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MAXIMUM USE OF WELL PROFILE INFORMATION

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ABSTRACT

Interpretation of the information obtained from well profiles is not an exact science. Preliminary interpretation is subject to local conditions, experience, and performance data. As with all types of log interpretation, other surveys are sometimes required.

Profiles are valuable to supply information on completion and production efficiency, for control of injected water to obtain maximum flood sweep, to determine the efficiency of the mechanical conditions of the well, and to determine the causes of unpredictable behavior of a well.

Methods and tools are discussed in respect to each technique's application to the well conditions and the information desired. Typical surveys shows the capabilities and hole conditions that can contribute to interpretation errors. From this discussion, techniques on techniques can be selected to obtain the maximum information on each well.

The future of profiles will be determined by the ability to select the technique and the development of well histories to enable further interpretation of the information obtained.

References and illustrations at end of paper.

INTRODUCTION

The knowledge of injected fluid movement in and adjacent to the borehole is an approach to determining reservoir behavior.

Interpretation of these observations is not an exact science. There are many known parameters that apply; but as with all types of surveys, many more must be assumed. Any preliminary interpretation is subject to alteration by local conditions and experience, prior or subsequent information from logs and performance data, etc.

Useful and valid information can be obtained in both primary and secondary operations, however, by utilizing the proper surveys and equipment for the information desired. Knowledge of both the response and limitations of various tools and techniques, and the effects of possible or probable downhole conditions are necessary to the correct choice.

To obtain the desired flood sweep, the injection well conditions are of the utmost importance. Assumptions as to the mechanical conditions of the well can be misleading and result in wasted effort. The nature of waterflood operations creates many problems in that the wells are not new, records are sometimes inadequate, original completions are not efficient, and equipment is worn. Injectivity profiles can provide most of the answers to questions

concerning the condition of a well.

Profiles are used to determine a wide variety of downhole conditions in both injection wells and producing wells in waterflood operations. Various tools and techniques are available to meet all well conditions. The two most commonly used are the tracejector with dual detectors and the packer spinner tool, supported by calipers and temperature tools as required [Fig. 1].

REASONS FOR PROFILES

1. To confirm predicted performance or determine cause of unpredictable behavior by:

A. Initial injection [or production] pattern.
B. Initial physical problems [thief zones, channels, parting planes, etc.].
C. Stabilized injection patterns.
D. Developed or induced problems.

2. To determine effective zone flooding by observing effects of:

A. Pressure build-up.
B. Fill-up.
C. Flushing or top washing.
D. Vertical sweep.
E. Formation solubility or "weathering".
F. Plugging.

3. To assist in determining economic feasibility by:

A. Indicating extent of preparation and/or remedial work needed for effective operation.
B. Determining optimum rates and pressures needed.
C. Observing formation characteristics under actual operation.

4. To determine effectiveness of stimulation and corrective measures by comparison of performance results correlated with subsequent surveys.

METHODS AND TOOLS

Basic Tracers[1]

Radioactive material is introduced into fluid stream at the surface or dumped in the hole above the zone with dump bailer and its path of travel and accumulation observed by successive logging runs over the zone of interest [Fig. 2]. Qualitative evaluation is derived from the points of accumulation as indicated by gamma log. Very little control can be exerted once the material is placed, and considerable masking of true information can result from screening, spreading, and fall-out. Recommended for frac tracer [sand or resins] and zones of extremely high permeability or porosity.

Tools Used:

A. Simple gamma detector
B. Gamma detector with attached dump bailer

Materials:

A. Solid particles [sand-resins-flakes]
B. Miscible carriers [water-oil-benzene]

Applications:

A. In lost circulation zones
B. In some channels
C. In determining effectiveness of stimulation

Expanded or Improved Tracer

Analytical runs are made by releasing miscible material into the flow stream at selected points [above zone, bottoms and tops of zones and/or perforations, etc.]. The path and amount and rate of dissipation or flushing is observed by successive logging runs through the zone of interest [Fig. 3]. The character of these observations is interpreted to locate zones of fluid acceptance, channels, thin zones or bedding planes both in and out of zone or behind the pipe. Zones of fluid acceptance in adjacent strings and/or by specialized well equipment [sleeves, plug valves, etc.]. Only slight quantitative information is available by this method; and irregular borehole, scale, paraffin deposits, etc., can cause misleading results where no supporting information is available.

Tools Used:

Gamma detector with ejector capable of repeated and variable placement of radioactive materials.

Materials:

Miscible and compatible carriers, either liquid or gas.

Applications:

A. In qualitative analysis of zones and channels accepting fluid
B. In planning of logging techniques to obtain quantitative information from profiles
C. In supporting information derived by other means [velocities-flowmeter-temperature]

Quantitative Rates

Velocity determinations are made by positioning the tool at a pre-selected point in the borehole and a small amount of material released. The transitions over a known distance is recorded and the rate of fluid movement over that interval calculated by volume of interval vs transit time. Variations in indicated volume are then plotted as injection profile. There are several methods of determining rate of flow:

A. The standing velocity or multiple burst. Material is released and time measured over a given length of tool [Fig. 4]. This procedure is repeated at each station.

B. Controlled interval or single burst. Material is released and the tool lowered to a pre-selected point, transit time recorded and the tool again moved to a successively lower point, etc. [Fig. 5]. These resultant transit times are computed to a cumulative time plot and related to flow rate between intervals of inspection.

C. Controlled time plot, single burst. Material is released and the tool immediately lowered well below the material. A logging run is made at an index time interval, noting the position of the material in the hole [Fig. 6]. This process is repeated at precise time intervals and the variations of distance of slug travel per unit of time plotted as rate of flow.

[All velocity techniques are subject to error from hydraulic diameters, borehole configuration, zones of fluid egress, inaccurate calipers, channels, etc.; and when used as the sole technique, fall short of complete information. Results should be supported by one or more of the other methods for accurate determination of conditions.]

Tools Used:

Gamma detector with ejector or energizer capable of releasing small amounts of radioactive material to the flow stream.

Materials:

A. Miscible or compatible carrier
B. Solid or ionizing nodule or pill

Applications:

A. In quantitative analysis of rate of fluid movement at selected depths in the borehole to determine injection profile or pattern.

B. In lending quantitative values to the information derived by other methods.

Volumetric Measurements

A Flowmeter Tool [Fig. 7] is lowered into zone and stopped at a selected position. A packer or deflector is expanded against the borehole walls, diverting all, or a known increment, of the moving fluid through the metering device. This rate of flow is transmitted to the surface and recorded as volume or percentage of flow. The tool is then released and moved to another position and the process repeated. The volumes recorded at each station are plotted and the production or injection profiled derived from these plots. Accuracy is excellent where good packoff or isolation can be obtained; but channels outside pipe, or vertical erosion and fracturing near the borehole allow fluid by-pass in unknown amounts. Most of these tools are limited in borehole size to seven in.; therefore, flowmeters are not recommended for shot or enlarged holes. These tools are excellent for production evaluation and for use with borehole fluid densiometer to define volumes of the various fluids moving in the borehole. Temperature is considered, since the packer elements on some tools are limited to 180F.

Tools Used:

A turbine or metering device capable of being lowered into the hole and recording either all, or a known portion, of the fluids moving at any given point.

Materials:

None, with the exception of an expandable packer of bladder used on several of the tools.

Applications:

A. In quantitative determination of fluids moving at any given point [Fig. 8]

B. In identification and isolation of thin zones and/or holes in casing

C. In production evaluation [zones and rates of production defined]

D. In determining optimum production rates [flowing or gas lift wells]

E. In evaluation of stimulation treatments and remedial work

Borehole Fluid Identification

A Borehole Fluid Densiometer is lowered to zone of inspection and a log or plot of relative densities at various depths made by two logging techniques, station settings or standing readings, and continuous logging runs. A sample of the borehole fluids is impressed across the detecting elements and the resultant changes in density or resistance are plotted as fluid identification at their respective depths [Fig. 9]. High resolution is possible with calibrated sensitivities. Interpretation is simple in two-phase flow, more complicated in three-phase systems since the densities of the total fluids

at any given point are recorded. Velocity effects in compressible fluids must be reconciled by surface calculations and downhole volumetric measurements with a flowmeter. Identification of static or moving fluids is also a flowmeter function. Log is not recommended where production is 90 per cent water, or more.

Tools Used:

Downhole tools capable of detecting differences in borehole fluids at any depth in the well [Fig. 10]. Several methods are used, i.e., resistance between electrodes, capacitance, sonic detectors and radiation detectors. The last is the most commonly used, since the parameters affecting the detectors are more simply recognized and controlled.

Materials:

None

Applications:

A. In qualitative identification of borehole fluids in place
B. In quantitative analysis of production in two- and three-phase systems
C. In determining gas/oil/water contacts
D. In pinpointing gas and oil entry points

Temperature Analysis

The temperature tool has been used, both successfully and unsuccessfully, in a wide variety of applications, and much has been written of these efforts by authors such as Boone, Bird, Dale, Ramey, Nowack, Terry and others. An outstanding study and compilation of these records was presented by Edward T. Connolly with Imperial Oil Limited of Canada.[3] For purposes of brevity, we shall discuss the Temperature Log as supporting information related to fluid movement analysis, or flow characteristics and evaluation.

Tools Used:

A downhole tool capable of detecting slight changes in borehole temperatures, either absolute or differential, and transmitting this information to the surface for recording.

Points for Analysis:

A. Injection profiles
B. Fractures and stimulation
C. Production analysis [gas entry]
D. Communication [producing wells]

Several tools and techniques have not been listed here. The group discussed should provide a good cross-section for understanding, since all others in use at the present time are variations on the main theme and can be studied at length in individual articles.

CONDITIONS AND REQUIREMENTS FOR SURVEYS

Fluid movement analysis is subject to a great number of constantly changing conditions, some proven and some only assumed. To obtain the most information at the least expense, we must reduce these variables and unknowns as much as possible.

Pre-job preparation should include several items to assure efficient operation and valid results, i.e.:

A. A check on the physical and mechanical conditions of the well. Numerous jobs have been cancelled or delayed because of restricted tubing, pin collars, packers set below perforations, undue fill-up, improper valving, etc.
B. Positive control of injection or production fluids [valves, meters, chokes, etc.]
C. Surface indication of rates and pressures for correlation to profile results
D. Stabilization. This is of prime importance. Wells fluctuating in rates require much longer to survey, since each reading must be reconciled with the total rate at that moment. Some zones are balanced quite critically, and may take fluid at one rate and pressure and not at another.
E. A history of the well, such as logs, lithology, completion procedures, workovers, etc., should be available for reference, as well as any unusual conditions in the project [breakthrough, sealing, rapid pressure changes, plugging]. A log showing some unusual results may be resolved by the first alternate technique, instead of "fishing" or eliminating possibilities by trial-and-error methods.

Special well conditions or suspected difficult logging conditions in a proposed flood can many times be alleviated somewhat by deciding the type information needed and tailoring the well set-up to fit the tools indicated. In the case of the dual injector [Fig. 11], a sliding sleeve was installed just above the packer and well below the zone of interest. Normal injection was down the annular space; but when surveys were needed, a plug was dropped on the seat. The sliding valve was opened, allowing injection into the zone from the tubing. After sufficient stabilization period the survey was run from inside the tubing by ejecting material from the tool; and a simple annular velocity log and tracer was run upward from the bottom of the zone.

SELECTION OF TECHNIQUES

The methods and techniques available for

fluid movement analysis are legion, each having both strong and weak points. The information obtained from these operations is overlapping; but one type may be inadequate in an area in which another is strong, i.e., a velocity profile alone may leave doubt as to a channel behind the pipe and conversely, analytical runs may show the channel with good detail but the distribution percentages may be greatly in error.

As with primary logs, complete information can be obtained by running all the surveys offered by several different companies, but the cost would be prohibitive. A combination of several of these techniques in a single presentation is available from a limited number of service companies at present, but even these must be adapted to the particular conditions of each job.

Flexibility of tool selection is governed by several aspects. One consideration, for example, is physical set-up. Small diameter tubing and/or packers [1-in. tubing — cement-lined 2-in. tubing limits the tools presently available to the tracer-type probes with single detectors and/or less sensitive components, thus limiting the amount and quality of the information received.] Dual string injectors and annular injection set-ups require special attention in tool arrangement and techniques. Material must be introduced into one stream and logged from inside the adjoining tubing to prevent hanging tools. Dual detectors at various spacings must be used if velocities are to be obtained. Miscible radioactive materials must be used in these instances to prevent masking effect in the annulus.

High injection or production rates may affect the choice of tools, since the flowmeter has definite rate limits and the rate may have to be altered to allow surveying. This can, in turn, alter the actual profile until it is no longer representative of normal conditions.

A suspected bedding plane or thin weathered and eroded zone may call for a flowmeter for pinpoint determination, but a log in an area of known channeling should definitely include tools capable of detecting and delineating a channel.

Producing wells must have both flowmeter and borehole fluid densiometer for complete analysis, but qualitative identification of gas entry zones can be accomplished with B.F.D. alone at a considerable savings in total job expense.

A quantitative breakdown of total produced fluids can be the function of flowmeter alone, with slight indication of gas breakout or entry into borehole [erratic and unstable reaction of turbine].

Thin zones or single-point perforations may be qualitatively analyzed by either a basic tracer run or analytical runs [injection wells or "pump in" production logs] where conditions prevent use of flowmeter.

Areas of known corrosion build-up resulting in decreased or erratic borehole diameters are best quantitatively surveyed by the flowmeter, unless the build-up prohibits the use of packers [sharp projections] or tends to flake off, plugging the turbine.

Extremely low rates decrease the accuracy of all radiation-type techniques and increase the time needed to obtain a survey, but a minute breakdown of low rates may cause several runs with a flowmeter to change turbines.[5] Rates lower than seven B/D cannot be detected with flowmeter.

High pressures limit tools to those with enough weight to overcome pressure interference or necessitate the use of special surface equipment [at extra cost].

These and many more problems or considerations affect the choice of tools and techniques. These are better suggested by one who is familiar with all the limitations of tools and methods.

The engineer in charge of the project should determine the major point of interest and discuss this and any known well or field conditions with the service company representative before positively selecting the type of service most needed. This allows tailoring the service to a particular condition and reduces the probability of inadequate information.

SOME TYPICAL PROBLEMS DISCLOSED BY FLUID MOVEMENT ANALYSIS

Converting fields to flood and pressure maintenance generates many problems, since old wells are normally used for injectors. Records are usually inadequate; perforations may be plugged or never have existed; some zones may be more pressure sensitive than others; liner tops may leak or channels may exist that never show during the production period.

One example of these problems is the well [Fig. 12] which was converted to injection, assuming all perforations open and open-hole porosities equal to those in the perforated interval. Profiles run after two months injection showed only one set of perforations and a portion of the open hole accepting fluid. Later remedial work re-opened plugged perforations and adjusted profile until it was acceptable.

Not all formations accept fluids at the same pressure and rate. Profiles run at two

different rates [Fig. 13], showed that patterns altered considerably by rate increase. Better distribution of fluids at higher rates indicate that the normal rate of injection should be increased.

Wells in the same field do not react in the same manner, as shown in Fig. 14. The three wells, although completed in the same formations at approximately the same zones, show different profiles when surveyed. To obtain efficient sweep, remedial action must be taken to make these injection patterns acceptable.

Liner tops always warrant investigation. In Fig. 15, we find that all injected fluids are leaving the borehole at the top of the liner. In this instance, a simple squeeze job corrected the situation.

Casing shoes are another trouble point in many old fields. In Fig. 16, all fluids are leaving at, or just below, the shoe. When this condition is observed, a channel is immediately suspected.

Profiles alone do not determine the existence or extent of a channel. Let's follow the technique of further analysis after determining that all fluids are leaving at the casing seat. A further check is made for channeling by positioning the tool at a point above the casing seat [Fig. 17] and ejecting another burst of radioactive material. Recordings of the reaction of both detectors are run for a period of time and the secondary reactions interpreted as fluid moving up outside the casing to a point opposite or above the detector. [Note reactions detector 2 and detector 1 after the initial burst.]

For further information as to the channel, we must follow the path of the radioactive material [Fig. 18]. In this instance, several other considerations entered into the analysis. First, the 100 per cent rate indicated by the velocity in the pipe was not consistent with the indicated rate at the surface. Second, there was abnormal action of the sensitive collar locator at a point two joints above the casing shoe. A new burst of radioactive material was ejected above this point, and its movement traced by successive logging runs. Note that in runs one, two and three, immediate build-up of radioactive material, or profiling, is apparent above the casing shoe, although the main body of the slug has not yet reached the shoe. The build-up, or path, of radioactivity indicates that a portion of the material is leaving the borehole at approximately 4,900 ft and moving down outside the pipe to about 4,980 ft. The main body of the burst moves downward to the casing shoe and channels back up outside the pipe to about 4,980 ft. The sequence of build-up and dissipation of radioactive material identifies the thin zone and bedding plane at 4,980 ft as the point accepting nearly all the fluid. In this manner, an immediate problem has been identified and a possible troublesome formation characteristic pointed out for further reference.

Fig. 19 is a chart of the incidence of some of the problems encountered in various fields.

All injection problems are not insurmountable, however. Profiles can be changed by several different methods. An undesirable profile may many times be made more acceptable by the simple expedient of changing rates and pressures. In the case of relatively new flood efforts, the adverse effect of oriented fractures, or directional permeability, can be changed by changing the position or orientation of the injection wells. [Moss Unit Flood - Ector County, Tex.]

Extreme localized conditions may dictate alterations of injection technique, such as the intermittent injection used in the Sprayberry Trend area.

Individual wells respond to remedial work in many cases and plugging agents are now receiving a lot of interest. New materials and methods are being devised and tested, one of which has been comparatively successful [Fig. 20].

The two profiles shown here are the before and after profiles illustrating the results of a chemical grout application to an unacceptable profile. Much of the injected fluid was channeling around the casing seat as well as being injected into an undesirable zone. Application of the AM-9 grouting material changed the injection pattern into one more nearly compatible with the flood endeavor.

CONDITIONS CONTRIBUTING TO ERROR

All surveys are either accepted as being correct, or rejected because of incomplete or irrational results. These erratic results can sometimes be rationalized or the reasons for them eliminated or accounted for by recognizing some of the conditions that produce them.

The mechanical or volumetric tools are subject to error or difficulty in operation by several conditions.

In cases of fluid by-pass, all readings are compared to the total flow or 100 per cent reading at a point that assures total fluids moving [in casing or tubing above any possible zone of fluid loss]. The packer is set and a total fluid flow is diverted through the turbine. All future readings are compared with this rate. Assuming a tot seal at each setting, the readings would reflect all fluid moving at that depth

with a valid log resulting. Some formations, however, have vertical fractures or errosion extending past the perimeter of the borehole. When the packer is set total seal does not result. This allows a portion of the fluid to move outside the tool and not be measured by the turbine rotation. The resultant log reflects less than the actual fluid moving in the borehole. The error is then reflected in the profile calculated from the volumes indicated.

An example of this type of error is shown in Fig. 21. A flowmeter was run and the larger portion of fluids was lost above 4,870 ft.

Subsequent readings below 4,870 ft showed an apparent increase in volume of fluid moving in the borehole, indicating a possible zone of discharge below that point. The totals of all the readings dictated a profile as shown, with a zone in the center of the section discharging fluids to the borehole. There was no reverse flow observed, however; and this, coupled with the engineer's information as to the formation characteristics, led him to believe that fluid was by-passing the flowmeter over the upper portion of the zone.

A radioactive profile [velocity and analytical runs] was run and the resultant profile is shown in Fig. 22, compared with the incorrect results from the flowmeter. As seen, the results show almost all the water leaving near the bottom of the well.

The flowmeter results, though in error, proved a localized condition of the formation--that vertical fractures exist in the upper portion of the zone, but do not extend through the impermeable zone from 4,950 to 4,965 ft.

Paraffin or algae in small quantities can restrict the rotation of the turbine to a point that erroneous readings result. Large quantities of paraffin, as well as sand, scale and other debris, can plug turbine completely.

Sulphate or Sulphide crystals form "needles" and sharp projections that sometimes puncture a flowmeter packer or cause "pin-holes" that make complete packoff impossible.

Unstable and very low pressure or vacuum conditions usually result in erroneous logs, if the readings taken at any single interval are not reconciled with the total rate at that time. Usually these pulsations will follow a time pattern or cycle. Valid results can be obtained by monitoring the entire cycle and comparing total results at each station. "Zone swapping"[2] can also be a problem in interpretation, if not recognized.

The radioactivity types of surveys, when used in individual techniques, are subject to the more insidious hazards. Consequently, a great amount of care and experience must be used in determining the results.

One of the more troublesome, but more readily identifiable errors, is that effective hydraulic diameter.

The effective velocity stream is affected by such conditions as proximity to tubing or liner top, perforations [both type and density], zones of large fluid loss, casing seats, borehole size and configurations, rates at any given point downhole, position of tool in well, and others.

Some of the problems existent in logging under these conditions can be seen in Fig. 23. Note obvious changes in velocity, and that true diameter does not necessarily mean true hydraulic diameter. Turbulence and fluid traps can retain enough material to confuse a tracer run. Velocity shots alone would be very erratic, as shown in Fig. 24 [per cent fluid remaining in borehole]. Careful use of several of the techniques available would be needed to reconcile the results and obtain a valid profile.

Some of the erratic results in cased hole can be made more consistent by centralizing the tool; but in irregular open hole, there is little to be gained. Effective slug or material dispersal in the total fluid stream is another means of minimizing this error.

Effective hydraulic diameters can also be altered by algae, soft parrafin, or scale build-up through and adjacent to the injection zone. The actual fluid stream diameter may be reduced to two in., or less. In the case of algae or other soft deposits, the caliper may not indicate this reduction since the legs protrude through it. In this instance, diameter reference for velocity determination would be completely in error. Algae, bacteria, and parrafin have other undesirable side effects, in that radioactive material has an affinity to hydrocarbons. Small deposits, or bubbles, of oil accumulate radioactive material and give the erroneous interpretation of profiling and fluid loss at that point.

Fluids channeling between perforations to a point behind the pipe can often indicate fluid loss at the top or bottom of a set of perforations. Actual zone of fluid entry into the formation can be at a point well removed from the perforated intervals. Care in observation of material dissipation can identify these zones, however.

Back-flow, high pressure discharge, zone swapping, unstable conditions, etc., also effect the results of a radioactive-type survey--as with the flowmeter. These erratic results can be

rationalized, however, by proper manipulation of other techniques.

Extremely low injection rates increase the error in profile determination, since the velocities are based upon cohesive slug travel. As rates are reduced, the material tends to spread and reactions are much less pronounced, causing time intervals to be more subject to error.[2]

TEMPERATURE LOGS

Though much study has been done on temperature logs as a waterflood monitoring device, no method of consistent quantitative evaluation using them has been discovered. The qualitative information overlaps with, and is usually much less defined than, the results of other types of surveys. The temperature log is good supporting evidence to other results, however, and adds a depth of investigation into another disputed condition--cross flow within the formation due to vertical permeability or fractures.

Special attention must be given to operating technique and run series, since the principle of interpretation is the comparison of relative rate of cooling or heating under controlled conditions. The relative heat transfer coefficients of saturated and unsaturated formations must be compared to normal thermal characteristics. Areas that do not have a large amount of controlled temperature log information usually need several runs at spaced time intervals to correctly judge the results.[3]

The temperature log is an extremely informative tool, if used properly; but extending it past its capabilities can produce misinformation --or at best, no compatable information.

FUTURE OF PROFILES

The great value of profiles in analyzing present conditions, assisting in performance predictions, and forcing new remedial developments, has cause the industry to overlook momentarily the period when they will become infinitely more valuable--the day in the future when a series of profiles is correlated to known performance of a reservoir to determine whether a project or flood has been exploited to its economic limits, or not.

Although the process of true profiling is still in its infancy, enough correlative results have been accumulated in certain areas to allow additional recovery from projects apparently depleted. Production results compared with consecutive profiles during the flooding process identified zones still unflushed and helped determine the type of remedial work needed to recover oil still remaining in strata or lenses. Conversely, expensive work-overs to improve injection into some zones have been curtailed when profile series indicated a zone to be flooded out.

The projection of the formations in a West Texas flood, as shown in Fig. 25, should serve to stress the complexity of the problems inherent in secondary recovery operations.

The era of fluid movement analysis as a helpful tool is just dawning. Caution should be taken in the future to prevent inadequate or erroneous profile information.

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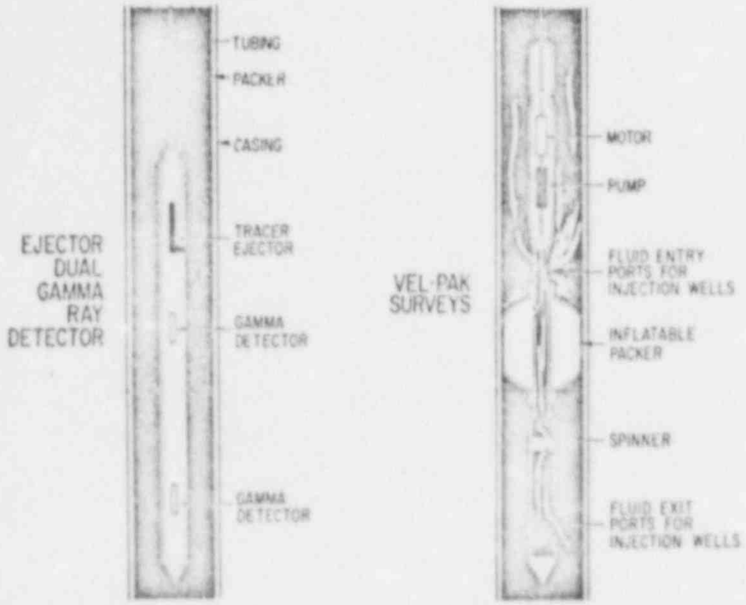

Fig. 1 - Traceject Tools and Flowmeter

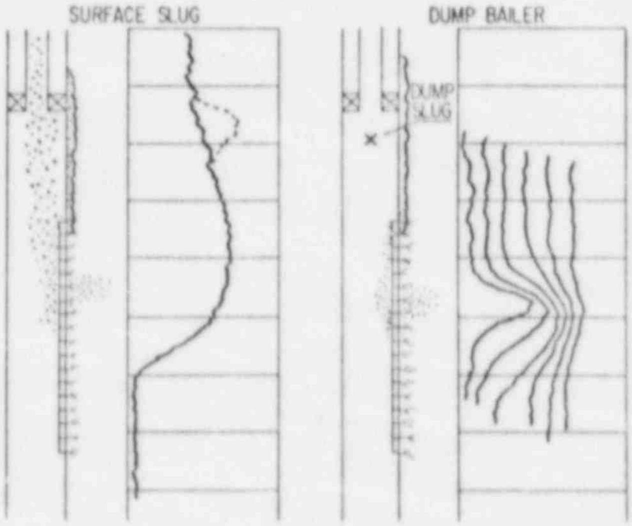

Fig. 2 - Comparison of Tracer Material Dispersion Between Surface Injected Slugs and Dump Bailer

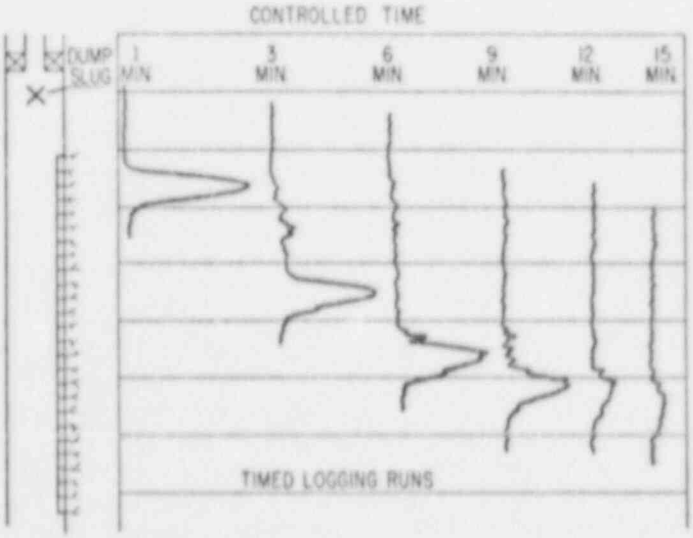

Fig. 3 - Fluid Movement Observations from Successive Runs Using Improved Tracer Technique

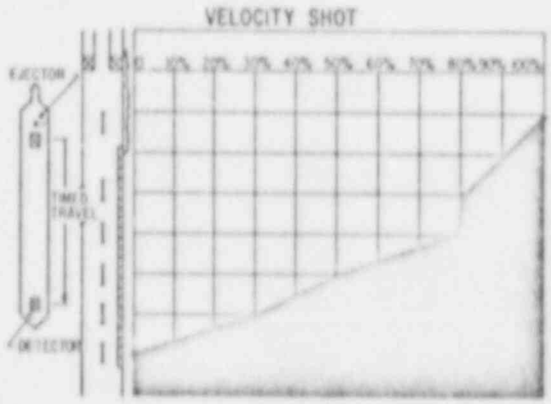

Fig. 4 - Profile as Determined by Standing Velocity Technique; Interval Points as Indicated in the Borehole

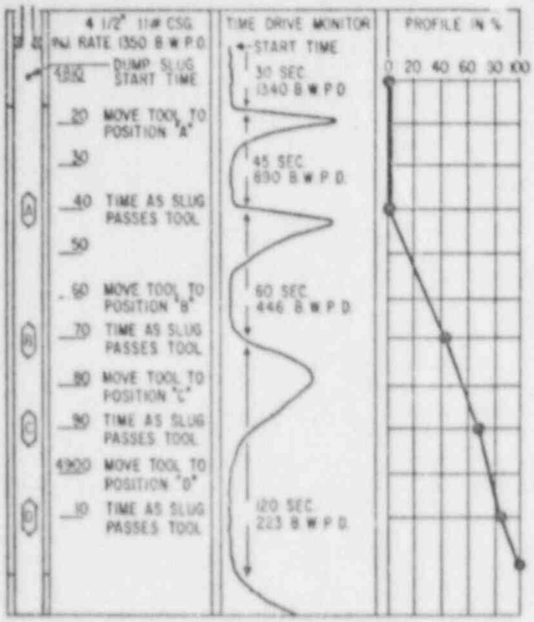

Fig. 5 - Controlled Interval Profile (Note Cumulative Time Drive Plot in Center)

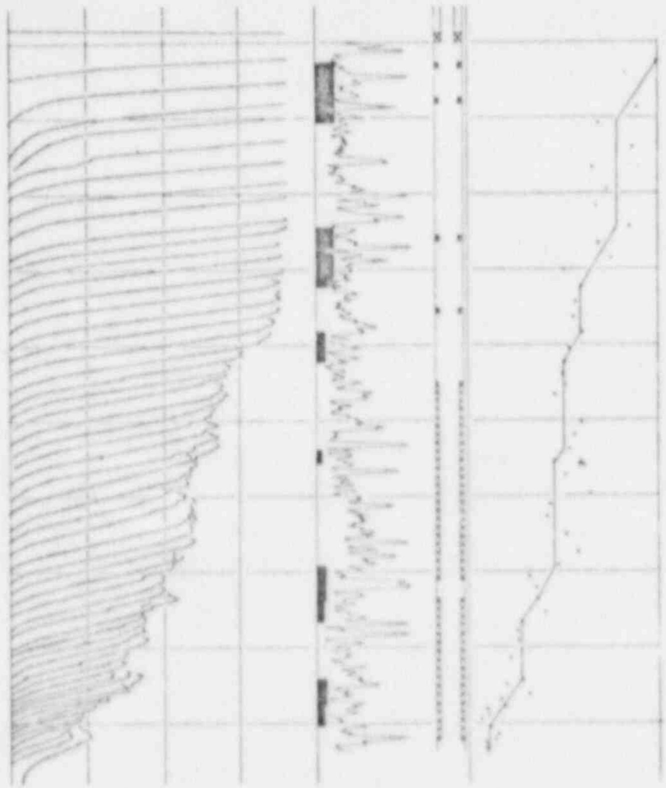

Fig. 6 - Profile as Derived by Determining Interface Movements Down Hole by Successive Logging Runs (Note Dissipation of Radioactive Material as Portions of of Fluids are Lost to Formation)

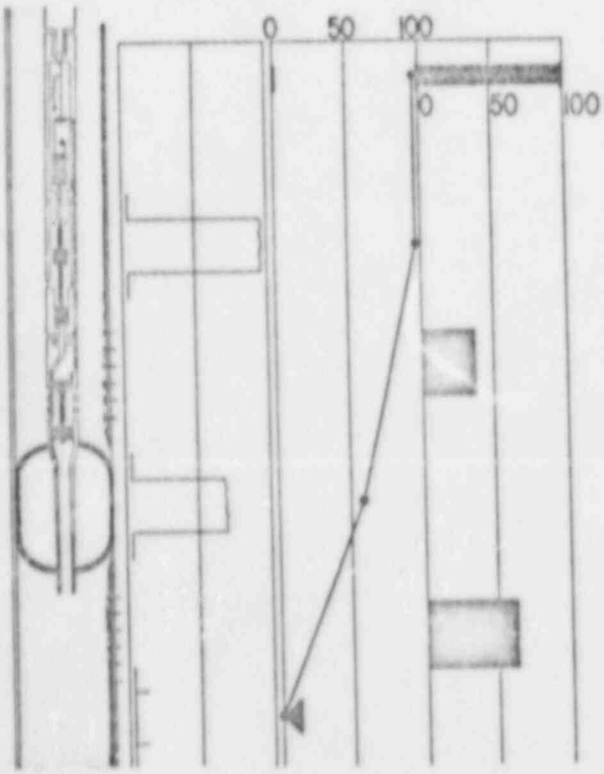

Fig. 7 - Schematic of Flowmeter Tool

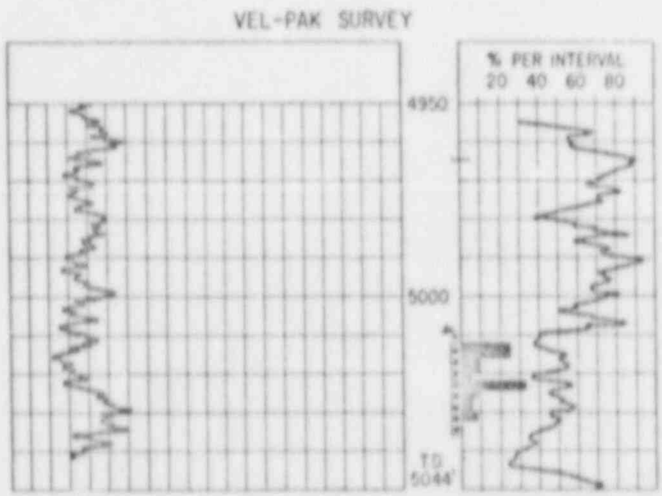

Fig. 8 - Vel-Pak Profile--Thin Zones of Fluid Acceptance Defined

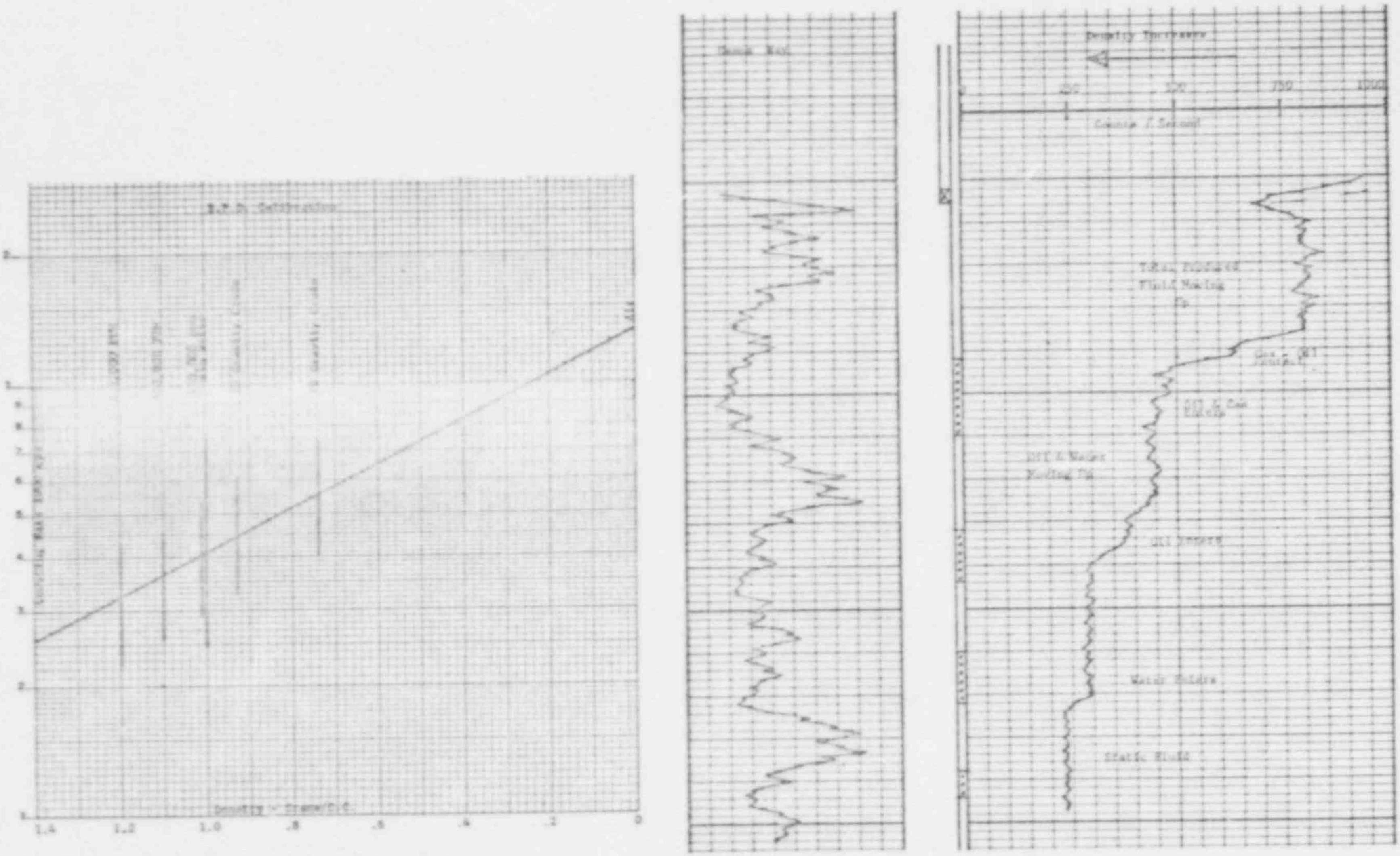

Fig. 9 - Fluid Density Log Showing Reaction as Different Fluids Enter Borehole

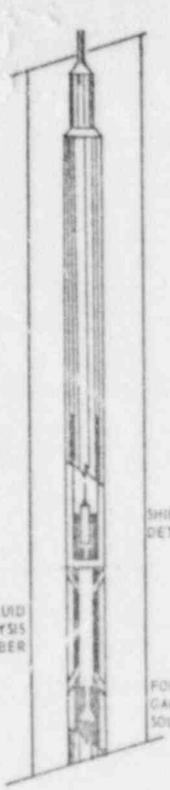

Fig. 10 - Borehole Fluid Densiometer

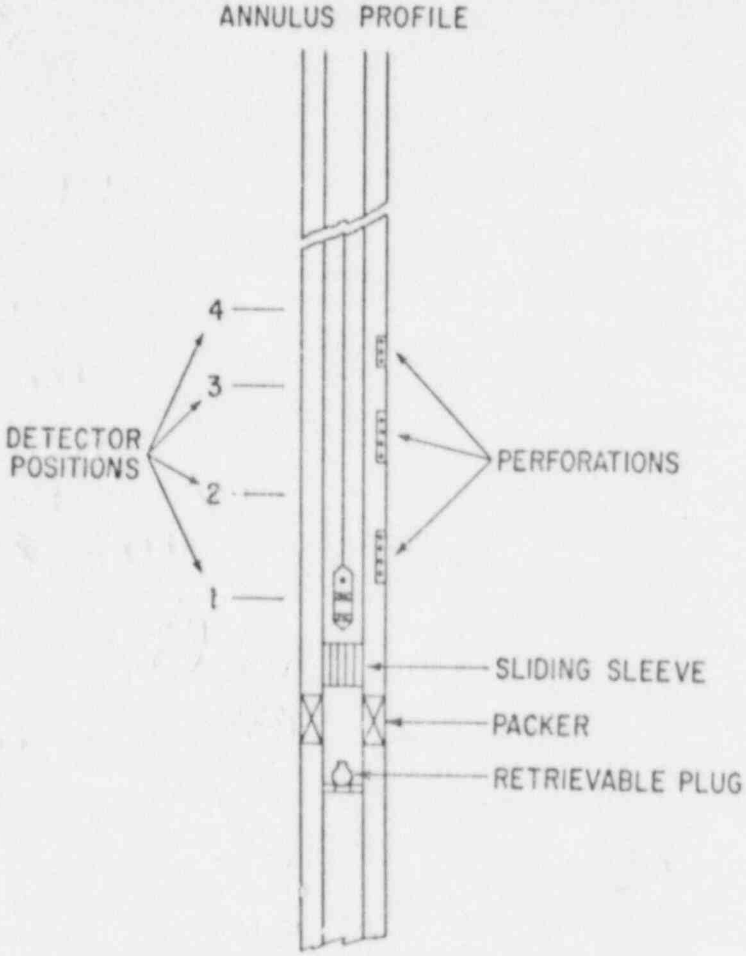

Fig. 11 Dual Injector Rigged for Annulus Profiling

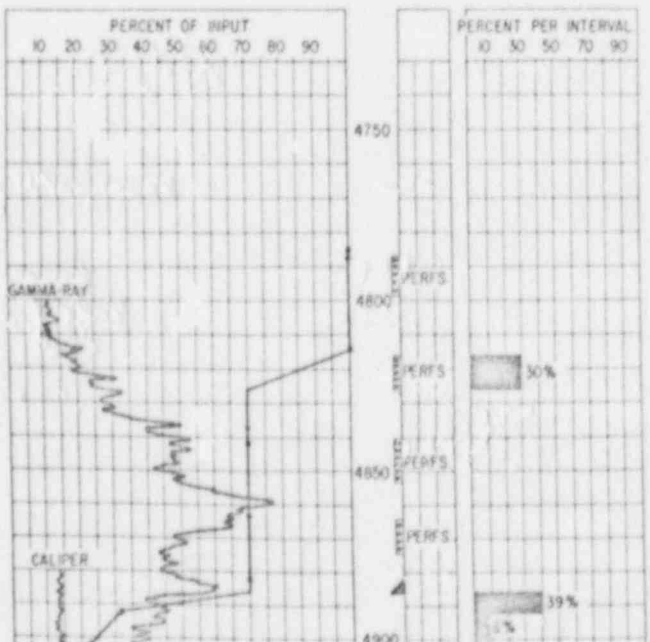

Fig. 12 - Injector Perforations Plugged

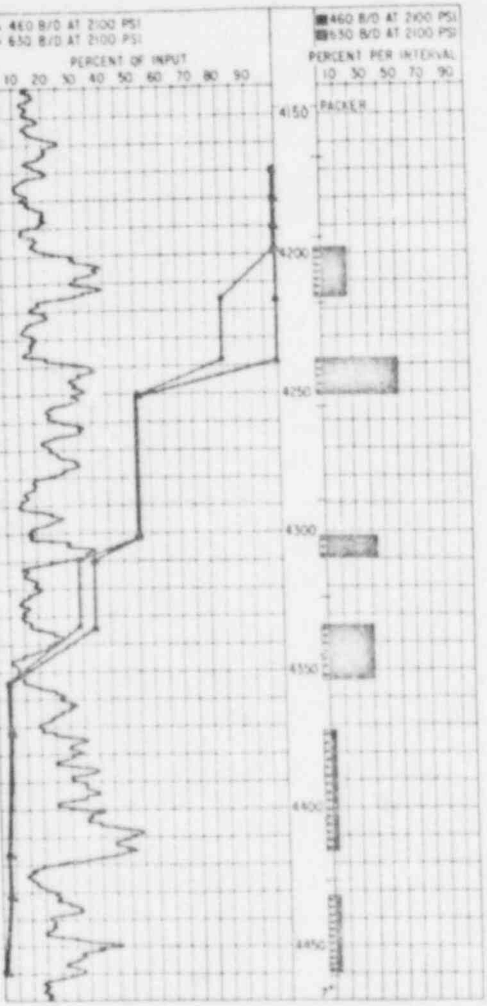

Fig. 13 - Profiles-
Two Different Rates

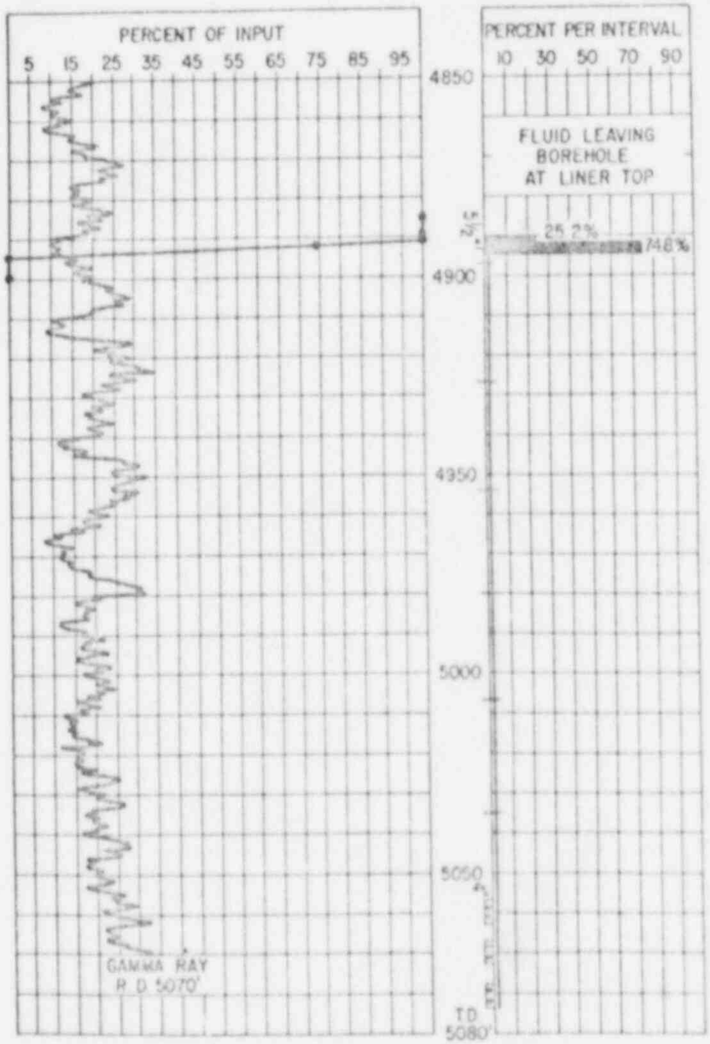

Fig. 15 - Liner Top Leaks

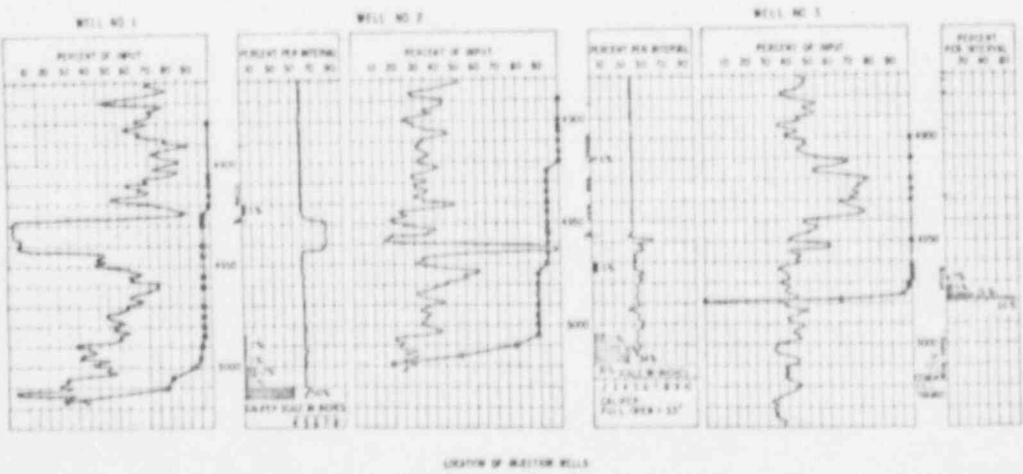

Fig. 14 - Three Wells--Same Formation, Different Profiles

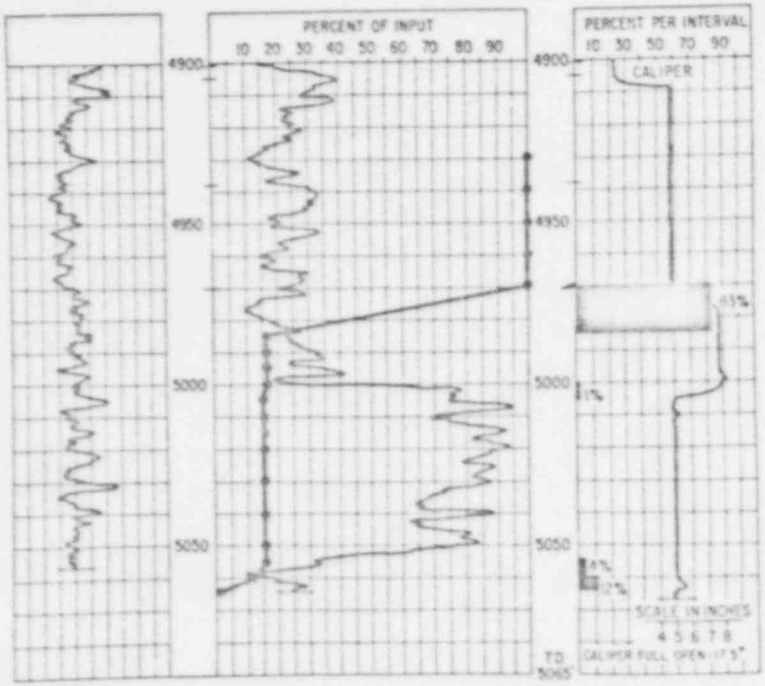

Fig. 16 - Casing Shoe Suspected Channel

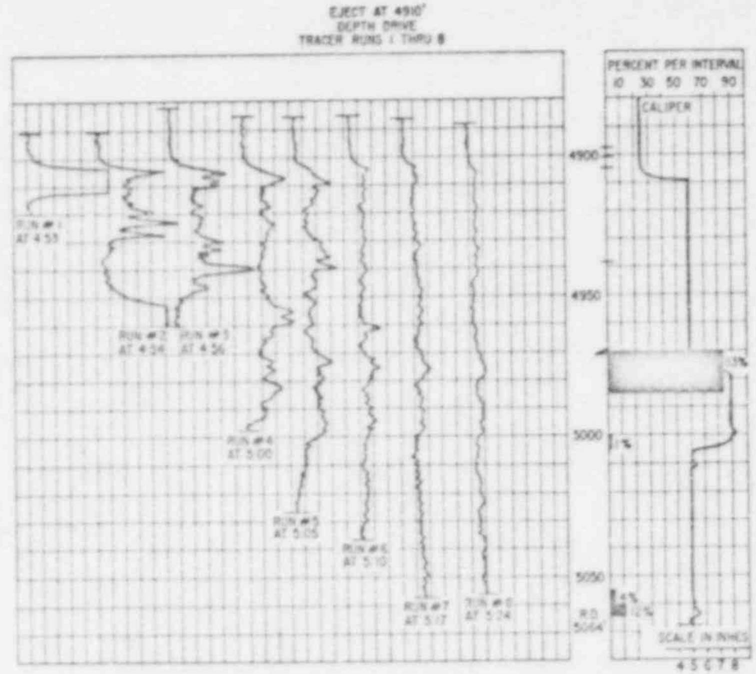

Fig. 18 - Analytical Runs - Channel Definition

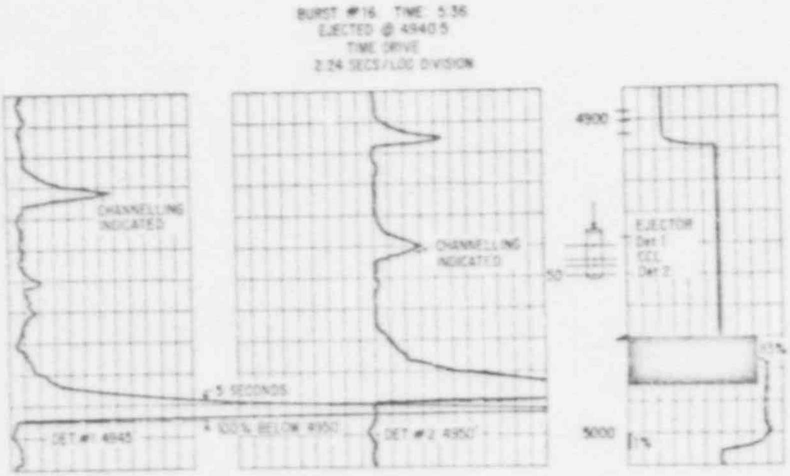

Fig. 17 - Time Drive Recording Channel Check

INJECTIVITY PROFILE
(In Percent)

Field	No. of Wells	Cased Hole: Desired Distribution	Cased Hole: Perforations Not Open	Cased Hole: Thief Zones	Cased Hole: Communication	Cased Hole: Undesired Distribution	Open Hole: Desired Distribution	Open Hole: Thief Zones	Open Hole: Communication At Shoe	Open Hole: Undesired Distribution
Cedar Lake	16						18.7	31.2		50
Slaughter Field	69		15.9	4.3		2.9	46.3	20.2	4.3	26.1
Goldsmith	1		100							
West Loco Hills	8		72.5				25	37.5		25
Midland Farms	3		66-2/3		66-2/3			33-1/3		
Corsico Bend Conglomerate	7	14.3	71.4	28.6	42.8	28.6				
South Caprock Queen	5	20			60	20		20	20	
Scarbrough	2	50	50			50				
Langlie Mattix	7		85.7	14.3	85.7	28.6				

Fig. 19 - Breakdown of Problems--Various Fields

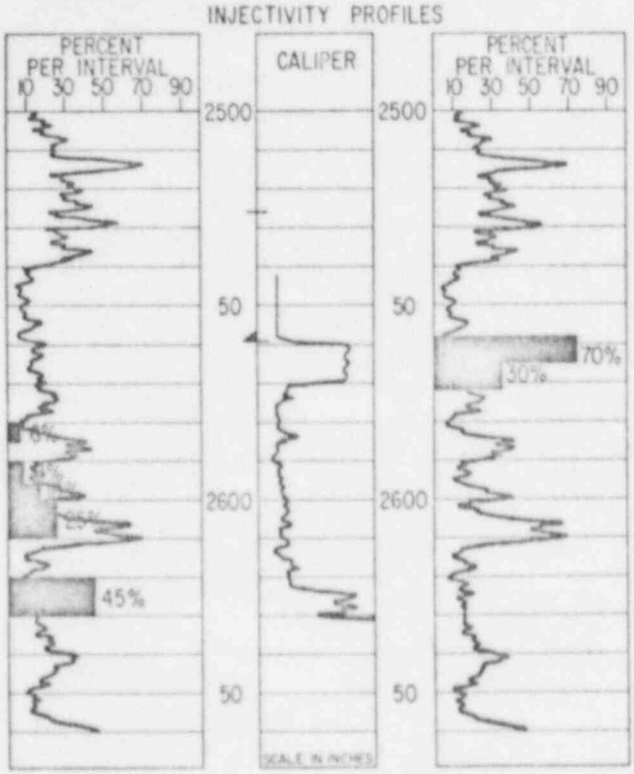

Fig. 20 - Before and After Profiles
Chemical Grout Treatment

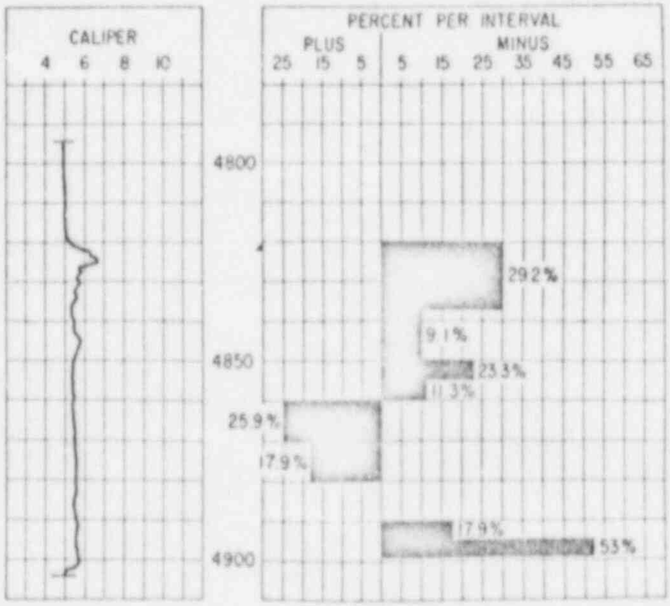

Fig. 21 - Incorrect Profile Flowmeter

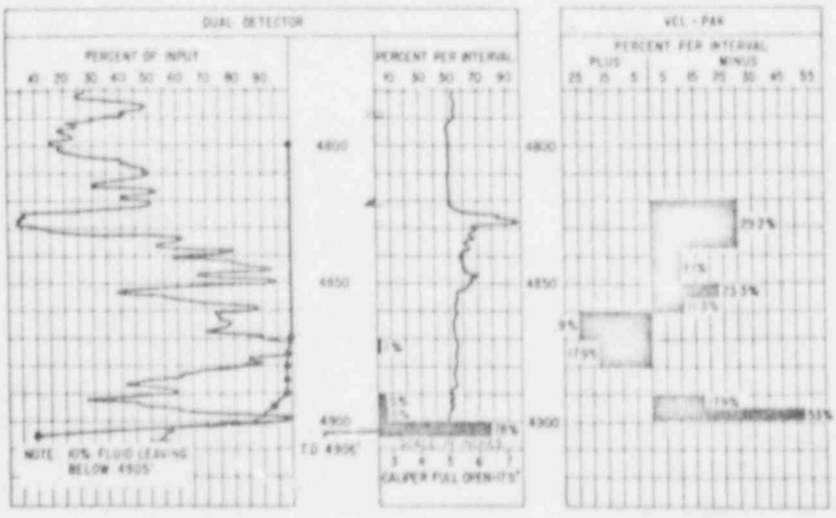

Fig. 22 - Correct Profile vs Incorrect Profile

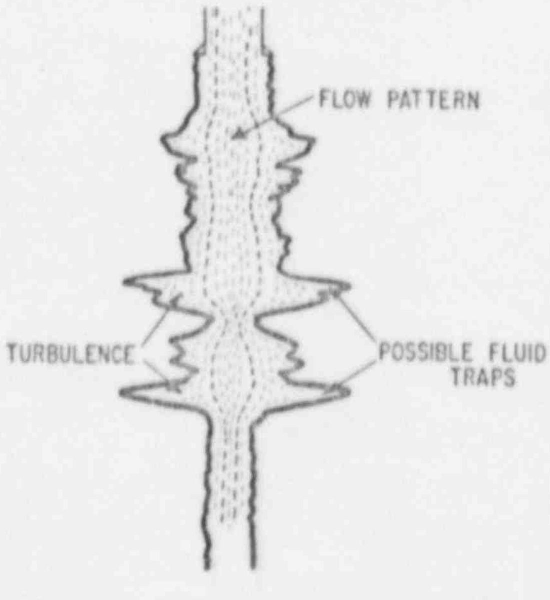

Fig. 23 - Hydraulic Diameter Effects
Caused by Erratic Borehole Diameters

Customer Flow Rate ______ BPS ______ BPD

Western Flow Rate ,0023 BPS 200 BPD

Customer Pressure 900 PSI

Western Pressure 1000 PSI

Time Drive Conversion Factor 1 = 1

Date Injection Started 11-60

Cumulative Injection 459,427 BW to 2-1-65

Distance-Ejector - Top Det. 4-1/2'

Distance-Top Det - CCL 2'

Distance-CCL - Bottom Det. 3'

Distance-Top - Bottom Det. 5'

Perforations
Open Hole

Burst No.	Depth Interval	Time Drive Units	Time Seconds	Interval Capacity (bbls)	Hole Size	Injection Volume (bbls)	% Fluid Remaining in Bore	Remarks
20	4795-4800		48	.1110	5	.1110	100	
19	4810-15		48	.1110	5	.1110	100	
18	4815-20		48	.1110	5	.1110	100	Cased Hole
17	4820-25		43	.1250	5-1/4	.1005	124	Open Hole
16	4825-30		64	.1960	6-1/2	.1490	132	
15	4830-35		61	.1585	5-7/8	.1420	112	
14	4835-40		55	.1445	5-5/8	.1280	113	
13	4840-45		49	.1380	5-1/2	.1140	121	
12	4845-50		55	.1515	5-3/4	.1280	118	
11	4850-55		60	.1315	5-3/8	.1400	98	
10	4855-60		54	.1250	5-1/4	.1260	99	
9	4860-65		50	.1185	5-1/8	.1170	101	
8	4865-70		54	.1230	5-1/4	.1260	99	
7	4870-75		50	.1250	5-1/4	.1170	107	
6	4875-80		54	.1250	5-1/4	.1260	99	
5	4880-85		54	.1250	5-1/4	.1260	99	
4	4885-90		51	.1185	5-1/8	.1190	99	
3	4890-95		50	.1185	5-1/8	.1260	94	
2	4895-4900		55	.1125	5	.1280	88	
1	4900-05		313	.0685	4	.7280	10	

Fig. 24 - Chart--Erratic Velocities

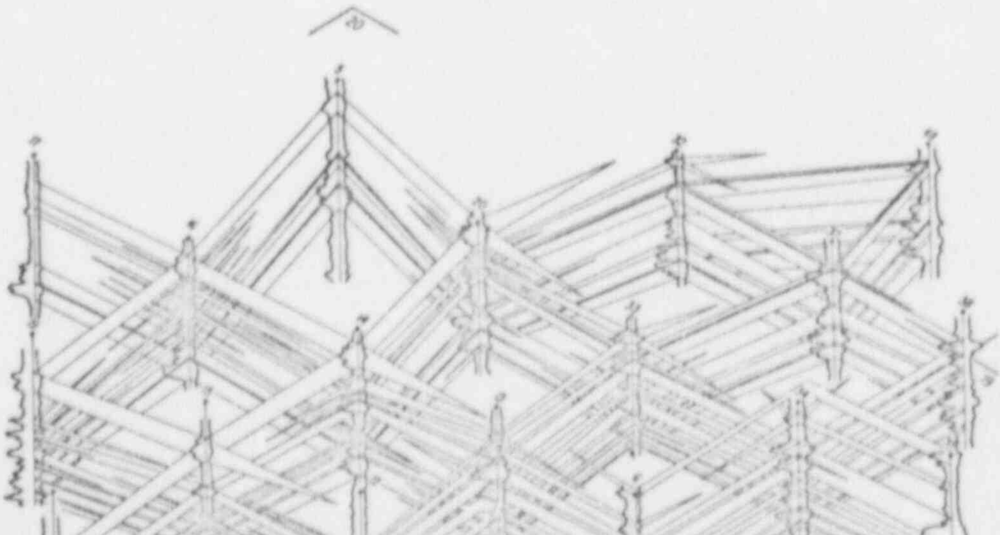

Fig. 25 - Isometric Projection--West Texas Flood

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FACTORS TO BE CONSIDERED IN THE INTERPRETATIONS OF INJECTIVITY PROFILES

Billy P. Morris - The Western Company
R. D. Cocanower - The Western Company

2001

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ABSTRACT

The increasing knowledge of the problems of fluid injection in secondary recovery operations has resulted in the need for improved accuracy of well profile information

As profiling techniques have been improved and well information accumulated, the importance of well conditions to the interpretation of profile surveys is becoming more apparant. Conditions such as changes in tubing or casing sizes, variations in open hole diameter, paraffin or scale deposits, and vertical fractures are some of the factors that cause errors in interpretation.

The mechanical and chemical conditions, as well as the human factor, are covered in this paper to provide the engineer with information needed and the proper procedure to use to obtain more efficient profiles.

INTRODUCTION

Fluid movement surveys, or profiles are "coming of age" in the field of analysis. These surveys, no longer just logs with a rather nebulous meaning, are being used to detect reservoir behavior heretofore only suspected. The interest evidenced by the use of this "new" evaluation technique indicates that it should be placed in its proper perspective as a highly informative survey. The information can only be obtained, however, if the survey is properly executed and analyzed.

The profile log is derived from observing dynamic, or constantly changing conditions downhole by means of one or more tools and methods. The interpretation technique, therefore, must also be dynamic in its approach. A thorough understanding of tools, their reactions, and the conditions that cause these reactions is essential to conclusive analysis.

The tools, applications and operations have been discussed in detail in several other publications, so only primary identification is presented here. The basic "tools of the trade" fall into these categories:

1. Mechanical - Metering Devices, Flowmeters, Spinners

2. Radiation Detectors - Gamma Tools and Ejectors

3. Associated Tools - Borehole Fluid Analyzers, Samplers, Manometers, Temperature, Calipers, etc.

MECHANICAL TOOLS

Assuming absolute or ideal conditions, the mechanical tools probably present fewer problems in interpreting since the signals are usually presented as a direct readout, and can be calibrated for accurate quantitative results. Interpretation of the results falls into the realm of placement technique and controlled conditions rather than of the actual readings. For example: (Figure 1) This well in a Yates Sand Flood showed good distribution into the upper zones at 400 BWPD and 540 psi surface injection pressures. The survey was run under stabilized conditions and found to repeat over a period of several hours. Initial stabilization occurred in approximately 4-1/2 hours and the resultant survey showed that 77% of the additional 180 BWPD was being distributed rather equally over a 15 foot interval of the lower end. Three (3) hours later, however, a slight increase in pressure (20 pounds) and a rate decrease to 520 BWPD prompted another profile run. The results showed that now only one foot (or less) of the lower pay was accepting water, and the upper zone was actually accepting less than at the original rates and pressures. This condition continued for approximately 2 hours, after which time the survey was terminated. Interpretation of results seems to indicate that exceeding the initial rates and pressures did not result in better distribution, but poorer results, and that both zones could not be flooded simultaneously without additional preparation or equipment. The lower zone appeared to accept fluid only so fast (or only a small volume) and the thin section in the lower zone broke down when pressures exceeded 650 pounds. This information is supported by the history of numerous premature breakthroughs in this area.

Results are not always so concrete,however, and the reasons are sometimes operational in nature. The spinner and flowmeter both have similar shortcomings in accuracy.

Fluid Bypass - the reaction of the tools depends upon fluid impressed across the turbine or spinner (Figure 2). As the blades are energized, a pressure differential is formed across them. The differential, though slight, is sufficient to force an increment of fluid past the tool outside the perimeter of the spinner, if the space is not completely sealed. This amount could be calculated if the exact bypass and precise rate at that point were known, but in actual operation these are some of the variables to be determined. The percentage bypassing the spinner would change with every rate or borehole change, and since the survey is attempting to determine the rates at different depths, this parameter is not available to "plug in" to formulation. Moving the spinner, as in the continuous log, serves to increase the probable error, reducing the survey to only a relative pattern of injection.

The packer type flowmeter (Figure 3) fares only slightly better under bypass conditions. The caliper cannot serve as a guideline since, presumably, the bypass area is sealed by the packer. A small bypass area outside the perimeter of the borehole or casing would result in a small increment of fluid passing undetected, while a larger one would result in greater error at the same injection rates. The chart of differential pressures vs operating capacity calls attention to the lower two-thirds of the capacity.

production rates were determined by examining the profile results and the stimulation results were judged inadequate. Subsequent re-treatment resulted in increased production. A point to remember when evaluating flowmeter production logs is the calibration system used for the tools. Most surface conditions dictate the calibration curves be derived with a constant medium such as water or refined oil. The volumes are usually expressed in BWPD.

When calculating downhole flowing volumes of oil and gas, the results must be reconciled and corrected to the calibration medium. GOR's, pressures shrinkage, etc. must be considered to reduce the indicated downhole volumes to the actual calibration volumes before the true profile can be determined. The proper values for these corrections should be determined by a production test <u>during</u> the survey, since a previous test is not necessarily indicative of constant or current conditions.

Total equivalent volumes downhole (gas, oil & water) cannot exceed the volume capacity of the flowmeter tools. The packing element begins to bypass fluid and be "swept away" from the sides of the hole at approximately 12-14 # differential and above this point the element will burst or the tool forced up hole. Always check with the service company's operating engineer for the limitations of each tool and well set up.

Debris (sand, scale, algea, paraffin and precipitates, etc.) also cause operational problems (Reference 1) due to the precise construction of the tools. The conditions are often severe enough to make logging impractical by this method. There are no operating techniques or methods available for correction when this occurs and another method of surveying should be investigated. Temperature in producing wells becomes a problem since the materials used in the packing element become permeable to gas at 180^{o} or above and lose elasticity and tensil strength.

RADIATION DETECTORS

Profiles obtained using tracer ejectors and multiple radiation detectors provide a combination of methods to measure fluid movement in the borehole and behind the tubing or casing. The use of solution tracers have been found to provide more reliable interpretations than the earlier activated solids. (Ref. 4)

The velocity type survey utilizing the dual detector system has eliminated the human error present in the single detector tools. The interpretation of the information obtained requires a knowledge of the fluid flow types and the borehole mechanical conditions.

FLUID FLOW CONSIDERATIONS

The interpretation of time readings has customarily been made on the basis of piston type displacement between the two detectors and utilizing the calip ed hole diameter over the interval to determine the volume rate of

flow. (Ref. 5) It is possible that in some cases such interpretations could be correct, but quite clearly it would only be happenstance, and could be in error by 20 to 100%.

The reasons for such large errors can be described as follows. The initial discussion is based on fluid flow in a round circular pipe without a logging tool being present. When a fluid flows in a pipe, there exists a continuous increase in velocity from the wall to the center of the pipe. At the wall of the pipe the water velocity is zero and increases to a maximum velocity at the center of the pipe. The maximum water velocity in the center may range from 20 percent to 100 percent greater than the average water velocity. This large difference between the average and maximum water velocity depends primarily on the Reynolds number of the fluid. Figure 8 shows a plot of the daily injection rate in barrels/day versus Reynolds number, DV_p/u for various pipe sizes. This chart was constructed for a salt water of 64.7 lbs./cu. ft. density and temperature of 90°F., which is believed to be sufficiently representative to have fairly general application of water injection service.

The interpretation of the transit times on the dual gamma ray tool should consider three flow regimes. (Turbulent, Transition, and Streamline)

Turbulent Flow:

Turbulent flow of water occurs when the Reynolds number exceeds 2,850. This number represents an average value and can vary. Reviewing Figure 8, it will be seen that turbulent flow will occur in the tubing and for a considerable distance into the open hole for most all water injection wells serviced thus far. Turbulent flow provides for mixing inside of the fluid, but the average fluid velocity will range from about 0.72 to 0.82 of the fastest streamline measured in the center of the hole. If the water injection rate is 1,000 barrels of water per day through 2" tubing, Figure 8 shows that this corresponds to a Reynolds number of 50,000. For this case, the average water velocity is only 0.805 of the maximum water velocity.

Transition Zone:

The flow regime changes from turbulent to strea line as the Reynolds number decreases from 2,850 to 2,100. Referring to Figure 8, it is seen that a flow of 200 barrels/day in 9" open hole results in a Reynolds number of 2,500. This is in the transition region and the average velocity may range from 0.5 to 0.72 times the maximum velocity. This is based on circular hole without the tool present. The transition zone should be studied carefully. Since this is a region of uncertainty, it is suggested that the remainder of the interpretation start at the bottom of the hole and work up.

Streamline Flow Zone:

For an injection profile, the flow will always be streamline at the bottom of the hole as the water rate is near zero. In the streamline region, the average water velocity is one-half the maximum water velocity. This value of 0.5 was developed for circular pipe without a logging tool present.

The transition to turbulent flow occurs as follows:

Hole Size	Transition Water Rate, bbls/day
5 in. pipe	80
6-5/8 in. pipe	115
9-5/8 in. pipe	170
12 in. hole size	220
16 in. hole size	290
20 in. hole size	370
28 in. hole size	510

From the above table,it is seen that for a water injection rate of 1,000 barrels of water per day, 80 to 90 percent of the injected water will be calculated as a turbulent flow problem. Only the lower 100 to 200 bbls. a day rate will be in the streamline region for holes of 6-5/8" to 12" diameter.

In the streamline region the velocity ration is constant as 0.5. There is a sharp increase in average to maximum velocity in the transition region at values of the Reynolds number between 2,000 and 4,000. The velocity ration increases from 0.72 to 0.81 as the Reynolds number increases to 100,000.

It should be noted that the Reynolds number may be based on either the maximum or average water velocity. If the radioactive tracer is mixed with the water by turbulence, the velocity of the fastest streamlines will be represented by the first arrival times seen on the G/R detectors.

Annular Flow String

The presence of the G/R detector causes the water to flow in the annular region. In an annular region, the velocity distribution is much different than that in a round circular pipe.

Figure 9 shows the velocity distribution for streamline flow about a 1-3/8" diameter tool in a 6-3/4" from the center and the streamlines have about the same velocity for the radius 1.75 to 2.0 inches. The maximum water velocity when the 1-3/8" diameter tool is present in a 6-3/4" diameter hole was calculated to be a 1.55 times the average water velocity, or the average water velocity was 0.645 times the maximum water velocity.

It should be noted that if the radioactive material only extends 1/4" from the tool, the velocity of the streamline will be about 80 percent of the average velocity. The tracer should be at a distance of 1" from the tool to be in the fastest streamline for a 6-3/4" hole.

If the G/R tool is in a pipe smaller than 6-3/4", the average velocity increases to a maximum of 0.667 times the maximum velocity.

Turbulent Flow:

With the G/R tool in the hole, the value of the pipe diameter in the Reynolds number calculation should be represented by the effective diameter. The effective diameter is eaual to D hole - D tool) with the units on feet. This is the appropriate value when the tool is centered in the hole. It would seem likely that with turbulence being present for most of the interpretation one could feel reasonably sure that the tracer reached the fastest velocity zone. Without turbulence, the tracer should be sent out with sufficient velocity to reach the fastest streamline.

BOREHOLE CONDITIONS

Some of the present interpretative procedures used on the dual gamma ray detector tool indicate that the flow in the hole below a particular point may be much greater than the flow above this point.

In reviewing this problem, it was found this frequently occurred where the caliper logs indicated a washout or enlarged hole diameter, Figure 10. Interpretations for this condition could be made by assuming no fluid loss and calculating the effective hole diameter for a wash-out region. Where fluid is going into the formation, the data will be wrong. Areas of abrupt hole diameter changes or restrictions could be by-passed and velocity readings made at the more uniform sections. The profile obtained would be accurate for comparisons of long intervals only. More detailed and accurate profile information can be obtained using a comparison of tracer runs. A stack plot of the tracer as shown in Figure 11, compares favorably with the velocity profile shown on the right. The tracer runs serve as an excellent check on doubtful areas indicated by a velocity profile.

An extension of the "Stack Plot" and Analytical Run Techniques now affords a method of accurate quantitative results from tracer runs. Analysis of these runs has heretofore been confined to "plate out" technique in the case of partical tracers and rate of dissipation in the instance of soluable tracers. These methods have dealt with the amounts of tracer material deposited or left behind the moving slug or burst of tracer in the fluid stream. The problems of erratic accumulation fluid traps material proximity to tool, extreme borehole diameter change, etc. (Ref. 1 & 3) all caused error in the interpretation. Measuring the radiation intensity remaining in the fluid stream and deducting this measurement from the total intensity originally introduced offers a means of comparing finite values to derive the profile.

Radioactive materials decay with a characteristic rate and intensity for each isotope. The emission from this decay can be measured and recorded by a gamma detector held in close proximity to the material. Since the confines of the borehole and/or the moving stream of injection water are small enough to hold all, or nearly all the moving material close to the tool detector, each logging run thru a moving slug of material is a graph

of activity, time and dispersal, or re-stated, the total detectable number of gamma emissions occurring in a given section of borehole at a given time. Intensity recorded varies with concentration of material, therefore, the same number of decay occasions can cause high recorder deflection when concentrated in a few feet, or lower deflections when spread over 20 to 30 feet of hole

Intensities will appear higher in tubing and very small diameters of hole due to the total emission being held very close to the detector. The very weak radiations that can be shielded by less than one inch of water are also detected in this instance. A correction factor based on absorbtion coefficient must be used in intensities in tubing are used vs those in csg or open hole.

Using a soluable tracer material, the isotope follows the water path proportionately, therefore, if 40% of the injected water enters the formation, 40% of the isotope is also lost. the isotope remaining in the borehole will reflect this loss by a proportionate loss of activity.

Calculation of the amounts is not difficult. The active limits of the moving slugof material are defined by marking the leading and trailing interfaces and the base line intensity. The triangle thus formed represents the amounts of introduced radiation remaining in the hole.

The relative number of detectable particals apparent (Self index) is determined by triangulation. Comparison of the indices of each run reveals the percentages of fluid loss in direct ratio. Figure 12 shows the basic concept.

Run #1 in tubing - 100% of radiation
Run #2 in casing - 100% radiation, 12.4% absorbtion factor applied to Self index.(Tubing to Casing)
Run #3 in casing - 100% of radiation (3% difference in index from run #2)
Run #4 in casing past perforations - 12% loss indicated.

Explanation of the actual calculations are not presented at this time but the calcualtions have been used on over 300 logs to date, with excellent accuracy. Any profile logging runs performed properly and using soluable isotopes can be calculated by this method. The technique has the disadvantage of being less selective in depths investigated and, in some cases, several bursts must be fired and traced before sufficient breakdown of zone results. The advantages are - elemination of hydraulic diameter and shot hole error, and quantitative analysis of injection pattern when all other techniques are inadequate.

CONCLUSION

Interpretation of fluid movement surveys (profiles) is a science which utilizes not only the recorded log, but all the knowledge of formation characteristics, hydraulics and mechanical probabilities available. The interpreter must have a good insight into tool operation and reaction, the conditions that may affect these reactions, and be able to apply this knowledge with an open mind.

Profiles properly run and analytically applied yeild a wealth of information, not only in the wells surveyed, but of the reservoir conditions therselves. The associated information obtained during profile operations can lead to better control, more efficient stimulation of primary producers in the area and assist in avoiding possible development of future problems heretofore unknown.

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3. Johnson, Wallace and Morris, Billy P., "Review of Tracer Surveys", presented at the Southwestern District, Division of Production, API, March 18-20 , 1964

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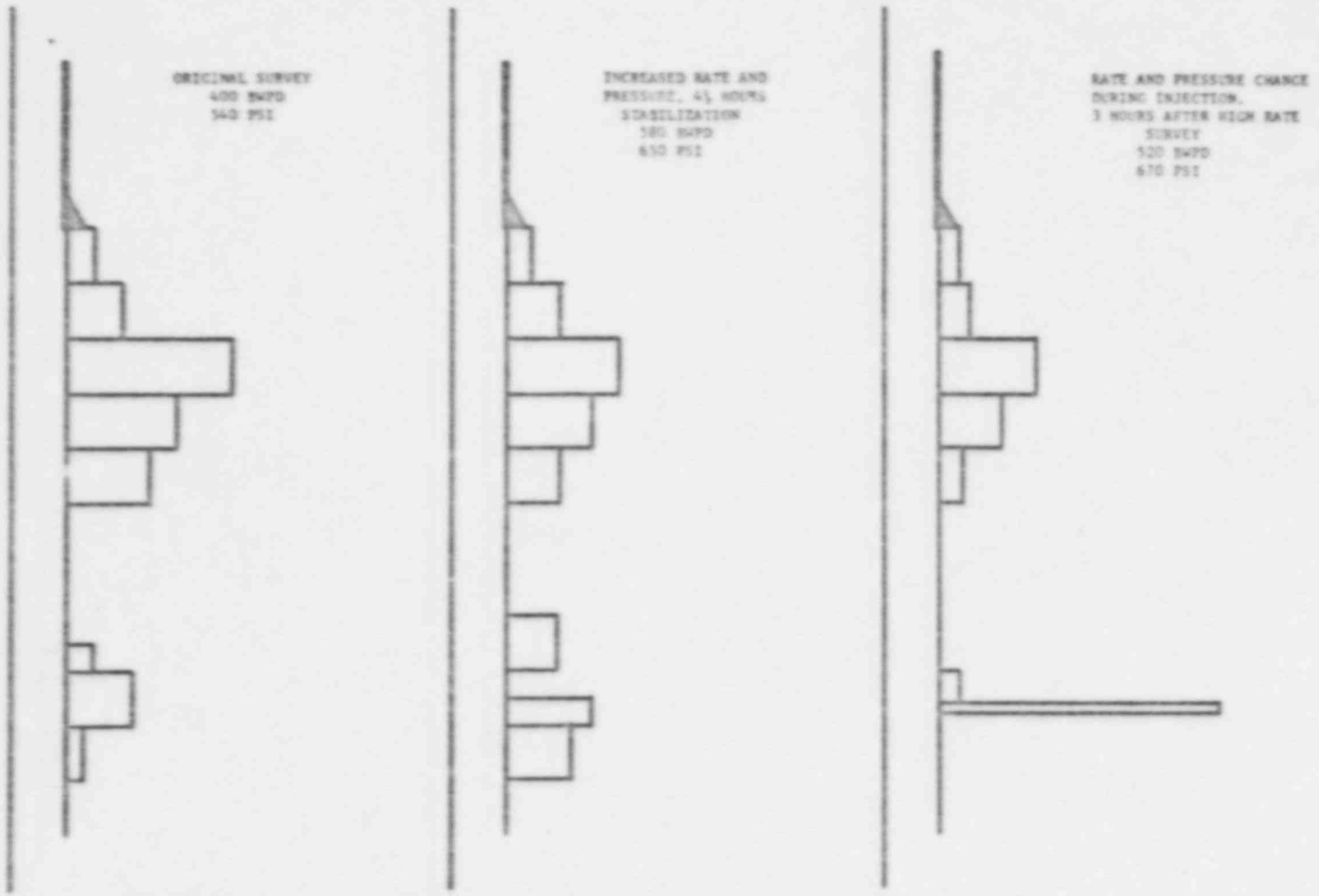
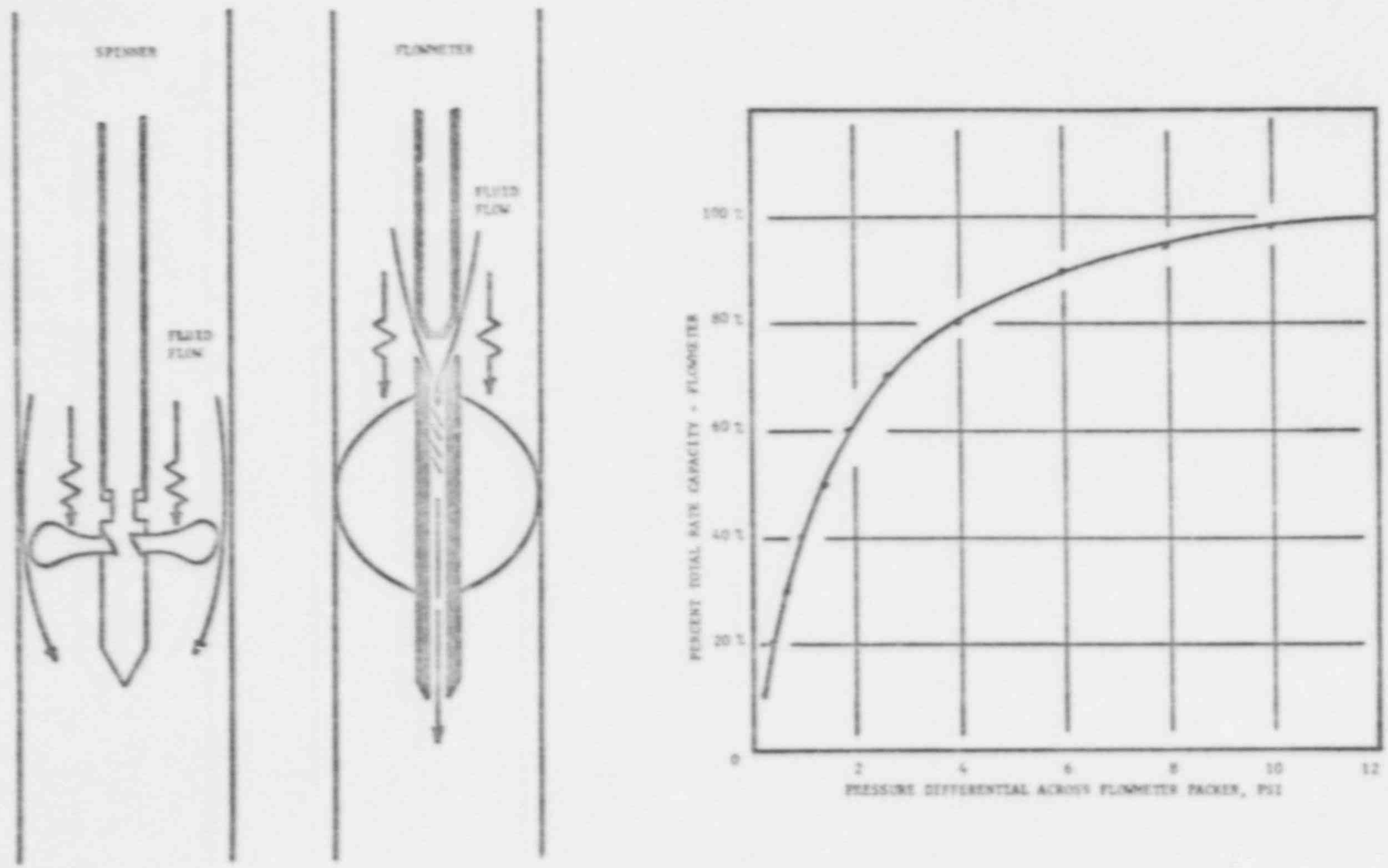
5. Figure 16, Journal of Petroleum Technology, Page 856, August, 1964.

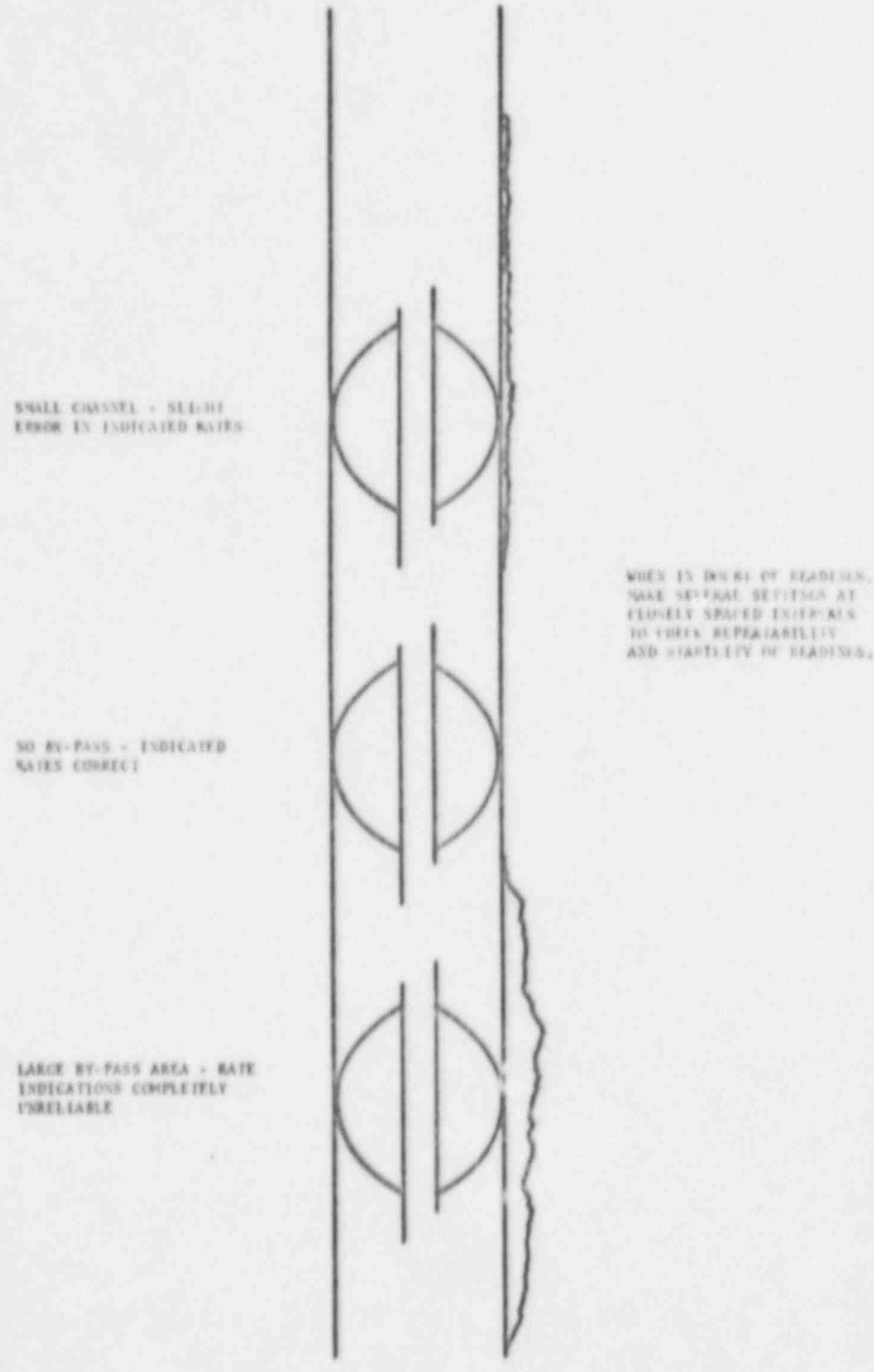


CHANGE OF PROFILE, RATE AND PRESSURE CHANGE (TATES)

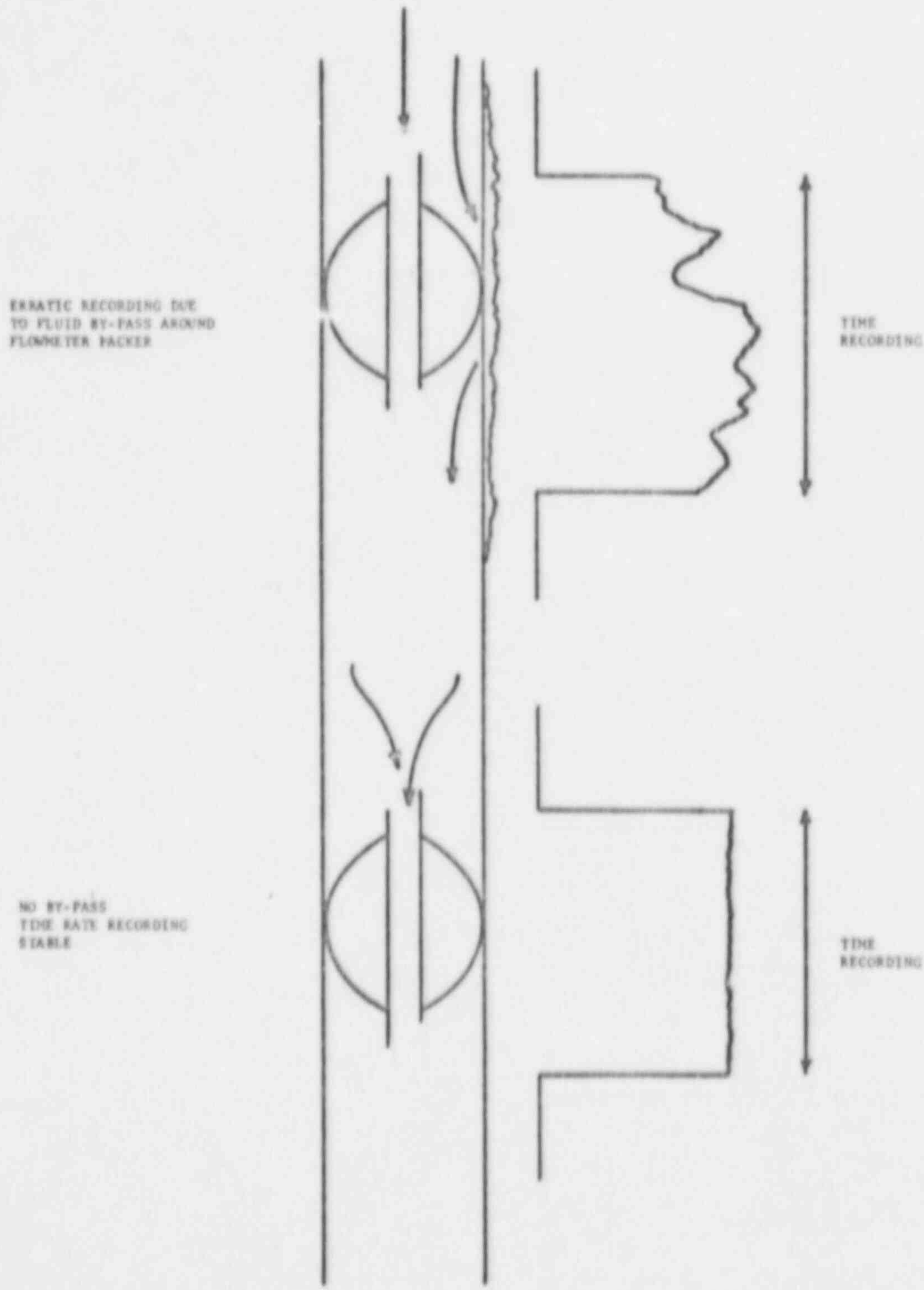
FIGURE # 1



DIFFERENTIAL PRESSURES
FIGURE # 2

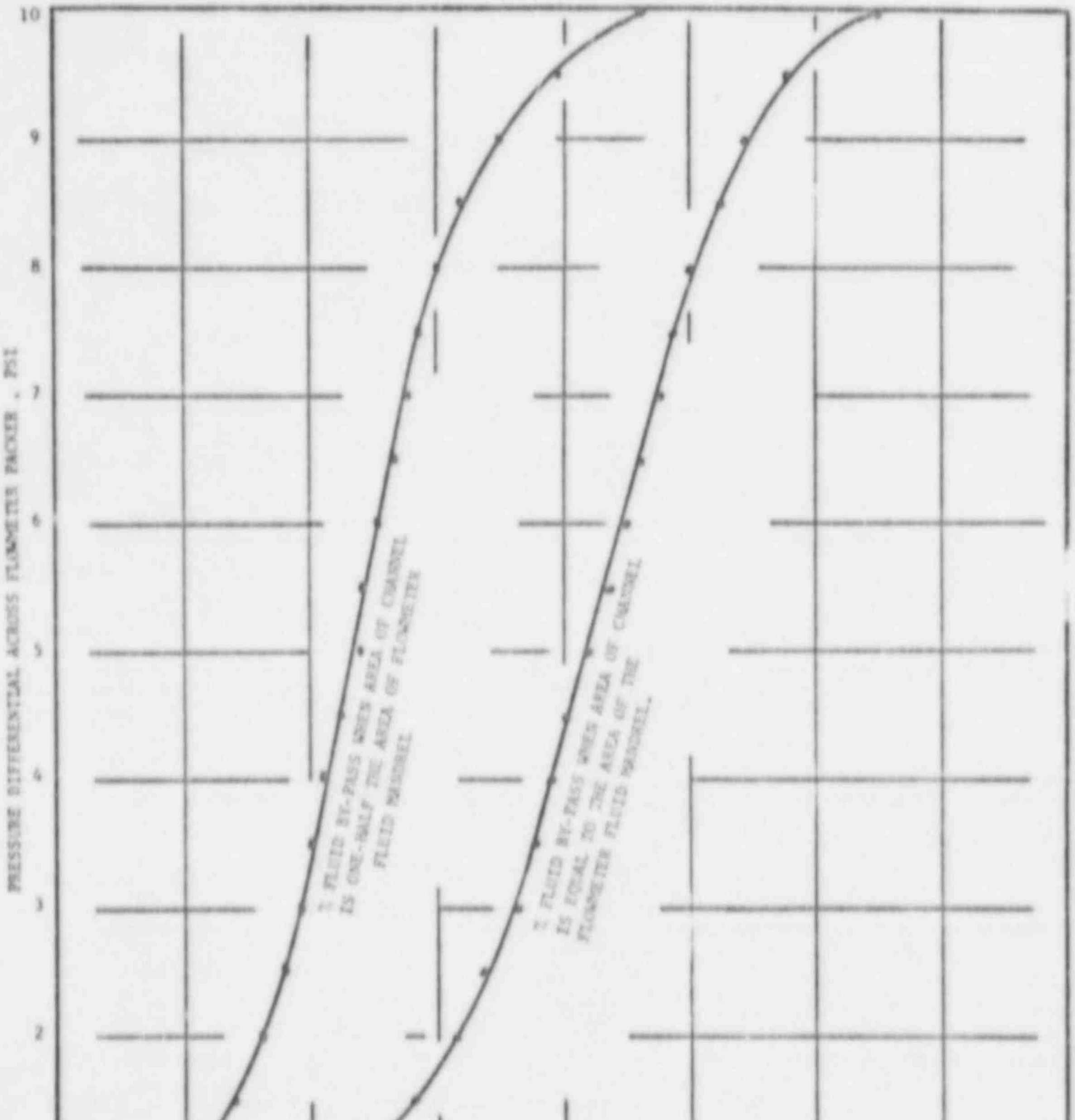


FLUID BY-PASS FIGURE #3



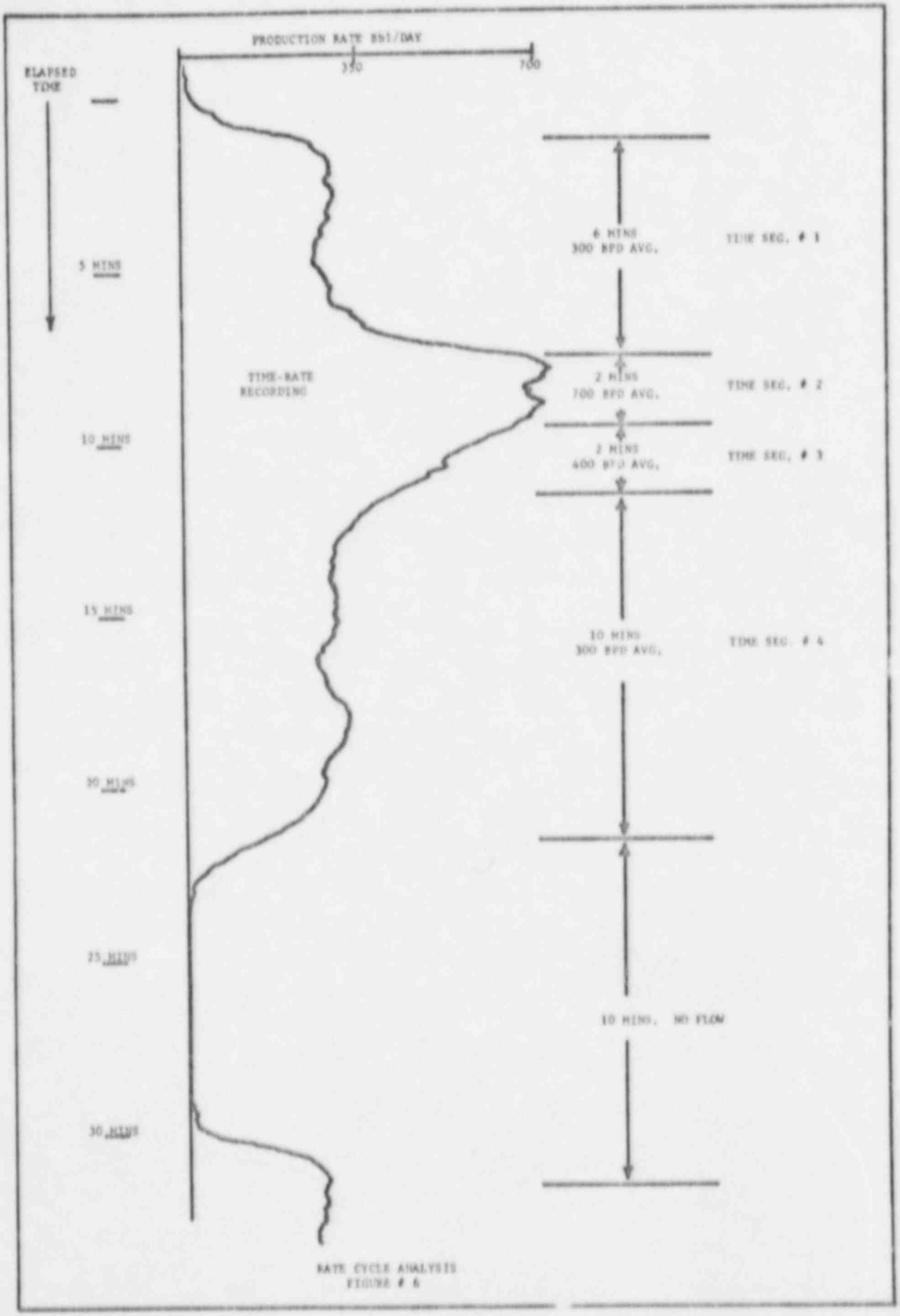
STABLE V.S. ERRATIC RATE
RECORDINGS

FIGURE # 4

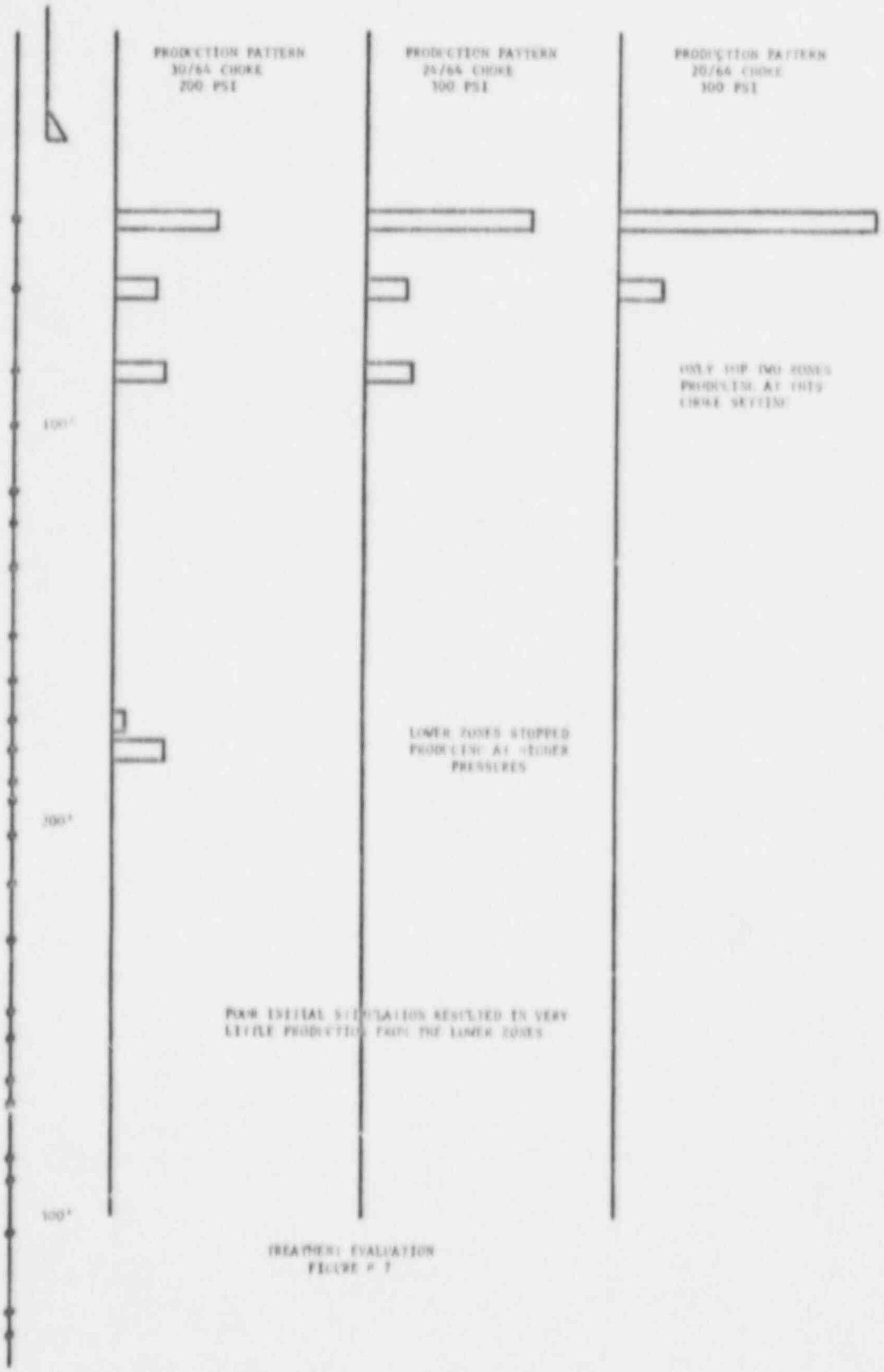


RELATIVE FLUID LOSS FOR VARIOUS CHANNEL SIZES

FIGURE # 5



RATE CYCLE ANALYSIS
FIGURE # 6



TREATMENT EVALUATION
FIGURE # 7

REYNOLDS NUMBER AS A FUNCTION OF
WATER RATE AND PIPE SIZE
(No tool in hole)

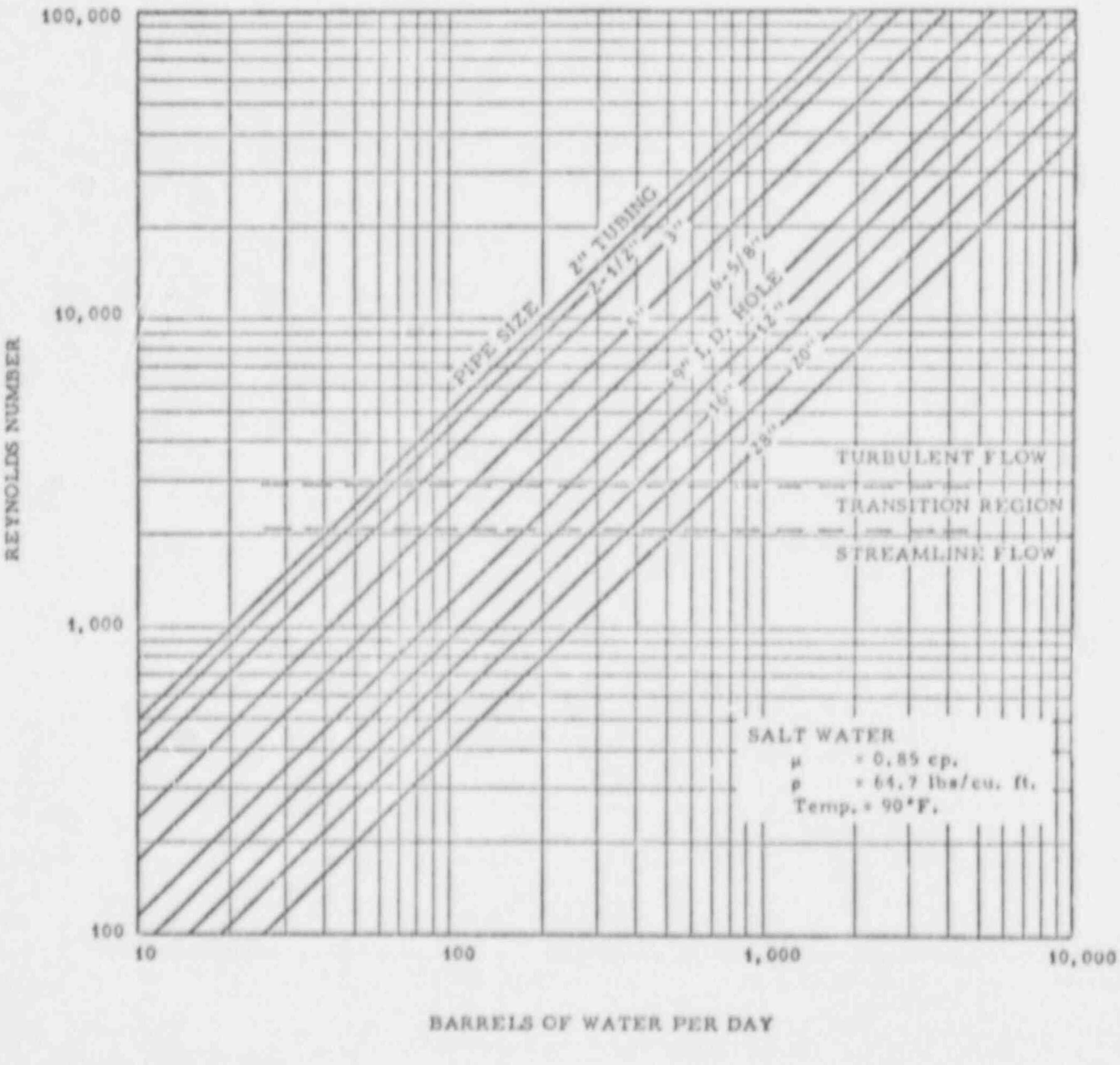
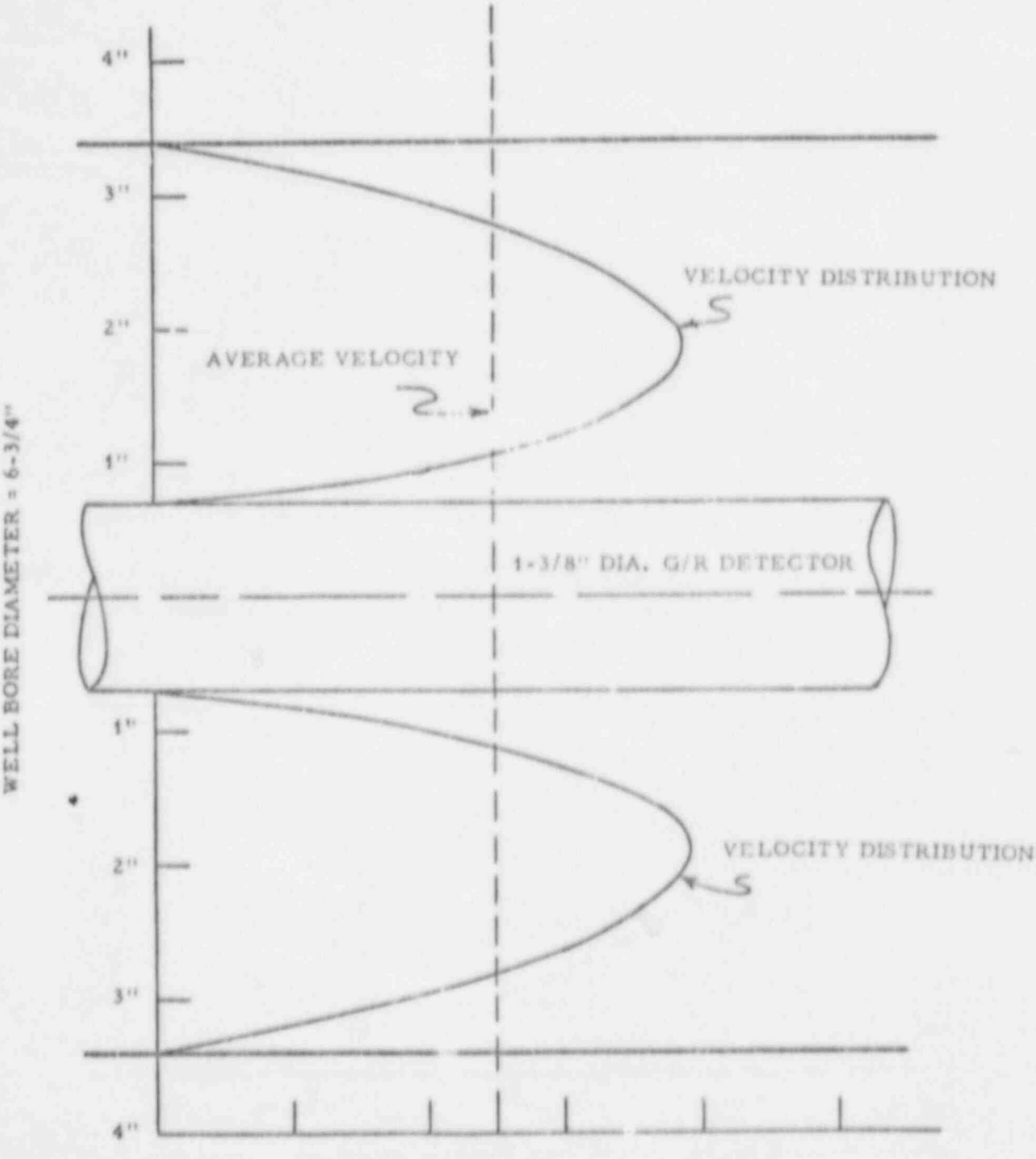


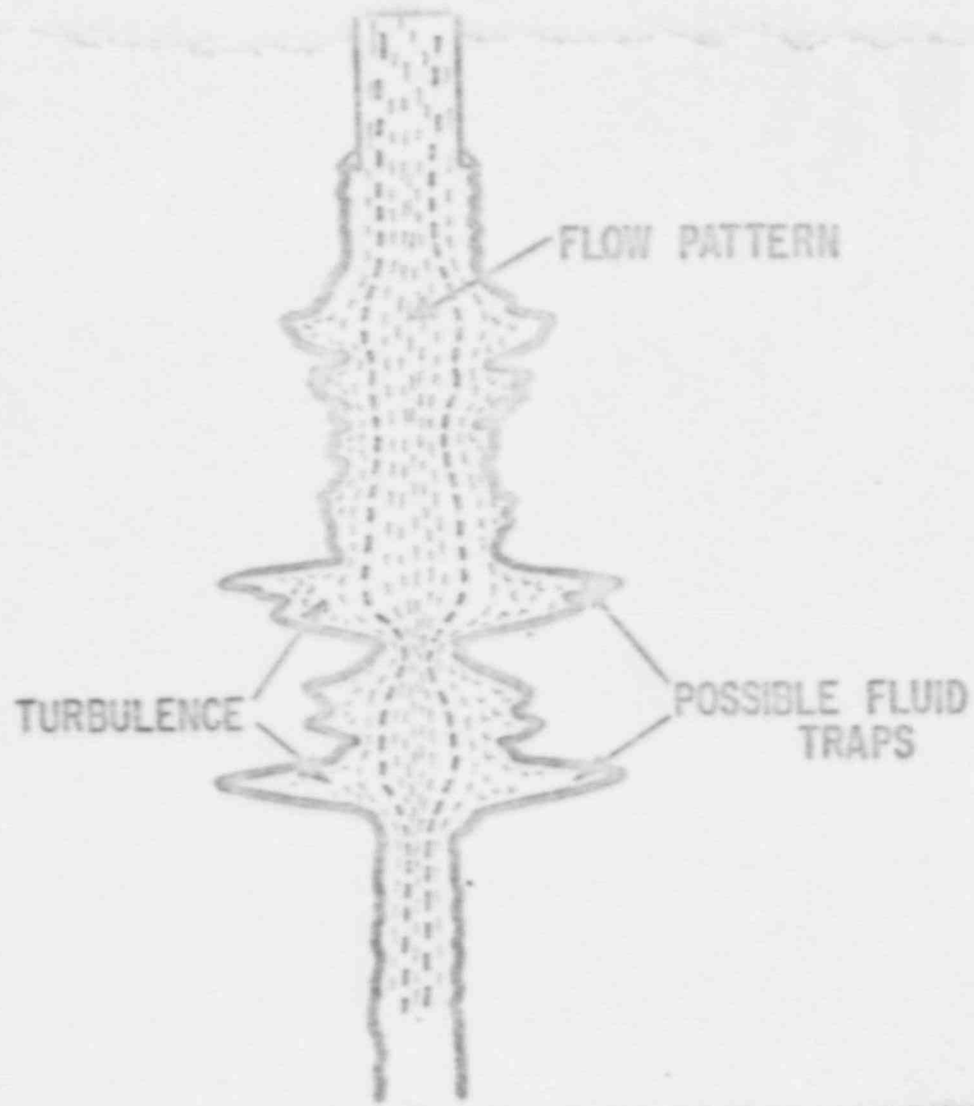
FIGURE # 8

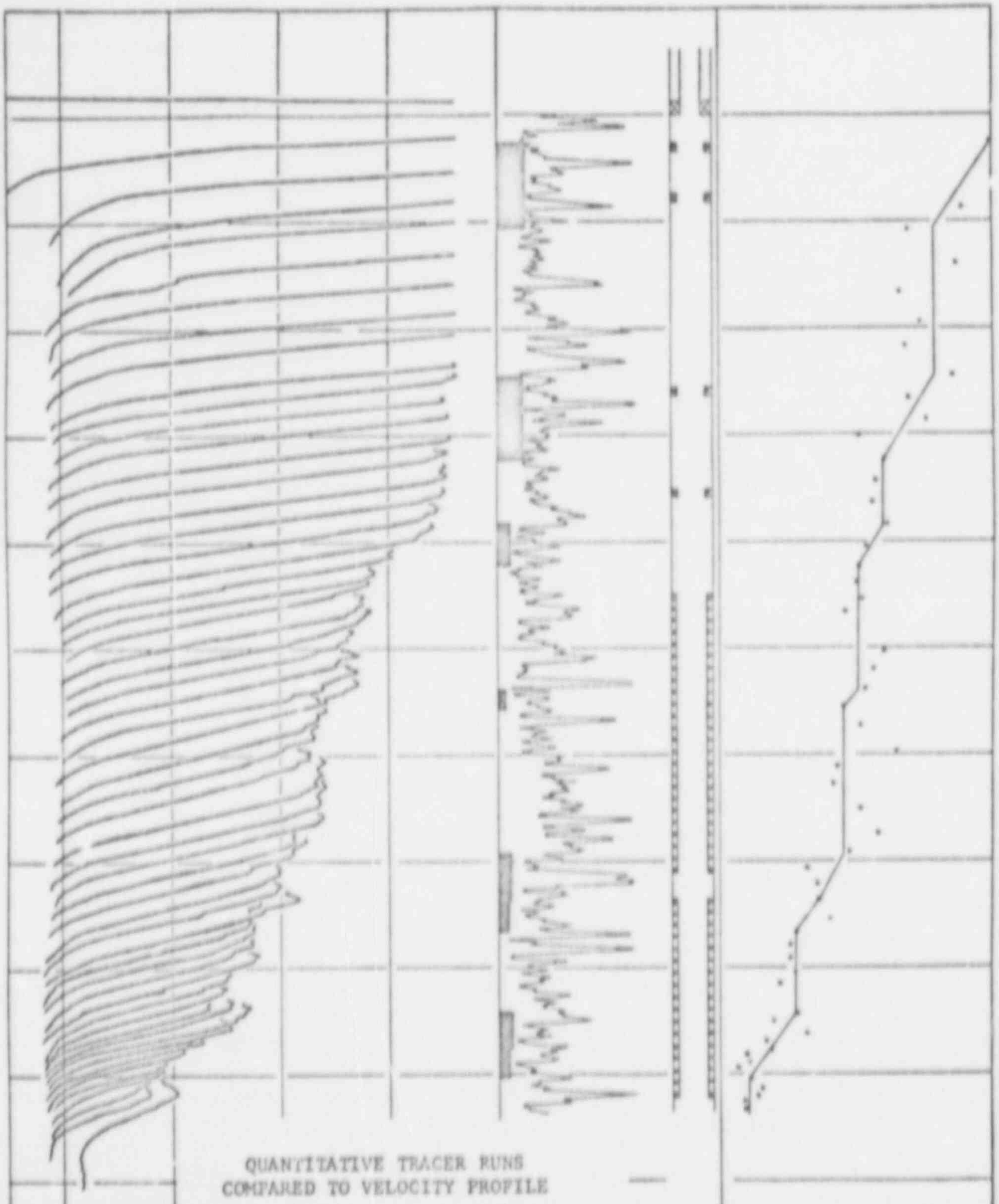
STREAMLINE VELOCITY DISTRIBUTION WITH GAMMA RAY
TOOL IN HOLE



RATIO OF STREAMLINE VELOCITY TO AVERAGE WATER VELOCITY

FIGURE # 9


FLOW PATTERN
TURBULENCE
POSSIBLE FLUID
TRAPS



QUANTITATIVE TRACER RUNS
COMPARED TO VELOCITY PROFILE

FIGURE # 11

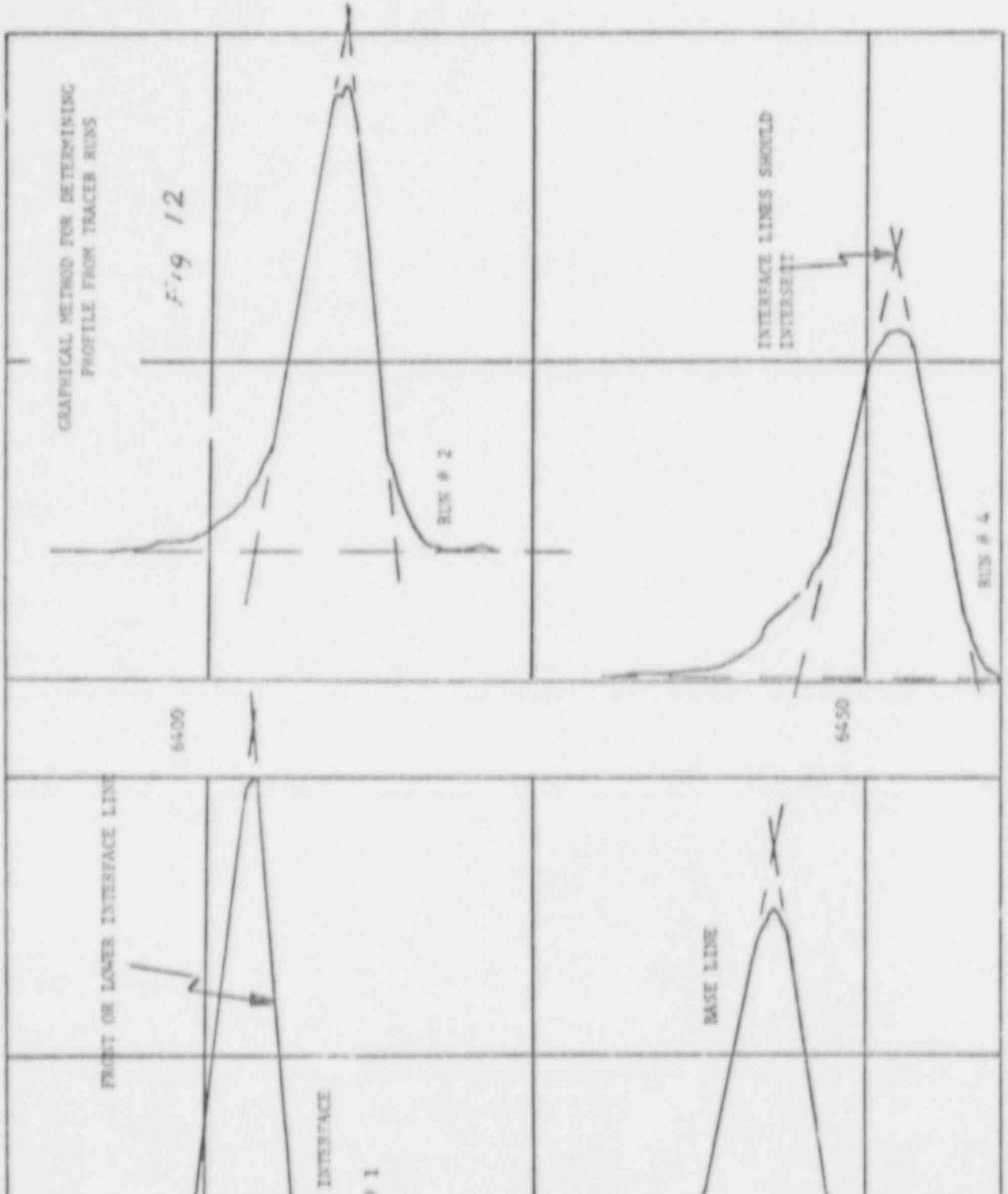

GRAPHICAL METHOD FOR DETERMINING PROFILE FROM TRACER RUNS
Fig 12
RUN # 2
INTERFACE LINES SHOULD INTERSECT
RUN # 4
6400
6450
FRONT OR LOWER INTERFACE LINE
BACK INTERFACE
RUN # 1
BASE LINE
RUN # 3

Exhibit C

Regulatory File Cy.

WELL ANALYSIS COMPANY, INC.

Subsidiary SONICS INTERNATIONAL, INC.

WACO LOGGING SERVICES

563-0331
P. O. Box 1609
Odessa, Texas 79760

DOCKET NO. 40-8027

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RECEIVED MAY 16 1972 U.S. ATOMIC ENERGY COMMISSION Regulatory Mail Section

DOCKETED USAEC MAY 16 1972 REGULATORY MAIL SECTION DOCKET CLERK

Mr. D.J. Foley, Manager
Project Engineering
Nuclear Operation Division
Kerr-McGee Corporation
Kerr-McGee Building
Oklahoma City, Okla. 73102

Dear Mr. Foley;

RE: Reservoir Analysis, Sequoyah Facility

Purpose

To establish feasibility of consistent storage of liquid waste materials into target reservoir without contamination of potable waters and other useable geologic horizons or endangering surrounding surface environment.

General Conditions for Consideration

Target well is completed in the Arbuckle Limestone with 7" completion string set through a Hunt, Sylan and Simpson and cemented at 1619', approximately 260 feet below the top of the arbuckle Limestone. Injection interval completed with uniform 11" open hole extending to the top of the granite at 3102'. Location is bounded by two major faults, one five miles to the northwest and one intersected by a third fault, approximately one mile to the East southeast. Total radial exposure to the nearest fault plane approximately 120°. Formation displacement and slippage control derived from seimic data and correlation of two dry hole attempts (the Smith #1, two miles east and the Highfield #1, approximately three miles south-southwest).

Target well is located upon Company controlled land both surface and sub-surface.

Reservoir evaluation was to be based primarily upon computer calculations and reservoir modeling utilizing high accuracy pressure, flow, time, and injection profile and inhole flow data developed during a well testing program made up of alternating periods of water injected and zero inflow. Additional evaluations of the reservoir and of the well casing and packer and near well bore formation from a leakage stand point were to be made by standard thermalprofile and radioactive profile techniques.

2001

H.J. Gruy & Associates, Inc. of Dallas, developed the testing program, evaluated the pressure, flow, time, and injection profile data, performed the computer analysis and reservoir modeling, and evaluated the proposed injection well from an overall stand point. Well Analysis Company, Inc. of Odessa, Texas, provided downhole wireline services and performed caliper measurements, all thermal measurements and all radioactive tracer measurements and calculated the injection pattern and flow characteristics from established radioactive profile techniques and provided a progressive temperature decay analysis. High accuracy downhole and surface pressure recording instruments and chart conversion were provided by Sperry-Sun Well Surveying Company of Oklahoma City, Okla. Water injection, total injection flow, time measurements and additional surface pressure measurements were made by Kerr-McGee.

Multiple dependent and unpredictable parameters dictated that the water injection and data collection be done in phases, each phase determining the details of the subsequent test phase and series of data to be collected.

This discussion is primarily concerned with the interpretation and sequence of the injection profiles and temperature data analysis.

Greater in-depth discussion of the development and application of the survey methods utilized in this study is provided in the accompanying techical articles.

A.P.I. #906-9-E Review of Tracer Surveys.

S.P.E. #1829 Maximum Use of Profile Information.

A.P.I. "Factors Considered in Interpretation".

S.P.W.L.A. "Computers to Increase Value of Temperature Logs".

S.P.E. #1752 "Fluid Flow Analysis Techniques".

S.P.E. #2255 "Computerized Temperature Decay".

S.P.E. #2685 "Interpretation of Injection Profiles".

A.P.I. #906-15-J "Practical Field Interpretation of Temperature Surveys".

Other accompanying information:

5 Panel Composite of the Survey Results for Reference during discussion. Panel 1 and 2 are represenative of Phases One and Two, respectively. Panel 3 and 4 are Injection and Counterflow tests described during Phase Three. Panel 5 display the injection profiles of each of the three phases, plotted together for comparison. Panel 5 composit results are the qualified conclusion of the WACO log analyst. Quantitative results of the surveys have been modified by qualitative interpretation of both Temperature and Radioactive Surveys.

TECHNIQUES OF PROFILE INVESTIGATION

1. RADIOACTIVITY PROFILES - INJECTION OR PRODUCTION

1. Tools

Instruments used are two gamma sensitive detectors and a dispenser of a water solution containing Iodine-131 incorporated into a single downhole tool. The device is run in the well on a conductor line to a measured depth and a base radiation activity of the well bore recorded. A small quantity of the radioactive iostope solution is then released at a selected interval in the well and the path and rate of movement of the shot of liquid containing the radioactivity within the well bore is charted by observing the reaction of the detectors at various depths. These reactions are recorded and the data evaluated, both qualitatively and quantitatively, to define the pattern and relative volumes of injection accepted by each of the subsurface intervals.

2. Calculations and Methods

Two methods of data collection are used in the investigations.

a. VELOCITY DETERMINATIONS

Radioactive solution is released upstream of the gamma detectors and is carried past the detectors by the moving stream of injection. The transit time over a given interval (5' normal spacing) is measured and corrected for parabolic flow variations and well bore diameters. The volume of fluid contained in the measured interval of well bore (5') is calculated; and utilizing this information along with the transit time, the rate of fluid movement, expressed in bbl/day, past the interval is derived. This action is repeated at selected intervals in the well and a subtraction curve developed. The results are then plotted as fluid acceptance intervals, or the injection profile.

b. RADIATION EQUIVALENT VOLUMES R.E.V. OR SELF METHOD

These measurements are accomplished by releasing a given amount of solution containing a radioactive isotope at a point upstream of the zone of interest and measuring its relative activity by recording the reactions of logging tools (radiation detectors) during a traverse run through the zone containing the radioactive material. The resulting curve (or graph) is triangulated and an index number assigned which represents the total amount of radioactivity in the designated interval of the well bore. As this volume of fluid moves downstream, repeated timed traverses are made through the radioactive zone, charting the position and activity level in each instance. These curves are also triangulated and their indices assigned.

Should a portion or all of the increment of fluid carrying the isotope leave the well bore and enter the formation, a proportional amount of radiation will also be diverted, since the isotope is completely soluble and mixed within the fluid stream. (The radioactive material traveling into the formation quickly becomes non-dectible to the radioactivity instruments). The variation of the assigned indices will reflect the radioactivity and hence, fluid loss at each interval and may be plotted in relative percentage to the original index. When vertical dispersal of the isotope increases to the point that accurate measurement becomes difficult, a new increment of isotope is released, and assigned the percentage represented by the last traverse through the original shot or increment. The new shot of material is then followed downstream by the same logging methods and the continued reduction of index and hence, loss of fluid into the formation is defined.

These techniques are both subject to a possible 15% error (related to 100% fluid travel), but the parameters affecting each are different than those of the other and accuracy control is effected by comparison of the two results. Additional information may be inferred by these comparisons (i.e., vertical erosion or fracturing adjacent to and connecting with the well bore). These would affect the velocity determination, but leave the radiation equivalent relatively unaffected. Thin zones of fluid acceptance may be closely defined by velocity techniques but only averaged over an extended interval by R.E.V. methods. Caliper logs are essential to velocity calculations but not needed for R.E.V. velocity calculations usually represent maximum flow rate at any given interval- R.E.V. measurements are necessarily minimal determinations.

Profiles derived from these combined methods can be expected to exceed 95% accuracy with respect to total flow.

11. TEMPERATURE DECAY SERIES.

1. Tools:

The downhole instruments consist of pulsing oscillator controlled by a calibrated temperature sensor. The downhole tool is run into the well by conductor line containing signal wire running back to surface recording equipment and the indingent temperature is monitored at each depth. The signals are sent back to the surface and recorded as temperature in degrees F°.

2. Methods and Techniques:

Temperature data are collected in ambient temperature only. Variations expressed as differential, or delta logs, are derived from the basic collected data. Data may be recorded by station setting, (tool held stationary at selected depths for a specific recording time) or by a continuous traverse over the entire interval of interest. Repeated runs or traverses made with the smae tools and calibrations reflect the changing temperatures at all depths with respect to time, and are termed a "Temperature Decay Series".

Decay series are recorded with respect to time. A basic temperature under constant conditions is recorded by either traverse logs, or station settings. The base, or constant conditions are then altered and the resultant temperature transients during well bore recovery are recorded at timed intervals.

3. Interpretation:

The data recorded must be considered the temperature of the well bore only, since the information is collected at the terminal point of an equilibrium process.

The Temperatures at any point are the net results of all the surrounding thermal transfers. The temperature of the surrounding matrix is the influence for well bore temperature progression, however, and bore hole fluid attempts to assume the temperature of the adjacent dominant thermal field.

A depth of investigation may then be inferred by observation of the rates of change caused by these adjoining fields or cells.

Temperature fields generated by convection thermal transfer differ in initial recovery rates from fields caused by radiation or conduction only.

Comparison of these varying rates of recovery identifys the zone of fluid movement thru the formation by reflecting the influence of the more nearly isothermic conditions extending to a greater radius from the well bore.

Temperature influence from any matrix surrounding the well bore depends upon a completely static fluid column, else the reflected temperature will be distorted by vertical in-hole convection thermal transfer.

4. Information:

Properly executed, thermal decay surveys confirm fluid exit or entry intervals in the well, and define zone thickness or height beyond the limits of any in-hole rate determination method. Quantitative values cannot be applied however except under ideal conditions. They may also be useful in determining leakage from the casing or upward around the casing an thence into a higher formation.

111. ANALYSIS OF SURVEY RESULTS

The operating requirement of injectivity profiling and single point pressure fall off are not compatable to simultaneous surveying. A sequence of operation was scheduled to allow the most valid and efficient collection of all data.

Preinjection Testing:

1. After setting up well head for entrance of logging tools, dummy run was made to check hole for obstruction using simulated instrument package.

2. Cali,er survey of the open hole was made.

3. Pressure survey and static bottonhole measurements.

Phase One Sequence:

1. Well was placed on injection at a selected rate and allowed to to reach initial relatively stabilized conditions.

2. A Radioactive profile was run using both velocity, and Radiation Equivilent Volumes for quantitative calculations. A base injection temperature run was made at this time.

3. Sperry-Sun pressure equipment and WACO Temperature Tool placed downhole @ 2900' and Well shut-in (injection stopped) for monitor of pressure.

4. Sperry-Sun instrument retrieved and well placed back on injection.

5. Injection stabilized and well shut-in for Temperature Decay Series.

6. Well placed back on injection.

Profile and Temperature Analysis of Phase One determined:
Four gross injection intervals.

A. 1720' to 1820' 30% of injection volume with 24% between 1755' and 1790'.

B. 2610' to 2655' 38% of injection volume.

C. 2760' to 2780' 12% of injection volume.

D. 2820' to 2855' 20% of injection volume.

No injection continued below 2860' during the first injection period and no other zones were accepting fluid at the time of the Radioactive Survey. (See plots of Velocity and R.E.V. calculations on right side of 1st. panel).

Temperature Decay monitors indicated that a Fifth zone may have opened up and accepted some small portion of injection during the second injection period. This is inferred from the definite indication of after shut-in counterflow from 2700' upward into three intervals. The injection zone "B" 2610'-2655' and two new intervals, 2300'-2305' and 2360'-2365' strong counterflow exists from 2700' into zone "B" (note isothermic pattern of temperature decay curves over this interval) with only a small amount continuing upward to the two new intervals.

The influence of the additional zone of injection, and the after shut-in counterflow was observed on both the pressure monitor and the station setting temperature decay. This evidence of the net injection interval change with fill up caused phase two to be designed around both short and long term pressure decline with an injection profile to determine the current net injection pattern.

Phase Two Sequence:

1. Injection resumed after the decay series temperature program was completed and continued for 112 hours for stabilization.

2. Radioactive Tracer (Velocity and R.E.V.) was run to establish injection pattern.

3. Sperry-Sun pressure equipment and WACO Temperature Tool run into hole to fixed position and well shut-in (injection stopped) for testing.

4. Five hour pressure and Temperature monitor run @ 2650', Then tools removed and replaced with Sperry-Sun pressure instrument only with recorder set for 72 hour record period.

5. Pull and re-run pressure instrument with recorder set for 72 hour pressure measurement.

6. Analyze first 72 hour pressure chart then remove pressure equipment and resume injection.

Phase Two Profile and Temperature Analysis:

Original gross intervals of injection still exist, but with a significant change in the fluid distribution into zone "B" 2610'-2635'. The net interval decreased to 25' (2620'-2645') and the volume into zone decreased from 38% (Phase 1) to 11% of total injection. The water originally entering this zone was diverted into three thin intervals between 2710' and 2810' (see panel 5). Both zone "A" and "D" decreased in net thickness with very little change in accepted volume.

A small interval just below the small areas which the temperature profiles indicated were accepting counterflow during Phase One, now accepted approximatley 8% of the diverted injection (2420'-2425').

Reference to the decay series of Phase One indicates that this zone may have been accepting injection intermittently during the first tests. (note retarded recovery of first shut-in temperature decay with respect to subsequent runs 1st. panel).

Erratic velocities between 2240' and 2370' indicate possible zone interference during injection but R.E.V. calculations show no significant fluid losses through the interval.

Phase Two pressure and temperature data again reacted to the after shut-in counterflow conditions and Phase Three was projected to chart the magnitude and full extent of fluid movement during shut-in.

Phase Three Sequence:

1. Injection continued for 24 hours.

2. Injection Profile run using R.E.V. methods only.

3. Well shut-in and production profile techniques used to determine counterflow extent.

Phase Three Results:

Injection patterns again changed but the 4 original gross intervals continued to accept fluid. The lower zones show a marked tendency toward reduced volumes with continued injection, and the diverted fluids are being accepted by the top interval (increased injection into zone "A" from 30% to 46% during testing phases).

The counterflow conditions during shut-in were more extensive than first analysis indicated (see panel 4).

Shots of Radioactive Isotope, placed at indicated depths and traced, show fluid moving up from zone "D" past "C" and"B" and a portion moving to the top of the section into zone "A".

Rate of initial counterflow is approximately 240-280 bbl/day but about 60% of this volume re-enters the formation between 2280' and 2380',one of the original zones accepting counterflow. The remainder of the fluid moves up the hole and is lost to zone "A" (1750'-1800').

Zone "B" (2620'-2645') which originally accepted the major portion of the counterflow is presently receiving none, but appears to be contributing a small increment instead.

No fluid is moving at 1700' and none is entering the well bore below 2870'. (see shots #3 @ 2865' and #8 @ 1675' 4th. panel).

Lines connecting the average slope centers of each shot of material as they progress uphole show a visual reference to the relative rates of fluid movement.

Zones of fluid acceptance may also be qualified by distortion of the material distribution patterns. (See consistant distortion and intensity loss @ 2300', and runs 10 thru 22).

Conclusion:

Examination of primary open hole logs show a net probable injection zone thickness of approximately 700' over the open hole section. Of this, only 175' (approximate) is accepting injection.

Permeabilities are layered throughout the entire interval with no apparent vertical permeabilities or fractures connecting the zone. (Hence, the counterflow under shut-in conditions).

Fluid is being accepted well above total depth, (bottom of the hole) and below the casing point, and there seems to be no problem in containing injection well within the vertical limits of the formation at this point in the reservoir.

From analyzing the thermal profiles and radioactive tracer records, there are no indication of channels, leaks, holes, or other mechanical failure at the casing seat or above and no channel or leak around the packer.

Injection zone locations and extent seem rather sensitive to pressure build up and the amount of fluid injected into new zones could probably be increased by selective acidizing. The tendency for intermittent injection seems to bear this inferrence out.

The tendency of the lower zones to accept progressively smaller volumes points to the possibilities of relativity smaller pore volumes of permeability pinch outs or local restrictions near the well. Should the pressure data indicate the latter, selective treatment will alleviate this problem.

The opinion of WACO analysts is that net injection interval could be increased approximately 200% by proper treatment.

A program of consistant scheduled monitoring should be initiated to identify and control net volume per foot into each interval and to guard against shortening the life of injection through ineffecient injection patterns.

Billy P. Morris

Billy P. Morris
Vice President
Well Analysis Company, Inc.
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ATTACHMENT TO EXHIBIT C

Regulatory File Cy.

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REVIEW OF TRACER SURVEYS

by

Wallace Johnson
Cardinal Chemical, Inc.
Midland, Texas

and

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Cardinal Surveys Co.
Midland, Texas

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MAY 16 1972
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For presentation at the
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Division of Production
Scharbauer Hotel, Midland, Texas
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--oOo--

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(The statements and opinions expressed herein are those of the authors and should not be construed as an official action or opinion of the Institute.)

--oOo--

Division of Production
American Petroleum Institute
Dallas, Texas

2C

Wallace Johnson* and Billy P. Morris+

INTRODUCTION

Gamma ray detectors for use in oil wells were developed in the late 1930's. Since then radioactive isotopes have been applied in various manners in the attempt to chart fluid movements within the well bore. A variety of materials, tools and techniques have been used in tracer logging and most of the logging tools were satisfactory for their specific purpose. However, failure in understanding the limitations of and the improper use of isotopes has resulted in a great volume of erroneous and misleading information. These errors have implanted a deep mistrust of all "tracer" logging operations in the minds of many people.

The emphasis on secondary recovery operations, of which water injection constitutes the major portion, has increased the need and demand for valid tracer logging information. This validity is a direct function of the knowledge and application of isotopes and detector tools. Therefore, every individual concerned with obtaining valid data should thoroughly analyze the problems and become as familiar as possible with radioactive materials and detection tools before attempting to use them.

First, who can run these surveys? Many service companies, both large and small, offer these services in many and varied forms. The personnel doing the logging and handling of the isotopes must be operating under a current and valid Atomic Energy Commission license. This means the logging operator must have been schooled and tested in the basic concepts of nuclear and atomic structure, types of radioactive decay, reaction of matter, health physics, radiation tolerances, preventive safeguards, and first aid for overexposure. In addition to Federal regulations an operator must comply with State regulations. Failure to comply with these regulations can result in legal action and possible loss of life.

In addition to the preceding, a logging engineer must have a thorough knowledge of well completion, well equipment, production and injection procedures and how these affect the logging operations. Otherwise, the data obtained will be just so much blue ink on white paper. In order to obtain a meaningful log, it is necessary for the logging engineer to be able to calculate and interpret on the job.

RADIOACTIVE MATERIAL

Isotopes to be used for surveys should be chosen with consideration as to their properties and limitations. There is no "universal" tracer material that can be used in all instances. For example I-131 in benzene or xylene carrier will not disperse in water. Potassium iodide I-131 in water solution will not perform properly in oil. The conditions under which the isotope is to be used should be considered and made known to the service company when the job is planned. Some factors to be considered are temperature, type of fluid in the well, acids, and various oxidizing agents.

The yardstick for computing the length of time the isotope will continue to emit radiation of measurable intensity is its "half life". For example, I-192 has a half life of 74 days which means that the radiation intensity decreases by 50 percent every 74 days. Wells in which one expects to run a series of surveys should not be subjected to materials of long life. This is particularly true of particle type or plate out materials. Radiation from these isotopes interferes with future survey operations for the life of the material. The following tabulation describes the more commonly used isotopes.

---

*Cardinal Chemical, Inc., Midland, Texas
+Cardinal Surveys Co., Midland, Texas

INSOLUBLES

ISOTOPE	FORM	PROPERTIES	REMARKS
Cobalt Co-60	Solid-spherical particles 25 - 1000 microns in diameter	5.3 years half life. Temperature tolerance 900° F. Gamma emitter oxidizes to radioactive sulphide residue. Half life long enough to interfere with radioactivity logging operations for 21 to 26 years.	Can be mixed with cement or propping agents - not recommended for oil well tracers.
Cobalt Co-60	Particle in nearly neutral Aqueous Collodial suspension		For placement in injection streams by surface placement or dump bailer for "plate out" tracer, lost circulation, filter cake evaluation, etc.
Cobalt Co-60	Solid, Nodule or button		Attached to downhole tool-tracer material produced by ionization downhole. Used in velocity determination
Silver Ag-110	Particles in nearly neutral Aqueous Collodial suspension	270 day half life. Temperature tolerance 950° F. High intensity gamma emitter. Oxidizes to radioactive sulphides. Interferes with radioactivity logging operations for 3 to 4 years.	For placement in injection stream by surface placement or dump bailer for plate out operations. Fine particle size 5 - 20 microns allows some intrusion into more permeable zones.
Iridium Ir-192	Varnish baked onto Ottawa Sand of selected mesh size	74 day half life. Temperature tolerance of 2454° F. Medium gamma emitter. Use in oil or water. No interference with logging after one year.	For placement in sand or propping agents for frac evaluation. Can be handled with reasonable safety.

INSOLUBLES (Continued)

ISOTOPE	FORM	PROPERTIES	REMARKS
Iridium I-192	Impregnated resin. Density 1.1. Mesh sizes 16-400	74 day half life. Temperature tolerance of 212° F. in brine carrier. Unstable in oil at 212° F.	Surface placement or downhole dump bailer for "plate out" operations, lost circulation, filter cake evaluation, etc.
Iodine I-131	Impregnated resin. Density 1.1. Mesh sizes 16-400	8.1 day half life. Temperature tolerance of 212° F. in brine. Carrier is unstable in oil at 212° F. After 45 days no logging interference.	Surface placement or downhole dump bailer for "plate-out" operations, lost circulation, filter cake evaluations, etc.
		GAS TRACERS	
Bromine Br-82	Gas tracer containing Methyl Bromide (CH_3Br) in pressurized cylinder	35.9 hours half life. High energy gamma emitter. Boiling point is 40° F. at 150 psi. No interference with future logging operations.	For surface placement or special downhole carrier. Dangerous to handle on surface without proper equipment.
Iodine I-131	Liquid Ethyl Iodide (C_2H_5I) in sealed glass ampules	8.1 day half life. Medium energy gamma emitter. Specific gravity of carrier 1.93. Boiling point is 163° F.	For surface placement or special downhole carrier.
Iodine I-131	Liquid Methyl Iodide (CH_2I) in sealed glass ampules.	Specific gravity of carrier 2.279, boiling point 108.5° F.	Low boiling point gas tracer for use as above.

OIL SOLUBLES

ISOTOPE	FORM	PROPERTIES	REMARKS
Cobalt Co-60	Cobalt Naphtenate in Benzene or Xylene carrier	5.3 years half life. High energy emitter. Completely oil soluble. Insoluble in water. Stable to 300° F.	Surface placement down-hole, dump bailer or ejector. "Pump-in" tracers on production wells. Erratic results if water is present in well fluids.
Antimony Sb-124	Radioantimony in benzene carrier	60 day half life. Medium energy gamma emitter. Completely oil soluble. Insoluble in water. Stable to 475° F.	Surface placement down-hole dump bailer or ejector. Pump in oil tracer for high tempera-ture wells or where ex-treme chemical stability is needed, erratic results if water present in well fluids.
Iridium I-192	Radioactive iridium in benzene or xylene carrier	74 day half life. Medium energy gamma emitter. Oil soluble. Insoluble in water. Stabilized for organic solutions.	Surface placement or downhole dump bailer or ejector pump in oil tracer. Erratic results if water present in well fluids.
Iodine I-131	Solution of Elemental Iodine in Benzene	8.1 day half life. Medium energy gamma emitter. Moderately stable in oil to 250° F. Oxidizes at temperatures above 250° F. Insoluble in water.	Surface placement or downhole dump or ejector. Oil tracers where short half life is desired. Erratic results if oxi-dized or if water present in well fluids.

OIL SOLUBLES (Continued)

ISOTOPE	FORM	PROPERTIES	REMARKS
Iodine I-131	Liquid - pure Iodo-Benzene C_6H_5I	8.1 day half life. Medium energy gamma emitter. Specific gravity is 1.8. Boiling point is 400° F. Oil soluble. Insoluble in water.	Surface placement, down-hole dump or ejector. Oil tracer. Very stable at high temperatures or in organic solutions. Erratic results if water present in well fluids.
		WATER SOLUBLES	
Iridium Ir-192	Iridium in water solution	74 day half life. Medium energy gamma emitter. Stabilized and miscible in water and acid. Insoluble in oil. No interference with logging operations after one year.	Surface placement, down hole dump or ejector. Water flood injection profiles, channel location, etc.
Iodine I-131	Radioiodine in water solution	8.1 day half life. Medium energy emitter. Miscible in water. Insoluble in oil. Available in three forms. Stabilized to prevent oxidation in air, water or acid.	Surface placement, down-hole dump or ejector for water flood profiles and tracers. Cement top and squeeze locator tag. Indicate when ordering to obtain correct solution.

DETECTORS

The detector is one of the basic factors to be considered when planning tracer work. Since downhole conditions are variable, the effectiveness of the tools will also vary.

The two most common detectors in use today are the geiger mueller tube and the scintillation crystal. The scintillation detector crystal is usually sodium iodide and is coupled optically with a light sensitive amplifier tube or photo-multiplier. Gamma rays striking the crystal will produce small light flashes that are sensed and amplified by the photo-multiplier. It has excellent efficiency (approximately 85 percent) in the detection of small amounts of radiation and produces a good quality correlation log for depth control and identification. The photo-multiplier is heat sensitive and becomes inoperative at about 185 degrees Fahrenheit and requires careful handling to avoid shock damage. The scintillation detector used in small through-tubing tools cannot be refrigerated as is possible in large diameter casing type tools. This 185 degrees Fahrenheit temperature limit is not a problem in most water injection wells. Also, it does not become a problem in producing wells until extreme depths are reached in the Permian Basin.

The geiger mueller tube which is used in most through-tubing or tracer tools is more rugged. It is heat resistant to 350 degrees Fahrenheit but has a low resolution efficiency of ten to twelve percent. This means that it produces poor quality correlation logs. The efficiency can be improved in larger diameter tools by coupling or bundling tubes together. However, the size of through-tubing tools prohibits this. Therefore, if a quality correlation log is needed, it should not be attempted with the small diameter tracer tool with a geiger tube. Also, small amounts of activity or material some distance away from the bore hole can be completely missed with this tool. This is especially true if the fluid velocity is high, as it will be in a small channel.

TOOL TYPES

Several types of through tubing tools are available for use in radioactive tracer work. Listed below are the three common types and their general uses.

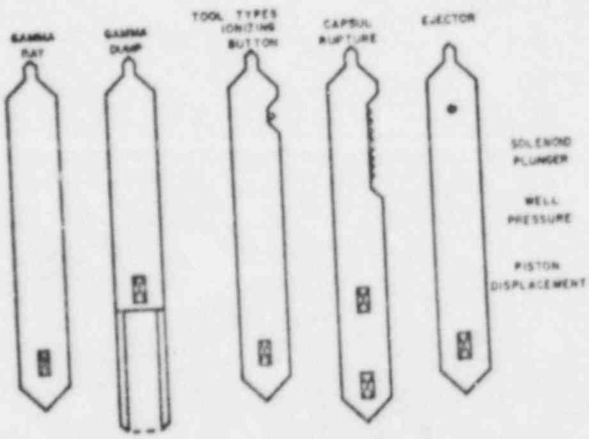

FIGURE No. 1

1. Standard Gamma Detector. This detector is used when radioactive material is introduced in the well at the surface. Logging runs are made to observe dispersal.

2. Gamma-Dump Bailer. Material is carried down hole in a dump bailer attached to the bottom of a gamma tool. The material is dumped by electrical means and after waiting, timed logging runs are made with the tool.

3. V·locity Measurements. Rate determinations are made at selected depths for injection profiles. Small slugs of radioactive material are released and the travel time over a known distance is recorded. The injection rate is then calculated. Several methods of introducing material into the fluid stream are available.

(a) Ionizing "button"
A cobalt "button" is attached to the tool above the detector. The "button" is ionized by an electrical current, thereby releasing some radioactive material into the fluid stream.

(b) Capsule rupture - single and double detector
Several small ampules of radioactive material are positioned on the tool above the detector. These are ruptured at will by an electrical current and the material released into the well stream.

(c) Ejector c·lind·rs - single and double detector
This type tool has a cylinder which can be filled with liquid radioactive material. This material can be ejected into the fluid stream by actuating an ejector.

There are three types of ejectors presently in use: (1) the solenoid plunger, (2) well pressure operated, and (3) positive piston displacement. All these types vary in the amount of fluid the cylinder will hold. They also vary in the amount of material that can be ejected at a single time. With some tools it is possible to make the ejections vary in strength and amount while it is fixed with others.

WELL EQUIPMENT

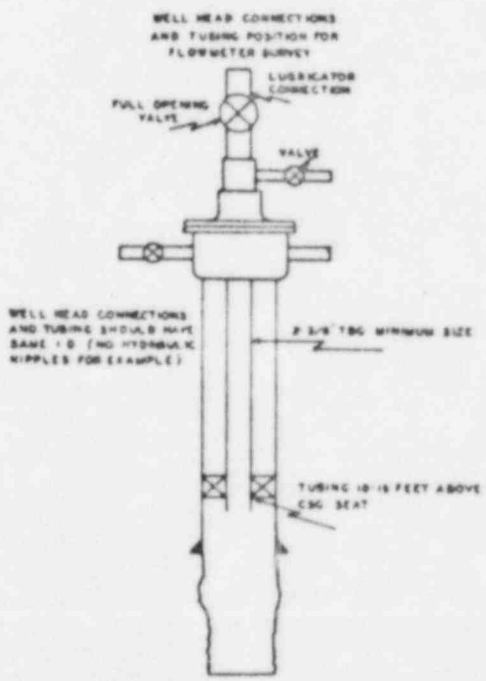

FIGURE No. 2

As with other survey work the well equipment must be considered. Injection profiles being the most common application, a typical injection well arrangement is shown in Figure 2. This ideal arrangement is satisfactory for all work except for the isotope interface survey which requires tubing to the bottom of the well and no packe·. The well head should permit the tool to be run into the well without altering the injection rate or pressure in any manner. It is also very desirable to have the tubing and packer set high enough above the top perforation or casing seat so as to permit the location of at least two casing collars. In addition, locating a channel behind the casing is much more positive when working below the packer. Channel determination above a packer becomes very uncertain and confusing.

Prior to any injection profile survey the well head should be examined for hydraulic nipples, bent subs and other restrictions. If a full opening valve is not on the well head above the injection valve, one should be installed at least 24 hours prior to the survey. This will permit the logging operator to attach his lubricator and run the tool into the well without stopping injection.

The tubing must be open ended and free of restrictions. Also, in making velocity measurements with ejector tools the 100 percent rate measurement must not be made too close to the end of the tubing if any reasonable accuracy is to be expected as there is a considerable jetting effect and turbulence near the end of the tubing.

Some modification of the above equipment is permissible when using tracer materials while pumping into a producing well for channel detection. However, the swab valve on top of the well head is a desirable feature in case of trouble.

STABILIZATION

Stabilization of injection is of the utmost importance in injection profile surveys and it cannot be overemphasized. Nothing should be done to the well to interrupt or alter the injection rate or pressure for at least 24 hours prior to running an injection profile survey. In most cases it is virtually impossible to detect unstable downhole injection with tracer tools.

To illustrate the point several examples of erratic downhole fluid behavior are shown. Erratic downhole conditions that have been observed during flowmeter surveys cannot be detected at the surface. Briefly, for those not familiar, the flowmeter makes positive volumetric fluid measurements downhole at any desired point and the direction of fluid movement through the tool is always known. This tool has been extremely valuable in interpreting tracer work and vice versa.

Erratic fluid behavior downhole can completely confuse the running and interpretation of a tracer log, but if one is aware of these possibilities, certain techniques can be employed to advantage.

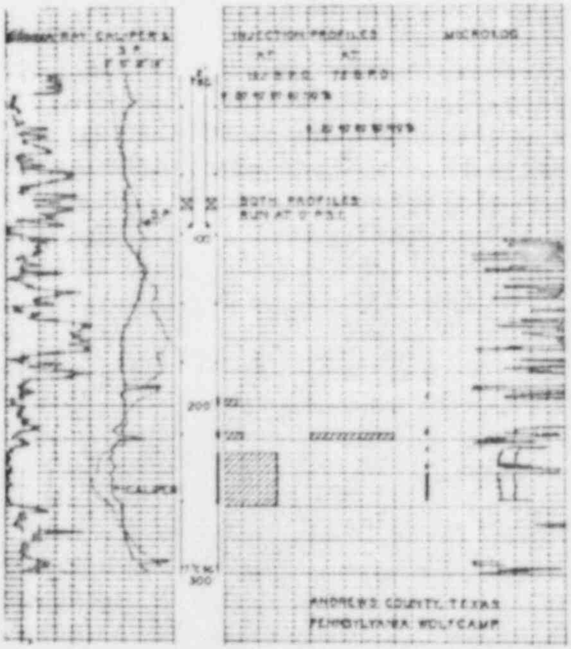

FIGURE No. 3

Figure No. 3 illustrates a change in profile as a result of a change in injection rate. The profile was made at 192 B.W.P.D. and zero injection pressure and water was found to be leaving the borehole in a good distribution pattern. The rate was reduced to 72 B.W.P.D. and zero injection pressure. This reduced rate profile showed the thin middle set of perforations to be taking 100 percent of the injection water. At the high rate (192 B.W.P.D.) the middle set of perforations was taking 21 percent of the fluid or 40 B.W.P.D. These perforations and the cement job were checked with a radioactive tracer and no communication was found.

Rate changes in this well during a tracer log would have affected the response of the tracer drastically, especially if a plate out type tracer were used and there was no opportunity to allow the well to clear up and a second survey to be run.

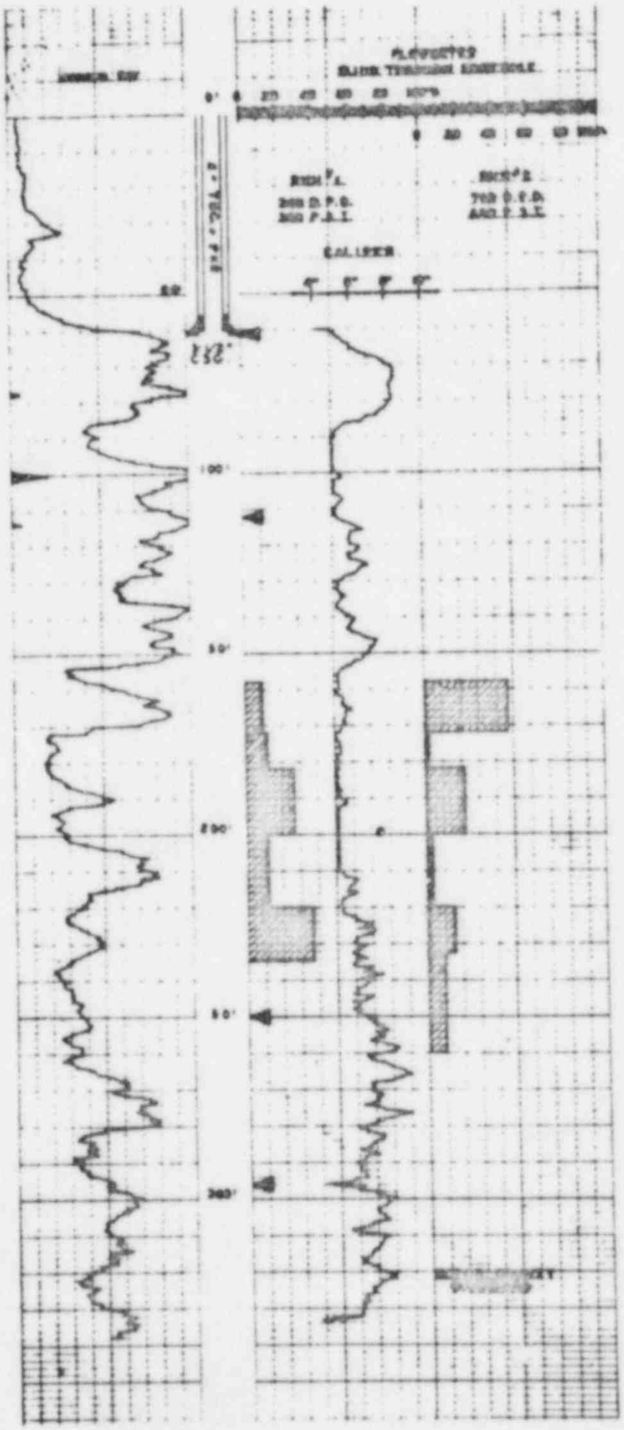

FIGURE No. 4

Figure No. 4 illustrates a change in profile by changing injection rate and pressure. The first profile was run at 340 B.W.P.D. and 300 psi injection pressure which yielded the profile on the left. The second profile was run at 785 B.W.P.D. and 400 psi. No appreciable change in profile was noted with the exception that the upper zone actually broke down and accepted 48 percent of the total injected fluid.

Figure No. 5. Injection on this well had been interrupted for about 12 hours. Two hours after injection was resumed all surface indications were that the well had stabilized. The survey indicated that all the injection fluid was entering the formation in the upper third portion of the zone. In the middle there was a back flow which divided as it entered the well, part of it moving up hole and into the zone directly above, and part moving down hole to re-enter the formation. The back flow zone was monitored for eight hours until all back flow ceased. The second profile was then obtained, and it was found that the middle section was still unstable as variations were still taking place. It is interesting to note that the injection pressure at all times was zero.

Many times during injection surveys the water plant will stop for 10 to 15 minutes. As a result zone swapping has occurred for two to three hours. A certain zone will be taking 10 percent of the fluid and another adjacent zone taking 40 percent, these zones will swap back and forth.

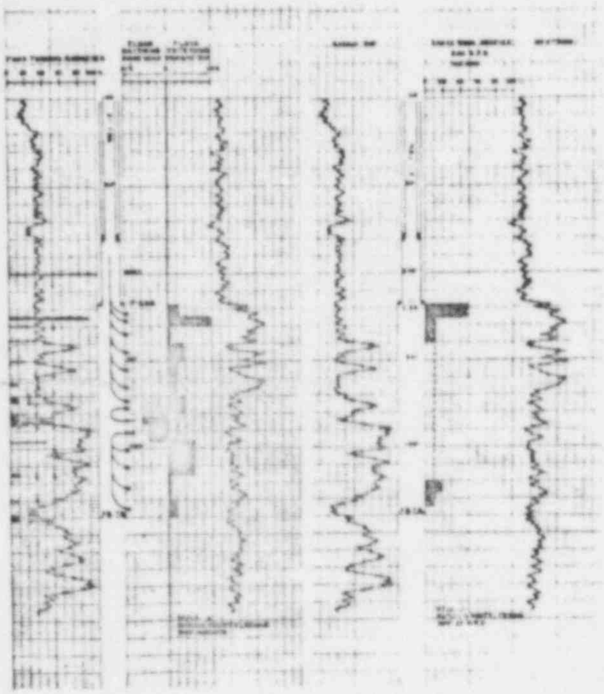

FIGURE No. 5

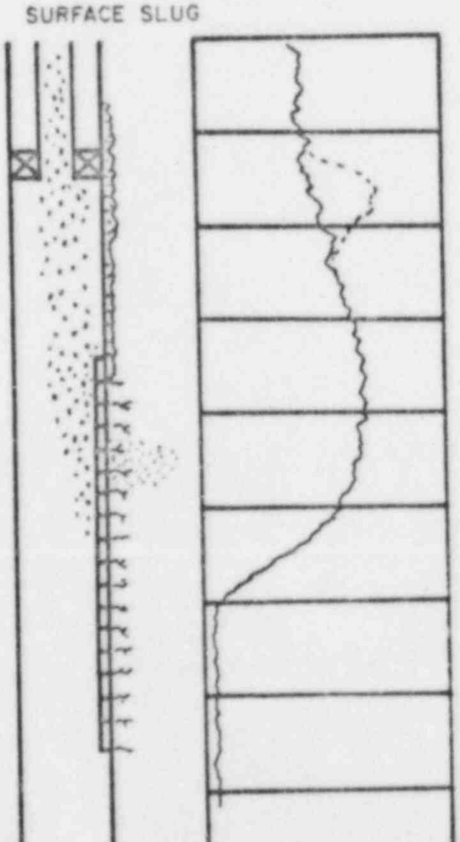

FIGURE No. 6

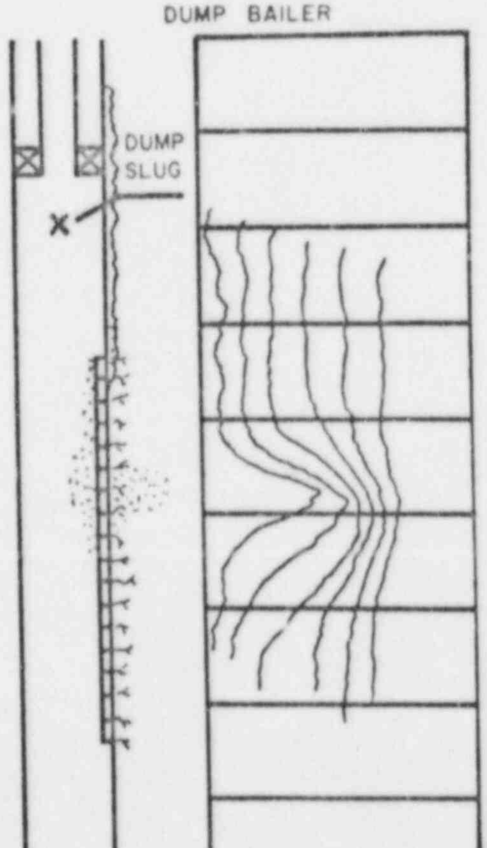

FIGURE No. 6-A

LOGGING TECHNIQUES

The logging methods possible with the series of tools illustrated can yield a wealth of information if, as stated previously, the technique is used in the manner intended and the shortcomings and pitfalls of the methods are realized.

Surface Injected Slug - Figure No. 6

This is the first and oldest method of tracer logging. An insoluble material is injected into the stream, pumped downhole into the zone and logged. Interpretation is based on accumulation of material over the zone, with the "hottest" areas supposedly the zone of greatest fluid acceptance. This method is very time consuming at most normal injection rates and the slug scatters badly, with as much as 200 or 300 feet of bore hole being occupied with contaminated fluid, thus making subsequential runs for interpretations impossible. Since the slug is usually pumped and stopped intermittently, little or no true injection pattern is obtainable. Particles depositing in collars, depressions, packers, turbulence traps and channeling from perforations further confuse the interpretation. Soluble isotopes used in this manner also scatter badly, masking the true picture of fluid movement outside casing with that of the contaminated fluid inside. The one advantage of having enough material in the hole to observe profiling in subsequent runs is almost completely negated by the disadvantages. This method is practically unused today.

Gamma-Dump Bailer - Figure No. 6-A

This operation is performed in much the same manner as the surface slug injection with the exception that the material is carried into the well and dumped just above the zone by a dump bailer, reducing both the time consumed in pumping the slug downhole and reducing the tendency of it to scatter. Insolubles still accumulate in much the same manner as with a surface slug. The dump bailer attached to the bottom of the tool tends to scatter the particles badly on successive trips through the slug.

Soluble materials can be used by this method with some degree of success if intermittent pumping is avoided and the log is run under usual injection conditions. The controlled interval method of velocity determination can be used with this type placement if successive runs are made with enough material for observing profiling while following slug downhole. The time delay in the first stages of the operation usually results in loss of indication of chaneling up from perforations or casing seat, if any exists. Any delay or waiting time can also result in dissipation of radioactive material in the zone of greatest fluid acceptance, leaving only the areas of least injection apparent on the log.

Several methods of velocity determinations are used to plot injection profiles. A brief examination of these follows:

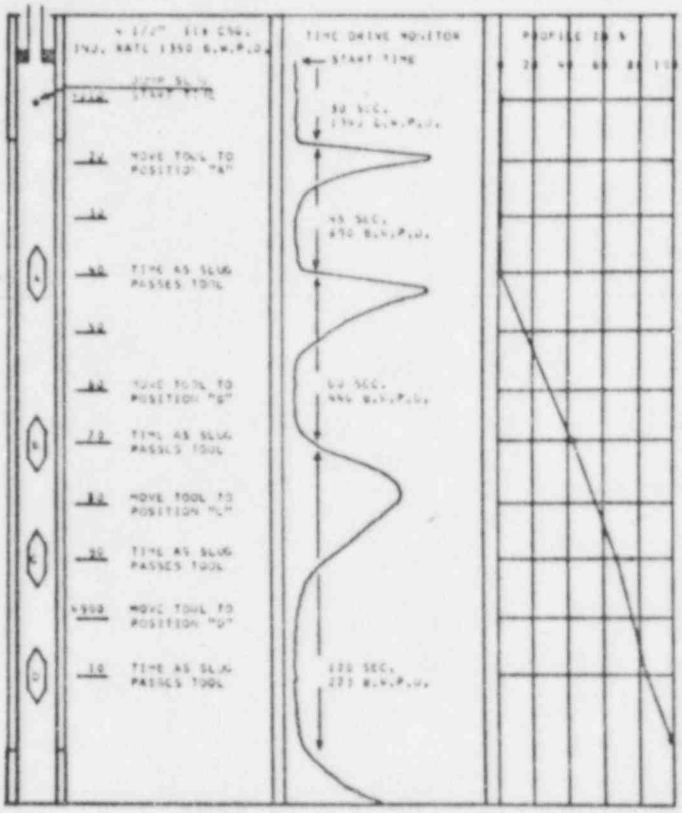

FIGURE No. 7

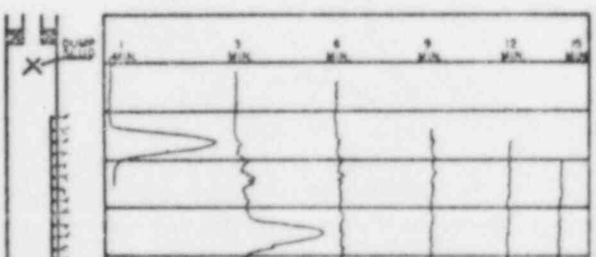

FIGURE No. 8

Controlled Interval Log - Figure No. 7

In this method the down hole travel time of a slug is recorded over predetermined and uniform intervals. Soluble material is released some distance above the perforations and the gamma tool is then lowered to a point below the slug and held stationary. The arrival of the slug is recorded on time drive. Next, the tool is rapidly lowered to another point downhole, held stationary and the slug arrival recorded. This process is repeated until the formation has been surveyed. In cased holes these traverse times over uniform distances can be plotted as percentages of injection rates. In open holes which have been calipered, volumetric calculations over each zone must be made.

The accuracy of this method is good in the medium velocity ranges. However, at high velocity rates the tool cannot be lowered and observations made over short intervals due to the time available. Therefore, at high rates the inspection zones are of necessity over long intervals, which is not desirable. At low velocities the exact time of slug arrival at the detector is difficult to determine. Generally this occurs in the last 10 percent to 20 percent of the total injection volume. Since no regular logging runs are made through the formation considerable information is by-passed and thin or narrow zones of injection will be missed. Also communication between sets of perforations and channels can be missed.

Controlled Time Log - Figure No. 8

This method is essentially the same as the previous method; however, in this method the time is held constant and the slug travel distance permitted to vary. A slug is released some distance above the formation. The time of release and position is recorded. Then at regular and frequent

time intervals the gamma tool is pulled through the slug. In this manner the slug is logged as it moves down hole. By plotting these runs side by side and in proper chronological order considerable information is obtained. Volumetric calculations can be made and channeling or communication detected; however, the rate or volumetric calculations will not be too accurate. The material used in this method should be soluble, and the open hole must have been calipered.

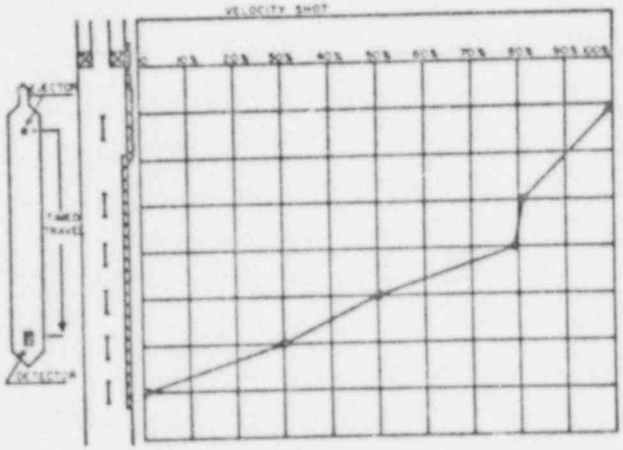

FIGURE No. 9

Velocity Shot - Figure No. 9

Rate determination is made by positioning the ejector tool at predetermined depths, ejecting material, timing it over a known tool length and then calculating volume.

This technique, when properly utilized, will yield accurate rate measurements in the high and medium injection rates. Generally during an injection survey the last 10 to 20 percent of the fluid remaining cannot be accurately broken down into small increments. This is due to the slow movement of the material making it impossible to determine just when the slug arrives at the detector.

The time recordings should not be made with a stop watch and count rate meter. This type of recording has several considerable sources of error that should be apparent. The recording should be done with a calibrated time drive on logging paper. This technique furnishes a record of each time measurement and permits one to analyze the accuracy of the measurements. This method of fluid volume measurement can give results over short intervals that are reasonably accurate. Inside casing the accuracy can be in the order of 95 percent. To do this the size and weight of the casing must be known. In open holes the accuracy can be in the order of 80 percent to 90 percent. In open holes there must be a recent and good caliper log. Obviously this accuracy cannot be obtained in ragged open holes.

The position of the tool down hole when making velocity shots is important. The 100 percent measurement will be abnormal if it is attempted within a few feet of the end of the tubing. Since the position of the tool within the bore hole greatly affects the accuracy, numerous attempts have been made to overcome these problems. Some tools have the ejector ports (3) spaced 120 degrees apart. This is to eject material into all portions of the fluid stream. Another ejector tool has two detectors and the slug is timed between them. This eliminates the problem of dispersal. The slug is well formed by the time it hits the first detector, and this arrangement results in good accuracy for straight velocity measurements.

Velocity measurements using ejector type tools have become a very important phase of tracer work. However, when used alone they do not present a complete and valid picture of fluid movement down hole. Also, velocity shots should be substantiated by other means during the survey. When velocity measurements are supported by logging runs through the tracer slug, calipers and primary logs, then and only then can a complete and valid analysis be made.

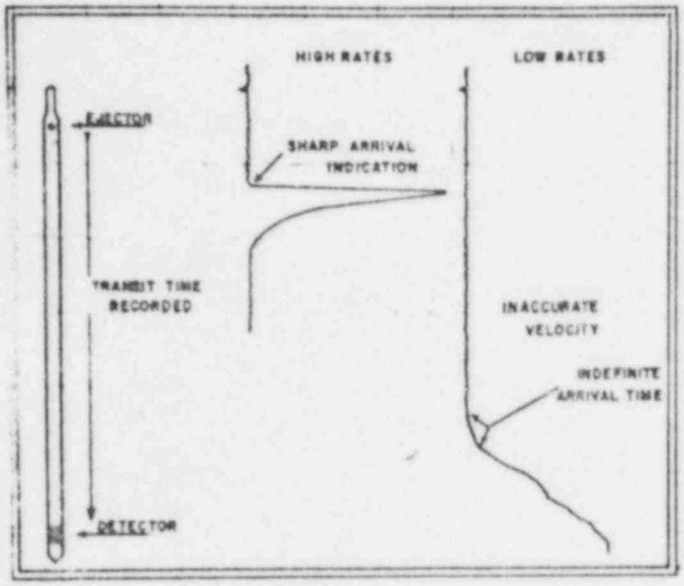

FIGURE No. 10

Two examples of typical velocity measurements are shown in Figure No. 10. The first one represents a sharp and easily defined slug arrival at the detector point. This sharp curve normally occurs at high and medium injection rates. The second curve is typical of low rates and it is impossible to determine with any accuracy the time of arrival at the detector point. All that can be said about the second curve is the fluid is still moving. This illustrates why velocity shots must be recorded on calibrated time drive.

RECOMMENDED SURVEY METHODS

A number of logging techniques commonly used have been discussed. Each of these has serious shortcomings and when used alone fail to present the complete picture. However, when the good features of each is combined into a single operation, then a complete picture is much more likely.

Single Detector - Ejector Type - Figure 11

The example shown is a typical Permian Basin water injection well. The injection rate is 800 B.W.P.D. at 1800 psi, 5½ inch and 15½ pound casing, 2 inch tubing, packer and 4 3/4 inch open hole. The recommended procedure is as follows:

1. Run open hole caliper, gamma correlation log, collar locator, then base log for tracer operations at reduced sensitivity. The work should be done with a scintillation type gamma detector where temperature permits.

2. Position ejector port at 4895 feet and detector at 4900 feet. Put recorder on calibrated time drive. Eject a heavy slug of water soluble I-131 material and monitor for a sufficient length of time to allow material to indicate a channel behind the pipe. Generally two to four minutes are sufficient. However, once the material behind the casing passes the detector it might be flushed out in a matter of seconds. In this first step we now have the 100 percent velocity measurement and indication of a channel behind the pipe.

3. Switch recorder back to normal logging (depth correlation). Drop the tool below the slug for series of timed logging runs over interval (logging runs number one through nine). Note residual radiation in zones "A" and "B" on run number one

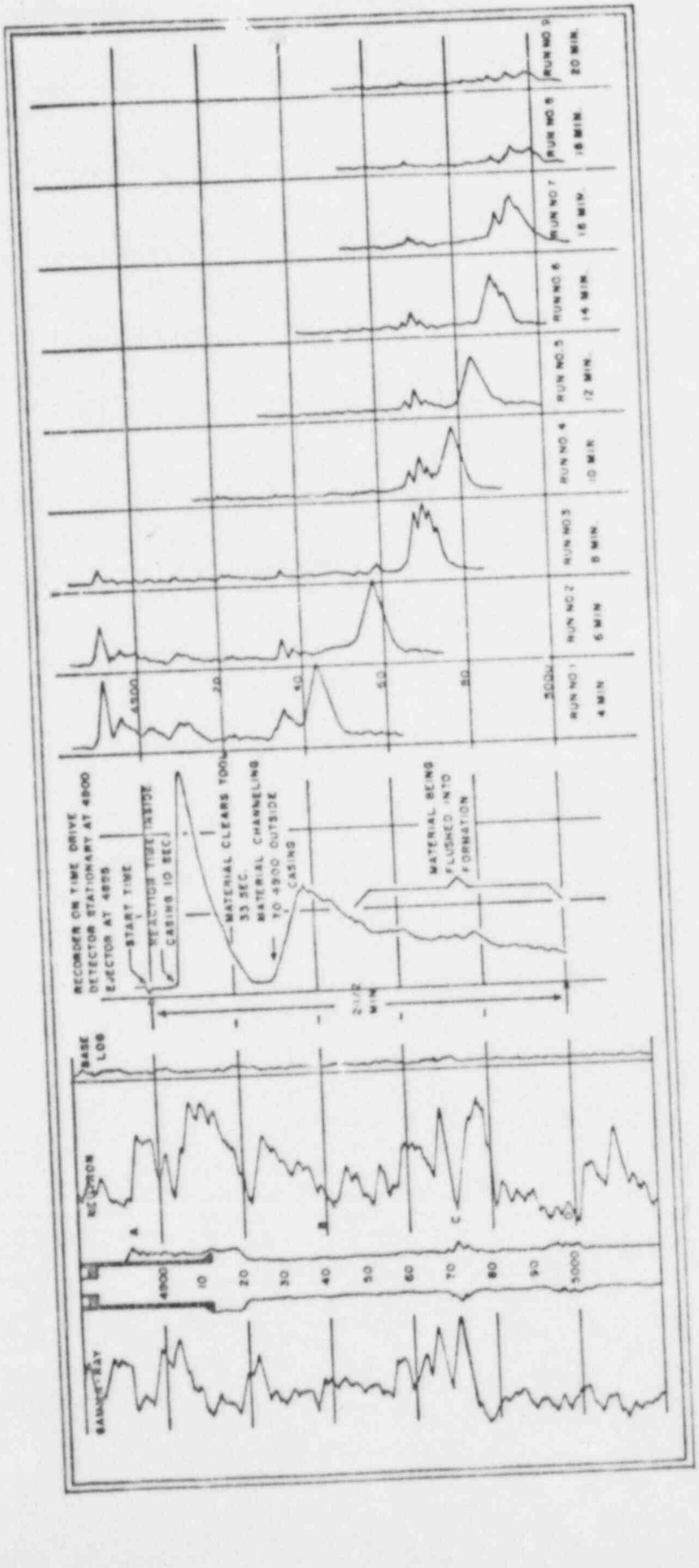
RECORDER ON TIME DRIVE
DETECTOR STATIONARY AT 4900
EJECTOR AT 4895
START TIME
REACTION TIME INSIDE
CASING 10 SEC
MATERIAL CLEARS TOOL
33 SEC.
MATERIAL CHANNELING
TO 4900 OUTSIDE
CASING
MATERIAL BEING
FLUSHED INTO
FORMATION
2-1/2 MIN
RUN NO 1 4 MIN
RUN NO 2 6 MIN
RUN NO 3 8 MIN
RUN NO 4 10 MIN
RUN NO 5 12 MIN
RUN NO 6 14 MIN
RUN NO 7 16 MIN
RUN NO 8 18 MIN
RUN NO 9 20 MIN
BASE LOG
NEUTRON
GAMMA RAY

FIGURE No. 11

dissipates on subsequent runs. This indicates zones of rapid flushing. Zone "A" (4890 - 4895 feet) behind the casing first builds up radiation intensity, then flushes rapidly and within eight to ten minutes all traces of material are gone.

These logging runs are made until the slug comes to rest and the hole cleans up. At this point in the operation considerable information is available to the logging engineer. By examining these runs he can then plan the work necessary to thoroughly analyze the fluid movement.

4. The examination reveals profiling as the material moves down hole. Note log as slug moves past sections taking fluid ("B" 4930 - 4940 feet, "C" 4970 - 4980 feet, and "D" 4995 - 5002 feet). There is negligible spreading of material for two reasons, (1) the material is soluble and completely miscible in water, and (2) the tool is smooth and without traps.

The closely timed logging runs make it possible to compute approximate rate of down hole fluid movement. This is done by knowing bore hole diameter and noting the rate of down hole movement of the slug. Slug moved from 4942 - 4955 feet in two minutes; this rate is approximately 188 B.W.P.D. The next interval, 4955 - 4967 feet as shown in runs two and three calculates approximately 170 B.W.P.D. This indicates a slight fluid loss in this area. Note the slight irridation at 4958 - 4960 feet in run number three. The slug shape at about 4970 feet (run number three) shows profile action here. Also profiling as shown on runs four, five and six show zone "C" (4970 feet) to be taking some fluid. Since runs numbers three and four are in a rate change area, a velocity check here would be unreliable. However, a check on slug movement as shown on runs four, five and six shows that about 94 - 120 B.W.P.D. are moving between 4976 - 4988 feet. Immediately below 4988 feet the final or lower most zone of injection becomes apparent at 4990 - 5000 feet (zone "D").

We now have this general information: (1) 100 percent rate measurement inside the casing, 800 B.W.P.D., (2) channel behind the casing up to 4890 feet, (3) three major fluid loss zones 4930 - 4940 feet, 4965 - 4975 feet, and 4988 - 5000 feet. About 75 percent of the injection fluid is going into the bore hole above 4940 feet and into the channel. About 10 percent is entering the formation between 4965 - 4980 feet. Also some water is entering the formation between 4995 - 5000 feet.

With this general picture in mind the gamma ray neutron log and caliper log should be examined. This examination shows definite changes in lithology and porosity at 4937 - 4940 feet, a shale break between 4968 - 4974 feet and another porosity change at 4990 feet. The caliper shows a fairly uniform hole except for the slight enlargement at 4990 - 5000 feet, shale wash out at 4968 - 4974 feet and the 7 7/8 inch drill hole just below the casing seat. Velocity shots should not be made in these enlargements or in the middle of a section where rates are changing.

This procedure is such that each step provides information to plan the next one. Also it requires that the logging engineer must be well trained and able to do more than just run a tool into the hole. The thin zones revealed by the correlation of primary logs, tracer logs and caliper information can now be closely bracketed with velocity shots and more accurate quantitative values placed on rates and injection patterns.

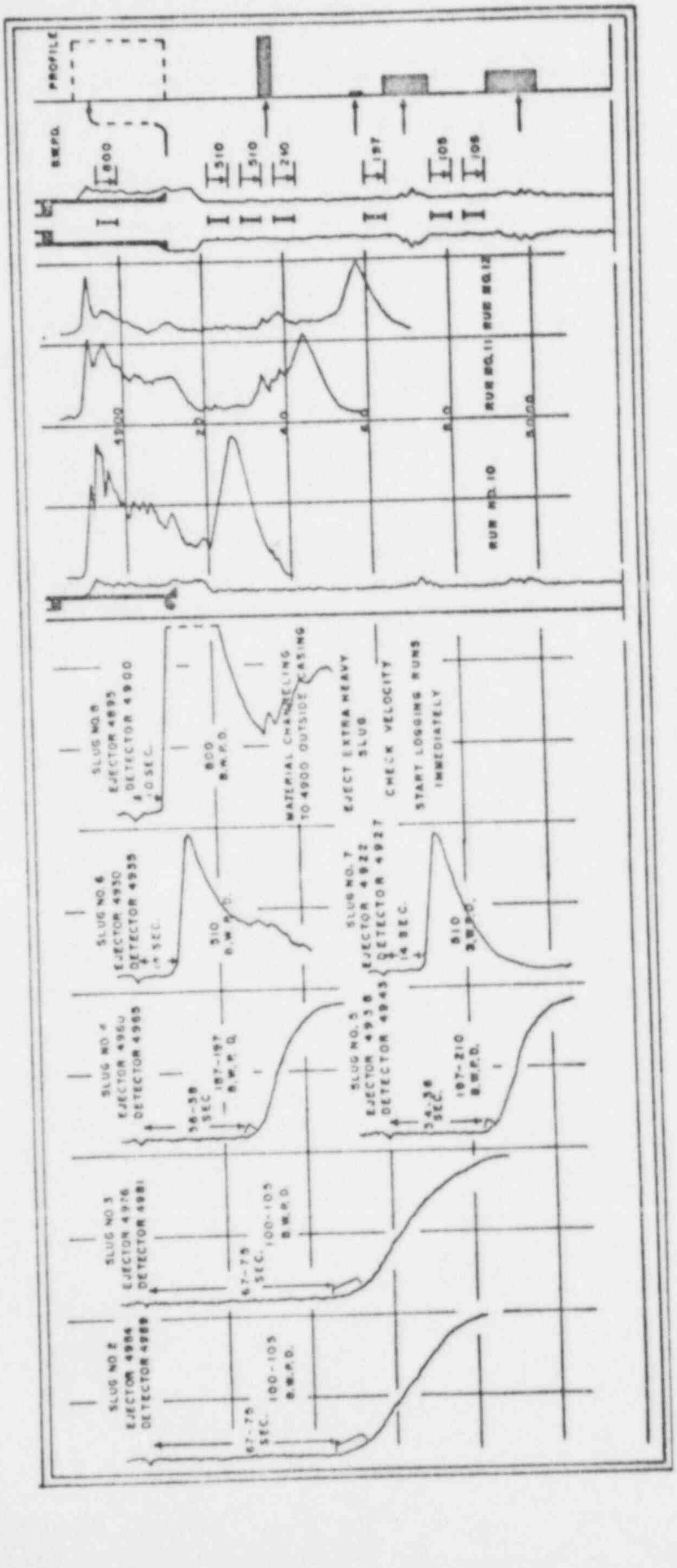

FIGURE No. 12

Figure No. 12. Rates determined at the points indicated by slugs two through seven correspond to the general profile derived from the logging runs, define the zones much more closely and establish the quantitative profile in the open hole. They also show the amount channeling up behind the casing by indicating the down hole rate immediately below the casing seat (slugs 6 and 7) versus the rate determined in the casing (slug 8).

Slug number eight is intentionally very heavy to more completely identify the extent of the channel behind the pipe. (Note indication of channel before the large slug clears the tool inside the casing.) Immediate logging runs through the section also catch the material behind the pipe before it dissipates and more clearly shows the single thin zone of fluid acceptance.

The overall pattern or profile of injection is shown at the right hand side of Figure No. 12 and can now be accepted as a true and accurate pattern.

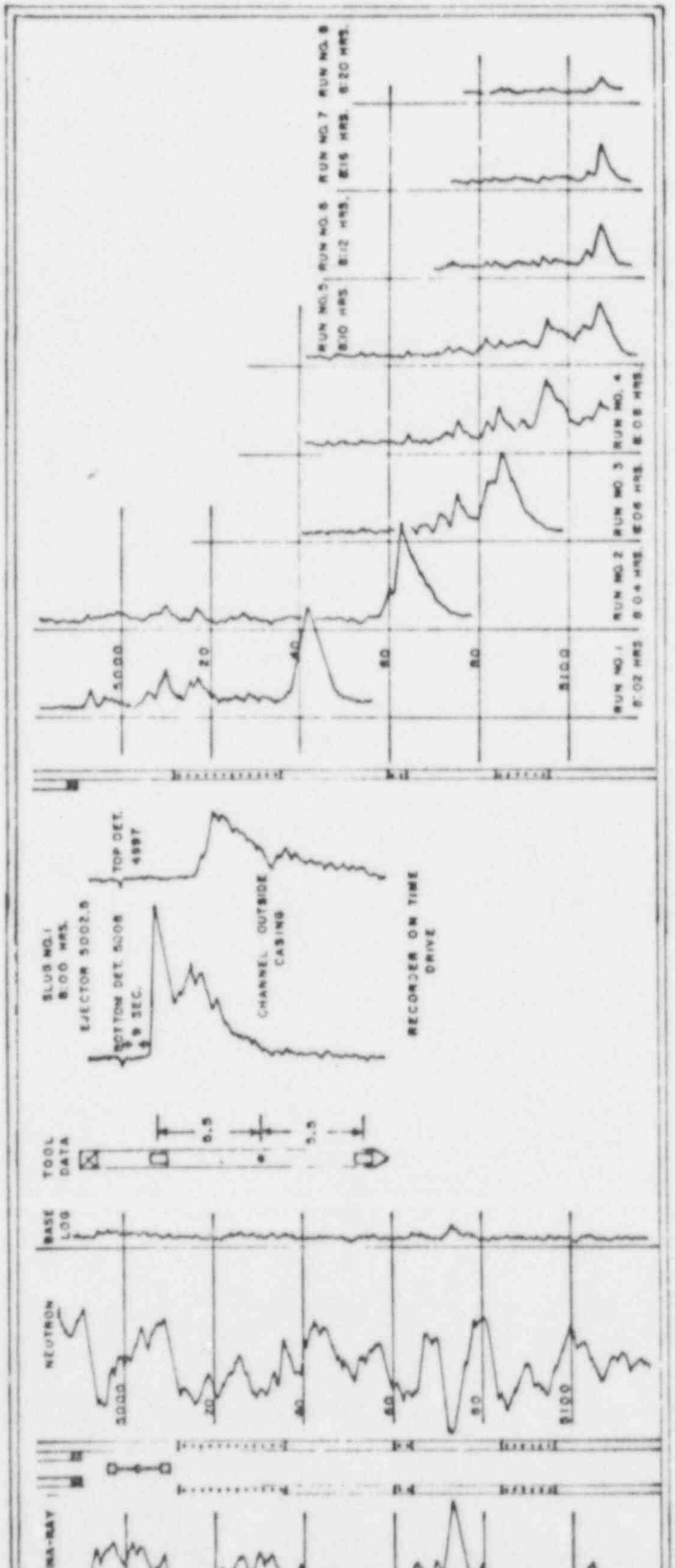
GAMMA-RAY
NEUTRON
BASE LOG
TOOL DATA
CHANNEL OUTSIDE CASING
RECORDER ON TIME DRIVE

FIGURE No. 13

Double Detector - Ejector Type

Often it is necessary to place the detector at or near the top perforation. In this situation a channel and thief zone near this point can be missed. This is because the material will be affecting the detector from inside and outside the pipe at the same time.

This problem is easily solved by using a detector above and below the ejector. Since the material is ejected into the injection stream below the top detector, an reaction on the top detector can only be from behind the casing.

Figure No. 13 represents a typical application of this type tool.

1. Run gamma correlation log, collar locator, then base log at reduced sensitivi for tracer operations. Scintillation detectors should be used.

2. Position ejector port at 5002.5 feet with detectors 5.5 feet above and below the ejector as shown in sketch. Tool is held stationary, both detectors recordir simultaneously on calibrated time drive.

3. Eject heavy slug of material into the injection stream (I-131 water soluble) Monitor until material has cleared lower detector. Also, monitor for sufficient time for channel to be indicated on top detector.

Note - bottom detector shows fluid travel time of 9 seconds inside the casi (910 B.W.P.D.). The shape of this recording (ragged return to base curve) indi s possible channeling or fluid trapped at or near the top perforation. However, reaction by the top detector clearly indicates a rapid channel behind the pipe at least 4997 feet. Also, note that almost complete dissipation occurs in 90 s nd

4. Switch recorder back to normal logging (depth correlation). Drop tool belo slug and log up hole as indicated. Make several regular and frequent runs thro the slug as it travels down hole.

5. Examination of slug travel as indicated by runs number one through eight re ls

(a) Slight indication of activity behind the casing (at 4994 feet) which completely disappeared between run number one and two. This clean up has occurred in four minutes. At this time it is not certain if this the top of the channel or not.

(b) No indication of communication between top and middle set of perforat ns

(c) Profiling between middle and bottom set of perforations indicates communication.

(d) Evidence of material indicates fluid movement below the bottom set of perforations. At this time it cannot be determined whether it is a chan l or not.

(e) Approximate rate-volume calculations based upon slug travel down hole indicates: 495 B.W.P.D. leaving the casing at or near the top perfora ion 75 B.W.P.D. leaving the middle set of perforations, 170 B.W.P.D. leaving near the top of the lower set of perforations, and the remainder movi down hole to 5108 feet - probably outside the casing.

6. Check the 100 percent injection rate again (ejector at 5002.5 feet) to make certain that the rate has not changed. The first slug has indicated that a rather detailed procedure will be necessary to make a complete fluid movement analysis. This slug number two is not illustrated.

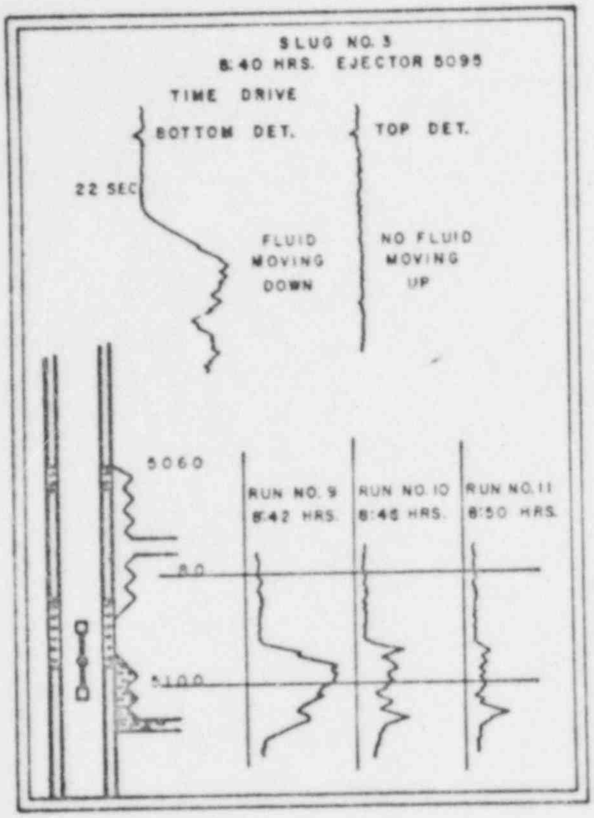

FIGURE No. 14

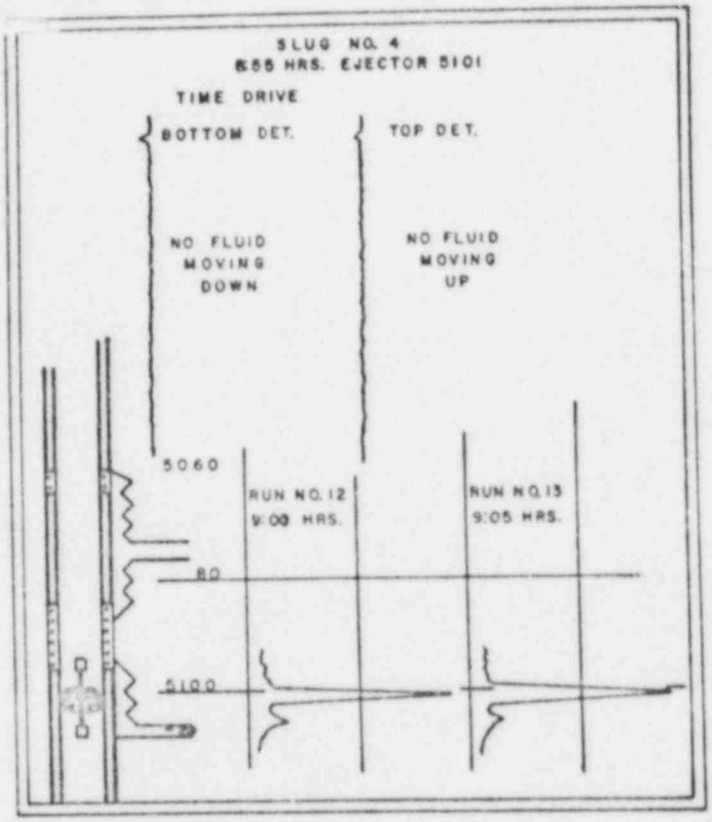

FIGURE No. 15

7. Identify channel at bottom perforations. Figure No. 14. Tool is positioned as shown with ejector at 5095 feet which is immediately above the bottom perforation. Slug number 3 is ejected and monitored on time drive. Reaction occurs on bottom detector and no reaction on the top detector. This indicates fluid moving down, probably outside the pipe. Note logging runs numbers 9 through 11 again show material as low as 5108 feet.

8. Figure No. 15. Ejector is positioned below bottom perforation. Slug number 4 is ejected and monitored on time drive. No reaction occurs on either detector. Logging runs numbers 12 and 13 at five minute intervals show slug remaining static at 5100 feet. This procedure proves that the material detected at 5108 feet is behind the casing.

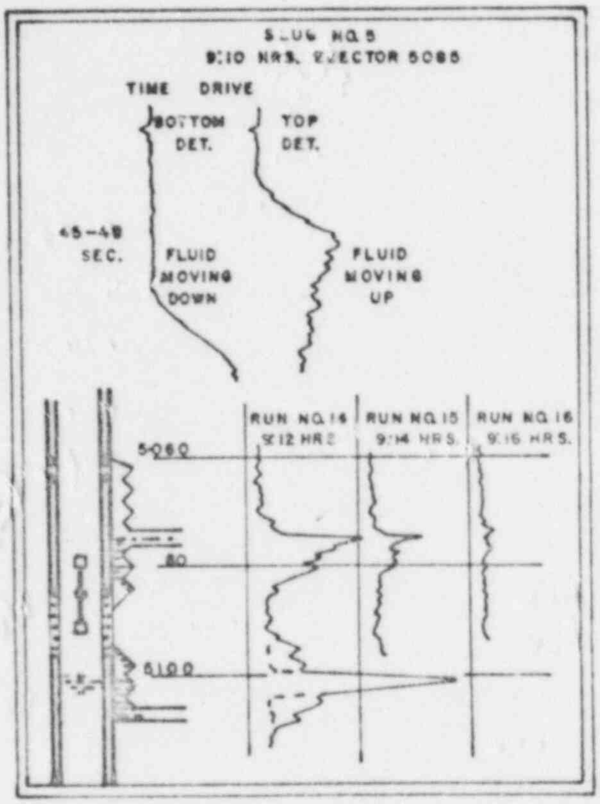

FIGURE No. 16

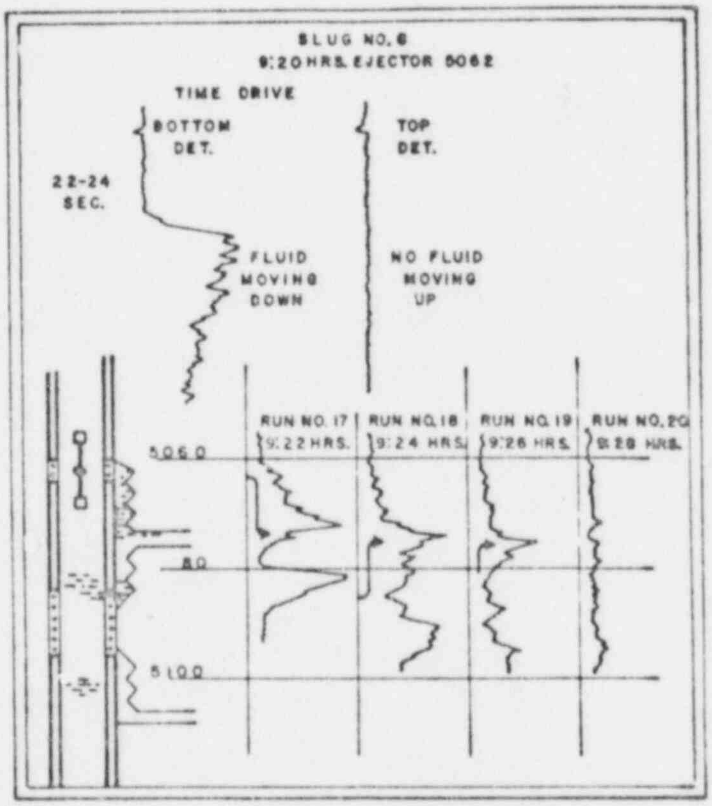

FIGURE No. 17

9. <u>Figure No. 16</u>. Ejector is placed immediately below the top of the lower set of perforations. Analysis of slug number one indicates a rate change across these perforations and a channel. Slug number five is ejected and both detectors are monitored on time drive. Top detector reacts in 18 to 20 seconds indicating fluid moving up outside the casing. Material reaches the lower detector in about 45 seconds which is approximately 170 B.W.P.D. rate. This checks with the amount indicated with analysis of slug number one. Several logging runs are made to define channel limits. Material is detected to 5074 feet which means water leaving top of these perforations is channeling to 5074 feet. Dissipation or clean up is rapid which indicates a zone of high permeability behind the pipe.

Analysis of slug number one, logging runs numbers 3, 4 and 5 indicated channeling between the middle and lower sets of perforations.

10. <u>Figure No. 17</u>. Tool is positioned across the middle set of perforations. Slug number six is ejected and monitored on time drive. Bottom detector shows fluid moving inside casing at approximately 340 B.W.P.D. (approximate because tool is in a rate change zone.) Shape of recording also indicates a channel outside casing is retaining some material. Top detector shows no channeling up behind the casing. Runs numbers 17 through 20 further substantiate water channeling down from this middle set of perforations to 5074 feet.

Run number 17 shows material channeling outside the pipe down 5074 feet. Runs number 18 and number 19 show remainder of slug inside the pipe leaving perforations at 5084 feet and moving up to 5074 feet.

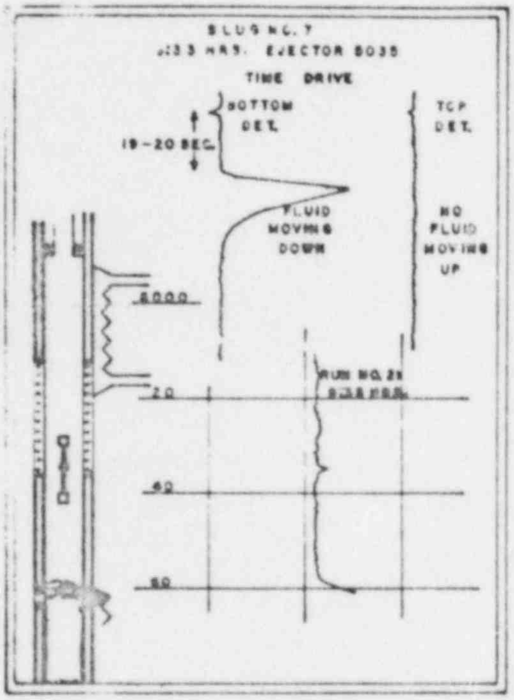

FIGURE No. 18

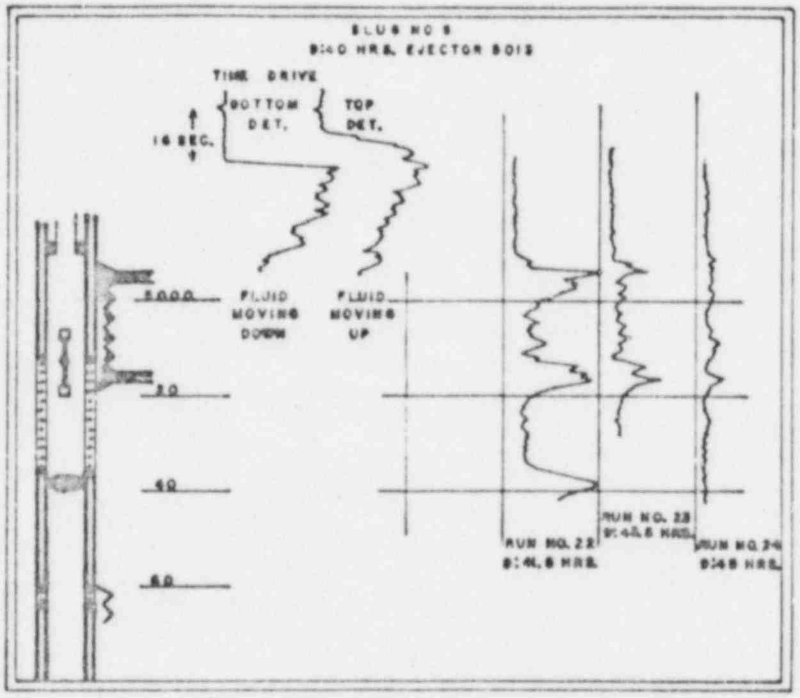

FIGURE No. 19

11. Figure No. 18. Check to determine if top set of perforations is in communication with the middle set of perforations. Tool is positioned as shown. Slug number seven is ejected and monitored on time drive. Bottom detector (19 - 20 seconds) indicates 420 - 435 B.W.P.D. moving down inside the pipe. Also, rapid return to base curve indicates no channel downward. No reaction on top detector indicates no channel upward. Logging run number 21 also indicates no channel.

12. Figure No. 19. Check for channel from top perforation. Slug number one did not clearly define the top of the channel. Tool is positioned as shown and heavy slug number eight is ejected. Note reaction times on both detectors - the material moves behind the casing at a more rapid rate up outside the pipe than downward inside the pipe.

Logging runs 22 through 24 also indicate a high velocity channel to 4994 feet. Also, an apparent zone of injection between 5014 - 5018 feet.

13. All the preceding work has defined all channels and zones of rate changes. Velocity measurements must be made above and below zones where rate changes occur. Measurements made in a zone of rate change are of little value. Five velocity shots are made and recorded as shown in Figure No. 20.

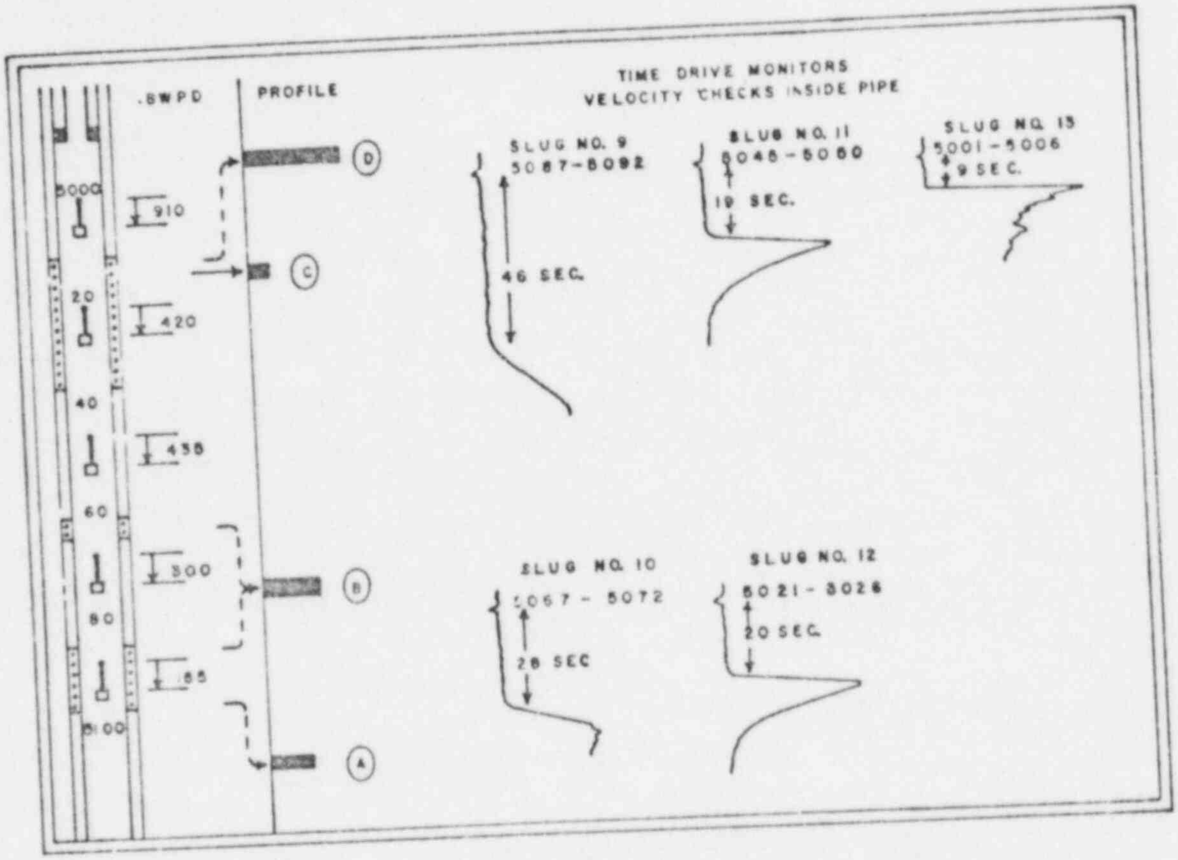

FIGURE No. 20

The injection profile is determined as follows:

(a) 185 B.W.P.D. leaving the perforations at 5096 feet as indicated by velocity shot (slug number nine). The injection zone behind the pipe is indicated by slugs numbered three and four. This material is approximately 5106 - 5108 feet.

(b) Velocity shot slug number 10 indicates 300 B.W.P.D. moving down inside the casing. The rate difference between slugs 9 and 10 is 115 B.W.P.D. (300 minus 185). This means that 115 B.W.P.D. is moving out at 5084 feet. Slugs numbers five and six show it to be moving up outside the pipe to 5076 feet. The difference between velocity shots, slugs number 10 and 11, show 135 B.W.P.D. to be leaving pipe at 5064 feet. Slugs numbers 5 and 6 also show this to be moving down outside the pipe to 5074 feet. Therefore, the volume into zone "B" (5074 - 5076) is 115 plus 135 or 250 B.W.P.D.

(c) Notice that velocity shots, slugs numbers 11 and 12 do not agree by one second, probably due to turbulence in perforated area. The rate of 435 B.W.P.D. (slug number 11) is more representative. It is known that 475 B.W.P.D. is leaving the perforations between 5012 - 5021 feet. This is the difference between slug number 13 and number 11. (Refer to slug number 8.) 515 B.W.P.D. is moving down inside the pipe (5013 - 5018 feet). Therefore 515 minus 435 is 80 B.W.P.D. into zone "C" (5014 - 5017 feet), as indicated on runs numbers 22 through 24.

(d) By subtraction (910 minus 515) 395 B.W.P.D. is the amount channeling to zone "D" (4094 - 4096 feet). (Refer to slug number eight, runs 22 through 24.)

PRODUCTION PROFILES

The use of tracer ejector tools and isotopes to obtain production profiles is not recommended. The main reasons for this are: (1) the isotope presents a hazard upon returning to the surface; (2) no universal isotope is available for use in a three phase mixture of oil, gas and water. Various attempts have been made to obtain production profiles by using an isotope that is compatible with the most representative well fluid being produced, but this has not yielded valid results. In selecting an isotope that is oil soluble for use in a well producing more oil than gas or water, we encounter a mixture of the three fluids in all zones of investigation and resulting turbulence will cause the material to plate out or string out. Thus, any readings obtained will be unreliable.

CONCLUSION

Tracer logging can be extremely reliable in diagnosing well problems when properly employed by trained personnel. Two types of problems outlined in the preceding examples are indicative of the information obtainable from tracer logs.

In planning a tracer logging operation, the company engineer has a considerably more involved task than he has in planning a primary logging operation. First, he must consider the physical equipment of the well to be certain it will accommodate the logging tools. Next he should be thoroughly familiar with the reservoir conditions, injection rates and pressures and the information on lithology, porosity and permeability as reflected by pertinent primary logs. Also, he should determine what specific information is desired from tracer logs. Then the company engineer should consult with the logging engineer and discuss the above factors before a proper isotope can be selected and correct tools and techniques be employed to adequately collect and evaluate tracer logging data.

A few basic rules for successful tracer logging can be stated as follows: (1) Have maximum control over fluid movement, (2) Reduce variables to a minimum, (3) Avoid use of compressible gases, (4) Use isotopes of short half life, (5) Use only miscible isotopes that are compatible with well fluids to avoid plate out or settling, (6) Observe the isotope in transit, (7) Carefully note clock times of each run or operation, (8) Let each logging operation set the stage for following operations, and (9) Double check each operation if possible.

When a trained logging engineer and a company representative confer on location as to what information is desired and what data has been obtained as the logging job progresses, a complete picture as presented by tracer logging can usually be obtained and a preliminary interpretation afforded by the time the well logging has been completed. In this manner rapid planning of any necessary remedial work on the well can be accomplished.

COMPUTERS -- TO INCREASE THE VALUE OF TEMPERATURE LOGS

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R. D. COCANOWER*

ABSTRACT

Temperature logs have been utilized to gain information on fluid movement in and adjacent to well bores for many years. Much research, both field and laboratory, has been done in an attempt to apply mathematical standards to the information obtained. Detailed quantitative interpretation has been generally unsuccessful because of local geology, bore hole effects, unstable well conditions, and the time required to approach thermal stability. The application of the temperature log to injection profiling has focused our attention on these problems more pointedly.

The technique discussed in this paper provides a means of investigating injection strata more thoroughly and minimizing the well condition influence. A digital system is employed, recording a series of runs on tape at predetermined time intervals. The tapes are programmed through a computer to establish the temperature decay rate through selected intervals in the well bore. When the rate is established, an extrapolation data provides an accurate progression toward thermal equilibrium in the strata. This data is used to determine the fluid acceptance profile. For further analysis of data, a differential is available for any selected interval.

Field examples are presented comparing the various temperature logging techniques with the computerized logs to further demonstrate the validity of the information obtained.

INTRODUCTION

Temperature logs are one of the oldest means of investigating downhole conditions. Many new applications and methods of interpretation of results have been developed, most of them valid to a limited degree. These "new" premises and techniques are, for the most part, extensions of, or improvements upon prior work. Supporting information, both theoretical and actual, lend credence to some individual histories, which are then accepted as the "standards" for their particular approach. Our ability to compute results from physical data has improved almost without bounds, and some highly sophisticated data calculations has evolved. The advancement in this area has pre-supposed that the methods of gathering and extracting these basic data has kept pace with our analytical ability

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Unfortunately, such is not the case. We still must work with information collected by, basically, a thermometer in a very restricted environment, the well bore.

These "thermometers" have been improved radically, and in our zeal to get to the final answer, we tend to impute capabilities to the tools that cannot exist under the conditions in which they operate. We then supply the missing data from our individual understanding of the conditions and our opinions are "read in" to the log as actual recorded data. The results computed from this information are as varied as the number of qualitative "facts" we supply.

The widespread differences in temperature log interpretation indicate that we should re-examine the raw data and attempt to validate the basic components of our formulations.

The total amount of temperature information available to us at a given time exists in the absolute temperature curve (Figure 1); therefore, we must devise a method to extract this data, then determine what condition affected it. To do this, an understanding of the tools, their reactions and methods of recording, and the environmental reactions surrounding them is imperative.

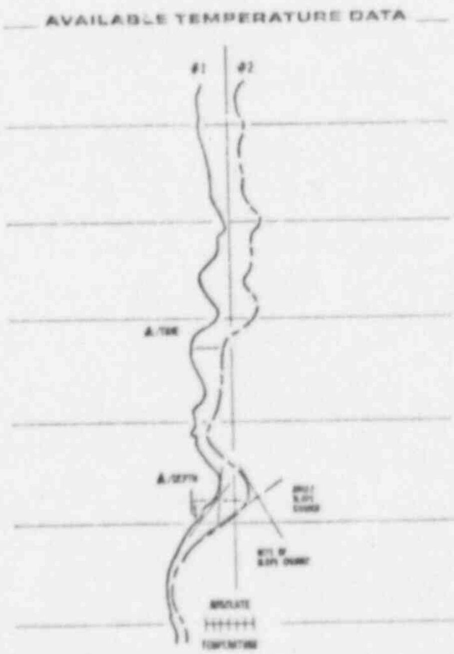


Figure 1. Absolute Temperature Curves

TOOLS

Surface recording tools can be divided into three basic classifications:

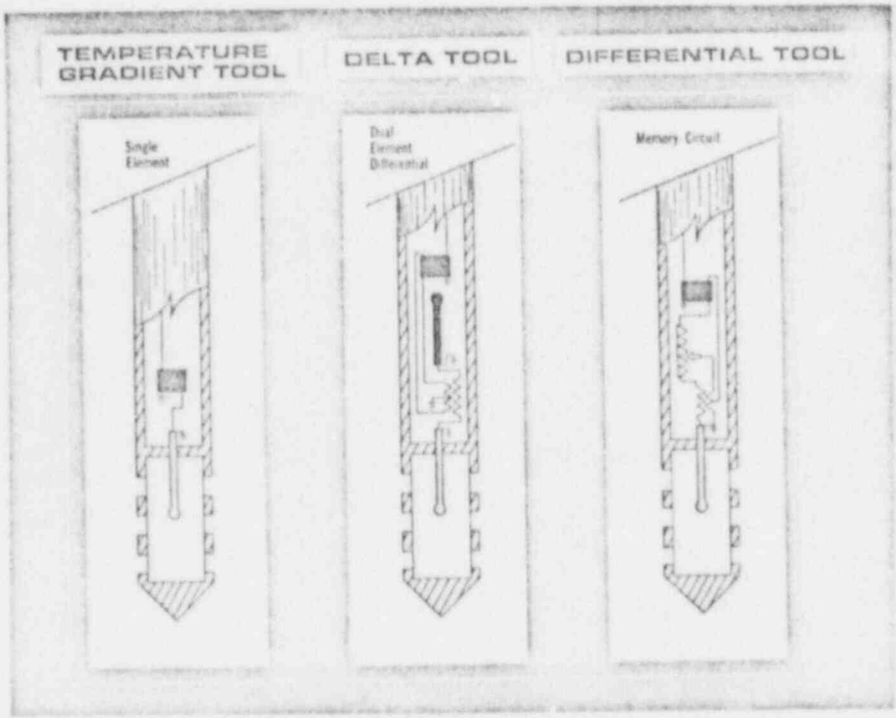


Figure 2. Basic Temperature Tools

1. Absolute or normal temperature: A single element tool, calibrated and aligned to detect the existing temperature downhole and transmit this information to the surface, where it is recorded as actual temperature versus depth.

   This tool measures the temperature of the borehole fluids at a single point and is subject to the total of the vertical as well as lateral effects of temperature transition zone. Sharp definition of temperature interfaces is improbable unless the differential is extreme, and slight changes often go unnoticed unless recording sensitivity is high. Total transition from one temperature to another is usually averaged over a long vertical interval.

2. Temperature Differential: The differential tool utilizes two elements physically separated by a given distance. Both elements detect the absolute temperature of the fluids at their respective depths. These temperatures are impressed upon a "comparison circuit" and the difference between them is transmitted to the surface and recorded. Hence, if one element

detects 76 degrees and the other, 5' above it, registers 75 degrees, a 1 degree progression for the interval is recorded. As long as this progression remains the same as the tool is moved downhole, no further deflection is recorded, but should the rate of change increase to 2 degrees per five feet interval (i.e. top element 78 degrees and bottom 80 degrees) an additional one degree deflection would appear on the recording for the given interval.

The two element tool can be calibrated and used as a "true differential" indicator by taking stationary readings. The actual difference in temperature would be determined by the deflection. During most logging operations, the progress downhole is usually continuous; therefore, both the rate and the amount of temperature change affect the readings, and the log is used as a relative temperature change indicator. The actual temperature is recorded simultaneously on a separate circuit. The advantage in this usage is a more prominent indication of temperature change over a given interval.

3. <u>A - Priori "Differential":</u> This principle simulates the differential effect by using a single element and an electronic "memory circuit." The single element detects the temperature of the well fluids and sends this information to a memory cell or delay circuit. After a pre-selected time this temperature impulse is fed back into a "comparison circuit" and is impressed with the impulse currently generated by the temperature element. The difference in temperature detected at the two time-intervals is recorded as differential.

   This tool is not a true differential indicator with respect to depth since it depends upon movement for its depth spacing. Theoretically, the spacing is controlled by logging speed, but in actual practice, the time delay for feed back in milliseconds and normal logging speeds are not compatible. No consistent spacing control is possible without electronic "gateing" keyed to the depth meter. Continuous movement again incurs effect from both the rate and amount of temperature change, and confines the use of this curve to an instantaneous slope change indicator. As with the other differential tools, the actual temperature is recorded on a separate circuit. The downhole tool used in the A-priori method is only the normal or absolute temperature sonde. All the delay circuits are in the surface instrumentation. NOTE: The electronic description in the foregoing discussion is not technically correct, but has been simplified to emphasize the sequence of occurrence and reaction.

APPLICATION

Temperature analysis is useful in four separate applications. All the interpretations have overlapping variations.

1. <u>Definition of long enduring effects,</u> such as cement top location. Timing is not critical since the heat evolved by cement reaction is continuous for some time and relatively slow to dissipate. Good definition is possible for long periods of

time after operation. Absolute temperature tools are competent for this work, as anomalies are usually quite pronounced.

2. Production Logging. Location of production entering well bore. Identification of channels when produced fluids cause changes in ambient temperatures. Differential tools assist in interpretation and definition of slight changes of temperature.

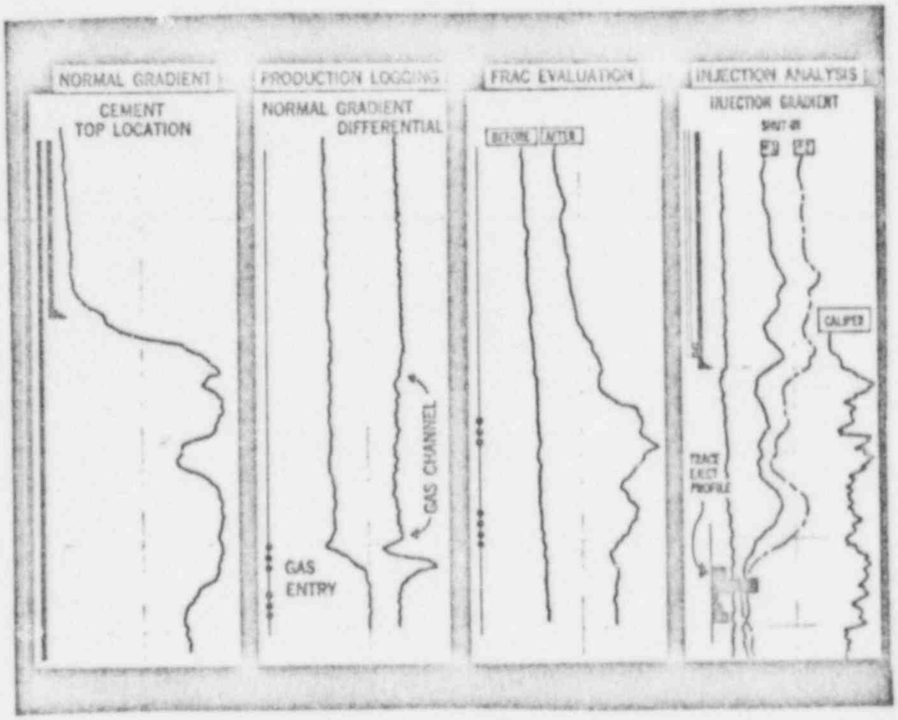


Figure 3. Temperature Analysis Applications

Thin zones of production entry can be better defined with short spaced investigation.

3. Frac or Stimulation Evaluation. Identification of short term temperature effects. Zone identification is made by comparison of normal gradient curve before operations to the anomalies induced by pumping fluids downhole. Temperature effects are comparatively short lived and time is rather critical. Interpretation will vary with the direction of induced anomalies (heated or cooled) and with the treating fluids used.

Absolute temperature sonde must be used but the differential curve can assist in defining limits of zones, especially when differentials from normal gradient are small.

4. Injection Analysis. Identification of zones of injection by observing the changes in well bore temperatures induced by injection, and comparing the relative rates of recovery opposite various strata when injection is discontinued. The absolute temperature tool must be used for valid interpretation, and the differential tool may be used for upper and lower limits of zones.

ENVIRONMENTAL EFFECTS

All temperature analysis is accomplished by observing the reaction when ambient temperatures are disturbed by some means, resulting in downhole temperatures other than normal gradient. The gathering points for all temperature data are confined to the well bore and all measurements must be considered from these indices only. Reaction in the formation is inferred from its effect on the well bore temperatures.

The temperature curve is a graph of temperature versus depth within the borehole. As such, it considers only two moments -- vertical and lateral - but the effect of all the conditions surrounding the data point dictates its temperature at any given time. Since the temperature observed at a specific point is the result of its total environment, a method of defining the variables and eliminating or computing their effect is necessary before valid quantitative work can be accomplished.

The definition must be done with the raw data derived from the temperature curve, which is subject to the inherent limitations of the collecting process. A better understanding of these limitations can be established when we examine the basic principles involved. (Figure 4).

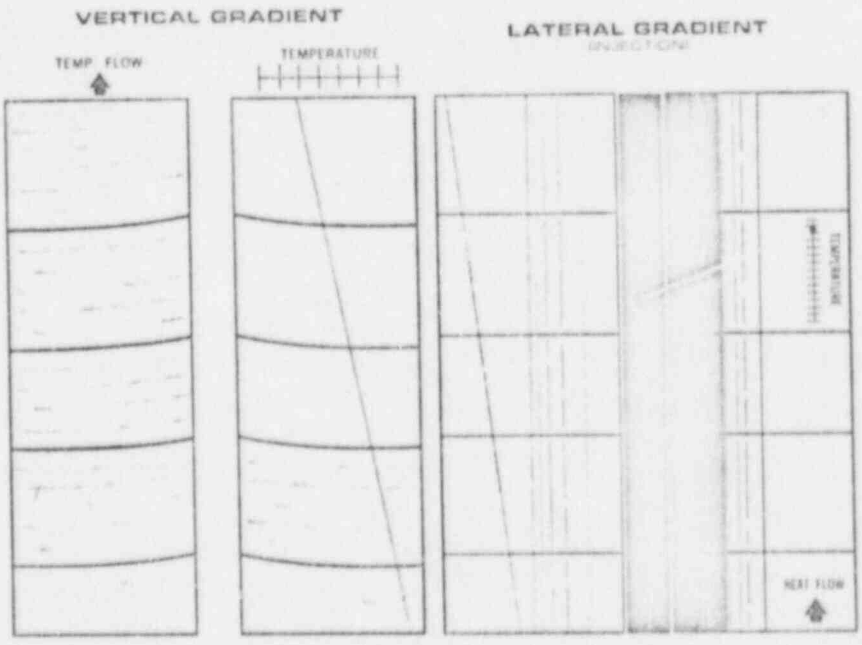


Figure 4. Vertical and Lateral Effects

The geothermal gradient is caused by the continuous flow of heat outward from the interior of the earth. The flow of heat is an equilibrium process between the heat sources, the conductivities of the transmitting material and the temperature differential between two points; therefore, there is no accumulation of thermal energy in the path of heat transmission. The thermal gradient for a given medium is dependent upon its conductivity.

The normal gradient of a given formation is not appreciably disturbed by the existence of a hole or well since the differential still exists vertically, and the ambient temperature at any given depth remains the same throughout the strata. This provides an infinite reservoir of heat at the existing temperature for a given depth, which can be recorded by the absolute temperature tool. (Normal Gradient Curve).

Injecting cooler fluids into the well bore causes a differential to occur between the well and the reservoir of heat at any given depth, and the equilibrium process is established immediately, forming a horizontal gradient at that depth. Assuming injection conditions (rate and temperature) to remain constant, a constant rate of heat replacement is established that is dependent upon the formation to borehole differential and the conductivity of the medium between the two temperature extremeties.

Since the rate of heat flow is constant for these given conditions, steady state heat flow is approached after the initial injection period, and thermal equilibrium with the ambient formation temperatures is established at some radius from the well bore (Figure 5). Continued injection results in no further measurable cooling of the well bore or formation around it, and the rate of heat absorption by the water becomes constant for each depth. Therefore, the well bore gradient is established as a near constant progression at some temperature cooler than normal formation gradient.

The zone or zones of fluid entry can sometimes be recognized by the slight slope change at the top of the injection interval but close definition of the zones under injection conditions is improbable unless considerable vertical separation between zones exists (strata cooling between injection zones discussed later.) The injection zones have an additional effect imposed. The fluid entering the zone at some temperature less than ambient formation temperature, not only cools the formation face by passage, but the reservoir of heat is displaced to an ever-increasing radius from the well bore by the fluid. Since the fluid in the borehole is the coolest in the system and the well bore is the collection point for the temperature data, no additional cooling is recorded at this depth as a result of continued injection.

After these conditions have been established, the recorded injection temperature gradient in the well bore remains essentially constant throughout the total period of injection, and a gradient curve run under injection conditions will reflect only the temperature of the injection fluids at their respective depths. The result is a gradient curve of relatively constant progression, depressed by some degree cooler than normal formation gradient. The two temperature extremes have now been

established and the conditions are at steady state.

When injection is discontinued, the well bore to formation differential still exists. The water is no longer moving, and the equilibrium process attempts to bring the fluid in the well back to the ambient formation temperature at each depth.

The conductivities of each strata allow a characteristic rate of heat replacement at their depth, and the relative rate of heating is not equal for each zone. The rates of heating at various levels differ but are proportional for each zone with respect to conductivity and differential at any given time.

The result in the well bore is a progressive, proportional heating at all depths except the interval that has accepted the injection. This interval has not only been cooled to the thermal equilibrium radius, but the reservoir of heat has been displaced from the bore hole to the point that lateral or horizontal flow of heat to the well is either effectively blocked, or is radically decreased.

Any replacement of heat at the points opposite the injection zones must come from above or below the strata, or be delayed until the fluid bank in the formation is warmed to the degree that it will, in turn, transmit heat to the well bore fluid. These variances in recovery rate can be identified by a temperature traverse of the hole with the absolute temperature tools. Several traverses at selected time intervals after shut-in reflect these relative rates and a DT with respect to time is evolved for each interval. As previously stated, these relationships are proportional except over the zone of fluid entry. These progressive or "decay series" curves can be used for qualitative identification of injection zones. Identification of the true injection incurred anomalies is not always simple, since many conditions can affect the recovery rate observed in the well bore. (Figure 6).

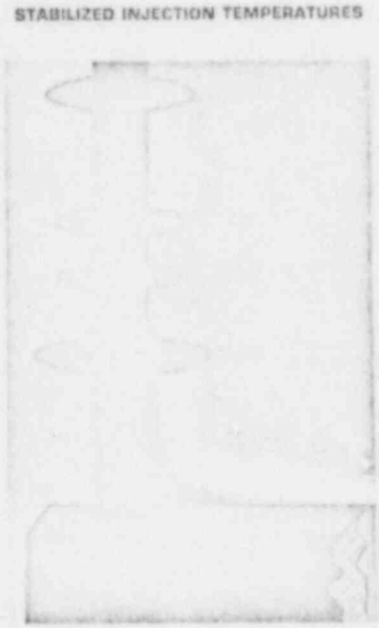
Mechanical conditions such as casing, tubing, hole size and cementing programs behind casing, changing bore hole size, thin zones widely separated, or closely spaced, or any other than uniform physical conditions can cause variations in well bore heat replacement rates. A sufficient number of subsequent traverses must be made to identify the true injection zones.

Theoretically, once the zone is identified, the DT with time established after recovery of the injection zone commences can be used for quantitative calculation of percent fluid intake per interval.

This application, used without other control data, assumes several hypothetical conditions:

1. Each strata is thermally independent of adjacent formations.
2. Vertical heat interchange between strata and within the bore hole is negligible.
3. The heat flow effects precisely reverse themselves during the recovery period.

Graphic examination of the sequence of thermal transfer will reveal that these effects must be considered in any quantitative work.



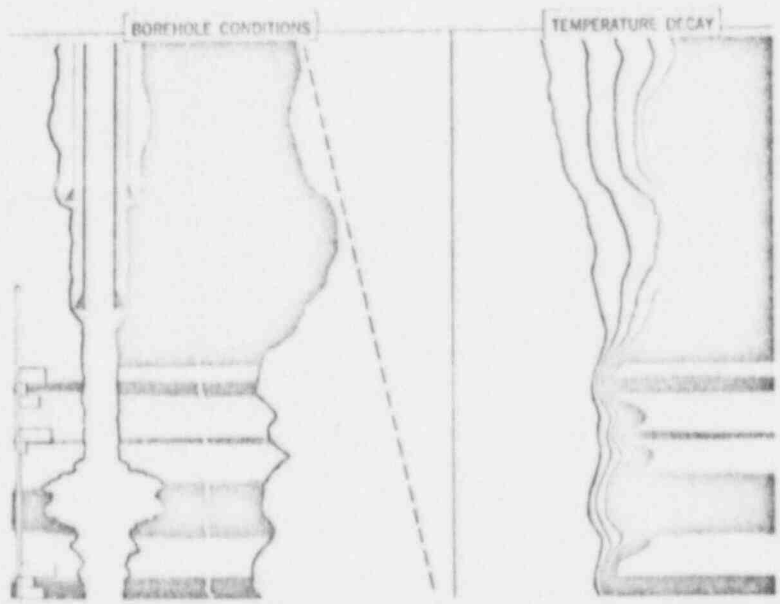


Figure 5

Figure 6. Conditions Affecting Recovery Rates

THEORY AND VARIATIONS

The many attempts at quantitative evaluation of injection well temperature logs have evolved an approach that is closely analogous to the radial flow pressure decline calculations, which assume only two dimensional flow. The application to thermal evaluation considers individual strata, with the cooling approaching the ideal or complete thermal equilibrium at an infinite radius. Figure 7-A.

At the initiation of injection, the radius of cooling is slight (T_1), increasing throughout the period of injection to the ideal temperature distribution (T_6). This progression is assumed to be independent of boundary temperature effects. Figure 7-B illustrates the temperature distribution in adjacent strata under this assumption.

Theorizing that temperature flow effects precisely reverse themselves upon interrupting injection allows calculation of the rate of recovery within the well bore. Relating this recovery rate to the heat transfer co-efficient of the formation, period of injection, total injection volume, and ambient to injection temperature differential, a formula can be evolved that should indicate the injection distribution.

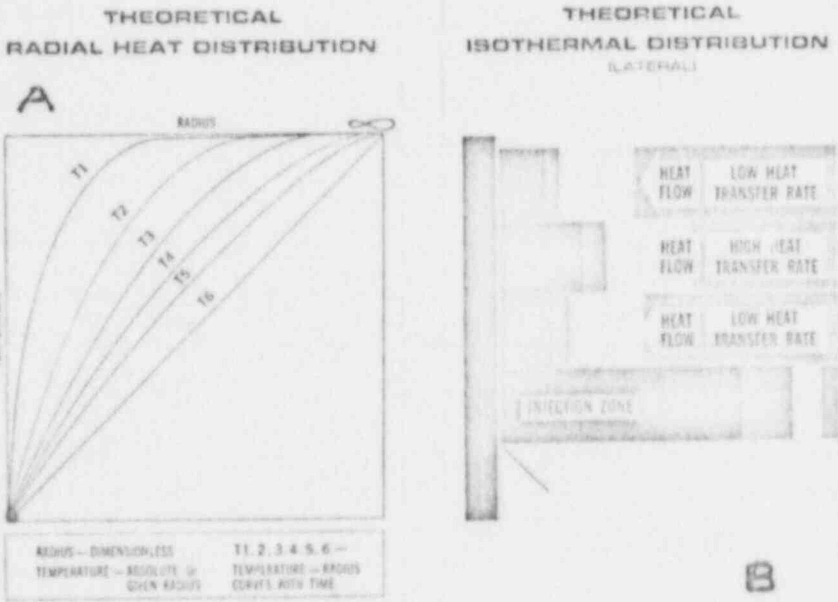


FIGURE 7.

The mechanics of heat flow are not limited by vertical permeability boundaries as are pressure or fluid flow effects; therefore, this approach toward evaluation must be modified to consider the effects of heat flow within the formation upon the well bore temperatures.

The constant proportional progression of heat distribution through a given strata which must be assumed quantitative evaluation does not actually exist. Figure 8-A illustrates the complexities of heat flow mechanics by joining the center points of the isotherm distribution of Figure 7-B.

It becomes apparent that as the vertical heat differential between strata not accepting fluid becomes more pronounced, a greater amount of heat is taken from the adjacent strata to attempt local equilibrium. These effects become self-limiting, and disrupt proportional cooling progression of individual strata. For practical interpretive uses, the cumulative cooling is fixed at some finite radius. Figure 8-B.

This radius cannot be established as a constant for a given formation without also considering the strata thickness, since a thin formation will be more affected by the adjacent temperatures than a thicker one. As a result of these reactions, a calculation based upon the radial flow principle must consider additional control data to become accurate. The premise of precisely reversed recovery effects is also invalid for calculations. The zones do not reverse the heat flow but the reactions observed in the well bore are reversed, with limitations.

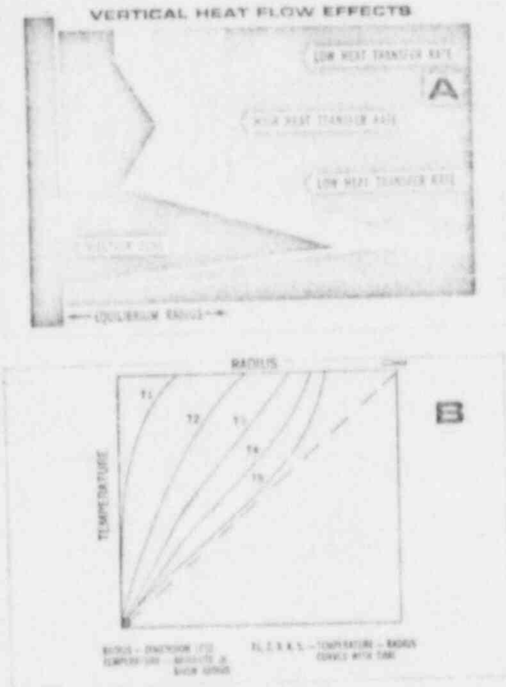


Figure 8. Complexities of Heat Flow Mechanics

The steady state heat flow approached during injection cannot be established during shut-in since there is no heat carried away under static fluid conditions. The rates of recovery observed in the well bore constantly diminish with the decreasing temperature differential until recovery to ambient formation temperature is effected. The resulting isothermic distribution sequence is depicted in Figure 9.

As injection is interrupted, only slight vertical differential exists between strata in the proximity of the well bore, but the well to ambient formation differential is at its maximum. Lateral heat flow from the formation to the well is at peak rate and very slight vertical heat inter-change occurs near the well. During the collapse of the heat sink, or cool cell, the recovery of the more conductive formations surpasses the slower conductive strata, and a temperature differential develops between zones, establishing a local equilibrium process near the well bore.

The formations of lower transmitting efficiency are then warmed by vertical, as well as lateral heat flow, and in turn, affect the well bore fluids. Since all the temperature data is gathered from the well bore, these effects obliterate the lateral recovery rate data needed for quantitative calculations.

The period of maximum lateral, and minimum vertical effect on the well bore temperature is transient, occurring during the initial recovery process after shut-in. The recovery rate data must be collected during this "optimum time" period when the rates more nearly approach the lateral

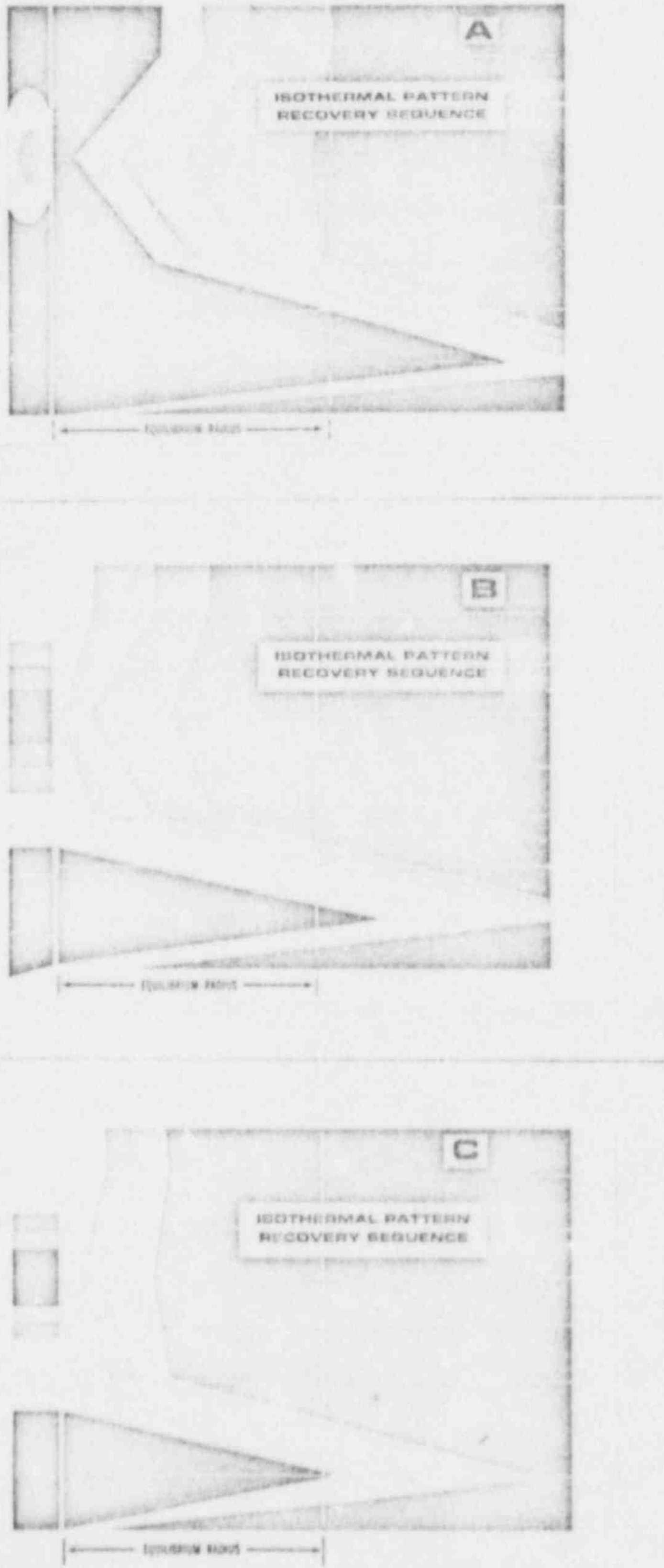


Figure 9. Isothermal Pattern Recovery Sequence

flow characteristics necessary for valid calculations.

These initial data may be extrapolated through the time interval where distortion occurs to the total recovery point, or ambient formation temperature. The extrapolated rates then reflect the true lateral recovery characteristics, relatively independent of vertical flow effects. Projection of these data from injection temperature to indigenous formation temperature will identify the zones that have accepted injection, since their proportional recovery rate has been interrupted. (Figure 10).

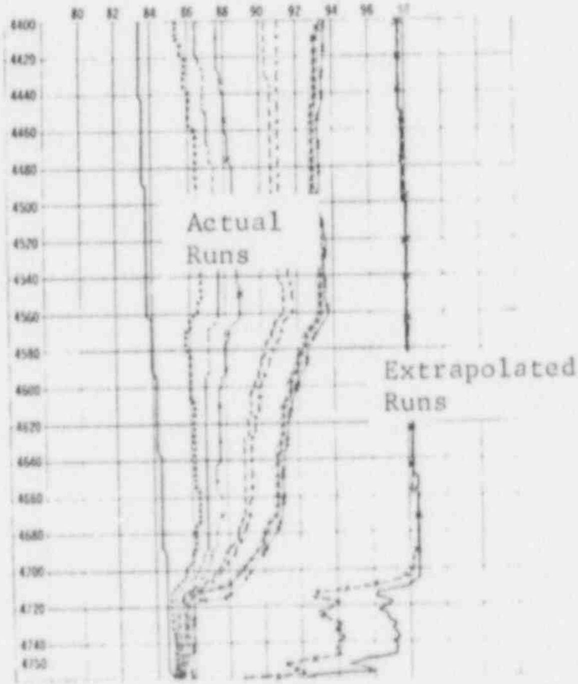


Figure 10. Actual versus Extrapolated Progression

The source of heat required for proportional recovery has been displaced past the thermal equilibrium radius by the injection fluid, and does not contribute a lateral flow of heat to the well bore during the inspection period (logging time duration). Figure 11.

Heat for recovery opposite the injection zones must be supplied vertically from adjacent strata. These formations have been cooled by proximity to the injection zone and cannot contribute heat flow at normal formation temperature. The source heat for recovery is less than ambient formation temperature; therefore, proportional extrapolations, based on decay data, cannot approach gradient temperature at these depths.

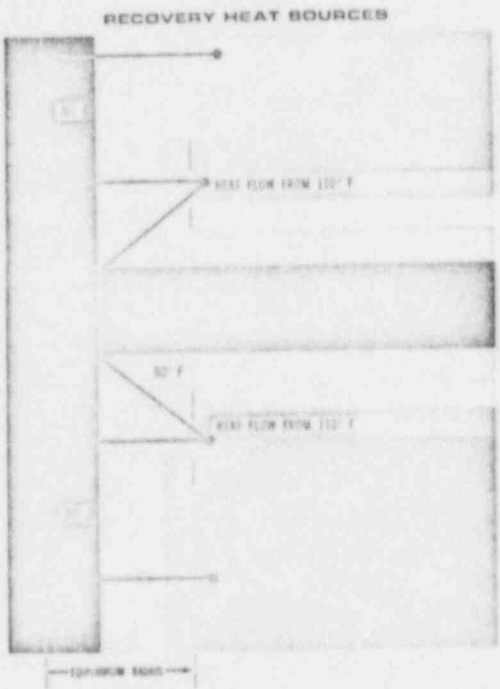


FIGURE 11.

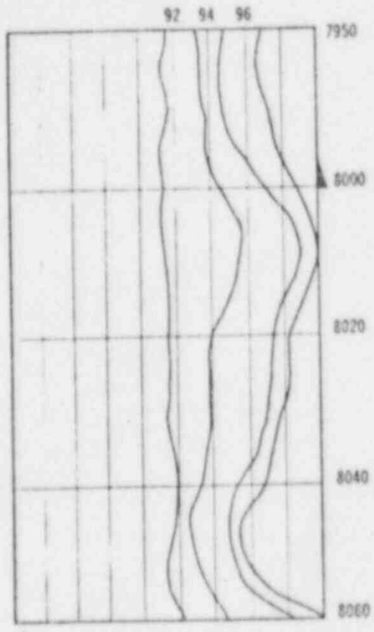
An example of this first basic extrapolation step is shown in Figure 12. The average DT with time from three runs is used for brevity in explanation rather than the proportional extrapolation that must be used for true quantitative work.

Through the 84 hour extrapolation based on 2 hour decay time, the deepest point to equal normal gradient is 8030 (118.5 degrees). All points above 8032 were eliminated from the next extrapolation at 95 hours. Temperatures from 8057 to TD were also equal to normal gradient and eliminated as injection zones.

The 95 hour extrapolation eliminatcd the zones from 8032 to 8040 and the 2' interval from 8055-57. A thin zone from 8047-49 exceeded the gradient temperature at 327 hours and the ratio of progression of the two remaining zones indicate that extrapolation to normal gradient would require an unrealistic time, even considering an average DT with time.

The remaining temperature differences at four inspection depths were prorated to percentage injection in these zones. The assignation of these percentages must be modified by the effects of zone cooling and zone thickness in multi-zone injector.

Figure 9 depicts a single zone of injection bounded on both sides by non-injection zones. Multi-zone injectors must consider strata not accepting injection sandwiched with zones which have had the indigenous heat reservoir displaced by injection water.



COMPUTER EXTRAPOLATION

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	NORMAL	[illegible]	[illegible]
91.8	96.0	0.50	117.0				117.0		
91.8	96.0	0.55	117.0				117.1		
91.8	95.8	0.44	112.6				117.3		
91.8	95.9	0.50	116.9				117.4		
91.8	96.0	0.55	117.5				117.5		
91.8	95.7	0.35	110.4				117.6		
91.8	95.6	0.33	110.3				117.8		
91.8	95.4	0.25	105.9				117.9		
91.8	95.6	0.40	112.2				118.0		
91.8	95.4	0.40	112.2				118.1		
91.8	95.3	0.35	110.0				118.3		
91.8	95.3	0.35	110.5				118.4		
91.8	95.6	0.55	118.5				118.5		
91.8	95.2	0.30	107.8	109.5			118.6		
91.8	95.3	0.40	112.1	114.4			118.8		
91.8	95.5	0.40	112.1	114.4			118.9		
91.9	95.4	0.50	116.4	119.0			119.0		
91.9	94.7	0.10	98.9	95.5	102.1	111.1	119.1	8.0	13.9
91.9	94.3	0.05	96.4	96.7	98.2	102.7	119.3	16.6	29.8
91.9	94.8	0.15	101.8	102.6	106.7	119.7	119.4		
91.9	94.5	0.05	96.6	96.9	98.4	102.9	119.5	16.4	26.5
91.9	94.5	0.05	96.6	95.9	98.4	102.9	119.6	16.5	28.7
91.9	94.5	0.25	105.4	106.7			119.8		
91.9	96.0	0.75	119.9				119.9		
91.9	96.4	0.85	120.0				120.0		

Figure 12. Trial Extrapolation-lateral Only

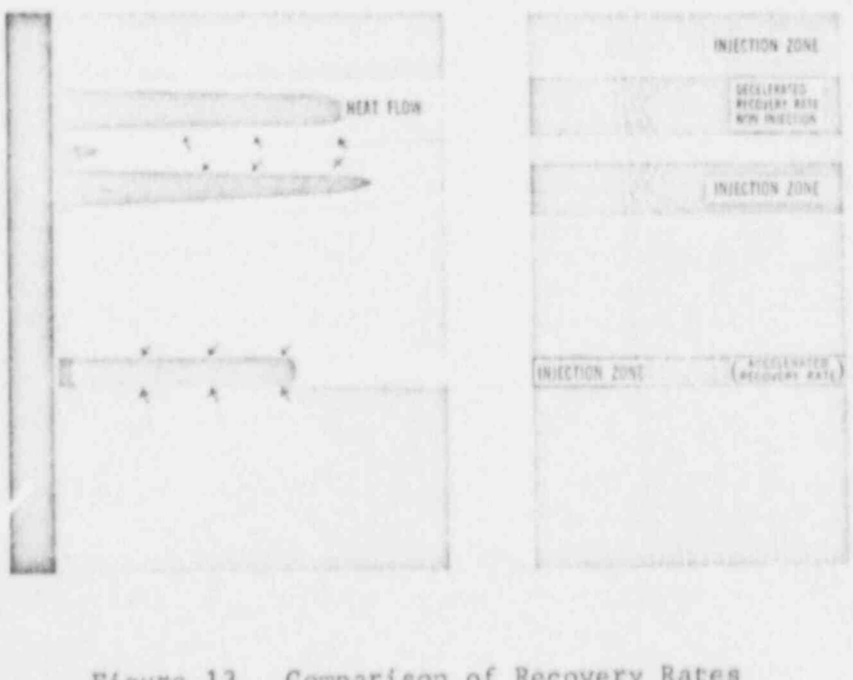


Figure 13. Comparison of Recovery Rates

These formations are effectively isolated from vertical heat flow, and a portion of the lateral flow replacement heat is constantly scavenged by the injection strata on both boundaries. (Figure 13). Since the source of replacement heat is being constantly displaced further from the well bore, the temperature in these zones is often reduced to approximately injection zone temperature.

Upon shut-in, the recovery rate of these strata is retarded by the continuous thiefing of heat over the lateral path to the well bore, and by the lesser formation to well bore differential at a given radius. The equilibrium effects do still exist; however, and all but the very thin zones can be identified. Conversely, a thin injection zone between non-injection strata is affected by the proximity of the two dominant heat sources, and the recovery within the well bore is accelerated.

Qualitative identification of the injection zones can usually be made after a relatively long shut-in period. A single traverse is made and the cool anomalies assumed to be the injection zones. Vertical heat effects tend to average all the temperature parameters, however, and only the top and bottom of the gross injection interval can be determined by this means. These interpretations are subject to error due to the myriad temperature influences on the well bore fluids.

Projecting the initial data through the time of maximum vertical effects allows identification based on lateral heat flow. This establishes a rate of recovery at each depth that is the result of temperature differential at a given radius, formation characteristics, well bore mechanics, injection conditions. These projections provide data that can be used in formulations based on the radial flow concept of heat transfer.

The data derived from extrapolation of lateral recovery rates evolves a relationship that can be used in quantitative calculation of water distribution in the injection well.

Projection of the non-injection zone temperature to the normal gradient leaves the anomalies caused by the water injection zones. These anomalies have a relationship that reflects the distribution of water, but only if additional correction based on zone thickness and bore hole to formation differential is applied. Determination of the actual zone thickness presents a problem, but a method incorporating the angle of slope change and degree of slope progression is being used at present, with good results.

Sufficient corroborating data has not been compiled at this writing to present these calculations, but a progress report to the industry will follow at a later date.

INSTRUMENTATION

The heart of the computerized application is the sensitive digital recording system.

Through use of digital tapes, accurate recording of slight temperature changes is possible. Regular analog recording systems use time

constant circuitry that averages many of these pertinent data, and visual definition becomes impossible.

The major objective of a digital recording system at the well site is to record the information obtained from the sonde in the bore hole with maximum accuracy, eliminating the variables inherent in electronic conversion systems and accuracy limitations of strip chart recorders.

This is accomplished by recording the frequency output of the sonde directly on tape as frequency and making the conversions to temperature in a computer. Additional information, such as vertical and horizontal differentials, can be computed with realistic values at maximum accuracy. The computer output can then be printed in columnar or graphic form for visual interpretation.

The mechanics of the system are shown schematically in Figure 14. The temperature sonde uses a sensitive probe (usually a linear compensated thermistor).

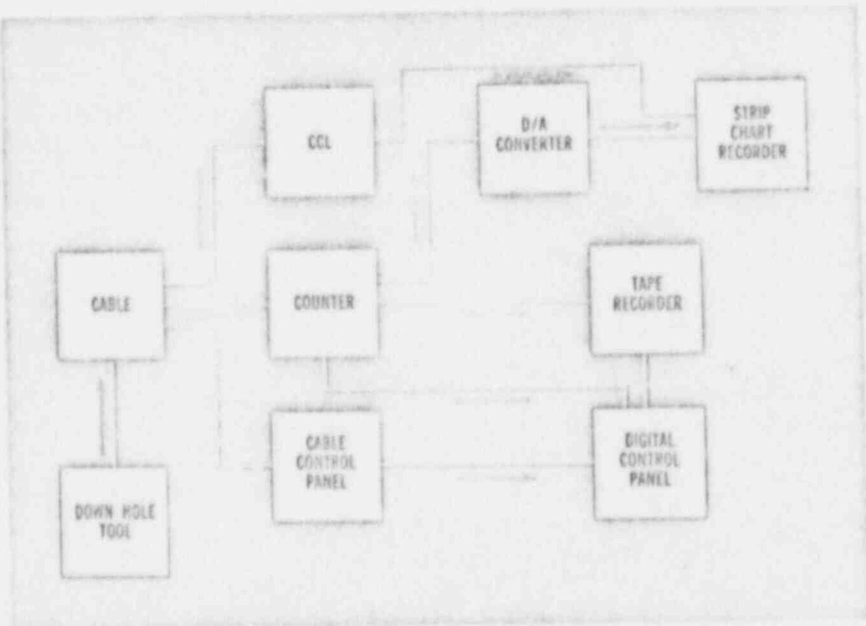


Figure 14. Digital System Schematic

This sensor will vary with resistance depending upon its temperature and is incorporated in an RC circuit which controls a relaxation oscillator. The frequency output is directly proportional to the resistance of the sensor. The downhole signals are fed through the conductor cable to an event counter, coded, and put on magnetic tape in a BCD 1248 code. The BCD output will also go to a digital to analog converter which will drive a strip chart recorder. The function of the strip chart

recorder is to provide a visual record of the temperature runs for reference only. All interpretations will be made from the digital tape through a computer. A minimum of four temperature logging run data is digitally recorded on tape. The first run during injection and runs 2, 3, and 4 at a set interval not to exceed 2 hours between runs with the well shut in. Temperature readings can be recorded 1/2 foot intervals or one foot, two feet, etc. as desired.

COMPUTER PROGRAM

The digital field tape containing runs data is processed through the program tapemake and a Fortran tape is output. This data is in frequency and is converted to temperature. A report on all real runs is generated and through a program the ability is provided to extrapolate new runs to any elapsed time.

Each run real or extrapolated contains temperatures per depth interval, vertical differential at selected depth intervals, and horizontal decay rate from previous runs or to the normal gradient. Computer plots of this information can better define the injection zone as to vertical span and injection volume. All computed variables such as differentials have real values providing improved interpretation information. Typical computer print-outs are shown in Figure 15.

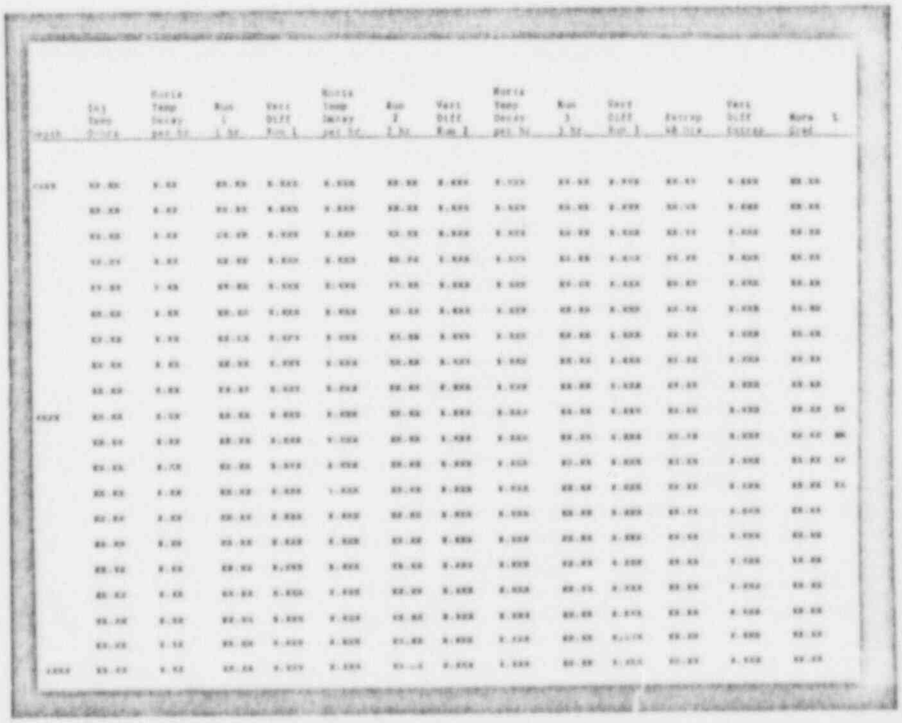


Figure 15. Information from Computer Print-out

The first column is the injection temperatures versus depth. The second column is the horizontal differential or rate of decay vs. depth from the injection run to the first shut-in run. The third column is the first shut-in temperatures versus depth. The fourth column is the horizontal differential between shut-in Run 1 and 2. The fifth column is the vertical differential versus depth for the first shut-in run, and can be selected for any vertical depth interval. Columns 6, 7, 8, 9, 10, and 11 are the shut-in runs at indicated times, decay rate, and vertical differential. Column 12 is the extrapolated run at a selected time based on the decay rate of the previous runs. Any number of extrapolations can be made to observe the data until the indigenous temperature of the undisturbed rock is reached. Column 13 is the normal gradient for the local area. Any set of figures can be printed separately and compared for more detailed interpretation. After column 13, the percentage distribution versus depth is shown. Further information on total volume injected can be obtained by applying the percentage figures to the volume injected.

CONCLUSIONS

The use of digital recording and computer analysis, coupled with logging technique, allows the selection of meaningful temperature data exclusive of the masking effects inherent in regular logging methods. Extrapolation provides a means of projecting this "pure" data to established reference indices, resulting in an accurate injection water distribution pattern from temperature logs.

This concept of temperature log analysis is in its infancy, and the forthcoming months will provide a base of well histories to support the validity of this new service to the industry.

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Reference Notes: All the authors listed were not directly referred to in this text. Their works were studied for any major conflict of theory principle or fact.