Investigation of conventional rotary drilling and casing drilling technique with comparison of drill string and casing stresses during drilling

Thesis

Bacsó Tamás

Consultants:
Dr. Federer Imre egyetemi docens
Feczkó Zsolt okl. olajmérnök

9th May, 2014
Szakdolgozat kiírás
"Intézeti igazoló lap szakdolgozat/diplomamunka benyújtásához"
# Table of contents

1. Introduction .................................................................................................................. 5
2. Phrasing .......................................................................................................................... 6
2.1. Conventional Drilling .................................................................................................. 6
2.2. Drill String .................................................................................................................... 7
2.3. Kelly .............................................................................................................................. 8
2.4. Drill pipe ....................................................................................................................... 8
2.5. Drill collars ................................................................................................................... 9
2.6. Stabilizers ................................................................................................................... 11
2.7. The bit ......................................................................................................................... 11
2.8. Tool joints for Conventional drilling .......................................................................... 12
2.9. Conventional bottom-hole assembly, BHA ............................................................... 13
2.10. Casing string ............................................................................................................. 15
3. Casing Drilling ............................................................................................................... 18
3.1. General introduction .................................................................................................. 18
3.2. Tool joints for casing drilling ................................................................................... 19
3.3. Casing drilling equipment .......................................................................................... 22
3.4. Casing Drive System .................................................................................................. 23
3.5. Top Drive .................................................................................................................... 24
3.6. Casing Alternatives .................................................................................................... 25
4. Stress analyses of conventional rotary and casing drilling technique with comparison ....... 27
4.1. Requisitions which influences to drilling rods ............................................................. 27
4.2. Calculation of loads and requisitions ......................................................................... 28
4.2.1. Drill string design .................................................................................................... 28
5. Calculations of Conventional drill string and casing stresses during drilling .................. 37
5.1 Conventional Rotary Drilling ....................................................................................... 38
5.2 Casing Drilling ............................................................................................................. 43
6. Comparison of conventional drill string and casing stresses during drilling ................. 47
6.1 Comparison of calculation results in the course of conventional rotary drilling and casing drilling 52
7. Conclusion .................................................................................................................... 59
8. Köszönetnyilvánítás ...................................................................................................... 62
1. Introduction

The aim of my thesis to determine and introduce loads and requisitions which are emerged on drilling rods in the course of conventional and casing drilling. This essay seems to be exciting because the most common and oldest drilling technique is compared with a relatively new drilling technique which is casing drilling.

I chose this theme because as far as I know a similar comparative investigation is not made up to this point and I reckon it is worthy to take up with this question because it can be based onto a future drilling design program.

In the first part of my essay I introduce how a conventional drilling and a drilling with casing is built up, what the general construction of conventional and casing drilling technique is and how a drilling process is going on. Then I specify ultimate differences between conventional and casing drilling tools and equipments.

In the second part of essay I determine and resemble what kind of loads, requisitions and stresses have an effect on rods during drilling which can be emerging. The requisitions which work up to rods: collapse pressure, tension and torsion on drill string, shock loading, buckling or bending forces, tensile, load on drill pipe, torque limit and pipe body stretch.

To determine these stresses and loads I applied well-known computational methods. The base data for drilling rods are made from Drilling Data Handbook. The results are interpreted and evaluated which are performed on next chapters.
2. Phrasing

2.1. Conventional Drilling

The conventional drilling is the oldest (Drake, 1856) and the most prevalent drilling technology at these days. It is a type of oil and gas excavation in which a well is drilled vertically from the surface to the reservoir zone. This drilling technique is high-powered and rotary drilling. Generally a rotary drilling is based on loaded bit to bottom-hole and transmitting of torque. In addition it can be operated by bottom-hole driving or surface driving mechanism.

In case of bottom-hole driving the drill string can be seemed as a tube-pillar which does not rotate. It is only used to be flushing the hole and keep moving on motor. Functionally on the surface driving there is a rotary table where driving-gear is horizontally whirling and rotary movement is transmitted to bottom-hole bit by rotary shaft. More modern rigs are equipped with Top Drive which will be given an introduction later in phase 2.2.5. Drilled cuttings are flushed to the surface by drilling mud which can be water-based or oil-based and bentonite clay, polymer, foam or a combination of these.

Simultaneously with rock-wrecking, drilling mud is pumped from active tank then it is forwarded to swivel across standing pipe sequentially it secedes form circulating valve of bit to annular. When cuttings with drilling fluid reached to surface, flow to slush pit then it will be separated across shale-shaker hereby the cleaned mud will be pumped to recirculate to the borehole. I must mention that other important functions of mud are cooling and lubricating to bit, ensuring the stability of formation. [1]
2.2. Drill String

To begin with a drill string is used to transmit mechanical energy and torque to the bit. A conventional drill string is a mechanical linkage connection so that the bit on bottom to the rotary drive system on the surface. Drill string can be perceived as a large-pressure tapping, multi-elements container which is encumbered by pressurized flushing and torsional, bending, pressing stresses.

Besides one of the most important property that has to be put up with more stresses with safety which generally are grown up in direct ratio with depth because a windup of broken rod is uncertain upcome and what is more it consumes high costs. In occasion of conventional drilling, the drill string consists of Kelly, drill pipe, drill collars, bit and accessories. Accessories mean that heavy-walled drill pipe, stabilizers, reamers and other equipments.
2.3. Kelly

The first important part of string is the Kelly (Figure 2.). It is the most upper part of string but according to someone’s opinion, is not directly part of drill string. On the other hand the Kelly is a rotating link between the rotary table and drill string. It provides as the pre-requisite requirement for drilling which its main functions are: transmitting rotation and weight-on-bit to the bit, supporting weight of drill string, connecting to swivel and conveying drilling mud from the swivel to drill string. The average length of Kelly can be from 12.2 to 16.7 meters with cross section such as triangular, square and hexagonal.

![Figure 2: Kelly](http://www.jaoilfield.com)

(Source: http://www.jaoilfield.com)

2.4. Drill pipe

Drill pipe is used to apply mechanical energy to the bit as well as to provide a hydraulic conduit for the drilling fluid. We can choose the most available drill pipe we need to know their yield strength (Table 1.). The grade of drill pipe describes the minimum yield strength of pipe. This value is highly important as it is used in burst, collapse and tension calculations for determining the correct grade of pipe to be used. In most drill string design the pipe grades is increased for extra strength rather than increasing the pipe weight.
Table 1: Designations of Drill pipe
(Source: Hussain Rabia: Well Engineering & Construction)

<table>
<thead>
<tr>
<th>Grade</th>
<th>Letter Designation</th>
<th>Alternate Designation</th>
<th>Minimum Yield Strength (PSI)</th>
</tr>
</thead>
<tbody>
<tr>
<td>D</td>
<td>D</td>
<td>D-55</td>
<td>55 000</td>
</tr>
<tr>
<td>E</td>
<td>E</td>
<td>E-75</td>
<td>75 000</td>
</tr>
<tr>
<td>X</td>
<td>X</td>
<td>X-95</td>
<td>95 000</td>
</tr>
<tr>
<td>G</td>
<td>G</td>
<td>G-105</td>
<td>105 000</td>
</tr>
<tr>
<td>S</td>
<td>S</td>
<td>S-135</td>
<td>135 000</td>
</tr>
</tbody>
</table>

Drill pipe can be classified to account for the degree of wear. Drill pipe classification is a high priority factor in design and use of drill pipe since the degree of wear will affect the pipe properties and emerged strengths. The API has established guidelines for pipe classification in API RP7G. A summary of the classes follows:

- **NEW**: There is no wear. It has never been used.
- **Premium**: Uniform wear and the minimum wall thickness of 80% of a new pipe.
- **Class 2**: A minimum wall thickness of 65% with all the wear on one side so long as the cross sectional area is the premium class.
- **Class 3**: Drill pipe with a minimum thickness of 55% with all the wear on one side.

2.5. Drill collars

Furthermore an important part of drill string is drill collar (Figure 3.). The drill collars are predominant component of bottom-hole assembly as BHA. Both slick and spiral collars are used at industry (Figure 4.). The drill collars are needed to use as a long collar-pillar that we can gain available drilling velocity and it can resist to requisitions. The sizing of drill collar consists of a sizing of thread of joining bit. To keep clear of breaking that endurance limit is needed to increase. In normal case the drill collars have to be oversized.
In that areas where differential sticking is a possibility spiral drill and spiral heavy-walled drill pipe can be used in order to minimize contact area with the formation. The drill collars are the first section of drill string which is needed to be designed. At undermentioned table we can see what is recommended DC size to available hole-section:

<table>
<thead>
<tr>
<th>Hole section (inch)</th>
<th>Recommended Drill Collars OD (inch)</th>
</tr>
</thead>
<tbody>
<tr>
<td>36</td>
<td>9 1/2 + 8</td>
</tr>
<tr>
<td>26</td>
<td>9 1/2 + 8</td>
</tr>
<tr>
<td>17 1/2</td>
<td>9 1/2 + 8</td>
</tr>
<tr>
<td>16</td>
<td>9 1/2 + 8</td>
</tr>
<tr>
<td>12 1/4</td>
<td>8</td>
</tr>
<tr>
<td>8 1/2</td>
<td>6 1/4</td>
</tr>
</tbody>
</table>
2.6. Stabilizers

The next mentioned devices are followed by stabilizers (Figure 5.). These tools are placed above the drill bit to control hole deviation and prevent differential sticking. There are basically two types which are rotating or not-rotating stabilizers. The rotating stabilizers include an integral blade, sleeve or welded blade stabilizers. Integral blade stabilizers are machined from solid piece of high strength steel alloy. It can be straight or spiral. The non-rotating stabilizers comprise a rubber sleeve and mandrel. The sleeve is designed to remain stationary while mandrel is rotating. This type is used to prevent reaming of the hole during operation and to protect drill collars against wall contact wear.

![Integral Spiral Blade Stabilizer](http://www.pdsdrilling.com)

![Integral Straight Blade Stabilizer](http://www.pdsdrilling.com)

**Figure 5:** Stabilizers

(Source: http://www.pdsdrilling.com)

2.7. The bit

Finally the drilling bit is attached to the end of string. It breaks the rock formations when drilling a wellbore. Drill bit has some nozzles to allow for the expulsion of the drilling mud with high velocity and high pressure to help clean the bit and help to break apart the rock.

There are kind of bit such as tricone roller (Figure 6.) bit or PDC bit (Figure 7.). The teeth break rock by crushing as the rollers move around the bottom of the borehole. A polycrystalline diamond compact (PDC) bit has no moving parts and works by scraping the rock surface with disk-shaped teeth made of a slug of synthetic diamond attached to a tungsten carbide cylinder. Precession of bit means sagging of drilling rod which depends on loadability of bit and type of rocks.
2.8. Tool joints for Conventional drilling

The one of the most significant parts of drill pipe are tool joints. These determine the efficiency of drill rods connection. Drill pipe joints are an assembly of three components which are drill pipe with plain-ends and a tools joint at each end (Figure 8.). Drill pipes are connected together by applying a certain calculated torque which depends on the size of pipe and its grade. API tool joints have minimum yield strength of 120,000 PSI regardless of the grade of drill pipe they are used on (E, X, G, S). API sets tool joint torsional strength at 80% of tube torsional strength. The make-up torque is determined by pin ID. The make-up torque is 60% of the tool joint torsional capacity. [11][10]
There are different threads and connections type in conventional drilling. The most common thread style is NC, numbered connection (Figure 9.). This thread has a V-shaped form and is identified by pitch diameter, measured at a point 5/8” from the shoulder (Figure 10.).

Nominal weight of drill pipe is always less than the actual weight of drill pipe and tool joint because of the extra weight added here by the tool joint and due to extra metal added at the pipe ends to increase the pipe thickness. This increased thickness is called “Upset” and is used to decrease the frequency of pipe failure at the meeting point between pipe and tool joint. Drill pipe have internal upsets (IU), external upset (EU) and internal-external upset (IEU).

2.9. Conventional bottom-hole assembly, BHA

Generally the BHA contains drill collars, stabilizers and other equipments. BHA is needed to design to all wells - vertical or deviated, too – to control the direction of the well in order to achieve the target objectives. There are five basic types of bottom-hole assembly (Figure 11.):

1. Pendulum assembly
   a. It makes use of the gravitational effects acting on the bit and the lower part of BHA to maintain vertical hole. It is achieved by placing the first string stabilizers approximately 12-18 meters above the bit.
2. Packed bottom-hole assembly
   a. It is used to maintain vertical hole when higher weights are used. A packed assembly incorporates a near-bit stabilizer and string stabilizer further 10-20 meters from the bit. It is often used where formation dip has in angle building tendency.

3. Rotary build assembly
   a. It is usually used to build hole angle after initial steering runs on deviated wells. It is based on fulcrum rule. Near bit stabilizer is incorporated then a first string stabilizer is located on a further 12-13 meters from the bit. It is followed by a further string stabilizer 10 meter above. By applying weight to the bit, the bending drill collars above the near bit stabilizer causes the bit to be loaded on the high side of hole and thus angle increasing are achieved.

4. Steerable assembly
   a. There are two types: Bent motor housing tool and double tilted U-joint housing.
      i. These are run stabilized and can be used to drill tangent sections in addition to build section. The advantage of it that can be used to make corrections to azimuth and inclination in steering mode and can be used maintain direction in rotary mode.

5. Mud motor and bent Sub assembly
   a. It is typically run for performing initial kick-off and build sections of deviated wells. [11]

There are different variant to collate a bottom-hole assembly what can be seen below:
2.10. Casing string

In that case of conventional drilling, a casing string must be used because it is a high important part of further precession of drilling. It must be taken great care to design and install effective well casing system. During drilling and production operations, all groundwater-bearing rock formations are protected from the contents of the well by layers of casing pipe and cement sheaths. The casing string ensures that:

- Keeping the hole opened and providing a support for weak or fractured formations.
- Isolating porous media with different fluid or pressure regime from contaminating the reservoir zone.
- Preventing contaminations from surface water zones.
- Providing suitable connection for the well-head equipment. The casing serves to connect the blowout preventer (BOP) which is used to control the well while drilling.
- At least but not last providing a hole of known diameter and depth of facilitate the running of testing and completion equipment.
A well construction can have between three and four main components depending on a design of well (Figure 12.). These components include conductor, surface, intermediate and production casing.

The first casing string is usually called as Conductor casing. It is run from the surface to a shallow depth to protect near unconsolidated formations or water-zones and provide protection against shallow gas flows. It is usually installed extends between 25 and 45 meters below surface.

Conductor casing is followed by the Surface casing is installed and cemented, the hole is drilled deeper and surface casing is installed and cemented in place. The main purpose of it is for well control. The Surface casing can be set anywhere up to 600 meters or more. It is also cemented all the way from the bottom of the hole to ground surface, completely isolating the well from groundwater aquifers. The Surface casing is installed with the deepest local groundwater aquifers in mind and regulated accordingly.

Generally it is followed by the Intermediate casing which is set in the transition zone below over-pressured zone to seal off a severe-loss zone or protect against problem formation such as mobile salt zones or caving shales. Good cementation of casing must be ensured to prevent communication behind the casing between the lower HC zones and upper water formations.

The Production casing is the final length of steel pipe used in wellbore construction. The Production casing typically runs the entire depth of the well and may be cemented in place all the way to ground surface. The primary purpose of production casing is to isolate the zone containing natural gas from other subsurface formations. It’s also used to pump hydraulic fracturing fluids into the producing formation without contacting other formations along the wellbore. [11]
Figure 12: Casing string design

(Source: http://www.wajr.com)
3. Casing Drilling

3.1. General introduction

The Casing drilling is one of the greatest development in drilling industry. It was developed by Tesco Drilling Technology which aims to reduce costs, improves drilling efficiency and minimize hole problems.

It involves drilling and casing a well simultaneously. There are many problems and situations where can be used such as lost circulation, well-control incidents, borehole stability and further problems which are sloughing and swelling formations and swabbing but the main causes why was developed that were cost reducing and drilling efficiency improving.

Drilling with casing technology uses newy rig and downhole equipment that functions as a kind of drilling system where casing tube is used to transmit mechanical and hydraulic energy to the drill bit. A wireline retrievable drilling assembly that is latched into the casing eliminates the need for tripping with a conventional drill string.

In other cases it is difficult to run the casing after the drill string is tripped out because of poor borehole quality. Some of these problems caused by borehole stability issues are directly attributed to drill string vibrations. The casing drilling system can reduce these incidents by eliminating tripping operations and providing a drill string that is less prone to vibrations.

In these days there are two methods of casing drilling technology. According to first one that latched retrievable BHA is inside casing tube that incorporates a motor to drive a conventional bit and under-reamer (Figure 14.). Accordance with the second one, it ensures to rotate the casing at surface system incorporating an internal casing drive system and a drillable cement in place drilling BHA (Figure 13.).

The casing string is fabricated in sections that are usually about 12 meters long and screwed together to form longer lengths of casing, called casing strings. [4]
3.2. Tool joints for casing drilling

The one of innovation is torque ring which is a pressure-actuated, metal-to-metal sealing system. When it is made up, initial contact force is established between the pin end and the fulcrum center torque ring.

In addition, internal pressure increases sealing contact force beyond axial loads and pressure of accepted string design limits. To make up the casing a special insertion tool was used to install and seat the ring in the J-area prior to coupling. When torque begins to rise quickly, the pin nose has shouldered up to the rings.

The function of torque ring that takes up make-up torque which is issued at between joints (Figure 15.). Make-up torque is the recommended amount of torque to apply when tightening a drill pipe prior to running it down the hole. The amount depends on the connection, the inside diameter of the pin and the outside diameter of the box. A lot of common thread problems can be traced back to improper make-up torque. If too little then connections could continue to tighten during drilling and over tighten (meaning over torque) causing box shoulders to mushroom and pins to stretch and break. Too much torque applied at the table can lead directly to pin breakage.

The efficiency of tool joints is the ratio of the critical cross-section of the connection (pin or box end) to the steel cross-section of the pipe body (Figure 17.). The efficiency also represents the ratio of the tension at the yield strength of the connection to the tension at the yield strength of the pipe body unless the coupling is of a different grade form the pipe body.
Since the API 5C3 formulas for calculating the strength of API round and buttress joints employ considerations of pull-out and only account for the minimum tensile strength, it is not possible to apply the concept of efficiency to these connections for casings.

*Efficiency is under 100 means that the connection is weaker than the pipe body!*

The efficiency hence serves to calculate three parameters:
- The critical cross-section of the joint
- The tension at yield stress of the joint
- The minimum tensile strength of the joint

To determine a Make-up torque for a chosen joint we can find some tables in API database.

**Buttress:**

In sizes 4 ½” through 13 3/8” make-up torque values should be determined by carefully noting the torque required to make up each of several connections to the base of triangle then using the torque value thus established, make up the balance of the pipe of that particular weight and grade in the string (Figure 16.).

**API STC or LTC:**

In sizes 4 ½” through 13 3/8” make-up torque values listed are optimum. The minimum torque should be not below 75 % of the optimum value. The maximum torque should be not over 125 % of the optimum value.

In sizes 16”, 18 5/8” and 20” values listed are minimum values. Make-up shall be to a position on each connection represented by the thread vanish point on 8-round and the base of triangle on buttress thread using the minimum torque. These “old-fashioned” thread types are not recommended for complex oil or gas wells, especially not recommended for casing drilling.

**Grant Prideco:**

Make-up torque values listed are optimum values. Minimum value is generally 5 to 10 percent below optimum value and maximum value is generally 5 to 10 percent over optimum value.
**Hydril:**

Make-up torque values listed are optimum values for SLX, 511, 533, CS, PH-4, PH-6. For 563, the torque is a minimum make-up torque and applies to all grades of steel. For 521 listed values are minimum make-up torque. A field target torque 10% over minimum is recommended.

**Vallourec and Mannesmann:**

Make-up torque values are optimum values. Minimum value is 10 percent below optimum value and maximum is 10 percent over optimum. [10]

---

**Figure 15:** Casing tool joints [13]
(Source: http://www.tenaris.com)

**Figure 16:** Buttress thread form for Casing joints
(Source: Institut Francias du Pétrole Publications: Drilling data handbook)
Another important aspect is the connections are tightened prior to running. For the efficiency operating it must be always keep clear and lubricate with a good grade of tool joint compound. [14]

### 3.3. Casing drilling equipment

Its significant part is the casing drilling equipments as CDE (Figure 18.). It eliminates the conventional drill string by using the casing as the hydraulic conduit and means of transmitting mechanical energy to the bit. A short wireline retrievable BHA generally consists of a pilot bit and expandable underreamer which are used to drill a hole of adequate size to allow the casing to pass freely.
The pilot bit and underreamer pass through the drill-casing and drill a hole that provides adequate clearance for the drill-casing and subsequent cementing. The BHA is attached to a drill lock that fits into a full bore landing sub on the bottom of the casing in such a way that it can be retrieved with a wireline without needing to trip pipe out of the well. [2]

The wireline retrievable drill lock assembly is the heart of the casing drilling system. It lands in a lower section of casing consisting of a casing shoe, torque lock profile and axial no-go and lock profile located in a specially machined collar section.

The drill lock engages both a fluted profile to transmit rotational torque from the casing to the drilling assembly and an internal flush no-go and axial lock profile to transfer compressive and tensional loads to the BHA. A stabilizer on the BHA positioned opposite of the casing shoe reduces lateral motion of the assembly inside the casing.

The casing shoe is normally dressed with hard material to ensure that a full gauge hole is drilled ahead of the casing but it provides a torque indication if the underreamer drills undergauge. Centralizers on the casing stabilize it within the borehole and prevent wear on the couplings. [6]

### 3.4. Casing Drive System

Casing drilling is executed by a special rig development which can be perceived as a modified conventional drilling rig. One of the most important that is a casing drive system which provides safe, non-threaded connection between top-drive and casing string. Casing drive system is run hidraulically and it transmits torque and mud to the casing string.

There are two types of Casing Drilling System. The first type is internal for greater casing radius and external for smaller casing radius. It is controlled automatically from the drillers cabine with Programmable Logic Control.

Casing Drive System comprises a quick connect slip assembly that grips either the exterior or interior of the casing, depending on pipe size and attaches the casing to the top drive without threaded connections to prevent thread damage. An internal spear assembly provides a fluid seal inside the pipe. The Casing Drive System is fundamentally operated by a top-drive system that is suspended from the derrick block therefore the whole top drive rotary mechanism is free to travel up and down. A top drive differs radically from the more conventional rig-floor rotary table and Kelly method of turning the drill string because it allows drilling to be performed with three joints at a time instead of single joints.
of pipe. It also allows drillers to quickly engage the rig pumps or the rotary drive while tripping pipe which minimizes both the frequency of stuck pipe and the cost per incident. [8]

3.5. Top Drive

Generally the Top drive is a mechanical device as a motor that is suspended from the derrick of the rig. Substantially it is an alternative to rotary table. It is located on the swivel place and allows a vertical movement up and down the derrick. These power swivels boast at least 1,000 horsepower that turn a shaft to which the drill string is screwed. It can be imaged as a replacing traditional Kelly or rotary table.

There are advantages of using Top Drive (Figure 19.). First is that allows the drilling rig to drill longer sections of a stand of drill pipe. A rotary table type rig can only drill 9.1 m sections of drill pipe while a top drive can drill 18 - 27 meters. A triple being three joints of drill pipe is screwed together depending on the drilling rig type. Having longer sections of drill pipe allows the drilling rigs to drill deeper sections of the wellbore, thus making fewer connections of drill pipe. [12]

Another advantage of top drive systems is time efficiency. When the bit progresses under a Kelly, the entire string must be withdrawn from the well bore for the length of the Kelly drive. With a top drive, the draw works only has to pick a new stand from the rack and make two joints. The savings in time reduces the risk of a stuck string from annulus clogging. Top drive increases safety and efficiency in addition it provides several key benefits such as:

- A top drive is capable of drilling with three joints stands, instead of just one pipe at a time.
- Top drives typically decrease the frequency of stuck pipe, which contributes to cost savings.
- A top drive allows drillers to more quickly engage and disengage pumps or the rotary while removing or restringing the pipe.
- Top drives are also preferable for challenging extended-reach and directional wells.
Top drives are usually completely automated, rotational control and maximum torque as well as control over the weight on the bit.

Figure 19: Construction of Top drive
(Source: www.streicher-drillingtechnology.de)

3.6. Casing Alternatives

There is an alternative solution to save money which is running of a liner string is run into the well instead of a casing string, it is called Casing Alternatives (Figure 20.). While a liner string is very similar to casing string in that it is made up of separate joints of tubing, the liner string is not run the complete length of the well. A liner string is hung in the well by a liner hanger, and then cemented into place. Using casing for drilling has shown significant potential compared with conventional drilling.
**Figure 20:** Conventional Drilling vs. Casing Drilling

(Source: www.offshore-mag.com)
4. Stress analyses of conventional rotary and casing drilling technique with comparison

4.1. Requisitions which influences to drilling rods

The requisition which has an effect on rods is complex. The most important parts are tensile, torsional, twisting and bending (and pressing) forces. One part of stresses are temporary as long as the other ones are variable pendulous. Drilling-rod is needed to prototion to this repeating load. I have to take into consideration tenacious substance and fatigue limit.

Swing of rod is generated by length changing which is arisen as a result of wobble of bending, centrifugal, longitudinal and pumping-pressure. It can lead to critical rev that increases the requisition of drilling rod.

The rods, which are in resonance, are impressed by bending force between interchanges it leads to fatigue of rod or lasting bending. Hereby bending rod can be starting to wear in several place and hole can be dismantled, either.

Further on, vertical-longitudinal and torsional-transversal swing can be generated which are perpendicular to axis of rod. To alleviation of swings, we can use rubber subs which are built in between bit and drill-collar. It reduces the amplitude of swings thus effectivity of bits can be increased with 50 %. Peak requisition is significantly reduces by shock-absorver than with this durability of joining of drill-collar can be increased. Critical rev of transversal swings are determined by amount of stresses which come up in rods and property of drilling mud. Powerlessness is increases by flushing inside rod, swing can be reduced with rubbing outside rod. Critical rev depends on longitudinal efforts, from pressing requisition that is reduced.
4.2. Calculation of loads and requisitions

4.2.1. Drill string design

There are criteria which used in a drill string design which are:

A. Collapse
B. Tension
C. Severity analysis

Burst pressure is not considered in drill string design due to the fact that burst loads and back-up loads are provided by the same fluid in the well. Therefore under normal circumstances there are no effective burst load, expect during squeeze operations where surface pressure is applied. If squeeze pressure is high, back-up annulus pressure would normally be applied to reduce the effective burst pressure.

Collapse and tension considerations are used to select the pipe weights and couplings. Slips crushing affects the tension design and pipe selection. Dogleg analysis is performed to study the fatigue damage resulting from rotation in doglegs. Dogleg analysis may not affect the selection of the pipe.

According to API R7G the design criteria is that:

1. Anticipated total depth with drill string
2. Hole size
3. Mud weight
4. Desired safety factor in tension, in collapse and margin of overpull
5. Length of drill collar
6. Desired drill pipe sizes and classes
A. Collapse Design

This criteria is used as a worst case for the collapse design of drill pipe is typically DST. The maximum collapse pressure should be determined for an evacuated string with mud hydrostatic pressure acting on the outside of the drill pipe. Using of this criterion accounts for incidence of a plugged bit or failure to fill the string when a float is used to during trips into the hole.

I. Drill Stem Testing – DST

\[ P_c = \frac{L P_1 (L - Y) P_2}{19,251} \]

where,

- \( P_c \): Collapse pressure
- \( Y \): depth of fluid inside drill pipe
- \( L \): total depth of well

If drill pipe is completely empty, \( Y=0 \) and \( P_2=0 \) then drilling fluid density inside pipe is the same as that outside drill pipe \( P_1=P_2=P \).

If a drill string can be looked on as a cavernous pillar in that case the air-depression influences to exterior surface of pillar then it will be become in isotropic tension. In accordance with the three main tensions will be equal with a pressure which is suitable for given depth.

In addition if tensions, which impact inside pillar, can be determined beyond that we need to add further pressure generated by air-depression. With growth of exterior pressure, the neuter section is going upward. It means that if pillar is cut at \( \delta_n = 0 \) point balance will not be disintegrated.

Subsequently the status of neuter section depends on exterior pressure and depth of draught of drill pipe. It was the most important conclusion of Klinkenberg. What is more if hydrostatical pressure is equal inside and outside suspended drill string so there is a flushing interval, we need to take into consideration that hydrostatic pressure is continuously growing with depth in line ratio.

- \( P_1 \): fluid density outside the drill pipe
- \( P_2 \): fluid density inside the drill pipe
B. Tension Design

The tension load is evaluated using the maximum load concept. Buoyancy is included in the course of design to represent realistic drilling conditions. The tension design is established by consideration of the following:

**Tensile forces:**

I. Weight carried
II. Shock loading
III. Bending forces

I. Weight carried

![Diagram showing tension design](image)

**Figure 21:** Tension Design

(Source: Hussain Rabia: Well Engineering & Construction)

The biggest tension on the drill string occurs at the top of joint at the maximum drilled depth.

\[ P = \left[ (L_{dp} w_{dp} L_{dc} w_{dc}) \right] BF \]

where,

- \( L_{dp} \): length of drill pipe
- \( W_{dp} \): weight of drill pipe
- \( W_{dc} \): weight of drill collars
- \( L_{dc} \): length of drill collars
- BF: buoyancy factor

The value of \( P \) is the total weight of submerged drill string. It must be mentioned that it is highly depends on mud weight. The influence of mud weight is performed by the BF as buoyancy factor. Actually the drill string can be designed to maximum yield strength to prevent drill pipe from yielding and deforming. To can progress with calculation buoyancy factor is needed to determine. Drill collars are used to provide weight for use at the bit and at the same time keep the drill pipe in tension. Drill collars have a significantly greater stiffness when compared to drill pipe as such can be run in compression.
On the other hand the drill pipe tend to buckle when run is compression. Repeated buckling lead to early drill pipe failure by fatigue. Since elastic member can only buckle in compression and fatigue failure of drill pipe can be eliminated by maintaining drill pipe in tension. In practice weight on bit should not exceed 85% of the bouyed weight on the collars.

Determination of buoyancy factor is: \( BF = 1 - \frac{\rho_{\text{mud}}}{\rho_{\text{steel}}} \)

At the yield the drill pipe has:
1. deformation which made of elastic and plastic deformation
2. permanent elongation
3. permanent bending

I need to keep in mind to prevent these phenomena: API recommends that use of maximum allowable design load (Pa) which is given by: \( P_a = 0.9 \times P_t \) where,

\( P_a \): maximal allowable design load
\( P_t \): theoretical yield strength from API tables

MOP (margin of overpull) = \( P_a - P \)

The MOP is the minimum tension force above expected working load to account for any drag or stuck pipe. When deciding on the magnitude of MOP or DF, the following steps are needed to be considered:
- Overall drilling conditions
- Hole drag
- Likelihood of getting stuck

That we can onwards further on need to determine the maximum hole depth:

From spring by aforementioned equations the maximum hole depth can be determined:

\[
L_{DP} = \frac{0.9 P_t - MOP}{W_{DP} BF} - \frac{W_{DC}}{W_{DP}} L_{DC}
\]
**Tension design**

1. Determining maximum design load: \( P_a = 0,9 \times \text{Minimum Yield Strength} \)

2. Calculating the total load of surface using: \( P = [(L_{dp} w_{dp} L_{dc} w_{dc})] BF \)
   a. MOP = \( P_a - P \)
   b. The maximum length of drill pipe:
      \[
      L_{DP} = \frac{P_t \times 0,9 - MOP}{W_{DP} \times BF} - \frac{W_{DC}}{W_{DP}} \times L_{DC}
      \]

**II. Shock loading**

There is an additional tensile force generated by shock loading which is given by

\[
Fs = 1500 \ W_{DP}
\]

where, \( W_{dp} \) is weight of drill pipe.

**III. Bending/Buckling**

Buckling means when the compressive load and casing geometry creates a sufficient bending so that the casing becomes unstable. When it became unstable, it is incapable of supporting the compressive load without lateral support but it does not mean that there is a structural failure. There is nothing destructive in the fact that the casing buckles, but the buckling causes two effects that may be detrimental. The lateral contact forces between the drill-casing and borehole wall can cause wear on the casing and will increase the torque that is required to rotate the casing.

Secondly the buckling causes the casing to assume a curved geometry within the borehole that increases the stress in the pipe and may increase the tendency toward lateral vibrations. For casing drilling it is important to determine whether or not the casing is buckled and if so whether or not the buckling is sufficient to cause a problem (wear, high torque, or high stress).

Moreover, in straight holes the compressive load that causes buckling is determined by the stiffness of the pipe, the lateral force of pipe weight and distance from the bore hole wall. In a perfectly vertical hole, the portion of the drill-casing that is in compression is
always buckled if the bore hole does not provide lateral support through centralizers as drill collars are buckled in a vertical hole.

If the well is straight, the normal wall contact force from the pipe laying on the low side of the hole provides a stabilizing influence and increases the compressive load that can be supported before the drill-casing buckles. The other additional tensile force generated by bending which is given by:

$$F_B = 63 \varnothing W_{dp} D$$

where,

- \(W_{dp}\): weight of drill pipe
- \(\varnothing\): dogleg severity
- \(D\): outside diameter of drill pipe

### a. Slip Crushing

The maximum allowable tension load must be designed to prevent slip crushing of the pipe. On the score of analysis of the slip crushing, Reinhold and Spini calculated the relationship between the hoop stress caused by the action of the slips and tensile stress in the pipe resulting from the load of the pipe hanging in the slips.

$$T_S = TL x \frac{SH}{ST}$$

where,

- \(T_S\): Tension load due to slip crushing
- \(TL\): Load line tension
- \(\frac{SH}{ST}\): Hoop stress, tension stress ratio as derived from:

$$x(1 + x)^n = \left[ 1 + \frac{DK}{2L_S} + \left(\frac{DK}{2L_S}\right)^2 \right]^{0.5}$$

where,

- \(SH\): Hoop stress
- \(ST\): Tensile stress
- \(D\): OD of the pipe
- \(K\): later load factor on slips \(\frac{1}{\tan(\gamma + \alpha)}\)
y: Slip taper
z: Arctan μ
Ls: length of slips
μ: coefficient of friction

When all tension loads are plotted, the pipe grade selected in the collapse calculation can be assessed and modified for the tension requirements. It is usually preferable to increase the grade rather than the weight as increasing weight usually has negative effects in terms of clearance and pressure drop. Couplings are selected based on the tension design.

**Additional Design variable - Pipe stretch of drill pipe:**

On hand the stretch of drill pipe is dued to own weight:
\[ A_1 = 0.0785 \frac{L^2}{2E} \]

On the other hand, it is dued to buoyancy in mud:
\[ A_2 = -\frac{d_b L^2}{E} (1 - \vartheta) \]

At least but not last one, it depends on temperature [10]:
\[ A_3 = 11.88 \times 10^6 \text{ L dt} \]

**Total stretch** (A) = \( A_1 + A_2 + A_3 \)
C. Dogleg Severity Analyses

I. Fatigue damage considerations

The most common type of drill pipe failure is mentioned above fatigue wear. Fatigue is the tendency of material to fracture under repeated cyclic stress and chemical attack. Practically it is an irreversible aging process that can not be detected early stage. Drill pipe fatigue wear usually occurs because the outer wall of pipe in a dogleg is stretched resulting additional tension loads.

Bending stresses cause the microscopic grains of material to slide over each other. At higher stress level, the grains start pulling apart, leaving microscopic cracks in the material. Rotations will simply connect these small cracks and produce larger cracks. With further loading major crack develops in the material and grows progressively until the pipe can no longer withstand the load. At this stage when the pipe is said to have failed in fatigue mode.

II. Position of pipe in well

The most fatigue failures occur within 1 meter from the tool joints because the slip marks which help to initiate fatigue cracks. Another typical site for crack initiation is the engaged threads of connection. Drill pipe is subjected to the same bending stresses during drilling or rotating off bottom through a dog-leg.

III. Dogleg Severity

Fatigue damage from rotation in doglegs is a significant problem if the severity is greater then the critical value for the tubulars used. The maximum permissible dogleg severity for fatigue damage considerations can be calculated using the following formula:

\[
\max D_s = \frac{432000}{\pi} \times \frac{\sigma_b}{ED} \times \frac{\tan(h)KL}{KL}
\]

\[
K = \sqrt{\frac{T}{EI}}
\]
where,

\[ E = \text{Young Modulus of elasticity} \]
\[ D = \text{Drill pipe OD} \]
\[ L = \text{Half distance between tool joints} \]
\[ T = \text{Tension load below th dogleg} \]
\[ \sigma_b = \text{Maximum permissible bending stress} \]
\[ I = \text{Drill pipe moment of inertia} \]

**IV. Vibration and harmonics stresses**

At least but not last one there are some drill string vibration and harmonics stresses. The drill string can be vibrated by Axial, Torsional and Transverse vibration. Axial vibration can be recognised by Kelly and whipping of the drill line. Torsional and transverse vibration can not see at rotary table.

Vibration of string means the frequency of force equal the natural vibration frequency of the drill string. Rotation of string at its natural resonant frequency result in excessive and rapid wear of the drill string and fatigue failure can be resulted. [12]

There are some methods to avoid or reduce the vibrations:

- Changing length of the collars or HWDP is needed to use.
- Use a shock-sub
- Avoiding rotating the string at the natural resonant frequency of the drill string.
5. Calculations of Conventional drill string and casing stresses during drilling

Base parameters to calculations about drilling techniques:

**Table 3: Typical base parameters about drilling pipe**

(Own editing by author, 2014)

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Unit</th>
<th>Conventional Drilling</th>
<th>Casing Drilling</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pipe body</strong></td>
<td></td>
<td><strong>PREMIUM CLASS</strong></td>
<td></td>
</tr>
<tr>
<td>Pipe diameter</td>
<td>in</td>
<td>5&quot;</td>
<td>9 5/8&quot;</td>
</tr>
<tr>
<td>Grade</td>
<td></td>
<td>E75</td>
<td>N80</td>
</tr>
<tr>
<td>Nominal weight</td>
<td>lb/ft</td>
<td>25,60</td>
<td>53,50</td>
</tr>
<tr>
<td>Wall thickness</td>
<td>mm</td>
<td>12,70</td>
<td>13,84</td>
</tr>
<tr>
<td>Inside diameter</td>
<td>in</td>
<td>4,00</td>
<td>8,535</td>
</tr>
<tr>
<td>Collapse resistance</td>
<td>MPa</td>
<td>79,00</td>
<td>45,60</td>
</tr>
<tr>
<td>Minimum Yield Strength</td>
<td>MPa</td>
<td>517,00</td>
<td>551,00</td>
</tr>
<tr>
<td><strong>Connection efficiency</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grant Prideco TCI</td>
<td></td>
<td></td>
<td>62,90</td>
</tr>
<tr>
<td>Hydril LX</td>
<td></td>
<td></td>
<td>77,60</td>
</tr>
<tr>
<td>Hydril 563</td>
<td></td>
<td></td>
<td>93,90</td>
</tr>
<tr>
<td>Vallourec &amp; Mannesmann</td>
<td></td>
<td></td>
<td>65,10</td>
</tr>
<tr>
<td><strong>Type of tool joint</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Type of tool joint (OD/ID/app weight)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NC50 (XH)</td>
<td>mm/mm/(kg/m)</td>
<td>161,90 / 95,30 / 40,00</td>
<td></td>
</tr>
<tr>
<td>NC50 (IF)</td>
<td>mm/mm/(kg/m)</td>
<td>168,30 / 88,90 / 40,70</td>
<td></td>
</tr>
<tr>
<td>5 1/2 FH</td>
<td>mm/mm/(kg/m)</td>
<td>117,80 / 95,30 / 42,14</td>
<td></td>
</tr>
<tr>
<td><strong>Drill collar</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OD</td>
<td>in</td>
<td>8,50</td>
<td>-</td>
</tr>
<tr>
<td>ID</td>
<td>in</td>
<td>2,50</td>
<td>-</td>
</tr>
<tr>
<td>Weight of DC</td>
<td>kg/m</td>
<td>234,43</td>
<td>-</td>
</tr>
<tr>
<td><strong>Hole</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Inclination</td>
<td>°</td>
<td>1,40</td>
<td>1,40</td>
</tr>
<tr>
<td><strong>Density</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mud density</td>
<td>kg/m³</td>
<td>1130</td>
<td>1130</td>
</tr>
<tr>
<td>Steel density</td>
<td>kg/m³</td>
<td>7850</td>
<td>7850</td>
</tr>
<tr>
<td><strong>Temperature</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average temperature on surface</td>
<td>°C</td>
<td>11</td>
<td>11</td>
</tr>
<tr>
<td>Average temperature gradient</td>
<td>°C/m</td>
<td>0,048</td>
<td>0,048</td>
</tr>
</tbody>
</table>
5.1 Conventional Rotary Drilling

1. Determination of Buoyancy factor:

\[ BF = 1 - \frac{\rho_{mud}}{\rho_{steel}} = 1 - \frac{1130 \text{ kg/m}^3}{7850 \text{ kg/m}^3} = 0.856 \text{ [-]} \]

2. Determination of Drill Collar’s length:

\[ L_{DC} = \frac{10^5 WOB}{BF \cos \alpha F_P N W_{DC}} = \frac{10^5 WOB}{BF \cos \alpha F_P N W_{DC}} \]

\[ L_{DC} = \frac{10^5 (20809) \text{ kg}}{0.856 \cos (1.4) (85) (234.43) \text{ kg/m}} \]

\[ L_{DC} = 122 \text{ m} \]

3. Determination of WOB that is desired weight on the bit:

\[ WOB = L_{DC} \times W_{DC} \times BF \times 0.85 \]

\[ WOB = 122 \text{ [m]} \times 234.43 \text{ [kg/m]} \times 0.856 \times 0.85 \]

\[ WOB = 20809 \text{ kg} = 20.8 \text{ t} \]

4. Determination of Drill Pipe’s length:

\[ L_{DP} = \frac{0.9 P_t - MOP}{BF W_{DP}} - \frac{W_{DC}}{W_{DP}} \times L_{DC} \]

\[ L_{DP} = \frac{0.9 \times 411690}{0.4535} \text{ [kg]} - \frac{32000}{234.43} \text{ kg/m} - \frac{(0.856)(38) \text{ [kg/m]}}{38} \times 122 \text{ [m]} \]

\[ L_{DP} = 3466.97 \text{ m} \]
5. **To increase the safety of drilling we need to use a safety factor which is assumed at SF= 1.7**

\[
L_{DP} = \frac{0.9 \cdot P_t}{BF \cdot W_{DP} \cdot SF} = \frac{0.9 \cdot \left(\frac{414690}{0.4535}\right)[kg]}{(0.859)(1.7)(38) \left[\frac{kg}{m}\right]}
\]

\[
L_{DP} = 2308 \text{ m}
\]

6. **Determination of Collapse pressure:**

\[
P_{hydr} = \rho \cdot g \cdot h = (9.81) \left[\frac{m}{s^2}\right] (1.13) \left[\frac{kg}{m^3}\right] (3466.97 - 122) \ [m]
\]

\[
P_{hydr} = 370.79 \text{ bar}
\]

\[
P_t = 11459 \text{ psi} = 790 \text{ bar}
\]

\[
SF = \frac{P_t}{P_{hydr}} = \frac{790}{370.79} = 2.13
\]

7. **Tension Design:** The tension load is evaluated using the maximum load concept. Buoyancy is included in the design to represent realistic drilling conditions. The tension design is established by consideration of the following criteria:

- Tensile forces
  - I. Weight carried
  - II. Shock loading
  - III. Bending/Buckling forces

**I. Weight Carried:**

The greatest tension (\(F_a\)) on drill string:

\[
F_a = BF \left( L_{DP} \cdot W_{DP} + L_{DC} \cdot W_{DC} \right) =
\]

\[
F_a = 0.856\{(3466.97)[m](38)\left[\frac{kg}{m}\right] + (122)[m](234.43)\left[\frac{kg}{m}\right]\}
\]

\[
F_a = 137255.59 \text{ kg}
\]
II. Shock loading: will it be available for SF=1,9?

\[ F_{shock} = 3200 \ W_{dp} = (3200)(38) = 121600 \ kg \]

\[ F_a = 0.856((3466.97)[m](38)[\frac{kg}{m}] + (122)[m](234.43)[\frac{kg}{m}]) \]

\[ \sum F = F_a + F_{shock} \]

\[ \sum F = 258855.59 \ kg \]

safety factor:

\[ SF = \frac{0.9 \ P_t}{(F_a + F_{shock})} = \frac{(0.9)(414690 \ lb \times 0.4535)}{(137255.59 + 121600 \ kg)} = 0.72 \]

\[ SF = 0.72 < 1.97 \]

III. Buckling forces in drill pipe:

\[ F_{cr} = 2 \sqrt{\left( E \times l \times W \times \sin(\alpha) \right)} \]

\[ F_{cr} = 2 \sqrt{\left( 29 \times 10^6 \ (psi) \times l \times W \times \frac{\sin(\alpha)}{r} \right)} \]

\[ l = \frac{\pi}{64} [ (5)^4 - (0.4953)^4 ] = 30.66 \ in \]^4

\[ W = \frac{26.88}{12} \times 0.856 = 1.9174 \ \frac{lb}{in} \]

\[ r = 8.5 - 5.0 = 2.5 \ in \]

(Result was converted into metric unit)

\[ F_{cr} = 1068.63 \ kgf \]
8. **Combination of tensile and torsional loads:**

**Table 4:** Determined parameters to conventional drilling

(own editing by author, 2014)

<table>
<thead>
<tr>
<th></th>
<th>Length [m]</th>
<th>Weight on air [kg/m]</th>
<th>Weight on mud [kg/m]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drill Collar P_{DC} = 234,43 [kg/m]</td>
<td>122</td>
<td>28,6</td>
<td>25,3</td>
</tr>
<tr>
<td>Drill Pipe P_{DP} = 38,0 [kg/m]</td>
<td>3466</td>
<td>131,7</td>
<td>116,5</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>3588</strong></td>
<td><strong>160,3</strong></td>
<td><strong>141,8</strong></td>
</tr>
</tbody>
</table>

The string is at the maximum depth.

**Tensile Yield Strength = 184,3 daN**

**Load on drill pipe:**

Torque at maximum allowable stress of drill pipe: \( M_e = 3465 \) daN

\[
T = (\rho_{DC} + \rho_{DP}) \times 0,981 + 32
\]

\[
T = 171,1 \text{ da.N}
\]

\[
M < 3465 \sqrt{1 - \left( \frac{\text{Load on Drill pipe}}{\text{Tensile Yield Strength}} \right)^2}
\]

\[
M < 3465 \sqrt{1 - \left( \frac{171,1}{184,3} \right)^2}
\]

Torque limit should be; \( M = 1408,5 \) daN.m

9. **Pipe stretch:**

Temperature gradient= 0,048°C/m

Average temperature based on literary data \( T_{\text{average}} = 11°C \)

a. **Due to own weight**

\[
A_1 = 0,0785 \frac{L^2}{2E} = 0,0785 \frac{(3466)^2}{(2)(210000)} = 2,245 \text{ m}
\]
b. *Due to buoyancy in mud*

\[ A_2 = \frac{L^2}{9.625 \times 10^{-7}} \times (65.44 - 1.44 \rho_{mud}) = \frac{(3466)^2}{9.625 \times 10^{-7}} = 6,471 \text{ m} \]

c. *Due to temperature variation in mud*

\[ A_3 = 11.88 \times 10^{-6} L \ dt \]

\[ A_3 = 11.88 \times 10^{-6} \times ((3466 \times 0.048) + 11) \]

\[ A_3 = 0.002107 \text{ m} \]

*Total Pipe stretch = \( A_1 + A_2 + A_3 \)*

*Total Pipe stretch = \( (2.245 + 6.471 + 0.002107) = 8.718 \text{ m} \)*
5.2 Casing Drilling

1. **Determination of Buoyancy factor:**

\[
BF = 1 - \frac{\rho_{\text{mud}}}{\rho_{\text{steel}}} = 1 - \frac{1130 \text{ kg/m}^3}{7850 \text{ kg/m}^3} = 0.856 \text{ [-]}
\]

2. **Determination of length of Casing Pipe:**

\[
L_{DP} = \frac{0.9 \times P_t - \text{MOP}}{BF \times W_{DP}} = \frac{0.9 \times \frac{553000}{0.4535} \text{ kg}}{(0.856)(79.6) \text{ kg/m}} - 34000
\]

\[
L_{DP} = 5299 \text{ m}
\]

3. **To increase the safety of drilling we need to use a safety factor which is assumed at SF= 1.7:**

\[
L_{DP} = \frac{0.9 \times P_t}{BF \times W_{DP} \times SF} = \frac{0.9 \times \frac{553000}{0.4535} \text{ kg}}{(0.856)(1.7)(234.43) \text{ kg/m}}
\]

\[
L_{DP} = 3217 \text{ m}
\]

4. **Determination of Collapse pressure**

\[
P_{\text{hydr}} = \rho \times g \times h = (9.81) \text{ m/s}^2 \times (1130) \text{ kg/m}^3 \times (5299) \text{ m}
\]

(Converted into available unit)

\[
P_{\text{hydr}} = 587.41 \text{ bar}
\]

\[
P_t = 456 \text{ bar}
\]

\[
SF = \frac{P_t}{P_{\text{hydr}}} = \frac{456}{587.41}
\]

\[
SF = 0.77
\]
5. **Tension Design:** The tension load is evaluated using the maximum load concept. Buoyancy is included in the design to represent realistic drilling conditions. The tension design is established by consideration of the following criteria:

- **Tensile forces**
  - I. **Weight carried**
  - II. **Shock loading**
  - III. **Bending forces**

**I. Weight Carried:**

The greatest tension ($F_a$) on casing string:

$$ F_a = BF \left( L_{DP}, W_{DP} \right) = 0.856 \left( (5299)m \left( 234,43 \right) \right)^{\frac{k_g}{m}} $$

$$ F_a = 1063361,35 \text{ kg} $$

**II. Shock loading: will it be available for SF=1,9?**

$$ F_{shock} = 3200 W_{DP} = (3200)(79,6) = 254720 \text{ kg} $$

$$ F_a = 1063361,35 \text{ kg} $$

$$ \sum F = F_a + F_{shock} $$

$$ \sum F = 1318081,35 \text{ kg} = 1318 \text{ t} $$

$$ SF = \frac{0,9 P_t}{(F_a + F_{shock})} = \frac{(0,9)(553000 \text{ kg})}{(1063361,35 + 254720 \text{ kg})} = 0,37 $$

$$ SF = 0,37 < 1,9 $$

**III. Buckling forces in casing pipe:**

$$ F_{Cr} = 2 \sqrt{\left( E \times l \times W \times \frac{\sin(\alpha)}{r} \right)} = $$

$$ F_{Cr} = 2 \sqrt{\left( 29 \times 10^6 \text{ (psi)} \times l \times W \times \frac{\sin(\alpha)}{r} \right)} $$

$$ I = \frac{\pi}{64} \left[ \left( \frac{9}{8} \right)^4 - (0,545)^4 \right] = 421,06 \text{ in}^4 $$
Combination of tensile and torsional loads:

**Table 5: Determined parameters to casing drilling**

(own editing by author, 2014)

<table>
<thead>
<tr>
<th>Casing Pipe (P_{DP}= 79.6 \frac{[kg]}{m})</th>
<th>Length [m]</th>
<th>Weight on air (\frac{[kg]}{m})</th>
<th>Weight on mud (\frac{[kg]}{m})</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>5299</td>
<td>421.8</td>
<td>373.1</td>
</tr>
</tbody>
</table>

The string is at the maximum depth.

**Tensile yield strength:** 591 daN

**Load on casing pipe:**

Torque at maximum allowable stress of drill pipe: \(M_e= 2169 \text{ DaN.m} \)

\[
T = (\rho_{DP})0,981 + 34 = 400 \text{ daN}
\]

**Torque limit should be:** \(M = 2169 \text{ daN.m} \)

**Pipe stretch:**

Temperature gradient= 0.048°C/m

Average temperature based on literary data \(T_{average} = 11°C\)

a. **Due to own weight**

\[
A_1 = 0.0785 \frac{L^2}{2E} = 0.0785 \frac{(5299)^2}{(2)(210000)} = 5.24 \text{ m}
\]
b. *Due to buoyancy in mud*

\[ A_2 = \frac{l^2}{9,625 \times 10^7} \times (65,44 - 1,44 \rho_{mud}) = \]

\[ A_2 = \frac{(5299)^2}{9,625 \times 10^7} \times (65,44 - 1,44 \rho_{mud}) \]

\[ A_2 = 18,616 \text{ m} \]

c. *Due to temperature variation in mud*

\[ A_3 = 11,88 \times 10^{-6} \ L \ dt \]

\[ A_3 = 0,003152 \text{ m} \]

*Total Pipe stretch* = \( A_1 + A_2 + A_3 \)

*Total Pipe stretch* = \((5,24 + 18,616 + 0,003152) = 23,859 \text{ m}\)
6. Comparison of conventional drill string and casing stresses during drilling

The Casing Drilling system may eliminate costs related to purchasing, handling, inspecting, transporting, and tripping the drill-string, reduce hole problems that are associated with tripping and save on rig equipment-and operating costs. Casing Drilling system has been already used in more than 500 well intervals to drill more than 460,000 meters with casing since it was introduced in 1999.

Based on the knowledge gained to date, the CDS in its current state of development is well suited for drilling softer formations with casing sizes of 7” or larger. Prior to apply casing drilling in any particular well, the hole condition, such as unscheduled events and litological characteristics of the formations have to be examined in order to evaluate the design criteria of the casing and to improve drilling performance.

The first important statement is about drilling mechanism. In the course of conventional drilling that casing string is not rotated. When the planned depth was reached, casing string is simply put down into the hole if it can be allowed by formation. On the other hand if a drilling problem is emerged which can be caused by formation conditions supposedly casing string cannot be pulled down at this time it can be solved by reaming. It means that casing string is needed to rotate slowly with extra flushing and knuckled down.

Otherwise casing drilling is compared with conventional drilling while it minimizes rig downtime resulting from unexpected occurrences such as stuck pipe, loss of well control. Evidence indicates that drilling with larger diameter tubular connections reduces lost circulation by mechanically plastering cuttings and drilled solids into the borehole wall. It is eventuated that hole problems can be reduced and drilling efficiency can be increased.

During casing drilling minimizing the number of pipe trips during drilling operations, it reduces incidents of hole collapse from swabbing, decreases the chance of an unintentional sidetrack. It improves wellsite safety, increase drilling efficiency.
The other significant difference between that drill collars are not used to provide weight-on-bit at casing drilling. The lower part of the casing supports only a limited compressive load before it buckles.

There are also differences between tool joints. Casing strings have longer and distinct joints than standard drill pipe, which means that drillers make about 25% fewer connections. To be continued with threads, there is significantly difference.

Another benefit is less time spent circulating fluid or back-reaming to maintain hole stability while making pipe connections. Analysis of wells drilled to date with casing indicates that this technique can reduce nonproductive rig time by as much as 50% and cut drilling time by a nominal 10 to 35% per well in some applications.

I executed a basic well construction for conventional rotary and casing drilling that basically differences can be exemplified (Figure 19.). It is continued by making a Drilling Time chart which is a time vs. depth curve. This diagram performs that what the time differences are between two drilling methods. How many time needed to finish a hole and needed to put down a casing shoe at several depth. Used data for drawing are made of a materialized drilling technical summary.
Figure 22: Well construction for Casing drilling (left) and Conventional rotary drilling (right)

(Own editing by author, 2014)
Figure 23: Drilling time chart - conventional vs. casing drilling

(Own editing by author, 2014)
Table 6: Determined parameters for comparison

(Own editing by author, 2014)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Conventional Drilling</th>
<th>Casing Drilling</th>
</tr>
</thead>
<tbody>
<tr>
<td>Buoyancy factor</td>
<td>[-]</td>
<td>0,856</td>
<td>0,856</td>
</tr>
<tr>
<td>Length of Drill Collars</td>
<td>m</td>
<td>122</td>
<td>-</td>
</tr>
<tr>
<td>Weight on the bit</td>
<td>t</td>
<td>20,8</td>
<td>-</td>
</tr>
<tr>
<td>Margin of overpull</td>
<td>t</td>
<td>32</td>
<td>34</td>
</tr>
<tr>
<td>Max. Length of Drill Pipe or Casing pipe</td>
<td>m</td>
<td>3466,97</td>
<td>5299,00</td>
</tr>
<tr>
<td>Max. Length of Drill Pipe or Casing pipe with Safety factor</td>
<td>m</td>
<td>2308,00</td>
<td>3217,00</td>
</tr>
<tr>
<td>Determined Collapse pressure</td>
<td>bar</td>
<td>790,00</td>
<td>456,00</td>
</tr>
<tr>
<td>Greatest tension on drill string</td>
<td>t</td>
<td>137,25</td>
<td>1063,36</td>
</tr>
<tr>
<td>Shock loading</td>
<td>t</td>
<td>121,60</td>
<td>254,72</td>
</tr>
<tr>
<td>Buckling forces in drill pipe</td>
<td>kgf</td>
<td>1068,63</td>
<td>263768,82</td>
</tr>
<tr>
<td>Tensile Yield Strength</td>
<td>daN</td>
<td>184,30</td>
<td>390,00</td>
</tr>
<tr>
<td>Load on Drill pipe</td>
<td>daN</td>
<td>171</td>
<td>398</td>
</tr>
<tr>
<td>Torque limit</td>
<td>daN.m</td>
<td>1408,5</td>
<td>2169</td>
</tr>
<tr>
<td>Total Pipe body stretch</td>
<td>m</td>
<td>8,718</td>
<td>23,859</td>
</tr>
</tbody>
</table>
6.1. Comparison of calculation results in the course of conventional rotary drilling and casing drilling

In this chapter I summarize what kind of calculations were executed and what the results were. The emerging stress, loads and requisitions calculation based on Drill string design chapter of Hussain Rabia: Well Construction & Engineering and Drilling Data Handbook. Prior to calculations I chose the most often used drill string and casing string type then I collected the all base data whereat can be needed to use in calculating and it was attached on Table 3.

Calculus was begun with Buoyancy factor determination. It depends on solely density of mud and steel as we can see the results in Table 6. It is not hang on more variation. Its value is the same for casing and conventional drilling methods: $0,856 [-]$. 

To can determine the main requisitions first I had to calculate more variations which refer to pipe body ($L_{DP}$, $L_{DC}$). At first proceed with length of drill pipe and drill collar in the case of conventional drilling. Calculation of the maximum pipe length taking account of the desired MOP thus the maximum length of drill pipe was 3466 m. But usually needed to increase safety and I tried for more safety so that needed to use a safety factor which is assumed at SF=1.7. I executed calculations with safety factor then result of length of maximum drill pipe was 2308 m. To continue with the maximum length of casing drill string was 5299 m and with safety factor it was 3217 m. At the next step I defined the length of applied drill collar which was 122 m. As I mentioned in above chapter there is no drill collar application at casing with drilling. As I mentioned above that drill collars are not used at casing drilling.

To continue with hydrostatic pressure determination. At the conventional drilling we calculate without length of drill collar thus got result is 370 bar and 587 bar in course of casing drilling. It depends on density of mud, gravity pick-up and length of drill or casing string. On the score of calculations, two drilling methods were compared with together it seems that differences - which are here and there significant - turn up from mostly the geometrical differences.
The next determination is the first main stress which need to know is Collapse pressure. It can be seen in Figure 24. These values are contained in Drilling Data Handbook which are: conventional drilling=\textbf{760 bar} and casing drilling= \textbf{456 bar}.

![Collapse pressure](image)

**Figure 24:** Collapse pressure  
*(Own editing by author, 2014)*

The following loads which needed to be determined that Tensile forces. Definition of Tensile forces consist of three components: Weight carried, Shock loading and Bending forces. Calculations were executed to Casing and Conventional drilling, too.

The weight carried means the greatest tension on drill or casing string. It depends on Buoyancy factor, length of drill pipe and drill collar (in the case of conventional drilling) and string’s weight. The results of calculation can be seen at Figure 25. In conventional drilling the greatest tension is \textbf{137,25 ton} until in casing drilling it is \textbf{1063,40 ton}. The casing string is harder and more massive therefore it can tolerate higher tension on string.

I determined Shock loading which is depends on solely weight of drill or casing string. In conventional drilling is \textbf{121,60 ton} until in casing drilling it is \textbf{254,72 ton} (Figure 25).
Calculated load on drill string can be seemed in Figure 26. In this tensile section the last one factor is bending or buckling forces. It depends on mostly geometrical parameter of drill or casing string and hole-deviation. These were taken into consideration in the case of conventional drilling the buckling force in drill pipe is 1068,63 kgf until in casing drilling it is 263768,82 kgf which can be seem in Figure 27.
This proportion is absolutely acceptable considering the geometrical differences between two pipe body.

**Figure 27:** Determination of Buckling force

*(Own editing by author, 2014)*

The next big area of requisitions which have to be determined to can design a drill string that is definition of tensile and torsional loads. These loads are enough complex. To can determine we need to know several base data of body pipe which are *Load on pipe, length of pipe, Tensile yield strength, maximum allowable torque, weight of pipe in air and in mud and several geometrical factor of pipe.*

After these mentioned base parameters determination - when the string is at the maximum depth – Tensile Yield Strength is 184,3 da.N, Torque at maximum allowable stress of drill pipe: \( M_e = 3465 \text{ da.N} \) and Load on drill pipe is 171,1 da.N. These data are taken into consideration the torque limit should be: 1408,5 da.N.m in the case of conventional rotary drilling.

It is compared with casing drilling, I got that Tensile Yield strength is 591 da.N, Torque at maximum allowable stress of drill pipe: \( M_e = 2169 \text{ DaN.m} \) which can be seen as the most upper border (Figure 28). The load on drill pipe is 400 da.N.
At least but not last one, another important factor is Pipe stretch. It due to own weight, buoyancy in mud and temperature variation in mud. Own weight calculation depends on length of pipe and steel’s Young modulus. The buoyancy factor depends on length of pipe and density of mud. To the value of temperature I gave an average value which is made from literature. The average temperature on surface is 11 °C and the temperature gradient can be acceptable as 0,048 C/m.

Taking into consideration the mentioned criteria, the total pipe stretch of conventional drilling string is 8,718 m until in the case of casing drilling it is 23,859 m which can be seemed at Figure 29.
In my opinion these calculations can give an excellent base to further design of conventional drilling string design or casing drilling because it contains several important and interested information about stresses, loads and requisitions which being influence with drilling rods during drilling.
Bibliography

[7] Casing drilling technology, Nediljka Gaurina-Medimurec, University of Zagreb, Croatia, 2005
7. Conclusion

Dolgozatom célja, hogy bemutassam a hagyományos rotary fúrás és a béléscsővel történő fúrás közben a fúrószárral ható terhelések és igénybevételek meghatározását. A szakdolgozat első felében részletesen bemutatom a két fúrási módszer felépítése közötti különbségeket, illetve a fúráshoz szükséges berendezéseket és eszközöket. A dolgozat kifejtését követően láthatjuk az említett fúrási módszerek közötti elvi eltéréseket, az előnyöket és hátrányokat.

Az első alapvető különbséget a fúrás mechanizmusában találjuk. A hagyományos rotary fúrás során a béléscsövet nem forgatjuk, nem fúrásra használjuk. Amikor elérünk a béléscső tervezett mélységét, akkor - ha a lyuk kondícióik megengedik - egyszerűen beépíthetjük. Míg a béléscsővel történő fúrás során a béléscsövet, mint fúrószárat használjuk. A béléscsővel való fúrás előnyeként említhetjük a fúrási idő csökkenését, a kevesebb szerszám ki- és beépítést illetve minimalizálja a fúrási problémák előfordulását (pl. szerszám szorulás) amellyel együtt megnő a fúrás hatékonysága.

A hagyományos fúrással ellentétben a béléscsővel történő fúrás során nem használunk súlyosbító rudazatot. Lényeges technikai különbséget találunk még a rudazat kapcsolók között. Míg a konvencionális fúrásnál használatos zsinór menetes kapcsolódás van addig a béléscsővel való fúrásnál a Buttress menetes, különleges nyomaték gyűrűvel ellátott kapcsolódással épül össze a szerszám.

A dolgozat további részeiben áttért a fúrás közbeni fúrószárra ható igénybevételek meghatározására és számítására, melyek közül a Collapse nyomást, a húzófeszültségeket, a lőkésszerű terheléseket, a kihajlásból eredő igénybevételeket és a csavaró erőhatásokat vettem figyelembe. Végül pedig az önsúlynak, a felhajtóerőnek és a hőmérséklet változásnak köszönhető rudazatmegnyúlást számítottam. A számítások alapjául Hussain Rabia Well Construction & Engineering illetve a Drilling Data Handbook jegyzetek szolgáltak.
Az igénybevételi számításokat megelőzően több alapadat számítására volt szükségem, melyek a további kalkulációk input adataiként funkcionáltak. Ezen adatokat a 3.sz. táblázat tartalmazza.

A számításokat az izzappal feltöltött fúrólyukban ható felhajtó erő meghatározásával kezdtem, mely kizárólag az iszap és az acél sűrűségétől függő. Így mindkét esetben az értéke azonos, 0,856 dimenzió nélkül.

Következő lépésben meghatároztam a maximális megszolgáltató csőreakt hosszát, melyet konvencionális esetben 3466 m, a bélésövel történő fúrássorán, pedig a kiválasztott csőtípusoknak megfelelően 5299 m. Törekedve a biztonságra, a számításokat egy adott biztonsági tényezővel növelte végezzük, mely értékének 1,7-t választottam irodalmi adatok alapján. Így a hagyományos fúrás esetében 2308 m, bélésövel történő fúrás során pedig a megengedhető rudazat hossza 3217 m. Hagyományos fúrás során szükséges meghatározni a súlyosbító rudazat összes hosszát, melyre a kiindulási körülményeket tekintve 122 m-t számítottam.

Meghatározásra került még a lyukban lévő hidroszatikai nyomás, mely hagyományos fúrásnál 370 bar illetve a bélésövel való fúrás során 587 bar alakult. A kalkulált értékek abszolút megfelelnek a két fúrásból adódó geometriai különbségekből származó differenciának. Ahogyan emlittettem első lépésben meghatároztam a belső nyomásból származó, Collapse nyomást, mely konvencionális esetben 760 bar míg bélésövel való fúrás során and 456 barra alakult.

Következőben a húzóterhelést - mely három főkomponensből áll – határoztam meg. A fúrócsőben vagy bélésöben a legnagyobb feszültség értéke hagyományos esetben 137,25 tonna, míg a bélésövel történő fúrás során 1063,40 tonna lett. A lökésszerű terhelésből adódó erő 121,6 tonna konvencionális fúrásnál és 254,72 tonna a bélésövel való fúrás esetében.

A hajlíísi vagy kihajlási erők melyek a fúrószer adottságaitól és a lyukferdeségtől függőek kizárólag, konvencionális fúrás során 1068, 63 kgf illetve bélésövel való fúrás során 263768,82 kgf értékű. Itt jelentős a különbség a geometriai eltérések miatt.

A húzó- és csavaró erőhatásokat számítottam a következőkben. A hagyományos fúrás során alkalmazott rudazatkapcsolók kialakítása miatt, a menetek jóval erősebbek mint a cső anyaga. Így ez esetben csak a bélésönel vesszük figyelembe a maximális megengedett nyomatéket, mely 2169 daN.m.

A nyomaték számítások után a rudazat megnyúlását határoztam meg, mely az önsúlytől, a felhajtó erőtől és az iszapban a hőmérséklet változásától függő.A három változó összege
adja a szerszám teljes megnyúlását, mely hagyományos fúrás esetében mindösszesen 8,718 míg a bélcsővel történő fúrás során ez 23,859 m.

Véleményem szerint a szakdolgozatomban bemutatott fúrási módszerek összehasonlítása és a fúrás közbeni a rudazatra ható terhelések és igénybevételek meghatározása kiváló alapjául szolgálhat egy jövőbeni hasonló fúrási probléma megoldására.
8. Köszönetnyilvánítás

Köszönetemet szeretném kifejezni a szakdolgozatom témavezetőjének, dr. Federer Imrének, a Miskolci Egyetem Kőolaj-és Földgáz Tanszék egyetemi docensének, akitől a dolgozat megírása során mindig nagyfokú figyelmet, a szakmai kérdéseimre pedig kiterjedt és részletes válaszokat kaptam.

Köszönetemet szeretném kifejezni, Feczkó Zsoltnak (okl. olajmérnök) a TXM Falcon Oil&Gas Ltd. műszaki igazgatójának aki a dolgozatom készítése során komoly szakértelemmel felügyelte a munkám. A felmerülő problémák megoldása során mindig a segítségemre volt.

Köszönetemet szeretném kifejezni dr. Szabó Tibornak, a Miskolci Egyetem Kőolaj-és Földgáz Tanszék egyetemi adjunktusának aki az igénybevételi számításaim során felmerült kérdéseimre kellő gondossággal és alapossággal válaszolt.

…………………………………………