INTERNATIONAL JOURNAL OF MULTIDISCIPLINARY RESEARCH AND ANALYSIS

ISSN(print): 2643-9840, ISSN(online): 2643-9875

Volume 05 Issue 10 October 2022

DOI: 10.47191/ijmra/v5-i10-20, Impact Factor: 6.261

Page No. 2706-2716

Tubing Movement Analysis in Completion Process at Well X

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ABSTRACT: The completion process in oil and gas production is one of the most important steps and affects to the final result of the entire process. In actual conditions, many things must be considered in the completion process. One of the most important things is about tubing movement. Tubing movement is the movement of tubing caused by differences in pressure and temperature in the well. Tubing movement can cause deformation of the tubing structure, and if the selection of tubing and packer is not appropriate, it can cause damage to the tubing or well structure. Calculating tubing movement can be done by calculating the total movement and force generated by this four tubing movement effects, which is: temperature effect, ballooning effect, buckling effect, and piston effect. The case study analyzed in this proposal is horizontal well X, and has a total tubing movement of 13,48 in elongation, or produces a force of 47.864,36 lbs. Because the value is positive, the force that applies is the compression force. By knowing the total force and displacement generated by the tubing movement, the engineer can design what type of packer will be used. For the case study in this report, it can be concluded that a force of 47.864,36 lbs can still be resisted by tubing which has a body yield strength specification of 361.000 lbs. Therefore, the tubing can be design to use a no slip packer where there is no movement between the tubing and the packer.

KEYWORDS: oil and gas, completion process, tubing movement

I. INTRODUCTION

The oil and gas industry has an important role in today's modern society in meeting various needs such as vehicle fuel, electricity generators, and so on [1][2]. Exploitation of oil wells in various places around the world is keep going to meet the demand for petroleum[3]. The technology used to mine oil is also growing [4]. Even in some cases, wells that are considered exhausted can still produce oil with newer technology [5][6].

Some of the products of the service company are to provide and consult of tools used to produce petroleum [7]. The tools used are varied and adapted to the conditions of the well that you want to produce. Some wells have extremely high temperatures and pressures, and some contain gases that can damage production equipment [8]. For this reason, analysis is needed in the selection of components in the production equipment for each well [1], [4], [8]–[11].

One of the main components in production is tubing [10][9]. At high temperatures and pressures that fluctuate during a scenario like the installation and production process of the well [11], the tubing will experience a shortening or elongation called tubing movement [4][10]. In a well that is hundreds of meters long, the shortening and lengthening of the tubing will greatly affect the safety and smooth of the production. The factors that caused it are due to the effect of the piston, ballooning, temperature, and buckling [9][6][2].

Tubing movement can interfere with operation and can even cause damage if not given proper handling [4][1]. Therefore, an analysis of the tubing movement is a crucial thing to do in the petroleum production process [6] in a well so that engineers can design the right completion tools for the condition of the well.

II. METHODOLOGY

A. Analysis Method

This study uses well X as an analytical medium with the scenario being run is a production scenario. The analysis of well X conducted in this study used an analytical methodology to process the data obtained. Based on the well data that has been provided, the wells to be analyzed are shown in Figure 1. Table 1 shows a description of the completion tools installed in well X.

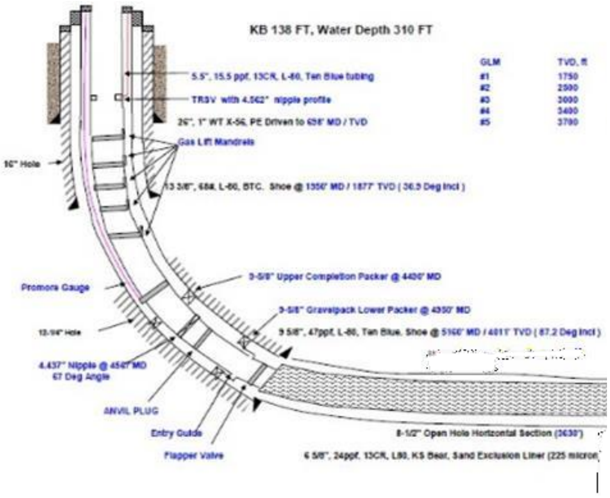

Figure 1. Schematic of Well X

Table 1. Data On Equipment Used.

No.	Completion Tools Parts
1	Surface Casing
2	Intermediate Casing
3	Annulus
4	Production Casing
5	Tubing
6	Packer
7	Liner

B. Data Collection

To get the results of the tubing movement that occurs, a calculation analysis is carried out using an empirical formula, ignoring the calculation of heat loss, normal force, drag force, and pressure loss because the values are not significant and have been covered by the safety factor value.

Table 2 below is the specification of the completion tools used in the calculations in well X.

Table 2. Data Specifications On Completion Tools.

Parameter	Casing	Tubing	Packer
Size/Weight	9-5/8 in / 47 lb/ft	5-1/2 in / 15,5 lb/ft	6-5/8 in / 24 lb/ft
Grade	L-80	13 Cr-80	13 Cr-L80
OD Nominal	9,62 in	5,5 in	7,68 in
ID Nominal	8,58 in	4,95 in	5,92 in
A_o	-	23,77 in^2	-
A_i	-	19,25 in^2	-
A_p	-	-	46,44 in^2
A_s	-	4,51 in^2	-
I	-	15,44 in^4	-

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In addition to the specifications of the completion tools, the initial and final conditions of the reservoir in well X are also required to be able to calculate the tubing movement. Table 3 describes the condition of the well along with the initial and final phases in the production scenario.

Table 3. Reservoir Data For Well X

Reservoir Properties	**Value**
well depth	3.900 ft TVD
Fluid	Oil and gas
Tubing Length to Packer Installed	4.490 ft MD
Initial Surface Temperature	70°F
Initial Bottom Hole Temperature	212°F
Final Surface Temperature	212°F
Final Bottom Hole Temperature	212°F
Average Initial Temperature	141°F
Average Final Temperature	212°F
Change in Average Temperature between Initial Condition and Final Condition (ΔT)	71°F
Initial Tubing Pressure (P_1 initial)	0 psig
Initial Casing/Annulus Pressure (P_0 initial)	0 psig
Final Tubing Pressure (P_1final)	0 psig
Final Casing/Annulus Pressure (P_0 final)	1.715,31 psig
Change of Average Tubing Pressure between Initial Condition and Final Condition (ΔP_1)	1.488,83 psig
Change in Average Annulus Pressure between Initial Condition and Final Condition (ΔP_0)	0 psig
Initial Tubing Fluid Density	9,5 ppg
Final Tubing Fluid Density	8,53 ppg
Initial & Final Annulus Fluid Density	9,5 ppg
Area of moment inertia	15,43 in^4

C. Tubing Movement

Tubing Movement is a calculation of how the tubing string will be affected by pressure, temperature, and mechanical changes in a well, this effect depends on the condition of the well, tubing to packer, and configuration of the casing and tubing restraint [12].

Prediction and calculation of tubing movement is an important part in the design of completion in wells. Changes in tubing length due to forces are the main cause of problems in the completion section [12].

There are various methods that can be used to determine changes in length and force value on tubing, here are the effects that can cause tubing movement in a well.

C.1 Ballooning Effect

Changes in pressure outside or inside the tubing string can cause a ballooning effect shown in Figure 2. The length of the tubing may shorten due to the greater internal pressure. Under different conditions, the pipe can elongate because the annulus pressure is greater than the pressure inside the tubing, this is also called reverse ballooning [12]. Therefore, the calculation of the change in tubing length due to ballooning is based on the average pressure change in the tubing and annulus. Changes in length and force value due to ballooning or reverse ballooning can be calculated using equations (1) and (2):

$$\Delta F_{ballooning} = -2\mu(A_i\Delta P_i - A_o\Delta P_o) \quad (1)$$

$$\Delta L_{ballooning} = -\frac{2\mu L}{E(A_o - A_i)}(A_i\Delta P_i - A_o\Delta \quad (2)$$

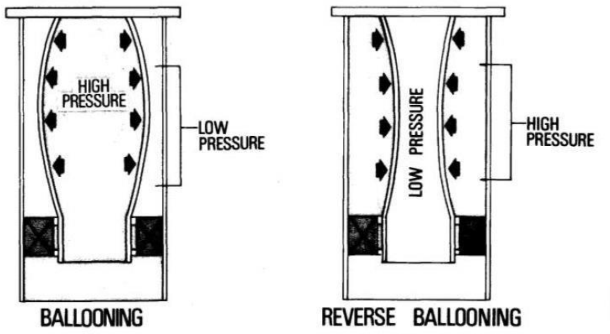

Figure 2. Ballooning Effect on Tubing

C.2 Temperature Effect

Changes in temperature can occur due to producing hot fluids or injecting cold fluids, this can cause changes in the length of the tubing and generate a tension or compression force due to changes in temperature. A well with a decreasing temperature will make the tubing shrink while a well with an increasing temperature will make the tubing expand shown in Figure 3. The value of the force and length change of tubing due to changes in temperature can be calculated using equations (3) and (4)

$$\Delta F_{temperatur} = \beta E \Delta T A_s \quad (3)$$

$$\Delta L_{temperatur} = L\beta\Delta T \quad (4)$$

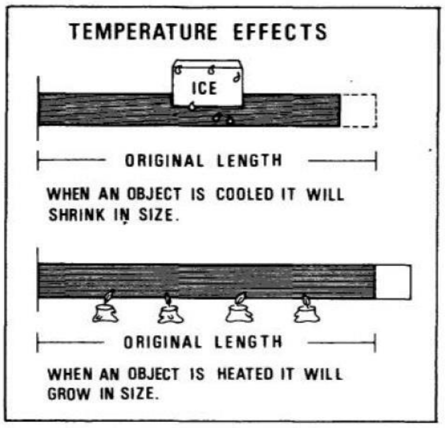

Figure 3. Effect of Temperature on Tubing

C.3 Piston Effect

The piston effect is the result of the pressure difference at the end of the tubing and the pressure at the annulus. The pressure difference at the end of the tubing occurs in the area difference between the packer valve (A_p) and the tubing I.D. (A_i).
The pressure difference in the annulus acts on the difference in area between the packer valve (A_p) and the O.D tubing area. (A_o). This will cause an unbalanced force on the packer area and will tend to push or pull the tubing resulting in a piston effect.

Changes in pressure between the end of the tubing and the annulus due to the piston effect result in changes in the force and length of the tubing shown in Figure 4. Therefore, it is necessary to calculate the change in length and force value which is calculated using equations (5) and (6):

$$\Delta F_{piston} = (A_p - A_i)\Delta P_i - (A_p - A_o)\Delta P_o \quad (5)$$

$$\Delta L_{piston} = -\frac{L\Delta F_{piston}}{EA_s} \quad (6)$$

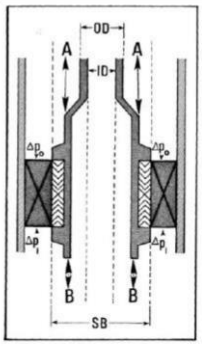

Figure 4. Piston Effect on Tubing

C.4 Buckling Effect

Buckling phenomenon as Figure 5 can be caused by two different force distributions. Which is, the force from the end of the tubing like the weight of the tubing itself, and the distribution of forces acting across the tubing wall by pressure [7]. The part of the tubing that is exposed to compression forces will have the possibility of buckling. However, parts that are below the tension point will not face buckling problems. Neutral point is the point that limits the occurrence of buckling, where the area above the neutral point will not experience buckling. Here is the formula for finding the neutral point:

$$n = \frac{(A_p)(P_{ifinal} - P_{ofinal})}{(W_s + W_i - W_o)} \qquad (7)$$

F_f (fictitious force) is a combination of internal pressure, external pressure and piston force. The F_f is not the actual force acting on the bottom of the tubing. F_f is used to indicate whether the pipe is buckling or not. tubing will buckling if F_f is positive. However, if F_f is zero or less than zero, the pipe will not experience buckling because the pipe is in tension. Here is the F_f formula:

$$F_f = (P_o A_o - P_i A_i) \qquad (8)$$

To be able to find out whether the buckling that is happening is helical or sinusoidal, it is necessary to find the critical force that occurs and compare it with the current force. The following formula is used to determine the critical Helical and Sinusoidal forces:

$$Fc_{\text{Helical}} = -1{,}41\sqrt{\frac{4EIwsin\theta}{rc}} \qquad (9)$$

$$Fc_{\text{Sinusoidal}} = -\sqrt{\frac{4EIwsin\theta}{rc}} \qquad (10)$$

If *Feff < -Fcsinusoidal* then tubing will tend to experience Helical buckling, but if *Feff > -FcHelical* then tubing tends not to buckling. But if *Feff* is between the helical and sinusoidal critical forces, the tubing tends to experience sinusoidal buckling. If the tubing has been determined to be buckling, then an analysis is carried out on how much change in length occurs due to buckling using the equation 11:

$$\Delta L_{buckling} = -\left(\frac{R_c{}^n A_p^2 (\Delta P_i - \Delta P_o)^2}{8EI(W_s + W_i + W_o)}\right) \qquad (11)$$

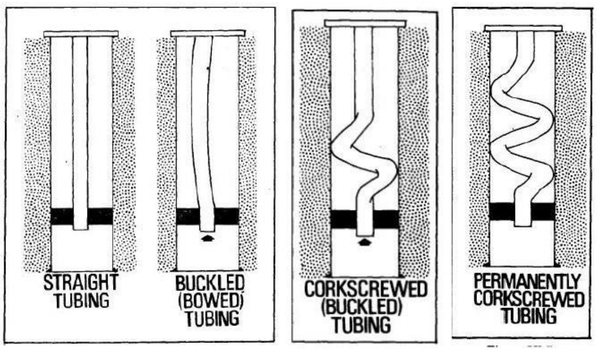

Figure 5. Buckling Effect on Tubing

D. Well Trajectory

Well Trajectory design is the first step before directional drilling or as a reference for the implementation of the drilling program, from determining the azimuth, inclination angle, and determining the total length of the path predicted from the calculation. In addition, the well trajectory is an important parameter for the installation of completion tools under the well. Figure 6 shows the well trajectory obtained from the given well X report data, with input data in the form of measured depth (MD), inclination angle, azimuth angle, dogleg (DLS) and packer depth to be installed at a depth of 4.490 ft (1.368,55 m). In well X, the direction of the well is not vertical and will be horizontal at a depth of about 5.000 ft. The bends in the well will be entered into the value of the angle of inclination and dogleg (DLS).

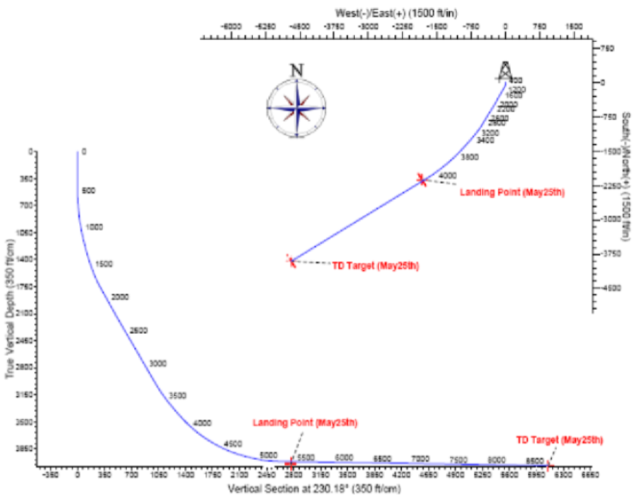

Figure 6. Well Trajectory of the X Well

E. Burst and collapse

Burst and collapse pressure is the resultant of the pressure difference in the tubing and in the annulus. Meanwhile, each type of tubing has its own burst and collapse rating (resistance) which can be calculated by the following formula:

E.1 Burst and collapse Rating

The burst and collapse rating is the value of burst or collapse that can be assigned to a tubing. Burst and collapse rating can be calculated using the following equation:

$$P_{b/c} = 0{,}875 \left(\frac{2(Y_p)(t)}{D}\right) \quad (12)$$

E.2 Burst and collapse Load

Burst and collapse load is the difference between the pressure inside and outside the tubing. This value represents the burst or collaspe load that is currently occurring on the tubing. Here is the equation used to find the burst and collapse load:

$$P_b = P_i - P_o \quad (13)$$

$$P_c = P_o - P_i \quad (14)$$

E.3 Burst and collapse Safety Factor

Burst and collapse (Figure 7) safety factor is the ratio value between the burst/collapse value that the tubing can withstand and the pressure value that occurs in the tubing plus the design factor value. The design factor value is the security value of an item determined by the costumer. The equation for finding the safety factor for burst or collapse is as follows:

$$SF_{burst/collapse} = \frac{Burst/collapse\ Rating}{Design\ Factor\ x\ Burst/collapse\ Load}$$

(15)

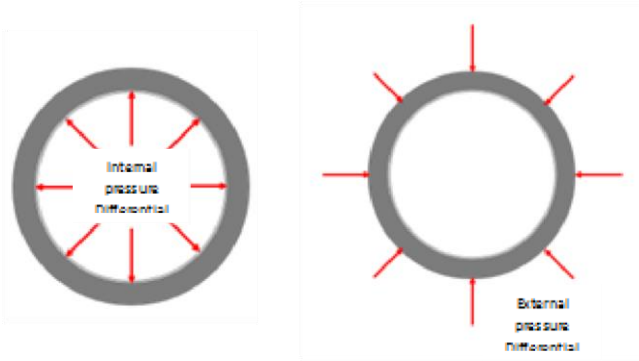

Figure 7. Burst (left) And Collapse (right) Effects on Tubing

III. RESULTS

For tubing movement analysis, we calculated the changes in length and force value caused by piston force, buckling, ballooning, and temperature effects. This analysis uses table 2 and table 3 as input data for calculating changes in length and force due to the effects of piston, buckling, ballooning, and temperature. The following is a description and explanation of the calculations for each effect.

A. Ballooning Effect

In the ballooning effect, there are several things to look for so that the calculation of changes in length and force can be found. After getting the area values from the outer and inner diameters of the tubing, the next step is to calculate the average value of Po and Pi at the initial condition in the following way:

$$P_o avg = \frac{P_o surface + P_o packer}{2}$$

$$P_o avg = \frac{0 + 2.218{,}06}{2}$$

$$P_o avg = 1.109{,}03\ psi$$

$$P_i avg = \frac{P_i surface + P_i packer}{2}$$

$$P_i avg = \frac{0 + 2.218{,}06}{2}$$

$$P_i avg = 1.109{,}03\ psi$$

Other than calculating the change in the average pressure of the initial condition, we also have to find out the value at the final condition. After knowing the values of Pi and Po from the packer, which are 3.706,89 psi and 2.218,06 psi, then we can calculate the average value of Po and Pi at the time of the final condition as follows:

$$P_o avg = \frac{P_o surface + P_o packer}{2}$$

$$P_o avg = \frac{0 + 2.218{,}06}{2}$$

$$P_o avg = 1.109{,}03\ psi$$

$$P_i avg = \frac{P_i surface + P_i packer}{2}$$

$$P_i avg = \frac{1.715{,}31 + 3.706{,}89}{2}$$

$$P_i avg = 2.711{,}10 psi$$

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After obtaining the initial and final average pressure in the tubing and annulus, the next step is to calculate the change in the average pressure in the tubing and annulus as follows:

$$\Delta P_o = P_o avg\ final - P_o avg\ initial$$

$$\Delta P_o = 1.109,03 - 1.109,03$$

$$\Delta P_o = 0\ psi$$

$$\Delta P_i = P_i avg\ final - P_i avg\ initial$$

$$\Delta P_i = 2.711,10 - 1.109,03$$

$$\Delta P_i = 1.602,07\ psi$$

After getting the values that will affect the change in length caused by the ballooning effect, and the Poisson ratio is known to be 0,3 for steel, then calculate the change in length by:

$$\Delta L = -\frac{2\mu L}{E(A_o - A_i)}(A_i \Delta P_i - A_o \Delta P_o)$$

$$\Delta L = -\frac{2(0,3)4.490}{3\ x\ 10^6(23,76 - 19,25)}((19,25)(5.1602,07) - (23,76)(0))$$

$$\Delta L = -12,5\ in$$

Thus, the change in length due to the ballooning effect is -12,5 in. Since the value is negative, the tubing will shorten. Meanwhile, the force caused by the ballooning effect can be calculated by:

$$F_{Ballooning} = -2\mu\ (A_i \Delta p_i - A_o \Delta P_o)$$

$$F_{ballooning} = -2(0,3)\big((19,25)(1.602,07\ ) - (23,76)(0)\big)$$

$$F_{ballooning} = -18.505,81\ lbs$$

Thus, the force generated by the ballooning effect on the tubing is -18.505,81 lbs. A negative value indicates that the tubing is under tension.

B. Temperature Effect

On the effect of temperature, the first thing that needs to be done is to find the average temperature change that occurs in the initial and final conditions as follows:

$$T_{avg} initial = \frac{Tsurface + T_{BHT}}{2}$$

$$T_{avg} initial = \frac{70 + 212}{2}$$

$$T_{avg} initial = 141\ °F$$

$$T_{avg} final = \frac{Tsurface + T_{BHT}}{2}$$

$$T_{avg} final = \frac{212 + 212}{2}$$

$$T_{avg} final = 212\ °F$$

After getting the average temperature value in the initial and final conditions, then calculate the temperature change in the following way:

$$\Delta T = T_{avg} final - T_{avg} initial$$

$$\Delta T = 212 - 141$$

$$\Delta T = 71\,°F$$

After getting the values that will affect the change in length caused by the temperature effect and it is known that the expansion coefficient is $6{,}9 \times 10^{-6}$ (/F), then calculate the change in length by:

$$\Delta L = \beta L \Delta T$$

$$\Delta L = (\mathbf{6{,}9 \times 10^{-6}})(\mathbf{4.490})(\mathbf{71})$$

$$\Delta L = 2{,}19\ ft$$

$$\Delta L = 26{,}39\ in$$

Thus, the change in length due to the effect of temperature is 26,39 in. Because the value is positive, the tubing will experience elongation. While the force caused by the temperature effect can be calculated by:

$$F_{temperatur} = 207(As)(\Delta T)$$

$$F_{temperatur} = 207(4{,}51)(71)$$

$$F_{temperatur} = 66.370{,}18\ lbs$$

Thus, the force produced by the temperature effect on the tubing is 66.370,18 lbs. The positive force indicates that the force acting due to the temperature effect is a compression force.

C. Piston Effect

In the piston effect, there are several things to look for, so that the calculation of changes in length and force can be found. After getting the Pi packer and Po packer values in the initial conditions and final conditions in Table 5.

Table 5. The Value Of The Pressure Difference On The Packer

	Initial	**Final**
Pi Packer (Psi)	2.218,06	3.706,89
Po Packer (Psi)	2.218,06	2.218,06

Then proceed by calculating the pressure changes in the annulus and tubing in the packer area as follows:

$$\Delta P_o = P_o final - P_o initial$$

$$\Delta P_o = 2.218{,}06 - 2.218{,}06$$

$$\Delta P_o = 0\ psi$$

$$\Delta P_i = P_i final - P_i initial$$

$$\Delta P_i = 3.706{,}894 - 2.218{,}06$$

$$\Delta P_i = 1.488{,}83\ psi$$

After obtaining the values that will affect the magnitude of the force caused by the piston effect. Then calculate the magnitude of the force by:

$$F = (A_p - A_i)\Delta P_i - (A_p - A_o)\Delta P_o$$

$$F = (46{,}43 - 19{,}25)1.488.83 - (46{,}43 - 23{,}76)0$$

$$F = 40.478{,}35 \text{ lbs}$$

The change in force that occurs due to the piston effect is 40.478,35 lbs and the force created is a compression force because the value of the change in force that occurs is positive. However, because the packer and tubing cannot move, the force due to the piston effect is only retained in the packer area and has no effect on the tubing string, the force due to the piston effect is 0 lbs.

F = 0 lbs

Then proceed to calculate the change in length by:

$$\Delta L = -\frac{LF}{EA_s}$$

$$\Delta L = -\frac{(4.490)(0)}{(3\ x\ 10^7)(4{,}51)}$$

$$\Delta L = 0\ in$$

Thus, the change in length due to the piston effect is 0in.

D. Buckling Effect

In the buckling effect, there are several things to look for in order for the calculations can be carried out. First is getting the annulus and tubing pressures on the packer, which is 2.218,06 psi and 3.706,89 psi. These numbers have been added to the hydrostatic value of the depth where the packer is installed.

After that, calculate for the fictitious force and neutral points, in the following way:

$$F_f = A_p\ (P_i packer - P_o packer)$$

$$F_f = 46{,}43\ (3.706{,}89 - 2.218{,}06)$$

$$F_f = 69.141{,}34\ lb$$

$$n = \frac{F_f}{W}$$

$$n = \frac{69.141{,}34}{1{,}2}$$

$$n = 57.342{,}9\ in$$

Because the value of the neutral point is greater than the length of the tubing being analyzed, buckling can occur all along the tubing. In addition, it is also necessary to calculate the weight per unit length of tubing and fluid by adding up the steel load (W_s), the fluid load in the tubing (W_i), and the fluid load outside the tubing (W_o). By knowing the weight and length of the tubing in the tubing specifications, the calculation of the weight per unit can be known as follows:

$$W = W_s + W_i - W_o$$

$$W = 1{,}29 + 0{,}79 - 0{,}87$$

$$W = 1{,}2\ lb/in$$

In addition, using formulas 9 and 10, the critical helical and sinusoidal values can be calculated as 269.014,9 lb and 190.791 lb, respectively. Because the Feff value is smaller than the critical helical value, the tubing will experience helical buckling.

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To find the change in length due to the buckling effect, use the formula for n > L as follows:

$$\Delta L = -\left(\frac{r^2 F_f{}^2}{8EIW}\right)\left(\frac{LW}{F_f}\left(2-\frac{LW}{F_f}\right)\right)$$

$$\Delta L = -\left(\frac{1{,}59^2\ (69.141{,}34^2)}{8(3\ x\ 10^7)(15{,}43)(1{,}2)}\right)\left(\frac{4.490(1{,}2)}{69.141{,}34}\left(2-\frac{4.490(1{,}2)}{69.141{,}34}\right)\right)$$

$$\Delta L = -0{,}4\ in$$

E. Burst and Collapse

Because the pressure in the tubing is greater than the pressure in the annulus, no collapse load is applied to the tubing. However, there was a burst load of 1.715,31 psi, with a burst rating of 7.000 psi. then the safety factor obtained for burst and collapse is 3,71.

IV. CONCLUSIONS

Based on the results obtained, it can conclude into several points as follows:

A. The change in total length when the tubing is free to move caused by the effect of temperature is 26,39 in elongation; Ballooning effect is 12,5 in shortened; piston effect is 0 in; and the buckling effect is 0,4 in shortened. Then the total change in length caused by the movement of the tubing is 13,48 in elongation. However, because the type of packer used does not allow for tubing movement, the effect of temperature will produce a compression force on the tubing of 66.370,18 lbs; the ballooning effect will produce a tension force on the tubing of 18.505,81 lbs; and the piston effect will produce a force on the tubing of 0 lbs. so the total force on the tubing is 47.864,36 lbs compression.

B. Tubing does not experience collapse load because the pressure in the tubing is greater than in the annulus. However, there is a burst load on the tubing of 1.715,31 psi which is considered safe with a safety factor obtained after entering the tubing properties and design factor of 3,71.

C. Analysis of the tubing movement in the completion process is very important to be done correctly. By knowing how much force is caused or how far the tubing will move by the tubing movement, the engineer will be able to consider the actions taken to prevent failure of the tool or well by considering safety and cost. In the case of well X with a force of 47.864,36 lbs tubing is still considered safe because the specification of the body yield strength possessed by tubing is 361.000 lbs (5-1/2 in 13 Cr-80). Then the selection of no motion packer can be used.

ACKNOWLEDGMENT

The Author would like to thank the Faculty of Engineering, Diponegoro University which has provided research grants with the number: 455/UN7.F3/HK/2022

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