NODAL ANALYSIS OF PLUNGER LIFT OPERATIONS

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Typical Plunger System

Plunger lift is, in its best form, a method that uses only the power from the existing well to produce liquids from the well and bring them to the surface using gas pressure that has built up in the well during a time when the surface production valve is closed. One type of a typical installation is shown Figure 1.

The components in the Figure 1 installation include:
-A downhole bumber spring to catch the plunger which is wirelined into the well
-A plunger free to travel the length of the tubing
-A well head designed to catch the plunger and allow flow around the plunger
-A motorized valve which can open and close the production line.
-A sensor on the tubing to sense arrival of the plunger
-An electronic controller which contains logic to decide how the cycles of flowing production and time of well shut-in period are determined for best production

Cycle Description:

The events of a plunger lift cycle are described in the following list and are also illustrated by the following figure showing the casing and tubing pressures and other values during the flow cycle and the build-up cycle.

1. The well is opened after the casing pressure is built up to a workable value.

2. The tubing pressure drops, then rises as the slug of liquid passes and then continuously drops during the remainder of the flow cycle. If there is no second rise in tubing pressure , then the plunger has failed to surface or perhaps it could have come up dry.

3. The casing pressure drops at first, but then may build up as the tubing begins to liquid load as the gas velocity begins to drop to low values during the flow cycle.

4. The BHP drops at first during the flow cycle but builds back up as the liquids begin to load the well.

6. The well is shut-in.

6. The tubing and casing pressure build up but the tubing pressure is less than the casing pressure due to liquids in the tubing. The BHP builds up during the build-up portion of the cycle as well.

7. The cycles continue and may be adjusted according to several available types of control logic in different commercial plunger lift controllers.

Note that for a plunger cycle, the pressure that is built up in the off cycle is the major energy that is used to surface the plunger and the liquids. The well inflow adds some energy as the plunger rises, but the majority of the energy comes from the pressure of the gas in the casing. That is why most successful installations do not have packers in the well. However, there are some successful plunger lift installations with packers in the well, but these wells must have more pressure and GLR to operate well compared to installations that have the packer removed.

Previous Studies

There have been a number of papers published discussing selection criterion for plungers. Some of these are listed in the references in this paper. Reference 1 is a paper that correlates some data from the Ventura field in California for 2" and 2 1/2" plungers. The data listed in this paper shows the 2" plungers in 5 1/2" , 7" and 11 3/4"-7" casing. The data for the 2 1/2" plungers is mostly for 7" casing. The data is correlated and application charts are generated, some of which (discussed below) are still in use today.

In 1965, Foss and Gaul (Reference 2), developed a more mathematical model of plunger performance. The model was designed to deliver the plunger and liquid slug to the surface with an assumed average velocity, typically 1000 feet/second. The model also assumed 2000 feet/second for fall through gas and 172 feet/second for plunger fall velocity though liquid. The main result of their very thorough work, was to develop a model for the required casing pressure that must be built up for each cycle, which must be present to be sure the plunger and slug would surface. Of course, this requires a determination (from pressures, or production data, etc.) of the slug size.

The main Foss & Gaul[2] formula's are:

$$P_{casing, minimum} = (P_p + P_t + (P_{lh} + P_{lf})) (1 + D/K)$$

Where: Pcasing is the casing pressure just as the plunger and liquids surface (@ 1000 ft/sec average velocity)

Pp is the pressure needed to lift the plunger, psig (about 5 psi)
Pt is the sales pressure or separator pressure when the well is opened, psig
Plh is pressure needed to lift the weight of liquid per barrel, psig
Plf is the pressure needed to overcome the liquid friction in the tubing, psig
(Plh + Plf) was determined to be about 165 for 2 3/8 inch tubing and about 102 for 2 7/8 inch tubing
D is the bumper spring depth, feet
K is a factor to account of the gas friction in the tubing (about 33,500 for 2 3/8's tubing and about 45,000 for 2 7/8's tubing. Note: this can be calculated for other conditions mathematically- see Appendix A)

So the casing pressure needed before opening the well is P casing, max

$$P_{casing, max} = (A_a + A_t) / A_a) (P_{casing, minimum})$$

Where: Aa = cross section area of the annulus between the casing & tubing

At = cross section area of tubing inside area.

The ratio of area's used to calculate the maximum casing pressure from the minimum casing pressure is really a ratio of volumes with the depth canceled.

Hacksma [3] combined Foss and Gaul results with the IPR to determine the effects of available gas on plunger performance .

White [4] presented a model of plunger lift in an intermittent gas lift well. His work contains expressions to explain liquid fallback. Some results indicated that a hole in the center of the plunger increased plunger performance. Lea [5] presented a model calculating the changing pressures, and forces on a plunger as it rises to the surface. Also a discussion of leakage tests past various plungers is included. Reference 6 by Rosina includes some laboratory tests and critiques of other models compared to his.

Reference 7 includes some practical guidelines to selection of plunger lift. References 8 and 9 discuss the critical velocity in a well. When the gas flows below the critical velocity, the gas does not lift the liquid efficiently and liquids accumulate in the well and can stop or reduce production. When this situation occurs, tubing re-sizes, or lowering well head pressure can be implemented. Another approach is to use plunger lift.

Reference 10 is a study where beam pumping units, pumping gassy production , were successfully replaced with plunger installations.

Reference 11 is a more comprehensive model that includes a reservoir model in the plunger predications. This is probably more accurate than what is described in this paper, but takes longer to run and requires more data for screening and optimization.

Selection Criterion

There are many selection criterion, some very simple and others more complex using the results of the references discussed above. From Reference 7 the mention is made of the test that the well should produce about 400 scf/(bbl-1000 feet) Other operators use somewhat different figures for this test.

Example:

Well data: GLR = 4000 scf/bbl, depth = 5000 ft. Is this well a candidate for plunger lift?

GLR/(depth/1000) = 4000/5 = 800 scf/(bbl-1000 ft)

Since this is greater than a "needed" 400 scf/(bbl-1000 ft) the well **is** assumed to be a candidate.

Another test is the use of figures from the oldest reference listed in this paper, Reference 1. These figures are shown as Figures 3&4 (for 2 3/8's and 2 7/8's tubing applications). These figures are in terms of net pressure and GLR (gas-liquid ratio) and depth. Why are they still

used? They are correlation's from data and are very easy to use. Often times data is not available to use more sophisticated methods anyway.
Example of use of the Figures 3 & 4:

Depth = 5000 ft
GLR = 4000 scf/bbl
Plunger size = in 2 3/8's tubing
Casing pressure = 400 psi
Separator pressure = 100 psi

Net operating pressure = 400 - 100 = 300 psi

Entering Figure 2, at 300 psi and going to 5000 ft (between 4000 and 6000 ft) and reading to the left, it shows about 3,300 scf/bbl GLR from the well is needed. Since the well is stated to have a GLR = 4000 scf/bbl, then it should be a candidate. It is interesting to note that in Reference 1, the authors state that you should enter the chart with a depth equal to the actual depth minus 2000 ft. If you do this, then only about 1500 scf/bbl or less is needed for the well to be a candidate. It is unknown if this practice has apparently been done away with to make the prediction more conservative, or because it is more accurate (from experience) to not subtract the 2000 feet. It is definitely more conservative to not subtract the 2000 ft.

Field studies have been made using Figures 3 & 4. Another approach that has been used is to insure that the well has sufficient gas (GLR) and build-up pressure to operate with plunger lift using the Foss & Gaul equations. When a gas well is loading with liquids you have data on the gas and perhaps not the liquid production which may have to be estimated.

New Model Description:

Although Figures 3 & 4 do give an indication if the well has enough GLR and pressure to operate with plunger lift, they do not give any sort of relation to the well's inflow capabilities. Also as a well begins to decline due to liquid loading, the operator has a choice to use plunger lift (which does better with larger tubing up to a point) or go to coiled tubing, which usually means a tubing down size. Because of this it is desirable to have a method to help decide if you should use coiled tubing to operate a gas well into the future (when liquid loading begins) or if you should use plunger lift. Because of these needs, an attempt is made here to generate a method to help relate plunger lift performance to reservoir performance and also a method to compare plunger lift performance to coiled tubing or smaller tubing performance.

This analysis is not intended to take the place of using a reservoir model as is described in Reference 11, but is instead an attempt to make use of IPR or inflow expressions to get a picture of plunger performance.

Plunger lift is a transient phenomenon, and to cover all the possibilities of reservoir transient behavior, a reservoir model would be necessary as discussed in Reference 11. However, two limiting cases are used here to generate models so plunger lift performance can be shown like tubing performance on a Nodal type plot.

The first case is assuming that a constant flow of gas comes from the formation during the plunger lift cycle. This would approximate the situation of a very steep gas deliverability expression such that changes in the flowing BHP would result in little change in rate. This is pictured in Figure 5, showing a present and some future gas inflow curves. Note that the future curves become very steep. For instance an inflow curve like curve "C" in Figure 5 would show little change in flow rate with changes in bottom hole pressure. This situation would be one in which the "constant" flow model" described in Appendix A would be more applicable. On the other hand, assuming the well is very permeable and has a small time constant before it returns to steady state flow (as on an IPR type expression), then that would be the situation that is modeled in the variable rate model as detailed in Appendix B.

As described in Appendices B and C, both models have a build up portion when the well pressures up to a situation where the casing pressure has a value of Pcasing, max. The value of casing pressure used is the value described in Appendix A, as derived by Foss & Gaul. Both models A and B determine the time required for the casing pressure to build up from a calculated pressure to the Foss & Gaul Pcasing, max pressure. This pressure is the pressure that allows the slug and plunger to arrive at the surface with a prescribed average velocity (1000 fpm used here) at a casing pressure of Pcasing, min as described by Foss & Gaul. With formation gas coming in during the plunger rise, it is possible to describe a smaller Pcasing, max than used by Foss & Gaul. However, this correction is not made, and only the expansion of casing gas is used to bring the slug and plunger to the surface. This makes both models conservative in this sense. The constant flow model assumes that the rate of gas calculated in the model is the same for all parts of the plunger cycle. The variable rate model uses the steady state inflow expression to vary the rate during the plunger cycle, assuming the well recovers to steady state conditions very rapidly as pressures change during the plunger cycle. Neither condition would occur in most wells, but one or the other model may be close enough to a particular well's characteristics to determine how plunger lift may perform relative to the inflow expression and expected coiled or smaller tubing performance. Figures 6 and 7 show some sample cycles calculated from the new model.

After the build-up portion of the analysis, the rise condition is modeled, with the final condition being when the plunger and slug arrive at the surface with the Foss & Gaul casing pressure of Pcasing, min.

Next both models consider a blow-down flow period in which liquids interference is not considered in the Gray correlation used for tubing performance. A transient continuity equation is used to approximate what the flow and time required and final conditions are for this period. During this period, the pressure in the casing is calculated to drop from the Pcasing,min to a typically lower value and when the pressure no longer changes, this is the time and pressure and flow at which this assumed period ends.

Next a final flow period is assumed in which the bbl/mmscfd of liquids are assumed to rise in the tubing with time and the velocity of the fluids in the tubing. When the flow is calculated to drop below a critical velocity (References 7 & 8), this period is assumed to end. If the pressure rises to a target value before the critical velocity is reached, then this criterion is used to end this period. A value of 1/2(Pcasing, min + Pcasing, bd) is used as an arbitrary value pressure to end this final flow period. The Pcasing,bd is the pressure at the end of the assumed blow-down period.

These models are approximate and assumptions are used to build the cycles that are used to find the flow and pressures during the calculated plunger lift cycles. No leakage is calculated across the plungers. No accounting for liquid slug build up in the tubing during the pressure build-up is done to show a difference in the casing pressure and the tubing pressure. The gas production assumptions have been already discussed. The gas used in each cycle is not to be greater than the

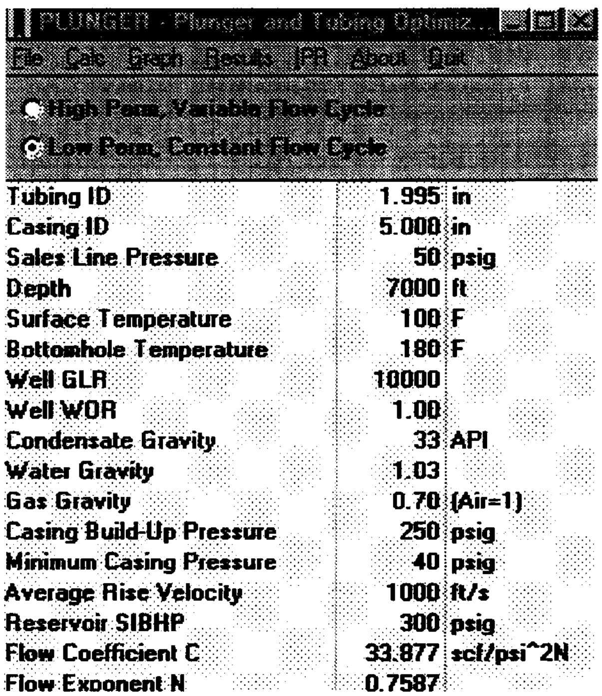
GLR of the well multiplied by the slug size used for each cycle calculation, the well gas to liquid ratio is maintained during each cycle. If a slug size is assumed and gas calculated from the model gives a GLR necessary for the cycle greater than the well's actual input GLR_{well}, then this is not shown as a point of possible plunger lift operation.

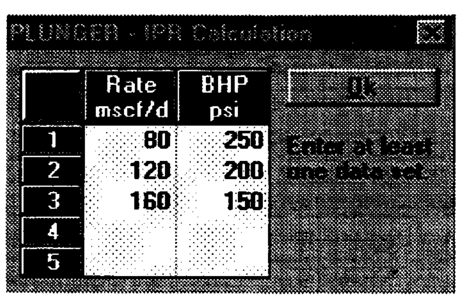
Continued use of the two model's compared to well performance will determine their usability to screen wells for plunger and also to determine their utility of determining whether you should use plunger lift or smaller tubing (coiled tubing) to solve problems encountered when a gas well begins to load with liquids.

<u>Sample Results from New Models:</u>

Several example results are presented to illustrate program output.

Base Case:





The above data is used for a base case for some sample outputs for plunger lift. The example is for a weak well that is producing some liquids.

Figure 8 shows output from the constant rate model. It shows good performance of plunger compared to the various sizes of smaller tubing with 50 psi on the tubing. No tubing intersections are possible for all the sizes of small tubing

Figure 9 shows the same case as Figure 6, but with the surface pressure up to 75 psi. No tubing performance is possible but plunger lift is possible. This is still for the constant rate model.

Figure 10 shows highly degraded plunger performance as the tubing pressure is raised to 100 psi and no tubing performance for a flowing well is possible. This is still using the constant rate model.

Figure 11 shows tubing performance with a flowing well is possible with 25 psi at the surface. However plunger lift is shown to be better This figure is using the variable rate model.

Figure 12 shows using the variable rate model, that 50 psi does not allow plunger lift operation and no tubing performance is possible.

Figure 13 with the variable rate model shows that increasing the input well GLR improves the predicted tubing performance and plunger is possible at a lower pressure as well. This case has the tubing surface pressure dropped back to 25 psi.

As expected the results using the constant rate model are much more optimistic than the variable rate case. This is because the flow into the well is not hindered as the pressure builds up in the well.

<u>REFERENCES</u>:

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Appendix A: Foss & Gaul Basic Plunger Lift Equations (Ref. 2)

The minimum pressure, Pmin, is the casing pressure when the plunger and liquid arrive at the surface of the well. To arrive at the surface, the plunger and the liquid slug had to overcome the pressure due to the plunger weight, the tubing surface pressure when the well is open, the friction and weight due to the liquid slug and the gas friction in the entire section of tubing from top to bottom.

$$P_{min} = (14.7 + P_{lgr\ wt.} / A_{tbg} + P_{t(min)} + (P_{lh} + P_{lf}) \times L) (1 + D/K)$$

Where: Plgr. wt is the plunger weight, lbf
Atbg is the tubing inside cross sectional area, ft^2
Pt(min) is the flow line pressure, psig
L is the slug size for one cycle, bbls
Plh is a factor when multiplied by L gives the pressure due to the weight of the liquid slug
Plf is a factor when multiplied by L gives the pressure due to the friction of the liquid slug
D is the well depth, ft
K is a factor when divided into the depth and multiplied by the pressure, gives the pressure due to the gas friction in the tubing.

Let Xl = 5.615/ (π d2/(4 x 144))..............ft/ bbl

where: 5.615 = ft^3/bbl

d = the tubing ID, inches

then: Plh = .433 x SG x Xl................psi/ft

where: SG = the specific gravity of the liquid

Plf = SG x .433 x f x Xl x V^2/ ((d/12) x 2 x g)............psi/ft

where: f = the friction factor for the flow of the slug inside the tubing

V= the rise velocity of the plunger/slug, ft/sec

g = 32.2 lbm-ft/(lbf-sec^2)

.433 = pressure per ft of water in a column, psi/ft

K = (T + 460) x Z x 2 x g x (d/12) x 144 / (V^2 x GG x R/144 x f)..... ft

where: T is the average temperature in the tubing, °F

GG = the gas gravity, air = 1.0

R = the gas law constant, 53.34 lbf-ft/(lbm-°R)

Pcmax is the casing pressure when the slug and the plunger at the bottom of the tubing just before the well is opened and the slug/plunger begin to rise. The Foss and Gaul method conservatively predicts that the energy of the gas stored in the casing just before the well is opened is all that is driving the slug/plunger to the surface. Additional production from the well during this period adds additional energy for lifting the slug/plunger and actually reduces the required Pcmax needed to lift the slug, L, and the plunger.

Pcmax = C x Pmin

Where: C = (Atbg + Aann)/ Acsg , and Aann is the cross sectional area of the casing annulus area between the casing ID and the tubing OD, in units of ft^2.

So using the Foss & Gaul approach, Pcmax is needed for the casing pressure before opening the well to lift the slug L, and the plunger weight to the surface. V is typically about 1000 ft/min for good plunger lift operations.

Foss & Gaul suggested the following numbers for the above equations, although different values could be calculated from the above equations.

Tubing ID................	1.995"	2.441"	2.992"	
(Plh + Plf)................	165	102	63	psi/ft
K..............................	33,500	45,000	57,600	ft

The equations for needed Pcmax and the casing pressure at slug/plunger arrival, Pmin, are used in this paper to determine casing pressures before release and after arrival of the slug/plunger. Other modifications such as leakage across the plunger and accounting for production during the plunger travel can be used to refine the equations if desired.

Appendix B: Constant Reservoir Rate Cycle Model

For this approximate cycle model, an IPR with a steep slope would give the best results. . This assumes that whatever the average rate for the plunger cycle, changes in flowing pressure at the sand face will have slight changes in the flow rate into the well bore during a complete plunger cycle.

The cycle must be started at some point. The beginning point of the analysis will be at the starting point of the shut-in period or the pressure "build up". A small slug size is assumed and a cycle is iterated for until results are obtained. Next a larger slug size is assumed and the calculations repeated. When the slug size and the calculations are repeated until the gas rate is greater than the input IPR AOF, the run is completed.

Build-Up Portion of the Cycle:

The time for build-up, Tbu, days, related to the rate and change in pressure in the well is:

Tbu, days = (Pcmax - Pf) (Vol) (144/R) (SG)/ ((Qmscfd)(ρ_{sc}) (T + 460)(1000)(Z))

where: Pf = casing pressure before shut-in, psi
Pcmax = casing pressure necessary before well is opened to flow, psi
Vol = volume in casing and tubing, ft^2
144/R = in2/(ft2-R) , where R = the gas law constant, 53.34 lbf-ft/(lbm-°R)
Qmscfd = the average and instantaneous gas rate into the well bore during the cycle
T = the average temperature in the well, °F
Z = "average" compressibility factor for the well

The average pressure during the "build-up" is taken as (Pcmax + Pf) / 2

Rise Portion of the Cycle:

When the well is opened, the slug and the plunger rise. When the slug/plunger arrives at the surface, the casing pressure is Pmin.

The time for the rise is, Trise = Depth/Velocity, where the velocity of rise is taken as 1000 fpm for the model.

The average pressure during the rise is taken as (Pcmax + Pmin)/2

Blow-Down Portion of the Cycle:

During this portion of the cycle, a period of flow out of the well, while the well is still producing into the well is happening, A simplified "continuity" equation is used to simulate the storage of gas in the well bored, and the flow into and out of the well. This portion of the cycle is continued until the flow out of the well drops to below "critical flow" or the production out of the well drops to the production into the well, at which time the pressure in the well has dropped as low as it can go.

The approximate equation used for the annulus between the tubing and casing is:

d mass/ dt = mass rate, in - mass rate, out

or:

{ Vol, csg (144/R)(SG)/ ((T + 460) (Z)} dP/dt = { Qmscfd, reservoir x - Qmscfd, tubing x ρ_{sc} } x 1000

Where: P is the instantaneous pressure in the casing, psi
Qmscfd, reservoir is the constant rate during the cycle
Qmscfd, tubing is the instantaneous rate flowing through the tubing as a function of the surface pressure, and the changing pressure at the bottom of the casing

The pressure at the entrance to the tubing at the bottom of the tubing is taken as:
P (at the casing surface, psi) x exp(.01877 x GG x Depth)/(Z x (T +460)). The flow is iterated until the flow corresponding to this pressure at bottom and the surface tubing pressure is found. The Gray correlation is used for this calculation , although other calculations could be used.

The pressure is advanced with time by using a finite difference expression for dP/dt in the above "continuity" equation, or:

P(t+Δt) = K (Qmscfd, reservoir, Qmscfd, tubing) + P(t)

Where: K = { (T+460)(Z)(ρ_{sc})(Δt, days)/ (Vol, csg (144/R)(SG)) }

The procedure is advanced until the critical velocity is reached in the tubing or the flow in the well equals the flow out of the well.

The average pressure can be calculated from the point by point calculations, The time for the blow down is the sum of the Δt, days, or ΣΔt, days as the pressure is advanced step by step. This section of the cycle is assumed to flow with the interference of liquids in the well since they are assumed to be lifted out of the well by the plunger.

The critical flow is determined from Turner , Ref. 8, and the formulas used are:

Y=.0031*Tbg, press
Vgwater =5.62*((67.-y)$^{.25}$)/(y$^{.5}$)
Vgcond = 4.02*((45.-y)$^{.25}$)/(y$^{.5}$)

Qcrit=3.06*tbg, press*Vg*Atubing/((Ttop+460)*Z)

A later correlation (20 % less) than above was developed for gas wells with surface pressure less than about 1000 psi and can be used instead of the above correlation's.

Final Flow Portion of the Cycle Model:

In this final section of the model, the well is flowed with increasing liquids in the well bore, increasing to the point of the input value of the input bbls/mmscfd of liquids. The flow begins with no liquids in the tubing but the portion of the tubing flowing gas with liquids increases up the hole at the rate of the insitu velocity of the gas in the well. This section continues until the pressure arbitrarily reaches Pf, which is set as
1/2 (Pmin + Pblow,down), where the minimum value of the blow-down pressure is used. This increased using calculations with 1 minute as the time interval for calculations as the gas proceeds up the tubing. During this portion of the cycle, the flowing BHP continually increases with time.

Once this final flow is done, the complete cycle has been completed.

<u>Iteration:</u>

Now the cycle is repeated with the below adjusted Cycles per day and flow quantities:

Cycles per day = 24.* 60. /(Tbuild-up + Trise + Tblow-down + Tflow)

The liquid production is then: Qliquid = Cycles x Slug (used for each point calculation) , bpd

The gas production is Qgas, total = GLR, well, Qliquid

The average pressure during the cycle is :

Paverage = (Tbu x Pbu + Trise x Prise + Tblowdown x Pblowdown + Tflow x Pflow)
/ (Total Time)

This is continued until quantities are constant for new iterations. Then a larger slug is assumed and the new cycle is calculated as above.

The gas produced for one cycle is compared to slug size x GLR well. If the calculated gas used per cycle is greater than the slug size x GLR well, then the rate is set to zero, since this is not a point where the plunger could operate continuously.

Appendix C: Variable Rate Cycle Analysis

This analysis considers that whatever the well bore pressure is, the rate from reservoir follows the downhole pressure from an IPR or gas deliveribility curve. It is a transient situation when a plunger is operating and when pressures change, the rate will not instantaneously respond in a steady state manner to changes in the well bore pressure. However, the more permeability the well has, the quicker the well will respond in a manner that approaches steady state flow as from a gas well deliveribility expression. So, in summary, this method of analysis presented in this section is best for very high permeability wells.

The cycle must be started at some point. The beginning point of the analysis will be at the starting point of the shut-in period or the pressure "build up". A small slug size is assumed and a cycle is iterated for until results are obtained. Next a larger slug size is assumed and the calculations repeated. When the slug size and the calculations are repeated until the gas rate is greater than the input IPR AOF, the run is completed.

Build-Up Portion of the Cycle:

ΔT, days = (ΔP) (Vol) (144/R) (SG)/ ((Qmscfd)(ρ_{sc}) (T + 460)(1000)(Z))

where: Pf = casing pressure before shut-in, psi
Pcmax = casing pressure necessary before well is opened to flow, psi
Vol = volume in casing and tubing, ft^2
144/R = in2/(ft2-R) , where R = the gas law constant, 53.34 lbf-ft/(lbm-°R)
Qmscfd = C (Pr^2 - Pwf^2)^n
T = the average temperature in the well, °F
Z="average" compressibility factor for the well

The above equation is solved by using "Simpson's" rule. The equation is integrated numerically from the initial casing pressure of Pf (described below) to Pcmax which is the max casing pressure needed before opening the well for the plunger to rise. The pressures in the equation are corrected from surface values to average values for the well for the above integration. At the end of the integration, the time for this build-up is obtained. Also the average flow into the well during this time, and the average pressure in the well during this time can be obtained.

Rise Portion of the Cycle:

When the well is opened, the slug and the plunger rise. When the slug/plunger arrives at the surface, the casing pressure is Pmin.

The time for the rise is, Trise = Depth/Velocity, where the velocity of rise is taken as 1000 fpm for the model.

The average pressure during the rise is taken as (Pcmax + Pmin)/2

Blow-Down Portion of the Cycle:

During this portion of the cycle, a period of flow out of the well, while the well is still producing into the well is happening, A simplified "continuity" equation is used to simulate the storage of gas in the well bored, and the flow into and out of the well. This portion of the cycle is continued until the flow out of the well drops to below "critical flow" or the production out of the well drops to the production into the well, at which time the pressure in the well has dropped as low as it can go.

The approximate equation used for the annulus between the tubing and casing is:

d mass/ dt = mass rate, in - mass rate, out

or:

{ Vol, csg (144/R)(SG)/ ((T + 460) (Z)} dP/dt = { Qmscfd, reservoir -_Qmscfd, tubing x ρ_{sc} } x 1000

Where: P is the instantaneous pressure in the casing, psi

Qmscfd, reservoir is now calculated from a back pressure equation or from

$$Qmscfd = C (Pr^2 - Pwf^2)^n$$

Qmscfd, tubing is the instantaneous rate flowing through the tubing as a function of the surface pressure, and the changing pressure at the bottom of the casing

The pressure at the entrance to the tubing at the bottom of the tubing is taken as:
P (at the casing surface, psi) x exp(.01877 x GG x Depth)/(Z x (T +460)). The flow is iterated until the flow corresponding to this pressure at bottom and the surface tubing pressure is found. The Gray correlation is used for this calculation , although other calculations could be used.

The pressure is advanced with time by using a finite difference expression for dP/dt in the above "continuity" equation, or:

$P(t+\Delta t)$ = K (Qmscfd, reservoir, Qmscfd, tubing) + P(t)

Where: K = { (T+460)(Z)(ρ_{sc})(Δt, days)/ (Vol, csg (144/R)(SG)) }

The procedure is advanced until the critical velocity is reached in the tubing or the flow in the well equals the flow out of the well.

The average pressure can be calculated from the point by point calculations, The time for the blow down is the sum of the Δt, days, or $\Sigma\Delta t$, days as the pressure is advanced step by step. This section of the cycle is assumed to flow with the interference of liquids in the well since they are assumed to be lifted out of the well by the plunger.

The critical flow is determined from Turner , Ref. 8, and the formulas used are:

$Y = .0031 * Tbg, press$
$Vgwater = 5.62*((67.-y)^{.25})/(y^{.5})$
$Vgcond = 4.02*((45.-y)^{.25})/(y^{.5})$

Qcrit=3.06*tbg, press*Vg*Atubing/((Ttop+460)*Z)

A later correlation (20%less) than above was developed for gas wells with surface pressure less than about 1000 psi and can be used instead of the above correlation's.

This pressure at the end of this portion of the cycle is used to determine what the current shut-in pressure, Pr, is using Fetdovitch[12] for future IPR conditions, where $Qgas = C\ Pr/Prs\ (Pr^2 - Pwf^2)^n$. All quantities in the program at know at some point of iteration in the cycle calculations, except Pr, so Pr can be iteratively calculated.

Final Flow Portion of the Cycle Model:

In this final section of the model, the well is flowed with increasing liquids in the well bore, increasing to the point of the input value of the input bbls/mmscfd of liquids. The flow begins with no liquids in the tubing but the portion of the tubing flowing gas with liquids increases up the hole at the rate of the insitu velocity of the gas in the well. This section continues until the pressure arbitrarily reaches Pf, which is set as
1/2 (Pmin + Pblow,down), where the minimum value of the blow-down pressure is used. This increased using calculations with 1 minute as the time interval for calculations as the gas proceeds up the tubing. During this portion of the cycle, the flowing BHP continually increases with time.

Once this final flow is done, the complete cycle has been completed.

Iteration:

Now the cycle is repeated with the below adjusted Cycles per day and flow quantities:

Cycles per day= 24.* 60. /(Tbuild-up + Trise + Tblow-down + Tflow)

The liquid production is then: Qliquid = Cycles x Slug (used for each point calculation) , bpd

The gas production is Qgas, total = GLR, well, Qliquid

The average pressure during the cycle is :

Paverage = (Tbu x Pbu + Trise x Prise + Tblowdown x Pblowdown + Tflow x Pflow)
/ (Total Time)

This is continued until quantities are constant for new iterations. Then a larger slug is assumed and the new cycle is calculated as above.

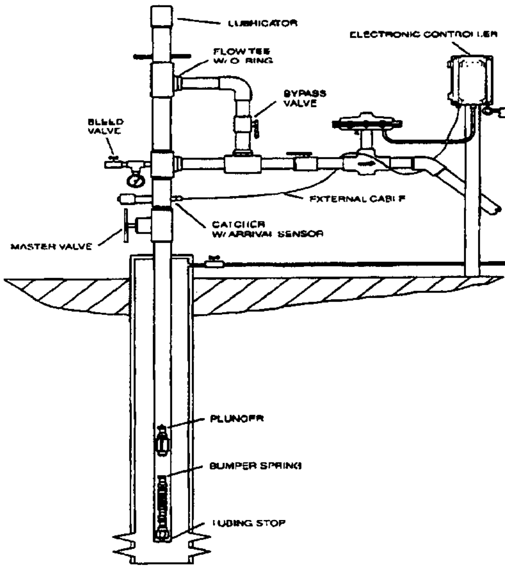

Figure 1 - Typical Plunger Lift Installation

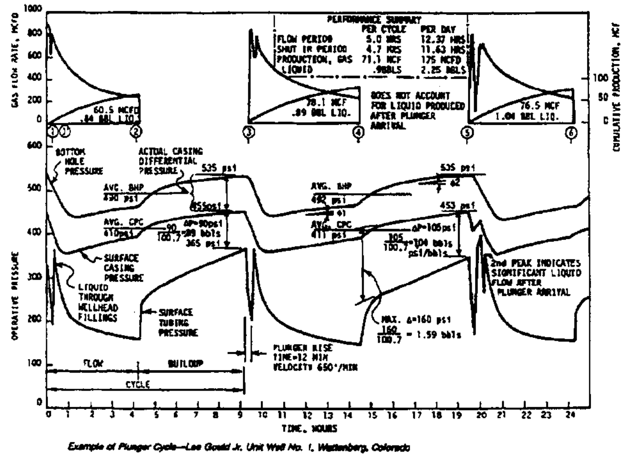

Figure 2 - Typical Events During a Plunger Lift Cycle

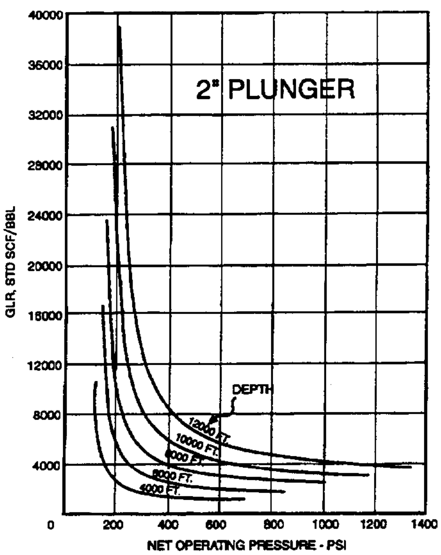

Figure 3 - Selection Chart 2 3/8's Tubing, Reference 1

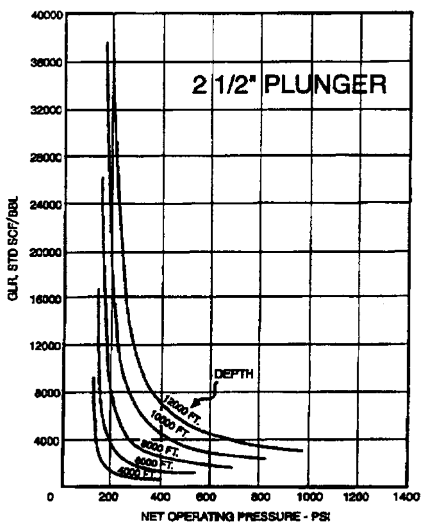

Figure 4 - Selection Chart 2 7/8's Tubing, Reference 1

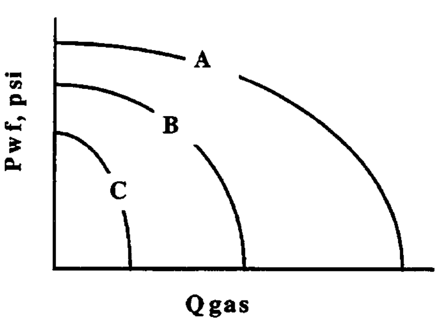

Figure 5 - Concept of Future IPR Curves. Later Curves are "Steep"

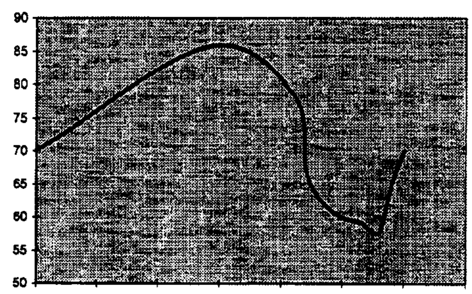

Figure 6 - Example Cycle Calculation for Constant Rate Model, .2 bbl Slug

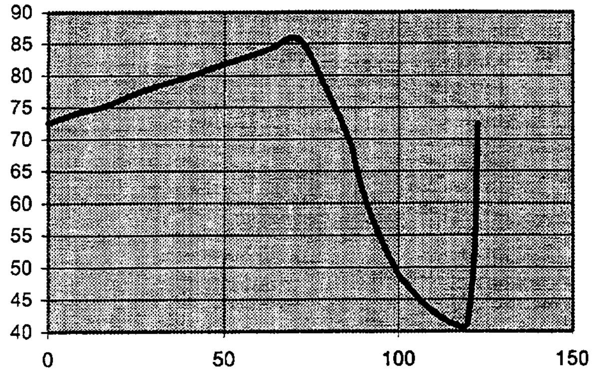

Figure 7 - Example Cycle Calculation for Variable Rate Model, .2bbl slug

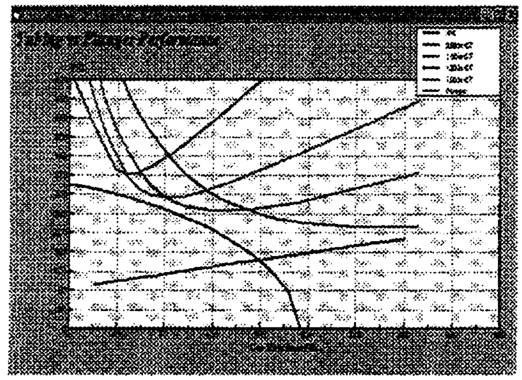

Figure 8 - psi Surface Pressure, Constant Rate Analysis

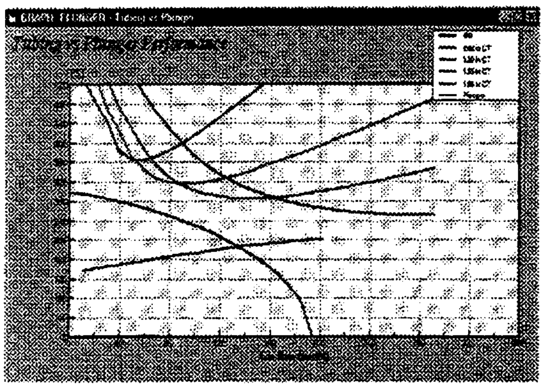

Figure 9 - psi Surface Pressure, Constant Rate Analysis

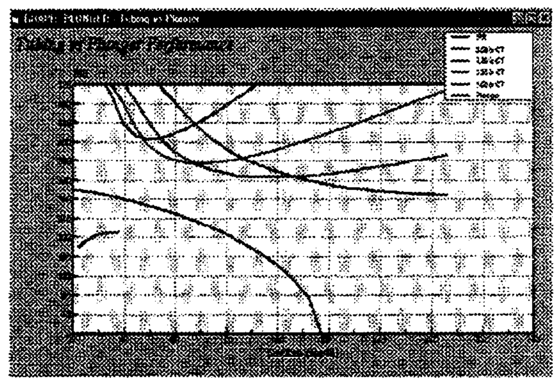

Figure 10 - psi Surface Pressure, Constant Gas Rate Cycle

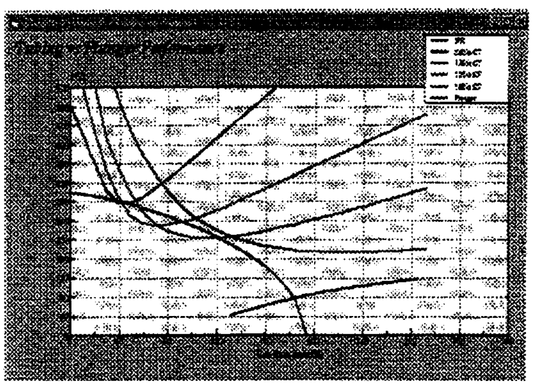

Figure 11 - 25 psi Surface Pressure, Variable Rate Analysis

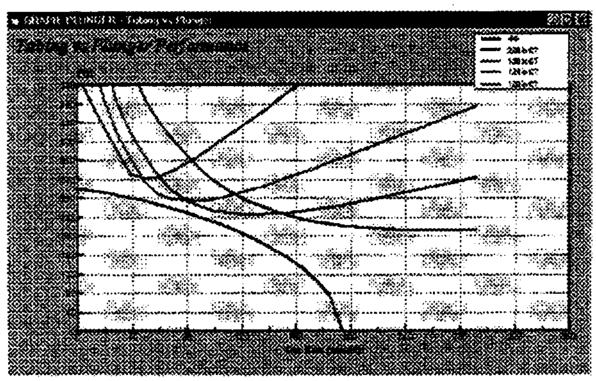

Figure 12 - psi Surface Pressure, Variable Rate Analysis

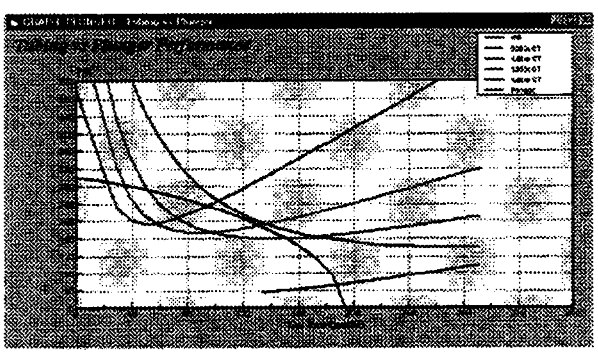

Figure 13 - Higher GLR (30,000) and 25 psi Wellhead Pressure, Variable Rate cycle