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SCHOOL OF MINERAL RESOURCES ENGINEERING
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Design of the full casing program in a deviated well

MSc Thesis

Panagiotis Aslanidis
Mineral Resources Engineer

Scientific Advisor: Prof. Vassilios Gaganis

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Panos

Abstract

Casing design constitutes of one of the major challenges in the oil industry. This is due to the fact that casing has to protect the well from the formation environment, which is going through and also from the variation of different conditions that occur in the subsurface.

To initiate the design procedure, the construction of the pore and fracture pressure profile is required based on which, the number of the casing strings will be selected. Subsequently, the outside diameters (OD) of each casing string must be defined, as wells as the equivalent mud density (EMD), which will be used in each section. In addition, survey of the well is needed in order to convert the true vertical depth (TVD) to measured depth (MD). Finally, the calculations of the major forces that act on the well (burst, collapse and tension) are required, so that the final casing thickness and grade can be selected.

The objective of this project is to provide a casing design on deviated, deep well (type slanted at target depth of 13000 ft) by taking into account the worst case scenario of all the above forces.

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1. Introduction to casing design

1.1. Introduction

When drilling a well, it is generally not possible to reach the target depth in one hole section. This is due to the uncertainty of the pressure distribution at subsurface formations that could cause several problems while drilling. Therefore, the well is drilled in sections, with each section being sealed off by steel pipe known as casing and cementing the void space between the borehole and the casing string. Depending on the conditions of each field, 3 or 4 strings are required to reach the target depth. The functions that casing string serves in **drilling** and **completion** are the followings:

- Prevents collapse of the borehole during drilling
- Prevent unstable formations from caving in
- Hydraulically isolates the wellbore fluids from the subsurface formations and formations fluids
- Minimizes damage to the subsurface environment by the drilling process and to the well by the hostile subsurface environment
- Provides a high strength flow conduit that directs the drilling fluid to the surface
- Enables the safe control of formation pressure with blowout preventers (BOPs)
- Allow selective access for production/injection/control the flow of fluids from, or into the reservoir.

For all the above reasons, casing has become one of the most expensive parts of a drilling program that may constitute up to 30% of the total cost of the well. Therefore, the duty of the drilling engineer is to achieve the optimum design of a casing program by means of **cost** and **safety**.

1.2. Casing assembly

A casing string consists of individual joints of steel pipe (approximately 40 feet long each) which are connected together by threaded connections. The most important component parts of a casing string are:

- A **guided shoe** or **casing shoe,** which is a device that guides the casing toward the center of the hole and minimizes problems such as hitting rock ledges or washouts in the wellbore as the casing is lowered into the hole and,
- A **casing hanger**, which supports the casing string when it is run into the wellbore. Provides a means of ensuring that the string is correctly located and also isolates the casing annulus from upper wellhead component

There are various other items of equipment that is present at a casing assembly such as float collar, centralisers and scratchers.

A typical casing program is depicted at figure 1.1. Furthermore, all the generic terms that are needed to describe the basic parts of a casing string are shown and described below.

1.2.1. Conductor casing

The casing conductor is the first casing string that is placed to the well when the drilling procedure is initiated. It set to shallow depths down to 100 feet below the ground level or the seabed. It has the greatest diameter among the other casing strings that is approximately 20 inches at a 25-30 inches hole. It is needed to seal off the unconsolidated formations in order to protect the subsequent casing strings from corrosion, washout of the borehole when drilling to the next casing string and support structurally some of the wellhead load. The conductor casing is usually driven into the ground with the use of a truck mounted pile-driver, where soil resistance governs its length.

1.2.2. Surface casing

The surface casing is set after the conductor casing at the depth down to 2000 feet. Its diameter is usually at 13 3/8 inches at a 17 1/2 inches hole. At this point the circulation of the mud down to the drill bit starts for cleaning the hole from cuttings, remove heat and lubricate. The surface casing is needed to prevent cave-in of unconsolidated, weaker near-surface sediments, to protect the shallow, freshwater sands from contamination, to support and to protect from corrosion any subsequent casing string run into the well and finally, to support the BOP and wellhead equipment. The setting depth of this casing string is important in an area where abnormally high pressures are expected. In the case that a kick happens, surface casing usually allows the flow to be contained by closing the BOP. Because of the possibility of contamination the of shallow-water-supply aquifers, surface casing setting depths and cementing practices are subject to government regulations.

1.2.3. Intermediate casing

After the surface casing, intermediate casing string is placed at the depth down to 6000 feet. A typical diameter of an intermediate casing is 9 5/8 inches at a 12 1/4 inches hole. This kind of casing is used at deeper wells that penetrate troublesome formations under the surface casing (abnormally pressured zones, lost circulation zones, unstable shale sections and squeezing sands) to protect them from the pressures created by the required high drilling fluid density. The number of the above troublesome formations generally will require one or more strings of intermediate casing.

1.2.4. Production casing

Production casing is run through the pay zone down to True Vertical Depth (TVD) at a hole approximately of 8 1/2 inches. The diameter of the production casing depends on factors that will be explained later on Chapter 3. This casing string isolates the production interval from other formations (water bearing sands), provides protection for the environment in the event of a failure of the tubing string during production operations and finally acts as a conduit for the production tubing permitting it to be replaced or repaired later in the life of a well.

1.2.5. Liner

Liners are short casing strings (less than 500 feet) that do not extend to the surface but are suspended from the bottom of the next large casing string by a liner hanger (a device that is attached to the top joint of the casing in the string). Liners could be used as an intermediate string or as a production string and their principal advantage is their lower cost.

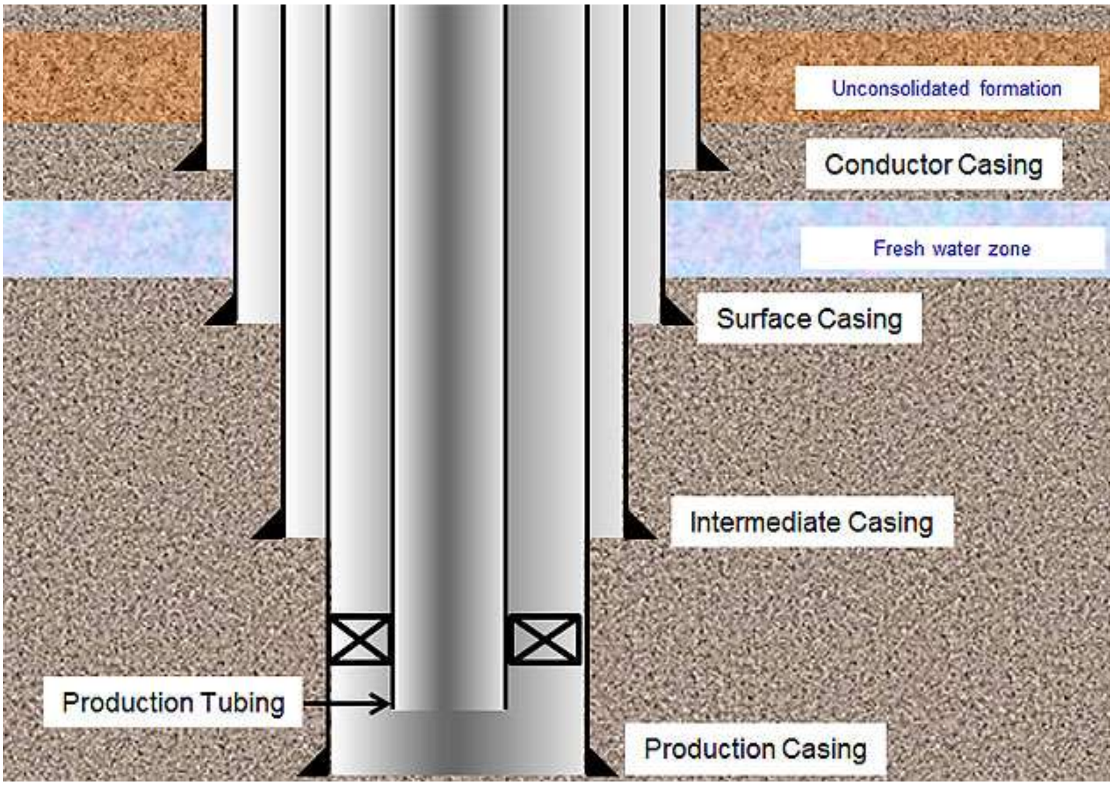

Figure 1: A typical casing program.

2. Acting forces in a well

2.1. Introduction

Each casing string must carefully designed to withstand the anticipated loads to which it will be exposed during installation, when drilling the next hole section and when producing from the well. These loads are a highly complex combination of many types, including loads from the **environment** and loads from **temperatures** changes and they depend on the types of the formation to be drilled, the formation pore pressure, the formation fracture pressure, the geothermal profile and the nature of the fluids in the formations which will be encountered. Finally, pressures **inside the well** should also be considered for ensuring the pressure stability against the environment. Therefore, a drilling engineer must bear in mind all the above parameters before a casing design.

2.2. Formation pore pressures

The pressure in the pores of a formation is known as **formation pore pressure.** This pressure plays a significant role for the casing design calculations and also to the mud weight selection. It necessary to be able to have knowledge of the pressure profile of the field that will be drilled to avoid unpleasant situations like blow-out, collapse of the string etc.

The pore pressure can be measured and plotted against depth as it is shown at Figure 2.1. This pressure is often expressed in terms of **pore pressure gradient** (field units psi/ft) by taking as a datum the Mean Sea Level, MSL. The pore pressure gradient for the brine ranges from 0.433(pure water) to about 0.50 psi//ft depending on the salt content. In most areas the pore pressure gradient is approximately 0.45 psi/ft (assumes 80,000 ppm salt content). Finally, when the pore fluids are normal pressured the formation pore pressure is also said to be hydrostatic.

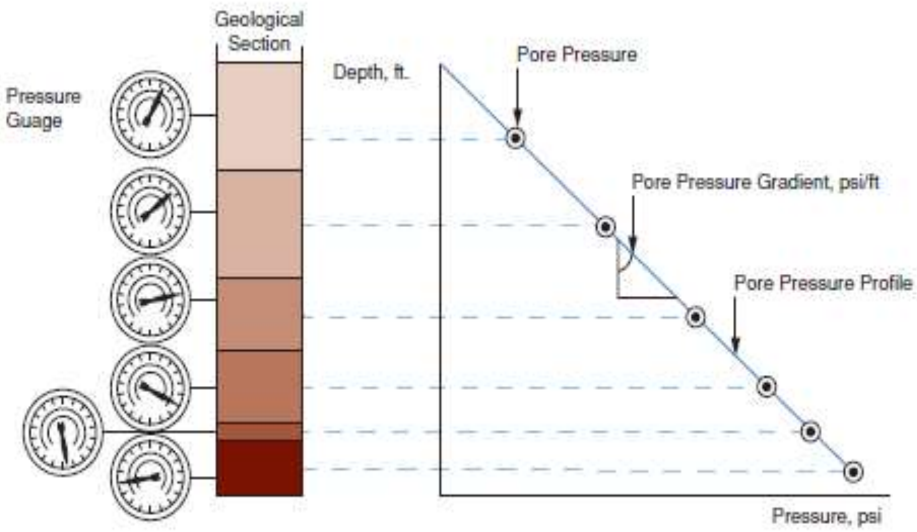

Diagram 1: Pressure-depth profile

2.3. Overburden pressures

All the above pressures discussed refer to pressure in the pores of the formations. Overburden or geostatic or lithostatic pressure describes the vertical stress at any depth. This pressure will have a significant impact on the pressure at which the borehole will fracture. It is a function of the mass of rock and fluid above the point of interest and its gradient is derived from a cross plot of overburden pressure versus depth (Diagram 2).

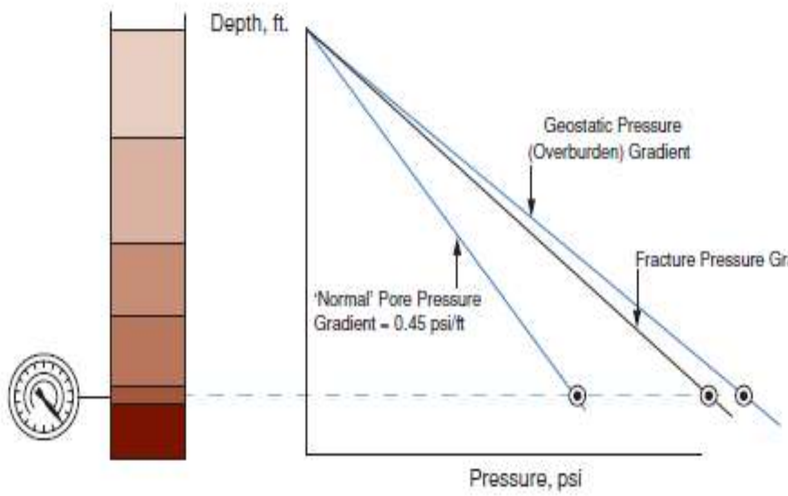

Diagram 2: Pore, Fracture and Overburden pressures and gradients for a particular formation

For the calculation of the of the overburden pressure at any point, the average density of the material (rock and fluids) above the point of interest must be determined. The average density of the rock and fluid in the pores is known as the **bulk density** of the rock:

$$\rho_b = \rho_f * \Phi + \rho_m * (1-\Phi) \tag{2.12}$$

where,

ρ_b = bulk density of the porous sediment
ρ_m = density of the rock matrix
ρ_f = density of fluid in pore space
Φ = porosity

Since the matrix material (rock type), porosity and fluid content vary with depth, the bulk density will also vary with depth due to compaction and changing lithology. The overburden pressure at any point is therefore the integral of the bulk density from surface down to the point of interest.

The specific gravity of the rock matrix vary from 2.1 (sandstone) to 2.4 (limestone).

2.4. Abnormal pressures

Pore pressures which are found to lie above or below the "normal" pore pressure gradient line are called abnormal pore pressures (Diagram 3 and 4). These formation pressures may be either **Subnormal** (i.e. less than 0.45 psi/ft) or **Overpressured** (i.e. greater than 0.45 psi/ft).

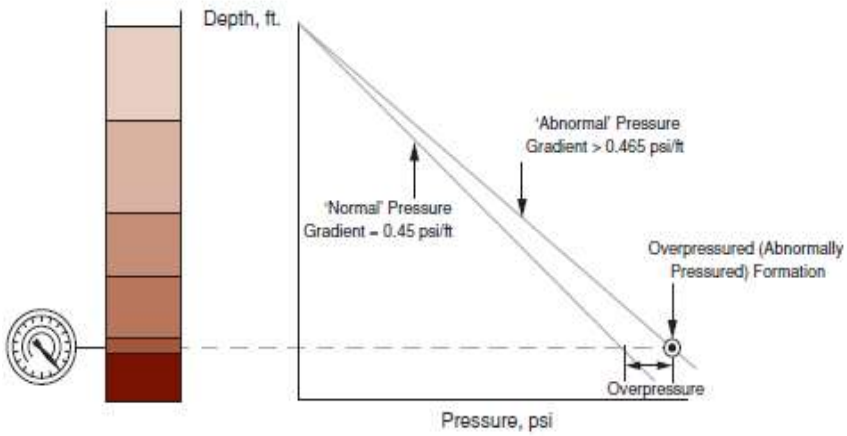

Diagram 3: Overpressured formation

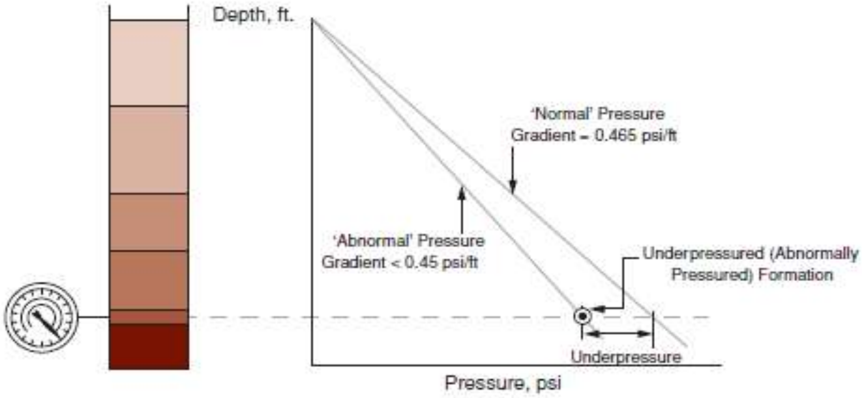

Diagram 4: Underpressure (subnormal) formation

The major mechanisms by which **subnormal** (less than hydrostatic) pressures occur may be summarized as follows:

A. Thermal expansion
B. Formation foreshortening
C. Depletion
D. Precipitation
E. Potentiometric surface
F. Epeirogenic movement

Figure 4 depicts an example of a subnormal pressure due to formation shortening. Shortening of bed B due to the warping of beds A and C causes unique pressure problems.

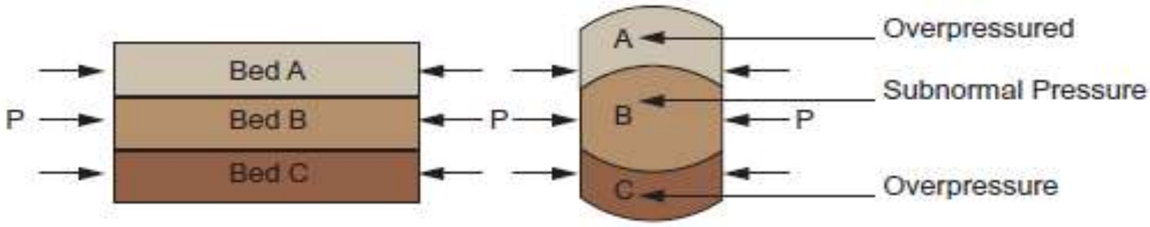

Figure 2: Foreshortening of intermediate beds.

Formation shortening along with potentiometric surface is also two of the major mechanisms for overpressures. The other mechanisms that cause such pressures to develop are summarized below:

A. Incomplete sediment compaction (Figure 5)
B. Faulting
C. Phase changes during compaction
D. Massive rock salt deposition
E. Salt diaperism
F. Tectonic compression

G. Repressuring from deeper levels
H. Generation of hydrocarbons

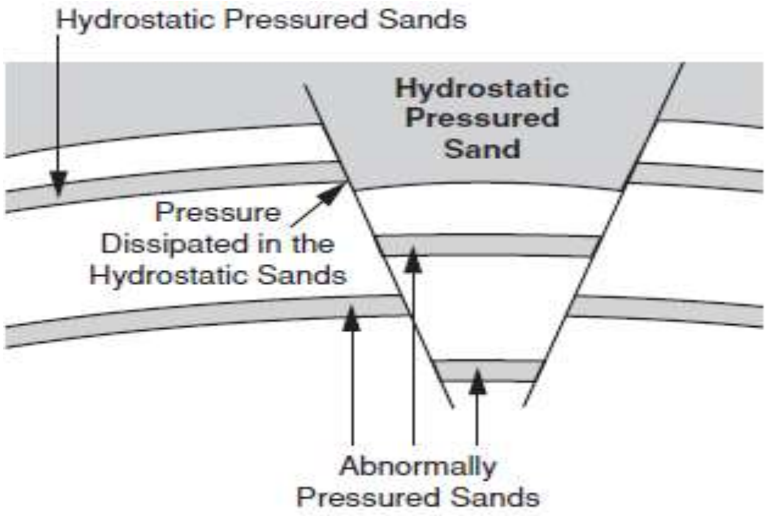

Figure 3: Barriers to flow and generation of overpressured sand

The techniques which are used to predict (before drilling) and detect (whilst drilling) and confirm (after drilling) abnormal pressures are summarized at Table 1.

Source of Data	Parameters	Time of Recording
Geophysical methods	Formation velocity (Seismic) Gravity Magnetics Electrical prospecting Methods	Prior to spudding well
Drilling Mud	Gas Content Flowline Mudweight "kicks" Flowline Temperature Chlorine variation Drillpipe pressure Pit volume Flowrate Hole Fillup	While drilling
Drilling parameters	Drilling rate d,d_c exponent Drilling rate equations Torque Drag Drilling	While drilling Delayed by the time required for mud return
Drill Cuttings	Shale cuttings Bulk density Shale factor Electrical resistivity Volume Shape and Size Novel geochemical, physical techniques	While drilling Delayed by time required for sample return
Well Logging	Electrical survey Resistivity Conductivity Shale formation factor Salinity variations Interval transit time bulk density hydrogen index Thermal neutron cam capture cross section Nuclear Magnetic Resonance Downhole gravity data	After drilling
Direct Pressure Measuring Devices	Pressure bombs Drill stem test Wire line formation test	When well is tested or completed

Table 1: Methods for predicting and detecting abnormal pressures.

2.5. Formation fracture gradient

Fracture is a crack or surface of breakage within rock not related to foliation or cleavage in metamorphic rock along which there has been no movement. The stress within a rock can be resolved into three principal stresses (Fig. 6). A formation will fracture when the pressure in the borehole exceeds the least of the stresses within the rock structure.

To initiate a fracture in the wall of the borehole, the pressure in the borehole must be greater than the least principal stress in the formation. To propagate the fracture the pressure must be maintained a level greater than the least principal stress.

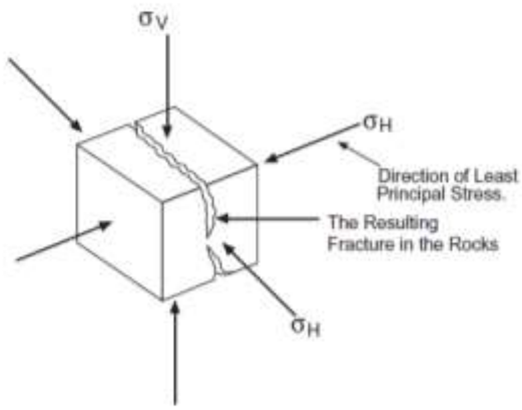

Figure 4: Idealized view of the stress acting on the block.

Exceeding the formation's fracture pressure on one hand could cause drilling fluid loss to the formation and consequently problems to the well. On the other hand, fractures can enhance permeability of rocks greatly by connecting pores together, and for that reason, when needed fractures are induced mechanically in some reservoirs in order to boost hydrocarbon flow.

2.5.1. Tests for formations fracture pressure

The pressure at which formations will fracture when exposed to borehole pressure is determined by conducting one of the following tests:

A. The **''Leak-off test''**. It is used to determine the pressure at which the rock in the open hole section of the well just starts to break down. In this type of the operation is terminated when the pressure no longer continues to increase linearly as the mud is pumped into the well.
B. The **''Limit Test''**. It used to determine whether the rock in the open hole section of the well will withstand a specific, predetermined pressure. This pressure represents the maximum pressure that the formation will be exposed to whilst drilling the next wellbore section.
C. The **''Formation Breakdown Test''**. It is used to determine the pressure at which the rock in the open hole section of the well completely breaks down.

2.6. Drilling hydraulics

The pressures of the fluids that act to a well are numerous and extremely large therefore the science of fluid mechanics is of high importance to the drilling engineer. The presence of these subsurface pressures must be considered in almost every well problem encountered. In the following subchapters the relations needed to determine the subsurface fluid pressure for will be developed for **static** well conditions.

When pressure is normal hydrostatic, its gradient is constant (Fig 2.1). In most cases when the depth increases we face a variety of different pressures. These pressures can be determined taking the free body diagram of a fluid slice (Fig 2.2) for the vertical forces acting on an element of fluid at a depth **Z** in a hole of cross-sectional area **A**.

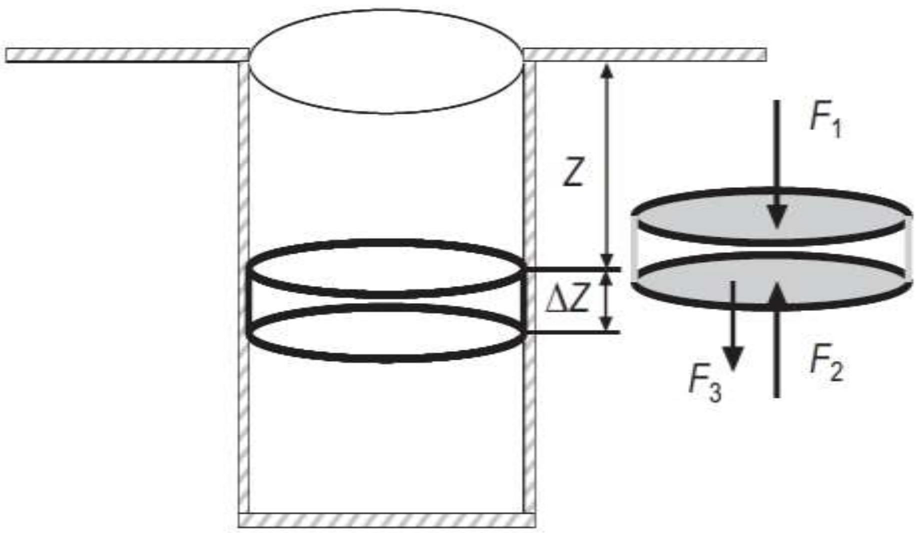

Figure 5: Acting forces at fluid slice

Where:

$$F_1 = p*A \tag{2.1}$$

$$F_2 = (p + \frac{dp}{dZ}) * A \tag{2.2}$$

$$F_3 = \rho*g*A*\Delta Z \tag{2.3}$$

Since we are in static conditions and the fluid is at rest, no shear forces exist and the three forces shown must be in equilibrium:

$$F_1 - F_2 - F_3 = 0 \tag{2.4}$$

By combining all these relations above we get the following relationship for the pressure gradient:

$$\frac{dp}{dZ} = 0.052*\rho \tag{2.5}$$

(field units **ρ** in lbm/gal, **Z** in ft, **p** in psi)

2.6.1.1. Liquid columns

In the case that we are dealing with an incompressible fluid such as drilling mud or salt water, fluid compressibility is neglected and as specific weight is considered constant with depth.

Integration of the equation 2.5 for an incompressible liquid will give:

$$p = 0.052*\rho *Z + p_o \qquad (2.6)$$

where p_o is the overburden pressure of the point of interest.

The most common application of the hydrostatic pressure equation in petroleum engineering is for the determination of the proper drilling fluid density. This density must be high enough to avoid a kick but not extremely high because it will fracture the formation and cause furthermore problems.

2.6.1.2. Gas columns

The variation of pressure with depth in a static column is more complicated than in a static liquid column because the gas density changes with changing pressure.

The gas behavior can be described using the real gas equation defined by

$$p*V = z*n*R*T \qquad (2.7)$$

By replacing V = m/ρ and n = m/MW, the gas density can be expressed as a function of pressure as

$$\rho = \frac{p*MW}{z*R*T} \qquad (2.8a)$$

Changing units to common field units Eq. 2.8a gives

$$\rho = \frac{p*MW}{80.3*z*T} \qquad (2.8b)$$

When the gas pressure lies above 1,000 psia, the hydrostatic equation for incompressible fluids given by Eq. 2.6 can be used together with Eq. 2.8a without mush loss in accuracy. However, when the gas column is not short or highly pressured, the variation of gas density with depth within the gas column is significant. Therefore the change in pressure for a gas is calculated from the combination of Eq.2.5 and 2.8b as

$$dp = \frac{0.052*p*MW}{80.3*z*T} *dZ \qquad (2.9)$$

2.6.1.3. Complex fluid columns

During many drilling operations, the well fluid contains several sections of different fluid densities. The variation of pressure with depth in this type of complex fluid column must be determined by separating the effects of each fluid segment.

Figure 4 illustrates a complex liquid column consisted of n sections that occur in different depths and have different densities.

The general equation that expresses the pressure at any vertical depth Z is

$$p = p_o + g* \sum_{i=1}^{i=n} \rho_i * (Z_i - Z_{i-1}) + g*\rho_n*(Z-Z_{n-1}) \tag{2.10}$$

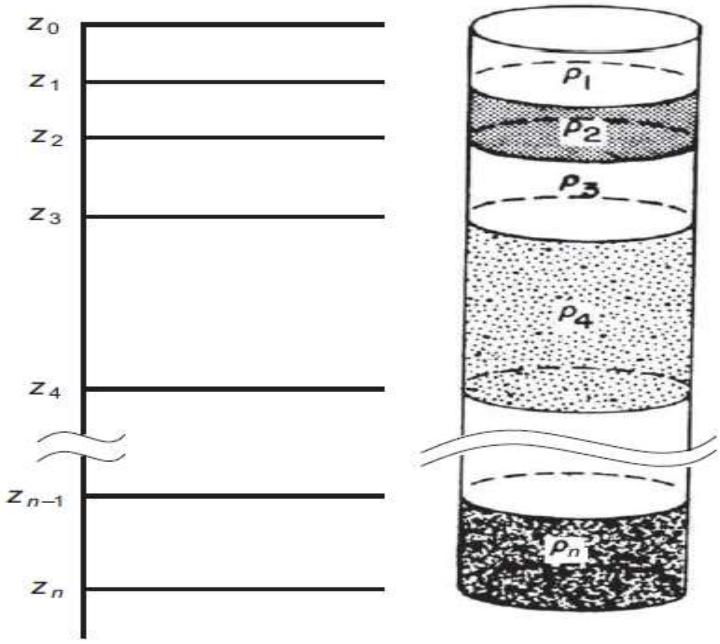

Figure 6: A complex fluid column.

where $Z_{n-1} < Z < Z_n$. It is frequently desirable to view the well fluid system shown in Fig. 4 as a manometer when solving for the pressure at a given point in the well.

2.6.1.4. Equivalent mud density (EMD)

Field experience in a given area often allows guidelines to be developed for the maximum mud density that formations at a given depth will withstand without fracture during normal drilling operations. It is sometimes helpful to compare a complex well fluid column to an equivalent single-fluid column that is open to the atmosphere. This is accomplished by calculating the equivalent mud density ρe, which is defined by

$$\rho_e = \frac{p}{0.052*Z} \tag{2.11}$$

The equivalent mud density always should be referenced at a specified depth.

The EMD is an important parameter in avoiding kicks and losses, particularly in wells that have a narrow window between the fracture gradient and pore-pressure gradient.

3. Casing Design Data

3.1. Introduction

In this chapter, all the required data that are needed for the initiation of the calculation will be explained.

3.2. Survey

A completed measurement of the inclination and azimuth of a location in a well (typically the total depth at the time of measurement) is called **survey** (Fig 7). In both directional and straight holes, the position of the well must be known with reasonable accuracy to ensure the correct wellbore path and to know its position in the event a relief well must be drilled. The measurements themselves include inclination from vertical and the azimuth (or compass heading) of the wellbore if the direction of the path is critical. These measurements are made at discrete points in the well, and the approximate path of the wellbore computed from the discrete points. Measurement devices range from simple pendulum-like devices to complex electronic accelerometers and gyroscopes used more often as MWD becomes more popular. In simple pendulum measurements, the position of a freely hanging pendulum relative to a measurement grid (attached to the housing of the tool and assumed to represent the path of the wellbore) is captured on photographic film. The film is developed and examined when the tool is removed from the wellbore, either on wireline or the next time pipe is tripped out of the hole.

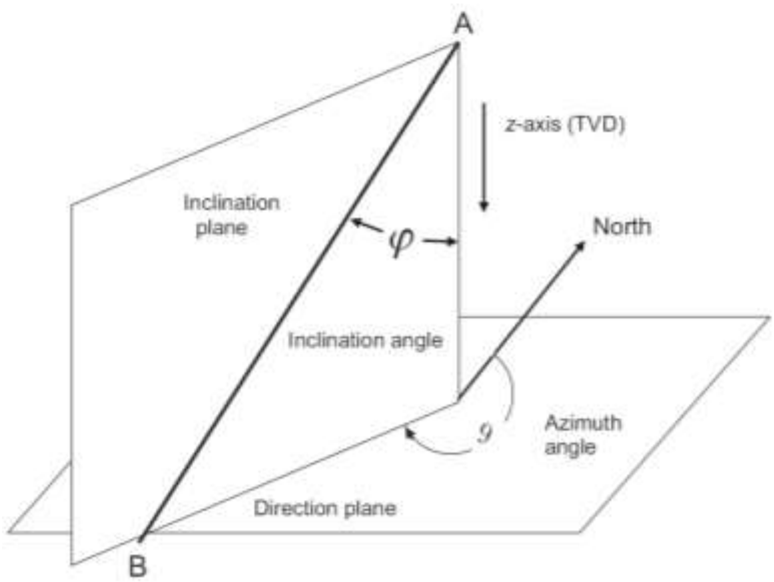

Figure 7: Hole inclination and azimuth angles.

There are three basic 2D directional well trajectories, as shown in Fig. 8

Type 1 consists of a vertical part, a build section, and a tangent that is also called a hold part or slant section. This well profile is also called a slant well. Type 2, also called an S-shaped pattern, and consists of five segments: vertical, buildup, tangent, drop-off, and another vertical at the bottom. A modified S-shaped trajectory has a tangent segment (not vertical) at the bottom of the drop-off part. The S-shaped pattern penetrates the target vertically, and the modified S-shaped pattern penetrates the formation at some desired inclination angle. Type 3 is called a continuous-build trajectory and consists of a vertical part and a buildup section. Horizontal wells and ERWs are additional types.

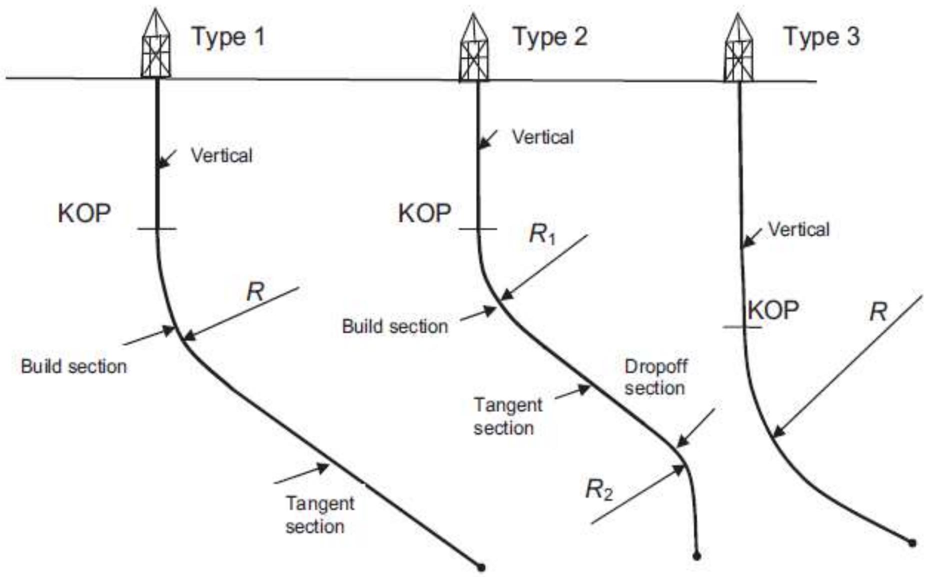

Figure 8: Three major types of 2D wellbore trajectories.

In this thesis, a Type 1 well will be examined and through some plain geometrical principles the **Measured Depth (MD)** will be obtained.

3.3. Setting depths - Pressure profile

The selection of the number of casing strings and their respective setting depths is generally based on consideration of the pore-pressure gradients and fracture gradients of the formations to be penetrated. The example shown in Fig. 7.9 illustrates the relationship between casing setting depth and these gradients. The pore-pressure-gradient and fracture-gradient data are obtained by the methods presented in Chapter 2.6, expressed as equivalent densities, and plotted against depth. A line representing the planned mud-density program is also plotted. The mud densities are chosen to provide an acceptable trip margin above the anticipated formation pore pressures to allow for reductions in effective mud weight caused by upward pipe movement during tripping operations. A commonly used trip margin is 0.5 lbm/gal or one that will provide 200 to 500 psi of excess bottomhole pressure (BHP) over the formation pore pressure.

To reach the depth objective, the effective drilling-fluid density shown at point a is chosen to prevent the flow of formation fluid into the well (i.e., to prevent a kick). However, to carry this drilling-fluid density without exceeding the fracture gradient of the weakest formation exposed within the borehole, the protective intermediate casing must extend at least to the depth of Point b, where the fracture gradient is equal to the mud density needed to drill to Point a. Similarly, to drill to Point b and to set intermediate casing, the drilling-fluid density shown at Point c will be needed and will require surface casing to be set at least to the depth at Point d. When possible, a kick margin is subtracted from the true fracture-gradient line to obtain a design fracture-gradient line. If no kick margin is provided, it is impossible to absorb a kick at the casing-setting depth without causing a hydrofracture and a possible underground blowout.
Other factors, such as the need to protect freshwater aquifers, the presence of vugular lost-circulation zones, the presence of depleted low-pressure zones that tend to cause stuck pipe, the presence of salt beds that tend to flow plastically and close the borehole, and government regulations, can also affect casing-depth requirements. Moreover, experience in an area may show that it is easier to achieve a good casing-seat cement job in some formation types than in others, or that fracture gradients are generally higher in some formation types than in others. Under such conditions, a design must be found that simultaneously will meet these special requirements and the pore pressure and fracture-gradient requirements outlined above.

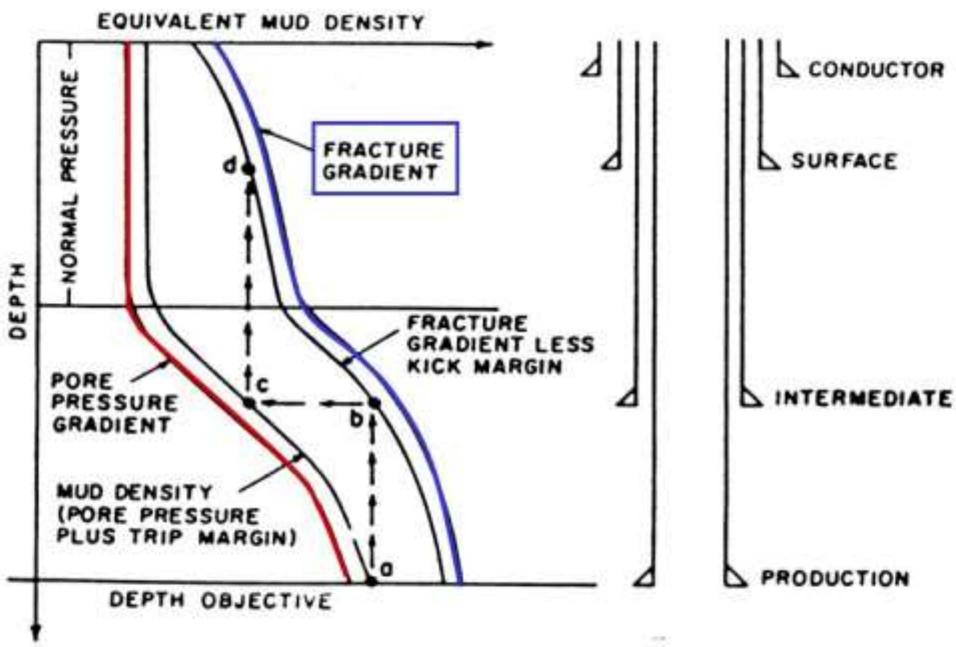

Figure 9: Casing setting depths.

3.4. Casing sizes

The size of the casing strings is controlled by the necessary ID of the production string and the number of intermediate casing strings required to reach the depth objective. To enable the production casing to be placed in the well, the bit size used to drill the last interval of the well must be slightly larger than the OD of the casing connectors. The selected bit size should provide sufficient clearance beyond the OD of the coupling to allow for mudcake on the borehole wall and for casing appliances such as centralizers and scratchers. This, in turn, determines the minimum size of the second-deepest casing string. Using similar considerations, the bit size and casing size of successively more shallow well segments are selected. Selection of casing sizes that permit the use of commonly used bits is advantageous because the bit manufacturers make readily available a much larger variety of bit types and features in these common sizes. However, additional bit sizes are available that can be used in special circumstances. Fig. 10 shows common hole and bit sizes used to drill wells.

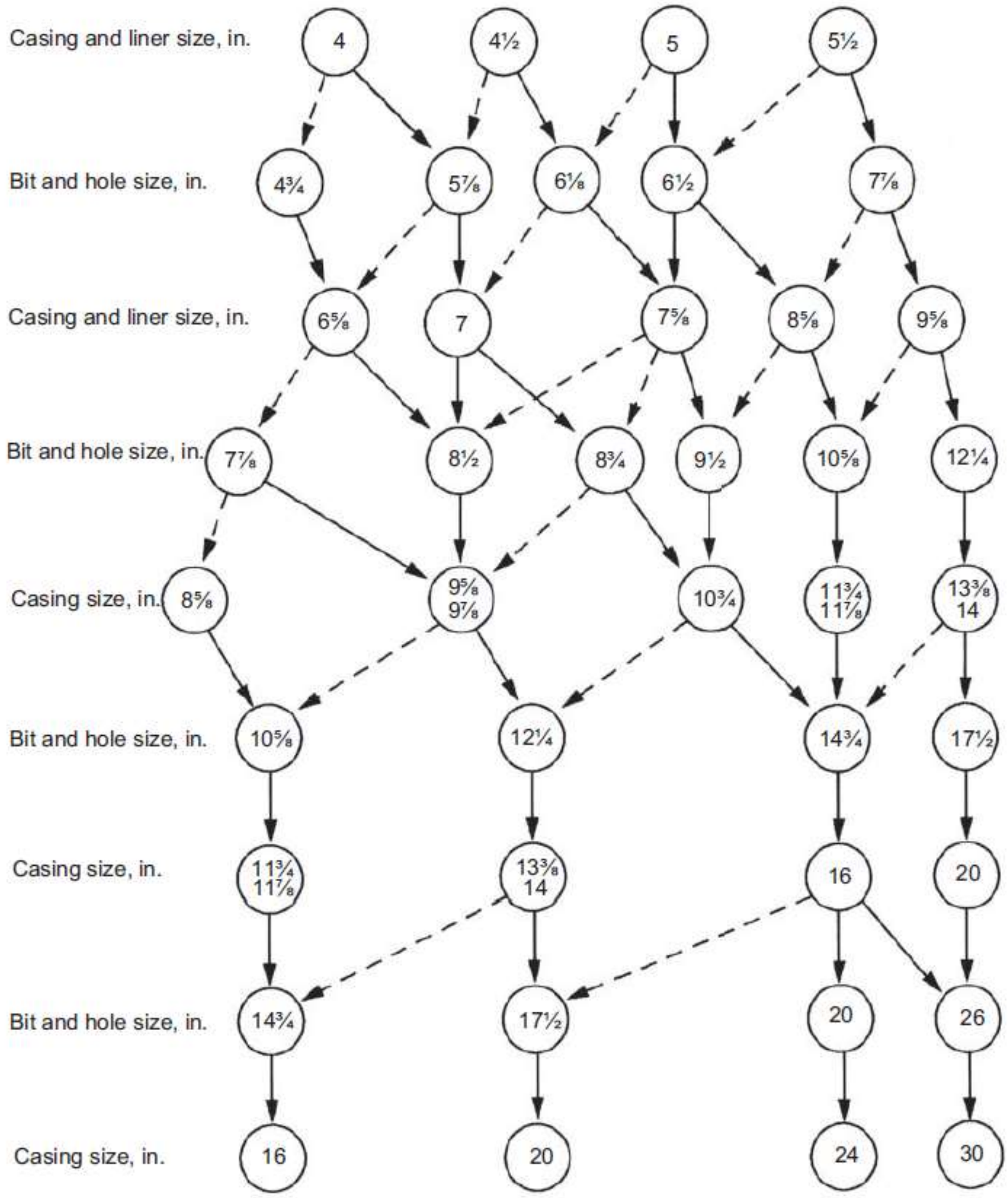

Figure 10: Casing hole size.

Solid lines indicate commonly used bits for that size pipe and can be considered adequate clearance to run and cement the casing or liner. The broken lines indicated less common hole sizes used. The selection of one of these broken paths requires that special attention be given to the connection, mud weight, cementing, and doglegs.

3.5. Casing forces

Having defined the size and the setting depth for the casing strings, the loads to which the casing will be exposed can be computed. The particular weight and grade of casing required to withstand these loads can then be determined.

The total forces that are a casing string suffers are a combination of **uniaxial** and **axial** forces. When those two types of forces are combined, they result a biaxial or triaxial load.

3.5.1. Uniaxial forces

The uniaxial loads to which the casing is exposed are:

A. Collapse Load

The casing will experience a net collapse loading if the external radial load exceeds the internal radial load (Fig. 11). The greatest collapse load on the casing will occur if the casing is evacuated (empty) for any reason. The collapse load, P_c at any point along the casing can be calculated from:

$$P_c = P_e - P_i \tag{3.1}$$

B. Burst Load

The casing will experience a net burst loading if the internal radial load exceeds the external radial load. The burst load, P_b at any point along the casing can be calculated from:

$$P_b = P_i - P_e \tag{3.2}$$

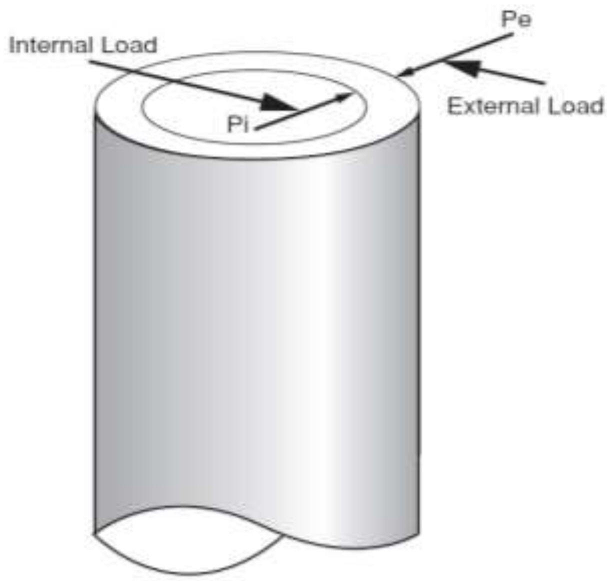

Figure 11: Radial loads on casing

3.5.2. Axial forces

The axial load on the casing can be either tensile or compressive, depending on the operating conditions (Fig. 12). The axial load on the casing will vary along the length of the casing. The casing is subjected to a wide range of axial loads during installation and subsequent drilling and production. The axial loads which will arise during any particular operation must be computed and added together to determine the total axial load on the casing.

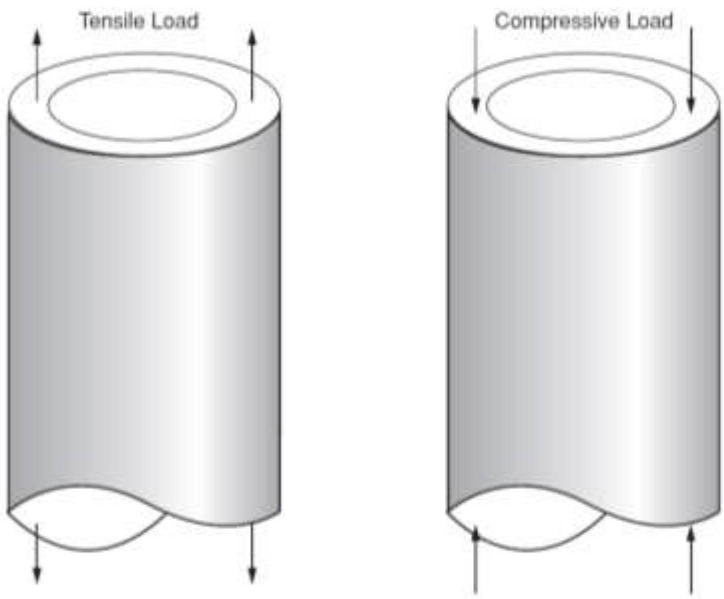

Figure 12: Axial Loads on Casing.

3.5.3. Biaxial and Triaxial loading

It can be demonstrated both theoretically and experimentally that the axial load on a casing can affect the burst and collapse ratings of that casing. This is represented in Figure 13. It can be seen that as the tensile load imposed on a tubular increases, the collapse rating decreases and the burst rating increases. It can also be seen from this diagram that as the compressive loading increases the burst rating decreases and the collapse rating increases. The burst and collapse ratings for casing quoted by the API assume that the casing is experiencing zero axial load. However, since casing strings are very often subjected to a combination of tension and collapse loading simultaneously, the API has established a relationship between these loadings.

The Ellipse shown in Figure 14 is in fact a 2D representation of a 3D phenomenon. The casing will in reality experience a combination of three loads (Triaxial loading). These are Radial, Axial and Tangential loads (Figure 17). The latter being a resultant of the other two. Triaxial loading and failure of the casing due to the combination of these loads is very uncommon and therefore the computation of the triaxial loads on the casing are not frequently conducted. In the case of casing strings being run in extreme environment (>12,000 psi wells, high H_2S) triaxial analysis should be conducted.

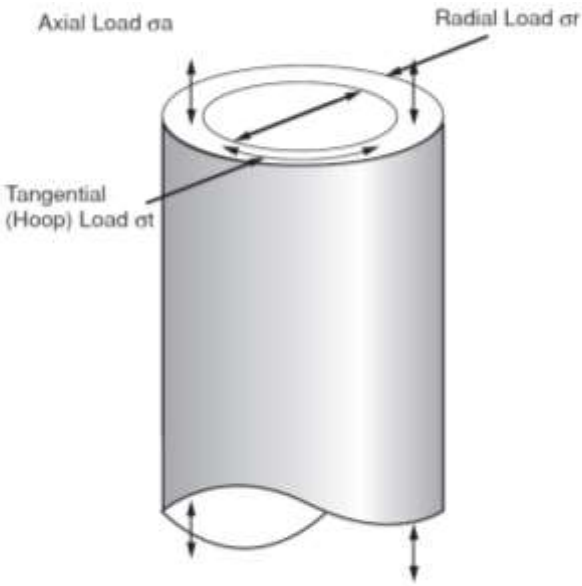

Figure 13: Tri-axial loading casing.

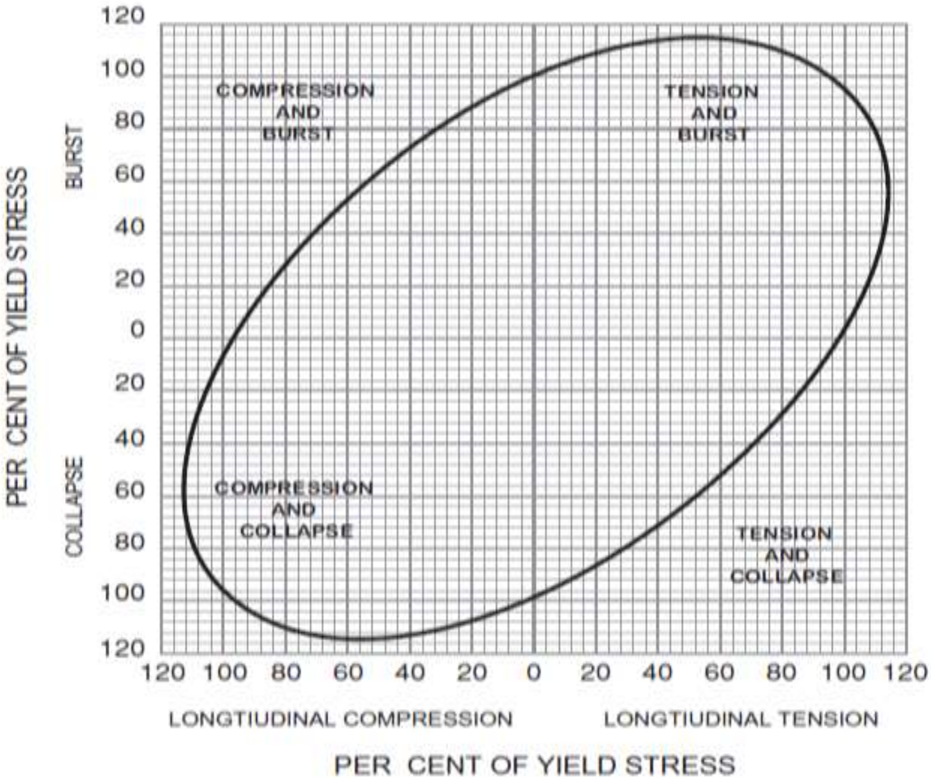

Figure 14: Tri-axial loading ellipse.

3.6. Surface casing[2]

Examples of design loading conditions for surface casing are illustrated in Fig.15 for burst, Fig.16 for collapse, and Fig.17 for tension. The high-internal-pressure loading condition used for the burst design is based on a well-control condition which is assumed to occur while circulating out a large kick. The high-external-pressure loading condition used for collapse design is based on a severe lost-circulation problem. The high-axial-tension loading condition is based on an assumption of stuck casing while the casing is being run into the hole before cementing operations.

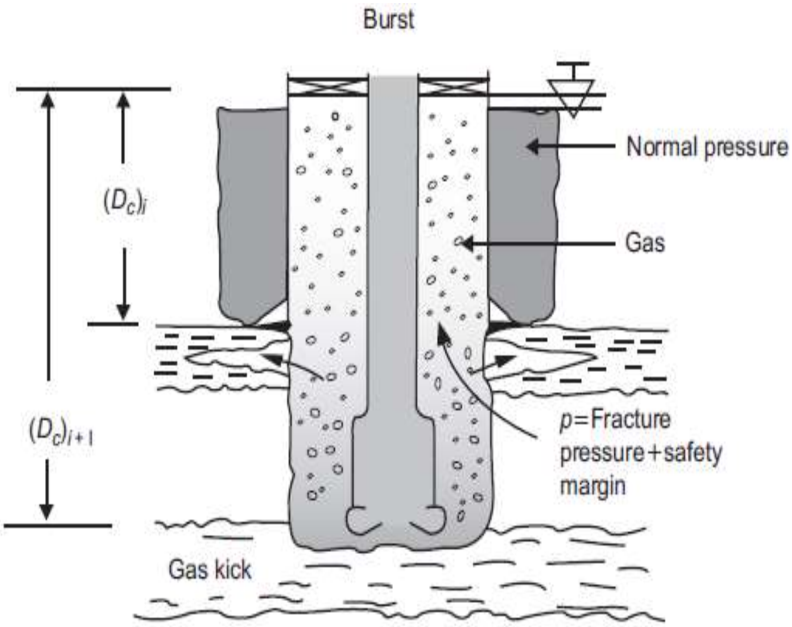

Figure 15: Burst loads.

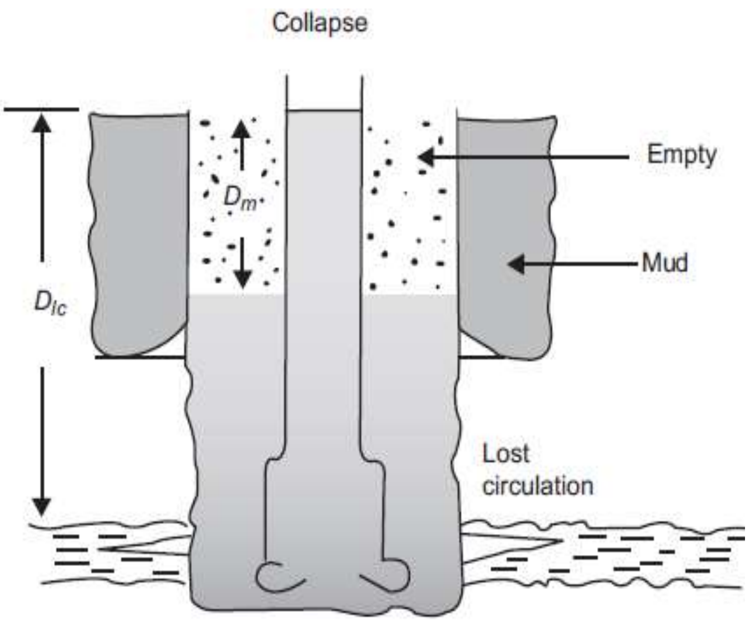

Figure 16: Collapse loads.

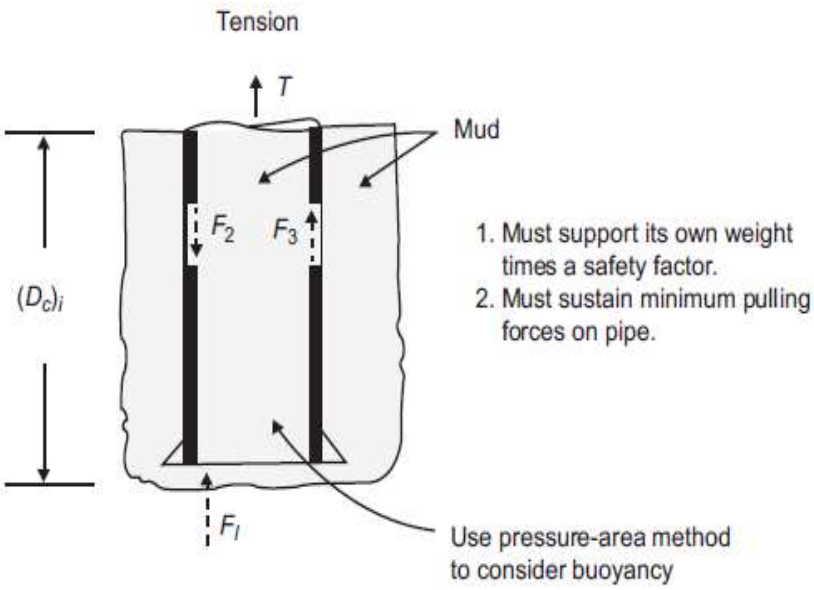

Figure 17: Tension loads.

The **burst** design should ensure that the formation-fracture pressure at the casing seat will be exceeded before the casing burst pressure is reached. Therefore, this design uses formation fracture as a safety pressure-release mechanism to ensure that casing rupture will not occur at the surface and endanger the lives of the drilling personnel. The design pressure at the casing seat is equal to the fracture pressure plus a safety margin to allow for an injection pressure that is slightly greater than the fracture pressure. The pressure within the casing is calculated assuming that all the drilling fl uid in the casing is lost to the fractured formation, leaving only formation gas in the casing. The external or backup pressure outside the casing, which helps to resist burst, is assumed to be equal to the normal formation pore pressure for the area. The beneficial effect of cement or higher-density mud outside the casing is ignored because of the possibility both of a locally poor cement bond and of mud degradation over time. A safety factor is also used to provide an additional safety margin for possible casing damage during transportation and field handling of the pipe.

The **collapse** design is based either on the most severe lost-circulation problem that is believed to be possible or on the most severe collapse loading anticipated when the casing is run. For both cases, the maximum possible external pressure, which tends to cause casing collapse, will result from the drilling fluid that is in the hole when the casing is placed and cemented. The beneficial effect of the cement and of possible mud degradation is ignored, but the detrimental effect of axial tension on the collapse-pressure rating is considered. The beneficial effect of pressure inside the casing can also be taken into account by the consideration of a maximum possible depression of the mud level inside the casing. A safety factor is generally applied to the design loading condition to provide an additional safety margin.

If a severe lost-circulation zone or a pore-pressure regression zone is encountered near the bottom of the next interval of the hole and if no other permeable formations are present above the zone, the fluid level in the well can fall until the BHP is equal to the pore pressure of the zone. Equating the hydrostatic mud pressure to the pore pressure of the lost-circulation zone gives

$$0.052*\rho_{max}*(Z_{lc} - Z_m) = 0.052*g_p*Z_{lc} \quad (3.3)$$

where Z_{lc} is the depth (true vertical) of the lost-circulation zone, g_p is the pore-pressure gradient of the zone, r_{max} is the maximum mud density anticipated in drilling to Z_{lc}, and Z_m is the depth to which the mud level will fall. Solving this expression for Z_m yields

$$Z_m = \frac{(\rho_{max} - g_p)}{\rho_{max}} * Z_{lc} \quad (3.4)$$

There is usually considerable uncertainty in the selection of the minimum anticipated pore-pressure gradient and the maximum depth of the zone for use in Eq. 3.4. In the absence of any previously produced and depleted formations, the normal pore-pressure gradient for the area can be used as a conservative estimate of the minimum anticipated pore-pressure gradient. Similarly, if the lithology is not well known, the depth of the next full-length casing string can be used as a conservative estimate of Z_{lc}.

The minimum fluid level in the casing when it is placed in the well depends on field practices. The casing usually is filled with mud after each joint of casing is made up and run in the hole, and an internal casing pressure that is approximately equal to the external casing pressure is maintained. However, in some cases the casing is floated in, or run at least partially empty, to reduce the maximum hook load before reaching bottom. If this practice is anticipated, the maximum depth of the mud level in the casing must be compared to the depth computed using Eq. 3.4, and the greater value must be used in the collapse-design calculations.

The most difficult part of the collapse design is the correction of the collapse-pressure rating for the effect of axial tension. The difficulty lies in determining the axial tension that is present at the time the maximum collapse load is imposed. If the maximum collapse load is encountered when the casing is run, the axial tension can be readily calculated from a knowledge of the casing weight per foot and the mud hydrostatic pressure in accordance with the principles previously presented. However, if the maximum collapse load is encountered after the cement has hardened and the casing has been landed in the wellhead, the determination of axial stress is much more difficult. In the case of hand calculations, it is common to compute axial tension as the hanging weight for the hydrostatic pressures present when the maximum collapse load is encountered plus any additional tension put in the pipe during and after casing landing. This assumption will result in a maximum tension value and a corrected minimum collapse-pressure rating.

Tension design requires consideration of the axial stresses that are present when the casing is run during cementing operations, when the casing is landed in the slips, and during subsequent drilling and production operations throughout the life of the well. In most cases, the design load is based on conditions that could occur when the casing is run. It is assumed that the casing may become stuck near the bottom and that a maximum amount of pull, in excess of the hanging weight in mud, would then be required to work the casing free. A minimum safety-factor criterion is applied so that the design load will be dictated by the maximum load resulting from the use of either the safety factor or the overpull force, whichever is greater. The minimum overpull force tends to control the design in the upper portion of the casing string, and the minimum safety factor tends to control the design in the lower part of the casing string. Once the casing design is completed, the maximum axial stresses anticipated during cementing, casing loading, and subsequent drilling operations should also be checked to ensure that the design load is never exceeded. In some cases where internal pressure or density has increased and external pressure has decreased because of setting conditions, added tension loads can exceed the overpull force.

In the design of a combination string of non-uniform wall thickness, the effect of buoyancy is most accurately included using the effective tension concept. The drilling fluid in use at the time the casing is run is used to compute the hydrostatic pressure at each junction between sections of different wall thicknesses, so that the actual tension can be calculated from the effective tension.

In directional wells, the additional axial stress in the pipe body and connectors caused by bending should be added to the axial stress that results from casing weight and fluid hydrostatic pressure. The directional plan must be used to determine the portions of the casing string that will be subjected to bending when the pipe is run. The lower portion of the casing string will have to travel past all the curved sections in the wellbore, but the upper section of the casing string may not be subjected to any bending.

When the selection of casing grade and weight in a combination string is controlled by collapse, a simultaneous design for collapse and tension will be the most exact. The greatest depth at which the next most economical casing can be used depends on its corrected collapse-pressure rating, which in turn depends on the prior computation of axial tension. An iterative procedure can be used in which the depth of the bottom of the next most economical casing section is first selected on the basis of an uncorrected table value for collapse resistance. The axial tension at this point is then computed, and the collapse resistance is corrected. This procedure enables the depth of the bottom of the next casing section to be updated for a second iteration. Several iterations may be required before the solution converges.

3.7. Intermediate casing[2]

Intermediate casing is similar to surface casing in that its function is to permit the final depth objective of the well to be reached safely. Several methods are used by the industry to ensure that this string is designed for safe handling of formation kicks, lost returns, and other drilling problems that may occur during deep drilling.

Similarly to surface-casing design, internal and external pressure design loads are determined using both burst and collapse analysis. For burst design, the external pressure, or the backup pressure outside the casing that helps resist burst, is typically assumed to be equal to the normal formation pore pressure for the area. The beneficial effect of cement or higher-density mud outside the casing is ignored because of the possibility both of a locally poor cement bond and of mud degradation over time.

Internal-pressure design-load assumptions for burst analysis vary significantly in the industry. Some operators calculate the internal pressure that would result at every depth in a string from circulating out a design kick. The design-kick intensity and volume is chosen to result in well pressures that are equal to (or slightly greater than) the predicted formation pressure at the intermediate-casing shoe. This ensures that the design kick can be successfully circulated past the intermediate-casing shoe without compromising formation integrity at the casing shoe. If the design-kick pressure exceeds the formation strength at the intermediate-casing shoe, a lost return or an underground blowout would likely result, after which the kick could not be circulated to the surface. The maximum surface pressure while circulating out the design kick can also be calculated, and the BOP working pressure is chosen to exceed this maximum surface pressure from the kick-circulation process.

Some operators use the general procedure outlined for surface casing for intermediate-casing strings. However, in some cases, the burst-design requirements dictated by the design-loading condition illustrated in Fig.7.15 are extremely expensive to meet, especially when the resulting high working pressure is in excess of the working pressure of the surface BOP stacks and choke manifolds for the available rigs. In this case, the operator may accept a slightly larger risk of losing the well and select a less severe design load. The design load remains based on an underground blowout situation which is assumed to occur while a gas kick is being circulated out. However, the acceptable mud loss from the casing is limited to the maximum amount that will cause the working pressure of the surface BOP stack and choke manifold to be reached. If the existing surface equipment is to be retained, it is pointless to design the casing to have a higher working pressure than the surface equipment.

When the surface burst-pressure load is based on the working pressure of the surface equipment, P_{max}, internal pressures at intermediate depths should be determined, as shown in Fig.7.15. It is assumed that the upper portion of the casing is filled with mud and the lower portion of the casing is filled with gas. The depth of the mud/gas interface, Z_m, is determined using the following relationship:

$$P_{inj} = P_{max} + 0.052*\rho_m*Z_m + 0.052*\rho_g*(Z_k - Z_m) \qquad (3.5)$$

where P_{inj} is the injection pressure opposite the lost-circulation zone; r_m and r_g are the densities of mud and gas, respectively; and Z_{lc} is the depth of the lost-circulation zone. Solving this equation for Z_m gives

$$Z_m = \frac{P_{inj} - P_{max}}{0.052*(\rho_m - \rho_g)} - \frac{\rho_g - Z_{lc}}{(\rho_m - \rho_g)} \qquad (3.6)$$

The density of the drilling mud is set to the maximum density anticipated while drilling to the depth of the next full-length casing string. This makes it possible to calculate the maximum intermediate pressures between the surface and the casing seat. The depth of the lost circulation zone is determined from the fracture gradient vs. depth plot as the depth of the weakest exposed formation. The injection pressure is equal to the fracture pressure plus an assumed safety margin to account for a possible pressure drop within the hydraulic fracture.

Collapse-loading design assumptions for intermediate casings are usually similar to those used for surface casing design, taking lost returns into account. Typically, an intermediate-casing-string design will result in a lower casing grade and weight per foot than those for a production string. As a result, an intermediate string designed only for deep drilling often will not meet production-casing design specifications.

3.8. Production casing[2]

Example burst-design and collapse-design loading conditions for production casing are illustrated in Fig. 7.18. The example burst-design loading condition assumes that a producing well has an initial shut-in BHP equal to the formation pore pressure and a gaseous produced fluid in the well. The production casing must be designed so that it will not fail if the tubing fails. A tubing leak is assumed to be possible at any depth. External pressure for production-casing burst design is generally assumed to be the formation pressure outside the casing. Experience has shown that mud left outside the casing will decrease in density over time if the mud can interact with an open hole. An exception is if the casing annulus outside the production casing is sealed with cement and the mud trapped in the annulus is not free to interact with the open hole. A sealed annulus also creates a fixed-volume annulus, which is subject to annulus mud expansion creating annulus pressure with a temperature increase.

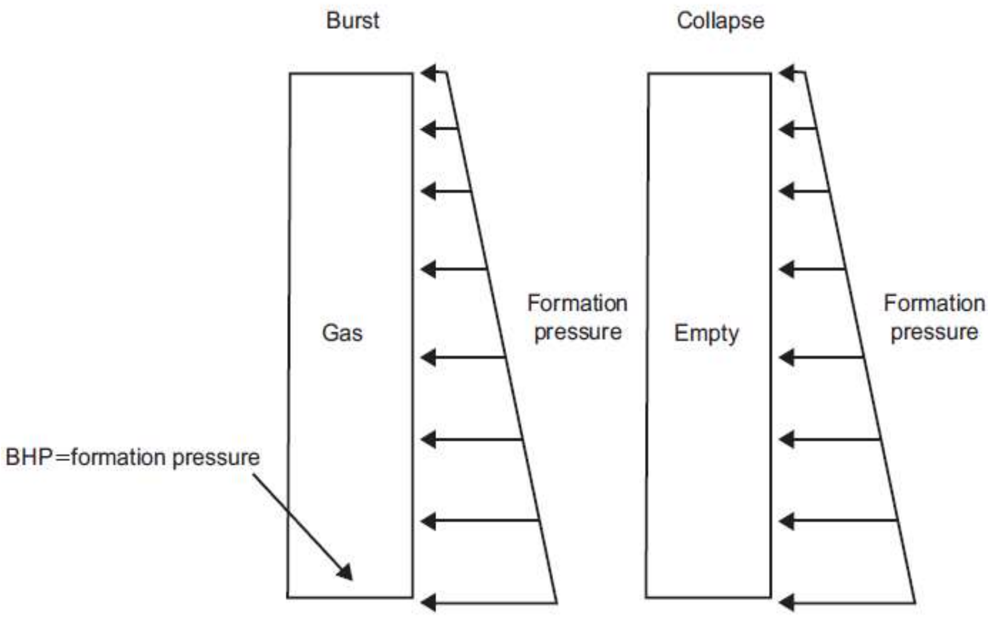

Figure 18: Production casing design and loads.

The collapse design load shown in Fig. 7.18 is based on conditions late in the life of the reservoir, when reservoir pressure has been depleted to a very low (negligible) abandonment pressure. A leak in the tubing or packer could cause loss of the completion fluid, and therefore the low internal pressure is not restricted to the portion of the casing below the packer. Therefore, for design purposes, the entire casing is considered to be empty. For collapse design, the fluid density outside the casing is assumed to be equal to the formation pressure, and the beneficial effect of the cement is ignored.

In the absence of any unusual conditions, the tension design load criteria for production casing are the same as for surface and intermediate casing. When unusual conditions are present, the maximum stresses associated with these conditions must be checked to determine whether they exceed the design load in any portion of the string.

4. Calculations

4.1. Description of the well

A slanted well with kickoff point at 2500 ft, build-up rate of 3^o/100 ft and maximum inclination (which is preserved until reaching the target) equal to 45^o was examined. The total true vertical depth (TVD) of well is 13,000 ft. The water table is approximately at a depth of 1500 ft. The pore and fracture pressures of the well are attached at Appendix I.

4.2. Pore and fracture profile

For creating the pore and fracture pressure profile, the equivalent mud density for each depth was calculated (eq. 2.11). In order to add the safety margins in each case (trip and kick) a pressure of 150 psi was added to eq. 2.11 to the areas with normal hydrostatic pressures, whereas higher pressures where used to the abnormal section of the well (after 8000 ft) as the pore pressure increases significantly.

After the calculations, the pore and fracture pressure diagram was derived (Diagram 5).

From the above diagram, the 5 final casing sections were emerged considering the limits that trip and kick margins were settled as:

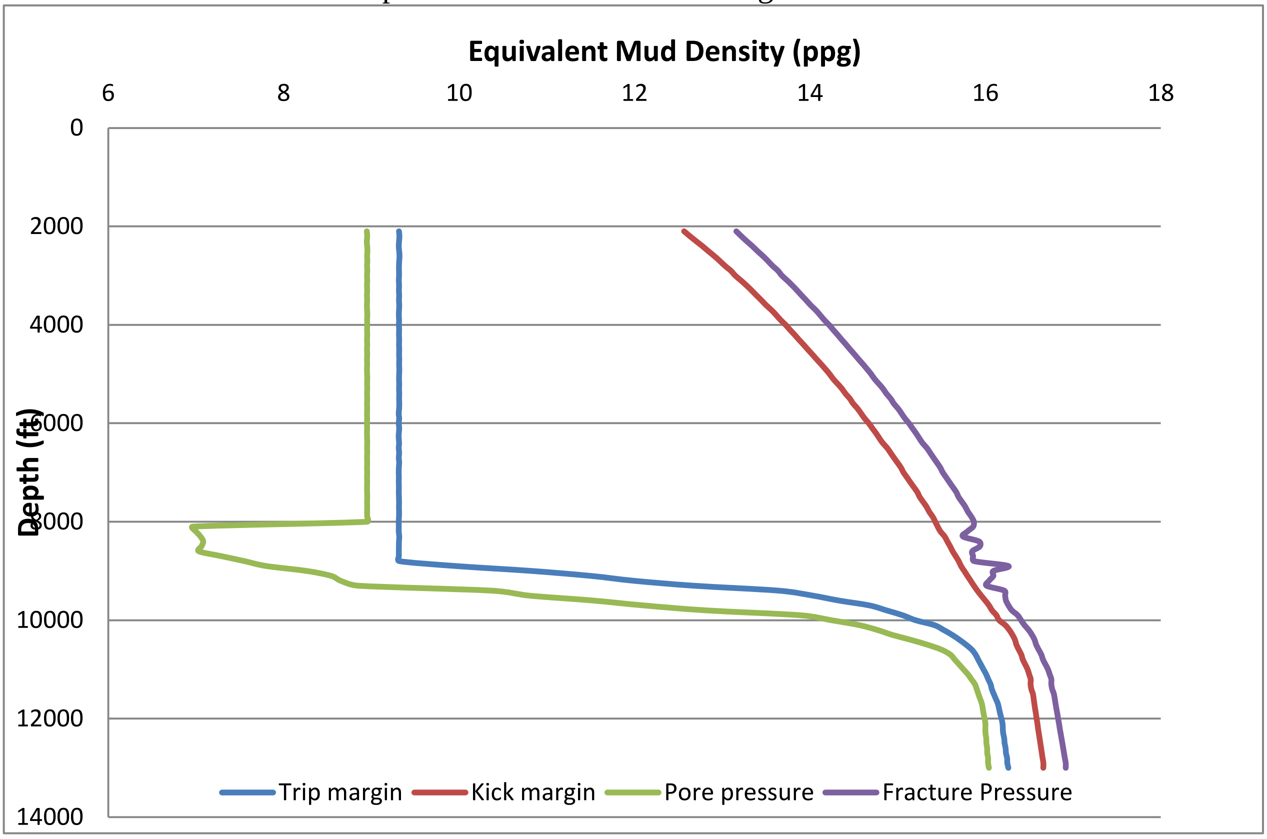

Diagram 5: Pore and fracture pressure profile

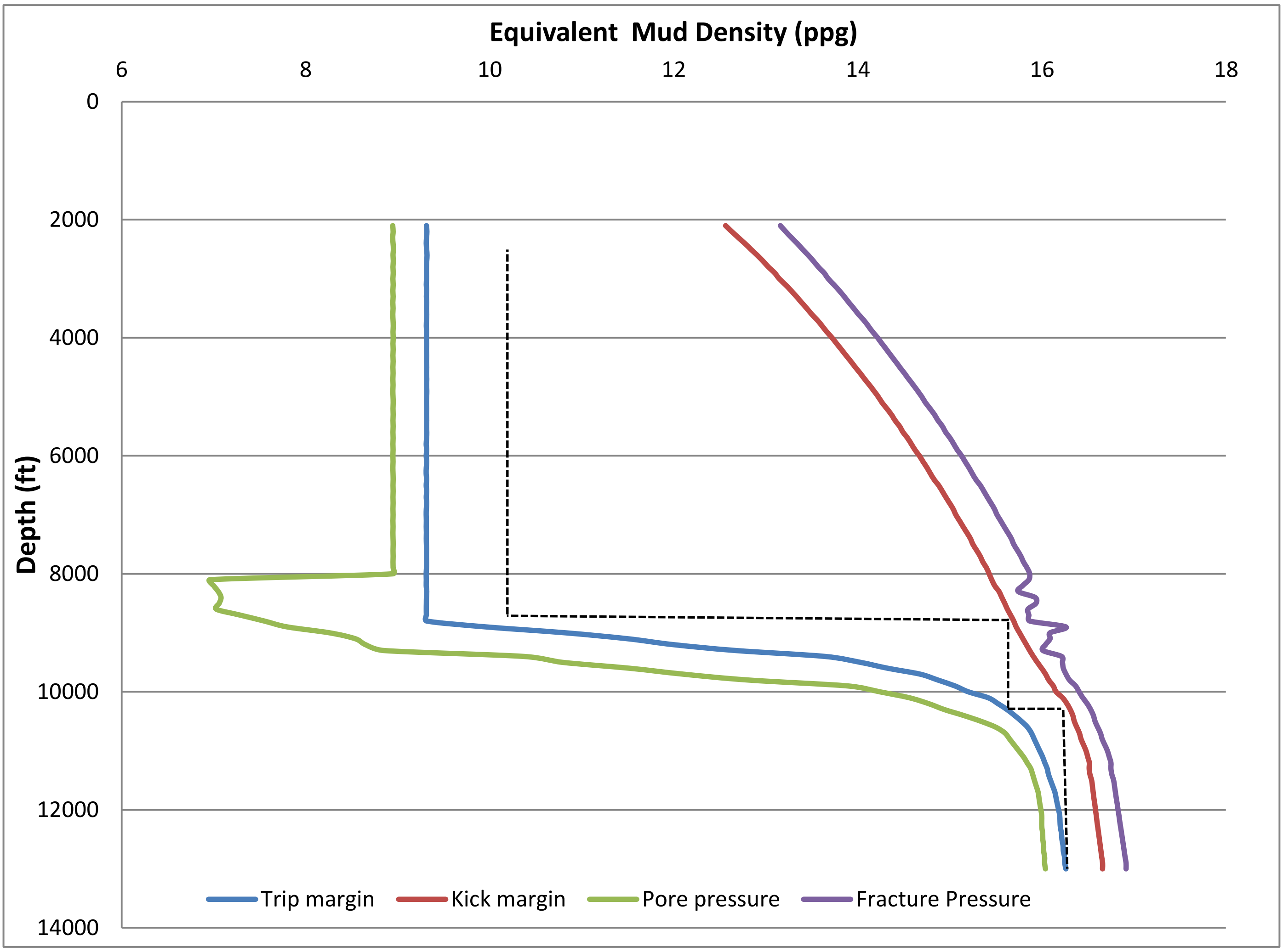

Diagram 6: Pore and fracture pressure profile with the sections selection.

From surface until the first 100 ft, the **conductor** casing will be placed with an EMD of 9.5 ppg. From 100ft to 2500ft, the **surface** casing will be placed with an EMD of 9.7 ppg while until the 8700 ft an **intermediate** casing with 10 ppg will be used. In order to reduce the final cost of the operation, the two final sections will be covered with two liners. The **intermediate liner** casing will take place at depths from 8700ft to 10200ft with 15.5ppg EMD and finally the **production liner** casing will be placed from 10200 ft to the final depth of 13000 ft with an EMD of 16.2 ppg. The final two liners will be placed 100 ft above their initially depths at 8600 ft and 10100 ft respectively.

Figure 19 depicts the basic geometrical principals for the calculation of the measured depths at a typical slanted well that will be needed for further calculations.

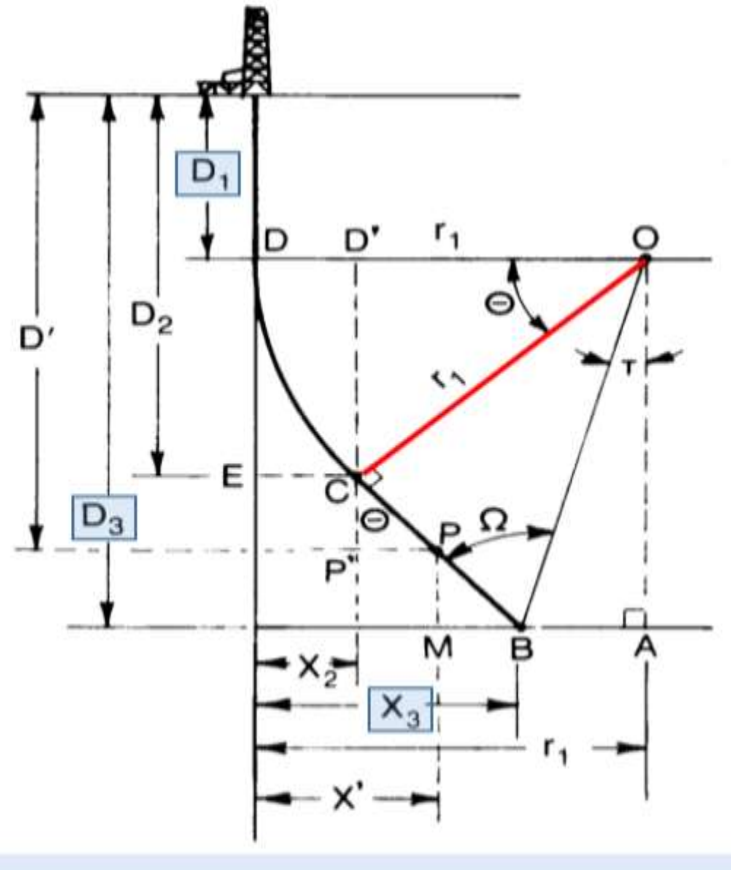

Figure 19: Design built and hold trajectory.

The radius r_1 is a function of the build-up rate q and can be calculated as:

$$r_1 = \frac{180}{\pi}\ \frac{1}{q} \tag{4.1}$$

From Eq. 4.1 the radius r_1 was found to be **1910.8 ft**.

The length of the curved section DC can be calculated as:

$$DC = r_1\ (\theta\ \frac{\pi}{180}) \tag{4.2}$$

Where θ is the maximum inclination angle (45^o). Finally DC = **1500 ft**.

The total measured depth of the well was found from a combination of some basic geometrical principals **16940 ft**. Subsequently, with similar procedure the desired depth for each casing section was calculated and the results are presented at the Table 2.

TVD (ft)	MD (ft)
3851	4000
5100	5766
8600	10716
8700	10857
10100	12837
10200	12979
12050	15595
13000	16939

Table 2: Measured depth for each desired casing section.

4.3. Selection of casing sizes

The selection of the casing size for each casing section was based on the Figure 10 that discussed at Chapter 3. At Table 3, the results for each section are summarized as following:

Depths	Type of casing	EMD (ppg)	Cs size (in)	Hole (in)
From 10,100 ft to 13,000 ft	Production Liner	16,2	5	6 1/8
From 8,600 ft to 10,200 ft	Intermediate Liner	15,5	7	8 3/4
From 2,500 ft to 8,700 ft	Intermediate	10	9 5/8	12 1/4
From 100 ft to 2,500 ft	Surface	9,7	13 3/8	17 1/2
From 0 ft to 100 ft	Conductor	9,5	20	24

Table 3: Final selection of depths, OD's and EMD's.

As it is shown at Table 3, Intermediate Liner and Production liner have a kick off point 100 feet above the previous casing shoe section. Based on the EMD and casing size, the collapse, burst and tension design was made.

4.4. Surface casing design

As described at chapter 3.6, the design of each casing string is calculated based on the worst case scenario that occur during the lifetime of the well.

4.4.1. Collapse design of surface casing string

The worst case scenario at the depth that is planned to place the surface casing is the case that the column will be partially or completely evacuated due to an eventual mud loss during drilling the next section. The calculation of the depth that the mud will fall D_m is required. **The lowest point that the mud level will fall is the most vulnerable point at the casing.** Considering a normal hydrostatic pressure, the worst scenario is that the mud level will fall while drilling at the shoe depth of the next casing section. Since in our case there are abnormal pressures, the calculation of the mud level for each depth is required (Table 4).

Fracture depth (ft)	Pp (EMD)	Mud level (ft)	Dm (ft)	P mud (Dm) (psi)
2500	8,95	2238	262	132
2600	8,95	2327	273	138
2700	8,95	2417	283	143
2800	8,95	2506	294	148
2900	8,95	2596	304	153
3000	8,95	2685	315	159
3100	8,95	2775	325	164
3200	8,95	2863	337	170
3300	8,95	2954	346	175
3400	8,95	3042	358	180
3500	8,95	3133	367	185
3600	8,95	3221	379	191
3700	8,95	3312	388	196
3800	8,95	3402	398	201
3900	8,95	3490	410	207
4000	8,95	3581	419	211
4100	8,95	3669	431	217
4200	8,95	3760	440	222
4300	8,95	3848	452	228
4400	8,95	3938	462	233
4500	8,95	4027	473	239
4600	8,95	4117	483	243
4700	8,95	4206	494	249
4800	8,95	4296	504	254
4900	8,95	4385	515	260
5000	8,95	4475	525	265
5100	8,95	4565	535	270
5200	8,95	4654	546	275
5300	8,95	4744	556	280
5400	8,95	4833	567	286
5500	8,95	4923	577	291
5600	8,95	5012	588	297
5700	8,95	5102	598	302

5800	8,95	5190	610	307
5900	8,95	5281	619	312
6000	8,95	5369	631	318
6100	8,95	5460	640	323
6200	8,95	5548	652	329
6300	8,95	5638	662	334
6400	8,95	5729	671	339
6500	8,95	5817	683	344
6600	8,95	5908	692	349
6700	8,95	5996	704	355
6800	8,95	6087	713	360
6900	8,95	6175	725	366
7000	8,95	6265	735	371
7100	8,95	6354	746	376
7200	8,95	6444	756	381
7300	8,95	6533	767	387
7400	8,95	6623	777	392
7500	8,95	6713	787	397
7600	8,95	6802	798	403
7700	8,95	6892	808	407
7800	8,95	6981	819	413
7900	8,95	7071	829	418
8000	8,95	7160	840	424
8100	6,96	5638	2462	1242
8200	7,00	5740	2460	1241
8300	7,05	5852	2448	1235
8400	7,08	5948	2452	1237
8500	7,06	6002	2498	1260
8600	7,03	6046	2500	1261
8700	7,29	6342	2358	1189

Table 4: Collapse load calculation for surface casing.

It proved that the column in that case will be completely evacuated; therefore the maximum pressure that will cause collapse is 1261 psi at the depth of 2500 ft. This value multiplied by the Collapse Design Factor (1.125) will give a pressure value of 1419 psi. This pressure will define the selection based on collapse criteria.

From the specifications of the 13' 3/8'' casing (Appendix II), the selection of J-55 with nominal weight of 61 lbm/ft is selected. This string provides a collapse resistance of 1540 psi.

4.4.2. Burst design of surface casing string

The procedure described at Chapter 3.6 has been followed for the burst design. At this case the worst case scenario is that the column will be completely filled with gas caused by a kick.

The distribution of the internal pressure requires two points; bottom hole pressure and pressure at surface. The BHP is calculated multiplying the shoe depth (2500ft) with the Formation Breakdown Pressure (0.696 psi/ft) which the point that the formation will break down.

Considering the surface pressure, the calculation of the gas gradient is required. Taking as gas methane with a molecular weight of 16 gr/mole, the gas gradient from the real gas law was calculated 0.033 psi/ft. So the burst force at surface will be the BHP – gas gradient x shoe depth.

From the above 2 points the pressure-depth profile was made (Diagram 7).

At this diagram, the pressure profile of collapse is also included.

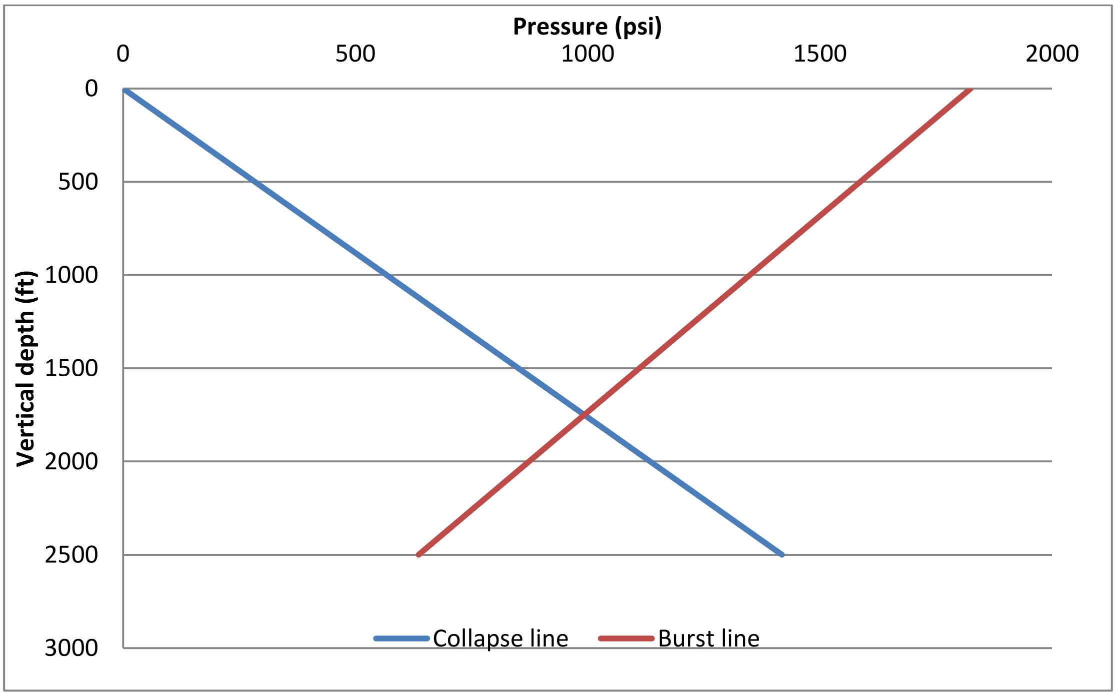

Diagram 7: Burst and collapse pressure profile for surface casing.

The lightest casing string that has enough burst resistance to anticipate the highest load above is the J-55 with nominal weight of 54.5 lbm/ft.

For making the design more economical, the two strings must be combined. The collapse resistance of the J-55 (54.5 lbm/ft) is 1130 psi. This pressure corresponds to a depth of 2100 ft at collapse line.

Finally, the J-55 (54.5 lbm/ft) will be used from surface until the depth of 2100 ft, while the J-55(61 lbm/ft) will be used from 2100ft to 2500ft.

4.4.3. Tension design of surface casing string

The tension design was made taking into account the **buoyant load**, the **static load** and the **weight in air load** for the two previous sections (0ft to 2100ft and 2100ft to 2500ft).

Multiplying each depth with the corresponding nominal weight of each casing string we get the own true weight in air:

Surface to 2100 ft	114450	lb
2100 ft to 2500ft	24400	lb

Table 5: Own true weight in air for surface casing.

Consequently, the weight on air on top of each section is found as:

Surface to 2100 ft	138850	lb
2100 ft to 2500ft	24400	lb

Table 6: Weight in air on top of each section for surface casing.

The buoyant load for each section is calculated by multiplying the buoyancy factor with each weight in air value for each string:

Buoyant weight of the whole string	118190	lb
Buoyant load at 2100 ft	3740	lb
Buoyant load at 2500 ft	-20660	lb

Table 7: Buoyant load of each section for surface casing.

The final load that will be calculated in this project is the static load. The static load is the combined result of bending and buoyancy. The bending force F_b is derived from the formula below:

$$F_b = 63*\varphi*d_o*W_n \qquad 4.3$$

Where φ is the inclination of the well (when vertical assume that φ=2°/100 ft), d_o the OD of the casing and W_n the nominal weight per unit of the casing string. The bending force for this string are presented at Table 8.

Fb for J-55 of 54,5 lbm/ft	91846	lb
Fb for J-55 of 61 lbm/ft	102800	lb

Table 8: Bending force of each selected casing for surface casing.

Finally, the static load for each section was calculated and the results are shown at Table 9.

Static Load at 0ft J-55 of 54,5 lbm/ft	210037	lb
Static Load at 1800ft J-55 of 54,5 lbm/ft	95587	lb
Static Load at 1800ft J-55 of 61 lbm/ft	106541	lb
Static Load at 2500ft J-55 of 61 lbm/ft	82141	lb

Table 9: Static loads for each section for surface casing.

All the above loads are shown graphically at Diagram 8, along with the Pipe Body Joint Strength:

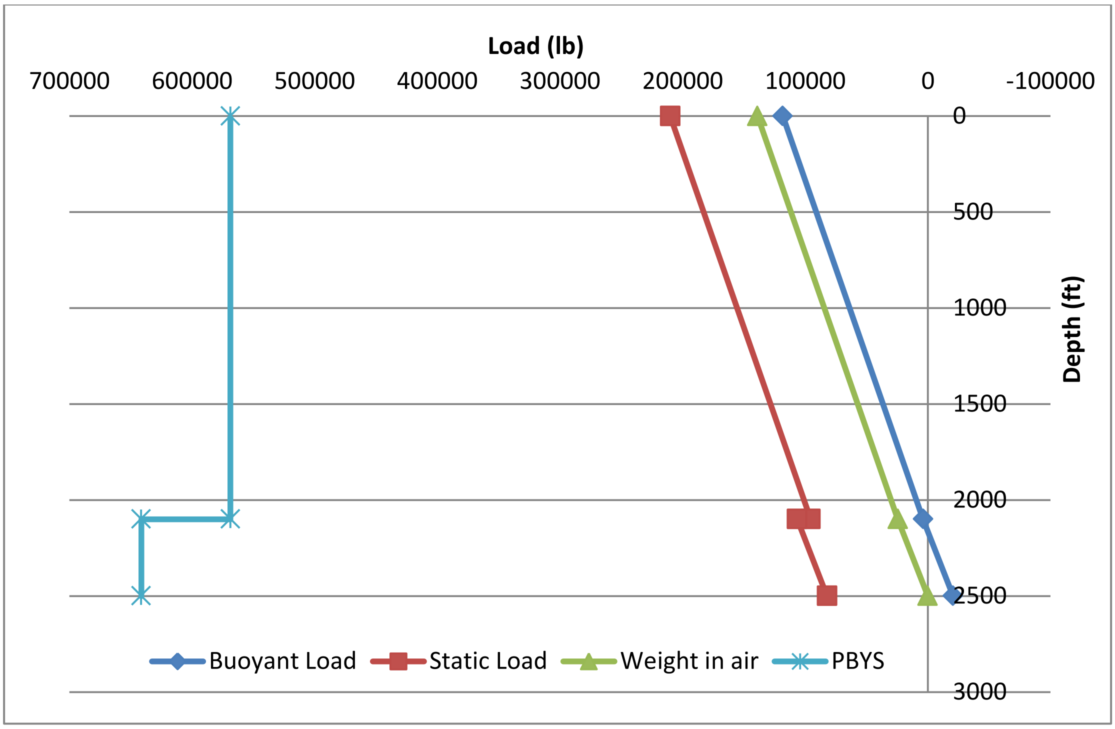

Diagram 8: Tension loads for surface casing.

It is obvious that the joint strength of the chosen material (light blue line) can successfully resist to tension, therefore the initial selection is kept as it is.

4.4.4. Combined stresses check for surface casing

From the ellipse of plasticity, the values of axial and tangential stresses gave as result values of 0.62 and 0.53, -0.93 respectively. As discussed at chapter 3.5.3, the loads are inside the ellipse, therefore the effect of combined stresses are not detrimental in order to change the type of casing.

4.5. Intermediate casing design

Similarly to the surface casing design, the collapse design was made exactly the same while the burst design the mud-gas level was calculated as explained at chapter 3.7.

4.5.1. Collapse design of Intermediate casing string

For the collapse design of the Intermediate casing string, the calculation of the mud level for each depth is required as well (Table 10).

Fracture depth	Pp (EMD)	Mud level (ft)	Dm (ft)	P mud (Dm)
8700	7,29	4092	4608	2396
8800	7,55	4287	4513	2347
8900	7,80	4479	4421	2299
9000	8,26	4797	4203	2186
9100	8,54	5014	4086	2125
9200	8,65	5134	4066	2114
9300	8,85	5310	3990	2075
9400	10,37	6289	3111	1618
9500	10,79	6613	2887	1501
9600	11,52	7135	2465	1282
9700	12,10	7572	2128	1107
9800	12,81	8099	1701	884
9900	13,89	8872	1028	534
10000	14,24	9187	813	423
10100	14,56	9488	612	318
10200	14,77	9720	480	250

Table 10: Collapse load calculation of the intermediate casing string.

The maximum pressure that will cause collapse is 2396 psi at the depth of 4608 ft. This value multiplied by the Collapse Design Factor (1.125) will give a pressure value of 2695.5 psi. This pressure will define the selection based on collapse criteria.

From the specifications of the 9’ 5/8’’ casing (Appendix II), the selection of C-75 with nominal weight of 40 lbm/ft is selected. This string provides a collapse resistance of 2990 psi.

4.5.2. Burst design for the intermediate casing string

The burst design for the intermediate casing string was done with the calculation of the mud-gas level Z_m. The reason of this calculation is mainly economic as described at chapter 3.7. For each depth below and above that surface, the Burst Load was calculated as it shown at Table 11:

Fracture depth	FP (psi)	FP (EMD)	Pp (psi)	Pp (EMD)	ρg	P_{out} (psi)	P_{in} (psi)	Burst Load
0	-	-	0	8,95	0	0	6000	6000
100	-	-	47	8,95	0,017	47	6080,60	6034
200	-	-	93	8,95	0,035	93	6161,20	6068
300	-	-	140	8,95	0,052	140	6241,80	6102
400	-	-	186	8,95	0,069	186	6322,40	6136
500	-	-	233	8,95	0,086	233	6403,00	6170
600	-	-	279	8,95	0,103	279	6483,60	6204
700	-	-	326	8,95	0,120	326	6564,20	6238
800	-	-	372	8,95	0,137	372	6644,80	6272
900	-	-	419	8,95	0,154	419	6725,40	6307
1000	-	-	465	8,95	0,171	465	7166,13	6701
1100	-	-	512	8,95	0,187	512	7164,29	6652
1200	-	-	558	8,95	0,204	558	7162,29	6604
1300	-	-	605	8,95	0,220	605	7160,11	6555
1400	-	-	652	8,95	0,237	652	7157,77	6506
1500	-	-	698	8,95	0,253	698	7155,27	6457
1600	-	-	745	8,95	0,269	745	7152,60	6408
1700	-	-	791	8,95	0,285	791	7149,77	6359
1800	-	-	838	8,95	0,302	838	7146,77	6309
1900	-	-	884	8,95	0,318	884	7143,62	6259
2000	-	-	931	8,95	0,334	931	7140,30	6210
2100	-	-	977	8,95	0,350	977	7136,83	6159
2200	-	-	1024	8,95	0,365	1024	7133,20	6109
2300	-	-	1070	8,95	0,381	1070	7129,42	6059
2400	-	-	1117	8,95	0,397	1117	7125,47	6009
2500	1742	13,40	1164	8,95	0,413	1164	7121,36	5957
2600	1820	13,46	1210	8,95	0,428	1210	7117,13	5907
2700	1898	13,52	1257	8,95	0,444	1257	7112,71	5856
2800	1976	13,57	1303	8,95	0,459	1303	7108,18	5805
2900	2056	13,63	1350	8,95	0,474	1350	7103,45	5753
3000	2134	13,68	1396	8,95	0,490	1396	7098,63	5703
3100	2215	13,74	1443	8,95	0,505	1443	7093,60	5651
3200	2296	13,80	1489	8,95	0,520	1489	7088,49	5599
3300	2377	13,85	1536	8,95	0,535	1536	7083,16	5547
3400	2458	13,90	1582	8,95	0,550	1582	7077,75	5496
3500	2540	13,96	1629	8,95	0,565	1629	7072,14	5443
3600	2622	14,01	1675	8,95	0,580	1675	7066,45	5391

3700	2706	14,06	1722	8,95	0,595	1722	7060,54	5339
3800	2789	14,11	1769	8,95	0,610	1769	7054,50	5285
3900	2872	14,16	1815	8,95	0,624	1815	7048,38	5233
4000	2957	14,22	1862	8,95	0,639	1862	7042,05	5180
4100	3041	14,26	1908	8,95	0,654	1908	7035,66	5128
4200	3126	14,31	1955	8,95	0,668	1955	7029,05	5074
4300	3211	14,36	2001	8,95	0,683	2001	7022,38	5021
4400	3297	14,41	2048	8,95	0,697	2048	7015,50	4967
4500	3383	14,46	2094	8,95	0,711	2094	7008,56	4915
4600	3470	14,51	2141	8,95	0,726	2141	7001,40	4860
4700	3557	14,55	2187	8,95	0,740	2187	6994,19	4807
4800	3645	14,60	2234	8,95	0,754	2234	6986,77	4753
4900	3733	14,65	2280	8,95	0,768	2280	6979,30	4699
5000	3821	14,70	2327	8,95	0,782	2327	6971,61	4645
5100	3908	14,74	2374	8,95	0,796	2374	6963,79	4590
5200	3998	14,79	2420	8,95	0,810	2420	6955,93	4536
5300	4088	14,83	2467	8,95	0,824	2467	6947,85	4481
5400	4176	14,87	2513	8,95	0,838	2513	6939,73	4427
5500	4267	14,92	2560	8,95	0,852	2560	6931,39	4371
5600	4355	14,96	2606	8,95	0,865	2606	6923,02	4317
5700	4447	15,00	2653	8,95	0,879	2653	6914,43	4261
5800	4537	15,04	2699	8,95	0,893	2699	6905,81	4207
5900	4627	15,08	2746	8,95	0,906	2746	6896,96	4151
6000	4720	15,13	2792	8,95	0,920	2792	6888,10	4096
6100	4811	15,17	2839	8,95	0,933	2839	6879,00	4040
6200	4903	15,21	2885	8,95	0,946	2885	6869,89	3985
6300	4994	15,24	2932	8,95	0,960	2932	6860,56	3929
6400	5086	15,28	2979	8,95	0,973	2979	6851,10	3872
6500	5182	15,33	3025	8,95	0,986	3025	6841,63	3817
6600	5275	15,37	3072	8,95	1,000	3072	6831,93	3760
6700	5368	15,41	3118	8,95	1,013	3118	6822,22	3704
6800	5462	15,45	3165	8,95	1,026	3165	6812,28	3647
6900	5556	15,48	3211	8,95	1,039	3211	6802,34	3591
7000	5647	15,51	3258	8,95	1,052	3258	6792,17	3534
7100	5742	15,55	3304	8,95	1,064	3304	6782,00	3478
7200	5837	15,59	3351	8,95	1,077	3351	6771,60	3421
7300	5933	15,63	3397	8,95	1,090	3397	6761,20	3364
7400	6029	15,67	3444	8,95	1,103	3444	6750,56	3307
7500	6121	15,69	3491	8,95	1,116	3491	6739,82	3249
7600	6218	15,73	3537	8,95	1,128	3537	6729,08	3192
7700	6315	15,77	3584	8,95	1,141	3584	6718,11	3134
7800	6409	15,80	3630	8,95	1,153	3630	6707,15	3077
7900	6507	15,84	3677	8,95	1,166	3677	6695,95	3019
8000	6601	15,87	3723	8,95	1,178	3723	6684,78	2962
8100	6680	15,86	2932	6,96	0,926	2932	6784,87	3853

8200	6734	15,79	2985	7,00	0,941	2985	6773,69	3789
8300	6795	15,74	3043	7,05	0,958	3043	6761,70	3719
8400	6957	15,93	3093	7,08	0,971	3093	6750,67	3658
8500	7044	15,94	3121	7,06	0,978	3121	6742,57	3622
8600	7088	15,85	3144	7,03	0,984	3144	6735,11	3591
8700	7175	15,86	3298	7,29	1,030	3298	7175	3877

Table 11: Burst load calculations of intermediate casing string.

From the above calculations, the maximum burst pressure for the intermediate casing that is derived is 6641 psi. Multiplying with the burst design factor, will result a pressure of 7305 psi.

At diagram 9, the pressure profile of collapse and burst loads are presented.

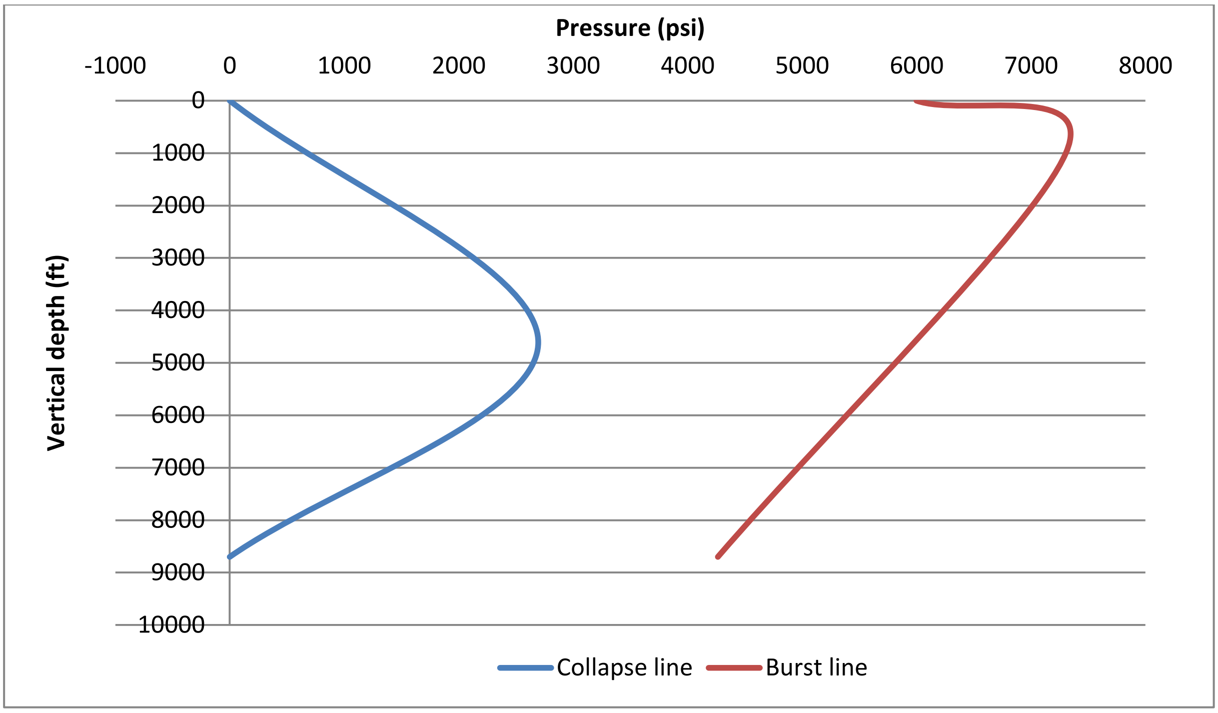

Diagram 9: Burst and collapse pressure profile for intermediate casing.

The lightest casing string that has enough burst resistance to anticipate the highest load above is the C-95 with nominal weight of 43.5 lbm/ft.

This casing string has a collapse load greater than 2695.5 psi, therefore this casing string will be selected for the whole section.

4.5.3. Tension design of Intermediate casing string

Following the exact procedure for tension loads at surface casing, the tension loads for the intermediate casing string were calculated.

At Diagram 10, all the calculated loads are shown along with the Pipe Body Joint Strength of the selected casing.

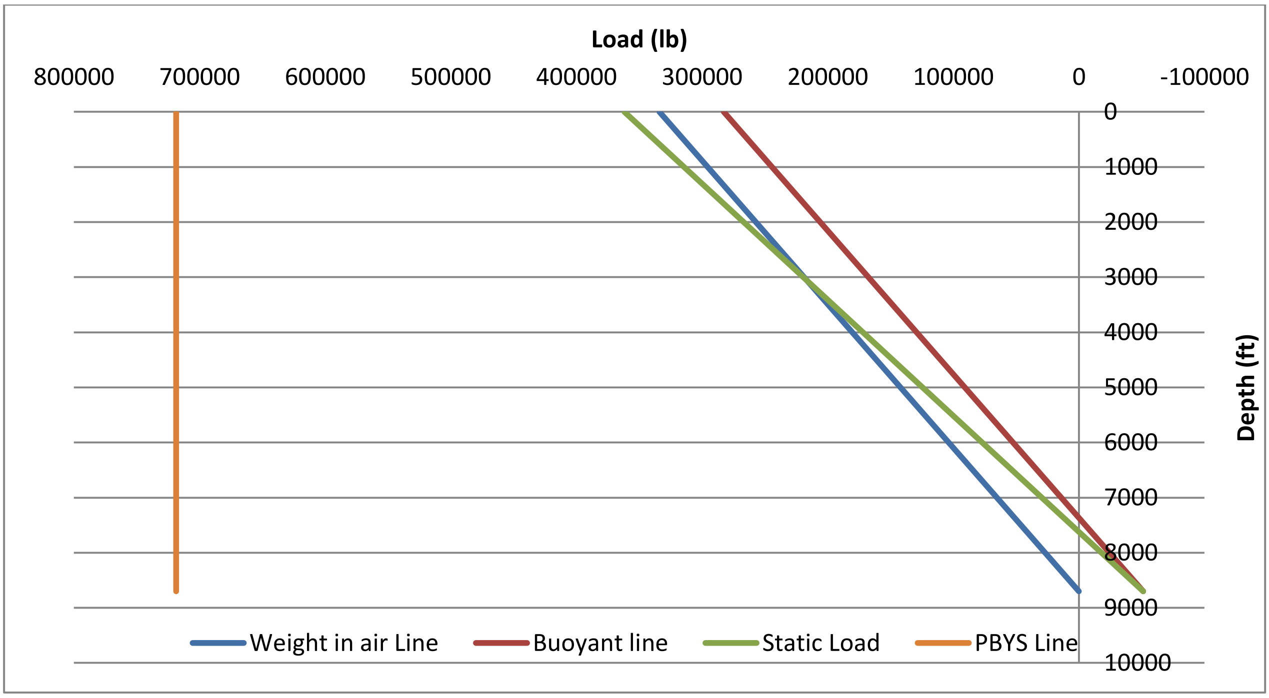

Diagram 10: Tension loads for the intermediate casing.

It is obvious that the joint strength of the chosen material (orange line) can successfully resist to tension, therefore the initial selection is kept as it is.

4.5.4. Combined stresses check for intermediate casing string

The values of the axial and tangential stresses in this case exceeded the permitted value of ±1. Therefore, the effect of plasticity is detrimental to the casing design therefore, a new casing string must be selected. The new casing string that is selected and covers the ellipse criteria, is the P-110 of 53.5 lbm.

4.6. Intermediate liner casing design

The design of this section was made identically to intermediate casing string.

4.6.1. Collapse design of Intermediate casing string

As it shown at Table 12, not a critical consideration is taken into account for intermediate liner casing, since the collapse loads for this casing have very low values.

Fracture depth	Pp (EMD)	Mud level (ft)	Dm (ft)	P mud (Dm)
10200	14,77	9300	900	726
10300	14,94	9499	801	646
10400	15,15	9726	674	543
10500	15,34	9943	557	449
10600	15,50	10142	458	369
10700	15,60	10304	396	319
10800	15,65	10433	367	296
10900	15,70	10564	336	271
11000	15,75	10694	306	246
11100	15,80	10826	274	221
11200	15,84	10951	249	201
11300	15,88	11077	223	180
11400	15,90	11189	211	170
11500	15,92	11301	199	160
11600	15,94	11414	186	150
11700	15,96	11527	173	140
11800	15,97	11632	168	135
11900	15,98	11738	162	131
12000	15,99	11845	155	125
12100	16,00	11950	150	121
12200	16,00	12049	151	122
12300	16,00	12149	151	122
12400	16,01	12254	146	117
12500	16,01	12354	146	118
12600	16,02	12460	140	113
12700	16,02	12559	141	113
12800	16,03	12666	134	108
12900	16,03	12765	135	109
13000	16,04	12872	128	104

Table 12: Collapse load calculation of the intermediate liner casing string.

From the specifications of the 7’ casing (Appendix II), the selection of H-40 with nominal weight of 17 lbm/ft is selected. This string provides a collapse resistance of 1420 psi.

4.6.2. Burst design for the intermediate liner casing string

Similarly to the previous case of the intermediate casing, burst design for the intermediate liner casing was made with the calculation of the mud gas interface. As it came through, the Zm was found to be 910.9 feet, therefore this procedure was pointless, since the burst pressure profile could be acquired by taking the point at the top of the liner and the point at its shoe.

The results of burst load are shown at Table 13.

Fracture depth	FP (psi)	FP (EMD)	Pp (psi)	Pp (EMD)	ρg	P_{out} (psi)	P_{in} (psi)	Burst Load
8600	7088	15,85	3144	7,03	0,98	3144	8666	5522,1
8700	7175	15,86	3298	7,29	1,03	3298,00	8668	5369,6
8800	7262	15,87	3455	7,55	1,08	3455	8670	5214,6
8900	7526	16,26	3610	7,80	1,123	3610	8672	5062
9000	7530	16,09	3866	8,26	1,200	3866	8673	4807,1
9100	7614	16,09	4041	8,54	1,252	4041	8676	4635,3
9200	7674	16,04	4138	8,65	1,280	4138	8681	4543,4
9300	7744	16,01	4280	8,85	1,321	4280	8686	4406,1
9400	7926	16,22	5069	10,37	1,562	5069	8683	3614
9500	8015	16,22	5330	10,79	1,639	5330	8688	3358,3
9600	8104	16,23	5751	11,52	1,765	5751	8693	2941,9
9700	8203	16,26	6103	12,10	1,870	6103	8699	2596,3
9800	8307	16,30	6528	12,81	1,996	6528	8706	2178,4
9900	8426	16,37	7151	13,89	2,183	7151	8714	1562,9
10000	8531	16,41	7405	14,24	2,256	7405	8725	1319,5
10100	8637	16,45	7647	14,56	2,325	7647	8736	1088,9
10200	8748	16,49	7834	14,77	2,378	7834	8748	914

Table 13: Burst load calculations of intermediate liner casing string.

From the above calculations, the maximum burst pressure for the intermediate liner casing that is derived is 5522 psi. Multiplying with the burst design factor, will result a pressure of 6074 psi.

The lightest casing string that has enough burst resistance to anticipate the highest load above is the P-110 with nominal weight of 26 lbm/ft.

This casing string has a collapse load greater than the maximum collapse load of the string; therefore this casing string will be selected for the whole section.

4.6.3. Tension design of intermediate liner casing string

Following the exact procedure for tension loads at surface casing and intermediate casing string the tension loads for the intermediate casing string were calculated.

At Diagram 11, all the calculated loads are shown along with the Pipe Body Joint Strength of the selected casing.

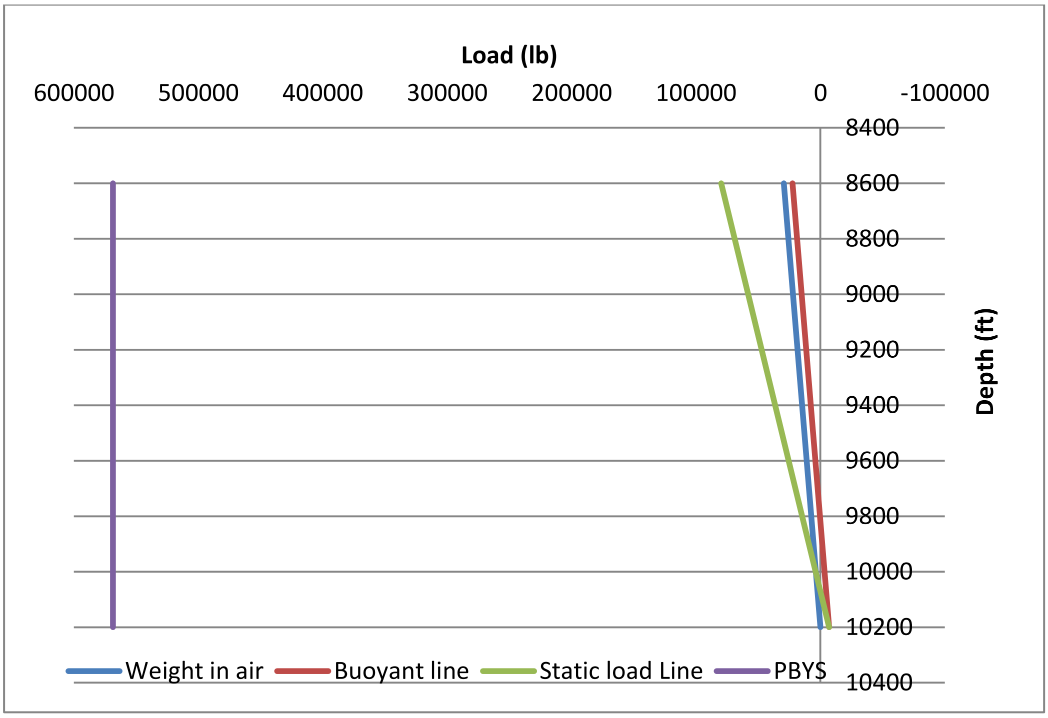

Diagram 11: Tension loads for the intermediate liner casing.

It is obvious that the joint strength of the chosen material (purple line) can successfully resist to tension, therefore the initial selection is kept as it is.

4.6.4. Combined stresses for intermediate liner casing

From the ellipse of plasticity, the values of axial and tangential stresses gave as result values of 0.0027 and 0.0027, -0.0028 respectively. As discussed at chapter 3.5.3, the loads are inside the ellipse, therefore the effect of combined stresses are not detrimental in order to change the type of casing.

4.7. Production liner casing design

The design for the production casing string has been made according to chapter 3.8. At collapse design the column is considered to be completely evacuated, whereas at burst load, the column considered to be filled with gas.

4.7.1. Collapse design of production liner casing string

For the calculation of the collapse load along the production liner casing string, two points are required. The first point is the point that the liner is ‘’hanging’’ from the previous one and the other at its shoe.

Internal pressure is zero at both cases and external pressure is pore pressure. From those two points the Diagram of pressure-depth for the collapse load is constructed.

The maximum pressure that will cause collapse is 10843 psi at the depth of 13000 ft. This value multiplied by the Collapse Design Factor (1.125) will give a pressure value of 12198 psi. This pressure will define the selection based on collapse criteria.

From the specifications of the 5’ casing (Appendix II), the selection of N-80 with nominal weight of 21.4 lbm/ft is selected. This string provides a collapse resistance of 12760 psi.

4.7.2. Burst design of production liner casing string

The burst design of production liner was made according to the procedure that discussed at chapter 3.8, where the string must be designed even if the tubing fails. In that case we consider the whole column is full of gas.

Considering the pressure at the depth of 10100 ft, the calculation of the gas gradient is required. Taking as gas methane with a molecular weight of 16 gr/mole, the gas gradient from the real gas law was calculated 0.175 psi/ft. So the burst force at 10100 ft will be the BHP – gas gradient x previous shoe depth. The pressure at the bottom is pore pressure, so the Pressure- Depth diagram for the burst load can also be constructed.

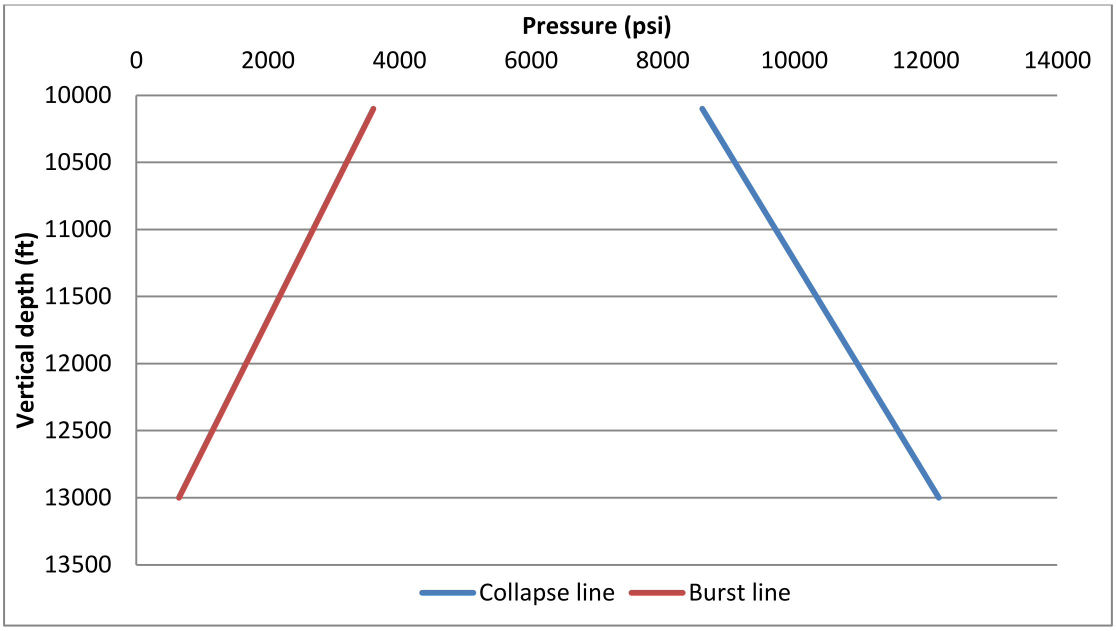

Diagram 12: Collapse and pressure profile for the production liner casing.

The lightest casing string that has enough burst resistance to anticipate the highest load above is the J-55 with nominal weight of 11.5 lbm/ft.

This casing string has a collapse load lower than 12198 psi, therefore the initial N-80 (21 lbm/ft) will be selected for the whole string.

4.7.3. Tension design of production liner casing string

Following the exact procedure for tension loads at surface casing and intermediate casing string the tension loads for the intermediate casing string were calculated.

At Diagram 13, all the calculated loads are shown along with the Pipe Body Joint Strength of the selected casing.

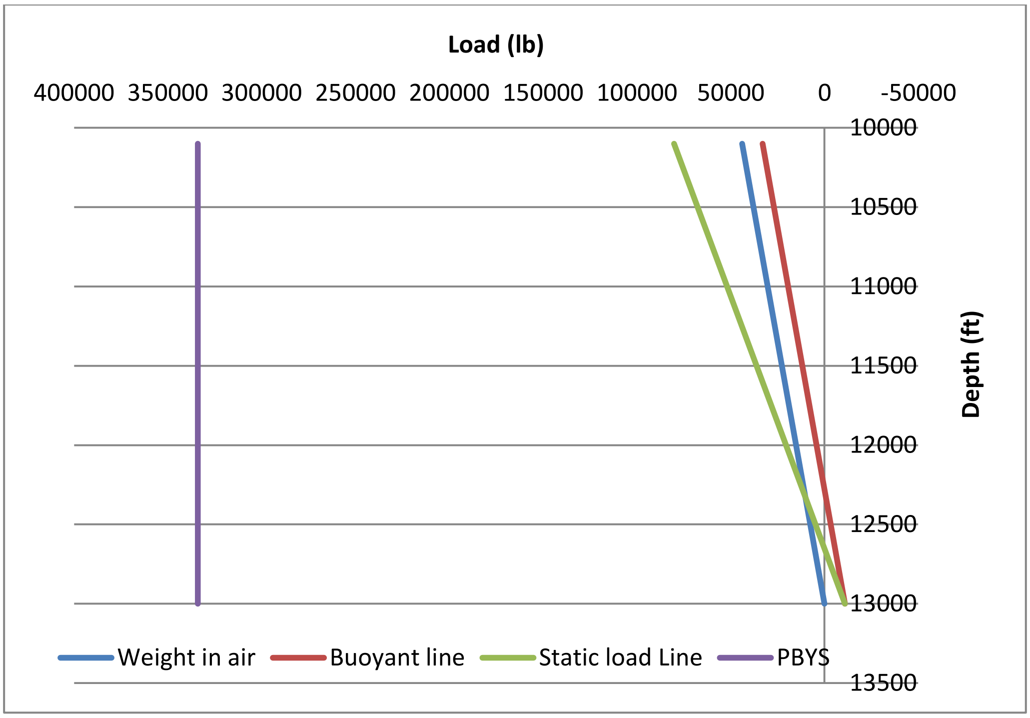

Diagram 13: Tension design for the production casing string.

It is obvious that the joint strength of the chosen material (purple line) can successfully resist to tension, therefore the initial selection is kept as it is.

4.7.4. Combined stresses for production liner

From the ellipse of plasticity, the values of axial and tangential stresses gave as result values of -0.15 and -0.13, 0.25 respectively. As discussed at chapter 3.5.3, the loads are inside the ellipse, therefore the effect of combined stresses are not detrimental in order to change the type of casing.

5. Conclusions

From all the above study we have concluded that for the given well, the proposed casing design based on collapse, burst and basic tension criteria has the following specifications:

Depth (ft)	Type	OD (in)	EMD (mud)	Casing
0 ft – 100 ft	Conductor	20’	9.5	-
100 ft – 2500 ft	Surface	13’ 3/8’’	9.7	• J-55 (54.5 lbm/ft) from surface to 2100 ft • J-55(61 lbm/ft) from 2100 ft to 2500 ft
2500 ft – 8700 ft	Intermediate	9’ 5/8’’	10	P-110 (53.5 lbm/ft)
8600 ft – 10200 ft	Intermediate Liner	7	15.5	P-110 (26 lbm/ft)
10100 ft – 13000 ft	Production Liner	5	16.2	N-80 (21 lbm/ft)

6. Suggestions for further study

In a casing design of a well, there are some additional parameters that need to be taken into account for a more complete work. The study of those parameters requires much more time and more data to work with. Some of them are the calculation of the installation load, the buckling force, the shock load, the drag force, the torsion load and the design of the well head.

7. Bibliography

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APPENDIX I

Pore and fracture pressure data:

Vertical Depth (ft)	Pore Pressure (psi)	Fracture pressure (psi)	Vertical Depth (ft)	Pore Pressure (psi)	Fracture pressure (psi)	Vertical Depth (ft)	Pore Pressure (psi)	Fracture pressure (psi)
2100	977	1437	5900	2746	4627	5700	2653	4447
2200	1024	1512	6000	2792	4720	5800	2699	4537
2300	1070	1588	6100	2839	4811	5700	2653	4447
2400	1117	1665	6200	2885	4903	5800	2699	4537
2500	1164	1742	6300	2932	4994	5700	2653	4447
2600	1210	1820	6400	2979	5086	10100	7647	8637
2700	1257	1898	6500	3025	5182	10200	7834	8748
2800	1303	1976	6600	3072	5275	10300	8002	8854
2900	1350	2056	6700	3118	5368	10400	8193	8956
3000	1396	2134	6800	3165	5462	10500	8376	9052
3100	1443	2215	6900	3211	5556	10600	8544	9154
3200	1489	2296	7000	3258	5647	10700	8680	9257
3300	1536	2377	7100	3304	5742	10800	8789	9354
3400	1582	2458	7200	3351	5837	10900	8899	9457
3500	1629	2540	7300	3397	5933	11000	9009	9560
3600	1675	2622	7400	3444	6029	11100	9120	9658
3700	1722	2706	7500	3491	6121	11200	9225	9756
3800	1769	2789	7600	3537	6218	11300	9331	9843
3900	1815	2872	7700	3584	6315	11400	9426	9936
4000	1862	2957	7800	3630	6409	11500	9520	10035
4100	1908	3041	7900	3677	6507	11600	9615	10128
4200	1955	3126	8000	3723	6601	11700	9710	10221
4300	2001	3211	8100	2932	6680	11800	9799	10314
4400	2048	3297	8200	2985	6734	11900	9888	10408
4500	2094	3383	8300	3043	6795	12000	9978	10501
4600	2141	3470	8400	3093	6957	12100	10067	10595
4700	2187	3557	8500	3121	7044	12200	10150	10688
4800	2234	3645	8600	3144	7088	12300	10234	10782
4900	2280	3733	8700	3298	7175	12400	10323	10876
5000	2327	3821	8800	3455	7262	12500	10407	10970
5100	2374	3908	8900	3610	7526	12600	10496	11064
5200	2420	3998	9000	3866	7530	12700	10580	11158
5300	2467	4088	9100	4041	7614	12800	10670	11252
5400	2513	4176	9200	4138	7674	12900	10753	11347
5500	2560	4267	9300	4280	7744	13000	10843	11435
5600	2606	4355	9400	5069	7926			

APPENDIX II

Performance properties of casing strings:

Surface casing:

TABLE 7.6—MINIMUM PERFORMANCE PROPERTIES OF CASING (cont.)

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
												**Internal Pressure Resistance, psi							*Joint Strength—1,000 lbf							
					Threaded and Coupled			Extreme Line							Buttress Thread				Threaded and Coupled							
																					Buttress Thread					
													Round Thread		Regular Coupling		Special Clearance Coupling		Round Thread						Extreme Line	
Size Outside Diameter (in.)	Nominal Weight Threads and Coupling (lbm/ft)	Grade	Wall Thickness (in.)	Inside Diameter (in.)	Drift Diameter (in.)	Outside Diameter of Coupling (in.)	Outside Diameter Special Clearance Coupling (in.)	Drift Diameter (in.)	Outside Diameter of Box Powertight (in.)	Collapse Resistance (psi)	Pipe Body Yield Strength (1,000 lbf)	Plain End or Extreme Line	Short	Long	Same Grade	Higher Grade	Same Grade	Higher Grade	Short	Long	Regular Coupling	Regular Coupling Higher Grade†	Special Clearance Coupling	Special Clearance Coupling Higher Grade†	Standard Joint	Optional Joint
13⅜	48.00	H-40	0.330	12.715	12.559	14.375	—	—	—	740	541	1,730	1,730	—	—	—	—	—	322	—	—	—	—	—	—	—
	54.50	J-55	0.380	12.615	12.459	14.375	—	—	—	1,130	853	2,730	2,730	—	2,730	2,730	—	—	514	—	909	909	—	—	—	—
	61.00	J-55	0.430	12.515	12.359	14.375	—	—	—	1,540	962	3,090	3,090	—	3,090	3,090	—	—	595	—	1,025	1,025	—	—	—	—
	68.00	J-55	0.480	12.415	12.259	14.375	—	—	—	1,950	1,069	3,450	3,450	—	3,450	3,450	—	—	675	—	1,140	1,140	—	—	—	—
	54.50	K-55	0.380	12.615	12.459	14.375	—	—	—	1,130	853	2,730	2,730	—	2,730	2,730	—	—	547	—	1,038	1,038	—	—	—	—
	61.00	K-55	0.430	12.515	12.359	14.375	—	—	—	1,540	962	3,090	3,090	—	3,090	3,090	—	—	633	—	1,169	1,169	—	—	—	—
	68.00	K-55	0.480	12.415	12.259	14.375	—	—	—	1,950	1,069	3,450	3,450	—	3,450	3,450	—	—	718	—	1,300	1,300	—	—	—	—
	68.00	C-75	0.480	12.415	12.259	14.375	—	—	—	2,220	1,458	4,710	4,550	—	4,710	—	—	—	905	—	1,496	—	—	—	—	—
	72.00	C-75	0.514	12.347	12.191	14.375	—	—	—	2,600	1,558	5,040	4,550	—	4,930	—	—	—	978	—	1,598	—	—	—	—	—
	68.00	L-80	0.480	12.415	12.259	14.375	—	—	—	2,260	1,556	5,020	4,550	—	4,930	—	—	—	952	—	1,545	—	—	—	—	—
	72.00	L-80	0.514	12.347	12.191	14.375	—	—	—	2,670	1,661	5,380	4,550	—	4,930	—	—	—	1,029	—	1,650	—	—	—	—	—
	68.00	N-80	0.480	12.415	12.259	14.375	—	—	—	2,260	1,556	5,020	4,550	—	4,930	4,930	—	—	963	—	1,585	1,585	—	—	—	—
	72.00	N-80	0.514	12.347	12.191	14.375	—	—	—	2,670	1,661	5,380	4,550	—	4,930	4,930	—	—	1,040	—	1,693	1,693	—	—	—	—
	68.00	G-90	0.480	12.415	12.259	14.375	—	—	—	2,320	1,750	5,650	4,550	—	4,930	—	—	—	1,057	—	1,683	—	—	—	—	—
	72.00	G-90	0.514	12.347	12.191	14.375	—	—	—	2,780	1,869	6,050	4,550	—	4,930	—	—	—	1,142	—	1,797	—	—	—	—	—
	68.00	C-95	0.480	12.415	12.259	14.375	—	—	—	2,330	1,847	5,970	4,550	—	4,930	—	—	—	1,114	—	1,772	—	—	—	—	—
	72.00	C-95	0.514	12.347	12.191	14.375	—	—	—	2,820	1,973	6,390	4,550	—	4,930	—	—	—	1,204	—	1,893	—	—	—	—	—
	68.00	P-110	0.480	12.415	12.259	14.375	—	—	—	2,330	2,139	6,910	4,550	—	4,930	4,930	—	—	1,297	—	2,079	2,079	—	—	—	—
	72.00	P-110	0.514	12.347	12.191	14.375	—	—	—	2,890	2,284	7,400	4,550	—	4,930	4,930	—	—	1,402	—	2,221	2,221	—	—	—	—

Intermediate casing:

TABLE 7.6—MINIMUM PERFORMANCE PROPERTIES OF CASING (cont.)

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
						Threaded and Coupled		Extreme Line				**Internal Pressure Resistance, psi							*Joint Strength—1,000 lbf							
															Buttress Thread				Threaded and Coupled							
																					Buttress Thread					
													Round Thread		Regular Coupling		Special Clearance Coupling		Round Thread						Extreme Line	
Size Outside Diameter (in.)	Nominal Weight Threads and Coupling (lbm/ft)	Grade	Wall Thickness (in.)	Inside Diameter (in.)	Drift Diameter (in.)	Outside Diameter of Coupling (in.)	Outside Diameter Special Clearance Coupling (in.)	Drift Diameter (in.)	Outside Diameter of Box Powertight (in.)	Collapse Resistance (psi)	Pipe Body Yield Strength (1,000 lbf)	Plain End or Extreme Line	Short	Long	Same Grade	Higher Grade	Same Grade	Higher Grade	Short	Long	Regular Coupling	Regular Coupling Higher Grade†	Special Clearance Coupling	Special Clearance Coupling Higher Grade†	Standard Joint	Optional Joint
9⅝	32.30	H-40	0.312	9.001	8.845	10.625	—	—	—	1,370	365	2,270	2,270	—	—	—	—	—	254	—	—	—	—	—	—	—
	36.00	H-40	0.352	8.921	8.765	10.625	—	—	—	1,720	410	2,560	2,560	—	—	—	—	—	294	—	—	—	—	—	—	—
	36.00	J-55	0.352	8.921	8.765	10.625	10.125	—	—	2,020	564	3,520	3,520	3,520	3,520	3,530	3,520	3,520	394	453	639	639	639	639	—	—
	40.00	J-55	0.395	8.835	8.679	10.625	10.125	8.599	10.100	2,570	630	3,950	3,950	3,950	3,950	3,950	3,660	3,950	452	520	714	714	714	714	770	770
	36.00	K-55	0.352	8.921	8.765	10.625	10.125	—	—	2,020	564	3,520	3,520	3,520	3,520	3,520	3,520	3,520	423	489	755	755	755	755	—	—
	40.00	K-55	0.395	8.835	8.679	10.625	10.125	8.599	10.100	2,570	630	3,950	3,950	3,950	3,950	3,950	3,660	3,950	486	561	843	843	843	843	975	975
	40.00	C-75	0.395	8.835	8.679	10.625	10.125	8.599	10.100	2,990	859	5,390	—	5,390	5,390	—	4,990	—	—	694	926	—	926	—	975	975
	43.50	C-75	0.435	8.755	8.599	10.625	10.125	8.599	10.100	3,730	942	5,930	—	5,930	5,930	—	4,990	—	—	776	1,016	—	934	—	975	975
	47.00	C-75	0.472	8.681	8.525	10.625	10.125	8.525	10.100	4,610	1,018	6,440	—	6,440	6,440	—	4,990	—	—	852	1,098	—	934	—	1,032	1,032
	53.50	C-75	0.545	8.535	8.379	10.625	10.125	8.379	10.100	6,350	1,166	7,430	—	7,430	7,430	—	4,990	—	—	999	1,257	—	934	—	1,173	1,053
	40.00	L-80	0.395	8.835	8.679	10.625	10.125	8.599	10.100	3,090	916	5,750	—	5,750	5,750	—	5,140	—	—	727	947	—	934	—	975	975
	43.50	L-80	0.435	8.755	8.599	10.625	10.125	8.599	10.100	3,810	1,005	6,330	—	6,330	6,330	—	5,140	—	—	813	1,038	—	934	—	975	975
	47.00	L-80	0.472	8.681	8.525	10.625	10.125	8.525	10.100	4,760	1,086	6,870	—	6,870	6,870	—	5,140	—	—	893	1,122	—	934	—	1,032	1,032
	53.50	L-80	0.545	8.535	8.379	10.625	10.125	8.379	10.100	6,620	1,244	7,930	—	7,930	7,930	—	5,140	—	—	1,047	1,286	—	934	—	1,173	1,053
	40.00	N-80	0.395	8.835	8.679	10.625	10.125	8.599	10.100	3,090	916	5,750	—	5,750	5,750	5,750	5,140	5,140	—	737	979	979	979	979	1,027	1,027
	43.50	N-80	0.435	8.755	8.599	10.625	10.125	8.599	10.100	3,810	1,005	6,330	—	6,330	6,330	6,330	5,140	5,140	—	825	1,074	1,074	983	1,074	1,027	1,027
	47.00	N-80	0.472	8.681	8.525	10.625	10.125	8.525	10.100	4,760	1,086	6,870	—	6,870	6,870	6,870	5,140	5,140	—	905	1,161	1,161	983	1,161	1,086	1,086
	53.50	N-80	0.545	8.535	8.379	10.625	10.125	8.379	10.100	6,620	1,244	7,930	—	7,930	7,930	7,930	5,140	5,140	—	1,062	1,329	1,329	983	1,229	1,235	1,109
	40.00	C-90	0.395	8.835	8.679	10.625	10.125	8.599	10.100	3,250	1,031	6,460	—	6,460	6,460	—	5,140	—	—	804	1,021	—	983	—	1,027	1,027
	43.50	C-90	0.435	8.755	8.599	10.625	10.125	8.599	10.100	4,010	1,130	7,120	—	7,120	7,120	—	5,140	—	—	899	1,119	—	983	—	1,027	1,027
	47.00	C-90	0.472	8.681	8.525	10.625	10.125	8.525	10.100	5,000	1,221	7,720	—	7,720	7,720	—	5,140	—	—	987	1,210	—	983	—	1,086	1,086
	53.50	C-90	0.545	8.535	8.379	10.625	10.125	8.379	10.100	7,120	1,399	8,920	—	8,460	8,920	—	5,140	—	—	1,157	1,386	—	983	—	1,235	1,109
	40.00	C-95	0.395	8.835	8.679	10.625	10.125	8.599	10.100	3,320	1,088	6,820	—	6,820	6,820	—	5,140	—	—	847	1,074	—	1,032	—	1,078	1,078
	43.50	C-95	0.435	8.755	8.599	10.625	10.125	8.599	10.100	4,120	1,193	7,510	—	7,510	7,510	—	5,140	—	—	948	1,178	—	1,032	—	1,078	1,078
	47.00	C-95	0.472	8.681	8.525	10.625	10.125	8.525	10.100	5,090	1,289	8,150	—	8,150	8,150	—	5,140	—	—	1,040	1,273	—	1,032	—	1,141	1,141
	53.50	C-95	0.545	8.535	8.379	10.625	10.125	8.379	10.100	7,340	1,477	9,410	—	8,460	8,460	—	5,140	—	—	1,220	1,458	—	1,032	—	1,297	1,164
	43.50	P-110	0.435	8.755	8.599	10.625	10.125	8.599	10.100	4,420	1,381	8,700	—	8,700	8,700	8,700	5,140	5,140	—	1,106	1,388	1,388	1,229	1,388	1,283	1,283
	47.00	P-110	0.472	8.681	8.525	10.625	10.125	8.525	10.100	5,300	1,493	9,440	—	9,440	9,160	9,160	5,140	5,140	—	1,213	1,500	1,500	1,229	1,500	1,358	1,358
	53.50	P-110	0.545	8.535	8.379	10.625	10.125	8.379	10.100	7,950	1,710	10,900	—	9,670	9,160	9,160	5,140	5,140	—	1,422	1,718	1,718	1,229	1,573	1,544	1,386

Intermediate liner casing:

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
					Threaded and Coupled			Extreme Line				**Internal Pressure Resistance, psi							*Joint Strength—1,000 lbf							
															Buttress Thread				Threaded and Coupled							
																					Buttress Thread					
Size Outside Diameter (in.)	Nominal Weight Threads and Coupling (lbm/ft)	Grade	Wall Thickness (in.)	Inside Diameter (in.)	Drift Diameter (in.)	Outside Diameter of Coupling (in.)	Outside Diameter Special Clearance Coupling (in.)	Drift Diameter (in.)	Outside Diameter of Box Powertight (in.)	Collapse Resistance (psi)	Pipe Body Yield Strength (1,000 lbf)	Plain End or Extreme Line	Round Thread Short	Round Thread Long	Regular Coupling Same Grade	Regular Coupling Higher Grade	Special Clearance Coupling Same Grade	Special Clearance Coupling Higher Grade	Round Thread Short	Round Thread Long	Regular Coupling	Regular Coupling Higher Grade†	Special Clearance Coupling	Special Clearance Coupling Higher Grade†	Extreme Line Standard Joint	Extreme Line Optional Joint
7	17.00	H-40	0.231	6.538	6.413	7.656	—	—	—	1,420	196	2,310	2,310	—	—	—	—	—	122	—	—	—	—	—	—	—
	20.00	H-40	0.272	6.456	6.331	7.656	—	—	—	1,970	230	2,720	2,720	—	—	—	—	—	176	—	—	—	—	—	—	—
	20.00	J-55	0.272	6.456	6.331	7.656	—	—	—	2,270	316	3,740	3,740	—	—	—	—	—	234	—	—	—	—	—	—	—
	23.00	J-55	0.317	6.366	6.241	7.656	7.375	6.151	7.390	3,270	366	4,360	4,360	4,360	4,360	4,360	3,950	4,360	284	313	432	432	421	432	499	499
	26.00	J-55	0.362	6.276	6.151	7.656	7.375	6.151	7.390	4,320	415	4,980	4,980	4,980	4,980	4,980	3,950	4,980	334	367	490	490	421	490	506	506
	20.00	K-55	0.272	6.456	6.331	7.656	—	—	—	2,270	316	3,740	3,740	—	—	—	—	—	254	—	—	—	—	—	—	—
	23.00	K-55	0.317	6.366	6.241	7.656	7.375	6.151	7.390	3,270	366	4,360	4,360	4,360	4,360	4,360	3,950	4,360	309	341	522	522	522	522	632	632
	26.00	K-55	0.362	6.276	6.151	7.656	7.375	6.151	7.390	4,320	415	4,980	4,980	4,980	4,980	4,980	3,950	4,980	364	401	592	592	533	561	641	641
	23.00	C-75	0.317	6.366	6.241	7.656	7.375	6.151	7.390	3,750	499	5,940	—	5,940	5,940	—	5,380	—	—	416	557	—	533	—	632	632
	26.00	C-75	0.362	6.276	6.151	7.656	7.375	6.151	7.390	5,220	566	6,790	—	6,790	6,790	—	5,380	—	—	489	631	—	533	—	641	641
	29.00	C-75	0.408	6.184	6.059	7.656	7.375	6.059	7.390	6,730	634	7,650	—	7,650	7,650	—	5,380	—	—	562	707	—	533	—	685	674
	32.00	C-75	0.453	6.094	5.969	7.656	7.375	5.969	7.390	8,200	699	8,490	—	8,490	7,930	—	5,380	—	—	633	779	—	533	—	761	674
	35.00	C-75	0.498	6.004	5.879	7.656	7.375	5.879	7.530	9,670	763	9,340	—	8,660	7,930	—	5,380	—	—	703	833	—	533	—	850	761
	38.00	C-75	0.540	5.920	5.795	7.656	7.375	5.795	7.530	10,680	822	10,120	—	8,660	7,930	—	5,380	—	—	767	833	—	533	—	917	761
	23.00	L-80	0.317	6.366	6.241	7.656	7.375	6.151	7.390	3,830	532	6,340	—	6,340	6,340	6,340	5,740	6,340	—	435	565	—	533	—	632	632
	26.00	L-80	0.362	6.276	6.151	7.656	7.375	6.151	7.390	5,410	604	7,240	—	7,240	7,240	7,240	5,740	7,240	—	511	641	—	533	—	641	641
	29.00	L-80	0.408	6.184	6.059	7.656	7.375	6.059	7.390	7,020	676	8,160	—	8,160	8,160	8,160	5,740	7,890	—	587	718	—	533	—	685	674
	32.00	L-80	0.453	6.094	5.969	7.656	7.375	5.969	7.390	8,610	745	9,060	—	9,060	8,460	9,060	5,740	7,890	—	661	791	—	533	—	761	674
	35.00	L-80	0.498	6.004	5.879	7.656	7.375	5.879	7.530	10,180	814	9,960	—	9,240	8,460	9,960	5,740	7,890	—	734	833	—	533	—	850	761
	38.00	L-80	0.540	5.920	5.795	7.656	7.375	5.795	7.530	11,390	877	10,800	—	9,240	8,460	10,800	5,740	7,890	—	801	833	—	533	—	917	761
	23.00	N-80	0.317	6.366	6.241	7.656	7.375	6.151	7.390	3,830	532	6,340	—	6,340	6,340	6,340	5,740	6,340	—	442	588	588	561	588	666	666
	26.00	N-80	0.362	6.276	6.151	7.656	7.375	6.151	7.390	5,410	604	7,240	—	7,240	7,240	7,240	5,740	7,240	—	519	667	667	561	667	675	675
	29.00	N-80	0.408	6.184	6.059	7.656	7.375	6.059	7.390	7,020	676	8,160	—	8,160	8,160	8,160	5,740	7,890	—	597	746	746	561	702	721	709
	32.00	N-80	0.453	6.094	5.969	7.656	7.375	5.969	7.390	8,610	745	9,060	—	9,060	8,460	9,060	5,740	7,890	—	672	823	823	561	702	801	709
	35.00	N-80	0.498	6.004	5.879	7.656	7.375	5.879	7.530	10,180	814	9,960	—	9,240	8,460	9,960	5,740	7,890	—	746	876	898	561	702	895	801
	38.00	N-80	0.540	5.920	5.795	7.656	7.375	5.795	7.530	11,390	877	10,800	—	9,240	8,460	10,800	5,740	7,890	—	814	876	968	561	702	965	801
	23.00	C-90	0.317	6.366	6.241	7.656	7.375	6.151	7.390	4,030	599	7,130	—	7,130	7,130	—	6,450	—	—	447	605	—	561	—	666	666
	26.00	C-90	0.362	6.276	6.151	7.656	7.375	6.151	7.390	5,740	679	8,150	—	8,150	8,150	—	6,450	—	—	563	687	—	561	—	675	675
	29.00	C-90	0.408	6.184	6.059	7.656	7.375	6.059	7.390	7,580	760	9,180	—	9,180	9,180	—	6,450	—	—	648	768	—	561	—	721	709
	32.00	C-90	0.453	6.094	5.969	7.656	7.375	5.969	7.390	9,380	839	10,190	—	9,520	9,520	—	6,450	—	—	729	847	—	561	—	801	709
	35.00	C-90	0.498	6.004	5.879	7.656	7.375	5.879	7.530	11,170	915	11,210	—	9,520	9,520	—	6,450	—	—	809	876	—	561	—	895	801
	38.00	C-90	0.540	5.920	5.795	7.656	7.375	5.795	7.530	12,820	986	12,150	—	9,520	9,520	—	6,450	—	—	883	876	—	561	—	965	801
	23.00	C-95	0.317	6.366	6.241	7.656	7.375	6.151	7.390	4,140	632	7,530	—	7,530	7,530	—	6,810	—	—	505	636	—	589	—	699	699
	26.00	C-95	0.362	6.276	6.151	7.656	7.375	6.151	7.390	5,880	717	8,600	—	8,600	8,600	—	6,810	—	—	593	722	—	589	—	709	709
	29.00	C-95	0.408	6.184	6.059	7.656	7.375	6.059	7.390	7,830	803	9,690	—	9,520	9,690	—	6,810	—	—	683	808	—	589	—	757	744
	32.00	C-95	0.453	6.094	5.969	7.656	7.375	5.969	7.390	9,750	885	10,760	—	9,520	10,050	—	6,810	—	—	768	891	—	589	—	841	744
	35.00	C-95	0.498	6.004	5.879	7.656	7.375	5.879	7.530	11,650	966	11,830	—	9,520	10,050	—	6,810	—	—	853	920	—	589	—	940	841
	38.00	C-95	0.540	5.920	5.795	7.656	7.375	5.795	7.530	13,440	1,041	12,820	—	9,520	10,050	—	6,810	—	—	931	920	—	589	—	1,013	841
	26.00	P-110	0.362	6.276	6.151	7.656	7.375	6.151	7.390	6,230	830	9,960	—	9,520	9,960	9,960	7,480	7,480	—	693	853	853	702	853	844	844
	29.00	P-110	0.408	6.184	6.059	7.656	7.375	6.059	7.390	8,530	929	11,220	—	9,520	11,220	11,220	7,480	7,480	—	797	955	955	702	898	902	886
	32.00	P-110	0.453	6.094	5.969	7.656	7.375	5.969	7.390	10,780	1,025	12,460	—	9,520	11,640	11,790	7,480	7,480	—	897	1,053	1,053	702	898	1,002	886
	35.00	P-110	0.498	6.004	5.879	7.656	7.375	5.879	7.530	13,020	1,119	13,700	—	9,520	11,640	11,790	7,480	7,480	—	996	1,096	1,150	702	898	1,118	1,002
	38.00	P-110	0.540	5.920	5.795	7.656	7.375	5.795	7.530	15,140	1,205	14,850	—	9,520	11,640	11,790	7,480	7,480	—	1,087	1,096	1,239	702	898	1,207	1,002

Production liner casing:

TABLE 7.6—MINIMUM PERFORMANCE PROPERTIES OF CASING (cont.)

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
												**Internal Pressure Resistance, psi							*Joint Strength—1,000 lbf							
					Threaded and Coupled			Extreme Line							Buttress Thread				Threaded and Coupled							
															Regular Coupling		Special Clearance Coupling				Buttress Thread				Extreme Line	
Size Outside Diameter (in.)	Nominal Weight Threads and Coupling (lbm/ft)	Grade	Wall Thickness (in.)	Inside Diameter (in.)	Drift Diameter (in.)	Outside Diameter of Coupling (in.)	Outside Diameter Special Clearance Coupling (in.)	Drift Diameter (in.)	Outside Diameter of Box Powertight (in.)	Collapse Resistance (psi)	Pipe Body Yield Strength (1,000 lbf)	Plain End or Extreme Line	Round Thread Short	Round Thread Long	Same Grade	Higher Grade	Same Grade	Higher Grade	Round Thread Short	Round Thread Long	Regular Coupling	Regular Coupling Higher Grade†	Special Clearance Coupling	Special Clearance Coupling Higher Grade†	Standard Joint	Optional Joint
5	11.50	J-55	0.220	4.560	4.435	5.563	—	—	—	3,060	182	4,240	4,240	—	—	—	—	—	133	—	—	—	—	—	—	—
	13.00	J-55	0.253	4.494	4.369	5.563	5.375	—	—	4,140	208	4,870	4,870	4,870	4,870	4,870	4,870	4,870	169	182	252	252	252	252	—	—
	15.00	J-55	0.296	4.408	4.283	5.563	5.375	4.151	5.360	5,560	241	5,700	5,700	5,700	5,700	5,700	5,130	5,700	207	223	293	293	287	293	328	—
	11.50	K-55	0.220	4.560	4.435	5.563	—	—	—	3,060	182	4,240	4,240	—	—	—	—	—	147	—	—	—	—	—	—	—
	13.00	K-55	0.253	4.494	4.369	5.563	5.375	—	—	4,140	208	4,870	4,870	4,870	4,870	4,870	4,870	4,870	186	201	309	309	309	309	—	—
	15.00	K-55	0.296	4.408	4.283	5.563	5.375	4.151	5.360	5,560	241	5,700	5,700	5,700	5,700	5,700	5,130	5,700	228	246	359	359	359	359	416	—
	15.00	C-75	0.296	4.408	4.283	5.563	5.375	4.151	5.360	6,940	328	7,770	—	7,770	7,770	—	6,990	—	—	295	375	—	364	—	416	—
	18.00	C-75	0.362	4.276	4.151	5.563	5.375	4.151	5.360	9,960	396	9,500	—	9,500	9,290	—	6,990	—	—	376	452	—	364	—	446	—
	21.40	C-75	0.437	4.126	4.001	5.563	5.375	—	—	11,970	470	11,470	—	10,140	9,290	—	6,990	—	—	466	510	—	364	—	—	—
	23.20	C-75	0.478	4.044	3.919	5.563	5.375	—	—	12,970	509	12,550	—	10,140	9,290	—	7,000	—	—	513	510	—	364	—	—	—
	24.10	C-75	0.500	4.000	3.875	5.563	5.375	—	—	13,500	530	13,130	—	10,140	9,290	—	6,990	—	—	538	510	—	364	—	—	—
	15.00	L-80	0.296	4.408	4.283	5.563	5.375	4.151	5.360	7,250	350	8,290	—	8,290	8,290	8,290	7,460	8,290	—	295	379	—	364	—	416	—
	18.00	L-80	0.362	4.276	4.151	5.563	5.375	4.151	5.360	10,500	422	10,140	—	10,140	9,910	10,140	7,460	10,140	—	376	457	—	364	—	446	—
	21.40	L-80	0.437	4.126	4.001	5.563	5.375	—	—	12,760	501	12,240	—	10,810	9,910	—	7,460	—	—	466	510	—	364	—	—	—
	23.20	L-80	0.478	4.044	3.919	5.563	5.375	—	—	13,830	543	13,380	—	10,820	9,910	—	7,460	—	—	513	510	—	364	—	—	—
	24.10	L-80	0.500	4.000	3.875	5.563	5.375	—	—	14,400	566	14,000	—	10,810	9,910	—	7,460	—	—	538	510	—	364	—	—	—
	15.00	N-80	0.296	4.408	4.283	5.563	5.375	4.151	5.360	7,250	350	8,290	—	8,290	8,290	8,290	7,460	8,290	—	311	396	396	383	396	437	—
	18.00	N-80	0.362	4.276	4.151	5.563	5.375	4.151	5.360	10,500	422	10,140	—	10,140	9,910	10,140	7,460	10,140	—	396	477	477	383	477	469	—
	21.40	N-80	0.437	4.126	4.001	5.563	5.375	—	—	12,760	501	12,240	—	10,810	9,910	12,240	7,460	10,250	—	490	537	566	383	479	—	—
	23.20	N-80	0.478	4.044	3.919	5.563	5.375	—	—	13,830	543	13,380	—	10,820	9,910	13,380	7,460	10,260	—	540	537	614	383	479	—	—
	24.10	N-80	0.500	4.000	3.875	5.563	5.375	—	—	14,400	566	14,000	—	10,810	9,910	13,620	7,460	10,250	—	567	537	639	383	479	—	—
	15.00	C-90	0.296	4.408	4.283	5.563	5.375	4.151	5.366	7,840	394	9,320	—	9,320	9,320	—	8,400	—	—	311	404	—	383	—	430	—
	18.00	C-90	0.362	4.276	4.151	5.563	5.375	4.151	5.366	11,530	475	11,400	—	11,400	11,150	—	8,400	—	—	396	487	—	383	—	469	—
	21.40	C-90	0.437	4.126	4.001	5.563	5.375	—	—	14,360	564	13,770	—	12,170	11,150	—	8,400	—	—	490	537	—	383	—	—	—
	23.20	C-90	0.478	4.044	3.919	5.563	5.375	—	—	15,560	611	15,060	—	12,170	11,150	—	8,400	—	—	540	537	—	383	—	—	—
	24.10	C-90	0.500	4.000	3.875	5.563	5.375	—	—	16,200	636	15,750	—	12,170	11,150	—	8,400	—	—	567	537	—	383	—	—	—
	15.00	C-95	0.296	4.408	4.283	5.563	5.375	4.151	5.360	8,110	416	9,840	—	9.840	9,840	—	8,850	—	—	326	424	—	402	—	459	—
	18.00	C-95	0.362	4.276	4.151	5.563	5.375	4.151	5.360	12,030	501	12,040	—	12,040	11,770	—	8,850	—	—	416	512	—	402	—	493	—
	21.40	C-95	0.437	4.126	4.001	5.563	5.375	—	—	15,160	595	14,530	—	12,840	11,770	—	8,850	—	—	515	563	—	402	—	—	—
	23.20	C-95	0.478	4.044	3.919	5.563	5.375	—	—	16,430	645	15,890	—	12,850	11,770	—	8,850	—	—	567	563	—	402	—	—	—
	24.10	C-95	0.500	4.000	3.875	5.563	5.375	—	—	17,100	672	16,630	—	12,850	11,770	—	8,850	—	—	595	563	—	402	—	—	—
	15.00	P-110	0.296	4.408	4.283	5.563	5.375	4.151	5.360	8,850	481	11,400	—	11,400	11,400	11,400	10,250	11,400	—	388	503	503	479	503	547	—
	18.00	P-110	0.362	4.276	4.151	5.563	5.375	4.151	5.360	13,470	580	13,940	—	13,940	13,620	13,940	10,250	13,940	—	495	606	606	479	606	587	—
	21.40	P-110	0.437	4.126	4.001	5.563	5.375	—	—	17,550	689	16,820	—	14,870	13,620	16,820	10,250	13,980	—	613	671	720	479	613	—	—
	23.20	P-110	0.478	4.044	3.919	5.563	5.375	—	—	19,020	747	18,400	—	14,880	13,630	18,400	10,260	13,990	—	675	671	780	479	613	—	—
	24.10	P-110	0.500	4.000	3.875	5.563	5.375	—	—	19,800	778	19,250	—	14,870	13,620	18,580	10,250	13,980	—	708	671	812	479	613	—	—