PLUNGER LIFT EVALUATION FOR OIL WELLS

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Introduction

It is the purpose of this paper to provide some assistance whether or not plunger lift is an economically viable alternative production method for specific wells. An evaluation spread sheet has been developed to assist in determining whether or not a rod pumped well is a likely candidate for plunger lift. The paper seeks to describe the assumptions and derivations of the equations in the spread sheet to provide a through understanding of the methods used in developing the spread sheet.

Theory Of Plunger Lift Operation

Plunger lift operates by providing a mechanical seal between the fluid being lifted and the lift gas, allowing the fluid to be lifted at a much lower velocity than is possible in flowing wells.

In normal practice for oil wells the operating cycle consist of a period of off time which allows liquid and gas to accumulate in the annulus and the tubing, an on time cycle during which the accumulated gas lifts the fluid to the cycle and a fall time which allows the plunger to fall from the surface to the seating nipple.

In gas production operations the well is allowed to produce until liquid accumulates in the annulus, then the flow line valve is closed to allow the plunger to fall to the seating nipple. After a sufficient time period to allow the plunger to fall from the lubricator to the seating nipple the flow line is opened and the plunger travels from the seating nipple to the lubricator, bringing with it a slug of accumulated liquid.

There are two critical parameters in the operation of a plunger lift system; gas volume and gas pressure. There must be sufficient gas volume stored in the annulus to displace the volume of the tubing, in order to cause the plunger and fluid slug to travel from the seating nipple to the surface. At the end of the producing cycle there must be sufficient casing/tubing pressure overcome the weight of the plunger and the fluid slug, the flow line pressure and the fluid and mechanical friction between the plunger and the tubing.

The low capital cost and low operating cost of plunger lift systems make the an attractive alternative to rod pumping lift systems. In making the decision to convert a well from rod pump to plunger lift it is necessary to know both the liquid production rate and the gas production rate. In many cases the gas production rate of rod pumped oil wells is not well known.

GAS PRODUCTION ESTIMATION FROM PRESSURE BUILD UP

A relatively simple pressure build up test can be used to estimate the gas production rate for a well. Using the relationship $\frac{P_1 \times V_1}{T_1} = \frac{P_2 \times V_2}{T_2}$ the gas volume increase for a time period can be calculated. It is reasonable that the temperature of the gas in the annulus at the end of the build up test is the same as that at the beginning of the test, thus eliminating the temperatures form the calculation leaving: $P_1 \times V_1 = P_2 \times V_2$. Where P_1 is the pressure at the beginning of the test, V_1 is the volume of the tubing / casing annulus, P_2 is the pressure at the end of the test and V_2 is the gas volume at the end of the test. Solving the equation $V_2 = P_1 \times V_1 / P_1$ will yield the volume of gas in the casing /tubing annulus at the end of the test. V_2-V_1 is the volume of gas produced during the test. When the gas produced is divided by the duration of the test in hours and the result is multiplied by 24 hours a fair estimate of the daily production rate is derived. The initial pressure should be at or above the minimum required pressure.

The Plunger Lift Evaluation Spread Sheet provides fields for the input of the casing diameter, tubing diameter, initial pressure, final pressure, initial time and final time. These values are used in the estimation of gas production. The annular volume and the tubing volumes used in the Plunger Lift Evaluation Spread Sheet are derived from the Halliburton® Cementing Tables.

Minimum Pressure
The minimum pressure required to operate a plunger is the sum of the flow line pressure, the pressure to overcome the weight of the plunger (P_p), the pressure required to overcome the weight of the fluid (P_L), the flow line pressure (P_{fl}) and the pressure required to store a volume of gas in the annulus sufficient to purge the tubing (P_a). $P_{min} = P_p + P_L + P_{fl} + P_a$

Plunger Pressure
The pressure required to overcome the weight of the plunger is calculated by dividing the weight of the plunger by the area of the plunger.

Fluid Pressure
The pressure to overcome the weight of the fluid slug is calculated by dividing the volume of the fluid slug by the unit volume of the tubing, barrels of fluid / barrels per foot, multiplying the product by the liquid gradient and dividing the product by the area of the tubing. $Pl=[(V_L/UV_t) \times Gl]/At$

Flow Line Pressure
The flow line pressure is a measured variable. The highest expected flow line pressure should be used in the *Plunger Lift Evaluation Spread Sheet* calculation.

Storage Pressure
The pressure to store a volume of gas in the annuls sufficient to displace tubing is calculated by using the PVT relationship between the tubing and the annulus. For the purpose of the *Plunger Lift Evaluation Spread Sheet* it is assumed that the plunger is 80% efficient in sealing the gas from the liquid slug.
$Pt \times Vt = Pa \times Va$ or
$Pa = Pt \times (Vt/Va)$
substituting flow line pressure for tubing pressure
$Pa = Pfl \; X \; (At \times Lt)/(Aa \times Lt)$
Canceling the tubing length
$Pa = Pfl \; X \; At/Aa$

Volume To Displace The Tubing
For the plunger to lift the fluid from the seating nipple to the surface it is necessary for the gas stored in the annulus to displace volume of gas in the tubing above the fluid. For the purposes of the *Plunger Lift Evaluation Spread Sheet* the volume of the tubing from the surface to the seating nipple is used, ignoring the volume of the liquid slug and the plunger. While this assumption is not exactly correct it will yield a conservative result.

The volume of gas required to displace the tubing is the volume of the tubing multiplied by the flow line pressure. $Vt = (Uvt \times Lt) \times Pfl$.

Pressure Build Up Time
Using the production rate from either a production test or a pressure build up test the time required to reach the required gas volume required to purge the tubing is calculated by dividing the tubing volume by the production rate in standard cubic feet per minute.

Plunger Travel Time
The plunger travel time is calculated using an average fall time of 170 ft/min and an average production speed of 750 ft/min. The tubing depth is divided by 170 and the product is added to the tubing depth divided by 750 to give the total plunger travel time, in minutes.

Plunger travel time = tubing depth/170 + tubing depth/750

Total Cycle Time
The total cycle time is the sum of the plunger travel time and the pressure build up time.

Maximum Number of Cycles per Day
The estimated maximum number of daily producing cycles is calculated by dividing the total cycle time into 1440.

Assumptions
The following assumptions have been made in the development of the Plunger Lift Evaluation Spread Sheet:
Gas flow from the formation into the annulus is at a constant rate.
The plunger falls at an average rate of 170 feet per minute.
The plunger and fluid slug travel at an average rate of 750 feet per minute.

The tubing and casing dimensions and annular volumes were taken from the Halliburton® Cementing Tables copyright 1972 .

Spread Sheet
Exhibit 1 is an example of the *Plunger Lift Evaluation Spread Sheet.* Exhibit 2 is a listing of the cell contents of the *Plunger Lift Evaluation Spread Sheet.* By entering the contents of the cells the form and function of the *Plunger Lift Evaluation Spread Sheet* may be duplicated.

The *Plunger Lift Evaluation Spread Sheet* is intended to assist the user in evaluating wells for plunger lift operations. No warranty, expressed or implied is made as to the accuracy or suitability of the *Plunger Lift Evaluation Spread Sheet* or calculations therein.

PLUNGER LIFT EVALUATION FOR OIL WELLS

B	A	B	C	D	E
1	Operator	Name of operator here			Input Data
2	Well Name	Well name or number			Input Data
3	Lease	Lease identification			Input Data
4	Well Number	Well number			Input Data
5	Producing zone	Producing zone			Input Data
6	Total Depth	7500			Input Data
7					
8	Liquid - BPD oil	6	bopd	BOPD	Input Data
9	water	6	bwpd	BWPD	Input Data
10	Tubing Depth	7500	Feet	L_t	Input Data
11	Tubing Size	2.5	Inches	D_t	Input Data
12	Casing Size	5 1/2	Inches	D_c	Input Data
13	Flow Line Pressure	60	PSI	P_f	Input Data
14	Weight of Plunger	10	lb	W_p	Input Data
15	Initial Pressure	1000	PSI	P_i	Observed Data
16	Final Pressure	1100	PSI	P_e	Observed Data
17	Initial Time*	0	Hrs *use 24 hour time	T_i	Observed Data
18	Final Time*	2359	2359	T_e	Observed Data
19	Gas Production Rate (Well Test)	0	MCFD Enter 0 if no test is avalable.	$MCFD_t$	Observed Data
20					
21	Test Duration	23.98	Hrs	T_t =	T_f - T_i
22	Pressure Build Up	100	PSI	P+ =	P_f - P_i
23	Annular Volume	665	CF	V_a =	CF/Ft x Lt
24	Volume Increase	66,450	SCF	V_i =	P+ x V_a
25	Gas Production Rate	66	MCFD	MCFDc =	((Vi / Tt) x 24) / 1000
26		46.18	SCFM	SCFM =	(MCFD x 1000)/1440
27	Gas/Liquid Ratio	5,541	SCF/BBL	GLR =	MCFD / (BOPD+BWPD)
28	Production Index	739	SCF/BBL/1000ft	PI =	(GLR X 1000)/(L_t/1000)
29					
30	Is the well a PL candidate	YES	PI<400=NO >400&<420=MARGINAL >420=YES		
31	Minimum Pressure	230	PSI	P_{min}	(P_{fp} + P_f) + ((V_a/V_t)xP_f)
32					
33	Volume to displace tubing	14,940	SCF	V_t =	SCF
34	Storage Pressure Required	22	PSI		
35	Fluid/Plunger Pressure	54	PSI		
36	Pressure Build Up Time Required	324	Min	Tbu=	Vt/SCFM
37	Cycle Time (travel time)	54	min (fall time+production time)	T_c =	L_t/170 + L_t/750
38	Total Cycle time	378	Min (fall time+production time+build up)		
39	Maximum number of trips	4	Trips	NTmax =	1440/Tc or CFD/Vt
40	BBL per Trip	2.696	BBL	V_f =	(BWPD+BOPD)/Nt
41	Fluid/Plunger Pressure	10.1	PSI	P_{fp} =	Wp + (Vfbbl/42gal/bbl*6lb/gal/At)
42					
43	Assumptions:	1. Gas flow into the annulus is constant.			
44		2. Plunger fall rate is 170 FPM.			
45		3. Plunger trip rate is 750 FPM			
46					
47		2 3/8" Tubing	2 7/8" Tubing		
48		Annulus	Annulus		
49	Casing Size	Cft/Lft	Cft/Lft		
50	2 3/8" Tubing	0.02170			
51	2 7/8" Tubing	0.03320			
52	4 ½" (13.5 lb/ft)	0.05650	0.03870		
53	5 ½" (15.5 lb/ft)	0.10290	0.08860		
54	7" (23 lb/ft)	0.17778	0.16150		
55	7 5/8" (29.7 lb/ft)	0.22700	0.21270		
56	8" (26 lb/ft)	0.26680	0.25250		
57	Selected annular value	0.10290	0.08860		
58	Working registers UVa	0.0886			
59	UVt	0.0332			

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