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DRILLSTRING DESIGN

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Abstract :
The "drill string" is composed of "knobbies," drill pipe, a bottomhole meeting (see the bha tool sheet), and a chunk (see the center bit tool sheet). It's miles used to installation and retrieve (i.E., "run" and "pull") all of odp's coring/drilling bhas, reentry systems, completion hardware, and related equipment. A drill string undergoes higher tensile, bending, and torque stresses than general pipe; consequently, the tool joints have shoulders that provide stiffness to save you bending and breaking. The drill string may be run to a maximum coring/drilling intensity of ~8375 m in slight climate (at 6° roll with one hundred,000 lb overpull and a typical bha). All drill string factors have a four.125 in. (10.47 cm) minimal internal diameter (id) during to allow different equipment to bypass thru; therefore, the drill string is compatible with the odp coring systems, water samplers, temperature/strain probes, and logging tools. This compatibility reduces pipe journeys and maximizes the time spent drilling a hole or recovering core to achieve the science targets.

Key Words: **Drill Pipe Selection,BHA Selection Standard BHA Configuration,Drill Collar Selection ,Top Drive,Drillstring Design Critaria**

1.INTRODUCTION:

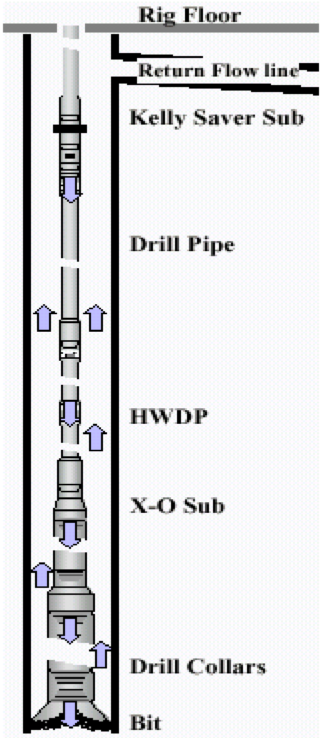
The drill string is the mechanical linkage connecting the drill bit at the bottom of the hole to the rotary drive system on the surface. The drillstring serves the following functions:

1. Transmits rotation to the drill bit
2. Exerts weight on the bit; the compressive force necessary to break the rock
3. Guides and controls the trajectory of the bit; and
4. Allows fluid circulation which is required for cooling the bit and for cleaning thehole.

The components of the drillstring are:

1. Drillpipe
2. Drill collars
3. Accessories including:

• Heavy-walled drillpipe (HWDP)
• Stabilizers
• Reamers
• Directional control equipment



1.1 Sub Heading 1

1.2 INTRODUCTION TO KELLY/TOP DRIVE

The Kelly is the rotating link between the rotary table and the drill string. Its main functions are:

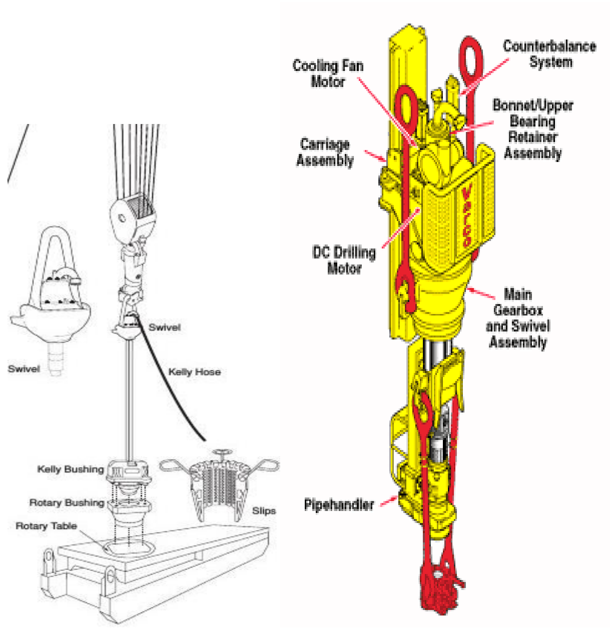
• transmits rotation and weight-on-bit to the drillbit
• Supports the weight of the drillstring
• connects the swivel to the uppermost length of drillpipe; and
• conveys the drilling fluid from the swivel into the drill string.

The Kelly comes in lengths ranging from 40 to 54 ft with cross sections such as hexagonal (most common), square or triangular. The Kelly is usually provided with two safety valves, one at the top and one at the bottom, called upper and lower Kelly cocks, respectively. The Kelly cock is used to close the inside of the drillstring in the event of a kick. The lower Kelly cock is always manual.

The top drive is basically a combined rotary table and Kelly. The topdrive consists of a DC drive motor that connects directly to the drillstring without the need or a rotary table.

The topdrive is mounted on the rig's swivel, the swivel attaches to the travelling block and supports the drillstring weight. The topdrive has a pipe handler consisting of a torque wrench and aconventional elevator to assist in pipe handling during connection and round trip operations.The elevator and elevator links are supported on a shoulder located on the extended swivel stem.

The top drive functions in the same way as the Kelly. However, it has many advantages over the Kelly system including circulating while back reaming, circulating while running in hole or pulling out of hole in stands. The Kelly system can only do this in singles; i.e. 30 ft.



2.<u>DRILL PIPE SELECTION</u>

DRILL PIPE GRADE

The grade of drill pipe describes the minimum yield strength of the pipe, API defines five grades: D,E, X,G and S. However, in oil well drilling, only grades E,G and S are actually used. In most drillstring designs, the pipe grade is increased if extra strength is required.

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Table -1: Drillpipe Grade And Yield Strength Sample

Grade		Minimum Yield Strength, psi
Letter	Alternate	
Designation	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

DRILL PIPE CLASSIFICATION

Drill pipe, unlike other oilfield tubulars such as casing and tubing, is re-used and therefore
often worn when run. As a result the drill pipe is classified to account for the degree of wear.
The API has established guidelines for pipe classification in API RP7G. A summary of the classes follows.
New: No wear, has never been used.
Premium: Uniform wear and a minimum wall thickness of 80% of new pipe.
Class 2: Drill pipe with a minimum wall thickness of 65% with all the wear on one side so long as the cross sectional area is the same as the premium class.
Class 3: Drill pipe with a minimum wall thickness of 55% with all the wear on one side.

WASHOUTS IN DRILLSTRINGS

A washout is a place where a small opening resulting in forcing of drilling fluid through it has
occurred in the pipe.lt usually is the result of a fatigue crack penetrating the pipe wall.Wash out
may also be caused by a damaged shoulder of box and/or pin damaged as a result of striking while stabbing for connection.

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WASHOUT

OTHER FEATURES OF TOOL JOINTS

Casing wear is caused mainly by the rotation of drillpipe tool joints against the walls of the casing. Some casing wear is also produced by wireline tools.

The life of a tool joints can be tripled if the tool joints is hardfaced with composites of steel and tungsten carbide. The hard-facing bands are welded onto the tool joints box close to the elevator shoulder. The pin tool joint is not hardfaced to protect the make-up tongs. The hardfacing on the box tool joint should be flush with the tool joint OD instead being raised above the OD to minimize casing wear.

Unprotected tool joints can cause:

- Severe casing wear by adhesion under certain mud conditions; and
- severe wear of tool joint surface if it comes in contact with abrasive formation

BHA SELECTION

DRILL COLLAR SELECTION

Drill collars are the predominant component of the bottom hoe assembly (BHA). Both slickand spiral drill collars are used. In areas where differential sticking is a possibility spiral drill collars and spiral heavy-walled drillpipe (HWDP) should be used in order to minimize contact area with the formation.

The drill collars are the first section of the drillstring to be designed. The length and size of the collars will affect the grade, weight and dimensions of the drill pipe to be used.

Table 2illustrates typical sizes of collars to be run in each hole section.

Hole Section	Recommended Drill Collar OD (ins)
36	$9^{1/4} + 8$
26	$9^{1/4} + 8$
$17^{1/2}$	$9^{1/4} + 8$
16	$9^{1/4} + 8$
$12^{1/4}$	8
$8^{1/4}$	$6^{1/4}$
6	$4^{3/4}$

Drill collar selection is usually based on buckling considerations in the lower sections of the string when weight is set on the bit. The design approach that satisfies this criteria is the buoyancy factor method.

BUOYANCY FACTOR METHOD

Drill collars are used to provide weight for use at the bit and at the same time keep the drillpipe in tension. Drill collars have a significantly greater stiffness when compared to drill pipe and as such can be run in compression. Drill pipe, on the other hand will tend to buckle when run in compression. Repeated buckling will eventually lead to early drill pipe failure by fatigue. Since elastic members can only buckle in compression, fatigue failure of pipe can be eliminated by maintaining drill pipe in tension.

Research and field experience proved that buckling will not occur if weight on bit is maintained below the buoyed weight of the collars. In practice weight on bit should not exceed 85% of the buoyed weight on the collars.

Procedure for Selecting Drillcollars

1. Determine the buoyancy factor for the mud weight in use using the formula below:

$$BF = 1 - \frac{MW}{65.5} \qquad (1)$$

Where,
BF=Buoyancy Factor, dimensionless
MW=Mud weight in use, ppg
65.5=Weight of a gallon of steel, ppg

2. Calculate the required collar length to achieve the desired weight on bit:

$$WOB = \text{air weight of drillcollars} \times BF \times 0.85 = \text{DC length} \times W_{dc} \times BF \times 0.85$$

$$\text{DC length} = \frac{WOB}{0.85 x BF x W_{dc}}$$

Where,
WOB=Desired weight on bit, lbf (x 1000)
BF =Buoyancy Factor, dimensionless
Wdc =Drill collar weight in air, lb/ft
0.85 =safety factor.

The 0.85 safety factor ensures that only 85% of the buoyant weight of the drillcollars is used as weight on bit. Hence the neutral point remains within the collars when unforeseen forces (bounce, minor deviation and hole friction) cause fluctuations on the WOB.

BENDING STRENGTH RATIO

The bending strength ration (BSR) is defined as the ratio of relative stiffness of the box to the pin for a given connection 1. From field experience, a BSR value of 2.5 gives a balanced connection. Above 2.5 BSR, there is a risk of premature failure in the pin and a BSR of below 2.5 gives a risk of premature failure in the box.

Large OD's drillcollars (8" and above) suffer mainly from box failure caused by fatigue cracks despite the fact that they are operated at a BSR of 2.5. Higher BSR's may therefore be used for large OD drillcollars 1,4,5. Large OD drillcollars provide greater stiffness and reduces hole deviation problems.

STIFFNESS RATIO (SR)

The stiffness ratio (SR) is defined as follows:

SR = Section Modulus of lower section tube /Section modulus of upper section tube

SR = OD2 (OD12 - ID12) / OD1 (OD22 - ID22)

From field experience, a balanced BHA should have:
SR = 5.5 for routine drilling
SR = 3.5 for severe drilling or significant failure rate experience

DRILL COLLAR PROFILES

Slick Drill Collars

As the name implies, slick drillcollars have the same nominal outside diameter over the total length of the joint. These drill collars usually have the following profiles:

- a slip recess for safety, and
- an elevator recess for lifting.

Spiral Drill Collars

Spiral drillcollars are used primarily to reduce the risk of differential sticking. The spirals reduce the weight of the collar by only 4 -7% but can reduce the contact area (proportional to sticking force) by as much as 50%.

Square Drill Collars

These are used in special drilling situations to reduce deviation in crooked hole formations. They are used primarily due to their rigidity.

Slick Drillcollar **Spiral Drillcollar**

HEAVY-WALLED DRILLPIPE (HWDP)

The HWDP has the same OD as a standard drillpipe but with much reduced inside diameter (usually 3") and has an extra tool joint, figure a is a standard HWDP and figure b is a spiral type.

HWDP is used between standard drillpipe and drillcollars to provide a smooth transition between the section moduli of the drillstring components.

HWDP can be distinguished from standard drillpipe by an integral wear centre wear pad which acts as a stabiliser thereby increasing the overall stiffness of the drillstring. In directional and horizontal wells, HWDP is used to provide part or all of the weight on bit while drilling.

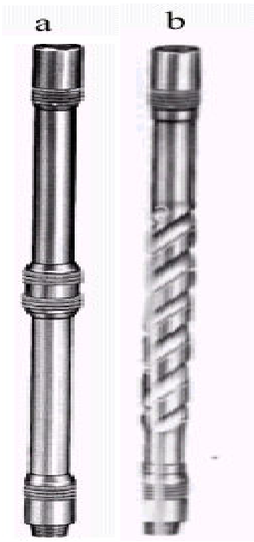


Fig -: Standard HWDP Spiral type HWDP

STABILISERS

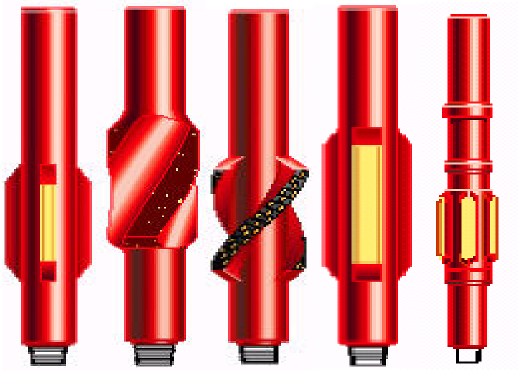
Stabilisers are tools placed above the drill bit and along the bottom hole assembly (BHA) to control hole deviation, dogleg severity and prevent differential sticking. They achieve these functions by centralising and providing extra stiffness to the BHA.Improved bit performance is another beneficiary of good stabilisation.

There are basically two type of stabilisers:
• Rotating stabilisers
• Non-rotating stabilisers

Rotating stabilisers include: integral blade stabiliser, sleeve stabiliser and welded blade stabiliser.

Integral blade stabilisers (first four pictures on left) aremachined from a solid piece of high strength steel alloy. The blade faces are dressed with sintered tungsten carbide inserts. The blades can either be straight or spiral.

Non-rotating stabilisers comprise a rubber sleeve and a mandrel (picture on right). The sleeve is designed to remain stationary while the mandrel and the drillstring arerotating. This type is used to prevent reaming of the hole walls during drilling operation andto protect the drillcollars from wall contact wear.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Straight Blade | Standard | Three Blade | Full Pac | Non- rotating Stabilizers

Figure: Types of Stabiliser

STANDARD BHA CONFIGURATION

The bottom hole assembly refers to the drillcollars, stabilisers and other accessories.All wells whether vertical or deviated require careful design of the bottom hole assembly (BHA) to control the direction of the well in order to achieve the target objectives. **Stabilisers** and drillcollars are the main components used to control hole direction.

The main means by which directional control is maintained on a well is by the effective positioning of stabilisers within the BHA. There are five basic types of assembly which may be used to control the direction of the well.

1. Pendulum assembly

2. Packed bottom hole assembly

3. Rotary build assembly

4. Steerable assembly

5. Mud Motor and bent Sub assembly

DRILLSTRING DESIGN CRITERIA

When drilling highly deviated, extended reach or horizontal wells, computer modelling of torque and drag should be used for establishing grades, size and weight of drill and couplingto be used. On such wells, calculation of the effects of deviation on predicted torque and drag are too complicated to calculate manually

The criteria used in a drill string design are:
1. Collapse
2. Tension
3. Dogleg Severity Analysis

Burst pressure is not considered in drillstring 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 loads, except during squeeze operations where surface pressure is applied. If squeeze pressures are high, a 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 grades and couplings.Slip crushing affects the tension design and pipe selection. Dogleg analysis is performed to study the fatigue damage resulting from rotation in doglegs. Doglegs analysis may not affect the selection of the pipe, however it will assist in determining the maximum permissible dogleg during any section of the well.

API R7G[1] gives the following design criteria:

1. Anticipated total depth with this drillstring
2. Hole size
3. Expected mud weight
4. Desired safety factor in tension and/or margin of overpull

5. Desired safety factor in collapse
6. Length of drillcollars, OD, ID and weight per foot
7. Desired drillpipe sizes and inspection class

3. CONCLUSIONS

1- Higher capability of the designed program to detect and recognise the reasons for drill string failure is obtained with less effort and short time, and this program will be a guide for any future case, as it will be used to characterize the reasons that may lead to that failure.

2- Drill string failure does not usually occur due to a unique reason or a unique factor. It depends on a lot of reasons and factors that could be accumulated and lead to the drill string failure. The best way to avoid drill string failure before and while drilling is to run the designed program to carefully diagnose and detect if the drill string is close to fail and hence an immediate action is taken to improve the drilling parameters to prevent the drill string failure.

3- The major factors that lead to drill string failure, for the tested cases are: dogleg severity, rotary bottom hole assembly, higher operating torque while drilling, hard formation, and hole size specially 12.25-inch.

4- New drill pipe material grade that combines ultra-high strength with excellent fracture toughness has been developed.

5- This new drill pipe can help expand the extended reach drilling envelop by enabling drill strings with excellent strength to weight properties.

6- Combining the V-150 material with light weight, thinner wall drill string designs can reduce torque and drag loads while providing high axial tension capacities and torsional strengths necessary to drill the next generation of ERD wells.

7- The ultra-high strength material is also well suited to landing string applications where the loading demands to run longer and heavier casing strings in deep-water continue to increase.

• It is anticipated that innovative drilling professionals may also discover additional critical drilling applications that can benefit from this new drill pipe technology.

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