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A PRACTICAL APPROACH FOR ESTIMATION OF THE AVERAGE RESERVOIR PRESSURE FROM MULTI-RATE TESTS IN LONG HORIZONTAL WELLS

(APROXIMACIÓN PRÁCTICA PARA ESTIMAR LA PRESIÓN PROMEDIA DEL YACIMIENTO DE PRUEBAS MULTITASAS EN POZOS HORIZONTALES LARGOS)

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RESUMEN

Si se dispone de buenos datos de presión-tiempo durante estado pseudoestable, es posible determinar la presión promedia de un yacimiento utilizando simplemente balance de materia que considere la historia de caudales. De otro lado, la metodología más usada para este fin es el uso de pruebas de restauración de presión. Éstas, por su parte, introducen un impacto económico negativo producto del cierre del pozo durante la prueba. Aunado a ello, es incluso difícil el desarrollo del régimen de flujo pseudorradial durante una prueba de presión en un pozo horizontal, cuando existen formaciones de poca permeabilidad o yacimientos muy grandes. Puesto que las pruebas de restauración de presión constituyen el caso más particular de una prueba multitasa, entonces, éstas también se pueden extender para estimar la presión promedia del yacimiento. Los métodos convencionales para determinar la presión promedia del yacimiento podrían también extenderse a pruebas multitasas una vez el tiempo riguroso sea convertido a tiempo equivalente mediante el principio de superposición.

En este artículo, se presenta una aproximación fácil y práctica para determinar la presión promedia del yacimiento a partir de una prueba multitasa corrida en un pozo horizontal largo. La metodología aplicada a yacimientos anisotrópicos usa un valor normalizado de la presión y la derivada de presión leído en un punto arbitrario durante estado pseudoestable, el cual se usa en una única ecuación que inmediatamente proporciona el valor de la presión promedia del yacimiento.

El método se verificó comparándolo con varios resultados de pruebas sintéticas que fueron obtenidas usando un simulador comercial. Se encontró que los valores estimados de presión promedia coinciden muy bien con aquellos estimados por el simulador comercial. Esta propuesta es útil para obtener un estimativo de la presión cuando no se dispone de programas comerciales.

Palabras claves: Estado pseudoestable, técnica TDS, yacimiento cerrado, yacimiento anisotrópico, factor de forma, derivada de presión, superposición, pozo hidráulicamente fracturado

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ABSTRACT

If good pressure-time well data during pseudosteady-state flow are available, then a simple material balance that accounts for rate history would give us the value of average reservoir pressure. On the other hand, pressure buildup analysis is the most popular methodology to obtain this value. However, pressure buildup testing involves a negative economic impact caused by shutting-in the well during the test. Moreover, either in low permeability or very large size reservoirs, a test conducted in a horizontal well hardly reaches the pseudorradial flow regime. Since buildup tests are the most particular case of multi-rate tests, therefore, they can also be used for estimation of the average reservoir pressure. Conventional methods for determination of the average reservoir pressure may also be extended to multi-rate tests once the test time is converted to equivalent time by using the superposition principle.

In this paper, an easy and practical approximation for determining average reservoir pressure from a multi-rate test run in a long horizontal is presented. The methodology which is applied to anisotropic reservoirs uses a normalized pressure and pressure derivative point read at any arbitrary point on the pseudosteady-state flow regime. This point is then used into a simple equation which readily provides the average reservoir pressure value. Obviously, another limitation appears when the pressure derivative is so noisy.

The method has been verified by comparing the results from analyzing several synthetic tests that were obtained from a commercial well testing software. The estimated values of average reservoir pressure by using the proposed methodology agree quite well with those estimated from the commercial software. This methodology is useful when a commercial software is unavailable.

Keywords: Pseudosteady state, TDS technique, bounded reservoir, anisotropic reservoir, shape factor, pressure derivative, superposition, hydraulically fractured well.

INTRODUCTION

Research on average reservoir pressure determination via well test analysis was practically absent during the last three decades and, therefore, only conventional semilog analysis has been used. Recently, Chacón et al. (2004) presented a solution for estimation of the average reservoir pressure in vertical wells, vertical fractured wells and horizontal wells. Molina et al. (2005) introduced a practical solution for estimating this for vertical wells in naturally fractured formations. Later, Escobar et al. (2007) also presented a methodology for determination of the average reservoir pressure from a vertical well test conducted in either homogeneous or heterogeneous reservoirs using multi-rate testing. These three studies were based upon the philosophy of the *TDS* technique, Tiab (1993).

On one hand, it is inconvenient to shut-in a well for a buildup test since it causes loss of economic revenue. The problem increases dramatically when a horizontal well drains either a low permeability formation or a large reservoir. In both cases, only early radial, early linear, and pseudorradial flow regimes may be observed within a reasonable frame of testing time. Sometimes, time for the development of pseudorradial flow regime is not long enough. Multi-rate test, on the other hand, avoid shutting-in the well to provide the average reservoir pressure measurement or determination. Therefore, in this study, we have extended the *TDS* technique for developing an easy-to-use solution for estimating this discussed parameter from a multi-rate test run in a long horizontal well which is drilled in an anisotropic oil formation. For modeling purposes, we employed the analogy that a long horizontal well mathematically behaves as a hydraulically fractured vertical well.

2. MATHEMATICAL DEVELOPMENT

2.1. Vertical Fractured Well

Here, the procedure presented by Chacón et al. (2004) to obtain an expression for estimation of the average reservoir pressure for a vertical well with an infinite-conductivity fracture is employed. For convenience, let us start with the dimensionless pressure equation for both a horizontal and a vertical well, respectively:

$$P_D = \frac{\overline{k} L_w}{141.2 q \mu B}\left(P_i - p\right) \tag{1}$$

$$P_D = \frac{\overline{k} h_z}{141.2 q \mu B}\left(P_i - p\right) \tag{2}$$

Dimensionless time based upon wellbore radius, half-fracture length and reservoir drainage area are given as:

$$t_D = \frac{0.0002637\bar{k}t}{\phi\mu c_r r_w^2} \quad (3)$$

$$t_D = \frac{0.0002637\bar{k}t}{\phi\mu c_r x_f^2} \quad (4)$$

$$t_{DA} = \left(\frac{0.0002637\bar{k}}{\phi\mu c_t A}\right) t = t_D \frac{r_w^2}{A} \quad (5)$$

Dimensionless horizontal wellbore length:

$$L_D = \frac{L_w}{2h\underline{k}}\sqrt{\frac{k_z}{\_}} \quad (6)$$

According to Raghavan (1993), a material balance for a slightly compressible fluid in bounded reservoirs leads to:

$$\overline{P_D}(t_{DA}) = 2\pi t_{DA} \quad (7)$$

For a well with infinite-conductivity hydraulic fracture, the dimensionless pressure equation during pseudosteady state is given by Russell and Truit (1964) as:

$$P_D = 2\pi t_{DA} + \frac{1}{2}\ln\left[\left(\frac{x_e}{x_f}\right)^2 \left(\frac{2.2458}{C_A}\right)\right] \quad (8)$$

We should take into account that solution given by Eq. 8 is not general for any type of geometry. It only applies when x_e/x_f is larger than 8 or 16 so that the vertical well shape factors can be used for hydraulically-fractured vertical wells. In general, the shape factor, C_A, in Eq. 8 is a function of the aspect ratio x_e/x_f.

For long producing time, the pressure derivative function yields a unit-slope straight line which corresponds to the pseudosteady-state flow regime, starting at a t_{DA} value of approximately 0.2. Taking derivative to Eq. 8 and multiplying the resulting expression by t_{DA}, it yields,

$$(t_{DA} * P_D') = 2\pi t_{DA} \quad (9)$$

Dividing Eq. 8 by Eq. 9,

$$\frac{P_D}{(t_{DA} * P_D')} = 1 + \frac{1}{4\pi t_{DA}} \ln\left[\left(\frac{x_e}{x_f}\right)^2 \left(\frac{2.2458}{C_A}\right)\right] \quad (10)$$

Substituting the dimensionless quantities, Eqs. 2 and 5 into Eq. 10, and solving for the shape factor, C_A, as performed by Chacón et al. (2004), will result:

$$C_A = 2.2458\left(\frac{x_e}{x_f}\right)^2 \left\{\exp\left[\frac{\pi\, 0.0010548\, \bar{k}t_{pss}}{\phi\mu c_t A}\ 1 - \frac{(\Delta P)_{pss}}{(t^*\Delta P')_{pss}}\right]\right\} \quad (11)$$

Using the concept given by Eq. 7, Eq. 10 becomes,

$$\frac{P_D}{(t_{DA} * P_D')} = \frac{11}{2\pi t_{DA}}\left\{\overline{P_D} + \frac{}{2}\ln\left[\left(\frac{x_e}{x_f}\right)^2 \left(\frac{2.2458}{C_A}\right)\right]\right\} \quad (12)$$

Then, Chacón et al. (2004) substituted Eqs. 2 and 5 into Eq. 12 and solved for the average reservoir pressure:

$$\overline{P} = P_i - \frac{q\mu B}{kh}\left\{\begin{array}{l}\dfrac{3.276\bar{k}t_{pssp}}{\phi\mu c_{tp} A}\left(\dfrac{(\Delta P)_{ss}}{(t^*\Delta P')_{ss}}\right) - \\ 70.6\ln\left[\left(\dfrac{x_e}{x_{fA}}\right)^2 \left(\dfrac{2.2458}{C}\right)\right]\end{array}\right\} \quad (13)$$

Tiab (1994) presented an expression to estimate the drainage area of a reservoir drained by a vertical well by utilizing the intersection point of the radial and pseudosteady-state flow regimes, t_{rpi}, by using:

$$A = \frac{\bar{k}t_{rpi}}{301.77\phi\mu c_t} \quad (14)$$

where,

$$\bar{k} = \sqrt{k_x k_y} \quad (15)$$

2.2. Average Reservoir Pressure for a Horizontal Well

Clonts and Ramey (1986), Daviau et al. (1988), and Kuchuk et al. (1990) assumed that the horizontal wellbore section has infinite conductivity so they have virtually no pressure drop within the wellbore. Then, an analogy of the pressure behavior of a horizontal well with an infinite-conductivity fractured-vertical well was used by Chacón et al. (2004) for the analysis. It means that the horizontal portion of the well behaves like an infinite-conductivity hydraulic fracture especially when the horizontal well length is long, e.g. $L_w \geq 10h_z\ (\overline{k}/k_z)$. As depicted in Fig. 1, the horizontal well is treated as a special case of an infinite-conductivity fractured vertical well. As expressed above, considering only one wing of the infinite-conductivity fracture, the following analogies can be made, Chacón et al. (2004):

$$x_f \approx L_w \tag{16}$$

$$x_e \approx h_x \tag{17}$$

$$q = q_{ef}/2 \tag{18}$$

Here, q stands for the flow rate in the horizontal system and q_{ef} represents the flow rate from the equivalent two wings of a vertically fractured well. Replacing the equivalences given by Eqs. 16 to 18 into Eq. 8, an analogous expression on the equivalent horizontal well system is obtained:

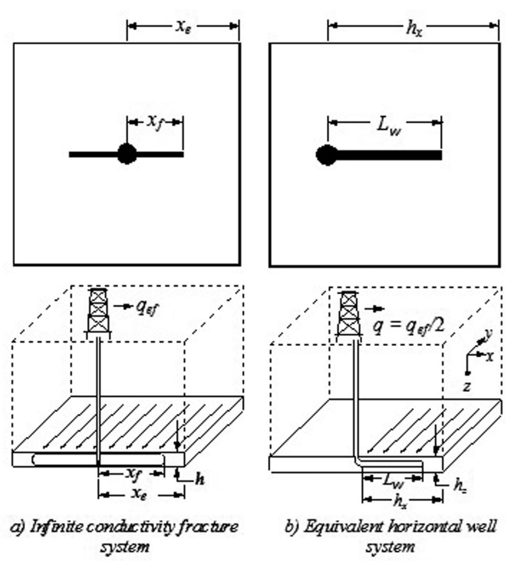

Fig. 1. Horizontal well system compared to an infinite conductivity fractured vertical well, after Chacón et al. (2004)

$$t_D = 2\pi_{DA} + \frac{1}{2}\mathrm{In}\left[\left(\frac{h_x}{L_{wA}}\right)^2\left(\frac{2.2458}{C}\right)\right] \tag{19}$$

Again, dividing Eq. 19 by its pressure derivative which is also represented by Eq. 9, Chacon et al. (2004) obtained:

$$\frac{P_D}{(t_{DA} * P_D')} = 1 + \frac{1}{4\pi t_{DA}}\,\mathrm{In}\left[\left(\frac{h_x}{L_w}\right)^2\left(\frac{2.2458}{C_A}\right)\right] \tag{20}$$

Substituting Eqs. 1 and 5 into the above expression and solving for the shape factor yields:

$$C_A = 2.2458\left(\frac{h_x}{L_w}\right)^2 e^{\frac{0.0033137\overline{k}t_{pss}}{\phi\mu c_t A t}\left(1 - \frac{(\Delta P)_{pss}}{(*\Delta P')_{pss}}\right)} \tag{21}$$

Using the concept given by Eq. 7, Eq. 20 can be rewritten as,

$$\frac{P_D}{(t_{DA} * P_D')} = \frac{11}{4\pi t_{DA}}\left\{\overline{P_D} + \frac{}{2}\ln\left[\left(\frac{h_x}{L_w}\right)^2\left(\frac{2.2458}{C_A}\right)\right]\right\} \tag{22}$$

Considering only one wing of a vertically fractured well, replacing the dimensionless quantities, Eqs. 1 and 5 into Eq. 22, and solving for the average reservoir pressure, Chacón et al. (2004) obtained:

$$\overline{P} = P_i - \frac{q_{ef}\mu B}{\overline{k}h}\left\{\begin{matrix}\dfrac{3.216\overline{k}t_{pss}}{\phi\mu c_t A}\left(\dfrac{(\Delta P)_{pss}}{(t*\Delta P')_{pss}}\right) - \\ 70.6\ln\left[\left(\dfrac{h_x}{L}\right)^2\left(\dfrac{2.2458}{C_A}\right)\right]\end{matrix}\right\} \tag{23}$$

which can be rewritten as:

$$\overline{P} = P_i - \frac{q\mu B}{h_z\overline{k}}\left\{\begin{matrix}\dfrac{0.116867\overline{k}t_{pss}}{\phi\mu c_t A}\left(\dfrac{(\Delta P)_{pss}}{(t*\Delta P')_{pss}}\right) - \\ 35.3\ln\left[\left(\dfrac{h_x}{L}\right)^2\left(\dfrac{2.2458}{C_A}\right)\right]\end{matrix}\right\} \tag{24}$$

2.3. Multi-rate Testing

When the flow rate changes, time superposition is applied to account for the rate variation on the solution of the pressure equation. Onur et al. (1988) introduced the normalized pressure approach concept, and Earlougher (1977) presented the governing equation for a well subjected to variable rate conditions:

$$\Delta P_q = \frac{162.6\mu B}{kh}\left[X_n + \log\frac{k}{\phi\mu c_t r_w^2} - 3.23 + 0.87\,s\right] \qquad (25)$$

where,

$$\Delta P_q = \frac{P_i - P_{wf}(t)}{q_n} \qquad (26)$$

$$X_n = \sum_{i=1}^{n}\left(\frac{q_{ii} - q_{-1}}{q_n}\right)\log\left(t - t_{i-1}\right) \qquad (27)$$

Mongi and Tiab (2000) and Hachlaf et al. (2002) used the equivalent time concept for the application of the *TDS* technique to multi-rate and variable injection tests, respectively:

$$t_{eq} = \prod_{i=1}^{n}\left(t_{nn} - t_{-1}\right)^{\left(\frac{q_i - q_{i-1}}{q_n}\right)} = 10^{X_n} \qquad (28)$$

where;

$$t_n = t_{n-1} + \Delta t \qquad (29)$$

The dimensionless variables ought to be reformulated. Therefore, the dimensionless pressure for a horizontal well:

$$P_{Dq} = \frac{\bar{k}L_w}{141.2\mu B}\left(\frac{P_{iw} - P_f(t)}{q_n}\right) \qquad (30)$$

and the dimensionless time is now expressed as:

$$t_{D_{eq}} = \frac{0.0002637\bar{k}t_{eq}}{\phi\mu c_t r_w^2} \qquad (31)$$

A similar procedure as the one performed for the constant-rate case is followed here to obtain the average pressure equation for a horizontal well producing at a continuously changing flow rate is given by:

$$\bar{P} = P_i - \frac{q_n\mu B}{h\bar{k}}\left\{\frac{0.1168687\bar{k}_{eq}(t_{pss})}{\phi\mu c_t A}\left(\frac{(\Delta P_q)_{pss}}{(t*\Delta P_q')_{pss}}\right) - 35.3\ln\left[\left(\frac{h_x}{L_w}\right)^2\left(\frac{2.2458}{C_A}\right)\right]\right\} \qquad (32)$$

Eq. 21 is also used to estimate the shape factor, C_A.

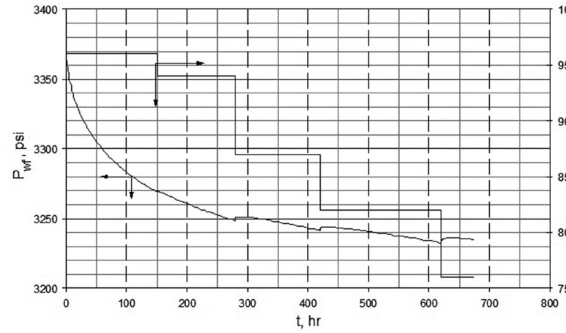

Fig. 2. Pressure and rate data for simulated example 1

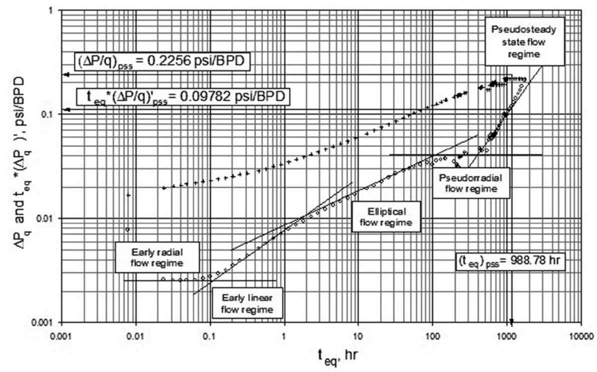

Fig. 3. Pressure and pressure derivative for simulated example 1

3. SYNTHETIC EXAMPLES

3.1. Simulated Example 1

The pressure and rate data for a simulated pressure multi-rate test run in a square reservoir is given in Fig. 2 and the pressure derivative is shown in Fig. 3. Other important data concerning reservoir, well and fluid properties are given below.

k_x = 50 md	k_y = 50 md
k_z = 16.67 md	ϕ = 22 %
c_t = 1x10^{-5} psi^{-1}	h_z = 100 ft
h_x = 4000 ft	r_w = 0. 4 ft
L_w = 1000 ft	h_s = 50 ft
μ= 2.5 cp	B = 1.23 rb/STB
s_m = 0	P_i = 3400 psi
A = 16x10^6 ft^2	C_A = 30.8822

Solution. From the pressure derivative plot, Fig. 3, it can be observed that the early radial, early linear, elliptic, pseudorradial and pseudosteady flow regimes are well defined. Since, During rate number 5 (any arbitrary point during pseudosteady state regime is chosen) the following information is read:

q_n = 760 BPD, $(t_{eq})_{pss}$ = 988.8 hr, $(\Delta P_q)_{pss}$ = 0.2256 psi/BPD, $t_{eq}*(\Delta P_q)'_{pss}$ = 0.09782 psi/BPD

From Eq. 32, we obtain an average reservoir pressure of 3332 psi. We also estimated the average reservoir pressure using a very commercial software obtaining 3344 psi from the Material Balance method, and 3340 psi from the steady/pseudosteady state model.

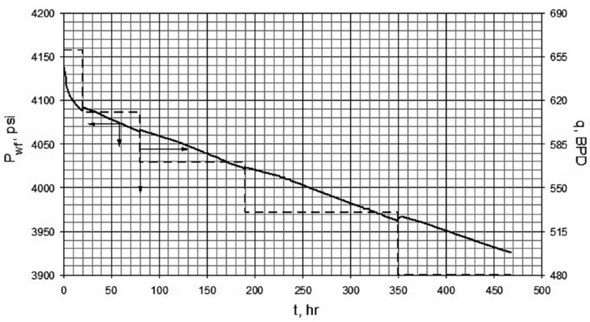

Fig. 4. Pressure and rate data for simulated example

3.2. Simulated Example 2

The pressure and rate data for a simulated pressure multi-rate test run in a square reservoir is given in Fig. 4 and the pressure derivative is shown in Fig. 5. Other relevant data concerning this test is given as follows:

k_x = 50 md	k_y = 50 md
k_z = 16.67 md	ϕ = 2 %
c_t = 3x10^{-6} psi^{-1}	h_z = 70 ft
h_x = 10000 ft	r_w = 0.4 ft
L_w = 600 ft	h_s = 20 ft
μ = 0.9 cp	B = 1.4 rb/STB
s_m = 0	P_i = 4200 psi
A = 100x10^6 ft^2	C_A = 30.8822

Solution. From the pressure derivative plot, Fig. 5, it is only observed the early linear, pseudorradial and pseudosteady flow regimes. During rate number 4 – again, any arbitrary point during pseudosteady state regime is chosen-, the following information is read:

q_n = 502 BPD, $(t_{eq})_{pss}$ = 788.27 hr, $(\Delta P_q)_{pss}$ = 0.4893 psi/BPD, $t_{eq}*(\Delta P_q)'_{pss}$ = 0.75752 psi/BPD

From Eq. 32, we obtain an average reservoir pressure of 4115 psi. From a commercial software, the estimated average reservoir pressure was 4110.1 psi using the Steady/pseudosteady state model and 3971 from the Material Balance method.

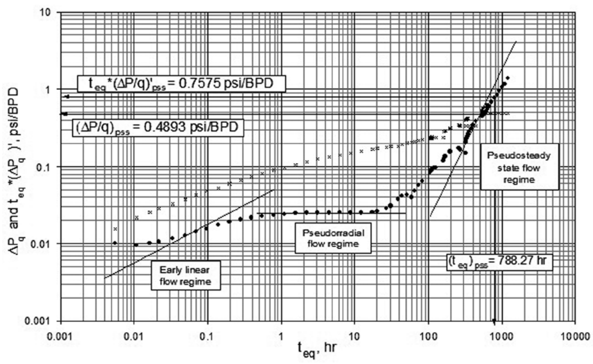

Fig. 5. Pressure and pressure derivative for simulated example 2

4. ANALYSIS OF RESULTS

The average reservoir pressure values obtained from the proposed equation agree quite well with the results from material balance. For instance, in the first synthetic example the absolute deviation was 0.12 % and for the second one of 0.23 %. This analysis indicates that the proposed solution provides results within a margin error acceptable if compared to actual values estimated from other sources and, confirms the assumption that a hydraulic fracture and a long horizontal well behave mathematically in a similar fashion.

5. CONCLUSION

Using the mathematical analogy between a hydraulic fracture and a horizontal well, a new relationship to estimate the average reservoir pressure for an isotropic and homogeneous reservoir drained by a long horizontal well under multi-rate testing conditions is presented. It was tested with simulated examples and was found to provide results that match well with those obtained from conventional software using material balance even though the wells are not so long. The methodology is limited to cases where the pseudosteady-state flow is observed and the horizontal length of the well is so short.

NOMENCLATURE

A	Drainage area, ft^2
B	Oil volume factor, rb/STB
C_A	Dietz's shape factor
c_t	Total compressibility, 1/psi
h_z	Formation thickness, ft
h_s	Distance from top reservoir boundary to well, ft
h_x	Reservoir length along x-direction, ft
$\overline{k}$	Horizontal permeability (Eq. 15), md
k_x	Reservoir permeability in x-direction, md
k_y	Reservoir permeability in y-direction, md
k_x	Reservoir permeability in vertical direction, md
L_w	Effective horizontal well length, ft
P	Pressure, psi
$\overline{P}$	Average reservoir pressure, psi
P_D	Dimensionless pressure
P_i	Initial pressure, psi
P_{wf}	Well-flowing pressure, psi
q	Oil flow rate, BPD
r_w	Wellbore radius, ft
t	Time, hrs
t_{eq}	Equivalent time, hrs
t*DP'	Pressure derivative, psi
t_{eq}*DP_q'	Normalized pressure derivative, psi/(STB/D)
t_D	Dimensionless time referred to welbore radius
t_{DA}	Dimensionless time referred to reservoir area
t_{rpi}	Intercept of radial and pseudosteady state lines, hr
t_{DA}*P_D'	Dimensionless pressure derivative based on reservoir area
t_{DA}*P_D'	Dimensionless pressure derivative based on well radius
x_e	Reservoir length, md
x_f	Half-fracture length, md
X_N	Time superposition

Subscripts

D	Dimensionless quantity
eq	Equivalent
f	Formation or fracture
i	Initial conditions, intercept
pss, p	Pseudosteady-state

Greek

Δ	Change, drop
ΔP_q	Rate-normalized pressure drop, psi/(STB/D)
ϕ	Porosity, fraction
μ	Viscosity, cp

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