Uniport Journal of Engineering and Scientific Research (UJESR)

Vol. 6, Special Issue, 2022, Page 01-06
ISSN: 2616-1192

(www.ujesr.org)

Prospects of Estimating Permeability from Limited Pressure Build-Up Test

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Abstract
Motivated by the simplicity and cost-effectiveness of the well-established short-duration slug test used to characterize the hydraulic conductivity (permeability) of an aquifer in hydrogeology, this paper examines the prospects of evaluating permeability of a petroleum reservoir from limited pressure build-up (PBU) tests. The potential of this modified technique to monitor permeability changes between different PBU tests of limited duration is also investigated. A mathematical model that can be used to evaluate permeability from a simple analysis of limited PBU test data is formulated and solved. The results of two field examples presented show that the proposed method is promising, especially for evaluating permeability changes over time. However, its major improvement area is in achieving robust and more accurate estimation of permeabilities for a wide range of well-reservoir systems.

Keywords: *Permeability estimation; Hydraulic conductivity; Pressure build-up test, Slug test*

Received: 1st July, 2022 *Accepted: 14th July, 2022*

1. Introduction

Multiple techniques are available to determine the permeability of a reservoir. These techniques, which vary in complexity, cost and reliability, include core analysis, nuclear-magnetic resonance logs, transformation of wireline logs as well as formation testing. Drawdown and pressure build-up (PBU) tests belong in the class of formation testing. Compared to other techniques, formation testing offers the advantage of characterizing permeability at a large scale, which is crucial for proper assessment of the productivity and injectivity of a well-reservoir system at field scale to drive critical business decisions.

A PBU test requires shutting the subject well, hence either production or injection deferments are always incurred. This shut-in yields a PBU curve that, in principle, can be submitted for standard analyses to characterize the well, reservoir and boundary system. Although a PBU test is more robust than its drawdown counterpart because of the vulnerability of the latter to flowrate fluctuations, it is important to note that shutting the well for long is not a guarantee that the test objectives would be met in terms of obtaining a PBU curve that is of satisfactory quality for standard analysis. Against this backdrop, there is motivation for a limited but fit-for-purpose PBU test data and analysis that may provide useful subsurface characteristics while minimizing the deferments often associated with such tests in practice.

In hydrogeology, slug test is a widely used method to determine in-situ permeability of an aquifer for various well geometries and subsurface conditions (Bouwer, 1989; Black 1978; Bouwer and Rice, 1976). A slug test entails either a short-term introduction or removal of water from an aquifer through either a well or borehole. Measurements of the rise or fall in water level within the well (or borehole) as it returns to quasi-equilibrium conditions can be analysed to estimate the hydraulic conductivity of the connected aquifer (Campbell et al., 1990). As the name implies, a slug test is often short-lived, hence it does not require a long time to execute and complete.

As described by several authors (Campbell et al., 1990; Hvorslev, 1951), the slug test requires monitoring the temporal evolution of the ratio H/H_o; where H_o is the depth differential that the water level falls upon removal of a water slug, while H refers to the height of the water level below the static water level at any instant t since the slug is removed. In principle, a semi-log plot of this ratio versus time should yield a straight line. Some workers have shown that the results of the slug test are not sensitive to the slug volume used, and that only a few depth-to-water measurements are required to obtain a straight line on the semi-log plot (Campbell et al., 1990).

In principle, we consider a slug test as analogous to a PBU test because both tests require well shut-in, such that mass exchange is restricted to the wellbore and the reservoir during the tests. In other words, there is no mass transfer between the surface and subsurface systems during either of these tests. However, a slug test is faster, and the analysis of its dataset is less complex. Motivated by the foregoing advantages, it is worthwhile to explore the prospects of using knowledge of slug test to simplify the traditional PBU test and analysis.

In this paper, under reasonable assumptions, we adapt the principle and theory developed for the use of slug tests to evaluate the in-situ permeability (hydraulic conductivity) of aquifers to analyse the PBU tests conducted in a system of petroleum well and reservoir. Rather than focusing on the often time-consuming and expensive full PBU test period, our interest is in the short time interval between when a well is shut-in for PBU test and when the rising pressure begins to approach the reservoir pressure asymptotically. This period describes the fastest response during a PBU test. In principle, this relatively short (and early-time) PBU interval is largely a manifestation of the reservoir behaviour, as against the boundary responses, hence we speculate that it should provide reasonable insights into the permeability of the rock connected to the wellbore in question.

Furthermore, unlike the traditional Horner analysis (Bourdet, 2002; Horner, 1951), which is relatively intensive in terms of data input and rigour of analysis, the proposed method is simpler, faster, and always guarantees much less production and injection deferments.

2. Model formulation

We consider a simple vertical well that fully penetrates a homogenous reservoir. On shut-in, a slug of inflow occurs from the reservoir into the wellbore over the lag time required for the shut-in signal to travel between the choke and sandface (Fig. 1). For an incompressible flow at steady state, the mass balance over the control system is given by:

$$Q_{in} = Q_{out} + \frac{dV}{dt}, \tag{1}$$

where Q_{in} (m^3/s) and Q_{out} (m^3/s) are inflow into and outflow from the system of interest (control volume), respectively. V is the volume (m^3) of the system and t is time (s). The accumulation term is the additional fluid volume (i.e., slug) produced into the wellbore from the upstream porous medium from the instant of well shut in.

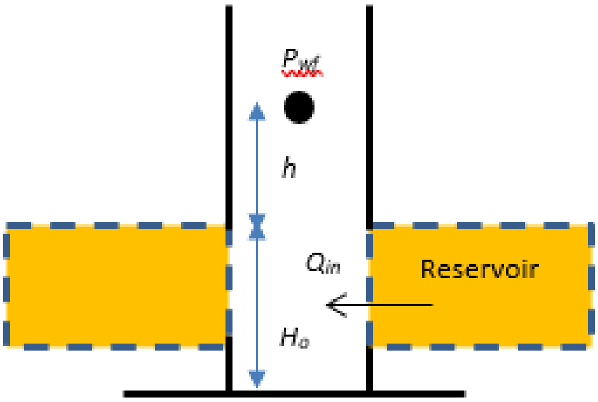

Fig. 1: Schematic of the physical model of a production well at shut-in conditions

Under shut-in conditions, $Q_{out} = 0$, while the inflow Q_{in} from the porous medium into the wellbore can be expressed as a function of the head gradient in the wellbore as follows:

$$Q_{in} = \frac{k_c A h}{\Delta r}, \tag{2}$$

in which k_c (m/s) = hydraulic conductivity of the porous medium feeding the control volume, A (m^2) = cross-section of the porous medium, Δr (m) = radius of porous medium in near-well area and h (m) = change in liquid level within the control volume. The ratio $h/\Delta r$ is the so-called hydraulic head gradient. Combining Eqs. 1 and 2 while expressing the accumulation term in an appropriate form, we have

$$\frac{k_c A h}{\Delta r} = \pi r_w^2 \frac{dh}{dt}, \tag{3}$$

where r_w (m) = radius of control volume. Specifically, if the downhole pressure gauge is located within the tubing, then r_w refers to the tubing radius, as against the casing or open-hole radius. Fig. 2 is a simple schematic that illustrates the importance of referring r_w as the radius of the section accommodating the pressure gauge, as against referring to the open-hole or casing. Both wellbores in Fig. 2 are of same length but different diameters. Both are charged with same liquid type and volume. Due to differences in liquid levels, the static pressures differ by a factor of 4. Solving the ordinary differential equation (3) for the quantity h, under the following initial conditions $h = H_o$ at

$t=0$ and $h=H_o+h$ at $t=t$, we have the following solution to describe the instantaneous liquid level h within the control volume during shut-in conditions.

$$\log_e\left[\frac{h+H_o}{H_o}\right]=\frac{k_c A}{\pi r_w^2(\Delta r)}t. \tag{4}$$

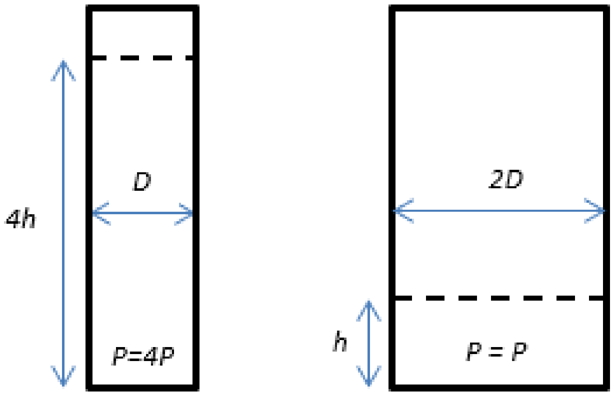

Fig. 2: Graphical illustration of the effect of control-volume radius on static head.

For convenience, we re-write Eq. 4 as

$$\log_e\left[\frac{h+H_o}{H_o}\right]=\frac{k_c G}{\pi r_w^2}t, \tag{5}$$

where the quantity G (m) is an empirical constant commonly referred to as the shape factor. Under shut-in conditions, instantaneous static pressure is largely proportional to liquid level i.e., $P_{wf}\,\alpha(h+H_o)$ and $P_o\alpha H_o$. Here P_{wf} (Pa) is the shut-in bottomhole pressure at any time during shut-in while P_o (Pa) is the bottomhole pressure just at shut-in (at t = 0). For convenience in downhole monitoring during shut-in we re-cast Eq. 5 in terms of static pressure as follows.

$$\log_e\left(\frac{P_{wf}}{P_o}\right)=\frac{k_c G}{\pi r_w^2}t. \tag{6}$$

Eq. 6 suggests that a plot of $\log_e\left({P_{wf}}/{P_o}\right)$ versus shut-in time t should yield a straight line in the interval $t=0$ to when P_{wf} starts approaching the equilibrium reservoir pressure. The slope of the straight line from this semi-log plot is the quantity m (cycle/s), given by:

$$m=\frac{k_c G}{\pi r_w^2}. \tag{7}$$

From Eq. 7, we can estimate the hydraulic conductivity of the feeding porous medium as

$$k_c=\frac{\pi r_w^2 m}{G}. \tag{8}$$

We recognize that permeability k (m^2) and hydraulic conductivity are related by the following expression

$$k=\frac{k_c\mu}{\rho g}, \tag{9}$$

in which μ = fluid viscosity (Pas), ρ = fluid density (kg/m^3) and g = gravitational acceleration (m/s^2). By combining Eqs. 8 and 9, we derive the following expression for estimating the permeability of the porous medium connected to and feeding the control volume (wellbore).

$$k=\frac{\pi r_w^2 m\mu}{G\rho g}. \tag{10}$$

Several studies have presented different expressions for estimating the shape factor G for various well geometries and aquifer systems (Hvorslev, 1951; Mathias and Butler, 2006; Ratnan et al., 2001). However, for the typical limiting case in which the completion interval L is much larger than the open-hole wellbore radius R (i.e., $L/R>>1$), the shape factor can be estimated as follows (Mathias and Butler, 2006).

$$G=\frac{2\pi R}{\log_e\left(2L/R\right)}. \tag{11}$$

Note that the original expression by Mathias and Butler [8] has the numerator as $2\pi L$, but we have re-written it as $2\pi R$ for a more appropriate description of the wellbore circumference. Incidentally, as would be shown later, this modification provides more robust estimation of permeability than the original expression for shape factor. Substituting Eq. 11 into Eq. 10 and simplifying, we obtain the following expression to generate a first-order estimate of in-situ permeability of the porous medium connected to a wellbore from a limited PBU test dataset.

$$k=\frac{m\mu r_w^2}{2R\rho g}\log_e\left(2L/R\right). \tag{12}$$

Note that the quantities L and R are required to be in metres for application in Eq. 12.

3. Results and discussion

To test the applicability of the proposed method, we consider two field examples. Both cases refer to vertical wells completed in oil-bearing sandstone reservoirs. The wells, which are of cased-hole completions, are equipped with permanent downhole gauges (PDHG) for real-time monitoring of downhole pressure and temperature. In wells A and B, PDHGs are at vertical offsets of ca. 250m and 32m from the corresponding sandfaces, respectively.

In Fig. 3, the full pressure history during the test, which includes drawdown and build-up responses, is displayed for well-A. Extract and analysis of the early-time PBU data in line with the method proposed in this study are illustrated in Fig. 4 for the same well A. Corresponding plots for well B are presented in Figs. 5 and 6 for the full test pressure history and extracted PBU dataset, respectively.

A close examination of Figs. 4 and 6 would suggest that the early PBU responses of both wells correlate reasonably to a semi-log approximation as described by Eq. 6. Although the reasons for lack of full conformance to a linear (semi-log) trend are not yet fully understood at this time, we speculate that these might not be unconnected with wellbore storage effects and other physical phenomena not captured in the current conceptual framework.

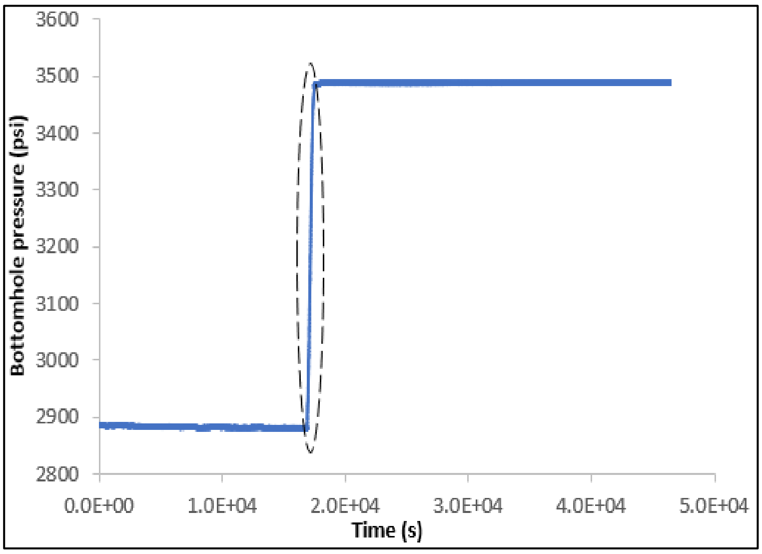

Fig. 3: Full pressure history highlighting section of limited PBU for analysis (well A)

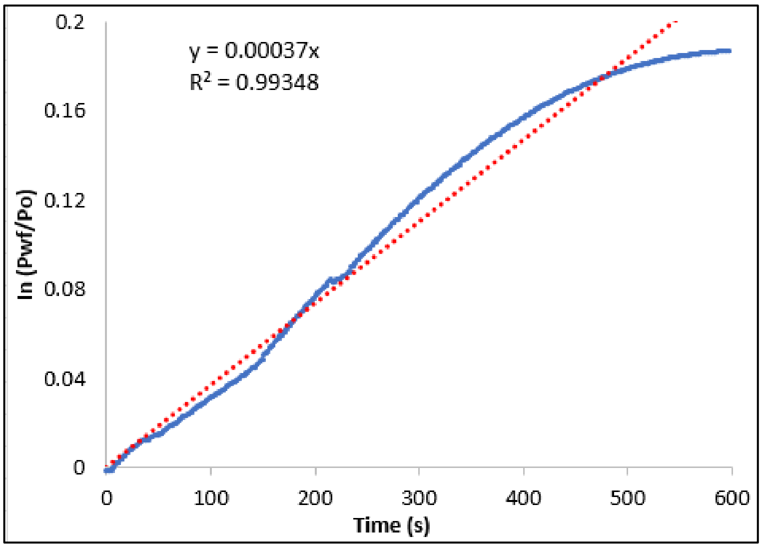

Fig. 4: Analysis of extracted early-time PBU history (well A)

Relevant input data and the results of both examples are summarized in Table 1. For completeness, permeability estimates obtained from this method are compared against the corresponding estimates obtained from rigorous application of the Horner method to the full PBU history. The results suggest that the permeability estimates of both methods are comparable. Most important, the results provide useful insights into the first-order magnitude of permeability without having to execute the expensive full PBU test and to perform a rigorous and computationally intensive analysis of resulting full PBU dataset.

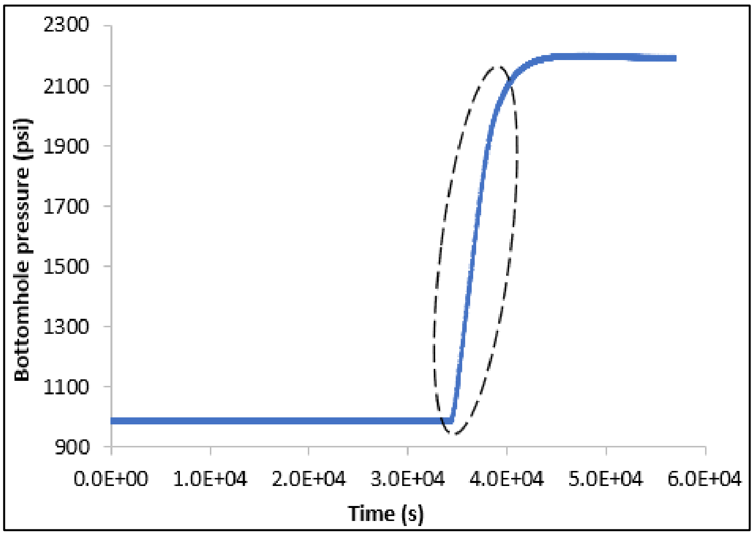

Fig. 5: Full pressure history highlighting section of limited PBU for analysis (well B)

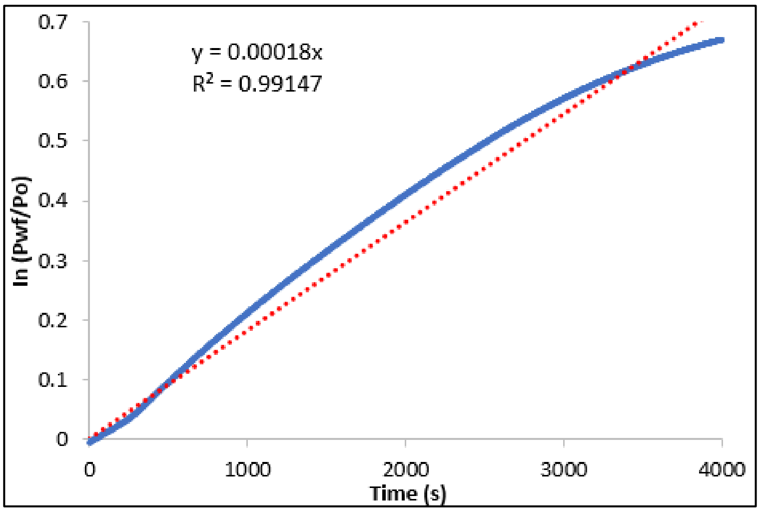

Fig. 6: Analysis of extracted early-time PBU history (well B)

For emphasis, in its current form, the proposed method is not yet considered sufficiently mature to replace the conventional use of extensive PBU dataset and Horner analysis to characterize and establish the permeability of a reservoir. However, through further development and maturation of the ideas presented in this work as well as further validation tests with different case studies and diverse well-reservoir systems, the potential of the proposed method is considered promising as a useful addition to the toolbox of a practising petroleum engineer.

Another useful application of the proposed method is in monitoring and trending permeability changes between PBU tests. Following from the direct relationship between permeability and the slope *m* in Eq. 12, a simple comparison of the slope *m* for different PBU tests can readily provide useful insights into the variability of permeability in the intervening period between the reference PBU tests. Indeed, assuming other variables do not undergo significant changes over a given period, the ratio of slope *m* between PBU tests can be used to quantify the magnitude of change that the reservoir permeability might have undergone over the period of interest.

Table 1: Input data and results for the example applications

Quantity	**Description**	**Well A**	**Well B**
r_w (m)	tubing internal radius within which downhole pressure gauge is hosted	0.05	0.038
L (m)	completion interval	4.9	4.7
R (m)	open-hole radius	0.155	0.155
μ (Pa s)	oil viscosity at downhole conditions	0.0005	0.0006
ρ (kg/m^3)	oil density at downhole conditions	750	760
g (m/s^2)	gravitational acceleration	9.81	
m (cycle/s)	Slope of semi-log plot of extracted early PBU data	0.00037	0.00018
k (m^2)	Permeabilities estimated from applying proposed method on limited PBU datasets are reasonably comparable to results from applying Horner analysis on extensive PBU datasets	8.4×10^{-13}	2.8×10^{-13}
k from Horner analysis of full PBU history (m^2)	Horner analysis of full PBU history was performed for individual wells A and B according to standard procedure [6]	9.6×10^{-13}	1.1×10^{-13}

4. Conclusion

This work has examined the potential to adapt the conceptual framework and analytical techniques of slug test to characterize petroleum reservoirs from limited PBU test data. Relevant mathematical model has been formulated and solved to accomplish this objective. While the idea is still at infancy, results of preliminary tests conducted on two field examples show that the proposed method is promising, though further work is required to have this method compete favourably against established (but more expensive) methods of characterizing the permeability of petroleum reservoirs. The major strength of the proposed method is its applicability to quickly monitor permeability changes over time, thereby improving the surveillance and management of petroleum fields. An important improvement area for the new technique is in achieving robust and more accurate estimation of permeabilities for a wide range of well-reservoir systems and conditions.

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