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AVERAGE RESERVOIR PRESSURE DETERMINATION FROM DRAWDOWN TESTS BY THE TDS TECHNIQUE

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Abstract

The average reservoir pressure plays an important role in all phases of reservoir appraisal. Although buildup pressure tests are meant to be used for the estimation of this parameter, drawdown tests can also be used by a mathematical combination with material balance. Therefore, in this study, the TDS Technique is applied to drawdown tests for the development of expressions to obtain the average reservoir pressure for vertical wells in homogeneous and heterogeneous systems, and fractured wells in homogeneous formations, as well. Applications to three simulated and one field cases were successfully compared to those from material balance providing absolute derivation errors lower than 3 %.

Keywords*: Formation pressure; Shape factor; Pressure derivative; Pseudosteady-state.*

1. Introduction

Average reservoir pressure is an important parameter involved, among others, in material balance calculations and secondary and tertiary recovery projects. Since the first published methods by Miller, Dyes, and Hutchinson [1], Matthews *et al.* [2], and Dietz [3], research on average reservoir pressure was interrupted for about three decades. Arari [4] presented simple expressions for the estimation of the average reservoir pressure. His volumetric method includes solutions for bounded and constant-pressure boundary reservoirs.

Tiab [5] introduced the Direct Synthesis Technique (TDS) for well test data interpretation. This technique uses unique features found on the pressure and pressure derivative plot to develop direct, practical, and accurate equations for reservoir characterization. Complete detail of such technique can be found in the books of Escobar [6-7]. Also, Escobar *et al.* [8] recently provided an updated state-of-the-art on TDS.

Chacon *et al.* [9] presented equations for the estimation of the average reservoir pressure by using the TDS Technique. Their scope included circular and rectangular homogenous reservoirs and hydraulically fractured wells in homogeneous reservoirs. Molina *et al.* [10-11] also made use of the TDS Technique to provide a solution for the estimation of the average reservoir pressure in naturally fractured reservoirs. Escobar *et al.* [12] also extended the TDS technique to develop expression to determine the average reservoir pressure for both homogeneous and naturally fractured formations from multirate testing, so they avoided to have the well being shut-in. A similar procedure was employed by Escobar *et al.* [13] for a horizontal well. However, since a horizontal well and a fractured well have similar mathematical behaviors, their approach used a fractured well model as a horizontal well model.

Amin *et al.* [14] provided a method to estimate the average reservoir pressure in naturally fractured reservoirs from transient rate decline analysis by plotting the relationship of oil flow rate versus time. Two straight lines are observed on such a plot which slope and intercept of these lines can be used to estimate the average reservoir pressure.

Only pressure buildup and multirate tests are meant to be used for the estimation of the average reservoir pressure. However, Agarwal [15] presented a mathematical procedure that involves the combination of material balance with the pseudosteady-state pressure solution equation to arrive to an expression to estimate the average reservoir pressure from flow tests. His solution however only includes the circular geometry. In this study, the idea initially formulated by Agarwal [15] is extended to estimate the average reservoir pressure in homogeneous reservoir, naturally fractured formation and vertically-fractured wells in a homogenous formation. TDS Technique, Tiab [5], is extended to obtain the solutions.

2. Data processing

The dimensionless pressure and pressure derivative for oil phase are given by:

$$P_D = \frac{kh\Delta P}{141.2\,q\,B\mu} \tag{1}$$

$$t_D * P_D' = \frac{kh(t*\Delta P')}{141.2\,q\,B\mu} \tag{2}$$

The dimensionless pressure and pseudopressure derivative for gas phase are given by:

$$m(P)_D = \frac{hk\left[m(P_i)-m(P)\right]}{1422.52 q_g T} \tag{3}$$

$$t*\Delta m(P)_D' = \frac{hk\left[t*\Delta m(P)'\right]}{1422.52 q_g T} \tag{4}$$

The dimensionless time based upon area, wellbore radius and half-fracture length are, respectively, given by:

$$t_{DA} = \frac{0.0002637kt}{\phi\mu c_t A} \tag{5}$$

$$t_D = \frac{0.0002637kt}{\phi\mu c_t r_w^2} \tag{6}$$

$$t_{Dxf} = \frac{0.0002637kt}{\phi\mu c_t x_f^2} \tag{7}$$

As performed by Agarwal [15], the work by Ramey and Cobb [16] was taken for a single phase fluid in a closed reservoir, the produced reservoir volume is equal to the expansion of the fluids at initial time, mathematically:

$$5.615qB\frac{t}{24} = Ah\phi c_t(P_i - \bar{P}) \tag{8}$$

Which can be expressed as:

$$P_{Dmb}(t_{DA}) = \frac{kh\,(P_i - \bar{P})}{141.2\,q\,B\,\mu} = 2\pi t_{DA} \tag{9}$$

Equation (9) is referred as the material balance dimensionless pressure equation.

The governing equations for the pseudosteady-state pressure behavior for a well in a homogeneous reservoir, a naturally fractured reservoir and a hydraulically fractured well in a homogeneous reservoir were given by Ramey and Cobb [16], DaPrat [17] and Russell and Truit [18], respectively, as:

$$P_D(t_{DA}) = 2\pi t_{DA} + 0.5\left[\ln\left(\frac{2.2459A}{C_A r_w^2}\right)\right] \tag{10}$$

$$P_D(t_{DA}) = 2\pi t_{DA} + 0.5\left[\ln\left(\frac{2.2459A}{C_A r_w^2}\right)\right] + \frac{2\pi\,(1-\omega)^2}{\lambda A} \tag{11}$$

$$P_D(t_{DA}) = 2\pi t_{DA} + 0.5\left[\ln\left(\left[\frac{x_e}{x_f}\right]^2 \frac{2.2459}{C_A}\right)\right] \quad (12)$$

The arithmetic and logarithmic dimensionless pressure derivatives for the three above equations are:

$$P_D'(t_{DA}) = 2\pi \quad (13)$$

$$t_D * P_D'(t_{DA}) = 2\pi t_{DA} \quad (14)$$

Equation (13) suggests that a log-log plot of P_D' versus t_{DA} will give a horizontal line, zero slope, intercepting the pressure derivative axis at a value of 2π. According to Agarwal [15], during a pressure test, the pseudosteady state period starts, t_{pps}, when the arithmetic pressure derivative becomes flat. For practical purposes that time is referred here with the suffix *Pwf*.

Comparing the right-hand side of Equation (14) with the general form of the material balance equation, Equation (9), it follows that they have the same expression. This suggests that during the pseudosteady-state flow period:

$$t_D * P_D'(t_{DA}) = P_{Dmb}(t_{DA}) = 2\pi t_{DA} \quad (15)$$

This observation was obtained by Agarwal [15] and is the fundamental of his work and this.

For a well flowing, the pressure drop, ΔP is defined as $P_i - P_{wf}$. Subtracting and adding the average reservoir pressure to this, $\bar{P}$, it yields,

$$P_i - P_{wf} = (P_i - \bar{P}) + (\bar{P} - P_{wf}) \quad (16)$$

Which becomes in dimensionless form:

$$P_D(t_{DA}) = P_{Dmb}(t_{DA}) + \bar{P}_D(t_{DA}) \quad (17)$$

where,

$$P_D(t_{DA}) = \frac{kh\,(P_i - P_{wf})}{141.2\,q\,B\,\mu} \quad (18)$$

$$P_{Dmb}(t_{DA}) = \frac{kh\,(P_i - \bar{P})}{141.2\,q\,B\,\mu} \quad (19)$$

$$\bar{P}_D(t_{DA}) = \frac{kh\,(\bar{P} - P_{wf})}{141.2\,q\,B\,\mu} \quad (20)$$

As stated by Agarwal [15], an expression can be obtained during the pseudosteady-state flow period by solving for the dimensionless average reservoir pressure from Equation (17), such as:

$$\bar{P}_D(t_{DA}) = P_D(t_{DA}) - P_{Dmb}(t_{DA}) \quad (21)$$

Recalling that Equation (10) is given for the homogeneous reservoir case, and replacing it, and substitute Equation (15) into Equation (21), it results:

$$\bar{P}_D(t_{DA}) = 2\pi t_{DA} + 0.5\left[\ln\left(\frac{2.2459\,A}{C_A r_w^2}\right)\right] - 2\pi t_{DA} \quad (22)$$

Dividing Equation (22) by the dimensionless pressure derivative, Equation (14), will provide,

$$\frac{\bar{P}_D(t_{DA})}{t_D * P_D'} = \frac{0.5\left[\ln\left(\frac{2.2459\,A}{C_A r_w^2}\right)\right]}{2\pi t_{DA}} \quad (23)$$

Replacing Equation (20) into Equation (23), and then replacing the dimensionless quantities given by Equations (2) and (5) in the resulting expression and solving for the average reservoir pressure will result:

$$\bar{P} = P_{wf} + \frac{301.77(t*\Delta P')_{Pwf}\,\phi\mu c_t A}{kt_{Pwf}}\left[\ln\left(\frac{2.2459\,A}{C_A\,r_w^2}\right)\right] \quad (24)$$

For this type of systems, Agarwal [15] developed an expression to estimate the average reservoir pressure from flow tests. This solution, however, does not include the reservoir shape factor, C_A:

$$\bar{P} = P_{wf} + \frac{887.18q\mu B}{kh} \quad (25)$$

$$\bar{P} = P_{wf} + \frac{8937.96q_g T}{kh} \quad (26)$$

A similar procedure is followed for the case of a naturally fractured reservoir. Combining Equations (11), (15) and (21) will yield:

$$\frac{kh\,(\bar{P}-P_{wf})}{141.2\,q\,B\,\mu} = 2\pi\,t_{DA} + 0.5\left[\ln\left(\frac{2.2459\,A}{C_A\,r_w^2}\right)\right] - 2\pi t_{DA} \quad (27)$$

Dividing Equation (27) by the dimensionless pressure derivative, Equation (14), gives:

$$\frac{\bar{P}_D(t_{DA})}{t_D * P_D'} = \frac{0.5\left[\ln\left(\frac{2.2459\,A}{C_A\,r_w^2}\right)\right] + \frac{2\pi\,(1-\omega)^2}{\lambda A}}{2\pi t_{DA}} \quad (28)$$

As for the case of a homogeneous reservoirs, the average pressure derivative is solved for after plugging in Equation (21) the dimensionless parameters given by Equations (2) and (5) plus the definition given by Equation (20),

$$\bar{P} = P_{wf} + \frac{301.77(t*\Delta P')_{Pwf}\,\phi\mu c_t A}{kt_{Pwf}}\left[\ln\left(\frac{2.2459\,A}{C_A\,r_w^2}\right)\right] + \frac{3792.188(t*\Delta P')_{Pwf}\,\phi\mu c_t(1-\omega)^2}{\lambda kt_{Pwf}} \quad (29)$$

In a similar fashion for the case of a vertically fractured well, use of Equations (21), (12) and (15) gives:

$$\bar{P}_D(t_{DA}) = 2\pi\,t_{DA} + 0.5\left[\ln\left(\left[\frac{x_e}{x_f}\right]^2 \frac{2.2459}{C_A}\right)\right] - 2\pi t_{DA} \quad (30)$$

As for the two former cases, dividing Equation (30) by the dimensionless pressure derivative, Equation (14), replacing the dimensionless expressions, Equation (2) and (5) and the definition given by Equation (20) and then solving for the average reservoir pressure will yield:

$$\bar{P} = P_{wf} + \frac{301.77(t*\Delta P')_{Pwf}\,\phi\mu c_t A}{kt_{Pwf}}\left[\ln\left(\left[\frac{x_e}{x_f}\right]^2 \frac{2.2459}{C_A}\right)\right] \quad (31)$$

For gas wells, the product μct in Equation (5) through (7) is evaluated at initial conditions. Using the pseudopressure and pseudopressure derivative functions given by Equations (3) and (4) and repeating the above procedure, the analog Equations (24), (29) and (31) for gas wells are:

$$m(\bar{P}) = m(P_{wf}) + \frac{301.77[t*\Delta m(P')]_{Pwf}\,\phi(\mu c_t)_i\,A}{kt_{Pwf}}\left[\ln\left(\frac{2.2459\,A}{C_A\,r_w^2}\right)\right] \quad (32)$$

(33)

$$m(\bar{P}) = m(P_{wf}) + \frac{301.77[t*\Delta m(P')]_{Pwf}\,\phi(\mu c_t)_i\, A}{kt_{Pwf}} \left[\ln\left(\left[\frac{x_e}{x_f} \right]^2 \frac{2.2459}{C_A} \right) \right] \quad (34)$$

Notice that Equations (24), (29) and (31) can also be applied for gas wells using the product μct at initial conditions.

The Dietz shape factors C_A -for homogeneous and hydraulically fractured wells, respectively- can be determined by the expressions provided by Chacon *et al.* [9].

$$C_A = \frac{2.2458\, A}{r_w^2} \left\{ e^{\frac{kt_{Pwf}}{301.77\,\phi\mu c_t A}\left(\frac{(\Delta P)_{Pwf}}{(t*\Delta P')_{Pwf}} - 1 \right)} \right\}^{-1} \quad (35)$$

$$C_A = \frac{2.2458}{r_w^2} \left(\frac{x_e}{x_f} \right)^2 \left\{ e^{\frac{kt_{Pwf}}{301.77\,\phi\mu c_t A}\left(\frac{(\Delta P)_{Pwf}}{(t*\Delta P')_{Pwf}} - 1 \right)} \right\}^{-1} \quad (36)$$

For heterogenous reservoirs, Molina *et al.* [10-11] adapted the expression presented by Chacon *et al.* [9] for the homogeneous reservoir. However, here the expression is developed by dividing Equation (11) by Equation (14), replace the dimensionless parameters given by Equations (1), (2) and (5), and then solving for C_A, thus:

$$C_A = \frac{2.2458\, A}{r_w^2} \left\{ e^{\frac{kt_{Pwf}}{301.77\,\phi\mu c_t A}\left(\frac{(\Delta P)_{Pwf}}{(t*\Delta P')_{Pwf}} - \frac{3792.188\,\phi\mu c_t (1-\omega)^2}{\lambda kt_{Pwf}} \right)} \right\}^{-1} \quad (x)$$

3. Examples

Estimate the average reservoir pressure for three following simulated examples. All the examples were run for circular reservoir geometry, C_A=31.62, and the average reservoir pressure was estimated by material balance using a commercial well test interpretation software and reported in Table 1.

Table 1. Fluid, reservoir and well data for worked examples

Parameter	Example 1	Example 2	Example 3	Field case
k, md	50	100	10	208
ϕ, %	10	15	7	18
c_t, 1/psi	$3x10^{-6}$	$3x10^{-5}$	$1x10^{-6}$	$26.4x10^{-5}$
h, ft	30	220	80	16
r_w, ft	0.3	0.35	0.4	0.267
s	0	0	0	6
q, bbl/D	300	400	600	250
B, rb/STB	1.2	1.1	1.35	1.229
μ, cp	2.2	5	0.75	1.2
C, bbl/psi	0.001	0.0011	0	0.0434
P_i, psi	3500	3800	4000	2733
$\bar{P}$, psi (*)	3351	3743	3865	2393
λ	-	$1x10^{-6}$	-	-
ω	-	0.1	-	-
x_f, ft	-	-	200	-
A, Ac	72.121	288.5	288.5	16.5
Abs. Error, %	2.8	1.4	2.09	0.6

3.1. Synthetic example 1

Figure 1 presents a log-log plot of the pressure and pressure derivative versus time generated for a homogeneous system using data from the second column of Table 1. From that plot, the following information was read:

t_{Pwf} = 28 psi $(\Delta P)_{Pwf}$ = 657.1 psi; $(t^*\Delta P')_{Pwf}$ = 87.62 psi

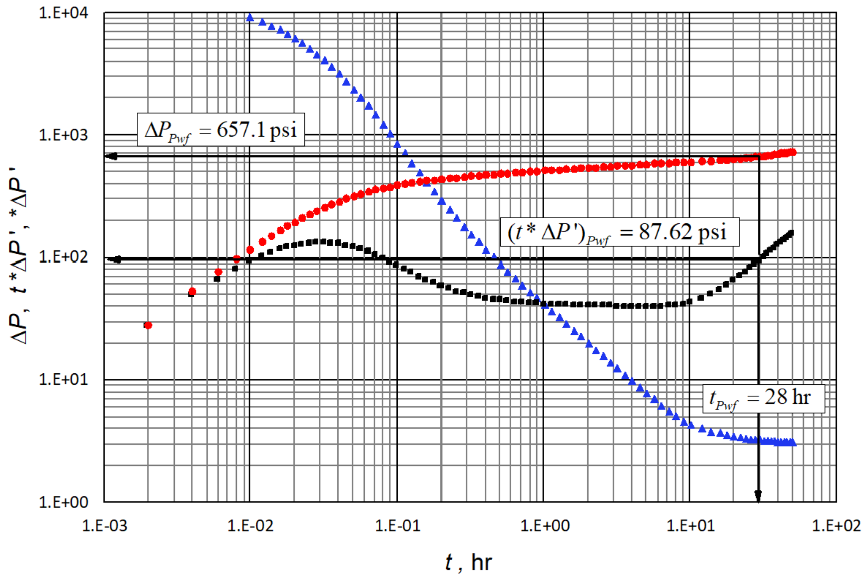

Figure 1. Pressure and pressure derivative versus time log-log plot for synthetic example 1 – homogeneous reservoir

Use Equation (24) to compute the average reservoir pressure:

$$\bar{P} = (3500 - 657.1) + \frac{301.77(87.62.54)(0.1)(2.3)\left(3\times10^{-6}\right)(3141593)}{(50)(28)}\left[ln\left(\frac{2.2459\,(3141593)}{(31.62)(0.3^2)}\right)\right]$$

$$= 3445.2 \text{ psi}$$

Use of Equation (25) – from Agarwal [15] – gives:

$$\bar{P} = (3500 - 657.1) + \frac{887.18(300)(1.2)(2.3)}{50(30)} = 3332.6 \text{ psi}$$

3.2. Synthetic example 2

A drawdown test in a naturally fractured reservoir was generated with data from the third column of Table 1. The pressure and pressure derivative versus time data are reported in Figure 2. From that plot, the following information was read:

t_{Pwf} = 585 psi $(\Delta P)_{Pwf}$ = 292.8 psi $(t^*\Delta P')_{Pwf}$ = 35.74 psi

The average reservoir pressure is estimated with Equation (29);

$$\bar{P} = (3800 - 298.8) + \frac{301.77(35.74)(0.15)(5)(1\times10^{-5})(12566370.6)}{(100)(385)}\left[ln\left(\frac{2.2459(12566370.6)}{31.62(0.35^2)}\right)\right] + \frac{3792.11(35.74)(0.15)(5)(1\times10^{-5})(1-0.1)^2}{1\times10^{-6}(100)(385)} = 3795.7 \text{ psi}$$

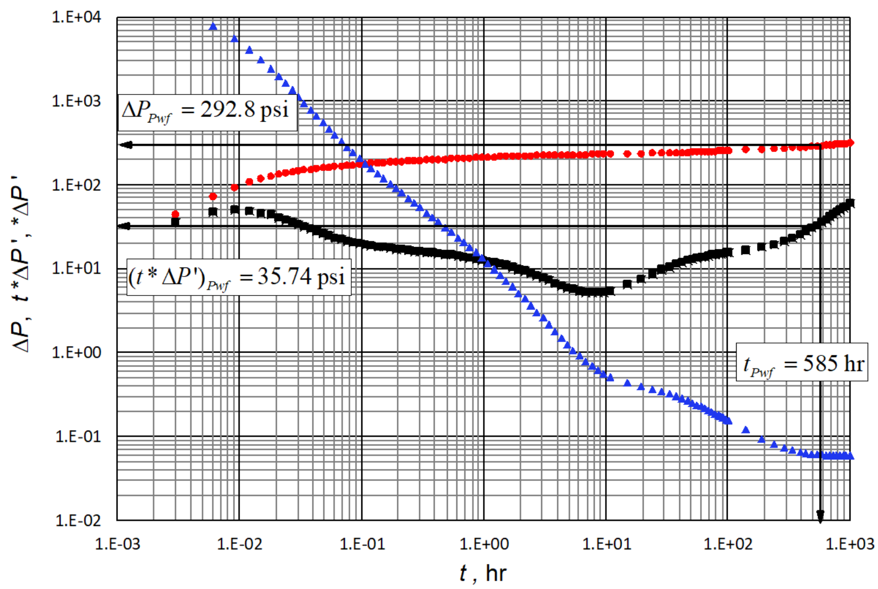

Figure 2. Pressure and pressure derivative versus time log-log plot for synthetic example 2 – heterogeneous reservoir

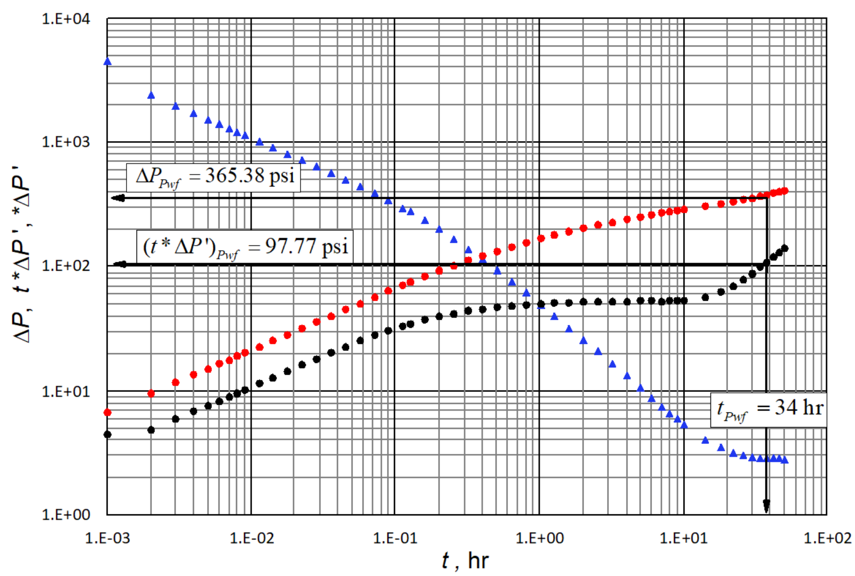

Figure 3. Pressure and pressure derivative versus time log-log plot for synthetic example 3 – hydraulically fractured well in a homogeneous reservoir

3.3. Synthetic example 3

Figure 3 presents a log-log plot of the pressure and pressure derivative versus time generated for a hydraulically fractured well in a homogeneous system with data from the fourth column of Table 1. From there, the following information was read:

t_{Pwf} = 34 psi $(\Delta P)_{Pwf}$ = 365.4 psi $(t*\Delta P')_{Pwf}$ = 97.77 psi

Use Equation (31) to find the average reservoir pressure:

$$\bar{P} = (4000 - 365.4) + \frac{301.77(97.77)(0.07)(0.75)(1\times 10^{-6})(12566370.6)}{(10)(34.01)} \left[ln\left(\left[\frac{2000}{200}\right]^2 \frac{2.2459}{31.62} \right) \right]$$

$$= 3784.59 \text{ psi}$$

3.4. Field example

Figure 4 presents a log-log plot of the pressure and pressure derivative versus time of a vertical well in a homogeneous reservoir in Oklahoma. Reservoir, well, and fluid properties data are provided in the fifth column of Table 1. The well is believed to be located at the center of a square with C_A = 30.8828. From that plot, the following information was read:

t_{Pwf} = 50 psi $(\Delta P)_{Pwf}$ = 454 psi $(t^*\Delta P')_{Pwf}$ = 7.94 psi

The average reservoir pressure is obtained from Equations (24) and (25) – Agarwal [15]:

$$\bar{P} = (2733 - 454) + \frac{301.77(7.94)(0.18)(1.2)(26.4 \times 10^{-5})\ (718740)}{(208)(50)} \left[ln\left(\frac{2.2459(718740)}{(30.8828)(0.267^2)}\right)\right]$$

$$= 2406 \text{ psi}$$

$$\bar{P} = (2733 - 454) + \frac{887.18(250)(1.2)(1.229)}{208(16)} = 2377.3 \text{ psi}$$

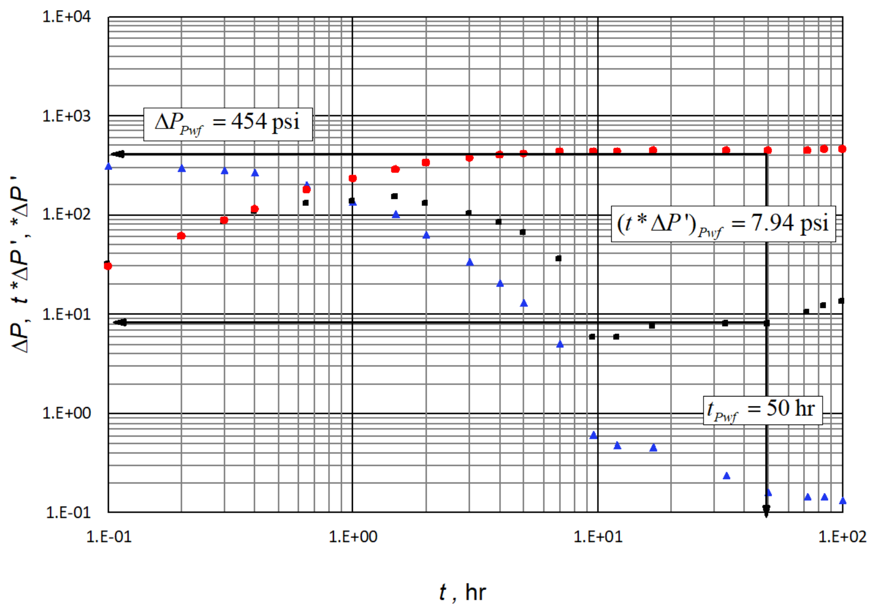

Figure 4. Pressure and pressure derivative versus time log-log plot for field case – homogeneous reservoir

4. Comments on the results

The average reservoir pressure values were compared to results obtained from material balance provided by commercial software and reported in Table 1, along with the absolute deviation errors. The obtained absolute errors were lower than 3 which indicates that the proposed equations work well. For the homogeneous case, there is a deviation of 0.55 % was obtained with respect to the equation provided by Agarwal [15].

5. Conclusion

New expressions to estimate the average reservoir pressure from pressure flow tests using the TDS Technique are presented for vertical wells in three cases: homogeneous reservoir, naturally fractured reservoir, and a hydraulic fractured well in a homogeneous reservoir. The results are successfully compared to results from material balance.

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