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Effect of Drilling Cuttings Transport on Pressure Drop in a Flowing Well

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Abstract

Cuttings transport has a major impact on the economics of the drilling process. It is one of the major factors affecting cost, time and quality of drilling wells. In spite of the many technological advances that have attempted to prevent the cuttings transport along the fluid, one significant challenge remains predicting the effect of cutting transport on pressure drop. Many interdependent variables affect cuttings transport and the complexity of the phenomena present challenges to the production engineer whose tries to determine how the cuttings transport affect the pressure in vertical flow.

Meanwhile, many correlations have been developed to determine the effect of cutting transport in vertical flow but there is little information related to effect of cuttings transport on pressure drop and cutting hold up along the vertical pipe.

This paper presents comprehensive details of effect of cutting transport on pressure drop and the detrimental effect of drill cutting hold-up on fluid flow along the vertical pipe.

Introduction

In the recent years, underbalanced drilling technique has been highly promoted because of its robustic benefits to the oil and gas industries. The light fluids used in underbalanced drilling are usually air, gas; foam and aerated water. However formation fluid (oil and water) influx appears most time while drilling or cleaning the hole because formation pore pressure gradient are higher than hydrostatic pressure gradient[1-5]. When a well is drilled underbalanced, hydrocarbon production begins as soon as productive zone is penetrated[5]. It is possible to produce portion of the reservoir fluid while drilling or cleaning hole. With suitable processing equipments, some underbalanced wells may pay for their cost entirely from production before drilling operations were completed[5]. The technique requires the simultaneous flow of fine drilling cuttings and formation fluid (gas, oil and water). If the pressure profile in an underbalanced well can be predicted within reasonably accuracy, it would be possible to get good estimates of the power required to lift the accumulated cutting and formation liquid while drilling or cleaning the hole. Furthermore, the effect of injection rate, cutting transport and annulus sizes on these quantities can be evaluated before any design decision is made on the drilling, hole cleaning and operation of the flow string.

Studies on simultaneous flow of fine drilling cuttings and formation fluid influx (gas, oil and water) in vertical pipe have sought to develop a technique with which the pressure drop can be accurately calculated. A lot of research has been conducted to determine the effect of cutting transport in vertical flow but little information has been reported on effect of cuttings transport on pressure drop and cutting hold up along the vertical pipe. Bulter and Gregory[6] (1995) and Smith et al[7] (1998) presented the application of multiphase flow modelling to underbalanced drilling which was considered a key tool for underbalanced drilling engineer to identify the bottom-hole pressure. Guo et al[3] (2008) presented three analytical models that are coded in a spreadsheet program to simulate solid, water, oil, and gas flow in underbalanced drilling and pressure drop was predicted. Recently Nguyen[5] (2009) formulated a model that coupled underbalanced well bore pressure distribution with the productivity parameters.

In this study, a methodology which uses a single phase flow model to simulate multiphase fluid flow system and the mixing rule that correspond to the fluid flow pattern is presented. The formulation also presents methods that incorporate the effects of solution gas in the liquid phases and slippage at the phase interfaces.

This study presents a formulation that describe the comprehensive details of effect of cutting transport on pressure drop and the detrimental effect of drill cutting hold-up on fluid flow along the vertical pipe in underbalanced drilling.The formulation includes all pressure dependence parameters such as oil formation factor, water formation factor, gas deviation factor, solution gas in liquid phase

Model Development

Assumptions

The analytical expressions derived in this study are based on the following fundamental and general assumptions[1-12]:

1 Steady-state flow of cutting with the formation fluid was considered throughout the process.

2 Change in kinetic energy is small and may be neglected

3 Temperature of system is assumed constant at some average value

4 Apparent friction is considered and assumed constant over the length of the conduit

The Formulation

Consider the mist flow of gas, liquid and cutting flowing upward in a conduit. The pressure increment Δp over a small length of a conduit ΔL can be expressed as [9, 12]:

$$\frac{144}{\rho_m}dp+\frac{u_m du_m}{2\alpha g_c}du_m+\frac{g}{gc}dz+\frac{fu_m{}^2}{2g_c D}DL+Ws=0 \tag{1}$$

Assuming no mechanical work is done and change in kinetic energy is negligible. Equation (1) can be reduced to:

$$\frac{144}{\rho_m}\mathrm{dp} + \frac{g}{g_c}\mathrm{dz} + \frac{f_m u_m{}^2}{2g_c D}\mathrm{dL} = 0 \tag{2}$$

The concept of apparent or average multiphase density and viscosity are quite useful in characterizing mixture of cutting and formation liquid influx. The apparent density and viscosity of a multiphase mixture is defined respectively by observing the “mixing rule”[9,12].

$$\rho_m=\rho_{dc}H_c+\rho_f(1-H_{dc}) \tag{3}$$

$$\mu_m=[\mu_o h_o+\mu(1-h_o)]H_L+\mu_g(1-H_L) \tag{4}$$

Drilling Cutting Density

The density of drilling cutting can be expressed as a ratio of flow rate of the cutting to cutting production rate[3-5]. That is

$$\rho_{dc}=\frac{W_{dc}}{q_{dc}}=62.4\frac{\pi}{4}\left(\frac{d_b{}^2}{12}\right)G_c\left(\frac{86400R_p}{3600q_{dc}}\right) \tag{5}$$

$$\rho_{dc} = \frac{8.165 d_b{}^2 G_c R_p}{q_{dc}} \qquad (6)$$

Gas density

Density of gas (ρ_g) at a point in a vertical pipe at pressure and temperature may be obtained from the definition of the Gas law as[9]:

$$\rho_g = \frac{28.97 G_g P}{ZRT} \qquad (7)$$

Density of the Formation Fluid

The density of the formation liquid (oil and water) is obtained as[9]:

$$\rho_L = \rho_O h_O + \rho_W h_W \qquad (8)$$

$$\rho_L = \frac{\{62.4 G_O + 0.010036 G_g R_S\} h_O}{B_O} + \frac{62.4 G_W h_w}{B_W} \qquad (9)$$

Density of the Mixture

Density of mixture is defined in this paper as the summation of apparent density of the entire components, simultaneous flowing in the conduit. The density of the mixture is obtained by substituting equation (6), (7), and (9) into equation (3), we obtained multiphase density as:

$$\rho_m = \Bigg\{\Bigg[\Bigg[\Bigg(\frac{62.4 G_O + 0.0136 G_g R_S}{B_O}\Bigg) h_O + \frac{62.4 G_W h_w\}}{B_W}\Bigg] H_L + \frac{28.97 P G_g (1 - H_L)}{ZRT}\Bigg\}[1 - H_{dc}] + \Bigg[\frac{8.165 d_b{}^2 G_c R_p}{q_{dc}}\Bigg] H_{dc} \qquad (10)$$

Velocity of Mixture

The velocity of the multiphase fluid flow at a cross-section of a vertical pipe may be defined as[6]:

$$\mathrm{U_M} = \frac{1}{A}\left[q_g \left(\frac{14.65}{P}\right)\left(\frac{T}{520}\right)\left(\frac{Z}{1}\right)\left(\frac{10^6}{86400}\right) + \frac{q_O B_O (5.615)}{86400} + \frac{q_w B_w (5.615)}{86400} + \frac{q_{dc}}{86400}\right] \qquad \mathbf{(11)}$$

$$\mathrm{U_M} = \frac{0.4152 q_g T Z}{P D_{AN}{}^2} + \frac{0.000082735 B_O q_O}{D_{AN}{}^2} + \frac{0.000082735 B_w q_w}{D_{AN}{}^2} + \frac{0.00001471 q_{dc}}{D_{AN}{}^2} \qquad (12)$$

Substituting equation (10) and (12) into equation (2) and converting diameter D (inches) to feet, we have:

$$\frac{144 dp}{\left\{ X H_L + \frac{2.70 P G_g (1 - H_L)}{ZT} \right\}[1 - H_{dc}] + \left[\frac{1.454 d_b{}^2 G_c R_p}{q_{dc}}\right] H_{dc}} = \left[1 + F_1\left(\frac{Z}{P}\right)^2 + F_2 B_O{}^2 + F_3 B_W + F_4 + F_5 B_O\left(\frac{Z}{P}\right) + F_6 B_W\left(\frac{Z}{P}\right) + F_7 B_O B_W + F_8\left(\frac{Z}{P}\right) + F_9 B_O + F_{10} B_W\right] dL \qquad (13)$$

Re- arranging equation (13) we have:

$$\frac{\frac{Z}{P}\Delta p}{\left[1 + F_1\left(\frac{Z}{P}\right)^2 + F_2 B_O{}^2 + F_3 B_W + F_4 + F_5 B_O\left(\frac{Z}{P}\right) + F_6 B_W\left(\frac{Z}{P}\right) + F_7 B_O B_W + F_8\left(\frac{Z}{P}\right) + F_9 B_O + F_{10} B_W\right]\left\{\frac{q_{dc} X H_L T}{2.7 G_g} + \left[\frac{1.454 d_b{}^2 G_c R_p H_r T}{2.7 G_g}\right] + \frac{P}{Z} q_{dc} (1 - H_L)\right\}} = \frac{0.01875 G_g L}{T}$$

(14)

Let

$$\mathrm{F1} = \frac{667 f_m q_g{}^2 T^2}{D_{AN}{}^5} \qquad (15)$$

$$\mathrm{F2} = \frac{2.65 x 10^{-5} f_m q_O{}^2}{D_{AN}{}^5} \qquad (16)$$

$$\text{F3}=\frac{2.65x10^{-5}f_m q_w{}^2}{D_{AN}{}^5} \tag{17}$$

$$\text{F4}=\frac{8.35x10^{-7}f_m q_{dc}}{D_{AN}{}^5} \tag{18}$$

$$\text{F5}=\frac{0.2657f_m q_o q_g T}{D_{AN}{}^5} \tag{19}$$

$$\text{F6}=\frac{0.2657f_m q_w q_g T}{D_{AN}{}^5} \tag{20}$$

$$\text{F7}=\frac{5.30x10^{-5}f_m q_o q_w}{D_{AN}{}^5} \tag{21}$$

$$\text{F8}=\frac{4.72x10^{-2}f_m q_g q_{dc} T}{D_{AN}{}^5} \tag{22}$$

$$\text{F9}=\frac{9.4x10^{-6}f_m q_o q_{dc}}{D_{AN}{}^5} \tag{23}$$

$$\text{F10}=\frac{9.4x10^{-6}f_m q_w q_{dc}}{D_{AN}{}^5} \tag{24}$$

$$D_{AN}=D_H-D_P \tag{25}$$

$$\text{X}=\left[\left(\frac{62.4G_O+0.0136G_g R_S}{B_O}\right)h_O+\frac{62.4G_W h_w}{B_W}\right] \tag{26}$$

Where

$$h_o=\frac{q_o}{q_o+q_w} \tag{27}$$

$$h_w=1-h_o \tag{28}$$

$$H_L=\frac{q_L}{q_L+q_g} \tag{29}$$

$$H_{dc}=\frac{q_{dc}}{q_{dc}+q_L+q_g} \tag{30}$$

$$H_r=\frac{H_{dc}}{1-H_{dc}} \tag{31}$$

Considering single phase gas reservoir, where $q_w = 0$, $q_{o=}0$ and $q_{dc}=0$ the expression in equation (14) degenerates to the normal Sukar and Cornnel's model[14-15] for single phase flow in a pipe.

$$\frac{\frac{Z}{P}\,dp}{\left[1+F_1\left(\frac{Z}{P}\right)^2\right]}=\frac{0.01875\,G_g\,L}{T} \tag{32}$$

ANALYSIS OF RESULTS

Using the data (table1) from the literatures, the developed model was solved by iteration following the procedure that was presented by Nguyen et al[5] (2009). The choke pressure (Ps) is known as it is estimated from the surface which left the bottom-hole pressure (Pb) as unknown which is the point of focus in this regard. Subtract the calculated flowing bottom-hole pressure of fluid from that of calculated bottom-hole pressure of cutting and fluid to find the pressure drop due to drilling cutting effect.

The new method is capable of providing a satisfactory pressure differential result, during simultaneous flow of cutting and formation fluids while drilling or cleaning hole. All pressure dependent variables are treated as a function of pressure and not a constant as opined by many investigators.

Figure 1 shows the effect of cutting flow rate on pressure drop in flowing well. The cutting flow rate increases with low pressure differential and decrease with increase in pressure differential. This depicts that cutting retards fluid flow and increases bottom-hole pressure and fluid density, resulting in low fluid velocity and cutting lifting capacity of the drilling fluid. This may result in cutting accumulation at the bottom of the hole and eventually stuck the drilling string.

Figures 2 shows the effect of influx rate on pressure drop of a flowing well. The influx rate increases as the pressure differential increases. High bottom-hole pressure experiences as a result formation fluid influx may require high kinetics energy to lift the fluid influx from the hole to the surface. The heavier the formation fluid influx, the higher the corresponding bottom-hole pressure and the more rate of drilling fluid required to lift the influx.

Table 1: Input Data[3,4,14]

Surface Pressure (psia)	14.7psia
Surface Temperature (^{o}R)	543 ^{o}R
Gas Flow Rate (MMSCF/Day)	10.65 MMSCF/Day
Oil Flow Rate (bbl/day)	10.89 bbl/day
Water Flow Rate (bbl/day)	10 bbl/day
Cutting Flow Rate ft^3/day	3.56ft^3/day
Bit Diameter (inch)	3.5inch
Specific Gravity of Gas	0.8
Specific Gravity of Oil	0.9
Specific Gravity of Water	1.07
Specific Gravity of Cutting	3.75
Rate of Penetration (ft/day)	0.0167ft/day
Hole Diameter (inch)	6.11in
Drilling Pipe Diameter (inch)	4.5in
Pipe Length (ft)	5700ft
Temperature Gradient (^{o}F/ft)	0.01 ^{o}F/ft
Hole Roughness (inch)	0.08in
Pipe Roughness (inch)	0.0018in
Casing Roughness (inch)	0.00018

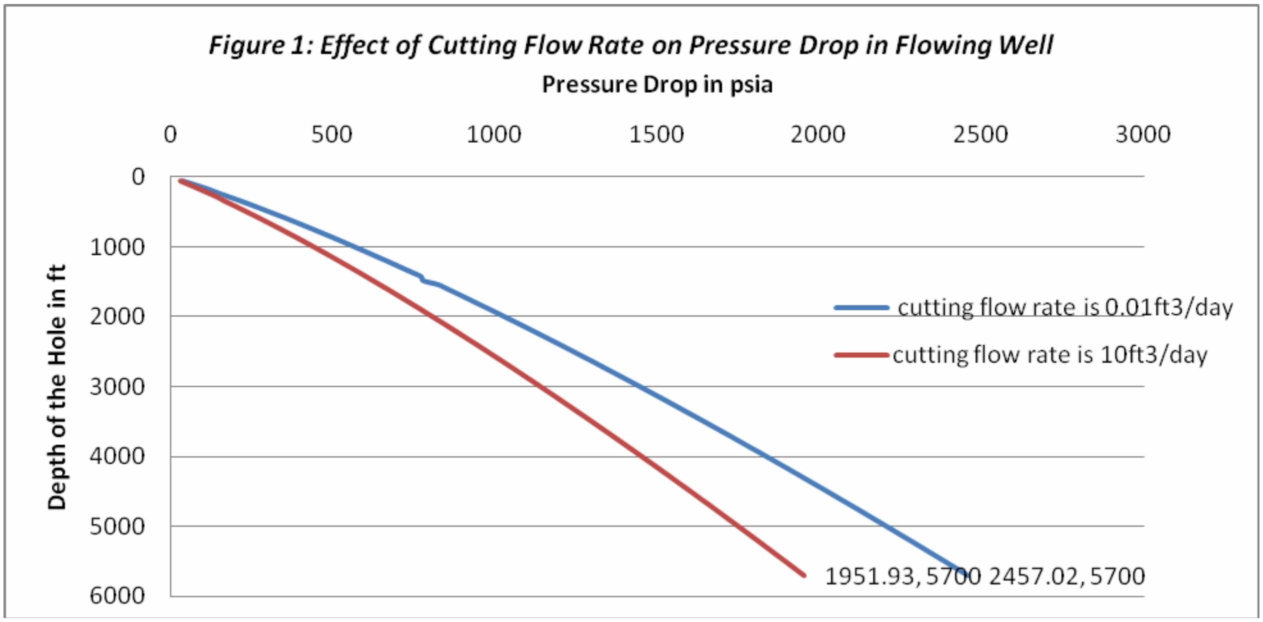

Figure 1: Effect of Cutting Flow Rate on Pressure Drop in Flowing Well

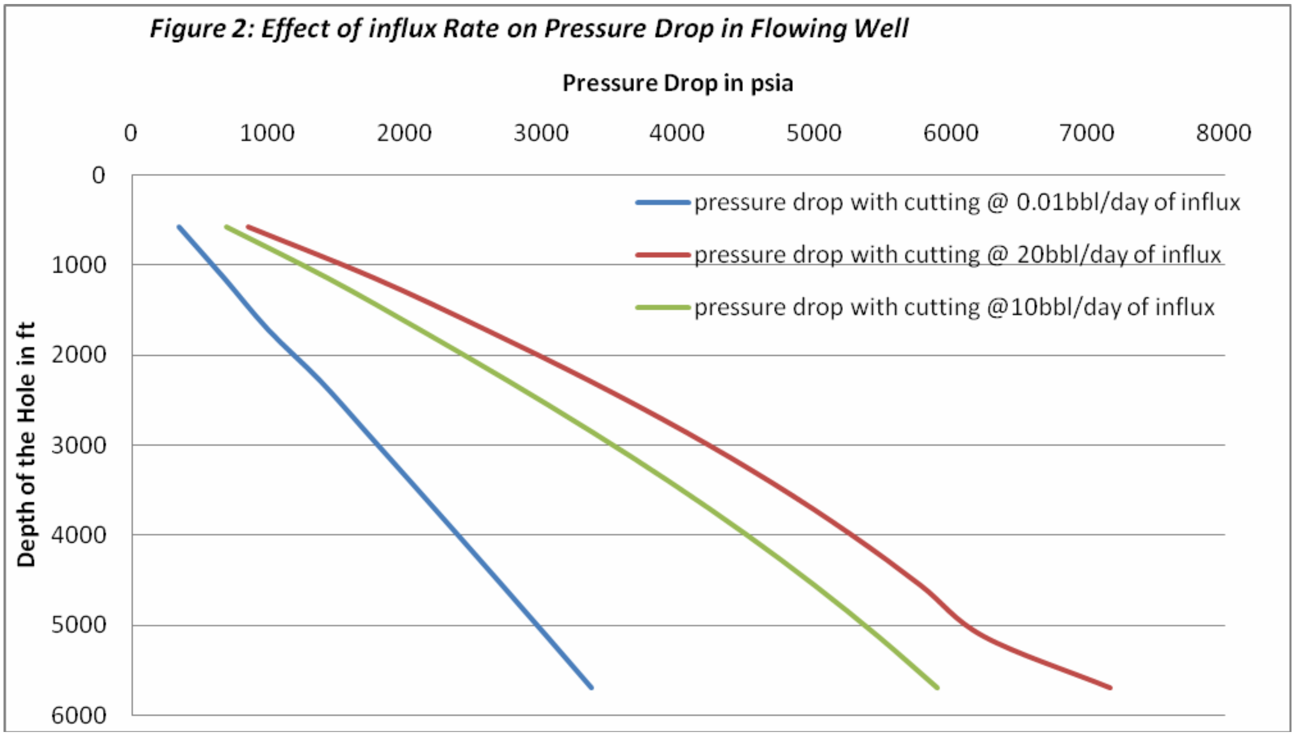

Figure 2: Effect of influx Rate on Pressure Drop in Flowing Well

Conclusion

The model was perfectly accurate as compared with Guo et al (2002) for multiphase flow and Sukkar and Cornnel's model (1955) for single phase flow.

Accountability of interdependence variables have been thoroughly done for the accuracy of the model.

Pressure dependent variables are treated as a function of pressure and not a constant which gives the model edge over the previous models.

The influx rate of formation fluid increases as the pressure differential increases, while that of cutting decreases as pressure differential increases.

The developed model can be used for single phase as well as simultaneous flow of cutting and formation cutting along the well bore during underbalanced drilling.

RECOMMENDATION

Pressure differential should be monitored to ensure proper cutting transport under underbalanced drilling.

Developed model works best by integrating the right-hand side of equation (13) numerically at several constant (average) temperatures.

In terms of the degree of accuracy required, it should be noted that the overall accuracy of the model is subject to the measurement of gas rate and liquid rate, measurement of flowing wellhead pressure and temperature, measurement of specific gravity of cutting, oil, gas and water as well as proper estimation of liquid hold up and rate of penetration. These variables, if not properly estimated may subject the model interpretation to apparent error.

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NOMENCLATURE

A=cross-sectional area of pipe,ft^2
API=API gravity, degree
B=formation volume factor, $\frac{bbl}{stb}$
D=inside diameter of the pipe,inch
$D_{b=}$ bit Diameter in inch

f=moody friction factor, dimensionless
g=acceleration due to gravity, $\frac{ft}{\sec^2}$
gc=conversion factor,32.17 $\frac{lbmft}{lbfs}$
G=specific gravity,dimensioless
h=volume fraction in the liquid
H=liquid holdup
L=length of the flowstring,ft(for a vertical flowstring,L=Z)
M=molecular weigh of air, 28.97G
P=pressure, psia
dp=pressure differential, $\frac{lb}{ft^3}$
PPR=pseudo reduced pressure
q=volumetric flow rate , $\frac{ft^3}{\sec}$
R= gas constant,10.73 $\frac{ft^3 psia}{lb - mole^O R}$
Rp= Penetration Rate in ft/day
T=temperature,^{0}R
TPR=pseudo reduced temp.
U=average velocity of the fluid, $\frac{ft}{\sec}$
V= specific volume of fluid, $\frac{ft^3}{lbm}$

W_s=mechanical work done on or by the gas(w_s=0)
z=gas compressibility factor,dimensioless
dZ=incremental depth
$\frac{udu}{2\alpha g_c}$ =pressure drop due to kinetic energy
$\frac{fu^2 dl}{2g_c D}$ =pressure drop due to friction effects
$\rho =$ density , $\frac{lbm}{ft^3}$
α =correction factor to compensate for the variation of velocity over the tube cross-section

Subscripts
AN=annulus
b=base
c=cutting
dc drilling cutting
g=gas
L=liquid
m=mixture
o=oil
s=solid
w=water

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