Production Logging Experiences In Rod Pumped Wells

By ALAN N. SIMON AND JOHN J. KEESEY

Pan American Petroleum Corporation

INTRODUCTION

The need for reliable methods of identifying intervals of production under dynamic conditions in producing wells has long been a major concern of the petroleum industry. Of special interest are wells in secondary recovery projects where the flow behavior at the producing wellbore, as well as at the injection wells, often needs to be determined in order to evaluate waterflood performance and plan remedial operations. This is particularly true for stratified reservoirs where variations in permeability ranging from 0.1 millidarcy to several hundred, or even several thousand millidarcies are not uncommon. Waterflooding in reservoirs with these characteristics could lead to floodout of the highly permeable zones before response is obtained in the remaining pay. If this occurs, water production from the flooded zone could become so great that continued production of the well would be uneconomical. Even if production were continued, backflooding of the lower permeability zones might occur. In either case, vertical sweep efficiency would be reduced and ultimate recovery from the well decreased.

To insure maximum recovery under secondary operations it is therefore imperative that these situations be properly identified. If this can be done, then remedial operations may be performed in the producing well to shut-off the offending zone and/or in the injection wells to reduce or eliminate injection into a corresponding interval. If such remedial operations are successful, vertical sweep and ultimate recovery can be improved.

The most common method of identifying the nature of fluid production under dynamic conditions has been to obtain selective production tests by interval isolation with one or more production packers. Some success has been achieved with this method but too often, hole conditions prohibit positive definition. In shot-hole completions, for example, the hole size is usually irregular and large and isolation of zones with open-hole packers is often impossible. Even if a packer seat can be obtained in a shot-hole or in a relatively gauge hole that has been stimulated by other means, there are problems which must be contended with. For instance, the existence of vertical fractures often prevents complete isolation of intervals, thereby resulting in erroneous test results. Adding to this problem is the fact that the presence of fractures is often difficult to detect, especially when testing an upper zone while attempting to shut off a lower zone. The existence of fractures is also troublesome in cased and perforated wells in that communication between perforated intervals in the same horizon is established. Pumping from below a packer presents another major problem in that pumping efficiency is generally found to be low due to gas-locking of the pump.

A newer method of obtaining dynamic production profiles that has gained prominence over recent years is the production log, or dynamic production profile survey. This method consists of running one of a variety of tools down the tubing or through the tubing-casing annulus and measuring rates and percentages of fluid phases at numerous points over the zones in question. It is acknowledged that some mechanical problems and limitations are probable when running the production logs; however, it is felt that the data gained is useful in evaluating reservoir and waterflood performance. In view of this and considering the limitations of other selective test methods, the production log offers not only a desirable means but in many cases the only means of obtaining dynamic production profiles in completions in fractured, stratified reservoirs.

During mid-1968, a total of thirteen dynamic production logs were obtained in five of Pan American's waterflood projects in the Permian

Basin area of West Texas. One log was run through tubing in an 8300-ft cased, flowing well. The remaining twelve logs were all obtained on pumping wells ranging in depth from 4200 to 4800 ft. All of these wells were open-hole completions that had been stimulated by shooting, acidizing or fracturing or a combination of two or more of these treatments. Eleven wells were logged through the tubing-casing annulus in 5-1/2 in. or 7-in. casing. The twelfth pumping well was logged through tubing while the well was produced through a second string of tubing.

This paper presents typical results of the two types of production logs run and discusses interpretation of these results. Results of remedial work on several wells are reviewed along with comments pertaining to problems and experiences encountered during the running of these logs. The discussion relates primarily to open-hole completions but would also apply to cased holes in most instances.

TYPES OF PRODUCTION LOGS

The material discussed in this paper has been accumulated from the use of two different types of production logs. The two types of logs differ basically in that one type uses an inflatable packer flowmeter to isolate productive intervals. This type, normally run in cased or relatively gauge holes, uses what is commonly referred to as the inflatable combination tool, shown as Tool A in Fig. 1. The majority of the experience reported in this paper has been gained using this type tool which involves the use of an inflatable packer flowmeter in combination with fluid identification devices. It is pointed out that the difficulties associated with trying to obtain a selective test with an inflatable open-hole production packer, as discussed earlier, do not present a major problem with this type tool. This is due to the fact that (1) the packer bag setting pressure is normally between 15 and 18 psi, as opposed to several thousand pounds employed in setting open-hole production packers, (2) the differential across the packer bag, and through the tool, is low (approximately 6 psi at 500 BFPD), and (3) the packer bag is not a supporting element and no upward or downward movement of the production tubing is transmitted to the packer element as is the case when pumping from below a production packer.

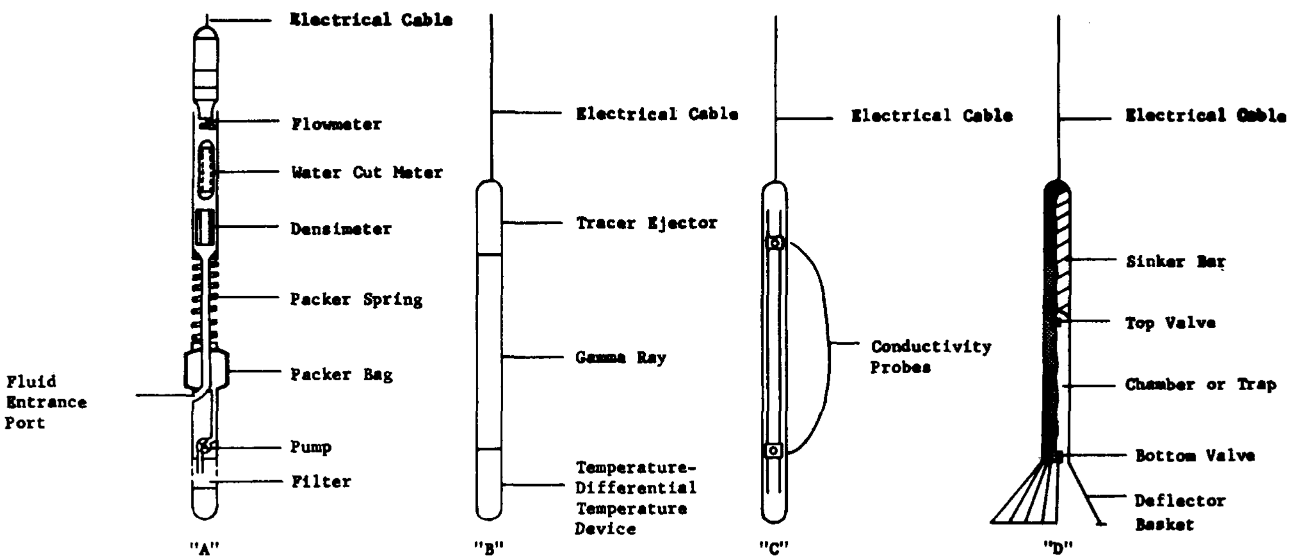

FIGURE 1

Schematic of Typical Logging Tools

The inflatable packer flowmeter is a spinner type velocity meter used to measure flow rates at selected depths. The tool is designed so that when the packer bag is inflated by the hydraulic pump, flow is directed through a small diameter metering section containing the spinner. As shown in Fig. 1, the fluid identification devices used were a water-cut meter and a densimeter. The water-cut meter is fundamentally a capacitor sensitive to the dielectric constants of fluids flowing through the metering section and is thus used primarily to define the hydrocarbon and water fractions by giving a water-cut index. In the densimeter, flow is directed through a cylinder containing radial blades in line with the fluid stream. An electro-magnetic driving system sets the cylinder into circular vibration, oscillating at a natural frequency that varies with the density of the fluids.

Another type of fluid identification device which is available for use with the inflatable packer flowmeter is a fluid density analyzer. This device uses a focused gamma source at one end with a shielded detector on the other. The counts per second which are recorded are a direct function of the density of the fluid through which the gamma rays pass.

The other type of production log, which does not include an inflatable packer flowmeter, normally is comprised of a temperature measuring tool, a tracer ejector, a gamma ray log, and a fluid analyzer tool (the surveys discussed in this paper employed a salinometer as the fluid analyzer). This type log can be used in shot or irregular sized open holes where packer bag seats are unavailable as well as for cased or gauge open holes. Two runs are made with these tools. The first, shown as Tool B in Fig. 1, consists of a temperature gradient and differential temperature log, a tracer profile, and a gamma ray log. The information gathered by these tools is used to define the producing zones and detect fluid movement. The second run consists of the salinometer, Tool C in Fig. 1, which measures the conductivity of the fluids. From these conductivity measurements, the fraction of water in the fluid is obtained. Also, oil-water interfaces should be detected using the salinometer.

Other variations or combinations of the above tools are available. One such tool, Tool D, Fig. 1, utilizes a motor-driven deflector to divert the produced fluid through the tool. By a combination of surface controlled valves a fluid sample is trapped within the tool and sensing elements determine the relative volume of oil. This tool, used in conjunction with temperature and tracer profile tools, is designed to provide a quantitative production profile in cased or relatively uniform holes.

WELL PREPARATIONS AND PRODUCTION LIMITATIONS

The steps required in preparing a well for logging depend upon the type of well and the size of the casing and producing equipment. Normally, the necessary equipment changes are made and the well is returned to production for several days in order to stabilize. Of the thirteen wells surveyed, one was flowing, eight were pumping in 5-1/2 in. casing and four were pumping in 7-in. casing.

Generally, it is desired to have the production tubing set above the zones of interest during logging. This is true whether a packer or other fluid diverting tool is run or not. In flowing wells, this presents no problem since the tubing is normally set above the productive interval. In pumping wells, however, the tubing and pump are usually set near the bottom of the well or in the middle of the productive interval. Raising the tubing and pump then alters the normal pumping conditions and will increase the hydrostatic head on the formation. In the wells discussed in this paper, this became critical since these wells were generally low bottom-hole pressure wells with relatively high productivity indexes. In most cases, it was necessary to raise the pumps 150 to 300 ft which resulted in increases in hydrostatic head of 60 to 130 psi. This increase in hydrostatic head resulted in considerable reductions in total fluid production from several of the wells tested. The effect on fluid production can be seen by a review of the well test data on Table I. In higher pressure wells, the effect of raising the tubing should not be as pronounced. This is also true for wells where the change in tubing and pump depth is minor.

Another limitation encountered with several wells was the necessity to change the pump size when equipping the well for logging. Most of the pumping wells had 5-1/2 in. casing with 2-7/8 in. tubing and a 2-in. pump. To provide

TABLE I

WELL	TYPE SURVEY*	WELL TEST DATA						PRODUCTION LOG RESULTS				
		NORMAL PRODUCTION - BPD			PRODUCTION DURING TEST - BPD			TOTAL FLOW RATES - BPD				
		OIL	WATER	TOTAL	OIL	WATER	TOTAL	OIL	WATER	TOTAL FLUID	GAS	TOTAL FLOW RATE
A	1-TA-5½	54	140	194	43	148	191	52	95	147	36	183
B	1-TA-5½	56	143	199	16	165	181	15	152	167	-	167
C	1-TA-5½	149	123	272	62	165	227	92	108	200	-	200
D	1-TA-5½	155	183	338	71	122	193	95	74	169	56	225
E	1-TA-5½	57	391	448	29	251	280	131	159	290	15	305
F	1-TA-5½	104	235	339	61	154	215	87	104	191	17	208
G	1-TA-5½	7	45	52	4	54	58	7	81	88	-	88
H	1-TA-5½	150	225	375	54	261	315	140	300	440	**	440
I	2-TA-7	44	145	189	35	144	179		Qualitative Results Only			
J	2-TA-7	36	130	166	3	130	133		"	"	"	
K	2-TA-7	41	212	253	41	186	227		"	"	"	
L	1-TT-7	80	143	223	54	117	171	60	102	162	13	175
M***	1-TT-5½	333	72	405	333	72	405	269	108	377	523	900

* Type Survey: 1 - Packer Flowmeter Type
2 - Temperature - Tracer - Salinometer Type
TA - Through Annulus
TT - Through Tubing
5½ or 7 - Casing Size

** Densimeter Clogged - Could not calculate gas volume

*** Flowing Well

sufficient annular clearance to run the logging tools, it was necessary to install 2-3/8 in. O. D. tubing with a 1-3/4 in. pump. On high volume wells (over 300 BPD), this reduction in pump size is believed to have contributed to the decrease in total fluid production discussed above.

In view of the above, a prerequisite, or rule of thumb, that has been adopted is that the producing water-oil ratio with the well equipped for logging should approach the water-oil ratio under normal conditions. If the water-oil ratios are approximately the same, the percentages of oil and water from the productive intervals can be considered to be comparable with the higher production rates with the normal equipment in place. In contrast, if a significant change in the water-oil ratio is observed, a severe alteration in fluid entry would be indicated and logging results would be questionable.

In the flowing well the only preparation required was to install a valve on the wellhead so that the lubricator could be installed and the tools run without shutting-in the well. No alterations in the 2-in. production tubing were required as there were no seating nipples or other downhole equipment to prevent passage of the logging tools. In addition, the normal tubing depth was well above the perforations.

The first pumping well in which a production log was obtained was equipped with 7-in. casing. In this well the 2-7/8 in. production tubing was replaced with two strings of 2-3/8 in. O. D. tubing; one to produce through and the other to log through. The logging string was set in the casing with the production string set five feet above the logging string.

The remaining eleven wells were logged through the annulus, eight through 5-1/2 in. casing and three through 7-in. casing. The procedure for preparing to log the wells with 5-1/2 in. casing consisted of replacing the 2-7/8 in. tubing with 2-3/8 in. O. D. integral joint tubing (set above the casing shoe) in order to enlarge the tubing-casing annulus area to allow clearance for the logging tools. The O. D. of the tools employed ranged from 1-7/16 in. to 1-11/16 in. Also, a dual-head was installed on the well to allow entry of the logging tools into the annular space. Preparation for the wells with 7-in. casing consisted of raising the 2-7/8 in. production tubing above the intervals to be logged and installing a dual-head.

LOGGING OPERATIONS

In conjunction with the packer flowmeter type survey, a caliper log is run through the dual-head and down the tubing-casing annulus after the well is prepared for logging and stabilized. Using the results from the caliper log and data from available formation evaluation logs, such as the gamma ray - neutron log, packer setting depths are selected which are the most likely to yield good definition of the production profile. The production logging tool, as described in Fig. 1, is then lowered down the tubing-casing annulus to a depth below the tubing but still in the casing. At this depth, the packer bag is inflated and readings are taken for flow rate, density, water-cut and direction of flow. These readings in the casing should be an approximation of total amount of oil, gas and water being produced from the well. The packer bag is deflated and the tool lowered into the open hole to a depth determined from the caliper and formation evaluation logs. As before, the packer bag is inflated and readings are taken which indicate the rate and relative volumes of fluid phases flowing through the tool from downhole. A sufficient number of these packer bag settings are made to adequately define a production profile.

It has been found that readings of the fluid flow rates are very unstable when the pump is running. Therefore, in practice, the pumping unit is momentarily shut down while obtaining readings. A reading is taken both while the pumping unit is running and immediately after the pumping unit is shut down. The reading immediately after the pump is shut down is generally used to estimate the total flow rate. This method of obtaining the flow rates is not completely accurate, but it is the best method available, and it does give comparable data for different setting depths if the readings are all taken immediately after shutting down the pump. The pumping unit is re-started as soon as the necessary readings are obtained, so that the well should be stabilized by the time the packer bag is deflated and set at the next depth.

Logging operations with the temperature tracer fluid analyzer type survey are basically the same as above. The primary difference is that with this type log all readings are made with the well pumping. A caliper log may be run first to select intervals in which to take tracer velocity readings, if appropriate. The temperature, tracer and gamma ray tools are then run together and several passes are made to define the major zones of fluid entry, to determine flow rates and obtain an estimate of relative amounts of water and oil. The fluid analyzer tool (salinometer) is then run separately to more accurately define the percentage of water and oil production from zones of interest and to determine the producing water-oil interface.

Several mechanical problems have developed while running the production log, but none which have not been overcome while successfully obtaining a log. The first problem which developed was a tendency for the logging cable to wrap around the tubing while retrieving either the caliper logging tool or the production logging tool. No resistance has been met when raising or lowering the tools through the tubing-casing annulus until the tools approach the top 30 ft of the casing while retrieving the tools. At this point we have on occasion found the tool wrapped approximately one-half turn around the tubing which has required a joint or two movement of the tubing to free the tool. Therefore, in order to save time, a pulling unit is considered as standard equipment when running a production log and is used during logging in lieu of a logging mast. It is important when freeing the tool not to unseat the subsurface pump and lose the fluid column in the tubing if logging operations are incomplete. Losing the fluid column would generally necessitate pumping the well several additional hours for restabilization.

It should be pointed out that most of the pumping wells logged were low-pressure, low gas volume producing wells. In such wells, raising the tubing to unwrap the cable presents no particular problem. However, if a pumping well produced considerable volumes of gas, raising the tubing would require that the well be blown down or even killed prior to removing the bonnet. This, of course, would alter the stabilization of the well and require excessive restabilization periods, thus delaying completion of the survey. If such an incident is probable, consideration should be given to obtaining the caliper log when the tubing string is replaced.

Ordinarily, only one run into the well with the packer flowmeter production tool has been necessary to isolate the productive intervals. However, on two occasions, a packer bag has been punctured either by a rough spot on the casing or by the formation, and it was necessary to retrieve the tool for repairs. The most severe trouble was experienced during one of the logging runs when, after several packer settings had been made, the tool's pump apparently failed to respond to signals and the packer bag was not completely deflated. The tool was then run up and down the open hole several times in an attempt to puncture the bag. However, the bag apparently would not puncture, and the tool was pulled slowly up the hole. When the tool reached a point 450 ft up into the tubing-casing annulus, it suddenly parted from its cable and fell approximately 1000 ft to the bottom of the well. Another tool was immediately set up and run to complete the logging program. The lost tool was fished out the next day.

In a third well, the production logging tool was dropped as it was being retrieved. This particular well had 7-in. casing with a 5-1/2 in. liner set about 40 ft above the 7-in. casing shoe. The tool hung momentarily and pulled loose at the rope socket while coming into the annular space between the 5-1/2 in. casing and 2-3/8 in. tubing. It is possible, although unconfirmed, that the packer bag was not completely deflated and was snared by the tubing or casing. The tool was retrieved the next day.

INTERPRETATION OF RESULTS

Table I depicts the fluid volumes logged and measured on the ten wells surveyed with a packer-flowmeter type tool. Although no detailed proof of the tool's accuracy is attempted herein, good agreement exists between the logged and measured data. Some variations are noted and would be expected. For instance, the logged volumes are based on instantaneous readings taken during a one to two-hour survey period whereas measured volumes are based on stabilized 24-hour surface metered tests taken either during the day of the survey or 24 hours prior to the survey. Two wells reflected significant variations in logged and measured fluid volumes. The large increase in oil production and total fluid in Well H is attributed to the well's gas production and the fact that the densimeter became clogged with solids from the wellbore, possibly paraffin. The free gas production caused the flowmeter to record a higher total fluid rate. Normally, this rate would be adjusted by determining the volume of free gas from the densimeter readings; however, when this tool became clogged, this was not possible. An attempt was made at verifying the results of this survey by selective testing with an open-hole packer. This attempt was inconclusive due to wellbore fracturing that prevented a complete packer seal.

The increase in oil production and decrease in water production between the logged and measured volumes in Well E is currently unexplained. No apparent tool problems were encountered and the well was not producing any significant volumes of gas that might have altered readings in some manner. However, the measured fluid volumes were obtained on a stabilized 24-hour production test taken the day before the production log was run. A production test was not taken during the period the well was logged due to difficulties with surface test facilities. This much change in fluid production over a 24-hour period does not seem likely, however.

Figure 2 depicts a typical graphical presentation of results of a packer flowmeter type production log in Well F. The data may be presented in two ways, i. e., a zone analysis or a production profile. The first presents the volume and type of fluid being produced from a given interval while the latter is a cumulative picture of the zone analysis and illustrates the volumes of each phase of fluid moving past any given point.

This log clearly shows that the interval below 4738 ft was producing 100 per cent water. As a result of this log, the well was plugged back to 4739 ft. This plug-back was successful with the water production being reduced from 225 to 52 BPD, thus indicating that the log was correct. It is noted that oil production also decreased from 104 to 71 BPD following this plug-back.

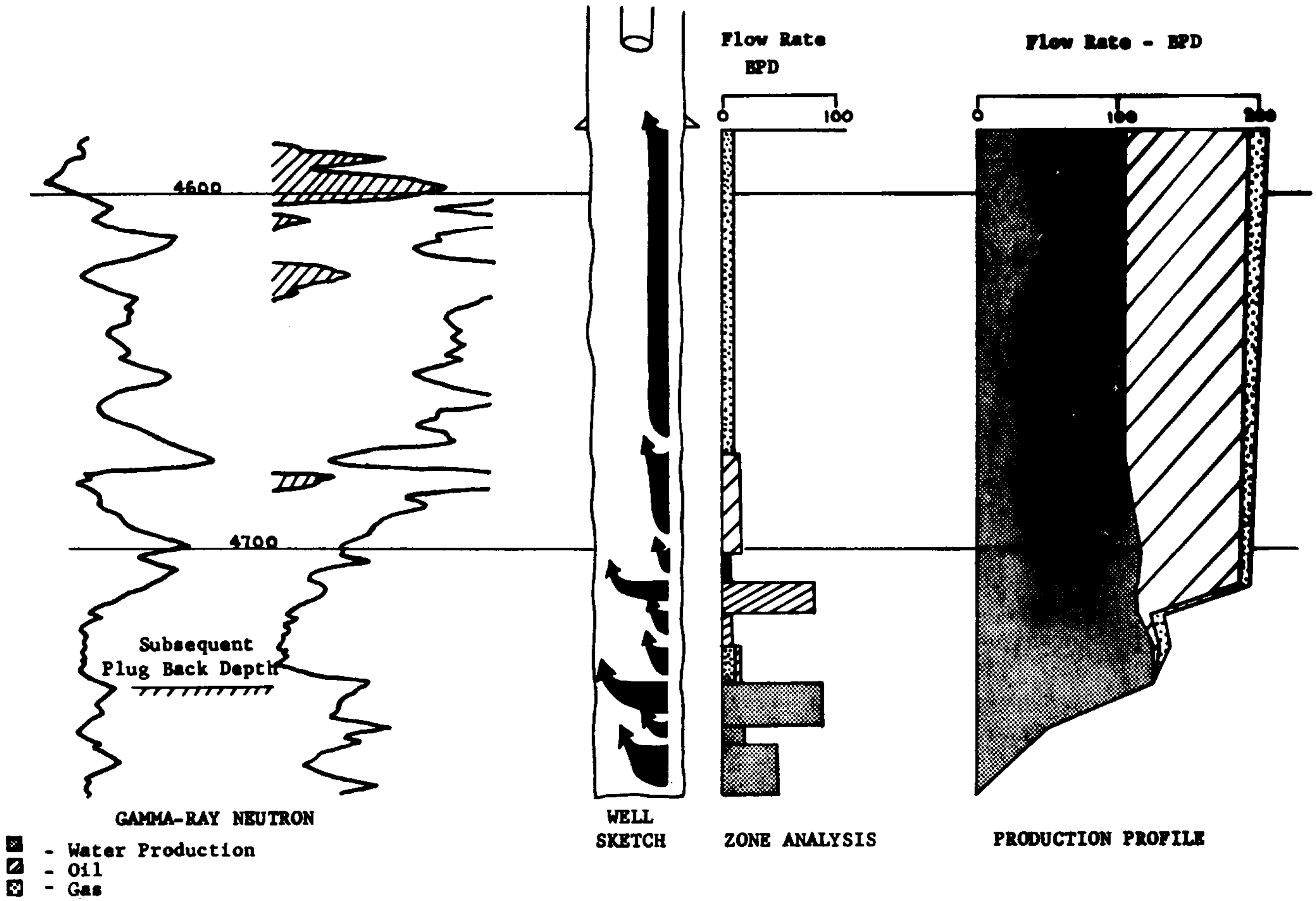

FIGURE 2

Results of Packer Flowmeter Type Production Log — Well "F"

Since the log indicated only a trace of oil coming from the interval pluggedback, the exact cause of this decrease in oil production is unknown. Possibly, back pressure resulting from raising the pump 200 ft and from installation of the smaller 1-3/4 in. pump prevented this interval from producing at normal capacity. Therefore, only a trace of oil was indicated. A second possibility is that some damage of the upper productive intervals may have occurred at the time the plug was set. In this particular well, the interval pluggedback is believed to have considerably higher pressure than the upper interval. Thus, some backflowing of plugging material could have occurred.

A plug-back was also attempted in Well B to the top of the zone indicated as producing most of the water. The plug-back was not successful in reducing production. Further plugbacks could not be attempted without shutting off all indicated oil production. The fact that the plug-back was unsuccessful does not condemn the results of the production log. Considering the history of this well, it is felt that the log was correct and the plug-back was simply ineffective, possibly due to formation fracturing.

No other attempts have been made to alter fluid production based on the results of the ten packer flowmeter type production logs. However, another log in conjunction with the log on Well F, clearly indicates waterflood front advance. As shown on Fig. 3, Well F is the north offset to a water injection well and, as discussed above, reflected large volumes being produced from the lower 1-B zone with oil production coming from the upper 1-B zone and the 1-A zone. A plug-back in Well F proved this log to be valid. A production log on Well E, the north offset to Well F, reflected all the measurable water and oil production coming from the 1-C zone and base of the 1-B zone. Insufficient fluid was indicated to be coming from the main portion of the 1-B zone or the 1-A zone to be seen with this survey. These results are what would have been expected when considering normal flood front advancement from the south offset water injection well through the structurally lower, more permeable zones. Core data on offset wells show that permeability values for the 1-C zone are two to six times greater than for the 1-B and 1-A zones. Thus, flood front advancement would be expected to proceed at a faster rate through the 1-C zone.

The remaining three dynamic surveys were obtained through the annulus with the temperature-tracer-salinometer type apparatus. Figure 4 depicts a typical presentation of results obtained with this type log in an open-hole completion. Keep in mind that since these three surveys were run in shot-hole completions, tracer velocity readings could not be obtained and the results are therefore qualitative. In addition, note that the tubing in this example well is set near bottom with the perforated nipple set from approximately 4166 to 4170 ft. Flow above this point should therefore be downward while any fluid being produced below this point should

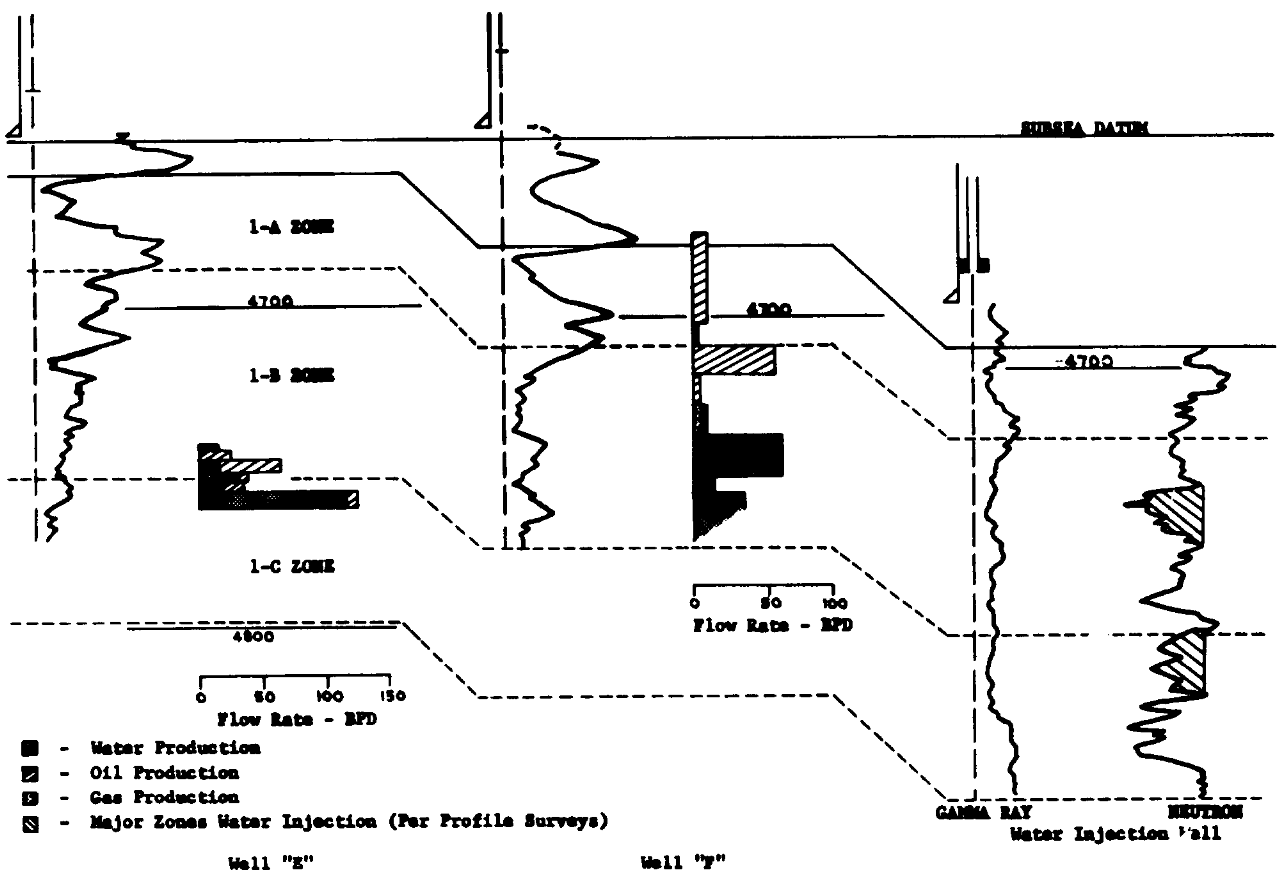

FIGURE 3

Evaluation of Flood Front Advancement

move upward. This is the only well which was equipped in this manner and the logging tools were run through the tubing-casing annulus and through the annular space between the tubing and the wellbore.

The temperature and differential-temperature log reflect the fluid producing zones to be ward but did not disperse, indicating, essentially, water production below 4138 ft. No fluid movement is indicated below 4172 ft since the drag runs show that this slug did not move.

Considering the three logs together, this survey indicates that the main zones of fluid production are from 4002 to 4012 ft, 4046 to 4073 ft

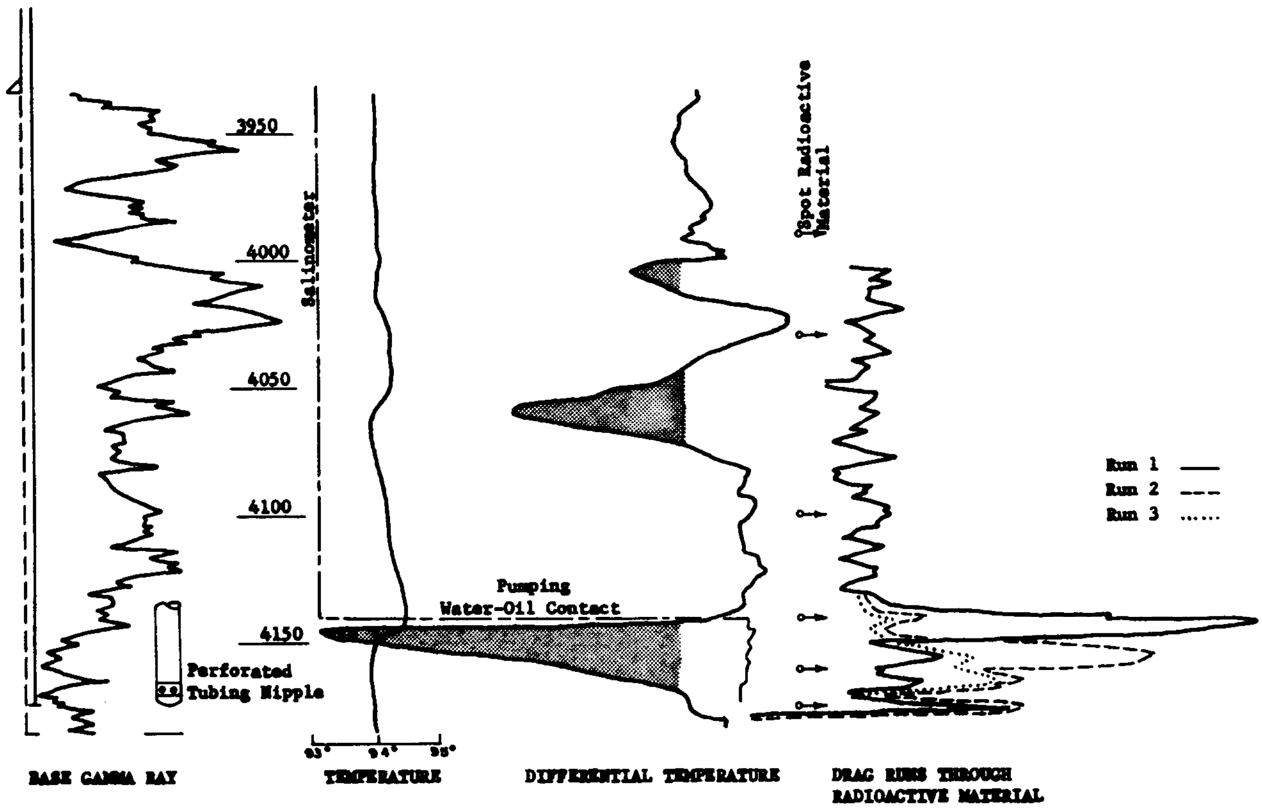

FIGURE 4

Typical Results of Temperature — Tracer — Fluid Analyzer Type Survey

4002 to 4012 ft, 4046 to 4073 ft and 4142 to 4168 ft. The salinometer shows a producing water-oil contact at 4142 ft, indicating water, or possibly water with some oil, being produced below this point. The drag runs shown were made after placing oil-dispersible radioactive material opposite all the indicated producing zones while the well was pumping. These runs show that all material above 4138 ft readily dispersed, thus indicating oil production above this point. The material between 4138 and 4172 ft moved downand 4142 to 4172 ft with oil production above 4142 ft and water production, with possibly some oil, being produced from 4142 to 4172 ft. No production is coming from below 4172 ft.

At the present time, results of this type of survey have not been confirmed through remedial work. At the time of writing this paper, an attempt is being made in one well to shut off an apparent zone of water breakthrough defined by one of these surveys.

SUMMARY

The results of the thirteen surveys reviewed show that production logging offers a suitable means of analyzing wellbore flow behavior in wells where reservoir or wellbore conditions prevent effective testing by other methods. In fact, even in stratified reservoirs where effective separation between zones is available, production logging may be preferred over other methods of testing. This is based on the consideration that all the zones can be evaluated individually under dynamic conditions more nearly representing normal flow behavior. It is recognized that in some wells conditions such as the existence of high gas-oil ratio or gas producing zones will make the results of production logging questionable.

When preparing a well for production logging, it is probable that some changes in producing conditions will be required, such as raising the tubing or changing the tubing and pump size. In either event, the effect of this change on flow conditions will need to be considered and evaluated on each well. If the resultant change in producing characteristics can be tolerated when production logging, even under the somewhat adverse conditions of logging through the annulus, results suitable for analyzing reservoir and waterflood performance should be obtained.