Pressure Buildup Test of Horizontal Wells: A Review Study

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***Abstract*— Test analysis of horizontal wells is much more complex than that of conventional vertical wells because of the complex geometry and possible presence of four flow regimes as an opposed to having a single radial flow period for conventional vertical wells. Possible problems associated with the skin factor make analysis more difficult,unlike traditional vertical wells. This paper presents a review steady for pressure build up test of horizontal wells . A case study of horizontal wells analysis using analytical solutions has been presented.**

Keywords—horizontal well; buildup; flow regimes; well test analysis

I. INTRODUCTION

Oil well test analysis is a branch of reservoir engineering. Information obtained from flow and pressure transient tests about in situ reservoir conditions. are important to determining the productive capacity of a reservoir. Pressure transient analysis also yields estimates of the average reservoir pressure. The reservoir engineer must have sufficient information about the condition and characteristics of reservoir well to adequately analyze reservoir performance and to forecast future production under various modes of operation. The production engineer must know the condition of production and injection wells to persuade the best possible performance from the reservoir. Pressures are the most valuable and useful data in reservoir engineering. Directly or indirectly, they enter into all phases of reservoir engineering calculations. Therefore, accurate determination of reservoir parameters is very important. In general, oil well test analysis is conducted to meet the following objectives:

• To evaluate well condition and reservoir characterization;
• To obtain reservoir parameters for reservoir description;
• To determine whether all the drilled length of oil well is also a producing zone;
• To estimate skin factor or drilling- and completion-related damage to an oil well. Based upon the magnitude of the damage, a decision regarding well stimulation can be made.

Transient pressure analysis of horizontal wells is more complex than that of vertical wells. This paper includes a method for buildup analysis as in the example case study flow regimes and application of pressure derivative in well test analysis [1].

II. APPLICATIONS AND LIMITATIONS OF HORIZONTAL WELLS

Horizontal wells have been used effectively in the following applications:

1. In naturally fractured reservoirs, horizontal wells have been used to intersect fractures and drain them and the reservoir effectively.
2. In reservoirs with water and gas coning problems, horizontal wells have been used to minimize coning problems and enhance oil production.
3. In gas production, horizontal wells can be used in low-permeability as well as in high-permeability reservoirs. In low-permeability reservoirs, horizontal wells can improve drainage area per well and reduce the number of well that are required to drain the reservoir. In high-permeability reservoir, where near-wellbore gas velocities are high in vertical wells, horizontal wells can be used to reduce near-wellbore velocities. Thus, horizontal wells can be used to reduce near-wellbore turbulence and improve well deliverability in high-permeability reservoirs.
4. In EOR applications, especially in thermal EOR, horizontal wells have been used A long horizontal well provides a large reservoir contact area and therefore

enhances infectivity of an injection well. This is especially beneficial in EOR applications where infectivity is a problem. Horizontal wells have also been used as producers.

5. the major advantage of a horizontal well is a large reservoir contact area. Currently, one can drill as long as 0333 to 4000 ft long wells, providing significantly larger contact area than a vertical well.

The major disadvantage is that only one pay zone can be drained per horizontal well. Recently, however, horizontal wells have been used to drain multiple layers. This can be accomplished by two methods: 1) one can drill a "staircase" type welt where long horizontal portions are drilled in more than one layer, and 2) one can cement the well and stimulate it by using propped fractures. The vertical fractures perpendicular to the wells could intersect more than one pay zone and thereby drain multiple zones.

The other disadvantage of horizontal wells is their cost. typically, it costs about 4.1 to 3 times more than a vertical well, depending upon drilling method and the completion technique employed. Fig. 1 An additional factor in cost determination is drilling experience in the given area. Typically, a first horizontal well costs much more than the second well. As more and more wells are drilled in the given area, an incremental drilling cost over a vertical well, as shown in Fig. 2 [2].

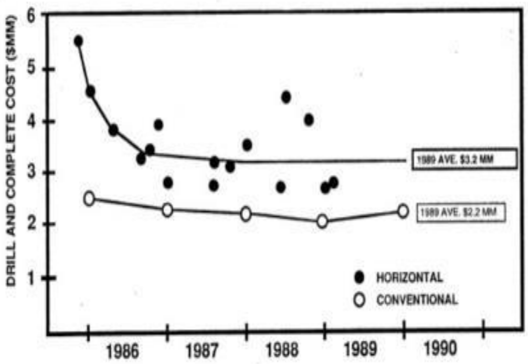

Figure 1. A Comparison of Horizontal and Vertical Well Costs [2]

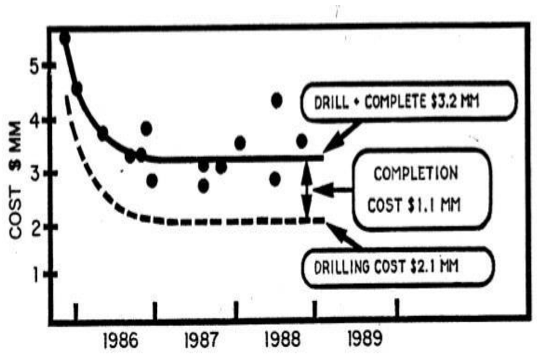

Figure 2. Compound of Drilling completion cost of horizontal wells [2]

III. EFFEFCTIVE WELLBORE RADIUS

- The effective wellbore radius concept it used to represent the well which is producing at a rate different than that expected from the calculation. effective wellbore radius is the theoretical well radius required to match the observed production rate. A steady –state equation with effective wellbore radius can be written as: [2]

$$q = 0.007078 * k * h * \Delta p / (\mu o * Bo * \ln (re/ r'w)) \quad (1)$$

where:

$q =$ oil rate ,STB/day
$k =$ permeability, md
$h =$ reservoir thickness, ft
$\mu_o =$ viscosity, cp
$B_o =$ formation volume factor, RB/STB
$r_e =$ drainage radius, ft
$r'_w =$ effective wellbore radius, ft
$\Delta p =$ pressure drop from the drainage radius to the wellbore, psi

- Can calculate the effective wellbore radius of a horizontal well by converting productivity of a horizontal well into that of an equivalent vertical well.
  - The concept of effective wellbore radius can be extended to calculate the ratio of horizontal and vertical well productivity indices.
- Can be used to calculate effective wellbore radius r'w if the reservoir is anisotropic then equation; [2]

$$r'w = \frac{\mathrm{reh}\,(\frac{L}{2})}{a\left(1+\sqrt{1-\left[\frac{L}{2a}\right]^2}\right)\left(\frac{h}{2rw}\right)^{\frac{h}{L}}} \quad (2)$$

$$a = \left(\frac{L}{2}\right)\left[0.5+\sqrt{0.25+\left(\frac{2reh}{L}\right)^4}\right]^{0.5} \quad (3)$$

where:

$h =$ reservoir thickness, ft
$r_e =$ drainage radius, ft
$r'_w =$ effective wellbore radius, ft
$reh =$ drainage radius of horizontal well , ft
$rev =$ drainage radius of vertical well, ft
$a =$ half-lengh the major axis of drainage ellipse, ft
$L =$ long horizontal well , ft

- On the transient analysis of horizontal wells in an infinite reservoir (Renared ;Raghavan & Joshi report the following equation for effective wellbore radius of a horizontal well in a reservoir with two different permeability the areal plane ,namely Kx and Ky , and vertical permeability Kv [2].

$$r'w = \frac{\frac{L}{2}}{\exp(1+\theta)}\{4\sin\left\{\frac{\pi}{h}\left(Zw+\frac{rw}{2}\sqrt{\frac{Kv}{Ky}}\right)\right\}\sin\left(\frac{\pi}{2h}rw\sqrt{\frac{kV}{kY}}\right)^{m'} \quad (4)$$

$$m' = (\tfrac{h}{L})\sqrt{\frac{Kx}{Kv}}Kh = \sqrt{Kx\,Ky}\text{ , }and\,(XD) = 0.732 \quad (5)$$

$$\frac{Jh}{Jv} = \left\{\ln\left(\frac{\mathrm{rev}}{\mathrm{rw}}\right)\right\} / \left\{\ln\left(\frac{\mathrm{reh}}{\mathrm{r'w}}\right)\right\}, for\ L > h\sqrt{\frac{Kh}{Kv}} \quad (6)$$

$$and (L/2) < 0.9\,reh$$

where:

$\frac{Jh}{Jv}$ = ratio of horizontal and vertical well productivity indices

h = reservoir thickness, ft

kh = horizontal permeability md,

kv = vertical permeability md,

μ_o = viscosity, cp,

B_o = formation volume factor, RB/STB

r_e = drainage radius, ft

r'_w = effective wellbore radius, ft

Δp = pressure drop from the drainage radius to the wellbore, psi

zw = vertical distance of a horizontal well from the bottom boundary of the pay zone, ft

The comparison of the productivity index above imposes the presence of a non-stimulated vertical well. because it differs from one region to another, the productivity of non-stimulated vertical wells is used only for the general comparison. Calculated throughput increments should be adjusted based on local experience with vertical well stimulation treatments using the above equation valid only for tanks above bubble point.

IV. FLOW REGIMES FOR HORIZONTAL WELLS

When the well is opened for flow or closed and the first pressure wave moves into the reservoir, three types of flow systems occur in horizontal wells. Usually, the flow is in part of the reservoir. The beginning of the matter is the (early radial) type due to the change in the horizontal and vertical permeability, and then when the pressure wave reaches the upper and lower limits of the reservoir have the flow from all sides and it is called (linear) or so-called spherical, and after the pressure wave reaches all the area of the reservoir, then the flow is called (late-time radial) and each case can be analyzed and calculations made for it as shown in fig. 3 below: [4]

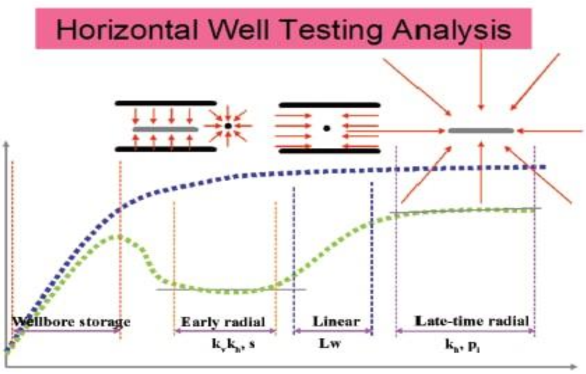

Figure 3. Identification of Flow Regimes and parameter Estimation from each Flow Regime [5]

V. FLOW TIME EQUATIONS OF A HORIZONTAL WELL

Sets of equations are presented here for estimating the various flow regimes based on the concepts of Goode and Thambynayagam's Equations . [1]

Early-Time Radial Flow

The early-time radial flow period ends at Fig. 4

$$t_{e1} = \frac{190.0 d_z^{2.095} r_w^{-0.095} \phi \mu_o c_t}{k_v} \quad (7)$$

where:

t_{e1} = time for the early-time radial flow, hr

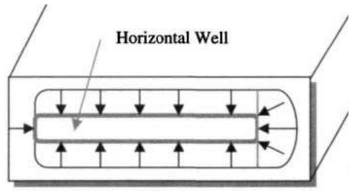

Figure 4. Early-Time radial flow [1]

Intermediate-Time Linear Flow

Intermediate-time linear flow is estimated to end at fig.5 [1]

$$t_{e2} = \frac{20.8 \phi \mu_o c_t L^2}{k_v} \quad (8)$$

where:

t_{e2} = time for intermediate-time radial flow, hr

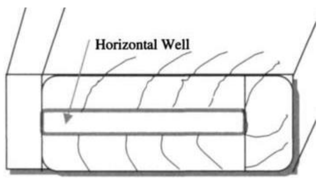

Figure 5. Intermediate-time linear flow [1]

Late-Time Radial Flow or Pseudo-Radial Flow

If late-time radial flow or pseudo-radial flow develops, it will begin at approximately [1]

$$t_{e3} = \frac{1230.0 L^2 \phi \mu_o c_t}{k_v} \quad (9)$$

Where:

$te3$ = time for late-time radial flow

dz =distance from the upper reservoir boundary to the center,ft

Kv= permeability in vertical direction , md

L = effective length of horizontal well ,ft

Kx = permeability in x-direction ,md

VI. PRESSURE BUILDUP TEST IN HORIZONTAL WELLS

Early-Time Radial Flow

Pressure buildup response during this flow period is given by:
For infinite reservoir [1]

$$p_i - p_{ws} = \frac{162.6 q_o \beta_o \mu_o}{\sqrt{k_z k_y} L_w}\left[\log\left(\frac{t_p + \Delta t}{\Delta t}\right) + \gamma_1\right] \tag{10}$$

Intermediate-Time Linear Flow

Pressure buildup response during this flow period is given by:
For infinite reservoir (first linear flow) [1]

$$p_i - p_{ws} = \frac{8.128 q_o \beta_o}{hL}\sqrt{\frac{\mu_o \Delta t}{k_y \phi c_t}} + \gamma_3 \tag{11}$$

Late-Time Radial Flow

Pressure buildup response during this flow period is given by:
For infinite reservoir [1]

$$p_i - p_{ws} = \frac{162.6 q_o \beta_o \mu_o}{h\sqrt{k_x k_y}}\left[\log\left(\frac{t_p + \Delta t}{\Delta t}\right)\right] \tag{12}$$

Late-Time Linear Flow

During this flow period (infinite reservoir case does not exist) (pseudo radial flow) the pressure buildup response for finite (bounded) reservoir is given by [1]

$$p_i - p_{ws} = \frac{8.128 q_o \beta_o}{h h_x}\sqrt{\frac{\mu_o}{k_y \phi c_t}}\left(\sqrt{t} - \sqrt{\Delta t}\right) \tag{13}$$

Where:

$$\gamma_1 = \frac{L}{h}\sqrt{\frac{k_v}{k_x}}\left[\log\left(\frac{k_x t}{\phi \mu_o c_t L_w^2}\right) - 2.023\right] - \log(t) - \log\left(\frac{\sqrt{k_v k_y}}{\phi \mu_o c_t r_w^2}\right) + 3.227 + 0.869 s_z \tag{14}$$

$$\gamma_3 = \frac{162.6 q_o \beta_o \mu_o}{h\sqrt{k_x k_y}}\left[\log\left(\frac{k_x t}{\phi \mu_o c_t L^2}\right) - 2.023\right] \tag{15}$$

VII. APPLICATION OF PRESSURE DERIVATIVE IN WELL TESTING ANALYSIS

Application of pressure derivative includes the use of the pressure type curves and the pressure derivative, and when using the pressure derivative with pressure behavior curves, it gives greater confidence in the results and clarifies the features that are difficult to see in the Horner plot or that are difficult to distinguish due to the similarity in the reservoir
Homogeneous reservoir: The type of curve is used in the analysis of the test with the effect of well storage and skin factor, pressure match gives (KH) time match gives (C) and (CD) curve match gives (S).
Naturally fractured reservoirs:
Pseudo-Steady-State flow: This type of tank shows a pseudo-interference in a stable state, the derivative curve displays the behavior of double porosity and the boundaries of the three bands, as well in production, the primary flow system (homogeneous behavior), the production is continuous - the transient flow system, when the pressure is balanced between two media characterizes the homogeneous behavior (total system). Transient flow: The transient system is described by a set of early homogeneous curves (curves other than pressure and time divided by 2). Vertical fractured reservoirs: It is used to analyze both pseudo-steady-state and transient interference tests of fractured reservoir system as shown below: [1]

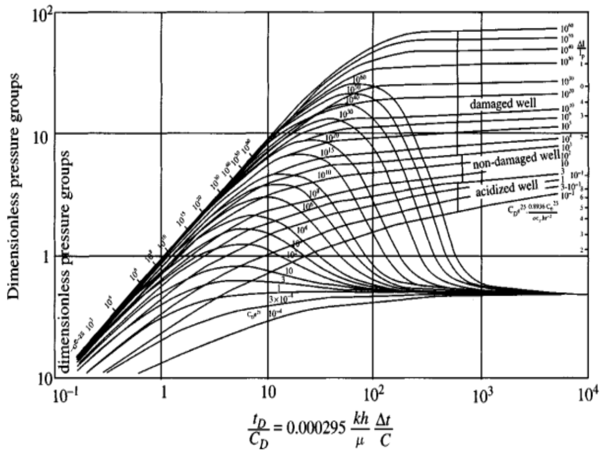

Figure 6. Dimensionless pressure groups [1]

By combining the pressure versus time plot with the logarithm plot of the pressure derivative it will be easier to interpret the transient pressure and also more clear in interpreting the different flow patterns with a higher level of accuracy where the pressure derivative gives a distinctive behavior.

$$tD = 0.000264\ kt / \Phi\mu ctr_w^2,\qquad tDA = 0.000264\ kt/ \Phi\mu ctA \tag{16}$$

Large storage in the wellbore creates difficulty in interpreting the first radial flow when performing the test as shown below:

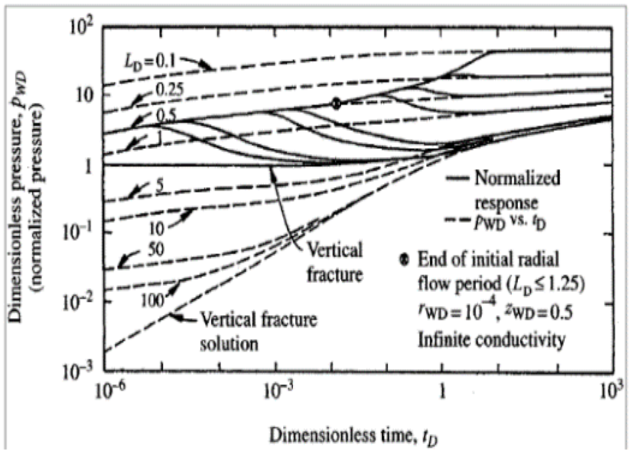

Figure 7. Dimensionless pressure *PwD* [1]

And also in a horizontal well it cannot be calculated in a short period because it is complex and challenging to interpret. The first stability represents the initial radial flow while the last stability refers to the stray radial flow. Some parameters can be known through the complete determination of the flow systems and their response to the derivative, it is used to estimate the thickness of the permeability KHh and the storage coefficient of the well C, and after matching the pressure and time, the first half of the effective well is predicted from the linear flow system, while the first derivative determines the permeability ratio KV/KH and mechanical skin factor SW.[1]

Case Study

Consider a horizontal well in an isotropic
(kv, kx, ky, = kh, = k) and finite reservoir. The following parameters are given: [2]

Rotary Kelly Bushing, ft	78
Perforations, ft (MD)	3771-4599 and 4678-5381
Total Perforated Length, ft	1531
Pump Depth, ft (MD)/TVD (SS)	1965/1817
Gauge Depth, ft (MD)/TVD (SS)	2182/1980
Top of Perforation, ft (MD)/TVD (SS)	3771/2583
Bottom Hole Temperature, °F	155
Wellbore Radius, rw, ft	265
API Gravity	18.5
Formation Volume factor, B, RB/STB	1.078
Oil Viscosity, μ, cp	31
Porosity ,Φ	33%
System Compressibility, c, psi™	10^5
Reservoir Thickness, h, ft	45
Average Oil Gradient, psi/ft	377
Average Water Gradient, psi/ft	440

Production schedule

First shut-in period- Δt	5.47 hours	stimulating well
First Pumping Period	5 minutes	using submersible Pump
Second Shut-in Period	9.25 hours	take out plug at 1963 (MD) and BHP gauge to 2182 (MD)
Second Pumping Period	8.08 hours	using submersible Pump
Final Shut- in Period	12.08hours	buildup test

After stimulation, the well pumped 811 STB in 8.08 hours and then was shut-in for a 12.08 hour buildup test. The measured pressure data are given in Table-1. The well volume between the pump suction and bottom perforation is:

$$V = \pi r_w^2 L' = \pi (0.265\ \mathrm{ft})^2 (5381\ \mathrm{ft} - 1965\ \mathrm{ft}) = 753.6\ \mathrm{ft}^3 \times \frac{1\ \mathrm{bbl}}{5.615\ \mathrm{ft}^3} = 134.2\ \mathrm{barrels}. \qquad (17)$$

Table 1. Pressure buildup data [2]

Δ t (mins)	te (mins)	t+Δt /tΔ	log (t+Δt/Δt)	P (psi)
0				800
5	4.95	98	1.991	810
10	9.8	49.5	1.695	813
15	14.55	33.33	1.523	815
20	19.21	25.25	1.402	817.25
30	28.25	17.17	1.235	820.66
40	36.95	13.13	1.118	823.6
50	45.33	10.7	1.029	826.17
60	53.39	9.08	0.958	828.42
80	68.67	7.06	0.849	832.2
100	82.91	5.85	0.767	835.25
120	96.2	5.04	0.703	837.75
140	108.64	4.46	0.65	839.85
160	120.31	4.03	0.605	841.63
180	131.28	3.69	0.568	843.16
200	141.61	3.43	0.535	844.49
240	160.55	3.02	0.48	846.69
280	177.52	2.73	0.437	848.43
320	192.8	2.52	0.401	849.85
360	2.6.63	2.35	0.371	851.02
420	222.76	2.15	0.333	852.45
180	241.28	1.99	0.303	853.58
540	255.51	1.9	0.278	854.5
600	268.2	1.81	0.257	855.26
660	279.56	1.73	0.239	855.91
725	290.6	1.67	0.222	856.5

The flow rate prior to shut-in is:

$$q = (811 STB / 8.08\ hours) * (24\ hrs / 1 day) = 2409\ STB/D \qquad (18)$$

Based on the pressure buildup data calculate permeability and skin factors

Case Analysis

Horner time ratio (t+Δt)/At and equivalent time t, are calculated in Table, Figure bellow presents a semi log plot of buildup pressure Pws versus Horner time ratio. From Figure there appears to be a fined semi log straight line with slope m = 38.5 psi/cycle. This semi log straight line to Δt = 1 hour gives pws = 828 psia. This straight line might correspond to early time radial flow or pseudo flow. Responds to early-time radial flow around the wellbore. For isotropic formation the permeability is [2]

$$k = 162.6 \times 2409 \times 31 \times 1.076 / 38.5 * 1531 = 222.1\ md \qquad (19)$$

Now we can use this permeability value to estimate the time corresponding to the end of early-time radial-flow period as shown below in fig. 8.

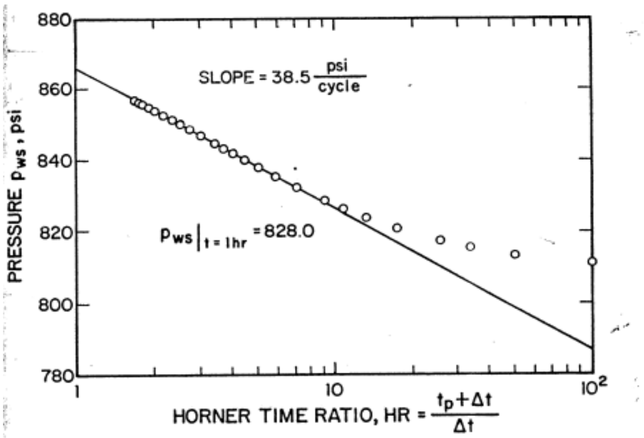

Figure 8 semilog Plot Pws , psi –Horner time ratio [2]

Method I:

$$t_{e1} = \frac{190\, d_z^{2.905}\, r_w^{-0.095}\, \phi\mu c_t}{k_v}$$
$$= \frac{190 \times (22.5)^{2.095} \times 0.265^{-0.095} \times 0.33 \times 31 \times 10^{-5}}{222.1}$$
$$= 0.068 \text{ hours}$$

Method II:

$$t_{e1} = \frac{1800\, d_z^2\, \phi\mu c_t}{k_v}$$
$$= \frac{1800 \times 22.5^2 \times 0.33 \times 31 \times 10^{-5}}{222.1}$$
$$= 0.42 \text{ hours}$$

and

$$t_{e1} = \frac{125\, L^2\, \phi\mu c_t}{k_y}$$
$$= \frac{125 \times 1531^2 \times 0.33 \times 31 \times 10^{-5}}{222.1}$$
$$= 134 \text{ hrs} = 5.6 \text{ days.}$$

The minimum is 0.42 hours, which represents time to end early-time radial flow. (Note we assumed that the well is in the middle of formation thickness.) The semi log straight line shown on figure starts at t = 1.33 hours. Obviously, it does not correspond to the early-time radial flow for an isotropic reservoir.

Let us assume the semi log straight line corresponds to pseudo-radial flow [2]

$$K = 162.6*2409*31*1.078 / 38.5*45 = 7555.5 \text{ md} \qquad (20)$$

Method 1 - Goode and Thambynayagam's Equations

$$t_{s3} = \frac{1230 L^2\, \phi\mu c_t}{k_x}$$
$$= \frac{1230 \times 1531^2 \times 0.33 \times 31 \times 10^{-5}}{7555} = 39.04 \text{ hrs}$$

Method 2 - Odeh and Babu's Equations

$$t_{s3} = \frac{1480 L^2\, \phi\mu c_t}{k_y}$$
$$= \frac{1480 \times 1531^2 \times 0.33 \times 31 \times 10^{-5}}{7555}$$
$$= 46.97 \text{ hrs}$$

Actual buildup time is At 12.08 hours. The inconsistency indicates that = the semi log straight line shown on figure 8 above does not represent the pseudo radial flow.

Next we plotted Δp (= Pws - Pwis) and its derivative versus equivalent time t_2 on log-log scale; see Figure bellow. It is clear that there are severe wellbore storage effects. Even at the end of the buildup period, the wellbore storage effects are still not negligible. Figure shows that the straight line shown does not represent radial flow. Also emphasize that one should first plot pressure data on log-log scale to detect wellbore storage effects when analyzing well testing data. As shown in figure below: [2]

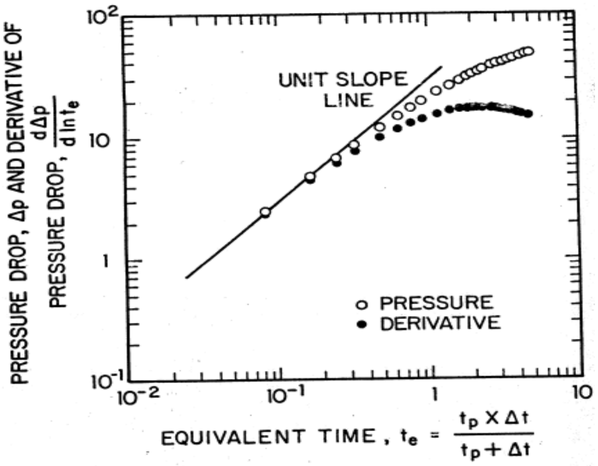

Figure 9. Pressure drop and derivative pressure equivalent time. [2]

VIII. CONCLUSIONS

This review paper included a simplified explanation for a buildup test in horizontal well. Applications and limitations of horizontal well have been presented. It is also the impact of well bore storage has been illustrated. All flow regimes of build up test in horizontal well with the equations have been shown. Analysis of a build up test in a horizontal well has been shown using a case study.

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