PLUNGER LIFT RISE VELOCITY PREDICTION MODEL PLUNGER LIFT "OPEN" CRITERIA

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ABSTRACT

During the shut-in time period the plunger falls through gas, liquid and then rests at bottom on the bumper spring; over this same time period pressure is required to build to sufficient magnitude in order to unload the accumulated liquid and conventional plunger from the bottom of the well when the surface valve opens. An industry rule-of-thumb criterion is used to determine at what casing pressure build, Pc, the well should be opened to unload the liquid to the surface P_C. The difference of (P_C - P_L) represents the energy available to unload the well, where P_L is the line pressure. The difference of (P_C – P_T) represents the back-pressure due to the liquid load in the tubing, where P_T is the tubing pressure. The energy available to lift the liquid load and unload the well should be more than twice the pressure due to the liquid load, or in other words the Load Factor (P_C - P_T)/(P_C - P_L) calculation should be less than one-half (½). The best technique to predict the maximum casing build pressure, Pcmax, may be to use a Foss and Gaul[1] type model to predict the rise velocity within a range of 500-1000 feet per minute (fpm), more optimally at 750 fpm that will unload the plunger and liquid to the surface. These criteria are compared to one another and 10 different well examples are analyzed using the Foss and Gaul method. The results allow an operator to determine the shut-in casing pressure a plunger lift well should be allowed to build to before opening the valve to unload the liquid.

INTRODUCTION

The most common form of plunger lift is the conventional plunger lift method. This method includes an after-flow production time period with the plunger held at the surface. During the latter time of the production period, liquids are sensed to be accumulating in tubing of the well. Then the well is shut in and time is required for the plunger to fall through gas, through accumulated liquids and a period of shut in time with the plunger on the bottom hole bumper spring. The well is then opened to begin the unloading period and the plunger with liquids above, rises to the surface, delivers the liquid slug and then the production period begins again with the plunger held by differential pressure at the surface. Another form of plunger lift is continuous flow or a quick drop plunger cycle with minimum shut-in time. The type of plunger that opens to allow gas to pass through the plunger during the fall is not discussed in the paper. The emphasis of this paper is a model (compared to field data) to predict, during shut-in, when the casing operating pressure has reached a value of pressure that will bring the plunger and liquid slug up the well at a desired average velocity of rise. The desired velocity of rise, from industry experience, is 500-1000 fpm with be best value being 700-800 fpm average rise velocity in most cases. This paper presents a modified Foss and Gaul model to determine how casing operating build up pressure relates to average rise velocity of the plunger and liquid slug.

Fig. 1 illustrates the components of a typical well equipped with a conventional plunger lift system:

The components of the system include (After Hearn, Weatherford):

- *Controller:* Electronic-based system with control parameters to determine under what conditions to exert control by opening/closing the motor valve
- *Transducer:* Electronic device that emits an electronic signal to be converted within controller to engineering units
- *Motor Valve:* Diaphragm-operated device controlled by controller to open/close sales/tank line
- *Lubricator/Catcher:* Uppermost stopping point for plunger; acts as shock absorber; catcher is mechanical device that locks plunger in lubricator for removal and for inspection
- *Arrival Sensor:* Magnetic device strapped around lubricator to detect plunger arrivals… Vibration sensors have been used
- *Bumper Spring:* Shock absorber at plunger's deepest stopping point

- *Plunger:* Pig-type device that provides a seal between gas and liquid inside tubing to deliver fluid and gases to surface with differential pressure. The plunger travels entire length of tubing from catcher to bumper spring.

The plunger, conventional in this case, can be a barstock gooved plunger, a brush plunger to accommodate some sand production without the plunger sticking, a single or double spring loaded expandable pad plunger, or other conventional plungers. Conventional plungers typically require the well to be shut in for a sufficient time period for the plungers to fall to bottom, whereas continuous flow plungers (not discussed in this paper) have a bypass or other configuration such that the continuous plunger or it's components will fall against flow with the well open to production.

PLUNGER LIFT OPERATION CYCLE

The plunger lift cycle can be divided into three distinct parts: Unloading, Afterflow and Shut-in[2]. **Fig. 2** shows the operation of a conventional plunger annotated with key events labeled during the plunger cycle. **Fig. 3** plots the tubing, P_T, casing, P_C, pressures and acoustic signal for one plunger lift cycle where the key events are identified and annotated with respect to the pressures. Shut-in occurs over the time period when the motor controlled valve is closed and the time period is identified beginning at [A] through [B]. Unloading and Afterflow occur over the time period when the motor controlled valve is open, and this time period is identified beginning at [B] through [C].

Points [A-B] identify the ***Shut-in*** time period that begins when the flowline motor valve closes, the flow is shut-in and the plunger falls down the tubing. The plunger falls through gas until it hits the accumulated liquid at the bottom of the tubing. The plunger then falls through at least some of the accumulated liquid at the bottom of the tubing. Ideally the plunger should fall to the bottom of the tubing and rest on a plunger catcher or bumper spring before being lifted to the surface again. During shut-in, the casing pressure should build high enough to lift the accumulated fluids and the plunger to the surface during the next valve open period.

Over time period from [A-1] the plunger falls past the tubing collar recess and acoustic pulses are generated from the rapid release of the differential pressure across the plunger. This acoustic pulse, which is generated at the tubing collar recess, travels through the gas to the surface and is detected by the microphone and also by the tubing pressure transducer. These acoustic pulses are normally obtained when a plunger falls down the tubing in a well that produces a limited amount of liquid so that the tubing interior is relatively dry. These tubing recess pulses are monitored at the surface so that the plunger travel is followed on a continuous basis.

Point [2] identifies the time when the plunger reaches the liquid at the bottom of the tubing. This time is generally characterized by the disappearance of the signals generated by the plunger as it passes through the tubing collars and by a large amplitude pulse followed by reduced noise level. When the plunger enters the liquid, these tubing recess acoustic pulses are generally not transmitted through the liquid, so the acoustic noise level drops indicating that the plunger is submerged in the liquid. The field acquired acoustic and tubing pressure data in **Fig 3.** show tubing collar recess echoes both in the gas above the liquid. When the plunger finally rests on bottom on the bumper spring, the noise level drops again and a small increase in tubing pressure is frequently observed, and the minimum shut-in time for the plunger to reach bottom may usually be determined with certainty. At point [B] the liquid load, P_C - P_T, in the tubing can be estimated by the casing pressure, P_C, minus the tubing pressure, P_T, both at the end on the shut-in time period.

At point [B] the ***Unloading*** period begins when the valve opens. The time when the valve controller opens the motor valve between the tubing and the flowline is usually based on meeting some type of operational pressure or elapsed time criteria. The pressure from the reservoir and the pressure from the gas stored in the casing annulus are used to lift the accumulated liquid and plunger to the surface. During the unloading period the surface tubing pressure, P_T, at shut-in [B] drops to a value close to the line pressure, P_L, when the liquid begins to arrive at the surface at point [3]. The differential pressure across the plunger; casing pressure at the end of shut-in [B] minus line pressure when liquid arrives [3], P_C - P_L, represents the energy that lifts the plunger and the liquid slug above the plunger to the surface.

Point [3] identifies the arrival of the liquid to the surface and point [4] identifies the arrival of the plunger at the surface. Points [3] and [4] identify key events during the Unloading period. These events are generally apparent both on the pressure and the acoustic signals and are characterized by rapid changes in amplitude and slope of the traces. The event [3], when liquid arrives at the surface, is characterized by an increase of the tubing pressure and the detection of significant noise amplitude on the acoustic signal as gassy liquid flows by the microphone. If there is liquid in the tubing above the plunger, then the time [4] when the plunger arrives in the lubricator occurs at the point of peak tubing pressure while the motor valve is open. If liquid is above the plunger, the pressure spike always occurs and once the plunger arrives in the lubricator the tubing pressure rapidly drops as the gas flows unrestricted into the surface flow line. If there is no liquid above the plunger, there may be a sudden, slight increase in the tubing pressure and a sharp noise on the acoustic data with the arrival of the plunger at the surface.

The arrival of the plunger at the surface at point [4] identifies the beginning of the ***Afterflow*** [4-C] period. When the plunger arrives the flow valves are open, the plunger can be held at surface by a mechanical catcher or by differential pressure due to the flow of gas up the tubing through the lubricator. During afterflow the well is producing gas up the tubing down the sales line. During the afterflow period, as the gas rate decreases, liquids are not carried to surface because the gas velocity becomes too low and the liquid will tend to fall back and accumulate at the bottom of the tubing. If the afterflow period is too long, the liquid accumulation at the bottom of the tubing will cause the pressure at the bottom of the well to build-up and further reduce the flow from the formation. In some cases, the bottom hole pressure may increase to the static reservoir pressure and stop the flow from the formation. The shut-in time period starts after specific flow rate is met or pressure control criteria is reached, or a predetermined time elapses, and then the motor valve closes.

A digital fluid level instrument[6] can be used to acquire operational tubing casing pressures and acoustic data that define key events at any time during the plunger lift cycle. The casing pressure and tubing pressure traces shown in the **Fig. 3** are from a typical conventional plunger lifted well.

LOAD FACTOR DETERMINES IF PLUNGER WILL SURFACE

The load factor is one of the primary rules-of-thumb used to determine if the plunger will come to the surface after the controlled motor valve is opened to unload the well. Load factor depends upon casing pressure at end of shut-in, P_C, tubing pressure at the end of shut-in, P_T, and line pressure before liquid arrives at the surface, P_L. The load factor should be less than 0.5 or the energy stored in the casing and in the formation may not be enough to lift the plunger and liquid load in the tubing to the surface. The liquid load can be thought of as (P_C - P_T) and the energy provided by the well to lift the liquid load to the surface would be (P_C - P_L). **Eq. 1** is the Liquid Load Factor Rule-of-Thumb equation:

$$(P_C - P_T)/(P_C - P_L) < \tfrac{1}{2} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

In **Fig. 3** a line placed at the end of the shut-in time period [B] identifies the values of the casing pressure, P_C = 306.0 psig, and the tubing pressure, P_T = 272.8 psig. There is 33.3 (P_C - P_T) psi of liquid load or backpressure in the tubing to be unloaded to the surface. In **Fig. 3** a line is placed at point [3] identifying where the tubing pressure begins to increase due to liquid arriving at the surface during unloading. The line pressure is equal to the lowest value of tubing pressure after the well is opened to the flow line just before liquid arrives. The separator pressure can also be used as an estimate of the line pressure, but usually the wellhead pressure is used for the line pressure. The line pressure beyond the wellhead could be lower downstream of the wellhead, but point [3] is the effective line pressure, P_L = 126.3 psig. In this well there is 179.7 psi (P_C - P_L) of pressure available to lift the liquid load in the tubing to the surface. Some controllers use the load factor and the value of ½ may be adjusted up or down to best control the well.

The load factor (P_C - P_T)/(P_C - P_L) in this well is equal to 0.185 and the plunger and liquid were brought to the surface. In **Fig. 3** the well was shut-in for a long enough time period to allow the casing pressure to build enough driving energy (P_C - P_L) sufficient to lift the plunger and liquid load (P_C - P_T) to the surface. When the load factor is less than 0.5 the plunger is predicted to come to the surface at a reasonable rise velocity.

PLUNGER RISE VELOCITY AND MAXIMUM UNLOADING TIME

The optimum rise velocity[3] is plunger dependent, although the optimum for most plungers is a rise velocity near 750 ft/min. If the plunger is driven to the surface at too high of speed, then the well's energy will be wasted and the high arrival velocity can result in damage to the equipment. If the plunger rise velocity is too slow, then gas tends to slip by the plunger and the plunger may stall and not reach the surface. In general, for optimized plunger lift installations for most conventional types of plungers the Rule-of-Thumb rise velocity should be in a range between

500 ft/min and 1000 ft/min. **Fig. 3** displays valve open [B] at an elapsed time of 69.276 minutes, liquid begins to arrive at the surface [3] after an elapsed time of 79.560 minutes, the plunger arrives at the surface [4] at 80.718 minutes, and the plunger rises to the surface at an average rise velocity of 679.3 ft/min over the 11.442 minute unloading time period. These are industry guidelines, but the objective is to not rise too fast and to not rise too slow.

Methods to determine what casing pressure will give the desired rise velocity include:

1. Monitor tubing pressure or tubing pressure minus line pressure on trial and error basis.
2. Monitor casing pressure or casing pressure minus line pressure on trial and error basis.
3. Monitor load factor (to be explained below)
4. Use Foss and Gaul Model (modified version discussed in this paper)

FOSS AND GAUL MODEL

The Foss and Gaul method is a model[1] of plunger rise published in 1965. Among other things the model predicts a required casing operating pressure to bring the plunger and liquid to the surface at a given average rise velocity.

The model begins by defining the casing pressure as the plunger and slug are at the surface. The equation is:

$$P_{c,\min} = (14.7 + P_p + P_t + P_c\ L)(1 + D/K) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (2)$$

Where the term K (Appendix A) accounts for friction of gas flowing in the tubing, Pc accounts for the liquid slug weight and friction, Pp accounts for the weight of the plunger and D is the depth of the well (bumper spring).

Pc, min is the casing pressure after the casing shut-in pressure expands into the tubing. The casing pressure before the casing annulus gas expands into the tubing is:

CPR = (Aann + At)/Aann ……………….………………………….(3)
Pc, max = CPR x Pcmin

Where Aann is the cross section to flow between the casing and tubing and At is the open area in side the tubing.

The Pc,max is the initial casing pressure just before the plunger lift well is opened to flow. The rise velocity enters the equations (see Appendix A) through the friction terms in the friction of the slug to the tubing and the friction of the flowing gas to the tubing. For purposes of relating the casing build up pressure to the rate of rise, this is then the basic Foss and Gaul relationship.

An additive modification to the Foss & Gaul relationship is derived in Appendix A to account for the fact the well is producing some gas into the tubing below the plunger as it rises and the fact that some of the gas below the plunger is leaking upwards past the plunger as it rises. The production, if accounted for, reduces the predicted casing build up pressure to rise at a given velocity and leakage increases the predication of casing build up pressure , all other variable being constant.

The additive term from Appendix A is shown below and terms are defined in Appendix A.

$$P_{c,\max} = P_{c,\min} CPR - \frac{14.7(T_{R,avg})(z)(1000)(Mscd_p - Mscfd_l)}{(520)(24)(60)(V)} \text{.....Eqn. A14}$$

Where $Mscfd_p - Mscfd_l$ is the difference of the flowrate of formation produced gas minus the flowrate of gas leaking past the plunger during plunger rise

Eq. A14 gives the original Foss and Gaul relationships and a modified model to account for the well production and plunger leakage as the plunger rises. The variables in the Foss and Gaul model are detailed in **Appendix A** and one method is to calculate the terms K, Pc = Pweight + Pfriction and K using well know techniques to find the friction factors between the gas/tubing and the liquid slug/tubing. In this paper relationships for smooth pipe for the friction factor were used as outlined in Appendix A. The smooth pipe relationships for friction shows a smaller required casing build up pressure than the original relationships published by Foss and Gaul is used. Foss and Gaul tabulate values of Pc and K with some default values to calculate these numbers for a given tubing size.

Essentially 4 modes are possible for calculating Pc,max, the casing buildup pressure for a given rise velocity. The four methods are:

1. Calculate Pc,max using a calculated friction factor and no production or leakage during rise
2. Calculate the Pc,max using a calculated friction factor and production and leakage during rise.
3. Calculate the Pc,max using the original values of Pc and K with no leakage or production during rise from Foss and Gaul.
4. Calculate the Pc,max using the original values of Pc and K with leakage and well production used during the rise of the plunger.

This paper uses data collected during complete plunger cycles on 10 different wells as case studies where the rise velocity was accurately measured along with the actual casing pressure, Pc. All four modes for calculating Pc,max were done at the actual measured rise velocity and compared to the measures shut-in casing pressure for the 10 wells produced with conventional plunger lift.

SLIPPAGE PAST PLUNGER

Gas slippage past the plunger during the unloading portion of the cycle reduces the energy to lift the plunger and liquid to the surface; if this gas slippage volume is known then modifications to the Foss and Gaul calculations can be performed. Gas slippage is determined by analyzing data collected using an acoustic liquid level instrument to record the pressure and acoustic data shown in **Fig. 3**. The surface pressures are used to compute the total cumulative standard volume of gas produced from the well during the plunger cycle. From the tubing intake depth to the surface the known tubing volume corrected for gas free liquid in the bottom and the casing/tubing annulus volume are used to determine the mass of gas in the tubing and casing annulus as a function of pressure and temperature at all times during the cycle. A mass balance type calculation is used to allocate gas produced from the formation, into/out of the casing annulus, tubing, and flow down the flow line.

Well bore information important in accurately calculating the gas volumes and flow rates are: 1) Average Joint Length, 2) Fall Velocity, 3) Gas Specific Gravity, 4) Acoustic Velocity, 5) Plunger Depth, 6) Tubing & Casing Sizes and Weight /foot, and 7) Tubing Intake Depth.

The pressure at the beginning of the cycle is important, because the pressures will be equal if the gas that flows down the Flow Line is equal to the gas that flows out of the Formation. The total system pressure will increases if all of the gas produced from the formation does not flow down the flow line, and the system pressure decreases if MORE gas flows down the flow line than is produced from the formation.

The Formation Gas Volumes are determined over time period [A-1-2-B], where the formation gas volume is equal to the cumulative tubing gas volume plus the casing gas volume. The formation gas flow rate is the derivative of the formation gas volume as a function of elapsed time. The casing pressure is used to determine the gas volume stored in the casing. The tubing pressure is used to determine the gas volume in the tubing, where the tubing length is adjusted for the gas free height in the bottom of the tubing.

The next step is to determine the gas flow rate versus flowing pressure at the bottom of the tubing/casing annulus. The flowing bottom hole pressure during shut-in versus the instantaneous gas flow rate from the formation define the dynamic inflow performance of the plunger lifted well during shut-in.

Over time periods [B-3-4-C] the dynamic inflow performance calculated during shut-in is used to calculate the inflow from the formation when the surface valve is open to flow. The casing pressure is used to determine the flowing pressure at the bottom of the tubing/casing annulus. Once the flow rates are determined then the total gas volume from the formation can be calculated by integrating gas rate over the time period the valve is open.

The Flow Line gas flow rate over time period [A-1-2-B] is Zero because the surface valve is closed. During time period the plunger comes to surface and pushes all the [B-3] gas and [3-4] liquid down the flow line. The gas that flows down the flow line is the decrease in volume of gas in the tubing plus any gas that slips by the plunger. At any time during time period [B-3] the volume of gas down the flowline is equal to the decrease in gas volume from the tubing gas from the time when unloading began. As the plunger comes to the surface some gas below the plunger leaks around the plunger.

Over time period [3-4] the gas down flow line is equal only to the gas that slips by plunger. For time period [4-C] the plunger is held at the surface and no gas slips by the plunger. The gas that flows down the flow line for time period [4-C] is the decrease in volume of gas in the casing, plus any decrease in volume in the tubing, plus the gas that flows out of the formation. The gas volume that slips by the plunger when the valve is closed [A-B] is accounted by the increase in tubing pressure during shut-in. Gas slips from below the plunger to above the plunger over time period [B-3] and [3-4] when the surface valve is open during the unloading portion of the cycle. This volume of gas that slips by the plunger during the unloading portion [B-4] of the cycle is equal to the volume of gas that leaves the casing plus the volume of gas that flowed out of the formation minus the gas volume that is still in the tubing when the plunger arrives at the surface. This gas volume that slips past the plunger during the unloading portion of the cycle can be scaled up to a daily Mscf/D rate depending on the elapsed time of the cycle [A-C] and the "Mscf/D Leaking" is entered into the EXCEL spreadsheet as shown in Table 1. Table 1.a shows the general well information used as required input into the EXCEL spreadsheet for each of the 10 example plunger lift wells. Table 1.b shows the gas leakage during the unloading time period of the cycle analyzed for each of the 10 example plunger lift wells.

RESULTS

Table 1 shows the calculated results for the example plunger lifted well labeled Normal Cycle. This detailed output for the well displays the calculations possible by using the Foss and Gaul spread sheet. Measured data for the Normal Cycle well was the plunger arrived at the surface with an average rise velocity of 679.3 ft/min, the load factor was equal to 0.185, and the casing pressure at the end of the shut-in time period was 320.7 psia. For the Modified Foss and Gaul input case at the measured rise velocity of 679.3 ft/min, the Pc,max with no considered production and leakage during the rise is 323.73 psia, with a 1% error error from actual casing pressure. Accounting for production and leakage, Pc,max is 311.29 psia, with a -3% error from actual casing pressure. **Fig. 4** shows output from the spread sheet showing a relationship between the maximum casing buildup pressure and the load factor, where for the actual casing pressure Pc of 320.7 Psia the load factor is predicted to be 0.33. The 0.33 predicted load factor is greater 0.185 load factor for the Normal Cycle well. **Fig. 5** shows output from the spread sheet showing a relationship between the casing buildup pressure and the average rise velocity, this a relationship between the empirical load factor and casing build up pressure and average velocity of rise of the plunger/slug. The load factor becomes ½ at about 600 fpm and is about 0.3 for the case example of the "Normal Cycle" example well. The EXCEL Spreadsheet is available from Echometer Co. or PLTech LLC for general use.

The Modified Foss and Gaul EXCEL spreadsheet is a predictive tool with options to calculate what pressure the well should build to on the casing before the well is opened. To test the accuracy, 10 cases of measured data were compared to the predictions from the spread sheet.

Table 1.c: 10 wells with measured data compared to the predictive Foss and Gaul Spread sheet.

From the results in **Table 1.c** it can be seen that the most accurate overall method for this particular group of wells was using the Spread Sheet with the Pc and K values calculated with a newly calculated smooth pipe friction factor. The results of doing this gave an average error of 1 % for all ten cases and an average absolute error of 14.4%. While certainly not exact, the method allows predicted values that are close to the required casing build pressure for a given average velocity of rise.

This method can be used to help set controllers perhaps more quickly than using trial and error and could even be incorporated into a controller as a control technique[4].

CONCLUSIONS

A modified Foss and Gaul model is presented. The predicted minimum casing pressure compares favorably to within an average 1% error of the measured build casing pressure before opening to unload the 10 plunger lifted example wells at the rise velocity of the selected cycle. The prediction accounts for liquid load, frictional effects, tubular sizes and lengths, surface line pressure and fluid properties. The option to consider or not, the influx of gas and leakage past the plunger as the plunger rises is available. Data from ten wells was compared to the model favorably, although this is not enough data to statistically decide on what options are best for use with this model. The results indicate that the original Foss and Gaul model used friction associated with the liquid slug is in excess of what is experienced in these 10 selected plunger lifted wells.

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Table 1
Results for Normal Cycle

	INPUTS-Yellow, Pink	
	0, Orig F&G, 1,JIO	1
1,2,3	**2 3/8, 2 7/8, 3 1/2**	1
	Tbg ID, Inches	1.995
	Pwh, psig	126.3
	Pp, psig	2.3
	Depth, ft	7773
	Slug, bbl	0.58
	Slug length/bbl, ft	258.80
	Avg Temp, F	130
	SG Liquid	0.8938
	Frac Liquid in Slug	0.2283
	SG Gas	0.7436
	Rise Velocity, ft/min	679.33
	Friction, f, Gas	0.015
	Friction f, Liquid	0.016
	Mscf/d Produced	100
	Mscf/d Leaking	21.3
	Casing ID, inches	4.09
	Pweight, psig/bbl	100.16
	Pfriction, psig/bbl	86.68
	Pc, psig/bbl	186.84
	K	197634
	Pcmin, psia	261.56
	CPR	1.24
	Pcmax, psia	323.79
	Pcmax, NEW	311.29

Table 1.a

Well ID	Tbg ID, Inches	Pwh, psig	Pp, psig	Depth, ft	Slug, bbl	Slug length/bbl, ft	Avg Temp, F	SG Liquid	SG Gas	Rise Velocity, ft/min
Normal Cycle	1.995	126.3	2.6	7773.0	0.6	258.8	130.0	0.9	0.7	679.3
EFM Flowrate Well	1.995	68.3	3.35	6276.0	0.5	258.8	120.0	1.0	0.8	499.8
EFM Flowrate Well	1.995	167.6	3.5	7728.0	0.1	258.8	125.0	0.9	0.8	933.3
EFM Flowrate Well	1.995	159.3	0	6082.0	0.2	258.8	120.0	0.9	0.8	1730.9
Optimize Before	1.995	65.3	2	8687.0	0.7	258.8	160.0	0.8	0.8	610.7
Optimize After	1.995	69.6	7.5	8687.0	0.1	258.8	160.0	0.8	0.8	1396.2
SV Before	1.995	79.2	2.5	6273.0	0.1	258.8	120.0	0.9	0.8	792.4
SV After	1.995	64	2	6273.0	0.4	258.8	120.0	0.9	0.8	636.5
Horiz 0 Load	2.441	110	5	4173.6	0.0	172.9	79.0	1.0	0.7	1923.8
	2.441	110	5	4173.6	1.5	172.9	79.0	1.0	0.7	332.8

Table 1.b

Mscf/d Produced	Mscf/d Leaking	Casing ID, inches
100.0	21.3	4.1
100.0	5.5	4.1
60.0	2.6	4.1
65.0	18.2	4.1
168.0	8.6	4.1
241.0	11.7	4.1
45.0	8.3	5.0
45.0	11.8	5.0
176.0	21.2	6.5
176.0	21.2	6.5

Table 1.c

Well ID	Rise Velocity ft/min	Actual Pc Psia	Pcmax psia	% Error	Abs % Error	Pcmax NEW	% Error	Abs % Error	Pcmax psia ORIG	% Error	Abs % Error	Pcmax NEW ORIG	% Error	Abs % Error
Normal Cycle	679.3	320.7	324.0	1.0	1.0	311.0	-3.0	3.0	380.2	18.6	18.6	367.7	14.6	14.6
EFM Flowrate Well 1	499.8	163.1	204.0	25.1	25.1	184.0	12.8	12.8	211.1	29.4	29.4	191.0	17.1	17.1
EFM Flowrate Well 2	933.3	303.1	277.5	-8.4	8.4	270.4	-10.8	10.8	323.0	6.6	6.6	317.0	4.6	4.6
EFM Flowrate Well 3	1730.9	390.0	388.5	-0.4	0.4	285.4	-26.8	26.8	625.0	60.3	60.3	622.0	59.5	59.5
Optimize Before	610.7	268.7	246.0	-8.4	8.4	216.0	-19.6	19.6	304.0	13.1	13.1	274.0	2.0	2.0
Optimize After	1396.2	308.7	192.0	-37.8	37.8	174.0	-43.6	43.6	311.0	0.7	0.7	293.0	-5.1	5.1
SV Before	792.4	144.0	151.0	4.9	4.9	147.7	2.6	2.6	170.4	18.3	18.3	167.1	16.0	16.0
SV After	636.5	131.7	171.6	30.3	30.3	167.9	27.5	27.5	192.5	46.2	46.2	188.7	43.3	43.3
Horiz 0 Load	1923.8	211.7	177.5	-16.2	16.2	177.4	-16.2	16.2	220.0	3.9	3.9	217.0	2.5	2.5
Horiz 100 Load	332.8	275.6	306.8	11.3	11.3	289.9	5.2	5.2	307.0	11.4	11.4	289.0	4.9	4.9
			Average	**0.1**	**14.4**		**-7.2**	**16.8**		**20.8**	**20.8**		**15.9**	**17.0**

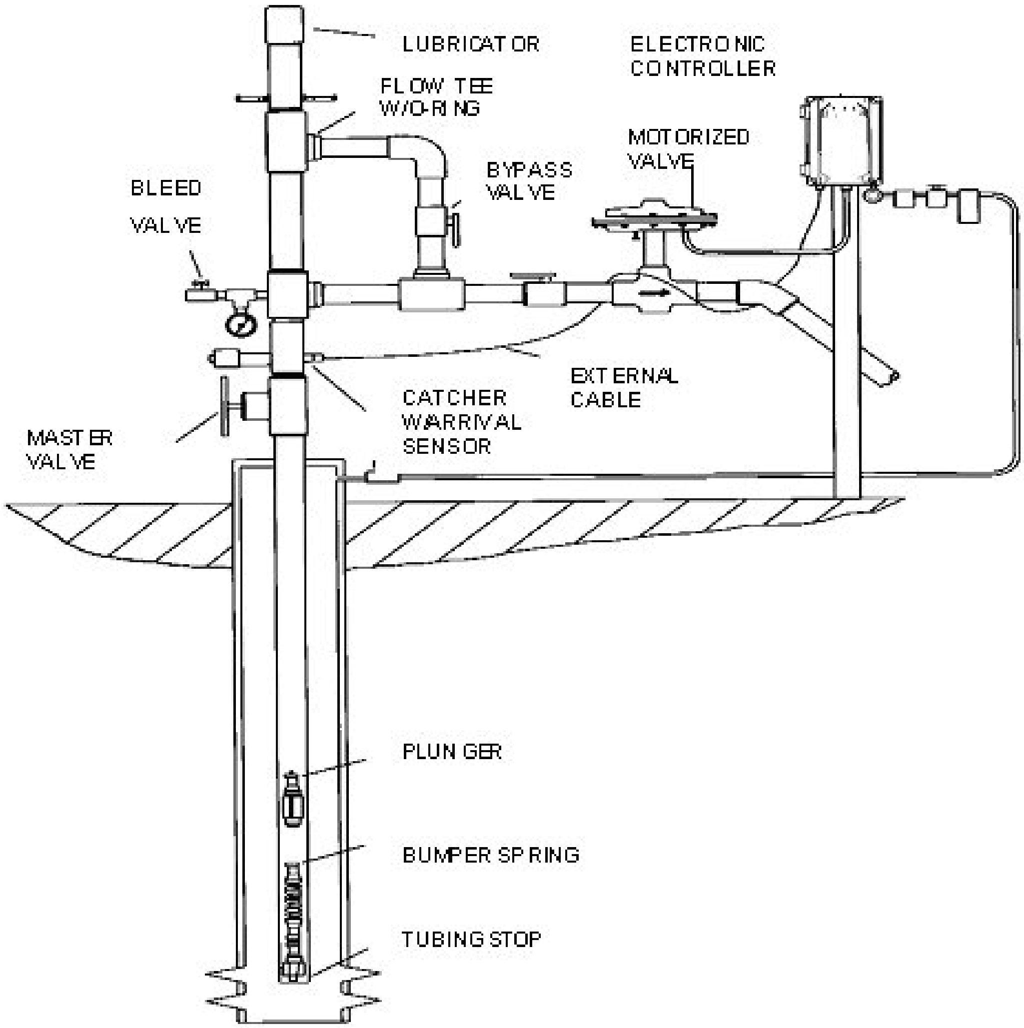

Figure 1 - Typical Conventional Plunger Lift Well System

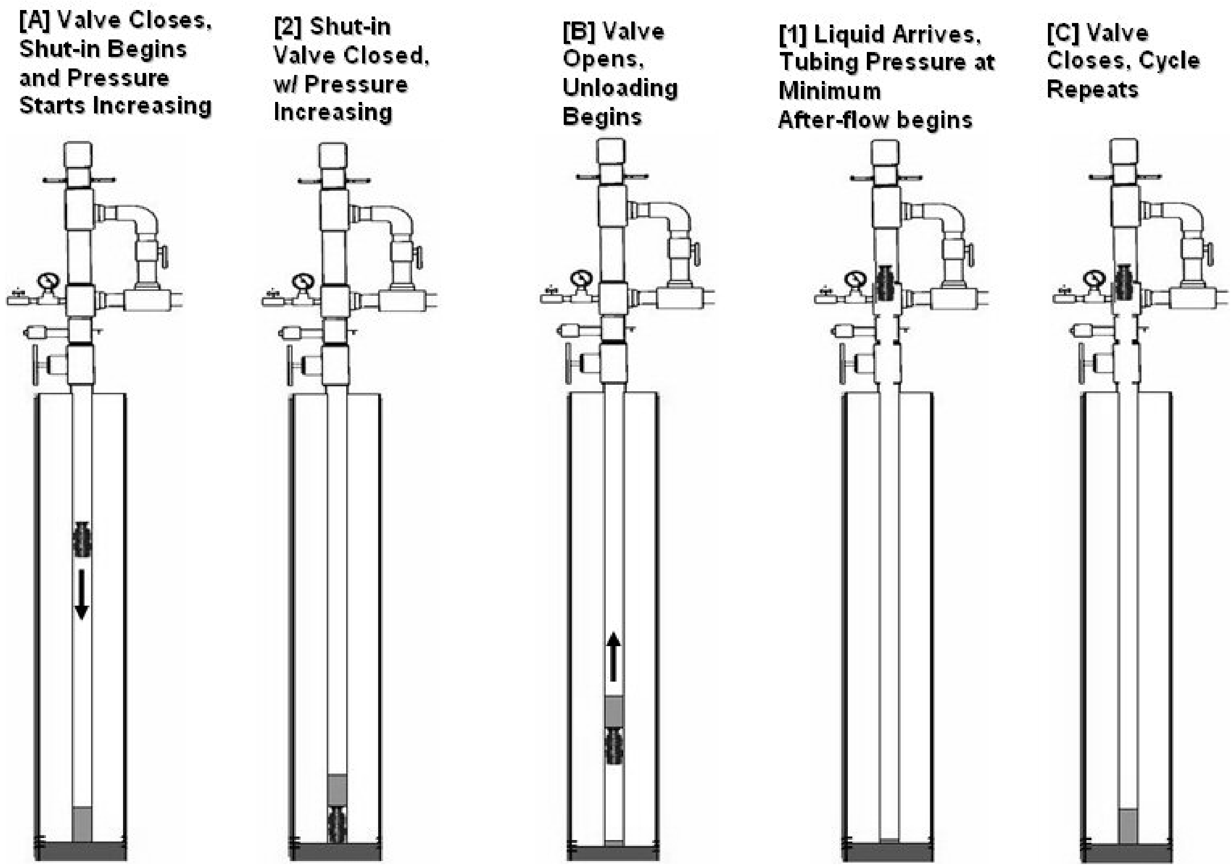

Figure 2 - Conventional Plunger Cycle Events

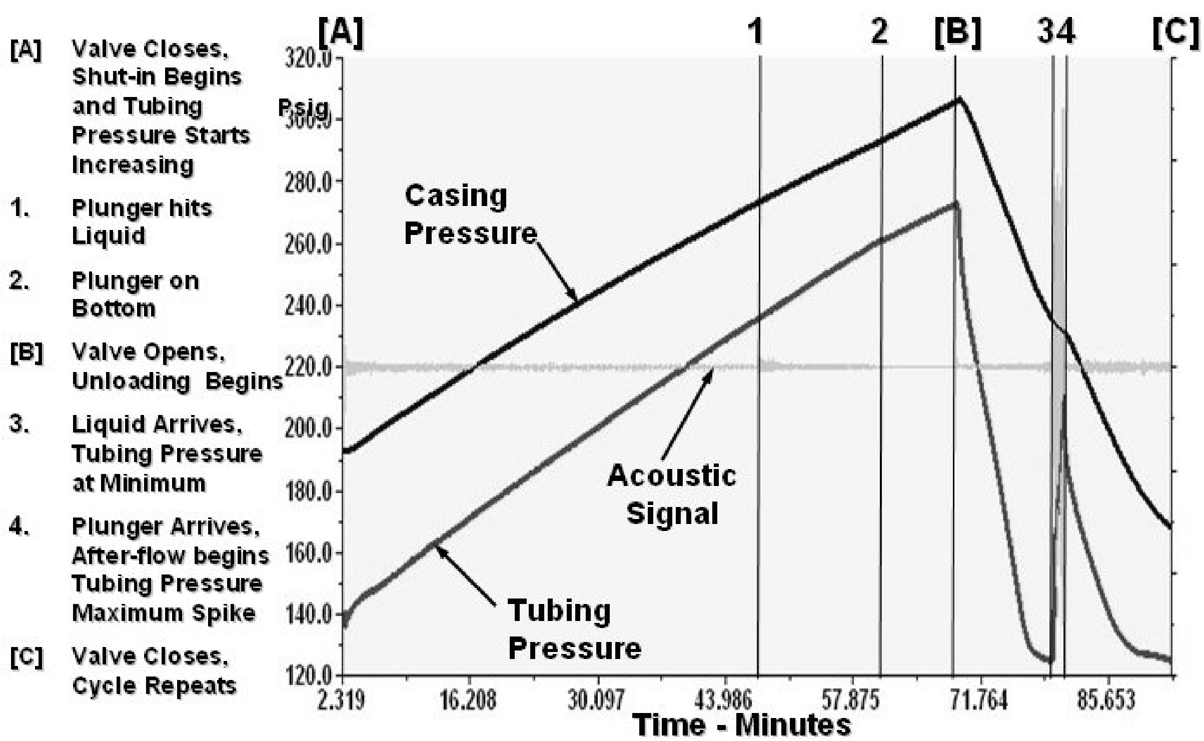

Figure 3 - Casing (highest pressure) and tubing pressure recordings during a conventional plunger lift cycle.

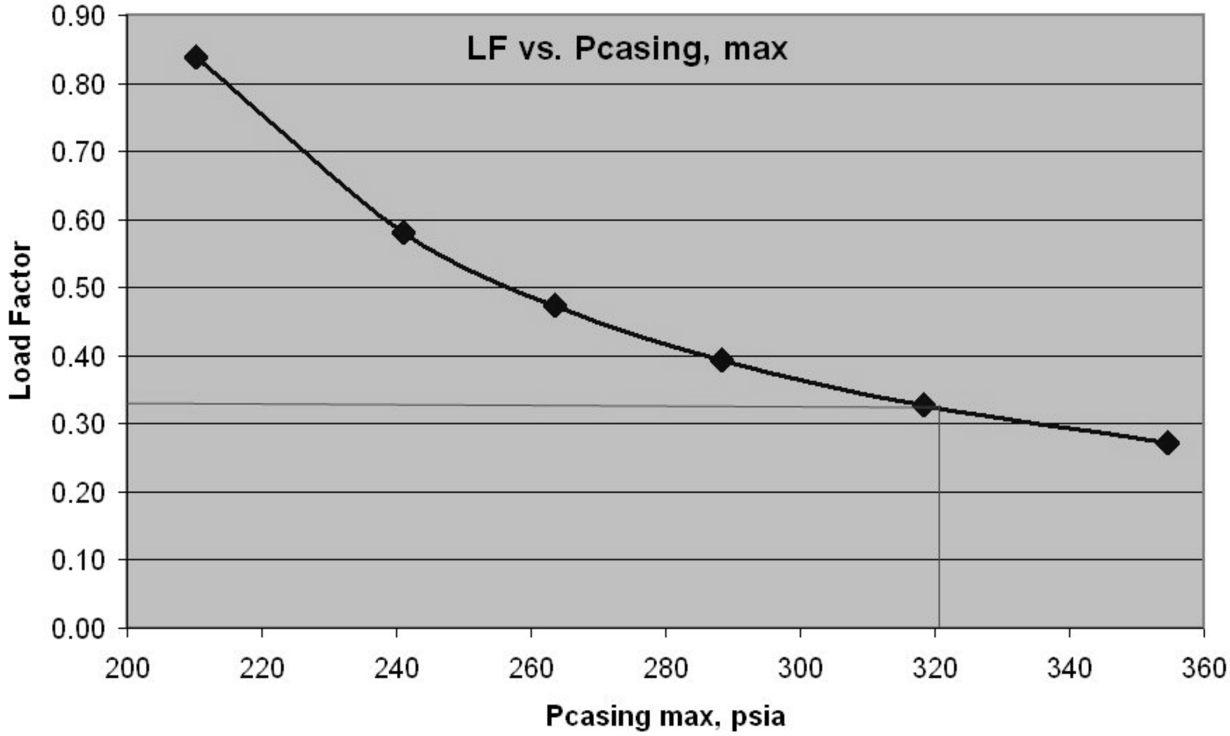

Figure 4 - Load Factor VS Casing Pressure Outputs from Foss and Gaul Spread Sheet.

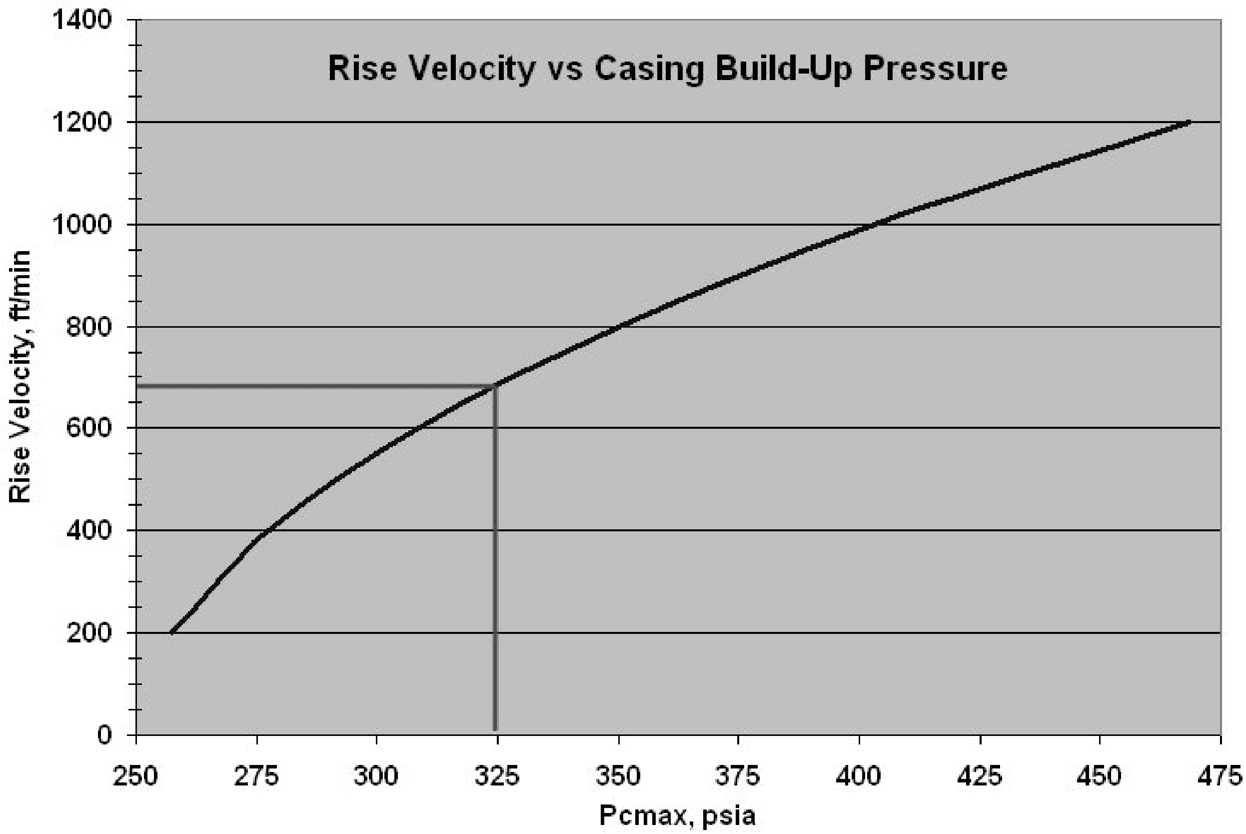

Figure 5 - Rise Velocity VS Casing Pressure Outputs from Foss and Gaul Spread Sheet.

APPENDIX A: Foss and Gaul Equations: Original and Modified

Foss, D. L. and Gaul, R. B.: "Plunger-Lift Performance Criteria With Operating Experience-Ventura Field, "Drilling and Production Practice, API (1965), 124-140.

Their original equation from the above reference for the casing pressure when the liquid arrives at surface is:

$$P_{c,\min} = (14.7 + P_p + P_t + P_c\ L)(1 + D/K) \quad \ldots\ldots\ldots\ldots\ldots \text{Eqn. A1}$$

$$\begin{aligned}
&\text{Where:}\\
&\text{Pcmin} = \text{casing pressure on plunger arrival at surface, psig}\\
&\text{Pp} = \text{pressure to support weight of plunger, psig}\\
&\text{Pt} = \text{line pressure, psig}\\
&\text{Pc} = \text{Plh} + \text{Plf}\\
&\text{Plh} = \text{pressure to lift weight of liquid, per barrel, psig}\\
&\text{P1f} = \text{liquid frictional pressure loss, per barrel}\\
&\text{L} = \text{load size, bbl}\\
&\text{D} = \text{depth of tubing, ft}\\
&\text{K} = \text{constant (related to gas friction in tubing_}
\end{aligned}$$

For the following tubing sizes, Pc and K have the following approximate values according to Foss & Gaul:

Tubing	*K*	*Pc*
2 3/8's	*33,500*	*165*
2 7/8's	*45,000*	*102*
3	*57,600*	*63*

Aann is the annulus cross section area between casing and tubing , ft^2
At is the tubing inside cross section area, ft^2
CPR = (Aann + At)/Aann …………………………………….. Eqn. A2
Pc, max = CPR x Pcmin ………………………………………. Eqn. A3

This approach assumes conservatively, that all energy comes from expansion of the gas from the casing to the casing to the tubing as the plunger comes up. It can be corrected to account for the gas that is produced as the plunger is coming up to the surface.
K(gas friction)can be calculated using the following formula:

$$K = \frac{(T_{avg} + 460)(Z)(Tbg_{OD}/12)(\ 2 \text{ x } 32.2 \text{ x } 144 \text{ x } 3600)}{\{(144/53.3)(\ Sg)(\ \ f_{gas})(V^2)\}} \ldots\ldots\text{Eqn. A4}$$

Pc (slug, psi/bbls) can be calculated from:

$$P_{weight} = Slug_{length} \text{ x } .433 \text{ x } SG_{liquid} \ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{Eqn. A5}$$

$$P_{friction} = \frac{62.4 \text{ x } SG_{liquid}\ (f_{liquid})\ (Slug_{length})\ V^2}{\{(Tbg_{id}/12)(2)(32.2)(144)(3600)\}} \ldots\ldots\ldots\ldots \text{Eqn. A6}$$

$$P_c = P_{weight} + P_{friction} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots Eqn. A8$$

This completes the derivation of the original Foss and Gaul in terms of known parameters.

Derivation of Modified Foss and Gaul accounting for production during the rise time and for plunger leakage during the rise time.

$$\frac{(PV/TZ)_1}{(PV/TZ)_2} = M_1 \big/ M_2 \quad \ldots\ldots \text{ Eqn. A9 where M denotes mass}$$

$$\frac{(Pc,\max)(A_{ann}D)}{(Pc,\min)(A_{nn}+A_t)D} = \frac{M_2 - (M,Gas_p - M,Gas_l)}{M_2} \quad \ldots\ldots\ldots \text{Eqn. A10}$$

where Gas_p, Gas_l refer to gas produced, leaked past plunger during plunger rise

$$\frac{P_{c,\max}}{P_{c,\min}}\left(\frac{A_{ann}}{A_{ann}+A_t}\right) = \frac{\rho_{2g}(A_{nn}+A_t)D - (\dot{m}_p - \dot{m}_l)D/V}{\rho_{2g}(A_{nn}+A_t)D} \ldots \text{Eqn. A11}$$

where $\dot{m}$ refers to mass rate of flow and V is average rise velocity, fpm

$$(\dot{m}_p - \dot{m}_l)D/V = \frac{(2.7)(14.7)(1000)(Mscfd_p - Mscfd_l)D}{(T_{R,avg})(z)(24)(60)} \ldots\ldots \text{Eqn A12}$$

, unit of lbm

where $T_{R,avg}, z$ are average values of degree Rankine, gas deviation factor for well

$$\rho_{2g}(A_{nn}+A_t)D = \frac{P_{c,\min}(2.7)(\gamma_g)(A_{nn}+A_t)D}{(T_{R,avg})(z)} \ldots\ldots \text{Eqn.A13}$$

So the modified F & G method with production and plunger leakage can be written as :

$$P_{c,\max} = P_{c,\min}CPR - \frac{14.7(T_{R,avg})(z)(1000)(Mscd_p - Mscfd_l)}{(520)(24)(60)(V)} \ldots\ldots \text{Eqn. A14}$$

Where $Mscfd_p - Mscfd_l$ is the difference of the flowrate of formation produced gas minus the flowrate of gas leaking past the plunger during plunger rise

Where the friction factor for gas and liquid can be approximated by the following for smooth pipes or other values to account for rougher pipe:

f = .0056 + 0.5 Nre $^{-.32}$ … Eqn. A15 for smooth pipes and Nre is the Reynolds number