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CONVENTIONAL PRESSURE ANALYSIS FOR NATURALLY-FRACTURED RESERVOIRS WITH NON-NEWTONIAN PSEUDOPLASTIC FLUIDS

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ABSTRACT

Conventional oil reserves are coming to an end, then, some unconventional sources, such as heavy oil, are being the aim of oil companies. Most of heavy oils, drilling fluids and fracturing fluids behave as non-Newtonian and these fluids are erroneously approximated by Newtonian fluid flow models.

Currently, there are no mathematical expressions for the application of the straight-line conventional analysis method for the interpretation of pressure tests in heterogeneous or naturally-fractured occurring formations (dual porosity) which are saturated by a non-Newtonian pseudoplastic fluid. The literature includes an analytical solution for predicting the behavior of the pressure in dual porosity reservoirs containing a non-Newtonian fluid; this solution was subsequently used to interpret the well-pressure data using the pressure and pressure derivative log-log plot without employing type-curve matching. None commercial software includes up to date such analytical solution.

Several expressions to complement the conventional straight-line method are presented in this work so pressure tests in naturally fractured reservoirs with a non-Newtonian power-law fluid can be interpreted. This is accomplished mainly by estimating the interporosity flow parameter and dimensionless storage coefficient. The developed equations were successfully tested using well pressure tests reported in the literature. Very good results were obtained from the worked examples when compared to the reference values.

Keywords: Non-newtonian fluids, Naturally-fractured reservoirs, Conventional technique.

Análisis convencional de pruebas de presión para yacimientos naturalmente fracturados con fluidos pseudoplásticos no newtonianos

RESUMEN

Las reservas convencionales de petróleo están llegando a su fin, por tanto, las compañías petroleras le están apuntando a algunas fuentes no convencionales como los crudos pesados. La mayoría de los crudos pesados, fluidos de perforación y fracturamiento se comportan en forma no Newtoniana y son erróneamente aproximados por los modelos de flujo de fluidos Newtonianos.

Actualmente, no existen expresiones matemáticas para la aplicación del método convencional de la línea recta para interpretar pruebas de presión en yacimientos heterogéneos o naturalmente fracturados (doble porosidad) saturados con un fluido no Newtoniano pseudoplástico. La literatura incluye únicamente una solución analítica para predecir el comportamiento de la presión en yacimientos de doble porosidad con fluidos no newtonianos; solución que fue más tarde usada para interpretar datos de presión usando la presión y derivada de presión sin emplear curvas tipo. Ningún programa comercial incluye a la fecha dicha solución analítica.

En este trabajo se presentan varias expresiones para complementar el método convencional de la línea recta para caracterizar yacimientos naturalmente fracturados cuando un fluido no Newtoniano pseudoplástico fluye a través del medio poroso. El principal propósito es la estimación del parámetro de flujo interporoso y el coeficiente de almacenamiento adimensional. Las expresiones desarrolladas se verificaron satisfactoriamente con pruebas de presión reportadas en la literatura, encontrándose muy buenos ajustes con los valores de referencia.

Palabras Clave: Fluidos no newtonianos, Yacimientos naturalmente fracturados, Técnica convencional.

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INTRODUCTION

Naturally-fractured formations form part of the largest and most productive fields of the world and contribute over half of the hydrocarbons reserves in the planet; however, fracture effects are not very well known and are largely underestimated. Therefore, there is a need of developing a methodology attempting to describe a naturally-fractured reservoir in a full extent from the characteristics of the rock to the management of fluids in the reservoir.

Viscosity of non-Newtonian fluid varies with temperature and pressure. In a non-Newtonian fluid, the relationship between shear stress and shear rate is nonlinear and can even be time-dependent. Therefore, a constant coefficient of viscosity cannot be defined. Its simplest model is the power law. Pseudoplastic, a particular type of power-law fluid, has no yield stress. These include heavy oils and stimulation treatment fluids.

Few researches have been reported in the field of well test analysis for characterization of heterogeneous formations with non-Newtonian fluids. Olarewaju[1] was the first to develop an analytical solution for the transient behavior of dual-porosity formations containing a non-Newtonian pseudoplastic fluid. Its solution also considered damage and storage effects. More than a decade later, Escobar et al.[2] based on Olarewaju's solution, developed and successfully tested a methodology for the interpretation of pressure tests in heterogeneous formations bearing a non-Newtonian fluid, based upon the pressure and pressure derivative plot, so they presented new equations for estimation of the naturally-fractured reservoir parameters. They tested their expressions with synthetic examples.

In this work, we are also based on Olarewaju's solution to study the dimensionless behavior of pressure versus time so new expressions are presented to calculate the naturally fractured parameters by complementing the well-known conventional straight-line method. The developed expressions were successfully tested with some examples reported in the literature.

MATHEMATICAL MODEL

Considering the Laplace parameter $f(z)$ which is a function of the model type and geometry of the fracture system,

$$f(z)=\frac{\omega(1-\omega)z+\lambda}{(1-\omega)z+\lambda} \tag{1}$$

Variables ω and λ are the naturally-fractured reservoir parameters introduced by Warren and Root[3].

Equation (2) applies to various types of existing geometries regardless skin factor. $f(z)=1$ for the homogeneous case. For the constant-rate case and infinite reservoir, the dimensionless solution given in the Laplacian domain was presented by Olarewaju[4].

$$\tilde{P}_D=\frac{K_{\frac{1-n}{3-n}}\left(\frac{2}{3-n}\sqrt{zf_z}\right)+s\sqrt{zf_z}\,K_{\frac{2}{3-n}}\left(\frac{2}{3-n}\sqrt{zf_z}\right)}{z\left(\sqrt{zf_z}\,K_{\frac{2}{3-n}}\left(\frac{2}{3-n}\sqrt{zf_z}\right)+zC_D\left[K_{\frac{1-n}{3-n}}\left(\frac{2}{3-n}\sqrt{zf_z}\right)+s\sqrt{zf_z}\,K_{\frac{2}{3-n}}\left(\frac{2}{3-n}\sqrt{zf_z}\right)\right]\right)} \tag{2}$$

When wellbore storage and skin effects are negligible, Equation 2 becomes,

$$\tilde{P}_D=\frac{K_{\frac{1-n}{3-n}}\left(\frac{2}{3-n}\sqrt{zf_z}\right)}{z\left(\sqrt{zf_z}\,K_{\frac{2}{3-n}}\left(\frac{2}{3-n}\sqrt{zf_z}\right)\right)} \tag{3}$$

These expressions form the basis for this work since they allowed studying the dimensionless pressure. New equations are developed to characterize adequately pressure tests from naturally-fractured reservoirs containing non-Newtonian fluids. It is very common to find non-Newtonian fluids in the oil industry (heavy oil, drilling fluids, or injected gel during stimulation process) in naturally-fractured systems which becomes worth this study.

DIMENSIONLESS PARAMETERS

Dimensionless pressure, P_{DNN}, and dimensionless time, t_{DNN}, for non-Newtonian fluids were presented by Ikoku and Ramey (1979a):

$$t_{DNN}=\frac{t}{Gr_w^{3-n}} \tag{4}$$

Where,

$$G=\frac{3792.188\,n\phi c_t\mu_{eff}}{k_1}\left(96681.605\,\frac{h}{qB}\right)^{1-n} \tag{5}$$

And,

$$P_{DNN}=\frac{\Delta P}{141.2(96681.605)^{1-n}\left(\frac{qB}{h}\right)^n\left(\frac{\mu_{eff}r_w^{1-n}}{k}\right)} \tag{6}$$

PRESSURE DERIVATIVE BEHAVIOR

Observations of the pressure behavior against time were the basis for developing the needed expression to estimate both the *dimensionless storage coefficient, ω, and the interporosity flow parameter, λ,* defined by Warren and Root[3]. This work does not focused on either the estimation of permeability or skin factor since it was previously done by Ikoku and Ramey[4][5][6], Ikoku and Ramey (1979b), Ikoku and Ramey (1979c), and Lund and Ikoku[7] using semilog analysis.

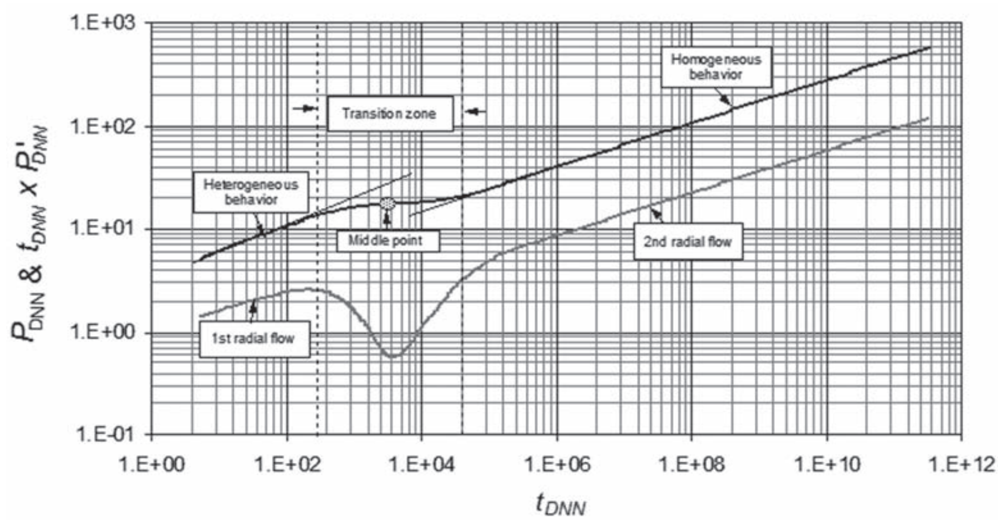

Figure 1. Dimensionless pressure and pressure derivative log-log plot displaying the typical behavior of a dual-porosity reservoir for ω=0.01, λ=1x10-7 and n=0.25

Although, conventional analysis is not based upon the pressure derivative plot, it is not unlawful to use it as reference. Then, Figure 1 illustrates some characteristics points found on the dimensionless pressure and pressure derivative versus time log-log plot for a naturally fractured reservoir with a power-law fluid with a flow behavior index, *n*, of 0.25. This behavior was first reported by Escobar et al.[2]. Notice that when radial flow occurs in both systems -fractures and matrix-fracture set- two straight-lines are seen in that plot and they are interrupted by a depression caused by the transition from heterogeneous to equivalent homogeneous behavior. The first straight line corresponds to the early time when fractures dominate the flow and the second line occurs during late time which corresponds to the response of an equivalent homogeneous reservoir. Note that the transition middle point of the pressure curve corresponds approximately to the minimum point of the pressure derivative curve. As far as pressure derivative is concerned during radial flow regime, for the case in which the flow behavior index is less than one (0 < *n* <1, unconventional pseudoplastic fluid) the developed slope decreases as the n value increases until becoming fully flat, zero slope, as happens for the conventional-fluid case, which means n equals to unity, Newtonian fluid. Note that the lower part of this curve is dependent of the dimensionless storage coefficient, but independent of the interporosity flow parameter.

PRESSURE BEHAVIOR

The emphasis of this paper is to develop expressions for the application of the straight-line conventional analysis interpretation methodology for estimating the naturally-fractured (dual-porosity) reservoir parameters. The idea is to use the slope, intercept and the relationship of logarithmic cycles of a pressure vs. time behavior plot which are used in the calculation of the parameters.

Figure 2 shows a log-log plot of dimensionless pressure vs. dimensionless time when the dimensionless storage coefficient varies from the range of $1x10^{-7}$ to 1 and constant values of λ and *n*. Neither wellbore storage nor skin effects are taken into account as indicated by Equation 6. Observe that the impact of the dimensionless storage coefficient is high. Although not shown in here, the lower its value the more pronounced is the pressure derivative during the transition from heterogeneous to equivalent homogeneous behavior.

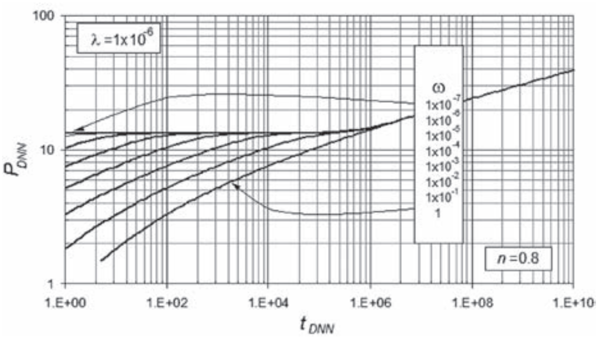

Figure 2. Effect of the dimensionless storage coefficient on the pressure response of a heterogeneous reservoir

On one hand, Figure 3 shows the effect of the variation the interporosity flow parameter but keeping constant both the dimensionless storage coefficient and the flow behavior index. In all the cases the typical s-shape behavior of double-porosity is observed. On the other hand, Figure 4 shows the effect of the flow index behavior on the pressure behavior. For this case, both the dimensionless storage coefficient and the interporosity flow parameter were kept constant. In this plot is seen that as the flow index behavior becomes higher, the slope decreases, thereby an inverse relationship is established. It is worth noting that, although for values of $n \leq 0.6$, the slopes (m'_1 and m'_2) are the same, for values of flow behavior index close to unity ($n > 0.7$), the radial flow corresponding to the equivalent-homogeneous system is smaller than the first one; then, decreases the parallelism between the two straight lines.

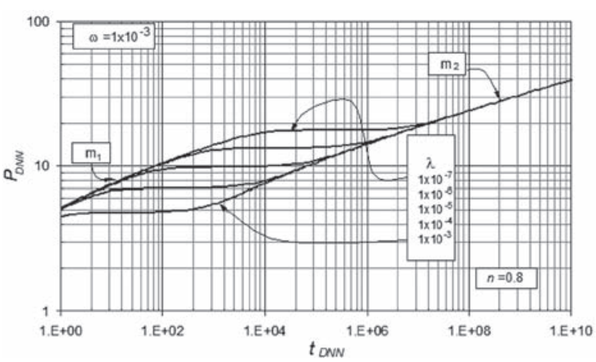

Figure 3. Effect of the interporosity flow parameter on the pressure response in a heterogeneous reservoir

Determination of the Interporosity Flow Parameter, λ

Ikoku and Ramey[4] provided an expression to relate the flow behavior index with semilog slope, m', on the second slope at later times, as follows,

$$n = \frac{3m'-1}{m'-1} \tag{7}$$

It is recommended to use the second semilog slope since it is expected to be free of wellbore storage and skin effects.

We study the behavior of the dimensionless pressure times the square root of the interporosity flow parameter versus the dimensionless time multiplied by (λ/ω) so a summary of the observations are reported in Figure 5. From this behavior, the following averaged equation was obtained;

$$\ln(\lambda^{0.5}) = \ln\left(\frac{\Delta P}{141.2(96681.605)^{1-n}\left(\frac{qB}{h}\right)^{n}\left(\frac{\mu_{eff}\, r_w^{1-n}}{k}\right)}\right) + 0.16412\ln(\lambda) + 0.2484 + [0.14644\ln(\lambda) + 0.09761]\,n + [0.11021\ln(\lambda) + 0.45275]\,n^{3/2} \tag{8}$$

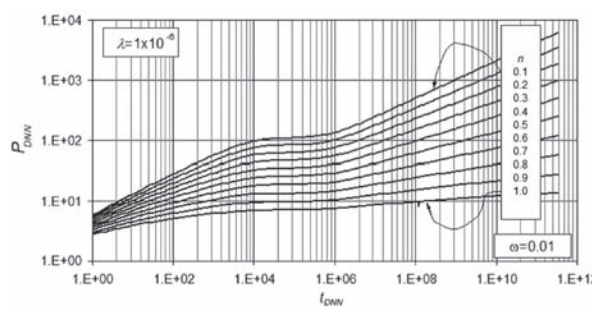

Figure 4. Effect of flow behavior index on pressure response in a heterogeneous reservoir

From which the interporosity flow parameter is solved as a function of the flow index behavior and the dimensionless pressure value read at the midpoint of a log-log plot of pressure versus time, as follows:

$$\lambda = \frac{\left[(0.2484) + n(0.0976)1 + n^{1.5}(0.45275) - \ln\left(\frac{\Delta P}{141.2(96681.605)^{1-n}\left(\frac{qB}{h}\right)^{n}\left(\frac{\mu_{eff}\, r_w^{1-n}}{k}\right)}\right)\right]}{(0.33588) - n(0.14644) - n^{1.5}(0.11021)} \tag{9}$$

This equation was proved for λ values between $1\text{x}10^{-3}$ and $1\text{x}10^{-7}$ and is valid for $0.1 \leq n < 1$.

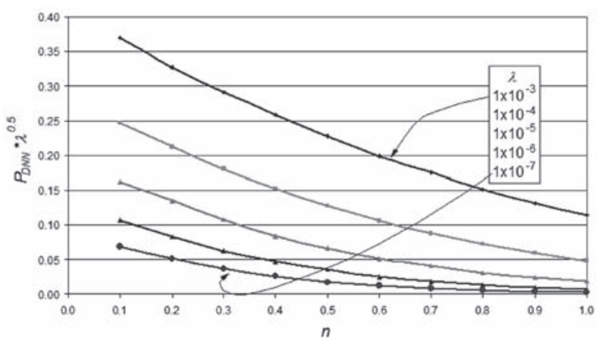

Figure 5. Effect of the interporosity flow parameter on the dimensionless pressure multiplied by the square root of the interporosity flow parameter versus the flow behavior index.

Figure 6. Effect of the interporosity flow parameter on the dimensionless pressure multiplied by the square root of the interporosity flow parameter versus the interporosity flow parameter for several values of the flow behavior index

$$\lambda^{0.5} = \frac{\left[1.2087e^{0.5315n}\right]\lambda^{0.2568n+0.1515}}{\dfrac{\Delta P}{141.2(96681.605)^{1-n}\left(\dfrac{qB}{h}\right)^{n}\left(\dfrac{\mu_{eff}r_w^{1-n}}{k}\right)}} \tag{10}$$

Table 1. Correlations for the determination of ω.

Eq.	Correlations
11	$\ln(\omega) = -2.3025851(Cycles)$
12	$\ln(\omega) = -2.3025721 - 2.3516663\,(Cycles)^{0.5}\ln(Cycles)$
13	$\ln(\omega) = -1.0518712 - 1.2508026\,(Cycles)^{1.5}$
14	$\ln(\omega) = -2.302705 - 1.6461502(Cycles)\ln(Cycles)$
15	$\omega^{0.5} = -0.023404325 + 0.9230909e^{-Cycles}$
16	$\ln\omega = \dfrac{0.99684106 + 5.4967445e^{-(cycles\times n)} - \ln P_{DNN}}{0.29403111}$

Determination of the Dimensionless Storage Coefficient, ω

A further observation of the pressure behavior is shown in Figure 7. In this case, a plot of dimensionless pressure times the dimensionless storage coefficient against dimensionless time is built. Notice that pressure curves with the same value of ω and different values of λ coincide for $t_D \geq 1\text{x}10^8$; therefore, characteristic points were read at that dimensionless time as reported in Figure 8. These observations lead to the estimation of the dimensionless storage coefficient, ω, from the reading of relationship between the distance equivalent to the transition zone and one log cycle measurement. The developed correlations in this study are reported in Table 1. Those expressions were proved for ω values ranging from $1\text{x}10^{-6}$ to 1.

We found that Equation 16 presents very good results, however, the exponential function included in it approaches unity as n increases; then, accuracy is lost. Thereby, this equation is recommended only for $n < 0.6$.

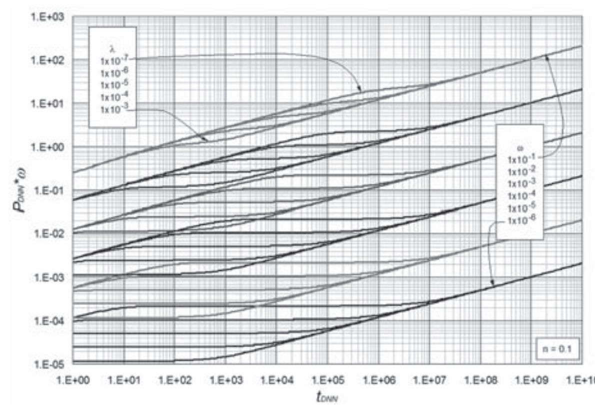

Figure 7. Effect of λ and ω on the pressure response for a dual-porosity reservoir, n = 0.1

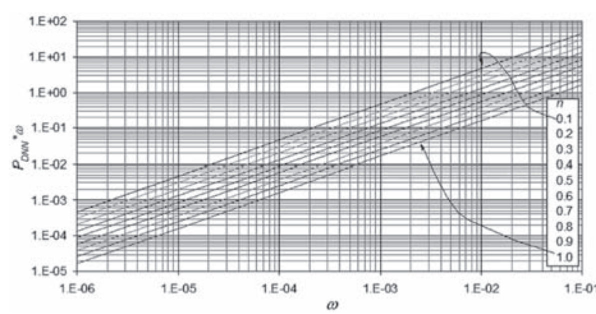

Figure 8. Values of the dimensionless pressure times the dimensionless storage coefficient against storage coefficient for several values of the flow behavior index

The values of permeability and skin factor can be estimated from the semilog plot of ΔP vs. time according to the expressions given by Ikoku and Ramey[4]:

$$k = \frac{\mu_{eff}[q/(2\pi k)]^{(n+1)/2}[(3-n)^2/(n\phi c)_t]^{(1-n)/2}}{[\Delta P_1(1-n)\Gamma(2/(3-n))]^{(3-n)/2}} \tag{17}$$

$$s = \left(\frac{\Delta P_o}{r_w^{1-n}}\right)\left(\frac{2\pi k}{q}\right)^{n}\left(\frac{k}{\mu_{eff}}\right) + \left(\frac{1}{1-n}\right) \tag{18}$$

Equations 17 and 18 are given in SI units. n is found from Equation 7 using the semilog slope, m', and ΔP_o and ΔP_1 correspond to the pressure drop readings at times of 0 and 1 second, respectively.

EXAMPLES

Three of the four examples worked by Escobar et al. (2011) were also used in this work.

Example 1

Information for example 1 is given in the second column of Table 2 and the pressure-time data is given in the log-log plot of Figure 9, in which the transition zone has a length of 1.5312 log cycles. Other important information read from this plot is:

t = 0.01182 hr ΔP_T = 749.844 psi m' = 0.2097

Use Equation 7 to find n = 0.4693. The values of ω and λ calculated in this example are presented in the third column of table 3.

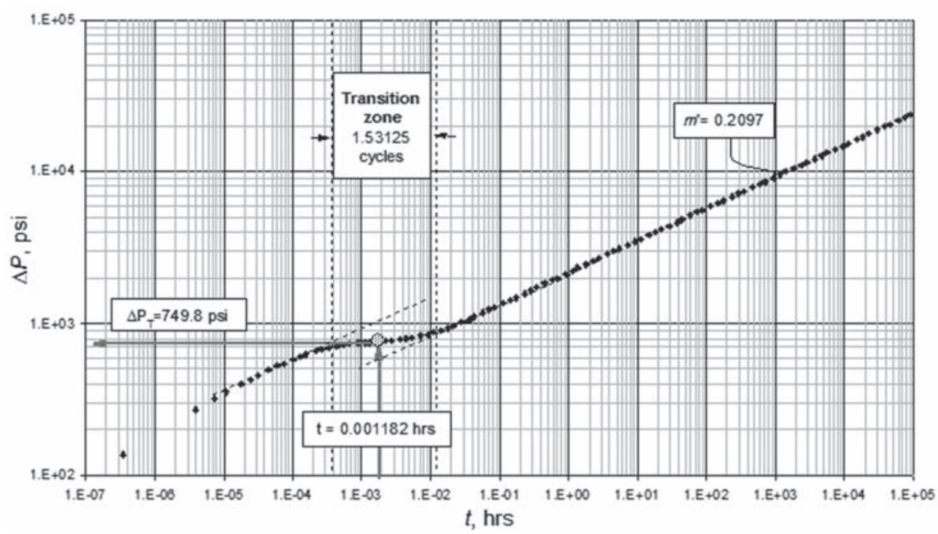

Figure 9. Log-log plot of ΔP vs. t for example 1

Table 2. Data for examples.

Parameter	Example 1	Example 2	Example 3
rw, ft	0.25 (0.0762 m)	0.25 (0.0762 m)	0.25 (0.0762 m)
q, STB/D	500 ($9.2x10^{-4}$ m^3/s)	1000 ($1.84x10^{-3}$ m^3/s)	2500 ($4.6x10^{-3}$ m^3/s)
h, ft	120 (36.576 m)	50 (15.24 m)	30 (9.144 m)
ct, 1/psi	$1x10^{-6}$ ($1.45x10^{-10}$ 1/Pa)	$1x10^{-6}$ ($1.45x10^{-10}$ 1/Pa)	$1x10^{-6}$ ($1.45x10^{-10}$ 1/Pa)
f, %	5	5	5
µeff, cp	1.5 (0.0015 Pa.s)	1.5 (0.0015 Pa.s)	1.5 (0.0015 Pa.s)
k, md	2000 ($1.97x10^{-12}$ m^2)	1000 ($9.87x10^{-13}$ m^2)	100 ($9.87x10^{-14}$ m^2)
B, bbl/stb	1.2 (1.2 m^3/m^3)	1.2 (1.2 m^3/m^3)	1.2 (1.2 m^3/m^3)
n	0.48	0.76	0.97
w	0.03	0.05	0.005
l	$3x10^{-5}$	$4x10^{-6}$	$3.4x10^{-6}$

Example 2

Information for this example is also found in Table 2, third column. The logarithmic plot of pressure drop against time is given in Figure 10 from which the transition zone has 1.33 log cycles and the following information is read:

t =0.001816 hr ΔP_T = 326.928 psi m' =0.12

Equation 7 allows the calculation of a value of *n* of 0.727. The naturally fractured parameters were estimated with several expressions is also given in Table 3.

Table 3. Results for naturally-fractured reservoirs parameters for the examples

Parameter	Equation	Value		
		Example 1	Example 2	Example 3
l	9	2.82×10^{-5}	4.07×10^{-6}	1.85×10^{-6}
l	10	2.358×10^{-5}	3.629×10^{-6}	3.844×10^{-6}
w	11	0.0294	0.0464	0.0053
w	12	0.0289	0.0458	0.0054
w	13	0.0326	0.0509	0.00476
w	14	0.0341	0.0532	0.00459
w	15	0.0310	0.0489	0.00509
w	16	0.0302	-	-

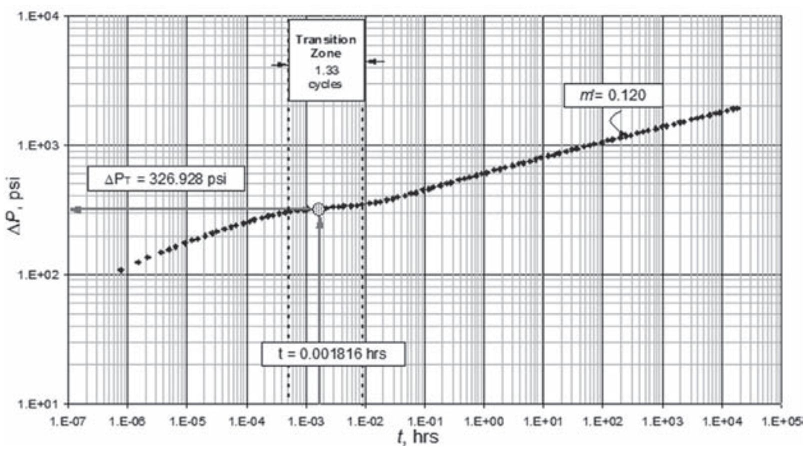

Figure 10. Log-log plot of ΔP vs. t for example 2

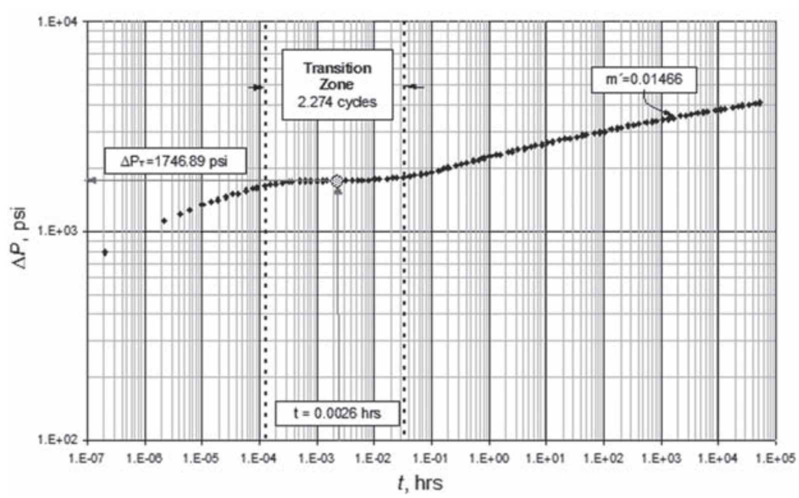

Figure 11. Log-log plot of ΔP vs. t for example 3

Example 3

Information for this example is given in the fourth column of Table 2 and the logarithmic plot of pressure drop against time is given in Figure 11 from which the transition zone has 2.274 log cycles and the following information is read:

t =0.0026 hr ΔPT = 1476.89 psi m' = 0.01466

A value of n of 0.9702 is estimated from Equation 7. The naturally fractured parameters were estimated with several expressions as shown in Table 3.

ANALYSIS OF RESULTS

A very close agreement of the results of the interporosity flow parameter and the dimensionless storage coefficient can be seen from tables 2 and 3. By simple inspection small differences are obtained. No deviation errors are provided since even one order of magnitude of difference is accepted for these parameters. The authors agree that the values provided by the empirical expressions are very good.

CONCLUSIONS

Two new empirical equations for the estimation of the interporosity flow parameter and six for the dimensionless storage coefficient were introduced to complement the conventional analysis method. They were successfully tested with the synthetic examples reported in the literature.

We found that ω is only function of the horizontal length of the transition zone found in the logarithmic pressure-time curve, and independent of such variables as λ and n, while λ is calculated with the reading of a pressure midpoint on the transition area of the curve and n.

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NOMENCLATURE

B	Oil formation factor, rb/STB
c_t	System total compressibility, 1/psi
h	Formation thickness, ft
H	Consistency (power-law parameter),cp*sn-1
k	Permeability, md
n	Flow behaviour index (power-law parameter)
P	Pressure, psi
PR	Reservoir pressure, psi
$\tilde{P}$	Laplace domain pressure
PT	Pressure read at the midpoint of the transition zone, psi
q	Flow/injection flow, STB/D
r	Radius, ft
rw	Radio de pozo, ft
s	Skin factor
t	Time, hr
z	Laplace parameter

Greek

ω	Dimensionless storage coefficient
Δ	Change, drop
Ø	Porosity, fraction
λ	Interporosity flow parameter
μ	Viscosity, cp

Suffix

D	Dimensionless
DNN	Dimensionless No-Newtonian
r	Radial o pseudorradial
w	Wellbore
eff	Effective

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