ARROW™
COMPLETION SYSTEMS
AN **EVI** OIL TOOLS DIVISION

APPLIED HYDRAULICS MANUAL

FOR

DOWNHOLE TOOLS

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Section I
General Calculations

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Area of Circles

The formula to find the area of a circle is:

$$A = D^2 \times 0.785$$

where A = the area of the circle and D = the diameter of the circle. The constant 0.785 = $\pi \div 4$; π is defined mathematically as the ratio of the diameter to the circumference of a circle.

In packer calculations, D is expressed in inches and the area A, is expressed in *square inches.*

If you need to know the difference in area between two circles, find the area of one circle, then the area of the other circle, and subtract the *areas.* You will not get the correct answer by subtracting diameters, or by subtracting diameter from area. It is necessary to know the difference in areas to calculate the end area of a string of pipe, or to know the annular area above a packer.

To make these calculations easier, some tubular goods tech data tables feature not only ID and OD, but inside and outside area.

Example Calculations:

What is the outside area of 2 3/8" 4.7# tubing?
From the tubing tables we find that 2 3/8" tubing has a 2.375" OD.

$$A = (2.375)^2 \times 0.785$$
$$A = 5.6406 \times 0.785$$
$$A = 4.43 \text{ IN}^2$$

What is the end area of the tubing above?
Again from the tubing tables:

OD = 2.375 inches
ID = 1.995 inches

and we know from the first calculation that the outside area = 4.43 IN^2

$$A_o = 4.43 \text{ IN}^2$$
$$A_i = (1.995)^2 \times 0.785$$

$$A_i = 3.98 \times 0.785$$
$$A_i = 3.12 \text{ IN}^2$$

the difference between inside and outside areas is equal to the end are of the tubing;

$$A_o - A_i = \text{ end area}$$
$$4.43 - 3.12 = 1.31 \text{ IN}^2$$

Calculate the annular area between the 2 3/8" tubing used above, and 5 1/2" 20# casing.

Let A_{ic} = the area inside the 5 1/2" casing
and A_o = the are outside the tubing
from the example above, we know that A_o = 4.43 sq.in.

$$A_{ic} = (\text{casing ID})^2 \times 0.785$$
$$A_{ic} = (4.778)^2 \times 0.785$$
$$A_{ic} = 22.829 \times 0.785$$
$$A_{ic} = 17.92 \text{ IN}^2$$

and we know that annular area is the difference between A_{ic} and A_o;

$$A = A_{ic} - A_o$$
$$A = 17.92 - 4.43$$
$$A = 13.49 \text{ IN}^2$$

Casing and Tubing Capacities

The data used to calculate capacity can be found under *Engineering Tables* in this book. Data is presented in a variety of formats for your convenience.

To calculate the capacity of tubing in barrels, locate the column "Barrels per Lin. Ft." in the Engineering Tables. The value listed is the number of barrels of fluid contained in one linear foot of tubing. Multiply this number by the length of the tubing in feet to get total displacement. The process for casing is the same.

Note: You cannot find annular volume by subtracting tubing capacity from casing capacity. Remember that annular capacity is based on annular area, which is calculated using casing ID and tubing OD. Tubing capacity data is calculated based on tubing ID, not OD.

When the capacity data for your particular tubular goods are not given, it can be calculated using the end area of the *inside* of the pipe times unit length (usually one foot) to get volume. Remember to convert this volume to proper units e.g. barrels.

Example Calculations:

Using:
2 3/8" 4.60# tubing to the packer
12,500 ft. to the packer
12,600 ft. to the perforations
5 1/2" 20# casing below the packer
Find displacement to the perforations.

From the Engineering Tables:
Tubing = 0.00387 bbl/lin ft
Casing = 0.0222 bbl/lin ft

Capacity of tubing:
=12,500 X 0.00387
=48.38 barrels
Capacity of casing:
=(12,600 - 12,500) X 0.0222
=100 X 0.0222
=2.22 barrels
Displacement= 48.38 + 2.22= 50.6 barrels

When data from tables is not available:
Using:
2 7/8" 10.7# PH-6 Hydril Tubing
(ID=2.091")
7" 38# casing
Depth to Packer = 18,500 ft.
Depth to perforations = 18,700 ft.

Capacity of tubing:
$A_i=(ID)^2 X 0.785$
$A_i=(2.091)^2 X 0.785$
$A_i=4.372 X 0.785$
$A_i=3.432$ in^2
and volume = area X length:
Volume of a linear foot of tubing = $A_i X 12$
$V= 3.432 X 12$
$V=41.187$ *in*^{3}
and :
1 barrel = 9702 in^3
the capacity of this tubing is:
$=41.187 \div 9702$
=0.00425 bbl/lin ft
Using the same method for calculating casing displacement yields:
0.0340 bbl/lin ft

Displacement to the Packer:
=18,500 X 0.00425
=78.54 barrels
Displacement from the Packer to the perforations:
=100 X 0.0340
=3.40 barrels
Displacement to the perforations:
=3.40 + 78.54
=81.94 barrels
or approximately 82 barrels.

Pressure
Hydrostatic and Applied Pressure

Both hydrostatic and applied pressure are denoted by the amount of pounds force pushing on a unit area. Units are commonly expressed as pounds per square inch (psi). Applied pressure is that pressure exerted on the system by an external source, such as a pump. Applied pressure is usually derived from a pressure gage mounted on a manifold or at the pump. Hydrostatic pressure is that pressure created by the weight of a column of fluid.

Applied Pressure

Pressure applied to a fluid at surface is uniform throughout the entire column of fluid. The value of applied pressure at the top of the well will be equal at the bottom of the well and into the formation *provided there is little or no fluid flowing.* Flowing fluid has an inherent friction pressure loss that must be subtracted from the applied pressure to obtain true bottom hole pressure. Friction pressure calculation is a science unto itself as it is dependent on the rheology of the fluid, pump rate, and dimensions of the tubular goods and well.

Hydrostatic Pressure

Hydrostatic pressure is applied by any column of fluid; remember gas is also a fluid. The most common reference to hydrostatic pressure is that pressure exerted by the column of gas we call our atmosphere; barometric pressure. Weather reports give the hydrostatic head of approximately 30,000 feet of air measured in inches of mercury (it can also be expressed as 14.696 psi).

Petroleum service applications refer to fluid weights as pounds per gallon (ppg). To calculate hydrostatic pressure, the formula below can be used:

$$PSI = 0.052 \times (ppg) \times depth$$

where 0.052 is the number of psi/ft of a fluid having a density of 1 ppg.

Tables may give the "psi/ft" of a fluid. Multiplying that value by depth will give the hydrostatic pressure at that depth.

Specific Gravity

Specific gravity is defined as the density of a given fluid divided by the density of fresh water under the same conditions.

For example, knowing that fresh water has a density of 8.333 ppg and a fluid gradient of 0.433 psi/ft, if a completion fluid has a specific gravity of 1.5, we know that it weighs 1.5 X 8.333 or 12.5 ppg and that it has a fluid gradient of 1.5 X 0.433 or 0.650 psi/foot.

Example Calculations:

8400 ft to perforations

12.2 ppg mud weight

1500 psi pump pressure

Assuming friction loss is negligible, calculate pressure at surface and at the perforations.

Applied pressure = 1500 psi

Hydrostatic pressure:

$= 12.2 \times 0.052 \times 8400$

$= 5329$ psi

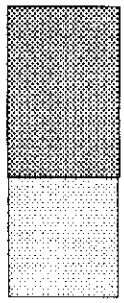
Pressure @ surface = 1500 psi

Pressure @ perfs = 1500 + 5329 = 6829 psi

Note: There may be a slight difference in pressures calculated using different approaches. This is usually due to rounding of decimals.

Pressure of a Water/Oil Mixture

Calculation of the hydrostatic pressure of an oil/water mixture is accomplished from the density data for produced water, for produced oil, and for the percent water cut. If the well has been shut in, the oil and water would be separated but the calculation would remain the same.



Example Calculation:

A well is 35% cut with 9.2 ppg water and produces 38 gravity oil. Calculate the fluid gradient.

Water: $9.2 \times 0.052 = 0.478$ psi/ft

Oil: from table or calc $= 0.362$ psi/ft

Fluid gradient:

$= (0.35 \times 0.478) + (0.65 \times 0.362)$

$= 0.403$ psi/ft

Hydrostatic and Applied Pressure

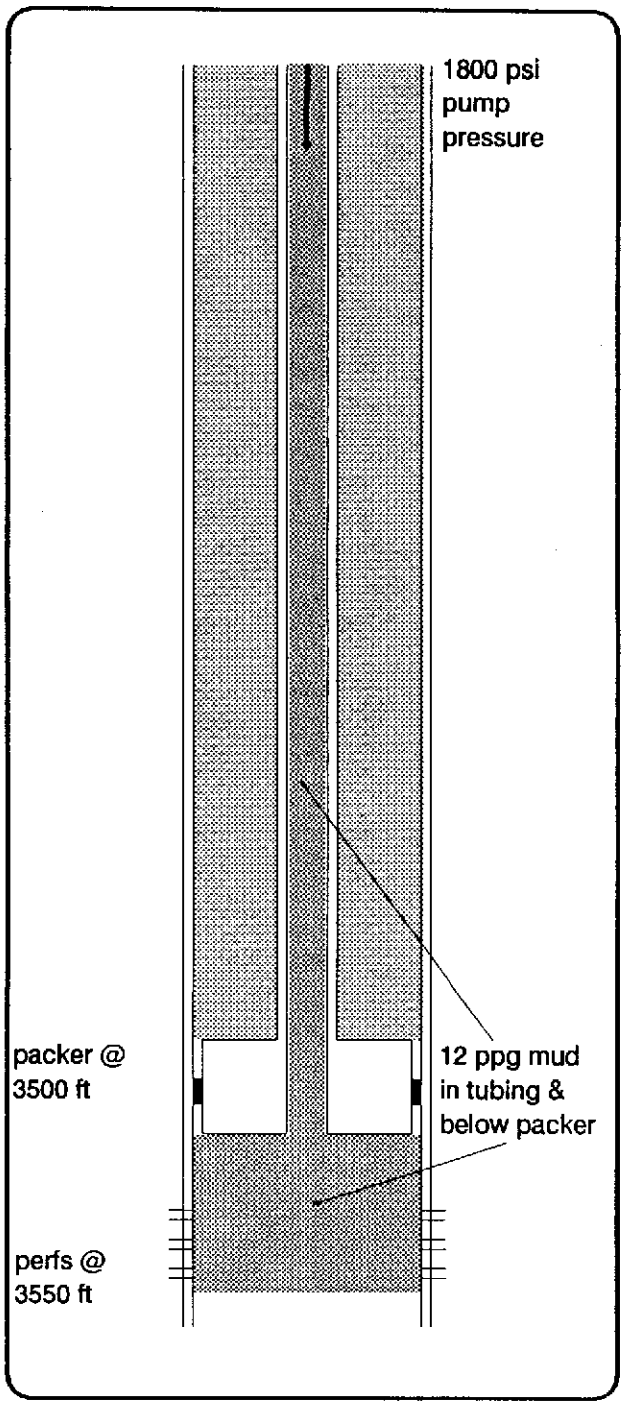
Using the well schematic at right:
Pump pressure = 1800 psi
Fluid in tubing = 12 ppg mud
Packer @ 3500 ft
Perforations @ 3550 ft
What is the pressure at surface?
What is the bottom hole pressure at the perforations?

Calculate fluid gradient:
$= 12 \times 0.052$
$= 0.624$ psi/ft

Calculate the hydrostatic pressure:
$= 3550 \times 0.624$
$= 2215$ psi

Pressure @ perfs:
$= P_h + P_a$
$= 2215 + 1800$
$= 4015$ psi

The only pressure at the surface is the pump pressure, 1800 psi.



How To Calculate Fluid Gradients

If you are given the fluid weight in *pounds per gallon*:

psi/ft = ppg X 0.052

Example: 12.5 ppg completion fluid
psi/ft = 12.5 X 0.052
psi/ft = 0.650

If you are given the fluid weight in *pounds per cubic foot*:

psi/ft = (#/cu. ft.) X 0.007

Example: 98 #/cu. ft. mud
psi/ft = 98 X 0.007
psi/ft = 0.686

If you are given the fluid weight in *specific gravity*:

psi/ft = S.G. X 0.433

Example: Mud with 1.72 specific gravity
psi/ft = 1.72 X 0.433
psi/ft = 0.745

If you are given the fluid weight in *API Gravity:*

psi/ft = 61.37 ÷ (131.5 + API Gravity)

Example: Oil of 38° API Gravity
psi/ft = 61.37 ÷ (131.5 + 38)
psi/ft = 61.37 ÷ 169.5
psi/ft = 0.362

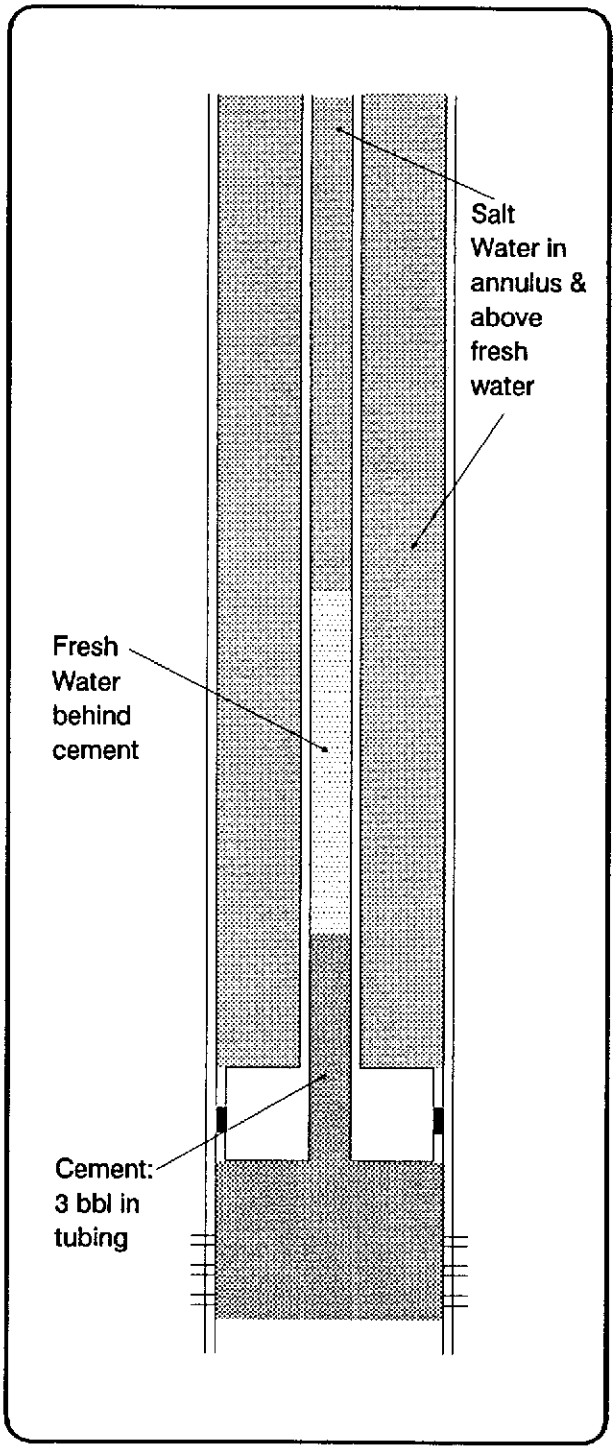
Differential Pressure

A frequent requirement is to balance two columns of fluid having different densities. A well that has been squeeze cemented, has cement in the tubing and mud in the annulus when cement is to be reversed out, is an example. The information required is "what is the difference in hydrostatic pressure at the tool between the two columns". The information given is often "how many barrels of cement are left in the tubing". Information from Engineering Tables can be used to convert the *given* information into the *required* information.

Calculation of the hydrostatic pressure of a column of fluids is done as if each fluid were separate. The results for the separate fluids is then added together to give a total hydrostatic pressure acting at the tool as a result of all fluids in the column. There can be any number of fluids, and there can be gas as well as liquid (remember gas is a fluid and can exert a hydrostatic pressure).

Differential Pressure Calculations

You are the tool man on the well pictured at right. The following information is supplied:
Squeeze tool set at 8500 ft. on 2 7/8" 6.5# EUE tubing
Annulus is filled with 9.2 ppg salt water
Cement remaining in the tubing is 3 barrels
Cement (16.5 ppg) is followed by 5 barrels of fresh water
You need to pull out of the tool and reverse out the cement.
What pressure should be held on the backside to prevent cement from flowing out around the tool?



From Engineering Tables:
2 7/8" 6.5# has 172.8 lin ft/bbl

Calculate fluid gradients:
Fresh water = 0.433 psi/ft
Salt water = 9.2 X 0.052 = 0.478 psi/ft
Cement = 16.5 X 0.052 = 0.858 psi/ft

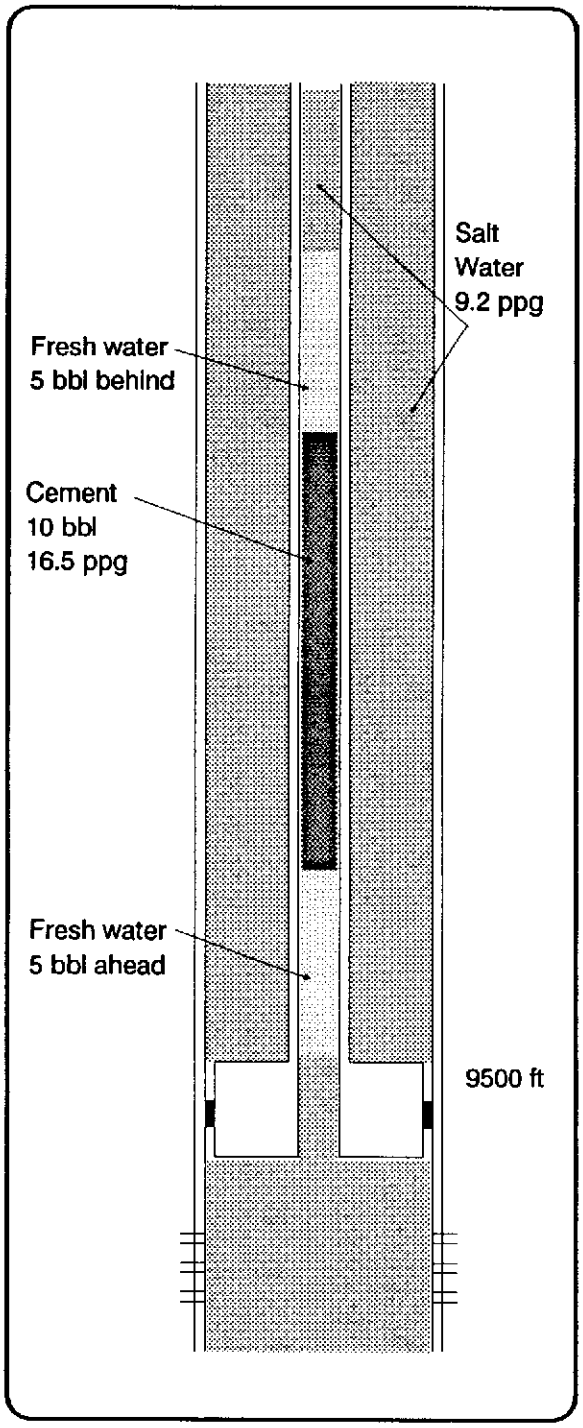
Calculate fluid heights:
Starting at the tool
Cement = 3 X 172.8 = 518.4 ft
Fresh water = 5 X 172.8 = 864.0 ft
Salt water = 8500 - 518.4 - 864.0 = 7117.6 ft

Calculate hydrostatic pressure at tool:
Tubing:
Cement: 518.4 X 0.858 = 444.8 psi
Fresh water: 864.0 X 0.433 = 374.1 psi
Salt water: 7117.6 X 0.478 = 3402.2 psi
Tubing total = 4221 psi
Casing:
Salt water: 8500 X 0.478 = 4063 psi

Differential at the tool
4221 - 4063 = 158 psi
in favor of the tubing. This means that when the tool is released, and the work string pulled from the tool, cement will flow from the tubing to the casing unless 158 psi is applied to, or held, on the casing.

Differential Pressure Calculations

Using the well schematic at right:
Packer @ 9500 ft
Tubing is 2 7/8" 6.4#
Saltwater above, below, and in annulus (9.2 ppg)
Cement is 10 bbl @ 16.5 ppg
Fresh water 5 bbl ahead and behind
You are circulating cement to the tool at a low pump rate (tubing open to the annulus). You want to control the cement flow so the tool's bypass can be closed before cement reaches the tool.
Assuming pump pressure is zero, what pressure must be held on the casing to balance the column of fluid in the tubing?



Calculate fluid gradients:

Saltwater	= 9.2 X 0.052 = 0.478 psi/ft
Fresh water	= 0.433 psi/ft
Cement	= 16.5 X 0.052 = 0.858 psi/ft

Calculate fluid heights:
2 7/8" 6.4 # tubing = 172.8 ft/bbl

Fresh water	= 10 X 172.8 = 1728 ft
Cement	= 10 X 172.8 = 1728 ft
Saltwater	= 9500 - 2(1728) = 6044 ft

Calculate hydrostatic pressure:

Tubing	= (1728 X 0.433) + (1728 X 0.858) + (6044 X 0.478) = 748.2 + 1482.6 + 2889.0 = 5119.8 psi
Casing	= (9500 X 0.478) = 4541.0 psi

Differential at the tool:
= 5119.8 - 4541.0 = 578.8 psi

To balance the column of fluids in the tubing, and thus control fluid placement, 579 psi must be held on the casing.

Converting Pressure into Height or Capacity

Tools that require pressure to set (hydraulic set such as the Arrow Hydrow-I packer) are common. Sometimes too much pressure will damage the tool, or will cause the tool to pre-maturely set while running in the hole. It is imperative to get the correct amount of pressure to the tool at the correct time.

If the well is full of fluid (hole loaded) the matter of pressure control at the tool is simple. Apply the proper amount of pressure to the well using a surface pump. But in the case of a *low fluid level well,* you need to be able to convert the required pressure into feet or barrels required.

For example, assume your task is to set a Hydrow-I packer in a low fluid level well using a wireline plug seated in a profile nipple below the packer. When the plug is set, the tubing is not loaded. Hydrostatic pressure generated by loading the tubing would not only set the packer, but could damage the setting mechanism by exceeding the pressure rating of the setting chambers.

Converting Pressure into Height

Find or calculate the fluid gradient (psi/ft) for the fluid you intend to use, then divide that into the pressure.

height (ft) = PSI ÷ Fluid Gradient (psi/ft)

Converting Pressure to Barrels

Often the desired information is the number of barrels in this size pipe to get the required pressure. The first step is to consult the Engineering Tables to obtain the "psi/bbl", or if not available, the "ft/bbl". The "psi/bbl" converts directly, while the "ft/bbl" requires converting pressure into height first (see above).

barrels = PSI ÷ "psi/bbl"

Notes:

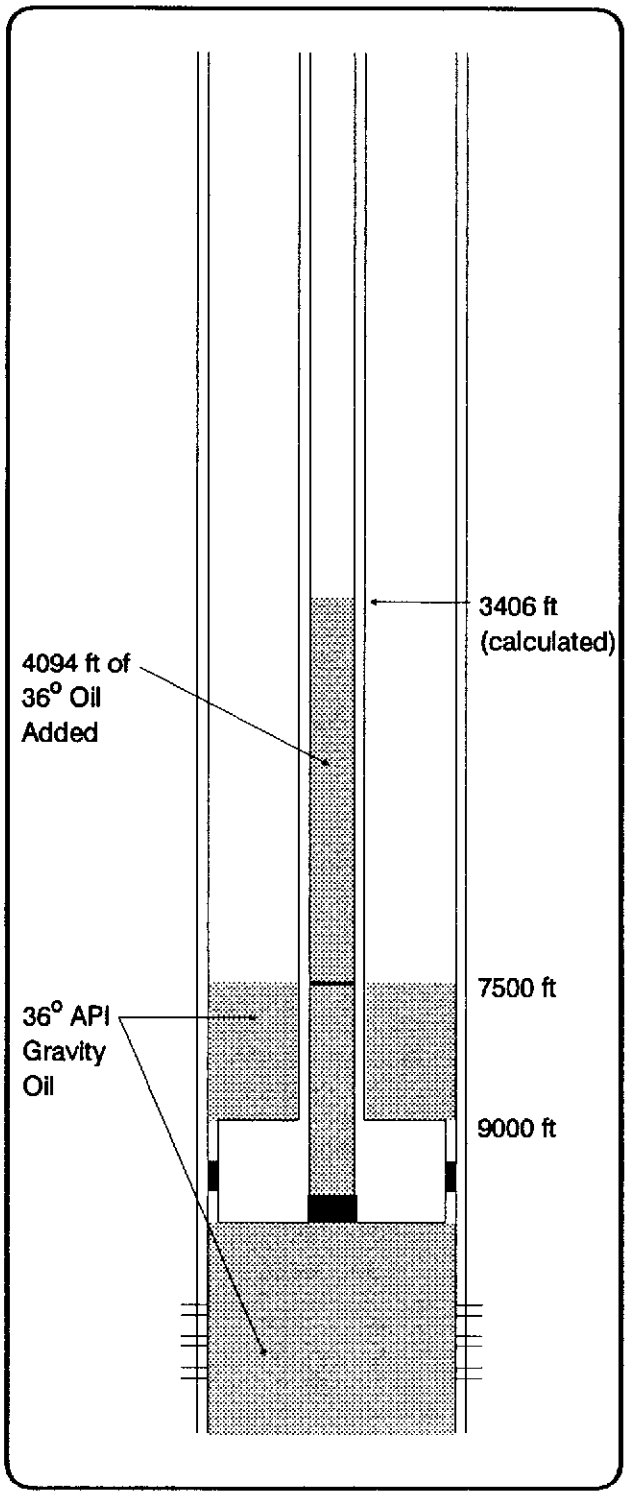
How Many Feet to Get Pressure
Using the well schematic at right:
9000 ft to the tool
36° API gravity oil to 7500 ft
2 7/8" 6.4# tubing
Need 1500 psi to set the tool
How much fluid (in barrels) should be pumped?

Calculate fluid gradient of 36° oil:
=61.37 / (131.5 + 36)
=0.366 psi/ft

Calculate feet required:
=1500 / 0.366
=4094 feet

How Many Barrels to Get Pressure
From the Engineering Tables:
2 7/8" 6.4# tubing has 0.00579 bbl/ft

Using the height calculated above (4094 ft),
=0.00579 X 4094
=23.7 barrels of 36° Oil



Hydrostatic and Applied Pressure in a Low Fluid Level Well

Using the well schematic at right:
Packer set @ 3800 ft
Tubing is 2 7/8" 6.4#
Fluid level is 3000 ft of 9.2 ppg salt water
Tool is hydraulic set requiring 2000 psi tubing press.
What operations are required to set the packer?

Calculate fluid gradient of saltwater:
= 9.2 X 0.052
= 0.478 psi/ft

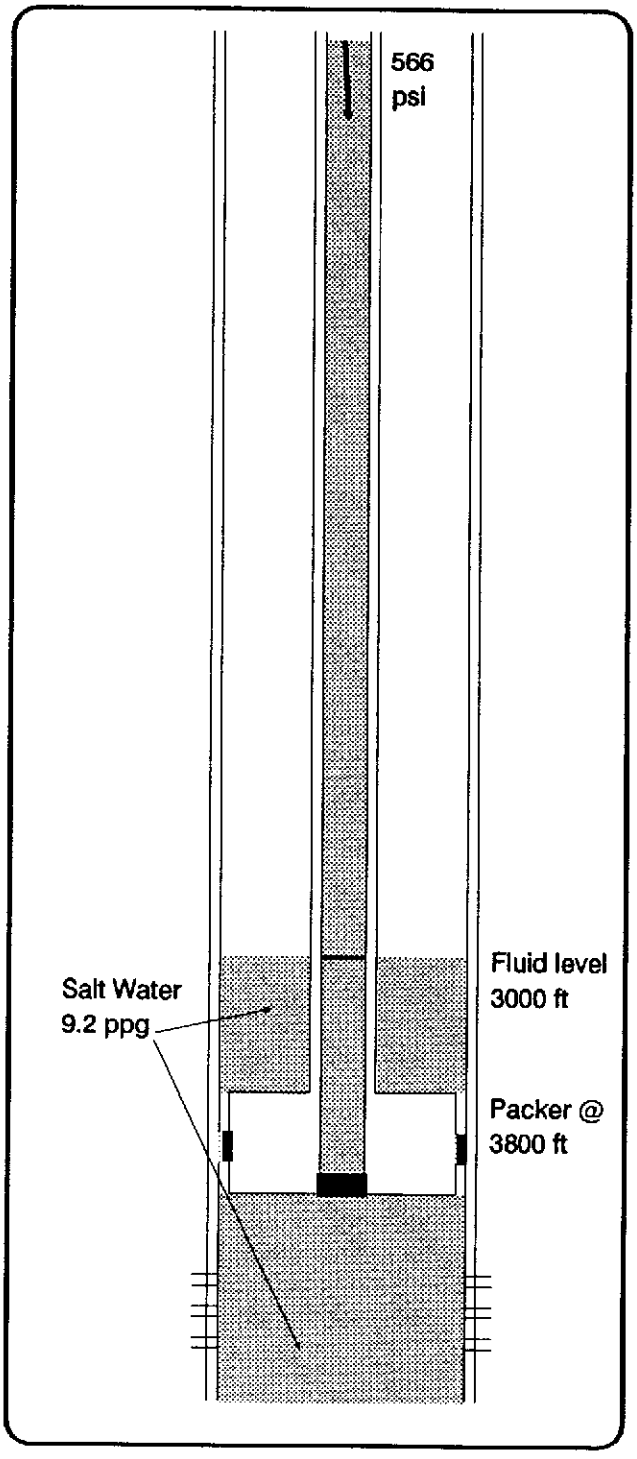
Calculate height of fluid required to set:
= 2000 ÷ 0.478
= 4184 feet
but we have a fluid level of 3000 feet and cannot get 4184 feet of fluid in this well. As discussed earlier in this section, there are two sources of pressure, hydrostatic and applied. If hydrostatic will not accomplish the task, we must use applied pressure.

Calculate maximum differential with tubing loaded:
= 3000 X 0.478
= 1434 psi

Calculate amount of fluid required to fill 3000 feet of tubing.
From the Engineering Tables:
2 7/8" 6.4# = 0.00579 bbl/ft
Fluid required:
= 3000 X 0.00579
= 17.37 barrels

If 2000 psi differential is required to set the tool, we can calculate the required applied pressure:
= 2000 - 1434
= 566 psi

To accomplish the task of setting the packer, we must add 17.4 barrels of fluid to the tubing and apply 566 psi pump pressure to the tubing.



Timing Cement Plugs

Cement plugs are pumped down either by a pump truck or by the rig pump. It is necessary to know when they will bump the float collar or shoe to avoid over displacing or damaging the casing with excessive pressure. If a pump truck is used, fluid volume can accurately be measured through the use of inventory tanks. If the rig pump is used to displace fluid from a tank of unknown displacement, time the plug to determine when it should bump the collar or shoe.

Calculations:

Refer to the pump efficiency tables on the following page.

Caution: Use the proper column - one is for barrels and the other for cubic feet.

1. First calculate the capacity of the casing (in bbl or cu.ft.)
2. Multiply the strokes/bbl. (cu.ft.) for the correct liner size times the capacity of the pipe. This tells how many pump strokes are required to displace the plug.
3. Time the pump by counting strokes of one piston rod to get the strokes per minute. A stroke is considered a full forward and backward motion of the piston rod. These tables are for a duplex pump. Convert this figure to minutes per stroke to get factor "B" from the chart.
4. Multiply the minutes per stroke times the number of strokes to displace the plug (from #2 above). Minutes per stroke is obtained by dividing 1 by the number of strokes per minute.

Note:

The chart is calculated based on 85% efficiency as that is the value most often used.

There is a difference between these tables and other cementing handbooks where the displacement of the piston rod is included on the backstroke.

Example Calculations:

Using:
7 5/8" 39# casing
9500 ft to float collar
6" liner
18" stroke
60 strokes per minute

Using the barrel method:
Calculate the displacement of the pipe to the collar using 0.0426 bbl/ft from the engineering tables;

= 0.0426 X 9500
= 404.7 barrels to displace

Calculate the number of pump strokes required using 6.14 strokes per bbl from the chart;

= 404.7 X 6.14
= 2485 strokes to displace

Knowing 60 strokes per minute, minutes per stroke

= 1 / 60
= 0.0167 min/stk

Time to bump the plug:

= 0.0167 X 2485
= 41.42 minutes

or 41 minutes 25 seconds

Factors Required for Calculating Cement Plug Displacement Time

Liner Size Inches	Stroke Inches	Stroke/BBL Factor "A" 85% Eff.	Stk/cu.ft Factor "A" 85% Eff.	Liner Size Inches	Stroke Inches	Stroke/BBL Factor "A" 85% Eff.	Stk/cu.ft Factor "A" 85% Eff.
4.00	6	40.708	7.251	6.50	16	5.804	1.034
4.00	8	30.532	5.438	6.50	18	5.159	0.919
4.00	10	24.425	4.351	6.50	20	4.644	0.827
4.00	12	20.354	3.625	6.75	12	6.951	1.238
4.50	8	23.748	4.230	6.75	14	5.958	1.061
4.50	10	18.998	3.384	6.75	16	5.351	0.953
4.50	12	15.832	2.820	6.75	18	4.756	0.847
4.50	14	13.570	2.417	6.75	20	4.281	0.762
5.00	10	15.796	2.813	7.00	12	6.442	1.147
5.00	12	13.164	2.345	7.00	14	5.521	0.984
5.00	14	11.284	2.009	7.00	16	4.949	0.881
5.00	16	10.381	1.849	7.00	18	4.400	0.784
5.00	18	9.227	1.644	7.00	20	3.960	0.705
5.50	12	10.718	1.909	7.25	14	5.249	0.935
5.50	14	9.186	1.636	7.25	16	4.593	0.818
5.50	16	8.372	1.491	7.25	18	4.082	0.727
5.50	18	7.441	1.326	7.25	20	3.674	0.654
6.00	12	8.905	1.586	7.50	14	4.885	0.871
6.00	14	7.633	1.360	7.50	16	4.274	0.761
6.00	16	6.907	1.231	7.50	18	3.800	0.676
6.00	18	6.140	1.094	7.50	20	3.420	0.609
6.25	12	8.169	1.455	7.75	14	4.558	0.812
6.25	14	7.002	1.247	7.75	16	3.988	0.711
6.25	16	6.319	1.126	7.75	18	3.545	0.632
6.25	18	5.616	1.000	7.75	20	3.191	0.568
6.50	12	7.522	1.340	7.75	22	2.900	0.516
6.50	14	6.447	1.148	8.00	20	2.985	0.532

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Applied Hydraulics

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Weighing Casing

To find the hook load of different strings of casing, you cannot simply multiply the "weight per foot" by the length of the string. Casing weighs less in fluid than it does in air, where its "weight" rating is calculated. The difference is the bouyant force which is equal to the weight of the volume of fluid displaced by the metal in the casing.

Some engineering tables give the displacement of the metal in the string along with the displaced fluid per 100 couplings. While this rather exacting method is technically correct, a very close approximation can be made for straight holes by using the hydrostatic head of the fluid at the bottom of the string, acting against the cross sectional end area of the casing. In highly deviated and horizontal completions there are many other variables affecting string weight, such as friction in areas of high build angle.

Calculations are done by first obtaining the casing inside and outside diameters, from the engineering tables, and calculating the end area of the string. The hydrostatic head of the column of fluid is then calculated and the resultant force applied as to lift the string from the well.

Guide Shoe

With a guide shoe, the only area affected is the cross sectional area of the casing itself; and the casing is being "pushed" upward, or lightened, by the hydrostatic pressure at the bottom of the shoe acting on this end area. Everything inside the shoe will cancel out. To calculate casing weight, multiply the #/ft by the depth of that weight casing, then subtract your estimate of the bouyant force. The bouyant force is calculated by multiplying the end area of the casing by the hydrostatic pressure at the shoe. If casing of different weight (and I.D.'s) of casing are used, you can add the number of feet of casing times the weight per foot for each section, however, changes in casing I.D. affect the bouyant force and its calculation. The required calculation method will be covered later in this section.

Float Shoe

When a float shoe is run on the end of the casing string, none of the wellbore fluid is allowed to enter the casing and the string acts as if it were plugged at the bottom. Casing weight is estimated by calculating the end area of the casing using casing O.D. then multiplying by the hydrostatic pressure at the shoe. Any fluid inside the casing (sometimes the rig crew will "fill" the casing using a mud hose) should be taken into account by first estimating the amount of fluid inside the casing (in ft.) then estimating the hydrostatic pressure at the shoe (remember the fluid inside the casing may be of different density than that outside) and multiplying by the inside area of the casing. Remember to add the casing weight in air to obtain correct hook load. When different weights of casing are used, the same rules apply as those used in the Guide Shoe example. Also remember that the bouyant force estimated cannot exceed the weight of casing in air, that is, negative hookload.

Differential Fill Equipment

The general rule for running differential fill float equipment states that when one piece of differential equipment is used, the casing will be 90% full, with two pieces (collar and shoe) 81% full. Practice is to calculate the casing weight when the casing has stopped filling and the valve has closed. At this point, your calculations should be made exactly as you would a float shoe with the casing partially filled. The only difference is that you have a somewhat more accurate estimate of the height of the fluid column inside the casing; you also know that the fluid is the same as the fluid outside the casing.

Guide Shoe Calculations:

Using the well schematic at left:
8700 feet of 5 1/2" 23# casing
Mud at 12.6 #/gal

Example calculation of hookload:
Calculate fluid gradient:
$= 12.6 \times 0.052$
$= 0.655$ psi/ft

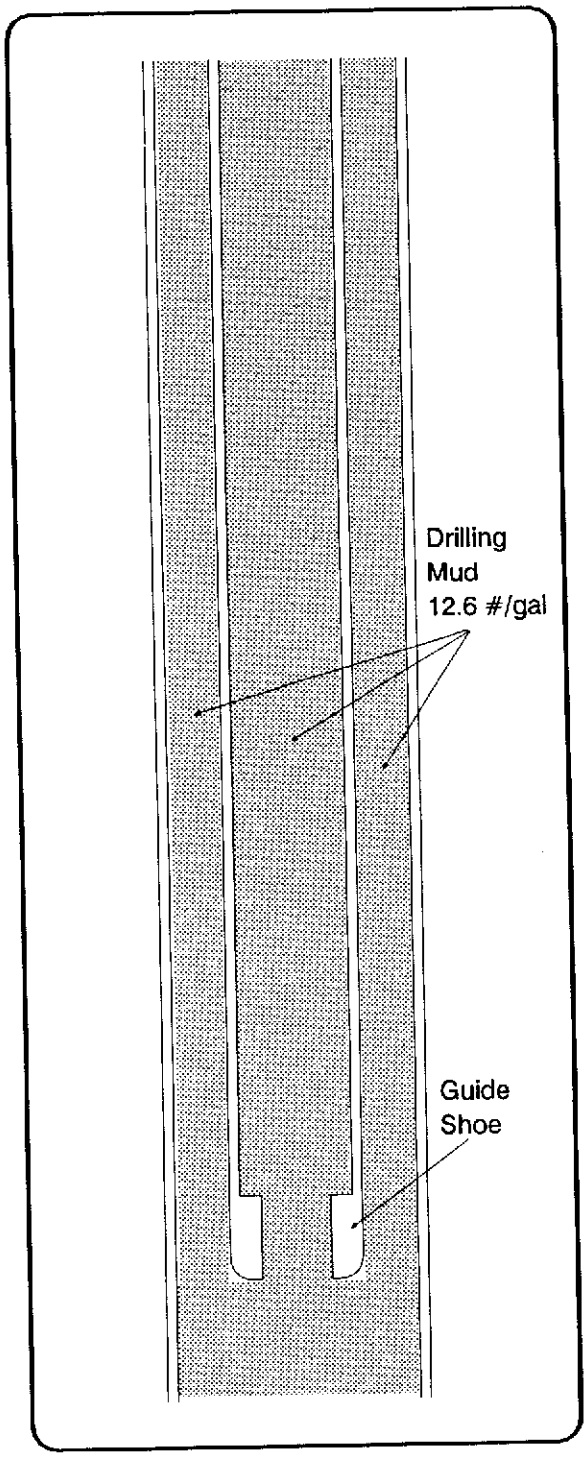
Calculate the hydrostatic pressure:
$= 8700 \times 0.655$
$= 5698.5$ psi

Calculate the end area of the casing:
$= 0.785 \times (5.5^2 - 4.670^2)$
$= 6.626$ in^2

Estimate the bouyant force:
$= 5698.5 \times 6.626$
$= 37{,}762$ # ↑

Calculate the weight of casing in air:
$= 23 \times 8700$
$= 200{,}100$ # ↓

Hookload of casing:
$= 200{,}100 - 37{,}762$
$= 162{,}338$ # ↓



Float Shoe Calculations

Using the well schematic at left:
4800 feet of 7" 20# casing
Mud at 9.2 #/gal

Example calculation of hookload:
Calculate the fluid gradient:
$= 9.2 \times 0.052$
$= 0.478$ psi/ft

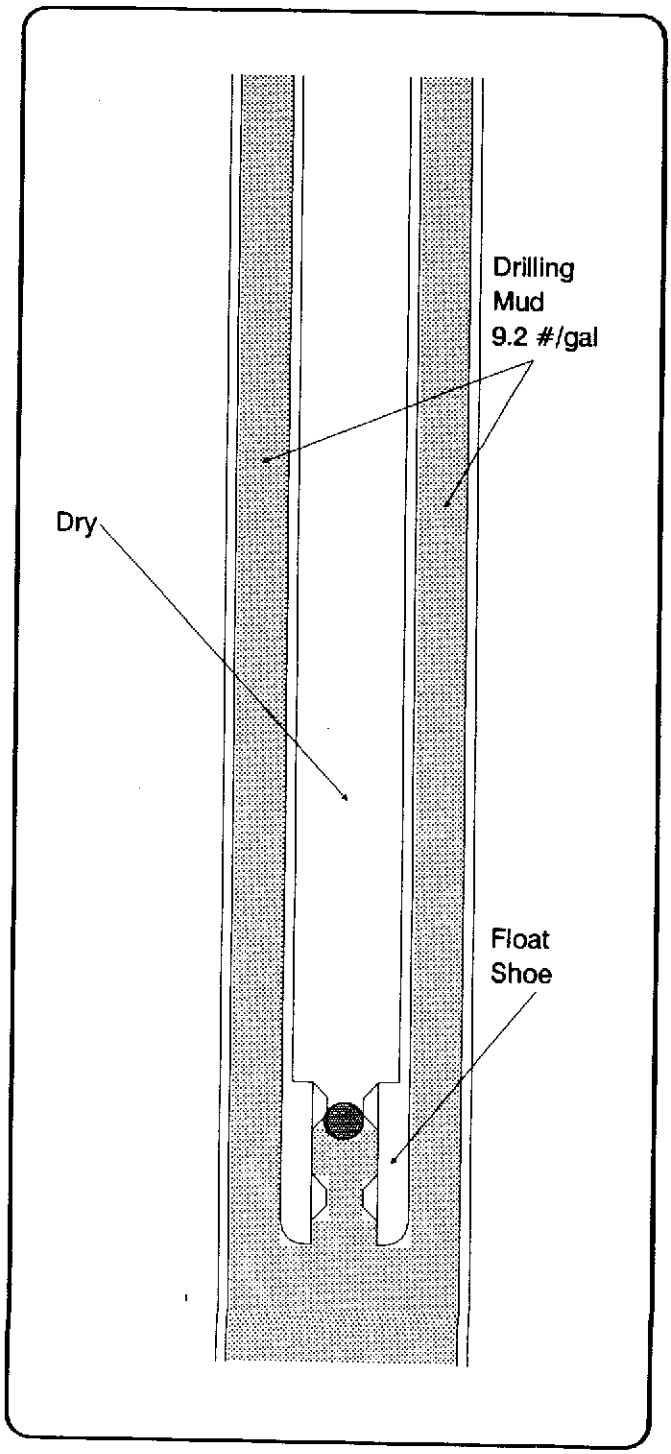
Calculate the hydrostatic pressure:
$= 4800 \times 0.478$
$= 2296$ PSI

Calculate the end area of the casing:
$= 0.785 \times 7^2$
$= 38.465$ in^2

Estimate the bouyant force:
$= 2296 \times 38.465$
$= 88{,}315$ # ↑

Calculate the weight of casing in air:
$= 20 \times 4800$
$= 96{,}000$ # ↓

Hookload of casing:
$= 96{,}000 - 88{,}135$
$= 7{,}865$ # ↓



Differential Fill Calculations

Using the well schematic at left:
4800 feet of 7" 20# casing
Mud at 10.8 #/gal
Differential fill shoe on bottom

Example calculation of hookload:
Calculate the fluid gradient:
$= 10.8 \times 0.052$
$= 0.562$ psi/ft

Calculate the depth of fluid inside the casing:
Using a single piece of differential equipment means that 90% of the casing will be filled:
$= 0.90 \times 4800$
$= 4320$ feet

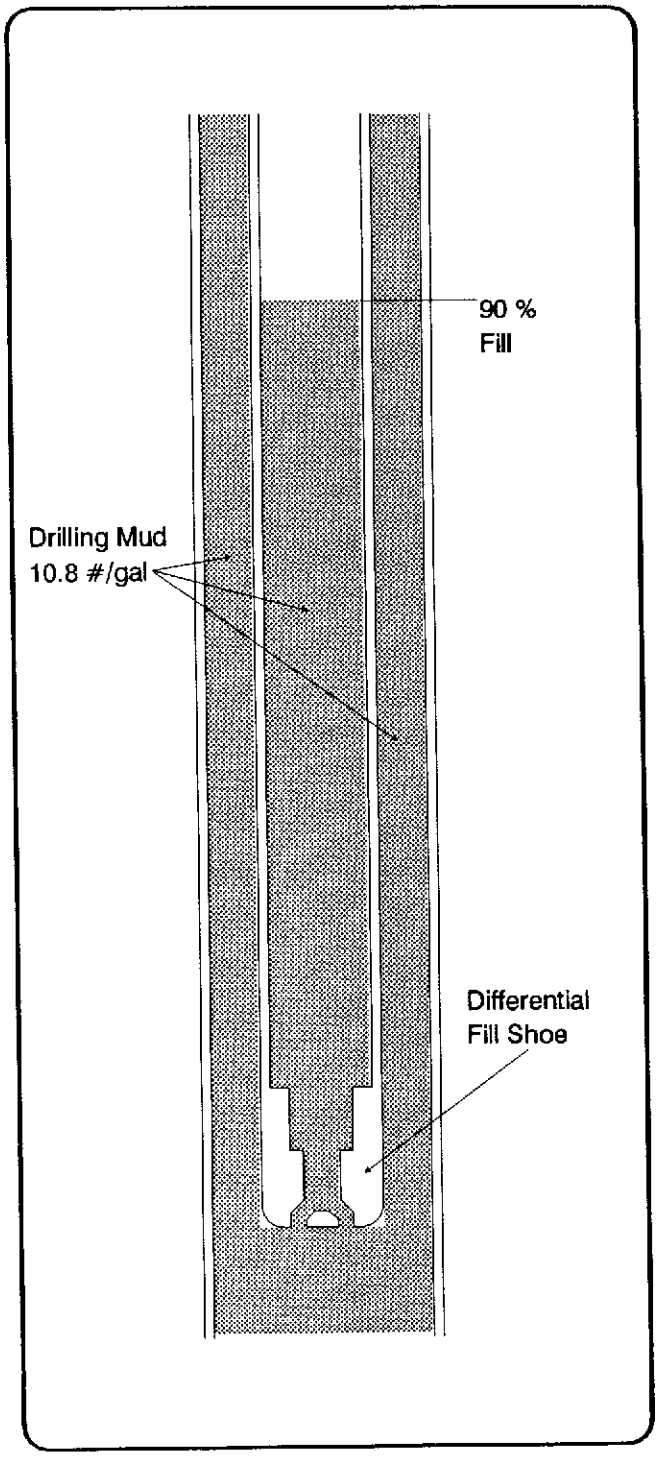
Calculate the hydrostatic pressures:
Inside: $= 4320 \times 0.562$
$= 2428$ psi
Outside: $= 4800 \times 0.562$
$= 2968$ psi

Calculate the areas of the casing:
Inside: $= 0.785 \times 6.456^2$
$= 32.719$ in^2
Outside: $= 0.785 \times 7^2$
$= 38.465$ in^2

Calculate the weight of casing in air:
$= 4800 \times 20$
$= 96{,}000$ # ↓

Balance forces:
Inside: $= 2428 \times 32.719$
$= 79{,}441$ # ↓
Outside: $= 2968 \times 38.465$
$= 114{,}164$ # ↑
Casing weight: $= 96{,}000$ # ↓

Hookload:
$= 96{,}000 + 79{,}441 - 114{,}164$
$= 61{,}277$ # ↓



Calculation using More Than One Casing Weight in the String

Using the "Guide Shoe" example from a previous page, modify the casing schedule to read:
1500 ft of 5 1/2" 23#
2500 ft of 5 1/2" 20#
4700 ft of 5 1/2" 15.50#
Mud at 12.6 #/gal
Remember: Casing schedules read from the bottom, up.

Calculate hydrostatic pressure:
At 4700 ft:

$$= 4700 \times 0.655$$
$$= 3078 \text{ psi}$$

At 7200 ft:

$$= 7200 \times 0.655$$
$$= 4716 \text{ psi}$$

At 8700 ft:

$$= 8700 \times 0.655$$
$$= 5700 \text{ psi}$$

Calculate areas at casing I.D. changes:
At 4700 ft:

$$= 0.785 \times (4.950^2 - 4.778^2)$$
$$= 1.314 \text{ in}^2$$

At 7200 ft:

$$= 0.785 \times (4.778^2 - 4.670^2)$$
$$= 0.801 \text{ in}^2$$

At 8700 ft calculate end area of casing:

$$= 0.785 \times (5.5^2 - 4.670^2)$$
$$= 6.626 \text{ in}^2$$

Calculate forces acting at casing I.D. changes:
At 4700 ft:

$$= 1.314 \times 3078$$
$$= 4044 \text{ \#} \downarrow$$

At 7200 ft:

$$= 0.801 \times 4716$$
$$= 3776 \text{ \#} \downarrow$$

At 8700 ft:

$$= 6.626 \times 5700$$
$$= 37{,}768 \text{ \#} \uparrow$$

Calculate weight of casing in air:

$$= (1500 \times 23) + (2500 \times 20) + (4700 \times 15.50)$$
$$= 34{,}500 + 50{,}000 + 72{,}850$$
$$= 157{,}350 \text{ \#} \downarrow$$

Hookload of casing:

$$= 157{,}350 + 4044 + 3776 - 37{,}768$$
$$= 127{,}402 \text{ \#} \downarrow$$

Packer Plugs

A packer plug is simply a small bridge plug that is designed to fit into the bore of a packer. Pressure from above acts downward on it and pressure from below acts upward.

Pressure from above acts downward on an area equal to that of the bore of the packer (the area of being sealed). Any part of the plug above the packer bore is balanced as essentially equal pressure is exerted on both upward and downward facing surfaces.

To determine the amount of upward or downward force, pressures above and below the plug must first be determined. Multiply the area of the seal bore of the packer by the amount of pressure beneath the plug to determine upward force. Multiply the same area by the pressure above the plug to determine downward force. Subtract to obtain the net force on the plug and its direction. Remember, some plugs seat on a shoulder tranferring the downward force directly into the packer.

If you wish to calculate the amount of force required to retrieve the plug, you must calculate the pressure above the plug, estimate the pressure below the plug, and calculate the net force on the plug. You must overcome this force plus or minus a small amount of seal drag to retrieve the plug.

Be advised that while obtaining an accurate value for downhole pressure is not always possible, your educated estimate is better than no information.

If the plug was recently run, hydrostatic pressure at the plug when it was run would be a good estimate, especially if the well had a low fluid level. If the hole was full and the possibility of the well coming in exists, you may have the customer estimate bottom hole pressure.

Notes:

Packer Plug Calculations

Using the well schematic at right:
Arrow XL-W Packer set at 8800 ft
7" - 29# casing
Casing swabbed to 5800 ft
Bottom hole pressure = 2650 PSI
40° API oil in the hole
Want to equalize forces before releasing plug.

From the tech insert we know that a standard 7" Arrow XL-W has a seal bore of 3.250"

Calculate seal bore area:

$= 0.785 \times 3.250^2$
$= 8.292 \text{ in}^2$

Calculate hydrostatic pressure at top of plug:

$= 0.357 \times (8800 - 5800)$
$= 1071 \text{ psi}$

Calculate force down on plug:

$= 8.292 \times 1071$
$= 8881 \# \downarrow$

Calculate force up on plug:

$= 2650 \times 8.292$
$= 21{,}973 \# \uparrow$

Net force on plug:

$= 21{,}973 - 8881$
$= 13{,}092 \# \uparrow$

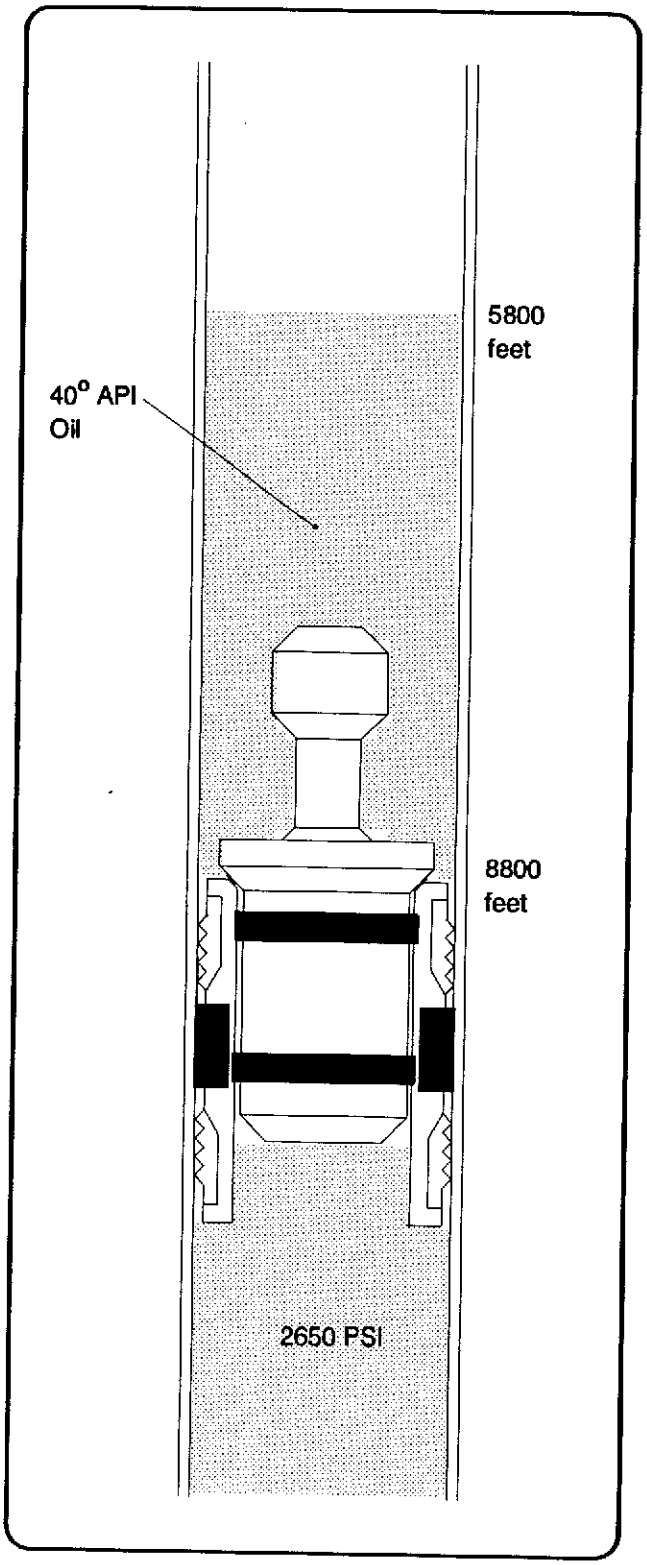
Need to set 13,100 # down to equalize plug.

If you can't get more than 8,000 # down to the tool?

Need to increase hydrostatic above tool to obtain 13,973 # down due to hydrostatic:

$= 13{,}973 \div 8.292$
$= 1685 \text{ PSI}$
$1685 \div 0.357 = 4720 \text{ ft of oil}$

Add 40° API oil to obtain 4720 feet.



Retrievable Bridge Plugs

Opening Valves to Equalize Pressure and Release Plug

Calculating the forces across the plug itself are quite simple. Force down on the plug is calculated by multiplying the plug top area, using the plug O.D. (casing I.D.), by the pressure acting above the plug. Force up is calculated by multiplying the same area by the pressure below the plug. Subtracting one force from the other yields net force acting on the plug.

The problem encountered when retrieving a bridge plug is how much to push or pull to open the valve and equalize pressure across the plug.

Pressure from above will not only be pushing down on the valve, but also on the control rod. Area is calculated on the complete outside area of the valve. Pressure from below also pushes up on the rod, as well as the valve, so again the complete outside area of the valve is used.

Forces are calculated as above, using the O.D. of the valve instead of the O.D. of the plug. Force down is the valve area multiplied by the pressure above, and force up is the valve area multiplied by the pressure below. Subtracting one from the other to find whether push or pull is required, and the amount.

Notes:

Retrievable Bridge Plug

Arrow Type B Bridge plug
5 1/2" 13-17# set in 5 1/2" 15.50# casing
Set at 5200 feet
20^{o} API Oil above to 2500 feet (0.405 psi/ft)
Pressure below: 2850 PSI

From your tech manual, valve O.D. is 1.250"
Valve area:

$= 0.785 \times 1.250^2$
$= 1.227\ in^2$

Calculate pressure above:

$= 0.405 \times (5200 - 2500)$
$= 1094$ PSI

Balance forces:

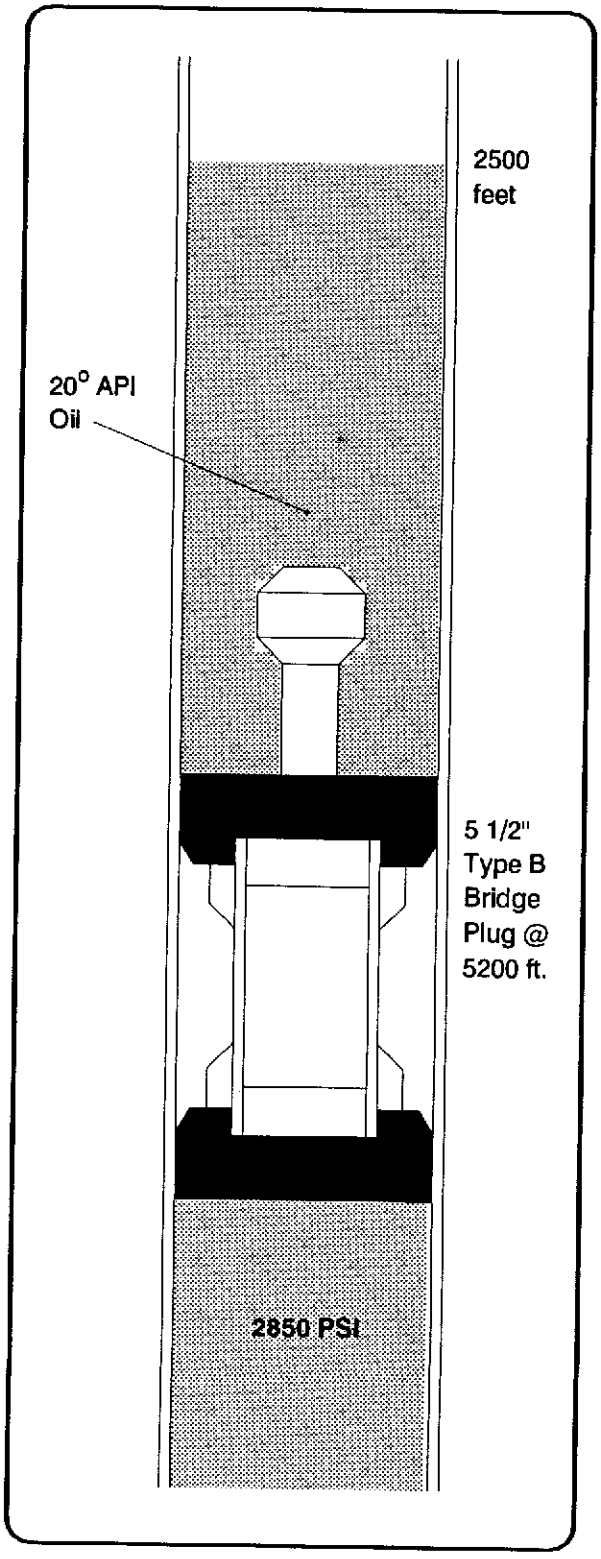
Force down: $= 1.227 \times 1094$
$= 1342\ \# \downarrow$

Force up: $= 1.227 \times 2850$
$= 3497\ \# \uparrow$

Net force: $= 3497 - 1342$
$= 2155\ \# \uparrow$

This implies that you must set down 2155 lbs at the tool to open the valve and equalize pressure. There should be no problem getting this weight to the tool, however, if the value were quite large, you may want to consider adding fluid to increase the hydrostatic on top of the tool.

If tension were required to equalize, consult the tech insert for maximum tension rating for the single and/or double pin retrieving head.



Sealbore Packer

Hookload to Release When Tubing Larger Than Packer Bore

The objective of this calculation, is the estimation of weight indicator reading under a neutral condition at the packer. To find this value, first calculate the weight of the tubing string in air, then calculate the pressures acting on the string and their respective areas.

The schematic at right is a permament packer with the tubing larger than the bore of the packer. Pressure in the annulus pushes up on area "a" which is from the O.D. of the tubing inward to the seal bore of the packer. Pressure acting on area "f" acts both upward and downward between the packer bore and the seal nipple O.D. cancelling out. Pressures acting on surface "e" (the packer itself) transmit forces into the casing and do not play a part in tubing calculations.

Since the bore of the tubing is larger than the bore of the packer, pressure in the tubing will act downward on the area from the tubing I.D. inward to the packer bore, area "b". Area "c" from the packer bore inward to the I.D. of the seal assembly, is balanced by area "d" below the packer and cancels out of this calculation. This results in tubing pressure applied to area "b" against annulus pressure applied to area "a".

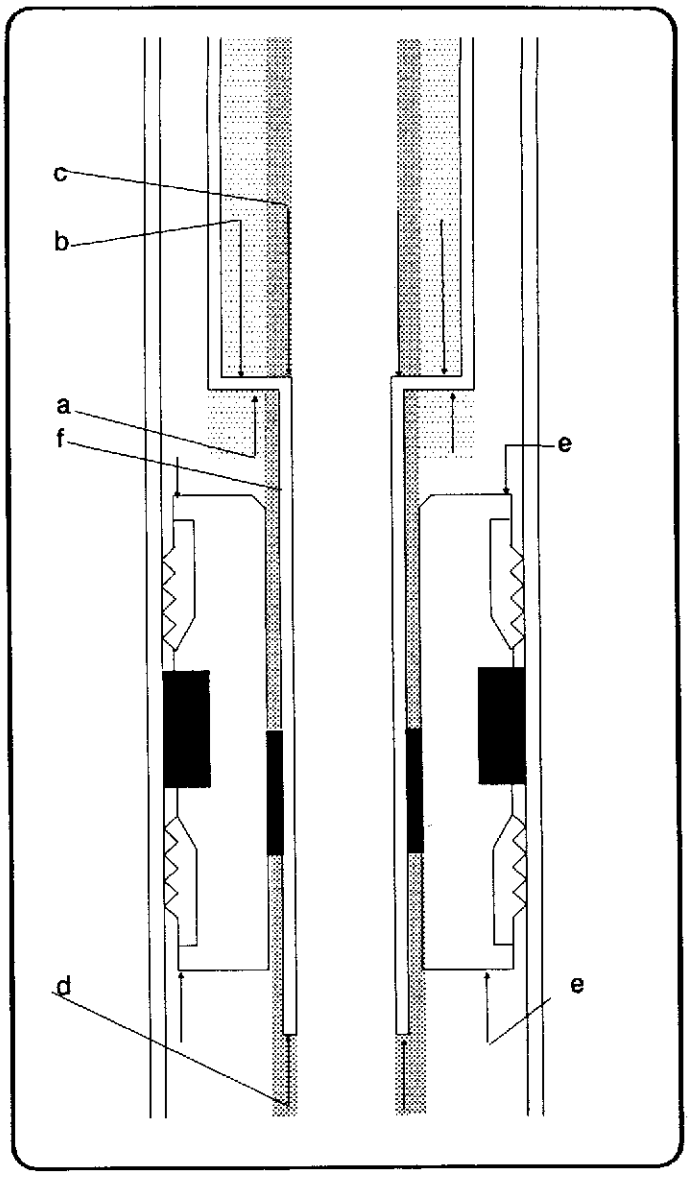
To make the required calculation, take the following steps:

Annulus

Calculate the pressure in the annulus at the packer. Calculate the area from the O.D. of the tubing to the packer bore. Multiply the pressure by the area and assign an upward force to the value.

Tubing

Calculate the pressure inside the tubing at the packer. Calculate the area from the I.D. of the tubing to the packer bore. Multiply the pressure by the area and assign a downward force to the value



Hook Load

Calculate the weight of the tubing string in air and assign a downward force to the value. Add the three forces together with their respective directions to obtain hook load.

Sealbore Packer

Hookload to Release When Tubing Larger Than Packer Bore

Using the well schematic at right:
Arrowdrill 4 1/2" set at 12,500 feet in
4 1/2" 15.10# casing
7.8# completion fluid in annulus
9.2# salt water in tubing
Seals set on 2 7/8" 6.50# P-105 tubing

From the tech manual for Arrowdrill packers, the packer bore is 2.390", and from the engineering tables the tubing I.D. is 2.441".

Annulus

2 7/8" O.D.	$=6.489\ in^2$
Packer bore	$=0.785 \times 2.390^2$
	$=4.484\ in^2$
Area "a"	$=6.489 - 4.484$
	$=2.005\ in^2$
Hydrostatic:	$=12{,}500 \times 7.8 \times 0.052$
	$=5070$ PSI
Force up:	$=5070 \times 2.005$
	$=10{,}165$ # ↑

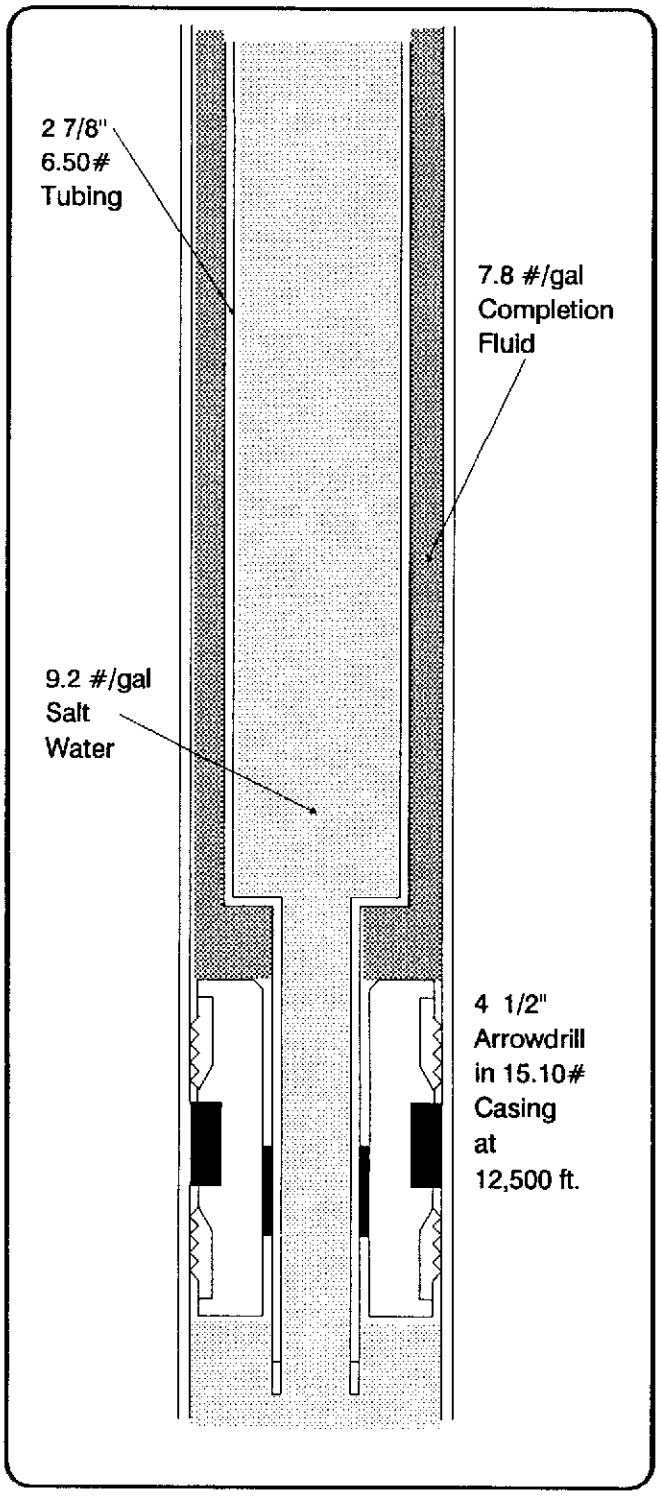
Tubing

2 7/8" I.D.	$=4.677\ in^2$
Packer bore	$=4.484\ in^2$
Area "b"	$=4.677 - 4.484$
	$=0.193\ in^2$
Hydrostatic:	$=12{,}500 \times 9.2 \times 0.052$
	$=5980$ PSI
Force down:	$=5980 \times 0.193$
	$=1154$ # ↓

Hook load

Tubing weight	$=12{,}500 \times 6.5$
	$=81{,}250$ # ↓
Annulus	$=10{,}165$ # ↑
Tubing	$=\ 1{,}154$ # ↓
Hook load	$=81{,}250 + 1{,}154 - 10{,}165$
	$=72{,}239$ # ↓

Required to reach neutral point at the packer



2 7/8" Tubing in a 2.688" Packer Bore

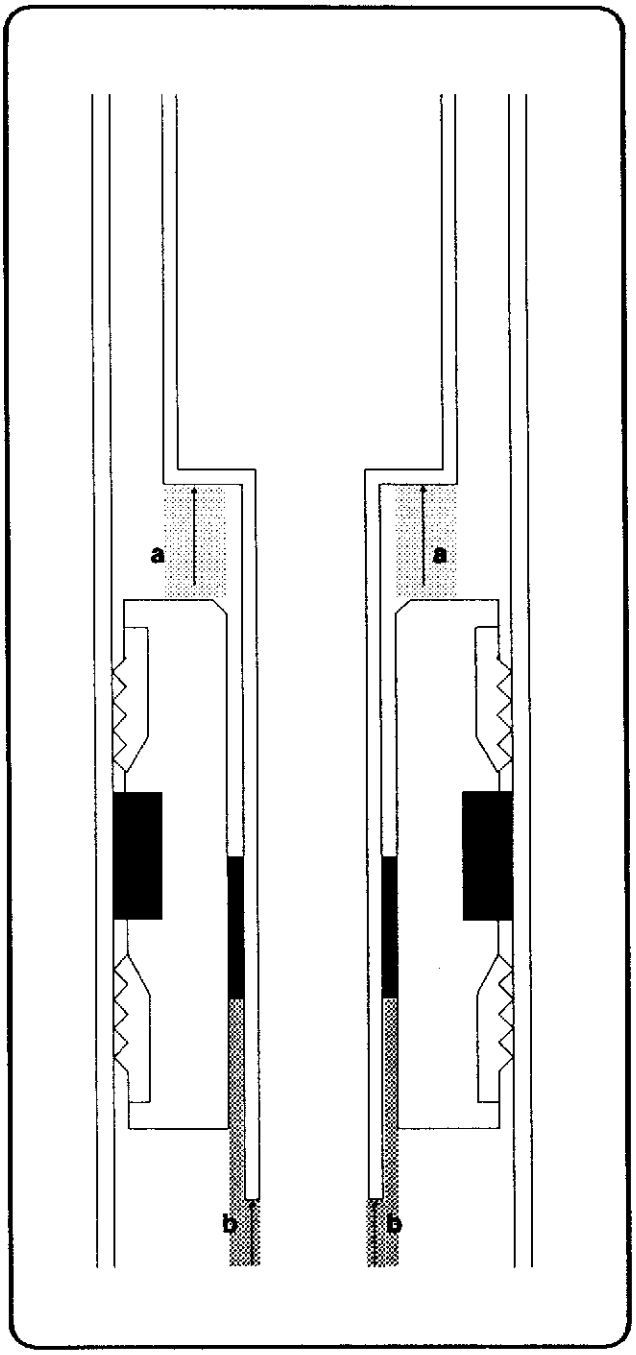
This section calls particular attention to a common tubing/packer combination where the bore is between the tubing I.D. and O.D..

The I.D. of the most common weight 2 7/8" tubing is 2.441", which is smaller than the 2.688" bore. In this case, pressure in both the tubing and the annulus will act on areas "a" and "b" to lift the tubing.

Note that in the schematic at right, pressure in the annulus will result in an upward force because the O.D. of the tubing is larger than the bore of the packer.

Since the I.D. of the tubing is smaller than the packer bore, tubing pressure will result in an upward force.

To solve for hook load, remember that forces due to pressure in the annulus and tubing are additive and the sum will be subtracted from the weight of the string in air.



2 7/8" Tubing in a 2.688" Bore

Using the well schematic at right:
Arrow XLW 5 1/2" set at 12,500 feet in
5 1/2" 20# casing
7.8 # completion fluid in annulus
9.2 # salt water in tubing
Seals set on 2 7/8" 6.40 # tubing

From the tech manual for Arrow XLW packers, we confirm that the packer bore is 2.688" and that the tubing I.D. is 2.441".

Annulus

2 7/8" O.D.	$=6.489\ in^2$
Packer bore	$=0.785 \times 2.688^2$
	$=5.672\ in^2$
Area "a"	$=6.489 - 5.672$
	$=0.817\ in^2$
Hydrostatic	$=12{,}500 \times 7.8 \times 0.052$
	$=5070$ PSI
Force up	$=5070 \times 0.817$
	$=4142$ # ↑

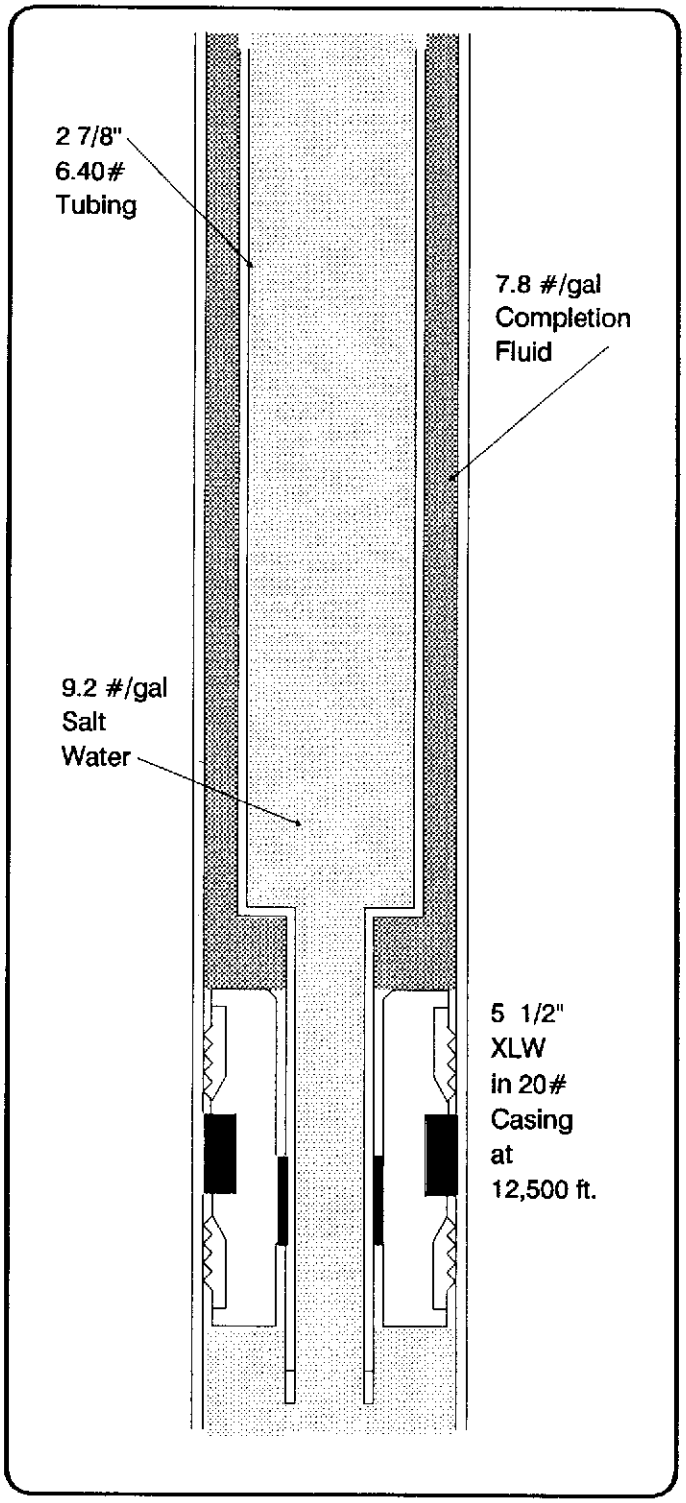
Tubing

2 7/8" I.D.	$=4.677\ in^2$
Packer bore	$=5.672\ in^2$
Area "b"	$=5.672 - 4.677$
	$=0.995\ in^2$
Hydrostatic	$=12{,}500 \times 9.2 \times 0.052$
	$=5980$ PSI
Force up	$=5980 \times 0.995$
	$=5950$ # ↑

Hook Load

Tubing weight	$=12{,}500 \times 6.4$
	$=80{,}000$ # ↓
Annulus	$=4{,}142$ # ↑
Tubing	$=5{,}950$ # ↑
Hook load	$=80{,}000 - 4{,}142 - 5{,}950$
	$=69{,}908$ # ↓

Required to reach neutral point at the packer.



Tubing Smaller Than Packer Bore

The objective remains the same, to calculate hook load when the tubing is in neutral at the packer. The procedure is again the same, calculate the weight of the tubing string in air, then the pressures and areas that would change that weight as seen by hook load.

The schematic at right shows the tubing smaller than the bore of the packer. Pressure in the annulus pushes down on the area "a" from the packer seal bore to the O.D. of the tubing. Again any pressure outward of the seal bore would go into the casing through the packer and do not play a part in this calculation.

Since the I.D. of the tubing is smaller than the packer bore, pressure inside the tubing pushes up on the area from the packer seal bore to the tubing I.D., area "b".

To make the required calculation, take the following steps:

Annulus

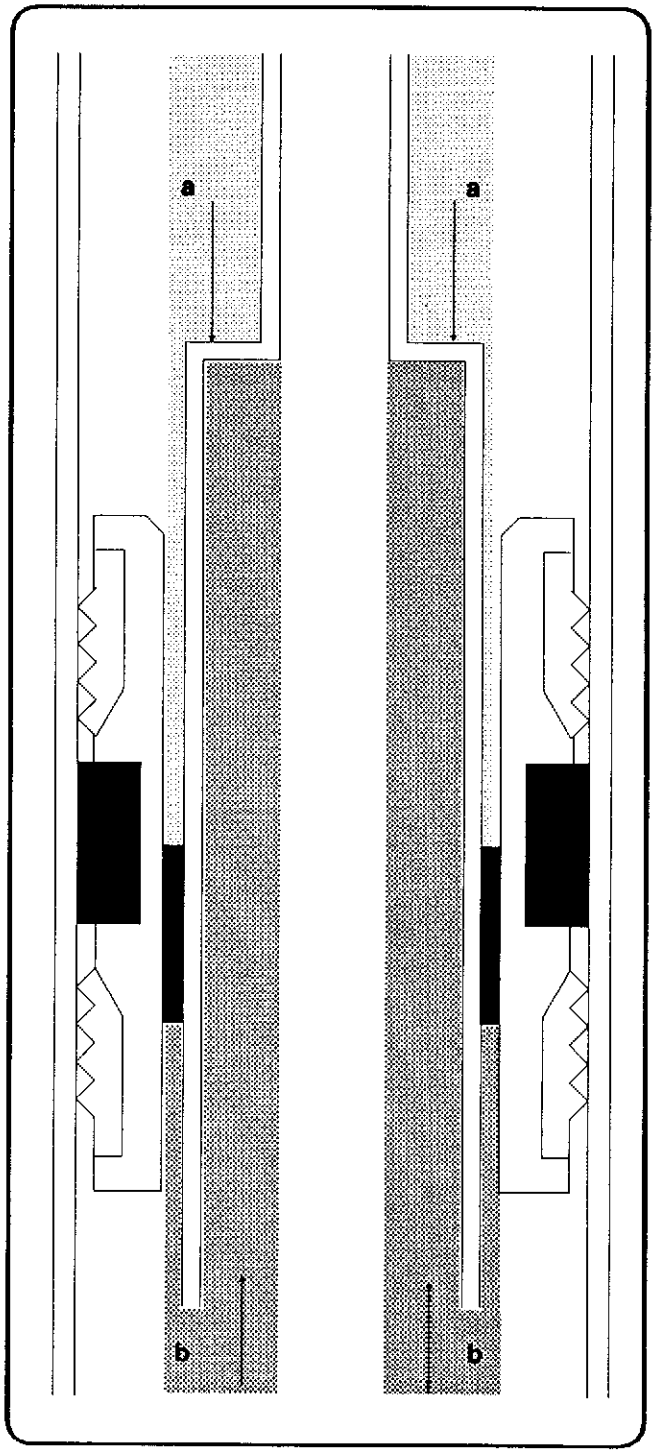
Calculate the pressure in the annulus at the packer. Calculate the area from the packer bore to the O.D. of the tubing. Multiply the pressure by the area and assign a downward force to the value.

Tubing

Calculate the pressure inside the tubing at the packer. Calculate the area from the packer bore to the I.D. of the tubing. Multiply the pressure by the area and assign an upward force to the value.

Hook Load

Calculate the weight of the tubing string in air and assign a downward force to the value. Add the three forces together with their respective directions to obtain hook load.



Tubing Smaller Than Bore

Using the well schematic at right:
Arrowdrill 4 1/2" set at 12,500 feet in
4 1/2" 13.50# casing
7.8 # completion fluid in annulus
9.2 # salt water in tubing
Seals set on 2 3/8" 6.20# P-105 tubing

From the tech manual for Arrowdrill packers, the packer bore is 2.688", and from the engineering tables the tubing I.D. is 1.853".

Annulus

2 3/8" O.D.	$=4.428\ in^2$
Packer bore	$=0.785 \times 2.688^2$
	$=5.672\ in^2$
Area "a"	$=5.672 - 4.428$
	$=1.244\ in^2$
Hydrostatic	$=12{,}500 \times 7.8 \times 0.052$
	$=5070$ PSI
Force down	$=5070 \times 1.244$
	$=6707\ \# \downarrow$

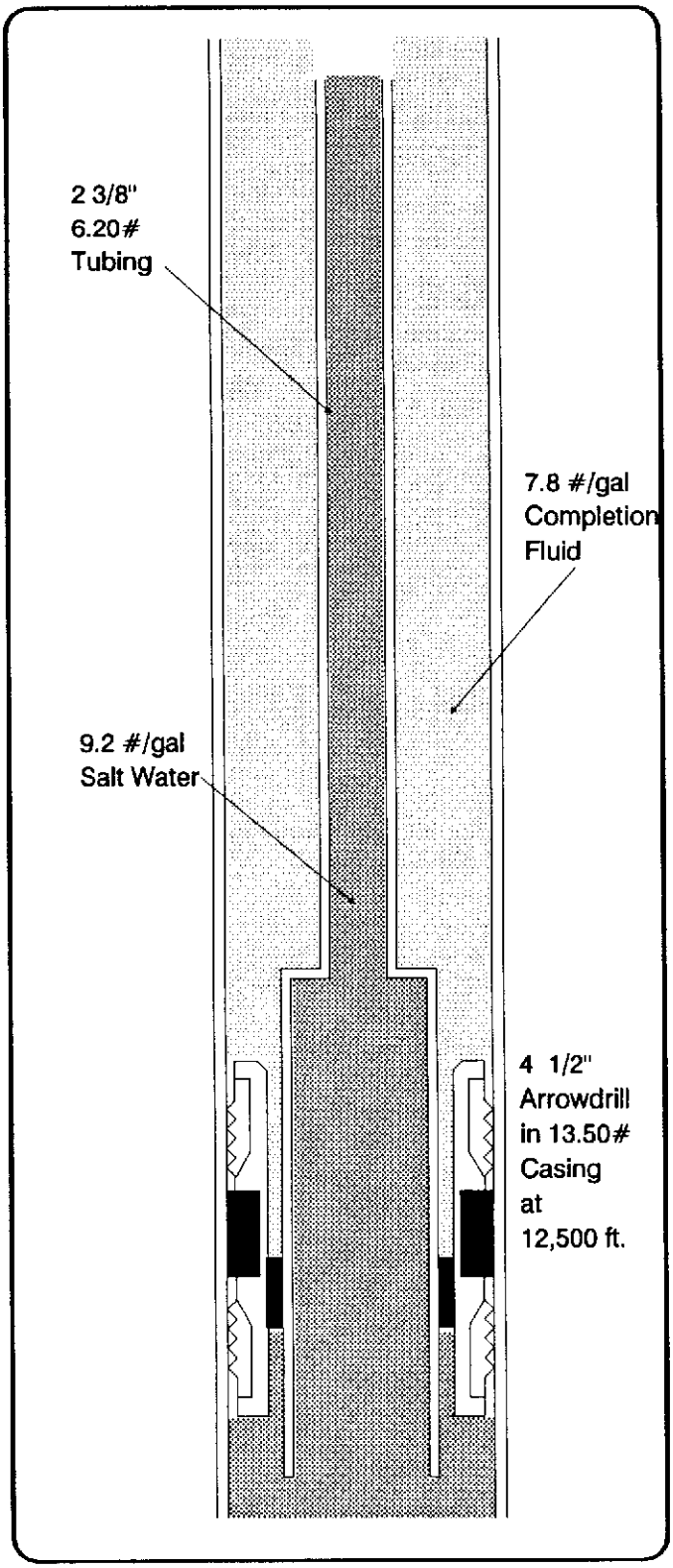
Tubing

2 3/8" I.D.	$=2.695\ in^2$
Packer bore	$=5.672\ in^2$
Area "b"	$=5.672 - 2.695$
	$=2.977\ in^2$
Hydrostatic	$=12{,}500 \times 9.2 \times 0.052$
	$=5980$ PSI
Force up	$=5980 \times 2.977$
	$=17{,}802\ \# \uparrow$

Hook Load

Tubing weight	$=12{,}500 \times 6.20$
	$=77{,}500\ \# \downarrow$
Annulus	$=\ 6{,}707\ \# \downarrow$
Tubing	$=17{,}802\ \# \uparrow$
Hook load	$=77{,}500 + 6{,}707 - 17{,}802$
	$=66{,}405\ \# \downarrow$

Required to reach neutral point at the packer.



Weight on a Locator Seal Assembly to Hold Pressure

Hook load is not a consideration in this operation. The only forces in question are those across the seal assembly. Since you are not calculating hook load, assume that the seal assembly will be balanced when you sting into the packer, then calculate what is done to the assembly from that point.

With this type situation, you may wish to know how much weight to set on the packer to hold a certain amount of pressure. You may also wish to determine the amount of pressure to apply to the annulus to hold the seal assembly in the packer. In certain instances, you may want to determine *whether* the application of pressure to the annulus tends to hold the seal assembly in the packer, or pump it out.

Setting Weight to Hold in Place

These calculations are based on the assumption that the tubing I.D. is smaller than the packer bore, which is usually the case, causing the tubing to be lifted with increased tubing pressure. Calculation is the straightforward application of tubing pressure to the area between the tubing I.D. and the packer bore. This force acts upward, and the addition of tubing weight equal to this amount should keep the seal assembly in the packer.

Pressure on Annulus to Hold in Place

These calculations are based on the assumption that the tubing O.D. is smaller than the packer bore, which again is usually the case. Addition of annular pressure would result in a downward force tending to keep the seal assembly in the packer. Calculate the upward force generated by tubing pressure beneath the seal assembly, subtract from it the amount of set-down force, leaving you with an upward acting force. Calculate the area between the tubing O.D. and the packer bore and divide it into the upward force. This is the amount of annulus pressure required to keep the seal assembly in the packer.

This approach to locator type seal assemblies is considerably simplified and is accurate only on low pressure, shallow, moderate temperature wells. For deep wells, high temperature wells, or high pressure wells, tubing movement calculations should be made and applied where applicable. Procedures for calculating tubing movement can be found in a later section of this manual. Should your work involve a critical well, or you are unsure of your results, consult your Arrow Technical Service representative or Arrow Engineering.

Notes:

How Much Weight to Set-Down on Locator Seal Assembly to Hold Pressure

Arrow XL-W set at 8500 feet in 7" 29# casing
Seals run on 2 7/8" 6.40# tubing
8.8 # fluid in both tubing and annulus
Treatment expected at 5000 PSI
Max. casing pressure 1500 PSI

How much weight will have to be set on the seals?

From the Arrow Model XL-W tech manual, packer bore is 3.250" and from the engineering tables, tubing I.D. is 2.441".

Annulus

Packer bore	$=8.292\ in^2$
2 7/8" O.D.	$=6.489\ in^2$
Area	$=8.292 - 6.489$
	$=1.803\ in^2$
Force down	$=1500 \times 1.803$
	$=2704\ \# \downarrow$

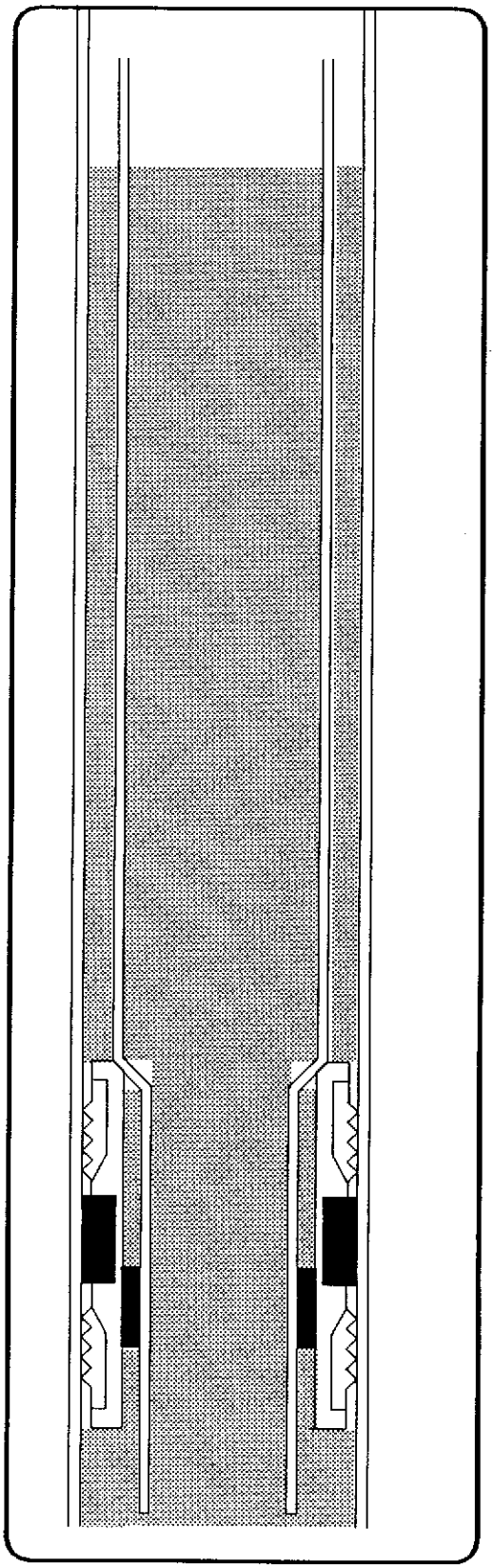
Tubing

Packer bore	$=8.292\ in^2$
2 7/8" I.D.	$=4.677\ in^2$
Area	$=8.292 - 4.677$
	$=3.615\ in^2$
Force up	$=5000 \times 3.615$
	$=18{,}075\ \# \uparrow$

Set-Down Weight

$=18{,}075 - 2{,}704$
$=15{,}371\ \# \uparrow$

15,371 pounds must be set down at the packer to keep the seal assembly inside.



Plugged Tubing

The most common method of creating plugged tubing, is to run a blanking plug in a profile nipple below the packer. The same principles apply whether the tubing is plugged by accident or by design.

The two schematics at right show the tubing smaller than the packer bore (case #1) and larger than the packer bore (case #2). Again, we must find both the weight of the string in air, pressures at the packer, and the areas they act upon.

In schematic #1, notice that the annulus pressure acts on the area between the packer bore and the tubing O.D., area "a", pushing downward. Inside, the tubing pressure will be acting downward on the full I.D. of the tubing, area "b". Area "c" cancels. Pressure trapped under the packer pushes upward on the entire packer bore, area "d".

In schematic #2, annulus pressure again acts on the area between the packer bore and the tubing O.D., area "a", but results in an upward force. Tubing pressure again results in a downward force created by tubing pressure acting on the full tubing I.D., this time the sum of areas "b" and "c". Pressure below the packer acts upward on the entire packer bore area "d".

The procedure for calculating hook load to place the tubing in neutral would be:

Annulus

Determine pressures and areas, multiply to obtain the resultant force and determine whether it acts upward or downward.

Tubing

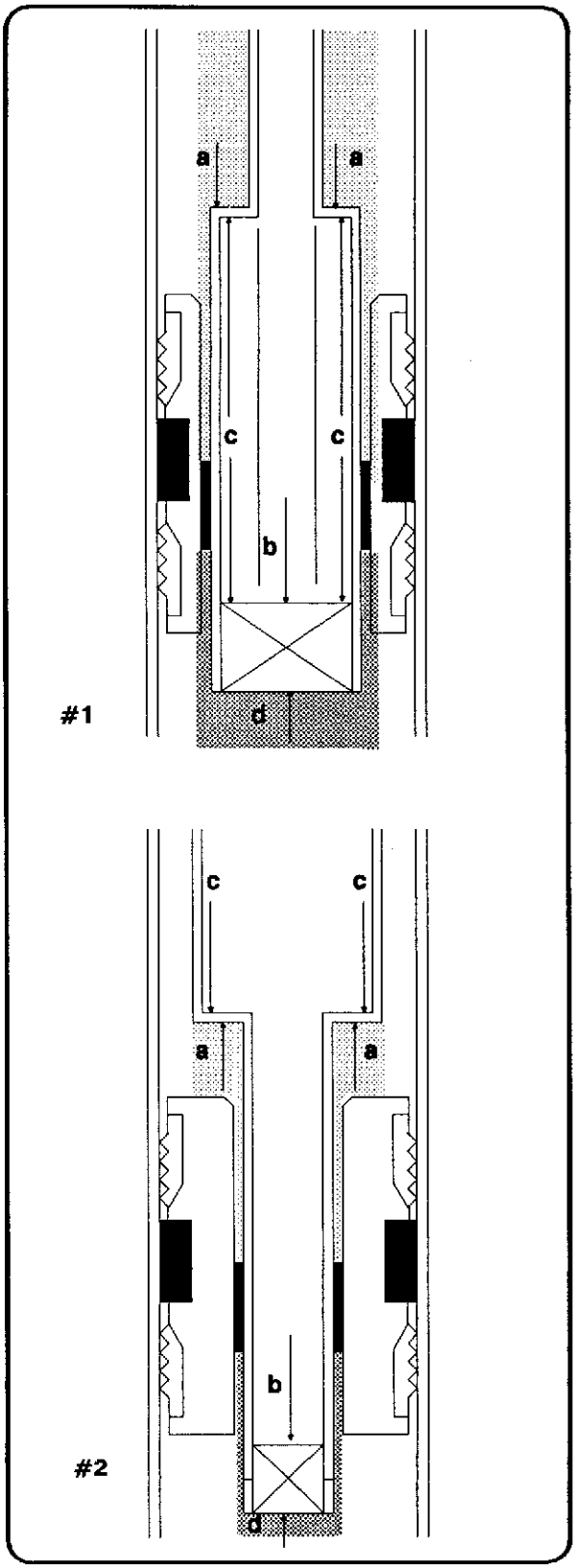
Multiply the area of the inside of the tubing by the tubing pressure. This force always acts downward.

Under the Packer

Multiply the area of the packer seal bore by this pressure. This force always acts upward.

Hook load

Calculate the weight of the string in air, add the force due to tubing pressure, subtract the force due to pressure under the packer, and modify the answer with values calculated in the annulus.



Releasing From a Packer With Plugged Tubing

Small Tubing - Large Bore (Case #1)

Arrow Model XL-W Packer - 7"
Set at 8500 feet in 7" 26# casing
9.2 # salt water in the annulus
40° API oil in the tubing
Seals set on 2 3/8" 4.70# tubing
3500 PSI under the packer

From the tech manual for Model XL-W packers, the packer bore is 3.250", and from the engineering tables the tubing I.D. is 1.995".

Annulus

Packer bore	$=8.292\ in^2$
2 3/8" O.D.	$=4.428\ in^2$
Area "a"	$=8.292 - 4.428$
	$=3.864 in^2$
Hydrostatic	$=8500 \times 9.2 \times 0.052$
	$=4066$ PSI
Force down	$=4066 \times 3.864$
	$=15{,}711\ \# \downarrow$

Tubing

2 3/8" I.D.	$=3.124\ in^2$
Hydrostatic	$=8500 \times 0.357$
	$=3034$ PSI
Force down	$=3034 \times 3.124$
	$=9{,}478\ \# \downarrow$

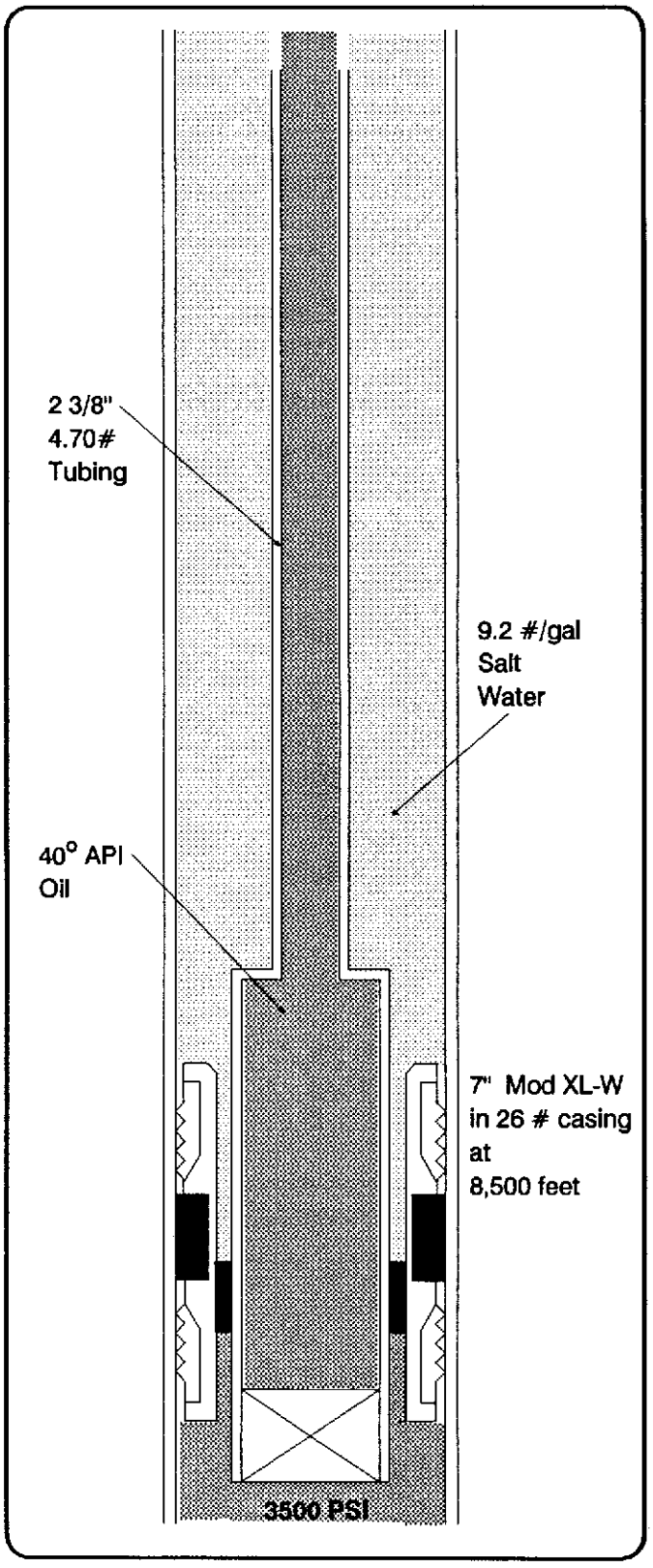
Under the Packer

Packer bore	$=8.292\ in^2$
Force up	$=3500 \times 8.292$
	$=29{,}022\ \# \uparrow$

Hook Load

Tubing weight	$=8500 \times 4.7$
	$=39{,}950\ \# \downarrow$
Annulus	$=15{,}711\ \# \downarrow$
Tubing	$=\ 9{,}478\ \# \downarrow$
Under packer	$=29{,}022\ \# \uparrow$
Hook load	$=39{,}950 + 15{,}711 + 9{,}478 - 29{,}022$
	$=36{,}117\ \# \downarrow$

Required to reach neutral at the packer.



Pressure on the Annulus to Remain in the Packer

Arrowdrill 5 1/2" set at 8500 feet in
5 1/2" 20# casing
8.8 # fluid in both tubing and annulus
Seals run on available workstring 2 3/8" 4.70#
Treatment pressure expected - 4500 psi
Set down force - 8,000 #

What annulus pressure is required to use this workstring for the job?

From the Arrowdrill tech manual we see that there are two bore sizes for this packer, for this example, use the 3.000" bore.

Annulus

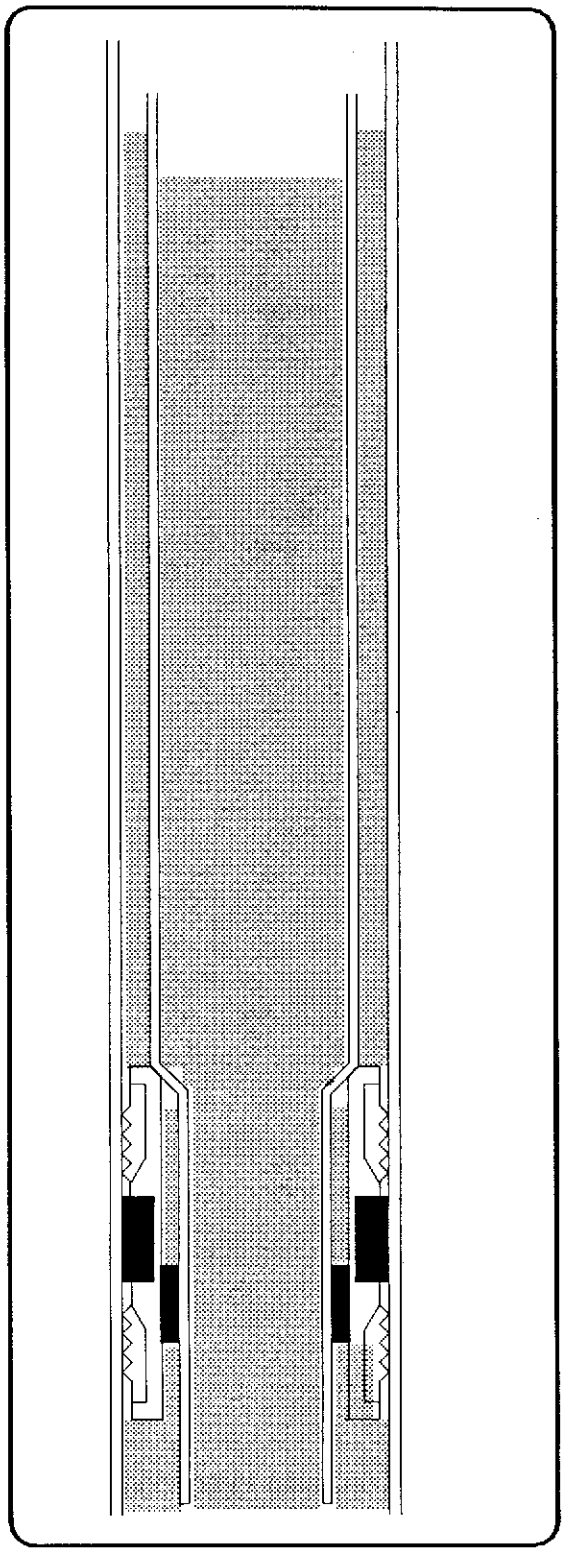
Packer bore	$=7.065\ in^2$
2 3/8" O.D.	$=4.428\ in^2$
Area	$=7.065 - 4.428$
	$=2.637\ in^2$

Tubing

Packer bore	$=7.065\ in^2$
2 3/8" I.D.	$=3.124\ in^2$
Area	$=7.065 - 3.124$
	$=3.941\ in^2$
Force up	$=4500 \times 3.941$
	$=17{,}734\ \#\ \uparrow$
Set-down	$=\ 8{,}000\ \#\ \downarrow$
Net force	$=\ 9{,}734\ \#\ \downarrow$

Pressure req'd	$=9734 \div 2.637$
	$=3692$ PSI

Note that slack-off charts prohibit setting-down much more weight. If the casing is not capable of this pressure, a larger work string should be used.



Retrievable Tools

Situations on the previous pages concerned themselves with the calculation of hook load. Retrievable tools concern themselves with the amount of pull, set-down weight, and the amount of pressure that is applied to a tool.

To determine the amount of push, pull, or pressure that can be applied to a tool, you only need to consider the forces across the tool itself. When tools are first run and set, they are considered to be balanced; that is, there is no pressure differential across the tool.

Under some circumstances, forces are locked into the tool at the time it is set. If a packer is set in heavy fluid, the tubing string is shorter than if it was set in lighter fluid, due to the additional bouyancy of the heavier fluid displaced by the steel in the string. If the heavier fluid is displaced in either tubing or annulus after the packer is set, these "stored" forces must be considered. To help visualize this, consider the entire string as a long spring. This spring is slowly compressed by hydrostatic pressure acting on its bottom surface. The spring compresses only until its stored force equals the hydrostatic pressure multiplied by the bottom area. When hydrostatic pressure decreases, the spring relaxes, but only until it reaches its initial length. For example, the string would not get longer if it were run in a well filled with helium at atmospheric pressure, just because the helium were lighter than air. This topic will be covered in some depth in the *Tubing Movement* section of this book.

We can summarize that If you run a retrievable tool in a well with a lighter fluid, the string would be longer. If the fluid were heavier, the string would be shorter. There is no differential across the packer until it is set and you, or the well, change fluids, weights, or pressures. No differential implies there is no force; the packer is balanced.

Once the packer is set, any forces changed by you or the well must be taken into account and/or balanced as the tool is no longer free to move and build up a resisting force.

Since the forces in the tubing string are identified and their presence definitely known, they must be included in your calculations.

You may be inclined to add the weight of the tubing string to your calculations. Remember that we originally stated that we are concerned only with changes at the tool, and that the tubing weight was present when the tool was set. It is easier to assume that the tool was balanced when set, and all that is required is an analysis of what has been done to the tool *since* it was set. Things done since that time usually fall into the following catagories:

- Pulled tension or set-down compression of a known value on the packer.
- Bled pressure from a specific area. Any pressure above hydrostatic held at the time the tool was set such as high formation pressure held by a valve, or pump pressure used to balance a column of heavier fluid between tubing and casing.
- Swabbed. Removal of hydrostatic pressure from either tubing or annulus.
- Pressure applied on a specific area by either pump or well. Setting a packer with TCP (Tubing Conveyed Perforating) guns, firing the guns, and bringing in the well is a common example.

When calculating the amount of weight required to set the tool, and you arrive at an amount smaller than the amount stated in the tech manual, use the larger figure. For example, if you calculate that you need 5000 # ↓ for a particular situation and the tech manual says the tool requires 10,000 # ↓, use the larger amount. The logic behind the tech manual amount is that it takes a certain amount of force to obtain proper pack-off. Remember, some conditions may require an initial value higher than the tech manual; this will be covered later in this chapter.

Retrievable Tools

Remember...If you are calculating hook load, or what the weight indicator will read, calculate the weight of the string in air, then calculate the forces due to pressures and areas that act on the string. Add forces and directions to obtain hook load.

When you want to determine the forces across the tool itself, assume the tool was balanced when it was set, then calculate what was done to the tool since that time.

There are four basic types of retrievable tools:

- Tension tools: requiring tubing tension for initial set, and continued tension to maintain set.
- Compression tools: requiring set-down weight for initial set, and continued compression to maintain set.
- Neutral Set: requiring either tension or compression for initial set, but lock setting energy into the tool by some mechanical means. These tools allow the tubing to be left in tension, compression, or neutral.
- Hydraulic Set: requiring force generated by hydraulic means to set, either from well hydrostatic pressure or applied pressure. Setting forces are usually locked in the tool allowing tubing to be left in either tension, compression, or neutral.

Situations involving each of these tools are covered in this section of the calculation handbook.

In actual practice, you may have two or more of these situations, all dealing with the same run on the same tool. Combinations of these situations are easily handled by first assuming the tool was balanced when set, then each subsequent operation, and its effect, calculated as it is performed. Be careful not to calculate an initial and final without considering intermediate steps. Intermediate conditions may overstress a tool or cause it to unset or leak, giving false results.

Notes:

Tension Packers

There are three basic questions concerning tension type packers:

- How much strain must be pulled to hold a given amount of annulur pressure?
- For a given amount of strain, how much annular pressure can be applied?
- For a given amount of strain, to what depth can you swab?

In the first situation, the desired quantity is force, in the second pressure, and the third depth.

Remember at the time the tool is set, forces are balanced across the tool. You must calculate based on what was done *from* that point.

How much strain?

Since the tool is balanced to start, and you intend to apply pressure, calculate the downward force this pressure will exert. Multiply the intended pressure by the annular area and provide at least that much upstrain. This upstrain is in addition to the amount used to set the tool.

How much pressure?

First determine the amount of upstrain on the tool. Divide this amount by the annular area of the tool to obtain pressure.

How deep can you swab?

First, determine the area below the packer; the area acted on by hydrostatic pressure. Divide this area into the upward strain on the tool. The result gives the amount of hydrostatic pressure you can remove from under the packer with a given amount of upstrain. Convert hydrostatic pressure to depth by dividing pressure by the fluid gradient (psi/ft) for the fluid removed. This will be the number of feet you can swab (not the depth you can swab to) before the tool will move downhole.

Anytime you circulate a fluid of different weight down to the tool, then set the tool and bleed off back pressure, calculate the effect of bleeding pressure and apply it to future calculations. Remember, you are accounting for all operations done *after* the tool was set.

Whenever your calculations result in an upstrain less than the amount required for initial pack-off, pull the larger amount. This will assure adequate tension to get a good pack-off and also perform the operation in question.

Notes:

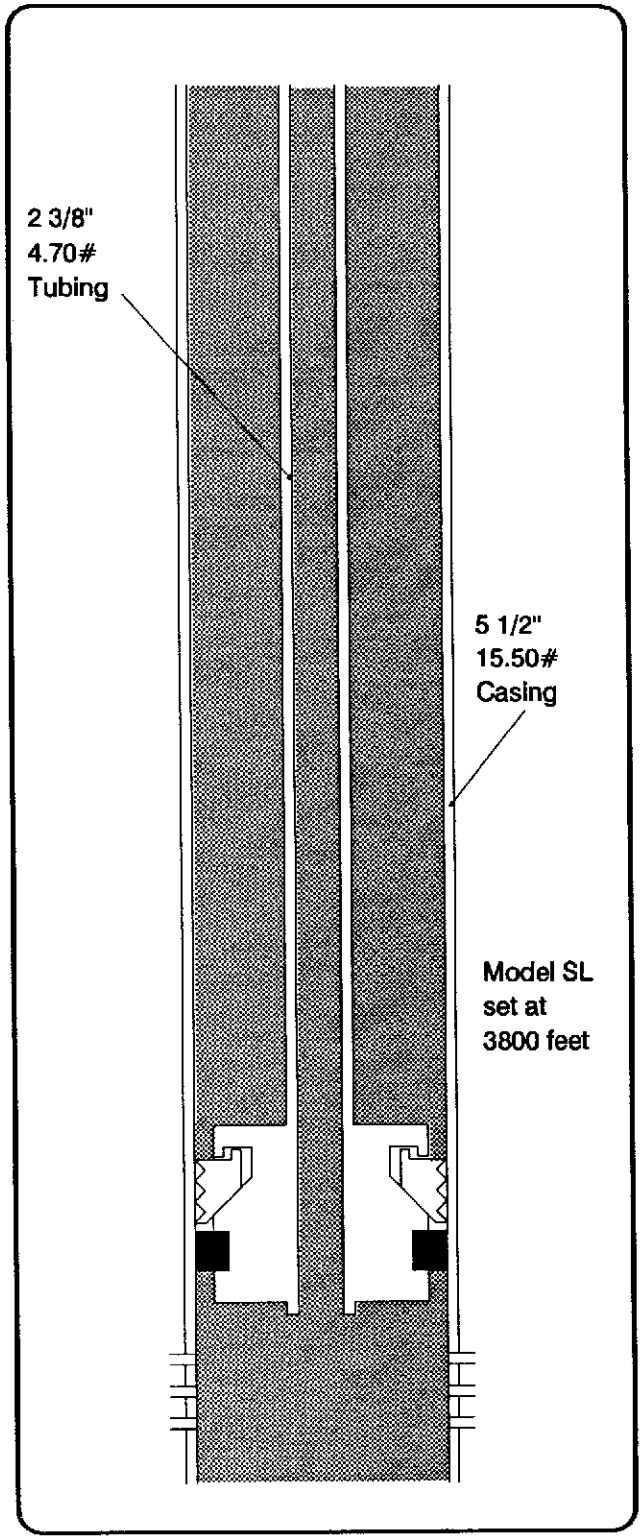
How Much Tension to Hold Pressure?

Arrow Model SL Packer - 5 1/2"
Set at 3800 feet in 5 1/2" 15.50 # casing
2 3/8" EU 4.70# tubing
9.2 # salt water in the hole
Pressure annulus to 1500 PSI

Annulus

Casing I.D.	$= 19.234\ in^2$
2 3/8" O.D.	$= 4.428\ in^2$
Annular area	$= 19.234 - 4.428$
	$= 14.806\ in^2$
Force down	$= 1500 \times 14.806$
	$= 22{,}209\ \# \downarrow$

The tool will be pushed down by 22,209 # by the 1500 PSI. You must pull at least this amount of upstrain to keep the packer stationary.



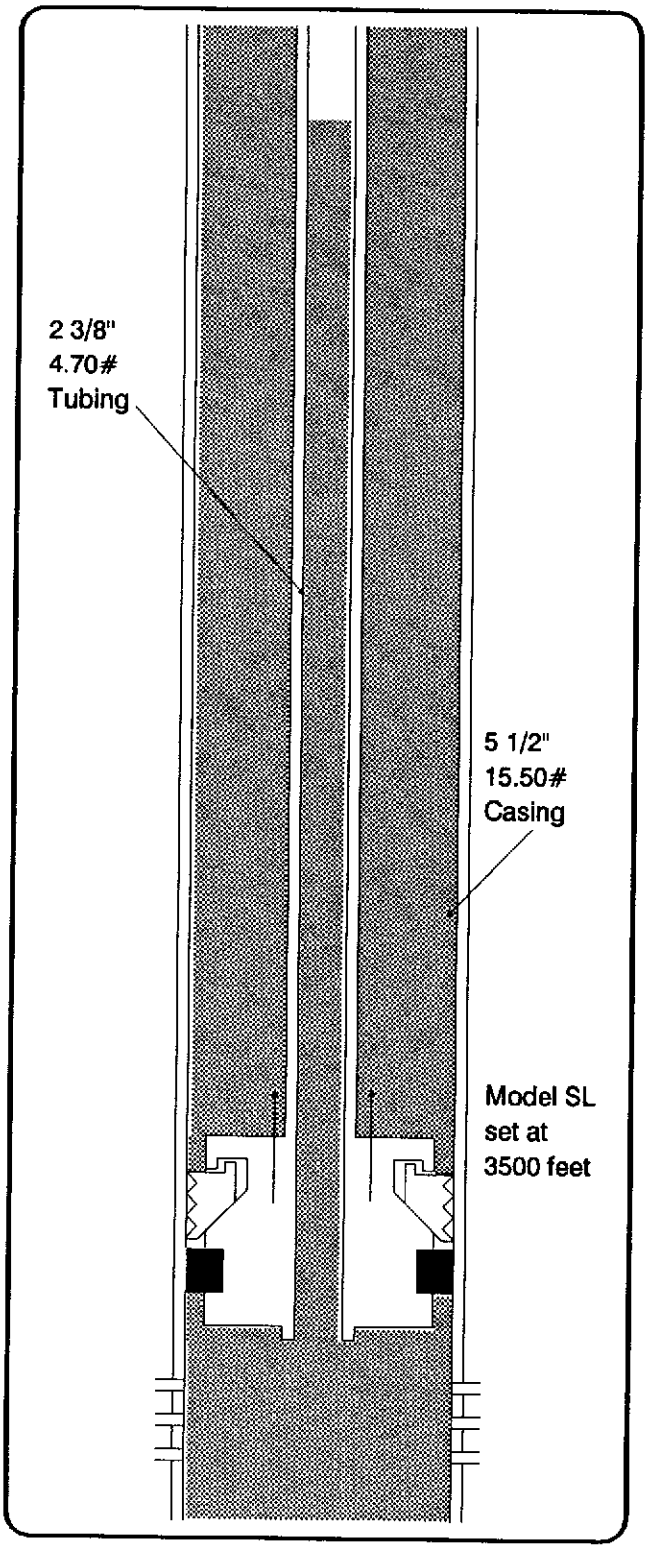
How Much Pressure Can be Applied to the Annulus?

Arrow Model SL Packer - 5 1/2"
Set at 3500 feet In 5 1/2" 15.50# casing
2 3/8" EU 4.70# tubing
9.2# salt water in the hole
12,000 # ↑ pulled on the tool

Annulus

Casing I.D.	$= 19.234\ in^2$
2 3/8" O.D.	$= 4.428\ in^2$
Annular area	$= 19.234 - 4.428$
	$= 14.806\ in^2$
Pressure	$= 12{,}000 \div 14.806$
	$= 810.5$ PSI

The 810 PSI can be put in the annulus before it will overcome the initial 12,000 # ↑ put into the tool.



Depth Limitation for Swabbing

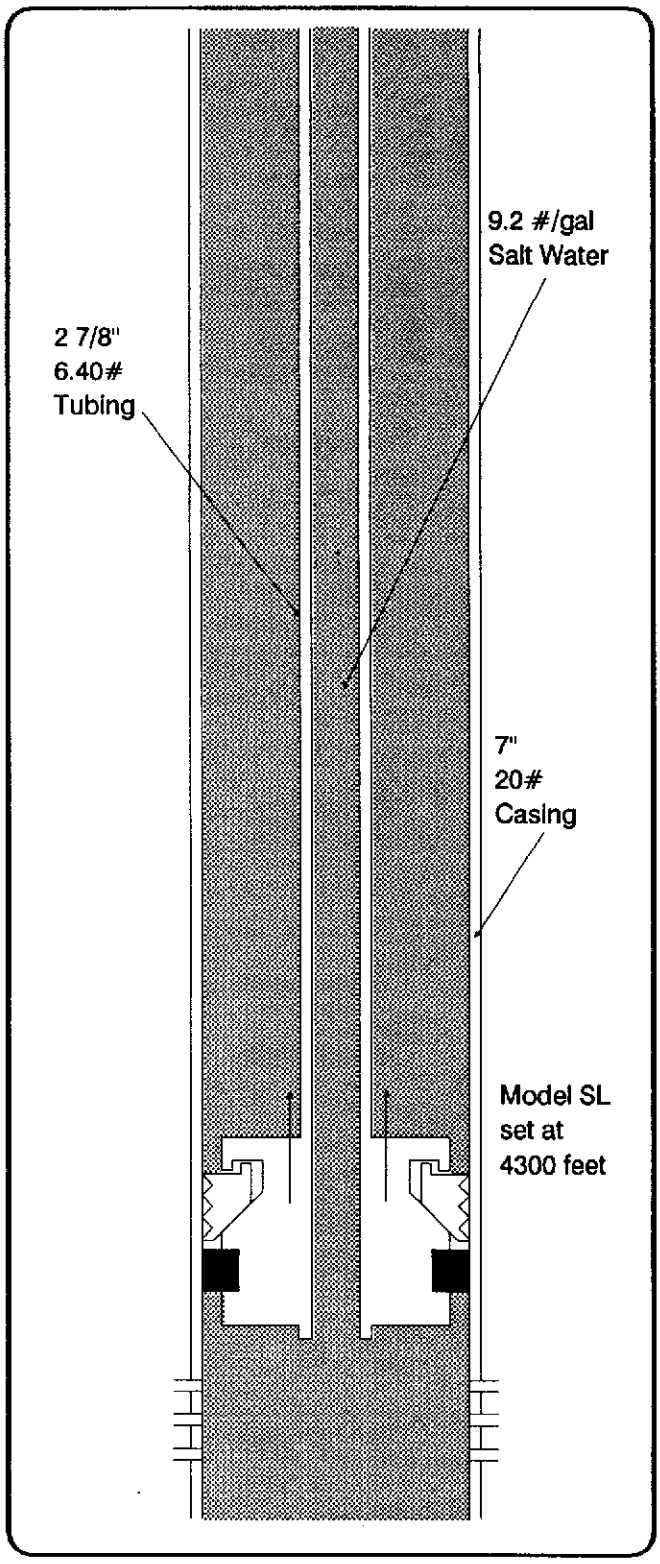
Arrow Model SL Packer - 7"
Set at 4300 feet in 7" 20# casing
2 7/8" 6.40# tubing
9.2# salt water in the hole
15,000 # ↑ on the tool

Casing I.D. =32.735 in^2
Tubing I.D. =4.679 in^2
Area under pkr =32.735 - 4.679
=28.056 in^2

Hydrostatic
removed =15,000 ÷ 28.056
=535 PSI

Ft of 9.2 fluid =535 ÷ (9.2 X 0.052)
=1118 feet

Feet of fluid to be swabbed = 1118
or the well can be swabbed to a fluid level of
=4300 - 1118
=3182 feet



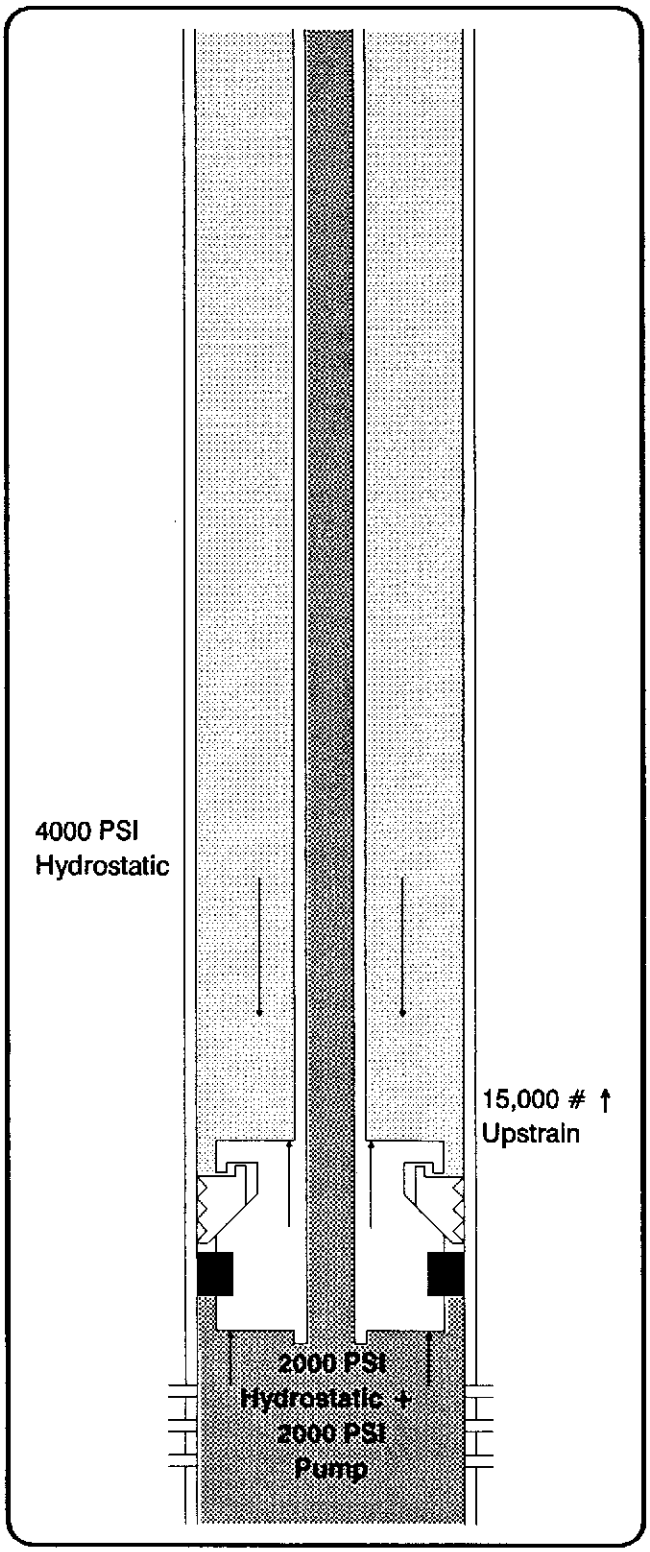
Circulating a Different Weight Fluid to the Packer

Consider the condition where you circulate a different weight fluid to the packer, then set the packer. The same rule applies; if you perform an operation subsequent to setting the packer, consequences of that operation must be calculated and considered. Removing pressure from an area is treated just like applying pressure to that same area.

The first step is to consider what takes place when a fluid of different weight is circulated. The tool is "broken loose" and fluid is circulated to the tool. If the fluid was of different weight, you must be holding pressure somewhere as the hole is out of balance. You might be holding pressure on the tubing if you are circulating a lighter fluid down tubing. When you finish circulating, you would ordinarily bleed off pressure.

Forces across the tool were balanced when you started to set it. When the setting operation was complete, you unbalanced the system by the amount pulled on the tool. When you bled off this pressure, you removed a force from the packer. Since the force was removed, it acts in the opposite direction. For example, if the removed force was in the annulus, it is an upward force; if it was under the packer, it acts as a downward force.

In the illustration at right, 2000 PSI is held on the tubing while setting the tool, or fluid would flow from the annulus to the tubing. After setting the tool (15,000 # ↑), bleed 2000 PSI from the tubing. You will be removing a force (2000 X area underneath packer). If this force is 15,000 # or more, the packer will fail immediately. If it is less, you have reduced the amount of pressure you can apply to the annulus or the depth that can be swabbed.



Circulating Different Weight Fluids with a Tension Packer

Arrow Type H Pressure Packer - 7"
Set in 7" 26# casing at 7200 feet
2 7/8" 6.40# tubing
9.6# salt water in annulus
42° API oil circulated down tubing

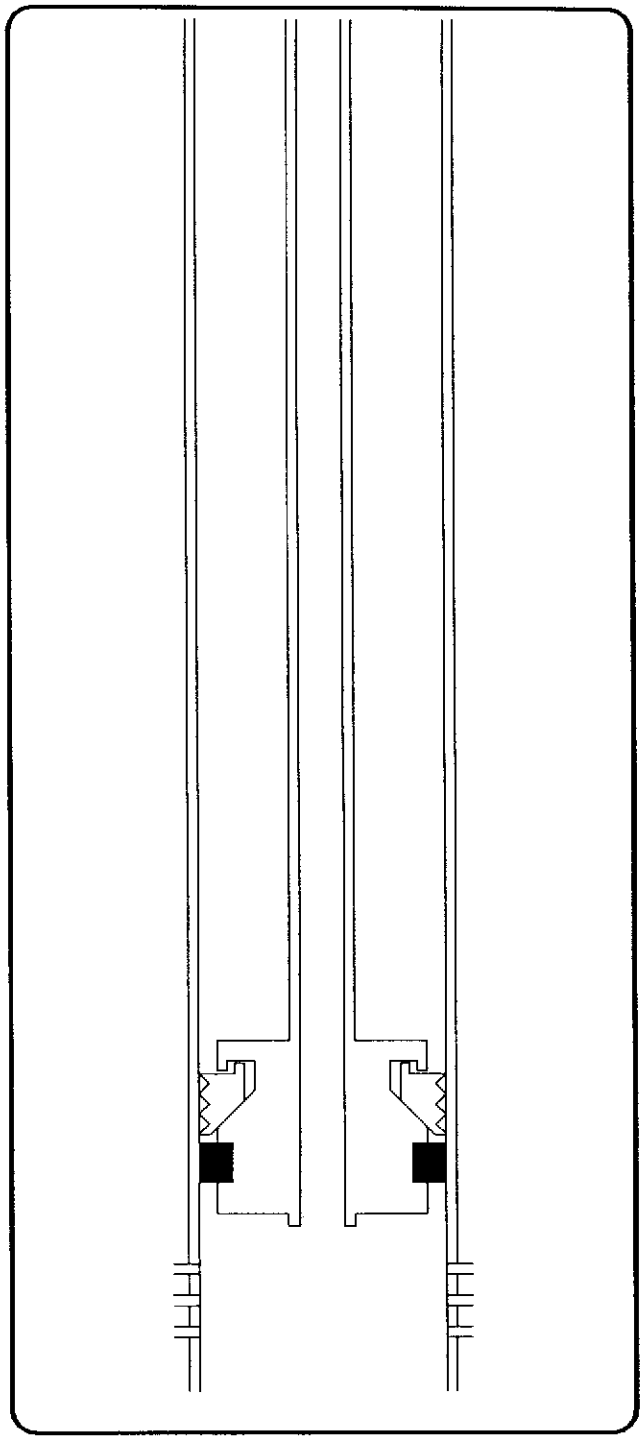
How much tension will have to be pulled on the packer to bleed off the circulating pressure after the packer is set?

Annular fluid = 0.499 psi/ft
Tubing fluid = 0.354 psi/ft
Differential = 0.145 psi/ft
Differential pressure
= 7200 X 0.145
= 1044 PSI

This differential pressure is observed as pump pressure, as it would be held as you set the packer. The tool is balanced as long as this pressure is maintained; with the exception of the upstrain you apply during setting.

Casing I.D. = 30.920 in^2
Tubing I.D. = 4.678 in^2
Area under the packer
= 30.920 - 4.678
= 26.242 in^2
Force = 1044 X 26.242
= 27,397 # ↓

If you set the packer and plan to bleed-off the 1044 PSI, you will be removing an upward force of 27,397 # and will have to have at least this amount pulled or the packer will move downhole.



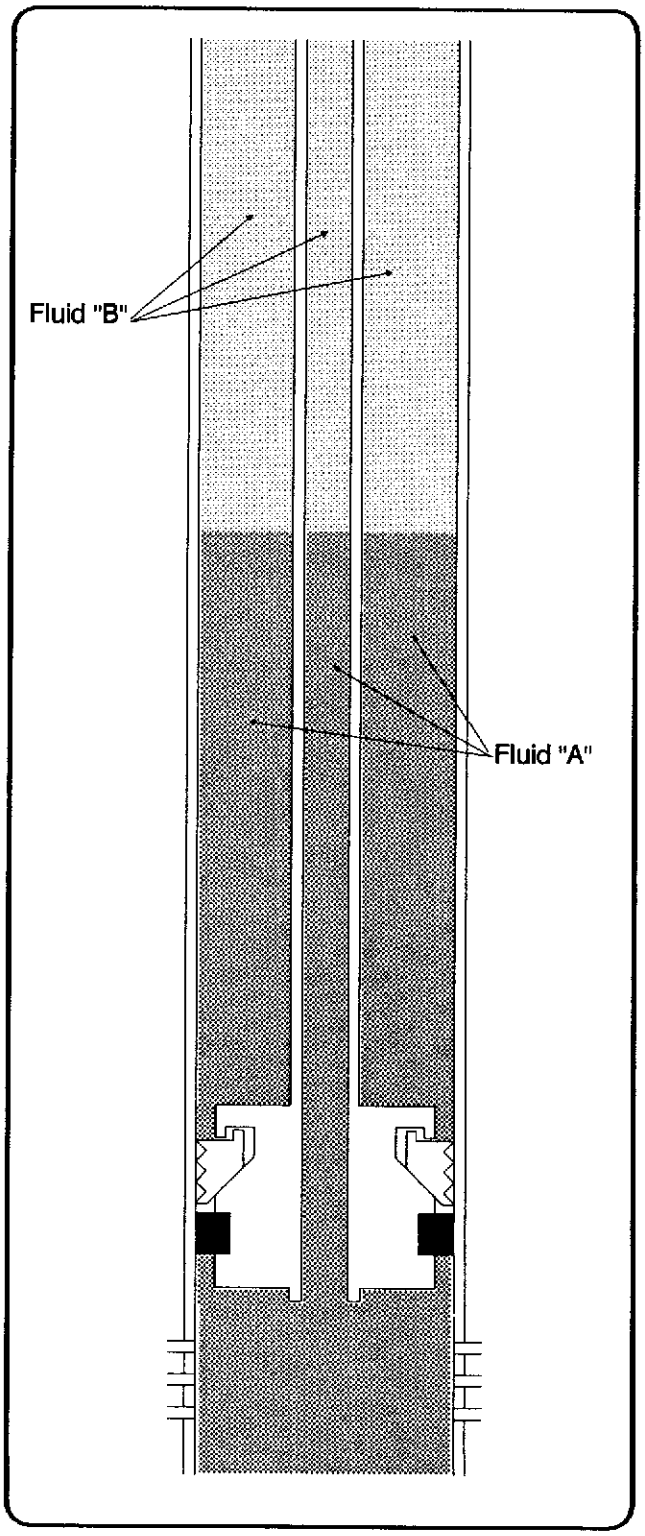
Setting Tension Packers in Low Fluid Level Wells

This section serves to remind you of the difference between having fluid in the hole when the packer is set, and adding fluid after it is set.

As you remember, forces across the packer are balanced when the tool is set. Tubing shortens when exposed to a bouyant force. After the packer is set and fluid is added, the tubing is fixed and not free to shorten. The force generated must be calculated and accounted for.

In the example shown, the tool was set with fluid "A"in the hole. It was balanced at that time as the tubing was free to move.

When the hole is filled with fluid "B", additional forces are added to the annulus and underside of the packer due to the change in hydrostatic pressure acting on those areas.



Setting Tension Packers in Low Fluid Level Wells

Arrow Model SL Packer - 7"
Set in 7" 26# casing at 7430 feet
2 7/8" 6.40 # tubing
42° API oil at 6360 feet
20,000 # ↑ pulled to set the packer
Hole to be filled with 42° oil after packer is set

What force exists across the tool when the hole is filled ?

Annulus

Casing I.D.	$=30.920\ in^2$
Tubing O.D.	$=6.489\ in^2$
Area	$=24.431\ in^2$
Hydrostatic	=6360 X 0.354
	=2251 PSI
Force down	=2251 X 24.431
	=54,994 # ↓

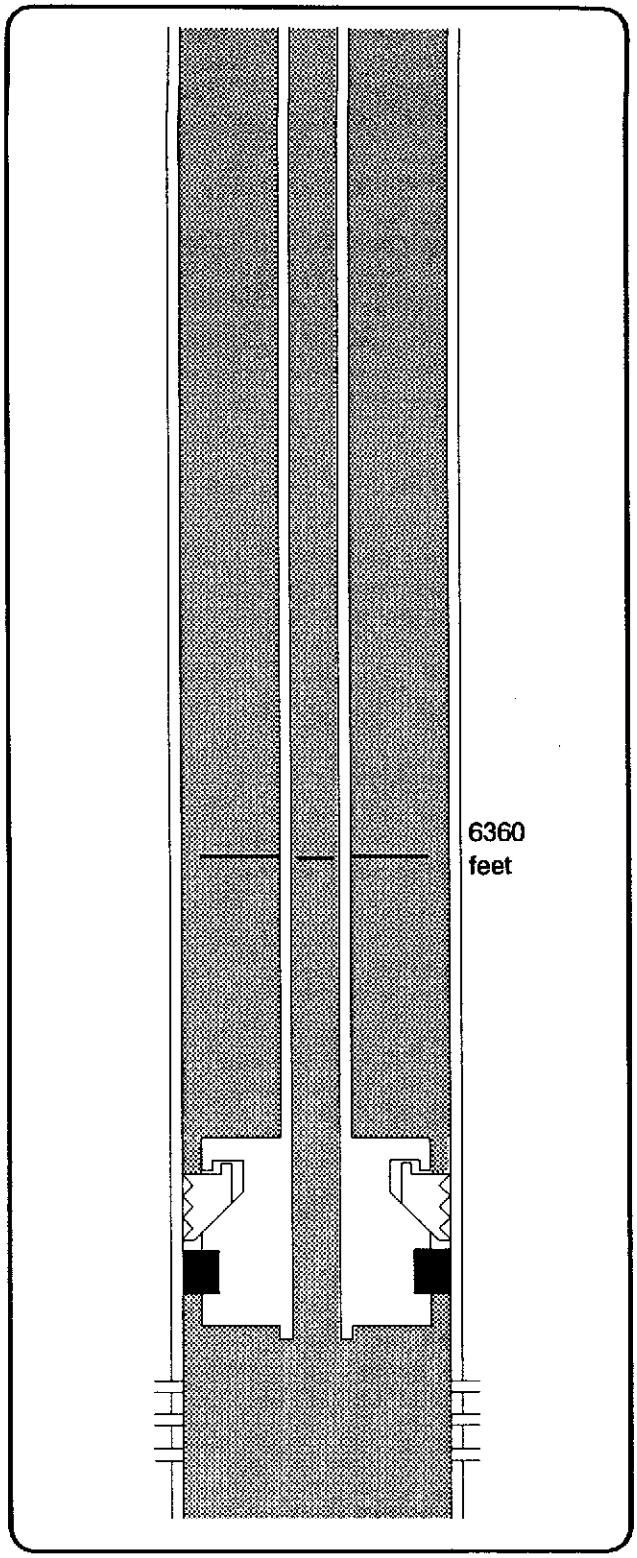
Tubing

Casing I.D.	$=30.920\ in^2$
Tubing I.D.	$=4.677\ in^2$
Area	$=26.243\ in^2$
Hydrostatic	=2251 PSI
Force up	=2251 X 26.243
	=59,073 # ↑

Force Balance

	=20,000 # ↑
	=59,073 # ↑
	=54,944 # ↓
Net force	=24,129 # ↑

Note that filling the annulus first would create a downward force that would cause packer failure.



Set Down Type Tools

There are three basic situations encountered when running set-down, or compression type tools:

- What weight is required on the packer to hold a given pressure under the tool?
- With a given amount of weight on the tool, how much pressure can be put underneath?
- With a given amount of set-down weight, and a certain pressure underneath, how much pressure will be required on the annulus to hold the packer down?

The additional situation exists, as with the tension tool, when a fluid of different weight is circulated down to the tool.

Remember...forces across the tool are balanced at the time the tool is set. Calculate what is done to the tool from that point. Quite often you will determine that the tool requires a hold-down to keep it in place.

How much to set down?

The tool is balanced to start. A certain amount of pressure will be applied under the packer. Calculate the force by multiplying the area under the packer by the pressure exerted. Set down this amount to hold the tool in position.*

How much pressure can be exerted under the packer?

Use the known amount of set-down force to calculate maximum permissible pressure. Divide this downward force by the area under the packer to obtain the maximum pressure under the tool.

How much annulus pressure to hold the packer down?

Again the set force (down) is known. Calculate the upward force caused by pressure under the tool by multiplying the area under the packer by the pressure. The net force will be upward where annulus pressure is required. Divide the annular area into this net force to obtain the amount of pressure required on the annulus to hold the tool down.

Whenever you calculate an amount of set-down weight less than the amount of weight required to obtain initial pack-off, you must use the higher amount. This will ensure an adequate amount of weight to seal, and to do the job calculated.

* There are definite limitations on the amount of weight that can reach packers by slacking off. Some of the following problems may not cosider these particular limitations for all weights of a particular work string. The examples are intended to illustrate principles of the piston effect only.

How Much Set-Down Weight to Hold Pressure?

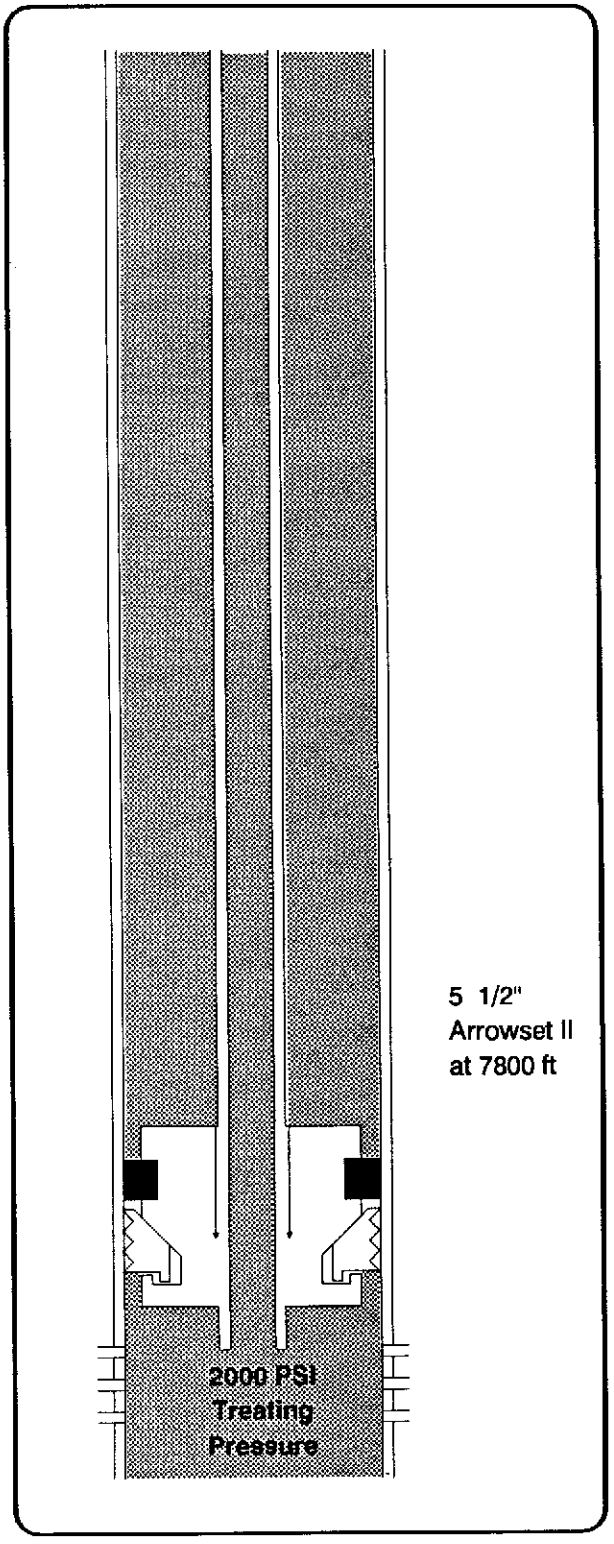
Arrowset II Packer - 5 1/2"
Set in 5 1/2" 15.50# casing at 7800 feet
2 7/8" 6.40# tubing
9.2 # salt water in the hole
Treating pressure = 2000 PSI
Note: This problem will first be calculated as if the Arrowset II did not have the hold-down feature of upper slips, as some packers feature a "single grip" design without hold-downs.

Remember...the packer is balanced when set.

Casing I.D. $= 19.234\ in^2$
Tubing I.D. $= 4.678\ in^2$
Area $= 14.556\ in^2$

Force up $= 2000 \times 14.556$
$= 29{,}112\ \#\ \uparrow$

You will have to set at least 29,112 # ↓ to hold the packer in place. Note that the slack-off charts indicate that this amount of slack-off is not practical for 2 7/8" tubing. You must, therefore, use a packer with the hold-down feature such as the upper slips found on the Arrowset II. In this case, the 29,112 # force would be transferred through the upper slips into the casing, and the bypass would remain closed helped by the balance piston.



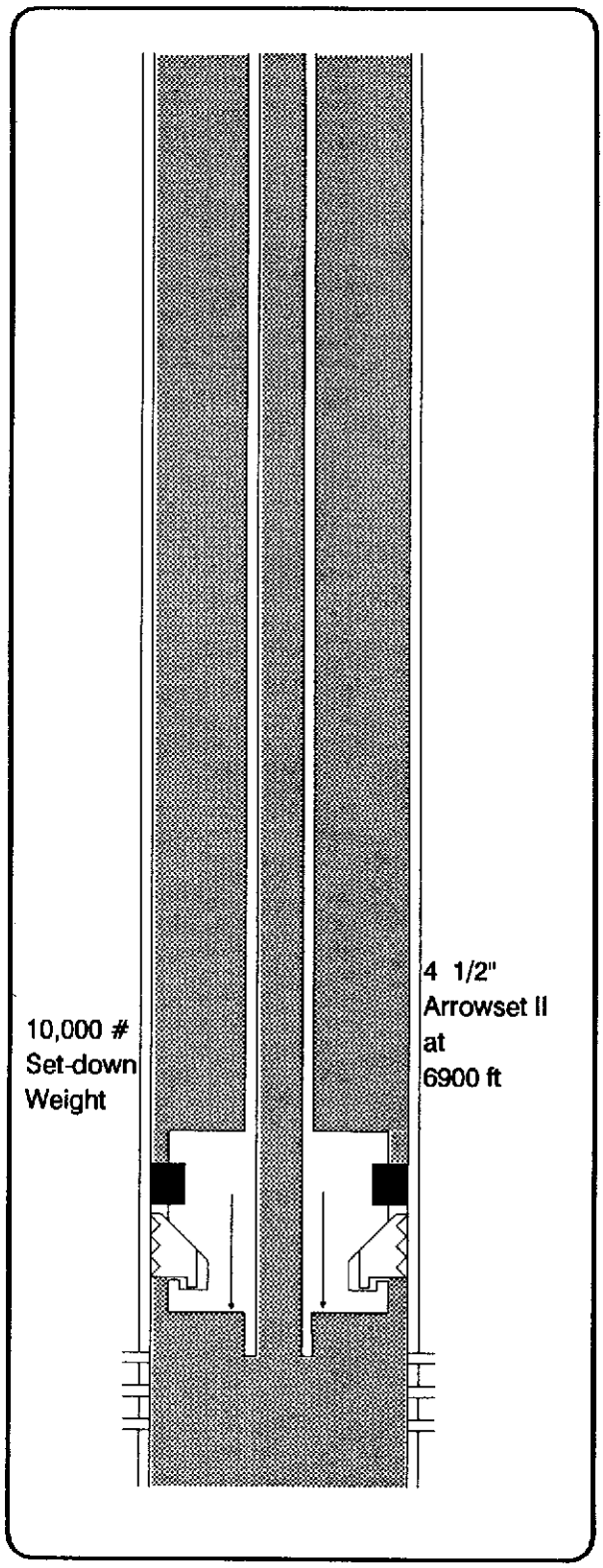
How Much Pressure Can Be Applied Under a Set-Down Packer?

Arrowset II Packer - 4 1/2"
Set in 4 1/2" 11.60# casing at 6900 feet
2 3/8" 4.70# tubing
9.2# salt water in the hole
10,000 # ↓ at the packer

Casing I.D. $= 12.560\ in^2$
Tubing I.D. $= 3.124\ in^2$
Area $= 9.436\ in^2$

Pressure $= 10{,}000 \div 9.436$
$= 1060$ PSI

Any pressure below the packer that exceeds 1060 PSI would move a single grip packer up the hole. In the case of the Arrowset II, force will be transmitted to the upper slips when pressure exceeds 1060 PSI.

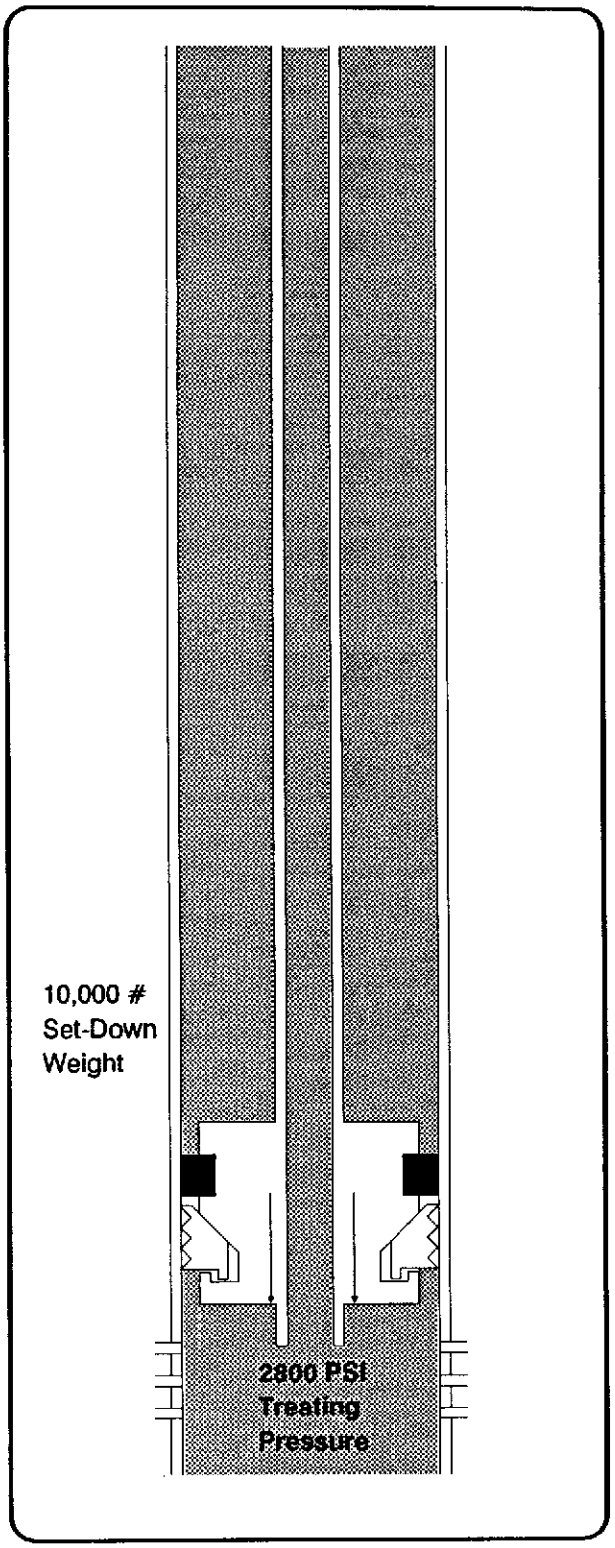


How Much Annulus Pressure to Hold Packer Down?

Arrowset III Packer - 4 1/2"
Set in 4 1/2" 11.6# casing at 8000 feet
2 3/8" 4.70# tubing
9.2# salt water in the hole
10,000# ↓ set on the packer
Treating pressure = 2800 PSI

Casing I.D.	$=12.560\ in^2$
Tubing I.D.	$=3.124\ in^2$
Area	$=9.436\ in^2$
Force up	$=2800 \times 9.436$
	$=26{,}420\ \#\ \uparrow$
Force balance	$=26{,}420\ \#\ \uparrow$
	$=10{,}000\ \#\ \downarrow$
Force to be balanced	$=16{,}420\ \#\ \uparrow$
Annular area:	
Casing O.D.	$=12.560\ in^2$
Tubing O.D.	$=4.428\ in^2$
Area	$=8.132\ in^2$
Pressure	$=16{,}420 \div 8.132$
	$=2020$ PSI

2020 PSI should be applied to the annulus of a single grip packer application to hold the packer in place.



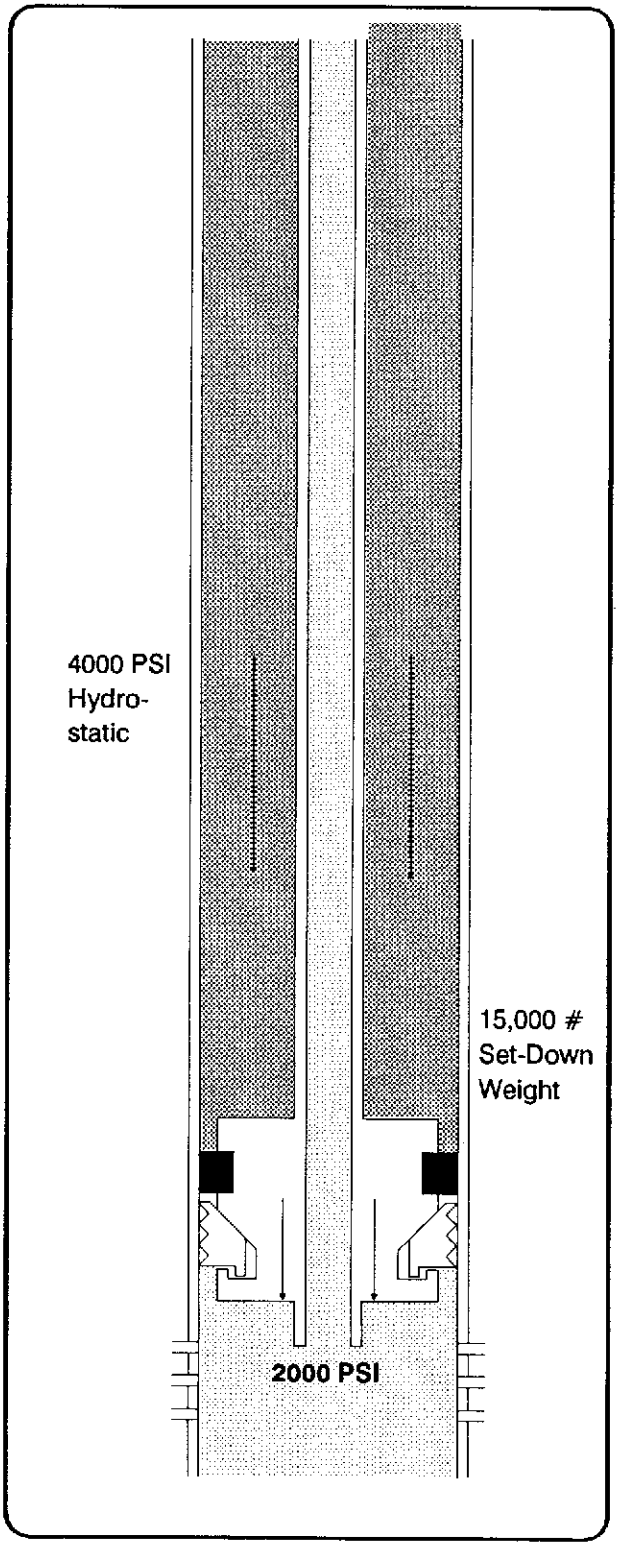
Circulating a Different Weight Fluid to the Packer

Consider the condition where you circulate a different weight fluid to the packer, then set the tool. Once again, the rule applies that the tool is balanced when set, and any subsequent operation must be taken into account. Bleeding pressure from an area is one of these operations.

First, figure what is done when circulating a different weight fluid to the packer. Break the packer loose and circulate to the tool. Becasue you are circulating a different weight fluid, you must be holding pressure as the hole is now unbalanced. You might be holding pressure on the tubing if you circulated a lighter fluid, or back pressure on the annulus if you circulated a heavier fluid. Either way, when the tool is set, you will be bleeding pressure.

Forces across the packer were balanced when you began to set it. When the tool was set, you unbalanced it by the amount of set-down force. When you bled pressure, you removed a force from the packer. This force will be equal to the pressure multiplied by the area upon which it acts. Since it is a removed force, remember it acts in the opposite direction.

In the illustration at right, 2000 PSI is held on the tubing while seting the packer, or fluid would flow from the annulus to the tubing. After setting the packer with 15,000 # ↓, bleed off 2000 PSI from the tubing. This action removes a force (2000 X area under the packer) and will put that much more downward force into the tool.



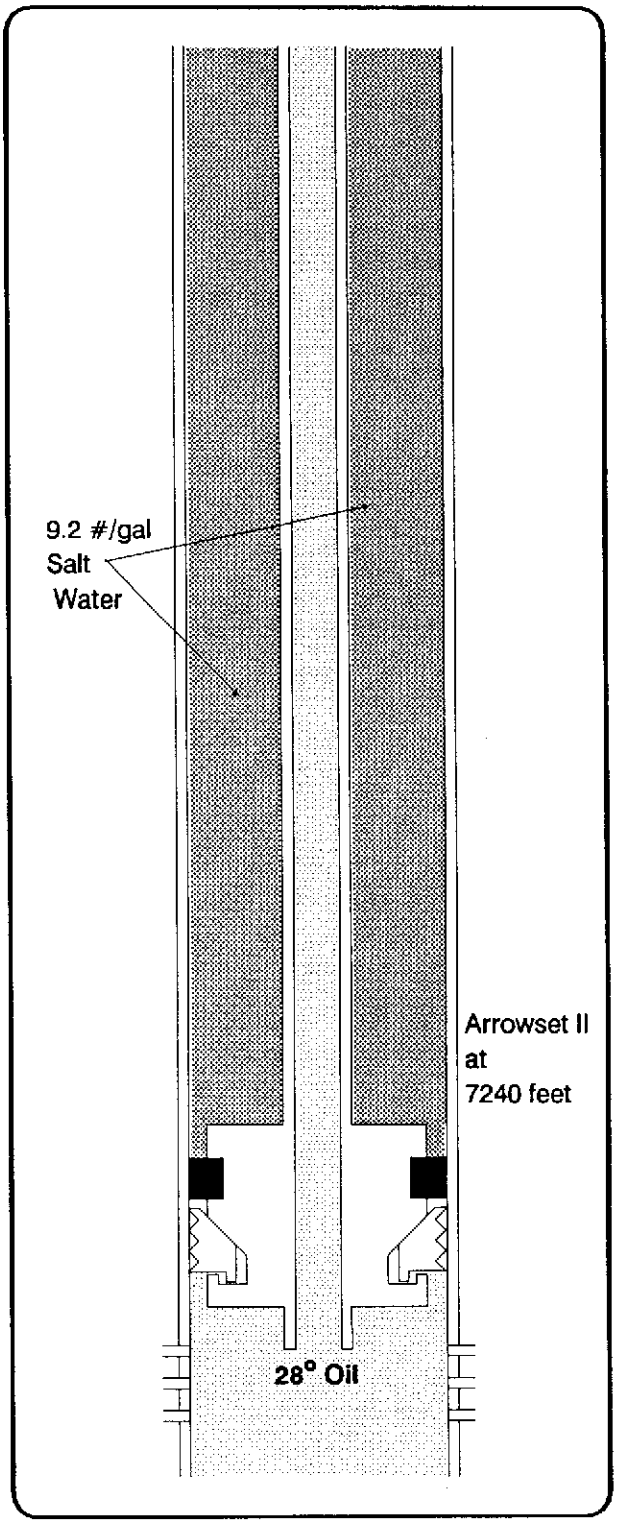
Circulating a Different Weight Fluid to the Packer

Arrowset II Packer - 5 1/2"
Set in 5 1/2" 17# casing at 7240 feet
2 7/8" 6.40# tubing
9.2 # salt water in the annulus
28° API oil circulated down the tubing
Set the tool with 16,000 # ↓
Bleed off the tubing

What will the forces be on a single grip packer?

Gradient H_2O	= 0.478 psi/ft
Gradient Oil	= 0.384 psi/ft
Differential	= 0.094 psi/ft
Pump pressure	= 0.094 X 7240
	= 681 PSI
Casing I.D.	= 18.786 in^2
Tubing I.D.	= 4.678 in^2
Area	= 14.108 in^2
Force	= 681 X 14.108
	= 9608 # ↓

16,000 # ↓ set on the packer
9,608 # ↓ created by bleeding pressure
25,608 # ↓ Net force after bleeding pressure



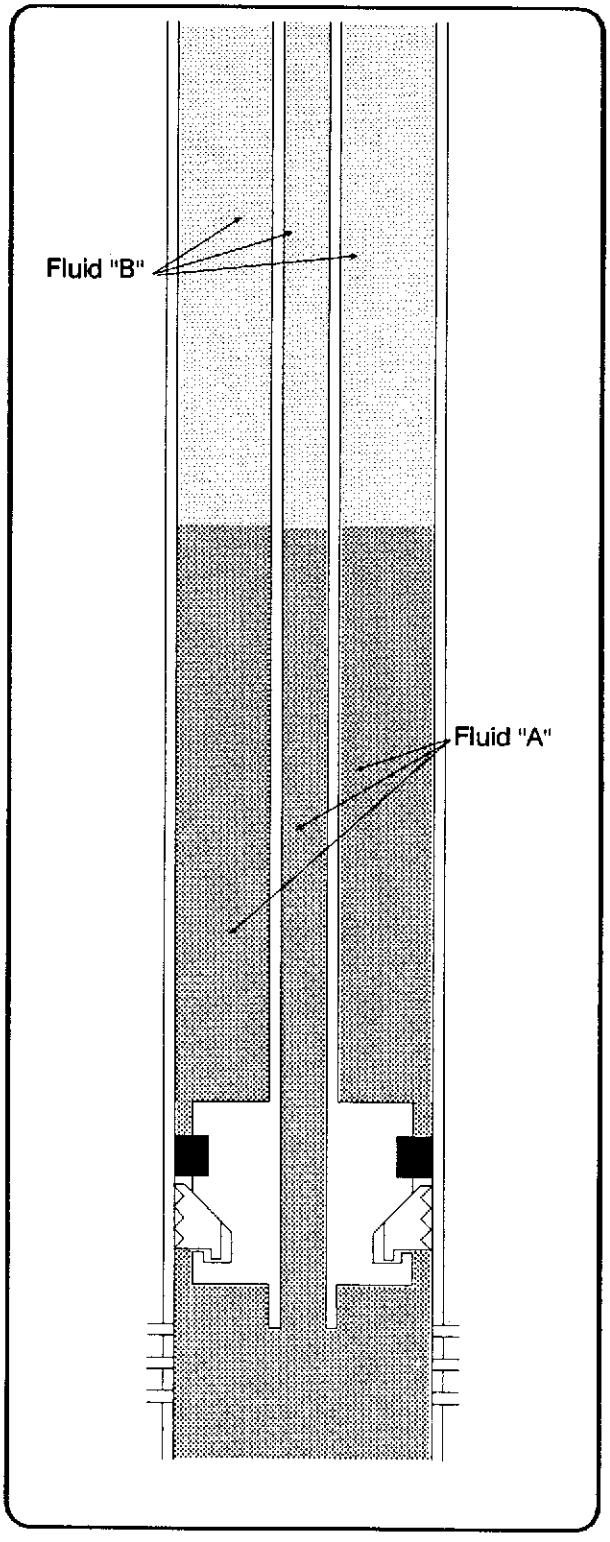
Setting in a Low Fluid Level Well

This explanation serves as a reminder of the difference in having a fluid in the hole before setting the tool, and filling it after the tool is set.

Remember that the forces across the tool are balanced when the tool is set. Tubing shortens when exposed to a bouyant force. After the packer is set and fluid is added, the tubing is fixed and not free to shorten. The force generated by the tubing must be calculated and accounted for.

In the example shown, the tool was set with fluid "A" in the hole. It was at that time as the tubing was free to move.

Once the hole was filled with fluid "B", additional forces were added to the annulus and underside of the tool due to the change in hydrostatic pressure acting on those areas.



Setting a Compression Packer in a Low Fluid Level Well

Arrowset II Packer - 7"
Set in 7" 26# casing at 5800 feet
3 1/2" 9.20# tubing
42° API oil at 3500 feet
20,000 # ↓ set on packer
Hole is filled with 42° Oil after the tool is set.

Annulus

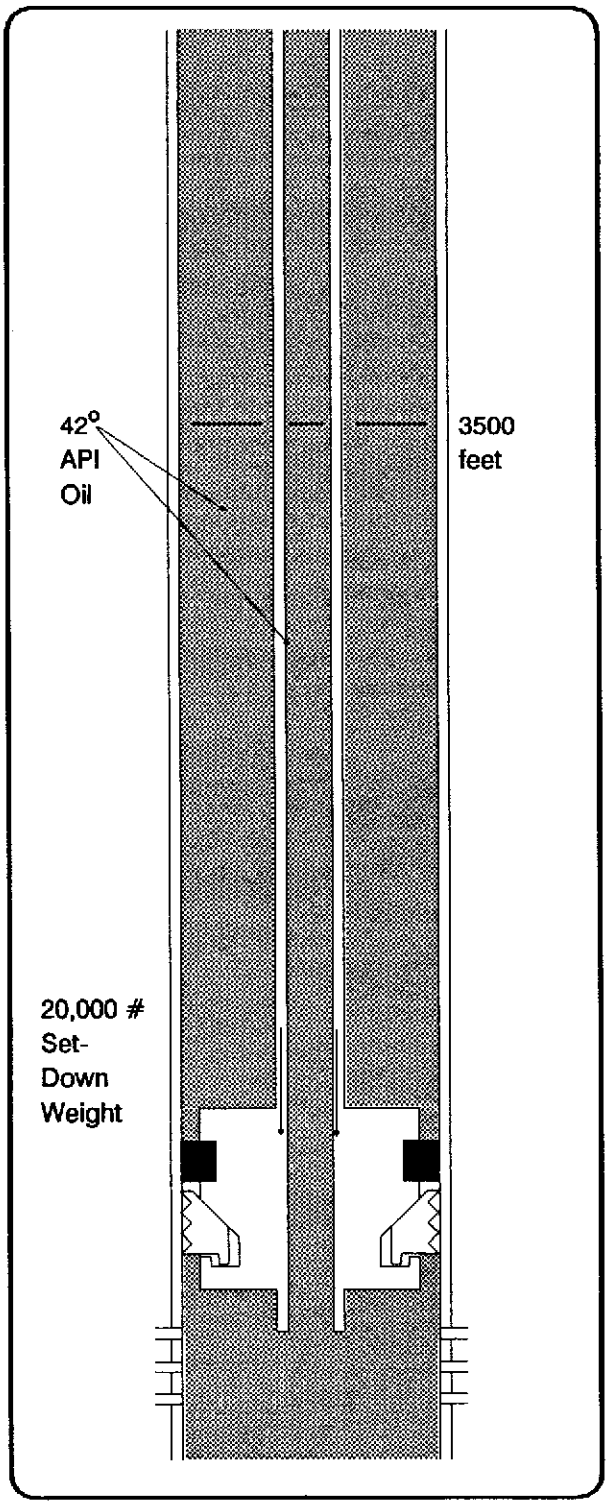
Casing I.D.	$=30.920\ in^2$
Tubing O.D.	$=9.616\ in^2$
Area	$=21.304\ in^2$
Hydrostatic	$=3500 \times 0.354$
	$=1239$ PSI
Force down	$=1239 \times 21.304$
	$=26{,}396$ # ↓

Tubing

Casing I.D.	$=30.920\ in^2$
Tubing I.D.	$=7.027\ in^2$
Area	$=23.893\ in^2$
Hydrostatic	$=1239$ PSI
Force up	$=1239 \times 23.893$
	$=29{,}603$ # ↑

Force balance

	$=20{,}000$ # ↓ set-down weight
	$=26{,}396$ # ↓ annulus
	$=29{,}603$ # ↑ tubing
Net force	$=16{,}793$ # ↓



Neutral Set Packers

There are a number of packers, the Arrowset I, Arrowset I-X, I-X 10K, Arrowset I-XS and Neutraset II-A, that can be classified as neutral set tools. This implies that whatever energy you placed in the tool during the setting process is locked into the tool, and anything done to the tubing after the tool is set (with the exception of activation of the release mechanism), will not release the packer. The string can be left in tension, compression, or neutral. The packers themselves may be set by applying tension or compression.

Forces we have discussed, and calculated, in the previous pages do not apply to neutral set tools *while* they are set. When neutral set tools are to be retrieved, there may be forces stored in the tool that were applied subsequent to setting. For example, you may have set down 10,000 # to pack-off a compression set packer, locking the 10,000 # into the tool. Subsequent to setting, additional force may have been locked into the packer by a pressure imbalance in favor of the tubing. This "extra" force may play a role in the force required to retrieve the tool. Note that this principle is dependent on tool design.

Tubing Anchor/Catchers

The purpose of a tubing anchor is to pre-stretch the tubing string in a pumping well beyond the point it would be stretched by fluid induced loads and temperature increases, and anchor it to the casing wall. As a result, pump efficiency increases while wear and friction are decreased.

Without this pre-stretching, tubing has a tendency to buckle producing the following effects:

- As tubing buckles, it rubs against the sucker rods causing rod wear and tubing wear resulting in rod and/or tubing failure
- Friction caused by the rod to tubing contact requires an increase in power at surface
- Buckled tubing can contact casing causing additional wear
- Buckling action forces rods out of alignment with the pump causing excessive pump wear

Tension required:

The amount of tension required to eliminate buckling is the tension that exists in the fully elongated free tubing string of a rod pumped well on the downstroke. This tension is placed on the tubing string at the time of installation by anchoring the bottom of the tubing string.

Tables provided later in this section permit the calculation of the distance free tubing will elongate from the time tubing is landed until the fluid level has been pumped down to operating level.

Tubing elongation is caused by three factors:

- Tubing string filled with warm fluid
- Loss of bouyancy caused by pumping down the annulus
- Weight of fluid inside the tubing when the standing valve is closed

Tubing tension requirements calculated from the tables include all three of these factors.

The following formula is used with the tables:

$F_T = F_1 + F_2 - F_3$

Where:

F_T = Total tension required in pounds

F_1 = Result of table #1

F_2 = Result of table #2

F_3 = Result of table #3

Tubing Anchor - Example Calculations

Using the example well profile for all of the following calculations:

Tubing Size:	2 3/8" 4.70# EUE J-55
Tubing Yield Strength:	71,730 lb
Pump & Anchor depth:	4000 feet
Fluid Level when Anchor Set:	3000 feet
Operating Fluid Level:	4000 feet
Fluid temperature @ surface:	70°F
Mean Yearly Temperature:	37°F
Tubing String Weight:	18,800#
Rod String Weight:	8000#
Pump Plunger Size:	1 1/2"
Weight of Fluid in Tubing:	6000# (est)
Shear Value of Anchor:	50,000#

Determining Tension

Using the well data above:

F_1 (from Table #1) = 6300#

F_2 (from Table #2) = 4050#

F_3 (from Table #3) = 1220#

$$F_T = 6300 + 4050 - 1220$$
$$= 9130\ \#$$

Tension required to eliminate buckling = 9130#

Note: The value calculated represents the *minimum* tension required and it is presumed well data is accurate. A greater prestrain than calculated is usually recommended as a safety factor.

Tubing Loads

Maximum anticipated tubing loads should be determined and compared with string strength to prevent tubing damage.

Top Joint:

$$F_T + \text{String Weight}$$
$$= 9130 + 18{,}800$$
$$= 27{,}930\ \#$$

Tubing Load @ Anchor:

Maximum load on a tension anchor will occur when the weight of the rod string is added. This weight will not affect the anchor unless it is released with the rods still in the tubing string.

$$F_T + \text{Tubing Wt.} + \text{Rod Wt.}$$
$$= 9130 + 18{,}800 + 8000$$
$$= 35{,}930\#$$

This value is well below the safe string load of 71,730# (71,730 # comes from the engineering tables for the joint yield strength of the tubing string), and the tool can be released normally.

Tubing Anchor/Catchers
Example Calculations

Shear Release

Tension Anchors are furnished with an adjustable shear release. This release is a secondary or safety release and is not used unless the anchor cannot be released normally. It is usual practice to run anchors with a high shear value to insure against accidental or pre-mature releasing. If too high a shear value is used, it may be impossible to use the shear release without damaging the tubing.

If the rods, pump, and standing valve are pulled from the well and the anchor must be sheared to release, you would be required to pull the weight of the string plus the shear value of the tool.

In this case:

= Tubing Wt. + Shear Value
= 18,800 + 50,000
= 68,800#

Caution: we are now within 5% of the joint yield strength of the tubing.

If the rods are pulled but the tubing remains trapped full of fluid, you must now pull the weight of the tubing plus the shear value of the tool *plus* the weight of the column of fluid.

= Tubing Wt + Shear + Fluid Wt
= 18,800 + 50,000 + 6000
= 74,800#

We now risk tubing damage by pulling over the joint strength. For this application, it is suggested a lighter shear value be used as the required tension is considerably less than the shear value.

Assuming the worst case, where the rods and pump cannot be pulled and the tubing is trapped full of fluid. We must now add the weight of the rod string to the answer directly above.

= 74,800 + 8000
= 82,800# to shear

Tubing damage is now certain with this configuration. Our options include a lighter shear value or a stronger tubing string.

Minimum Shear Values

Tubing Anchors are shipped with all shear screws installed (maximum shear value). In the preceding example, the shear value should have been reduced to allow for *all* operational contingencies. If too low a value is used, you run the risk of pre-mature release. The following table lists *minimum* recommended shear values. The table does not take into account, the type of donut or tubing hanger used as some types require tension higher than F_T to install.

F_T	Min. Shear Value
0-10,000#	25,000#
10-20,000#	30,000#
20-30,000#	40,000#
30-40,000#	50,000#

Tubing Anchors
Tension Force Charts - 2 3/8" Tubing

F_1 Table#1

Anchor Depth (ft)

1000	610	1550													
2000	520	1220	2080	3100											
3000	500	1110	1830	2660	3590	4640									
4000	480	1060	1700	2430	3250	4140	5130	6300							
5000	470	1020	1630	2300	3040	3840	4730	5670	6670	7750					
6000	470	1000	1580	2210	2900	3650	4450	5310	7220	7200	8210	9300			
7000	460	980	1540	2150	2800	3500	4260	5060	5900	6800	7740	8730	9760	10,850	
8000	460	970	1520	2100	2730	3400	4120	4870	5660	6510	7380	8300	9260	10,270	11,310
9000	460	960	1500	2060	2670	3310	4010	4720	5470	6270	7100	7970	8870	9820	10,790
10,000	460	960	1480	2040	2630	3520	3910	4600	5320	6090	6870	7700	8550	9450	10,370
	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500

Operating Fluid Level (feet)

F_2 Table #2

Temperature Increase Factor

°F	10	20	30	40	50	60	70	80	90	100	110	120	130	140	150
F_2	1350	2700	4050	5400	6750	8100	9450	10,800	12,150	13,500	14,850	16,200	17,550	18,900	20,200

To obtain F_2: Subtract the mean yearly temperature for the area in which the well is located from the temperature of the well fluid at surface. Locate your answer in the °F row. Read F_2 immediately below.

Tubing Anchors
Tension Force Charts - 2 3/8" Tubing

F_3 Table #3

Anchor Depth (ft)

Anchor Depth (ft)	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500
1000	180	460													
2000	150	360	610	910											
3000	150	330	540	780	1060	1370									
4000	140	310	500	720	960	1220	1510	1820							
5000	140	300	480	680	890	1130	1390	1670	1960	2290					
6000	140	290	460	650	850	1070	1310	1560	1830	2130	2430	2740			
7000	140	290	450	630	820	1030	1250	1490	1740	2010	2290	2580	2880	3200	
8000	140	280	450	620	800	1000	1210	1430	1670	1920	2180	2450	2730	3030	3340
9000	140	280	440	610	780	980	1170	1390	1610	1850	2100	2350	2620	2900	3180
10,000	130	280	430	600	770	960	1150	1350	1570	1800	2030	2270	2530	2790	3060

Fluid Level When Anchor Is Set (ft)

Tubing Anchors

Tension Force Charts - 2 7/8" Tubing

F_1 Table #1

Anchor Depth (ft)

1000	890	2180													
2000	770	1790	3040	4540											
3000	730	1630	2670	3890	5270	6800									
4000	710	1540	2490	3560	4760	6070	7520	9090							
5000	700	1500	2380	3370	4460	5630	6930	8310	9770	11,350					
6000	690	1460	2310	3240	4250	5340	6530	7790	9110	10,530	12,040	13,630			
7000	680	1440	2250	3150	4110	5130	6240	7410	8640	9960	11,340	12,790	14,320	15,890	
8000	680	1420	2210	3080	4000	4980	6030	7130	8300	9520	10,810	12,160	13,580	15,040	16,560
9000	680	1410	2180	3020	3920	4850	5870	6920	8020	9180	10,400	11,680	13,000	14,370	15,800
10,000	670	1400	2160	2980	3850	4760	5630	6740	7800	8910	10,080	11,290	12,550	13,800	15,190
	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500

Operating Fluid Level (ft)

F_2 Table #2

Temperature Increase Factor

^0F	10	20	30	40	50	60	70	80	90	100	110	120	130	140	150
F_2	1880	3750	5630	7500	9370	11,250	13,100	15,000	16,900	18,800	20,600	22,500	24,400	26,100	28,100

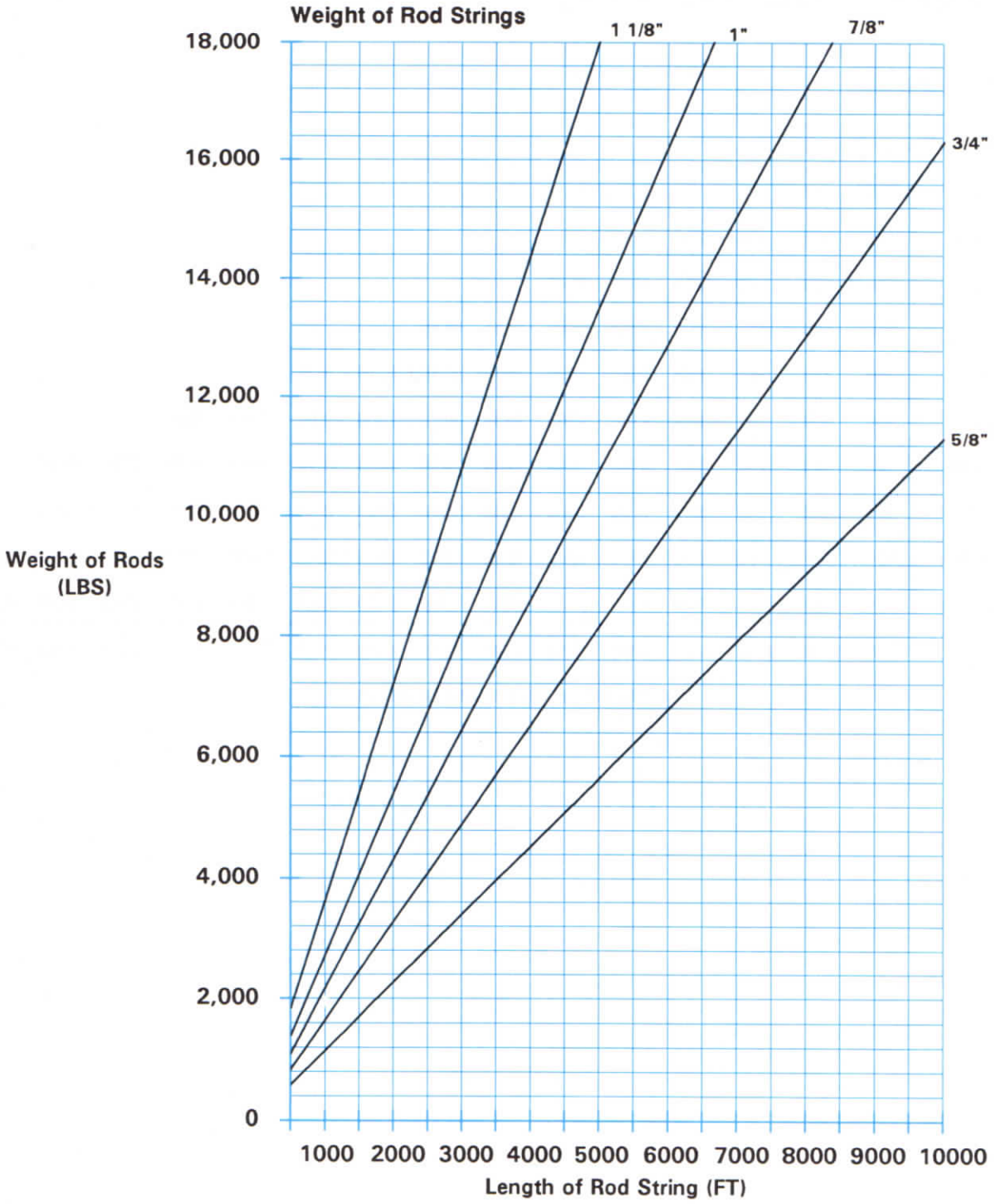
To Obtain F2: Subtract the mean yearly temperature for the area in which the well is located from the temperature of the well fluid at surface. Locate your answer in the ^0F row. Read F_2 immediately below.

Tubing Anchors
Tension Force Charts - 2 7/8" Tubing

F3 Table #3

Anchor Depth (ft)

Anchor Depth (ft)	Fluid Level When Anchor Is Set (ft)														
1000	250	630													
2000	210	500	850	1260											
3000	200	450	740	1080	1470	1910									
4000	200	430	690	990	1330	1700	2100	2540							
5000	190	410	660	940	1240	1580	1940	2320	2730	3170					
6000	190	410	640	900	1180	1500	1830	2170	2550	2940	3360	3800			
7000	190	400	630	880	1140	1440	1750	2070	2420	2780	3160	3570	3990	4440	
8000	190	390	620	860	1110	1400	1690	1990	2320	2660	3020	3390	3790	4210	4630
9000	190	390	610	840	1090	1360	1640	1930	2240	2560	2900	3260	3630	4020	4420
10,000	190	390	600	830	1070	1330	1600	1880	2180	2490	2810	3150	3500	3870	4250
	500	1000	1500	2000	2500	3000	3500	4000	4500	5000	5500	6000	6500	7000	7500


Weight of Rod Strings
1 1/8"
1"
7/8"
3/4"
5/8"
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Weight of Rods (LBS)
1000 2000 3000 4000 5000 6000 7000 8000 9000 10000
Length of Rod String (FT)

Hydrostatic Pressure Exerted by Fluid/Sand Mixtures

On occasion you may be required to operate a tool in the presence of a sand laden slurry. To properly operate that tool, you will need to know the hydrostatic pressure exerted by a column of this slurry. The following chart will provide factors for use in making this calculation, based on the true density of the sand being 22.144 lb/gallon.

Densities of Sand/Fluid Slurries:

#/Gal Slurry=(PPG + PSA) ÷ [(.0456 X PSA) + 1]

Example Calculation:

The customer tells you he is going to pump 500 bbls of 9.2 #/gal gelled brine adding 2 pounds sand per gallon of fluid.

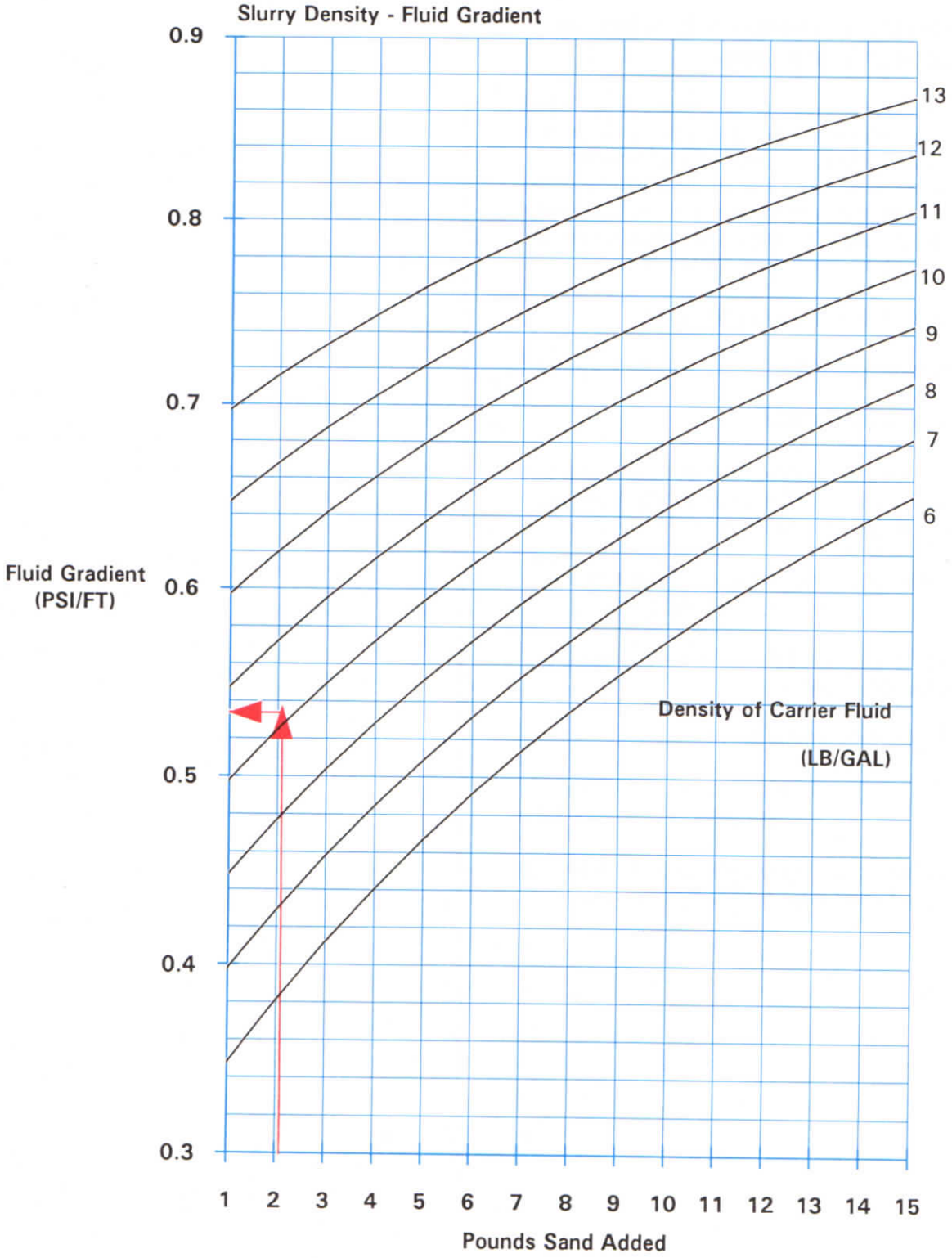
#/Gal Slurry =(9.2 + 2) ÷ [(.0456 X 2) + 1]
=10.264 #/Gal Slurry

Note: This is the fluid density used to calculate hydrostatic pressure.

Calculate fluid gradient:

=10.27 X 0.052
=0.534 psi/ft

Use the calculation procedure from the preceding chapter to determine pressures at the tool.


Slurry Density - Fluid Gradient
Fluid Gradient (PSI/FT)
0.9
0.8
0.7
0.6
0.5
0.4
0.3
13
12
11
10
9
8
7
6
Density of Carrier Fluid (LB/GAL)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15
Pounds Sand Added

Bottom Hole Pressure for a Column of Nitrogen

It is often necessary to calculate the bottom hole pressure for a well displaced with nitrogen gas. Being a gas, its weight changes with temperature and pressure according to the "Perfect Gas Law"

$$PV = nRT$$

This formula is presented for your information only to show the linear relationship between pressure, volume, and temperature. It is not to be used to calculate bottom hole pressure.

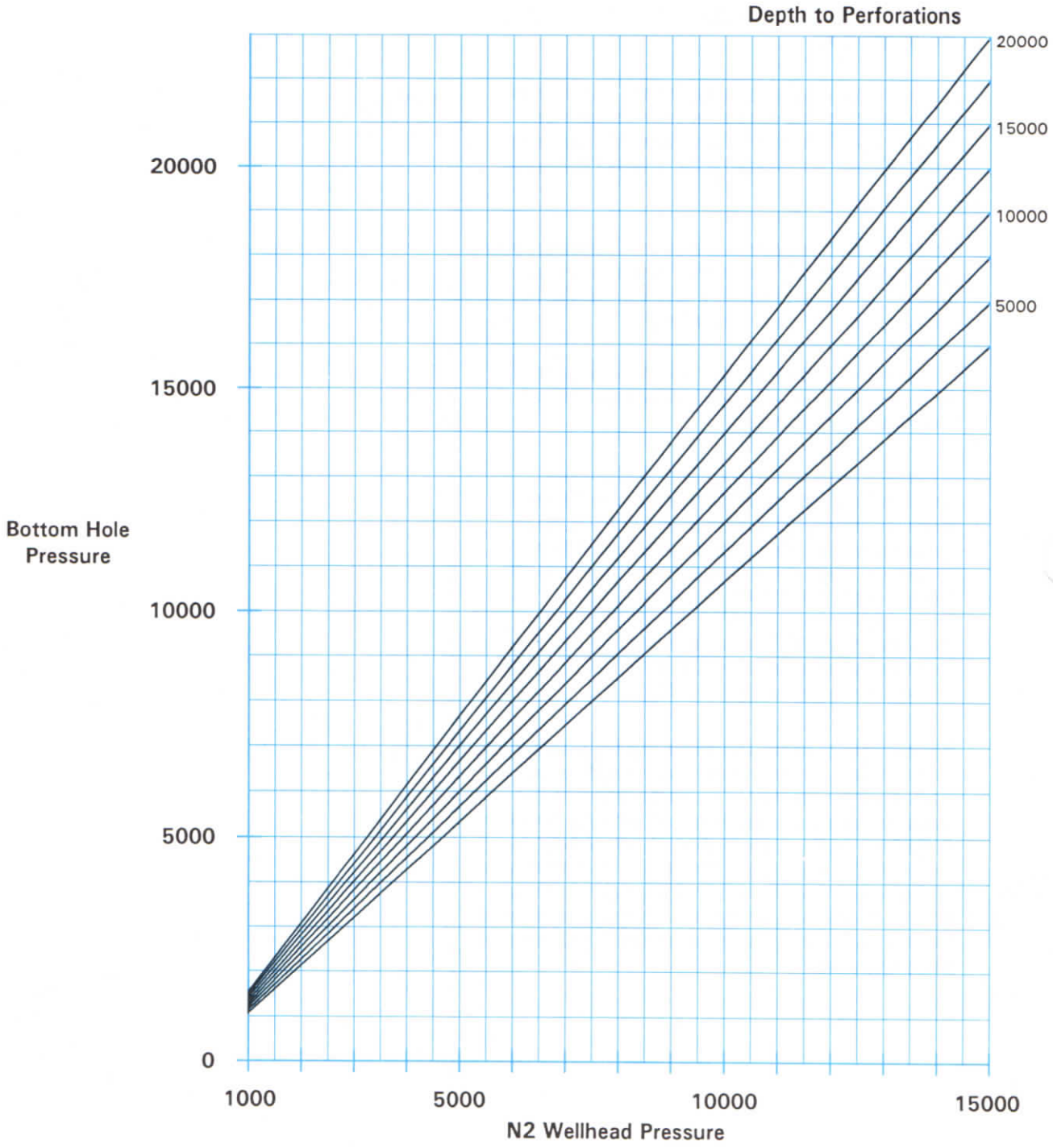
The density, and hence the weight, increases with an increase in pressure and decreases with an increase in temperature.

To present a simplified graph of bottom hole pressure and hydrostatic pressure with different wellhead pressures, we must assume a surface temperature and temperature gradient. It is well known that temperatures are not the same in all wells at a specific depth, but an average temperature is assumed for this graph. This average will be 70°F at surface with a 0.016°F per foot temperature gradient. On a 10,000 foot well, this would equate to 230°F BHT.

The primary purpose of calculating the bottom hole pressure of a column of nitrogen is to balance fluids across a packer. To use the chart on the following page, calculate the bottom hole pressure at the tool (hydrostatic of the column of fluid), read across to the well depth, then down to get nitrogen pressure at the wellhead. The difference between bottom hole pressure and the nitrogen pressure at the wellhead is the hydrostatic head of the column of nitrogen gas.

Notes:

Nitrogen Wellhead Pressure vs Bottom Hole Pressure



Section III
Dynamics of Tubulars

Tubular Goods

- Stretch & Free Point Calculations ____ III-1
- Stretch Charts ____ III-3
- Slack Off Charts ____ III-14
- Slack Off Weight Actually Reaching Packer ____ III-21

Dynamics of Tubular Goods

- Force, Pressure, and Area ____ III-28
- Ballooning & Reverse Ballooning ____ III-29
- Ballooning Chart ____ III-32
- Reverse Ballooning Chart ____ III-33
- Temperature Effect ____ III-34
- Temperature Effect Charts ____ III-36

Total Analysis ____ III-42

Short cut to hanging wt for tubing stretch.
Wt of ths. ÷ 2
2⅞" 7300' Ex. 36K ÷ 2 = 18K Then go to Stretch Chart to Hanging wt to Depth 36"
↓ Divide by 2 will give hanging stretch

Tubular Goods - Stretch Data

The stretch or elongation of oilwell tubular material resulting from an applied tension force is a commonly required determination. Robert Hooke (1635-1702) discovered the law (Hooke's Law) that states, strain or distortion is proportional to stress or force providing the elastic limit of the material has not been exceeded. The elastic limit is that amount of strain or distortion that would cause permanent deformation.

The amount of stretch that will occur when a tension force is applied varies with the magnitude of the applied force, the length of the tubular string being stretched, the elasticity of the material, and its cross sectional area. Hooke's Law is commonly expressed as:

$$\Delta L = (F \times L) \div (A_s \times E)$$

where:
- ΔL = stretch (IN)
- F = Tension force (LB)
- L = Depth (IN)
- A_s = Cross sectional area of tubing (IN^2)
- E = Modulus of elasticity (PSI)

Note: There is a misconception that rate of stretch varies with grade of steel (J-55, P-105, etc.). All grades of steel have essentially the same elastic modulus, though some have higher elastic limits before permanent deformation.

Example:
Determine the amount of stretch for 30,000# pull on 7000 ft of 2 7/8" 6.40# tubing.

From engineering tables, we find the ID of the tubing is 2.441.

$$A_s = (2.875^2 - 2.441^2) \times 0.785$$
$$= 1.811 \text{ in}^2$$

Stretch
$$= \frac{30{,}000 \times 7000 \times 12}{1.811 \times 30 \times 10^6}$$

$$= 46.38 \text{ inches}$$

Some engineering tables contain a value called a stretch constant. This constant applies to a particular tubing size and weight, and assumes the tubing has a modulus of elasticity equal to that of steel (remember, *all* steels have the same modulus of elasticity). To obtain stretch using this constant, the equation would appear:

$$\Delta L = F \times L \times S.C.$$

where:
- ΔL = stretch (IN)
- F = Tension force (1000#)
- L = Length (1000 ft)
- S.C. = Stretch Constant

Note: stretch constants are usually presented in units of inches stretch per thousand pounds tension per thousand feet of tubing.

Determining Free Point

Calculating free point, that point at which stuck or anchored pipe becomes free to move, is easily calculated by manipulating the variables of the general stretch formula. When the amount of stretch is known and the amount of tension force is known, we can change the equation to yield:

$$L = (\Delta L \times E \times A_s) \div (12 \times F)$$

where:
- L = Length of free pipe
- ΔL = Stretch (IN)
- E = Modulus of Elasticity
- A_s = Cross sectional area (IN^2)
- F = Tension Force (LB)

Free Point Constants (F.P.C.) can also be used to estimate free point according to the following formula:

$$L = \Delta L \times F.P.C. / F$$

where:
- F.P.C. = Free Point Constant

F.P.C. is usually located in an engineering table but can be calculated.

Stretch and Free Point

Calculation of Stretch & Free Point Constants

For any pipe size commonly used or not found in any chart, constants can be calculated as follows:

$$S.C. = 0.4 / A_s$$
$$F.P.C. = 2500 \times A_s$$

where:

S.C. = Stretch Constant
F.P.C. = Free Point Constant
A_s = Cross Sectional Area (IN^2)

Note: When calculating free point of stuck or anchored pipe, there are friction forces acting on the string which cannot be determined. These forces would give the impression of a calculated free length shorter than the actual free length. For this reason, free point calculations should be considered with a certain margin of error based on well configuration.

Example:
Determine the stretch constant and free point constant for:
2 3/8" 4.60# tubing
2 7/8" 6.40# tubing

2 3/8" 4.60#

$A_s = (2.375^2 - 1.995^2) \times 0.785$
$= 1.3036\ IN^2$
$S.C. = 0.4 / A_s$
$= 0.3068$
$F.P.C. = 2500 \times A_s$
$= 3260$

2 7/8" 6.40#

$A_s = (2.875^2 - 2.441^2) \times 0.785$
$= 1.8111\ IN^2$
$S.C. = 0.4 / A_s$
$= 0.2209$
$F.P.C. = 2500 \times A_s$
$= 4527.75$

Stretch and free point can also be used for casing and drill pipe when dimensional data is known.

Stretch Graphs

Stretch charts are included on the following pages for tubing in the most common weight for each size. Should your tubing weight differ from these examples, you should either make calculations based on the previous formulae, or consider the charts as a rough estimate.

Charts are based on:

1.660" 2.40#
1.900" 2.90#
2 1/16" 3.40#
2 3/8" 4.60/4.70#
2 7/8" 6.40/6.50#
3 1/2" 9.20#

Each stretch graph involves only three variables; tension force, length, and amount of stretch. When two of the variables are known, the third can be read from the graph.

A more comprehensive discussion of these charts and their application will follow.

Example:
Apply 15,000# tension to 2-3/8" 4.60# tubing.
Measure 37" stretch.
How long is the free pipe in the hole?

$Length\ (L) = (\Delta L \times F.P.C.) \div F$
$= (37 \times 3260) \div 15.0$
$= 8041$ feet

Stretch Charts

The use of stretch charts is well known. If you are calculating the amount of force exerted up or down due to a temperature or ballooning change, this force can be converted to inches (or inches to force) by use of the stretch charts..

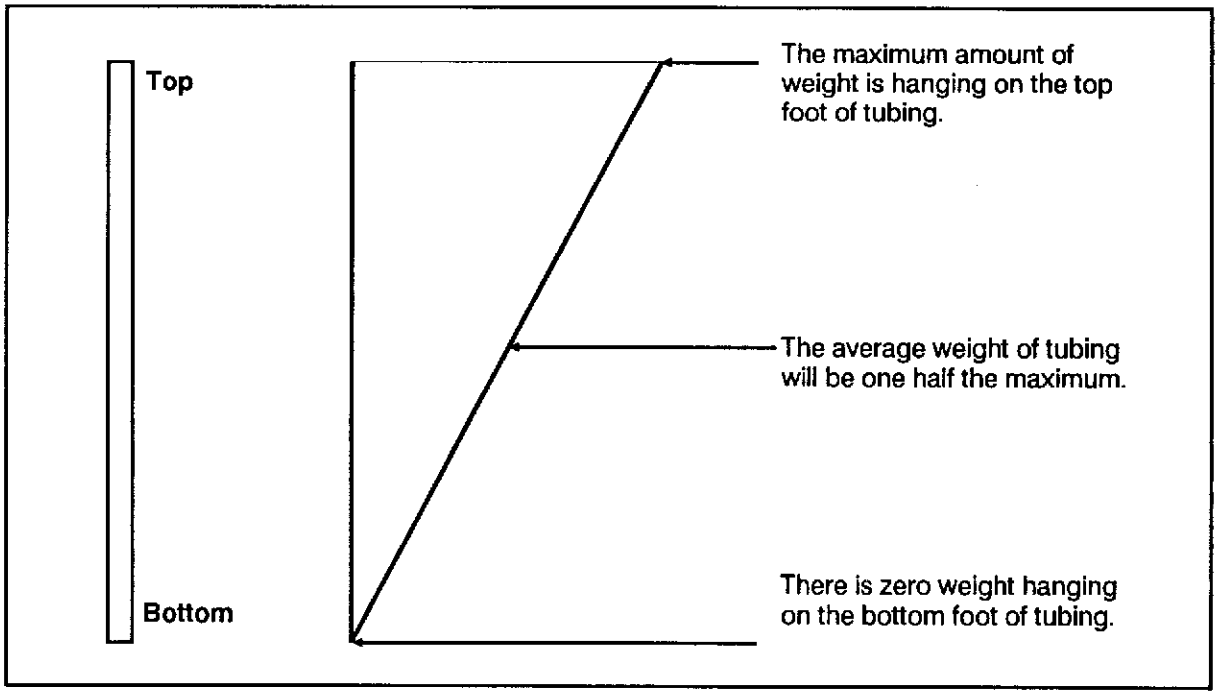
For example, you are injecting cold fluid inside 2 3/8" tubing creating a 25,000# contraction in the string. Associated with the injection pressure is a 7,000# upward force. You are 11,000 feet deep with a 32,000 # upward force.

If you refer to the stretch chart for 2 3/8" tubing, reading up from the 11,000 foot line until you intersect with the 32,000 # tension line, you will see a value of 110 inches.

Stretch of Tubing Hanging in a Well

Sometimes it is necessary to calculate the stretch in a tubing string that is hanging in a well to determine the true length. This may be necessary to place a tool between two sets of closely spaced perforated zones.

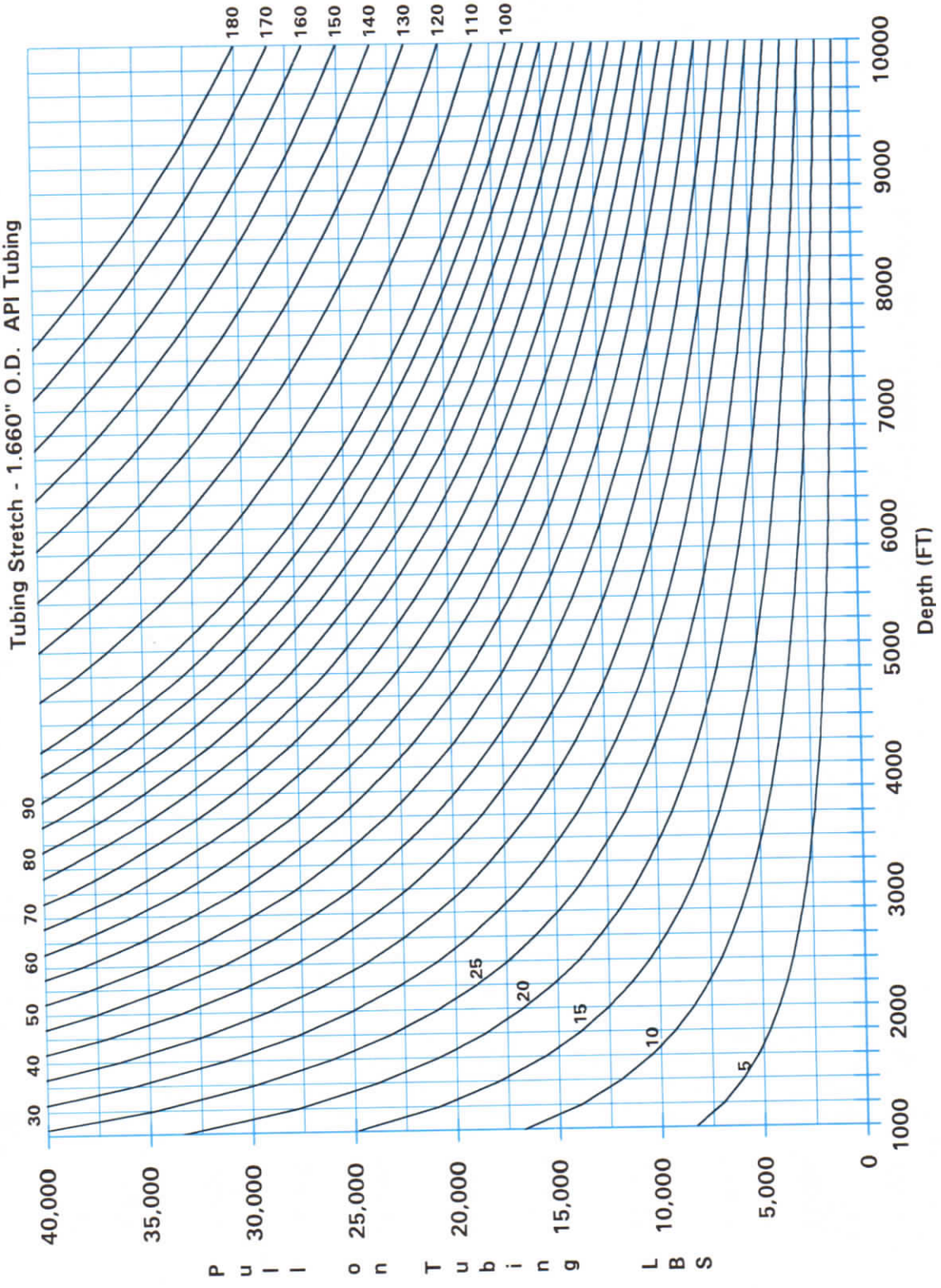
Stretch charts will give stretch if the tension force is known. In this case, the tension force varies throughout the string. To obtain the true length, find the average weight of the string. This is the weight of the string (adjusted for bouyancy) divided by two. Apply this amount to the stretch chart to obtain the number of inches the string has elongated due to its own hanging weight.

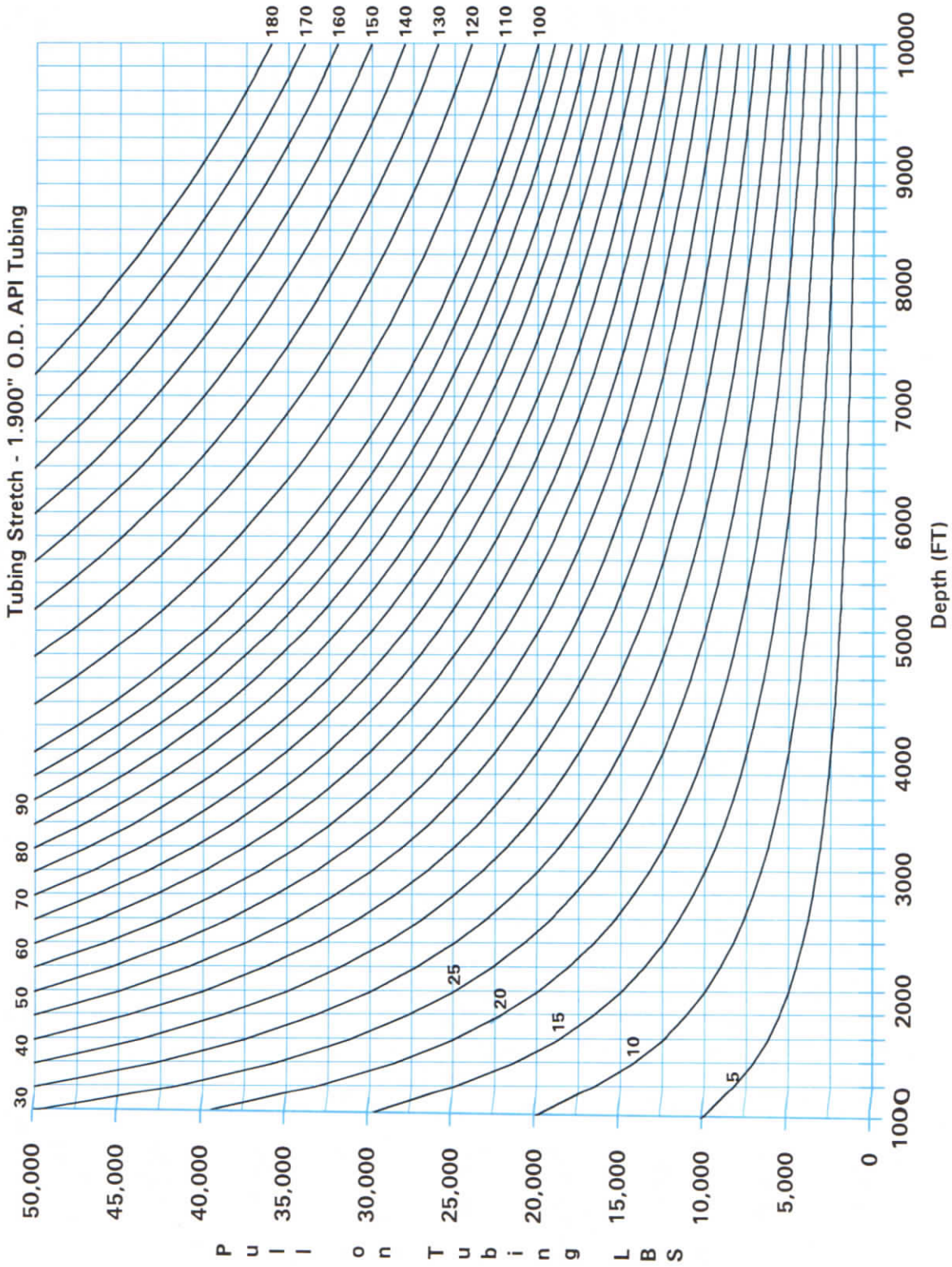


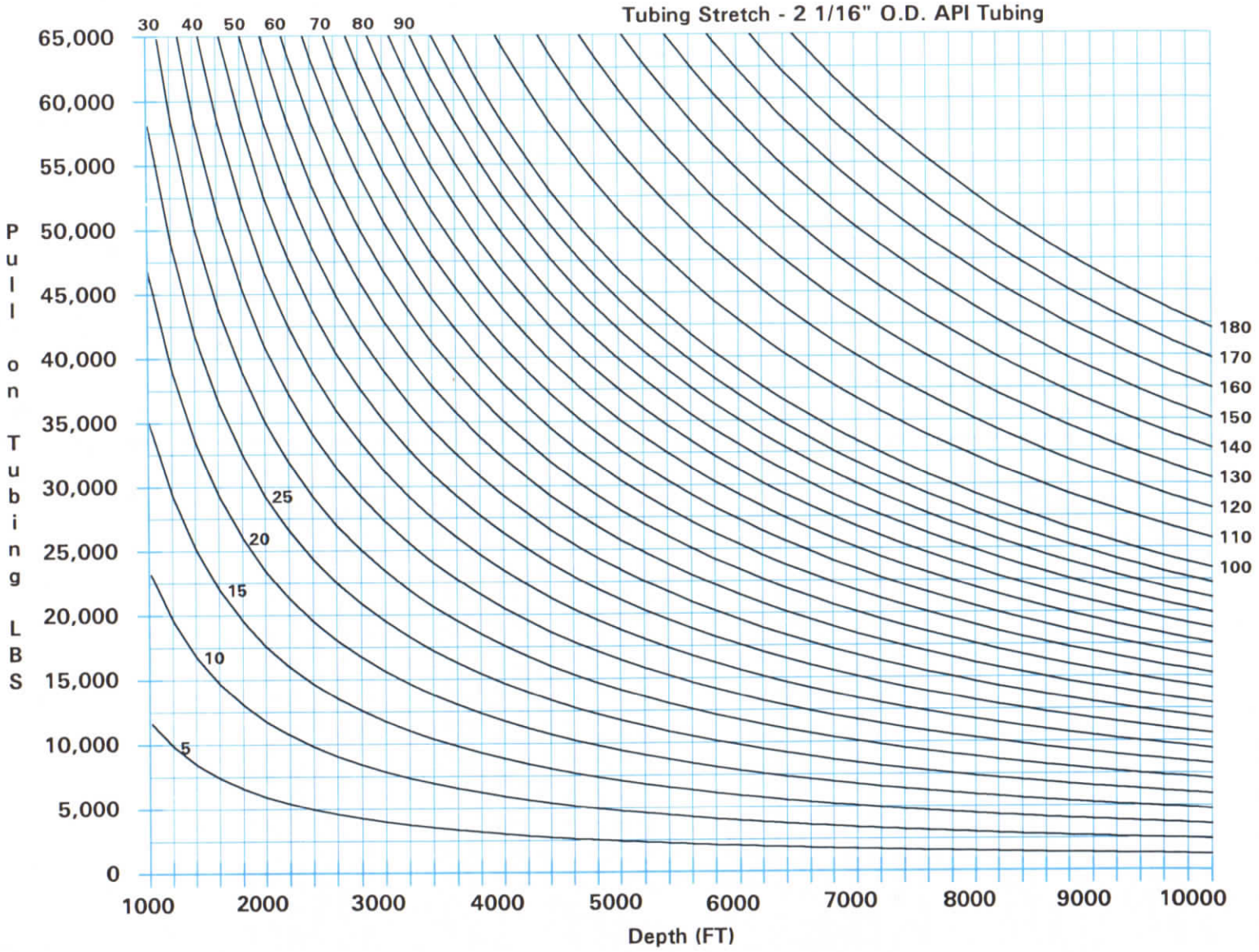
This means that the tubing will shorten 110 inches. You either need to put 110 inches of additional tubing into the well to compensate, or if you have a locator seal assembly, you may put 110 inches of additional seals on bottom. This procedure will assure the tubing stays packed off during the treatment.

Piston Effect

The piston effect (see Lubinski formula) works on the same principle as the stretch charts. The force, however is not tension, but the hydrostatic force acting on the end area of the tubing. Its resultant tubing movement can be shown on the stretch charts.


Tubing Stretch - 1.660" O.D. API Tubing
Pulling on Tubing LBS
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
180
5
10
15
20
25
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
Depth (FT)


Tubing Stretch - 1.900" O.D. API Tubing
Pull on Tubing LBS
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
180
5
10
15
20
25
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
Depth (FT)


Tubing Stretch - 2 1/16" O.D. API Tubing
30
40
50
60
70
80
90
65,000
60,000
55,000
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Pull on Tubing LBS
25
20
15
10
5
180
170
160
150
140
130
120
110
100
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
Depth (FT)

Stretch Chart Examples:

Example #1:

Application of 15,000 # tension on a string of 2 3/8" tubing 8000 feet long would result in a length change, or stretch, of approximately 37 inches.

Locate the 15,000 # value on the Y axis. Follow this value across horizontally until you intersect a vertical line from the 8000 foot value on the X axis. The corresponding stretch value is approximated at 37 inches.

Example #2:

If you have a known length of 8000 feet of 2 3/8" tubing and you stretched the string 37 inches measured at surface, you would have applied a tension force of 15,000#.

Follow a vertical line upward from the 8000 foot value on the X axis until you intersect with a stretch value line (or estimate) of 37 inches. Follow a horizontal line from this point to the Y axis to read 15,000 #.

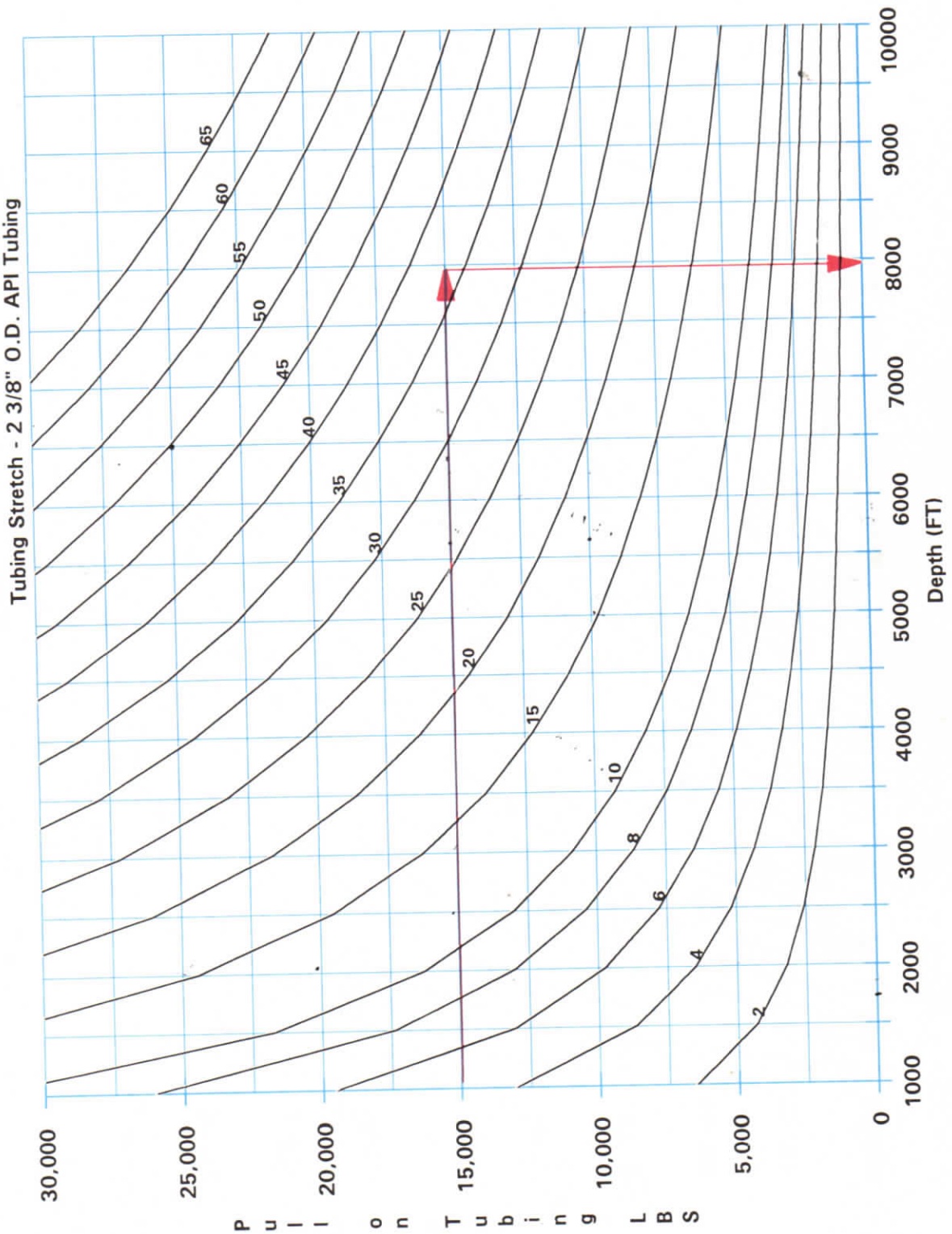
Example #3:

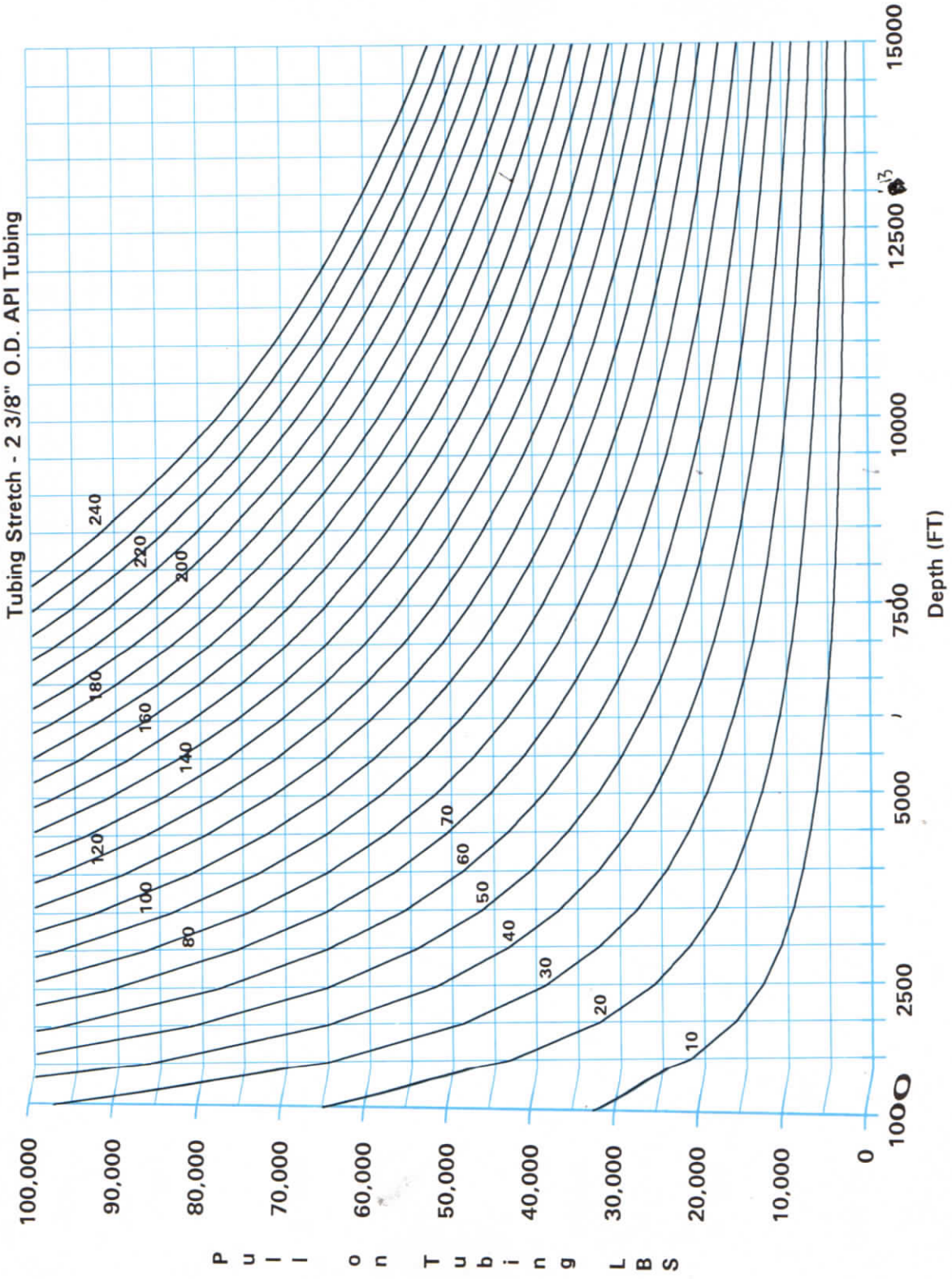
If you have applied a tension force of 15,000# to a string of 2 3/8" tubing and have measured a 37" stretch at surface, your string is 8000 feet long.

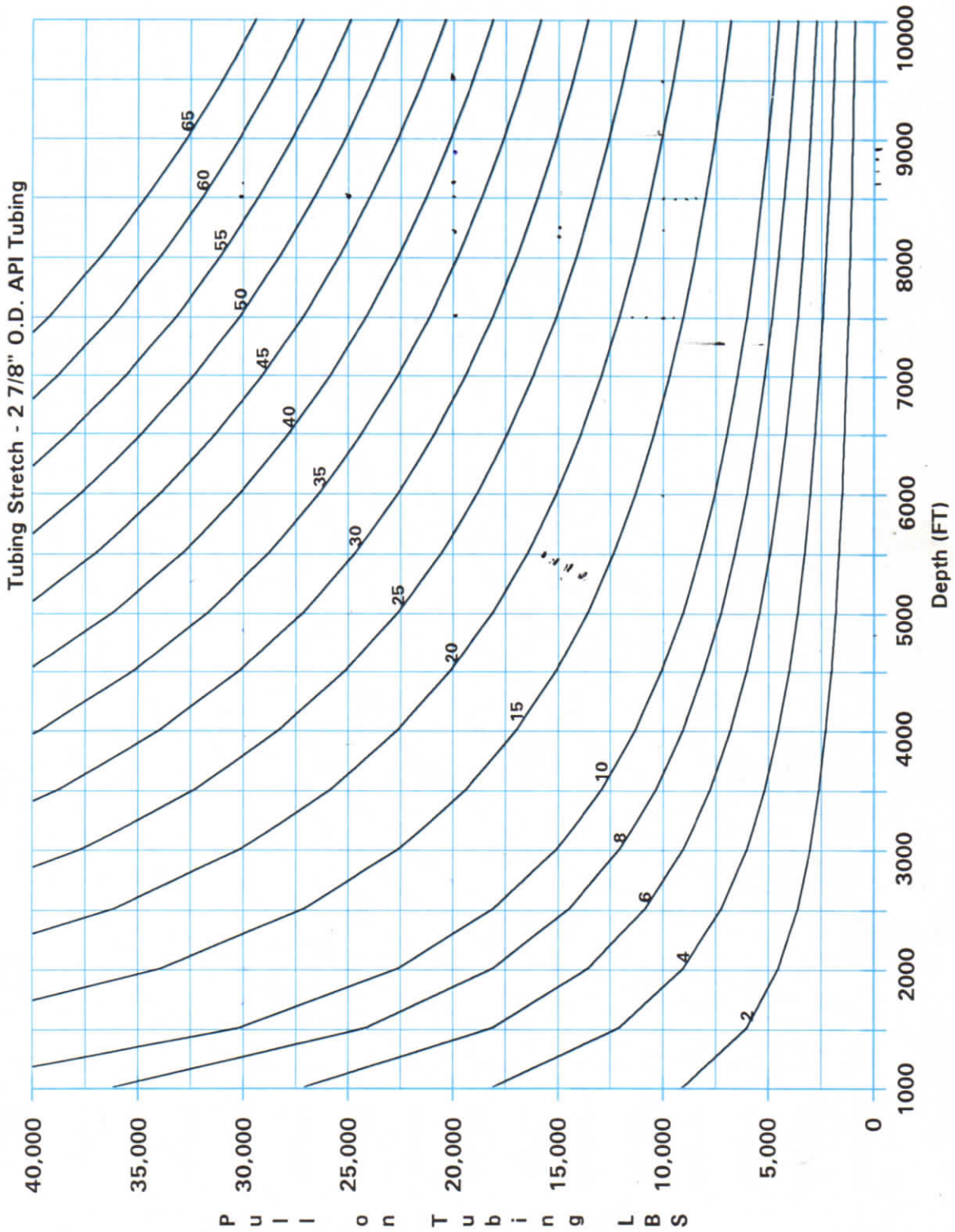
Follow a horizontal line from the 15,000# value on the Y axis until you intersect with a stretch value (or estimate) of 37 inches. Follow a vertical line from this point to the X axis to read 8000 feet.

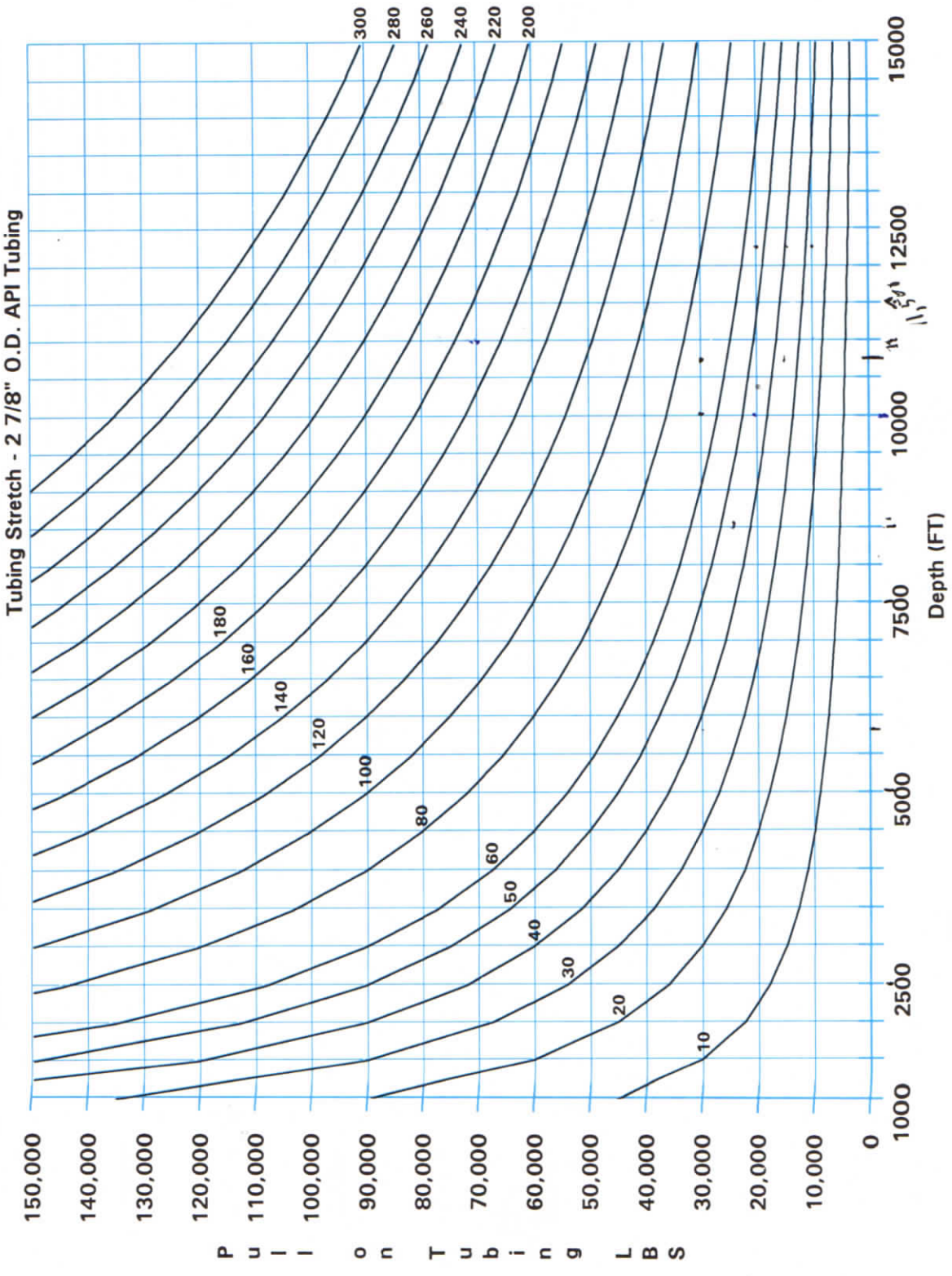
This example illustrates not only use of the stretch chart, but the principle behind determination of *free point.*

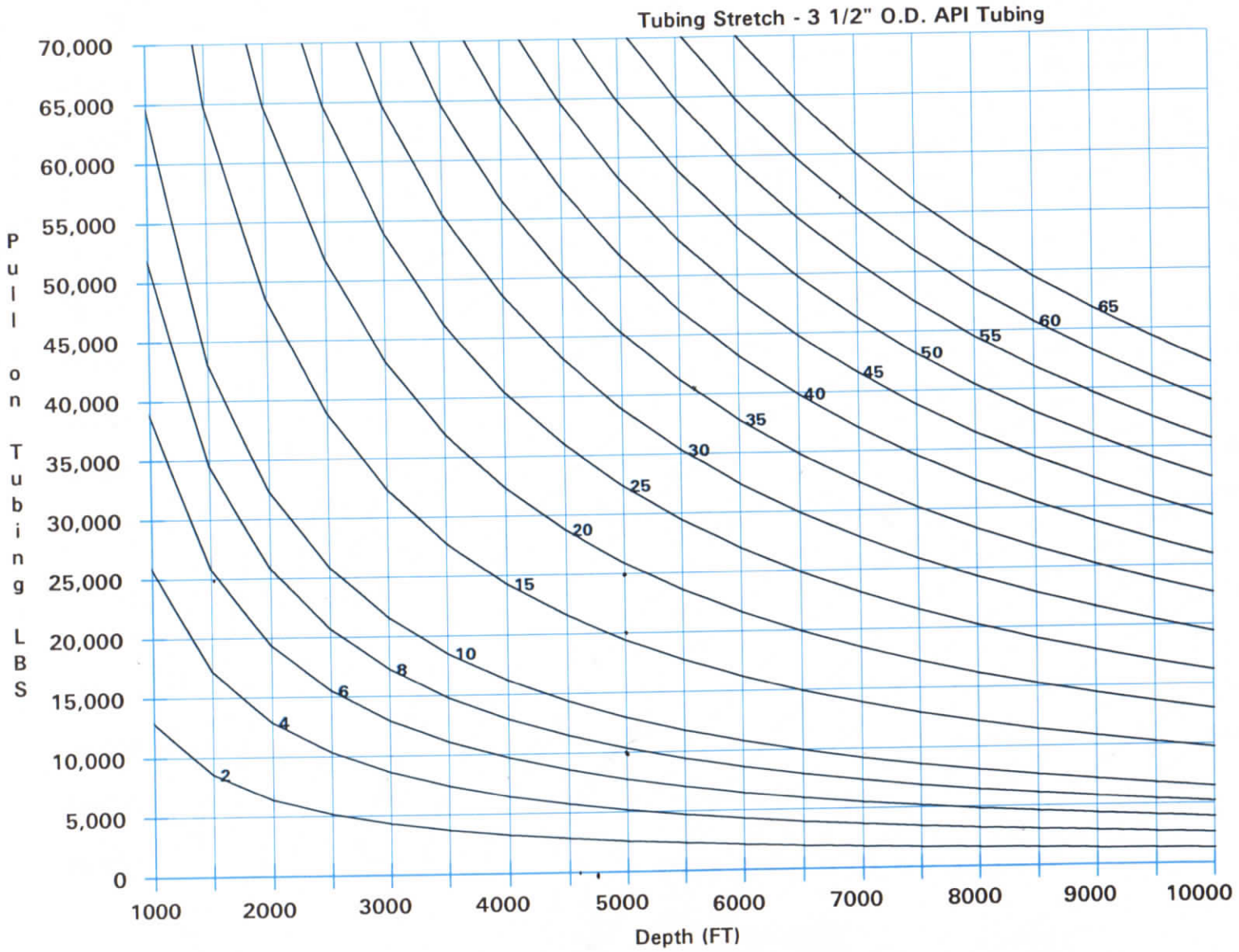
As you can see, there are many uses for the tubing stretch charts. Note that they were constructed for a particular (most common) weight tubing and constitute an approximation for other weights. As the weights differ from the most common, accuracy decreases.

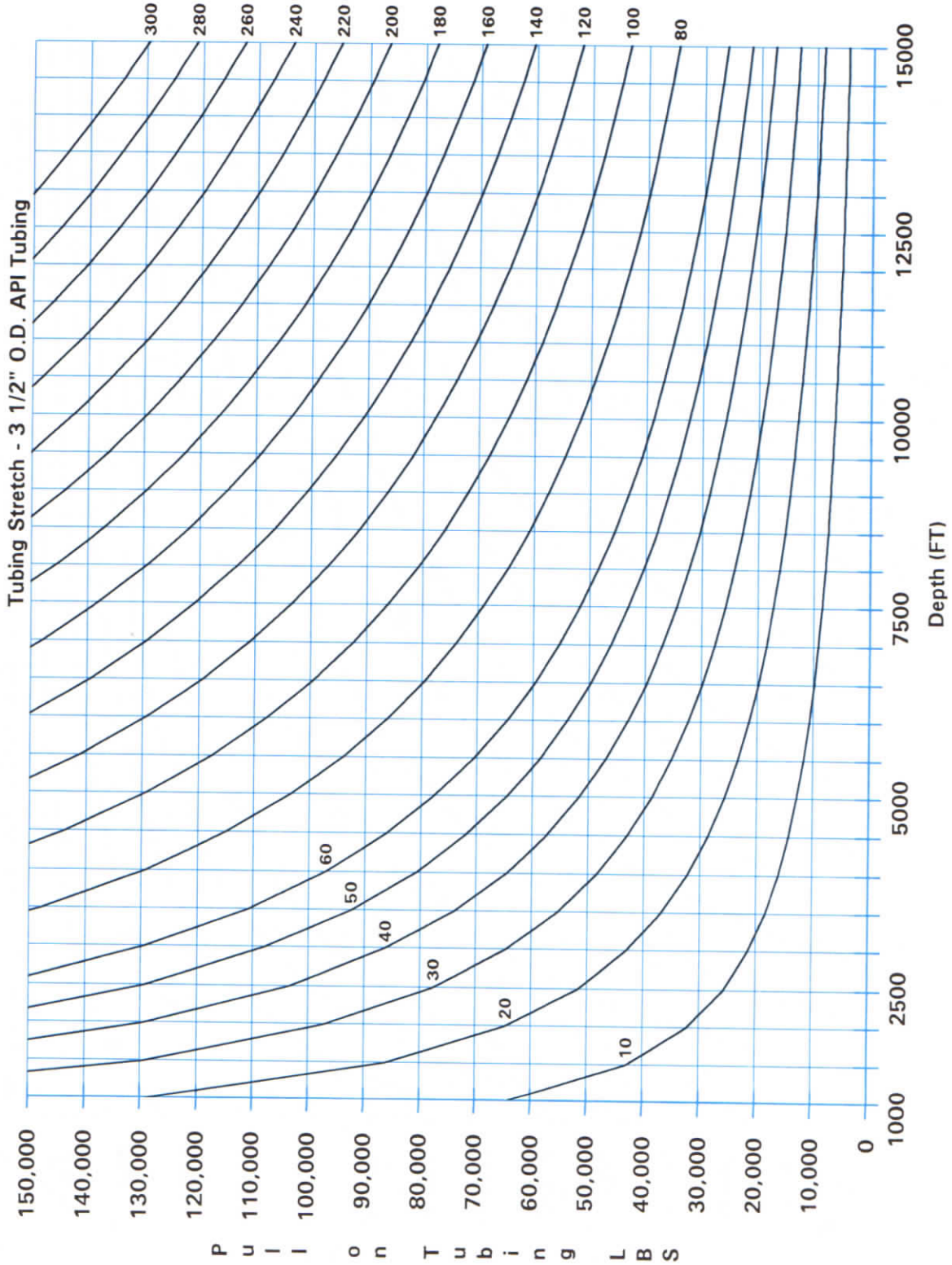

Tubing Stretch - 2 3/8" O.D. API Tubing
Pull on Tubing LBS
30,000
25,000
20,000
15,000
10,000
5,000
0
Depth (FT)
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
65
60
55
50
45
40
35
30
25
20
15
10
8
6
4
2


Tubing Stretch - 2 3/8" O.D. API Tubing
Pull on Tubing LBS
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
1000
2500
5000
7500
10000
12500
15000
Depth (FT)
240
220
200
180
160
140
120
100
80
70
60
50
40
30
20
10


Tubing Stretch - 2 7/8" O.D. API Tubing
Pull on Tubing LBS
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
Depth (FT)
65
60
55
50
45
40
35
30
25
20
15
10
8
6
4
2


Tubing Stretch - 2 7/8" O.D. API Tubing
Pull on Tubing LBS
150,000
140,000
130,000
120,000
110,000
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
1000
2500
5000
7500
10000
12500
15000
Depth (FT)
300
280
260
240
220
200
180
160
140
120
100
80
60
50
40
30
20
10


Tubing Stretch - 3 1/2" O.D. API Tubing
Pull on Tubing LBS
70,000
65,000
60,000
55,000
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
Depth (FT)
2
4
6
8
10
15
20
25
30
35
40
45
50
55
60
65


Tubing Stretch - 3 1/2" O.D. API Tubing
Pull on Tubing LBS
150,000
140,000
130,000
120,000
110,000
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
1000
2500
5000
7500
10000
12500
15000
Depth (FT)
300
280
260
240
220
200
180
160
140
120
100
80
60
50
40
30
20
10

Slack Off Charts

There may be times when you are required to operate a tool without the benefit of a weight indicator, or the indicator available is not functioning properly. Slack off charts give the amount of tubing to slack off to get a pre-determined weight set down on the tool or seal assembly.

Slacking tubing into a well has three resultant effects on the string:

1. Steel compression
2. Buckling inside casing
3. Friction between tubing & casing

Steel Compression

Steel compresses at the same rate as it stretches. Assuming that steel is perfectly elastic throughout the range of compression or stretch, if 20,000# stretches a sample six inches, 20,000# down will also compress the same sample six inches. While this simple principle is involved in the slack off charts, it does not completely describe the mechanics of slack off.

Buckling

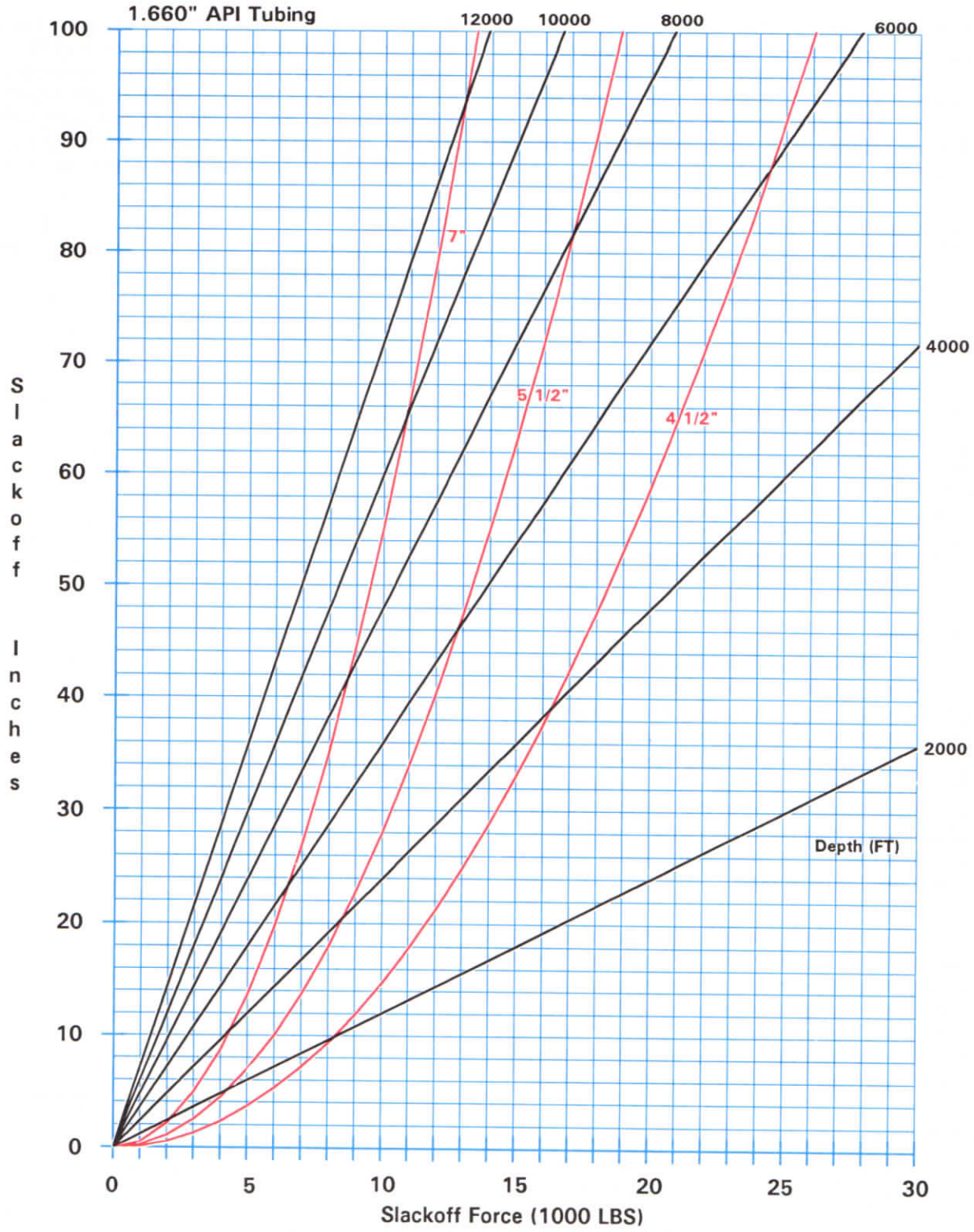
Slacking off weight on drill pipe or tubing has a tendency to buckle the string. If there is space between the tubing and casing, the tubing will buckle outward until it contacts the wall of the casing. While slacking off, you lose inches due to steel compression, and you also lose inches due to the sideways movement of the tubing buckling. When tubing buckles inside casing, its buckled shape follows the contour of the casing forming a corkscrew shape or helix.

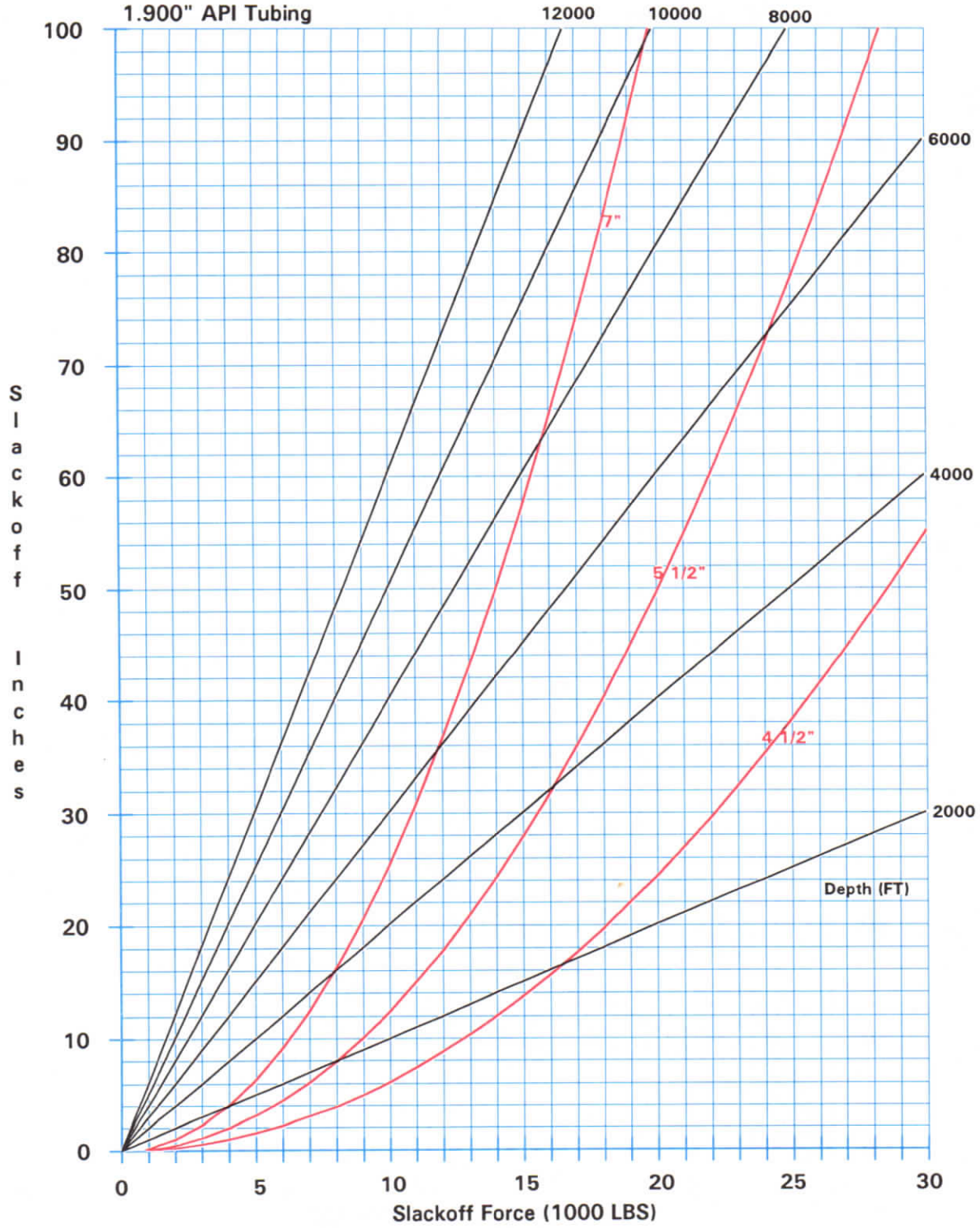
As you can see, the number of inches to slack off to account for buckling will be dependent on the tubing OD and the casing ID, the annular space available to accommodate buckling. From the charts, you can see that 3 1/2" tubing in 7 casing accommodates little buckling, while 2 3/8" tubing in 9 5/8" casing allows for considerable buckling.

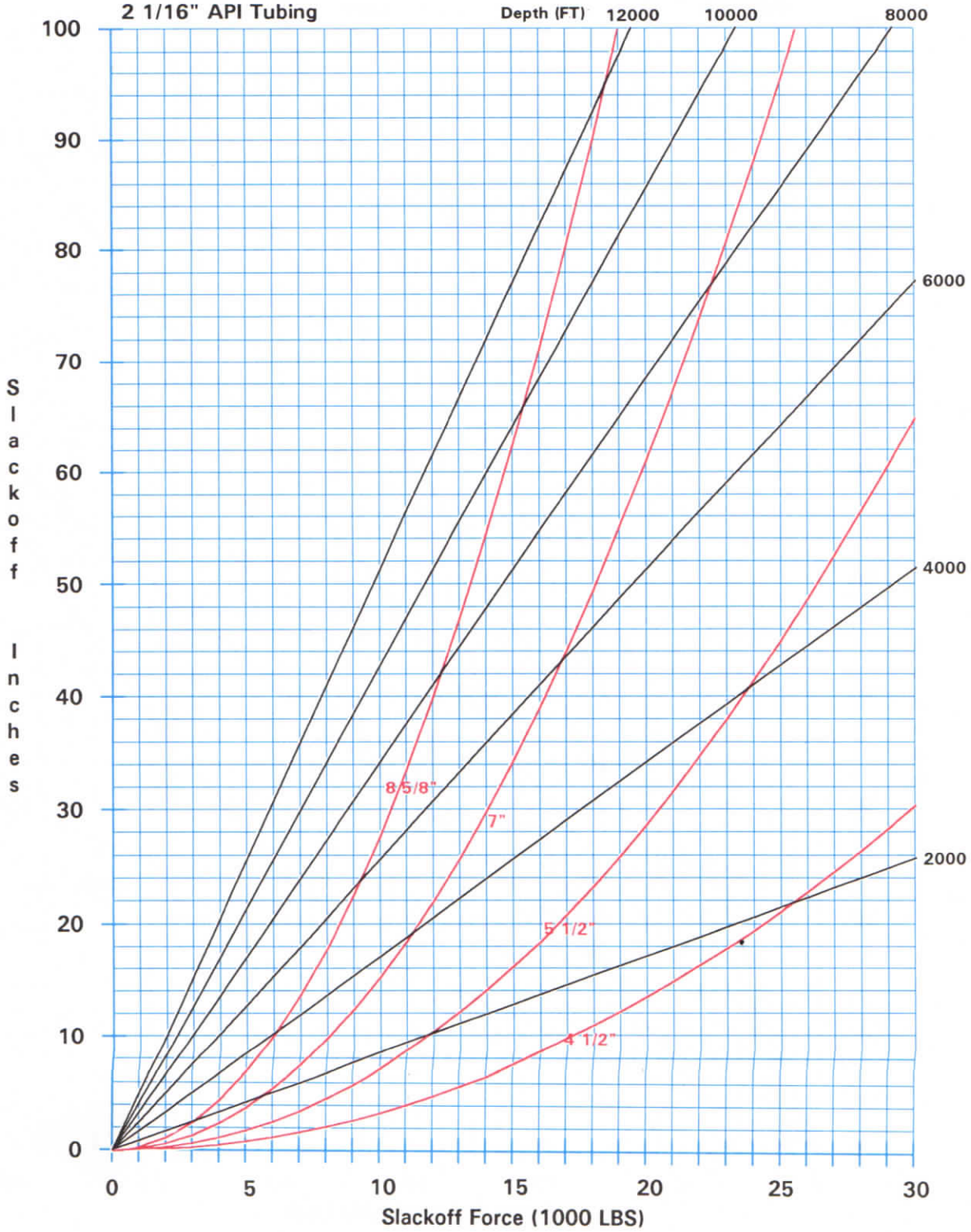
The following six charts show the number of inches to slack off to account for steel compression and buckling; friction is not taken into account.

When you have calculated how many inches to slack off, you still don't know how much of this weight will be transferred to bottom. The number of inches to slack off tells how much weight has been transferred from the elevators to some point within the well, it will not tell you how much of this weight went into friction and how much went to bottom.

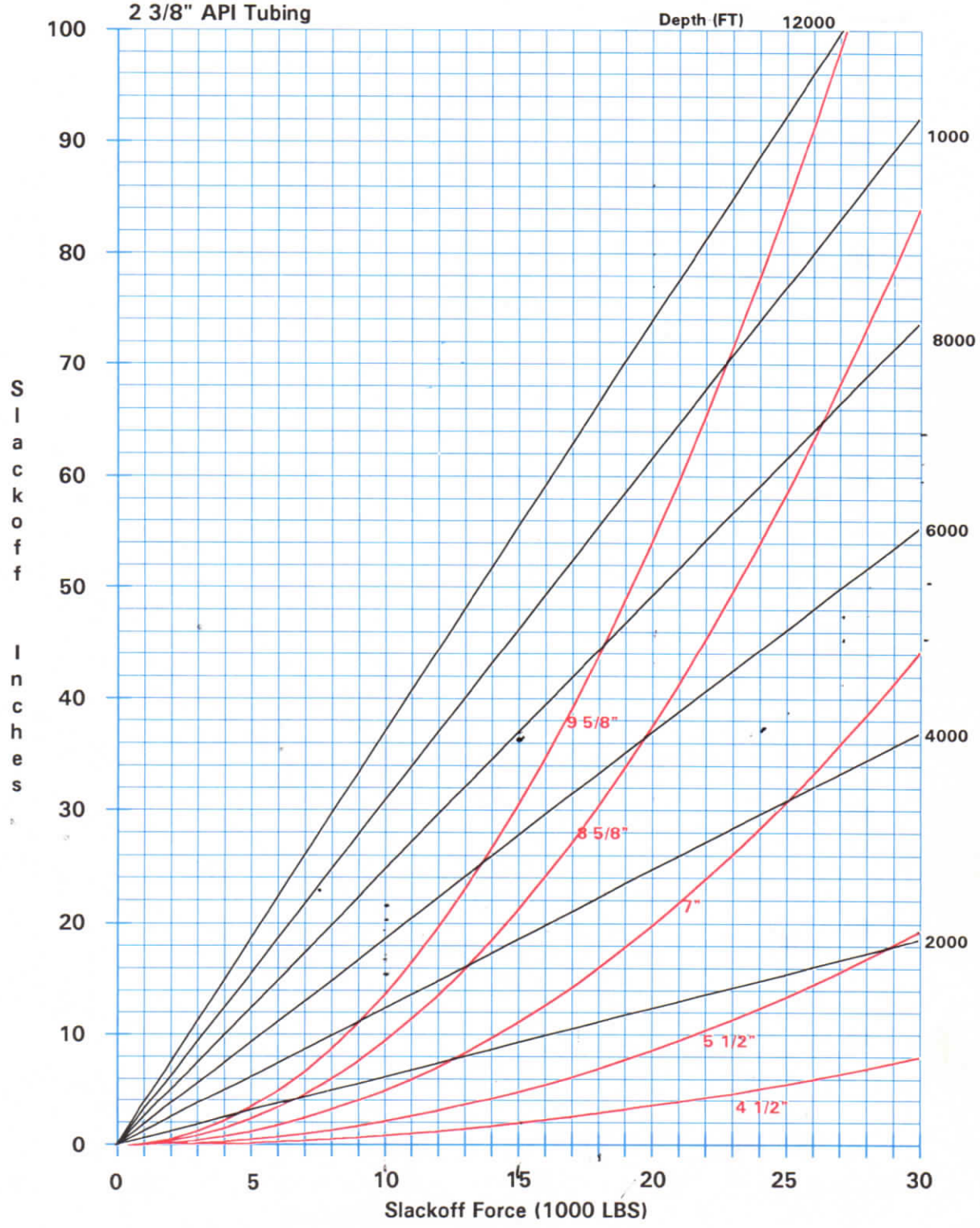
Example:
Refer to the 2-7/8" Slack-off chart for an example of these calculations.


1.660" API Tubing
12000
10000
8000
6000
4000
2000
Depth (FT)
7"
5 1/2"
4 1/2"
Slackoff Inches
100
90
80
70
60
50
40
30
20
10
0
0
5
10
15
20
25
30
Slackoff Force (1000 LBS)

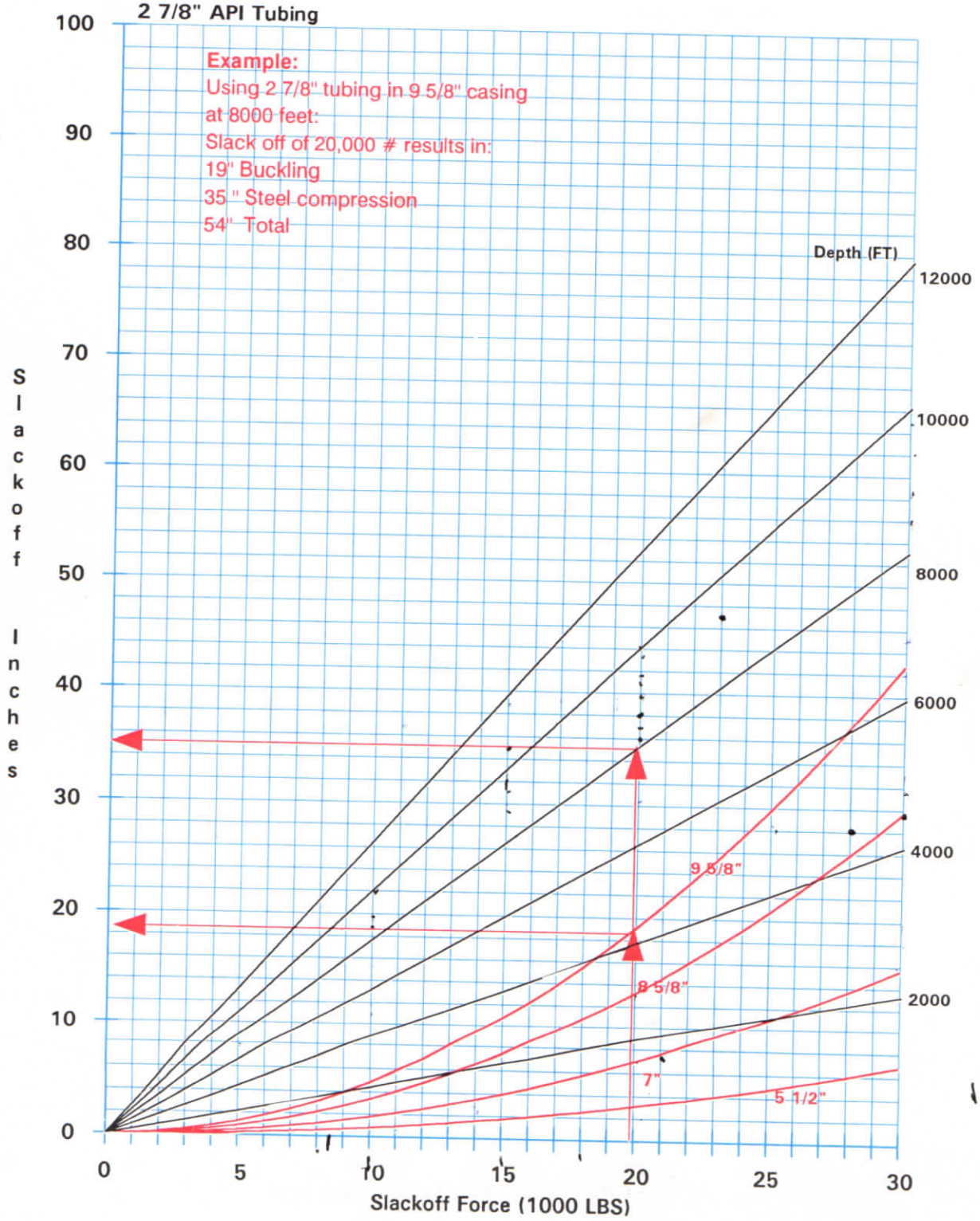

1.900" API Tubing
12000
10000
8000
6000
4000
2000
Depth (FT)
7"
5 1/2"
4 1/2"
Slackoff Inches
Slackoff Force (1000 LBS)
0
10
20
30
40
50
60
70
80
90
100
0
5
10
15
20
25
30

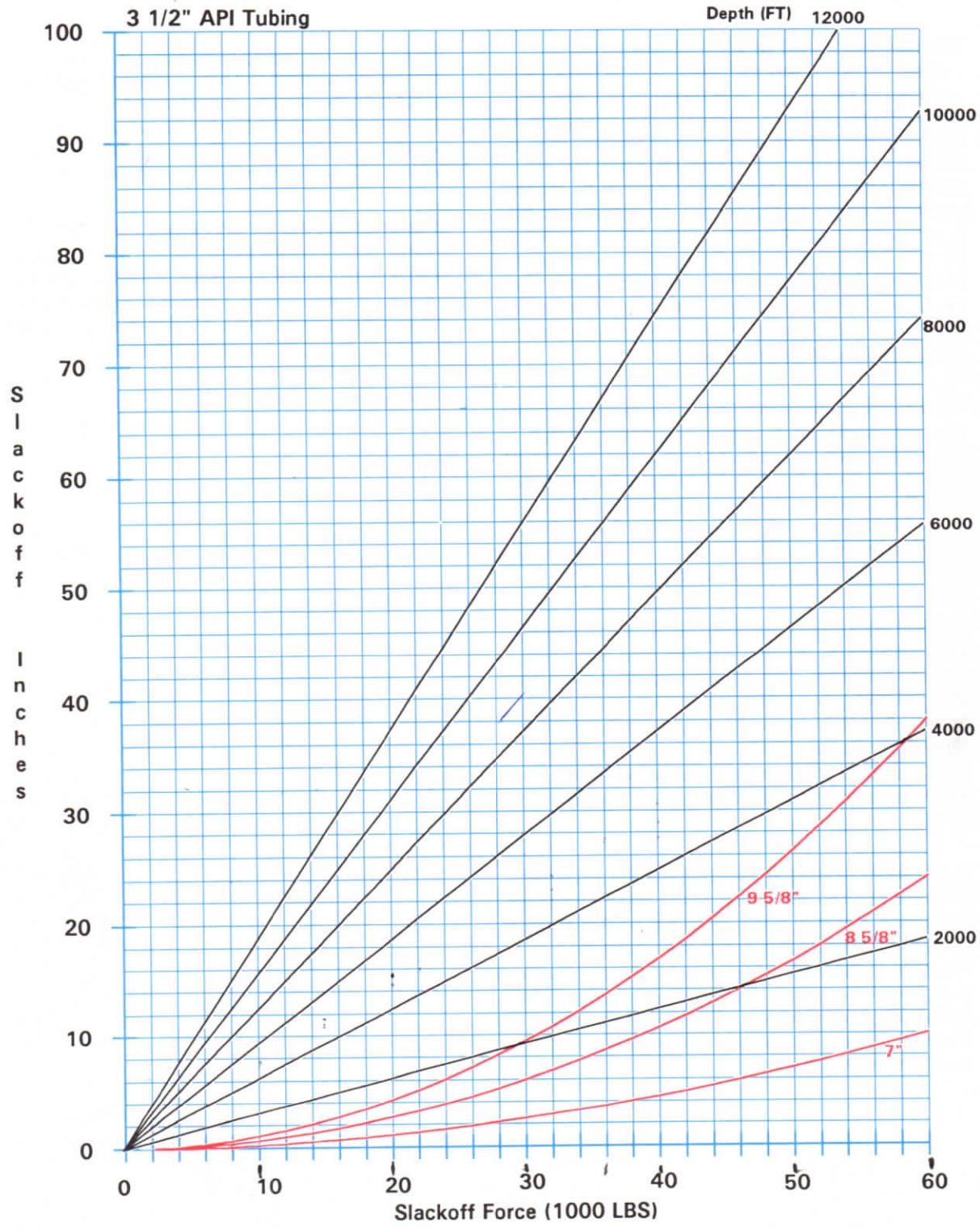

2 1/16" API Tubing
Depth (FT)
12000
10000
8000
6000
4000
2000
8 5/8"
7"
5 1/2"
4 1/2"
Slackoff Inches
Slackoff Force (1000 LBS)
0
10
20
30
40
50
60
70
80
90
100
0
5
10
15
20
25
30

39 48


2 3/8" API Tubing
Depth (FT)
12000
1000
8000
6000
4000
2000
9 5/8"
8 5/8"
7"
5 1/2"
4 1/2"
Slackoff Inches
Slackoff Force (1000 LBS)
0
10
20
30
40
50
60
70
80
90
100
0
5
10
15
20
25
30

11
37


2 7/8" API Tubing
Example:
Using 2 7/8" tubing in 9 5/8" casing
at 8000 feet:
Slack off of 20,000 # results in:
19" Buckling
35 " Steel compression
54" Total
Depth (FT)
12000
10000
8000
6000
4000
2000
9 5/8"
8 5/8"
7"
5 1/2"
Slackoff Inches
100
90
80
70
60
50
40
30
20
10
0
0
5
10
15
20
25
30
Slackoff Force (1000 LBS)


3 1/2" API Tubing
Depth (FT)
12000
10000
8000
6000
4000
2000
9 5/8"
8 5/8"
7"
Slackoff Inches
Slackoff Force (1000 LBS)
0
10
20
30
40
50
60
70
80
90
100

Slack Off Weight Actually Reaching Bottom

Whether you intend to slack off weight using inches, or by the weight indicator, you have the problem of estimating how much of this weight actually gets down to the tool. Once the tubing has been buckled into contact with the casing wall, a portion of the additional slack off is lost due to friction between the tubing and casing. As more and more of the tubing comes in contact with the casing wall, you will reach a point where the friction force is enough to support the weight of the rest of the string. At this point, you will not be able to get any more weight to bottom. The larger the casing, for a given tubing size, the more it can buckle and the greater the friction force.

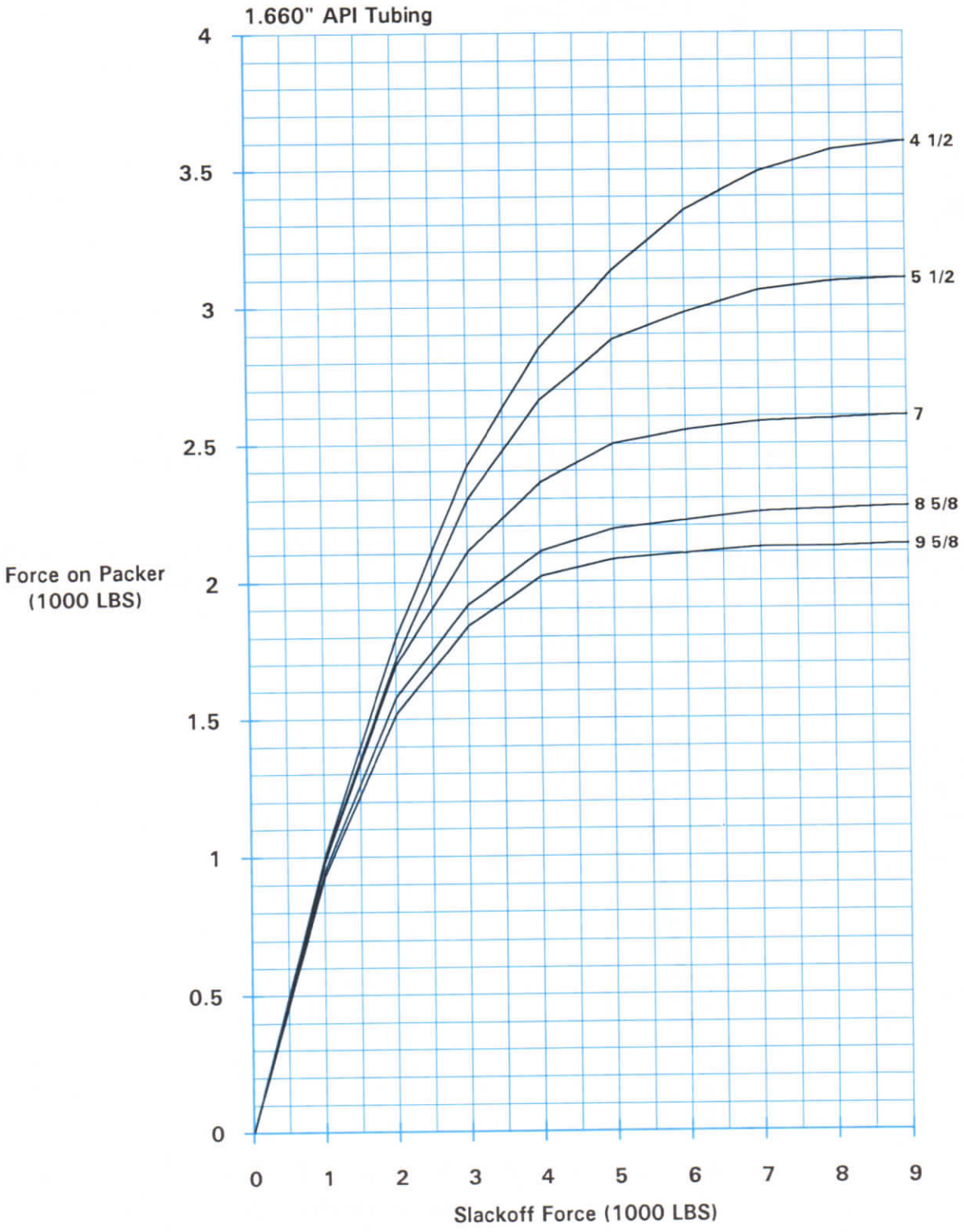
The following charts estimate how much force will get to bottom for a tubing/casing configuration. It should be understood that to calculate how much weight will get to bottom, a coefficient of friction must be assumed. Values obtained should be considered estimated, however they have been found to be reasonably accurate. All charts assume that the weight is available for slack off.

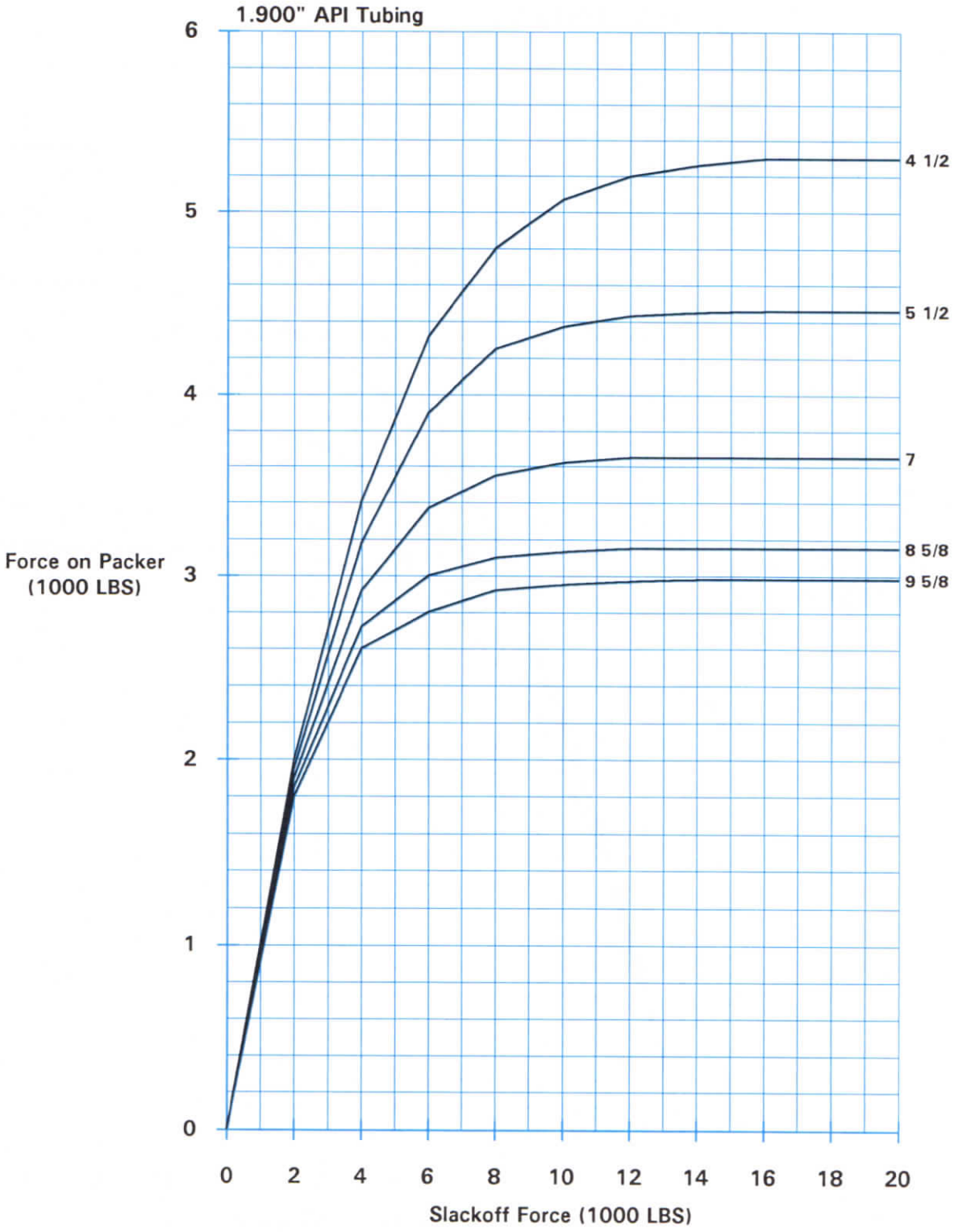
You will notice after slacking off so much weight, additional slack off transfers very little additional weight to bottom. This implies that the tubing has buckled into a helix. The friction has become so great between the tubing and casing that it will not allow any more weight to pass to bottom. This frictional force will eventually be capable of supporting more weight than can be applied by the string.

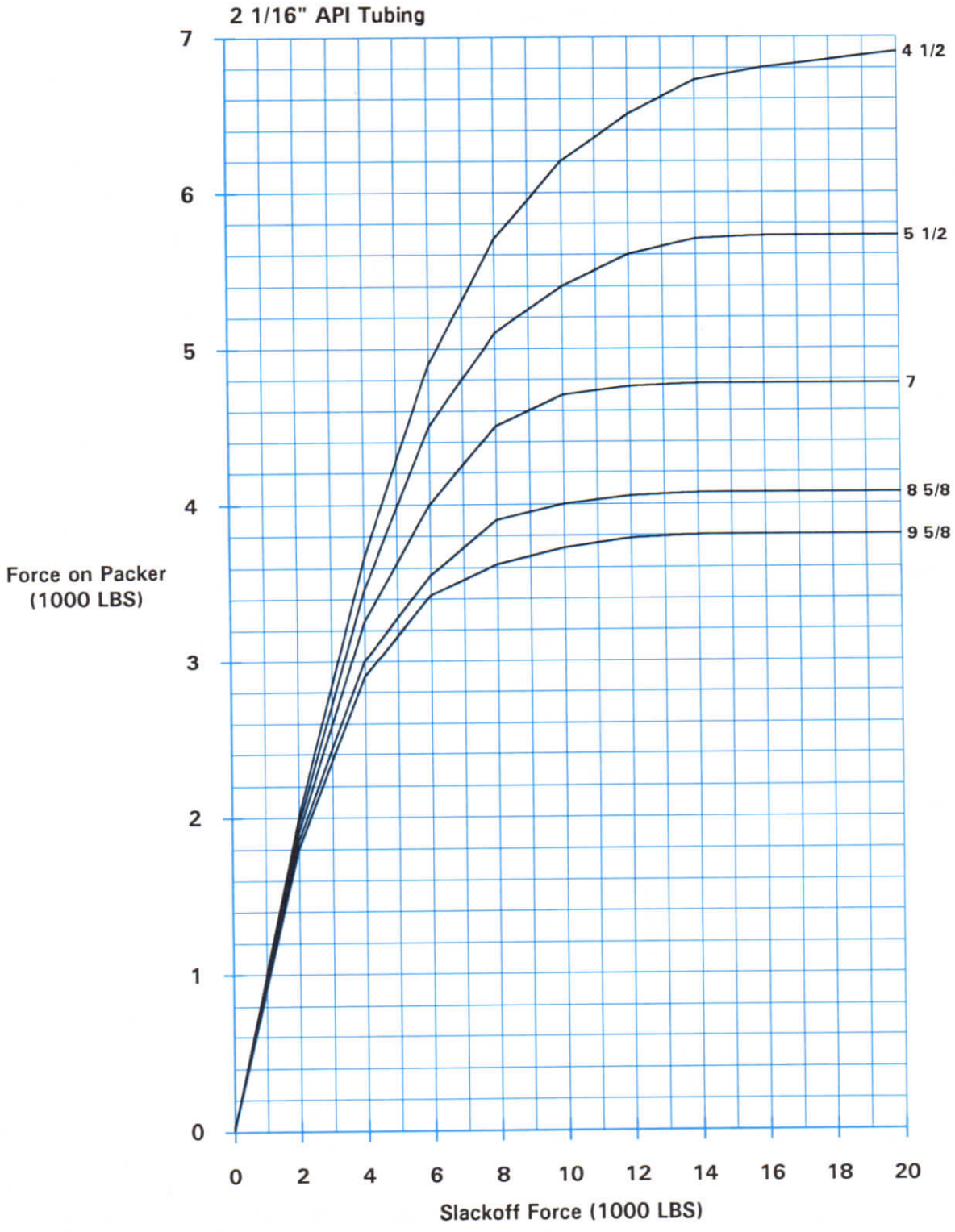
The amount of weight necessary to set a packer, published in the tech insert, is the weight required at the tool, not at surface. Slacking off this amount of weight does not mean that the weight is available at the tool. There are a number of options available at this point, depending on the type and operating characteristics of the particular tool involved. Please consult the Arrow Packer tech insert for your options.

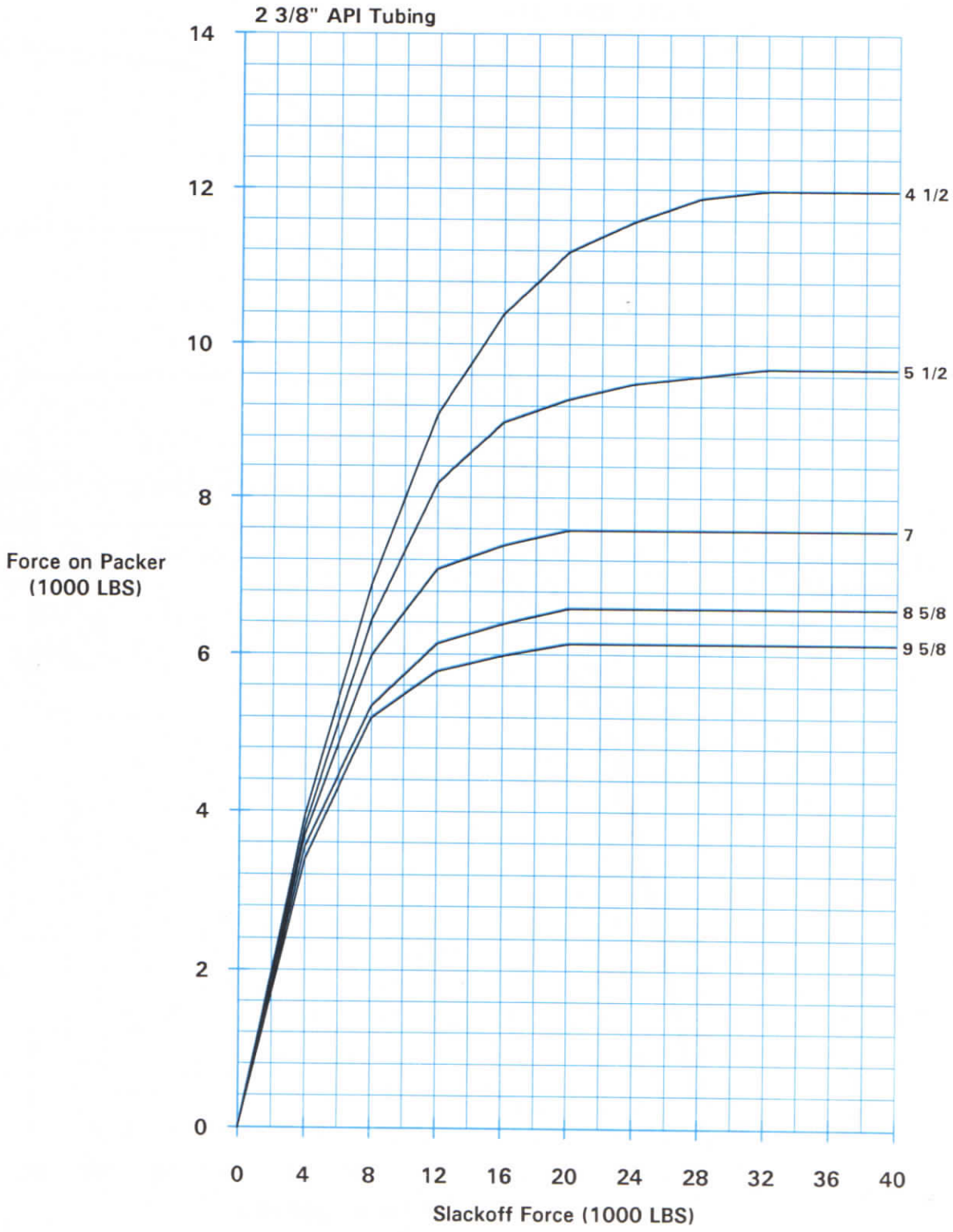
These slack off charts were not put in this calculation handbook to be used as absolute numbers. The effects of friction are highly dependent upon the fluid in the casing, the condition of the casing ID, the condition of the tubing OD, and a number of other variables.

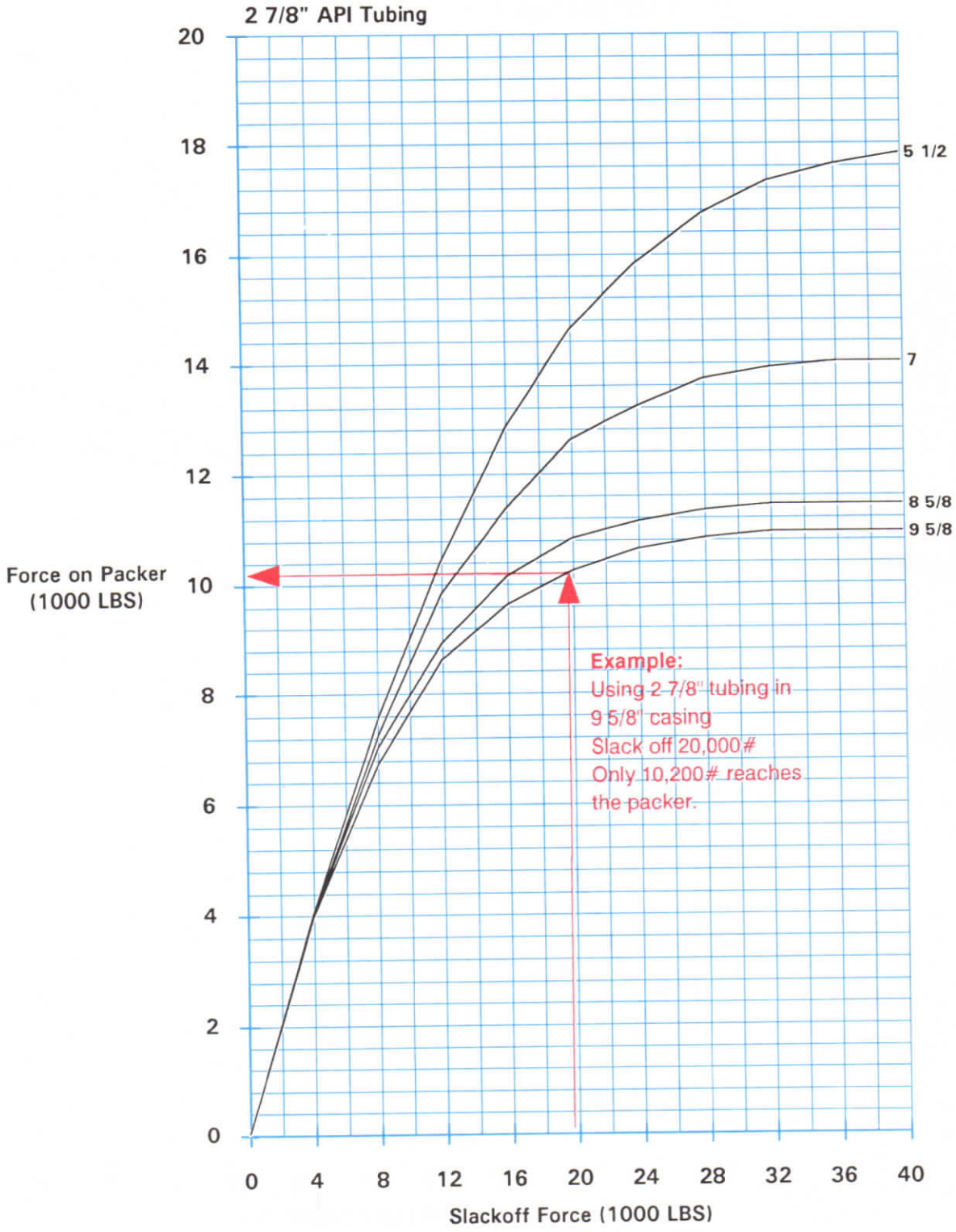
When running the second string of a dual string of tubing, treat it as if it were the first string. The logic is that even though you don't have the same radial clearance for buckling, there is the added friction of the primary string. This added friction offsets the benefit of reduced annular clearance.

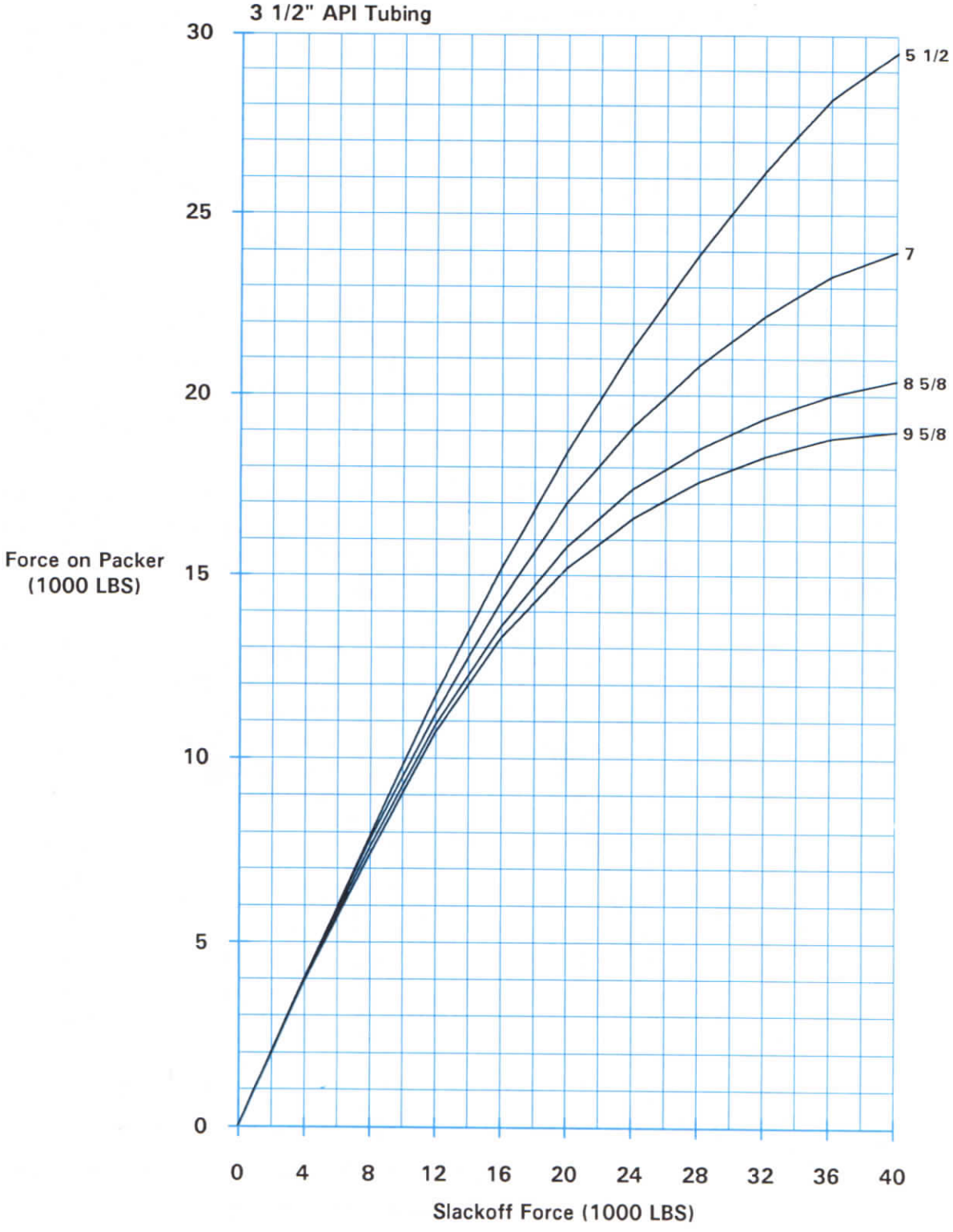

1.660" API Tubing
4
3.5
3
2.5
2
1.5
1
0.5
0
Force on Packer
(1000 LBS)
4 1/2
5 1/2
7
8 5/8
9 5/8
0
1
2
3
4
5
6
7
8
9
Slackoff Force (1000 LBS)


1.900" API Tubing
Force on Packer (1000 LBS)
Slackoff Force (1000 LBS)
0
1
2
3
4
5
6
0
2
4
6
8
10
12
14
16
18
20
4 1/2
5 1/2
7
8 5/8
9 5/8


2 1/16" API Tubing
Force on Packer (1000 LBS)
0
1
2
3
4
5
6
7
0
2
4
6
8
10
12
14
16
18
20
Slackoff Force (1000 LBS)
4 1/2
5 1/2
7
8 5/8
9 5/8


2 3/8" API Tubing
14
12
10
8
6
4
2
0
Force on Packer
(1000 LBS)
4 1/2
5 1/2
7
8 5/8
9 5/8
0
4
8
12
16
20
24
28
32
36
40
Slackoff Force (1000 LBS)


2 7/8" API Tubing
Force on Packer (1000 LBS)
20
18
16
14
12
10
8
6
4
2
0
0
4
8
12
16
20
24
28
32
36
40
Slackoff Force (1000 LBS)
5 1/2
7
8 5/8
9 5/8
Example:
Using 2 7/8" tubing in
9 5/8" casing
Slack off 20,000#
Only 10,200# reaches
the packer.


3 1/2" API Tubing
30
25
20
15
10
5
0
Force on Packer
(1000 LBS)
5 1/2
7
8 5/8
9 5/8
0
4
8
12
16
20
24
28
32
36
40
Slackoff Force (1000 LBS)

Dynamics of Tubular Goods

Force - Pressure - Area

Completion of oil and gas wells generally involves a string of tubing and a packer either located, anchored, or free. Changes in temperature, pressure, and applied force will cause that tubing string to move. If the string is free to move within the packer, its length will increase or decrease. If the string is latched into the packer, or permitted only limited movement, the string will apply or release the force initially applied to the packer.

There are three basic methods of affecting the string subsequent to completion; change in applied force, pressure, or temperature.

Changing the initial force with applied tension requires the application of Hooke's Law and the stretch charts. The assumption here is that the tubing is not buckled when installed.

Changing the initial force with applied compression requires the application of slack-off charts. This length or force change calculation is inherently less accurate due to its estimation of the effect of friction where the tubing comes in contact with the casing wall.

Changing pressure and/or temperature affects string length according to four generally accepted formulae set forth in an SPE (Society of Petroleum Engineers) technical paper " *Helical Buckling of Tubing Sealed in Packers*" by Lubinski, et.al.; Journal of Petroleum Technology; June, 1962. The four effects are piston, buckling, ballooning, and temperature. They are additive and in most cases are assumed to be applied simultaneously.

When setting tools, or performing service operations, in critical wells, you should be aware of the movement of the tubing string. Weight slacked-off and temperature increase may not occur simultaneously. There may be bouyant forces acting on tubing strings when a gas well is first brought in.

All must be accounted for when calculating the amount of force reaching or remaining on a tool during subsequent well operations.

When performing an analysis of tubing movement, there are only five tubing installation variables that need to be considered:

Surface Condition:

Fixed

Movable

Downhole Condition:

Free motion

Limited motion

Fixed

You will become familiar with these notations as you work with the Arrow Tubing Movement computer analysis.

Any calculation that is done on the tubing string results in either a force (if the tubing is *not* free to move) or length (if the tubing *is* free to move) change. This will be reflected in the following equations resulting in a ΔL or ΔF.

Force - Pressure - Area Relationships

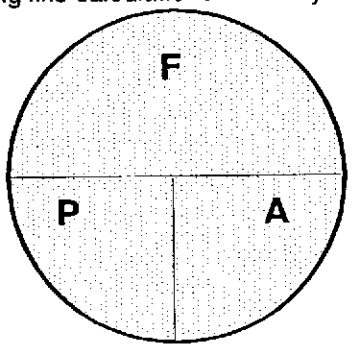
There is one very basic, and very important relationship governing tubing movement calculations. That realtionship is:

Force = Pressure X Area

or

$$F = P \times A$$

Complete understanding of this relationship and its application are imperative to accurate results when using the following tubing movement calculations or interpreting like calculations made by others.



Ballooning and Reverse Ballooning

Pressure changes in the tubing tend to swell, or balloon it. When tubing increases its size radially, the steel to accommodate this increase results in a shortening of the string. By the same theory, pressure changes in the casing cause the diameter to contract resulting in reverse ballooning and an elongation of the string. As treating pressures increase and depths become greater, the resulting changes in length can be considerable.

The following charts result in a force change, as this value is independent of length. To obtain length changes, refer to the stretch charts.

Two charts are presented; one considering ballooning and one reverse ballooning. The charts differ in that ballooning acts on the ID of the tubing and reverse ballooning on the OD of the string.

In considering the results of ballooning and reverse ballooning, two points to consider are:

1. The pressure that is responsible for ballooning or reverse ballooning is the pressure change in the tubing and/or annulus. The fact that a differential pressure exists between tubing and casing *does not* imply ballooning exists.

2. Pressure calculations are based on changes in the surface tubing or casing pressure (applied) and changes in fluid density (hydrostatic).

With the understanding of the two points on the preceding page, calculations should be fairly straightforward. Remember that all you are interested in is change in pressure either in tubing or annulus, not differential pressure.

Look at an example well as follows:
Depth = 10,000 ft
2 7/8" tubing
11.36 #/gal Mud with 5900 PSI hydrostatic
Displace nitrogen into tubing with 4600 PSI pump pressure equal to 5900 PSI BHP
Set the tool and bleed the tubing.

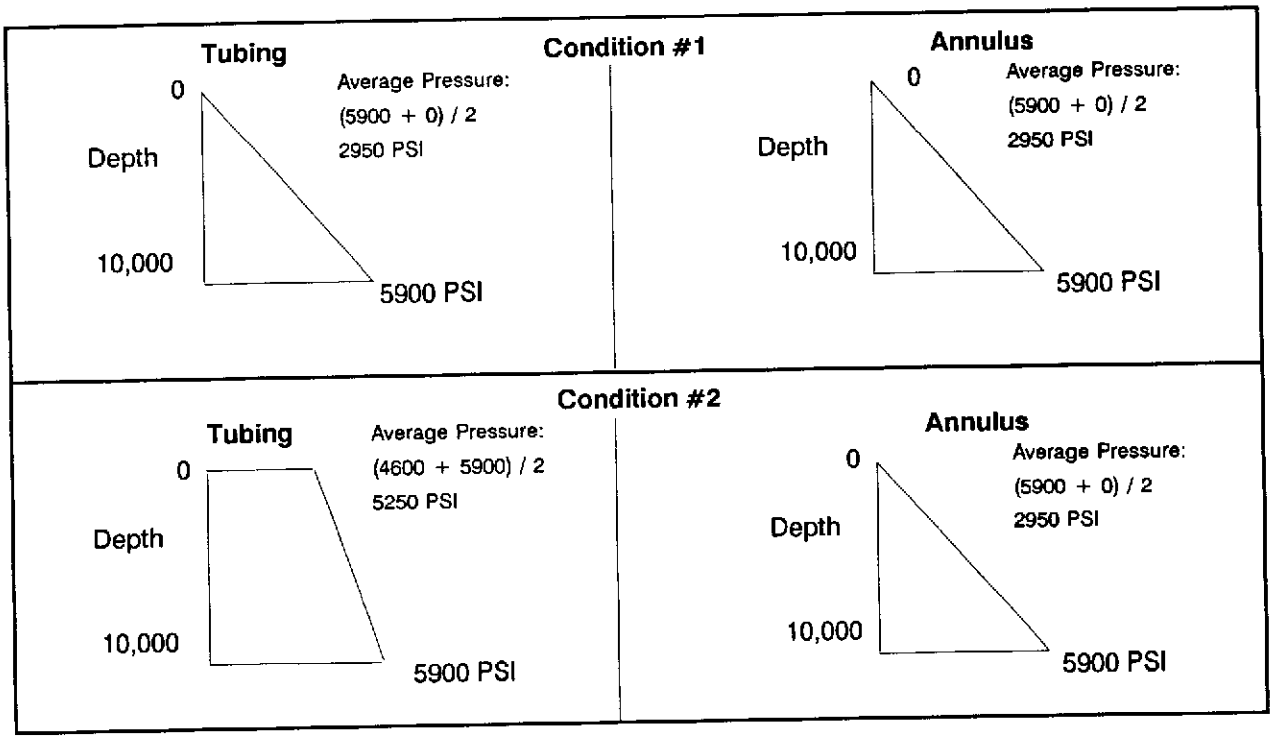
The simplified illustrations below plot depth vs. pressure in both tubing and annulus. Condition #1 illustrates the hole balanced with mud on both the tubing and annulus. The average pressure is 2950 PSI on both sides. Using data for displacing nitrogen, calculations indicate that 4600 PSI must be held on the tubing to balance the column of mud.

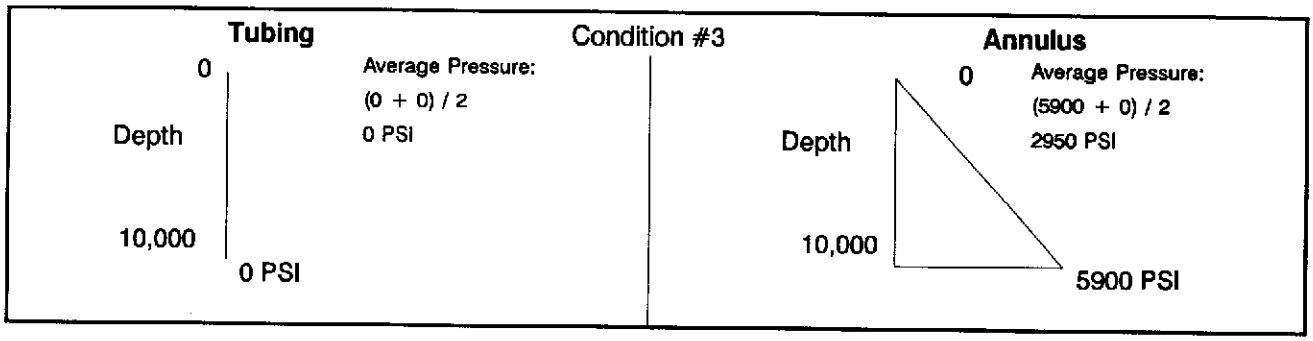
Condition #2 illustrates the well following displacment with nitrogen. Average pressure change in the tubing shows a 2300 PSI increase.This increase results in a 6500 # upward force or about 14 inches of tubing movement.

Consider some of the effects of this action. If you had seated in an Arrowdrill permanent packer with mud in the hole, marked the tubing, picked up and spaced out, then put the flange and tree on, and circulated nitrogen to the packer, the tubing would be over a foot short of the packer.

If you had an Arrowset III set and circulated nitrogen through a sleeve, the tubing would shorten. This would take 6500# of set-down weight off the string, either from the extra weight that was buckled inside the casing or from the tool itself.

Remember, this change was not caused by any differential pressure; it was caused by an average pressure change within the tubing.





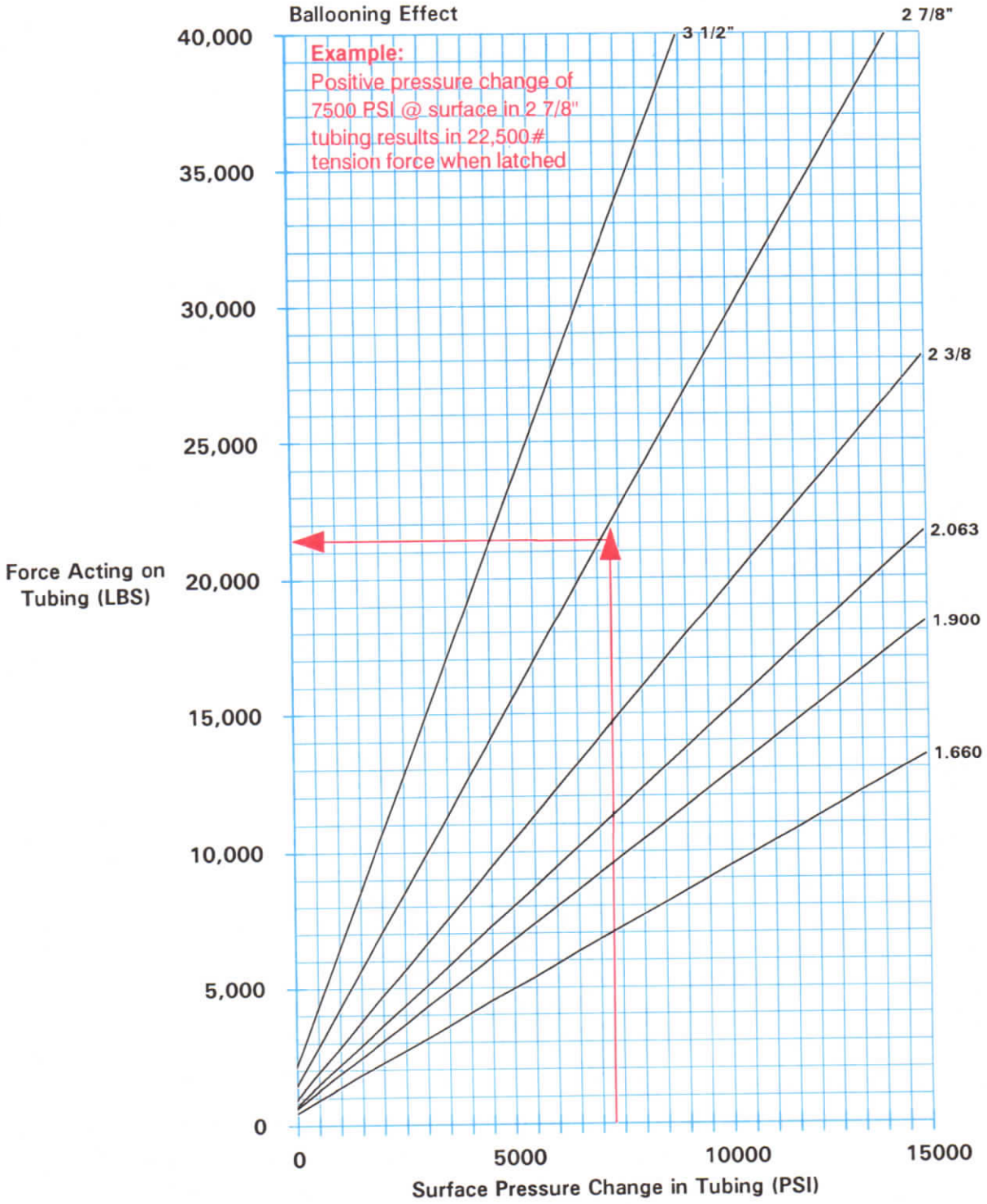
Now assume the tool is set and bleed the pressure off the tubing. Since nitrogen is a gas, when pump pressure is bled, hydrostatic pressure is essentially lost as well. Assuming that no fluid enters the tubing:

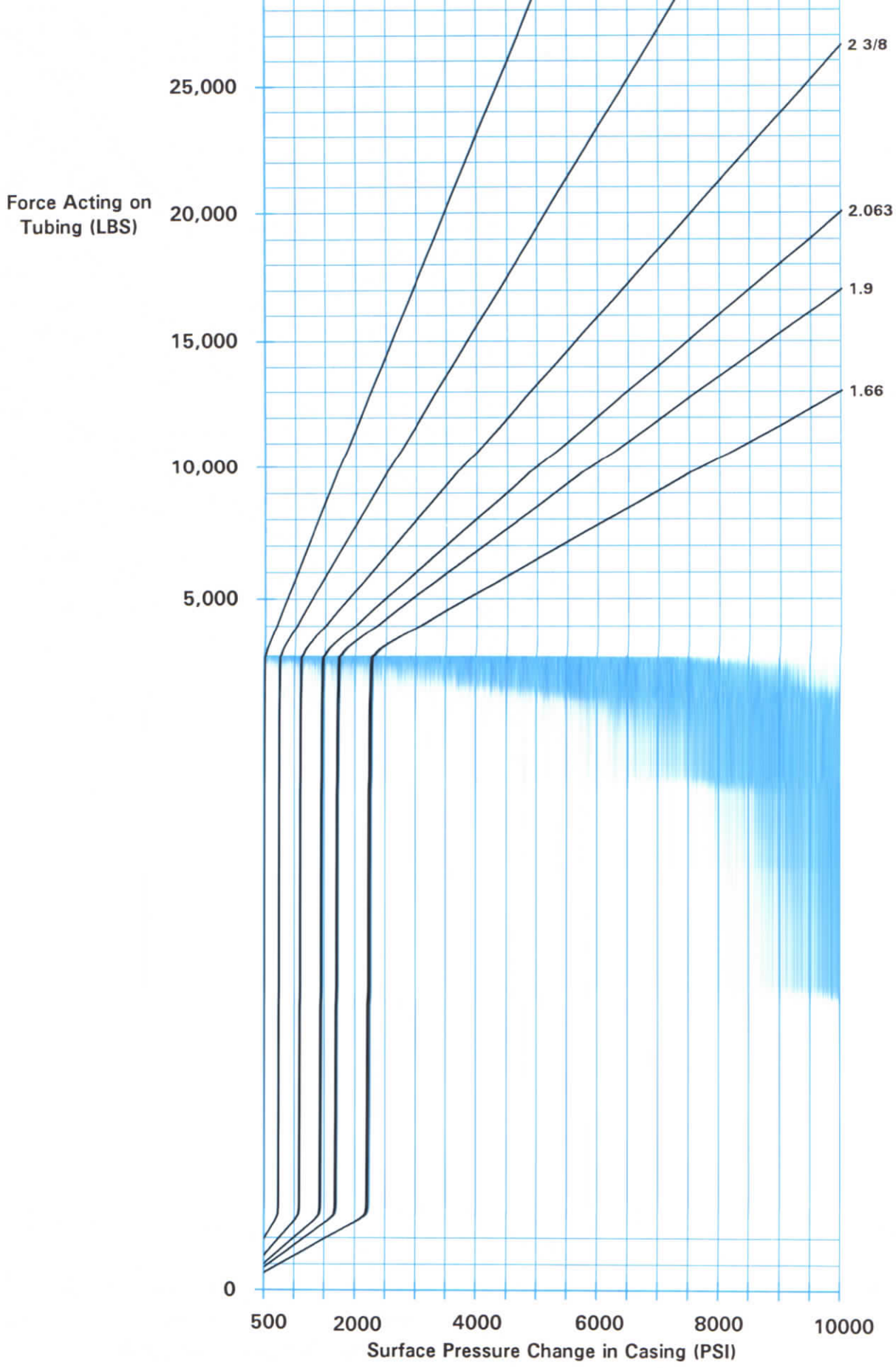
Change in average tubing pressure from #1
2950 - 0 = 2950 PSI *decrease*
Change in average tubing pressure from #2
5250 - 0 = 5250 PSI *decrease*
Change in average annulus pressure
None

Examining what has occurred since condition #1: When nitrogen displaced the mud in the tubing, the average tubing pressure increased 2300 PSI making the tubing 14" shorter. The tool was set and the nitrogen bled off. The average tubing pressure from condition #2 to condition #3 decreased 5250 PSI causing the tubing to become 32 inches longer. The net effect is that of the tubing having an average pressure decrease of 2950 PSI and being 18 inches longer. This would all be in addition of the fact that the piston effect of removing 5900 PSI from underneath the tool would result in considerable movement and/or force.

If fluids of different weights are used, remember to calculate average pressure for tubing and annulus for each condition. Also remember to add and subtract tubing from tubing, and annulus from annulus. The correct graph (Ballooning or Reverse Ballooning) must be used depending on pressure increase or decrease respectively.

If there is any question in your well analysis, please contact your Arrow technical representative.


Ballooning Effect
Example:
Positive pressure change of
7500 PSI @ surface in 2 7/8"
tubing results in 22,500#
tension force when latched
3 1/2"
2 7/8"
2 3/8
2.063
1.900
1.660
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Force Acting on
Tubing (LBS)
0
5000
10000
15000
Surface Pressure Change in Tubing (PSI)


Force Acting on Tubing (LBS)
25,000
20,000
15,000
10,000
5,000
0
2 3/8
2.063
1.9
1.66
500
2000
4000
6000
8000
10000
Surface Pressure Change in Casing (PSI)

Temperature Effects on Tubing Length Due to Injecting Cold Fluids

Heated metal expands and cooled metal contracts. In a long string of tubing with a temperature change over its entire length, this expansion or contraction can be considerable. Three main areas where temperature effects are prevalent are:

Producing

This subject has been the realm of the tubing anchor. Warmer fluids were brought to surface through tubing resulting in an elongation of the string. The calculation necessary for this can be found in the tubing anchor section of this handbook.

More recently, temperature effects have been considered when deep, hot gas wells are brought on production through TCP (Tubing Conveyed Perforating) guns are used. Tubing may be run in at ambient temperature, seated in a seal bore, TCP guns fired slightly underbalanced, and a gas well brought in at 400°F bottom hole temperature. This completion results in considerable movement over a period of days as the string heats and expands.

Steam

Elongation of tubulars due to the injection of steam can be extreme. This is due to the tremendous change in average temperature over a short period of time.

Injecting Fluids

The most common situation for the service tool hand is the injecting of cold fluids (as during water floods, acid treatments, sand control completions and hydraulic fracturing treatments) which are almost always colder than the well and tend to shorten the string. This shortening can pick up a locator seal assembly or rob set down weight from a compression set packer. With a tension set packer, additional upstrain may shear the safety release allowing the tool to come loose and leak. In the worst case, additional tension could exceed the limits of the work string causing the tubing to part.

Results of your calculations can again be inches or pounds, depending on your application of the formulae. Either way, the first step toward solution is determination of the average temperature change in the tubing string when it is cooled to its minimum temperature during the job and compared to the average temperature before the operation began.

To calculate the average temperature of a string of tubing, temperature at both ends of the string must be known. Average temperature is simply the average of the surface and bottom hole temperature. Convention is to take the temperature at the top of the string to be the mean yearly temperature 30 feet from surface (taken to be 70°F) and the bottom hole temperature.

To calculate the average temperature of the string during injection, the temperature at the top of the string is taken to be the same as the temperature of the fluid you are injecting. Temperature at the bottom of the string will be dependent on three things: fluid temperature, injection rate, and injection time period.

The figures on the amount to cool a string for a short duration or low rate job are not available, however, some empirical data is available and is presented as a guideline:

Example
7000 ft depth
210°F BHT
60°F Fluid
2 7/8" Tubing
Water in annulus
Injecting 2 BPM (barrels/minute) for 1 hour brings the temperature at the bottom of the string down to 83°F

Injecting 4 BPM for 1 hour would yield 72°F

Injecting 6 BPM for 1 hour would yield 68°F

Injecting 2 BPM for 6 hours would yield 62°F

At these rates and times, temperature of the bottom of the string is brought down close to the temperature of the injected fluid.

Temperature Effects (Cont'd)

Example:
10,000 feet
270°F BHT
60°F Injection Fluid
2 7/8" Tubing

Injecting 2 BPM for 1 hour would bring the temperature of the bottom of the string down to 102°F

Injecting 4BPM for 1 hour would yield 83°F

Injecting 6 BPM for 1 hour would yield 76°F

Injecting 2 BPM for 6 hours would yield 64°F

In the preceding examples, even at the lowest rate and the shortest time, the bottom of the string is cooled 168°F. In the 6-hour test, the bottom of the string was cooled to within 4°F of the injection fluid temperature. Injection for long periods, such as water floods will cool the string down to the temperature of the injected fluid.

For a hydraulic fracturing or acid treatment, it is accepted practice to make calculations based on the string being cooled to the injection fluid temperature. This assumption results in maximum tubing movement.

Charts:

The following charts are calculated based on the ambient conditions mentioned. Charts output in units of force; should length be required, please consult the stretch charts.

Elongation of Tubing Due to Temperature Running in the Hole

Tubing will elongate due to temperature when run in the hole. To calculate this elongation, you can use the simple Lubinski formula for tubing movement due to temperature:

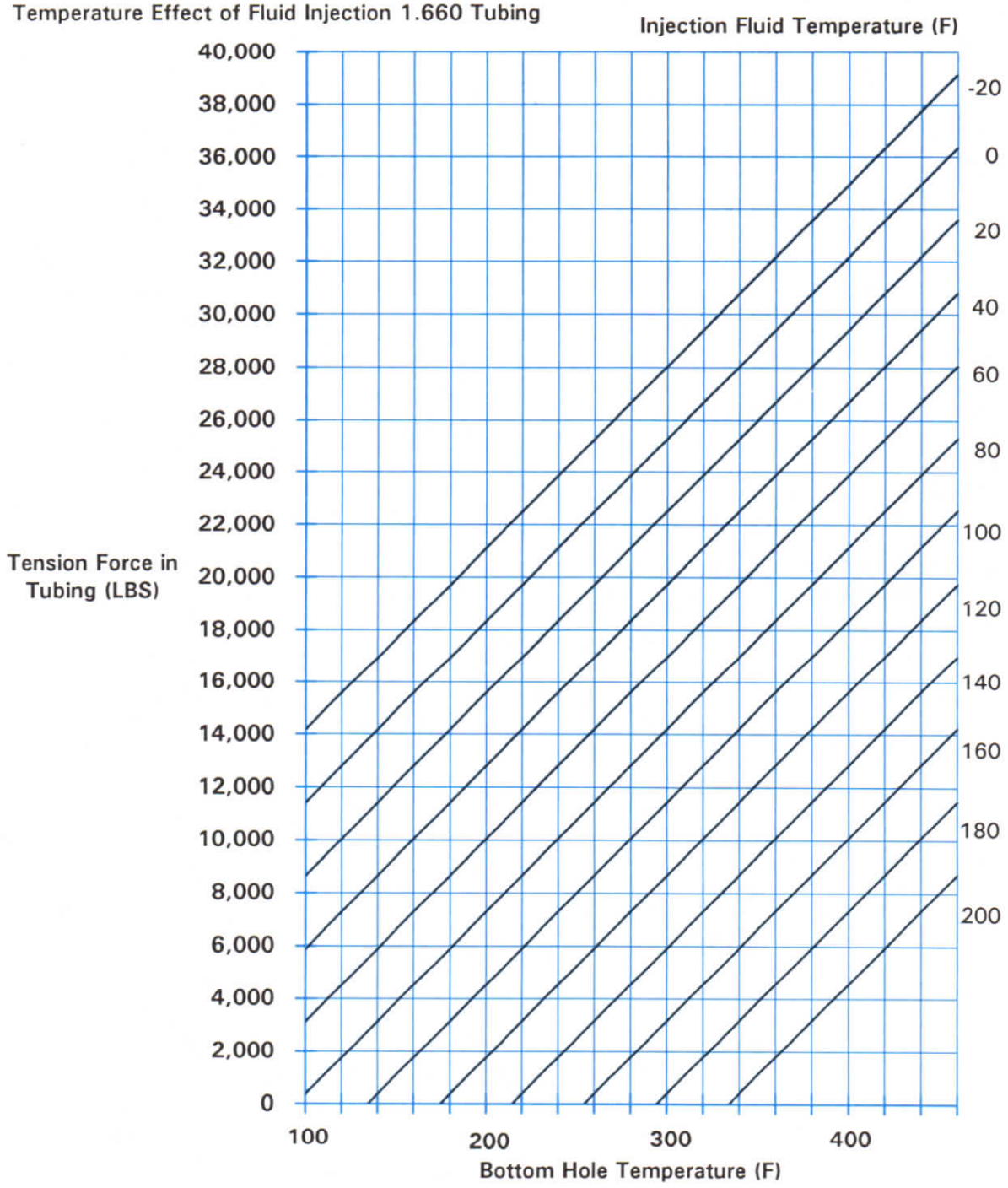
$$\Delta L = L \times \beta \times \Delta t \times 12$$

where:

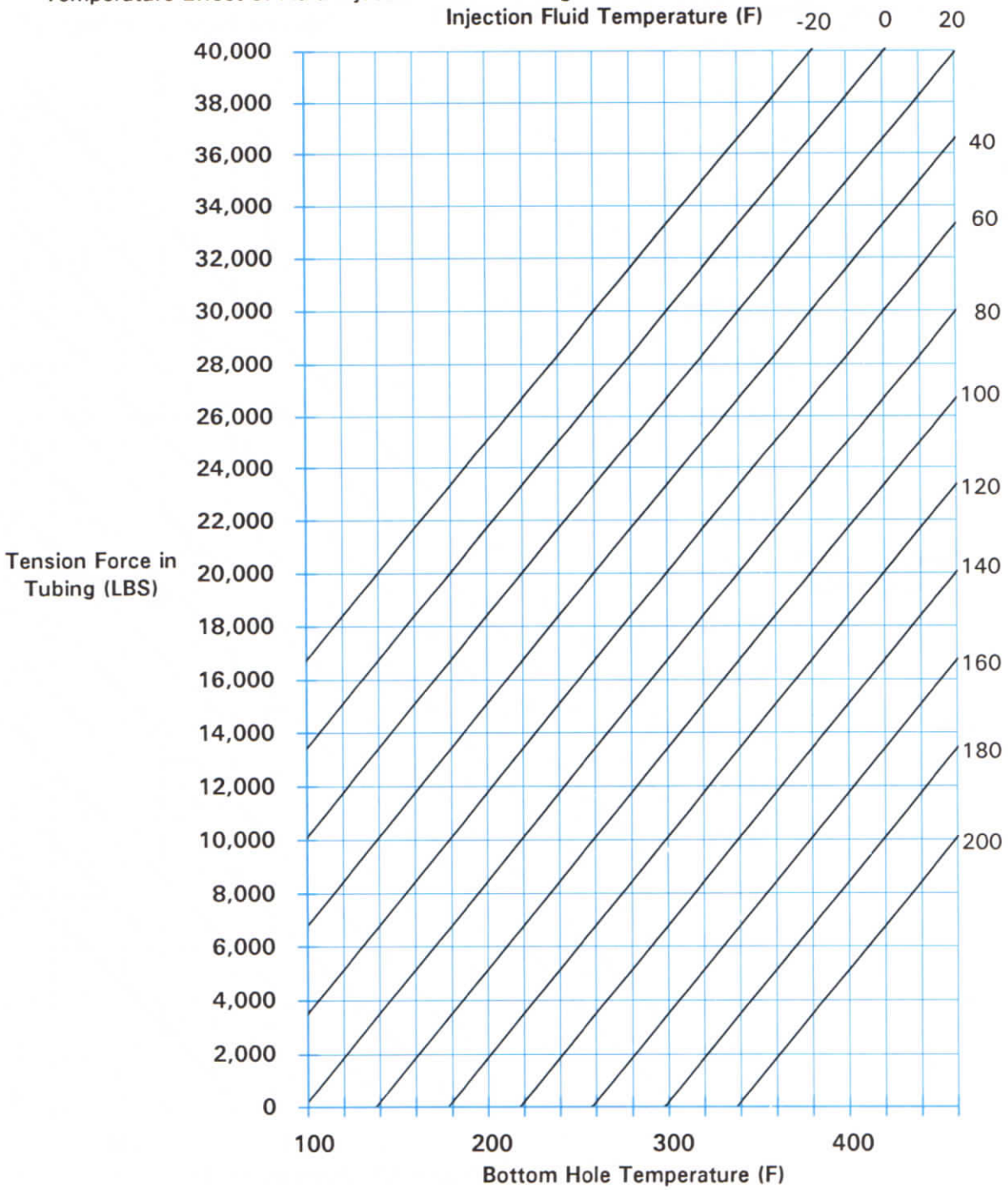
ΔL = Length change (IN)
L = Length of string (FT)
β = Co-efficient of Expansion
= 0.0000069 for steel
Δt = Average temperature change

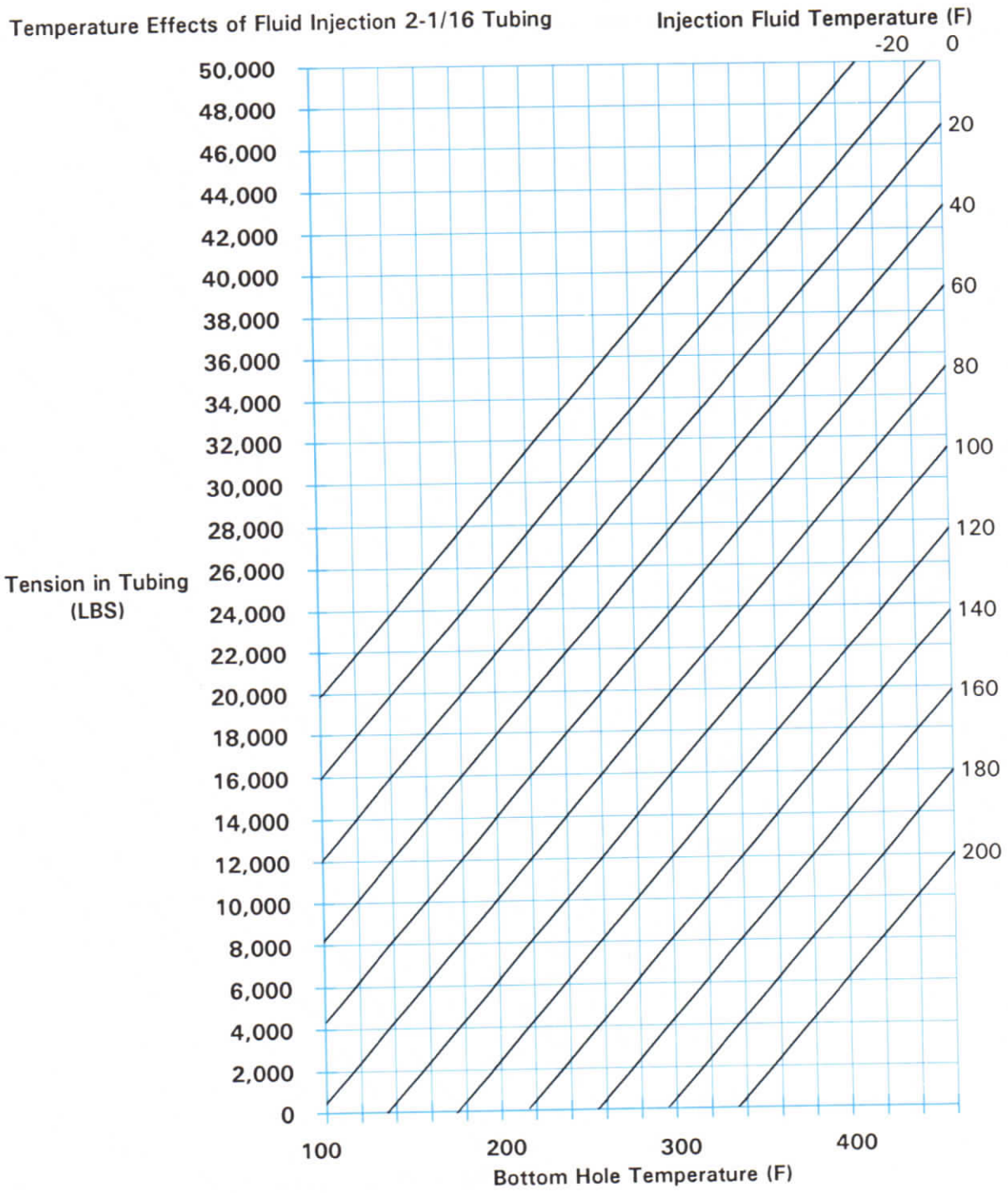
The average temperature of the string before running is assumed to be the ambient air temperature. The average temperature of the string in the well is taken to be the mean yearly temperature (70°F) averaged with the BHT.

Temperature Effect of Fluid Injection 1.660 Tubing

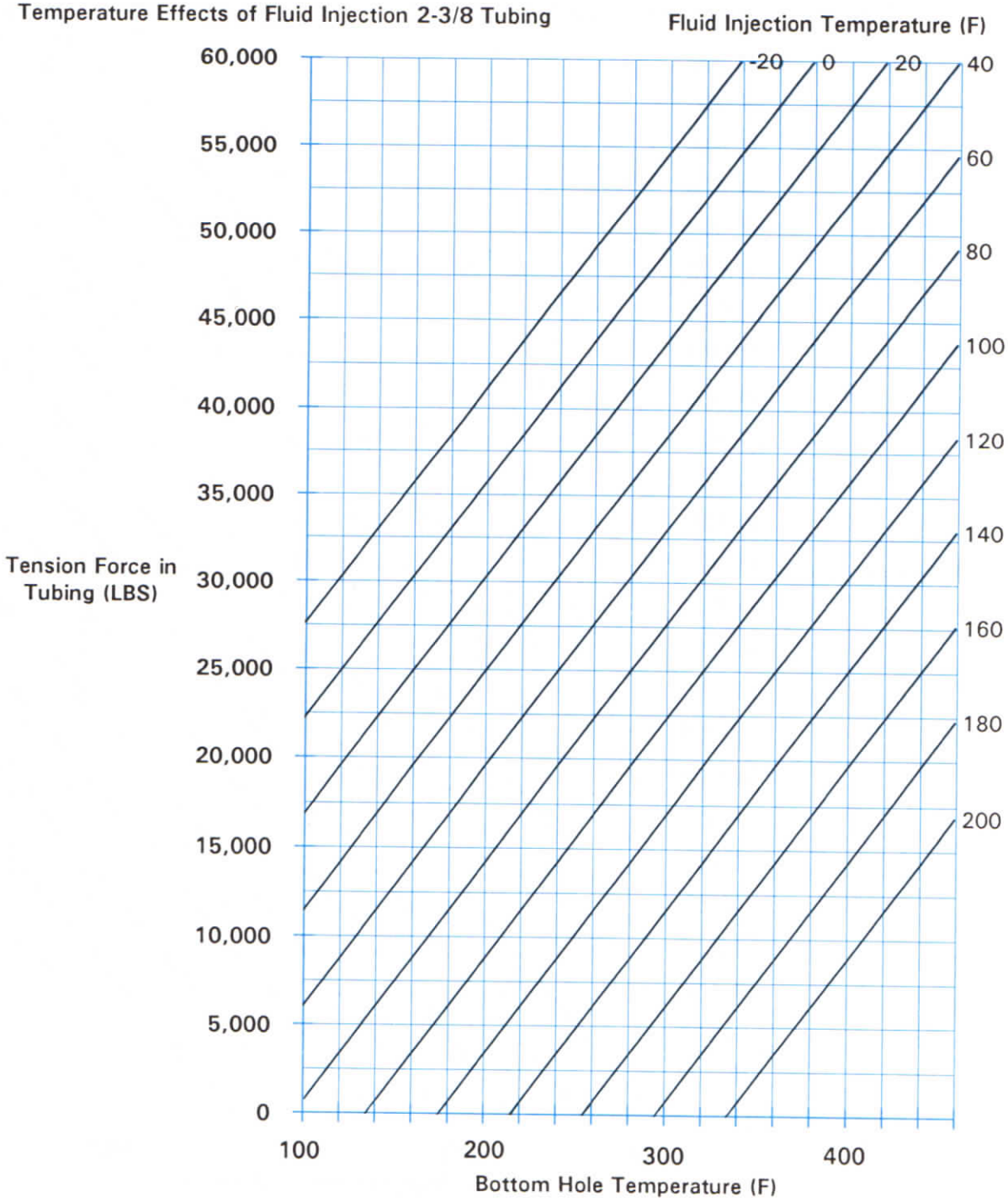


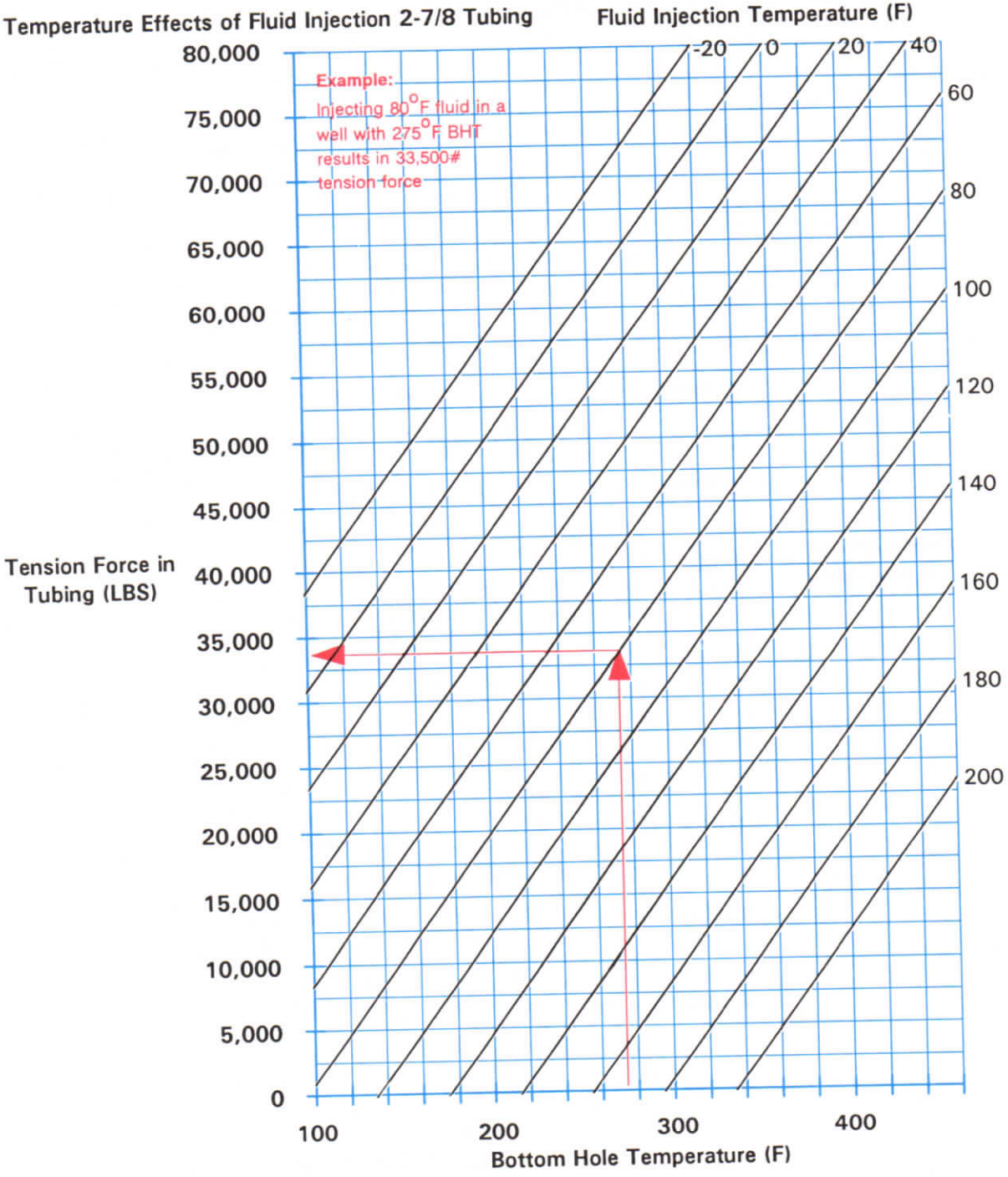
Temperature Effect of Fluid Injection 1.900 Tubing

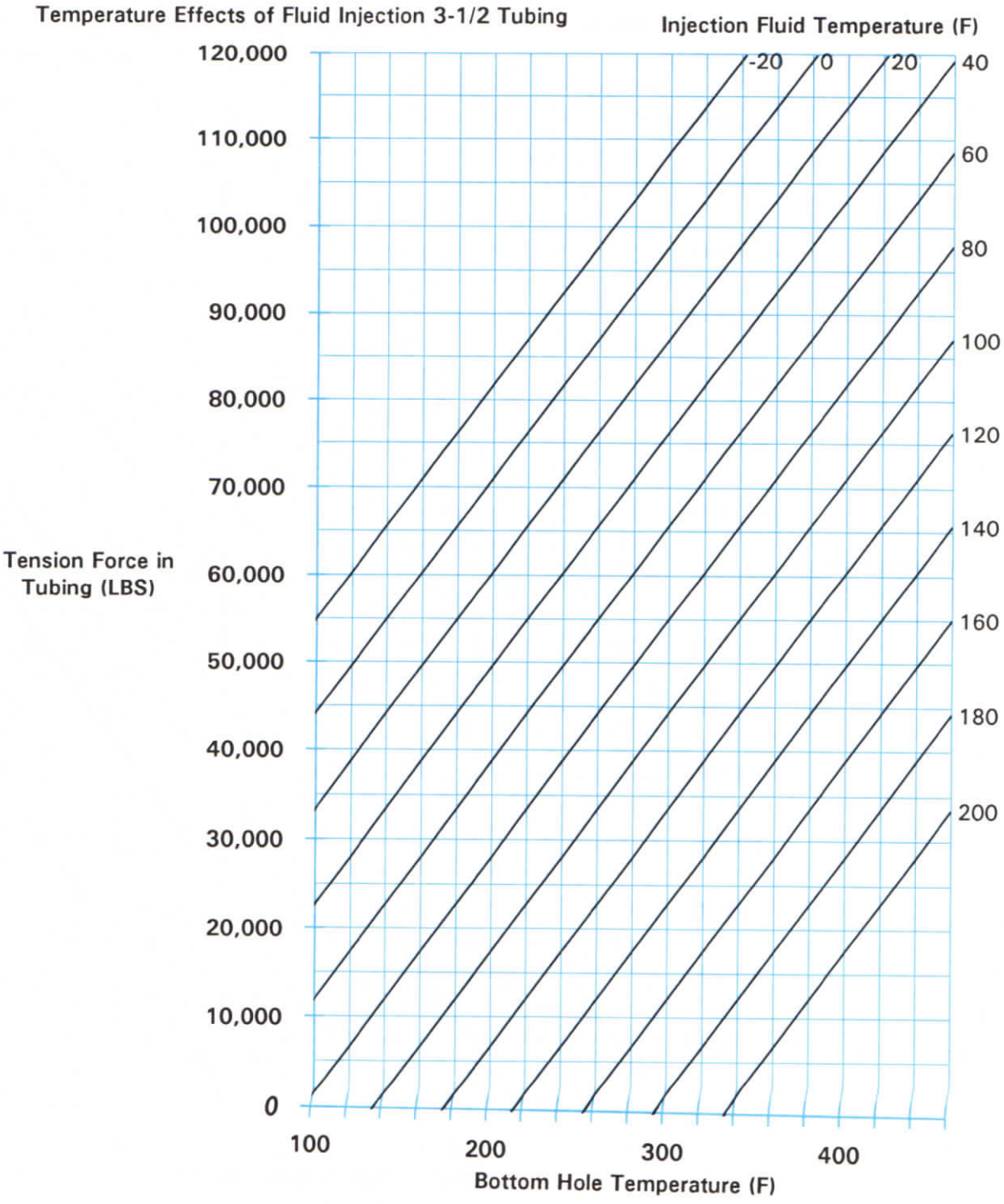



Temperature Effects of Fluid Injection 2-1/16 Tubing
Injection Fluid Temperature (F)
-20
0
20
40
60
80
100
120
140
160
180
200
Tension in Tubing (LBS)
50,000
48,000
46,000
44,000
42,000
40,000
38,000
36,000
34,000
32,000
30,000
28,000
26,000
24,000
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
100
200
300
400
Bottom Hole Temperature (F)

Temperature Effects of Fluid Injection 2-3/8 Tubing




Temperature Effects of Fluid Injection 2-7/8 Tubing
Fluid Injection Temperature (F)
-20
0
20
40
60
80
100
120
140
160
180
200
Example:
Injecting 80°F fluid in a well with 275°F BHT results in 33,500# tension force
80,000
75,000
70,000
65,000
60,000
55,000
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Tension Force in Tubing (LBS)
100
200
300
400
Bottom Hole Temperature (F)


Temperature Effects of Fluid Injection 3-1/2 Tubing
Injection Fluid Temperature (F)
-20
0
20
40
60
80
100
120
140
160
180
200
120,000
110,000
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Tension Force in Tubing (LBS)
100
200
300
400
Bottom Hole Temperature (F)

Total Analysis

Movement of tubular goods can be created by exerting a mechanical force, changing a pressure, or effecting a temperature change. Mechanical effects are presented in the form of stretch and slack-off charts. Pressure and temperature changes are defined by four formulae set forth in a technical paper written by Arthur Lubinski. While there may be additional forces, and the four results may not simultaneously apply, they are generally accepted and will be presented as such.

The four classical Lubinski formulae for pressure and temperature effects are:

Piston Effect

$$\Delta L_1 = \frac{FL}{A_s E}$$

Where:

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

Piston effect assumes a pressure acting on the end area of the string produces an upward force tending to shorten the string as if it were a long compression spring with a spring rate equal to the modulus of elasticity (E) of steel.

Pressure Buckling Effect

$$\Delta L_2 = \frac{r^2 A_p^{\,2} (\Delta P_i - \Delta P_o)^2}{8EI\,(W_s + W_i - W_o)}$$

Changes in pressure that result in a higher pressure inside the tubing than inside the casing cause pressure buckling. Pressure buckling is a shortening of the effective length of the string because the tubing tends to spiral (or helix) within the casing, and can only shorten the tubing.

Ballooning Effect

$$\Delta L_3 = \frac{\mu L^2}{E}\,\frac{\Delta \rho_i - R^2 \Delta \rho_o}{R^2 - 1} + \frac{2\mu L}{E}\,\frac{\Delta p_i - R^2 \Delta p_o}{R^2 - 1}$$

Changes in the average pressure cause a radial swelling (ballooning) or contraction (reverse ballooning) and the corresponding decrease or increase in tubing length.

Temperature Effect

$$\Delta L_4 = L\beta\Delta t$$

Changes in average temperature result in thermal expansion or contraction of the tubing string.

Terms

L = Depth (IN)
E = Modulus of Elasticity (PSI) {30 X 10^6 steel}
A_s = Cross sectional area of tubing (IN^2)
A_i = Area of tubing ID (IN^2)
A_o = Area of tubing OD (IN^2)
A_p = Area of packer seal bore (IN^2)
ΔP_i = Change in tubing pressure @ packer (PSI)
ΔP_o = Change in casing pressure @ packer (PSI)
Δp_i = Change in surface tubing pressure (PSI)
Δp_o = Change in surface casing pressure (PSI)
Δt = Change in average tubing temperature (°F)
r = Radial clearance between tubing OD and casing ID (IN)
I = Moment of inertia of tubing (IN^4)
W_s = Weight of tubing (LB/IN)
W_i = Weight of fluid in tubing (LB/IN)
W_o = Weight of fluid in casing (LB/IN)
R = Ratio of tubing OD to ID
β = Coefficient of thermal expansion in/in °F) (0.0000069 for steel)
μ = Poisson's Ratio (0.3 for steel)
$\Delta \rho_i$ = Change in density of fluid in tubing (PSI/IN)
$\Delta \rho_o$ = Change in density of fluid in casing (PSI/IN)

LENGTH CHANGES (in inches)

Piston Effect

$$\Delta L_1 = \frac{FL}{A_s E}$$

Where:

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

Buckling Effect

$$\Delta L_2 = \frac{r^2 A_p^{\,2}\,(\Delta P_i - \Delta P_o)^2}{8EI\,(W_s + W_i - W_o)}$$

Ballooning Effect

$$\Delta L_3 = \frac{\mu L^2}{E}\,\frac{\Delta \rho_i - R^2 \Delta \rho_o}{R^2 - 1} + \frac{2\mu L}{E}\,\frac{\Delta p_i - R^2 \Delta p_o}{R^2 - 1}$$

Temperature Effect

$$\Delta L_4 = L \beta \Delta t$$

Total Tension

$$\Delta L = \frac{FL}{A_s E}$$

Terms

L = Depth (IN)
E = Modulus of Elasticity (PSI) {30 X 10^6 steel}
A_s = Cross sectional area of tubing (IN^2)
A_i = Area of tubing ID (IN^2)
A_o = Area of tubing OD (IN^2)
A_p = Area of packer seal bore (IN^2)
ΔP_i = Change in tubing pressure @ packer (PSI)
ΔP_o = Change in casing pressure @ packer (PSI)
Δp_i = Change in surface tubing pressure (PSI)
Δp_o = Change in surface casing pressure (PSI)
Δt = Change in average tubing temperature (°F)
ΔP_{ia} = Change in average tubing pressure (PSI)
ΔP_{io} = Change in average casing pressure (PSI)

FORCE CHANGES (in pounds)

Piston Effect

$$F_1 = [\,(A_p - A_i)\,\Delta P_i - (A_p - A_o)\,\Delta P_o\,]$$

Buckling Effect
(This effect will shorten the tubing)

Ballooning Force

$F_3 = .6\,(\Delta P_{ia}\,A_i - \Delta P_{oa}\,A_o)$

or

$$F_3 = \frac{A_s \mu}{(R^2 - 1)}\left[L(\Delta p_i - R^2 \Delta p_o) + 2(\Delta P_i - R^2 \Delta P_o)\right]$$

Temperature Effect

$$F_4 = 207 A_s \Delta t$$

Total Slackoff

$$\Delta L = \frac{LF}{EA_s} + \frac{r^2 F^2}{8EI\,(W_s + W_i - W_o)}$$

r = Radial clearance between tubing OD and casing ID (IN)
I = Moment of inertia of tubing (IN^4)
W_s = Weight of tubing (LB/IN)
W_i = Weight of fluid in tubing (LB/IN)
W_o = Weight of fluid in casing (LB/IN)
R = Ratio of tubing OD to ID
β = Coefficient of thermal expansion in/in °F) (0.0000069 for steel)
μ = Poisson's Ratio (0.3 for steel)
$\Delta \rho_i$ = Change in tubing fluid density (PSI/IN)
$\Delta \rho_o$ = Change in casing fluid density (PSI/IN)

Example Calculation Using Lubinski Formulae

Assume the following well conditions:
Locator Seal assembly with 10,000# set down
Packer @ 8500 feet
Production string: 2 7/8" 6.50# N-80 tubing
Casing: 5-1/2" 17#
Packer Bore: 3.000"
BHT: 275 °F
Fluid Temperature: 70 °F
Frac fluid: 9# KCl water with 10 PSA(# sand added) max.
Casing fluid: 7.5# completion fluid
Surface treating pressure: 6000 PSI
Casing (backside) pressure: 1500 PSI
Tubing filled with 9# KCl water prior to job
Pump time expected: 4 hours
There are 6 feet of seals in the packer.
Packer is Arrowdrill Seal bore packer
Can this job be performed without communication between the tubing and casing?
If not, how many feet of seals would be required?

Calculate variables needed for Lubinski formulae:
Look up tubular dimensional data from engineering tables:
Tubing ID = 2.441
Casing ID = 4.892

Calculate fluid gradients:
7.5# casing = 7.5 X 0.052
= 0.390
9# tubing = 9 X 0.052
= 0.468
9# KCl with 10 PSA = 0.680 from chart in section 3

Calculate hydrostatic pressures:
Tubing (initial) = 8500 X 0.468
= 3978 PSI
Tubing (slurry) = 8500 X 0.680
= 5780 PSI
Casing = 8500 X 0.390
= 3315 PSI

Calculate Pressures:
Tubing:
Δp_i = 6000 PSI

	Applied	*Hydrostatic*	*Total*
P_{io}	0	3978	3978
P_{if}	6000	5780	11,780

Casing:
Δp_o = 1500 PSI

P_{oo}	0	3315	3315
P_{of}	1500	3315	4815

Pressure Changes (ΔP):
Tubing:
Δp_i = 11,780 - 3978
= 7802 PSI
Casing:
Δp_o = 4815 - 3315
= 1500 PSI

Calculate Temperature Changes:

	Surf.	*BHT*	*Average*
T_o	70	275	172.5
T_f	70	70	70

Δt = 172.5 - 70
= 102.5 °F

Calculate Areas:

A_p $= 3.00^2 \times 0.785$
$= 7.065\ IN^2$

A_o $= 2.875^2 \times 0.785$
$= 6.4885\ IN^2$

A_i $= 2.441^2 \times 0.785$
$= 4.6774\ IN^2$

A_s $= A_o - A_i$
$= 1.8111\ IN^2$

Calculate Moment of Inertia:

$I = \pi(D_o^4 - D_i^4) / 64$
$= \pi(2.875^4 - 2.441^4) / 64$
$= 1.6109\ IN^4$

Calculate Fluid Weights:

W_s $= 6.40 / 12$
$= 0.5333$ LB/IN

W_i $= (A_i \div 231) \times (0.680 \div 0.052)$
$= 0.2648$ LB/IN

W_o $= (A_o \div 231) \times (7.5)$
$= 0.2107$ LB/IN

Note: Lubinski calls for weight of fluids in LB/IN. To obtain this value, first find the gallons of fluid per inch (there are 231 in^3/gal) by taking the volume of a lineal inch, then dividing by 231. Multiply the number of gallons by the weight per gallon to get LB/IN.

Calculate Ratios:

R $= (2.875 \div 2.441)$
$= 1.1778$

r $= (4.892 - 2.875) / 2$
$= 1.0085$ IN

Compression Due to 10,000# Initial Set-Down Weight:

From stretch chart $= 18"$

Calculated:

$= (10{,}000 \times 8500 \times 12) / (1.8111 \times 30 \times 10^6)$
$= 18.7731$ IN

We are now ready to begin the solution to the Lubinski equations:

Lubinski Solutions:

Piston Effect:

$$\Delta L_1 = \frac{(8500 \times 12)}{(30 \times 10^6) \times (1.811)} [(7.065 - 4.6774) \times (7802) - (7.065 - 6.4885) \times (1500)]$$

$$= 33.35 \text{ IN}$$

Helical Buckling:

$$\Delta L_2 = \frac{(1.0085)^2 \times (7.065)^2 \times (7802 - 1500)^2}{(8) \times (30 \times 10^6) \times (1.6109) \times (0.5333 + 0.2648 - 0.2107)}$$

$$= 8.87 \text{ IN}$$

Ballooning:

$$\Delta L_3 = \frac{(0.3) \times (8500 \times 12)^2}{(30 \times 10^6)} \frac{(0.0177)}{[(1.1778)^2 - 1]} + \frac{(2) \times (0.3) (8500 \times 12)}{(30 \times 10^6)} \frac{[6000 - (1.1778)^2 \times (1500)]}{[(1.1778)^2 - 1]}$$

$$= 25.40 \text{ IN}$$

Temperature:

$$\Delta L_4 = (8500 \times 12) \times (0.0000069) \times (102.5)$$

$$= 72.14 \text{ IN}$$

Total Tubing Movement:

$$= \Delta L_1 + \Delta L_2 + \Delta L_3 + \Delta L_4$$
$$= 33.35 + 8.87 + 25.40 + 72.14$$
$$= 139.76 \text{ IN}$$

Your answer *may* differ from the *Arrow Tubing Movement Program*. The program uses no chart values and does not use approximations (such as the substitution of 0.785 for $\pi/4$); along with the fact that the program does not round off any numbers. With as many calculations as are used in the Lubinski equations, some differences are to be expected.

Remember the 18.78 IN of compression from the initial 10,000# set-down weight:

$$= 139.76 - 18.78$$
$$= 120.98 \text{ IN of tubing contraction during the 10 PSA stage}$$

Since you have only 6 feet of seals (72 IN), this treatment cannot be performed without communication between tubing and casing. You would probably want to recommend at least 15 feet of seals (180 IN) or more, depending on you confidence in the accuracy of stated job parameters and your judgement as to whether situations could change during the job such as a screen out resulting in a higher surface treating pressure.

			$w_s + w_i - w_o$												
Tubing OD (in)	Weight (lb/in)	w_i & w_o (lb/in)	7.0 52.3	8.0 59.8	9.0 67.3	10.0 74.8	11.0 82.3	12.0 89.8	13.0 97.2	14.0 104.7	15.0 112.2	16.0 119.7	17.0 127.2	18.0 134.6	lb/gal lb/cu ft
1.660	w_s = .200	w_i	.045	.052	.058	.065	.071	.078	.084	.091	.097	.104	.110	.116	
		w_o	.065	.075	.084	.094	.103	.112	.122	.131	.140	.150	.159	.169	
1.900	w_s = .242	w_i	.062	.070	.079	.088	.097	.106	.115	.123	.132	.141	.150	.159	
		w_o	.086	.098	.110	.123	.135	.147	.159	.172	.184	.193	.209	.221	
2.000	w_s = .283	w_i	.066	.076	.085	.095	.104	.114	.123	.133	.142	.152	.161	.171	
		w_o	.095	.109	.122	.136	.150	.163	.177	.190	.204	.218	.231	.245	
2 1/16	w_s = .283	w_i	.073	.083	.094	.104	.114	.125	.135	.146	.156	.167	.177	.187	
		w_o	.101	.116	.130	.145	.159	.174	.188	.202	.217	.231	.246	.260	
2 3/8	w_s = .392	w_i	.095	.108	.122	.135	.149	.162	.176	.189	.203	.217	.230	.243	
		w_o	.134	.153	.172	.192	.211	.230	.249	.268	.288	.307	.326	.345	
2 7/8	w_s = .542	w_i	.142	.162	.182	.203	.223	.243	.263	.284	.304	.324	.344	.364	
		w_o	.196	.225	.253	.281	.309	.337	.365	.393	.421	.450	.478	.506	
3 1/2	w_s = .767	w_i	.213	.243	.274	.304	.335	.365	.395	.426	.456	.487	.517	.548	
		w_o	.291	.333	.365	.416	.458	.500	.541	.583	.625	.666	.708	.749	

Weight of Steel W_s = [Pipe Weight (lb/ft) ÷ 12]
Weight of Fluid in Tubing W_i = A_i X [Mud Weight (lb/gal) ÷ 231]
Weight of Displaced Fluid W_o = A_o X [Mud Weight (lb/gal) ÷ 231]

Section IV
Tubing Data

Dimensional Data and
Minimum Performance of API Tubing ____ IV-1

Tubing Capacities ____ IV-5

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Recommended Make-Up Torque
- Non-Upset Tubing ____ IV-22
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DIMENSIONAL & MINIMUM PERFORMANCE DATA - API TUBING

OD (in.) (mm)	Nominal Weight			Wall Thickness (lb.)	ID (in.) (mm)	Drift Dia. (in.) (mm)	ID Area (in^2) (mm^2)	OD Area (in^2) (mm^2)	Cross Sectn'l Area	Moment of Inertia I ($in.^4$)	$\frac{OD}{ID}$ Ratio R
	T&C Non-Up (lb/ft)	T&C Up (lb/ft)	Int. Jt (lb/ft)								
1.050 26,67	1.14	1.20		0.113	0.824 20,93	0.730 18,54	0.53327 34,40	0.8659 55,87	0.33263	0.03704	1.2743
1.315 33,40	1.70	1.80	1.72	0.133	1.049 26,64	0.955 24,26	0.86430 55,76	1.3581 87,62	0.49388	0.08734	1.2536
1.660 42,16	2.30	2.40	2.10	0.125	1.410 35,81		1.56140 100,74	2.1642 139,63	0.60279	0.17870	1.1773
			2.33	0.140	1.380 35,05	1.286 32,66	1.49570 96,503	2.1642 139,63	0.66853	0.19470	1.2029
1.900 48,26			2.40	0.125	1.650 41,91		2.13820 137,95	2.8353 182,91	0.69704	0.27590	1.1515
	2.75	2.90	2.76	0.145	1.610 40,89	1.516 38,51	2.03580 131,35	2.8353 182,91	0.79946	0.30990	1.1801
2.063 52,40			3.25	0.156	1.751 44,48		2.40800 155,36	3.3426 215,66	0.93460	0.42770	1.1782
2.375 60,33	4.00			0.167	2.041 51,84	1.947 49,45	3.27170 211,09	4.4301 285,83	1.15842	0.71000	1.1636
	4.60	4.70		0.190	1.995 50,67	1.901 48,29	3.12590 201,68	4.4301 285,83	1.30423	0.78420	1.1905
	5.80	5.95		0.254	1.867 47,42	1.773 45,03	2.73770 176,63	4.4301 285,83	1.69248	0.96540	1.2721
2.875 69,85	6.40	6.50		0.217	2.441 62,00	2.347 59,61	4.67980 301,94	6.4918 418,85	1.81203	1.61090	1.1778

DIMENSIONAL & MINIMUM PERFORMANCE DATA - API TUBING

Coupling or Box OD				Grade	Collapse Resistance (psi)	Internal Yield Pressure (psi)	Joint Yield Strength			OD (in.) (mm)
Non-Upset (in.) (mm)	Upset Reg. (in.) (mm)	Upset Spec. (in.) (mm)	Int. Joint (in.) (mm)				T&C Non-Up (lb.)	T&C Upset (lb.)	Integral Joint (lb.)	
1.313 33.35	1.660 42.16			H-40 J-55 C-75 N-80	7,680 10,560 14,410 15,370	7,530 10,360 14,120 15,070	6,360 8,740 11,920 12,710	13,310 18,290 24,950 26,610		1.050 26.67
1.660 42.16	1.900 48.26		1.550 39.37	H-40 J-55 C-75 N-80	7,270 10,000 13,640 14,550	7,080 9,730 13,270 14,160	10,960 15,060 20,540 21,910	19,760 27,160 37,040 39,510	15,970 21,960 29,940 31,940	1.315 33.40
			1.880 47.75	H-40 J-55	5,570 7,660	5,270 7,250			22,180 30,500	1.660 42.16
2.054 52.17	2.200 55.88		1.880 47.75	H-40 J-55 C-75 N-80	6,180 8,490 11,580 12,360	5,900 8,120 11,070 11,810	15,530 21,360 29,120 31,060	26,740 36,770 50,140 53,480	22,180 30,500 41,600 44,370	
			2.110 53.59	H-40 J-55	4,920 6,640	4,610 6,330			26,890 36,970	1.900 48.26
2.200 55.88	2.500 63.50		2.110 53.59	H-40 J-55 C-75 N-80	5,640 7,750 10,570 11,280	5,340 7,350 10,020 10,680	19,090 26,250 35,800 38,180	31,980 43,970 59,960 63,960	26,890 36,970 50,420 53,780	
			2.325 59.05	H-40 J-55 C-75 N-80	5,590 7,690 10,480 11,180	5,290 7,280 8,920 10,590			35,690 49,070 66,910 71,370	2.063 52.40
2.875 73.03				H-40 J-55 C-75 N-80	5,230 7,190 9,520 9,980	4,920 6,770 9,230 9,840	30,130 41,430 56,500 60,260			2.375 60.33
2.875 73.03	3.063 77.80	2.910 73.91		H-40 J-55 C-75 N-80 P-105	5,890 8,100 11,040 11,780 15,460	5,600 7,700 10,500 11,200 14,700	35,960 49,450 67,430 71,930 94,410	52,170 71,730 97,820 104,340 136,940		
2.875 73.03	3.063 77.80	2.910 73.91		C-75 N-80 P-105	14,330 15,280 20,060	14,040 14,970 19,650	96,560 102,990 135,180	126,940 135,400 177,710		
3.500 88.90	3.668 93.17	3.460 87.88		H-40 J-55 C-75 N-80 P-105	5,580 7,680 9,910 10,570 13,870	5,280 7,260 9,910 10,570 13,870	52,780 72,580 98,970 105,570 138,560	72,480 99,660 135,900 144,960 190,260		2.875 69.85

DIMENSIONAL & MINIMUM PERFORMANCE DATA - API TUBING

OD (in.) (mm)	Nominal Weight			Wall Thickness (lb.)	ID (in.) (mm)	Drift Dia. (in.) (mm)	ID Area (in^2) (mm^2)	OD Area (in^2) (mm^2)	Cross Sectn'l Area	Moment of Inertia I ($in.^4$)	OD / ID Ratio R
	T&C Non-Up (lb/ft)	T&C Up (lb/ft)	Int. Jt (lb/ft)								
2.875 73.03	7.80	7.90		0.276	2.323 59.00	2.229 56.62	4.2383 273.46	6.4918 418.85	2.2535	1.92420	1.2376
	8.60	8.70		0.308	2.259 57.38	2.165 54.99	4.00790 258.59	6.4918 418.85	2.48385	2.07540	1.2727
3.500 88.90	7.70			0.216	3.068 77.93	2.943 74.75	7.39270 476.98	9.6211 620.75	2.22847	3.01720	1.1408
	9.20	9.30		0.254	2.992 75.99	2.867 72.82	7.03090 453.63	9.6211 620.75	2.59019	3.43230	1.1698
	10.20			0.289	2.922 74.22	2.797 71.04	6.70580 432.66	9.6211 620.75	2.91533	3.78780	1.1978
	12.70	12.95		0.375	2.750 69.85	2.625 66.68	5.93960 383.22	9.6211 620.75	3.68155	4.55880	1.2727
4.000 101.60	9.50			0.226	3.548 90.12	3.423 86.94	9.88680 637.89	12.5664 810.78	2.67954	4.78770	1.1274
		11.00		0.262	3.476 88.29	3.351 85.12	9.48960 612.27	12.5664 810.78	3.07674	5.40020	1.1507
4.500 114.30	12.60	12.75		0.271	3.958 100.53	3.833 97.36	12.30390 793.85	15.9043 1026.15	3.60045	8.08210	1.1369

DIMENSIONAL & MINIMUM PERFORMANCE DATA - API TUBING

Coupling OD				Grade	Collapse Resistance (psi)	Internal Yield Pressure (psi)	Joint Yield Strength			OD (in.) (mm)
Non-Upset (in.) (mm)	Upset Reg. (in.) (mm)	Upset Spec. (in.) (mm)	Int. Joint (in.) (mm)				T&C Non Up (lb.)	T&C Upset (lb.)	Integral Joint (lb.)	
3.500 88.90	3.668 93.17	3.460 87.88		C-75 N-80 C-90 P-105	13,020 13,890 15,620 18,220	12,600 13,440 15,120 17,640	132,100 140,900 158,500 184,900	169,000 180,300 202,800 236,600		2.875 73.03
3.500 88.90	3.668 93.17	3.460 87.88		C-75 N-80 P-105	14,350 15,300 20,090	14,060 15,000 19,690	149,360 159,310 209,100	186,290 198,710 260,810		
4.250 107.95				H-40 J-55 C-75 N-80	4,630 5,970 7,540 7,870	4,320 5,940 8,100 8,640	65,070 89,470 122,010 130,140			3.500 88.90
4.250 107.95	4.500 114.30	4.180 106.17		H-40 J-55 C-75 N-80 P-105	5,380 7,400 10,040 10,530 13,050	5,080 6,980 9,520 10,160 13,340	79,540 109,370 149,140 159,090 208,800	103,610 142,460 194,260 202,220 271,970		
4.250 107.95				H-40 J-55 C-75 N-80	6,060 8,330 11,360 12,120	5,780 7,950 10,840 11,560	92,550 127,250 173,530 185,100			
4.250 170.95	4.500 114.30	4.180 106.17		C-75 N-80 P-105	14,350 15,310 20,090	14,090 15,000 19,690	230,990 246,390 323,390	276,120 294,530 386,570		
4.750 120.65				H-40 J-55 C-75 N-80	4,060 5,110 6,350 6,590	3,960 5,440 7,420 7,910	72,000 99,010 135,010 144,010			4.000 101.60
	5.000 127.00			H-40 J-55 C-75 N-80	4,900 6,590 8,410 8,800	4,590 6,300 8,600 9,170		123,070 169,220 230,750 246,140		
5.200 132.08	5.563 141.30			H-40 J-55 C-75 N-80	4,500 5,720 7,200 7,500	4,220 5,800 7,900 8,430	104,360 143,500 195,680 208,730	144,020 198,030 270,040 288,040		4.500 114.30

TUBING CAPACITY

OD (in.)	WT (lb/ft)	ID (in.)	BBL/FT	FT/BBL	Cu FT/ FT	FT/ Cu FT
1.050	1.14/1.20	0.824	0.00066	1515.2326	0.00370	270.0415
1.315	1.70/1.80	1.049	0.00107	934.9379	0.00600	166.6226
1.660	2.30/2.40	1.410	0.00193	517.4823	0.01084	92.2246
	2.33	1.380	0.00185	540.2261	0.01039	96.2779
1.900	2.40	1.650	0.00265	377.8904	0.01485	67.3468
	2.75/2.90	1.610	0.00252	396.9008	0.01414	70.7348
2.063	3.25	1.751	0.00298	335.5532	0.01672	59.8016
2 3/8	4.00	2.041	0.00405	246.9720	0.02272	44.0148
	4.60/4.70	1.995	0.00387	258.4925	0.02171	46.0680
	5.80/5.95	1.867	0.00339	295.1516	0.01901	52.60130
2 7/8	6.40/6.50	2.441	0.00579	172.6626	0.03250	30.77150
	8.60/8.70	2.259	0.00496	201.6050	0.02783	35.92960
3 1/2	7.70	3.068	0.00915	109.3007	0.05134	19.47930
	9.20/9.30	2.992	0.00870	114.9240	0.04882	20.48150
	10.20	2.922	0.00830	120.4962	0.04657	21.47460
	12.70/12.95	2.750	0.00735	136.0405	0.04125	24.24480
4	9.50	3.548	0.01224	81.7272	0.06866	14.56520
	11.00	3.476	0.01174	85.1480	0.06590	15.17490
4 1/2	12.60/12.75	3.958	0.01523	65.6723	0.08544	11.70400

DIMENSIONAL DATA NON-API TUBING

OD (in.)	Weight (lb/ft)		Tubular			Type of Joint	Joint		
	Plain End	Nom.	Wall (in.)	ID (in.)	Drift (in.)		ID* (in.)	Regular OD (in.)	Special OD (in.)
1.050	1.13	1.20	0.113	0.824	0.730	GST Streamline Hydril CS VAM	 0.687 0.807	1.310 1.327 1.299	1.300
	1.47	1.50	0.154	0.742	0.648	Hydril CS VAM	0.687 0.728	1.327 1.339	
1.315	1.68	1.80	0.133	1.049	0.955	Rucker Atlas Brad.DS-HT Rucker Atlas Bradford DSS-HT & IJ-3SS Rucker Atlas Brad.IJ-3S GST Streamline Hydril CS VAM	 0.985 0.985 0.970 1.004	1.551 1.562 1.551 1.550 1.552 1.555	 1.525
	2.17	2.25	0.179	0.957	0.848	Rucker Atlas Brad.DSS-HT Hydril CS VAM	0.849 0.864 0.906	1.600 1.600 1.614	
1.660	2.27	2.40	0.140	1.380	1.286	Rucker Atlas Brad.DS-HT Rucker Atlas Bradford DSS-HT & IJ-3SS Rucker Atlas Brad.IJ-3S GST Streamline Hydril A-95 Hydril CS VAM	 1.301 1.301 1.300 1.300 1.307	1.889 1.893 1.889 1.880 1.898 1.883 1.913	 1.858 1.858
	2.99	3.02	0.191	1.278	1.184	Hydril CS VAM	1.218 1.209	1.927 1.976	
	3.09	3.24	0.198	1.264	1.170	Hydril CS	1.200	1.927	

DIMENSIONAL DATA NON-API TUBING

OD (in.)	Weight (lb/ft)		Tubular			Type of Joint	Joint		
	Plain End	Nom.	Wall (in.)	ID (in.)	Drift (in.)		ID* (in.)	Regular OD (in.)	Special OD (in.)
1.900	2.75	2.90	0.145	1.610	1.516	Rucker Atlas Brad.DS-HT		2.125	
						Rucker Atlas Bradford DSS-HT & IJ-3SS	1.531	2.123	
						Rucker Atlas Brad.IJ-3S	1.531	2.125	
						GST Streamline		2.110	
						Hydril A-95	1.530	2.134	2.094
						Hydril CS	1.530	2.113	2.094
						Mannesmann Omega	1.594	2.039	
						VAM	1.535	2.142	
	3.63	3.64	0.200	1.500	1.406	Hydril CS	1.440	2.162	
						VAM	1.429	2.220	
	3.93	4.19	0.219	1.462	1.368	Hydril CS	1.390	2.179	
2.000	3.23	3.40	0.165	1.670	1.576	National Buttress		2.500	2.300
						Pittsburgh 8 Acme		2.500	2.300
2.063	3.18	3.40	0.156	1.750	1.656	Rucker Atlas Brad.DS-HT		2.320	
						Rucker Atlas Bradford DSS-HT & IJ-3SS	1.685	2.340	
						Rucker Atlas Bard.IJ-3S	1.685	2.320	
						GST Streamline		2.310	
		3.25				Hydril A-95	1.700	2.325	2.300
						Hydril CS	1.700	2.330	2.300
						VAM	1.677	2.331	
	4.41	4.50	0.225	1.613	1.519	Hydril CS	1.550	2.375	

DIMENSIONAL DATA NON-API TUBING

OD (in.)	Weight (lb/ft)		Tubular			Type of Joint	Joint		
	Plain End	Nom.	Wall (in.)	ID (in.)	Drift (in.)		ID* (in.)	Regular OD (in.)	Special OD (in.)
2.375	4.43	4.47	0.190	1.995	1.901	Rucker Atlas Brad.DS-HT		2.700	
		4.70				Rucker Atlas Bradford DSS-HT & IJ-3SS	1.930	2.710	
						Rucker Atlas Brad.IJ-3S	1.935	2.700	
						Rucker Atlas Brad.IJ-4S	1.945	2.750	
						Rucker Atlas Brad.TC-4S		2.875	2.750
						Rucker Atlas Bradford FL-3S & FL-4S	1.926	2.375	
						Armco Nu-Lock & Seal Lock	1.950	2.875	2.700
						Extreme Line	1.935	3.000	
						GST Streamline		2.700	
						Hydril A-95 & CS	1.945	2.700	2.630
						Hydril CFJ-P	1.945	2.525	
		4.60	0.218	1.939	1.845	Hydril Super FJ	1.945	2.437	
						Annesmann Omega	1.988	2.551	
						Mannesmann TDS		2.875	
						Buttress & 8 Acme		2.875	2.700
						VAM	1.929	2.697	2.618
	5.01	5.30				Rucker Atlas Bradford DSS-HT & IJ-3SS	1.875	2.710	
						Rucker Atlas Brad.IJ-4S	1.840	2.750	
						Rucker Atlas Brad.TC-4S		2.875	2.750
						Hydril CS	1.890	2.740	
						Hydril CFJ-P	1.890	2.525	
		5.10				VAM	1.929	2.697	2.618

DIMENSIONAL DATA NON-API TUBING

OD (in.)	Weight (lb/ft)		Tubular			Type of Joint	Joint		
	Plain End	Nom.	Wall (in.)	ID (in.)	Drift (in.)		ID* (in.)	Regular OD (in.)	Special OD (in.)
2.375	5.75	5.95	0.254	1.867	1.773	Rucker Atlas Bradford DSS-HT & IJ-3SS	1.805	2.910	2.800
						Rucker Atlas Brad.IJ-4S	1.820	2.800	
						Rucker Atlas Brad.TC-4S		2.875	
						Rucker Atlas Bradford FL-3S & FL-4S	1.823	2.375	
		5.80				Armco Seal Lock	1.450	2.875	2.697
		5.95				Extreme Line	1.807	3.000	
						Hydril PH-6	1.805	2.906	
		5.80				Mannesmann Omega	1.870	2.614	
						Mannesmann TDS	1.867	2.875	
						VAM	1.867	2.776	
	5.89	6.20	0.261	1.85.	1.759	Rucker Atlas Bradford DSS-HT & IJ-3SS	1.791	2.910	2.800
						Rucker Atlas Brad.IJ-4S	1.806	2.800	
						Rucker Atlas Brad.TC-4S		2.875	
						Hydril PH-6	1.795	2.937	
	6.26	6.65	0.280	1.815	1.721	Rucker Atlas Bradford FL-3S & FL-4S	1.771		
		6.30				VAM	1.866	2.856	
	7.30	7.70	0.336	1.703	1.609	Rucker Atlas Bradford DSS-HT & IJ-3SS	1.641	3.135	2.400
						Rucker Atlas Brad.IJ-4S	1.656	2.900	
						Rucker Atlas Brad.TC-4S		3.000	
						Hydril PH-6	1.645	3.125	
		7.30				VAM	1.866	2.856	

DIMENSIONAL DATA NON-API TUBING

OD (in.)	Weight (lb/ft)		Tubular			Type of Joint	Joint		
	Plain End	Nom.	Wall (in.)	ID (in.)	Drift (in.)		ID* (in.)	Regular OD (in.)	Special OD (in.)
2.875	6.16	6.50	0.217	2.441	2.347	Rucker Atlas Brad.DS-HT		3.218	
						Rucker Atlas Bradford DSS-HT & IJ-3SS	2.379	3.230	
						Rucker Atlas Brad.IJ-3S	2.379	3.218	
						Rucker Atlas Brad.IJ-4S	2.394	3.250	
						Rucker Atlas Brad.TC-4S		3.500	3.250
						Rucker Atlas Bradford FL-3S & FL-4S	2.372	2.875	
						Armco Nu-Lock	2.396	3.500	3.220
		6.40				Armco Seal Lock	2.396	3.500	3.220
		6.50				Extreme Line	2.381	3.500	
						GST Streamline		3.220	
						Hydril A-95		3.220	3.155
						Hydril CS	2.375	3.220	3.155
						Hydril CFJ-P	2.375	3.000	
		6.40				Hydril Super FJ	2.375	2.968	
						Mannesmann Omega		3.079	
						Mannesmann TDS		3.500	
						ANtional Buttress		3.500	3.220
						Pittsburgh 8 Acme		3.500	3.220
						VAM	2.375	3.197	3.150
	6.48	7.90	0.276	2.323	2.229	Rucker Atlas Bradford DSS-HT IJ-3SS	2.261	3.385	
						Rucker Atlas Brad.IJ-4S	2.276	3.375	
						Rucker Atlas Brad.TC-4S		3.500	3.375
						Rucker Atlas Bradford FL-3S & FL-4S	2.279	2.875	
						Hydril PH-6	2.265	3.437	

DIMENSIONAL DATA NON-API TUBING

OD (in.)	Weight (lb/ft)		Tubular			Type of Joint	Joint		
	Plain End	Nom.	Wall (in.)	ID (in.)	Drift (in.)		ID* (in.)	Regular OD (in.)	Special OD (in.)
2.875	6.48	7.70	0.276	2.323	2.229	VAM	2.323	3.327	3.264
	8.44	8.70	0.308	2.259	2.165	Rucker Atlas Bradford DSS-HT & IJ-4SS	2.197	3.510	
						Rucker Atlas Brad.IJ-4S	2.212	3.375	
						Rucker Atlas Brad.TC-4S		3.500	
						Rucker Atlas Bradford FL-3S & FL-4S	2.215	2.875	3.375
		8.60				Armco Seal Lock	2.396	3.500	
		8.70				Extreme Line	2.199	3.625	
						Hydril PH-6	2.200	3.500	
		8.60				Mannesmann Omega		3.154	
						Mannesmann TDS		3.500	
						VAM	2.260	3.327	3.264
	9.78	9.50	0.340	2.195	2.101	Rucker Atlas Bradford DSS-HT & IJ-3SS	2.133	3.635	
						Rucker Atlas Brad.IJ-4S	2.148	3.450	
						Rucker Atlas Brad.TC-4S		3.500	3.450
						Hydril PH-6	2.130	3.625	
	9.69	10.40	0.362	2.151	2.057	Rucker Atlas Bradford FL-3S & FL-4S	2.107	2.875	
		9.70				VAM	2.260	3.453	
	10.39	10.70	0.392	2.091	1.997	Hydril PH-6	2.030	3.687	

DIMENSIONAL DATA NON-API TUBING

OD (in.)	Weight (lb/ft)		Tubular			Type of Joint	Joint		
	Plain End	Nom.	Wall (in.)	ID (in.)	Drift (in.)		ID* (in.)	Regular OD (in.)	Special OD (in.)
2.875	10.66	11.00	0.405	2.065	1.972	Rucker Atlas Bradford DSS-HT & IJ-SS	2.003	3.760	
						Rucker Atlas Brad.IJ-4S	2.018	3.500	
						Rucker Atlas Brad.TC-4S		3.625	3.500
						Hydril PH-4	2.000	3.750	
						Hydril PH-6	2.000	3.750	
		10.70				VAM	2.205	3.453	
	11.44	11.65	0.440	1.995	1.901	Rucker Atlas Bradford DSS-HT &IJ-3SS	1.933	3.760	
						Rucker Atlas Brad.IJ-4S	1.948	3.550	
						Rucker ATlas Brad.TC-4S		3.625	3.550
						Hydril PH-4	1.945	3.750	
3.500	7.57	7.70	0.216	3.068	2.943	Rucker Atlas Bradford FL-3S & FL-4S	2.968	3.500	
						Mannesmann Omega	3.067	3.701	
						VAM	2.972	3.803	
	8.81	9.30	0.254	2.992	2.867	Rucker Atlas Brad.DS-HT		3.875	
						Rucker Atlas Bradford DSS-HT & IJ-3SS	2.417	3.875	
						Rucker Atlas Brad.IJ-3S	2.417	3.875	
						Rucker Atlas Brad.IJ-4S	2.932	3.950	
						Rucker Atlas Brad.TC-4S		4.250	3.950
						Rucker Atlas Bradford FL-3S & FL-4S	2.917	3.500	
						Armco Nu-Lock	2.947	4.250	3.865
		9.20				Armco Seal Lock	2.927	4.250	3.865

DIMENSIONAL DATA NON-API TUBING

OD (in.)	Weight (lb/ft)		Tubular			Type of Joint	Joint		
	Plain End	Nom.	Wall (in.)	ID (in.)	Drift (in.)		ID* (in.)	Regular OD (in.)	Special OD (in.)
3.500	8.81	9.30	0.254	2.992	2.867	Extreme Line	2.907	4.250	
						GST Streamline		3.865	
						Hydril A-95 & CS	2.920	3.905	3.805
						Hydril CFJ-P	2.920	3.609	
		9.20				Hydril Super FJ	2.930	3.594	
						Mannesmann Omega	2.992	4.250	
						MAnnesmann TDS	2.992		
						National Buttress		4.250	3.865
						Pittsburgh 8 Acme		4.250	3.865
						VAM	2.972	3.862	3.793
	9.91	10.30	0.289	2.922	2.797	Rucker Atlas Bradford			
						DSS-HT & IJ-3SS	2.847	3.947	
						Rucker Atlas Brad.IJ-4S	2.862	3.950	3.950
						Rucker Atlas Brad.TC-4S		4.250	
						Rucker Atlas Bradford			
						FL-3S & FL-4S	2.847	3.500	
						Hydril CS	2.878	3.955	
						Hydril CFJ-P	2.878	3.609	
		10.20				Hydril Super FJ	2.860	3.594	
						Mannesmann Omega	2.921		
						Mannesmann TDS	2.921	4.250	
						VAM	2.925	3.917	
									3.852
	12.31	12.70	0.368	2.764	2.639	Rucker Atlas Bradford			
						FL-3S & FL-4S	2.689	3.500	
		12.80				Hydril Super FJ	2.700	3.594	
						Hydril PH-6	2.700	4.312	

DIMENSIONAL DATA - NON-API TUBING

OD (in.)	Weight (lb/ft)		Tubular			Type of Joint	Joint		
	Plain End	Nom.	Wall (in.)	ID (in.)	Drift (in.)		ID* (in.)	Regular OD (in.)	Special OD (in.)
3.500	12.52	12.95	0.375	2.750	2.625	Rucker Atlas Bradford DSS-HT & IJ-3SS	2.675	4.260	4.100
						Rucker Atlas Brad.IJ-4S	2.690	4.100	
						Rucker Atlas Brad.TC-4S		4.250	
						Rucker Atlas Bradford FL-3S & FL-4S	2.675	3.500	
		12.70				Armco Seal Lock	2.927	4.250	
		12.95				Extreme Line Hydril PH-6	2.687	4.312	
		12.70				Mannesmann Omega	2.752		
						Mannesmann TDS	2.752	4.250	
						VAM	2.925	4.035	3.957
	13.60	13.70	0.413	2.673	2.548	VAM	2.835	4.138	4.026
	14.62	15.50	0.449	2.602	2.477	Rucker Atlas Bradford FL-3S & FL-4S	2.527	3.500	
						Hydril Super FJ	2.540	3.594	
		14.70				VAM	2.756	4.138	4.026
	15.37	15.80	0.476	2.548	2.423	Rucker Atlas Brad.DSS-HT	2.470	4.385	
						Rucker Atlas Bradford IJ-4S	2.488	4.200	
						Rucker Atlas Brad.TC-4S		4.375	4.200
						Hydril PH-6	2.485	4.500	
	15.68	15.80	0.488	2.524	2.399	VAM	2.756	4.252	4.128
	16.28	16.70	0.510	2.480	2.355	Rucker Atlas Brad.DSS-HT	2.391	4.525	
						Rucker Atlas Brad.IJ-4S	2.420	4.250	
						Rucker Atlas Brad.TC-4S		4.375	4.250
						Hydril PH-4	2.406	4.562	
						Hydril PH-6	2.406	4.562	
	16.81	17.05	0.530	2.440	2.315	Extreme Line	2.398	4.374	
						Hydril PH-4	2.375	4.562	

DIMENSIONAL DATA - NON-API TUBING

OD (in.)	Weight (lb/ft)		Tubular			Type of Joint	Joint		
	Plain End	Nom.	Wall (in.)	ID (in.)	Drift (in.)		ID* (in.)	Regular OD (in.)	Special OD (in.)
4.000	9.11	9.50	0.226	3.548	3.423	Rucker Atlas Bradford FL-3S & FL-4S	3.448	4.000	
						Mannesmann Omega	3.547	4.209	
						VAM	3.480	4.325	
	10.46	11.00	0.262	3.476	3.351	Rucker Atlas Brad.DS-HT		4.412	
						Rucker Atlas Bradford DSS-HT & IJ-3SS	3.401	4.385	
						Rucker Atlas Brad.IJ-3S	3.401	4.412	
						Rucker Atlas Brad.IJ-4S	3.416	4.450	
						Rucker Atlas Brad.TC-4S		4.500	4.450
						Rucker Atlas Bradford FL-3S & FL-4S	3.401	4.000	
						Hydril A-95 & CS	3.395	4.405	4.315
						Hydril CFJ-P	3.395	4.100	
						Hydril Super FJ	3.395	4.094	
						Mannesmann Omega	3.476	4.236	
						Mannesmann TDS	3.476	4.748	
		10.90				Pittsburgh 8 Acme		4.750	4.400
						National Buttress		4.750	4.400
						VAM	3.457	4.366	4.315
	11.34	11.60	0.286	3.428	3.303	Rucker Atlas Bradford FL-3S & FL-4S	3.353	4.000	
						Hydril SUper FJ	3.350	4.094	
	12.93	13.40	0.330	3.340	3.215	Rucker Atlas Bradford DSS-HT & IJ-3SS	3.265	4.572	
						Rucker Atlas Brad.IJ-4S	3.280	4.525	
						Rucker Atlas Brad.TC-4S		4.625	4.525
		14.00				Rucker Atlas Bradford FL-3S & FL-4S	3.265	4.000	
		13.40				Hydril Super FJ	3.260	4.094	
						Hydril PH-6	3.275	4.625	
		13.00				VAM	3.457	4.468	4.356

DIMENSIONAL DATA - NON-API TUBING

OD (in.)	Weight (lb/ft)		Tubular			Type of Joint	Joint		
	Plain End	Nom.	Wall (in.)	ID (in.)	Drift (in.)		ID* (in.)	Regular OD (in.)	Special OD (in.)
4.000	14.66	14.80	0.380	3.240	3.115	VAM	3.346	4.614	
	16.36	16.50	0.430	3.140	3.015	VAM	3.346	4.614	
	18.69	19.00	0.500	3.000	2.875	Hydril PH-4	2.920	5.000	
	22.08	22.80	0.610	2.780	2.655	Rucker Atlas Brad.DSS-HT	2.705	4.885	
						Rucker Atlas Brad.IJ-4S	2.720	4.850	
						Rucker Atlas Brad.TC-4S		5.000	4.850
		22.50				Hydril PH-4	2.700	5.187	
4.500	9.40	9.50	0.205	4.090	3.965	Rucker Atlas Bradford FL-3S & FL-4S	3.990	4.500	
	10.23	10.50	0.224	4.052	3.927	Rucker Atlas Bradford FL-3S & FL-4S	3.952	4.500	
	11.35	11.60	0.250	4.000	3.875	Rucker Atlas Bradford FL-3S & FL-4S	3.925	4.500	
	12.24	12.75	0.271	3.958	3.833	Rucker Atlas Brad.DS-HT		4.880	
						Rucker Atlas Bradford DSS-HT & IJ-3SS	3.883	4.940	
						Rucker Atlas Brad.IJ-4S	3.898	4.960	
						Rucker Atlas Brad.TC-4S		5.000	4.960
		12.60				Rucker Atlas Bradford FL-3S & FL-4S	3.883	4.500	
		12.75				Hydril A-95 & CS	3.865	4.910	4.825
						Hydril CFJ-P	3.865	4.609	
		12.60				Hydril Super FJ	3.880	4.594	
						Mannesmann Omega	3.957	4.744	
						Mannesmann TDS	3.957	5.201	
						National Buttress		5.200	4.920
						Pittsburgh 8 Acme		5.200	4.920
						VAM	3.933	4.862	

DIMENSIONAL DATA - NON-API TUBING

OD (in.)	Weight (lb/ft)		Tubular			Type of Joint	Joint		
	Plain End	Nom.	Wall (in.)	ID (in.)	Drift (in.)		ID* (in.)	Regular OD (in.)	Special OD (in.)
4.500	13.04	13.50	0.290	3.920	3.795	Rucker Atlas Brad.DSS-HT	3.845	4.940	
						Rucker Atlas Brad.IJ-4S	3.860	4.960	
						Rucker Atlas Brad.TC-4S		5.000	4.960
						Rucker Atlas Bradford			
						FL-3S & FL-4S	3.845	4.500	
						Hydril CS	3.840	4.935	
						Hydril Super FJ	3.840	4.594	
						Mannesmann TDS	3.921	5.201	
	14.98	15.50	0.337	3.826	3.701	Rucker Atlas Bradford DSS-HT & IJ-3SS	3.751	5.060	
						Rucker Atlas Bradford IJ-4S	3.766	5.200	
						Rucker Atlas Brad.TC-4S		5.250	5.200
		15.10				Rucker Atlas Bradford FL-3S & FL-4S	3.751	4.500	
		15.50				Hydril PH-6	3.765	5.125	
		15.10				Mannesmann TDS	3.827	5.201	
	16.44	16.90	3.73	3.754	3.679	Rucker Atlas Brad.DSS-HT	3.679	5.150	
						Rucker Atlas Brad.IJ-4S	3.680	5.200	
						Rucker Atlas Brad.TC-4S		5.250	5.200
						Rucker Atlas Bradford FL-3S & FL-4S	3.679	4.500	
	18.69	19.20	0.430	3.640	3.515	Rucker Atlas Bradford DSS-HT & IJ-3SS	3.565	5.260	
						Rucker Atlas Brad.IJ-4S	3.580	5.200	
						Rucker Atlas Brad.TC-4S		5.250	5.200
						Rucker Atlas Bradford FL-3S & FL-4S	3.565	4.500	
						Hydril PH-6	3.560	5.312	

DIMENSIONAL DATA - NON-API TUBING

OD (in.)	Weight (lb/ft)		Tubular			Type of Joint	Joint		
	Plain End	Nom.	Wall (in.)	ID (in.)	Drift (in.)		ID* (in.)	Regular OD (in.)	Special OD (in.)
4.500	21.36	21.60	0.500	3.500	3.375	Rucker Atlas Brad.DSS-HT	3.425	5.375	
						Rucker Atlas Brad.IJ-4S	3.425	5.375	
						Rucker Atlas Brad.TC-4S		5.375	5.300
						Rucker Atlas Bradford			
						FL-3S & FL-4S	3.425	4.500	
						Hydril PH-4	3.420	5.500	
	23.56	24.60	0.560	3.380	3.255	Hydril PH-4	3.300	5.562	
	26.04	26.50	0.630	3.240	3.115	Hydril PH-4	3.160	5.687	

TUBING STRETCH TABLE

OD (in.)	WT (lb/ft)	ID (in.)	Stretch Constant (in./1000 lb /1000 ft)	Free Point Constant
1.050 (3/4)	1.14	0.824	1.20120	832.5
	1.20	0.824	1.20120	832.5
1.315 (1)	1.30	1.125	1.09890	910.0
	1.43	1.097	0.96852	1,032.5
	1.63	1.065	0.85653	1,167.5
	1.70	1.049	0.80972	1,235.0
	1.72	1.049	0.80972	1,235.0
	1.80	1.049	0.80972	1,235.0
1.660 (1 1/4)	2.10	1.410	0.66335	1,507.5
	2.30	1.380	0.59791	1,672.5
	2.33	1.380	0.59791	1,672.5
	2.40	1.380	0.59791	1,672.5
1.9000 (1 1/2)	2.40	1.650	0.57389	1,742.5
	2.60	1.610	0.50063	1,997.5
	2.72	1.610	0.50063	1,997.5
	2.75	1.610	0.50063	1,997.5
	2.76	1.610	0.50063	1,997.5
	2.90	1.610	0.50063	1,997.5
2.000 (2)	3.30	1.670	0.42061	2,377.5
	3.40	1.670	0.42061	2,377.5
2.063 (2 1/16)	2.66	1.813	0.52562	1,902.5
	3.25	1.751	0.42781	2,337.5
	3.30	1.751	0.42781	2,337.5
	3.40	1.751	0.42781	2,337.5

TUBING STRETCH TABLE

OD (in.)	WT (lb/ft)	ID (in.)	Stretch Constant (in./1000 lb /1000 ft)	Free Point Constant
2.375 (2 3/8)	3.10	2.125	0.45249	2,210.0
	3.32	2.107	0.42418	2,357.5
	4.00	2.041	0.34542	2,895.0
	4.60	1.995	0.30675	3,260.0
	4.70	1.995	0.30675	3,260.0
	5.30	1.939	0.27082	3,692.5
	5.80	1.867	0.23641	4,230.0
	5.95	1.867	0.23641	4,230.0
	6.20	1.853	0.23081	4,332.5
	7.70	1.703	0.18587	5,380.0
	4.36	2.579	0.31546	3,170.0
	4.64	2.563	0.30008	3,332.5
2.875 (2 7/8)	6.40	2.441	0.22075	4,530.0
	6.50	2.441	0.22075	4,530.0
	7.90	2.323	0.17746	5,635.0
	8.60	2.259	0.16103	6,210.0
	8.70	2.259	0.16103	6,210.0
	8.90	2.243	0.15748	6,350.0
	9.50	2.195	0.14771	6,770.0
	10.40	2.151	0.13996	7,145.0
	11.00	2.065	0.12727	7,857.5
	11.65	1.995	0.11884	8,415.0
3.500 (3 1/2)	5.63	3.188	0.24405	4,097.5
	5.75	3.188	0.24405	4,097.5
	7.70	3.068	0.17953	5,570.0
	9.20	2.992	0.15444	6,475.0
	9.30	2.992	0.15444	6,475.0
	10.20	2.922	0.13722	7,287.5
	10.30	2.922	0.13722	7,287.5
	12.80	2.764	0.11047	9,052.5
	12.95	2.750	0.10864	9,205.0
	13.70	2.673	0.09975	10,025.0
	14.70	2.601	0.092885	10,770.0
	15.10	2.602	0.09294	10,760.0
	15.80	2.524	0.08662	11,545.0
	17.05	2.440	0.08089	12,362.5

TUBING STRETCH TABLE

OD (in.)	WT (lb/ft)	ID (in.)	Stretch Constant (in./1000 lb /1000 ft)	Free Point Constant
4.000 (4)	9.40	3.548	0.14925	6,700.0
	9.50	3.548	0.14925	6,700.0
	10.80	3.476	0.13000	7,692.5
	10.90	3.476	0.13000	7,692.5
	11.00	3.476	0.13000	7,692.5
	11.60	3.428	0.11987	8,342.5
	13.40	3.340	0.10512	9,512.5
4.500 (4 1/2)	12.60	3.928	0.11111	9,000.0
	12.75	3.928	0.11111	9,000.0
	15.10	3.826	0.09076	11,017.5
	15.50	3.826	0.09076	11,017.5
	16.90	3.754	0.08271	12,090.0
	19.00	3.640	0.07275	13,745.0

NON-UPSET RECOMMENDED MAKE-UP TORQUE

OD (in.)	Weight (lb/ft)	Grade	Torque (ft-lb)		
			Minimum	Optimum	Maximum
1.050	1.14	H-40	110	140	180
		J-55	140	180	230
		C-75	170	230	290
		N-80	190	250	310
1.315	1.70	H-40	160	210	260
		J-55	200	270	340
		C-75	270	360	450
		N-80	290	380	480
1.660	2.30	H-40	200	270	340
		J-55	260	350	440
		C-75	350	460	580
		N-80	370	490	610
1.900	2.75	H-40	240	320	400
		J-55	310	410	500
		C-75	410	540	680
		N-80	430	570	700
2.375	4.00	H-40	350	470	590
		J-55	460	610	760
		C-75	600	800	1,000
		N-80	640	850	1,060
	4.60	H-40	420	560	700
		J-55	550	730	910
		C-75	720	960	1,200
		N-80	770	1,020	1,280
		P-105	960	1,280	1,600
	5.80	C-75	1,040	1,380	1,730
		N-80	1,100	1,460	1,830
		P-105	1,380	1,840	2,300
2.875	6.40	H-40	600	800	1,000
		J-55	790	1,050	1,310
		C-75	1,040	1,380	1,730
		N-80	1,100	1,470	1,840
		P-105	1,390	1,850	2,310
	8.60	C-75	1,570	2,090	2,600
		N-80	1,660	2,210	2,760
		P-105	2,090	2,790	3,490

NON-UPSET RECOMMENDED MAKE-UP TORQUE

OD (in.)	Weight (lb/ft)	Grade	Torque (ft-lb)		
			Minimum	Optimum	Maximum
3.500	7.70	H-40	690	920	1,150
		J-55	910	1,210	1,510
		C-75	1,200	1,600	2,000
		N-80	1,280	1,700	2,130
	9.20	H-40	840	1,120	1,400
		J-55	1,110	1,480	1,850
		C-75	1,460	1,950	2,440
		N-80	1,550	2,070	2,590
		P-105	1,970	2,620	3,280
	10.20	H-40	980	1,310	1,640
		J-55	1,290	1,720	2,150
		C-75	1,700	2,270	2,840
		N-80	1,810	2,410	3,010
	12.70	C-75	2,270	3,030	3,790
		N-80	2,410	3,210	4,010
		P-105	3,050	4,060	5,080
4.000	9.50	H-40	710	940	1,180
		J-55	930	1,240	1550
		C-75	1,230	1,640	2,050
		N-80	1,310	1,740	2,180
4.500	12.60	H-40	990	1,320	1,650
		J-55	1,310	1,740	2,180
		C-75	1,730	2,300	2,880
		N-80	1,830	2,440	3,050

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EXTERNAL UPSET RECOMMENDED MAKE-UP TORQUE

OD (in.)	Weight (lb/ft)	Grade	Torque (ft-lb)		
			Minimum	Optimum	Maximum
1.050	1.20	H-40	350	460	580
		J-55	450	600	750
		C-75	590	780	980
		N-80	620	830	1,040
1.315	1.80	H-40	330	440	550
		J-55	430	570	710
		C-75	560	740	930
		N-80	590	790	990
1.660	2.40	H-40	400	530	660
		J-55	520	690	860
		C-75	680	910	1,140
		N-80	720	960	1,200
1.900	2.90	H-40	500	670	840
		J-55	660	880	1,100
		C-75	860	1,150	1,440
		N-80	920	1,220	1,530
2.375	4.70	H-40	740	990	1,240
		J-55	970	1,290	1,610
		C-75	1,280	1,700	2,130
		N-80	1,350	1,800	2,250
		P-105	1,700	2,270	2,840
	5.95	C-75	1,590	2,120	2,650
		N-80	1,680	2,240	2,800
		P-105	2,120	2,830	3,540
2.875	6.50	H-40	940	1,250	1,560
		J-55	1,240	1,650	2,060
		C-75	1,630	2,170	2,710
		N-80	1,730	2,300	2,880
		P-105	2,180	2,910	3,640
	8.70	C-75	2,140	2,850	3,560
		N-80	2,270	3,020	3,780
		P-105	2,860	3,810	4,760
3.500	9.30	H-40	1,300	1,730	2,160
		J-55	1,710	2,280	2,850
		C-75	2,260	3,010	3,760
		N-80	2,400	3,200	4,000
		P-105	3,040	4,050	5,060

EXTERNAL UPSET RECOMMENDED MAKE-UP TORQUE

OD (in.)	Weight (lb/ft)	Grade	Torque (ft-lb)		
			Minimum	Optimum	Maximum
3.500	12.95	C-75	3,030	4,040	5,050
		N-80	3,220	4,290	5,360
		P-105	4,070	5,430	6,790
4.000	11.00	H-40	1,460	1,940	2,430
		J-55	1,920	2,560	3,200
		C-75	2,540	3,390	4,240
		N-80	3,420	4,560	5,700
4.500	12.75	H-40	1,620	2,160	2,700
		J-55	2,150	2,860	3,180
		C-75	2,840	3,780	4,730
		N-80	3,020	4,020	5,030

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INTEGRAL JOINT RECOMMENDED MAKE-UP TORQUE

OD (in.)	Weight (lb/ft)	Grade	Torque (ft-lb)		
			Minimum	Optimum	Maximum
1.315	1.72	H-40	230	310	390
		J-55	300	400	500
		C-75	390	520	650
		N-80	410	550	690
1.660	2.10 & 2.33	H-40	280	380	480
		J-55	380	500	630
	2.33	C-75	490	650	810
		N-80	520	690	860
1.900	2.40 & 2.76	H-40	340	450	560
		J-55	440	580	730
	2.76	C-75	570	760	950
		N-80	610	810	1,010
2.063	3.25	H-40	430	570	710
		J-55	560	740	920
		C-75	730	970	1,210
		N-80	770	1,030	1,290

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Section V
Casing Data

Casing Areas - ID, OD, and Cross Sectional ____ V-2

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Recommended Make-Up Torque
- Short Thread ____ V-46
- Long Thread ____ V-49

CASING AREAS

OD (in.)	WT (lb/ft)	ID (in.)	ID Area (in^2)	OD Area (in^2)	Cross Sectional Area (in^2)
4 1/2"	9.50	4.090	13.1382	15.9043	2.76609
	10.50	4.052	12.8952	15.9043	3.00910
	11.60	4.000	12.5664	15.9043	3.33790
	12.60	3.958	12.3039	15.9043	3.60040
	13.50	3.920	12.0687	15.9043	3.83560
	15.10	3.826	11.4969	15.9043	4.40740
	16.60	3.754	11.0682	15.9043	4.83610
	16.90	3.740	10.9858	15.9043	4.91850
	17.70	3.696	10.7289	15.9043	5.17540
	18.80	3.6740	10.4062	15.9043	5.49810
	21.60	3.500	9.6211	15.9043	6.28320
	24.60	3.380	8.9727	15.9043	6.93160
	26.50	3.240	8.2448	15.9043	7.65950
5"	11.50	4.560	16.3312	19.6349	3.30370
	13.00	4.494	15.8619	19.6349	3.77300
	15.00	4.408	15.2606	19.6349	4.37430
	18.00	4.276	14.3603	19.6349	5.27460
	20.30	4.184	13.7491	19.6349	5.88590
	20.80	4.156	13.5656	19.6349	6.06930
	23.20	4.044	12.8443	19.6349	6.79060
	24.20	4.000	12.5664	19.6349	7.06860
5 1/2"	14.00	5.012	19.7293	23.7583	4.02900
	15.50	4.950	19.2442	23.7583	4.51410
	17.00	4.892	18.7959	23.7583	4.96240
	20.00	4.778	17.9301	23.7583	5.82820
	23.00	4.670	17.1287	23.7583	6.62960

CASING AREAS

OD (in.)	WT (lb/ft)	ID (in.)	ID Area (in^2)	OD Area (in^2)	Cross Sectional Area (in^2)
5 1/2"	26.00	4.548	16.2454	23.7583	7.51290
	28.40	4.490	15.8337	23.7583	7.92460
	32.30	4.276	14.3603	23.7583	9.39790
	36.40	4.090	13.1382	23.7583	10.62010
6"	18.00	5.424	23.1062	28.2743	5.16810
	20.00	5.352	22.4969	28.2743	5.77750
	23.00	5.240	21.5651	28.2743	5.70920
	26.00	5.132	20.6853	28.2743	7.58900
6 5/8"	20.00	6.049	28.7380	34.4716	5.73360
	24.00	5.921	27.5347	34.4716	6.93690
	28.00	5.791	26.3388	34.4716	8.13270
	32.00	5.675	25.2942	34.4716	9.17740
7"	17.00	6.538	33.5722	38.4845	4.91230
	20.00	6.456	32.7353	38.4845	5.74920
	23.00	6.366	31.8290	38.4845	6.65550
	26.00	6.276	30.9354	38.4845	7.54910
	29.00	6.184	30.0351	38.4845	8.44940
	32.00	6.094	29.1672	38.4845	9.31730
	35.00	6.004	28.3120	38.4845	10.17250
	38.00	5.920	27.5254	38.4845	10.95910
	41.00	5.820	26.6033	38.4845	11.88120
	44.00	5.720	25.6969	38.4845	12.78750
	49.50	5.540	24.1051	38.4845	14.37940
7 5/8"	24.00	7.025	38.7599	45.6635	6.90360
	26.40	6.969	38.1444	45.6635	7.51910
	29.70	6.875	37.1223	45.6635	8.54120

CASING AREAS

OD (in.)	WT (lb/ft)	ID (in.)	ID Area (in^2)	OD Area (in^2)	Cross Sectional Area (in^2)
7 5/8"	33.70	6.765	35.9439	45.6635	9.71960
	39.00	6.625	34.4716	45.6635	11.19190
	45.30	6.435	32.5227	45.6635	13.14080
8 5/8"	24.00	8.097	51.4918	58.4262	6.93440
	28.00	8.017	50.4793	58.4262	7.94690
	32.00	7.921	49.2776	58.4262	9.14860
	36.00	7.825	48.0904	58.4262	10.33580
	40.00	7.725	46.8691	58.4262	11.55710
	44.00	7.625	45.6635	58.4262	12.76270
	49.00	7.511	44.3083	58.4262	14.11790
	52.00	7.435	43.4162	58.4262	15.01000
9 5/8"	32.60	9.001	63.6313	72.7597	9.12840
	36.00	8.921	62.5053	72.7597	10.25450
	40.00	8.835	61.3059	72.7597	11.45380
	43.50	8.755	60.2007	72.7597	12.55900
	47.00	8.681	59.1874	72.7597	13.57230
	53.50	8.535	57.2132	72.7597	15.54650
	58.40	8.435	55.8804	72.7597	16.87930
	61.10	8.375	55.0883	72.7597	17.67140
	71.80	8.125	51.8485	72.7597	20.91120
10 3/4"	32.75	10.192	81.5846	90.7625	9.17790
	40.50	10.050	79.3271	90.7625	11.43540
	45.50	9.950	77.7563	90.7625	13.00620
	51.00	9.850	76.2012	90.7625	14.56130
	55.50	9.760	74.8151	90.7625	15.94740
	60.70	9.660	73.2898	90.7625	17.47270

CASING AREAS

OD (in.)	WT (lb/ft)	ID (in.)	ID Area (in^2)	OD Area (in^2)	Cross Sectional Area (in^2)
10 3/4"	65.70	9.560	71.7803	90.7625	18.98220
	71.10	9.450	70.1380	90.7625	20.62450
	76.00	9.350	68.6614	90.7625	22.10110
	81.00	9.250	67.2006	90.7625	23.56190
11 3/4"	42.00	11.084	96.4901	108.4339	11.94390
	47.00	11.000	95.0331	108.4339	13.40080
	54.00	10.880	92.9710	108.4339	15.46300
	60.00	10.772	91.1344	108.4339	17.29960
	35.00	10.682	89.6179	108.4339	18.81610
	71.00	10.586	88.0143	108.4339	20.41960
13 3/8"	48.00	12.715	126.9762	140.5002	13.52410
	54.50	12.615	124.9868	140.5002	15.51350
	51.00	12.515	123.0131	140.5002	17.48720
	68.00	12.415	121.0551	140.5002	19.44520
	72.00	12.347	119.7326	140.5002	20.76770
	77.00	12.275	118.3403	140.5002	22.16000
	80.70	12.215	117.1862	140.5002	23.31410
	85.00	12.159	116.1142	140.5002	24.38610
	86.00	12.125	115.4657	140.5002	25.03450
	92.00	12.031	113.6823	140.5002	26.87190
	98.00	11.937	111.9128	140.5002	28.58740
16"	65.00	15.250	182.6540	201.0618	18.40780
	75.00	15.124	179.6482	201.0618	21.41360
	84.00	15.010	176.9501	201.0618	24.11160
	109.00	14.688	169.4396	201.0618	31.62220
18 5/8"	87.50	17.755	247.5887	272.4470	24.85830

CASING AREAS

OD (in.)	WT (lb/ft)	ID (in.)	ID Area (in^2)	OD Area (in^2)	Cross Sectional Area (in^2)
20"	94.00	19.124	287.2414	314.1590	26.91760
	106.50	19.000	283.5285	314.1590	30.63050
	133.00	18.730	275.5276	314.1590	38.63140

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
4 1/2 114,3	9.5	0.205 5,207	4.090 103,8	3.965 100,7	5.000 127,00	H-40 J-55 K-55	2,770 3,310 3,310
	10.5	0.224 5,689	4.052 102,9	3.927 99,75	5.000 127,00	J-55 K-55	4,010 4,010
	11.6	0.250 6,350	4.000 101,6	3.875 98,43	5.000 127,00	J-55 K-55 C-75 N-80 C-95 P-110	4,960 4,960 6,130 6,350 7,010 7,560
	12.6	0.271 6,883	3.958 100,5	3.833 97,36		K-55 C-75 N-80 C-95	5,720 7,200 7,500 8,400
	13.5 13.6	0.290 7,366	3.920 99,57	3.795 96,39	5.000 127,00	K-55 C-75 N-80 C-95 P-110 V-150	6,420 8,170 8,540 9,650 10,670 12,880
	15.1	0.337 8,559	3.826 97,18	3.701 94,00	5.000 127,00	K-55 C-75 N-80 C-95 P-110 V-150	7,620 10,390 11,080 14,320 18,110
	16.6 16.8 17.1	0.373 9,474	3.754 95,35	3.629 92,17		K-55 C-75 N-80 C-95 P-110 V-150	8,360 11,400 12,160 14,440 16,720 22,110

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
3,190	3,190			111	77		4 1/2
4,380	4,380			152	101		114,3
4,380	4,380			152	112		
4,790	4,790			165	132		
4,790	4,790			165	146		
5,350	5,350	5,350	5,350	184	154	162	
5,350	5,350	5,350	5,350	184	170	180	
7,290		7,290	7,290	250		212	
7,780		7,780	7,780	267		223	
9,240		9,240	9,240	317		234	
10,690		10,690	10,690	367		279	
5,790				199			
7,900				271			
8,440				289			
10,010				343			
6,200				211			
8,460		8,460	8,460	288		257	
9,020		9,020	9,020	307		270	
10,710		10,710	10,710	364		284	
12,410		12,410	12,410	422		338	
16,920				576			
7,210				242			
9,830				331			
10,480				353			
				419			
14,420		14,420	13,460	485		406	
19,660				661			
7,980				266			
10,880				363		299(8)	
11,600				387		314(8)	
13,780				459		330(8)	
15,960				532		393(8)	
21,760				725			

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
4 1/2 114,3	16.9	0.380 9,652	3.740 94,99	3.615 91,82		C-95 P-110 V-150	14,690 17,010 22,890
	17.7	0.402 10,21	3.696 93,87	3.571 90,70		C-95 P-110 V-150	15,450 17,890 24,390
	18.8 20.0	0.430 10,92	3.640 92,56	3.515 89,28		K-55 C-75 N-80 C-95 P-110 V-150	9,510 12,960 13,830 16,420 19,010 25,930
	21.6	0.500 12,70	3.500 88,90	3.375 85,73		K-55 C-75 N-80 P-110 V-150	10,860 14,810 15,800 21,730 29,630
	24.6	0.560 14,22	3.380 85,85	3.255 82,68		N-80 P-110 V-150	17,430 23,970 32,690
	26.5	0.630 16,00	3.240 82,29	3.115 79,12		N-80 P-110 V-150	19,260 26,490 36,120
5 127,0	11.5	0.220 5,588	4.560 115,82	4.435 112,65	5.563 141,30	J-55 K-55	3,060 3,060
	13.0	0.253 6,426	4.494 114,14	4.283 108,79	5.563 141,30	J-55 K-55 C-75 N-80	4,140 4,140 4,990 5,140

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
14,040 16,260 22,170				467 541 738			4 1/2 114,3
14,810 17,140 23,380				492 569 776			
9,200 12,540 13,380 15,890 18,390 25,080				302 412 440 522 605 825			
10,690 14,580 15,560 21,390 29,170				345 471 503 691 942			
17,420 23,960 32,670				554 762 1,040			
19,600 26,950 36,750				613 842 1,040			
4,240 4,240	4,240 4,240			182 182	133 147		5 127,00
4,870 4,870 6,640 7,090	4,870 4,870	4,870 4,870	4,870 4,870	208 208 283 302	169 186	182 201	

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
5 127,0	15.0	0.296 7,518	4.408 111,96	4.283 108,79	5.563 141,30	J-55 K-55 C-75 N-80 C-95 P-110 V-150	5,550 5,550 6,970 7,250 8,090 8,830 10,260
	18.0	0.360 9,144	4.276 108,61	4.151 105,44	5.563 141,30	K-55 C-75 N-80 C-95 P-110 V-150	7,390 10,000 10,490 12,010 13,450 16,860
	20.3	0.408 10,36	4.184 106,27	4.059 103,09		K-55 C-75 N-80 P-100 V-150	8,240 11,240 11,990 16,490 21,470
	20.8	0.422 10,72	4.156 105,56	4.031 102,39		K-55 C-75 N-80 P-110 V-150	8,500 11,590 12,360 17,000 22,870
	23.2 23.6	0.478 12,14	4.044 102,72	3.919 99,54		K-55 C-75 N-80 C-95 P-110 V-150	9,510 12,970 13,830 16,430 19,020 25,940
	24.2	0.500 12,70	4.000 101,60	3.875 98,43		K-55 N-80 P-110 V-150	9,900 14,400 19,800 27,000

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
5,700 5,700 7,700 8,290 9,840 11,400 15,540	5,700 5,700	5,700 5,700 7,700 8,290 9,840	5,700 5,700 7,700 8,290 9,840	241 241 328 350 416 481 656	207 228	223 246 295 311 326	5 127.00
6,970 9,500 10,140 12,040 13,940 19,000		9,500 10,140 12,040 13,940	9,290 9,910 11,770 13,620	290 396 422 501 580 791		376 396 416 495	
7,850 10,710 11,420 15,710 21,420				324 441 471 647 883			
8,120 11,080 11,820 16,250 22,160				334 455 486 668 910			
9,200 12,500 13,380 15,890 18,400 25,100				373 509 543 645 747 1,019			
9,630 14,000 19,250 26,250							

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
5 1/2 139,7	14.0	0.244 6,198	5.012 127,30	4.887 124,13	6.050 153,67	H-40 J-55 K-55 C-75	2,630 3,120 3,120 3,560
	15.5	0.275 6,985	4.950 125,73	4.825 122,56 4.653 118,19 (10)	6.050 153,67	J-55 K-55 C-75 N-80 P-110	4,040 4,040 4,860 4,990 5,620
	17.0	0.304 7,722	4.892 124,26	4.767 121,08 4.653 118,19 (10)	6.050 153,67	J-55 K-55 C-75 N-80 C-95 P-110 V-150	4,910 4,910 6,070 6,280 6,930 7,460 8,300
	20.0	0.361 9,169	4.778 121,36	4.653 118,19	6.050 153,67	K-55 C-75 N-80 C-95 P-110 V-150	6,610 8,440 8,830 10,000 11,080 13,480
	23.0	0.415 10,541	4.670 118,62	4.545 115,44	6.050 153,67	K-55 C-75 N-80 C-95 P-110 V-150	7,670 10,400 11,160 12,920 14,520 18,390

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
3,110	3,110			161	130		5 1/2
4,270	4,270			222	172		139,70
4,270	4,270			222	189		
5,820				302			
4,810	4,810	4,810	4,810	248	202	217	
4,810	4,810	4,810	4,810	248	222	239	
6,560				339			
7,000				362			
9,620				497			
5,320	5,320	5,320	5,320	273	229	247	
5,320	5,320	5,320	5,320	273	252	272	
7,250		7,250	7,250	372		327	
7,740		7,740	7,740	397		348	
9,190		9,190	9,190	471		374	
10,640		10,640	10,640	546		445	
14,510				744			
6,310				321			
8,610		8,610	8,430	437		403	
9,190		9,190	8,990	466		428	
10,910		10,910	10,680	554		460	
12,640		12,640	12,360	641		548	
17,220				874			
7,270				365			
9,900		9,260	8,430	497		473	
10,560		9,880	8,990	530		502	
12,540		11,730	10,680	630		540	
14,520		13,580	12,360	729		643	
19,810				994			

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
5 1/2 139,7	26.0	0.476 12,09	4.548 115,52	4.423 112,34		K-55 C-75 N-80 C-95 P-110 V-150	8,700 11,860 12,650 15,020 17,390 23,720
	28.4	0.530 13,46	4.440 112,78	4.315 109,60		C-75 N-80 P-110	
	32.3	0.612 15,54	4.276 108,61	4.151 105,44		N-80 P-110 V-150	15,820 21,760 29,670
	36.4	0.705 17,91	4.090 103,89	3.965 100,71		N-80 P-110 V-150	17,880 24,590 33,530
6 152,4	18.0	0.288 7,315	5.424 137,77	5.299 134,59	6.625 168,28	H-40 J-55 N-80	2,780 3,620 4,740
	20.0	0.324 8,229	5.352 135,94	5,227 132,80	6.625 168,28	N-80	5,690
	23.0	0.380 9,652	5.240 133,09	5.115 129,92	6.625 168,28	N-80 P-110	7,180 10,380
	26.0	0.434 11,02	5.132 130,35	5.007 127,18	6.625 168,28	P-110	12,380
6 5/8 168,3	20.0	0.288 7,315	6.049 153,64	5.924 150,47	7.390 187,70	H-40 J-55 K-55 N-80 C-95	2,520 2,970 2,970 3,480 3,830

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread		Short	Long	
	Short	Long					
8,330 11,360 12,120 14,390 16,660 22,720				413 563 601 714 826 1,127	464(8) 488(8) 513(8) 610(8)	503(3) 629(3) 805(3)	5 1/2 139,7
				621 662 910			
15,580 21,420 29,210				752 1,034 1,410			
17,950 24,680 33,650				850 1,168 1,593			
	3,360 4,620	6,720		206 283 412	179 239	279 323	6 152,40
		7,560		461		366	
		8,870 12,190		737 536		432 565	
		13,920		833		646	
3,040 4,180 4,180 6,090 7,230	3,040 4,180 4,180	4,180 4,180	4,180 4,180	229 315 315 459 545	184 245 267	266 290	6 5/8 168,28

Section V

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
6 5/8 168,3	24.0	0,.352 8,941	5.921 150,39	5.796 147,22 5.730 145,54 (10)	7.390 187,70	J-55 K-55 C-75 N-80 C-95 P-110 V-150	4,560 4,560 5,570 5,760 6,290 6,710 7,350
	28.0	0.417 10,59	5.791 147,09	5.666 143,92	7.390 187,70	K-55 C-75 N-80 C-95 P-110 V-150	6,170 7,830 8,170 9,200 10,140 12,130
	32.0	0.475 12,07	5.675 144,15	5.550 140,97	7.390 187,70	K-55 C-75 N-80 C-95 P-110 V-150	7,320 9,830 10,320 11,800 13,200 16,510
7 177,8	17.0	0.231 5,867	6.538 166,07	6.413 162,89	7.656 194,46	H-40	1,450
	20.0	0.272 6,909	6.456 163,98	6.331 160,81	7.656 194,46	H-40 J-55 K-55 C-75	1,980 2,270 2,270 2,660
	23.0	0.317 8,052	6.366 161,69	6.241 158,52 6.151 156,24 (10)	7.656 194,46	J-55 K-55 C-75 N-80 C-95	3,270 3,270 3,770 3,830 4,150

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
5,110	5,110	5,110	5,110	382	314	340	6 5/8
5,110	5,110	5,110	5,110	382	342	372	168,28
6,970		6,970	6,970	520		453	
7,440		7,440	7,440	555		481	
8,830		8,830	8,830	659		546	
10,230		10,230	10,230	763		641	
13,960				1,041			
6,060				447			
8,260		8,260	8,260	610		552	
8,810		8,810	8,810	651		586	
10,460		10,460	10,460	773		665	
12,120		12,120	12,120	895		781	
16,510				1,220			
6,900				504			
9,410		9,410	9,200	688		638	
10,040		10,040	9,820	734		677	
11,920		11,920	11,660	872		769	
13,800		13,800	13,500	1,009		904	
18,820				1,377			
2,310	2,310			196	122		7
							177,80
2,720	2,720			230	176		
3,740	3,740			316	234		
3,740	3,740			316	234		
5,100				431			
4,360	4,360	4,360	4,360	366	284	313	
4,360	4,360	4,360	4,360	366	309	341	
5,940		5,940	5,940	499		416	
6,340		6,340	6,340	532		442	
7,530		7,530	7,530	632		505	

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
7 177,8	26.0	0.362 9,195	6.276 159,41	6.151 156,26	7.656 194,46	J-55 K-55 C-75 N-80 C-95 P-110 V-150	4,320 4,320 5,250 5,410 5,870 6,210 6,890
	29.0	0.408 10,36	6.184 157,07	6.059 153,89	7.656 194,46	K-55 C-75 N-80 C-95 P-110 V-150	5,410 6,760 7,020 7,820 8,510 9,800
	32.0	0.450 11,43	6.094 154,79	5.969 151,61	7.856 194,46	K-55 C-75 N-80 C-95 P-110 V-150	6,460 8,230 8,600 9,730 10,760 13,020
	35.0	0.498 12,65	6.004 152,50	5.879 149,33	7.656 194,46	K-55 C-75 N-80 C-95 P-110 V-150	7,270 9,710 10,180 11,640 13,010 16,230
	38.0	0.540 13,72	5.920 150,37	5.795 147,19	7.656 194,46	K-55 C-75 N-80 C-95 P-110 V-150	7,830 10,680 11,390 13,420 15,110 19,240

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
4,980	4,980	4,980	4,980	415	334	367	7
4,980	4,980	4,980	4,980	415	364	401	177,8
6,790		6,790	6,790	566		489	
7,240		7,240	7,240	604		519	
8,600		8,600	8,600	717		593	
9,960		9,960	9,960	830		693	
13,580				1,132			
5,610				465			
7,650		7,650	7,650	634		562	
8,160		8,160	8,160	676		597	
9,690		9,690	9,690	803		683	
11,220		11,220	11,220	929		797	
15,300				1,267			
6,230				512			
8,490		8,490	7,930	699		633	
9,060		9,060	8,460	745		672	
10,760		10,760	10,050	885		768	
12,460		12,460	11,640	1,025		897	
16,980				1,397			
6,850				559			
9,340		8,680	7,930	763		703	
9,960		9,240	8,460	814		746	
11,830		10,970	10,050	966		853	
13,700		12,700	11,640	1,119		996	
18,660				1,526			
7,420				603			
10,120		8,660	7,930	822		767	
10,800		9,240	8,460	877		814	
12,820		10,970	10,050	1,041		931	
14,850		12,700	11,640	1,205		1,087	
20,240				1,644			

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
7 177,8	41.0	0.590 14,99	5.820 147,83	5.695 144,65		C-95 P-110 V-150	14,670 16,990 23,160
	44.0	0.640 16,26	5.720 145,29	5.595 142,11		C-95 P-110 V-150	15,780 18,820 24,920
	49.5	0.730 18,54	5.540 140,72	5.415 137,54		P-110 V-150	20,550 28,020
7 5/8 193,7	24.0	0.300 7,620	7.025 178,44	6.900 175,26	8.500 215,9	H-40	2,040
	26.4	0.328 8,331	6.969 177,01	6.844 173,84 6.750 171,45 (10)	8.500 215,9	J-55 K-55 C-75 N-80 C-95 P-110 V-150	2,890 2,890 3,280 3,400 3,710 3,930 4,080
	29.7	0.375 9,525	6.875 174,62	6.750 171,45	8.500 215,9	C-75 N-80 C-95 P-110 V-150	4,670 4,790 5,120 5,340 6,060
	33.7	0.430 10,92	6.765 171,83	6.640 168,66	8.500 215,9	K-55 C-75 N-80 C-95 P-110 V-150	5,090 6,320 6,560 7,260 7,850 8,860

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
14,010 16,220 22,120				1,129 1,306 1,782			7 177,8
15,200 17,600 24,000				1,215 1,407 1,918			
20,080 27,380				1,582 2,157			
2,750	2,750			276	212		7 5/8 193,7
4,140 4,410 5,650 6,020 7,150 8,280 11,290	4,140 4,140	4,140 4,140 5,650 6,020 7,150	4,140 4,140 5,650 6,020 7,150	414 414 564 602 714 827 1,128	315 642	346 377 461 490 560	
6,450 6,890 7,150 9,470 12,910		6,450 6,890 7,150 9,470	6,450 6,890 7,150 9,470	641 683 714 940 1,281		542 575 659 769	
5,430 7,400 7,900 8,180 10,860 14,800		7,400 7,900 8,180 10,860	7,400 7,900 8,180 10,860	535 729 778 923 1,069 1,458		635 674 772 901	

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
7 5/8 193,7	39.0	0.500 12,70	6.625 168,28	6.500 165,10	8.500 215,9	K-55 C-75 N-80 C-95 P-110 V-150	 8,430 8,810 9,980 11,060 13,450
	45.3	0.595 15,11	6.435 163,45	6.310 160,27		K-55 C-75 N-80 P-110 V-150	7,910 10,790 11,510 15,420 19,680
7 3/4 196,9	46.1	0.595 15,11	6.560 166,62	6.500 165,10	8.500 215,9	K-55 N-80 S-95 S-105 P-110 V-150	7,800 11,340 12,650 1,3960 14,980 19,050
8 5/8 219,1	24.0	0.264 6,706	8.097 205,56	7.972 202,49	9.625 244,48	J-55 K-55	1,370 1,370
	28.0	0.304 7,722	8.017 203,63	7.892 200,46	9.625 244,48	H-40 K-55	1,640 1,880
	32.0	0.352 8,940	7.921 201,19	7.796 198,02 7.700 195,58 (10)	9.625 244,48	H-40 J-55 K-55 C-75 N-80 P-110	2,210 2,530 2,530 2,950 3,050 3,430

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
8,610 9,180 9,380 12,620 17,220		8,610 9,180 9,380 12,620	8,610 9,180 9,380 12,620	615 839 895 923 1,231 1,679			7 5/8 193,7
7,510 10,240 10,920 15,020 20,480				723 986 1,051 1,446 1,971			
7,390 10,750 12,760 12,760 14,780 20,150		12,460 12,460	11,620 11,620	1,070 1,271		992 1,065	7 3/4 196,9
2,950 2,950	2,950 2,950			381 381	244 263		8 5/8 219,01
2,470 3,390	2,470			318 437	233		
2,860 3,930 3,930 5,360 5,710 7,860	2,860 3,930 3,930	3,930 3,930	3,930 3,930	366 503 503 686 732 1,006	279 372 402	417 452	

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
8 5/8 219,1	36.0	0.400 10,16	7.825 198,76	7.700 195,58	9.625 244,46	J-55 K-55 C-75 N-80 C-95 P-110	3,450 3,450 4,020 4,100 4,360 4,700
	40.0	0.450 11,43	7.725 196,22	7.600 193,04	9.625 244,46	K-55 C-75 N-80 C-95 P-110 V-150	4,400 5,350 5,520 6,010 6,380 7,040
	44.0	0.500 12,70	7.625 193,68	7.500 190,50	9.625 244,46	K-55 C-75 N-80 C-95 P-110 V-150	5,350 6,680 6,950 7,730 8,400 9,645
	49.0	0.557 14,15	7.511 190,78	7.386 187,60	9.625 244,46	K-55 C-75 N-80 C-95 P-100 V-150	6,440 8,200 8,570 8,690 10,720 12,950
	52.0	0.595 15,11	7.435 188,85	7.310 185,67		K-55 C-75 N-80 P-110 V-150	7,060 9,210 9,650 12,260 15,160
8 3/4 222,3	49.7	0.557 14,15	7.636 193,95	7.500 190,50	9.625 244,46	S-95 S-105	10,260 11,100
9 5/8 244,5	32.6	0.312 7,925	9.001 228,63	8.845 224,66	10.625 269,88	H-40	1,400

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
4,460	4,460	4,460	4,460	568	434	486	8 5/8
4,460	4,460	4,460	4,460	568	468	526	219.1
6,090		6,090	6,090	775		648	
6,490		6,490	6,490	827		688	
7,710		7,710	7,710	982		789	
8,930				1,137			
5,020				636			
6,850		6,850	6,850	867		742	
7,300		7,300	7,300	925		788	
8,670		8,670	8,670	1,098		904	
10,040		10,040	10,040	1,271		1,055	
13,700				1,734			
5,580				702			
7,610		7,610	7,610	957		834	
8,120		8,120	8,120	1,021		887	
9,640		9,640	9,640	1,212		1,017	
11,160		11,160	1,160	1,404		1,186	
15,210				1,915			
6,220				776			
8,480		8,480	8,480	1,059		939	
9,040		9,040	9,040	1,129		997	
10,740		10,740	10,740	1,341		1,144	
12,430		12,430	12,430	1,553		1,335	
16,940				2,120			
6,640				826			
9,050				1,126			
9,660				1,201			
13,280				1,651			
18,110				2,252			
10,580		10,580	10,580	1,362		1,017	8 3/4
10,580		10,580	10,580	1,362		1,095	222,3
2,270	2,270			365	254		9 5/8
							244,5

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
9 5/8 244,5	36.0	0.352 8,940	8.921 226,59	8.765 222,63	10.625 269,88	H-40 J-55 K-55 C-75 N-80 P-110	1,740 2,020 2,020 2,320 2,370 2,470
	40.0	0.395 10,03	8.835 224,40	8.679 220,45 8.599 218,41 (10)	10.625 269,88	J-55 K-55 C-75 N-80 C-95 P-110	2,570 2,570 2,980 3,090 3,330 3,480
	43.5	0.435 11,05	8.755 222,38	8.599 218,41	10.625 269,88	K-55 C-75 N-80 C-95 P-110 V-150	3,250 3,750 3,810 4,130 4,430 4,750
	47.0	0.472 11,99	8.681 220,49	8.525 216,54	10.625 269,88	K-55 C-75 N-80 C-95 P-100 V-150	3,880 4,630 4,750 5,080 5,310 6,020
	53.5	0.545 13,84	8.535 216,79	8.379 212,83	10.625 269,88	K-55 C-75 N-80 C-95 P-110 V-150	5,130 6,380 6,620 7,330 7,930 8,970

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
2,560 3,520 3,520 4,800 5,120 7,040	2,560 3,520 3,520	3,520 3,520	3,520 3,520	410 564 564 769 820 1,128	294 394 423	453 489	9 5/8 244,5
3,950 3,950 5,390 5,750 6,820 7,900	3,950 3,950	3,950 3,950 5,390 5,750 6,820	3,950 3,950 5,390 5,750 6,820	630 630 859 916 1,088 1,260	452 486	580 561 694 737 847	
4,350 5,930 6,330 7,510 8,700 11,860		5,930 6,330 7,510 8,700	5,930 6,330 7,510 8,700	691 942 1,005 1,193 1,381 1,818		776 825 948 1,106	
4,720 6,440 6,870 8,150 9,440 12,870		6,440 6,870 8,150 9,440	6,440 6,870 8,150 9,440	746 1,018 1,086 1,289 1,493 2,036		852 905 1,040 1,213	
5,450 7,430 7,930 9,410 10,900 14,860		7,430 7,930 9,410 10,900	7,430 7,930 9,410 10,900	855 1,166 1,244 1,477 1,710 2,332		999 1,062 1,220 1,442	

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
9 5/8 244,5	58.4	0.595 15,11	8.435 214,25	8.279 210,29 8.375 212,73 (11)	10.625 269,88	K-55 C-75 N-80 S-95 P-110 V-150	5,990 7,570 7,890 9,950 9,750 11,570
	61.1	0.625 15,88	8.375 212,73	8.219 208,76	10.625 269,88	C-95 S-95 P-110 V-150	9,800 10,500 10,840 13,130
	71.8	0.750 19,05	8.125 206,38	7.969 202,41	10.625 269,88	P-110 V-150	15,810 19,640
9 3/4 247,7	59.2	0.595 15,11	8.560 217,42	8.500 215,90 (11)	10.625 269,88	S-95 S-105	9,750 10,470
9 7/8 250,8	62.8	0.625 15,88	8.628 219,15	8.500 215,90 (11)	10.625 269,88	S-95 S-105	10,180 11,010
10 3/4 273,1	32.75	0.279 7,087	10.192 258,88	10.036 254,91	11.750 298,45	H-40	880
	40.5	0.350 8,890	10.050 255,27	9.894 251,31	11.750 298,45	H-40 J-55 K-55 C-75	1,420 1,580 1,580 1,720
	45.5	0.400 10,16	9.950 252,73	9.794 248,77	11.750 298,45	J-55 K-55 C-75 N-80 P-110	2,090 2,090 2,410 2,480 2,610

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
5,950 8,110 8,650 10,280 11,900 16,230		10,280	10,280	928 1,266 1,350 1,604 1,857 2,530		1,357	9 5/8 244,5
10,800 10,800 12,500 17,050		10,800	10,490	1,680 1,679 1,944 2,650		1,430	
15,000 20,450		18,060	16,560	2,300 3,137		2,672	
10,150 10,150		10,150 10,150	10,150 10,150	1,626 1,626		1,204 1,297	9 3/4 247,7
10,520 10,520		10,520 10,520	10,490 10,490	1,725 1,725		1,123 1,210	9 7/8 250.8
1,820	1,820			367	205		10 3/4 273,1
2,280 3,130 3,130 4,270	2,280 3,130 3,130		3,130 3,130	457 629 629 858	314 420 450		
3,580 3,580 4,880 5,210 7,160	3,580 3,580		3,580 3,580	715 715 975 1,041 1,430	493 528		

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
10 3/4 273,1	51.0	0.450 11,43	9.850 250,19	9.694 246,23	11.750 298,45	J-55 K-55 C-75 N-80 C-95 P-110	2,700 2,700 3,100 3,220 3,490 3,670
	55.5	0.495 12,57	9.760 247,90	9.604 243,94	11.750 298,45	K-55 C-75 N-80 C-95 P-110 V-150	3,320 3,950 4,020 4,300 4,630 5,040
	60.7	0.545 13,89	9.660 245,36	9.504 241,40	11.750 298,45	K-55 C-75 N-80 C-95 P-110 V-150	4,160 5,020 5,160 5,566 5,860 6,560
	65.7	0.595 15,11	9.560 242,82	9.404 238,86	11.750 298,45	K-55 C-75 N-80 C-95 P-110 V-150	4,920 6,080 6,300 6,950 7,490 8,330
	71.1	0.650 16,51	9.450 240,03	9.294 236,07	11.750 298,45	C-95 S-95 P-110 V-150	8,470 9,600 9,280 10,890
	76.0	0.700 17,78	9.350 237,49	9.194 233,53		C-95 P-110 V-150	9,850 10,900 13,220
	81.0	0.750 19,05	9.250 234,95	9.094 230,99	12.750 323,85	P-110 V-150	12,530 15,550

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
4,030	4,030		4,030	801	565		10 3/4
4,030	4,030		4,030	801	606		273,1
5,490	5,490		5,490	1,092	756		
5,860	5,860		5,860	1,165	804		
6,960	6,960		6,960	1,383	927		
8,060	8,060		8,060	1,602	1,080		
4,430				877			
6,040	6,040		6,040	1,196	843		
6,450	6,450		6,450	1,276	895		
7,660	7,660		7,660	1,515	1,032		
8,860	8,860		8,860	1,754	1,203		
12,090				2,392			
4,880				961			
6,650				1,310			
7,100				1,390			
8,436				1,648			
9,760	9,760		9,760	1,922	1,338		
13,310				2,620			
5,330				1,134			
7,260				1,424			
7,750				1,519			
9,200				1,803			
10,650	10,650		10,650	2,088	1,472		
14,530				2,847			
10,050				1,856			
10,050	9,710		9,480	1,959	1,403		
11,640	11,200		10,980	2,269	1,618		
15,070	15,070		14,970	3,094	2,174		
10,830				2,100			
12,530				2,431			
17,090				3,315			
13,430				2,592			
18,310				3,534			

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
11 3/4 298,5	42.0	0.333 8,458	11.084 281,53	10.928 277,57	12.750 323,85	H-40	1,070
	47.0	0.375 9,525	11.000 279,40	10.844 275,44	12.750 323,85	J-55 K-55 C-75 N-80	1,510 1,510 1,620
	54.0	0.435 11,05	10.880 276,35	10.721 272,31	12.750 323,85	J-55 K-55 C-75 N-80	2,070 2,070 2,380
	60.0	0.489 12,42	10.772 273,61	10.616 269,65	12.750 323,85	J-55 K-55 C-75 N-80 C-95 P-110 V-150	2,660 2,660 3,070 3,180 3,440 3,610 3,680
	65.0	0.534 13,56	10.682 271,32	10.526 267,36	12.750 323,85	K-55 C-75 N-80 S-95 P-110 V-150	3,290 3,810 3,870 5,740 4,490 4,850
	71.0	0.582 14,78	10.586 268,88	10.430 264,92	12.750 323,85	S-95	7,280
11 7/8 301,6	71.8	0.582 14,78	10.711 272,06	10.625 269,88 (11)	12.750 323,85	S-95	7,190
13 3/8 339,7	48.0	0.330 8,382	12.715 322,96	12.559 318,99	14.375 365,13	H-40	770
	54.5	0.380 9,652	12.615 320,42	12.459 316,46	14.375 365,13	J-55 K-55 N-80 P-110	1,130 1,130 1,130 1,130

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
1,980	1,980			478	307		11 3/4 298,5
3,070 3,070 4,190	3,070 3,070		3,070 3,070	737 737 1,005 1,072	477 509		
3,560 3,560 4,860	3,560 3,560		3,560 3,560	850 850 1,160 1,237	568 606		
4,010 4,010 5,460 5,830 6,920 8,010 10,920	4,010 4,010 5,460 5,830 6,920		4,010 4,010 5,460 5,830 6,920	952 952 1,298 1,384 1,644 1,903 2,595	649 693 869 924 1,066		
4,370 5,960 6,360 7,560 8,750 11,930	7,560		7,560	1,035 1,411 1,505 1,788 2,070 2,822	1,189		
8,230	8,230		8,230	1,940	1,306		
8,150	8,150		8,150	1,962	1,153		11 7/8 301,6
1,730	1,730			541	322		13 3/8 339,7
2,730 2,730 3,980 5,470	2,730 2,730		2,730 2,730	853 853 1,241 1,629	514 547		

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
13 3/8 339,7	61.0	0.430 10,92	12.515 317,88	12.359 313,92	14.375 365,13	J-55 K-55 C-75 N-80	1,540 1,540 1,660 1,670
	68.0	0.480 12,19	12.415 315,34	12.259 311,38	14.375 365,13	J-55 K-55 C-75 N-80 C-95	1,950 1,950 2,220 2,270 2,330
	72.0	0.514 13,06	12.347 313,61	12.191 309,65	14.375 365,13	K-55 C-75 N-80 C-95 P-110	2,230 2,590 2,670 2,820 2,880
	77.0	0.550 13,97	12.275 311,79	12.119 307,82	14.375 365,13	C-75 N-80	2,990 3,100
	80.7	0.580 14,73	12.215 310,26	12.059 306,29	14.375 365,13	S-80 S-95	4,800 4,990
	85.0	0.608 15,44	12.159 308,84	12.003 304,88	14.375 365,13	C-75 N-80 P-110	3,810 3,870 4,490
	86.0	0.625 15,88	12.125 307,98	11.969 304,01	14.375 365,13	S-95	6,240
	92.0	0.672 17,07	12.031 305,59	11.875 301,63		C-75 N-80 P-110	4,910 5,050 5,700
	98.0	0.719 18,26	11.937 303,19	11.781 299,24	14.375 365,13	C-75 N-80 P-110	5,720 5,910 6,930
13 1/2 342,9	81.4	0.580 14,73	12.340 313,44	12.250 311,15	14.375 365,13	S-95	4,860
13 5/8 346,1	88.2	0.625 15,88	12.375 314,33	12.250 311,15	14.375 365,13	S-95	5,930

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
3,090 3,090 4,220 4,500	3,090 3,090		3,090 3,090	962 962 1,312 1,400	595 633		13 3/8 339,7
3,450 3,450 4,710 5,020 5,970	3,450 3,450		3,450 3,450	1,069 1,069 1,458 1,556 1,847	675 718		
3,700 5,040 5,380 6,390 7,400	5,040 5,380 6,390 7,400		5,040 5,380 6,390 7,400	1,142 1,558 1,661 1,973 2,284	978 1,040 1,204 1,402		
5,400 5,760	5,400 5,760		5,400 5,760	1,662 1,773	1,054 1,122		
4,170 7,210	4,170 7,210		4,170 7,210	1,282 2,215	1,118 1,389		
5,970 6,360 8,750	5,970 6,360		5,970 6,360	1,829 1,951 2,682	1,177 1,252		
7,770	7,770		7,750	2,378	1,507		
6,590 7,030 9,670				2,011 2,145 2,950			
7,060 7,530 10,350				2,144 2,287 3,145			
7,140	7,140		7,140	2,236	1,225		13 1/2 342,9
7,630	7,630		7,630	2,425	1,178		13 5/8 346,1

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

OD (in.) (MM)	Weight w/ Cplg (lb/ft)	Wall Thickness (in.) (MM)	ID (in.) (MM)	Drift Dia. (in.) (MM)	Cplg or Jnt OD Round or Buttress (in.) (MM)	Grade	Collapse Resistance (psi)*
16 406,4	65.0	0.375 9,525	15.250 292,74	15.062 382,57	17.000 431,80	H-40	670
	75.0	0.438 11,13	15.124 384,15	14.936 379,37	17.000 431,80	J-55 K-55	1,020 1,020
	84.0	0.495 12,57	15.010 381,25	14822 376,48	17.000 431,80	J-55 K-55	1,410 1,410
	109.0	0.656 16,66	14.688 373,08	14.500 368,30	17.000 431,80	K-55 C-75 N-80	2,560 2,980 3,080
18 5/8 473,1	87.5	0.435 11,05	17.755 450,98	17.567 446,20	19.625 498,48	H-40 J-55 K-55	630 630 630
20 508,0	94.0	0.438 11,13	19.124 485,75	18.936 480,97	21.000 533,40	H-40 J-55 K-55	520 520 520
	106.5	0.500 12,50	19.000 482,60	18.812 477,82	21.000 533,40	J-55 K-55	770 770
	133.0	0.635 16,13	18.730 475,74	18.542 470,97	21.000 533,40	J-55 K-55	1,500 1,500

DIMENSIONAL DATA & MINIMUM PERFORMANCE - CASING

Internal Yield Pressure (psi)*				Body Yield Strgth (1000 lb)*	Joint Yield Strength (1000 lb) Threaded & Cpld Joint Round Thread*		OD (IN) (MM)
Plain End or Extreme Line	Round Thread		Buttress Thread				
	Short	Long			Short	Long	
1,640	1,640		1,640	736	439		
2,630	2,630		2,630	1,178	710		16
2,630	2,630		2,630	1,178	752		406,4
2,980	2,980		2,980	1,326	817		
2,980	2,980		2,980	1,326	865		
3,950	3,950		3,950	1,739	1,181		
5,380	5,380			2,372	1,499		
5,740	5,740			2,530	1,594		
1,630	1,630			1,994	559		18 5/8
2,250	2,250			1,367	754		437,9
2,250	2,250			1,367	794		
1,530	1,530			1,077	581		20
2,110	2,110	2,110		1,480	784	907	508,0
2,110	2,110	2,110		1,480	824	955	
2,410	2,410	2,410		1,685	913	1,057	
2,410	2,410	2,410		1,685	960	1,113	
3,060	3,060	3,060		2,125	1,192	1,380	
3,060	3,060	3,060		2,125	1,253	1,453	

* Collapse Resistance, Internal Yield Pressure and Joint Yield
Strengths are minimum values with no safety factor, reproduced from API Bulletin 5C2, Bulletin on Performance Properties of Casing and Tubing, and from published literature of manufacturers of premium threads and tubular goods.

≠ These casing sizes have standard API 8 Round or Buttress threads or, in some sizes, certain Hydril or Rucker Atlas-Bradford premium threads, of the next smaller OD and the threads are interchangeable. For example, 7 3/4 inch casing will have the same thread as standard 7 5/8 inch casing and will use standard casing collars.

Data for premium threads and tubular goods are identified as follows:

(1) Hydril TS Tripleseal
(2) Hydril FJ-P Flush Joint (joint OD and ID same as pipe)
(3) Hydril Super FJ-P
(4) Hydril Super EU
(5) Hydril CTS
(6) Hydril CTS-4
(7) Rucker Atlas-Bradford TC-4S
(8) Rucker Atlas-Bradford FL-3S and FL-4S
(9) Vallourec VAM
(10) Extreme Line
(11) Lone Star Steel Company
(12) Buttress Thread

CASING CAPACITY

OD (in.)	WT (lb/ft)	ID (in.)	BBL/FT	FT/BBL	Cu FT/ FT	FT/ Cu FT
4 1/2	9.50	4.090	0.01626	61.5017	0.09124	10.9607
	10.50	4.052	0.01596	62.6606	0.08955	11.1672
	11.60	4.000	0.01555	64.3004	0.08726	11.4595
	12.60	3.958	0.01523	65.6723	0.08544	11.7040
	13.50	3.920	0.01494	66.9517	0.08381	11.9320
	15.10	3.826	0.01423	70.2820	0.07984	12.5255
	16.60	3.754	0.01370	73.0038	0.07686	13.0106
	16.90	3.740	0.01360	73.5513	0.07629	13.1082
	17.70	3.696	0.01328	75.3130	0.07450	13.4221
	18.80	3.640	0.01288	77.6481	0.07226	13.8383
	21.60	3.500	0.01191	83.9842	0.06681	14.9675
	24.60	3.380	0.01110	90.0534	0.06231	16.0491
	26.50	3.240	0.01020	98.0040	0.05725	17.4661
5	11.50	4.560	0.02021	49.4771	0.11341	8.8177
	13.00	4.494	0.01963	50.9410	0.11015	9.0786
	15.00	4.408	0.01889	52.9481	0.10597	9.4363
	18.00	4.276	0.01777	56.2676	0.09972	10.0279
	20.30	4.184	0.01702	58.7693	0.09548	10.4737
	20.80	4.156	0.01679	59.5638	0.09420	10.6153
	23.20	4.044	0.01590	62.9088	0.08919	11.2115
	24.20	4.000	0.01555	64.3004	0.08726	11.4595
5 1/2	14.00	5.012	0.02442	40.9554	0.13701	7.2990
	15.50	4.950	0.02382	41.9878	0.13364	7.4830
	17.00	4.892	0.02326	42.9893	0.13052	7.6615
	20.00	4.778	0.02219	45.0652	0.12451	8.0314
	23.00	4.670	0.02120	47.1737	0.11895	8.4072
	26.00	4.548	0.02011	49.7385	0.11281	8.8643

CASING CAPACITY

OD (in.)	WT (lb/ft)	ID (in.)	BBL/FT	FT/BBL	Cu FT/ FT	FT/ Cu FT
5 1/2	28.40	4.490	0.01960	51.0318	0.10995	9.0948
	32.30	4.276	0.01777	56.2676	0.09972	10.0279
	36.40	4.090	0.01626	61.5017	0.09124	10.9607
6	18.00	5.424	0.02860	34.9699	0.16046	6.2323
	20.00	5.352	0.02784	35.9171	0.15622	6.4011
	23.00	5.240	0.02669	37.4689	0.14975	6.6776
	26.00	5.132	0.02560	39.0625	0.14364	6.9616
6 5/8	18.00	6.049	0.03557	28.1168	0.19956	5.0109
	24.00	5.921	0.03408	29.3456	0.19121	5.2299
	28.00	5.791	0.03260	30.6780	0.18290	5.4674
	32.00	5.675	0.03130	31.9449	0.17565	5.6932
7	17.00	6.538	0.04155	24.0682	0.23313	4.2894
	20.00	6.456	0.04051	24.6835	0.22732	4.3990
	23.00	6.366	0.03939	25.3864	0.22103	4.5243
	26.00	6.276	0.03829	26.1197	0.21482	4.6550
	29.00	6.184	0.03717	26.9026	0.20857	4.7945
	32.00	6.094	0.03610	27.7031	0.20254	4.9372
	35.00	6.004	0.03504	28.5399	0.19661	5.0863
	38.00	5.920	0.03407	29.3556	0.19114	5.2317
	41.00	5.820	0.03292	30.373	0.18474	5.4130
	44.00	5.720	0.03180	31.4443	0.17845	5.6039
	49.50	5.540	0.02983	33.5208	0.16739	5.9740
7 5/8	24.00	7.025	0.04797	20.8469	0.26916	3.7153
	26.40	6.969	0.04721	21.1833	0.26488	3.7752
	29.70	6.875	0.04594	21.7665	0.25779	3.8792
	33.70	6.765	0.04448	22.4801	0.24960	4.0064
	39.00	6.625	0.04266	23.4402	0.23938	4.1775

CASING CAPACITY

OD (in.)	WT (lb/ft)	ID (in.)	BBL/FT	FT/BBL	Cu FT/ FT	FT/ Cu FT
7 5/8	45.30	6.435	0.04025	24.8449	0.22585	4.4278
8 5/8	24.00	8.097	0.06373	15.6923	0.35757	2.7966
	28.00	8.017	0.06247	16.0070	0.35054	2.8527
	32.00	7.921	0.06099	16.3974	0.34220	2.9223
	36.00	7.825	0.05952	16.8022	0.33395	2.9944
	40.00	7.725	0.05800	17.2400	0.32547	3.0725
	44.00	7.625	0.05651	17.6951	0.31710	3.1536
	49.00	7.511	0.05484	18.2364	0.30769	3.2500
	52.00	7.435	0.05373	18.6111	0.30149	3.3168
9 5/8	32.60	9.001	0.07875	12.6985	0.44187	2.2631
	36.00	8.921	0.07736	12.9273	0.43405	2.3039
	40.00	8.835	0.07587	13.1802	0.42572	2.3489
	43.50	8.755	0.07450	13.4221	0.41805	2.3921
	47.00	8.681	0.07325	13.6519	0.41101	2.4330
	53.50	8.535	0.07081	14.1230	0.39730	2.5170
	58.40	8.435	0.06916	14.4598	0.38805	2.5770
	61.10	8.375	0.06818	14.6678	0.38255	2.6141
	71.80	8.125	0.06417	15.5843	0.36005	2.7774
10 3/4	32.75	10.192	0.10097	9.9041	0.56654	1.7651
	40.50	10.050	0.09817	10.1860	0.55087	1.8153
	45.50	9.950	0.09623	10.3917	0.53996	1.8520
	51.00	9.850	0.09431	10.6038	0.52916	1.8898
	55.50	9.760	0.09259	10.8003	0.51953	1.9248
	60.70	9.660	0.09070	11.0250	0.50894	1.9649
	65.70	9.560	0.08883	11.2569	0.49846	2.0062
	71.10	9.450	0.08680	11.5205	0.48706	2.0532
	76.00	9.350	0.08497	11.7682	0.47680	2.0973

CASING CAPACITY

OD (in.)	WT (lb/ft)	ID (in.)	BBL/FT	FT/BBL	Cu FT/ FT	FT/ Cu FT
10 3/4	81.00	9.25	0.08317	12.024	0.46666	2.1429
11 3/4	42.00	11.084	0.11942	8.3741	0.67005	1.4924
	47.00	11.000	0.11761	8.5025	0.65993	1.5153
	54.00	10.880	0.11506	8.6911	0.64561	1.5489
	60.00	10.772	0.11279	8.8663	0.63286	1.5801
	35.00	10.682	0.11091	9.0163	0.62233	1.6069
	71.00	10.586	0.10893	9.1806	0.61119	1.6361
13 3/8	48.00	12.715	0.15714	6.3636	0.88175	1.1341
	54.50	12.615	0.15468	6.4649	0.86794	1.1522
	51.00	12.515	0.15224	6.5686	0.85423	1.1706
	68.00	12.415	0.14982	6.6748	0.84064	1.1896
	72.00	12.347	0.14818	6.7486	0.83145	1.2027
	77.00	12.275	0.14646	6.8280	0.82178	1.2169
	80.70	12.215	0.14506	6.8952	0.81377	1.2288
	85.00	12.159	0.14370	6.9589	0.80633	1.2402
	86.00	12.125	0.14290	6.9979	0.80182	1.2472
	92.00	12.031	0.14069	7.1077	0.78944	1.2667
	98.00	11.937	0.13850	7.2201	0.77715	1.2868
16	65.00	15.250	0.22605	4.4238	1.26840	0.7884
	75.00	15.124	0.22233	4.4978	1.24752	0.8016
	84.00	15.010	0.21899	4.5664	1.22879	0.8138
	109.00	14.688	0.20970	4.7688	1.17663	0.8499
18 5/8	87.50	17.755	0.30641	3.2636	1.71932	0.5816
20	94.00	19.124	0.35549	2.8130	1.99468	0.5013
	106.50	19.000	0.35089	2.8499	1.96889	0.5079
	133.00	18.730	0.34099	2.9326	1.91333	0.5226

CASING STRETCH TABLE

OD (in.)	WT (lb/ft)	ID (in.)	Stretch Constant (in./1000 lb /1000 ft)	Free Point Constant
(4 1/2)	9.50	4.090	0.14461	6,915.0
	10.50	4.052	0.13293	7,522.5
	11.60	4.000	0.11983	8,345.0
	13.50	3.920	0.10428	9,590.0
	15.10	3.826	0.09076	11,017.5
	16.90	3.740	0.08133	12,295.0
(5)	11.50	4.560	0.12107	8,260.0
	13.00	4.494	0.10602	9,432.5
	15.00	4.408	0.09145	10,935.0
	18.00	4.276	0.07583	13,187.5
	20.80	4.156	0.06591	15,172.5
(5 1/2)	14.00	5.012	0.09928	10,072.5
	15.50	4.950	0.08861	11,285.0
	17.00	4.892	0.08061	12,405.0
	20.00	4.778	0.06863	14,570.0
	23.00	4.670	0.06033	16,575.0
(6 5/8)	20.00	6.049	0.06976	14,335.0
	24.00	5.921	0.05766	17,342.5
	28.00	5.791	0.04918	20,332.5
	32.00	5.675	0.04359	22,942.5
(7)	17.00	6.538	0.08143	12,280.0
	20.00	6.456	0.06958	14,372.5
	23.00	6.366	0.06010	16,640.0
	26.00	6.276	0.05299	18,872.5
	29.00	6.184	0.04734	21,122.5
	32.00	6.094	0.04293	23,292.5
	35.00	6.004	0.03932	25,430.0
	38.00	5.920	0.03650	27,397.5
(7 5/8)	24.00	7.025	0.05794	17,260.0
	26.40	6.969	0.05320	18,797.5
	29.70	6.875	0.04683	21,352.5
	33.70	6.765	0.04115	24,300.0
	39.00	6.625	0.03574	27,980.0

CASING STRETCH TABLE

OD (in.)	WT (lb/ft)	ID (in.)	Stretch Constant (in./1000 lb /1000 ft)	Free Point Constant
(8 5/8)	24.00	8.097	0.05769	17,335.0
	28.00	8.017	0.05033	19,867.5
	32.00	7.921	0.04372	22,872.5
	36.00	7.825	0.03870	25,840.0
	40.00	7.725	0.03461	28,892.5
	44.00	7.625	0.03156	31,682.5
	49.00	7.511	0.02833	35,295.0
(9 5/8)	32.30	9.001	0.04382	22,820.0
	36.00	8.921	0.03901	25,635.0
	40.00	8.835	0.03492	28,635.0
	43.50	8.755	0.03185	31,397.5
	47.00	8.681	0.02947	33,930.0
	53.50	8.535	0.02573	38,865.0
(10 3/4)	32.75	10.192	0.04358	22,945.0
	40.50	10.050	0.03498	28,587.5
	45.50	9.950	0.03076	32,515.0
	51.00	9.850	0.02747	36,402.5
	55.50	9.760	0.02508	39,867.5
	60.70	9.660	0.02289	43,682.5
	65.70	9.560	0.02107	47,455.0
(11 3/4)	42.00	11.084	0.03349	29,860.0
	47.00	11.000	0.02985	33,502.5
	54.00	10.880	0.02587	38,657.5
	60.00	10.772	0.02312	43,250.0
(13 3/4)	48.00	12.715	0.02958	33,810.0
	54.50	12.615	0.02578	38,785.0
	61.00	12.515	0.02287	43,717.5
	68.00	12.415	0.02057	48,612.5
	72.00	12347	0.01926	51,920.0
(16)	65.00	15.250	0.02173	46,020.0
	75.00	15.124	0.01868	53,535.0
	84.00	15.010	0.01659	60,280.0
(20)	94.00	19.124	0.01486	67,295.0

SHORT THREAD RECOMMENDED MAKE-UP TORQUE

OD (in.)	Nom. Weight (lb/ft)	Grade	Torque (ft-lb)		
			Minimum	Optimum	Maximum
4 1/2	9.5	H-40 J-55 K-55	580 760 840	770 1,010 1,120	960 1,260 1,400
	10.5	J-55 K-55	990 1,100	1,320 1,460	1,650 1,830
	11.6	J-55 K-55	1,160 1,280	1,540 1,700	1,930 2,130
5	11.5	J-55 K-55	1,000 1,100	1,330 1,470	1,660 1,840
	13.0	J-55 K-55	1,270 1,400	1,690 1,860	2,110 2,330
	15.0	J-55 K-55	1,550 1,710	2,070 2,280	2,590 2,850
5 1/2	14.0	H-40 J-55 K-55	980 1,290 1,420	1,300 1,720 1,890	1,630 2,150 2,360
	15.5	J-55 K-55	1,520 1,670	2,020 2,220	2,530 2,780
	17.0	J-55 K-55	1,720 1,890	2,290 2,520	2,860 3,150
6 5/8	20.0	H-40 J-55 K-55	1,380 1,840 2,000	1,840 2,450 2,670	2,300 3,060 3,340
	24.0	J-55 K-55	2,360 2,570	3,140 3,420	3,930 4,230
7	17.0	H-40	920	1,220	1,530
	20.0	H-40 J-55 K-55	1,320 1,760 1,910	1,760 2,340 2,540	2,200 2,930 3,180
	23.0	J-55 K-55	2,130 2,320	2,840 3,090	3,550 3,860
	26.0	J-55 K-55	2,510 2,730	3,340 3,640	4,180 4,550
7 5/8	24.0	H-40	1,590	2,120	2,650

SHORT THREAD RECOMMENDED MAKE-UP TORQUE

OD (in.)	Nom. Weight (lb/ft)	Grade	Torque (ft-lb)		
			Minimum	Optimum	Maximum
7 5/8	26.4	J-55 K-55	2,360 2,570	3,150 3,420	3,940 4,280
8 5/8	24.0	J-55 K-55	1,830 1,970	2,440 2,630	3,050 3,290
	28.0	H-40	1,750	2,330	2,910
	32.0	H-40 J-55 K-55	2,090 2,790 3,020	2,790 3,720 4,020	3,490 4,650 5,030
	36.0	J-55 K-55	3,260 3,510	4,340 4,680	5,430 5,850
9 5/8	32.3	H-40	1,910	2,540	3,180
	36.0	H-40 J-55 K-55	2,210 2,960 3,170	2,940 3,940 4,230	3,680 4,930 5,290
	40.0	J-55 K-55	3,390 3,650	4,520 4,860	5,650 6,080
10 3/4	32.75	H-40	1,540	2,050	2,560
	40.5	H-40 J-55 K-55	2,360 3,150 3,380	3,140 4,200 4,500	3,930 5,250 5,630
	45.5	J-55 K-55	3,700 3,960	4,930 5,280	6,160 6,600
	51.0	J-55 K-55 C-75 N-80 C-95 P-110	4,240 4,550 5,670 6,030 6,950 8,100	5,650 6,060 7,560 8,040 9,270 10,800	7,060 7,580 9,450 10,050 11,590 13,500
	55.5	C-75 N-80 C-95 P-110	6,320 6,710 7,740 9,020	8,430 8,950 10,320 12,030	10,540 11,190 12,900 15,040
	60.7	P-110	10,040	13,380	16,730
	65.7	P-110	11,040	14,720	18,400

SHORT THREAD RECOMMENDED MAKE-UP TORQUE

OD (in.)	Nom. Weight (lb/ft)	Grade	Torque (ft-lb)		
			Minimum	Optimum	Maximum
11 3/4	42.0	H-40	2,300	3,070	3,840
	47.0	J-55	3,580	4,770	5,960
		K-55	3,850	5,090	6,360
	54.0	J-55	4,260	5,680	7,100
		K-55	4,550	6,060	7,580
	60.0	J-55	4,870	6,490	8,110
		K-55	5,200	6,930	8,660
		C-75	6,520	8,690	10,860
		N-80	6,930	9,240	11,550
		C-95	8,000	10,660	13,330
13 3/8	48.0	H-40	2,420	3,220	4,030
	54.5	J-55	3,860	5,140	6,430
		K-55	4,100	5,470	6,840
	61.0	J-55	4,460	5,950	7,440
		K-55	4,750	6,330	7,910
	68.0	J-55	5,060	6,750	8,440
		K-55	5,390	7,180	8,980
	72.0	C-75	7,340	9,780	12,230
		N-80	7,800	10,400	13,000
		C-95	9,030	12,040	15,050
16	65.0	H-40	3,290	4,390	5,490
	75.0	J-55	5,330	7,100	8,880
		K-55	5,640	7,520	9,400
	84.0	J-55	6,130	8,170	10,210
		K-55	6,490	8,650	10,810
18 5/8	87.5	H-40	4,190	5,590	6,990
		J-55	5,660	7,540	9,430
		K-55	5,960	7,940	9,930
20	94.0	H-40	4,360	5,810	7,260
		J-55	5,880	7,840	9,800
		K-55	6,180	8,240	10,300
	106.5	J-55	6,850	9,130	11,410
		K-55	7,200	9,600	12,000
	133.0	J-55	8,940	11,920	14,900
		K-55	9,400	12,530	15,660

LONG THREAD RECOMMENDED MAKE-UP TORQUE

OD (in.)	Nom. Weight (lb/ft)	Grade	Torque (ft-lb)		
			Minimum	Optimum	Maximum
4 1/2	11.6	J-55	1,220	1,620	2,030
		K-55	1,350	1,800	2,250
		C-75	1,610	2,150	2,690
		N-80	1,710	2,280	2,850
		C-95	1,940	2,580	3,230
		P-110	2,270	3,020	3,780
	13.5	C-75	1,950	2,600	3,250
		N-80	2,070	2,760	3,450
		C-95	2,350	3,130	3,910
		P-110	2,750	3,660	4,580
	15.1	P-110	3,300	4,400	5,500
5	13.0	J-55	1,370	1,820	2,280
		K-55	1,510	2,010	2,510
	15.0	J-55	1,670	2,230	2,790
		K-55	1,850	2,460	3,080
		C-75	2,220	2,960	3,700
		N-80	2,360	3,140	3,930
		C-95	2,670	3,560	4,450
		P-110	3,130	4,170	5,210
	18.0	C-75	2,830	3,770	4,710
		N-80	3,000	4,000	5,000
		C-95	3,410	4,550	5,690
		P-110	3,980	5,310	6,640
5 1/2	15.5	J-55	1,630	2,170	2,710
		K-55	1,790	2,390	2,990
	17.0	J-55	1,850	2,470	3,090
		K-55	2,040	2,720	3,400
		C-75	2,450	3,270	4,090
		N-80	2,610	3,480	4,350
		C-95	2,970	3,960	4,950
		P-110	3,470	4,620	5,780
	20.0	C-75	3,020	4,030	5,040
		N-80	3,210	4,280	5,350
		C-95	3,650	4,870	6,090
		P-110	4,270	5,690	7,110

LONG THREAD RECOMMENDED MAKE-UP TORQUE

OD (in.)	Nom. Weight (lb/ft)	Grade	Torque (ft-lb)		
			Minimum	Optimum	Maximum
5 1/2	23.0	C-75	3,550	4,730	5,910
		N-80	3,770	5,020	6,280
		C-95	4,290	5,720	7,150
		P-110	5,010	6,680	8,350
6 5/8	20.0	J-55	2,000	2,660	3,330
		K-55	2,180	2,900	3,630
	24.0	J-55	2,550	3,400	4,250
		K-55	2,790	3,720	4,650
		C-75	3,400	4,530	5,660
		N-80	3,610	4,810	6,010
		C-95	4,120	5,490	6,860
		P-110	4,810	6,410	8,010
	28.0	C-75	4,140	5,520	6,900
		N-80	4,400	5,860	7,330
		C-95	5,020	6,690	8,360
		P-110	5,860	7,810	9,760
	32.0	C-75	4,790	6,380	7,980
		N-80	5,080	6,770	8,460
		C-95	5,810	7,740	9,680
		P-110	6,780	9,040	11,300
7	23.0	J-55	2,350	3,130	3,910
		K-55	2,560	3,410	4,260
		C-75	3,120	4,160	5,200
		N-80	3,320	4,420	5,530
		C-95	3,790	5,050	6,310
	26.0	J-55	2,750	3,670	4,590
		K-55	3,010	4,010	5,010
		C-75	3,670	4,890	6,110
		N-80	3,890	5,190	6,490
		C-95	4,450	5,930	7,410
		P-110	5,200	6,930	8,660
	29.0	C-75	4,220	5,620	7,030
		N-80	4,480	5,970	7,460
		C-95	5,120	6,830	8,540
		P-110	5,980	7,970	9,960
	32.0	C-75	4,750	6,330	7,910
		N-80	5,040	6,720	8,400
		C-95	5,760	7,680	9,600
		P-110	6,730	8,970	11,210

LONG THREAD RECOMMENDED MAKE-UP TORQUE

OD (in.)	Nom. Weight (lb/ft)	Grade	Torque (ft-lb)		
			Minimum	Optimum	Maximum
7	35.0	C-75	5,270	7,030	8,790
		N-80	5,600	7,460	9,330
		C-95	6,400	8,530	10,660
		P-110	7,470	9,960	12,450
	38.0	C-75	5,270	7,670	9,590
		N-80	6,110	8,140	10,180
		C-95	6,980	9,310	11,640
		P-110	8,150	10,870	13,590
7 5/8	26.4	J-55	2,600	3,460	4,330
		K-55	2,830	3,770	4,710
		C-75	3,460	4,610	5,760
		N-80	3,680	4,900	6,130
		C-95	4,200	5,600	7,000
	29.7	C-75	4,070	5,420	6,780
		N-80	4,310	5,750	7,190
		C-95	4,940	6,590	8,240
		P-110	5,770	7,690	9,610
	33.7	C-75	4,760	6,350	7,940
		N-80	5,060	6,740	8,430
		C-95	5,790	7,720	9,650
		P-110	6,760	9,010	11,260
	39.0	C-75	5,630	7,510	9,390
		N-80	5,980	7,980	9,980
		C-95	6,860	9,140	11,430
		P-110	8,000	10,660	13,330
8 5/8	32.0	J-55	3,130	4,170	5,210
		K-55	3,390	4,520	5,650
	36.0	J-55	3,650	4,860	6,080
		K-55	3,950	5,260	6,580
		C-75	4,860	6,480	8,100
		N-80	5,160	6,880	8,600
		C-95	5,920	7,890	9,860
	40.0	C-75	5,570	7,420	9,280
		N-80	5,910	7,880	9,850
		C-95	6,780	9,040	11,300
		P-110	7,910	10,550	13,190

LONG THREAD RECOMMENDED MAKE-UP TORQUE

OD (in.)	Nom. Weight (lb/ft)	Grade	Torque (ft-lb)		
			Minimum	Optimum	Maximum
8 5/8	44.0	C-75	6,260	8,340	10,430
		N-80	6,650	8,870	11,090
		C-95	7,630	10,170	12,710
		P-110	8,900	11,860	14,830
	49.0	C-75	7,040	9,390	11,740
		N-80	7,480	9,970	12,460
		C-95	8,580	11,440	14,300
		P-110	10,010	13,350	16,690
9 5/8	36.0	J-55	3,400	4,530	5,660
		K-55	3,670	4,890	6,110
	40.0	J-55	3,900	5,200	6,500
		K-55	4,210	5,610	7,010
		C-75	5,210	6,940	8,680
		N-80	5,530	7,370	9,210
		C-95	6,350	8,470	10,590
	43.5	C-75	5,820	7,760	9,700
		N-80	6,190	8,250	10,310
		C-95	7,110	9,480	11,850
		P-110	8,300	11,060	13,830
	47.0	C-75	6,390	8,520	10,650
		N-80	6,790	9,050	11,310
		C-95	7,800	10,400	13,000
		P-110	9,100	12,130	15,160
	53.5	C-75	7,490	9,990	12,490
		N-80	7,970	10,620	13,280
		C-95	9,150	12,200	15,250
		P-110	10,670	14,220	17,780
20	94.0	J-55	6,800	9,070	11,340
		K-55	7,160	9,550	11,940
	106.5	J-55	7,930	10,570	13,110
		K-55	8,350	11,130	13,410
	133.0	J-55	10,350	13,800	17,250
		K-55	10,900	14,530	18,160

Section VI
Drill Pipe Data

API Internal Upset Drill Pipe ____ VI-1

Tool Joints ____ VI-3

Drill Pipe Capacities ____ VI-9

Drill Pipe Stretch Tables ____ VI-10

API INTERNAL UPSET DRILL PIPE

Size O.D. In.	Wt. Per Ft.With Cplg. Lb.	I.D. In.	I.D. at Full Upset In.	Collapse Pressure		
				C PSI	D PSI	E PSI
2 3/8	4.80	2.000	1.437	5,340	6,850	8,360
2 3/8	6.65	1.815	1.125	7,960	10,140	12,480
2 7/8	6.45	2.469	1.875	4,760	6,100	7,470
2 7/8	8.35	2.323	1.625	6,420	8,150	10,150
2 7/8	10.40	2.151	1.187	8,420	10,730	13,210
3 1/2	8.50	3.063	2.437	4,270	5,450	6,660
3 1/2	11.20	2.900	2.125	5,860	7,470	9,200
3 1/2	13.30	2.764	1.875	7,200	9,170	11,290
3 1/2	15.50	2.602	1.750	8,550	10,900	13,420
4	14.00	3.340	2.375	5,790	7,380	9,080
4	15.70	3.240	2.250	6,580	8,380	10,320
4 1/2	12.75	4.000	3.250	3,935	5,020	6,170
4 1/2	13.75	3.958	3.154	4,270	5,440	6,690
4 1/2	16.60	3.826	2.812	5,300	6,760	8,310
4 1/2	20.00	3.640	2.812	6,610	8,420	10,370
5	19.50	4.276	3.687	5,140	6,550	8,060
5 1/2	21.90	4.778	3.812	4,520	5,770	7,100
5 1/2	24.70	4.670	3.500	5,340	6,800	8,370
5 9/16	19.00	4.975	4.125	3,600	4,580	5,640
5 9/16	22.20	4.859	3.812	4,300	5,480	6,740
5 9/16	25.25	4.733	3.500	5,280	6,730	8,290
6 5/8	22.20	6.065	5.187	2,560	3,260	4,020
6 5/8	25.20	5.965	5.000	3,010	3,840	4,720
6 5/8	31.90	5.761	4.625	3,940	5,020	6,170

API INTERNAL UPSET DRILL PIPE

Internal Yield Pressure			Tensile Strength			Wt. Per Ft. With Cplg. Lb.	Size O.D. In.
C PSI	D PSI	E PSI	C 1000 lb.	D 1000 lb.	E 1000 lb.		
6,200	7,110	9,600	57	70	97	4.80	2 3/8
7,280	11,350	15,470	83	101	138	6.65	2 3/8
7,250	6,860	9,350	77	94	128	6.45	2 7/8
7,560	9,240	12,620	101	124	169	8.35	2 7/8
9,910	12,120	16,530	128	157	214	10.40	2 7/8
4,900	6,000	8,200	102	125	170	8.50	3 1/2
6,750	8,230	11,240	135	165	225	11.20	3 1/2
8,280	10,120	13,800	163	199	272	13.30	3 1/2
10,110	12,350	16,840	194	237	323	15.50	3 1/2
6,500	7,940	10,830	171	209	285	14.00	4
7,480	9,140	12,470	194	238	324	15.70	4
4,380	5,360	7,300	155	189	257	12.75	4 1/2
4,750	5,810	7,920	169	203	281	13.75	4 1/2
5,900	7,210	9,830	198	242	331	16.60	4 1/2
7,520	9,200	12,540	247	302	412	20.00	4 1/2
5,700	6,960	9,500	237	290	396	19.50	5
5,170	6,320	8,620	262	321	437	21.90	5 1/2
5,940	7,260	9,900	298	365	497	24.70	5 1/2
4,170	5,090	6,950	219	267	365	19.00	5 9/16
4,990	6,090	8,300	259	317	432	22.20	5 9/16
5,870	7,180	9,790	302	369	503	22.25	5 9/16
3,330	4,160	5,530	251	307	418	22.20	6 5/8
3,920	4,800	6,540	294	359	489	25.20	6 5/8
5,125	6,275	8,540	379	463	631	31.90	6 5/8

TOOL JOINTS

Size	Joint OD	Joint ID	Interchangeable With
API Regular			
2 3/8	3 1/8	1	-----
2 7/8	3 3/4	1 1/4	-----
3 1/2	4 1/4	1 1/2	-----
4 1/2	5 1/2	2 1/4	-----
5 1/2	6 3/4	2 3/4	5 Union Tool Regular
6 5/8	7 3/4	3 1/2	5 Union Tool F.H. 6 Union Tool Regular
7 5/8	8 7/8	4	-----
8 5/8	10	4 3/4	-----
Union Tool Regular			
3	4 1/4	1 1/2	-----
4	5 3/4	2 1/4	-----
5	6 3/4	2 3/4	5 1/2 API Regular
6	7 3/4	3 1/2	6 5/8 API Regular
API Full Hole			
2 7/8	4 1/4	2 1/8	-----
3 1/2	4 5/8	2 7/16	-----
4	5 1/4	2 13/16	4 1/2 Reed Double Streamline
4 1/2	5 3/4	3	-----
5 1/2	7	4	-----
6 5/8	8	5	-----
Union Tool Full Hole			
4 1/2	6	3	-----
5 1/2	7 1/4	3 1/2	6 5/8 API Regular
6 5/8	8 3/8	4 15/16	-----

TOOL JOINTS

Size	Joint OD	Joint ID	Interchangeable With
API Internal Flush Hughes and Reed I.F.			
2 3/8 2 7/8	3 3/8 4 1/8	1 3/4 2 1/8	2 7/8 Slim Hole 3 1/2 Slim Hole
3 1/2	4 3/4	2 11/16	3 1/2 Reed Wide Open 4 1/2 Slim Hole
4	5 3/4	3 1/4	4 Reed Wide Open 4 1/2 Hughes Xtra Hole 4 1/2 Reed Xtra Hole 5 Reed Double Streamline
4 1/2	6 1/8	3 3/4	4 1/2 Reed Wide Open 5 Hughes Xtra Hole 5 1/2 Reed Double Streamline
5 1/2	7 3/8	4 13/16	-----
Hughes Acme Regular			
2 3/8 2 7/8 3 1/2 4 1/2 5 1/2 6 5/8	3 1/8 3 3/4 4 1/4 5 1/2 6 3/4 7 3/4	1 1 1/4 1 7/8 2 1/2 3 3 1/2	----- ----- ----- ----- ----- -----
Hughes Acme Streamline Reed Acme Full Hole			
2 3/8 2 7/8 3 1/2 4 1/2 5 1/2	3 3/8 4 4 5/8 5 3/4 7	1 7/16 1 9/16 2 7/16 3 4	----- ----- ----- ----- -----

TOOL JOINTS

Size	Joint OD	Joint ID	Interchangeable With
Hughes Xtra Hole			
2 7/8	4 1/4	1 7/8	2 7/8 Reed Xtra Hole 3 1/2 Reed Double Streamline 3 1/2 Hughes Double Streamline
3 1/2	4 3/4	2 7/16	3 1/2 Reed Xtra Hole 4 Hughes Slim Hole 4 1/2 Hughs External Flush 4 1/2 F.H. Reed External Flush
4 1/2	6	3 1/4	4 API I.F. 4 1/2 Reed Xtra Hole 5 1/2 Reed Double Streamline
5	6 1/4	3 3/4	4 1/2 API I.F. 5 Reed Xtra Hole 5 1/2 Reed Double Streamline
Hughes External Flush			
2 3/8 2 7/8 3 1/2	2 1/2 3 3 5/8	1 1 1/16 1 1/2	2 3/8 Homco External Flush ----- 3 1/2 F.H. Reed External Flush
4 1/2	4 11/16	2 3/16	3 1/2 Reed Xtra Hole 3 1/2 Hughes Xtra Hole 4 Hughs Slim Hole 4 1/2 F.H. Reed External Flush
Hughes Slim Hole, Reed Slim Hole			
2 3/8 2 7/8 3 1/2	2 7/8 3 3/8 4	1 1/4 1 3/4 2 1/8	----- 2 3/8 API I.F. 2 7/8 API I.F.
4	4 1/2	2 9/16	3 1/2 Hughes Xtra Hole 3 1/2 Reed Xtra Hole 4 1/2 Reed External Flush 4 1/2 F.H. Reed External Flush
4 1/2	5	2 11/16	3 1/2 API I.F.

TOOL JOINTS

Size	Joint OD	Joint ID	Interchangeable With
Hughes Double Streamline			
3 1/2	3 7/8	1 13/16	2 7/8 Hughes Xtra Hole 3 1/2 Reed Double Streamline
4 4 1/2	4 1/2 5	2 3/8 2 11/16	4 Reed Double Streamline 4 1/2 Reed Double Streamline
Reed External Flush			
2 3/8 Reg 2 3/8 FH 2 7/8 FH 3 1/2 FH	2 3/8 2 1/2 3 3 5/8	7/8 1 1 1/4 1 1/2	----- ----- ----- 3 1/2 Hughes External Flush
4 1/2 FH	4 11/16	2 3/16	3 1/2 Hughes Xtra Hole 3 1/2 Reed Xtra Hole 4 Hughes Slim Hole 4 1/2 Hughes External Flush
Reed Double Streamline			
2 7/8	3 1/4	1 1/4	-----
3 1/2	3 7/8	1 13/16	2 7/8 Hughes Xtra Hole 2 7/8 Reed Xtra Hole 3 1/2 Hughes Double Streamline
4 4 1/2	4 1/2 5	2 3/8 2 11/16	4 Hughes Double Streamline 4 1/2 Hughes Double Streamline
5	5 9/16	3 3/8	4 API I.F. 4 1/2 Hughes Xtra Hole
5	5 9/16	3 3/8	4 1/2 Reed Xtra Hole
5 1/2	6 1/8	3 3/4	4 1/2 API I.F. 5 Hughes Xtra Hole 5 Reed Xtra Hole
Reed Full Hole			
2 3/8 2 7/8	3 3/8 4	1 7/16 1 7/8	----- -----

TOOL JOINTS

Size	Joint OD	Joint ID	Interchangeable With
Reed Xtra Hole (Semi-Internal Flush)			
2 7/8	4 1/4	1 7/8	3 1/2 Reed Double Streamline
3 1/2	4 3/4	2 7/16	3 1/2 Hughes Xtra Hole 4 Hughes Slim Hole 4 1/2 Hughes External Flush 4 1/2 F.H. Reed External Flush
4 1/2	6	3 1/4	4 API I.F. 4 1/2 Hughes Xtra Hole 5 Reed Double Streamline
5	6 3/8	3 3/4	4 1/2 API I.F. 5 Hughes Xtra Hole 5 1/2 Reed Double Streamline
Reed Open Hole Reed Full Opening			
2 3/8 2 7/8 3 1/2 4 4 1/2	3 1/8 3 3/4 3 5/8 5 1/4 5 3/4	2 2 7/16 3 3 15/32 3 31/32	2 3/8 American Open Hole 2 7/8 American Open Hole 3 1/2 American Open Hole 4 American Open Hole -----
Reed Wide Open (W.O.)			
2 3/8 2 7/8	3 3/8 4 1/8	2 2 7/16	----- -----
3 1/2	4 3/4	3	3 1/2 API I.F. 4 1/2 Slim Hole
4	5 3/4	3 7/16	4 API I.F. 4 1/2 Reed Xtra Hole 4 1/2 Hughes Xtra Hole 5 Reed Double Streamline
4 1/2	6 1/8	3 7/8	4 1/2 API I.F. 5 Reed Xtra Hole 5 Hughes Xtra Hole 5 1/2 Reed Double Streamline

TOOL JOINTS

Size	Joint OD	Joint ID	Interchangeable With
American P.A.C.			
2 3/8	2 7/8	1 3/8	-----
2 7/8	3 1/8	1 1/2	-----
3 1/2	3 3/4	2	-----
American Open Hole			
2 3/8	3 1/4	1 13/16	2 3/8 Reed Open Hole (F.O.)
2 7/8	3 7/8	2.151	2 7/8 Reed Open Hole (F.O.)
3 1/2	4 3/4	2 11/16	3 1/2 Reed Open Hole (F.O.)
4	5 1/2	3 1/4	4 Reed Open Hole (F.O.)

DRILL PIPE CAPACITY

OD (in.)	WT (lb/ft)	ID (in.)	BBL/FT	FT/BBL	Cu FT/ FT	FT/ Cu FT
2 3/8	4.80	2.000	0.00389	257.2016	0.02182	45.8379
	6.65	1.185	0.00136	732.6508	0.00766	130.5714
2 7/8	6.45	2.469	0.00593	168.7686	0.03325	30.0776
	8.35	2.323	0.00525	190.6493	0.02943	33.9771
	10.40	2.151	0.00450	222.3581	0.02523	39.6282
3 1/2	8.50	3.063	0.00912	109.6579	0.05117	19.5430
	11.20	2.900	0.00817	122.3313	0.04587	21.8016
	13.30	2.764	0.00743	134.6659	0.04167	23.9999
	15.50	2.602	0.00658	151.9565	0.03693	27.0813
4	14.00	3.340	0.01084	92.2233	0.06084	16.4358
	15.70	3.240	0.01020	98.0040	0.05725	17.4661
4 1/2	12.75	4.000	0.01555	64.3004	0.08726	11.4595
	13.75	3.958	0.01523	65.6723	0.08544	11.7040
	16.60	3.826	0.01423	70.2820	0.07984	12.5255
	20.00	3.640	0.01288	77.6481	0.07226	13.8383
5	19.50	4.276	0.01777	56.2676	0.09972	10.0279
5 1/2	21.90	4.778	0.02219	45.0652	0.12451	8.0314
	24.70	4.670	0.02120	47.1737	0.11895	8.4072
5 9/16	19.00	4.975	0.02406	41.5669	0.13499	7.4080
	22.20	4.859	0.02295	43.5753	0.12877	7.7659
	25.25	4.733	0.02177	45.9262	0.12218	8.1849
6 5/8	22.20	6.065	0.03575	27.9687	0.20062	4.9845
	25.20	5.965	0.03458	28.9143	0.19406	5.1530
	31.90	5.761	0.03226	30.9983	0.18101	5.5245

DRILL PIPE STRETCH TABLE

OD (in.)	Nominal Weight (lb/ft)	ID (in.)	Stretch Constant (in./1000 lb /1000 ft)	Free Point Constant
(2 3/8)	4.85 6.65	1.995 1.815	0.30675 0.21704	3,260.0 4,607.5
(2 7/8)	6.85 10.40	2.441 2.151	0.22075 0.13996	4,530.0 7,145.0
(3 1/2)	9.50 13.30 15.50	2.992 2.764 2.602	0.15444 0.11047 0.09294	6,475.0 9,052.5 10,760.0
(4)	11.85 14.00	3.476 3.340	0.13000 0.10512	7,692.5 9,512.5
(4 1/2)	13.75 16.60 18.10 20.00	3.958 3.826 3.754 3.640	0.11111 0.09076 0.08271 0.07275	9,000.0 11,017.5 12,090.0 13,745.0
(5)	16.25 19.50	4.408 4.276	0.09145 0.07583	10,935.0 13,187.5
(5 1/2)	21.90 24.70	4.778 4.670	0.06863 0.06033	14,570.0 16,575.0
(6 5/8)	25.20	5.965	0.06129	16,315.0

Section VII
Miscellaneous

Fluid Gradient Table _____ VII-1

Gas Fluid Density _____ VII-2

Common Formulas & Conversion Factors _____ VII-4

Misc. Formulas _____ VII-6

Fluid Gradient Table

Weight (#/GAL)	Fluid Gradient (PSI/FT)	Density API Gravity
6.160	0.3203	60
6.325	0.3289	55
6.499	0.3379	50
6.572	0.3417	48
6.646	0.3456	46
6.721	0.3495	44
6.760	0.3515	43
6.799	0.3535	42
6.838	0.3556	41
6.878	0.3577	40
6.918	0.3597	39
6.959	0.3619	38
7.001	0.3641	37
7.042	0.3662	36
7.085	0.3684	35
7.128	0.3707	34
7.171	0.3729	33
7.215	0.3752	32
7.259	0.3775	31
7.304	0.3798	30
7.396	0.3846	28
7.490	0.3895	26
7.586	0.3945	24
7.685	0.3996	22
7.786	0.4049	20
7.890	0.4103	18
8.052	0.4187	15
8.220	0.4274	12
8.337	0.4335	10

Weight (#/GAL)	Fluid Gradient (PSI/FT)	Weight (#/cu ft)
8.337	0.4335	62.36
8.400	0.4368	62.83
8.600	0.4472	64.33
8.800	0.4576	65.82
9.000	0.4680	67.32
9.200	0.4784	68.82
9.400	0.4888	70.31
9.600	0.4992	71.81
9.800	0.5096	73.30
10.000	0.5200	74.80
10.200	0.5304	76.30
10.400	0.5408	77.79
10.600	0.5512	79.29
10.800	0.5616	80.78
11.000	0.5720	82.28
11.200	0.5824	83.78
11.400	0.5928	85.27
11.600	0.6032	86.77
11.800	0.6136	88.26
12.000	0.6240	89.76
12.200	0.6344	91.26
12.400	0.6448	92.75
12.600	0.6552	94.25
12.800	0.6656	95.74
13.000	0.6760	97.24
13.200	0.6864	98.74
13.400	0.6968	100.23
13.600	0.7072	101.73
13.800	0.7176	103.22
14.000	0.7280	104.72
14.200	0.7384	106.22
14.400	0.7488	107.71
14.600	0.7592	109.21
14.800	0.7696	110.70
15.000	0.7800	112.20
15.200	0.7904	113.70
15.400	0.8008	115.19
15.600	0.8112	116.69
15.800	0.8216	118.18
16.000	0.8320	119.68
16.200	0.8424	121.18
16.400	0.8528	122.67
16.600	0.8632	124.17
16.800	0.8736	125.66
17.000	0.8840	127.16
17.200	0.8944	128.66
17.400	0.9048	130.15
17.600	0.9152	131.65
17.800	0.9256	133.14
18.000	0.9360	134.64
18.200	0.9464	136.14
18.400	0.9568	137.63
18.600	0.9672	139.13
18.800	0.9776	140.62
19.000	0.9880	142.12
19.200	0.9984	143.62
19.400	1.0088	145.11
19.600	1.0192	146.61
19.800	1.0296	148.10
20.000	1.0400	149.60

Steel = 65PPG

Gas Fluid Density Calculations

To estimate the density of a gas whose specific gravity is different from the gas illustrated (0.6), or when the gas is at a different temperature than illustarted (68° F), apply correction factors as shown below:

Step 1

Find the average pressure of the gas by taking the average of the surface flowing pressure and the bottomhole flowing pressure.

Example:

Flowing Surface Pressure: 7800 PSI

Flowing Bottomhole Pressure: 9000 PSI

Average Pressure = (7800 + 9000) ÷ 2

= 8400 PSI

From the chart, density of dry gas (sp gr 0.6) at 8400 PSI and 68°F is 3.51 LB/GAL

Step 2

Calculate the temperature factor as follows:

Gravity Measured at 68 °F

Flowing Surface Temperature = 200 °F

Flowing Bottomhole Temperature = 300 °F

Average gas temperature = (200 + 300) ÷ 2

Average temperature = 250 °F

Temperature Factor =

(68 + 460) ÷ (250 + 460)

= 0.744

Step 3

Calculate the specific gravity factor as follows:

Specific gravity of flowing gas = 0.70

Specific gravity of charted gas = 0.60

Specific gravity factor = 0.70 ÷ 0.60

= 1.167

Step 4

Calculate the adjusted gas density as follows:

Density from chart =

Temperature factor = 0.744

Specific gravity factor = 1.167

Adjusted density = 3.51 X 0.744 X 1.167

= 3.05 LB/GAL

Gas Fluid Density

Assumed Gas Gradient for Varied Pressure

(For Dry Gas Specific Gravity 0.6 with respect to air)

Pressure	Grad	LBS/GAL
0	0	0.00
200	0.005	0.10
400	0.009	0.17
600	0.013	0.26
800	0.018	0.34
1,000	0.022	0.42
1,200	0.026	0.51
1,400	0.031	0.59
1,600	0.035	0.67
1,800	0.039	0.76
2,000	0.044	0.84
2,200	0.048	0.92
2,400	0.052	1.01
2,600	0.057	1.09
2,800	0.061	1.17
3,000	0.065	1.26
3,200	0.070	1.34
3,400	0.074	1.43
3,600	0.078	1.51
3,800	0.083	1.59
4,000	0.087	1.68
4,200	0.091	1.76
4,400	0.096	1.84
4,600	0.100	1.93
4,800	0.105	2.01
5,000	0.109	2.09
5,200	0.113	2.18
5,400	0.118	2.26
5,600	0.122	2.34
5,800	0.126	2.43
6,000	0.131	2.51
6,200	0.135	2.59
6,400	0.139	2.68
6,600	0.144	2.76
6,800	0.148	2.84
7,000	0.152	2.93
7,200	0.157	3.01
7,400	0.161	3.09

Pressure	Grad	LBS/GAL
7,600	0.165	3.18
7,800	0.170	3.26
8,000	0.174	3.35
8,200	0.178	3.43
8,400	0.183	3.51
8,600	0.187	3.60
8,800	0.191	3.68
9,000	0.196	3.76
9,200	0.200	3.85
9,400	0.204	3.93
9,600	0.209	4.01
9,800	0.213	4.10
10,000	0.217	4.18
10,200	0.222	4.26
10,400	0.226	4.35
10,600	0.230	4.43
10,800	0.235	4.51
11,000	0.239	4.60
11,200	0.243	4.68
11,400	0.248	4.76
11,600	0.252	4.85
11,800	0.256	4.93
12,000	0.261	5.01
12,200	0.265	5.10
12,400	0.269	5.18
12,600	0.274	5.27
12,800	0.278	5.35
13,000	0.282	5.43
13,200	0.287	5.52
13,400	0.291	5.60
13,600	0.295	5.68
13,800	0.300	5.77
14,000	0.304	5.85
14,200	0.309	5.93
14,400	0.313	6.02
14,600	0.317	6.10
14,800	0.322	6.18
15,000	0.326	6.27

Common Formulas and Conversion Factors

Multiply	By	to Obtain
Inches	2.54	Centimeters
Feet	0.3048	Meters
Square Inches	0.00694	Square Feet
Square Inches	6.452	Square Centimeters
Square Feet	0.0929	Square Meters
Cubic Inches	0.0005787	Cubic Feet
Cubic Inches	0.00433	Gallons
Cubic Inches	16.387	Cubic Centimeters
Cubic Feet	7.48	Gallons
Cubic Feet	0.02832	Cubic Meters
Pounds	0.4536	Kilograms
Pounds/Foot	1.488	Kilograms/Meter
Pounds/Square Inch	0.07031	Kilograms/Square Centimeter
Pounds/Gallon	7.48	Pounds/Cubic Foot
Pounds/Gallon	0.1193	Grams/Cubic Centimeter
Pounds/Cubic Foot	0.01602	Grams/Cubic Centimeter
Pounds/Square Inch/Foot	0.231	Kilograms/Square Centimeter/Meter
^{o}F	0.5555	^{o}C
^{o}C	1.8002	$^{o}F + 32$

Note: To convert the right column to the left column, divide by the conversion factor

English/Metric & Metric/English Unit Conversion

Base Unit	A Metric Units	B English Units	C Factor	D Factor
Length	Millimeters (mm)	Inches (in)	0.0393701	25.40
	Meters (m)	Feet (ft)	3.28084	0.3048
		Yards (yd)	1.09361	0.9144
	Kilometers (Km)	Statute Miles	0.621373	1.609394
		Nautical Miles (UK)	0.539613	1.85318
		Nautical Miles (Other)	0.539957	1.852
Area	Square Centimeters (cm^2)	Square Inches (in^2)	0.155	6.4516
	Square Meters (m^2)	Square Feet (ft^2)	10.7639	0.0929
	Hectares	Acres	2.47105	0.404686
	Square Kilometers (Km^2)	Square Miles (mi^2)	0.386102	2.58999
Volume & Capacity	Cubic Centimeters (cm^3)	Cubic Inches (in^3)	0.0610236	16.3871
	Cubic Decimeters (dm^3)	Cubic Feet (ft^3)	0.0353147	28.3168
		Gallons [US] (Gal)	0.264178	3.78533
		Gallons [UK] (Gal)	0.219976	4.54596
	Cubic Meters (m^3)	Cubic Feet ft^3)	35.3147	0.0283168
		Barrels [US] (bbl)	6.28994	0.158984
Force	Grams (gf)	Grains (gr.f)	15.4324	0.0647989
		Ounces (oz.f)	0.035274	28.3495
	Kilograms (kgf)	Pounds (lbf)	2.20462	0.453592
	Newtons (N)		0.224809	4.44822
	Ton [Metric]	Short ton [US]	1.10231	0.907185
		Long Ton	0.984204	1.01605
Pressure	Atmospheres (atm)	Pounds Force per	14.6960	0.0680459
	Bars (bar)	Square Inch (psi)	14.5038	0.0689475
	Kilograms/Sq. Centimeter (kgf/cm^2)		14.2234	0.0703069
	Kilograms/Sq. Millimeter (kgf/mm^2)	Short tons/Sq. Inch	0.711167	1.40614
		Short tons/Sq. Foot	102.408	0.00976486
	Pascals (Pa)	Pounds/Sq. Inch (psi)	0.000145	6894.757
Torque	Kilogrammeters (kg.m)	Foot Pounds (ft lb)	7.23301	0.138255
	Newton-Meters (Nm)		0.737562	1.35582
Energy, Work & Power	Joules (J)	British Thermal Units (BTU)	0.000947813	1055.06
	Kilocalories (Kcal)		3.96707	0.252075
	Kilocalories per Sq. Meter ($Kcal/m^2$)	British Thermal Units per Sq. Foot (BTU/ft^2)	0.368553	2.71331
	Kilocalories per Kilogram (Kcal/kg)	British Thermal Units per Pound (BTU/lb)	1.79943	0.55573
	Kilocalories per Cubic Meter ($Kcal/m^3$)	British Thermal Units per Cubic Foot (BTU/ft^3)	0.112335	8.90196
	Watts (W)	Horsepower (HP)	0.00134102	745.7
Flow	Liters per Minute (L/min)	Gallons [US] per Minute (gal/min)	0.26420	3.785
	Cu Meters per Hour (m^3/hr)	Barrels per Day (bbl/day)	150.953	0.0066245
	Metric Tons per Year [40° API Oil]	Barrels per Day (bbl/day) [40° API Oil]	0.02091	47.83

English-To-Metric Unit Conversion
To Convert from units in Col. "B" to unit in Col. "A", multiply the number of Col. "B" units by the factor in Col. "D"

Metric-To-English Unit Conversion
To convert from units in Col. "A" to units in Col. "B", multiply the number of Col. "A" units by the factor in Col. "C"

Formulas

Area of Circle

$$A=(0.785)D^2$$

$$A=\Pi\frac{D^2}{4}$$

Area of Rectangle

$$A=(L)(W)$$

End Area of Tubulars

$$A_S=0.785(D_o^2-D_i^2)$$

Volume

$$V=(A)(L)$$

Capacity of Tubulars

$$BBL/FT=0.0009714(D^2)$$

$$FT/BBL=\frac{1029.4}{D^2}$$

Annular Capacity

$$BBL/FT=0.0009714(D_o^2-D_i^2)$$

$$FT/BBL=\frac{1029.4}{(D_o^2-D_i^2)}$$

Fluid Gradient (PSI/FT)

$$=0.052[LB/GAL]$$

$$=0.007[LB/FT^3]$$

$$=0.433[Sp.Gr.]$$

$$=\frac{61.37}{(131.5+°API)}$$

Hydrostatic

$$Pressure=Gradient(L)$$

Force

$$F=(P)X(A)$$

Stretch

$$\Delta L=\frac{12(FL)}{A_sE}$$

$$\Delta L=\frac{FL(S.C.)}{10^6}$$

Stretch Constant

$$S.C.=\frac{0.4}{A_s}$$

Free Point

$$L=\frac{(\Delta L)(EA_s)}{12F}$$

$$L=\frac{1000(\Delta L)(F.P.C.)}{F}$$

Free Point Constant

$$F.P.C.=2500(A_s)$$

Lubinski Tubing Movement:

See Tubing Movement section in of this handbook

Moment of Inertia (In inches^4)

$$I=\frac{\pi}{64}(D^4-d^4)$$

Where: D = tubing OD
d = tubing ID

Capacity of Rectangular Tanks & Pits
(Length & Width in FEET)

$$BBL/INCH=0.01484(L)(W)$$

$$GAL/INCH=0.6234(L)(W)$$

Capacity of Vertical Round Tanks
(Diameter in INCHES)

$$BBL/INCH=0.01165(D^2)$$

$$GAL/INCH=0.4896(D^2)$$

Contents of Pipeline
(Diameter in INCHES)

$$BBL/FT=0.0009714(D^2)$$

$$GAL/FT=0.0408(D^2)$$

Gas Flow Through Choke

$$Q=\frac{CP_a}{\sqrt{GT}}$$

Temperature Conversions

$$degF=1.8(degC)+32$$

$$degC=\frac{degF-32}{1.8}$$

$$degR=degF+459.6$$

$$degK=degC+273$$

Fluid Velocity

$$FT/SEC=\frac{17.154(BPM)}{D^2}$$

Hydraulic Horsepower

$$HHP=0.0245(P)(BPM)$$

$$HHP=\frac{(GPM)(P)}{1714}$$

Minimum Casing ID for Multiple Strings
Two Strings

$$D_c=2(D_p)$$

Three Strings

$$D_c=2.1547(D_p)$$

Four Strings

$$D_c=2.414(D_p)$$

All dimensions are inches except where specifically noted. If you are unsure about the units used, please refer back to the applicable section of this handbook.

Choke Flow Variables
Q = MCF/Day @ 14.4 PSIA and 60 °F
C = Coefficient
P = Upstream pressure PSIA
G = Specific Gravity of Gas (Air = 1.0)
T = Upstream Temperature °R

Coefficient "C"

Choke Size	"C"
8	6.25
12	14.44
16	26.51
20	43.64
24	61.21
28	85.13
32	112.72
40	179.74
48	260.99