Willard Unit Fracture Treatments--Case History

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INTRODUCTION

The Willard Unit is about four miles north of Denver City, Texas, in the Wasson Field. The San Andres dolomite is 1500 feet thick in this area. The reservoir has a solution gas-drive and its productive lower limit is defined by a gradual increase in water saturation. There is no water-drive nor is there a gas cap in this area. The productive interval, which is some 250 feet thick with a net pay thickness of 90-150 feet, has a porosity of 10-14 per cent and an average permeability of 2 millidarcies.

Most wells were completed between 1938 and 1945. Generally the casing was set about 400 feet down into the San Andres. Open-hole completions were made with casing set at 4700 feet and total depth of 5000 feet. Many of these wells were shot with nitroglycerin upon completion and some were acidized. These early acid jobs used as much as 10,000 gallons of 15 per cent hydrochloric acid.

Water injection was started on this unit in April of 1965 in a peripheral pattern. When converted to injectors, the wells were deepened to a point where water saturation was high. Injection wells on the west line are bottomed at about 5295 ft (1560 ft subsea), south line wells at about 5235 ft (1560 ft-1530 ft subsea), and east line wells down to 5330 ft (1700 ft subsea).

When producing wells were deepened prior to stimulation, they were deepened to near 1600 ft subsea in most instances. However, Willard Unit No. 132 was deepened to 1700 ft subsea. The high water saturation cut-off point occurs at a deeper level on the east side of the unit.

Most of the wells stimulated to date have shown some response to flood prior to treatment. Water injection is limited to 1100 psi surface pressure with no limit set on the volume. Currently the injection rate is 37,000 to 40,000 BWPD into 49 injection wells. Also, at the present time 265 production wells are producing 12,000 BOPD. To date over 40 wells have been fracture-treated with an increase of 4000 BOPD directly attributable to these treatments.

TREATMENT DESIGN

In addition to the usual objectives — substantial production increases and good economics — there were two other very important requirements for treatment design: (1) the lower interval, in particular, must be effectively treated and (2) propped fracture length must be restricted to avoid undue interference with waterflood patterns. Acid was used as the first approach to stimulation. Several wells were treated using volumes up to 20,000 gallons of 20 per cent HC1. Some were multistage treatments using salt plugs to divert fluid and temperature logs to define the zones treated. The temperature logs were not helpful and treatment response was uniformly poor.

The next approach was to try sand fracture treatments. The first wells were treated below open-hole formation packers. These jobs gave much better increases than the acid jobs. However, in each case the fracture extended above the packer. This produced two undesirable results: (1) sand settled on top of the packer and caused extensive clean-out operations and (2) fracture growth was limited due to the loss of fluid to the annulus.

To avoid these open-hole packer problems, multistage fracture treatments were tried with salt plugs as diverting agents. Most of these jobs resulted in good production increases with minimum in-hole problems. However, these jobs were both tedious and time consuming. Further, sizing and handling of salt plugs was difficult.

Before starting the next group of treatments all prior treatments were thoroughly reviewed. Three things became obvious: (1) fracture treatments were better and cheaper than acid treatments; (2) major increases in production came from the very bottom of the original hole and the newly-deepened section; and (3) the use of salt plugs and multistage treatments served no real purpose.

The temperature logs showed that once a fracture was opened or created, the upper and lower limits were not changed by salt plugs. In fact, logs showed that the 100 barrel breakdown fluid volume created a fracture over the entire productive interval in all cases. The salt plugs simply changed the point of entry of fluid from the wellbore into the same fracture. A number of engineering calculations to estimate fracture area and volume created by these treatments seemed to confirm these views. This engineering review and analysis led to the design now in use.

As can be seen from the preceding discussion, the design now in use is based on a combination of experience and engineering calculations. Practically all of the treatments have been done with the frac tubing set to near the bottom of the hole. This means that the fracturing fluid leaves the tubing at the bottom of the hole, makes a 180° turn, then flows up the annulus between tubing and open hole, entering the fracture along the way. This is opposite to the generally used technique on which sand transport calculations are made. This low tubing placement has certain advantages in that it assures that the entire formation can be logged with temperature tools after fracturing.

There are basically two steps in the design of a fracture treatment. One is to calculate the volume of fluid needed to create the proper size fracture. The other is to calculate the quantity of propping agent, usually sand, required to keep the fracture open and conductive after frac fluid injection stops.

Fracture area created by a fracture treatment depends mainly on the total volume of fluid injected and the rate at which this fluid is injected. Obviously, physical properties of the fracturing fluid — viscosity and fluid loss control coefficient in particular — and of the reservoir itself are also important. An equation relating these parameters was published several years ago by Howard and Fast.[1] It has become the basis for practically all fracture design calculation procedures in use today. Calculations with this equation showed that 30,000 to 40,000 gallons of gelled water injected at 20 to 25 BPM rate would create the proper sized fracture for the Willard Unit wells. This volume should create a vertical fracture about 200 feet high extending out about 300 feet on either side of the wellbore.

The quantity of sand needed to keep the fracture open depends on how the sand is placed in the fracture. Usual practice, or rather the usual aim, is to fill almost all of the fracture with sand. This is impractical in these wells for two reasons. First, the fracturing fluid must be very viscous to carry the sand around the 180° turn out of the tubing resulting from the "low-tubing-set" type of treatment. Consequently, there is little or no tendency for sand to settle into a pack. In fact, calculations show that a 20-40 mesh size sand could be carried several thousand feet from the wellbore if the fracture were long enough. The second reason is that it would take about 120,000 lbs of sand to fill the fracture — to be carried in 30,000 gallons of fluid. In other words, the sand would have to be injected at an average of about 4 lbs per gallon concentration. Such a treatment would almost certainly screen out. To increase fluid volume would simply create a larger fracture which would in turn require more sand to fill it.

Most of the Willard Unit wells have been treated with about 40,000 lbs of sand, or about a third of the amount required to fill the fracture. Productivity has improved about as predicted, averaging nearly four-fold. This suggests that the fractures have been well propped with the lesser quantity of sand. The probable explanation is that a network of sand bridges and channels develop throughout the fracture. As the fracture extends, sand particles are carried out to near the end of the fracture where crack width is less than particle diameter. The sand starts to bridge across the end of the fracture. With continued injection, the fracture grows in length, width and, up to a point, height. The slurry then breaks through or around the relatively weak bridge and erodes a channel. As slurry injection continues, this process repeats itself until a network of bridges and channels throughout the fracture is developed. These bridges should begin to form first where fracturing fluid leak-off is greatest, that is, where matrix permeability is greatest or where small natural fractures intersect the induced fracture. Figure 1 illustrates this "bridge and channel" concept of sand placement.

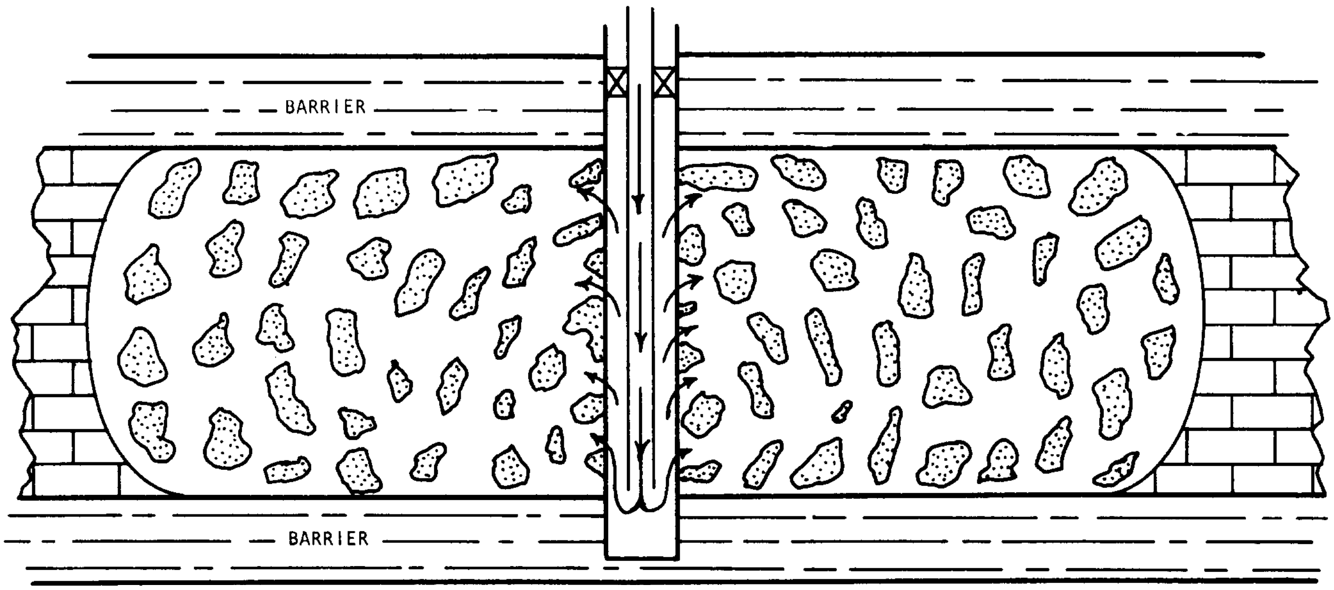


FIGURE 1

Idealized Illustration of "Sand Bridge and Channel" Concept of Sand Placement in a Vertical Fracture

CASE HISTORY

After several wells had been fractured in this program, treating records were studied and reviewed in detail. Logs were examined and actual results were compared with predicted response. In this process we narrowed the treatment down to approximately 40,000 pounds of sand and 30,000 gallons of gelled fresh water injected at 20-25 BPM rate. This design seemed to be close to optimum. Substantial production increases were obtained, few mechanical problems were experienced, and costs were reasonable. However, there was some question about vertical sand distribution in the fracture. Was the fracture propped uniformly from top to bottom? This could be a critical factor later on in the performance of the water flood. Did the use of the low tubing placement technique cause the fracture to be propped only in the lower zone?

Two wells were chosen for direct comparison. They were treated the same except that in one well the frac tubing was set above the pay in the conventional manner, and in the other well, tubing was set below the pay as was done in most previous Willard Unit jobs. We felt that while the temperature logs generally showed the location of the frac fluid, they did not show actual sand distribution. For this reason, radioactive sand was used in these two wells in addition to the temperature logs for frac evaluation. The two wells that were chosen for this comparison were the Willard Unit No. 21 and 55.

Willard Unit No. 55

This well is located near the southeast corner of the unit and in the second row of wells from the lease line. There are five injection wells in the immediate vicinity. This well was originally completed as follows: 7-in. casing set at 4618 ft, T.D. at 5263 ft (1651 ft subsea), and the open hole shot with 680 quarts of nitroglycerine from 5055 ft to 5190 ft.

The well was not deepened prior to treatment. Frac tubing (2-7/8 in. O.D.) was set to 5236 ft (27 ft off bottom) with a packer at 4545 ft inside the casing. In this well there was some 640 ft of open hole with the lower 142 ft the main pay and the zone of interest.

The treatment specifications were:

1. 40,000 lbs of 20/40 sand with 40 units of Ray-Frac and 47,000 gallons gelled fresh water.
2. Maximum sand concentration—1 lb/gal.
3. Injection rate 20-25 BPM with a limit of 4500 psi on the tubing

4. Pad volume of 6000 gallons of gelled fresh water with 40 lbs/1000 gallons of guar gum and 50 lbs/1000 gal. of silica
5. Frac fluid — fresh water gelled with 40 lbs/1000 gal. guar and 16 lbs/1000 gal. silica
6. Flush with 2740 gallons of gelled fresh water.

The procedure was as follows:

Frac tubing was run, packer set and then a base temperature (absolute) log was run. Next, 1000 gallons of 15 per cent HC1 acid was pumped in followed by 4200 gallons of fresh water at ambient temperature (81°F). These breakdown and "trace" fluid volumes were pumped at 14 BPM and 3900 psi. Following this, a temperature log was run to locate the fluid entry. This "trace" fluid entered the formation from 5258 ft to 5116 ft, which was the entire productive interval. No fluid entry was detected above the pay or above the casing seat.

Frac fluid was gelled and checked with a Fann viscometer. The 6000-gallon pad was pumped at 23 BPM and 2900 psi. Sand was then started at 1/4 lb/gal. and gradually increased to 3/4 lb/gal. during which time the pump rate was 23 BPM and the pressure gradually increased up to 2950 psi. The one lb/gal. mixture was pumped at 23 BPM and 3050 psi with a gradual increase to 3600 psi. The instantaneous shut-in pressure was 700 psi.

The post-fracturing temperature logs were then run. They showed that the interval from 5040 ft to 5253 ft had taken fluid. Also, there was only 3 ft of sand fill on the bottom of the hole. The gamma ray log showed sand distribution from 5060 ft to 5255 ft (top of fill-in). In this case, both logs show the same interval within a few feet. Refer to Fig. 2.

Willard Unit No. 21

This well is located in the second row from the south line and aobut midway from the east and west lines. It is approximately 1-1/2 miles southwest of No. 55 and there are three injection wells in the immediate area.

At original completion the T.D. was 5194 ft. Prior to treatment it was deepened to 5254 ft (1660 ft subsea). It had not been shot with nitroglycerine. For the frac treatment the 2-7/8 in. O.D. tubing was set at 5020 ft or 234 ft off bottom. The top of pay is at 5032 ft. A packer was set in the 5-1/2 in. casing at 4431 ft (casing seat at 4563 ft).

The treatment specifications and procedures were the same as No. 55. The breakdown and "trace" fluids were pumped in at 14 BPM and 3900 psi. The temperature log showed that fluid entered the formation from 5216 ft to 5140 ft with no entry up the hole or behind the casing. Next, the 6000-gallon pad was pumped at 23 BPM and 2700 psi. Sand was then started at 1/4 lb/gal. and gradually increased to one lb/gal. The injection rate was 23 BPM throughout. The injection pressure at start of sand was 2700 psi with a gradual increase to 3250 psi. The instantaneous shut-in pressure was 600 psi.

After-frac temperature logs showed cooling or fluid entry into two intervals; 5243 ft to 5156 ft and 5108 ft to 5044 ft. There was 11 ft of sand fill-in on bottom. The gamma ray log showed sand placement from 5000 ft to 5243 ft (top of fill) as one continuous interval. In this case the R/A log showed sand in the temperature log blank (5108 ft-5156 ft) and to a point 27 ft below that shown by the temperature log. It should be noted that all these logs were run by the same men using the same equipment. Also, the temperature logs in this particular well were unusually difficult to interpret.

CONCLUSIONS

A comparison of the treating records of these two wells showed that the wells were treated almost identically. Injection rates were the same and injection pressures were within 200 psi, which is a normal variation in this area. No unusual problems were noted either during or after the treatments.

Temperature logs in the Willard Unit No. 55 well (Fig. 2) showed a vertical fracture height of 212 feet. Gamma ray logs showed that sand was distributed over the lower 200 feet of this 212-foot fracture leaving only a few feet at the top unpropped. This resolved the primary concern that the low tubing placement technique might lead to poor distribution of the propping agent over the whole fracture.

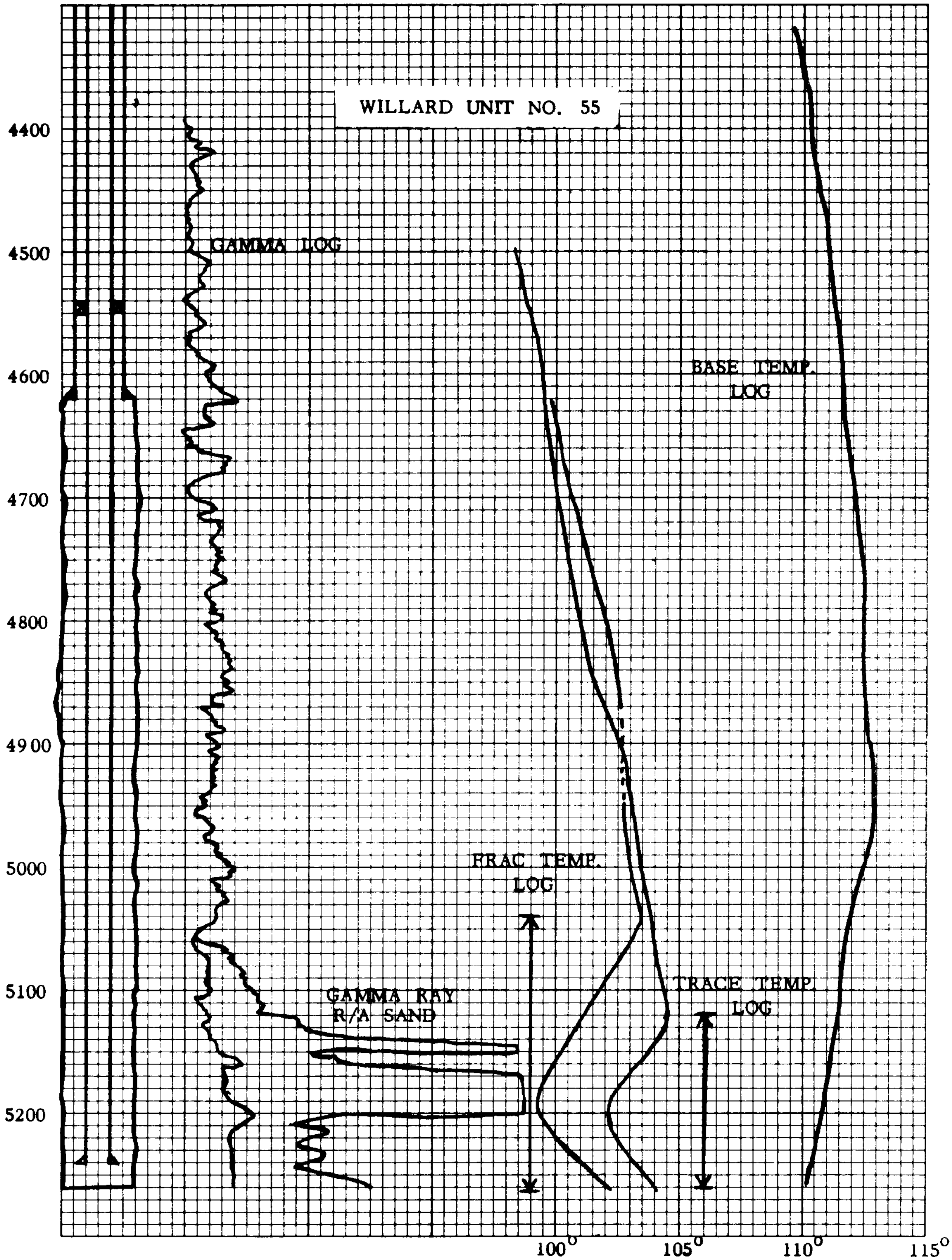
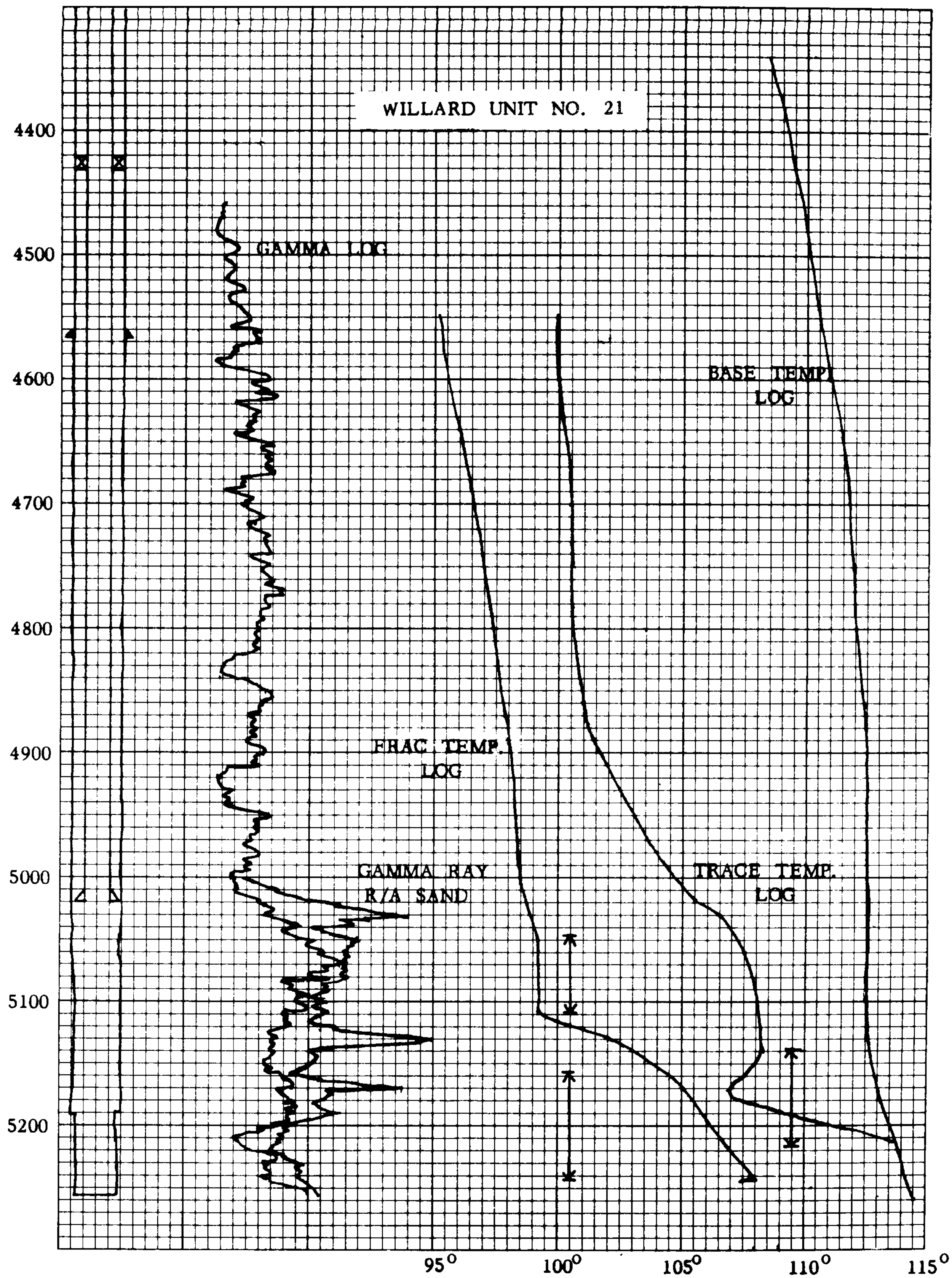

WILLARD UNIT NO. 55
4400
4500
4600
4700
4800
4900
5000
5100
5200
GAMMA LOG
BASE TEMP. LOG
FRAC TEMP. LOG
TRACE TEMP. LOG
GAMMA RAY R/A SAND
100°
105°
110°
115°

FIGURE 2



WILLARD UNIT NO. 21
GAMMA LOG
BASE TEMP. LOG
FRAC. TEMP. LOG
GAMMA RAY R/A SAND
TRACE TEMP. LOG
4400
4500
4600
4700
4800
4900
5000
5100
5200
95°
100°
105°
110°
115°

FIGURE 3

Temperature logs in the Willard Unit No. 21 (Fig. 3) were more difficult to interpret. They indicated, at least to one interpreter, that two separate fractures over a gross interval of 235 feet were created with a 44-foot separation between them. The gamma ray log indicated a gross fracture height of about 250 feet with a fairly even distribution of sand from top to bottom. The gamma ray log also showed a particularly high peak at the center of the supposedly nonfractured 44-foot section. Obviously, the fracture is continuous and extends over the entire interval. The anomalous results from the temperature logs can probably be rationalized in several ways. We think that the fracture probably initiated in this section and a sand bridge formed near the wellbore early in the treatment. This diverted frac fluid around the bridge, and consequently very little cooling occurred in this section — hence, the anomaly. Whatever the explanation, the fracture undoubtedly extends over the whole zone and is well-propped from top to bottom.

Based on these two treatments, we have concluded that these wells can be treated successfully with tubing set at either the top or bottom of the zone. Production increases after treatment confirm the results indicated by the frac evaluation logs. After several months, oil production rates in each well have stabilized at about three times the rate before treatment. Water-cut has stayed about the same in the Willard Unit. No. 21 but increased sharply in the Willard Unit No. 55. The high water-cut in the No. 55 well probably means the fracture was too long and extended into the waterflood front. This simply reaffirms the need for careful treatment design to limit fracture lengths (smaller treating volumes have been used in most of these wells).

The low-tubing-set fracturing technique used in most of the Willard Unit wells seems to be gaining popularity in West Texas. We are convinced these treatments accomplished our objectives. However, this type treatment has certain disadvantages which make it a special-purpose treatment rather than a generally-recommended procedure. First, the carrying fluid must be a premium quality fluid. It must be very viscous or it must have excellent gel strength in order to carry sand around the 180° bend as it leaves the tubing. Good gels can be expensive. There are more opportunities for sand bridges to form, particularly if the gel is mediocre, and the chances for a screen-out are much greater than with a conventional treatment. If the zone is quite thick, sand may not be carried to the top of the fracture. While sand was carried to very near the top of the fracture in the Willard Unit No. 55 well, we did note on the gamma ray logs that sand seemed to be distributed more uniformly with the conventional treatment in the Willard Unit No. 21 well. We used the low-tubing-set technique simply to assure that temperature logs could be run. Most of these wells had several hundred feet of open hole, questionable cement jobs, and many had been shot with nitroglycerine. The frac evaluation logs were needed to be sure the right zone was treated. We felt this information was important enough to justify the use of the potentially more hazardous low-tubing-set treatment.

REFERENCE

1. Howard, G. C., and Fast, C. R., "Optimum Fluid Characteristics for Fracture Extension", API Drilling and Production Practice (1957), p. 261.

ACKNOWLEDMENTS

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