabilization, at a value 360/θ times the initial radial flow stabilization. If the well is much closer to one fault (2), the single fault doubling of the derivative may be seen before a second jump

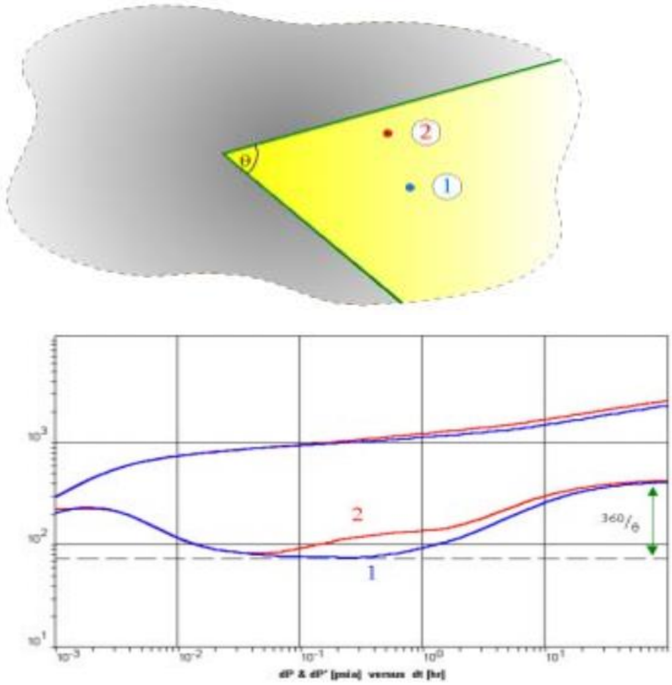

Figure 38. Intersecting faults

When at least one of the 'faults' is a constant pressure, the pressure will stabilize and the derivative will tend to zero. The constant pressure boundary will dominate the pressure response, so that nothing more distant will be observed.

4. Parallel Faults (Channel)

The well is either between parallel faults or in a channel:

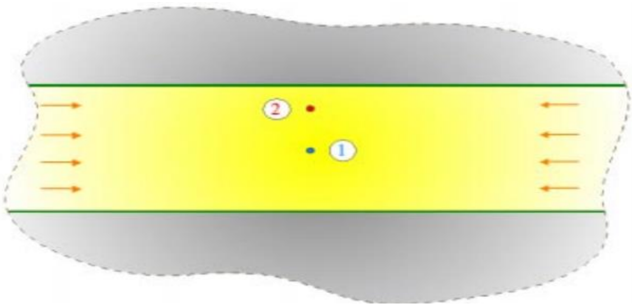

Figure 39. Parallel Faults

The late time behavior will be linear flow, resulting in a 1 /2-unit slope on both the log-log and derivative plots, as for a fracture in early time. Before that there may be infinite-acting radial flow, and there may be a doubling of the derivative due to the first fault being a lot closer than the second:

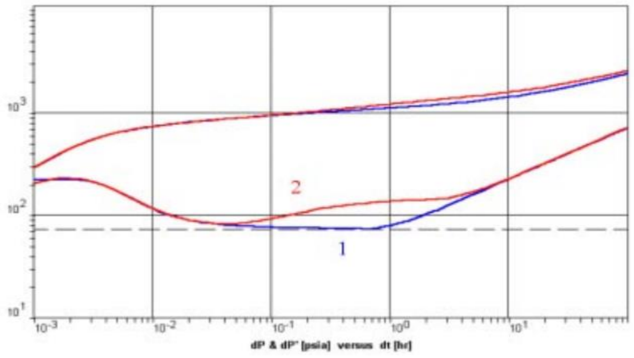

Figure 40. Parallel Faults

VI. CASE STUDY

In this study, the interpretation of well test data will be for the test data of Well #1 in Field X, the counter map of this field is shown below:

The field consists of two parts separated by fault.

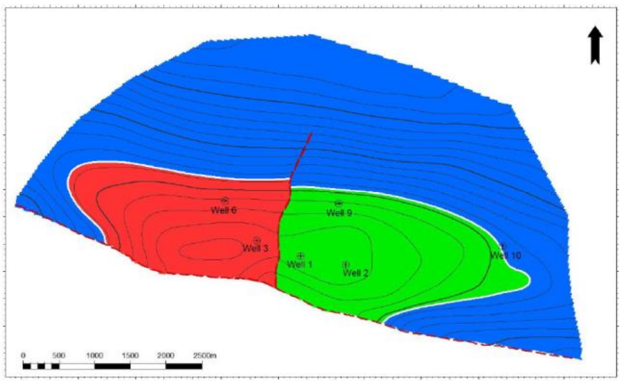

Figure 41. field map

The well test data of Well#1 is illustrated in the below figure:

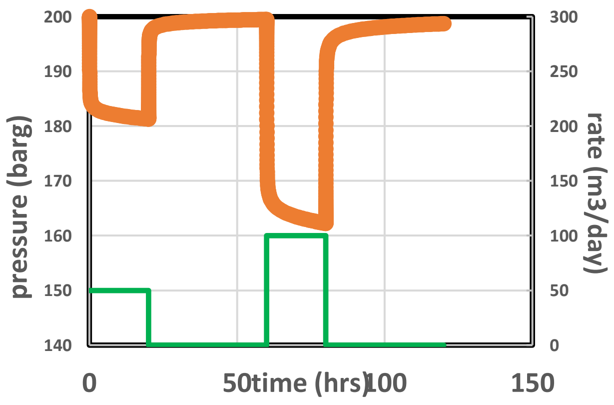

Figure 42. well test data

The data of the above figure is separated to periods in the below table:

A. PVT properties and reservoir data

API	25	-
µo	0.002	pa.s
Bo	1.22	m3/m3
Ct	4.35E-10	pa-1
rw	0.1	m
h	10	m
Φ	0.2	-
Pi	200	bar
Tr	60	°C
Pwf	181.3	bar

B. Drawdown interpretation

1. Permeability estimation

The data for the first drawdown is plotted (MDH plot), ΔP on the y-axis versus ln t on the x-axis

$$m = \frac{\mu}{4\pi k h} \quad \text{……………………..(19)}$$

$$\alpha = \frac{2.25}{t_c} \quad \text{……………………………………..(20)}$$

$$t_c = \frac{\mu c_t \phi r_w^2}{k} \quad \text{……………………………….….(21)}$$

$$t_D = \frac{t}{tc} \quad \text{………………………………………………….(22)}$$

$$\Delta p(t) = p_i - p_{wf}(t) \quad \text{……..…………………..(22)}$$

$$p_{wf}(t) = p_i - \frac{q\mu}{4\pi k h}(\ln 2.25 t_D + 2S) \quad \text{….…….(23)}$$

$$\Delta p(t) = mq\,(\ln \alpha t + 2S) \quad \text{……………………...(24)}$$

$$\Delta p(t) = mq \ln t + mq\,(\ln \alpha + 2S) \quad \text{……...…..(25)}$$

Flow period	Elapsed time (hr)	Duration (hr)	oil rate (m3/d)
DD1	20	20	50
BU1	60	40	0
DD2	80	20	100
BU2	120	40	0

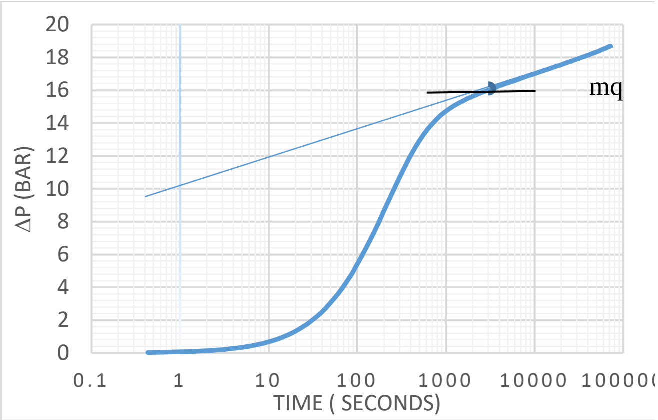

Figure VI3. Drawdown plot

Q	50	m3/d
Q	0.000578704	m3/s

Data obtained from the diagram:

m	76000	pa/s
Δp intersection	1000000	pa
tc	0.011762683	
α	191.2	

So, the calculated data from the first drawdown will be as below:

Reservoir Permeability K	1.47925E-13	m2
Reservoir Permeability K	147.93	md

2. Calculation of Skin factor, Radius of investigation, and Productivity index

Productivity Index = J = Q/(Pe-Pwf) ………….(3)

$$r_d = 1.5\sqrt{\frac{k}{\mu c_t \phi} t}$$ ……………………………….(4)

The skin factor calculated from the intersection of the straight line with y-axis in the above figure.

The intersection = mq (ln (α)+2S)

The calculated data are as following

Skin factor S	3.95	(-)
Radius of investigation rd	239.55	m
Productivity Index PI	2.67	m3/d/bar

3. Pressure derivative interpretation

$$\Delta p(t) = mq \ln t + mq(\ln \alpha + 2S)$$ ………...(25)

$$\Delta p(t) = p_i - p_{wf}(t)$$ …………………………...(23)

$$\Delta p'(t) = \frac{d\,\Delta p}{d\,lnt} = mq$$ …..……………………(26)

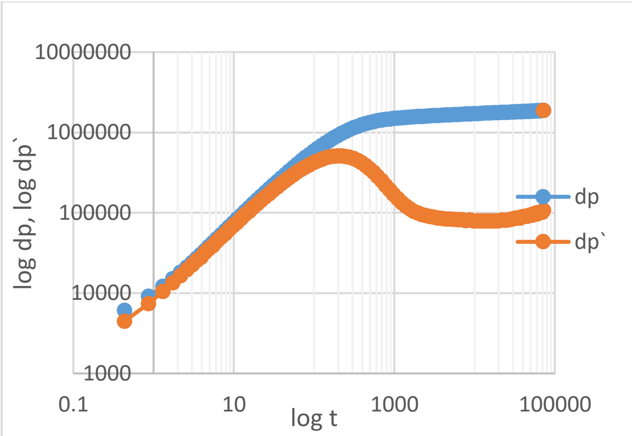

Figure VI1. Pressure derivative plot

From the pressure derivative curve, we can see the effect of wellbore storage and skin (well effect) and this effect will hide after 1000 seconds (0.3 hr), then the response of reservoir will start where, the radial flow is commenced and the reservoir is homogenous until reach 30000 seconds (8.5 hr) of well flowing at 50 m3/day. The pressure derivative will increase and this indication of touching one boundary.

The radius of investigation is calculated at time 30000 seconds, it equal to about 250m. If we compare this distance with the field map, we will see the same distance between Well#1 and sealing fault.

VII. CONCLUSION

A well test induces a dynamic response in a reservoir by producing reservoir fluids to surface. The information acquired, such as, fluid properties, pressure and temperature data, become inputs to a reservoir model to aid in making development decisions.

The well test objectives are the principal reason for conducting the test. The objectives influence many aspects of the design and are therefore an important reference in the program. The well test objectives should be listed in the Well Test Program as stated by the subsurface team, using the same wording.

It is useful to monitor performance, well condition, and changes in average reservoir pressure so that we can refine our forecasts of future reservoir performance. Also, it helps in reservoir evaluation and reservoir descriptions.

VIII. ACKNOWLEDGEMENTS

Thanks for everyone who had contributed to the successful completion of this project. I like to express my gratitude to my research supervisor,

Our supervisor Nasir Atallah his invaluable advice,

guidance and his enormous patience throughout the development of the research.

In addition, I also express my gratitude to my loving parent and friends who had helped and given me encouragement....

IX. NOMENCLATURE

J	Productivity index
DST	Drill stem test
h	thickness
S	Skin factor
ΔPs	Pressure drop due to skin
k	Permeability
ks	Permeability of damaged zone
rs	Radius of damaged zone
h_w	Thickness of perforated interval
rw	Well radius
Q	Production rate
µ	Viscosity
B	Formation volume factor
c_t	Total compressibility
Φ	Porosity
ts	Time to reach pseudo-steady state
r_e	Reservoir radius
C	Wellbore storage constant
m	Straight line slop
tp	Production time
C_D	Dimensionless wellbore storage
t_D	Dimensionless time
tc	Critical time
X_f	Fracture-half length
Kr	Radial permeability
Kz	Vertical permeability
M	Mobility ratio
D	Storativity
mu	Mobility

X. REFERENCES

[1] Horne, Roland N. "Modern well test analysis." Petroway Inc 926 (1995).

[2] Bourdet, Dominique. Well test analysis: the use of advanced interpretation models. Elsevier, 2002.

[3] Britt, L. K., et al. "Development of a Reservoir Description Through Interference Testing of the Clayton Field Prairie du Chien Formation." *paper SPE* 19846: 8-11.

[4] Abaszadeh M and Kamal MM: “Pressure Transient Testing of Water-Injection Wells,” SPE Reservoir Engineering 4 (February 1989): 115–124.

[5] Agarwal RG: “Real Gas Pseudo-Time: A New Function for Pressure Buildup Analysis of MHF Gas Wells,” paper SPE 8279, presented at the 54th SPE Annual Technical Conference and Exhibition, Las Vegas, Nevada, September 23–26, 1979.

[6] Al-Hussainy R, Ramey HJ Jr and Crawford PB: “The Flow of Real Gases Through Porous Media,” Journal of Petroleum Technology 18 (May 1966): 624–636.

[7] Ayestaran L, Minhas HN and Kuchuk FJ: “The Use of Convolution Type Curves for the Analysis of Drawdown and Buildup Tests,” paper SPE 18535, presented at the SPE Eastern Regional Meeting, Charleston, West Virginia, November 1–4, 1988.

[8] Bourdet D, Ayoub JA and Pirard YM: “Use of Pressure Derivative in Well Test Interpretation,” paper SPE 12777, presented at the SPE California Regional Meeting, Long Beach, California, April 11–13, 1984.

[9] Bourdet D, Whittle TM, Douglas AA and Pirard YM: “A New Set of Type Curves Simplifies Well Test Analysis,” World Oil 196, no. 6 (May 1983): 95–106.

[10] Ehlig-Economides C and Ayoub JA: “Vertical Interference Testing Across a Low-Permeability Zone,” SPE Formation Engineering 1 (October 1986): 497–510.

[11] Ehlig-Economides CA, Hegeman P and Vik S: “Guidelines Simplify Well Test Interpretation,” Oil and Gas Journal (July 18, 1994).

[12] Ehlig-Economides CA, Joseph JA, Ambrose RW Jr and Norwood C.: “A Modern Approach to Reservoir Testing,” Journal of Petroleum Technology 42 (December 1990): 1554–1563.

[13] Erdle JC, Upchurch JM and Warren DA: “Early-Fluid Entry Determination; Key to Safe, Optimum Drill Stem Testing,” paper SPE 6884, presented at the 52nd SPE Annual Technical Conference and Exhibition, Denver, Colorado, October 9–12, 1977.

[14] Gringarten AC, Bourdet DP, Landel PA and Kniazeff VJ: “A Comparison Between Different Skin and Wellbore Storage Type Curves for Early-Time Transient Analysis,” paper SPE 8205, presented at the 54th SPE Annual Technical Conference and Exhibition, Las Vegas, Nevada, September 23–26, 1979.

[15] Hegeman PS, Hallford DL and Joseph JA: “Well-Test Analysis With Changing Wellbore Storage,” SPE Formation Engineering 8 (September 1993): 201–207.

[15] Kabir CS, Kuchuk FJ and Hasan AR: “Transient Analysis of Acoustically Derived Pressure and Rate Data,” SPE Formation Engineering 3 (September 1988): 607–616.

[17] Shah PC, Gupta DK, Singh L and Deruyck BG: “A Field Application of the Methodology for Interpretation of Horizontal Well Transient Tests,” paper SPE 20611, presented at the 65th SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, September 23–26, 1990.