The Evolution of Completion Techniques in Carbonate Reservoirs Containing Vertical Fractures

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INTRODUCTION

The years from 1958-1960 were transitional. It was the beginning of a new era, the time for each geologist to re-evaluate past procedures and in fact to re-educate himself. During these formative years oil companies were faced with a whole series of problems, some of which were the disposing of water, communication to gas caps, collapsed pipe, emulsion block and many yet undetected problems. Since 1959, every conceivable completion technique has been, and is still being analyzed and tested. The primary concern shall therefore be with recent history and not ancient history.

This paper will be confined to the Middle and Lower Permian, since they are the dominate reservoirs in West Texas. A very generalized description is as follows: tan to brown, fine to very fine crystalline, stylolitic, locally extremely evaporatic, randomly fractured dolomite, with numerous very thin shale partings and porosities, which range from pinpoint to vugular and fracture.

The petroleum geologist of today must have a complete knowledge of the reservoir rock and its behavior; he must know the limitation of each logging device in order to properly evaluate the potential pay, and last but certainly not least, he must learn enough engineering to communicate properly.

FORMATIVE YEARS

The middle 1930's were the formative years in West Texas. The first wells were drilled and completed in the Tubb and San Andres sections with cable tool rigs, to a depth often determined by the amount of hydrocarbons encountered. The oil string was set at the top of the pay and later the well was swabbed in. Most wells come in naturally, but when remedial action or stimulation was necessary, the operator simply shot the well with nitroglycerin and cleaned it out. This was in reality the first fracture treatment.

Very little progress was made during the 1940's, with regard to well completion. A few wells were drilled deeper, some were bullet and jet perforated, but the big innovation was a new treating method called acidizing. Acidizing was an immediate success, as it not only cleaned up the well bore, but created new void space into which the oil could drain. This, however, was only a temporary remedy.

During the early 1950's, oil companies active in this area were faced with problems such as dwindling oil production in field wells and poor initial production from the newly completed ones. The early remedial method, born of necessity, was hydraulic fracturing. The first primitive treatments consisted of several thousand gallons of refined oil with varying amounts of sand. These fluids were usually pumped down tubing with resulting high breakdown pressures, low injection rates, sanding out and communication to gas or water. Sometime later, acid was used as a spearhead in front of the fracturing fluid, with good success. It cleared the perforations before the more viscous fluids arrived. The use of refined oils became prohibitive from an economical standpoint; hence, the use of crude oil and various additives to lower surface tension. The old problems were not completely solved, but they were lessened.

Thus far, only the perforating of an oil string has been mentioned. All companies perforated tens of feet at a time, on some occasions several hundred continuous feet. The typical method was to open up all available porosity with four jet holes per foot. Why do this? Obviously, it was to treat all available pay, and not allow any potential production to remain behind the casing. The pay was then treated by an appropriate method, and with a fluid which had been proven successful for that zone in a particular area. By 1958 and 1959, much had been learned. This new knowledge consisted of (1) the need for less perforating in the pay zone, and (2) the need for larger fracturing volumes. Why less perforating? It was found that treatment of several zones developed communication most of the time while attempting to selectively acidize and fracture. The reason is not obvious, but for a starter, poorly cemented oil strings caused some of the trouble. Communication between zones, though annoying, was of little concern, because good initial production was obtained, except in isolated cases.

In 1960, the first serious experimental work was commenced in western Crane County, to determine the reason or reasons why new and recompletion attempts were not responding properly. Experience was gained with various perforating techniques, including the following: sand jetting, mechanical notching, radial jet notching, implosion tubes in conjunction with radial and expendable jet guns, and at present, jet perforating designed to give optimum hole size and shot density for a desired injection rate.

The theory behind sand jetting, mechanical notching, and radial jet notching, was simply to create a horizontal fracture which could be extended some distance beyond the well bore. The reason for wanting this type of fracture was selective treating, which would be less likely to create communications to zones of lower permeability (which could release capillary pressure and potential water) or to gas zones. These conditions are possible, providing proper reservoir characteristics and good cementing procedures are present. Unfortunately the reservoir characteristics within the Permian Series are generally hard to predict, horizontal fractures are not likely,[1] and not all problems can be attributed to poor cement jobs.

Implosion tubes (glass vacuum tubes) ranging in size from ¾ in. x 6 in. to ¾ in. x 12 in. were used in conjunction with expendable carrier, jet perforating, to dampen the destructive forces accompanying detonation.

Figure 1 diagrams an experiment which was conducted, in a San Andres well, with the use of seismic recording equipment. This type of setup was designed to measure the relative wave amplitudes as recorded from several strategically located geophones.

In Fig. 2 the four traces on the right were recorded from a shot at 3390 ft. and without the use of implosion tubes. The four traces of the left are from a shot at 3280 ft. in the same well. They were recorded using six ¾ in. x 6 in. tubes above the shot and four ¾ in. x 12 in. tubes below. It is evident that the attenuated energy is less on the latter four traces, indicating some merit for this type of perforating. Even though some questions remain unanswered, the vacuum tubes are still being used when perforating with expendable jet guns.

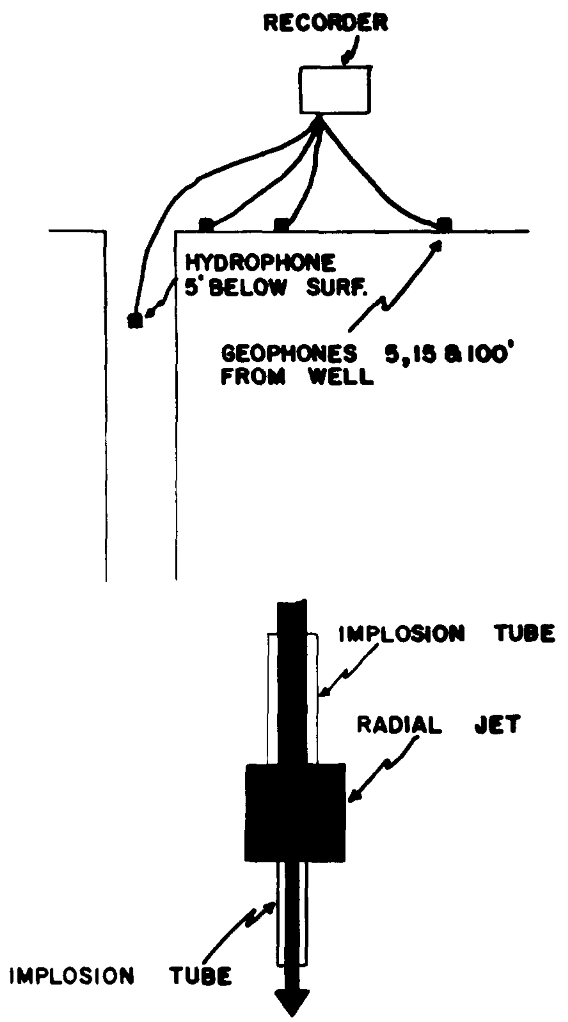

FIG. 1

Logging and its interpretation also underwent considerable change. In 1962 a new technique for the determination of true porosity and lithology, using the gamma ray-neutron, density and acoustic surveys, was introduced, and is still being used successfully. Each of these porosity surveys is affected to some degree by the admixture of evaporites (anhydrite and gypsum) contained within the carbonate reservoirs. The simultaneous solution of porosity, assuming matrix parameters for each survey as limited variables, provides more accurate porosity values. The per cent of limestone or dolomite, gypsum and anhydrite may also be determined.[2] These calculated porosities have been corroborated with core porosities using the more recent "gypsum free" method of analysis. A detailed descriptive procedure of the "gypsum free" core analysis and reasons for using it are beyond the scope of this paper, but the method is recommended for use in the Permian Series of West Texas.

During the year 1962, impression packers were set in the open hole section of numerous wells before and after hydraulically fracturing, in an effort to establish a better completion technique. Impressions of vertical fractures, Figs. 3 through 5, appeared bisecting the well bore after treatment, but never prior to treatment. Additional evidence for the establishment of vertical fractures during treatment was communication around a well-set packer and subsequent inability to contain fluids after resetting at higher and lower depths.

Experimental work with radioactive tracer sands prior to 1961 was conducted by Messrs. R. George Mihram and L. A. Weinrich, with Halliburton.[3,4] Briefly, their work indicated that a sand packed fracture less than 0.2 in. thick could not be identified, and that a radioactive sand more than 12 in. from the well bore could not be seen. One might then at first, and justly so, suspect that all radioactive anomalies seen on tracer logs come from fractures greater than 0.2 inches wide or sand filled channels behind pipe. The latter is more probably true, because impressions of fractures obtained after fracturing at high injection rates and large volumes have indicated none as large as 0.2 inches.

In 1962 actual well tests and model studies were conducted, using various concentrations of radioactive sand and a horizontal traversing logging tool, in an attempt to corroborate the above work. The data obtained, using a model, indicate induced radiation could not be determined accurately if more than six inches from the well bore. The data obtained did show promise, provided yet higher radioactive sand concentrations could be used; more sensitive tools could be built, and extremely close logging supervision could be made available.

Several years ago the major electric logging companies introduced a logging technique which utilized "compressional and shear acoustic amplitudes for the location of fractures."[5] Laboratory studies indicated that the location of fractures dipping at an angle greater than 78 degrees was not possible. This technique was rarely used, because the formation fracture system dips are greater than 78 degrees as shown by the impression packers, Figs. 3-5.

For many years now, temperature logging has been used to locate the top of cement behind casing. Approximately 13 years ago the differential temperature survey was introduced for use in determining anomalous conditions such as: location of squeeze cement, and gas entry or flow. Some years later the frac evaluation log

PARTIAL SEISMOGRAMS

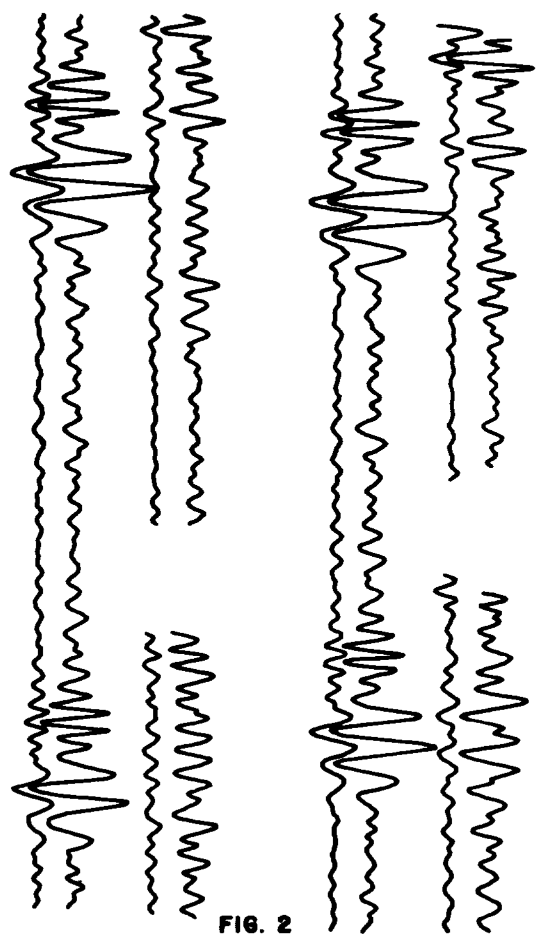

FIG. 2

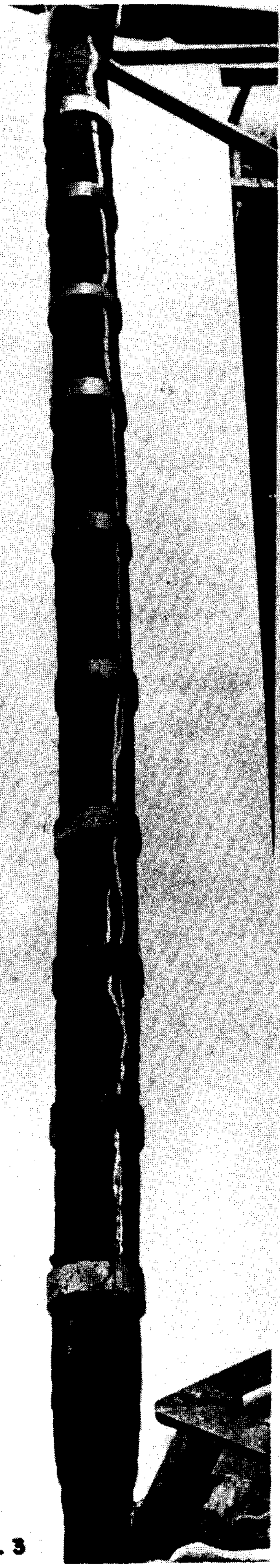

FIG. 3

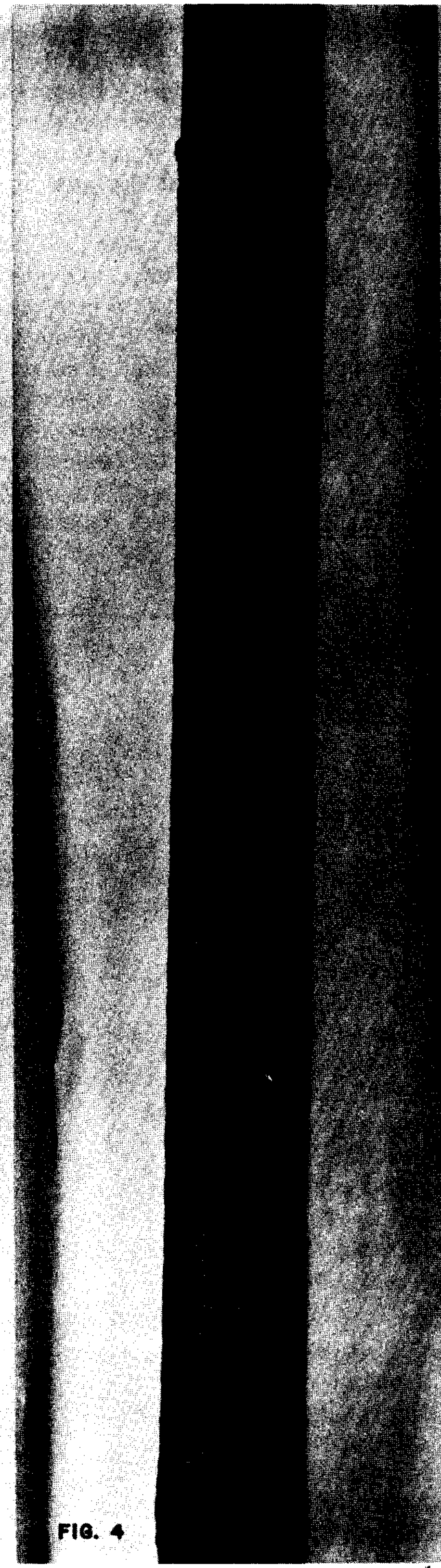

FIG. 4

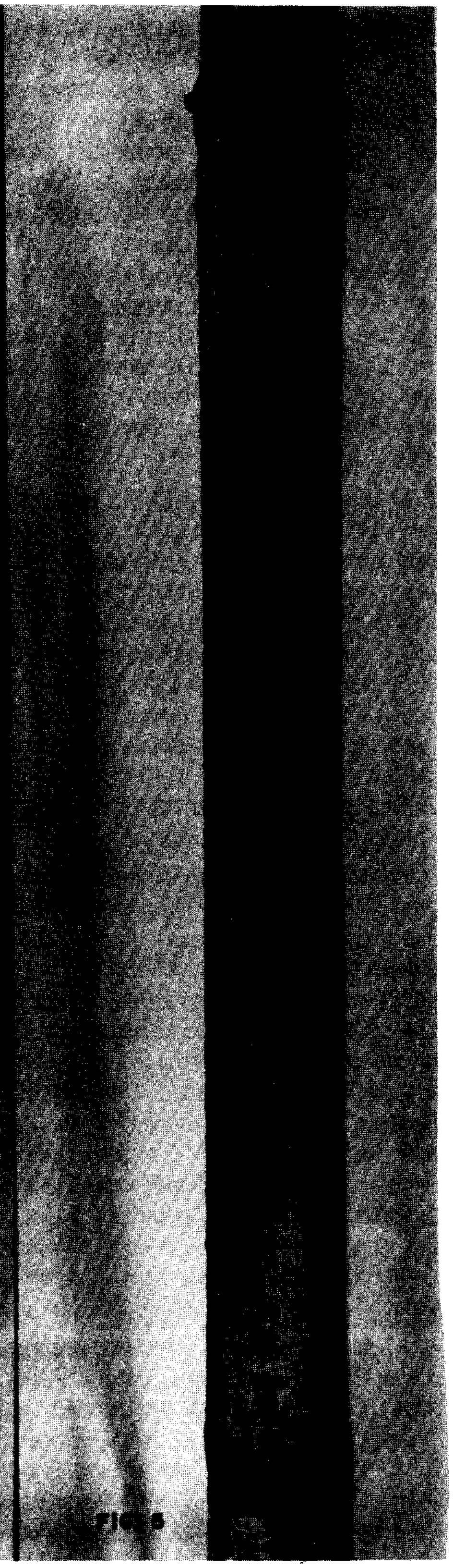

FIG. 5

was introduced. The theory behind this survey has been adequately explained in a recent publication;[6] however, prior to this paper, this method was used for stimulation evaluation and squeeze cement location.

Figure 6 shows a frac evaluation log which was run on a San Andres well in western Crane County. The curve on the left was run prior to treatment and indicates that a normal temperature gradient is present. The frac log on the right was run several hours after a heated fracture treatment. The top and bottom of the hydraulically fractured zone cover some 60 ft. An extension of the normal gradient can be seen between the two notches, thus indicating non-communication between notches.

Figure 7 shows vertical communicaiton between notches as well as communication above the upper notch for approximately 80 ft. through vertical fractures. The slightly vertical trend

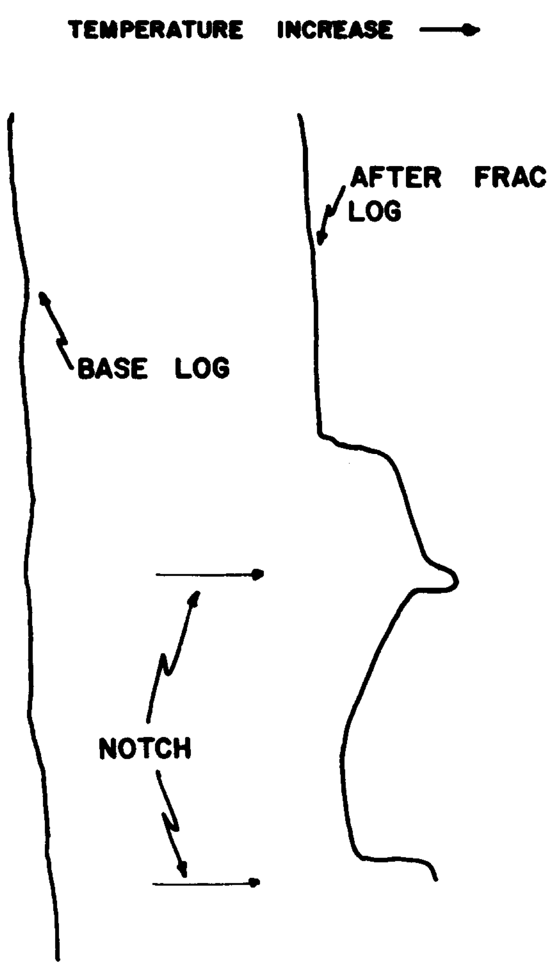

FIG. 6

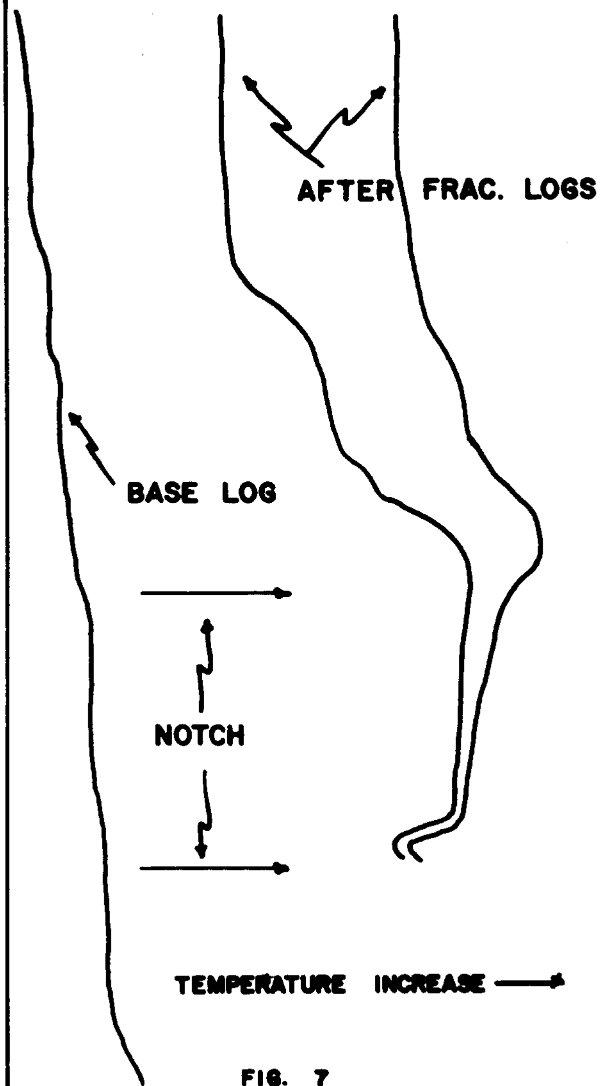

FIG. 7

above the treated portion indicates abnormal cooling or possible gas movement, most probably through cement channels. High gas volumes were obtained and subsequent squeezing of the upper notch was unsuccessful.

Figures 8 and 9 show two methods of evaluating a fracture treatment. Casing and formation notching in this example are unique, because radioactive ribbon was attached to selected collars prior to running casing, and formation notches were cut, using specially prepared steel cutting blades. After notching, 500 gal. of 15 per cent non-emulsifying acid was squeezed into each notch. The fracture treatment consisted of 15,000 gal. gelled reef water containing one lb. of sand per gal. and 750 lbs. (30 units) of radioactive sand. It is obvious from Fig. 8 that the lower notch took most of the fluid and little, if

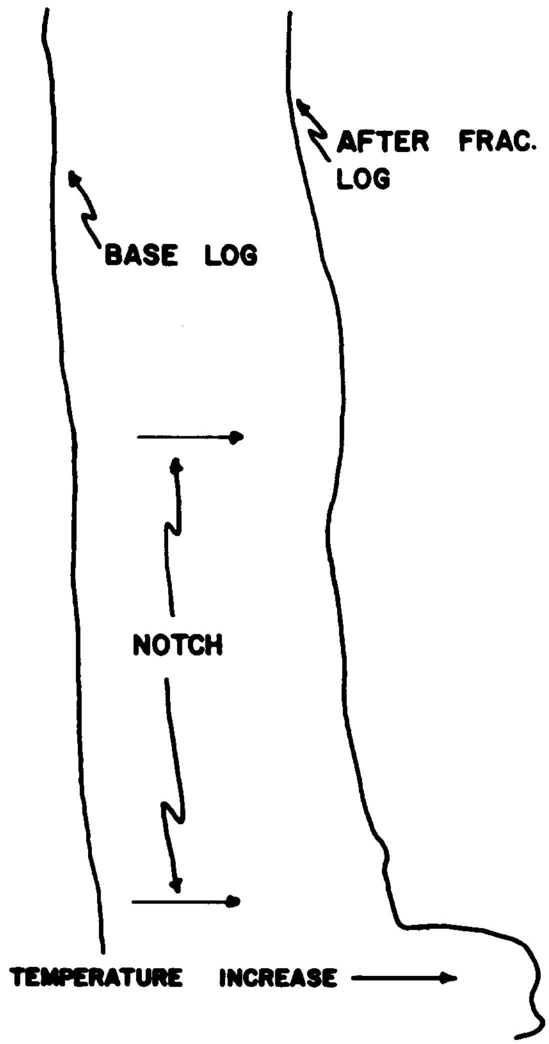

FIG. 8

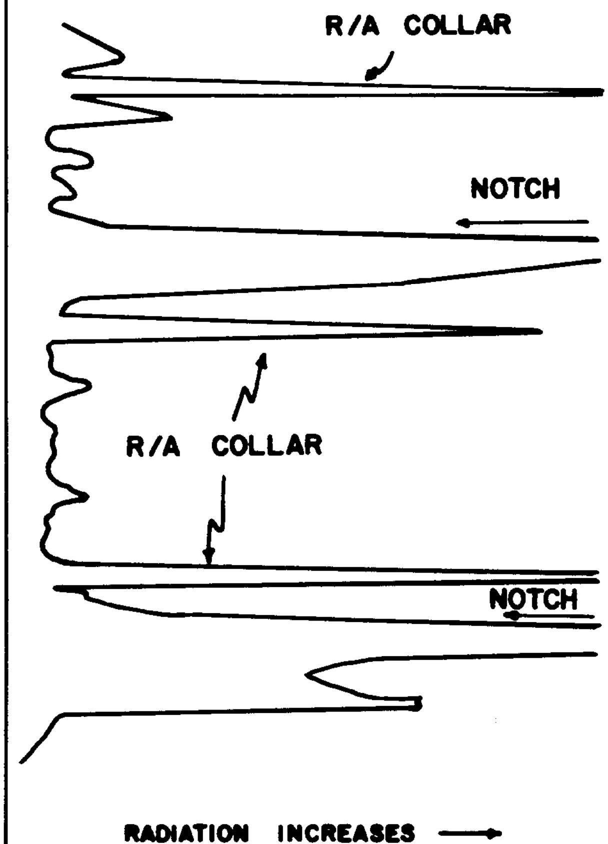

FIG. 9

any, entered the pay above. The well communicated to an upper gas zone during treatment, but through channeling along the cement. We can make this interpretation because there is no hot temperature anomaly at or near the gas zone.

Interpretation of the radioactive log (Fig. 9) is complicated in this case because of the radioactive ribbon attached to the casing near the notches. An interpretation of this survey would indicate that both zones were treated at least below the perforations. A comparison of Figs. 8 and 9, keeping in mind the maximum depth of investigation for a radioactive survey, would indicate sand filled channels, because the radiation count of the collars is very close to the count just below each notch.

The most recent completion aid is a full evaluation of each drill stem test taken. For years now, a visual analysis of the drill stem test has been made, but all too often an experience factor, often a poor one, was applied. Using fluid recovery and pressure data, the following information can be obtained: formation damage if any, ultimate daily fluid capabilities of the well, type of stimulation needed, and some indication of reservoir size.

Chart 1 is a plot of flow rate versus differential pressure across an entry hole. In order to use the chart one must decide the following: the injection rate desired, the preferred differential pressure across the perforation being treated and perforation entry hole size. Example: 150 psi differential and a hole size of ½-in. will allow a flow of 1.7 bbl./min. or 10 holes will allow an injection rate of 17 bbl./min. at a pressure differential of 150 psi.

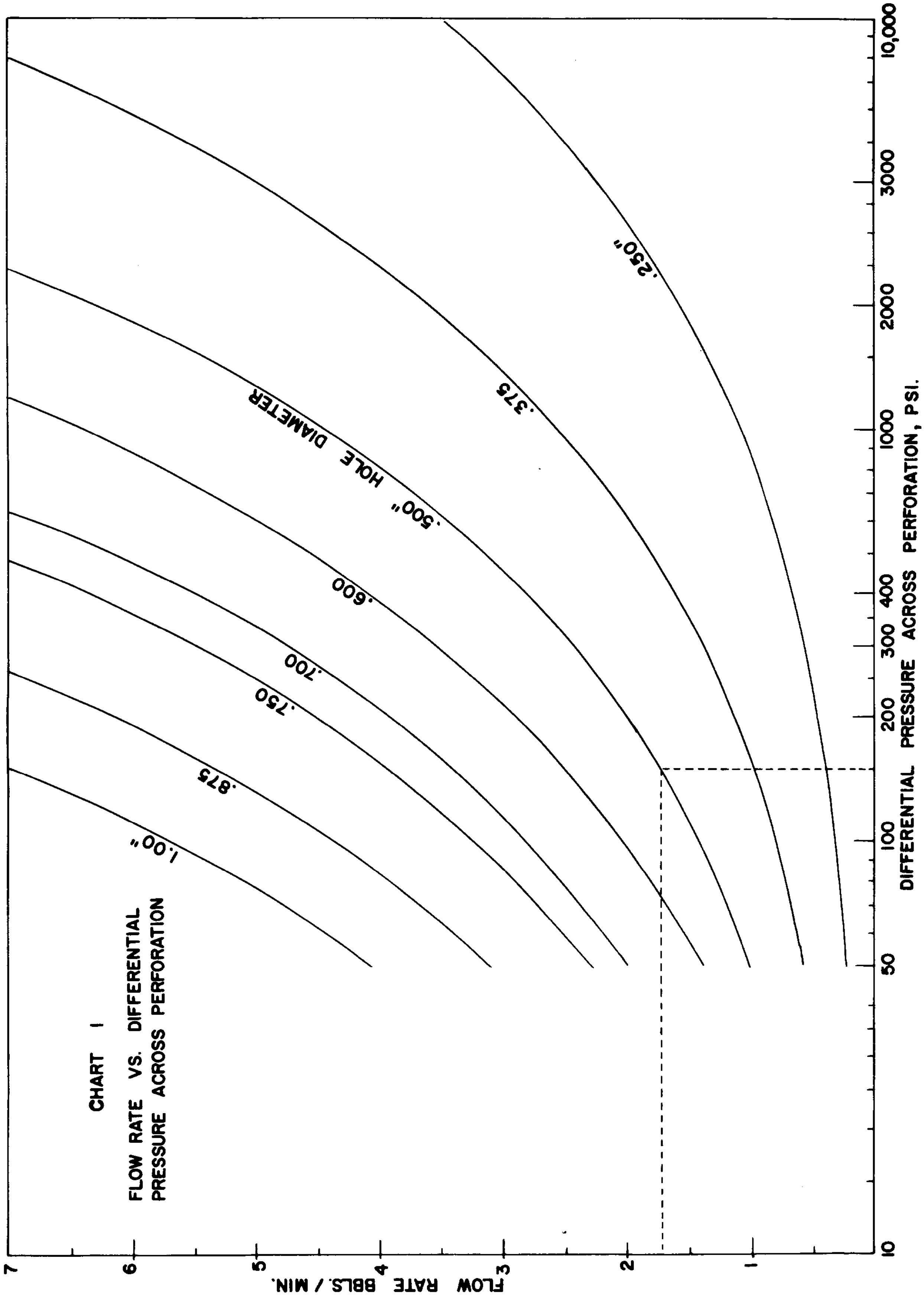
CHART I
FLOW RATE VS. DIFFERENTIAL PRESSURE ACROSS PERFORATION
1.00"
.875
.750
.700
.600
.500" HOLE DIAMETER
.375
.250"
FLOW RATE BBLS / MIN.
7
6
5
4
3
2
1
DIFFERENTIAL PRESSURE ACROSS PERFORATION, PSI.
10
50
100
200
300
400
1000
2000
3000
10,000

CONCLUSION

One may conclude with the above discussion, the following:

1. The production geologist must be intimately acquainted with the reservoir rock.

2. He must adequately inform the completion engineer of special problems for proper treatment.

3. Excessive perforating, or too few holes, are equally detrimental as shown by Chart 1.

4. Fracture orientation and type can be determined with inflatable impression packers after hydraulic fracturing.

5. Fracture determination and section treated can be evaluated very well and economically with differential temperature logging. Also, promise is indicated by radioactive sand surveys providing higher ratdioactive sand concentrations are used, higher tool sensitivity and closer supervision can be obtained.

6. Drill stem testing, if properly used, can yield invaluable completion information.

ACKNOWLEDGEMENTS

The author wishes to express his appreciation to Gulf Oil Corporation for permission to prepare and publish this paper. Special thanks to G. B. Bell for his able help in preparing this paper, to J. H. Loader, Jr., for the photography, and to Beverly Guest for editing.

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