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Pressure Transient Analysis Comparative Review Study on Candidate Wells in Cambay Basin, India

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ABSTRACT

When it comes to well performance even in modern days, people tend to go back to the basics of Pressure Transient Analysis. For a 100 year old industry well test interpretation reliably gives a lot more clarity about the formation pressures, permeability, flow-regime and reservoir extent.

This paper deals with the challenges faced during the interpretation of a set of onshore candidate wells in Cambay Basin, India. There were differences in the flow-regime and the stabilization time. The reasons behind such behavior were to be pointed out and ascertained.

The wells were tested conventionally by lowering the electronic memory gauges on a slick-line and measuring bottom-hole pressure while changing flow parameters at the wellhead. Such BHP measurements were taken at the reservoir datum depth in two wells. One of the well was vertical and the other was inclined. Those measurements show that both wells behave differently when measured in in-situ conditions. It was observed that the pressure transient response varied a lot and depended on the time taken for the build up. Further it was observed that the parameters such as stabilization of flowing well head pressure and flow rate were not the only limiting factors responsible for pressure transient (time removed) to reach in Late Time Region (LTR). The fluid fall out and wellbore storage were significantly different at two wells due to their placement. In general the fallout and wellbore storage decided the entry of pressure response in Middle Time region.

This paper includes the observations and illustrates the reasons behind the well behavior. The comparison is very useful while designing the well test at other set of wells. Regular reviews of this kind can significantly save cost, reduce test time and cut the production down-time due to excessive build-up.

INTRODUCTION

Well testing in an oil and gas well is carried out by changing the production rate. Generally there are two main objectives for testing a well. First objective is to know wellbore behavior and second is to analyze the reservoir boundary limit. The first objective can be met by acquiring the bottom-hole pressure data up to two days; while second objective can be met by acquiring data over several months. Fluid movement in reservoir is not uniform with respect to time and it depends on shape and size of reservoir.

it is an important part of reservoir modelling and well test models are different from the geo-models. This is in the sense that well-test models are dynamic models and categorically an average model. The results can be used in reservoir geo-models to determine a production strategy for the reservoir. Based on this strategy the modern wells can be controlled. Since more and more data becomes available during production, it is possible to improve the reservoir model by updating production history. In Figure 1, the direction of the arrows shows the order in which these steps are taken.

In this paper various flow regime (edited) regimes are discussed. These are categorized in terms of the time region they occur and what kind of wellbore (vertical or horizontal) was used to drill into the formation. Since the pressure response depends on the properties of the reservoir, it is possible to estimate some reservoir properties from the pressure response. At first, the flow rate is varied at the well and this variation causes a change in the existing pressure p(r, t) in the reservoir. It is important to note that the pressure is location dependent in the reservoir. The variation in pressure is measured at the well mostly close to the perforations as a function of time.

The typical change in pressure-time plots with the different time segments marked in fig 2.

1. Early Time (E.T.)
2. Middle Time (M.T.): Transient
3. Late Time (L.T.): Steady State (S.S.) / Pseudo-Steady State (P.S.S.)

Early Time Region:
In early-time, wellbore & near-wellbore effects dominate. These effects include wellbore storage, formation damage, partial penetration, phase redistribution and stimulation (hydraulic fractures or acidization).

Middle Time Region:
In middle-time, a reservoir will ordinarily be infinite acting. For a homogeneous reservoir, the pressure derivative will be horizontal during this time region. Data in this region lead to the most accurate estimates of formation permeability.

This region further classify the transient state duration.

During transient state, it is observed before constant pressure and closed boundary system are reached and pressure variation with time is function of well geometry and reservoir properties i.e. dp/dt=f(x,y,z,t). This testing interpretation is focused on transient pressure responses.

Late Time Region:
In late-time region of the plot the boundary effects dominate. The types of boundaries that may affect the pressure response include sealing faults, closed reservoirs and gas/water, gas/oil and oil/water contacts.
Further, this time region is sub divided into two part:
A) Steady State (S.S.)
B) Pseudo Steady State (P.S.S.)

During steady state the pressure does not change with time such as reservoir producing under gas cap or water drive which ensures pressure maintenance/ support in system. i.e. dp/dt=0
During pseudo steady state the pressure will be changing with time such as closed system. For a constant rate production the pressure drop is constant with unit time. i.e. dp/dt=constant

The fields in cambay basin have shown some different flow pattern based regimes and are categorized in different time interval. Refer Table 1.

During well testing the well is shut in and the pressure change near to the perforations of the wellbore is measured as a function of time. The measured pressure change is called the pressure response and a plot of this pressure response can be represented in various ways. These plots are called type curves and are used to estimate the reservoir properties. During these shut-in well tests, the reservoir cannot produce any oil. Pressure transmission is an inherently diffusive process and hence is governed largely by average conditions rather than by local heterogeneities in properties such as permeability and porosity.

The estimation of these four reservoir properties is the goal of well testing.

1) Well bore storage
2) Permeability
3) Skin
4) Reservoir Boundaries/Limit

1) Wellbore Storage
When a producing well is shut-in at the surface, flow into the wellbore at sand-face continues after shut-in. This type of flow regime is referred to as after-flow or wellbore storage. Wellbore storage is typically controlled by the compressibility of the fluid in the wellbore. For a gas-filled wellbore the compressibility is high and wellbore storage effects will occur over a longer period of time. For a liquid-filled wellbore the compressibility is much lower and wellbore storage effects will dissipate more quickly. The flow rate measurements can be done at two locations: the first one is the bottom of the wellbore and in this case the system consists only of the reservoir and the wellbore is not part of the system. In the second case the measurements are done at wellhead. However during measurements at wellhead the wellbore is part of the system. Wellbore storage is an effect that only needs to be taken into consideration when the wellbore is part of the system. When the x-tree flow arm valve is opened the fluid in the wellbore expands due to a pressure drop in the wellbore. Due to this expansion, the production of the well in the beginning period is dominated by fluid that was already in the wellbore. One can imagine that in a multiple phase flow situation where gas is present with oil this effect is larger than the single phase flow. Similarly when a well is closed at surface the flow rate will become zero at the wellhead but not instantaneously zero at the bottom of the well due to the compressibility of the fluids in the wellbore, see the fig 7 further its derivative comparison in Fig 8.

Wellbore storage has been found to exhibit its own characteristic shape. If the pressure data recorded during a well test has a unit slope log-log straight line passing through early time data it is indicative of wellbore storage. However, it should be kept in mind that the appearance of a straight line is not proof of wellbore storage; it may not be the straight line that is desired for the reservoir system being tested. Because Δp is proportional to Δt the same data points will plot as a straight line on Cartesian coordinates. This is often referred to as a specialized plot.

The most common example of volumetric behavior is wellbore storage which dominates during the early-time region. The wellbore is basically tank, in which the pressure is uniform. Fluid either leaves this tank (earliest times in a flow test, before the reservoir begins to respond) or enters the tank (earliest times in a buildup test).

2) Permeability
The definition of ‘permeate’ is ‘to enter something and spread to every part’ [Simpson and Weiner, 2008]. Permeability is a measure for the level to which something e. g. rock is permeable. Oil has to flow through the reservoir and the permeability of the reservoir determines how much force is needed to get it through. The pressure response of the reservoir is very sensitive to the permeability and actually we can get fair idea of permeability from MTR as discussed above.

3) Skin Factor
During drilling operations changes occur in the reservoir properties close to the well. It represents the increase or decrease/damage of the pressure drop predicted with Darcy’s law. The skin factor can be positive and negative. We desire skin to be negative or zero. Positive skin means an increase in pressure drop/ damage to near wellbore perforations refer the Fig 9.

4) Reservoir Boundary
When a reservoir is discovered, one tries to estimate the amount of recoverable oil from this reservoir. The size of the reservoir (location of the boundaries) plays of course an important role in this estimation. Therefore, reservoir engineers are very interested in locating the boundary of a reservoir. Also the type of the boundary is important.
Two types are most common: the open and closed boundaries. The closed boundaries imply no flow through the reservoir boundaries. The open boundaries imply a constant pressure at these boundaries, that is, the reservoir is pressure supported by e.g. an aquifer/ some other distinct pool. The more certain the type and location of the boundaries can be predicted, the more accurate the predictions of the amount of recoverable oil are. In other words, when the radius of investigation is larger, the oil reserves that can be booked by the oil companies will probably be higher.

Case Details:

The different types of flow regime is observed in Cambay basin from different wells and this has become an important parameter while deciding reservoir boundary in well test software for matching.
<u>Radial Flow:</u> Infinite-acting radial flow is common in reservoirs and data in the radial flow regime can be used to estimate formation permeability and skin factor. Common situations in which radial flow occurs include

- Flow into vertical wells after wellbore storage distortion has ceased and before boundary effects;
- Hydraulically fractured wells after the transient has moved well beyond the tips of the fracture, horizontal wells before the transient has reached the top and bottom of the productive interval and
- In Horizontal wells after the transient has moved beyond the ends of the wellbore. Flow is in the horizontal radial direction.

This type of flow exists in the time period before the pressure transient has reached the boundaries of the reservoir (infinite-acting time period). Refer Fig 3.
In case of radial flow the ΔP vs log T follows a linear trend (refer Fig 4).

$(1/r)(d/dr(rdp/dr))= (\varphi\mu c/k).(dp/dt)$ ....(1)

Linear Flow: This flow is also common and occurs in channel reservoirs, hydraulically fractured wells and horizontal wells. Data from linear flow regimes can be used to estimate channel width or fracture half length. If an estimate of permeability is available. In horizontal wells, an estimate of permeability perpendicular to the well can be made if the productive well length open to flow is known.

An equation that models linear flow in a channel reservoir of width w is:

$\Delta p=16.26qB\mu/khw(kt/\varphi\mu c_t)^{1/2}+\Delta p_s$ ....(2)

Linear flow on the diagnostic plot is indicated when a derivative follows a half-slope line—that is a line that moves up vertically by one log cycle for each two cycles of horizontal movement (Fig. 4).

The pressure change may or may not also follow a half-slope line. In a hydraulically fractured well, the pressure change will follow a half-slope line unless the fracture is damaged. In a channel reservoir, a hydraulically fractured well with damage, or a horizontal well, the pressure change will approach the half-slope line from above.

Bilinear flow: Bilinear flow occurs primarily in wells with low-conductivity hydraulic fractures. Flow is linear within the fracture to the well and also linear (normal to fracture flow) from the formation into the fracture. Estimates of fracture conductivity, wfkf, can be made with data from this flow regime when estimates of formation permeability are available.
For a hydraulically fractured well, an equation that models bilinear flow is:
$\Delta p=(44.1qB\mu/h)(1/w_f k_f)^{1/2}.(t/\varphi\mu C_t k)^{1/4} + \Delta ps$ ....(3)

Bilinear flow derivatives plot show a quarter-slope line on the diagnostic plot (Fig. 5). The quarter-slope line moves up one log cycle as it moves over four log cycles. The pressure change does not necessarily follow a quarter-slope line. In a damaged, hydraulically fractured well, the pressure change curve will approach the quarter-slope line from above; in an undamaged hydraulically fractured well ($\Delta ps = 0$), the pressure change will typically follow the quarter-slope line when the effects of wellbore storage have ended.

Spherical flow: The flow pattern is spherical when the pressure transient can propagate freely in three dimensions and converge into a "point." This can occur for wells that penetrate only a short distance into the formation (actually hemispherical flow), wells that have only a limited number of perforations open to flow, and horizontal wells with inflow over only short intervals and during wireline formation tests.
Data in the spherical-flow regime can be used to estimate the mean permeability,

$$p_{wf} = p_i - \frac{70.6qB\mu}{k_s r_s} + \frac{2456\sqrt{\phi\mu c_t}\,qB\mu}{k_{sp}^{3/2}}\frac{1}{\sqrt{t}} - \frac{70.6qB\mu}{k_{sp} r_{sp}} s,$$

Equation No...(4)

Spherical flow on the diagnostic plot produces a derivative line with a slope of −1/2. The pressure change during spherical flow approaches a horizontal line from below and never exhibits a straight line with the same slope as the derivative (Fig. 6). Spherical flow can occur during either buildup or drawdown tests.

Physical Model System:

Well tests are regularly carried out at the referred wells in Cambay using bottom-hole gauges and surface control valves. In this work the well testing software package Saphir version 4.30.05, developed by KAPPA is used as a reference of the current state of well test analysis.
De-convolution is the inverse of convolution. Where convolution can be used to calculate the output of a system where the input and the system dynamics, often described by the impulse response, are known. De-convolution has been used to calculate the impulse response as the input signal and output signal were known.
In the our experience of well testing de-convolution has often seen as a tool to estimate the shut in pressure response of the reservoir based on the pressure response during a varying flow rate.
When the impulse response is calculated using deconvolution, the pressure response of the reservoir can be calculated for another flow rate history using convolution. Some fellow researchers Levitan et al. 2005, and Gringarten, 2008, it is agreed that this technique improves the estimation of the type curve by reshaping the data and therefore improves the estimation of the reservoir properties.

The type curve is a representation of the system. Type curves might be seen as overly simplistic, difficult to distinguish and/or cumbersome to use. However, type curves are able to link the pressure response to the physical properties. If type curves are to be removed from the identification, there has to be an alternative link between the measured pressure response and the properties that have to be estimated. It must be possible to express the reservoir properties as a function of the estimated model.

The current costs of testing are high and involve a lot of efforts. During well tests, the well is shut in and oil production is delayed/ lost. The production rate is the input signal of the system.

In this case the aim was to reduce the build-up time while getting a good estimation on well test. For our field analysis the following assumptions was considered while choosing fracture with finite conductivity:
The well intercepts a single fracture in the vertical plane. The finite conductivity fracture also assumes that there is a pressure gradient along the length of the fracture. The well is at the center of the fracture length. Wellbore storage effect may be present or not.
Behaviors of such reservoir: At early time, after the possible effects of wellbore storage have subsided, the response is bilinear, at right angles to the fracture and along the length of the fracture. On a log-log scale this is characterized by a quarter unit slope on both the pressure and derivative curves. After this the response corresponds to linear flow in the reservoir, characterized by a half-unit slope. The quarter unit slope is essentially a very early time feature and is very often masked by the effect of wellbore storage.

Results of Well X-4:

The well test software plot is shown in fig 12 & 13 (for deconvolution) and fig 13 & 14 (general) for vertical well X-4. The study indicates the

1) Deconvolution result:

Reservoir is homogenous but has parallel fault with finite conductivity and following properties are determined.

- Initial Reservoir Pressure=1802.4 psi

- Permeability=12.5 md
- Skin=0.157
- Xf (Fracture half length given by the time match)=1680 ft
- C(Wellbore storage coefficient)=0.0354 bbl/psi
- Fc (Fracture conductivity)=1300 md.ft

Fracture conductivity = kf.w,
(kf and w = fracture permeability and width)

2) General result:

Reservoir is homogeneous and infinite in all directions except one where the reservoir and fluid characteristics change across a linear front. On the farther side of the interface the reservoir is homogeneous and infinite but with a different potential (kh).

- Initial Reservoir Pressure=1789.63 psi
- Permeability=8.2 md
- Skin=-4.4
- M(Mobility ratio)=0.901
- D(Diffusivity ratio)=0.966
- Li(Distance from well to interface)=173 ft
- C(well bore storage coeff.)=0.0328 bbl/psi

Results of Well X-3:

The Well test software plot is shown in fig 15 & 16 (for deconvolution) and fig 17 & 18 (general) for inclined well X-3. The study indicates the

1) Deconvolution result:

Reservoir is homogenous but has parallel fault with finite conductivity and following properties are determined.

- Initial Reservoir Pressure=1782 psi
- Permeability=23.7 md
- Skin=6.09
- M=36.1
- D=756
- Ri=8.69 ft
- C(Wellbore storage coefficient)=0.00697 bbl/psi

2)General result:

Reservoir is slanted and has radial composite type flow regime having infinite boundary.

- Initial Reservoir Pressure=1775.32 psi
- Permeability=23.7 md
- Ri=8.69 ft
- Skin=6.09
- M(Mobility ratio)=36.1
- D(Diffusivity ratio)=756
- C(well bore storage coeff.)=0.00697 bbl/psi

CONCLUSION

Based on the results obtained from the well test software de-convolution is best method to obtain better results in the case of vertical as well as inclined well. It is also observed from the well test analysis of the inclined well that build-up time must be greater than thrice the total well flowing duration rather than old conventional method of two times.

ACKNOWLEDGMENTS

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DEFINITIONS, ACRONYMS, ABBREVIATIONS

dp/dt: pressure derivative with respect to time

C=Well bore storage

ΔV=Change in Volume (in bbls)

ΔP=Change in Pressure (in psi)

Co=Oil well bore storage Cofficient

Vwb=Volume of wellbore

Δt=change in Time

q=liquid rate (in bbls/d)

B=Formation volume factor (in rb/stb)

r=radius of transient pressure (in ft)

φ=porosity

μ=Viscosity in cp

k=permeability in md

m= slope of line (in cycle/psi)

Pi= Initail Reservoir Pressure (in psia)

Pwf= Well flowing pressure (in psia)

h= pay zone thickness (in ft)

r_w = Wellbore radius (in ft)

c_t=Total compressibility (in psia-1)

REFERENCE:

Wellbore Configuration	Early Time	Middle Time	Late Time
Vertical Wells	Wellbore Storage Linear Fracture Flow Bilinear Fracture Flow Spherical Flow	Radial Flow	Pseudo-Steady State Flow Steady State Flow
Horizontal Wells	Wellbore Storage Vertical Radial Flow Linear Horizontal Flow Elliptical Flow	Horizontal Radial Flow	Pseudo-Steady State Flow Steady State Flow

Table 1: Flow pattern based regime with different transient time

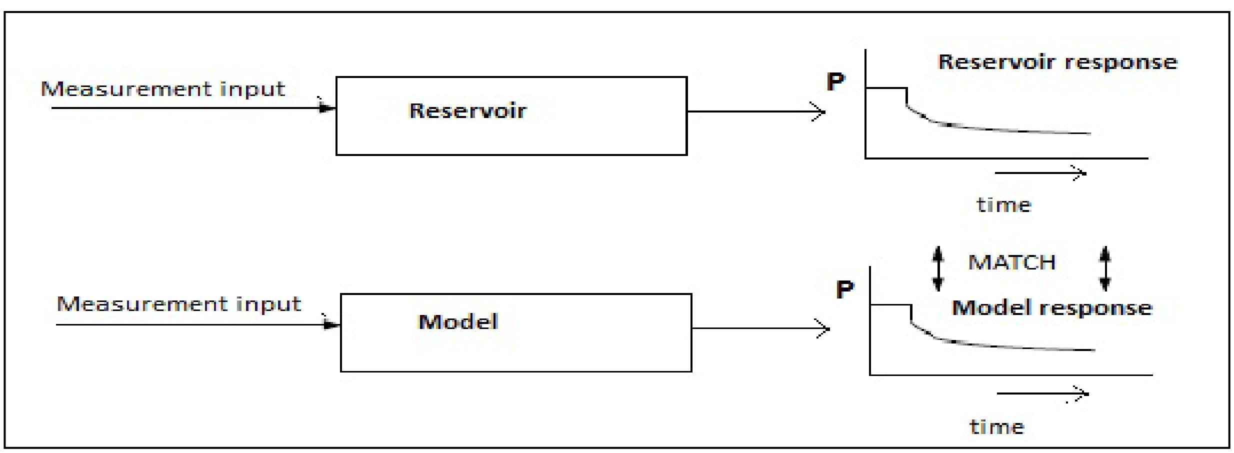

Fig 1:Matching & Comparing pressure response with expected pressure response based on a model

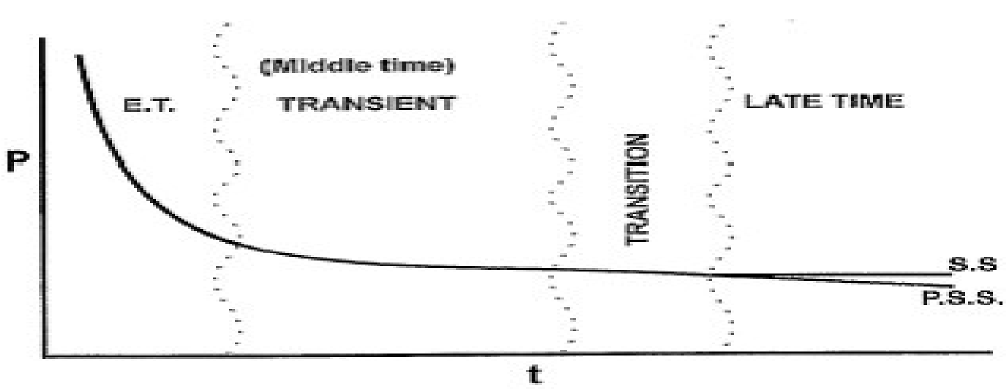

Fig 2: Pressure time plot with respect to different time

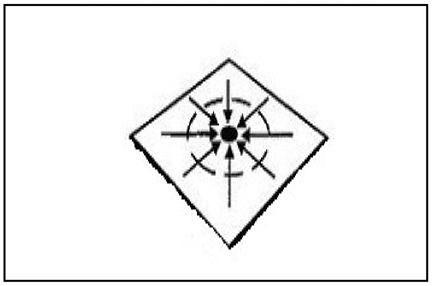

Fig 3: Radial flow pattern

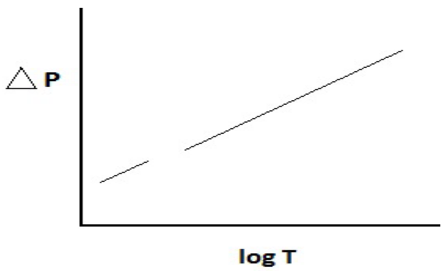

Fig 4:Change in Pressure vs log time for radial flow

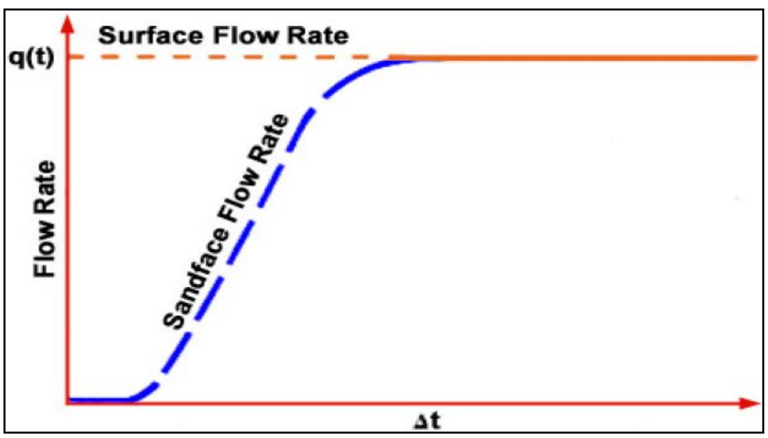

Fig 7: Surface and sand face flow rate vs elapsed time (Δt: Elapsed time from opening of well)

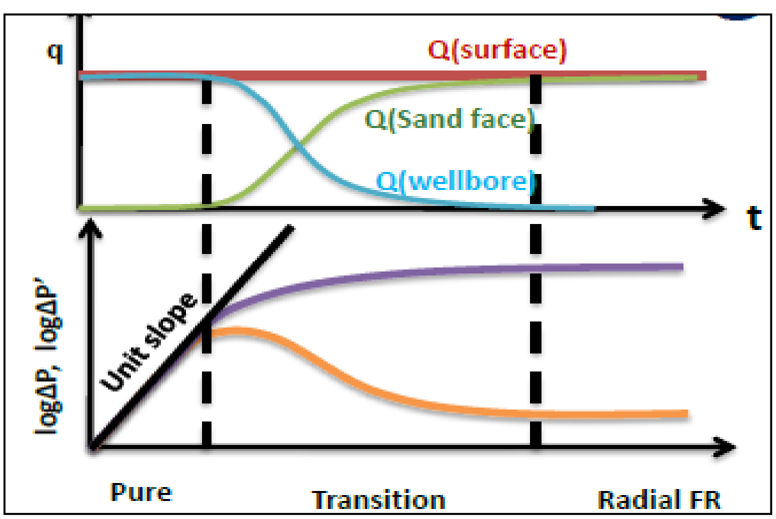

Fig 8: flow rate vs time & derivative pressure vs time

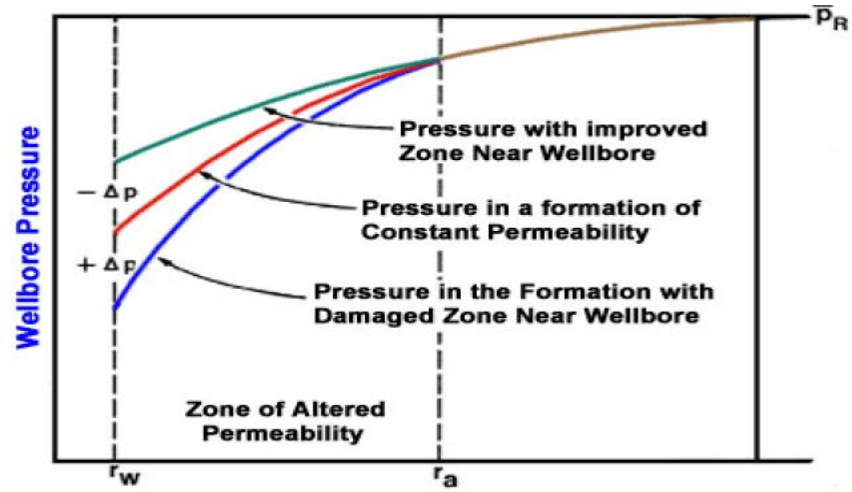

Fig 9: Skin alteration with drawdown in wellbore

INTERPRETATION GRAPHS FOR WELL X-4

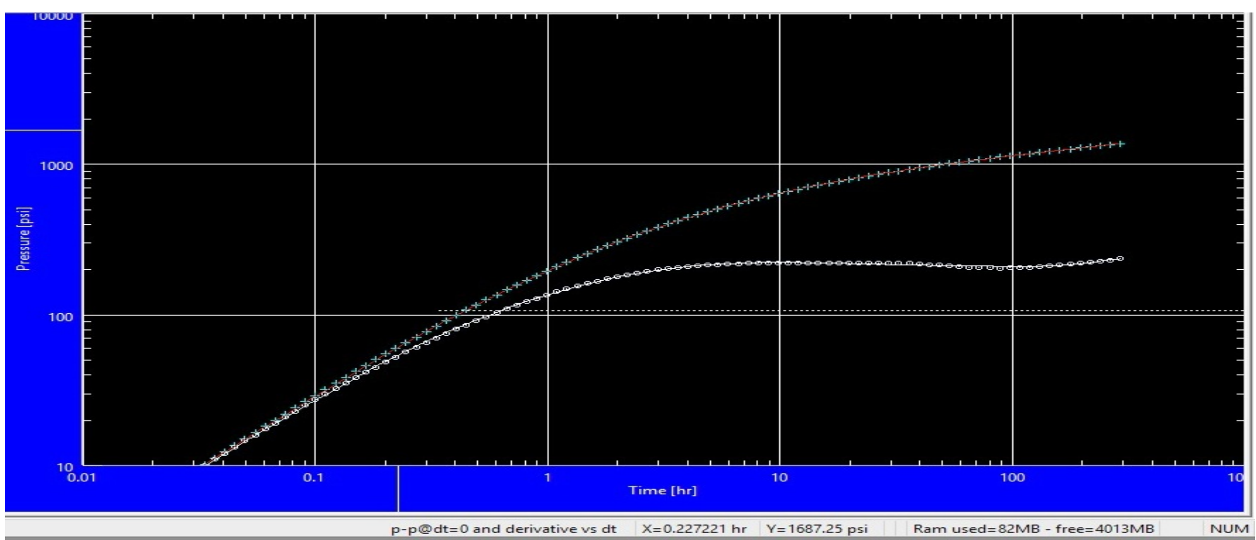

Fig 12: Log Log deconvolution Plot with time for Well X-4

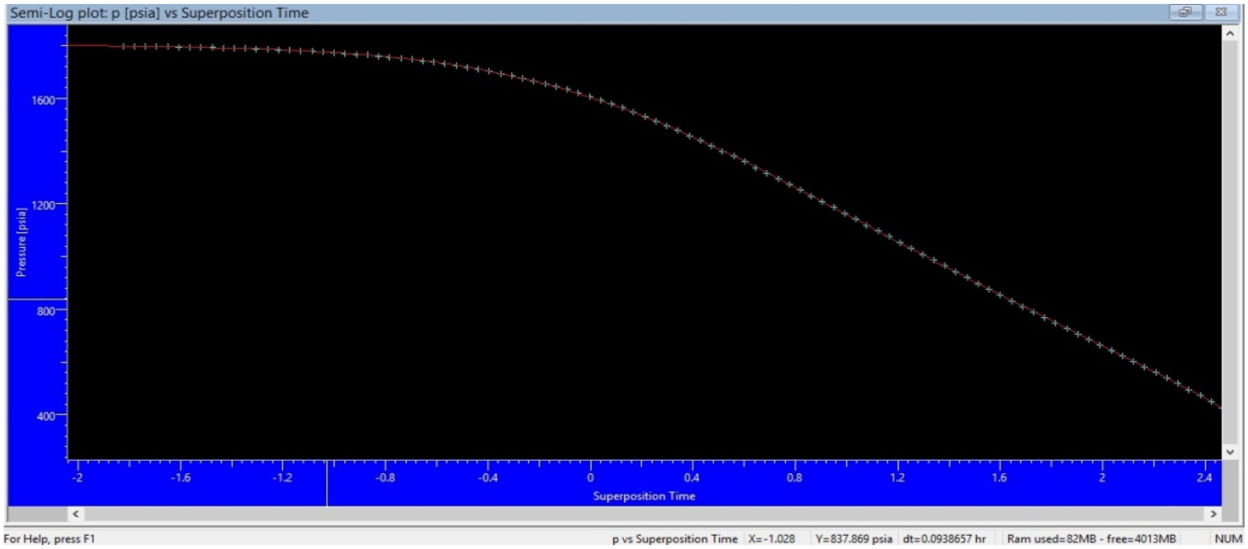

Fig 13: Semi log deconvolution plot with time for Well X-4

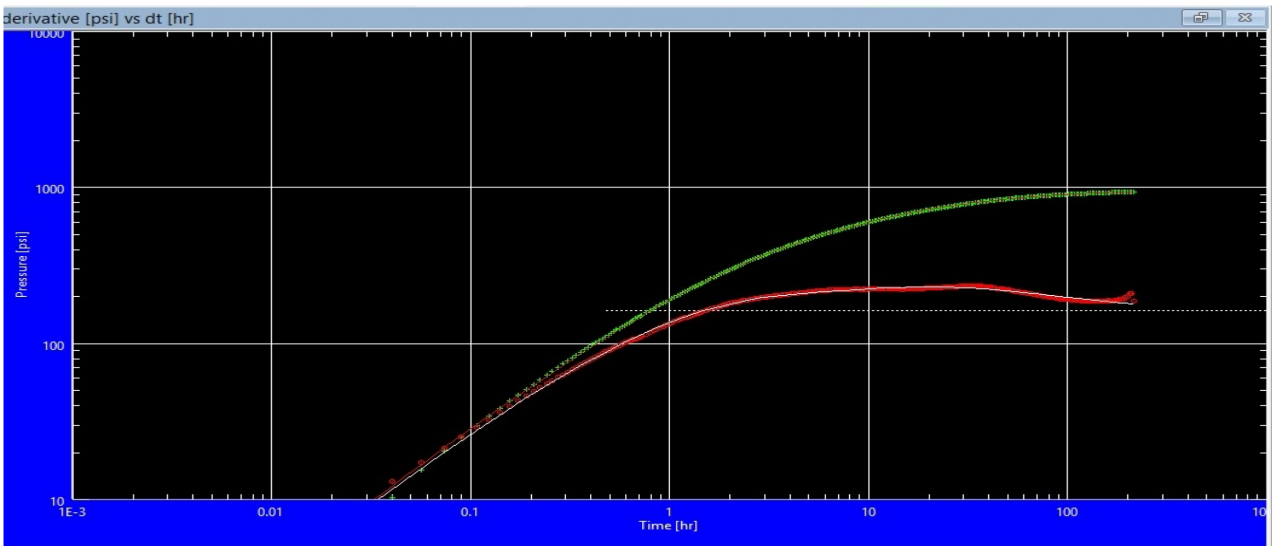

Fig 14: Log Log Plot with time for Well X-4

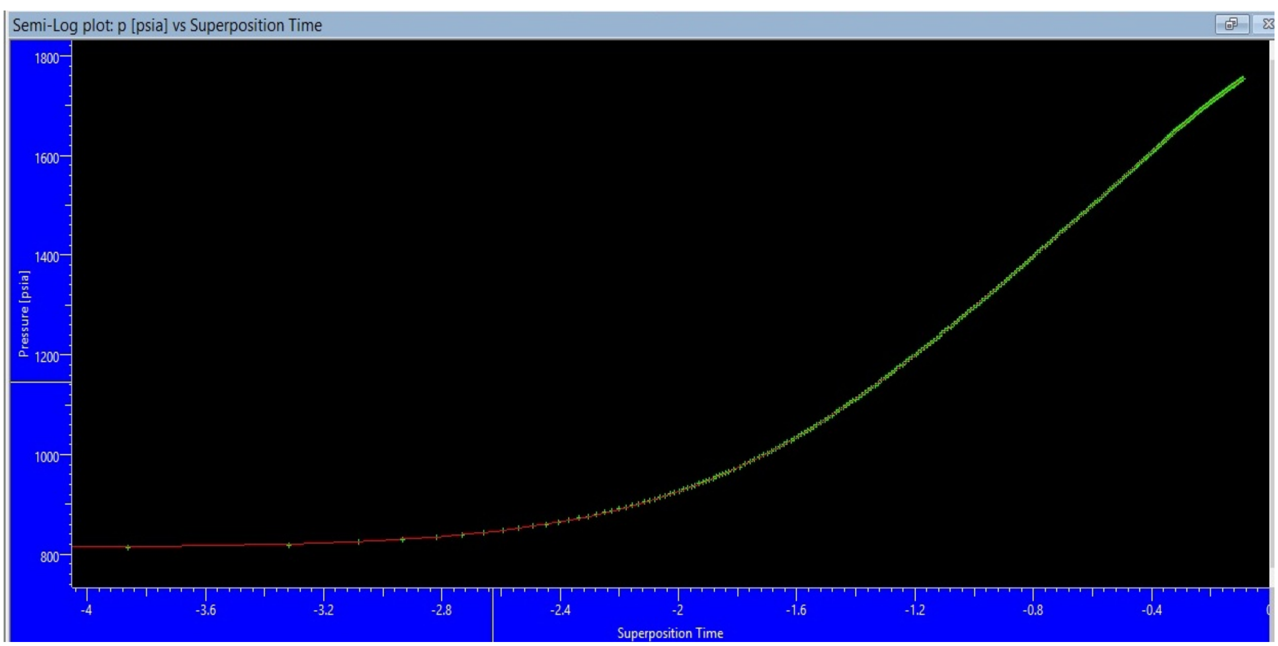

Fig 15: Semi log plot with time for Well X-4

INTERPRETATION GRAPHS FOR WELL X-3

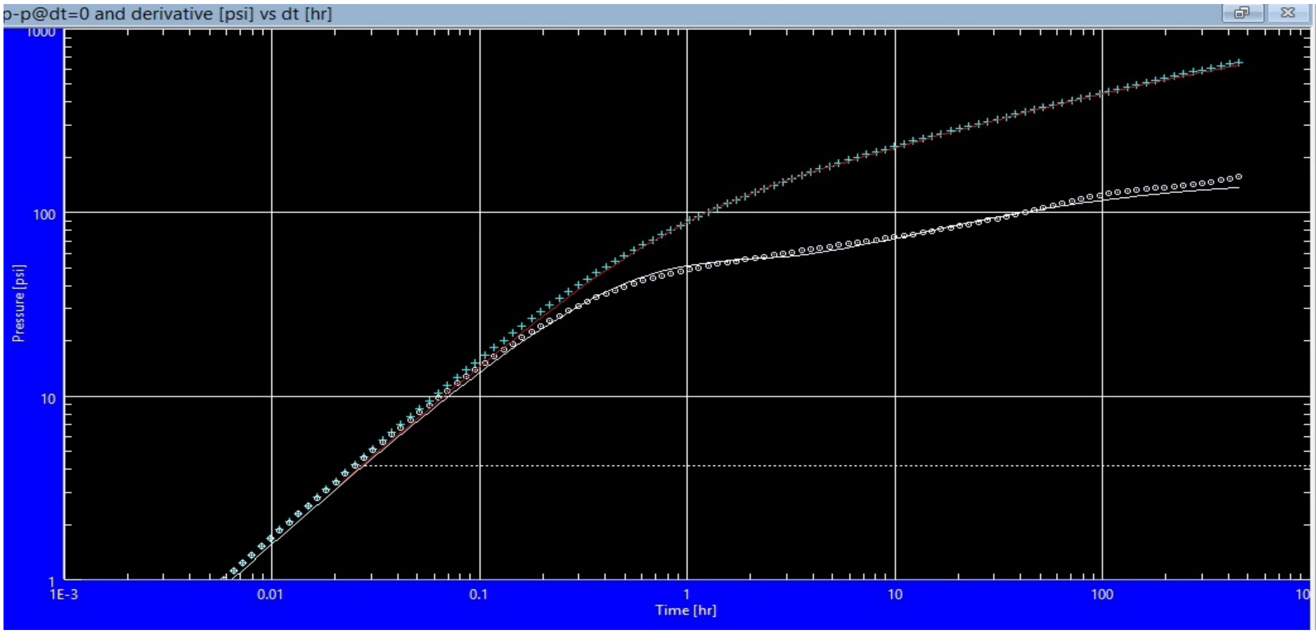

Fig 16: Log Log deconvolution Plot with time for Well X-3

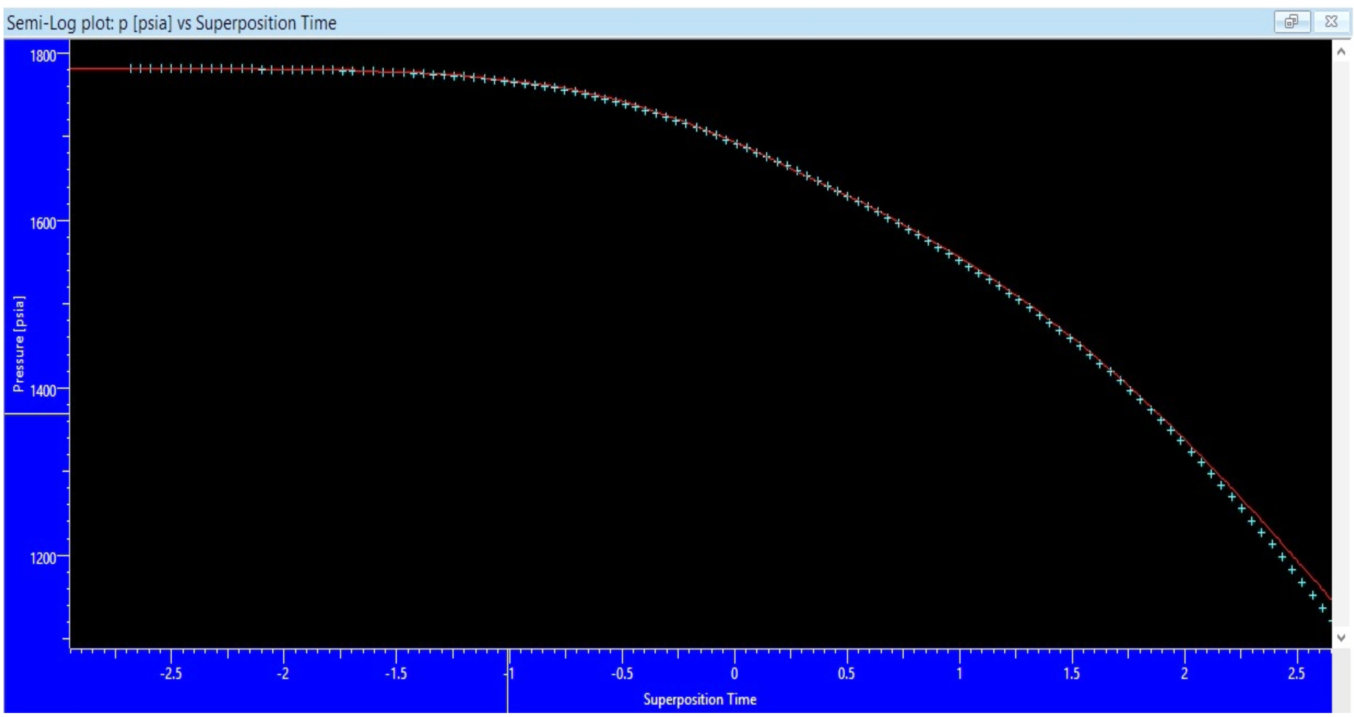

Fig 17: Semi log deconvolution plot with time for Well X-3

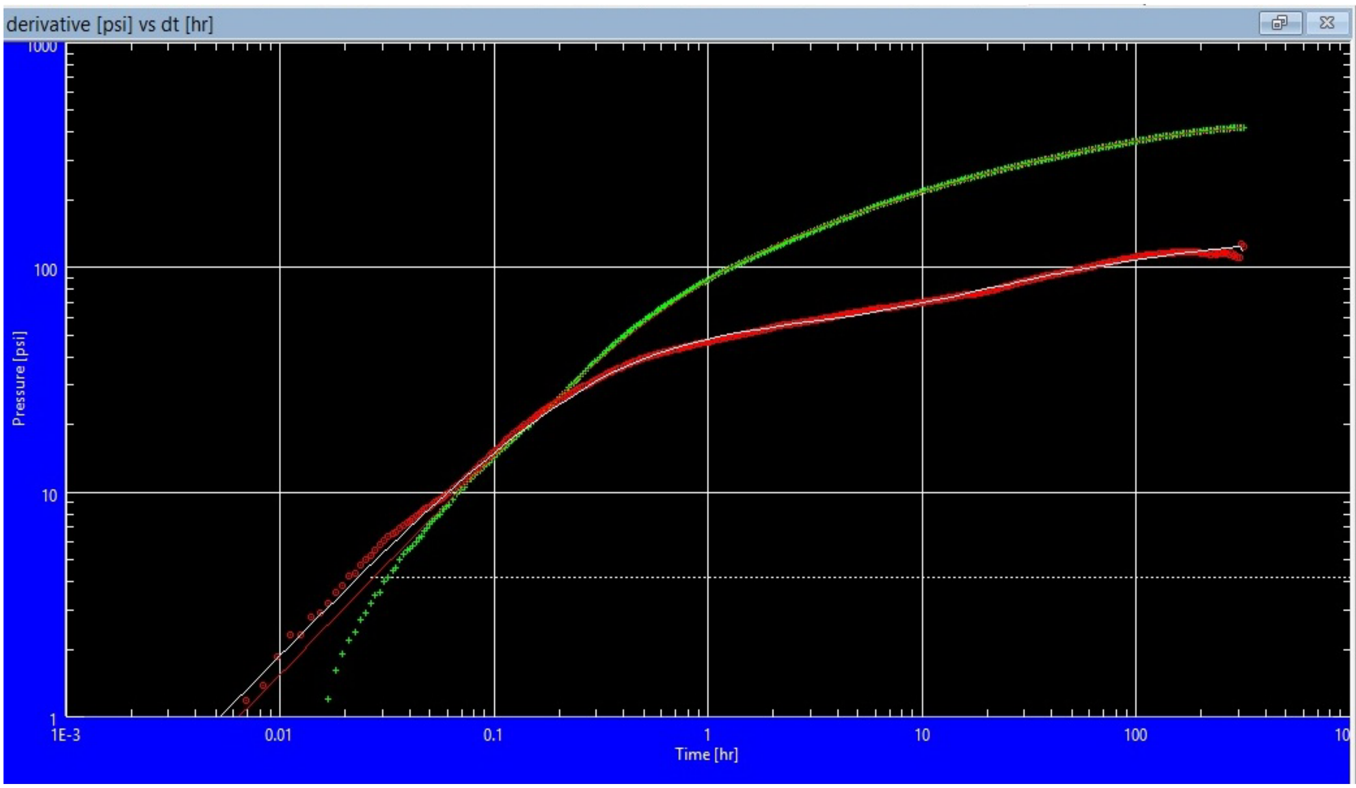

Fig 18: Log Log Plot with time for Well X-3

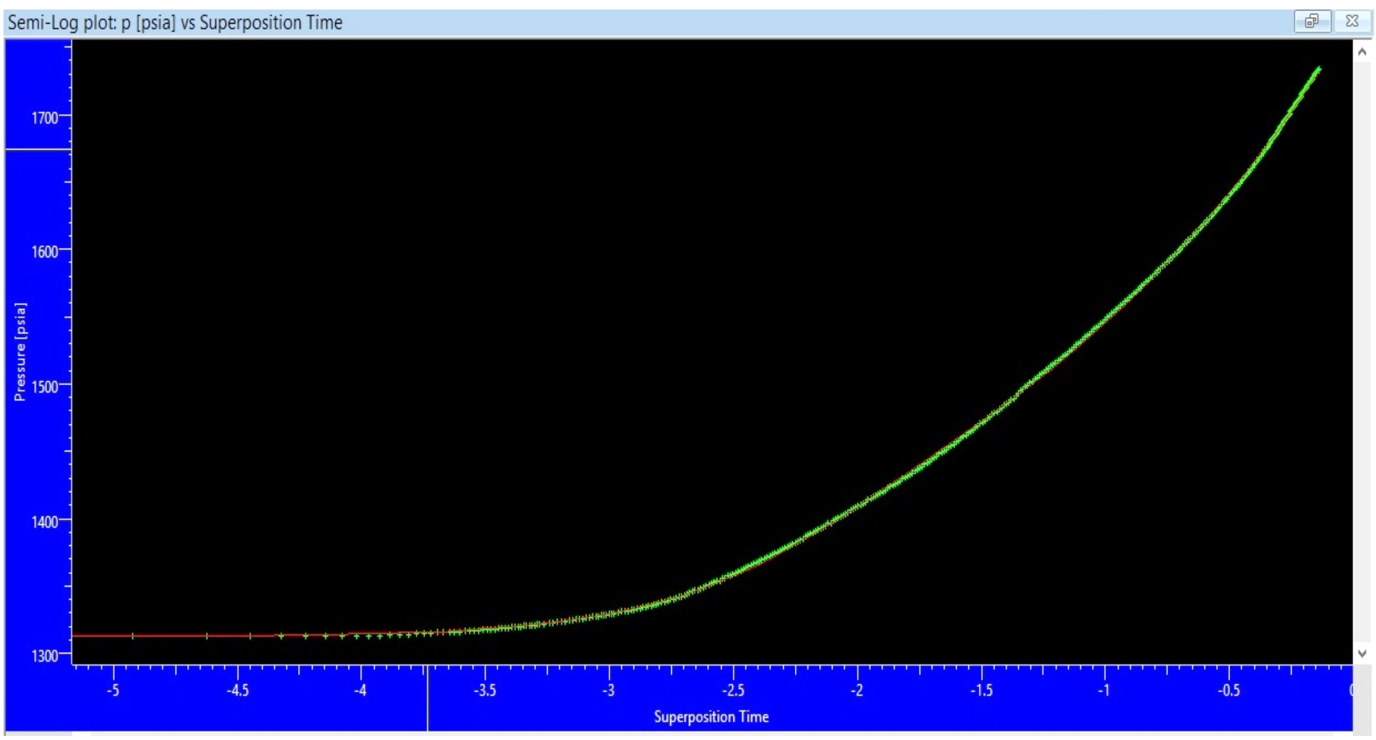

Fig 19: Semi log plot with time for Well X-3