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Use of type Curve in Analyzing Pressure Build Up Data: A Case Study of a well in the Niger Delta Basin

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ABSTRACT

Build up test is traditionally conducted in other to restore the initial reservoir energy. This allows for the determination of reservoir properties such as average reservoir pressure, permeability, wellbore storage, skin effect from the straight line pressure build-up graph. Sometimes, the effect of the wellbore storage is so dominant that it distorts the middle time region that is used for analysis and then a model will be required such as type curve that can predict the dynamic behavior of the field in terms of transmissibility and storativity for different operating conditions.

This study reviewed the use of type curves to determine its applicability in the analysis of pressure build up data of a vertical well in the Niger Delta. The well was shut for an extended period of 35hours, to allow the pressure transient generated in the wellbore to travel deeper into the formation. A diagnostic plot of pressure change, ΔP (psi) versus elapsed time, Δt (hours) was done on a log-log graph with same scale as that of the chosen type curve and a match was obtained. Horners plot was also used to verify the results obtained using type curve analysis. A diagnostic plot of derivative of pressure change, ΔP' showed different flow regimes and the possible boundary effects. The huge agreement between the results obtained from both Horner and type curves means that type curves are very efficient in analyzing pressure data from a well in the Niger Delta Basin. The 3.2% difference between the core derived porosity and well test porosity, means that type curves can also serve as an authentication tool to verify this rock property. The derivative plot also showed the various flow regimes and the possible boundary effects which was multiple no flow boundaries.

Introduction

The interpretation of pressure buildup data recorded during a well test has been used mostly to evaluate reservoir characteristics. Static reservoir pressure measured in shut-in wells is used to predict reserves in place through material balance calculations. Many methods have been proposed for interpretation of transient test[1], the conventional Horner's method, and the use of type curves which first appeared in oil industry literature in the seventies. Several kinds are used

Ramey, showed that the graphs could be used to identify the effects of fractured wells[4]. But the presentation technique of Gringarten et al achieved the most widespread use because of its simplicity and the coincidence at the time when well test analysis can be carried out with the use of computer programs generally in the industry. Gringarten solved the radial diffusivity equations for wells with given skin factor and wellbore storage[5]. The latter being defined as a measure of the wells capacity to store fluid during the period of after flow.

Gringarten's type curves are plots of dimensionless pressure versus dimensionless time divided by dimensionless wellbore storage constant, and cater for both idealized wellbore storage, not allowed for in semi log plotting technique, and the period transience. This type curve provides dimensionless solutions to flow equations of an infinite acting radial flow (IARF), the type curves differ by the constant value, and thus they have similar shapes. In 1979 Gringarten and Bourdet proposed a computer program using the curves for model identification did a Horner analysis, then compared field data with a stimulated parameter and thus verified the interpretation[6].

They presented a convenient type curve for model and semi log straight line identification. The reason for linking the dimensionless time divided by dimensionless wellbore storage constant is that during the period completely dominated by after flow the dimensionless pressure equals dimensionless time divided by dimensionless wellbore storage constant, and consequently all the functions converge to a 45^0 straight line. This type curve was a remarkable improvement and was therefore subsequently accepted, this ending the long controversy over the best form of type curves. The various methods sought to remove the non-uniqueness problem that was associated with type curve matching.

There were disadvantages in applying type curve analysis, the first being that the plotting of pressure on a logarithmic scale removed the advantage of semi log plot that for a buildup analysis there was a linear section following an after flow, which includes the transient response, also the resolution in pressure is diminished and the transient response non-linear. Secondly there is no insurance because the log log plot does not have a defined shape characterizing the transient period; hence a mismatch of the buildup plot with a drawdown type curve was possible.

However in 1983, Bourdet[7] took the dimensionless time derivative of Gringarten drawdown curves with the parameter remaining unchanged, superimposed the log-time derivative of the storage and

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[4] Ramey, H.J.Jr:(1970) "Short Time Well Data Interpretation in the presence of Skin effect and Wellbore Storage" JPT 1970, pp97-104

[5] Gringarten, A.C., Bourdet, D.P., Landel, P.A. et al.(1979) "A Comparison between Different Skin and Wellbore Storage Type-Curves for Early-Time Transient Analysis" SPE-8205-MS, pp2-6. http://dx.doi.org/10.2118/8205-MS

[6] Ibid

[7] Bourdet, D. et al. (1983) "A New Set of Type Curves Simplifies Well Test Analysis" World Oil pp 95.

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skin solution on the accepted form of the storage type curve. They observed therefore that a combination of the two type curves could lead to a unique match and hence eliminates the need for a Horner plot. It was also observed that the interpretation of data taken before the semi log straight line was possible, hence solving the problems of the type curves analysis by Gringarten.

Pressure measurements and computers allow pressure derivative analysis at well site, thus the derivative type curve permits diagnosis of a flowing pressure error, thus with a too high flowing pressure, the pressure difference will be low and the early data points approach a unit slope from below the vice versa.

The derivative response is sensitive and hence diminishes the pressure versus time solutions. One limitation however is that the difficulties in gathering the differential pressure transient data but in the last two decades new generational bottomhole pressure gauges, however, allow the rate of

Pressure change with time to be accessible and analysis based on this pressure differential, ΔP', is more descriptive. And since the pressure derivative versus time is represented in the diffusivity equation, this made it to be mathematically satisfying. Other workers that have contributed to the development of type curve include Slide and Falade. Their works forms a greater part of the reference. According to Falade[8], type curve could be used in detecting and evaluating changes in wellbore storage factors and skin due to rebalancing of stratification induced differential.

In a conventional pressure build up test, the test is effectively over at the end of the drawdown period when the dynamic message from the formation is already recorded the pressure gauge in the wellbore, its expression being contained in the dimensionless pressure which is characteristic of the reservoir under tests. When the pressure/pressure derivative ratio is used as a parameter in constructing the type curves, the vertical scales on both curves and field data plots are identical. This alignment of vertical scale make the new type curves easier to match and use in computer aided analysis, thus permitting the effective identification of flow regime. Perhaps the most commonly used method of attempting to overcome the difficulty in applying type curves.

He assumed that the equation could be evaluated for transient conditions, and then the Gringarten plots could be used directly for buildup analysis using the so called equivalent time. Unfortunately, this method is restricted in application to test in which the total flow and buildup periods occur under purely transient conditions[9].

Methodology of Type Curve Analysis

The solutions plotted on type curves are usually presented in terms of dimensionless variables. To review dimensionless variables, consider the *Ei*-function solution to the flow equation, Eq. 1, presented in terms of dimensional variables[10]:

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[8] Falade,G.K. (1980) "Application of Type-curve Analysis In Interpreting Pressure Data From a Stratified Reservoir" 80-01-05 PETSOC Journal Paper – pp 3-4

[9] Ibid

[10] Earlougher,R.C.Jr and Kersch, KM (1974) "Analysis of Short Time Transient Test Data by Type Curve Matching" JPT July 1974, pp793-800.

$$p = p_i + 70.6\frac{qB\mu}{kh}Ei\left(\frac{-948\phi\mu c_t r^2}{kt}\right).$$
.... (1)

Eq. 1 can be rewritten in terms of conventional dimensionless variables as follows.

$$p_D = -\frac{1}{2}Ei\left(-\frac{r_D^2}{4t_D}\right).$$
.... (2)

In Eq. 2, the definitions of the dimensionless variables are

$$p_D \equiv \frac{kh(p_i - p)}{141.2qB\mu},$$
.... (3)

$$t_D \equiv \frac{0.0002637kt}{\phi\mu c_t r_w^2},$$
.... (4)

And $r_D \equiv \frac{r}{r_w}.$ .... (5)

The dimensionless form of Eq. 1 has the advantage that this solution, p_D, to the diffusivity equation can be expressed in terms of a single variable, t_D, and single parameter, r_D. This leads to much simpler graphical or tabular presentation of the solution than would direct use of Eq. 1. Solutions to the diffusivity equation for more realistic reservoir models also include the dimensionless skin factor, *S*, storativity, $\Phi C_t h$ and wellbore storage coefficient, C_D, where

$$C_D = \frac{0.8936C}{\phi c_t h r_w^2}.$$
.... (6)

And $\Phi C_t h = \frac{0.0373qB}{r_{w^2}} \text{ x } \frac{\Delta tm}{tDm} \text{ x } \frac{pDm}{\Delta pm}$ .... (7)

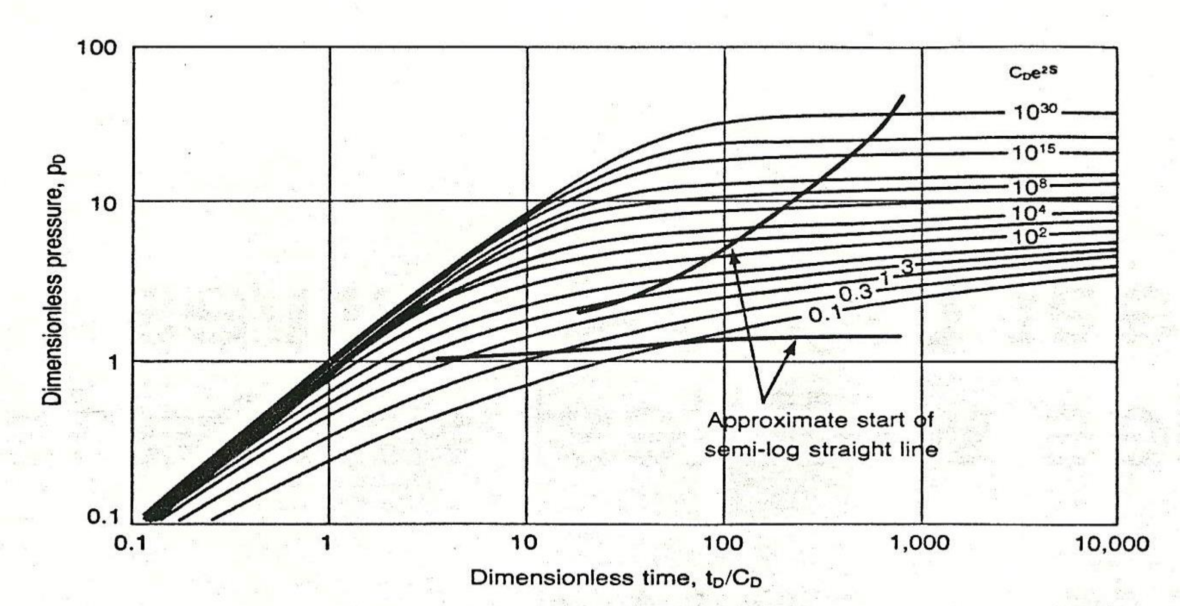

Figure 1-Type curves for a well with wellbore storage and skin in a reservoir with homogeneous behaviour

Interpretation Based On Pressure Behaviour

In this field example of an extended buildup carried out in a well in a field in the Niger Delta Basin after the well was shut in initially for about 2 hours (short build up) to get an idea of the reservoir pressure and the nature of the behaviour, this time however was not adequate to permit more

detailed investigation hence the need to shut in the well for an extended period of 35hours(extended build up), so as to allow the pressure transient generated in the wellbore to travel deeper into the formation. A diagnostic plot of pressure change, ΔP and pressure change derivative, ΔP' versus elapsed time, Δt, for a particular flow period was plotted on a log-log scale. This plot is shown in fig. 2 (data are listed in Table 1).

This plot is diagnostic because it allows the identification of well and reservoir behaviour[1]. Once the behaviour has been identified, which involves comparing actual pressure response with theoretical responses known as type curves, the correct analysis can be performed. Also, Horner' plot analysis was also done to compare the validity of results obtained using type curve analysis as shown in Figure 3.

The well and reservoir data are:

Porosity, Φ =0.309
Pay thickness, h = 16ft
Wellbore radius = 0.51ft

Oil FVF, B_o= 1.493Rb/STB
Production time, t_p = 22.59hrs
Effective compressibility, C_t = 2.46 x10^{-5} psi^{-1}

Table 1: Buildup Data: A Representative Sample

Elapsed Time, t (Hrs)	P_{ws} (psi)	Pressure Change, $p(psi)$	Derivative of pressure change, Δp'	Elapsed Time, t (Hrs	P_{ws} (psi)	Pressure Change, $p(psi)$	Derivative of pressure change, Δp'
0.0056	2201.86	50.072	36.219	**2.0833**	2419.287	267.499	19.175
0.0111	2229.774	77.986	40.8	**2.1055**	2419.467	267.679	19.13
0.0167	2248.712	96.924	46.35	**2.1278**	2419.646	267.858	19.092
0.0222	2263.33	111.542	51.3197	**2.15**	2419.823	268.035	19.043
0.0278	2274.817	123.029	51.016	**2.1667**	2419.95	268.162	19.011
0.0389	2292.816	141.028	53.513	**2.1889**	2420.122	268.334	18.967
0.05	2305.58	153.792	50.466	**2.2111**	2420.287	268.499	18.919
0.0611	2315.625	163.837	48.895	**2.2333**	2420.453	268.665	18.869
0.0778	2327.022	175.234	45.756	**2.2556**	2420.616	268.828	18.836
0.0944	2335.623	183.835	43.111	**2.2778**	2420.779	268.991	18.789
0.1167	2344.479	192.691	40.315	**2.3**	2420.931	269.143	18.759
0.1389	2351.179	199.391	37.707	**2.3222**	2421.094	269.306	18.719
0.1611	2356.567	204.779	35.678	**2.344**	2421.245	269.457	18.678
0.1833	2361.028	209.24	34.018	**2.3667**	2421.403	269.615	18.638
0.2056	2364.854	213.066	32.693	**2.3722**	2421.439	269.651	18.628
0.2278	2368.104	216.316	31.441	**2.3778**	2421.475	269.687	18.619

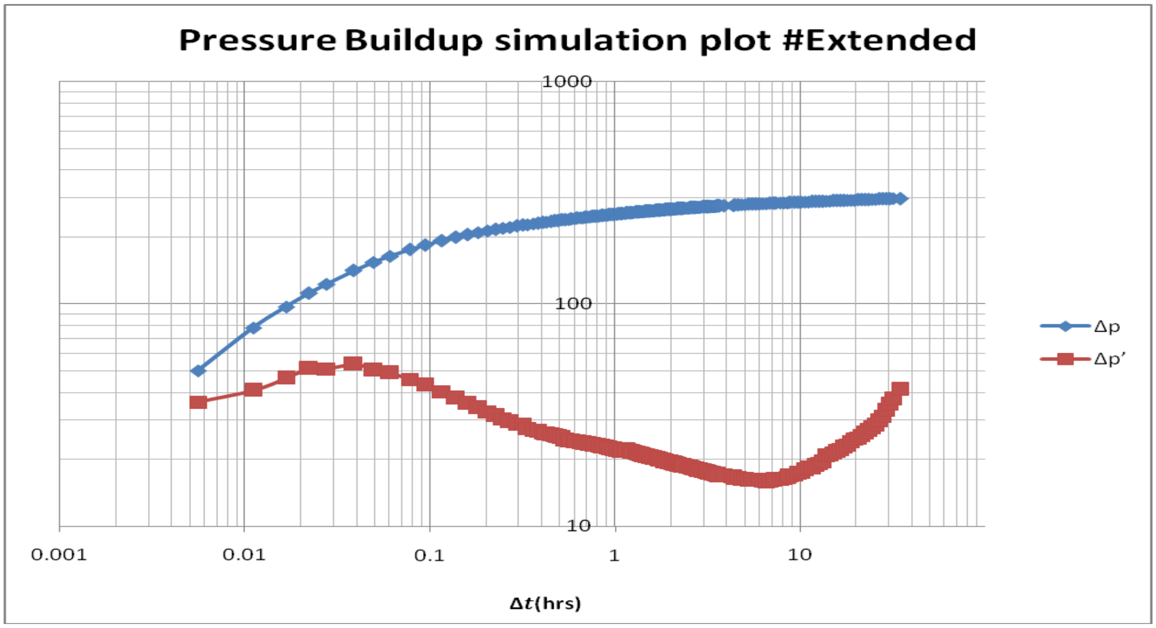

Figure 2 - Buildup Diagnostic Plot

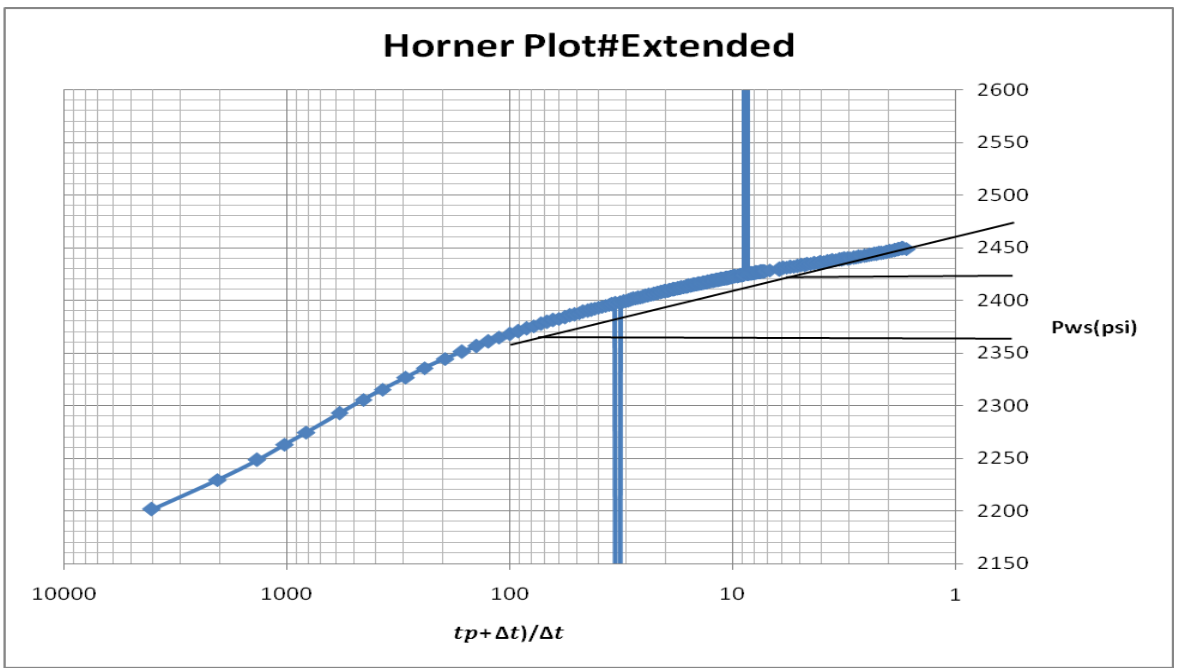

Figure 3 - Horner plot

Procedure for Matching

Analysis is usually performed either with computer programs or manually[11]. The later approach is presented in this work. The initial match was made by sliding the plot of the test data of Δp in

[11] Ibid

Figure 2 over the type curves, with respect to the unique straight line at early time, and then selecting the best possible match-curve. The end of wellbore storage and the start of infinite acting radial flow are then obtained from the limits marked on the type curves (**Figure 1**).

After obtaining a match, the ordinate of the match point is measured in the type curve system of axes $P_D$and in the Diagnostic plot of axes Δp to obtain;

Pressure match, $\frac{(PD)m}{(\Delta p)m}$ = $1.998\text{x } 10^{-2}$

Also in the same way the abscissa of the match point, M, is measured in the type curve system of axes, t_D/C_D and in the Diagnostic plot of axes, Δt to obtain;

Time match, $\frac{\Delta tm}{(tD/cD)m}$ = $2.2214 \text{ x } 10^{-3}$

Presentation of Results

From Equation 3

Reservoir thickness, Kh= $141.2q B \mu \frac{(PD)m}{(\Delta p)m}$

Kh= 141.2 x 320 x 0.537 x 1.493 x $1.998 \ast 10\text{^} - 2$

= 723.8mDft

Permeability, K = $\frac{723.8}{16}$

= 45.25mD

Also, wellbore storage coefficient, C= $\frac{0.000295kh(\Delta t)m}{\mu(tD/CD)m}$

C= $\frac{0.000295 \text{ x } 723.8 \text{ x } 2.2214 \text{ x } 10^{-3}}{0.537}$

C = $8.8331 \text{ x } 10^{-4}$ bbl/psi

Therefore,

Dimensionless wellbore storage coefficient, C_D= $\frac{0.8937C}{\Phi Cehr_{w^2}}$

C_D= $\frac{0.8937 \text{ x} 8.8331 \text{ x } 10^{-4}}{0.309 \text{ x } 2.461 \text{ x } 10^{-5} \text{ x } 16 \text{ x } 0.51^2}$

C_D = 24.95

The value of $C_D e^{2s}$is used to determine the skin, S

log $C_D e^{2s}$=1.83

$\log(24.95e^{2s}) = 1.83$

S = 0.4984

Storativity, $\Phi C_t h = \frac{0.0373 qB}{r_{w^2}} \text{ x } \frac{\Delta tm}{tDm} \text{ x } \frac{pDm}{\Delta pm}$

$= \frac{0.0373 \text{ x } 320 \text{ x } 1.493}{0.51^2} \text{ x } 8.9034 \text{ x } 10^{-5} \text{x} 1.998 \text{X} 10^{-2}$

$= 1.2188 \text{x } 10^{-4} \text{psi}^{-1} \text{ft}$

Porosity, $\Phi = \frac{1.2188 \text{ x } 10^{-4}}{2.461 \text{ x } 10^{-5} \text{ x } 16}$

$\Phi = 0.32$

The percentage difference between the core derived porosity value and the well test porosity is calculated below as Percentage difference= $\frac{\textit{Well test value} - \textit{Core Derived value}}{\textit{Core Derived value}}$

Therefore, % difference for $\Phi = \frac{0.32 - 0.31}{0.31} \text{ x } \frac{100}{1}$

= 3.2%

Also, the analysis from Horner plot, figure 3 is as follows;

Pressure @ $(tp + \Delta t)/\Delta t$ =1, P_{1hr} = 2480psia

Slope, m = $\frac{2428 - 2371}{1}$ = 57 psi/cycle

$m = \frac{162.6qu\Phi B}{kh}$

$kh = \frac{162.6qu\Phi B}{m}$

$kh = \frac{162.6 \text{ x } 320 \text{ x } 1.493 \text{ x } 0.537}{57}$

kh = 731.86mDft

$k = \frac{731.86}{16}$

= 45.74mD

The percentage deviation of the results obtained using type curve analysis from that obtained via Horner analysis is calculated below as

Percentage Deviation $= \frac{\textit{Type curve Analysis} - \textit{Horner Analysis}}{\textit{Horner Analysis}}$

Therefore, % deviation for K $= \frac{45.25 - 45.74}{45.74} \text{ x } \frac{100}{1} = 1.1\%$

Skin factor, S = 1.151[$\frac{\text{P1hr} - \text{Pwf}}{m}$ - log $\frac{\text{k}}{\Phi\text{ucer}_{\text{w}^2}}$ + 3.23]

S = 1.151[$\frac{2475 - 2198.597}{57}$ -

log$\frac{45.74}{0.309\text{x}0.537 \text{ x } 2.461 \text{ x } 10^{-5} \text{ x } 0.51^2}$ + 3.23]

S = 0.5124

Percentage Deviation $= \frac{\textit{Type curve Analysis} - \textit{Horner Analysis}}{\textit{Horner Analysis}}$

Therefore, % deviation for S $= \frac{0.4984 - 0.5124}{0.5124} \text{ x } \frac{100}{1}$ =2.7%

Observations: From the results;

- The positive skin indicating damage to the wellbore causing a reduction in the flow efficiency.
- From the plot of the derivative pressure change, the beginning of build up signifies the wellbore storage effect which was prominent and lasted between 0.006hours to 0.8hours.
- Also, the plot of the derivative pressure shows an upturn of the curve late in the buildup between 6hours to 40hours. This upturn is possible due to multiple no flow boundaries.

Conclusion

- The results obtained both from type curves and Horner plot are in huge agreement as can be seen in the percentage deviation which is less than 5%, this implies that type curves are very efficient in analyzing pressure build up data from a well in the Niger Delta Basin.

- The derivative plot clearly showed the various flow regimes and possible boundary effects. A clear demonstration of type curves potential.

- It also performed well when used in the authentication of laboratory results of rock property such as porosity as can be seen from the percentage difference above.