A New Approach to Permeability Profiles

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INTRODUCTION

As the number of secondary recovery projects have increased within the last ten years, so has the need for reliable injection profiles increased. The recent development of the subsurface flowmeter has answered this need. As a result, the interest in flowing profiles for producing wells has been also intensified. Processes available in the past, while reliable to some degree in injection wells, have been almost completely unreliable in flowing wells. The new subsurface flowmeter has been responsible for this new interest in producing well surveys. It has revealed reservoir producing actions previously only suspected but not proven. Also, because of its versatility, field worthiness, ease of operation and because the profile obtained requires no interpretation the tool has made the producing well profile a valuable and easily obtained source of information.

The flowmeter, when used in conjunction with the nuclear fluid density tool, is an extremely useful tool in remedial planning. The density tool permits the operator to pin-point water, oil and gas entry into the borehole.

DESCRIPTION OF TOOLS

The flowmeter is a slim (1-11/16 in. O D) steel tube An inpeller or turbine is in the lower end; an inflatable ballon type packer is above the impeller section; and a positive displacement pump with an electric motor completes the tool which is run on a conventional electric conductor cable. When in position to measure fluid downhole, the packer is inflated with well fluids by the pump; then with the packer inflated, all fluids then pass through the tool and volumetric measurements are made.

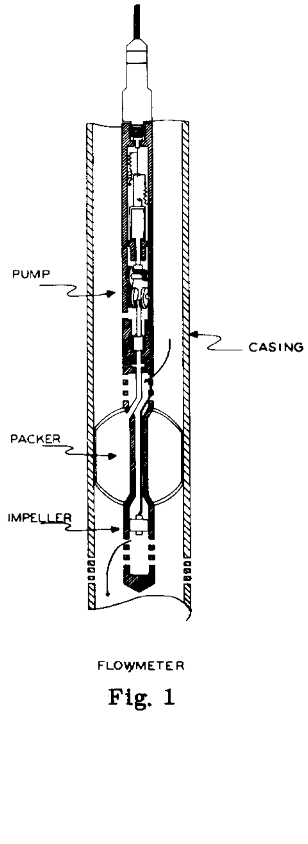

Fig. 1

FLOWMETER

The instrument is so designed that the direction of rotation of the impeller is known. This feature makes it possible to detect fluid flow reversal or split flow in a producing well.

The 1-11/16 in. O D instrument is designed to be run through 2-3/8 in. tubing and to operate inside 2-3/8 in. tubing, casing or open hole up to 7-7/8 in.. A larger packer section, 2-13/16 in. O D, is available to be run through 2-7/8 in. O D tubing and to operate in open hole up to 10 in. in diameter. The packers operate at a maximum differential of 14 psi. The flowtube in the 1-11/16 in. O D tool has the following pressure drops:

0.5 psi at 700 BFPD
3.5 psi at 1000 BFPD
10 psi at 1400 BFPD

These low differentials mean that, when set, the packer does not create any abnormal flow or pressure situations within the borehole during logging operations. It also means that fluid slippage by the packer is negligible or non-existent, and any fractures detected are open during normal injection or flow.

The nuclear fluid density tool is 1-11/16 in. O D, designed to be run separately or in conjunction with the Flowmeter.

DENSITY TOOL

A constant gamma source is focused upwards through a fluid inspection chamber to a shielded receiver detector. Fluids passing through this chamber absorb or shield the focused gamma rays in proportion to their density. Since the densities of the reservoir fluids are

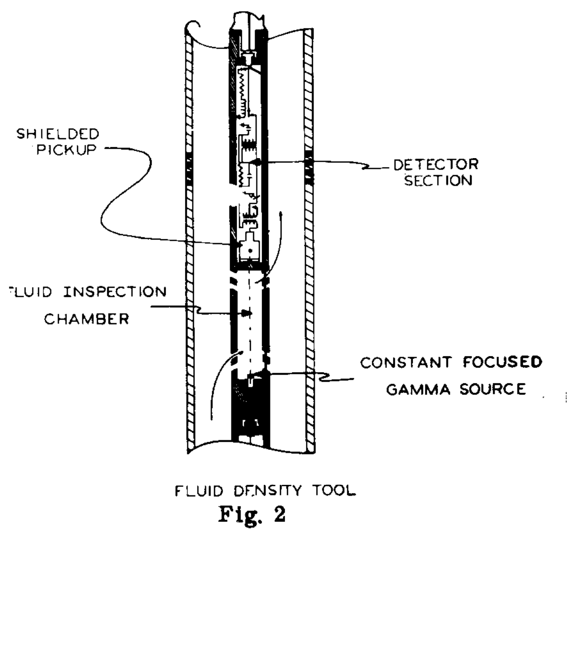

Fig. 2

known, it then becomes a simple matter to calibrate the instrument and identify the fluids as oil, water or gas. The focusing and shielding system is such that natural gamma ray radiation does not interfere with the operation, calibration, or interpretation of the instrument.

When used in a flowing well which is primarily two phase flow, the interpretation is relatively simple. With a three phase flow system, the flowmeter and a reliable well production test are desirable for pin-point accuracy. Accurate and consistent results have been obtained under difficult and irregular flow conditions.

OPERATIONAL PROCEDURES

FLOWMETER

To obtain the injection profile it is necessary that the tubing be open-ended and positioned above the casing perforations. In surveying open hole completions, the tubing should be positioned up the casing 10 to 15 ft. Well head connections should be modified to allow installation of a lubricator, allowing entry without stopping injection.

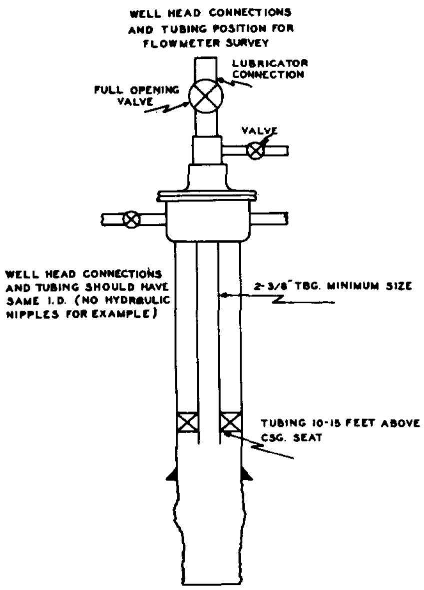

Fig. 3

Typical Well Arrangement

When the flowmeter is positioned above the perforations, the packer is inflated and the recording instruments adjusted to read 100 per cent flow through the tool. Then, with the recorder set in this manner, the only calculation necessary during logging operations is one of subtraction. After the 100 per cent check, the packer is deflated and lowered into the formation at some predetermined point and the packer is again inflated. It is to be noted that the flowmeter impeller normally will not rotate unless the packer is fully inflated except at extremely high flow rates. The reduced flow percentages through the tool, as it is progressively set down hole, indicate the injection profile. Time recordings of the injection or flow rates are made at the various points downhole, and these time recordings on the logging chart reveal instantly the degree of stabilization.

The survey of a flowing production well is made in essentially the same manner. The only real difference is that after the 100 per cent check is made above the formation, the tool is lowered to bottom and the well logged coming up hole.

FLUID DENSITY TOOL

This tool is run into the well in the same manner as is the flowmeter. It is lowered to bottom, then pulled through the perforated or open hole interval at 10 to 15 ft per minute. This "drag log" produces a curve which indicates changes in flowing fluid density. The tool is calibrated in well fluids of known density. In some instances this "drag log" by itself will indicate the type of fluid entering the borehole. The density tool is next positioned at various points, and time recordings made as a further check. However, in most cases it is necessary to also obtain flowmeter volumes at points where density changes occur to make a valid interpretation. When the possibility exists that a dense fluid such as water, for example, is entering the borehole at two or more points, then it becomes absolutely necessary that it be known where fluid movement occurs and at what rate.

SURVEY CONDITIONS

To obtain a reliable and representative injection or production profile there are several conditions that must be taken into account.

(1) STABILIZATION: The injection rate should be stable during the survey. A well that is taking water on a vacuum or very low pressure and that is surveyed in an unstable condition will breathe or fluctuate between zones. In other words, a zone taking 10 per cent will start taking fluid at 30 per cent, then after a while go back to a 10 per cent rate. This situation has been observed several times: the injection well is stablized (surface and downhole); and, during logging operations, the water plant considerably reduces the rate or ceases altogether. After the regular rate is resumed and the surface (well head) injection meter shows a stable rate, the downhole flowmeter will show unstable injection or "zone swapping" for 2 or 3 hr. The point to be noted is that on a vacuum or low pressure injection well, it is possible to have stable injection at the well head and yet have very unstable or erratic conditions at the face of the formation.

A well that is taking water at a low rate and high pressure also presents a problem. If it is allowed to back flow during the period of tool entry, then the survey made immediately after resuming injection will not give a representative profile. In most cases it will give a constantly changing profile until the water volume back-flowed has been injected.

(2) Fill-Up: An injection survey made prior to reservoir is not indicative of what is occurring after fill-up.

(3) RATE AND PRESSURE CHANGES: The profile will change whenever the injection rate and pressure are altered. Sometimes just a change in rate will result in a drastic alteration of the injection profile. Hence: when an undesirable injection profile is found, a change in rate and injection pressure might be the best remedial approach to the problem.

All these factors vary in importance and effect from reservoir to reservoir. However, one fact that does not change is that a survey must be run under actual injection conditions if it is to be truly representative.

(4) WELL LOGS AND CORES: Most valuable and often neglected while running an injection or production profile is the use of primary well logs such as radioactivity, sonics, electric and core analysis data. The survey should be planned to investigate fluid rates at points of interest on the logs. If the log is available to the men on location while they are running the profile survey, then, when breaks in fluid rates occur, the well log can be examined for possible points to be surveyed in

greater detail. It has been observed that, in injection well surveys, large volumes of water, many times leave the borehole in the vicinity of a shale break. Also, in production well surveys, it has been noticed that water break-through occurs along a shale bedding plane. This is one good reason for making a well log available and using it during a survey.

INJECTION AND PRODUCTION PROFILE USES

As previously stated, a profile run prior to fill-up is not truly representative of the entire flood. However, it can be used to an advantage in numerous cases. If a major thief zone is suspected, then an early survey on a pilot well might provide such information. Discovery of such a situation early in the pilot stages will give a better economic evaluation of the project. There is an attitude in some quarters that "if nothing can be done to the well, why run an injection profile?" An injection profile on such a well will certainly provide information to answer the question, "Is this flood economically feasible?"

The profile obtained after fill-up will indicate whether the proper zones are being flooded. After a well pressures up, certain zones will break down and start taking fluid at an excessive rate. If it is assumed that this zone is oil bearing then some adjustment in rate or pressure might be desirable to flood out all zones at nearly the same time. In other cases, a high injection pressure will force out water along a shale break.

A waterflood usually requires a large expenditure of money and injection operations for a year or two before any return is realized. Also, all in-hole remedials are expensive. Therefore, it just makes good economic sense to find out where, in the formation, the water is going.

The production profile probably has its greatest use in the evaluation of well perforations and stimulation. To properly evaluate a producing well it must be surveyed under actual reservoir conditions: a "pump in" type survey is of almost no value on a flowing well. On the other hand, a "pump-in" survey will locate zones taking fluid, but these certainly are not necessarily the zones that will produce. This fact is particularly true in lime reservoirs with varying streaks of porosity, permeability, and pressures as found throughout West Texas and New Mexico. Also, a "pump-in" type survey produces a bottom hole pressure and fluid viscosity problem not normal to the producing reservoir and almost impossible to correct or control.

A production profile run under actual producing conditions (down hole) will reveal production anomalies not apparent at the surface, e.g., water entering at the top of the formation and flowing to the surface, while part of it goes down hole, drowning an oil zone. Also, in other cases, as the choke size is reduced, some zones quit producing entirely rather than produce at a reduced rate. The production profile can be used to determine optimum flow rates and to aid in the estimation of ultimate recovery under primary and secondary operations.

Profile Illustrations and Discussions

Illustrating the various points previously discussed are the following injection and production profiles:

Figure 4 is an injection well in which a profile was obtained after water break-through into the off-set

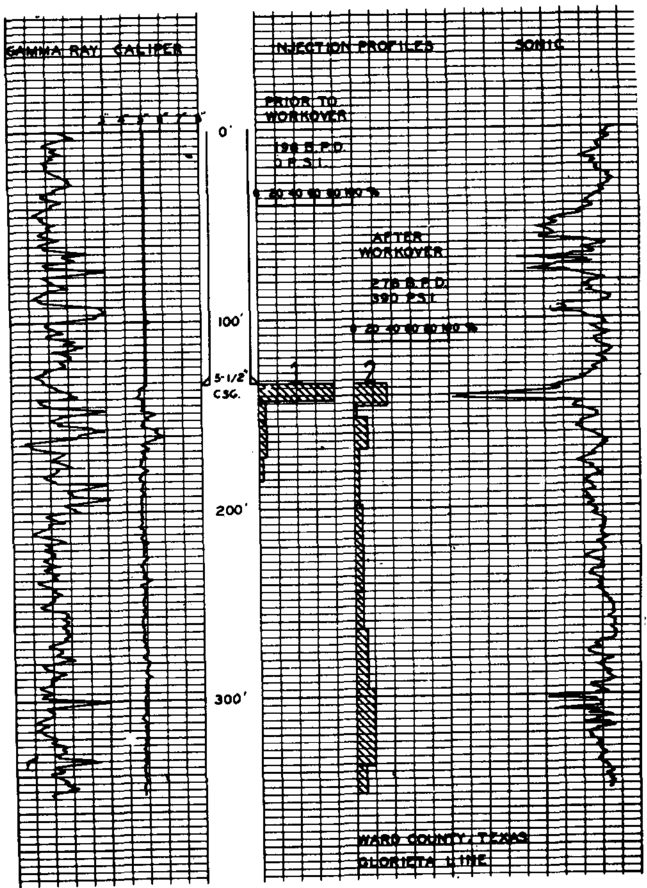

Fig. 4
Profile Before & After Cement Squeeze

producer. As shown on the profile, run No. 1, 80 per cent of the water (157 BWPD) was leaving the borehole in a 5 ft interval just below the casing seat. The total injection rate was 196 BWPD at zero pressure. A plug was set just below the water loss zone; then the interval was squeezed with approximately 300 sacks of cement. The hole was drilled and cleaned out to bottom and was not treated. Injection was resumed at an increased rate (278 BWPD) and pressure (390 psi). This second profile was made, No. 2, and the 5 ft zone at the top received 35 per cent water flow or 111 BWPD. However, the entire formation is now taking water in a fair distribution pattern.

The cement squeeze has not entirely eliminated the break-through zone, but it has restricted the flow sufficiently to allow water to be injected into the entire formation. During primary life this well was fractreated down the casing at 1300 psi and 18 BPM. This treatment and the log configuration indicate that without the cement squeeze it would have been impossible to inject water into the entire formation. This formation is a lime formation with some shale breaks and it appears that the large water loss (Run No. 1) occurs along a shale bedding plane.

Figure 5 illustrates a profile change with plugging material. This represents an injection well completed in the Clearfork formation which is a dolomite with small anhydrite and carbonaceous shale streaks. Profile No. 1 at 1025 BWPD injection on a vacuum was run after the cumulative injection volume was 63,881 bbl. This survey indicated a poor profile: all the water was leaving the

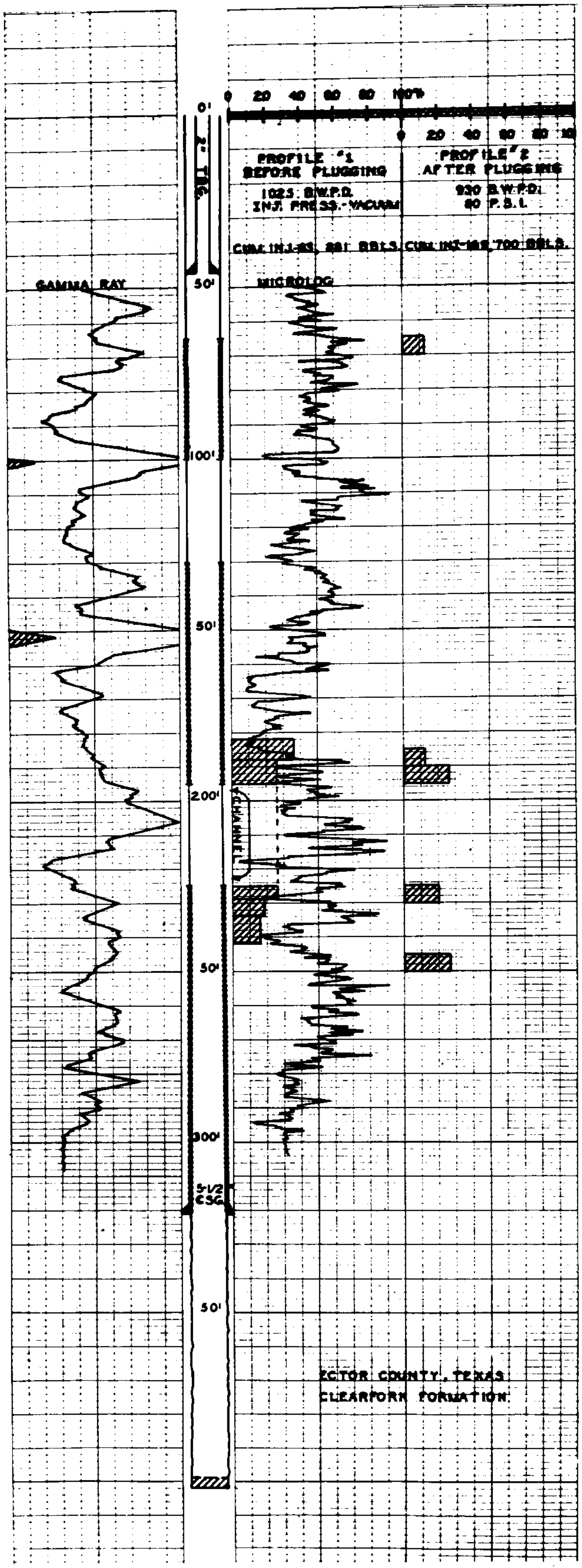

Fig. 5

Injection Profile Before and After Soluble Plug Treatment

borehole near a major thief zone. Also, channeling or communication was found to exist between the middle and lower set of perforations. The well was plugged with approximately 300 lb. of paper pulp material consisting of a mixture of medium and very coarse sizes. This batch treatment resulted in an injection pressure increase. Profile No. 2 at 930 BWPD and 80 psi was run about 2-1/2 months after No. 1. At this time, the cumulative injection volume was 169,700 bbl. This second profile resulted in the changed profile as shown. The major thief zone was plugged (point 230 ft to 245 ft) and the channel between the two sets of perforations was also plugged. No doubt this profile has been affected by the increased cumulative. However, it is believed that the major changes are entirely due to the plugging treatment.

Figure 6 illustrates a change in profile as a result of an injection rate. The profile was made at 192 BWPD and zero injection pressure, and water was found to be leaving the borehole in a good distribution pattern. The rate was reduced to 72 BWPD and zero injection pressure. This reduced rate profile showed the thin middle set of perforations to be taking 100 per cent of the injection water. At the high rate (192 BWPD), the middle set of perforations was taking 21 per cent of the fluid or 40 BWPD. These perforations and the cement job were checked with a radio-active tracer, and no communication was found.

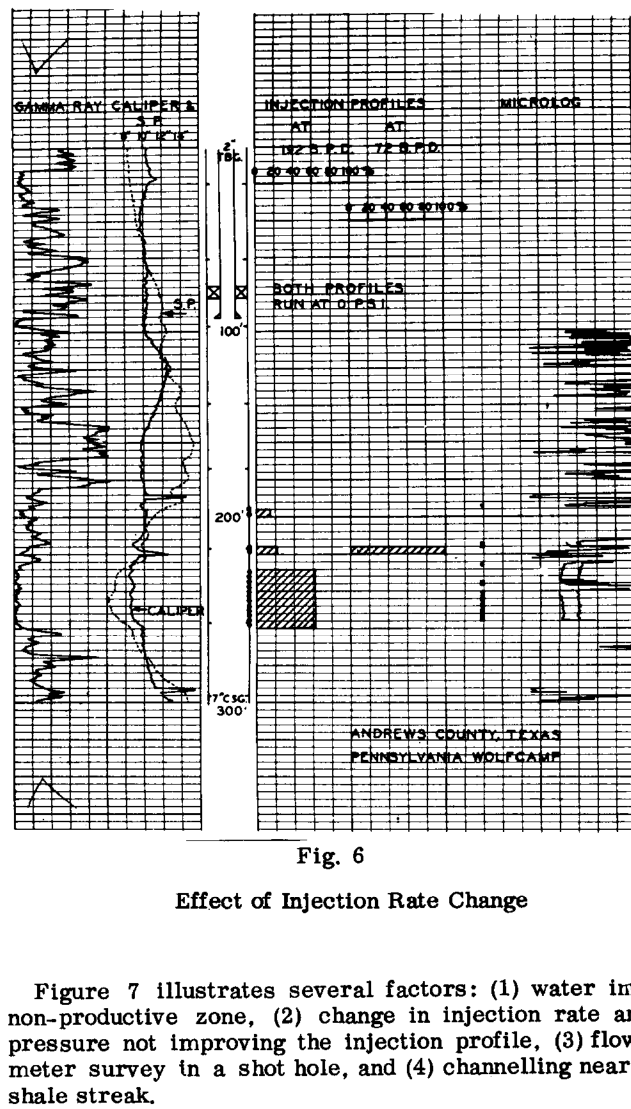

Fig. 6

Effect of Injection Rate Change

Figure 7 illustrates several factors: (1) water into non-productive zone, (2) change in injection rate and pressure not improving the injection profile, (3) flowmeter survey in a shot hole, and (4) channelling near a shale streak.

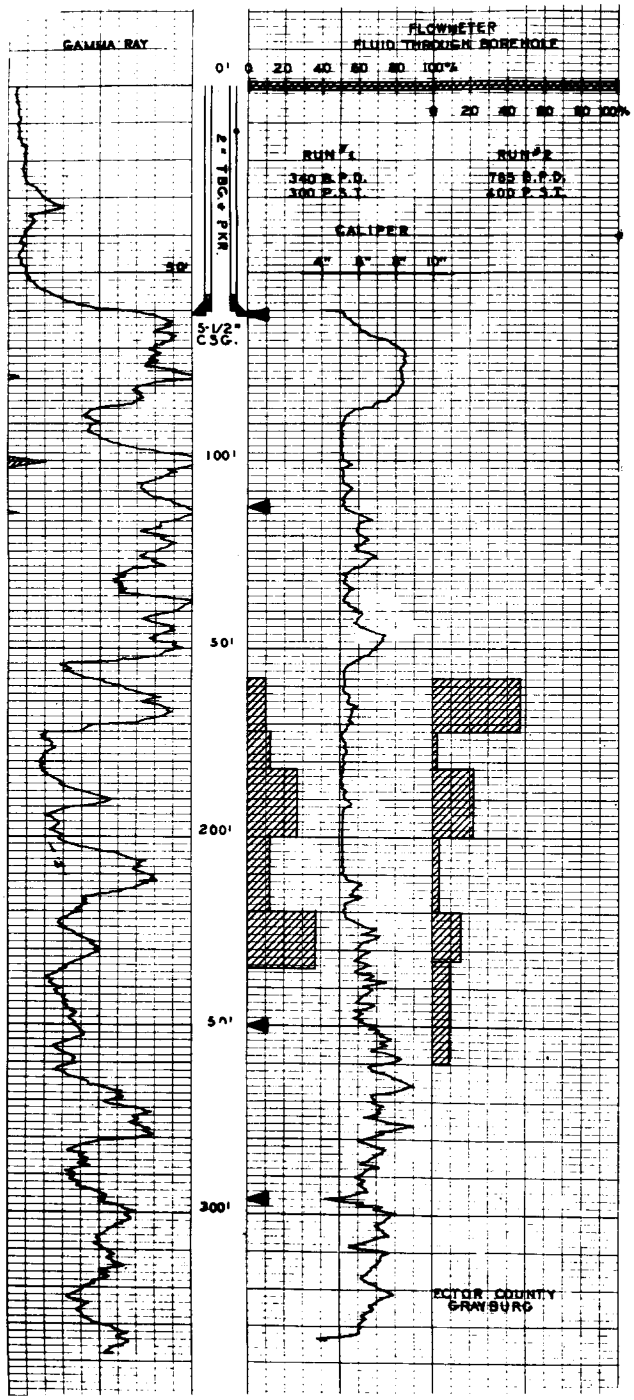

Fig. 7

Profile in Shot Hole and Effect of Rate Change

This well was completed in the Grayburg formation and shot from total depth to the 210 ft point with three quarts nitro per foot. Water break-through had occurred in this five-spot area. The first profile was run at 340 BWPD and 300 psi injection and all fluid was found leaving the borehole above the main oil-bearing section. Several flowmeter settings were made in the shot hole and no fluid movement detected. All these settings were checked by pulling 150 lb on the electronic weight indicator. Also, fluid samples from this bottom section were thick and dirty and served as a further check on the non-movement of fluid. During the survey, fluid channelling (approximately 6 per cent) was detected between the 194 ft and 200 ft points; this point was rechecked with the same results. The gamma ray log was not run until after the profile survey was made and it is interesting to note that this channelling corresponds near the sharp kick in the gamma ray.

The second profile was run the next day at 785 BWPD and 400 psi injection. The fluid loss occurred again in the same area, except that some water, about 78 BWPD, went into the top part of the shot hole. In this case the increased rate and pressure did not materially help the situation. It should be noted that the upper fluid loss zone actually broke down and took about 48 per cent of the total fluid. Available information and production history indicate that the lower portion, which was shot, was the oil-bearing section.

Figure 8 illustrates (1) apparent stable injection rate at the surface but unstable formation (inhole injection), and (2) back-flow or reverse flow in an injection well.

This well had been on injection for several months. However, immediately preceding the survey the water plant was down some 12 hr. Water injection was resumed while the equipment was being rigged up; and the flowmeter positioned down hole for the 100 per cent check. It was necessary to wait about 2 hr for the surface meter to indicate stable injection, and the flowmeter, positioned up in the casing, also indicated stable injection. The survey was run and all the injection fluid (258 bbl) was accounted for in the upper half of the formation (direction shown by arrows). Then the lower portion was checked and fluid movement was detected. A detailed survey of the lower half showed that about 156 BWPD was entering the well bore in the middle and that part (46 BWPD) of the water was flowing upwards and into the formation. About 110 BWPD was flowing downward from this entry zone, leaving the borehole as indicated by the arrows in Figure 8.

Continuous fluid measurements were made during the day until the downhole injection rate was fairly stable. The second or final profile was run about 8 hr after the first. This second profile, as shown on the right, indicated that back flow or re-entry had ceased. However, it was indicated that very small channelling did exist in the center section.

Figure 9 is a cross-section which illustrates that wells are different even in the same project. These six wells were profiled during a two day period. It should be noted that well "A" is the well discussed in the preceding illustration. All these wells were on injection several months, taking water as follows:

WELL	RATE: BWPD	PRESSURE
A	258	Vacuum
B	280	Vacuum
C	288	100 psi
D	195	Vacuum
E	176	Vacuum
F	210	100 psi

Figure 10 indicated a large water loss in a narrow interval. The radioactive log was on location during

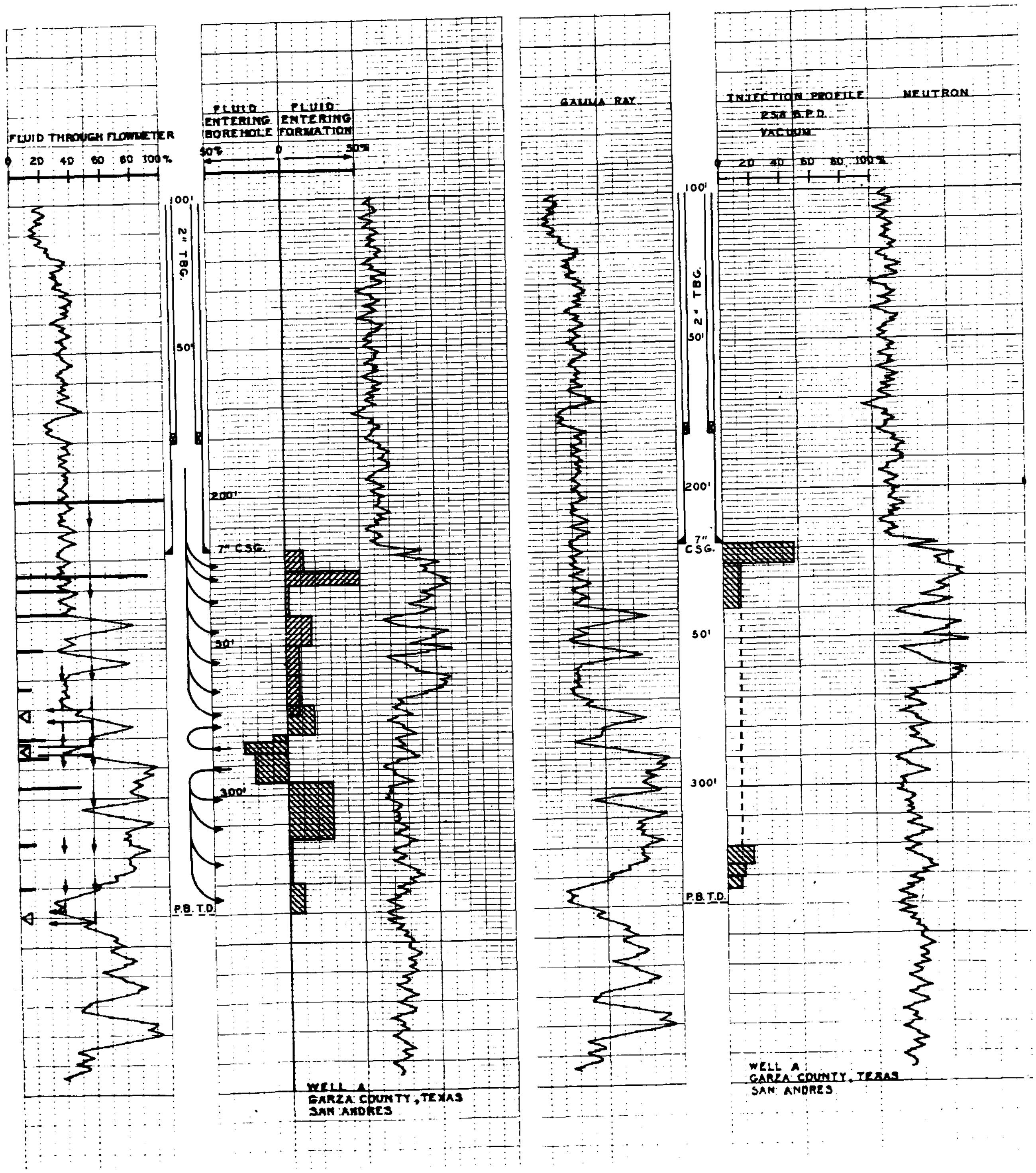

Fig. 8

Unstable Downhole Injection and Backflow During Injection

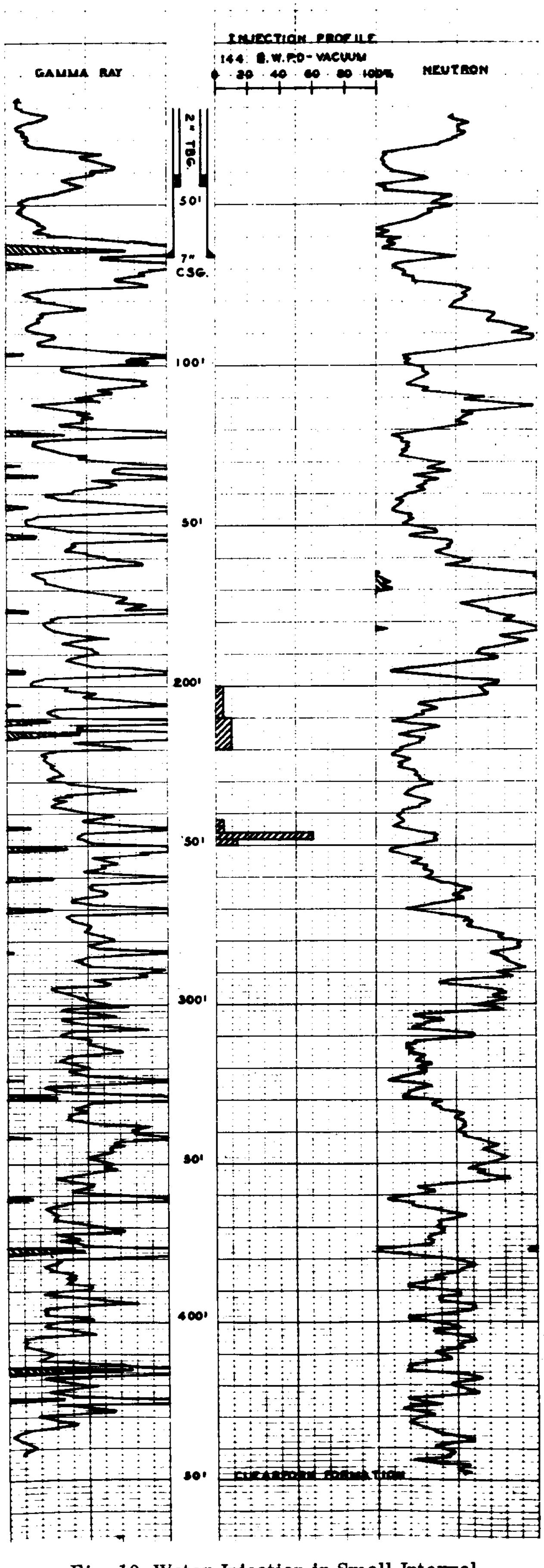

Fig. 10 Water Injection in Small Interval

the survey; and when the major loss zone was discovered, the R/A log was examined and noted. As a result, the major loss zone was then re-surveyed in detail (four intervals of 2 ft each).

Figure 11 illustrates a large water loss over an 8 ft interval. The R/A log was not available during the survey; and had the log been available, the sharp kick probably would have been investigated.

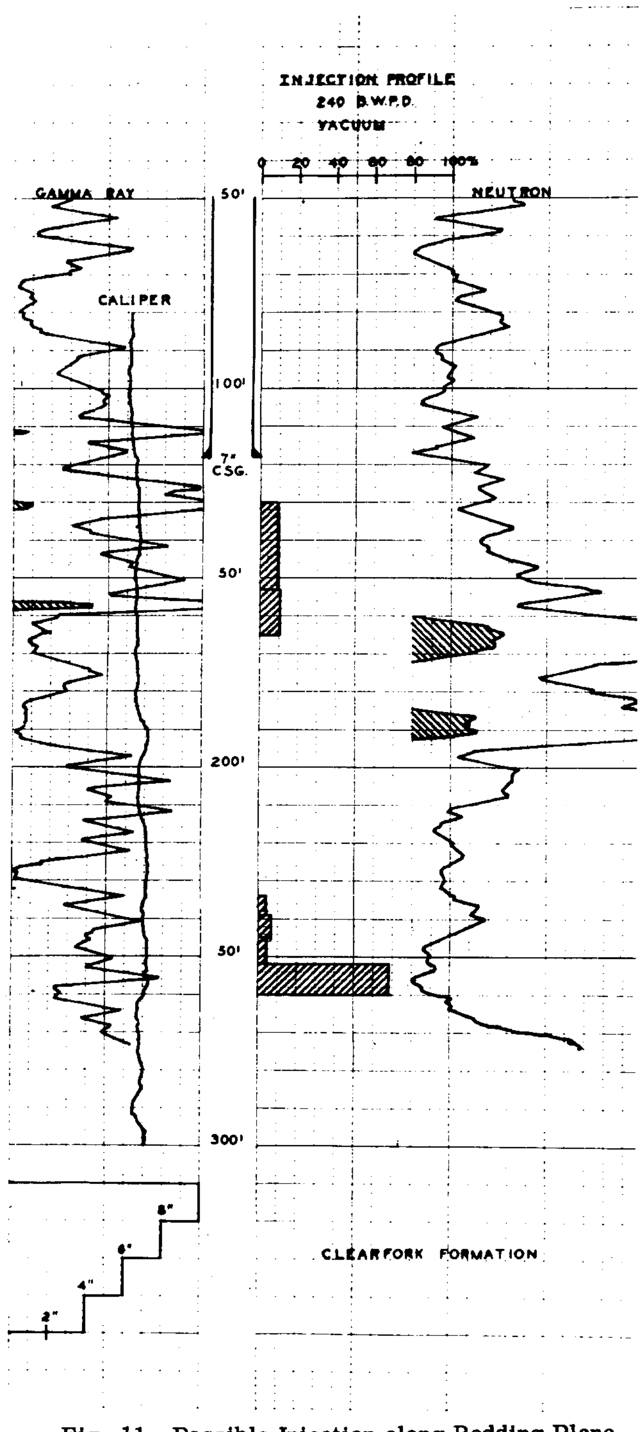

Fig. 11 Possible Injection along Bedding Plane

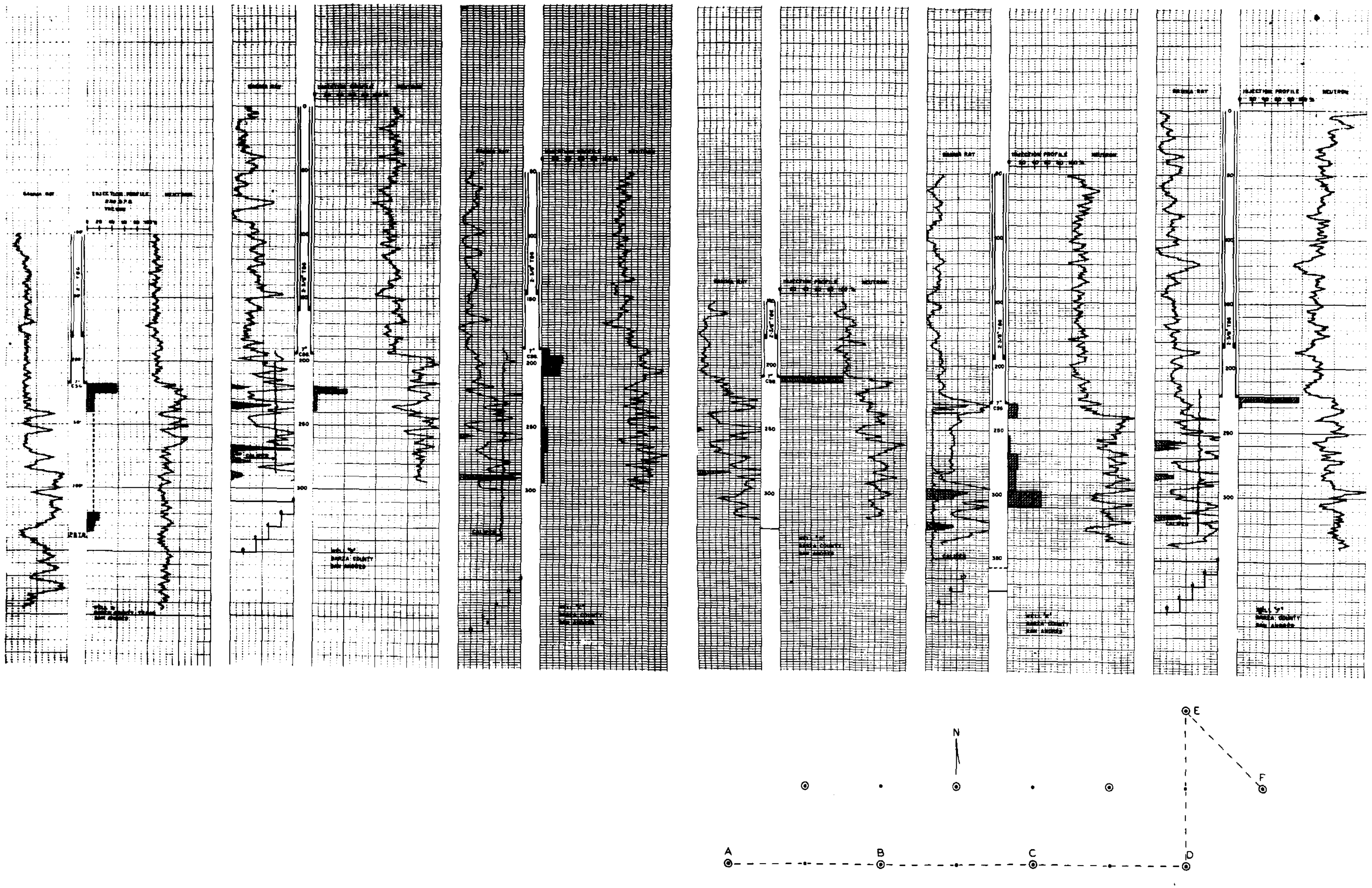

Fig. 9

Cross-Section With Different Injection Profiles. Wells Have Similar Completion and Injection Rates.

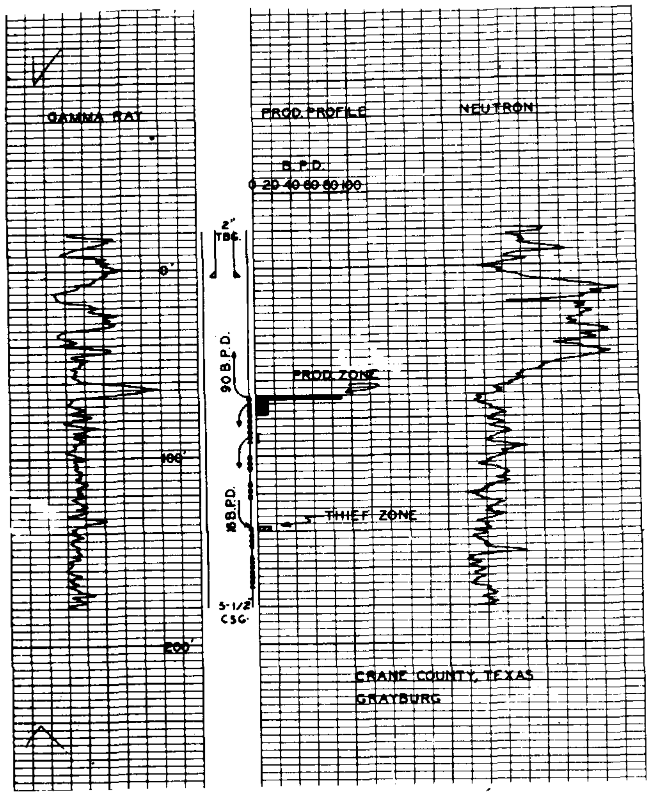

Fig. 12

Split Flow In A Producing Well

Figure 12 illustrates water break through in a producing well and split flow; this is a Grayburg producing well in a water flood project. Water break-through had occurred and the well was flowing 90 BFPD, almost all water. The production profile was run and it was found that approximately 90 BFPD was coming into the well bore in a 1 ft section, as shown, and flowing to the surface. Meanwhile, 14 BFPD was found entering the thin section near the 120 ft point. This was checked by the operator who tested the well with a packer and swabbing unit. It was noted that the major break-through zone was thin and occurred just below the sharp and pronounced kick in the gamma ray log.

Figure 13, which is a production well, illustrates the following:

(1) Zones pumped into, indicating some relative permeability but not necessarily productivity
(2) An evaluation of a frac-treatment
(3) Production, at different draw-downs, of various zones in the same reservoir; small pressure changes involved
(4) Also indication of optimum producing rates
(5) Aid in evaluating the reservoir

This deep Devonian well was perforated with one hole as shown at each of the 26 zones, and it was frac-treated

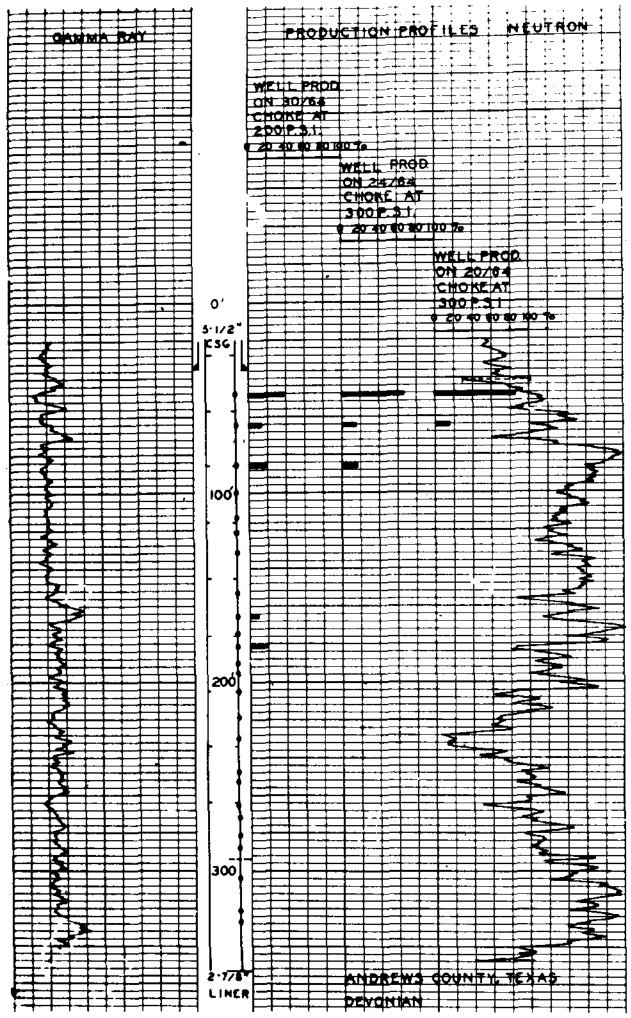

Fig. 13

Frac-Treatment Evaluation And Effect Of Production Choke Variation

by using ball sealers. After treatment, 18 balls were recovered; they had deep impressions which indicated that at least 18 zones were affected. The production profile was run at about 150 BOPD and Run No. 1 was made on a 30/64th choke and 200 FTP. This run found five zones producing. Run No. 2, on a 24/64th choke and 300 FTP showed three zones producing. The third run on a 20/64th choke and 300 FTP found two zones producing.

Figure 14 illustrates the use of the fluid density tool and flowmeter. This production well was being produced by gas lift through open ended tubing as shown. Water break-through had occurred and the well was producing 94 BWPD and 54 BOPD. The off-set injection well was surveyed first (2500 BWPD at 940 psi) and most of the water was found to be going into the lower section. The production well was profiled, and producing fluid density checks were made as shown on the bar graph. The density break occurred at the bottom of the top-producing profile and indicated that the water break-through was in the entire lower section and that the upper section was the oil producing zone. This indication was proven when a packer was set between the two zones and the well was restored to natural flow, 100 per cent oil.

It is interesting to note that the major injection zone (1200 BWPD) is below the water break-through zone in the subject producer. Since this major injection zone is

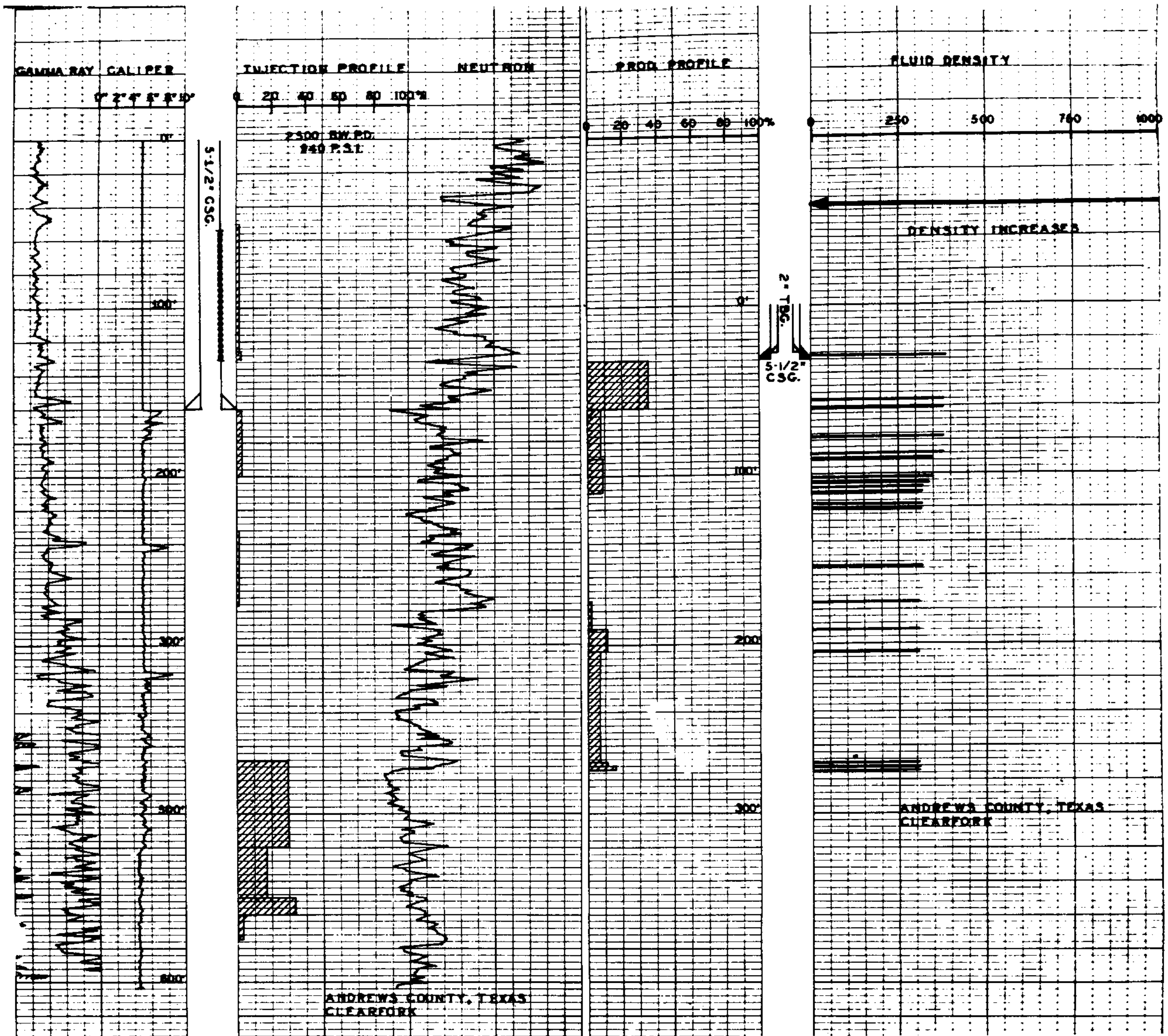

Fig. 14 Water Break-through Determined by Flowmeter and Fluid Density profiles. Injection Well Profile Shown at Left for Correlation.

known to be oil-bearing there are two questions that should be investigated prior to any plug-back consideration. One: is the producer well deep enough? Two: is this oil in the bottom injection zone being swept down-structure to another producer?

SUMMARY

Most of the well actions shown give no apparent surface indications until after a passage of time. These detrimental inhole actions are manifested in a number of ways, such as by injection for a year or two and no oil increase, by rapid water break-through, or, in producing wells, by rapid declines in production not commensurate with the original analysis of the reservoir. Since it takes time, production history, etc., to find this information, money has been wasted or lost. However, a good injection or production profile can alert the operator to the fact that all is not perfect, and this early information can enable the operator to act accordingly and in time to prevent the waste of additional money or to take proper remedial actions and increase recovery. One point often overlooked by everyone except the bankers is interest on money. The remedial dollar saved by the "wait and see" policy is all too often more than offset by the interest rates alone on deferred production.

With the actual running of an injection or production profile there are several points that can not be overemphasized.

(1) A profile must be run under actual operating conditions.
(2) A survey made at a reduced rate and pressure or immediately after a shut-down is in most cases of no value at all. Extremely short shut-down periods will affect the down-hole actions for several hours. In cases where the well rate is altered during tool entry, then logging operations should not be attempted until the well is stabilized down-hole--one must be cautious!
(3) Before attempting an expensive workover on an injection well one should determine the effect of changed injection rate and pressure and should keep in mind the afore mentioned recommendations.