# Measurement and Interpretation of Fluid Levels Obtained by Venting Casing Gas

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## Abstract

A new computerized fluid level measurement method is described. Instead of using the traditional gas gun and microphone system, a transient wave is created by venting a small amount of gas from the casing and the fluid level is located with help of an ordinary pressure transducer. The method measures acoustic velocity of well gas external to the well in a known length of coiled tubing. This eliminates the need to count tubing collars to determine velocity. Much of the equipment is off-the-shelf, and cost is less than with traditional systems.

Results from field measurements show that the new method provides accuracy which is comparable to traditional systems. The new technique presents an uncluttered result without electrical or digital filtering which clearly shows the fluid level in the majority of cases. The simplicity of the return echo helps differentiate other objects and conditions that might pose as fluid level such as uphole leaks, liner tops, and tubing anchors.

The paper discusses many practical applications of the technique in locating fluid levels. It also describes how $CO_2$ movement within the reservoir can be tracked as a by-product of measuring fluid levels. The paper also illustrates how the wave equation can be used to explain various fluid level echoes encountered in the field.


## Introduction

Well surveillance has always been important in oil production operations. In the modern era, many surveillance methods are employed. Periodic production tests, monitoring with POCs, dynamometer surveys, and fluid level measurements are the principal tools. Fluid levels are often the most cost effective way of providing surveillance.

Fluid level is an indirect indicator of wellbore pressure. Fluid level is important because it is involved in so many cause and effect relationships. When fluid level is high, flood response may have occurred, a tubing leak may have developed, or lift equipment may have failed. Discovery of a high fluid level should prompt the operator to discover the cause. Sophisticated diagnostic procedures can identify lift equipment problems. Simple follow-up pressure tests can identify tubing leaks. Larger equipment can be sized to handle increased production made possible by flood response. A fluid level near the reservoir suggests that maximum production is being obtained. The rate of decline of fluid level is sometimes indicative of well inflow problems. Long term buildup surveys can verify the existence of wellbore damage. Thus it is seen that measurement of fluid level is a central activity in the oil producer's effort to maintain or increase production.

At any given time, most wells are operating satisfactorily. They do not need in-depth investigation on a continual basis. All that is needed is a simple, cost effective way of **sensing a change** in the well. Historically this has been provided by the fluid level instrument. When a problem is suggested, more intensive investigations can be made as appropriate.

Because of the importance of fluid level measurement as a surveillance tool, improving and extending the art and science of making fluid level measurements is a worthy field of investigation. The subject method is yet another effort in this direction.


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## Brief Description of the Method

The measurement of acoustic velocity is a distinctive feature of the new method.[2] This is done externally from the well using a simple procedure with relatively crude instrumentation. The delicate microphone equipment for sensing tubing collar echoes and the sophisticated analog equipment or digital filtering routines required to separate the echoes from background noise are not required. Acoustic velocity is measured with equipment shown schematically in Figure 1-a. With valves $V_1$, $V_2$, $V_5$, and $V_4$ open and with supply line $L_2$ connecting the shooting nipple and the coiled tubing unit (valve $V_3$ is closed), casing gas is bled into the coiled tubing to purge gas remaining from the previous well. Then valves $V_4$ and $V_5$ are closed after pressuring the coiled tubing for measurement of velocity. With the transducer sensing pressure in the coiled tubing unit, the computer controlled valve is quickly opened and closed which causes a rarefaction wave to travel to the closed valve $V_4$ and return. The computer and A to D equipment monitors the pressure wave and determines the round trip time from which velocity is determined. The coiled tubing is only about 50 ft long and is constructed from a corrosion resistant, lightweight material. The coiled tubing unit can be housed in a small suitcase weighing about 25 lbs total or permanently mounted in a properly vented, pickup toolbox. Figure 2 is a typical velocity measurement showing the pressure waveform, roundtrip time and acoustic velocity.

The actual fluid level is measured in a similar fashion. The coiled tubing unit is disconnected (Figure 1-b) and the pressure transducer is connected to the shooting nipple. With valves $V_1$ and $V_2$ open, a small amount of casing gas is bled from the casing, either manually or with a computer controlled valve, $V_3$. The duration of venting is usually less than 0.5 sec so atmospheric pollution is not an issue. The rarefaction wave so created travels from the surface to the fluid top and returns to the surface. Its round trip time is measured by the computer and fluid level is computed from

$$D = vT_r / 2 \quad .... (1)$$

Figure 3 is a typical fluid level measurement. Note that tubing collar reflections do not show on the pressure plot. The two principal features are the induced wave caused by venting and the echo from the fluid top. No ambiguity exists concerning which of the features is the actual fluid level echo. It should also be noted that several methods can be employed to induce the transient wave. Venting is only the preferred method. The several methods are summarized below:

| Method of Creating Wave | Application | |
|---|---|---|
| Vent with manual valve | Usually preferred. | High pressures. |
| Vent with automatic valve | Remote firing | |
| Gas gun with manual valve | High pressures | |
| Gas gun with automatic valve | Remote firing | |
| Implosion with manual valve | High pressures | |
| Implosion with automatic valve | Remote firing | |
| Suck method with manual valve | Casing vacuum | |

## Fluid Level Surveillance

Surveillance usually involves repetitive fluid level measurements on the same well. Thus it is desirable to store measured velocity in a well database. Often, reservoir conditions and gas composition do not change rapidly. Thus re-measurement of acoustic velocity each time a new fluid level is taken is usually not necessary.

Rather than store velocity in the database, it is more convenient to store a specific gravity index that is derived from measured velocity, temperature, and pressure. This allows extrapolation of measured velocity to slightly different pressure and temperature conditions. Commonly used formulas for relating velocity to specific gravity are

$$v = \sqrt{1716.1\, k\, z\, T / G} \,........\, 2$$

or

$$G = 1716.1\, k\, zT / v^2 \,..........\, 3$$

Formula 2 gives good accuracy when supplied with good data. For example, gas properties from a particular well obtained from chromatographic measurements and accurate instrumentation are

G = 0.854 k = 1.161 z = 0.9953 p = 16 psig T = 69 deg F

from which a velocity $v = 1108$ fps is computed. This compares favorably with measured velocity of 1105 fps.

There is no precise way of relating velocity to specific gravity without knowledge of gas composition. Determining gas composition is cumbersome and oil companies will not diligently make this measurement on individual wells. To compute specific gravity index with equation 3, an average value of k = 1.28 is used and a correlation is employed to estimate compressibility factor for the gas. When this is done, a specific gravity index of 0.933 is computed for the gas described above which is based on measured velocity of 1105 fps. As noted this differs from the measured specific gravity of 0.854 so care is taken not to mentally equate specific gravity with specific gravity index. Obviously when k = 1.28, specific gravity index = 0.933 and the same correlation for z is used, the measured velocity of 1105 fps is recomputed. Thus equation 2 is used to recover previously measured velocities or to extraplolate them to slightly different pressure and temperature conditions.

In reservoirs which have reached semi-steady state, there is no need to measure velocity each time a fluid level is evaluated. Time is saved by converting the stored specific gravity index into velocity using equation 2 and proceeding immediately to measuring the fluid level. As will be noted later, changes in acoustic velocity might be deliberately sought in order to discern changes in produced gas composition, i.e. $CO_2$ fraction.

## Mathematical Model of the Process

The traditional fluid level method uses sensitive microphone and amplification equipment to determine acoustic velocity by sensing minute echoes from tubing joints of known length. No effort is made to deduce information from the entire pressure waveform created by the gas gun in the traditional method.

Although practical application of the new method does not hinge on mathematical manipulations, a mathematical model of the process is useful to explain unusual phenomena. The process can be reduced to solving simple boundary value problems in mathematical physics.[1] The pressure waves (either rarefaction or compressional) traveling in the casing can be represented by the one dimensional wave equation.

$$\frac{\partial^2 H(x,t)}{\partial t^2} = v^2 \frac{\partial^2 H(x,t)}{\partial x^2} - c \frac{\partial H(x,t)}{\partial t} \,..........\, (4)$$

The damping term $c\partial H(x,t)/\partial t$ is included to remove energy from the pressure waves as they progress through the casing. The acoustic velocity $v$ can be varied with depth if required. The boundary conditions are

$$V(D,t) = 0 \quad ........................\, (5)$$

at the fluid top. The pressure disturbance created at the surface is

$$H(0,t) = \begin{cases} 0 & \text{for } t < t_b \\ h(t) & \text{for } t_b \le t \le t_e \\ 0 & \text{for } t > t_e \end{cases} \quad \ldots\ldots\ldots\ldots(6)$$

If venting is used, h(t) creates a rarefaction wave which is plotted leftward. Otherwise if high pressure gas is discharged into the casing, h(t) causes a compressional wave which is plotted rightward. The initial conditions are

$$V(x,0) = 0 \quad \ldots\ldots\ldots\ldots.(7)$$

$$H(x,0) = \text{constant} \quad \ldots\ldots\ldots.(8)$$

because the wave equation has been written without a gravity term.

## Some Practical Examples

**Polarity of Fluid Level Echoes.** Figure 4-a shows an actual fluid level at 4624 ft in a well with the pump set at 6534 ft. The vent method is used which causes rarefaction waves (plotted leftward). Note that the polarity of the fluid level echo is the same as the induced wave. Figure 4-b shows another well (fluid level at 1411 ft and pump set at 2672 ft) wherein a gas gun is used to create a compressional wave (plotted rightward). Note again that the echo from the fluid level has the same polarity as the created wave. In the simplest cases, the fluid level echo will always have the same polarity as the initial disturbance, h(t).

The above polarity phenomena can be simulated by assigning negative or positive values to the induced wave

- h(t) for rarefaction waves (venting), or

h(t) for compressional waves (gas gun).

**Detection of Fluid Entry Point.** Fluid can enter the casing via casing leaks, tubing leaks, or perforations. In this case the polarity of the echo will not always be the same as that of the initial wave. This phenomenon is demonstrated in the actual well of Figure 5-a which has a casing leak at 1643 ft. The mathematical model can explain the alternating polarity of reflections from the fluid entry point. Below the point of fluid entry, the mechanical properties of the medium and flow path are altered. The effective density of the medium is greater which diminishes the acoustic velocity. Liquid droplets of various sizes are falling. Also the damping effects of the acoustic medium below the entry point are greater. Fluid is running down the walls of the tubulars. The wave equation

$$\frac{\partial^2 H_u(x,t)}{\partial t^2} = v_u^{\,2} \frac{\partial^2 H_u(x,t)}{\partial x^2} - c_u \frac{\partial H_u(x,t)}{\partial t} \ldots\ldots(9)$$

is solved in the upper casing above the entry point. Similarly in the casing below the entry point another wave equation problem is solved

$$\frac{\partial^2 H_l(x,t)}{\partial t^2} = v_l^2 \frac{\partial^2 H_l(x,t)}{\partial x^2} - c_l \frac{\partial H_l(x,t)}{\partial t} \quad \text{.........(10)}$$

The solutions of both problems are linked by enforcing continuity of pressure at the fluid entry point. The change in physical properties above and below the fluid entry point are expressed by requiring $c_l >> c_u$ and $v_l < v_u$.

Figure 5-b shows the results of a simulated casing leak at 1643 ft derived from the mathematical model. The signals with alternating polarity are successive echos from the fluid entry point caused by changes in physical properties. No echo from the fluid level below the entry point is seen in this well. The acoustic energy has dissipated before it can return to the surface.

**Locating the Fluid Level Below Productive Perforations.** A variation of the fluid entry phenomenon described above is the case of locating the fluid level beneath productive perforations. Such may be possible provided the fluid level is sufficiently close to the perfs. An actual example is shown in Figure 6-a. For a rarefaction wave, according to the mathematical model, the opposite (rightward) kick occurs at the top productive perforation at 4470 ft. The leftward kick defines the fluid level at 4665 ft. Figure 6-b shows a fluid level echo waveform derived from the wave equation where the top perf and fluid level are located at the same points as in the actual well. The actual and theoretical waveforms are similar. In future work, fluid level echo waveform as affected by distance from top perf to fluid level, induced pulse duration, etc. should be investigated. The new method, especially when venting is used, creates a long wavelength disturbance. Thus it should be capable of detecting fluid levels farther below fluid entry points than the traditional method. This expectation relates to the reason why fog horns are made to produce low pitched sounds. Their low frequency (long wave length) sound carries farther in foggy weather.

**Locating Fluid Level Beneath Liner Tops.** Liner tops are usually visible in the return echo of the new method. At the liner top, the cross sectional area of the annular conduit suffers a sudden decrease and some of the induced signal is reflected back to the surface. The remainder of the energy passes into the liner and (usually) reflects off the fluid level back to the surface. Figure 7-a shows an actual well completed with 7.0 inch casing and 2.375 inch tubing. To shut off a casing leak, a 4.5 inch liner is installed with top at 3500 ft. The fluid level measurement shows echoes both from the liner top and from the fluid level at 5506 ft, some 2006 ft below the liner top.

This case can be simulated by solving a wave equation problem in the casing (such as equation 9) and another in the liner (such as equation 10). The sudden contraction in flow area is simulated by requiring

$$A_c V_c = A_l V_l \quad \text{. . . . . . . . . . . . (11)}$$

in which the velocities are computed from finite difference versions of

$$\frac{\partial H_u(x,t)}{\partial x} = -\frac{1}{g} \frac{\partial V_u(x,t)}{\partial t} \quad \text{. . . . . . . . . . . . (12)}$$

and

$$\frac{\partial H_l(x,t)}{\partial x} = -\frac{1}{g} \frac{\partial V_l(x,t)}{\partial t} \quad \text{. . . . . . . . . . . . (13)}$$

The acoustic velocities in the casing and liner are set equal ($v_l = v_u$). The damping effect in the liner is evidently higher than in the casing where the flow area is larger ($c_l > c_u$). Refer to Figure 7-b for the theoretical simulation of a liner top echo with fluid level below.

**Tracking $CO_2$ Movement with Fluid Levels.** In managing a flood it is desirable to track the movement of $CO_2$ in the reservoir. At present, chromatographic analyses, titration procedures and infrared equipment are used to sense the arrival of $CO_2$ at a production well. Ideally, tracking $CO_2$ movement can be a by-product of fluid level surveillance with the new method. The arrival of carbon dioxide at a producing well may be indicated by 1) a rise in fluid level and 2) a change in acoustic velocity of the produced gas. Both can be detected. With respect to item 2), a simple approach is to to infer $CO_2$ fraction from specific gravity index which in turn is derived from velocity. We begin by writing the formula for specific gravity after $CO_2$ response

$$G = 44\ fc / Ma + (1 - fc)\ G_b$$

and then solve for $CO_2$ fraction. After simplification, substitution of the molecular weight of air, and replacement of G by $G_i$ we obtain

$$fc = 1.924\ (G_i - G_b) \ldots\ldots\ldots\ldots\ldots\ldots (14)$$

Tracking of $CO_2$ fraction in an actual well is shown below. The actual $CO_2$ fractions are measured with chromatographic methods.

| Specific gravity index ($G_i$) | Actual $CO_2$ fraction, % | Inferred $CO_2$ fraction, % |
|---|---|---|
| 0.94 ($G_b$) | 0.3 | 0 |
| 1.024 | 22.5 | 16 |
| 1.126 | 36.5 | 36 |
| 1.193 | 45.7 | 49 |
| 1.237 | 52.6 | 57 |

Though not in perfect agreement with measured values, the inferred $CO_2$ fractions have practical utility. This happy result is probably due to offsetting errors and the fact that the k value for $CO_2$ is virtually equal to the average k used to calculate specific gravity index. The above procedure applies to wells in which the reference specific gravity index $G_b$ is obtained prior to $CO_2$ arrival. A slightly different procedure is used if surveillance is started after $CO_2$ production begins.

## Other Distinctive Features of the Method

**Enhancing Fluid Level Echoes by Varying Vent Time.** In deep wells and those in which casing pressure is very low, it is difficult to determine fluid level with confidence because the return signal is weak. With the traditional technique it is hard to identify the single fluid level echo among the many similar looking signals caused by noise in the casing. The new method allows the user to control the duration of the induced wave, especially when the manual vent method is used. This creates a series of echoes from the fluid level in a packet. As Figure 8 shows, the width (w) of the echo is about the same as the width of the induced pulse. If a question exists, the induced pulse width can be varied. This in turn varies the width of the fluid level echo. The result is that the fluid level echo can be located with greater certainty.

**Invisibility of Tubing Collars and Tubing Anchors.** The microphone used in traditional fluid level measuring equipment is unusually sensitive to short (high frequency) sound waves. The short waves reflect off small objects in the well such as tubing collars and tubing anchors. Filtering is used (electronic filtering for analog systems and digital filtering for computerized systems) to identify the weak echoes in the background noise.

Echoes from tubing collars and tubing anchors do not appear in the return signal in the new method. This is partly due to the limited sensitivity of the pressure transducer used to monitor pressure. But primarily it is due to the long wavelength of the induced pressure pulse. In the new method the longest wavelength in the induced pulse may be hundreds of feet long, i.e. much larger than downhole objects. Thus small objects do not produce discernable surface echoes (at all) in the new method. Figure 9 shows a well in which a tubing anchor is installed at 7014 ft. Neither tubing anchor nor collar echoes appear in the record. Yet the induced pulse travels past the anchor without reflection to clearly show the fluid level at 7998 ft.

Invisibility of tubing anchors is a mixed blessing. A disadvantage is that the tubing anchor can not be used to cross-check acoustic velocity since the anchor echo does not show. An advantage is that little of the induced energy is reflected by the anchor. This increases the likelihood that fluid level below the tubing anchor will be discernable.

**Noise Created From Rod Pumping Systems.** In some cases, sound caused by movement of the rods can appear on the return signal plot in the new method. It is important to recognize this possibility so that the fluid level echo will not be mistaken for some noise event caused by the pumping system. Figure 10-a shows an actual well in which pumping noise is being sensed along with the echo from the fluid level. If the record is long enough, periodicity (repeatability) will be shown in the signals caused by pumping equipment. In fact, pumping speed of the unit can be read from the fluid level chart by identifying the period P of recurring pressure waveforms. Recognizing that pressure disturbances that originate downhole arrive at the surface without making round trips, the formula for pumping speed is

$$SPM = 60 / P \qquad \ldots\ldots\ldots\ldots (15)$$

For the example of Figure 10-a, P = 5.89 sec. Thus the speed of the pumping unit is 60 / 5.89 = 10.2 SPM. Figure 10-b shows the same well with the unit turned off to eliminate the signals from the pumping equipment. No ambiguity exists as to which feature represents the fluid level echo. The fluid level is indicated to be at about 5000 ft with the unit stopped (or running). The echo plot will not repeat from shot to shot (with unit running) unless the initial wave is induced at precisely the same point in the stroke each time.

## Future Development Plans

This paper should be considered as a progress report. More work is planned to further increase the utility of the method.

Fluid level technology is useful in making long term reservoir pressure buildup studies. These are helpful in evaluating skin damage and other inflow problems.[4] The new method will be adapted to this application. It offers advantages because casing gas will supply the energy for creating the pressure wave from which fluid level is measured. No separate source of compressed gas will be needed.

The methods for computing pump intake pressure from fluid level were developed for hydrocarbon gas. These need to be validated for $CO_2$ / hydrocarbon mixtures or else new techniques should be developed. An ability to track $CO_2$ movement within the reservoir will help to apply the technology.

## Conclusions

1. A new method for measuring fluid level has been developed. The concept is simple and is implemented with inexpensive, off-the-shelf equipment using a pressure transducer as the sensing element. The microphone used with traditional methods is eliminated.

2. The monitored pressure wave is quantitative and requires no filtering. In the traditional method, the microphone output is qualitative and requires filtering to minimize background noise.

3. Mathematical modeling of the waveform is useful in explaining unusual phenomena such as polarity of echoes.

4. The waveform features are easy to interpret. Tubing collars and tubing anchors are not shown. However, distinctive features such as shot and fluid echoes are clearly shown. Tubing and casing leaks and fluid levels below perfs can be identified from their waveforms.

5. Acoustic velocity is measured external to the well. This has side advantages and makes possible the measurement of fluid level in wells without tubing, wells with more than one tubing string and wells without tubing collars.

6. Tracking $CO_2$ content in produced gas can be a by-product of fluid level surveillance.

## Nomenclature

$A_l$ = cross sectional area of liner / tubing annulus, $ft^2$
$A_c$ = cross sectional area of casing / tubing annulus, $ft^2$
c = damping coefficient, $sec^{-1}$
D = fluid level depth, ft
$f_c$ = gravimetric fraction of $CO_2$
g = acceleration of gravity, $ft/sec^2$
G = gas specific gravity
$G_b$ = specific gravity index before $CO_2$ arrival
$G_i$ = gas specific gravity index
h(t) = representation of transient wave, ft
H(x,t) = pressure head, ft
k = ratio of specific heats $c_p / c_v$
$_l$ = subscript denoting lower interval
$M_a$ = molecular weight of air, lb / mol
P = period of pumping unit cycle, sec
p = pressure, psi
SPM = pumping speed, cycles/min
T = absolute temperature, deg Rankine
t = time, sec
$t_b$ = beginning time, sec
$t_e$ = ending time, sec
$T_r$ = round trip time of transient wave, sec
u = subscript denoting upper interval
$v$ = acoustic velocity, ft/sec
V = gas velocity, ft/sec
x = depth, ft
z = gas compressibility factor

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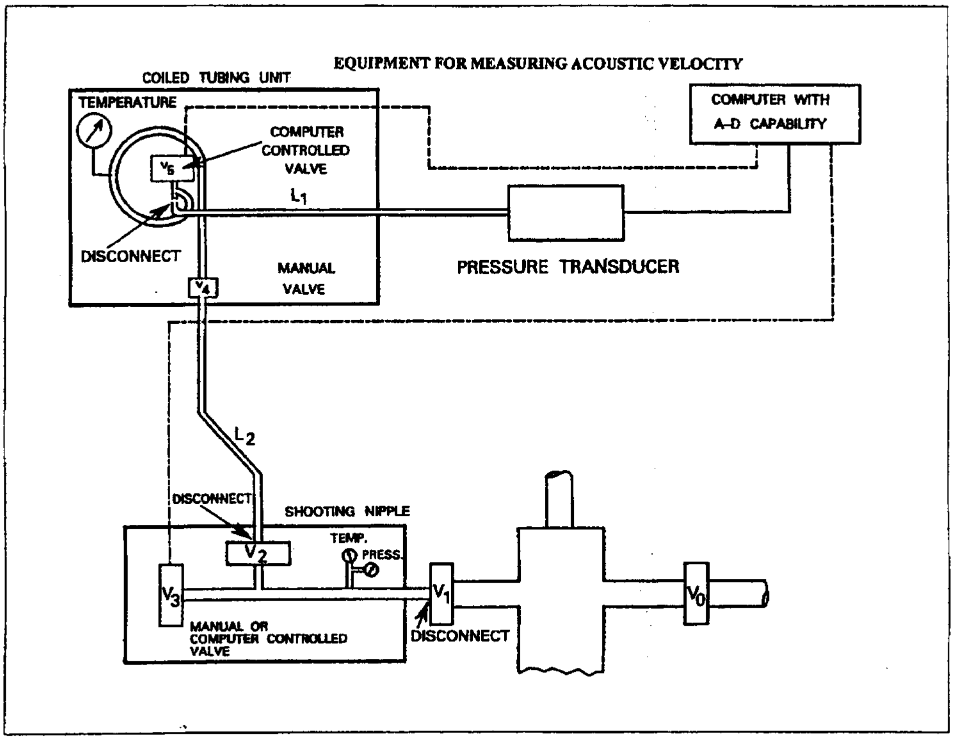


Figure 1A

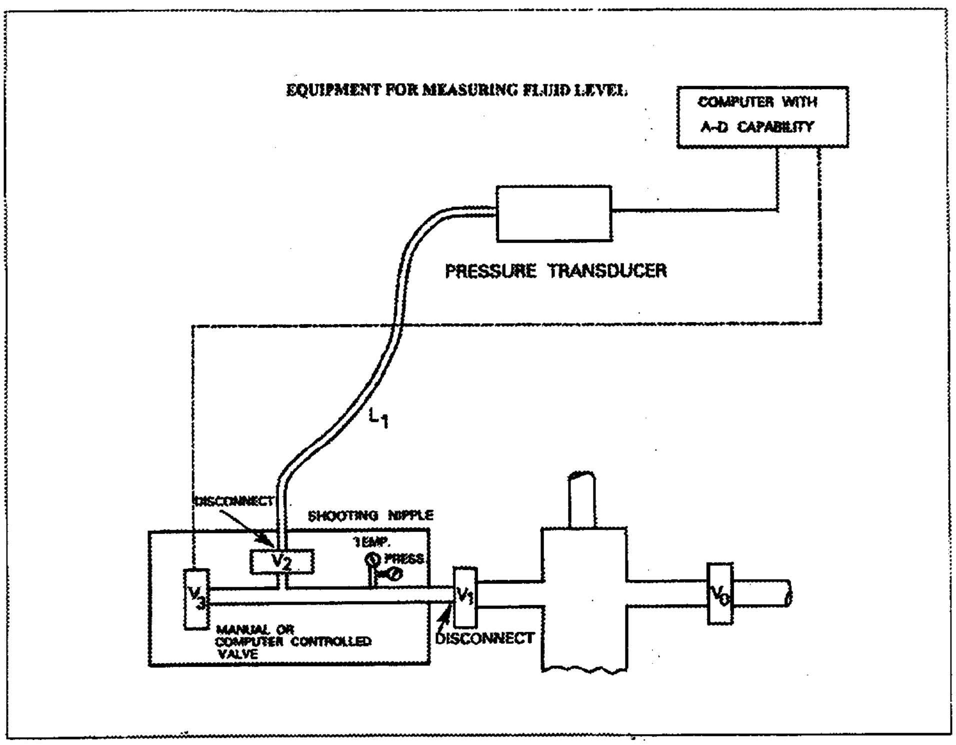


Figure 1B

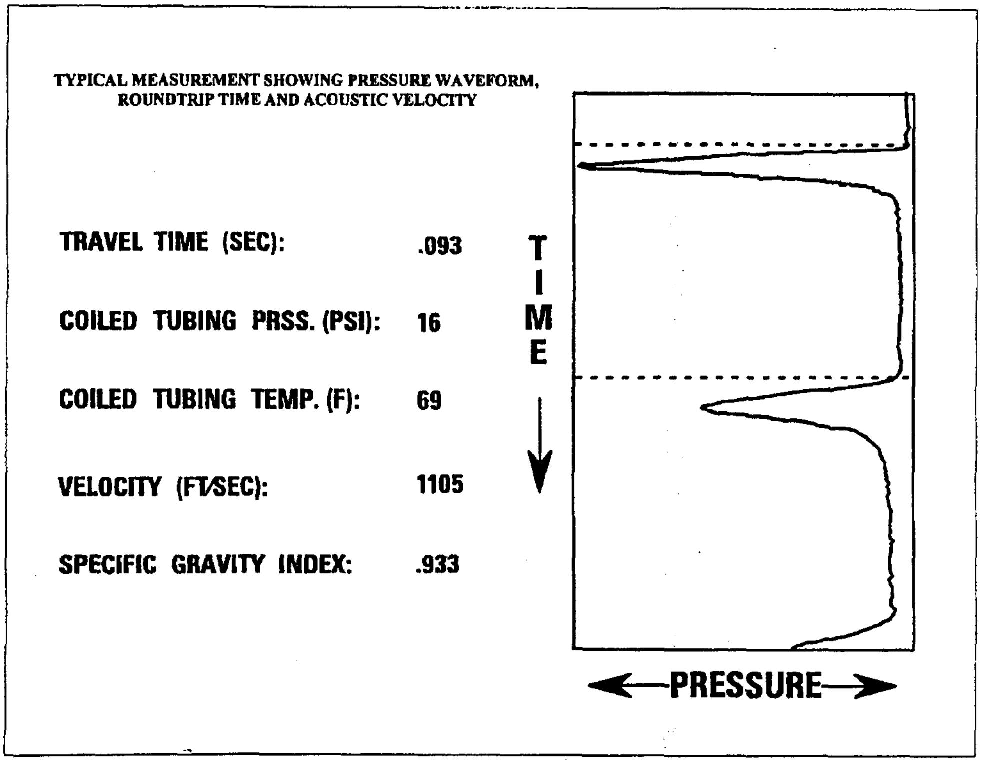


Figure 2

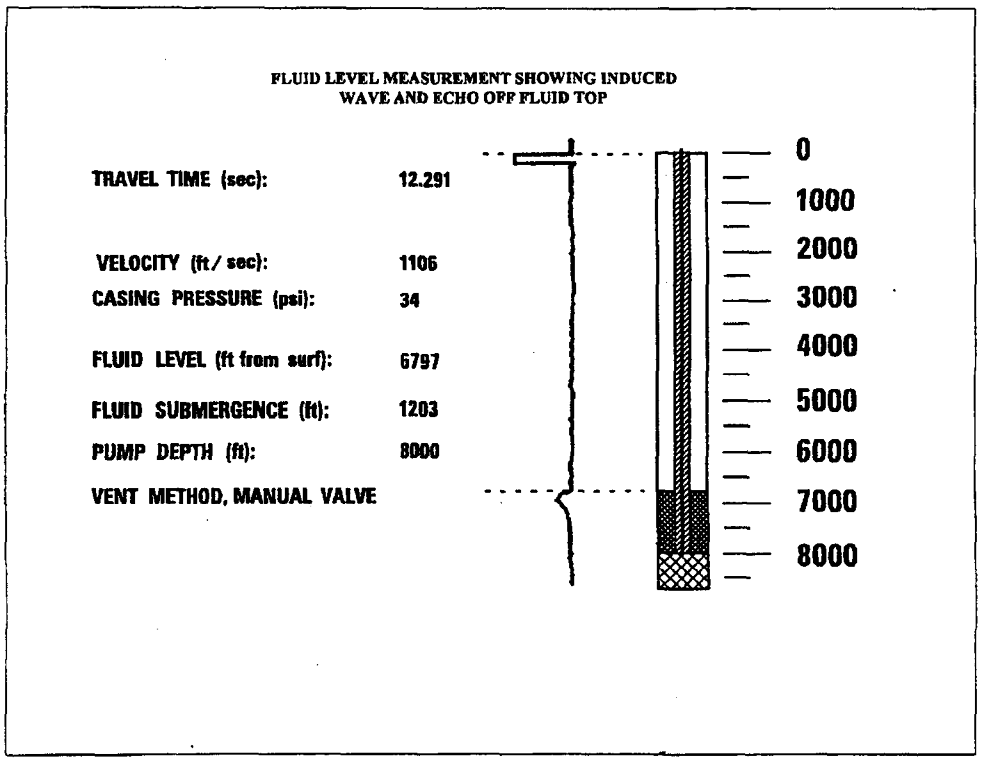


Figure 3

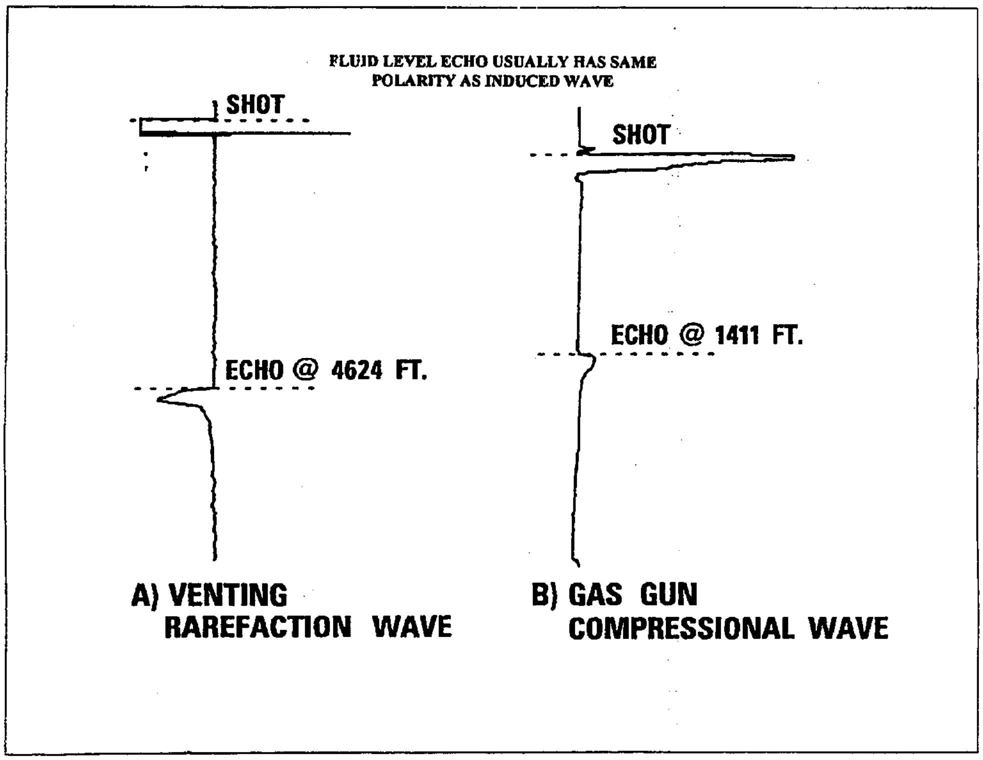


Figure 4

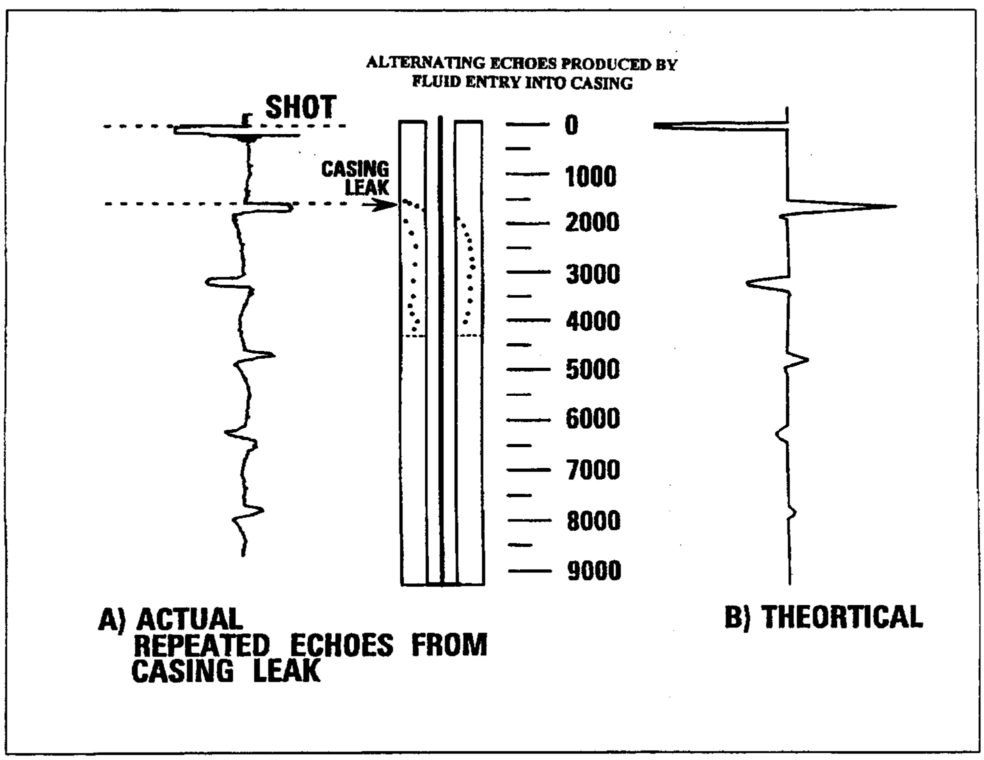


Figure 5

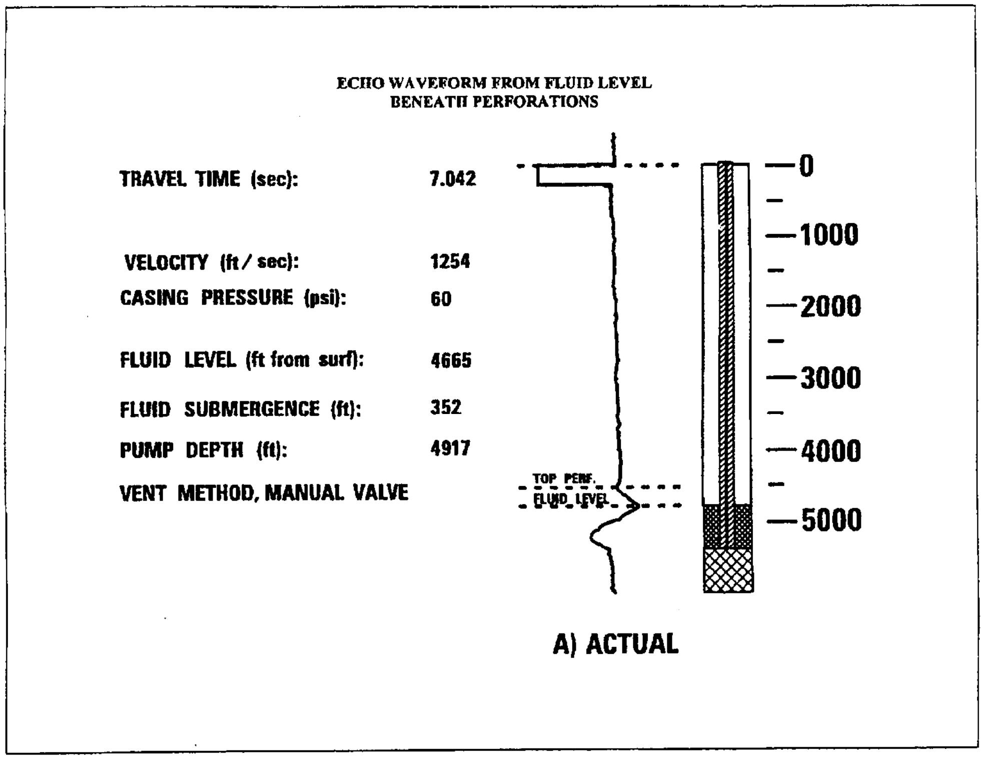


Figure 6A

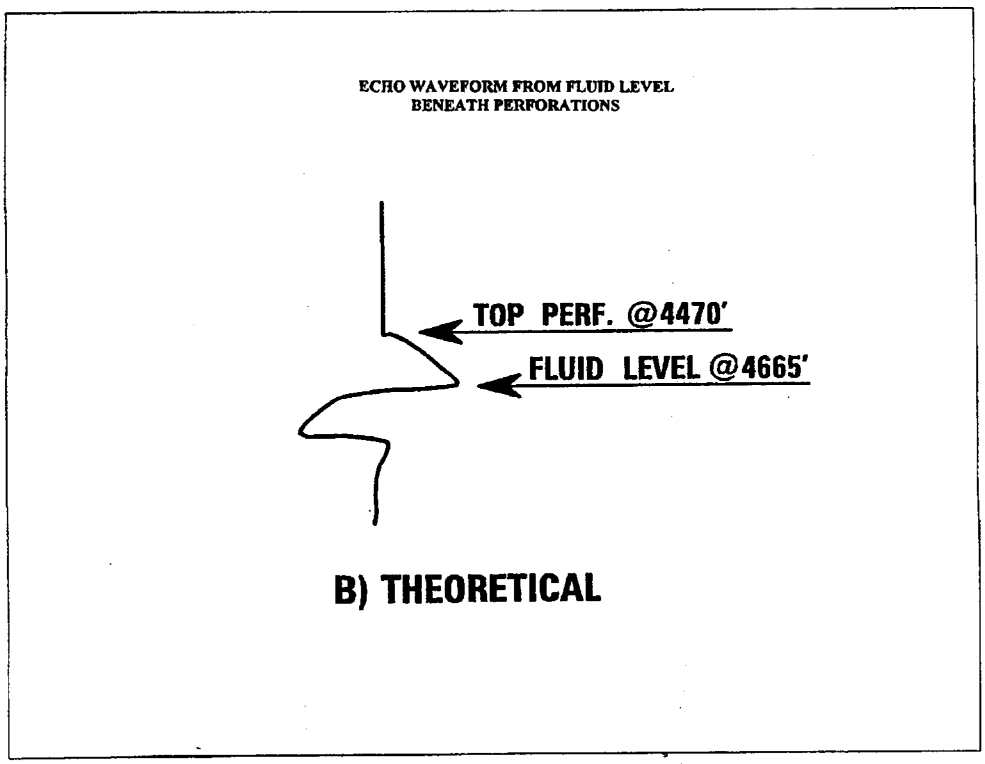


Figure 6B

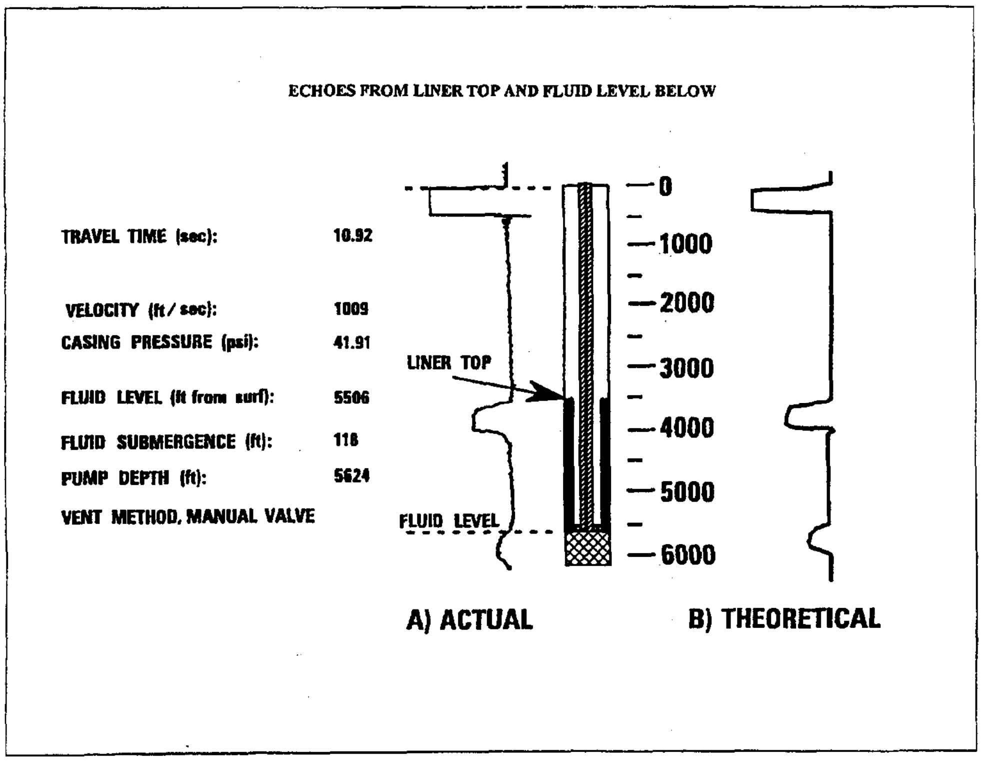


Figure 7

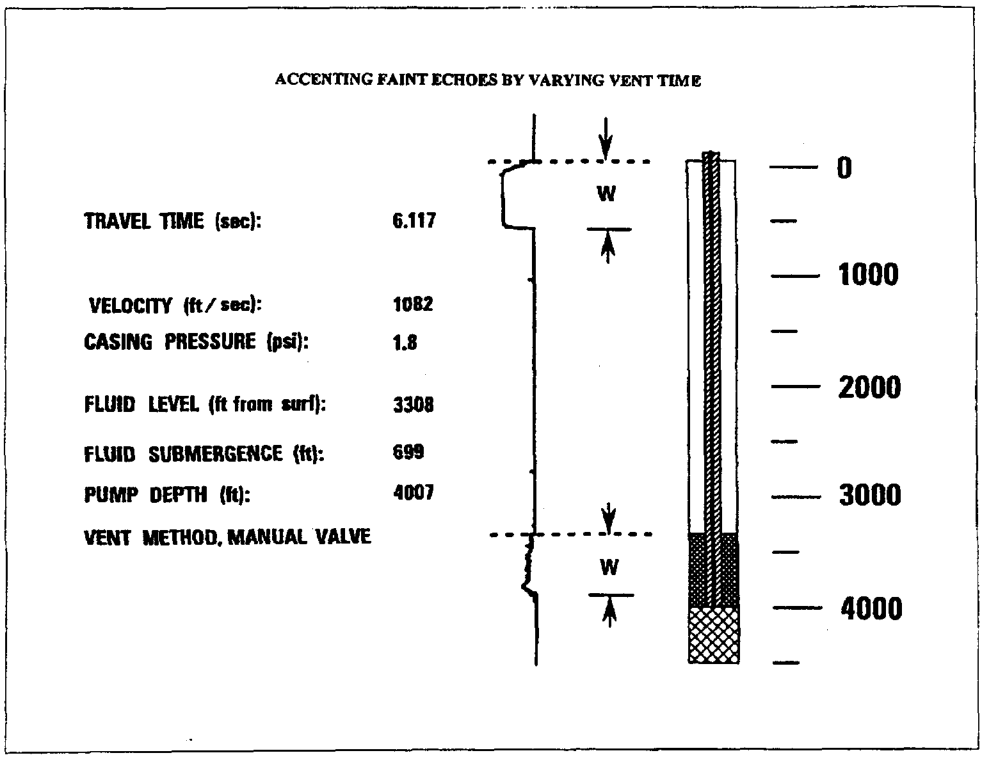


Figure 8

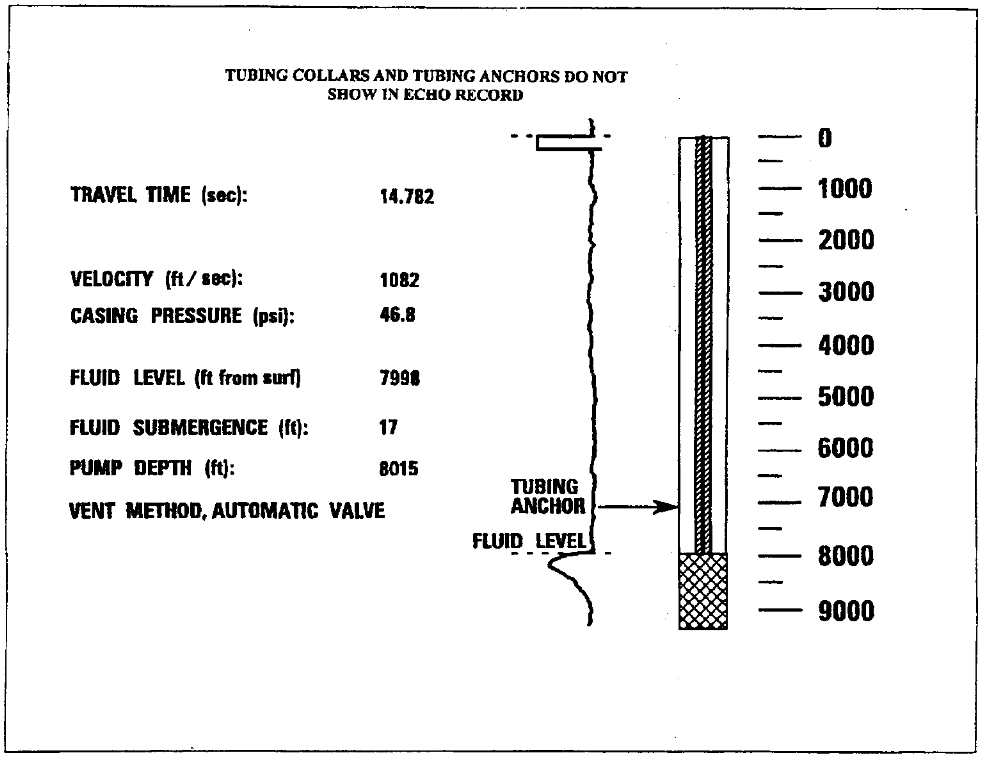


Figure 9

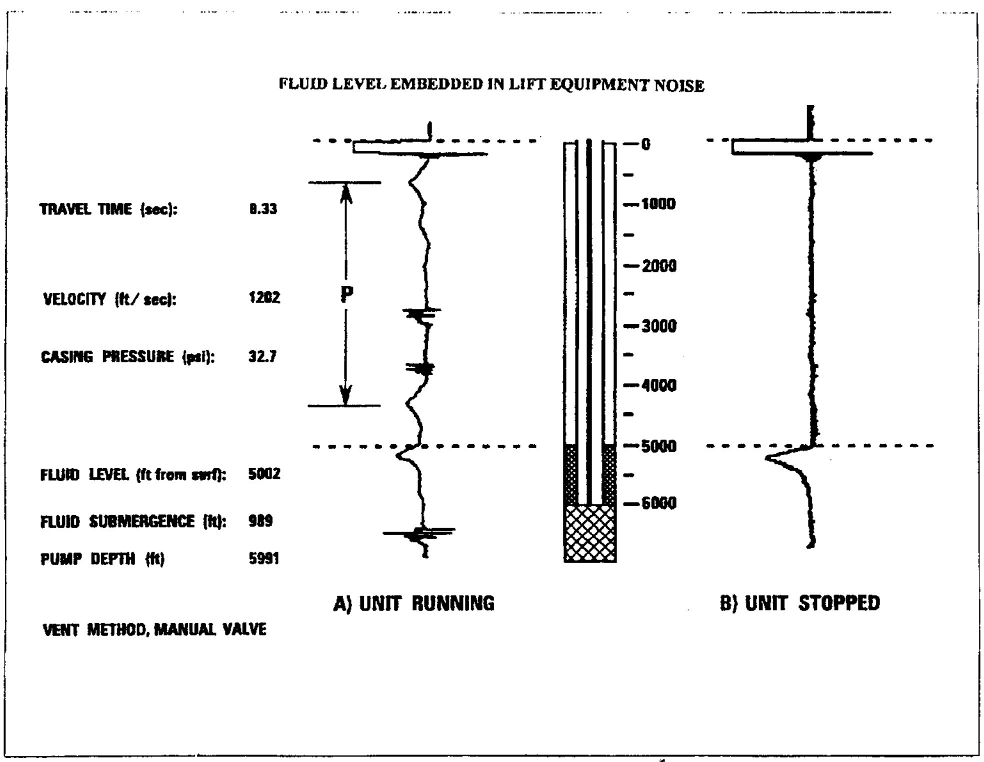


Figure 10