OPTIMIZING PRODUCTION RATES THROUGH ENHANCED WELL DESIGN

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Optimizing Production Rates Through Enhanced Well Design

by

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Abstract

For decades, reservoir and drilling engineers have independantly strived to provide optimal production rates through various methods. The method studied for this research was based on a post-drilling analysis of optimizing production rates by designing a well path that could be drilled sucessfully. This was achieved by combining a wellflow simulator, $NETool^{TM}$, with a torque and drag modelling program, $PowerPlan$®, to prove better results could be obtained. The work consisted of creating a methodology that was sucessfully implemented to first optimize the production rates by modifying an existing well path. Each new well path was placed in the torque and drag program to analyze the torque, sideforces and hookloads experienced on the drillsting. The success of the study was dependant on not exceeding the limitations of the system which in this case included the drillstring, connections and topdrive system. A component of cost-based risk was incorporated into the study to add a measure of uncertainty associated with drilling each new well path. This analysis proved very successful in obtaining higher production rates and a future in-depth study is recommended to develop an advanced tool that will integrate the two areas of oil and gas engineering.

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Nomenclature

A	Area
A_x	Points along a survey
B_o	Oil formation volume factor
$B_o{}^*$	Oil formation volume factor at reference point P^*
$B_o(p_k)$	Oil formation volume factor during single phase oil flow at the pressure of node k
C_f	Cost of Failure
C_i	Initial Cost of drilling a well
C_o	Isothermal compressibility
d	Diameter of Drillstring, m
D	Diameter of cross-section, in this case it is the hydraulic diameter, D_h
D_x	True Vertical Depth, m or ft
$D_{(x)TMD}$	Total Measured Depth to target, m or ft
f	Friction factor
F	Failure measured as a percetage
F_f	Friction Force
F_{sc}	Factor of the ratios of straight line segments to curved segments
i	Node number to which fluid is flowing into
I	Inclination, m^2
j	Node number from which fluid is flowing
k_{rg}	Relative permiability to gas at the current liquid saturation (calculated as $1 - S_g$) from the SLGOF table of relative permiabilities
k_{ro}	Relative permiability to oil at the current oil saturation
k_{roE}	Relative permiability to oil at the current oil saturation using Eclipse Default Method
k_{rog}	Relative permiability to oil at the current liquid saturation (calculated as $1 - S_g$) from the SLGOF table of relative permiabilities
k_{rogE}	Relative permiability to gas at the current gas saturation from the SGFN table of relative permiabilities using Eclipse Default Method
k_{row}	Relative permiability to water from SWOF table of relative permiabilities at the current water saturation
k_{rowcw}	Relative permiabilty to oil from SWOF table of relative permiability at connate water saturation, with connate water saturation used as the lowest in the SWOF table

k_{rowE}	Relative permiability to water from SOF3 table of relative permiability data at the oil saturation calculated as $(1 - S_w)$ using Eclipse Default Method
k_{rw}	Relative permiability to water at current water saturation from SWOF table of relative permiabilities
L_{OB}	Length of segment OB
L_n	Latitude North/South Coordinate
M_n	Longitude East/West Coordinate
n	Number of survey stations
N	Normal Force, m
p_i	Node pressures at each i
p^*_{bh}	Pressure at the node connecting to surface
P^*_k	Pressure at each reservoir node
PI	Local productivity index
q	Volumetic flowrate accross each bridge
$q_{i,j}$	Total volumetric flow rates in the bridges
q_i	Rate of inclination build up or drop, degrees per unit length
Q^*	Total outlet volumetric flowrate
r	Radius of Curvature
R	Reliabilty
Re	Reynolds number
S_{gE}	Current gas saturation using Eclipse Default Method
S_{wcoE}	Connate water saturation - highest water saturation for which relative permiability to water is zero in SWFN table of relative permiabilities using Eclipse Default Method
S_{wE}	Current water saturation using Eclipse Default Method
T	Tension, $4A/P$
T_o	Torque, U^2
W	Weight of Incrimental Drillstring Length, m
x	Random variable repesenting stress placed on a system
X	Horizontal Departure, m or ft

$\alpha_{i,j}$	Oil volume fractions in the bridges between two adjacent nodes
β	Overall angle change, degrees
Δ	Incrimental Values
ϵ_n	Direction or azimuth angle, degrees
μ	Fluid viscosity
μ_f	Coefficient of Friction, m^2
μ_x	Mean stress placed on a system
Ω	Angle between toe of trajectory and arbitrary point, O, along segment OB
ϕ	Azimuth of Drillstring, m
ρ	Density of fluid
τ	Angle between segment OA and segment OB
θ	Maximum inclination angle, degrees
v	Speed of the fluid

Chapter 1

Introduction

Placing a well in a reservoir and simulating the configuration with steady state flow shows a snap shot of oil recovery at a specific moment in time. This data is very useful in predicting total oil production from a well over the life of the reservoir. It can provide insight into optimization techniques and advanced oil recovery methods that may increase the rate of production.

The oil and gas industry strives for high revenue, low cost, and time efficiency in its goal to be successful and sustainable. There is a need to bridge the gap between reservoir and drilling engineering in order to increase oil production and decrease the impacts on the drillstring and bit. These goals are echoed through past studies that have showed production optimization and well design optimization is effective and necessary to stay in the forefront of advancing technology.

Engineers in the oil and gas industry use several different computer tools to assist in the analysis of reservoir potential and optimal well design. These tools are implemented at various stages of well life in order to plan and carry out the operations necessary to achieve maximum production in a timely, cost effective manner. A tool is necessary that would combine both areas of optimization and provide the most accurate information to decision makers so that they can make the right choices for long term success. It would provide oil companies with an opportunity to achieve the higher production rates and enhanced well design in the various stages of the project.

There were several goals put in place to ensure that the project was successful. The first goal was to provide a methodology that could be used to optimize production rates in a designed well path. The second goal was to prove that production optimization could occur by incorporating advanced well design techniques. The project was a two-phase optimization study of two well designs with an associated reservoir. In the first phase, an optimization of the production rates was achieved and in the second phase the well design was analyzed to determine torque and drag losses. The third goal was to incorporate an associated risk with each well design to determine its level of success or failure based on the limitations of the system. Finally, the last goal was to show that future implementation of a program that integrates reservoir simulation and torque and drag analysis would be applicable and useful in the oil and gas industry.

1.1 Driving Force

There are many ways to approach production optimization from a technical stand point. There are many different parameters, such as the completions selection for example, that can be optimized to provide ideal production rates. For the sake of simplicity in this study, the completion configuration was contant, and the changing parameter was the well path. Having the ability to choose a well path that can give the highest possible production rates can be achieved using a production simulation tool. Selecting this tool is based on cost, availability, accuracy and ease of use. One downfall of a reservoir simulator is that it cannot determine if the well path selected is actually drillable. Another tool is required to do this.

There are many well design analysis tools available on the market. Again, it is a matter of how much money can be invested in the technology, if it provides accurate results, and if it is available for use. The main function of the tool for this production optimization study was to prove or disprove that the well could actually be drilled with the selected drillstring and rig equipment.

The motivation to carry out the research on the two case studies presented in this thesis was based on the following three factors. Firstly, to be successful, it was important to first show that by developing a methodology, production optimzation could be achieved by enhancing the well design. Secondly, by incorporating a failure scenario, risk associated with the new well designs could be measured in terms of cost to the company. Lastly, to indicate success, it would be necessary to show that integrating the simulation and well analysis tools would create improved technology that connected the reservoir and drilling engineering fields.

1.2 Scope of Research

There were 3 different areas of implementation that this research could have followed. The study could have been performed during well planning (pre-drilling), while drilling, or post-drilling. Under the scope of this project and with the information provided, a post-drilling analysis was performed. There were two wells used in the analysis and were offshore, horizontal wells drilled by a semi-submersible rig. The tools used to provide the analysis were $NETool^{\text{TM}}$ for reservoir and well flow simulation and $PowerPlan^{®}$ for torque and drag analysis. These wells had already been drilled successfully. In a post-analysis study, the focus would be on proving if alternative paths existed, and if so, could they be drilled and produce higher production rates. The study did not consider anti-collison issues, i.e. its proximity to other wells. This would be an important factor in the planning and drilling stages of a mulitple-well project and be incorporated into the methodology presented for this project.

1.3 Thesis Outline

This first section gives a short summary of the thesis. It identifies the driving force behind the research and the areas of interest the research would encompass. Chapter 2 is a literature review which focuses on torque and drag modelling, well trajectory and production optimization and touches on risk analysis. Chapter 3 gives background information about the reservoir and well flow simulation tool used in the research. It allows the reader to understand the principles and calculations behind the simulation and how to set up a case study like the ones performed in this researh. Chapter 4 attempts to describe the other optimization tool used to analyze the well profiles using torque and drag modelling. It explains the five main modules of the program and how they are utilized in this research. Special focus is given to DrillSafe (torque and drag analysis tool) and the concepts behind torque and drag. Chapter 5 describes the methodolgy used to optimize production rates and well paths for this research which can be applied to any given trajectory. In chapter 6 and 7 the first and second case studies are explained in terms of their geological structure, the production profiles, well designs, and torque and drag analysis. Each study has a base case with three associated optimal paths. The results of the case studies are described with the aide of comparison graphs. Chapter 8 explains general risk and gives the results of considering the addition of risk to each case study. By determining the expected failure of the modified well cases as compared to the initial ones and associated costs, the reader can see the risk involved with optimizing each base case. The final chapter gives the conclusions of the analysis and recommendations for future studies.

The appendices include additional information that might be useful to the reader. Appendix A outlines various well path designs and commonly used survey calculation methods. Appendix B includes the equations for calculating torque and drag. Appendix C and D are have the data tables from case studies one and two, respectively, and are burnt onto cd's attached to the back of the thesis.

Note: Any text written throughout the thesis denoted in italics is case study specific data.

Chapter 2

Literary Review

To begin my research, I collected and read through several papers that were related to my project and could help me understand the importance of my project in todays oil and gas industry.

2.1 Torque and Drag Modelling

Torque and Drag Modeling can be used during various phases of the drilling engineering cycle. During the operations design phase it is used to determine the feasibility of various well designs. In the drilling stage it is used as a monitoring tool to observe the hole conditions and well cleaning. Post drilling it can be used to compare drilling performance to what was planned for the well and provide information for subsequent wells. The main purpose of T&D Modeling is to analyze the effects of friction on the axial and rotational dynamics of the drilling assembly (Spanos et al., 2003).

To get started, define torque and drag as it is associated with the drillstring and drilling wells. According to Johancsik et al. (1984) drillstring drag is the incremental force required to move the pipe up or down inside the wellbore while torque is the moment required to rotate the pipe. T&D Modeling has become very important in optimizing directional well paths such as high angle, horizontal, and extended reach wells as it proves to reduce the T&D lost in the drillstring by controlling the borehole profile. Due to their complexity, these wellbores tend to be in contact with more of the drillstring and therefore exhibit high friction forces. Johancsik et al. (1984), supported by Sheppard et al. (1987) and Aston et al. (1998), state that friction is the key source in creating torque and drag in the wellbore. The interaction between the wellbore and the drillstring as it moves down the hole will create sliding friction which is a function of the normal force acting on the drillstring and the coefficient of friction. Chapter 4 and appendix B go into more detail on how to calculate friction. Other then sliding friction itself, Johancsik et al. (1984) lists some of the factors that can cause higher friction and therefore increase T&D on the drillstring. They include:

1. Tight hole conditions
2. Sloughing hole - formation falling in on drillpipe
3. Differential sticking
4. Poor hole cleaning
5. Key seating - when the drill collar of another part of the drill string becomes wedged in a section of crooked hole.

By reducing some of these problems in the wellbore, the torque and drag loss on the drillstring will be reduced. Futhermore, from his study of the role that friction plays on T&D values exhibited on a drillstring in a directional well, Johancsik et al (1984) proves that computer models can accurately predict friction factors as compared to those obtained from field data.

Payne and Abassian (1996) take a closer look at different types of torque that have an effect on the drillstring. They describe the total torque measured at surface being comprised of the following:

- Frictional string torque
- Bit torque

- Mechanically induced torque - generated from interaction between drillstring and sources such as cutting beds, borehole ledges, and stabilizer blades digging into formation which can increase torque and drag.
- Dynamic torque - created when the drillpipe is moving in or out of the wellbore in rotation.

They decide that by looking at each component of torque seperately and measuring the amount of torque applied to the drillstring by that component, steps can be taken to reduce some of the factors that increase the torque lost in the drillstring.

As already mentioned Aston et al. (1998) supports the fact that firction forces are the main source of torque and drag on the drillstring. He also notes that in his opinion, mud type and whether the drillstring is in open hole or cased hole help determine the friction factors associated with the drillpipe. They go on to provide ways of reducing T&D on the drillstring in the planning stages of the well such as:

- Optimizing the well profile
- Modifying casing or tubing design
- Changing the mud type
- Ajdusting operating practises

Looking a little closer at optimizing the well path, there are several parameters involved in directional planning that can be addressed and manipulated to reduce the overall torque and/or drag. They include:

- Kick Off Point (KOP)
- Build Up Rate (BUR)
- Inclination

- Azimuth
- Tangent sections
- Target location
- Friction factors

If there are still issues with high torque and drag, Aston et al (1998) have suggestions for other reduction techniques such as adding rotating and/or non-rotating drillpipe protectors, subs, centralizers, and chosing the best lubricants (additives to the drilling fuids).

The main purpose for reducing torque and drag in the drillstring is so that the well can be drilled effectively and efficiently under a variety of constraints. There are certain limitations to the amount of torque and push or pull that can be applied to the drillstring. McKown (1989) explains that the rig capacities will have an effect on the drillstring and well design because the rig has a certain hoisting and pump capacity, and a certain amount of torsional rotation that can be applied to the drillstring at the kellybushing or by the topdrive. If the model indicates higher T&D values then can be applied at surface then the wellpath and/or drillstring design will have to be modified. The limitations of the drillstring itself will be a determining factor in what well path can be designed and what drillstring will be required to drill the well. The strength of the drillpipe components as well as the connections will need to be considered in the planning stages.

Due to the limiting capabilities of drilling equipment and characteristics of the reservoir it is critical to plan the design such that the objectives can be realistically achieved. In this case, the goal is to retrieve the maximum amount of oil from the reservoir as possible during the primary recovery. Changing the well design will inherently test the mechanical limitations on the drillstring, connections and rig equipment and therefore requires analysis as well to ensure the capacity of the equipment is sufficient for the design.

2.2 Well Trajectory Optimization

The first step in trajectory optimization is determining where it will be located and what the well path will look like. Determining where the well path should be placed in the reservoir is dependant on factors such as reservoir location and fluid characteristics, surface equipment specs as well as economic feasibility. In turn these factors will help determine the parameters associated with the actual well design. They include:

- Surface location
- Target location
- Total depth (TD)
- Inclination, KOP, BUR, Max Dog-leg severity (DLS)
- Casing program
- Mud program
- Bottom hole assembly (BHA) program
- Bit program
- Geological program
- Equipment specs (including drill string)

It is often difficult to determine which parameters will be kept constant and which will be optimized to get the overall optimal well path.

If one were to attempt to optimize well path with all of the parameters, certain models would be necessary in order to achieve this. Guyagular and Horne (2001) developed an algorithm HGA (Hybrid Genetic Algorithm) to allow the combination of all the possible design criteria in both the reservoir and well design and provide outputs based on the most optimal solution. The HGA combines an optimizational tool with a numerical model to reduce the computational burden of making many simulations for optimization.

Yeten et al. (2003) use a simular approach for optimizing nonconventional wells (deviated, horizontal, extended reach). He also uses a genetic algorithm (GA) for the optimization procedure. As already metioned, the GA requires several simulation runs and in order to reduce this number, however, Yeten accelerated the process by introducing 3 "helper" algorithms. According to Yeten, there are several other researchers that have developed optimization tools for the purposes of optimizing the wellbore such as using the GA, Polytope search methods, Tabu search methods, Kriging along with reservoir simulations.

Amara et al. (1990) uses a little different approach in their attempt to optimize the well trajectory. They look at each of the design parameters seperately and optimize each of them before placing them in the "Offshore Directional Drilling Advisor" (ODDA) which then models the well path and the optimized parameters.

Yet another option is to optimize only certain parameters while keeping others constant to reduce the number of simulations required to do the analysis. Even with this type of optimization, there could be significant impacts on the production rates and drilling performance. One parameter that could be optimized is the drillstring design, especially important in high angle wells. As McKown (1989) explains, it is necessary to first understand the required functions of the drillstring and its importance in overall well design. The major factors limiting the drillstring performance are the torque and drag forces that will be acting on the drillpipe downhole. These forces are largely dependant on the well profile. Other factors to consider when optimizing the drillstring are rig capacities, hydraulic requirements, and any drillstring accessories that are required such as stabilizers, centralizers, or heavy weight drillpipe (HWDP). Knowing the limitations of the drillstring with respect to its tensile and torsional capacity, compressive strength, and previous wear, are critical in high angle wells where high bending stresses can occur. By determining where loads are acting on the drillstring it can allow one to optimize the design and subsequently optimizing the trajectory of the well.

Eissa (2001) decides to optimize the bit and fluid type used to drill a horizontal well which in turn will improve drilling efficiency. Drilling fluid (commonly refered to as drilling mud) is essential for drilling a well as it transports cuttings to surface, lubricates the bit, maintains wellbore stability, and provides many other important functions. There were two main systems of drilling muds available at the time Eissa wrote this paper, water based and oil based muds, each having characteristics and properties that can be optimized for a certain drilling application. Eissa optimizes the mud system to be used in future wells by analyzing data from previous wells. Using information from offset wells (wells that have already been drilled in the area and/or of simular design) can help identify any problems or issues that may have been associated to the drilling fluids used and help choose the best possible system for any future wells in the area.

Drillbits are continuously being modified to fit varying geological conditions, lowering loss time and costs by requiring less trips in and out of the hole to change the bit, increasing Rate of Penetration (ROP), and so on. Again, Eissa looks at what was used previously to help determine what will be used for future wells. From his research, he determines that PDC (polycrystalline diamond cutters)bits with suitable cutter sizes for each formation hardness and redesigning nozzle size to optimize bit hydraulics will increase horizontal drilling performance. As can be seen from his results both choices lead to higher ROP, less bit runs, lower costsm abd higher production rates from having a better hole.

Another optimization study was completed by Shokir et al. (2004) to find the optimimum drilling depth of directional and horizontal wells. They too use a genetic algorithm optimization tool to find minimum values for KOP, inclination and BUR. From their research, they find that these minimums reduce dog-leg severity (DLS) and therefore reduce overall drilling operational issues.

Overall, there are a number of methods used to optimize the well trajectory. It is important to determine the objectives that are to be achieved and the resources available to do the job before choosing the method most suitable for a particular application.

2.3 Well Production Optimization

As discussed in the introduction, the reservoir well simulation tool used in the research for production optimization of the horizontal wells was $NETool^{TM}$. This tool was used for four main reasons:

1. readily avaliable
2. user friendly
3. models production fluids flowing from the reservoir and through the wellbore
4. incorporates well placement

This is supported by Ouyang and Huang (2005) who used this tool for their analysis of well completions. To them "this program fills the gap between conventional reservoir simulators and current well hydraulic simulators". It is a great tool for analyzing horizontal well production.

In general, there are several parameters that affect production rates in the reservoir. These will be discussed in more detail in a later chapter. For now, some of these parameters are:

- reservoir parameters including porosity, permiability, oil/water contact
- well location

- completions
- production scheduling
- well direction plan
- bit design
- BHA design

For this research, all parameters except the well plan remained constant to help optimize production rates. This was necessary in order to simplify the number of variables present in the system for comparison. The well design was manipulated by changing the inclinations and azimuths in order to obtain higher production rates from the reservoir. This was achieved by manually changing that parameter, essentially a trial and error process, but having some previous experience in the area of well design to help with the process. Rennau et al. (1999) used a simular approach when trying to optimize the Al Shaheen field in Qatar. The project began in 1992 and over the four years of drilling they were able to optimize the the production rates simply by evaluating the parameters listed above and modifying them to create a cost savings of 18% from four years prior. This is further supported by Pinto et al. (2001) who also used previous experience to help design wells that allowed high production rates by looking at a series of parameters including completions, gas lift, and others.

In my analysis, the production from the reservoir was considered at a specific moment in time in order to reduce time required to complete the study. Some studies have considered the value of time-dependant information to make better decisions in terms of reduced uncertainty and increased NPV (Net Present Value). Ozdogan and Roland (2004) used this approach to determine the value of time-dependant information. From their research, they were able to prove that the new approach of combining this with optimization would not only maximize the prior information level but maximize the production rate as well.

Another option for optimization based on time placement is real-time analysis. Sapirtelli et al. (2003) used real-time data to combine well placement and reservoir optimization. Data from a well as it is being drilled can provide information to make decisions on how to optimize the design, completions, and the overall production rates. From their study, they determined that the real-time data did indeed improve field economics by creating a more efficient well design, optimizing the completion configuration and reservoir stimulation strategy.

Nyhavn et al. (2000) also used real-time field data to improve reservoir characterization and accelerate production by utilizing Permanent Monitoring and Control Systems (PMCS). With this system, the researchers were able to determine that real-time systems contributed to reservoir optimization but differed depending on the particular function for which the system was being used. It was more suited for physical processes having short time constants and large amounts of data that were two large for handling maunally.

The methods used to calculate production optimization are the same as those for well optimization because regardless of the application or function to be analyzed the basic concept of optimization is the same. Just as genetic algorithms were used for trajectory optimization, they can be also be applied to reservoir simulation based on this principle. Bittencourt et al. (1997) backs up the principle by applying a hybrid genetic algorithym to evaluate the reservoir parameters listed earlier in order to optimize reservior development and therefore the best economic strategies. The HGA (developed was based on three direct methods including the GA, a polytype search, and Tabu search. The objective function they used was net cash flow. From their study, they concluded that the HGA did provide more profitable strategies for reservoir development.

Cullick et al. (2005) also chose a hybrid approach for the optimization of subsurface locations for producing and injecting wells. The optimization solver included using global search methods such as Tabu search, scatter search, linear programming, and neural networks to provide a set of new well locations based on productions of ultimate recovery and NPV.

Another approach used by Fang and Lo (1996) to generate a well management scheme for reservoir simulation was the simplex/separable programming technique. This method was non-linear in nature and could handle production optimization under several constraints and can be used for full field simulation. The results of their study proved that the new scheme gave results of higher oil production rates then other approaches used in two full field models (Fang and Lo, 1996,p.120).

Lastly, Kalla and White (2005) used yet another method to optimizing reservoir production. They employed design and response surface models to analyze the reservoir. From their study they determined that response surfaces using classical polynomial models and high-dimension Kriging can be used more quickly then numerical models to optimize the reservoir. The model chosen is based on the number of parameters used, the importance of each parameter, and the number of runs chosen. Each model has its limitations and viable uses but no matter what method is chosen, there is inherent uncertainty in the reservoir and a measure of risk in production optimization. This leads into the last section.

2.4 Risk Analysis

As with almost every event in time and place, there is a level of uncertainty or risk associated with the probability of success or failure. There is a distinction between risk and uncertainty; uncertainties being unknown variables and risk being things that can go wrong (Peterson et al., 2005). There are also various ways in which one can measure risk and uncertainty and find better ways to manage it using risk management strategies. As Peterson et al. (2005) discussed in their paper, risk management is a process that combines two defined forms of risk and uncertainty analysis - qualitative and quantitative.

Qualitative risk analysis uses methods that prioritize risk by providing the context of a scenario, listing all the risks associated with that scenario and ranking them in order of their impact on the event. Quantitative analysis gives a measure of risk or uncertainty by analyzing the prioritized risks outlined in the qualitative analysis and the values designated to them.

There are various probabilistic techniques used to measure risk including the Monte Carlo simulation, exponential distribution models, probabilistic estimating, decision trees, and many others designed to provide more accurate information about the uncertainties in a particular situation.

Risk and uncertainty can be applied to almost any situation but to relate it to this research we will take a closer look at how risk is applied in the oil and gas industry and then more specifically for drilling and reservoir engineering. Quantifying risk and adding it into drilling and production operations provide oil companies with a better understanding of the potential for loss with respect to injury, time, and money. Risk has become more important in recent years with the more advanced technology and increased complexity of the industry and its many facets (Lewis et al., 2004). It is necessary to have a good grasp on potential problems that can occur down hole while drilling and the consequences to the company. Due to the unlimited number of scenarios associated with oil and gas production, risk-based approaches help to focus and shortlist valuable scenarios. An important tool which was used in this research was a risk (cost/benefit) analysis which provided information about the costs associated with a specific event and the benefit of carrying out that event. If the costs were greater then the rewards then it would not be realistic to carry out that scenario. The likelihood of success of the scenario (part of risk assessment methodology) will help determine if it is worth the risk to potentially reep the rewards.

In general, companies will base decisions on this concept also known as return on investment (ROI). For oil and gas companies the ROI is based on the following (Lewis et al., 2004):

1. The core projects or producing reserves
2. Enhancing or redeveloping existing fields
3. Investments
4. High risk projects that may make or break a company

The ROI for oil companies is measured as:

1. Economic Value added
2. Payback
3. Net Present Value (NPV)
4. Internal rate of return (The interest rate an investment earns when the present value of all costs equals the present value of all returns)

The last three being the ones used most often to measure the benefits to the company.

Focusing now on drilling engineering, risk analysis has been used extensively in recent years to better estimate the risks associated with various drilling operations. There are many unknowns when drilling a well that have a level of uncertainty associated with them as Lewis et al. explains in their 2004 study. They include:

- Rate Of Penetration (ROP)
- Differential sticking
- Formation characteristics
- Loss circulation
- Downhole failures
- Borehole instability

- Well control
- Human error

If carrying out a simple cost/benefit analysis using these variables, one would assign a value to each input and determine how likely it would occur in a defined scenario. It is up to the user how many variables they choose to use in the model and the likelihood it will occur in real life. The more inputs considered, the more complex the model but the more accurate or realistic the results will be. A good tool to use for large amounts of data is the Monte Carlo simulation. This is backed by Lewis et al. (2004) who states "the employment of statistical uncertainty analysis using Monte Carlo Simulations is the best way to vary a large number of inputs over a varying range of known or suspected values".

Cunha et al. (2005) also used Monte Carlo simulation to determine a cumulative distribution function for expected well costs. The Monte Carlo simulation was carried out with 16 items of uncertain costs associated with drilling an offshore well and randomly varied and combined with other costs. The simulation was repeated 500 times, each time taking one possible cost from the 16 uncertainties and adding it to the fixed cost for drilling the well. The results provided the engineer with more information to help prepare the Authorization for Expenditure (AFE).

Akins et al. (2005) develop a drilling and completions time and cost model which can be used throughout the well life cycle. Probablistic estimating is a method for forcasting time and cost of a drilling project. Each operation is outlined step by step and a time and cost is assigned to it based on offset well information; probability of occurance of events representing productive and non-productive time (NPT). As the saying goes, "time means money" and using this method engineers are provided with a tool that can be used to understand the possible time and cost outcomes about various operational steps and make better decisions about what to do or what to be prepared for should a certain event happen.

Lets take a look now at the combined risks and uncertainties assocaited with drilling and reservoir engineering. As already mentioned, the more parameters included in measuring uncertainty the more accurate the level of risk will be, which can help decision makers choose well designs that have lower risk and more benefit.

The reservoir itself has a huge level of uncertainty assocaited with it because of its complexity. Some of the uncertainties are:

- The geology/lithology of the reservoir
- Petrophysical Properties
- Stresses on the rock
- Properties of the fluids in the reservoir
- Amounts of fluids in the reservoir
- Rock/fluids interactions

There are many tools such as Measurement While Drilling (MWD), gamma ray tools, neutron tools, and so on, that can provide some useful information about these uncertainties while the well is being drilled. Decision makers will use this information to extrapolate data for future offset wells in the same area. This may help lower the uncetainties existing in the reservoir.

In 1999, W.A. Aldred wrote a paper about *PERFORM*™, a *Schlumberger*® tool that provided a framework for risk management and loss control. Combined with technical experience and knowledged personnel, it helped enhance drilling performance. Specific areas that were analyzed were:

- Drillstring failure
- Stuck Pipe

- Wellbore Stability
- Drilling efficiency and ROP
- Pore pressure analysis

This tool has been used all over the World to measure loss associated with operations, processes and profit. Its main purpose is to provide information and analysis of the current and future state of the well so that decisions can be made as far ahead of a situation as possible. By informing engineers early in the process of potential risks, decisions can be made to mitigate it as quickly as possible.

Another tool that has been used in drilling and reservoir operations is $FIELDRISK^{\text{TM}}$. Discussed by Irrgang et al. (2001), this is a knowledged-based drilling system combined with a probabilistic cost and risk assessment tool. It integrates drilling, reservoir, and development risks using previous field data to give more accurate estimates of cost and risk. This tool has also been used over the World to help analyze risk associated with drilling a well in a particular location.

No matter what tool is used to calcualte uncertainty and associated risk in drilling a well, the fact remains there will always be unknowns. It is up to decision makers to have the best, most reliable information and tools available to them to provide a measure of the amount of risk in order to determine if it is worth drilling a well. Economics plays a major role in this decision. Incorporating risk at any level is more valuable then excluding it from the well design process.

Chapter 3

Reservoir and Well Flow Simulation

3.1 Reservoir Simulation Tool

The simulation tool that was used in the research was $NETool^{TM}$, a product from Drilling Production Technology (DPT) AS. It is a steady-state detailed completion modelling and well planning simulation tool. It simulates fluid flow through the reservoir, annulus, and wellbore. From the $NETool^{TM}$ User Guide (2004) there are three main functions of the NETool program for the user. They include:

- Estimate the behavior for a given reservoir with associated well design through interactive well placment selection and suitable pressure drop correlations.
- Provides an understanding of the well deliverability by combining reservoir effects and completion design effects. In other words, it is filling the gap between conventional reservoir simulation tools and well hydraulic modelling.
- Allows fast upscaling of detailed reservoir data along with completion details to model multiphase flow in the wellbore and inflow from the reservoir.

As just mentioned, NETool can simulate single phase and multiphase fluid flow through the well completions and wellbore. These two regions are represented by a series of nodes that are connected via flow channels. There are two main types of network configurations used in NETool. They include:

1. NETool Node Configuration

    - As Represented in Figure 3.1 the top row of nodes represent the reservoir, the middle row of nodes represent the annular region and the bottom row, in this case, corresponds to the inside of the the production tubing/liner. The blocks joining the nodes represent the inflow peformance relationship (IPR) based on local upscaling of reservoir permeability.

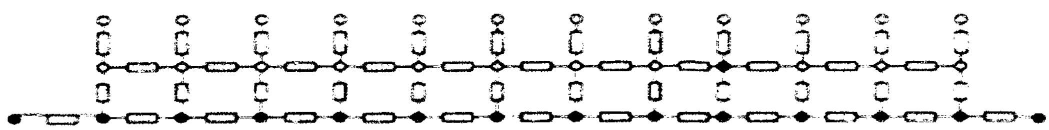

Figure 3.1: *NETool*™ Node Configuration

2. Node Configuration for Downhole Surface Adjustable Valve Completion

    - Typically used when flow from a long reservoir is controlled by a single entry point into the production tubing, through the completions and seperated by a series of packers. See Figure 3.2.

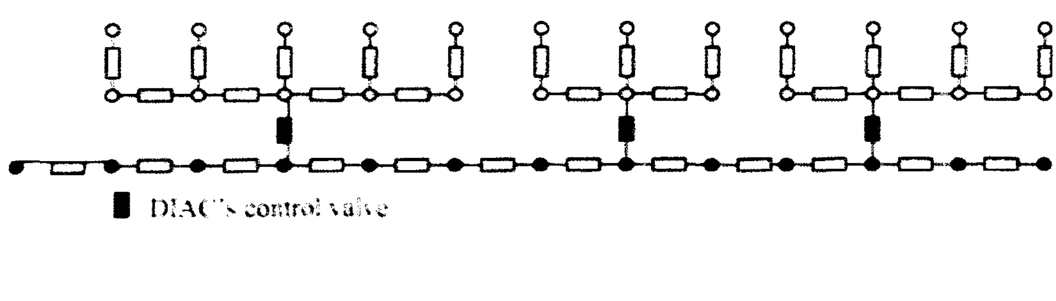

Figure 3.2: *NETool*™ Node Configuration for DSAV Completion

Mathematically, NETool is based on the conservation of mass and momentum of the components of the three phases in the system: oil, gas, and water.

3.2 Implementation in Research

NETool is a great tool to use for reservoir simulations because it reflects real life situations in the reservoir and wellbore. The purpose of using NETool for the modelling and analysis of the data was to characterize the reservoir, the completions, and well design in order to determine the well cases that provided comparatively increasing rates in productivity. More specifically, the portion of the well path from its entry point into the reservoir to the toe (end point) was modified by moving the trajectory points from their initial positions to arbitrary locations in the reservoir to create new paths. With the greatest detailed reservoir information, NETool quickly calculated the overall production performance of the well. It also gave inclination, azimuth and measured depths that would be exported into a torque and drag modelling program to determine its drillability. The name of the reservoir used for this analysis was the *Beta* reservoir.

In order to redesign the existing well paths in the *Beta* reservoir, there were several parameters that were kept constant and these are explained in detail in section 3.7. Some of these were default values from the program and others were inputs from the well case. This was necessary so that the only variable for comparision would be the production rates. To calculate the production profiles along the path in the reservoir, NETool used a solver, which is explained in more detail in the next section.

3.3 NETool Solver

NETool uses a network of nodes like that in figure 3.1 for single-phase and multiphase systems with several assumptions and boundary conditions, to calculate the pressure in each node, flow rate between the nodes and phase fractions. Figure 3.3 represents a simple, specific node configuration with the top row of nodes representing the reservoir and the middle row of nodes representing the internal flow of fluid through the annulus, and the bottom the flow through the tubing, all connected by a series of bridges. The simple configuation below was used as an example to describe the principles of the solver.

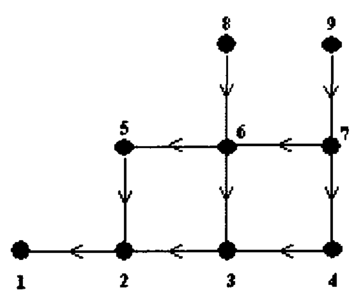

Figure 3.3: $NETool^{TM}$ Solver Configuration

The nodes are numbered from one through nine. For the sake of simplicity we assumed undersaturated, isothermal conditions for the system. The boundary conditions are given as:

- Pressure at each reservoir node, denoted P_k^*
- Either: Total outlet volumetric flowrate, Q^*, or pressure at the node connecting to surface, p_{bh}^* (node 1)
- Saturations (100%) at the reservoir nodes for multi-phase runs

The unknowns for the system are the node pressures (p_i), oil volume fractions in the bridges between two adjacent nodes ($\alpha_{i,j}$), and the total volumetric flow rates in the bridges ($q_{i,j}$). In order to solve for the unknowns the first step is to set up the material and momentum balance equations as well as the boundary condition equations.

Material Balance Equations

For the material balance, it will be assumed that it is a single phase flow oil system. Therefore for the oil volume fraction, $\alpha = 1$, and with our general equation in the form

$$\Sigma \left(\frac{1}{B_o(p_k)} \times \alpha \times q \right)_{k,j} = 0 \tag{3.1}$$

Breaking it down for each node with $\alpha = 1$ you get

Node 2:

$$\frac{1}{B_o(p_2)} \times (q_{23} + q_{25} - q_{12}) = 0 \tag{3.2}$$

Node 3:

$$\frac{1}{B_o(p_3)} \times (q_{34} + q_{36} - q_{23}) = 0 \tag{3.3}$$

Node 4:

$$\frac{1}{B_o(p_4)} \times (q_{47} - q_{34}) = 0 \tag{3.4}$$

Node 5:

$$\frac{1}{B_o(p_5)} \times (q_{56} - q_{25}) = 0 \tag{3.5}$$

Node 6:

$$\frac{1}{B_o(p_6)} \times (q_{68} + q_{67} - q_{56} - q_{36}) = 0 \tag{3.6}$$

Node 7:

$$\frac{1}{B_o(p_7)} \times (q_{79} - q_{67} - q_{47}) = 0 \tag{3.7}$$

Assuming single phase oil flow, B_o is given by

$$B_o(p_k) = \frac{B_o^*}{1+C_o(P_k - P^*)} \tag{3.8}$$

The momentum balance equations are used for each bridge in the network. The equation takes the general form

$$\Delta P = P_{up} - P_{down} = \frac{f\rho v^2}{2D} \tag{3.9}$$

where

$$v = \frac{q}{A} \tag{3.10}$$

and q is the unknown volumetric flowrate accross each bridge and A is the area. For the bridges that signify flow throught the annulus, the diameter of the cross-section is expressed as hydraulic diameter, D_h. For the bridges symbolizing the tubing flow, the diameter, D, is that of the tubing itself.

Assuming turbulent flow in a smooth channel, the friction factor, f is given by Blasius formula

$$f = \frac{0.3164}{Re^{\frac{1}{4}}} \tag{3.11}$$

where Reynolds number, Re, is calculated as:

$$Re = \frac{\rho v D}{\mu} \tag{3.12}$$

The final equations that need to be included in the system are the boundary condition equations. Assuming the pressure in the reservoir is the same as that for nodes eight and nine, the total volumetric phase rate for the bridges joining an external node (reservoir node) to the well are expressed as

$$q_{79} = PI(P_9 - P_7) \tag{3.13}$$

$$q_{68} = PI(P_8 - P_6) \tag{3.14}$$

Here, PI is choosen by the user or upscaling based on detailed reservoir data.

The system of equations represents a single phase oil flow configuration in a reservoir. The system has to be linearized by defining a vector and the associated Jacobian in order to solve for the unknown pressures and flowrates in the system by a Newton-Raphson method.

3.4 Well Case Creation and/or Modification

When a new well case is created or an existing one editted, there are four main areas of interest:

1. Defining the Well Path
2. Defining the Fluid Properties
3. Defining the Model Global Settings
4. Defining the Segment Settings/Completions

Within each area there are parameters required as input in order to simulate the data. As mentioned, for the purposes of this research, every parameter required in NETool was kept constant throughout the analysis with the exception of the well trajectory.

3.4.1 Measurement Units

The units within $NETool^{\text{TM}}$ can be measured in either metric units or field units. The default units are metric but in any case it is important to keep the selection consistant for accurate comparisons.

3.4.2 Defining the Well Path

There are two ways in which to design a well path or edit an existing one. It can be done interactively using the mouse or importing a text file using one of three methods which include using x,y,z coordinates, choosing the directional survey, or choosing reservoir simulation grid blocks and entering the well trajectory in i,j,k coordinates. On NETool's main screen there are two sectional views of the reservoir. As can be seen in Figure 3.4, the top window is the X-Y section looking down on the well path also known as the "birds eye view". The bottom window indicates the depth (z-direction) of the reservoir along the X-Y trajectory of the well.

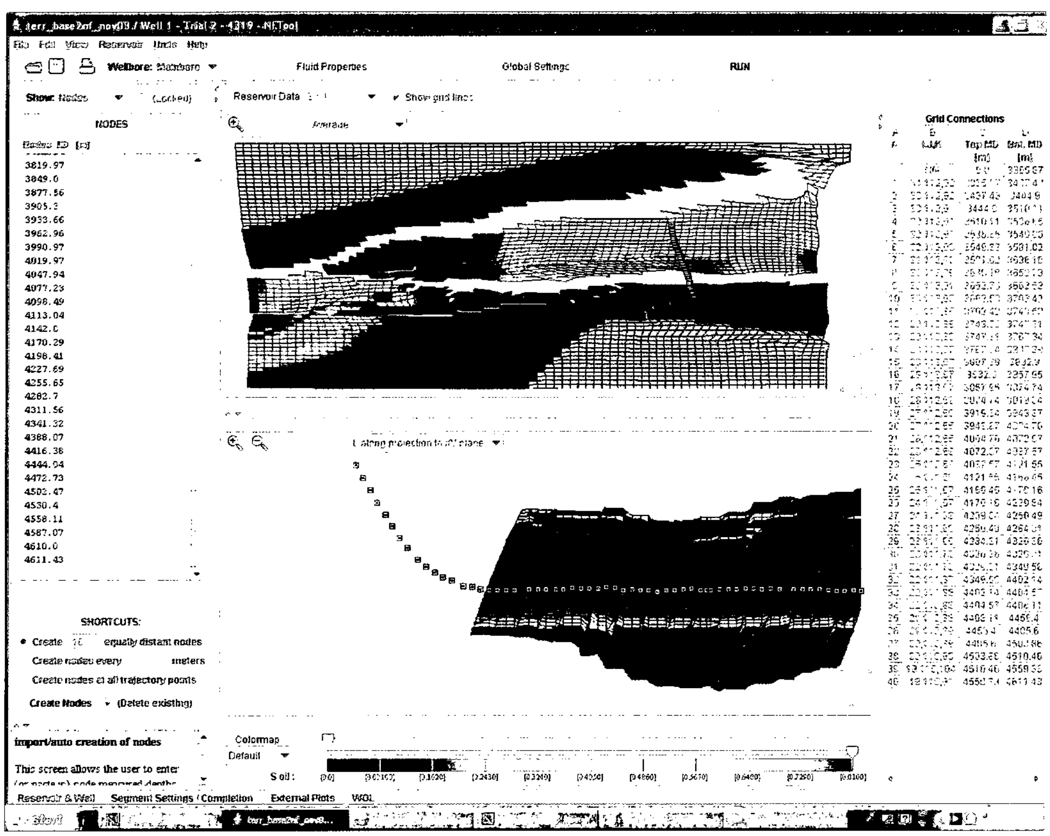

Figure 3.4: $NETool^{\text{TM}}$ Screen

It is important to note that whatever method is used to create the well path, the program has to be in *Trajectory Mode*.

Using The Mouse

To create a well path using the mouse, the user can use the top view to define the horizontal portion of the well and then use the bottom window to indicate the depth of the path. Each point that is selected to define the path is called a node. The lines that connect the two nodes together are, of course, the well path. Any of the points can be editted by placing the mouse on the point, and with the left button down, moving the node to the desired location and then releasing the button when finished. The design can be extended to include multi-lateral wells if required.

Importing/Defining Text File

If importing or defining a well path from a text file is selected, there are three options for inserting the data:

1. Entering x,y, and z coordinates
2. Importing a Directional Survey
3. Import as i,j,k coordinates in Grid Blocks (Eclipse)

The initial well path from ***Well A*** *is imported into NETool by using the directional survey and selecting the Measured Depths (meters), Inclinations (degrees), and Azimiths (degrees) from the definitive survey. The UTM coordinates from the first survey point are also required and given as follows: X(East) 728272.00m, Y(North) 5.184E06m, Z(TVD) 0.00m. NETool converts the directional survey information into UTM coordinates in the trajectory mode. This conversion is only one way. If modifying the well path, the data can only be exported in UTM coordinates rather then as a directional survey or in grid block format. The well path defined for Well A begins at surface and goes to TD.*

*The same method is used for **Well B** as well the only difference being the location of the UTM coordinates from the first survey point. They are in this case: X(East) 728263.600m, Y(North) 5183981.100m, z(TVD) 0.00m.*

3.4.3 Fluid Properties

Within the fluid properties menu, the user can input the water properties, PVT data, relative permiabilty data, as well as the Lift Curve (Vertical Flow Profiles(VFP)) data (see Figure 3.5).

The PVT and relative permiability tables are extracted from the Eclipse Initialization File. The data can be edited at any time if required. The relative permiabilty data for three-phase oil, water and gas is calculated in NETool using either:

- Stone's 2nd Method (Modified)(Aziz & Settari, 1979)

  or

- Eclipse Default method (Schlumberger-Geoquest, 2006)

In both models, the gas and water relative permiabilities are calculated as a function of gas and water saturation $(F(S_g), F(S_w))$ from the values entered in the relative permiability table.

Stone's 2nd Method (Modified)

In order to use this method, the user has to specify the permiability information for a two-phase oil water system and a three-phase system with water at connate water saturation. The following lists the information for two phase/ three phase systems placed in two tables (Eclipse keywords - SWOF/SLGOF):

- Water Saturation/ Liquid Saturation

- Relative Water Permiability/ Relative gas Permiability

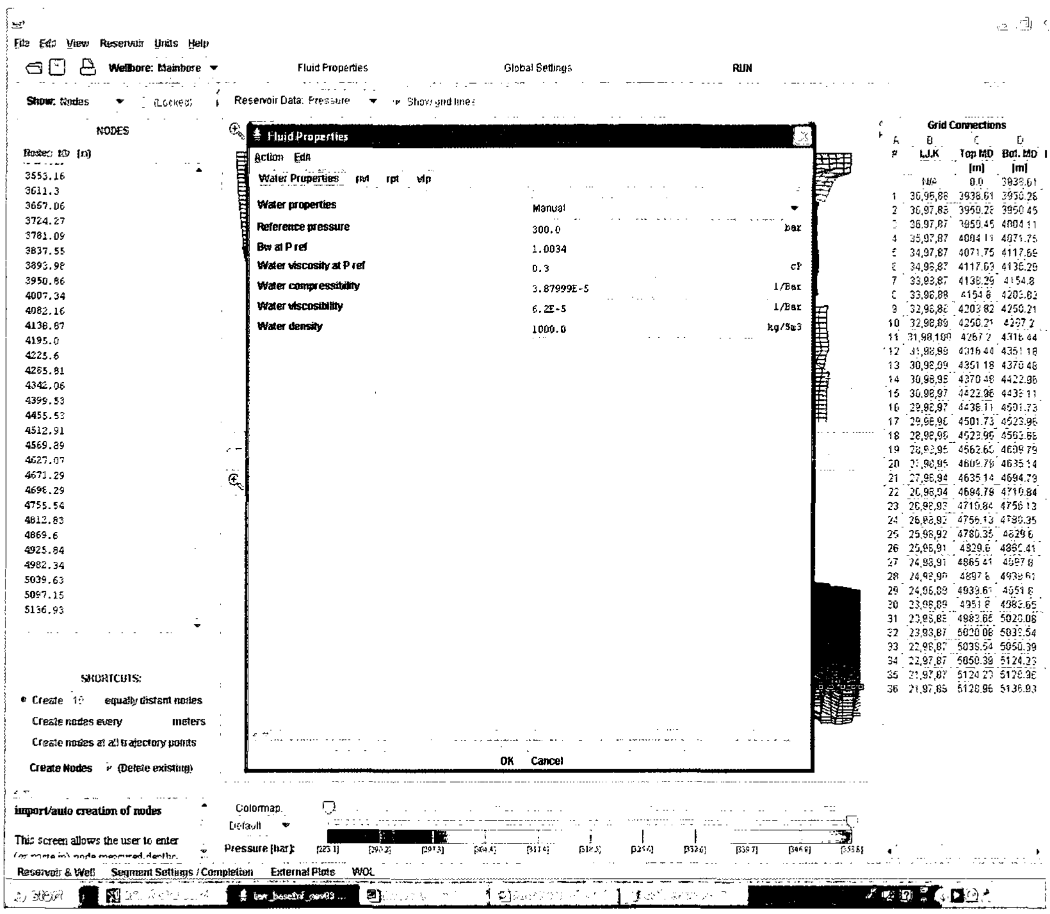

Figure 3.5: Fluid Properties of the Beta Reservoir

- Relative Oil-Water Permiability/ Relative Oil-Water Permiability
- Capillary Oil-Water Pressure/ Capillary Oil-Gas Pressure

The highest oil relative permiability values have to be the same in both phases.

The relative permiability to oil is calculated as

$$k_{ro} = k_{rowcw}((k_{row}/k_{rowcw} + k_{rw})(k_{rog}/k_{rowcw} + k_{rg}) - k_{rw} - k_{rg}) \tag{3.15}$$

It is important to note that $-k_r o = 0$.

Eclipse Default Method

In this method gas and water are assumed to be completely segregated. The following information is required:

- Water Saturation(SWFN)
- Gas Saturation(SGFN)
- Oil Saturation(SOF3)
- Relative Water Permiability(SWFN)
- Relative gas Permiability(SGFN)
- Relative Oil-Water Permiability(SOF3)
- Relative Oil-Gas Permiability(SOF3)
- Capillary Oil-Water Pressure(SWFN)
- Capillary Oil-Gas Pressure(SGFN)

Inside the brackets is the Eclipse keyworded table for which the data is required.

The relative oil permiability is given as

$$k_{roE} \quad = \quad (S_{gE}k_{rogE} + (S_wE - S_{wcoE})k_{rowE})/(S_{gE} + S_{wE} - S_{wcoE}) \qquad (3.16)$$

The Vertical Flow Profile tables are necessary in NETool when the well is controlled by the tubing head pressure. They contain information on the pressure drop for flow up the tubing string and is used by NETool to "convert" the tubing head pressure to bottom hole pressure. For production wells, a production VFP is required and for injection wells, an injection VFP is needed. The only artifical lift option currently in NETool is Gas Lift based on gas injection rates.

The Beta Reservoir for the initial well case was imported as an .INIT file and the .PVT and .RPT files were formed into subfolders. The Beta.INIT file requires the corresponding .egrid or .grid file and therefore the Beta.egrid file is imported. The next step is to import "restart" files if desired as .UNRST files. The Beta.UNRST file is imported at that time. The vertical Flow Profile tables are set up as default based on the other data available for a production well.

3.4.4 Model Global Settings

The *Global Settings Menu* consists of four tabs: General, Inflow, Advanced, and Output.

General

The general control settings are shown in Figure 3.5 for the simulation and include the following:

1. Well Type: Include the type of well to be simulated. There are three selections to choose from:

    - Producer - a well that is producing oil and/or gas

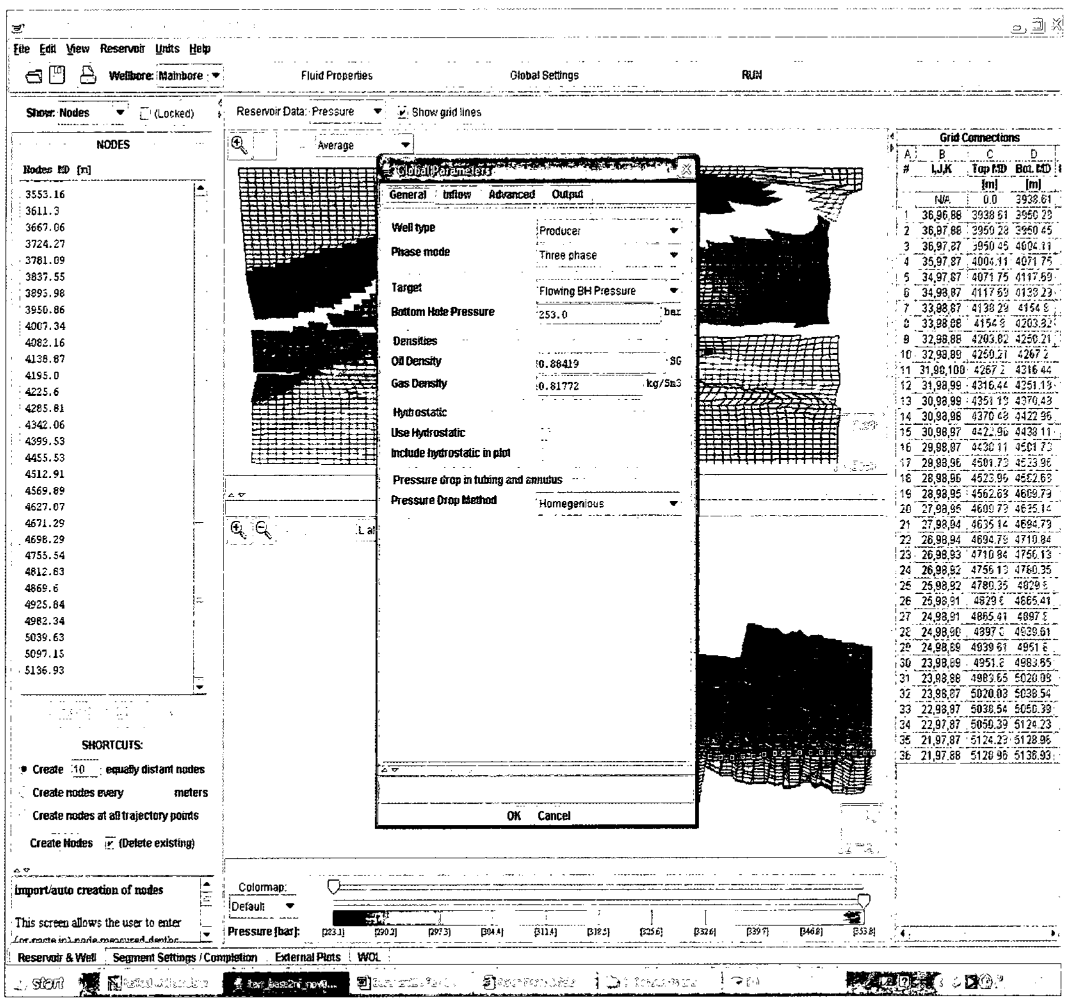

Figure 3.6: $NETool^{\mathrm{TM}}$ General Global Properties

- Water Injector - a well that is injecting single phase water
- Gas Injector - a well that is injecting single phase dry gas

It is important ot note that when injecting water or gas, it is assumed that only gas or water is flowing and the phase relative permiability is one.

2. Phase Mode: This option is only used when the producer well type is selected and there are several options of phases to choose from:

   - Single Phase Gas - assumes single phase dry gas, the flowing fraction of gas is one and the gas saturation is such that relative permiability to gas is one. Non-Daarcy flow is activated in PI-Model through a non-zero Forchheimer coefficient
   - Two Phase Gas, Oil - assumes water is not flowing, otherwise three phase flow. Non-Daarcy flow is activated in PI-Model through a non-zero Forchheimer coefficient
   - Two Phase Oil, Gas - same as Two phase gas, oil except that non-Darcy flow cannot be used
   - Three Phase - uses Black Oil PVT data. For example, gas dissolves in oil only (no oil in gas, no gas in water)
   - Oil Based Emulsion - assumes an analytical model for viscosity as a function of shear rate and water cut. A default model is implemented for this.
   - Water Base Emulsions - Simular to Oil Based Emulsions but for water based emulsions

3. Work With: Flow fractions of oil, water and gas can be calculated based on *Saturations* and relative permiability curves or *Fractions* by directly entering flowing fluid fractions.

4. Target: This is where the boundary conditions are set for the well. There are several options for the target rate and bottom hole pressure as the outlet boundary condition. They include:

- Bottom Hole - if selected as target, specify the flowing bottom hole pressure at the heel node
- Tubing Head - if selected, specify the flowing tubing head pressure. Note: To use this option lift curves are required generated by *Prosper*™ and entered in fluid properties - vertical flow profiles (VFP) section. The Gas Lift Rate is also required if the VFP information includes gas lift
- Total Reservoir Rate - if selected, specify the total bottom hole flowrate and NETool will determine the bottom hole pressure (BHP) that gives this flowrate. Also there needs to be a limiting bottom hole pressure entered. For producers this will be a minimum BHP and a maximum for injection wells
- Oil Flow Rate - if selected, specify the desired flowrate of oil in volumes at standard condition. Again, the limiting bottom hole pressure will be required, same as for Total Reservoir Rate
- Gas Flow Rate - if selected, specify the desired flowrate of gas in volumes at standard condition. Again, the limiting bottom hole pressure will be required, same as for Total Reservoir Rate
- Water Flow Rate - if selected, specify the desired flowrate of water in volumes at standard condition. Again, the limiting bottom hole pressure will be required, same as for Total Reservoir Rate
- None, Make IPR - if selected, NETool will create an IPR curve for the specified starting and ending BHP in the number of steps specified. There are no pressure and flow rates specified

5. Densities: Specify the oil and gas densities at stock tank conditions.
6. Hydrostatic Pressure: There are three boxes to select different options about the how to handle the hydrstatic pressure in NETool. They include:
    - Use Hydrostatic - if selected, the effect of TVD differences along the well are included in the calculations

- Include Hydrostatic in Plot - if selected, hydrostatic pressure is included in the tubing and annulus pressure plots. Note: If *Use Hydrostatic* is selected and *Include Hydrostatic in Plots* is not selected, the effects of hydrostatic pressure is included in the calculations but then subtracted when the tubing and annulus pressures are plotted. If *Use Hydrostatic* is not selected and *Include Hydrostatic in Plots* is selected, the effects of hydrostatic pressure is not included in the calculations but is added to the plots in the results.
- Add Hydrostatic to Pres - if selected and the reservoir pressures are manually entered (including taking it from a log), the hydrostatic pressure due to differences in TVD along the length of the well is added to the reservoir pressure used in the NETool calculations.

  This option has no effect if *Use Hydrostatic* is not selected.

7. Pressure Drop in Tubing and Annulus: There are three methods currently supported by NETool for calculating the pressure drop of flow of fluids in the tubing and open annulus. They include:

    - Homogeneous - used in single phase flow calculations using average density and viscosity of the flowing phases
    - Beggs and Brill - uses two phase (gas and oil) flow correlations
    - OlgaS2000 - only appears when the OlgaS2000.dll from Scandpower is available. This is an add on feature to NETool

Inflow(PI Models)

To account for the complete range of of deviations of wells, NETool incorporates both vertical and horizontal productivity index (PI) models. Vertical wells are characterized as having $0^o - 10^o$ deviation from vertical and in this case, vertical well PI models are used. For deviationd from $10^o - 80^o$ a combination of both models are used. Horizontal PI models are used for wells with deviations from vertical greater then 80^o.

There are two ways of calculating PI in NETool. The first is steady state in which NETool assumes that there is a constant pressure support for the reservoir. The semi-steady state PI model assumes that there is a constant pressure drop accross the reservoir. Figure 3.6 shows the tab for the Inflow information used in NETool.

Advanced

In the *Advanced* tab shown in Figure 3.7, the precision of calculations is set which indicates the error allowed in the simulation. The stability value is also set as the minimum flowrate that will be allowed in NETool. The NETool solver will not allow a zero value for the local flowrate and dependant on the flowrate case, the value may be as small as $1E^{-8}Sm^3$/sec or even smaller. Another section in *Advanced* considers that flow can change directions. There are four selections for possible cross flow situations. They include: in tubing, in annulus, in annulus/tubing, and in reservoir annulus.

The next section in the *Advanced* tab is the Flow Mode. It includes the option of treating laterals as independents. This option is only applicable in multi-lateral wells. The other option is to allow laminar flow. If selecting this option NETool will use both laminar and turbulent flow models.

Output

The *Output* tab is the last tab under the Global parameters and is shown in Figure 3.8. Under this tab the user can select the various plots they want to view after they run the simulations.

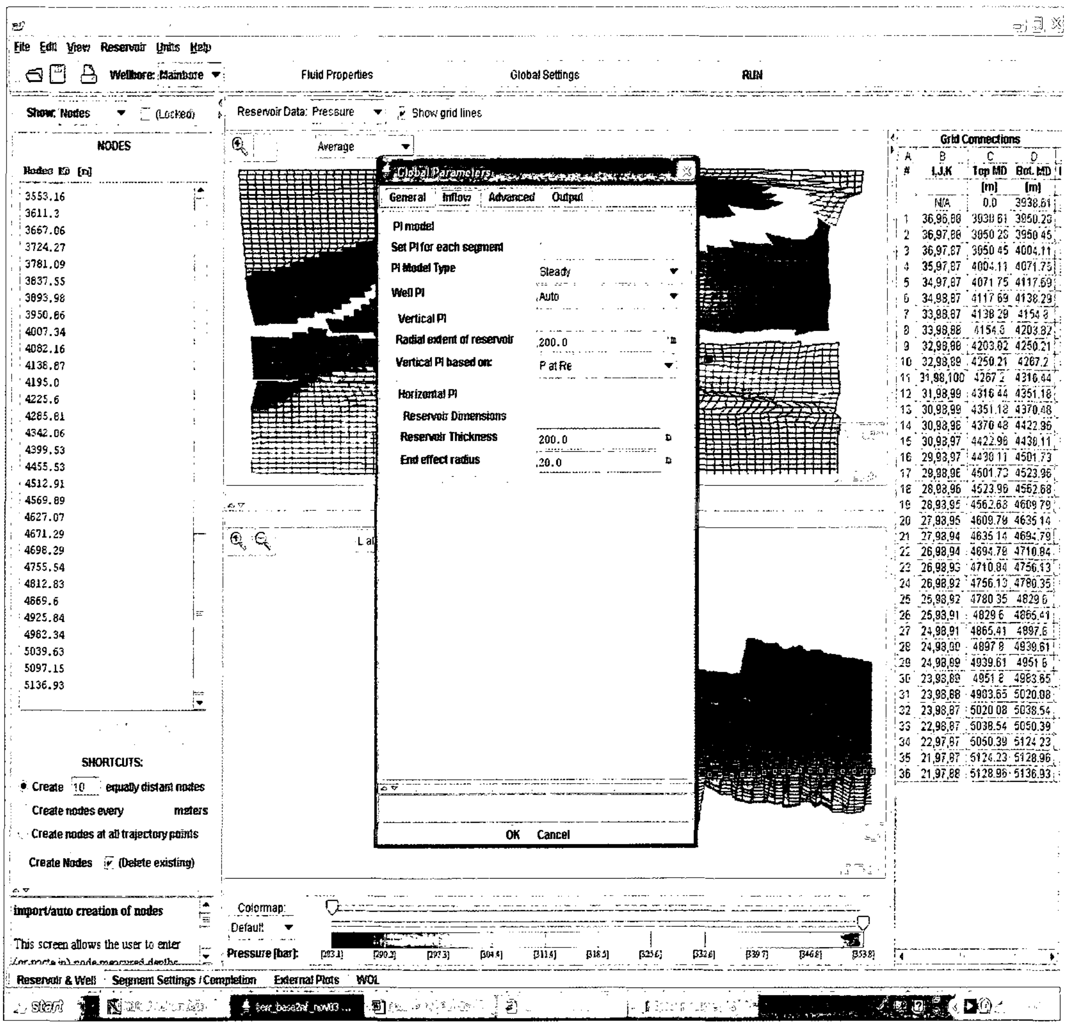

Figure 3.7: $NETool^{\mathrm{TM}}$ Inflow Global Properties

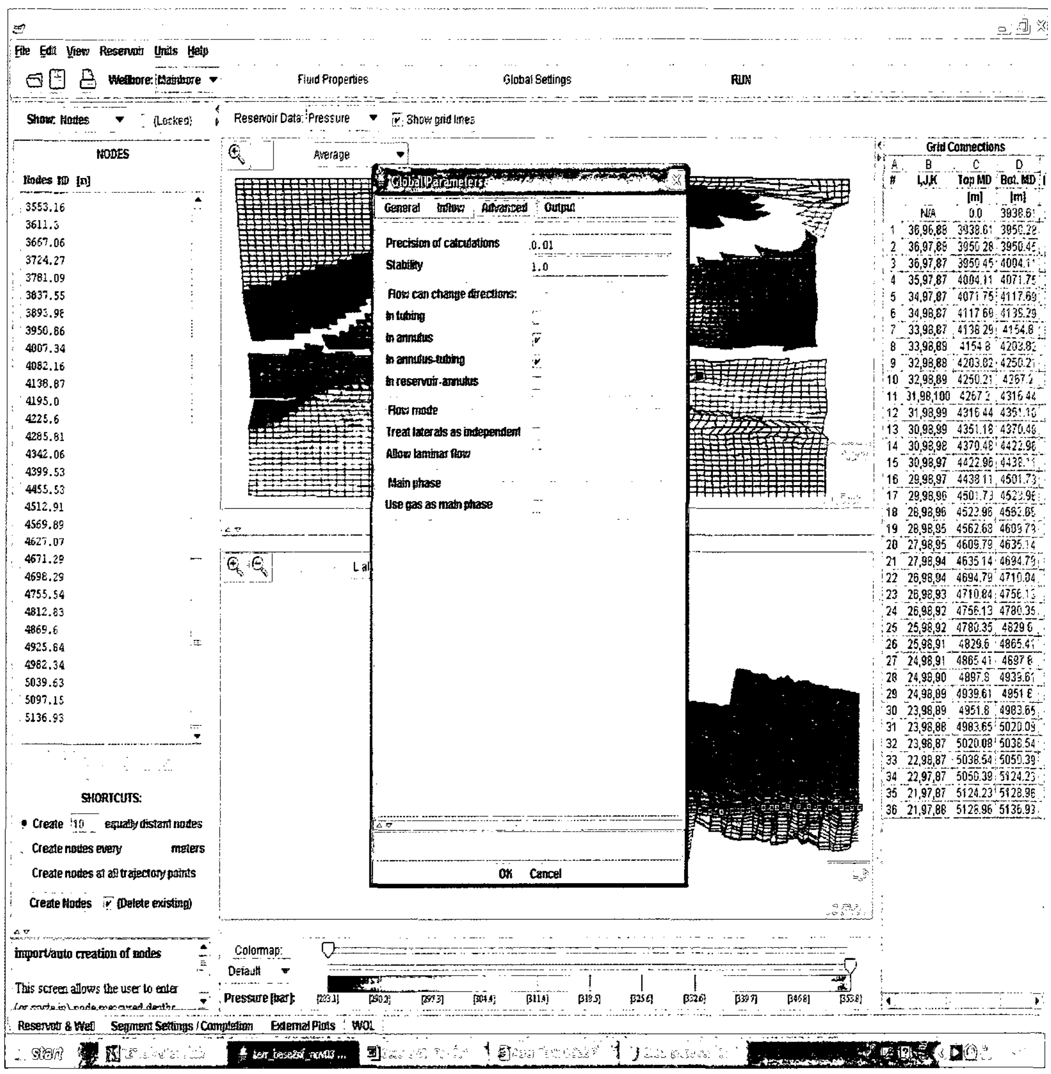

Figure 3.8: $NETool^{\text{TM}}$ Advanced Global Properties

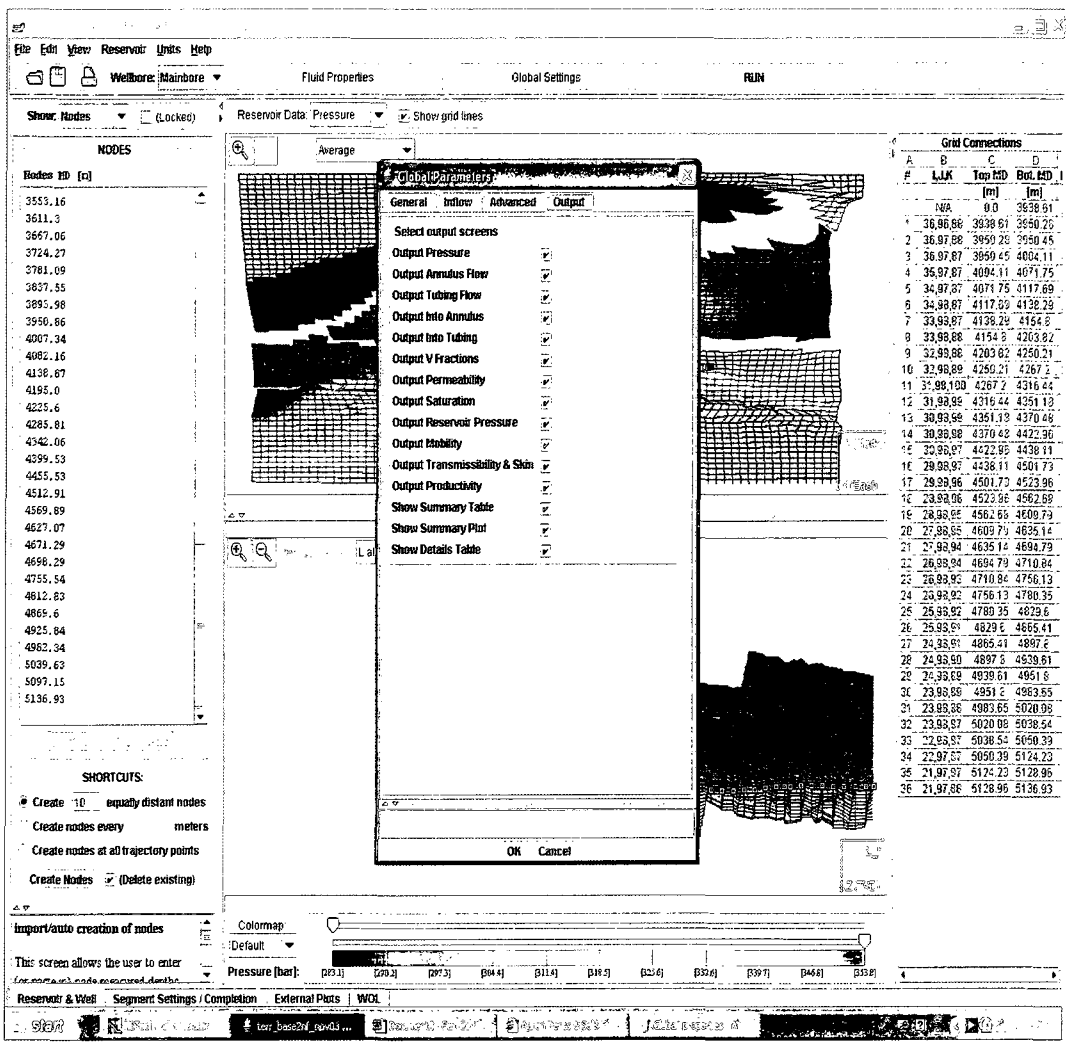

Figure 3.9: $NETool^{TM}$ Output Global Properties

3.5 Segment Settings/Completions

The last step in creating a new well case or modifying an existing one is defining the completions for the well. NETool allows for either simple or advanced completion settings depending on the reservoir details and company requests. On the Segment Settings/Completions screen the user has to select the type of completion by first selecting the completion type and then the parameters for that specific completions type. Some of the various types of completions include open hole, wire-wrapped screen, and perforated cemented liner, to name a few. Other options from which to select are the reservoir parameters including reservoir pressure and permiability, liquid components including oil and water saturation, as well as the skin factor. These parameters are selected for each segment of the well. The last option under the completions settings screen is the Advanced folder. Within this folder the following are the input items:

1. Number of Intermediate Nodes
2. Inner Tubing Roughness
3. Annular Space Roughness

Once the well case is completed the user has to select the RUN button to run the NETool simulations.

The completion details that were assigned to the base case wells when they were designed by the company for the field were perforated cemented liner. Without a background in completions, it would be difficult to maintain the same completion design as the well changed. Perforations are designed for different areas of the reservoir and can vary in number and it would be difficult to keep it consistent when the well was positioned in different locations. Therefore, in order to eliminate the completions variable, an open-hole wirewrap screen was selected from the entry point into *the reservoir to the toe for all wells, including the base cases, in this research. This was used consistently throughout the analysis.*

3.6 Assumptions

The *NETool*™ Simulation Tool is based on some general underlying assumptions as listed in the *NETool*™ User Guide (2004). They include:

- Flow is steady state.
- Flow is locally 1-Dimensional (i.e. between two adjacent nodes).
- Flow through the Reservoir is incorporated into network locally through up-scaled properties for each segment along the well path.
- Three phase behavior calculations are based on pre-generated PVT tables for the hydrocarbon system, treating water as an independant phase.
- Network geometry is general to allow simulation of any completion type in the list, and yet simple enough to satisfy requirements for computational efficiency.
- For pressure drop, the momentum equations are replaced by correlations. At the junctions the flow is treating by simple relationships.

3.7 Constants

As explained earlier, there are several parameters used throughout the research that have been left constant because of the need to eliminate variability in the results. The values for the parameters listed below came from the initial well design and field, except for the completions design, which was explained in the last section. The objective was to achieve higher production rates and in order to do this other information needed to stay consistant and therefore constant. The following outlines the different parameters that were inputs and remained the same throughout the optimization procedure in NETool.

1. Units - Metric
2. Well type - Producer
3. Phase Mode - Three Phase
4. Target - Flowing Bottom Hole Pressure = 253 bar
5. Completions - Open Hole Wire Wrap Screen

Choosing a constant value for the bottom hole pressure created a boundary condition for the system and allowed the flowrate to vary with the changing well path. All other data in the properties tabs were defaults and based on the reservoir characteristics.

Chapter 4

Well Design

4.1 Well Design Tool

The well design and analysis tool that was used to assist in production optimization was *Schlumberger's*™ *PowerPlan*® Suite. It is a well design optimzation tool that assists in reducing drilling costs and minimizing risk within the wellbore. Within the *PowerPlan*® suite, there are several software modules that are used for the optimization.They include:

- DataBrowser
- BHA (Bottom Hole Assembly) Editor
- Survey Editor
- Well Design
- DrillSafe

DataBrowser has to be set up first because it creates the database structure for the project. The BHA Editor, Survey Editor and Well Design can be done independantly of each other however DrillSafe requires all these be set up before running torque and drag analysis. There are other modules as well but they are not necessary for this research.

4.2 Implementation in Research

The PowerPlan suite was chosen as the analysis tool for this research for two main reasons. My familiarity with the program from previous optimization work made it the obvious choice for this study. It is a very user friendly program once you get accustomed to the different modules. The second reason for using this program is that it is used widely in industry and is compatable with Microsoft Excel. DrillSafe provides a very precise torque and drag modelling program that allows the user to choose single or multiple friction factors and select from various operating modes which are explained more in section 4.1.5. The primary function of PowerPlan for the study was using the torque and drag program however, in order to use this tool Databrowser, BHA Editor, and Well Design were also important in obtaining the results.

In order to accurately model the torque and drag forces acting on the drillstring, there were several parameters that were keep constant throughout the analysis. They are described in more detail in section 4.5.

4.3 *PowerPlan*® Modules

The following sections provide descriptions of the five major modules used in this research from the *Schlumberger*™ *PowerPlan*® Technical Manual, May 2004.

4.3.1 DataBrowser

The DataBrowser is analogous to Windows Explorer in that it gives you a directory of every file and its location. It uses a heirarchy system to create a directory tree. It includes the field, structure, slot, well, borehole, and target for each and every well in the system. Figure 4.1 shows the databrowser directory for this project.

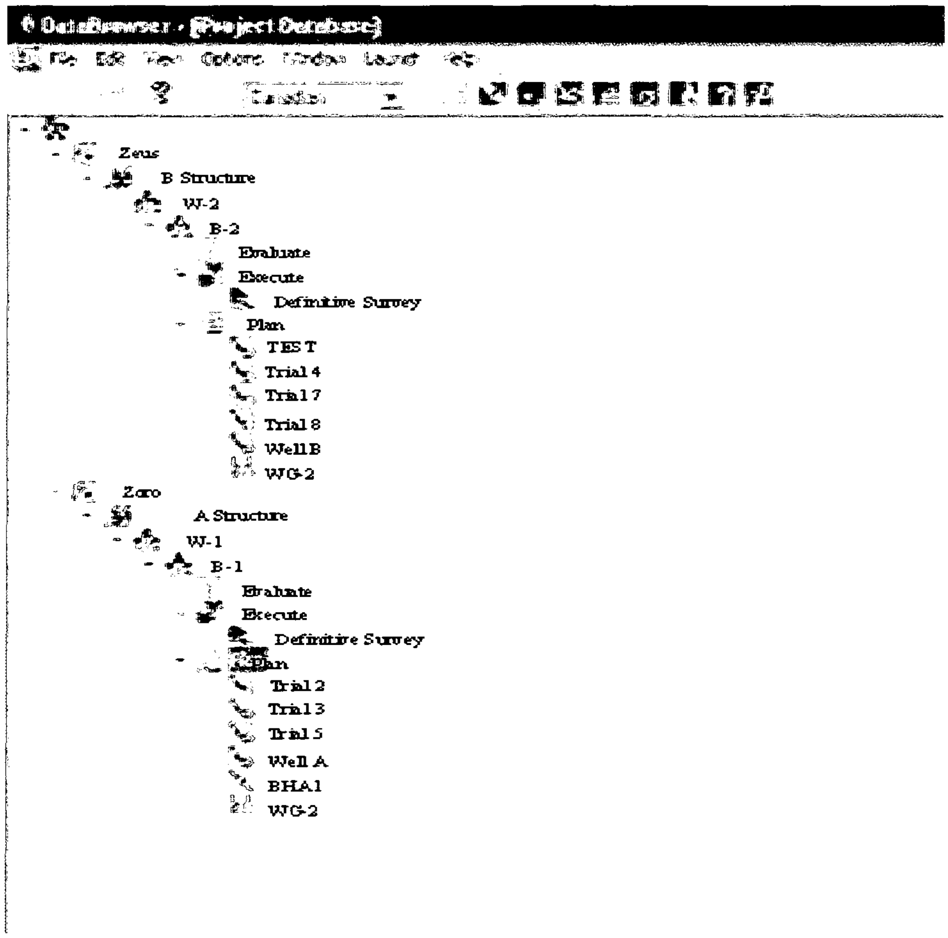

Figure 4.1: *PowerPlan*® Databrowser Screen

FIELD

The field is located in a region with an associated timezone and referenced to a selected coordinate system. the horizontal coordinates are listed as either geodetic or grid coordinates. The elevation is also required and is typically designated as mean sea level. The field can contain many structures.

The name of the two fields used in the research were Zoro and Zeus. The region was specified as well as the coordinate system. The reference point was given in geodetic *coordinates as Latitude and Longitude. The elevation, in this case, was also given as mean sea level (MSL).*

STRUCTURE

Each structure is also given a coordinate system and timezone. The reference point from which the associated slots, wells, and boreholes will be positioned, is entered in one of two ways:

- Absolute System
- Relative System

The absolute system includes the geodetic latitude/longitude or grid northing/easting. On the other hand, the relative system uses local cartesian (NS/EW) or local polar coordinates in relation to the field reference point. In this system if the field is repositioned then the structure reference point is moved along with the field reference point.

The scale factor is automatically calculated at the field reference point to indicate the conversion from local coordinates to the geodetic/grid coordinates of the structure reference point. The grid convergence is the horizontal angle between grid north and true north.

The default survey tool error model is also selected from SLB ISCWSA, SPE ISCWSA, Shell, or Wolff & Dewardt. Also NONE can be selected if there is no tool error model used.

Other entries include the elevation relative to mean sea level from either:

- Platform Elevation
- Pad Elevation

- Drillsite System

Also the seabed/ground level elevation is given relative to mean sea level.

The Structure for the Zoro field was named A.Structure and for the Zeus field it was B.Structure. The same structure was used for both fields and it was a semi-submersible rig. The absolute system was used to designated the location of the rig. The scale factor was calculated to be approximately 1.00 with a grid convergence of about 2.179 degrees for both fields. The tool error model used was the SLB ISCWSA. The elevation was taken from the rotary table and calculated as 23ft from MSL. The Seabed/Ground elevation level to MSL was -130ft.

SLOT/WELL

The slot and the well are located in the same position at the top of the slot or wellhead. As with the structure, the cooridnates are entered as absolute or relative to the either the structure or the field reference point.

If the relative system is chosen, the appropriate scale factor is computed depending on the whether it is referenced to the structure or the field. It is again used in the conversion from local coordinates to geodetic/grid coordinates of the slot/well location.

The elevation for the slot/well is entered relative to the structure or the field elevation. If entered relative to the structure elevation, then PowerPlan will automatically calculate the slot/well elevation to the field elevation. The converse is also true.

The well and slot for the Zoro field was denoted W-1 and BH-1, respectively. The same was true of the Zues field with the well named W-2 and the slot as BH-2.

4.3.2 BHA Editor

The BHA Editor module is used to design bottom hole assemblies and complete drillstring designs for drilling a planned well. It also details the wellbore geometry for the same well. To assist in the design, it includes an equipment database with various components to describe the BHA for the particular well. All the components listed can be modified to customize the BHA if necessary.

The following is a list of the categories that make-up the catalog of tools for the BHA. They include:

- Bent Sub
- Bit
- Collar
- Downhole Sensor
- Drillpipe
- Heavy Weight Drillpipe
- Hole Opener and Reamer
- Jar/Shock Sub
- Misc. sub
- Motor
- MWD/LWD
- Rotary Steerable
- Stabilizer
- Wellbore

The bit comes in several sizes ranging from $1\frac{3}{4}$ inches to 30 inches maximum Outer Diameter. Once the appropriate size is selected then the user can select the type of bit such as Diamond, Milled Tooth, PDC, etc. the manufacturer can also be selected as well as the connection type.

The BHA configuration used in the research is shown in figure 4.2. It was used throughout the analysis to drill the wellbore. It was initially designed for the Zoro field for a total depth of approximately 4611 meters but could also be easily applied to the wells in the Zeus field by adding lengths of drillstring to the end of the BHA (towards the surface) to a depth of approximately 5140m. This did not affect the torque and drag analysis in any way.

The wellbore geometry was also designed in Survey Editor. As you can see in figure 4.3, the well geometry consists of the wellbore and casing depths and diameters to create a profile. The well geometry had to be deisgned individually for both wells because of the differences in the drilling and casing setting depths. They were denoted WG1 for the Zoro field and WG2 for the Zeus field.

4.3.3 Survey Editor

This module is used to import and export existing survey data files. It also creates plan views, vertical section plots and drill maps for the well survey.

Within Survey Editor, the user could select from the following survey calculation methods:

- Minimum Curvature Method
- Radius of Curvature Method
- Tangential Method
- Average Angle Method

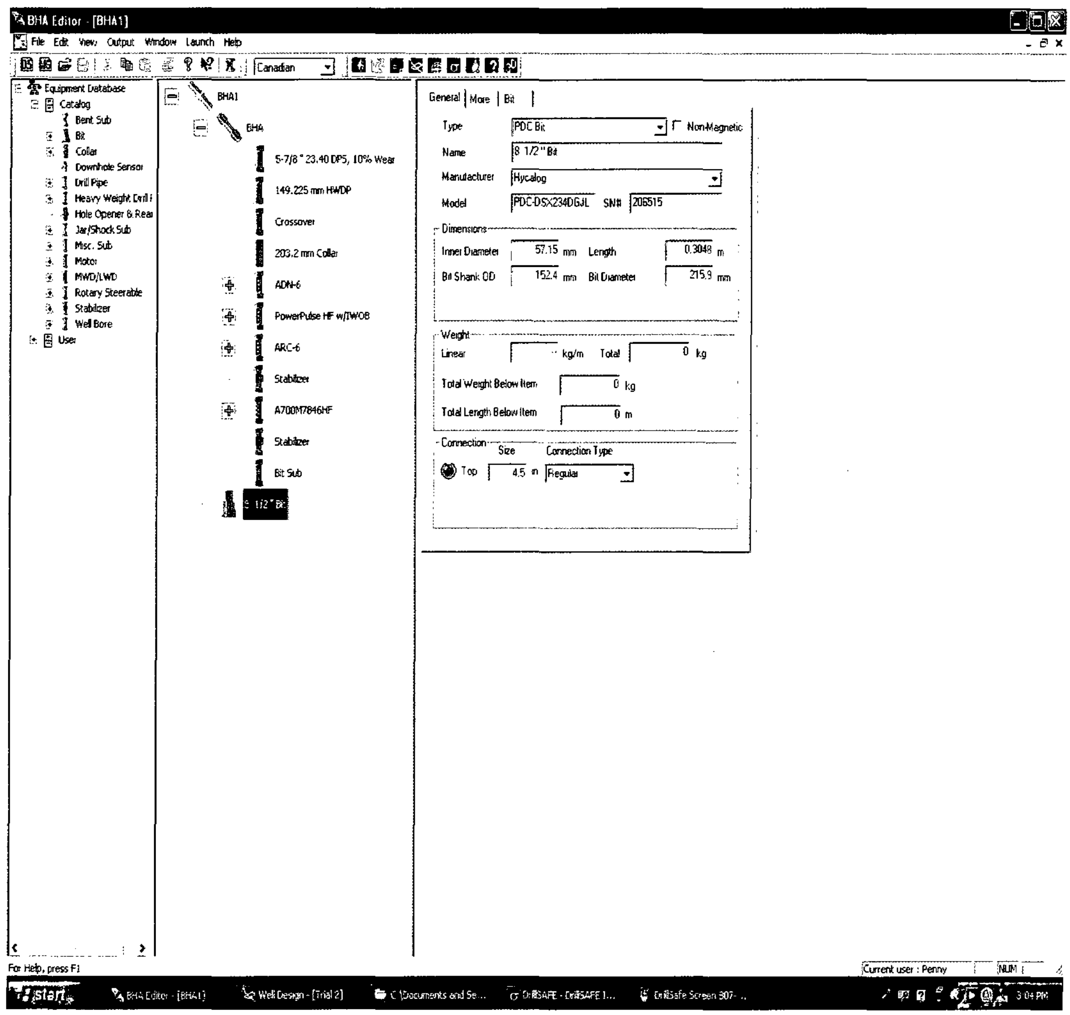

Figure 4.2: *PowerPlan*® BHA Editor Bit Assembly Screen

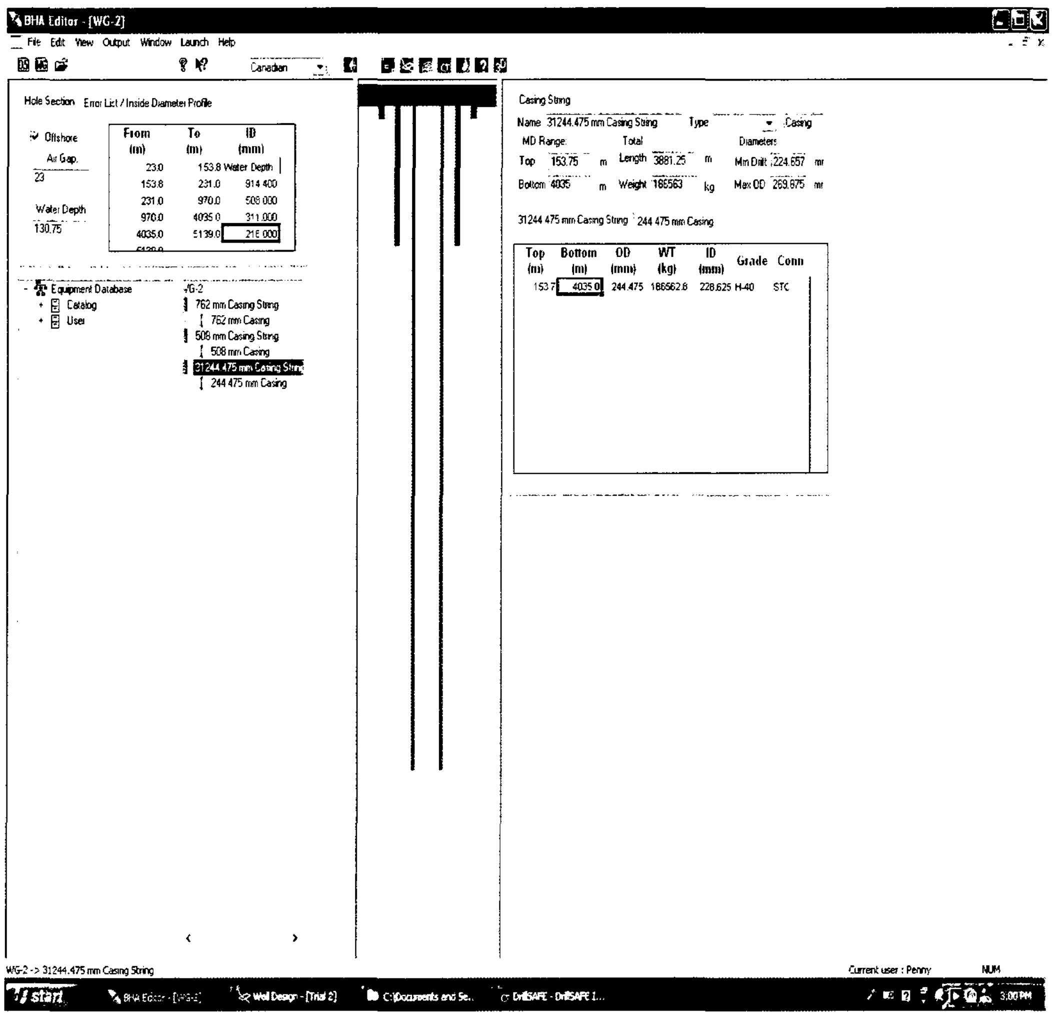

Figure 4.3: *PowerPlan*® Well Geometry and Casing Details Screen

- Balanced Tangential Method
- Mercury Method
- Lubinski or Wilson dogleg serverity (DLS)Method

The most common and accurate methods are explained in more detail in Appendix A. For the purposes of this research, the minimum curvature method was selected. As well, survey editor was not needed for the anaylsis in this case because all wells were new designs.

4.3.4 Well Design

After the targets have been created in Databrowser and assigned to the appropriate boreholes, Well Design can be used to create the trajectory from surface to the reservoir. Well Design is very simular to Survey Editor in that it will create plan views, vertical section views and drill maps. The primary difference between the two programs is that Well Design is utilized in the planning stages to design a well path using the appropriate trajectory calculations from Appendix A. Survey Editor, on the other hand, uses survey computation methods as already mentioned, to calculate the measured depth, borehole inclination and azimuth at various stations along the well path.

In the program the user is able to choose from a selection of standard profiles (in 2-D and 3-D) such as:

- Hold, Curve (2D) to fixed target
- Curve, Hold (J-2D) from fixed KOP (kick off point)
- Curve, Hold, Curve (S-2D)
- Curve, Hold, Curve (S-3D)

- Hold or Curve to Target

The well path is "Holding" when it stays at a constant build-up rate (BUR) over a chosen length of well. The well path will "Curve" by increasing the BUR over a selected length of well.

There are others as well, each having certain requirements in order to design the selection. The programs uses a survey method, selected by the user, to generate the path between the existing point and the new one. Appendix A explains the various survey methods in more detail and additional information can also be found in Chapter 8 the "Applied Drilling handbook" (Bourgoyne et al., 1986). There is an additional option within the standards profile window, if choosing a S-2D or S-3D, where by the user can choose to end the curve before target. This is particularly useful is drilling a horizontal well because curvature is not desirable in the horizontal portion of the well.

For each section of well path design there are inputs required to complete the section. They include some combination of the following list depending on what profile is selected to build the trajectory and what information is available:

- Measured Depth, m
- Azimuth, degrees
- Inclination, degrees
- True Vertical Depth (TVD), m
- Vertical Section, m
- Build Rate (BR), degrees/30m
- Dog Leg Severity (DLS), degrees/30m
- North/South, m

- East/West, m

Once the design is completed, Well Design will then create geodetic reports and vertical and horizontal profiles of the design. The completed trajectories will be necessary to run the DrillSafe Module.

4.3.5 DrillSafe

DrillSafe is the most crucial component of the PowerPlan suite for this study. The above modules play an integral part in the anaylsis performed by this program. It is typically used in the planning stages of a well to determine the expected torque and drag acting on the drillstring and bit while drilling. It can also be used however, while drilling to ensure that the drillstring is working within the limits of the equipment and topdrive and as a post-drilling anaylsis for optimization of trajectory design. The post analysis is achieved by using definitive surveys (wells already drilled) to calculate the actual friction losses experienced along the drillstring and identifying areas where changes in well path would have lowered those losses. It is also a guide to predict the friction factors for future wells. Figure 4.4 shows a typical DrillSafe screen.

There are four main analyses available within DrillSafe however only the first two were used in this study. They include:

- **Single point torque and drag analysis**
  It performs an analysis on a single point on the drillstring at any bit depth for a specific operating mode and set of parameters. From the analysis, it allows the user to determine drillability of the well path based on the strength of the drill-string. Several outputs including Von Mises stress, maximum bending stress, and sideforces occuring between the drillstring and wellbore can be compared to the limitations of the drillstring and connections. Rotation off bottom is the only operation able to be selected to run this analysis.

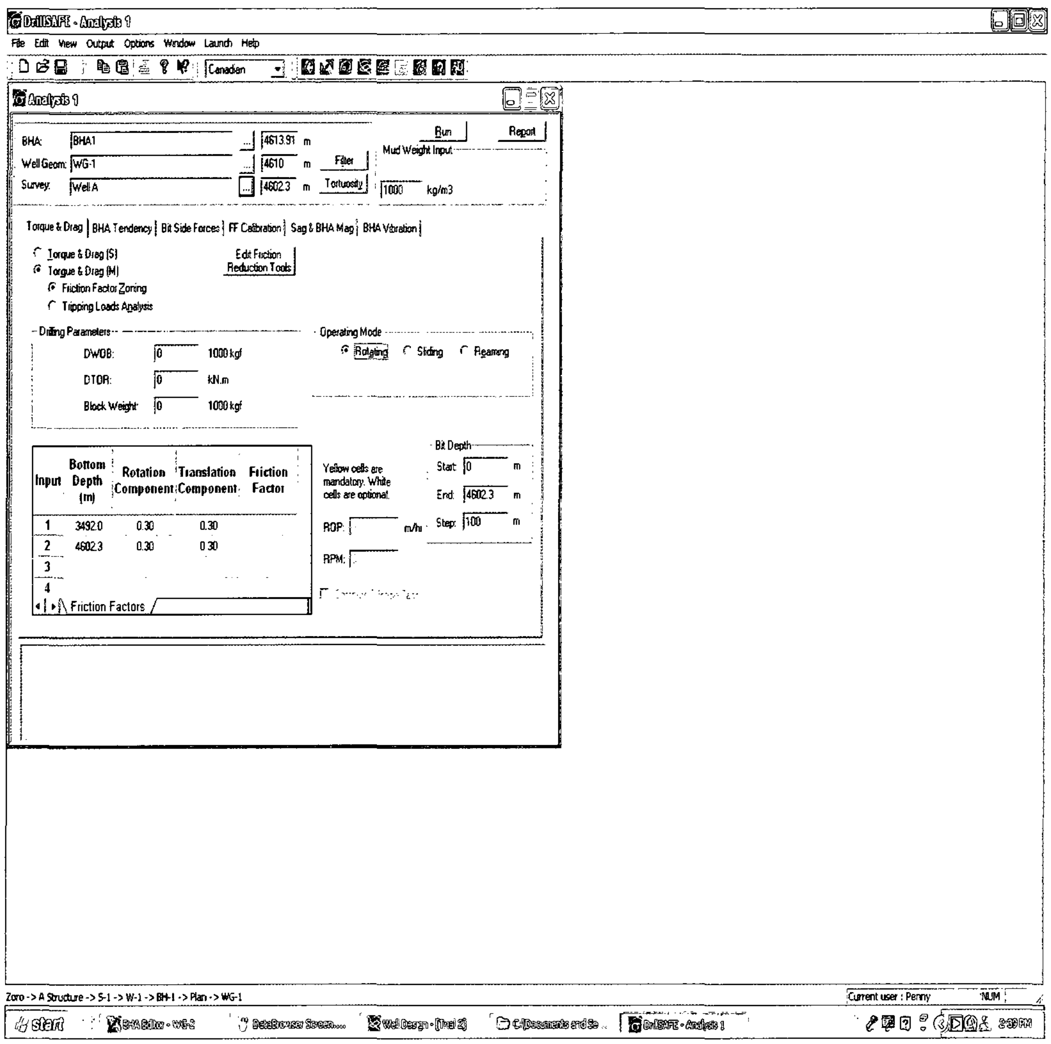

Figure 4.4: *PowerPlan*® DrillSafe Screen

- **Multi-point torque and drag analysis (single friction factor and multiple friction factor)**

  Single friction factor - By using a single friction factor, the user can compare various well trajectories with associated torque and drag calculations in order to select the optimum design. The analysis can be run in different drilling operations (i.e. running the driilstring in the hole or pulling out) to help locate the critical bit measured depths including maximum hookload and surface torque. Also, this analysis can be combined with the single-point analysis at the critical bit measured depths to determine the appropriate drillstring configuration for drilling the well and compare the outputs to the limitations of the equipment and top drive.

  Multiple friction factor - This analysis performs the same calculations as the single friction factor but allows up to five different values. This is useful in looking at the changes in calculated surface torque and hookloads resulting from variations in the friction factor.

- **BHA tendency analysis**
  This is useful in planning and executing directional wells because it represents the interaction between the bit and the wellbore while drilling and allows valid predictions of the directional tendency of the BHA. Using the peformance history of a BHA, the planner can select the components that will make up an existing BHA as well as make adjustments to achieve the desired curve rates.

- **Bit side force calculations**
  There are two main purpose for this analysis. The first is combined with the BHA tendency analysis, it can determine the equilibrum rate at the bit in terms of the side forces acting on the bit. The second purpose is to aid in the study of the mechanical behavior of the BHA. It will help in determining tool failure and stuck pipe issues.

Inputs

As can be seen in Figure 4.4 above, the inputs that go into the DrillSafe module for the torque and drag analysis include:

- BHA - detailed bottom hole assembly
- Well geom - wellbore geometry and casing details
- Survey - wellbore directional profile (survey or proposal)
- Mud weight
- WOB - weight on bit
- TOR - torque on bit
- Block weight
- Operating mode
- Friction factors
- Bit depth end
- Bit step
- ROP and RPM - rate of penetration and revolutions per minute

Tortuosity can be considered as well if deemed necessary for the analysis. It can be described as a series of small curves that can be added to a smooth well path to more closely match irregularities that occur in the actual drilled wellbore.

Operating Modes

The program allows the user to select from three different operating modes to analyze the torque and drag. They include:

1. Rotating Off Bottom (ROB)

2. Sliding in (slacking off) or sliding out (picking up) of the hole

3. Reaming in or out of the hole

For this report, the rotating off bottom operation was selected for both single point and multi-point analysis while the sliding in and out operations were only used in the multi-point analysis. Reaming in or out was not chosen because it is a special operation only necessary to make a wellbore bigger. It is not a typical operating mode.

Rotating Off Bottom

In this operation, the bit is raised a certain amount (2m+) from the bottom of the hole. This operation is required for circulating fluids through the wellbore. Using torque and drag analysis, it is a technique used to ensure the drillpipe weight is calibrated correctly in the hole. It can be done with or without fluids flowing however, more accurate results are found while the pumps are off since flowing fluids create a bouyancy factor.

Sliding In (Slacking Off)

During this operation, the drillstring is going in the hole with only the bit rotating and hookload is measured at various intervals. It is a function of weight off the drill pipe below the surface and the frictional force. The weight of the pipe is a function of the Total Vertical Depth (TVD) and the friction force is a function of the Measured Depth (MD) and Friction Factor (FF).

- *Weight of the Drillpipe*

  As long as drillstring is in tension, the weight of the drill pipe will pull it down through the wellbore. Since the weight of the Drill pipe and tension is a function of TVD, an increase in TVD will ensure the weight of the drillpipe will continue to pull it down hole.

- *Friction Force*

When the angle gets to be about 70^0 or greater the slack off becomes a function of measured depth and friction factor because the drill pipe goes into compression and therefore results in drag forces acting on the drillstring. This requires surface weight to push the drill string through the wellbore.

Sliding Out (Picking Up)

In the last operation used, the drillstring is being pulled out of the hole and hookload is measured at specified intervals. Pick Up is also a function of weight of drill pipe below the surface (again a function of TVD) and the friction forces (which is a function of MD and FF). Both factors will determine the amount of Drag exhibited on the string as it is pulled to surface.

Other factors that can influence the torque and drag analysis in directional well planning include buoyancy, stiffness, and tortuosity. Buoyancy is described in the DrillSafe section of the PowerPlan Manual (p.6 of 78, 2004) as the upward hydrostatic force imposed on and object in the wellbore and is caused by the pressure of the drilling fluids. In a wellbore it is the pressure differential between the drillstring and BHA assembly and the drilling muds. The amount of buoyancy in the wellbore is critical to well planning because it will reduce the drillstring weight that is measured at surface and used for calculations. The weight reduction is calculated by a buoyancy factor and has to be considered for all sections of the wellbore.

The Stiffness of the drillstring is also important in the analysis because the contact between the pipe and bit and the wellbore is different depending on which of the two models are used; the soft-string model or the stiff-string model. The components of drillstring stiffness include axial, torsional, and bending stiffness.

1. Soft-string Model

   In this model it is assumed that the drillstring tends to deform to the shape of the borehole and thus has continuous contact over the length of the drillstring. Under this same assumption, the axial forces and moments (tension and torque) are supported by the drillstring, and the lateral forces (contact) are supported by the wellbore.

2. Stiff-string Model
   In this model it is not assumed that the drillstring will take the general shape of the wellbore. Rather, it suggests that the drillstring will have a certain amount of bending stiffness and thereby not allowing sections of it to be in contact with the wellbore. This concept is more a realistic model of what is really happening in the wellbore especially in high angle and/or highly tortuous wells. The model also enables more realistic bounds to be placed on the torque and drag losses experienced by the drillstring.

Applying tortuosity to a planned well path in DrillSafe also enables more realistic bounds to be placed on the torque and drag losses due to the more realistic design. The value for tortuosity given in literature ranges from 0.5 to 0.75 and uses one of three models:

1. Sine Wave
2. Random Independant Inclination Azimuth
3. Random Dependant Inclination Azimuth

If employed, the tortuosity of the well could have large impacts on the side force distribution on the drillstring and is explained in detail in the PowerPlant Technical Manual (2004).

DrillSafe Outputs

The outputs needed from the torque and drag anaylsis are in report and plot format and include:

- Hookload and Surface torque profiles for multi-point analysis

- Side force profiles for single-point analysis

There are several other options for outputs however for this analysis only the above listed were important.

4.4 Well Design Selection and Techniques

In Well Design, it is important to choose a well path that is both drillable and economical. For this reason, the selection has to be based on several deciding factors including knowledge of the reservoir, knowledge of drilling parameters and design techniques, equipment availability and limitations, past well performance, anti-collision concerns, and many other pieces of information. The technique in which the well is designed is based on the profile chosen in the Well Design module and calculated in Appendix A.

4.5 Torque and Drag Concept

As already mentioned, torque and drag analysis tools provide companies in the oil and gas industry with an accurate perception of what happens to the drillstring under specified conditions. In knowing this, engineers and decision makers can use the information to design optimal well paths. As indicated in Chapter 2 there are other methods available for optimization and the PowerPlan program described above is just one of the tools used to achieve this. The calculations for torque and drag used in PowerPlan are explained in Appendix B. Torque can be defined as the rotational moment generated from contact loads between the wellbore and the drillstring, BHA, and bit. The total torque is calculated from three different sources; the frictional torque, mechanical torque, and bit torque. The torque and drag concept is explained in detail in the following paragraphs and can also be found in Appendix E in presentation form.

Frictional Torque

Frictional torque is a function of measured depth, side forces (sideloads) and friction forces. The measured depth affects the amount of torque applied at the bit because of the addition of more drillpipe and drill collars. The added drillpipe and collars increase the total length of the drilling assembly and therefore increasing the weight and the torque lost at the bit. To maintain the required amount of torque at the bit, the top drive system has to increase the torque applied at surface.

The side force is a function of the dog-leg severity (DLS) and tension in the drillstring. The DLS is defined as a measure of the amount of change in the inclination and/or direction of a borehole, usually expressed in degrees per 30m (100ft) course of length. The DLS can be calculated using a number of different formulations. The most commonly used ones for defining the DLS are the

- Lubinski Formula
- Mason and Taylor Formula

These calculations are independent of the survey calculation methods because they make no assumptions about the well path, although the Mason and Taylor formula may only be used in conjunction with the minimum curvature method. Additional references for these formulas can be found in the reference section at the end of chapter 8 in the "Applied Drilling handbook" (Bourgoyne et al., p.365, 1986). The sideloads are greater in sections in the well that are curved and less in straight sections due to the fact that there is greater contact between the drillstring and the wellbore in those curved sections. As well, the size (outer diameter) of the pipe will affect the sideloads because the larger the pipe diameter, the greater the contact between the pipe and the wellbore.

Friction factor is described as the force required to move an object divided by the side force between the object and the surface on which it is resting. It generally ranges from 0.1 to 0.5. It is most desirable to choose a friction factor that is above what is established for a well to account for unexpected abnormalties in the wellbore such as high doglegs. The overall objective is to minimize the FF as much as possible while drilling (within its limits) because this will lead to lower torque and drag values and ensure a successful well. Prior to drilling a new well, friction factors are based on historical data with similar characteristics and general knowledge of well and reservoir profiles. While drilling, actual survey data torque readings and different hookloads while slacking off and picking up help determine friction factors.

Mechanical torque

Mechanical torque is also a function of friction and generated by the interaction of the drillstring and BHA with cutting beds, unstable formations, or differential sticking. These interactions can create substantially high friction fractors due to the increased contact between the two surfaces. In practise, mechanical and frictional torque are considered as one measurement.

Bit torque

The bit torque (TOB) is also a component of the total torque generated. It is inevitably the interaction of the bit and the formation being drilled. It depends heavily on the bit design used for the operation. The bit torque is calculated by multiplying the radius of the wellbore by the weight-on-bit (WOB) value and the bit efficiency factor. The bit toruqe is useful in helping determine bit vibration which can damage the bit and create fatigue in the drillstring.

There are several factors that can increase torque and drag in the wellbore. These include:

1. Differential Sticking - When the drillstring is sucked against the formation wall as a result of the higher pressure in the wellbore then that in the formation

2. Tight Hole Conditions - When there is a an increase in drag over the length of the wellbore, either while tripping in or tripping out

3. Cuttings Build Up (Poor Hole Cleaning) - An increase in the amount of drill cuttings in the wellbore because of insufficient cleaning of the hole to get rid of them and therefore increases friction factors

4. Sliding Wellbore Friction - When the drillstring is not rotating, just the bit itself, is refered to as sliding. This operation leads to increased wellbore friction because the drillstring has increased the amount of surface area in contact with the wellbore, increasing the friction between the two.

There are several ways of reducing torque and drag losses in the wellbore. Some of these include:

1. Conduct wiper trips
2. Add fluid additives
3. Ream or back ream and/or
4. Trip the pipe

4.6 Constants

As explained in section 4.1.5, there are many inputs required in DrillSafe to run the analysis. In order to maintain consistency when comparing the results, several of these parameters were keep constant throughout. The following list are those values that did not change throughout the study.

- *Mud Weight*
  The mud weight selected for the analysis was $1270 kg/m^3$. This value was based on average mud weights used while drilling a well.

- *WOB*

  The WOB was 0MT for this analysis. This is because the bit is rotating off the bottom of the wellbore and therefore there is no weight applied to the bit. This option is only avalable while rotating off bottom. This value would be variable throughout the analysis as formations changed, equipment changed and other factors and therefore it was important to standardize it for all operations.

- *TOB*

  The TOB was 0KN.m for this analysis. This is because the bit is rotating off the bottom of the wellbore and therefore there is no torque applied to the bit. This option is only avalable while rotating off bottom. This value would be variable throughout the analysis as formations changed, equipment changed and other factors and therefore it was important to standardize it for all operations.

- *Block Weight*

  The block weight was 0 MT for this analysis. This value was selected so that the results could be directly compared to other analysis done in the future on other rigs.

- *Friction Factors*

  Both the open hole and cased hole friction factors for rotation and translation were selected as 0.3. As already mentioned the friction factor can vary throughout the formations and this value reflects a fairly conservative but realistic number.

- *Bit Step*

  The step choosen for the multi-point torque and drag analysis is at 100m intervals.

Tube	**Premium**
OD (in)	5.731
ID (in)	5.153
Torsional Strength (KN.m)	112.5
80% Torsional Strength (KN.m)	90
Connection	
OD (in)	7.125
ID (in)	4.25
Torsional Strength (KN.m)	128
80% Torsional Strength (KN.m)	102.4
Max. Make-up Torque (KN.m)	76.85
80% Max. Make-up Torque (KN.m)	61.48

Table 4.1: Performance Characteristics of $5^{7/8}$" Drill Pipe

4.7 Limitations of Design

In order to successfully drill a well path it is important to know the limitations of the design and ensure that the well can be drilled effectively. For this analysis, there were three major limitations that determined if the well could be drilled. They included:

- Drillpipe performance characteristics
- Tool joint connection characteristics
- Topdrive System capacity

The characteristics of the drillpipe indicates that it is rated for a torsional strength of 112.5 KN.m. The tool joint connection is rated for a torsional strength of 128 KN.m but it has a maximum makeup torque, the torque required to connect two joints of drillpipe together, of only 76.85 KN.m. In practise however, it is recommended to only use up to 80% of this value for both the drillpipe and tool joint connection. This provides a margin to allow for higher then estimated torque as well as torsional weaknesses. Table 4.1 summarizes the results.

The top drive system used to drill the well has a continuous drilling torque rating for 54.91 KN.m. Therefore the top drive capacity governs the amount of torque that can be applied to the drillstring. The maximum torque values that were seen in the analysis had to be equal to or below **54.91 KN.m** in order to be able to drill the well.

Other limiting considerations are the sideload limitations on the drillingstring. The drillstring described above has a limit of 9,000 (kgf/10m) force without protectors. Protectors can be applied to increase this value. The rig derrick has a drawworks and crown block pulley system that holds the drillstring in the hole. The rig used in this analysis has a hookload capacity of 680,000 kgf.

All values obtained in the analysis have to be within these limits.

Please note that the units for sideforces used in my research is kilogram force (kgf) which was the output given for the results from DrillSafe. The conversion into Newtons is multiplication by $9.81m/s^2 (N = 9.81x1kgf)$.

Chapter 5

Methodology

5.1 General Process

The process of collecting and using the data for this research project was very extensive and required the help of peers, supervisors, and professional engineers in the industry. As already discussed in chapter two, the first step in the research was to collect information relevant to the topic and determine the importance of the research in todays oil and gas industry. There had been a substantial amount of research done on torque and drag analysis to date, however many of these studies had involved the use of algorithms and other computer analysis programs.

Once the prelimiary work was completed, the next step involved determining what companies were using as design and optimzation tools in the industry. It began by studying the calculations of various well path trajectories in the design phase as well as ways companies calculated the survey of the well trajectory. Appendix A goes into detail on many of the well designs including build and hold, modified "S", and horizontal to name a few. It also explains the various methods used to calculate the well survey of a given trajectory. It was determined that the Minimum Curvature Method was the most widely used trajectory calculation method used in industry. This was illistrated in a presentation given to my two supervisors involved in the research. In the following few months more information was gathered from research papers and other presentations were given to supervisors and industry and a plan was formulated as to how the optimization would proceed. It was important to decide on the optimization tools that would be implemented in the research. From discussions with my supervisors it was decided to utilize the $NETool^{TM}$ well flow and reservoir simulation tool already in place at Memorial University and extensively used by other students in the faculty for the production and completion simulation. From previous experience with a well design program, it was decided to request the *PowerPlan*® suite of products from Schlumberger to be used as the design optimization tool.

Initially, the concept was going to include optimization in the planning stages of the well, as well as while drilling and post drilling. From examining the procedure it was determined that the methodology developed for the post drilling phase could be modified to include either of the other two stages of development. After signing an agreement with ZEBRA Oil Company it was decided to do a post analysis of two wells already drilled to examine other options for higher production.

The purpose of this project was not to undermind the design of the wells by the company. The idea essentially was to be provided with a real reservoir and existing wellpath with associated BHA and Well Geometry which I could use as a guide to examine alternative profiles. Several parameters were used in the study such as the completions in the reservoir simulator and the BHA in the BHA Editor, which were kept constant throughout the full analysis. In the analysis, it is important to remember that no consideration was given to other wells drilled in the area. The following figure 5.0 is a flowchart which outlines the procedure used for production and drilling optimization of Well A and Well B.

5.2 Methodolgy Flowchart

Prodı

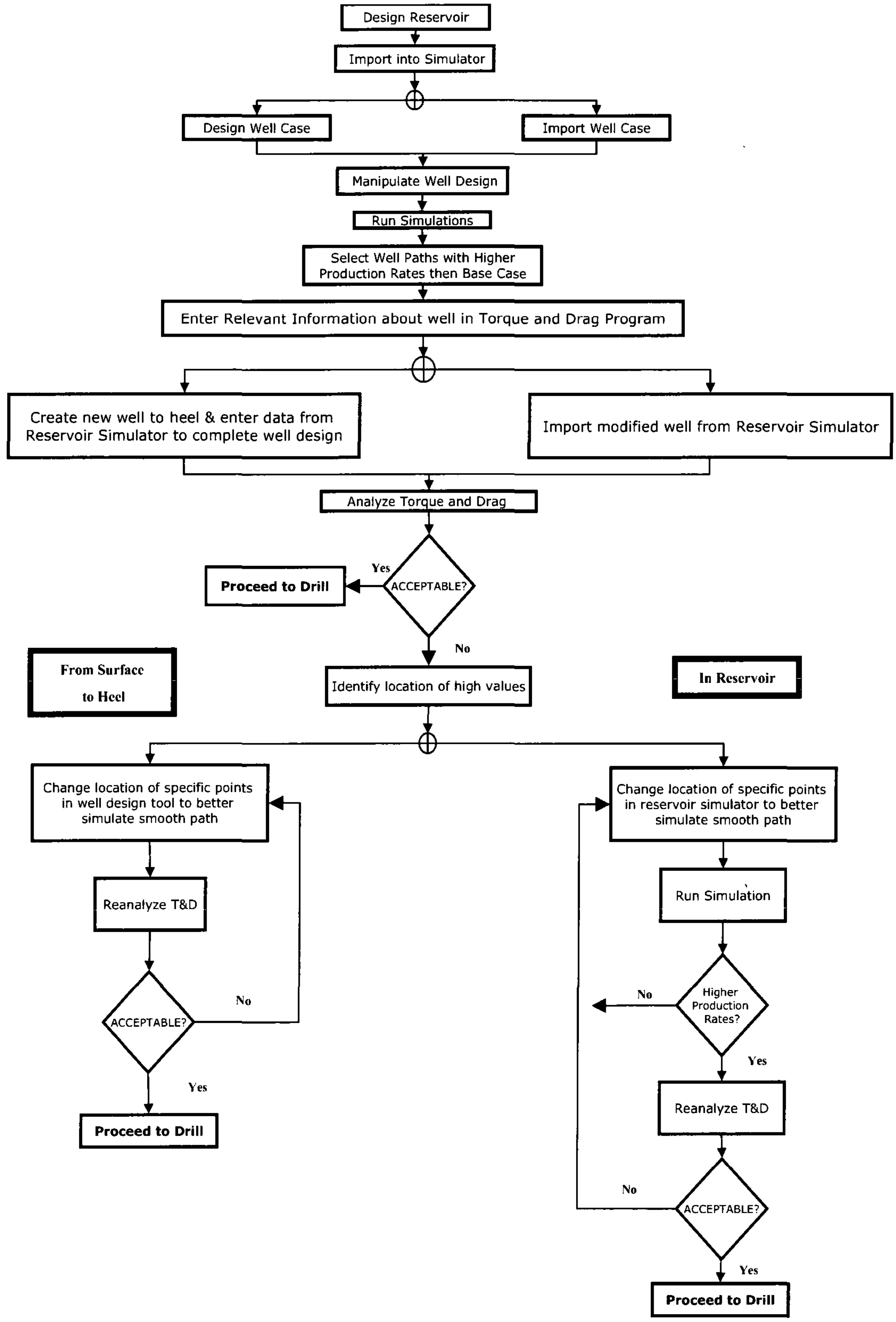

Figure 5.1: Methodology Flowchart

5.3 Flowchart Process

In the first step, the user designs the reservoir in Eclipse reservoir simulator, creating grid files that contain the reservoir profile and its associated reservoir properties including pvt, permiability and relative permiability, and lift curve data. The next step is to import these files into the reservoir simulator, $NETool^{TM}$. As explained in the NETool section, the files necessary for import include an INIT file, .EGRID file and restart files if present. By simply pressing the *Import a Reservoir* button the reservoir is placed in NETool. After the reservoir is imported, the well cases have to be designed or imported into the simulator. This is described in detail in section 3.4.2.

Step 4 is the when the first optimization technique takes place. The initial well profile is manipulated from the heel (entry point into reservoir) to the toe (end of reservoir) by moving the trajectory points that make up the well path in various directions. The decision as to where each point should be moved is based two things. One, general knowledge of the properties of the reservoir using the oil saturation profile will help in selectng the upper and lower oil-water contact boundaries. From figure 3.3, the red area identifies the oil saturation in the reservoir and as the color changes to yellow, green and blue the oil saturation decreases to zero. The other factor that helps determine where to place the trajectory point is a knowledge of well design. Some paths would be completely impractical to drill because of the limitations of the drillstring and top drive system. Once each modified well path has been created and saved to different files the simulation is run and the production rates are sumarized. The wells that have higher production rates then the initial design are used for the second part of the analysis.

In the next step the user leaves the reservoir simulation tool and opens the well design and analysis tool, in this case $PowerPlan^{®}$. Several inputs are required in the program to run the necessary analysis including the surface location. As already described in Chapter 4, Databrowser has to be set up first and then the subsequent modules can be set up before running DrillSafe. There are two options available to define the well path. The user can design a new well to the heel or import the well path from the simulation tool if possible. If choosing to design the upper portion of the well from scratch, it is important to select the type of well that will be used to run the analysis. Appendix A explains the more common types of well profiles used today. Included in the design will be KOP (Kick Off Point), BUR (Build Up Rate), anti-collision points, tangent angle, and total depth (TD). Then the information from the reservoir simulator is copied and pasted to complete the well design. If the option is available to import from the reservoir simulator, the information required include measured depths, inclinations, and azimuths. This information is copied and pasted from $NETool^{TM}$ into Well Design.

The next step in the procedure is to analyse the torque and drag forces acting on the drillstring using a torque anddrag modelling program. DrillSafe was used for this analysis and the inputs required have already been discussed in Chapter 4. Once run, reports are generated and the user has to determine if the torque and drag values are acceptable as compared to the limitations set by the drillstring performance characteristics and topdrive system. If yes, then the goal of the study has been reached: there is a well profile that can be drilled sucessfully with higher production rates from the reservoir then initially designed.

In the event that the torque and drag forces are higher then the limitations of the system then necessary steps have to be implemented to resolve the issue. The first thing to do is consider the difference in magnitude of the torque and drag values in the new well and the base case design and where it is located. If there are differences in the upper portion of the well from surface to the heel, then the user can make changes to the KOP or BUR, for example, where the drillstring experiences the high forces, that will help create smooth curvature in the well path. If it is in the portion that goes through the reservoir then the user has to return to the simulation tool and change the coordinates of the points that are creating higher then acceptable forces on the drillstring to simulate smooth curvature in the well path. The new design has to run through the reservoir simulator to ensure that the production rates are still higher then the initial design. If they are acceptable then this new well path then has to be imported back into the well design tool and reanalyzed for torque and drag. However, if the updated path in the reservoir is no longer producting higher production rates then the user has to re-examine the profile and make more changes until the design is acceptable. If it can not be achieved then the design has to be abandoned.

Chapter 6

Case Studies

6.1 Introduction

The data obtained from ZEBRA Oil Company was carefully and thoroughly studied to determine possible alternative well paths in order to achieve better production profiles. There were specific areas of interest that would shape the the design and optimization techniques used. They included:

- Geological Structure
- Production Data
- Well Design

After examination of the given information the next step was to determine if the well and production rates could be optimized. Alternate well paths were designed and torque and drag analysis was done in accordance with the methodology in Chapter 5 and results were obtained. The following sections are the case studies of Well A and Well B.

6.2 Case Study 1

Well A was the base case well path for the Zoro field and the focus of the first study. The geological structure for the field was made of several different types of rock and clay. Core samples and mud returns were used to determine the formations in the reservoir and the assocaited properties. It was important to identify the areas that provided significant amounts of sandstone, the primary source rock for oil. Once the formations were studied, Well A was simulated to determine the production rate that would be considered the minimum and all other profiles would be compared to these results.

6.2.1 Geological Structure

There were several formations that made up the geological structure of the Zoro field. The significant portion of the reservoir began at about 2250m MD to 4610m MD. The structure consisted of several different rock materials with properties categorized by color, hardness, shape, atomic structure, and texture. Some of the more abundant rocks included claystone, siltstone, limestone, sandstone, and some traces of shale and marlstone. All the distances discussed in this section are measured depth (MD) along the well path from surface.

The majority of claystone was in the upper portions of the reservoir, from about 1100m to 2250m. It was also seen throughout other portions of the reservoir as well. The properties of the claystone were as follows:

- Color: dark brown, light to medium grey, dark grey in places.
- Hardness: soft to firm, hard in some places.
- Aggregate shape: subrounded, subangular.
- Atomic structure: Amorphous - no definite crystaline molecular structure.

The siltstone existed from about 2250m to 3450m with some traces to total depth but the predominant area of the rock was from about 2480m to 3350m. The siltstone properties included:

- Color: light medium grey to dark grey and greenish to brownish grey in parts.
- Hardness: soft to firm, hard in some places.
- Composition: agrillaceous and calcareous.

The limestone was present in areas from 2300m to 2715m and ranged anywhere from 10% to 70% of the total material in the 5-m sections. Some of the general properties of the limestone included:

- Color: white to off white, light grey to very light grey and occasionally greenish in color.
- Hardness: soft to firm.
- Texture: chalky, silty.

The most important material was the sandstone because it was the material that held the oil. In this reservoir it began at approximately 3465m to 4610m. The formation also consisted of trace amounts of siltstone throughout. The properties of the sandstone were as follows:

- Color: light grey to grey, white to offwhite, translucent, occasionally medium brown.
- Hardness: soft to firm, occasionally hard.
- Texture: well sorted, very fine grained.

These properties would change slightly depending on the location in the reservoir.

6.2.2 Production Data for Well A

In order for the focus of the study to be on production rates, there were changes made within the simulation tool to eliminate variability of certain parameters that were not being optimized in this study, including completions and bottom hole pressure. As explained in section 3.5, the completions chosen for all well paths designed in the analysis was a open hole wire wrap screen. As well, a bottom wellbore pressure of 253 bars was used. This is an average bottom hole pressure and was used in the original analysis of the well design in the reservoir. The production data calculated for Well A based on these changes was $4177.32m^3/day$. The production profile is shown in Figure 6.1. The production rate steadily increased through the wirewrapped completions and the main surge of flow came at the beginning of the casing string at approximately 3400m MD. It continued to increase until it stabilized in the casing and flowed to surface.

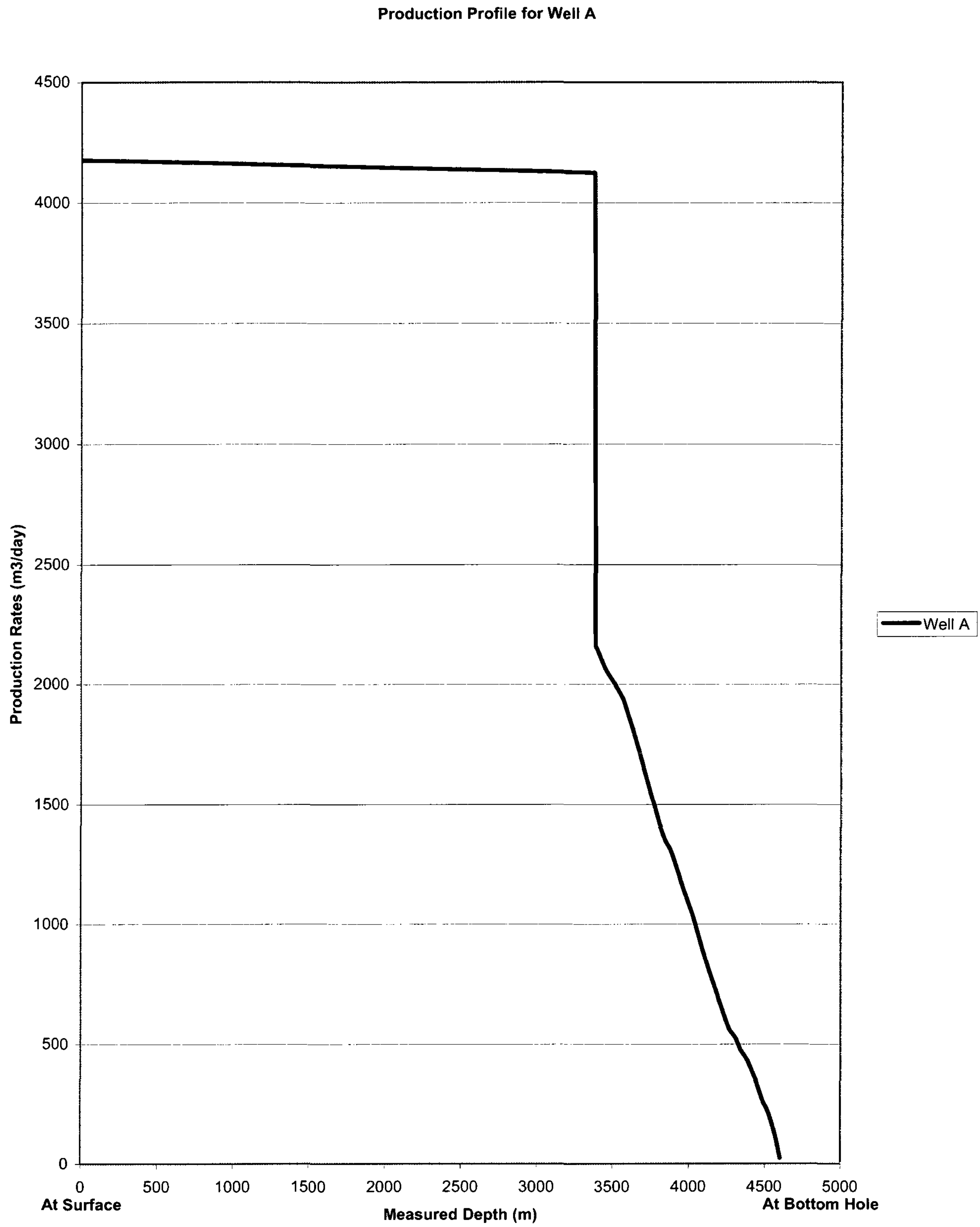

Figure 6.1: Production Rate Profile for Well A

6.2.3 Well Design for Well A

The initial well design was a typical horizontal well profile. The vertical profile in Figure 6.2 shows that the path followed a fairly straight vertical line to about 1050m TVD and then veered to the left (negative vertical section) to -135.10m at a depth of about 2400m TVD. At this point the curve section began. It built at a continuous rate to an inclination of about $91^o \pm 1^o$ at 2942m TVD (3275m MD). The path was fairly constant to TD with an inclination ranging from 89^o to 92^o. The well path finished with 4602m length (2939.67 mTVD) and an inclination of 90.19^o and azimuth of 267.64^o.

Figure 6.3 shows the birds eye view (N/S and E/W) of the well which followed a very unique path. It began at a N/S coordinate of -8.34m and E/W coordinate of 43.38m. It was drilled in the southeast direction to 197m East and 72.54m South with a TVD of about 2400m. At that point, the path changed direction and began moving southwest. It followed a fairly linear path to TD with a couple of small deviations. At TD, the coordinates were 399.18m South and 1671.92m West.

The well was made up of four hole sections and three casing sizes. Figure 6.4 shows the well geometry used for the Zoro field. The first section was the 36"(914.4mm) hole section drilled to 231.0m MD. The 30" (762mm) casing was set at 227.0m MD. The 20" (508.0mm) hole was drilled to 1102.0m with the 13 3/8" (340.0mm)casing run to 1086.4m MD. The third section of the well was a 12 1/4" (311mm) hole drilled to 3492m MD and the 9 5/8"(244mm)casing was set at 3482m MD. The final hole was 8"'s and drilled to TD(4613m MD). A wire-wrapped screen not shown here was placed in the final hole section to TD. The well geometry described here is used for all wells designed for case study one. It represents a general configuration of the wellbore and casing for the Zoro field.

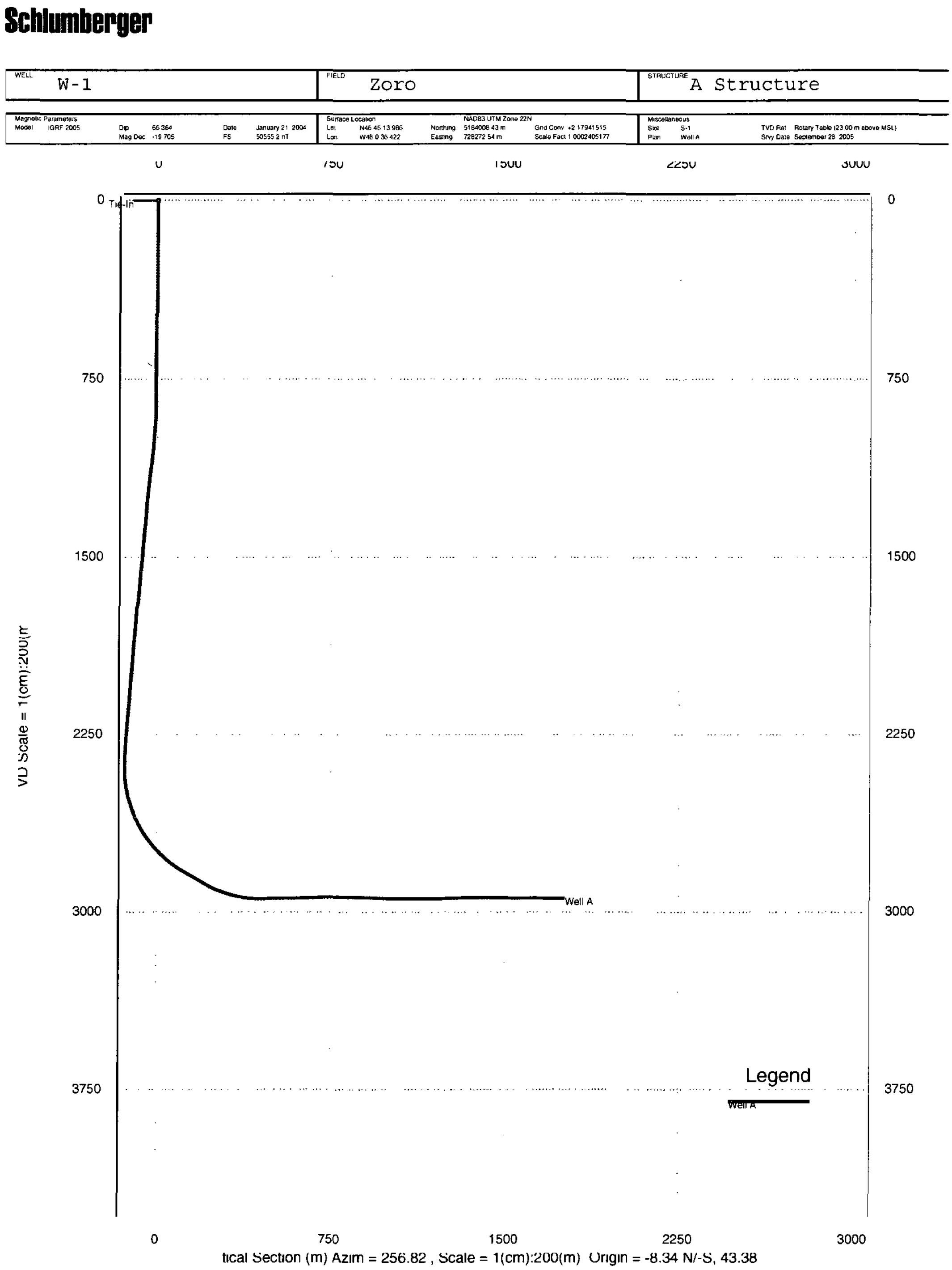

Figure 6.2: Vertical Profile of Well A

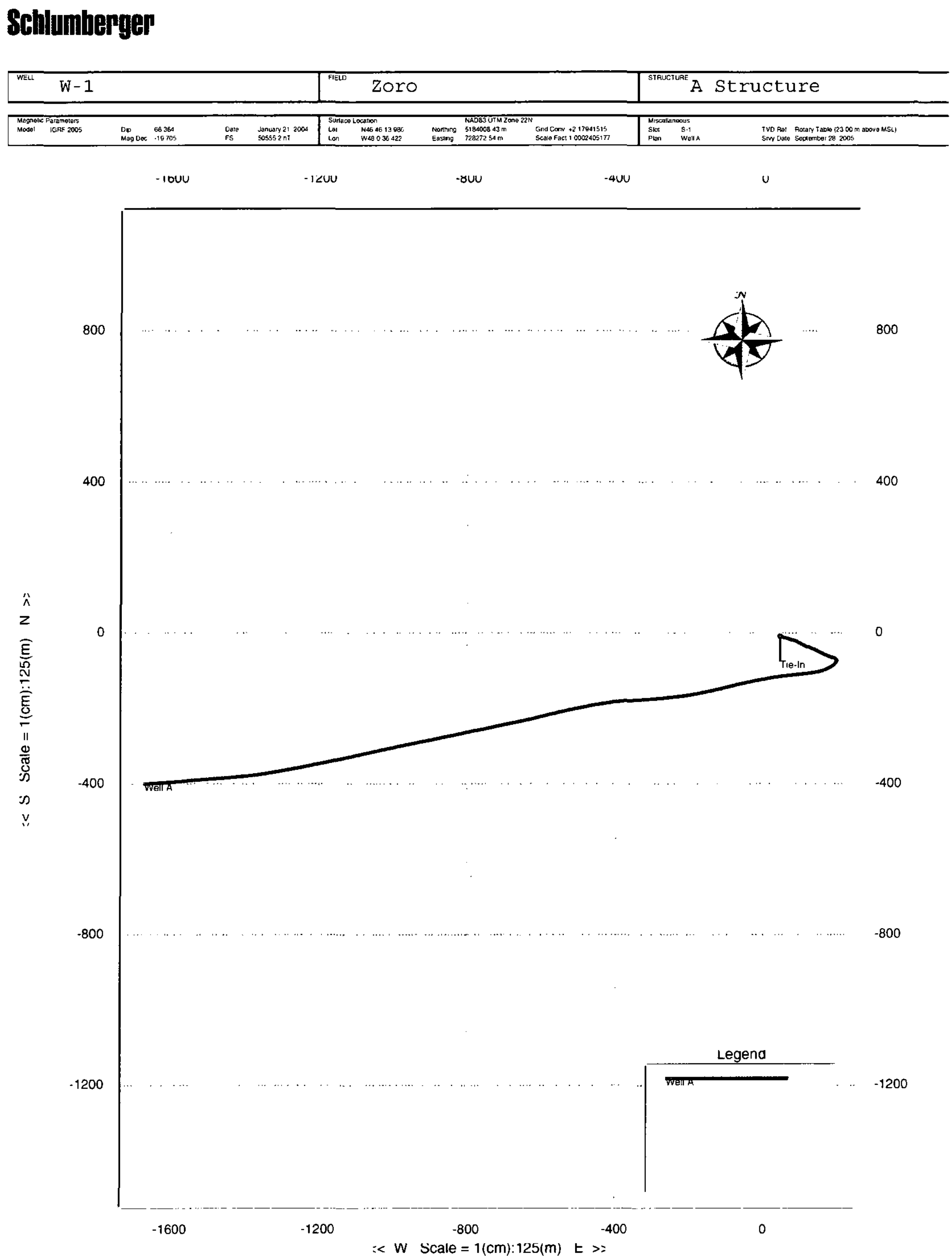

Figure 6.3: Well A Horizontal ("Birds Eye") Profile

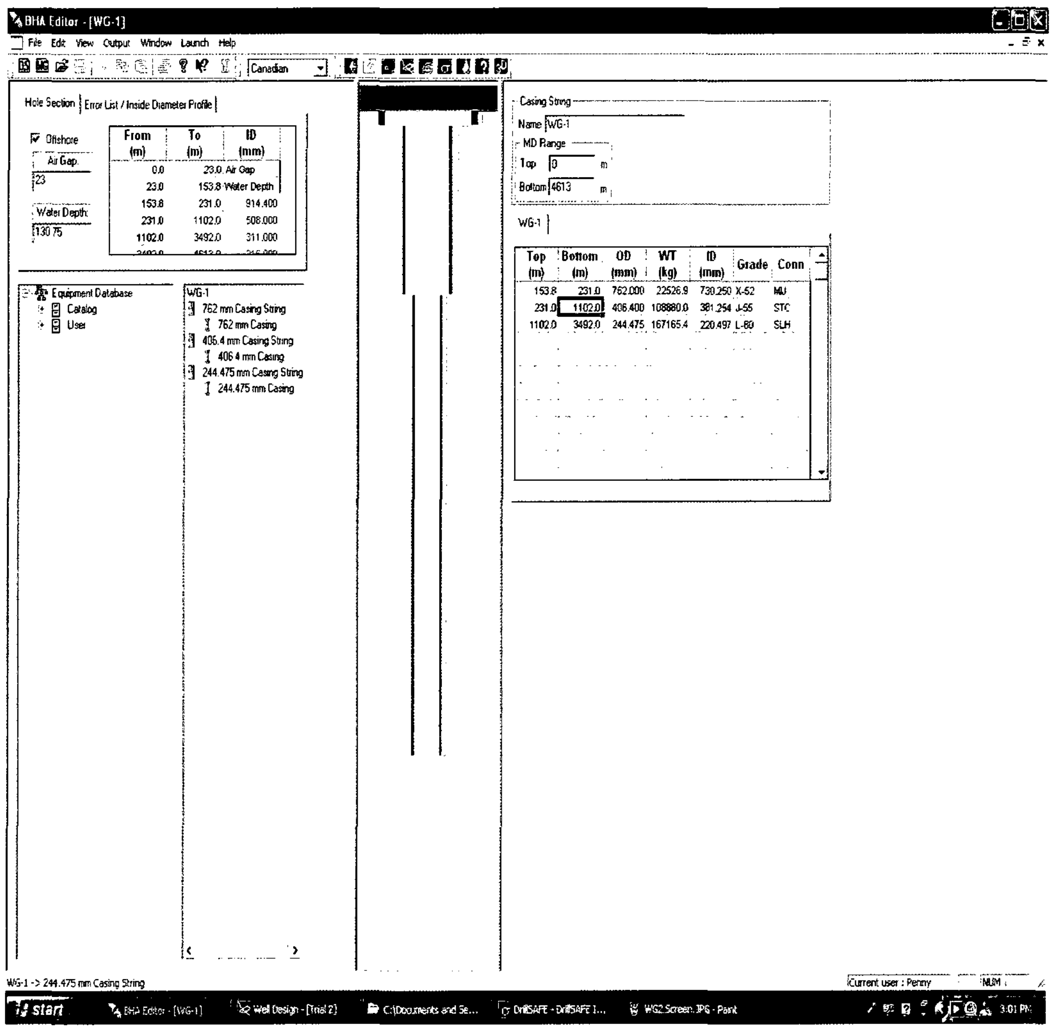

Figure 6.4: Well Geometry and Casing Details for Zoro Field

6.2.4 Analysis

This section describes the analysis that was carried out with specific details for the Zoro field. As described in the methodology it was a two-phase project with the first being optimization of the production rates by changing the trajectory points through the reservoir and secondly; analyzing torque and drag on the well path to determine if it was drillable based on the limitations set in Section 4.7.

Production Optimization

The base case Well A was imported into the Beta reservoir in $NETool^{\text{TM}}$ for simulation. By moving the trajectory points in the reservoir, many modified well paths were created. The selection of where these points were positioned was based on a general knowledge of well design and reservoir properties. Each well was simulated to note the production rates obtained. With time as the main constraining factor, a total of six new wells were designed. From an analysis of the production rates, 3 new paths gave higher production rates then the base case, namely; Trial 2, Trial 3, and Trial 5. Figure 6.5 is a bargraph of the production rates for the four wells.

From the vertical profile (Figure 6.6) of the well paths in the Zoro field, all three modified profiles were the same in design as the original to approximately 3100m MD. This was near the entry point into the reservoir and changing the trajectory points from that point on would affect the production rates obtained. It was important that the shape of the well from the entry position follow a seemingly drillable path based on general knowledge of well design. From the figure, Trial 2 was directed a little below Well A and followed a straight line to TD.Trial 3 was even lower then Trial 2 in the reservoir. At about 3000m MD (2940m TVD) it deviated from the original design to a TVD of about 2967m and stayed around this value to TD(4613.06m MD). Trial 5 deviated below Well A at 2918m TVD. The path decended to a TVD of 2961m and then began making a low constant ascend to TD from $\approx 90^o$ inclination to $\approx 99^o$

(measured postive from negative y-direction) to rest at a TVD of 2907.48m.

From a birds eye view of the Zoro field in Figure 6.7, there was no change in the N/S and E/W coordinate system. Changes were attempted for various trial runs but the simulation showed that the production rates were lower then the base case.

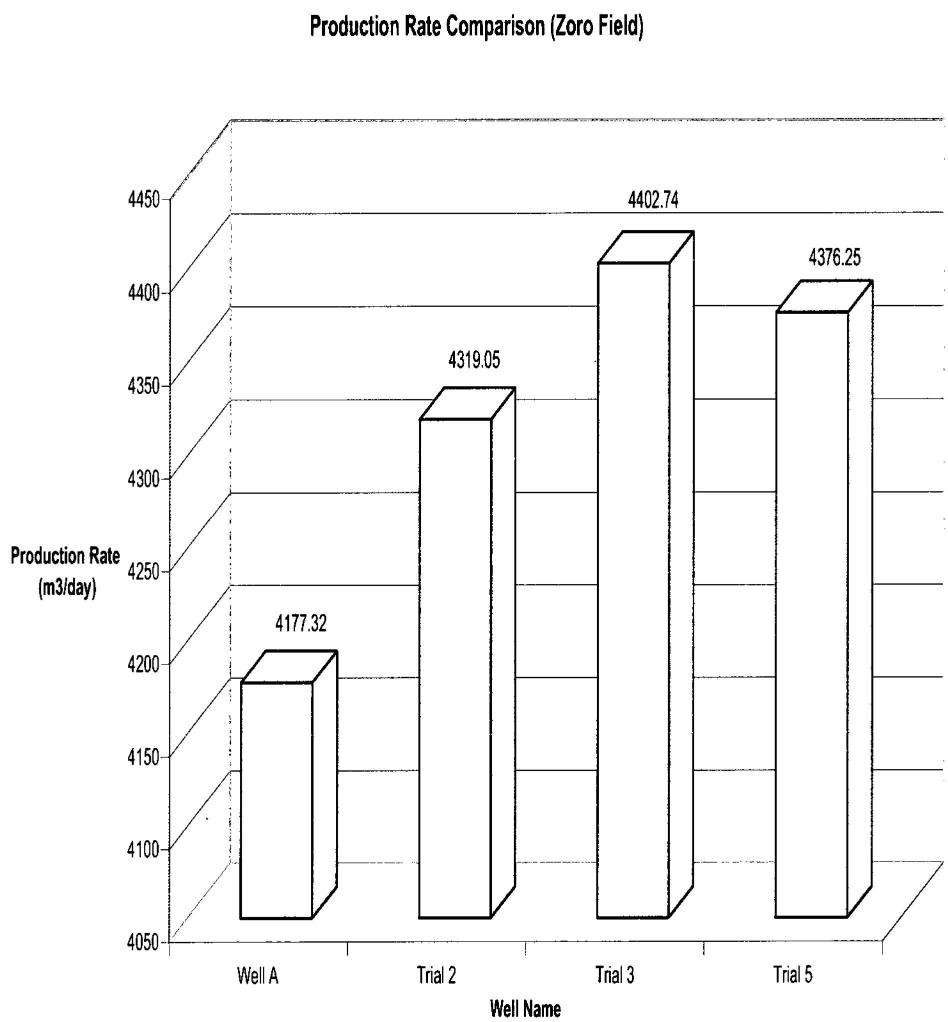

Figure 6.5: Production Rate Summary for the Zoro Field

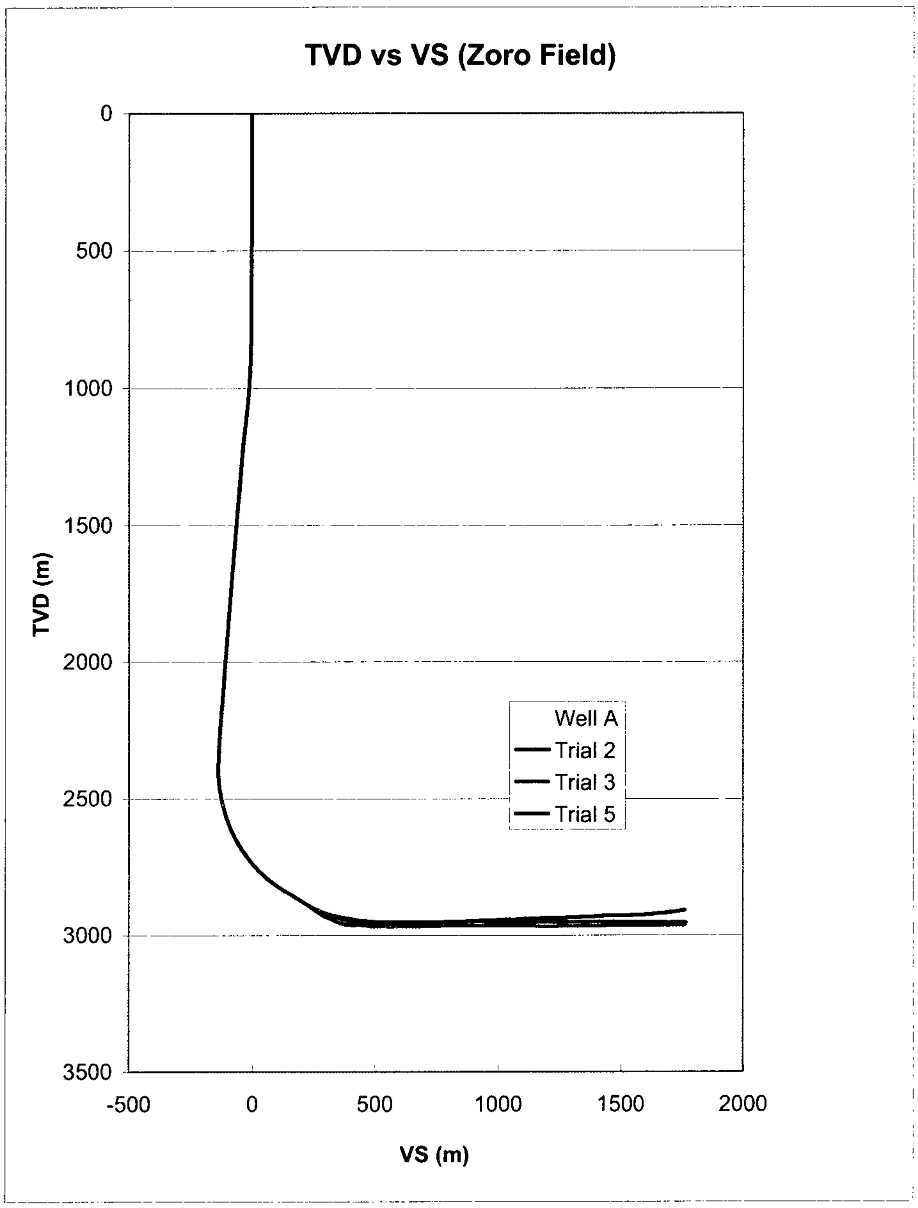

Figure 6.6: Vertical Profile of all Wells in Zoro Field

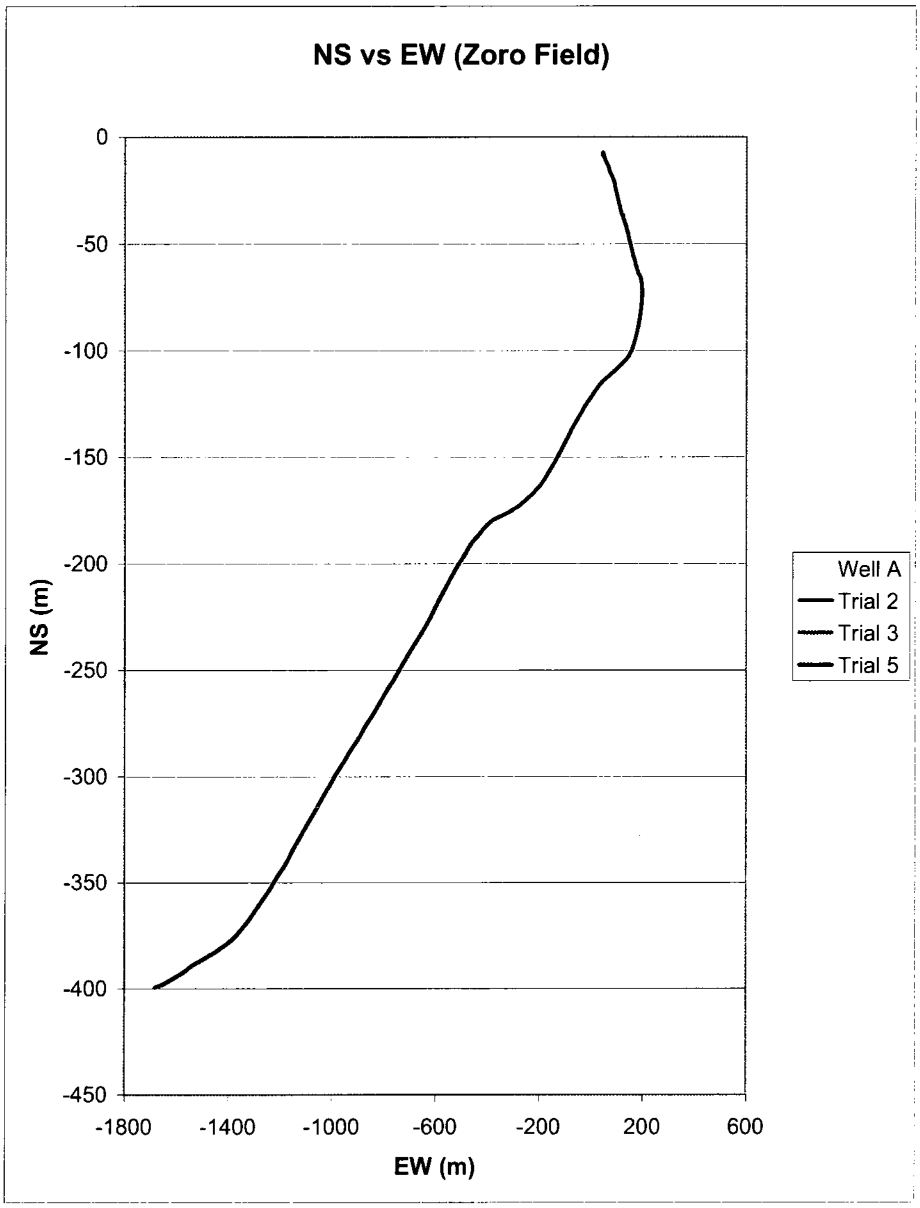

Figure 6.7: Horizontal Profile for all Wells in Zoro Field

Torque and Drag Analysis

Firstly, please note that the units for sideforces used in my research is kilogram force (1000kgf/10m) which was the output given for the results in DrillSafe. The conversion into Newtons is multiplication by $9.81m/s^2(N = (9.81x1000kgf/10m)$. The BHA used in the torque and drag analysis is shown in Figure 6.8. The well geometry for the Zoro field was already explained in section 6.2.3. Once all simulations in the reservoir tool were analyzed, Well A was imported into $PowerPlan^{®}$ and the torque values, sideloads, and hookloads while picking up and slacking off were obtained. The method of importing was explained in the the Methodology chapter. The results are discussed in section 6.2.5. The analysis was repeated for Trial 2, Trial 3, and Trial 5. Both Trial 2 and Trial 5 had results that were within the limitations set in section 4.7. When running the analysis for Trial 3, there were high sideforces experienced up to 45.35 (1000kgf/10m) near and at the entry point into the reservoir ($\approx 3377mMD$). These values were unacceptable as compared to the limiting sideloads (900 1000kgf/10m) that can be experienced by unprotected drillpipe. Following the methodology in Chapter 5, the next step was to go back into $NETool^{TM}$ and modify the points in that section of the well. After doing so, the simulation was run again to ensure the production rates were still higher then the base case. This being so, the well path was once again imported into $PowerPlan^{®}$'s Well Design module and the torque and drag analysis was re-ran. The results showed that the new sideforces were within the limitations of the drillstring.

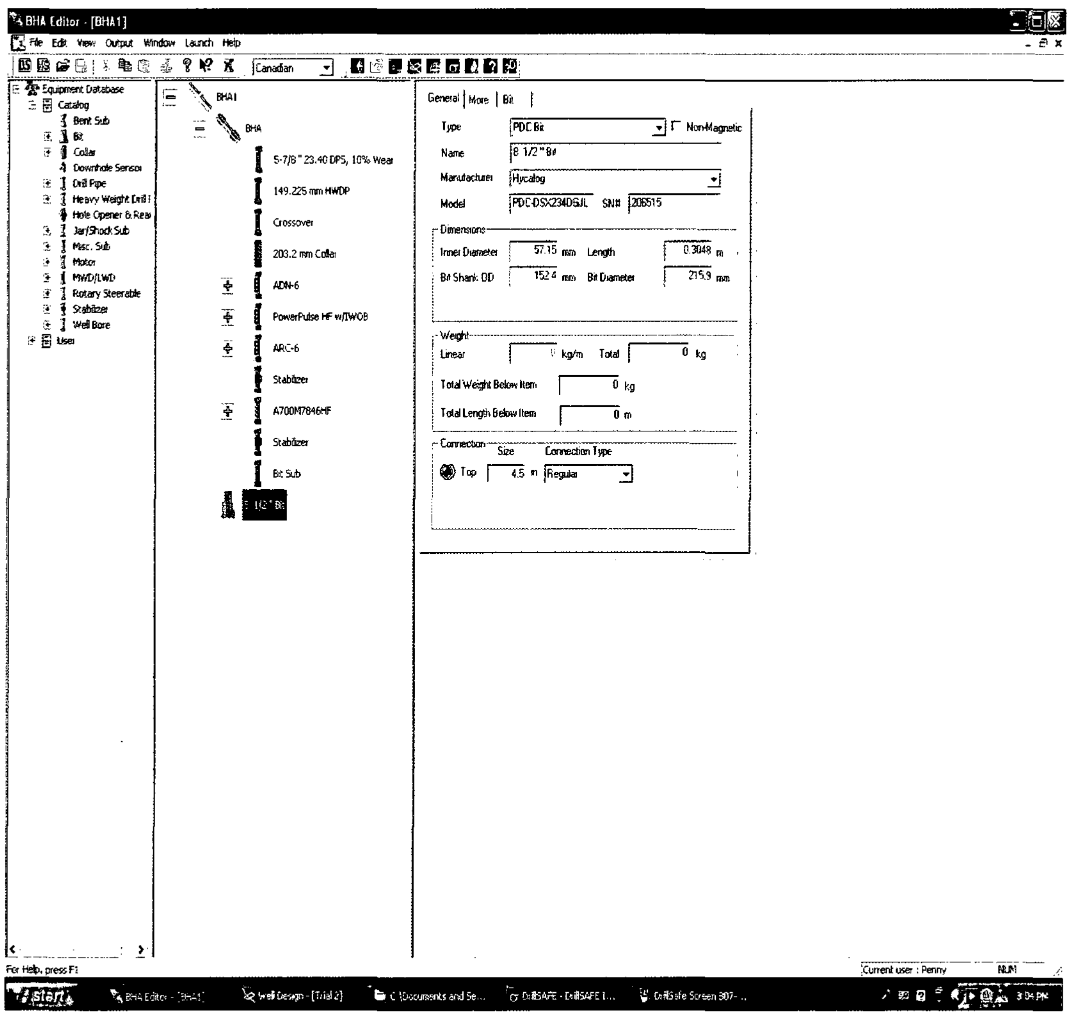

Figure 6.8: BHA Screen - Used for Torque and Drag Analysis

6.2.5 Results

The results from the production and torque and drag analysis are summarized below.

As seen in Figure 6.9 and summerized in Table 6.1, the production rate increase from the original well path Well A was highest for Trial 3 with a 5.46% increase. This was followed by Trial 5 with a 4.76% increase and Trial 2 with a 3.39% increase. The actual increase in oil in cubic meters per day for Trial 3 was $227.95m^3/day$ followed by Trial 5 with $199m^3/day$ and Trial 2 with $172m^3/day$.

The maximum torque loss encountered on the drillstring was for Trial 3 which experienced torque values up to 40.61kN.m located at the bit, as expected (see Figure 6.10). This was still within the limitations of the system.

From Figure 6.11, the sideloads were at a maximum in Trial 5 with values of 2.79 - 4.47 (1000kgf/10m) from 3200m MD to 3400m MD. The maximum sideloads were encountered between 2400m MD and 2500m MD for Well A, Trial 2 and Trial 5. As explained in section 4.5, the sideforces were greater in sections in the well that were curved and less in straight sections. The sideforces experienced at the bit were not included because these are generally very high due to the BHA interface with the wellbore and DrillSafe is designed to interpret high sideloads at TD.

As seen in Figure 6.12, the maximum hookload while picking up was located at the bottom of the drillstring where the maximum weight would be measured. It is the point at which the maximum amount of drillstring is in the hole. For the four wells in the Zoro field it was found that Trial 3 had the highest value at 185.37 kgf.

While slacking off (going in the hole) the hookload is a function of weight of the drillpie which is determined from the TVD and the friction force. For all four wells the hookload was a maximum at 3000m MD with a value of 75.43 kgf (see Figure 6.13). They were all the same because the trajectory points at that location in the well we not going into the reservoir and therefore were not changed.

Well Name	Production Rate (m3/day)	Production Rate Increase	Torque Loss		Sideloads		Hookload While Picking Up		Hookload While Slacking Off	
			Maximum(kN.m)	Depth of Maximum(m MD)	Range of Maximum(1000 kg/10m)	Range Depth of Maximum(m MD)	Maximum(1000 kgf)	Depth of Maximum(m MD)	Maximum(1000 kgf)	Depth of Maximum(m MD)
Well A	4177.32		39.61	4602.30	3.49 - 3.05	2400 - 2500	174.94	4602.30	75.53	3000.00
Trial 2	4319.05	3.39%	40.43	4610.95	3.58 - 3.12	2400 - 2500	184.93	4610.95	75.53	3000.00
Trial 3	4405.27	5.46%	40.61	4613.00	3.64 - 3.17	2400 - 2500	185.37	4613.00	75.53	3000.00
Trial 5	4376.25	4.76%	39.97	4613.00	4.47 - 2.79	3200 - 3400	179.09	4613.00	75.53	3000.00
Limitation	No Limit		54.91 kN.m		9.00 (1000 kg/10m) (without protectors)	9.00 (1000 kg/10m) (without protectors)	680 (1000 kgf)	680 (1000 kgf)	680 (1000 kgf)	680 (1000 kgf)

Table 6.1: Result Summary for the Zoro Field

Note: Maximum Sideload value does not include sideloads experienced at the bit. These are generally very high due to the BHA interface with the wellbore and DrillSafe is designed to interpret high sideloads at TD.

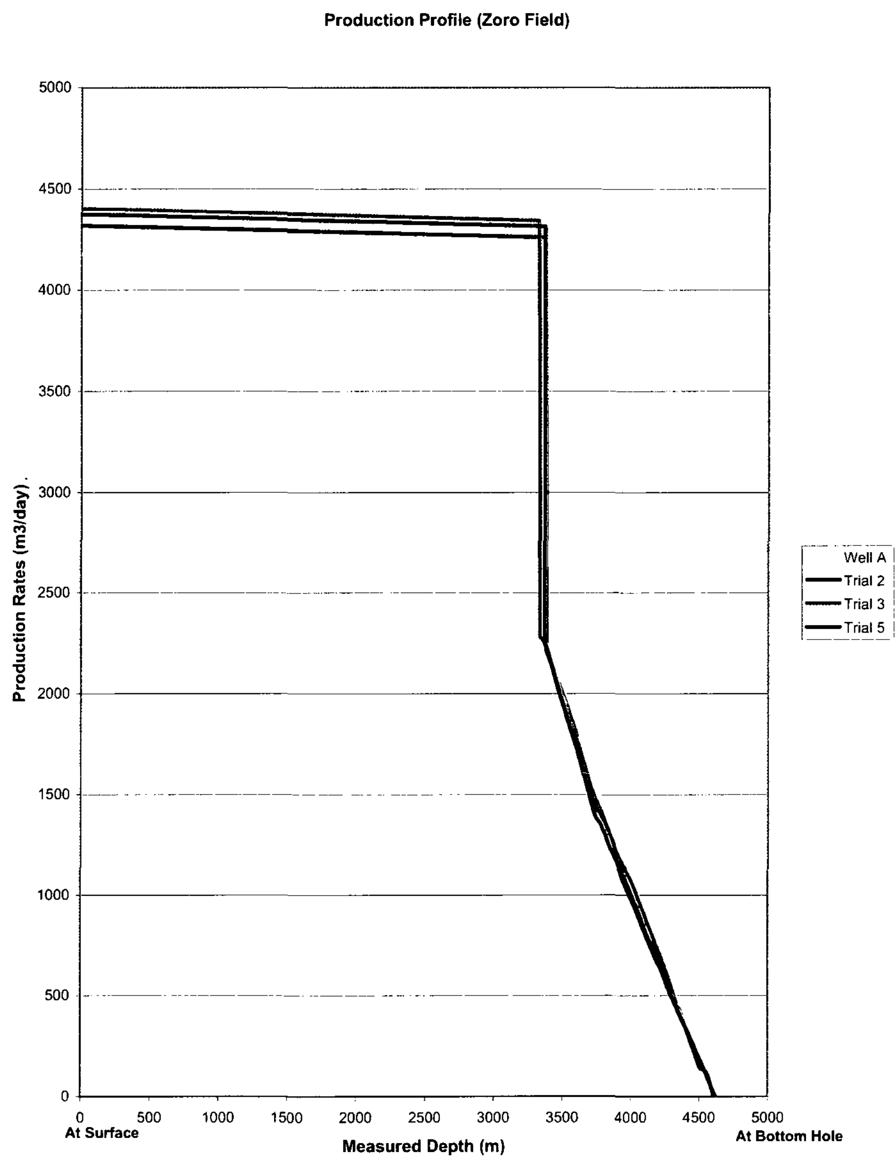

Figure 6.9: Production Profiles for Wells in Zoro Field

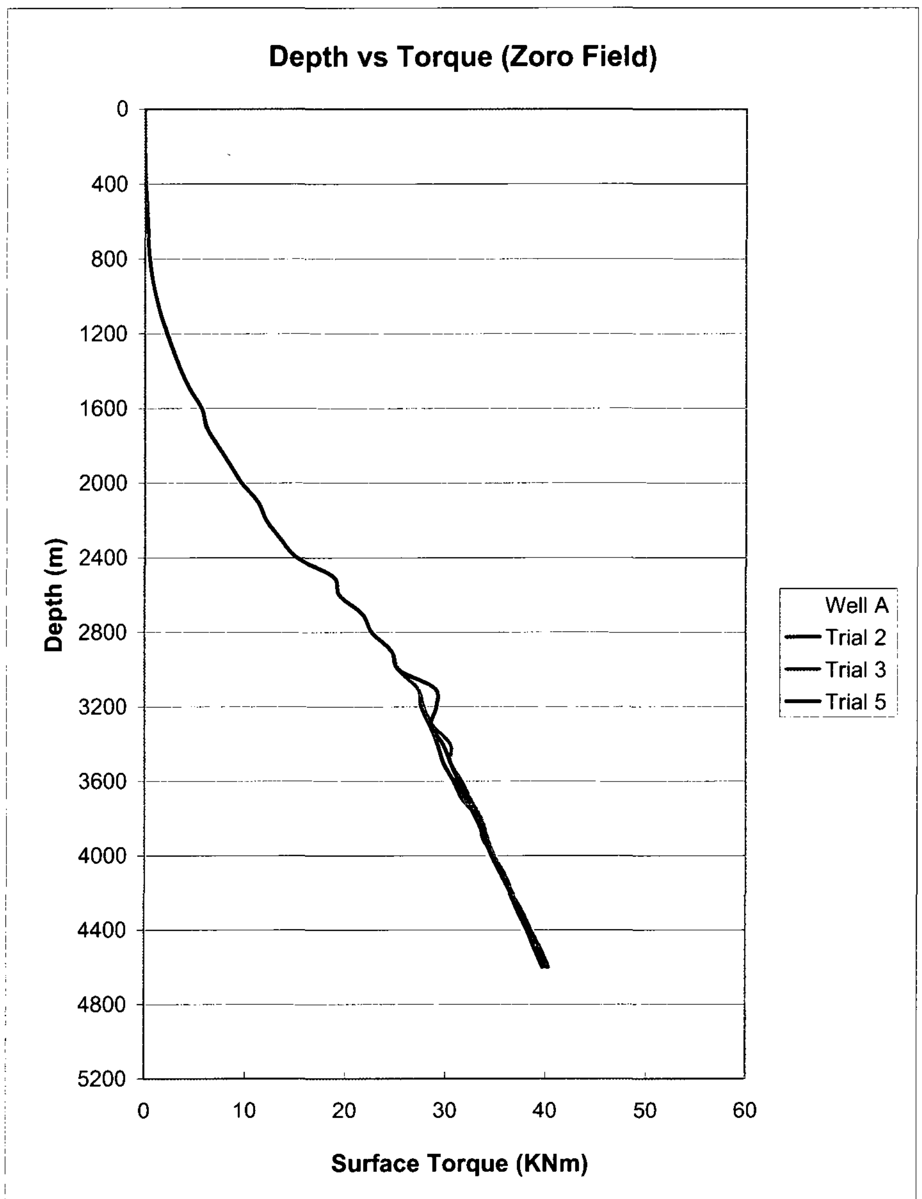

Figure 6.10: Torque Profile for Wells in Zoro Field

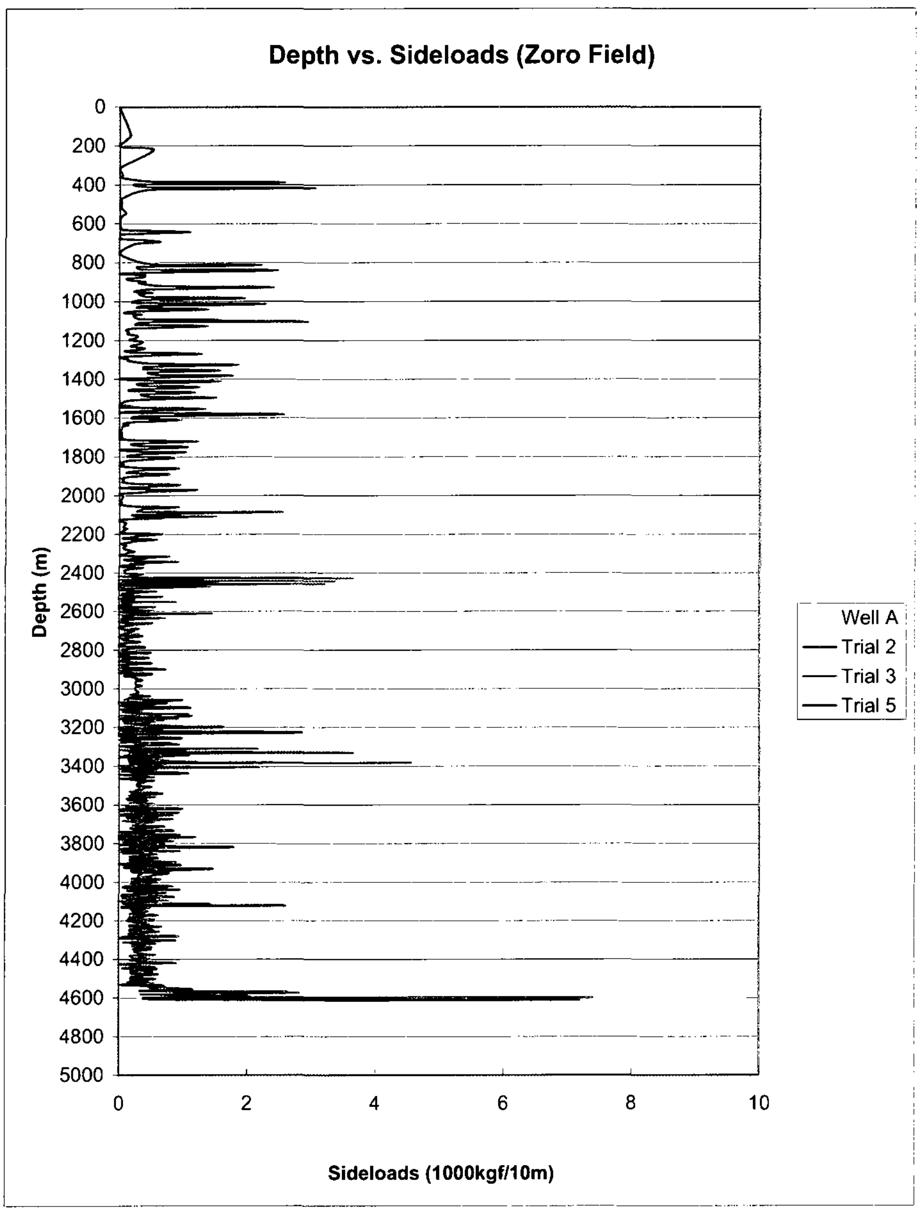

Figure 6.11: Sideloads for Wells in Zoro Field

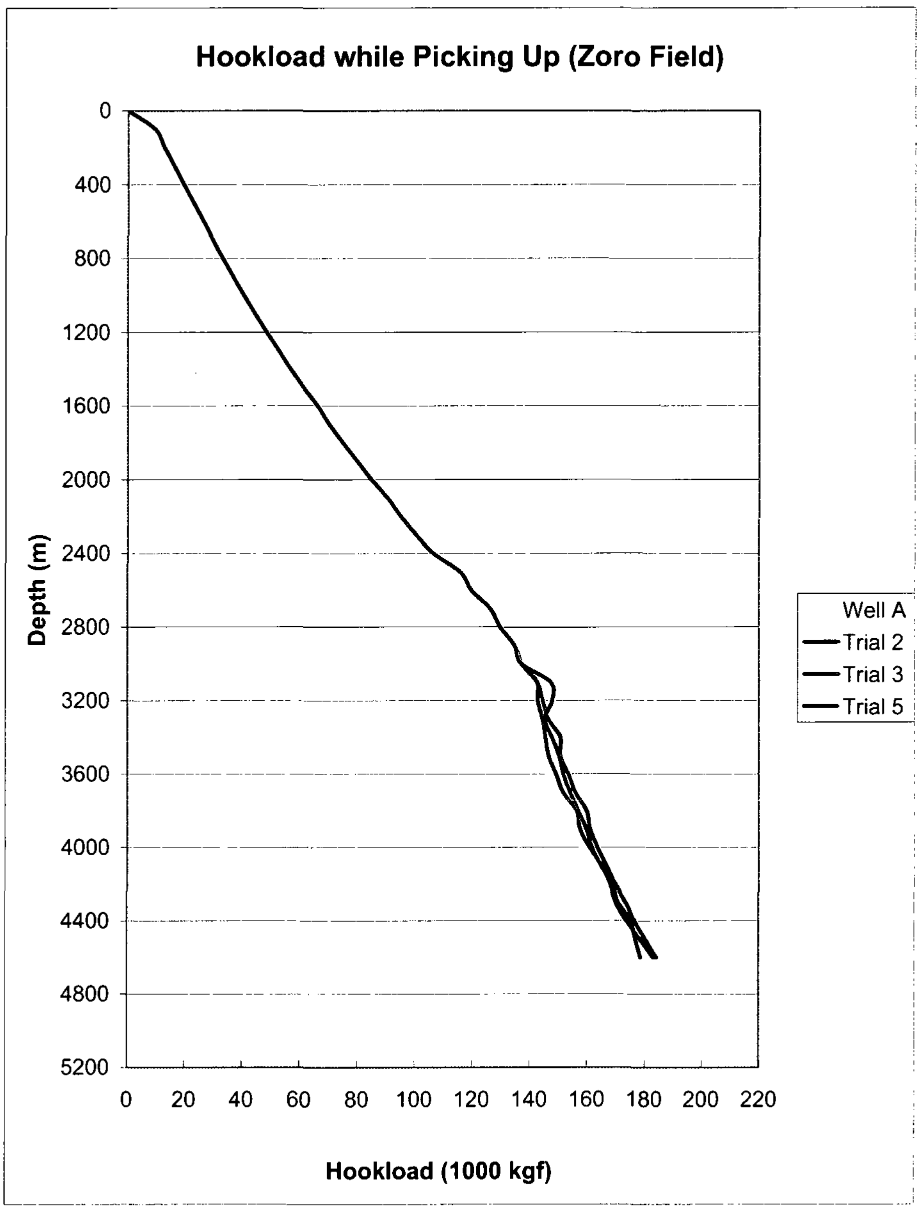

Figure 6.12: Hookload While Picking Up Profile for Wells in Zoro Field

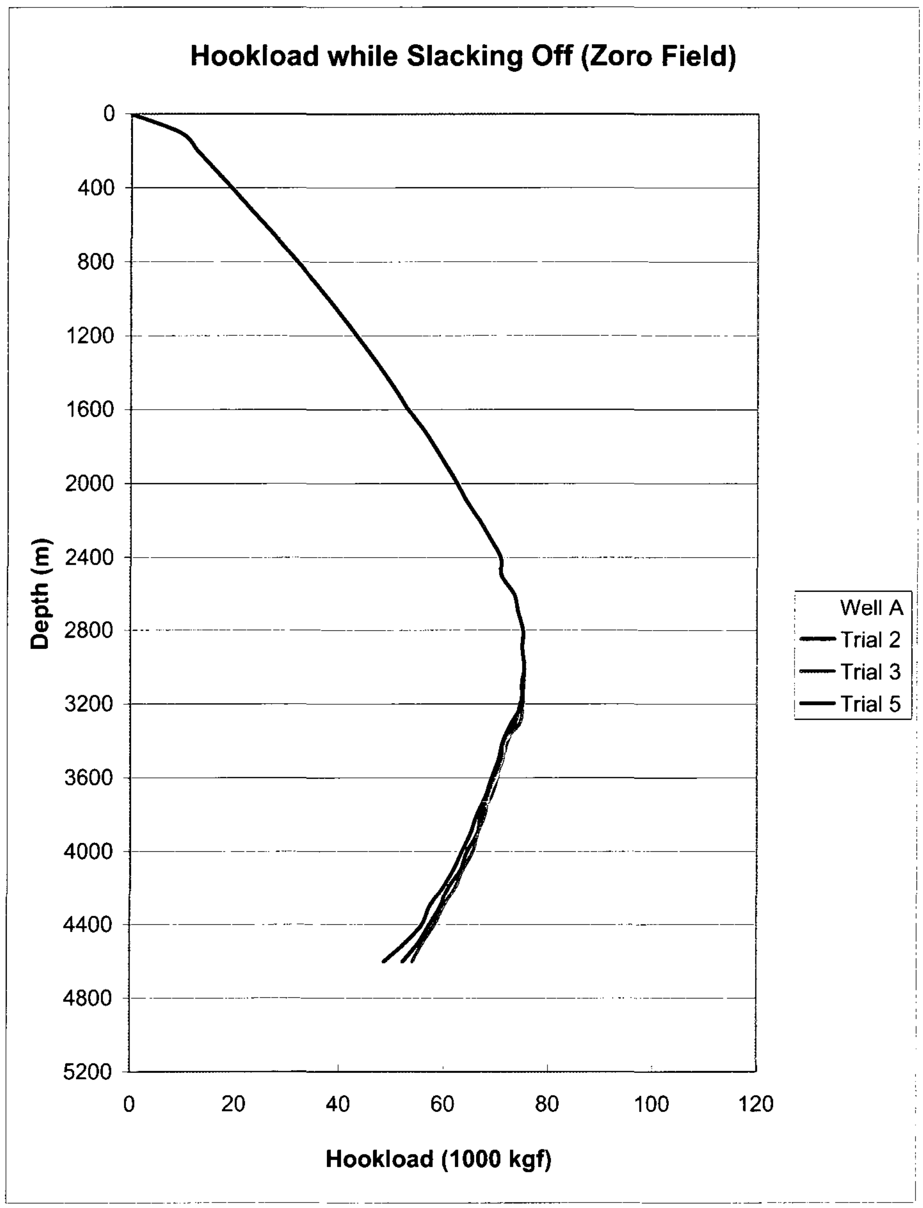

Figure 6.13: Hookload While Slacking Off Profile for Wells in Zoro Field

6.3 Case Study 2

Well B was the base case well for the Zeus field and the focus of the second case study. The geological structure for the field was made of several different types of rock and clay as well. Core samples and mud returns were used to determine the formations in the reservoir and the assocaited properties. Once the formations were studied, Well B was simulated to determine the production rate that would be considered the minimum and all other profiles would be compared to these results. All wells that were selected for the study were analysed using torque and drag modelling. Several plots were then created to summarize the results from the analysis.

6.3.1 Geological Structure

The geological structure for the Zeus field was much the same as the Zoro field; however, Well B was much longer then well A and therefore encompassed different amounts of various rock properties in different locations. The formation sampling began at 970m MD for this well and continued to TD (5137m MD). The main rocks present in the reservoir were claystone, siltstone, limestone, marlstone, and sandstone. Each of these were identified in different sections of the reservoir and were characterized in the same format as Case Study 1.

The claystone was dominant in the upper portions of the reservoir from about 970m to 2600m with traces to 2670m. The mineral properties of the claystone were summarized as:

- Color: dark brown, light to medium grey, dark grey.
- Hardness: soft to firm, hard.
- Atomic structure: amorphous in part.
- Aggregate shape: blocky, sub rounded, platy in part.

- Texture: silty.
- Composition: trace limestone, trace pyrite, trace glauconite, trace dolomite, trace siltstone.

The siltstone became present at around 2600m and continued through to 4005m MD. It was not consistent through the formations. It was dominant in two areas: from 2600m to 2700m and again from 3225m to 3870m. The properties of the minerals in these sections were:

- Color: occasional light grey, medium grey, dark grey, dark brown to dark grey brown, rare translucent.
- Hardness: firm to hard.
- Aggregate shape: sub rounded to sub angular, blocky, argillaceous.
- Composition: limy in part, marly in part, trace glauconite, trace carbonate, calcareous.

The limestone existed from about 2700m MD to 2800m MD with trace amounts to 3455m MD ranging from 10 - 30% of the total core sample in the section. The properties of the minerals comprised in this rock were:

- Color: light to medium grey, off white.
- Hardness: soft to firm.
- Aggregate shape: blocky.
- Texture: silty.
- Composition: limy in part, trace greenish grey shale, marly in part, trace glauconite.

- Atomic Structure: micro crystalline.

The marlstone was predominantly located from approximately 2700m MD to 3140m MD with decreasing amounts to 3385m MD. Marlstone is a metamorphic rock and its properties were similar to the limestone. They were as follows:

- Color: light to medium grey, occasionally off white.
- Hardness: soft to firm to hard.
- Aggregate shape: blocky.
- Texture: silty.
- Composition: limy in part, trace greenish grey shale, trace pyrite, trace glauconite.

The last formation consisted entirely of sandstone. Sandstone is a sedimentary rock and as already mentioned, the primary reservoir rock for oil. The thickness of the formation was approximately 1128 m. The properties of sandstone were:

- Color: occasionally off white to white, light brown, clear translucent quartz grains.
- Hardness: firm to hard.
- Texture: very fine to fine grain.
- Composition: siliceous matrix, slightly calcareous, moderately cemented.
- Porosity: fair to good.
- Florescence: bright yellow.
- Streaming cut: bright yellow.

6.3.2 Production Data for Well B

The same constants were used for Well B as were used for Well A, the completions were open hole wire-wrapped screen and the bottom hole pressure was 253 bars. All other data in the simulator was default set from importing the Beta reservoir. The production rate obtained from simulating Well B was $4748.72m^3/day$. The production profile for this well is shown in Figure 6.14.

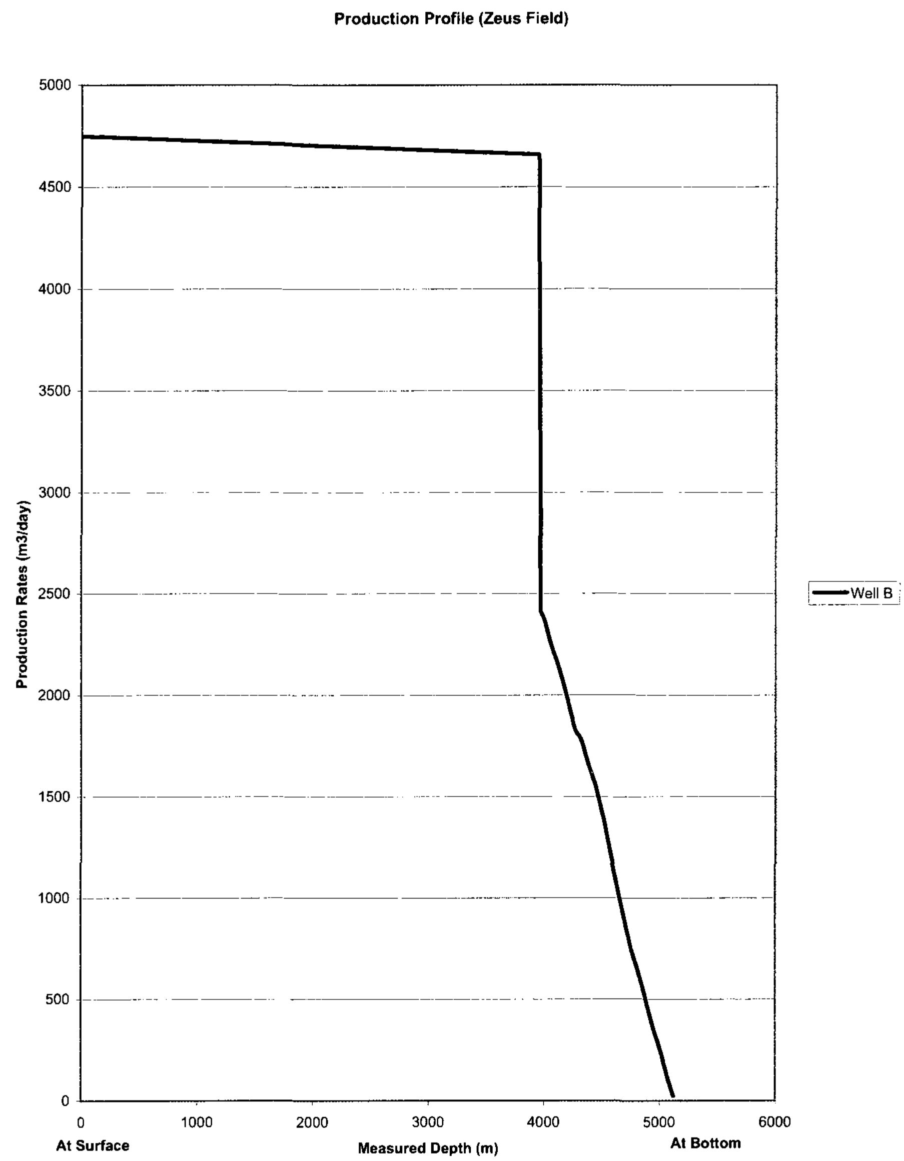

Figure 6.14: Production Rate Profile of Well B

6.3.3 Well Design for Well B

The vertical well profile for base case Well B followed a deviated horizontal path with 2 tangent sections (see Figure 6.15). The kick off point for the well began at about 375m TVD with an inclination of about 4.1 degrees. At approximately 1075m TVD there was another deviation from vertical as it increased to an inclination of about 16.25 degrees and dogleg severity (DLS) of 5.88 degrees/30m. The path followed a tangent line to 2438m TVD where it deviated again in the positive vertical section direction. The DLS at this point was much higher at 14 degrees/30m. The path was tangential to a TVD of 2935m. Well B continued to drill in a fairly horizontal line to TD (5123.67m MD).

From the horizontal profile in Figure 6.16, Well B appears to be in the shape of a backwards "L". The vertical section origin is 35.79m South and 34.49m East. The drillstring moves southeast in a linear path to about 1275m South and 390m East. At this point the path changes direction and turns towards the southwest. It follows an arc shape path to approximately 160m West and 1680m South where it then continues in a fairly straight path to TD.

The well geometry for the Zeus field is shown in Figure 6.17. The well was made up of four hole sections and three casing sizes. The first section was the 36"(914.4mm) hole section drilled to 231.0m MD. The 30" (762mm) casing was set at 227.0m MD. The 20" (508.0mm) hole was drilled to 970.0m with the 13 3/8" (340.0mm)casing run to 955.37m MD. The third section of the well was a 12 1/4" (311mm) hole drilled to 4035m MD and the 9 5/8"(244mm)casing was set at 4022.66m MD. The final hole was 8"'s and drilled to TD(5137m MD). A wire-wrapped screen not shown here was placed in the final hole section to TD. The well geometry described here is used for all wells designed for case study two. It represents a general configuration of the wellbore and casing for the Zeus field.

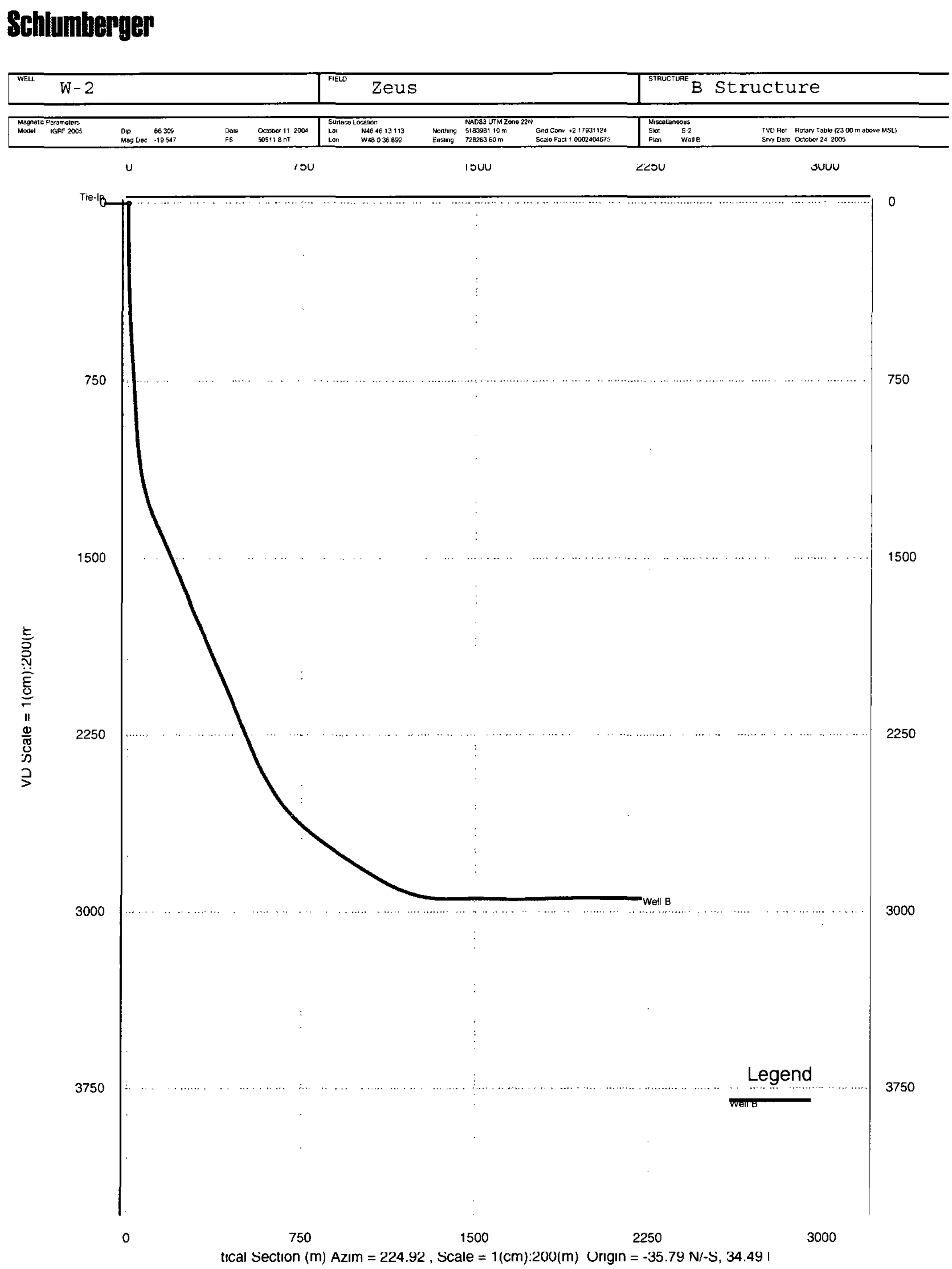

Figure 6.15: Vertical Profile of Well B

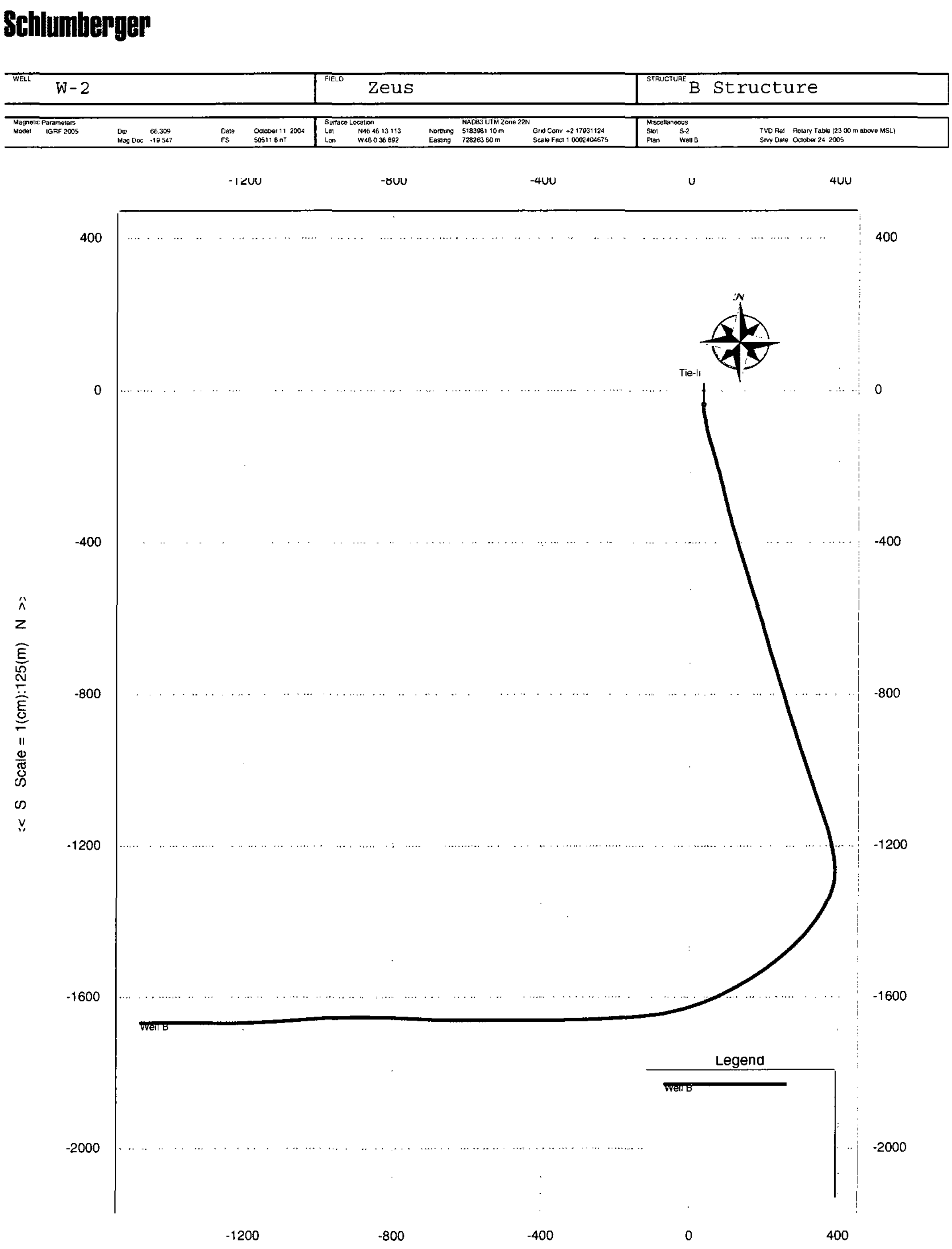

Figure 6.16: Horizontal Profile of Well B

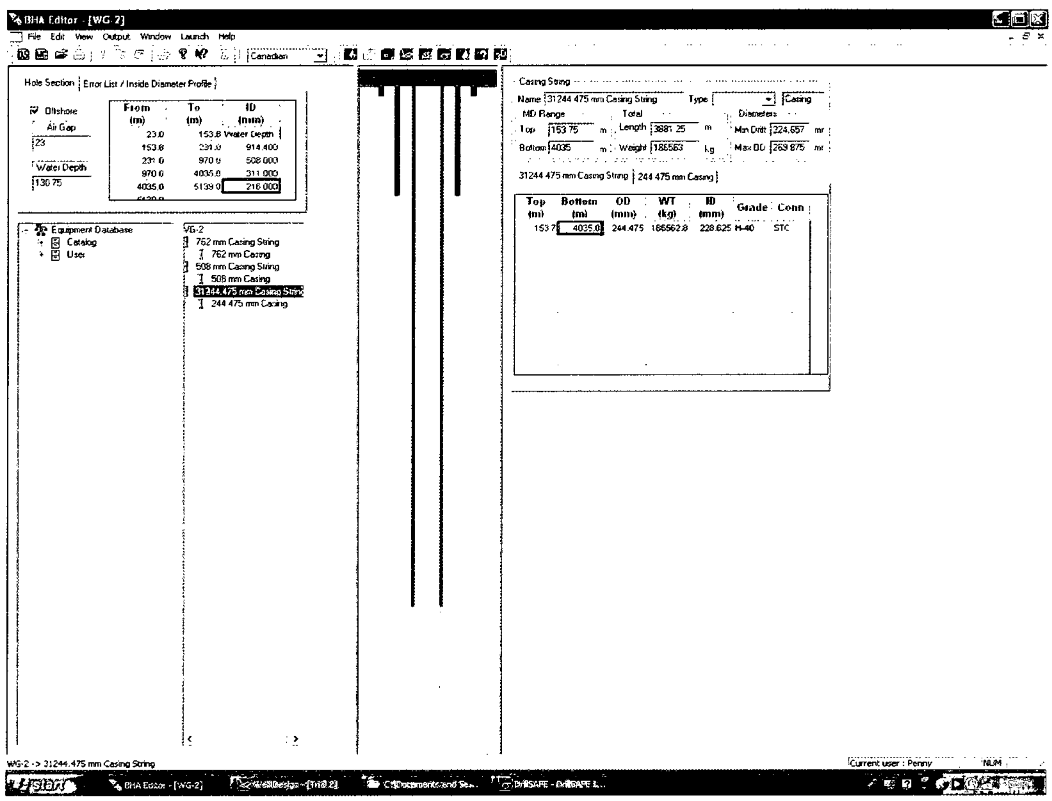

Figure 6.17: Well Geometry and Casing Details for Zeus Field

6.3.4 Analysis

This section described the analysis carried out for case study 2 in the Zeus field. The analysis began with the production simulation and optimization and then continued with torque and drag analysis of the selected well cases.

Production Optimization

For the production optimization of the Zeus field using base case Well B, the well was modified by moving the points up and down in the reservoir (changing TVD locations) and across the reservoir (changing North/South direction), from the entry point to the end of the well. For this case study several wells were created in the reservoir. Many of the wells that were developed by changing the TVD of the trajectory points provided production rates that were lower then the original case. By incorporating changes to the North/South direction as well one trial had increased production. Other wells were created by changing the North/South coordinates alone, from which two more wells gave higher rates then the base case Well B. A total of ten wells were designed but only three provided the required results: Trial 4, Trial 7 and Trial 8. Figure 6.18 shows the comparison of production rates for each well.

Looking at the vertical profile of all wells in the Zeus field in Figure 6.19, all wells follow closely the same path as Well B except for Trial 4. It stayed on the same trajectory until about 3665m MD (2900m TVD) but continued to deviate downward to a TVD of about 2955m. It continued horizontal for a brief period (vertical section of appoximately 1500m) and then began to rise pass the 90-degree inclination, keeping in mind that inclination is measured counter-clockwise from south direction. The well continued a fairly constant build rate (1.5 - 2.5 degrees per 30m) to a total inclination of 93^o at a TVD of 2914.94m (5138.89m MD) and vertical section of 2232.61m.

Trial 7 and Trial 8 have basically the same path except for a 4m difference in TVD at the end of the well. Trial 7 is 4m higher then Trial 8 with a slightly higher associated inclination of 88.9°. The vertical section for both wells end at 2223.33m and the measured depth for Trial 7 is 5120.35m while the measured depth for Trial 8 is 5120.70m. Both wells start their curved sections slightly before and above Well B.

In Figure 6.20, the well paths are similar to Well B to a measured depth of about 4400m. Looking down on the profiles from a birds-eye view, both Well B and Trial 4 follow the same path (red and yellow behind) and Trial 7 and Trial 8 follow the same path (blue and green behind). Trial 7 and Trial 8 did not differ significantly in the vertical profile but in the horizontal view the wells continue in a fairly horizontal direction from -1661.76m N/S and -755.36m E/W to a final destination of -1668.11m N/S and -1477.28m E/W. The north/south coordinate barely changes.

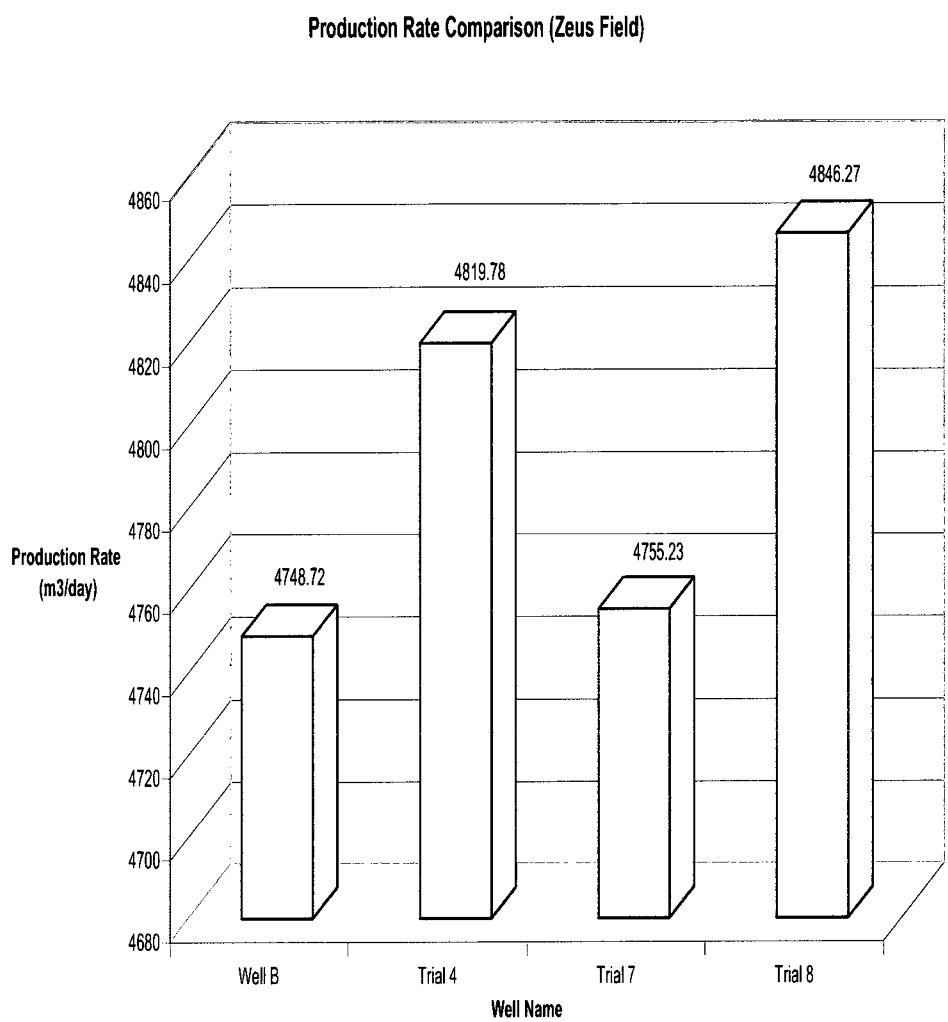

Figure 6.18: Production Rate Summary for the Zeus Field

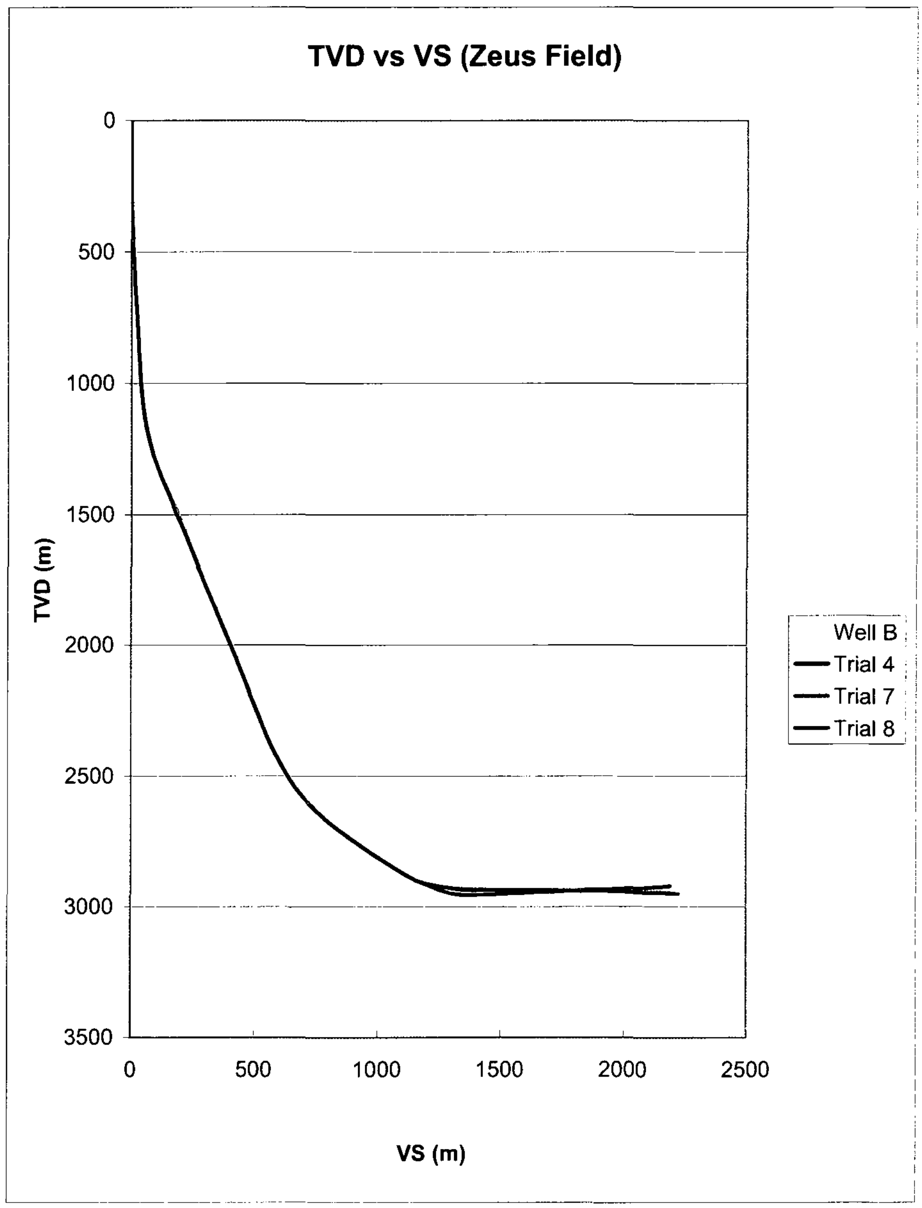

Figure 6.19: Vertical Profile of all Wells in Zoro Field

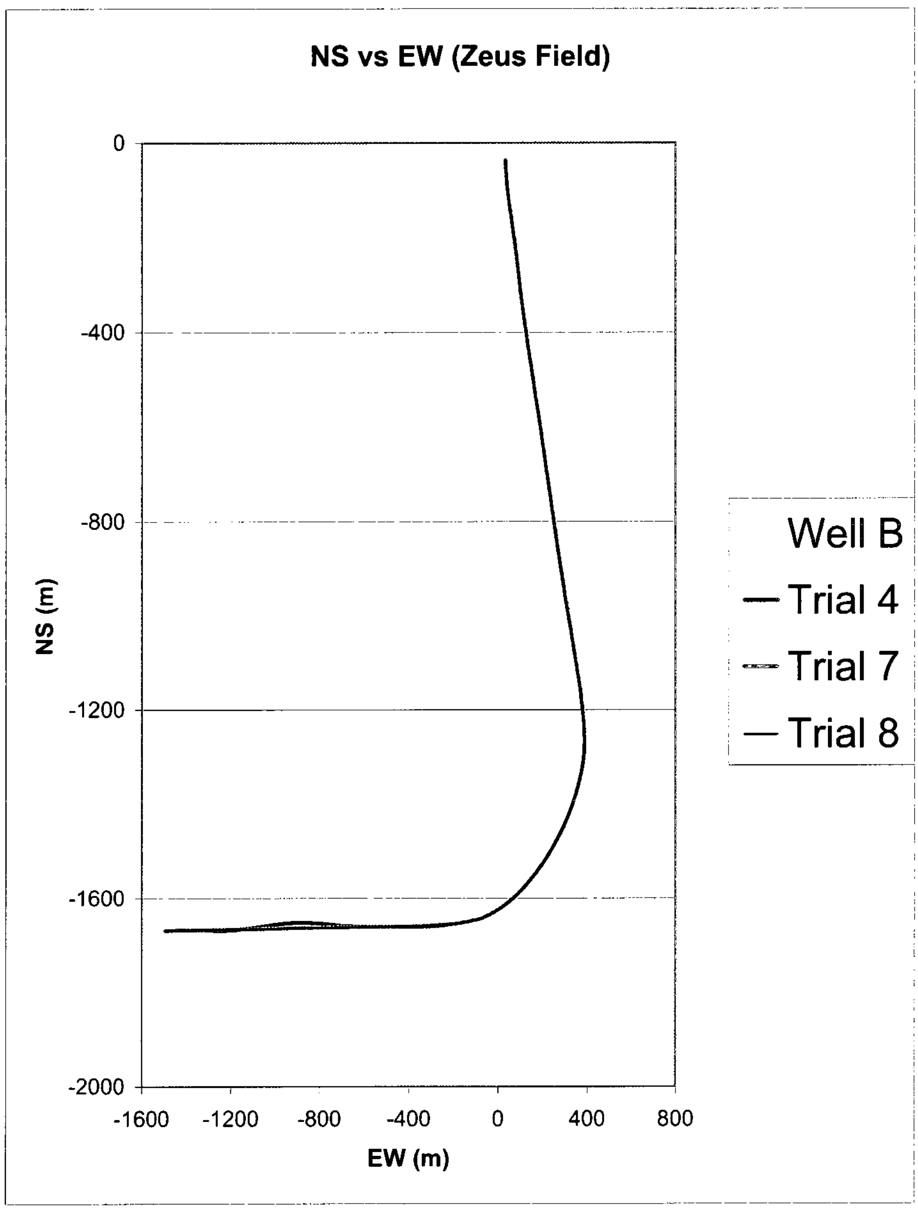

Figure 6.20: Horizontal Profile of all Wells in Zoro Field

Torque and Drag Analysis

Agaun, please note that the units for sideforces used in my research is kilogram force (1000kgf/10m) which was the output given for the results in DrillSafe. The conversion into Newtons is multiplication by $9.81m/s^2 (N = (9.81x1000kgf/10m)$.The BHA used in the torque and drag analysis was shown in Figure 6.8. The same BHA was used for both case studies to minimize variability in the analysis. The well geometry for the Zeus field was already explained in section 6.2.3. Once all simulations in the reservoir tool were analyzed, Well B was imported into $PowerPlan^{®}$ and the torque values, sideloads, and hookloads while picking up and slacking off were obtained. The method of importing was explained in the the Methodology chapter. Trial 4, Trial 7, and Trial 8 were also imported into the program and the torque and drag was analysed to determine if the wells could be drilled. All outputs from the analysis were within the limitations of the system. The results are discussed in section 6.3.5.

6.3.5 Results

The results from the production simulation and torque and drag analysis are summarized below in Table 6.2.

The production rate increase from the original path was highest for Trial 8 with an increase of 2.05%. Trial 4 was close behind with a 1.5% increase while Trial 7 had only 0.14% increase in oil production. In terms of actual volume per day, Trial 8 produced $98m^3/day$ more then Well B with Trial 4 producing $71m^3/day$ more oil then the base case. Figure 6.21 shows the production profiles for all the wells in the Zeus field.

As seen from the summary, the maximum torque loss occured in Trial 8 at the bottom of the well with a value of 49.5 kN.m. Trial 7 is just below this with torque losses of 49.4 kN.m experienced at the bottom of the well (Figure 6.22). This is to be expected as torque loss increases as you add more drillstring and the bit goes further in the well (see section 4.5). This torque value is still within the limitations of the system.

From Figure 6.23, the maximum sideloads ranged from 3.33 (1000kg/10m) to 2.19 (1000kg/10m) for Trial 8 occured at a depth ranging from 1000m to 1400m. As explained earlier in section 6.2.5, sideforces at the bit were not considered for this analysis as there is a high degree of contact between the bit and the wellbore and do not give a representation of the sideforces on the drillstring itself. All wells experienced very simular sideloads in the same depth range which was to be expected with such closely designed well paths. These values were within the limitations of the system as well.

In Figure 6.24, the maximum hookload while picking up was found in Trial 8 with a value of 191.21 (1000kgf) occuring at the bottom of the drillstring where the maximum weight would be located because it has all the load of the drillstring above it. This value is well below the limitation of 680 (1000 kgf) set for the system. The lowest hookload is experienced in Trial 4 with a hookload of 174.6 (1000kgf).

While slacking off, or going in the hole, the maximum hookload calculated was 68.38 (1000kgf) experienced by both Well B and Trial 4. Both of these wells had very simular profiles which accounts for the same values of hookload while slacking off. Trial 7 and Trial 8 had the same hookload as well with a value of 66.97 (1000kgf). All of these values occured at 3600m MD as seen in figure 6.25. This was were the inclinations reached 70^0+ and therefore the drillstring went into compression (see operating modes in section 4.3.5).

Well Name	Production Rate (m3/day)	Production Rate Increase	Torque Loss		Sideloads		Hookload While Picking Up		Hookload While Slacking Off	
			Maximum(kN.m)	Depth of Maximum(m MD)	Range of Maximum(1000 kg/10m)	Range Depth of Maximum(m MD)	Maximum(1000 kgf)	Depth of Maximum(m MD)	Maximum(1000 kgf)	Depth of Maximum(m MD)
Well B	4748.72		46.24	5123.67	3.30 - 2.07	1000 - 1400	177.11	5123.67	68.38	3600.00
Trial 4	4819.78	1.50%	45.98	5138.89	3.23 - 2.02	1000 - 1400	174.58	5138.89	68.38	3600.00
Trial 7	4755.23	0.14%	49.41	5120.35	3.31 - 2.07	1000 - 1400	190.61	5120.35	66.97	3600.00
Trial 8	4846.27	2.05%	49.52	5120.7	3.33 - 2.19	1000 - 1400	191.21	5120.7	66.97	3600.00
Limitation	No Limit		54.91 kN.m		9.00 (1000 kg/10m) (without protectors)	9.00 (1000 kg/10m) (without protectors)	680 (1000 kgf)	680 (1000 kgf)	680 (1000 kgf)	680 (1000 kgf)

Table 6.2: Result Summary for the Zeus Field

Note: Maximum Sideload value does not include sideloads experienced at the bit. These are generally very high due to the BHA interface with the wellbore and DrillSafe is designed to interpret high sideloads at TD.

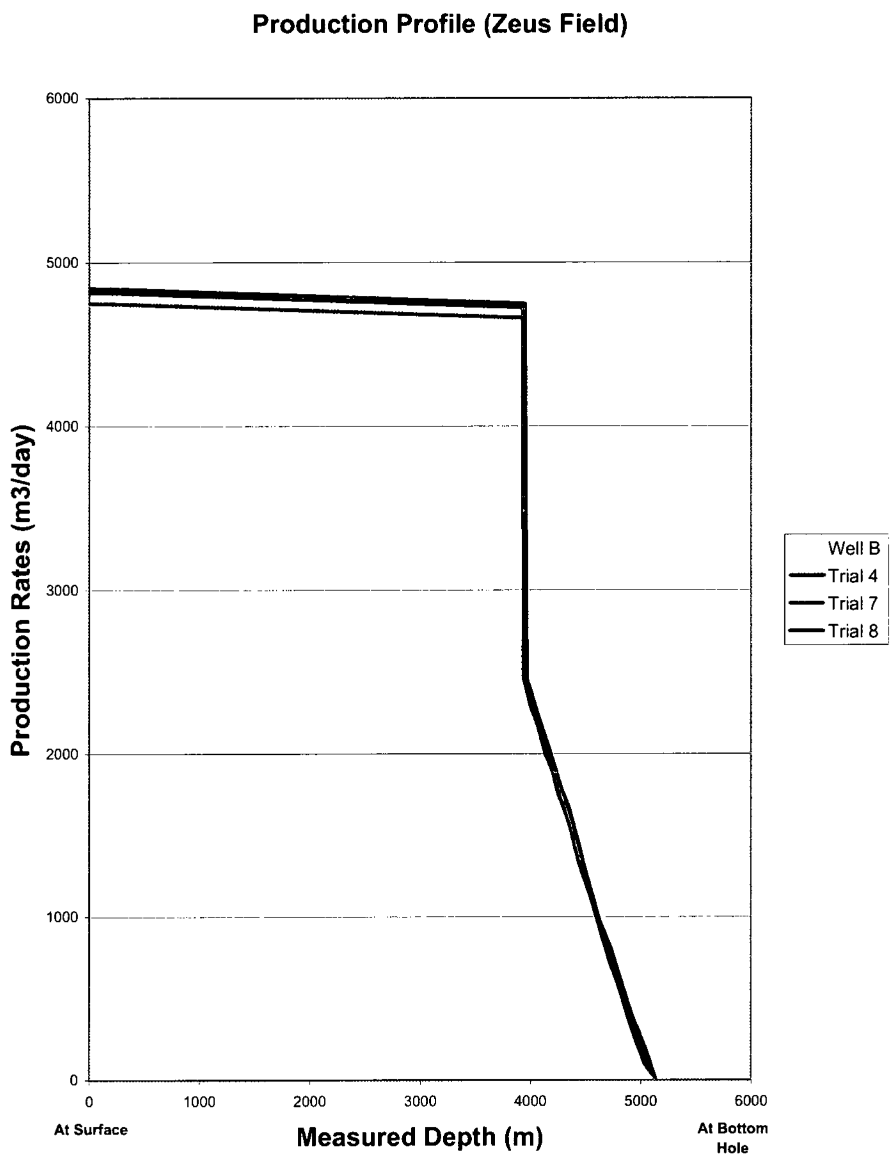

Figure 6.21: Production Profiles for Wells in Zeus Field

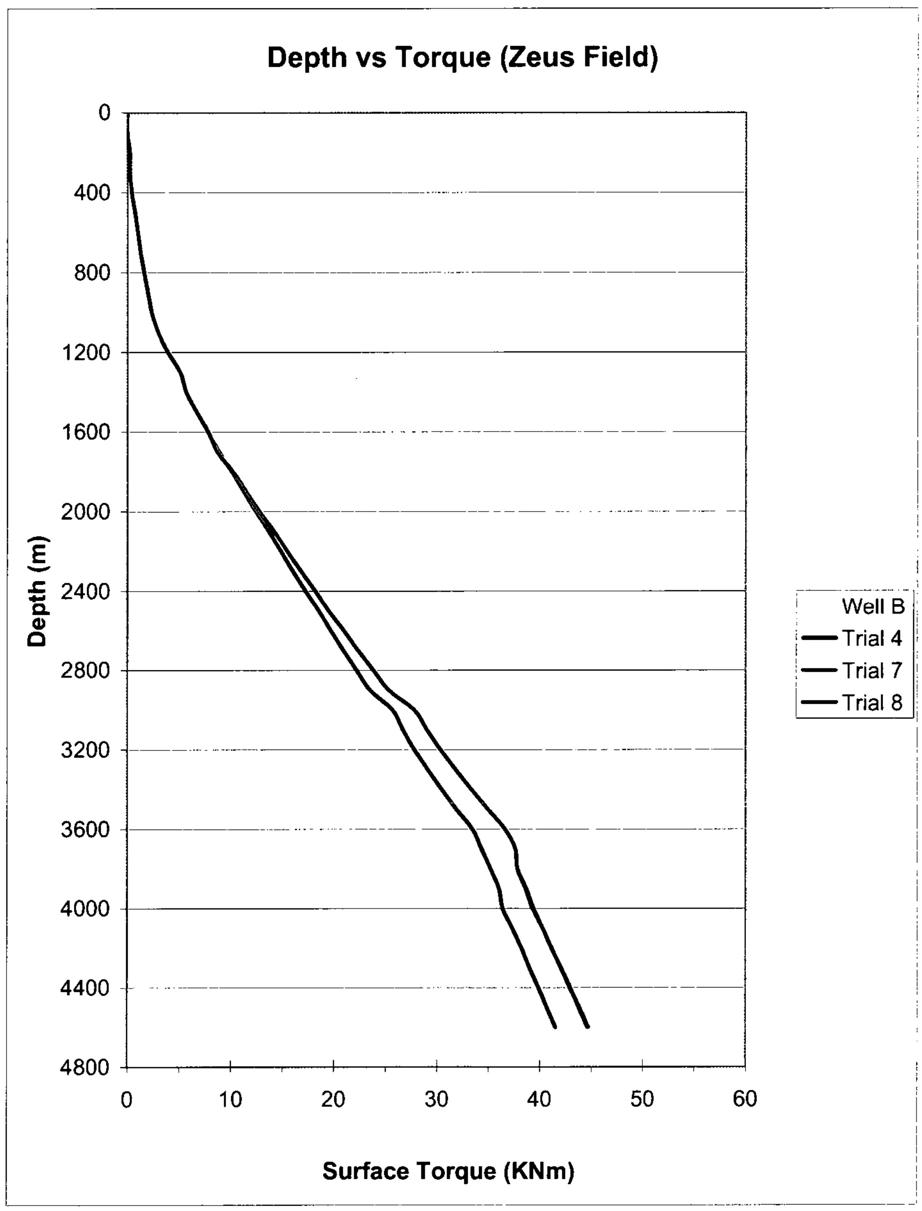

Figure 6.22: Torque Profile for Wells in Zeus Field

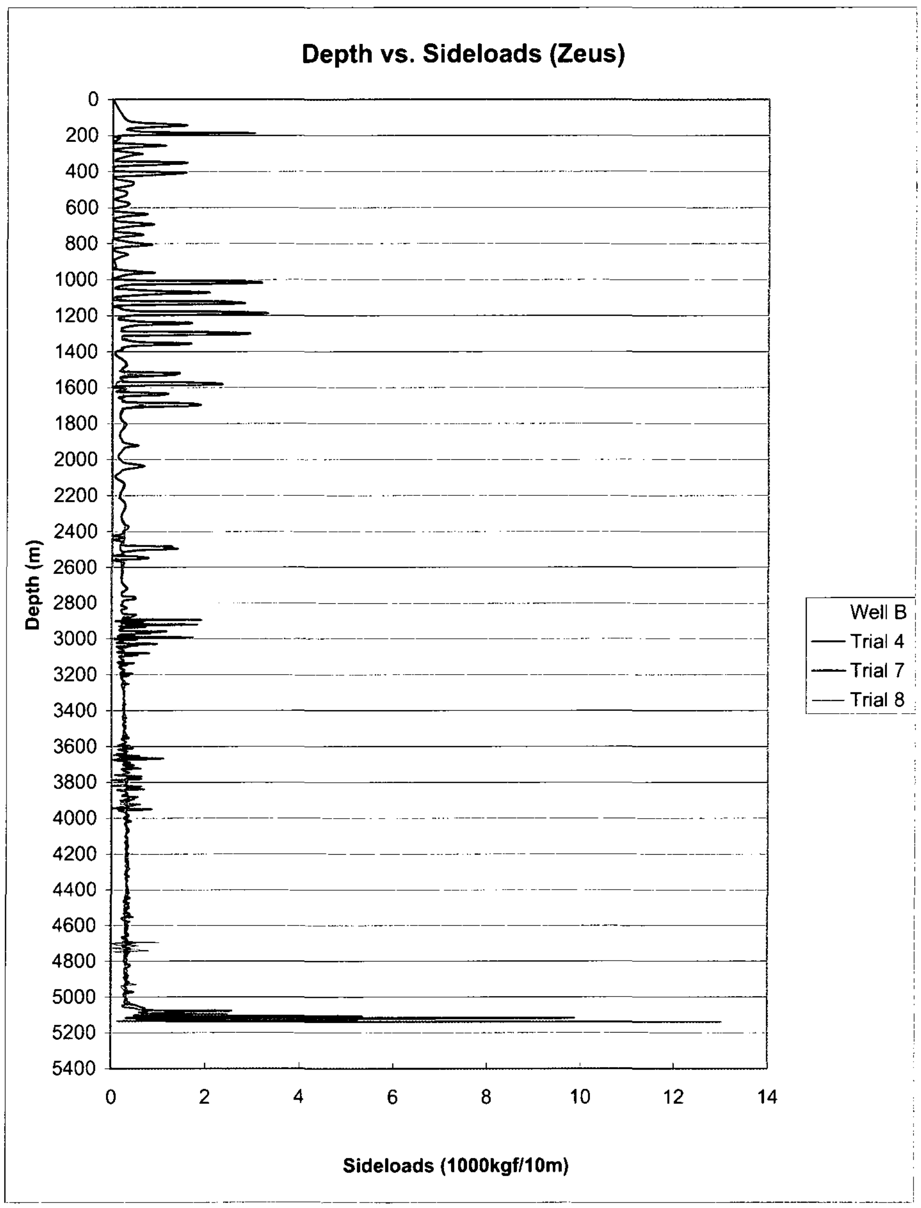

Figure 6.23: Sideloads for Wells in Zeus Field

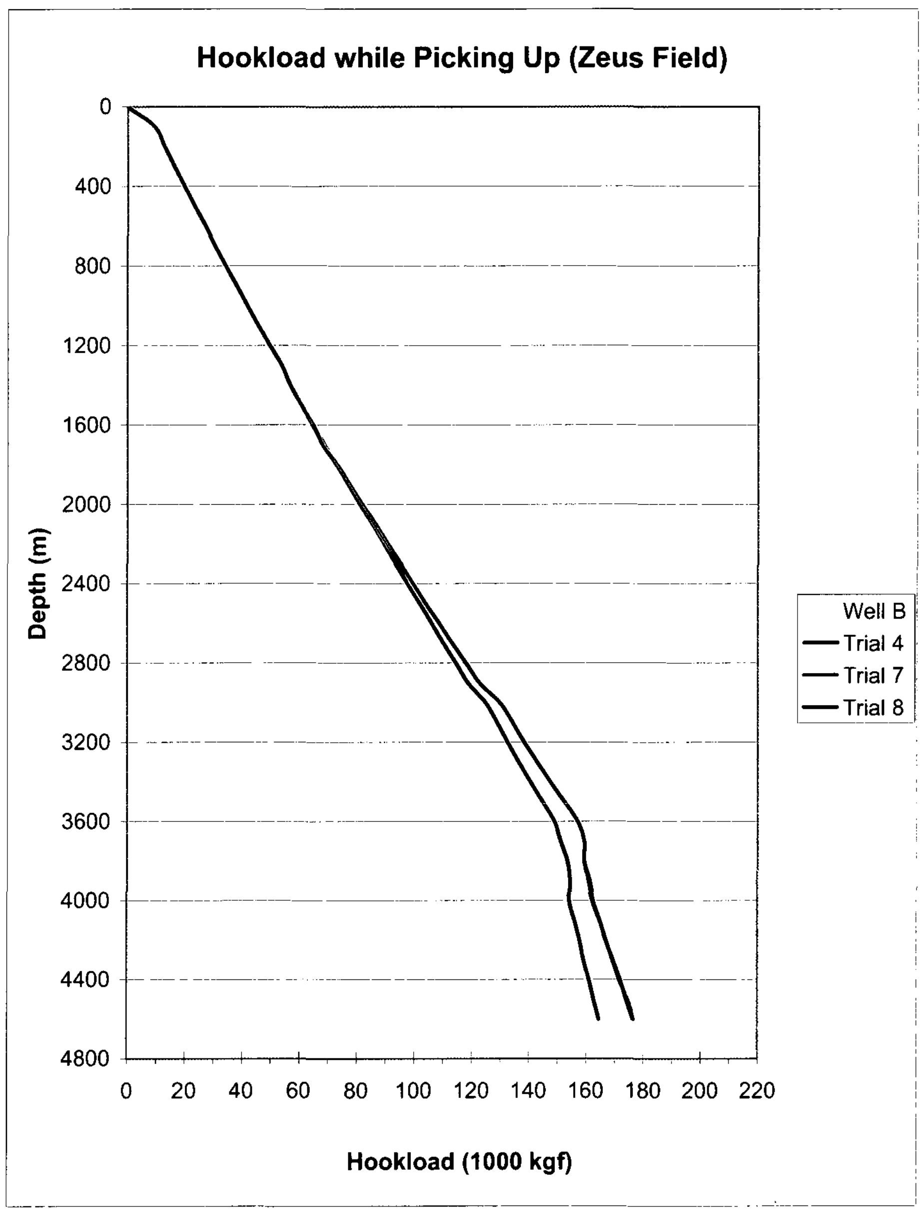

Figure 6.24: Hookload While Picking Up Profile for Wells in Zeus Field

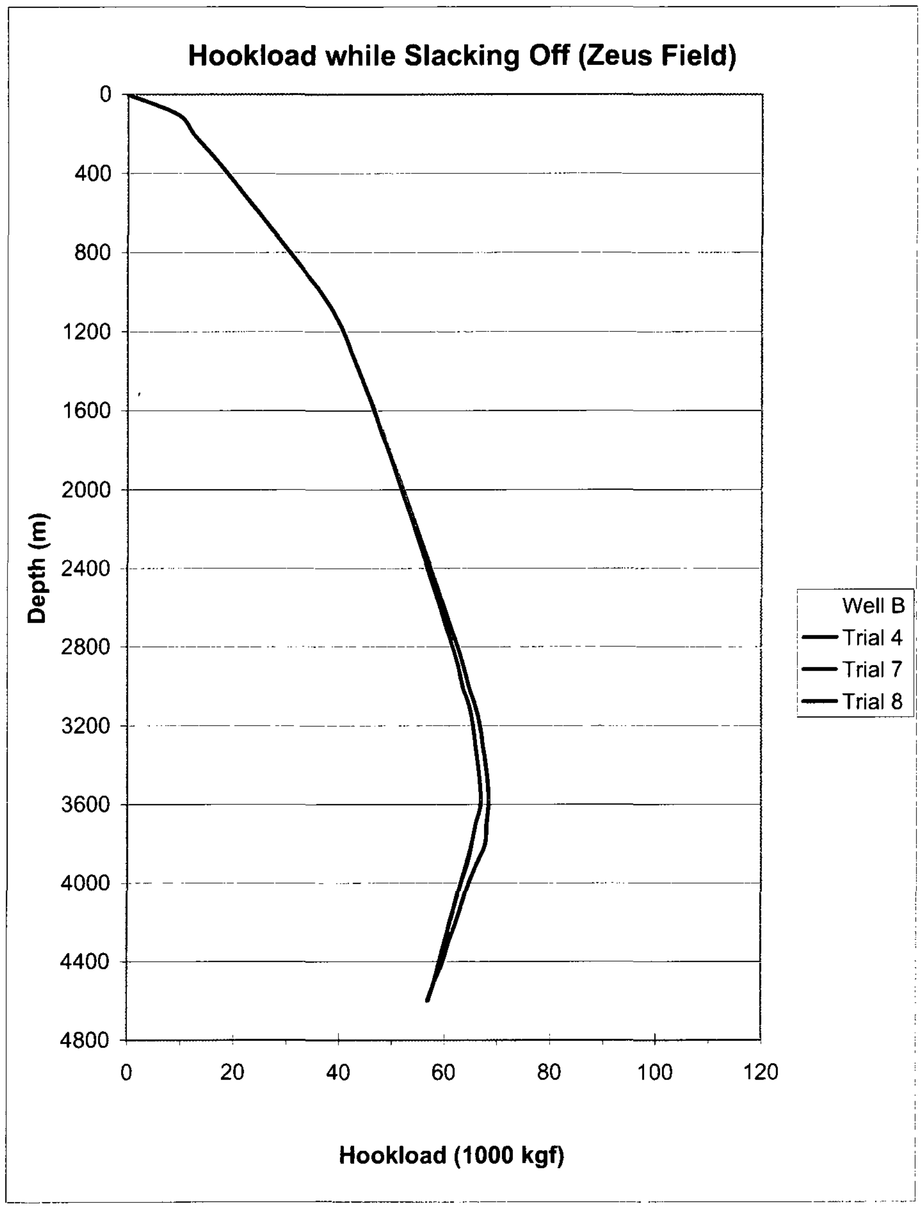

Figure 6.25: Hookload While Slacking Off Profile for Wells in Zeus Field

Chapter 7

Risk Measurement

This chapter explains the definition of risk and reliability and how it was useful in the research carried out for this thesis. To best explain its use all wells were compared using a risk-based study of static physical reliability models.

7.1 What is Risk and Reliability?

Risk is used to quantify the uncertainty associated with a specific event in time and place. It is the likelihood of harm or loss and a combination of occurance probability times the consequence loss. The uncertainty can be based on only one parameter or several parameters that work together to create a combined risk associated with an event. Risk can be applied to many dfferent areas of oil and gas from structure failure to the probability of blowouts. It can be measured in terms of lost time, injury, and cost, as well as other important measures. In order to effectively measure risk, a failure scenario has to be incorporated into the system. Failure occurs when a component is unable to perform the required function over a certain measurement, for example, budget, time or distance.

Reliabilty is defined as "the probability that a component will perform desired operations for a given time period under the defined operating conditions" (Khan, 2006). Reliability does not always have to be measured over time. It can be a function of distance as well. Reliability modelling is a method of understanding or predicting the reliability of a given system. Reliability testing is used to learn about the potential for problems in the system early enough to insure that it will meet the requirments set.

7.2 Why is it Useful in this Research?

Risk is an important consideration in this research because it allows for a level of uncertainty to be incorporated into each well case. When each new well case was designed as a modification of the base case, it was analysed for new torque and drag forces that would act on the drillstring. In comparing the results to the initial case, there is an associated amount of risk involved if the new torque values are higher then the base case scenario. Alternatively, if the likelyhood of failure and consequent risk values are lower then the initial well design then there is a lower risk of drilling the new path.

The risk calculation is important in this research also because it provides additional information about the alternative well paths and helps engineers and other decision makers select designs with high production rates and a high degree of reliability. The reliabilty of this system was based on failure due to instantaneous load stress, in this case torque, placed on the system having no prior effects or history. In laymen terms, the torque was applied at 100m-depth intervals on the drillstring at one moment in time and assumed that the drillstring had not had torque applied to it at any other time. Reliability modelling combined with risk modelling can show how reliabilty affects the risk associated with a given well.

The calculations for the analysis follows an exponential distribution model for a system of random stress and constant strength. The strength of the system is based on the limiting amount of torque that can be applied by the top drive system. In this case that value is 54.91 kN.m. The stress that occurs at any point throughout the torque and drag analysis cannot exeed this value. When torque is applied to the drillstring an associated amount of risk is involved due to the incresing probability of failure, which is in this case, reaching the limitations of the system.

Incorporating a cost-based risk analysis into the case studies helps determine if the wells are profitable to drill and produce under the specified conditions and the inherent probability of failure in the system due to applied torque at surface. If the torque loss experienced in the drillstring was higher then the output torque by the Top Drive system then the probability of failure would be 100%.

7.3 Quantifying Reliabilty and Risk in Each Case Study

This section provides the reader with the failure, reliability, and risk calculations used to quantify the risk associated with each well case in the study.

7.3.1 Failure and Reliability Calculations

In this research, the probability of failure represents the likelihood of the drillstring reaching the limitations of the Top Drive system. The amount of failure determines how reliable the system will be.

The failure calculation for an exponential distribution is given by

$$F = \frac{1}{\mu_x} e^{\frac{-x}{\mu_x}} \tag{7.1}$$

Based on the failure calculation, the reliabilty is found by

$$R = 1 - \frac{1}{\mu_x} e^{\frac{-x}{\mu_x}} \tag{7.2}$$

7.3.2 Risk Calculation

The risk calculation is measured in terms of the cost of failure, C_f, in addition to the initial cost of drilling a well, denoted C_i. The initial cost of a well is based on drilling and associated costs. The cost breakdown for each case study is shown in the two figures below (Figure 7.1 and Figure 7.2). The costs are based on typical values for drilling & producing an offshore well (Costello, personal communication, October 27th, 2005 and Downton, personal communication, October 21st, 2005). The days to drill the well were based on the time it actually took to drill Well A and Well B. All costs indicated in this report were based on values available at the time it was written and are subject ot change with time.

Zoro Field		Cost
Drilling		
Dayrate ($/day)		$425,000.00
Drilling Fluids		$400,000.00
Drilling Bits (4 total)		$350,000.00
	Length (ft)	
Casing		
30" Conductor ($80/ft)	745	$59,600.00
13 3/8" Surface ($20/ft)	3565	$71,300.00
9 5/8" Tubing ($40/ft)	11425	$457,000.00
Wellhead Equipment		$140,000.00
Production		
Operating Cost ($/bbl)		$3.28
Production Rate (bbl/day)		100,000
Total Production cost ($/day)		$328,000.00
Total Days on Project		69
Total Cost for the well ($CAD)		$31,130,900.00

Assume it takes same amount of time to drill each case study

Figure 7.1: Cost Breakdown for typical well in Zoro Field

Zoro Field		Cost
Drilling		
Dayrate ($/day)		$425,000.00
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Total Days on Project		69
Total Cost for the well ($CAD)		$31,130,900.00

Assume it takes same amount of time to drill each case study

Figure 7.2: Cost Breakdown for typical well in Zeus Field

The cost of failure is calculated as

$$C_f = FxC_i \tag{7.3}$$

and the total risk for the well is

$$Risk = C_f + C_i \tag{7.4}$$

7.3.3 Results

The reliabilty and risk calculated for each well are summarized in the plots below. As well, a comparison of reliability for each well shows what wells were more reliabilty then others. The torque plots show the increase on torque over the depth of the well.

Case Study 1

Figure 7.3 shows the torque plot for case study 1. The torque for each well increased as it was calculated down the length of the drillstring and measured at surface. As compared to the limiting torque value, shown as the blue-green line, all torque values were below this value. Comparitively, from figure 7.4, the reliabilty decreased along the measured depth of the well which was expected. The reliability remained 1.00 while the probability of failure was 0.00. As the torque increased the probability of failure increased and therefore the relaibility of the system decreased.

Figures 7.5 to 7.8 show the risk and reliabilty plots for all wells in case study one. Each model followed the same trend based on the system conditions. The risk was measured in terms of cost to the company for each well. It was based on the increased probability of failure as the torque value approached the limiting value. The straight lines in the models were the trend lines based on the input data and indicated the natural trend of the system.

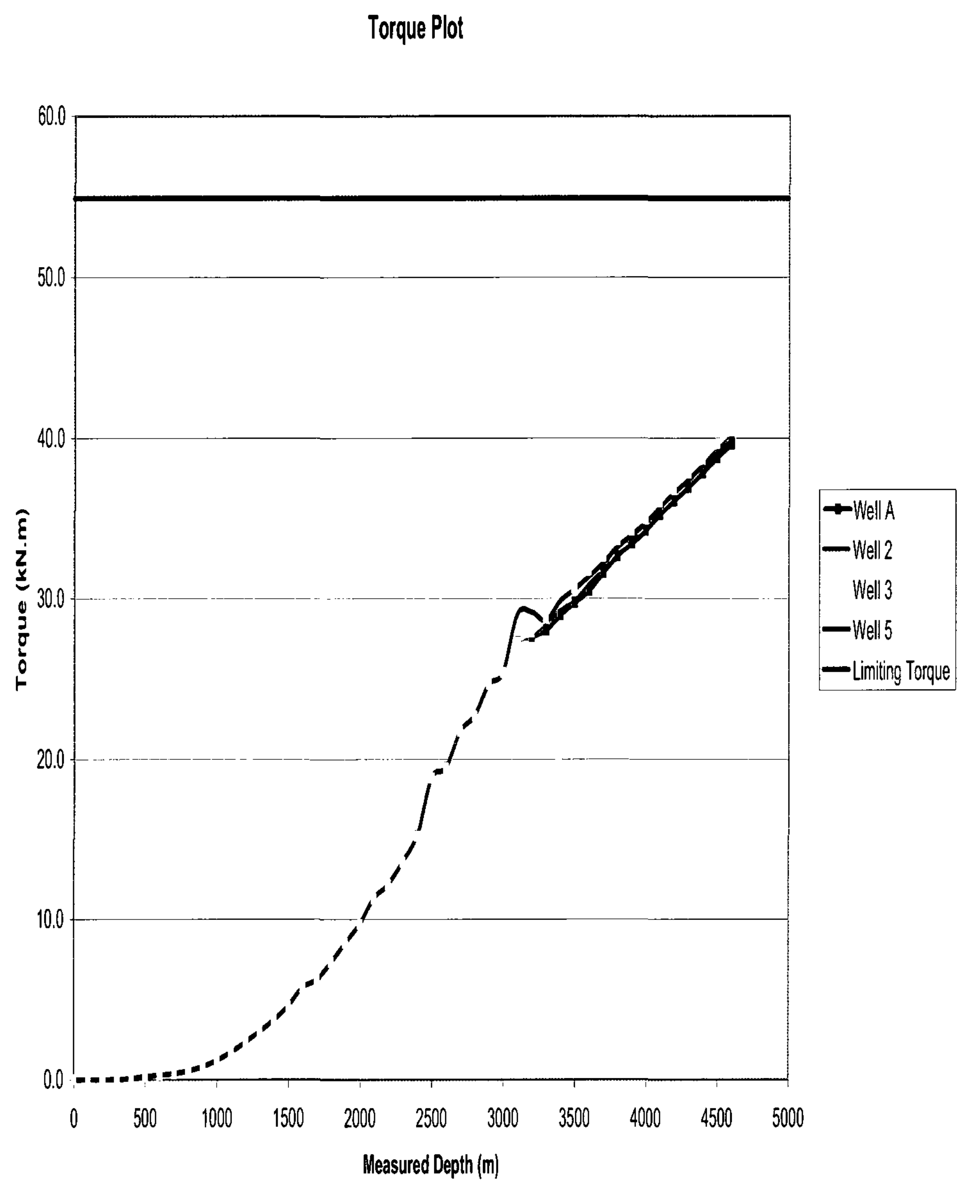

Figure 7.3: Torque Plot for Case Study 1

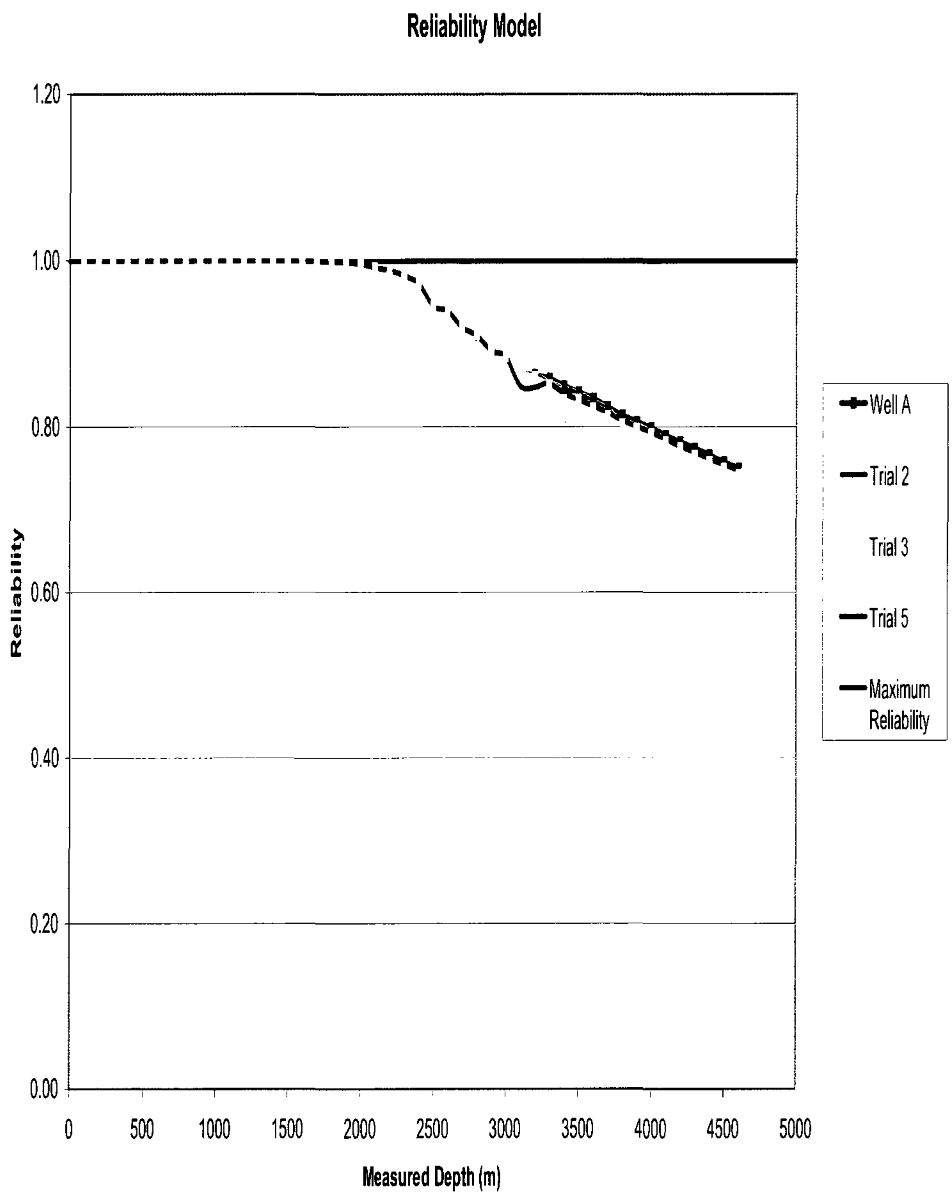

Figure 7.4: Relaibilty Model for Case Study 1

All wells had 100% reliability up to 1300m because the torque applied was not significant enough to cause any failure to the system. After this point, the stresses on the system created a percentage of failure which in turn lowered the reliability of the system. This means that the associated risk involved was going to increase at the same rate.

For Well A and Trial 5, the probability of failure increased to $\approx 25\%$ for a torque of 39.6 kN.m for Well A and 40 kN.m for Trial 5. The reliabilty based on equation 7.2, was $\approx 75\%$ for both wells. The risk associated with these values was $\$38,910,000$ for Well A and $\$39,010,000$ for Trial 5.

Trial 2 and Trial 3 also had the same failure rate at $\approx 26\%$. Therefore the reliability was $\approx 74\%$ for both wells. These values were based on a torque of 40.4 kN.m for Trial 2 and 40.6 kN.m for Trial 3. The associated risk for Trial 2 was $\$39,140,000$ and $\$39,190,000$ for Trial 3.

The calculated risk for the three modified wells was higher then the risk of drilling Well A. There was a $\$280,000$ dollar difference between Trial 3 which had the highest amount of risk and Well A. Based on this information the engineers would need to determine if the risk outweighed the benifits for the project.

Case Study 2

Figure 7.9 shows the torque plot for case study 2. The torque followed the same path as that for case study one; it increased along the length of the drillstring. As compared to the limiting torque value, shown as the blue-green line, all torque values were also below this line. From figure 7.10, the reliabilty decreased along the measured depth of the well which was to be expected. As the torque increased down the drillstring the probability of failure increased and therefore the relaibility of the system decreased.

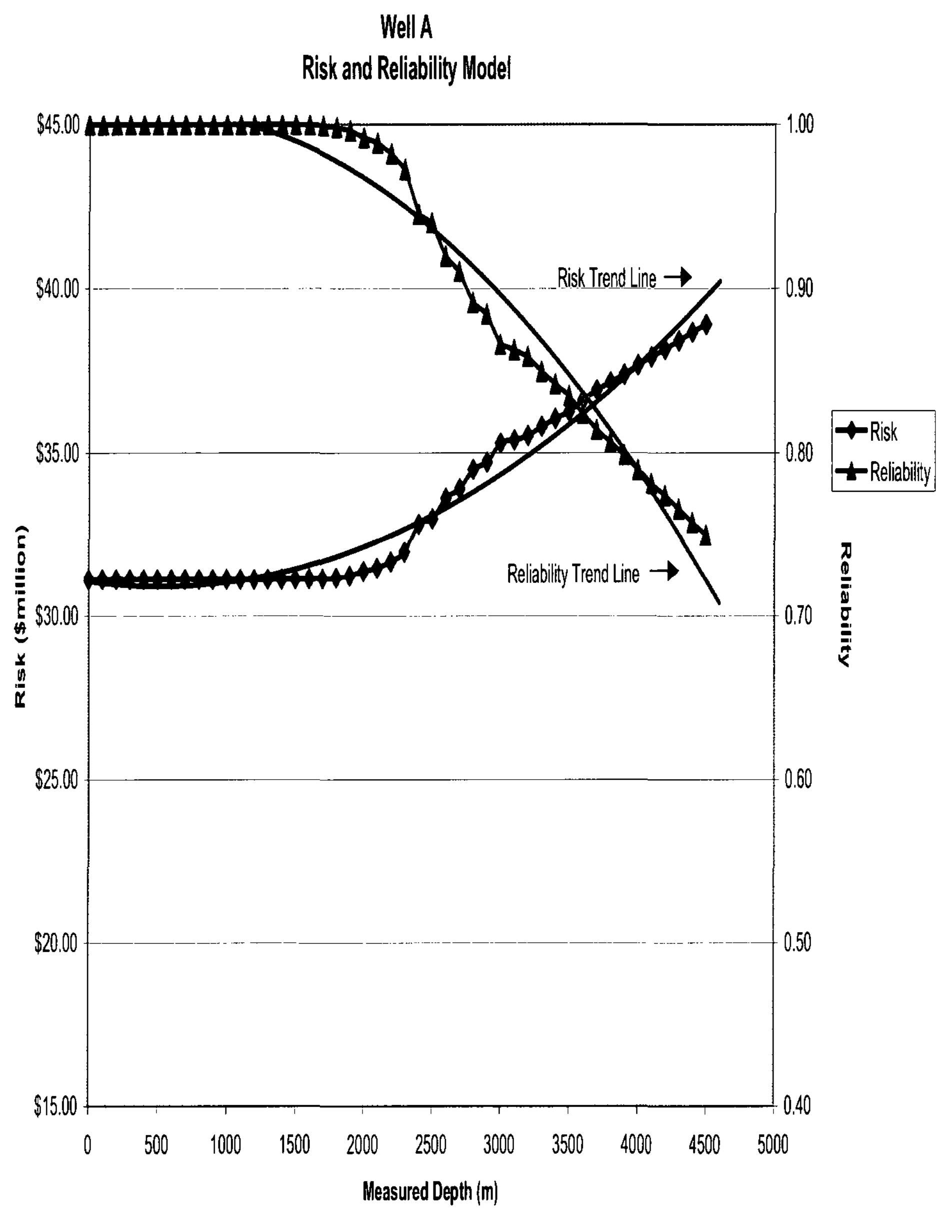

Figure 7.5: Risk Model for Well A

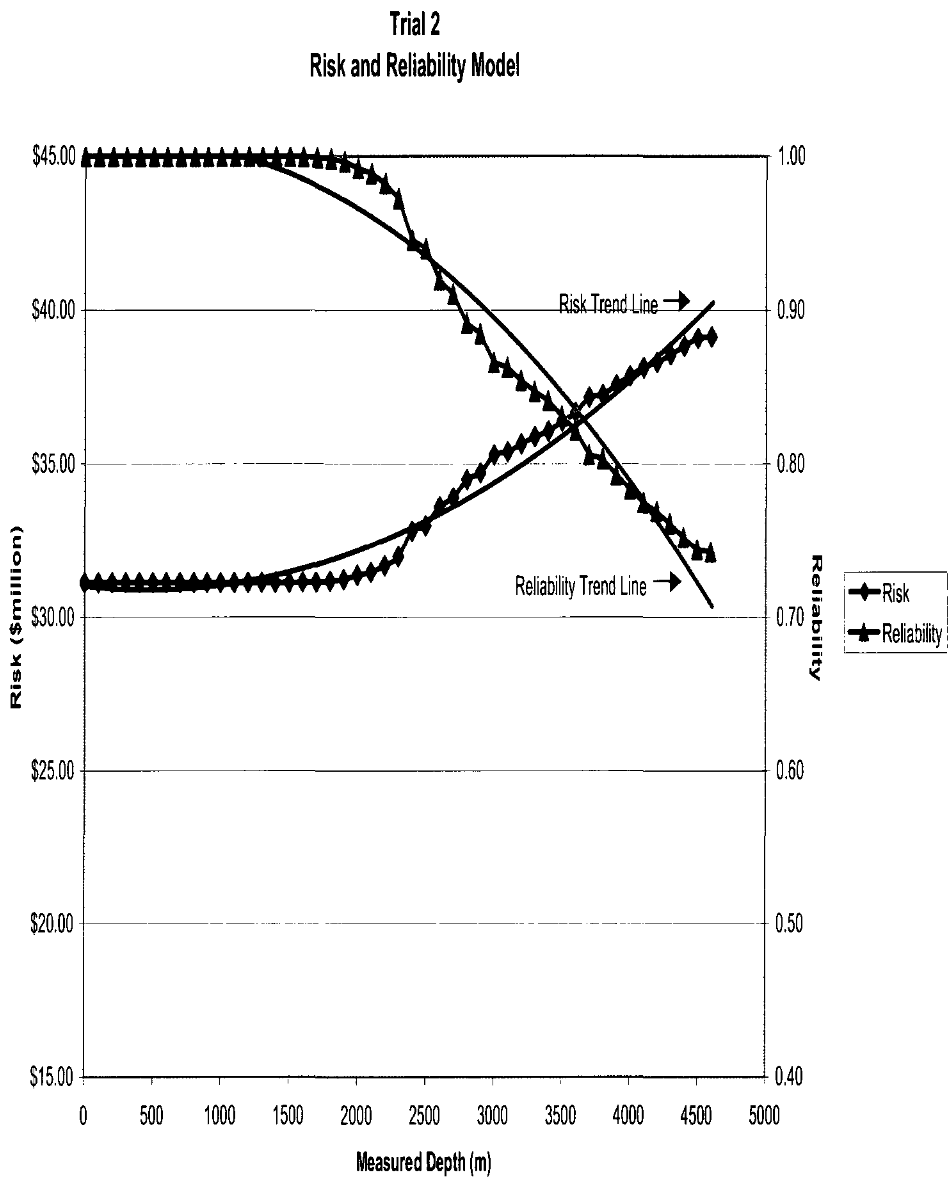

Figure 7.6: Risk Model for Trial 2

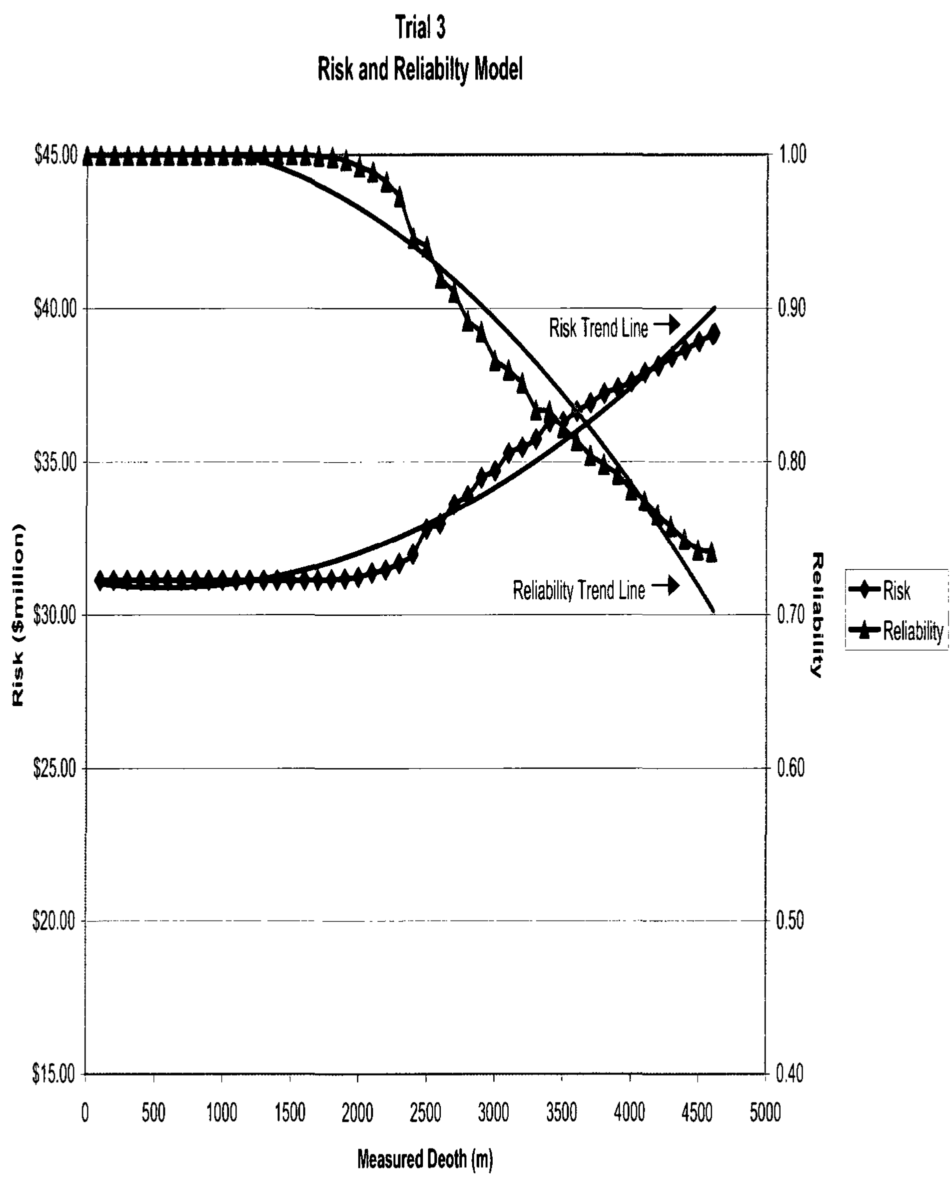

Figure 7.7: Risk Model for Trial 3

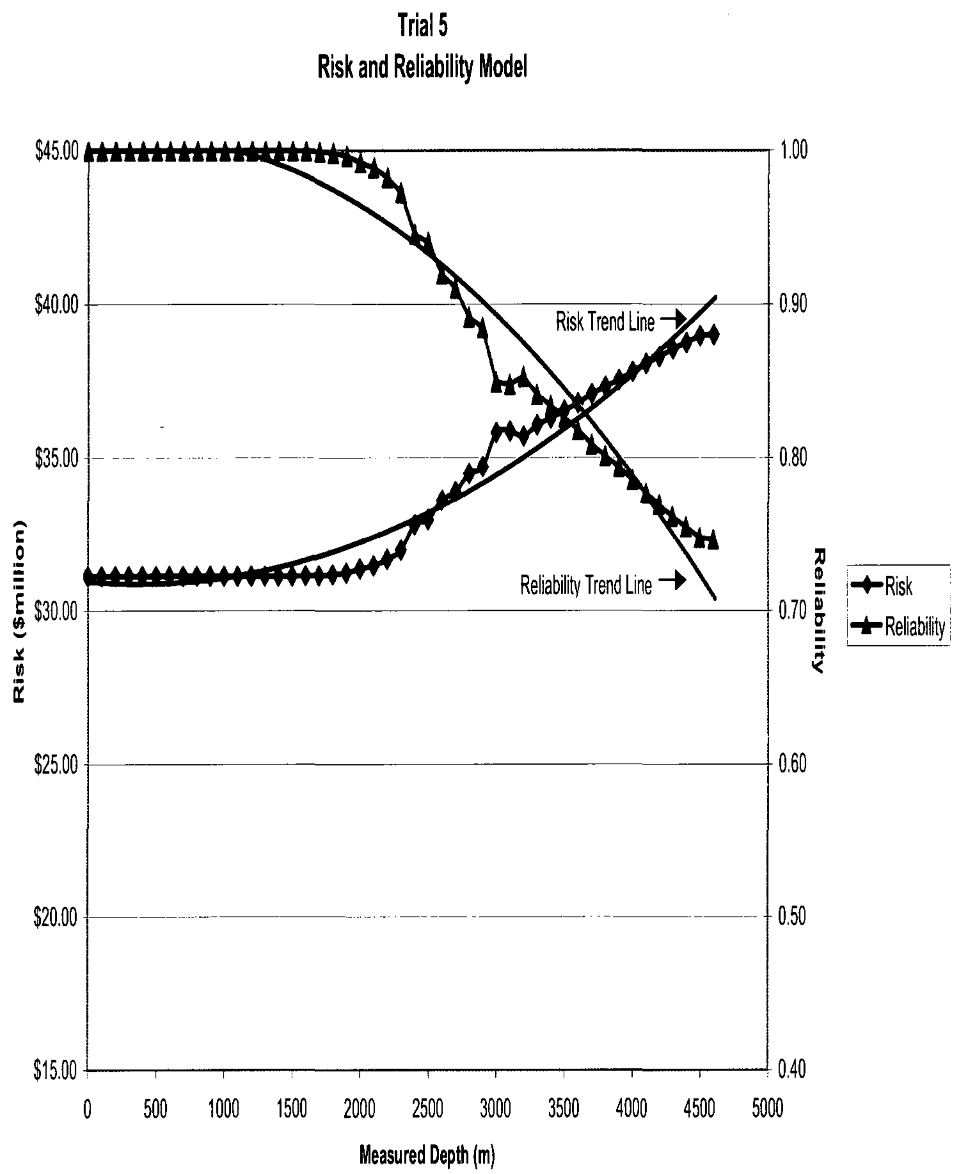

Figure 7.8: Risk Model for Trial 5

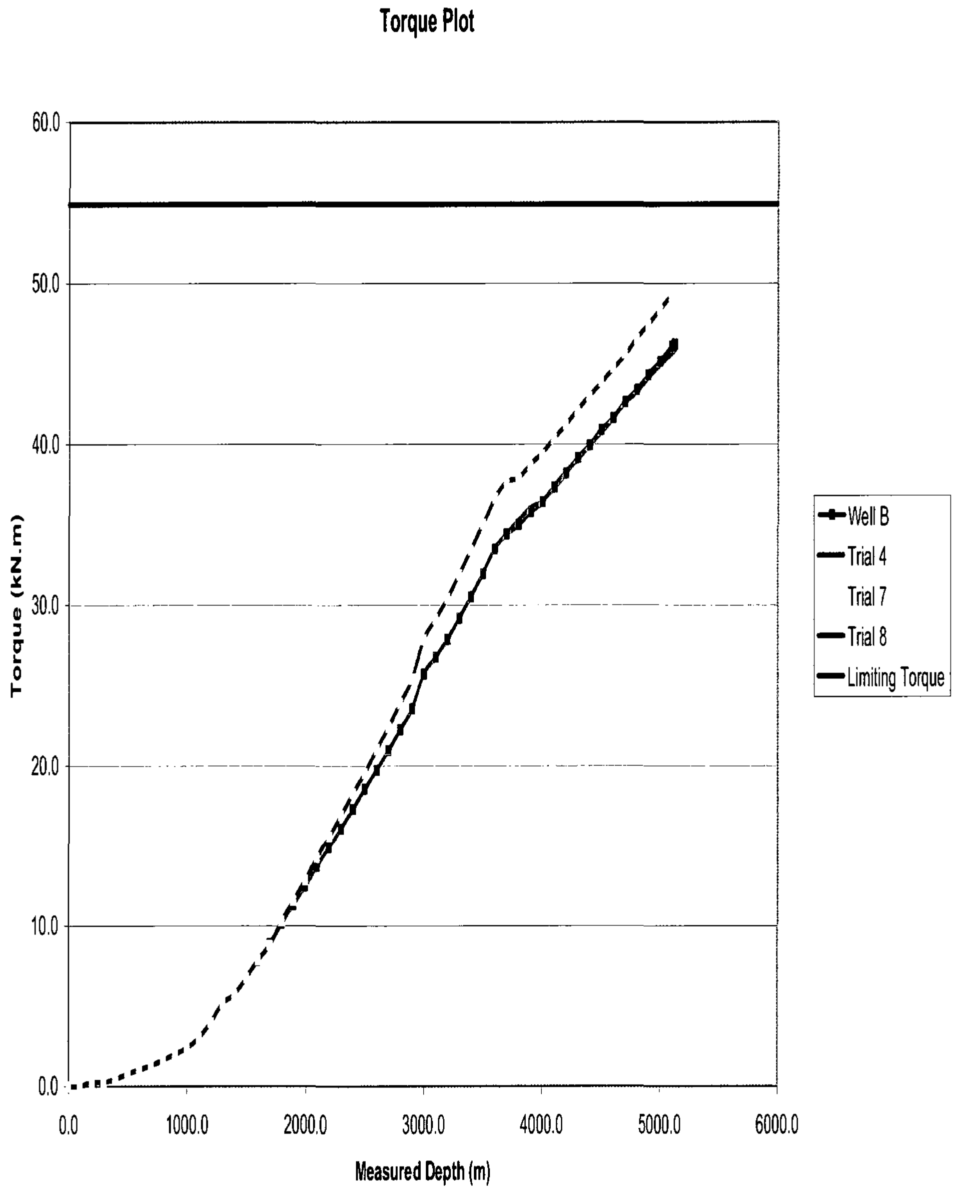

Figure 7.9: Torque Plot for Case Study 2

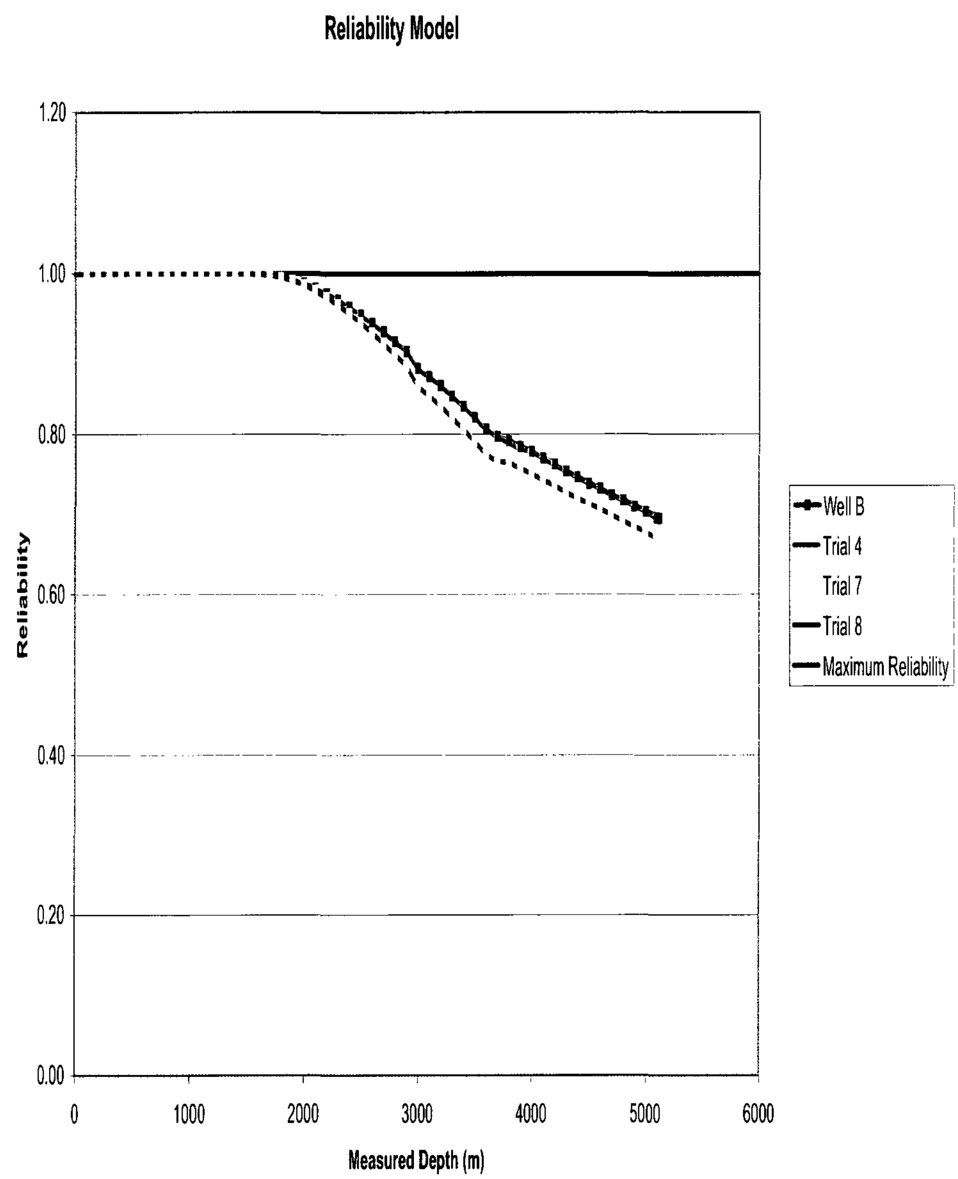

Figure 7.10: Relaibilty Model for Case Study 2

For Well B and Trial 4 in figures 7.11 and 7.12, the probability of failure increased to $\approx 30\%$ for a torque of 49.4 kN.m for Well B and 49.5 kN.m for Trial 4. The reliabilty based on equation 7.2, was $\approx 70\%$ for both wells. The risk associated with these values was $\$21,290,000$ for Well B and $\$21,260,000$ for Trial 4.

Trial 7 and Trial 8 also followed the same trend with the probability of failure increasing to $\approx 33\%$ and therefore a reliabilty of $\approx 67\%$. The torque associated with these values was 49.41 kN.m for Trial 7 and 49.5 kN.m for Trial 8. As a result, the risk calculated reached $\$21,690,000$ for both wells.

The calculated risk for Trial 7 and Trial 8 was higher then the risk of drilling Well A. There was a $\$400,000$ dollar difference between these two wells and Well B. Based on this information the engineers would need to determine if the risk outweighed the benifits for the project.

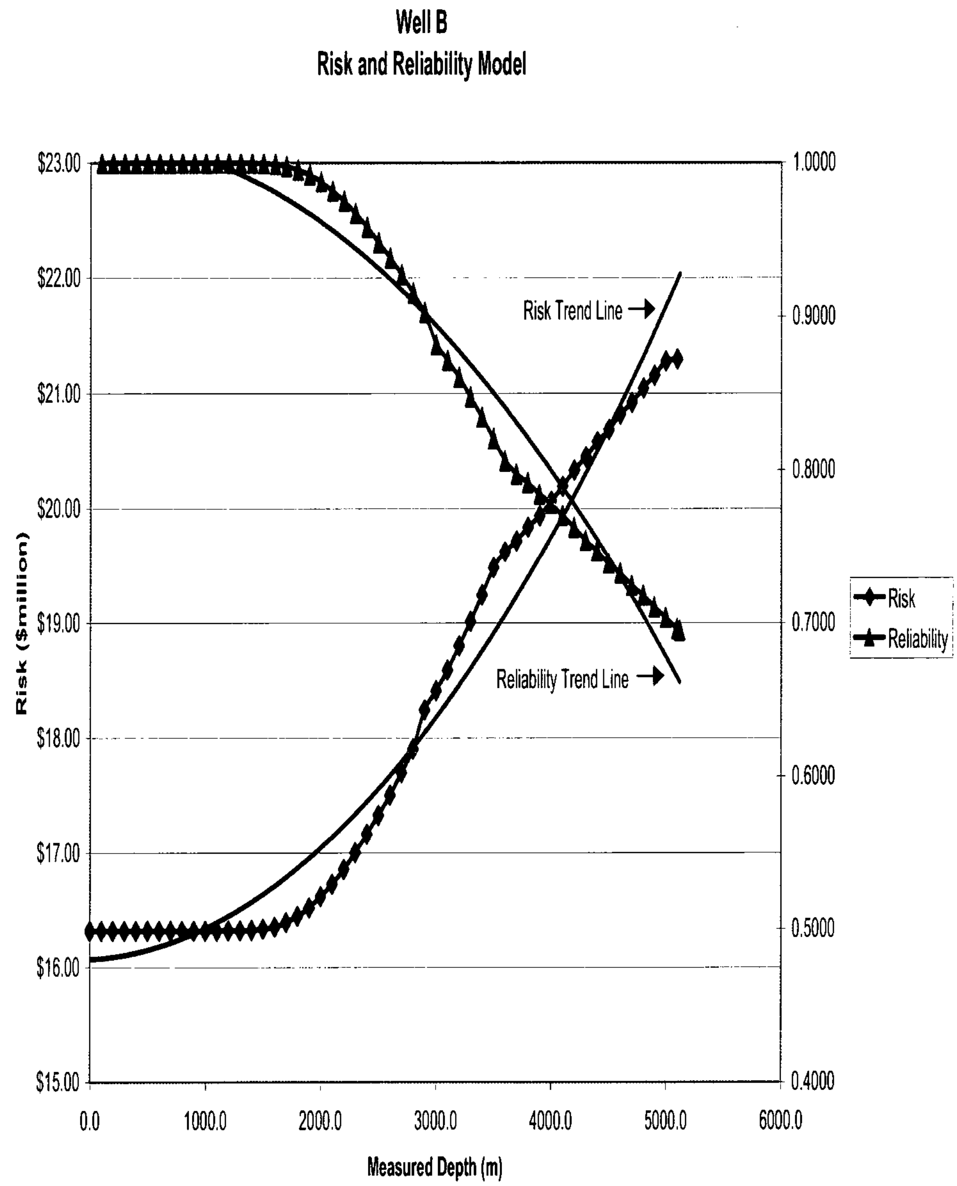

Figure 7.11: Risk Model for Well B

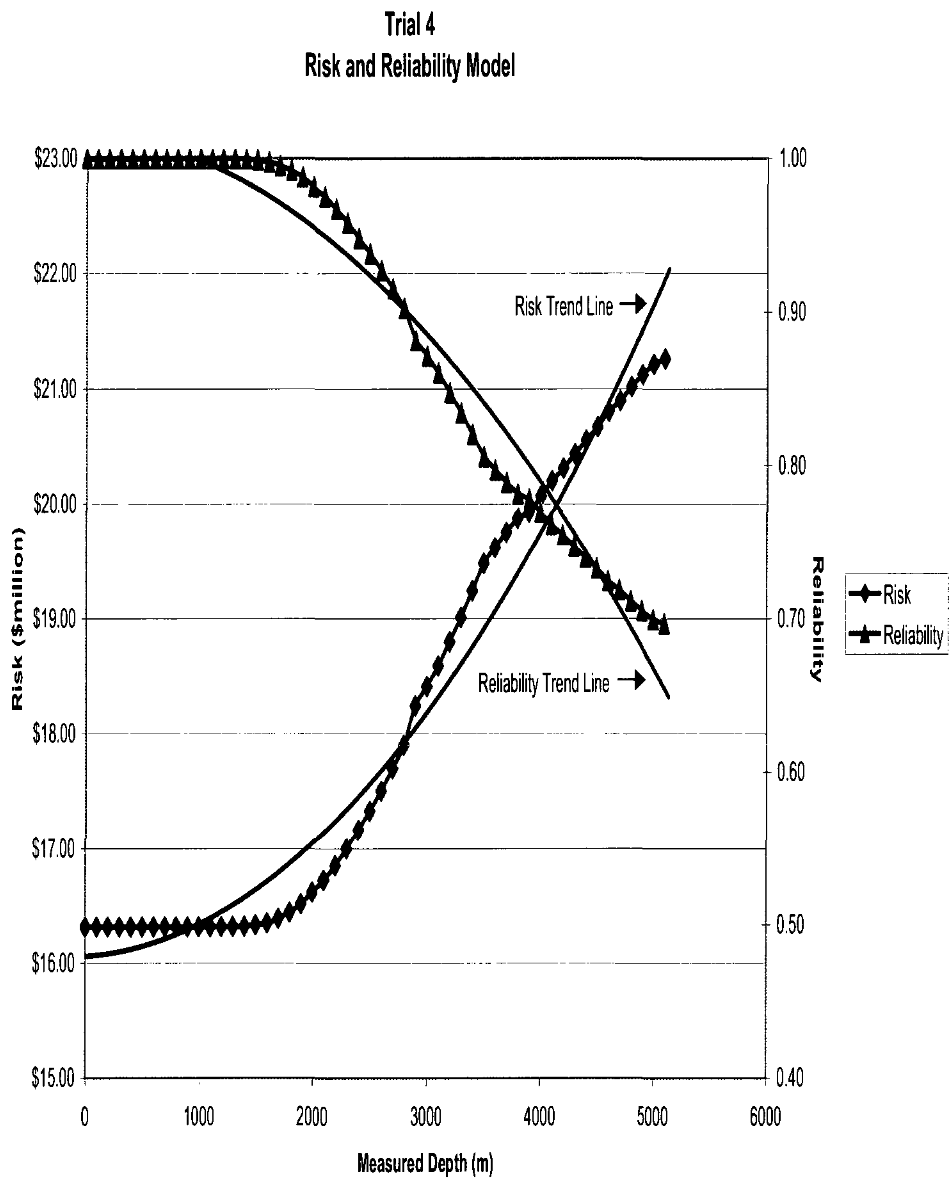

Figure 7.12: Risk Model for Trial 4

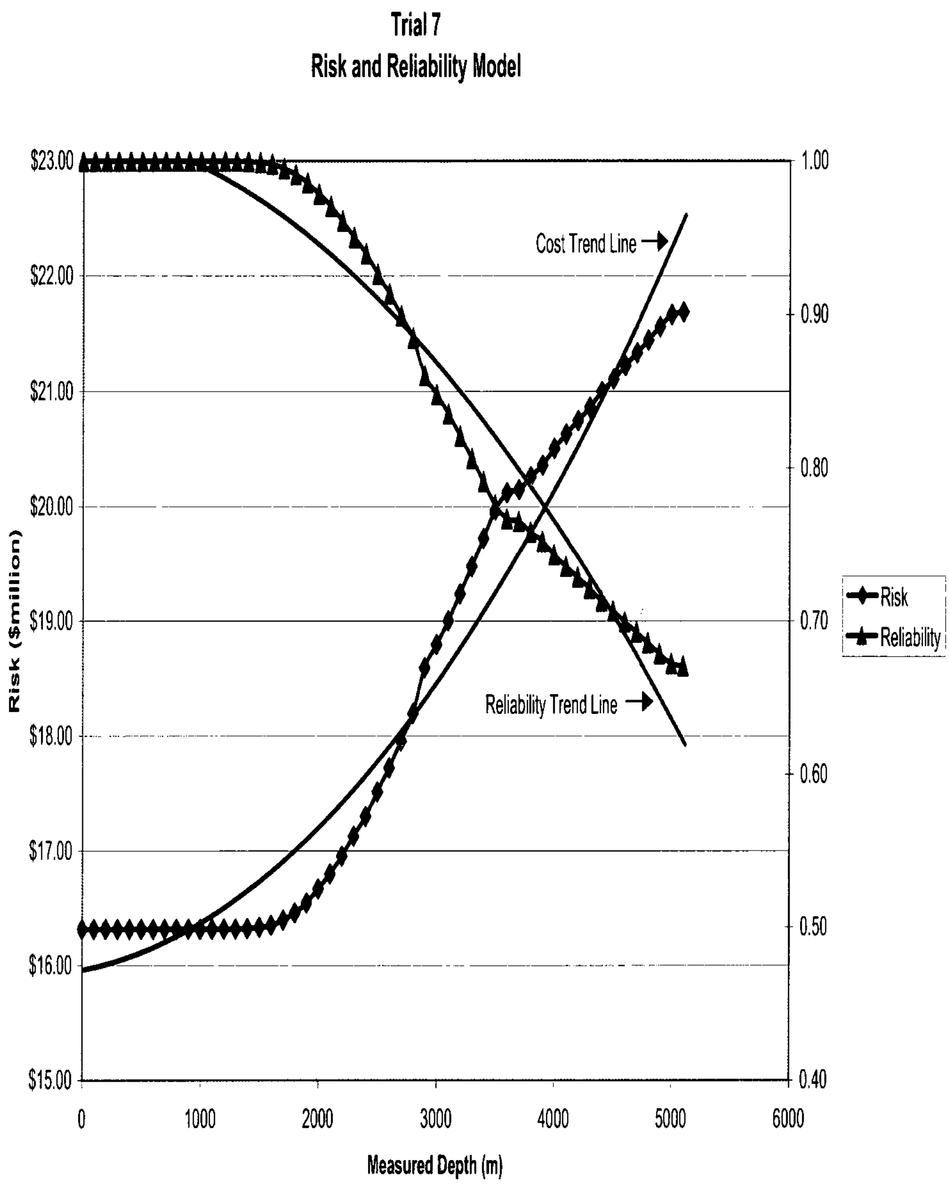

Figure 7.13: Risk Model for Trial 7

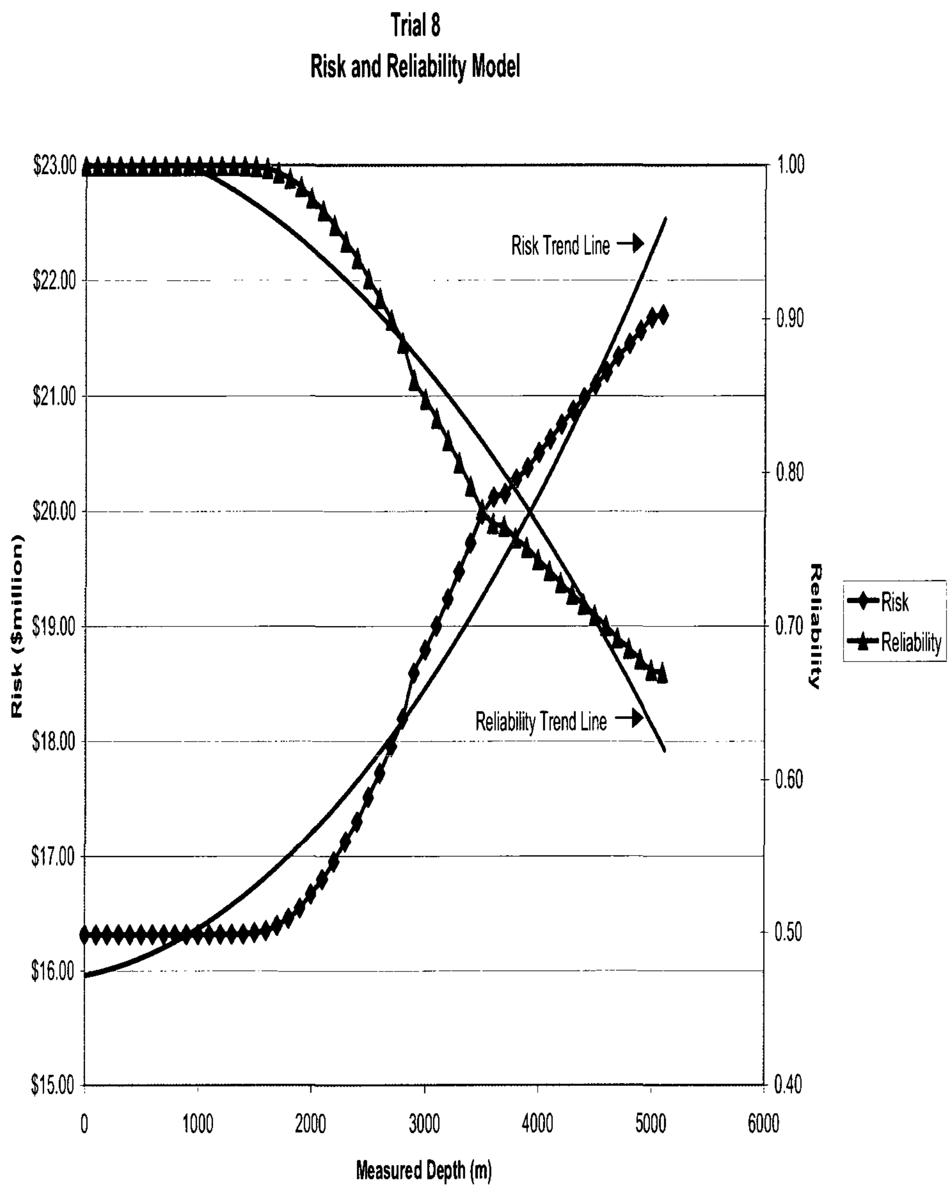

Figure 7.14: Risk Model for Trial 8

Chapter 8

Conclusions and Recommendations

This section summarizes the research project and provides reccomendations for future researchers continuing the study in production and well path optimzation.

The study was a mutli-faceted engineering investigation that involved creating a methodology, testing it with given parameters and standardized variables, and determining the risk associated with the results. The main focus of the research was to analyze various horizontal well profiles in a reservoir in order to optimize the production rates. Essential to the study was incorporating a torque and drag analysis program that would look at all the forces acting on the drillstring used to drill the profile. This was necessary to ensure that the well could be drilled successfully.

The methodolgy was designed for a post-drilling analysis of optimibility, however it could easily be modified for well planning or while-drilling operations. Two wells were submitted for the study which were considered the base cases and to which all other wells were comapared. The results from case study one indicated that three wells were able to be drilled sucessfully under the given limitations of the system, while maintaining higher production rates then the base case, Well A. Trials 2, 3, and 5 had increased production rates of 3.39%, 5.46%, and 4.76%, respectively, from the original well. The maximum torque required was highest for Trial 3 with a value of 40.61 kN.m but this was under the limit of 54.91 kN.m which is the maximum that can be exerted by the Top Drive system.

In case study two, there were also three wells that gave higher instantaneous oil production flow rates then Well B, the base case for this study. Trial 4 had an increase of 1.5% over the original, while Trials 7 and 8 had higher production rates of 0.14% and 2.05%, respectively. The torque loss experienced by this set of wells was highest for Trial 8 which had a torque loss of 49.52 kN.m. This was again lower then the limitation of the system.

The level of reliabilty associated with each well path was also calculated and the results showed an overall trend that as the torque applied at surface increased the reliabilty of the well decreased and the economic risk increased.

Overall, the study proved that the methodology was very useful in finding wells that could produce higher production rates and be drilled sucessfully. It also showed that there is an associated amount of risk involved with drilling any horizontal well profile.

There are several reccomendations outlined below for future analysis.

1. Design a study to create a methodology for the well planning stage and while-drilling operations.

2. Future study be done incorporating more factors in well design to include optimizing drillstring design, fluid selection, and completions.

3. Provide an in-depth study of cost-benefit analysis based on the life of the project.

4. Design a new piece of software that encompasses both areas of optimization. Either,

    - A reservoir simulation tool that has a torque and drag interface that can instantaneously model the stresses on a drillstring after the profile has been changed **OR**

- A well design tool that can import the data from a reservoir and model the oil recovery at a moment in time
- Combine with a geostatistical reservoir model to incorporate reservoir uncertainty (Willcott, 2005)

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Appendix A

Well Trajectory Calculations

There are several types of well paths that are used today in directional drilling to reach a given target. Some of these include:

- Continuous Build
- Build and Hold
- Build, Hold and Drop
- Extended Reach
- Horizontal

With each of these designs there are a set of calculations used to create the trajectory in the planning stages of the well. Some of these calculations include:

- Radius of Curvature
- Inclination (maximum)
- True Vertical Depth (TVD)
- Horizontal Departure (HD)
- Total Measured Depth (MD)(as well as any measured depth throughout the wellbore)

These calculations are necessary to ensure the well path hits the target at the correct location during the planning stages of the well.

After the well has been planned and drilling commences, the trajectory of the well is calculated from survey stations along the path. There are several methods available that will perform the survey calculations. The two main categories consist of those that use straight line approximations and those that assume curvature in the wellbore. Some of the more common methods include:

- Tangential Method
- Average Angle Method
- Minimum Curvature Method

The following sections are expanded explainations and calculations of a presentation I gave in January 2004 for Norsk Hydro. Section A.1 gives detailed information about the various well designs available while section A.2 expands on the trajectory calculations that were used to create the survey of the well path. The information was obtained from "Applied Drilling Engineering" by Bourgoyne, A. et al. 2003.

A.1 Well Design Calculations

Build and Hold Trajectory

A Build and Hold (B&H) Trajectory is the simplest well design and is depicted in Figure 1. It begins with a vertical section from surface to point D. It then builds at a constant build up rate (BUR) from point D to point C where it then holds the angle to total depth (point B).

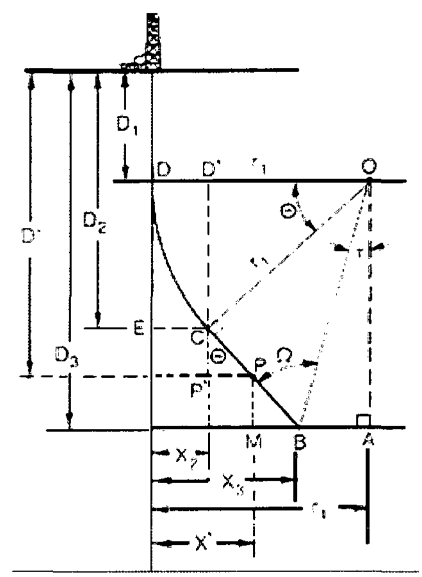


Figure 1: A1 - Build and Hold Trajectory

The Radius of Curvature, r_1, is calculated as:

$$r_1 = \left(\frac{180}{\Pi}\right)\left(\frac{1}{q_i}\right) \tag{1}$$

In order to calculate the maximum inclination, first consider that

$$90^o = \theta + (90^o - \Omega) + \tau \tag{2}$$

Therefore,

$$\theta = \Omega - \tau \quad (3)$$

This is evident from Figure 1. (Fig 8.9)

Using simple trigonometry, Ω can be found from triangle OBC as

$$\sin\Omega = \tfrac{r_1}{L_{OB}} \quad (4)$$

where L_{OB} is the length of segment OB and expressed as

$$L_{OB} = \sqrt{(r_1 - X_3)^2 + (D_3 - D_1)^2} \quad (5)$$

The angle τ is found by using triangle OAB such that

$$\tan\tau = \tfrac{BA}{AO} = \tfrac{r_1 - X_3}{D_3 - D_1} \quad (6)$$

Collecting all the terms, the maximum inclination angle becomes

$$\theta = \arcsin\left[\tfrac{r_1}{\sqrt{(r_1-X_3)^2+(D_3-D_1)^2}}\right] - \arctan\left(\tfrac{r_1-X_3}{D_3-D_1}\right) \quad (7)$$

The preceeding inclination is valid for $X_3 < r_1$. In the case when $X_3 \geq r_1$, the maximum inclination angle becomes

$$\theta = 180 - \arctan\left(\tfrac{D_3-D_1}{X_3-r_1}\right) - \arccos\left\{\left(\tfrac{r_1}{D_3-D_1}\right) \times \sin\left[\arctan\left(\tfrac{D_3-D_1}{X_3-r_1}\right)\right]\right\} \quad (8)$$

To calculate the Total Vertical Depth (TVD) D_3, first assume that section D_1 is known because it is the vertically drilled section of the well path and the value can be taken from the well design data. To determine the TVD at any point along the build section up to and including point C, consider triangle OD'C from figure 1. The vertical length from point D' at some angle θ' is calculated as

$$D'_N = r_1 \sin\theta' \tag{9}$$

where N is an arbitrary point along path D'C. From surface, the total TVD to point N is

$$D'_N = D_1 + r_1 \sin\theta' \tag{10}$$

At the end of the build section, the TVD to point C is calculated as

$$D_2 = D_1 + r_1 \sin\theta \tag{11}$$

To determine the TVD to target (point B) it is assumed that the section is held to TD (total Depth) which means that it has a constant inclination. The vertical length of the segment from point C to point B is added to D_3 and calculated as follows:

$$D_3 = D_2 + \sqrt{\left(\tfrac{r_1}{\tan\Omega}\right)^2 - ((X_3 - X_2)^2} \tag{12}$$

The Horizontal Departure (HD) is the distance from the surface location of the borehole to the target in the x-direction. The total horizontal departure can be seen in figure 1 as X_3. To calculate the horizontal departure to the end of build, X_2, where the maximum inclination is attained, consider triangle D'OC in the figure. It follows:

$$X_2 = r_1 - r_1 \cos\theta \tag{13}$$

To find the total HD, consider line segment L_{CB} and θ from the figure above. The horizontal component of the segment is found to be $L_{CB} \times \sin\theta$ and with the addition of X_2, the result is

$$X_3 = X_3 + L_{CB} * \sin\theta \tag{14}$$

The Measured Depth (MD) is the actual length of the well being drilled and can also be calculated at any point along the well path. Again, the measured depth from surface to point D is the same as the vertical depth and denoted D_1. The length of the arc segment DC can be calculated by considering pie section ODC. It follows:

$$\begin{aligned} L_{DC} &= \left(\tfrac{\pi}{180}\right) \times r_1 \times \theta \\ &or \\ L_{DC} &= \left(\tfrac{\theta}{q}\right) \end{aligned} \tag{15}$$

From figure 1, the length of segment CB can be determined as

$$L_{CB} = \left(\tfrac{r_1}{\tan \Omega}\right) \tag{16}$$

Therefore the total measured depth (TMD) to target is

$$D_{(3)TMD} = D_1 + \left(\tfrac{\theta}{q}\right) + \left(\tfrac{r_1}{\tan \Omega}\right) \tag{17}$$

The maximum inclination angle, θ, is not only valid for $X_3 < r_1$ as indicated in the figure but it is also valid for $X_3 \geq r_1$.

Build, Hold, & Drop Trajectory

The build, hold, and drop trajectory, also known as the "'S"' trajectory is similar to the build and hold except for the last segment of the well path where the inclination angle drops to form a second radius of curvature to TD. There are also two different profiles of the "'S"' trajectory. The profile 1, shown in Figure 2:A2, is when the radius of curvature r_1 is less then the length of the HD at drop off X_3 and $r_1 + r_2$ is less then the total HD, X_4. In Figure 3:A3, the first condition is the same however, $r_1 + r_2$ is greater then X_4, giving you profile 2.

The radius of curvature for r_1 is found from equation 1. For the second radius of curvature $r2$ the same derivations are applied and with the only difference being q, in this case as inclination drop off rate, it is found to be

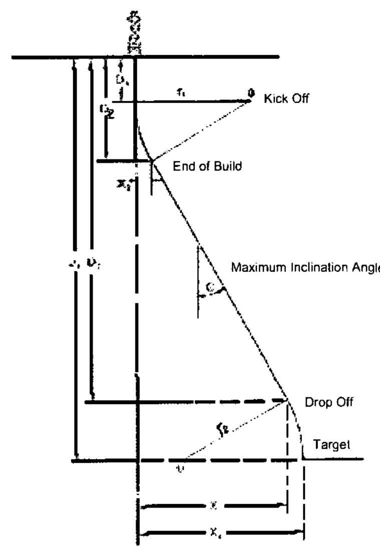


Figure 2: A2 - Build, Hold & Drop Trajectory (Profile 1)

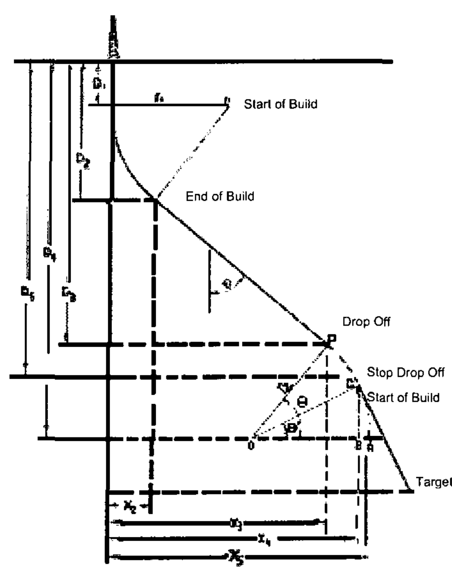


Figure 3: A3 - Build, Hold & Drop Trajectory (Profile 2)

$$r_2 = \left(\tfrac{180}{\Pi}\right)\left(\tfrac{1}{q}\right) \tag{18}$$

The maximum inclination is different for the two different profiles shown in the figures above. In the case when r_1+r_2 is less then the total HD, X_4, the inclination is derived as

$$\theta = 180^o - \arctan\left(\tfrac{D_4-D_1}{X_4-(r_1+r_2)}\right) - \arccos\left\{\left(\tfrac{r_1+r_2}{(D_4-D_1}\right) \times \sin\left[\arctan\left(\tfrac{D_4-D_1}{X_4-(r_1+r_2}\right)\right]\right\} \tag{19}$$

When the well design is like that of figure 3, then $r_1 + r_2$ is greater then the total HD, X_4, and the maximum inclination is calculated as

$$\theta = \arctan\left(\tfrac{D_4-D_1}{r_1+r_2-X_4}\right) - \arccos\left\{\left(\tfrac{r_1+r_2}{D_4-D_1}\right) \times \sin\left[\arctan\left(\tfrac{D_4-D_1}{r_1+r_2-X_4}\right)\right]\right\} \tag{20}$$

The TVD, HD, and MD for the "'S"' trajectory are easily found by adding the extra lengths from the dropped portion of the well to the B&H trajectory calculations. If a second θ is assigned to the drop off portion at point O' and denoted as θ_2, then using simple mathematics, the TVD (D_4), HD (X_4), and MD (D_{TMD}) are respectively:

$$D_4 = D_3 + r_2 \sin\theta_2 \tag{21}$$

$$X_4 = X_3 + r_2 - r2\cos\theta_2 \tag{22}$$

$$D_{(4)TMD} = D_{(3)TMD} + \left(\tfrac{\theta_2}{q}\right) \tag{23}$$

As was shown, the calculations for any well path is found by applying basic mathematical concepts and principles. The design is based on using straight line and curved segments which in reality is very hard to achieve. Therefore engineers require the use of surveying methods to help configure the actual trajectory being drilled downhole. These are described in detail below.

A.2 Well Survey Methods

As already listed above there are different methods available for calculating the survey points of a given trajectory. The method that is used by PowerPlan to calculate the well path is the minimum curvature method. This is one of the most accurate and realistic techniques to use because it gives minimal error when compared to actual surveying data (Bourgoyne et al.,1986,table 1,pg.366). The radius of curvature method also gives minimum error but is not as widely used in industry. The tangential method, average angle method, and minimum curvature method are described below. All other methods can be found in various papers and textbooks including "Applied Drilling Engineering"(Bourgoyne, 1986).

Tangential Method

The tangential method is the simpliest method used to calculate the trajectory of a well. It assumes straight line approximations of the path from survey point A_1 to A_2 and so on down to TD. This means that the inclination is constant over the length of each segment, $D_{M(n)}$, where n is the number of the survey station being considered. Figure 4 depicts the 3-D view of the trajectory broken into segments with survey stations at points A_2 through A_4. The main survey calculations of interest are:

- Latitude North/South Coordinate, L_n
- Longitude East/West Coordinate, M_n
- TVD, D_n

For each course length D_m the north/south coordinate can be found as

$$L_n = D_{M(n)} \times \sin(\alpha_n) \times \cos(\epsilon_n) \tag{24}$$

where α_n is the inclination angle and ϵ_n is the direction angle, or azimuth angle.

The total north/south coordinate is calculated as

$$L_k = \sum_{n=1}^{k} L_n \tag{25}$$

Likewise, the east/west coordinate can found by:

$$M_n = D_{M(n)} \times \sin(\alpha_n) \times \sin(\epsilon_n) \tag{26}$$

and the total east/west coordinate is

$$M_k = \sum_{n=1}^{k} M_n \tag{27}$$

The TVD for each segment is expressed as

$$D_n = D_{M(n)} \times \cos(\alpha_n) \tag{28}$$

and, as before, the total TVD is calculated by

$$D_k = \sum_{n=1}^{k} D_n \tag{29}$$

It has been concluded that the tangential method has a high degree of error due to the fact that it does not account for any curvature in the well path as well as not considering the inclination or direction of the previous survey point. Therefore, it is not used in industry today.

Average Angle Method

The average angle method tries to resolve some of the problems with the tangential method by including the information given for the previous survey station. It does this by using the average of the inclination and direction angles over the length of the segment. The parameters are calculated as follows:

The north/south coordinate is calculated for each survey station as

$$L_n \quad = \quad D_{M(n)} \sin\left(\tfrac{\alpha_n+\alpha_{n-1}}{2}\right) \cos\left(\tfrac{\epsilon_n+\epsilon_{n-1}}{2}\right) \tag{30}$$

The total north/south coordinate is calculated the same as that for the tangential method:

$$L_k \quad = \quad \sum_{n=1}^{k} L_n \tag{31}$$

and the east/west coordinate is found by

$$L_n \quad = \quad D_{M(n)} \sin\left(\tfrac{\alpha_n+\alpha_{n-1}}{2}\right) \sin\left(\tfrac{\epsilon_n+\epsilon_{n-1}}{2}\right) \tag{32}$$

Again the total east/west coordinate is calculated as

$$M_k \quad = \quad \sum_{n=1}^{k} M_n \tag{33}$$

and the TVD for each segment is

$$D_n \quad = \quad D_{M(n)} \cos\left(\tfrac{\epsilon_n+\epsilon_{n-1}}{2}\right) \tag{34}$$

The total TVD is

$$D_k \quad = \quad \sum_{n=1}^{k} D_n \tag{35}$$

As indicated in the table above the average angle method has less error then the tangential method however, it still does not consider curvature in the wellbore. To account for this the minimum curvature method was introduced as a more accurate survey calculation method.

Minimum Curvature Method

This method considers both straight line segments as well as any curvature made by the drillstring from survey station A_1 to A_2. The overall angle change, β, between these two survey points is calculated as

$$\cos_\beta = \cos(\alpha_2 - \alpha_1) - \{\sin(\alpha_1)\sin(\alpha_2)[1 - \cos(\epsilon_2 - \epsilon_1)]\} \tag{36}$$

Figure (8.22 pg.366) shows a curved segment from station A_1 to A_2 to help exlain the above equation.

To determine the ratio of straight line section to the curved section, first look at figure (8.21 p. 365). The straight line segments A_1B and A_2B are connected to the curved segments A_1Q and A_2Q at points A_1 and A_2. This means that

$$A_1Q = OA_1(\tfrac{\beta}{2}) \tag{37}$$

and

$$A_2Q = OA_2(\tfrac{\beta}{2}) \tag{38}$$

Also,

$$A_1B = OA_1\tan(\tfrac{\beta}{2}) \tag{39}$$

and

$$A_2B = OA_2\tan(\tfrac{\beta}{2}) \tag{40}$$

Therefore,

$$\frac{A_1B}{A_1Q} = \frac{\tan(\frac{\beta}{2})}{(\frac{\beta}{2})} = \frac{2}{\beta}\tan\left(\frac{\beta}{2}\right) \tag{41}$$

and

$$\frac{A_2B}{A_2Q} = \frac{\tan(\frac{\beta}{2})}{(\frac{\beta}{2})} = \frac{2}{\beta}\tan\left(\frac{\beta}{2}\right) \tag{42}$$

It follows then that the factor of the ratios of stright line segments to curved segments, defined as F, is

$$F_{sc} = \frac{2}{\beta_n}\tan\left(\frac{\beta_n}{2}\right) \tag{43}$$

Using this calculation, if the overall angle change, β, is less then 0.25 radians then it is acceptable to set F to 1. From there, the north/south and east/west coordinates can be calculated as well as the TVD for each segment. They are as follows:

$$L_n = \left(\frac{D_n}{2}\right)\left[\sin(\alpha_{n-1})\cos(\epsilon_{n-1}) + \sin(\alpha_n)\cos(\epsilon_n)\right] F_n \tag{44}$$

$$M_n = \left(\frac{D_n}{2}\right)\left[\sin(\alpha_{n-1})\sin(\epsilon_{n-1}) + \sin(\alpha_n)\sin(\epsilon_n)\right] F_n \tag{45}$$

and

$$D_n = \left(\frac{D_n}{2}\right)\left[\cos(\alpha_{n-1}) + \cos(\alpha_n)\right] F_n \tag{46}$$

The totals for each of the above are calculated using equations 31, 33, and 35.

As can be seen from table 1, the minimum curvature method gives the most accurate results as compared to data taken from test hole. This is why it is so widely used in industry today.

Appendix B

Calculating Torque and Drag for Computational Analysis

The calculations for torque and drag acting on the drillstring for computer analysis are based on mathematical models. The model is based on single short lengths of drillstring which are joined by connections to make up the total drillstring in the wellbore. Each segment produces its own torque, drag and weight. The resulting forces and torques are added together to obtain the total torque and drag in the drillstring which can be used to analyze the drillability of the well. The following figure 1 shows a free body diagram of a single element of drillstring.

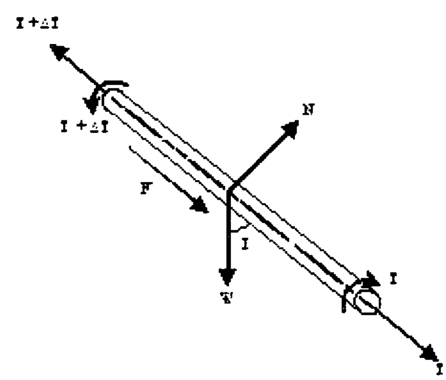


Figure 4: B1 - Free Body Diagram of Elemental Drillstring

The Friction Factor is

$$F_f \;=\; \mu_f N \tag{47}$$

Torque in Horizontal Section (No Doglegs) - Non-Rotating

Assuming pipe lay on the bottom of the wellbore like in figure 2, the torque is found to be as follows:

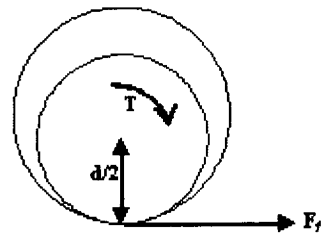


Figure 5: B2 - Pipe Lying in Bottom of Wellbore

$$T_o = F_f(d/2) = \mu N(d/2) \tag{48}$$

Torque in Horizontal Section (No Doglegs) - Rotating

If the pipe is rotating then it is assumed that it will ride up the side of the wellbore to some angle , as indicated in figure 3.

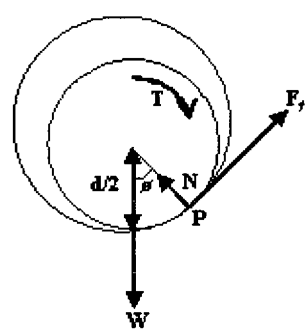


Figure 6: B3 - Pipe Rotating in Wellbore

In this case, taking the moments about P, we get

$$T_o = W(d/2)\sin\phi \tag{49}$$

To Find ϕ :

Look at forces along tangent:

$$\sum F = F_f - W\sin I\sin\phi = 0 \tag{50}$$

Therefore:

$$\mu N = W \sin I \sin \phi = 0 \tag{51}$$

Forces perpendicular tangent:

$$\sum F = N - W \sin I \cos \phi = 0 \tag{52}$$

Therefore:

$$N = W \sin I \cos \phi = 0 \tag{53}$$

And

$$(\mu N = W \sin I \sin \phi) \, / \, (N = W \sin I \cos \phi) \tag{54}$$

Cancelling like terms:

$$\mu = \tan \phi \tag{55}$$

$$\phi = \tan^{-1} \mu \tag{56}$$

The next consideration is the effect of doglegs:

First we will look at a dropoff wellbore like the one in figure 4.

Initially we will neglect any axial friction i.e. pipe rotating

The sum of the forces in the X-direction (along the normal plane):

$$\sum F = W \sin I + (T + \Delta T) \sin(\delta/2) + T(\sin(\delta/2)) - N = 0 \tag{57}$$

Therefore:

$$W \sin I + (\Delta T) \sin(\delta/2) + 2T(\sin(\delta/2)) - N = 0 \tag{58}$$

The $\sin \delta/2$ will go to zero and the remaining equation approximates to:

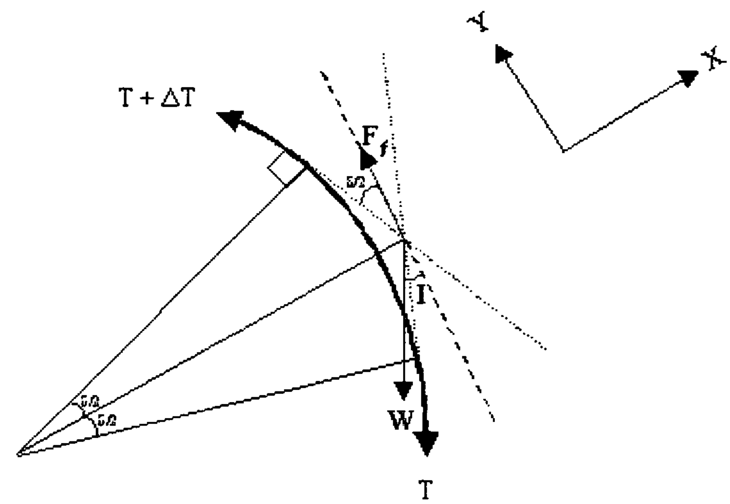


Figure 7: B4 - Dropoff Wellbore

$$N = W \sin I + 2T(\sin(\delta/2)) \tag{59}$$

Next we will sum the forces acting along the tangent in the Y-direction.

$$\sum F = -W \cos I + (T + \Delta T)\cos(\delta/2) - T(\cos(\delta/2)) = 0 \tag{60}$$

With the $T(\cos(\delta/2))$'s cancelling the equation goes to:

$$W \cos I = \Delta T \cos(\delta/2) \tag{61}$$

Since $\delta/2$ goes to 1 as δ approaches zero we find,

$$\Delta T = W \cos I \tag{62}$$

In the next step we will include axial friction forces acting on the drillstring. Summing the forces while rotating gives:

$$N = W \sin I + 2T \sin(\delta/2) \tag{63}$$

$$\Delta T = W \cos I \tag{64}$$

This result is the same as above because the friction acting on the body is axial.

If we consider the forces acting on the drillpipe while we are lowering it (running in the hole), the normal force is calculated as:

$$N = W \sin I + 2T \sin(\delta/2) \tag{65}$$

and in the y-direction,

$$\Delta T = W \cos I - F_f = W \cos I - \mu N \tag{66}$$

Plugging equation into the last equations gives

$$\Delta T = W \cos I - \mu[W \sin I + 2T \sin(\delta/2)] \tag{67}$$

If we then consider the forces acting on the pipe as we pull out of hole (POOH), they are the opposite of going in the wellbore and are as follows:

X-direction (same as previous):

$$N = W \sin I + 2T \sin(\delta/2) \tag{68}$$

and in the Y-direction:

$$\Delta T = W \cos I + F_f = W \cos I + \mu N \tag{69}$$

and plugging in N,

$$\Delta T = W \cos I + \mu[W \sin I + 2T \sin(\delta/2)] \tag{70}$$

Calculating for torque, we get:

$$T_o = (F_f)(d/2) = \mu N(d/2) = \mu(d/2)[W\sin I + 2T\sin(\delta/2)] \tag{71}$$

Lastly we will take a look at the forces acting on a drillstring in a buildup wellbore such as the one in figure 5. Initially we will neglect any axial friction i.e. pipe rotating

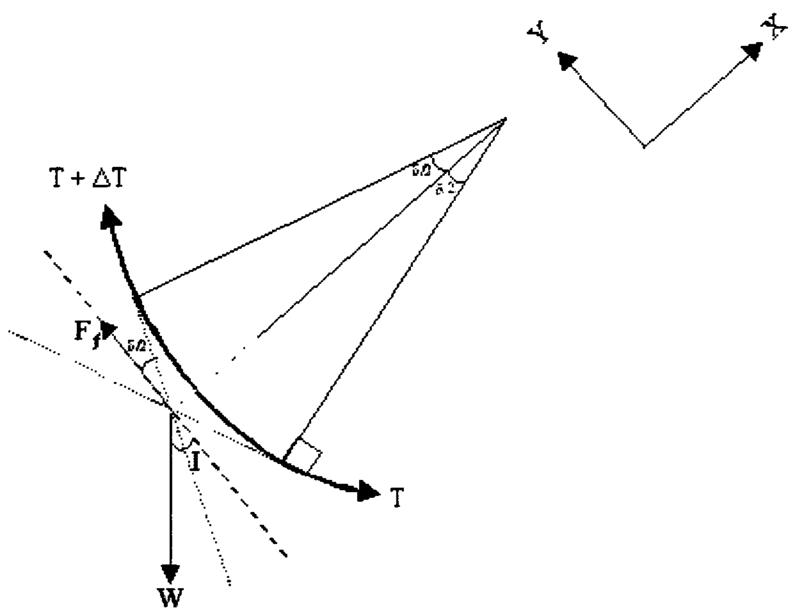


Figure 8: B5 - Buildup Wellbore

The sum of the forces in the X-direction (along the normal plane):

$$\sum F = W\sin I - (T + \Delta T)\sin(\delta/2) - T(\sin(\delta/2)) - N = 0 \tag{72}$$

applying the same principles as before the $\sin\delta/2$ will go to zero and the remaining equation approximates to:

$$N = W\sin I - 2T(\sin(\delta/2)) \tag{73}$$

Next we will sum the forces acting along the tangent in the Y-direction.

$$\sum F = -W\cos I + (T + \Delta T)\cos(\delta/2) - T(\cos(\delta/2)) = 0 \tag{74}$$

Since $\delta/2$ goes to 1 as δ approaches zero we find,

$$\Delta T = W \cos I \tag{75}$$

In the next step we will again include axial friction forces acting on the drillstring. Summing the forces while rotating gives:

$$N = W \sin I - 2T \sin(\delta/2) \tag{76}$$

$$\Delta T = W \cos I \tag{77}$$

As stated previously this result is the same as above because the friction acting on the body is axial.

If we consider the forces acting on the drillpipe while we are lowering it (running in the hole), the normal force is calculated as:

$$N = W \sin I - 2T \sin(\delta/2) \tag{78}$$

and in the y-direction,

$$\Delta T = W \cos I - F_f = W \cos I - \mu N \tag{79}$$

Plugging equation 78 into the last equation gives

$$\Delta T = W \cos I - \mu[W \sin I - 2T \sin(\delta/2)] \tag{80}$$

If we then consider the forces acting on the pipe as we pull out of hole (POOH), they are the opposite of going in the wellbore and are as follows:

X-direction (same as previous):

$$N = W \sin I - 2T \sin(\delta/2) \tag{81}$$

and in the Y-direction:

$$\Delta T = W\cos I + F_f = W\cos I + \mu N \tag{82}$$

and plugging in N,

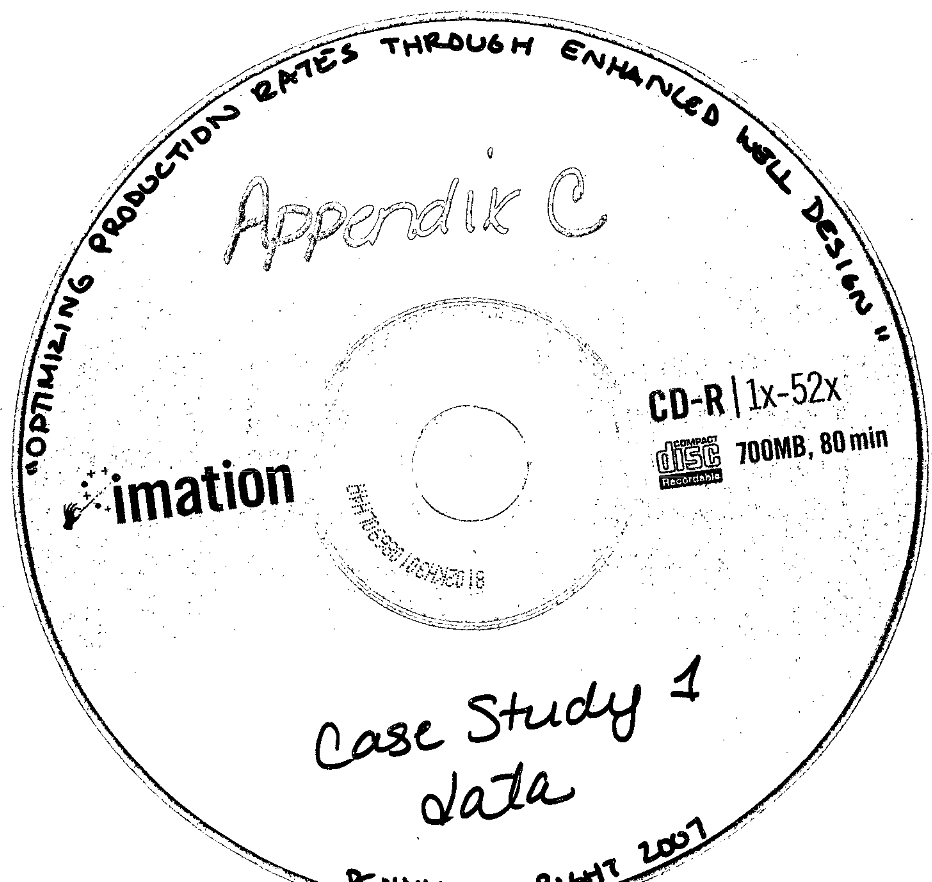
$$\Delta T = W\cos I + \mu[W\sin I - 2T\sin(\delta/2)] \tag{83}$$

Calculating for torque, we get:

$$T_o = (F_f)(d/2) = \mu N(d/2) = \mu(d/2)[W\sin I - 2T\sin(\delta/2)] \tag{84}$$

Appendix C

Case Study One Data



Appendix D

Case Study Two Data