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IMPROVE RESERVES ESTIMATION USING INTERPOROSITY SKIN IN NATURALLY FRACTURED RESERVOIRS

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ABSTRACT

An alternative method, named to as direct synthesis, is proposed for interpreting pressure transient tests in naturally fractured reservoirs. This new method offers consistent results from pressure tests with or without all reservoir flow regimes observed during the test period. Direct synthesis utilizes the characteristic intersection points and slopes of various straight lines from a log-log plot of reservoir or well parameters for improve reserves estimation.
The direct synthesis method (Tiab, 1989) offers the following advantages: (1) consistent results from using the exact, analytical equations to calculate reservoir parameters; (2) independent verification is frequently possible, (3) useful information is obtained when not all flow regimes are observed, as a direct result of the additional characteristic values developed by the method, and (4) determination of flow rate and cumulative production when It is shown that in deep and super deep wells the Temperature they are compared with a original volume it is generated the recuperation factor.
Application of this technique is presented for single-well pressure tests in a naturally fractured reservoir with transient interporosity flow with skin. Both the effect of wellbore storage and skin are included in the analysis. New analytical and empirical expressions were developed as a result of this work. These expressions are an integral part of the technique and provide the desired accuracy and versatility.
Several field examples are given to clarify the technique and also illustrate the consistency acquired by the method. When possible, a comparative analysis with other methods is included.

INTRODUCTION

The basic equations for radial flow in naturally fractured reservoirs were originally formulated by Barebblatt et al. (1960). Using continuum mechanics, the medium and flow parameters of two media, fractures and matrix, are defined at each mathematical point. The transfer of fluid between the two media is maintained in a source function, where the flow is assumed to be pseudosteady state in the matrix system.
Warren and Root (1963) used this approach to develop a solution to pressure drawdown or buildup tests in a naturally fractured reservoir. From their work several flow regimes could be identified from semilog analysis. In chronological order there exists an early period straight line representing fracture depletion only, a transition period when the matrix contribution to flow is dominant, and a late period, semilog straight line is parallel to the first straight line which corresponds to the time when the entire reservoir produces as an equivalent homogeneous reservoir (Warren and Root, 1963). Two key parameters were derived to characterize naturally fractured reservoirs the dimensionless storage coefficient (ω) that provides an estimate of the magnitude and distribution of matrix and fracture storage and the interporosity flow parameter (λ) which is a measure of the mass transfer rate from the matrix to the fracture network and therefore describes the matrix flow capacity available to the fractures.
Further developments by Mavor and Cinco-Ley (1979) included wellbore storage and skin in the solution for naturally fractured reservoir pseudosteady-state interporosity flow. This was accomplished in Laplace space and numerically inverted using the Stehfest (1970) algorithm.
As a direct consequence, type curves were developed by Bourdet and Gringarten (1980) which included both wellbore storage and skin in naturally fractured reservoirs. Subsequently, reservoir parameters could be estimated when wellbore storage dominated the early time pressure data.
Cinco y Samaniego (1982) used the transfer of fluid between the two media is maintained in a source function, where the flow is assumed to be transient in the matrix system with a skin between two media, to develop a representative and applicable solution to pressure drawdown or buildup tests in a dual porosity, naturally fractured reservoir. From their work several flow regimes presented in a semilog graph. In chronological order there exists an early period straight line representing fracture depletion only, a transition period when the matrix contribution to flow is dominant, one half slope to the first straight line, a late period, semilog straight line is parallel to

the first straight line which corresponds to the time when the entire reservoir produces as an equivalent homogeneous reservoir.

Three key parameters were derived to characterize naturally fractured reservoirs the dimensionless storage coefficient (ω) that provides an estimate of the magnitude and distribution of matrix and fracture storage, the dimensionless hydraulic diffusivity by area unit parameter $\left(\eta_{maD} / H_D^2\right)$ which is a measure of the mass transfer rate from the matrix to the fracture network and therefore describes the matrix flow capacity available to the fractures referenced to size of matrix block and the new parameter dimensionless: interaction area for fluid transfer $\left(A_{fbD}\right)$. Qualitatively verified, the effect of matrix block size on the transition response, via joint use of pressure and pressure derivative data. The pseudo steady state interporosity flow, also was found to have its merits. A damaged zone in the periphery of the matrix block retards the matrix contribution, resulting in a pseudo steady state type behavior.

Continued advancement of naturally fractured type curves occurred with the addition of the derivative curve (Bourdet et al., 1983). The increased sensitivity of the derivative curve in naturally fractured reservoirs results in better accuracy of the type curve match.

This method combines the characteristic points and slopes from a log-log plot of pressure and pressure derivative data with the exact, analytical solutions to obtain reservoir properties. It has been successfully applied to infinite conductivity vertical fracture models (Tiab, 1989), to homogeneous reservoirs with skin and wellbore storage (Tiab, 1995), to vertically fractured wells in closed systems (Tiab, 1994) and to NFR with pseudosteady-state interporosity flow (Engler and Tiab, 1996).

This work extends the new method to naturally fractured reservoirs with transient interporosity flow, using the solution obtained by Pulido et. al (2006) for transient interporosity flow with skin.

THEORY

An actual naturally fractured formation is composed of a heterogeneous system of vugs, fractures and matrix which are random in nature. To model this system it is assumed that the reservoir consists of discrete matrix block elements separated by an orthogonal system of continuous uniform fractures.

These fractures are oriented parallel to the principal axes of permeability. Two commonly assumed geometries, i.e. layers and cubes, are also shown in Fig. 1.

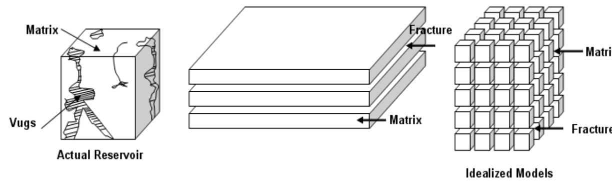

Fig. 1. Comparison of a random, heterogeneous reservoir with idealized models.

The flow between the matrix and the fractures is governed by the transient condition, but it has been conceptualized that only the fractures feed the wellbore at a constant rate. The fluid is assumed to be single phase and slightly compressible.

The wellbore pressure generalized solution in an infinite acting reservoir (Pulido et. al, 2006), is given by:

$$p_{wD} = \frac{1}{2}\left[\ln(t_D) + 0.80908 - Ei\left(-\frac{C_{fbD}\eta_{fbD}t_D}{S_{mfD}H_D^2[1-\omega]}\right) + Ei\left(-\frac{C_{fbD}\eta_{fbD}t_D}{S_{mfD}H_D^2\omega[1-\omega]}\right)\right] + S_m \quad . \quad (1)$$

Dimensionless variables are defined by:

$$r_D = \frac{r}{r_w} \quad (2)$$

$$t_D = \frac{0.000264\, k_{fb} t}{(\phi c_t)_{mb+fb}\, \mu r^2_w} \quad (3)$$

$$p_{wD}(t_D) = \frac{k_{fb} h \Delta p(t)}{141.2 q B_o} \quad (4)$$

Wellbore storage:

$$C_D = \frac{0.8935\ C}{(\phi c_t)_{mb+fb}\, \mu r^2_w} \quad (5)$$

Mechanical skin:

$$S_m = \frac{2\pi koh \Delta p_s(t)}{q\mu} \quad (6)$$

Dimensionless size block matrix:

$$H_D = \frac{H}{r_w} \quad (7)$$

Total bulk volume:

$$V_b = V_{pm} + V_{pf} + V_S \quad (8)$$

The bulk fracture porosity:

$$\phi_{mb} = \frac{V_{pm}}{V_b} \quad (9)$$

The bulk matrix porosity:

$$\phi_{fb} = \frac{V_{pf}}{V_b} \quad (10)$$

Storativity coefficient:

$$\omega = \frac{\phi_{fb} c_{fb}}{\phi_{mb} c_{mb} + \phi_{fb} c_{fb}} \quad (11)$$

Interporosity flow coefficient:

$$\lambda = \sigma r_w^2 \frac{k_{mb}}{k_{fb}} \quad (12)$$

Shape factor reflects the geometry of the matrix elements:

$$\sigma = \frac{A_f}{V_b \ell_c} = \frac{6H^2}{H^3 H/2} = \frac{12}{H^2} \quad (13)$$

Dimensionless exposed area to flow:

$$A_{fbD} = \frac{A_f H^2}{V_b \ell_c} = \sigma H^2 \quad (14)$$

Dimensionless hydraulic diffusivity matrix-fracture:

$$\eta_{mfD} = \frac{k_{mb}\phi_{fb}\mu c_{tfb}}{\phi_{mb}\mu c_{tmb} k_{fb}} = \frac{\eta_{mb}}{\eta_{fb}} \quad (15)$$

Dimensionless hydraulic diffusivity matrix-fracture per exposed area size block matrix:

$$\eta_{maD} = \frac{\eta_{mfD}}{H_D^2} = \frac{r_w^2}{H^2}\frac{k_{mb}\phi_{fb}\mu c_{tfb}}{\phi_{mb}\mu c_{tmb} k_{fb}} \quad (16)$$

Interporosity flow skin:

$$S_{mfD} = \frac{\ell_d}{r_w}\frac{\sqrt{k_{mb}k_{fb}}}{k_d} \quad (17)$$

Using the definition proposed by Cinco and Samaniego (1985):

$$\lambda = \frac{A_{fbD}\,\eta_{maD}}{S_{mfD}} = \frac{A_{fbD}\,\eta_{fbD}}{S_{mfD}\,H_D^2} \quad (18)$$

Substituting the definition provided by Cinco-Ley et al (1985) into Pulido's solution (2006), the solution is the same that obtained by Warren and Root (1963):

$$p_{wD}(t_D) = \frac{1}{2}\left[\ln(t_D) + 0.80908 - Ei\left(-\frac{A_{fbD}\eta_{fbD}t_D}{S_{mfD}H_D^{2}[1-\omega]}\right) + Ei\left(-\frac{A_{fbD}\eta_{fbD}t_D}{S_{mfD}H_D^{2}\omega[1-\omega]}\right)\right] + S \quad (19)$$

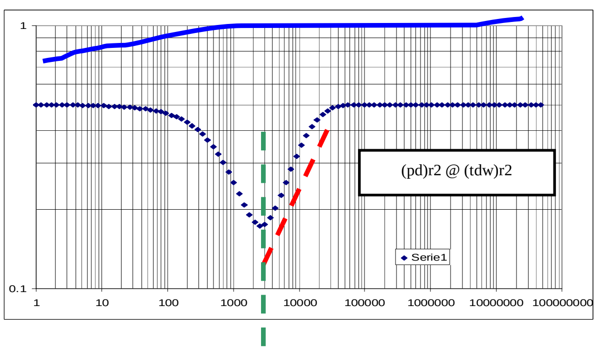

Fig. 2. Characteristic lines and prints of a Naturally Fractured Reservoir with pseudo-steady state interporosity flow $\omega = 0.01$ and $\lambda = 1x10^{-6}$ neither wellbore nor skin.

Applying the Leibnitz rule for the derivative:

$$\frac{dp_{wD}}{dt_{Dw}} = \frac{1}{2}\left[\frac{1}{t_{Dw}} - \frac{e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2[1-\omega]}}}{t_{Dw}} + \frac{e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2\omega[1-\omega]}}}{t_{Dw}}\right] \quad (20)$$

The logarithmic derivative of Eq. 1 can readily be obtained as:

$$t_{Dw}\frac{dp_{wD}}{dt_{Dw}} = \frac{1}{2}\left[1 - e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2[1-\omega]}} + e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2\omega[1-\omega]}}\right] \quad (21)$$

The derivative during these times is given by:

$$p_{wD}(t_D) = \frac{1}{2}\left[\ln(t_D) + 0.80907\right] \quad (22)$$

$$\frac{dp_{\omega D}(t_D)}{dt_D} = \frac{1}{2}\frac{1}{t_D} \quad (23)$$

$$t_D\frac{dp_{wD}(t_D)}{dt_D} = \frac{1}{2} \quad (24)$$

Substituting dimensionless variables and rearranging results in a simple and quick technique for determining bulk fracture permeability.

$$\frac{k_{fb}h(t\Delta p')_r}{141.2qBo} = \frac{1}{2} \quad (25)$$

Solving:

$$k_{fb} = \frac{70.6qBo}{h(t\Delta p')_r} \quad (26)$$

where:

$(t\Delta p')_r$ is the pressure derivative at some convenient time, $t_{D\omega} < t_{D\omega ei}$.

CHARACTERISTIC POINTS AND LINES

Dimensionless pressure and pressure logarithmic derivative versus time for a naturally fractured reservoir are illustrated in a log-log plot, which is shown in Fig. 2.

In a pressure logarithmic derivative plot, the infinite-acting radial flow periods are represented by a horizontal straight-line. The first segment corresponds to fracture depletion and the second to the equivalent homogeneous reservoir response.

The characteristic trough on the pressure logarithmic derivative in a "v" shape indicates pseudo steady state interporosity flow in the transition period for naturally fractured reservoirs. The characteristic trough on the logarithmic derivative curve in a "u" shape indicates transient interporosity flow in the transition period for naturally fractured reservoirs.

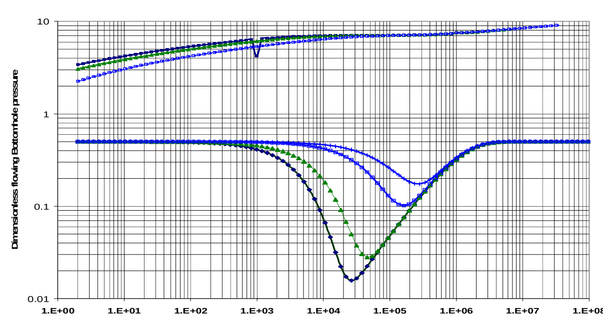

Fig. 3. Effect of storage coefficient on the pressure response in an infinite-acting, naturally fractured reservoir with pseudosteady-state interporosity flow, $\lambda = 1.0x10^{-6}$, no skin or wellbore storage.

The depth of this trough is dependent on the dimensionless storage coefficient, but independent of the interporosity flow parameter (Fig. 3). For a given dimensionless storage coefficient, the minimum dimensionless pressure coordinate is independent of the interporosity flow parameter, while the minimum dimensionless time coordinate is a function of interporosity flow parameter λ, in Fig. 4.

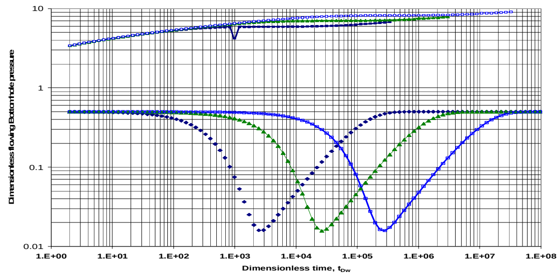

Fig. 4. Effect of variable interporosity flow parameter on the pressure response in an infinite-acting naturally fractured reservoir with pseudosteady-state interporosity flow, ω=0.005, no skin or wellbore storage.

Minimum point in a pressure logarithmic derivative.

Taking the second derivative with respect to the time of Eq. 4 and setting the result equal to zero:

$$\frac{d^2 p_{wD}}{dt_{Dw}^2}=\frac{1}{2t_{Dw}}\left[+\frac{A_{fbD}\eta_{fbD}}{S_{mfD}H_D^2[1-\omega]}e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2[1-\omega]}}-\frac{-A_{fbD}\eta_{fbD}}{S_{mfD}H_D^2\omega[1-\omega]}e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2\omega[1-\omega]}}\right]-$$
$$-\frac{1}{2t_{Dw}^2}\left[1-e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2[1-\omega]}}+e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2\omega[1-\omega]}}\right]=0 \quad (27)$$

The second part is neglected:

$$\frac{d^2 p_{wD}}{dt_{Dw}^2}=\frac{1}{2t_{Dw}}\left[+\frac{A_{fbD}\eta_{fbD}}{S_{mfD}H_D^2[1-\omega]}e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2[1-\omega]}}-\frac{-A_{fbD}\eta_{fbD}}{S_{mfD}H_D^2\omega[1-\omega]}e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2\omega[1-\omega]}}\right]=0$$

Only the second term can be equal to zero:

$$\frac{A_{fbD}\eta_{fbD}}{S_{mfD}H_D^2[1-\omega]}e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2[1-\omega]}}-\frac{-A_{fbD}\eta_{fbD}}{S_{mfD}H_D^2\omega[1-\omega]}e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2\omega[1-\omega]}}=0\,;$$

$$e^{\frac{A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2\omega[1-\omega]}}e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2[1-\omega]}}-\frac{1}{\omega}e^{\frac{A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2\omega[1-\omega]}}e^{\frac{-A_{fbD}\eta_{fbD}t_{Dw}}{S_{mfD}H_D^2\omega[1-\omega]}}=0$$

$$e^{\frac{A_{fbD}\eta_{fbD}t_{Dw}[1-\omega]}{S_{mfD}H_D^2\omega[1-\omega]}}=\frac{1}{\omega}\,;$$

$$\frac{A_{fbD}\eta_{fbD}t_D}{S_{mfD}H_D^2\omega}=\ln\left(\frac{1}{\omega}\right).$$

Subsequently, the minimum dimensionless time is given by:

$$(t_D)_{\min}=\frac{S_{mfD}H_D^2\omega}{A_{fbD}\eta_{fbD}}\ln\left(\frac{1}{\omega}\right) \quad (28)$$

Substituting the time in the first pressure logarithmic derivative:

$$\left(t_{D\omega}\frac{dp_D}{dt_{D\omega}}\right)_{\min}=\frac{1}{2}\left[1+e^{-\frac{\frac{A_{fbD}\eta_{fbD}}{S_{mfD}H_D^2}t_{D\omega}}{1-\omega}}-e^{-\frac{\frac{A_{fbD}\eta_{fbD}}{S_{mfD}H_D^2}t_{D\omega}}{\omega[1-\omega]}}\right]=$$
$$=\frac{1}{2}\left[1+e^{-\frac{A_{fbD}\eta_{fbD}}{S_{mfD}H_D^2[1-\omega]}\left[\frac{S_{mfD}H_D^2\omega}{A_{fbD}\eta_{fbD}}\ln\left(\frac{1}{\omega}\right)\right]}-e^{-\frac{A_{fbD}\eta_{fbD}}{S_{mfD}H_D^2\omega[1-\omega]}\left[\frac{S_{mfD}H_D^2\omega}{A_{fbD}\eta_{fbD}}\ln\left(\frac{1}{\omega}\right)\right]}\right]$$
$$\left(t_{D\omega}\frac{dp_D}{dt_{D\omega}}\right)_{\min}=\frac{1}{2}\left[1+e^{\frac{\omega}{1-\omega}[\ln(\omega)]}-e^{\frac{1}{[1-\omega]}[\ln(\omega)]}\right]=\frac{1}{2}\left[1+e^{\ln\left(\omega^{\frac{\omega}{1-\omega}}\right)}-e^{\ln\left(\omega^{\frac{1}{1-\omega}}\right)}\right]$$

Finally,

$$(t_{D\omega}\frac{dP_D}{dt_{D\omega}})_{\min}=\frac{1}{2}\left[1+\omega^{1/(1-\omega)}-\omega^{1/(1-\omega)}\right] \quad (29)$$

This method was originally proposed by Uldrich and Ershaghi (1979) to determine the interporosity flow parameter, using by Engler and Tiab (1995).

Normalized minimum point in a pressure logarithmic derivative.

To make this expression universal in real units, a normalized form was developed by dividing the minimum derivative point by the value of the infinite-acting, radial flow derivative line:

$$\frac{(t\frac{dP_D}{dt_{D\omega}})_{\min}}{(t\frac{dP_D}{dt_{D\omega}})_r}=\frac{\frac{1}{2}\left[1-\omega^{\frac{1}{[1-\omega]}}-\omega^{\frac{\omega}{[1-\omega]}}\right]}{\frac{1}{2}}=\left[1+\omega^{1/(1-\omega)}-\omega^{\omega/(1-\omega)}\right] \quad (30)$$

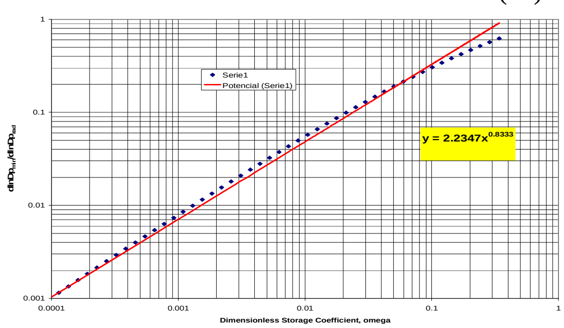

Fig. 5. Normalized correlation between storage coefficient (ω) and pressure logarithmic derivatives ratio for pseudosteady-state or transient interporosity flow.

Fig. 5. Illustrates the smooth relationship between the pressure logarithm derivatives ratio and ω.

For convenience, a correlation was developed,

$$\omega=\left(\frac{1}{2.234}\frac{(t\frac{dP_D}{dt_{D\omega}})_{\min}}{(t\frac{dP_D}{dt_{D\omega}})_r}\right)^{0.84} \quad (31)$$

And is valid from 0 ≤ ω ≤ 0.10 with less than ± 1.5 % error.

An alternative method to determine the dimensionless storage coefficient is shown in Fig. 2 is possible from the pressure logarithmic derivative. These times include the end of the first horizontal straight line, t_{Dwei}; the beginning of the second horizontal straight line, t_{Dwb2}, and the time corresponding to the minimum derivative, $t_{Dw\min}$.

$$\frac{1}{\lambda}=\frac{S_{mfD}H_D^{\;2}}{A_{fbD}\eta_{fbD}}=\frac{50t_{Dwei}}{\omega[1-\omega]};\qquad(32)$$

$$\frac{1}{\lambda}=\frac{S_{mfD}H_D^{\;2}}{A_{fbD}\eta_{fbD}}=\frac{t_{b2}}{5[1-\omega]}$$

(33)

The following relationships, which is independent from the interporosity flow parameter, can be developed from the time ratios.

$$\frac{50t_{e1}}{\omega[1-\omega]}=\frac{t_{b2}}{5[1-\omega]}=\frac{t_{\min}}{\omega\ln(1/\omega)}\qquad(34)$$

The dimensionless storage coefficient can be determined directly from the ratio of the end of the first straight line and the end of the first straight line.

$$\frac{t_{\min}}{50t_{e1}}=\frac{\ln(1/\omega)}{1-\omega}\qquad(35)$$

Or from the ratio of the minimum time to the time of the beginning of the second straight line:

$$\frac{t_{\min}}{t_{b2}}=\frac{\omega\ln\left(\frac{1}{\omega}\right)}{5[1-\omega]}\qquad(36)$$

Figs. 6-7. Illustrate the behavior of these time relationships and shows the comparison of the correlation with the analytic results.

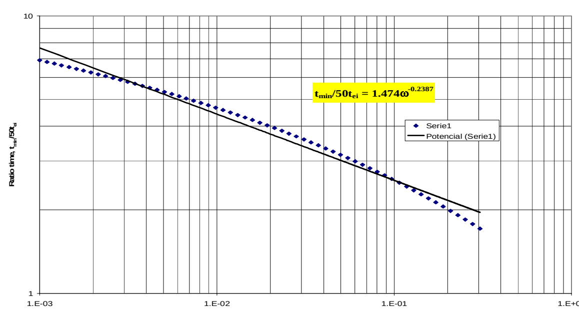

Fig. 6. Correlation between dimensionless storage coefficient and ratio of characteristics times, tmin/50tei.

Correlations for ease of solving for Dimensionless storage coefficient

Due to the time ratios with the minimum time coordinate are implicit functions, therefore correlations were developed for ease solving for dimensionless storage coefficient.

The correlation for the ratio of the minimum time to the time to the end of the first straight line, valid for ω ≤ 0.2 with less than ± 2 % error, is:

$$\frac{t_{\min}}{50t_{e1}}\approx 1.474\omega^{-0.2387}\qquad(37)$$

Solving for storage:

$$\omega=0.197\left(\frac{t_{\min}}{50t_{e1}}\right)^{-4.189}\qquad(38)$$

The correlation for the ratio of the minimum time to the time of the beginning of the second straight line, valid for ω ≤ 0.2 with less than ± 5 % error is given by:

$$\frac{5t_{\min}}{t_{b2}}\approx 1.474\omega^{0.7315}\qquad(39)$$

Solving for storage:

$$\omega=1.664\left(\frac{5t_{\min}}{t_{b2}}\right)^{1.31}\qquad(40)$$

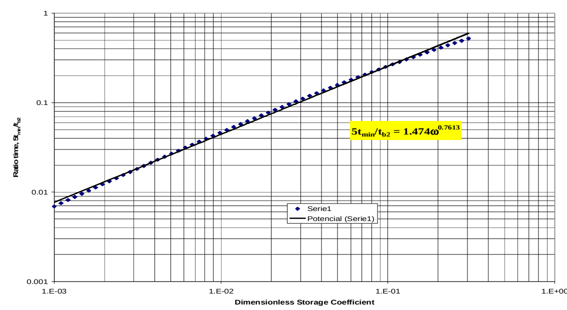

Fig. 7. Correlation between storage dimensionless coefficient and ratio of characteristics times, tmin/tb2.

Dimensionless interporosity flow

Method of determining λ can be achieved by observing a characteristic unit slope, straight line during the late transition period.

Fig. 8 is a magnified view of the pressure derivative curve during the transition period for various ω values. Notice the smaller the dimensionless storage coefficient (deeper the trough) the more accurately the data fit the unit slope line. A ω less than 0.05 results in an accurate estimate of λ. For ω > 0.05, λ will be overestimated.

A plot of $\log\left(t_{Dw}\frac{dp_{wD}}{dt_{D\omega}}\right)_{\min}$ vs. $\log\lambda(t_D)_{\min}$ results in a straight line with unit slope.

The corresponding equation is:

$$\ln\left(t_{D\omega}dp_{wD}/dt_{D\omega}\right)_{\min}=\ln\left(\frac{A_{fbD}\eta_{fbD}}{S_{mfD}H_D^{\;2}}(t_{D\omega})_{\min}\right)+\ln(0.63)\qquad(41)$$

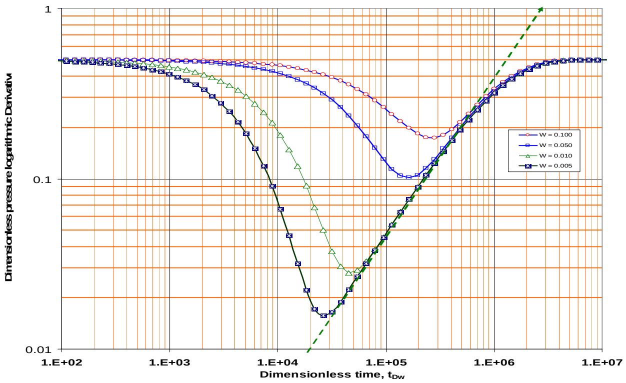

Fig. 8. Expanded view of the transition region illustrating the unit slope derivative line $\lambda = 10^{-6}$, no wellbore storage or skin.

Expressing Eq. 34 in real units and rearranging, provides a method for determining λ:

$$\lambda = \frac{A_{fbD}\eta_{fbD}}{S_{mfD}H_D^{\,2}} = \frac{42.5\phi_t c_t h r_w^{\,2}}{qBo}\left(\frac{t\,\frac{d\Delta p(t)}{dt}}{t}\right)_{\min} \tag{42}$$

The analytic equation for this late transition time behavior is:

$$\ln\left(t_{D\omega}\left(\frac{dp_{wD}}{dt_{D\omega}}\right)_{US}\right) = \ln\left(\frac{A_{fbD}\eta_{fbD}(t_{D\omega})_{US}}{S_{mfD}H_D^{\,2}\,2}\right) \tag{43}$$

The intersection of the transition period unit slope line with the infinite-acting, radial flow pressure derivative line (shown in Fig. 8), develops a very simple expression to determine λ,

$$\lambda = \frac{A_{fbD}\eta_{fbD}}{S_{mfD}H_D^{\,2}} = \frac{1}{(t_{D\omega})_{US,i}} \tag{44}$$

In real units,

$$\lambda = \frac{A_{fbD}\eta_{fbD}}{S_{mfD}H_D^{\,2}} = \left[\frac{\phi_t \mu c_t \mu r_\omega^{\,2}}{0.0002637k_{fb}}\right]\frac{1}{t_{US,i}} \tag{45}$$

In general, the interporosity flow parameter can be estimated from any of the characteristic time values by the following relationships,

$$\lambda = \frac{\omega[1-\omega]}{50\,\beta t_{e1}} = \frac{\omega\ln(1/\omega)}{\beta t_{\min}} = \frac{1}{\beta t_{US,i}} = \frac{5[1-\omega]}{\beta t_{b2}} \tag{46}$$

Where β represents the inverse of the group of constants in parentheses in Eq. 38.

For the unit slope intersection point, only an estimate of bulk fracture permeability is required, while for the remaining characteristic times the dimensionless storage coefficient must also be known.

Fortunately, to determine λ from Eq. 17 only requires identification of the minimum coordinates and thus provides an advantage over other methods.

The skin factor can be determined from the pressure and pressure derivative values at a convenient time during either infinite-acting, radial flow line segments.

From the early time analytic equations, in real units, the skin factor is given by:

$$S_m = \frac{1}{2}\left[\left(\frac{\Delta p(t)}{t\,\frac{d\Delta p}{dt}}\right)_{r1} - \ln\left(\frac{k_{fb}t_{r1}}{S_T\mu r_w^{\,2}}\frac{1}{\omega}\right) + 7.43\right] \tag{47}$$

Where the subscript r1 denotes the early time straight line. Similarly, during the late time period an expression for skin factor can be developed;

$$S_m = \frac{1}{2}\left[\left(\frac{\Delta P}{tdP_D/dt_{Dw}}\right)_{r2} - \ln\left(\frac{k_{fb}t_{r2}}{S_T\mu r_w^{\,2}}\right) + 7.43\right] \tag{48}$$

Pressure response with wellbore storage

As a direct consequence of wellbore storage, the early time, infinite-acting radial flow period is likely to be hidden. Therefore, the late time, infinite-acting radial flow line is essential for estimating the skin factor and bulk fracture permeability as discussed previously (eq. 21).

Several direct methods are possible to determine the wellbore storage constant from the pressure and pressure derivative curves. The pressure curve has a unit slope during early time. This line corresponds to pure wellbore storage flow. The equation of this straight line is:

$$p_{wD} = \frac{t_D}{C_D} \tag{49}$$

Combining eqs. and gives:

$$p_{wD} = \frac{0.000295k_{fb}ht}{\mu C} \tag{50}$$

The early time, unit slope pressure and pressure derivative lines are indicative of wellbore storage. In real unit, the pressure curve can be used to solve for the wellbore storage constant,

$$C = \left[\frac{q_o B_o}{24}\right]\frac{t}{\Delta P} \tag{51}$$

Time in hours, ΔP pressure drop between pipe full and the tubing is compressed.

Similarly, from the unit slope pressure logarithmic derivative line,

$$C = \left[\frac{q_o B_o}{24}\right]\frac{t}{tdP_D/dt_{Dw}} \tag{52}$$

An alternative is to use the intersection of the early time, unit slope pressure line with the infinite-acting, radial flow line. From this intersection point the C can be estimated.

$$C = \frac{k_{fb}ht_i}{1695\mu} \tag{53}$$

The influence of wellbore storage on the minimum coordinates is of major importance in the analysis.

As shown in Fig. 8, the dilemma is whether the observed minimum point is the actual minimum or a

"pseudo-minimum" as a direct result of wellbore storage.
Detailed investigations have shown the minimum point is unaffected by wellbore storage for all ω and λ, provided,

$$\frac{(t_{D\omega})_{\min,0}}{(t_{D\omega})_x} \geq 10.0 \qquad (54)$$

Subsequently, the procedures described previously are valid.
When the minimum-to-peak time ratio is less than the limit defined by Eq 27, a "pseudo-minimum" occurs on the pressure derivative curve.
An empirical correlation generated during this region provides a method of calculating the interporosity flow parameter:

$$[\lambda \log(1/\lambda)]_{\min} = \frac{1}{C_{D\omega}}\left[5.565\frac{t_x}{t_{\min,0}}\right]^{10} \qquad (55)$$

where:

$$\lambda = \left(\frac{[\lambda \log(1/\lambda)]_{\min}}{1.924}\right)^{1.0845} \qquad (56)$$

An alternative method to determine λ is based on the ratio of the minimum pressure derivative coordinate to the peak pressure derivative coordinate.

$$\lambda = \frac{1}{10C_D}\frac{(tdP_D/dt_{Dw})_{\min}}{(tdP_D/dt_{Dw})_x} \qquad (57)$$

This correlation is valid only when $C_D\lambda$ > 0.001.

Details of wellbore storage effects on the pressure response in naturally fractured reservoirs can be found in Engler (1995).
If a pseudo-minimum is observed the following method is recommended to determine ω.
First, the wellbore storage constant, skin factor, and interporosity flow parameter must be known a priori to form the dimensionless group shown in Fig. 9.
This group coupled with the minimum- to infinite-acting radial flow pressure derivative ratio, provides a means of determining the storage coefficient.
Tiab (1995) describes methods using the peak coordinates which provide alternatives to determining Skin, C and k_{fb} when certain flow regimes are absent. These methods are applicable to naturally fractured reservoirs if a homogeneous reservoir pressure response is indicated or the true minimum coordinate is observed. If the pseudo-minimum coordinate is observed. If the pseudo-minimum is present, then the peak coordinates are influenced by λ and ω, and results are in error.

CONCLUSIONS

A new method was used to analyze pressure data without type curve matching. It is applicable to the interpretation of buildup and drawdown tests.
Unique characteristic points and lines have been identified from the pressure derivative curve, including the minimum derivative coordinates and the intersection point of the late transition unit slope line with the infinite-acting, radial flow line. These points and lines are coupled with the exact, analytical solution to produce accurate results.
Correlations were developed to include the influence of wellbore storage on the pressure derivative curve. A systematic approach was shown applicable when the pressure response is dependent on ω, λ, Skin and CDω simultaneously.
When a new model is built to represent the interaction of several types of porous media is necessary to model the transition between them in transient interporosity with skin due to the pseudo state is not adequate. And this allows improve reserves estimation in Naturally Fractured Reservoirs.
Frequently, the results of the new technique are verifiable from an independent source, i.e. a separate characteristic point or line. Also, with the additional characteristic points or lines developed as an outcome of the method, not all flow regimes are required to be observed for the analysis.
Field examples demonstrate the step-by-step procedures and accuracy of the direct synthesis technique.

NOMENCLATURE

Bo	Formation volume factor (rb/stb)
ctmb	Total matrix compressibility (psi-1)
ctfb	Total fracture compressibility (psi-1)
CD	Dimensionless storage coefficient
h	Formation thickness (ft)
kmb	Bulk matrix permeability (mD)
kfb	Bulk fracture permeability (mD)
pD	Dimensionless wellbore pressure
P´D	Dimensionless wellbore pressure derivative
Δp	Pressure difference (psi)
Δp'	Pressure difference derivative (psi)
q	Surface flow rate (stb/d)
rw	Wellbore radius (ft)
Sm	Mechanical skin factor
ST	Total storage of the formation, = (φc)1+2(psi-1)
t	Test time (h)
tD	Dimensionless time
α	Shape factor (ft-2)
β	Group define by Eq. 20
λ	Interporosity flow parameter
μ	Viscosity (cP)
Φ	porosity
ω	Dimensionless storage coefficient

SUBSCRIPTS

1	Bulk matrix property

2	Bulk fracture property
b2	Beginning of second radial flow period
D	Dimensionless
e1	End of first radial flow period
f	Intrinsic fracture property
i	WBS unit slope-radial flow line intersection point
m	Intrinsic matrix property
min	True minimum
min,o	Observed minimum
r1	Early time, radial flow period
r2	Late time, radial flow period
us,i	Unit slope intersection point
x	Maximum point or peak
w	Wellbore

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