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Advanced Workflow to Evaluate and Compare the Performance of Directional Drilling Control Tools

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Affidavit

I declare in lieu of oath that I wrote this thesis and performed the associated research myself using only literature cited in this volume.

Eidesstattliche Erklärung

Ich erkläre an Eides statt, dass ich diese Arbeit selbständig verfasst, andere als die angegebenen Quellen und Hilfsmittel nicht benutzt und mich auch sonst keiner unerlaubten Hilfsmittel bedient habe.

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Amir Maleki Moghaddam, 10 September 2018

Abstract

Directional drilling has become more critical than ever in the petroleum industry due to continuous development in offshore deepwater fields, environmentally sensitive areas and locations with restricted surface access. In addition to the significant increase in re-entries operations to extend the lifetime of onshore and offshore production facilities and on horizontal completion of wells to improve production rates and to have an ultimate recovery.

The involvement of extra tools, expertise and processes make directional wells way more expensive than vertical wells, therefore, any moderate improvement in drilling process or tools selection could bring significant cost-effective results especially for offshore fields. However, the improvement is not an easy task, due to the complexity associated with directional wells. Nevertheless, it could be achieved by deeply analyzing directional drilling data in order to precisely determine the areas of improvement and to select cost effective tools. From this perspective, the ultimate goal of this thesis is to develop a comprehensive workflow which can be used to evaluate and compare the performances of commonly used directional drilling control tools and to propose the best tool in term of low cost and high performance.

At first part of this thesis two topics will be discussed, the pros and cons of most used deviation technologies and the working principles of Rotary Steerable System. In the second part methodology overview of the developed workflow is explained in details. Briefly, the developed workflow consists of four phases, data gathering phases, in which pertinent data of highly deviated wells are collected. Since data quality and validation always have a significant impact on final results, therefore, in the second phase the predetermined data is certificated. In the third phase, Landmark software is used to process the data. Finally, by using specific key performance indicators (KPIs) and weighted decision matrix tool, the performance of different directional control techniques are compared and ranked.

The third part of this thesis is specified as a case study, where the real data from Iranian field is analyzed by using the sequential steps of the developed workflow. The main purpose of conducting the case study was to evaluate and determine the shortcomings of the developed workflow. The final results of the case study reveal that the workflow is reliable and easy to use.

Zusammenfassung

Richtbohren in der Erdöl- und Erdgasindustrie erlang eine größere Bedeutung durch die kontinuierliche Weiterentwicklung von Offshore-Feldern, von Feldern mit sensiblen Umweltgegebenheiten und von Standorten mit eingeschränkten Zugang an der Oberfläche. Zusätzlich wird Richtbohren für re-entry Operationen angewandt, um die Lebensdauer von Bohrungen zu verlängern beziehungsweise eine horizontale Komplettierung zu ermöglichen, um eine höhere Produktionsrate zu erreichen.

Die Verwendung von zusätzlichen Tools, Expertise und Prozessen erhöht die Kosten von Richtbohrungen signifikant. Daher verbessert nicht nur die sorgfältige Auswahl der Tools die Kosteneffektivität, speziell für Offshore-Felder, sondern auch moderate Verbesserungen des Bohrprozesses. Solche eine Verbesserung ist nicht einfach zu erreichen, da Richtbohren mit einem hohen Grad an Komplexität einhergeht. Jedoch kann eine detaillierte Analyse von Bohrdaten die Bereiche, die eine Verbesserung zulassen, aufzeigen. Von diesem Standpunkt aus gesehen, ist das Hauptziel dieser Arbeit einen Arbeitsablauf zu entwickeln, der verwendet werden kann, um die Performance von häufig genutzten Richtbohr-Kontrolltools zu vergleichen und zu evaluieren. Zusätzlich soll dadurch das beste Kontrolltool in Bezug auf niedrige Kosten und hohe Performance vorgeschlagen werden.

Im ersten Teil dieser Arbeit werden zwei Themengebiete behandelt, zuerst die Vor- und Nachteile der am häufigsten verwendeten Richttechniken. Anschließend wird das Arbeitsprinzip von Rotary Steerable Systems (RSS) erklärt.

Der zweite Teil umfasst eine detaillierte Beschreibung der notwendigen Methodik für den entwickelten Arbeitsablauf. Dieser Arbeitsablauf besteht aus vier unterschiedlichen Phasen, in welchen Daten von stark abgelenkten Bohrungen gesammelt werden. Phase eins dient ausschließlich zur Sammlung von Daten. Da die Qualität der Daten und deren Validierung einen maßgeblichen Einfluss auf die Endergebnisse hat, werden in der zweiten Phase die vorab gesammelten Daten bewertet. In der dritten Phase wird die Software Landmark verwendet, um die angemessenen Daten zu verarbeiten. Schlussendlich dient die vierte Phase, mithilfe von speziellen Key Performance Indicators (KPIs) und einer gewichteten Entscheidungsmatrix, zum Vergleich der Leistung der unterschiedlichen Richtbohr-Kontrolltechniken und deren Reihung.

Der dritte Teil dieser Arbeit umfasst eine Fallstudie, die reale Daten eines iranischen Feldes mithilfe der oben angeführten Schritte des Arbeitsablaufes analysiert und bewertet. Der Hauptzweck der Fallstudie ist, den ausgearbeiteten Arbeitsablauf auf eventuell auftretende Nachteile zu testen. Das Endergebnis der Fallstudie zeigt, dass der Arbeitsablauf verlässlich und einfach zu verwenden ist.

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1 Introduction

1.1 Overview

As the search for oil continues and economics allows reservoirs of progressively lower yield to be put onto production, directional drilling becomes increasingly synonymous with oil well drilling. The offshore drilling industry bears its foundation on directional drilling. Without this techniques that have been developed over the years there would be no multi-well platforms and consequently many nations would become increasingly dependent on those countries with large shore based reserves.

As the era of the easy oil becomes close to the end, geological targets are becoming narrower which forces the drilling engineers to improve the directional drilling accuracy. Accuracy in reaching the low tolerance targets could be achieved by optimizing the drilling process and the use of new technology. However, reducing the uncertainty related to boreholes placement is not the only challenge, there are several other issues which have to be addressed, among them enhancing total rates of penetration and reducing drilling costs, these make the challenge even worse.

In oil industry the most common method used to deviate well paths is steerable motor, which bent motor assembly adjusted at the surface and there is no control on motor bent degree in downhole. Disadvantages of this method can be cited which included: Pipe sticking in lost circulation zones, well path control in unstable shales, and slide drilling which is time consumer and high-risk operation.

In order to overcome shortcomings associated with steerable motors, Rotary Steerable Systems (RSS) have been invented in late 1990s. These systems have shown the capacity for reducing the drilling costs while providing optimized directional control. Elimination of sliding mode drilling improves rates of penetration, achieves smoother trajectory, less chance of differential sticking, more efficient whole cleaning; and drill further interval with one BHA. Nevertheless, there is some concern while using rotary steerable system such as tools failure and cost of services and etc. Due to rotary steerable system is high technology tools which comprise of some mechanical and electrical components, while drilling these parts are prone to failure these parts are prone to failure, consequently, the drill string has to be pulled out to replace the damaged components, this action impose more time and cost. Moreover, in trouble zone at which possibility of losing BHA are high , adding expensive element to BHA will cause the cost to be very high in case fishing operation is failed to retrieve the entire BHA. . As per aforementioned cons and pros selecting rotary steerable system as directional techniques should be evaluated and compared with alternative during the design phase.

1.2 Motivation

As it was clarified in the previous section, RSS cannot be always the best solution; other deviation techniques could offer better results in some cases. From this perspective three factors are set up to be the main motivation for this thesis:

1. Drilling is an expensive operation, small optimization in drilling time will cause significant cost saving
2. Knowing when to select a rotary steerable system and when to use a high-performance mud motor is critically essential to optimize the drilling operation from both a cost perspective and an engineering performance
3. Analyzing ROP, hole condition, well trajectory for each type of BHAs is a proper engineering approach for performance evaluation.

1.3 Objective

The prime objective of this thesis is to demonstrate both tangible and intangible benefits resulting from the use of rotary steerable systems in comparison of steerable system in an offshore field. The comparison has been performed using carefully selected KIPs. These sophisticated KPIs cover wide range of known business and technical KPIs. In order for this thesis to be able to achieve the mentioned goal, the following objectives were set to be the main focus of the thesis:

- Create a literature review that focuses on comparing between most commonly used deviation tools and directional control techniques.
- Review of currently most newly developed rotary steerable systems.
- Develop a workflow which can be efficiently used to evaluate and compare different directional control methods.
- Apply the developed workflow to one of Iranian offshore field in order to select best technique that is cost effective.

2 Directional Control Techniques Overview and Comparison

2.1 Directional Drilling History

In prior circumstances, directional drilling was utilized fundamentally as a remedial operation, either to sidetrack around fishing, take the wellbore back to vertical, or in drilling relief wells to kill blowouts. interests in controlled directional drilling started around 1929 after new and rather precise methods for estimating hole angle was introduced during the development of Eminole, Oklahoma field. The main use of oil well surveying happened in the Seminole field of Oklahoma amid the late 1920's. a subsurface geologist discovered it greatly hard to create sensible contour maps on the oil sands or other deep key beds. The acid bottle inclinometer was introduced into the region and uncovered the purpose behind the issue; every one of the holes was crooked, having as much as 50 degrees inclination at some check focuses. In the spring of 1929 a directional inclinometer with a magnetic needle was brought into the field. Gaps that showed an inclination of 45 degrees with the acid bottle were really 10 or 11 degrees less in deviation. The reason was that the acid bottle perusing graph had not been rectified for the meniscus distortion caused by capillary pull. Along these lines better and more precise survey instruments were developed over the next years. The utilization of these inclination instruments and the outcomes revealed that in the vast majority of the wells surveyed, drill stem measurements had next to no connection to the genuine vertical depth came to, and that most of the wells were "screwy". A portion of the wells was slanted as much as 38 degrees off vertical. Directional drilling was utilized to straighten crooked holes.

In the mid-1930's the primary controlled directional well was drilled in Huntington Beach, California. The well was drilled from an onshore location into offshore oil sands utilizing whip-stocks, knuckle joints and bits. An early form of the single shot instrument was utilized to orient the whip-stock. Controlled directional drilling was at first applied as a part of California for unethical purposes, that is, to deliberately cross-border lines. In the development of Huntington Beach Field, two secret wells completed in 1930 were extensively deeper and yielded more oil than different producers in the field which at that point must be pumped. The conspicuous conclusion was that these wells had been deviated and bottomed under the sea. This was recognized in 1932, when drilling was done on town parcels for the declared motivation behind broadening the producing zone of the field by tapping oil reserves underneath the sea along the shoreline front.

Controlled directional drilling had gotten rather troublesome attention until the point that it was used as a part of 1934 to kill a wild well near Conroe, Texas. The Madeley No.1 had been spudded half a month sooner and, for some time, everything had been going typically. Yet, on a cold, wet, dreary day the well developed a high pressure leak in its casing, and after a short time, the getting away pressure made a tremendous cavity that gobbled up the drilling rig. The hole, around 170 feet in distance across and of obscure profundity, loaded with oil blended with sand in which oil boiled up always at the rate of 6000 barrels for every day. For killing the well, the significant oil organizations in Conroe recommended that an offset well be drilled and deviated so it would bottom out near the borehole of the cratered well. At that point mud under high pressure could be pumped down this offset well so it would channel through the formation to the cratered well and in this manner control the blow out. The recommendation was affirmed and the operation was completed effectively, to the satisfaction of all concerned. Accordingly, directional drilling ended up plainly settled as one approach to defeat wild wells, and it subsequently increased good acknowledgment from the two organizations and contractual workers. With typical oil field inventiveness, drilling engineers and contractors started applying the standards of controlled directional drilling at whatever point such strategies gave off an impression of being the best answer for a specific issue.

In the late 1980s, new steerable motor drilling frameworks, joined with polycrystalline diamond minimal (PDC) drill bits and measurement-while-drilling (MWD) technology, fundamentally enhanced directional drilling productivity and well placement accuracy. These frameworks decreased the requirement for the continuous bottom hole assembly changes that are required with more seasoned rotary strategies and could utilize the more regular survey readings gave by MWD tools to practice more tightly control over the well's trajectory. The steerable motor framework was the key system behind the quick development of horizontal drilling in the mid-1990s.

However, drillers soon found the constraints of these frameworks. steerable motors expected drillers to exchange between a non-rotating 'sliding' mode—when the assembly's bent housing would be oriented to divert the well path—and 'turning' mode when the whole drill string would be rotated to drill a straight section. Introduction amid sliding required tool adjustments from the surface, so it was regularly troublesome, particularly in long horizontal sections. Opening cleaning was more troublesome without pipe rotation, so regular short trips were required. drilling ahead with a bent assembly here and there prompted hole issues like spiraling, edges and over-gauge hole that muddled casing runs. Rotary steerable frameworks were developed to dispose of the requirement for bent tools, to accomplish the borehole quality conceivable with consistent string rotation, and to give robotized down hole control over the well path. With these capacities, directional drilling could take another jump forward in productivity and placement accuracy, empowering the standard utilization of extended reach and complex 3D well profiles. While the rotary steerable drilling idea flourished in the late1980s, it was almost 10 years sooner practical systems wound up noticeably accessible.

The Schlumberger Company has developed its well-known Power-Drive X5, the backbone of its rotary steerable armada. Since Schlumberger commercially introduced RSS in the late 1990s, it has seen the immense development of the technology in the market.

Since its first commercial run in 1996. There have been 230 Power-Drive tool runs to date, including thousands of hours of operation in more than 40 wells. The longest single run drilled a 5255-ft [1602-m] section. In the Njord field of the Haltenbanken territory of western Norway, operator Norsk Hydro first utilized the Power Drive framework to drill the reservoir section of the A-17-H well, completing 22 sooner in the program. This achievement set the STAGE for a considerably more difficult multi-target well with a sinusoidal profile to deal with the double challenges of geological vulnerability and poor reservoir availability. The A-13-H well was drilled with the Power Drive framework in April 1999.

The PowerDrive rotary steerable system added to the drilling of the world's longest oil and gas production well, the 37,001-ft [11,278-m] Wytch Farm M-16SPZ well, in 1999.

2.2 Reasons and Applications of Directional Drilling

Directional drilling is a complicated and new drilling method which can deviate wellbore to the planned trajectory with a specific end goal to achieve the reservoir targets. These days, directional drilling is generally utilized far and wide on the grounds that it has a few focal points over a typical vertical well. Oil and gas reservoir shapes have the lateral length more than vertical length so the directional drilling will have more chances to achieve potential sands. At last, hydrocarbon reserves can be extricated with the directional wells. The applications of directional drilling can be grouped into the following categories:

- Sidetracking.
- Drilling to avoid geological problems.
- Controlling vertical holes.
- Drilling beneath inaccessible locations.
- Offshore development drilling.
- Multilateral well.
- Shoreline drilling.
- Horizontal drilling.
- Relief Wells.

2.2.1 Side-tracking

Sidetracking out of an existing wellbore is common application of directional drilling, basically it is considered as remedial operation. The most common type of sidetracking is used to;

- Bypass an obstruction (e.g., lost pipe and tools, cemented or plugged-back well) in the original wellbore.
- Explore the extent of the producing zone in a certain sector of a field.
- Sidetrack a dry hole to a more promising target.
- Access more reservoir by drilling a horizontal hole section from the existing well bore.
- Bring the wellbore back to vertical by straightening out crooked holes.

2.2.2 Restricted Locations

Targets located beneath a city, a river or in environmentally sensitive areas make it necessary to locate the drilling rig some distance away. A directional well is drilled to reach the target

2.2.3 Salt Dome Drilling

Salt domes have been observed to be natural traps of oil gathering in strata underneath the overhanging hard cap. There are severe drilling issues related to drilling a well through salt formations. These can be fairly eased by utilizing a salt-saturated mud. Another way is to drill a directional well to achieve the reservoir, so we can stay away from the issue of drilling through the salt.

2.2.4 Fault Controlling[1]

Crooked holes are normal when drilling is vertical. This is frequently because of faulted sub-surface formations. It is frequently simpler to drill a directional well into such formations without intersection the fault lines

2.2.5 Multiple Exploration Wells from a Single Well-bore

A single wellbore can be plugged back at a specific depth and deviated to make another well. A single well bore is usually utilized as a point of departure to drill others. It permits exploration of structural areas without drilling other complete wells.

2.2.6 Onshore Drilling

Reservoirs situated beneath expansive rivers which are inside drilling compass of land are being tapped by finding the wellheads on land and drilling directionally under the water. This saves money-land rigs are much cheaper.

2.2.7 Offshore Multi-well Drilling

Directional drilling from a multi-well offshore platform is the most financial approach to grow offshore oil Fields. Onshore, a comparable technique is utilized where there are space confinements e.g. jungles, swamps. Here, the rig is skidded on a pad and the wells are drilled in "clusters".

2.2.8 Multiple Sands from a Single Well-bore[2]

In this application, a well is drilled directionally to meet a few slanted oil reservoirs. This permits completion of the well by means of a multiple completion framework. The well may need to enter the targets at a particular angle to guarantee greatest penetration of the reservoirs.

2.2.9 Relief Well

Directional methods are utilized to drill relief wells from a further area to kill wells which are flowing out of control.

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[1] Ref- Mike Smith, "Directional Drilling Training Manual" Schlumberger, Page 7, 06 Dec 1996.
[2] Ref- Mike Smith, "Directional Drilling Training Manual" Schlumberger, Page 9, 06 Dec 1996.

2.2.10 Horizontal Wells

Horizontal drilling is becoming more common in the oil industry; briefly it is a drilling process in which the well is turned horizontally at depth. The primary function of the horizontal drilling is to:

- Increasing the drainage area of the platform.
- Mitigate gas coning or water coning problems.
- Increased penetration of the producing formation.
- Increase the efficiency of enhanced oil recovery (EOR) techniques.
- Improve the productivity of natural fractured reservoirs by intersecting a number of vertical fractures.

2.3 Deflection Methods[3]

A deflection tool is a drill string device that causes the bit to drill at an angle to the existing hole. Deflection tools are sometimes called kickoff tools because they are used at the kickoff point to start building angle. There are two basic methods of forcing the bit to deviate from its natural trajectory. One is simply to push the bit sideways by means of a whip-stock which is external to the string. The others use equipment included in the string. Normally this is equipment which causes the bit to rotate about an axis which is at an angle to the axis of the main part of the assembly, it follows that, in order for this to be effective, the drill string must be not rotated at least until the required trajectory has been achieved. In other words, only the bit is rotating. This method involves the use of the downhole motors. Nevertheless the recent technology combines the two basic methods involving pushing the bit sideways by means of equipment installed in the bottom hole assembly. This method involves the use of rotary steerable system.

Briefly, the choice of the deflection tools and techniques depends upon the degree of deflection needed, formation hardness, hole depth, temperature, presence or absence of casing, and economics. The most important factor is the formation in which the deflection is to be made, because it is the only factor beyond control. The fundamental deflection tools utilized as a part of directional drilling can be grouped as following:

1. First Group
   - ✓ Jetting
   - ✓ Whip-stocks
   - ✓ Rotary Assemblies
2. Second Group
   - ✓ Positive Displacement Motors
   - ✓ Turbines
3. Third Group
   - ✓ Rotary Steerable System (RSS)

[3] Ref- Mike Smith, “Directional Drilling Training Manual” Schlumberger, Page 152, 06 Dec 1996.

2.3.1 Whip-stock

A variety of Whip-stocks is available for special purposes. A non-retrievable Whip-stock (permanent casing Whip-stock), for instance, may be used to bypass a stuck fish; it is left in place after the deflection has been accomplished. A retrievable Whip-stock, on the other hand, is tripped out with the bit. A circulating Whip-stock directs fluid to the bottom of the hole to flush out cuttings and ensure a clean seat for the tool. In this section only the procedures followed when retrievable Whip-stock is used will be explained.

The retrievable, open hole whip-stock is just utilized as a part of particular operations e.g. rigs with little pumps, sidetrack in deep and furthermore for high temperature condition. The whip-stock is stuck to a nimble BHA. A common BHA used with The retrievable, open-hole whip-stock consists of:

- Whip-stock
- Pilot Bit
- Stabilizer
- Shear pin sub
- 1 Joint of Drill Pipe
- Universal bottom hole orientation subs
- Non-magnetic drill collar

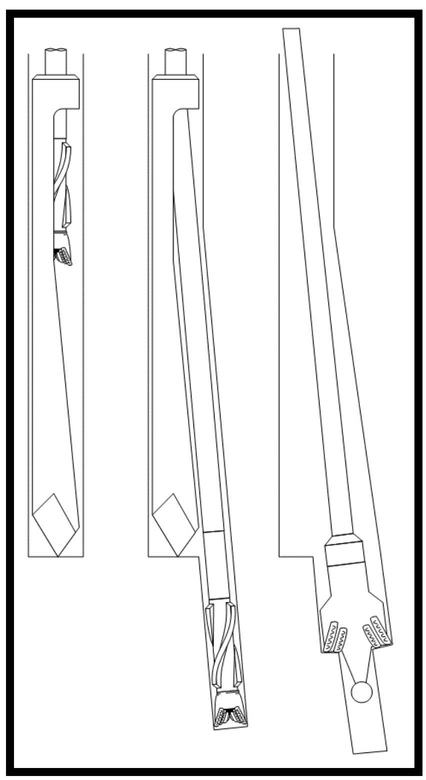


Figure 1: Whipstock deflection method[4]

[4] Ref- Mike Smith, "Directional Drilling Training Manual" Schlumberger, Page 152, 06 Dec 1996.

The hole must be spotless before running the whip-stock. On achieving bottom, circulation is begun. The sunken face of the whip-stock is oriented in the intended direction. The tool is determined to bottom. The toe of the wedge is anchored solidly set up by applying adequate weight to shear the stick. The bit is let down the whip-stock confront. Pivot of the drill-string is begun around 15' - 20' of rat hole are drilled at a controlled rate.

The whip-stock is retrieved and the rat hole opened with a pilot bit and hole opener. Another trip utilizing a full-gauge bit, near-bit stabilizer and nimble BHA is then made. Around 30' are drilled. More hole deflection is acquired. A full-gauge directional BHA is then run and standard drilling is continued.

Clearly, the real detriment of the standard whip-stock is time consuming and the number of "trips" included. The other significant weakness is that the whip-stock produces a sudden, sharp deflection as such, a severe dogleg - which may ascend to consequent issues with the hole . The positive points are that it is a genuinely basic bit of hardware which requires moderately little maintenance and has no temperature confinements.

2.3.2 Jetting

This operation is done to deviate the wellbore in delicate and friable formations. The well can be kicked off and built up to most extreme inclination utilizing one BHA. Exceptional jetting bits can be utilized or it's conceivable to utilize a standard long-tooth bit, regularly utilizing one huge nozzle and two other blank (or very small) nozzles. An exemplary jetting BHA comprises of:

- Bit
- Near-bit Stab
- Universal Bottom Hole Orientation (UBHO) subs
- Measurement while drilling
- Non-Magnetic drill collar
- Stabilizer
- Drill collar
- Stabilizer

A proper formation for jetting must be chosen. There must be adequate room left on the kelly to take into consideration jetting and drilling the initial couple of feet after the jetted interval. The focal point of the big nozzle demonstrates to the tool face and is oriented in the intended direction. Greatest circulation rate is utilized while jetting. The drill-string is determined to bottom. In the event that the formation is adequately delicate, a pocket is washed in the formation inverse the vast nozzle. The bit and near-bit stabilizer work their way into the pocket (path of slightest protection). Enough hole should be jetted to "bury" the near-bit stabilizer. In the event that required, the bit can be pulled off bottom and the pocket "spudded". the strategy is to lift the string around 5' off bottom and afterward let it fall, getting it with the brake so the extent of the string (as opposed to the full weight of the string) makes it spud on bottom. Spudding can be severe on drill-string, drilling line and derrick and ought to be kept to the lowest possible point.

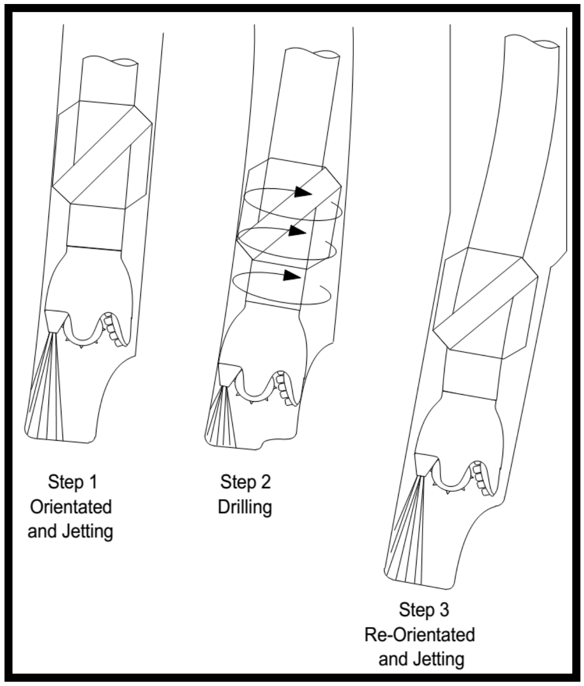


Figure 2: Jetting deflection method[5]

After a couple of feet (normally 5') have been jetted, the pumps are kept for around half of that are used for jetting. The drill-string is rotated. It might be important to pull off bottom quickly because of high torque (near bit stabilizer wedged in the pocket). High WOB and low rpm are utilized to endeavor to bend the collars over the near-bit stabilizer and power the BHA to finish the pattern set up while jetting. The rest of the recording on the Kelly is drilled down. Avoidance is produced in the direction of the pocket i.e. the direction in which the big jet nozzle was originally oriented. To clean the hole preceding connection/survey, the jet ought to be oriented in the direction of deviation. After surveying, this orientation setting (tool face setting) is adjusted as required, contingent upon the outcomes accomplished with the past setting. Dogleg severity must be observed watchfully and reaming executed as needed.

The operation is rehashed as regularly as is vital until the point when adequate inclination has been accomplished and the well is heading in the coveted direction. The hole inclination would then be able to be built up to most extreme angle utilizing 100% rotary drilling. Little direction fluctuations can be made if necessary. The jetting technique is good with the single-shot strategy or MWD. for utilizing single shot strategy the drilling ought to be halted and gyro will be run inside string and sit on UBHO sub-profile and read the inclination and azimuth of deviated hole , above figure delineates the succession. Streaming BHAS. In delicate formation where Hole erosion makes it difficult to keep enough WOB when drilling, a more flexible jetting BHA might be required. The kind of nozzle and stabilizer position are two principle contrast of ordinary BHA and jetting BHA.

[5] Ref- Mike Smith, “Directional Drilling Training Manual” Schlumberger, Page 153, 06 Dec 1996.

2.3.2.1 Advantages and Disadvantages of Jetting Technique

Advantages

- There is no offset in the assembly. Thus, survey errors are minimal compared to PDM/Bent sub alternative.
- Surveys can be taken much closer to the bit than when using a PDM.
- There is no reactive torque when jetting. The "tool face" can be oriented more accurately than when using a PDM. This is particularly important when close to other wells

Disadvantages

- The primary issue with jetting is that sporadic, now and again severe doglegs can happen over short sections of hole. The issue is aggravated by the way that these doglegs might be disparaged by typical survey rehearses. The ascertained dogleg is really a normal incentive over the aggregate interim between surveys. Quite a bit of this dogleg may have been made in the short section of hole which was jetted. The real dogleg severity in this piece of the hole might be substantially higher than that figured from the surveys. For dogleg severity real time assessment the MWD can be utilized to avert inconsistent well trajectory.
- Below 2,000' TVD, the formation normally becomes too firm for efficient jetting/spudding. A mud motor/bent sub kickoff would be preferable.

2.3.3 Directional Control with Conventional Bottom hole Assemblies

Rotary bottom hole assemblies are one of the least expensive methods used to deflect a well and should be used whenever possible. Unfortunately, the exact response of a rotary BHA is very difficult to predict, and the left or right hand walk is almost impossible to control. The rotary BHA is not cost effective if a number of trips are required to change the stabilizer placement on the BHA or to make a correction run with a motor. Rotary BHA's are seldom used today but do have specific applications. Additionally, most steerable motor assemblies and rotary steerable assemblies use the techniques learned from rotary BHA. A bottomhole assembly is the arrangement of bit, stabilizer, reamers, drill collars, subs and special tools used at the bottom of the drill string. Anything that is run in the hole to drill, ream or circulate is a bottomhole assembly. The simplest assembly is a bit, collars and drill pipe and is often termed a slick assembly. The use of this assembly in directional drilling is very limited and usually confined to the vertical section of the hole where deviation is not a problem. There are three basic types of assemblies used in directional drilling. They are:

1. Building Assemblies [Fulcrum Principle].
2. Dropping Assemblies [Pendulum Principle].
3. Holding Assemblies [Stabilization Principle].

A building assembly is intended to increase hole inclination; a dropping assembly is intended to decrease hole inclination; and a holding assembly is intended to maintain hole inclination. It should be noted that a building assembly may not always build angle. Formation tendencies may cause the assembly to drop or hold angle. The building assembly is intended to build angle. The same is true for the dropping and holding assemblies.

2.3.3.1 Advantages and Disadvantages of Conventional Bottom hole Assemblies Technique

Advantages

- It's an inexpensive (no need to use Steerable Motor or Rotary Steerable System).

Disadvantages

- Dogleg capability is affected by distance between stabilizers, drill collar diameter and stiffness, formation dip, rotary speed, weight on bit, formation hardness and bit type. The ability to balance the BHA against these factors can be crucial for reaching a planned target.
- These techniques allowed some control over hole inclination, but little or no control over the azimuth of the wellbore.

2.3.4 Downhole Mud Motors

In directional drilling with conventional bottom hole assemblies, extra trips are sometimes required to change the bottom hole assemblies for directional control purposes. Other important point, which has to be mentioned here, is that, the bit performance may be reduced by conventional deflection techniques. Several methods exist for continuously controlled directional drilling using steerable system. A steerable assembly is defined as a bottom hole assembly whose directional behavior can be modified by adjustment of surface controllable drilling parameters including rotary speed and weight on bit. The ability to modify behavior in this way enables the assembly to be steered toward a desired objective without its removal from the wellbore. These methods are based on tilting the axis of the bit with respect to the axis of the hole and/or creating a side force at the bit. If the drill string, and hence the body of the motor, is rotated from surface [Rotary Drilling Mode], then the bit will tend to drill straight ahead. However, if the drill string is not rotated from surface [Sliding Mode] then the bit will drill a curved path determined by the orientation of the side force or the tilt of the bit axis.

The two major types of down hole motor are:

- The Turbine, which is basically a centrifugal or axial pump
- .The Positive Displacement Motor (PDM).

The standards of operation of both turbine and PDM are appeared in the following figure. The design of the tools is entirely unique. Turbines were popular for using a few years earlier. Nonetheless, enhancements in bit and PDM configuration have implied that turbines are just used as a part of extraordinary applications today. For this proposal just PDMS will be clarified in points of interest in this part.

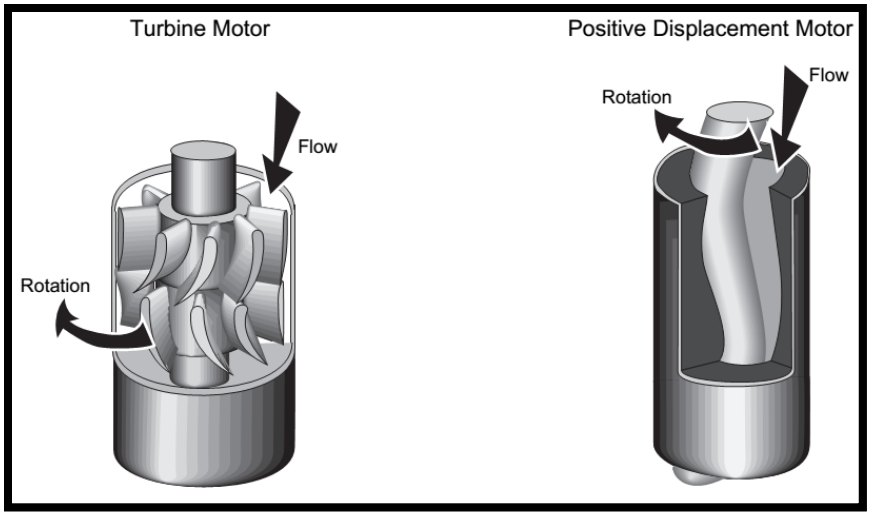


Figure 3: Principles of operation of turbine and PDM

2.3.4.1 Positive-Displacement Motors[6]

The positive displacement motor may be used for directional drilling, sidetracking, straight hole drilling and to maintain or improve penetration rates while correcting or controlling hole deviation. It is run with a full gauge bit, thus eliminating the need for reamers or hole openers on subsequent runs. Directional control is achieved.by the use of a bent housing placed between the motor section and transmission assembly or a stabilized bent housing for a steerable motor. An offset stabilizer configuration is also used. The objective is to cause the bit to drill at a pre-determined angle relative to the wellbore while sidetracking or when initiating or changing the course of the wellbore. For straight hole drilling, tools are equipped with stabilizers on the outer barrel.

As fluid cannot easily pass through the tool a by-pass valve placed on top of the tool allows the mud to by-pass the motor and fill the drill string, it also allows the drill string to drain when tripping out or making a connection. This valve automatically closes as soon as the pumps are started. The multi-stage motor in the PDM consists of two parts: the rubber molded stator with a spiraled, around cross section and the solid steel rotor of a helical configuration. Rotation is caused when fluid is forced under pressure into the cavities which are formed between the rotor and stator. The lower end of the rotor is attached to the top of the drive shaft by means of a connecting rod or universal joint. This connecting rod, in addition to transmitting motor torque, converts the eccentric motion of the rotor to smooth rotary movement at the top end of the drive shaft. The drive shaft runs inside a bearing assembly which assumes both axial and lateral forces. Radial bearings and axial bearings allow rotation and are lubricated by the drilling fluid. Part of the mud flow is diverted through the bearing housing for lubrication and passes out

[6] Ref- Mike Smith, "Directional Drilling Training Manual" Schlumberger, Chapter 7, 06 Dec 1996

between the bearing assembly and bit sub. The main part of the mud ·flow passes through a port in the drive shaft and is directed down to the bit.

2.3.4.1.1 Positive Displacement Motor Components

A positive displacement motors comprise five major elements. From top to bottom they are:

- ✓ By-pass valve (Dump Valve Assembly)
- ✓ Power Section (Rotor/Stator)
- ✓ Transmission Assembly
- ✓ Output Shaft/Bearing Assembly
- ✓ Bit Box (Sub)

Dump Valve Assembly- this enables the mud to fill or deplete from the drill-string while at the same time tripping. At the point when a base flow rate is set up, the valve cylinder is constrained down, shutting the ports to the annulus. Consequently, all the mud is guided through the motor. At the point when the flow rate turns out to be not as much as this lowest point, a spring returns the valve cylinder to the "open" position, which opens the ports to the annulus. To stay away from the entrance of solids from the annulus when the pumps are off (particularly in free sand), it's customary to run a float sub as near the motor as could be allowed.

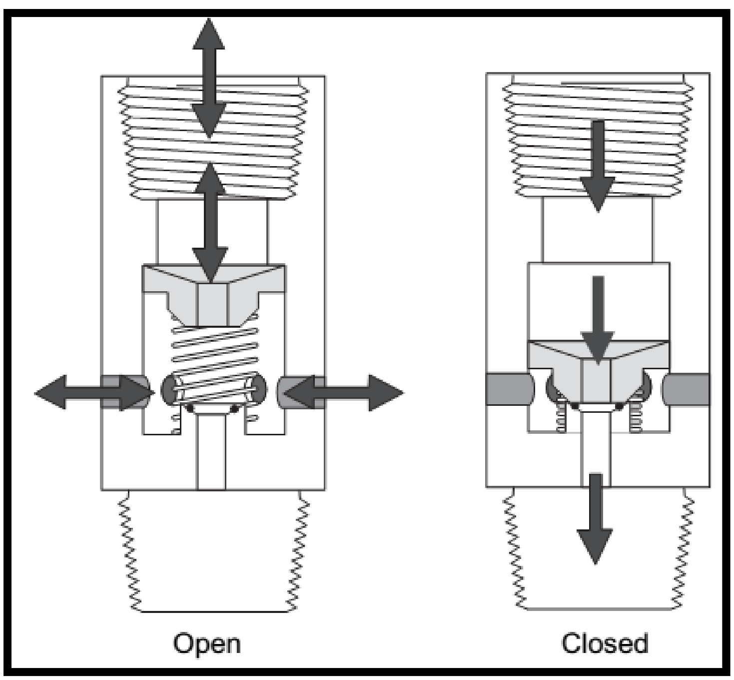


Figure 4: Typical Dump Valve Assembly[7]

The motor will work efficiently without a dump valve - it can be set down and supplanted by a sub having similar connections or run with the ports blanked-off. In any case, it is desirable over

[7] Ref- Mike Smith, "Directional Drilling Training Manual" Schlumberger, Page 182, 06 Dec 1996

run the dump valve. It permits the drill string to fill on the trip in the hole and, if the ports are not blocked off by formation, it enables the string to be pulled "dry".

Power Section- The positive displacement motor is a turnaround utilization of the Moineau pump. Liquid is pumped into the motor's dynamic depressions. The power of the fluid development makes the shaft rotate inside the stator. In this manner, it is a positive displacement motor (regularly called a PDM). The rotational power is then transmitted through the interfacing rod and drive shaft to the bit.

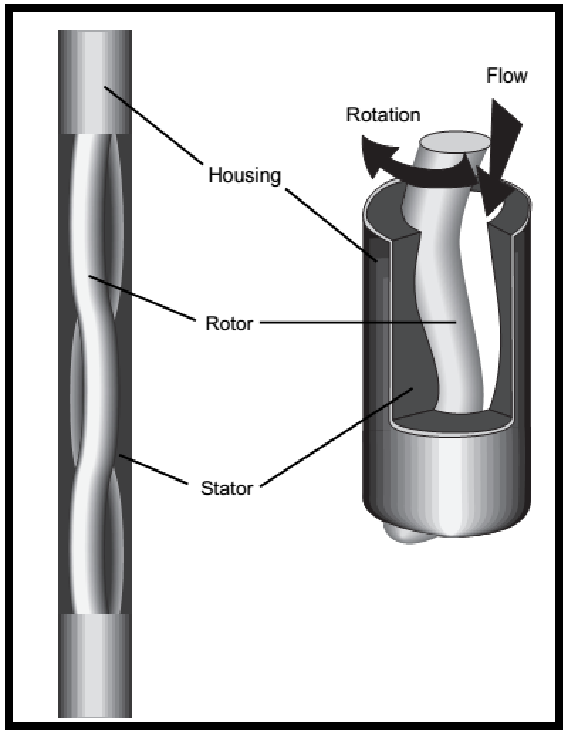


Figure 5: Positive displacement motor

The rotor is chromed composite steel of spiral-helix shape. The stator is an empty steel housing, fixed with a shaped set up elastomer rubber compound. A spiral-shaped cavity is produced in the stator amid manufacture. The rotor is produced with coordinating "Projection" profile and comparative helical pitch to the stator, yet with one lobe less. The rotor can along these lines be coordinated to and embedded inside the stator. Whenever collected, the rotor and stator frame a constant seal along their coordinating contact focuses. Cases of 1-2 and 5-6 rotor/stator design are appeared in underneath figure

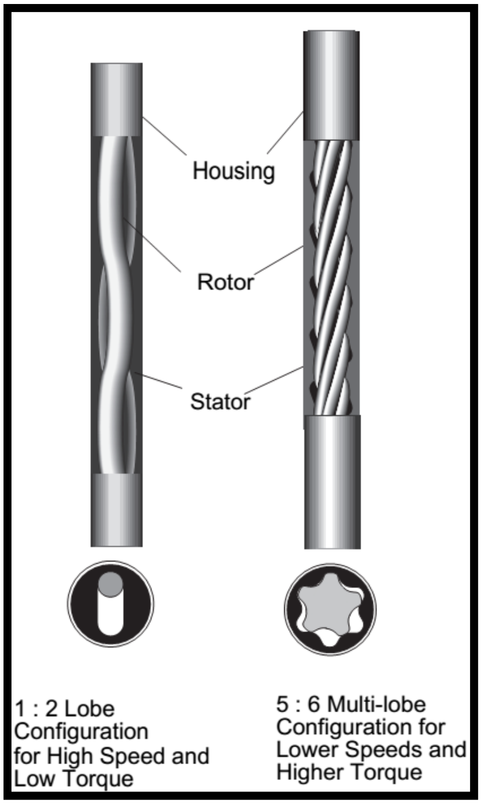


Figure 6: PDM lobe configurations[8]

Each entire spiral of the stator is known as a stage. A slight obstruction fit between rotor O.D. furthermore, stator I.D. controls motor power. Mud motors are separated into moderate speed, medium-speed and high-speed writes. This is finished by changing the pitch of the motor stages and by the quantity of "Flaps" and resultant depressions of the stator. Tests of the different motor profiles that are accessible are outlined in underneath figure.

The more prominent the quantity of lobes, the higher the motor torque and the lower the yield RPM. A D-500 Dynadrill is a 1-2 LOBE motor. The Drilex PDMs and the Dynadrill F2000S are multilobe motors. Ana drill manufactures both 1-2 and multi-lobe motors. Different designs are accessible. (Allude to the fitting motor details). There are diverse applications for 1-2 LOBE and multilobe motors. The power section is frequently called the motor section.

[8] Ref- Mike Smith, "Directional Drilling Training Manual" Schlumberger, Page 183, 06 Dec 1996

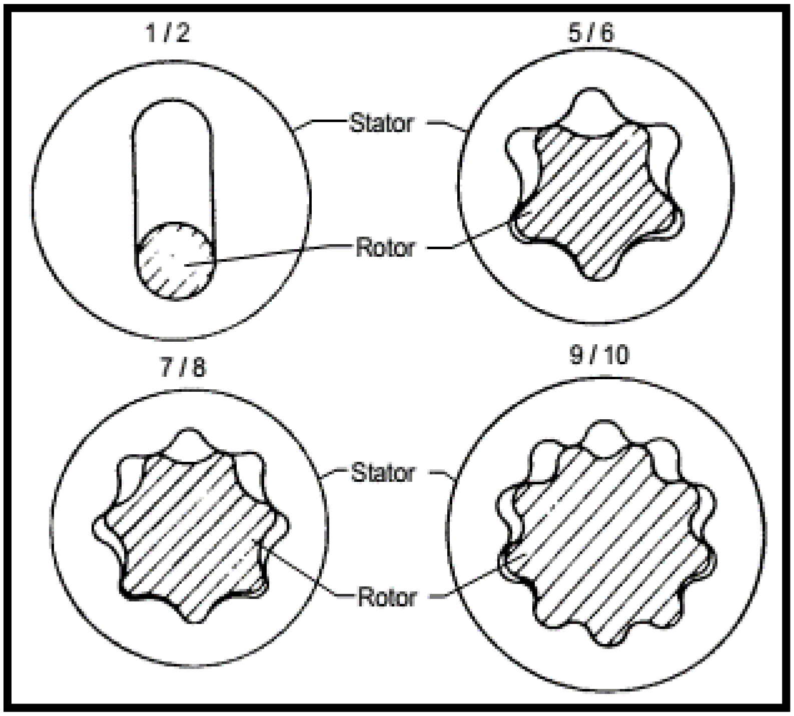


Figure 7: illustrations of various motor profiles

Transmission Assembly (Connecting Rod Assembly)- This is connected to the lower end of the rotor. It transmits the torque and rotational speed from the rotor to the drive shaft and bit. General joints change over the flighty movement of the rotor into concentric movement at the drive shaft. On a few models of mud motor, strengthened rubber "boots" cover the U-joints. These avoid erosion by the mud.

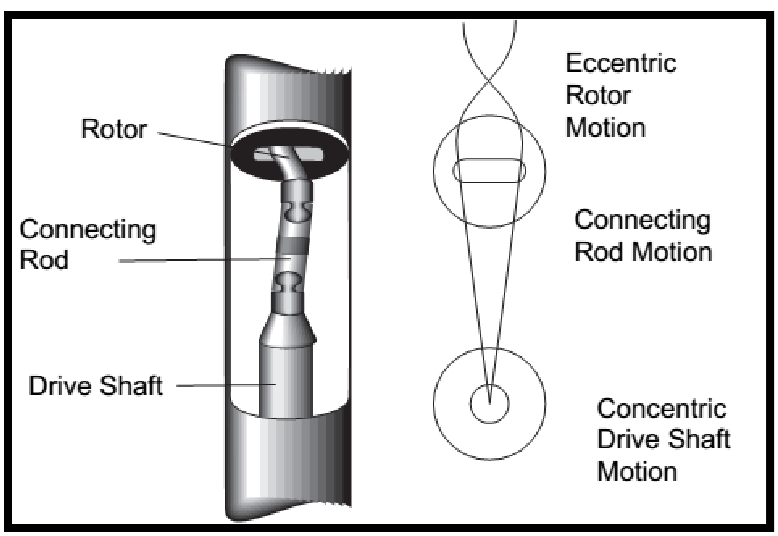


Figure 8: Typical PDM connecting rod assembly[9]

[9] Ref- Mike Smith, "Directional Drilling Training Manual" Schlumberger, Chapter 7, Page 184, 06 Dec 1996

Bearing and Drive Shaft Assembly- -The drive shaft is an unbendingly developed empty steel segment. It is bolstered inside the bearing housing by radial and pivotal thrust bearings. The bearing assembly transmits drilling thrust and rotational power to the drill bit. The majority of the mud flows straight through the focal point of the drive shaft to the bit.

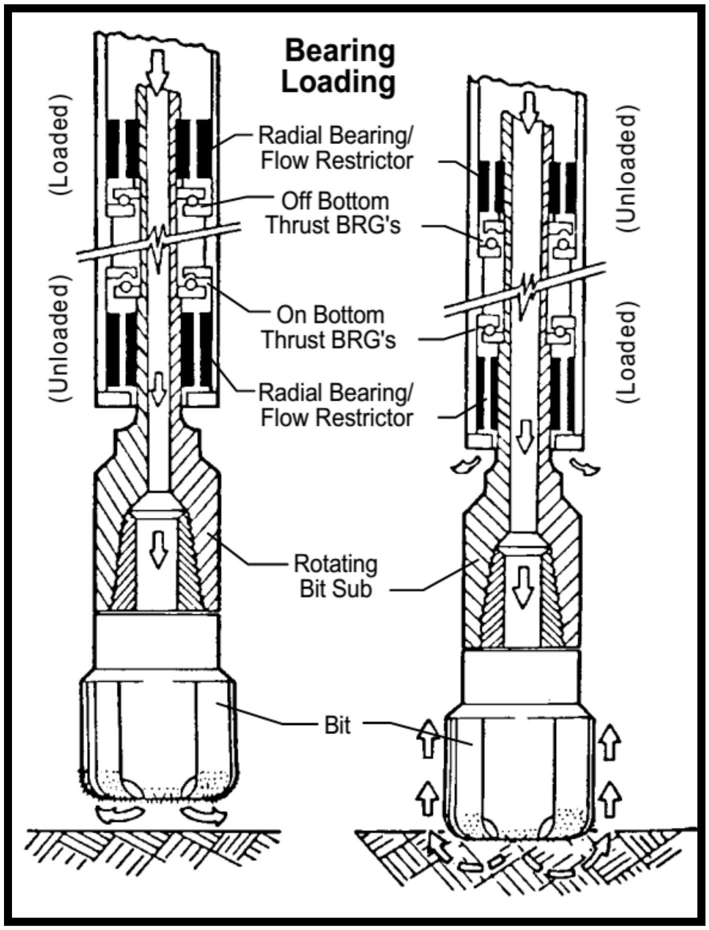


Figure 9: Typical PDM bearing loading

A An exemplary PDM has the accompanying fundamental bearing components -

- **Off-bottom Thrust Bearings-** These help the hydraulic thrust and weight of the rotor, interfacing rod, drive shaft and drill bit when the tool is hanging and rotating unreservedly off bottom. They are regularly ball bearing compose outline.
- **Radial Support Bearings-** A sleeve-type configuration is utilized for both upper and lower radial bearings. The radial bearings in the Anadrill motor comprise of tungsten carbide-coated Sleeves. These give radial help to the drive shaft. They additionally control the flow of MUD through the bearing assembly. This occupied mud (as a rule 4 - 10%) is utilized to cool and lubricate the shaft, radial and thrust bearings. It ways out to the annulus straightforwardly over the bit drive sub. The correct level of mud occupied is dictated by the state of the bearings and the pressure drop over the BIT. A fixed, oil-filled BEARING is another option to the mud-lubricated bearing. A fixed bearing would

be suggested where destructive MUDs are utilized, where a ton of LCM of different sizes is pumped or where there is a prerequisite for a low pressure drop over the bit (Pbit).

- **On-bottom Thrust Bearings-** These transmit the drilling load from the non-rotating motor housing to the rotating drill bit. These bearings take the heap while drilling.

They are either involved ball-bearing races (e.g. anadrill motor) or diamond friction bearings (e.g. Dynadrill F2000S). The rotating bit (drive) sub is the main remotely moving piece of a mud motor. It has standard API bit box connections.

On a few outlines of PDM, a crossover/saver sub is utilized between the stator housing and the dump valve. It ensures the strings of the costly stator. A run of the mill PDM (for this situation, a 1-2 lobe motor) demonstrating its significant parts is delineated in beneath figure

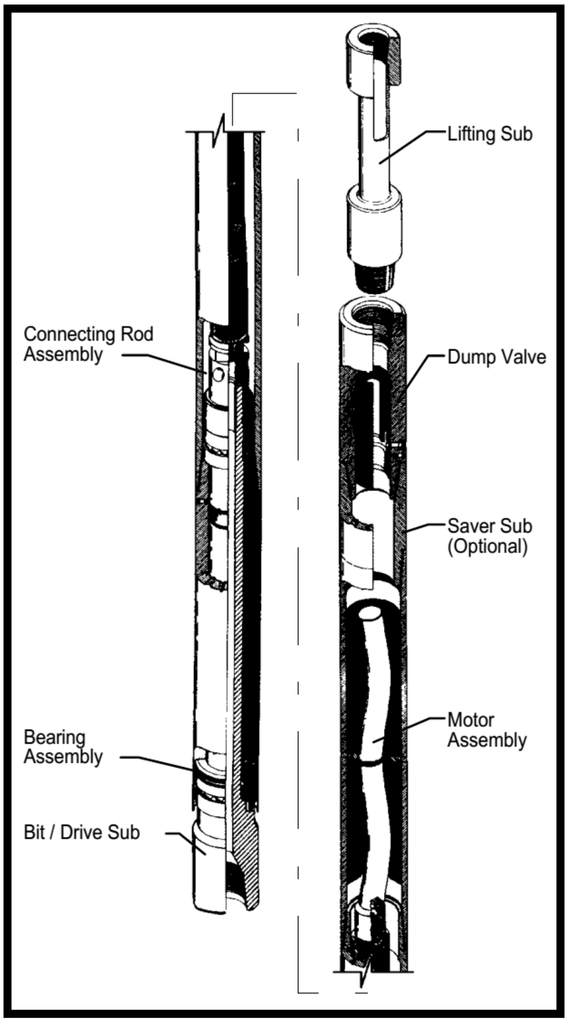


Figure 10: Typical 1-2 lobe PDM[10]

The lifting sub ought to be utilized to get and set out the mud motor as it were.

[10] Ref- Mike Smith, "Directional Drilling Training Manual" Schlumberger, Chapter 7, Page 186, 06 Dec 1996

2.3.4.1.2 Hydraulic Performance of Positive Displacement Motor

The majority of the pressure drop across motor occurs across the power section. The motors are designed to keep the pressure drop across the remainder of the motor as low as possible by maximizing the flow areas. After passing through the power section, most of the drilling fluid travels down through the hollow output shaft to the bit. Approximately 10% of the mud flow is diverted through the bearing section to provide lubrication and cooling. This mud is then vented to the annulus above the bit box. This hydraulic performance generally is true for bit pressure drops up to 1,500 psi.

Should the maximum specified bit pressure drop be exceeded due to bit nozzle plugging or unavoidable needs to increase flow rate or mud weight, a higher percentage of mud may pass through the bearing assembly. Extreme caution should be observed when running motors with a high pressure drop across the bit. Where it is necessary to utilize a high flow rate which exceeds the maximum specified, then a nozzle may be inserted in the top of the hollow rotor. This allows part of the total fluid flow to by-pass the power section but be available at the bit for jetting and hole cleaning. Figure 11 shows an example of a positive displacement motors performance curve.

Under free running conditions bit speed and pressure drops will increase in proportion to flow rate. The pressure drop across the motor will increase as torque is absorbed at the bit, generally by an increase in weight. Maximum power torque is approximately 70% of stall torque for any given flow rate. Because stall can occur very rapidly, it is inadvisable to drill at maximum power torque. The working pressure range between no- load and torque output is independent of the free-running pressure drop across the motor, although all motors have lower stall torques at lower flow rates.

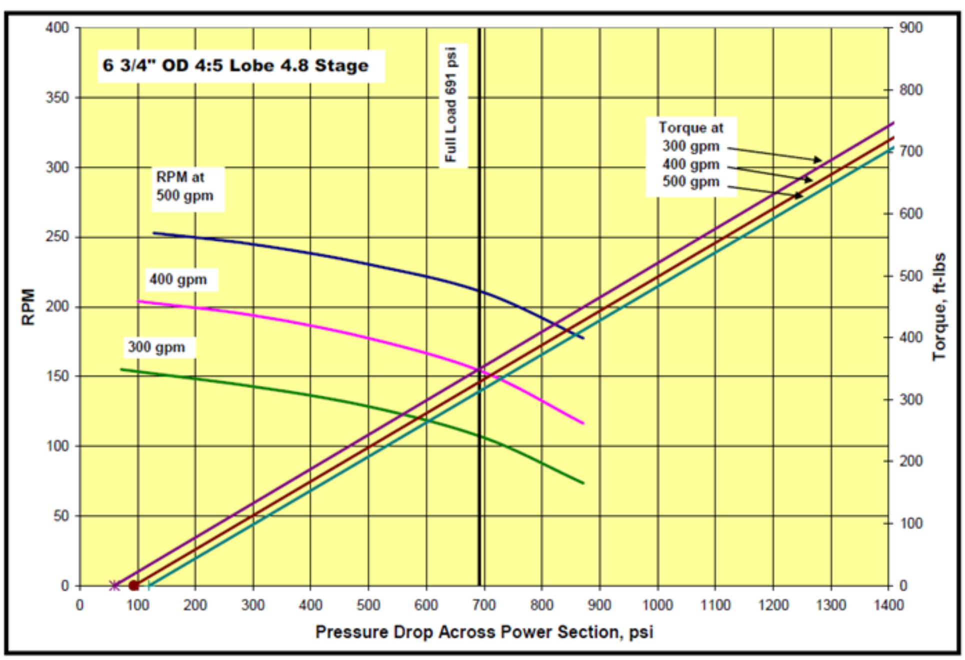


Figure 11. Positive Displacement Motors Performance Curve Example[10]

2.3.4.1.3 Operational Problems Associated with Positive Displacement Motor

Bit Stall out: On shallow depths if the bit should stall out, care must be taken when picking up off bottom so that the Kelly drive (Top drive) does not disengage as the reactive torque may be great enough to overcome friction developed in the hole and spin the whole drill string.

Bit Condition: With the higher bit rotation of some of these tools bit life may be reduced in comparison to hours run with a normal rotary assembly. Repeated stalling of the PDM for no apparent reason, for example no further weight applied, pump output constant, and may indicate a locked cone on the bit.

Stall out Pressure Decreasing: As the tool wears, the motor becomes weaker and the pressure loss through the tool or differential pressure reduces. This · becomes apparent when the stall out pressure gradually reduces. The tool will continue to work but at reduced power and should be replaced on the next trip.

Bit Pressure Differential: The pressure loss across the bit is restricted as this directly affects the amount of fluid flowing through the bearings. Excessively high pressure drop will over-step the designed flow and result in damage to the radial bearing.

2.3.4.1.4 Advantages and Limitations Positive Displacement Motor

Advantages

- ✓ High buildup rates of up to 30°/100ft
- ✓ Complex well designs, including simultaneous builds and turns
- ✓ The required number of bottom hole assembly (BHA) changes was reduced considerably compared to previous rotary methods
- ✓ Power applied directly at the bit which help to improve drilling efficiency
- ✓ Directional drilling became based more on engineering principles than on empirical art learned through lengthy field experience.
- ✓ LWD partially decoupled from bit dynamics

Limitations

- ✓ Slow rate of penetration (ROP): Reduced by as much as 50% compared to rotating
- ✓ Orienting the bend in the motor for steering is time consuming
- ✓ Introduce high local doglegs as the distance between bit and the MWD tools is long
- ✓ Poor hole cleaning in high angle wellbore (While sliding)
- ✓ Uneven fluid velocities around the pipe
- ✓ Cuttings will drop out of suspension to the low side of the hole
- ✓ Cuttings bed may form on the low side of the hole
- ✓ Increase the risk of stuck pipe and Pack off tendency
- ✓ Unable to apply optimum WOB due to motor stall-out

- ✓ Drill-string RPM limited by motor bend
- ✓ Over-gauged hole due to the changes between sliding and rotating

2.3.5 Rotary Steerable Systems

Rotary steerable systems allow actively steering the bit while continuously rotating the drill string. They permit the guidance of well trajectory: inclination and azimuth, while rotating the drill string. As a result, the directional well can be placed within optimal reservoir position and orientation. The rotary steerable concepts were patented in 1950's. The objectives of the earlier rotary steerable systems were to laterally direct the bit, to eliminate tripping in and out of the hole required to set a Whip-stock for well trajectory guidance, and to alter borehole trajectory. However, the earliest systems did not have effective downhole sensors and control systems which hindered their technological and commercial success. The steerable motors direct the bit along a particular path by providing a relatively rigid geometry that biases the bit to drill along the arc of a circle. The tool geometry describes the bit position with respect to the two non-cutting upper contact points. The side cutting capability of the bit allows it to move along the circular arc trajectory that minimizes the side force on the bit. The trajectory in a rotary steerable system is also determined by the three-point geometry. The ideal condition is to align the bit axis with the well path arc, described by the three control points.

2.3.5.1 Rotary Steerable Systems Characteristics

Rotary Steerable Systems have advanced characteristics compared to downhole mud motors, these characteristics are summarized here:

- ✓ Rotary steerable systems allow actively steering the bit, inclination and azimuth, while continuously rotating the drill string
- ✓ The tool-face of the assembly is oriented by the guidance system downhole.
- ✓ Allow changing well trajectory in response to real time downhole data
- ✓ The systems use a continuously adjusted steering function to produce a smooth wellbore, free of steps and unnecessary deviations from the target profile.
- ✓ Rotary steerable systems can be run in conjunction with more or less complete MWD / LWD tools (Geo-steering applications).

2.3.5.2 Advantages and Limitations of Rotary Steerable Systems

Advantages

- Continuous Steering for Smooth Wellbores
- Eliminating the "Slide and Rotate“
- Free of steps and unnecessary deviations from the target profile
- In-gauge borehole
- Reduce Wellbore Tortuosity
- Better Quality LWD Measurements
- Reduced Friction Factor

- Reduced TQ & Drag
- Easier tripping
- No Annular Bottlenecks
- Reduced rig time
- Rotary steering system delivers substantially higher overall ROP
- Time spent to orient the tool-face prior to conventional sliding is eliminated.
- No sliding, faster overall ROP
- Range of Bit selection.
- Improve Instantaneous ROP and reduce trip time
- Hole cleaning is improved in high angle wells as the pipe is rotated both while steering the well and drilling straight.
- ECD will be kept consistent, rather than fluctuating as the hole is loaded with cuttings while sliding and then cuttings beds agitated and unloaded while rotating.
- RSS eliminates additional wiper trips for the hole cleaning
- RSS allows higher surface rotary speed, as there is no bend in the mud motor to limit rpm.
- Improve cutting transport, and wellbore placement
- Early warning of any unwanted deviation
- Minimize unwanted doglegs and reduce failure risk

Limitations

- When rotary drilling, all of the mechanical power required by the bit to drill the rock is provided from the rig rotary system (No additional power source).
- High % of provided energy is lost through borehole friction. This results in less power being delivered to the drill bit, reducing drilling efficiency and ultimately limiting the reach which the well could be efficiently drilled to. As a result of this energy loss, instantaneous ROP may not be as high as achieved while rotary drilling ahead with a PDM powered conventional or performance drilling assembly.
- To achieve acceptable ROP, rotary steerable systems are often operated towards the upper limits of rig rotary speed capability. This varies by rig capacity, but frequently involves rotating the drill string continuously at between 130 and 180 rpm. While this very high string rotary speed is good for ROP and beneficial to hole cleaning, it can also be mechanically damaging.
- When pure rotary drilling, there is no decoupling of drill bit dynamics from the BHA immediately above it, consequently, torsional vibration (stick-slip) can be generated either by the friction of the drill string against the borehole wall or directly by the drill bit. In the event the drill bit induces torsional vibration, this vibration is transmitted to the entire BHA as there is no decoupling or dampening as there is with PDM assemblies. Sever vibration could lead to tool failure.

3 Rotary Steerable System

A rotary steerable system (RSS) is a new type of drilling technology utilized as a part of directional drilling. It utilizes the application of particular down hole tools to substitute conventional directional equipment, for example, mud motors. RSS perform directional drilling with constant rotation of drill string, there is no sliding operation, unlike drilling with a conventional steerable system. One of the causes why RSS technology was revived after quite a few years of mud motors domination in drilling market is increasing needs of drilling Extended Reach Drilling (ERD) wells. The ability of steerable motors was insufficient to meet the necessities of productive and financially efficient drilling of ERD wells. Another region where RSS turned out to be very effective is offshore drilling with its ERD complicated horizontal wells with complex geometries of well trajectory. Mud motors are not reasonable for some of such ERD wells and most possible utilization of motors won't be financially successful regardless of whether it would be actually conceivable. [11]

3.1 History of Rotary Steerable System

In the late 1980s, new steerable motor drilling system, joined with polycrystalline Diamond Compact (PDC) drill bits and measurement-while drilling (MWD) technology, fundamentally enhanced directional drilling productivity and well placement accuracy. These system decreased the requirement for the continuous bottom hole assembly changes that are required with more seasoned rotary strategies and could utilize the more regular survey readings gave by MWD tools to practice more tightly control over the well's trajectory. The steerable motor framework was the key system behind the quick development of horizontal drilling in the mid-1990s.

However, drillers soon found the constraints of these frameworks. steerable motors expected drillers to exchange between a non-rotating 'sliding' mode—when the assembly's bent housing would be oriented to divert the well path—and 'rotating' mode when the whole drill string would be rotated to drill a straight section. Introduction amid sliding required tool adjustments from the surface, so it was regularly troublesome, particularly in much long horizontal sections. Hole cleaning was more troublesome without pipe rotation, so regular short trips were needed. drilling ahead with a bent assembly here and there prompted hole issues like tight spot, edges and over-gauge hole that make trouble casing runs. RSS were developed to dispose of the requirement for bent tools, to accomplish the bore hole quality conceivable with consistent string rotation, and to give robotized down hole control over the well trajectory. With these capacities, directional drilling could take another jump forward in productivity and placement accuracy, empowering the standard utilization of extended reach and complex 3D well profiles. While the rotary steerable drilling idea flourished in the late1980s, it was almost 10 years sooner practical systems wound up noticeably accessible.

[11] T. Warren, "Steerable Motors Hold Out Against Rotary Steerables", SPE-104268, Tesco Corp., San Antonio, 2006

The Schlumberger Company has innovated its well-known PowerDrive, the backbone of its rotary steerable armada. Since Schlumberger presented RSS in the late 1990s commercially, it has seen the immense development of the technology in the drilling market. Because of its first industrial run in 1996. There have been 230 PowerDrive tool runs to date, consist of thousands of hours of operation in more than 40 wells. The longest single run drilled a 1602m directional section. In the Njord field which located western Norway, operator Norsk Hydro first utilized the RSS to drill the reservoir section of the specified well, completing 22 days sooner than drilling program. This achievement cause RSS usage for a considerably more difficult multi target well with a crooked profile to deal with the double challenges of geological vulnerability and poor reservoir availability. The other well was drilled with the RSS in April 1999. The PowerDrive rotary steerable system added to the drilling of the world's longest oil and gas production well, the 11,278-m Wytch Farm M16well, in 1999

3.2 Steering Principal

There are two operating principles that are often referred to when discussing rotary steerable systems namely push the bit or point the bit.

3.2.1 Push the Bit Working Principle

A push the bit rotary steerable system steers simply by applying a side load to the bit, usually using pads close to the bit to apply this load. This forces the bit outer cutting structure and gauge to cut sideways into the formation to drill a curved hole in that direction. Systems employing this principle are restricted to very short gauge bits, where the gauge is set with an active cutting structure. While these systems are agile, permitting a quick and precise response to any required changes in wellbore deviation, the short gauge bits used by these systems may drill a spiraled hole, when high side-loading is applied.

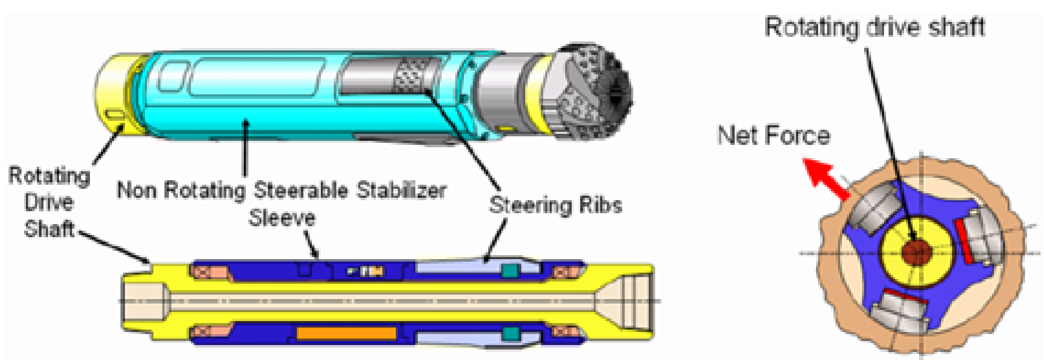
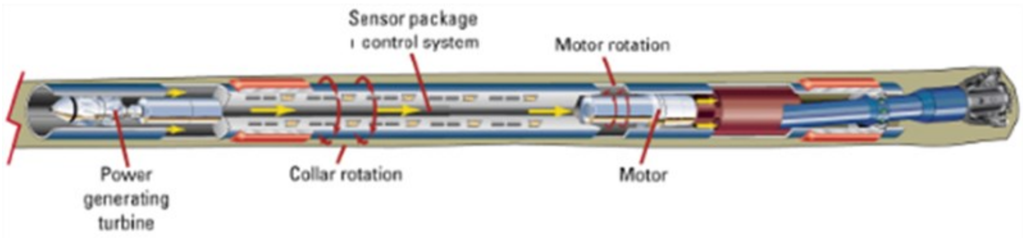


Figure 12. Push the Bit RSS Working Principle[12]

3.2.2 Point the Bit Working Principle

Point the bit rotary steerable system steers by precisely pointing (tilting) the bit in exactly the direction the well path needs to be steered. In doing so, the drill bit's face is pointing perfectly in the direction to be drilled and there is no side loading on the bit. The advantage of this principle is that longer gauge bits can be used to avoid hole spiraling. Unfortunately, these systems are slower to respond to required trajectory changes and the overall dogleg severity capability is typically lower than that of a push the bit system. Table 1 below shows the advantages and disadvantages of the two systems.



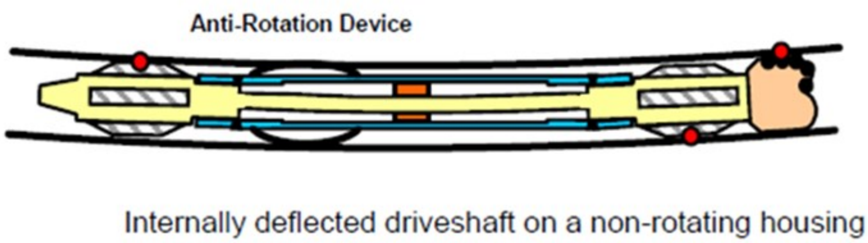


Figure 13. Point the Bit RSS Working Principle[12]

Table 1. Advantages and Disadvantages of Push the Bit and Point the Bit

System	Advantages	Disadvantages
Push the Bit	– Rapid response to required wellbore deviation changes	– Dependence on contact with the borehole wall for directional control – Directional performance can be affected by borehole washouts – Wellbore quality can be impaired as very short gauge bits with active gauge cutting structure are used – over-gauge and irregular hole, especially in weak formation, due to short gauge bit
Point the Bit	– Less influences from wellbore condition on tool performance – The tool requires less reaction from the formation – longer gauge bits can be used and incidents of hole spiraling or irregular hole gauge quality are reduced	– These systems are slower to respond to required trajectory changes – Typically more sensitive to systems are typically more sensitive to loss of predictability of steering control if the hole is over gauge – have an inherent mechanical weakness in the bent or tilted driveshaft mechanism

3.3 Review of Commercial Rotary Steerable Systems

3.3.1 Push the Bit- Power Drive[12]

3.3.1.1 Over view

The Power-Drive RSS is utilized to control the direction in which a well is drilled while the drill string is pivoting. The system comprises of a control unit mounted on bearings inside a committed nonmagnetic collar. The control unit holds itself about its longitudinal (move) axis by servo control. This is accomplished by using;

- Internal sensors to quantify its orientation, both in free space and inside the collar, and
- Electrical torquers utilized as magnetic brakes.

The control unit is mechanically connected to the bias unit. The bias unit contains three pads which can be extended to push against the bore hole - along these lines digressing the direction of drilling. The control unit controls a rotary valve in the bias unit, the position of this ROTARY valve as for the bias unit figures out which pad is pushed against the formation. By controlling the orientation of the control unit to a settled angle, the pads push against an indistinguishable point on the formation from the bias unit rotates along these lines making the drilling be redirected in a settled direction relating to the angle of the control unit. The orientation of the control unit is performed by contrasting the requested control unit angle and the genuine control unit angle as inferred by its on-board sensors (eg, Magnetometers, Accelerometers, etc.). The direction in which the BHA is steered is dictated by the angular orientation of the control unit as for the formation. The information from the interior sensors is logged inside the unit for later investigation once the unit has been retrieved from the bore hole. Cautious examination of this information can uncover framework execution and profile information. This manual is intended to give an introduction into the log analysis software and the process of data log Analysis.

3.3.1.2 General

The control unit is mounted on two arrangements of bearings, which enables it to rotate around the BHA focus line axis. The direction of rotation is controlled by the activity of the Upper and Lower torquers. The control unit comprises of four modules,

- A Lower torquer,
- A Sensor module,
- A Communications (Comms) module, and
- An upper torquer.

[12] Ref- Matthew Donovan, "PowerDrive Uniform Operating Procedures", Schlumberger, Dec-2004.

A Communications module controls the exchange of information and logging inside the control unit. A real-time clock is executed inside the Communications module enabling this information to be logged against time.

3.3.1.3 Sensor

There are two kinds of sensor modules utilized inside the PowerDrive product. The two modules are fundamentally the same as and the yield information portrayed here is indistinguishable. Where the two sensor module variations vary, the minor varieties will be noted in the content. With a specific end goal to comprehend the information that is logged and in this manner prepared it is critical to comprehend the sensors utilized and their terms of reference.

- **3-Axis Magnetometer**

A 3-Axis magnetometer is utilized to gauge the world's magnetic field and in this way the outright position of the control unit in respect to the earth. The essential capacity of the 3-Axis magnetometer amid operation amid drilling is to give a reference to kick-off from the vertical in drilling at Angles from vertical to 5º of inclination (magnetic tool-face)

- **Roll Rate Gyro**

The roll rate gyro measures the angular rate of rotation of the control unit regarding the earth. This information is utilized as a part of a few courses by the control unit roll servo (eg, to enhance servo execution and to empower the framework to summon the control unit to rotate at a specific rate of rotation regarding the earth). The measurement range of the rate gyro is just +/ - 18rpm.

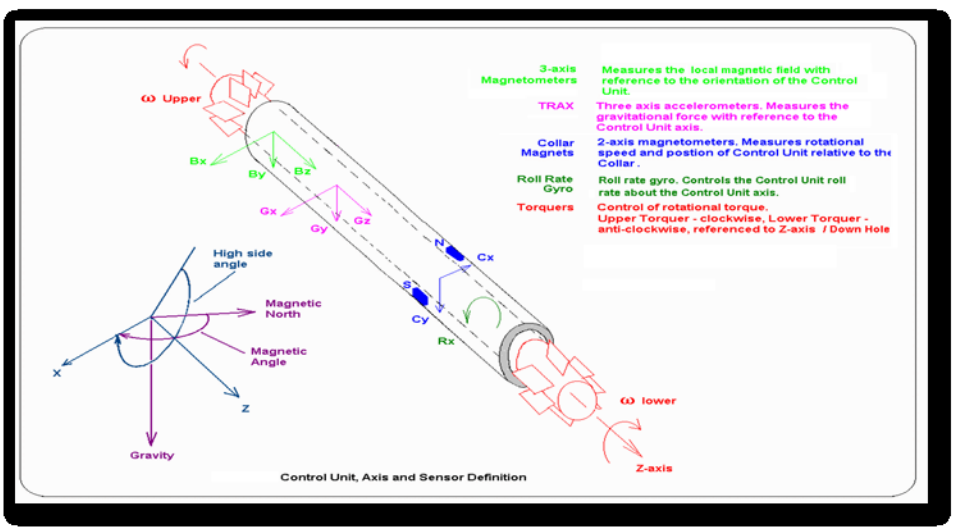


Figure 14: Control Unit Sensors[13]

[13] Ref- Matthew Donovan, "PowerDrive Uniform Operating Procedures", Schlumberger, Chapter 9, Dec-2004.

A block diagram, demonstrates a streamlined portrayal of the control loop. It will be seen that either the original programming or a telemetry change by means of the mud framework gives the requested arrangement. The two loops, with input by means of the roll rate gyro and by means of the positional sensors - 3-Axis Magnetometers - control the rotational speed and ANGLE in respect to the formation. The underlying steering setting is given in the SCB put away inside the control unit. At the point when the tool is down hole, another setting can be sent to the tool by mud-flow telemetry translated by Upper torquer rpm varieties.

3.3.1.4 System Control Block

The System control block is an information record, produced remotely to the control unit. It contains an arrangement of pre-modified esteems to control the drilling direction, the eras for inspecting and logging of the sensor information and a matrix of customized drilling information that might be actualized after a telemetry charge. A System control block will be downloaded into the control unit (both sensor and control modules) before the unit is sent down hole. The substance of a SCB document might be seen and altered with the System Control Block (SCB) Editor program, included inside the PowerDrive surface System Software. An example SCB document is appeared in beneath figure. The sections of a SCB document are depicted quickly underneath.

- **Servo**

The servo section has preset esteems for the increases in different parts of the control loop. The qualities in this section ought not to be modified. They are secret key secured in the SCB Editor program to avoid inadvertent changes. The rate PWM settings are utilized for measurement or demonstrative purposes just in the factory.

- **Control**

These qualities decide the greatest and least flow rates outside which the control unit will endeavor to apply additional torque to keep the torquer impeller speeds inside the controllable range. Task outside these qualities has the impact of lessening dynamic range of the framework.

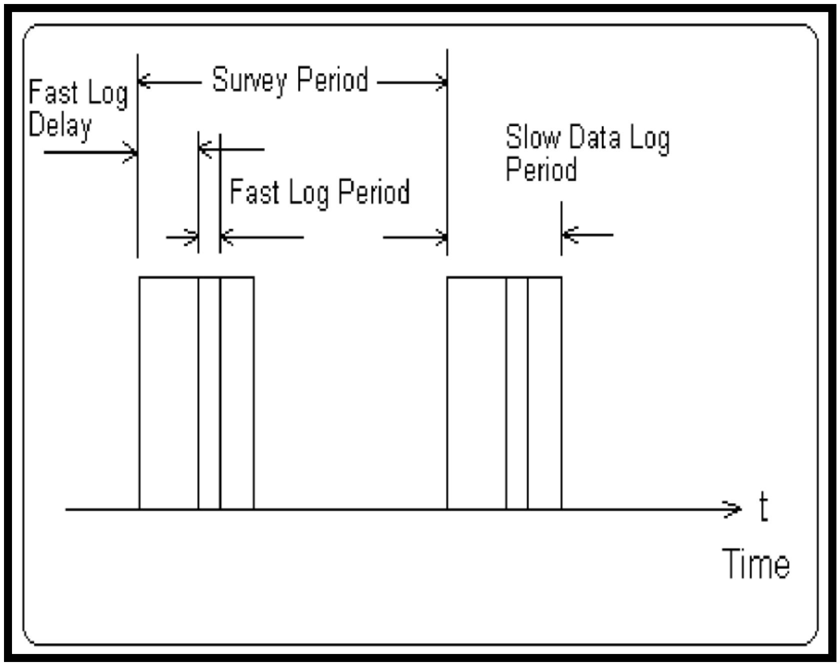


Figure 15: Data Logging Periods

- **Logging**

This section subtle elements the sensor information to be logged and the logging interims. The parameters which are appeared as rates are utilized to parcel the accessible memory inside the Comms module. Alternate parameters recorded are the different time settings for testing of the quick and moderate information parameters. These happen each time that a 'Review' is taken, i.e. information is recorded.

- **Acquisition**

This demonstrates the moderate information sensor parameters that are logged to record

- **Navigation**

This section points of interest whether gravitational or magnetic sensors are utilized to compute the control unit position. It additionally characterizes the steering and build angles that are accessible. The control unit might be steered by preset Angles and build rates applied by the steer direction and level of the time it drills at full bias or no bias. These preset esteems are given in a navigation Table inside the SCB. The underlying quality, and ensuing esteems, sent to the control unit by means of the telemetry framework are given as column and quantities of the navigation table. Along these lines, telemetry information is kept to a base and if the telemetry information contains a blunder, the resultant setting will be exceptionally near the coveted setting. There is an incentive for the tool-face stage move in the SCB. This is a mechanical esteem set by the physical parameters of the bias unit and drill bit. By including this incentive as a steady, the coveted drilling angle can be referenced to whatever drill bit is utilized.

- **Downlink & Uplink**

These sections set the planning time frames, edges and so forth for the downlink information. These qualities depend significantly of the length of the drill string and the execution of the pump. The uplink order esteems characterize the reaction of the control unit to great and terrible got telemetry information.

3.3.1.5 Mechanical

The mule shoe phase angle is a basic esteem that sets the mule shoe arrangement to a known reference orientation. This angle is usually known as a high side (HS) offset, and it must be recorded. This esteem speaks to the physical arrangement of the sensor module to the mule SHOE. The mule shoe stage Angle or HS offset angle should just be recorded once the mule shoe is appended to the CU that is being customized and a soul level has been oriented effectively into that mule shoe. This esteem, and that of the tool-face (set in the navigation section), permits the request steering Angles to be referenced without equivocalness. Different parameters in this section characterize the reaction time of the mud pumps when the flow rate s are fluctuated to send telemetry information.

3.3.2 Point the Bit- Power Drive Xceed[14]

3.3.2.1 Over View

PowerDrive Xceed is the most recent age point-the-bit rotary steerable innovation. Point the bit controls the direction of build by pointing the bit in the coveted direction while ceaselessly rotating the drill string. The tool accomplishes point-the bit with no sliding stabilizers or uncovered steering components. Rather, an inner servomotor continually controls the bit shaft tool-face. This Produces steady steering control in a wide assortment of hole conditions with least wear on the tool and fittingly bring down utilize costs.

Penetrating execution is refreshed in real-time through LTB correspondence with the MWD/LWD framework so mind boggling trajectories and high ROP formations can be drilled. Thus, the tool must be run with the PowerPulse MWD. While the tool can be run, the favored strategy is to run with real-time refreshes through PowerPulse. Directional control is accomplished by sending downlink orders to the tool for wanted tool-face and steering proportion settings. More than 600 distinct blends are conceivable. Downlink is performed by physically fluctuating pump now rate while drilling.

PowerDrive Xceed utilizes magnetometer measurements from its 6-Axis UDI sensor bundle to control steering. Well trajectories should thusly be 5 Degrees off from the Earth's magnetic field line for the tool to steer.

Instrument power is provided by a turbine driven alternator. High power is utilized by the steering motor and standard are utilized for the sensors and electronics. A little real time clock battery keeps up basic tool design information between power cycles.

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[14] Ref- Curtis Robinson, “PowerDrive Xceed Uniform Operating Procedures” Schlumberger, Dec-2004.

PowerDrive Xceed will steer successfully with both roller cone and PDC bits. A noteworthy advantage of the tool is its capacity to steer with Bi-focus BITS.

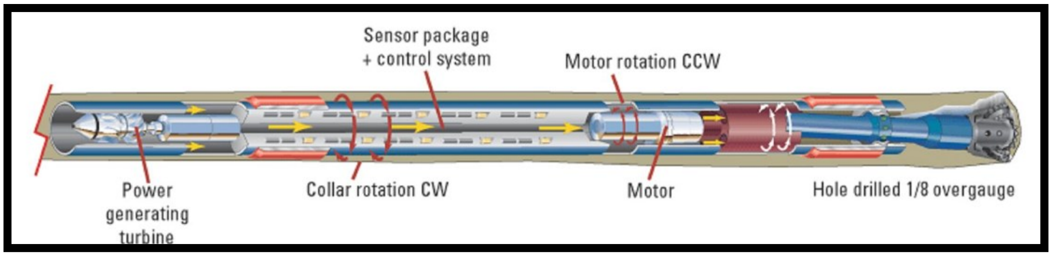


Figure 16: PowerDrive Xceed Tool

3.3.2.2 General

This section contains a general depiction of the tool and the assemblies that go together to influence it to up. Bellow figure demonstrates the tool and its segment assemblies (resources), the sections that take after give a concise depiction of every assembly.

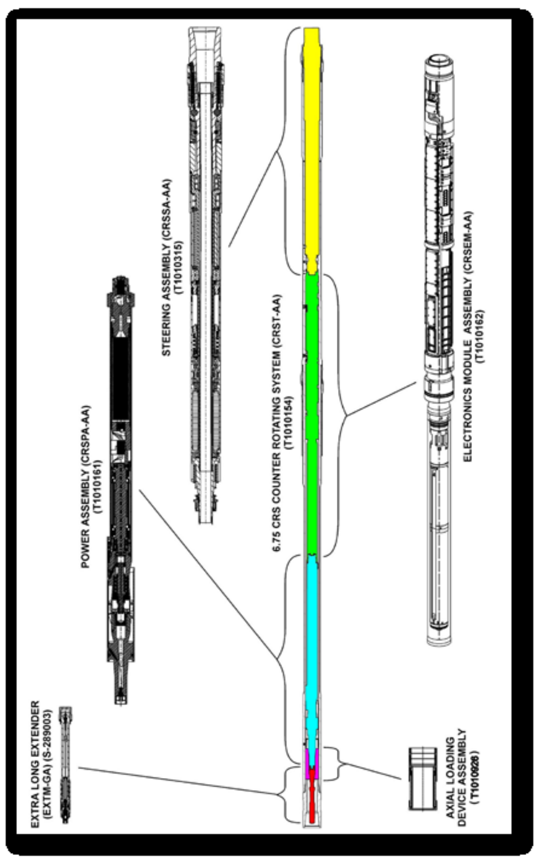


Figure 17: Power Drive Xceed Assembly[15]

[15] Ref- Curtis Robinson, "PowerDrive Xceed Uniform Operating Procedures" Schlumberger, Chapter-2, Dec-2004.

3.3.2.3 Features

The fundamental highlights of the PowerDrive Xceed tool are the accompanying -

- Flow range from 290 to 800 GPM
- Maximum downhole rpm 350
- Continuous Inclination and Azimuth while drilling
- Magnetic and gravity tool-face measurements
- Stick Slip indicator measurement
- Downhole collar RPM measurement
- LTB communication compatible with PowerPulse MWO
- Maximum LCM 50 IBS/BBL Medium Nut Plug
- Downlink commands are accepted anytime, even while drilling.

4 Applied Methodology Overview

4.1 Overview

In this section, the detailed steps of the developed workflow will be explained. The workflow was designed in the way that it covers the minimum requirement to deliver reliable and fair results, which will help to improve the directional drilling in term of planning, tools selection, and cost reduction. In generally, the workflow consists of four preparation stages in addition to the conclusion stage. Figure 18 illustrates underlying phases of the workflow.

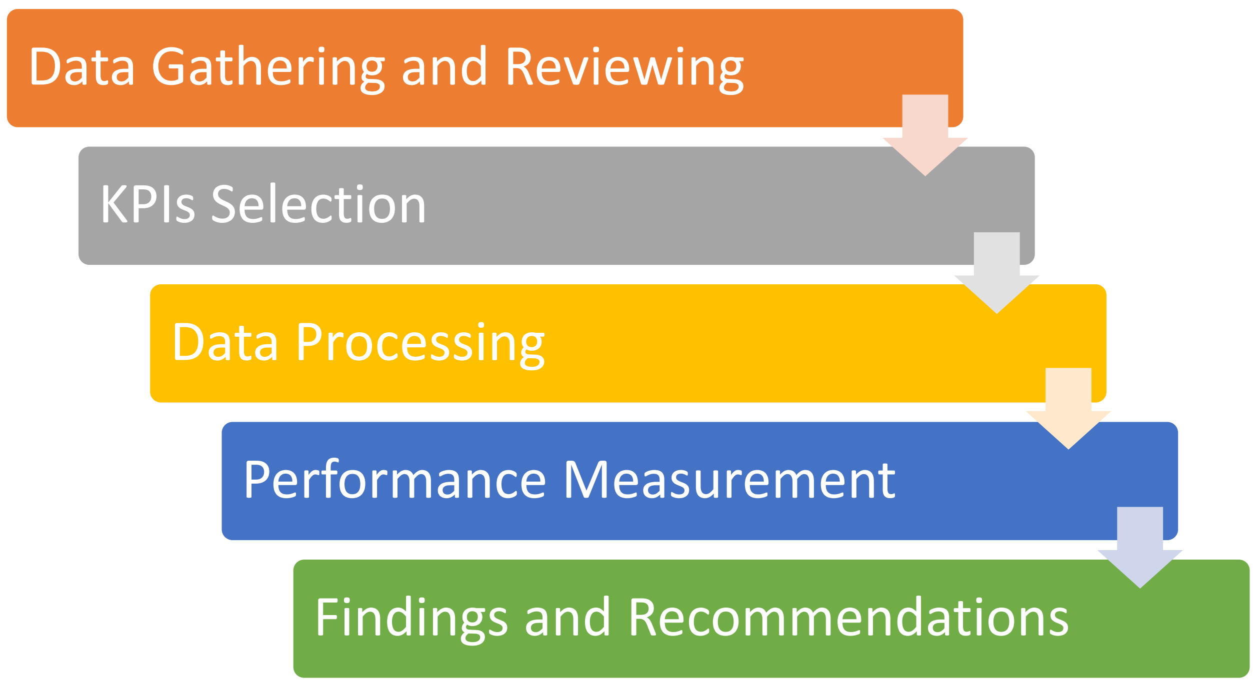


Figure 18. Developed Workflow Main Phases

4.2 Workflow Executive Phases

4.2.1 Data Gathering Phase

This phase composed of four steps; data collection, filtering, classification, and validation.

4.2.1.1 Data Collection

Measuring the performance of directional drilling tools involves several factors, the information about these factors cannot be found in one report, for instant, directional service provider will typically generate a report of as-drilled surveys versus the well trajectory plan, the geological operations team generates its own report of formation tops encountered during the course of drilling, the electronic data system captures data in real time and stores it in its own database, drilling tools employed downhole are often equipped with sensors that record useful information on downhole operating dynamics, thus it is necessary at this stage to collect all the all accessible data, including;

1- Geological and reservoir data
2- Daily drilling report,
3- Barge report,
4- BHA tally,
5- Mud report,
6- Cement report,
7- Mud logging report,
8- Geology report,
9- Formation pressure and temperature

4.2.1.2 Data Filtering

At this stage, the user has the choice to determine the section of the well which is under question; therefore, screening has to be performed on the gathered data. For example, in the performed case study (Chapter 5), 8 ½'' hole sections were selected, based on the following facts:

- Four different directional control methods were used
- Several challenges had been encountered while drilling this section
- The section covers the entire reservoir
- In few wells this section is horizontal

4.2.1.3 Data Classification

By classifying data effectively more reliable results could be obtained. Hence, the data categorization was integrated into the workflow as an essential step. At this step, the data of interest are sorted out based on the BHA used. In the performed case study, five BHAs were determined:

- Steerable motor BHA
- Rotary steerable system BHA with push the bit mechanism
- Rotary steerable system BHA with point the bit mechanism
- Vortex BHA (Combination of RSS and steerable motor) with push the bit mechanism
- Vortex BHA with point the bit mechanism

4.2.1.4 Data Reviewing

In drilling process, there are many parameters that are reported by two or more sources, such as, rate of penetration, total depth, etc.. Therefore, data reviewing is very important prior to moving to the next step. In the context of the developed workflow, data reviewing is performed by comparing the data recorded by multiple sources and consulting the expertise in order to define the most accurate values and to reduce the involved data.

4.2.2 Key Performance Indictors Selection Phase

In well construction operations, KPIs are produced by the different operations that take place during drilling and completion operations; by either a rig or crew or by a machine automated operations or a combination of both. As for directional drilling, KPIs can be classified into two types, KPIs related to the planning phase and KPIs related to the execution phase. Planning phase KPIs includes Mechanical Risk Index, Directional Difficulty Index, and Joint Association Survey. Whereas execution phase KPIs can be further categorized into technical and business KPIs. The technical KPIs covers, Target Deviation, Average Dogleg Severity, Rate of Penetration ,Tools failure, while the business ones covers, Cost per length Unit, Footage drilled, actual drilling time. Since the developed workflow is interested particularly at the actual performance of the directional drilling tools, therefore, only the execution phase KPIs are considered and used. In the following section, all the proposed KPIs will be explained.

4.2.2.1 Target Deviation

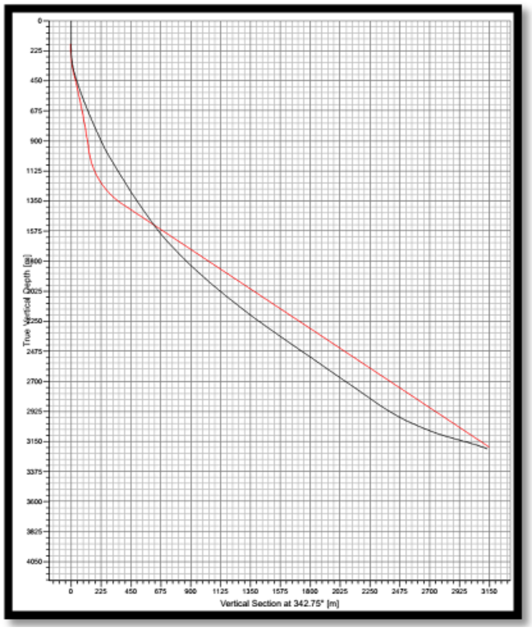
Target deviation can be defined as the divergence between the actual survey and planned survey at the particular depth. In deviated wells, two survey points are more important than the others, theres are , the survey at the landing piont and the survey at the target depth. Any deviation at these two points could have a significant impact on the subsequent operatios and productivety of the well later on. Normally in a new well following steps are followed to determing the deviation.

- Identify geological and drilling objective
- Planned survey with the software based on objective
- Drill the well and take definitive survey
- Determine maximum uncertainty of definitive survey based on MWD specification
- Compare the deviation of planned survey with definitive survey data
- Correction of well trajectory in case of deviation from plan.
- Compare the target and landing point deviation at the end of the well.

In this study the well trajectory was investigated after drilling the well so following steps followed for determining the target deviation:

- Inputting the planned survey data in Landmark software
- Inputting surveying tools specification on Landmark software
- Inputting definitive survey inside Landmark software
- Extract software output including different plots of actual survey vs. planned survey (Vertical View, Plan view, 3D view) and horizontal and vertical offset from the target.

Figure 19 shows the planned and definitive survey in vertical and plan view for one studied well the target has 80.75m vertical and 12.89m horizontal offset from the planned survey.



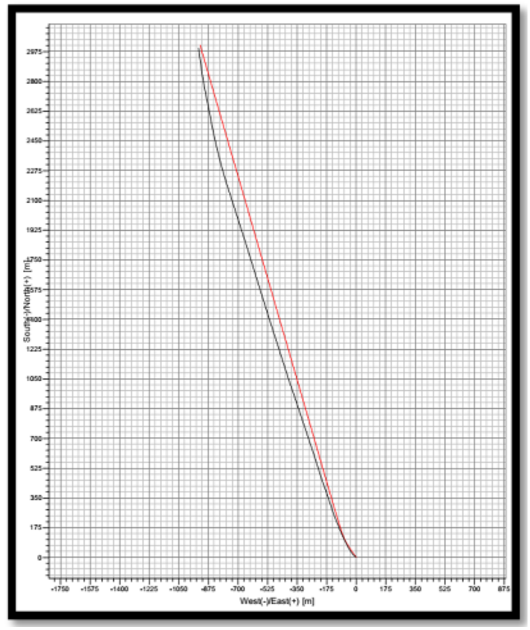


Figure 19: Vertical View (right) & Plan View (Left) Well#12A-01 Vortex PowerDrive BHA, Black Plan, Red Actual (definitive survey)

4.2.2.2 Directional Difficulty Index (DDI) Actual versus Planned

This is a practical method for measuring the complexity of a directional well before and after it has been drilled. The DDI for planned wells is calculated with an average dogleg where a dogleg rate of 0.5/100 ft is assumed for straight sections.

The DDI is calculated using the following formulas

$$DDI = log_{10}[\frac{(MD)(LHD)(N)}{TVD}] \quad (1)$$

Where:

MD = measured depth

LHD = the horizontal distance measured along the well-path

N = the planned or actual accumulated dogleg for the survey (Tortuosity)

TVD = true vertical depth

The directional difficulty index values may indicate the complexity of the directional well based on the following guidelines

Table 2 - Directional Difficulty Index Guideline

Calculated DDI	Well Type
< 6.0	Simple profile with low tortuosity
6.0 to 6.4	Regular well with normal tortuosity
6.4 to 6.8	Longer well with relatively tortuous path
> 6.8	Long tortuous well profile with high degree of difficulty

The horizontal distance measured along the well-path (LHD) is computed from an elliptical integral, and The "N" term in DDI formula shows the well-path tortuosity. When planning a well, well-path modelling commonly creates smooth curves, whereas an actual well contains severe doglegs and other indiscretions. More tortuous well cause higher torque and drag and more string fatigue and also more geometrical stuck, determining the tortuosity factors to apply in the well trajectory is always a challenge during the planning phase. Going back to reality, extensive turning of a well trajectory may twist a downhole pipe string, greatly increasing the forces applied, causing deformation. When the tortuosity of the well increase while sliding operation all applied weight will not transfer to drilling bit, as result ROP while sliding will significantly decrease. Generally, the DDI factor has direct impact on well cost, and by decreasing the DDI a simple profile with low tortuosity will be achieved which cause the cost and time of a well to decrease.

4.2.2.3 Rate of Penetration (ROP)

Rate of penetration [ROP] is one of the most important factors that affect the economic success of a drilling operation; it is defined as the ratio of the total length drilled to the advancement in unit time. There are two kinds of ROP which can be measured while drilling is still in progress, instantaneous ROP and average ROP. Instantaneous ROP is measured over a finite time or distance; it reflects the function of the instantaneous drilling system under specific operational conditions. Whereas, the average ROP is measured over the total interval drilled; it can be phase ROP, job ROP or Run ROP. There are several factors which have a direct impact on ROP, such as weight on bit (WOB), rotation speed (RPM), flow rate, bit diameter, bit tooth wear, bit hydraulics, formation strength and the formation abrasiveness. Higher ROP can generally be obtained at higher WOB and higher RPM. However it can reduce the operating life of the BHA components also after determined WOB and RPM by increasing these two parameters the ROP will not change and sometimes will be reduced. In the directional drilling point of view, average ROP can be used as KPI to compare the efficiency of different BHAs. Generally, the drilling mechanism has a significant role on the ROP, while sliding mode the ROP is lower than rotation mode; some of the reasons behind lowering the ROP in sliding mode are listed:

- Mostly the lower RPM will cause lower ROP.
- While sliding hole cleaning will decrease due to lack of string rotation.

- Friction force exerts on stable drill string while sliding is always more than rotating.
- The applied WOB should be limited; high WOB will cause stall or worn out of downhole motor.
- Direction of BHA must be controlled carefully while sliding

In regard to rotary steerable system sliding mode is eliminated. Therefore, there is no limitation regarding the drilling parameter , hence optimised drilling parameter can be applied for best performance of BHA.

4.2.2.4 Trip time and hole problem

Tripping is the act of pulling the drill string out of the hole and then running it back in wellbore. This is done by breaking out or disconnecting (when pulling out of the hole) and making up or connecting (when running in the hole) every drill pipe stand. The most common reason for tripping out the pipe is to replace damaged downhole tools such as drill bit, drill pipe, MWD (measurement while drilling), LWD (logging while drilling) or mud motors. Another common reason for tripping is to change the type of BHA and also for running casing. Hole problems such as key seat, ledge have a direct effect on tipping in or out speed. And also bad hole condition due to unconsolidated formation will increase the trip time. Tripping KPI in open hole specially while trip out of BHA can be an indicator of proper hole cleaning and smooth well path and the time which spent while trip out can be extended due to different hole problem such as tight spot and stuck pipe. Whenever more hole problem observed while trip in or trip out it shows that the efficiency of BHAs is not good and more tripping time and hole problem cause more operation time and cost.

4.2.2.5 Tool Failure

It's the Negative KPIs which will impose more cost to the operation while using the rotary steerable system some extra tools will be added to BHAs. As described in previous chapter the rotary steerable system has mechanical and electrical components which are exposed to failure while drilling. Some failure can be rectified in down hole, for example, some time MWD signal fail to receive which by second or third attempt the survey or by changing the mud pump the problem will be solved, however, in some cases, failure cannot be rectified in downhole and string should be pulled out of hole to surface and change the damaged tools which will cause wasting in time and cost of operation. In this study the failures which stop operation and cause to trip for changing the BHA are discussed, this type of failure effects on BHA selection. Count of failure and in each type of BHA will be investigated. In "tripping time and hole problem" section, wasted time for each trip will be shown.

4.2.2.6 Cost (Cost per length Unit)

The main KPI for accepting one new technology is the effect of this equipment on overall cost of the well, Cost per length is one of main KPI for evaluation the efficiency of any change in drilling operation. The role of this KPI for evaluating the new technology is significant and sometimes effect on other KPIs, for example, one new technology such as RSS cause more risk of tools failure in BHAs but due to overal cost optimization by using this technology cause that tools failure possibility can be neglected and company accepts to use it. The steps followed to obtain the cost KPIs are summarized below

- The daily rig cost including all services is considered.
- The cost of each BHA is determined.
- The cost per hour of each BHA based on ROP is counted
- The costs of all BHAs are compared.

4.2.3 Data Processing Phase

In context of the developed workflow, data processing mainly related to the use of Landmark software as a tool to process the data and obtaining reliable results which can be used later to compute some of the predefined KPIs . Certain directional drilling data can be processed in order to generate specific results which can be used in conjunction with predefined KPIs to measure and compare the efficiency and the performance of different BHA. Data processing in Landmark software can be shown in the following figure, by inputting validated data such as well location, formation lithology, BHA information and survey data, the three main KPIs including target deviation, dogleg severity and (DDI) can be extracted from software.

The other important KPIs such as the ROP, tripping time and hole problem, tool failure are extracted from DDR and mud logging report. Figure 20 depicts the data used by Landmark and the expected output, whereas, Figure 21 shows the extracted data from DDR and mud logging report. More details about Landmark software can be found in the appendix.

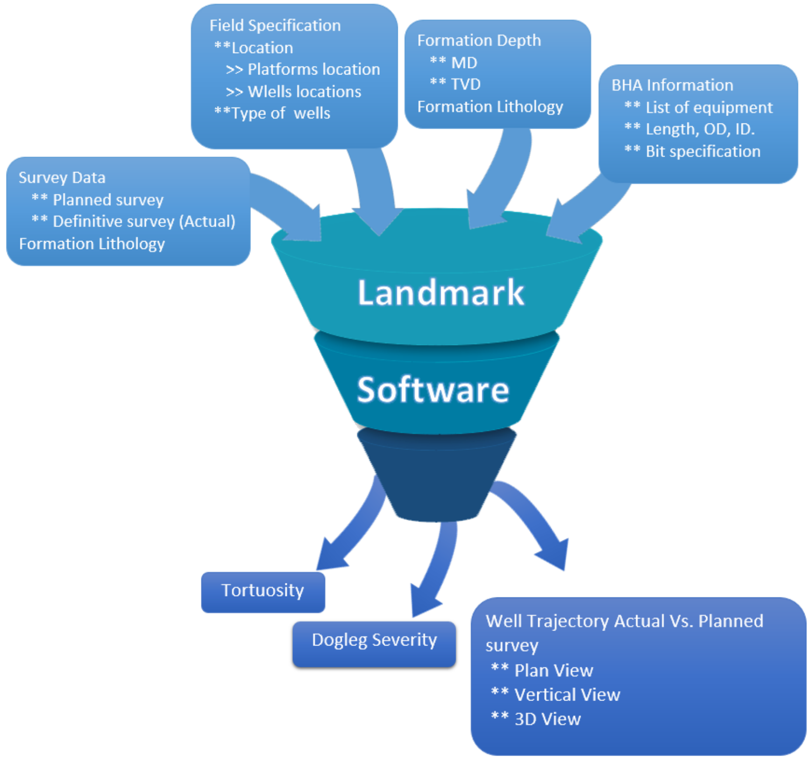


Figure 20- Data processing in Landmark software

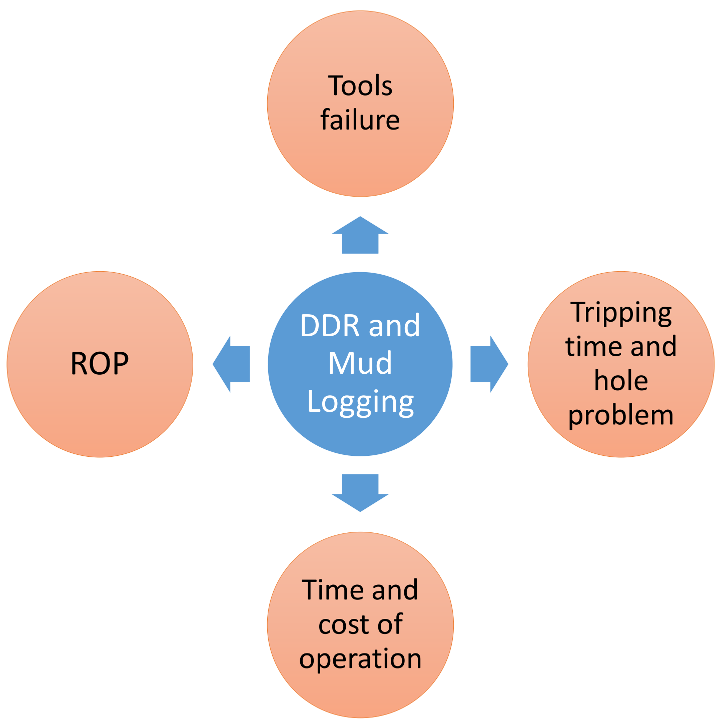


Figure 21- Extracted data from mud logging and DDR

4.2.4 Performance Evaluation and Comparison

The predefined KPIs alone cannot be sufficient to evaluate and compare the performance of directional control tools. Therefore, it was necessary to integrate an additional tool, which makes the comparison easy and fair. The tool intended to be used is weighted decision matrix. In order to professionally conduct the performance evaluation, the developed workflow proposes to split this task into two subtasks, first, one covering the collecting all the results from predefined KPIs in one table, whereas the second subtask covers the implementation of the weighted decision matrix.

4.2.4.1 KPIs Gathering

Performance evaluation is performed via comparing the output of Landmark software and extracted data from daily drilling reports and mud logging reports for all type of BHAs. The performance evaluation KPIs including well trajectory, dogleg severity, tortuosity, tripping time and hole problem, ROP, tools failure and cost. For example, for well trajectory KPI comparison, the result of different BHAs on trajectory is illustrated and base on distance form planned target the efficiency of different BHAs has been compared, also for tripping and hole problem time comparison the tripping time of different BHAs has been collected in one table and the efficiency of different steering mechanism on hole cleaning and hole problem has been evaluated. As well as for cost comparison based on ROP and tripping time the cost of directional drilling services for different BHAs type and rig cost by considering all operational and standby service onboard during drilling operation has been collected together and cost efficiency for all type of BHAs has been analyzed. Table 3 shows the sample of KPIs with related units for evaluate the performance of different type of BHAs.

Table 3: Sample of KPIs for performance comparison

BHA Type	Trajectory "Distance to plan (m)"	Average DLS (⁰/100 ft)	Tortuosity (DDI)	Trip Time (Hrs) (include hole problem)	ROP (m/hr)	Cost ($m)
PDM	-	-	-	-	-	-
RSS with point the bit mechanism	-	-	-	-	-	-
Push with push the bit mechanism	-	-	-	-	-	-
Vortex (RSS +PDM) with point the bit mechanism	-	-	-	-	-	-
Vortex (RSS +PDM) with push the bit mechanism	-	-	-	-	-	-

4.2.4.2 Weighted Decision Matrix

The weighted decision matrix is a valuable decision-making tool that is used to evaluate multiple options based on specific evaluation criteria weighted by importance. By evaluating options based on their performance with respect to individual criteria, a value for the each option can be identified. The values for each option can then be compared to create a rank order of their performance related to the criteria as a whole. The tool is important because it treats the criteria independently, helping avoid the over-influence or emphasis on specific individual criteria.

The use of the weighted criteria matrix to compare performance of tools is not an easy task. Thus a series of steps are created to make the implementation of this tool, easy and has a value. The following steps explain how the weighted criteria matrix can be used to compare performance of the BHAs.

1. Divide the KPIs into two categories negative and positive. The negative KPIs includes: trajectory distance to plan, average DLS, DDI, tripping time, number of failures and overall cost, whereas the positive includes only ROP.
2. Define the minimum value for each negative KPIs and the maximum value for each positive KPIs.
3. Assign a relative weighting factor to each KPI, based on how important that KPI is to the company. Do this by distributing 10 points among the KPIs, in other words , the sum of all weight factors should be 10.
4. Calculate the score for each KPI individually, it is done as follows:
   - ✓ For negative KPI $\left(\frac{\text{KPI}}{\text{Maximum KPI value}}\right) * \text{ KPI weighting factor}$ (2)
   - ✓ For positive KPI $\left(\frac{\text{KPI}}{\text{Maximum KPI value}}\right) * \text{ KPI weighting factor}$ (3)
5. Compute the total score for each BHA; simply it is the sum of all individual score determined in step 4.

4.2.5 Findings and Recommendations

Based on the performance evaluation and comparison explained on the previous step, effective recommendations can be proposed based on the final scores. Bear in mind that the weighting factors have a significant impact on the final scores. Therefore it is very critical. The selection of the weighting factors can vary from one opinion to another and must be selected carefully. The best practice for identifying this factors is to determine the goal of the company as the first step then assign the weighing factors, for example, if the company looking for less cost and high ROP then the weighting factors for these 2 KPIs should be given the highest value.

5 Case Study

The main purpose of presenting the following case study is to:

- Evaluate and validate the developed workflow by using real data
- Identify the key issues that may help to improve the developed workflow.
- Use the outputs of the developed workflow to create feasible strategies for the company to be used in future wells.
- Selecting different BHAs among variety of choices in studied field.
- Analyse real effect of changing BHA in overall drilling performance
- Comparative investigation that shows relationships between two or among more than two subjects

5.1 Field Overview

Figure 22 Shows the geographical location of the South Pars Gas field. It lies on the Persian Gulf, approximately 100 km from the shore . Four huge condensate rich gas bearing reservoirs have been discovered there. As it can be seen in Figure 22, the field straddles the Iranian-Qatari maritime border.

Figure 22: South Pars gas field location

The Iranian side of South Pars is scheduled to develop 28 blocks for the production of 790 million cubic meters of gas on a daily basis from South Pars Gas Field in the form of 24 phases. 12th phase is the biggest phase of South Pars field which includes three platform namely SPD12A, SPD12B, SPD12C. Each jacket contains 12 wells and totally 36 wells were drilled in this phase. The center well of each platform is a vertical well and the rest of 11 wells are directional wells. Figure 23 shows the schematic of one directional wells in this phase.

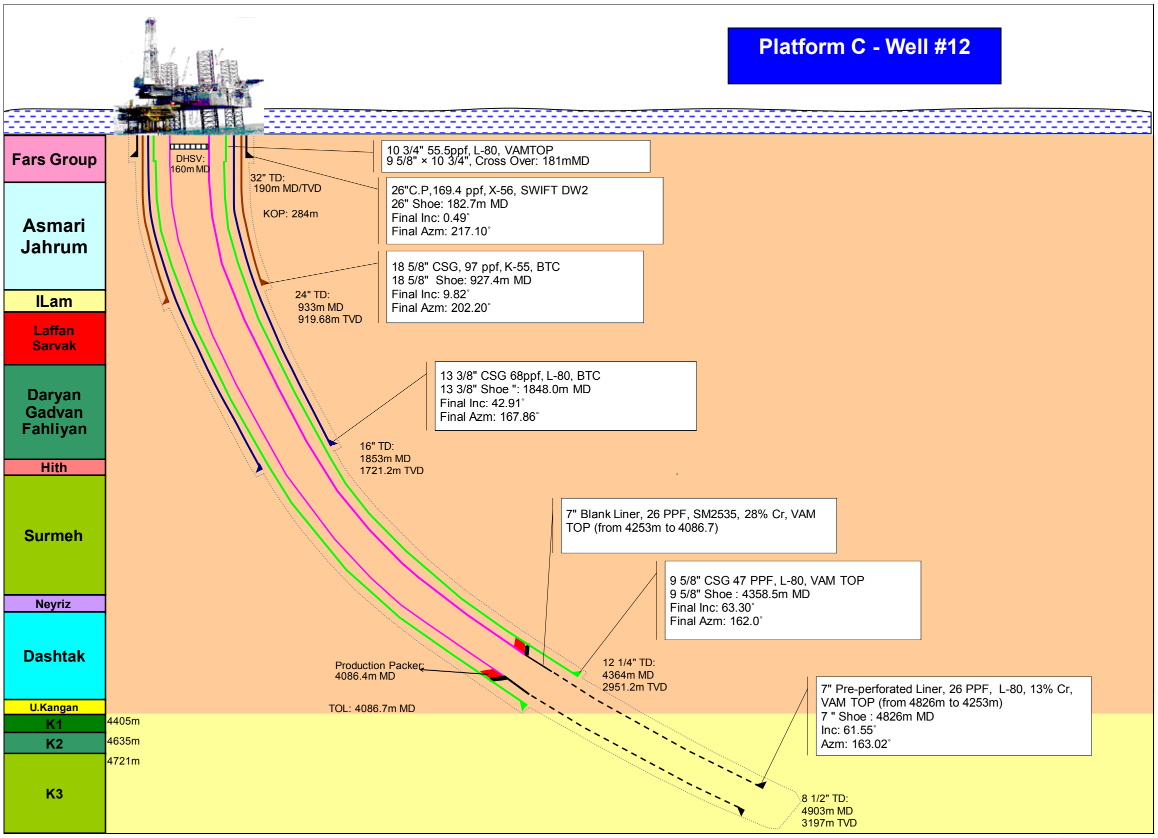


Figure 23: Well Schematic of one directional well in South Pars field

As shown in Figure 23 the shoe depth of each casing and liner , also the name of formations which were covered in each hole section are illustrated. The KOP is in top hole section (24'') and all down hole sections were drilled with directional BHAs. The offset wells data clearly shows that several of directional BHAs were used in 8.5'' hole section in comparison to other holes sections, hence, this section was selected to accomplish this study. Table 4 below depicts illustrates the Stratigraphic column of South Pars Gas Field

Table 4 : Stratigraphic sequence in the South Pars field

Geologic time unit		Group	Formation and lithostratigraphic units	Lithology	Formation Top Measured Depth (TVD) m (Sea Level)
Period	Epology/Age				
TERTIARY	Oligocene-Miocene	Fars	Mishan	Gray Marl +limestone	110
			Gachsaran	Anhydrite + Marl + Limestone + Dolomite	250
		-	Asmari	Limestone + Dolomite	306
	Paleocene-Eocene		Jahrum	Dolomite + Limestone	411
			Sachun	Dolomite + Limestone + Anhydrite	524
CRETACEOUS	Campa-Santonian	Bangestan	Ilam	Limestone + Shale + Dolomite	881
	Ceno. Turonian Alb-Cenimanian		Sarvak	Clacareous Shale + Limestone	1009
	Albian		Kazhdumi	Clacareous Claysonte + Sandstone	1176
	Aptian	Khami	Dariyan	Limestone + Marl + Shale	1230
	Barrerrian-Aptian		Gadvan	Argillaceous Limestone	1355
	Neocomian		Fahliyan	Limestone	1467
JURASSIC	Malm		Hith	Anhydrite + Dolomite	1683
	Dogger		Surmeh	Limestone + Dolomite + Claysone	1769
	Liassic	Kazerun	Neyriz	Dolomite + Limestone + Anhydrite	2495
TRIASSIC			Dashtak	Shale + Claystone + Dolomite + Limestone	2508
		Dehram	Kangan	Dolomite + Claystone + Anhydrite	2978
PERMIAN	Middle-Upper		Dalan	Limestone + Dolomite + Anhydrite	3125
	Lower		Faraghun	Dolomite	3250

5.1.1 Lithology Characterization and Associated Technical Challenge

In 8 ½’’ hole section Kangan and Dalan formation were drilled, These formation has been classified in four layer which a brief information of these layers and possible potential challenge in each layers are as follow:

- **First Layer**

Mainly consisted of dolomite, Packstone-Wackstone limestone and streaks of shale. There are also three rather thin anhydrite sub layers at the middle and in the lower half of the layer.

- **Second Layer**

This layer consisted of Wackstone, Packstone, and Grainstone limestone interbedded with thick dolomite layers, the main challenge of this layer is differential stuck due to high porous media layer.

- **Third Layer**

The mostly consisted of Mudstone, Grainstone limestone interbedded with thick dolomite layers significant anhydrite interval occurs at the bottom part of this layer.

- **Forth Layer**

This layer mostly consisted of Packstone, Oolitic Grainstone limestone, dolomite and rare thin layers of anhydrite. The main challenge of this layer was complete loss and hole pack off.

5.1.2 Directional Drilling

The 8.5′′ section hole drilled directionally from 9 ⅝" casing in upper main formation down to ±6m TVT (True Vertical thickness) into fourth layer of formation (40m TVT above expected GWC). It is desired to drill the whole section in minimum bit runs. In this study only directional BHAs are analyzed, different types of directional BHAs such as PDM, RSS and Vortex were used in 8.5′′ hole section, By selecting two BHAs from each type, totally of 10 BHAs are selected. All type of BHAs has been selected from nine wells, brief information of wells are shown in the table below.

Table 5: Basic well information of studied BHAs

Well Name	Hole Section (Inch)	Mud type	Total Vertical Depth TVD m	Total Measured Deoth MD m	Trajectory	Inclination @ TD (degree)	Casing Size and Depth
SPD12A-01	8 1/2	KCl Polymer Mud	3204	4750	Highly Deviated	70	7" Liner @ 4748m
SPD12A-02	8 1/2	KCl Polymer Mud	3194.5	4100	Deviated	58	7" Liner @ 4050m
SPD12A-04	8 1/2	KCl Polymer Mud	3105	4353	Highly Deviated	70.45	7" Liner @ 4073m
SPD12A-06	8 1/2	KCl Polymer Mud	3195	3970	Deviated	39	7" Liner @ 3968m
SPD12C-14	8 1/2	KCl Polymer Mud	3194	4586.5	Highly Deviated	71	7" Liner @ 4584m
SPD12C-09	8 1/2	KCl Polymer Mud	3198	4373	Deviated	32	7" Liner @ 4370m
SPD12C-12	8 1/2	KCl Polymer Mud	3206	4950	Highly Deviated	62	7" Liner @ 4948m
SPD12C-02	8 1/2	KCl Polymer Mud	3208	3914	Deviated	58	7" Liner @ 3912m
SPD12C-03	8 1/2	KCl Polymer Mud	3198	4808	Highly Deviated	73	7" Liner @ 4806m

5.2 Pre-Processing

The pre-processing step in this study is identical to the data gathering and reviewing phase of the developed workflow.

5.2.1 Data Description

As per described in previous chapter, field data were collected and data filtration stage has been passed and required data for this study has been selected, the data which has been selected to achieve the goal of this study are:

- Survey data
  - Planned and actual survey
- BHA data
  - Type of BHA
  - BHA component with specification such as OD, ID, Weight, connections, etc.
  - Motor or RSS specification such as optimum flow rate, motor efficiency (Rev/Gal)
  - Bit type
- Daily Drilling Report (DDR)

- Bit records
- Daily Mud Logging Report (DMLR)
- Geology report
- Mud report

Once the data collected, the involved BHAs were classified based on used drilling mechanism.

Table 6: Selected BHA mechanism

Item	Well No.	BHA Type	Drilling Mechanism
1	SPD12A-02	PDM	Steerable system
2	SPD12A-04	PDM	Steerable system
3	SPD12C-14	RSS Exceed	Rotary steerable system with point the bit mechanism
4	SPD12C-09	RSS Exceed	Rotary steerable system with point the bit mechanism
5	SPD12C-14	RSS Power drive	Rotary steerable system with push the bit mechanism
6	SPD12A-06	RSS Power drive	Rotary steerable system with push the bit mechanism
7	SPD12A-01	Vortex Power Drive	Rotary steerable system push the bit mechanism + steerable system
8	SPD12C-12	Vortex Power Drive	Rotary steerable system push the bit mechanism + steerable system
9	SPD12C-02	Vortex-Exceed	Rotary steerable system point the bit mechanism + steerable system
10	SPD12C-03	Vortex-Exceed	Rotary steerable system point the bit mechanism + steerable system

5.2.2 Data Preparation and Verification

In this phase, the collected data was certified. The main reason behind this step is to identify and remove the outlier and rogue data and to select the more accurate Meta data when multiple sources are available. A simple procedure has been developed for this study to validate ROP, the steps of these procedures are explained below.

- Define the BHA which is in question.
- Use the DDRs to determine the exact date and time when this BHA was drilling.
- Extract from the other reports all the ROP data.
- Compare the data among each other.
- Identify rational ROP value.

- Use the identified ROP value as KPI

5.3 Data Processing

For this study, the landmark Compass module used to process the data. As explain in chapter 4, BHA information, planned survey, definitive survey, reservoir temperature and pressure information and formation depth and lithology were used as input.

5.4 Post-Processing

After exporting data from Landmark software and other reports, a comparison tables which includes all the KPIs are structured. The mentioned tables contain the following KPIs:

- Target Deviation
- Dogleg severity
- ROP
- Trip Time
- Tools failure
- Cost

5.5 Performance Measurement

5.5.1 Target Deviation

Table 7 presents the target deviation for all studied BHA. As shown in table the PDM BHAs has the highest distance to target (directional plan) and, the Vortex Push the bit BHA and RSS point the bit has the best result in catching the directional plan. However should be noted that the experience of directional driller in application of equipment has so many effects on the result of operation, normally directional driller has more experience with steerable system than rotary steerable system.

Table 7: Target Deviation of the studied BHAs

Well Name	Target Deviation (m)
Well#12A-02 (PDM)	**176**
Well#12A-04 (PDM)	**168.79**
Well#12C-14 (Exceed)	**42.77**
Well#12C-09 (Exceed)	**4.06**
Well#12C-14 (PD)	**26.12**
Well#12A-06 (PD)	**84.78**
Well#12A-01 (Vortex-PD)	**81.78**
Well#12C-12 (Vortex-PD)	**123.84**
Well#12C-02 (Vortex-Exceed)	**22.02**
Well#12C-03 (Vortex-Exceed)	**129.42**

5.5.2 Dogleg Severity

Average Dog leg for all investigated BHAs is shown in the following table.

Table 8 : Average Dogleg over survey the studied BHAs

#	Well Name (BHA Used)	Average DLS (^{0}/100 ft)
1	**Well#12A-02 (PDM)**	0.84
2	**Well#12A-04 (PDM)**	2.48
3	**Well#12C-14 (Exceed)**	1.78
4	**Well#12C-09 (Exceed)**	1.44
5	**Well#12C-14 (PD)**	1.39
6	**Well#12A-06 (PD)**	2.89
7	**Well#12A-01 (Vortex-PD)**	0.89
8	**Well#12C-12 (Vortex-PD)**	0.66
9	**Well#12C-02 (Vortex-Exceed)**	1.23
10	**Well#12C-03 (Vortex-Exceed)**	0.97

As shown in the above table steerable system and rotary steerable system push the bit mechanism have more DLS than other type of BHAs.

5.5.3 Directional Difficulty Index (DDI)

For understanding practical effect of different BHAs usage on the tortuosity and complexity of directional well the directional difficulty index has been compared in drilled interval for all studied BHAs. The final results are demonstrated in Table 9.

Table 9- Directional difficulty Index of the studied BHAs

#	Well Name (BHA Used)	DDI
1	**Well#12A-02 (PDM)**	5.4
2	**Well#12A-04 (PDM)**	7.1
3	**Well#12C-14 (Exceed)**	5.4
4	**Well#12C-09 (Exceed)**	6.0
5	**Well#12C-14 (PD)**	5.6
6	**Well#12A-06 (PD)**	5.7
7	**Well#12A-01 (Vortex-PD)**	5.3
8	**Well#12C-12 (Vortex-PD)**	5.4
9	**Well#12C-02 (Vortex-Exceed)**	5.4
10	**Well#12C-03 (Vortex-Exceed)**	5.9

5.5.4 Rate of Penetration (ROP)

The ROP for all studied BHAs is calculated based on bit on bottom time and footage drilled. The ROP in meter per hour for all the BHAs are summarised in Table 10. It is obvious from Table 10 that Vortex RSS push the bit mechanism has the highest ROP in comparison with another type of BHAs. Due to PDC bit has been used for all BHAs by increasing RPM normally the ROP should be increased which is one the reason of more ROP in Vortex RSS BHAs than normal RSS BHAs.

Table 10- Rate of Penetration of the studied BHAs

Well Name	Drilled Depth (m)	ROP (m/hr)
Well#12A-02 (PDM)	**427**	**5.4**
Well#12A-04 (PDM)	**466.5**	**5.4**
Well#12C-14 (Exceed)	**444.5**	**6**
Well#12C-09 (Exceed)	**595**	**6.3**
Well#12A-06 (PD)	**429**	**7.9**
Well#12C-14 (PD)	**319**	**5**
Well#12A-01 (Vortex-PD)	**317**	**13.2**
Well#12C-12 (Vortex-PD)	**539**	**12.2**
Well#12C-02 (Vortex-Exceed)	**511**	**7.9**
Well#12C-03 (Vortex-Exceed)	**938**	**8.3**

5.5.5 Trip Time and Hole Problems

Trip time is a KPI which is an indicator of hole condition and hole cleaning efficiency, sometimes excessive ROP could cause bad hole condition and will increase the tripping time and tight spot and will led to stuck pipe, while analysing the ROP data the tripping time and spent time for clear tight spot should be considered to achieve more correct evaluation, as shown in table trip time and hole problem has been compared for 5 type of directional BHAs. Trip out times have been considered to see more effect of BHAs and hole cleaning. This data has been extracted from DDR. The PDM BHAs have more stuck time and tight spot than other BHAs due to sliding mode drilling and lower hole cleaning due to loss of surface rotation while sliding. Vortex RSS point the bit mechanism BHAs has the lowest trip time in comparison with other 4 type of directional BHAs.

Table 11: Trip time and hole problem comparison

Well Name	Trip Depth (m)	Total Trip Time (hr)	Extra Time due to Tight Holes (hr)
Well#12A-02 (PDM)	**3882**	**24.0**	**10.0**
Well#12A-04 (PDM)	**4075**	**18.0**	**2.0**
Well#12C-14 (Exceed)	**4586**	**16.5**	**0.0**
Well#12C-09 (Exceed)	**4373**	**15.0**	**0.0**
Well#12C-14 (PD)	**4112**	**16.5**	**0.0**
Well#12A-06 (PD)	**3970**	**15.0**	**0.0**
Well#12A-01 (Vortex-PD)	**4631**	**16.0**	**0.0**
Well#12C-12 (Vortex-PD)	**4903**	**19.0**	**2.0**
Well#12C-02 (Vortex-Exceed)	**3914**	**13.5**	**0.0**
Well#12C-03 (Vortex-Exceed)	**4808**	**15.0**	**0.0**

5.5.6 Tools Failure

There are some disadvantages by using Rotary Steerable System such as tools failure, as described in Chapter 3, rotary steerable system is high technology tools which comprise of some mechanical and electrical components, while drilling operation these part are expose to failure and result in Pull out of hole string and changed damaged components which impose more cost and time for operation. For decreasing the tools failure lowest non-soluble solid should be in drilling mud and proper drilling parameter should be applied. In the following part few failure cases of the studied BHAs will be explained.

Failure Report No. 1 Well#12 (Power Drive)

The 8 1/2" BHA was run into hole, after drilling the 8 1/2" hole section from 4542m to 4660m (118m) in 28.5Hrs, inclination started to drop. It was tried several times to downlink the power drive and set it in 100% building mode, which was not successful and inclination kept dropping. After drilling to the bottom at 4800m (total drilling time 50 Hrs), inclination dropped to 64.49 while the planned inclination was 73.53 deg. After pull out of hole, it was observed that all of Power Drive's pads pistons had been damaged and failed, one of top anchor bolts was lost in the hole and the other one was damaged. Furthermore, one tiny crack had initiated on the collar body. The reason for inclination dropping was due to Power Drive failure. Since the drilling condition was normal, and Power Drive working hours was just 28.5Hrs, failure can be due to improper maintenance and low quality spare parts.

Failure Report No. 2 Well#11 (Power Drive)

While drilling the 8 1/2" hole section from 4294m to 4863m (TD), the 8 1/2" BHA including Power Drive was run into the hole in 89 Hrs, but even though different Power Drive settings were tried it was not possible to catch the plan. At the TD, inclination reached to 53.3 Deg and Azimuth to 92.6 deg. (the planned inclination was 56.08 and Azimuth was 80.45). TD was 12.7m below and 16.1m right of the plan. After pulling out of hole, it was observed that two Power Drive pad's pistons were damaged and failed, and one pad was loose. The reason that the well plan could not be followed was due to power drive failure.

Failure Report No. 3 Well#06 (Power Drive & LWD)

A brief description of the event are as follows:

In Well#06, RIH to bottom, Tried drill 8 ½'' hole section to the TD as per plan, the first stand was drilled with command of (252 Deg - 50%) to drop & turn as per planned. The result of the setting was shown in the second stand from the MWD tool which is giving a survey with dropping in the inclination and same azimuth direction, then decided to increase the tool setting to compensate for the turn needed in the azimuth. put the setting (234 Deg - 75%) and follow the PD continuous closely to see changing in the azimuth as the tool face is changed in the command, when has been realized that there is no response again increased the setting to (270 Deg - 100%) making the tool in a pure turning mode to see the result, but tool was still not responding to the different tool faces which applied and at that time it was very clear the tool is not turning direction while we are getting drop in the inclination on the previous settings. Decision made POOH to surface. Found RA source cap inside AND was broken and some pieces missed. L/D ADN. Work on GVR to replace batteries, found some mud in side battery area. Discussed with town, decided to L/D GVR and ADN and power drive.

5.5.7 Cost

As shown in Table 12 , cost per meter ($/m) for all type of BHA has been compared. Vortex Power drive (PD) (Push the bit RSS mechanism +PDM) BHAs have more cost optimization than other type of BHAs. And demonstrated that the RSS BHAs mostly have more cost efficiency than PDM BHA, but in some case RSS show deficiency in cost optimization as shown in well#12C-14 (PD). Averagely RSS BHAs shows 9 percent cost saving and Vortex BHAs shows 40 percent cost optimization in comparison wit PDM BHAs, However the above cost comparison table is based on ROP and normally the optimization of RSS is more than above result since by using the RSS more better hole cleaning and smoother well can be achieved, so tripping time and running casing time will effectively decrease and more time and cost saving were obtained in comparison with the conventional steering system.

Table 12: Cost comparison

Well No.	Drilled Depth (m)	Time to Drill 1000m (hr)	Extra Trip time (hr)	Overall Cost for Drilling 1000 m ($)
Well#12A-02 (PDM)	**427**	**185.3**	**6**	**2150322**
Well#12A-04 (PDM)	**467**	**185.2**	**6**	**2149113**
Well#12C-14 (Exceed)	**445**	**166.7**	**-**	**2006167**
Well#12C-09 (Exceed)	**595**	**159.8**	**-**	**1923492**
Well#12A-06 (PD)	**429**	**126.6**	**-**	**1523671**
Well#12C-14 (PD)	**319**	**200.0**	**-**	**2407400**
Well#12A-01 (Vortex-PD)	**317**	**75.8**	**-**	**931591**
Well#12C-12 (Vortex-PD)	**539**	**82.0**	**-**	**1007951**
Well#12C-02 (Vortex-Exceed)	**511**	**126.6**	**-**	**1556582**
Well#12C-03 (Vortex-Exceed)	**938**	**120.5**	**-**	**1481566**

As the last step prior to going to the next one, all the results of the mentioned KPIs for all the studied BHAs are collected in one table.

Table 13 : KPIs values for all studied BHAs

Well No. (BHA)	Target Deviation	DLS (°/100 ft)	DDI	Trip Time (hr)	ROP (m/hr)	Cost ($m)
Well#12A-02 (PDM)	176	0.84	5.4	24.0	5.4	2083
Well#12A-04 (PDM)	168.79	2.48	7.1	18.0	5.4	2082
Well#12C-14 (Exceed)	42.77	1.78	5.4	16.5	6	2006
Well#12C-09 (Exceed)	4.06	1.44	6.0	15.0	6.3	1923
Well#12C-14 (PD)	26.12	1.39	5.6	16.5	5	1524
Well#12A-06 (PD)	84.78	2.89	5.7	15.0	7.9	2407
Well#12A-01 (Vortex-PD)	81.78	0.89	5.3	16.0	13.2	932
Well#12C-12 (Vortex-PD)	123.84	0.66	5.4	19.0	12.2	1008
Well#12C-02 (Vortex-Exceed)	22.02	1.23	5.4	13.5	7.9	1557
Well#12C-03 (Vortex-Exceed)	129.42	0.97	5.9	15.0	8.3	1482

5.6 Weighting Factor

As discussed in the previous chapter, assessing the performance of a directional control tool based on individual KPI may lead to unfair judgments. Therefore, it was vital to adapt an available tool, which can be used to combine multiple KPIs in order to measure and compare the performances of alternatives. In order to overcome this issue, it was agreed to use Weighted Decision Matrix. The only challenge, which can be faced when using Weighted Decision Matrix, is the weighting factor. For this study, three persons were involved to define the weighting factors, the drilling manager, senior drilling engineer and directional driller. They agreed to give the cost the highest weighting factors, followed by ROP and Target Deviation.

Table 14: KPIs weighting factor

KPIs	Target Deviation	DLS (˚/100 ft)	DDI	Trip Time (hr)	ROP (m/hr)	Cost ($m)	Total
Weighting Factor	***2***	***1***	***1***	***1***	***2***	***3***	***10***

Once the weighting factors were obtained, the steps explained in chapter four to compute the final scores were followed literally. The final results can be seen in Table 15

Table 15: BHA final score

Well (BHA) / **KPIs** / **Factor**	**Target Deviation (m)**	**Average DLS (˚/100 ft)**	**DDI**	**Trip Time (hr)**	**ROP (m/hr)**	**Cost ($m)**	**Total**
	2	**1**	**1**	**1**	**2**	**3**	**10**
Well#12A-02 (PDM)	0.05	0.79	0.98	0.56	0.82	1.34	4.54
Well#12A-04 (PDM)	0.05	0.27	0.75	0.75	0.82	1.34	3.97
Well#12C-14 (Exceed)	0.19	0.37	0.98	0.82	0.91	1.39	4.66
Well#12C-09 (Exceed)	2.00	0.46	0.88	0.90	0.95	1.45	6.65
Well#12C-14 (PD)	0.31	0.47	0.95	0.82	0.76	1.83	5.14
Well#12A-06 (PD)	0.10	0.23	0.93	0.90	1.20	1.16	4.51
Well#12A-01 (Vortex-PD)	0.10	0.74	1.00	0.84	2.00	3.00	7.68
Well#12C-12 (Vortex-PD)	0.07	1.00	0.98	0.71	1.85	2.77	7.38
Well#12C-02 (Vortex-Exceed)	0.37	0.54	0.98	1.00	1.20	1.80	5.88
Well#12C-03 (Vortex-Exceed)	0.06	0.68	0.90	0.90	1.26	1.89	5.69

5.7 Case Study Conclusions

The main conclusion of the presented case study can be summarized in the following points:

1) Generally by adding one component to BHA the chance of tool failure would increase, as per tools failure analysis the RSS push the bit BHAs has more failure in comparison with RSS point the bit BHAs. Surly the possibility of tools failure in Vortex BHAs are higher than normal RSS BHAs and steerable motor BHAs.

2) As shown in target deviation table, the PDM BHAs has the highest distance to target (directional plan) and, the Vortex Push the bit BHA and RSS point the bit achieved the closest distance. However should be noted that the experience of directional driller in application of equipment has so much impact on result of operation, normally directional driller has more experience with steerable system than rotary steerable system.

3) From the ROP comparison, it can be concluded that:

- The normal RSS & Vortex BHA has better hole cleaning due to eleminating of sliding mode in these two systems.
- The Vortex BHA has better ROP comparing to normal RSS BHA & PDM

4) In practical, there were no sensible optimization in dogleg severity due to directional driller has lower knowledge to RSS and vortex RSS BHA that PDM system. Also when one system be used in special field periodically, the experience of directional driller will increase therefore the performance will be optimize.

5) Base on cost comparison table, the cost of wells which has been drilled using RSS or vortex BHA has lower cost , as a percentage, the cost is between 5 to 25% lower than PDM directional well.

6) In this study, the highest weighting factor was assigned to cost related KPI.

7) As shown in Table 17 the PDM BHAs with 4.54 and 3.97 total score have the lowest performance and the power drive vortex BHAs with push the bit mechanism have the best performance with 7.68 and 7.38 total score. Between the RSS BHA mechanism point the bit mechanism (Exceed) with 4.66 and 6.65 total score has better efficiency than push the bit mechanism (Power Drive) with 4.51 and 5.14 total score.

6 Conclusions and Recommendations

6.1 Conclusions

The main conclusion of the thesis can be summarized in the following points:

- Several downhole tools can be used to deviate the well bore; each of them has advantages and disadvantages, which have direct impact on the performance of the tool.
- By Comparing RSS with PDM based on the case study finds , the following conclusions can be drawn:
  - The RSS improves borehole quality, which makes cuttings removal more efficient. This ensures that casing and liner systems can be run to bottom smoothly. This fact can be seen in DLS and tripping time, maximum DLS of RSS was away lower than PDM, there was no extra time spending while tripping RSS, however for PDM the crew spent couple of hours fighting the tight spots.
  - RSS delivers substantially higher overall ROP , the ROP range can be between 6 to 13 m/hr as it can be seen in Table 10, however using PDM , the average ROP could not exceed 5.5 m/h
  - By using rotary steerable system fewer trips are expected which will cause cost and time saving.
  - RSS system is an expensive service, in land rigs in which the rig rental cost is near four times less than offshore rigs, using rotary steerable system may increase the cost of well significantly but it can decrease the time of project by increasing the rate of penetration.
- In order to effectively evaluate and measure the performance of directional control tools, a comprehensive workflow was developed.
- Several procedures were created to help to improve the deliverables of the developed workflow for better comparison. These procedures were set up to improve the data quality control.
- In order to extend the function of the developed workflow to be used to select the most effective directional control tools, a Weighted Decision Matrix was integrated to the workflow.
- To achieve the main goal of using a Weighted Decision Matrix, several changes were applied to original steps to make Weighted Decision Matrix fit for purpose.
- The main advantages of the Weighted Decision Matrix over the other tools are that Weighted Decision Matrix combines the measurements of multiple KPIs and propose just one figure as an overall measurement which can be eventually used to evaluate and compare the performance.
- Ultimately, the case study proved that the developed workflow is a good tool regardless of its shortcomings.

6.2 Recommendations

Based on the findings of this thesis the following recommendations can be drawn

Recommendations related to directional drilling tools future studies

- Well bore stability has a big roll on drilling optimization, so research to compare the impact of using RSS and PDM system on well bore stability is recommended.
- Other important research could be to study the impact of different directional control tools on the drill string fatigue life.
- Bit selection has a significant influence on the RSS performance, thus comparing the different bit type and design on RSS performance could be a good study.
- BHA design of RSS and PDM differ in many aspects, one of main difference is drilling hydraulic, which has an effect on drilling performance; we can study and design the best hydraulic program for the RSS in one specific field.

Recommendations related to developed workflow

- Integrate more KPIs to the workflow , such as:
  - Use of the caliper log to Indicate of hole quality (washout, over-gauge hole)
  - Extend the target deviation KPI to cover other sensitive points along the wellbore
  - A KPI which deals with spontaneous deviation
- Develop a mechanism which can help companies to define the weighing factors.
- Improve the workflow by establishing standard procedures for data quality control and verifications

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8 Abbreviations

ROP	Rate of penetration
HSE	Health, Safety and Environment
RSS	Rotary steerable system
AV	Apparent viscosity
PV	Plastic viscosity
YP	Yield point
TVD	True vertical depth
MWD	Measurements while drilling
LWD	Logging while drilling
ECD	Equivalent circulating density
RPM	Rotations per minute
RA	Radio Active
ADN	Azimuthal Density Neutron
LTB	Low power Tools Bus
SCB	System Control Block
EDM	Engineer's Drilling Data Model

9 Appendix

9.1 Landmark

Halliburton company (Landmark) software is one of the top industry solutions. For drilling engineer it is very important, to have possibility make all calculation from the beginning to last stage using the same software. Landmark is a software package which include several programs, these programs are comprised of:

- COMPASS (This software will be explained).
- Well Plan (This software will be explained).
- Well Cat

The Well Cat (Well Casing and Tubing) software is an integrated set of programs that prognoses pressures and temperature in the wellbore, and analyze stresses and deformation in all type of string.

- Stress Check

Stress Check is a module for casing design, casing strings can be designed to meet all relevant design criteria from top to bottom. The Stress Check module is based on casing design principles that are well accepted and extensively employed in the industry.

- Profile

Profile is a tools for visualization of downhole, surface and completion equipment.

- Casing Seat

Casing-Seat software is an precise user friend tool that determines casing setting depth, and casing schematics. Also provides lithology-based and layer characterization of stratigraphic boundary status and operating limits, including those associated with minimum overbalance, Wellbore stability, and differential sticking of strings.

- Open Well

Open Well is an extensive tools to provide daily drilling report and proper records of daily job operation.

9.1.1 COMPASS

The Computerized Planning and Analysis Survey System (COMPASS) is a complete tool designed for use in directional well planning by either client or directional service provider. COMPASS is a tool that enables you to agile and precise planning the wells and identify potential problems at the start of each stage.

All of the specification for detailed well path design, analysis and monitoring are comprised. The list of specifications include survey and design methods, torque-drag improvement, anti-collision analysis with ellipse of uncertainty and traveling cylinder.

COMPASS comprises of three main sections (Planning, Survey and Anti-collision), also an complete graph tool. Main section are included:

- Survey

The Survey module analyses a wellbore’s courses. COMPASS assume a survey to be a bunch of observations made with a single shot survey tool in the same tool run. Information can be inputted in a spreadsheet or entered and processed using industry calculation standard methods. The subsequent survey files can be modified, printed or evaluated. Surveys may be merged together to form a definitive 'best course' using a tool interval editor. Special provisions are made for Inertial and Inclination only surveys. Survey delivers an advanced "project ahead" from survey position to target, formation or well path.

Two approaches allow you to evaluate survey data for wrongly entered survey data or bad readings from the survey instrument. Input Validation will separate bad survey data as soon as it is imported. Varying curvature segregates improper survey point data by highlighting their contradiction. Survey analysis graphs are available that make evaluation plots of survey and plan data for a number of different parameters.

- Planning

Use the Plan Editor to scheme the shape of planned wellbores. The Planning module has an interactive modification worksheet permitting the user to build up the well path in sections. There are many diverse plan sections accessible for each section and they can be based on 2 or 3 Axis Slant or S Shaped profiles or 3 dimensional dogleg/tool-face or build/turn curves. Otherwise the plan can be inputted or imported directly into the spreadsheet line by line. At each phase of well planning, the user can observe the wellbore graphics dynamically update as changes are made.

The Wellbore optimizer incorporates torque drag analysis into the planning section. It will control the best mixture of well trajectory design elements that cause minimum cost, anti-collision or torque and drag resolution.

- Anticollision

Anticollision can be utilized to check the departure of surveyed and planned Wellbores from nearby wells. This module provides ladder plots, spider plots, traveling cylinder, and present of well proximity scans. Any scans will be run with planning, surveying or projecting ahead interactively. All anticollision designs are integrated with wellbore uncertainties that are shown on plots or reported as separation ratios. Alarm may be arranged to alert the user when the Wellbores congregate within a minimum ratio or interval specified by client policy.

Planning module

In this chapter we will be only explain the Planning module which has been used mostly in this study

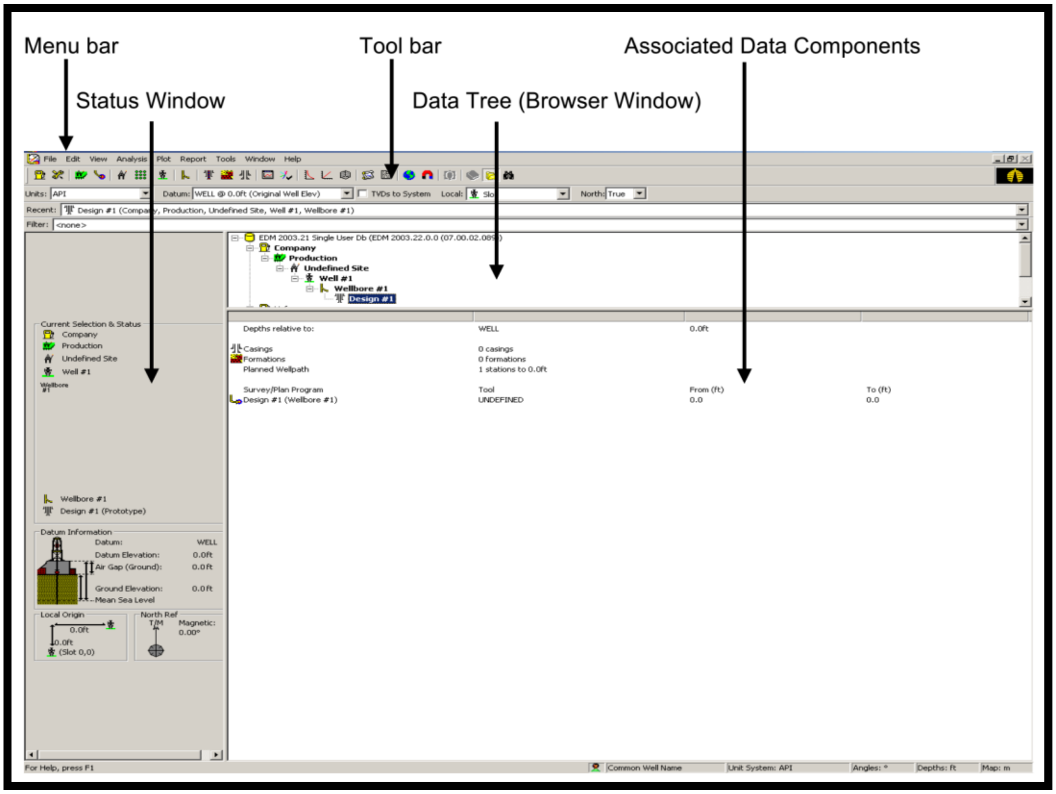

Figure 24 - COMPASS User Interface

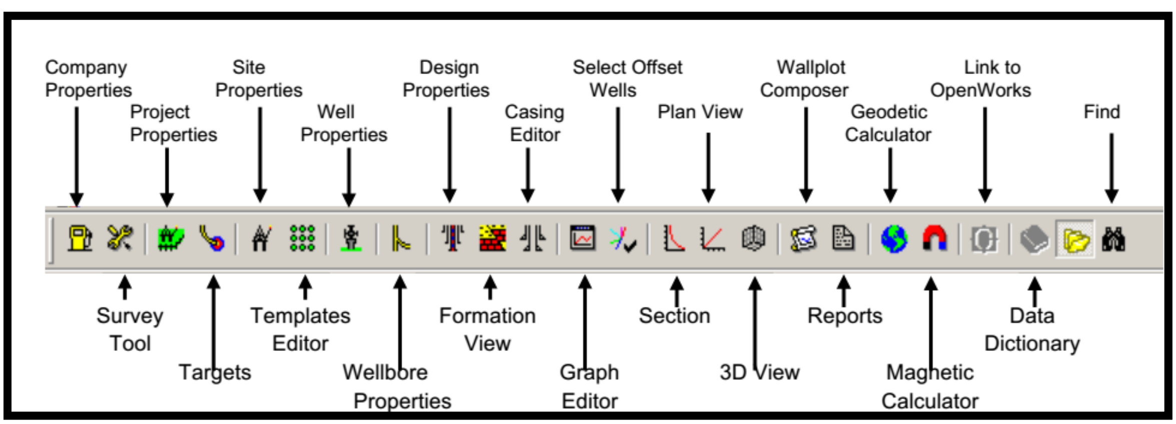

Figure 25 : Tools Bars of COMPASS

The toolbar is located below the menu bar and enables quick access to commonly used functions within COMPASS.

Status Window

The Status Window represent the following data: The currently open data suite comprising the Company, Project, Well, Wellbore, and Design.

- Drawing of vertical datum reference with elevation information for the open Wellbore
- Drawing of the slot position with north arrow for co-ordinate information for the open well
- Vertical section origin and angle

➢ **Data Tree**

It is a hierarchical tree where you can view and edit different levels within the engineering data management model hierarchy. Operations the data tree consists of eight levels. They are the following:
- Database Level
- Company Level
- Project Level
- Site Level
- Well Level
- Wellbore Level
- Design Level
- Case (Well Plan only)

First three level has been shown in following figures and in each tab different data can be modified.

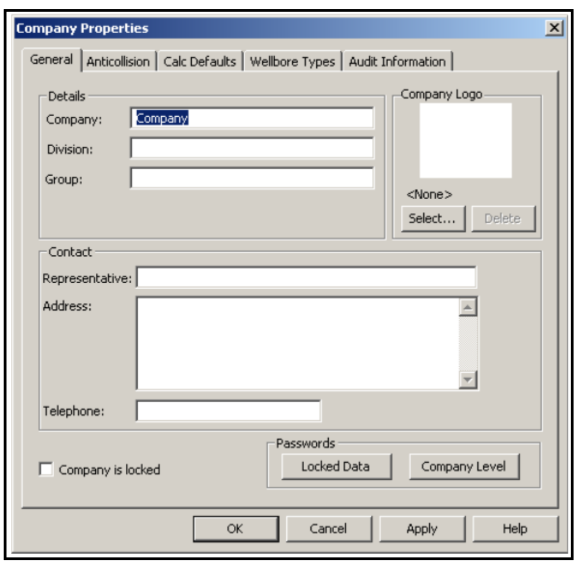

Figure 26 : Company level Properties

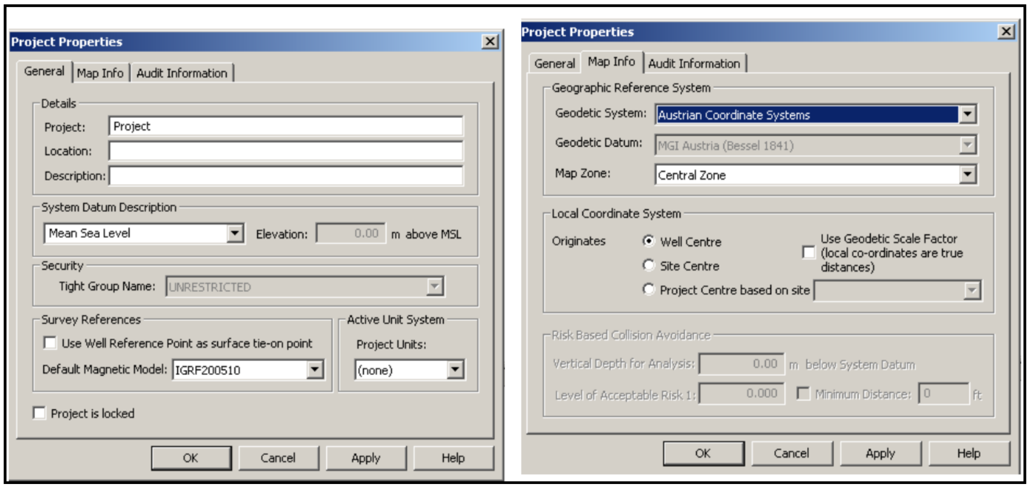

Figure 27 : Project level Properties

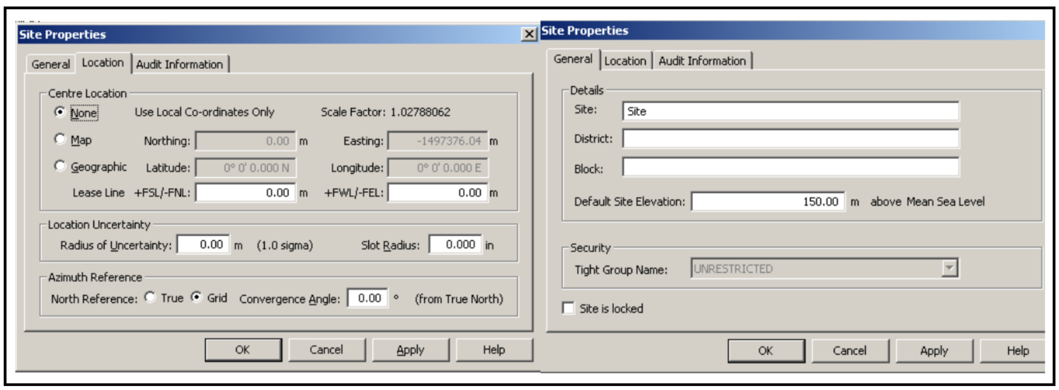

Figure 28 : Site level Properties

In each above level related data about the directional well bore design will be imported and in design level different method of directional well design can be utilized to plan a directional well Also the target editor is in well design level and the shape of target can be determined in this level

- **Target Editor**

To apply targets in well planning, the drilling engineer must have the location and geometry of any drilling and geological targets within the Target Editor. These targets must be assigned to the current Well-path before they can be used. To access the Target Editor: file➔Properties➔Project➔Targets

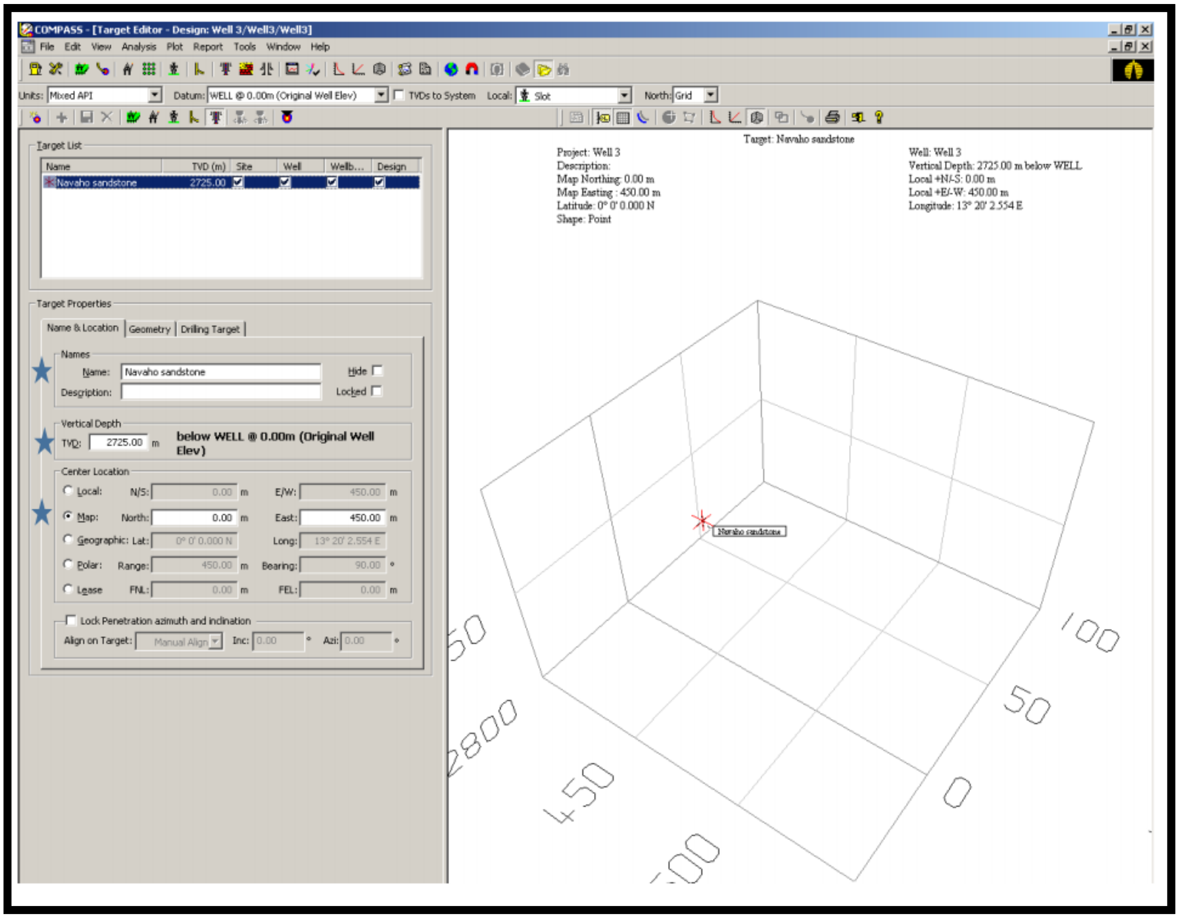

Figure 29 : Target editor

- **Plan Editor**

For your project select slant as planning method, then fill out the parameters (1st Hold Length and 1st Built, choose your target from the list and then click on the Calculate button.

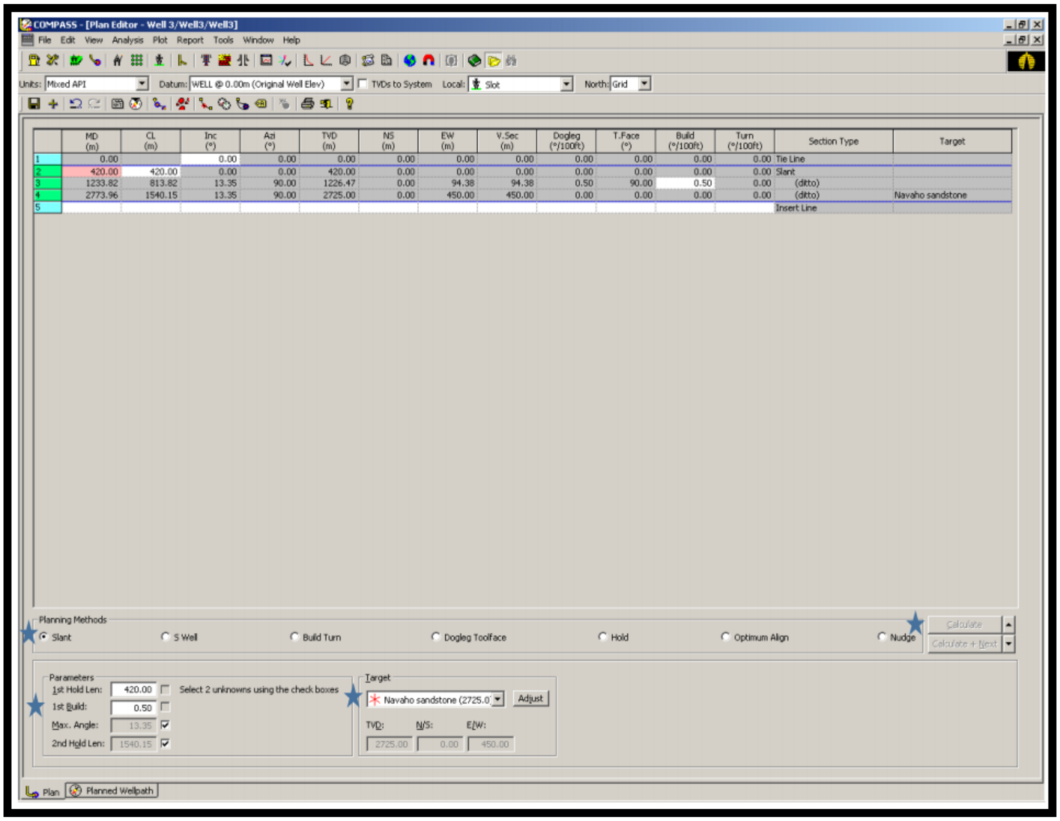

Figure 30 : Plan editor

Planning Methods

1- 2D Directional Well Planning

The 2-dimensional well planning tools build wellbore trajectories that follow the plane of a vertical profile. That is, there is no turn from the slot to the final target. COMPASS delivers two methods for planning 2D wells:

Slant Well: a simple Hold-Build-Hold profile. It has four elements, from which two are to define and two are to calculate.

S-Well: it can be a Build-Hold-Drop-Hold profile or a Build-Hold-Build-Hold profile. It has seven variable from which you must define five, the rest will be computed.

2- 3D Directional Well Planning

3D planning methods and tools include following parameters

- Build/Turn curves for rotary drilled sections,
- Dogleg/Tool-face curves for steerable drilling design
- Optimum Align
- Nudge.
- Hold which used no build or turn while design well.

9.1.2 Well Plan

Well Plan software is a Company-server engineering system for drilling, completion, and well service operations.

Well Plan software is based on a database. This database is named the Engineer's Drilling Data Model (EDM) and provisions the various levels of data that are required to use the drilling software. This is a significant pros while using the software because of enhanced integration between drilling software products. COMPASS, Well Plan, Stress Check and Casing Seat software use the common database and data structure. Although the common database improves integration between drilling products.

Well Plan provides competitive edge to solve engineering problems during the design and operative phases for drilling and well completion.

In Well Plan software following data has been inputted:

- Hole section data
- Drilling fluid data
- Drill string data
- BHA data
- Geothermal data
- Circulating system specification
- Torque and drag data
- Transport analysis data
- ….

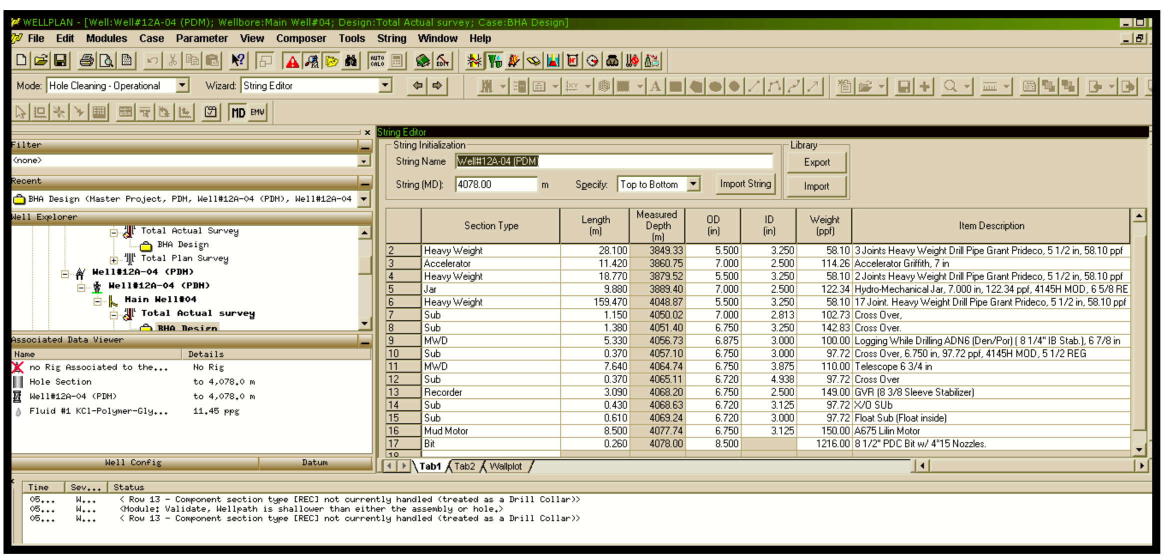

Figure 31 : BHA input inside well plan software

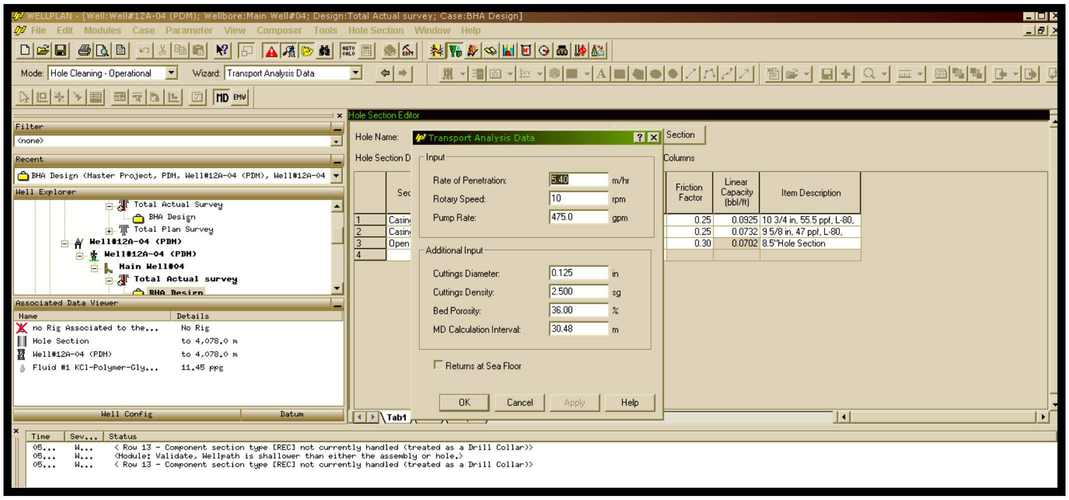

Figure 32 : Drilling parameter input inside Well Plan software

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