A PRIMER TO DST CHART INTERPRETATION

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INTRODUCTION

Qualitative interpretation of drill stem test (DST) pressure-time charts often is more of an art than a science. However, logical and efficient interpretation can be easily accomplished by understanding the basic factors involved in producing a chart. No two DST charts are exactly the same, and thus the guidelines given in this paper are designed to be general in nature. With knowledge of the basic DST shapes and forms in mind, even complicated charts can be broken into components and satisfactorily interpreted.

A DST is a temporary completion of an interval within a well to help determine as much useful reservoir information as possible about the interval. The fluids recovered from a DST help describe the fluid type available from the reservoir and how well it may flow. The pressure-time chart is a valuable record of the test events and serves to validate the test results.

At the wellsite, a properly interpreted DST chart also can give an indication of important reservoir parameters, such as productivity, permeability, pressure, and wellbore damage. In addition, determination of reservoir characteristics such as depletion, supercharge, permeability anomalies, and multiple zones often is possible when the chart interpretation is coupled with information such as reservoir geology.

Finally, the quantitative pressure-time DST data can be analyzed using standard industry pressure transient analysis methods. These can yield valid numerical approximations of important reservoir parameters, and further support the chart interpretation. Quantitative analysis will not be covered in this paper.

FUNDAMENTALS

To conduct a drill stem test various tools are run into the well on the drill stem, hence the name. Although there is a broad spectrum of tools available to cover the equally broad range of DST conditions, in a conceptual form there are only five tools necessary for a complete test.

Figure 1 illustrates the five fundamental components necessary for a DST, as shown in an open hole environment. The drill pipe carries the other tools to the bottom of the hole and acts as a conduit into which the fluid, hopefully oil or gas, may flow during the test. The packer seals off the reservoir from the rest of the hole and supports the drilling mud within the annulus during the test. The valve assembly controls the test, allowing the reservoir to flow or be closed-in as desired. The perforated pipe allows fluid to enter the tool string. The pressure-time gauges record the events of the test. Usually a minimum of two gauges are run for comparison of results and to check for mechanical difficulties during the test.

The charts, recordings of the pressure-time events of the test, are recovered from the gauges. Figure 2 is a hand-drawn, idealized chart showing the events of a generic DST. The axis configuration shown, pressure increasing downward and time increasing to the right, is common in the industry. However, this is only a function of the type of gauge used, and the shapes and forms to be discussed will still apply regardless of the gauge configuration. For comparison purposes in this paper, the "standard" chart in Figure 2 is considered to have resulted from a test on a well in the center of an infinite-acting, homegeneous, isotropic, and uniform reservoir.

Beginning on the baseline, a zero-pressure reference line, the gauge records the various events of a common DST as shown in Figure 2. Pressure increases while tripping in the hole due to increased mud hydrostatic head. After isolating the reservoir with the packer and opening the valve assembly, the gauges measure the pressure in the drill pipe. This will begin at almost zero for empty drill pipe, then increase as hydrostatic head builds up with liquid production during a flow period. If a water blanket or other cushion is installed in the drill pipe the initial opening pressure will begin at the cushion hydrostatic pressure, and then start increasing.

The flow of fluid from the reservoir will draw down its pressure; then upon closing in the well the reservoir pressure will begin to recharge. The idealized chart shows a test with two flow and closed-in periods, a very common practice. At the conclusion of the test the hydrostatic pressure of the mud is released back on the reservoir, bringing it completely back under control, and the tools are withdrawn from the well.

With increased chart reading experience several general observations can be made about the test procedure and events. A few examples of these are given in Figure 3. The interpretation of these observations as well as the flow and closed-in periods should always agree with the other information available, such as the hole and test data, job log, and equipment data.

RESERVOIR PARAMETERS

There are four reservoir parameters which can be estimated from the pressure-time changes recorded on a DST chart: productivity, permeability, pressure, and wellbore damage. Productivity, or the well's ability to produce, is determined from the flow periods. The productivity, used in combination with the quickness of pressure recharge during the closed-in periods, yields an idea of the reservoir permeability. If the closed-in periods build to near stabilization, reservoir pressure may be estimated. Finally, a comparison of flow and closed-in information yields an estimate of wellbore damage.

Figure 4 is an accurate reproduction of an actual chart, with parameters similar to the idealized chart. On this and most of the actual charts used in this paper, the additional horizontal lines below the baseline are in 1000 psi increments, and the numbers shown are references to the test and gauge used.

The steepness of a pressure-time line reflects the rate at which pressure is building up or releasing. During flow periods this indicates the speed with which hydrostatic head is increasing within the drill pipe: the steeper the line the greater the productivity. During the closed-in periods this indicates the speed with which the reservoir is able to recharge pressure to the wellbore after a flow period: the steeper, or quicker, the pressure buildup the greater the permeability. Figures 5 through 10 illustrate a range of possibilities.

Damage may be considered to be an infinitesimally thin ring right around the wellbore, with very low permeability, which requires a substantial pressure drop across it to allow flow. This leads to conflicting information on a chart. During the flow periods damage will restrict the well from flowing at full productivity and thus not allow drawdown in the reservoir as might be expected. Upon closing in the tools the pressure will recharge very quickly to the wellbore. Hence the conflicting information: the chart shows low productivity but quick pressure recharge. By contrast, negative damage, or wellbore stimulation, will allow increased reservoir drawdown and thus the corresponding closed-in buildup will take longer than might be expected. Figures 11 through 16 illustrate the interpretation of damage from charts.

RESERVOIR CHARACTERISTICS

The preceeding interpretation of reservoir parameters has been based on DST's from liquid producing wells assumed to be in the center of an infinite-acting, homogeneous, isotropic, and uniform reservoir. This assumption, however, is never truly valid. Quite often interpretation of possible reservoir characteristics, such as depletion, supercharge, permeability anomalies, and multiple zones, can be made from charts resulting from a test on a non-ideal reservoir. The interpretation of these characteristics should always be substantiated by all other test results available, including applicable quantitative analysis where possible.

Depletion is the partial exhaustion of reservoir energy during the flow periods of a DST, most often due to a limited size reservoir. Note the word used is reservoir "energy," not "reserves," as the DST chart measures pressure response, and is not commonly applicable to estimation of reservoir size. The two main indicators of depletion are loss of closed-in pressure and loss of productivity, as idealized in Figure 17. It is important to recognize that both indicators are necessary to conclude depletion, not just one of the indicators by itself. For instance, apparent loss of productivity can occur during the flow periods simply due to the buildup of hydrostatic back pressure within the drill pipe.

Supercharge is the buildup of excess pressure around the wellbore due to non-dissipated hydrostatic head from the mud filtrate. It most likely exists in low to medium permeability reservoirs drilled highly overbalanced. If the first flow period of a DST is not long enough to relieve the supercharge, the first closed-in may build to an excessive, or false, pressure not indicative of true reservoir pressure. Figures 17 through 23 show examples of reservoir depletion and supercharge characteristics.

Permeability anomaly is a generic term used to cover all changes in permeability with radial distance away from the wellbore. The possibilities include reservoir boundaries such as sealing faults, pinchouts, and facies changes, fluid contacts, and dual porosity and naturally fractured systems. As illustrated in Figure 24, the idealized behavior is an increasing radius during the closed-in period buildup. This behavior takes on several appearances so that accurate interpretation of the exact anomaly present is seldom possible. In addition, the closed-in buildup usually will not stabilize and thus estimating static reservoir pressure is difficult. Finally, depletion often accompanies detection of an anomaly, as both may be indicating reservoir boundaries. Chart examples of a permeability anomaly are shown in Figures 25 and 26.

It is assumed that the tested interval contains only one zone. If distinctly different multiple zones exist within the tested interval it is possible to see the influence of each zone during a closed-in period. However, layered reservoirs are seldom so clearly defined, and may appear as a permeability anomaly. Figures 27 through 29 illustrate the detection of multiple zones open to flow during a DST.

The interpretation of reservoir characteristics is a difficult art to master, and the interpretor should always consider all other information available. For instance, geologic knowledge that the tested reservoir is a fractured carbonate leads to the expectation of a buildup showing a permeability anomaly. In another instance, the loss of extrapolated reservoir pressure from first to second closed-in on a standard semilog analysis plot may help confirm depletion. To further complicate interpretation, multiple characteristics easily can exist within a given reservoir, as shown in the chart illustrations, and the relationship between them should be considered also.

GAS WELLS

Gas has no appreciable hydrostatic weight compared to liquids, and thus a gas well DST chart usually will not show a continually increasing pressure throughout the flow period. As illustrated in Figure 30, the flow period pressure ideally will level out as the flow of gas to the surface stabilizes. Pressure increases may be due to flow of rat-hole fluid, mud filtrate or condensate into the wellbore, or to pressurization of the wellbore against a choke prior to stabilized flow. A decrease in pressure from the end of the first flow to the beginning of the second flow frequently occurs due to bleedoff of pipe pressure during the first closed-in. Figures 31 and 32 show examples of gas test charts.

Gas reservoir parameters can not be accurately interpreted without knowledge of the surface equipment used during the test. For instance, a medium flow pressure against a small choke may indicate a fairly low production rate, but against a large choke may indicate a high rate. Also, choke size may be changed several times during a flow period, and different sizes will cause different flow pressures as recorded on the chart. Figure 33 shows step-like decreases in pressure during the flow period as progressively larger chokes are installed; the larger chokes are less restrictive and thus exert less back pressure. Note that pressure increases upward in Figure 33, but the chart fundamentals, baseline, trip in, flow (against a full cushion), closed-in, and trip out are still present and behave according to the basic guidelines given.

Gas well DST reservoir characteristics can be interpreted in the same manner as those from liquid well tests, keeping in mind the differences in flow period response. For instance, a depleting gas well will show the character-

1. Vertical sweep efficiency.

2. Time response thus dynamics of vertical sweep.

3. Best thin bed resolution of monitoring tools.

4. Integrity of cement which is important in fiberglass wells.

Radioactive tracers with different half-lives have been injected into separate zones in the same injector to determine if they commingle in the reservoir. The zones in the monitor well may not be connected to the zones in the injector. By monitoring with a high frequency, the decay of the response has been interpreted to be proportional to the amount of a particular tracer in that zone. This has obvious problems since fluid movement in the reservoir constantly changes the tracer concentration at the monitor well bore. This will give a similar response to the change in concentration of tracer with a particular half-life. The NGT is a good solution to this problem. Different tracers have different energy levels. On the tracers materials tested the longer the half life the higher the energy observed. The NGT with its five energy windows can measure the difference in the energy spectrum of the radioactive tracers. The result can be displayed in terms of the percentage of each tracer in each zone similar to its use to determine the amount of different clays. Different tracers can be injected into alternate zones of various injectors at offsetting times with the previous four results as well as:

5. Zone communication in reservoir.

6. Areal sweep effeciency.

7. Three dimensional modelling of sweep.

8. Lower logging costs since less frequent monitoring can give accurate results.

Resistivity Monitor

This monitor procedure is run on fiberglass cased wells. Often IES is used because of its thin bed resolution. By injecting waters of known salinity usually starting with a fresh water, followed by brine, then CO_2 and then brine again, the effect of waterflooding can compare to CO_2 flooding. The oil saturation is determined using traditional Archie equations for before and after CO_2 flooding thus indicating the sweep efficiency. The CNL monitor is usually run at the same time as resistivity monitor.

istic loss of pressure from first to second closed-in, but the loss of productivity will appear as a continually decreasing flow pressure. Note that a gas well may flow for a long time before reaching a stabilized rate, and thus decreasing flow pressure alone by no means verifies depletion. Figures 34 through 36 show charts of gas well DST's with various reservoir characteristics.

COMMON PROBLEMS

Problems can occur on a DST due to the great number of factors influencing the test, such as test procedure, tool configuration and hole conditions. While experience is the best teacher for interpreting DST problems, a few simple guidelines will help narrow down the possible causes. Referring back to the fundamental tool diagram, Figure 1, note that there are only three different regions of pressure available during a common DST. These are: the pressure above the valve assembly within the drill pipe (be it liquid hydrostatic head or flowing gas pipe pressure); the recharging reservoir pressure below the valve assembly during a closed-in period; and the hydrostatic head of the mud in the annulus. Because a chart records pressure with time, deviations from the expected often can be traced by evaluating the changes in pressure based on the three sources available.

Open hole testing can be very difficult due to unstable hole conditions. An inadequately conditioned hole may have fill on the bottom resulting in several potential problems. These may include difficulty reaching bottom, sliding the tools to bottom upon opening causing gauge overtravel, and sticking the tools creating the need to jar loose when the test is completed (Figure 3).

The most common open hole problem is plugging, the partial or complete sealing off of flow restrictions by hole debris. Plugging can occur in either of the two flow restrictions in a tool string, the perforated pipe or the valve assembly (Figure 1). Figure 37 shows the sudden spikes of pressure buildup and release indicative of major plugging. As debris seals off flow through a restriction, the gauge upstream of the plugging no longer registers the increasing head in the pipe, but rather a quickly building "closed-in" pressure from the reservoir. Then, when the pressure builds high enough to blow the plug free, the pressure suddenly releases. Repetitions of this rapid buildup and release result in the sawtooth flow periods shown in Figure 37. Obviously the severity of the plugging can vary greatly. The location of the plugging can be estimated as illustrated in Figure 38 when two gauges are used in the tool string as shown in Figure 1.

Inadequate hole conditions can lead to meaningless test results, as shown by the test in Figure 39. Bad enough hole conditions or an unstable packer seat can lead to a total misrun as shown by the first attempt to test in Figure 40. Note that at point 4 in Figure 40 there is a sudden increase in pressure. This is interpreted as a momentary packer failure by evaluation of the pressure sources available. During the closed-in period the only source of pressure greater than the building reservoir pressure is that of the mud hydrostatic in the annulus. Thus it is concluded that communication, or leakage, around the packers is occurring, allowing the higher pressure to be registered.

Communication can also occur through the valve assembly during a closed-in period, resulting in leakage of the higher reservoir pressure up into the lower pressured drill pipe, as in Figure 41.

Finally, a leak in the drill pipe itself can occur, leading to increases in pipe pressure when none should occur, such as during the closed-in periods, as shown in Figure 42.

An improperly prepared or operated gauge can record incorrect information, problems which are a function of the gauge alone. Examples of this are shown in Figures 42 and 43. Lastly, severe conditions during a test may adversely affect a chart recording. For example, the firing of perforating guns to begin the flow period of the cased hole test in Figure 44 produced such severe gauge vibrations that the stylus assembly was shifted within the gauge. The accuracy of the recorded pressures beyond this point is highly questionable.

The problems shown in these examples are typical, but far from inclusive. However, most problems encountered can be logically explained by keeping in mind the possible sources of pressure available, the events which occurred and the conditions present during the test.

SUMMARY

1. A chart from a standard DST is a record of the events of the test, such as trip in, flow, closed-in, and trip out, and these should correspond with all other available test information.

2. Changes in pressure with time during the flow and closed-in periods of a DST can be interpreted to describe reservoir parameters such as productivity, permeability, pressure, and wellbore damage.

3. Deviations from the results expected from a test on a well in an infinite-acting, homogeneous, isotropic, and uniform reservoir can be interpreted to describe reservoir characteristics such as depletion, supercharge, permeability anomalies, or multiple zones.

4. Charts from gas well tests will be different than those liquid tests because gas has relatively no hydrostatic weight, a factor which normally will be reflected by non-uniform buildup of pressure during the flow periods.

5. A wide range of problems can occur on DST's due to variations in test procedure, tool configuration and hole conditions.

6. For any given DST chart, the general guidelines illustrated in the given examples can be used in combination with all other test information available to lead to an accurate and meaningful chart interpretation.

ACKNOWLEDGEMENTS

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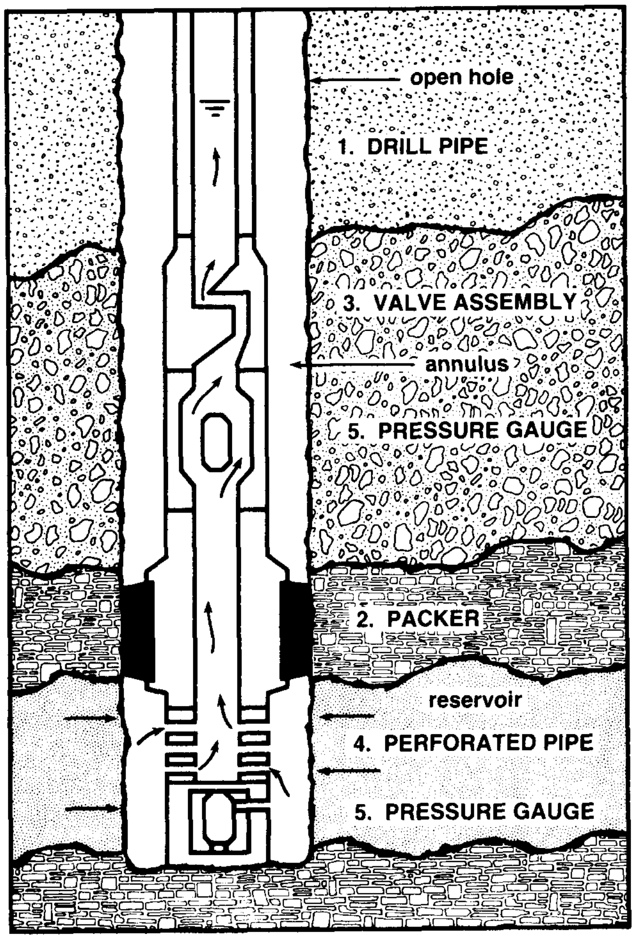

Figure 1 - Fundamental tool string necessary for basic DST. Packer set and valve open to allow flow from reservoir into drill pipe.

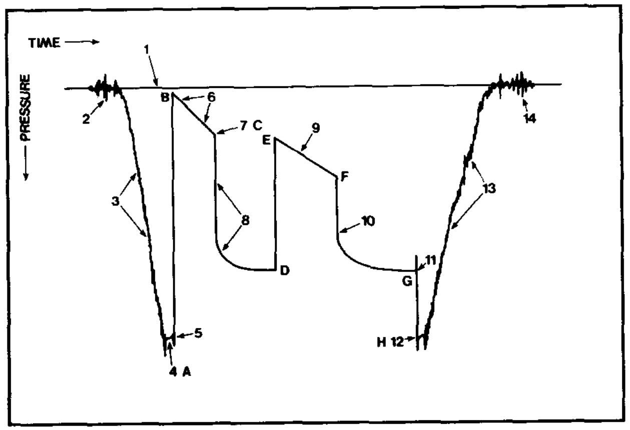

Figure 2 - Idealized DST pressure/time chart recording.

1. Baseline
2. Making up tools
3. Tripping in hole
4. On bottom, setting packer
5. Packer set, valve opening
6. Flowing liquid into pipe
7. Valve closed
8. Closed-in pressure buildup
9. Second flow period
10. Second closed-in period
11. Valve by-passed, mud hydrostatic released back on reservoir
12. Packer pulled loose
13. Tripping out of hole
14. Breaking down tools

A. Initial hydrostatic
B. Initial first flow
C. Final first flow
D. Final first flow
E. Initial second flow
F. Final second flow
G. Second closed-in
H. Final hydrostatic

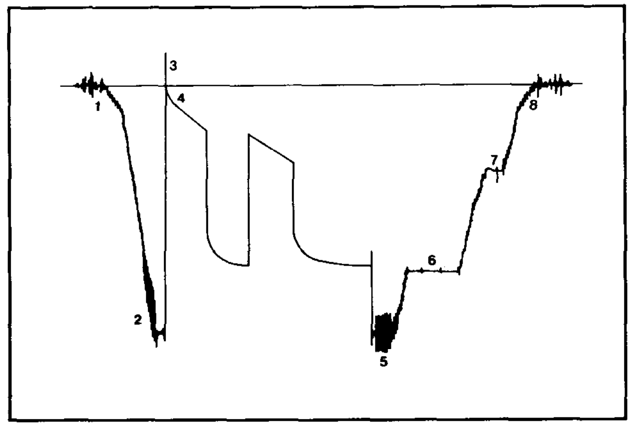

Figure 3 - Frequent chart observations.

1. Running collars
2. Difficulty tripping in hole
3. Gauge overtravel upon opening
4. Collar break (pipe diameter change)
5. Jarring to pull loose
6. Waiting on daylight
7. Reversing out recovery
8. Pulling collars

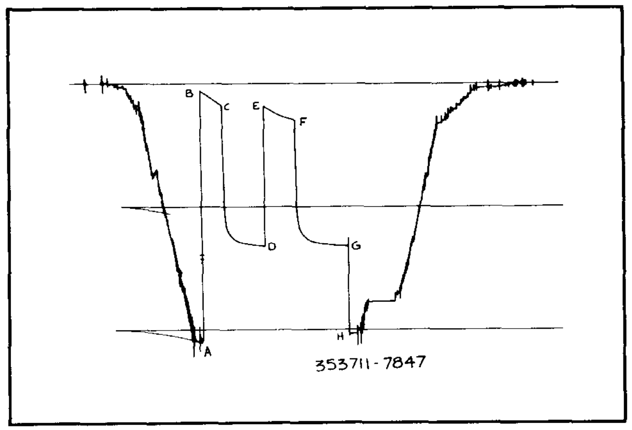

Figure 4 - Reproduction of actual chart; indicates medium productivity and permeability, reservoir pressure about 1350 psi, and no wellbore damage.

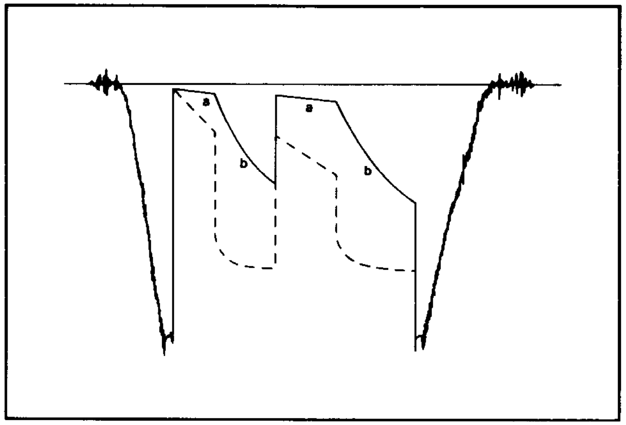

Figure 5 - Low productivity and permeability. As compared with idealized chart (dashed line), shallow slope of flow period (a) indicates low productivity, and, with the slow buildup during the closed-in period (b), low permeability. Can not accurately estimate reservoir pressure.

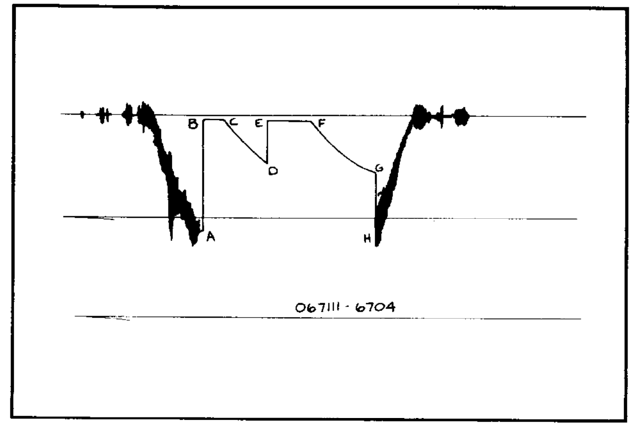

Figure 6 - Low productivity and permeability.

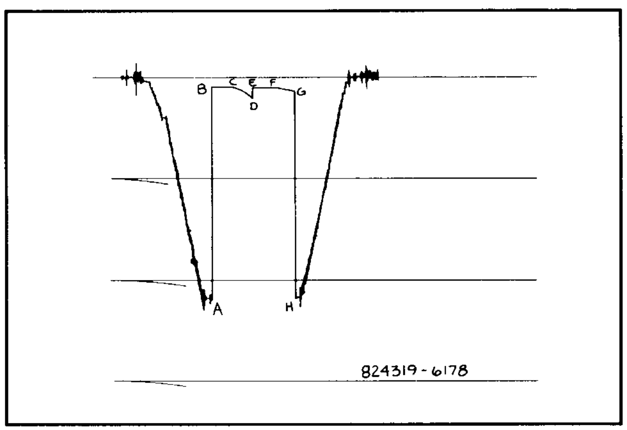

Figure 7 - Very low productivity and permeability. Horizontal flow period lines indicate no liquid influx during flows.

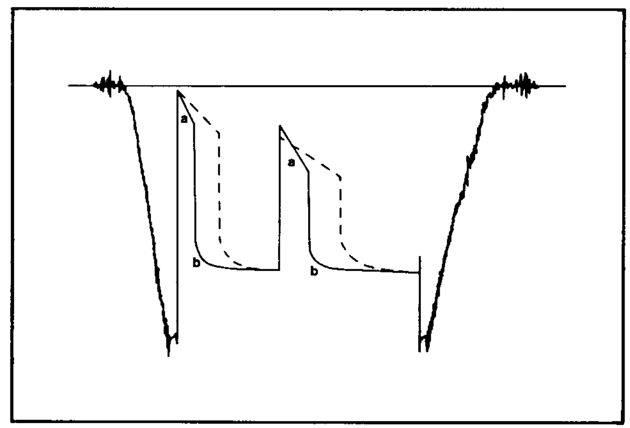

Figure 8 - High productivity and permeability. As compared with idealized chart (dashed line), steep slope of flow period (a) indicates high productivity, and, with quick closed-in buildup (b), high permeability. Reservoir pressure about equal to second closed-in pressure.

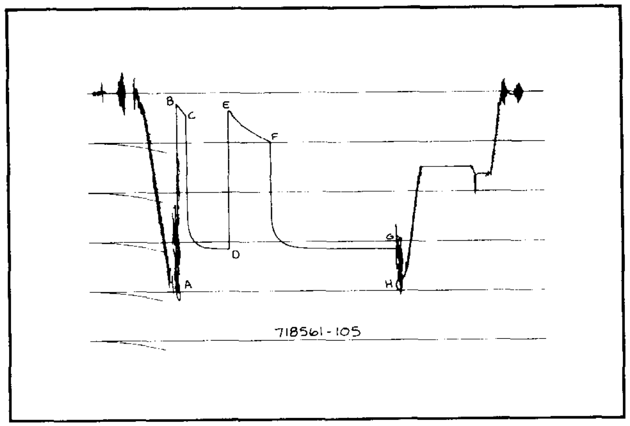

Figure 9 - High productivity and permeability, reservoir pressure about 3200 psi.

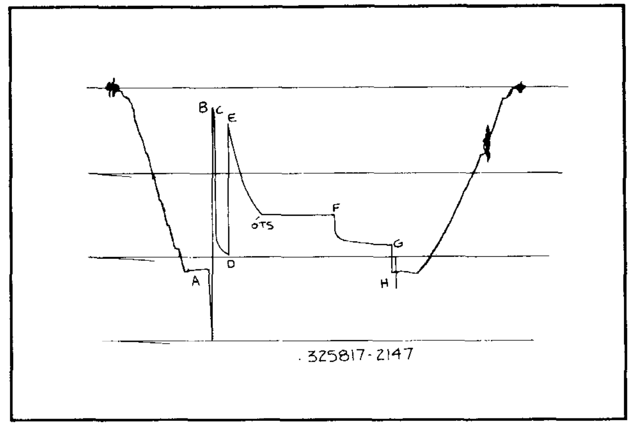

Figure 10 - Very high productivity and permeability, reservoir pressure about 1900 psi. Well flowed oil to surface during second flow period at OTS.

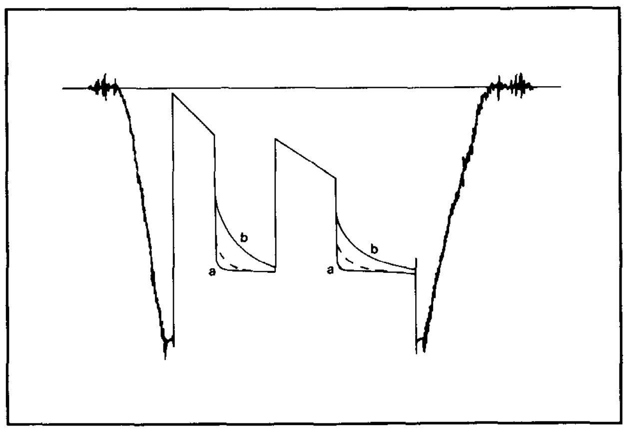

Figure 11 - Wellbore damage. As comapred with idealized chart (dashed line), quicker buildup (a) indicates positive damage, and longer, drawn out buildup (b) indicates negative damage, or stimulated condition.

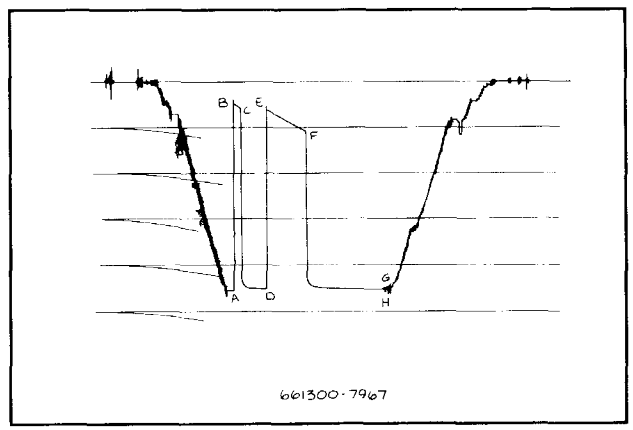

Figure 12 - Positive wellbore damage; medium productivity indicated, high permeability, pressure about 4550 psi.

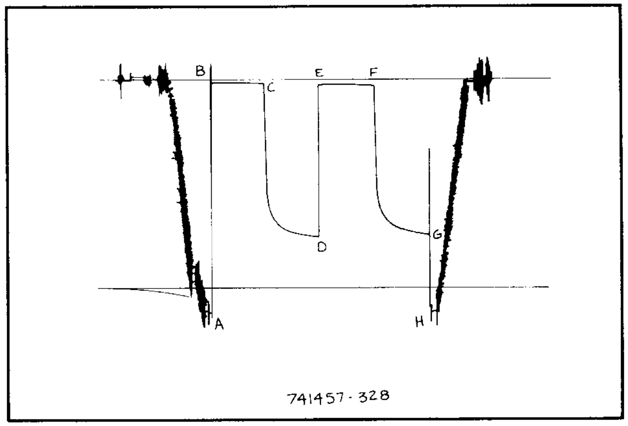

Figure 13 - Positive wellbore damage; low productivity and permeability.

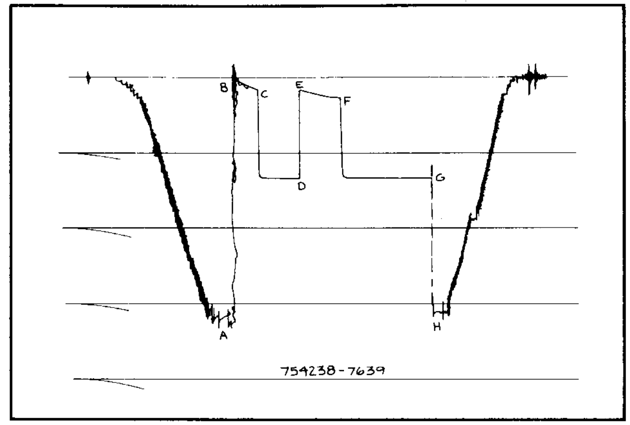

Figure 14 - Very severely damaged wellbore.

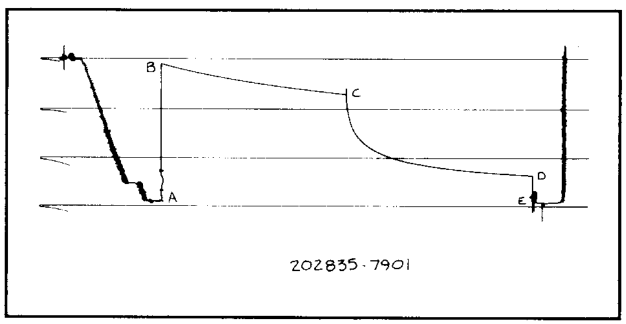

Figure 15 - Negative wellbore damage. Broad, slow buildup following low to medium productivity indicates stimulated conditions.

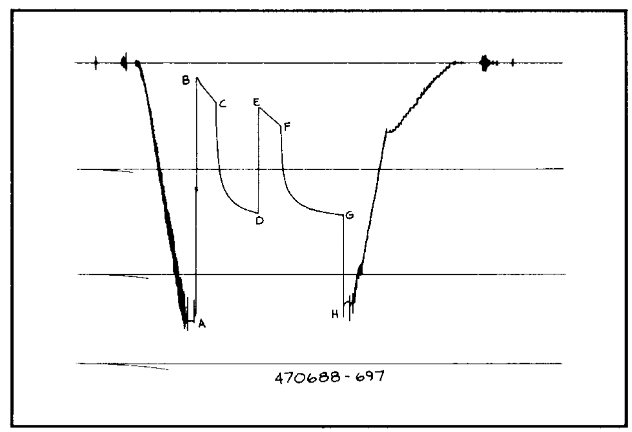

Figure 16 - Negative wellbore damage, medium productivity and permeability.

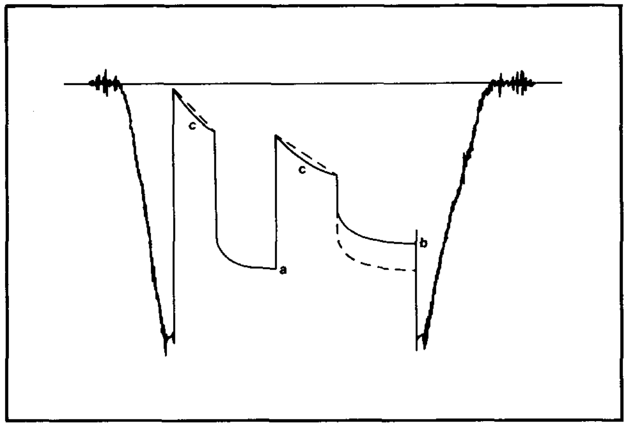

Figure 17 - Depletion of reservoir energy during test. Chart shows reservoir losing pressure from first (a) to second (b) closed-in periods, and slowing productivity during flow periods (c).

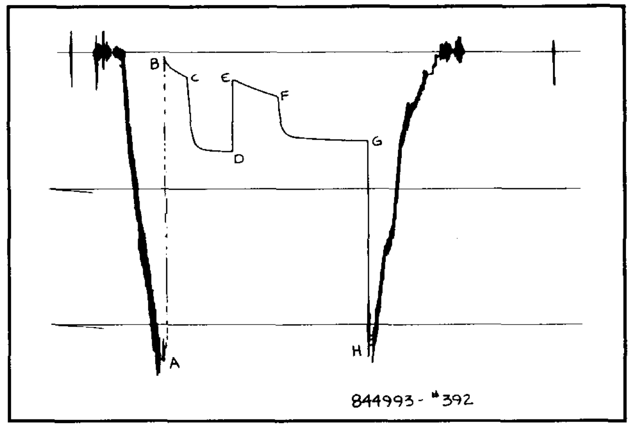

Figure 18 - Reservoir depletion; loss of pressure from first to second closed-in, and slight loss in productivity during flows.

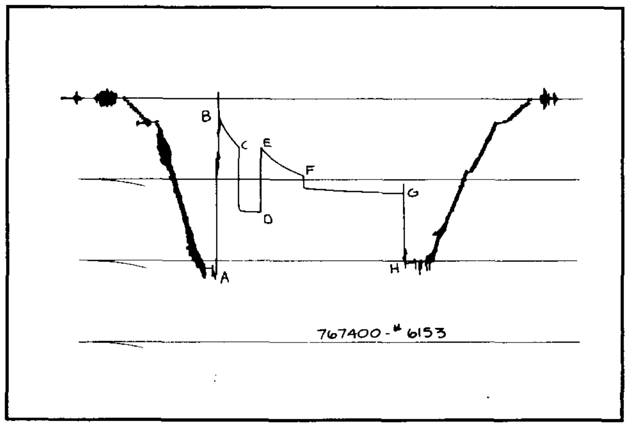

Figure 19 - Reservoir depletion of highly productive and permeable interval.

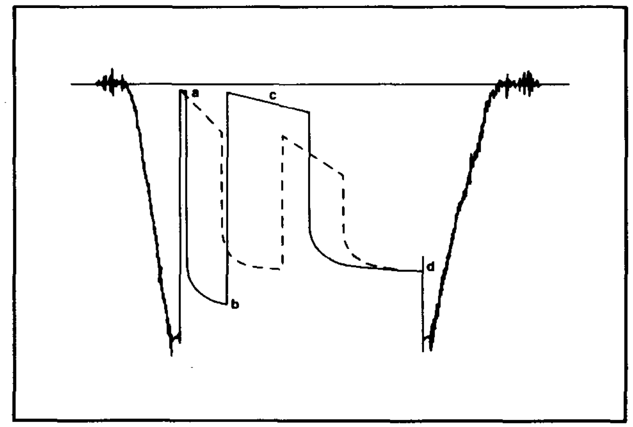

Figure 20 - Supercharged conditions around wellbore. Very short first flow period (a) is not long enough to release supercharged, or overpressured zone around wellbore, resulting in abnormally high first period buildup (b). Constant productivity during second flow (c) indicates no depletion, and second buildup (d) gives more realistic approximation of reservoir pressure.

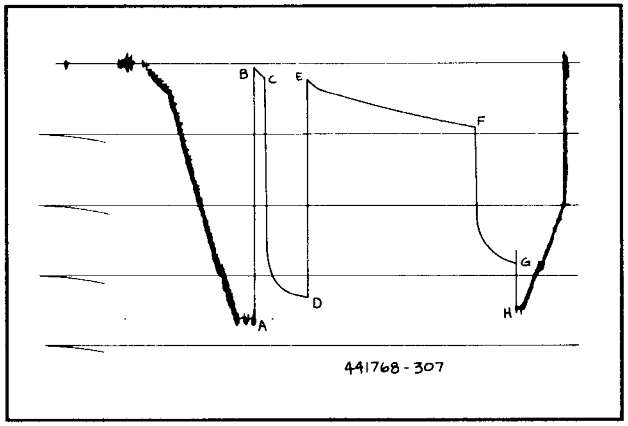

Figure 21 - Supercharged conditions around wellbore.

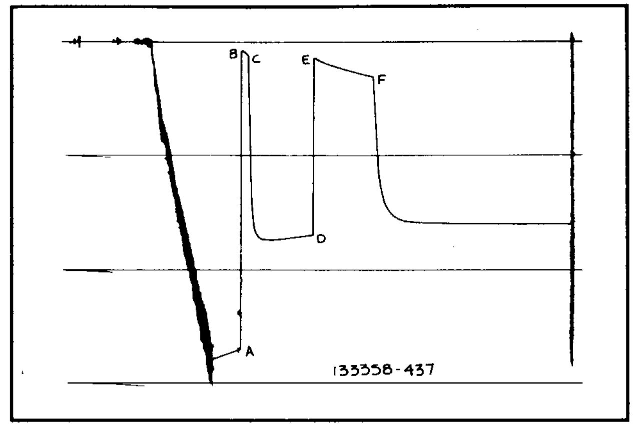

Figure 22 - Supercharged conditions; but first closed-in is long enough to allow reservoir to begin absorbing excess pressure.

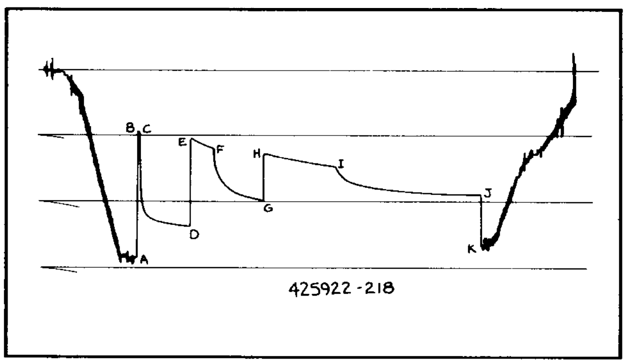

Figure 23 - Combination of supercharge and depletion. Substantial loss of pressure from first to second closed-in after very short first flow indicates supercharged conditions, but continued loss of pressure to third closed-in and loss of productivity during second and third flows verifies depletion also.

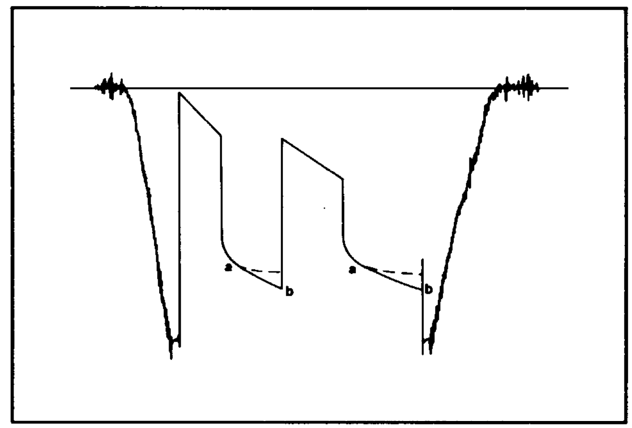

Figure 24 - Permeability anomaly detected during test. After initial bend in buildup (a), curve increases in radius. Closed-in pressures (b) not necessarily indicative of stabilized reservoir pressure.

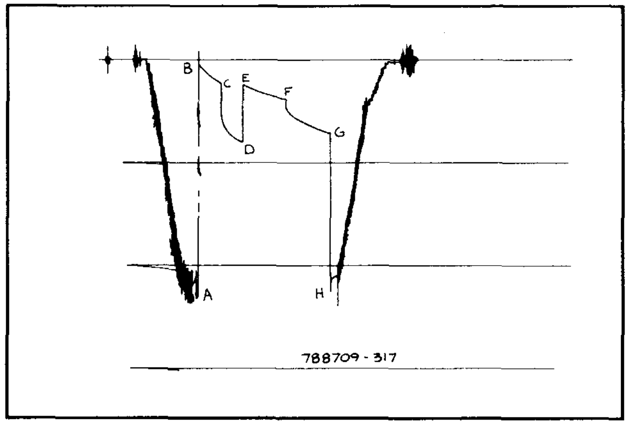

Figure 25 - Permeability anomaly detected during test. First closed-in not long enough to verify presense of anomaly, but good indication shown by increasing radius during second buildup.

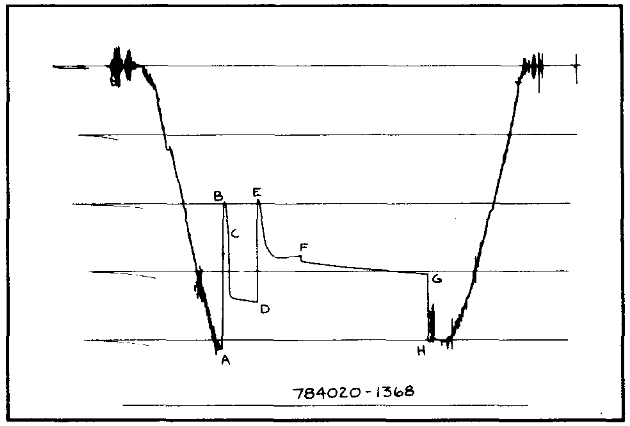

Figure 26 - Combination of permeability anomaly and depletion. Buildup curves show anomaly, and loss of pressure from first to second closed-in along with inability to stabilize flowing oil pressure during second flow indicate depletion.

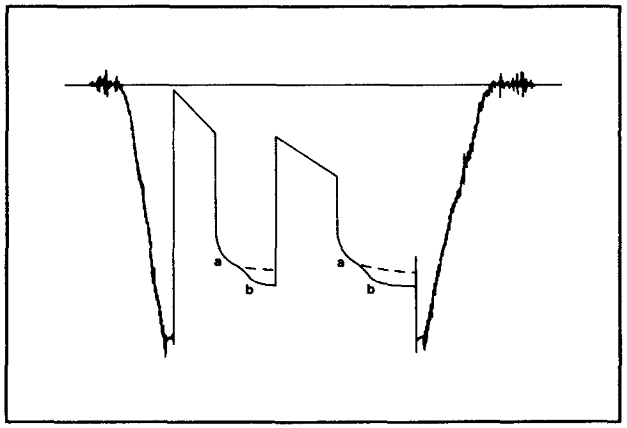

Figure 27 - Multiple zones open to flow during test. Early buildup of pressure by higher permeability zone (a) is overtaken by buildup from lower permeability (slower responding), higher pressure zone (b).

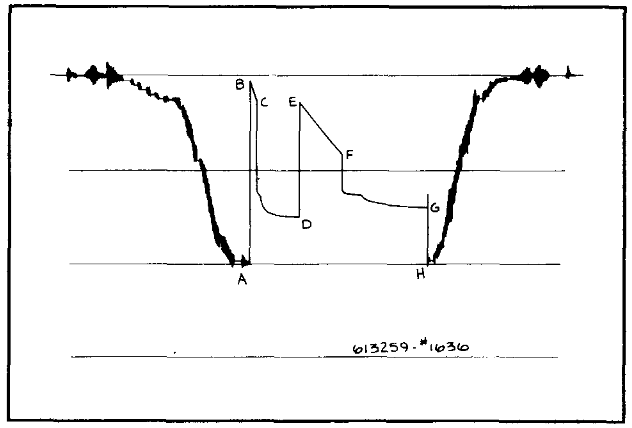

Figure 28 - Multiple zones open to flow during test. Distinctly different zone parameters; first zone has about 1300 psi, but second zone with lower permeability and higher pressure builds up and ends test with about 1400 psi. Note that second zone loses pressure from first to second closed-in, indicating possible supercharge or depletion.

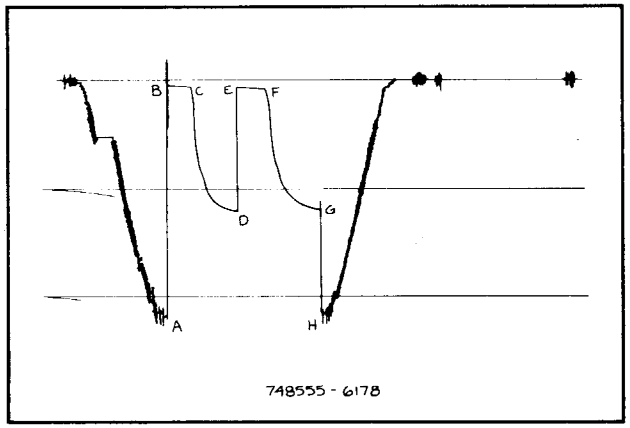

Figure 29 - Multiple zones open to flow. Low productivity and permeability, very subtle wave in buildups indicating possible multiple zones.

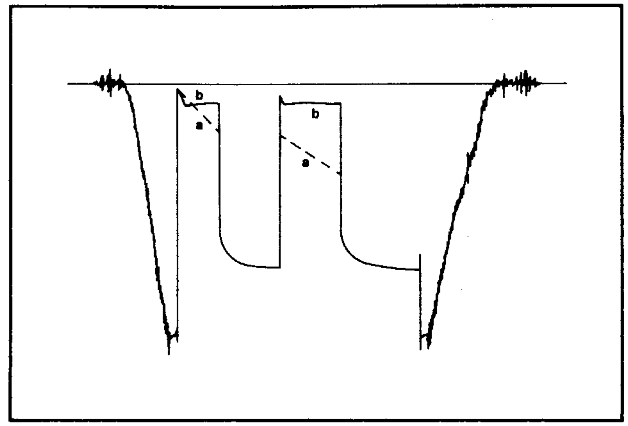

Figure 30 - Gas well test. Compared with idealized liquid flow periods (a, dashed lines), gas flows ideally show slight buildup followed by stabilized flow to surface (b). Can not estimate productivity without additional information about surface equipment used.

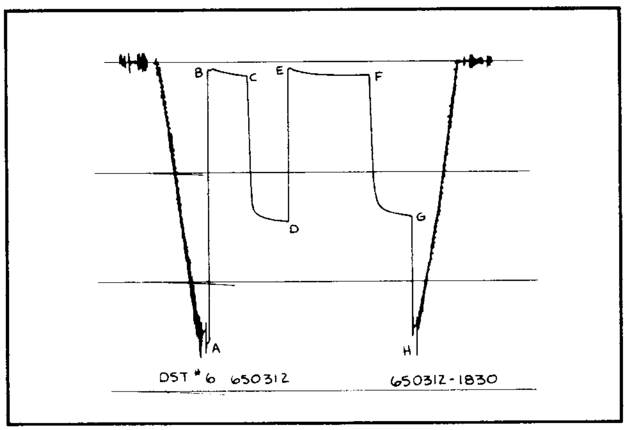

Figure 31 - Gas well test. Complete quantitative data analysis results show low permeability, slightly damaged conditions.

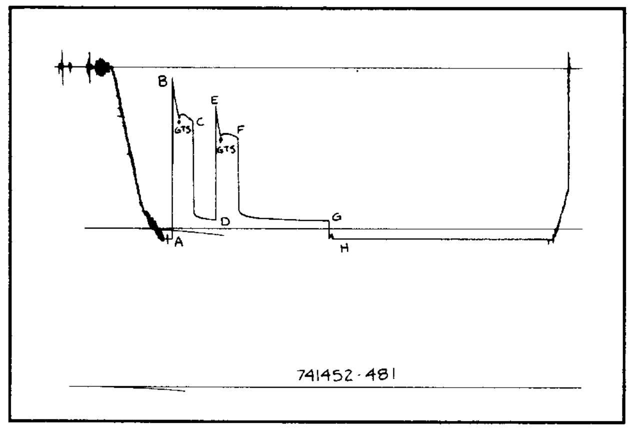

Figure 32 - High productivity and permeability gas test. Flow period pressures continued to increase even after flowing gas to surface (GTS).

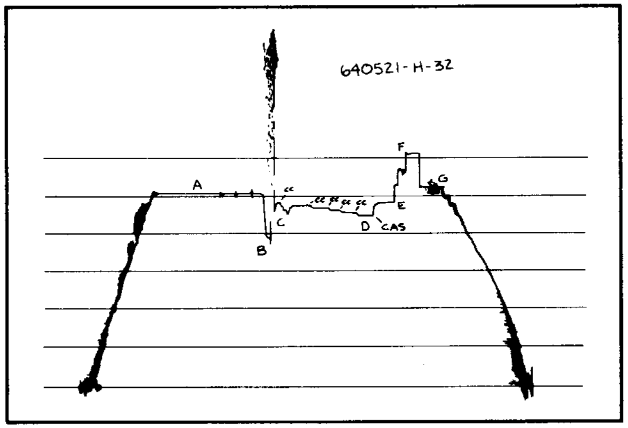

Figure 33 - Very high productivity gas test. Firing of perforating guns at C vibrates gauge severely, allows flow to begin. Various choke changes (cc) shown before well is closed at surface (CAS) for buildup. Well flowed over 6.7 MMCF/D on largest choke. (Pressure increased upward.)

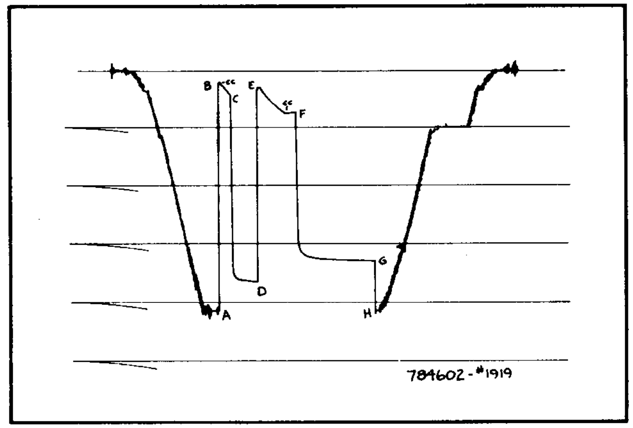

Figure 34 - Depleting as (and condensate) well. Loss in closed-in buildup pressure and inability to maintain rate pressure after choke change (cc) during second flow indicate depletion.

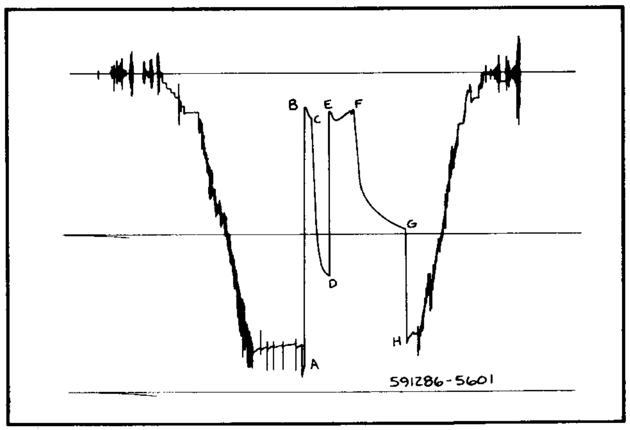

Figure 35 - Combination of permeability anomaly and depletion on gas well test. Non-radial buildups indicate anomaly detection, and substantial loss in closed-in pressures and second flow period rate pressure suggest depletion.

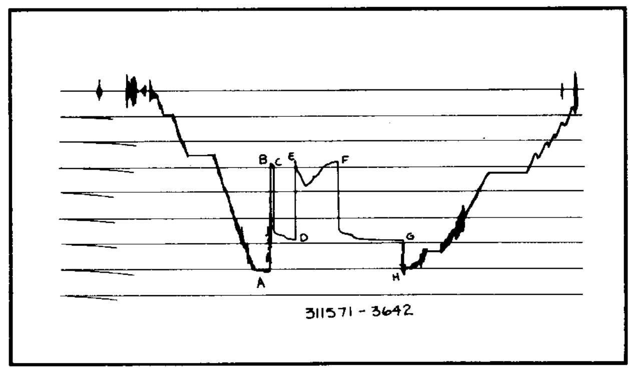

Figure 36 - Highly productive gas test with double buildup during closed-ins distinctly indicating multiple zones open to flow.

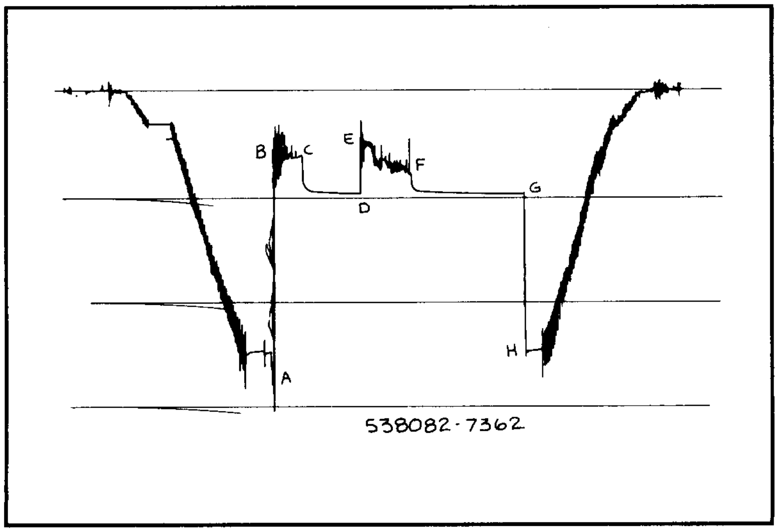

Figure 37 - Spikes of pressure buildup and release during flow periods indicative of plugging.

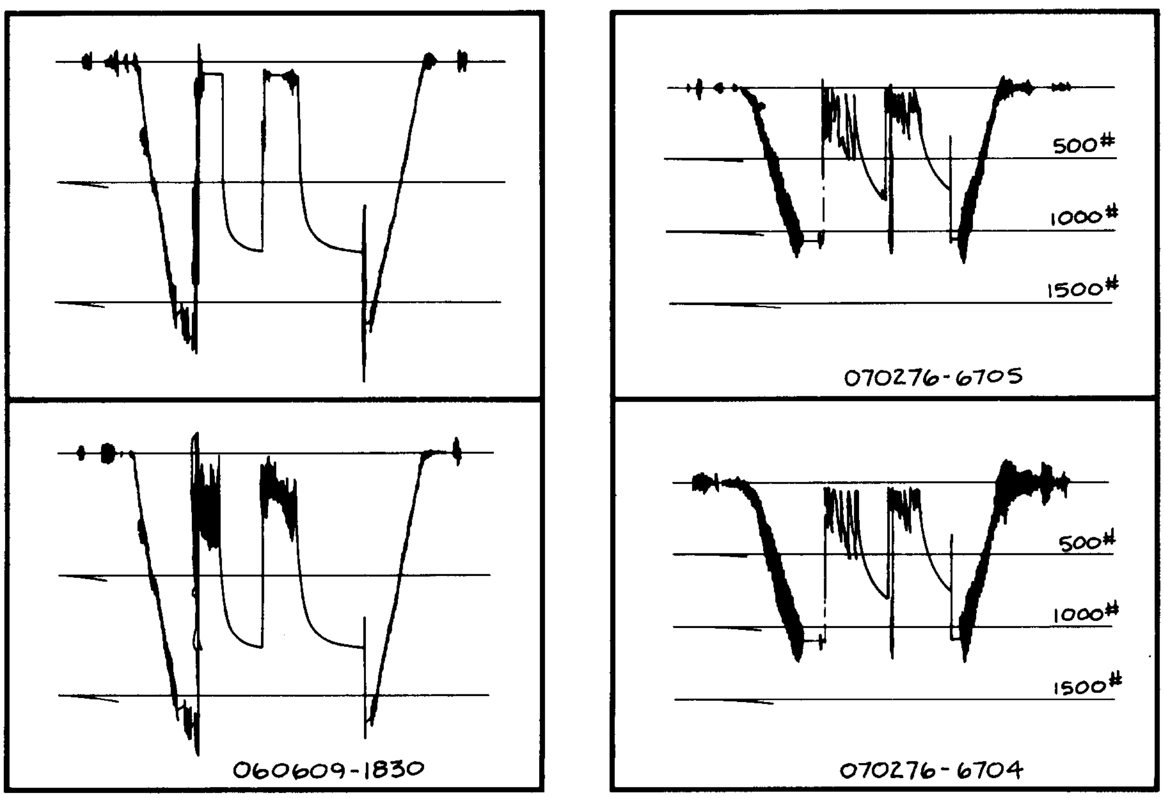

Figure 38 - Comparison of possible locations for plugging. Pair of charts on left, from top and bottom gauges, are different, with bottom chart showing spikes indicating plugging downstream of that gauge only, or in perforated pipe. Pair on right show identical spikes indicating plugging downstream of both gauges, or in valve assembly.

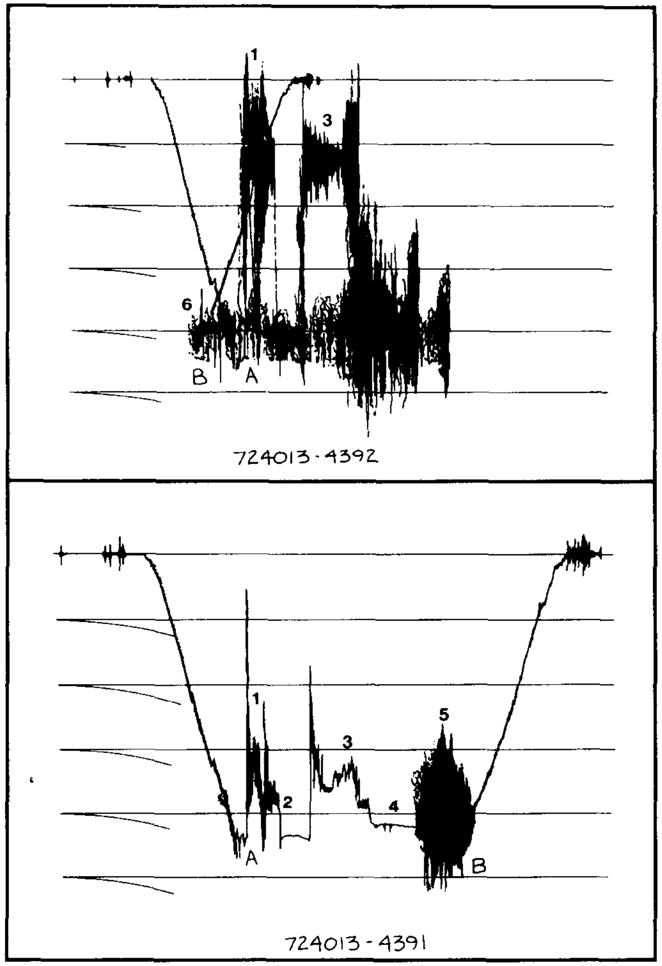

Figure 39 - Complete lack of useful information due to inadequate hole conditions. Very severe plugging during first flow (1) even prevents recording of smooth buildup during first closed-in (2); likewise for second flow (3) and closed-in (4). Repeated jarring to pull tools off bottom (5) vibrates top gauge enough to cause clock to back up (6) before recording trip out of hole.

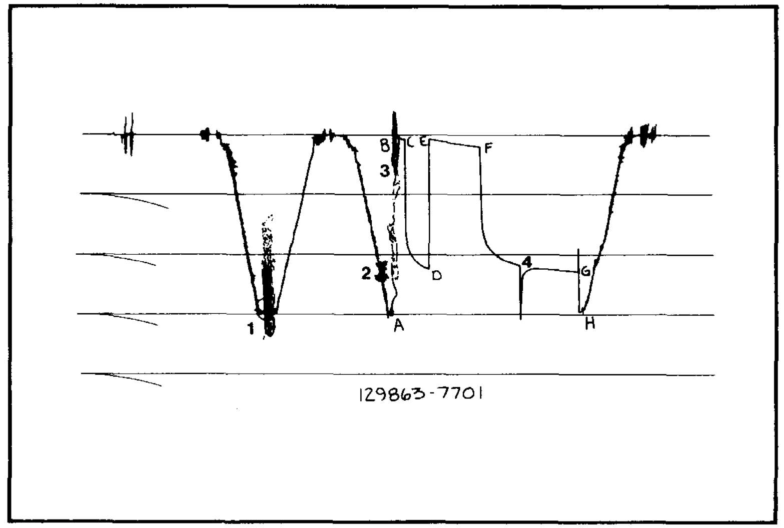

Figure 40 - Inadequate packer seat fails twice when attempted to set during first trip in hole (1). After hitting tight spot on second trip in hole (2), packer slides to bottom when opened for flow (3). Packer then fails momentarily during second closed-in as indicated by sudden pressure increase when mud leaks around packer into tested interval (4).

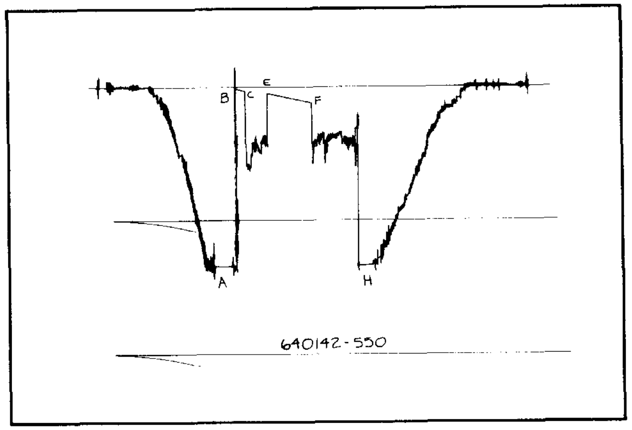

Figure 41 - Leakage in valve assembly. During the closed-ins, release of building reservoir pressure into lower pressure region within drill pipe indicates leakage through valve assembly.

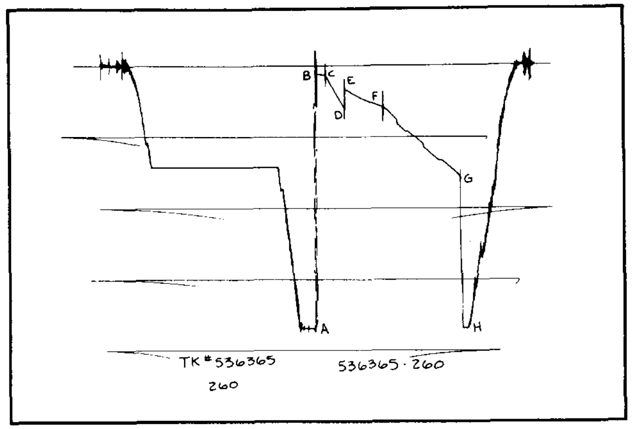

Figure 42 - Leakage in drill pipe. Substantial increase in drill pipe pressure from first (C) to second (E) flow indicates leak of mud hydrostatic from annulus into drill pipe, probably beginning during first closed-in. "Stairsteps" in second closed-in due to sticking of chart-carrying drum within gauge.

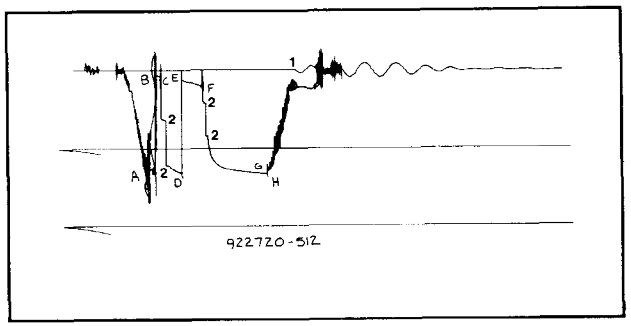

Figure 43 - Improperly drawn baseline (1) and stairstepping gauge (2).

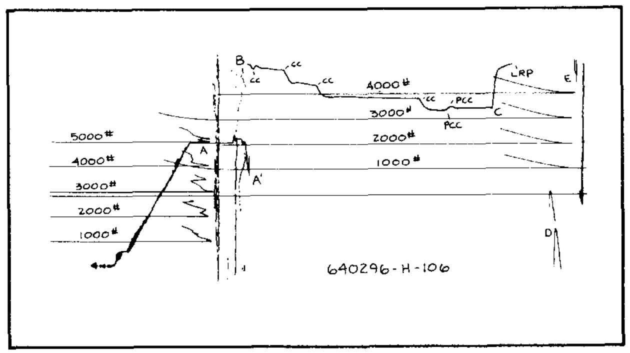

Figure 44 - Stylus assembly shifted upward by about 2900 psi due to severe shock to gauge when perforating guns were fired at A'.