DEFINING THE CHARACTERISTICS AND PERFORMANCE OF GAS LIFT PLUNGERS

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SUMMARY

A laboratory investigation was conducted to provide data necessary to better predict the behavior of gas lift plungers. The laboratory phase of the study was necessary since no data was available on full size commercially available 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 data bank representing 132 individual runs 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. The laboratory data should provide a basis for improved plunger selection and design.

As a second part of the evaluation program, actual field data was collected and the correlations developed for the laboratory tests were finally adjusted to fit field data. The field data was collected from four field locations with a variety of operating conditions. 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.

INTRODUCTION

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 for 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., which would provide an adequate data base to predict and validate performance of actual plungers.

The initial phase of the project was a laboratory investigation which was intended to improve our understanding and efficiency of utilization of this artificial lift method. A 735-ft laboratory test well was instrumented to provide carefully controlled conditions of pressure, temperature and volumes needed to provide a valid data base on 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 slip and fallback. The program contains equations similar to a previous model developed by Foss & Gaul[2] of Shell Oil Company. In addition to using correlations developed in this test program, the equations include accounting for the gas produced during the plunger cycle.

CONCLUSIONS

Laboratory test data have clearly demonstrated that some gas slippage from under the plunger into the liquid slug above the plunger occurs with liquid removal. 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 field data.

Comparison of the plunger model to field data is presently limited to only a few tests. Additional field data will be collected to verify (or indicate the need for further adjustment of) the model and correlations developed. The field data measured to date indicates less pressure necessary to operate with plunger lift than would have been predicted by a model based solely on the laboratory test results.

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 DP-15 pressure transducer, were spaced at approximately 179 ft intervals from a 715 ft depth to 179 ft. The mandrels were connected by hydraulic hose to provide a conduit for the transducer signal wiring. In addition, transducers were installed to measure surface casing and tubing pressure. The downhole temperature was measured with a copper-constantan thermocouple. Static and differential pressure transducers mounted on flange taps provided gas measurement during the production cycle.

The liquid slug volume, during downhole placement, was determined by a Rockwell 5/8 in. S-04 water meter, and also by a change in differential pressure indicated by a Validyne DP-15 Transducer located at the bottom of the separator. The transducer provided a dynamic indication of produced liquid volumes during the production cycle.

Raw data were processed via a statistical analysis program to provide graphical output of pressure response during fall and rise cycles.

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 thirteen 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 I lists the types of plungers tested, together with a brief description and identifier number.

TABLE I
Plunger Description

Plunger Number	Type	Valve Arrangement	Weight lbs	Threshold SCFM	Lift PSIG
1,21	Capillary	None	5.125	48.8	
2	Turbulent Seal	None	7.375	51.4	2.44
3	Brush	Integral Valve Rod	5.4375	34.1	1.82
4	Brush	Lubricator Actuated	6.75	22.6	2.20
5	Dual Turbulent Seal	Integral Valve Rod	10.0	32.1	3.28
6	Turbulent-Expanding	Integral Valve Rod	10.125	23.4	3.43
7	Dual Expanding Blade	Integral Valve Rod	10.75	22.7	3.50
8	Expanding Blade	None	5.375	32.1	2.09
9	Dual Expanding Blade	Integral Valve Rod	8.25	28.2	3.32
10	Sgl. Expanding Blade	Integral Valve Rod	6.1875	41.5	2.35
11	Wobble Washer	Integral Valve Rod	10.375	29.3	3.39
12	Dual Expanding Blade	Lubricator Actuated	10.25	21.9	3.25

TEST PROGRAM AND PROCEDURES

The threshold lift characteristics (see Table I) of each plunger were measured at the surface using a 1.990 in. 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 I. 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 Plungers 8, 9 and 10, for which no explanation is apparent other than possibly friction loss past the plungers.

Plunger performance was evaluated with slug sizes of 5 and 10 gallons 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 collection 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 level. It is interesting to note that the change in pressure during plunger passage is nearly equal to the expected threshold lift pressure for plungers 8, 9, and 10. 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. Fall velocities in air collected in the lab as a function of pressure were not sufficient to extrapolate to high pressure field conditions. The fall velocities in water for plungers 1-12 are: 1.22, .95, 1.86, 3.07, 1.43, 1.1, 1.21, .656, 1.536, 2.45, 7.45 and 3.94 fps.

Typical rise cycle pressure response is shown in Figures 3-6, representing a series of plunger runs with slug size of approximately 10 gallons of water and with initial casing pressure sequentially decreased from 80 psig to 30 psig 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 present time-and-pressure related events during plunger rise. Beginning from the left hand side of the chart, it may be observed that these 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 feet or approximately 179 feet 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 several bends and fittings before reaching 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 increased 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. At stall-out, the plunger ceases to move upward, and liquid removal is effected by gas lift with the plunger acting essentially as a downhole restriction. 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 7 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 all velocities.

Figure 8 depicts the pressure history with no plunger in the well. Even though the initial casing pressure was 70 psig, the pressure behavior looks more like Figure 6, where stall-out occurred with a plunger at 30 psig casing pressure.

Total gas slippage from below to above the plunger for each run was also measured. A typical plot of gas slip in scf versus plunger average velocity is shown in Figure 9. The physics gas slip are analyzed in more detail in following discussion.

A summary of data from 132 valid tests processed is shown in Appendix A. These data provide the basis for characterizing gas slip and liquid fallback.

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 tied in to a Hewlett Packard 9826 computer. In those fields having automation systems, existing 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 made by tank gauging or by sight glass measurement where temporary tanks permitted. Pressure measurement sampling frequency was at 0.1 second intervals during critical periods and at longer intervals during non critical periods. Operating conditions such as cycle time and back pressure were adjusted where possible to produce as many types of operating conditions as possible. Figure 10 shows an overall view of a typical instrumental well site.

The initial test was conducted near Pampa, Texas. The well is approximately 10,000 ft deep, cased with 7 in. and dually completed with two strings of 2-3/8 in. tubing. Normal average daily production prior to the test was reported as 800 MCFD, 39.6 Bbl condensate, and 5.8 Bbl water.

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

The third well tested was also in the Carthage field lifting small slugs on a frequency of about 10 cycles per day, produced 3-4 barrels per day. Normal operation was to continue afterflow following plunger arrival and shut in on low tubing pressure of about 250 psi.

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 ft casing and 2 in. tubing to 5039 ft. 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 11 shows a normal but slow lift cycle while Figure 12 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 1-8).

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. This method is outlined in detail in the following discussion.

Modification of Foss & Gaul[2] Theoretical Model to Fit Data Collected

Foss and Gaul[2] have presented a method for analyzing and designing pressure requirements for plunger lift.

The following formula for maximum and minimum casing pressure during a plunger cycle summarizes much of their theoretical work.

$$P_{max} = P_{min}\ CPR \qquad (1)$$

where: $CPR = \frac{Aa + At}{Aa}$

Aa = cross-sectional area of annulus
At = cross-sectional area of tubing
P_{max} = casing pressure just before tubing is opened, psia and cycle begins
P_{min} = casing pressure just as slug arrives at surface, psia

$$P_{min} = \langle PP + 14.7 + P_t + (P_{LH} + P_{LF})XL\rangle * \langle 1 + \frac{Depth}{K}\rangle \qquad (2)$$

where: PP = pressure to lift plunger weight, psi

P_t = tubing pressure, psig

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

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

XL = barrels of liquid in the slug

Depth = well depth, feet

K = term for gas friction in tubing

The particular expressions for the components of P_{min} are:

$$P_{LH} = SPG * G_w * L \qquad (3)$$

where: SPG = the specific gravity of fluid to be lifted

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

G_w = .433 psi/ft (fresh water gradient)

$$P_{LF} = \frac{SPG \times .433 \times f_{\ell} \times L \times V^2}{D/12 \times 2.0 \times 32.2} \quad (4)$$

where: f_{ℓ} = a Darcy Weisbach friction factor for the liquid slug
V = velocity in fps
D = tubing diameter, in.

$$\frac{1}{K} = \frac{f_g \times V^2 \times G_g}{D/12 \times 2 \times 32.2 \times (T + 460) \times Z \times R} \quad (5)$$

where: f_g = a Darcy Weisbach friction factor for gas flow through the tubing

G_g = gas gravity

R = gas law constant, 53.3 lbf-ft/(^{o}R-1bm)

T = temperature, ^{o}F

Z = gas compressibility factor, dim'less

The P_{min} described in the above equations is the pressure in the casing as the slug and plunger just reach the surface. The P_{max} is the level the casing pressure must reach before the slug and plunger are allowed to begin to surface after a normally required well shut-in period. The P_{max} is a function of the velocity of rise which can be selected as a function of measured plunger characteristics. In the above form, no gas is assumed to produce into the well during the rise of the plunger and the liquid.

If gas production from the formation during plunger rise is accounted for, then the maximum (P_{max}) pressure requirement is reduced, but the minimum (P_{min}) requirement remains the same.

Also, if gas is lost from below the plunger to above it during rise (gas slippage), the requirement for P_{max} will increase, but the P_{min} requirement remains constant.

The following illustrates the functional dependence of P_{max} on slip and well production.

$$P_{max} = P_{min}\ CPR - \frac{(PRGAS-SLIP)(14.7)(T + 460)}{V_c\ 520} \quad (6)$$

where: V_c = volume of casing, ft^3

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

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

For laboratory test conditions, PRGAS was zero. The slip was measured, and can be calculated from the correlation developed in Appendix B and plotted in Figure 13. Note that the slip is used to increase the required P_{max} because casing shut-in pressure must be larger than normal so that, as expansion and slip occur, the P_{min} requirement is met at the surface.

Another effect which tends to reduce pressure requirements is liquid fallback. As shown in Figure 7, liquid fallback increases as the velocity increases but at different rates for different plungers. Since the P_{min} is calculated as a function of the slug size at the surface, the P_{min} based on a starting bottom-hole slug size is reduced by the amount of liquid fallback as the plunger rises. A P_{min} based on surface measured production is unaffected. However, operation at high velocities is to be avoided to prevent large liquid losses from above the plunger.

Adjustment of Laboratory Correlations to Match Field Data

The method of Foss & Gaul[2] is to consider a force balance on the liquid slug and plunger as it surfaces. The expressions for the casing pressure requirements are outlined in Eqs. (1) through (6).

When comparing field data to the model developed from Foss and Gaul and laboratory correlations, a plot of actual casing minimum pressure, P_{cmin} versus P_{cmin} from calculations was made. From Figure 14, it can be seen that the adjusted Foss & Gaul underpredicts for low slugs (low pressures) and overpredicts for large slugs (large pressures). Therefore, the following purely empirical adjustment was made to the Foss & Gaul model to fit the field data more closely.

$$P_{c,min} = -9.9242 + 1.67722 * P_{minlab} - 0.0008643 * P^2_{minlab}$$

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 $P_{c,min}$. 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.

Model for Plunger Lift Cycles

A typical cycle for a plunger lifted well is to shut the well in and allow the casing pressure 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, then 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 changed. 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 P_{max} casing pressure (Eq. (6)). If the well is allowed to blow down to a pressure P_{low} with the plunger at the surface, the buildup time required t_{bu} can be found from:

$$t_{bu} \text{ (minutes)} = \text{mass/mrate} \qquad (7)$$

where: mass = change in mass of gas in the casing plus tubing as the pressure changes from P_{low} to P_{max} lbm

mrate = (rate,MCFD)($\rho_{g\ s.c.}$)1000/(24)(60), lbm/min

rate = input approximate rate of gas production from well, MCFD

$\rho_{gs.c.}$ = density of gas at standard conditions, lbm/ft^3

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 complete cycle, t_{cycle}.

$$t_{cycle} = \left(\frac{\text{slug size, bbls}}{\text{rate, MCFD}}\right) \left(\text{GLR}, \frac{\text{SCF}}{\text{bbl}}\right) \frac{(24)(60)}{(1000)} \text{, minutes} \tag{8}$$

The difference between the cycle time, t_{cycle}, and the buildup time, t_{bu}, is the production time, t_{prod}, while the tubing is open to flow.

$$t_{prod} = t_{cycle} - t_{bu} \quad \text{for } t_{cycle} \geq t_{bu}$$

$$\tag{9}$$

$$t_{prod} = 0 \qquad \text{for } t_{bu} > t_{cycle}$$

Note that if $t_{bu} > t_{cycle}$, then the required buildup time is greater than the total cycle time, t_{cycle}, and t_{prod} is zero. For $t_{bu} > t_{cycle}$, production is not possible, for the given slug size, for continuing similar cycles.

There are other restrictions on a plunger lift cycle. If the P_{max} (Eq. (6)) is calculated to be higher than the well shut-in pressure, then production is not possible.

Also 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 gas in the tubing at P_{cmax} before production is possible. 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 P_{min} casing pressure to a low limit P_{low} 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 P_{max} to P_{min} as the plunger rises. This assumption fits field collected data fairly well.

An example output is as shown in Figure 15. On the left is a series of slug sizes. The well is shown to be unable to produce continuously below a slug size of 0.85 bbls because the well GLR is too low. These results are, of course, for the particular well input data shown at the top of Figure 15. Also note that the well cannot continuously produce a slug size of greater than

2.85 bbls because the buildup pressure required then exceeds the well input shut-in pressure. This example was generated with a rise velocity in the program of 1000 fpm but other values could be input which might better suit the slip and liquid fallback characteristics of each plunger tested in the lab and field tests. For analysis purposes, a program allowing the input of actual velocity could be used to compare program predicted operation to actual operation.

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 wells should still be calculated using realistic assumptions.

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APPENDIX A

Table 1 summarizes the test results and the comparisons to the Foss and Gaul[2] model corrected for gas bypass and liquid fallback. The columns "CALSLP" and "ACTSLP" just compare actual data to data from correlations or curve fits developed. The "VEL, FPM" column is the actual measured average velocity of rise. The "ACTUAL CSG P" column is the actual casing pressure measured and the "P_{max}" is the pressure calculated from the corrected Foss and Gaul equations.

The error column is the percent error between the measured casing pressure and the calculated P_{max}. The column "FALBK" is measured liquid fallback in gallons.

At the end of the table are summaries of average errors for the whole series of tests. Note that the average absolute error for the minimum pressure compared to data is 5.92% (minimum pressures not tabulated) and the average absolute error for the P_{max} compared to data is 7.03%. Summing errors with the plus or minus considered give 2.7% error, and the standard deviation of the absolute errors for P_{max} is 8.8%.

The average error of 7% for P_{max} compared to the data is probably close to the accuracy of some of the data collected, such as liquid fallback with small slug sizes.

Table 1
Tabulated Results from Laboratory Tests

PLUNGER NUMBER	CALSLP SCF	ACTSLP SCF	VEL FPM	ACTUAL CSG P	PMAX F + G	ERROR	FALBK
1	160.172	170.760	303.620	29.440	29.351	0.303	0.0
1	53.460	46.580	859.260	39.450	33.639	14.730	0.0
1	36.309	32.150	1197.540	49.560	42.749	13.743	0.210
1	26.684	25.850	1504.090	59.320	48.849	17.652	0.630
1	18.583	20.330	1860.970	69.280	62.741	9.438	0.920
1	17.127	19.200	1976.610	79.680	64.019	19.655	1.250
2	132.307	135.970	336.600	29.240	29.178	0.212	0.0
2	50.242	45.910	847.670	39.160	34.694	11.403	0.0
2	36.787	34.550	1130.050	49.120	41.359	15.800	0.070
2	21.315	20.480	1643.710	58.880	51.775	12.067	0.760
2	17.685	16.790	1862.990	68.940	64.129	6.978	0.690
2	14.523	18.540	2082.030	79.390	74.135	6.619	0.740
3	51.933	57.960	416.370	24.800	23.644	4.661	0.0
3	38.733	41.970	577.370	29.880	27.745	7.145	0.0
3	17.907	15.210	1205.100	39.690	38.786	2.277	0.680
3	10.799	10.040	1834.470	49.310	46.534	5.629	0.940
3	10.525	9.430	1953.390	59.220	59.988	-1.296	1.210
3	11.267	13.620	1946.750	69.180	64.807	6.321	1.070
4	12.955	15.600	659.540	24.410	25.558	-4.703	0.0
4	10.677	10.500	939.470	29.290	30.670	-4.713	0.220
4	9.227	7.590	1394.970	39.550	41.440	-4.778	0.640
4	8.980	6.670	1705.170	49.750	52.242	-5.009	0.900
4	9.101	7.430	1893.800	59.270	60.064	-1.340	1.230
4	9.534	12.140	1964.560	69.670	67.030	3.789	1.270
4	9.372	10.300	2265.070	78.900	76.276	3.326	1.380
5	98.217	91.400	452.020	30.020	27.493	8.418	0.0
5	59.780	55.430	809.330	39.350	33.193	15.646	0.0
5	49.039	46.880	1061.380	49.410	41.528	15.952	0.0
5	38.171	37.470	1434.580	59.370	49.169	17.181	0.0
5	34.798	37.060	1651.080	69.090	63.167	8.572	0.060
5	34.550	34.290	1750.350	79.190	73.072	7.726	0.140
6	79.320	91.220	291.640	24.600	24.698	-0.400	0.0
6	33.042	32.560	664.130	29.590	27.239	7.944	0.0
6	14.701	9.330	1275.500	39.740	41.352	-4.055	0.350
6	11.338	8.970	1548.850	49.410	49.754	-0.695	0.740
6	10.883	9.220	1641.620	59.420	56.249	5.336	0.850
6	7.598	8.250	1982.700	69.670	65.976	5.303	1.030
6	6.458	9.840	2147.100	79.340	77.485	2.338	1.230
7	37.018	37.880	629.110	29.150	27.000	7.374	0.0
7	23.528	18.540	1023.640	39.300	34.634	11.873	0.0
7	17.423	11.530	1398.000	49.750	49.391	0.721	0.0
7	16.710	18.480	1516.040	58.930	59.878	-1.609	0.010

Table 1 (cont'd)
Tabulated Results from Laboratory Tests

PLUNGER NUMBER	CALSLP SCF	ACTSLP SCF	VEL FPM	ACTUAL CSG P	PMAX F + G	ERROR	FALBK
7	13.890	15.770	1814.440	68.990	66.506	3.600	0.420
7	10.449	10.900	2259.110	77.390	61.731	20.233	0.780
8	48.043	49.670	502.780	24.360	23.542	3.357	0.0
8	32.034	31.640	784.680	29.540	27.183	7.979	0.020
8	21.901	19.050	1219.650	39.740	39.029	1.788	0.040
8	17.627	15.620	1581.650	49.560	52.009	-4.942	0.080
8	17.210	16.900	1714.250	59.520	60.245	-1.218	0.060
8	16.248	16.190	1893.800	69.530	71.318	-2.571	0.280
8	15.004	15.720	2110.170	79.290	80.508	-1.536	0.390
9	62.884	64.360	351.000	24.260	23.849	1.694	0.0
9	35.816	34.960	650.140	29.150	26.935	7.600	0.0
9	24.183	23.700	1046.510	39.010	37.194	4.655	0.0
9	20.408	20.070	1330.500	49.020	46.731	4.669	0.0
9	17.578	16.950	1637.960	59.470	57.176	3.857	0.0
9	15.037	15.520	1994.210	69.230	70.367	-1.642	0.200
9	16.206	15.510	1955.610	78.560	79.524	-1.227	0.270
10	106.235	104.140	420.890	29.000	28.114	3.055	0.0
10	45.431	43.300	986.980	39.790	32.219	19.028	0.030
10	40.217	38.030	1161.900	49.510	39.284	20.654	0.0
10	30.558	25.850	1504.090	59.320	52.088	12.192	0.620
10	25.851	27.030	1760.510	69.380	59.688	13.969	0.320
10	24.574	27.180	1886.870	79.490	74.149	6.719	0.410
11	47.608	47.420	489.500	24.650	24.728	-0.315	0.0
11	37.672	34.450	663.110	29.630	27.219	8.136	0.0
11	29.156	26.310	956.030	39.300	34.797	11.459	0.0
11	23.323	23.400	1317.230	49.560	43.856	11.508	0.0
11	21.939	22.580	1514.700	59.660	54.281	9.016	0.0
11	21.223	21.710	1667.110	68.890	63.405	7.962	0.010
11	19.539	17.720	1933.600	79.240	73.383	7.391	0.230
12	25.036	28.870	594.900	29.390	29.480	-0.306	0.0
12	13.864	8.760	1288.260	39.350	41.200	-4.701	0.0
12	14.536	10.860	1346.490	49.460	49.464	-0.008	0.130
12	12.774	10.200	1707.990	59.420	65.600	-10.401	0.0
12	11.942	10.040	2008.980	69.820	67.543	3.261	0.720
12	11.828	14.440	2175.190	79.590	84.047	-5.600	0.790
21	74.569	73.440	529.110	29.540	26.970	8.700	0.0
21	38.293	32.760	969.890	39.640	34.086	14.012	0.0
21	21.288	18.440	1479.060	49.650	47.662	4.004	0.450
21	17.424	16.640	1700.670	59.760	57.589	3.633	0.760
21	14.397	15.060	1903.600	69.670	66.615	4.385	0.870
21	14.251	17.720	1953.390	79.240	73.676	7.022	0.810
1	242.496	261.330	224.930	39.550	43.010	-8.748	0.0

Table 1 (cont'd)
Tabulated Results from Laboratory Tests

PLUNGER NUMBER	CALSLP SCF	ACTSLP SCF	VEL FPM	ACTUAL CSG P	PMAX F + G	ERROR	FALBK
1	61.541	56.560	871.770	59.710	54.538	8.662	0.010
1	31.066	32.450	1519.620	89.350	86.820	2.832	0.410
2	205.347	230.270	243.900	39.500	43.947	-11.257	0.0
2	48.090	41.050	988.870	59.660	57.672	3.332	0.030
2	26.455	27.690	1606.310	89.250	89.058	0.215	0.510
3	45.808	51.390	542.310	39.500	36.692	7.109	0.0
3	21.100	19.770	1197.540	59.570	61.445	-3.148	0.320
3	14.516	16.950	1771.410	89.300	93.912	-5.164	0.740
4	14.132	16.540	730.510	39.350	41.673	-5.902	0.020
4	10.859	8.150	1381.510	59.520	70.762	-18.887	0.660
4	10.995	13.930	1827.310	89.400	100.212	-12.094	1.300
5	188.386	213.640	255.980	39.600	41.590	-5.024	0.0
5	66.748	64.380	849.770	59.660	53.093	11.008	0.0
5	47.177	49.700	1382.620	89.600	85.455	4.626	0.040
6	58.526	64.790	447.420	39.690	37.943	4.401	0.0
6	17.734	12.960	1250.430	59.570	63.038	-5.822	0.100
6	10.653	13.880	1797.360	89.450	99.607	-11.354	0.760
7	74.224	79.580	363.370	39.500	39.921	-1.067	0.0
7	42.406	43.560	659.040	48.870	47.157	3.505	0.0
7	30.603	32.400	937.940	59.570	57.896	2.811	0.0
7	24.997	26.980	1167.690	69.430	67.782	2.373	0.0
7	20.954	21.190	1398.380	78.710	77.343	1.737	0.110
7	19.411	19.610	1544.210	89.550	69.345	22.563	0.110
8	47.777	50.310	593.180	39.600	37.192	6.082	0.040
8	27.024	26.570	1161.900	59.570	58.872	1.171	0.0
8	21.329	26.420	1651.080	89.550	99.141	-10.710	0.020
8	21.329	26.420	1651.080	89.550	99.805	-11.451	0.100
9	59.292	60.140	440.050	39.500	38.764	1.864	0.0
9	29.545	29.640	1009.010	59.420	59.812	-0.660	0.0
9	20.633	22.880	1650.550	89.200	100.131	-12.255	0.0
10	226.831	241.940	222.210	39.500	43.523	-10.186	0.0
10	71.826	71.390	765.790	59.470	51.060	14.142	0.050
10	45.235	48.670	1279.620	89.640	80.177	10.557	0.180
11	64.101	67.970	425.510	39.450	39.262	0.478	0.0
11	33.009	33.220	992.680	59.710	60.104	-0.660	0.0
11	26.240	29.640	1497.100	89.250	94.630	-6.028	0.0
12	27.722	32.920	596.140	39.500	38.596	2.288	0.0
12	23.554	27.290	781.350	49.560	49.629	-0.140	0.0
12	17.264	15.770	1202.010	59.660	64.850	-8.699	0.0
12	15.670	15.110	1446.260	69.620	78.363	-12.559	0.280
12	14.754	14.600	1657.990	79.440	89.333	-12.453	0.610
12	14.376	16.690	1818.930	89.550	99.301	-10.889	0.590

Table 1 (cont'd)
Tabulated Results from Laboratory Tests

PLUNGER NUMBER	CALSLP SCF	ACTSLP SCF	VEL FPM	ACTUAL CSG P	PMAX F + G	ERROR	FALBK
12	14.306	16.390	1931.420	99.170	120.240	-21.247	0.700
12	14.534	16.590	1892.410	98.970	110.407	-11.556	0.700
21	46.940	41.260	937.940	59.470	55.593	6.520	0.0
21	27.492	29.590	1466.430	89.300	86.441	3.202	0.410

AVG PCT ERROR(FOSS)= 7.03

AVG PCT ERROR(MIN PRESS)= 5.92
AVG ERR WITH SIGN FOR FOSS 2.71
STANDARD DEVIATION = 8.853

APPENDIX B

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 $\cong$ 0) and that friction is small over the short length of the plunger. This gives:

$$(P_b - P_f)\ A = Wt$$

where: P_b = pressure under plunger, psi

P_f = pressure over plunger, psi

A = cross sectional area of plunger, sq. in.

W_t = plunger weight, lbs

or

$$\Delta P = (P_b - P_f) = Wt/A$$

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 past an orifice. Then:

$$Q = C_D \, A_e \sqrt{\frac{\Delta P \; Zg}{\rho}}$$

where: ρ = gas density

Q = volumetric flow rate of gas

A_e = the effective annular area past the plunger

C_D = effective discharge coefficient for flow across plunger

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

$$Q_{s.c.} \approx K_1 \sqrt{\Delta P \cdot P} \approx K_1 \sqrt{\frac{Wt \; P}{A}}$$

$$\approx K_2 \sqrt{Wt \; P}$$

where: K_1, K_2 = constants

Wt = plunger weight

P = pressure at which equation evaluated. The average of max and min casing pressure used in this report

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

$$VOL = Q_{s.c.} \times t \approx K_2 \sqrt{W_t \cdot P} \times t$$

where: t = time to make one trip, Depth/Vel where: Vel = average velocity

Then, for the test well conditions:

$$Vol \cong K \frac{Depth}{Vel} \sqrt{Wt \cdot P}$$

If K is set to one and VOL is identified as total slip, then the grouping

$$\frac{SLIP \cdot VEL}{Depth \cdot \sqrt{Wt \cdot P}}$$

should be a correlating parameter for a plot of this grouping vs, say velocity for the test results. 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 unknown effects could 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 13. While 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.

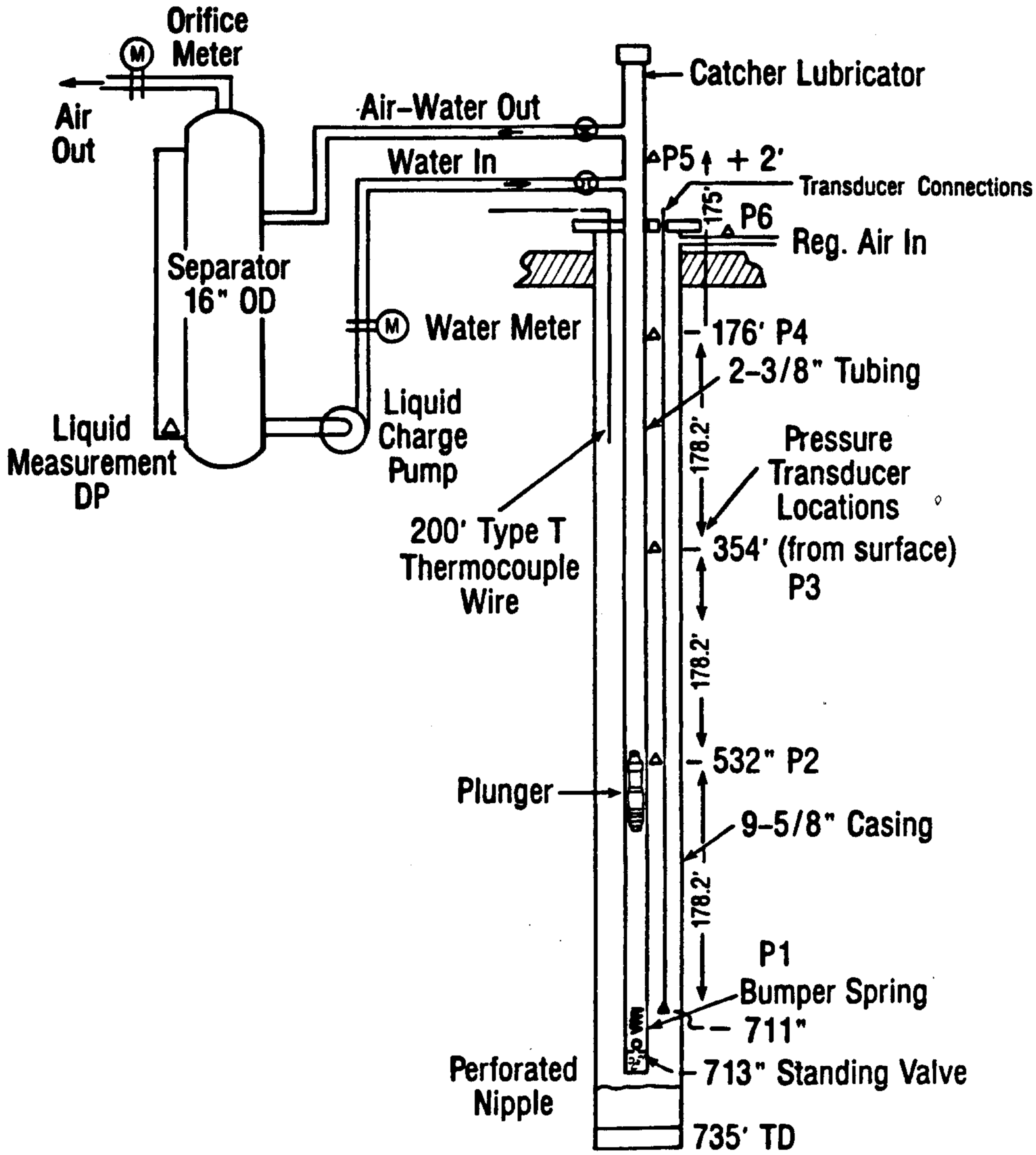

Figure 1 - Plunger lift laboratory test assembly

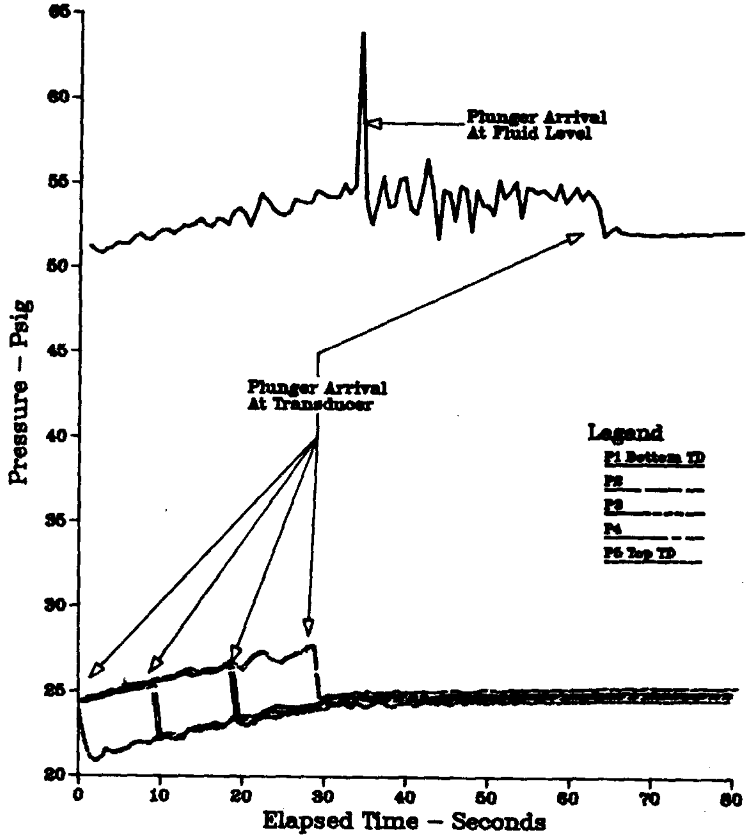

Figure 2 - Plunger fall test
plunger No. 7 casing pressure 70 psig
water load 10 gallons

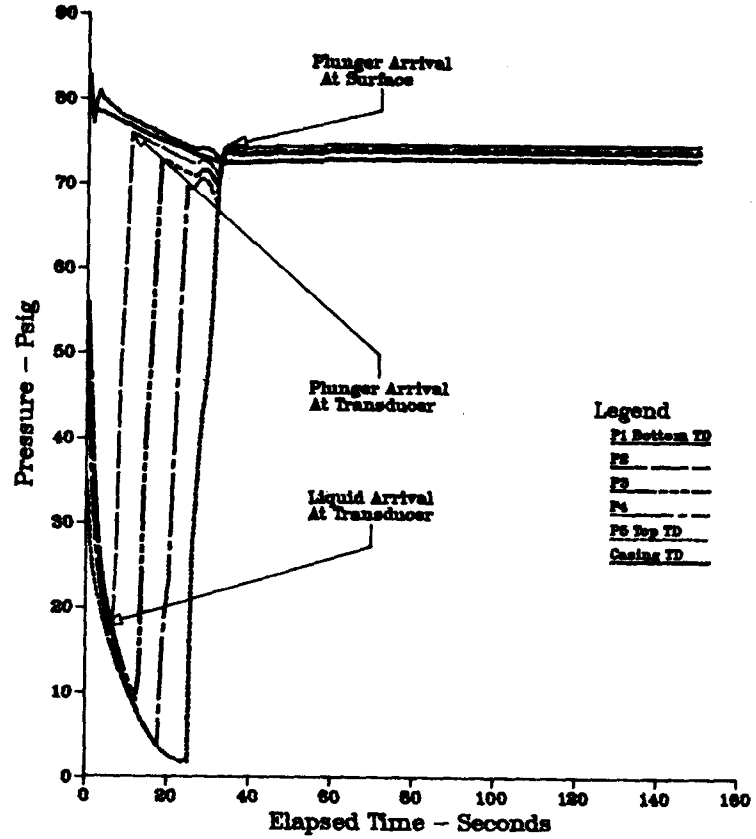

Figure 3 - Plunger rise test
plunger No. 7 casing pressure 80 psig
water load 10 gallons

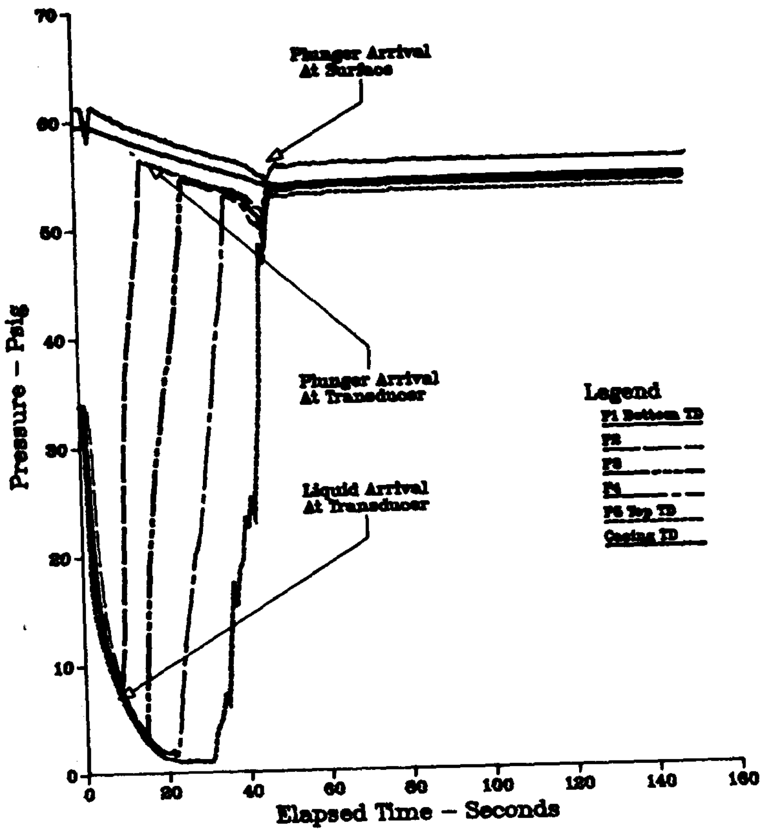

Figure 4 - Plunger rise test
plunger No. 7 casing pressure 60 psig
water load 10 gallons

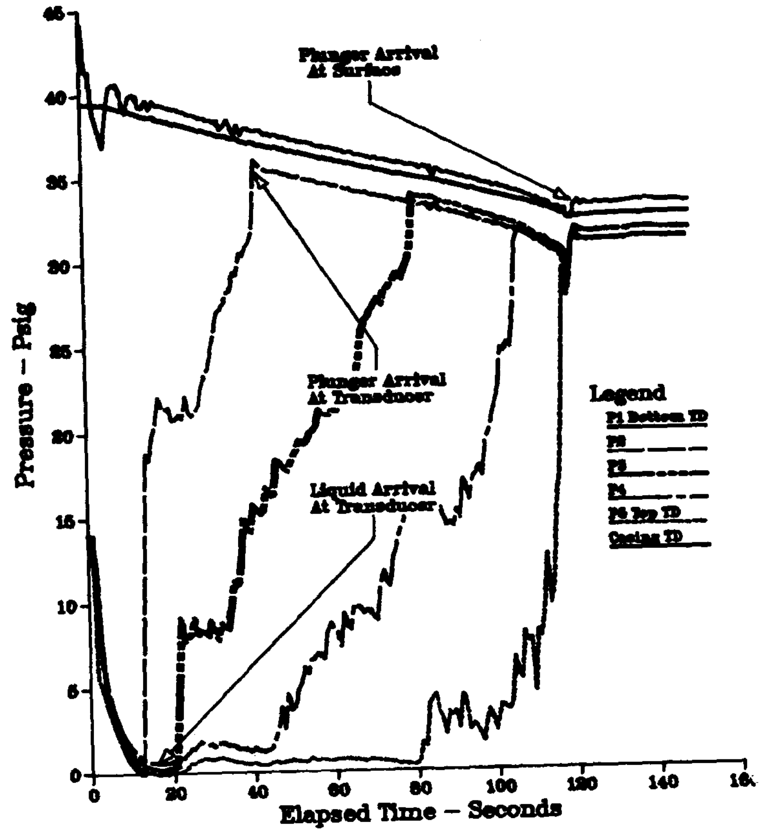

Figure 5 - Plunger rise test
plunger No. 7 casing pressure 40 psig
water load 10 gallons

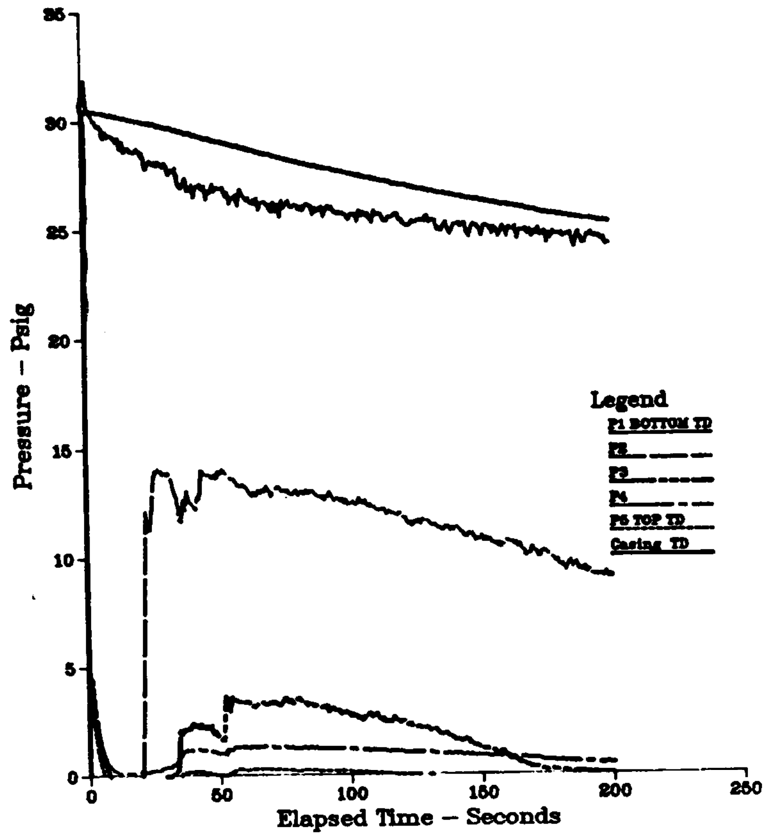

Figure 6 - Plunger rise test
plunger No. 7 casing pressure 30 psig

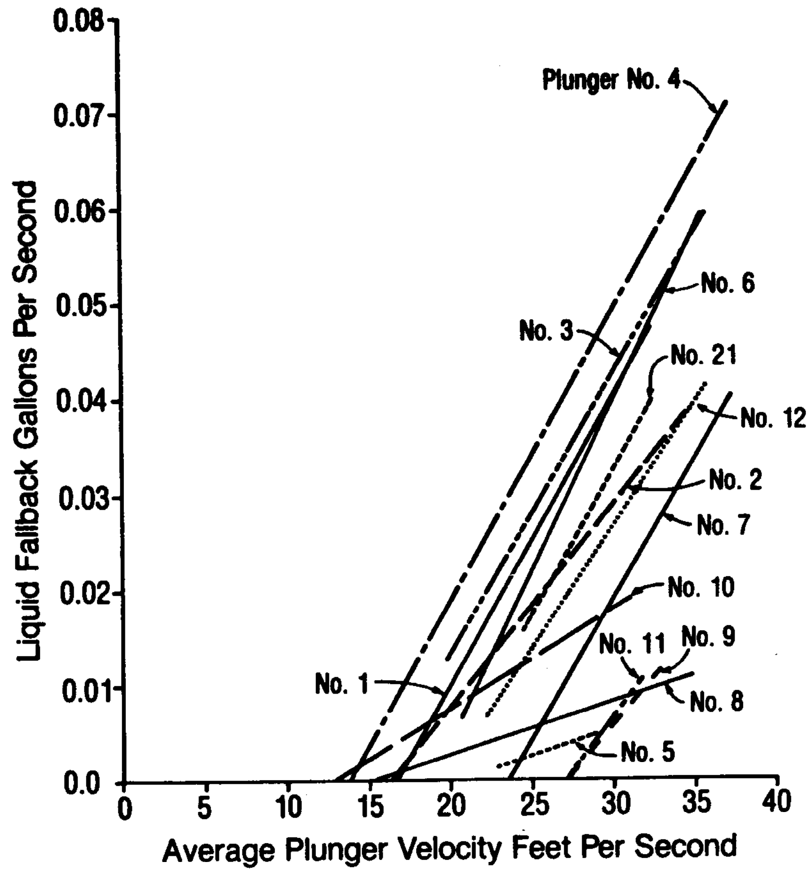

Figure 7 - Plunger evaluation
fallback correlation

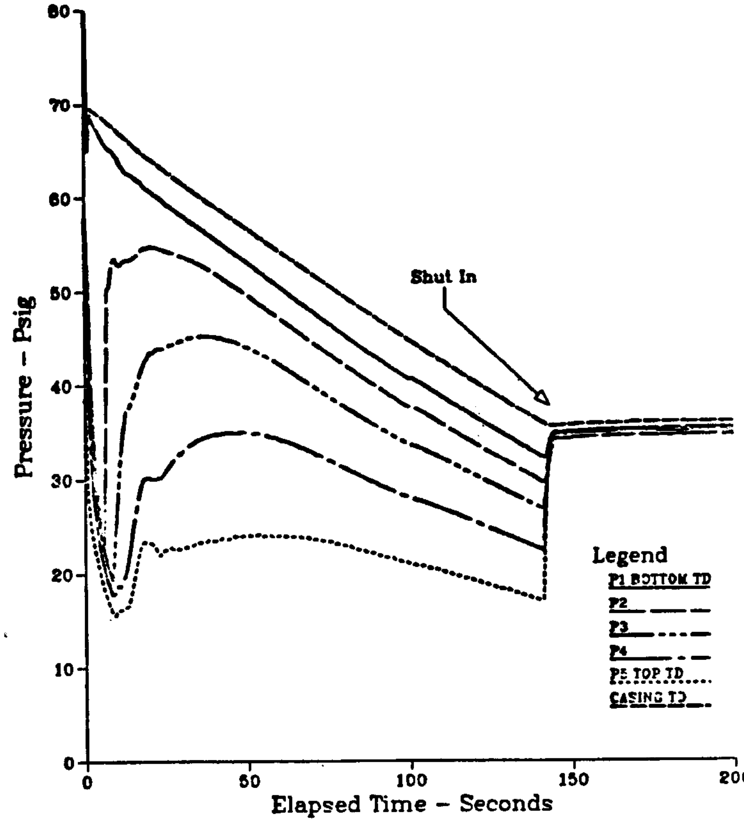

Figure 8 - Plunger test
no plunger - gas lift only 70 psig
water load 10 gallons

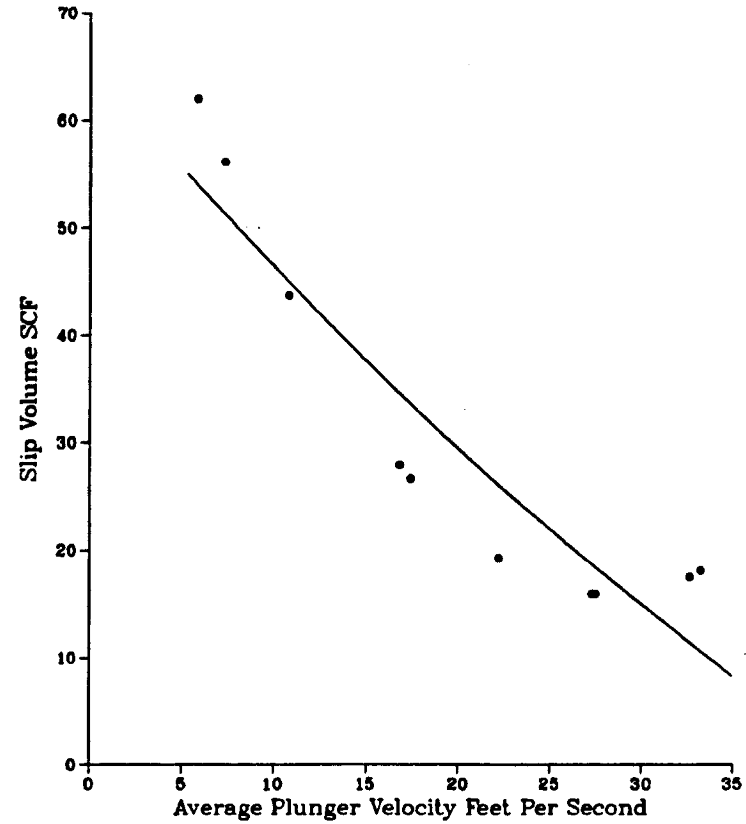

Figure 9 - Plunger slip evaluation
plunger No. 9

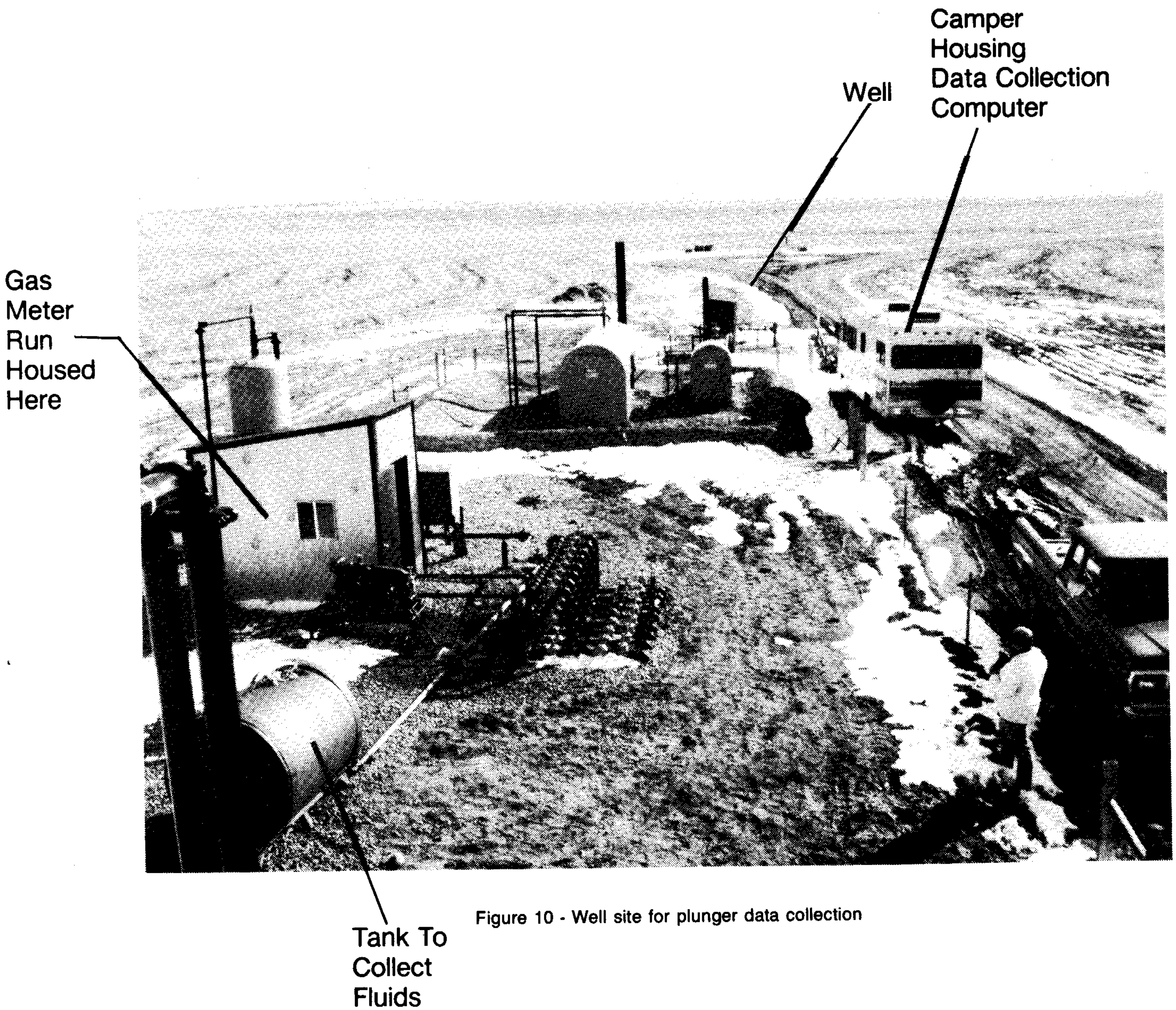

Figure 10 - Well site for plunger data collection

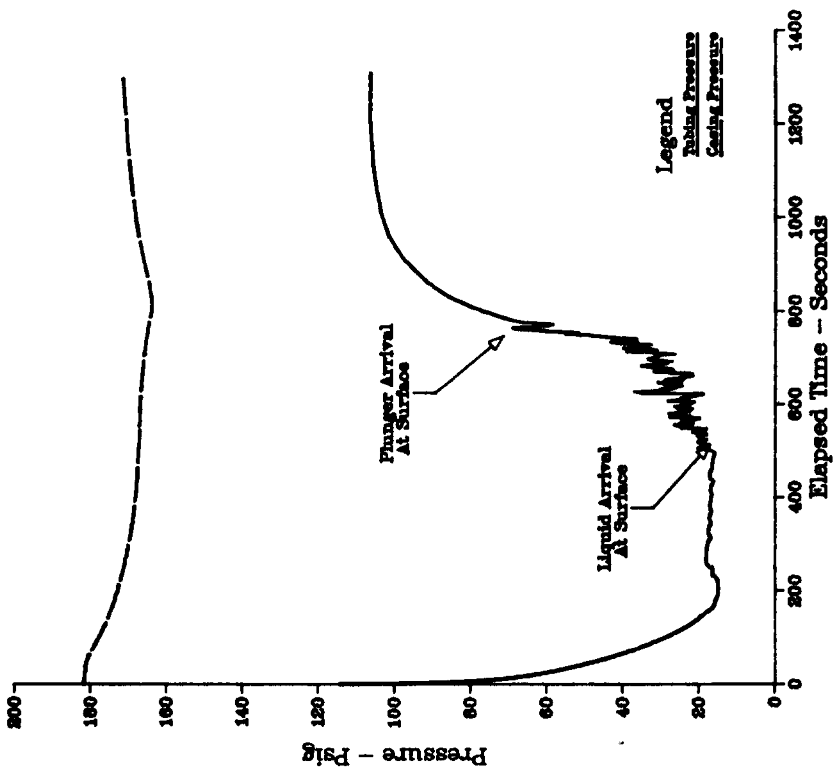

Figure 11 - Plunger field test
Elkhorn B No. 3

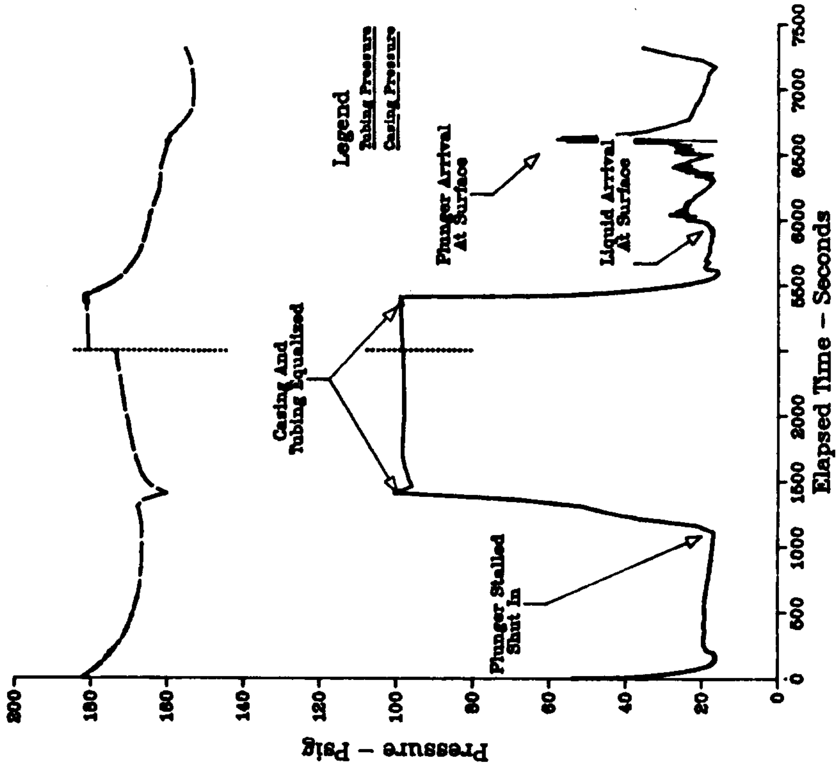

Figure 12 - Plunger field test
Elkhorn B No. 3

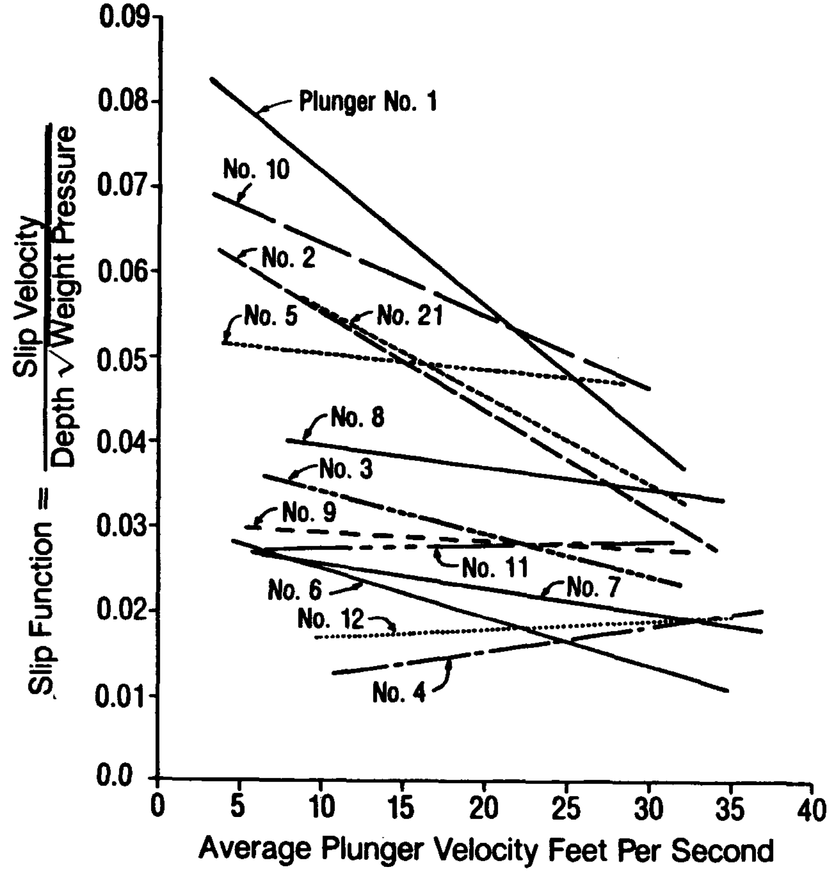

Figure 13 - Plunger evaluation
slip correlation

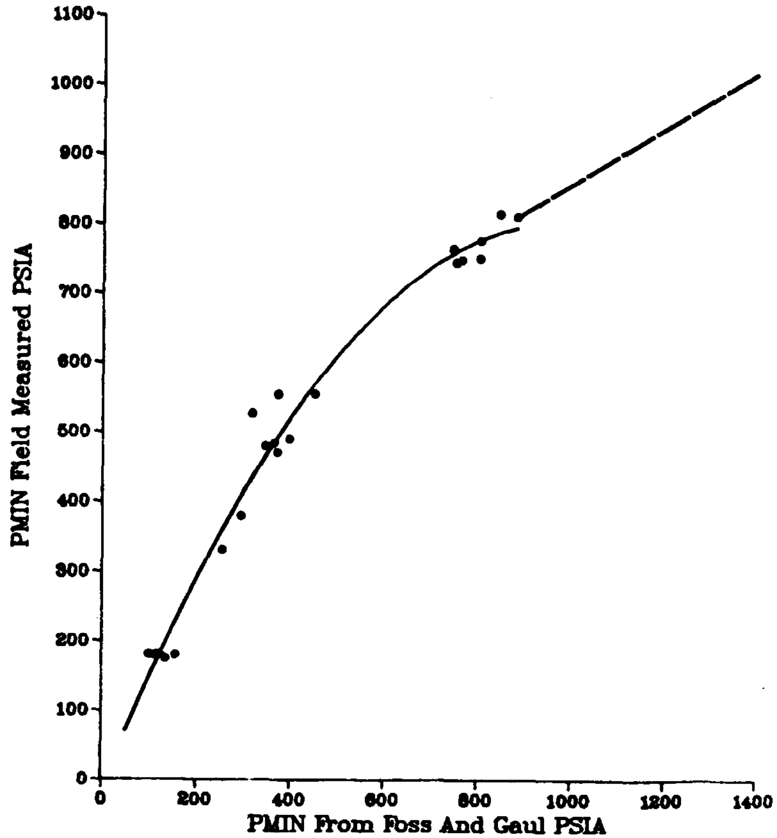

Figure 14 - Pmin correction
correlation

****TO CONTINUE: ENTER --TO STOP: ENTER HX

****
*   *
*   NOTES FOR INTERPRETATION OF ABOVE OUTPUT   *
*   *
****

PLUNGER LIFT IS POSSIBLE AT CONDITIONS BETWEEN THE ABOVE REQUIREMENTS FOR CLR AND SHUTIN PRESSURE. ANY CONDITIONS ABOVE WHERE THE SHUTIN PRESS. IS ABOVE 900.AND THE GLR IS MORE THAN 10000. CAN BE PRODUCED BY PLUNGER LIFT--IF THE WELL GLR IS GREATER THAN THE REQUIRED GLR, GAS MAY BE VENTED WITH PLUNGER AT SURFACE.

** EVEN IF CONDITIONS FOR GLR AND PRESSURE ARE SATISFIED, THERE MUST BE A PRODUCING TIME CALCULATED OR THE SHUT -IN TIME EXCEEDS CYCLE TIME AND PRODUCTION NOT POSSIBLE IF BELOW ASSUMPTIONS HOLD.

CAUTION**--THE ASSUMPTION USED TO CALCULATE THE BUILDUP AND PRODUCING TIMES IS THAT THE WELL IS A TIGHT FORMATION WELL WHERE CHANGES IN BHP DO NOT AFFECT THE RATE GREATLY. IF THIS DOES NOT APPLY TO YOUR WELL, THE REQUIRED PRESSURES ARE STILL CORRECT BUT THE VALUES OF TIMES REQUIRED WILL BE LONGER THAN CALCULATED ABOVE.

Example Data File Generated from Interactive Input

EXAMPLE FOR PLUNGER LIFT REPORT

2	IDENTIFIER NUMBER FOR PLUNGER TYPE
1.995	(1) I. D. OF TUBING, INCHES
5.00	(2) I. D. OF CASING, INCHES
100.	(3) SURFACE TUBING PRESSURE, PSI
10000.	(4) WELL DEPTH , FT
100.	(5) AVERAGE TEMPERATURE, DEG F
100.	(6) AVG. GAS PRODUCTION ,MCF/D
10000.	(7) WELL GAS/LIQUID RATIO SCF/BBL
900.	(8) SHUT-IN PRESSURE OF WELL,PSI
300.	(9) LOW CSG P. LIMIT WITH PLUNGER AT SURFACE,PSI

****
*   *
*   AMOCO PLUNGER LIFT DESIGN AND ANALYSIS PROGRAM   *
*   *
****

EXAMPLE FOR PLUNGER LIFT REPORT

YOUR INPUT VALUES ARE AS FOLLOWS

TBG (ID),INCHES, =	1.99
CSG (ID),INCHES, =	5.00
TBG PRESS,PSI, =	100.
DEPTH,FT =	10000.
AVG. WELL TEMP,DEG F. =	100.
ESTIMATED GAS PRODUCTION,MSCF/D =	100.
WELL CLR, SCF/BBL =	10000.
WELL SHUT IN PRESSURE,PSI =	900.
LOW PRESSURE LIMIT FOR CSG,PSI	315.

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

SLUG SIZE BBLS	SHUT-IN TIME TIME,MINS	PRODUCING TIME MINUTES	SHUT-IN PRESS REQ,D PSIA	MINIMUM REQ,D GLR,SCF/B
0.10	102.16	0.0	401.42	79221.44
0.35	96.70	0.0	401.42	21427.23
0.60	98.86	0.0	432.30	12726.65
WELL GLR= 10000.		CAN OPERATE AT LOWER REQUIRED GLRS --		\/\/\/
0.85	120.31	2.09	501.31	9941.48
1.10	154.12	4.28	565.89	8342.98
1.35	188.88	5.52	626.09	7273.64
1.60	223.91	6.49	681.90	6486.27
1.85	259.20	7.20	733.33	5867.02
2.10	294.42	7.98	780.38	5356.14
2.35	329.69	8.71	823.05	4919.31
2.60	365.08	9.32	861.34	4535.40
2.85	400.25	10.15	895.24	4190.77
WELL SHUTIN PRESS=	900.	CAN OPERATE AT LOWER	/\/\ REQUIRED	PRESSURES
3.10	435.44	10.96	924.76	3876.20
3.35	470.57	11.83	949.90	3585.29
3.60	505.87	12.53	970.66	3313.47
3.85	540.84	13.56	989.03	3066.26

Figure 15