The drill stem component description engineering essay

CHAPTER 3

INTRODUCTION

This chapter presents general procedures for drill string design. The design aspects of critical importance and factors controlling drill pipe selection are highlighted.

The term “ Drill Stem” is used to refer to the combination of tubulars and accessories that serve as a connection between the rig and the drill bit (RGU lecture slides). It consists mainly of Drill Pipe, Drill Collars (DC) and Heavy Weight Drill Pipes (HWDP) and accessories including bit subs, top drive subs, stabilisers, jars, reamers etc. Drill stem is often used interchangeably with the term “ Drill String” which actually refers to the joints of drill pipe in the drill stem.

For the purpose of this report, “ Drill String” will be used to refer to the string of drill pipes that together with drill collars and heavy weight drill pipe make up the drill stem see fig 3. 1.

3. 1 DRILL STEM COMPONENT DESCRIPTION

3. 1. 1 Drill Pipe

The drill pipes are seamless pipes usually made from different steel grades to different diameters, weights and lengths. They are used to transfer rotary torque and drilling fluid from the rig to the bottom hole assembly (drill collars plus accessories) and drill bit. Each drill pipe is referred to as a joint, with each joint consisting of a pipe body and two connections (see fig 3. 2). Drill pipe lengths vary, and these different lengths are classified as ranges, the available or more common ranges include:

Range 1: 18 – 22 ft

Range 2: 27 – 30ft

Range 3: 38 – 40ft.

Drill Stem.

Fig 3. 1: Drill Stem with components. (Heriott Watt University lecture Notes: Drilling Engineering)

Drill pipes are also manufactured in different sizes and weights which reflects the wall thickness of the drill pipe. Some common sizes and their corresponding weights include 31/2 in. 13. 30 lb/ft and 4 1/2in. 16. 60 lb/ft. The indicated weight is the nominal weight in air (pipe body weight excluding tool joints) of the drill pipe. A complete listing of API recognised drill pipe sizes, weight and grades are published in the API RP 7G.

The drill pipe grade is an indication of the minimum yield strength of the drill pipe which controls the burst, collapse and tensile load capacity of the drill pipe. The common drill pipe grades are presented in the table below

Grade

Yield Strength, psi

Letter Designation

Alternate Designation

D

D-55

55, 000

E

E-75

75, 000

X

X-95

95, 000

G

G-105

105, 000

S

S-135

135, 000

Table 3. 1: Drill Pipe Grades.

Drill pipes are often used to drill more than one well, therefore in most cases the drill pipe would be in a worn condition resulting in its wall thickness being less than it was when the drill pipe was brand new. In order to identify and differentiate drill pipes, they are grouped into classes. The different classes are an indication of the degree of wear on the wall thickness of the drill pipe. The classes can be summarised as follows according to API standards:

New: Never been used, with wall thickness when to 12. 5% below " nominal".

Premium: Uniform wear with minimum wall thickness of 80%.

Class 2: Allows drill pipe with a minimum wall thickness of 70%.

It is essential that the drill pipe class be identified in drill pipe use or design, since the extent of wear affects the drill pipe properties and strength.

When specifying a particular joint of drill pipe, the class, grade, size, weight and range have to be identified, the specification could therefore appear thus: 5″ 19. 5 lb/ft Grade S Range 2

Fig 3. 2: Parts of Drill pipe. (Handbook for Petroleum and Natural gas)

3. 1. 2 Tool Joints

Tools joints are screw type connections welded at the ends of each joint of a drillpipe. The tool joints have coarse tapered threads and sealing shoulders designed to withstand the weight of the drill string when it is suspended in the slips. Tool joints are of two kinds; the pin (male section) and the box (female section). Each drill pipe has a pin attached to one end and a box attached at the other end. This makes it possible for the pin of one joint of drill pipe to be stabbed into box of a previous drill pipe. There are several kinds of tool joints widely used:

Joint Type

Diagram

Description

Internal Upset (IU)

Tool joint is less than the pipe. Tool joint OD is approximately the same as the pipe.

Internal Flush (IF)

Tool joints ID is approximately the same as the pipe. The OD is upset.

Internal / External Upset (IEU)

Tool joint is larger than the pipe such that the tool joint ID is less than the drill pipe. The tool joint OD is larger than the drill pipe.

Table 3. 2 Types of tool joints. (The Robert Gordon University Lecture Notes: Drill String Design)

3. 1. 3 Drill Collars

Drill collars are thick walled tubes made from steel. They are normally the predominant part of the bottom hole assembly (BHA) which provides Weight on Bit (WOB). Due to the large wall thickness of the drill collars, the connection threads could be machined directly to the body of the tube, thereby eliminating the need for tool joints (see fig 3. 3). Drill collars are manufactured in different sizes and shapes including round, square, triangular and spiral grooved. The slick and spiral grooved drill collars are the most common shapes used currently in the industry. There are drill collars made from non-magnetic steel used to isolate directional survey instruments from magnetic interference arising from other drill stem components. The steel grade used in the manufacture of drill collars can be much lower than those used in drill pipes since they are thick walled.

Functions

Provide weight on bit

Provide stiffness for BHA to maintain directional control and minimise bit stability problems.

Provide strength to function in compression and prevent buckling of drill pipes.

Fig 3. 3: Carbon Steel Drill Pipes.

3. 1. 4 Heavy Weight Drill Pipe

Heavy weight drill pipes (HWDP) are often manufactured by machining down drill collars See fig 3. 4. They usually have greater wall thickness than regular drill pipe. HWDP are used to provide a gradual cross over when making transition between drill collars and drill pipes to minimise stress concentration at the base of the drill pipe. These stress concentrations often result from:

Difference in stiffness due to the difference in cross-sectional area between the drill collar and drill pipe.

Bit bouncing arising from rotation and cutting action of the bit.

HWDP can be used in either compressive or tensile service. In vertical wellbores it is used for transition and in highly deviated wells, it used in compression to provide weight on bit.

Fig 3. 4: Heavy Weight Drill Pipe. (Heriott Watt University lecture Notes: Drilling Engineering)

3. 1. 5 Accessories

Drill Stem accessories include:

Stabilisers: these are made of a length of pipe with blades on the external surface. The blades are spiral or straight, fixed or mounted on rubber sleeves to allow the drill string rotate inside.

Functions of the stabiliser include:

Stabilise the drill collars to reduce buckling and bending

Ensure uniform loading of tricone bits to reduce wobbling and increase bit life.

To provide necessary wall contact and stiffness behind the bit to induce positive side force to build angle when drilling deviated wells.

Reamers: used in the BHA to enlarge the well bore diameter and ream out doglegs, key seats, ledges.

Drilling Jars: incorporated in the BHA to deliver a sharp blow and assist in freeing the drill string should it become stuck.

3. 2 DRILL STRING DESIGN

The drill string design is carried out in order to establish the most efficient combination of drill pipe size, weight, and grades to fulfil the drilling objectives of any particular hole section at the lowest cost within acceptable safety standards.

In order to design a drill string to be used in a particular hole section, the following parameters need to be established:

Hole section depth

Hole section size

Expected mud weight

Desired safety factors in tension and overpull.

Desired safety factor in collapse

Length of drill collars required to provide desired WOB including OD, ID and weight per foot.

Drill pipe sizes and inspection class

The drill string design has to meet the following requirement:

The working loads (tension, collapse, burst) on the drill string must not exceed the rated load capacity of each of the drill pipes.

The drill collars should be of sufficient length to provide all required WOB to prevent buckling loads on the drill pipe.

The drill pipes used have to ensure the availability of sufficient fluid flow rate at the drill bit for hole cleaning and good rate of penetration.

3. 2. 1 Design Safety Factors

Design safety factors are applied to calculated working loads to account for any unexpected service load on the drill string. They are used to represent any features that are not considered in the load calculations e. g. temperature and corrosion, thus ensuring that service loads do not exceed the load capacity of the drill pipe. Design safety factor values are often selected based on experience from operating within a particular area, the extent of uncertainty in the operating conditions e. g. when operating in HPHT conditions, a larger safety factor is applied than when operating in less harsh conditions. Some commonly used design safety values are illustrated in the table below

Load

Design Safety Factor Value

Tension

1. 1 – 1. 3

Margin of overpull (MOP)

50, 000 – 100, 000. MOP of 400, 000 have been used in ultra deep wells

Weight on Bit

1. 15 or 85% of available Weight on bit to ensure neutral point is 85% of drill collar string length measures from the bottom (API RP 7G)

Torsion

1. 0 (based on the lesser of the pipe body or tool joint strength)

Collapse

1. 1 – 1. 15

Burst

1. 2

3. 2. 2 Drill Collar Selection

The drill collars are selected with the aim of ensuring that they provide sufficient WOB without buckling or putting the lower section of the drill string in compression.

3. 2. 2. 1 Size selection

Lateral movement of the drill bit is controlled by the diameter of the drill collar directly behind it. Therefore the size/diameter of the drill collar closest to the bit will be dependent on the required effective minimum hole diameter and the relationship can be given as

When two BHA components of different cross-sectional areas are to be made – up, it is essential that the bending resistance ratio (BRR) be evaluated. This is important because BHA components have tensile and compressive forces acting on them when they are bent in the well bore. These forces cause stress at connections and any location where there is a change in cross-sectional area. Therefore it is important to ensure that these stresses are within acceptable ranges. The bending resistance (BR) of a drill string component is dependent on its section modulus which is given as

Z = section modulus, in3

I = second moment of area, in4

OD = outside diameter, in

ID = inside diameter, in

The BRR is used to express any change in BR and can be calculated using

BRR should generally be below 5. 5 and in severe drilling conditions, below 3. 5.

3. 2. 2. 2 Connections

When selecting connections to be used with drill collars, it is essential to check that the BRR of the pin and box indicates a balanced connection. The BRR for drill collar connection is calculated as the section modulus of the box divided by the section modulus of the pin. The API RP 7G contains tables that can be used to determine BRR for any box and pin OD. BRRs of 2. 5 have given balanced connections (RGU Lecture notes, 2005).

3. 2. 2. 3 Weight on Bit

The maximum weight on bit required is normally a function of the bit size and type. The rule of thumb is:

Maximum WOB of 2000lbf per inch of bit diameter when using Polycrsyalline Diamond Compact bits (PDC) and mud motors.

Maximum WOB of 5000lbf per inch of bit diameter when using tricone bits.

Other factors controlling WOB include inclination, hole size and buckling.

In vertical wellbores the length of drill collars required to provide a specified weight on bit is given by

LDC = Length of Drill Collars, ft

WOB = Weight of Bit, lb

DFBHA = Safety factor to keep neutral point in drill collars.

WDC = Weight per foot of Drill Collars, lb/ft

Kb = Buoyancy Factor.

The neutral point as described by (Mian, 1991) referring to Lubinksi, is the point that divides the drill stem into two portions, with the section above the neutral point in tension and that below in compression. Therefore in order to ensure that the entire length of drill pipes remain in tension, the neutral point of the drill stem has to be maintained within the drill collars. According to the API RP 7G, the height of the neutral point measured from the bottom of the drill collars will be 85% of the total length of drill collars used, with 85% being the safety factor.

In inclined wellbores, the angle of inclination has to be taken into consideration when calculating the maximum WOB that can be applied without buckling the drill pipe. This is because although the WOB is applied at the inclination of the wellbore, this weight acts vertically, thus reducing the available weight at the bit.

Therefore to allow for this reduction, the buoyed weight of the BHA would be reduced by the cosine of the well inclination, thus WOB in inclined holes is calculated with the formula

All parameters remain as defined in equation 5; Î¸ is the angle of inclination of the well.

As a result of the vertically acting weight of the BHA, the drill string tends to lie on the low side of the hole and is supported to some extent by the wall of the well bore. Therefore the pipes above the neutral point could only buckle if the compressive forces in the drill string exceed a critical amount. This critical buckling force is calculated as follows

Fcrit = critical buckling force, lb

ODHWDP = outside diameter of HWDP, in.

ODtj = maximum outside diameter of pipe, in.

IDHWDP = inside diameter of HWDP, in.

Kb = buoyancy factor.

Dhole = diameter of hole, in.

Î˜ = hole inclination, degrees.

Since HWDP are sometimes used to apply WOB in inclined wells, and drill pipes are sometimes used in compression, the critical buckling force is calculated for both HWDP and drill pipes.

3. 2. 3 Drill Pipe Selection

Factors to be considered for drill pipe selection include:

Maximum allowable working loads in tension, collapse, burst, and torsion.

Maximum allowable dogleg severity at any depth in order to avoid fatigue damage in the drill pipe.

Combined loads on the drill pipe.

The loads considered when selecting drill pipes to be used in the drill string is dependent on the well depth, well bore geometry and hole section objectives.

In shallower vertical wells, collapse and tension are of more importance than burst or torsion. Burst is normally not considered in most designs since the worst case for a burst load on the drill pipe would occur when pressuring the drillstring with a blocked bit nozzle, even with this condition, the burst resistance of the drill pipe is likely to be exceeded. Torsion is of less importance in vertical well bores because drag forces are at minimal amounts unlike in highly deviated wells. The dogleg severity of the well for both vertical and deviated wells is important because of increased fatigue in the drill pipe when it is rotated in the curved sections of the wellbore.

A graphical method is recommended for drill pipe selection, with the loads plotted on a load versus depth graph. This makes it possible for loads at particular points on the drill string to be easily visualised, and any sections of the drill pipe that do not meet the load requirements are easily identified and redesigned.

3. 2. 3. 1 Collapse

Drill pipes are sometimes exposed to external pressures which exceed its internal pressures, thereby inducing a collapse load on the drill pipe. The worst scenario for collapse in a drill pipe is during drill stem tests when they are run completely empty into the wellbore. The collapse loads are highest at the bottom joint of the drill pipes, as a result, the collapse load would normally control the drill pipe grade to be used at the bottom of the drill string. The API specified collapse resistance for different sizes and grades of drill pipe assuming either elastic, plastic or transition collapse depending on their diameter to wall thickness ratio have been calculated and are published in the API RP 7G with the relevant formulae.

The maximum collapse pressure on the drill pipe when it is completely empty can be calculated as follows:

Pc = collapse pressure, psi

MW = mud weight, ppg

TVD = true vertical depth at which Pc acts, ft.

On some occasions, the mud weight outside the pipe varies from that inside the pipe, also the fluid levels inside and outside the pipe may also vary. This situation could also induce collapse loads. The collapse loads induced by this scenario can be calculated thus

L = Fluid depth outside the drill pipe, ft

MW = Mud weight outside the drill pipe, ppg

Y = fluid depth inside drill pipe, ft

MW' = Mud weight inside drill pipe, ppg.

The value for Pc is then plotted on the collapse load graph as the collapse load line see fig 3. 5.

It is recommended practice to apply a design safety factor to the collapse load calculated from equations 8 or 9 (depending on expected scenarios) in order to account for unexpected additional loads as wells as unknown variables. The value of the design factor is often between 1. 1 – 1. 5 for class 2 drill pipes. According to (Adams, 1985) the design factor should be 1. 3 to account for the fact that new drill pipes are often not used for drill stem tests. The value of the collapse load multiplied by the collapse design factor is plotted on the collapse load graph as the design line, this is then used to select an appropriate grade and weight of drill pipe to fulfil these load conditions.

Fig 3. 5: Sample Collapse load graph.

3. 2. 3. 2 Tension Load

The tensile load capacity of the drill string should be evaluated to ensure there is enough tensile strength in the topmost joint of each size, weight, grade and class of to support the weight of the drill string submerged in the wellbore, hence the need to include buoyancy in the calculations. There has to also be enough reserve tensile strength to pull the drill string out of the well if the pipe gets stuck. The stabiliser and bit weight can be neglected when calculating the drillstring weight.

In a vertical wellbore, the forces acting on the drill string are tension from its self weight and the hydrostatic pressure from the fluid in the wellbore. The hydrostatic pressure in the wellbore exerts an upward force on the cross sectional area of the drill string, which is commonly referred to as buoyancy. Therefore the resulting tensile load on the drill string attached to drill collars, taking account of buoyancy is calculated as:

FTEN = resultant tensile load on drill string, lb

LDP = length of drill pipe, ft

LDC = length of drill collars, ft

WTDP = air weight of drill pipe, lb/ft

WTDC = air weight of drill collars, lb/ft

MW = Mud weight, ppg.

ADC = Cross sectional area of drill collars, in2

FTEN is plotted on the tension load graph as the tensile load line.

The tensile strength values for different sizes, grades and inspection classes of drill pipes are contained in the API RP 7G, and can be calculated from the equation:

Fyield = minimum tensile strength, lb

Ym = specified minimum yield stress, psi

A = cross section area, in2

Fyield is plotted as the minimum tensile strength line on the tension load graph.

However, these values (Fyield) are theoretical values based on minimum areas, wall thickness and yield strength of the drill pipes. Therefore, these values only give an indication of the stress at which a certain total deformation would occur and not the specific point at which permanent deformation of the material begins. If a pipe is loaded to the minimum tensile strength calculated from equation 11, there is the possibility that some permanent stretch may occur, thereby making it difficult to keep the pipe straight in the wellbore. In order to eliminate the possibility of this occurrence, 90% of the minimum tensile strength as recommended by the API (American Petroleum Institute), should be used as the maximum allowable tensile load on the drill pipe, i. e

Fdesign = maximum allowable tensile load

0. 9 = a constant relating proportional limit to yield strength.

Fdesign is plotted on the tension load graph as the maximum allowable tensile load line.

As with the collapse load, a design factor would be applied to the tensile loads to account for dynamic loads in the drill pipe which occur when the slips are set, as well as prevent the occurrence of pipe parting close to the surface. The product of FTEN and the design factor is plotted as the tension design load line in the tension load graph see fig 3. 6.

Margin Of Overpull

A margin for overpull is added to the tension load to ensure there is sufficient tensile strength in the drill pipe when it is pulled in the event of a stuck pipe. This margin is normally 50, 000 – 100, 000lb, but in deeper wells margins of overpull have reached 300, 000lb. The value obtained after adding the margin of overpull is also plotted on the tension load graph see fig 3. 6.

The difference between the calculated tensile load at any point in the drillstring (FTEN) and the maximum allowable tension load would also represent the available overpull. This value represents available tensile strength of the drill pipe to withstand any extra forces applied to the drill string when trying to release it from a stuck pipe situation.

FTEN and Fa can also be expressed as a safety factor

This safety factor is an indication of how much the selected drill pipe will be able to withstand expected service loads. Due to uncertainty with actual service loads and conditions, a safety factor greater than 1 is always required.

Slip Crush

Slip crushing is generally not a problem if the slips are properly maintained. However, it is necessary to apply a safety factor for slip crushing when designing the drill string. This helps account for the hoop stress (SH) caused by the slips and the tensile stress (ST) caused by the weight of the drill string suspended in the slips. This relationship between SH and ST can be represented by the following equation

SH = hoop stress, psi

ST = tensile stress, psi

D = outside diameter of the pipe, in.

K = lateral load factor on slips,

Ls = length of slips, in.

= slip taper usually 9° 27′ 45″

z = arctan Î¼

Î¼ = coefficient of friction, (approximately 0. 08)

The calculated tensile load is multiplied by the slip crush factor () to obtain the equivalent tensile load from slip crushing:

Ts = tension from slip crushing, lb

TL = tension load in drill string, lb

SH / ST = slip crush factor.

Ts is also plotted on the tension load graph as the slip crush design line.

Fig 3. 6: Sample Tension load graph

The general step-by-step procedure for drill pipe selection using the graphical method is given as

1. Calculate the expected collapse load on drill pipe and apply the collapse design safety factor to derive the design load. Use the result to select weight and grade of drill pipe that satisfy collapse conditions. Plot expected collapse load and design load on a pressure vs. depth graph.

2. Calculate maximum allowable tensile load for the drill pipe selected in (1) above. Also calculate tension load on the drill string including buoyancy effects. Plot the tension load, specified minimum yield strength, and maximum allowable tensile load values on axial load vs. depth graph.

3. Apply tension design factor, margin of overpull, and slip crush factor to the calculated tension load and plot the individual results on the axial load vs. depth graph. Of the three factors applied to the tension load, the one resulting in the highest value is selected as the worst case for tensile loads.

4. Inspect graph and re-design any sections not meeting the load requirements.

When designing a tapered drill string, the maximum length of a particular size, weight, grade and class of drill pipes that can be used to drill the selected hole section with specified WOB can be calculated as:

All parameters remain as defined in equation 10 and 11. Note that equation 16 is only used when the MOP design line is the worst case scenario for tensile loads. When slip crushing is the worst case, the formula below is used

SF = safety factor for slip crushing.

The lightest available drill pipe grade should be used first in order to ensure that that the heavier grades are used upper section of the drill string where tensile loads are the highest.

3. 2. 4 Dog Leg Severity

Fatigue damage is the most common type of drill pipe failure. It is known to be caused by cyclic bending loads induced in a drill pipe when it is rotated in the curved sections of the wellbore. The rotation of the drill pipe in the curved hole sections induce stresses in the outer wall of the drill pipe by stretching it and increasing its tensile loads. Fatigue damage from doglegs tends to occur when the angle exceeds a critical value. This critical value can be calculated as:

C = maximum permissible dog leg severity, deg/100ft

E = Young's modulus, psi (30 x 106 for steel, 10. 5 X 106 for aluminium)

D = Drill pipe outer diameter, in.

L = half the distance between tool joints, (180 in, for range 2 pipe)

T = tension below the dogleg, lb

Ïƒb = maximum permissible bending stress, psi.

I = drill pipe second moment of area, =

Ïƒb, is calculated from the buoyant tensile stress (Ïƒt) and is dependent on the grade of the pipe.

Ïƒt = T/A, where T is defined in equation 19, and A is the cross sectional area of the pipe body in in2.

For grade E pipe,

The results from equation 20 are valid for Ïƒt values up to 67, 000psi.

For grade S pipe,

The results from equation 21 are valid for Ïƒt values up to 133, 400psi.

It is recommended that an allowable dogleg severity (DLS) versus depth chart be plotted for every hole section with a particular drill string design since DLS changes with depth. The chart is plotted with the DLS on the x-axis and depth on the y-axis (see fig 3. 7). When DLS lies to the left of the line or below the curve, the drill pipe is in safe operating conditions, and when it falls above or to the right of the curve, it is in unsafe conditions.

Fig 3. 7: Allowable Dogleg Severity Chart. (Mian, 1991)

3. 2. 5 Torsion

Drill pipe torsional yield strength is important when planning deviated wells and ultra deep wells. In deviated wells, increased drag forces acting on the drill string from its interaction with the wellbore increase torsional loads on the drill pipe. In deeper wells, it is important in stuck pipe situations, in order to know the maximum torque that can be applied to the drill string.

The pipe body torsional yield strength when subjected to torque alone can be calculated from the equation:

Q = minimum torsional yield strength, ft lb

J = polar second moment of area, Ï€/32 (D4 – d4)

D = pipe OD in, d = pipe ID in.

Ym = minimum yield strength, psi.

3. 2. 6 Combined Loads On The Drill String

Collapse and Tension

The collapse resistance of the drill pipe is often reduced when the drill pipe is exposed to both tension and collapse loads. This happens because tensile loads stretch the drill pipe thereby affecting its D/t (diameter -wall thickness ratio) which controls the collapse resistance of the drill pipe.

In ultra deep wells, the effect of combined collapse and tension is experienced when function testing the Blow out Preventers (BOP). It is becoming common practice in ultradeep drilling to equip BOPs with test rams in order to enable the BOP be tested without setting plugs in the well head. This is done to save tripping time due to extreme well depths. An example given by (Chatar, 2010), using 65/8in 27. 70lb/ft drill pipe showed that with 65/8in drill pipe having 860kips of maximum allowable tensile loads, at half of this load, the drill string is only capable of withstanding 4, 500psi collapse loads, which is often not sufficient for ultradeep drilling BOPs.

The corrected collapse resistance of drill pipes under tension can be calculated using the formula

Where

R represents the percentage of the collapse resistance left when the drill pipe is under tension, therefore in equation 25, the value for R is used to multiply the normal plastic collapse resistance of the pipe to give the collapse resistance under tension.

R can also be determined graphically with the following steps

1. Calculate Z using equation 24

2. Enter the ellipse for biaxial stress (fig 3. 8) on the horizontal axis with the value for Z and draw a vertical line to the ellipse curve.

3. Draw a horizontal line from the vertical line drawn in (2) above to the vertical axis and read off the value.

4. Use the value from (5) above to multiply the collapse resistance to get the corrected collapse resistance with tension.

Fig 3. 8: Ellipse of Biaxial yield Strength: Effect of tensile loading om collapse resistance. (RGU Lecture notes: Casing design)

Combined tension and torsion

The torsional yield strength of a drill pipe is significantly reduced when the pipe is under tension loads. The torsional yield strength of the drill pipe under tension can be calculated with the equation

Q = minimum torsional yield strength under tension, ft lb

J = polar second moment of area.

D = pipe OD in, d= pipe ID in.

Ym = minimum yield strength, psi

P = total load in tension, lb

A = cross – sectional area, in2

3. 2. 7 Tool Joint Performance

The makeup torque to be applied to the tool joints when connecting drill pipes is calculated as follows

ID = inside diameter, in.

OD = outside diameter, in.

Values for X, M, B and Q for standard connections are presented in the table

be