REVIEW OF PRACTICAL METHOD OF CASING DESIGN FOR DEEP WELLS

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ABSTRACT

Design of casing and liner strings grows more critical as well depths and bottom-hole pressures increase. Service conditions, economics, material properties, and stress-inducing parameters must all be considered to arrive at an optimum casing or liner design. A practical approach to considering the three basic load conditions, i.e., internal pressure, collapse pressure, and tension, and how they affect casing string design decisions is presented here. Safety factors that have wide industry acceptance and use are discussed. Actual practice is then reviewed by comparing the "ideal" to the "practical." In addition, other considerations and their impact on the final design are examined.

INTRODUCTION

The tubular program of most wells represents the greatest single item of expense in initial well cost. Selecting weights and grades of casing which are economical yet will withstand the forces to which the casing is subjected is a challenge facing all designers. This selection constitutes an engineering and economic problem of great importance.

Although many different casing design procedures are used, all tubular designs without exception consider internal yield, collapse, and tension, and apply to each an adequate design factor over the anticipated loads. It is in the determination of the loads and design factors to be used that most design procedures differ.

In determining loading, the worst possible conditions are generally anticipated. However, the conditions and assumptions considered the worst possible will vary greatly from one designer to another.

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DESIGN FACTORS

The ratio of the casing performance properties (i.e., internal yield pressure, collapse pressure, or joint strength) to working pressure or load is referred to as the design factor. The term design factor is used instead of safety factor in view of the fact that actual physical properties are not generally known. Minimum performance properties from API bulletins are usually used.

The API Mid-Continent District Study Committee on Casing Programs in 1955 reported the results of questionnaires sent to all members of the committee concerning design factors. In response to this investigation, 50 replies were received from 38 companies. Following is a summary of the practices concerning design factors as indicated by this study:

1. Design factors for internal yield varied from 1.00 to 1.75, the most common factor being 1.10. This was used on 32% of the casing strings reported.
2. Design factors for collapse varied from 1.000 to 1.500, the most common factor being 1.125. This collapse design factor was used on 68% of the casing strings reported.
3. Design factors for tension varied from 1.50 to 2.00. The factors used and the percentages were:

Factor	Percentage
1.60	29%
1.75	21%
1.80	25%
2.00	24%

This study indicates that a standard design factor does not exist for any of the three major load conditions. However, the study does support the following design factors, which many consider standard:

Internal yield design factor	=	1.10
Collapse design factor	=	1.125
Tension design factor	=	1.80

Yield

The 1.1 internal-yield design factor was derived from the API method of rating tubular goods for internal pressure, calculated by using Barlow's formula:

$$P = 0.875\,(2Y_p t)/D$$

Nomenclature is listed in Table 1. By this equation, the minimum yield pressure is 0.875 of the yield pressure for nominal dimensions and minimum yield strength material. This takes into account the 12.5% wall thickness variation allowed by API specifications.

The 80% API test pressure is based on internal pressure calculated for nominal dimensions. The ratio of 0.875 to 0.80 is 1.09; thus, the use of a 1.10 factor is justified for internal pressure values up to API test pressures.

Collapse

The collapse design factor (1.125) represents the collapse pressure of the casing divided by the applied external pressure differential. Minimum collapse pressures for casing are determined by using the applicable collapse pressure formula from API Bulletin 5C3.

There are four formulas listed in this bulletin for calculating collapse pressures. Each is used for a given outside-diameter-to-wall-thickness (D/t) ratio. The yield strength collapse and elastic collapse formulas were derived on a theoretical basis. However, the plastic collapse formula was derived empirically from 2,488 collapse pressure tests, while the transition collapse formula was determined on an arbitrary basis.

The minimum values for the plastic collapse formula are obtained by subtracting a constant pressure determined for each particular grade from the average of the test pressure values. As a result, the minimum plastic collapse pressures are based on the conception that there is a 95% probability that the collapse pressure will exceed the minimum calculated value with no more than 0.5% failures.

TABLE 1 NOMENCLATURE

a = Axial load below section, lb
A_s = Cross-sectional area of pipe, sq in.
BF = Buoyancy factor
BI = Bending load, lb
D = Nominal outside diameter, in.
D_1 = Casing seat depth, ft
D_2 = Depth being considered, ft
DF_c = Collapse design factor
DF_t = Tension design factor
e = Base of natural logarithms = 2.7
F = Force due to temperature change, lb
G = Specific gravity of gas
G_{bd} = Overburden gradient, normally 1.0 or less, psi/ft
G_g = Gas gradient, psi/ft
L = Well depth, ft
P = Minimum internal yield pressure, psi
P_B = Bottom-hole pressure, psi
P_h = Internal pressure at depth D_1, where $D_2<D_1$, psi
P_c = Collapse resistance to satisfy design factor, psi
P_{ca} = Minimum collapse pressure under axial tension stress, psi
P_{co} = Minimum collapse pressure without axial tension stress, psi
P_j = Minimum joint strength, lb
P_s = Surface pressure, psi
S_a = Axial tension stress, psi
t = Nominal wall thickness, in.
W = Mud weight, lb/gal
W_n = Nominal weight of casing, lb/ft
W_o = Mud weight outside casing, lb/gal
Y_p = Minimum yield strength of the pipe, psi
ΔT = Temperature change, °F.
θ = The rate of change of angle, °/100 ft

Based on the collapse pressure derivations, it is apparent that a design factor greater than 1.00 should be used to insure against the possibility of a collapse failure. The 1.125 collapse design factor gives this extra margin of safety and has proven to be acceptable through its wide use and success in the past.

Tension

The tension design factor (1.80) is the ratio of connection joint strength to applied axial load. Joint strength refers to the joint fracture strength or joint pullout value.

For some connections, it is not necessary to consider joint pullout values since their design is such that joint fracture strength is always the smaller value. Thus, joint strength can be defined simply as the amount of hanging weight that can be placed on a connection without failure.

Since joint strengths are normally based on failure, the minimum ultimate strength of the casing material is used. However, exceeding the connection yield strength will often cause a failure of fluid leak tightness. Thus, design factors for parting loads should be chosen with the yield load design factor in mind.

Minimum tension design factors recommended by some operators vary with material grade, because the variation between minimum yield strength and minimum ultimate strength decreases as higher strength casing grades are selected.

Recommended tension design factors for different grades compared to the resultant design factor based on minimum yield strength are:

Grade	Design factors (ultimate)	Design factors (yield)
K-55	2.00	1.16
C-75	1.70	1.34
N-80	1.70	1.36
CY-90	1.70	1.45
C-95	1.60	1.45
P-110	1.60	1.41

These values should be increased for casing larger than 8-5/8-in. O.D. in order to compensate for the effect of bending.

DESIGN PROCEDURE

A practical design procedure which considers the three basic load conditions described above should follow a sequence which results in the most efficient use of the designer's time. This can be best accomplished by using a procedure which considers the worst possible load conditions in such a manner that the least amount of backtracking and recalculating is required. By establishing the boundaries for the worst possible load conditions at the outset, it is possible to design the safest, most economical string which will satisfy these conditions. A design example is included in the Appendix.

Internal Yield Pressure

In establishing design parameters the loading for internal pressure should be considered first. Once the design factor—internal pressure—and the available casing have been determined, all grades and weights of casing which will not meet the requirements can be eliminated. The task of determining the internal pressure is possibly the most difficult part of casing design. In the past, there have been many different methods employed for determining internal pressure requirements.

For areas where depths and bottom-hole pressures were moderate, it was usually assumed that the external pressure was zero and that the internal pressure was equal to the reservoir or bottom-hole pressure for the full length of the string. This was an acceptable procedure since for a majority of these wells, the pipe required for withstanding collapse and tension loads was more than strong enough to withstand the internal pressure considered. However, as depths and bottom-hole pressures steadily increased, this method became economically unfeasible. It is at this point that it becomes necessary to consider the maximum shut-in surface pressure to which the casing will be subjected. This surface pressure is arbitrary and depends largely on field experience in a given area. It is usually set equal to the working pressure rating of the surface equipment to be used.

Normally, when surface pressure is used as the internal load limit, it is assumed that the hole remains full of mud and that the mud density inside and outside the casing is equal. Thus, any surface pressure will be applied uniformly throughout the string (Figure No. 1). When the mud density inside the casing is not equal to that outside, the internal pressure load at any point is the sum of the surface pressure and the hydrostatic pressure differential between the different mud densities at the point behind considered.

The maximum possible surface pressure occurs when the closed-in casing is filled with formation gas. This surface pressure may be significantly lower than the bottom-hole pressure due to the effect of the weight of the gas column (Table 2).

An equation used to determine the surface

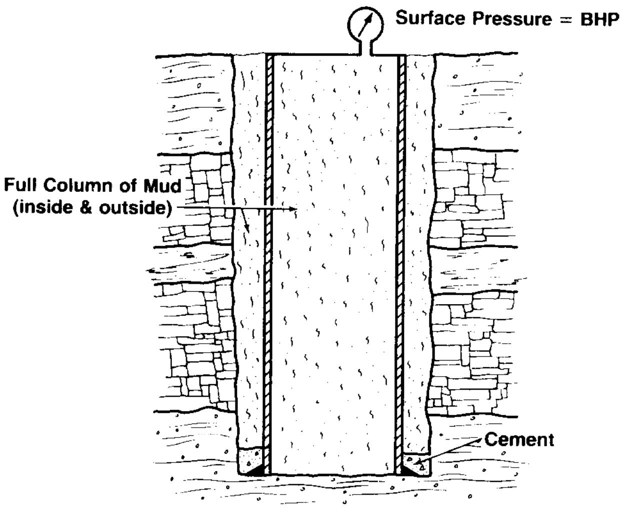

FIGURE 1 INTERNAL PRESSURE CONSIDERATION

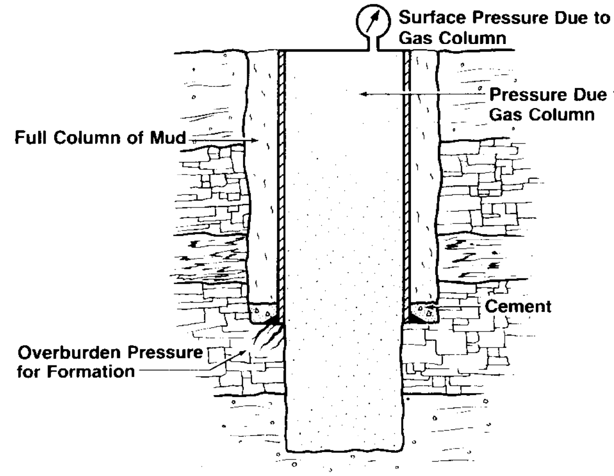

FIGURE 2 OTHER INTERNAL PRESSURE LIMITATIONS

pressure due to this effect for a given bottom-hole pressure, depth, and gas is as follows:

$$P_s = P_b/(e^{0.000034GL})$$

Methane gas (CH_4), with a sp gr of 0.554, is normally used when calculating the maximum possible surface pressure. It is considered conservative to use methane when specific gravity of gas is unknown, because the specific gravities of gases encountered are usually greater than that of methane.

Although the maximum surface pressure method of considering internal pressure is the most common method used today, other methods which establish limits on internal pressure are used. One such method considers the maximum pressure to be that which exceeds the fracture gradient of the formation below the casing seat, relieving any higher pressure (Figure No. 2).

TABLE 2 PRESSURE LOSS DUE TO WEIGHT OF GAS COLUMN

(Decimal ratio to be multiplied by bottom-hole pressure to obtain surface pressure)

Depth of well, ft	Specific gravity of the gas column													Depth of well, ft
	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90	0.95	Air 1.00	1.10	1.20	
	Decimal ratio—well head pressure/bottom hole pressure													
1,000	.983	.981	.979	.978	.976	.974	.973	.971	.969	.968	.966	.963	.959	1,000
2,000	.966	.963	.959	.956	.953	.949	.946	.943	.939	.936	.933	.927	.920	2,000
3,000	.949	.944	.939	.935	.930	.925	.920	.915	.911	.906	.901	.892	.883	3,000
4,000	.933	.927	.920	.914	.907	.901	.895	.889	.883	.876	.870	.858	.847	4,000
5,000	.917	.909	.901	.893	.886	.878	.870	.863	.855	.848	.841	.826	.812	5,000
6,000	.901	.892	.883	.873	.864	.855	.847	.838	.829	.821	.812	.795	.779	6,000
7,000	.886	.875	.864	.854	.844	.833	.823	.813	.804	.794	.784	.766	.747	7,000
8,000	.870	.858	.847	.835	.823	.812	.801	.790	.779	.768	.758	.737	.717	8,000
9,000	.855	.842	.829	.816	.804	.791	.779	.767	.755	.743	.732	.709	.687	9,000
10,000	.841	.826	.812	.798	.784	.771	.758	.745	.732	.719	.707	.683	.659	10,000
11,000	.826	.811	.795	.780	.766	.751	.737	.723	.709	.696	.683	.657	.633	11,000
12,000	.812	.795	.779	.763	.747	.732	.717	.702	.687	.673	.659	.633	.607	12,000
13,000	.798	.780	.763	.746	.729	.713	.697	.682	.666	.651	.637	.609	.582	13,000
14,000	.784	.766	.747	.729	.712	.695	.678	.662	.646	.630	.615	.586	.558	14,000
15,000	.771	.751	.732	.713	.695	.677	.659	.643	.626	.610	.594	.564	.536	15,000
16,000	.758	.737	.717	.697	.678	.659	.641	.624	.607	.590	.574	.543	.514	16,000
17,000	.745	.723	.702	.682	.662	.643	.624	.606	.588	.571	.554	.523	.493	17,000
18,000	.732	.709	.687	.666	.646	.626	.607	.588	.570	.552	.536	.503	.473	18,000
19,000	.719	.696	.673	.651	.630	.610	.590	.571	.552	.535	.517	.484	.453	19,000
20,000	.707	.683	.659	.637	.615	.594	.574	.554	.536	.517	.500	.466	.435	20,000
21,000	.695	.670	.646	.623	.600	.579	.558	.538	.519	.500	.483	.449	.417	21,000
22,000	.683	.657	.633	.609	.586	.564	.543	.523	.503	.484	.466	.432	.400	22,000
23,000	.671	.645	.620	.595	.572	.550	.528	.507	.488	.469	.450	.416	.384	23,000
24,000	.659	.633	.607	.582	.558	.536	.514	.493	.473	.453	.435	.400	.368	24,000
25,000	.648	.621	.594	.569	.545	.522	.500	.478	.458	.439	.420	.385	.353	25,000

Formula $P_S / P_B = 1 / e^{.000034GL}$ Where P_S = Surface pressure, psi; P_B = Bottom hole pressure, psi; e = Base of natural logarithm 2.71
G = Specific gravity of gas; L = Depth of well, ft

This procedure assumes the casing to be filled with formation gas, with the maximum pressure occurring at the bottom of the hole and decreasing as the depth decreases by the weight of the gas or gas gradient. Using this method, the internal pressure on the casing at any point is the pressure of the gas at that point, less the hydrostatic pressure outside the casing. This pressure can be calculated by:

$$P_b = G_{bd}D_l - G_g (D_l - D_2) - (0.052W_oD_2)$$

Once the internal pressure requirement has been determined, regardless of which method is used, the pressure should be multiplied by the internal yield design factor (1.10). All grades and weights of casing which have internal yield pressures less than this calculated value can be eliminated from design consideration.

Collapse Pressure

For casing which will meet the requirements for internal pressure, the controlling load conditions are collapse pressure in the lower part of the string and tension in the upper part of the string. The design of a string of casing in collapse consists of selecting the least expensive casing which has sufficient collapse resistance to provide the desired design factor (1.125).

When considering collapse loading, it is common practice to assume that the pressure outside the casing results from the external mud column extending to the surface, and the pressure inside the casing is zero (Figure No. 3). Thus, for the lowest section of casing in a string, the collapse resistance required can be determined by calculating the bottom-hole hydrostatic pressure and multiplying it by the collapse design factor. This procedure expressed mathematically is:

$$P_c = (0.052\ W_oD_l)\ (DF_c)$$

As the depth decreases, the hydrostatic pressure outside the casing also decreases. Thus, a combination string (i.e., a string consisting of more than one section) is often used in order to obtain a string which will satisfy the desired design factor with the least investment.

Determining setting depths based on collapse for sections other than the lowest section is complicated by the effect of tension loading on the collapse resistance. The reduction in minimum collapse pressure due to an axial tension load can be calculated by using the following equation, which is given in API Bulletin 5C3:

$$P_{ca} = P_{co}\,[1 - 0.75\,(S_a/Y_p)^2]^{0.5} - 0.5\,(S_a/Y_p)P_{co}$$

This equation is based on the Hecky-von Mises maximum strain energy of distortion theory of yield. When this effect is considered, the determination of setting depth normally involves the use of either trial-and-error or graphical solutions. This type procedure is necessary because the reduction of casing collapse resistance is a function of the axial load, and the axial load varies as the setting depth is adjusted to satisfy the design factor required.

The most common method used for determining the axial load for calculating the reduction in collapse is the in-air weight of the casing below the point being considered. Some methods, however, consider buoyancy in determining this axial load.

Axial load with buoyancy considered is determined by multiplying the same in-air weight as above by the buoyancy factor. The buoyancy factor can be determined by using the equation:

$$BF = (65.4 - W)/65.4$$

Tension

At some point up the hole, collapse resistance ceases to be the controlling factor in casing string design. From this point to the top of the string, the primary consideration is tension.

Tension design generally is based on the load imposed by the string hanging freely in air, with each section of the string required to support the entire weight of the string below it. To determine the length

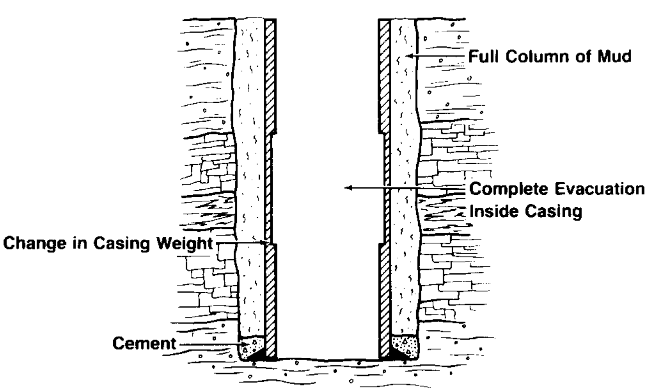

FIGURE 3 COLLAPSE PRESSURE CONSIDERATION

of a section which can be used once tension becomes the controlling factor, the following equation can be used:

$$\text{Section length} = [(P_j/DF_t) - a]/W_n$$

This procedure is repeated, using grades and weights of casing with increased joint strengths until the desired string length and tension design factor requirements are satisfied.

Although the most common procedure used for considering the tension load is the in-air weight of the casing, some operators consider the effect of buoyancy on tension load. The reduced load due to buoyancy is calculated by multiplying the in-air weight by the buoyancy factor. However, when buoyancy is considered, the tension factor is normally increased, reducing the significance of the buoyancy consideration except for wells drilled with mud weighing more than 10 lb/gal. Once the reduced load due to buoyancy is obtained, the same procedure is used for determining section length. This procedure expressed in the form an equation is:

$$\text{Section length (buoy)} = [P_j/DF_t - a\,(BF)]/W_n BF$$

Another method which is used for tension design is the "Marginal Load" method. This method applies a design factor to the deepest section of the string designed in tension and the sections above are designed to withstand the same marginal load. This procedure has not gained wide acceptance.

Bending Effect

When calculating tension loading, the effect of bending should be considered when possible. Since a bending load increases the tensile load, it must be deducted from the usable tension strength of the joint. For the determination of the effect of bending, the following equation can be used:

$$Bl = 63\,\theta\,DW_n$$

Since most casing has a relatively narrow range of wall thickness, the weight of casing is approximately proportional to its diameter. Bending load increases in proportion to the square of the diameter. However, the joint strength does not normally increase at this same rate. The result is that bending is a much more severe problem for large diameter casing than it is for the smaller sizes. It is necessary to increase the tension design factor for casing larger than 8-5/8-in. O.D.

Other Load Limitations

Although internal pressure, collapse pressure, and tension load are normally the controlling load conditions in a design, a number of other special cases, such as the effect of temperature and corrosion, are important. These conditions often place limits on the weight and grades of casing which can be used.

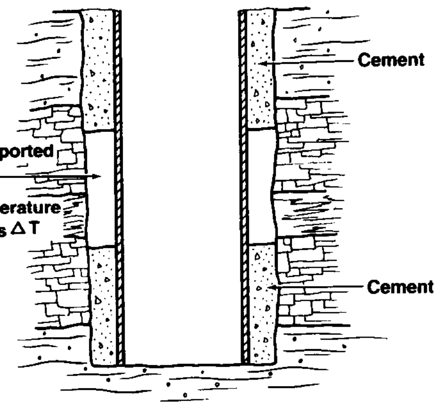

FIGURE 4—EFFECT OF TEMPERATURE

Changes in load on a casing string occur from time to time after the casing is set. Among the most severe of the changes is the effect of temperature change in an uncemented interval (Figure No. 4). For each change of 1° F., there is a change in stress of 207 psi. This stress can be expressed in terms of a force by using the equation:

$$F = 207\,A_s \Delta T$$

An interesting aspect of this equation is that the force is not affected by the length of the uncemented interval. Therefore, a short uncemented section experiences the same increase in load that a long section would if subjected to the same temperature change.

Corrosion Limitations

The presence of H_2S in a well limits the grades of casing which can be used safely without the danger of failure due to sulfide stress cracking (SSC). SSC is influenced by stress, environment, temperature, and metallurgical factors. The grades of tubing and casing normally considered acceptable for an SSC environment are as follows:

ALL TEMPERATURES	175°F AND ABOVE*
API Spec. 5A	API Spec 5A
H-40 n	H-40
J-55 n	N-80
K-55 n	API Spec 5AX
API Spec 5AC	P-105
C-75	P-110
L-80	API Spec 5AC
	C-95

*Continuous minimum temperature. If the possibility of lower temperature exists during shut-in, use resistance material.

† 70,000 psi maximum yield strength

‡ Shall be used only if full-lengths normalized or tempered after upset.

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APPENDIX—DESIGN EXAMPLE

Conditions:

(1) 10¾-in. casing to be set to a depth of 9,000 ft.

(2) Mud weight = 11 lb/gal.

(3) Maximum deviation = 2°/100 ft at 6,000 ft.

(4) Well may be emptied.

(5) Casing to be run in 12¼-in. hole and inside 13⅜-in.—68 lb/ft casing set to 5,000 ft.

(6) Casing to drift 9½-in. bit.

(7) Design factor required:

Internal yield design factor = 1.10.

Collapse design factor = 1.125.

Tension design factor = 1.80.

Solution:

The loading for internal pressure should be considered first. If internal pressure requirements are not known from field experience, it must be approximated from the anticipated mud weight and well depth.

Pressure gradient $= 0.052\ W_o = (0.052)\ (11) = 0.572$ psi/ft

Bottom-hole pressure

$= 0.052\ W_o\ D_1$

$= (0.052)\ (11)\ (9{,}000) = 5{,}150$ psi

Maximum surface pressure with methane gas column:

$$P_S = P_B/e^{0.000034GL}$$

$$= 5{,}150/e^{0.000034\ (0.554)\ (9{,}000)}$$

$$= 4{,}330 \text{ psi}$$

Internal yield strength required

$= 1.1\ (4{,}330)$

$= 4{,}760$ psi

Thus, any casing with internal pressure rating less than 4,760 psi can be eliminated from design considerations.

With internal pressure loading established, the requirements for collapse resistance must be determined.

Collapse strength required at casing seat

$= \text{BHP} \times$ collapse design factor

$= (5{,}150)\ (1.125) = 5{,}790$ psi

The following casing weights and grades will satisfy load requirements.

Size	Weight	Grade
10¾-in.	55.5 lb/ft	S-95
10¾-in.	60.7 lb/ft	P-110

Collapse strength	Internal yield strength
5,950 psi	7,660 psi
5,860 psi	9,760 psi

The 55.5 lb/ft S-95 casing is the one which should be used due to its lower weight and cost. With this casing the actual collapse factor is $= 5{,}950/5{,}150 = 1.155$.

The top of this bottom section of casing (Sec. 1) is determined by the setting depth of the next casing section (Sec. 2). The choice for Sec. 2 is the next lower collapse strength and cost casing, which is:

Size	Weight	Grade
10¾-in.	55.5 lb/ft	N-80

Collapse strength	Internal yield sterngth
4,020 psi	6,450 psi

Maintaining the collapse design factor the maximum collapse pressure which can be applied to the bottom of Sec. 2 is:

$$4{,}020/1.125 = 3{,}573 \text{ psi}$$

The approximate setting depth of Sec. 2 is determined by dividing this pressure by the pressure gradient.

Approx. setting depth (Sec. 2)

$= 3{,}573/0.572 = 6{,}247$ ft

However, the weight of Sec. 1 will reduce the collapse resistance at the bottom of Sec. 2 due to effect of axial tension on collapse.

The reduced collapse resistance can be expressed as a percentage of actual collapse pressure in the following manner:

$$P_{ca} = Y\ (P_{co})$$

Y, is a value taken from Table 3 based on a value X where:

$$X = a/Y_p\ A_s$$

Considering the above effect the approximate setting depth of Sec. 2 is 5,770 ft. The correct setting depth of Sec. 2 is found by trial and error. The solution by this method gives a setting depth of 5,850 ft as shown by the following calculations:

Length of Section 1
$= 9{,}000 - 5{,}850 = 3{,}150$ ft

Weight of Section 1
$= (3{,}150)\ (55.5)$
$= 174{,}825$ ft

$X = 174{,}825/(95{,}000)\ (15.947)$
$= 0.115$

The value of Y found in Table 3 is 0.937

$$P_{ca} = 0.937\ (4{,}020) = 3{,}766$$

The hydrostatic pressure at 5,850 ft is (0.052) (11) (5,850) = 3,346 psi. Therefore, the collapse safety factor for Section 2 is:

$$3{,}766/3{,}346 = 1.125$$

The connection to be used and the tension safety factor for Sec. 1 can now be determined.

Due to casing and hole size being considered, a clearance connection must be used. Thus, an SFJ-P connection is the choice. Joint strength for 10¾-in., 55.5 lb/ft, S-95, SFJ-P is 1,020,000 lb/ft.

Tension safety factor for Sec. 1 is 1,020,000/(3,150) (55.5) = 5.83.

At this point, it is decided to run Sec. 2 to the surface and not to reduce casing weight.

Joint strength for 10¾-in., 55.5 lb/ft, N-80, SFJ-P is 927,000 lb/ft, thus tension safety for Sec. 2 is (927,000)/(9,000) (55.5) = 1.86.

The casing design is completed to the surface with required tension and collapse safety factors satisfied. Now, the internal yield pressure safety factors should be determined to confirm that they meet the established requirements.

Initially, anticipated internal pressures were calculated and materials selected. The following equations are used to determine the actual internal yield safety factors:

Internal yield safety factor for Sec. 1 is (7,660)/(4,330) = 1.77

Internal yield safety factor for Sec. 2 is (6,450)/(4,330) = 1.49

Therefore, an appropriate casing design will be as follows from top to bottom: 5,850 ft, 10¾-in., 55.5 lb/ft, N-80, SFJ-P; 3,150 ft, 10¾-in., 55.5 lb/ft, S-95, SFJ-P.

TABLE 3 -SEAMLESS-COLLAPSE CURVE FACTORS

X	Y	X	Y	X	Y	X	Y	X	Y	X	Y	X	Y	X	Y
.002	.999	.082	.956	.162	.909	.242	.857	.322	.799	.402	.736	.486	.664	.570	.585
.004	.998	.084	.955	.164	.908	.244	.855	.324	.798	.404	.735	.488	.662	.572	.583
.006	.997	.086	.954	.166	.907	.246	.854	.326	.796	.406	.733	.490	.660	.574	.581
.008	.996	.088	.953	.168	.905	.248	.853	.328	.795	.408	.731	.492	.659	.576	.579
.010	.995	.090	.952	.170	.904	.250	.851	.330	.793	.410	.730	.494	.657	.578	.577
.012	.994	.092	.951	.172	.903	.252	.850	.332	.792	.412	.728	.496	.655	.580	.575
.014	.993	.094	.950	.174	.902	.254	.849	.334	.790	.414	.727	.498	.653	.582	.573
.016	.992	.096	.949	.176	.900	.256	.847	.336	.789	.416	.725	.500	.651	.584	.571
.018	.991	.098	.947	.178	.899	.258	.846	.338	.787	.418	.723	.502	.650	.586	.569
.020	.990	.100	.946	.180	.898	.260	.844	.340	.786	.420	.722	.504	.648	.588	.567
.022	.989	.102	.945	.182	.897	.262	.843	.342	.784	.422	.720	.506	.646	.590	.565
.024	.988	.104	.944	.184	.895	.264	.842	.344	.783	.424	.718	.508	.644	.592	.563
.026	.987	.106	.943	.186	.894	.266	.840	.346	.781	.426	.716	.510	.642	.594	.561
.028	.986	.108	.942	.188	.893	.268	.839	.348	.780	.428	.715	.512	.640	.596	.558
.030	.985	.110	.940	.190	.891	.270	.837	.350	.778	.430	.713	.514	.638	.598	.556
.032	.984	.112	.939	.192	.890	.272	.836	.352	.776	.432	.711	.516	.637	.600	.554
.034	.983	.114	.938	.194	.889	.274	.834	.354	.775	.434	.710	.518	.635	.602	.552
.036	.982	.116	.937	.196	.887	.276	.833	.356	.773	.436	.708	.520	.633	.604	.550
.038	.980	.118	.936	.198	.886	.278	.832	.358	.772	.438	.706	.522	.631	.606	.548
.040	.979	.120	.935	.200	.895	.280	.830	.360	.770	.440	.705	.524	.629	.608	.546
.042	.978	.122	.933	.202	.884	.282	.829	.362	.769	.442	.703	.526	.627	.610	.544
.044	.977	.124	.932	.204	.882	.284	.827	.364	.767	.444	.701	.528	.625	.612	.542
.046	.976	.126	.931	.206	.881	.286	.826	.366	.765	.446	.699	.530	.623	.614	.540
.048	.975	.128	.930	.208	.880	.288	.824	.368	.764	.448	.698	.532	.622	.616	.538
.050	.974	.130	.929	.210	.878	.290	.823	.370	.762	.450	.696	.534	.620	.618	.536
.052	.973	.132	.927	.212	.877	.292	.821	.372	.761	.452	.694	.536	.618	.620	.534
.054	.972	.134	.926	.214	.876	.294	.820	.374	.759	.454	.692	.538	.616	.622	.532
.056	.971	.136	.925	.216	.874	.296	.819	.376	.757	.456	.691	.540	.614	.624	.529
.058	.970	.138	.924	.218	.873	.298	.817	.378	.756	.458	.689	.542	.612	.626	.527
.060	.969	.140	.923	.220	.872	.300	.816	.380	.754	.460	.687	.544	.610	.628	.525
.062	.968	.142	.921	.222	.870	.302	.814	.382	.753	.462	.685	.546	.608	.630	.523
.064	.966	.144	.920	.224	.869	.304	.813	.384	.751	.464	.684	.548	.606	.632	.521
.066	.965	.146	.919	.226	.868	.306	.811	.386	.749	.466	.682	.550	.604	.634	.519
.068	.964	.148	.918	.228	.866	.308	.810	.388	.748	.468	.680	.552	.602	.636	.517
.070	.963	.150	.917	.230	.865	.310	.808	.390	.746	.470	.678	.554	.600	.638	.514
.072	.962	.152	.915	.232	.864	.312	.807	.392	.745	.472	.677	.556	.598	.640	.512
.074	.961	.154	.914	.234	.862	.314	.805	.394	.743	.474	.675	.558	.596	.642	.510
.076	.960	.156	.913	.236	.861	.316	.804	.396	.741	.476	.673	.560	.595	.644	.508
.078	.959	.158	.912	.238	.860	.318	.802	.398	.740	.478	.671	.562	.593	.646	.506
.080	.958	.160	.910	.240	.858	.320	.801	.400	.738	.480	.670	.564	.591	.648	.504
										.482	.668	.566	.589	.650	.502
										.484	.666	.568	.587	.652	.499