DETERMINING FLUID LEVEL IN WELLS WITH FLOW INDUCED PRESSURE PULSES

by

K. B. Nolen, S. G. Gibbs, M. W. Connally and W. C. Lynch
Nabla Corporation

Abstract

A new pressure transient wave method is presented for measuring fluid levels in wells. The method uses flow induced pressure phenomena to measure acoustic velocity externally from the well in a known length of coiled tubing. Similarly with a flow induced pulse in the well a fluid level is measured by sensing the distance traveled by the pressure wave. The method is flexible. The pressure wave can be created automatically or manually by venting a small amount of gas from the well, by abruptly releasing high pressure gas into the well or by implosion if the casing pressure is high. Simplified and less expensive equipment is involved. The method is applicable to routine surveillance, well productivity studies, lift equipment design, and reservoir evaluation. Fluid levels measured with the new method compare favorably with those obtained with traditional techniques.

Introduction

Knowledge of reservoir pressure is important in the production of oil wells. When this pressure is high enough, fluids from the reservoir are pushed to the surface with energy supplied by the reservoir alone. In this case the well is said to be a `flowing well'. But when this pressure diminishes, artificial lift equipment must be installed to raise fluid to the surface. The depth from which the fluid must be lifted is directly related to reservoir pressure and affects the size of lift equipment required. Fluid level is also an important parameter in determining the maximum production capability of a well. If fluid is pushed by reservoir pressure to a level near the surface, little additional lifting energy must be supplied by pumping equipment. Also a fluid level near the surface indicates a well with high reservoir pressure which is capable of more production if pumped more aggressively. On the other hand, if reservoir pressure is low and the fluid level is far below the surface, the pumping equipment will have to supply most of the lifting energy. The low reservoir pressure and the related deep fluid level means that the well is producing near its capacity. The end point is reached when reservoir pressure is so low that the fluid level is virtually at downhole pump depth. In this case the well would be producing at its maximum rate at that pump depth and termed as `pumped off'.

The previous discussion reveals that measurement of the fluid level in a well is an important activity in determining the well's productive capability which in turn is used in determining the size of lift equipment required. The fluid level can be expressed 1) as the distance downward from the surface or 2) as the fluid submergence above the reservoir or downhole pump.

Review of Traditional Fluid Level Measurements

Measurement of fluid level has been accomplished by acoustic means for many years. Well casing is set to reach or penetrate a productive reservoir. Segmented tubing is run inside of the casing. The tubing contains a downhole pump whose purpose is to lift fluid (oil, water and gas) to the surface. Depending upon the type of downhole pump in use, energy can be supplied by means of sucker rods or by electrical conductors or by pressurized fluid, among others. The segmented tubing is joined with screw connections which are larger than the outside diameter of the tubing. These form small obstructions to acoustic phenomena traveling in the casing-tubing annulus.

To measure the fluid level acoustically, a noise is induced in the casing at the surface. The sound in the past was created by discharging gunpowder or more recently by releasing pressurized gas such as carbon dioxide or nitrogen into the casing. The initial `blast' and subsequent echos are sensed by a microphone and amplification equipment. These signals are then recorded versus time on a fast running strip chart plotting device. The sound disturbance travels downward in the casing until it reaches the top of the fluid column in the casing-tubing annulus. Thereafter the disturbance reflects upward to the surface where its arrival is recorded by the strip chart device. The round trip time T (measured from the initial blast to the top of fluid thence to the surface again) is used to calculate the distance from the surface to the fluid by means of the formula

$$H = 0.5\,V\,T \qquad \ldots\ldots\ldots\ldots 1$$

where

H = distance from the surface to the fluid top, ft

V = velocity of sound in the gaseous medium filling the casing above the fluid level, ft/sec

T = round trip time (from the initial blast to the top of fluid thence to the surface again), sec

A variety of ways to determine the velocity of sound is known to those familiar with the art of measuring fluid levels, such as

1. Inferring velocity from the rate at which echos are received from connections in the segmented tubing. The distance (or at least the average distance) between connections, i.e. tubing joint length, is known and the velocity of sound can be calculated. This is the most commonly used method.

2. Using theoretical relationships between velocity, pressure, temperature and gas composition.

3. Inferring velocity from the measured round trip time to a downhole obstruction the depth of which is known and whose echo can be identified in the record.

In shallower wells it is sometimes possible to sense echos of tubing connections continuously from the surface to the fluid level. The fluid level can then be determined without measuring velocity according to the simple formula

$$H = N L_a \qquad \ldots\ldots\ldots\ldots 2$$

where

H = distance from the surface to the fluid top, ft

N = total number of tubing joints counted from initial blast to fluid level echo

L_a= average length of the segmented tubing joints, ft

In deeper wells and in wells in which `hearing' is poor, it is usually not possible to receive echos from every tubing connection from the surface to the fluid level. In these cases, the velocity is inferred using echos from the shallower tubing connections which are still discernible. Then equation 1 is used to calculate the depth to fluid. If desired, the explicit calculation of velocity in equation 1 can be avoided by using equation 3 below. The number of connection echos per inch on the paper recording (while the echos are discernable) is measured and this echo rate is applied to the number of inches on the chart representing the time between the initial blast and the fluid level echo. This is expressed in the formula

$$H = R L_a D \qquad \ldots\ldots\ldots\ldots 3$$

where

H = distance from the surface to the fluid top, ft

R = number of tubing connection echos per inch on the chart paper, jts/in

L_a= average length of the segmented tubing joints, ft

D = measured distance (on the chart paper) between the initial blast and the fluid level echo, in

In recent years, microcomputers have been used to collect, compute and display fluid level information. The computer is used to record and display the echos instead of the paper chart device. The methods of finding fluid level are the same as used in the older methods, but the techniques are merely implemented with the computer.

Existing technology, either traditional or digital, has certain aspects which are disadvantageous.

i) Creation of the noise in the casing in the usual way has inherent disadvantages because the faint echos from tubing connections tend to be lost in the noisy initial blast. The initial blast has a complex character. Consequently, it is necessary to use filtering techniques (either electronically with the traditional equipment or digitally with computer based equipment) in order to discern the faint echos in the noisy background caused by the initial blast.

ii) Inherent errors exist when theoretical relationships are used to compute the velocity of sound in the gaseous medium.

iii) The sensitive microphone and recording equipment tends to be delicate and costly.

iv) Determination of tubing joint length can introduce error. Ideally the tubing joints are measured (tallied) before running into the well. But this is not always done and the average joint length is often estimated. Range 2 tubing allows a variation in length from 28 to 32 feet and this can introduce a large error. Also the tubing joints, even when tallied, may be run at random and this too causes error.

v) Wells with more than one tubing string (duals and triples) introduce problems in counting joints and in computing velocity.

iv) Wells without tubing or with coiled tubing pose problems because acoustic velocity cannot be measured.

The Flow Induced Pressure Pulse Method

Measuring Velocity

A distinctive feature of this method concerns measurement of sound velocity. No need exists to evaluate velocity by sensing minute echos from tubing connections as in the traditional methods. Instead this velocity is literally measured in a short length of small diameter coiled tubing external to the well. Actual gas from the casing is allowed to flow into the coiled tubing (less than 0.1 cubic foot) thereby displacing gas remaining from the last measurement. The gas temperature and pressure are noted and a tiny amount of gas is allowed to escape at one end of the coiled tubing. The pressure wave so created travels to the other end of the tube and reflects back to the starting point. Using a pressure transducer and a fast running analog to digital converter, the round trip time is measured and applied to the known length of coiled tubing to calculate the velocity. The sound velocity so measured in the coiled tubing is adjusted to the temperature and pressure of the gas in the well itself and used with equation 1 to determine fluid level. Measuring sound velocity in the coiled tubing can be done quickly. What is unexpected is the accuracy with which the velocity can be determined in such a short length of tubing. By keeping the tubing length short and by coiling it, the apparatus can be light and portable (Figure 1).

The entire process can be automated and computer controlled by using snap acting electrically operated valves to emit the gas. Alternately the gas can be vented with a quick operating mechanical valve. When the round trip time has been measured, the acoustic velocity is calculated with the formula

$$V_T = 2\, L_T\, L_T \qquad \ldots\ldots 4$$

where

V_T = velocity of sound in the coiled tubing, ft/sec
L_T = length of coiled tubing, ft
T_T = round trip time of pressure wave, sec

Figure 2 is an example acoustic velocity measurement. By computing and saving the specific gravity corresponding to the measured velocity, temperature and pressure conditions the velocity will not have to be measured again unless gas composition changes.

Measuring Fluid Level

The method simplifies the process of obtaining a fluid level measurement. Instead of creating a noise in the casing to produce echos from the fluid top, a pressure disturbance is caused by quickly venting a small quantity of casing gas to the atmosphere. This venting is done rapidly such that the amount of gas emitted is small and not harmful to the environment or to people. In fact the venting usually occurs in less than 0.5 second. In addition to safety and environmental considerations, the brief duration is desirable because it provides a sharper wave front on the pressure pulse that reflects off the top of the fluid. The sharper front improves accuracy in timing the arrival of the reflected signal. The pressure distrubance so created is simple in wave form (in this writing, wave form is thought of as the relationship of gas pressure versus time during the measurement process). In contrast, the sound created in the traditional way is complex (constituted from high frequencies) and receipt of echos is more difficult. Also the simple wave form created by rapid venting allows use of inexpensive pressure sensing equipment.

With the same equipment as used for measuring acoustic velocity in the coiled tubing, the pressure wave created by venting the casing is sensed and digitized. The round trip time for this wave to travel to the fluid top and return is measured. The acoustic velocity measured in the coiled tubing is adjusted to the temperature and pressure of the gas in the well and used with equation 1 to determine the fluid level. An example of a fluid level measurement is shown in Figure 3.

The method uses equipment that is off-the-shelf with only minor modifications. Also the process is flexible. The pressure wave required to determine fluid level can be generated 1) by venting gas from the well (preferred), 2) by abruptly releasing high presuure gas into the well or 3) by implosion. In all three modes, the measurement of acoustic velocity external to the well is involved. In addition these processes can be performed either automatically or manually.

Figure 4 shows a hookup for venting using a computer controlled electrically operated solenoid valve. Figure 5 shows a manually operated valve for venting. A computer operated beeper signals the user when to abruptly open and close the ball valve. If necessary, compressed gas (typically carbon dioxide) can be used. Venting may not be safe if the well produces dangerous concentrations of hydrogen sulfide. In this case a compressed gas gun from other fluid level systems may be used. A simplified gas gun is available using a manually operated valve with beeper (Figure 6) or a computer controlled solenoid valve (Figure 7). If casing pressure is high, say above 100 psi, the pressure wave may be generated by implosion. Implosion is accomplished by having the gas gun chamber at atmospheric pressure then by abruptly opening the solenoid valve (automatic operation) or the ball valve (manual operation) to admit high pressure gas into the chamber. The rapid inrush of gas creates the desired pressure wave.

Some Applications

Calculating Producing Pressure

Depending on the casing fluid gradient, a high fluid level above the pump can indicate a high producing pressure. The most widely used method to evaluate the casing fluid gradient requires a shut-in casing pressure build-up rate. The pressure transducer previously used to obtain velocity and fluid level is used to collect pressure build-up data versus time . Once collected, the least squares method is used to fit the most probable straight line to the data. The slope of this line is the casing pressure build-up rate. Based on this rate and Gilbert's Modified "S" Curve[1], a casing fluid gradient correction factor is computed. Using this correction factor a bottom hole pressure is calculated based on the following equation:

$$P_p = P_c + P_g + \nabla C H \quad .... \quad 5$$

where

P_p = pump intake pressure, psi
P_c = surface casing pressure, psi
P_g = pressure from gas column weight, psi
∇ = stock tank (dead) oil gradient, psi/ft
C = gradient correction factor
H = fluid above pump, ft

It is important to compute pump intake pressure in gassy wells because the effects of a foamy fluid level are considered in the process. Figure 8 is an example computation of pump intake pressure from fluid level. The gassy fluid column in the casing (0.266 psi/ft gradient - 913 ft submergence) gives an overly optimistic impression of additional production available. Use of the Modified Gilbert "S" Curve considers the effect of the gas cut fluid level and shows that pump intake pressure is only 284 psi.

Calculating Additional Production Potential

If the well has a producing pressure substantially above the minimum attainable pressure then more production potential exists. To quantify additional production potential two reservoir models are used, i.e. the Vogel method[2] if the well produces a significant amount of gas and the Constant PI method if very little or no gas is produced. The user has the ability to vary the producing pressure and observe predicted changes in producing rates. Figure 9 is an example of the output showing additional production potential based on Vogel's method.

Routine Surveillance

Another application is in routine surveillance of wells where periodic fluid level measurements are made. If the well is found to have a low level (or at least one comparable to the last level which was measured) then no further action is likely required. If a high level is found, however, further action is probably needed. The well should be checked for a tubing leak, worn pump or flood response. A more detailed dynamometer analysis may be warranted. Using the subject method, acoustic velocity will not likely need to be re-measured. Also the database capabilities make it easy to compare the current level with the last level obtained.

Reservoir and Well Impairment Studies

Multiple fluid level shots with the casing closed are useful to oil company engineers and technicians. The manner in which fluid level (related to reservoir pressure) increases reveals the severity of wellbore impairment (skin damage)[3]. The static fluid level (measured over a long shut-in period or extrapolated from limited data) is useful in determining well productivity, flood response and reserve estimates. The subject method suits these applications nicely. It is not necessary to supply an auxiliary source of carbon dioxide or be troubled with equipment for `re-cocking' the system after each shot. With the subject method, all is done under computer control using energy supplied by the well.

Implementation

It is important to make a new technique as user friendly as possible. The subject method is computerized and implemented in the Microsoft Windows system which is familiar to many.

User manuals are apt to be misplaced or hard to read. The program associated with this method is internally documented and not dependent on a written manual. The user is led through the process by the program. If a fluid level is being measured with the vent method using the automatic solenoid valve, the user can click on HELP and the computer will describe the procedure for this firing mode. The instructions that appear on the monitor are either written or shown as digitized photographs. Safety is emphasized always.

Input data is entered in modular fashion. If only fluid level is required, then only the input data for fluid level is requested. It is unnecessary to build a database of information beforehand for computing pump intake pressure and productivity if these items are not needed. A database file can be created with a single mouse click if data and results need to be saved for future reference. When wells are monitored regularly, it is desirable to save results in the database. For easy retreival, a search feature is incorporated to locate the well by typing in the first few letters of its name. Much of the data will not change from time to time so the effort to locate and enter data is diminished. It is convenient to save specific gravity in the database since this item only depends on gas composition which changes very slowly. Practically speaking this means that acoustic velocity does not need to be determined every time the fluid level is measured. The stored specific gravity is merely recalled and combined with prevailing temperature and pressure to compute an acoustic velocity. This saves time. Another advantage of saving specific gravity is that variations of velocity with downhole temperature and pressure can be considered if this effect is important.

The modern computer has good graphics capabilities. Pictures can be incorporated into the program output to make the results easier to interpret than when they have to be gleaned from tabular information.

Computer programs are imperfect. Thus the human operator should be the final judge of computed results. The computer is programmed to pick the fluid level automatically but, even so, the user is allowed to change the solution should the program make an obvious error. Like computer programs, electrical hardware can fail at awkward moments. Redundancy is built into the system so that the manually operated valve can be used should the electrically operated solenoid valve fail.

It is not always convenient to carry a printer to the oilfield. Therefore the facility to save field data is included so that results can be re-created in the office where a printer is available. The program is usually run in a laptop computer which may not have an easy to use mouse (pointing device). Thus the computer code can also be manipulated with keyboard strokes rather than being totally dependent on the mouse.

Certain parts of the program are made available as separate utility functions. For example the methodology for computing compressibility factor[4] and acoustic velocity[5] from temperature, pressure and gas gravity is provided as a standalone module.

Conclusions

1. Determining acoustic velocity external to the the well is unique and in some cases has advantages over traditional methods. The new technique applies to wells with more than one tubing string and wells without tubing and wells without tubing joints (coiled tubing). The method also avoids

the complexities and uncertainties of filtering the return signal to discern the faint echos from tubing collars.

2. The method is flexible and uses inexpensive equipment. The same components are used to measure acoustic velocity, measure the fluid level and measure casing pressure build-up for computation of producing pressure. The pressure wave can be created i) by venting gas, ii) by quickly introducing high pressured gas or iii) by implosion. In addition, these functions can be implemented automatically or manually.

3. The method is capable of being computerized which allows it to be automated.

References

1. McCoy, J. N., Podio, A. L. and Huddleston, K. L., "Acoustic Determination of Bottomhole Pressure," SPE Formation Evaluation, Sept. 1988, 617-621.

2. Vogel, J. V. "Inflow Performance Relationships for Solution - Gas Drive Wells", JPT (Jan. 1968) 83-87;Trans. AIME , 243.

3. Matthews, C.S., Russell, D.G., "Pressure Buildup and Flow Tests in Wells", Monograph Volume 1, SPE of AIME, Dallas, TX (1967).

4. Himmelblau, David M., "Basic Principles and Calculations in Chemical Engineering", Prentice-Hall; Englewood Clifts, NJ, 1962, 163-168.

5. "Engineering Data Book", 8th ed., published by Natural Gas Processors Suppliers Association, Tulsa, Oklahoma (1966), 48.

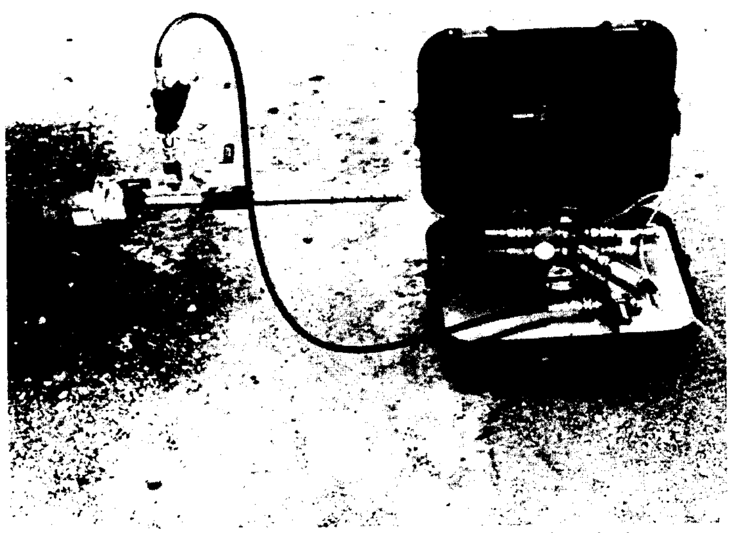

Figure 1 - Equipment used to measure acoustic velocity

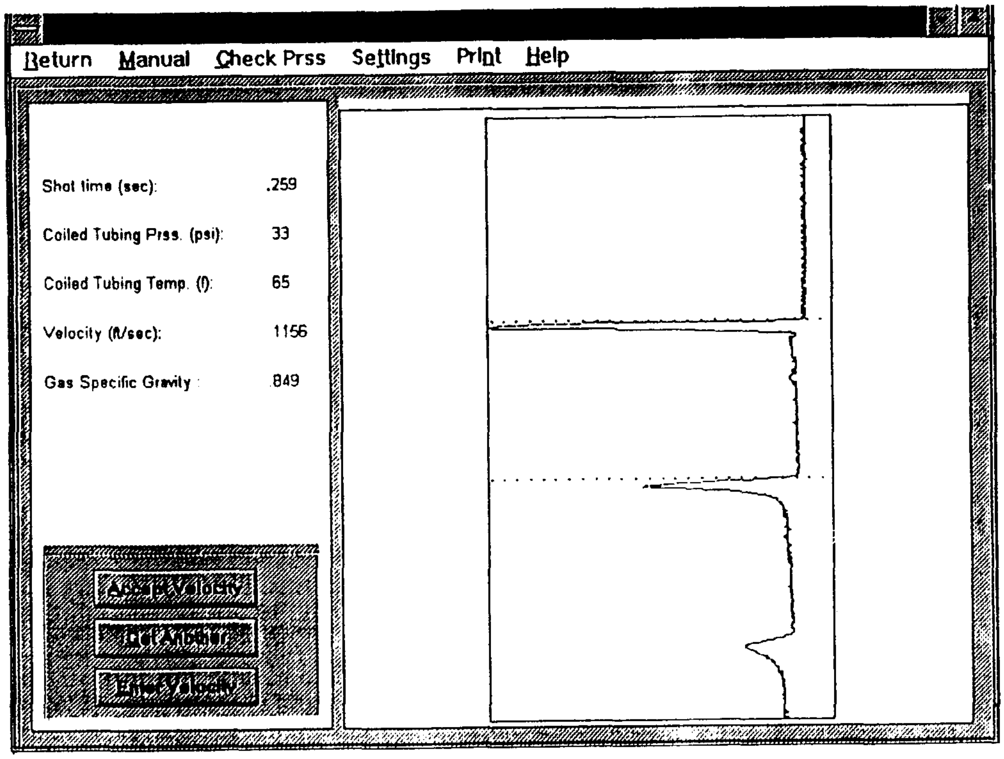

Figure 2 - Example of acoustic velocity measurement

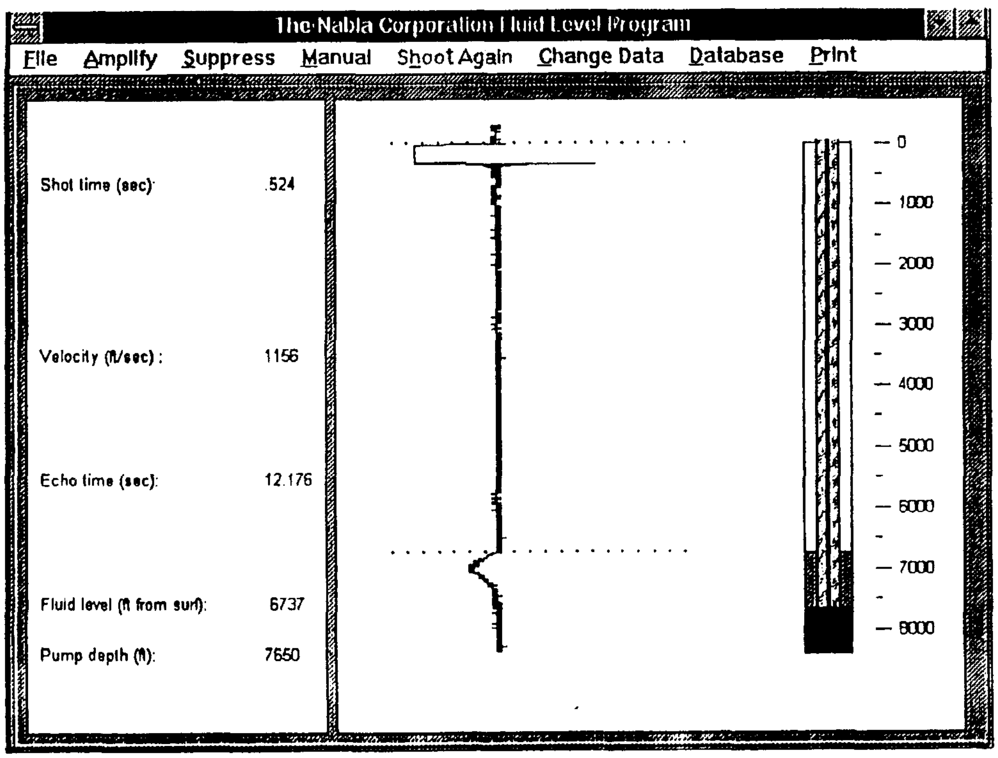

Figure 3 - Fluid level determined with flow induced pressure wave method

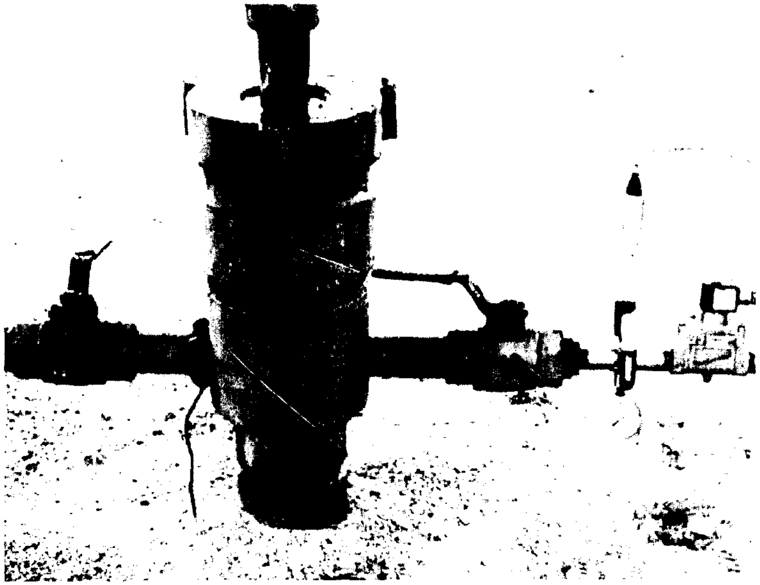

Figure 4 - Shooting fluid level with computer controlled electrically operated valve for venting

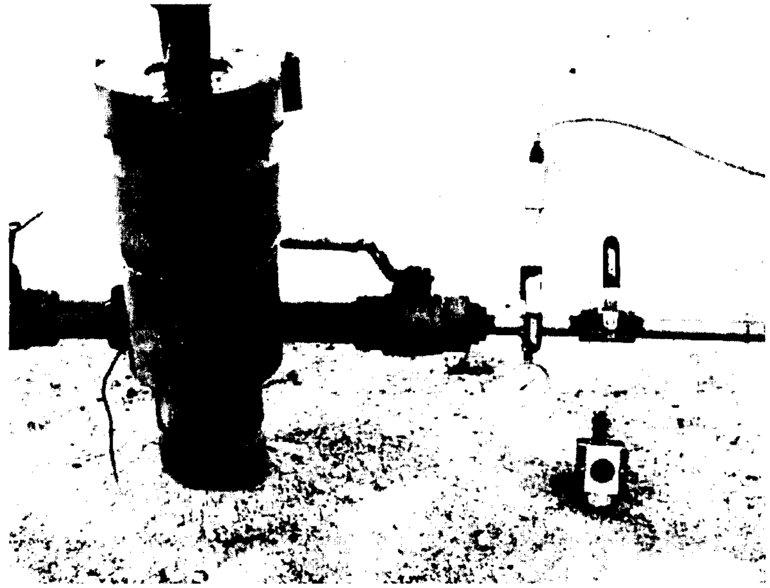

Figure 5 - Shooting fluid level with manually operated ball valve and beeper for venting

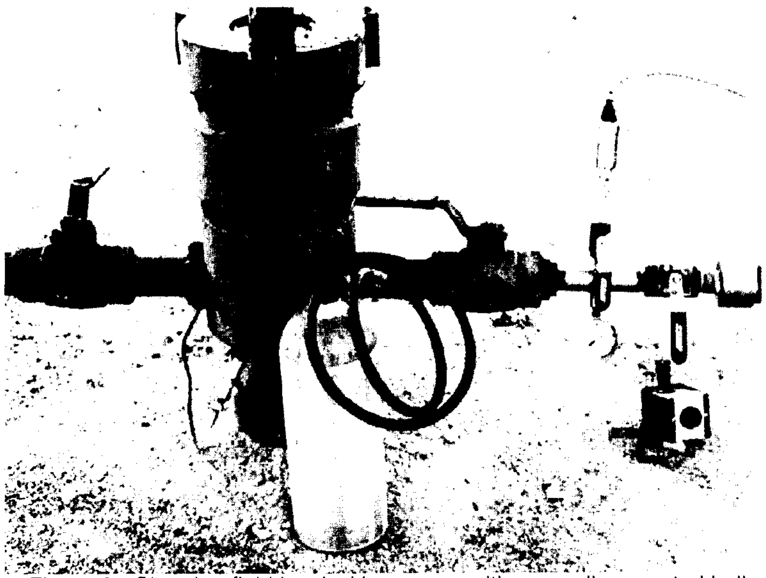

Figure 6 - Shooting fluid level with gas gun with manually operated ball valve and beeper

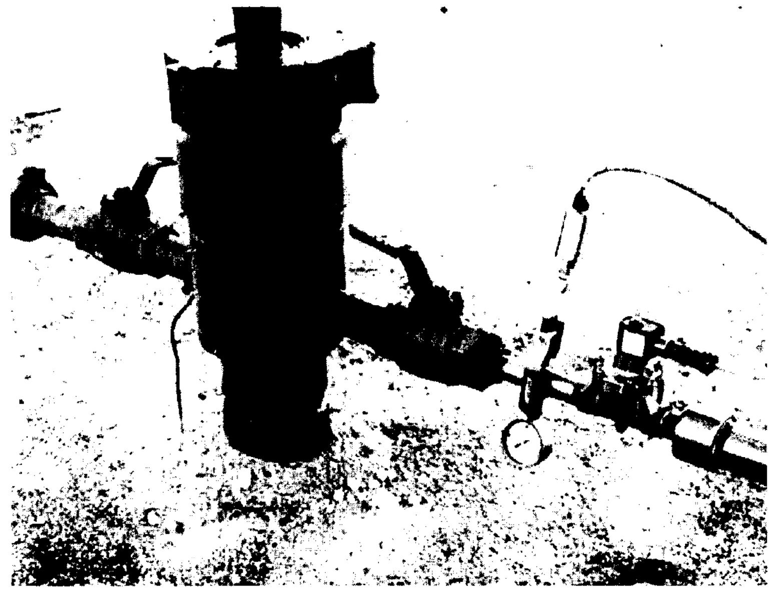

Figure 7 - Shooting fluid level with gas gun and computer controlled electrically operated valve

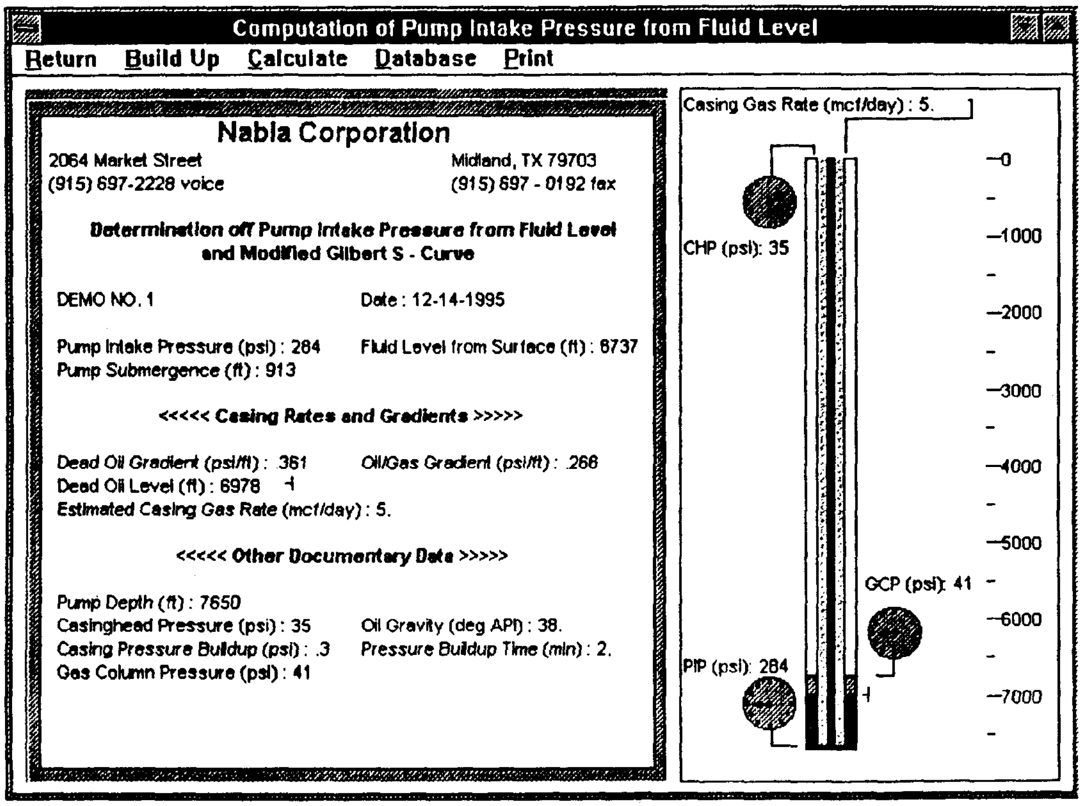

Figure 8 - Computation of pump intake pressure from fluid level.

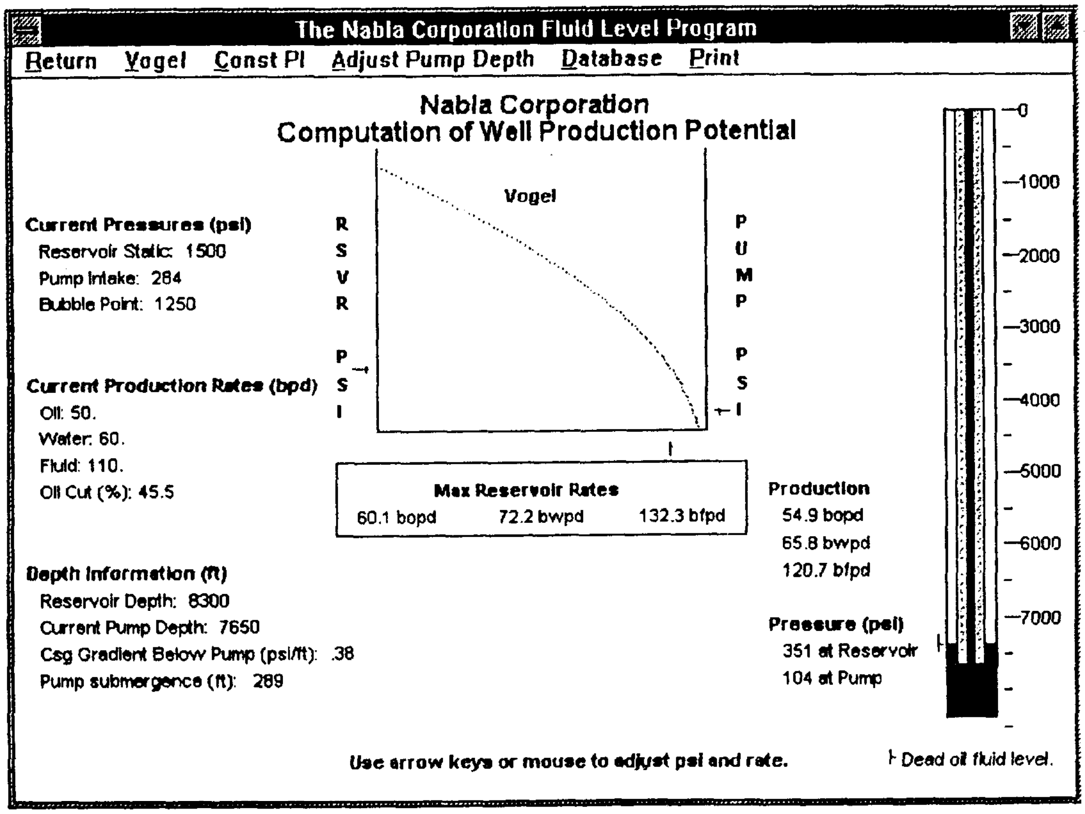

Figure 9 - Computation of well production potential