PLUNGER LIFT SYSTEM DESIGN EVALUATION

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ABSTRACT
The advent of "smart" microprocessor based plunger lift controllers has produces a renewed interest in the application of plunger lift to remove fluid from both oil and gas wells. While a great deal of information regarding the economics of plunger lift installations and operations exist there is little information available to assist in the design and evaluation of new plunger lift applications. This paper seeks to provide an approach to determining the operational feasibility of plunger lift operations in advance of equipment installation.

PURPOSE
This paper is a follow on to a paper presented at the Southwest Petroleum Short Course in 1999. Since that time there have been some enhancements and improvements in the methodology. The purpose of this paper is to present a tool for the evaluation of the design of a plunger lift installation before equipment is installed on the well. In the design of a plunger lift system consideration must be given to each of the variables that affect the operation of the lift system. A number of the variables are interrelated making a hand calculation of the effects of design changes onerous. To assist in evaluating the system design an Excel workbook is provided. The workbook consists of two independent spreadsheets. The "GAS PRODUCTION ESITMATOR USING TIMED PRESSURE BUILD UP" spreadsheet provides a means for estimating the daily rate of gas productions for wells with an unknown gas production rate. The "PLUNGER LIFT OPERATIONS EVALUALTION' spreadsheet provides a means for evaluating a plunger lift design for a specific set of conditions.

A number of assumptions have been made in the spreadsheet calculations. An attempt has been made to make the assumptions that will provide a conservative estimate of the operating parameters for a plunger lift system.

To obtain a copy of the Excel Workbook containing the two spreadsheets visit esisupply.com/Wayne. Please register when you download the file so that you can be advised of enhanced versions of the workbook.

THE PLUNGER LIFT SYSTEM
The purpose of a plunger lift system is to lift liquid from the well bore to the surface using the natural energy of the well. The plunger lift system employs the produced gas and reservoir pressure to lift the plunger and liquid slug to the surface. The plunger acts as an interface seal between the liquid slug being lifted and the lift gas. The presents of the plunger eliminate the critical velocity consideration of a flowing well, allowing the produced liquid to be lifted using the energy present in a well with insufficient gas volume to allow flowing operations.

Gas Volume During each production cycle (trip) a volume of gas equal to the volume of the tubing plus the volume of gas which bypasses the plunger during the trip must be present to cause the plunger to reach the surface. Lift gas is stored in the annulus between the tubing and the casing. Stated simply; for a successful trip there must be an adequate volume of lift gas stored in the annulus to purge the tubing.

Minimum Annulus Gas Pressure For a successful trip sufficient gas pressure must be present to: 1. Overcome the flow line pressure, 2. Lift the plunger, 3. Lift the liquid slug, 4. Store sufficient gas in the annulus to purge the tubing and, 5. Force the fluid in the annulus into the tubing.

Flow line pressure has a marked effect on the operation of a plunger lift system. The flow line pressure has a direct effect on the required casing pressure equal to the flow line pressure. The flow line pressure also has a directly proportional effect on the volume of gas required to purge the tubing and therefore the volume of gas that must be stored in the annulus. The volume of gas, in standard cubic feet, required to purge the tubing is equal to the volume of the tubing times the absolute flow line pressure plus the volume of gas that bypasses the plunger during the trip.

GAS BYPASSING THE PLUNGER
The amount of gas that bypasses the plunger while the plunger and the liquid slug are traveling to the surface is a bit nebulous and will vary between different plunger designs. In a paper presented at the Southwest Petroleum

Short Course in 1983 by Paul L. Ferguson and E. Beauregard' it is pointed out that the difference and area between a plunger and the tubing can be equivalent to a 5/8" to 3⁄4" hole in the plunger. Other research*also indicates that the rate of gas bypassing the plunger is constant. That is the volume of gas bypassing the plunger is proportional to the fit of the plunger and the trip time. In their 1965 paper' Foss and Gaul provide some indications of the relative efficiency of various plunger designs.

Plunger Pressure, the pressure required to lift the plunger, is constant; the weight of the plunger divided by the cross sectional area of the plunger. Some pressure is also required to overcome the friction forces acting on the plunger and the fluid column.

Tubing Fluid Pressure, the pressure to lift the fluid slug, is directly proportional to the amount of liquid lifted and therefore the hydrostatic head of the liquid in the tubing at the beginning of the plunger trip on each production cycle.

The liquid to be lifted on each trip is calculated by dividing the total liquid production per day by the number of possible production cycles per day.

The number of possible production cycles per day is calculated by dividing the daily gas production rate by the volume of gas required to purge the tubing.

The pressure required to lift the fluid slug is calculated by multiplying the height of the liquid in the tubing by the fluid gradient, in PSI per foot.

The height of the fluid column is calculated by multiplying the volume factor, in feet per barrel, by the number of barrels in the liquid to be lifted each cycle.

Casing Fluid Pressure is the pressure required to force the liquid that resides in the annulus at the beginning a plunger trip into the tubing.

At the beginning of a trip the liquid in the annulus must be forced into to the tubing in order for the gas stored in the annulus to flow into the tubing. Since the unit volume of the annulus is larger than the unit volume of the tubing the liquid in the annulus will occupy a height in the tubing that is proportional to the volume of liquid in the annulus and the ratio of the unit volumes of the annulus and the tubing.

Storage Pressure is the pressure required to store sufficient gas in the annulus to purge the tubing. Storage pressure is calculated by dividing the volume of gas required to purge the tubing by volume of the annulus the volume of gas that will bypass the plunger during the trip.

PLUNGER LIFT SYSTEMS DESIGN

The relationships of the design factors in a plunger lift installation are many, varied and interrelated. Hand calculation of all of the various values involved in a plunger lift installation is a daunting task. To assist in plunger lift design evaluation a spreadsheet has been developed.

Qualification For A Plunger Lift Installation

One rule of thumb that persists is that a will that produces 400 SCF per barrel of fluid per 1000 feet of vertical lift will be a successful plunger lift candidate. Field experience and results obtained in using the evaluation spreadsheet suggest that this is a valid rule of thumb. One of the qualifies used in the spreadsheet for a good plunger lift candidate is the availability of 400 SCF of gas per bbl/1000 feet. It is possible to operate a plunger lift system with less than 400 SCF/BBL/1000 feet. However, as can be seen through the use of the spreadsheet as the available gas is reduced the pressure requirements increase. Therefore, before installing a plunger lift system on a well it is well to be assured that not only the 400 rule is met but also that sufficient pressure is also available.

The second qualifier for a successful plunger lift operation used in the spreadsheet is sufficient produced gas and pressure to initiate and complete at least one cycle per day. There is no scientific reason for this qualifier. There are most likely any number of plunger lifted wells that operate very well on less than one cycle per day. However, when the production cycle time exceeds 24 hours consideration of all of the parameters is in order. It is also possible for the number of daily productions cycles to exceed one with a production index of less than 400, provided sufficient pressure is available.

The third qualifier is that the minimum casing pressure is less than the allowable or available casing pressure. The allowable casing pressure may be determined by conditions such as the age and strength of the casing or the cement job. Another limitation on casing pressure is the maximum pressure available from the formation. If the minimum casing pressure cannot be achieved for any reason the well is not a plunger lift candidate.

Flow Line Pressure

After available gas production rate the flow line pressure has the single greatest effect on the operation of a plunger lift system. **A** change in the flow line pressure will result in a substantially larger change in the minimum pressure required for successful plunger operation.

Example: Depth = 5000 feet Gas production = 50 MCFD Liquid Production = 10 BPD
Gas bypassed = 5% Fluid gradient = 0.37 Plunger Weight = 10 lb
Casing = 5 ½" Tubing = 2"

Flow Line Pressure	Casing Pressure
0 psi	46 psi
10 psi	93 psi
20 psi	141 psi
40 psi	236 psi

From the example it is evident that it is important to maintain the lowest possible flow line pressure in order to reduce the required annulus pressure. The example also points out the validity of the practice of operating a plunger lift well using a vent valve (often called the B valve) for wells with low pressure. Reducing the effective flow line pressure to atmospheric pressure allows the plunger and liquid slug to be lifted with a substantially lower casing pressure.

Lowest Minimum Casing Pressure

The lowest minimum casing pressure occurs when the number of production cycles is limited by the travel time of the plunger, trip time plus fall time. The gas production rate has a large influence on the pressure required for a successful production cycle.

Tubing Size

The conventional wisdom is that larger tubing is always a better choice, based on the fact that cross sectional area of the larger tubing will require less pressure to lift the same amount of liquid. This assumption is correct as far as it goes. However, the larger diameter tubing requires more gas for each trip and therefore fewer production cycles are possible in wells that do not produce a volume gas in excess of that needed for plunger lift operations.

Example: Depth = 5000 feet Flow line pressure = 30 PSI Liquid Production = 10 BPD
Gas bypassed = 5% Fluid gradient = 0.37 Plunger Weight = 10 lb Casing = 5 ½"

	Casing Pressure		
Gas Production	1 ½" Tubing	2" Tubing	2 ½" Tubing
10 MCFD	1009 psi	645 psi	696 psi
20 MCFD	542 psi	360 psi	387 psi
40 MCFD	309 psi	217 psi	233 psi
80 MCFD	193 psi	146 psi	156 psi
160 MCDF	134 psi	110 psi	117 psi
230 MCFD*	130 psi	103 PSI	109 psi

*For 1 ½" tubing operation is limited by plunger travel time, there is 33.6 MSCFD of excess gas available.

From the example it can be seen that the gas production rate has as substantial effect on the pressure required plunger operation. The tubing size has an effect on the required pressure.

Gas Requirements

The **Minimum Gas Required** is 400 standard cubic of gas per day per 1000 feet of tubing per barrel of liquid to be lifted and is provided as a bench mark value. As can be seen from the use of the spreadsheet it is physically possible to operate a plunger at lower gas volumes if adequate pressure is available.

Total Operating Gas Required is the volume of gas that is needed to operate the plunger lift system at the maximum cycle rate. It is possible to operate the well as a lower cycle rate, using less gas and increased casing pressure.

Plunger Velocity

The value of 170 FPM for the rate at which the plunger falls is based on empirical measurements of the average fall rate in gas and liquid for expanding pad plungers with one set of pads. The fall rate may be higher for solid plungers and lower is additional expanding pads are used. Other plunger configurations may produce other fall rates. The operator may edit the spreadsheet (row 29) to use other fall rates.

The velocity of 750 FPM of the plunger and fluid slug was selected as a compromise value to minimize the amount of gas bypassing the plunger, the amount of liquid fall back during the trip and mechanical considerations. The operator may edit the spreadsheet (row 30) to use other plunger travel rates.

Afterflow

In as much as the objective in the operation of a gas well is to maximize production time the afterflow calculations are designed to calculate the minimum possible number of production cycles for afterflow operations.

Until the operation of the plunger system becomes time limited by the plunger travel time all available gas is produced in the lifting of the plunger and the liquid at the maximum production cycle rate. Once the plunger operation becomes time limited afterflow is used produce the excess gas.

THE PLUNGER LIFT OPERATION EVALUATION SPREADSHEET

The spreadsheet is designed to assist in the evaluation of both oil production operations and de-liquefying gas wells. For oil production operations the assumption that the number of actual trips is equal to the maximum number of possible trips is the condition that will produce the maximum amount of well liquids. For gas production operations the assumption is made that the number of production cycles is equal to the minimum possible, using afterflow. A separate section concerning afterflow is provided on lines 36, 37,38 and 42. Please note that in afterflow operations the number of cycles reported in line 36 are used rather than the value reported in line 25.

Spreadsheet Design Considerations

To maintain simplicity and brevity of the spreadsheet a number of assumptions have been made. Some of the assumptions are based on empirical data and the values may vary from instillation to installation.

Assumptions:

1. The gas and liquid inflow rates are uniform and constant.
2. The plunger falls at an average rate of 170 feet per minute
3. The plunger and liquid slug travel up the tubing at an average rate of 750 feet per minute
4. The number of actual production cycles is equal to the maximum possible number of production cycles.
5. The temperature in the tubing fluids is equal to the temperature in the casing fluids.
6. The pressure to overcome the friction of moving the plunger and liquid slug is equal to 50% of the pressure required to lift the plunger.
7. The tubing pressure at the beginning of a trip is equal to 80% of the casing pressure.

To simplify the spreadsheet design and assist in comparison of operational factors each set of input data will return results for three tubing sizes, 1 ½”, 2”, and 2 ½”.

The casing sizes are limited to 4 ½”, 13.5 lblft – 5 ½”, 15.5 lblft – 7”, 23 lb/ft – 7 5/8”, 29.7 lb/ft and 8”, 26 lblft. The user may edit the casing sizes if desired. When editing for other casing sizes the accuracy of the dimensional data is critical to the operation of the spreadsheet.

All dimensional information has been taken from “Halliburton Cementing Tables”. (Little red book)

The Plunger Lift Operation Evaluation Spreadsheet Design And Function

The following is a description of each of the spreadsheet functions. It is hoped that the description will assist the user in understanding the operation of the spreadsheet and to make any desired changes.

	PLUNGER LIFT OPERATIONS EVALUATION
DATA INPUT SECTION	
Operator	Enter the name of the well operator*
Well Name	Enter the well name*
Lease	Enter the lease name*
Well Number	Enter the well number*
Producing zone	Enter the name of the producing zone(s)*
Total Depth	Enter the total depth of the well, in feet*
Liquid - BPD oil	Enter the number of barrels of oil that the well produces daily
water	Enter the number of barrels of water that well produces daily
Fluid pressure gradient	Enter the liquid gradient (PSI/Ft)
Tubing Depth	Enter the depth to the seating nipple.
Flow Line Pressure	Enter the flow line pressure in PSIG
Weight of Plunger	Enter the weight of the plunger
Gas Bypassing Plunger	Enter the percentage of the gas required to lift the plunger each trip that bypasses the plunger during a trip, entered as a decimal fraction.
Gas Production Rate	Enter the daily gas production rate in MSCFD
Casing Size	Enter the casing size as decimal number – 4.5, 5.5, 7, 7.6, 8
Maximum working pressure	Enter the highest allowable casing pressure
Tubing Size	DO NOT ENTER DATA IN THESE FIELDS
RESULTS SECTION	This section provides the summation of the results of the spreadsheet calculations.
Is the well a PL candidate?	If both [Trips > 1 AND Production index > 400] returns YES If [Trips < 1 OR Production index < 400] returns "Marginal" If [Trips < 1 AND Production index < 400] returns "NO" If [Minimum Casing Pressure > Tubing length times gradient] returns "Marginal"
Is Production Index OK?	If [Production index (SCF of gas / BBL of fluid / 100 feet) > 400] returns "YES" IF [Production index (SCF of gas / BBL of fluid / 100 feet) < 400] returns "NO"
Are Cycles OK?	If [Max Daily Cycles > 1] returns "YES' If [Max Daily Cycles < 1] returns "NO"
Is the Pressure OK?	If [Minimum Casing Pressure < Max Working Pressure]returns "YES" If [Minimum Casing Pressure > Max Working Pressure] returns "Marginal" If[minimum Casing Pressure > Gradient times tubing length] returns "Flow"
Production Index	Daily Gas production (SCFD) / 100 / barrels of liquid
Minimum Total Gas Reauired	Total SMCFD required to lift produced liquid – 400MCFD per BBL per 1000 feet.
Max number of trips per day	Maximum number of production cycles possible with available gas.
Minimum Casing Pressure	The minimum casing pressure necessary for a successful trip.

* al information fields

PUMPING WELL GAS PRODUCTION ESTIMATION

One of the major problems in evaluating a rod pumped well for conversion to plunger lift is a lack of accurate information regarding the volume of gas that the well produces. The following is a simple procedure to arrive at a good estimate of the wells potential to produce gas under conditions that will be encountered in plunger lift operations. The test requires reading two pressures and two times and entering those data into a simple spreadsheet.

$V1 = Vc \times P1$
$v2 = Vc \times P2$
$AV = V2 - V1$
Production Rate $= \Delta V/Ht$

Where P 1 is the pressure at the beginning of the test
P2 is the pressure at the end of the test
Vc = casing volume in cubic feet
AV = Change in volume
Ht = the test duration in hours
It is assumed that the temperature of the annulus gas at the beginning of the test is equal to the temperature of the annulus gas at the end of the test.

To conduct a valid test it is necessary to estimate the minimum operating pressure for a plunger lift operation. If the test starts at a pressure much below the minimum required pressure an overly optimistic result may result. Make a guess at the gas production rate and enter it into the “Plunger Lift Operation Evaluation Spreadsheet”, along with all of the other well information. Then from the “Minimum Casing Pressure” field determine the pressure at which the build up test will start, this is P 1 in the equation.

Shut in the casing until the pressure reaches P1, or greater. Then record the pressure and the time. For the entry into the spreadsheet record the time in the 24 hour format, ie 2:15PM = 1415.

After a time period, of less than 24 hours, again record the pressure (P2) and time.

Enter this data into the proper fields in the “Gas Production Estimator” spread sheet.

Read the estimated gas production rate and enter that value into the “Gas Production Rate” field of the “Plunger Lift Operation Evaluation Spreadsheet”.

The estimated operating conditions will be presented in the “Plunger Lift Operation Evaluation Spreadsheet”

GAS PRODUCTION ESTIMATOR USING TIMED PRESSURE BUILD UP
The following is a description of the data fields in the spreadsheet.

INPUT DATA

Operator	Enter the name of the well operator*
Well Name	Enter the well name*
Lease	Enter the lease name*
Well Number	Enter the well number*
Producing zone	Enter the name of the producing zone(s)*
Tubing Depth	Enter the depth of the seating nipple
Tubing Size	Enter the tubing size, use 1.5, 2.0 or 2.5
Casing Size	Enter the casing size, use 4.5, 5.5, 7, 7.6 or 8
Initial Pressure	Enter the pressure at the beginning of the test
Final Pressure	Enter the pressure at the end of the test
Initial Time	Enter the time at which the test started, use 24 hour format
Final Time*	Enter the time at which the test ended, use 24-hour format.

RESULTS

Test Duration	The spreadsheet calculates the duration of the test in hours and tents
Pressure Build Up	The spreadsheet calculates the pressure build up.
Annular Volume	The spreadsheet calculates the volume of the annulus in cubic feet
Volume Increase	The spreadsheet calculates the gas volume increase in standard cubic feet
Gas Production Rate	The Spreadsheet calculates the gas production in MCFMD

*Optional information fields

References:

1 E. Beauregard, P. L. Ferguson – "Will Plunger Lift Work In My Well", Southwest Petroleum Short Course, April 27-28, 1983

2 L. N. Mower, J. F. Lea and E. Beauregard, P. L. Ferguson – "Defining the Characteristics and Performance of Gas-Lift Plungers", Society of Petroleum Engineers, September 22-25, 1985

3. D. L. Foss and R. B. Gaul – "Plunger Lift Performance Criteria with Operating Experience –Ventura Avenue Field", Drilling and Production Practices- API, 1965, 124-140