DEVELOPMENT OF AN ALGORITHM TO ANALYZE THE INTERRELATIONSHIP AMONG FIVE ELEMENTS INVOLVED IN THE PLANNING, DESIGN AND DRILLING OF EXTENDED REACH AND COMPLEX WELLS

A Thesis in
Petroleum and Mineral Engineering

by
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Submitted in Partial Fulfillment
of the Requirements
for the Degree of
Master of Science

May 2009
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ABSTRACT

Extended Reach Drilling (ERD) is an integrated methodology for drilling high-angle well bores with long horizontal displacements. Typical problems that have come to be associated with this type of operation include: Directional Well Design, Torque and Drag Limitations, Hydraulics and Hole Cleaning, Vibration and Wellbore Stability, Equivalent Circulation Density Management, as well as Mud Rheology and Solids Control.

Given these problems, the drilling operation of ERD wells should be a closed-loop process that starts at the pre-job planning phase, is carried on through the design and execution phase, and results in the implementation of lessons learned. For high levels of performance improvement to be achieved, it is essential to analyze the interrelationship among the elements involved in the entire drilling process. This is because a system that considers the individual elements of the drilling system in isolation is inadequate to deliver desired performance improvement.

In this study, an algorithm that sets forth a design for a drilling program that is suitable to drill an extended reach well was developed using Visual Basic. Although the algorithm touches on several factors affecting extended reach drilling, the major focus is on the five elements, which are considered the critical factors. These are: Well Planning and Trajectory Design, Bottom Hole Assembly (BHA) Design, Drill String Design, Torque and Drag Analysis, as well as Hydraulics and Hole Cleaning.
The proposed algorithm evaluates the interrelationship among these critical factors and provides direction on the processes and tasks required at all stages in the design and drilling of an ERD well to achieve better drilling performance. It also affords both office and field personnel the capability to identify drilling performance problems and by evaluating results, identify remedial actions quickly and accurately.
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Acknowledgements

I would like to express my sincere gratitude and appreciation to my academic adviser, Dr. Robert William Watson for his consistent advice, fortitude, and receptiveness to opinions and ideas while I worked on this project. My appreciation also goes to the other members of my thesis committee, Dr. Larry Grayson and Dr. Jose Ventura for the unflinching support and encouragement I got from them in the course of doing this work.

A lot of credit goes to Jim Oberkircher, President and CEO of GF Eagle Corporation who first gave me the idea and suggestion to conduct research on Extended Reach Drilling. I would also like to acknowledge the help of individuals and companies in the oil industry that contributed immensely to the success of this work. Top on the list is Baker Hughes-INTEQ. I want to thank Pete Clark who first hired me as an intern and thus started my relationship with the company. Special thanks also go to Charles van Lammeren who is the brainchild and initiator of the involvement and partnership of Baker Hughes-INTEQ in this research. I must not fail to thank John Fabian and Carl Corson for the immense role they played in ensuring that I got all the materials I needed to carry out this work. The many meetings and discussions I had with the Baker Hughes Team greatly ensured that I stayed on course and on message throughout the duration of this study.

Of course I would like to thank my wife Elma, for staying strong and focused while I was several miles away, working on this project. It is impossible for me to list all the people that contributed in one way or the other to the success of this work. To all whose names have
been mentioned and those not mentioned, I say, THANKS is a small word, but it goes a long way to show how much I appreciate your love care and concern while I worked on this project.
Chapter One

Introduction

Extended Reach Drilling (ERD) is an integrated methodology for drilling high-angle wellbores with long horizontal displacements. ERD wells are typically kicked off from the vertical near the surface and built to an angle of inclination that allows sufficient horizontal displacement from the surface to the desired target. This inclination is held constant until the wellbore reaches the zone of interest and is then kicked off near the horizontal and extended into the reservoir. This technology enables optimization of field development through the reduction of drilling sites and structures, and allows the operator to reach portions of the reservoir at a much greater distance than is possible with conventional directional drilling technology. These efficiencies increase profit margins on projects and can make the difference whether or not a project is financially viable (Al-Suwaidi, El-Nashar, Allen and Brandao, 2001).

Extended Reach Drilling involves pushing drilling capabilities near their limits, whether it is to reach reserves far from existing facilities or to expose reservoir sections for production and reservoir management advantages. As a matter of fact, ERD needs to be viewed not only as Extended Drilling, but also as Extended Reservoir Drilling, or both Extended Reach and Reservoir Drilling (Payne, Wilton, and Ramos, 1995). In this perspective, ERD assumes a critical role in current industry operations.
The purpose of drilling extended reach, horizontal and complex design wells is to produce oil and gas in a field in the most cost effective way. The use of these new techniques can make old non-profitable fields profitable, prolong an existing field’s economic life and make new and uncertain field discoveries technically possible.

Exploitation of ERD procedures could also be made to:

1. Develop offshore reservoirs now considered uneconomical;
2. Drill under shipping lanes or under environmentally sensitive areas;
3. Accelerate production by drilling long sections of nearly horizontal holes in producing formations;
4. Provide an alternative for some subsea completions and
5. Reduce the number of platforms necessary to develop a large reservoir.

Some of the many advantages of using ERD to access reserves are based on the elimination of high capital cost items. For example, in Alaska, ERD can reduce the need for costly drilling and production islands and the inherent logistical problems associated with them (Nelson, 1997). For offshore drilling, such as in the North Sea and the Gulf of Mexico, ERD results in a substantial reduction in subsea equipment, including fewer pipelines. This not only has an impact on economics but also on environmental concerns and even permitting (Mason and Judzis, 1998).
1.1 Definition of Extended Reach Drilling

ERD wells are generally associated with accessing reservoirs at locations remote from a drill site. Generally, a well is defined as extended reach if it has a Step-Out Ratio of 2 or more. Step-out Ratio is defined as the horizontal displacement (HD) divided by the true vertical depth (TVD) at total depth.

The definition of what exactly is an extended reach well remains a debatable issue, but as was mentioned earlier, current consensus says it is a well in which the horizontal displacement is at least twice the true vertical depth of the well (Economides, Watters, and Dun-Norman, 1998). This definition also implies that as the ratio of displacement to TVD increases, the well difficulty increases. While there is no such thing as an “easy” ERD well, it is factual to say that with increased displacement comes increased difficulty (Williams, 2008). However, the depth of the reserves to be accessed is also critical – the shallower the reserves the more difficult it is to access the well using ERD. Therefore, displacement to TVD ratio provides an effective measure of total difficulty (Williams, 2008). Extended reach drilling can thus be viewed as an integrated methodology for drilling high-angle well bores with long horizontal displacements (Tolle and Dellinger, 2002).

There has been some debate on what exactly determines the difficulty in drilling an extended reach well. Some authors have used ERD ratio (HD/TVD) or even (MD/TVD) as measures of difficulty, where MD is the measured depth. Relative difficulty is a function of both HD/TVD ratio and absolute TVD and it is commonly referred to as Aspect Ratio.
Williams (2008) clearly supports the notion that the higher the ratio the more difficult the well is to drill. But in an earlier study, Mason and Judzis (1998) propounded that this is not true, as depicted in Figure 1.1.

![Figure 1.1: Industry Extended Reach Drilling Experience](image)

As seen in the figure, the largest step-out wells have been drilled at the highest ERD ratio. But this issue is far more complicated than this. For example in deep water fields where directional work is often not possible until drilling depth is below the sea bed, the total ERD ratio will normally be less than 1. This is the case even though the element of vertical depth over which any directional work is carried out would have a very high ERD ratio (Mason and Judzis, 1998).
In spite of these controversies, there is still no standard and generally accepted definition for an ERD well. Thus, there is the need for the industry to address this issue and come up with a generally acceptable method for characterizing all well designs.

It should be noted however, that the generally accepted definitions of an ERD well (Longwell and Seng, 1996) include:

1. Wells having horizontal displacements greater than twice the well’s true vertical depth, yielding inclination angles in excess of 63.4 degrees;
2. Wells which approach the limits of what has been achieved by the industry in terms of horizontal displacement;
3. High-angle directional wells that approach the capabilities of the contracted rig.

Typically, the Extended Reach Drilling limit is reached when one of the following occurs (Demong, Ruverbank and Mason, 2004):

1. The hole becomes unstable, due either to time exposure, geo-mechanical interaction, adverse pressure differential, or drilling fluids interaction (or incompatibility). The onset of these conditions is usually observed in the sudden increase of torque and drag in the drill string not related to dog leg severity (DLS) of the hole or the length of the drilled section.
2. The drill string will no longer travel to the bottom of the hole due to excessive drag. This situation is differentiated from the case above because this effect is not related to the friction factor which remains unchanged. Instead, it is related to the cumulative length drilled along with the DLS of the hole as drilled, Figure 1.2.

![Diagram of drill string with forces labeled](image)

\[ N \cdot \mu > F \]

- \(N\) = Component of string weight acting in the normal direction
- \(F\) = Component of string weight acting in the tangential direction
- \(\mu\) = Friction factor


**Figure 1.2**: ERD Limit - Reached when friction exceeds the force available to push the drill string down the hole

3. When rotation is used to overcome friction and advance the drill string, such as in rotary steerable application. The limit is reached when you reach the torque capacity of the tubulars as shown in Figure 1.3.
Figure 1.3: Limit of Rotary Steerable ERD - Reached when friction exceeds the torque available to turn the drill string

1.2 Extended Reach Drilling: A Historical Perspective

Horizontal well technology and extended reach drilling technology have been implemented in the industry since 1987. Early efforts of modern-day horizontal well technology were led by Atlantic Richfield in the late 1970s, Elf Aquitaine in the early 1980s, and BP Alaska in the mid 1980s. Estimates by Philip C. Crouse and Associates Incorporated (1995) placed worldwide implementation of horizontal well technology at over 11,000 horizontal wells during the period of 1986 through 1996.
Following the end of the era of “easy oil” and with major oil fields being situated in deep waters and difficult terrains, well trajectories being planned had long horizontal departures and increasingly became more complex. Extended Reach Drilling thus became the means of expanding production of these aging oil fields and made it possible to drill and produce hitherto impossible reserves.

The first extended-reach well with a horizontal reach of more than 5,000m was drilled from Statfjord Well C-10 in 1989-1990 (Rasmussen, Sorheim, Seiffert, Angeltvadt and Gjedrem, 1991). Statfjord Well C-3, which was drilled and completed in 1999, holds the record of being the first well in the industry to exceed 6,000m (Njaerheim and Tjoetta, 1992). It had a horizontal departure of 6.1km. In 1992-1993, Statoil’s Well C-2 set new world records and broke the 7km departure “barrier” for the first time. Well C-2 achieved 8.7km MD and a departure of 7.3km at the Statfjord reservoir TVD of 2,700m. In 1994, Norsk Hydro’s Well C-26 set another world record for well departure. Their Well C-26 achieved 9.3km MD with a departure of 7.85km at 2,270m TVD.

Since the Statfjord development projects, the industry has recorded breakthroughs in extended reach drilling. Some major industry achievements that followed the Statfjord successes are chronicled hereunder:
1.2.1 Horizontal and ERD Wells

In September 1991, Cliff Oil & Gas drilled the deepest horizontal well in the North Bayou Jack field in Louisiana. The well reached TD at 4,675m TVD (Drilling and Production Yearbook, 1992).

In November 1991, Maersk Oil & Gas completed the world’s longest horizontal well at Tyra West Bravo field, TWB-11a in the Danish sector of the North Sea. The horizontal extension record was 2,500m at a measured depth of 4,770m and a total vertical depth of 2,040m (Drilling and Production Yearbook, 1992). At about the same period, Unocal had the greatest horizontal displacement to true vertical depth ratio, HD/TVD of 3.95. This was achieved in Well C-29 in the Dos Cuadrea Field offshore Santa Barbara in California. The well had a measured depth of 1,335m (Drilling and Production Yearbook, 1992). The company also drilled the longest ERD well in the USA. The well A-21 was drilled in July 1991 from the Irene platform located in offshore California and has a lateral reach of 4,472m.

About the same period, Woodside Offshore Petroleum drilled a long extended reach gas well from the North Rankin-A platform in Australia. The well had a reach of 5,009m and a MD of 6,180m.
1.2.2 Dual Horizontal – Dual Lateral Wells

In 1992, Well A-36 achieved 5km departure in the shallower Gullfaks reservoir at 2,160m TVD, resulting in a MD/TVD ratio of 2.79. It was among the highest at the time.

In March 1992, Torch Energy Advisors completed the first Dual Horizontal Well, Basden 1-H, in Fayette County, Texas (Drilling and Production Yearbook, 1993). After drilling both horizontal laterals, the two slotted liners were run into opposing horizontal wellbores. The second liner was run through a window in the first. Each horizontal lateral extended 800m.

In 1993, Petro-Hunt Corporation used a unique horizontal well design to optimize development of an irregularly shaped lease in the McDennand Well No. 1 in the Austin Chalk formation in Texas (Cooney, Stacy and Stephens, 1993). Two medium-radius horizontal bores were drilled in opposite directions from one vertical hole to maximize horizontal displacement in the lease. The two bores had horizontal sections of 825m and 625m, respectively. Underbalanced drilling techniques were used to prevent formation damage. The high mechanical integrity of the Austin Chalk formation suited an openhole completion method.

In August-September 1991, Gemini Exploration Company drilled the longest total displacement of two lateral wells in the Pearsall field of south Texas (Drilling and Production Yearbook, 1992). The total combined displacement of the two laterals was 2,687m.
As the years went by (especially in the late 1990s), drilling techniques continued to be developed to push the limit beyond the then maximum 60 degree inclined wells. This was as a result of a combination of engineering research, application of new technology and field experience. During this period, BP also drilled wells that stretched 5km (3 miles) then 8km (5 miles) and then 10km (6¼ miles) offshore from the rig site located onshore at their Wytch Farm development (Williams, 2008). The Wytch Farm project thus broke the existing record and set a new one. The technical success of this project opened the “flood gates” and extended reach drilling not only increasingly became the “standard practice” for expanding production of aging oil fields, it also made it possible to drill and produce hitherto impossible reserves.

Figure 1.4 is an evolutionary plot, which shows that the most aggressive ERD activities indeed took place during the early 1990s. The inner envelope describes ERD wells drilled as of 1992 while the subsequent ones to the right describe the industry achievements over the years, based on recent industry literature.
As a result of improvements in personnel competency and technological advancement, not only were more ERD wells drilled, these wells continuously pushed the envelope in terms of lateral reach and geometric complexity in order to access more challenging geological targets. The complexity of ERD operations has progressed from 2D to complex 3D trajectories where, for example, an abandoned 2D ERD well has been sidetracked to tap shallower satellite reserves, requiring a highly complex uphill well profile (Ruszka, 2008).
In April 2007, Exxon Mobil Corporation announced that its subsidiary, Exxon Neftegas Limited (ENL), completed the drilling of the Z-11 well in the Sakhalin project. It was the longest measured depth ERD well in the world at the time. Located on Sakhalin Island offshore Eastern Russia, the record-setting Z-11 achieved a total measured depth of 11,282m or over seven miles. The Z-11 was the 17th ERD producing well to be completed as part of the Sakhalin-1 Project. It was drilled in 61 days, more than 15 days ahead of schedule and below expected cost with no safety or environmental incidents. Since the first Sakhalin-1 well was drilled in 2003, the time required to drill these world class wells has been reduced by more than fifty percent. When compared to industry benchmarks, Sakhalin-1 wells are among the world's fastest-drilled ERD wells.

However, the current world record for the longest ERD well drilled is held by Maersk Oil Qatar. In June 2008, the company was reported to have drilled the well in the Al-Shaheen Field offshore Qatar. This well broke the previous record length by over 610m; reaching a total depth of 12,289m, with a total step-out distance from the surface location of 10,902m. In all, the well set 10 records including the longest well ever drilled, the longest along-hole departure (11, 569m), the longest 8½-in section (10,805m), the highest ERD ratio (AHD/TVD = 10.485), the highest directional difficulty index (DDI = 8.279), the deepest directional control, the deepest downlink MWD transmission and LWD geosteering (12, 290m), the deepest battery-less operation, the longest reservoir contact (10,805m.) and finally the longest open hole (Drilling Contractor Magazine, July/August, 2008).
Record-breaking achievements continue to be made and these tend to demonstrate that it is indeed possible to exceed the current industry limit of ERD. What is less well understood, however, are the risks of drilling such wells. Experience has shown that the probability of encountering significant drilling problems in ERD wells is generally much higher than that experienced in conventional wells. Driven by a need to minimize environmental impact and improve recoverable reserves, it is anticipated that ERD activity will continue to increase. Simultaneously, advances in drilling technology development will continue to lower the operational risk. As a result, ERD limits will continuously be tested and pushed to new levels as the growing benefits outweigh the diminishing operational risks (Ruszka, 2008).

1.3 Statement of the Problem

Well profiles have become more challenging as a result of the need to reach new targets, depths and departures that in the past seemed improbable. Regardless of our current levels of success, there is the urgency to develop methods and processes that will further improve drilling efficiency. Well trajectories being planned today have such departures and complexity that viability, risk and economics are all vital parts of the evaluation process prior to investing in the project. These in large part are determined by the rig design and capacity to drill these extreme-reach well designs.

To reduce operational costs, the entire drilling process must be improved substantially. Researchers focusing on these challenges have identified the need for system-based solutions. Such an approach evaluates all the elements that influence the drilling process.
As such, it is imperative that a systematic, logical and quantifiable approach for developing and implementing technologies in these types of applications be defined. As the industry continues to move toward the more cost-effective technologies of computer-based instrumentation, power-handling tools, and automated drilling, there is the need to have a defined and structured approach for drilling extended reach wells.

1.4 Objectives of Study

The objective of this study is to integrate the parameters involved in the planning, design and drilling of extended reach and complex wells into a single computer model. The goal is to develop an algorithm that will evaluate the interrelationship among these parameters during the planning and design phases of the drilling operation in a technically sound and feasible way.

1.5 Scope of Study

As was mentioned earlier, the industry has made significant progress in developing improved technologies especially as it affects the drilling of complex and designer wells. This study will concentrate on the following areas:

- Well Planning of Extended Reach and Complex Wells, and
- Drilling Parameter Evaluation in Extended Reach and Complex Wells.
Under these two broad headings, the following technologies, which have been found to be critical to the success of ERD, would be analytically examined:

- Well Planning and Trajectory Design
- Bottom Hole Assembly Design
- Drill String Design
- Torque and Drag
- Hydraulics and Hole Cleaning
- Equivalent Circulation Density Management

1.6 Significance of the Study and Deliverables

At the end of this study, a Visual Basic algorithm will be developed. The model will have the capability to design the drilling program most suitable to drill an extended reach well. It will be versatile and flexible such that the components of extended reach drilling can either be chosen by the user based on availability, or by the program from its library/databank. Evaluation of these components will result in an output that will produce a viable wellplan and design for the given ERD well.
Chapter Two

Literature Review

Several studies have been carried out on the theory and practice of drilling extended reach and complex wells. A review of the literature gives us an insight into some of these studies, the technologies used and how they have impacted the drilling industry.

For any given drilling operation, numerous drilling technologies are typically available to ensure maximum recovery of the hydrocarbon from the reservoir. Over the years, the industry has made significant progress in developing improved technologies to tackle the complexities encountered in drilling extended reach wells. Some of these improvements are related to real-time formation evaluation, directional control while drilling, improved bottomhole assembly (BHA) components, and drilling fluids.

Based on the many lessons learned in recent projects, technologies that have been identified to be vital to the success of ERD (Payne, Cocking and Hatch, 1994) include:

- Torque and Drag
- Drillstring and Bottom Hole Assembly Design
- Wellbore Stability
- Hydraulics and Hole Cleaning
- Drilling Dynamics
- Rig Sizing
From the drilling fluid perspective, some crucial issues that can pose significant challenges for the operator (Cameron, 2001) include:

- Narrow Mud Weight/Fracture Gradient Window
- Equivalent Circulation Density (ECD) Management
- Lost Circulation
- Lubricity

Also related to these are surveying and well profile design. Other technologies of vital importance are the use of Rotary Steerable Systems (RSS) together with Measurement While Drilling (MWD) and Logging While Drilling (LWD) tools to geosteer the well into the geological target (Tribe, Burns, Howell and Cickson, 2001).

It is well known that ERD introduces factors that can compromise well delivery, and the first challenge prior to drilling an ER well is to identify and minimize risk (Karmaruddin, Lah, Sering, Good and Khun, 2000). The literature is replete with several experimental and theoretical studies that have been conducted on extended reach exploration and development drilling. Researchers have mainly concentrated on the critical factors outlined above. This literature survey will be carried out by reviewing the studies that have been made, based on these critical technologies.
2.1 Wellpath Planning

Extended Reach Drilling is playing an important role in the economic development of various oil reserves. For some ER wells, careful well planning and utilizing existing drilling practices are sufficient to avoid problems such as wellbore instability, lost circulation, and stuck pipe. However, results from several studies have shown that when well step-out ratios increase, some operational practices developed while drilling conventional wells become inadequate to successfully and cost-effectively deliver the ER wells. It should be noted, however, that careful planning alone cannot always prevent drilling problems.

ERD well profile design is not just a simple geometric curve design. It is an integrated process that requires an optimum wellpath profile with respect to torque and drag. There are two main principles that should be obeyed when planning an extended reach well (Shanzhou, Genlu, Jianguo, and Zhiyong, 1998). These are:

- Minimizing Torque and Drag
- Minimizing Well Length

Several papers have been written on this subject. McClendon and Anders (1985) described the use of the catenary well plan method for directional drilling. Catenary Wellplan is explained in detail in Chapter 3. A modified version of this method was used with great success when some of the ERD and horizontal wells on the Statfjord field were drilled. The method was mainly used to reduce torque and drag by reducing the wall forces in the
build-up section. This was done in the top part of the hole where the drill pipe tension and side loads were highest.

### 2.2 Torque and Drag

The ability to confidently predict that you can reach a reservoir target is probably the biggest problem when drilling an extended reach well. This makes the accurate prediction of torque and drag very essential. Drilling torque losses calculated on various plan trajectories are a good indication of drillability of a well plan. A review of these torque values and adjustments to the planned trajectory is a way to improve the plan or find the easiest path to drill. Selecting the appropriate well profile followed by modifying casing and tubular designs should be the key initial steps in torque reduction measures (Aston, Hearn and McGhee, 1998). Torque levels in ER wells are generally more dependent on wellbore length and tortuousity than tangent angle. Yet, higher angle wells do tend to reduce overall torque levels while drilling since more of the drill string is in compression, and the tension profile in the build section is reduced. However, higher torque values and associated problems such as accelerated casing wear and key seats are seen during backreaming operations (Modi, Mason, Tooms and Conran, 1997).

One of the major factors affecting torque and drag in an extended reach well is the tortuousity of the hole (Banks, Hogg and Thorogood, 1992). High tortuousity results from a lack of control of toolface and deviation rate. Thus if a steerable motor is hard to orient, this will result in higher torque and drag, which compounds the original orientation
problem. Low build-up rates, deep kick-off points, elimination of excessive tortuousity and optimum hole cleaning are the main factors that will affect the torque and drag values. Banks et al. (1992) also discussed the effect of excessive tortuousity. They stipulated that excessive tortuousity can severely limit the drillable depth and the elimination of this effect is a critical factor in successful ERD operations. They recommend that this should be used as an objective measure of the directional drilling contractor’s performance.

High drilling torque can pose significant problems in ERD wells. Meader, Allen and Riley, (2000) investigated methods of torque reduction at the Wytch farm project. The project had used Barafibre (crushed almond shell) as the prime method of torque relief. But during the drilling of Well M-16, a trial of an alternative mud additive was conducted. The product was Lubraglide (small plastic beads). The trial was conducted by stripping out all the Barafibre from the system and replacing it with Lubraglide. The initial results were quite impressive. The results showed that as the Barafibre was stripped from the system, the torque level rose from ± 40,000 ft-lbs to the limit of 45,000 ft-lbs where the top drive stalled out. As the Lubraglide entered the open hole the torque level dropped to 25,000 ft-lbs. This is a dramatic result but unfortunately the torque reduction was not sustained for the duration of the 8 ½” hole section. The torque was managed for the rest of the well with a combination of Lubraglide and Barafibre. The reasons why Lubraglide alone could not consistently reduce the torque are not well understood, and this underlines the need for extensive data gathering so that thorough post-well analysis can be conducted.
Many operators have reported the use of mechanical and chemical friction reducers to minimize torque and drag. Rubber element and plastic casing protectors have been reported to be successful in reducing torque. Some operators, (Ikeda, Takeuchi, and Crouse, 1996) reported torque reductions of over 25% by using Non-Rotating Drill Pipe Protectors (NRDPP). Bi-directional rollers for both drillpipe and casing have shown the most encouraging results especially inside casing while running liners and drill pipe conveyed logging tools. Other torque reduction strategies that are known to have been implemented by operators include torque reduction subs, beads, and downhole tractor systems. Experience on previous ER wells have also indicated that the use of fibrous Lost Circulation Materials (LCM) have a very beneficial effect in improving wellbore cleaning and reducing both torque and drag (Cocking, Bezant and Tooms, 1997). When torque values begin to increase in the 8½” section, lost circulation materials are known to have been used to reduce torque by improving hole cleaning effectiveness.

2.3 Hole Cleaning

ERD wells typically require higher density fluids to maintain stability as compared to vertical wells. High inclinations also expose more surface area of a particular zone to the drilling fluid for a greater period, thus increasing the potential for differential sticking or lost circulation. It has been reported that hole cleaning is critical to the success of extended reach drilling, especially where the hole inclination is high (Payne et al ,1994; Ryan, Reynolds and Raitt, 1995; Eck-Olsen, Sietten, Reynolds and Samuel, 1994; Aarrestad, and Blikra, 1994; and Ikeda et al. 1996).
Poor hole cleaning has resulted in problems of:

1. Inability to transfer weight to the bit
2. Unexplained and unplanned changes in direction
3. Lost mud in the pay zone, which limits ultimate productivity due to formation damage
4. Stuck pipe problems

Several papers have shown the importance of drillpipe rotation as a means of improving hole cleaning (Brett, Beckett and Holt, 1989; Guild and Jeffrey, 1994; Sanchez, Azar, and Martins, 1997). As the drillpipe is rotated, cuttings are agitated into the flowstream and circulated out of the wellbore. To enhance hole cleaning, drillstring rotation is used while drilling and backreaming, and with the pipe off the bottom. In another study, Sanchez et al. (1997) reported that the reduction in cuttings' weight in the annulus could be as high as 80% due to pipe rotation. There are obviously many factors involved in modeling hole cleaning, such as annular velocity and mud rheology. However, having continuous drill string rotation is possibly one of the most significant. Deviating the hole by sliding a motor will also hinder hole cleaning (Warren, 1997; Ikeda et al. 1996).

In reporting Statoil’s experiences in drilling horizontal, extended reach, and complex wells, Blikra, Drevdal and Aarrestad (1994) propounded that deep kick-off point and low build-up rates will reduce the inclination in the larger diameter hole sections. This generally gives better hole stability and improves hole cleaning. According to the report, high rotation of
the drill string in the region of 150-180 rpm have been known to improve hole cleaning, especially while drilling the 12 ¾” and 8 ½” hole sections with oil-ester- or ether-based mud systems. They also reported that disturbing the cuttings on the low side of the hole and creating a turbulent flow pattern around the drill pipe can lead to improved cuttings removal. Blikra et al. (1994) also showed that backreaming in open hole and inside casing/liners at high rotation speed has become standard procedure for ERD wells and has also resulted in improved cuttings removal. Other factors that have been known to enhance hole cleaning include high flowrates, tight control of mud properties (especially mud rheology) and controlled drilling rates.

Additional research is being conducted to address the problem of lost circulation in ERD wells. The high wellbore inclination presents significant challenges concerning placement techniques, sufficient coverage of the loss zone, and selection of non-damaging materials. Addition of lost circulation materials (LCM) has been found to greatly reduce open-hole torques through the formation of a low-friction bed between the drill string and the formation. Thus current investigations focus on a better understanding of loss and propagation mechanisms and the application of crosslink polymers and other fluids that provide low compressive strength.

2.4 Cuttings Transport

Efficient cuttings transport is one of the primary design considerations for an extended reach drilling fluid, especially for wells with horizontal and highly inclined sections of more
than 6,000m (Guild, Wallace, and Wassenborg, 1995; Gao, and Young, 1995; Schamp, Estes, and Keller, 2006). Guild et al. (1995) reported that, while being transported from the hole, cuttings can be ground to finer sand particles, especially when rotary drilling is being used. Under these conditions, drilling may not be able to proceed if cuttings transport remains a problem in the hole. As a result of excessive torque and drag caused by small cuttings settled at the lower side of the horizontal or inclined section, it may not be possible to run casing in place, even if drilling to the target depth is achievable. Horizontal and highly inclined wells drilled through unconsolidated sand reservoirs have also been known to have these same problems.

There is the argument that inefficient transport of small cuttings is the main factor for excessive torque and drag during extended reach drilling. However, very little is known about the transport behavior of small cuttings. Experimental observations (Parker, 1987; Ahmed, 2001) show that small cuttings are more difficult to transport under certain conditions. Ahmed (2001) also suggested that smaller particles tend to more easily stick to drill pipe due to their cohesive effects. Above all, it is even more difficult to release the pipe once it gets stuck by small sand-sized cuttings. By measuring total annular cuttings concentration, Parker (1987) observed that smaller cuttings are easier to transport in vertical wells, but slightly harder to transport in highly inclined wells. This is consistent with Larsen’s (1990) observation that at high hole inclination angles, smaller cuttings are harder to clean out. These cuttings need a higher fluid velocity to keep continuous forward movement.
Duan, Miska, Yu, Takach and Ahmed (2006) studied the transport of small cuttings in extended reach drilling. Their study involved extensive experiments with three sizes of cuttings in a bid to identify the main factors affecting small cuttings transport. The effects of cuttings size, drill pipe rotation, fluid rheology, flow rate and hole inclination were also investigated as part of the study. The results show significant differences in cuttings transport based on cuttings size. Their study produced some very important conclusions among which are:

1. In terms of cuttings concentration, smaller cuttings are more difficult to transport than larger cuttings in the horizontal annulus when tested with water. However, smaller cuttings are easier to transport than larger cuttings when 0.25 lbm/bbl of Polyanionic Cellulose (PAC) solutions were used.

2. Pipe rotation and fluid rheology are key factors affecting small cuttings transport. Improvement by pipe rotation in the transport efficiency of small cuttings is up to twice as large as the improvement in large cuttings transport. Compared with water, PAC solutions significantly improve smaller cuttings transport, while the transport of larger cuttings is only slightly enhanced.

3. Hole angle has only minor effects on cuttings concentration and bed height within the range of 70 – 90 degrees from vertical.
Duan et al. (2006) concluded this study by recommending that drillpipe rotation combined with polymeric drilling fluids should be used to efficiently transport small cuttings during extended reach and horizontal drilling.

The factors that affect cuttings transport have been well described in the literature and they include:

- Drilling fluid density
- Low shear rate rheology
- Flow rate
- Cutting size and concentration in the annulus
- Drill pipe size
- Rotary speed
- Shape of particles
- Drill string eccentricity in the wellbore

Studies have also been conducted to determine the critical transport fluid velocity necessary to prevent cuttings bed formation (Larson, Pilehvari and Azar, 1993). However, cuttings size is not the only factor that affects effective hole cleaning. Sifferman and Becker (1990) noted that cuttings size in itself only has minor effects on hole cleaning, but its influence on the effects of other parameters is noteworthy. In a later study, Bassal (1995) found that the effects of cuttings size on cuttings concentration in a horizontal annulus are quite dependent on other parameters. With low viscosity mud, smaller cuttings are harder to transport than larger ones at all pipe rotary speeds and flow rates. However, with high-viscosity mud, the tendency may reverse depending on different flow rates.
All the studies that have been conducted on cuttings transport have used different cuttings sizes. Thus, the conclusions about the effects of cuttings sizes on cuttings transport are quite varied and, in some cases, contradictory. The experiments upon which most of these conclusions are based were conducted under separate and un-equal conditions; therefore, it cannot be unequivocally stated that smaller cuttings are harder or easier to transport than larger ones. Any conclusion should thus represent a combination of various drilling parameters before it can be regarded as definitive.

### 2.5 Rotary Steerable Drilling Systems

Before the advent of Rotary Steerable Drilling Systems, there were two major means of directional drilling. The first method was the use of conventional rotary assemblies designed to give predictable deviation in a certain direction. Typical examples of such rotary assemblies are pendulum, packed hole and belly assemblies. The second is the use of a downhole steerable motor. This requires the drillstring to slide along the hole, without drillstring rotation, to control direction.

Variable-gauge stabilizers have been used to fine tune control of hole inclination (Odell, Payne and Cocking, 1995; Bruce, Bezant and Pinnock, 1996), with both of the above methods, but they have not been known to control azimuth. Steerable rotary drilling gives control of both inclination and azimuth and has a number of advantages over these methods (Barr, Clegg and Russell, 1996). Rotary Steerable Systems enhance the
penetration rate and increase the reach of ERD wells. This boosts the efficiency and lowers the overall cost of ERD operations. Using these systems, operators have been able to optimize hole quality and wellbore placement, achieve faster rates of penetration, and enhanced reservoir deliverability. Rotary steerable drilling systems were used on several extended reach wells at the Wytch Farm (Colebrook, Peach, Allen, and Conran, 1998).

One of the biggest advantages of rotary drilling is in applying weight to the bit in extended reach wells. As departure increases with respect to vertical depth, it becomes increasingly difficult to apply weight to the bit and subsequently to control that weight, due to axial friction (Cocking et al. 1997; Warren, 1997; Payne et al. 1994). Drillstring rotation has been described as a virtual “cure all” for the general reduction of drag (Payne and Abbassian, 1996) and the application of weight to the bit (Modi et al, 1997; Ryan et al, 1995). Use of rotary steerable systems allows the drilling parameters to be optimized for the bit and formation. The reactive torque from the bit does not disturb the toolface and so both weight on bit and rotary speed can be adjusted within wide limits.

It is a statement of fact that Extended Reach Drilling, using rotary steerable systems, has made it possible to drill and produce hitherto impossible wells. Several very deep wells would not have been possible to drill without rotary steerable systems because steering beyond 8,500m was not possible as axial drags were too high to allow the oriented steerable motor and bit to slide (Colebrook et al. 1998; Meader et al. 2000). In places like Brazil and Nigeria where major oilfields are located in deep waters, ERD wells might be, in
some cases, the only economically viable drilling solution (Cunha, Martins and Fernandez, 2000).

Ikeda et al. (1996) initiated a study that investigated developments, activities, and philosophies of the larger oil and gas industry in implementing horizontal well and extended reach technologies. North American and European operators, contractors, service companies, government agencies and educational institutions were directly interviewed. Along with the development of data resources, references and industry well information, significant findings and revelations were reported. Among the many findings from the investigation is the fact that many operators are now steering their wells with MWD and LWD tools. According to the report, operators noted that steering a well has been the best way to maximize pay zone penetration. The report also showed that the most common failures seen by most operators have been in motor and MWD failures, which causes downtime. Rotor and stator problems were commonly discussed for motor failure along with other components, and it was generally agreed that the failure rate for MWD increased with:

- Increase in temperature
- Increase in pressure
- Rapid temperature increase or severe pressure changes
- Smaller hole size
- Longer hole length
In underbalanced drilling situations, motor and MWD problems appeared to be higher. Operators also pointed out that the biggest improvements over the last couple of years have been made in MWD and motors, even though they may still contribute to downtime. Operators cautioned that the limiting boundary for MWD pulsing signals is not currently well defined by the vendor companies, and they also noted the fact that BHA steering capabilities are reduced as trajectory increases.

All of the factors indicated above lead to the conclusion that a much-improved overall ROP will be achieved while drilling with a rotary steerable drilling assembly than with a steerable motor. Indeed in certain extended reach or overbalanced drilling applications, rotary drilling is essential.

### 2.6 Concluding Remarks from Literature Review

Because long-term profitability is a primary concern of the oil and gas industry, major efforts are under way to optimize drilling procedures to make operations more cost effective. All phases of drilling are being subjected to economic analysis and, now emerging, is the possibility of obtaining substantial savings by upgrading conventional directional drilling techniques into advanced procedures for drilling high-angle, extended-reach and designer wells. Such a capability offers a variety of applications with the potential for significant reductions in cost.
Advances in drilling technology now enable the exploration for and development of offshore oil and gas resources without the installation of facilities and wells in offshore marine environments. Nowadays, more operators are identifying applications of ERD for reservoir development that will provide substantial financial benefit. In Alaska, a number of North Slope fields extend offshore and/or away from existing drill sites and reserves. These will warrant ERD operations. ExxonMobil and the California State Lands Commission both endorse ERD development of the South Ellwood Offshore Field using ERD from onshore sites (Starzer, Mount and Voskanian, 1994). BP is also considering ERD for its Liberty Project in Alaska. In the Gulf of Mexico, China, South America, the North Sea, Indonesia, the Middle East and elsewhere, many other ERD opportunities are being evaluated to optimize development drilling of new major projects (Payne, Wilton and Ramos, 1995).

This study will take extended reach drilling improvement one step further by integrating all the critical technologies for success of extended reach drilling into a single model. The model will design the program most suitable to drill an extended reach well.
Chapter Three

Critical Technologies for Success of Extended Reach Wells

The literature has shown that extended reach exploration and development drilling usually involves some significant issues that can pose significant challenges for the operator. As has been mentioned severally, technologies that have been found to be vital to the success of ERD include:

- Well Trajectory Design
- Torque and Drag
- Drillstring Design
- Wellbore Stability
- Hydraulics and Hole Cleaning
- Casing design
- Drilling Dynamics
- Rig Sizing and Selection
- Narrow Mud Weight/Fracture Gradient Window
- Equivalent Circulation Density (ECD) Management
- Lost Circulation
- Lubricity

The following sections will individually and collectively analyze these success factors with a view to understanding the science and technology behind them. However, before this is done, it is vital to first discuss the difference between the effects these issues have on extended reach wells, as compared to conventional wells.
3.1 What is Different about Extended Reach Drilling?

There are numerous issues that are different, or more critical for ERD wells when compared to conventional directional wells. In some cases, the challenges on ERD wells are the same as those of conventional directional wells, only that in extended reach wells, they are magnified. In other cases, the issues are specific to the type of ERD well that is being drilled (K & M Technologies, 2003). There are both general and specific differences in challenges between ERD and conventional directional wells. Some of the general differences are outlined hereunder.

3.1.1 Torque, Drag and Bucking

These factors are regularly encountered in ERD wells during both drilling and completion phases. Torque is generally only a significant limiting factor on long ERD wells or on slim-hole ERD wells where small diameter drill pipe is used. It is common to rotate casing liners strings on ERD wells to ensure that a good cement job is obtained. This is often the critical torque limitation (K & M Technologies, 2003). In ER wells, torque limits can be reached in a number of ways including:

- Top drive or rotary table output
- Drill pipe tool joints
- Casing connections
- Combined power usage
Axial drag occurs due to the interaction of the drill pipe or casing with the wellbore as it is run in (slack-off) or picked up (pick-up) out of hole (K & M Technologies, 2003). In ER wells, slack-off and pick-up become problems as the well gets deeper and as inclination increases.

Buckling of drill pipe and casing results from excessive compression loads that build up in the string due to axial friction. Drill string and completion string buckling are common problems in ERD wells. This is because, as the length of high angle sections becomes longer, unconstrained pipe tends to bend in the wellbore. As this situation becomes more severe, a helix will develop and eventually prevents the pipe from moving within the hole.

3.1.2 Hole Cleaning

Field experience has demonstrated that hole cleaning practices used for vertical or low angle wells are generally not successful in high angle ERD wells. A thorough understanding of the dynamics of hole cleaning is therefore critical to the success of ERD wells.

3.1.3 Equivalent Circulation Densities

Extended reach wells generally have higher equivalent circulation density fluctuations than conventional wells. With the advent of Measurement While Drilling (MWD) based Pressure While Drilling (PWD) technology, the industry’s understanding of ECD’s has been challenged (K & M Technologies, 2003). Studies have shown that the magnitude of ECD
fluctuations in ERD wells is far greater than previously thought. According to findings by K & M Technologies, ECD’s are more serious in ERD wells because:

i. The magnitudes of the fluctuations are worse due to longer measured depth (MD) relative to true vertical depth (TVD).

ii. Wellbore stability, lost circulation and other key effects are generally more severe and less tolerable in these wells.

iii. Temperature and pressure variations (and their effects on mud properties) are also more extreme in these wells.

3.1.4 Rig Capability and Power Requirements

Extended reach wells challenge the capabilities of the drilling rig more than a conventional directional well of the same measured depth – except for pick-up loads (K & M Technologies, 2003). The need to use continuous higher flow rates at higher pressures, use of higher pipe RPM and higher torque and drag forces will also continuously task a rig’s output capability. Also, power may be limited, especially in a backreaming scenario where pick-up, torque and pumps are all operating at/or near their limit. The combined power usage when deep on a long ERD well may thus become an issue because it is often at this point that maximum output levels are required from the mud pump, drawworks and the rotary system. Many of the industry’s rigs that are being utilized for conventional directional drilling do not have the capability to meet these combined output requirements.
3.1.5 Wellbore Instability, Differential Sticking and Stuck Pipe

Wellbore instability is usually more critical in ERD wells due to:

- The increased wellbore angle
- Increased hole exposure time
- Increased ECD fluctuations and effects

Differential Sticking is also a significant problem in ERD wells because:

- Mud weight is often higher in ERD wells (for wellbore stability at high angles)
- The exposed reservoir intervals are longer in length
- The exposed reservoir intervals are open for a longer period of time
- The drill string and BHA will be on the low side of the hole and at least partially buried in cuttings throughout the reservoir section

Differential sticking is even more important for wells where torque, drag, or buckling problems exist, since even minor differential sticking increases friction. Furthermore, the ability to jar or work the pipe free is reduced on ERD wells. This is as a result of the reduced ability to get weight or torsion down the BHA.
3.1.6 Well Control

This is generally more challenging in ERD wells because kicks are often more difficult to detect and measure as a result of the geometries of the wells. Not only is kick detection more difficult in ERD wells, the ability to manage and “kill the well control problem” are even more difficult as a result of the flow mechanics.

Other issues that have been reported to be, not only different, but more crucial for ERD wells than for conventional directional wells include: Survey Accuracy and Target Definition, Logistics, Time and Cost, HSE Issues, and Well Planning. Having established the differences in the challenges faced in conventional directional wells as compared to extended reach wells, the following sections will examine the parameters that have the greatest significance in the success or failure of an ERD project.

3.2 Well Planning and Trajectory Design

As is the case with all drilling operations, detailed engineering preplanning is of critical importance in successfully drilling ERD wells. To successfully drill an ER well, it is crucial to be able to accurately predict the following parameters under actual downhole conditions:

1. Static and Dynamic Temperature Profile in the Well
2. Hydraulic Pressures
3. Annular Pressure Loss
4. Equivalent Circulation Density
5. Mud Rheology
The operational requirements to drill extreme reach wells start with extensive planning. Well planning is usually an iterative process to determine the optimal balance among wellpath, fluid and hydraulic requirements, drillstring design, torque & drag analysis, casing setting depth etc. The iterative process not only covers the wellpath design, but also the operations planning as well. The well design has a large impact on the operation and planning of ER wells and since there are many variables in designing a well, such as Kick off Point (KOP), Dogleg Severity (DLS), Departure, etc., it becomes an iterative process aimed at yielding an optimal design which should result in the simplest path while still achieving all geological targets.

In order to achieve an optimum well path, several factors have to be considered and put into perspective. Based on reported industry experience gained from earlier wells, and confirmed during the drilling of more recent wells, the following aspects are considered to be key factors in well planning:

- Well Trajectory
- Build Rate
- Surveying and Target Sizing

### 3.2.1 Well Trajectory Design

To determine the optimum well trajectory that will achieve directional objectives, the most critical operations or wellbore characteristics, which are the limiting factors have to be identified. There are several approaches to trajectory design to achieve long reaches with the fewest possible limitations on other downhole operations. Table 3.1 is a general
comparison of the major options while Figure 3.1 is a representation of the various trajectory profiles.

### Table 3.1: Well Trajectory Options, Advantages and Disadvantages

<table>
<thead>
<tr>
<th>Option</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Multiple Build Profile</strong>: Rate of build increases with depth in several discrete steps to tangent angle, hold constant tangent angle</td>
<td>Very long reach, low torque/drag values, low casing wear</td>
<td>High tangent angle</td>
</tr>
<tr>
<td><strong>Build and Hold</strong>: Constant build rate to tangent angle, hold constant tangent angle</td>
<td>Simple, long reaches achievable, low tangent angle</td>
<td>Potentially high contact force in build (torque, casing wear)</td>
</tr>
<tr>
<td><strong>Double Build</strong>: Build-hold-build-hold trajectory, can use two different BURs in the build sections</td>
<td>Very long reaches possible with low contact forces in upper build</td>
<td>May require deep steering, High second tangent angle</td>
</tr>
<tr>
<td><strong>Under-Section</strong>: Build and hold with deep KOP</td>
<td>Reducing hanging weight below build section, reduces contact force in build</td>
<td>High tangent angle, shorter reach</td>
</tr>
<tr>
<td><strong>Inverted</strong>: Tangent angle above horizontal so the wellbore enters the reservoir from underneath</td>
<td>Flexibility for multiple targets, avoids gas cap</td>
<td>Higher axial (buckling) loads to push string uphill, deep steering required</td>
</tr>
<tr>
<td><strong>3-D</strong>: Any of the above with significant azimuth changes</td>
<td>Flexibility to handle anti-collision and multiple target requirements</td>
<td>More curvature means more torque and drag, deep steering may be required, shorter reach</td>
</tr>
</tbody>
</table>

**Source**: BP Extended Reach Drilling Guidelines, 1996
Another wellbore profile, which is frequently discussed, is the catenary well design that was first proposed and patented by Dailey Petroleum Services. In a catenary profile, the rate of inclination build continuously increases with depth to mimic the shape of a hanging cable. This design starts with a low build up rate (say $0.5^\circ - 1.0^\circ/100\text{ft}$), and accelerates to higher build rates as the angle increases (say up to $4^\circ - 5^\circ/100\text{ft}$). Theoretically, a catenary produces very low torque and drag as a result of low contact forces between the string and the wall of the hole. However, catenaries have not been widely used since creating the
catenary shape is impractical and cost-prohibitive even with the most modern BHA configurations. One of the downsides of the catenary design is that it considerably increases both the tangent angle and the overall total depth. This increased angle may also make wellbore stability more difficult to manage, which in turn can create hole cleaning problems.

In choosing among these options, a useful concept to keep in mind is the **Critical Tangent Angle**. This angle represents the limit beyond which a tool will not slide downhole under its own weight, meaning that it will have to be pushed from above. The Critical Tangent Angle is mathematically represented by:

\[
q \cos \alpha = \mu q \sin \alpha \\
\tan \alpha = \frac{1}{\mu}
\]

(3.1)

*Where:*

- \(q\) = Pipe buoyant weight,
- \(\mu\) = Friction factor
- \(\alpha\) = Critical tangent inclination angle

One approach to optimizing the trajectory is to try to position the Kick off Point (KOP) so that the tangent inclination equals the critical angle. If possible given other constraints, this will allow long reaches with reduced sliding problems.
3.3 Build Rate

An extended reach well needs optimum well design with respect to torque and drag and wellbore stability. Utilizing a low build rate is considered to be very important both for torque and drag at TD, and for wellbore stability in the upper part of the well. Due to its impact on casing wear and torque and drag, build rate can be viewed as the most important consideration when designing an extended reach well profile. When compared to a path having a single build rate, a combination of build rates usually offers a compromise. A review of record extended reach wells shows that most of the wells began with a low build rate, then gradually stepping up to a maximum of 1.5°/100 ft. However, in situations where the TVD of the target is shallow, a single more aggressive build rate may be the better option. For extended reach wellpath, the industry is gradually moving toward a catenary design where very low build rates are used and sail angles are at higher angles as a general trend.

3.3.1 Effect of Build Rate

Build rate may have a marginal effect on torque and drag levels for very high ratio wells. This is due to the increasing percentage of string weight supported on the low side of the hole resulting in lower tensile forces at surface. However contact forces may be sufficient to promote unacceptable casing wear at the higher build rates, especially when well operations such as extended backreaming are anticipated due to poor primary hole cleaning. As a guideline, build rates in excess of 2.5°/30m may cause concern with respect to high contact forces. If higher build rates than this are planned, the difficulty of achieving...
a smooth build also has to be considered where an increasing percentage of the build will be performed while sliding and not rotating the assembly. Some other important things to note about build rate are:

a) High Reach/TVD ratio wells may tolerate high BUR because the string tension in the curve is low and may even be in mechanical compression.

b) Low Reach/TVD ratio wells do not tolerate high BUR since drill string tension in the curve is higher.

c) High build rates can cause casing wear problems, especially in high Reach/TVD ratio wells where there may be high tensile loads through the build section during trips out of the hole and backreaming.

d) Low BURs result in lower contact forces. This typically means lower casing wear.

e) Low tortuosity is also achievable with low BURs. It tends to be more difficult to maintain low tortuosity with a high BUR.

f) Generally, with lower build rate, more can be achieved while rotating the assembly and thus the chances of achieving the desired smooth build will be greatest.

3.4 Hole Sizing and Selection

The majority of ERD wells drilled around the world use a combination of 17½”, 12 ¼”, and 8½” hole sizes (K & M Technologies, 2003). According to K & M Technologies, the reasons
for this include the availability of tools and equipment, ability to drill smaller hole sizes, and simply the depth of experience in these sizes.

However, there are some benefits associated with two-string well designs and 97/8” hole in particular. In ERD applications where two casings strings can be reliably used to TD, consideration may be given to using 13½” and 97/8” hole sizes (as an alternative to the traditional 17½” x 12 ¼” x 8½” design). The smaller hole sizes require less flow rate to keep them clean, or they can be cleaned faster with the same flow rate, thereby allowing for faster penetration rates (97/8” hole has 50% less volume than 12¼” hole). Where stability is a primary consideration, the smaller hole sizes are also inherently more stable.

The downside of this strategy however, is its inability to affect pipe movement during the cement job and therefore, limiting the probability for successful zonal isolation. It has therefore been suggested that when designing an ERD well, “standard” hole sizes that have been used in the past should not just be automatically selected. This is because, there may be advantages that might be gained by evaluating different hole sizes and combinations.

3.5 Torque and Drag

3.5.1 Torque

Torque is a rotational force and it can be described as the ability to overcome resistance to rotation. Its magnitude is measured by multiplying the perpendicular component of the force applied by the distance between the axis of rotation and the point where the force is
applied. In drilling applications this distance would of course be the drill pipe radius. As depicted by Figure 3.2 below, torque is mathematically represented as:

\[
\text{Torque} = \text{Force} \times \text{Distance}
\]

Where: \( d = \text{Drill pipe OD} \)

**Figure 3.2: Diagrammatic Representation of Torque Generating Forces**

Torque can also be regarded as a force that produces torsion or rotation. It is generated by power equipment from surface, as well as by friction working against the pipe rotation. Drillstring torque is the force required to rotate the pipe. (Unit: Nm (metric), ft-lbs (imperial) \( 1\text{ft-lbs}=1.3558\text{Nm} \)). Figure 3.2 is a representation of the forces responsible for creating torque.
Figure 3.3: Frictional and Surface-acting forces

In drilling operations, the torque at the surface is given by:

\[ TQ @ Surface = TQ @ Bit + TQ along the well bore + Mechanical TQ \]

Where:

**TQ @ Bit or bit torque** = the productive component of the torque and it depends on bit aggressiveness, WOB and bit diameter.

\[ TQ_{bit} = WOB \times Bit \text{ Diameter} \times Bit \text{ Aggressiveness} \]

**TQ along the well bore or frictional string torque** = the result of the interaction between the drill string and the bore hole wall. It increases with increased torsional friction losses as the drilling progresses and this is a function of friction factor and side forces (axial load, well profile ...etc.). **Mechanical Torque** = is generated by cutting beds, stabilizer effects, liner centralizer etc and is difficult to quantify.
Depending on well design and drilling operation, the torque will develop in different ways along the wellbore. Analysis and projections of torque should recognize that total surface torque is comprised of:

\[
\text{Total Surface Torque} = \text{String torque} + \text{Bit torque} + \text{Mechanical torque} + \text{Dynamic torque}
\]

Clearly, separating these torque components allows more accurate definition of friction for torque projections and for prioritizing measures for torque management. With techniques available for predicting bit torque, the implications of using different bit types can be assessed.

### 3.5.2 Drag

Drag is a resistance force to the motion of an object and it acts in the opposite direction of its axial movement. It is as a force that resists motion along a straight path. In drilling operations, drag results from contact between drill string components and bore hole wall or casing as the string moves up or down. It is generated by friction of drill pipe against hole wall or against inside of casing. Drag will always operate in the opposite direction to that in which the drill string is being moved. Drag is experienced as an extra load over the rotating string weight when tripping out of the hole. Unit N (metric), lbf (imperial) \(1 \text{lbf} = 0.4448 \text{N}\).

It accumulates mainly when picking up, slacking off or during oriented drilling with motor. It increases with increased hole inclination and curvature due to the gravity effect and compression pushing the drill string against the low side of the bore hole and due to drill
string tension pulling up the drillstring to the high side of the hole. Drag is the incremental force required to move the pipe up or down in the hole. Figures 3.3 and 3.4 shows the forces responsible for causing drag:

\[ \text{Forces to lift drill string} = F \]
\[ \text{Opposing Force Due to Friction} = \text{Drag} \]

**Figure 3.4:** Drill String Opposing Forces
Drag while drilling a well is a result of a combination of several factors like wellpath design, drilling fluid properties (lubricity), wellbore quality, tortuosity, formation type and drill string buckling.

### 3.5.3 Friction Forces

The key features of ERD are that horizontal departure is long and inclination is high. These typically gives rise to considerable torque and drag for drill-string and casing string, thus making torque and drag a major limitation for horizontal reach in ERD. This also makes the effective transmission of drill string weight and rotation to the Bottom Hole Assembly (BHA), major considerations in the planning of ER wells.
A puzzle that still remains un-an-answered in extended reach drilling is: What makes high ratio ERD wells so difficult to drill? The answer, according to Williams (2008) is friction and how best to overcome it.

Friction is a function of both torque and drag. From the definitions above it can be seen that torque is the rotational element while drag is the axial element. Torque losses are of prime importance while drilling, and drag losses are more important while tripping and running casing strings. In other words: Axial Friction (Drag) acts along the length of the pipe body (longitudinal axis) in the opposite direction to the direction of pipe travel (POOH, RIH) while Torsional Friction (Torque) acts along the circumference of the pipe body opposite to the direction of rotation.

While there are a myriad of challenges in ERD, minimizing torque and drag while drilling, running casing, and during completions continue to be one of the greatest challenges. As the length and percentage of any well at high angle increases, friction also increases due to the increased contact area between any string (drilling or casing) and the wellbore wall. This is further compounded by the mass of this string at high angle. The meaning and implication of this is that, when running drillstring in and out of the hole, we get to a point where enough weight (push) from surface cannot be exerted to move the string. The conventional approach to solving this problem is to rotate so as to reduce drag. While this temporarily solves the problem, as drilling progresses, we will reach another point where enough torque cannot be generated at the surface to turn the string. There is therefore,
the need to come up with techniques to reduce torque and drag if we want to reduce
downtime and successfully drill ER wells.

### 3.5.4 Influence of Friction Factor

Friction Factor (FF) also known as friction coefficient, expresses the relationship between
the forces needed to overcome frictional force and the normal force of the element. It is
defined by the interaction between two materials. Since torque and drag can be the
limiting design parameters, the optimum trajectory design depends heavily on our
representation of wellbore friction. We use cased hole and open hole friction factors in our
torque and drag studies, but they are not necessarily reflective of the coefficients of sliding
friction one might measure in a lab. Friction factors should thus be calculated from field
torque and drag data which depend upon a number of conditions including:

- Mud composition
- Hole cleaning (cuttings beds) and cutting type
- Operational procedures and type of operation (e.g. sliding or rotating)
- Wellbore tortuosity
- Formation type

There are several issues that affect friction factor. They include:

- Drill sting interaction with casing or with open hole.
- Type of Drilling Fluid (WBM, OBM, Foam, Air)
- Mud rheology and properties, which might change while drilling particularly in
  HTHP applications.
By the same token, there are some issues that do not affect Friction Factor. They include:

- Drilling mode (Whether Rotating or Sliding)
- The load applied

It should be noted that Torque and Drag predictions are only as good as the friction factors applied. Thus, it is recommended that each drilling project at the very beginning establish a database of local casing and open hole friction factors for the mud type used. Standard default friction factors have been derived (using commercially available software packages) from analyses of well data covering normal drilling operations in a range of wells.

### 3.5.5 Torque and Drag Reduction Methods

There are many ways to reduce torque and drag. Optimization of the well profile is one. We should select well trajectory that makes torque and drag values as low as possible. Mud additives and drillstring tools can also be used to reduce torque and drag. Construction of higher specification rigs capable of generating enough weight and torque to run strings in and out of the hole and also to rotate the pipe is another torque reduction method.

Based on field experience and end of well reports from several ERD projects, the following has been recommended for reducing torque and drag:
To reduce Torque:

- Use of a lighter BHA, and reduce the number of HWDP and DC's. Make sure there is enough WOB available,
- Use a mud system with lower friction factor (semi oil based or oil based),
- Use Non-Rotating Drill Pipe Protectors (NRDPP) for cased-hole torque reduction or bearing sub for open-hole torque reduction,
- Redesign the well when possible and consider designer wells with catenary curve build sections (gradual increase in curvature).

To reduce Drag:

- Optimize well trajectory and drill string design
- In horizontal wells use HWDP/DC near the vertical section.
- Use rotary steerable systems
- Use high power motors to increase stalling resistance
- Consider casing flotation.

Mechanical and chemical friction reducers are used by operators to reduce torque and drag. Rubber element and plastic casing protectors have also been reported to be successful in reducing torque. Several operators have reported torque reductions of over 25% by using non-rotating drillpipe protectors. Other torque reduction strategies that have been mentioned by operators include torque reduction subs, beads, and downhole tractor systems.
Non-Rotating Drill Pipe Protectors have also been used to reduce casing wear. Although there is a significant torque reduction with these tools, there is also an increase in drag. When the drillpipe protectors are used, there must be a compromise based on expected requirements for rotary or oriented drilling.

Torque and Drag values will increase with the well length up to the point where a rig equipment upgrade will be required. New techniques will also be required. For example, running the 95/8” casing in flotation will be necessary beyond a given departure and sailing angle, where all available weight is absorbed by the drag.

### 3.6 Equivalent Circulation Density Management

For easy comparison to critical mud density limits, the annulus pressure is often transformed into a virtual density value called Equivalent Circulating Density (ECD). ECD can be defined as the additional “mud weight” seen by the hole, due to the circulating pressure losses of the fluid in the annulus.

ECD is the density a static fluid needs to have in order to create the same pressure the actual fluid creates while circulating in the annulus at a certain depth. It takes into account the influence of pressure losses of the fluid flowing up the annulus as well as changes of the fluid’s average density due to the cuttings load in the annulus.
Equivalent Circulation Density can be calculated as follows:

\[
ECD = MW \text{ (ppg)} + \frac{P_A (\text{psi})}{0.052 \times TVD (\text{ft})}
\]  \hspace{1cm} (3.2)

Where: 
- ECD = Equivalent Circulating Density [ppg]
- MW = Mud Weight [ppg]
- \(P_A\) = Measured Annulus Pressure [Psi]
- TVD = True Vertical Depth [ft]

The principal variable in this equation is annulus pressure loss. This is affected by the following factors:

- Drill pipe configuration
- Mud weight
- Mud rheology
- Flow rate
- String RPM
- Hole cleaning efficiency
- Trip speed
- Annular Clearance

During drilling, the mud-column pressure has to be controlled and regulated. We do this by comparing it (i.e. the mud-column pressure) to the:

- Pore Pressure Gradient (PPG)
- Formation Break Gradient (FBG)
- Fracture Pressure Gradient (FPG)
We need to control the mud-column pressure because:

1. We do not want pore fluids to enter the borehole
2. We do not want to fracture the formation

The ECD is used to analyze the relationship of the downhole pressure to the pore pressure and the fracture pressure and has to be looked at in connection with pore and fracture pressure gradients. It needs to be inside the “window” created by the difference between pore and the fracture pressure gradient. If the ECD is lower than the pore pressure gradient, the well is prone to well control problems. If it is higher than the fracture pressure gradient, the well is prone to hole stability problems.

A critical ECD issue to look out for when drilling deviated wells is the casing shoe ECD, which is the pressure at the casing shoe. As previously noted, this is because the formation pressure and the pore pressure are a function of the TVD and the pressure drop contributing to the ECD is a function of the measured depth. This is explained in Figure 3.5.
Figure 3.6: Casing Shoe ECD Determination

From Figure 3.5, we can see that solving one problem by creating “low” pressure at the bit will create another problem. We will be in danger of creating a critical low pressure at the casing shoe as the pressure drop over this long distance \(\Delta L_2\) is bigger than the change in formation pressure over this vertical depth \((\text{TVD} - \Delta L_1)\). From the above, it can be seen that over a relatively small vertical depth change, i.e. a small formation pressure change, there is a big ECD change. This could lead to a collapsing hole or incoming pore fluids. The risk of this happening is most relevant at the casing shoe, since the ECD (mud pressure) is at its lowest there without being protected by the casing.
Some other important facts to note about ECD are:

1. If pipe OD and wellbore ID do not change and inclination is zero, ECD is constant.

2. The ECD increases in the openhole, where the annular clearance is less than in the casing. If the well is vertical and infinitely long, the ECD will reach a constant value again.

3. If the wellbore ID does not change, but the drillstring contains drill collars with large OD, the ECD increases.

4. If the wellbore opens up, or if the drillstring changes to smaller ID’s, the ECD will decrease.

5. ECD increases with increasing inclination. This is due to the fact that the annular pressure drop is a function of measured depth while ECD is a function of TVD.

6. In a vertical well, if Pressure Gradient is constant, the ECD will be constant as well.

7. If the openhole has larger ID than the Casing above, the total annular pressure drop is less, compared to a conventionally drilled well. Therefore, the ECD is also less.

3.6.1 Effects of ECD

ECDs are generally a more significant issue in ERD wells than for conventional wells. This is as a result of their long measured depth intervals relative to the vertical depths. Also, ERD wells are generally shallow in nature. This makes them particularly prone to ECD problems as their formations are often so shallow as to have very little integrity. Other reasons include the fact that extended reach wells generally use larger diameter drill pipe to
combat hydraulics or buckling problems; they require more aggressive parameters (flow rate and rpm) for hole cleaning; and they have longer exposure times with long intervals.

Some of the effects of ECDs are:

i. High ECDs increase the risk of lost circulation, especially while (a) drilling the 8½” or smaller diameter hole size, or (b) while running or circulating long casing strings. Also, if ECDs are not minimized, it could lead to reservoir damage.

ii. The constant flexing and relaxing of the wellbore when the pumps are turned on and off can lead to wellbore instability. This is particularly true if the formation is brittle.

iii. Casing collapse can be initiated by ECDs while running buoyancy assisted casing strings on long deep ERD wells.

3.6.2 ECD Management and Control

Reducing flow rate is generally the first option if ECD becomes an issue while drilling an extended reach well. It is important that any reduction in flow rate is within the hole cleaning limitations of the drilling system. The minimum allowable flow rate is dependent on many factors including mud rheology, RPM, slide frequency, hole size, ROP, and other practices. As was mentioned earlier, pipe rotation also affects ECDs especially in the 8½” hole or smaller. As with flow rate above, reducing pipe RPM is also an option to lower ECDs.
3.7 Drilling Hydraulics and Hole Cleaning

Hydraulics calculations are generally carried out to estimate the required rig pumps capacity to drill the objective well. The drilling hydraulic system is a function of the drilling fluid characteristics and its ability to deliver efficient drilling and ensure wellbore integrity and stability. Therefore the required pump pressure must be capable of providing the flow rate needed to transport the cuttings up and out of the wellbore, as well as overcoming the accumulated pressure losses associated with the surface equipment, the drill string, the bit and the annulus.

The hydraulics applications and analyses are based on drilling fluid behavior. This behavior is governed by rheology and hydraulics studies, which interrelate between each other. Rheology is the study of how matter (substance) deforms and flows while Hydraulics describes how fluid flow creates and uses pressures.

Aside from ECD Management, other critical drilling fluid success factors in the planning and construction of extended reach wells include:

- Borehole Stabilization
- Hole Cleaning
- Lubricity
The selection process for ERD drilling fluids must consider a number of critical factors. The fluid must:

a) Provide a stable wellbore for drilling long open hole intervals at high angles.
b) Maximize lubricity to reduce torque and drag
c) Develop proper rheology for effective cuttings transport
d) Minimize the potential for problems such as differential sticking and lost circulation
e) Minimize formation damage of the production intervals

3.7.1 Fundamentals of Hole Cleaning

Hole angle determines the mechanisms for cutting removal. Figure 3.6 is an angular depiction of a typical extended reach well trajectory.

![Diagram of Hole Angle and Well Trajectory]

**Figure 3.7:** Angular Depiction of Extended Reach Well Trajectory
In deviated wells, cuttings tend to settle on the low side wall and form cuttings beds. These cuttings are often transported along the low side of the hole either as a continuous moving bed or in separated beds/dunes.

Hole cleaning can be divided into three categories based on the wellbore inclination. Figure 3.7 below shows the movement of cuttings in the various angular regions of the wellbore. From the figure, it is obvious that the cuttings transport, and by extension the hole cleaning strategy, will be different for each inclination range.

Figure 3.8: Cuttings Transport at Different Inclinations
Based on the following references [Azar and Okrajni, SPE 14178; Clark and Bickham, SPE 28306; Saasen and Loklingholm, SPE 74558], the cuttings characteristics of the various inclination angles can be given as:

0 – 35\(^\circ\): Cuttings do not form

35 – 45\(^\circ\): Cuttings bed start to form

45 – 65\(^\circ\): Avalanching starts

65 – 90\(^\circ\): Stable beds

**Near vertical Wells (0 – 35\(^\circ\))**: Cutting Beds do not form in this hole section. This is because transport velocity is greater than slip velocity, thus the cuttings are effectively carried in suspension. The annular fluid velocity acts to overcome the cuttings settling force and there is a net upward movement of the cuttings. Hole cleaning is simply provided by the viscosity and flowrate of the drilling fluid. When the pumps are turned off, cuttings are suspended by the viscous drilling fluid, although some settling will occur with time.

**Intermediate Angles (35 – 65\(^\circ\))**: In this section, there is unstable, moving cuttings bed. This is because transport is via lifting mechanism. In this inclination range, cuttings begin to form “dunes”, as the distance for them to fall to the bottom is now very minimal. The cuttings move up the hole mostly on the low side, but can be easily stirred up in the flow regime. The most notable feature of this inclination range is that when the pumps are shut-off, the “dunes” will begin to slide (or avalanche) downhole. This significantly changes the hole cleaning strategy with respect to the vertical well scenario. Typically most
problems associated with hole cleaning in deviated wells occur in this section. This is because; it is the region where gravity effects can cause cuttings beds to slump down the hole.

**High Angles (greater than 65°):** Stationary cuttings bed form instantaneously in this region. This is because transport is via a rolling mechanism. This presents a different set of operational circumstances. Here, cuttings will fall to the low side of the hole and form a long, continuous cuttings bed. All of the drilling fluid will move above the drillpipe, and mechanical agitation is required to move the cuttings, regardless of the flowrate or viscosity of the mud.

To a reasonable extent, hole cleaning operation can be remedied by a good combination of:

1. Appropriate Mud Properties
2. Optimized well profile

However, continuous ECD measurement remains the best method to monitor hole-cleaning and minimize lost circulation problems or stuck pipe.

**3.7.2 Factors Affecting Hole Cleaning**

Perhaps the single most important aspect of ERD well planning is ensuring that the rig’s pumps, solids control equipment, drillstring components and selected mud system are
adequate to keep the hole clean. Hole cleaning is one of the most crucial areas in successfully drilling an ERD well. The parameters which affect hole cleaning more than any other (Payne et al, 1994); (Eck-Olsen et al, 1994) are:

- Flow Rate → Determines transport and annular velocity
- Hole Angle → Determines mechanism of removal
- Fluid rheology and flow regime
- Mud Density
- Rate of penetration
- Drill pipe rotation
- Geometry
- Eccentricity
- Cuttings Size
- Cuttings Shape
- Cuttings Density
- Formation

### 3.7.3 Consequences of Poor Hole Cleaning

Cuttings generated while drilling needs to be removed from the hole and transported through the annulus to the surface. A poorly cleaned hole will lead to a buildup of cutting beds and a reduction in the annulus area. This may result in many drilling problems such as:

- i. Formation of a stationary cuttings bed
- ii. Reduction in rate of penetration
iii. High Torque and Drag and Excessive Over-pull
iv. Difficulty in running casing
v. Fracturing of the formation
vi. Stuck pipe or stabilizer hanging
vii. Mud loss during cement jobs
viii. Increased costs
ix. Possible loss of hole
x. Increase in ECD causing wellbore instability issues

3.7.4 The Clean Hole Concept: What is a Clean Hole?

Every high angle wellbore will certainly have cuttings bed of some thickness and distribution. Cuttings beds will form in the high angle wellbores, regardless of how the hole cleaning practices are carried out. From Figure 3.7, it is obvious that the method of cuttings removal is a function of how the cuttings are distributed in the hole. However, a wellbore does not have to be 100% clean (or free of cuttings) before is will be considered “clean”. K & M Technologies defines a “Clean Hole” as: “A wellbore with a cuttings bed height and distribution such that operations are trouble free”.

It should be noted that a cuttings bed that is “clean” for drilling may not necessarily be the same as that for tripping a BHA or casing. This is mainly due to the differences in the
annular clearance seen in these various operations and also the ability to trip the pipe through the cuttings bed.

3.7.5 Hole Cleaning Mechanism

There are two main mechanisms for hole cleaning. These are:

- Dispersion
- Mechanical Removal

Dispersion effectively “dissolves” cuttings into the mud, which allows them to be easily removed from the hole. In general, dispersion only applies in large diameter hole sections that are drilled with low cost water-based-mud.

With mechanical removal, many different parameters work together to clean the hole. However, by far, the two most important parameters are rotation and flow rate. Rotation controls the hole cleaning efficiency, while flow rate controls the hole cleaning rate.

Drill Pipe Rotation

Rotation is the key parameter in hole cleaning efficiency for the high angle sections, where the drill pipe and drill cuttings will lie on the low side of the hole. Under these conditions, movement of the drill pipe (rotation and/or reciprocation) will mechanically disturb cuttings beds and assist in cleaning the hole. Rotation is more effective since this helps
equalize fluid velocities on the low and high side of the hole. The influence of drill pipe rotation is more pronounced in viscous muds and in smaller holes (less than 17½”). In cases where the pipe is not rotated (e.g. slide drilling), cuttings beds are more difficult to remove. Under these special circumstances, increased flow rate or changes in operation practices may be necessary to improve hole cleaning.

The rotary speed used is also critical for effective hole cleaning. According to K & M Technologies, there are at least two distinct hurdle rotary speeds at which step improvements in cuttings return will occur in high angle wellbore. These occur at 100 – 120 RPM and at 150 – 180 RPM. They claim that these speeds have proven to be quite consistent for different hole sizes and mud types. However, some operators like Baker Hughes-INTEQ have a problem with this practice because it essentially ignores the increased wear, the effects of the vibrations it creates on downhole equipment, as well as the increased possibility of tool failures and subsequent trips. Baker Hughes-INTEQ thus propound that higher RPM may not be necessary to effectively clean the hole. This has been partly corroborated by other operators as available information shows that several operators have experimented with rotary speeds of up to 220 RPM. While some benefits were recorded for RPMs greater than 120, very little benefits were recorded at RPMs over 180.
**Mud Flow Rate**

The mud flow rate is the most important factor for hole cleaning in deviated wells. Simply put, the faster you pump, the faster you move cuttings out of the hole when coupled with ample rotary speed. Thus, mud pumps and liner sizes should be selected to ensure a sufficiently high flow rate when drilling ERD wells. Pump pressure is often the limiting factor for achieving the required flow rate. Consideration should thus be given to this during the bottom hole assembly (BHA) design and bit nozzle selection to reduce pump pressure.

Ideally, maximum available flowrates should be used for every section of an ERD well, up to the surface pressure or downhole tool limits. As hole angle increases from vertical, cuttings transport becomes more difficult. The flow rate required to carry cuttings out of the hole increases rapidly from 0° to 60°. Above 60° the rate of flow rate increase levels off. Hole angles between 45° and 60° frequently present the most problems because cuttings tend to slide back down the annulus and pack-off.

There are several commercially available drilling hydraulics computer programs, which can be used to determine the achievable drilling circulation rates given the rig pump capacity, drillstring/wellbore configuration and drilling fluid rheology. These flow rates can then be evaluated using available hole cleaning models for high angle wellbores, which are capable of predicting overall hole cleaning effectiveness.
However, field experiences as well as various simulations by industry experts have come up with what can be referred to as recommended practices and typical flow rates to aim for in ERD wells. Table 2 is the industry recommended minimum and maximum (realistic) flowrates for different hole sizes.

**Table 3.2:** Recommended Minimum and Maximum Flow Rates for Different Hole Sizes

<table>
<thead>
<tr>
<th>Hole Size</th>
<th>Desirable Flow Rate (gpm)</th>
<th>Minimum Workable Flow Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>17½”</td>
<td>900 – 1200</td>
<td>800 gpm, with ROP @ 20 m/hr (65'/hr)</td>
</tr>
<tr>
<td>12 ¾”</td>
<td>800 - 1100</td>
<td>650 – 700 gpm, with ROP @ 10-15 m/hr (30-50' /hr)</td>
</tr>
<tr>
<td>97/8”</td>
<td>700 – 900</td>
<td>500 gpm, with ROP @ 10-20 m/hr (33-65' /hr)</td>
</tr>
<tr>
<td>8½”</td>
<td>450 – 600</td>
<td>350-400 gpm, with ROP @ 10-20 m/hr (33-65' /hr)</td>
</tr>
</tbody>
</table>

*Source: Drilling Design and Implementation for Extended Reach and Complex Well, K & M Technology, 3rd Edition, 2003, Pg 86*

As was mentioned earlier, flowrate alone is ineffective unless the pipe is being rotated fast enough to stir the cuttings into the flow regime. Table 3 presents the industry recommended drillstring RPM for the different hole sizes.

**Table 3.3:** Recommended Drill String RPM for Various Hole Sizes

<table>
<thead>
<tr>
<th>Hole Size</th>
<th>Desirable RPM</th>
<th>Minimum For Effective Hole Cleaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>17½”</td>
<td>120 – 180 rpm</td>
<td>120 rpm</td>
</tr>
<tr>
<td>12 ¾”</td>
<td>150 – 180 rpm</td>
<td>120 rpm</td>
</tr>
<tr>
<td>97/8”</td>
<td>120 – 150 rpm</td>
<td>100 rpm</td>
</tr>
<tr>
<td>8½”</td>
<td>70 – 100 rpm</td>
<td>60 rpm</td>
</tr>
</tbody>
</table>

*Source: Drilling Design and Implementation for Extended Reach and Complex Well, K & M Technology, 3rd Edition, 2003, Pg 87*
3.8 Vibration and Wellbore Stability

3.8.1 Vibrations

Compared to low angle and vertical wells, downhole vibrations are often less severe in ERD wells. However, they are of particular concern due to their direct and indirect impact on the overall drilling operation. Some of the effects of downhole vibration are:

1. BHA failures
2. Reduced Bit Life
3. Reduced ROP
4. Reduced Drill String life and Twist-off’s
5. Poor Hole Condition
6. Longer drilling time and cost

Vibrations can be minimized or eliminated by downhole monitoring, and adjusting drilling parameters and practices accordingly. It must be emphasized that it is not enough to just monitor surface vibrations. This is because; it is highly unlikely that what is happening downhole will be seen at the surface. In order to respond to vibrations and eliminate them, it is helpful to understand the different types of vibrations and what causes them. Table 4 is a description of the various types of vibrations.
Table 3.4: Types of Vibrations

<table>
<thead>
<tr>
<th>Type of Vibration</th>
<th>Description and Symptom</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bit Bounce (Axial)</td>
<td>• Often seen as large surface vibrations in short or vertical wells</td>
</tr>
<tr>
<td></td>
<td>• Often a result of drilling hard formations</td>
</tr>
<tr>
<td></td>
<td>• Bit damage</td>
</tr>
<tr>
<td>Bit and BHA Whirl</td>
<td>• Very complex and destructive</td>
</tr>
<tr>
<td>(Lateral)</td>
<td>• A major problem with early PDC bits</td>
</tr>
<tr>
<td></td>
<td>• Impact damage to bit gauge pads</td>
</tr>
<tr>
<td></td>
<td>• Localized tool joint wear</td>
</tr>
<tr>
<td></td>
<td>• Erratic surface torque</td>
</tr>
<tr>
<td>Stick-Slip (Torsional)</td>
<td>• Cyclic surface torque fluctuations/topdrive stalling</td>
</tr>
<tr>
<td></td>
<td>• MWD sensors have shown fluctuations of 0 - 300 rpm downhole</td>
</tr>
<tr>
<td></td>
<td>• Over-torqued tooljoints</td>
</tr>
</tbody>
</table>

Source: Drilling Design and Implementation for Extended Reach and Complex Well, K & M Technology, 3rd Edition, 2003, Pg 133

3.8.2 Wellbore Stability

ERD wells have hole sections of greater inclination than conventional directional wells. Hence, the risk of instability in an ERD well is greater. The very nature of extending the reach of wells in a given area will often increase the risk of instability. Therefore, greater care during the planning and drilling of an ERD well is required.

Hole instability refers to two extremes of Formation Collapse and Formation Breakdown. Formation Collapse can lead to spalling and/or hole closure. A number of factors can be responsible for this, but the most common reasons are:
o Insufficient support not provided to the wellbore wall as a result of low mud weight

o Incompatibility of the mud chemistry with the formation.

Formation Breakdown on the other hand describes the creation of an induced fracture (or opening of a natural fracture system) leading to massive mud losses. The primary reason for formation breakdown is use of too high a mud weight.

3.8.3 Preliminary Wellbore Stability Analysis

To conduct analyses of stress-induced wellbore instability, the basic information required includes:

o Strength and deformation response of the formation material to stress changes imposed by creation of the wellbore; and

o Knowledge of the in-situ stress regime.

To conduct an analysis of stress-induced wellbore instability the basic information required includes:

o Knowledge of the orientation and magnitude of the principal in-situ stresses and

o Strength and elastic properties of the rock material.

These input data are primarily obtained from geophysical logs and drilling data and are associated with varying degrees of uncertainty.
There are several commercially available software for monitoring vibration and wellbore instability. Because of the highly technical nature of this analysis, vibration and wellbore instability will not be discussed any further as they are beyond the scope of this work.
Chapter Four
Extended Reach Drilling Algorithm

4.1 Algorithm Defined

An algorithm is essentially a finite sequence of instructions. It is an explicit, step-by-step procedure for solving a problem. Technically, an algorithm must reach a result after a finite number of steps. However, for some, a program is only an algorithm if it eventually stops. For others, a program is only an algorithm if it stops before a given number of calculation steps. Thus, the term is also used loosely for any sequence of actions (which may or may not terminate).

Because an algorithm is a precise list of precise steps, the order of computation will always be critical to the functioning of the algorithm. Instructions are usually assumed to be listed explicitly and are described as starting "from the top" and going "down to the bottom." However, transition from one state to the next is not necessarily deterministic.

In general, the overall challenge of the petroleum industry has been and still is the efficient recovery of oil and maximization of net present value for the lifetime of the field. For this to be achieved, it is essential to have a structured approach to the drilling process. This concept formed the basis for the development of an algorithm that can be used for the planning, design and drilling of extended reach and complex wells.
4.2 The Visual Basic Algorithm for ERD

Several experimental and theoretical studies have been conducted on extended reach drilling. In the preceding chapters, an extensive review of most of these studies as well the critical technologies for their success were done. Based on the findings of the review, a Visual Basic Algorithm that integrates many of the elements of the planning, design and drilling of ERD wells into one single package has been developed. These elements include: Well Planning and Trajectory Design, BHA Design, Drill String and Casing Design, Torque and Drag, Hydraulics and Hole Cleaning, Equivalent Circulation Density, Bit Hydraulics and Optimization, Rig Sizing and Selection, Stuck Pipe Prevention, Pressure Management, Well Control, Surveying and Target Sizing, Rotary Steerable Systems Considerations, Vibration and Wellbore Stability and Well Completion.

Of these five elements, this project will consider five of these factors and evaluate their interrelationship. The factors are:

1. Well Planning and Trajectory Design
2. BHA Design
3. Drill String Design
4. Torque and Drag Analysis
5. Hydraulics and Hole Cleaning
The model is designed in accordance with industry Continuous Improvement Cycle (CIC) Principles. The continuous improvement cycle for drilling a well consists of three stages that follow one after another - planning, drilling, and post-well analysis. This cycle is represented in Figure 4.1 below. From the figure, it can be seen that the output from one stage serves as the input to the next, and this is the underlying principle that guided the development of this model.

![Diagram of Continuous Improvement Cycle]

**Figure 4.1:** The Continuous Improvement Cycle
4.2.1 Attributes of the Model

The Visual Basic model developed is a highly structured algorithm that provides direction on processes and tasks required at all stages in the design and drilling of an ERD well to achieve good drilling performance. The knowledge-base structure of the algorithm facilitates examination of the interrelationships of drilling parameters and operating practices. Figure 4.2 is a flow chart that shows the interrelationship of these drilling parameters. This figure is the building block for the software.
Figure 4.2: Drilling Design Flow Chart for Extended Reach Drilling

- WELLPLAN
  - Well Profile Design (if needed, Catenary well design)
  - SUR and KOP (Low, Medium or High Inclination)

- BHA Design
  - Use industry available Software
  - Determine if required BHA is achievable

- Drill String Design
  - Calculate Tension, Torision, etc

- T&D Analysis
  - Calculate TQ @ Bit, TQ along Wellbore and Mechanical TQ.
  - T&D Reduction Methods

- Hydraulics and Hole Cleaning Analysis
  - Determine Circulation/Flow Rate
  - Determine Mud Rheology
  - Determine String Rotation
  - Calculate Cutting Accumulation
  - Calculate ECD and compare to Fracture Gradient

- DELIVERABLES
  - Hydraulics Calculation Report
  - Section by section drilling procedure
  - Other Drilling Parameters
  - Optimized Well Proposal

During Drilling Operation
- Continuously measure and record flow cuttings.
- Always keep ECD below fracture gradient.
- Continuously record FRT, FEW, PUW and SOW.
- A significant increase in both radial and axial FF shows the need to clean hole.
The algorithm is divided into modules, each treating a specific issue that comes into play when drilling an extended reach well. Most of the calculations done in the various modules overlap each other and there may appear to be some redundancy. This is intentional because most of these calculations are closely inter-linked, so it is difficult and inappropriate to discuss these subjects in isolation.

The model evaluates the drilling process by presenting a structured approach, which enables office and field personnel to identify drilling performance problems as easily as possible. By evaluating results, the user can identify drilling problems early and is able to accurately take remedial actions. As a result of using the program, better and quicker information is obtained. It is then the user’s discretion to utilize the information and make informed decisions.

The output from the model is a report that is essentially an implementable Well Plan. This is made possible because common problems that could be encountered during the well planning and design phases would be mitigated by the program’s smart engineering knowledge.

Several flags have also been integrated into the code. These flags will pop up if an input/output that is incompatible with the pre-set standards is noticed by the program. When a flag pops up, the user will need to make the necessary changes so as to rectify the anomaly. Numerous iterations can be made until a technically feasible scenario is obtained. This will be noticed when the program user is allowed to proceed without any flags popping up. In this way, the user can correct his/her mistakes as soon as they are
made, instead of waiting for the final report to learn if indeed a mistake or incompatible selection has been made. If followed sequentially and with appropriate inputs, the model will be able to produce a workable well plan and design that can be used to drill the well.

4.3 Analysis of the Individual Modules

The model focuses on well design, well planning and implementation both at the office and field locations. Upon launching the program, a visual interface, which displays 20 tabs, is presented. Each tab brings a technology to the process that is necessary for success of extended reach drilling. Each tab is a module in itself and contains enhanced graphics depicting the parameter that is being analyzed. Each tab performs various calculations. The results of these calculations are stored and carried forward to the next tab. Depending on what is being calculated in the succeeding tab, data can either be called into the new tab or referenced during the calculations. Results obtained from the current tab are internally referenced to those of previous tabs. If new information that is not technically compatible with previous information is observed, a flag pops up and notifies the user so that appropriate adjustments can be made. In this way, the model continually updates the process until a technically feasible well design is achieved. The following sections describe the contents of the tabs/modules that have earlier been identified as critical to the success of extended reach wells.
4.3.1 Well Planning Module

An often overlooked area of importance, in ERD wells in particular, is the measurement process associated with fixing the physical position of the well bore. There are numerous inherent errors within the measurements used to calculate the bottom hole location (BHL). These measurements include:

- Depth
- Inclination
- Azimuth

Also of prime importance is the Build-Up Rate (BUR). Build-up-rates are selected to: (a) limit the fatigue loading on the drill string, and (b) reduce casing and tool joint wear. The selection of BUR will influence the final inclination, which maximizes production and/or avoids collision with other existing or planned wells. The build-up-rate is related to the build-up-radius in the following equation:

\[
R = \frac{360}{2\pi} \times \frac{\text{CharacteristicLength}}{\text{BUR}}
\]  (4.1)

Where \( R \) = Build Up Radius


Figure 4.3 is the visual interface design of the Well Planning Module.
Figure 4.3: Well Planning and Trajectory Design Module
This module shows the most important parameters we need to know from the outset before a well is planned. It calculates the following:

1. **Dogleg Severity**: This is given by:

   \[ DLS = \frac{AC \times 100}{CL} \]  

   \[ (4.2) \]

   Where: DLS = Dogleg Severity (Deg/100ft)  
   AC = Angle Change (degrees)  
   CL = Course Length (ft)


2. **Build Up Rate**: This is divided into the Build Section and the Tangent Section.

   The Build Section is given by:

   \[ BS = \frac{i \times 2\pi}{360} \times R \]  

   \[ (4.3) \]

   Where: BS = Build Section (Deg/100ft)  
   i = Inclination Angle (degrees)  
   R = Build Up Radius (ft)

   The Tangent Section is given by:

   \[ TS = \frac{R \sin i}{\cos i} \]  

   \[ (4.4) \]

   Where: TS = Tangent Section (Deg/100ft)  
   R = Radius of Curvature  
   i = Inclination Angle (degrees)

3. **Target Azimuth**: This is given by:

\[
A_t = \tan^{-1} \frac{\Delta E}{\Delta N} (+180^0)
\]  

*Where:* \(A_t = \) Target Azimuth (Deg)  
\(\Delta E = \) Surface Co-ordinates (Deg)  
\(\Delta N = \) Target Co-ordinate (Deg)  
\(\Delta E \) and \(\Delta N \) can be Negative South or Negative West


4. **Horizontal Departure**: This is given by:

\[
HD = \sin i \ast \text{Distance from Kick-off Point to Measured Depth}
\]  

*Where:* \(i = \) Inclination Angle (Degrees)

*Source:* *Formulas and Calculations for Drilling, Production and Workover, Lapeyrouse 2nd Ed., Pg. 200*

5. **Current True Vertical Depth**: This is given by:

\[
\text{Current TVD} = (\cos i \ast \text{Course Length}) + \text{Last TVD}
\]  

*Where:* \(i = \) Inclination Angle (Degrees)

*Source:* *Directional and Horizontal Drilling Equations, roughneckcity.com*

Having determined the above, projections can thus be made for the following:

1. **Build Up Rate Needed to Reach Target**: This is given by:

\[
\frac{(\sin \text{ Desired Angle}) – (\sin \text{ Current Angle}) \ast 5730}{(\text{Target TVD}) – (\text{Current TVD})}
\]  

*Where:* \(\text{TVD} = \) True Vertical Depth (Ft)  
5730 = Conversion Factor (Field Units)

*Source:* *Directional and Horizontal Drilling Equations, roughneckcity.com*
2. **Projected Angle Needed to Reach Target:** This is given by:

\[
(Target \ TVD) - (Present \ TVD) = \text{Arc tan of Angle (Usable VS)}
\]  

*Where:* VS = Vertical Section  
Usable VS = Target VS – Present VS  
If Arc tan of Angle > 90°, Add 90°  
If Arc tan of Angle < 90°, Subtract 90°

*Source:* Directional and Horizontal Drilling Equations, roughneckcity.com

3. **Projected Measured Depth:** This is given by:

\[
(Target \ Inc) - (Present \ Inc) = \frac{(DLS)}{(4.10)}
\]

*Where:* Inc = Inclination (Degrees)  
DLS = Dogleg Severity (Degrees)

*Source:* Directional and Horizontal Drilling Equations, roughneckcity.com

As was mentioned in Chapter 3, Well Planning is a design process, which utilizes a set of  
criteria (data and information) to develop an optimum directional well plan. As the prime  
critical success factor for ERD wells, well planning is connected to the other critical factors  
as shown in figure 4.4.
Figure 4.4: Interrelationship among ERD Critical Elements
4.3.2 Bottom Hole Assembly (BHA) Design Module

Figure 4.5 is the Bottom Hole Assembly (BHA) Design module. In this module, API Standard Drill Pipe and Drill Collar Specifications have been pre-entered. Using the drop down combo box, the user can simply select the specification that is applicable to the given project. It also contains a list of downhole tools that are typically used in BHA design. The check boxes are used to select any particular tool. All other critical BHA calculations are provided by the operator or Service Company. Values for these calculations are not calculated by the program, but are simply entered by the user. This is because the mathematics behind these calculations could not be obtained. Several attempts were made to get the underlying equations for these parameters but the custodians of the equations would not release them because they are regarded as proprietary/classified information. Thus, it is assumed that the user already has them in hand and simply needs to enter the values in the appropriate spaces. The program will then use these values during the evaluation process.

BHA design is also an iterative process that involves developing a BHA strategy that considers the key issues of the overall drilling and hole cleaning process. Figure 4.6 shows the interrelationship among these key issues and how they are factored into the design of the bottom hole assembly, while figure 4.7 is the module that implements the flow chart.
Figure 4.5: Flow Chart for the Design of Bottom Hole Assembly
Figure 4.6: Bottom Hole Assembly (BHA) Design Module
4.3.3 Drill String Design Module

The Drill String Design Module calculates all the required parameters for designing the drill string. Among others, it calculates:

1. **The Buoyancy Factor:** This is given by:

\[
BF = \frac{65.5 - \text{Mud Weight (ppg)}}{65.5}
\]  
(4.11)

*Where:* BF = Buoyancy Factor (Dimensionless)

*Source:* Formulas and Calculations for Drilling, Production and Workover, Lapeyrouse 2nd Ed., Pg. 20

2. **The Length of BHA Necessary for the Required Weight on Bit:** This is given by:

\[
\text{Length (ft)} = \frac{\text{WOB} \times \text{SF}}{\text{Wdc} \times \text{BF}}
\]  
(4.12)

*Where:* WOB = Desired Weight on Bit to be used while drilling  
SF = Safety Factor to place neutral points in drill collars  
Wdc = Weight of Drill Collar (lb/ft)  
BF = Buoyancy Factor

*Source:* Formulas and Calculations for Drilling, Production and Workover, Lapeyrouse 2nd Ed., Pg. 42

3. **The Maximum Allowable Tension in the Drill Pipe:** This is given by:

\[
\text{Max Tension (lb)} = (Y_m \times A) \times 0.85
\]  
(4.13)

*Where:* \(Y_m\) = Minimum Tensile Yield Strength (psi)  
A = Cross Sectional Area (in.\(^2\))  
0.85 = 85% of minimum yield strength of material

4. **The Maximum Allowable Torsion in the Drill Pipe:** This is given by:

\[
\text{Max Torsion (lb/ft)} = \frac{\{C \times J \times Y_m\} \times 0.85}{D}
\]  

(4.14)

*Where:* 
- \(Y_m\) = Minimum Tensile Yield Strength (psi)
- \(J\) = Polar Moment of Inertia: \(\frac{\pi}{32} (D^4 - d^4)\) (in.\(^4\))
- \(D\) = Outside Diameter of Drill Pipe (in.)
- \(d\) = Inside Diameter of Drill Pipe
- \(C = 0.096167\) (field units)
- \(0.85\) = 85% of minimum yield strength of material


5. **Minimum Torsion Yield Strength Under Tension:** This is given by:

\[
Q_T = \frac{C \times J \times (Y_m^2 - P^2)^{1/2}}{D \times A^2}
\]  

(4.15)

*Where:* 
- \(Q_T\) = Minimum Torsion Yield Strength Under Tension
- \(J\) = Polar Moment of Inertia: \(\frac{\pi}{32} (D^4 - d^4)\) (in.\(^4\))
- \(D\) = Outside Diameter of Drill Pipe (in.)
- \(d\) = Inside Diameter of Drill Pipe (in.)
- \(C = 0.096167\) (Conversion Factor – Field Units)
- \(Y_m\) = Minimum Unit Yield Strength (psi)
- \(A\) = Cross Sectional Area (in.\(^2\))
- \(P\) = Minimum Tensile Yield Strength (psi)

6. **The Maximum Allowable Dogleg Severity for Avoidance of Drill Pipe Fatigue:** This is given by:

\[
C = \frac{432,000}{\pi} \frac{\sigma_b}{ED} \tan h KL \tag{4.16}
\]

*Where:*  
\[K = \sqrt{\frac{T}{EI}}; \quad l = \frac{\pi}{64} (D^4 - d^4); \quad \tan h KL = \frac{e^{kl} - e^{-kl}}{e^{kl} + e^{-kl}}\]

\[\sigma_t = T/A; \quad A = \frac{\pi}{4} (D_1^2 - d_1^2)\]

For Grade “E” Drill Pipe;
\[\sigma_b = 19,500 - \frac{10}{67} \sigma_t - \frac{0.6}{(670)^2} [\sigma_t - 33,500]^2\]

For Grade “S” Drill Pipe;
\[\sigma_b = 20,000 [1 - \sigma_t/145,000]\]

*Where:*  
\(C = \) Maximum permissible dogleg severity (deg/100ft)  
\(E = \) Young’s Modulus (psi)  
\(D = \) Drill Pipe OD (in.)  
\(d = \) Drill Pipe ID (in.)  
\(L = \) Half the distance between tool joints (in.)  
\(T = \) Buoyant Weight (including tool joints) suspended below the dogleg (lb)  
\(\sigma_b = \) Maximum permissible bending stress (psi)  
\(I = \) Drill pipe moment of Inertia with respect to its diameter (in.\(^4\))

7. The Lateral Force for Avoidance of Casing Wear: This is given by:

\[ F \text{ (lb)} = \frac{\pi c \cdot LT}{108,000} \]  

(4.17)

Where: \( F \) = Lateral force  
C, L and T are as above


Like Well Planning and BHA design, drill string design is also an iterative process that involves designing a drill string strategy that considers the key issues relating to Friction Factors, Torque and Drag, Hole Cleaning and a host of others. Figure 4.8 shows the interrelationship among these key issues and how they are factored into the design of the drill string, while figure 4.9 is the module that implements this flow chart.
Figure 4.7: Flow Chart for Drill String Design
**Figure 4.8:** Drill String Design Module
4.3.4 Torque and Drag Analysis Module

This module performs Torque and Drag Analysis for the well design. Since there is a myriad of commercially available torque and drag analysis software, it is anticipated that one of the packages will be used. Examples of available Torque and Drag Analysis software include: Baker Hughes’ Advantage Torque and Drag, Halliburton’s WellPlan Torque and Drag, and Petris’ DDRAG – Torque and Drag Analysis Model. These models will provide the inputs necessary for this software.

However, in addition to the inputs provided by commercially available software, this module also performs the following calculations:

1. Torque Generated at the Bit: This is given by:

   \[ TQ \text{ @ Bit} = \text{Bit Diameter} \times \text{Bit Aggressiveness} \]  
   \[ \text{(4.24)} \]

2. Total Surface Torque: This is given by:

   \[ TST = \text{String Torque} + \text{Mechanical Torque} + \text{Dynamic Torque} \]  
   \[ \text{(4.25)} \]

3. Fracture Gradient: There are two principal methods of calculating Fracture Gradient – Mathews and Kelly and the Ben Eaton method. This model uses the Mathews and Kelly method which is mathematically represented as:
\[ FG = \frac{P}{D} + Ki \frac{\alpha}{D} \]  

(4.26)

**Where:**  
\( FG \) = Fracture Gradient (psi/ft)  
\( P \) = Formation pore pressure (psi)  
\( \alpha \) = Matrix stress @ point of interest (psi)  
\( D \) = Depth of interest [TVD] (ft)  
\( Ki \) = Matrix stress coefficient, (Dimensionless)

From the above, **Fracture Pressure** can be calculated by:

Fracture Pressure (psi) = \( FG \times D \)  

(4.27)

**Where:**  
\( FG \) = Fracture Gradient (psi/ft)  
\( D \) = Depth of Determining Ki

And **Maximum Mud Density** can be calculated by:

Max. Mud Density = \( \frac{FG}{0.052} \)  

(4.28)

**Where:**  
\( FG \) = Fracture Gradient (psi/ft)

**Source:** *Formulas and Calculations for Drilling, Production and Workover, Lapeyrouse 2nd Ed. Pgs. 190-192*

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Figure 4.9 is the visual interface design of the Torque and Drag Analysis Module.
Figure 4.9: Torque and Drag Analysis Module
4.3.5 Hydraulics and Hole Cleaning Module

This module predicts the flow rates and RPMs that are needed to clean the various hole sections. It was developed for hole sections from 8 ½” to 17 ½”. It is also able to calculate annular velocity as well as predict the characteristics of the cuttings that will be generated in the various hole sections. Once a hole section selection is made from the drop down combo box, the program automatically displays the required flow rate and RPM that will be required to clean that hole section. The flow rates and RPMs generated upon selection of a hole size have been adapted from the recommended values in Tables 3.2 and 3.3, reproduced hereunder:

Recommended Minimum and Maximum Flow Rates for Different Hole Sizes

<table>
<thead>
<tr>
<th>Hole Size</th>
<th>Desirable Flow Rate (gpm)</th>
<th>Minimum Workable Flow Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>17½”</td>
<td>900 – 1200</td>
<td>800 gpm, with ROP @ 20 m/hr (65’/hr)</td>
</tr>
<tr>
<td>12 ¼”</td>
<td>800 - 1100</td>
<td>650 – 700 gpm, with ROP @ 10-15 m/hr (30-50’/hr)</td>
</tr>
<tr>
<td>9 7/8”</td>
<td>700 – 900</td>
<td>500 gpm, with ROP @ 10-20 m/hr (33-65’/hr)</td>
</tr>
<tr>
<td>8½”</td>
<td>450 – 600</td>
<td>350-400 gpm, with ROP @ 10-20 m/hr (33-65’/hr)</td>
</tr>
</tbody>
</table>

*Source: Drilling Design and Implementation for Extended Reach and Complex Well, K & M Technology, 3rd Edition, 2003, Pg 86*

Recommended Drill String RPM for Various Hole Sizes

<table>
<thead>
<tr>
<th>Hole Size</th>
<th>Desirable RPM</th>
<th>Minimum For Effective Hole Cleaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>17½”</td>
<td>120 – 180 rpm</td>
<td>120 rpm</td>
</tr>
<tr>
<td>12 ¼”</td>
<td>150 – 180 rpm</td>
<td>120 rpm</td>
</tr>
<tr>
<td>9 7/8”</td>
<td>120 – 150 rpm</td>
<td>100 rpm</td>
</tr>
<tr>
<td>8½”</td>
<td>70 – 100 rpm</td>
<td>60 rpm</td>
</tr>
</tbody>
</table>

*Source: Drilling Design and Implementation for Extended Reach and Complex Well, K & M Technology, 3rd Edition, 2003, Pg 87*
This module also calculates the Annular Velocity (ft/min), which is another very important variable in the hole cleaning process. By maintaining the annular velocity at certain rates in conjunction with the rheological properties (density, viscosity, yield strength, gel strength) of the drilling fluid, the wellbore is kept clean of the drill cuttings to prevent them from settling back down to the hole bottom and causing drilling problems.

The Annular Velocity can be calculated using one of the following formulæ:

\[
AV = \frac{1029.4(PO_{bpm})}{ID^2 - OD^2} \quad \text{OR} \quad AV = \frac{24.5(PO_{gpm})}{ID^2 - OD^2}
\]  

Where:  
AV = Annular Velocity (ft/min)  
PO_{bpm} = Pump Output (bpm)  
PO_{gpm} = Pump Output (gpm)  
ID = Inside Diameter of the wellbore or casing (in\(^2\))  
OD = Outside Diameter of the drill pipe or tubing (in\(^2\))  
1029.4 = Conversion factor (Field Units)  
24.5 = Conversion factor (Field Units)

Source: Formulas and Calculations for Drilling, Production and Workover, Lapeyrouse 2\(^{nd}\) Ed. Pg. 170

Figure 4.10 is the visual interface design of the Hydraulics and Hole Cleaning Module.
Figure 4.10: Hydraulics and Hole Cleaning Module
4.3.6 Equivalent Circulation (ECD) Density Module

This module calculates both Equivalent Circulation Density as well as the Equivalent Static Density. The formula for calculating Equivalent Circulation Density was given in Equation 3.2 on page 57 and is reproduced hereunder:

$$
ECD = MW \text{ (ppg)} + \frac{P_a (psi)}{0.052 \times TVD (ft)}
$$

(3.2)

The Equivalent Static Density on the other hand is given by:

$$
ESD = \frac{P_{\text{Static Measured}}}{g \times TVD}
$$

(4.30)

Where:  
ESD = Equivalent Static Density (Dimensionless)  
g = Acceleration due to gravity (m/s²)  
TVD = True Vertical Depth (ft)

Based on these two calculations, the model is able to predict the equivalent circulation density that is needed to clean the hole. It does this by back-checking it with the pore pressure gradient, formation break gradient and the fracture pressure gradient that was earlier calculated by the Torque and Drag Module. It essentially checks to make sure that ECD is below (and always remains below) the fracture gradient.

Figure 4.11 is the visual interface design of the Equivalent Circulation Density Module.
**Figure 4.11:** Equivalent Circulation Density (ECD) Module
While the modules that have been described above are considered critical factors for the success of ERD wells, it does not in any way mean that the other factors listed among the tabs, namely: Casing Design, Bit Hydraulics and Optimization, Rig Sizing and Selection, Stuck Pipe Prevention, Pressure Management, Well Control, Surveying and Target Sizing, Rotary Steerable Systems (RSS) Considerations, Vibration and Wellbore Stability and Well Completion; are less important. Information and relevant data associated with these parameters will be provided by the operating or service Company.

4.4 Sensitivity Analysis – Example Problem

In this section, the sequence of iterations implemented by the algorithm when applied to different scenarios is presented. The interrelationship among the five identified critical factors in the planning and design of an extended reach well is seen as changes are continually made to the original well proposal until a technically feasible well plan and design is achieved. During the iteration process, various parameters will be tested for the selected decision variables, among these are:

1. Is proposed BUR achievable?
2. Is the proposed BHA achievable?
3. Is BHA bending limit exceeded?
4. Will the proposed design result in vibration issues?
5. Will the hole be effectively cleaned with the proposed design?
6. Will the proposed design result in components wear?
7. Will Torque and Drag values exceed operating limits of the proposed rig?

8. Will drill string material limits be exceeded?

These decision variables will be individually and collectively analyzed and the interconnectivity between the variables evaluated. In this way, the effects of changes in these variables and how they affect the final design will be seen. To show how the algorithm achieves this, let us consider a proposed ERD project in the Gulf of Mexico.

**Operator:** Armstrong Oil and Gas  
**Field:** La Corona  
**Well Number:** A-101  
**Well Type:** Extended Reach

**Objective Functions:**
- To drill an Extended Reach Well from top hole to a measured depth of 2900ft @ 1150ft TVD.
- To determine the appropriate wellpath for drilling the well.
- To design the appropriate BHA and Drill String for the given well.
- To determine if the hole can be effectively cleaned with the designed BHA and drill string.
Given the following data:

<table>
<thead>
<tr>
<th>Proposed Well Plan</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inclination Angle</td>
</tr>
<tr>
<td>Course Length</td>
</tr>
<tr>
<td>Build up Radius</td>
</tr>
<tr>
<td>TVD</td>
</tr>
<tr>
<td>Proposed Wellpath</td>
</tr>
<tr>
<td>Kick off Point</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Proposed Drill String Components</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drill Pipe</td>
</tr>
<tr>
<td>HWDP</td>
</tr>
<tr>
<td>Outer Diameter of Drill Pipe</td>
</tr>
<tr>
<td>Outer Diameter of HWDP</td>
</tr>
<tr>
<td>Inner Diameter of Drill Pipe</td>
</tr>
<tr>
<td>Inner Diameter of HWDP</td>
</tr>
<tr>
<td>Drill Collar</td>
</tr>
<tr>
<td>Outer Diameter of Drill Collar</td>
</tr>
<tr>
<td>Inner Diameter of Drill Collar</td>
</tr>
<tr>
<td>Maximum Allowable Hook Load</td>
</tr>
<tr>
<td>Drill String Weight in Air</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Proposed Bottom Hole Assembly</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tools</td>
</tr>
<tr>
<td>Drilling Bit</td>
</tr>
<tr>
<td>Steering Unit</td>
</tr>
<tr>
<td>Non-Magnetic Drill Collar</td>
</tr>
<tr>
<td>Heavy Weight Drill Pipe</td>
</tr>
<tr>
<td>Jars</td>
</tr>
<tr>
<td>MWD Tools</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Friction Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Local Friction Factor</td>
</tr>
<tr>
<td>Well Friction Factor</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Proposed Mud Properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mud Type</td>
</tr>
<tr>
<td>Mud Weight</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Other Relevant Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annulus Pressure</td>
</tr>
<tr>
<td>Formation Pore Pressure</td>
</tr>
<tr>
<td>Stress @ TVD</td>
</tr>
<tr>
<td>Matrix Stress Coefficient</td>
</tr>
</tbody>
</table>
The information given above is used as inputs in the relevant tabs of the model to perform the required calculations.

**Step 1: Determine Well Planning Parameters**

**Given:**
- Well Path/Trajectory = Build and Hold
- Kick off Point = 600ft
- Angle Change = 5 Deg
- Course Length = 2900 ft

**Determine:**
- Dogleg Severity
- Build Up Rate for the Build Section

**Dogleg Severity is given by:**

\[
DLS = \frac{AC \times 100}{CL} \tag{4.2}
\]

Where: $DLS =$ Dogleg Severity (Deg/100 ft)
- $AC =$ Angle Change (degrees)
- $CL =$ Course Length (ft)

From the given data: $DLS = \frac{(5 \times 100)}{2,900} = \text{0.17 Deg/100 ft}$

**Build Up Rate for Build Section is given by:**

\[
BS = \frac{i \times 2\pi}{360} \times R \tag{4.3}
\]

Where: $BS =$ Build Section (Deg/100 ft)
- $i =$ Angle Change (degrees)
- $R =$ Build Up Radius (ft)
From the given data, Angle Change = 5 degrees, Build up Radius = 3 ft

BUR for Build Section = \((5 \times 2\pi)/360\) * 3 = \(0.26 \text{ Deg/100 ft}\)

**Proceed to Step 2: BHA Design**

**BHA Design**

**Given the following Downhole Tools:**

<table>
<thead>
<tr>
<th>Drilling Bit</th>
<th>Near Bit Reamer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steering Unit</td>
<td>Modular Stabilizer</td>
</tr>
<tr>
<td>Non-Magnetic Drill Collar</td>
<td>String Stabilizer</td>
</tr>
<tr>
<td>Heavy Weight Drill Pipe</td>
<td>Shock Sub</td>
</tr>
<tr>
<td>Jars</td>
<td></td>
</tr>
<tr>
<td>MWD Tools</td>
<td></td>
</tr>
</tbody>
</table>

1. Using available industry software (e.g. *BHA SysPro*), design the BHA with these tools. From the proposed wellplan data, the build-up rate has been calculated to be \(0.26 \text{ deg/100 ft}\).

2. Determine if this is achievable with the BHA designed with the above downhole tools. Also determine if BHA bending limit is exceeded; if side forces can cause BHA wear and if the current design will result in BHA vibration.

3. If the BUR is not achievable, consider reducing the BUR by raising the KOP from 600 ft to 500 ft. Re-calculate the BUR @ KOP of 500 ft and check if this is achievable with the designed BHA. If not, continue reducing BUR and raising KOP until an achievable BUR is obtained.

4. If BUR remains unachievable, re-consider the placement and/or size of the stabilizers or use flex subs/flex stabs.
**Condition of STOP for BHA Design**
Continue iterations 1 - 4 as shown in Figure 4.6 until a BHA design that is compatible with the modified well plan is achieved.

**Proceed to Step 3: Drill String Design**
Given the following:

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Local Friction Factor</td>
<td>0.17</td>
</tr>
<tr>
<td>Well Friction Factor</td>
<td>0.22</td>
</tr>
<tr>
<td>Mud Density</td>
<td>13</td>
</tr>
<tr>
<td>Depth of Interest (TVD)</td>
<td>1150</td>
</tr>
<tr>
<td>Formation Pore Pressure</td>
<td>6692</td>
</tr>
<tr>
<td>Stress @ Point of Interest</td>
<td>7309</td>
</tr>
<tr>
<td>Matrix Stress Coefficient</td>
<td>0.522</td>
</tr>
</tbody>
</table>

The following information will be provided by the operator:

- *Rig Operating Limit*
- *Drill String Material Limits*
- *Yield Safety Factor*
- *Fatigue Safety Factor*
- *Side Forces*

Use Torque and Drag Module to perform Fracture Gradient Calculations:

1. **Fracture Gradient Using Ben Eaton Method** is given by:

   \[
   FG = \frac{P}{D} + Ki \frac{\alpha}{D} 
   \]

   _Where:_  
   
   - \( FG \) = Fracture Gradient (psi/ft)  
   - \( P \) = Formation pore pressure (psi)  
   - \( \alpha \) = Matrix stress @ point of interest (psi)  
   - \( D \) = Depth of interest [TVD] (ft)  
   - \( Ki \) = Matrix stress coefficient


Using this equation, the fracture gradient is calculated as follows:

\[
\frac{6692}{1150} + 0.522 \left( \frac{7309}{1150} \right) = 9.14 \text{ psi/ft}
\]

From the above, Fracture Pressure can be calculated by:

\[
\text{Fracture Pressure (psi)} = \text{FG} \times D \tag{4.27}
\]

Where:  
\( \text{FG} \) = Fracture Gradient (psi/ft)  
\( D \) = Depth of Determining Ki

Therefore, Fracture Pressure = 9.14 * 1150 = **10511 psi**

2. Using the combination of the Toque and Drag Module and industry software (*e.g.* Advantage Torque and Drag), determine:
   a) If Torque and Drag Values exceed Rig Operating Limits
   b) If this leads to Drill String Buckling
   c) If Drill String Material Limits are exceeded
   d) If all the above are compatible with the modified wellplan and designed BHA.

3. For each of a – d that is determined to be true, go back and re-design the drill string by:
   i. Considering changes in the DC and HWDP number and placement
   ii. Considering Surface Equipment Upgrade
   iii. Considering higher strength pipes
   iv. Considering Rotary Steerable Systems

   OR

Go back to the wellplan and consider either:
   i. Reducing the BUR and/or Hole Angle
   ii. Planning deeper BUR if possible
   iii. Changing the wellpath to Catenary Well Profile

4. Calculate the Equivalent Circulation Density using the ECD Module:
   Compare the Calculated ECD with fracture gradient. ECD should always remain below fracture gradient.
**Condition of STOP for Drill String Design**
Continue iterations 1 - 4 as shown in Figure 4.8 until a Drill String design that is compatible with the modified well plan and designed BHA is achieved.

---

**Stop Drill String Design**

**Proceed to Step 4: Prepare Well Proposal**
Prepare Well Proposal Showing the technically feasible and recommended Wellplan, BHA Design and Drill String Design

STOP

END
4.5 Limitations of the Model

The most significant limitation of this model is its inability to self-calculate certain parameters in the modules. This is because the mathematics behind some of these parameters could not be obtained. As a result of this, the model had to rely on already generated inputs from other industry software. In some cases, instead of first providing all the necessary input values before calculation, the user is simply asked to enter the final value which has been obtained from some other model. This partially reduces the ability of the model to independently iterate certain parameters. That notwithstanding, it generates an output in Excel, in a well report format which gives a re-evaluated and modified version of the original proposal. This new version of the proposal is a more technically feasible design that can be used to drill the well. An example of the report format is shown in Appendix B.

Another limitation of this model is the inability of the author to secure relevant field data to carry out further sensitivity analysis. As was mentioned in Section 4.3.2 on page 89, this is because these data are regarded as proprietary/classified information and therefore, could not be released. As can be seen, only one set of data was available, as such, only one run was made; as against several repeated runs. Even though it would have been nice to have more validation data, the fact that only one data set was used does not significantly affect the functional efficacy of the model.
Chapter Five

Summary, Conclusions and Recommendations

A Visual Basic algorithm that shows the interrelationship among the five critical elements involved in the planning, design and drilling of extended reach and complex wells has been developed. The development of the model is based upon information gathered from several sources, many new ideas from technical publications, along with information and feedback from field-based personnel. The ideas, suggestions and recommendations gathered from all these sources have been incorporated into the model.

Based on findings from the literature and results obtained from using the model, the following summary, conclusions and recommendations can be made:

5.1 General Observations

1. Well length is different for different types of curve shapes and well profile design is one of the critical technologies in ERD. We should therefore select a well trajectory that is as short as possible. This is because significant benefits come from reduction of footage.

2. Deep kick off point and low build-up rates will reduce the inclination in the larger diameter hole sections and this generally gives better hole stability and improves hole cleaning.
3. The principles of planning are making torque and drag as small as possible and making well length as short as possible.

4. ECD measurement is crucial to ECD management and understanding of the variety of downhole conditions that affect it.

5. The recognition of hole cleaning problems in the planning phase and the taking of immediate remedial action when the problems occur on the rig can lead to successful completion of drilling objectives.

5.2 Conclusions drawn from using the model

While the model that has been developed is not a substitute for an experienced drilling engineer, it will greatly assist in the well planning and design process by automatically proposing sound technical solutions and providing a smooth path through the well planning workflow. The use of the model has also revealed that:

1. The friction factor is one of the most crucial inputs in a Torque and Drag analysis.

2. There is a direct correlation between ECD and Friction Factor. This is as a result of the fact that both are functions of Hole Cleaning.
5.3 Recommendations

The testing of the program as well as key lessons learned and success factors identified from this study has also led to the following recommendations:

1. While using the model, when specifying changes or requesting modifications to a specific parameter, keep in mind that the systems are not independent and a change to one system may require a change to another.

2. Determining the best well plan and design is an iterative process. Always consider the factors affecting critical or marginal components. Determine if your assumptions were reasonable or overly conservative. Evaluate the well requirements and design to determine how changes may affect your specifications.

3. The iteration process is based on engineering principles and will yield a quantitative result based on many assumptions. When making these assumptions it is important to be aware of the objectives and constraints of the particular ERD project.

5.4 Concluding Remarks

In the light of the foregoing, it is this author’s conclusion that the definition of ERD will remain dynamic and should be updated as operators expand the ERD envelope. ERD wells drilled in specific fields and with specific rigs, equipment, personnel, project teams, etc. do not necessarily imply what may be readily achieved in other areas. Because of the myriad of variables, which control drilling mechanics and performance, local ERD definitions
should be developed in terms of the extent of experience within specific fields and with specific rigs. Thus, ERD wells should not be treated as “just another well”. Designs must be fit-for purpose and specific to the well in question. Time spent on detailed planning and design will definitely pay off in the operational phase in both performance improvements and the avoidance of Non-Productive Time (NPT) and the recording of No Drilling Surprises (NDS).

5.5 The Future of Extended Reach Drilling

Extended Reach Drilling is increasingly becoming the means of reviving and expanding the productivity of aging oil and gas fields. The careful application of ERD technology will provide an opportunity for reservoirs to add value beyond what would ordinarily be possible through conventional directional drilling. While it looks like we can solve the problems posed by the other critical technologies for success of ERD wells, torque and drag, hole cleaning, as well as vibration and wellbore stability will continue to remain a problem.

However, as drilling technology continues to evolve, and as operators strive to extend the life of existing structures and reduce the number of such structures on new field developments, the industry will continue to break drilling records and the limits of extended reach drilling will continue to be pushed further. And with records being continually broken, the obvious question will be: How Far Can We Go with Existing Technology?
Reliable rotary steerable tools have had a significant effect on drilling efficiency and flexibility especially at extreme departures. With the potential of Rotary Steerable Drilling technology, the limits for extended reach wells may now lie with the ability to complete and maintain production from a well rather than to drill it. As drilling technology continues to improve and as the limiting factors identified in this study are gradually overcome, the final constraint may well be economic rather than technical. Advances in ERD techniques are a continuous process, thus research on how to optimize ERD operations will be a continuous process that will be evolving alongside its development.

5.6 Further Studies

Beyond drilling, it is suggested that further studies should be carried out on Extended Reach Completions, Interventions and other Life Cycle issues that impact on the total value of Extended Reach Drilling. Studies should also be conducted on Vibration and Wellbore Stability, Rotary Steerable System Considerations, Stuck pipe prevention, Rig Sizing and Selection, Pressure Management, as well as Surveying and Target Sizing.
Appendix A: Program Code

Option Explicit
Dim Pi As Double
Private Sub CmdAnnularVelocity_Click()
'CALCULATING ANNULAR VELOCITY
Dim MFR As Double, IDCH As Double, ODPT As Double, ANV As Double
MFR = TxtMFR.Text
IDCH = TxtIDCH.Text
ODPT = TxtODPT.Text
ANV = (24.5 * MFR) / (IDCH ^ 2 - ODPT ^ 2)
TxtANV.Text = Round(ANV, 2)
End Sub

Private Sub CmdBF_Click()
'CALCULATING BUOYANCY FACTOR
Dim MW As Double, RBF As Double
MW = TxtMW.Text
RBF = (65.5 - MW) / 65.5
TxtRBF.Text = Round(RBF, 3)
End Sub

'CALCULATING THE BUILD SECTION
Dim INCA As Double, RAD As Double, BSEC As Double
INCA = TxtINCA.Text
RAD = TxtRAD.Text
BSEC = ((INCA * 6.285 / 360) * RAD)
TxtBSEC.Text = Round(BSEC, 2)
End Sub

Private Sub cmdCalculateCurrentTVD_Click()
Dim LastTVD As Double, CurrentTVD As Double
Dim CourseLength As Double, IncAngle As Double
LastTVD = Me.txt_Current_LastTVD.Text
CourseLength = Me.txt_Current_CourseLength.Text
IncAngle = Me.txt_Current_InclinationAngle.Text
CurrentTVD = (Cos(IncAngle * Pi / 180) * CourseLength) + LastTVD
Me.txt_Current_CurrentTVD.Text = Round(CurrentTVD, 2)
End Sub

Private Sub cmdCalculateProjectedAngle_Click()
Dim TTVD As Double, PTVD As Double
Dim TVS As Double, PVS As Double
Dim UVS As Double
Dim Res1 As Double
Dim Res2 As Double
TTVD = Me.txtTargetTVTD.Text
PTVD = Me.txtPresentTVTD.Text
TVS = Me.txtTargetVS.Text
PVS = Me.txtPresentVS.Text
UVS = (TVS - PVS)
Res1 = (TTVD - PTVD) / UVS
Res2 = Atn(Res1) * 180 / Pi
If Res2 > 90 Then
    Res2 = Res2 + 90
Else
    Res2 = Res2 - 90
End If
    txtProjectedAngle.Text = Res2
End Sub

'COMBINED MAXIMUM TENSION AND TORSION IN DRILL PIPE
Dim MTYS As Double, IDDP As Double, ODDP As Double, CSAP As Double,
CMATT As Double, MAT As Double
MTYS = TxtMTYS.Text
IDDP = TxtIDDP.Text
ODDP = TxtODDP.Text
MAT = TxtMAT.Text
CSAP = TxtCSAP.Text
CMATT = (0.096167 * (0.0981875 * (ODDP ^ 4 - IDDP ^ 4))) * (MTYS ^
2 - (MAT ^ 2 / CSAP ^ 2)) ^ 0.5 / (ODDP)
TxtCMATT.Text = Round(CMATT, 2)
End Sub

Private Sub CmdDoglegSeverity_Click()
    'CALCULATION OF DOGLEG SEVERITY'
Dim AC As Double, CL As Double, DLS As Double
AC = TxtAC.Text
CL = TxtCL.Text
DLS = (AC * 100) / CL
TxtDLS.Text = Round(DLS, 2)
End Sub

Private Sub CmdEquivalentCirculationDensity_Click()
    'CALCULATING EQUIVALENT CIRCULATION DENSITY'
Dim MWT As Double, ANP As Double, TVD1 As Double, ECD As Double
MWT =TxtMWT.Text
ANP = TxtANP.Text
TVD1 = TxtTVD1.Text
ECD = MWT + (ANP / (0.052 * TVD1))
TxtECD.Text = Round(ECD, 2)
End Sub

Private Sub CmdEquivalentStaticDensity_Click()
    'CALCULATING EQUIVALENT STATIC DENSITY'
Dim MSP As Double, TVD2 As Double, ADG As Double, ESD As Double
MSP = TxtMSP.Text
TVD2 = TxtTVD2.Text
ADG = TxtADG.Text
ESD = (MSP / (ADG * TVD2))
TxtESD.Text = Round(ESD, 2)
Private Sub CmdFractureGradient_Click()
'CALCULATING FRACTURE GRADIENT
Dim FPP As Double, SPI As Double, DOI As Double, MSC As Double,
FRAG As Double
FPP = TxtFPP.Text
SPI = TxtSPI.Text
DOI = TxtDOI.Text
MSC = TxtMSC.Text
FRAG = (FPP / DOI) + MSC * (SPI / DOI)
TxtFRAG.Text = Round(FRAG, 2)
End Sub

Private Sub CmdFracturePressure_Click()
'CALCULATING FRACTURE PRESSURE
Dim FRAP As Double, FRAG As Double, DOI As Double
FRAG = TxtFRAG.Text
DOI = TxtDOI.Text
FRAP = FRAG * DOI
TxtFRAP.Text = Round(FRAP, 2)
End Sub

Private Sub CmdHorizontalDeparture_Click()
'CALCULATION OF HORIZONTAL DEPARTURE
Dim IA As Double, KOP As Double, HD As Double
IA = TxtIA.Text
KOP = TxtKOP.Text
HD = Sin(IA * Pi / 180) * KOP
TxtHD.Text = Round(HD, 3)
End Sub

'LENGTH OF BHA NECESSARY FOR REQUIRED WEIGHT ON BIT
'SAFETY FACTOR = 1.15
Dim WOB As Double, WODC As Double, LBHA As Double, RBF As Double
WOB = TxtWOB.Text
WODC = TxtWODC.Text
RBF = TxtRBF.Text
LBHA = (WOB * 1.15) / (WODC * RBF)
TxtLBHA.Text = Round(LBHA, 2)
End Sub

Private Sub CmdMaximumAllowableDLS_Click()
'CALCULATING MAXIMUM ALLOWABLE DOGLEG SEVERITY FOR AVOIDANCE OF
DRILL PIPE FATIGUE
Dim IDDP As Double, ODDP As Double
Dim L As Double, MPBS As Double
Dim DPMI As Double, T As Double, C As Double
Dim E As Double, AngleChange As Double
ODDP = TxtODDP.Text
L = Me.txtHalfDistance.Text 'Half distance btw tool joint
MPBS = Me.txtMPBS.Text 'Maximum permissible bending stress
DPMI = Me.txtDPMI.Text 'Drill pipe moment of inertia
T = Me.txtBouyantWeight.Text 'Bouyant Weight
E = Me.txtYoungModulus.Text 'Young Modulus of Elasticity
AngleChange = Me.txtAngleChange.Text 'Angle Change
C = (432000 / Pi) * MPBS / (E * ODDP) * AngleChange
Me.txtMPDLS = Round(C, 2) 'Maximum Permissible Dog Leg Severity
End Sub

Private Sub CmdMaxMudDensity_Click()
'CALCULATING MAXIMUM MUD DENSITY
Dim MMD As Double, FRAG As Double
FRAG = TxtFRAG.Text
MMD = FRAG / 0.052
TxtMMD.Text = Round(MMD, 2)
End Sub

Private Sub CmdMeasuredDepth_Click()
'CALCULATING PROJECTED MEASURED DEPTH
Dim TAGI As Double, PRESI As Double, DLS2 As Double, PMD As Double
TAGI = TxtTAGI.Text
PRESI = TxtPRESI.Text
DLS2 = TxtDLS2.Text
PMD = (TAGI - PRESI) / DLS2
TxtPMD.Text = Round(PMD, 2)
End Sub

Private Sub cmdNRTVD_Click()
Dim DA As Double, CA As Double
Dim TTVD As Double, CTVD As Double
Dim Res1 As Double, Res2 As Double
DA = Me.TxtDA.Text
CA = Me.TxtCA.Text
TTVD = Me.TxtTTVD.Text
CTVD = Me.TxtCTVD.Text
Res1 = Sin(DA * Pi / 180) - Sin(CA * Pi / 180)
Res2 = Res1 / (TTVD - CTVD)
Me.TxtNRTVD.Text = Round(Res2, 4)
End Sub

Private Sub cmdOptimize_Click()
Dim ECD As Double, PPG As Double
Dim FPG As Double, FBG As Double
ECD = Me.TxtECD.Text
PPG = Me.txtPPG.Text
FPG = Me.txtFPG.Text
FBG = Me.txtFBG.Text
If ECD > FPG Then
Me.txtOptimizeECD.Text = "ECD is greater than Fracture Gradient. Check Mud Weight or Annulus Pressure"
Else
Me.txtOptimizeECD.Text = "ECD is good enough to clean the hole"
End If
End Sub

Private Sub cmdPredictCC_Click()
    Dim A As Integer
    A = Me.txtHoleAngle.Text
    Select Case A
        Case 0 To 34
            Me.txtDisplayCC.Text = "Cuttings do not form. Transport velocity is greater than slip velocity; the cuttings are effectively carried in suspension"
        Case 35 To 45
            Me.txtDisplayCC.Text = "Cuttings bed starts to form. There is unstable, moving cuttings bed and transport is via lifting mechanism."
        Case 46 To 65
            Me.txtDisplayCC.Text = "Avalanching starts. Most problems associated with hole cleaning will occur in this section."
        Case 66 To 90
            Me.txtDisplayCC.Text = "Astable beds. Stationary cuttings bed form instantaneously and transport is via a rolling mechanism."
        Case Else
            Me.txtDisplayCC.Text = ""
    End Select
End Sub

Private Sub cmdPredictFlowRate_Click()
    Dim I As Integer
    I = Me.cboHoleSize.ListIndex
    Select Case I
        Case 0
            txtDFR = "DESIRABLE FLOW RATE:"
            txtDFRV = "900 - 1200 gpm"
            lblMWFR = "MINIMUM WORKABLE FLOW RATE:"
            lblMWFRV1 = "800 gpm, with ROP @"
            lblMWFRV2 = "20 m/hr (65'/hr)"
        Case 1
            txtDFR = "DESIRABLE FLOW RATE:"
            txtDFRV = "800 - 1100 gpm"
            lblMWFR = "MINIMUM WORKABLE FLOW RATE:"
            lblMWFRV1 = "650 - 700 gpm, with"
            lblMWFRV2 = "ROP @ 10-15 m/hr (30-50' /hr)"
        Case 2
            txtDFR = "DESIRABLE FLOW RATE:"
            txtDFRV = "700 - 900 gpm"
            lblMWFR = "MINIMUM WORKABLE FLOW RATE:"
            lblMWFRV1 = "500 gpm, with ROP"
            lblMWFRV2 = "@ 10-20 m/hr (33-65' /hr)"
        Case 3
            txtDFR = "DESIRABLE FLOW RATE:"
            txtDFRV = "600 - 800 gpm"
            lblMWFR = "MINIMUM WORKABLE FLOW RATE:"
            lblMWFRV1 = "400 gpm, with ROP"
            lblMWFRV2 = "@ 10-15 m/hr (30-50' /hr)"
    End Select
End Sub
txtDFRV = "450 - 600 gpm"
lblMWFR = "MINIMUM WORKABLE FLOW RATE:"
lblMWFRV1 = "350-400 gpm, with"  
lblMWFRV2 = "ROP @ 10-20 m/hr (33-65' /hr)"

End Select
End Sub

Private Sub cmdPredictRotarySpeed_Click()
    Dim I As Integer
    I = Me.cboHoleSize2.ListIndex
    Select Case I
        Case 0
            txtDFR1 = "DESIRABLE RPM:"
            txtDFRV1 = "120 - 180 rpm"
            txtMWFR1 = "MINIMUM FOR EFFECTIVE HOLE CLEANING:"
            txtMWFRV1 = "120 rpm"
        Case 1
            txtDFR1 = "DESIRABLE RPM:"
            txtDFRV1 = "150 - 180 rpm"
            txtMWFR1 = "MINIMUM FOR EFFECTIVE HOLE CLEANING:"
            txtMWFRV1 = "120 rpm"
        Case 2
            txtDFR1 = "DESIRABLE RPM:"
            txtDFRV1 = "120 - 150 rpm"
            txtMWFR1 = "MINIMUM FOR EFFECTIVE HOLE CLEANING:"
            txtMWFRV1 = "100 rpm"
        Case 3
            txtDFR1 = "DESIRABLE RPM:"
            txtDFRV1 = "70 - 100 rpm"
            txtMWFR1 = "MINIMUM FOR EFFECTIVE HOLE CLEANING:"
            txtMWFRV1 = "60 rpm"
    End Select
End Sub

Private Sub CmdPressureLoss1_Click()
    'PRESSURE LOSS AT BIT..1
    Dim MW1 As Double, FLR As Double, BNZA As Double, BNPL As Double
    MW1 = TxtMW1.Text
    FLR = TxtFLR.Text
    BNZA = TxtBNZA.Text
    BNPL = (FLR ^ 2 * MW1) / (10858 * BNZA ^ 2)
    TxtBNPL.Text = Round(BNPL, 1)
End Sub

' This sub calculates the length of the tangent section.
' inclination should be in degrees.
Private Sub cmdTangentSection_Click()
    Dim R As Double, IncAngle As Double

    R = Me.txtTanTVD.Text 'this is the radius but used as TVD
    'because of compactibility
    'with earlier naming convention.
    IncAngle = Me.txtTanIncAngle.Text

    Dim R_IncAngle As Double 'Inclination angle converted to radians
    R_IncAngle = IncAngle * Pi / 180
    Me.txtTangentSectionResults.Text = Round(R * Sin(R_IncAngle) / Cos(R_IncAngle), 2)
End Sub

Private Sub cmdTargetAzimuth_Click()
    'this sub calculates the Tangent Azimuth.
    'Assumption is that the SurfaceCoordinate and TargetCoordinate are in degrees
    Dim SurfaceCoordinate As Double, TargetCoordinate As Double
    Dim Pi As Double, X As Double, GetTangentAzimuth As Double
    Pi = 3.14159265358979
    SurfaceCoordinate = Me.txtTargetSurfaceCoordinate.Text
    TargetCoordinate = Me.txtTargetCoordinate.Text
    X = Atn(SurfaceCoordinate / TargetCoordinate) * 180 / Pi
    GetTangentAzimuth = X + 180
    Me.txtTargetAzimuth.Text = GetTangentAzimuth
End Sub

Private Sub CmdTensionInDrillPipe_Click()
    'MAXIMUM ALLOWABLE TENSION IN DRILL PIPE
    Dim MTYS As Double, CSAP As Double, MAT As Double
    MTYS = TxtMTYS.Text
    CSAP = TxtCSAP.Text
    MAT = (MTYS * CSAP) * 0.85
    TxtMAT.Text = Round(MAT, 2)
End Sub

Private Sub CmdTorqueAtBit_Click()
    'TORQUE AT BIT
    Dim WOB2 As Double, BD As Double, BAG As Double, TQB As Double
    WOB2 = TxtWOB2.Text
    BD = TxtBD.Text
    BAG = TxtBAG.Text
    TQB = WOB2 * BD * BAG
    TxtTQB.Text = Round(TQB, 2)
End Sub

Private Sub CmdTorsionInDrillPipe_Click()
    'MAXIMUM ALLOWABLE TORSION IN DRILL PIPE
    Dim MTYS As Double, IDDP As Double, ODDP As Double, MTOYS As Double
    MTYS = TxtMTYS.Text

ODDP = TtxtODDP.Text
IDDP = TtxtIDDP.Text
MTOYS = ((0.096167 * (0.0981875 * (ODDP ^ 4 - IDDP ^ 4) * MTYS)) / ODDP) * 0.85
TtxtMTOYS.Text = Round(MTOYS, 2)
End Sub

Private Sub CmdTotalDragForces_Click()
'CALCULATING TOTAL DRAG FORCES
Dim STEN As Double, PUW As Double, SOW As Double, OBT As Double,
FRT As Double, FRW As Double, TDF As Double
STEN = TtxtSTEN.Text
PUW = TtxtPUW.Text
SOW = TtxtSOW.Text
OBT = TtxtOBT.Text
FRT = TtxtFRT.Text
FRW = TtxtFRW.Text
TDF = STEN + PUW + SOW + OBT + FRT + FRW
TtxtTDF.Text = Round(TDF, 2)
End Sub

Private Sub CmdTotalSurfaceTorque_Click()
'TOTAL SURFACE TORQUE
Dim TQB As Double, STRT As Double, MET As Double, DYT As Double,
TSTQ As Double
TQB = TtxtTQB.Text
STRT = TtxtSTRT.Text
MET = TtxtMET.Text
DTY = TtxtDYT.Text
TSTQ = TQB + STRT + MET + DYT
TtxtTSTQ.Text = Round(TSTQ, 2)
End Sub

Private Sub cmdTransfer_Click()
Me.txtMPDLS2.Text = Me.txtMPDLS.Text
Me.txtBouyantWeight2.Text = Me.txtBouyantWeight.Text
Me.txtHalfDistance2.Text = Me.txtHalfDistance.Text
End Sub

Private Sub CmdWeightOnBit_Click()
Dim IA As Double, TWOC As Double
Dim Res As Double
IA = Me.txtInclinationAngle.Text
TWOC = Me.txtTWOC.Text
Res = TWOC * Cos(IA * Pi / 180)
Me.txtAvailableWOB.Text = Round(Res, 2)
End Sub

Private Sub CmdYSC_Click()
'CALCULATING YIELD STRENGTH COLLAPSE
Dim MYS As Double, NWT As Double, ODC As Double, YSC As Double

MYS = CboMYS.Text
NWT = TxtNWT.Text
ODC = TxtODC.Text
YSC = (2 * MYS) / ((ODC / (NWT - 1)) / (ODC / NWT) ^ 2)
TxtYSC.Text = Round(YSC, 2)
End Sub

Private Sub Cbo1_Change()
    Call Display_Data_From_Combo_to_TextBox2
End Sub

Private Sub cmdCreateReport_Click()
    'Report dog leg severity
    Sheets("Reports").Range("B11") = Me.TxtDLS
    'Report Build up rate
    Sheets("Reports").Range("B13") = Me.TxtBSEC.Text
    'Report tangent section
    Sheets("Reports").Range("B14") =
    Me.txtTangentSectionResults.Text
    MsgBox "Reports Created Successfully"
End Sub

' This function calculates the length of the tangent section.
' inclination should be in degrees.
Function GetTangentSection(ByVal TVD As Double, ByVal IncAngle As Double) As Double
    Dim Pi As Double
    Pi = 3.14159265358979
    Dim R_IncAngle As Double 'Inclination angle converted to radians
    R_IncAngle = IncAngle * Pi / 180
    GetTangentSection = TVD / Cos(R_IncAngle)
End Function

Sub Display_Data_From_Combo_to_TextBox1()
    Dim I As Integer
    I = Me.Cbo1.ListIndex
    Select Case I
        Case 0
            Me.Txt1.Text = "This"
        Case 1
            Me.Txt1.Text = "That"
    End Select
End Sub
Sub Display_Data_From_Combo_to_TextBox2()
    Dim I As Integer
    I = Me.Cbo1.ListIndex
    Me.Txt1.Text = Cells(65520 + I, 2)
End Sub
Private Sub UserForm_Activate()
    Pi = 3.14159265358979
End Sub

Private Sub UserForm_Initialize()
    Pi = 3.14159265358979
End Sub

Private Sub UserForm_MouseMove(ByVal Button As Integer, ByVal Shift As Integer, ByVal X As Single, ByVal Y As Single)
    Pi = 3.14159265358979
End Sub
# Appendix B: Report Format

## ERD Planning and Design Report Format

### General Data

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<thead>
<tr>
<th>Operator</th>
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<th>Well</th>
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<td>Armstrong Oil and Gas</td>
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### Wellplan

- Well Type
- Dogleg Severity
- Build Up Rate
- Build Section
- Tangent Section
- Build-Up Rate Needed to Reach Target
- Target Azimuth
- Horizontal Departure
- Dogleg Angle
- Current TVD
- Projections
  - Projected Angle Needed to Reach Target
  - Projected Measured Depth

### Bottom Hole Assembly

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### Critical BHA Calculations

- Jar Triggering Load
- Wall Force
- Torsional Dampering
- Torque
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Bibliography


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