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A TRANSIENT PRESSURE STUDY ON THE INFLUENCE OF BLOCK SIZE FOR DRAWDOWN TESTS IN NATURALLY FRACTURED RESERVOIRS

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ABSTRACT

Block size has been concluded to be one of the main parameters of a naturally fractured reservoir. In one-phase flow, it controls the transition from the early fracture dominated stages of production to asymptotic composite (fracture plus matrix) behavior. Classical well test analysis in terms of a semilogarithmic graph of pressure vs time, has shown that drawdown pressures are not sensitive enough to the variation of block size method. This work presents the results of a study aimed at characterizing the naturally fractured reservoir by means of the transition period behavior of the pressure derivative function $t_D\ p'_{wD}$. Based on the numerical Laplace inversion results, it was observed that the pressure derivative function for the different block sizes can be correlated through a horizontal displacement of the t_D axis, when multiplied by the ratio $(h_{ma}\ h_{ma2})^2$, where h_{ma1} and h_{ma2} are two block sizes satisfying $h_{ma2} > h_{ma1}$. A discussion of previous results by Braester analyzed by means of the radial flow semilog graph of pressure vs time is also included.

INTRODUCTION

An important portion of the hydrocarbon and most geothermal reservoirs are contained in naturally fractured reservoirs (NFR´s). Optimizing the exploitation of these reservoirs requires a complete description of the formation. A reliable characterization of a reservoir can be achieved through an integrated approach, combining data from geophysics, geology, well logging, well tests, core and fluid analysis, and well flow rates, which allows the estimation of reservoir geometry, reserves, and flow characteristics of the formation, among other factors. Well testing provides a useful tool to find the reservoir-flow parameters and to detect and evaluate heterogeneities that affect the flow process in the formation.

A NFR is created under highly complex subsurface conditions. Fig. 1.a shows a portion of the rock in these types of systems, that may include several elements, such as fractures and matrix, and in sedimentary formations, vugs. Reservoir fluids (and heat) are contained in both fractures and rock matrix; usually fractures act as channels to yield high well-flow rates. Reservoir studies must carefully consider these heterogeneities because they significantly affect the energy recovery. Because of the importance of NFR´s, many publications are available that provide en understanding of the behavior of these systems. Currently, important advances in well test analysis allow a more accurate characterization of these systems, based on new flow models that better account for heterogeneities of fractured reservoirs.

Block size has been concluded to be one of the main parameters of a NFR. In one phase flow it controls the transition from the early fracture dominated stages of production, to asymptotic composite (fracture plus matrix) behavior. Among other methods, block size can be estimated through well logging (Najurieta, 1980), well test analysis (Cinco Ley and Samaniego, 1982; Da Prat, 1990) and tracer tests (Ramírez et al., 1995).

Classical analysis in terms of a semilogarithmic graph of pressure vs time, has shown that drawdown pressures are not sensitive enough to the variation of the block size (Braester, 1984). In 1984 Braester published an important paper which thoroughly addresses this type of transient pressure analysis. The author also presents drawdown solutions for variable block size conditions. The main conclusion of this paper based on numerical solutions to the flow problem in NFR´s, with ordered fractures and blocks, computed through the Galerkin method, was already stated in this paragraph.

The purposes of this paper is to present the results of a study aimed at characterizing NFR by means of the transition period behavior of the pressure derivative function $t_D\, p'_D$. The reservoir is represented by parallelepiped shaped matrix blocks alternated with fractures. A discussion of the radial flow semilog graph of pressure vs time is also included.

DESCRIPTION OF THE FLOW PROBLEM

Several reservoir flow models have been proposed to describe the behavior of NFR´s (Cinco Ley, 1996): (1) homogeneous reservoir, (2) multiple region or composite reservoir, (3) anisotropic medium, (4) single fracture system, and (5) double-porosity medium. The discussion of the present paper will be focus on the so-called classic model for NFR´s: the double-porosity model (Barenblatt et al., 1960, Warren and Root, 1963; de Swaan, 1976). We call this model as the first generation NFR model; it considers that the formation is composed of two media: fracture network and rock matrix. The models used to date in this category to represent the real fractured formation shown in Fig.1.a, consider regularly shaped matrix blocks represented by parallelepipeds and cubes, as shown in Figs. 1.a and 1.b, and also by cylinders and spheres.

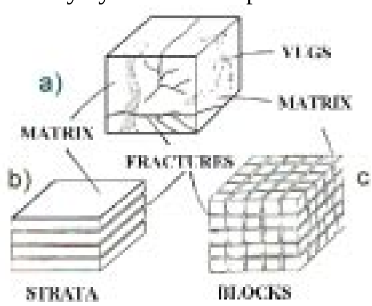

Fig.1. Representation of a naturally fractured reservoir

Fig. 2 shows the different flow periods for a well in a NFR composed of strata (parallelepipeds or slabs). At early times fluid production is due to expansion in the fractures, and fluid transfer from matrix to fractures is negligible (Fig. 2.a). This flow behavior is referred to as the fracture storage dominated flow period. As time goes on, the fluid transfer from matrix to fractures becomes important; when most of the fluid production is due to expansion in the matrix and for matrix transient linear flow conditions as shown in Fig. 2.b, the prevailing flow is called as matrix transient linear flow (Cinco Ley and Samaniego, 1982). At long times matrix flow becomes under pseudosteady-state flow conditions and the reservoir pressure behavior appears to be dominated by the total storativity of the system $(\phi_{fb}\, c_{tf} + \phi_{mab}\, c_{tma})$, as indicated in Fig.2.C. This behavior is called the total-system (fracture/matrix) dominated flow period.

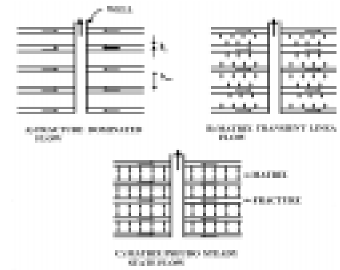

Fig.2. Flow periods for a well in a naturally fractured reservoir (strata).

It has been concluded that for purposes of estimating block size (and geometry), the most important flow period in a transient pressure test in a NFR, is the matrix linear flow (Cinco Ley and Samaniego, 1982; Braester, 1984), shown in Fig. 2.b. Thus, the discussion of the present paper will mainly address transient pressure results for this intermediate flow conditions.

FLOW MODEL AND GENERAL SOLUTION

The model used in this study is similar to that presented by de Swaan (1976) and Najurieta (1980), later further discussed by Streltsova (1993), Serra et al. (1993) and Cinco-Ley and Samaniego (1982). We will follow the discussion presented by the latter authors. This model considers the unsteady-state radial flow of a slightly compressible fluid in a double porosity system. In this work the model is particularized to the NFR representation of slabs, Fig. 2. It is assumed that the porous medium has a bulk fracture permeability k_{fb} and a bulk fracture porosity ϕ_{fb}; the matrix, has an intrinsic permeability k_{ma} and a porosity ϕ_{ma}. The fracture and matrix total compressibility are c_{tf} and c_{tma}, respectively. In addition, it is assumed that flow towards the well occurs only through the fractures, and flow from matrix to fractures is under unsteady-state flow conditions.

The flow equation in dimensionless form is as follows:

$$\frac{1}{r_D}\frac{\partial}{\partial r_D}\left(r_D \frac{\partial p_{fD}}{\partial r_D} \right) = \omega \frac{\partial p_{fD}}{\partial t_D} \tag{1}$$

$$+(1-\omega)\int_{oD}^{t_D} \frac{\partial p_{fD}}{\partial \tau}(\tau)\, F\,(\eta_{maD}, t_D - \tau)\, d\tau,$$

where the dimensionless variables are defined as:

Dimensionless pressure drop p_{fD}:

$$p_{fD} = \frac{k_{fb}\, h(p_i - p_f\,(r,t)}{\alpha q B \mu}; \tag{2}$$

Dimensionless time t_D :

$$t_D = \frac{\beta\, \mathrm{k_{fb}}\, \mathrm{t}}{(\phi\, \mathrm{c_t})_t \mu\, \mathrm{r_w^2}} \ , \tag{3}$$

where α and β are unit conversion constants (see the nomenclature).

Dimensionless radius:

$$r_D = \frac{r}{r_w} \ ; \tag{4}$$

Dimensionless fracture storativity (fracture storage parameter) ω*:*

$$\omega = \frac{\phi_{fb}\ c_{tf}}{\phi_{fb}\ c_{tf} + \phi_{mab}\ c_{tma}} = \frac{\phi_{fb}\ c_{tf}}{(\phi\ c_t\ )_t} ; \tag{5}$$

Dimensionless matrix hydraulic diffusivity η_{maD} :

$$\eta_{maD} = \frac{\eta_{ma}}{\eta_f} \frac{r_w^2}{h_{ma}^2} = \frac{k_{ma}\,(\phi c_t\,)_t\ r_w^2}{k_{fb}\,(\phi c_t\,)_{ma}\ h_{ma}^2} ; \tag{6}$$

Dimensionless fracture area A_{fD}:

$$A_{fD} = \frac{A_{fb}\ h_{ma}\ V_b}{V_{ma}} = A_{ma}\ h_{ma} ; \tag{7}$$

Fluid matrix-fracture transfer function for the slab geometry $F(\eta_{maD}, t_D - \tau)$:

$$F(\eta_{maD}, t_D - \tau) = 4\eta_{maD} \sum_{n=0}^{\infty} e^{-\eta_{maD}(2n+1)^2 \pi^2 (t_D - \tau)} \ . \tag{8}$$

The behavior of double-porosity models is characterized by four dimensionless parameters. The first three are the fracture storativity ω defined by Warren and Root (1965), Eq. 5, the dimensionless matrix hydraulic diffusivity η_{maD}, Eq. 6, and the dimensionless fracture area A_{fD}, Eq. 7. In addition for NFR with fractures partially filled by minerals, which reduce the flow interaction between matrix and fractures, a fourth parameter referred to as fracture skin factor, S_{maD}, has been defined (Cinco-Ley et al., 1985):

$$S_{maD} = \frac{k_{ma}\ \bar{x}_d}{k_d\ h_{ma}} \ , \tag{9}$$

where $\bar{x}_d$ and $\bar{k}_d$ are the average fracture-damage thickness and permeability. For high S_{maD} values (severe restriction in the matrix-fracture interaction), the NFR can be described by two parameters only: ω and λ. The λ results from a combination of A_{fD}, S_{maD}, and η_{maD} as

$$\lambda = \frac{A_{fD}\ \eta_{maD}}{S_{maD}} \ . \tag{10}$$

A high value of this parameter indicates a fast interaction between matrix and fractures and viceversa. This flow case is referred to as the pseudosteady-state matrix model, or the Warren and Root model.

The solution for radial flow described by Eq. 1, with constant flow rate at the wellbore, was obtained by means of the Laplace transform method, resulting in Eq. 11:

$$\bar{p}_{fD} = \frac{K_o\left\{ r_D\ s^{1/2}\left[\omega + (1-\omega)A_{fD}\ f(\eta_{maD}, s)\right]^{1/2}\right\}}{s^{3/2}\left[\omega + (1-\omega)A_{fD}\ f(\eta_{maD}, s)\right]^{1/2}} \cdot \frac{1}{K_1\left\{ s^{1/2}\left[\omega + (1-\omega)A_{fD}\ f(\eta_{maD}, s)\right]^{1/2}\right\}} \ . \tag{11}$$

Wellbore storage and skin effects can be easily incorporated into the solution (Cinco Ley and Samaniego, 1982).

DISCUSSION OF RESULTS

Results were calculated by applying the Stephest numerical algorithm (Stephest, 1970) to invert the Laplace space solution given by Eq. 11 As already mentioned, a slab matrix-fracture geometry was used in this study.

Fig. 3 shows a schematic semilogarithmic drawdown graph of the pressure drop Δp_w vs time *t*, for the matrix transient and for the pseudosteady-state matrix flow models. The difference occurs during the transition period between the two parallel semilog straight lines. For the flow period of interest in this study, the unsteady-state, when most of the fluid production is due to expansion in the matrix and for matrix transient linear flow conditions (Fig. 2.b), the wellbore pressure behavior expressed in dimensionless form is given by Eq. 12:

$$p_{wD} = \frac{1}{4} \ln t_D - \frac{1}{2}\left[(1 - \omega) A_{fD} \sqrt{\eta_{maD}}\right] + 0.2602 + S \quad . \quad (12)$$

Eq. 12 defines a semilog straight line of slope equal to half the slope of the parallel straight lines, corresponding for early times to fracture flow and for later times to the total-system dominated flow period, which occurs for small values of $\omega (\omega \leq 5 \text{x} 10^{-2})$.

With regard to the previous discussion, it can be stated that regardless of the value of the fracture storativity parameter ω, a minimum intermediate semilog slope m_{min} is shown during a drawdown test, which ranges from the lowest possible value of 0.50 (Eq. 12) to 1.0. Fig. 4 shows the relationship between the minimum slope ratio m_{min} / m and ω, where the strata (slabs) and the sphere matrix-fracture geometry are considered. Fig. 5 presents results for the intersection time between the minimum slope semilog straight line and the third straight line vs ω. It can be noticed that the higher the value of ω the higher the intersection time, and for small values of ω, the intersection is independent of this storativity parameter, and occurs at

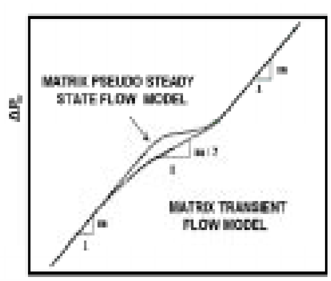

Fig.3. Cor fractured reservoirs

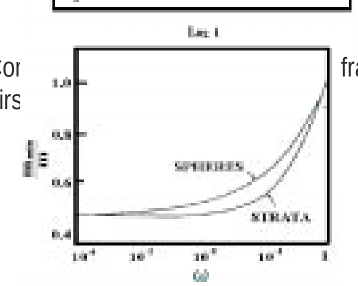

Fig.4. Variation of the minimum semilog straigth line ratio as a function of ω. (Cinco Ley and Samaniego,1982).

$$t_{D\,\mathrm{int}} = \frac{0.5615}{A_{fD}\, \eta_{maD}} \ , \quad (13)$$

or

$$t_{int} = \frac{0.5615}{\beta\, A_{fma}^{2}\, \eta_{ma}} \ . \quad (14)$$

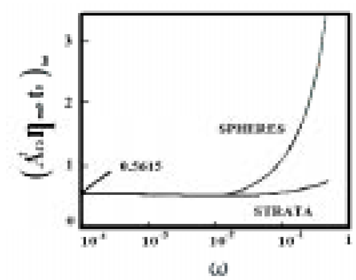

Fig. 5. Time of intersection between the second and third semilog straigth lines. (Cinco Ley and Samaniego,1982).

Eq. (13) can be derived combining Eq. 12 and the corresponding expression for large times where flow dominated by matrix pseudosteady-state prevails, given by Eq. 15

$$p_{wD} = \frac{1}{2}\left[\ln t_D + 0.80907\right] \ . \quad (15)$$

Estimation of the group $A_{fma}^{2}\, \eta_{ma}$, or any combination of the variables involved, is possible provided the pressure data display the second and third straight lines; for small values of ω Eq. 14 can be used. For conditions where the slope ratio of the second and third straight lines is greater than 0.5, the following equation is used instead of Eq. 25 (Cinco Ley and Samaniego, 1982):

$$t_{int} = \frac{(A_{fD}^{2}\, \eta_{maD}\, t_D)_{int}}{\beta\, A_{fma}^{2}\, \eta_{ma}\, \eta_{ma}} \ , \quad (16)$$

where $(A_{fma}^{2}\, \eta_{maD}\, t_D)_{int}$ is obtained from Fig. 5. It should be emphasided based on the results of this figure, that for small values of ω $(< 10^{-2})$ the parameter $A_{fma}^{2}\, \eta_{ma}$ is independent of the matrix geometry.

Braester (1984) presented an excellent study aimed at analyzing the influence of block size on the transition curve for a drawdown test. The Galerkin finite-element numerical solutions, were only studied by means of semilog radial flow graphs of pressure vs flowing time. The main conclusion of this work was that through this particular method of analysis, drawdown pressures are not sensitive enough to the variation of the block size, because results were quite similar. Fig. 6 presents a semilog drawdown dimensionless graph of the wellbore pressure vs flowing time, for three different block sizes, which closely resembles similar dimensional graphs of Braester.

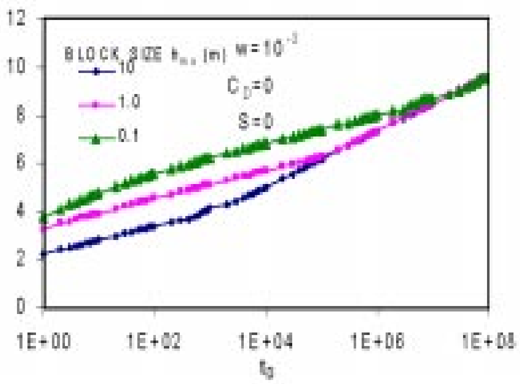

Fig. 6. The influence of the block size h_{ma} on a drawdown test.

Just about concurrent with the publication of this paper, the concept of pressure derivative with respect to time (Tiab and Kumar, 1980; Bourdet et al., 1983) was introduced, which offers several advantages as a flow diagnostic tool with respect to previous techniques. Fig. 7 presents the results of Fig. 6 through a semilog graph of the pressure derivative function $t_D p'_{wD}$ vs time. These results for the different block sizes look similar, and indeed they can be correlated into a single pressure response through a horizontal displacement of the t_D axis, when multiplied by the ratio $(h_{ma1}/h_{ma2})^2$, where h_{ma1} and h_{ma2} are two block sizes satisfying $h_{ma2} > h_{ma1}$. Nevertheless this uniqueness problem, the use of the pressure derivative function greatly improves the diagnosis of the intermediate and late time pressure behaviors in a well completed in a NFR.

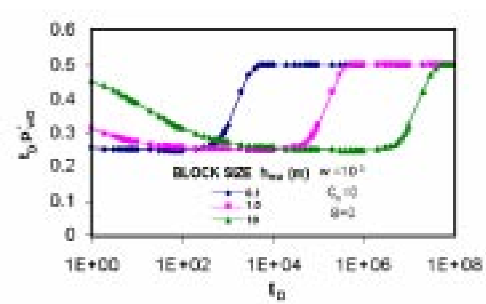

Fig.7. Presure derivative function t_D p'_{wD} for three different block sizes.

In addition to the pressure derivative function diagnostic tool, in a recent study, with the purpose of better characterizing a NFR through the analysis of the transition matrix linear flow pressure data, a logarithmic pressure derivative function $d[log\,(t_D\ p'_{wD})]/d(log\,t_D)$ has been defined (Cinco Ley, 1998; Rodríguez-Nieto, 2000; Rodríguez-Nieto et al., 2000). Fig. 8 presents an example of the application of this new logarithmic derivative function to same the cases discussed in Fig. 6 and 7.

Last, a brief discussion is included of a field build up test originally presented by Najurieta (1980), run in a NF carbonate reservoir, after a long producing time. *(t_p=8611/ hours).* The author indicated that through the analysis of all available information, the formation could be considered as stratified, with block size $h_{ma} = 17$ ft.

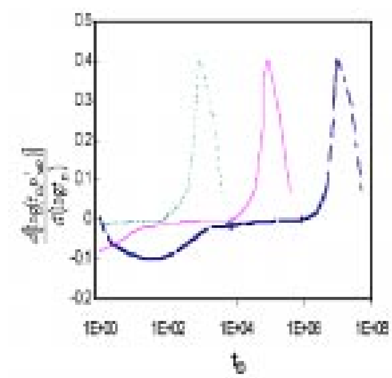

Fig.8. Log-log dimensionless pressure behavior in terms of the logarithmic pressure derivative d[log($t_D p'_{wD}$)]/d(log t_D) vs t_D, for different block size.

Fig. 9 shows a semilog graph of the pressure data and indicates that two straight lines can be drawn, the first with a 16.5 psi/cycle slope and the second with 30 psi/cycle. This yields a slope ratio equal to 0.55. The pressure data was also plotted (Fig. 10) in terms of the pressure derivative function $\Delta t\ p'_{ws}$ vs shut-in time Δt. It is important to mention that this data was recorded by means of a low accuracy pressure gauge, which explains its non smooth behavior. In spite of this problem, the intermediate and late times straight lines can reasonably be observed in Fig. 10, which helps toward getting a better test analysis.

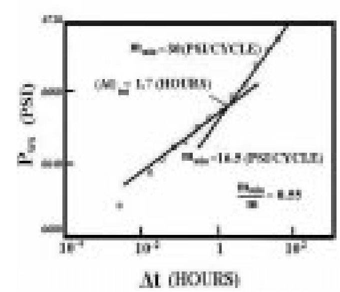

Fig.9. Semilog graph of pressure data for Najurieta´s example

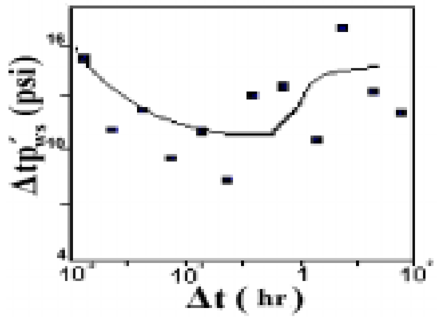

Fig. 10. Pressure derivative function log-log graph for Najurieta´s buildup test

Next, the estimation of the matrix (slab) size will be presented (Cinco Ley and Samaniego, 1982). From the graphical results of Fig. 9, the intersection time between the two straight lines occurs at 1.7 hours. Through the slope ratio for this test of 0.55 and the results of Fig. 4, a value of 6 x 10^{-2} is estimated for the fracture storativity ω. With this value and the results of Fig. 5, the intersection time dimensionless group $(A_{fD}^2 \, \eta_{ma} \, t_D)_{int} = 0.57$ can be estimated; then from Eq. 16,

$$A_{fma} \sqrt{k_{ma}} = A_{fma} \sqrt{\frac{(A_{fD}^2 \, \eta_{maD} \, t_D)_{int} (\phi \, c_t)_{ma} \mu}{\beta \, t_{int}}}$$

$$= \sqrt{\frac{0.57 x 0.21 x 8.1655 x 10^{-6} (psi) x 1 (cp)}{2.637 x 10^{-4} x 1.7 (hours)}}$$

$$= 4.7 x 10^{-2} \frac{md^{1/2}}{ft}$$

Najurieta stated that matrix permeability estimated from core analysis is 0.1 md, and considered that for a slab matrix-fracture geometry $A_{fma} = 2 / h_{ma}$, =

$$h_{ma} = \frac{2 \sqrt{k_{ma}}}{4.7 x 10^{-2}} = \frac{2 \sqrt{0.1 (md)}}{4.7 x 10^{-2} (md^{1/2} \, / \, ft)}$$

$$= 13.5 \, ft$$

This result is within 20 percent difference from the value of 17 ft given by Najurieta, calculated from core studies.

CONCLUSIONS

This study has presented a discussion related to the estimation of matrix block size in naturally fractured reservoirs, mainly based on the analysis of pressure data for the transition matrix transient flow, from the early fracture dominated stage of production to the asymptotic composite (fracture plus matrix) behavior. It has been confirmed that classical analysis in terms of a semilogarithmic graph of pressure vs time, show that drawdown pressures are not sensitive enough to the variation of block size. It has been concluded that the use of the pressure derivative function and of the new logarithmic pressure derivative function $d\left[log \, (t_D \, p'_{wD}) \right] / d (log \, t_D)$ improves the flow diagnosis capabilities. Once this step is accomplished, the estimation of block size can be carried out through already available methods.

NOMENCLATURE

A_{fma}	= Fracture area per unit of matrix volume
A_{fb}	= Fracture area per unit of bulk volume
A_{fD}	= Dimensionless fracture area
B	= Formation volume factor
c	= Fluid compressibility
c_{tf}	= Fracture system total compressibility
c_t	= Total compressibility
h	= Formation thickness
h_{ma}	= Strata (matrix) height (size)
k	= Permeability
p	= Pressure
p_D	= Dimensionless pressure
p'_D	= Dimensionless pressure derivative
p_i	= Initial reservoir pressure
Δp	= Pressure change
q	= Well flow rate
r	= Distance to production well
r_w	= Wellbore radius
S	= van Everdingen and Hurst skin factor
S_{maD}	= Dimensionless damage parameter
s	= Laplace transform variable for matrix fracture flow restriction
t	= Time

t_D	= Dimensionless time
V	= Volume
x	= Distance, thickness
α, β	= Unit conversion constants (for the English system, 141.2 and 2.637x10^{-4})
λ	= Interporosity flow coefficient
η	= Hydraulic diffusivity
ρ	= Fluid density
μ	= Fluid viscosity
ϕ	= Porosity
τ	= Dummy integration variable
ω	= Dimensionless fracture storativity

SUBSCRIPTS

b	= Bulk, beginning
d	= Damaged
D	= Dimensionless
e	= End
i	= Initial
int	= Interception
ma	= Matrix
t	= Total

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