SPE 163028

A New Model for Determining the Radius of Mud Loss during Drilling Operation in a Radial Fractured Network

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This paper was prepared for presentation at the 2012 SPE Nigerian Annual International Conference and Exhibition held in Abuja, Nigeria, 6-8 August 2012.

Abstract

A new solution for determining the amount of mud loss during drilling operation in a fractured reservoir having a regular two- or three-dimensional radial fractured network with the novel inclusion of a convective transport of filtrate in the matrix is presented. Convective-dispersive filtrate transport along the network is modeled in which drilling mud can be filtered in existing matrix. The filter cake effect at the fracture-matrix interface in the network is simulated by means of an empirically decaying filter rate equation. The numerical solution is used in this study. The consistency of numerical solution is checked and the best situation is considered. The sensitivity analysis on all parameters in the model has been done and the effect of each parameters such as wellbore loss rate, reservoir thickness, fracture opening size, matrix porosity, matrix permeability and dispersivity, on the amount of filtration are inversitaged. By means of developed model, the amount of mud filtration can be plotted against position in different fractured network configurations for different wellbore conditions, reservoir properties and reservoir geometries at different times. The position in the fracture network at which the curve of concentration reaches zero can be considered to represent skin radius caused by drilling operation. This radius can be used for determining the acid volume which is needed for acidizing operation and accurate well-log interpretation.

1. Introduction

Near-wellbore mud filtrates and fines invasion during drilling operations and the resulting formation damage and filter cake formation are amongst the most important problems involving the petroleum reservoir exploitation.

Prediction of the near-wellbore conditions, such as mud filtrate and fines invasion and distribution, are important for different issues. For example, if the radius of damage due to lost of drilling fluid can be determined, the volume of acid which is needed to conduct any acid job can be calculated accurately. Therefore, for modeling purposes, the coupling of the external filter cake build-up and the near-wellbore fluid invasion and formation damage are essential. Also, it can be used for accurate interpretation of the well-logs used for measurement and monitoring of the properties of the near-wellbore formations and accurate estimation of the hydrocarbon content of the reservoirs (Civan and Engler, 1994; Phelps, 1995; Ramakrishnan and Wilkinson, 1997).

The mud filtrate invading the near-wellbore formation mixes with and/or displaces the reservoir fluids (Civan, 1994, 1996a,b; Phelps, 1995; Bilardo et al., 1996). As a result, a damaged zone is created around the wellbore (Liu and Civan, 1993, 1994, 1996; Civan and Engler, 1994).

Donaldson and Chernoglazov (1987) developed a "leaky-piston" filtrate invasion and convection-dispersion filtrate transport model applicable to cases involving drilling mud that can mix with the formation fluid. This model considered the dispersion of the mud filtrate within the formation fluid in a single-phase fluid system to estimate the salinity variation in the near-wellbore region, but neglected the affect of mud fines invasion. This model was formulated for linear flow and the filter cake affect is simulated by means of an empirically determined, decaying filter rate equation. Civan and Engler (1994) extended and improved this model for the radial filtrate invasion case applicable to actual open hole wells.

Yao and Holditch (1996) and Bilardo et al. (1996) have developed radial filtration models for reservoirs containing some formation water. They assumed that the mud filtrate mixes with the formation water as a single phase. Because their interest is in the development of models to estimate the water phase saturation, they do not consider a convection-dispersion transport equation for estimation of the brine salinity variation due to the mixing of the mud filtrate with the formation brine. However, the salinity would be required for the resistivity measurements. Phelps (1995) presents a model to determine the fluid saturations in layered formations during mud filtrate invasion. Civan (1994, 1998a,b, 1999a,b, 2002) presented an improved formulation of the multispecies and two-phase fluid transport in deforming porous media; derivation of compressible and incompressible cake models with and without particle invasion; and an application for radial flow filter cake build-up and mud filtrate invasion. Olarewaju (1990) developed an analytical model for permeability alteration around wells due to drilling mud filtrate invasion and mud cake formation. Ramakrishnan and Wilkinson (1997) developed a radial model for water-based mud filtrate invasion. This model enables the determination of the saturations of the oil and water phases and the salt concentration in the water phase. They combine all the dissolved ions in brine into a single pseudo-component called "salt". Chin (1995) presents numerical models for formation invasion for various applications including formation damage, measurement-while-drilling and time lapse analysis. Liétard (1999) and Liétard et al. (1999) considered a naturally fractured reservoir formation separated into a series of matrix blocks by means of a conjugated system of parallel fractures. Lavrov and Tronvoll (2004, 2005 and 2006) and Pordel Shahri et al. (2011a) modeled borehole ballooning caused by the opening and closing of natural fractures in radial and rectangular coordinates with different mud rheology.

Recently, Pordel Shahri et al. (2011b) modeled the convection-dispersion filtrate transport with the novel inclusion of a convective transport of filtrate in the matrix so that the drilling mud can mixed with the formation fluid in a well with a finite-conductivity vertical fracture.

The objective of this paper is to present a new model for mud invasion in a fractured medium having a regular two- or three-dimensional fracture network. Convection-dispersion filtrate transport model is developed in which drilling mud can mix with the formation fluid and the filter cake affect is simulated by means of an empirically decaying filter rate equation. The novel aspect of this work includes the filtrate transport in both fracture and matrix by convection-dispersion processes. The influences of a number of key parameters (such as wellbore loss rate, reservoir thickness, fracture opening size, matrix porosity, matrix permeability and dispersivity) are examined on the mud filtration in both fracture and matrix.

2. Development of Model

Consider a well in a fractured porous media. It was assumed that there are three possible set of fractures. Referring to Fig. 1, suppose that z, r and θ are a set of radial reference direction; it is assumed that the first set of fracture are a distance $2H_1$ apart, of width $2h_1$, and exist in horizontal plane and in z-direction; the second set of fracture is assumed to be spaced at an interval of $2H_2$, of width $2h_2$ and in r-direction; the third set of fracture is assumed to be spaced at an interval $2H_3$, of width $2h_3$ and in θ-direction. The porous media adjacent to the wellbore is thus assumed to consist of a series of blocks made up a homogeneous matrix material separated by fractures having a width far smaller dimension of the blocks. As you can see in the Fig. 1, the mud filtrate can be loss in the fracture network during the drilling operation. If we assume the size of suspended particles in mud is less than fracture aperture, whole of mud loss into the fracture network and mud cake does not form at the wellbore. In this model we assumed that the mud filtrate can be mix with the reservoir fluid and the salt concentration varies. Thus, the fluid zone can be viewed in two parts: the water phase and oil phase zones placed respectively behind and ahead of the displacement front, located at a distance, $r_e(t)$. In this case, the front moves with time. The filtrate mixture is considered as a pseudo-component.

It was assumed that the interface of wellbore and the adjacent porous media is the horizontal plane and the porous media is quite extensive so that the predominant mechanism for transport of the mud filtrate will be one-dimensional convective-dispersive transport along fractures set 1 and 2 in r-direction accompanied by some convective-dispersive transport of mud filtrate into the intact blocks. It now follows from a consideration of conservation of mass in fracture network. The governing equation for the fracture component of the system is described by:

$$-v\frac{\partial C_f}{\partial r}+D_a\left[\frac{\partial^2 C_f}{\partial r^2}+\frac{1}{r}\frac{\partial C_f}{\partial r}\right]-\frac{2q}{2w}-\frac{2q'}{2w}=n_f\frac{\partial C_f}{\partial t} \quad (1)$$

Where $C_f = C_f(r,\theta,z)$ is the salt concentration [M/L^3], r is radial coordinate [L], t is time [T], v is the average radial steady-state filtration velocity in the fracture network assumed to be unidirectional in r [L/T], D_a is the apparent coefficient of hydrodynamic dispersion (L^2/T), w is the half fracture aperture [L], q is the source/sink term representing diffusion transport of mud across the matrix wall, q' is the source/sink term representing convection transport of mud across the matrix wall and n_f is the fracture volume fraction in the network which is equal to:

$$n_f=\frac{h_1}{H_1}+\frac{h_2}{H_2}+\frac{h_3}{H_3} \quad (2)$$

As one can see in the Fig. 1, the value of H_2 vary along the r direction so average value along the fracture network can be used in the developed model. Average value of H_2 can be obtained by:

$$\overline{H}_2=\frac{H_{2_{rw}}(r^2-r_w^2)}{2r_w(r-r_w)} \quad (3)$$

Where $H_{2_{rw}}$ is the half fracture distance at the wellbore.

The velocity term (v) can be represented by Darcy velocity of radial flow of incompressible fluid along the fracture network in r direction. Radial velocity is decreased as mud travel in r-direction:

$$v=\frac{v_{r_w}\cdot r_w}{r} \quad (4)$$

Where v_{r_w} is the filtration loss velocity at the wellbore which can be determine from filtration loss rate [L/T], r_w is the wellbore radius [L] and r is the radial coordinate [L], as a result the mud filtration along the fracture network stopped when radial velocity approach zero.

The coefficient of hydrodynamic dispersion along the fracture network may often be related to filtration loss velocity and dispersivity. Thus we have:

$$D_a=\alpha\cdot v \quad (5)$$

Where α is the dispersivity [L].

The source/sink term (q) represents the transfer of filtrate between the horizontal fracture and porous matrix, and is equal to the diffusive flux across the fracture–matrix interface. The diffusive flux is approximated using Fick`s first law:

$$q=-D_{zm}\cdot n_m\cdot\phi_m\cdot\left(\frac{\partial C_f}{\partial z}\right)_i \quad (6)$$

Where ϕ_m is matrix porosity, n_m is matrix volume fraction in network, D_{zm} is the effective matrix diffusion coefficient [L^2/T] given by:

$$D_{zm}=\tau\cdot D^* \quad (7)$$

Where τ is the matrix tortuosity and D^* is free solution molecular diffusion coefficient [L^2/T].

The gradient $\left(\frac{\partial C_f}{\partial z}\right)_i$ is the concentration gradient at the fracture – matrix interface. According to Donaldson and Chernoglazov (1987) this gradient can be assumed to have an exponential trend with respect to time. At time zero when no mud cake is formed, this gradient has its highest value and formation of mud cake causes it to decrease gradually until it reaches almost zero at the time when the mud cake is completely formed. The gradient $\left(\frac{\partial C_f}{\partial z}\right)_i$ also depends directly upon the concentration of drilling fluid in the fracture. Therefore, this gradient can be formulated as follows:

$$\left(\frac{\partial C_f}{\partial z}\right)_i=ACF\cdot C_f\cdot e^{-BCF\cdot t} \quad (8)$$

ACF and BCF are constant and should be determined experimentally for any specific fluid and rock properties. As shown in Fig. 2, the highest value for the gradient $\left(\frac{\partial C_f}{\partial z}\right)_i$ is at time zero and equal to $ACF\cdot C_f$ and constant BCF determines the slope of this curve.

The source/sink term (q') represents the transfer of filtrate between the fracture and the porous matrix, and is equal to the convective flux across the fracture–matrix interface. The convective flux is approximated using Darcy`s law:

$$q'=v_{f-m}\cdot C_f \quad (9)$$

Where v_{f-m} is velocity at the fracture-matrix interface [L/T]

The velocity at the fracture-matrix interface equal to:

$$v_{f-m} = \frac{\beta \cdot k_m \cdot n_m \cdot \phi_m}{\mu} \left(\frac{\partial P}{\partial z} \right)_i \tag{10}$$

Where β is the conversion factor, k_m is the fracture permeability [L^2], μ is the viscosity [M/L.T], the gradient $\left(\frac{\partial P}{\partial z} \right)_i$ is the pressure gradient at the fracture – matrix interface. This gradient can be assumed to have an exponential trend with respect to time. At time zero when no mud cake is formed, this gradient has its highest value and formation of mud cake causes it to decrease gradually until it reaches almost zero at the time when the mud cake is completely formed. The gradient $\left(\frac{\partial P}{\partial z} \right)_i$ also depends directly upon the pressure of drilling fluid in the fracture. Therefore, this gradient can be formulated as follows:

$$\left(\frac{\partial P}{\partial z} \right)_i = APF \cdot (\overline{P}_f - P_i) \cdot e^{-BPF \cdot t} \tag{11}$$

APF and BPF are constant and should be determined experimentally for any specific fluid and rock properties. The highest value for the gradient $\left(\frac{\partial P}{\partial z} \right)_i$ is at time zero and equal to $APF \cdot (\overline{P}_f - P_i)$ and constant BPF determines the slope of this curve.

Concentration variable can be written in dimensionless form as follows:

$$C_{Df} = \frac{C_f}{C_o} \tag{12}$$

Where C_o is the concentration of the drilling fluid at the wellbore [M/L^3].

The initial condition is given by

$$C_{Df} = 0 \qquad r_w < r < r_e \;;\; t = 0 \tag{13}$$

The boundary conditions at the wellbore and the moving front are given, respectively, by

$$C_{Df} = 1 \qquad r = r_w \;;\; t > 0 \tag{14}$$

$$\frac{\partial C_{Df}}{\partial r} = 0 \qquad r = r_e \;;\; t > 0 \tag{15}$$

The final form of the partial differential equation governing filtrate transport in the fracture network is obtained by substituting the equations (3)-(11) into equation (1), which gives

$$\begin{aligned} &- \frac{v_{r_w} \cdot r_w}{r} \frac{\partial C_{Df}}{\partial r} + \alpha \cdot \frac{v_{r_w} \cdot r_w}{r} \left[\frac{\partial^2 C_{Df}}{\partial r^2} + \frac{1}{r} \frac{\partial C_{Df}}{\partial r} \right] - \\ &\frac{D_{zm} \cdot n_m \cdot \phi_m}{h_1} \cdot ACF \cdot C_{Df} \cdot e^{-BCF \cdot t} - \\ &- \frac{\beta \cdot k_m \cdot n_m \cdot \phi_m}{\mu \cdot h_1} \cdot APF \cdot C_{Df} \cdot (\overline{P}_f - P_i) \cdot e^{-BPF \cdot t} = \\ &n_f \frac{\partial C_{Df}}{\partial t} \end{aligned} \tag{16}$$

3. Method of Simulation

Developed model was solved numerically using finite difference method. The forward difference approximation was used for first order derivative in time and central difference approximation was used for first and second order derivative in position for fracture network. The model was solved fully implicitly. The consistency of the model was investigated by means of Taylor series and it was found that if time increment becomes small, the numerical error can be eliminated.

4. Base Case Analysis

To illustrate the application of theory described in the previous section, consideration will be given to the filtrate transport in a fractured rock for the parameter value in Table 1 as a base case. The model was solved for 100 hr of lost circulation time. In order to determine the optimum values of time increment (Δt) and grid point numbers in r-directions, a parametric study has to be conducted. Fig. 3 is a comparison between the effects of different grid point numbers in r-direction on the plot of relative concentration of drilling fluid versus r-distance. One can observe that the optimum number of grid points is 1000. There is an insignificant difference between the result for Δt = 0.01 and Δt = 0.001. Subsequently, Δt = 0.01 is assumed as the appropriate time increment for reducing CPU time.

5. Parametric Analysis

Different simulations are presented to examine the influence of wellbore loss rate, reservoir thickness, fracture opening size, matrix porosity, matrix permeability and dispersivity on filtrate transport in the fracture network. The input parameters as base case for simulations are summarized in Table 1.

5.1. Effect of wellbore loss rate

The influence of the wellbore loss rate during drilling operation on filtrate transport in fracture network is presented in Fig. 4. The other parameters are kept constant as base case and the wellbore loss rate during drilling operation is changed between 4bbl/day to 16bbl/day. As you can see in the Fig. 4, if the wellbore loss rate increases, the velocity of mud loss at the wellbore increases so the filtrate can move further in the fracture network. Radial velocity decreases in r-direction according to equation 4 so filtrate can moves further to a limit in which radial velocity approach zero. This limit was influenced by the mud velocity at the wellbore.

5.2. Effect of Reservoir Thickness

The influence of the reservoir thickness during drilling operation on filtrate transport in fracture network is presented in Fig. 5. Same as other sensitivities analysis, the other parameters are kept constant as base case and the reservoir thickness is changed between 20ft to 200ft. Any parameter that can change the mud velocity at the wellbore, would affect the amount of filtration. If the reservoir thickness increases with the constant flow rate, the amount of mud velocity at the wellbore decreases which affect the filtration velocity along the fracture network. The smaller the filtration velocity causes the smaller mud invasion as shown in Fig. 5.

5.3. Effect of Fracture Opening Size

In fact, the fracture opening size is one of the most difficult parameter to determine and it is of interest to explore the implication of uncertainty regarding this parameter since the fracture porosity and, hence, fracture velocity both depend on this parameter. Fig. 6 shows the calculated filtration for four different fracture opening size. In these cases, fracture opening size is varied between 0.0000131ft and 0.0131ft. For the first three cases when the fracture opening size increases, the amount of filtration loss to the matrix decreases according to the transfer functions so filtration can move further in the fracture network. Fracture opening size also affects the fracture porosity. As the fracture opening size increases, the fracture porosity increases so the actual filtration velocity in the fracture decreases. In case 4, with fracture opening size of 0.0131, the effect of filtration velocity is dominated and the amount of filtration decrease.

5.4. Effect of Matrix Porosity

According to Fig. 7, it can be concluded that the velocity at which the filtration moves away from the well is related to the matrix porosity. Fig. 7 shows that, higher matrix porosity, reduces the filtration movement in the fracture network. When the matrix porosity is high and the other parameters kept constant, higher filtration take places to the matrix pore space so the amount of filtration radius in the fracture network is reduced.

5.5. Effect of Matrix Permeability

Any parameters that cause further filtration in the matrix cause a reduction in the radius of filtration in the fracture network. Fig. 8 shows the effect of matrix permeability variation on the filtration radius in the network. The permeability of matrix is changed from 0.01mD to 10mD. When the matrix permeability becomes larger, filtrate can move further in the matrix and reduce the filtration radius in the network.

5.6. Effect of Dispersivity

The influence of the dispersivity during drilling operation on filtrate transport in fracture network is presented in Fig. 9. A small dispersivity implying very little mechanical dispersion due to irregularity in the fracture system. Higher dispersivity causes the filtrate to spread over a greater volume of rock. Dispersivity is generally considered to increase with distance from the wellbore, at least until the distance involved is large compared to the scale of the non-homogeneities of the flow system which give rise to the dispersion process.

6. Conclusion

Convection-dispersion filtrate transport along a regular two- or three-dimensional radial fractured network in which drilling mud can mix with the formation fluid has been modeled with the novel inclusion of a convective transport of filtrate in the matrix. The filter cake affect for both concentration and pressure is simulated by means of an empirically decaying filter rate equation. In the range of the parameters considered in this study, it is conclude that

1. The amount of filtration transport in the fracture network significantly depends on the filtrate velocity. This filtrate velocity can be affected by the wellbore loss rate and the reservoir thickness. Wellbore loss rate has a positive effect on the filtrate velocity and reservoir thickness has a negative effect.
2. Fracture opening size can affect the filtration transport in two ways. Higher fracture opening size causes a reduction in the filtrate movement into the matrix so the filtration can move further in the network. Also in some situation filtration transport is effected by fracture porosity. With higher fracture opening size and higher fracture porosity, the amount of interstitial filtrate velocity in the fracture is increased and the filtrate can transport further in the network.
3. The larger the matrix porosity, the higher filtrate movement into the matrix which yeilds lower filtrate transport in the fracture network.

4. When the matrix permeability increase, the amount of filtrate movement into the matrix by convection process will be increased. This will reduce the filtrate transport in the fracture network.
5. Higher dispersivity causes the filtrate to spread more over the fracture network.

By developed model, Filtration transport along the naturally fracture reservoir under mentioned assumption can be plotted against position in different fractured network configuration for different wellbore conditions, reservoir properties and reservoir geometries at different times. By knowing the radius of filtration, the amount of acid needed to stimulate the well can be calculated. Also the effect of mud filtration on the well logging can be corrected.

Nomenclature

ACF	First Constant for Concentration in Fracture-Matrix Interface
BCF	Second Constant for Concentration in Fracture-Matrix Interface
APF	First Constant for Pressure in Fracture-Matrix Interface
BPF	Second Constant for Pressure in Fracture-Matrix Interface
C_f	Drilling Fluid Concentration in Fracture [M/L^3]
C_o	Drilling Fluid Concentration at the Wellbore [M/L^3]
C_{Df}	Dimensionless Drilling Fluid Concentration in Fracture
D_a	Apparent Coefficient of Hydrodynamic Dispersion [L^2/T]
D_{zm}	Effective Matrix Diffusion Coefficient in z-Direction [L^2/T]
D^*	Free Solution Molecular Diffusion Coefficient [L^2/T]
h	Reservoir Thickness [L]
h_1	Half Fracture Opening Size [L]
h_2	Half Fracture Opening Size [L]
h_3	Half Fracture Opening Size [L]
H_1	Half Fracture Distance [L]
$H_{2_{rw}}$	Half Fracture Distance at Wellbore [L]
H_3	Half Fracture Distance [L]
k_m	Matrix Permeability [Darcy]
n_f	Fracture Volume Fraction in the Network
n_m	Matrix Volume Fraction in the Network
P_i	Initial Reservoir Pressure [Psi]
P_w	Wellbore Pressure [Psi]
$\overline{P}_f$	Average Reservoir Pressure [Psi]
q_w	Mud Loss Rate at wellbore [L^3/T]
q	Source or Sink Term for Diffusion
q'	Source or Sink Term for Convection
r	Radial Coordinate [L]
r_w	Wellbore Radius [L]
r_e	External Radius [L]
t	Time variable [T]
v	Average Radial steady-state filtration velocity [L/T]
v_{r_w}	Filtration Loss Velocity at Wellbore [L/T]
v_{f-m}	Filtration Velocity at the Fracture-Matrix Interface [L/T]
w	Half Fracture aperture [L]
z	Vertical Spatial Coordinates [L]
α	Dispersivity [L]
β	Conversion Factor
ϕ_m	Matrix Porosity
μ	Viscosity [M/L.T]
τ	Tortuosity
θ	Coordinate

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Table 1: Base Case Parameter Considered in This Study

Parameter	*Symbol*	*Value*
Effective Matrix Diffusion Coefficient in z-Direction [ft^2/hr]	D_{zm}	2.86×10^{-6}
Free Solution Molecular Diffusion Coefficient [ft^2/hr]	D^*	14.3×10^{-6}
Reservoir Thickness [ft]	h	50
Matrix Permeability [Darcy]	k_m	0.001
Initial Reservoir Pressure [Psi]	P_i	2000
Wellbore Pressure [Psi]	P_w	2500
Average Reservoir Pressure [Psi]	$\overline{P}_f$	2250
Mud Loss Rate at wellbore [bbl/day]	q_w	8
Wellbore Radius [ft]	r_w	0.5
External Radius [ft]	r_e	200
Half Fracture Opening Size [ft]	h_1	0.000131
	h_2	0.000131
	h_3	0.000131
Half Fracture Distance [ft]	H_1	0.82
	$H_{2_{rw}}$	0.82
	H_3	0.82
Dispersivity [ft]	α	5
Viscosity [cp]	μ	1.2
Matrix Porosity	ϕ_m	10%
Tortuosity	τ	0.2
First Constant for Concentration in Fracture-Matrix Interface	ACF	1
Second Constant for Concentration in Fracture-Matrix Interface	BCF	0.5
First Constant for Pressure in Fracture-Matrix Interface	APF	1
Second Constant for Pressure in Fracture-Matrix Interface	BPF	0.5

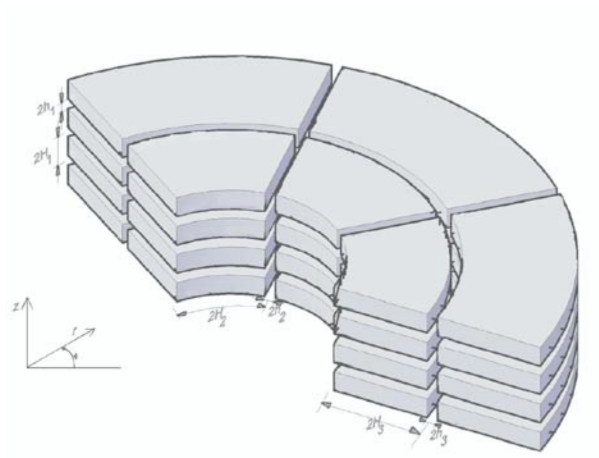

Fig. 1: Definition of Fracture Geometry

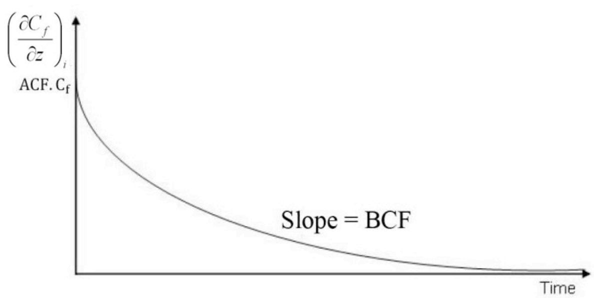

Fig. 2: Concentration Gradient at the Interface versus Time

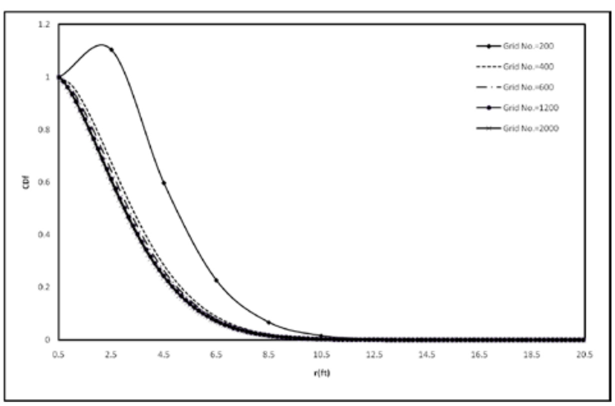

Fig. 3: Effect of Grid Number in Radial Direction on Filtrate Transport

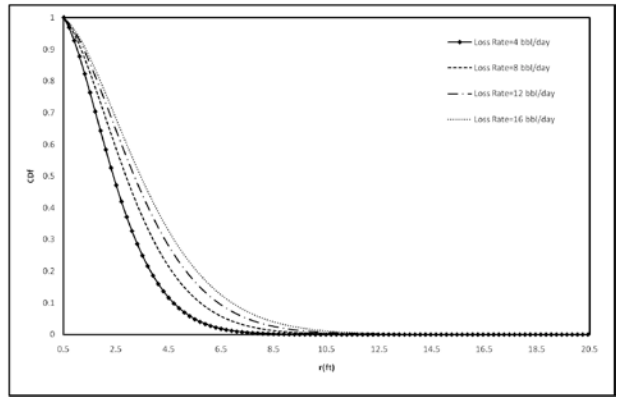

Fig. 4: Effect of Wellbore Loss Rate on Filtrate Transport

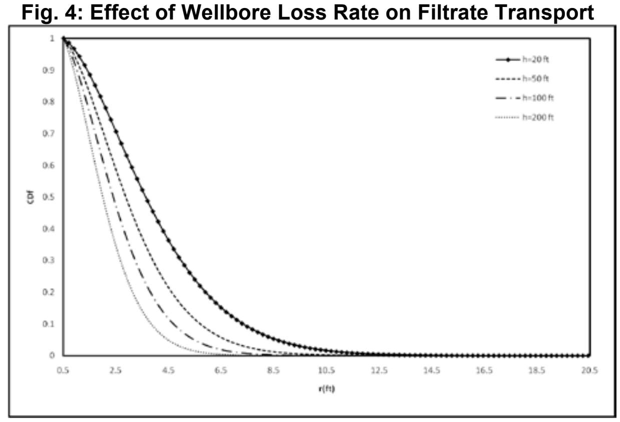

Fig. 5: Effect of Reservoir Thickness on Filtrate Transport

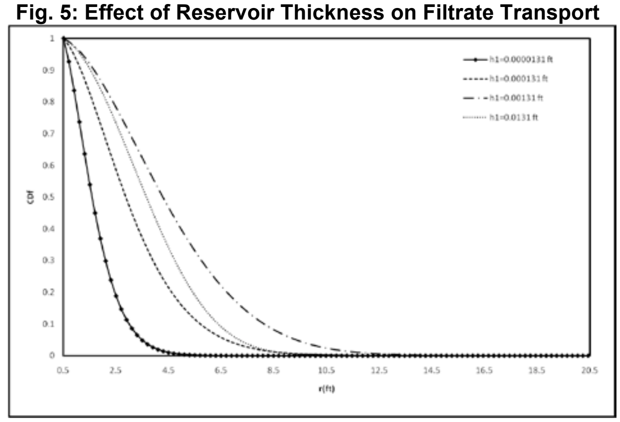

Fig. 6: Effect of Fracture Opening Size on Filtrate Transport

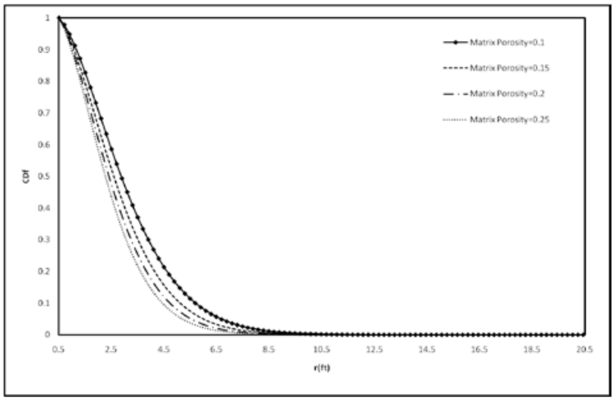

Fig. 7: Effect of Matrix Porosity on Filtrate Transport

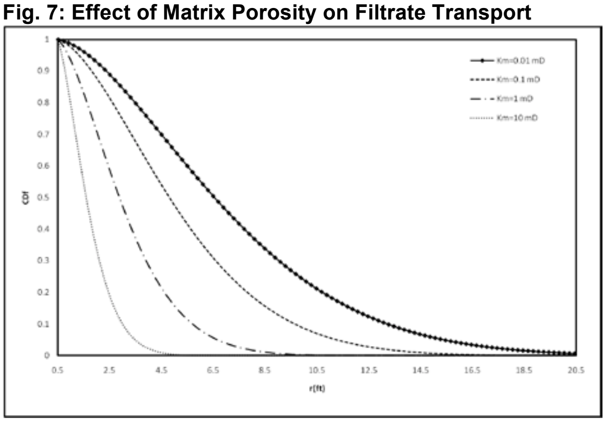

Fig. 8: Effect of Matrix Permeability on Filtrate Transport

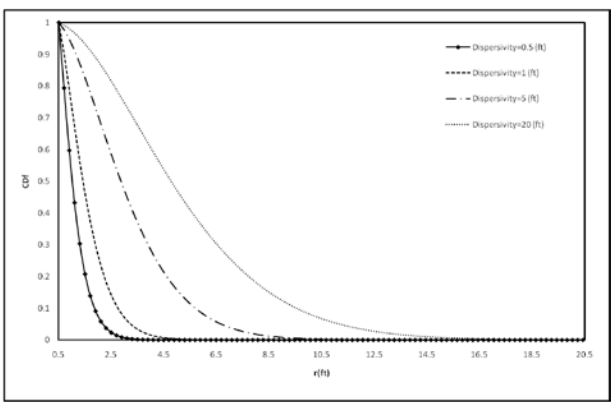

Fig. 9: Effect of Dispersivity on Filtrate Transport