Defining the Characteristics and Performance of Gas-Lift Plungers

TECHNICAL PAPER: By L.N. Mower and J.F. Lea, Amoco Production Co.,
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Abstract

A laboratory investigation was conducted to provide data necessary to better predict the behavior of gas lift plungers. A test well was instrumented to provide pressure, velocity, and volumetric information during the fall and rise cycle of a variety of commercially available plungers. A substantial data bank has been compiled and behavior of 13 different plunger configurations has been characterized by gas slippage, liquid fallback, and fall velocity. Performance characteristics of the individual plungers has been incorporated in a modified Foss and Gaul[2] mathematical model, which provides predicted minimum casing pressure in close agreement with actual laboratory tests.

As a second part of the evaluation program, actual field data was collected from four field locations with a variety of operating conditions. The correlations developed for the laboratory tests were then adjusted to fit field data. The final correlations and equations describing plunger-lift operations have been included in a computer program that can be used for design and analysis of plunger-lift operations.

Questions:

Plunger lift is an artificial lift method, which incorporates a plunger or piston traveling up and down in the production tubing string and utilizes expanding gas energy or its upward movement. This lift method is used in intermittent lift of high GLR oil wells, deliquefaction of gas wells, improved efficiency of intermittent gas lift wells, and for removal of paraffin and scale from wells. The plunger provides a partial seal between gas and liquid, reduces liquid fallback, and more efficiently uses gas lift energy.

A review of literature indicated the paucity of laboratory quality data which would adequately describe the expected behavior of full scale commercially available gas lift plungers. A cooperative test program was developed with Camco, Inc., and Ferguson Beauregard, Inc., to provide an adequate data base to predict and validate performance of actual plungers.

The initial phase of the project was a laboratory investigation intended to improve our understanding and efficiency of utilization of this artificial lift method. A 735/ft (224/m) laboratory test well was instrumented to provide carefully controlled measurement of pressure, temperature and volumes needed to provide a valid data base with which to accomplish these objectives.

Next, a series of field tests were made to compare laboratory correlations to actual field data. After correlation of the field data, a computer program for calculating the needed parameters was developed with the field corrected laboratory correlations for gas slippage and liquid fallback. The program uses basic equations developed by Foss and Gaul,[2] which are modified to predict trends indicated by the data. In addition to using correlations developed in this test program, the model accounts for produced gas.

Discussion of Laboratory Tests

Description of Laboratory Experimental Facilities

Test facilities employed during the plunger-lift evaluation are shown on Figure 1. Four specially designed mandrels, each containing a Validyne pressure transducer, were spaced at approximately 179 ft (54.6 m) intervals from a depth of 715 ft (217.9 m) to 179 ft (54.6 m). The mandrels were connected by hydraulic hose to provide a conduit for the transducer signal wiring. In addition, transducers were installed to measure casing and tubing pressure at the surface. The downhole temperature was measured with a copper-constantan thermocouple. Static and differential pressure transducers mounted on an orifice meter provided gas measurement during the production cycle. A MACSYM 350 computer was used for automated data collection.

The liquid slug volume, during downhole placement, was determined by a water meter, and also by a change in differential pressure indicated by a pressure transducer located at the bottom of the separator. The transducer provided a dynamic indication of produced liquid volumes during the production cycle.

Plunger Types Evaluated

Twelve plunger types were evaluated in the laboratory test program. This selection of plungers more than adequately covers the types of designs that are available for use. A noncommercial capillary type plunger was also tested with two sizes of orifices, resulting in the evaluation of a total of 13 plunger configurations. General types of plungers tested included capillary, turbulent seal brush, expandable blade, multiple turbulent seal, multiple expandable blade, combination turbulent seal and expandable blade, and wobble washer. Valving arrangements through the plungers included full opening, internal valve stem, and solid plug. Table 2 lists the types of plungers tested, together with a brief description and identifier number.

Test Program and Procedures

The threshold lift characteristics (see Table 2) of each plunger were measured at the surface using a 1.990 in. (50.5 mm) ID lucite tube. Air flowing into the bottom of the tube was gradually adjusted to the rate at which the plunger would be suspended in the flow stream. The corresponding flow rate in SCFM and the pressure under the plunger are listed in Table 1. In most cases, the threshold lift pressure simply equals the weight of the plunger divided by the cross sectional area of the tubing. Notable exceptions are Plunger eight, nine and ten, for which no mechanism is apparent other than possibly friction loss past the plungers.

Plunger performance was evaluated with slug sizes of five gallons (0.0189 m^3) and 10 gallons (0.0379 m^3) of water. Water was pumped out of the separator and metered upstream of the wellhead. Pressure on the lower transducer was monitored to determine when the liquid slug arrived on bottom. Since a check valve was in place, pressure on the bottom transducer would increase over the casing pressure by an amount corresponding to the hydrostatic head of the liquid slug. Tubing pressure was then bled off until the pressure in the bottom of the tubing was in balance with casing pressure.

When this hydrostatic balance was achieved, the plunger was dropped and the pressure response on the tubing transducers recorded. After the plunger reached bottom and pressure response stabilized, the tubing valve on the surface was opened to start the rise cycle and initiate data collection. The valve was closed immediately on plunger arrival, but data collectin was continued to reflect stable casing pressure and indicate liquid fallback.

Experimental Results

A typical pressure history during fall is shown on Figure 2. A slight increase in downhole tubing pressure was noted as the plunger fell. A sharp decrease in tubing pressure was seen as the plunger passed each transducer above the liquid livel. It is interesting to note that the change inpressure during plunger passage is nearly equal to the expected threshold lift pressure. These pressure changes, as a function of time, were used to calculate fall velocity in air and to predict plunger arrival at the top of the liquid slug. In most cases, a similar sharp drop in pressure was noted at the bottom transducer as the plunger stopped on the shock absorber at the check valve. This permitted the calculation of fall velocity in water shown on Table 1. Fall velocities in air collected in the lab were pressure dependent and not sufficient to extrapolate to high pressure field conditions.

Typical rise cycle pressure response is shown in Figures 3-6, representing a series of plunger runs with slug size of approximately 10 gallons (0.0379 m^3) of water and with initial casing pressure sequentially decreased from 80 psig (552 kPa) to 30 psig (207 kPa) or stall-out pressure. Pressure response during the plunger rise period is shown by six curves. Pressure changes recorded by the bottom transducer and the casing transducer reflect the decrease in lift gas pressure (and volume). The remaining four presen time-ant-pressure related events during plunger rise. Beginning from the left hand side of these figures, it may be observed that the transducers respond in similar fashion to a very rapid decline in tubing pressure above the liquid slug. The first upward inflection indicates the top of the liquid slug passing the transducer located at 536 ft (163 m) or approximately 179 ft (54.5 m) off bottom. By knowing the size of the liquid slug and its height above bottom, the average velocity and acceleration may be determined by the lapsed time to this point.

Pressure increases abruptly as the liquid slug continues to rise above the transducer with pressure reaching a plateau as the plunger passes. A slight increase in pressure may also be noted as the liquid slug reaches the surface and passes through piping to the separator.

At higher casing pressure, plunger velocity is high, gas slippage is low and a uniform fluid gradient is exhibited as the liquid slug passes the transducer. Tests run with lower casing pressure result in lower plunger velocity and longer plunger arrival time. The lower velocity permits increases gas slippage past the plunger, which is shown by an irregular liquid gradient during traverse past the transducer. This is seen as an elongating gas cut liquid slug, quite abvious in Figure 5. At stall-out (Figure 6), the plunger ceases to move upward, and liquid removal is effedted by gas lift with the plunger acting essentially as a downhole restriction.

Figure 7 depicts the pressure history with no plunger in the well. Even though the initial casing pressure was 70 psig (483 kPa), the pressure behavior looks more like Figure 6, where stall-out occurred with a plunger at 30 plig (207 kPa) casing pressure. By comparison, with 40 psig (276 kPa) casing pressure, the test with the plunger produced the entire 10 gallon (0.0379 m^3) slug to the surface. With the same pressure and slug size, only 4.5 gallons (0.017 m^3) was lifted to the surface without a plunger.

Pressure buildup on the bottom transducer after plunger arrival is a function of liquid fallback or penetration of the liquid slug during high velocity rise of the plunger. Figure 8 presents a least squares fit of fallback in gallons per second vs. plunger velocity. Note that fallback is depicted as being zero at low velocities, but if the period of measurement was extended, some liquid from the tubing walls would have probably been measured at bottom hole for all velocities.

Gas production to plunger arrival was measured and also calculated based on total system pressure change. The difference between the total produced volume and the volume of gas above the plunger and liquid prior to rise is gas slippage past the plunger. A typical plot of gas slip in scf vs. plunger average velocity is shown in Figure 9. The physics of gas slip are analyzed in more detail in Appendix A. Each plunger was tested at casing pressures decreasing from 100 psig (689.4 kPa) in 10 psi (68.9 kPa) increments to stall-out which was usually in the range of 30 psi (207 kPa). During the laboratory testing a data bank of 132 tests was obtained.

Field Testing

Field testing was conducted with multiple tests at four wells in three fields in conjunction with Camco, Inc. and Ferguson Beauregard, Inc. The purpose of the field tests was to obtain field data of sufficient quality to provide a basis for comparison with laboratory data. The expected end result was to be a mathematical model incorporating adjusted laboratory developed plunger correlations which would improve plunger selection and operation. Field pressure measurements were made with Rosemount transducers ties in to a Hewlett Packard 9826 computer. In those fields having automation systems, exiting transducers were used. Measurement was made of casing pressure, tubing pressure, and orifice meter static and differential pressure as a function of time during plunger cycles. Liquid volumes were measured by tank gauging or by sight glass measurement where temporary tanks were permitted. Pressure measurement sampling frequency was at 0.1 second intervals during critical periods and at longer intervals during non critical periods. Where possible, operating conditions such as cycle time and back pressure were adjusted to provide the greatest range of test data.

The initial test was conducted near Pampa, Texas. The well is approximately 10,000 ft (3048 m) deep, with 7 in. (177.8 mm) casing and dually completed with two strings of 2-3/8 in. (60.3mm) tubing. Normal average daily production prior to the test was reported as 800 MCFD (22,653 m), 39.6 bbl (6.29 m^3) condensate, and 5.8 bbl (0.92 m^3) water.

The next well tested was a relatively low volume producer completed in the Travis Peak Formation in the Carthage Field of East Texas. Typical oil producing rate was 6 BOPD (0.95 m^3). The well was scheduled to shut in on plunger arrival with a 3.5/hour shut-in period for a cycle frequency of six cycles per day.

The third well tested, also in the Carthage field was lifting a total of 3 to 4 bbls (0.48 to 0.64 m^3) per day on a frequency of about 10 cycles per day. Normal operation was to continue afterflow following plunger arrival and shut in on low tubing pressure of about 250 psi (1724 kPa).

The final well tested was near Dacona, Colorado. This well had low pressure and relatively small lift volume storage since it was equipped with 4-1/2 in. (114.3 mm) casing and 2-3/8 in. (60.3mm) tubing to 5039 ft (1536 m). Both the normal wobble washer plunger and an expanding seal plunger were run in this series of tests. This well was interesting because of its slow plunger travel and its tendency to stall. When the plunger stalled, it was necessary to equalize tubing and casing pressure at the surface and then shut in before initiating plunger rise. Figure 10 shows a normal but slow lift cycle while Figure 11 is representative of pressure behavior during stall, equalization of casing and tubing surface pressures, and lift.

Analysis of Laboratory and Field Data

Previous Analytical Work

There have been several previous publications in the area of plunger lift operations (see References 1 through 8).

Of those cited, the analysis by Foss and Gaul[2] is probably used the most frequently because it is simple and considers most of the necessary physics of the operation. Minimum casing pressure at slug arrival at the surface may be calculated by the following (Next Page):

$$P_{cmin} = [\ P_p + 14.7 + P_t + (\ P_{1h} + P_{1f}\ )\ XL\ ]$$

$$*[\ 1 + \frac{D}{K}\ ] \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (\ 1\ )$$

The expressions for the components of Pcmin are:

$$P_{1h} = s_1\ (.433)(L) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (\ 2\ )$$

$$P_{1f} = \frac{S_1\ (.433)(f1)(L)(V^2)}{(d/12)(2.0)(32.2)} \ldots\ldots\ldots\ldots (\ 3\ )$$

$$\frac{1}{K} = \frac{(f_g)(V^2)(gg)}{(d/12)(2)(32.2)(T+460)(Z)(R)} \ldots\ldots (\ 4\ )$$

P_{cmin} described in the above equations is the pressure in the casing as the slug and plunger just reach the surface. Pcmax is the level the casing pressure must reach before the slug and plunger are allowed to begin to rise. In its simplest form,

$$P_{cmax} = P_{cmin}\ (Ra) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (\ 5\ )$$

where: $R_a = \dfrac{A+A_t}{A_a}$

or simply the ratio of total cross-sectional area to the annulus cross-sectional area.

Modification of Foss and Gaul Model

If gas production from the formation during plunger rise is accounted for, the maximum (Pcmax) pressure requirement is reduced, but the minimum (Pcmin) requirement remains the same. Also, if gas is lost from below the plunger to above it during rise (gas slippage), the requirement for Pcmax will increase, but the requirement remains constant.

The following illustrates the functional dependence of Pcmax on slip and well production.

$$P_{cmax} = (P_{cmin})(R_a)\ -$$

$$\left[\frac{(\Delta G_f - \Delta G_s)(14.7)(T+460)}{V_c(520)}\right] \ldots\ldots\ldots\ldots (\ 6\ )$$

For laboratory test conditions, ΔGf was zero. The ΔGs was measured, and can be calculated from the correlation developed in Appendix A and plotted in Figure 12.

Another effect which would tend to reduce pressure requirements is liquid fallback. As shown in Figure 8, liquid fallback increases as the velocity increases, but at different rates for different plungers. Since the Pcmin is calculated as a function of the slug size at the surface, the Pcmin based on a starting bottomhole slug size is reduced by the amount of liquid fallback as the plunger rises. A Pcmin based on surface measured production is unaffected. However, operation at high velocities should be avoided to prevent large liquid losses from above to below the plunger.

Adjustment to Match Field Data

When comparing field data to the model developed from Foss and Gaul and laboratory correlations, a plot of actual minimum casing pressure, P_{cmin} vs. P_{cmin} from calculations was made. From Fig. 13, it can be seen that the adjusted Foss Gaul model underpredicts for low pressures and overpredicts for high pressures. Therefore, the following purely empirical adjustment was made to the model to fit the field data more closely.

$$\text{Adjusted } P_{cmin} = -9.9242 + 1.67722$$

$$(P_{cmin}) - 0.0008643\ (P_{cmin})^2 \ldots\ldots (\ 7\ )$$

This adjustment resulted in an expression which fit the field data within −1% average error with 9.4 standard deviation of actual compared to calculated P_{cmin}. This adjustment may have been due to larger amounts of gas being lost as slip in the laboratory when the plunger is accelerated compared to the total lost over long lengths of tubing. The loss when accelerating in field conditions would be a lesser percent of the whole.

Application to Plunger Lift Operations

During a typical plunger cycle, the well is shut-in and the casing pressure allowed to build to a required maximum. The tubing is then opened and the slug and plunger rise to the surface. If the gas/liquid ratio of the well is high enough, the plunger can be held at the surface to allow additional gas production before the well is shut-in again and the plunger is allowed to fall.

For many "tight" gas wells (low permeability), a plot of bottomhole pressure versus production is very steep indicating that production does not change much if the BHP is changes. If a plunger-lift well is assumed to produce at a constant rate regardless of pressure, then the shut-in and producing times for a cycle can be calculated.

The casing pressure must build to Pcmax casing pressure (Eq.(6)). If the well is allowed to blow down to a pressure Pclow with the plunger at the surface, the buildup time required tbu can be found from:

$$tbu = \Delta G_p / q_g \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (\ 8\ )$$

All of the above quantities can be calculated using appropriate gas law expressions.

Note that for a given slug size delivered, the time can be calculated for a complete cycle.

$$t_{cycle} = (----)(R_l)\frac{q_l\ (24)(60)}{q_g\ 1000} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (\ 9\ )$$

The difference between the cycle time, tcycle, and the buildup time, tbu, and the rise time, trise, is the production time, tprod, while the plunger is at the surface.

$$t_{prod} = t_{cycle} - t_{bu} - t_{rise} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (\ 10\ )$$

Note that if $t_{prod} < 0$, production is not possible for the given slug size.

There are other restrictions on a plunger lift cycle. If Pcmax (Eq. 6) is calculated to be higher than the well shut-in pressure, then production is not possible. If the well gas/liquid ratio is too low, then production is not possible. The minimum gas liquid ratio required must be at least equal to the sum of gas in the tubing at Pcmax plus gas slip during plunger rise divided by slug size. Once production is possible, the well GLR must exceed the gas produced during a cycle divided by the liquid produced for a cycle. In addition, the time to rise must be included in this buildup time, or alternatively the producing times must exceed the time to rise.

The remaining variable to be calculated is the time for the well to blow down from the Pcmin casing pressure to a low limit Pclow casing pressure. Since wells have a variety of surface hardware and line sizes, this is assumed to be in the same proportion as the time required for the casing pressure to change from Pcmax to Pcmin as the plunger rises. This assumption fits field collected data fairly well.

An example output is as shown in Table 2. On the left is a series of slug sizes. The well is shown to be unable to produce continuously below a slug size of 35 bbls because the well GLR is too low. The well cannot continuously produce a slug size of greater than 3.10 bbls because the required buildup pressure exceeds the input well reservoir shut-in pressure.

Figure 14 presents the predicted maximum and minimum slug sizes vs. velocity for a series of runs for a single plunger using the same production and input parameters. The result is a window within which the well may be operated. The lower limit of slug sizes is gas-liquid ratio dependent. The maximum slug size is influenced by available shut-in casing pressure. Low velocity slug sizes are influenced by gas slippage and high velocity slug sizes by increasing system friction losses.

Using this method, the well may be operated within the window to best meet specific requirements of cycle frequency, gas conservation, and flow rates. Again this type of analysis is dependent on assuming constant well gas production over the range of pressures needed for a complete cycle. If the well in question does not fit the assumption of a "tight" gas well, then the cycle times calculated would be in error. However, the shut-in pressure required for the produced slug sizes are still calculated using realistic assumptions. More detailed dynamic methods [6,9] can be used when well conditions are assumed to differ considerably from assumptions used here.

Conclusions

Laboratory test data has clearly demonstrated that some gas slippage is required for efficient plunger lift.

Total gas slippage generally decreases as plunger velocity increases, and liquid fallback increases as velocity increases.

The minimum operating velocity under laboratory conditions was about 250 ft/min. The optimum plunger rise velocity (considering slip and fallback) is plunger dependent although it is near 1000 fpm for most plungers tested.

A mathematical model, incorporating the slip and fallback characteristics determined in the laboratory tests, accurately matched the test conditions.

It was found that laboratory developed correlations required some adjustment before the program would provide results that matched limited field data.

The modified Foss and Gaul model may be used to predict performance of specific commercially available plungers

Nomenclature

A_a = cross-sectional area of annulus

A_e = effective annular area past the plunger

A_p = cross-sectional area of plunger, in.^{2}

A_t = cross-sectional area of tubing

C_D = Effective discharge coefficient for flow

across plunger

D = well depth, ft

d = tubing diameter, in.

f_g = a Darcy Weisbach friction factor for gas

flow through the tubing

f_l = a Darcy Weisbach friction factor for the

liquid slug

g_g = gas specific gravity

K = term for gas friction in tubing

K_1,K_2 = constants

L = the length of one barrel of liquid in the tubing

$\bar{P}$ = average of Pcmax and Pcmin

P_b = pressure under plunger, psi

P_{cmax} = casing pressure just before tubing is opened

And cycle begins, psia

P_{cmin} = casing pressure just as slug arrives at surface, psia

P_f = pressure over plunger, psi

P_{1f} = pressure to overcome liquid friction, psi/bbl

P_{1h} = pressure to lift liquid weight, psi/bbl

P_P = pressure to lift plunger weight, psi

P_t = tubing pressure, psig

q_g = gas production rate, MSCFD

q_{gp} = gas production rate at operation pressure

q1 = liquid slug size, bbl

R = Gas constant, 53.3 1bf-ft/(°R-1bm)

s1 = the specific gravity of fluid to be lifted

T = temperature, °F

t_{bu} = buildup time, minutes

t_{cycle} = time for one complete cycle, minutes

t_{rise} = plunger rise time, minutes

V = velocity in fps

Vc = volume of casing, ft^3

W_P = plunger weight, lbs

X_L = barrels of liquid in the slug

z = gas compressibility factor, dimensionless

ρ_g = gas density, lb/ft^3

ΔG_f = gas produced into well during the time period that the plunger rises, SCF

ΔGP = change in volume of gas in the casing and tubing as the pressure changes from P_{clwo} to P_{cmax}

ΔGs = gas slippage past the plunger (which was measured during laboratory tests in SCF)

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Appendix A

Correlation Parameter for Experimental Data For Gas Slippage Past a Plunger

If the data is examined from the tests performed in the test well, it will be seen that much of the data shows a near constant rate of gas slippage past the plunger, although some variations are seen. Figure 9 shows gas slippage as a function of velocity for Plunger No. 9.

The following shows how this may be explained.

Assume that near terminal velocity is reached (acceleration 0) and that friction is small over the short length of the plunger. This gives:

$(pb - pf)(AP) = WP$ ……….………………(A-1)

$\Delta p = (pb - pf) = WP/AP$ …………………..(A-2)

Note that this shows that the liquid slug size does not affect the amount of gas that comes upward across the plunger. Rather, it is only the change in pressure locally across the plunger that is present to cause gas flow. The slug size could influence the total gas passage by slowing down the plunger and liquid, which would then allow more total time for the gas to bypass the plunger, but the rate of gas passing the plunger should be unaffected directly by the slug size.

To quantify the gas slip past the plunger, assume that the gas is flowing according to the same parameters that cause gas to flow through an orifice. Then:

$\Delta p\ Z_g$ ……………………(A-3)

$q_g = C_D A_e \sqrt{\ } \rho_g$

With constant temperature, the above can be reduced to the following proportionality, by placing Q in terms of standard conditions and showing density ≈ pressure. Then:

$W_P\ P$

$q_g \approx K_1 \sqrt{\Delta_p}$ -- $\approx K_1 \sqrt{\ } A$

$\approx K_2 \sqrt{\ } W_P\ P$ ………………………………(A-4)

Define the total gas bypassing the plunger ofer one trip up the tubing as VOL, evaluated at standard conditions. Then:

$\Delta Gs = qg \times t \approx K2 \sqrt{Wt} \bullet P \times trise$…………(A-5)

Then for test well conditions:

ΔGs ⊠ K --- $\sqrt{Wt} \bullet P$ ………………………(A-6)

If K is set on one and ΔGs is identified as total slip, then the grouping

$$\frac{\Delta GsV}{D \sqrt{W_P}\ P}$$

Should be a correlating parameter for a plot of this grouping vs, for example, the average rise velocity. In other words, the experimental values inserted into this correlating group of parameters should give near constant values vs other changes in test results. Other effects also come into play, but it would be expected that this grouping, used as a correlating parameter, should organize the data without a lot of scatter. The composite for all plungers tested is shown in Figure 12. White the slip function does plot in fairly straight lines, the correlations for various plungers have slopes instead of constant values, perhaps due to a changing "orifice coefficient" across the plunger as a function of velocity.

Table 1
Plunger Description

Plunger Number	Type	Valve Arrangement	Weight lbs	Threshold Lift SCFM	Threshold Lift PSIG	Liquid Fall Velocity FPS
1,21	Capillary	None	5.125	46.8		1.22
2	Turbulent Seal	None	7.375	51.4	2.44	0.95
3	Brush	Integral Valve Rod	5.4375	34.1	1.92	1.86
4	Brush	Lubricator Actuated	6.75	22.6	2.20	3.07
5	Dual Turbulent Seal	Integral Valve Rod	10.0	32.1	3.28	1.45
6	Turbulent-Expanding	Integral Valve Rod	10.125	23.4	3.43	1.10
7	Dual Expanding Blade	Integral Valve Rod	10.75	22.7	3.50	1.21
8	Expanding Blade	None	5.375	32.1	2.09	0.656
9	Dual Expanding Blade	Integral Valve Rod	8.25	28.2	3.32	1.536
10	Sgl. Expanding Blade	Integral Valve Rod	6.1875	41.5	2.35	2.45
11	Wobble Washer	Integral Valve Rod	10.375	29.3	3.39	7.45
12	Dual Expanding Blade	Lubricator Actuated	10.25	21.9	3.25	3.94

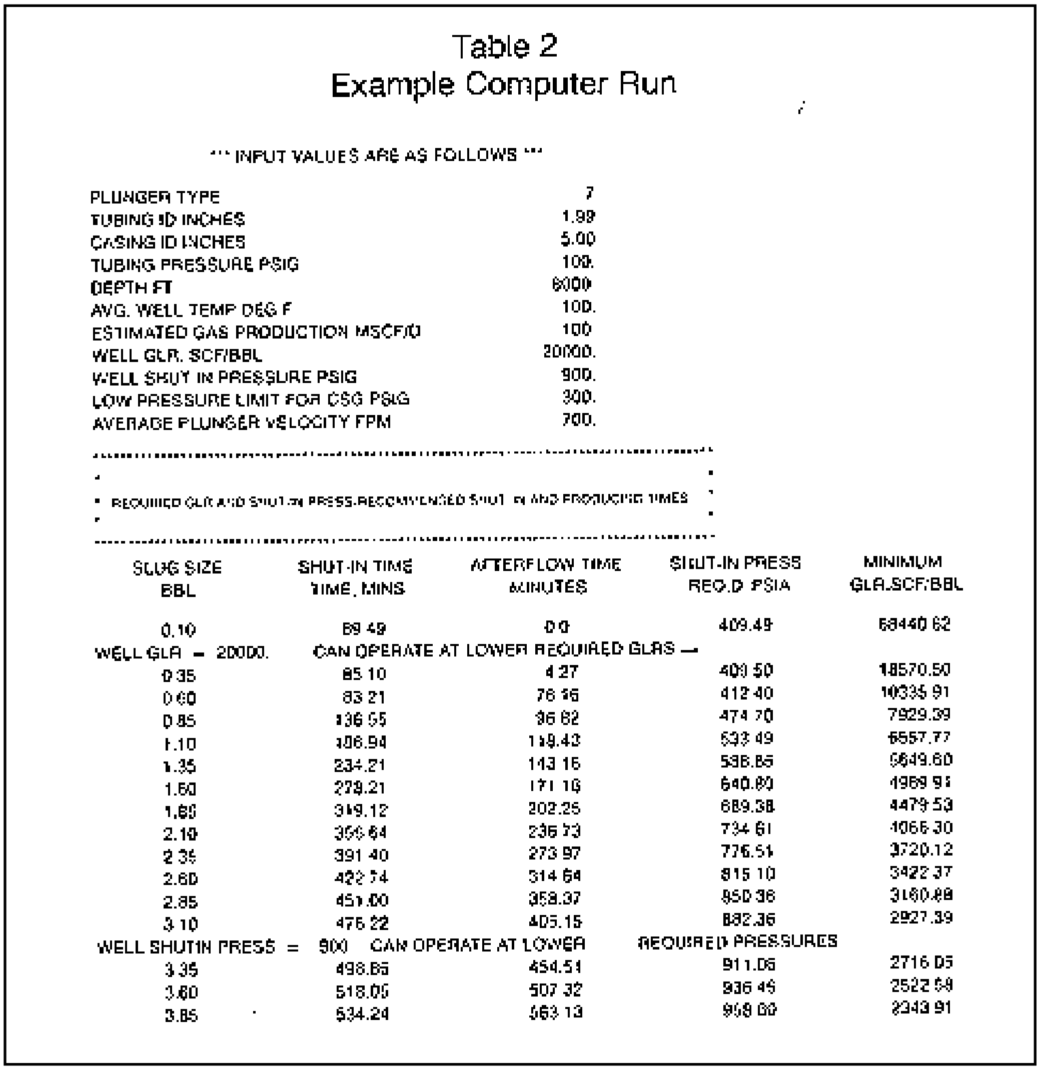

Table 2
Example Computer Run

```
        *** INPUT VALUES ARE AS FOLLOWS ***

PLUNGER TYPE                                   7
TUBING ID INCHES                            1.99
CASING ID INCHES                            5.00
TUBING PRESSURE PSIG                        100.
DEPTH FT                                    6000
AVG. WELL TEMP DEG F                        100.
ESTIMATED GAS PRODUCTION MSCF/D             100
WELL GLR. SCF/BBL                         20000.
WELL SHUT IN PRESSURE PSIG                  900.
LOW PRESSURE LIMIT FOR CSG PSIG             300.
AVERAGE PLUNGER VELOCITY FPM                700.

-----------------------------------------------------------------------
*                                                                     *
*  REQUIRED GLR AND SHUT-IN PRESS-RECOMMENDED SHUT IN AND PRODUCING TIMES *
*                                                                     *
-----------------------------------------------------------------------

   SLUG SIZE      SHUT-IN TIME     AFTERFLOW TIME    SHUT-IN PRESS     MINIMUM
      BBL          TIME, MINS         MINUTES         REQ.D PSIA     GLR.SCF/BBL

     0.10           69 49              0 0             409.49         68440 62
WELL GLR  =  20000.    CAN OPERATE AT LOWER REQUIRED GLRS --
     0.35           85 10              4 27            409 50         18570.50
     0.60           83 21             76 16            412 40         10335 91
     0.85          136 55             96 82            474 70          7929.39
     1.10          106.94            119.43            533 49          6557.77
     1.35          234.21            143 16            596.85          5649.60
     1.60          279.21            171 10            640.80          4969 91
     1.85          319.12            202.25            689.38          4479 53
     2.10          356 64            236 73            734 61          4066 30
     2.35          391 40            273 97            776.51          3720.12
     2.60          422 74            314 64            815 10          3422 37
     2.85          451.00            358.37            850 36          3160.88
     3.10          476 22            405.15            882.36          2927.39
WELL SHUTIN PRESS  =  900    CAN OPERATE AT LOWER     REQUIRED PRESSURES
     3.35          498.85            454.51            911.06          2716 05
     3.60          518.05            507 32            936 45          2522 59
     3.85          534.24            563 13            958 60          2343 91
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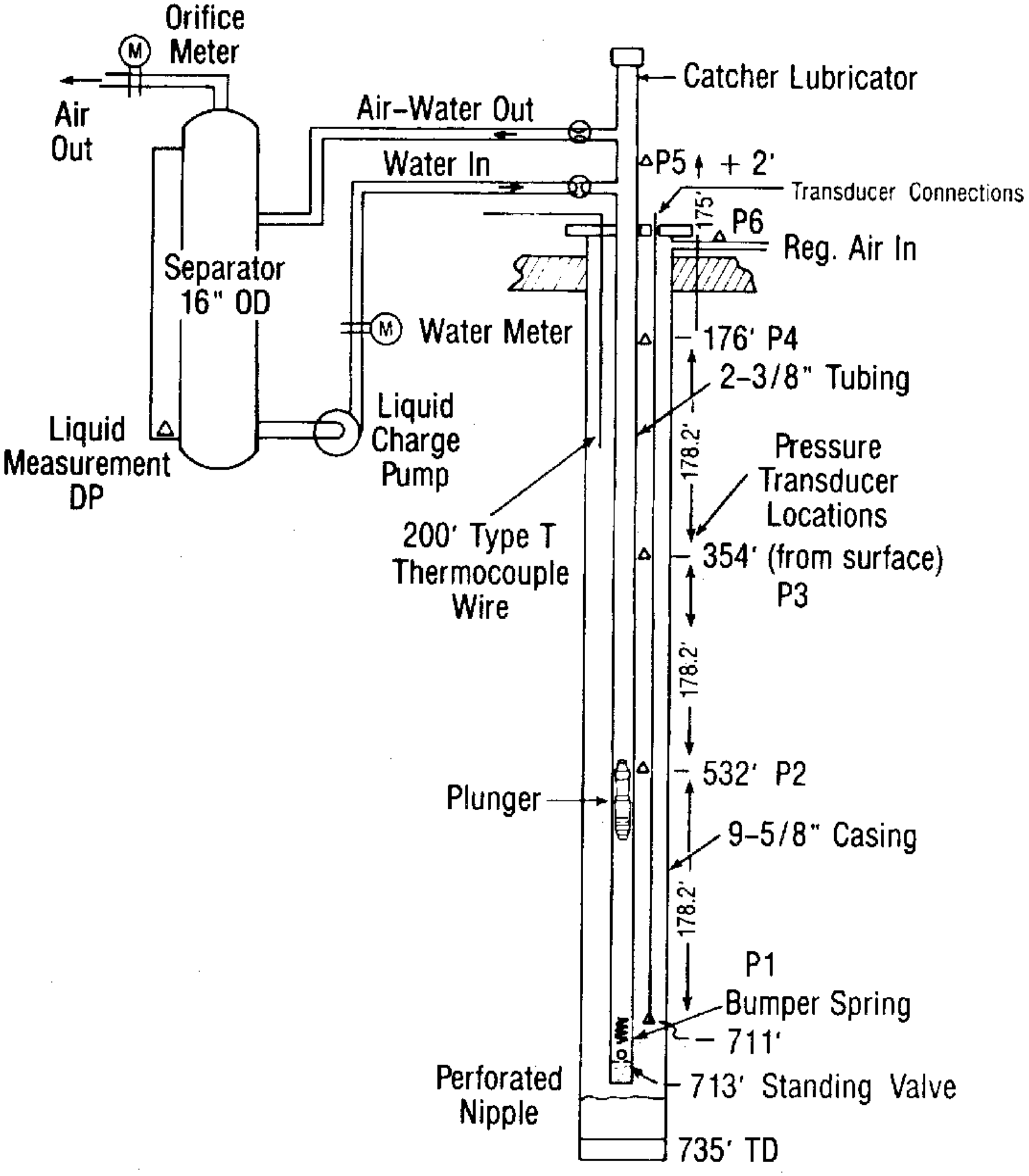

Fig. 1—Plunger lift laboratory test assembly.

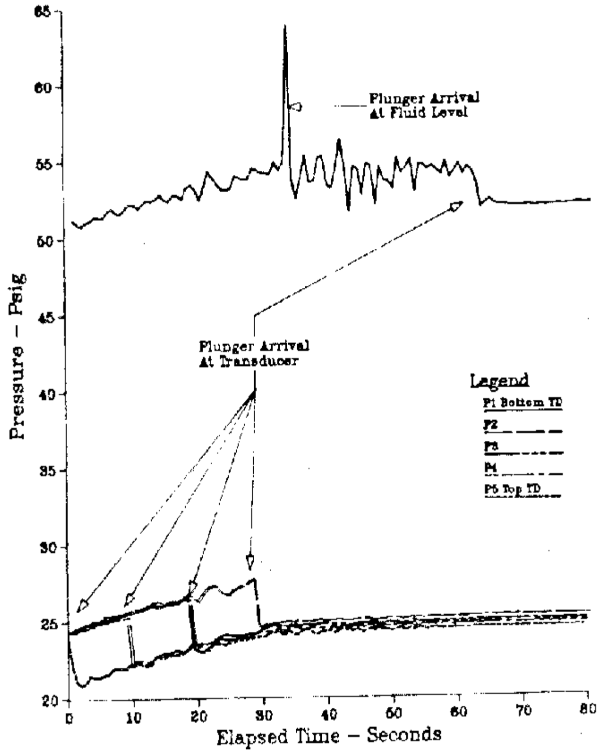

Fig. 2—Plunger fall test. Plunger 7—casing pressure 70 psig, slug 10 gal.

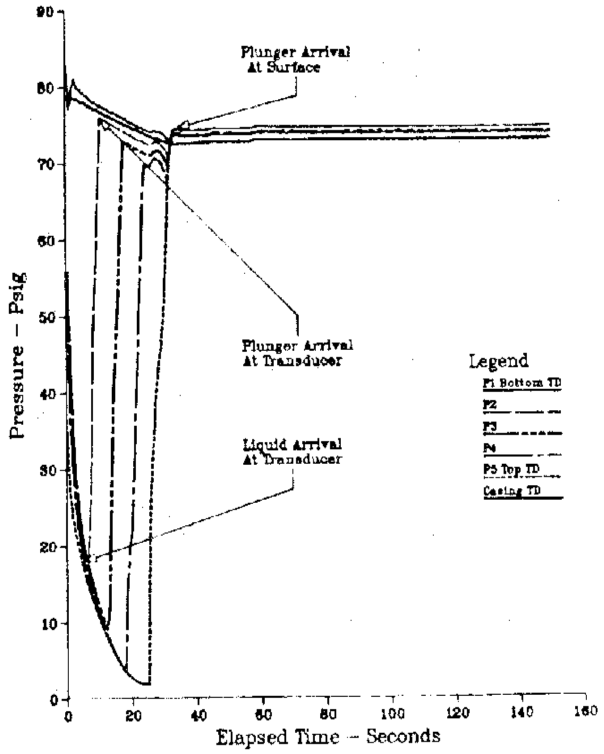

Fig. 3—Plunger rise test, Plunger 7—casing pressure 80 psig, slug 10 gal.

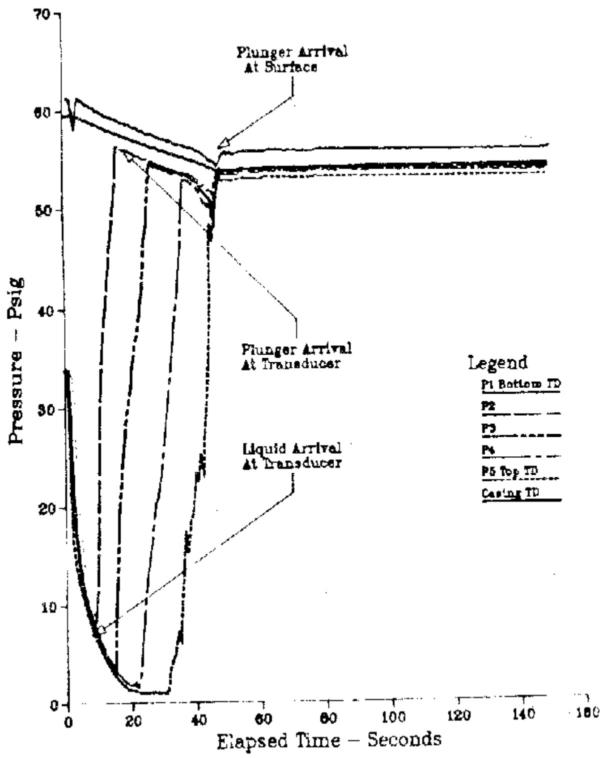

Fig. 4—Plunger rise test, Plunger 7—casing pressure 60 psig, slug 10 gal

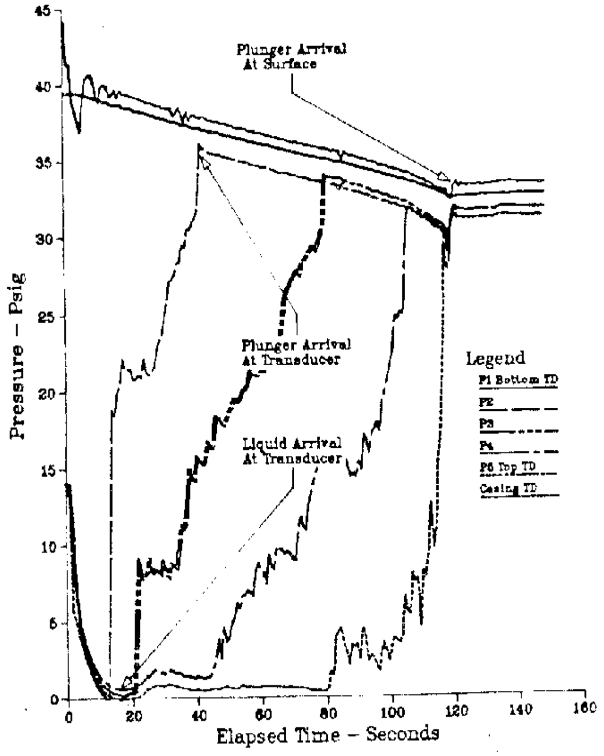

Fig. 5—Plunger rise test, Plunger 7—casing pressure 40 psig, slug 10 gal.

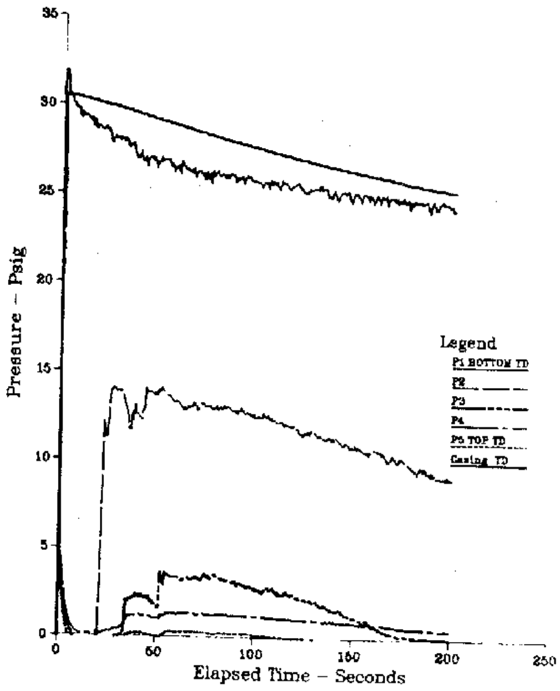

Fig. 6—Plunger rise test, Plunger 7—casing pressure 30 psig, slug 10 gal.

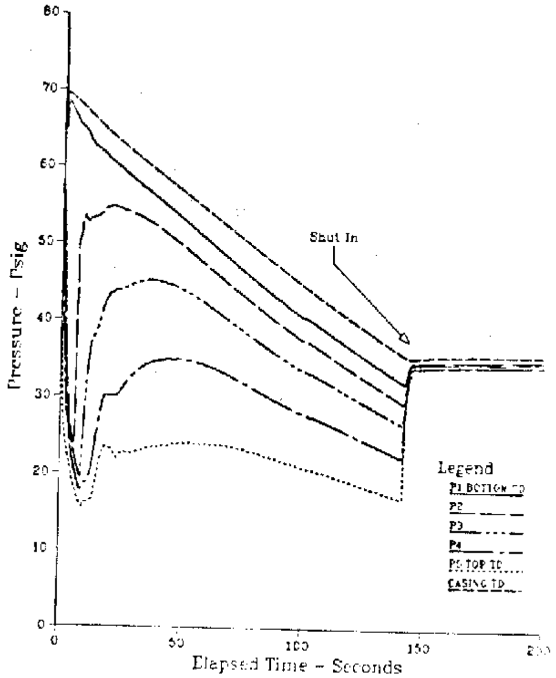

Fig. 7—Plunger test—no plunger—casing pressure 70 psig, slug 10 gal.

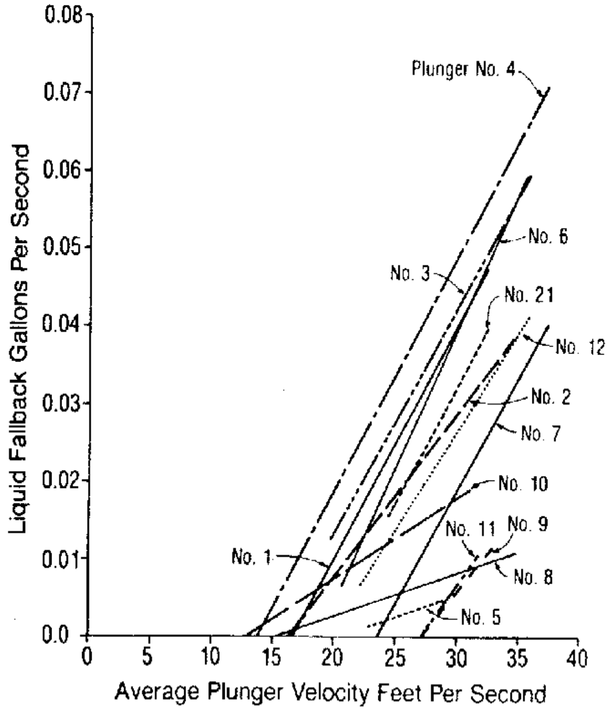

Fig. 8—Plunger test fallback correlation.

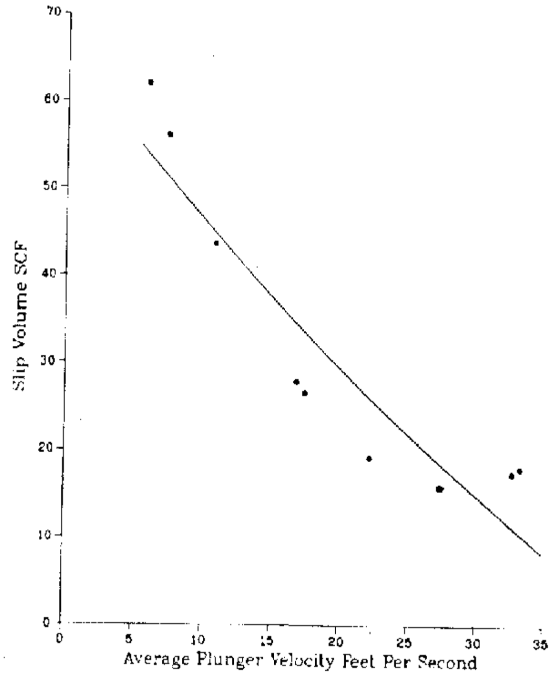

Fig. 9—Measured gas slip, Plunger 9.

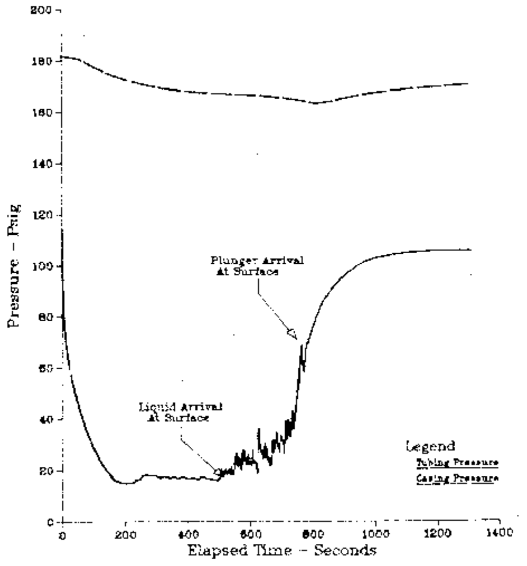

Fig. 10—Plunger field test normal rise.

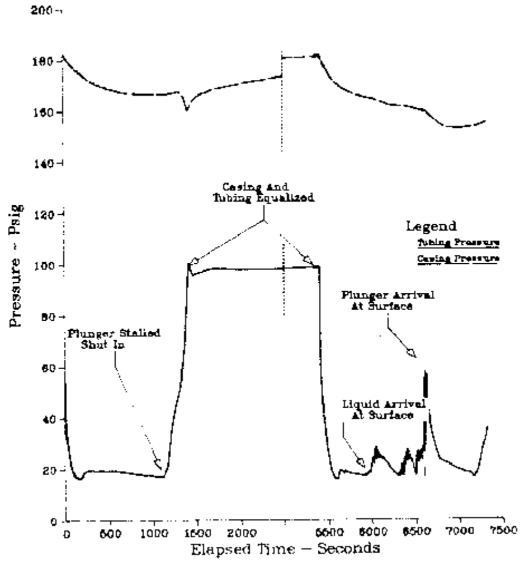

Fig. 11—Plunger field test stall-out.

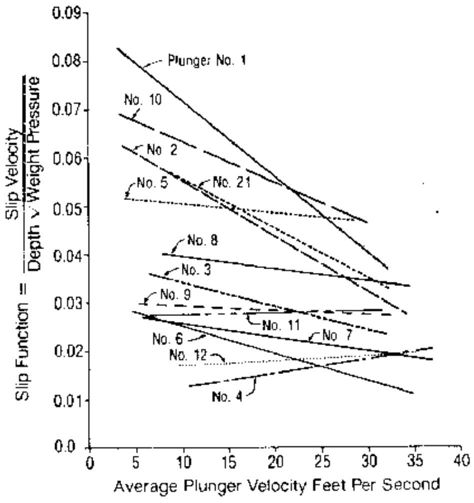

Fig. 12—Plunger evaluation slip correlation.

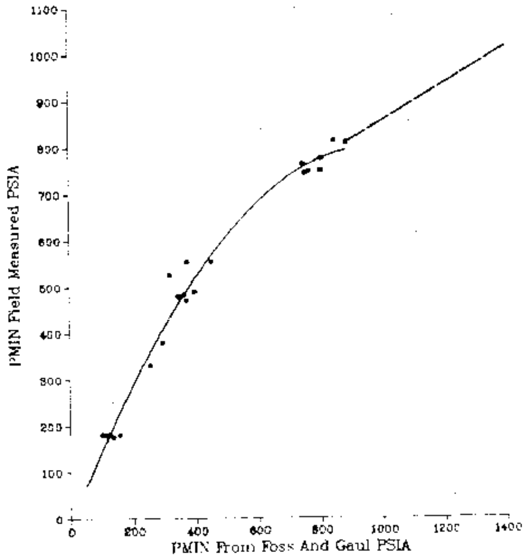

Fig. 13—P_{cmin} correction correlation.

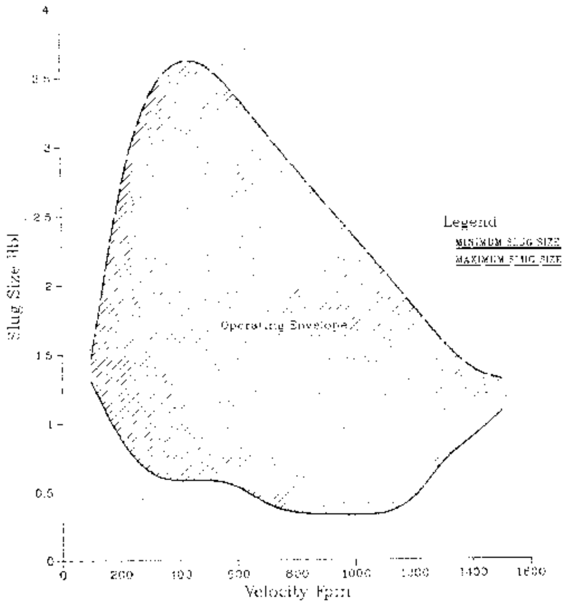

Fig. 14—Predicted performance, Plunger 7.