Analyzing Well Performance XV

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INTRODUCTION

Analyzing well performance is an important step toward increasing profits by improving production techniques. The analysis is made by field tests and examination of well data. The acoustic liquid level instrument permits determination of the producing and static bottomhole pressures and hence the producing rate efficiency of the well. Improvements in the acoustic determination of bottomhole pressures for practical needs have occurred in recent years and are presented herein.

FLUID FLOW

Fluid flow in a reservoir is caused by movement of fluid from a high-pressure area to a low pressure area. Fluid flow into a wellbore occurs when fluids present in the wellbore are removed so that the pressure is decreased in the wellbore. Then, fluid from an area of higher pressure flows into the lower pressure wellbore (Fig. 1).

Fluid flow increases as the differential pressure increases. Vogel[1] presents an Inflow Performance Relationship (IPR) curve for determining producing rate efficiency based upon the ratio of the wellbore pressure to the reservoir pressure. This curve is shown on the Well Analysis Sheet. Note: approximately 97% of the maximum flow rate will occur when the wellbore pressure is 10% of the reservoir pressure. Also note, 70% of the maximum flow rate will occur when the wellbore pressure is one-half of the reservoir pressure.

NECESSARY DATA FOR WELL ANALYSIS

Four factors are important in analyzing well performance: (1) reservoir pressure, (2) producing bottomhole pressure, (3) well test and (4) pump capacity.

For maximum withdrawal, the producing bottomhole pressure (PBHP) must be low compared to the reservoir pressure or static bottomhole pressure (SBHP). A PBHP of 100 psi is low compared to a SBHP of 1800 psi and practically all of the production is being obtained. However, if the SBHP is 150 psi, approximately 50% of the maximum production rate is being obtained. The well test and

References and illustrations at end of paper.

pump capacity must be known. Excessive wear and a mechanical loss of efficiency occur if the pump capacity greatly exceeds the production rate. A production loss occurs if the pump capacity is less than the well's producing capacity. See Table 1.

Note the importance of each item by trying to determine proper action on each well in Table 1 when only one of the four items is omitted.

DETERMINING WELLBORE PRESSURE

The pressure at the wellbore can be obtained from the depth to the liquid, the casing pressure, and a knowledge of the fluids present in the casing annulus. The wellbore pressure (whether the well is at static or producing conditions) is the sum of the casing pressure, the gas column pressure, and the liquid column pressure.

The casing pressure, gas column pressure and liquid column pressure must be totaled to determine the PBHP of a well making gas. oil and water. All the liquid above the pump will be oil due to gravity separation. If the pump is above the formation, the liquid below the pump and above the formation will be oil and water in approximately the same ratio as is produced from the well.

If the SBHP is desired, additional information is necessary. If the liquid level was at the pump before being shut-in, the liquid that collects in the annulus will be approximately the same ratio of oil and water that is produced from the well (Fig. 2A). If liquid existed above the pump while the well was being produced, the height of the column must be determined. This liquid above the pump is entirely oil if sufficient time has elapsed for oil to collect and fill the annular space. The liquid level rise, after the well is shut-in, consists of the same ratio of liquids that are normally produced (Fig. 2B). If the SBHP is desired on a high WOR well with raised tubing, assume the gradient of liquids below the tubing perforations to be the produced water gradient. The fill-up will be the gradient of the produced liquids (Fig. 2C). A gaseous liquid column cannot exist in a well at static conditions.

An improved technique for obtaining the SBHP in wells which produce casing gas is to close the casing valve a sufficient time before shutting-in the well so that the casing pressure can increase. The gas will collect in the casing annulus, increase the casing pressure and cause the top of the gaseous liquid column,

if present, to be depressed to the pump perforations. Continue to pump the well until the casing pressure ceases to increase. This results in a higher casing pressure and less liquid in the wellbore at static conditions which improves the accuracy. After shut-in, the fill-up will be the same ratio of oil and water that is normally produced by the well (Fig. 2D). In some wells, all of the wellbore pressure increase will be caused by gas entry, and liquid will actually flow back into the formation.

The gas column pressure can be determined with reasonable accuracy by the following equation:

Pgc = Pc x L/30,000

where Pgc = pressure due to weight of gas column, psi
Pc = casing pressure, psi
L = length of gas column, ft.

The gas gradient can be determined by:
Oil gradient (psi/ft.) = 61.3/(API + 131.5)

In a producing well, the gradient of the oil column must be corrected for aeration if casing gas flow exists. See "Gaseous Liquid Columns".

Pure water has a gradient of 0.433 psi/ft. The actual gradient of produced water can be determined by measuring the specific gravity using a conventional battery hydrometer, and then multiplying the pure water gradient of 0.433 psi/ft. by the specific gravity.

The calculations are simple, and reasonably accurate bottomhole pressures are obtained from acoustic liquid level information. The procedure presented herein for calculating bottomhole pressures is sufficiently accurate for most well analyses. References 2, 3 and 4 offer more accurate procedures than presented herein. The gas column pressure can be more accurately determined if the gas gravity is known, and the gas gravity can be determined from the acoustic velocity on the strip chart. Also, the oil gradient can be corrected for dissolved gas and temperature. While the greater accuracy is not necessary in most well analyses, the more accurate techniques can be used if desired.

Software is available for calculating bottomhole pressures. Input information includes well data, fluid data and acoustic data. The computer calculates the gas gravity, gas column pressure, corrected oil gradient and corrected water gradient and the resulting PBHP and SBHP. Contact Ken Huddleston with Echometer Company, 5001 Ditto Lane, Wichita Falls, Texas 76302, phone 817/767-4334, or Dr. A.L. Podio, Department of Petroleum Engineering, University of Texas, Austin, Texas 78712, phone 512/471-3161, for more information.

THE ACOUSTIC LIQUID LEVEL INSTRUMENT

The acoustic liquid level instrument can be used to determine the amount of liquid above the pump or formation. The instrument works on an echo principle much like a person's echo in a mountainous area; except, the original sound is made by generating a pressure pulse, and the echoes are reflections from tubing collars and the liquid. The acoustic liquid level instrument is connected to the casing annulus valve. The tubing in the well, and rods if present, are not disturbed in any manner. The pressure pulse is discharged into the casing annulus emitting a pressure wave which travels down the annular gas. Each tubing collar reflects a portion of this pressure wave, and the reflected pressure waves energize a microphone. These signals are amplified, filtered and recorded on a strip chart. The liquid level in the well reflects a high percentage of the pressure wave and is recorded as a relatively large pulse on the paper. The number of collar reflections to the liquid level and the average joint length indicate the depth to the liquid level. An acoustic chart and typical system are shown in Fig. 3.

GASEOUS LIQUID COLUMNS

The problem of a liquid column above the pump being gaseous can occur. A gaseous liquid column exists in wells which are producing gas from the casing annulus. After stabilization, if gas is not being produced from the casing annulus, the liquid column cannot be gaseous. A gaseous liquid column is identified if the casing pressure increases when the casing valves are closed and the well is allowed to continue to pump. The casing pressure increase occurs because gas flows upward from the gaseous liquid column into the closed annular volume.

Two techniques are offered for determining the PBHP in wells which have gaseous liquid columns.

The first technique involves measuring the increase in casing pressure over a certain period and obtaining the liquid level. With this data, a gradient correction factor can be determined which represents the effective amount of liquid present in the gaseous liquid column. Then, the gradient correction factor is multiplied by the liquid gradient in order to determine the gradient of the gaseous liquid column. This technique is less accurate when the casing annulus is almost full of the gaseous liquid column. Then, the second technique, which is more accurate but also more time consuming, is recommended.

Using the first technique to determine the pressure exerted by a gaseous liquid column, the operator should close the casing valve and continue to pump the well. Immediately, an acoustic liquid level test should be taken to determine the depth to the top of the gaseous liquid column (L). The well should be pumped with the casing valves closed until an increase in casing pressure has occurred, generally 10 to 60 minutes. The increase in casing pressure (dP) and the time period (dT) during the increase in casing pressure should be noted. Determine L x dP/dT. See Nomenclature. Enter this value in Fig. 4 and read F_g, the approximate fraction of gas present in the liquid column. Multiply F_g times H_p (or the gaseous liquid column height) to determine the equivalent amount of gas in the gaseous column. Add this equivalent height of gas in the gaseous liquid column to the gas column length (L) to obtain L'. L' is the distance from the surface to the gas/liquid interface, if the gaseous liquid column were separated. See Nomenclature. Determine the value of L' x dP/dT. Enter this value into Fig. 4 and proceed down to determine C which is the effective oil fraction. This effective oil fraction, or gradient correction factor, should be multiplied by the gradient of the gas-free oil to determine the gradient of the gaseous liquid column. Multiply the height of the gaseous liquid column by the gradient of the gaseous liquid column to determine the pressure exerted by the gaseous liquid column. Fig. 4 was obtained from extensive field tests and is discussed in Reference 2.

An example of determining the PBHP of the following data is given. An acoustic liquid level test indicates the liquid level at 3900 ft. The formation depth is 4900 ft. Casing pressure is 25 psi and increases 3 psi per minute when the casing valve is closed and the well continues to pump. Refer to well No. 8 on Table 2. The gas column pressure is 25 psi x 3900/30,000 or 3 psi. The value of L x dP/dT is 11,700. Enter this number into Fig. 4 and read upward to obtain F_g. Approximately 77% of the gaseous liquid column height of 1000 ft. is gas. Add this 770 ft. to the original distance to the top of the gaseous liquid column (3900 ft.) to obtain 4,670. This is L'. Multiply L' by dP/dT to obtain 14,010. Enter this value into Fig. 4 and read downward to obtain C, the effective oil fraction of the gaseous liquid column. Then, multiply the height

of the oil column of 1000 ft. by the oil gradient of 0.333 psi/ft. by .22 (effective oil fraction) to obtain 73 psi. The PBHP is the summation of the 25 psi casing pressure plus the gas column pressure of 3 psi plus the gaseous oil column pressure of 73 psi or 103 psi.

The second technique consists of obtaining two acoustic liquid level tests at two different casing pressures. The production rate must be stabilized and equal during both tests. This may take several days. The pressures at the top of both liquid levels can be determined. Extrapolation of the liquid level depth vs the pressure at the top of the gaseous liquid column will give the pressure which exists at the wellbore. Several tests may be taken if desired. For the greatest accuracy, the highest stabilized casing pressure should depress the top of the gaseous liquid column to be slightly above but not at the pump (Fig. 5). The gradient of the gaseous liquid column is constant throughout the column. See Reference No. 2.

The downhole separation of oil and gas can be improved by placing the tubing inlet perforations below the fluid entry from the reservoir. This results in better pump efficiency and often improves acoustic liquid level data. Use a short 2-foot mud anchor if necessary to get below gas entry (Fig. 6). If the pump cannot be set below the formation due to physical reasons or the pump should be up hole for increased capacity, a Modified Poor Boy Gas Anchor should be used (Fig. 7). The gas is permitted to escape upward as the liquid flows downward toward the pump inlet. Joe Clegg (Reference No. 5) presents information on Gas Anchors.

INTERPRETATION OF CHARTS

Two charts on the same well should repeat. If charts do not repeat, the difficulty should be corrected before attempting to interpret the chart. When attempting to record duplicate charts, follow the manufacturer's suggestions concerning well connections, control settings, etc. When identical charts are obtained, but the liquid level is not obvious because of multiple downhole reflections, the liquid level should be moved. A movement on the charts signifies the liquid level.

The liquid level can be raised by shutting-down a producing well. When shutting-down a well, the fill-up rate will depend upon the producing rate of the well and the annular area of the casing. A fill-up chart is shown in Fig. 8. The initial fill-up rate will be as shown on the chart. A decrease in fill-up rate will occur as the liquid exerts back-pressure on the formation. A high liquid level on an acoustic test can be depressed by increasing the casing pressure, if casing gas is produced.

PRINCIPLES OF WELL PRODUCTION

Numerous opinions exist about the proper method to produce wells. Some operators prefer to hold some casing pressure; other operators open the casing to atmospheric pressure. In order to study the factors involved, the following discussion presents some equivalent methods of producing wells and then recommends an operating policy for producing wells. In this article, fluid refers to oil and/or water and/or gas, while liquid refers to oil and/or water.

Vogel's IPR curve has been well documented. Applying this relationship to a producing well with a known SBHP is useful in determining equivalent methods of producing a well so that the effect of varying casing pressure, pump setting depth, and height of liquid over the pump can be predicted. The PBHP is the total of casing pressure, gas column pressure and liquid column pressure. The same PBHP can result from a high casing pressure with

little liquid above the pump or from a low casing pressure with a high liquid column over the pump. If the totals of the casing pressure plus the gas column pressure plus the liquid column pressure are equal in two different ways of producing a well, then the production rate will be the same in both cases.

Fig. 9 shows a well being produced at three different values of casing pressure. In all three cases, the PBHP is the same so the inflow rate is equal. Note that the fluid being produced from the formation and the fluid entering the pump cannot sense whether the surrounding pressure is the result of casing pressure or a gaseous liquid column so the inflow rate from the formation and the pump capacity remain constant. The production from the well is constant in all three cases, both up the tubing and from the casing annulus.

Pressure build-up data accuracy can be improved on a well with a high gaseous liquid column. A casing gas backpressure valve should be used to cause an increase in casing pressure which will result in the top of the gaseous liquid column being depressed. The casing gas backpressure valve should be adjusted until the top of the gaseous liquid column is located immediately above the tubing perforations. The oil and gas production rates, casing pressure and liquid levels must be allowed to stabilize, which may require several days. The PBHP will be the same as originally because the pump capacity and the formation characteristics have not changed. The high casing pressure can be measured with more accuracy than the gradient of the gaseous liquid column can be determined. This technique will improve the accuracy of pressure buildup data on wells having gaseous liquid columns.

After stabilization, the gas production from a well will not be increased or decreased by varying the casing pressure for a constant oil producing rate. After a period which could be up to several weeks during which the fluid in the casing annulus stabilizes, the operator will produce from the wellbore the oil and/or gas that is migrating into the wellbore. The migration rates of oil and gas are dependent upon the difference in pressure between the wellbore and the reservoir, and not upon what fluid was removed to cause the drop in pressure. Thus, the GOR is the same for any certain PBHP regardless of whether the gas is freely produced from the casing, or an attempt is made to restrict gas production by increasing the casing pressure. The casing annulus gas flow rate is the same in both cases and will remain the same unless the top of the gaseous liquid column is depressed to the pump and additional gas is forced into the pump which restricts flow and increases the PBHP.

Figure 10A shows three different methods of producing an oil well (no water) at partial capacity. In all three cases, the PBHP is 500 psi. In Case C, the 500 psi PBHP is the result of a casing pressure of 455 psi plus the gas column pressure of 45 psi. Gas is vented from the casing annulus. In Case D, the PBHP is 500 psi as the result of approximately 1500 ft. of oil above the formation. In case E, the pump is set up-hole which will also result in the 500 psi PBHP when the casing pressure is near 0 psi. The oil gradients and the heights of the gaseous liquid columns are approximately the same. The important factor is the PBHP and these cases are shown for illustrative purposes rather than exact conditions. The resulting PBHP is the controlling factor rather than the amount of casing pressure or liquid column pressure that caused the PBHP. In all three cases, the oil and gas production rates in the formation and from the well are the same after stabilization.

"Skimming" does not occur; the water/oil ratio is not changed by raising the pump if the oil production rate remains constant. Refer to Fig. 10B, cases G and H. These could be an example of a high

volume, high WOR well with the pump set at the formation and then with a raised pump. Oil has a gradient approximately two-thirds of water. If a pump in a high water/oil ratio well is raised approximately two-thirds of the oil column height, the same PBHP will exist. This assumes that the well does not produce gas or that the gas lightening effect in the oil column in case G is the same as in the water column in case H. In all cases shown in Fig. 10B, the same PBHP exists so the production of oil, water and gas will be the same as soon as stabilization occurs.

If the same PBHP exists using any one of numerous methods of producing a well, the oil, water and gas production will be the same. This applies whether the well is produced by beam pumping, hydraulic pumping, gas lift, turbine or any other method. Erroneous conclusions about the proper method to produce a well are sometimes reached on the basis of a brief production test immediately following a change in the manner in which the well is being produced. This test may not be representative of fluid flow from the formation due to changes of fluid content in the casing annulus. For example, if the casing pressure is increased on a well which is being produced with a high gaseous liquid column, the oil production will increase as the gaseous oil column is depressed. A well test during this time will indicate a greater oil production rate than will be obtained after stabilization.

PRACTICAL PRODUCTION CONSIDERATIONS

From the foregoing discussion, the present production, cumulative production and reservoir performance resulting from the manner in which an oil well (no water) is being produced will be the same if (1) the pump is set at the formation with a casing pressure of 100 psi, or (2) the pump is set approximately 300 ft. above the formation and the casing pressure is zero. In either case, the PBHP is approximately 100 psi. Whether the backpressure is the result of an oil column or gas pressure, the actual production from the well will be the same.

In a pumping well, the fact that a well is "pounding" does not necessarily indicate that the maximum production is being obtained. To have a minimum PBHP, the casing pressure must be low and the pump near or below the formation.

When a well is pumped with the casing valves closed, gas collects in the casing annulus and always depresses the liquid level to the tubing perforations unless the liquid pressures at the casing and tubing perforations exceed the bubble-point pressure (no free gas). When high casing pressure depresses the liquid to the tubing perforations, the well will be "pounding". But, the well is not being produced efficiently unless the PBHP is low compared to the reservoir pressure. Do not pump a well with the casing valves closed if a high casing pressure results and the liquid is depressed to the tubing perforations (if maximum production is desired). The liquid capacity of the pump is greatly reduced when the pump is required to handle free gas. The casing valve should be open to the flow line or a gathering system to prevent an excessive casing pressure and PBHP if the well produces free gas at the formation.

For maximum production, a low reservoir pressure well must be produced with low PBHP. For a high SBHP well, a higher PBHP can be tolerated. A PBHP of 100 psi (resulting from 60 psi casing pressure and a 100 ft. oil column due to setting the pump 100 feet above the formation) would not materially restrict the production from an oil well with a SBHP of 1800 psi. But, it would reduce the production rate from an oil well completed in a reservoir with a SBHP of 150 psi to approximately one-half the maximum rate. Refer to Table 1.

For the maximum production, a minimum producing bottomhole pressure is necessary. If mechanically possible, pipe should be set through the formation, the pump set below the formation, and a minimum casing pressure maintained. The casing pressure should be less than 5% of the SBHP if possible. Setting the pump below the formation will permit liquid to enter the wellbore during a short down-time without restricting production from the well since the liquid would not exert a back-pressure on the formation. Naturally, if some unfavorable condition develops through use of this practice, additional consideration, should be given to the method. This type of completion is also useful when gas production from a well has a tendency to gas-lock the pump. The interval of casing between the formation and the pump acts as a separator, with the liquid pumped out of the bottom and the gas bled off the top. This is considerably different from setting the pump above the formation where both the gas and liquid must pass by or through the pump.

ADDITIONAL PRACTICAL FIELD USES

A popular use of the liquid level instrument is to determine whether an oil well, which is responding to a waterflood, is being produced at its capacity. A loss of oil occurs when oil bypasses a producing well because the well has excessive back-pressure. The amount of this oil loss is dependent upon the location of the producing well with respect to other producing and water injection wells, the amount of back-pressure in the well, and numerous other conditions. A substantial loss of oil occurs if oil bypasses a producing well located on the edge of a field and injected water continues to drive the oil into an undeveloped portion of the reservoir.

Liquid level tests will often indicate a particular condition which cannot be found by any other means. For example, if a well producing from a high pressure reservoir had low casing pressure and 100 ft. of liquid above the pump, the pump would not "pound" and the operator would believe that additional fluid could be produced by installing larger equipment. The backpressure exerted by 100 ft. of oil is less than 35 psi. Installing larger equipment to "pump-down" the well would not be justified since only a very small increase in production would be obtained under these conditions.

The liquid level instrument is very beneficial in efficiently producing a high volume well when the well cannot be "pumped down" due to the limited size of the mechanical equipment (and economics do not justify the installation of larger equipment). If the high volume producer has a relatively high PBHP, the pump should be raised off bottom to obtain more production from the well. The proper depth to set the pump for maximum production can be determined in the following manner. See Figure 11. A SBHP and a PBHP with a well test can be used to determine available producing rates at various pump depths. The capacity of the pumping unit at various depths can be calculated from the API 11L bulletin. The equipment can then be sized to a particular well by raising the pump up the hole and enlarging the size of the pump to handle the liquid at that depth. The maximum efficiency from the producing equipment will then be utilized, since the equipment's maximum producing rate for a particular depth will be matched with the well's producing capacity at that depth. The producing rate of the well as the pump setting depth is lowered is plotted on the same graph as the lifting capacity of the equipment with the pump at various depths. The liquid gradient below the pump will be the liquid produced by the well. Normally, this high pump condition exists in high water-oil ratio wells and the liquid gradient below the pump is approximately 0.5 psi/ft. The static liquid level at zero producing rate would be the top of the liquid normally produced by the well supported by the SBHP. Divide the

reservoir pressure by the liquid gradient (approximately 0.5 psi/ft.) to obtain the height of the liquid column at zero production rate. The maximum producing rate is determined on the Well Analysis Sheet. The Vogel curve is adapted to these two points by determining a third point on the chart which is one-half of the height of the column and 70% of maximum production rate. Connect these three points by a smooth curve which resembles the Vogel curve. Plot the pumping unit capacity (obtained by using the API 11L procedure) vs depth on the same chart. The intersection of these two curves gives the maximum producing rate which can be obtained from the well with existing surface equipment. In this particular example, the producing rate would be increased from 200 BPD (30 BOPD and 170 BWPD) to approximately 365BPD (55 BOPD and 310 BWPD) with the pump at 4200 ft. Approximately 25 BPD additional oil would be obtained by raising the pump to the proper depth - an increase of 82%.

Raising a pump from the formation to the top of the oil liquid level in a high volume, high WOR well will decrease production since a heavy, predominantly water column will exist below the high pump, in contrast to a light oil column existing above the pump. Do not raise a pump over two-thirds of the distance to a high liquid level. The pump should normally be raised to a depth about midway between the liquid level and the pump depth and generally, increased in size.

WELL ANALYSIS SHEET

An analysis of a producing well requires knowledge of the PBHP, the SBHP, a well test, and the pump capacity. A convenient form for presenting this data is shown on the WELL ANALYSIS SHEET. In addition to the above data, the producing rate efficiency and the maximum production rates can be determined. The PBHP and SBHP should be expressed as absolute pressures. However, negligible differences will result with use of gauge pressure unless the reservoir pressure is low.

DISCUSSION OF LIQUID LEVEL TEST DATA

Table 2 is a summary of well analysis data. The SBHP, PBHP, producing rate efficiency, well test, maximum producing rate, pump data and remarks are on each well.

Well 1 is being produced efficiently. Well 2 has a high producing rate efficiency. However, the pump capacity excessively exceeds the production, and undue "pounding" in the pump will occur which is damaging to equipment. The pump capacity should be reduced to approximately 25% in excess of the maximum production rate of the well. Wells 3 and 4 have considerable wellbore pressure which restricts the entry of fluid into the wellbore. The pump capacity is in excess of the well's maximum producing capacity, and the excessive PBHP is indicative of a failure in the downhole pump equipment. Smaller pumps which have a capacity of 25% more than the maximum producing rates of the well should be run in these wells.

Wells 5 and 6 have maximum producing capacities exceeding the pump capacity. This often occurs in the later stages of a waterflood and in waterdrive reservoirs. Considerable amounts of fluid are prevented from entering the wellbore due to the high backpressure in the wellbore. Additional fluid production is possible, and the economic feasibility of increasing the pump capacities should be considered. The pump should be raised and increased in size if economics do not justify larger equipment at the formation which can produce all of the available fluids.

Well 7 has a PBHP of 547 psi and a SBHP of 1465 psi. It is being produced at 80 percent of maximum rate. The pump is operating at capacity. For maximum production, a pump with a capacity approximately 25% in excess of the maximum producing rate of 138 BPD should be used.

Well 8 has a PBHP of 103 psi, a SBHP of 1163 psi, and is being produced at 98 percent of its maximum production rate. The 1000 feet of gaseous liquid column above the pump restrict the oil production less then 1 BPD and installing larger equipment would not be justified.

ANALYSIS OF DOWNHOLE EQUIPMENT

A pump needs service if the liquid level instrument indicates excessive liquid above the pump and the maximum producing rate (shown on the Well Analysis Sheet) is less than pump capacity. Determination of a maximum producing rate exceeding pump capacity indicates the need for larger pump capacity. However, if a liquid level test and casing pressure information indicate that the wellbore pressure is already at a relatively low value compared to the SBHP, then pulling and servicing the pump will not increase the production rate.

Liquid level tests are often used to determine the pumping conditions of a new well when the maximum production rate is not known. Trouble with pumping equipment is often encountered in a newly completed well and the acoustic test will indicate if the fluid is being removed from the wellbore.

The dynamometer is a valuable tool to pinpoint a failure in the downhole equipment. The condition of the traveling valve, standing valve, tubing perforations and other possible trouble sources can be readily checked. This will permit the operator to select the proper procedure to correct the equipment failure. A pump "pounding" liquid does not indicate that maximum production is being obtained from the well unless the casing pressure is low compared to reservoir pressure and the pump is set at or below the formation.

SPECIAL RESERVOIR ANALYSIS

Several important reservoir characteristics can be determined by the rate at which the fluid enters the wellbore when a producing well is shut-in or when a shut-in well is put on production. Probably the one most important characteristic that can be measured is the amount of formation damage immediately surrounding the wellbore. Horner[6], Lee[7], Earlougher[8], Miller, et al[9], and numerous other authors offer techniques for obtaining wellbore and reservoir characteristics from BHP build-up and drawdown data. This information is useful in selecting wells for treatment and special consideration.

SPECIAL USES OF THE INSTRUMENT

The instrument records pressure wave reflections from the annular space of any conduit. Any enlargement or obstruction in the annular space is shown on the chart. For example: perforations, liners, parted tubing, shot holes, collapsed casing, tubing anchors, paraffin deposits, salt rings and gas lift valves are recorded. Generally, these conditions produce particular chart characteristics which permit the operator to distinguish which condition is present.

Distance to obstructions or liquid (in gas lines or untubed casing filled with gas) is possible by acoustic travel time and acoustic velocity developed by Podio[10], Thomas[11] or McCoy[12].

The location of the mud level in a drilling well is very useful for safety considerations.

CASING ANNULUS GAS FLOW RATE

The casing annulus gas flow rate can be calculated using the following equation:(See Fig. 8 for annular area) (See Reference 2 for details)

$$Q_g, CF/D = 0.68 \times A \times L' \times dP/dT$$

CONCLUSIONS

Analyzing well performance is a daily job. Careful attention, planning and testing are necessary to determine and maintain favorable downhole conditions. An increase in oil production, more efficient producing methods, better well treatments and lower operating costs are possible with a good well analysis program.

A new computerized Well Analyzer is available to perform the analysis described herein. The Well Analyzer consists of a laptop computer and an analog to digital converter.

The Well Analyzer is used in conjunction with acoustic sensors to obtain acoustic downhole data from which the depth to the liquid level is calculated automatically. The depth to the liquid level is used in conjunction with casing pressure data obtained with a pressure transducer to permit the calculation of a bottomhole pressure even in wells having gaseous liquid columns. This data is used in conjunction with well data contained in a well file data base to present the operator with the well analysis described in this paper. Software performs this analysis automatically for visual display or printout. Request reference #15 for details of system.

The Well Analyzer can be used with dynamometer sensors to acquire and analyze dynamometer data. The compact system permits load, position, and motor current acquisition and analysis. A downhole card is presented for ease of pump performance analysis. Refer to reference #14.

The Well Analyzer permits further in-depth well and reservoir analysis by acquisition and analysis of acoustic data, while unattended, thus permitting pressure transient data acquisition and analysis.

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15. SWPSC Acoustic.

NOMENCLATURE

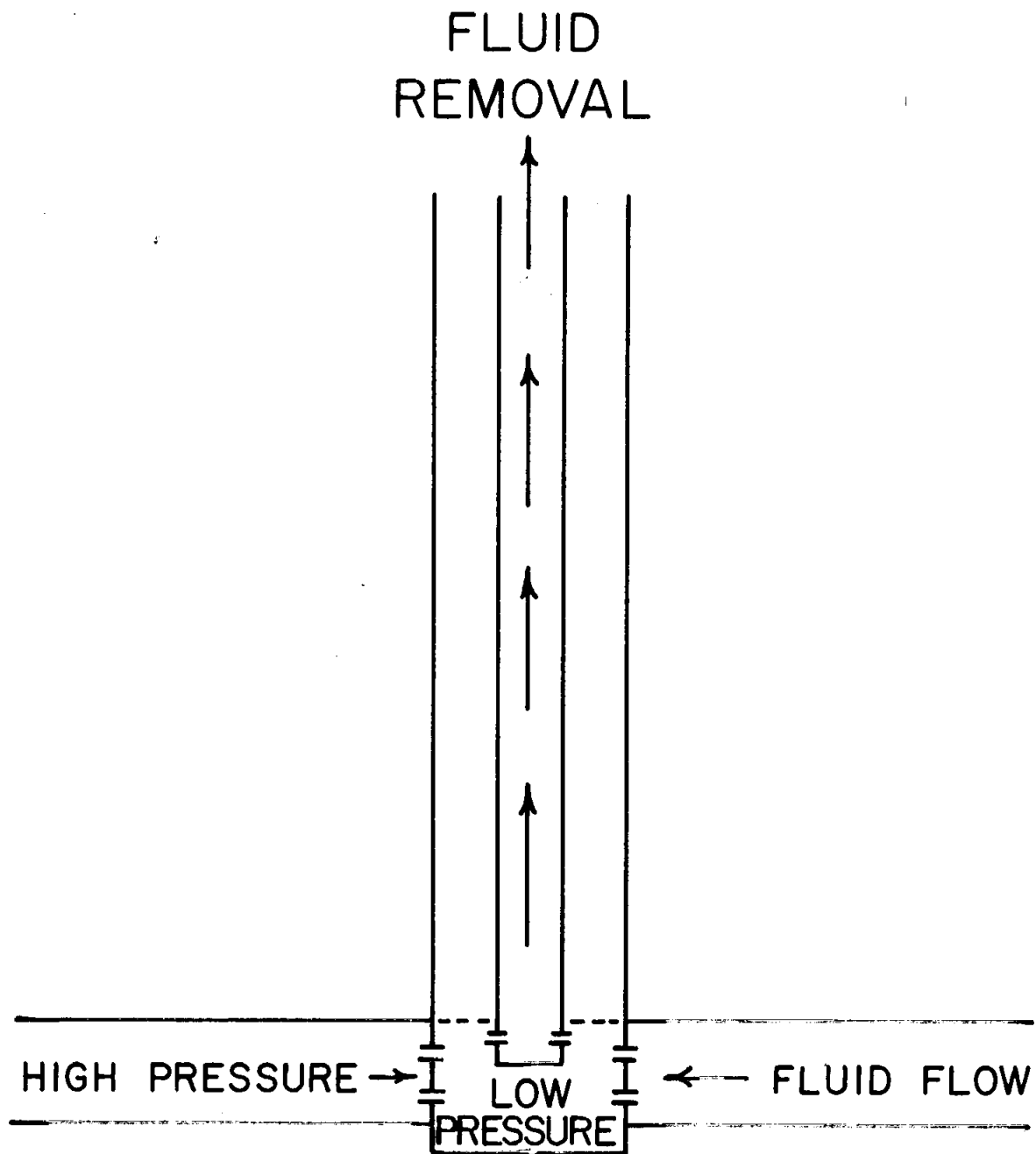|	
A	Annular Area, square inches
BPD	Flow rate, barrels per day
C	Effective oil fraction, approximates the fraction of oil in a gaseous liquid column
D	Depth from surface to formation, feet
dP/dT	Pressure build-up rate, psi/min.
F_g	Gas fraction in a gaseous liquid column. (The portion of a gaseous liquid column which would be gas if the gas and liquid were allowed to separate.)
H	Height of a liquid or gaseous liquid column above the formation, feet
Hos	Height of oil column in a static well, feet
H_p	Height of a liquid or gaseous liquid column above the formation in a producing well, feet
H_s	Height of the liquid column above the formation in a static well, feet
Hws	Height of a water column above the formation in a static well, feet
Lp	Distance from the surface to the top of the liquid or gaseous liquid column in a producing well, feet
L	Distance from the surface to the imaginary oil/gas interface in a gaseous liquid column if the gaseous liquid column were instantly separated, feet
Ls	Distance from the surface to the liquid level in a static well, feet
Pc	Casing pressure, psi
Pcp	Casing pressure in a producing well, psi
Pcs	Casing pressure in a static well, psi
Pgp	Gas column pressure in a producing well, psi
Pgs	Gas column pressure in a static well, psi
Q_g	Gas flow rate, CF/D
Q_0	Oil Production rate, BPD
Qw	Water production rate, BPD
Qt	Total production rate, BPD

FLUID
REMOVAL

HIGH PRESSURE → LOW
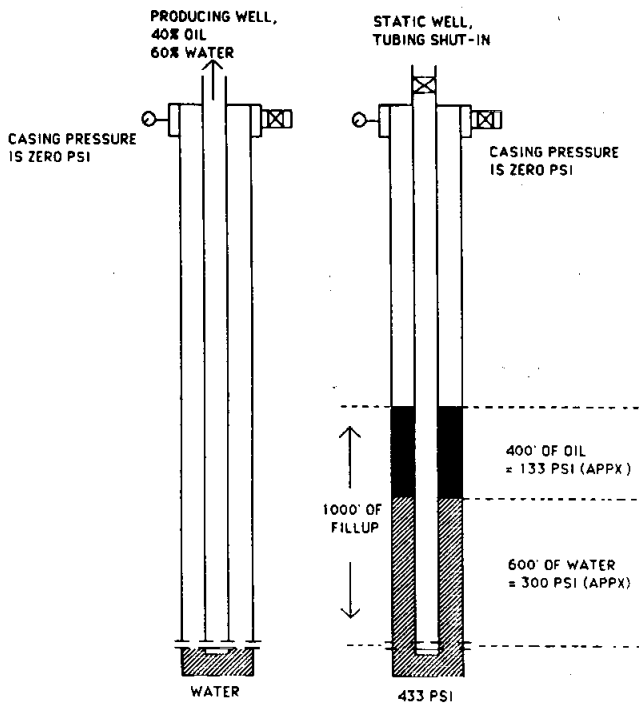PRESSURE ← — FLUID FLOW

FIGURE NO. 1   FLUID FLOW INTO A WELL

PRODUCING WELL,
40% OIL
60% WATER

STATIC WELL,
TUBING SHUT-IN

CASING PRESSURE
IS ZERO PSI

CASING PRESSURE
IS ZERO PSI

400' OF OIL
= 133 PSI (APPX.)

1000' OF
FILLUP

600' OF WATER
= 300 PSI (APPX)

WATER

433 PSI

FIG 2A - DETERMINING SBHP, LIQUID LEVEL AT FORMATION WHILE PRODUCING

PRODUCING OIL WELL,
40% OIL
60% WATER

STATIC WELL,
TUBING SHUT-IN

CASING PRESSURE
IS ZERO PSI

CASING PRESSURE IS
ZERO PSI

500' OF
OIL

ΔH

500' OF
OIL
= 167 PSI (APPX.)

400' OF
OIL
= 133 PSI (APPX.)

1000' OF
FILLUP

600' OF WATER
=300 PSI (APPX.)

500' OF
OIL

$Hws = \Delta H \cdot \frac{Qw}{Qt}$

WATER

600 PSI

FIG 2B - DETERMINING SBHP, LIQUID LEVEL ABOVE FORMATION WHILE PRODUCING

PRODUCING OIL WELL,
5 % OIL
95% WATER

STATIC WELL,
TUBING AND CASING
SHUT-IN

CASING PRESSURE
IS ZERO PSI

CASING PRESSURE IS
ZERO PSI

APPROXIMATELY 75' OF
OIL WILL ACCUMULATE
IN THIS REGION

500'
OF
FILLUP

WOR WILL BE EQUAL TO
OR GREATER THAN THE
PRODUCED WOR

1000' OF LIQUID
THAT HAS A WOR
GREATER THAN, OR
EQUAL TO THE PRO-
DUCED WOR

WATER

WATER

737 PSI

FIG. 2C. - DETERMINING SBHP; LIQUID LEVEL ABOVE FORMATION WHILE PRODUCING

PRODUCING OIL WELL,
40% OIL
60% WATER

PRODUCING OIL WELL,
40% OIL
60% WATER

STATIC WELL,
TUBING AND CASING
SHUT-IN

GAS FLOW

CASING
PRESSURE
IS ZERO PSI

CASING
PRESSURE
IS 330 PSI

CASING
PRESSURE
IS 400 PSI

CASING
SHUT-IN

GAS

2000'
OF
OIL

200' OF OIL
= 67 PSI

500'
OF
FILLUP

300' OF
WATER
= 150 PSI

WATER

WATER

630 PSI

FIG. 2D.- DETERMINING SBHP; IMPROVED TECHNIQUE
FOR GASEOUS LIQUID COLUMN.

AMPLIFIER
RECORDER

MIC

BLAST

(((ECHOMETER)))

ANOMALY

CASING
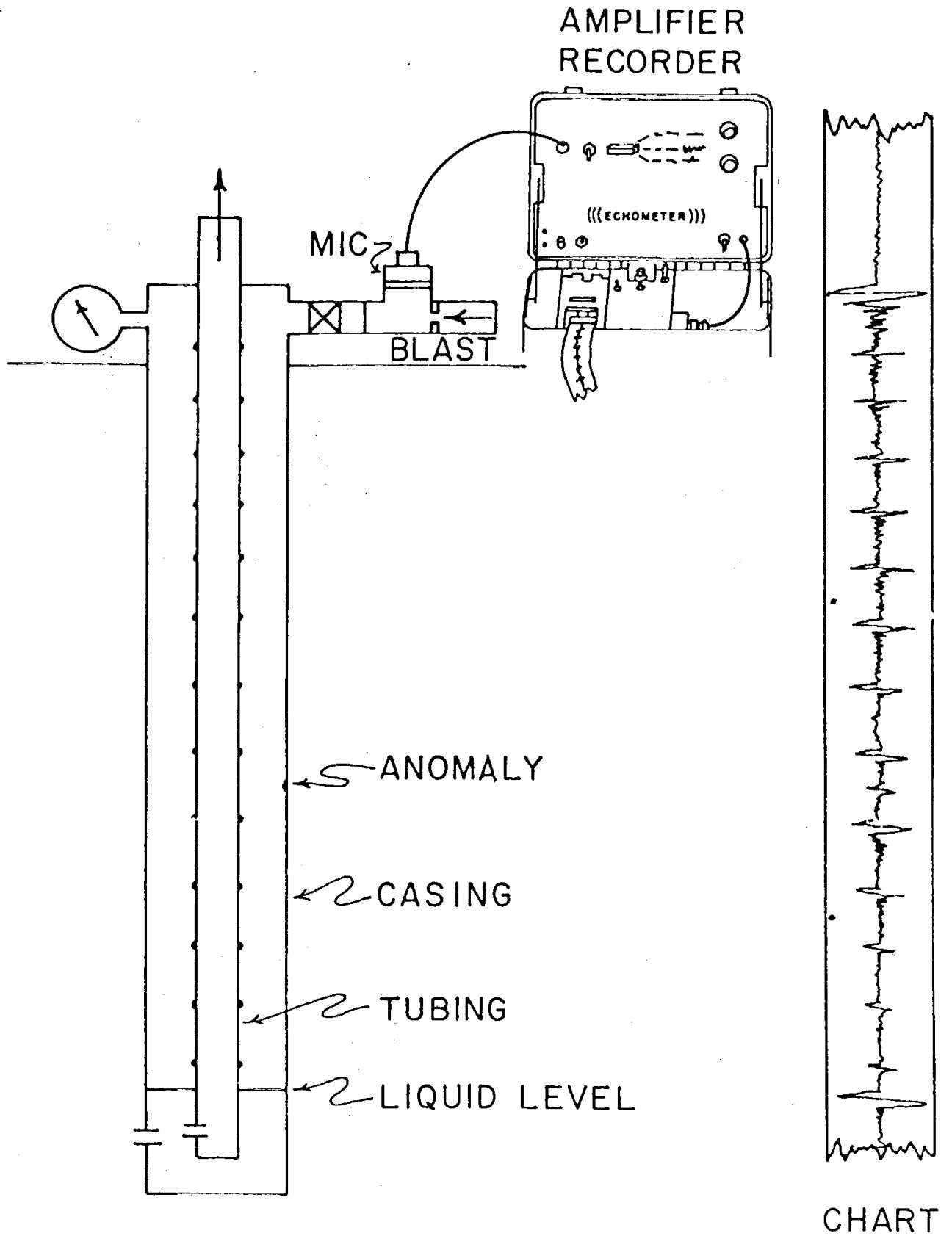
TUBING

LIQUID LEVEL

CHART

FIG. 3   ECHOMETER SYSTEM

TABLE I

WELL	RESERVOIR PRESSURE PSIA	PRODUCING BOTTOM HOLE PRESSURE PSIA	WELL TEST		TOTAL BPD	PUMP CAPACITY BPD
			BOPD	BWPD		
1	1800	100	86	3	89	105
2	150	100	86	3	89	200
3	166	10	25	5	30	190
4	340	170	45	10	55	57

TABLE 2 - WELL ANALYSIS DATA

Well	SBHP (psi)	Depth to Liq. (ft.)	Casing Pressure (Pc)	Pc Buildup Rate, dP/dT (psi/min)	PBHP @ Formation	Producing Rate Eff. (percent)	Well Test, BPD		Max. Producing Rate (BPD)		Pump Cap (BPD)	Remarks
							Oil	Total	Oil	Total		
1	1000	4805	20	1	23@4800'	99	60	64	61	65	73	OK
2	980	4800	5	0	26@4860'	99	98	105	99	106	172	OK
3	1020	3900	10	0	311@4800'	87	17	22	20	25	95	DEF
4	1010	4500	300	.5	389@4800'	78	4	87	5	111	157	DEF
5	1000	2500	10	.1	698@4900'	47	88	197	187	419	168	PPC
6	1040	4900	750	2	872@4900'	27	69	96	256	355	68	PPC
7	see 7s1	4910	470	0	547@4900'	80	66	110	83	138	113	PPC
7s1	1465	4400	1100	0	4900'							SBHP
8	see 8s1	3900	25	3	103@4900'	98	26	105	26.5	107	125	OK
8s1	1163	4900	1000	0	4900'							SBHP

The PBHP and SBHP were determined in gauge pressure because of negligible error and ease of data presentation.

Assumed Oil Gradient = 0.333 psi/ft
Assumed Water Gradient = 0.50 psi/ft
Assumed Pgc = Pc*L'/30,000

DEF: Downhole Equipment Failure
PPC: Producing Pump Capacity, consider larger pump and/or raising pump.
SI: Shut-in for SBHP: Pump set at formation on all wells.

Pump Data

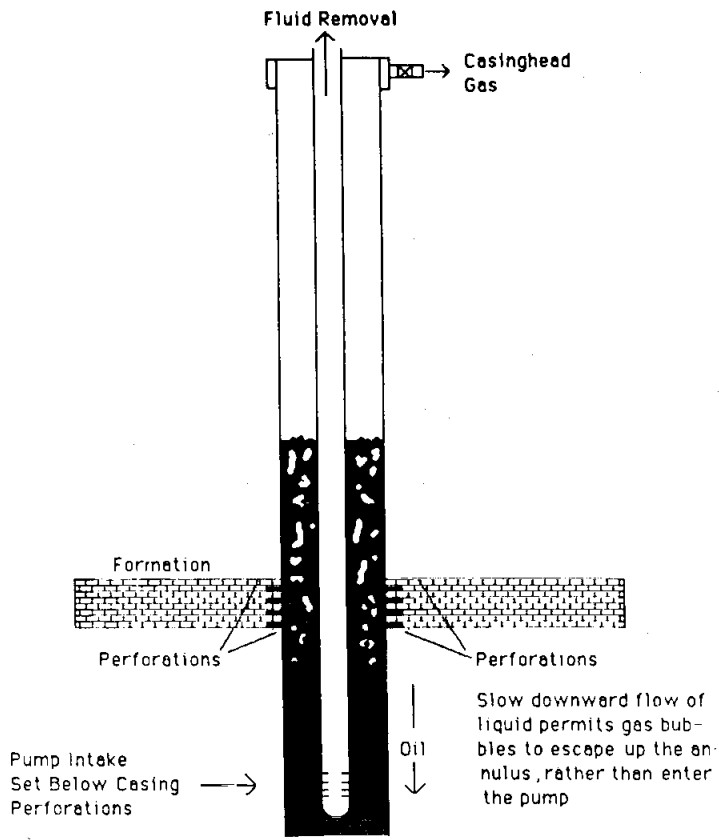| WELL #	Rod and Tubing Size, (In.)	Number of Strokes and Length, (In.)	Pump Size, (In.)
1	3/4 X 2	12 X 54	1 1/16
2	3/4 X 7/8 X 2	16 X 54	1 1/2
3	3/4 X 2	12 X 48	1 1/2
4	3/4 X 7/8 X 2	15 X 54	1 1/2
5	3/4 X 7/8 X 2	16 X 54	1 1/2
6	3/4 X 2	16 X 34	1 1/2
7	3/4 X 2	12 X 54	1 1/2
8	3/4 X 2	13 X 54	1 1/2

Fluid Removal

→ Casinghead Gas

Formation

Perforations — — Perforations

Pump Intake
Set Below Casing ——→
Perforations

Oil

Slow downward flow of
liquid permits gas bub-
bles to escape up the an-
nulus, rather than enter
the pump

Fig 6 - Natural Gas Anchor

Tubing

Casing

Gas Anchor

Downward Flow of Liquid
Should Be Less Than
1/2 Ft./Sec.

Dip Tube

Casing
Perforations —

Casing
Perforations

Fig. 7 - Modified Poor Boy Gas Anchor

PRODUCTION RATE, BARRELS PER DAY (x-axis)

FILL-UP RATE, FEET PER MINUTE (y-axis)

PIPE SIZE, IN.	ANNULAR CAPACITY BBLS/1000 FT.	A-ANNULAR AREA IN.²
2 X 4-1/2	10.8	8.7
2-1/2 X 4-1/2	8.2	6.6
2 X 5-1/2	19	15
2-1/2 X 5-1/2	16	13
2 X 7	35	28
2-1/2 X 7-1/2	32	26

Curve labels: 2" X 4-1/2", 2-1/2" X 4-1/2", 2-1/2" X 5-1/2", 2" X 5-1/2", 2-1/2" X 7", 2" X 7"

FIGURE 8 — FILL-UP RATE FOR VARIOUS PRODUCTION RATES IN DIFFERENT SIZES OF PIPES

Pc =100

-107 psi
@ 2070'

Pc =250

-282 psi
@ 3820'

Pc =400

STABILIZED

1) LIQUID LEVEL

2) CASING PRESSURE

3) CASING GAS FLOW RATE
   (SAME AS ORIGINAL)

4) WELL TEST
   (SAME AS ORIGINAL)

5) PBHP
   (SAME AS ORIGINAL)

477 psi
@ 5770'

6000'

500 psi   500 psi   500 psi

(A)   (B)   (C)
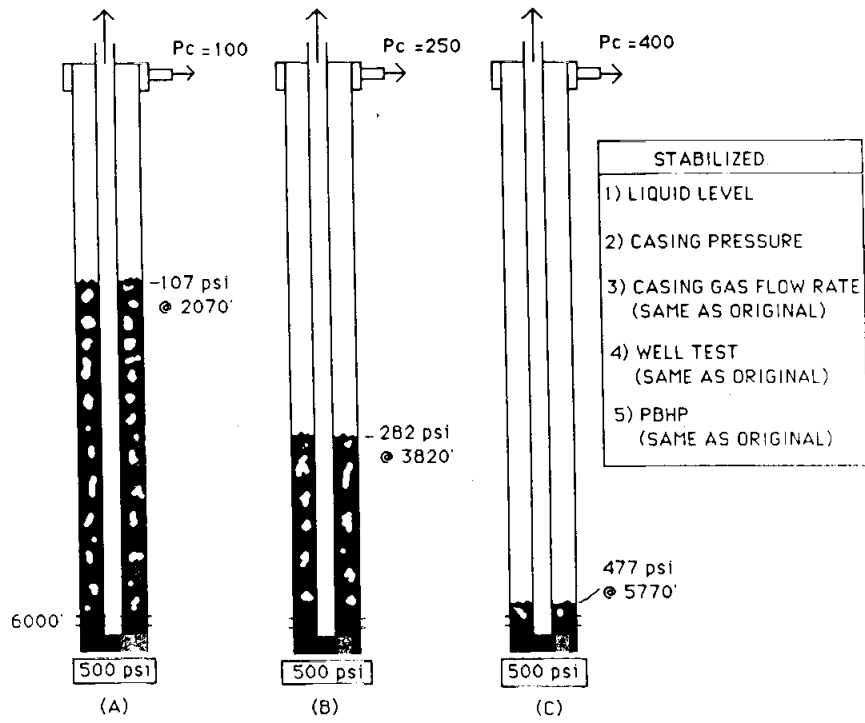
FIGURE 9 – EQUIVALENT PRODUCTION TECHNIQUES
(SEE FIGURE 5)

455 psi   Pc=0 psi   Pc=0 psi   455 psi   Pc=0 psi   Pc=0 psi

Liquid level is
approximately
1500 feet above
perforations

Liquid level is
approximately
1500 feet above
formation at
tubing perfora
tions

Liquid level is
approximately
1500 feet above
perforations

Liquid level is
approximately
1000 feet above
formation

Gas

Gas

Oil

Oil

Oil

Oil

Oil &
Water

liquid near,
ut above
erfs

Liquid near
but above
perfs

Oil

Gas

Oil

Oil &
Water

Water

Oil &
Water

Water

Water

500 psi   500 psi   500 psi   500 psi   500 psi   500 psi

(C)   (D)   (E)   (F)   (G)   (H)
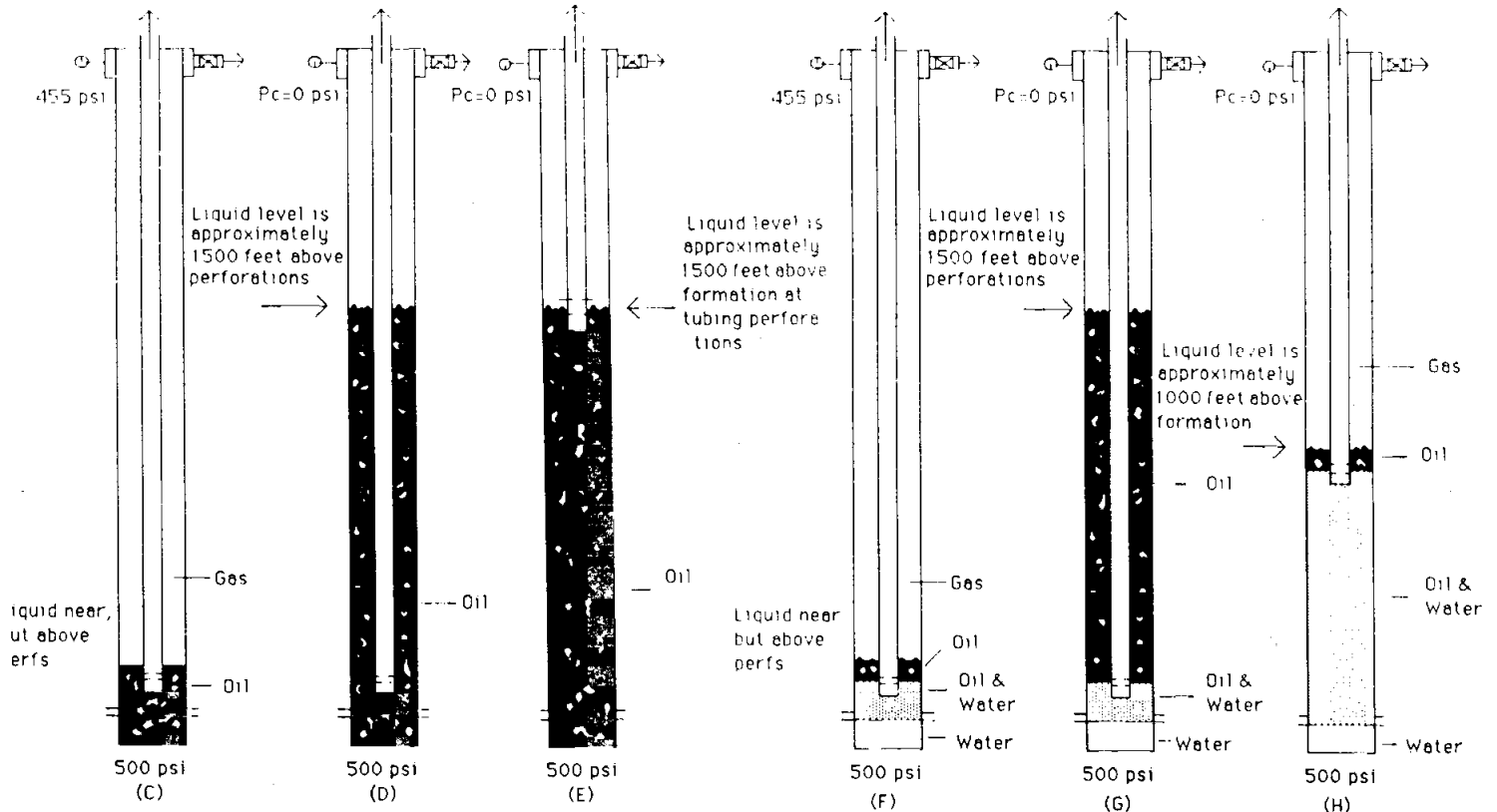
Fig 10 A - Methods of Producing an Oil Well at Partial Capacity

Fig 10 B - Methods of Producing an Oil and Water Well at Partial Capacity

Data:
   Static Bottomhole Pressure = 2000 psi
   PBHP = 1500 psi
   Producing Rate = 200 BPD (30 BOPD and 170 BWPD)
   Formation and Pump Depth = 6000 ft.
   Pumping Unit: 228,000" # Gear Box

See Well Analysis Sheet:
   PBHP/SBHP = 1500/2000 = 0.75
   Producing Rate Efficiency (PR%) = 40%
   Maximum Production Capability of Well:
   Qt*100/PR% = 200*100/40 = 500 BPD

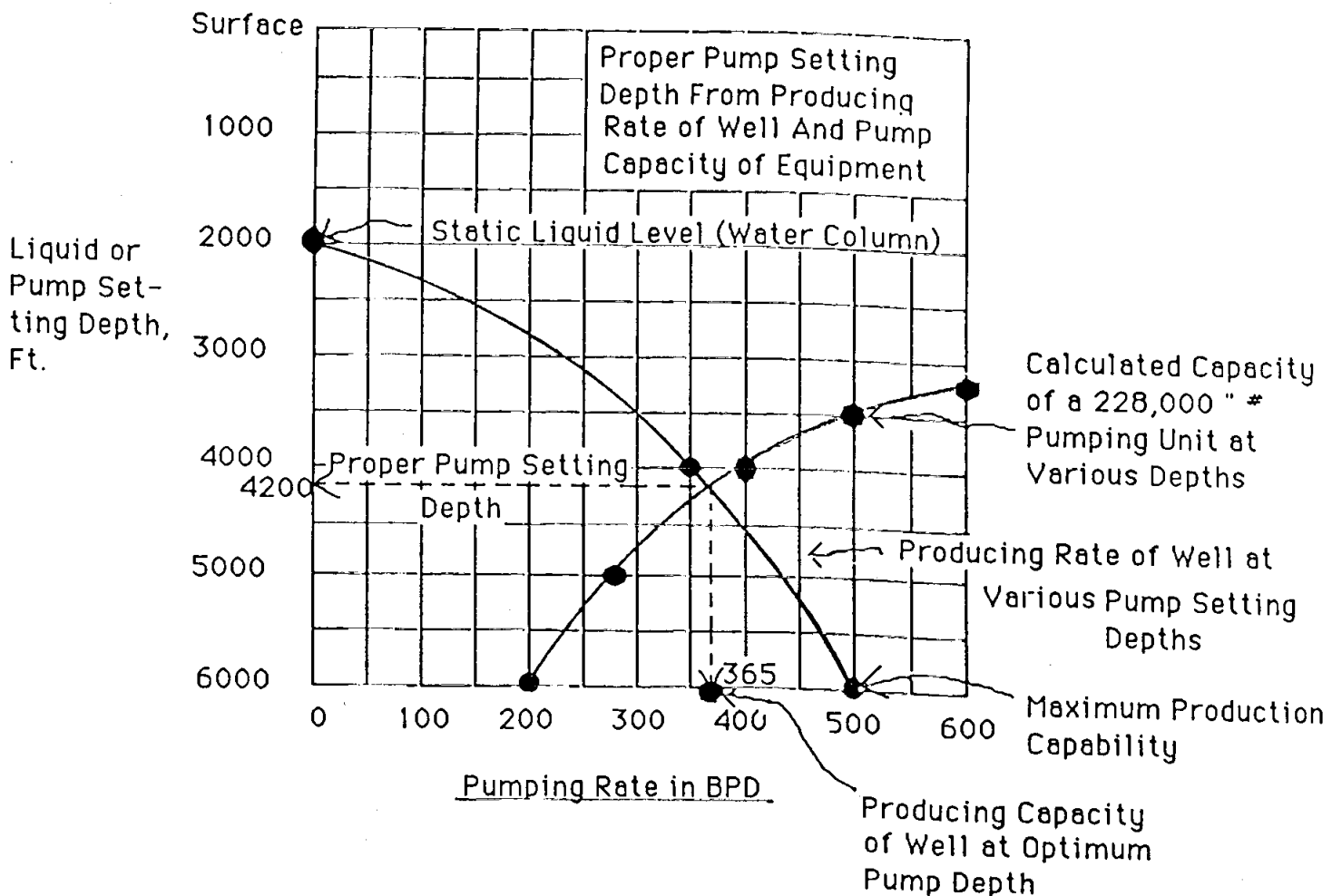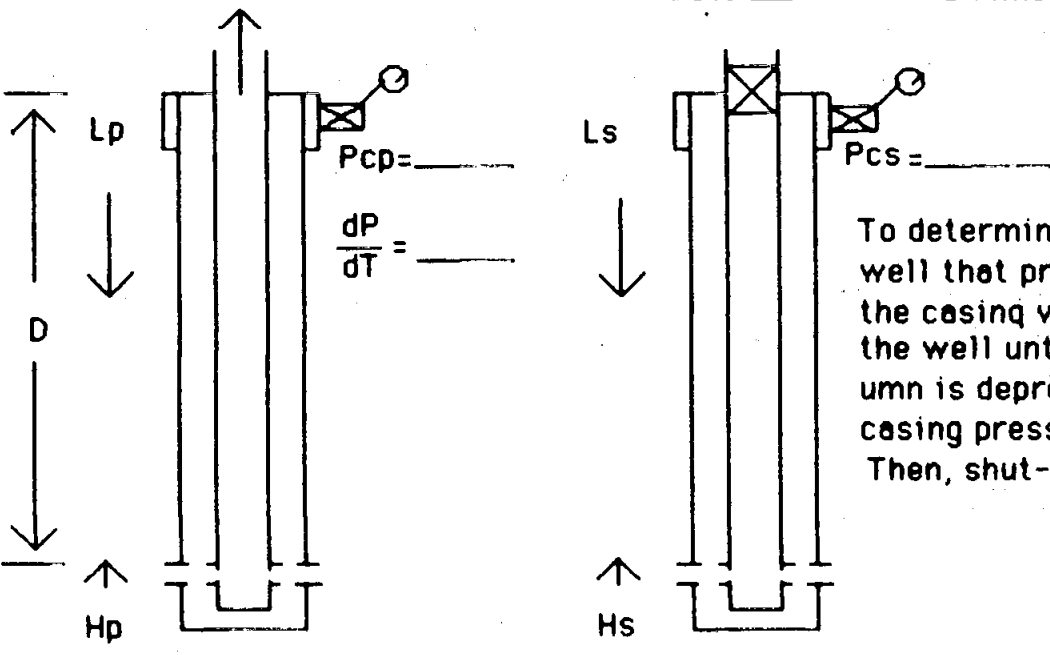Fig. 11 -Well Producing Capacity and Equipment Capacity Vs. Depth

Well _____ Date _____ Time _____

Lp

Pcp= _____

$\frac{dP}{dT}$ = _____
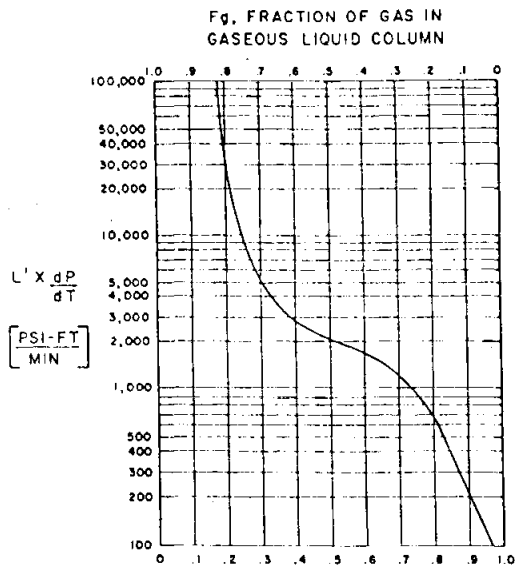
D

Hp

Ls

Pcs = _____

To determine the SBHP in a pumping well that produces casing gas, close the casing valve and continue to pump the well until the gaseous liquid column is depressed to the pump and the casing pressure becomes a maximum. Then, shut-in the tubing.

Hs

Fg, FRACTION OF GAS IN GASEOUS LIQUID COLUMN

$L' \times \frac{dP}{dT}$

$\left[\frac{PSI\text{-}FT}{MIN}\right]$

C, EFFECTIVE OIL FRACTION

ECHOMETER GASEOUS LIQUID COLUMN CORRECTION CURVE

WELL DATA

Formation Depth, Ft. _____ D

Oil Gravity, API _____

Oil Gradient, Psi/FT. = 61.3/(API+131.5) = _____

Water Specific Gravity = _____ SG

Water Gradient, Psi/FT. = .433*SG = .433*_____ = _____

Oil Production, Bpd = _____ Qo

Water Production, Bpd = _____ Qw

Total Production, Bpd = _____ Qt

PRODUCING BOTTOMHOLE PRESSURE

Depth to Liquid, Ft. = _____ Lp

Casing Pressure, Psi = _____ Pcp

Gas Column Pressure, Psi = Pcp*Lp/30,000 = _____*_____/ 30,000= _____ Pgp

Oil Column Length, Ft. = D-Lp = _____ - _____ = _____ Hp

Casing Pressure Buildup Rate, Psi/Min. = _____ dP/dT

Lp* dP/dT = _____ * _____ = _____ Fg = _____ (from graph)

L' = Fg*Hp+Lp =(_____*_____)+_____ = _____ L'

L' * dP/dT = _____ * _____ = _____ C = _____

Oil Column Pressure, Psi = Hp*C*Oil Grad. = _____ * _____ * _____ = _____ Po

PBHP, Psi = Pcp+Pgp+Po = _____ + _____ + _____ = _____

Casing Pressure, Psi.= _____ Pcs

Gas Column Pressure, Psi. =Pcs*Ls/30,000=_____ *_____/ 30,000 = _____Pgs

Water Column Height,ft. = [Hs-(Hp*C)]*Qw/Qt =[____-(____*___)]*_____/_____ = _____Hws

Note: Hp=0 if liquid level was at the pump when the well was shut down.

C=1 if gas is not produced up the annulus while the well is being produced.

Oil Column Height, Ft. = Hs-Hws = _____ - _____ = _____ Hos

Oil Column Pressure, Psi = Hos*Oil Gradient = _____ *_____ = _____ Pos

Water Column Pressure, Psi = Hws*Water Gradient = _____*_____ = _____ Pws

SBPH,Psi. = Pcs+Pgs+Pos+Pws = _____ +_____+_____+_____ = _____

Producing Rate Efficiency

PBHP/SBHP =_____ /_____=_____

Producing rate as a percentage of maximum (from IPR graph)   _____ PR%

Maximum Production Capability of Well

Maximum Oil Rate, BOPD = Qo*100/PR% =_____* 100 / _____ = _____

Maximum Total Rate, BPD = Qt*100/PR% = _____*100/_____ = _____

Pump Data

Pump Size, in. _____PS

Strokes per minute _____SPM

Length of stroke, in. _____

Rod size, in. _____

Tubing size, in. _____

Rod Stretch, in.(-)_____
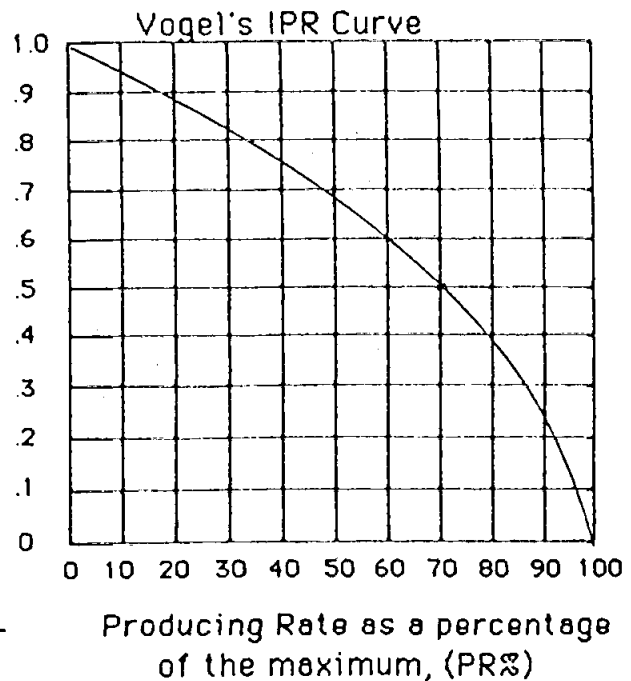
Tubing Stretch, in.(-)_____

Impulse Factor _____

Overtravel, in.(+) _____

Net Stroke, in. _____ NS

Pump Capacity, BPD = $0.1166*NS*SPM*PS^2$

= $0.1166*$_____$*$_____$*($_____$)^2=$_____

Vogel's IPR Curve

PBHP / SBHP

Producing Rate as a percentage of the maximum, (PR%)

Remarks: _____

_____

_____