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Pressure Transient Lag Time Analysis During Aerated Mud Drilling

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Abstract

Pressure propagation in fluid is analogous to sound velocity in that medium. The presence of multiphase mixtures, which are common in underbalanced drilling, adds complexity to pressure pulse propagation during drilling operations. In this paper, pressure pulse lag time is calculated using the concept of sound velocity in multiphase flow.

Sound velocity in liquid-gas mixture is a function of temperature, pressure, and void fraction. The worst case is showed here, to be a pressure pulse passing through the first 50 ft from the surface where the highest fluid velocity and the lowest sound velocity prevail in the wellbore.

Developing a model to estimate pressure pulse lag time would be beneficial to field engineers and researchers that are concerned with the pressure propagation in the wellbore and the time that a pressure adjustment on the choke is felt in the wellbore.

Introduction

Pressure Propagation

Pressure propagation in fluid is analogous to sound velocity in that medium. The time, which is required for the pressure pulse to travel from the choke to a desired target, is called pressure transient lag time. Usually the desired target is either the bottomhole or the standpipe. In field operation, pressure response on the standpipe confirms backpressure is successfully applied in the system. However, the amount of pressure change in the drillpipe does not indicate the magnitude of pressure change at the bottomhole.

The velocity of sound in multiphase fluids has been studied in nuclear engineering, seismology, and for multiphase flow measurement. Several[1-4] studies have been done to develop a model to determine sound velocity in mixtures. The same principals are used in this study to model pressure pulse propagation in the well during MPD.

A pressure pulse is simulated as a sound wave in the wellbore and drillstring to determine the time it takes for the pulse to reach the target. The same magnitude of pressure pulse induced by the choke at the surface is not expected at the bottomhole.

The bottomhole pressure change can be insignificant, greater than, or less than surface pressure change. Bottomhole pressure variation is likely to change the standpipe pressure, which can be used as a sign that the effect of the pressure change at the choke has been felt in the entire wellbore. The general opinion of well control is that an increase in choke pressure is reflected as an increase in bottomhole pressure that directly reads as an increase in drillpipe pressure. While it works for well kicks, this is not true when gas is injected into the drillpipe as with gaseated mud and foam drilling. Drillpipe pressure change does not represent the bottomhole pressure variation.

Propagation Velocity

The presence of multiphase mixtures, which are common in managed pressure drilling, affects the velocity of pressure pulse propagation. This velocity can be less than the pressure velocity in any of the individual (single phase) components of the mixture. In severe cases the pressure pulse may not be able to reach bottomhole.

Knowing the pressure transient lag time on the drillpipe eliminates excessive choke manipulation which may cause excessive bottomhole pressure changes. During well planning, severe conditions should be avoided to assure good communication between the wellbore annulus and the drillstring.

Gas-liquid mixture travels against the propagation direction of pressure which reduces the pressure propagation velocity in the well. For better estimation of pressure propagation velocity, the effect of gas-liquid mixture is considered.

To simulate pressure, the propagation velocity in the well, it is treated as a sound wave. Sound velocity in a mixture is a function of the liquid, gas, and wave properties. The velocity of sound in water/air mixture is less than the velocity of sound in single phase water or air. There are several equations to predict the sound velocity in a gas-liquid mixture. The most common equation in the literature is Wood's equation[2,5]. This equation uses liquid and gas properties to determine the velocity of sound in a homogenous mixture. A simplified Wood's equation as presented by Gudmundsson and Celius[2] is as follow

$$C_m = \frac{1}{A \times B}$$

$$A = \left[\alpha \rho_g + (1-\alpha)\rho_l\right]^{0.5}$$

$$B = \left[\left(\frac{\alpha}{\rho_g C_g^2}\right) + \left(\frac{\alpha}{\rho_l C_l^2}\right)\right]$$

Where

C = velocity of sound in the medium (m/s)

α = gas void fraction, dimensionless

ρ = density, kg/m^3

and subscripts m, g, and l represent mixture, gas, and liquid respectively.

Wood's equation is valid for homogenous mixtures. Mixture homogeneity for sound waves differs depending on the flow pattern. As a rough rule of seismic theory, if the wavelength (λ) is five times greater than length of the slug or bubble the mixture system behaves as a homogenous medium[3]. Sound frequency caused by chokes and valves is in the range of 1 to 10 Hz[2]. Therefore, in 8 inch and smaller open holes the system can be considered homogenous and Wood's equation applies.

Sound velocity in a mixture is a function of the liquid and gas phase properties. **Fig. 1** shows the velocity of sound in an air-water mixture as a function of gas void fraction for different pressures. Different pressure lines show the effect of pressure on the sound velocity at bottomhole conditions. Sound velocity drops drastically as gas bubbles enter the liquid phase and the velocity in this medium can be less than either pure water or pure gas. As pressure increases, the air phase becomes denser and tends to behave more like a liquid and the mixture velocity increases. At 500 psi pressure, for the range of 0.1 to 0.95 gas void fraction the sound velocity is less than the velocity of sound in air. The minimum sound velocity of 440 ft/s occurs between 0.45 to 0.55 gas void fraction which is about 40% of the sound velocity in air.

This graph shows the importance of knowing the gas void fraction in the gaseated and foam systems. Hydraulic models predict gas-liquid volume to determine pressure profile in the wellbore and drillpipe. In this study, a hydraulic model is combined with a sound model to predict pressure propagation in the system.

Methodology

To check if sound responds to the wellbore as a homogenous or heterogeneous media, as suggested by Gudmundsson and Celius[2] the wavelength of sound for frequencies of 1 to 10 Hz is considered. The worst condition is at the surface where the lowest pressure and sound velocity exists. A homogenous medium for sound occurs where the wavelength is five times greater than the sequences of gas and liquid.

For bubbly and annular flow cases, the system is homogenous. In the case of slug flow, the length of the slug is 16 times greater than the hydraulic diameter of the wellbore. So considering sound velocity and frequency, the wellbore can be considered a homogenous medium for a wellbore diameter of 8 inches or less. This is consistent with results reported by *Falk et al.*[3]

Wellbore diameters larger than 8 inches in slug flow should be checked for homogeneity based on operational conditions. If the length of the slug is less than one fifth of the wavelength, the system is homogenous. for a heterogeneous system profile of propagation velocity is a straight line from velocity of liquid to velocity of gas. Propagation velocity is higher in heterogeneous system than homogenous system.

For a given wellbore in **Table 1**, Guo's models[6,7] predict pressure, gas void fraction and annular velocity for aerated and foam drilling operations. Wood's equation uses pressure and temperature corrected properties of gas to determine sound velocity. The net velocity of sound propagation is the difference between the sound velocity and the fluid velocity. If the net velocity is zero or negative, sound does not propagate in the system. The same procedure is used in the drillstring to estimate the net velocity.

$$V_{net} = C_m - V_m$$

Where V_{net} is the net velocity of sound propagation in the medium, C_m is the velocity of sound in the medium, and V_m is the velocity of the gas-liquid mixture. The wellbore is divided into small sections. Propagation time in each section is determined by dividing the length of each section by the local net velocity and total propagation time is the sum of Δt of all sections.

$$\Delta t_i = \frac{L_i}{V_{i\,net}}$$

$$t = \sum \Delta t_i$$

Where Δt_i is the sound travel time, L_i is the length of the section, and $V_{i\,net}$ is the local net velocity in the section.

Gücüyener[8] proposes a nozzle jet velocity and pressure drop for aerated and foam operations. If the sound velocity is greater than the jet velocity, sound propagates into the drillstring. Propagation time through a nozzle is very short and ignored in our calculations.

There is a large difference between lab experiment results for sound velocity in liquids and field experience. From field experiences, the velocity of sound is believed to be one fifth of the lab results. A set of graphs was generated using lab and field data for velocity of sound in fluids. For field applications, the velocity of sound in liquid is modified and same degree of modification applied on velocity of sound in air.

Discussion of results

Aerated and foam drilling uses a mixture of gas and liquid as a drilling fluid. For these applications, the effects of backpressure for different injection rates are shown separately. As the first step, the bottomhole pressure and drillpipe pressure are calculated to check if backpressure manipulation has a noticeable effect on them. **Table 2** shows the effect of backpressure manipulation on an aerated system for different operational conditions. For comparison purposes, two terms are introduced, $\frac{\Delta BHP}{\Delta P_s}$ and $\frac{\Delta P_{stand}}{\Delta P_s}$. $\frac{\Delta BHP}{\Delta P_s}$ and $\frac{\Delta P_{stand}}{\Delta P_s}$ show the magnitude of bottomhole pressure and standpipe pressure changes for a given backpressure. If this value is equal to one, the pressure at the desired point varies by the same amount as the backpressure change. For values greater than one, the pressure change is higher than the change in backpressure. For values less than one, the pressure change is less than backpressure change.

For most cases studied here, the bottomhole pressure change is greater than the backpressure change and the drillpipe pressure change. For low liquid injection rates pressure changes are greater than for high liquid injection rates. A similar table would be helpful for field engineers to predict standpipe pressure change for low liquid injection rates.

For the steady state operational conditions given in **Table 2**, the gas void fraction volume and fluid velocity are predicted using Guo's hydraulic model. **Fig. 2** shows gas void fraction and annular pressure versus well depth. At the top, the annulus gas void fraction drops drastically and after that it is almost constant. At the top of the annulus pressure is lowest and annular velocity is high therefore the lowest "net velocity" is expected.

Fig. 3 shows the gas void fraction in aerated mud drilling with 300 gpm liquid injection rate and 600 scfm gas injection rate. Increasing back pressure reduces the gas void fraction near the surface. **Fig. 4** shows the net velocity of sound propagation for different backpressures. In this figure the dashed line on the right is the velocity of sound in liquid which is much higher than velocity of sound in the mixture. As this figure shows, the net velocity of sound propagation is lowest near the surface and increases with depth. Near the surface, the pressure and density of the gas are the lowest in the system. Also, high mixture velocity prevails near the surface. The net result of these factors causes the lowest sound propagation velocity in the system. For higher backpressures, the response time is shorter as **Fig. 5** shows. The net velocity propagation increases as the backpressure increases. For comparison pressure response time for water is shown in this figure. The pressure response time is four times longer than when only a liquid phase is present in the system. Although the mixture velocity is higher in the drillpipe than in the annulus, the pressure reaches surface faster through drillpipe.

Fig. 6 illustrates the gas void fraction for different liquid injection rates. The gas void fraction decreases as the liquid injection rate increases. **Figs. 7 and 8** show higher pressure propagation velocity and lower propagation time for higher liquid injection rates. A high liquid injection rate increases the pressure and the propagation velocity increases consequently. However, a high mixture velocity presence near the surface reduces propagation velocity. Higher mixture velocity makes the velocity curve skews to the left.

Fig. 9 shows the effect of gas injection rate on pressure propagation time. As this figure shows that for gas injection rates of 500 scfm and 600 scfm, pressure propagates faster in the annulus for 600 scfm gas injection rate. However, sound propagates faster in the drillpipe for the lower gas injection rate and over all propagation time is the same.

Based on field experiences, sound velocity in liquid is about 1000 ft/sec about one fifth of measured velocity in labs. Considering the same degree of effect on the velocity of sound in air pressure, the propagation velocity and time are calculated. **Figs. 10 through 12** illustrate the corrected pressure propagation time for field operation. These figures show severe effect of mixture velocity on pressure propagation. **Fig. 11** shows sonic velocity occurs in the annulus for liquid injection rate of 400 gpm. It takes 37 minutes for the pressure to travel in the annulus. **Fig. 12** shows the effect of gas injection rate on pressure propagation time. It takes about 50 seconds for pressure to travel the first 50 ft in the annulus for gas injection rate of 700 scfm. In situations where high liquid and gas injection rates are required for hole cleaning purposes, like long horizontal sections, sonic velocity may occur and increase propagation time. Long pressure propagation time may confuse field engineers about operational conditions and controlling bottomhole pressure.

Using the same methodology, pressure propagation time is studied for foam operations. As **Fig. 13** shows during foam drilling operations, increasing the backpressure increases the pressure propagation velocity and decreases the propagation time.

Fig. 14 shows the effect of liquid injection rate on pressure propagation velocity. From surface to 6000 ft depth, pressure propagates faster for lower liquid injection rates and after this, the depth propagation velocity is faster for high liquid injection rates. The total effect of liquid injection rate on pressure propagation time is not significant. As **Fig. 15** shows, the pressure reaches the bottomhole after 140 seconds for the different liquid injection rates considered in this study.

For different gas injection rates the pressure propagation velocity is the same as the liquid injection rate. As **Fig. 16** shows, for high gas injection rates, the pressure propagates faster down to 6000 ft., and after this depth, the propagation velocity is higher for lower gas injection rates. **Fig. 17** shows the gas injection rate does not affect pressure propagation time. The pressure reaches the bottomhole after 140 seconds.
During foam drilling operations, lower gas and liquid injection rates are required to clean the hole. Therefore, a high mixture velocity does not exist at the surface. Near the surface, the quality of foam is close to 95% and in aerated mud drilling this value is close to 80%. **Fig. 1** shows that the propagation velocity for aerated mud is less than foam. Also, the mixture velocity near the surface is higher for aerated mud drilling. As a result, the pressure propagation velocity can be critical for aerated mud operations.

Conclusions

1. The effect of back pressure on standpipe pressure should be studied to predict the amount of pressure change. The

pressure change on the standpipe can be less than or greater than the pressure change at the surface.
2. Sonic velocity can occur near the surface in the annulus and prevent pressure propagation in the wellbore.
3. During aerated mud drilling, pressure propagation time is affected by gas and liquid injection rates. Pressure propagation time should be studied for aerated mud drilling operations, especially when high gas and liquid injection rates are required. This can be a new design criterion for aerated mud drilling to ensure good communication between the annulus and drillpipe.
4. During foam drilling operations, sonic velocity does not occur. However, pressure propagation time is higher than when only gas is present in the wellbore.

Nomenclature

BHP = *Bottomhole pressure, psi*
C_g = *Velocity of sound in the gas phase*
C_l = *Velocity of sound in the liquid phase*
C_m = *Velocity of sound in the gas-liquid mixture*
L_i = *Length of segment*
P_{stand} = *Standpipe pressure, psi*
Ps = *Surface backpressure, psi*
V_m = *Velocity of gas-liquid mixture*
V_{net} = *Net velocity of sound propagation*
α = *Gas void fraction, dimensionless*
Δt_i = *sound travel time in a segment of the well*
ρ_g = *Density of gas*
ρ_l = *Density of liquid*

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Tables

Table 1—Wellbore geometry.

Wellbore diameter	5.5 in
TVD	10000 ft
MD	10000 ft
Drill pipe OD	3.5 in
Drillpipe ID	2.99 in

Table 2—Bottomhole pressure for different operational conditions for aerated mud drilling

Ql, gpm	Qg, scfm	P_s, psi	BHP, psi	P_{stand}, psi	$\frac{\Delta BHP}{\Delta P_s}$	$\frac{\Delta P_{stand}}{\Delta P_s}$
200	600	15	4569	976		
200	600	50	4630	1022	1.7	1.3
200	600	100	4747	1114	2.1	1.6
200	600	150	4862	1206	2.2	1.7
200	600	200	4966	1291	2.1	1.7
250	600	15	4764	1196		
250	600	50	4814	1237	1.4	1.2
250	600	100	4911	1319	1.7	1.4
250	600	150	5008	1401	1.8	1.5
250	600	200	5098	1479	1.8	1.5
300	600	15	4963	1490		
300	600	50	5005	1527	1.2	1.1
300	600	100	5088	1601	1.5	1.3
300	600	150	5173	1676	1.6	1.4
300	600	200	5253	1748	1.6	1.4
350	600	15	5172	1852		
350	600	50	5209	1886	1.1	1.0
350	600	100	5282	1953	1.3	1.2
350	600	150	5358	2023	1.4	1.3
350	600	200	5432	2091	1.4	1.3
400	600	15	5396	2279		
400	600	50	5429	2310	0.9	0.9
400	600	100	5496	2372	1.2	1.1
400	600	150	5565	2437	1.3	1.2
400	600	200	5633	2501	1.3	1.2
300	500	15	5028	1504		
300	500	50	5075	1545	1.3	1.2
300	500	100	5160	1623	1.6	1.4
300	700	15	4903	1482		
300	700	50	4941	1514	1.1	0.9
300	700	100	5021	1584	1.4	1.2

Figures

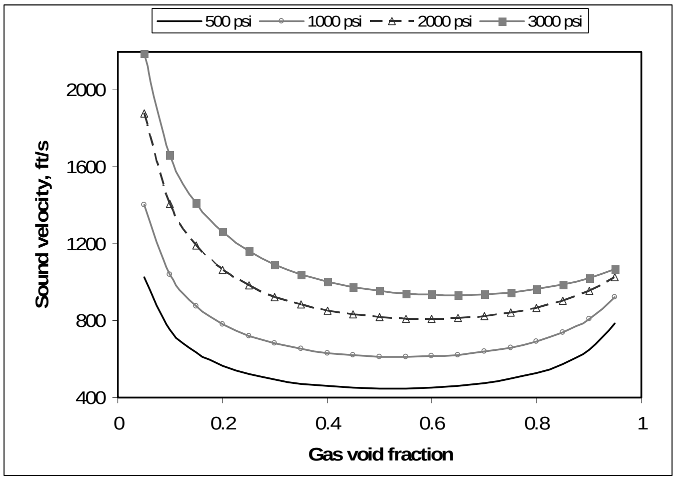

Figure 1—Velocity of sound in air-water mixture.

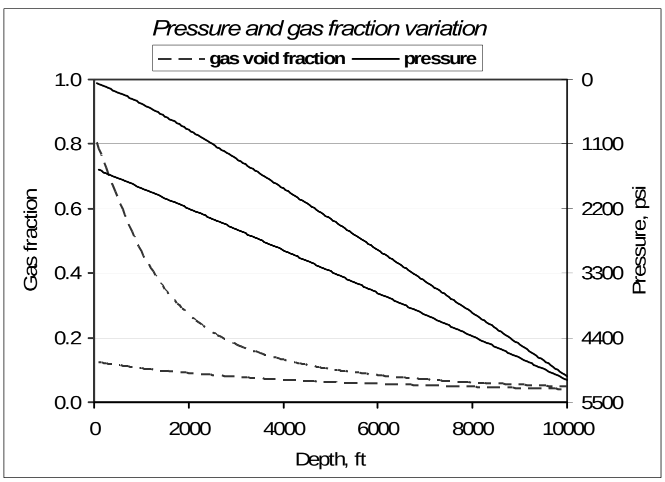

Figure 2—Pressure and gas void fraction versus depth

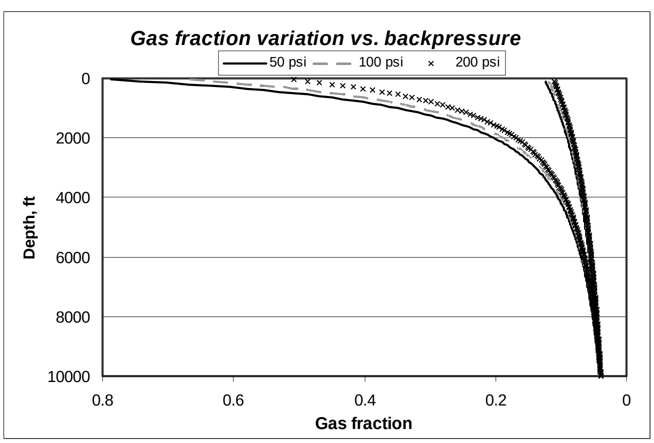

Figure 3—Gas void fraction for different backpressures versus depth in aerated mud

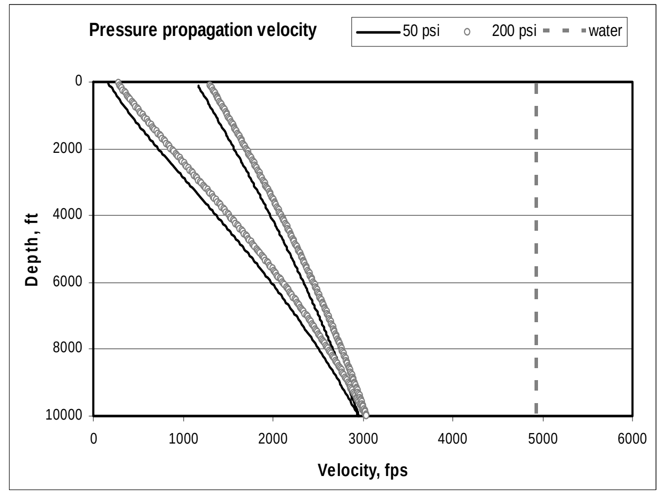

Figure 4—Net velocity of pressure versus depth for different backpressures in aerated mud

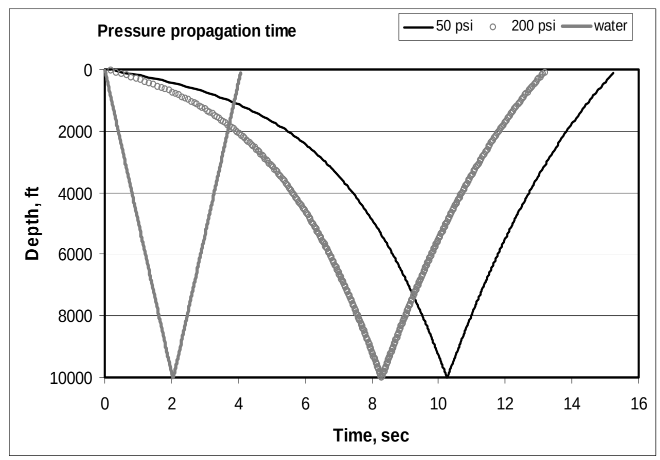

Figure 5—Pressure propagation time versus depth for different back pressures in aerated mud

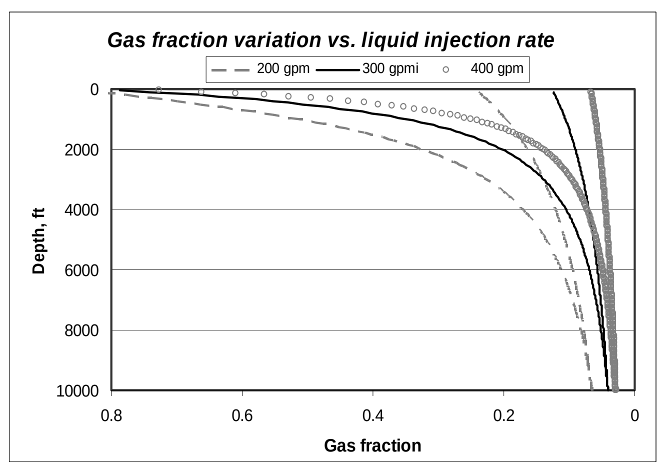

Figure 6—Gas void fraction for different liquid injection rates versus depth in aerated mud

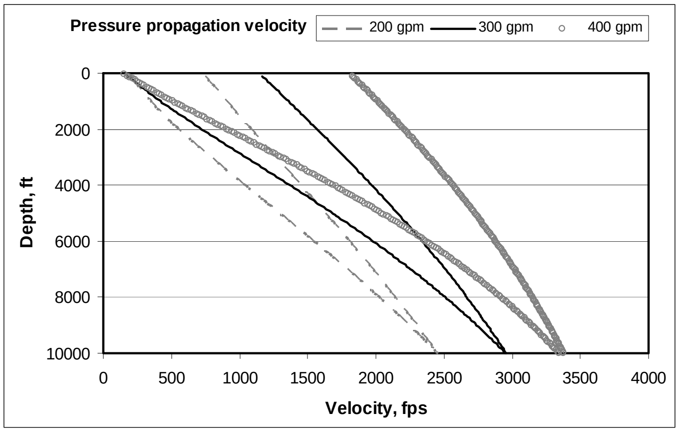

Figure 7—Net velocity of pressure versus depth for different liquid injection rates in aerated mud

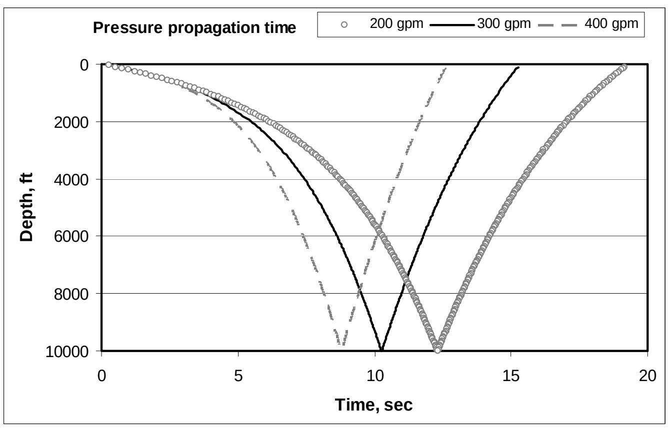

Figure 8—Pressure propagation time versus depth for different liquid injection rates in aerated mud

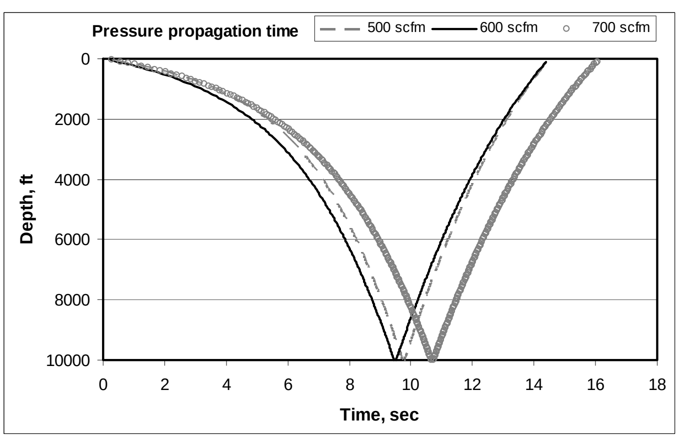

Figure 9—Pressure propagation time versus depth for different gas injection rates in aerated mud

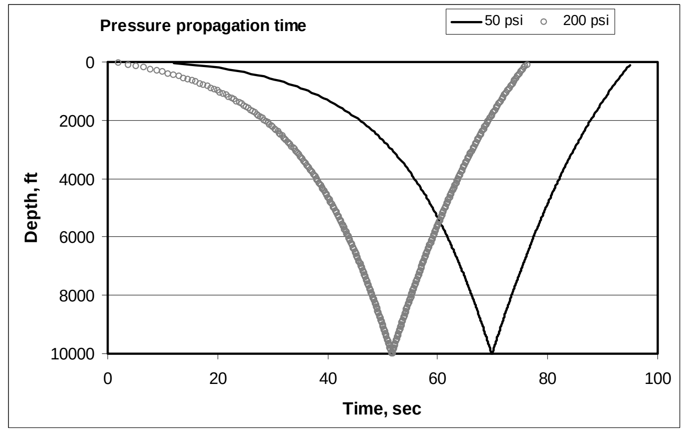

Figure 10—Pressure propagation time versus depth for different back pressures in aerated mud corrected for field practice

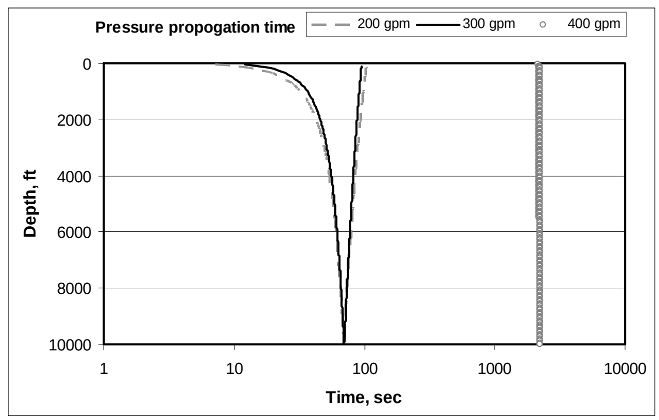

Figure 11—Pressure propagation time versus depth for different liquid injection rates in aerated mud corrected for field practice

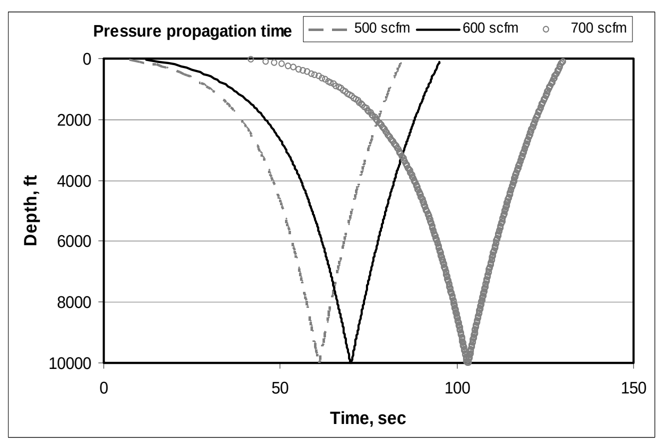

Figure 12—Pressure propagation time versus depth for different gas injection rates in aerated mud corrected for field practice

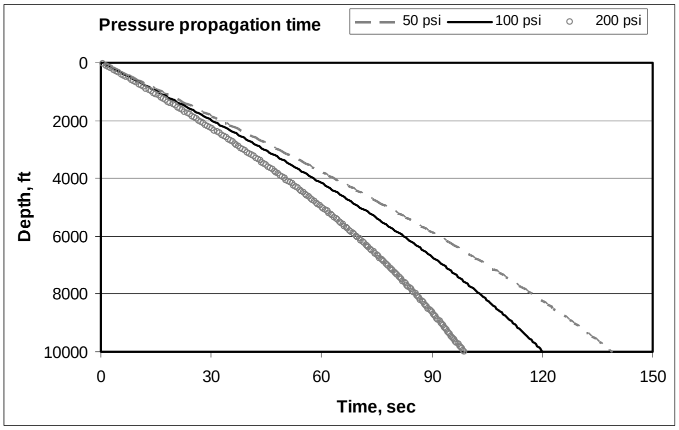

Figure 13—Pressure propagation time versus depth for different backpressures in foam drilling

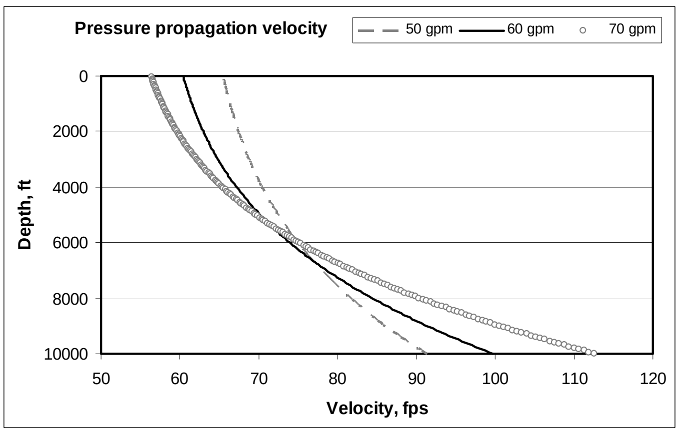

Figure 14—Pressure propagation velocity versus depth for different liquid injection rates in foam drilling

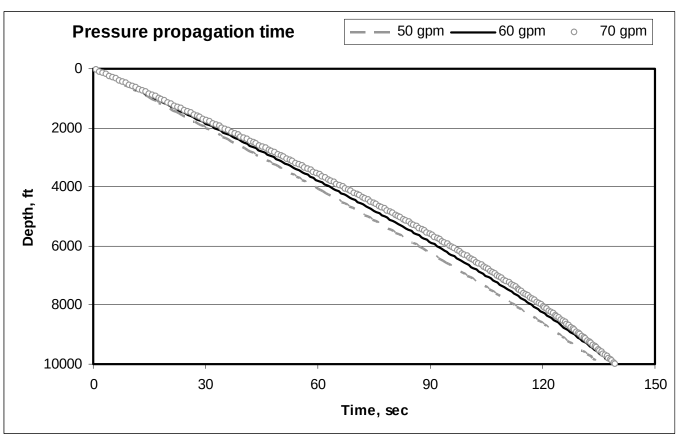

Figure 15—Pressure propagation time versus depth for different liquid injection rates in foam drilling

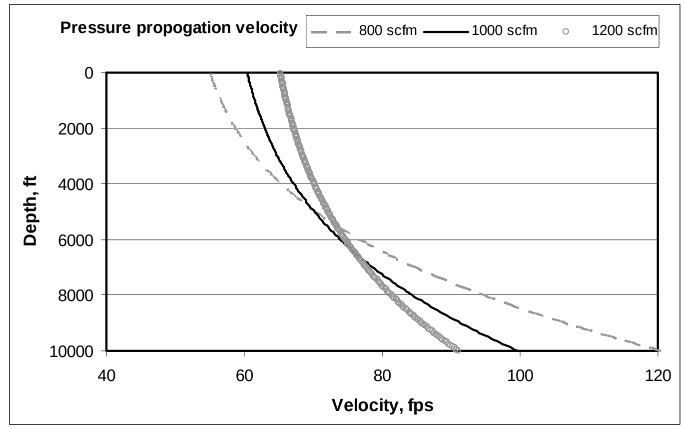

Figure 16—Pressure propagation velocity versus depth for different liquid injection rates in foam drilling

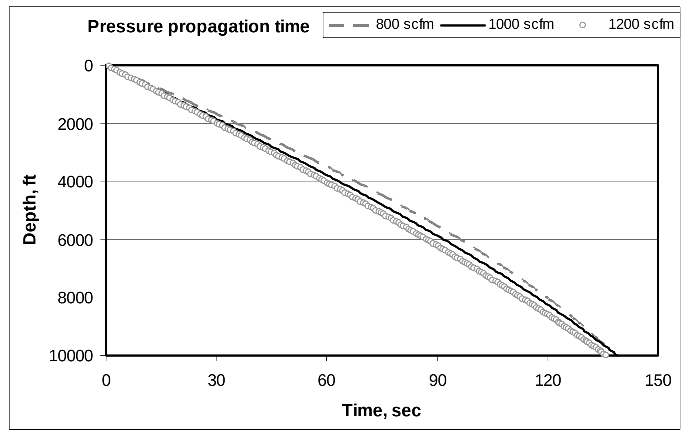

Figure 17—Pressure propagation time versus depth for different liquid injection rates in foam drilling