VOL. 12, NO. 5, MARCH 2017 ISSN 1819-6608
ARPN Journal of Engineering and Applied Sciences

www.arpnjournals.com

STRING HYDRAULICS IN OIL WELLS

Luis Humberto Orduz
Universidad Surcolombiana, Avenida Pastrana - Cra 1, Neiva, Huila, Colombia
E-Mail: fescobar@usco.edu.co

ABSTRACT

Every hydrocarbon well uses tools and equipment not only for drilling but also for well completion, stimulation and production activities; all equipment is tested at conditions of pressure and surface temperature before being lowered into the well; during the run and during program operation, all the equipment is exposed to pressures and temperatures and changes by fluid movements generating variations that can affect their behavior. In this document the changes to which they are exposed in the well and a condensed during the run in hole and during operations, with calculating regarding the proposed service by the company and some authors regard.

Keywords: hydraulics, elongation, resulting forces, deformation.

1. INTRODUCTION

On drilling texts and especially in Applied Drilling Engineering, (Bourgoyene *et al.;* 1991)[1], it states that the drill pipe due to the hydrostatic pressure of the drilling mud generate forces applied at points where there are changes in diameter string, partly relieved by buoyancy factor effect because the used mud density; generating Neutral point theory, string in tension and compression, but did not consider the effect of the load exerted on string by their own weight; then, forces as a result of the exerted on the string which supports the fundamentals of buoyancy, buckling and effect of weight in the fluid (Hook's law) as the design factor of drill pipe and drill collar. A similar analysis extrapolates coatings for designs considering the hydrostatic pressure, formation pressure and fracture gradient for the same reason.

Previously it was determined that the pipes were altered and deformed by effect of the pressure exerted by the fluids in the well given by Klinkenberg[2] (Klinkenberg 1951), either by internal pressure or external pressure as demonstrated by Lubinski[3], (Lubinnski, Althouse, and Logan, 1962) with mathematical procedure to determine the effect of elongation by temperature, and changes caused by weight, changes caused by buoyancy and the effect of pressure as summarized by Mitchell[4] (Mitchell, 2008) in the State-of-the-Arttext published by the SPE.

In service companies publications, as Watherford[5] (Weatherford, 2000) its propose the Hook law equation applied under the concept of steel deformation, the same regardless of the grade of steel, just not exceed the elastic limit of material. It raises the equation of free point based the distortion achieved by applying tension in the drill pipe when being stuck in the well; relates the force to the pressure and determines the way to find the string load in the well considering the buoyancy effect due to fluid density.

In chapter 4, of Hydraulic Forces Handbook of Schlumberger[6], (2000), proposes the effect of changing forces of pressure applied to the use of packaging enforcement Hook law; Chapter 5 presents all the modeling forces by swabbing, buoyancy, buckling effect of temperature and force application, which raises the three possible alternatives for the effects of elongation depending on the conditions, free movement, restricted movement and anchored. The proposed from the academic standpoint with combines teaching experience and learning approach resulting ina methodologic development which allows calculating the elongation resulting, when the string is run in hole, during injection operation conditions, and oil or gas well flow, and the effects on the tubing at run in holeorto seat packer in casing.

2. PROCEDURE

It is stated that the elongation occurs at several different points in time, during string is running into well hole with packer, then the technical operator must correct the depth effect of elongation occurred adjusting the string so that it is in a position, Subsequently the packaging is seated, if it is used tension is applied to the packer it is necessary to know the elongation that would be applied so that packer is in position at the indicated point.

When we do the corresponding work, there are two different actions; the first occurs if injection into the well and the second takes places if the well produces

2.1. Elongation down the drill string in a well

In surface, the components of the strings are under surface temperature (*Ts*) and atmospheric pressure, the tubing when measured it is considered the measure temperature (*Tm*), the tubing length (*L*) is the sum of all the lengths of each measured tubing (Lm) and atmospheric pressure, as it is not a real gauge pressure measurement for the effects is considered zero (0) or if there is an applied pressure is considered the value of the gauge reading in part internal pipe on the surface, indicating that the pressure would vary from the surface to the bottom, the variable that is suggested, is that changes annular pressures consider from top to bottom as another pressure averages, modifying the equation.

When the string reaches the set background, the temperature increases linearly from surface according to the gradient of local temperature to a Bottom Hole temperature downhole (BHT), the pressure in the wells varies linearly according to the density of the fluid hydrostatic pressure (Ph) on the inside and outside of the tubing provided when they are available, or the average of

ARPN Journal of Engineering and Applied Sciences

the internal hydrostatic pressure (Ph) or external (Pha) depending on the conditions and pressures in the tubing (Pt) or the annular pump pressure (Pap) if any .

For this assessment suggested equations and adjusted in field units for the oil industry are applied by BJ[7] (BJ, 2001).

a) Elongation temperature change

$$Et = L*C*\Delta T \quad (1)$$

Et = Change due to temperature effect in tubing, inches
C = steel Expansion coefficient = 0.000*028"*/1°F
ΔT =Temperature differential degrees, °F.
L =Total length of the tubing measured in surface, feet.

$$BHT = Ts + \Delta T*h, \text{ Bottom Hole temperature} \quad (2)$$

$$\Delta T= ((BHT - Ts)/2 - Tm) \quad (3)$$

b) Elongation by weight *(Ew)*

$$Ew = 7.4 \times L^2 \times (\Delta - 2W (1-\mu)) /E \quad (4)$$

L =Total length of the tubing, feet
E =Modulus of elasticity of steel = 30*106 psi
Δ =Density of steel= 65.4 ppg
W =Density of liquid o fluid in the well, ppg
μ = Poisson ratio, = 0.30

c) Elongation pressure change*(Ep)*

$$Ep = L(1-2\mu)*(Pm*d)/ 4Et \quad (5)$$

L Total length of the tubing, feet
Pm Medium pressure, psi.
d Inside diameter, inches
t Thickness, inches

$$d = \Sigma (dixLi) / 2(\Sigma Li) \quad (6)$$

$$t= \Sigma (ti \times li) / 2(\Sigma Li) \quad (7)$$

$$Pm = ((Ph+Pt)/2 + (Pha+Pap)/2) \quad (8)$$

$$d = \Sigma (OD-ID)/ 2 /\Sigma Li) \quad (9)$$

The total elongation *(ET)* to running in hole of tubing will be:

$$ET= Et + Ew + Ep \quad (10)$$

The length elongation is found to be lifted as the pipe on the table, so that the packer is depth set.

2.2. Packing

The second step is to lay the packaging if tension is determined that length should stress the pipe and how much to increase the weight on the recorder (Martin Decker) the effect of the applied pull on tubing, if not then increases wedges packaging do not act and this sliding gasket inside casing, the proposed equation by Weatherford International is used, Weatherford[8] (Weatherford, 2003) which is mostly used to determine the free point and amended as follows:

$$S\text{-}O = (L \times T \times C1)/ (1000x1000) \quad (11)$$

S-O = (Slack Off)
L =Packer set depth, feet
T =applied tension, pounds
C1 =Stretch constant, by Weatherford data from 1.009 to 2 7/8 OD inches Tubing; and OTIS[9] Catalog data, Otis (1983), from 3 1/2 to 4.5 OD inches Tubing, Drill pipe and casing

Data off running in hole, example:

Ew = 50, 27"
Ep = 14, 31"
Et = 29, 58"
ET = 99, 98"= 8, 4

VOL. 12, NO. 5, MARCH 2017 ISSN 1819-6608
ARPN Journal of Engineering and Applied Sciences

www.arpnjournals.com

Table-1. Tubing stretch contant.

OD (Inch)	**Tubing weight lb/ft**	**ID** (in)	**Stretch constant in/1000 lb/1000 ft C1**
1.004	1.14 1.20	0.824 0.824	1.20120 1.20120
1.305	1.30 1.43 1.63 1.70 1.72 1.80	1.125 1.097 1.065 1.049 1.049 1.049	1.09890 0.96852 0.85653 0.80972 0.80972 0.80972
1.660	2,10 2.30 2.33 2.40	1.410 1.380 1.380 1.380	066335 0.59791 0.59791 0.59791
1.900	2.40 2.60 2.72 2.75 2.76 2.90	1.650 1.610 1.610 1.610 1.610 1.610	0.57389 0.50063 0.50063 0.50063 0.50063 0.50063
2 1/16	2.66 3.25 3.30 3.40	1.813 1.751 1.751 1.751	0.52562 0.42761 0.42761 0.42761
2 3/8	3.10 3.32 4.00 4.60 4-70 5.30 5.80 5.95 6.20 7.70 4.36 4.64	2.125 2.107 2.041 1.995 1.995 1.939 1.867 1.867 1.853 1.703 2.579 2.563	0.45249 0.42418 0.34542 0.30675 0.30675 0.27082 0.23641 0.23641 0.23081 0.18587 0.31546 0.30008
2 7/8	6.40 6.50 7.90 8.60 8.70 8.90 9.50 10.40 11.00 11.65	2.441 2.441 2.323 2.259 2.259 2.243 2.195 2.151 2.065 1.995	0.22075 0-22075 0.17746 0.16103 0.16103 0.15748 0.14771 0.13996 0.12727 0.11884
3.5	7.70 9.20 9.30 10.20		0.224 0.193 0.193 0.172

OD (Inch)	**Tubing weight lb/ft**	**ID** (in)	**Stretch constant in/1000 lb/1000 ft C1**
	12.70 12.80 12.95 14.90 17.05		0.136 0.138 0.136 0.116 0.097
4	9.4 10.8 11 11.6 13.4		0.166 0.163 0.163 0.150 0.131
4.5	12.60 12.75 15.50 16.90 19.20		0.136 0.139 0.113 0.096 0.091
5 Csg	15 18 20.8 24.2		0.114 0.096 0.082 0.071
5.5 Csg	14 15.5 20 23		0.124 0.111 0.101 0.075
7 Csg	17 20 23 26 29 32 35 38		0.102 0.087 0.075 0.066 0.059 0.054 0.049 0.046

Another way to set the packer by tension, it is most practical operationally, is to rotate to liberty drack block, and setdraw wedges packer, applying tension and checking that the weight measuring increase the number of pounds required to seat; cases of hydraulic packer or other mechanisms not apply in this case.

2.3. Doing the job

The shares corresponds to injection training as acids, crude, remedial cement, steam, water, gas; or hydraulic fracturing, or petroleum, gas, water or mixed fluids in oil well production; The analysis on the injection is carried out initially or later the analysis of production.

2.3.1 Injection work in the well

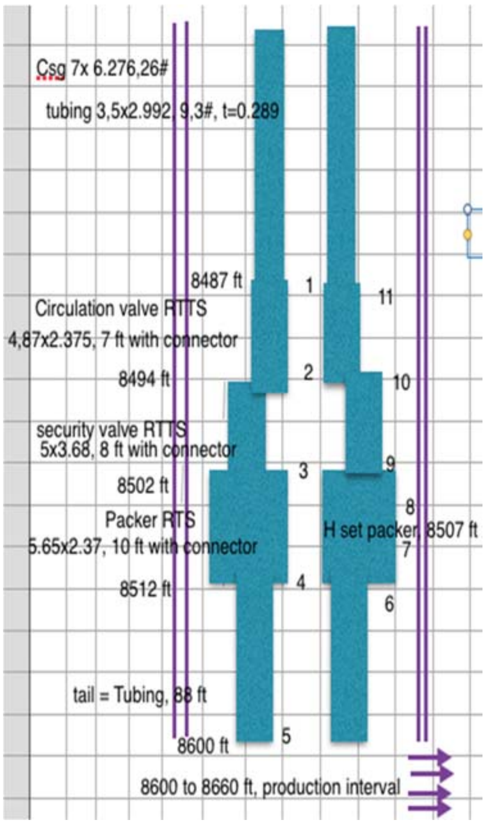
In this case there are two alternatives, the first one is injecting a homogeneous fluids with temperatures near atmospheric value and the second fluid are included

ARPN Journal of Engineering and Applied Sciences

www.arpnjournals.com

with appreciated temperature as in the case of hot raw or steam injection.

Table-2. Well data.



In the first case should be evaluated elongation effect of the forces resulting from the operation, considering that as injected, the analysis must be done at the event, for example. Pumping 20 bbl of acid, trough production tubing (previous data), will be calculate the resulting forces for periods each pumped 5 bbl (interval as every two, every three, every four) to estimate the behavior

In the first case should be evaluated elongation effect of the forces resulting from the operation, considering that as injected, the analysis must be done at the event, for example, pumping 20 bbl of acid, trough production tubing, will be calculate the resulting forces for periods each pumped bbl or a longer interval as every two, every three, every four or every 5 to estimate the behavior of the string during work, the general equation $F = P \times A$ is applied based on the diagram of the well and string, and it is an instantaneous pressure:

$$Fi = Pi \times Ai \tag{12}$$

Fi is force exerted at the point, pounds is the pressure at the point, psi inside of tubing

$$Pi = Ph + Pt - Dp\ Friction \tag{13}$$

Annular

$$Pa = Pha + Pap - Dp\ Friction \tag{14}$$

Where:

Ph Internal hydrostatic pressure in the tubing, psi
Pt Internal pressure in the heat tubing, psi
Pha Hydrostatic pressureAnnular, psi
Pap Pump pressure annular, psi
Δp Friction, friction loospressure of tubing head to infernal point

The following Table-2 is constructed to determine the pressure drops at all points where there are changes of area, by changes of internal or external diameters. The section corresponds to each of the points where changing area, where you go from one diameter to another either internal or external as appropriate; the table is constructed equal to the number of points where no change of area.

Table-3. Resulting force to 20 bbl of injected fluid.

Point	Pressure	Area	Force
	Pi=Ph+Pp-ΔFricc	$(D^2 - d^2)$ ¶/4	P x A
1	5354,49	2,601	13925,96
2	5357,44	-6,206	-33248,51
3	5361,87	6,225	33375,90
4	5367,41	-2,619	-14059,56
5	5416,13	-2,590	-14028,81
6	5367,41	-15,451	-82930,46
7	5364,64	-5,470	-29347,01
8	4438,1652	5,470	24278,77
9	4435,7472	5,437	24116,80
10	4431,8784	1,008	4466,20
11	4428,4932	9,006	39883,37
Total			-33567,35
			Acorta ↑

If there is no pressure applied to the annular (*Pap*) is zero (0) and by default no friction losses in the ring, on the inside is to be found depending on the length occupied by each fluid and its properties, or tables friction fallen suggested in this regard; where, the area (*A*) is given the general equation (15), from a larger diameter to a smaller diameter, or less diameter than one large diameter

$$A = \pi (D^2 - d^2) \tag{15}$$

The forces should have sign depending on whether lengthens (+) or shortened (-) tubing, the sum of the pipe is shortened and the sum of the tubing that

ARPN Journal of Engineering and Applied Sciences

stretches done, and resulting Force (FR) is the difference in the two with the corresponding sign. With this data, using equation (11) the amount of shortening or lengthening occurring in the string during events of different injection pump volume (5 to 20bbl) is determined, a graph viewing the effects in the tubing is constructed and thereby take appropriate action; in the graphic model, Figure-1, can thus appear to the case of injection acid, remember where the effect of temperature change of the Remembering that the change of temperature is not considered:

All FR of 0, 5, 10, 15 and 20 bbl pump acid are:

V, bbl	0	5	10	15	20
lb FR	-22986.87	-22030.01	-20836.04	-32594.04	-33567.35

In this case it is necessary to discharge this pound of material on the packer (puttingweightin string), to evite free packer

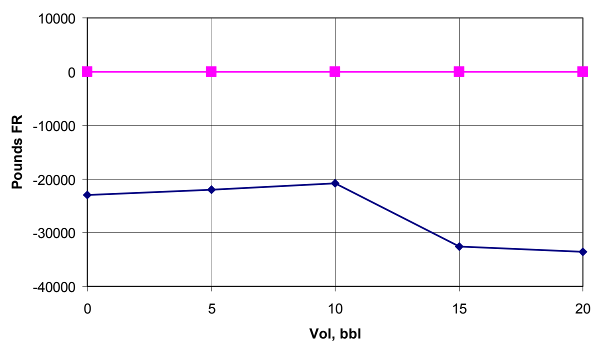


Figure-1. FR vs. injected fluid volume.

For the second case, it is considered the effect of the temperature of the injected fluid, particular case injection of hot oil or steam, consider evaluating the effect of the resulting forces due to change of pressure in the well, calculations similar to those previously described, in addition, consider the effect of temperature change, according to equation (15), the formation temperature does not vary, but the temperature gradient varies, proposed as:

$$Et = L*C*\Delta T \quad (16)$$

Et = Change due to temperature, inches
C = Expansion coefficient Steel = 0.000028”/1°F
ΔT = Temperature differential degrees, °F.
L = Total length of the pipe measured in surface, feet

Since the length is susceptible to change, affecting the drill string, the tail pipe may be altered and does not affect significantly the packaging

$$BHT = Ts + \Delta T*h \quad (17)$$

$$\Delta T= ((Tfs - BHT)/ 2) \quad (18)$$

Tfs = Temperature of the injectionfluid in head well, °F.

The effect of the change is greater in surface temperature and reduced to half that reaches the bottom, for that reason is considered average; if fluid surface is warmer than the bottom, steam, hot oil, the pipeline lengthens (+); if the injection temperature is lower, gas injection case, CO_2, the pipe is shortened (-) as it shrinks.

The total elongation by injection (*Eti*) in the string in these conditions is the sum of the elongation or shortening of the resultant force*(E(FR))* and the change in elongation by temperature*(Et)* variation, using the corresponding signs (+) Elongation, (-)

$$Eti = E\ (FR) + Et. \quad (19)$$

With this information the appropriate actions are taken to ensure the integrity of the operation, or prevent the release of the package, putting annular pressure or are you set tension to packer

2.3.2 Well oil production

With the string installed production, calculate the effects of the production of fluids on the string and / or packaging, in this case considered, similarly if oil or gas is produced to be considered the effects of resultant force and exchange temperature in the well; For purposes of calculating pressure at points of interest it is considered formation pressure (*Pf*) as a source of information:
Tubing internal pressure:

$$Pi = Pf - Phap - \Delta p \text{ Fricción} \quad (20)$$

where

(*Pi*) is the hydrostatic pressure from the formation to the point, psi
Pfap is the hydrostatic pressure from the formation to the point
Friction is the drop *Dp* friction from the formation to the point

The annular pipe pressure, will be used the equation (14)

$$Pfap= Pha + Pap - \Delta p \text{ Friction} \quad (21)$$

Pha Annular hydrostatic pressure, psi
Pap Annular pump pressure, psi
Δp Friction, friction if there are moving of the fluid

ARPN Journal of Engineering and Applied Sciences

The same procedure is performed to fill the table, pressure at each point- (section) - Area- Force, times numerous, until the well fluid moves and be replaced by fluid from the formation, graphics resulting force *(FR)* VRS injection volume is record.

To calculate elongation by temperature change, of the equation (1) (*Et)*, the variables are the changes of the temperature gradient where the fluids pass from one *(BHT)* to (*Ts)*, using the average change in the well is used, being as:

$$\Delta T = ((BHT - Ts) / 2) \quad (22)$$

However in the case of gas production must consider the expansion of the gas, which makes lower the outside temperature in the tubing *(Tsa)*, and on the other hand the temperature of internal surface *(Tsi*) flow in the tubing is reduced, is necessary finding an average of these changes*(Tmtb*), remaining as:

$$Tmtb = (Tsa + Tsi)/2) \quad (23)$$

However in the case of gas production must consider the expansion of the gas, which makes lower the outside temperature in the tubing, and on the other hand the temperature of internal surface flow in the tubing is reduced, so is because finding an average media tubing temperature *(Tmb)* of these changes, remaining as:

$$\Delta T = (((BHT - Ts) / 2) +((Tsa + Tsi)/2)))/2 \quad (24)$$

Similarly if the pipe is cooled it contracts (-) and heated lengthens (+).

calculation ended and made graphs of equation (19), *E*ti = *E* (*FR*) + *Et*used Figure-1, you can analyze the behavior of the string and / or packaging for the production of well fluid, this serves to select shirts extension to minimize or reduce the effect production elongation

3. CONCLUSIONS

There is always wells in which these effects alter the integrity, the first event is down the string and the second during operation; the most common remedial cementation occurs in high pressure, hydraulic fracturing and during the injection of steam and hot fluids where the internal pressure communication with the ring is common; with this procedure have a better estimate of what may happen and how to prevent it and during previous work, it is an indicator in the field; this allows more stringent packaging studies in fields where they have had these problems. Production have been known cases where over time the production due to the elongation or shortening which apparently should not happen falls, which can predict the behavior of the pipe and / or packaging and select the necessary extensions to compensate these variations.

Nomenclature

A	**Area**
BHT	Bottom Hole temperature
C	Expansion coefficient of the steel
C1	Stretch constant
D	Larger diameter
d	Minor diameter
E	Modulus of elasticity of steel
Eti	Internal injection total
Fi	Point Force
ID	Inside diameter
L	Total length of the tubing
OD	Outside diameter
Pap	Annulus pressure Applied
Pf	Formation pressure
Pi	internal pressure, reference point
Pm	Medium pressure
Pha	Hydrostatic pressure Annular
psi	Hydrostatic pressureInternal
t	Thickness
T	Temperature
Tfs	Surface fluid temperature
Ts	Surface pressure
Tm	Medium temperature
Tmb	Tubing medium temperature
Tsi	Internal surface temperature
x_f	Stretch constant
W	Fluid density in well
ΔT	Temperature differential degree, °F

Greeks

μ	Poisson ratio

ARPN Journal of Engineering and Applied Sciences

REFERENCES

Bourgoyene A.T, Millheim K, K, Chenever M, E, Young F, S. 1991. Applied Drilling Engineering, SPE. pp. 122-127, pp. 335-339.

Klinkenberg A. 1951. The Neutral Zones in Drill Pipe and Casing and Their Significance in Relation to Buckling and Collapse. Drill, and Prod. Prac., API. pp. 64-76.

Lubinski A., Althouse W.S. and Logan J.L. 1962. Helical Buckling of Tubing Sealed in Packers. JPT (June 1962) 655-670; Trans.

Mitchell R.F. 2008. Tubing Buckling-The State of the Art. SPE Drilling and Completions, December.

Watherford. 2000. Completion system. pp. 30-52.

Schlumberger. 2002. Hydraulic Calculations Handbookl2. Chapter 4: Hydraulic forces and Hook Loads.

BJ. 2001. Engineering Handbook, section. 6, p. 4.

Weatherford. 2003. Completion Engineering Data Handbook. p. 63.

Otis. 1983. Otis Catalog Appendix. p. 99.