CASING DESIGN: DISCUSSION ON LOAD CASES

Preliminary & Detailed Casing Design

Probability of casing failure in HPHT wells is very high if it not designed properly. As per data reported in the Zhaoguang et.al (IPTC 16704), casing damage has been experienced over 11 wells out of 18 wells that have been drilled in Ann Mag Field, South Texas. Nearly 61% of total wells were damaged during the production.

Post Macando 2010, many changes has been adapted by oil industry to design complex wells which includes HPHT environment, deepwater environment etc. Designed well should meet the standards give by International & local government authorities. Proper tubular selection plays very critical role in maintaining structural integrity of the wells. Hence special attention should be provided by the well designer during selection of grades, weight, metallurgy and connections. It’s mandatory to use qualified connections become more apparent following Macando incidence of 2010 [Ayodele A et.al.SPE 167580]. Well should be designed to withstand with worst case loads to encountered throughout life span of well.

Casing Stress Analysis

Well casings must be designed be for worst load cases. Casings load cases are broadly classified into two types on the basis of operation:

- Drilling Load Cases – Where loading during drilling operations are considered.
- Production Load Cases – Where loading during production operations are considered.

On the basis of pressure of load, it is classified as:

- Burst load
- Collapse load
- Axial load

But here we are classifying load cases into completely new category:

1. Burst load - Drilling load
2. Burst load- Production load
3. Collapse load – Drilling load
4. Collapse load- Production load
5. Axial load- Drilling & Production combined load case
### General Load Cases:

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</table>

The casing designer determines the internal pressure profile and external pressure profile for each load case. If the net resultant load is positive, then it is called as ‘Burst’ and if it’s negative then it’s called as ‘Collapse’ [Casing Design Guide].
Burst Loads - Drilling

1. Displacement to Gas

This case is assumed as ‘worst-case’ for calculation of burst pressure in designing of surface and intermediate casings. It assumes a gas kick while drilling next section. Gas column extends from casing shoe to the surface. Pressure exerted by column of gas termed as ‘Maximum Anticipated Surface Pressure (MASP)’. Pressure obtained at the surface should be limited by fracture pressure at shoe. It means if MASP is greater than fracture pressure at shoe in that case surface pressure should be calculated using difference between fracture pressure and column of gas up to the surface from shoe.

Load in this calculated using pore pressure at next TD or fracture pressure at casing shoe, gas column with gradient 0.1 psi/ft & mud weight.

It is recommended full displacement of casing if casing shoe depth is less than 3000 ft. Partial displacement of casing is assumed if shoe depth is greater than 3000 ft.

2. Gas Kick Profile

This drilling case simulates the pressure imposed by limited gas kick while circulating out from the wellbore. This criterion is comparatively less conservative than the previous one.

The profile is calculated on the basis of intensity at the kick depth, volume of kick that well has taken and maximum mud weight in use for drilling of next section.

General volume of kick is calculated from kick tolerance calculations. *Kick tolerance is maximum volume of kick that can be circulated out of hole without fracturing the previous casing shoe.*
3. Lost Returns with Water

This load case specifically applies for intermediate casings. Before understanding this load case, understanding of what is lost returns is important. Losses are generally categories into three classes; if losses in the annulus are less than 20 bbl/hr then it is called as seepage loss. In case of partial lost returns, losses are more than 20 bbl/hr but some still some returns comes to the surface. Full or complete lost returns are severe case where no returns found at the surface.

Annular losses cause reduction in hydrostatic head which may subsequently leads to flowing of another zone into the well. This situation is known as ‘loss-gain’. This case models the same situation. Where to avoid further deterioration of hydrostatic head inside the annulus, continuously water is pumped down, to condition fracture at shoe and migration of gas to the surface, by somehow maintaining the highest possible fluid level inside the annulus.

In second case assume stock of barite on rig site is exhausted so only water is pumping down the annulus. Internal profile will be based on fracture pressure at shoe and water column.
4. **Surface Protection**

This drilling load case represents a moderate way to overcome blowout during well control. This load case is a combination of ‘gas kick load’ profile and ‘lost returns with water’. The surface pressure in this case is calculated using ‘lost returns with water’ case i.e. surface pressure is the difference between fracture pressure at shoe and water column extending to the surface. Once surface pressure is estimated, pressure at deeper depths calculated by pressure applied by column of gas in addition with surface pressure.

This criteria makes sure the weakest point in the well is not the surface. Shallow design is based on surface protection criteria while deeper design is based on gas kick profile criteria.
5. Pressure Test

This drilling load case calculates internal pressure profile on the basis of test pressure applied at the top and the mud weight use for conducting the test. Generally the mud weight use is same mud to drill that section.

Objective of casing pressure test is to check the integrity of the casing string. Each casing string inside the wellbore should withstand with test pressure load. Generally test pressure load is calculated assuming maximum anticipated surface pressure which occurs when mud inside casing is completely displaced by the gas from next section.

Conventionally pressure test is conducted at the after the cementing where cement is still soft. To check proper integrity of casing, pressure test should be conducted at several depths using packer. At any cost maximum test pressure should not exceed 75 % of burst rating of the casing.

All the operators have their own standards for pressure testing or the standards are given by local governing bodies. These standards should be strictly followed in order to check integrity of the wellbore.

Recommendation for Pressure Test by BG (British Gas Manual):

- For surface / Intermediate casings/Liner
  - The test pressure must be the pressure required to conduct planned leak off test with some test margin. Recommended margins are 0.2 ppg for production wells & 0.5 ppg for exploratory wells due to more uncertainty.
  - Or maximum expected pressure while circulating out the gas kicks
- For production casing/Liner
  - Minimum test pressure should be equal to expected shut-in tubing pressure on the top of annulus fluid plus additional 200 psi as margin of safety.

Maximum casing pressure should never exceed:

- 80 % of burst rating of casing.
- Maximum rated pressure of BOP & Wellhead.
- 62 % of tensile yield for casing or connection.
6. Drill Ahead

This load case simulates drilling of next section once casing is landed down to shoe. This particular case is mostly applicable to half cemented casing strings in order to check the amount of buckling that can be occurs on the un-cemented section. This particular case is applicable for casings through which drilling of next section is planned.

This profile is calculated using highest mud weight use for drilling of next section.
Burst Loads—Production

1. Tubing Leak

Tubing leak is production load case applies only to burst design. This case assumes leakage in the tubing near wellhead. This shut-in tubing head pressure completely transferred through communication between annulus and tubing (Production annulus) to the annular fluid or packer fluid above the packer. This profile is basically divided into two parts i.e. above packer where pressure is due to column of fluid in addition to shut-in tubing pressure and below packer where pressure column is due to produced fluid.

Here shut-in tubing head surface pressure is an estimated as difference between reservoir pressure and column of fluid that is being produced.

2. Stimulation Surface Leak

This case is similar as above case with slight change that tubing here in this case is assumed to be leaked at the top while conducting stimulation job i.e. hydraulic fracturing. Injection pressure is applied to the top of production annulus.

This profile is divided into two parts i.e. above packer and below packer.
3. **Injection Down Casing**

This profile simulates the injection operations i.e. water injection or steam injection any kind of injection can modeled with this. This case is as similar as the above one except packer. Here no packer is assumed in the production annulus.

![Injection Down Casing Diagram]

4. **Gas Migration**

This is very special case applicable only in case of ‘tieback’ string. This case assumes migration of gas bubble between annulus of production casing and tieback casing. Gas rises upwards without any expansion since there no bleeding of pressure. Expansion of gas can be taken place if shoe fractures so additional space can be occupied by the gas. Since gas bubble emerges out from reservoir and there is no expansion certainly it carries pressure of reservoir. It applies same reservoir pressure at the wellhead. This leads to annular pressure buildup. Certainly in case of onshore wells production annulus can bleed down but in case of subsea completions it can cause catastrophic well integrity issue.

![Gas Migration through Annulus Diagram]
Collapse Load – Drilling

1. Full/Partial Evacuation

Drilling activity is full of uncertainties. Blowout or loss circulation is often faced industry hazards. This case models both blow-out and loss circulation while drilling. Generally if mud weight doesn’t maintained properly, if it crosses fracture pressure, losses may occur. If fractures are big enough, it may consume complete fluid inside the wellbore. And if it is partial, then losses will occur till hydrostatic column of mud inside wellbore is balanced by minimum encountered pore pressure while drilling next section.

Generally for designing casing with less shoe depth less than 3000 ft, complete losses are assumed. But speaking more technically, pressure drop needed in order to fluid to flow. When hydrostatic pressure inside wellbore balanced by minimum pore pressure, due to no pressure difference, losses should stop. This case not only models losses, but also blow-outs. Shallow blow-out in offshore (shoe depth is quite less) may lead to complete evacuation. Another special case, drilling with air or foam, where internal pressure is minimum, may lead to failure of casings if net pressure is more than collapse rating of pipe.

Find out TVD equivalent (TVD equivalent is height of mud column against pore pressure, where hydrostatic pressure and pore pressure get balanced). TVD equivalent gives depth of air/mud interface. Above TVD equivalent, assume that casing is filled with gas and below it it’s full of mud.
2. Cementing

This cementing case models the actual cementing operation irrespective standard external profiles chosen which will be discussed later in this chapter. Here cement is still assumed to be ‘green’ or not hardened. Annulus profile consists of mud in which casing is set, density of lead slurry and density of tail slurry. While internal profile consists of displacing fluid and cement in shoe track.

![Wellbore Cementing](image1.png)

3. Lost Returns with Mud

‘Lost returns with mud’ simulates the lost circulation case. It is assumed that during drilling of next section, lost circulation encountered. Mud is being continuously seeping into the formation till the hydrostatic column gets balanced with lowest pore pressure in the next section.

![Lost Returns with Mud](image2.png)
1. **Above/Below Packer**

Production case gives real operating condition of the well where well is divided into two chambers i.e. above packer and below packer. Above packer chamber is always filled with the completion fluid or packer fluid to prevent unsetting of packers due to production load from lower chamber. Basically here can be two cases in ‘above packer’ profile such that either production annulus is full of packer fluid or encounter of losses for packer fluid. If losses are encountered then level of packer fluid will dropped till it is balanced by the minimum pore pressure near packer.

‘Below packer’ profile has very simple assumptions which includes either empty lower chamber or chamber full of production fluid. General case assumes the lower chamber is filled with native formation fluid i.e. water with 8.33 ppg.
2. Full Evacuation

This case relates to the complete evacuation of packer fluid above the packer to the formation. The reason for full evacuation must formation of depleted reservoir due to continuous production. Even case of ‘gas lift’ can be simulated using same load case. In gas lift operation, production annulus is full of gas. Pressure profile in such case depends upon type of gas getting injected into the formation, density of gas, injection pressure at the wellhead and temperature.
3. Gas Migration

Annular pressure buildup is major problem for wells with ‘gas migration’. The only responsible factor ‘gas migration’ is poor cementing behind the casing. If this trapped annular pressure not treated properly, it can cause catastrophic well integrity issue by collapsing of casing.

Only sound cementing procedures can prevent gas migration issue. Assume poor cementing though which gas is migrating upwards. Since there is no space of expansion of gas, it carries the same formation pressure from where it is originated. This profile assumes pressure of gas plus the hydrostatic pressure of annular fluid generally which is mud in which casing is set. Pressure at the shoe can be calculated by estimating pressure of gas bubble and density of mud inside the annulus.

Now here two more cases can be generated i.e. mud properties are intact and mud is degraded. If mud properties are intact in that case it will apply normal hydrostatic pressure which solely depends on density of mud. But if second case is assumed, where mud is degraded, then it only applies pressure equivalent 8.33 ppg fluid (water).
External Load Profiles

Above mentioned profiles are mainly internal pressure profiles. Both internal pressure profile and external pressure profile requires to find resultant load at surface and at the shoe. Resultant load multiplied with design factor gives design load, on which is the basis for tubular grades selection.

External profiles mainly depend on the quality of cement and drilling fluid in the annulus. Once cement is set after spending enough waiting time on cement, it behaves like low permeability matrix. It stores pore fluid at certain pressure. Placement of cement against the formation type plays important factor in estimation of external profile. If cement column cement set against the good permeable formation, then pressure in the cement column will be equal to pore pressure in the formation. Fluids in the formation can easily stores in the cement column due to good communication.

If the cement column set against the low permeability formation, then actually quality of cement column decides the pressure regime. If quality of cement is good, then it acts as perfect sealing between cement top and permeable formation. In this case pressure profile will be the line joining pressure at cement top and pore pressure of the high permeability formation.

Quality of cement is poor then it doesn’t act as perfect seal. Pressure can be transmitted across the poor cement column. Pressure gradient across the low permeability formation will be depends on cement-mix water density. General assumed value for cement-mixed water is 8.33 ppg. The pressure line is extended from top of high permeability formation till surface with mixed-water density gradient.
Second important assumption while estimating external pressure profile is quality of annulus fluid. Assume density of annulus fluid equal to density of mud in which casing was set. Generally during process of cementing, quality of fluid in annulus remains intact. But as worst case scenario deterioration of annulus fluid is assumed which has density equal to 8.33 ppg.

1. Mud & Cement Mix-water

This profile assumes mud and cement outside the casing. Profile is estimated into two parts i.e. up to the top of cement (TOC) and below top of cement. Pressure at TOC is calculated using the mud gradient in which casing is set. Below TOC, up to the shoe, pressure is estimated using cement-mix water gradient.
2. Permeable Zones

As per above discussion, in case of permeable zones quality of cement makes most impact in estimation of external profile. If cement column is in good condition, then it acts as perfect seal. It does not allow transmitting the pressure through it.

If the quality of cement column is poor, then pressure can be easily transmitted across the column.
3. Pore Pressure with Sea Water Gradient

This profile simulates offshore drilling environment where column of seawater from Mean Sea Level (MSL) to Mud line plays important role in estimation of external profile. This profile also estimated into two parts i.e. above mud line and below mud line.

![Pore Pressure with sea water gradient](image)

Casing Axial Loads

1. Installations loads

Once casing string is designed to withstand with burst and collapse pressure, designer needs to make sure that it can also sustain axial loads during various drilling and production operations. Following loads comes under installation load category. One important assumption for installation loads is that it assumes casing just lowered in hole not yet cemented. Thus only one end at the top is fixed end while other end at the bottom of casing is free for movement.

A. Self-Weight If Casing in Air

Self string weight is own weight of casing hanging in hole due to effect of gravity. Self weight of string depends of depth of drilled section in which casing is to be installed and weight per unit length of the casing.

\[ W_{\text{total, lb}} = W_{(ppf)} \times L_{\text{feet}} \]
B. Buoyant Force

Buoyant forces are compressive forces acting the bottom of the casing. It supports the casing weight. This load arises due to differential area at the casing bottom and hydrostatic pressure of fluid.

C. Bending Load

Bending loads on casing induces due to curved portion in the wellbore. Bending load has its unique nature. Its compressive on inner wall of the casing while its extensive on external wall of the casing. Amount of bending will depend on curvature of the wellpath.

D. Dynamic Drag Load

This kind of load arises when object is in motion. When casing is running inside the well generally it contacts the wellbore wall. The velocity profile at point of contact of casing and wellbore generates axial and tangential force components. Drag loads mainly depends upon value of friction factor. It can be concluded that dynamic drag depends upon wellbore geometry, type of mud system and area of contact.

Friction Factor Values for Calculation:

<table>
<thead>
<tr>
<th>Type of Mud</th>
<th>Open Hole</th>
<th>Cased Hole</th>
</tr>
</thead>
<tbody>
<tr>
<td>WBM (Barite)</td>
<td>0.30</td>
<td>0.30</td>
</tr>
<tr>
<td>WBM (Dolomite)</td>
<td>0.30</td>
<td>0.25</td>
</tr>
<tr>
<td>OBM</td>
<td>0.20</td>
<td>0.15</td>
</tr>
<tr>
<td>Brine</td>
<td>0.30</td>
<td>0.50</td>
</tr>
</tbody>
</table>

Table - Friction Factor Values (Courtesy- Shell Well Engineering Distance Learning Module, 2002)

E. Shock Load

Casing shock loads are generated when casing is in motion i.e. while running in or pulling out of hole. In this case, shock waves are generated at the point of contact. Actually tensile wave generate at the point of contact and travels in direction of motion of casing. If casing is running in the hole, then compression wave will travel above the point of contact while tension wave will travel below the point of contact. In case of pulling out of hole, tensile wave will travels upwards above the point of contact and compression wave travel below the point of contact.

As per guidelines by one of the top of operator, shock loads are to be calculated from peak casing run velocity which is assumed to be one half times of average casing running speeds. Average running speed may change with respect to operating conditions and geology of the area. Average running speed of 13 seconds per 40 feet joint (3.07 ft/sec). So the estimated velocity will be around 4.6 feet/min should be used.
F. Point Load
Point loads are result of pressure testing operations or green pressure tests.

G. Static Drag Load
Static drag load refers to remaining stresses after casing movement. It has influence on distribution of stresses after casing movement stops. Detailed casing history is required to know the static drag loads on casing string.

H. Service Loads
Loads acting on casing when it is cemented in place are cover under service loads. Here both of end of casing are fixed i.e. top end at wellhead and bottom end as cemented section. It is necessary to ensure that cemented casing should not fail under the resulting changes from changes in pressure, temperature and point loads.

i. Pressure Loads

<table>
<thead>
<tr>
<th>Axial Load</th>
<th>Radial Load</th>
<th>Tangential Load</th>
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<tbody>
<tr>
<td>Changes due to change in internal/external fluid densities</td>
<td>Live annulus</td>
<td>Live annulus</td>
</tr>
<tr>
<td>Changes in internal/external surface pressure</td>
<td>Stimulation operations</td>
<td>Stimulation operations</td>
</tr>
</tbody>
</table>

Pressure Loads

ii. Temperature Loads

<table>
<thead>
<tr>
<th>Axial Load</th>
<th>Radial Load</th>
<th>Tangential Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tubular expansion/contraction</td>
<td>Annulus fluid expansion</td>
<td>Annulus fluid expansion</td>
</tr>
<tr>
<td>Annulus fluid expansion</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Temperature Loads

iii. Point Loads

<table>
<thead>
<tr>
<th>Axial Load</th>
<th>Radial Load</th>
<th>Tangential Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production packer load/Retrievable packer load</td>
<td>Retrievable packer load</td>
<td>Retrievable packer load</td>
</tr>
<tr>
<td>Conductor casing load</td>
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Point Loads