TUBING ANCHOR CATCHER APPLICATIONS AND OPERATION

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ABSTRACT

From the selection process to installation and continued maintenance, the Tubing Anchor Catcher (TAC) is one of the most important tools in achieving efficient pumping operation. The upstream oil and gas sector continues to evolve with new methods morphed from old methods as it pertains to artificial lift systems. While the people and parts continue to change, understanding the basic, yet important, aspects of TACs with relation to their applications, operational procedures, and tubing stretch is necessary. In covering the basics and importance of the TAC, the scope of this paper will expand on tubing stretch calculations, shear values, drag spring usage, troubleshooting, and other installation techniques.

TUBING ANCHOR CATCHER

A TAC is a device used to anchor tubing string to the casing at a desired depth, in order to pull and maintain tension in the tubing string during the pump cycle while simultaneously catching and preventing any parted pipe from falling into the well. It is used in most of the rod pumping applications where maintaining tubing tension is necessary. When set with proper tension to overcome both breathing and buckling, the TAC effectively cuts operating cost incurred from excessive rod, tubing, and casing wear, which results in fewer pulling jobs. Elimination of breathing and buckling increases production by lengthening the effective stroke of the pump, thereby increasing volumetric efficiency.

WHY USE A TUBING ANCHOR CATCHER?

Rod pumping with the tubing hanging free causes the following problems:

- Excessive wear of the rods, tubing, casing, and pump
- Reduced pumping efficiency
- Increased operating costs such as increased requirements of power consumption
- Tubing buckling due to piston effects like breathing (or referred to as plugging), buoyancy and ballooning effects

The movement of the bottom portion of the freely suspended tubing string along with the plunger as the pump strokes is referred to as breathing. This movement is caused by alternatively transferring the load of the fluid column from the rod string to the tubing string. On the down stroke, the tubing carries the fluid load and on the up stroke, the rods carry the fluid load. During the down stroke, tubing elongates and the rods shorten; while in the up stroke, rods elongate and the tubing shortens. The elongation and contraction of tubing string along with the rod string reduces the effective pump stroke and thus reduces the production rate. This also causes tubing buckling which results in tubing and casing wear, tubing collar leaks, and metal fatigue causing the tubing to part. Buoyancy and ballooning effects paper which also causes tubing string to buckle are discussed in length in the later part of this.

In practice, tubing undergoes bending or buckling which is characterized by a sudden failure of a tubing member subjected to high compressive stress, where the actual compressive stress at the point of failure is less than the ultimate compressive stress that the tubing material is capable of withstanding. This occurs on the up stroke of the pump. Since the tubing string is set free from tension, there is nothing to restrain the buckling forces. The rods remain straight, supporting the fluid load. The tubing string bends and coils helically [1] (Figure 1) rubbing against both rods and casing. Rods are forced out of alignment while the pump barrel wear is accelerated. In this case, rods, tubing, casing, and pump are subjected to extreme wear. It also consumes more lifting power in order to overcome the added friction, resulting in high operating costs.

Some of the means by which the tubing buckling can be handled are: tension anchors, tail pipe, sucker rod guides, and corrosion inhibitors. In order to keep the tubing string from buckling the structural member/tubing string should be subjected to tension. This paper discusses how the use of TACs at the bottom of the tubing string will greatly reduce tubing buckling problems during pumping operation. Using a TAC to anchor the tubing string at the bottom permits the tubing to stretch beyond the point that it would be stretched by fluid load and temperature variations. The TAC at the bottom of the tubing string helps in holding the tubing string straight and keeps the tubing from changing its length during the pump stroke.

INSTALLATION AND OPERATION

Selection of well head

The type of well head is an important factor in obtaining proper stretch in the tubing string. It is important to determine what type of well head to use before installing the TAC. Screw type (Figure 2) and slip type (Figure 3) are two commonly used well head devices. Both have their own advantages and disadvantages.

In slip type, the tubing is stretched and allows the tapered slips catch the tubing string. The teeth on the slips provide necessary friction to keep the tubing string stretched. To have proper friction between the slips and the tubing, it is necessary to make sure that the tubing is straight. Only a part of the slips will be in contact with the tubing string if it is crooked. This will cause the tube to stress and result in a tubing failure at the point of contact.

Screw type well head is another type of well head device where the tubing is screwed into the bottom of the flange. To use a screw type well head, the tubing must be overstretched 18" (457 mm) or more to install pulling unit slips under the top tubing collar. The installation of a screw type well head might introduce some slack in the tubing string if the tubing is not overstretched. At the same time, use of a higher shear value to overstretch the tubing could be detrimental to the low-strength tubing.

Installation

In the tubing string, the TAC should be positioned immediately below the pump. The seating nipple should be screwed into the top sub of the anchor. If the pump must be located below the TAC, special consideration must be given to the bore through the anchor and the tensile strength of the anchor mandrel. For the pump to be installed below the TAC, the pump has to go through the mandrel ID. In this case, the ID of the mandrel should be equal to or more than the ID of the tubing for that particular pump. Table 1 gives the common mandrel IDs' and it also gives a general idea on the sizes of pumps that can run through a specific TAC mandrel. When the TAC is installed below the seating nipple, the fluid load acts on the seating nipple; if the TAC is anchored above the seating nipple, the TAC mandrel is subjected to the fluid load. Table 2 gives the general strengths of the mandrel with the commonly used material.

Figure 5 shows the assembly of a Tubing anchor catcher. It shows the position of drag springs which create friction between the anchor and the casing ID. This will hold the TAC cage stationary while allowing the upper and lower cones to expand the slips. The drag springs also help in guiding the TAC through the casing.

Drag springs should not be used as a handle for carrying or tailing in tubing. This would bend the drag springs thereby impairing their function. In deep installations (8,000 ft. (2,438 Meters)), 2 or more drag springs should be used one on top of the other.

TACs should not be used in wells that have bad casing. The bad casing could cause a problem in wells that produce sand or scale build-up unless the casing is redressed.

Running and setting

To prevent the slips from becoming dulled before reaching the setting depth, it is advisable to put a right hand turn into the tubing every 5 or 10 stands while running in.

Up on reaching the desired depth, rotate the tubing to the left with hand wrenches until the slips contact the casing (approximately 5 to 8 turns). Maintain a left hand torque while alternately pulling strain and setting down a few times to work all play out of the tool. During this slip-setting operation, the strain pulled should at least be equal to the final strain that will be applied when the tubing is landed and full set-down weight should be applied. The torque

should be released until all the residual torque is removed. Apply the required amount of tubing tension as determined from the calculations shown in the "calculations section". Tubing tension should always be applied in inches of stretch rather than in pounds of pull because of the probable friction between the tubing and the casing. First, the weight of the tubing needs to be applied and then the actual stretching begins.

When the Tubing Anchor Catcher is run at some distance above the pump, the maximum allowable load below the TAC must not exceed the maximum load values as shown in Table 3. This load is a combination of the weight of the fluid inside the tubing (from the surface to the pump) and the tubing weight below the TAC.

Normal and emergency releasing

Tubing Anchor Catcher should be released with the tubing in slight compression as the upper cone is spaced so that the lower cone will be completely retracted when the slips lose their grip on the casing. Incomplete retraction of the lower cone will cause the slips to drag and dulling of the teeth. The tubing should be rotated to the right, sufficient to obtain 5 to 8 revolutions at the anchor. This will retract both cones and allow the slips to retreat into their housing. When the anchor is free, few more right hand turns should be put in before starting out of the hole. Additional right hand rotation is not harmful to the anchor. As an added precaution to avoid dulling the slips, few right hand turns are occasionally added on the way out of the hole.

In case of an emergency release (i.e. if the normal releasing procedure as described above fails), picking up against the TAC will induce an up-strain sufficient enough to shear the emergency pins in the lower cone. In practice, the amount of up-strain exerted should be greater than the total shear strength of the shear pins, plus the weight of the tubing. Shearing the shear pins will release the Tubing Anchor Catcher.

TUBING STRECH

Tubing strings are affected by mechanical, pressure, and temperature changes. In tubing string, there are different factors that cause length and force changes. These factors are dependent on well conditions, tubing anchor-casing configuration, and tubing restraint. Each factor acts independently and may either add to or nullify the effects of the other factors. Therefore, it is important to keep the direction of the length changes and forces correct. Furthermore, mechanically applied tension or compression may be used to negate the combined effect of the pressure and temperature changes. The present paper discusses the minimum amount of stretch; a tubing string should be subjected to with the use of a TAC to facilitate an efficient pumping condition.

It is important to consider factors like piston effect (breathing and buoyance), temperature effect, and ballooning effect while calculating the right amount of tubing pickup for tension anchor installation. These axial loads cause the tubing to be in compression and tension alternatively on freely suspended tubing causing the tubing string to undergo buckling. The pickup load in pounds is determined first and thereby converting the calculated load to tubing stretch in inches.

These hand calculations discuss the four types of axial loads to which the tubing string is exposed to during the installation and pumping. These forces are: piston effect on the tubing string due to buoyancy (F_{PB}), piston effect due to plugging (F_{pp}), the indirect effect of pressure on axial loads via radial forces or the ballooning effect (F_B), and the temperature effect on the tubing string (F_T). Picking up the tubing string to the calculated stretch with the tubing string anchored with the TAC will keep the tubing in tension throughout the pumping cycle. These calculated stretch values are the minimum values required to keep the tubing string in tension. Since some of these factors are dynamic i.e. they change during the service of the well, it is recommended to calculate at different scenarios (like, during the time of installation, during the time of pumped off condition and etc.). And consider the scenario that requires maximum stretch as the minimum required-stretch. It is also recommended to re-evaluate these stretch values from time to time during the well service. The tubing string can be stretched more than the calculated minimum value by finding out the maximum tensile strength of the weakest joint.

Piston effect on the tubing string due to buoyancy (F_{PB})

The piston effect due to buoyancy (Figure 5) occurs when the tubing is subjected to compression from fluid pressure acting on the bottom face of the freely hanging tubing. In that case the tubing is subjected to an axial compressive force (F_{PB}) with a pressure p acting underneath the tubing.

$$F_{PB} = pA_{cs} \qquad \text{Eq. 1[2]}$$

A_{cs} = area of cross section of the tubing

Pressure *p* could be a combination of the applied pressure and the pressure due to the fluid head.

$P_{fluid\ head} = \rho TVD$ Eq. 2[2]

TVD = true value depth in feet
Density ρ in psi/ft. Freshwater has a density of 0.433 psi/ft. The density of the fluid in relation to the freshwater can be calculated by multiplying the specific gravity of the fluid by 0.433.

$\rho = 0.433 s.g$ Eq. 3[2]

In a freely suspended position the buoyancy effect causes the tubing string below the neutral point to be under compression. This force is taken as negative in the final equation of initial force (F_I) (Eq. 8).

In case an external pressure is applied that should be added to $P_{fluid\ head}$

Piston effect on the tubing string due to plugging (F_{PP})

The fluid load results in an axial force (F_{pp}) on the tubing when the bottom of the tubing string is plugged. This causes piston effect due to plugging (Figure 6). During the down stroke, the travelling valve opens and the entire fluid load acts on the standing valve which behaves like a plug. When the tubing string is fixed, this axial load puts the tubing in compression.

The force in this case acts on the internal area (A_i) of the tubing. The pressure acting on the plug (Δp_{plug}) is the difference between the pressure due to the fluid head in the tubing string (p_{above}) and the fluid pressure below the seating nipple (p_{below}).

$F_{pp} = \Delta p_{plug} A_i$ Eq. 4[2]

$\Delta p_{plug} = p_{above} - p_{below}$

p_{above} and p_{below} should be considered at the operating fluid levels

During the downward movement of the plunger the tubing stretches due to the fluid load acting directly on the standing valve. This results in the elongation of tubing string when it is freely suspended. Force due to plugging piston effect is taken as positive in the minimum initial force equation (F_I) (Eq. 8).

Ballooning effect (F_B)

The fluid load on the tubing string results in an axial tensile strain causing the tubing to be under radial compression. When the pressure inside the tubing string is higher than the pressure outside, it causes the tubing to shrink axially due to the radial expansion. In such case, the tubing experiences an axial tensile force (F_B) when it is fixed on both ends, and this effect is called ballooning. When the pressure outside the tubing is greater than the pressure inside, it causes the tubing to stretch axially due to the radial compressive strain in the tubing string, and this force puts the tubing in axial compression when the tubing is fixed. This effect is called the reverse ballooning effect. (Figure 7)

$F_B = 2\upsilon (A_i \Delta p_i - A_o \Delta p_o)$ Eq. 5[2]

A_i = internal area of the tubing
A_o = external area of the tubing
Δp_i = internal pressure difference above and below the plug
Δp_o = external pressure difference above and below the plug
υ = Poisson's ratio~~, defined as~~ (approximately 0.3 for most of the steels used in oil field)

The ballooning effect can either be positive or negative based on the forces acting on the inside and outside surfaces of the tubing. These forces are also dependent on the level of the fluid in the casing. During the installation, the high fluid level in the tubing casing annulus counter acts the pressure inside the tubing; whereas the fluid level in the casing reduces to the pumped off condition level, leaving almost no pressure acting on the outside the tubing.

The fourth effect that induces stress in the tubing string is the temperature effect. Metals expand on heating and contract on cooling. Change in length due to change in temperature causes the tubing to be under compression or tension when it is fixed on both ends. The change in length due to change in temperature can be calculated with the following equation.

$$\Delta L_T = C_T L \Delta T \qquad \text{Eq. 6 [2]}$$

C_T = coefficient of thermal expansion ($°F^{-1}$)
ΔT = is the average change in temperature from the base case to the load case (°F)
L = length of the tubing (same units as ΔL_T)

The coefficient of thermal expansion (C_T) is a material property and varies with different metallurgies. For Carbon steels it is around $5.5 \times 10^{-6}\ °F^{-1}$ - $7.5 \times 10^{-6}\ °F^{-1}$. The coefficient of thermal expansion can itself be a temperature dependent property. Figure 8 [3] shows the variation of coefficient of thermal expansion with the variation of temperature for carbon and low-alloy steels.

When the tubing is fixed at both ends, heating will induce compressive force and cooling will cause tensile force in the tubing. If the ambient temperature is lower than the well fluid temperature at the surface, the tubing string expands and this expansion induces compressive forces in the string. In such a case the compressive loads are to be balanced by stretching the tubing to avoid buckling. This force can be calculated as following:

$$F_T = C_T E \Delta T (A_o - A_i) \qquad \text{Eq. 7[2]}$$

E= Young's modulus (30×10^6 psi for the for most of the steels used in oil field)

Figure 9 [2] shows the variation of well bore fluid temperature with the depth as the fluid flows to the surface.

After determining these individual forces acting on the tubing string the total initial force is calculated:

$$\text{Total minimum initial load } (F_I) = F_{pp} + F_T - F_B - F_{PB} \qquad \text{Eq. 8}$$

Once the loading is calculated in the above manner, the amount of stretch can be calculated. It also depends on the material properties like elasticity of the material, cross-sectional area. The tubing stretch in inches can be calculated using the following formula.

$$\Delta L = F_I \times L \times SC \qquad \text{Eq. 9[4]}$$

ΔL = stretch, in inches
F_I = pull force, in thousands of pounds
L = length, in thousands of feet
SC = stretch constant, in inches of stretch per thousand pounds of pull per thousand feet of length (Table 4[4] provides the stretch constants)

For any pipe sizes that are not included in Table 4, stretch constants can be calculated as following:

$$SC = \quad / \qquad \text{Eq. 10[4]}$$

A_{cs}= Area of cross section of the pipe

Table 5 shows the recommended shear values in the tension anchor based on the calculated pickup load.
Table 6 shows different grades of API tubing based on size, wall thickness and strength. In determining the maximum tensile load on the top tubing joint; tubing weight, shear value, fluid weight and rod string weight should be considered.

Example problem 1:

Tubing size: 2-3/8 OD
Depth of pump & anchor: 6,000'
Fluid level at the time anchor is set (from surface): 5,000'
Operating fluid level (from surface): 6,000'
Fluid temperature at surface: 90°F
Mean yearly temperature for area: 60°F
Tubing string weight: 28,200 lbs.
Rod string weight: 11,500 lbs.
Pump plunger size: 1-1/2"
Weight of fluid in tubing: 9,000 lbs. (est.)
Density (corresponding to a fluid of specific gravity 1.154): 0.5 psi/ft.
Calculate initial force (F_I) = $F_{pp} + F_T - F_B - F_{PB}$

From the equations given in the tubing stretch section

$F_{PB} = pA_{cs}$

$P_{fluid\ head} = \rho TVD$

p=0.5 x 1,000 = 500 psi

A_{cs} = 1.304 in^2

F_{PB} = 500 x 1.304 = 652 lbs.

$F_{pp} = \Delta p_{plug} A_i$

A_i = 3.125 in^2

F_{pp} = [(0.5 x 6000 x 3.125) – (0.5 x 0 x 3.125) = 9,375 lbs.

$F_T = C_T E \Delta T (A_o - A_i)$

$F_T = 7 \times 10^{-6} \times 30 \times 10^6 \times 30 \times 1.304$ = 8,215 lbs.

$F_B = 2\mu(A_i \Delta p_i - A_o \Delta p_o)$

F_B = 2 x 0.3 [(3.125 x 0.5 x 6,000) – (4.43 x 0.5 x 1,000)] = 4,296 lbs.

$(F_I) = F_{pp} + F_T - F_B - F_{PB}$

(F_I) = 9,375 + 8,215 – 4,296 – 652

(F_I) = 12,642 lbs.

$\Delta L = F_I \times L \times SC$

ΔL = 12.642 x 6 x 0.30675

ΔL = 23.26 inches of stretch

Example problem 2:

Tubing size: 2-7/8 OD
Depth of pump: 6,000'
Anchor depth: 6,500'
Fluid level at the time anchor is set: 4,000'
Working fluid level: 5,000'
Fluid temperature at surface: 100°F
Mean yearly temperature for area: 60°F
Density (corresponding to a fluid of specific gravity 1.154): 0.5 psi/ft.

Calculate initial force (F_I) = $F_{pp} + F_T - F_B - F_{PB}$

From the equations given in the tubing stretch section

$F_{PB} = pA_{CS}$

$P_{\text{fluid head}} = \rho TVD$

$p = 0.5 * 2500 = 1250$ psi

$A_{CS} = 1.812$ in^2

$\mathbf{F_{PB} = 1250 * 1.812 = 2,265\ lbs}$.

$F_{pp} = \Delta p_{plug} A_i$

$A_i = 3.125$ in^2

$\mathbf{F_{pp} = [(0.5 * 6000 * 3.125) - (.05 * 1000 * 3.125)] = 7,813\ lbs}$.

$F_T = C_T E \Delta T (A_o - A_i)$

$\mathbf{F_T = 6.9x10^{-6} * 30x10^6 * 40 * 1.812 = 15,003\ lbs}$.

$F_B = 2\mu(A_i \Delta p_i - A_o \Delta p_o)$

$\mathbf{F_B = 2 * 0.3\ [(3.125 * 0.5 * 6000) - (6.69 * 0.5 * 1000)] = 3,618\ lbs}$

$(F_I) = F_{pp} + F_T - F_B - F_{PB}$

$(F_I) = 7813 + 15003 - 3618 - 2265$

$\mathbf{(F_I) = 16,933\ lbs}$.

$\Delta L = F_I * L * SC$

$\Delta L = 16.933 * 6 * 0.22075$

$\mathbf{\Delta L = 22.43\ inches\ of\ stretch}$

Example problem 3:

Tubing size: 2-3/8 OD
Depth of pump & anchor: 8,500'
Fluid level at the time anchor is set (from surface): 7,500' Operating fluid level (from surface): 8,500'
Fluid temperature at surface: 100°F
Mean yearly temperature for area: 70°F
Tubing string weight: 39,950 lbs.
Rod string weight: 16,000 lbs.
Pump plunger size: 1-1/2"
Weight of fluid in tubing: 13,000 lbs. (est.)
Density (corresponding to a fluid of specific gravity 1.154): 0.5 psi/ft.

Calculate initial force (F_I) = $F_{pp} + F_T - F_B - F_{PB}$
From the equations given in the tubing stretch section

$F_{PB} = pA_{cs}$

$P_{fluid\ head} = \rho TVD$

p=0.5 x 1,000= 500 psi

$A_{cs} = 1.304 in^2$

F_{PB} = 500 x 1.304 = 652 lbs.

$F_{pp} = \Delta p_{plug} A_i$

$A_i = 3.125\ in^2$

F_{pp} = [(0.5 x 8,500 x 3.125) – (0.5 x 0 x 3.125) = 13,281 lbs.

$F_T = C_T E \Delta T\ (A_o - A_i)$

$F_T = 7 \times 10^{-6} \times 30 \times 10^6 \times 30 \times 1.304$ = 8,215 lbs.

$F_B = 2\mu(A_i \Delta p_i - A_o \Delta p_o)$

F_B = 2 x 0.3 [(3.125 x 0.5 x 8,500) – (4.43 x 0.5 x 1000)] = 6,640 lbs.

$(F_I) = F_{pp} + F_T - F_B - F_{PB}$

(F_I) = 13,281 + 8,215 – 6,640 – 652

(F_I) = 14,204 lbs.

$\Delta L = F_I \times L \times SC$

ΔL = 14.204 x 8.5 x 0.30675

ΔL = 37.03 inches of stretch

Table 1
Compatible pump sizes when the TAC is run above the pump

Tubing Anchor x Tubing Size	Mandrel ID (in)	Pump	Max. Pump (Seating Mandrel) OD
4-1/2 x 2-3/8	1.937	20-R	1.901
		20-175 TH	1.388
5 x 2-3/8	1.937	20-R	
		20-175 TH	
5 x 2-7/8	1.937	20-R	
		20-175 TH	
5-1/2 x2-3/8	2.405	25-R	2.334
		25-225 TH	2.118
5-1/2 x2-7/8	2.405	25-R	
		25-225 TH	2.118
7 X 2-3/8	2.500	25-R	
		25-225 TH	
7 X 2-7/8	2.500	25-R	
		25-225 TH	
7 X 3-1/2	3.000	30-R	2.844
		30-225 TH	2.688
7-5/8 X 2-3/8	2.500	25-R	
		25-225 TH	2.188

Table 2
Mandrel Strength (Baker Style)

Tubing Anchor x Tubing Size	4130 CDS @ FS 1.5 (lbs.)	1026 CDS @ FS 1.5 (lbs.)
4-1/2 x 2-3/8	80,031-89,791	70,272-83,935
5 x 2-3/8	80,031-89,791	70,272-83,935
5 x 2-7/8	80,031-89,791	70,272-83,935
5-1/2 x2-3/8	106,544-119,538	93,552-111,742
5-1/2 x2-7/8	106,544-119,538	93,552-111,742
7 X 2-3/8	118,023-132,417	103,632-123,781
7 X 2-7/8	118,023-132,417	103,632-123,781
7 X 3-1/2	135,407-151,921	118,896-142,013
7-5/8 X 2-3/8	118,023-131,417	103,632-123,781

Table 3
Maximum allowable load below Anchor Catcher when tool is run at a distance above pump

Tool Size	Maximum Load (lbs)
4 1/2” – 5”	20,000
5 1/2 “	30,000
6 5/8” – 7 5/8”	45,000
6 5/8” – 7 5/8” (3” ID)	35,000
8 5/8” – 9 5/8”	60,000

Table 4
Stretch constants for Tubing [4]

OD	Weight	ID	Wall Area	Stretch Constant
in.	lb/ft	in.	in2	in./1,000 lb/1,000 ft
1.050	1.14	0.824	0.333	1.20120
	1.20			
1.315	1.30	1.125	0.364	1.09890
	1.43	1.097	0.413	0.96852
	1.63	1.065	0.467	0.85653
	1.70	1.049	0.494	0.80972
	1.72			
	1.80			
1.660	2.10	1.410	0.603	0.66335
	2.30	1.380	0.669	0.59791
	2.33			
1.900	2.40	1.650	0.697	0.57389
	2.60	1.610	0.799	0.50063
	2.72			
	2.75			
	2.76			
	2.90			
2.000	3.30	1.670	0.951	0.42061
	3.40			
2.063	2.66	1.813	0.761	0.52562
	3.25	1.751	0.935	0.42781
	3.30			
	3.40			
2.375	3.10	2.125	0.884	0.45249
	3.32	2.107	0.943	0.42418
	4.00	2.041	1.158	0.34542
	4.60	1.995	1.304	0.30675
	4.70			
	5.30	1.939	1.477	0.27082
	5.80	1.867	1.692	0.23641
	5.95			
	6.20	1.853	1.733	0.23081
	7.70	1.703	2.152	0.18587
2.875	4.36	2.579	1.268	0.31546
	4.64	2.563	1.333	0.30008
	6.40	2.441	1.812	0.22075
	6.50			
	7.90	2.323	2.254	0.17746
	8.60	2.259	2.484	0.16103
	8.70			
	8.90	2.243	2.540	0.15748
	9.50	2.195	2.708	0.14771
	10.40	2.151	2.858	0.13996
	11.00	2.065	3.143	0.12727
	11.65	1.995	3.366	0.11884

Table 4 [4] (continued)

OD	Weight	ID	Wall Area	Stretch Constant
in.	lb/ft	in.	in2	in./1,000 lb/1,000 ft
3.500	5.63	3.188	1.639	0.24405
	5.75			
	7.70	3.068	2.228	0.17953
	9.20	2.992	2.590	0.15444
	9.30			
	10.20	2.922	2.915	0.13722
	10.30			
	12.80	2.764	3.621	0.11047
	12.95	2.750	3.682	0.10864
	13.70	2.673	4.010	0.09975
	14.70	2.601	4.308	0.09285
	15.10	2.602	4.304	0.09294
	15.80	2.524	4.618	0.08662
	17.05	2.440	4.945	0.08089
4.000	9.40	3.548	2.680	0.14925
	9.50			
	10.80	3.476	3.077	0.13000
	10.90			
	11.00			
	11.60	3.428	3.337	0.11987
	13.40	3.340	3.805	0.10512
4.500	12.60	3.958	3.600	0.11111
	12.75			
	15.10	3.826	4.407	0.09076
	15.50			
	16.90	3.754	4.836	0.08271
	19.20	3.640	5.498	0.07275

Table 5
Recommended shear values based on the calculated pickup load

Tension Required (from calculations)	Recommended Shear Value	Number of Shear Pins Required
0 – 10,000 lb.	25,000 lb.	5
10,000 – 20,000 lb.	30,000 lb.	6
20,000 – 30,000 lb.	40,000 lb.	8
30,000 – 40,000 lb.	50,000 lb.	10
40,000 – 50,000 lb.	60,000 lb.	12

Table 6
API Tubing weights, grades, wall thickness and strengths

Tubing Size		Nominal Weight		Grade	Wall Thickness	Inside Dia.	Threaded Coupling				Collapse Resistance	Internal Yield Pressure	Joint Yield Strength		Capacity Table	
								Coupling Outside Dia.								
Nom. in.	OD in.	T&C Non-Upset lb/ft	T&C Upset lb/ft		in.	in.	Drift Dia.in.	Non-Upset in.	Upset Reg. in.	Upset Spec in.	psi	psi	T&C Non-Upset lb.	T&C Upset lb.	Barrels per Linear ft	Linear ft per Barrel
3/4	1.05	1.14	1.20	H-40 J-55 C-75 N-80	0.113	0.824	0.730	1.313	1.660		7,200 9,370 12,250 12,710	7,530 10,360 14,120 15,070	6,360 8,740 11,920 12,710	13,300 18,290 24,940 26,610	0.0007	1516.13
1	1.315	1.700	1.800	H-40 J-55 C-75 N-80	0.113	1.049	0.955	1.660	1.900		6,820 8,860 11,590 12,270	7,080 9,730 13,270 14,160	10,960 15,060 20,540 21,910	19,760 27,160 37,040 39,510	0.0011	935.49
1 1/4	1.660	2.300	2.400	H-40 H-40 J-55 J-55 C-75 N-80	0.125 0.140 0.125 0.140 0.140 0.140	1.410 1.380 1.410 1.380 1.380 1.380	1.286	2.054	2.200		5,220 5,790 6,790 7,530 9,840 10,420	5,270 5,900 7,250 8,120 11,070 11,810	15,530 21,360 29,120 31,060	26,740 36,770 50,140 53,480	0.0019 0.0018 0.0019 0.0018 0.0018 0.0018	517.79 540.55 517.79 540.55 540.55 540.55
1 1/2	1.900	2.750	2.900	H-40 H-40 J-55 J-55 C-75 N-80	0.125 0.145 0.125 0.145 0.145 0.145	1.650 1.610 1.650 1.610 1.610 1.610	1.516	2.200	2.500		4,450 5,290 5,790 6,870 8,990 9,520	10,020 10,680	19,090 26,250 35,800 38,180	31,980 43,970 59,960 63,960	0.0026 0.0025 0.0026 0.0025 0.0025 0.0025	378.11 397.14 378.11 397.14 397.14 397.14
2 1/6	2.063			H-40 J-55 C-75 N-80	0.156	1.751					5,240 6,820 8,910 9,440	5,290 7,280 9,920 10,590			0.0030	335.75
2 3/8	2.375	4.00 4.60 4.00 4.60 4.00 4.60 5.80 4.00 4.60 5.80 4.60 5.80	4.70 4.70 5.95 4.70 5.95 4.70 5.95	H-40 H-40 J-55 J-55 C-75 C-75 C-75 N-80 N-80 N-80 P-105 P-105	0.167 0.190 0.167 0.190 0.167 0.190 0.254 0.167 0.190 0.254 0.190 0.254	2.041 1.995 2.041 1.995 2.041 1.995 1.867 2.041 1.995 1.867 1.995 1.867	1.947 1.901 1.947 1.901 1.947 1.901 1.773 1.947 1.901 1.773 1.901 1.773	2.875	3.063	2.910	4,880 5,520 6,340 7,180 8,150 9,380 12,180 8,660 9,940 12,890 13,250 17,190	4,920 5,600 6,770 7,700 9,230 10,500 14,040 9,840 11,200 14,970 14,700 19,650	30,130 35,960 41,430 49,450 56,500 67,430 96,560 60,260 71,930 102,990 94,410 135,180	52,170 71,730 97,820 126,940 104,340 135,400 136,940 177,710	0.0040 0.0039 0.0040 0.0039 0.0040 0.0039 0.0034 0.0040 0.0039 0.0034 0.0039 0.0034	247.12 258.65 247.12 258.65 247.12 258.65 295.33 247.12 258.65 295.33 258.65 295.33
2 7/8	2.875	6.40 6.40 6.40 8.60 6.40 8.60 6.40 8.60	6.50 6.50 6.50 8.70 6.50 8.70 6.50 8.70	H-40 J-55 C-75 C-75 N-80 N-80 P-105 P-105	0.217 0.217 0.217 0.308 0.217 0.308 0.217 0.308	2.441 2.441 2.441 2.259 2.441 2.259 2.441 2.259	2.347 2.347 2.347 2.165 2.347 2.165 2.347 2.165	3.500	3.668	3.460	5,230 6,800 8,900 12,200 9,420 12,920 12,560 17,220	5,280 7,260 9,910 14,060 10,570 15,000 13,870 19,690	52,780 72,580 98,970 149,360 105,570 159,310 138,560 209,100	72,480 99,660 135,900 185,290 144,960 198,710 190,260 260,810	0.0058 0.0058 0.0058 0.0050 0.0058 0.0050 0.0058 0.0050	172.76 172.76 172.76 201.72 172.76 201.72 172.76 201.72
3 1/2	3.500	7.70 9.20 10.20 7.70 9.20 10.20 7.70 9.20 10.20 12.70 7.70 9.20 10.20 12.70 9.20 12.70	9.30 9.30 9.30 12.95 9.30 12.95 9.30 12.95	H-40 H-40 H-40 J-55 J-55 J-55 C-75 C-75 C-75 C-75 N-80 N-80 N-80 N-80 P-105 P-105	0.216 0.254 0.289 0.216 0.254 0.289 0.216 0.254 0.289 0.375 0.216 0.254 0.289 0.375 0.254 0.375	3.068 2.992 2.922 3.068 2.992 2.922 3.068 2.992 2.922 2.750 3.068 2.992 2.922 2.750 2.992 2.750	2.943 2.867 2.797 2.943 2.867 2.797 2.943 2.867 2.797 2.625 2.943 2.867 2.797 2.625 2.867 2.625	4.250	4.500	4.180	4,070 5,050 5,680 5,290 6,560 7,390 6,690 8,530 9,660 12,200 7,080 9,080 10,230 12,920 12,110 17,200	4,320 5,080 5,780 5,940 6,980 7,950 8,100 9,520 10,840 14,060 8,640 10,160 11,560 15,000 13,330 19,690	65,070 79,540 92,550 89,470 109,370 127,250 122,010 149,140 173,530 230,990 130,140 159,090 185,100 246,390 208,800 323,390	103,610 142,460 194,260 276,120 207,220 294,530 271,970 386,570	0.0091 0.0087 0.0083 0.0091 0.0087 0.0083 0.0091 0.0087 0.0083 0.0073 0.0091 0.0087 0.0083 0.0073 0.0087 0.0073	109.37 114.99 120.57 109.37 114.99 120.57 109.37 114.99 120.57 136.12 109.37 114.99 120.57 136.12 114.99 136.12
4	4.00	9.500	11.00	H-40 H-40 J-55 J-55 C-75 C-75 N-80 N-80	0.226 0.262 0.226 0.262 0.226 0.262 0.226 0.262	3.548 3.476 3.548 3.476 3.548 3.476 3.548 3.476	3.423 3.351 3.423 3.351 3.423 3.351 3.423 3.351	4.750	5.000		3,580 4,420 4,650 5,750 5,800 7,330 6,120 7,780	3,960 4,580 5,440 6,300 7,420 8,600 7,910 9,170	72,000 99,010 135,010 144,010	123,070 169,220 230,750 246,140	0.0122 0.0117 0.0122 0.0117 0.0122 0.0117 0.0122 0.0117	81.78 85.20 81.78 85.20 81.78 85.20 81.78 85.20
4 1/2	4.500	12.600	12.750	H-40 J-55 C-75 N-80	0.271	3.958	3.833	5.200	5.563		3,930 5,100 6,430 6,810	4,220 5,800 7,900 8,430	104,360 143,500 195,680 208,730	144,020 198,030 270,240 288,040	0.0152	65.71

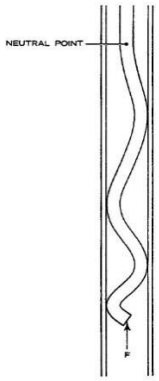

Figure 1
Tubing string bends and coils helically

Figure 2- Screw Type

Figure 3 – Slip Type

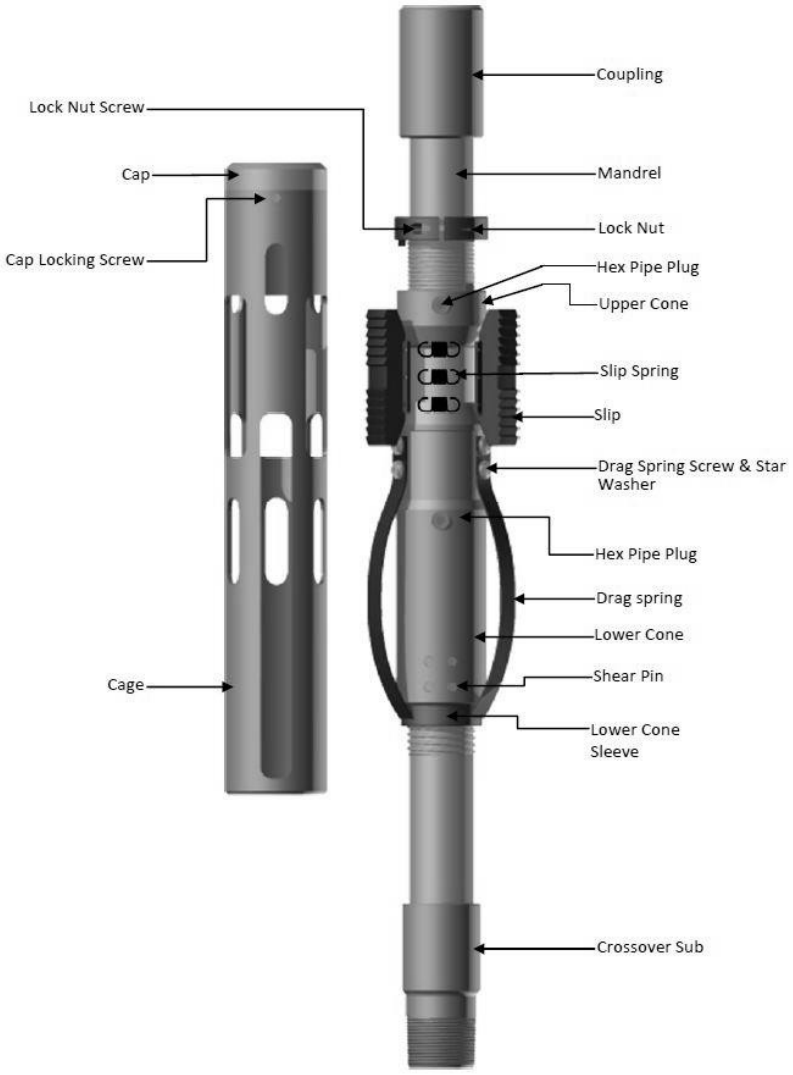

Figure 4
Tubing Anchor Catcher Assembly

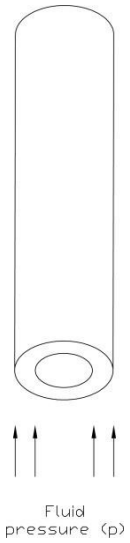

Figure 5 - Buoyancy

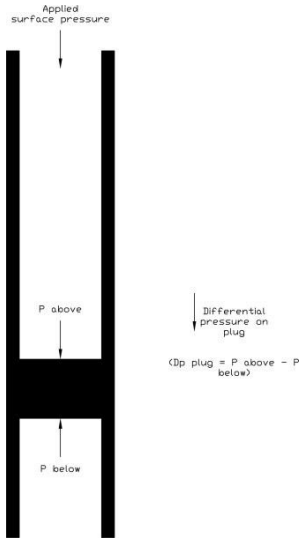

Figure 6 – Pistion effect due to plugging

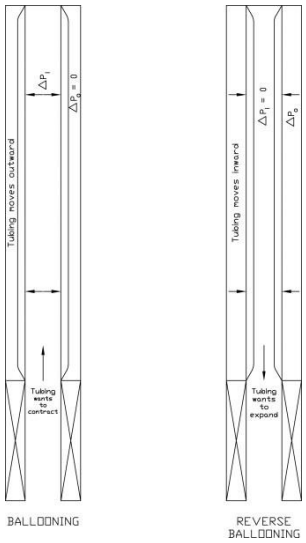

Figure 7 – Ballooing

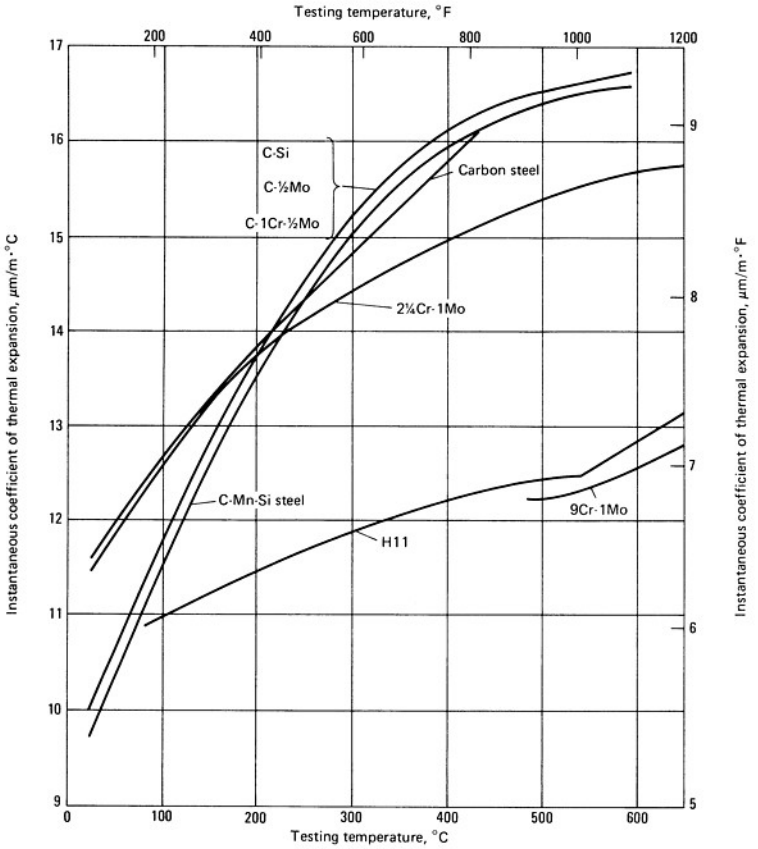

Figure 8– Coefficients of thermal expansion for carbon and low-alloy steels at various temperatures. There are not mean values of the coefficient over a range of temperatures [3].

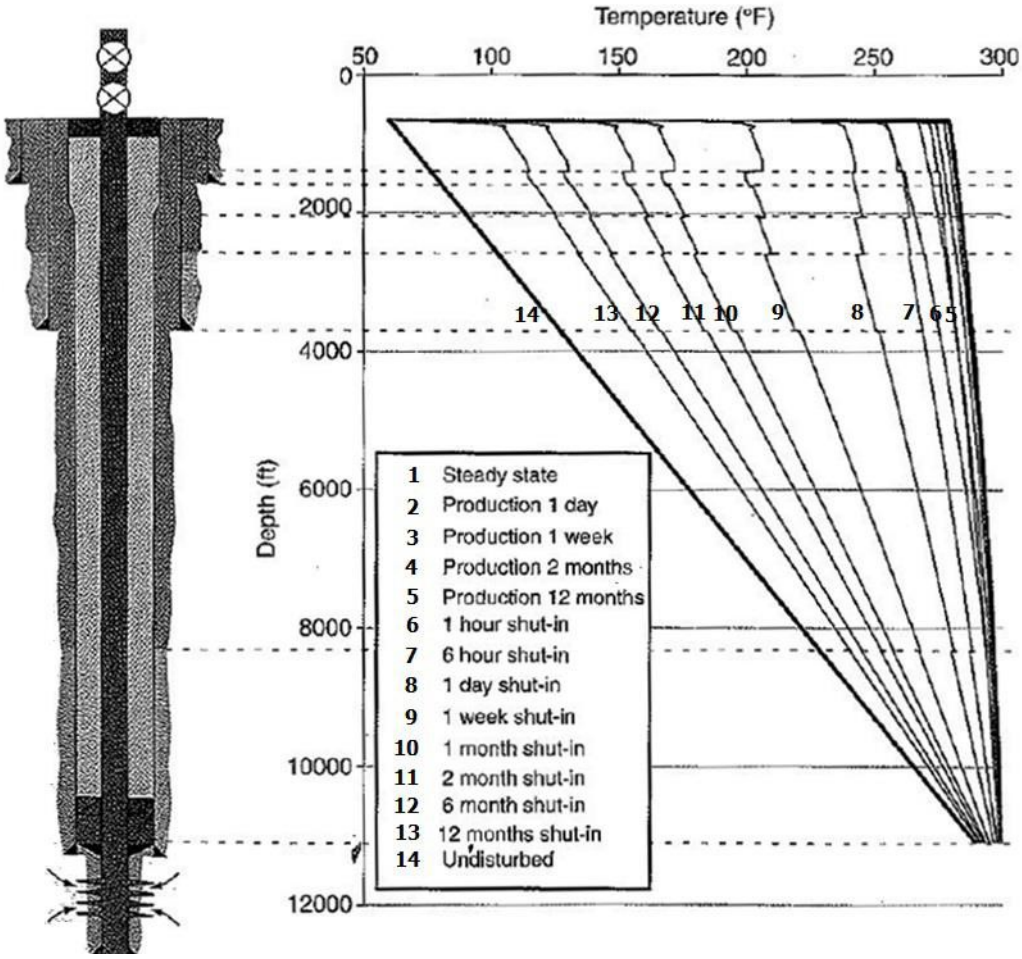

Figure 9 Variation of well bore fluid temperature with the depth [2]

References

[1] "Helical buckling of tubing sealed in pacer" by Arthur Lubinski, W.S. Althouse, J.L. Logan, Petroleum Transactions - society of Petroleum Engineers 1962
[2] Well completion design by Jonathan Bellaryby.
[3] ASM Handbook Volume 1 Properties and selection: Irons steels and High Performance Alloys.
[4] Baker Huges Tech Facts Engineering Handbook - Technical Information for Completion, Workovers and Fishing.