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APPLICATION OF TDS TECHNIQUE TO MULTIPHASE FLOW

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Although, the radial difussivitity equation has been solved for a single-fluid phase flow, in some cases more than one phase flows from the reservoir to the well; therefore, the single-phase solution has been previously extended to multiphase flow without losing a significant degree of accuracy. Practically, there exist two ways of dealing with multiphase flow: The Perrine method, Perrine (1956) which basically replaces the single-phase compressibility by the multiphase compressibility so that each fluid is analyzed separately using the concept of mobility. The other one is the use of pseudofunctions which have been found to be the best option. The TDS technique has been widely applied to a variety of scenarios. It has been even tested to successfully work on condensate systems with the use of pseudofunctions, Jokhio, Tiab and Escobar (2002). However, equations for estimation of phase permeability, skin factor and drainage area has not neither presented nor tested. In this article, we present new versions of a set of equations of the TDS technique to be applied to multiphase flow following the Perrine method along with a previously presented way of estimation of the absolute relative permeability. We successfully applied the proposed equations to synthetic and field examples.

Keywords: *perrine method, mobility, radial flow, relative permeabilities.*

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Aunque, la ecuación de difusividad ha sido resuelta para flujo monofásico, en algunos casos más de un fluido fluye del yacimiento hacia el pozo; por tanto, la solución monofásica se ha aplicado previamente a flujo multifásico sin perder un significante grado de exactitud. Practicamente, existen dos maneras de de tratar con flujo multifásico: El método de Perrine, Perrine (1956), en el cual básicamente se reemplaza la compresibilidad monofásica por la compresibilidad multifásica de modo que cada fluido se analiza separadamente usando el concepto de movilidad. La otra manera es usar las pseudofunciones. Esta se considera como mejor opción. La técnica TDS se ha extendido ampliamente a una gran variedad de escenarios. Incluso, se ha aplicado satisfactoriamente en sistemas de condensados mediante pseudofunciones, Jokhio,Tiab y Escobar (2002). Sin embargo, las ecuaciones para estimar la permeabilidad de las fases, el daño y el área de drene ni se han presentado y por tanto tampoco se han probado. En este artículo, se presentan nuevas versiones de ecuaciones de la técnica TDS para usarse en flujo multifásico siguiendo el método de Perrine, como también se conjuga con una aproximación ya expuesta en la literatura para estimar la permeabilidad absoluta del medio. Las ecuaciones desarrolladas se aplicaron satisfactoriamente a ejemplos simulados y de campo.

Palabras clave: *método de Perrine, mobilidad, flujo radial, permeabilidades relativas.*

NOMENCLATURA

A	Area, Ac
B	Formation volume factor, bbl/STB
c	Compressibility, 1/psi
h	Formation thickness, ft
k	Absolute permeability, md
k_g	Gas effective permeability, md
k_o	Oil effective permeability, md
k_w	Water effective permeability, md
k_{ro}	Oil relative permeability
k_{rw}	Water relative permeability
k_{rw}	Gas relative permeability
P	Pressure, psi
P_i	Initial reservoir pressure, psia
P_{wf}	Well flowing pressure, psi
q	Flow rate, bbl/D
r	Radius, ft
R_s	Gas dissolved in crude, scf/STB
R_{sw}	Gas dissolved in water, scf/STB
r_w	Well radius, ft
S	Fluid saturation, fraction
s	Skin factor
T	Reservoir temperature, ºR
t	Time, hr
$(t^*\Delta P')$	Pressure derivative, psi

GREEK SYMBOLS

ΔP	Pressure drop , psi
ϕ	Porosity, fraction
μ	Viscosity, cp
λ	Mobility, cp/md

SUFFICES

i	Intersection or initial conditions
g	Gas
o	Oil
r	Rradial flow
rpi	Intersection of pseudosteady-state line with radial line
t	Total
x	Maximum point (peak) during wellbore storage
w	Water

INTRODUCTION

Perrine (1956) introduced a method of analysis for multiphase flow from the method of single-fluid phase flow by replacing the single-phase compressibility by the multiphase compressibility and replacing the single-phase mobility by the sum of the mobilities of the fluids in the multiphase flows. The method assumes that (i) saturation gradients must be small and, therefore, are neglected which is not the case in reality, (ii) pressure gradients must be small, which is not the actual case and (iii) capillary pressure between the phases must be negligible, which is usually the case in for pressure transient testing. These assumptions are, however, justified by Martin (1959). Because of these assumptions, the Perrine approach has some limitations. For instance, as pointed out by Weller (1966) as the saturation increases the results are less reliable. The phase permeabilities can be underestimated, Chu , Reynolds and Raghavan (1986), and the skin effect can be overestimated if flow is blocked by gas in the near wellbore region, Ayan and Lee (1988).

Even though the Perrine approach is used in this work, it is worth to say that there exist more rigorous methods provided in the literature for analyzing multiphase flow without requiring the knowledge of the permeability curves. The reader should refer to Al-Khalifah, A-J.A., Aziz and Horne (1987) and Serra, Peres and Reynolds (1990) for further information.

A modern interpretation tool known as Tiab's Direct Synthesis (TDS) technique which employs the pressure and pressure derivative curves to interpret pressure buildup and drawdown tests without using type-curve matching has been introduced by Tiab (1993 and 1995). Because of its simplicity and practicality, this technique is used in most commercial softwares, although the name TDS has been never shown up. The TDS technique has been extended to include many cases as possible. Few recent examples of them are presented by Moncada *et al.* (2005), Molina, Escobar, Montealegre-M. and Restrepo (2005), Escobar *et al.* (2007a, 2007b, and 2007c). New basic equations to include multiphase flow are presented here.

THEORY

According to Perrine (1956) a *"total"* flow mobility is calculated as *Equation 1:*

$$\lambda_t = \left(\frac{k}{\mu}\right)_t = \frac{k_o}{\mu_o} + \frac{k_g}{\mu_g} + \frac{k_w}{\mu_w} = k\left(\frac{k_{ro}}{\mu_o} + \frac{k_{rg}}{\mu_g} + \frac{k_{rw}}{\mu_w}\right) \quad (1)$$

Then, the radial difussivity equation can be expressed in field units as *Equation 2:*

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial P}{\partial r}\right) = \frac{\phi c_t}{0{,}0002637\lambda_t}\frac{\partial}{\partial r} \quad (2)$$

According to Martin (1956) the total compressibility of the system can be expressed as *Equation 3.a:*

$$c_t = c_o S_o + c_g S_g + c_w S_w + c_f + \frac{S_o B_g}{5{,}615 B_o}\frac{\partial R_s}{\partial P} + \frac{S_w B_g}{5{,}615 B_w}\frac{\partial R_{sw}}{\partial P} \quad (3.a)$$

It is not the attempt of this work to study neither the sensitivity of the compressibility nor the effect of dissolved gas on the solution, but to provide new equations for application of the TDS technique for the case of multiphase flows. The reader is invited to use *Equation 3.a* for accuracy, however, for practical purposes *Equation 3.b* may be used instead:

$$c_t = c_o S_o + c_g S_g + c_w S_w + c_f \quad (3.b)$$

The total flow rate is then *Equation 4,*

$$q_t = q_o B_o + (1000 q_g - q_o R_s) B_g + q_w B_w \quad (4)$$

Application of the above relationships to the equations presented by Tiab (1993) leads to estimate the wellbore storage coefficient by *Equation 5* and *Equation 6:*

$$C = \left(\frac{q_t}{24}\right)\frac{t_i}{(\Delta P)_i} \quad (5)$$

$$C = \left(\frac{q_t}{24}\right)\frac{t_i}{(t^*\Delta P')_i} \quad (6)$$

For pressure drawdown tests, $\Delta P = P_i - P_{wf}$. For pressure buidup tests, $\Delta P = P_{ws} - P_{wf}(\Delta t = 0)$. Each phase's mobility ought to be determined from the following expressions, *Equations 7, 8* and *9:*

$$\frac{k_o}{\mu_o} = \frac{70{,}6 q_o B_o}{h(t^*\Delta P')_r} \quad (7)$$

$$\frac{k_w}{\mu_w} = \frac{70{,}6 q_w B_w}{h(t^*\Delta P')_r} \quad (8)$$

$$\frac{k_g}{\mu_g} = \frac{70600 q_g B_g}{h(t^*\Delta P')_r} \quad (9)$$

Being $(t^*\Delta P')_r$ the value of the pressure derivative during radial flow regime. If free gas is present, then, *Equation 9* should be reformulated as *Equation 10:*

$$\left(\frac{k}{\mu}\right)_g = \frac{70600[q_g - 0{,}0001(q_o R_s + q_w R_{sw})]B_g}{h(t^*\Delta P')_r} \quad (10)$$

The total mobility can be estimated either by *Equation 1*or by *Equation 11*:

$$\left(\frac{k}{\mu}\right)_t = \frac{70{,}6 q_t}{h(t^*\Delta P')_r} \quad (11)$$

Since the unit-slope line is the same for the pressure and pressure derivative curve, at the intersection point we have *Equation 12:*

$$(t^*\Delta P')_i = (\Delta P)_i = (t^*\Delta P')_r \quad (12)$$

Therefore, suffix *r* in *Equations 5* and *11* can be changed to *i* to indicate that these relationships can be applied at the point of intersection between the radial-flow line and early unit-slope line, t_i, which can also be applied to confirm the system mobility by *Equation 13:*

$$\left(\frac{k}{\mu}\right)_t = \frac{1695C}{ht_i} \tag{13}$$

By dividing the pressure equation and pressure derivative equation during radial flow regime and solving for skin factor, Tiab (1993) obtained an equation to estimate the skin factor using a point of pressure and pressure derivative read at any arbitrary time, t_r, during the infinite-acting behavior. The multiphase equation is *Equation 14:*

$$s = 0,5\left[\frac{\Delta P_r}{(t*\Delta P')_r} - \ln\left(\frac{\lambda_t t_r}{\phi c_t r_w^2}\right) + 7,43\right] \tag{14}$$

ΔP_r is the value of pressure read at the time t_r. The semilog slope is equal to the the value of pressure derivative during radial flow multiplied by the natural log of 10 then, the pressure drop due to skin factor is estimated as *Equation 15:*

$$\Delta P_s = 2s(t*\Delta P')_r \tag{15}$$

Tiab (1993) also presented several correlations to estimate reservoir permeability, skin factor and wellbore storage coefficient which use the time and pressure derivative values read at the maximum point of the pressure derivative (peak). These correlations which were rearranged for multiphase flow to estimate total fluid mobility, wellbore storage coefficient and skin factor are presented below, *Equations 16, 17, 18, 19* and *20:*

$$\lambda_t = \left(\frac{70,6q_t}{h}\right)\frac{1}{(0,01488q_t/C)t_x - (t*\Delta P')_x} \tag{16}$$

$$\lambda_t = \frac{4745,36C}{ht_x}\left[\frac{(t*\Delta P')_x}{(t*\Delta P')_r} + 1\right] \tag{17}$$

$$C = \frac{0,01488\,q_t t_x}{(t*\Delta P')_x + (t*\Delta P')_r} \tag{18}$$

$$s = 0,171\left(\frac{t_x}{t_i}\right)^{1,24} - 0,5\ln\left(\frac{0,8935C}{\phi h c_t r_w^{\,2}}\right) \tag{19}$$

$$s = 0,921\left(\frac{(t*\Delta P')_x}{(t*\Delta P')_i}\right)^{1,1} - 0,5\ln\left(\frac{0,8935C}{\phi h c_t r_w^{\,2}}\right) \tag{20}$$

Suffix *x* refers to the *maximum pressure derivative.* Tiab (1995) also derived an equation to estimate reservoir drainage area based upon the intersection point of the unit-slope pseudosteady state line presented during late time and the radial-flow regime line which was named t_{rpi}. This equation, for multiphase flow, results to be *Equation 21:*

$$A = \frac{\lambda_t t_{rpi}}{301,77\phi c_t}\frac{1}{43560} \tag{21}$$

Recently, Kamal and Pan (2008) formulated a practical methodology to estimate reservoir absolute permeability and average fluid saturations from two-phase well test data which is used in this work for complementary purposes. To apply the methodology, first estimate oil and water effective permeabilities using *Equations 7* and *8*, respectively. Then, estimate the permeability ratio k_o*/kw* and find water saturation, S_w, from a plot similar to Figure 1. With the S_w value just obtained enter into the relative permeability plot, like Figure 2, and find either water or oil relative permeabilities. Then, estimate absolute permeability using either *Equations 22* or *23.*

$$k = \frac{k_o}{k_{ro}} \tag{22}$$

$$k = \frac{k_w}{k_{rw}} \tag{23}$$

EXAMPLES

Synthetic example

A commercial well test interpretation software was used to generate the drawdown test using the input information given in Table 1. The generated pressure data are reported in Table 2. The software used a power-law model to generate the relative permeability information provided in Figures 1 and 2.

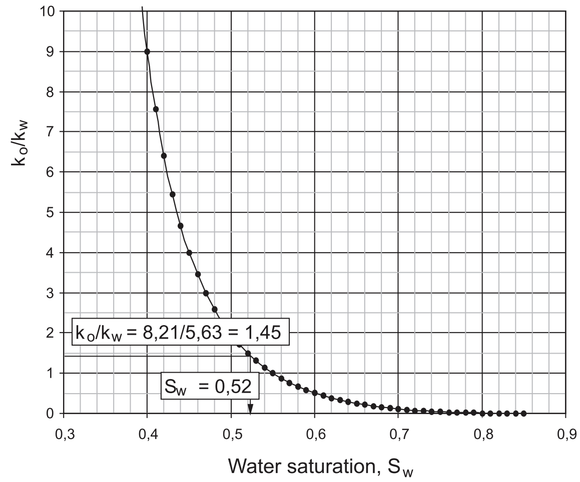

Figure 1. Effective permeability ratio vs. water saturation for synthetic example

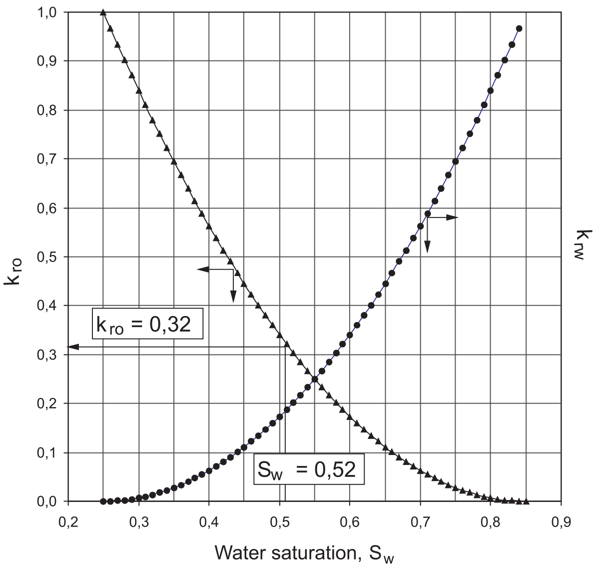

Figure 2. Relative permeability curves for synthetic example solution

Solution

From the pressure and pressure derivative plot, Figure 3, the following information was read with the help of a domestic software: t_r = 13,89 hr, ΔP_r = 586,57 psi, $(t^*\Delta P')_r$ = 48,68 psi, t_i = 0,0199 hr, t_x = 0,2751 hr, $(t^*\Delta P')_x$ = 188,055 psi, and t_{rpi} = 361,29 hrs. The effective permeabilities for oil and water are 8,2097 md and 5,6268 md, respectively, obtained from *Equations 7* and *8*. Also, for these parameters, values of 8,201 md and 5,6268 md were obtained using *Equation 13*. Besides, the correlation given in Equation 16 provides values of oil and water effective permeabilities of 8,034 and 5,507 md, respectively. The wellbore storage coefficient was estimated to be 0,01032 bbl/psi from *Equation 5* and 0,01033 bbl/psi from correlation *Equation 18*. A skin factor of 0,1135 was found with *Equation 13* and -0,117 from correlation *Equation 19*. Finally, a drainage area of 1096,3 Ac was calculated with *Equation 21*. This value matches well the one of 1110 Ac presented as input data in Table 1. The permeability ratio k_o/k_w resulted to be 8,21/5,63 = 1,4582. This value is used in Figure 1 to obtain a water saturation value of 0,52 which leads to a reading of k_{ro} = 0,32 from Figure 2. An absolute permeability of 25,6 md was estimated using *Equation 22* which closely agrees with the value of 23,3 md reported in Table 1.

Table 1. Parameters for the worked examples

	Synthetic Example	Field Example
Parameter	Value	
k, md	23,2	
ϕ, %	13	15,8
ct, psi^{-1}	7,34x10^{-6}	7,33x10^{-6}
s	0	
C, bbl/psi	0,0103	
h, ft	30	50
T, °F	212	110
P_i, psi	3200	904,9
S_o, %	50	45,9
P_{wf}, psi		157,8
S_w, %	50	54,1
A, Ac	1110	
μ_o, cp	0,804	6,7
μ_w, cp	0,295	0,6
B_o, rb/STB	1,0546	1,106
B_w, rb/STB	1,037	1,009
q_o, ft	200	68
q_w, ft	380	7,4
r_w, ft	0,3	0,3

Field Example

A buildup pressure test was run in a well located in the middle valley of the Magdalena River in Colombia, South America. Information concerning to well, fluid and reservoir properties is provided in Table 1. As for the first example, a power-law model to generate the relative permeability. Pressure data are reported in Table 2 and 3.

Table 2. Pressure data for synthetic example

t, hr	Δ*P*, psi	*t**Δ*P*', psi	*t*, hr	Δ*P*, psi	*t**Δ*P*', psi	*t*, hr	Δ*P*, psi	*t**Δ*P*', psi
0,001	2,50	2,59	0,202	303,17	177,50	31,93	776.26	49,08
0,002	4,98	5,16	0,254	345,47	181,44	40,20	787,53	48,95
0,003	7,44	7,81	0,319	388,62	180,10	50,11	798,28	49,10
0,004	9,95	10,27	0,402	430,22	173,82	60,11	807,14	49,38
0,005	12,48	12,64	0,506	469,85	161,34	70,11	814,64	49,05
0,006	14,77	15,04	0,637	506,50	146,66	80,11	821,24	49,49
0,007	17,33	17,27	0,802	537,52	130,26	90,11	827,09	49,52
0,008	19,56	19,68	1,010	565,27	112,39	100,11	832,34	49,64
0,009	22,07	22,13	1,271	589,60	97,81	130,11	845,45	50,01
0,0113	27,33	27,21	1,601	609,23	85,15	160,11	855,83	50,17
0,0143	34,36	33,22	2,015	627,00	74,13	190,11	864,43	51,15
0,018	42,70	41,33	2,537	643,01	66,90	220,11	871,84	51,78
0,0226	52,40	50,09	3,193	657,07	61,50	280,11	884,28	54,65
0,0285	65,31	60,06	4,020	670,45	57,32	340,11	894,82	58,66
0,0358	80,43	73,01	5,061	683,25	54,80	400,11	904,26	63,86
0,0451	97,79	86,45	6,372	695,46	53,02	470,11	914,49	70,51
0,0568	119,65	100,78	8,021	707,40	51,66	560,11	927,00	80,43
0,0715	144,93	117,55	10,10	719,15	50,80	650,11	939,11	91,33
0,090	173,22	133,05	12,71	730,72	50,22	765,11	954,36	106,00
0,113	206,28	148,47	16,00	742,19	49,77	985,11	983,28	135,26
0,127	223,85	156,24	20,15	753,60	49,47			
0,160	262,16	168,94	25,37	764,95	49,26			

Table 3. Pressure data for field example

t, hr	Δ*P*, psi	*t**Δ*P*', psi	*t*, hr	Δ*P*, psi	*t**Δ*P*', psi	*t*, hr	Δ*P*, psi	*t**Δ*P*', psi
0,167	27,4	25,34	5,849	529,1	119,86	24,59	625,3	85,29
0,334	50,5	46,88	6,183	532,4	104,97	25,76	630,3	88,21
0,501	73,4	68,72	6,684	538,5	90,13	27,10	635,7	90,53
0,668	95,7	88,53	7,185	541,4	77,88	28,27	639,6	93,17
0,836	117,1	107,67	7,853	545,7	68,82	29,77	642,2	99,71
1,003	138	125,69	8,541	551,9	64,61	31,78	649,7	103,52
1,170	158,6	139,90	9,210	556,2	64,91	34,63	656,6	106,19
1,337	178,3	154,82	9,879	561,7	67,19	37,97	667,4	106,36
1,504	198,3	167,67	10,55	566,1	65,31	40,65	675,9	108,17
1,671	214,7	179,15	11,22	570,8	68,82	43,66	684,4	110,14
1,838	233,1	198,86	11,88	575,7	66,98	46,84	693,3	111,54
2,006	249,3	216,20	12,55	579,5	66,65	49,44	700,3	111,66
2,173	266,3	235,84	13,22	582,7	63,98	53,78	708,8	106,54
2,507	300,2	272,27	14,22	588	66,28	55,79	712,9	105,89
2,841	338,2	300,10	14,73	589,8	62,00	60,47	718,8	103,48
3,176	376,4	307,92	14,89	589,5	67,07	62,47	722,9	104,80
3,510	411,1	299,54	16,06	594,3	65,57	65,15	728,7	105,40
3,844	443,4	279,16	17,23	598,9	68,95	69,49	735,5	107,81
4,178	470,1	257,09	18,40	602	71,87	71,50	737,7	109,88
4,513	488	226,06	19,74	606,1	73,32	75,35	739,4	114,10
4,847	502,1	197,93	20,91	609,7	75,66	79,58	746	120,56
5,181	511,6	169,77	21,91	615,4	79,75	81,63	747,1	125,09
5,515	522,2	140,97	23,08	617,8	82,89			

Solution

From the pressure and pressure derivative plot, Figure 3, the following information was read: t_r = 31,93 hr, ΔPr = 787,17 psi, $(t*\Delta P')_r$ = 66,02 psi, t_i = 0,4326 hr, and trpi = 43,7 hr. An oil effective permeability was estimated to be 10,7924 and 10,7809 md using *Equations 7* and *13*, respectively. From the pressure derivative plot, Figure 4, we observe that the wellbore storage decreases and the radial flow is developed at about 8 hr. It changes at about 16 hr developing a new plateau, possibly, reflecting a fault. The pseudosteady state is seen after 60 hr of testing.

A water effective permeability of 0,096 and 0,0958 with respectively found using *Equations 8* and *13*. The wellbore storage coefficient was estimated to be 0,02257 bbl/psi either *Equations* 5 and *13*. For comparative purposes, see Figure 7, a wellbore storage coefficient of 0,02 bbl/psi was found with a commercial software. *Equation 14* was used to estimate a skin factor value of -1,4821 and the drainage area resulted to be 5,0805 Ac with *Equation 23*. The permeability ratio *ko/kw* resulted to 112,4. This value is used in Figure 5 to obtain a water saturation value of 0,3 which allows us to read a value of *kro* of 0,83 from Figure 6. An absolute permeability of 13 md was estimated using *Equation 22*. It was also found from a commercial software, Figure 7, that the permeability was of 12,11 md, which closely agrees with the estimated value of 13 md from this study. Further analysis was not carried out since the pressure derivative found in this work differs in the final portion from the one reported by the commercial software, Figure 7.

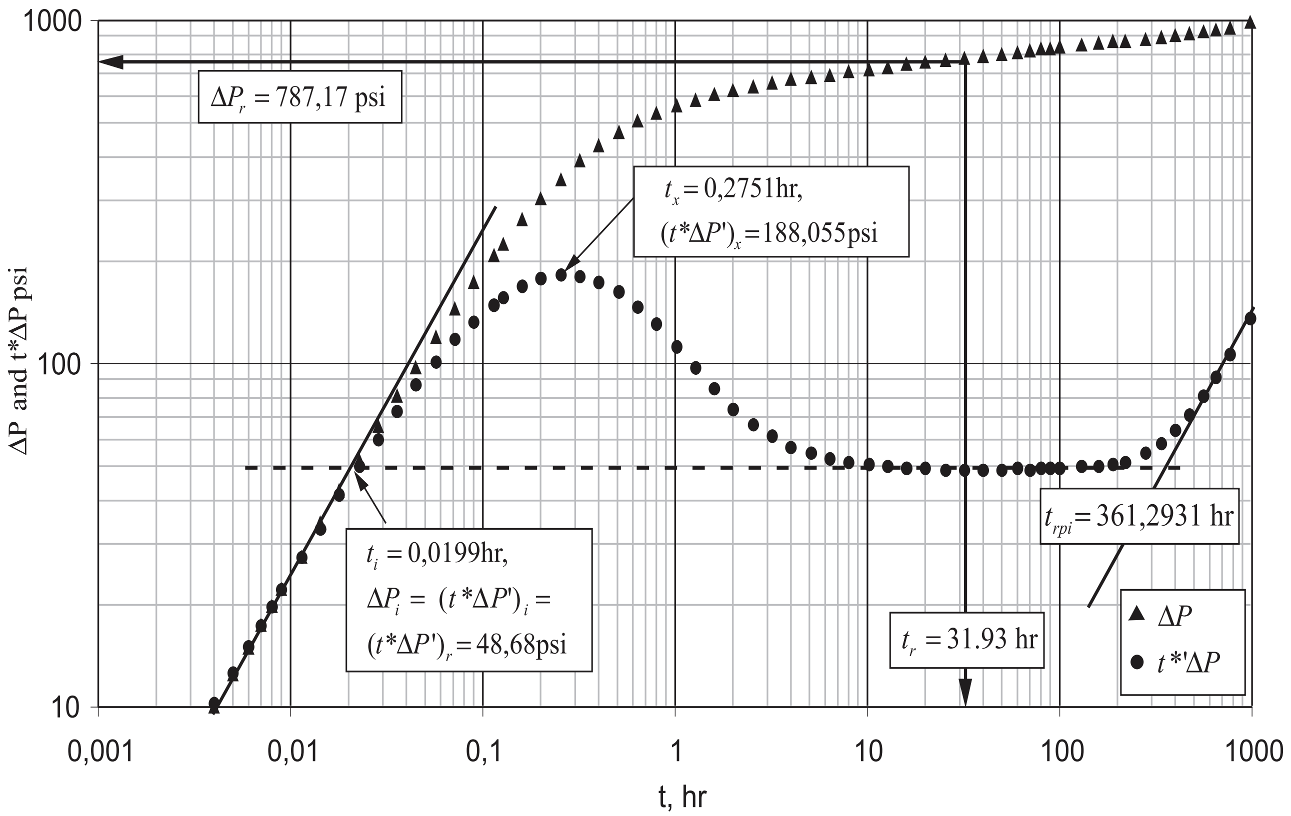

Figure 3. Pressure and pressure derivative plot for synthetic example

ANALYSIS OF RESULTS

The synthetic example was carried out with the purpose of demonstrating the effectiveness of the proposed equations work well if compared the results to the input data. As far of area is concerned, an absolute deviation factor of 1,23% was achieved (estimated area 1096,3 Ac, input area 1110 Ac). The absolute permeability, however, shows a deviation error of 10% (estimated permeability 25,6 md, input area 23,3 md). Part of the introduced error should be due to the use of generated relative permeability data. Although not shown here, for the field example, the results agreed well the conventional technique, as expected, and with results from a commercial software.

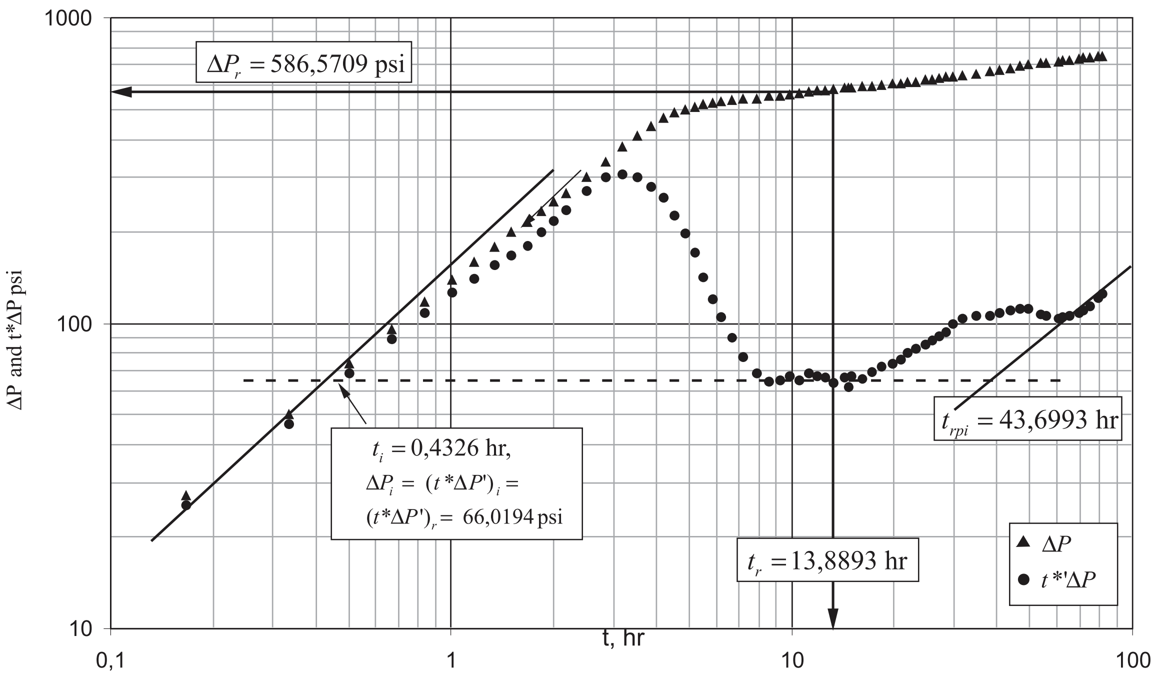

Figure 4. Pressure and pressure derivative plot for field example

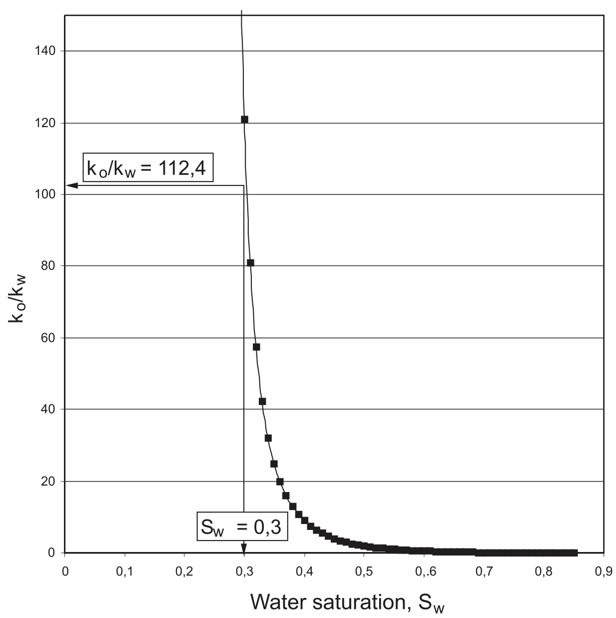

Figure 5. Effective permeability ratio vs. water saturation for field example

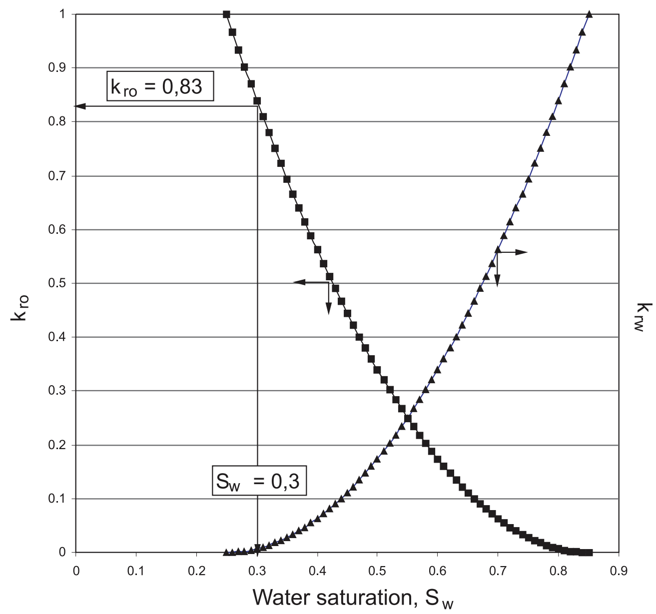

Figure 6. Relative permeability curves for field example

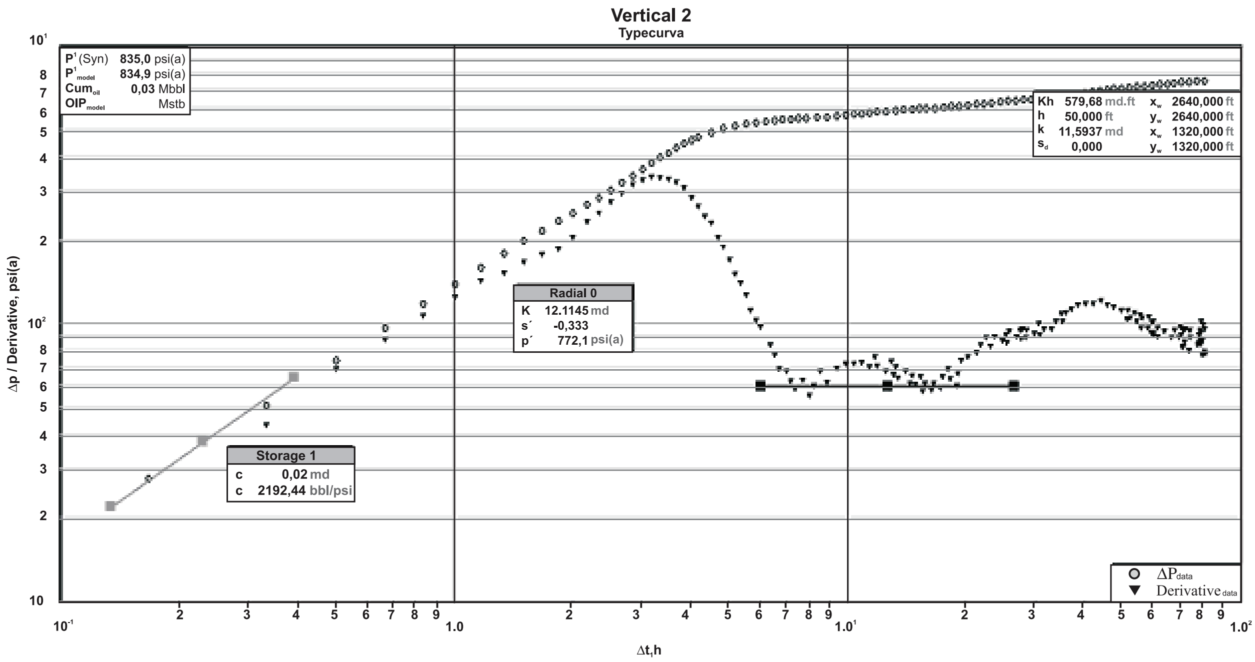

Figure 7. Results from a commercial software

CONCLUSIONS

- For multiphase flow, new equations are introduced to the TDS technique for estimation of phase permeabilities, wellbore storage coefficient, skin factor and reservoir drainage area. The application of the equations was verified through field and simulated well test data.

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