HNG'S DEEP WELL COMPLETION METHODS

R. R. FRAZIER
HNG Oil Company

INTRODUCTION

HNG Oil Company has completed over 20 deep gas wells in the past four years with remarkably few problems. The majority of the wells are located in the Delaware Basin of West Texas and range in deliverability from less than 1 MMCF/D to over 30 MMCF/D. Although each completion is different, the same basic steps were followed. Each was perforated in acid with a limited number of deep penetrating, burr-free perforations, and was originally stimulated with a moderate volume of 15% HCl using ball sealers to divert the acid. The mechanical hookup in each case consists of high quality, properly designed tubular goods and involved in these completions from the time the liner is cleaned out until it is flowing is four days for a single and five days for a dual.

The key to the entire completion program is simplicity. The more operations involved in a completion and the more equipment placed in the well, the greater the chances for failure.

PERFORATING

Large diameter jet casing guns are used to provide high quality, deep penetrating perforations. Decentralizing springs and extended steel port plugs are used on the guns to obtain the burr-free holes necessary for acid diversion using ball sealers.[1] Tubing guns are used only where a considerable time savings is possible and where deep penetration is less important.

To assist in opening all perforations and to lower breakdown pressures during stimulation, perforating is done in acid. The acid is spotted through tubing or drill pipe prior to perforating and is generally 15% acetic acid, weighted slightly heavier than the fluid in the hole and double inhibited. Hydrochloric acid is preferable to acetic acid and is used where the bottomhole temperature does not exceed 200°F.

In picking perforations, an adequate number of holes is used in each porosity unit to allow stimulation at the desired pump rate with perforation friction pressure of 150 to 300 psi. Additional holes serve no purpose and decrease the chances of completely shutting off the zone with ball sealers during stimulation. An equal number of holes is placed in each porosity unit and a like number of balls are run between stages during stimulation. The urge to saturate each porosity interval with perforations must be avoided.

An example of this concept is shown on Fig. 1 which is a gamma-ray sonic log across the Devonian section in HNG's Caprito "83" No. 1 located in Ward County, Texas. In this zone 300 feet of section were perforated with only eight holes. The section is divided into basically two porosity units, each of which was perforated with four holes. The well was acidized with 10,000 gal. acid in two equal stages at eight BPM. This zone began producing at the rate of 20 MMCF/D in 1970 and is currently producing over 10 MMCF/D.

STIMULATION

Regular 15% HCl is the stimulation fluid used by HNG in nearly all deep well completions. It is generally mixed only with corrosion inhibitor, friction reducer, and a nonemulsifying agent. In high temperature reservoirs a minimum pump rate of 10 BPM is necessary to transmit live acid past the immediate wellbore area and into the reservior where it can enlarge existing flow channels and create new ones. The acid is flushed with fresh water mixed with nitrogen and a foaming agent.

CAPRITO 83 No. I
WARD COUNTY, TEXAS

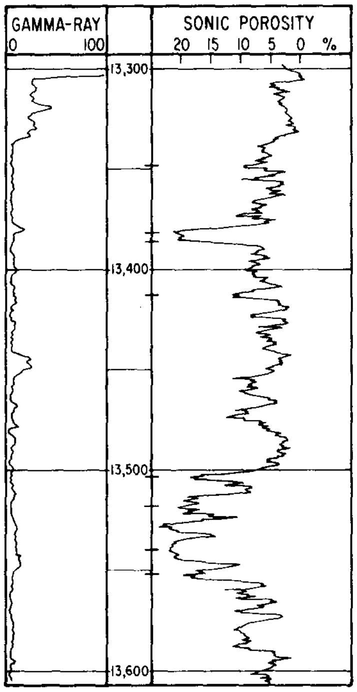


FIG. 1

Treatment volumes range from 5000 to 10,000 gal. per stage depending upon the amount of porosity present. Extremely large volume acid treatments or exotic acid mixtures appear unjustified.

TUBING

Due to the extremely large tensile loading and the high temperatures and pressures encountered in deep wells, tubing design is critical. High quality integral joints with metal-to-metal seals are necessary to provide a bubble-tight seal under extreme pressures. For added insurance against leaks, a Teflon seal ring is used in the box end of the tubing to provide an additional high-pressure seal.

Normally C-75 grade tubing is used because it resists corrosive well fluids better than N-80 or higher grades.

Tubing size must be large enough to handle the necessary stimulation rates and small enough to maintain a producing velocity above the minimum necessary to remove liquids from the well. Generally, 2-7/8 in. or 3-1/2 in. is run, the smaller being used where the anticipated producing rate is less than 5 MMCF/D.

All tubing is inspected for proper wall thickness, cracks, and connection defects prior to running in the well. The tubing is not pressure-tested while running in the hole and there have been no problems with tubing leaks.

PACKER BORE RECEPTACLES

Many types of packer arrangements have been used in deep wells with varying degrees of success.

Retrievable packers are seldom run due to pressure limitations and tubing movement.

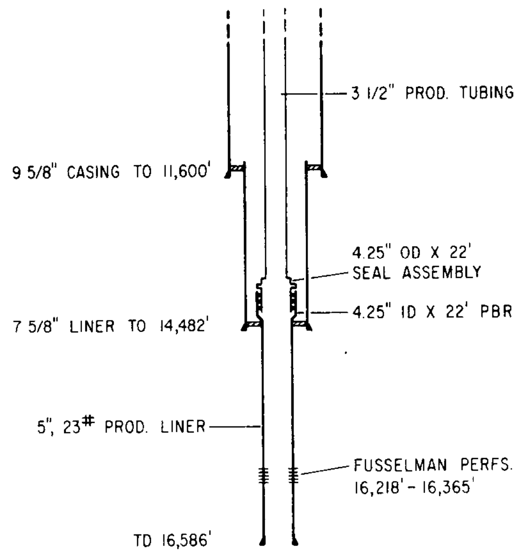
Permanent packers have been run in the majority of deep wells. They offer several advantages, such as: they may be wireline or tubing set; they withstand high differential pressures; they allow tubing movement, they are inexpensive, and they give protection against leaking liner tops. Permanent packers have two major drawbacks, however. They have small diameter seal assemblies which limit the amount of wireline work done beneath the packer, and they must be milled up in order to perform any remedial work on the well. These drawbacks are sufficient to cause HNG to use permanent packers only where there is no other choice.

The type of packer arrangement which we prefer has been gaining in popularity since about 1968. It is called a packer bore receptacle or PBR and consists of a machined joint of pipe which is connected to the top of the liner above the liner hanger.[2] The ID is slightly larger than the ID of the liner. A set of seals is run on the end of the tubing string and is forced into the PBR, thus making a positive connection between the production liner and the tubing and isolating all other casing strings.

The PBR allows unrestricted upward tubing movement during stimulation; but with the proper amount of slackoff, the tubing will not move during production or extended shut-in periods. This is essential since movement would eventually destroy the seals.

The PBR offers several advantages over permanent packers. The primary advantage is that the seals are removed by a straight pickup leaving the full ID of the liner open for remedial operations; in addition, there are no mechanical latches or jays to cause problems. The simplicity of the system and the limited number of operations involved reduce the chance of mechanical failure. The PBR may be obtained in any length so any reasonable amount of tubing movement may be handled. The primary drawback to the PBR is that this large seal bore area causes very large piston forces on the tubing during stimulation. These forces require careful study prior to treating; but by regulating the annulus pressure and the acid temperature it is nearly always possible to design for maximum treating pressures.

Figure 2 is a schematic of a typical Delaware Basin gas well showing the use of a PBR as an integral part of the 5-in. production liner. The seal assembly is attached to the bottom end of the tubing and seals in the PBR. For a 5-in., 23-lb liner we use a 4.25-in. PBR which is slightly larger than the ID of the pipe. Normally the length will be 15-22 ft to provide adequate room for travel under stimulation conditions.



SINGLE COMPLETION USING PBR

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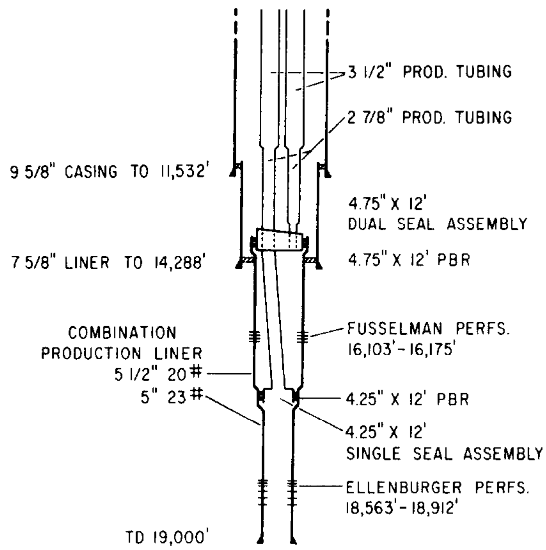
FIG. 2

When a dual completion is anticipated (Fig. 3) a combination 5-in by 5-1/2 in. production liner is run with a 4.75-in. PBR at the top of the liner and a 4.25-in. PBR at the crossover which is placed between the two producing zones.[3]. A single-seal assembly is placed in the 4.25-in. PBR and a dual-seal assembly seals in the 4.75-in. PBR.

Very heavy wall tubing is run between the two PBR's to withstand the severe loads imposed on it during stimulation of the lower zone and to serve as blast joints through the upper perforation interval.The distance between the PBR's is usually 2000-3000 ft and spacing it out creates a problem. The tubing should be spaced with approximately 6-in. extra length to allow weight to be setting down on the bottom PBR so no



DUAL COMPLETION USING TWO PBR'S

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FIG. 3

movement may occur during producing and shut-in conditions which could cause seal failure.

The surface area of each seal assembly is equal or "balanced" so that the upward and downward piston forces which occur during stimulation of the upper zone are cancelled.

The use of ball sealers in the upper stimulation treatment is impossible due to the small opening which exists in the short string side of the dual seal assembly. A solid-type diverting material such as rock salt or benzoic acid must be run in this situation.

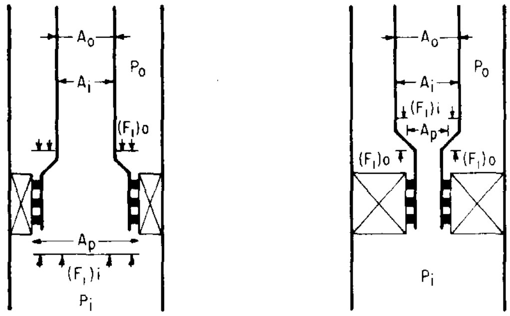
TUBING MOVEMENT CALCULATIONS

Movement calculations have been discussed in detail by other authors so only a brief review will be given here.[2, 4]

Four forces acting on tubing during the life of a well cause changes in the length of a tubing string. They are piston, buckling, temperature, and ballooning forces. At shallow depths where fluctuations in temperature and pressure are small these changes in tubing length are insignificant; however, in deep wells the tubing can travel more than 30 feet during stimulation, so this movement must be calculated and the completion designed to allow for it.

Piston Force (F_1): The seals in a PBR or packer may be likened to a piston in a cylinder of an engine. If the seal bore is larger than the tubing ID (as in PBR) tubing pressures cause a force from below which pushes upward as pressure is increased (Fig. 4a). The reverse is true if the seal bore is smaller than the tubing ID (as in most permanent packers) (Fig. 4b). Expressed mathematically the piston force is:

$$F_1 = \Delta Pi\,(Ap - Ai) - \Delta Po\,(Ap - Ao) \qquad (1)$$



(a) SEAL BORE LARGER THAN TUBING I.D.

(b) SEAL BORE SMALLER THAN TUBING I.D.

PISTON FORCES (F_1)

FIG. 4

Buckling Movement (ΔL_2): Helical buckling is not a true force. It is a shortening of the tubing caused by the spiraling effect which occurs when the pressure inside the tubing is greater than the pressure in the annulus (Fig. 5). It is greatly affected by the tubing-to-casing radial clearance as well as the relative pressure inside and outside the tubing. Lubinski expressed this movement by:

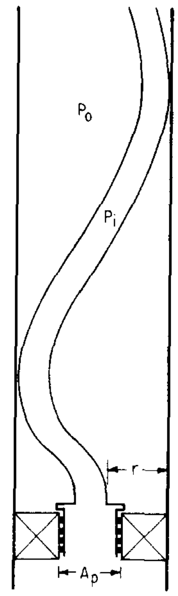
$$\Delta L_2 = \frac{r^2\,Ap^2\,(\Delta Pi - \Delta Po)^2}{8\,E\,I\,(Ws + Wi - Wo)} \qquad (2)$$

The movement calculated in this formula is expressed in inches.

Ballooning Force (F_3): Pressure applied inside the tubing causes the pipe to balloon, which shortens the string. Reverse ballooning is the lengthening effect which occurs when pressure is applied to the outside of the tubing. When the fluid density is the same inside and outside the tubing, a simplified form of the ballooning equation is:

$$F_3 = 0.6\,(\Delta Pia)\,(Ai) - (\Delta Poa)\,(Ao) \qquad (3)$$

Temperature Force (F_4): Tubing temperature changes drastically from treating to producing to shut-in conditions and forces develop when the tubing lengthens due to heating and contracts



BUCKLING MOVEMENT (ΔL_2)

FIG. 5

when cooled. This force is calculated by:

$$F_4 = 207\,(\Delta Ta)\,(As) \qquad (4)$$

To convert forces F_1, F_3, and F_4 to length changes, the following formula is used:

$$\Delta L = \frac{(L)\,(F)}{(3 \times 10^7)\,As} \qquad (5)$$

For any specific well, the only variables in these formulas are temperature and pressure changes. It has proven very helpful to plot curves for each force showing the movement as a function of temperature and pressure changes.[5] These curves are straight-line functions for all except the buckling movement. They may be referred to on location if something unexpected occurs, such as the acid temperature being cooler than expected or a leaking liner top making it difficult to hold the proper backup pressure on the annulus.

A check should be made to determine whether the most severe conditions will cause permanent damage to the tubing. This may be determined by calculating Si (combined stress at inner wall) and So (combined stress at outer wall). If either Si or So exceed the minimum yield strength of the tubing (75,000 psi for C-75; 80,000 psi for N-80, etc.) the tubing will permanently corkscrew. The formulas for calculating these stresses are:

$$Si = \sqrt{3\left[\frac{R^2 (Pi-Po)}{R^2-1}\right]^2 + \left[\frac{Pi-R^2Po}{R^2-1} + \sigma_a \pm \sigma_b/R\right]^2} \quad (6)$$

$$So = \sqrt{3\left[\frac{Pi-Po}{R^2-1}\right]^2 + \left[\frac{Pi-R^2Po}{R^2-1} + \sigma_a \pm \sigma_b\right]^2} \quad (7)$$

Where: σ_a = Fa*/As and σ_b = (Dr)(Ff*)/4I

To properly design a completion three things must be calculated:

1. Calculate tubing shortening during stimulation to make sure the seals will remain in the PBR. A treating pressure of 10,000 psi is normally used for design purposes.
2. Calculate the amount of slack off necessary to keep seals from moving when well is shut-in.
3. Calculate the movement which occurs during producing and stimulation conditions and check to see if tubing will permanently deform under these conditions.

NOMENCLATURE

Ao	Outside area of tubing, in.^{2}
Ai	Inside area of tubing, in.^{2}
Ap	Packer bore area, in.^{2}
As	Cross-sectional area of tubing wall, in.^{2}
E	Young's Modulus (30×10^6 for steel)
I	Moment of inertia (π/64) (OD^4 - ID^4)
L	Length of tubing string, ft
r	Tubing to casing radial clearance, in.
Ws	Weight of tubing, lb/in.
Wi	Weight of fluid in tubing, lb/in.
Wo	Weight of fluid in casing, lb/in.
ΔPi	Change in tubing pressure at seal level, psi
ΔPo	Change in annulus pressure at seal level, psi
ΔPia	Change in average tubing pressure, psi
ΔPoa	Change in average annulus pressure, psi
ΔTa	Change in average tubing temperature, °F
R	Ratio of tubing OD/tubing ID
Fa*	Actual force Fa* = (Ap-Ai) Pi - (Ap-Ao) Po
Ff*	Fictitious force Ff* = AP (Pi-Po)
D	Tubing OD, in.
ΔL	Change in length of tubing string, ft

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