Application of Dual Gradient Technology to Top Hole Drilling

by

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Phase I Final Project Report
Prepared for the Minerals Management Service
Under the MMS/OTRC Cooperative Research Agreement
1435-01-04-CA-35515
Task Order 39317
MMS Project Number 541

November 2006

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Executive Summary

Abstract

In 1996, three competing projects began aimed at mitigating many of the problems encountered in ultra-deepwater drilling, including the narrow window between pore pressure and fracture gradient, high riser loads, high deck loads, and high costs of drilling fluids, etc. These three projects were conducted by Shell on a Submersible Pump System, Transocean on DeepVision, and Hydril on the SubSea MudLift Drilling system in joint industry programs to develop the technology known as dual gradient drilling. All three projects achieved a dual gradient by placing a rotating diverter on top of the BOP stack, which diverted the mud returns from the annulus to a set of seafloor pumps. These pumps then circulated the mud and cuttings back to the rig via an external return line. The marine riser was filled with seawater rather than mud as in the conventional case. After an enormous amount of time, energy, and money were spent to develop dual gradient technology, a test well was drilled in the Gulf of Mexico by the members of the SubSea MudLift Drilling Joint Industry Project in 2001.

In all three of these industry projects, the dual gradient drilling package was designed to be emplaced after surface casing was set to manage the window between pore pressure and fracture pressure, thus, extending the length of open hole sections between casing strings, and minimizing mud costs. Although these systems lowered the riser loads with a water filled riser, the packages were still designed to be employed on fifth generation drilling vessels using the existing riser system. Because these projects focused on deeper portions of the wells, massive, elaborate, and complex systems were developed.

One dual gradient drilling application that has not been fully studied is the potential benefit of utilizing this technology in the top hole portion of the well. This would allow conductor and surface casing to be set deeper (possibly with a smaller third generation floater), which would allow safer drilling of the intermediate hole. Some of the hazards a THDG drilling system can minimize include methane hydrates, shallow gas, and shallow water flows.

From the results of Phase I of this project, it is believed a Top Hole Dual Gradient (THDG) drilling package would improve drilling safety by providing a mud circulating system which has limited pressure control while drilling in a managed pressure drilling mode. THDG systems can lead to better technology than the current “pump and dump” process currently utilized in top hole drilling. An additional benefit of this technology is setting conductor and surface casing deeper in HTHP deep gas well applications as well as in ultra deep water applications. By focusing more attention on the top portion of the wellbore, smaller lighter and simpler drilling equipment and facilities could be used to drill deeper water wells.

This report documents the results of our work on Phase I and includes one Master thesis, one conceptual design report on the equipment that could be utilized, and three preliminary reports on different concepts for equipment that could potentially be utilized.

Introduction

When starting a well, the operator needs to address and mitigate the shallow subsurface geotechnical hazards that threaten the safety of the drilling unit prior to installation of the blowout preventor (BOP). The purpose of the THDG package is to maintain the required borehole pressure in a riserless (i.e., conventional drilling riser not used) drilling mode, using a rotating head with a mechanical seafloor pump and mud return line to the ship to:

- Mitigate various pressure related geotechnical hazards at shallow penetration depths (e.g., pressured water and gas sands) by imposing the optimum circulating pressure and mud rheology to improve wellbore stability and hole cleaning without increasing mud weight;
- Mitigate formation fracturing and mud loss by controlling the pressure on the wellbore, using a seafloor pump either as an annular choke (i.e., to increase wellbore pressure) or as a mud lift pump in riserless mode (i.e., to eliminate the hydrostatic pressure effect of the mud column that would be in the riser);
- Reduce the seafloor pollution and loss of mud caused by the "pump and dump method;" and
- Reduce the number and size of casing strings required during drilling operations (i.e., by extending casing setting depths to cover problem formations with fewer casings).

Tasks

This project was proposed to be conducted in three phases with Phase I being funded by the U.S. Minerals Management Service through a contract with the Offshore Technology Research Center. The proposed tasks for all three phases are listed below.

<u>Phase I, Year 1</u>

1. ***Benefits of THDG*** **–** TAMU-PETE will analyze the benefits of THDG drilling over conventional riser and riserless (pump and dump) drilling. Even though some of this work has been performed, a complete study has not been made, nor have the benefits been fully discussed in industry publications. As part of our literature review, TAMU-PETE intends to gather information on the advantages of published THDG cases, assess the results, and prepare conclusions and recommendations. The results will be included in the final report to the MMS. We will also analyze how dual gradient technology may benefit the industry while drilling in known methane hydrate areas, artificially charged shallow marine sediments, and deep HTHP gas wells on the shelf. Along with this analysis, TAMU-PETE will develop THDG procedures that will mitigate these problems and will determine specifications for the equipment to implement proposed procedures. We will utilize the TAMU well control simulator and dual gradient hydraulics to study various kick scenarios that may be encountered while drilling these areas. TAMU-PETE will also use the simulator to test proposed well control procedures.

2. ***Minimum THDG Equipment Requirements*** **–** TAMU-PETE will determine the minimum equipment requirements for the THDG package, including any necessary pressure containment equipment. After defining the problems that can be mitigated with a THDG package, TAMU-PETE will provide comment on the specifications of the THDG package to TAMU-MEEN.

3. ***Define Mud Circulating System*** **–** TAMU will define the mud and circulating system requirements. TAMU-PETE will determine the mud density range and rheological properties to be utilized with the THDG package as well as the hydraulic and power requirements of the circulating system. TAMU-PETE will be involved in designing the entire mud circulating system, including surface mud pump requirements, drilling fluid properties, and mud cleaning equipment.

4. *Conceptual Engineering Design of Pumping Equipment* – TAMU-MEEN will begin conceptual engineering design of the equipment required to conduct THDG drilling, including (1) the option of using only the dual gradient pump package in a balanced drilling mode and (2) the option of drilling with a minimal (two barriers) BOP stack below the dual gradient pump package has been completed. An industry consultant will be employed to refine the preliminary design for well control and drilling operations.

5. *Conceptual Engineering Design of the Riser System* – TAMU-PETE will begin conceptual engineering design of the riser (mud return line and power supply for a dual gradient pump package) and associated running procedures for drilling riserless. TAMU-MEEN working with a consultant will perform the preliminary engineering design of the riser.

6. *Well Control and Drilling Procedures* – TAMU-PETE will begin to develop well control and drilling procedures for THDG drilling. TAMU-PETE will develop drilling and well control procedures for THDG drilling in parallel with the equipment design and testing. These procedures will include contingencies for handling shallow water flows, hydrates, shallow gas, and artificially charged formations below mudline sediments. TAMU-PETE will test these procedures with the dual gradient hydraulic and drilling simulator developed at Texas A&M University as part of the Subsea Mudlift Drilling JIP.

7. *Solicit Industry Support for Phase II and III* – Project results available from the first 9 months of the project will be used as the basis for soliciting industry support through a JIP, an organization such as the TAMU-PETE's Chrisman Institute, or other arrangement. Aside from the benefits of industry engagement and input, the industry will fund Phases II and III. Initial meetings with industry should be completed by 6 months and formal solicitation of support should be completed 3 month before the end of Phase I in order to avoid/minimize any delay in continuing the project with Phase II and III. It is envisioned that the project team would hold a meeting with industry as part of the solicitation process, and that the MMS will participate in that meeting to indicate their interest and support for this project.

8. *Report & Presentation on Current Phase* - A report documenting the progress and results completed in Phase I will be prepared. A presentation will be given to MMS staff in the GOM Regional Offices in New Orleans.

PROJECT PLAN FOR PHASE II:

Scope of Work: A steering team will be formed to provide the project team with input, guidance, and advice on project milestones, results, and plans though periodic meetings throughout Phases II & III. The steering team members will include representatives from industry supporters and the MMS. Phase II will include work on the following Tasks:

4. *Conceptual Engineering Design of Pumping Equipment* – The project team will complete the conceptual engineering design of the pumping equipment required to conduct THDG drilling,

5. *Conceptual Engineering Design of the Riser System* – The project team will complete the conceptual engineering design of the riser system (mud return line and power supply for a dual gradient pump package) and associated running procedures for drilling riserless.

6. *Well Control and Drilling Procedures* – TAMU-PETE will complete the well control and drilling procedures for THDG drilling. TAMU-PETE will develop drilling and well control procedures for THDG drilling in parallel with the equipment design and testing.

8. *Report & Presentation on Current Phase* - A report documenting the progress and results completed in Phase I will be prepared. A presentation will be given to MMS staff in the GOM Regional Offices in New Orleans.

9. *Risk Analysis* – TAMU-PETE will begin a risk analysis on the equipment and the procedures designed for this project. TAMU-PETE will perform a thorough HAZID and/or HAZOP on all drilling and well control procedures developed for this project to maximize the probability of success. When the risk associated with a procedure is too great, we will re-write or modify the procedure to mitigate the risk to an acceptable level. If the mitigation results in more than a minor change in equipment design or procedure, the risk analysis will be performed again. If requested, TAMU-PETE will also be involved in the risk analysis on the equipment designed for this project.

PROJECT PLAN FOR PHASE III:

Scope of Work: Phase III will include work on the following tasks:

9. *Risk Analysis* - The project team will complete the risk analysis on the equipment and the procedures designed for this THDG drilling system.

10. *Develop Plan for Phase IV* - The project team, in consultation with the project steering team, will develop a plan for the path forward for Phase IV to design, build, and field test a THDG system, and solicit industry support to fund and conduct the field test.

11. *Final Report* - The project team will prepare the Final Report on the Project. The report will provide a comprehensive documentation of all results completed in Phases I-III. Write final report. During the final year, the project team, MMS, and industry sponsors will determine the path forward and funding opportunities to design, build and shop test the prototype equipment. The project team will prepare the Final Project Report. The report will provide comprehensive documentation of all results completed in Phases I-III and the recommended path forward.

Phase I has been completed and this executive summary, attached thesis, and reports constitute the final report for Phase I. Phase II or III have not begun nor does this report detail any work beyond Phase I.

Results and Conclusions

Phase I of this project has been completed and is summarized with results and conclusions as follows:

Task I – Benefits of Top Hole Dual Gradient.

One of the major obstacles in deepwater drilling is the presence of shallow hazards, of which three could be mitigated by the implementation of Top Hole Dual Gradient drilling. The three hazards that were studied are shallow gas, natural gas hydrates, and shallow water flows. A dual gradient well control and hydraulics simulator was utilized to model kicks that could occur while drilling through zones containing either hydrates, gas, or water in shallow below mudline sediments. This was done to determine if kicks from these types of formations could be successfully killed. The results of this task are detailed in the attached thesis by Brandee Elieff entitled “Top Hole Drilling with Dual Gradient Technology to Control Shallow Hazards”

This work shows that a shallow kick could be circulated from the well with the use of dual gradient technology. This technology negates the adverse effect of deep water on the pore pressure/fracture pressure window and makes the probability of successfully killing a shallow kick nearly the same as a land well. The industry has successfully circulated many shallow kicks on land wells with only a few hundred feet of surface casing set and there should be no reason that this success rate could not be encountered utilizing THDG technology. The simulations show that kicks with 1000' or less of conductor casing can be successfully killed. The key factor is early detection to minimize the size of the influx.

Task 2 - Minimum THDG equipment requirements and Task 3 – Design the mud circulating system. These tasks have been completed and the results were passed on to the students in Mechanical Engineering who were charged with Task 4 and 5. Minimum and maximum circulation rates and pressures required to clean the wellbore and minimize hole enlargement are specified in the attached reports.

It was determined that the exact mud type to use would need to be determined on a site specific case to ensure that a mud compatible with the formation type and formation fluids would be utilized. Current drilling technology (pump and dump) only allows the use of an expensive mud such as gelled seawater to drill with until surface casing is set and the marine riser is in place. THDG will return all mud back to the rig where drilled solids can be removed, the mud treated, and re-circulated.

The use of an actual drilling fluid instead of gelled seawater will result in circulation rates that are low enough where hole enlargement is minimized. Drilling fluids that are compatible with the formations and formation fluids will not induce hydration of clays in the formations, and can be designed to either inhibit hydrate formation in the wellbore and the disassociation of naturally occurring hydrates that may be encountered. By drilling an in-gauge wellbore, the cement job on conductor and surface casing has a much higher probability of success.

Task 4 – Conceptual Engineering Design of Pumping Equipment and Task 5 - Conceptual Engineering Design of the Riser System. These tasks have been completed and are detailed in the attached reports entitled:

1. "Top Hole Dual Gradient Drilling System," by Amol Dixit and Chris Krueger
2. "Development of a Top Hole Dual Gradient Drilling System for Deep Sea Drilling that Provides Unobstructed Path for Mud Return," by Sukesh Shenoy, Amol Dixit, and A.S.Nandagopalan
3. "Embodiment Design Report: Top Hole Dual Gradient Drilling," by Chris Dharmawijatno, Mahesh Sonawane, and Chris Krueger
4. "Top Hole Dual Gradient System: Submersible Mud Removal Unit," by John Guinn, Gerald Thomas, and Lauren Wiseman

Dr. Steve Suh of the Mechanical Engineering Department at Texas A&M University supervised nine graduate students in a graduate Mechanical Engineering Design course. These students were placed in three teams and each team was charged with the conceptual design of the subsea pumping system, power system, and mud return system. Each team worked independently from each other and their results are detailed in reports 2, 3, and 4 above.

Based on the these reports and on oral presentations, Dr. Steve Suh, Dr. Jerome Schubert and Mr. Charlie Peterman picked the most likely of these three designs to be successful. Two of the nine Mechanical Engineering students (Amol Dixit and Chris Krueger) continued in the Spring semester of 2006 to further refine the chosen conceptual design. The details of this work are found in report number 1 above.

Task 6 – Well Control and Drilling Procedures. Well control procedures that were developed for the Subsea Mudlift Drilling Joint Industry Project were tested with a dual gradient well control simulator where it is determined that these kick detection, kick containment, and kick circulation procedures are just as applicable as deep kicks when kicks are taken while drilling shallow marine sediments if a THDG system is in place. The details can be found in the thesis by Elieff.

Task 7 – Solicit Industry Support for Phase II and III. Negotiations with potential industry partners are underway to determine the interest of the industry in pursuing Phase II and III.

From this work, the team has concluded:

1. A simplified design of the subsea pumping, and rotating equipment, and return riser is conceivable and has been provided which would allow sufficient circulation rates and pressure so that Top Hole Dual Gradient Drilling can be successfully implemented.
2. Dual gradient drilling technology is not beyond our reach. This technology has been designed, engineered and field tested for feasibility. This technology has been successfully applied to the top hole portion of a wellbore in a shallow water environment and in a deepwater environment after conductor and surface casing have been set.
3. The riserless drilling simulator indicates that applying dual gradient technology to top hole drilling, when used in conjunction with a proper casing program, successfully navigates the narrow window between formation pore pressure and formation fracture pressure.
4. The results of simulation also leads to the conclusion that the dual gradient technology applies safe well control methods while drilling the top hole portion and can control all three major shallow hazards.
5. Riserless Dual Gradient Top Hole Drilling can result in:
   · Rapid and accurate kick detection
   · Safe Well Control Procedures
   · Successful pore/fracture pressure window navigation
   · Control over pressured shallow gas zones
   · Control over shallow water flows
   · Control over dissociating methane hydrates
   · Improved casing seats and wellbore integrity
   · Reduced number of casing strings
   · Reduced overall costs
   · Prevention of methane hydrate formation
   · Reduced environmental impact.

Data Utilized

The team based its work on actual pore pressure and fracture pressure gradients found in the deepwater Gulf of Mexico. For parametric well control studies, the water depth was adjusted with corresponding changes in pore pressure and fracture pressure to show that well shallow below mudline kicks can be circulated successfully an virtually any water depth with the dual gradient system.

Limitation to Our Study and Recommendations for future work

This work includes only conceptual design of equipment and a well control study conducted through computer simulation. Detailed equipment design, building and testing prototypes in the shop, refinement of well control and drilling procedures, and finally a field test on an actual well will be required to advance this concept to a proven system that can be confidently used by industry.

Acknowledgement

The authors would like to thank the U.S. Minerals Management Service and the Offshore Technology Research Center for providing funding and data to complete this project.

Disclaimer

This report documents the work that we performed for Phase I and is only a conceptual design. Additional work must be performed before this technology can be utilized in the field. Additional design work on the equipment and procedures could change our conclusions.

Appendix A

Top Hole Drilling with Dual Gradient Technology to Control Shallow Hazards. (August 2006), M. S. Thesis, Brandee Anastacia Marie Elieff, B.S., Texas A&M University

TOP HOLE DRILLING WITH DUAL GRADIENT TECHNOLOGY

TO CONTROL SHALLOW HAZARDS

A Thesis

by

BRANDEE ANASTACIA MARIE ELIEFF

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2006

Major Subject: Petroleum Engineering

TOP HOLE DRILLING WITH DUAL GRADIENT TECHNOLOGY

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MASTER OF SCIENCE

Approved by:

Chair of Committee, Jerome J. Schubert
Committee Members, Hans C. Juvkam-Wold
Chii-Der Suh
Head of Department, Stephen A. Holditch

August 2006

Major Subject: Petroleum Engineering

ABSTRACT

Top Hole Drilling with Dual Gradient Technology

to Control Shallow Hazards. (August 2006)

Brandee Anastacia Marie Elieff, B.S., Texas A&M University

Chair of Advisory Committee: Dr. Jerome J. Schubert

Currently the "Pump and Dump" method employed by Exploration and Production (E&P) companies in deepwater is simply not enough to control increasingly dangerous and unpredictable shallow hazards. "Pump and Dump" requires a heavy dependence on accurate seismic data to avoid shallow gas zones; the kick detection methods are slow and unreliable, which results in a need for visual kick detection; and it does not offer dynamic well control methods of managing shallow hazards such as methane hydrates, shallow gas and shallow water flows. These negative aspects of "Pump and Dump" are in addition to the environmental impact, high drilling fluid (mud) costs and limited mud options.

Dual gradient technology offers a closed system, which improves drilling simply because the mud within the system is recycled. The amount of required mud is reduced, the variety of acceptable mud types is increased and chemical additives to the mud become an option. This closed system also offers more accurate and faster kick detection methods in addition to those that are already used in the "Pump and Dump" method. This closed system has the potential to prevent the formation of hydrates by adding hydrate inhibitors to the drilling mud. And more significantly, this system

successfully controls dissociating methane hydrates, over pressured shallow gas zones and shallow water flows.

Dual gradient technology improves deepwater drilling operations by removing fluid constraints and offering proactive well control over dissociating hydrates, shallow water flows and over pressured shallow gas zones. There are several clear advantages for dual gradient technology: economic, technical and significantly improved safety, which is achieved through superior well control.

DEDICATION

This work is dedicated to my mother and father for always being my inspiration and support. They have always been there for me; sometimes with encouraging words, sometimes with advice, sometimes just to lend an ear, but always with love and understanding. I know, no matter what I do in life or where I go, they will always be there for me, and that means the entire world to me.

Thank you mom and dad, I couldn’t have done it without either of you.

ACKNOWLEDGEMENTS

Sincere thanks go to my advisor, Dr. Jerome J. Schubert, for his continuous support, advice and patience in answering all of my questions. Working under you has been an honor.

Dr. Hans C. Juvkam-Wold, thank you for always being patient and available to answer my questions and offer advice. I have benefited greatly from your knowledge and experiences.

Dr. Steve Suh, thanks for all your help, support and for agreeing to be part of my committee. It has been extremely valuable for me to learn from someone outside my department.

My gratitude goes to Rob Romas for being my computer expert. Also, thank you to the rest of my family; your support is greatly appreciated.

I also want to thank my office mates, Arash Haghshenas and Amir Paknejad, for taking the time to problem solve with me.

Dr. Jonggeun Choe, thank you for permitting me to use the Riserless Drilling Simulator you created.

Finally, I would like to thank Minerals Management Service and the Offshore Technology Research Center for making this research project possible.

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CHAPTER I

INTRODUCTION

In order to meet the world's increasing demand for energy, the search for oil and gas extends into increasingly hostile and challenging environments. Among these problematical environments are the deepwater regions of the world. As technology progresses the definition of deepwater becomes greater and greater every day, and as the water depth increases, the associated technical, economic and safety complexities increase proportionately. This has led to a high demand for new technologies throughout the oilfield, but with a specific focus on improving drilling technologies. The industry wide goals are to: increase accessibility to reserves, improve wellbore integrity, reduce overhead costs and, most importantly, provide a safe working environment. Applying a dual gradient technology to offshore drilling is not a new concept, but one that is being addressed with new fervor and can help meet all of these industry goals.

1.1 Dual Gradient Drilling Technology

One of the many challenges faced when drilling deepwater offshore wells is the decreasing window between formation pore pressures and formation fracture pressures. "In certain offshore areas with younger sedimentary deposits, the presence of a very narrow margin between formation pore pressure and fracture pressure creates

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This thesis follows the style and format of *SPE Drilling and Completion.*

tremendous drilling challenges with increasing water depths."[1] This occurrence is explained as being the result of the lower overburden pressures, due to the lower pressure gradient of seawater, than that which is exerted by typical sand-shale formations. The resulting situation is that the overburden and fracture pressures in an offshore well are significantly lower, than those of an onshore well of a similar depth, and it is more difficult to maintain over pressure drilling techniques without fracturing the formations.[2] Typically, the method for combating this problem has been to fortify the wellbore casing, by increasing the number of casing strings set in the well during drilling and completions operations. However, this can be extremely costly, both from a materials cost perspective and a time cost perspective. It has been proven that the number of casing strings set in a well can be reduced if the difference between the pore pressure and fracture pressure can be managed better. This has resulted in the development of new Managed Pressure Drilling (MPD) techniques. The International Association of Drilling Contractors (IADC) Underbalanced Operations Committee defines MPD as: an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly.[3,4] One MPD technique that is being pursued for commercial use in deepwater environments is dual gradient drilling.

1.2 Dual Gradient Drilling Advantages

A dual gradient system removes the mud filled riser from the typical deepwater drilling system. In a conventional system the annulus section of the riser is filled with mud, and below the sea floor the pressure within the annulus is so high, that to avoid a pressure in the wellbore that exceeds the formation fracture pressure, it is necessary to set casing strings more frequently than is technically and economically desirable.

When using a dual gradient drilling system the riser is removed from the system (figuratively and/or literally depending upon the variation of the dual gradient system). This allows the pressure at the sea floor to be lower (salt water pressure gradient is lower than most drilling fluids' pressure gradient) than in a conventional system, and this allows the driller to more accurately navigate in the pressure window between formation fracture pressure and formation pore pressure. As long as there is a safe margin of approximately 0.5 ppg gradient between the wellbore annular pressure gradient and the fracture pressure gradient it is unnecessary to set casing strings as often as in the conventional system. An illustration of how the pressures are managed so that annular pressure remains above pore pressure at drilling depth but below fracture pressure at shallower depths in the well, can be seen in **Fig. 1**.

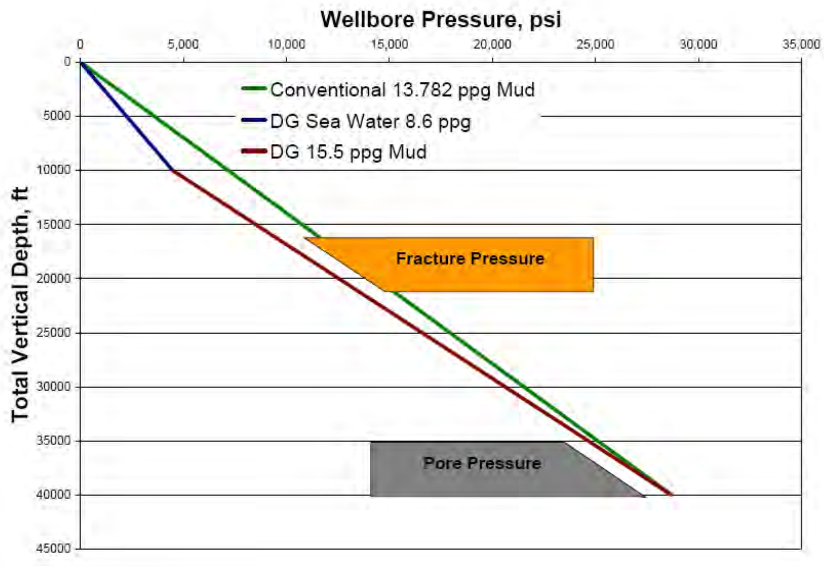

Fig. 1 - Illustration of Wellbore Pressures in a Dual Gradient System

Managing the pressure window between the formation fracture and pore pressures decreases the number of casing strings required to maintain wellbore integrity while drilling. A comparison between conventional deepwater drilling casing requirements and dual gradient deepwater drilling casing requirements can be seen in **Fig. 2** and **Fig. 3**.

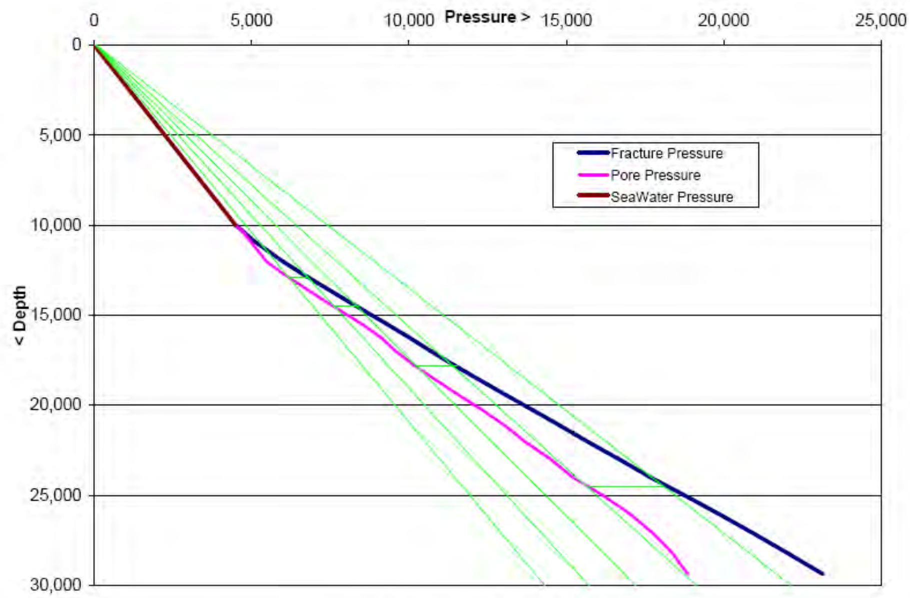

Fig. 2 - Graphical Casing Selection in a Conventional System

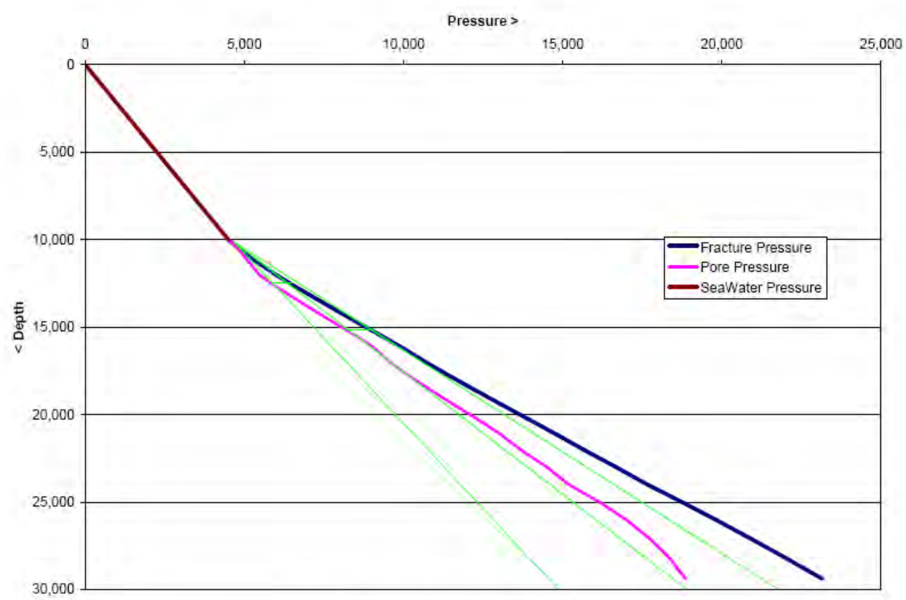

Fig. 3 - Graphical Casing Selection in a Dual Gradient System

When drilling conventionally in deepwater conditions the riser is treated as part of the wellbore and as the water depth increases the pressures within the wellbore change as though the depth of the well is increasing as well. However, when using the dual gradient drilling system procedures, the depth of the water is no longer a factor affecting wellbore pressure. It's like "taking water out of the way" (from the SubSea MudLift Drilling Joint Industry Project (SSMLDJIP) Phase III: Final Report through personal communication). Many benefits are realized by employing dual gradient drilling technology in a deepwater environment. A few of these benefits are:

- Fewer required casing strings
- Larger production tubing (accommodates higher production rates)
- Improved well control and reduction of lost circulation setbacks
- Lower costs, as the "water depth capabilities of smaller rigs may be extended".[5,6,7,8]

1.3 Dual Gradient Drilling History and Evolution

The concept of dual gradient drilling was first considered in the 1960s. At the time the idea was to simply remove the riser and therefore the technology was referred to as riserless drilling. The technology, however, was not pursued at the time, as there was no driving economic or technical need for improving offshore drilling. As offshore drilling progressed into deeper water the desire to improve project development economics and technical characteristics resurrected the technology in the 1990s.

Beginning in 1996, four main projects began in an effort to improve deepwater drilling technology by implementing dual gradient systems. The four projects were: Shell Oil Company's project, the Deep Vision project, Maurer Technology's Hollow Glass Spheres project and the SubSea MudLift Joint Industry Project.[9]

The most extensive study was the SubSea MudLift Joint Industry Project (JIP) that began in 1996 when a group of deepwater drilling contractors, operators, service companies and a manufacturer gathered to discuss the merits of riserless or dual gradient drilling. The result was an extensive system design, construction and field test that would span five years. The main reason the group was interested in developing this technology was the promise it held to potentially reduce the necessary number of casing strings, specifically in the Gulf of Mexico, where high pore pressures and low formation strengths require operators to set casing strings often during drilling and completion operations.[5,6,7]

The SubSea MudLift JIP was charged with the tasks of designing the hardware and the necessary procedures to effectively and safely operate the dual gradient drilling system. Phase I of the project took place from September, 1996 to April 1998 and cost approximately $1.05 million. Phase I was the Conceptual Engineering Phase and the participants were to create a dual gradient drilling design that: was feasible, considered well control requirements, and was adaptable to a large rig fleet (not just a few specialized rigs).[5,6,7] Phase I is considered to have been very successful and resulted in a design for drilling extended reach, 12¼" holes at TD, in 10,000 ft of water. One of the most challenging design issues was how to lift the mud after it had been circulated through the wellbore.

Once circulated, through the wellbore, the mud or drilling fluid, is loaded with free gases, metal shavings, rock chips and other drilling debris. What kind of pump is capable of pumping the mud from the sea floor back to the rig floor? The JIP answered this question in Phase I with the response of a positive displacement diaphragm pump. However, no such pump existed that met the JIP's needs, so it was concluded that the JIP would have to design and build one. Other conclusions of Phase I were: this technology is more than feasible, however, well control procedures would need to be modified, and a field test is necessary, specifically in the Gulf of Mexico where the driving need for this technology is based.

Phase II, or Component Design, Testing, Procedure and Development, began in January of 1998 and continued until April of 2000 and cost approximately $12.65 million. The purpose of Phase II was to actually design, build and test the subsea pumping system, create all the drilling operations and well control procedures and to determine the best methods for incorporating the dual gradient drilling technology onto existing drilling rigs. Phase II resulted in: a proven reliable seawater-driven diaphragm pumping system, drilling and well control procedures capable of withstanding potential equipment failure cases, and an understanding that system training program was necessary.

Phase III, or System Design, Fabrication and Testing, began in January of 2000 and was completed in November of 2001 with a budget of $31.2 million. The purpose of Phase III was to validate the design of the technology through an actual field application. This goal was accomplished and the first dual gradient test well was spudded on August 24th, 2001 and by August 27th, 2001 the 20" casing had been run and cemented. On August 29th, the JIP SubSea MudLift Drilling system was finally put to test in the field. Although there were many problems initially (especially with the electrical system), "Once a problem was identified and repaired, it stayed repaired." (From the SSMLDJIP Phase III: Final Report through personal communication). Ultimately ninety percent of the field test objectives were met and considered successful. Although still requiring industry support, dual gradient drilling was proven a viable and useful technology.

Another JIP project began in 2000 and culminated with a successful test application in 2004. This was the development of AGR Ability Group's (AGR) Riserless Mud Recovery System (RMR). The system was designed and tested specifically for the application of drilling the top hole portion of a wellbore. The desired results were to increase control over shallow water and gas flows, and to increase the depth of the surface casing strings by reducing the number of dynamically selected seats. The RMR system was rated to a depth of 450 meters of seawater, but was tested in only 330 meters of seawater. The successful field test took place in December of 2004 in the North Sea.[10] The conclusions of this JIP were that using dual gradient technology for top hole drilling results in:

- Improved hole stability and reduced washouts

- Improved control over shallow gas and water flows
- Improved gas detection (due to accurate flow checks and improved mud volume control)
- Prevention of the accumulation of mud and cuttings on subsea templates and preventing the dispersion of drilling fluids into environmentally sensitive areas
- Reduced number of necessary surface casing strings.

The most current research being done in the dual gradient drilling area is a project through the Offshore Technology Research Center (OTRC), a division of the National Science Foundation (NSF) that is a joint partnership between Texas A&M University and the University of Texas. The project the OTRC is pursuing, which is initially funded by the Minerals Management Service (MMS), is called the “Application of Dual Gradient Technology to Top Hole Drilling”. The purpose of the project is to begin a JIP that results in the design and test of a dual gradient drilling system geared specifically to drilling the top hole portion of the wellbore in a deepwater environment. Although this has already been done in shallow water, this OTRC project is to focus on the application of a Dual Gradient Top Hole Drilling System (DGTHDS) in deepwater. The driving factors for this project are the increasingly hazardous shallow hazards commonly found in deepwater environments, especially in the Gulf of Mexico. These shallow hazards: over pressured shallow gas zones, shallow water flows and methane hydrates are jeopardizing drilling activities in deepwater. It is hypothesized that a DGTHDS can control these shallow hazards while drilling in deepwater. The project will explore increasing control over these hazards in two ways: one is in the increased well control available from a DGTHDS and the second is to improve the wellbore integrity by setting surface casing deeper than in conventional drilling applications. Once the shallow hazards are controlled and the conductor and surface casing are set deeper this will also allow for safer drilling of the intermediate depth portions of the well and ultimately reduce the number of casing strings used throughout the well.

1.4 Achieving the Dual Gradient Condition

There are different methods used to achieve the dual gradient condition when drilling offshore. Basically, a dual gradient is achieved when there are two different pressure gradients in the annulus, the volume between the wellbore inner diameter (ID) and the drill string (DS) outer diameter (OD). The condition can be achieved by: reducing the density of the drilling fluid in a portion of the wellbore or riser, removing the riser completely and allowing sea water to be the second gradient, or managing the level of the mud within the riser and allowing the second gradient within the riser to be that of another fluid.[11]

One method, nitrogen injection, is based on air drilling procedures and underbalanced drilling techniques. This technique uses nitrogen to reduce the weight of the mud in the riser.[6] In an effort to reduce the amount of nitrogen required to lower the mud pressure gradient in the riser, a concentric riser system is considered the most economical. In this system a casing string is placed inside the riser with a rotating BOP at the top of the riser (in the moonpool) to control the returning flow. The mud is held in the annulus between the casing string and the riser, and nitrogen is injected at the bottom of the riser into the annulus. Buoyancy causes the nitrogen to flow up the annulus which reduces the density and pressure gradient of the drilling fluid as a result of nitrogen's liquid holdup properties. The injection of nitrogen can reduce the weight of a 16.2 ppg mud to 6.9 ppg. This is can be applied when the second gradient is desired to be even lower than that of seawater, which has a typical pressure gradient of 8.55 ppg. The most noteworthy characteristic about this method of using nitrogen injection to create two gradients is that the formation is not underbalanced, as one might initially conclude. The cased hole is underbalanced to a depth, but below the casing, in the open hole, the wellbore is actually overbalanced, which prevent an influx of fluids from the formation into the wellbore. One serious concern with this method of creating a dual density system is the uncertainty as to whether or not well control and kick recognition will be more difficult. In this case, the system is very dynamic and well control and kick detection are definitely more complex, however, not necessarily unsafe.[12]

Another method of creating a dual gradient system is to begin by drilling the upper portions of the well without a riser and by simply returning the drilling mud to the sea floor. In this setup the pressure inside the wellbore at the seafloor is the same as the pressure at the sea floor. In other words the pressure gradient from the ocean surface to the sea floor is that of the seawater pressure gradient. Then, inside the wellbore a heavier than typical mud is used to maintain proper pressures while drilling. Once the initial spudding has taken place and the structural pipe has been set, the subsea BOP stack is installed with some variation on a typical system. The mud returns are moved, from the wellhead by a rotating diverter, to a subsea pump which returns the mud to the rig floor through a 6” ID return line. Drilling continues with this setup and the remaining casing strings are set using this dual gradient system where mud returns, to the rig, through a separate line.[6] An illustration of this system can be seen in **Fig. 4**.

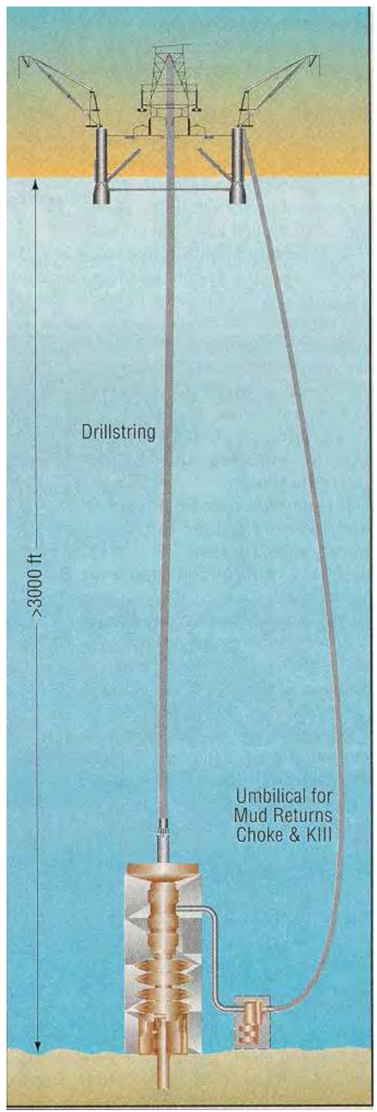

Fig. 4 - Illustration of a Riserless Dual Gradient System[12]

Initially, this method was regarded with skepticism because of the perceived difficulty of kick detection. However, with more advanced technology, and the ability to monitor pressure in the subsea BOP accurately, kick detection and the detection of circulation loss is reliable and safe. In fact, it is possible for the riser to act as a trip tank in this system.[12]

Another method of creating a dual gradient system is similar to that of the nitrogen injection. A Department of Energy (DOE) project was done to test how the injection of hollow spheres into the mud returning through the riser can create a dual gradient system. This system is similar to the nitrogen injection method, but separating the gas from the mud at the rig floor is simplified because dissolved gas in the drilling fluid is not a concern. The glass spheres are separated from the mud and re-injected at the base of the riser. **Fig. 5** illustrates a typical Hollow Glass Sphere Injection system.

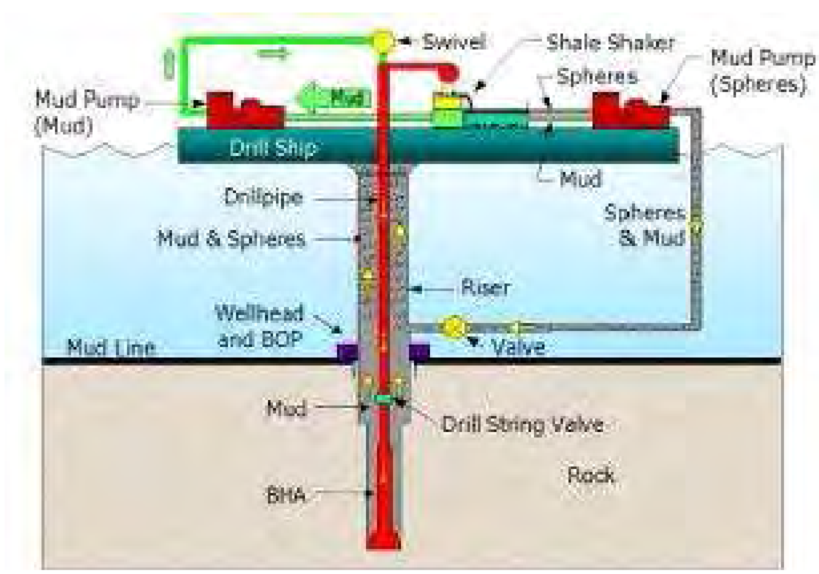

Fig. 5 - Illustration of a Hollow Sphere Injection Dual Gradient System[13]

1.5 A Typical Dual Gradient System and Components

The most commonly researched and pursued method of achieving a dual gradient system is the riserless system, described in Chapter I (1.4) and shown in Fig. 4. This system pumps the drilling mud through the drill string, out the drill bit nozzles, into the open hole, up the annulus, into the BOP stack, through the rotating head, into the subsea mud pump, and up the 6” return line to the rig floor. The mud is then cleaned at the rig floor and recycled back to the drill string to be circulated again.

The main components in this system that are unique to the dual gradient system are: the drill string valve, the rotating head, the subsea mud pump, and the mud return line.

Once the drilling mud flows up the annulus to the BOP it must be diverted so that it can be pumped up the return line. In the SubSea MudLift Drilling JIP this was accomplished through a rotating head referred to as the SubSea Rotating Diverter (SRD). This SRD is capable of handling $6^5/_8$” 5½” and 5” drill pipe and has a retrievable rotating seal rated to 500 psi. Although, typically, the pressure difference across this seal is less that 50 psi. Once the mud is diverted to the SubSea Mud Pump the main concern is handling of solids. This was addressed through the addition of a SubSea Rock Crusher Assembly. Basically, as the returning mud passes through this assembly any rock chips are crushed between two rotating spheres with teeth. A photo of this rock crusher assembly can be seen in **Fig. 6**.

Fig. 6 - SubSea Rock Crushing Assembly Used in SubSea MudLift JIP[I]

Once the cuttings are crushed and processed through the unit they have been reduced to small pieces. The crushed cuttings and mud are then passed through into the SubSea MudLift Pump. The requirements that the pump is subject to are very demanding. The pump must be able to pump up to 5% volume of mud cuttings, produce a flow rate between 10 and 1,800 gallons per minute, operate to a maximum pressure of 6,600 psi, within a temperature range between 28 ºF and 180 ºF, and finally be able to pump 100% gas when the need arises to circulate a gas kick out of the well. As mentioned earlier in Chapter I (1.3) the necessary result is a positive displacement diaphragm pump that is hydraulically powered by seawater. The seawater providing hydraulic power is pumped from the rig floor using conventional surface mud pumps down an auxiliary line to the mud pump. In **Fig. 7** you can see a cross section illustration of the mechanisms at work within this diaphragm pump.

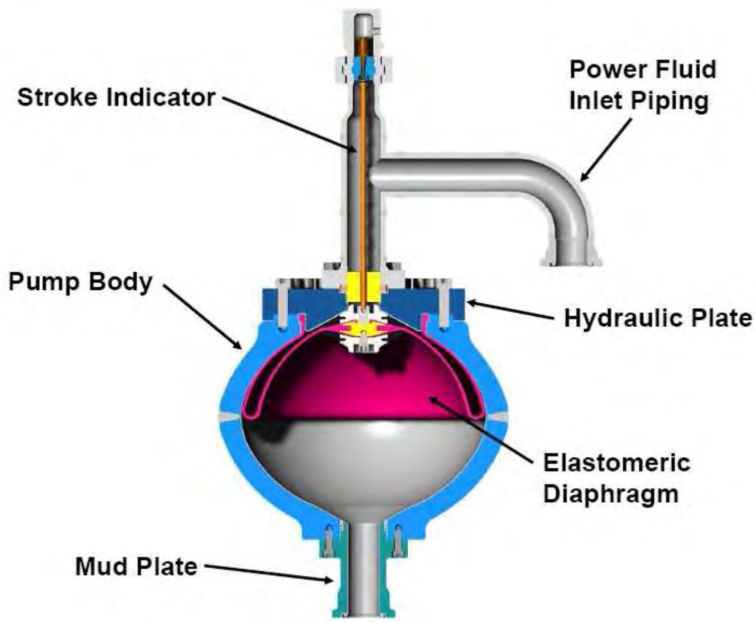

Fig. 7 - Illustration of a Cross Section of a Diaphragm Positive Displacement Pump[I]

This pump also acts as a check valve by preventing the hydrostatic pressure of the drilling fluid within the return line from impacting on the pressure within the wellbore. This pump is normally run in an automatic mode, which means it is set to run at a constant inlet pressure, and the pump rate is automatically altered to maintain a constant inlet pump pressure. This allows the driller to change the surface mud pumping rates as if the system were conventional.[14] During well control procedures the pump can be switched from a constant inlet pressure mode to a constant pump rate mode in the advent that a kick enters the well and annulus pressure needs to be increased to maintain a desirable annulus/pore pressure balance.

The last main component of the riserless dual gradient drilling system is the Drill String Valve (DSV). The DSV was developed to control the U-tube effect, which is often encountered in drilling and completion operations. The U-tube effect is cause when the total hydrostatic pressure (HSP) of the fluid in the DS is different than the total HSP of the fluid in the annulus. In response the fluid will flow through the drill bit nozzles from the region (DS/annulus) with the higher HSP to the region with the lower HSP. In conventional operations the U-tube effect only occurs occasionally and most commonly during cementing. However, in riserless dual gradient drilling, the U-tube effect is always a factor, as the HSP of the fluid in the DS is often more than the HSP of the fluid in the wellbore annulus plus the HSP at the seafloor. The concern is, when mud circulation is stopped to make or break a drill pipe connection, the mud within the drill string will drain into the wellbore and up the annulus. The DSV assembly is placed inline with the drill string, and when mud circulation is stopped the DSV is closed to prevent the free fall of drilling fluid within the drill string (from the SSMLDJIP Phase III: Final Report through personal communication). An illustration of the system with the DSV assembly in place can be seen in **Fig. 8**.

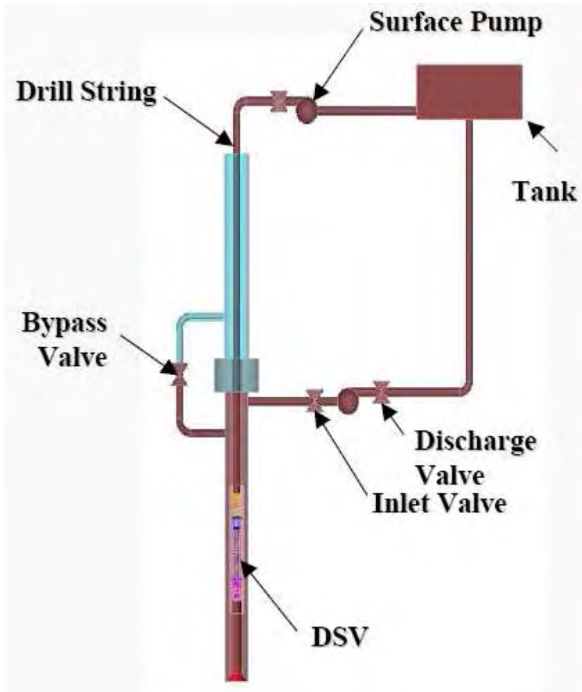

Fig. 8 - Illustration of Dual Gradient System w/ Drill String Valve[I]

1.6 Dual Gradient Operations versus Conventional Operations

There are several aspects of dual gradient drilling that are different from that of conventional drilling operations. Regarding general drilling operations a smaller rig may be used for applying dual gradient technology than what would be conventionally used. There are a couple of reasons for this: one is in order to support a 21” riser (common size used in conventional drilling) the rig must be large enough to support the weight of the riser. In a riserless dual gradient drilling system the weight hanging from the rig is reduced to that of the drill string, the mud return line and the umbilical control lines. Also contributing to the large rig size, necessary for conventional drilling, are the deck space limitations that are caused by the necessity of having large drilling fluid volumes on hand. In a conventional drilling system a large volume of mud is necessary in order to fill the riser. Also a problem, is that a high volume of mud is lost during the "Pump and Dump" method for drilling the tophole portion of the wellbore. In a DGTHDS only the drill string must be filled with mud and the mud is returned to the rig floor where it is cleaned and recycled. This reduces the necessary deck space and the costs associated with supplying the necessary mud. Reducing the weight rating of the rig and the necessary deck space allows for the use of a smaller rig.

Another difference between a conventional drilling system and a dual gradient drilling system is that removing the riser leaves only the drill string to be affected by the forces exerted by the ocean currents. Since the diameter of the drill string is considerably smaller than that of a 21" riser, the impact these forces have on drilling operations is reduced.

Perhaps the most time and cost saving benefit that results from the application of dual gradient drilling, over conventional drilling is how the necessary number of casing strings is reduced. This does two things, first this allows for the final tubing size to be larger, which increases production flow rates, and second the amount of time necessary to drill a deepwater well is reduced, because less time is spent on completions.

From a safety perspective the main differences between dual gradient drilling and a conventional drilling system are the well control procedures. Basically, a dual gradient system, as a managed pressure drilling technique, improves well control. A Modified

Driller's Method employed by riserless dual gradient drilling is described in Chapter I, Section 1.7.

The similarity between the two systems is that the drilling program is not significantly altered. Trips and connections are handled in the same manner and the basic acts of drilling, such as bit selection and general rig procedures, are not altered.[9]

1.7 Dual Gradient Systems' Well Control Procedures

Well control is not simply something that must be implemented in the eventuality of a kick. Proper well control must be considered throughout all phases of drilling operations. This means from the initial planning, through the well completion and into the abandonment stages. The basic purpose of proper well control is to prevent blowouts, and create a quality wellbore. This is best accomplished through proper prediction of formation pore and fracture pressures, the design and use of the proper equipment (BOP, kick detection devices and casing) and proper kick detection and kill procedures.[9,15]

Taking a kick while drilling is common and must be prepared for. Quick kick detection and proper well control response is imperative. Kicks may be detected through several different observations and the driller must be aware of all inconsistencies experienced while drilling. The most common methods of kick detections are: a drilling break, a flow increase, a mud pit gain, a decrease in circulating pressure that is accompanied by an increase in pump speed within the surface pumps, well flows when the surface pumps are off, an increase in rotary torque, drag and fill and an increase in drill string weight.

These kick detection techniques are just as applicable, if not more so, in dual gradient drilling as in conventional drilling. The major difference between dual gradient drilling and conventional drilling is the U-tube effect. The U-tube effect occurs when drilling mud circulation through the drill string, up the annulus and through the subsea mud pump is stopped. The U-tube effect causes the system to try and equalize the pressure difference between the hydrostatic pressure within the drill string and the hydrostatic pressure in the annulus by draining the drilling fluid contained within the drill string, through the drill bit nozzles, into the annulus. Again, this occurs any time the HSP of the fluid in the DS is different than the HSP of the fluid in the annulus. The solution to the U-tube effect is simply a drill string valve (DSV), which is described in Chapter I, Section 1.5. There is however, a benefit to the U-tube effect that occurs in dual gradient drilling. This effect allows for lower circulating pressures by the rig pumps and makes small changes in pressures easier to detect. These pressure changes often serve as excellent kick detectors.

Another method of kick detection involves the inlet and outlet pressure of the subsea mud pump. When a kick enters the wellbore the annular flow rate of the drilling fluid increases by an amount that is equal to that of the kick influx rate. Generally, while drilling, the subsea mud pumps are set to operate in a constant inlet pressure mode. This means, if the rate of flow increases due to a kick influx the pumping rate of the subsea mud pumps will automatically increase as well, to maintain a constant subsea pump inlet pressure. This is an excellent indicator to the driller that a kick is occurring and the driller can then take the measures necessary to stop the kick influx into the annulus.

Approximately half of all kicks occur while tripping the drill pipe into or out of the hole. The best method, which is also the earliest, of determining a kick has taken place is to measure the volume of mud required to fill the hole after removing some of the pipe. This is usually done every five stands of drill pipe. If the mud required to fill the hole is less than the volume of the drill pipe removed, a kick has entered the wellbore. This is a kick detection employed by conventional drilling practices. In dual gradient drilling this kick detection procedure must be considered for use both with a DSV and without a DSV. When operating without a DSV an accurate determination of the amount of mud necessary to fill the wellbore is not possible until after the U-tube effect has ceased. When operating with a DSV, the volume of mud to fill the hole is equal to the volume of a cylinder with a diameter equal to the OD of the pipe removed. The only major change from conventional operations is that more frequent hole fill intervals are necessary and if possible continuous fill of the hole is even more desirable.

As soon as a kick is detected it is necessary to take the necessary actions to stop the influx, so that excessive casing pressures can be avoided. Excessive casing pressures can result in lost circulation, formation fracturing and the worst case scenario of a surface blowout. When a kick is initially detected usually the response is to shut-in the well by closing the BOP stack. When shutting in a dual gradient drilling system immediate shut-in should not be performed unless a DSV is in place. The DSV must be closed before shut-in to ensure that the hydrostatic pressure of the mud within the drill string does not cause formation fracturing. If there is no DSV in place it is necessary to allow the U-tube effect to take place and then to shut-in the well by closing the BOP. When the U-tube effect is taking place it is difficult to prevent any additional influx from entering the wellbore. This is why it is recommended to employ the use of a DSV in all dual gradient drilling operations. A DSV allows immediate shut-in of the well and killing procedures can then commence in a manner more similar to that of conventional drilling. However, the following procedures should be adhered to when the driller is not employing a complete shut-in scenario, i.e. no DSV.[9,16,17,18] This is known as a modified Driller's Method, and is considered the most effective and common in a dual gradient system.

1 Slow the subsea pumps to the pre-kick rate (maintain the rig pumps at constant drilling rate).

2 Allow the drillpipe pressure to stabilize, and record this pressure and the circulating rate.

3 Continue circulating at the drillpipe pressure and rate recorded in step 2 until kick fluids are circulated from the wellbore.

4 The constant drillpipe pressure is maintained by adjusting the subsea pump inlet pressure in a manner similar to adjusting the casing pressure with the adjustable choke on a conventional kill procedure.

5 After the kick fluids are circulated from the wellbore, a kill fluid of higher density is circulated around to increase the hydrostatic pressure imposed on the bottom hole.

Other methods such as the Wait and Weight Method and the Volumetric Method are applicable to a riserless dual gradient system. However, these methods both require the use of a DSV. Although the DSV is applicable with the Driller's method it is unnecessary and it is always good to ensure that proper well control relys on as few of pieces of equipment as possible.

1.8 Dual Gradient Drilling Challenges

The main challenges that are associated with dual gradient drilling are basically those that are associated with all new technologies. The technology has been designed, developed and successfully field tested. The key now is to streamline the equipment and procedures to ensure that dual gradient technology is seamlessly the next step forward in deepwater drilling.

In the field test of the SubSea MudLift Drilling JIP the main delay while drilling the test hole was equipment commissioning problems. The technology successfully functioned the way it was designed but had electrical and commissioning delays. Once these "kinks" were worked out of the system the test hole was drilled with minimal delays (from the SSMLDJIP Phase III: Final Report through personal communication).

In order for the industry to embrace a new technology such as dual gradient drilling, the "kinks" must be all worked out and the new technology must offer substantial benefits over conventional technologies.

An interesting point is that a dual gradient system will need to be somewhat customized depending on: water depth, temperatures above and below the mud line, formation pressures, ocean conditions and a number of other conditions. However, even in conventional technology, no two wells are ever drilled with the exact same equipment or procedures. The difference is that personnel are familiar with how to alter conventional technology to fit with the current drilling environment. In order for personnel to become as familiar with dual gradient technology as conventional technology, training is a necessity (from the SSMLDJIP Phase III: Final Report through personal communication).

Eventually, dual gradient technology will become a conventional technology and be one of the many tools in a driller's toolbox. The remaining obstacles are equipment commissioning, personnel training and overcoming initial industry resistance.

CHAPTER II

SHALLOW HAZARDS

The category of shallow hazards includes three main subcategories: methane hydrates, shallow gas zones and shallow water flows. These hazards can be found in deepwater environments and generally between the mudline and approximately 5,000 ft below the mudline. Each of these hazards create a different problem for exploration and production (E&P) companies, which are pursuing oil and gas fields in deepwater. Shallow hazards may appear to cause problems only during drilling and completion operations, but in reality can have long term ramifications that affect production long into the life of the field. Shallow hazards compromise: the safety of operations, well control, wellbore integrity and reservoir accessibility.

2.1 Methane Hydrates

Hydrates are natural gases, typically methane, that are trapped within ice crystals. Since most of the hydrates that are found are methane gas, this shallow hazard is commonly referred to as methane hydrates. Methane hydrates form in low temperature, high pressure zones where water and methane are present together. Above 68 ºF methane hydrates cannot exist, however below 68 ºF methane hydrates can exist depending on the pressure within the zone. Typically methane hydrates are found along the sea floor and in isolated pockets below the mud line until the geothermal gradient causes the formation temperature to increase above 68 ºF. Methane hydrates can cause problems in two ways: by forming within equipment or by dissociating during drilling operations.

2.1.1 Formation of Hydrates Within Drilling Equipment

The most common way methane hydrates impact on drilling operations is when hydrates form within the drilling system. Particularly critical is if they form in the Blowout Preventer (BOP) stack or in the choke and kill lines. These hydrates can block the lines and BOP and prevent the BOP from functioning properly (closing in the case of an emergency). It is necessary, for the safety of the drilling and completions crew, that a system be in place that can prevent the formation of hydrates within equipment. Chemicals known as hydrate inhibitors can be added to the drilling fluid to prevent the formation of hydrates within the equipment, but in a conventional top hole drilling system, these chemicals are not an option, because of environmental restrictions. However, if a closed system is used and the drilling fluid is returned to the rig floor, hydrate inhibitors can be added to the drilling fluid.

2.1.2 Dissociation of Hydrates into the Wellbore During Drilling Operations

The second way hydrates can compromise the safety of operations is less common, but equally dangerous. When hydrates are lying on the sea floor or within the formation, the gas is trapped within the ice. Drilling through these hydrates breaks the ice crystals imprisoning the gas and allows the gas to dissociate from the ice and into the wellbore. This dissociating gas acts like a shallow gas kick and the driller is immediately faced with the complication of handling gas within the annulus. If the gas is not controlled and the pressures within the wellbore annulus are not stabilized more reservoir fluid (gas/oil/water) may enter the wellbore and further complicate well control procedures.

2.2 Shallow Gas Flows

Shallow gas flows are another common shallow hazard. It is even hypothesized that shallow gas flows are a result of methane hydrates that have been buried within the formation, and as the formation temperature increases the gas is released from the ice crystals and trapped within the formation. Shallow gas zones are often over pressured and pose a serious well control risk. Once a gas kick enters the wellbore the annulus pressure begins to decrease, which allows more gas to enter the wellbore. If the driller does not apply a well control method to increase annular pressure, prevent further influx and circulate the gas kick safely out of hole, disastrous events such as surface and underground blowouts can be the result. Not only can blowouts destroy the rig, but they can also result in the loss of life. One particularly catastrophic event was the explosion of the Piper Alpha rig in the North Sea in 1988.[19] The remnants of this disaster can be seen in **Fig. 9**. Events such as this are completely unacceptable and any method of preventing such an event needs to be designed, tested and implemented as a high priority.

Fig. 9 - The Piper Alpha Platform: North Sea – 167 Died in Explosion and Fire[20]

2.3 Shallow Water Flows

The third main shallow hazard is shallow water flows. Shallow water flows do not generally pose a safety threat to the rig and personnel, but the conventional method of dealing with shallow water flows is not conducive to high quality casing seats, and this can threaten the well's safety. In conventional top hole drilling, these water zones are often allowed to produce, and can cause erosion in the formation and ultimately compromise the integrity of the surface casing. Eventually the casing can collapse and the entire wellbore may be destroyed. This is a very time consuming and expensive problem that has been experienced by operators in the past. A particularly expensive and complicated example of this situation was experienced by the Shell Deepwater Development, Inc. Company in the Ursa field, located in the Mississippi Canyon Block 854 in the Gulf of Mexico. The field was discovered in 1990, and the first well, MC 854 #1 was plugged and abandoned after setting 20" surface casing as a result of buckling casing. Well MC 854 #2 was successfully drilled to TD, but was also plugged and abandoned due to severe shallow casing wear that resulted from the buckling of casing across shallow sands.[21] An illustration of how the production of these shallow water zones can cause erosion behind casing seats can be seen in **Fig. 10**.

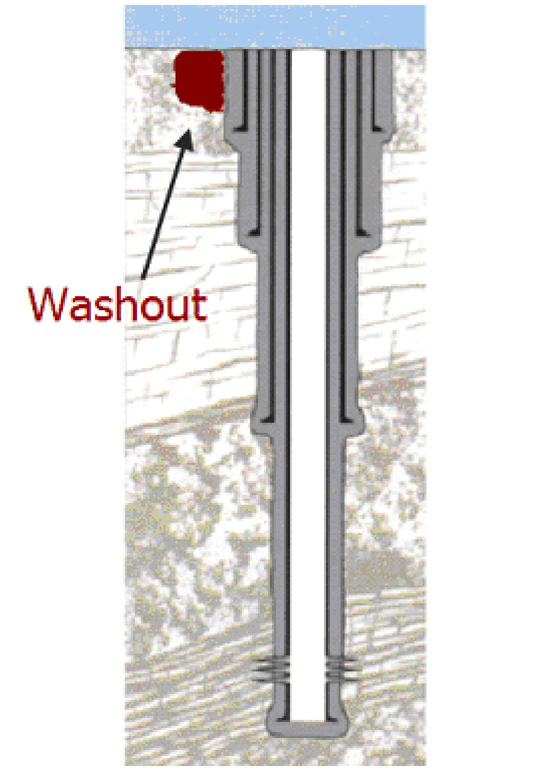

Fig. 10 - Formation Erosion Behind Casing Resulting from Shallow Water Flows

CHAPTER III

CONTROLLING SHALLOW HAZARDS WITH DUAL GRADIENT TECHNOLOGY

Shallow hazards are a problem and controlling these shallow hazards has become a priority for E&P companies operating in deepwater environments. That is why it is surprising to find the conventional method of drilling the top hole portion of the wellbore, “Pump and Dump”, is still used as the industry standard. “Pump and Dump” is lacking in many ways and dual gradient technology can easily control shallow hazards with acceptable modifications to current drilling and completions equipment, drilling procedures and well control procedures.

3.1 Conventional Technology: “Pump and Dump” Method Description

The current “Pump and Dump” method used to drill the top hole portion of the wellbore in deepwater, is fairly basic. The mud is pumped down the drill string, into the wellbore up the annulus and onto the seafloor. There is no BOP stack in place and there is no drilling fluid return to the rig floor. The “Pump and Dump” method can cause several problems. These problems include, but are not limited to: limited well control, increased number of shallow casing strings, poor wellbore integrity, increased initial hole size (requiring larger rigs), loss of mud and finally a negative environmental impact, which limits acceptable types of drilling fluids that meet regulations.

The “Pump and Dump” method offers few methods of kick detection and limited well control methods when a kick does occur. Because the mud is not returned to the rig floor there is limited down hole pressure information available to the driller and often the driller relies on visual kick detection methods to determine when an influx has entered the wellbore. In an effort to avoid shallow hazards like hydrates and shallow gas zones, seismic data is carefully analyzed and the surface location of the rig ma be moved to avoid these zones. This can result in longer measured depth (MD) direction wells. In the eventuality that these zones can not be avoided the driller has no proactive well control methods in their “tool box”. In the case of shallow water flows, these zones are generally allowed to produce until the formation pressure is reduced. Unfortunately, by the time this happens erosion of the formation has often already occurred.

Dealing with these shallow hazards can increase the number of shallow casing strings, when compared to drilling in normally pressured zones. To ensure that the drilling fluid can be heavy enough to maintain over balanced drilling, even when drilling through over pressured shallow gas zones, casing must be set often to prevent shallower parts of the wellbore from fracturing and causing lost circulation. Lost circulation can result is stuck pipe or worse, an underground blowout.

Poor wellbore quality is also often the result of “Pump and Dump”. The “Pump and Dump” method limits the use of specialty drilling fluids that lift cutting out of the hole at lower circulation rates. This means, in order to lift the cutting with a less specialized mud, the circulation rate is increased. This increased drilling fluid circulation rate can cause wellbore erosion, and the wellbore often becomes jaggedly shaped, which makes a high quality cement job become difficult to implement.

Aside from the technical, safety and economical disadvantages to “Pump and Dump” method, there is the obvious environmental impact, not to mention how the continuous loss of drilling fluid can become a high cost constraint to the development of a field. The environmental restrictions placed on the types of acceptable drilling fluids can prevent the driller from using the optimal fluid for the formation type and also prevents the addition of chemicals that prevent problems such as the formation of hydrates within equipment. The “Pump and Dump” method is not really a method at all. It is simply the standard rut that the industry has fallen into. It is obvious, upon reviewing the disadvantages and lack of advantages, that a new method of top hole drilling is imperative.

Applying dual gradient drilling technology to drilling the top hole portion of the wellbore is likely to eliminate the majority, if not all, of these associated problems.[22] Possibly the most important reason that dual gradient technology would be beneficial in top hole drilling is the control over shallow hazards, the improved well control and the improved safety.

3.2 Riserless Dual Gradient Drilling Technology Description

Understanding the DGTHDS does not require a significant stretch of the imagination. The flow of the drilling fluid does not vary greatly from conventional riser drilling. It is, however, different than the "Pump and Dump" method. The drilling fluid is pumped down the drill string, where it enters the wellbore and flows back through the wellbore annulus to the rotating diverter. The rotating diverter transfers the returning mud to the subsea mud pump. This subsea mud pump, when in typical drilling mode operations, is set to operate at a constant subsea inlet pressure. This means the pumping rate is automatically altered to maintain constant pump inlet pressure. This changes during well control procedures, which is discussed in Chapter III (3.2.2). The mud is then pumped up a 6" return line to the rig floor, where it is recycled and pumped back down the drill string. The other main line from the rig to subsea pump is the seawater supply line that supplies hydraulic power to the diaphragm subsea pump. There are inherent benefits to this system over "Pump and Dump", simply because the DGTHDS is a closed system. The amount of required mud is reduced because the drilling fluid is recycled and reused. Seafloor pollution is reduced and because there is no environmental impact, the number of drilling fluid type meeting regulation increase. It has been proven that selecting the proper drilling fluid can significantly improve drilling operations. Also important is, how the closed system allows for the admission of backpressure to increase the wellbore annulus pressure. This allows the driller to maintain the proper wellbore annulus pressure with heavier mud at lower circulation rates. This prevents the wellbore erosion that is commonly associated with the "Pump and Dump" method. This additional pressure control also improves kick detection, offers proactive well control methods and ultimately reduces the number of required shallow casing strings.

3.2.1 Kick Detection

The DGTHDS offers more accurate and faster kick detection methods in addition to those that are already utilized during the "Pump and Dump" method. As, discussed earlier, in standard drilling mode the subsea pump is operated at a constant inlet pressure. When a kick enters the wellbore the pump inlet pressure increases. In order to maintain a constant inlet pressure, the subsea pump responds by increasing its pumping rate to compensate for the additional inlet pressure created by the influx. This increase in pump rate is the first kick indicator. As the subsea pump increases its pumping rate, the subsea pump's outlet pressure increases and the levels in the mud pit increase. These are the second and third kick indicators. Finally, in response to the pressure changes within the wellbore the surface pump pressure decreases, the fourth kick indicator. When a kick is detected the system uses a modified driller's method to prevent further influx and circulate the kick safely out of hole.

3.2.2 Well Control "Modified Driller's Method"

As soon as the system detects a kick, the subsea pump is returned to the pre-kick rate and a constant pumping rate mode is maintained, which is equal to the surface pumping rate. This creates back pressure on the fluids within the wellbore annulus and increases bottomhole pressure until it is balanced with formation pore pressure, and further influx is prevented. It is important to record the stabilized drillpipe pressure and the pumping rate. Circulation of the fluids is then continued and the recorded drillpipe pressure is maintained at balance by changing the subsea pump rate. (This is similar to an adjustable choke in a conventional kill procedure.) Circulation is continued until kick fluids are removed from the wellbore. Once the kick fluids have been removed from the wellbore a kill weight mud is circulated to increase the hydrostatic pressure imposed on the bottomhole and drilling can resume. A graphical representation of this method can be seen in **Fig. 11**.

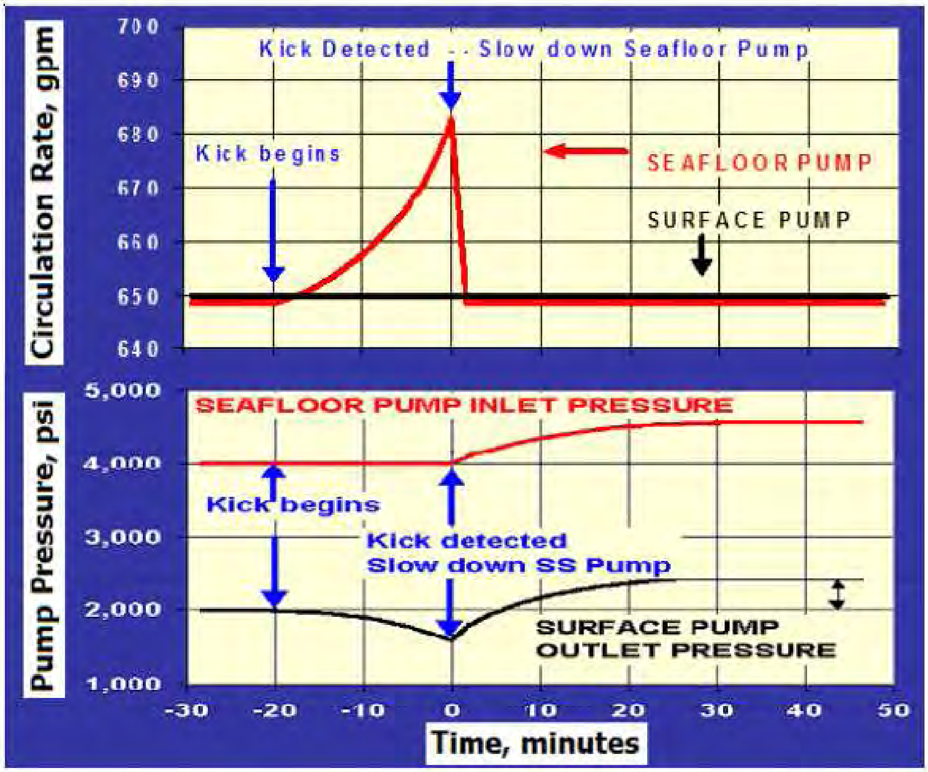

Fig. 11 - Graphical Depiction of Modified Driller's Method[12]

It is visible in Fig. 11, that the subsea pump rate increases, to maintain a constant inlet pressure, as the influx enters the wellbore. At the same time the surface pump outlet pressure decreases. Once the kick is detected and well control procedures commence you can see the rate of the subsea pump return to the pre-kick rate which is equal to that of the surface pump. It can also be seen how this causes the subsea pump inlet pressure and surface pump outlet pressures to increase.

3.3 Dual Gradient Controlling Methane Hydrates

As described earlier, methane hydrates impact on drilling operations by forming within the equipment and by dissociating within the wellbore annulus. Dual gradient technology applied to top hole drilling controls both of these problems caused by methane hydrates.

3.3.1 Preventing Hydrate Formation

The introduction of a closed system allows for chemicals, such as hydrate inhibitors to be added to the drilling fluid. These hydrate inhibitors have been proven very successful at preventing the formation of hydrates in drilling and production equipment.

3.3.2 Controlling Dissociating Hydrates

In the case of drilling through dissociating hydrates, a significant well control problem, dual gradient technology offers the advantage of fast kick detection. When methane hydrates dissociate into the wellbore, the dual gradient drilling systems reacts the same was as if a gas influx has entered the wellbore. The subsea pump inlet pressure will increase and the subsea pump rate will automatically increase to compensate. Then the pit gain warning and increased subsea pump outlet and decreased surface pump outlet pressures will alert the driller to employ well control methods. The subsea mud return system supplies the driller with back pressure control over the formation that prevents the dissociating methane hydrates from causing other influxes. The dissociating methane hydrates can be proactively and safely circulated from the wellbore and drilling can resume quickly.

3.4 Dual Gradient Controlling Shallow Gas Flows

A DGTHDS controls shallow gas flows the same way it controls dissociating methane hydrates: through effective kick detection and proactive well control methods. Again the gas influx into the wellbore is quickly detected and the modified driller's method quickly circulates the kick from the wellbore and prevents further influx. The drilling fluid weight is adjusted for the new formation pore pressure and drilling continues without the need to set, dynamically selected, casing seats.

3.5 Dual Gradient Controlling Shallow Water Flows

Shallow water flows are easier to control that methane hydrate dissolution or gas kicks. Controlling these shallow water flows will allow the driller to prevent the erosion of the formation and ultimately ensure that the operator will have a wellbore of high quality, because the casing seats are securely cemented to the formation.[23]

3.6 Dual Gradient Drilling Controlling Shallow Hazards Summary

This is a new technology that is still in the research and development stage, but it has all the signs of significantly benefiting the offshore drilling industry and to be adopted as a conventional technology. The technical and safety benefits associated with this new technology far outweigh the inherent industry resistance to the implementation of a new technology. The benefits that the industry stands to gain from the implementation of a DGTHDS vary from financial to safety to environmental.[10]

CHAPTER IV

TOP HOLE DUAL GRADIENT DRILLING SIMULATION

4.1 Riserless Drilling Simulator

The Riserless Drilling Simulator used, was originally created, as part of Dr. Jonggeun Choe's Ph.D. dissertation at Texas A&M University. The simulator was later adapted for use in the SSMLDJIP. A screen shot of the opening page to the simulator can be seen in **Fig. 12**.

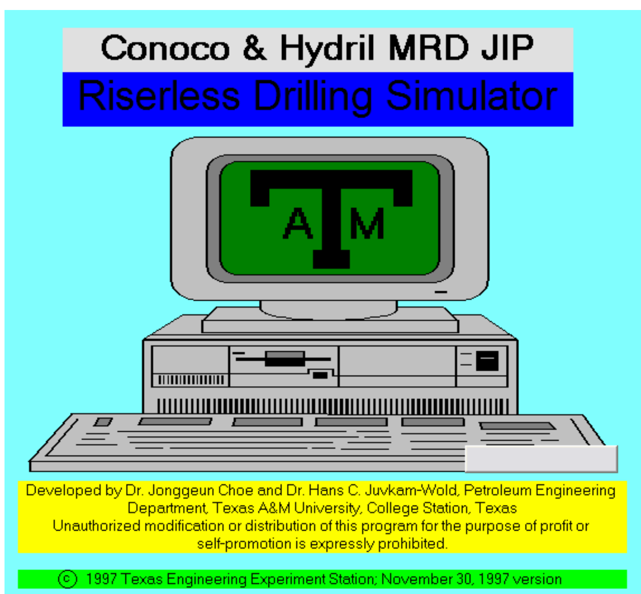

Fig. 12 - Riserless Drilling Simulator Introduction Page

This simulator was used, with the express permission of Dr. Jonggeun Choe and Dr. Hans C. Juvkam-Wold, exclusively for the purpose of researching the application of dual gradient technology to top hole drilling.

4.2 Simulation Parameters

After opening the simulator, the main menu is presented and several options are available. The first step is to change the input data from the default options, or open previously saved input data if re-running a previous simulation. The main menu can be seen below in **Fig. 13**.

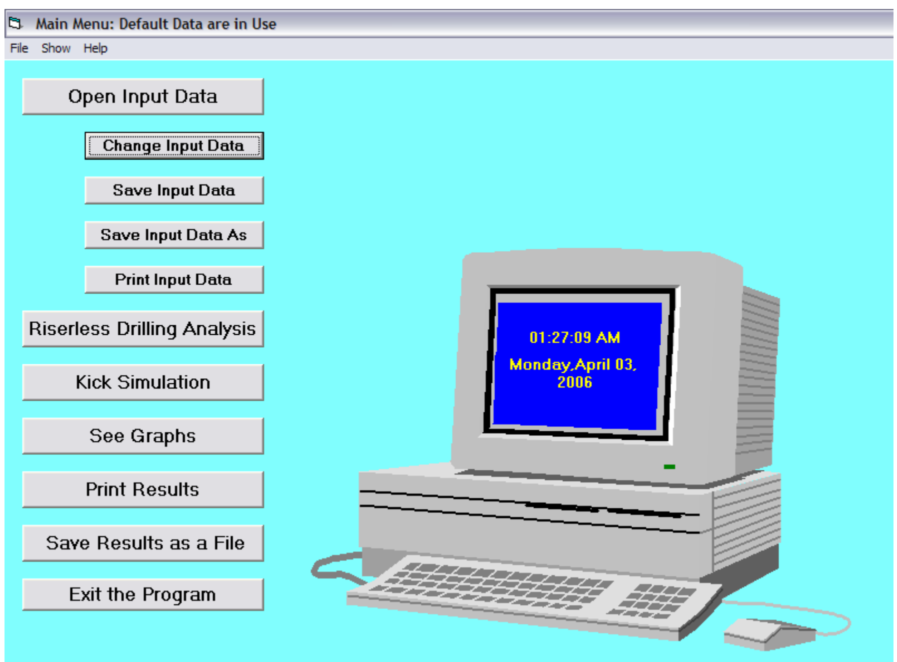

Fig. 13 - Main Menu of Riserless Drilling Simulator

Once the user has entered the necessary input data the gas kick simulation can be run by clicking the "Kick Simulation" button on the Main Menu screen. **Fig. 14, 15, 16, 17, 18** and **19** show the input data screens and the information required to properly run a kick simulation. The input data types are discussed below with each figure.

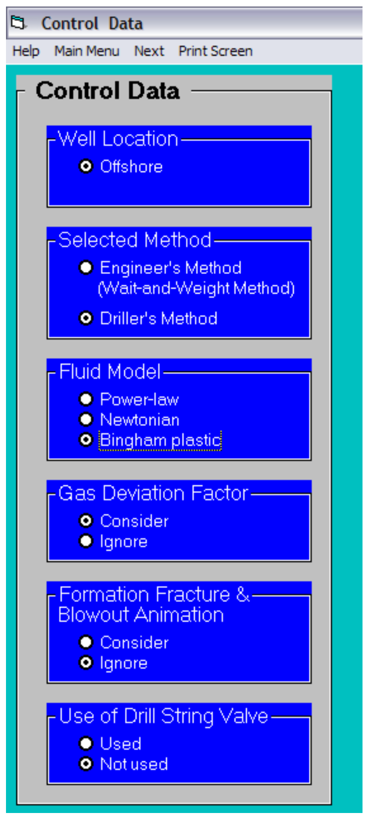

Fig. 14 - Simulator Control Data Input Screen

Fig. 14 shows the basic control data that needs to be entered for each simulation. The well control method used in all simulation runs is the "Modified Driller's Method" described previously in Chapter III. In the case of this simulation, the use of a Drill

String Valve (DSV) is not necessary when the “Modified Driller’s Method” is the choice of well control methods. During the “Modified Driller’s Method” the well is never shut-in, so the U-tube effect does not impact on operations. Since the U-tube effect is not applicable, the use of DSV is unnecessary. The rest of the data options selected in Fig. 14 remained constant throughout all simulation runs.

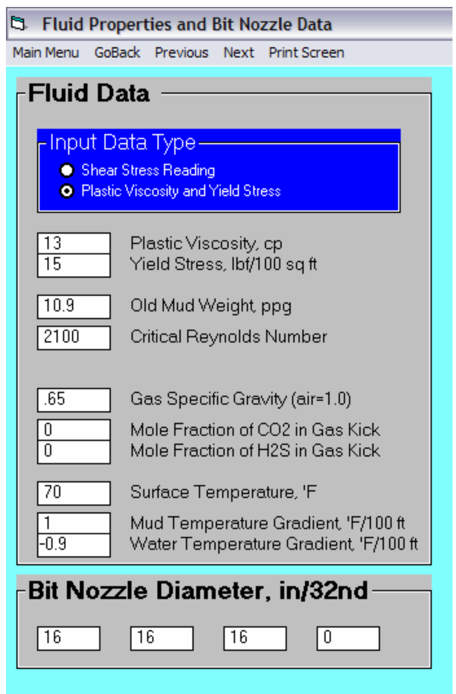

Fig. 15 - Simulator Fluid Data Input Screen

Fig. 15 shows the fluid data input screen. The only data, in this input screen, that was not held constant through all simulation runs were the Old Mud Weight, the Plastic Viscosity and the Yield Stress of the Mud. These parameters varied based on the pore pressures encountered at drilling depth. The different mud properties will be discussed in Chapter IV. The gas specific gravity, surface temperature, temperature gradients and bit nozzle sizes remained constant through all simulation runs.

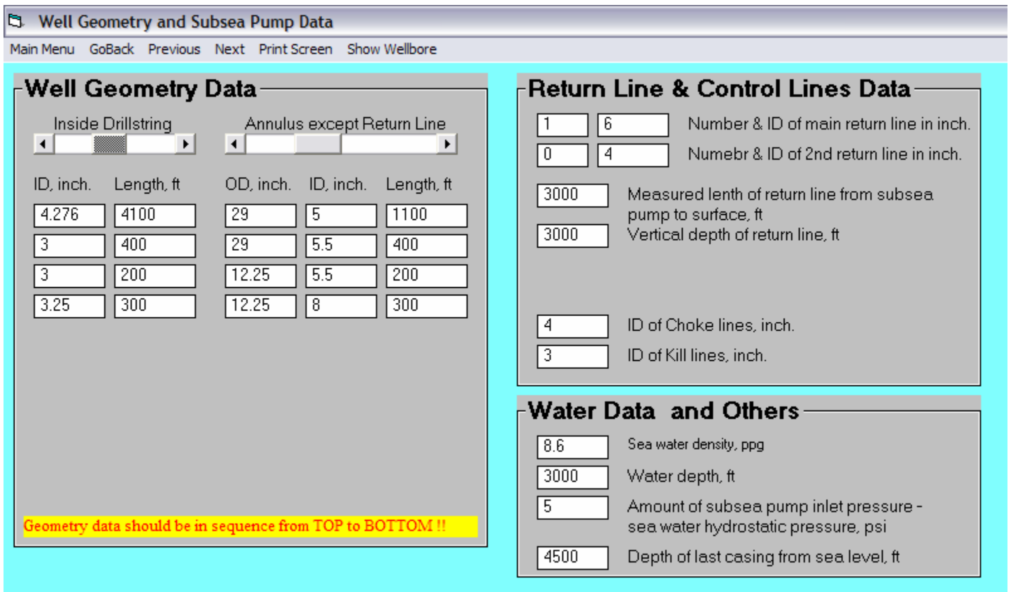

Fig. 16 - Simulator Well Geometry Data, Return Line and Control Lines Data and Water Data and Other Input Screen

Fig. 16 shows the well geometry data as well as the return line and water data. The use of one 6" main return line remained constant. Also remaining constant was the sea water density of 8.6 ppg and the 5 psi amount of subsea pump inlet pressure – sea water hydrostatic pressure. In each simulation run the well geometry was modified, as well as the length of the return line, the depth of the last casing point and the depth from the rig to the seafloor. After entering the well geometry data, the simulator produces a visual representation of the wellbore so the user may double check for any possible mistakes. An example of this visual representation of the wellbore can be seen in Fig. 17.

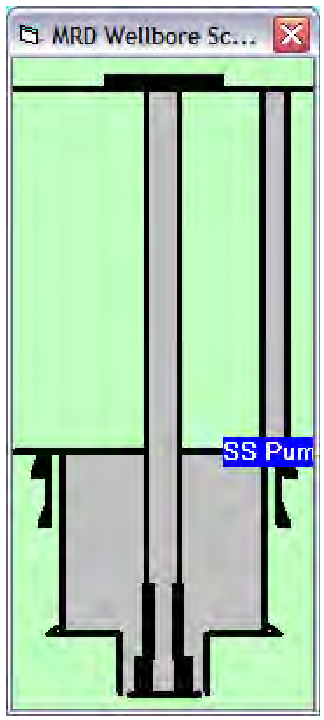

Fig. 17 - Illustration of Entered Wellbore Geometry Data

Other data that is modified, for each simulation run, is the kick data and the pore and fracture pressures, shown in Fig. 18. The kick data is manipulated by changing the amount of formation over pressure, which results in a kick intensity that is calculated in ppg. The pit gain warning level can be changed, so the pit gain kick indicator is more or less sensitive. Last on this input screen, the pore and fracture pressures are entered manually based on sea water depth. The pressures used varied based on water depth, but are analogous to a field found in the deepwater region of the Gulf of Mexico. This field actually possesses a pore/fracture pressure window that is abnormally small. The reason for using this window was to determine if this system (dual gradient top hole drilling) is capable of handling an extreme field environment. The Pore and Fracture Pressure Regimes (P&F PR) can be seen in Appendix B.

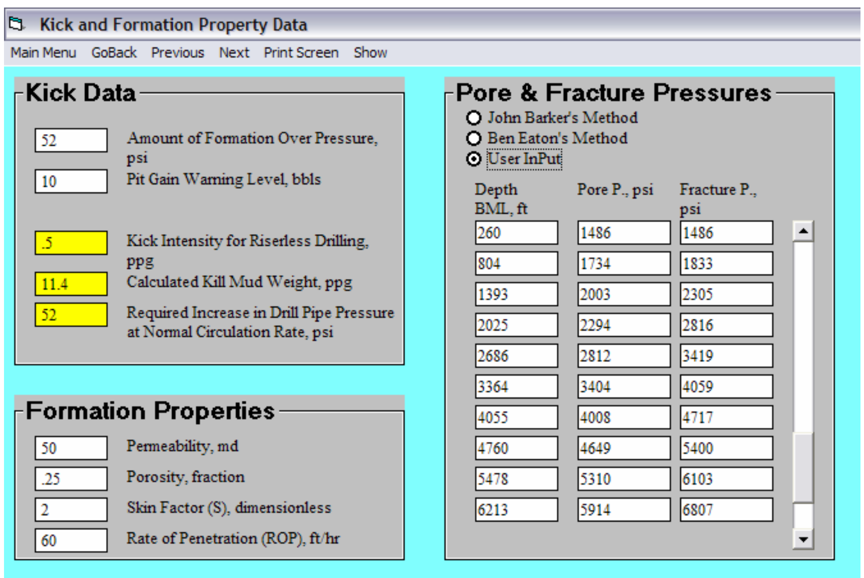

Fig. 18 - Simulator Kick Data, Formation Properties and Pore and Fracture Pressures Input Screen

The final input screen that must be entered is the pump data, surface choke valve data and the types of surface conditions. This screen can be seen in Fig. 19 and the data shown in this figure remained constant throughout all simulation runs.

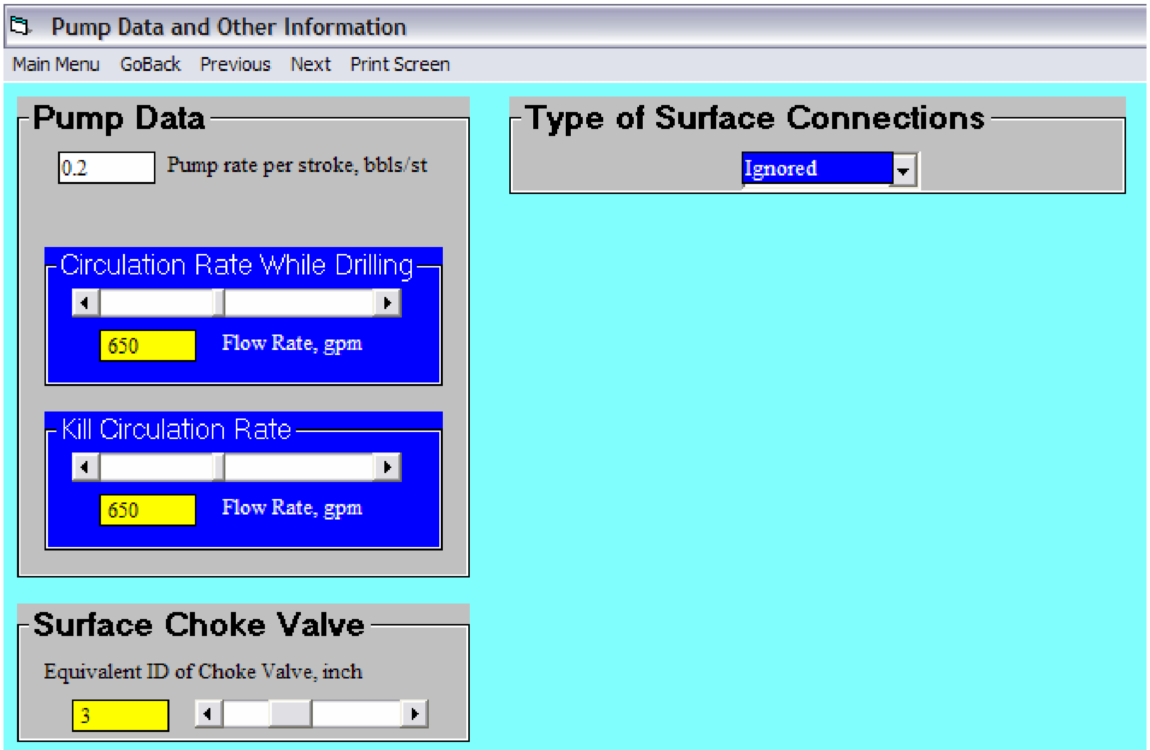

Fig. 19 - Simulator Pump Data, Surface Choke Valve and Type of Surface Connections Input Screen

Two sets of simulation runs were performed in order to determine the well control limits of this Dual Gradient Top Hole Drilling System (DGTHDS). The first set was designed simply to understand the limits of this system. The second was designed to test the limits of this system specifically in a field with a similar pore/fracture pressure window to the field that was already encountered in the Gulf of Mexico. The parameters of each simulation set are described in Chapter IV.

4.2.1 Simulation Run Set #1

In this simulation set the system was tested in three different water depths, resulting in different pore and fracture pressure regimes (P&F PR) and, therefore, different required mud properties, three different drilling depths below mud line (BML), two formation overpressures and finally two different kick sizes. One parameter that was chosen to remain constant based on typical wellbore schematics was the 30” conductor pipe set to a depth of 1,500 ft BML. Below the conductor pipe a pilot hole size of 12 ¼” was drilled. The variable parameters for each simulation are shown below in Table 1. The flowchart that describes the determination of run order can be seen in Appendix A, and the spreadsheets showing all of the input data for each run can be seen in Appendix C.

Table 1 - Variable Parameters of Simulation Set #1

Run #	Water Depth	P&F PR #	Mud Weight	Mud Plastic Viscosity	Mud Yield Point Stress	Depth of 12 ¼” Pilot Hole BML	Formation Over Pressure	Pit Gain Warning Level
	ft		ppg	cp	lbf/ 100 sq. ft	ft	ppg	bbl
1	3,000	#1	8.8	5	17	500	0.5	10
2	3,000	#1	8.8	5	17	500	0.5	50
3	3,000	#1	8.8	5	17	500	1	10
4	3,000	#1	8.8	5	17	500	1	50
5	3,000	#1	12.5	16.5	9	2,500	0.5	10
6	3,000	#1	12.5	16.5	9	2,500	0.5	50
7	3,000	#1	12.5	16.5	9	2,500	1	10
8	3,000	#1	12.5	16.5	9	2,500	1	50
9	3,000	#1	14	21	9	4,500	0.5	10
10	3,000	#1	14	21	9	4,500	0.5	50
11	3,000	#1	14	21	9	4,500	1	10
12	3,000	#1	14	21	9	4,500	1	50
13	5,000	#2	8.8	5	17	500	0.5	10

Table 1 Continued

Run #	Water Depth	P&F PR #	Mud Weight	Mud Plastic Viscosity	Mud Yield Point Stress	Depth of 12 ¼" Pilot Hole BML	Formation Over Pressure	Pit Gain Warning Level
	ft		ppg	cp	lbf/ 100 sq. ft	ft	ppg	bbl
14	5,000	#2	8.8	5	17	500	0.5	50
15	5,000	#2	8.8	5	17	500	1	10
16	5,000	#2	8.8	5	17	500	1	50
17	5,000	#2	12.5	16.5	9	2,500	0.5	10
18	5,000	#2	12.5	16.5	9	2,500	0.5	50
19	5,000	#2	12.5	16.5	9	2,500	1	10
20	5,000	#2	12.5	16.5	9	2,500	1	50
21	5,000	#2	14	21	9	4,500	0.5	10
22	5,000	#2	14	21	9	4,500	0.5	50
23	5,000	#2	14	21	9	4,500	1	10
24	5,000	#2	14	21	9	4,500	1	50
25	10,000	#3	8.8	5	17	500	0.5	10
26	10,000	#3	8.8	5	17	500	0.5	50
27	10,000	#3	8.8	5	17	500	1	10
28	10,000	#3	8.8	5	17	500	1	50
29	10,000	#3	12.5	16.5	9	2,500	0.5	10
30	10,000	#3	12.5	16.5	9	2,500	0.5	50
31	10,000	#3	12.5	16.5	9	2,500	1	10
32	10,000	#3	12.5	16.5	9	2,500	1	50
33	10,000	#3	14	21	9	4,500	0.5	10
34	10,000	#3	14	21	9	4,500	0.5	50
35	10,000	#3	14	21	9	4,500	1	10
36	10,000	#3	14	21	9	4,500	1	50

4.2.2 Simulation Run Set #2

Simulation Set #2 was run specifically to test the DGTHDS in a field when proper casing selections have been made. This means that the casing selections should be determined graphically based on the pore/fracture pressure window in the top hole portion of the wellbore. The graphical selection of surface casing seats for 3,000 ft of water depth can be seen in **Fig. 20**.

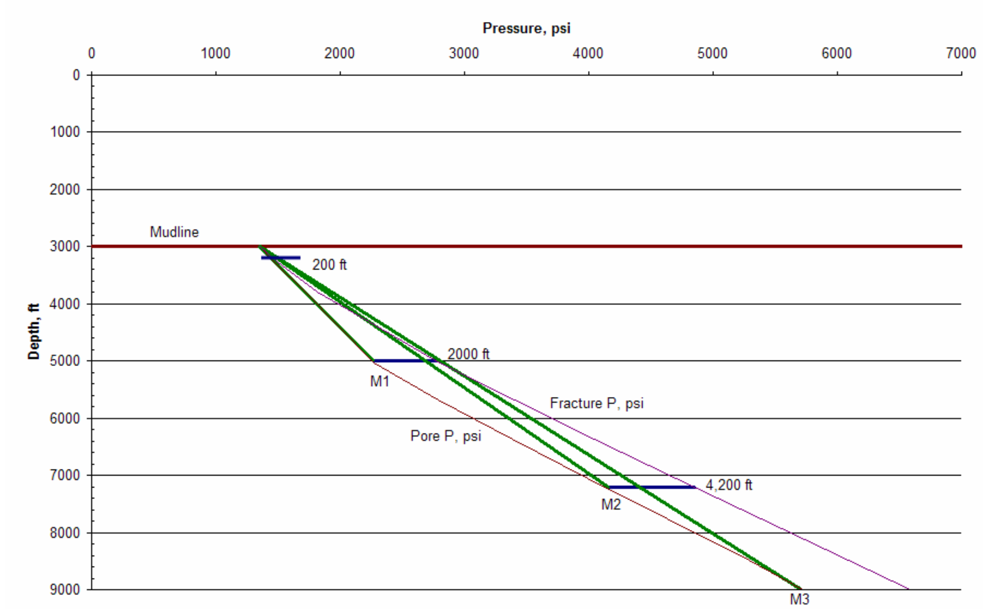

Fig. 20 - Graphical Casing Selection in 3000 ft Water Depth

Fig. 21 shows the graphical casing selection for 5,000 ft of Water Depth and **Fig. 22** shows the graphical casing selection for 10,000 ft of Water. It is important to note that while the actual pressures change with water depth, the pressure gradients remain the same. This means that the pore/fracture pressure window maintains a similar shape at all water depths and the selected casing points remain the same when depths are taken BML. The first casing seat at 200 ft BML is typical 36" Conductor Pipe that is usually jetted into the formation. The second casing seat at 2,000 ft BML is 30" Conductor Pipe and an 8.8 ppg mud must be used in order to reach this depth. The third and final top hole casing seat of 20" Conductor Pipe is at 4,200 ft BML and a 12.9 ppg mud is used to drill to this depth. For the purposes of this simulation top hole is defined as the first 6,000 ft BML. So, in order to drill to 6,000 ft BML, a mud weight of 14.0 ppg is used.

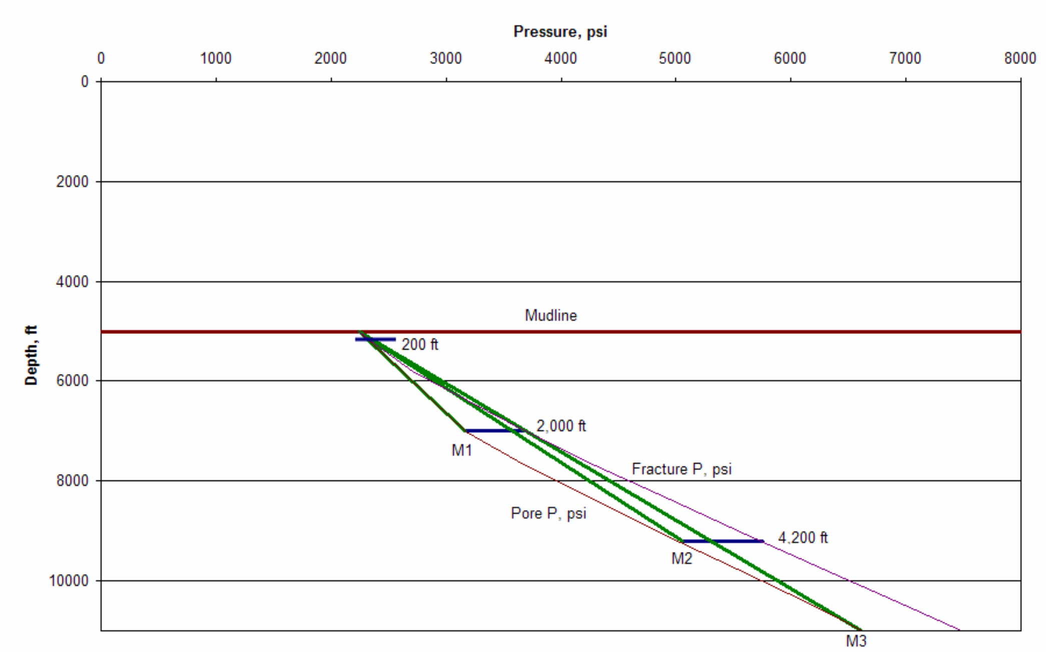

Fig. 21 - Graphical Casing Selection in 5000 ft Water Depth

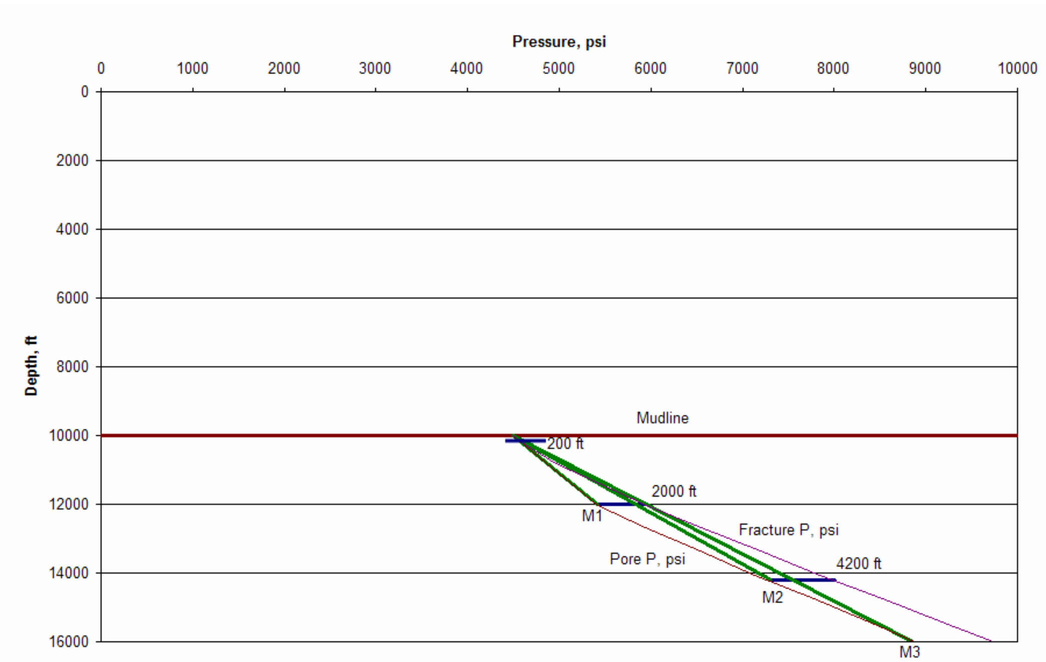

Fig. 22 - Graphical Casing Selection in 10,000 ft Water Depth

The resulting wellbore diagrams can be seen in **Fig. 23** for 3,000 ft Water depth, **Fig. 24** for 5,000 ft water depth and **Fig. 25** for 10,000 ft water depth. Again, notice how the depths BML of each casing are the same no matter what the water depth is.

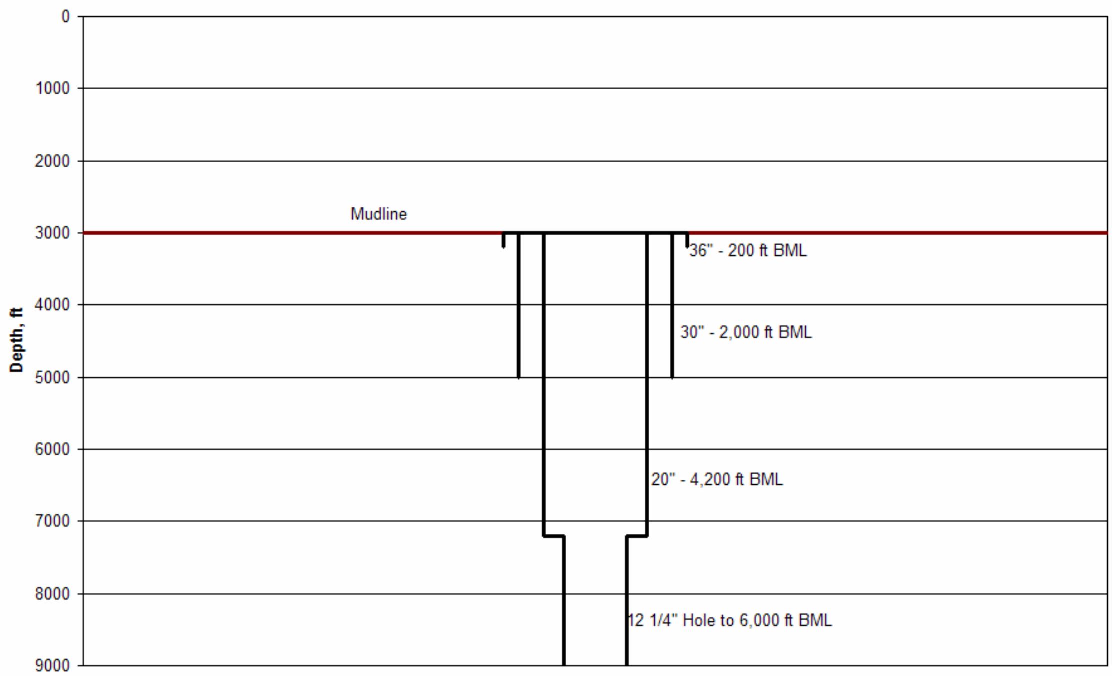

Fig. 23 - 3,000 ft Water Depth Wellbore Diagram

In this simulation set 18 different runs were completed, six for each water depth, and then two for each casing seat. For example, the first run for 3,000 ft water depth was with the casing set to 200 ft BML and the 12 ¼" pilot hole at 2,000 ft. The objective was to determine if the DGTHDS could drill to the depth of the next casing seat and successfully control a gas kick. Typically, the kick size was set at 50 bbl or the largest controllable kick based on the wellbore geometry. This was simulated with both

½ ppg formation overpressure and 1 ppg formation overpressure. Then the next casing seat was simulated by having 30" conductor pipe set to 2,000 ft BML and the 12 ¼"

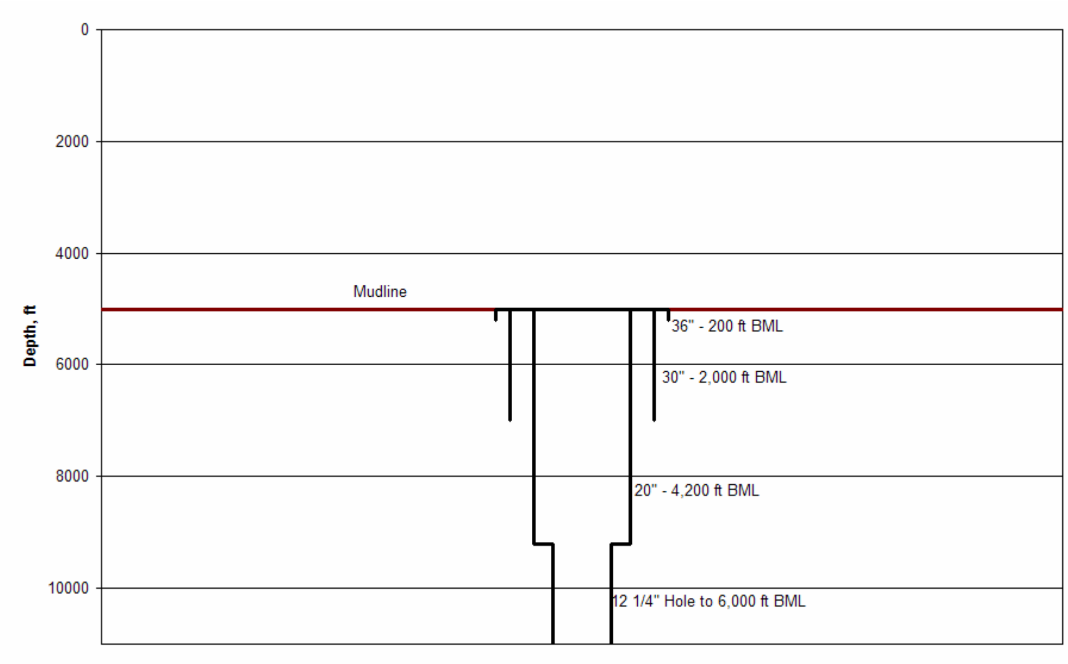

Fig. 24 - 5,000 ft Water Depth Wellbore Diagram

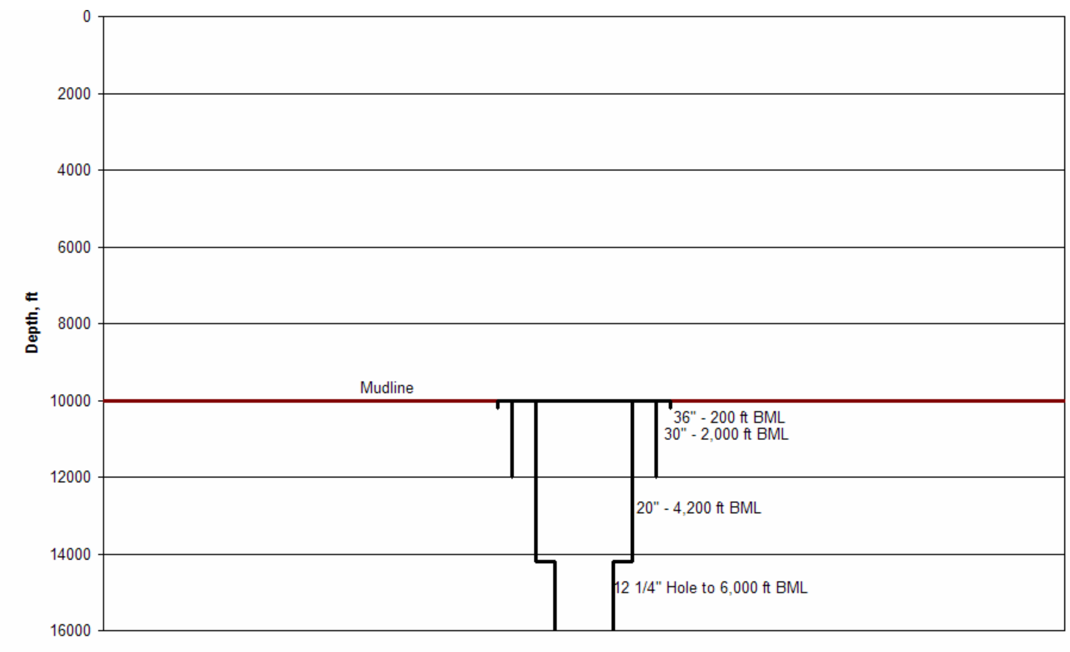

Fig. 25 - 10,000 ft Water Depth Wellbore Diagram

pilot hole drilled to a depth of 4,200 ft BML. Finally, the last test was to drill to 6,000 ft BML with the 20" conductor pipe set at 4,200 ft BML. This was then repeated for 5,000 ft water depth and 10,000 ft water depth. The variable parameters for each of the test runs can be seen in Table 2. The flowchart that describes the determination of run order can be seen in Appendix A, and the spreadsheets showing all of the input data for each run can be seen in Appendix D.

Table 2 - Variable Parameters of Simulation Set #2

Run #	Water Depth	Depth of Last Casing Seat	P&F PR #	Mud Weight	Mud Plastic Viscosity	Mud Yield Point Stress	Depth of 12 1/4" Pilot Hole BML	Formation Overpressure	Pit Gain Warning Level
	ft	ft BML		ppg	cp	lbf/100 sq. ft	ft	ppg	bbl
CS 1a	3,000	200	1	8.8	5	17	2,000	1	50
CS 1b	3,000	200	1	8.8	5	17	2,000	0.5	50
CS 2a	3,000	2,000	1	12.9	17.5	9	4,200	1	50
CS 2b	3,000	2,000	1	12.9	17.5	9	4,200	0.5	50
CS 3a	3,000	4,200	1	14	24	9	6,000	1	50
CS 3b	3,000	4,200	1	14	24	9	6,000	0.5	50
CS 4a	5,000	200	2	8.8	5	17	2,000	1	50
CS 4b	5,000	200	2	8.8	5	17	2,000	0.5	25
CS 5a	5,000	2,000	2	12.9	17.5	9	4,200	1	50
CS 5b	5,000	2,000	2	12.9	17.5	9	4,200	0.5	50
CS 6a	5,000	4,200	2	14	24	9	6,000	1	50
CS 6b	5,000	4,200	2	14	24	9	6,000	0.5	50
CS 7a	10,000	200	3	8.8	5	17	2,000	1	30
CS 7b	10,000	200	3	8.8	5	17	2,000	0.5	15
CS 8a	10,000	2,000	3	12.9	17.5	9	4,200	1	50
CS 8b	10,000	2,000	3	12.9	17.5	9	4,200	0.5	50
CS 9a	10,000	4,200	3	14	24	9	6,000	1	50
CS 9b	10,000	4,200	3	14	24	9	6,000	0.5	50

4.3 Simulation Procedure

Once all the simulation input data is entered the user returns to the main menu, seen previously in Fig. 13, to begin the kick simulation. The following procedure is followed to simulate a gas influx into the wellbore, prevent further influx, circulate the kick out of hole and weight up the mud and continue drilling. The kick simulation control panel can be seen in **Fig. 26**.

1. Increase Simulation Ratio to 10 times real time.
2. Increase Surface Pump rate to the standard pumping rate of 650 gpm.
3. Click Start Simulation Button

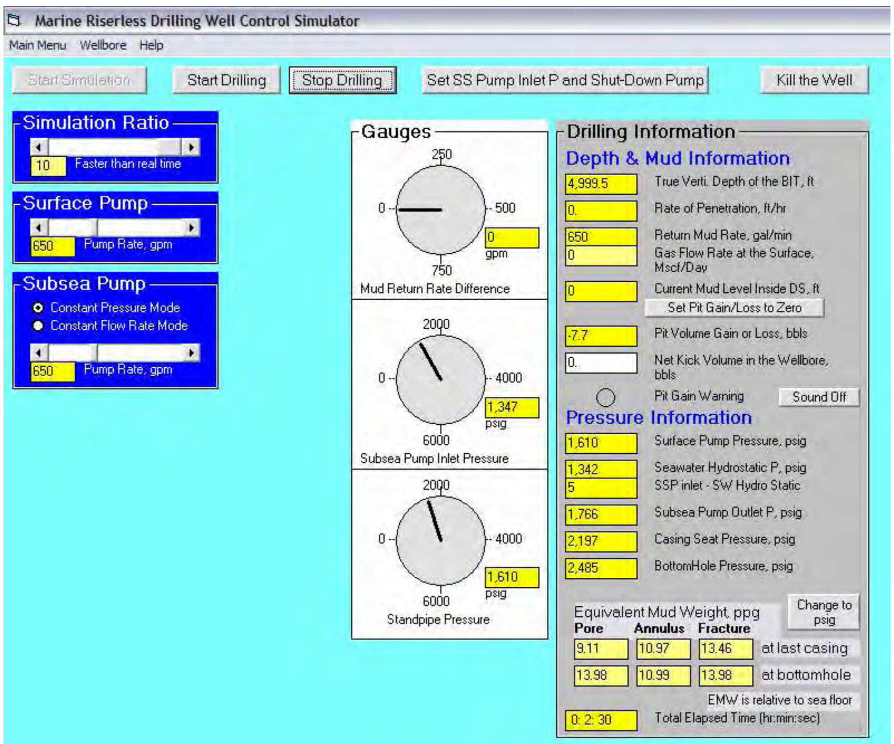

Fig. 26 - Kick Simulation Control Panel

4. Allow Drill String (DS) to fill with drilling fluid.
5. Once current mud level inside DS equals zero and the Subsea pump rate is constant at 650 gpm, set pit gain/loss to zero and then click start drilling button. (The simulator will begin simulating a gas kick momentarily).

6. As the gas kick enters the wellbore the subsea pump rate and the pit gain level warning will increase. While it is possible to detect the kick very rapidly in simulation, it is important to simulate actual drilling methods by waiting for the pit gain warning to go off when the pit level is increased by the previously specified volume. The wellbore schematic also illustrates the incoming kick as seen in **Fig. 27**.

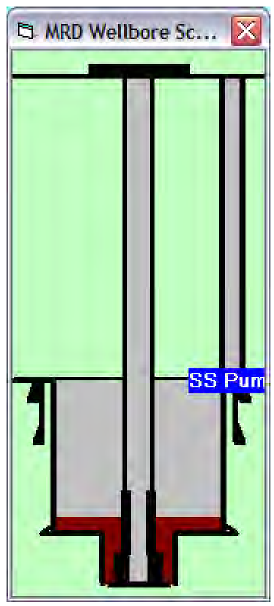

Fig. 27 - Illustration of Wellbore Showing Gas Kick Influx

7. Once the pit gain warning goes off, begin the "Modified Driller's Method". The pit gain warning level will flash as seen in **Fig. 28**. Change the Subsea pump to constant pumping rate mode and return the pumping rate to 650 gpm. This creates the necessary backpressure to prevent further influx into the wellbore.

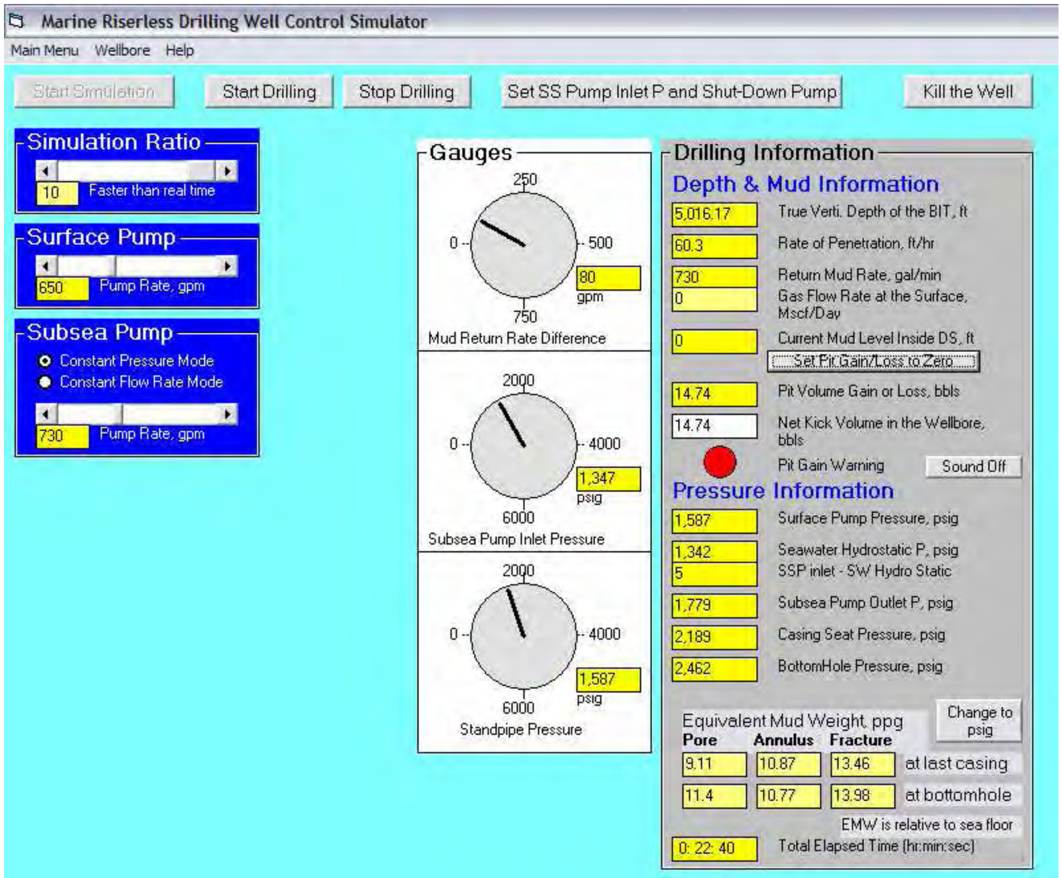

Fig. 28 - Flashing Pit Gain Warning Alarm

8. Monitor the annulus and formation pressures. When these pressures are balanced the simulated influx will be stopped and the user can simulate perfect well control by clicking the “Kill the Well” Button. (If the user does not properly prevent the influx a blowout can result and the simulator will return a warning box like what is shown in **Fig. 29**.

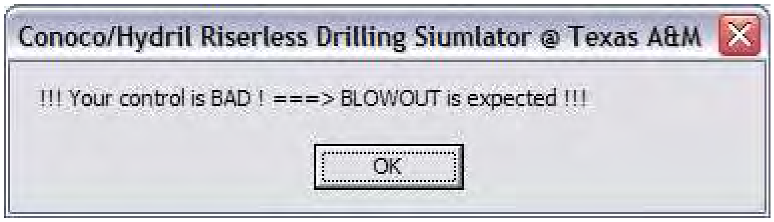

Fig. 29 - Simulator Blowout Warning Box

9. Once the "Kill the Well" button has been clicked the simulator allows the user to circulate the kick manually or with perfect control. For the purposes of testing the well control limits of the dual gradient system, perfect well control is selected.
10. The user is taken to a new screen where the user then selects a simulation acceleration ratio of 80 times that of real time. Then from the main menu the user selects: show wellbore and start circulation.
11. The simulator controls the pumping rate of the subsea pump to maintain perfect pressure balance between the formation and the annulus to prevent further influx while circulating the kick out of the wellbore.

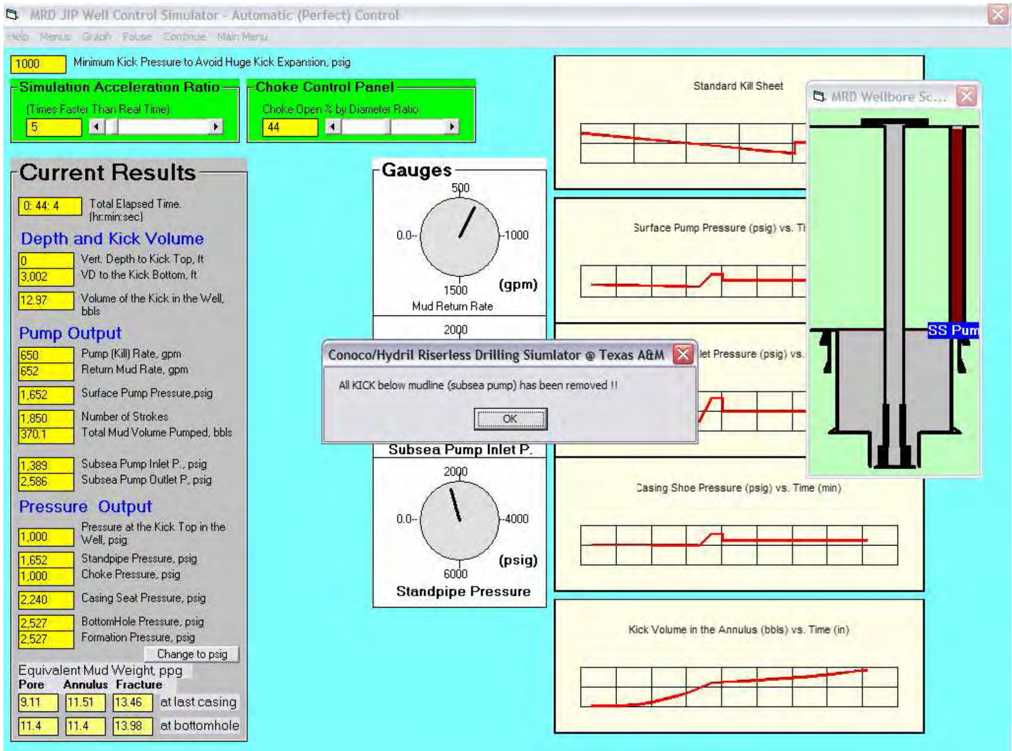

Fig. 30 - Simulator Kick Circulation Screen

12. Once the kick has been removed below the mudline the user will receive a message as seen in **Fig. 30**. The simulator then continues circulating the kick until the kick is completely removed from the system. Then the simulator shows an automatic circulation of kill weight mud to ensure the prevention of more gas influxes.
13. Now the user can continue on to analyze the data created by the simulator.

4.4 Simulation Results Analysis Procedure

Finally, the resulting data from the simulator is analyzed to determine if the pressure at the casing seat pressure and the pressure at the top of the kick caused formation fracturing, or damage to the casing seat. In **Fig. 31** you can see the results data from the simulator in graphical form. Aside from the pressure at the top of the kick the user can also track: standpipe pressure, choke pressure, casing shoe pressure, subsea inlet pump pressure, subsea outlet pump pressure, surface pump pressure, the volume of mud pumped, the mud and gas return rates at the rig floor, choke opening and the kick pressure, height, volume, and influx rate at all times during the simulation.

Fig. 31 - Simulation Results in Graphical Form

All of this data is important to the driller. The casing shoe pressure, subsea pump inlet and outlet pressures help to determine if the equipment pressure ratings have been exceeded and the mud and gas production determine necessary surface handling capacities. Most importantly, however, the simulation returns information on the kick as it progresses through the wellbore. You can expand each of the different plots to look at the graph zoomed in. **Fig. 32** shows the zoomed in version of kick pressure versus time.

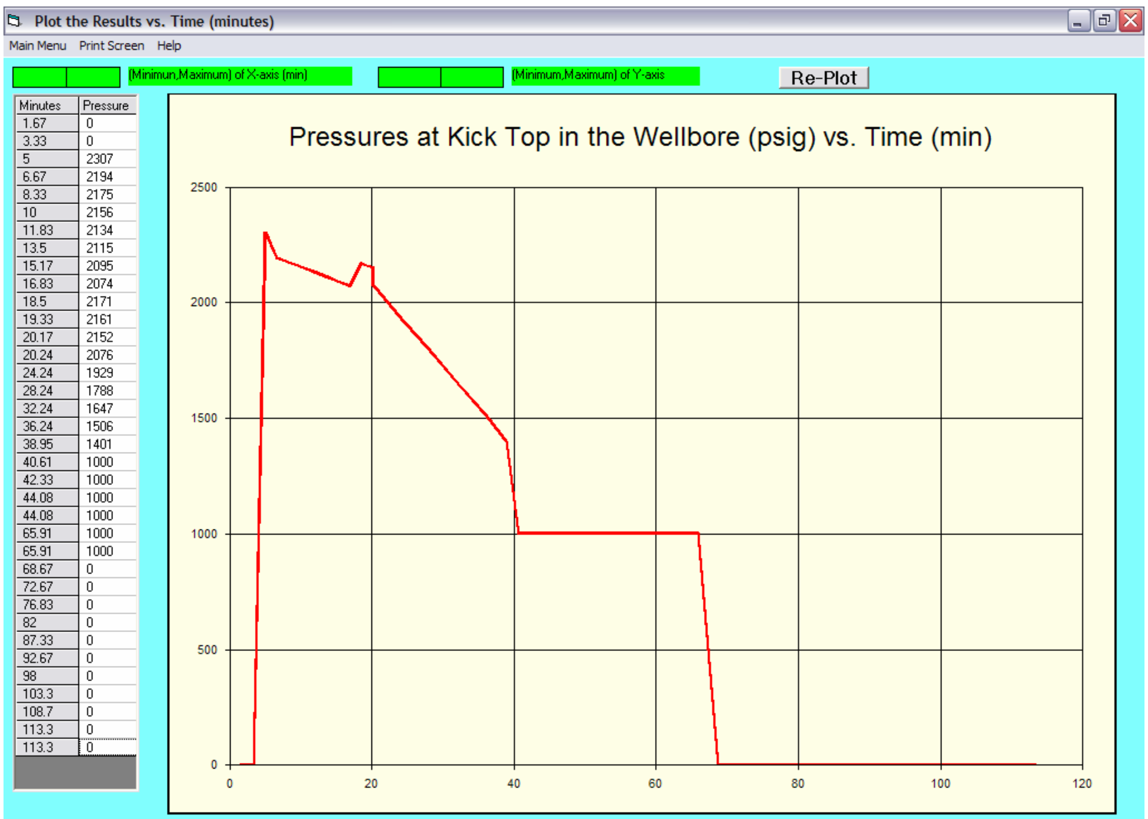

Fig. 32 - Zoomed in Graph of Pressure @ Top of Kick versus Time

The data can also be exported in table format. This information is important, because the pressure at the top of the kick can be plotted versus the location, within the wellbore, the top of the kick. Putting this plot together with a plot of formation pore and fracture pressures, the user can determine if circulating the kick resulted in formation fracture and lost circulation. An example of this plot can be seen in **Fig. 33**. In this example case, from simulation set #1, the sea water depth is 5,000 ft and the 30" conductor pipe was set 1,500 ft BML.

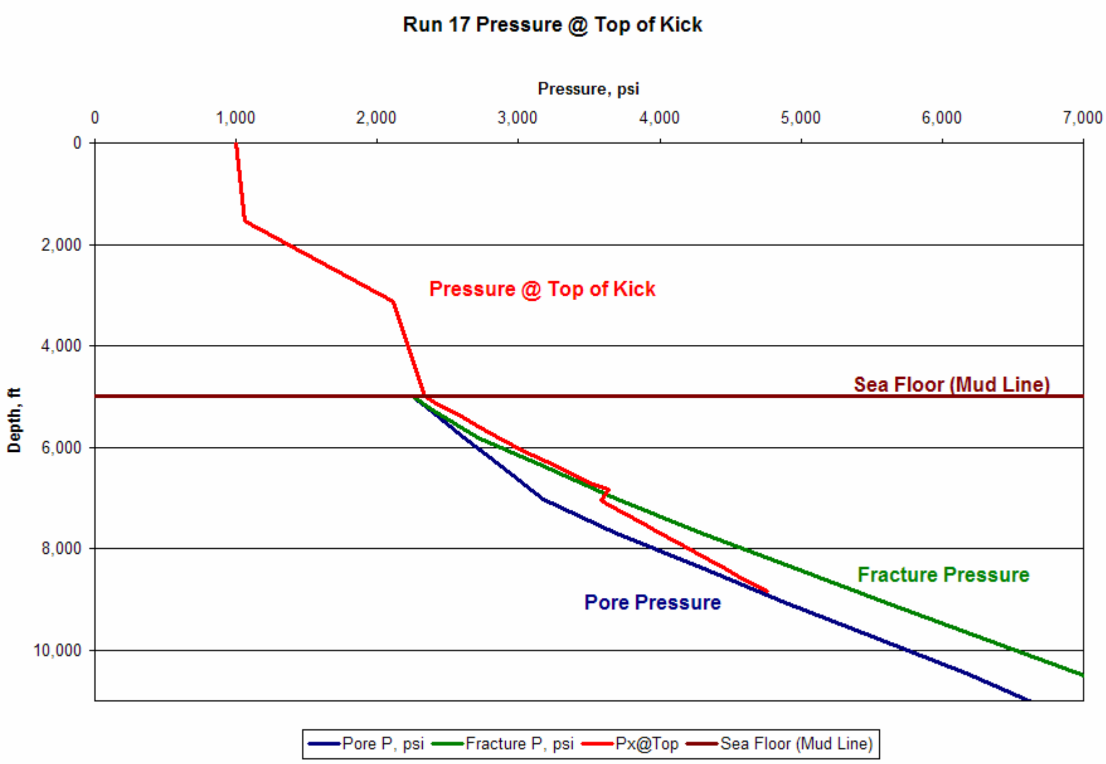

Fig. 33 - Kick Pressure, Pore Pressure and Fracture Pressure Plotted versus Depth

The pressure at the top of the kick is indicated by the red line, the pore pressure by the blue line and the fracture pressure by the green line. If the pressure at the top of the kick increases above the formation fracture pressure below the conductor pipe, the formation will fracture and an underground blowout could be experienced. This graph clearly shows that the pressure at the top of the kick increases above the fracture pressure at approximately 1,800 ft BML. In this case, the conductor pipe (set at 1,500 ft BML) was not set deep enough to prevent formation fracturing.

Also a consideration, are the pressures within the wellbore and at the subsea pump. These pressures are also tracked by the simulator and can be plotted versus time, as shown in **Fig. 34**. The casing seat pressure, Bottom Hole Pressure (BHP), subsea pump inlet pressure and stand pipe pressure (SPP), basically follow the same pattern. These regions are all impacted on before the mud enters the subsea pump. The subsea pump outlet pressure, however, is a pressure region located after the mud passes through the subsea pump. The four pressures in the region before the subsea pump begin to decrease as the kick enters the wellbore and the subsea pump rate increases to compensate. At the same time, a slight increase in pump outlet pressure can also be seen. In this example, at approximately 21 minutes, the kick is detected and the subsea pump rate is decreased to pre-kick rate. This is shown by the abrupt increase in casing pressure, BHP, drillpipe pressure and subsea pump inlet pressure. (The abrupt up and down spike is caused by the simulator, but would not typically be seen in the actual wellbore conditions.) Then as the kick is circulated these pressures become level. The subsea pump outlet pressure, however, remains constant until the point when the kick is circulated through the subsea pump and the pressure increases. Which, in this example, occurs at approximately 45 minutes.

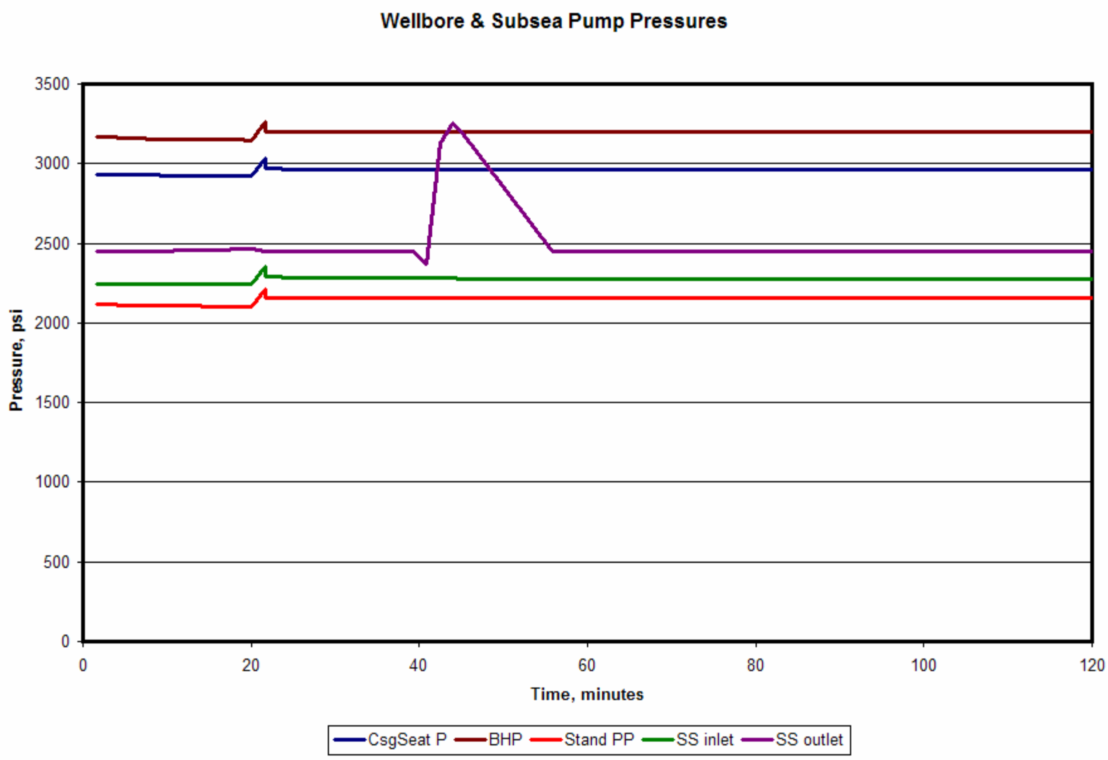

Fig. 34 - Wellbore and Subsea Pump Pressures Example Graph

This data is important, because it is important to track the pressure within the wellbore, not just the pressure at the top of the kick, to determine if there are any other potentially hazardous situations occurring within the system such as if the casing seat pressure exceeds the formation fracture pressure at the casing seat depth and an underground blowout occurs.

4.5 Simulation Results Analysis

Simulation Set #2 was extremely necessary upon the analysis of Simulation Set #1. It became obvious that an arbitrary selection of conductor pipe seat depth was unacceptable for the DGTHDS and the drilling program needs to be customized based on the P&F PR.

4.5.1 Simulation Results Analysis – Simulation Set #1

It became evident upon examining the results that the drilling depth BML had more of an impact on whether a simulation resulted in formation fracture than sea water depth. Runs 1 through 12 were executed in 3,000 ft of sea water at varying drilling depths of 2,000, 4,000 and 6,000 ft BML. Runs 1 through 4 (2,000 ft BML) did not result in fracturing of the formation. The casing seat at 1,500 ft BML was deep enough to prevent formation fracture. However, Runs 5 through 12 (4,000 and 6,000ft BML) all resulted in a fractured formation. The reason is that the heavier mud weights, required to maintain BHP above formation pore pressure, fractured the formation at shallower depths, and the conductor pipe was not set deep enough to prevent this formation fracture. These graphs for each run, similar to the example shown in Fig. 33 can be seen in Appendix E. **Fig. 35** shows the pressure at the top of the kick in Run 4. In this case the kick was successfully circulated without fracturing the formation.

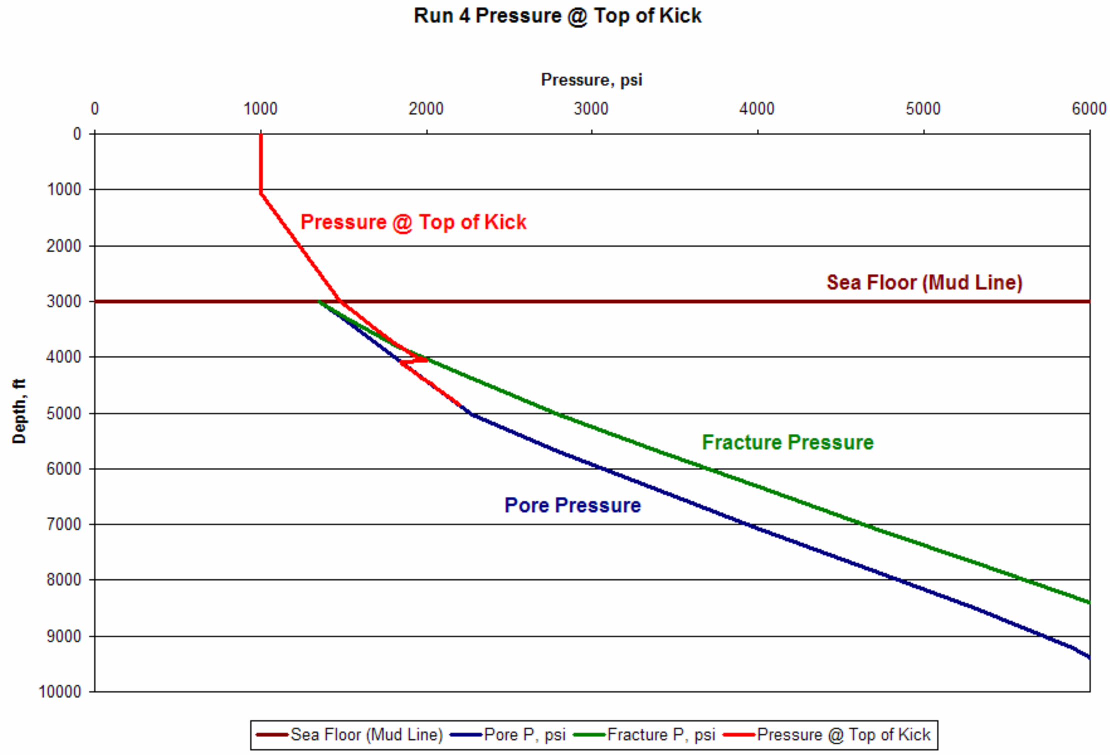

Fig. 35 - Pressure at the Top of the Kick in Run 4

Runs 13 through 24 (5,000ft of sea water) had the same results as Runs 1 through 12. Again, Runs 13 through 16 (2,000 ft BML) did not result in fracturing of the formation. Again, however, Runs 17 through 24 (4,000 and 6,000 ft BML) all resulted in fractured formation. **Fig. 36** shows how, in Run 24, the kick pressure, shown in red, rose above the fracture pressure, shown in green, below the conductor pipe seat at 1,500 ft BML. This signifies that the formation was fractured and an underground blowout would likely be the result if wellbore is not plugged rapidly. The rest of these graphs can be seen in Appendix E.

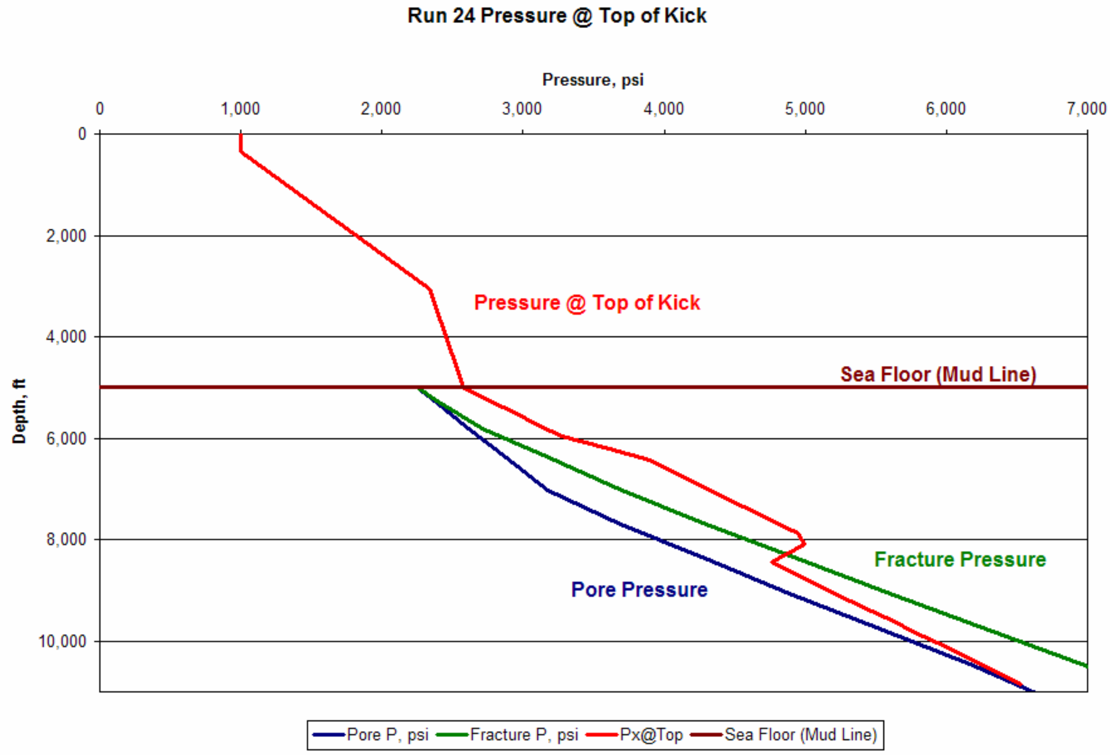

Fig. 36 – Pressure at the Top of the Kick in Run 24

Runs 25 through 36 were performed in 10,000 ft of sea water and had the same results as Runs 1 through 24. When the drilling depth was 2,000 ft BML (Runs 25 through 28), all kicks were successfully circulated. However, when the drilling depth was deeper than 2,000 ft BML (Runs 29 through 36), the formation was fractured during kick circulation. These graphs can be seen in Appendix E. Ultimately Simulation Set #1 resulted in the obvious conclusion that casing needs to be set deeper and more often than only at 1,500 ft BML.

4.5.2 Simulation Results Analysis – Simulation Set #2

Since the main purpose of the project is simply to prove that the DGTHDS is more reliable at circulating shallow hazards than the "Pump and Dump" method, it is acceptable to set casing more often than only at 1,500 ft BML. In a conventional "Pump and Dump" system, conductor pipe and surface casing would be set often, and usually more frequently than what was designed in the original drilling program. So, the key to a successful Simulation Set #2 was to determine the well control limits of the DGTHDS when a proper casing program is in place. Runs CS1a through CS3b were performed in 3,000 ft of sea water. In every case the kick of 50 bbl was successfully circulated above the conductor pipe before the pressure at the top of the kick increased above the formation fracture pressure. Runs CS3a and CS3b can be seen in **Fig. 37**.

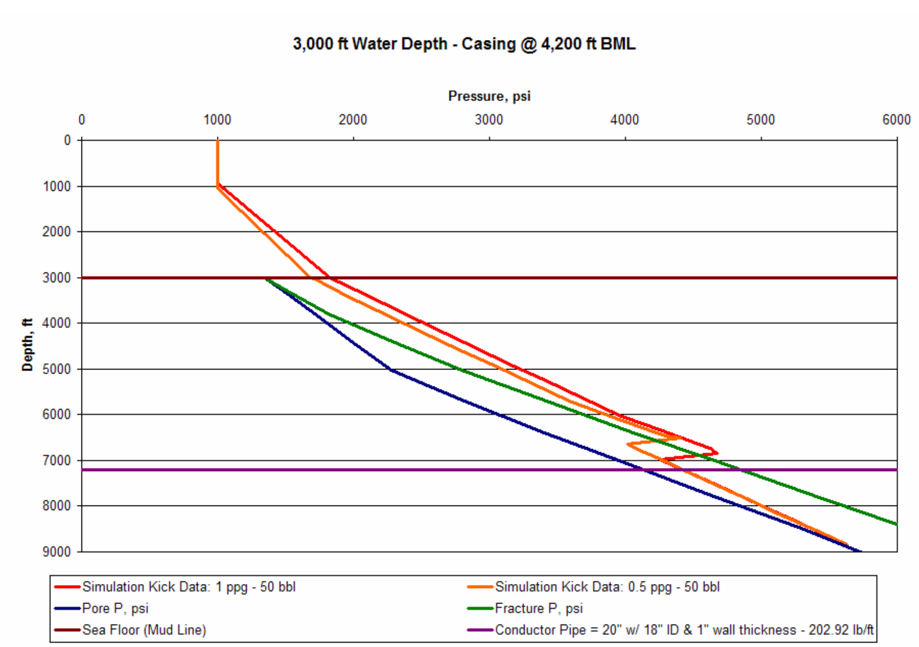

Fig. 37 - Pressure at the Top of the Kick in Runs CS3a and CS3b

In Runs CS4a through CS6b (5,000 ft of Sea Water) also resulted in successful kick circulation. A significant point is, in the shallow BML depths of Run CS4b the system was not able to successfully circulate a kick larger than 25 bbl in a 0.5 ppg over pressured formation. However, a 50 bbl kick was successfully circulated when the formation was 1 ppg overpressure. This can be seen in **Fig. 38** and the reason a smaller kick size in a 0.5 ppg over pressure formation results in a simulated blowout and a larger kick size in a 1.0 ppg over pressure formation does not, is that the kick in the 0.5 ppg formation over pressure kick enters the wellbore slower than the 1.0 ppg formation over pressure kick. This means that first bubble of the kick is circulated higher within the wellbore, in the same amount of time, even though the actual kick size is smaller. This causes the simulator to react as though the user did not properly detect the kick or take action, and a surface blowout is simulated as an expectation. This is a topic for future research that may lead the primary investigator to change some of the code in the riserless drilling simulator created by Dr. Choe.

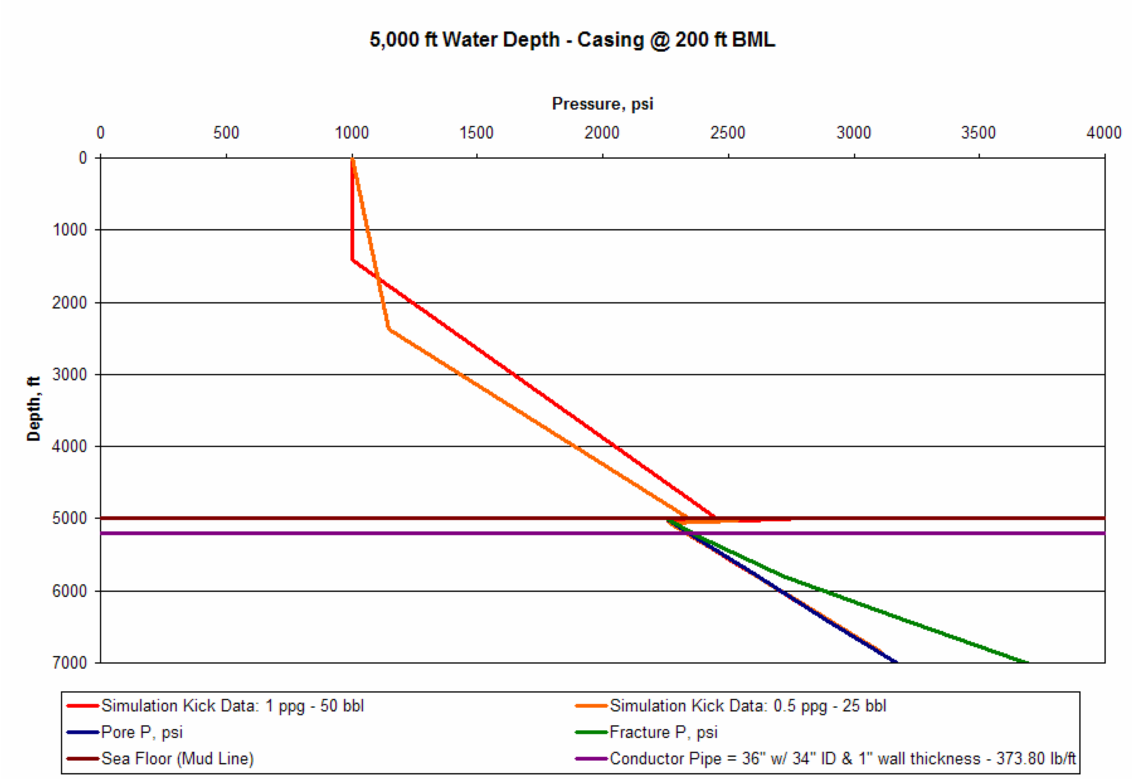

Fig. 38 - Pressure at the Top of the Kick in Runs CS4a and CS4b

In Runs CS7a through CS9b a similar result occurred. All kicks were successfully circulated without formation fracturing, but again the largest kicks that could be circulated without formation fracturing, in drilling depths of 2,000 ft BML, Runs CS7a and CS7b, were 30 bbl in 1 ppg formation overpressure and 15 bbl in a 0.5 ppg formation overpressure. In deeper BML drilling depths, Runs CS8a through CS9b, 50 bbl kicks were successfully circulated without formation fracturing. The successful circulation of a kick at 6,000 ft BML in 10,000 ft of seawater can be seen in **Fig. 39**.

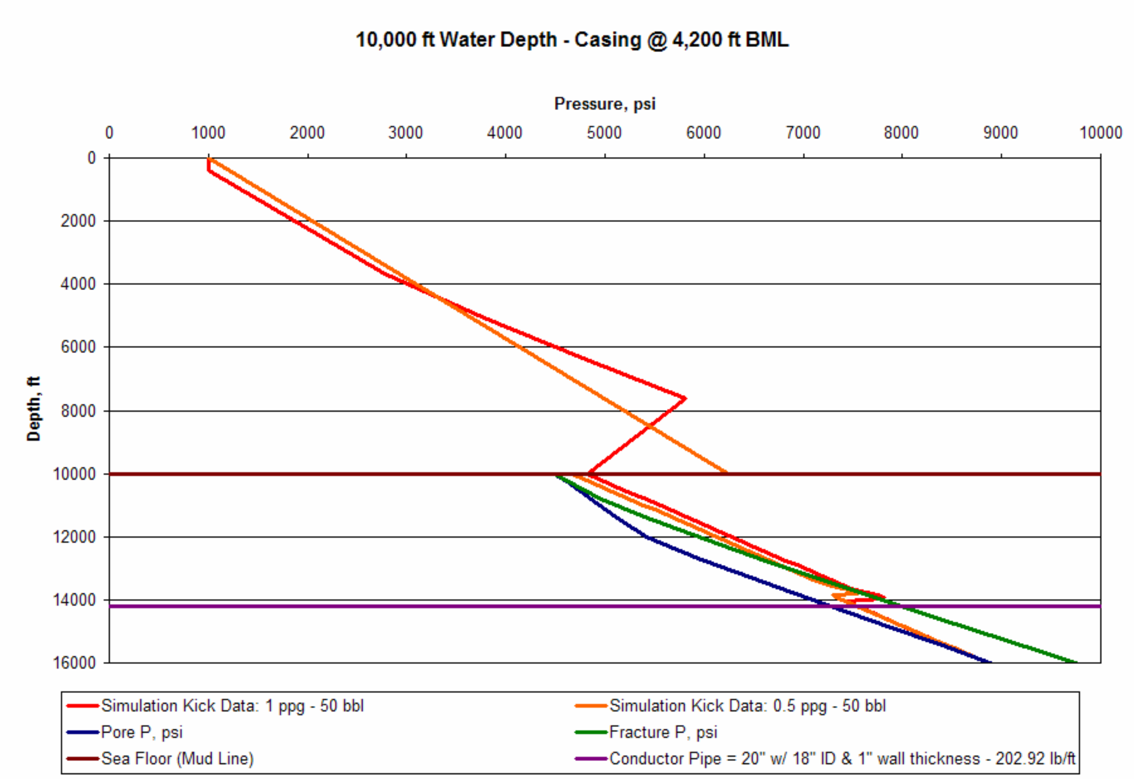

Fig. 39 - Pressure at the Top of the Kick in Runs CS9a and CS9b

The next step is to analyze the casing seat pressure as a method of double checking that the casing seat pressure does not rise above formation fracture pressure at the casing seat depth. Casing seat pressure data from the simulator is exported and plotted, along with the formation fracture pressure at casing seat depth. **Fig. 40** shows the casing seat pressure of run CS7 with respect to time. On the secondary y-axis the depth at the top of the kick, the casing seat depth and sea floor depth is plotted so that correlations between kick location and casing seat pressure can be drawn. In this run it can be seen that there is a jump in the casing seat pressure. This is a result of when the subsea mud pump rate is slowed to increase annulus pressure and prevent the influx of more reservoir fluids.

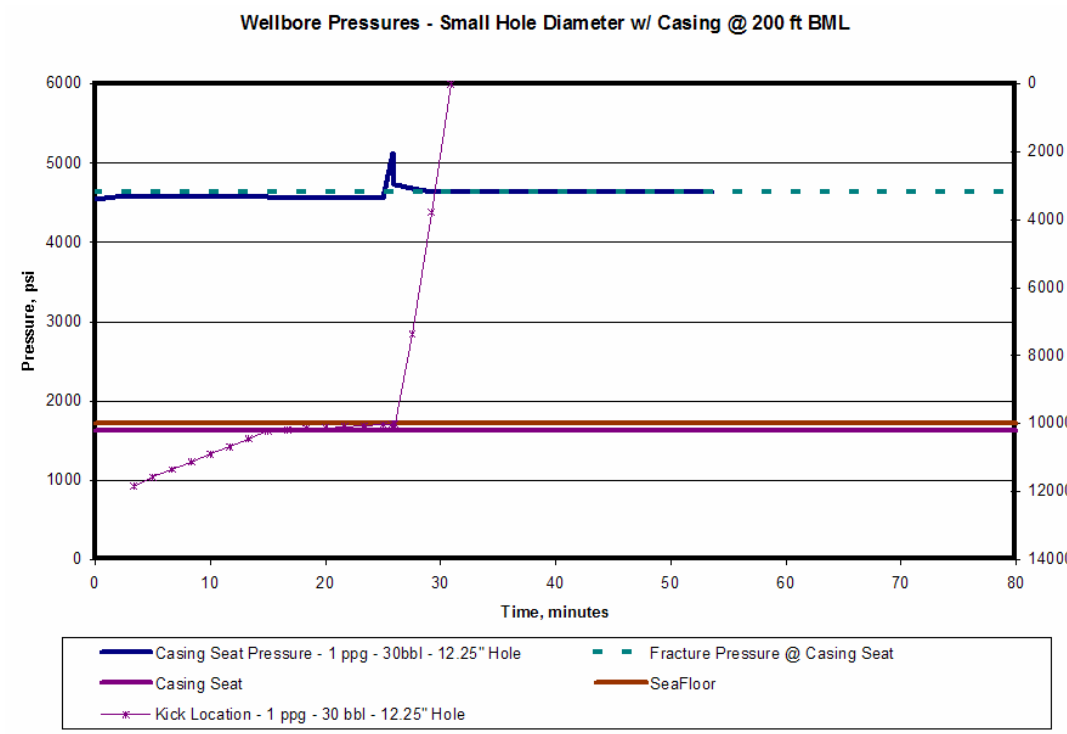

Fig. 40 - Casing Seat Pressure in Run CS7

Even once the casing seat pressure stabilizes, it is still very close to formation fracture pressure. This is a concern and a better understanding of why this occurs is a good idea for future research into the implementation of a DGTHDS. Similar results can be seen in **Fig. 41** and **Fig. 42** (results from Runs CS8 and CS9). Is this simply a glitch within the simulator? Does casing need to be set even more often? Would a smaller kick size have the same high pressure? These are all questions that need to be answered in order to fully understand a DGTHDS.

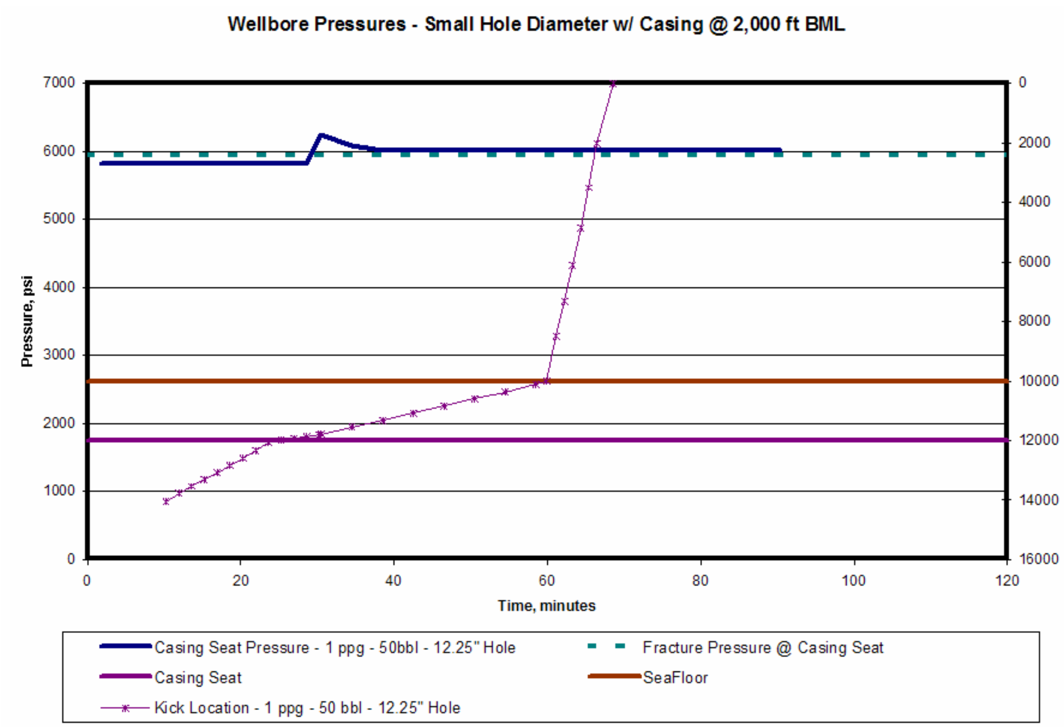

Fig. 41 - Casing Seat Pressure in Run CS8

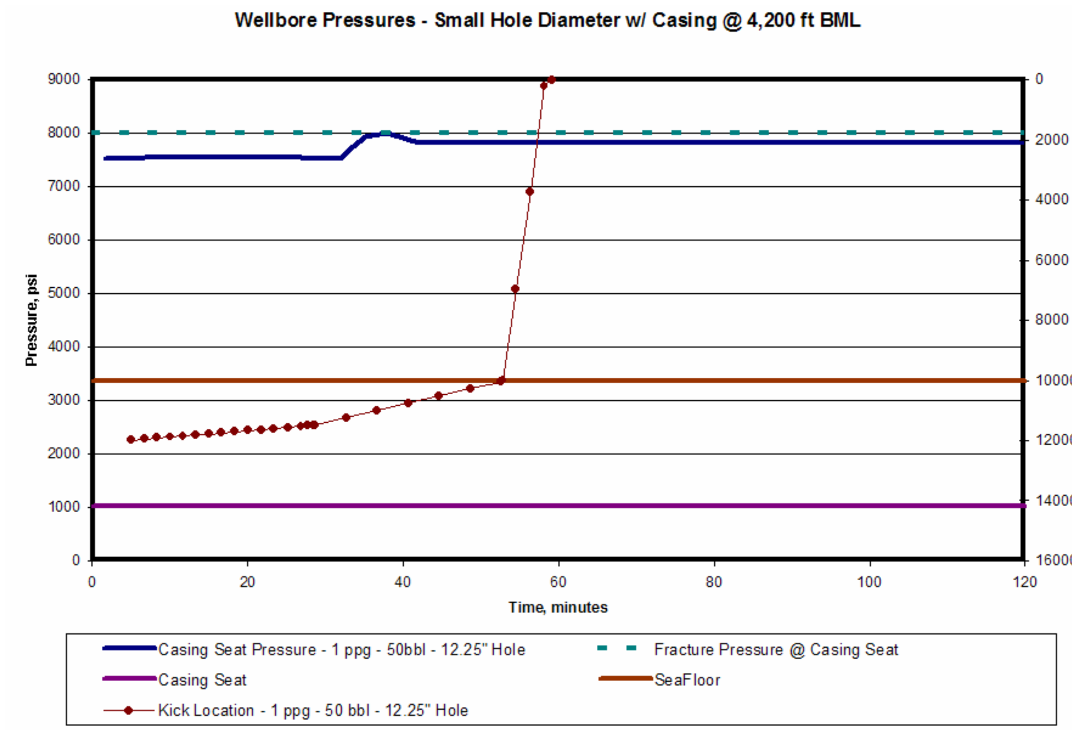

Fig. 42 - Casing Seat Pressure in Run CS9

Finally, it is apparent from Simulation Set #2 that when a proper casing program is designed and in place kicks can be rapidly detected and circulated out of the wellbore. There are still uncertainties within the system that need to be further addressed. An important point to note is that 50 bbl kicks are unlikely because in the DGTHDS kick detection happens rapidly and with a properly trained drilling crew most kicks should be detected and the "Modified Driller's Method" will begin well before the kick size reaches even 10 bbl.

Finally, a significant observation is that Simulation Set #2 was performed entirely with 12 ¼" pilot hole below the last conductor pipe seat. This is the current industry standard, because it is easy to pump cement into a 12 ¼" pilot hole when a kick is encountered. However, in this system the larger the hole diameter the less impact the kick has on wellbore pressures, and the easier the kick is to circulate. Conventionally, a smaller pilot hole resulted in safer drilling operations but, in the DGTHDS a larger pilot hole may result in safer drilling operations. This could save expensive rig time that is required to drill a pilot hole to the next casing depth and then ream the hole out to casing OD size.

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS FOR THE FUTURE OF DUAL GRADIENT TECHNOLOGY

5.1 Conclusions

Dual gradient drilling technology is not beyond our reach. This technology has been designed, engineered and field tested for feasibility. This technology has been successfully applied to the top hole portion of a wellbore in a shallow water environment and in a deepwater environment after conductor and surface casing have been set. The riserless drilling simulator indicates that applying dual gradient technology to top hole drilling, when used in conjunction with a proper casing program, successfully navigates the narrow window between formation pore pressure and formation fracture pressure. The results of simulation also leads to the conclusion that the dual gradient technology applies safe well control methods while drilling the top hole portion and can control all three major shallow hazards. Riserless Dual Gradient Top Hole Drilling results in:

- Rapid and accurate kick detection
- Safe Well Control Procedures
- Successful pore/fracture pressure window navigation
- Control over pressured shallow gas zones

- Control over shallow water flows
- Control over dissociating methane hydrates
- Improved casing seats and wellbore integrity
- Reduced number of casing strings
- Reduced overall costs
- Prevention of methane hydrate formation
- Reduced environmental impact.

The advantages of the system far outweigh the reluctance of the industry to implementing a new technology. The key is to continue to overcome the industries resistance to the new technology by education, training and gradual implementation of the DGTHDS into conventional practices.

Dual gradient technology still has uncharted territory, however, a DGTHDS has already been proven to be substantially safer and more reliable than the current “Pump and Dump” technology. The remaining questions need only be answered to streamline the DGTHDS. AGR has proven that a DGTHDS is the key to improving top hole drilling in shallow water depths. As AGR adapts their technology to conquer deeper water depths and academic research continues to improve the design of a DGTHDS for deepwater, a DGTHDS will cease to be a technology of the future and become the new industry standard that everyone strives to improve.

5.2 Recommendations for the Future of Top Hole Dual Gradient Drilling

While this technology still gives every indication of being an improvement over the current top hole drilling practice of “Pump and Dump”, there are still some uncertainties regarding the DGTHDS. There are three main questions that still remain to be answered. The first, as briefly discusses in Chapter IV, is how does the location, in the annulus, of the first bubble of the kick impact on annulus pressures and kick circulation. Is the simulator, originally created for training purposes, reacting from a human error point of view (meaning a lack of response results in a blowout) or from a technical point of view (meaning a bubble at shallow depths within the annulus will, in reality, result in a surface blowout). A new research project may be launched to get deep into the programming of the simulator to find the answer to this question.

The second question is regarding the tracking of the casing seat pressure. Will setting casing more often and at shallower depths BML keep the casing seat pressure below formation fracture pressure? Will smaller kick sizes result in lower casing seat pressure? Which brings us to the third and perhaps most interesting question? How does the pilot hole size affect the kick height and size and annulus pressures?

Several simulations were ran in 10,000 ft of sea water, but instead of using the standard 12.25” pilot hole, a hole the size of the next casing OD size was drilled below the last casing seat. The runs were done in a formation of 1.0 ppg over pressure, and the kick size was always as large as possible. The results were quite interesting and can be seen in **Fig. 43, 44** and **45**.

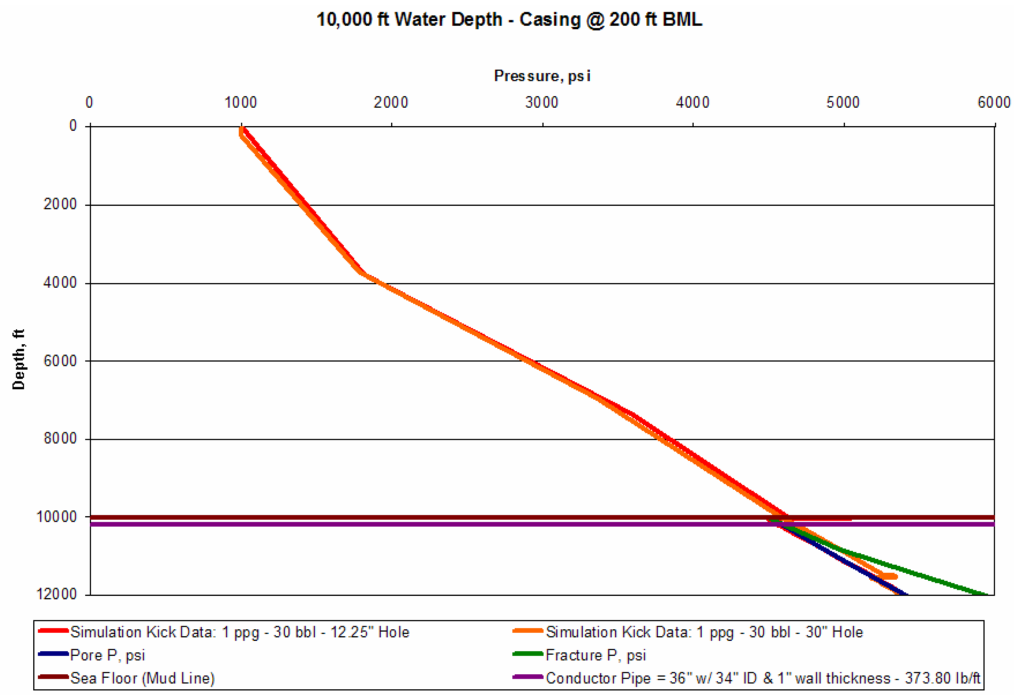

Fig. 43 - Larger Hole Diameter than Run CS7

In Fig. 43 the pressure at the top of the kick in the simulation with the larger size pilot hole can be seen in orange. The run with the conventional pilot size hole of 12.25” can be tracked in red. In the case of the larger hole diameter, the pressure at the top of the kick rises above formation fracture pressure before reaching the conductor pipe set at 200 ft BML. This is likely because even though the kick size is the same, the larger hole size reduces the total height of the kick. This means that when the subsea mud pump is slowed down to prevent additional influx the top of the kick is still a lot deeper than the last casing seat. Then as the kick is circulated, the pressure at the top of the kick can easily rise about formation fracture pressure. Which again leads to the question… Does casing need to be set more often and conservatively when dealing in a deepwater environment? Fig. 44 and Fig. 45 show the results of larger hole diameter when casing is set at 2,000 ft BML and 4,200 ft BML, respectively. The results are similar to those shown in Fig. 43. However in Fig. 45 the difference between in the pressure at the top of the kick in the 12.25” pilot hole and the larger pilot hole is minimal because the difference (from 12.25” to 17.5”) between hole diameter is minimal. To more fully understand the limitation of the DGTHDS more research into the effect of a larger pilot hole size is necessary.

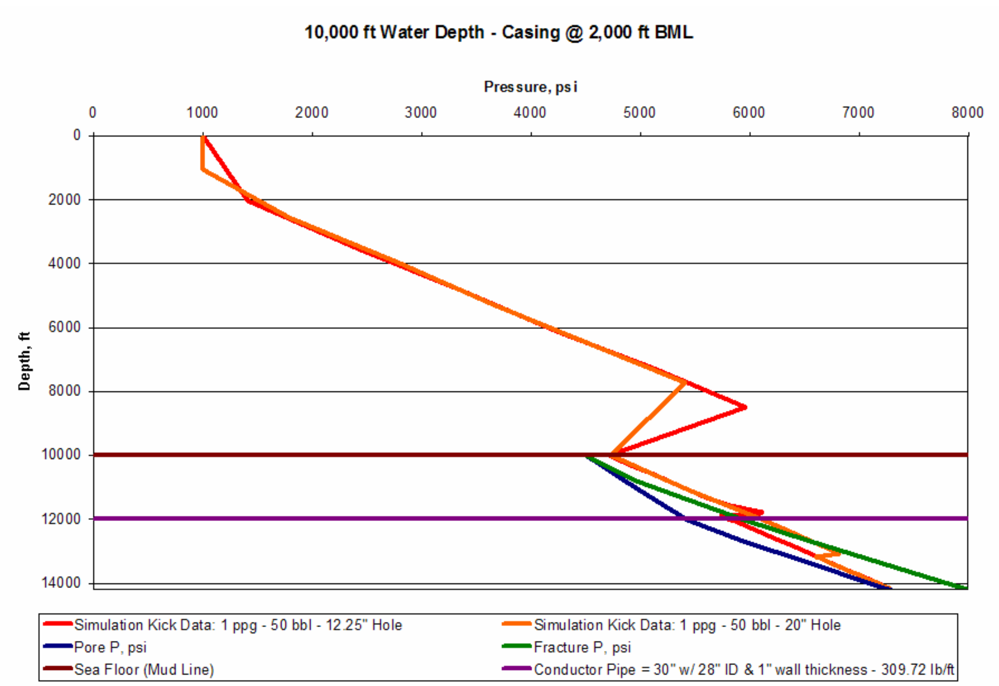

Fig. 44 - Larger Hole Diameter than Run CS8

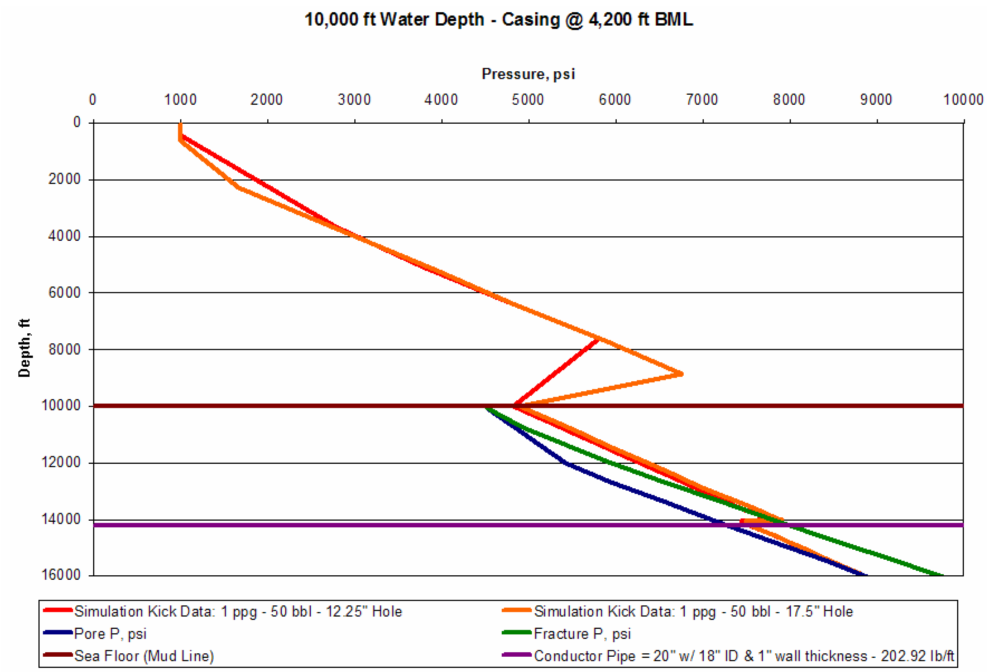

Fig. 45 - Larger Hole Diameter than Run CS9

To answer the questions regarding: the effect of bubble height within the well, the accuracy of the simulator's casing seat pressure predictions and the possible impact of larger pilot hole sizes, the next step is to design and field test a system that can be applied to drilling the top hole portion of a wellbore in a deepwater environment. In a continuation of the OTRC / MMS project "Application of Dual Gradient Technology to Top Hole Drilling", the top hole dual gradient equipment should be designed, constructed, commissioned and field tested. It is imperative that the industry be shown how beneficial the application of dual gradient technology to top hole drilling can be.

Dual gradient technology promises to: improve safety and well control while drilling, decrease costs, improve wellbore quality and reduce environmental impact.

Even so, developing a new technology can be expensive and difficult to implement. The step, that is paramount to implementing dual gradient technology into commercial use, is to convince the industry end users (operators and service companies alike) that dual gradient technology will significantly improve deepwater drilling operations through education and training. This can best be done is small steps, by focusing on improving one part of the current technology at a time. In this manner top hole dual gradient drilling will be implemented slowly, but seamlessly and to the advantage of everyone involved.

NOMENCLATURE

AGR	AGR Ability Group
bbl	Barrels
BHP	Bottom Hole Pressure
BML	Below Mud Line
BOP	Blow Out Preventer
cp	centipoises
DOE	Department of Energy
DGTHDS	Dual Gradient Top Hole Drilling System
DS	Drill String
DSV	Drill String Valve
E&P	Exploration and Production
ºF	Degrees Fahrenheit
ft	Feet
gpm	Gallons per Minute (gallons/minute)
HSP	Hydrostatic Pressure
IADC	International Association of Drilling Contractors
ID	inner diameter
JIP	Joint Industry Project
lbf/100 sq.ft	Pounds of Force per 100 square feet

MC	Mississippi Canyon
MMS	Minerals Management Service
MPD	Managed Pressure Drilling
NSF	National Science Foundation
OD	Outer Diameter
OTRC	Offshore Technology Research Center
P&F PR	Pore and Fracture Pressure Regime
ppg	Pounds per Gallon (lb/gal)
psi	Pounds per Square Inch (lb/in^2)
RMR	Riserless Mud Return
SPP	Standpipe Pressure
SSMLDJIP	SubSea MudLift Drilling Joint Industry Project
SRD	SubSea Rotating Diverter
TD	Total Depth

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APPENDIX A

SIMULATOR INPUT FLOWCHARTS

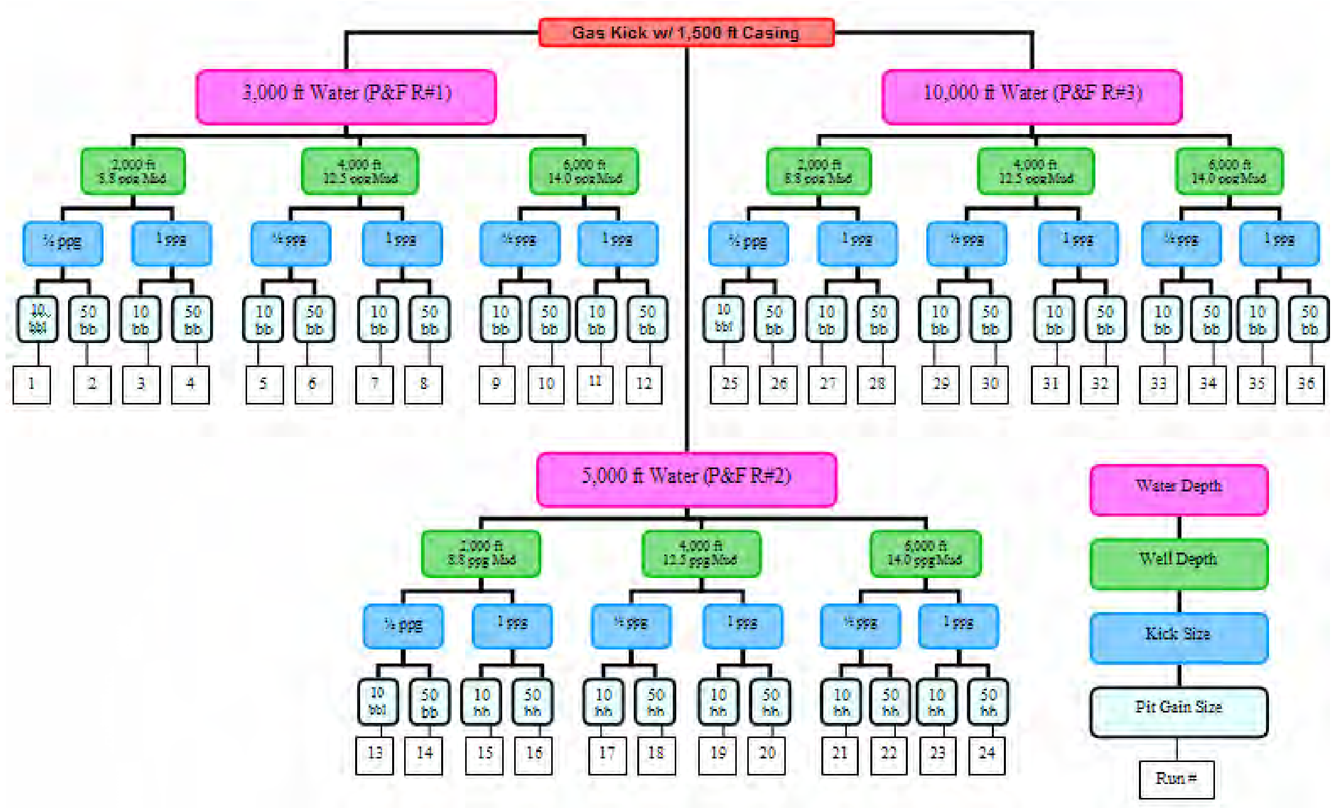

Fig. A1 – Simulation Set #1 Flowchart

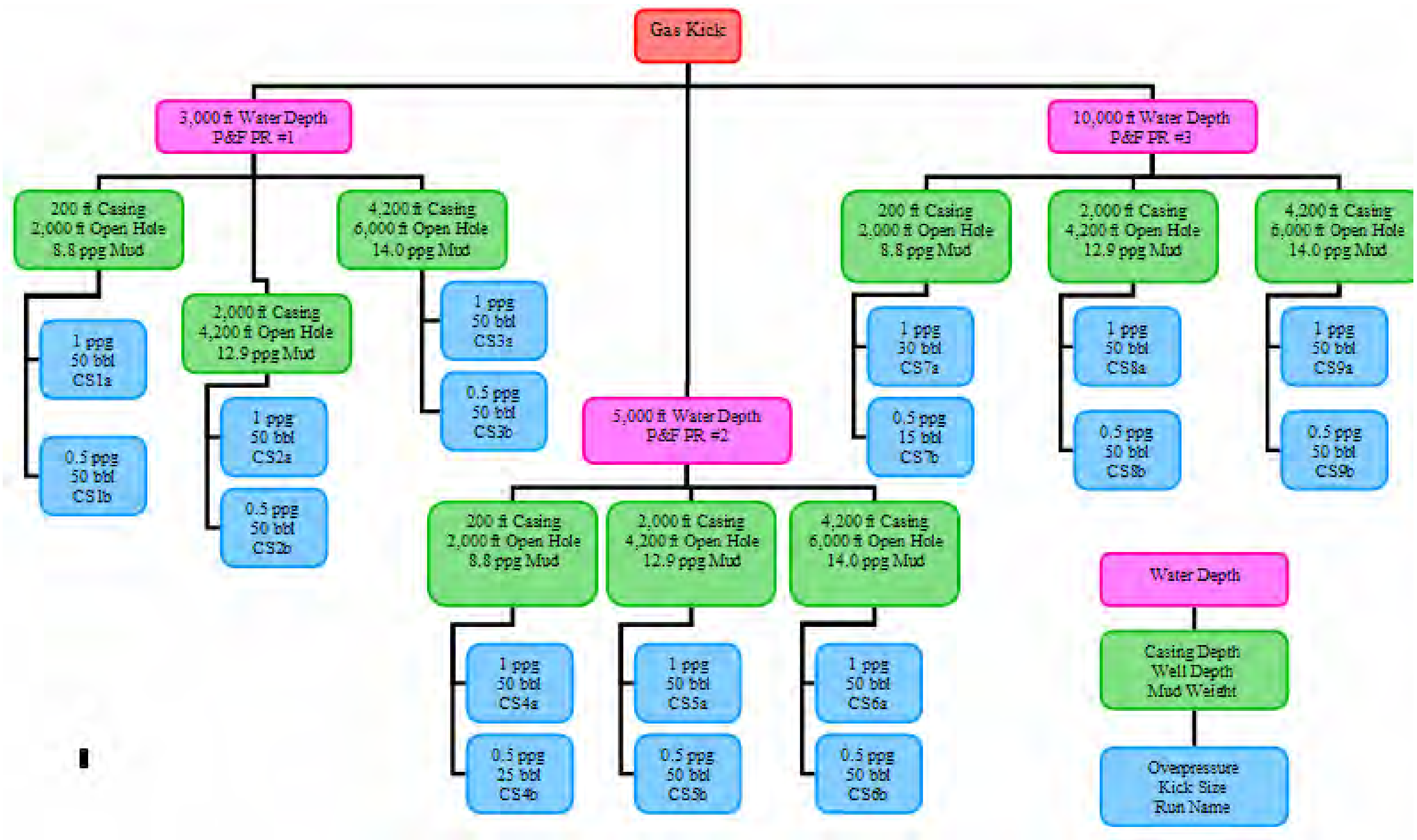

Fig. A2 – Simulation Set #2 Flowchart

APPENDIX B

PORE/FRACTURE PRESSURE REGIMES

Table B1 - P&F R#1 – 3,000 ft Water Depth

Pore & Fracture Pressures:		
Depth, SubSea, ft	Pore P, psi	Fracture P, psi
3,000	1,349	1,349
3,260	1,468	1,488
3,804	1,716	1,815
4,393	1,985	2,287
5,025	2,276	2,798
5,686	2,794	3,401
6,364	3,385	4,041
7,055	3,989	4,699
7,760	4,631	5,382
8,478	5,291	6,085
9,213	5,896	6,789
9,974	6,358	7,473
10,763	6,948	8,222
11,573	7,634	9,021
12,402	8,353	9,851
13,253	9,119	10,718
14,131	9,850	11,602
15,045	10,503	12,498
15,996	11,303	13,475
16,983	11,982	14,452
18,000	12,959	15,552
19,037	13,819	16,644
20,106	14,546	17,732
21,215	15,164	18,831
22,373	15,653	19,945
23,589	15,996	21,078
24,875	16,059	22,201
26,244	15,965	23,365
27,667	17,136	24,977
29,098	18,995	26,822
30,524	20,671	28,627

Table B2 - P&F R#2 – 5,000 ft Water Depth

Pore & Fracture Pressures:		
Depth, SubSea, ft	Pore P, psi	Fracture P, psi
5,000	2,249	2,249
5,260	2,368	2,387
5,804	2,615	2,715
6,393	2,884	3,187
7,025	3,176	3,698
7,686	3,693	4,300
8,364	4,285	4,941
9,055	4,889	5,598
9,760	5,531	6,282
10,478	6,191	6,985
11,213	6,796	7,688
11,974	7,258	8,373
12,763	7,848	9,122
13,573	8,534	9,921
14,402	9,252	10,751
15,253	10,018	11,618
16,131	10,749	12,501
17,045	11,402	13,397
17,996	12,203	14,374
18,983	12,882	15,352
20,000	13,859	16,452
21,037	14,719	17,544
22,106	15,445	18,631
23,215	16,064	19,731
24,373	16,553	20,845
25,589	16,896	21,977
26,875	16,959	23,100
28,244	16,865	24,265
29,667	18,036	25,876
31,098	19,894	27,721
32,524	21,571	29,526

Table B3 - P&F R#3 – 10,000 ft Water Depth

Pore & Fracture Pressures:		
Depth, SubSea, ft	Pore P, psi	Fracture P, psi
10,000	4,498	4,498
10,260	4,617	4,636
10,804	4,864	4,964
11,393	5,133	5,436
12,025	5,425	5,947
12,686	5,942	6,549
13,364	6,534	7,190
14,055	7,138	7,847
14,760	7,780	8,531
15,478	8,440	9,234
16,213	9,045	9,937
16,974	9,507	10,622
17,763	10,097	11,371
18,573	10,783	12,170
19,402	11,501	13,000
20,253	12,267	13,867
21,131	12,998	14,750
22,045	13,651	15,646
22,996	14,452	16,623
23,983	15,131	17,601
25,000	16,108	18,701
26,037	16,968	19,793
27,106	17,694	20,880
28,215	18,313	21,980
29,373	18,802	23,094
30,589	19,145	24,226
31,875	19,208	25,349
33,244	19,114	26,514
34,667	20,285	28,125
36,098	22,143	29,970
37,524	23,820	31,775

APPENDIX C

SIMULATOR INPUT DATA – SET #1

Run Number: **1**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	2000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

52	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C1 – Input Data Run #1

Run Number: 2

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	2000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea l

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

52	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C2 – Input Data Run #2

Run Number: 3

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	2000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C3 – Input Data Run #3

Run Number: 4

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	2000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C4 – Input Data Run #4

Run Number: 5

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	4000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea Fl

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C5 – Input Data Run #5

Run Number: 6

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	4000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea F

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C6 – Input Data Run #6

Run Number: 7

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	4000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea F

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

208	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C7 – Input Data Run #7

-

Run Number: **8**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	4000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea F

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

208	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C8 – Input Data Run #8

Run Number: 9

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	6000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea F

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

156	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C9 – Input Data Run #9

Run Number: 10

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	6000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickness

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea Fl

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

156	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C10 – Input Data Run #10

Run Number: 11

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	6000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea F

312	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C11 – Input Data Run #11

Run Number: 12

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	6000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000 Measured length of return line from subsea pump to surface, ft

3000 Vertical depth of return line, ft

Water Data & Others: Sea l

3000 Water Depth, ft

4500 Depth of last Casing from sea level, ft

Kick Data:

312 Amount of Formation Over Pressure, psi

50 Pit Gain Warning Level, bbls

Fig. C12 – Input Data Run #12

Run Number: 13

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	2000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea l

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

52	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C13 – Input Data Run #13

Run Number: 14

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	2000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

52	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C14 – Input Data Run #14

Run Number: 15

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	2000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea I

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C15 – Input Data Run #15

Run Number: **16**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	2000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne:

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C16 – Input Data Run #16

Run Number: **17**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	4000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C17 – Input Data Run #17

Run Number: 18

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	4000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

1600

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickness

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C18 – Input Data Run #18

Run Number: 19

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	4000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

1600

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

208	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C19 – Input Data Run #19

Run Number: 20

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	4000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

1600

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000 Measured length of return line from subsea pump to surface, ft
5000 Vertical depth of return line, ft

Water Data & Others: Sea F

5000 Water Depth, ft
6500 Depth of last Casing from sea level, ft

Kick Data:

208 Amount of Formation Over Pressure, psi
50 Pit Gain Warning Level, bbls

Fig. C20 – Input Data Run #20

Run Number: 21

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	6000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

156	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C21 – Input Data Run #21

Run Number: 22

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	6000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne:

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

156	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C22 – Input Data Run #22

Run Number: **23**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	6000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

312	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C23 – Input Data Run #23

Run Number: 24

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	6000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

312	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C24 – Input Data Run #24

Run Number: 25

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	2000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea l

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

52	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C25 – Input Data Run #25

Run Number: 26

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	2000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickness of 0

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others:

		Sea Floor (I
		Press
10000	Water Depth, ft	
11500	Depth of last Casing from sea level, ft	0
		350(

Kick Data:

52	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C26 – Input Data Run #26

Run Number: **27**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	2000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea F

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C27 – Input Data Run #27

Run Number: **28**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	2000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea F

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C28 – Input Data Run #28

Run Number: **29**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	4000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea F

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C29 – Input Data Run #29

Run Number: 30

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	4000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea l

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C30 – Input Data Run #30

Run Number: 31

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	4000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea F

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

208	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C31 – Input Data Run #31

Run Number:	**32**	
Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	4000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000 Measured length of return line from subsea pump to surface, ft
10000 Vertical depth of return line, ft

Water Data & Others: Sea F

10000 Water Depth, ft
11500 Depth of last Casing from sea level, ft

Kick Data:

208 Amount of Formation Over Pressure, psi
50 Pit Gain Warning Level, bbls

Fig. C32 – Input Data Run #32

Run Number: **33**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	6000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea F

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

156	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C33 – Input Data Run #33

Run Number: 34

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	6000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickness

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea Flc

10000	Water Depth, ft	P
11500	Depth of last Casing from sea level, ft	

Kick Data:

156	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C34 – Input Data Run #34

Run Number: 35

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	6000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickness of 0.5"

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others:

		Sea Floor (Mud Pressure
10000	Water Depth, ft	0
11500	Depth of last Casing from sea level, ft	35000

Kick Data:

312	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C35 – Input Data Run #35

Run Number: **36**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	6000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickness

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea Floo

10000	Water Depth, ft	Pr
11500	Depth of last Casing from sea level, ft	
		3

Kick Data:

312	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C36 – Input Data Run #36

APPENDIX D

SIMULATOR INPUT DATA – SET #2

Run Number:	**CS1**						
Kick Type:	Gas						
Casing Seat:	200	ft					
Water Depth:	3000	ft					
Well Depth:	2000	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	8.8	ppg					
Plastic Viscosity	5	cp					
Yield Point Stress	17	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 36" w/ 34" ID & 1" wall thickness - 373.80 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	3200		34	5	200		
4.276	900		12.25	5	900		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
3000	Measured length of return line from subsea pump to surface, ft						
3000	Vertical depth of return line, ft						
Water Data & Others:					Sea Floor (Mud Line)		
3000	Water Depth, ft					Pressure	Depth
3200	Depth of last Casing from sea level, ft					0	3000
						35000	3000
Kick Data:							
104	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D1 – Input Data Runs CS1a and CS1b

Run Number:	**CS2**						
Kick Type:	Gas						
Casing Seat:	2000	ft					
Water Depth:	3000	ft					
Well Depth:	4200	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	12.9	ppg					
Plastic Viscosity	17.5	cp					
Yield Point Stress	9	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 30" w/ 28" ID & 1" wall thickness - 309.72 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	5000		28	5	2000		
4.276	1300		12.25	5	1300		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
3000	Measured length of return line from subsea pump to surface, ft						
3000	Vertical depth of return line, ft						
Water Data & Others:						Sea Floor (Mud Line)	
3000	Water Depth, ft					Pressure	Depth
5000	Depth of last Casing from sea level, ft					0	3000
						35000	3000
Kick Data:							
218.5	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D2 – Input Data Runs CS2a and CS2b

Run Number:	**CS3**						
Kick Type:	Gas						
Casing Seat:	4200	ft					
Water Depth:	3000	ft					
Well Depth:	6000	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	14	ppg					
Plastic Viscosity	24	cp					
Yield Point Stress	9	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 20" w/ 18" ID & 1" wall thickness - 202.92 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	7200		18	5	4200		
4.276	900		12.25	5	900		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
3000	Measured length of return line from subsea pump to surface, ft						
3000	Vertical depth of return line, ft						
Water Data & Others:						Sea Floor (Mud Line)	
3000	Water Depth, ft					Pressure	Depth
7200	Depth of last Casing from sea level, ft					0	3000
						35000	3000
Kick Data:							
312	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D3 – Input Data Runs CS3a and CS3b

Run Number:	**CS4**						
Kick Type:	Gas						
Casing Seat:	200	ft					
Water Depth:	5000	ft					
Well Depth:	2000	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	8.8	ppg					
Plastic Viscosity	5	cp					
Yield Point Stress	17	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 36" w/ 34" ID & 1" wall thickness - 373.80 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	5200		34	5	200		
4.276	900		12.25	5	900		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
5000	Measured length of return line from subsea pump to surface, ft						
5000	Vertical depth of return line, ft						
Water Data & Others:					Sea Floor (Mud Line)		(
5000	Water Depth, ft					Pressure	Depth
5200	Depth of last Casing from sea level, ft					0	5000
						35000	5000
Kick Data:							
104	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D4 – Input Data Runs CS4a and CS4b

Run Number:	**CS5**						
Kick Type:	Gas						
Casing Seat:	2000	ft					
Water Depth:	5000	ft					
Well Depth:	4200	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	12.9	ppg					
Plastic Viscosity	17.5	cp					
Yield Point Stress	9	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 30" w/ 28" ID & 1" wall thickness - 309.72 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	7000		28	5	2000		
4.276	1300		12.25	5	1300		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
5000	Measured length of return line from subsea pump to surface, ft						
5000	Vertical depth of return line, ft						
Water Data & Others:					Sea Floor (Mud Line)		(
5000	Water Depth, ft					Pressure	Depth
7000	Depth of last Casing from sea level, ft					0	5000
						35000	5000
Kick Data:							
218.5	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D5 – Input Data Runs CS5a and CS5b

Run Number:	CS6						
Kick Type:	Gas						
Casing Seat:	4200	ft					
Water Depth:	5000	ft					
Well Depth:	6000	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	14	ppg					
Plastic Viscosity	24	cp					
Yield Point Stress	9	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 20" w/ 18" ID & 1" wall thickness - 202.92 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	9200		18	5	4200		
4.276	900		12.25	5	900		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
5000	Measured length of return line from subsea pump to surface, ft						
5000	Vertical depth of return line, ft						
Water Data & Others:					Sea Floor (Mud Line)		C
5000	Water Depth, ft					Pressure	Depth
9200	Depth of last Casing from sea level, ft					0	5000
						35000	5000
Kick Data:							
312	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D6 – Input Data Runs CS6a and CS6b

Run Number:	CS7						
Kick Type:	Gas						
Casing Seat:	200	ft					
Water Depth:	10000	ft					
Well Depth:	2000	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	8.8	ppg					
Plastic Viscosity	5	cp					
Yield Point Stress	17	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 36" w/ 34" ID & 1" wall thickness - 373.80 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	10200		34	5	200		
4.276	900		12.25	5	900		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
10000	Measured length of return line from subsea pump to surface, ft						
10000	Vertical depth of return line, ft						
Water Data & Others:					Sea Floor (Mud Line)		C
10000	Water Depth, ft					Pressure	Depth
10200	Depth of last Casing from sea level, ft					0	10000
						35000	10000
Kick Data:							
104	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D7 – Input Data Runs CS7a and CS7b

Run Number:	**CS8**							
Kick Type:	Gas							
Casing Seat:	2000	ft						
Water Depth:	10000	ft						
Well Depth:	4200	ft						
Kick Size:	1	ppg						
Pit Gain Warning:	50	bbl						
Fluid Data:								
Mud Weight	12.9	ppg						
Plastic Viscosity	17.5	cp						
Yield Point Stress	9	lbf/100 sq. ft						
Well Geometry Data:	Conductor Pipe = 30" w/ 28" ID & 1" wall thickness - 309.72 lb/ft							
Inside Drill String			Annulus Except Return Lin					
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft			
4.276	12000		28	5	2000			
4.276	1300		12.25	5	1300			
3	600		12.25	5.5	600			
3.25	300		12.25	8	300			
Return Line & Control Lines Data								
10000	Measured length of return line from subsea pump to surface, ft							
10000	Vertical depth of return line, ft							
Water Data & Others:					Sea Floor (Mud Line)			C
10000	Water Depth, ft					Pressure	Depth	
12000	Depth of last Casing from sea level, ft					0	10000	
						35000	10000	
Kick Data:								
218.5	Amount of Formation Over Pressure, psi							
50	Pit Gain Warning Level, bbls							

Fig. D8 – Input Data Runs CS8a and CS8b

Run Number:	**CS9**							
Kick Type:	Gas							
Casing Seat:	4200	ft						
Water Depth:	10000	ft						
Well Depth:	6000	ft						
Kick Size:	1	ppg						
Pit Gain Warning:	50	bbl						
Fluid Data:								
Mud Weight	14	ppg						
Plastic Viscosity	24	cp						
Yield Point Stress	9	lbf/100 sq. ft						
Well Geometry Data:	Conductor Pipe = 20" w/ 18" ID & 1" wall thickness - 202.92 lb/ft							
Inside Drill String			Annulus Except Return Lin					
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft			
4.276	14200		18	5	4200			
4.276	900		12.25	5	900			
3	600		12.25	5.5	600			
3.25	300		12.25	8	300			
Return Line & Control Lines Data								
10000	Measured length of return line from subsea pump to surface, ft							
10000	Vertical depth of return line, ft							
Water Data & Others:					Sea Floor (Mud Line)			C
10000	Water Depth, ft					Pressure	Depth	
14200	Depth of last Casing from sea level, ft					0	10000	
						35000	10000	
Kick Data:								
312	Amount of Formation Over Pressure, psi							
50	Pit Gain Warning Level, bbls							

Fig. D9 – Input Data Runs CS9a and CS9b

APPENDIX E

PRESSURE @ TOP OF KICK GRAPHS – SET #1

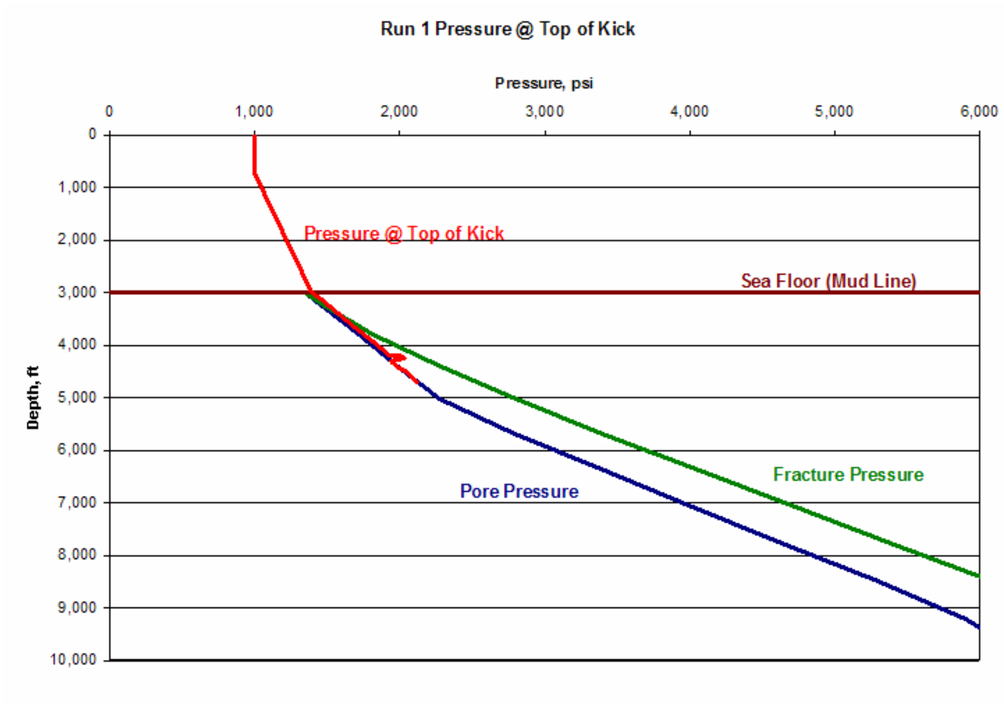

Fig. E1 – Pressure @ Top of Kick in Run 1

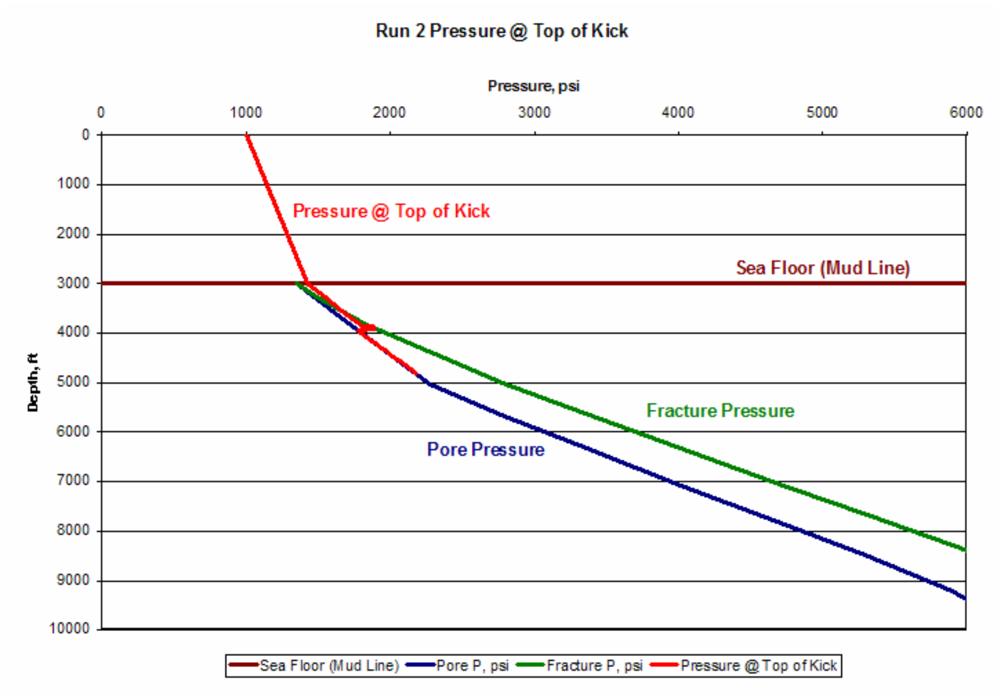

Fig. E2 – Pressure @ Top of Kick in Run 2

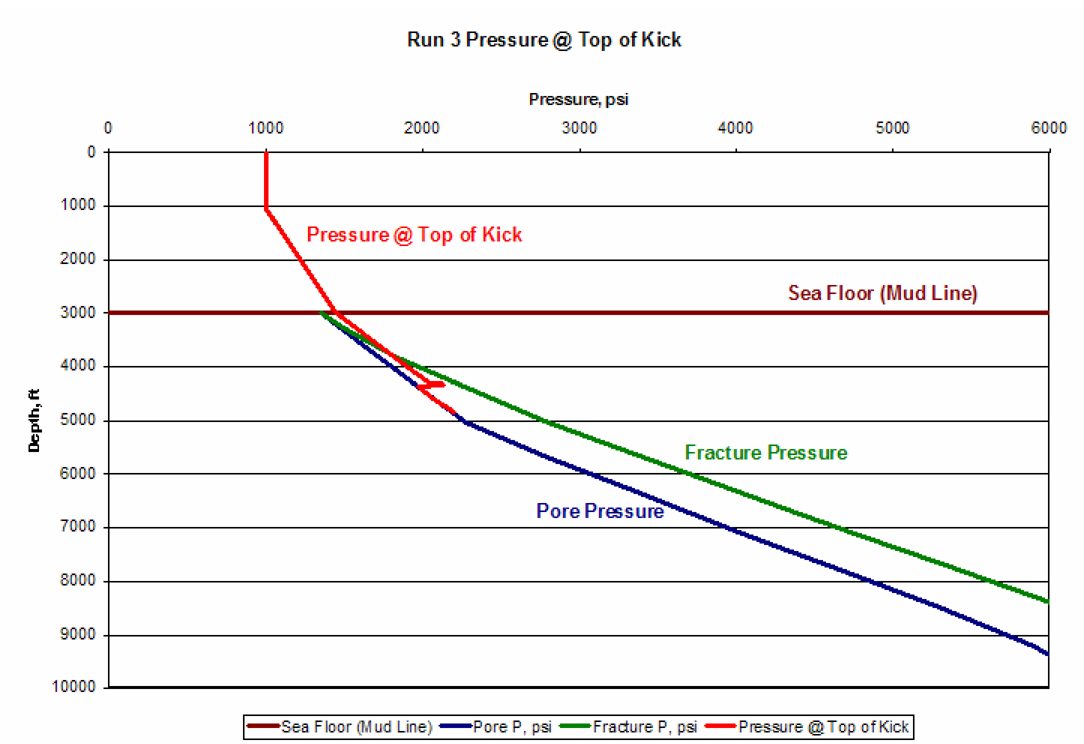

Fig. E3 – Pressure @ Top of Kick in Run 3

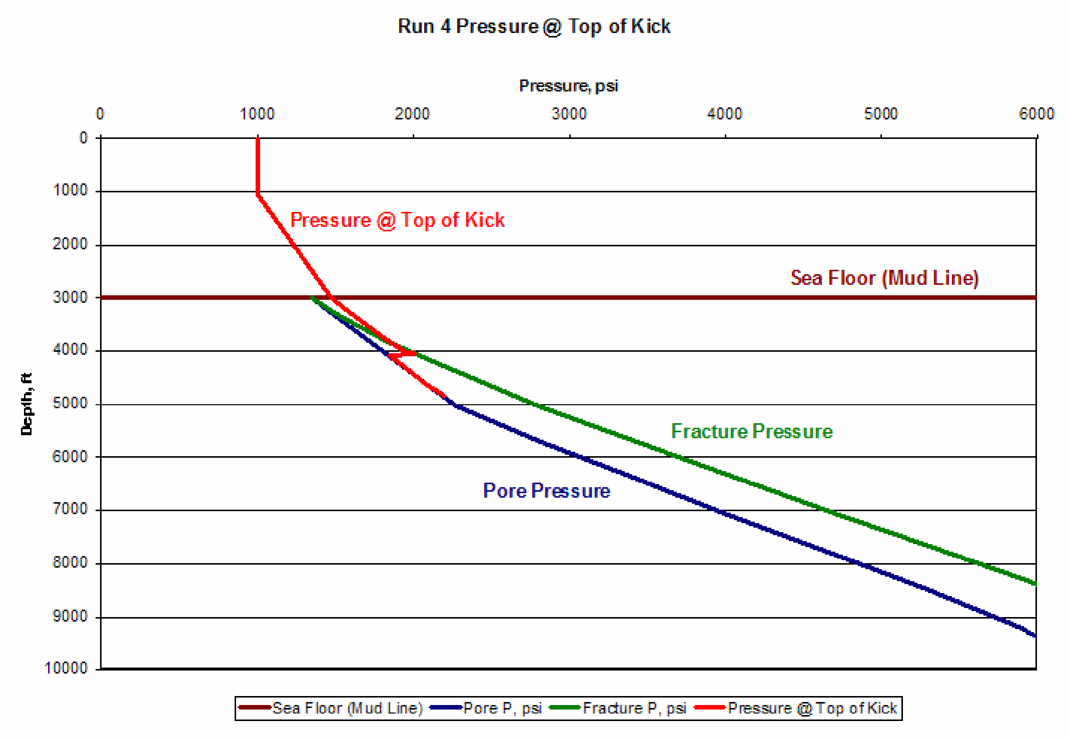

Fig. E4 – Pressure @ Top of Kick in Run 4

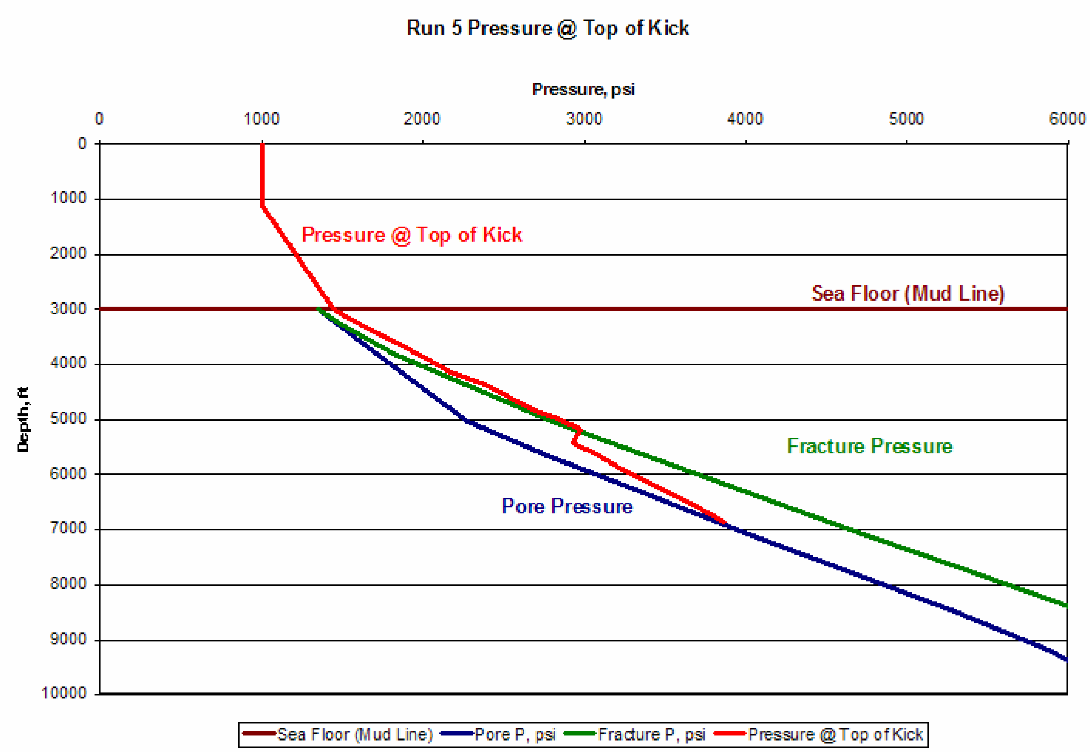

Fig. E5 – Pressure @ Top of Kick in Run 5

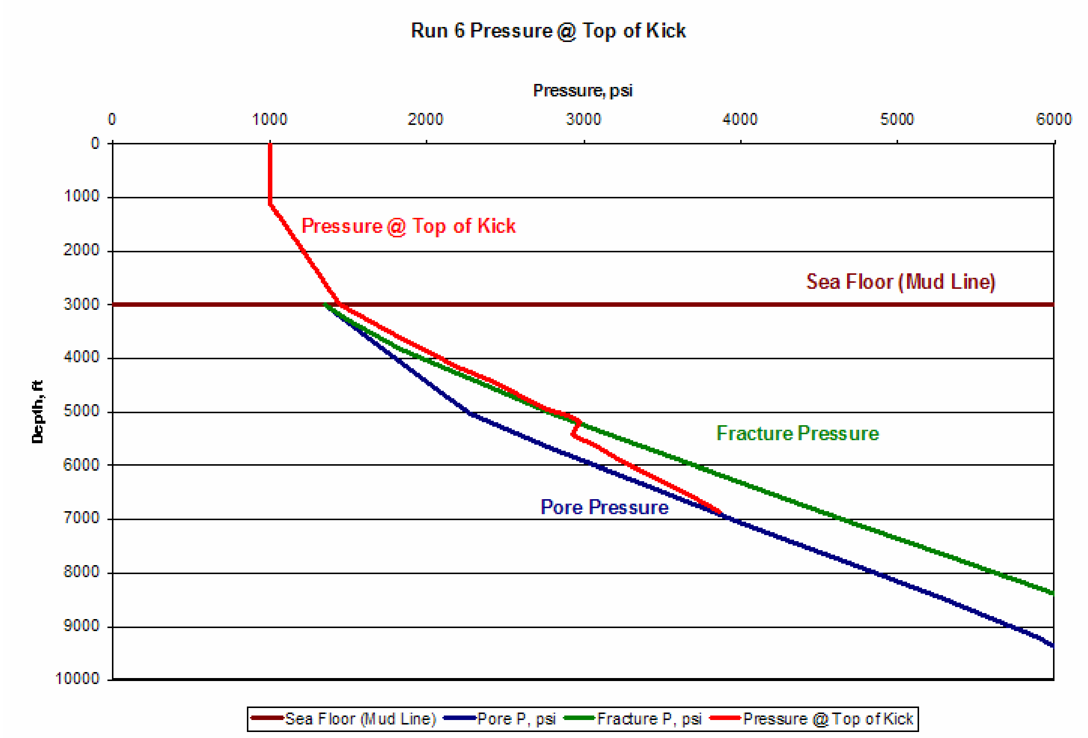

Fig. E6 – Pressure @ Top of Kick in Run 6

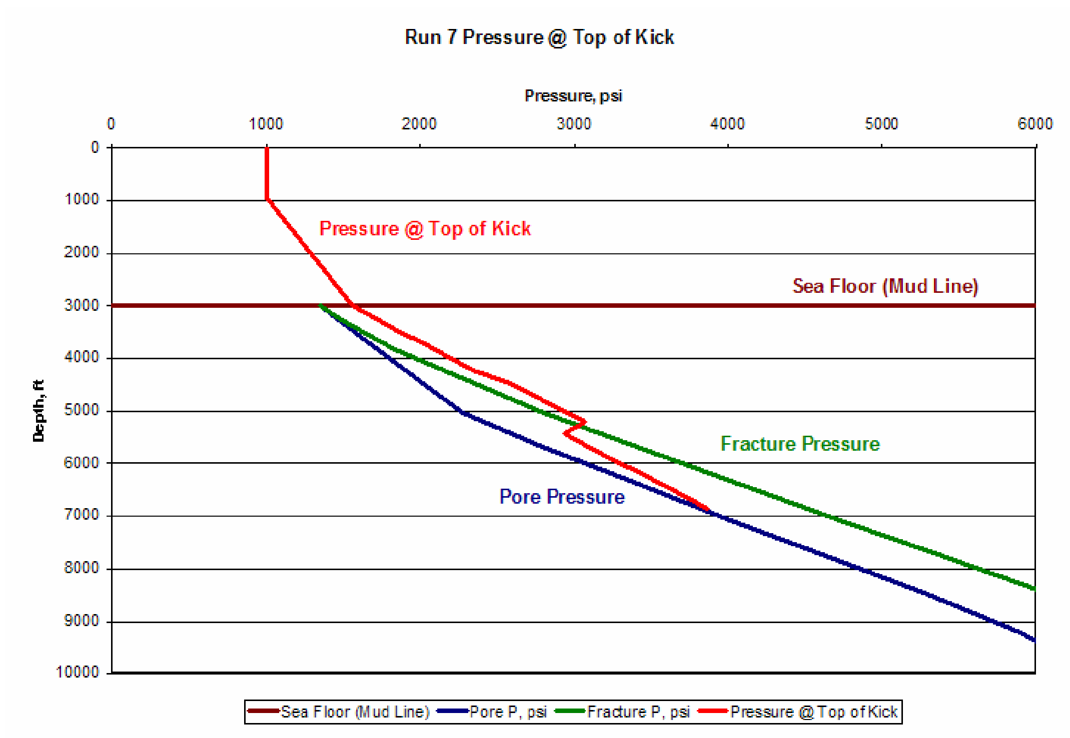

Fig. E7 – Pressure @ Top of Kick in Run 7

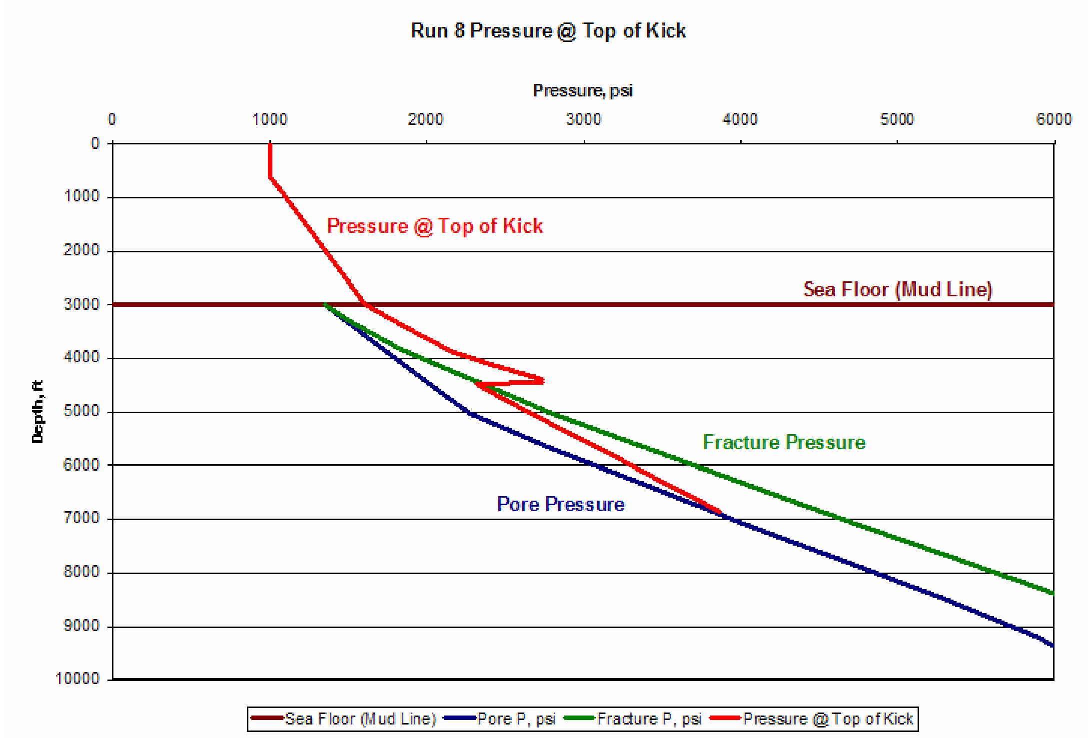

Fig. E8 – Pressure @ Top of Kick in Run 8

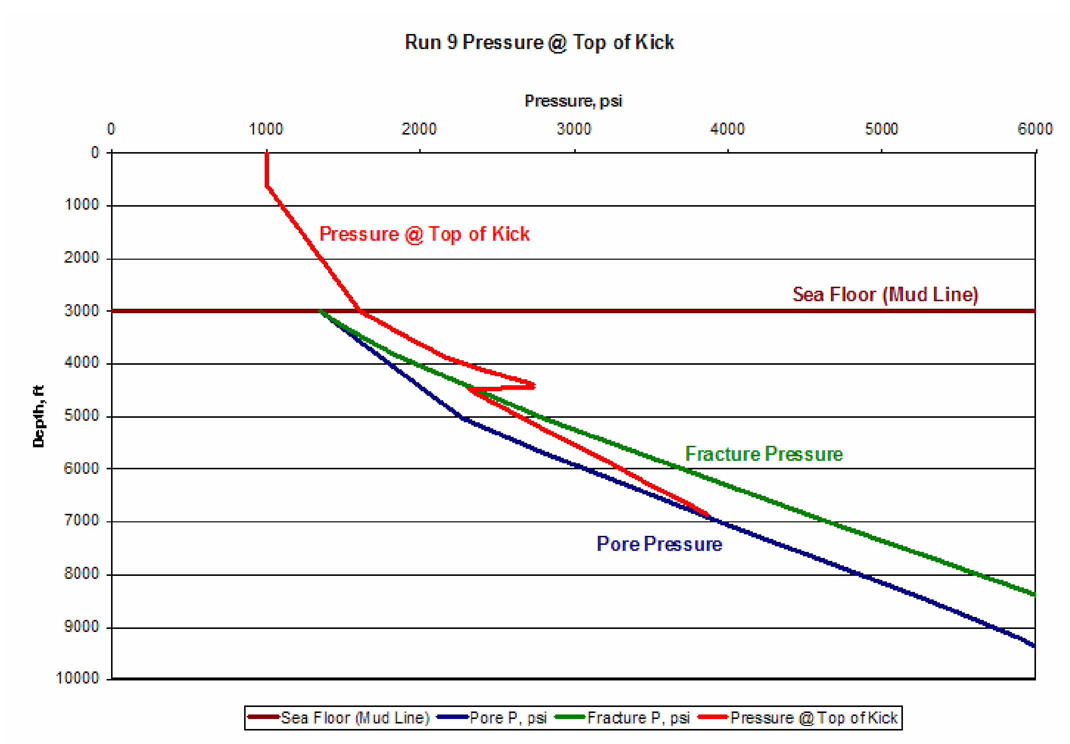

Fig. E9 – Pressure @ Top of Kick in Run 9

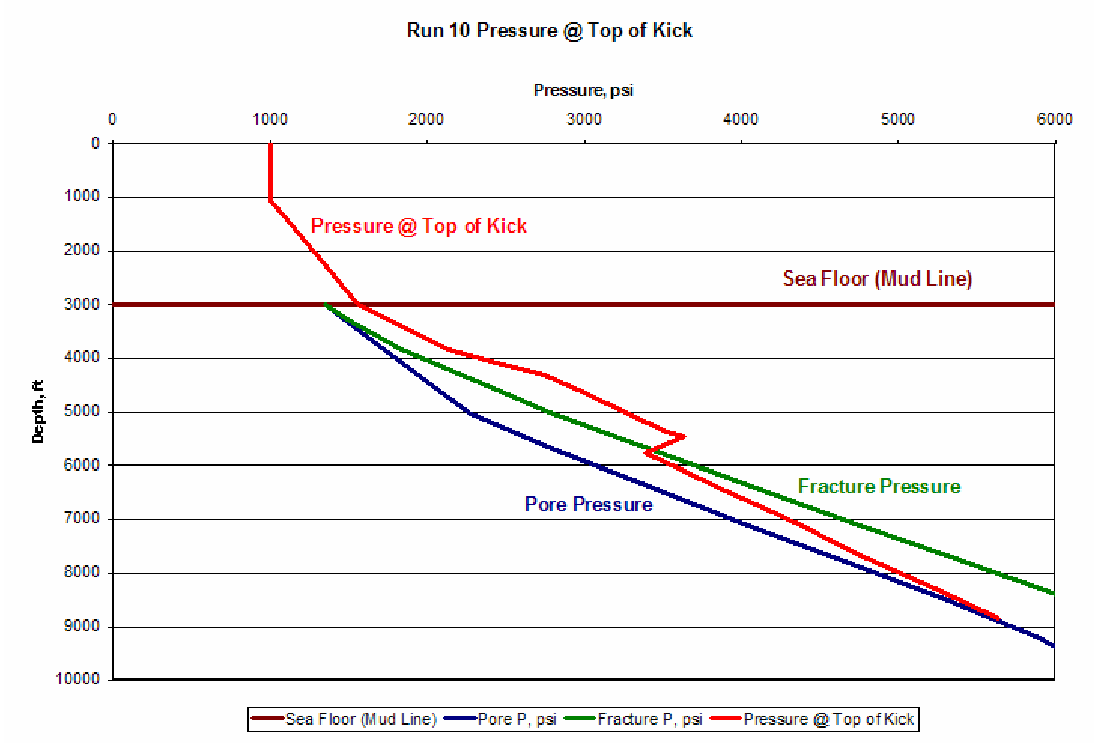

Fig. E10 – Pressure @ Top of Kick in Run 10

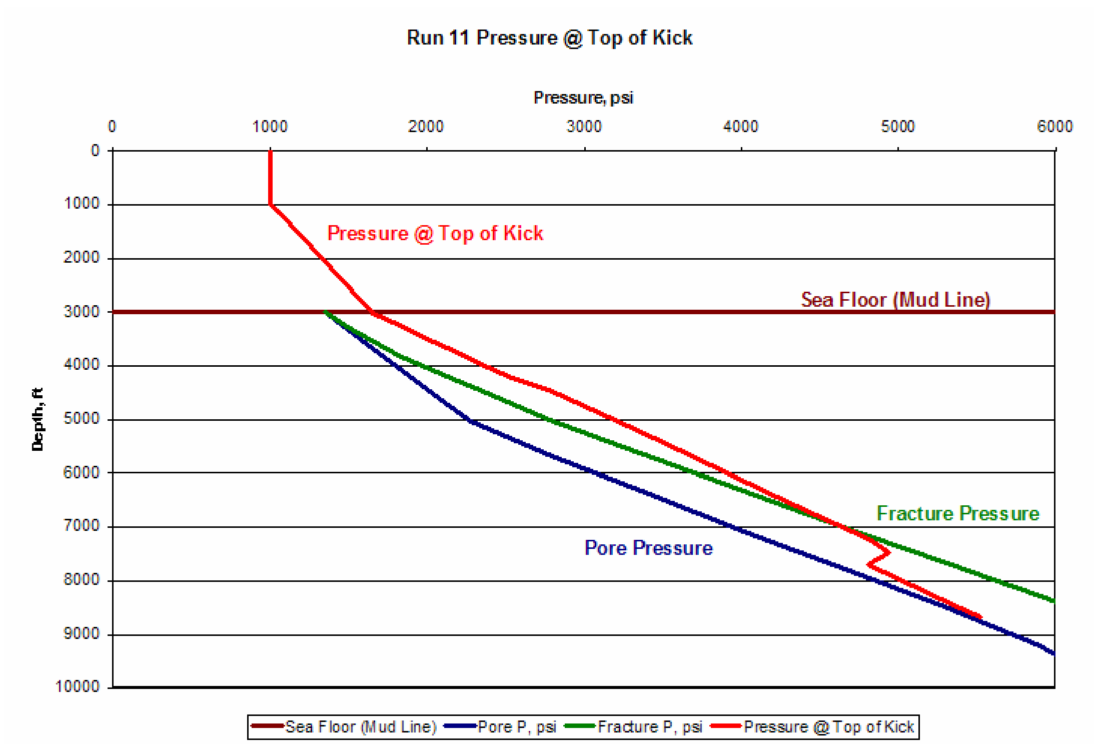

Fig. E11 – Pressure @ Top of Kick in Run 11

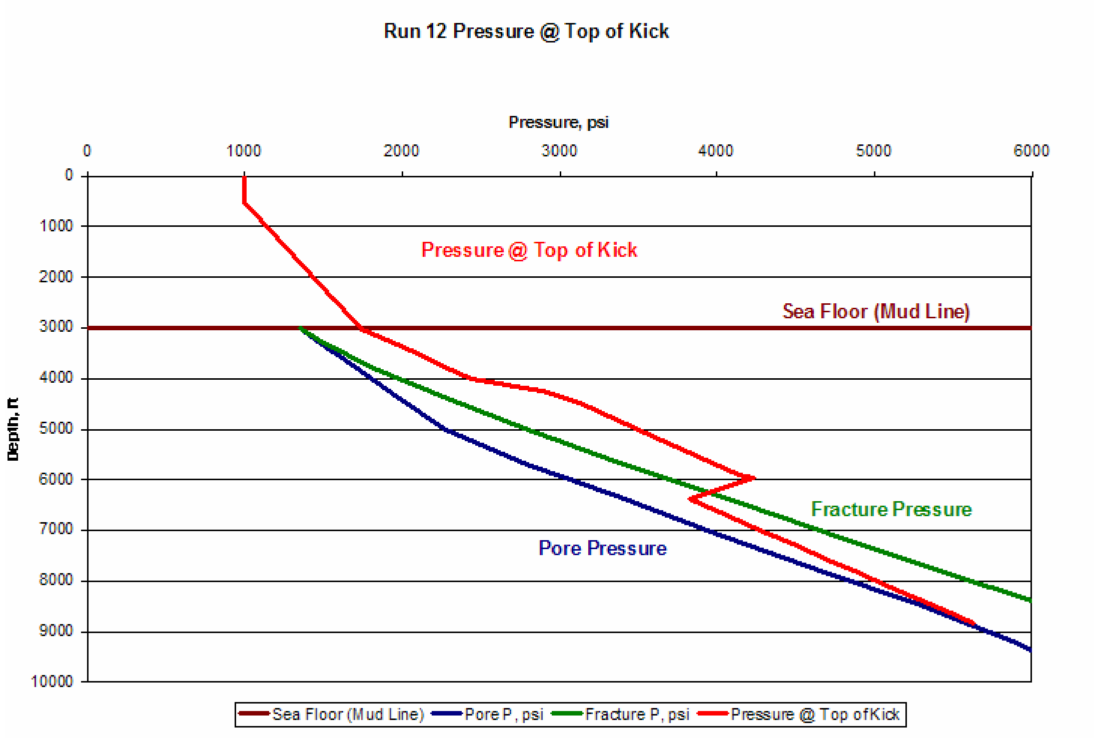

Fig. E12 – Pressure @ Top of Kick in Run 12

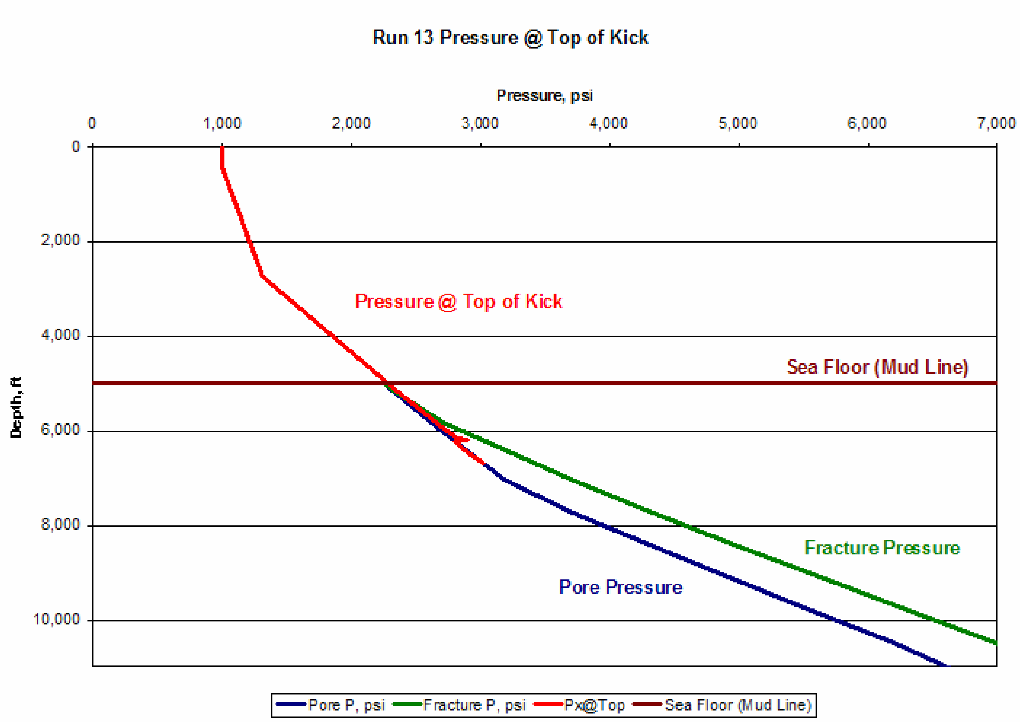

Fig. E13 – Pressure @ Top of Kick in Run 13

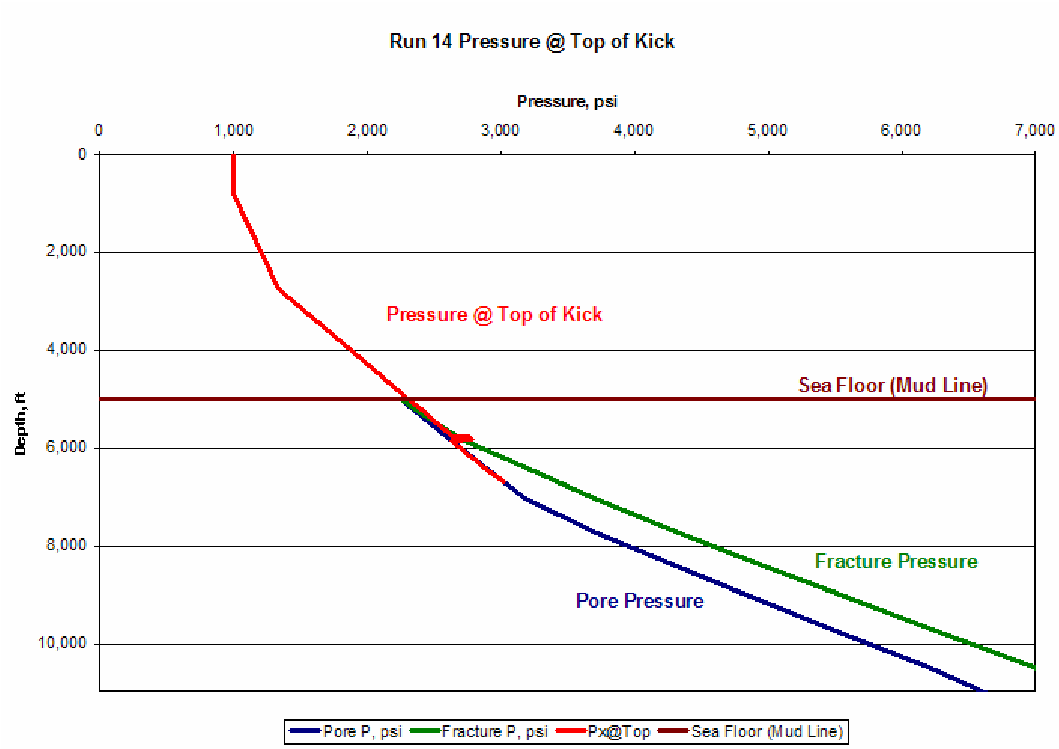

Fig. E14 – Pressure @ Top of Kick in Run 14

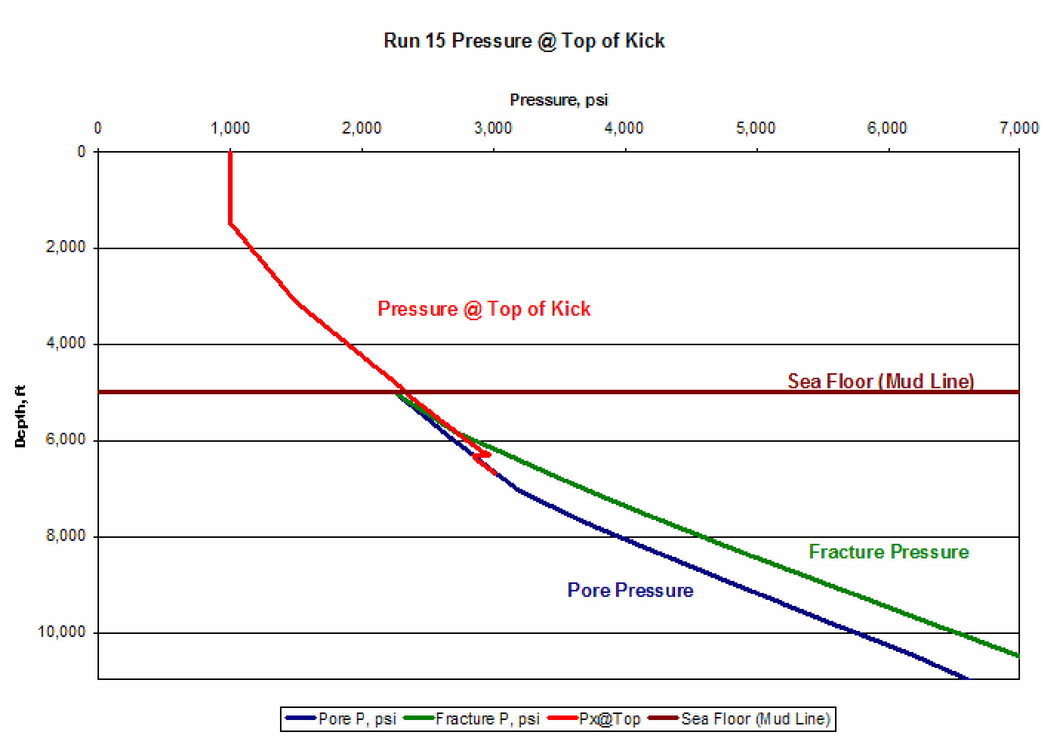

Fig. E15 – Pressure @ Top of Kick in Run 15

Fig. E16 – Pressure @ Top of Kick in Run 16

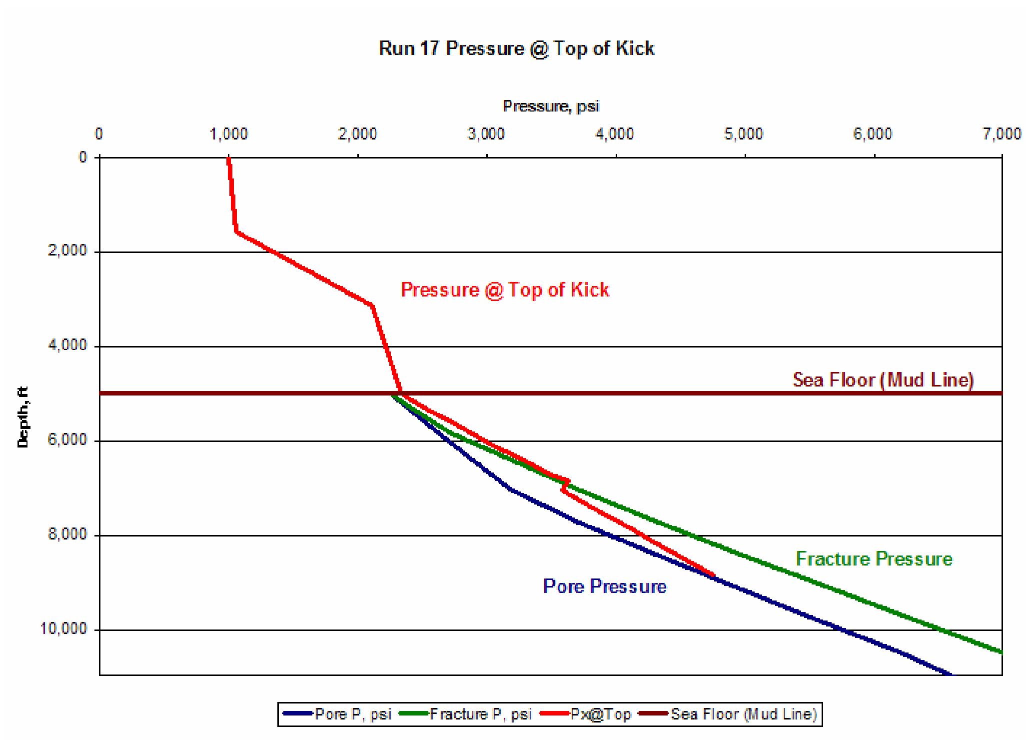

Fig. E17 – Pressure @ Top of Kick in Run 17

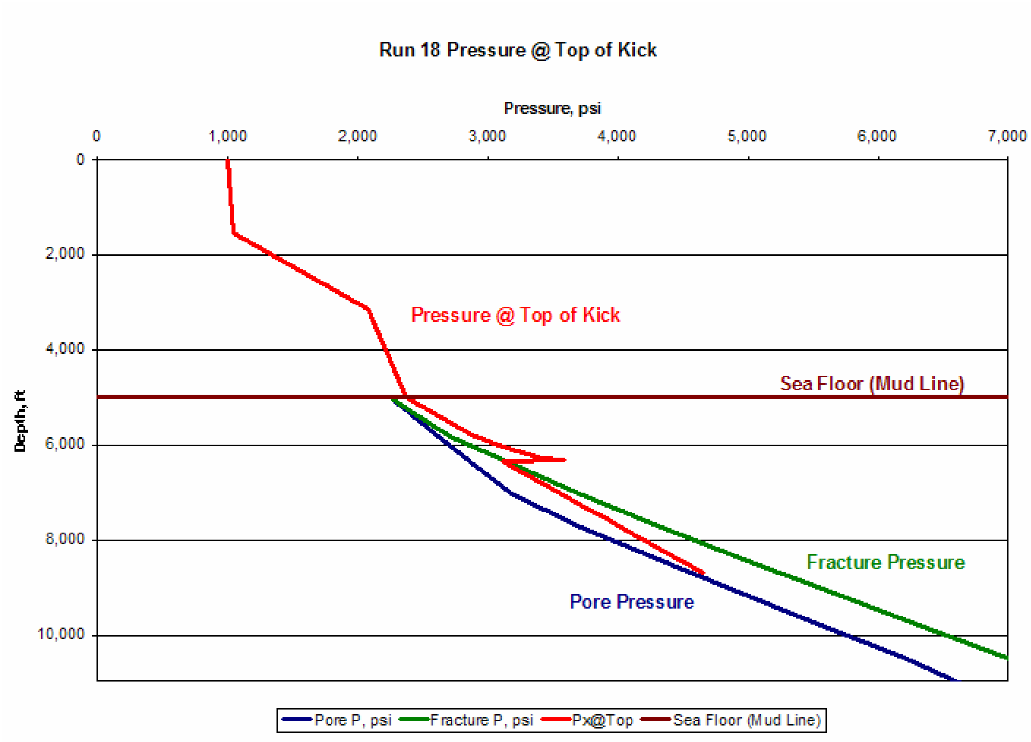

Fig. E18 – Pressure @ Top of Kick in Run 18

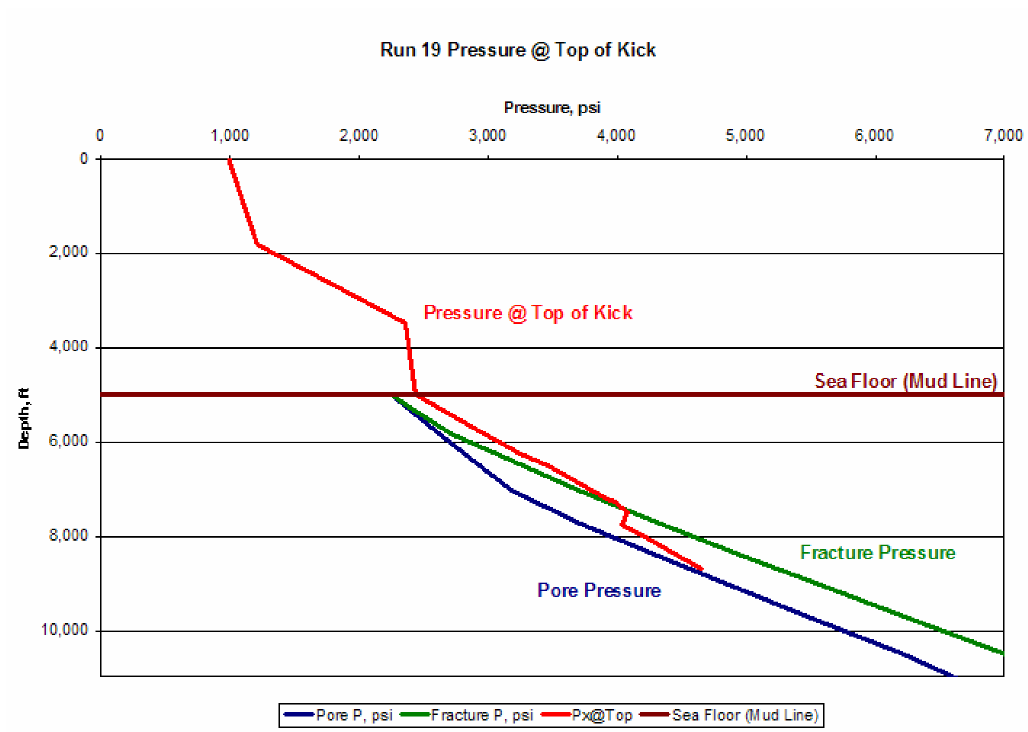

Fig. E19 – Pressure @ Top of Kick in Run 19

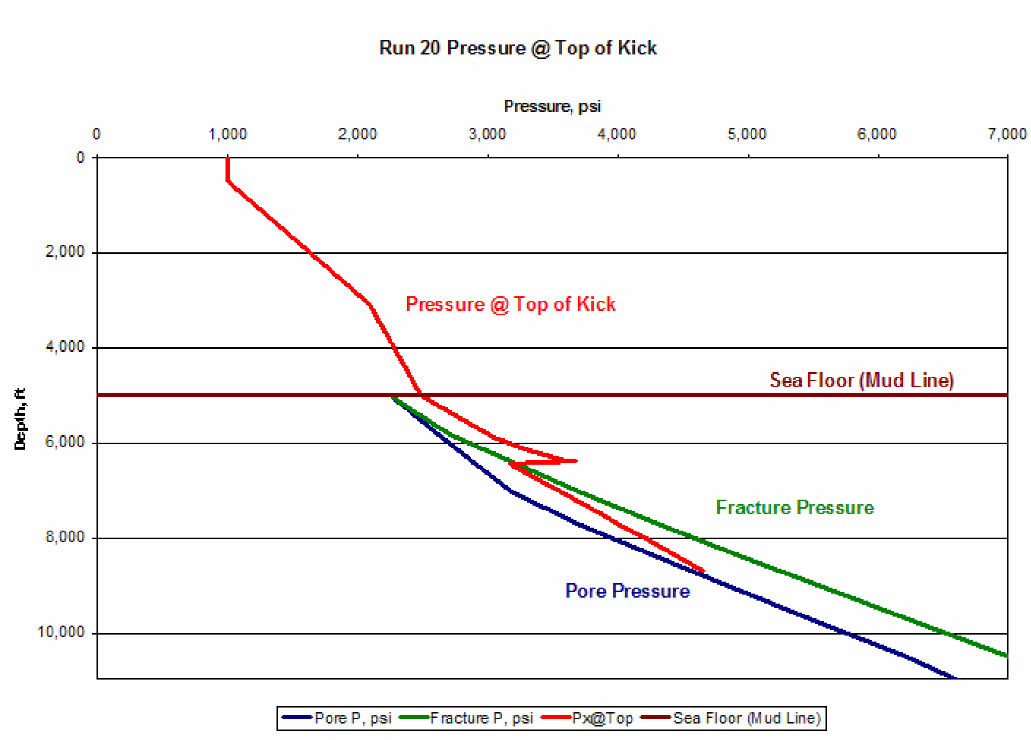

Fig. E20 – Pressure @ Top of Kick in Run 20

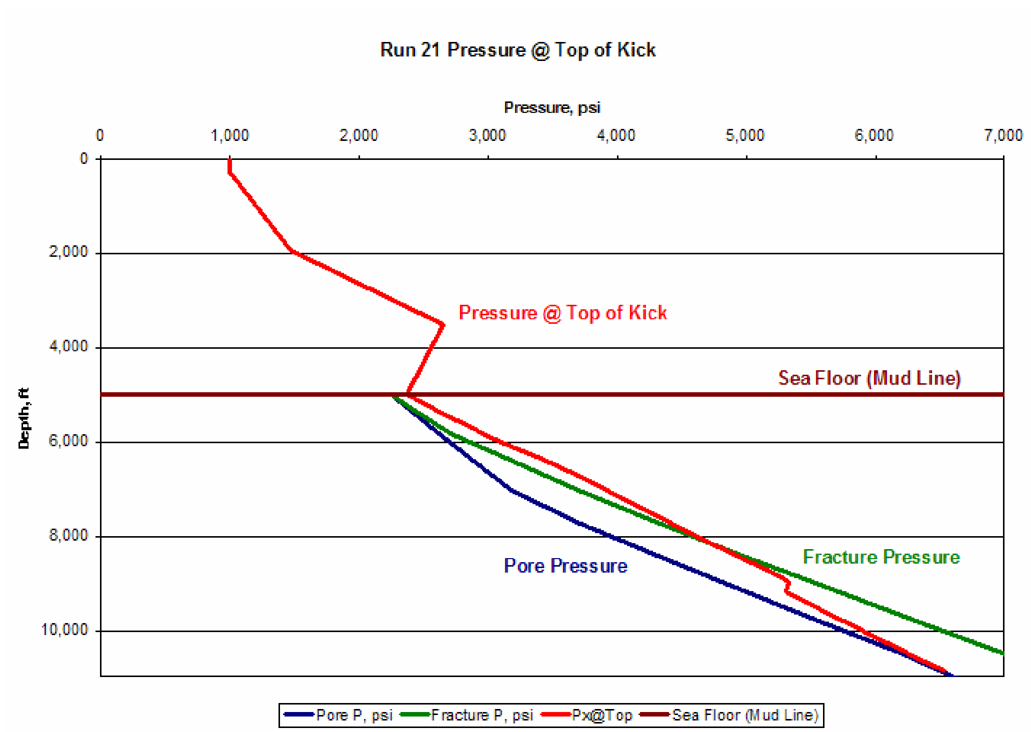

Fig. E21 – Pressure @ Top of Kick in Run 21

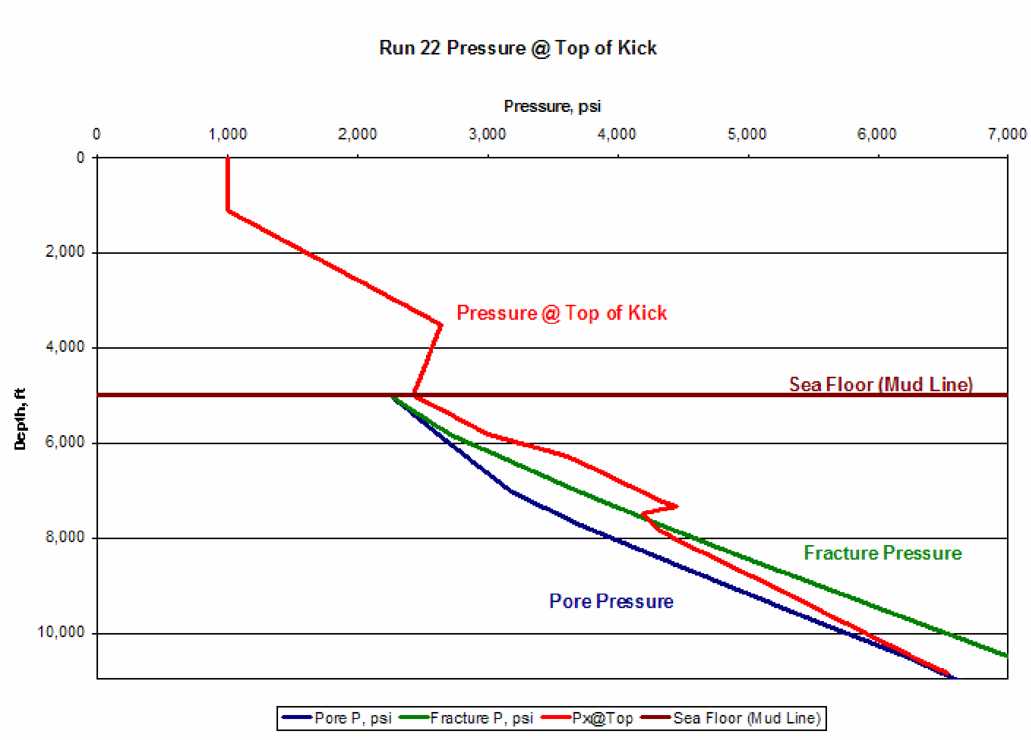

Fig. E22 – Pressure @ Top of Kick in Run 22

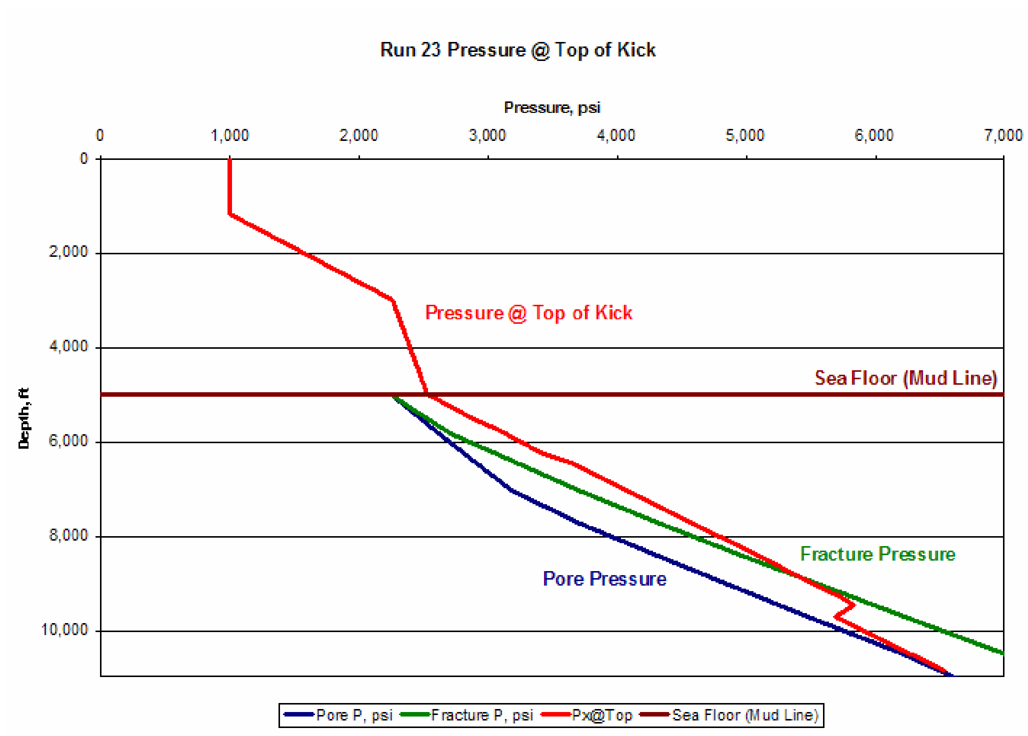

Fig. E23 – Pressure @ Top of Kick in Run 23

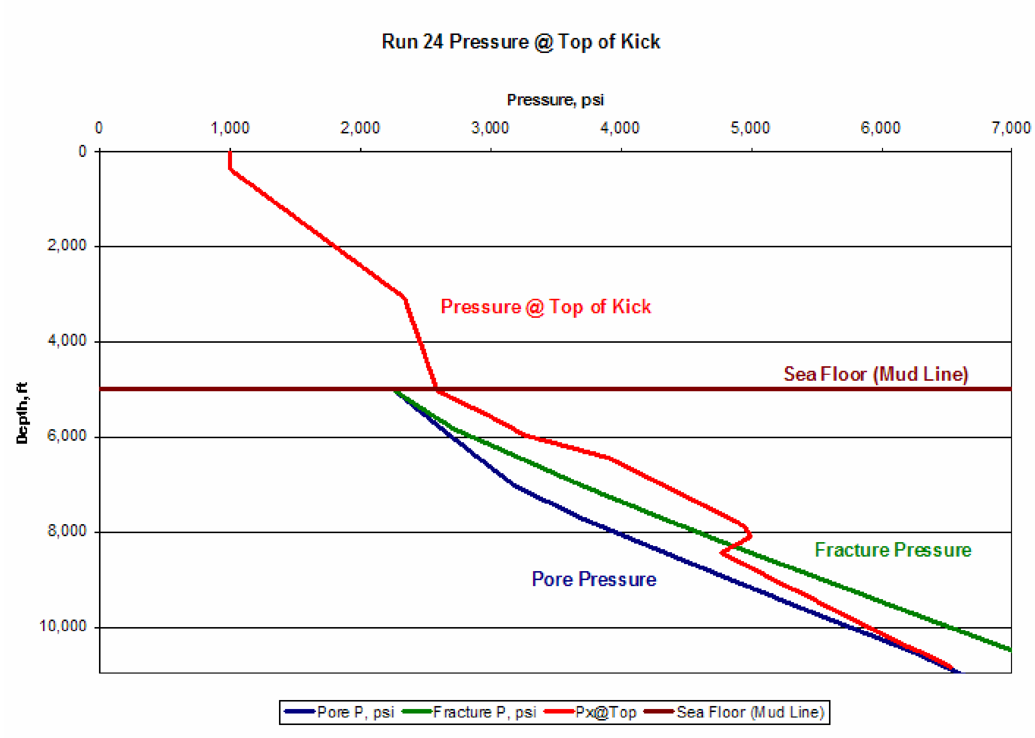

Fig. E24 – Pressure @ Top of Kick in Run 24

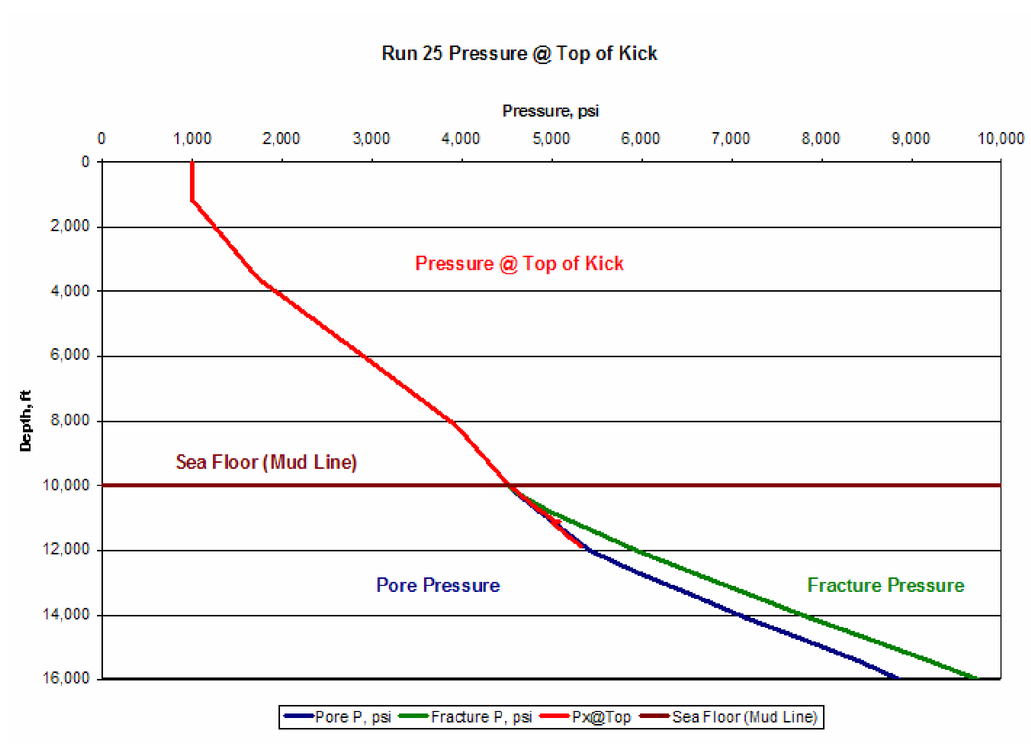

Fig. E25 – Pressure @ Top of Kick in Run 25

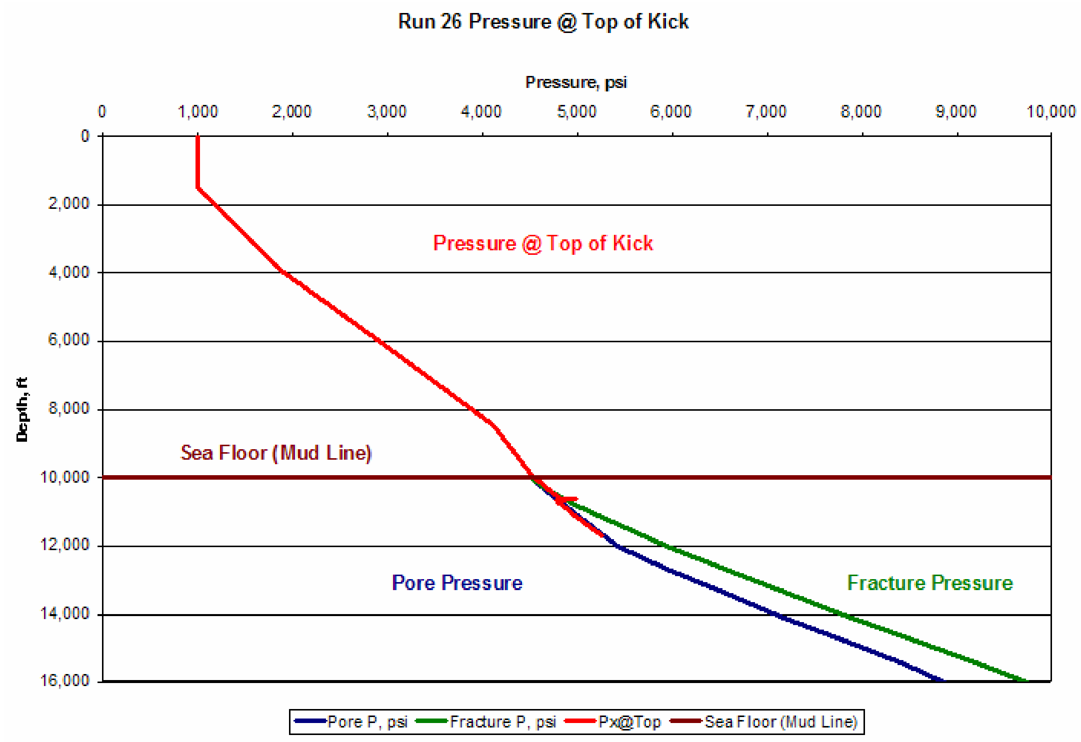

Fig. E26 – Pressure @ Top of Kick in Run 26

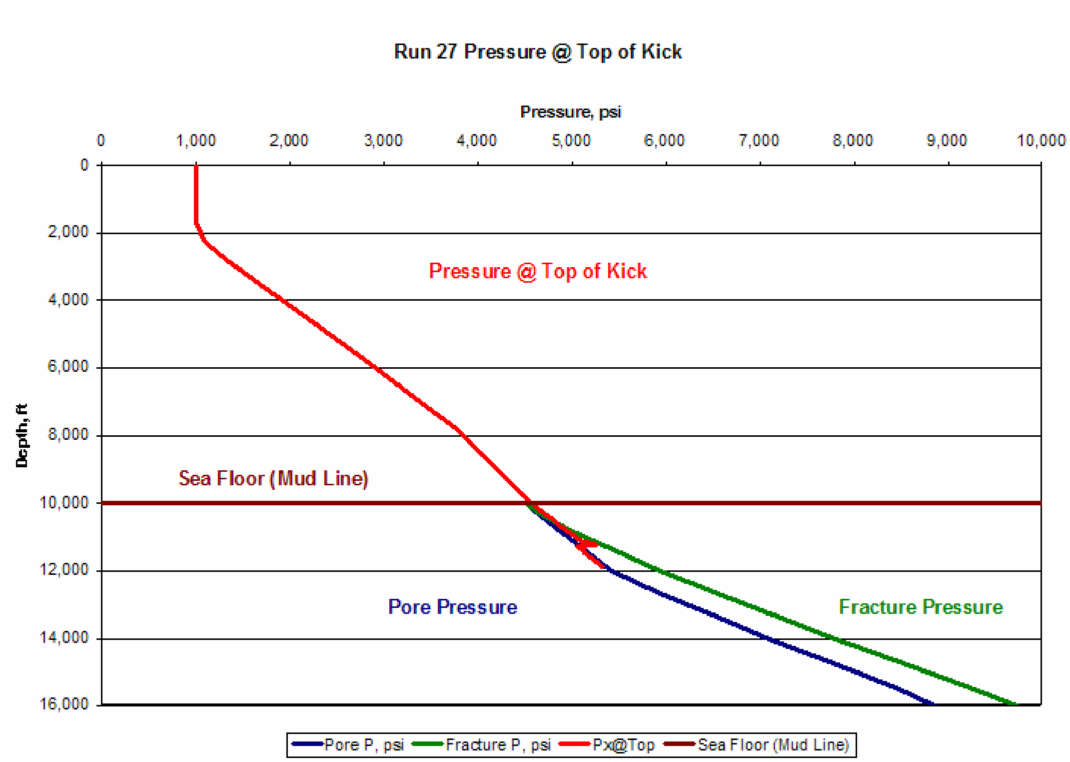

Fig. E27 – Pressure @ Top of Kick in Run 27

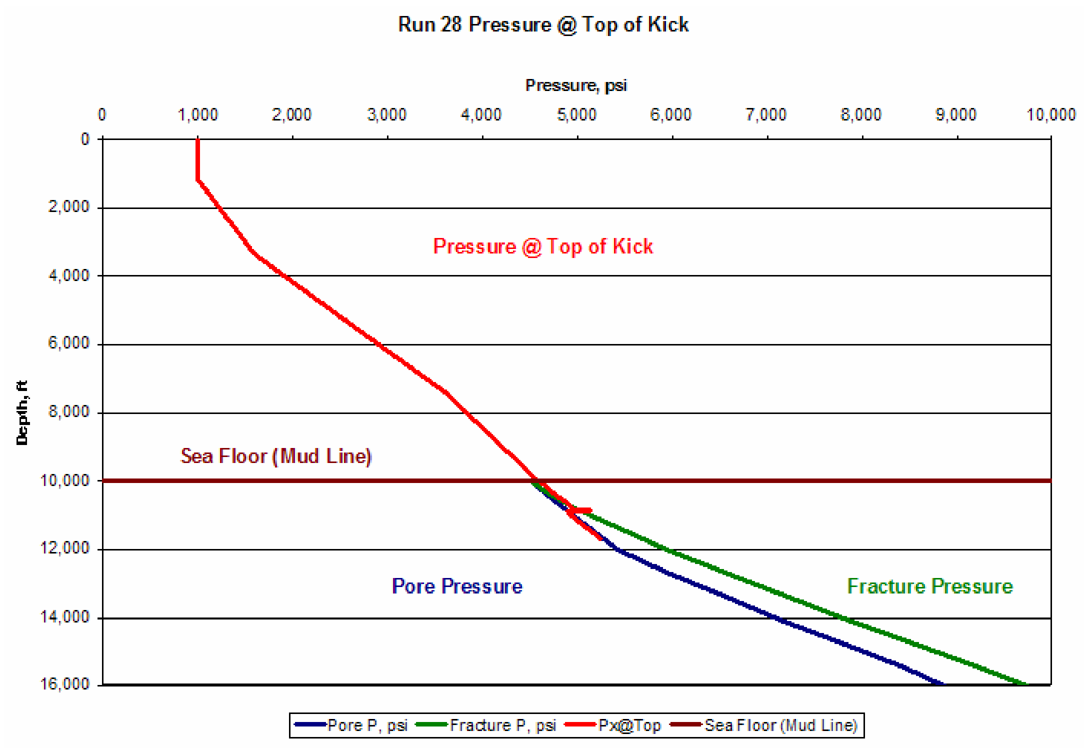

Fig. E28 – Pressure @ Top of Kick in Run 28

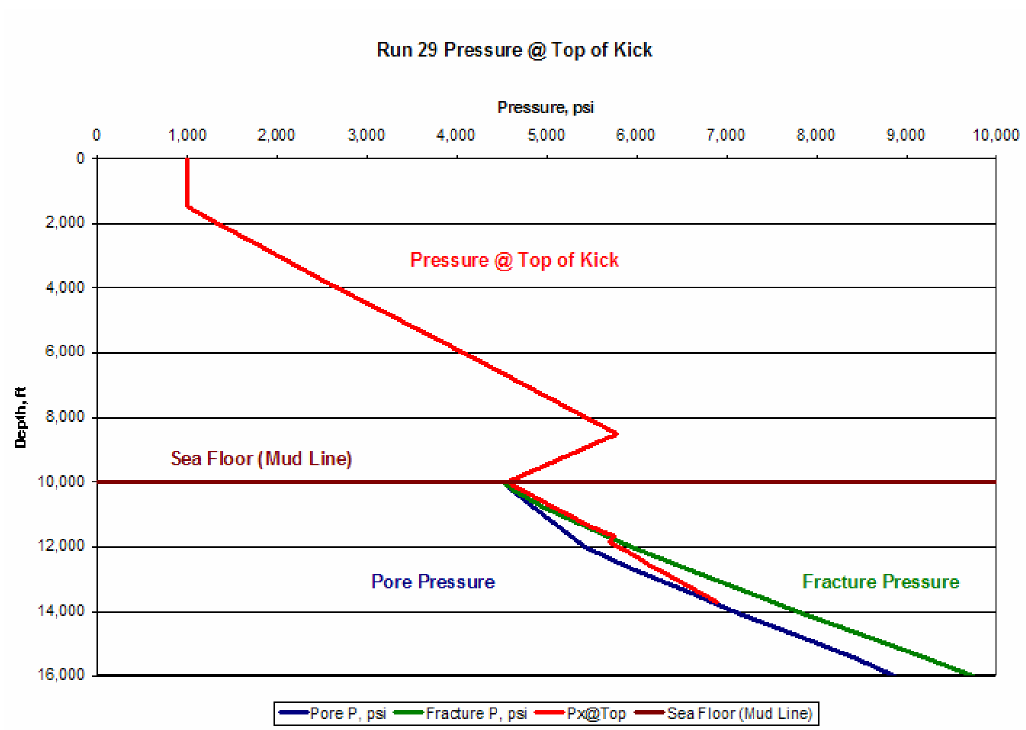

Fig. E29 – Pressure @ Top of Kick in Run 29

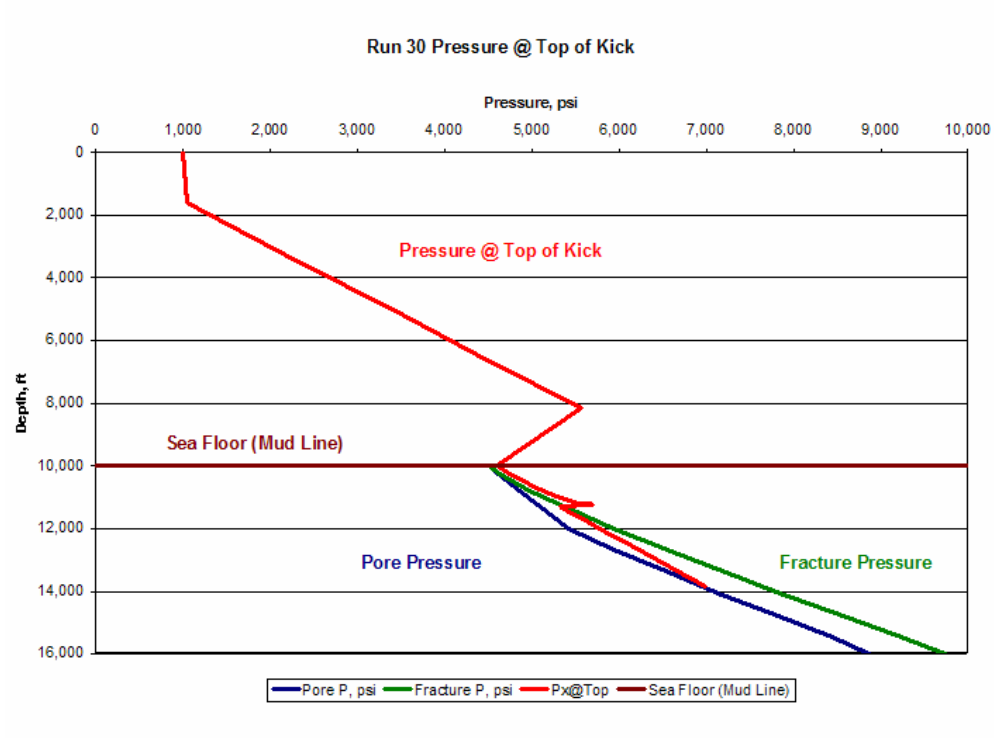

Fig. E30 – Pressure @ Top of Kick in Run 30

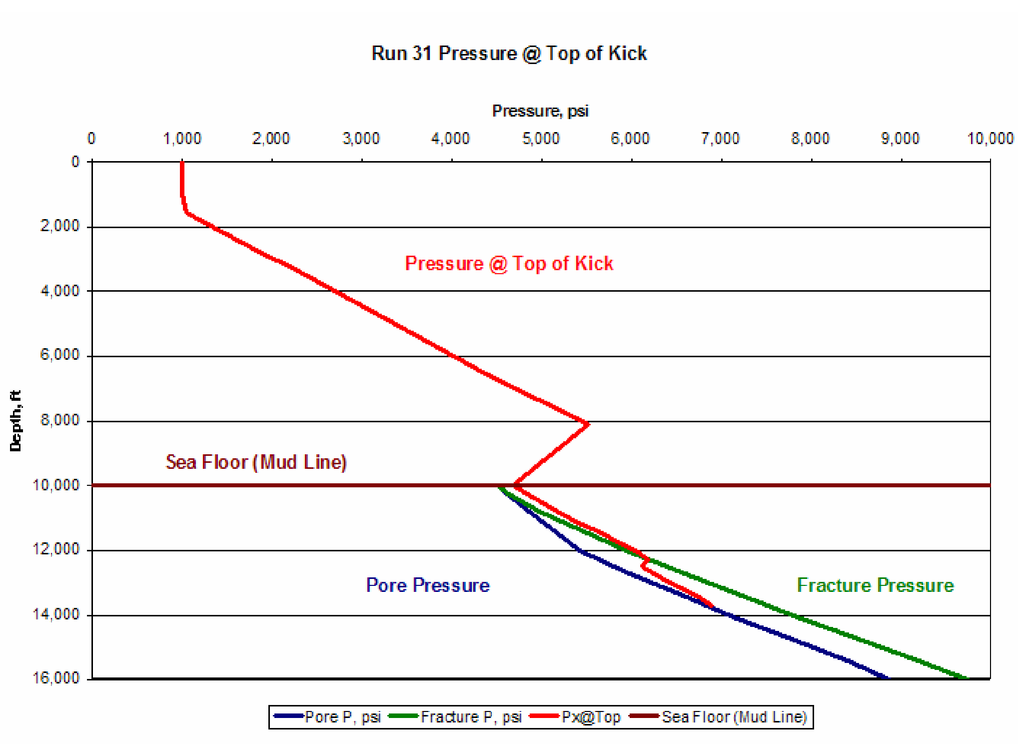

Fig. E31 – Pressure @ Top of Kick in Run 31

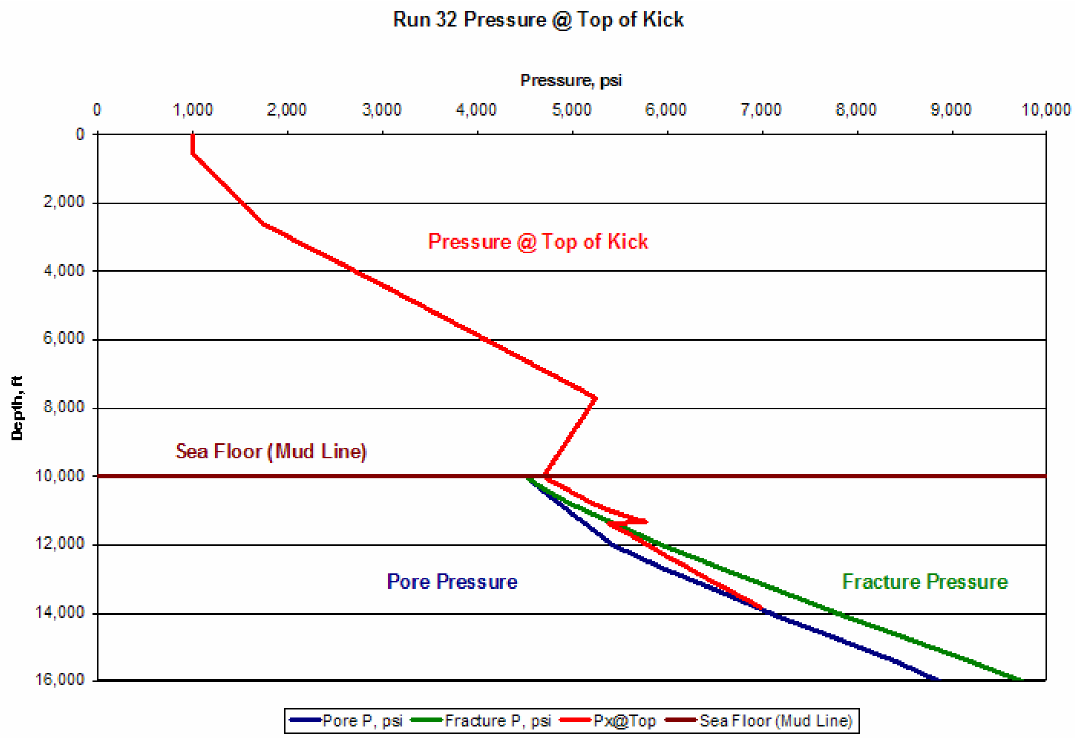

Fig. E32 – Pressure @ Top of Kick in Run 32

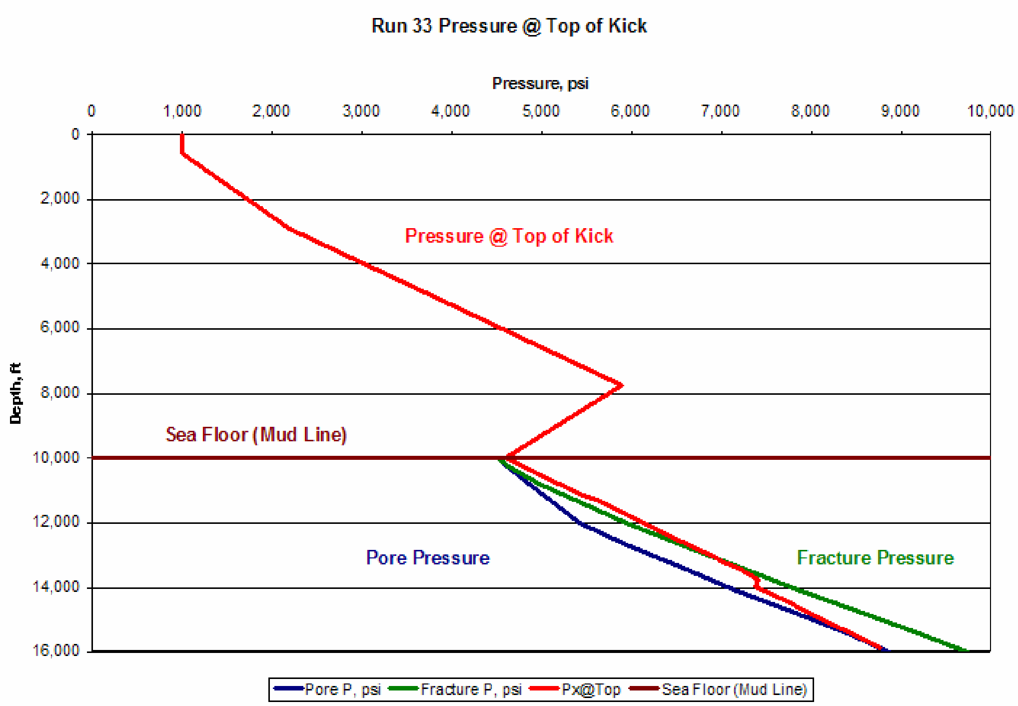

Fig. E33 – Pressure @ Top of Kick in Run 33

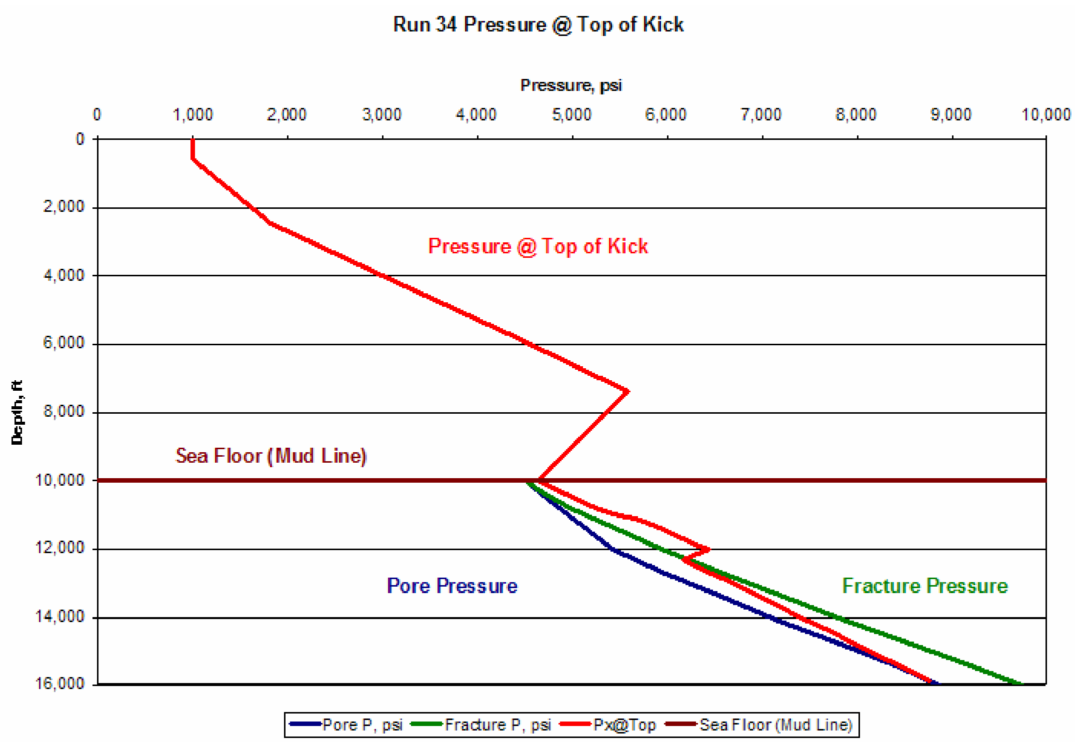

Fig. E34 – Pressure @ Top of Kick in Run 34

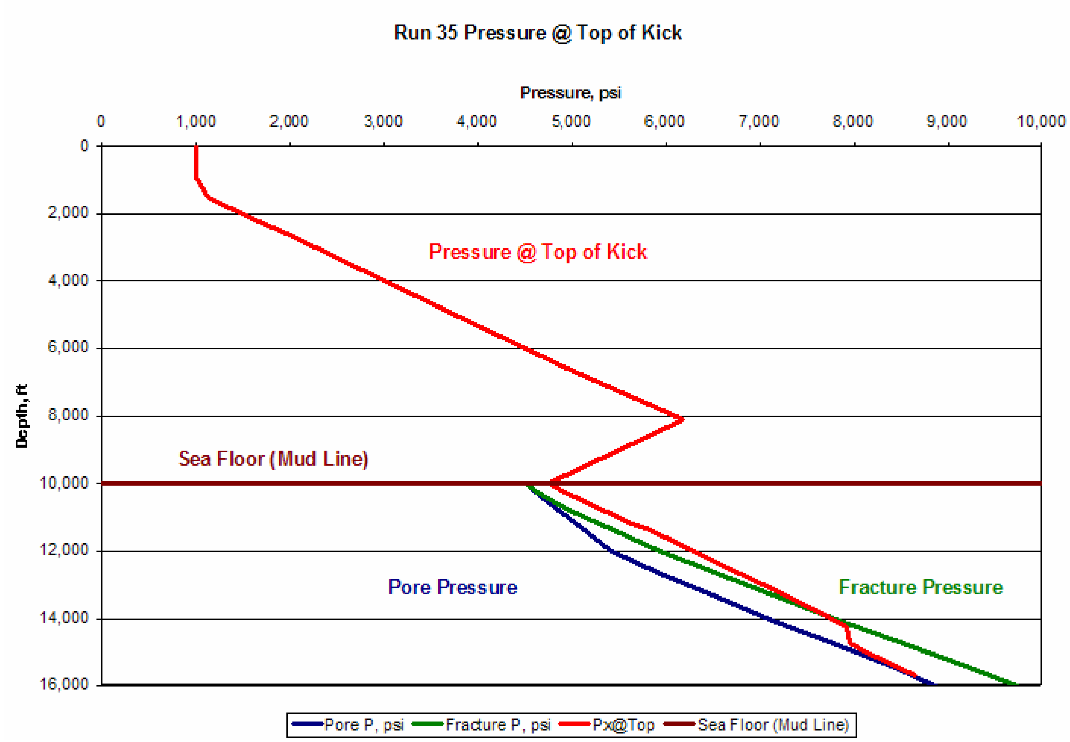

Fig. E35 – Pressure @ Top of Kick in Run 35

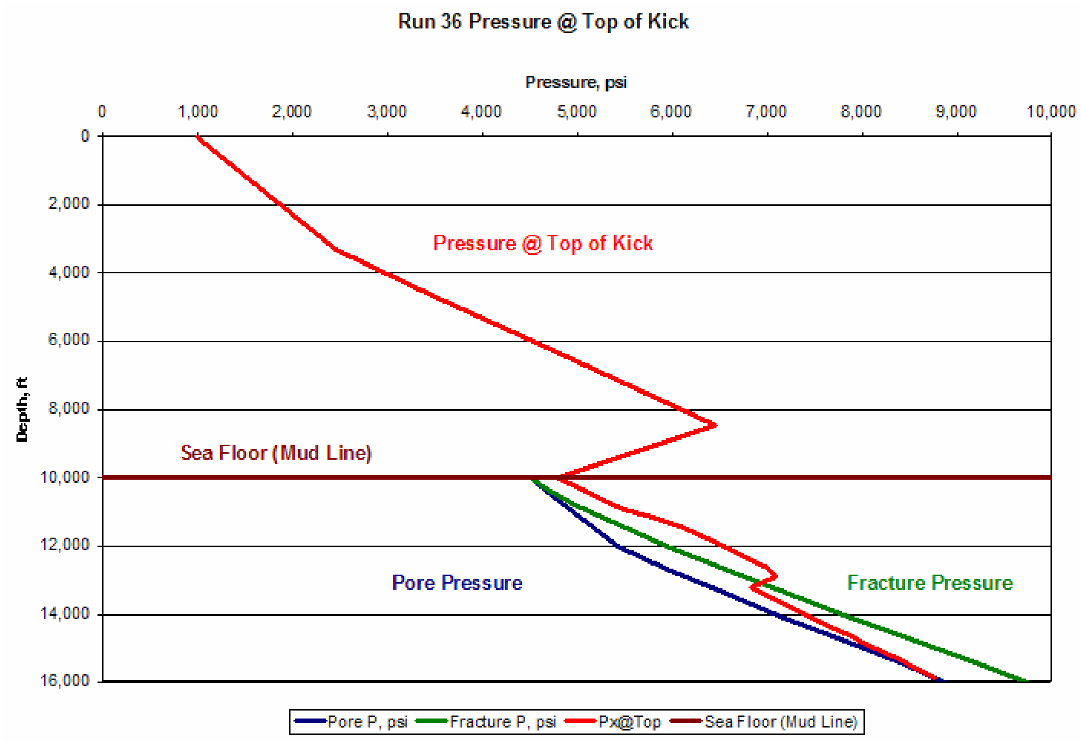

Fig. E36 – Pressure @ Top of Kick in Run 36

APPENDIX F

PRESSURE @ TOP OF KICK GRAPHS – SET #2

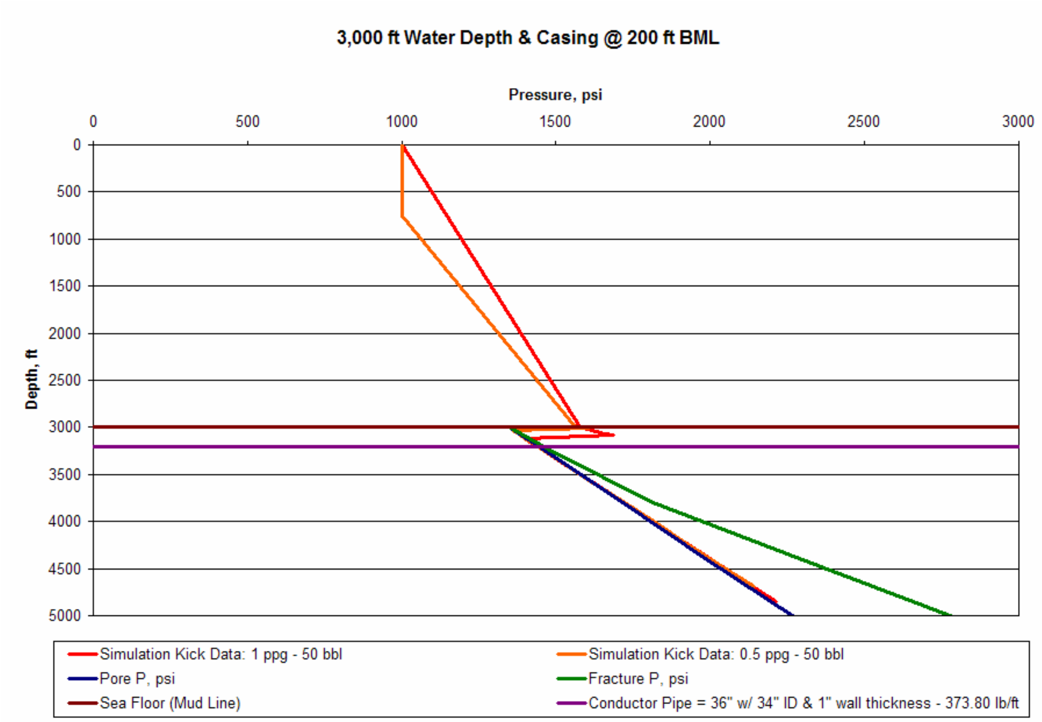

Fig. F1 – Pressure @ Top of Kick in Runs CS1a and CS1b

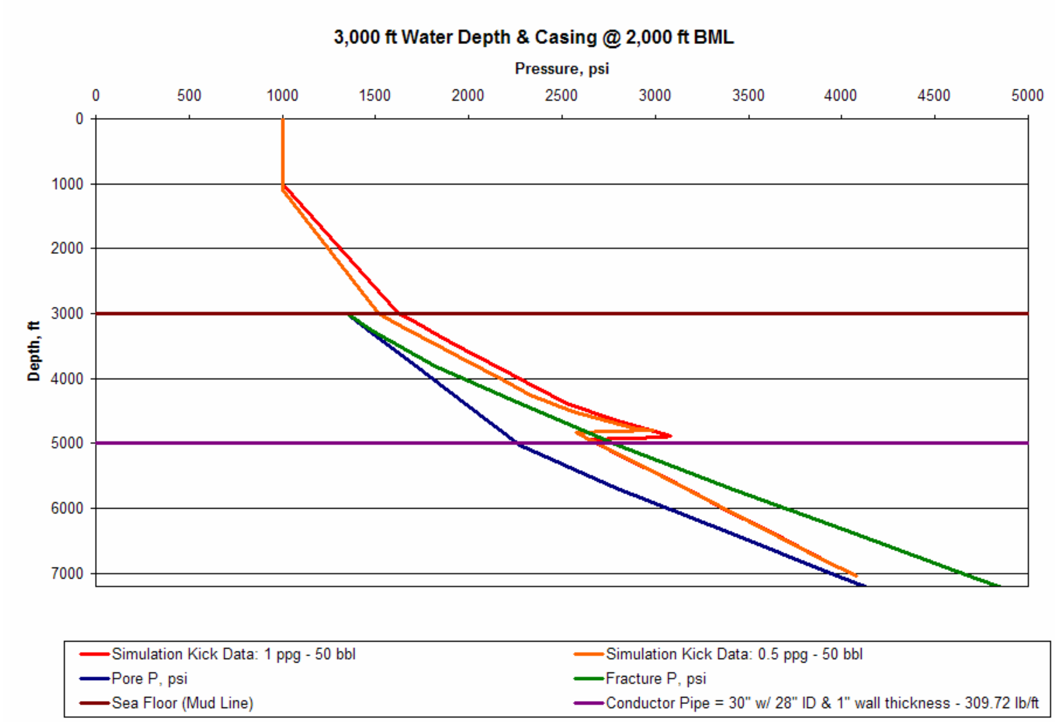

Fig. F2 – Pressure @ Top of Kick in Runs CS2a and CS2b

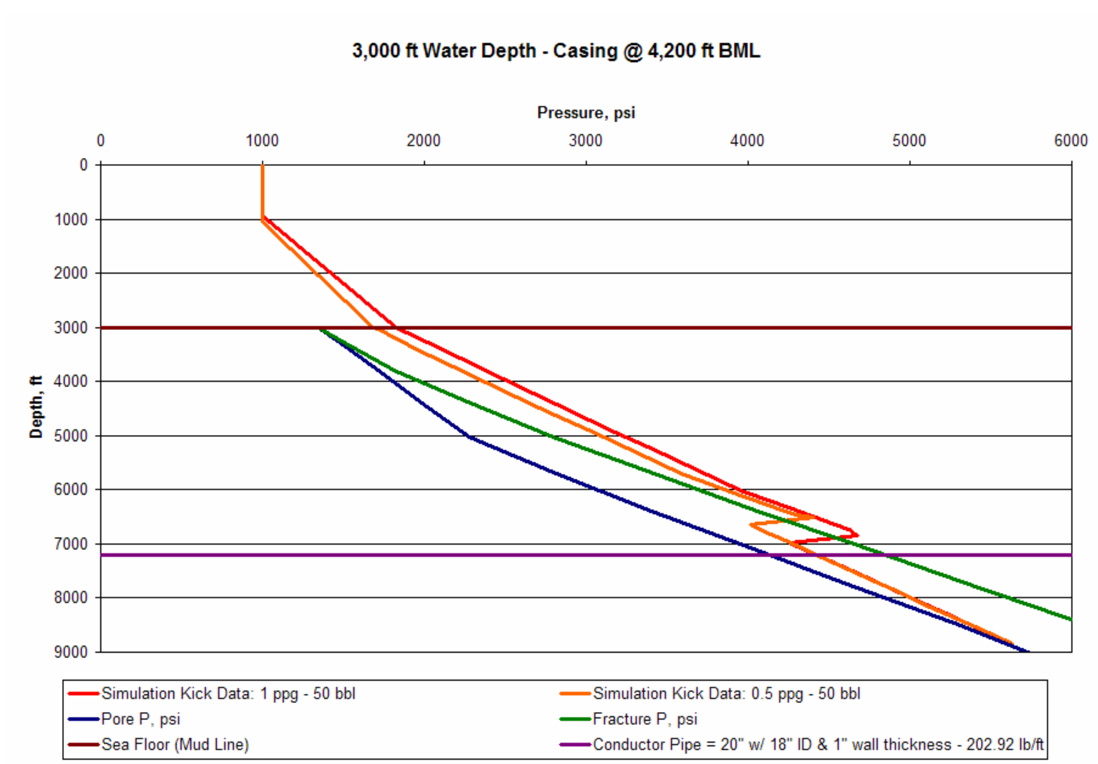

Fig. F3 – Pressure @ Top of Kick in Runs CS3a and CS3b

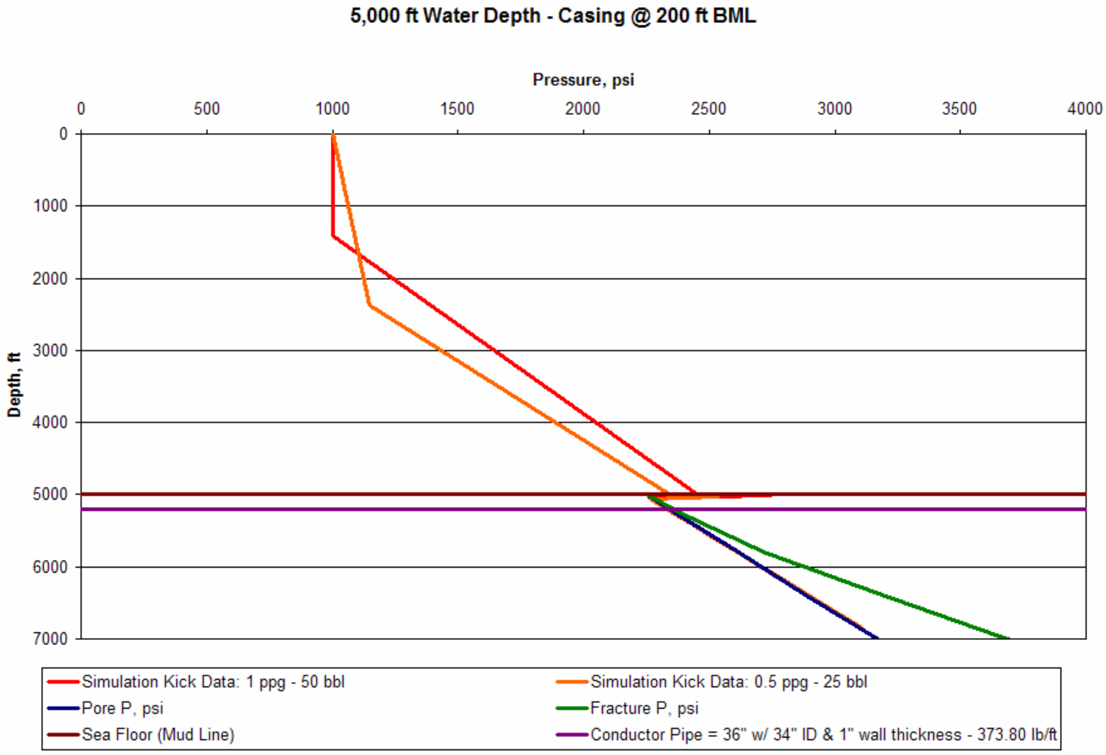

Fig. F4 – Pressure @ Top of Kick in Runs CS4a and CS4b

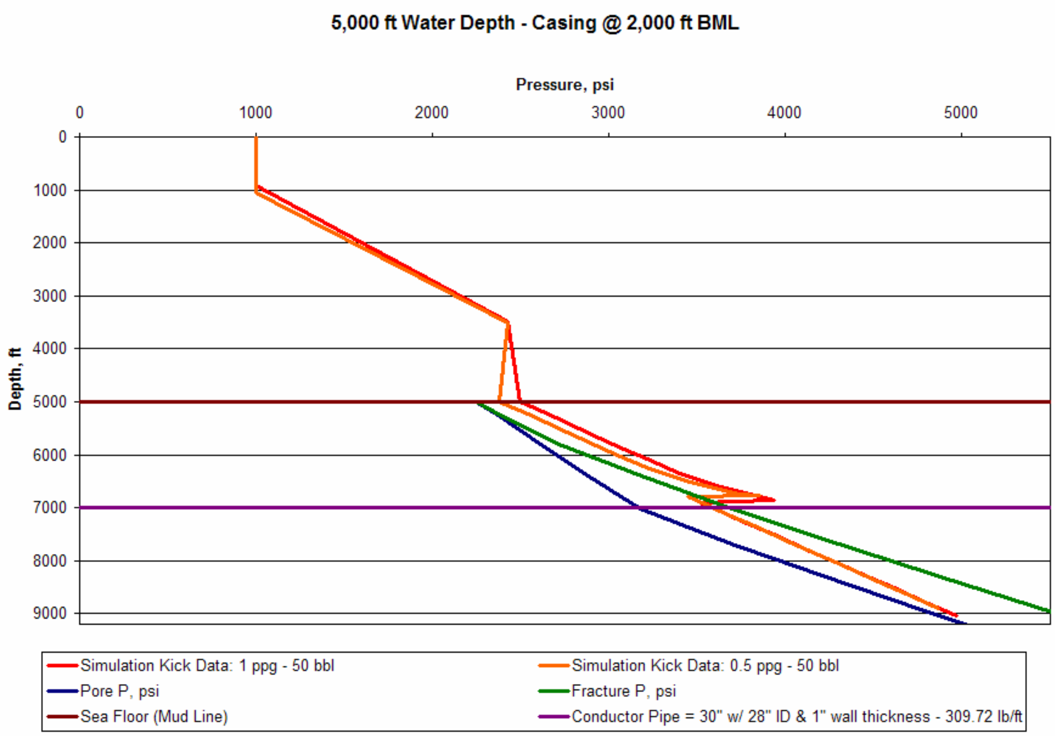

Fig. F5 – Pressure @ Top of Kick in Runs CS5a and CS5b

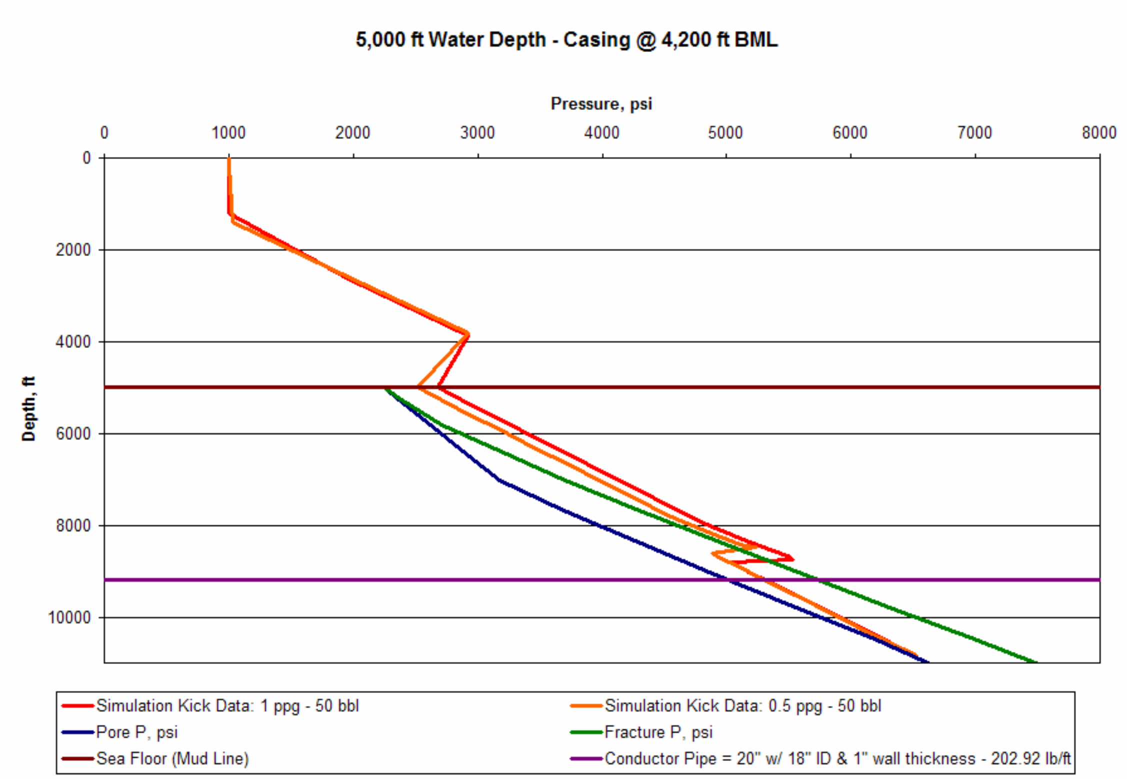

Fig. F6 – Pressure @ Top of Kick in Runs CS6a and CS6b

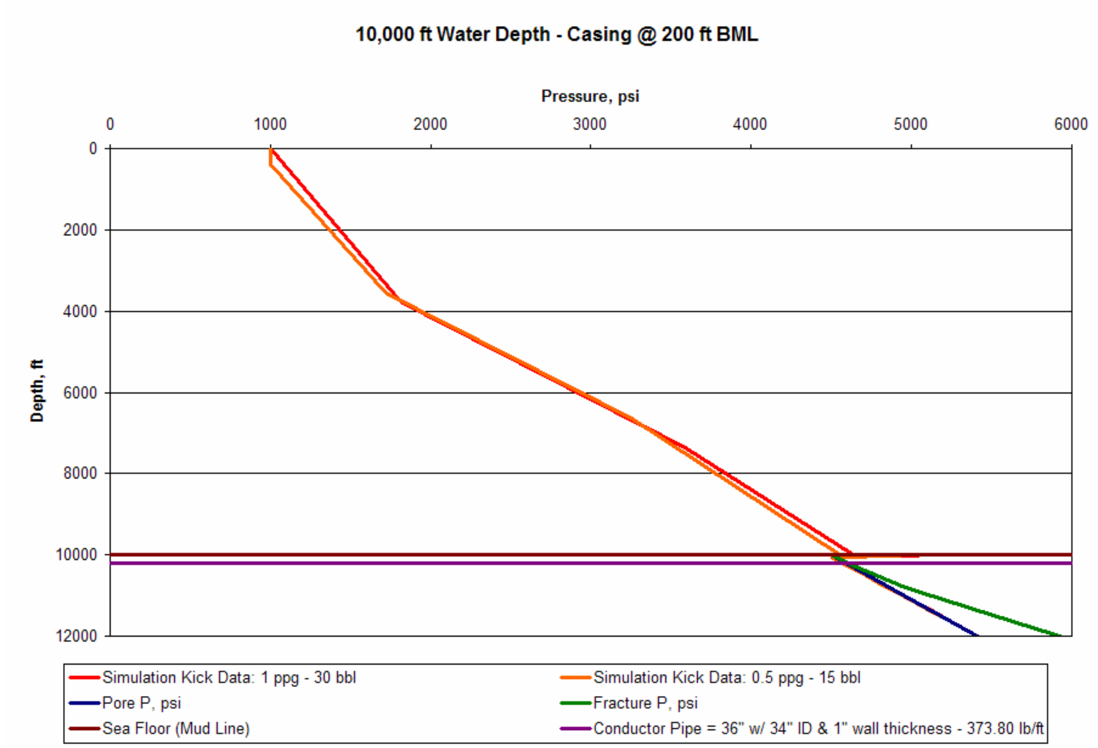

Fig. F7 – Pressure @ Top of Kick in Runs CS7a and CS7b

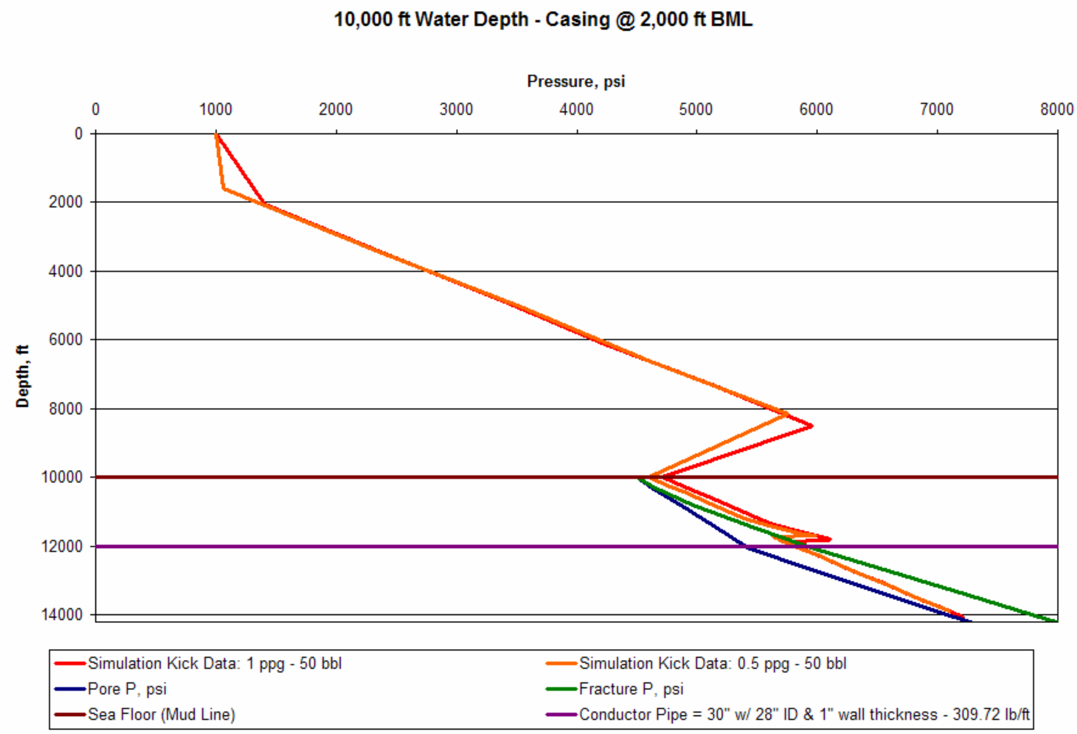

Fig. F8 – Pressure @ Top of Kick in Runs CS8a and CS8b

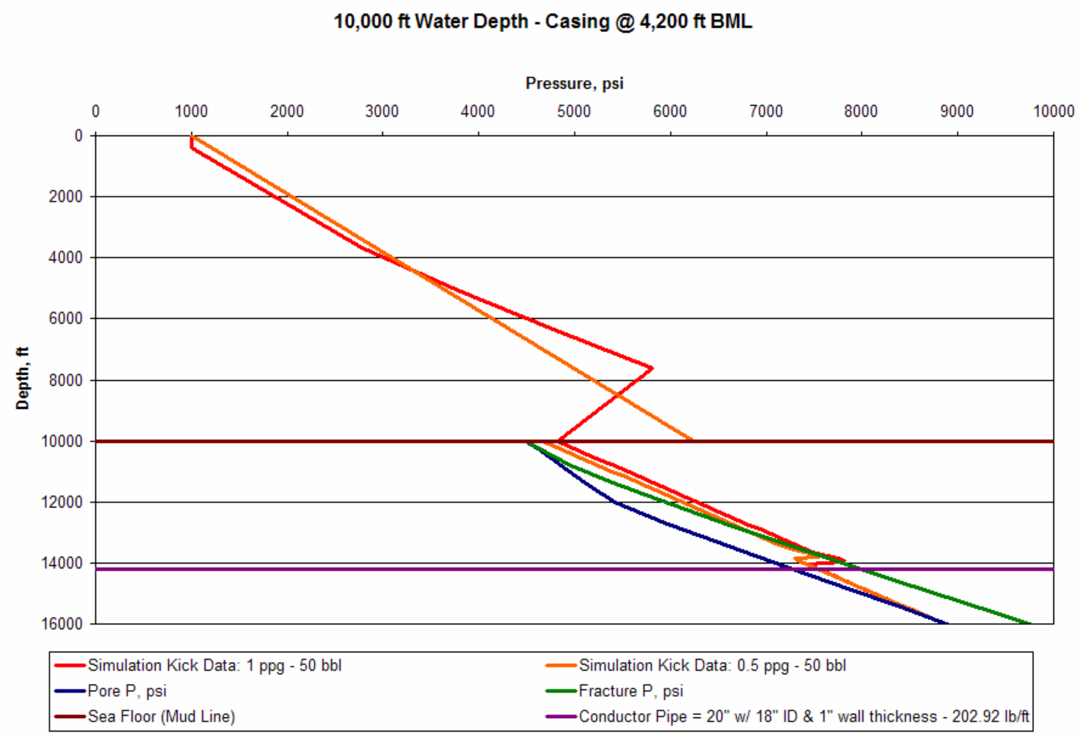

Fig. F9 – Pressure @ Top of Kick in Runs CS9a and CS9b

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Appendix B

Top Hole Dual Gradient Drilling System, Final Design Report, (May 2006) Amol Dixit and Chris Krueger, Department of Mechanical Engineering, Texas A&M University

Final Design Report

Top Hole Dual Gradient Drilling System

Prepared For

Mineral Management Services

Presented to:
Mineral Management Services
& Steve Suh, PhD

Prepared by:
Texas A&M University
Department of Mechanical Engineering

MEEN 685 – Spring 2006 – Section 604

Amol Dixit
Chris Krueger

May 2, 2006

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Glossary

The following terms are taken from the need statement, and required further definition to more clearly express the need.

Deep-Sea – This design will have to function in a marine environment with high pressure, low temperature, sub-sea currents, ecological considerations, differing water compositions, and must be mindful of local geology and geography.

Drilling Package – This is the system used to drill the hole through the ocean floor, including the extra equipment needed or to be discarded to perform the need, such as a power source, risers, valves, pumps, and/or new redesign of current equipment, such as the BOP, etc.

Top Hole Dual Gradient (THDG) Technology – Dual Gradient drilling technology involves drilling with a mud hydrostatic pressure gradient below the mudline, with a seawater hydrostatic pressure gradient in the riser above the mudline. Currently, Dual Gradient drilling technology is not able to be used in drilling operations for the first two layers of casing, including the structural and conductor casing strings.

Petroleum Well-bores – A sub-surface drilled hole concentrically encased in a series of fabricated casings and filled cement that is subject to extreme pressures, temperatures, and corrosive environments, for the extraction of petroleum. Casing is set based on the envelope provided between the pore and fracture pressure of the surrounding reservoir.

Optimal Amount of Materials – Currently, in order to drill deeper holes, larger rigs and equipment are needed to overcome the huge stresses and pressures involved. If THDG is employed, some of the equipment may be able to be designed at a smaller scale, thus saving money and material, and increasing the operable range of drilling operations.

Integration – It is reasonable to conclude that any THDG system will be best implemented if it can be easily integrated to the fullest extent possible with existing drilling packages.

Interface – Each component of the system (BOP, pump, wellbore, etc.) must be able to interface with adjoining components effectively and efficiently, so as to provide for continuous mud-return with minimal losses throughout the entire system.

Current Capacity – Offshore drilling is capable now of drilling in 12,000 feet of water.

Introduction

Dual Gradient drilling began with Shell Oil company's Marine Technology Group in the 1960's with their "3000 ft. Feasibility Study", where the beginnings of some of this technology were first conceptualized. In 1996, Conoco, Hydril, and 23 other companies conducted a "Riserless Drilling Feasibility Study", followed by the 1997 "Gas Lift Feasibility Report" conducted by Petrobras and LSU.

Currently, several projects are underway that in some way relate to Dual Gradient technology. One such project is Deep Vision, which is a collaborative effort amongst Baker-Hughes, BP, Chevron, and Transocean. This project utilizes a subsea centrifugal pump to circulate the mud through a mud-return line back to the drilling platform, which is then pumped back down the hole to circulate drilling products. Another project utilizes a sub sea pump to pump the mud back up the riser.

Mineral Management Services (MMS), would like to explore other methods of Dual Gradient technology, specifically a method or design which would implement Top Hole Dual Gradient technology, in which a dual pressure gradient would be employed when drilling the first two intervals of a petroleum well. It is hoped that such a system will make sub-sea drilling operations more efficient, less costly, and faster.

MEEN 632 was given the task of designing the mud-return system for THDG, including the pumping system, power source, and mud-return, among other things, in the Fall of 2005. 3 teams developed several concepts and presented final designs to MMS for those specific aspects of THDG assigned to MEEN. These designs were met with great enthusiasm, and it was desired that Mechanical Engineering continue it's work and develop the design of THDG further to include designing the THDG system below the wellhead, to include redesigning the casing structure for the different pressure gradient, among other variables, and providing specific interfaces between the wellhead and the pumping system and the drilling vessel, so that continuous mud-return throughout the entire system might be possible. MEEN expects to have developed and presented conceptual designs and a final design of this task to MMS by May of 2006.

Need Statement

Upon initially reviewing the problem and accompanying material, the team began to immerse themselves in the knowledge of deep-sea petroleum drilling to better understand the situation in which the problem was presented. After gaining a deeper understanding of the material, the team was able to apply that knowledge to the need presented, and the following need statement was developed:

"There is a need for a deep-sea drilling package that utilizes Top Hole Dual Gradient Technology to safely drill petroleum wellbores at a depth to exceed current capacity using an optimal amount of materials."

Another need statement developed by another team member covered other principles not covered by the above need statement.

"There is a need to design a system of device enabling the use of Top Hole Dual Gradient Technology, providing mud return, and enabling the ease of integration with the existing drilling rig equipment."

Additionally,

"There is a need for the development of a Top Hole Dual Gradient system for deep sea drilling and unobstructed path for mud return."

It was felt that all need statements covered points that should be included in a final need statement, from general descriptions to specific functions, which led the team to simply combine the need statements. This yielded the teams final need statement.

"There is a need for a petroleum well-bore design and corresponding interfaces with the mud-return pump and drilling vessel for a deep-sea drilling package, utilizing Top Hole Dual Gradient Technology to safely drill for petroleum at ocean depths exceeding current capacity using an optimal amount of material, while providing for maximum integration with the existing drilling package."

Function Structure

There is a need for a petroleum well-bore design and corresponding interfaces with the mud-return pump and drilling vessel for a deep-sea drilling package, utilizing Top Hole Dual Gradient Technology to safely drill for petroleum at ocean depths exceeding current capacity using an optimal amount of material, while providing for maximum integration with the existing drilling package.

Function 1

Maintain a regulated pressure differential between sea water and drilling mud

Function 2

Provide an unobstructed mud return path.

Function 3

Provide interface through the well-bore, BOP, and the pump.

Function 4

Provide interface between mud-return line and drilling vessel.

Function 5

Provide for a well-bore capable of integrating and operating efficiently with a dual gradient drilling system.

Figure 1: Primary Function Structure

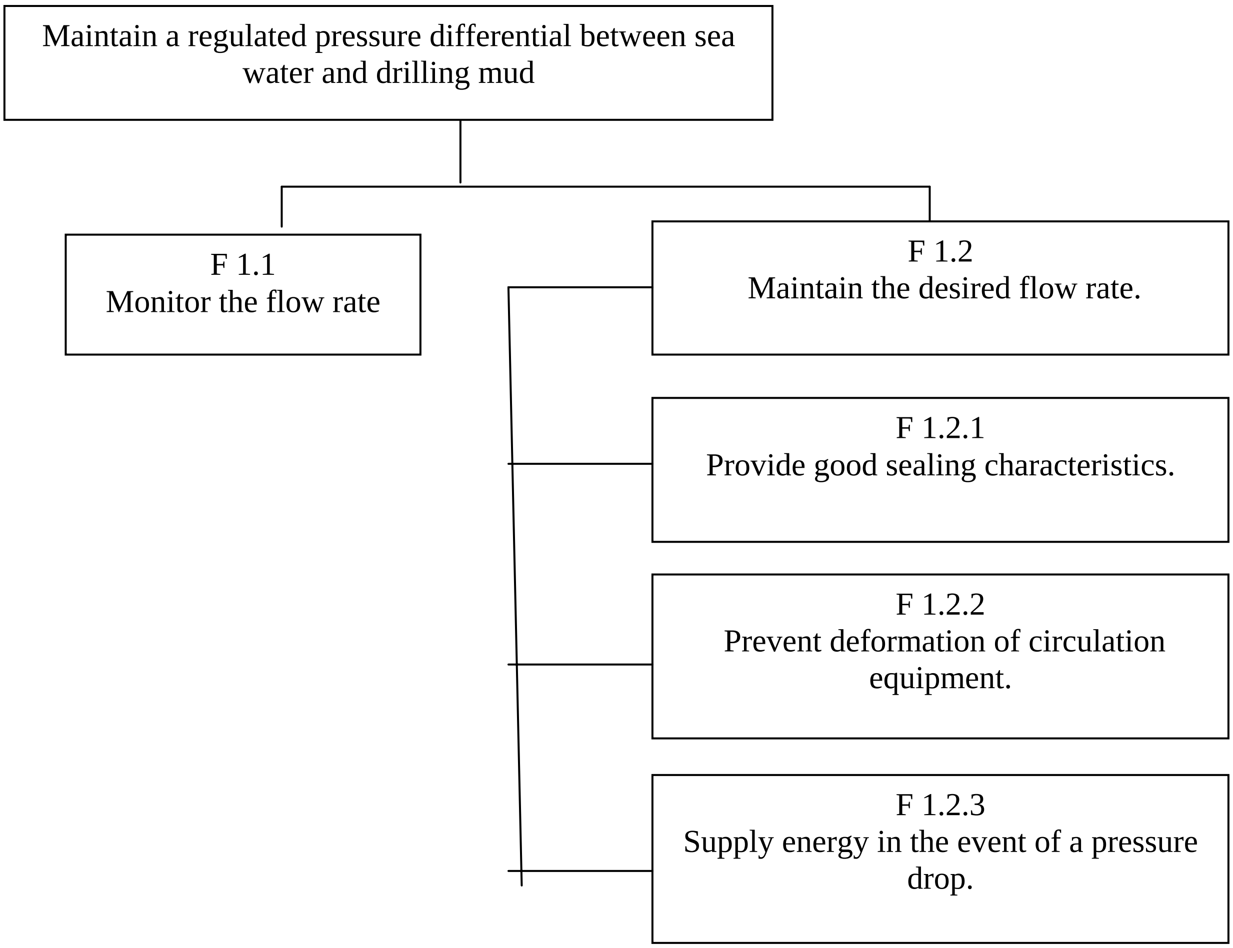


Figure 2: Function 1

Table 1: Function 1 – Design Parameters and Constraint Requirements

Function number	**Design Parameter**	**Constraint Requirement**
1.1	Flow velocity.	Maximum Allowable Pressure Difference
1.2.1	Drilling Mud Pressure	Material of seal
1.2.2	Strain	Maximum Allowable Strain, Material
1.2.3	Power	Capacity of power supply

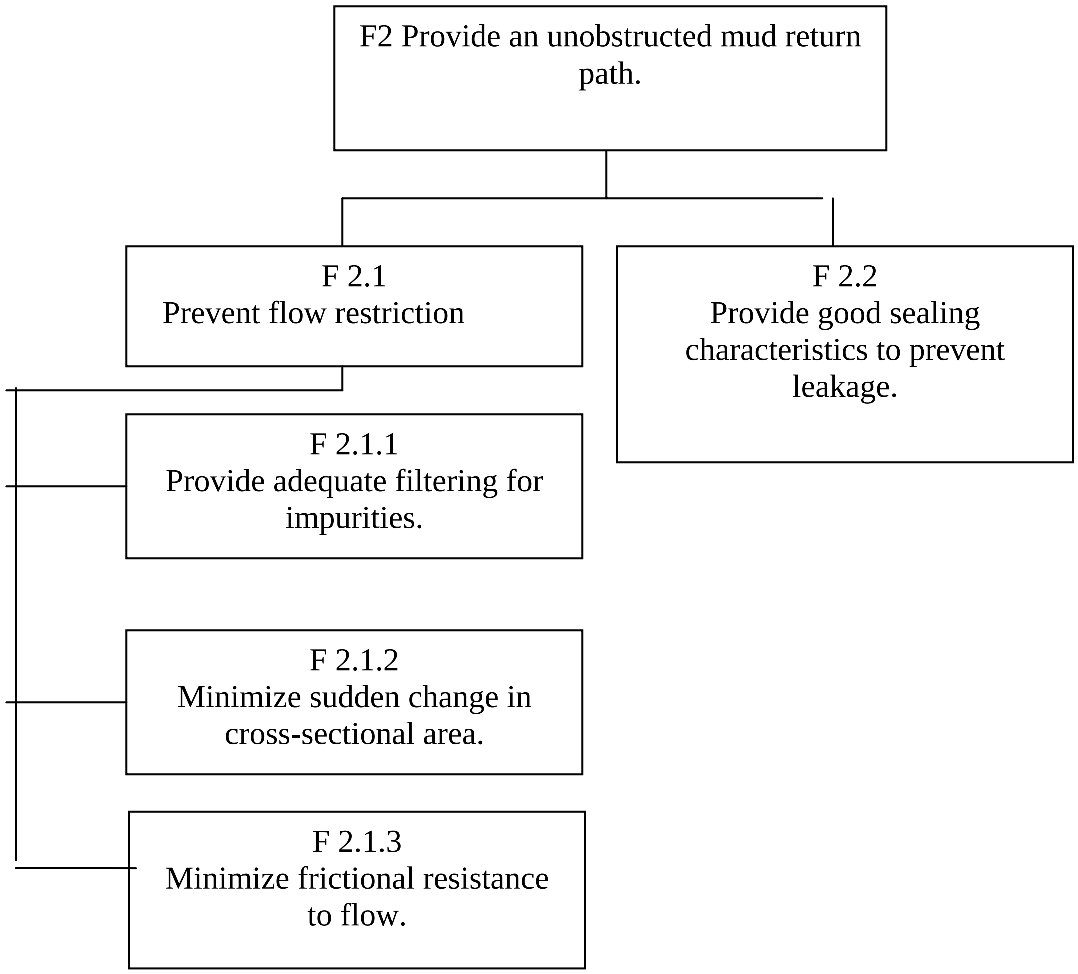


Figure 3: Function 2

Table 2: Function 2 – Design Parameters and Constraint Requirements

Function number	**Design Parameter**	**Constraint Requirement**
2.1.1	Size of impurities	Maximum permissible size
2.1.2	Diameter	Tolerance
2.1.3	Surface Finish	Manufacturing process
2.2	Drilling Mud Pressure	Material

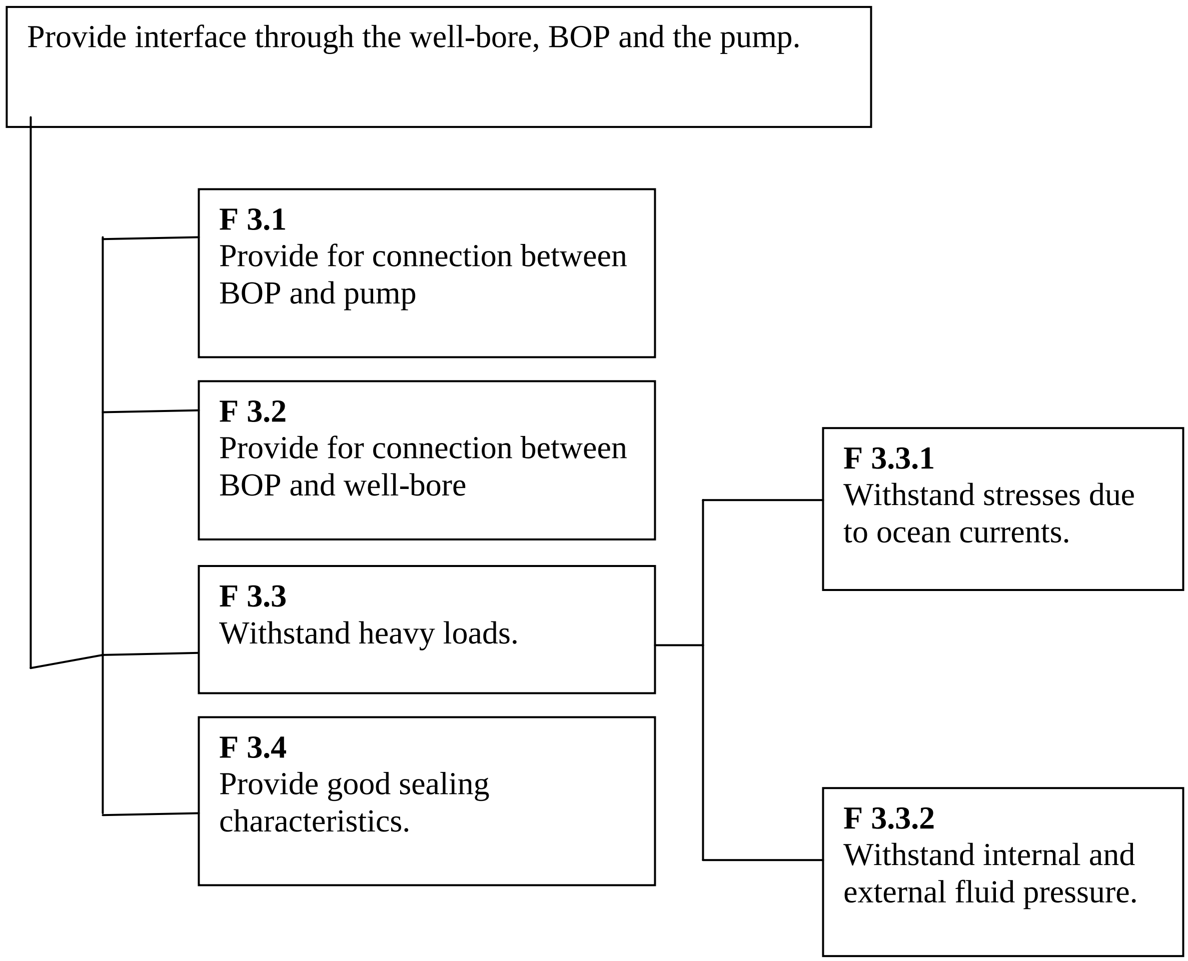


Figure 4: Function 3

Table 3: Function 3 – Design Parameters and Constraint Requirements

Function number	**Design Parameter**	**Constraint Requirement**
3.1	Connection type.	Permissible linear and angular misalignment.
3.2	Connection type.	Sealing capability, misalignment, size
3.3.1	Stress, Tension.	Size, Material.
3.3.2	Pressure.	Maximum allowable pressure.
3.4	Type of seal.	Material of seal.

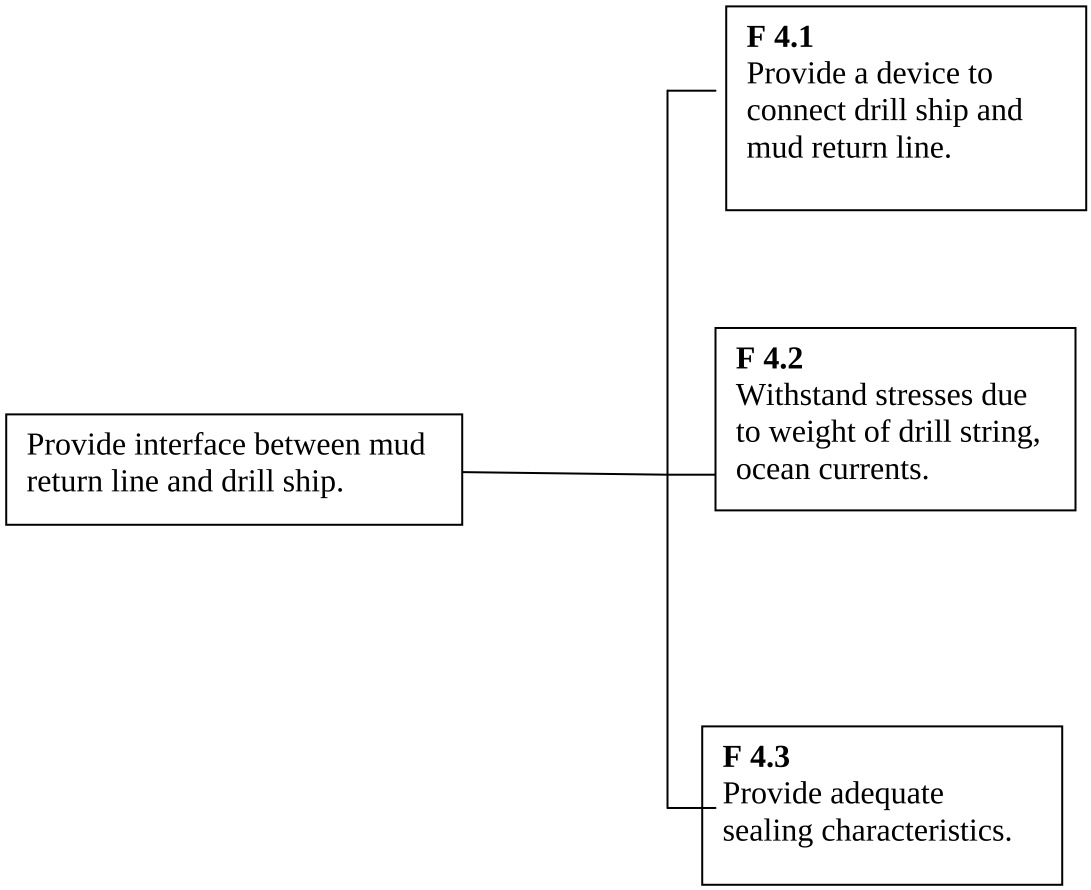


Figure 5: Function 4

Table 4: Function 4 – Design Parameters and Constraint Requirements

Function number	Design Parameter	Constraint Requirement
4.1	Connection type.	Permissible angular and linear misalignment.
4.2	Stress due to weight of drill string, tension and ocean currents.	Permissible stress level.
4.3	Type of seal, Clamping Pressure.	Material of the seal.

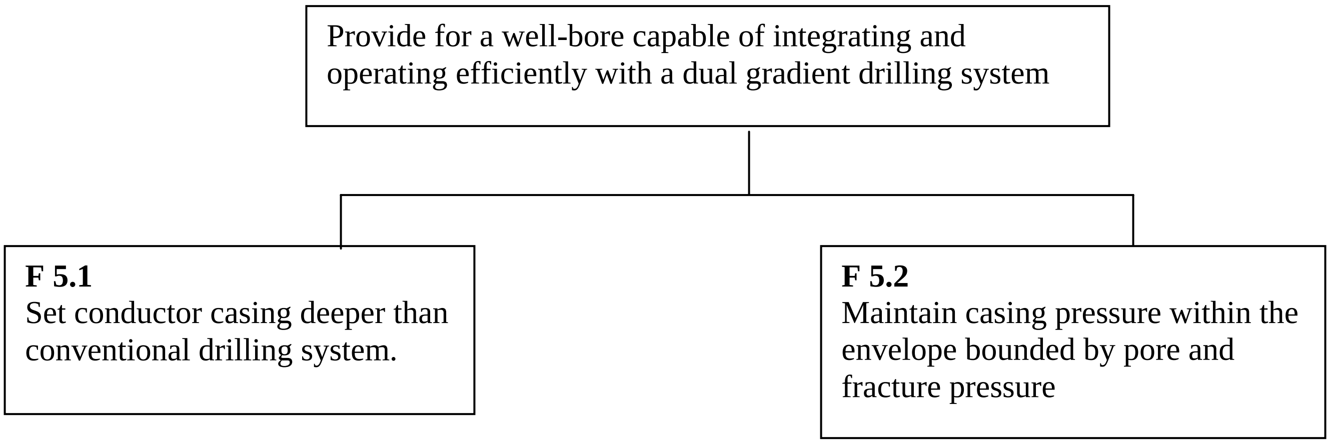


Figure 6: Function 5

Table 5: Function 5 – Design Parameters and Constraint Requirements

Function number	Design Parameter	Constraint Requirement
5.1	Conductor casing size	Optimum mud pressure
5.2	Stress, return line pressure	Size, Material, permissible stress level.

Overall System Description

Drilling fluid, or mud, is introduced to the system on the drilling vessel through the drillstring. The mud then flows down the drill string and through the drill bit as it is drilling, acting as a lubricant and coolant, as well as helping to wash particulate matter among other things away from the drill bit. After passing through the drill bit, the mud then floods the well-bore rises up around the drill string to the blow out preventer, or BOP. The mud is then diverted to undersea pumps that pump the mud up mud-return lines to the drilling vessel.

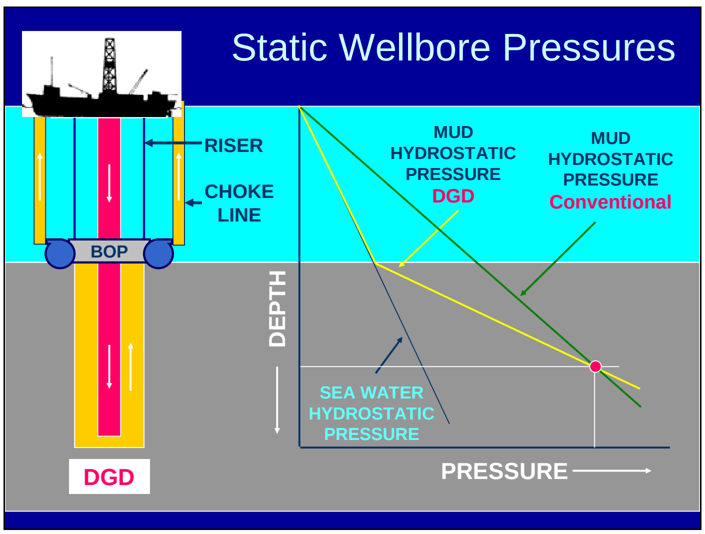


Figure 7: Dual Gradient Technology

This concept is known as dual gradient technology, because instead of using one pressure gradient as mud travels down the drillstring and back up around the drillstring and inside a riser all the way back to the drilling vessel, 2 gradients are used: an equivalent mud density below the BOP, and the hydrostatic water pressure above the BOP. This is important because as the hole is drilled, casing is set at certain intervals in the hole to prevent the hole from collapsing in on itself. Using dual gradient technology, the casing can be set at deeper intervals, and fewer casing sets are needed in most cases. Additionally, cement is poured around the casing in order to prevent fluid from seeping below the casing, which can cause fluctuations in formation pressure and floating of the casing.

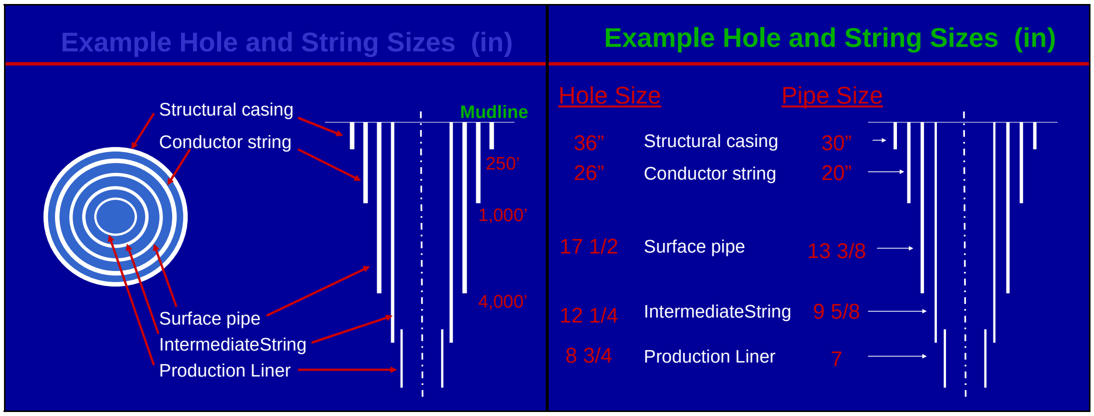


Figure 8: Casing Sizes and Depths

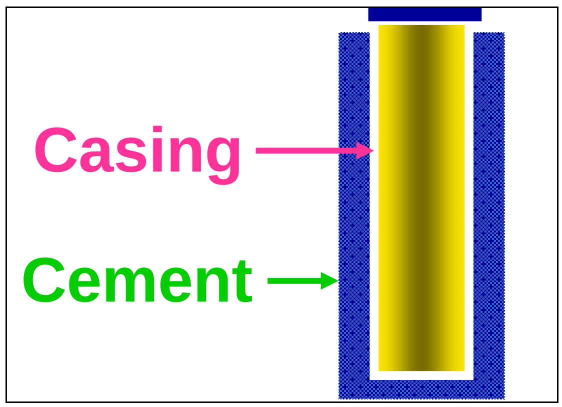


Figure 9: Casing with cement

Concept 1 – Conventional Casing with Rotating Diverter

This design utilizes conventional casing techniques and existing standardized casing, but with dual gradient technology employed. The dual gradient allows conventional casing to be set at deeper intervals, and with fewer sets of casing. This design was selected primarily because the components to be used have been tested and utilized in drilling environments for a number of years, and are reliable in their implementation. These components, because they are already in use, are also cheaper and more readily available, and their manufacture would prove much easier than the hollow or tapered casing concepts. The hollow concept, while providing a method for fluid separation from the drill string prior to the BOP, would be difficult in manufacture because of the long channels needed through the casing, and also the potential of particulate matter to become lodged in those channels. In such a situation, it would be nearly impossible to remove them. The tapered concept might have provided a way to increase the depth that each level of casing could service, and may even require fewer levels of casing, but there were issues brought up as far as problems regarding the installation of a tapered casing while drilling, and drilling procedures required for installation as well. In the end, as stated before, it came down to the concept which represented cheaper components that were easily manufactured and more readily available commercially.

Casing prevents collapse of the well-bore during drilling and hydraulically isolates the well-bore fluids from the subsurface formations and formation fluids. The average cost of casing is 18% of the average cost of the total well[10]. The selection of the quantity of casing strings and their respective setting depths generally is based on a consideration of an envelope created by the pore and fracture pressure gradients. A graphical method[10] is usually used to determine the casing intervals.

The method for determining mud density and casing setting for a conventional drilling system is shown below. The required mud density can be found from the following graph. This example, using pore and fracture pressure from Jefferson Parish, LA, illustrates that to achieve a desired depth of 15,000 feet below ground, the point at the pore pressure should be selected.

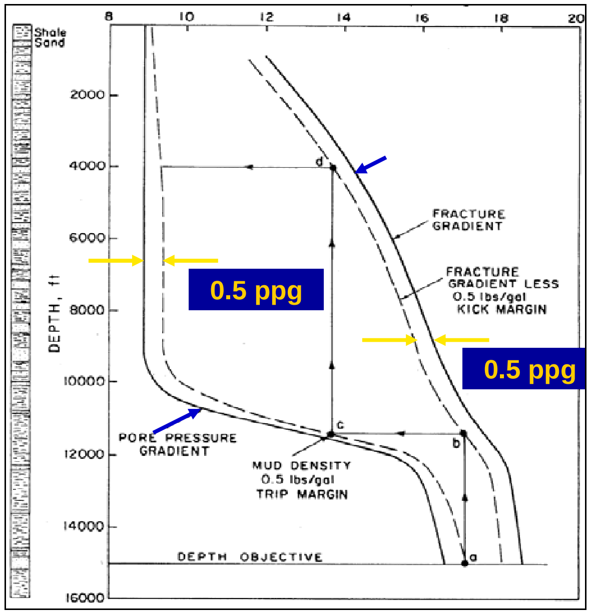


Figure 10: Example Pore/Fracture Pressure w/ Conventional Casing Setting

This point, point A in this example, corresponds to the mud density that should be used, 17.2 ppg, as shown on the top x-axis. Notice there is a 0.5 lb per gallon safety margin between the pore and fracture pressures. This is so the casing structure does not fail during a potential "kick" or "trip", where huge pressures are released unexpectedly as ancient pockets of gas are evacuated during drilling. When using pore and fracture pressure data, these margins should be used.

Casing is also set using this same graphical method. The production liner casing runs from the BOP to the bottom of the well at point A. It ranges in diameter from 4.5 to 9.625 inches. The diameter is determined from the desired amount of production from the hole, and then from the size drill bit needed to drill that hole. The drill bit must fit through the casing, as the most shallow casing is set first, and each level of casing afterwards is set one level deeper. Using the above graph, a line is vertically drawn from point A until it meets the fracture pressure gradient. This is point B, and the corresponding depth, at 11,400 feet, is the depth to which the next level of casing surrounding the production liner, called intermediate casing, should be set. This casing ranges in diameter from 7.625 to 13.375 inches. From point B, a straight line is drawn horizontally to the pore pressure. This is point C. Another vertical line is then drawn until the fracture pressure gradient is reached. This is point D. This depth, at 4,000 feet, is the depth at which the next level of casing, surface pipe, is set. Surface pipe is usually set between 2,000 and 4,000 feet, and ranges from 8.625 to 20 inches in diameter. If deeper casing is needed in particular situations, more intermediate casing is used. The next levels of casing are traditionally not determined by any method, they are merely taken as a standard for most all well bores, because the pressures at these depths are not overwhelming yet. Conductor casing is the next level of casing, and it is usually run to between 300 and 1,600 feet, and can range from 16 to 48 inches in diameter. Structural casing is the largest casing, laying on the outside of the well bore. It is usually run to between 150 and 300 feet, and can range from 16 to 60 inches in diameter.

However, because DG technology is to be analyzed, a different graph must be used. Instead of using the above graph, a plot of pressure as a function of depth must be used. To do this, the pore and fracture pressure information must be converted from ppg to pressure, which is done using the equation $P = 0.052\rho h$, where ρ is the mud density found from the above graph and h is the depth.

The dual gradients in DG drilling refer to the hydrostatic pressure gradient above the well head, and an equivalent mud density. The hydrostatic gradient is found merely by using ρgh from the ocean surface to the sea floor, with ρ being the sea water density. The equivalent mud density is found by drawing a gradient from the hydrostatic curve to the conventional mud gradient. The conventional mud gradient is found by using ρgh from the ocean surface to the desired drilling depth, with ρ being the mud density found from the procedure mentioned above.

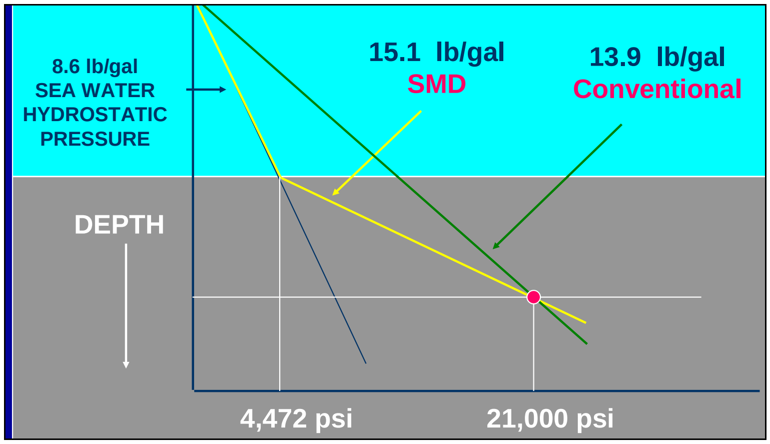


Figure 11: Conventional and Dual Gradients

Once the gradients have been found, it is then possible to do the analysis for casing setting. After converting graphs from ppg to pressure, it is possible to set casing for both DG and a conventional method using the method described below. A sample plot of a conventional gradient with pore and fracture pressure data is given below. A graphical method is employed here as well to set casing intervals. The production liner casing runs from the ocean floor to the bottom of the hole, as in all cases. The intersection of the conventional gradient and the fracture pressure gradient is selected as the first level of casing. From the ocean surface to this point is the intermediate casing. From this level, a horizontal line is drawn to the intersection of the pore pressure. Another line is then drawn from this intersection to the ocean surface level at 0 pressure. It is the intersection of this line and the fracture pressure that determines the next level of casing.

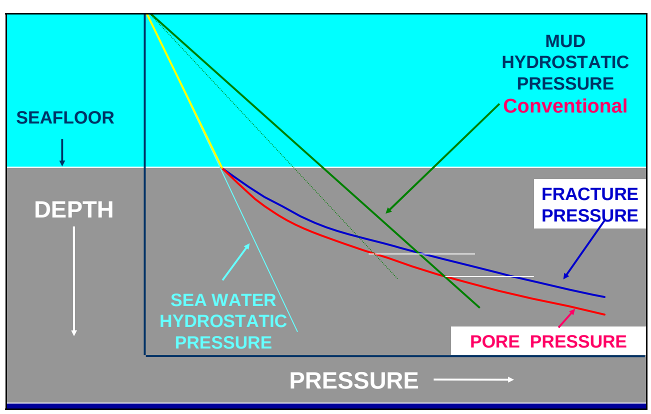


Figure 12: Conventional Casing Setting 1

This method is repeated continuously until the casing level is less than approximately 4,000 feet, where surface pipe casing is then laid, and pore and fracture pressure data is somewhat neglected. The finished process is shown graphically below.

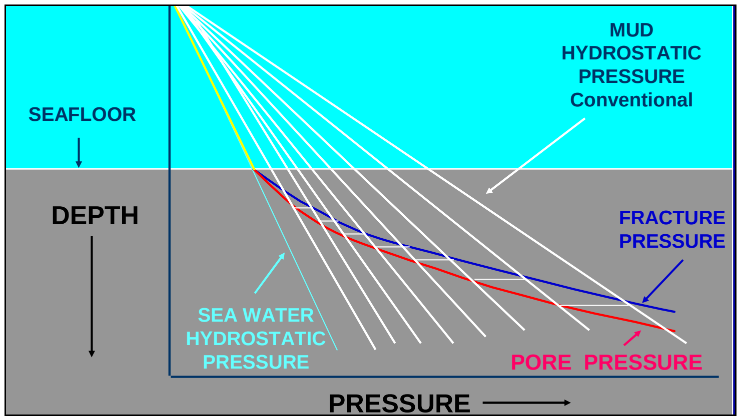


Figure 13: Conventional Casing Setting 2

DG drilling utilizes two gradients: a hydrostatic gradient above the well head, and an equivalent mud density gradient from the well head to the bottom of the hole. These gradients are shown in the graph below.

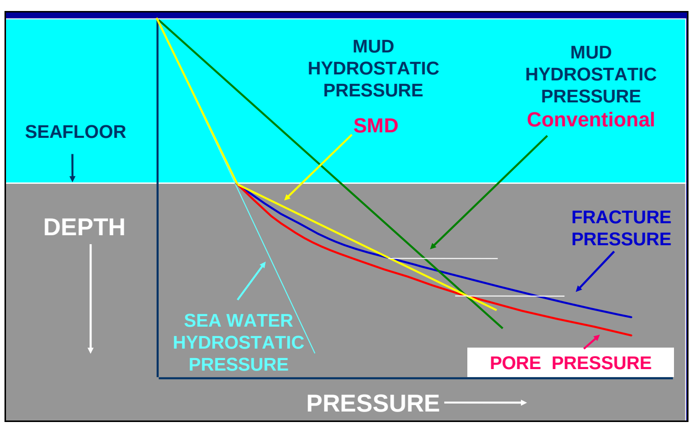


Figure 14: Dual Gradient Casing Setting 1

The same method as above is used, however with two key differences. While the intersection of the conventional gradient and the fracture pressure gradient is used in a conventional set up, DG drilling uses the intersection of the equivalent mud density gradient and the fracture pressure gradient. The second difference is that while in conventional drilling the casing lines are drawn from the ocean surface, DG drilling casing lines are drawn from the well head. This is shown graphically in the figure below.

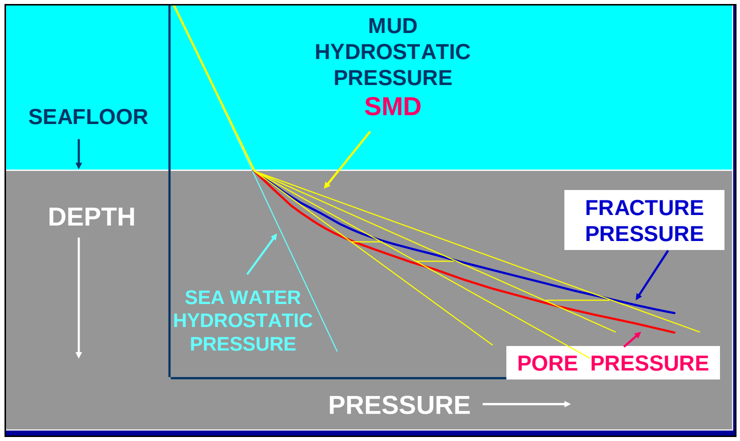
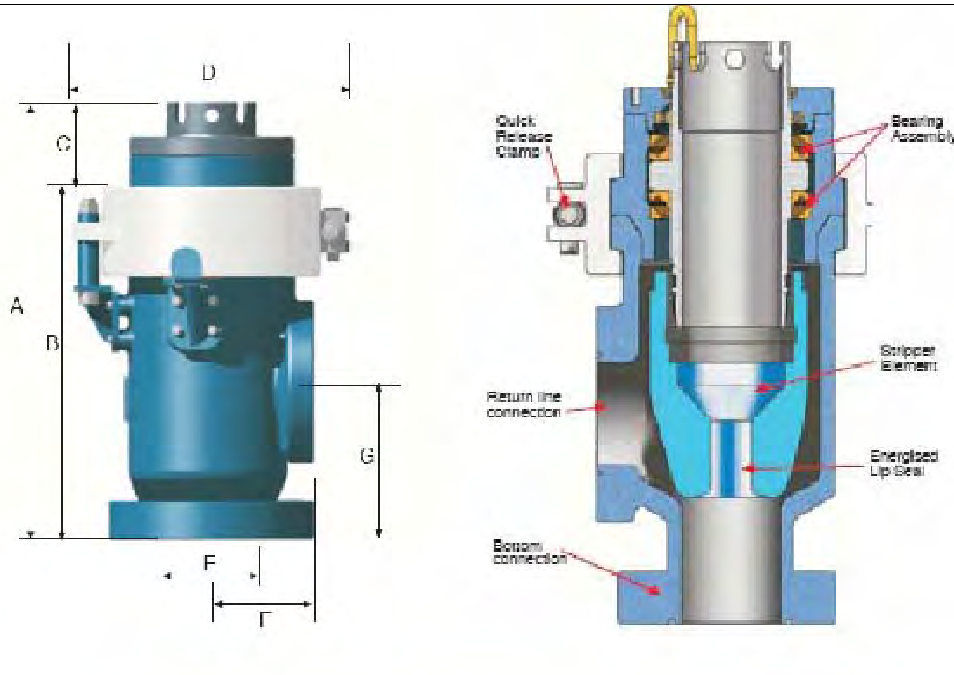


Figure 15: Dual Gradient Casing Setting 2

In this concept, the production casing is used initially during the drilling process as the pipe used for the mud-return line. After drilling, this pipe is moved from its role and position as the mud-return line, and is subsequently relocated and dropped down the hole as the production casing, thus saving money, effort, and material.

The problem of processing the mud as it is diverted from the BOP to the pumps to be sent up the mud-return line can be solved by the use of a rotating diverter. A variety of rotating diverters are available in the market depending upon the varying operating principles, applications, specifications and ratings. The critical components such as packing elements, bearings and hydraulic systems have proven expensive. This has expanded drilling programs without any serious failures and reliability has been proven. In a deepwater application, the development of rotating diverters is done for sub-sea installation on top of the BOP stack.



Inlet Flange	A	B	C	D	E	F	G	Outlet Flange
7 1/16" 5000#	40.5" 111.7cm	33" 84cm	12" 30cm	26" 66cm	7" 17.78cm	10 " 26.7cm	15 " 39.6cm	7 1/16" 3000#
9" 2/3000#	43" 109cm	32" 81cm	12" 30cm	26" 66cm	9" 22.9cm	10 " 26.7cm	15" 39cm	7 1/16" 3000#
11"RF 5000#	43.5" 114.3cm	34" 86.4cm	12" 30cm	26" 66cm	11" 27.9cm	10 " 26.7cm	16 " 42.4cm	9" 3000#
13 5/8" 5000#	45" 114.3cm	34" 86.4cm	12" 30cm	26" 66cm	11" 27.9cm	10 " 26.7cm	16 " 42.4cm	11" 3000#

Figure 16: Sub-Sea Rotating Diverter

Concept 2 - Hollow Casing Concept with redesigned Annular BOP

The second concept for casing is to use a hollow sieved casing thereby preventing ingress of large chunk of particles into mud return system. This will reduce damage to sub-sea mud pump which will increase its reliability and efficiency. The figure shows the concept of hollow casing which runs full of drilling mud and the drilling mud returns to BOP through inlet ports which prevent ingress of big chunk of rocks or gumbo. The drilling mud flows through the port and then circumferential cavity which is connected to BOP inlet. Mud gets diverted to sub-sea mud pump from the BOP. The annular blowout preventer is a large valve used to control well-bore fluids. In this type of valve, it is proposed to divert fluid in addition to its usual function of sealing the open hole.

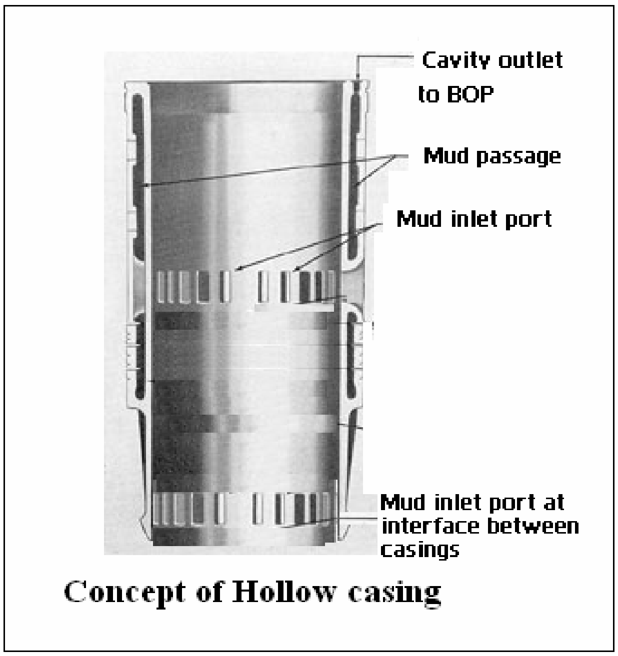


Figure 17: Hollow Casing

This may not be a good option as we need to modify BOP which is part supplied by a vendor and changes are to be made in the original design for prototype testing. As the total number of seals used in system would be less in this case, it would be good in sealing characteristics. However, in this case, there would be a sudden reduction in the cross section which can cause severe stresses within the system. This may result in fatigue failure.

Concept 3 - The Tapered Casing Concept

In this concept, a casing design with tapered cross section is proposed. The vertical depth capability of conventional casing can be a constraint because as the length of the casing increases total weight to also increases. Therefore, the capability to perform ultra-deep work also depends on the casing's total weight and the strength of the parent metal. Since proposed tapered casing is lighter in weight (if compared to equivalent casing of same outside diameter) and its design provides greater strength at the upper end of string, high depth capability can be realized over conventional casings. The figure shows tapered casing and equivalent cylindrical casing.

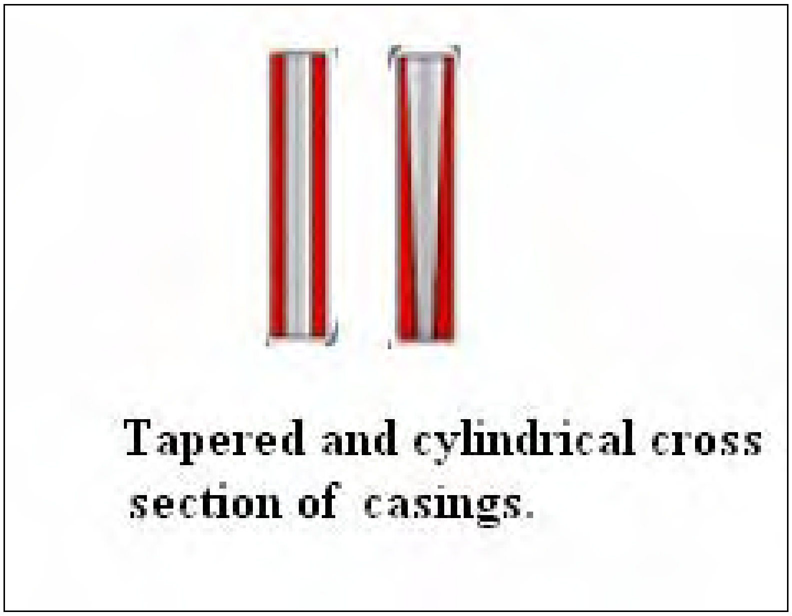


Figure 18: Tapered Casing

This can have disadvantages in terms of strength as compared to constant cross section cylindrical casing and also in terms of sealing at interface between two casings. The sealing can be expensive and overall cost can increase if thicker cross section is selected which is more than equivalent cross section of conventional in order to get more strength. An option of having tapered or stepped cross section makes it difficult and expensive to manufacture but the cost can be controlled and can be kept at par with conventional casing if it is mass produced.

Down-Selection

The down-selection method used was that of a quantitative weighted-average analysis. A set of criteria was developed describing aspects of the need that each concept had to address. Each criteria was given a certain weight percentage based upon how important that criterion was in relation to the rest of the criteria. These criteria along with their weight percentage are listed in table 6. The total weights of the criteria added up to 100%. For each criterion, each concept was assigned a certain number of points based on how well that concept met that criterion, relative to the other concepts. The total number of points assigned to all concepts for each criterion equaled 100. Each assigned point value was multiplied by the criteria weight to obtain the weighted points assigned. Then, all weighted points for each concept for every criteria were added together to obtain a total score for each concept, which rated its performance and the ability to meet the need relative to the other concepts. The total scores of all 3 concepts added up to 100. Table 6 provides an example of this process.

Table 6: Down-Selection Matrix

Criteria	Cost	Safety	Integration with current system	Reliability	Simplicity of Design	Efficiency	Innovative	Maintains Pressure	Unobstructed Flow	Scores
Weighted Value	0.05	0.1	0.1	0.2	0.1	0.2	0.05	0.1	0.1	1
Assigned Conventional Casing	70	33.33	85	40	50	40	20	40	40	418.33
Weighted Conventional Casing	3.5	3.333	8.5	8	5	8	1	4	4	45.333
Assigned Hollow Casing	15	33.33	10	30	25	20	40	30	20	223.33
Weighted Hollow Casing	0.75	3.333	1	6	2.5	4	2	3	2	24.583
Assigned Tapered Casing	15	33.33	5	30	25	40	40	30	40	258.33
Weighted Tapered Casing	0.75	3.333	0.5	6	2.5	8	2	3	4	30.083
Assigned Total	100	100	100	100	100	100	100	100	100	
Weighted Total	5	10	10	20	10	20	5	10	10	

Finally, each of these scores for each individual on the team was averaged with the other individuals from the team, and the final score was assigned to the concepts, from which the highest scored was chosen by the down selection process as the down-selected concept. This is shown in table 7. The concept selected was that of the conventional casing with rotating diverter.

Table 7: Down-Selection Results

	Amol	Chris	Average
Conventional Casing	33.88636	45.33333	39.60985
Hollow Casing	33.63636	24.58333	29.10985
Tapered Casing	32.47727	30.08333	31.2803

Recommendation

It is thus recommended that the conventional casing design with rotating diverter be developed as the final embodiment design. This design was selected primarily because the components to be used have been tested and utilized in drilling environments for a number of years, and are reliable in their implementation. These components, because they are already in use, are also cheaper and more readily available, and their manufacture would prove much easier than the hollow or tapered casing concepts. The hollow concept, while providing a method for fluid separation from the drill string prior to the BOP, would be difficult in manufacture because of the long channels needed through the casing, and also the potential of particulate matter to become lodged in those channels. In such a situation, it would be nearly impossible to remove them. The tapered concept might have provided a way to increase the depth that each level of casing could service, and may even require fewer levels of casing, but there were issues brought up as far as problems regarding the installation of a tapered casing while drilling, and drilling procedures required for installation as well. In the end, as stated before, it came down to the concept which represented cheaper components that were easily manufactured and more readily available commercially.

Final Design

It is obvious from the comparison of methods in the conceptual description that casing can be set at deeper intervals, and that fewer casings are required. However, a numerical example is provided below. Actual pore and fracture pressure data from figure 19 was used to plot conventional and DG casing levels as a comparison. The depth of water used was 6869 feet, and the desired drilling depth was 11,400 feet from the ocean floor. The following pore and fracture pressure data can be used in order to illustrate an example of the efficiency of dual gradient drilling as far as casing setting is concerned.

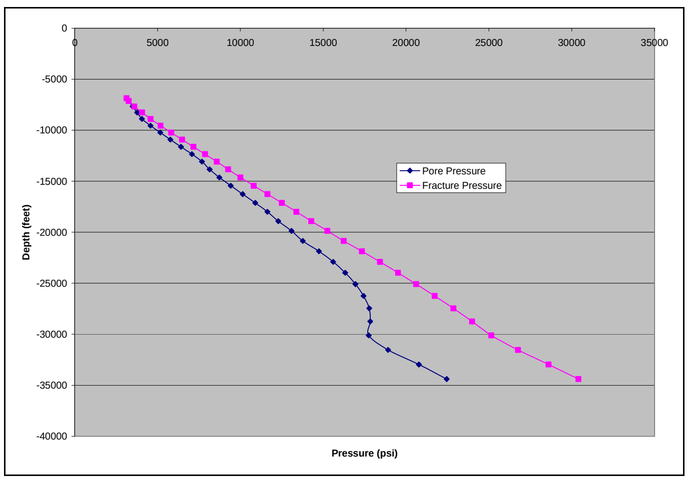


Figure 19: Pore and fracture pressure gradients for water at a depth of 6869 feet.

By performing the graphical method described in the conceptual design section for this design, a casing setting schedule can be determined and graphed, as shown in the following figures.

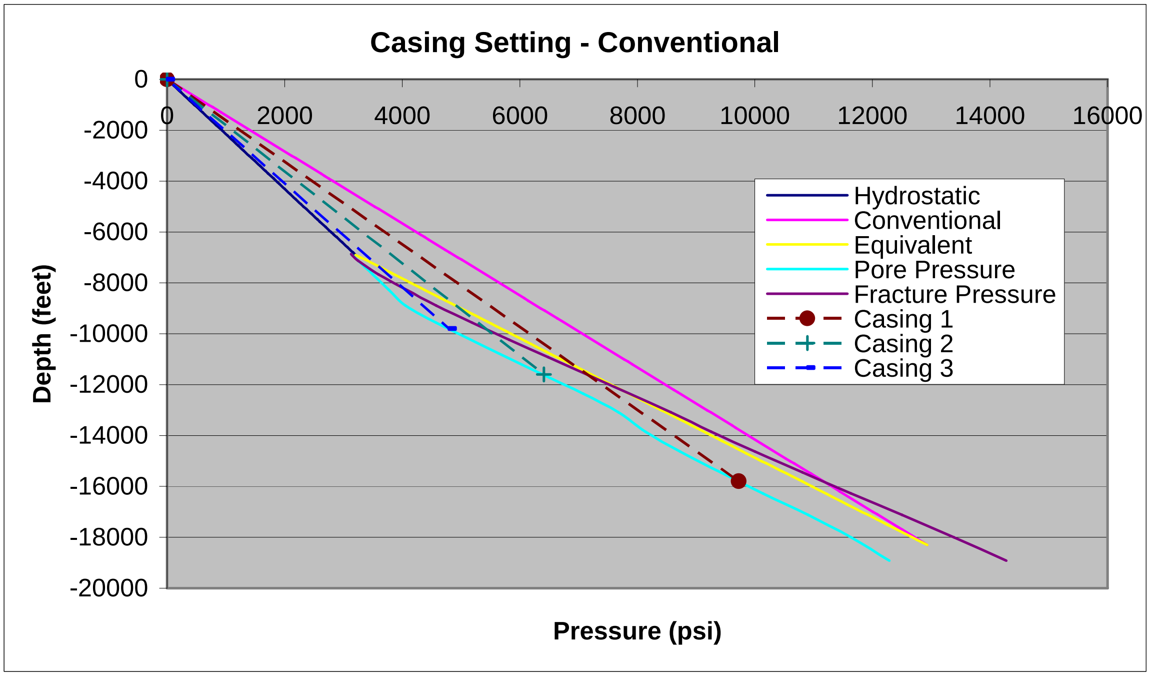


Figure 20: Graphical method for determining casing levels for conventional drilling.

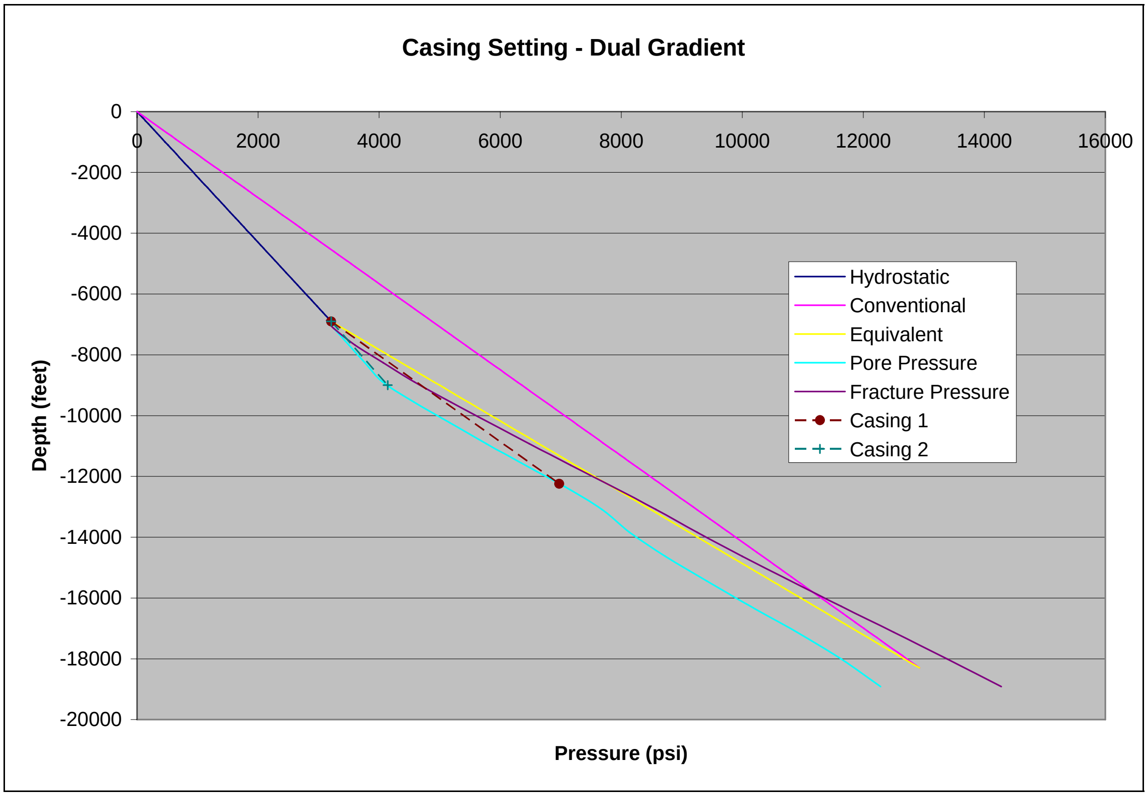


Figure 21: Graphical method for determining casing levels for dual gradient drilling.

It can be clearly seen from figures 20 and 21 that a dual gradient system will require less casing than the conventional system. The following figure provides a graphical comparison between Conventional and Dual Gradient Drilling casing setting for the above example.

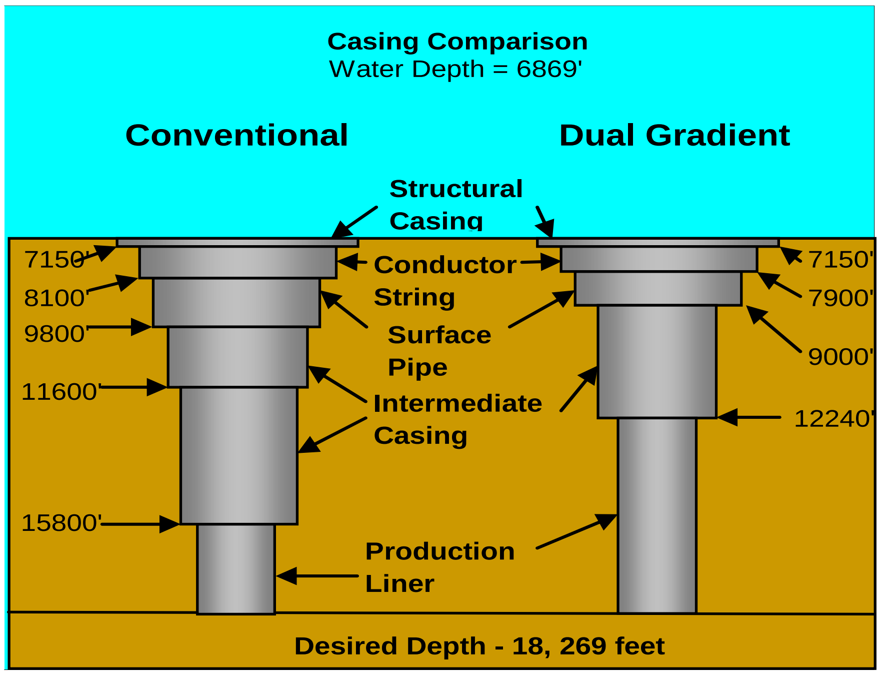


Figure 22: Casing Comparison

The desired production casing string size is determined by production requirement; so for a 7 in production casing string, a 9.625 inch intermediate casing and 13.375 inch conductor casing can be set. This selection is done based on requirement that bit size used to drill the last interval of the well must be slight larger than the OD of casing connectors[10]. Depending upon formation pressures and depending upon collapse resistance required for casings, a particular casing can be selected. The production casing string of 7 inches is selected and material grade can be selected for maximum yield strength and minimum weight. For production casing C-90 grade steel with 0.54 inch is selected which has 12,820 psi collapse resistance which is more than maximum formation pore pressure. Similar selections of P-110 grade 0.545 inch thick and P-110 grade 0.514 inch thick casings can be made for the case under consideration.

A quick analysis of the amount of casing involved in the above example yields a total of 29,505 feet of casing required in a conventional drilling system, whereas in the dual gradient system, only 20, 214 feet of casing is required. The following pricing schedule from Lone Star Steel is given:

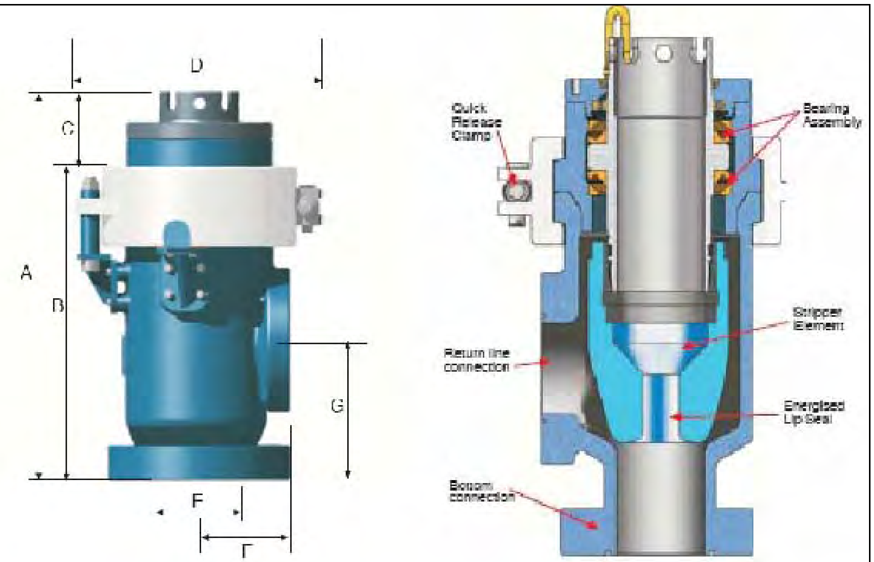
Table 8: Casing Price Schedule Comparison

Casing	Pipe Diameter	Pipe Length – Conventional	Pipe Length – Dual Gradient	Price per foot	Conventional Price	Dual Gradient Price
Production	7”	11,400 feet	11,400 feet	$42	$478,000	$478,000
Intermediate	9.625”	8,931 feet	5,371 feet	$54	$482,274	$290,034
Intermediate	13.375”	4,731 feet	0 feet	$82	$387,942	$0
Total		**25,062 feet**	**16,771 feet**		**$1,349,016**	**$768,834**

This analysis merely investigates casing pricing for the production and intermediate casings, and does not include potential savings from the surface pipe, conductor string, and structural casing. As can be seen from above, a savings on pipe can amount to $580,182 for this example. This figure only represents material savings. Given that operating expenses on an oil platform can reach $150,000 to $200,000 per day, and given that it might take approximately 3 days to set casing, because there is one less level of casing in DG than in conventional, those savings alone could reach up to $600,000. Total savings of using DG rather than conventional, from a pure standpoint of comparing the casing structures, reaches almost $1.2 million.

In this concept, casing is used initially during the drilling process as the pipe used for the mud-return line. After drilling, this pipe is moved from its role and position as the mud-return line, and is subsequently relocated and dropped down the hole as casing, thus saving money, effort, and material.

The problem of processing the mud as it is diverted from the BOP to the pumps to be sent up the mud-return line can be solved by the use of a rotating diverter. A variety of rotating diverters are available in the market depending upon the varying operating principles, applications, specifications and ratings. The critical components such as packing elements, bearings and hydraulic systems have proven expensive. This has expanded drilling programs without any serious failures and reliability has been proven. In a deepwater application, the development of rotating diverters is done for sub-sea installation on top of the BOP stack.



Inlet Flange	A	B	C	D	E	F	G	Outlet Flange
7 1/16" 5000#	40,5" 111,7cm	33" 84cm	12" 30cm	26" 66cm	7" 17,78cm	10 " 26,7cm	15 " 39,6cm	7 1/16" 3000#
9" 2/3000#	43" 109cm	32" 81cm	12" 30cm	26" 66cm	9" 22,9cm	10 " 26,7cm	15" 39cm	7 1/16" 3000#
11"RF 5000#	43,5" 114,3cm	34" 86,4cm	12" 30cm	26" 66cm	11" 27,9cm	10 " 26,7cm	16 " 42,4cm	9" 3000#
13 5/8" 5000#	45" 114,3cm	34" 86,4cm	12" 30cm	26" 66cm	11" 27,9cm	10 " 26,7cm	16 " 42,4cm	11" 3000#

Figure 23: Sub-Sea Rotating Diverter

Annular blowout preventer is a large valve used to control wellbore fluids. In this type of valve, the sealing element resembles a large rubber doughnut that is mechanically squeezed inward to seal on either pipe (drill collars, drill pipe, casing, or tubing) or the open hole. The ability to seal on a variety of pipe sizes is one major advantage of the annular blowout preventer over ram-type blowout preventers. Most blowout preventer (BOP) stacks contain at least one annular BOP at the top of the BOP stack, and one or more ram-type preventers below. While not considered as reliable in sealing over the open hole as around tubulars, the elastomeric sealing doughnut is required by API specifications to seal adequately over the open hole as part of its certification process.

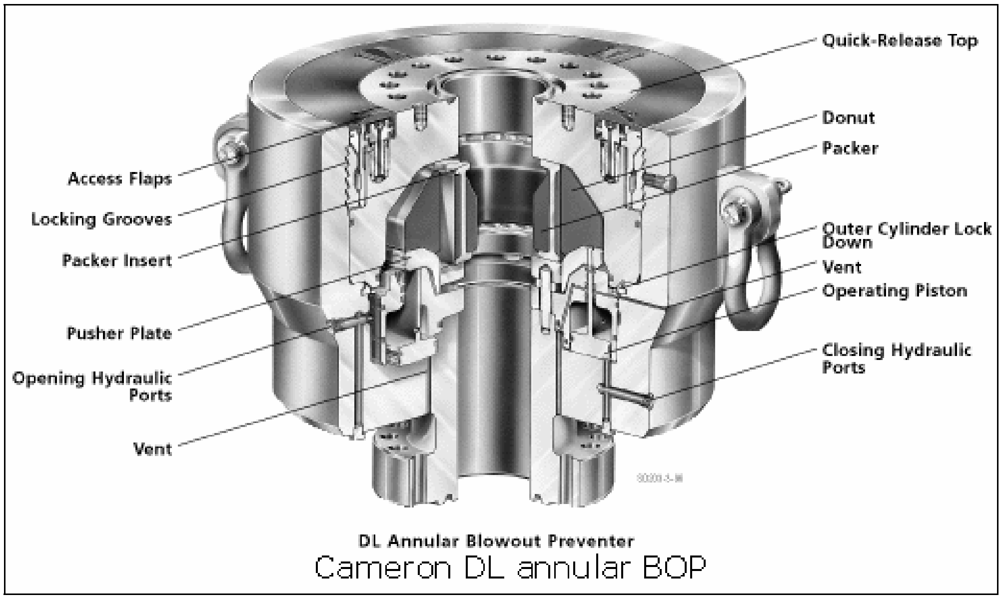


Figure 24: Cameron DL Annular BOP

The above figure shows an example of Cameron DL annular BOP. In the unique design of the Cameron DL annular BOP, closing pressure forces the operating piston and pusher plate upward to displace the solid elastomer donut and forces the packer to close inward. As the packer closes, steel reinforcing inserts rotate inward to form a continuous support ring of steel at the top and bottom of the packer. The inserts remain in contact with each other whether the packer is open, closed on pipe or closed on open hole. The Cameron DL BOP is shorter in height than comparable annular preventers. A quick-release top with a one-piece split lock ring permits quick packer change-out with no loose parts involved. The design also provides visual indication of whether the top is locked or unlocked. The DL BOP is designed to simplify field maintenance.

Components subject to wear are field-replaceable and the entire operating system may be removed in the field for immediate change-out without removing the BOP from the stack. Twin seals separated by a vented chamber positively isolate the BOP operating system from well bore pressure. High strength polymer bearing rings prevent metal-to-metal contact and reduce wear between all moving parts of the operating systems. The Cameron DL BOP is available in sizes from 7-1/16" to 21-1/4" and in working pressures from 2000 to 20,000 psi.

Following table shows BOP specifications for Canam services Inc.

ANNULAR AND RAM BOP SPECIFICATIONS												
VERTICAL BORE		WORKING PRESSURE		TESTING PRESSURE		MAX. RAM SIZE		MAX. OPERATION PRESSURE		BOP TYPE OPTIONS	SERVICES OPTIONS	OPERATION OPTIONS
IN	MM	BAR	PSI	BAR	PSI	IN	MM	BAR	PSI			
7 1/16	180	210	3,000	420	6,000	5 1/2	139.70	140	2,000	ANNULAR OR DOUBLE OR SINGLE	H2S OR STANDARD	HYDRAULIC OR MANUAL
7 1/16	180	350	5,000	700	10,000	5 1/2	139.70	140	2,000			
7 1/16	180	700	10,000	1,050	15,000	5 1/2	139.70	140	2,000			
7 1/16	180	1,050	15,000	1,575	22,500	5 1/2	139.70	210	3,000			
9	230	210	3,000	420	6,000	7	177.80	140	2,000			
9	230	350	5,000	700	10,000	7	177.80	140	2,000			
9	230	700	10,000	1,050	15,000	7	177.80	140	2,000			
9	230	1,050	15,000	1,575	22,500	7	177.80	210	3,000			
11	280	210	3,000	420	6,000	8 5/8	219.08	140	2,000			
11	280	350	5,000	700	10,000	8 5/8	219.08	140	2,000			
11	280	700	10,000	1,050	15,000	8 5/8	219.08	140	2,000			
13 5/8	346	210	3,000	420	6,000	10 3/4	273.05	140	2,000			
13 5/8	346	350	5,000	700	10,000	10 3/4	273.05	140	2,000			
13 5/8	346	700	10,000	1,050	15,000	10 3/4	273.05	140	2,000			
16 3/4	425	140	2,000	210	3,000			140	2,000			
16 3/4	425	210	3,000	315	4,500			140	2,000			
16 3/4	425	350	5,000	700	10,000			140	2,000			
21 1/4	540	210	3,000	315	4,500	16	406.40	140	2,000			

CANAM SERVICES INC BOP SPECIFICATIONS

Figure 25: BOP Specifications

During drilling operations, casing strings are installed in wells. Casing is an essential part of any well control program. After each casing string is installed, cement is used to bond the casing to the formation. The cemented casing provides a place to install the blowout preventor and seals the formations off for well control and formation isolation purposes. After the well reaches total depth, casing is run to the bottom of the well (referred to as the production casing or “long string”) and cemented in place. One problem encountered is that shallower formations are weak and break down under pressure. Because cement is a dense fluid, the hydrostatic head pressure produced by the cement column actually exceeds the breakdown pressure of the shallower formations. If this occurs, cement goes out into the formation and not up the space between the well’s casing and well bore, resulting in a poor seal between the casing and the formation. Different methods have been used to lighten up the cement to reduce the hydrostatic head pressure. A common method is to have two different types of cement that are pumped consecutively. The “lead” cement is pumped first, followed immediately by the heavier “tail” cement. The lead cement is lighter and is used to span the shallower and usually weaker formations.

The “tail” cement spans the deeper producing formations. After a well bore is drilled a caliper log can be run to determine the volume of cement to reach the targeted depth. If a caliper log is not obtained, common practice dictates that an excess volume of cement be pumped to assure that enough cement is available to span the shallower zones. Typical excess volumes can be on the order of 50% above the recommended volume.

The compressive strength of the cement is usually lowered by the addition of lightweight additives; these reduce how much pressure cement can hold back. If the compressive strength of the cement slurry is compromised, the seal is broken and the well has to be cemented again. The compressive strength of cement used to cement well casing is regulated by API standards. Current technology utilizes nitrogen “foam” lead cement.

The nitrogen is injected into the cement slurry while it is being pumped and forms small nitrogen pockets that reduces the overall hydrostatic head pressure. Although quite successful, the small nitrogen pockets coagulate during pumping forming larger pockets of nitrogen, reducing the compressive strength of the cement. Since the nitrogen is a gas and expands as pressure is reduced, it is not as controllable as a solid or liquid medium and has more of a tendency to channel.

Summary

Dual Gradient Drilling is a concept in which as opposed to conventional drilling where a conventional mud density gradient is used to drill, 2 gradients are used: the hydrostatic pressure gradient of the sea water, and an equivalent mud density gradient. Using these pressure gradients, it is possible to drill without the use of a riser, and is also possible to set casing at deeper intervals and using fewer casings. This results in petroleum drilling operations that are cheaper to conduct, and increases the capabilities of drilling engineers to drill in deeper water and drill deeper into the ground, making accessible untapped reservoirs of petroleum that can be used to satisfy the world's growing demand on petroleum.

This project was concerned with developing a casing structure suitable for use with dual gradient drilling. The first step in achieving these goals was to develop a Need Analysis for the project, to determine the scope and specific need of the project. This allowed the project team to isolate individual needs and design to those needs accordingly. The second step was to develop three working concepts that would address those needs. These concepts were a conventional casing structure with rotating diverter, a hollow casing concept, and a tapered casing concept. A quantitative down-selection procedure was used to select which concept to use, and a final design and recommendation was then developed. This design, included in this report, was a conventional casing structure with rotating diverter.

References

Mr. Charles Peterman and Dr. Schubert

Mineral Management Services

These two men were responsible for bringing the problem to MEEN 632,and subsequently MEEN 685, and were instrumental in answering many of our questions concerning petroleum drilling operations. Their presentations contained primarily all of the information used to develop this report.

Dr. Steve Suh

Dr. Suh is the instructor for MEEN 632, and his instruction, class notes and material were used in developing a report format and generating an appropriate need analysis of the problem. His guidance in the directed studies MEEN 685 proved invaluable in the production of this report.

Miss Brandee Elieff

Miss Elieff was instrumental in providing necessary information and expertise required to perform this need analysis.

Mr. Vastan Tchokoev

Sales/Tech Sales Engineer, Lone Star Steel Company. Dallas, TX.

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Appendix C

Development of a Top Hole Dual Gradient Drilling System for Deep Sea Drilling that provides Unobstructed Path for Mud Return, Final Design Report, (December 2005) Sukesh Shenoy, Amol Dixit, and A.S.Nandagopalan, Department of Mechanical Engineering, Texas A&M University

Development of a Top Hole Dual Gradient Drilling System for Deep Sea Drilling that provides Unobstructed Path for Mud Return

Final Design Report

Prepared For
Minerals Management Service

Presented to
Minerals Management Service
Dr. Steve Suh, PhD

Prepared by

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MEEN 632 - Fall 2005

12/09/05

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Introduction

Executive Summary

The offshore fraternity has been attempting to achieve the goal of “riserless” drilling for operations in deep water for several years now. Riserless drilling is more commonly known as “dual gradient” technique. Also, strong emphasis is being laid to move drill cuttings at the sea-bed and find an alternative to “pump and dump” for top hole drilling.

The primary purpose of our project is to access the oil deposits deep in the oceans. These oil deposits have been estimated to be at depths varying from around 5000 to 12000 feet. Our sponsors are interested in developing a drilling system that would be capable of drilling up to such depths in the oceans. Also, it is required that methods be developed to deal with seabed drill cuttings disposal, and eliminate the practice of “pump and dump” for top hole drilling by recovering the returning stream of mud and cuttings back to the rig rather than to the seabed. In other words, it is required to provide a drilling mud recirculation system.

The sponsors of our project are Minerals Management Service. The Minerals Management Service (MMS), a bureau in the U.S. Department of the Interior**,** is the Federal agency that manages the nation's natural gas, oil and other mineral resources on the outer continental shelf (OCS). The project assigned to us falls under their research area of offshore programs. Considering the importance of this area of research keeping in mind the ever-increasing energy and mineral resource demands of the world, we are grateful to our sponsors for showing faith in our abilities, placing confidence in us and bestowing us with the opportunity to work on this prestigious topic.

Need Analysis

The goal of the need analysis is the identification and articulation of the essential requirements of the project without constraining the scope of the design project. The primary step in the need analysis is to define, with clarity and precision, the need statement. We defined the need statement of our design project expecting it to perform the following functions.

- Provides understanding of the "real" need by ascertaining the scope of the design task, making us conversant with the hurdles in the path and helping us identify the primary functions, design parameters and their constraints.
- Promotes original thinking and creativity, enables a technically sound approach.
- Elucidates the information required, by demarcating the available from the unavailable information.
- Establishes the function structure of the design project by breaking it down to smaller sub-tasks, each clearly outlining its various functions.
- Proves conclusively whether we are on target at every stage and not digressing from our goal.
- Is independent of the method used.

Development of the Need Statement

The need statement elucidates the requirements of the design project by means of the design parameters and the constraint requirements. It fosters original and creative thinking and broadens the spectrum of thought. It aids the thought process in experimenting with ideas which are different with respect to methodologies already implemented. As a result, the focus is on the functions to be performed and not on development of former designs.

We began working on the design project with a very vague idea of what was required. As more and more work was put in, clarity of thought started percolating in. During this period, the need statement underwent a significant change, the important stages of which have been listed below. Finally, we zeroed in on what we have listed as our final need statement.

Evolution of the Need Statement

Primary Need Statement

Development of a top hole dual gradient system that provides re-circulation of the drilling mud.

Primary Function

Implement top hole dual gradient system and re-circulate the drilling mud.

Primary Constraint

From the primary need statement, it is not clear as to what "top hole dual gradient" means. "Dual gradient" system is to be incorporated at the "top hole" stage in this case. To go about doing this, the need statement should elucidate the concept of dual gradient as a method of maintaining differential pressures. This will enable the actual requirements to be quantified.

Refined Statement

To maintain a regulated pressure differential and provide an unobstructed mud return path between sea water and drilling mud.

Refined Function

Maintain pressure gradient and provide clear path for drilling mud return.

Refined Constraint

In the absence of the riser, the drill string needs to be directed to intercept the BOP valve. Further, since drilling is being undertaken at depths up to 12000 feet, proper interfaces need to be provided between BOP valve and the drill ship. Other significant factors like the effect of varying sea conditions on the drill string need to be addressed.

This results in a final need statement which takes into account the expected functions and the corresponding constraints and attempts to quantify them.

Final Need Statement

Following is the need statement of our project.

Development of a top hole dual gradient drilling system for deep sea drilling that provides unobstructed path for mud return.

Function Structure

The function structure is a diagram representing the requirements the design will meet. It is a pictorial illustration of the functional relationship of the items that form the need statement. It delineates each task and projects them as independent functions. Each of these sub-tasks is a functional requirement defined in the need statement. It exhibits the broad scope of the design project.

The design requirements are classified into three major groups for organization and visualization of the actual task:-

- Functional requirements
- Constraint requirements
- Non-functional requirements

The function structure serves to further identify the real need and encourages innovation. Each and every function is further classified into sub-tasks in order to state a specific operation of the function with precision. All these sub functions must act independently. The design parameters (DP's) and the constraints related to each of these are outlined. The design parameters are the important design variables with their permissible or appropriate value ranges while the constraints are the limiting conditions of each of those design parameters (i.e. efficiency, effectiveness, size, cost, time, safety, etc.).

In this case, we have developed a hierarchical function structure which identifies the major functions required in the design and develops those functions to the lowest level possible while staying solution independent. The comprehensive function structure is shown below.

Function Structure

The following function structure has been developed by utilizing the need statement. The fundamental function structure is represented in Figure A. Figures A1, A2, A3, A4 and A5 show each of the five functional requirements in more detail.

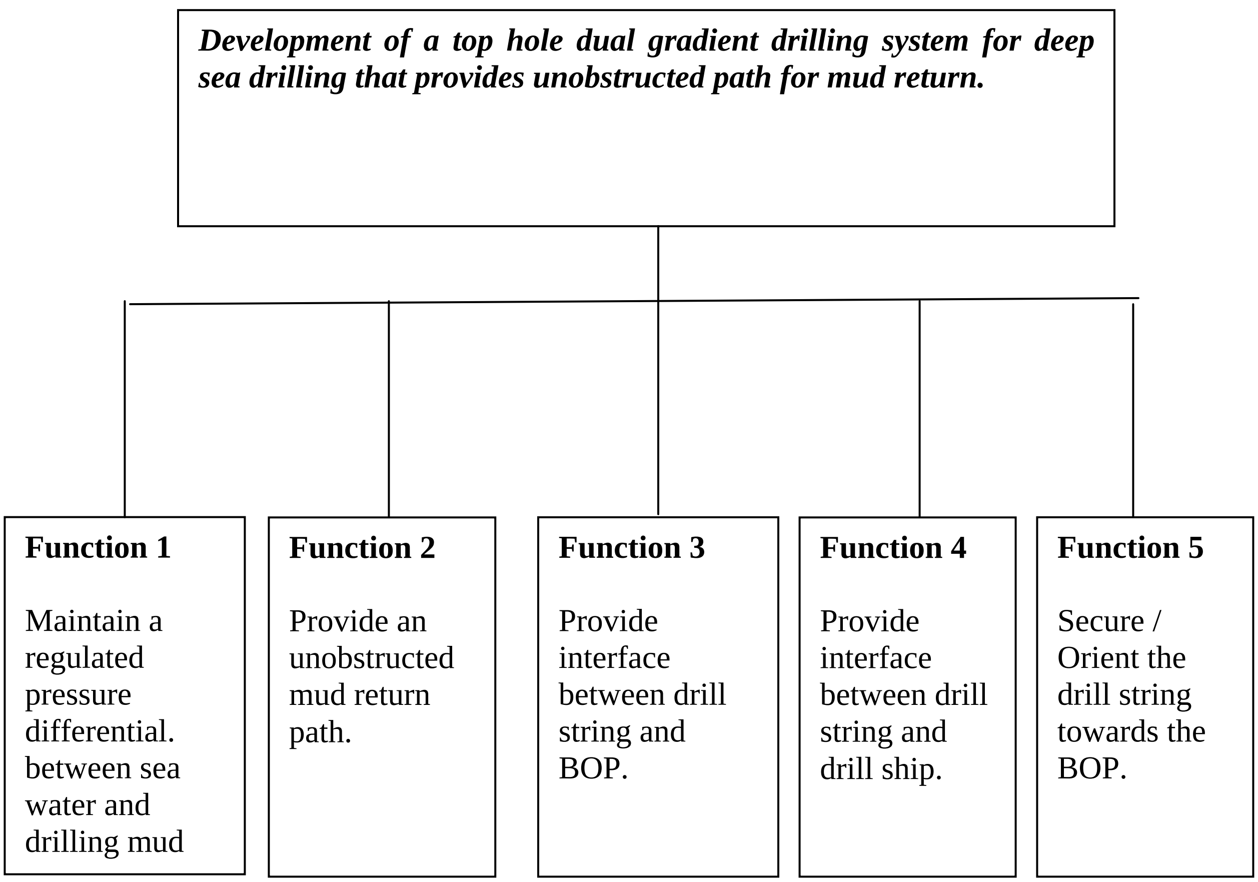


Figure A. Fundamental Function Structure

F 1
Maintain a regulated pressure differential.

F 1.1
FR: Monitor the flow rate.
CR: Maximum Allowable Pressure Difference
DP: Flow velocity.

F 1.2
FR: Maintain the desired flow rate.

F 1.2.1
FR: Provide good sealing characteristics.
CR: Material of seal
DP: Drilling Mud Pressure

F 1.2.2
FR: Prevent deformation of circulation equipment.
CR: Maximum Allowable Strain, Material
DP: Strain

F 1.2.3
FR: Supply of energy in the event of a pressure drop.
CR: Capacity of power supply
DP: Power

Figure B. Maintain a regulated pressure differential

F 2
Provide an unobstructed mud return path.

F 2.1
Prevent flow restriction

F 2.1.1
FR: Provide adequate filtering for impurities.
CR: Maximum permissible size
DP: Size of impurities

F 2.1.2
FR: Provide uniform cross-sectional area.
CR: Tolerance
DP: Diameter

F 2.1.3
FR: Minimize frictional resistance to flow.
CR: Manufacturing process
DP: Surface Finish

F 2.2
FR: Provide good sealing characteristics to prevent leakage.
CR: Material
DP: Drilling Mud Pressure

Figure C. Provide an unobstructed mud return path

F 3
Provide interface between drill string and BOP.

F 3.1
FR: Provide a device to connect BOP and drill string.
CR: Permissible angular and linear misalignment.
DP: Connection type.

F 3.2
FR: Withstand heavy loads.

F 3.2.1
FR: Withstand stresses due to ocean currents.
CR: Size, Material.
DP: Stress, Tension.

F 3.2.2
FR: Withstand internal and external fluid pressure.
CR: Maximum allowable pressure.
DP: Pressure.

F 3.3
FR: Provide good sealing characteristics.
CR: Material of seal.
DP: Type of seal.

Figure D. Provide interface between drill string and BOP

F 4

Provide interface between drill string and drill ship.

F 4.1

FR: Provide a device to connect drill ship and drill string.
CR: Permissible angular and linear misalignment.
DP: Connection type.

F 4.2

FR: Withstand stresses due to weight of drill string, ocean currents.
CR: Permissible stress level.
DP: Stress due to weight of drill string, tension and ocean currents.

F 4.3

FR: Provide adequate sealing characteristics.
CR: Material of the seal.
DP: Type of seal, Clamping Pressure.

Figure E. Provide interface between drill string and drill ship

F 5
Secure / Orient the drill string towards the BOP.

F 5.1
FR: Provide stiffening device.
CR: Maximum allowable tensile stress.
DP: Tension in the drill string.

F 5.2
FR: Guide the drill string.
CR: Maximum Allowable Displacement.
DP: Displacement of the drill string.

Figure F. Secure / Orient the drill string towards the BOP

Introduction to Conceptual Design

Once the Need Statement has been established, it is required to go about conceptualizing the statement to accomplish the requirements of the project. This demands that a variety of approaches be considered, tried and analyzed before implementation. The fundamental needs are required to be addressed through a comparative study of the various concepts which could accomplish the need. This kind of an approach enables a thorough understanding of the relative advantages and disadvantages of one concept over the other, thereby helping us figure out the most feasible and desired way of approaching the problem.

The objective of the Conceptual Design Report is to shed light on a number of concepts to arrive at the solution. The concepts put forth accomplish the need but an attempt is made to zero in on the most feasible one.

Design Specifications

The following table, Table I, summarizes the design requirements and specifications for this project.

Table I. Design Requirements and Specifications

Function	*Parameter*	*Constraint*	*Equation*	*Source*	*Comments*
1.1	Flow Velocity	Maximum Allowable Pressure Difference	$P+1/2\rho v^2 + \rho gh =$ constant	http://scienceworld.wolfram.com/physics/BernoullisLaw.html	Bernoulli's equation can be used to measure the flow velocity.
1.2.1	Drilling mud pressure	Material of Seal	-	-	The material chosen should be such that the seal withstands the drilling mud pressure.
1.2.2	Strain	Maximum Allowable Strain, Material	$\varepsilon = \Delta L/L$	http://www.omega.com/literature/transactions/volume3/strain.html	Strain is the amount of deformation per unit length.
1.2.3	Power	Capacity of power supply	Power = Pressure* capacity	http://www.zoeller.com/zep/techbrief/JF1article.htm	Capacity is the flow rate of the drilling mud.
2.1.1	Size of impurities	Maximum permissible size	-	-	-
2.1.2	Diameter of the return path	Pressure Drop	$\Delta P = f * L/D * \rho/2 * V^2$	http://www.engineersedge.com/fluid_flow/pressure_drop/pressure_drop.htm	Larger diameter pipe results in lesser power loss.
2.1.3	Surface finish	Manufacturing process	-	-	The surface should be smooth and this in turn is dependent on the manufacturing process.
2.2	Drilling mud pressure	Material of Seal	-	-	The material chosen should be such that the seal is able to withstand the drilling mud pressure.

The important sub functions which affect the system design are

- Diameters of return path
- Drilling mud pressure
- Flow velocity
- Power.

We need to look into the design of diameters of mud return path and sea water supply line for sub-sea mud pump. As we know the desired flow rates from the customer's system design requirements, we can get corresponding flow velocity for any particular diameter. Variation in diameter of pipes will give the corresponding flow velocity. The mud riser and sea water riser have the same length and they can be designed using standard pipe design methodology. In fact, they can be of same diameters. If the sea water, pumped from the surface pump is used to supply hydraulic power to the sub-sea mud pump, then, the flow rate of sea water can be obtained from the expected flow rate requirement from the sub-sea mud pump. From the calculated flow velocity and properties of sea mud and water, we can calculate the respective Reynolds number or plot it as a function of pipe diameter.

$$\mathbf{Re = (\rho\, \mathit{VD}) / \mu}$$

where

ρ - Density of fluid;
V - Fluid velocity;
μ - Fluid dynamic viscosity

The pressure drop can be calculated from,

$$\mathbf{\Delta P = f * L/D * \rho/2 * V^2}$$

where

f - The Moody friction (from the Moody chart);
L - Length of pipe;
D - Inner diameter of pipe;
ρ - Fluid density,
V - Fluid velocity

Thus, total pressure loss for approximately 12000 feet long pipe can be calculated for mud return line and sea water supply line for certain value of the inner diameter of pipe or can be plotted as a function of inner diameter of pipe. Larger diameter may give lower pressure loss but it will be a heavy design and will lead to increase in strain in the pipe due to tension loading and vice versa. The optimum pipe size would be selected from standard available sizes.

The drilling mud pressure can be determined from ρ*g*h, where h is around 12000feet.

The interface between well-bore casing and sub-sea mud-lift pump would take care of sealing requirements.

The power requirement to drive the surface pump which provides hydraulic power to mud pump can be determined as follows:-

Power= fluid Power/ overall efficiency

Fluid Power= $\boldsymbol{\rho * Q * H_{water} * g}$

<u>Efficiency</u>

The overall efficiency is defined in two different ways depending on the mode of drive provided to the sub-sea mud pump.

Overall efficiency = η mud-lift pump*η surface pump *η electric motor
(If sea water is used to drive sub-sea mud pump)

Or

Overall efficiency = η mud-lift pump *η electric motor
(If electric motor is used to drive sub-sea mud pump)

Overall System Description

This design primarily targets the mud recirculation system. The concept is shown in Figure B.

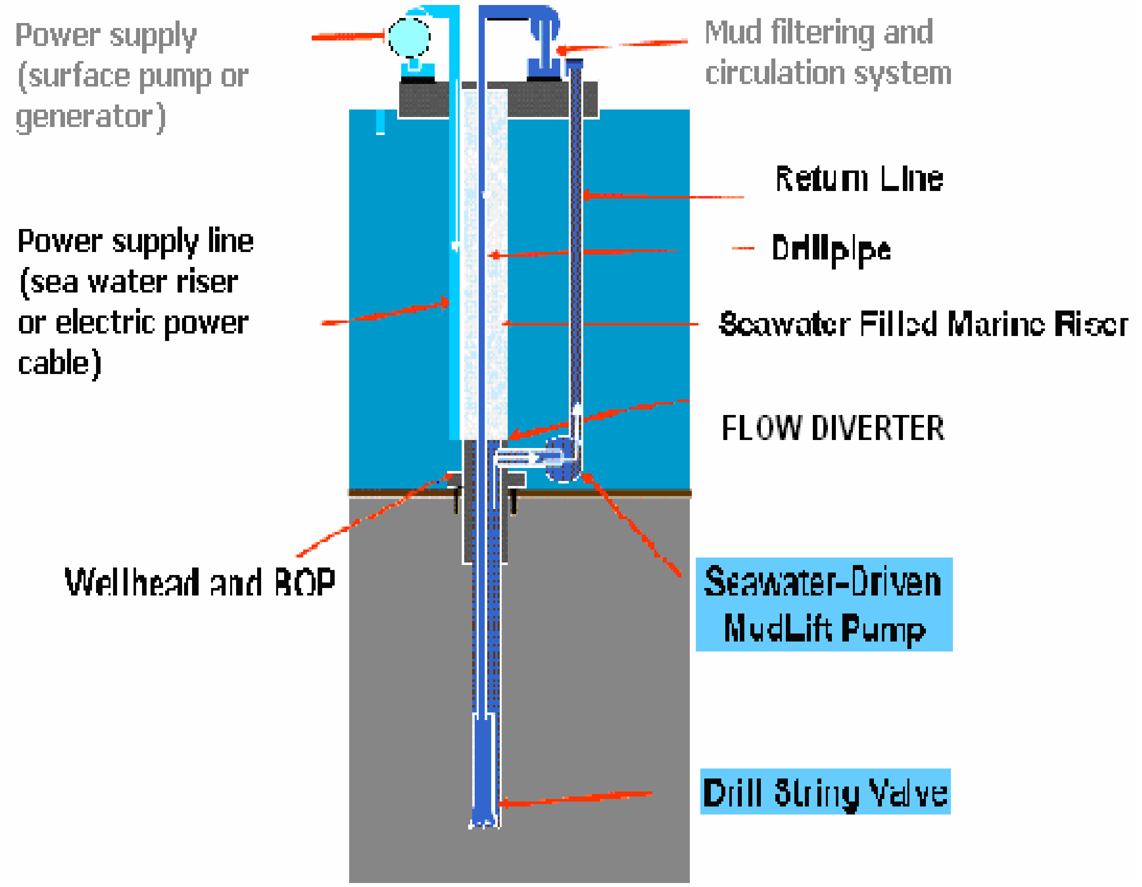


Figure G. Mud Return System
Ref.: Presentation1final.ppt (Material provided)

The mud return system shown above basically has the following important components i.e. power supply for sub-sea mud pump, power supply line flow diverter interface between flow diverter and inlet of sub-sea mud pump, sub-sea mud pump, mud return line (Mud riser) and the mud processing equipment.

The critical components from system design point of view are considered as sub-sea mud pump, interface between flow diverter and inlet of sub-sea mud pump, power supply for sub-sea mud pump, mud return line (Mud riser) and sea water riser or power supply cable.

Top and Bottom Interface

The following system gives the overall view of the top and bottom interface of the drill string.

Top Interface

The top interface has a load ring which is used to load or create tension in the mud riser and sea riser. Also, the inner load ring and outer load ring act together as a thrust bearing and provide flexibility in the system.

Bottom Interface

The bottom interface comprises of a Vetco Gray flex joint. A threaded joint connects the riser to the flange joint which is mounted on the flex joint. The flex joint provides relative movement of the riser pipes with respect to the drill ship and well head.

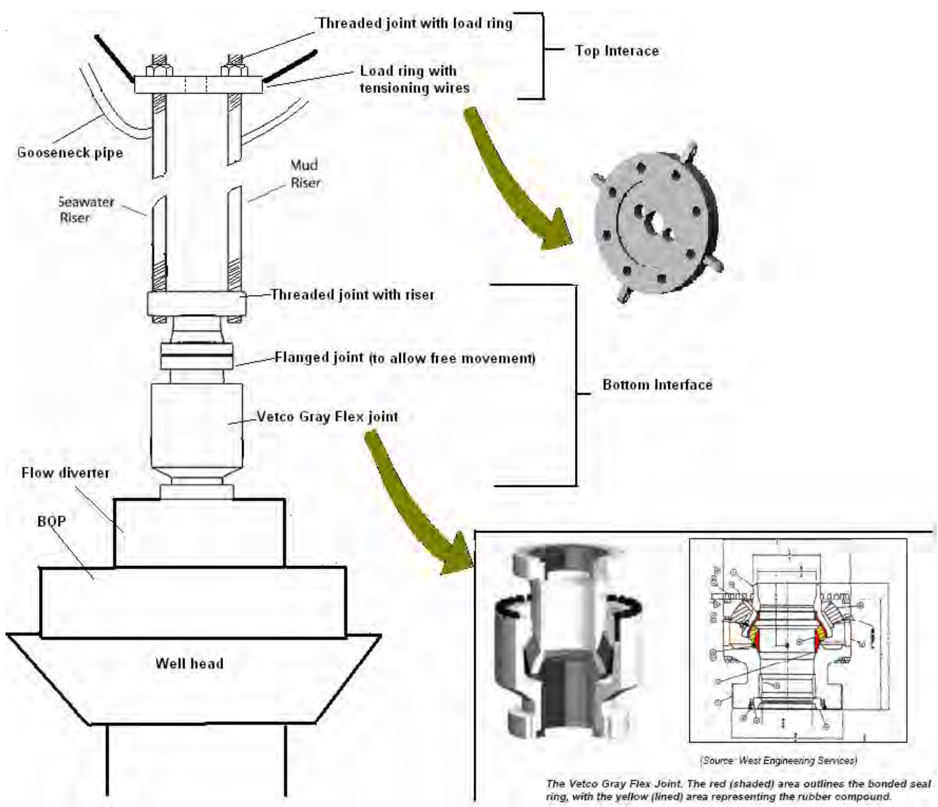


Figure H. Top and Bottom Interface
Source: http://www.cnsopb.ns.ca/whatsnew/pdf/Marathon_Report_FINAL.pdf

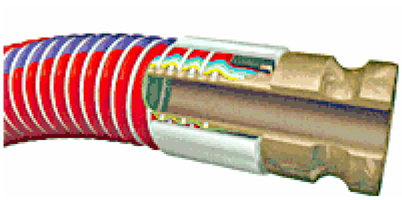
Concept Analysis 1:- Interface between top hole and sub-sea mud pump

The first concept for interfacing between the top hole and the sub-sea mud pump is by using a flow diverter device mounted on the top of BOP connecting the annular space in conductor casing to the inlet of subsea mudlift pump.

Another way is by using composite hoses and connectors interfacing Subsea rotating device (SRD) and mud pump inlet.

The same can be accomplished by the modified BOP design also which itself has another outlet for mud return which is to be supplied to mud pump.

Figure I1. Sub-sea Rotating Device
Source: http://www.worldoil.com/magazine/magazine_link.asp?ART_LINK=99-08_dwt_subsea-smith_fig8.htm



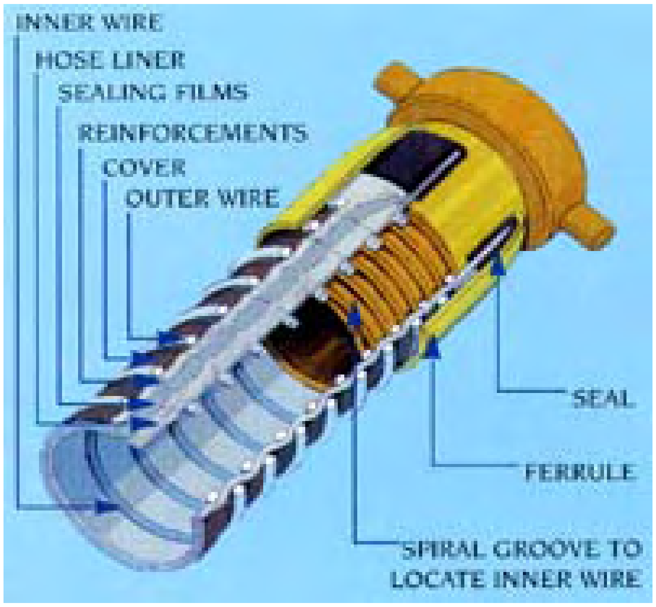


Figure I2. Existing Sub-sea rotating device and composite hose with flange connector
Source:
http://www.ushosecorp.com/index.cfm/datakey/3/category/TIFT%20COMPOSITE%20HOSE.html

Figure I1 shows concept-1 which isolates the fluid in the riser from the wellbore and diverts return drilling fluid from the riser base to the sub-sea mud pump suction. The solids-sizing process begins inside the SRD.

In this concept, we are designing the hose and connectors. Composite hoses are capable of withstanding heavy-duty applications, high pressure and handling of high density fluids. They are capable of withstanding corrosive environment internally and externally. Composite hoses, like other hoses, provide the vital flexible connection to compensate for vibration, movement or misalignment in a fluid transfer system.

A composite hose has a spiral internal metal supporting wire which can be galvanised mild steel, stainless steel, aluminium or polypropylene coated mild steel with a spiral external wire which is generally galvanised mild steel or stainless steel. In between the wires, there are layers of thermoplastic fabrics and film. The end fittings can be of the following types:- flanges, camlock, threaded, API(American petroleum institute) and dry break couplings. Common end fitting materials are carbon steel, stainless steel, gunmetal, aluminium and polypropylene, although other materials are also available.

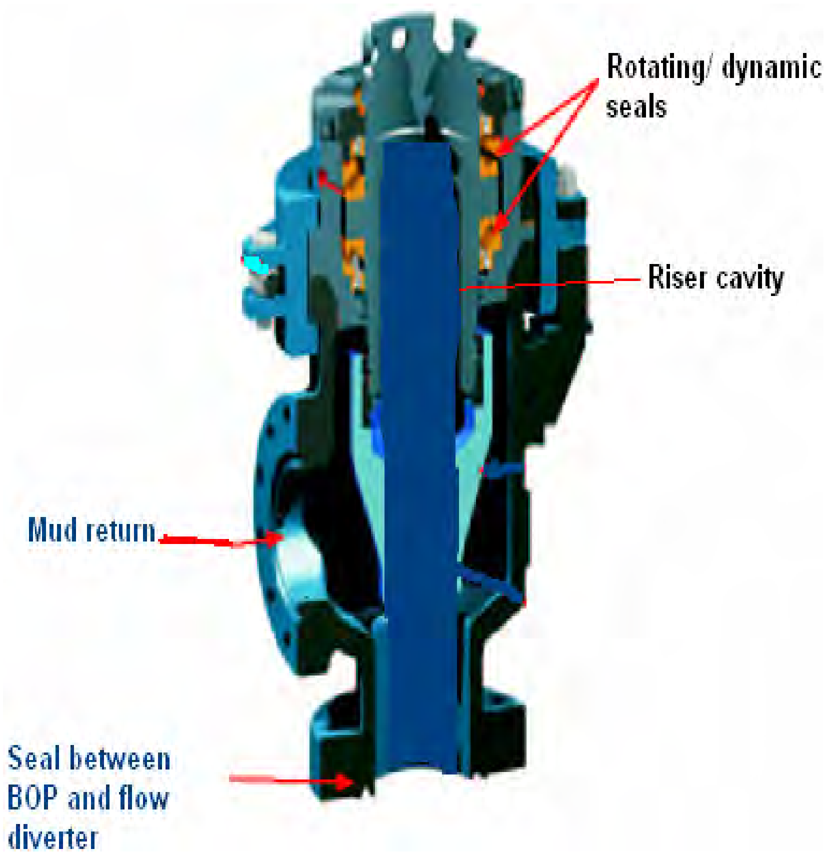


Figure J. Proposed Flow Diverter
Source: http://www.strataenergy.net/under_rotating.html

Figure I schematically depicts the proposed design which gives an idea about the flow diverter to be mounted on the top of BOP stack.

In the second concept, the flow diverter needs to have two dynamic/ rotating seals to prevent ingress of sea water on top and mud on bottom side. It is mounted on the top of the BOP and properly sealed at interface. The seal needs to seal water and mud on both sides and also work in both directions. The seal should also withstand high pressure and different fluids on both sides.

An unobstructed flow path can be obtained through the flow diverter by designing the area of cross section of flow diverter and mud supply line in such a way that there is no sudden reduction of cross section while the mud moves from top hole through flow diverter to mud pump. In the case of modified design, this function would be difficult to achieve.

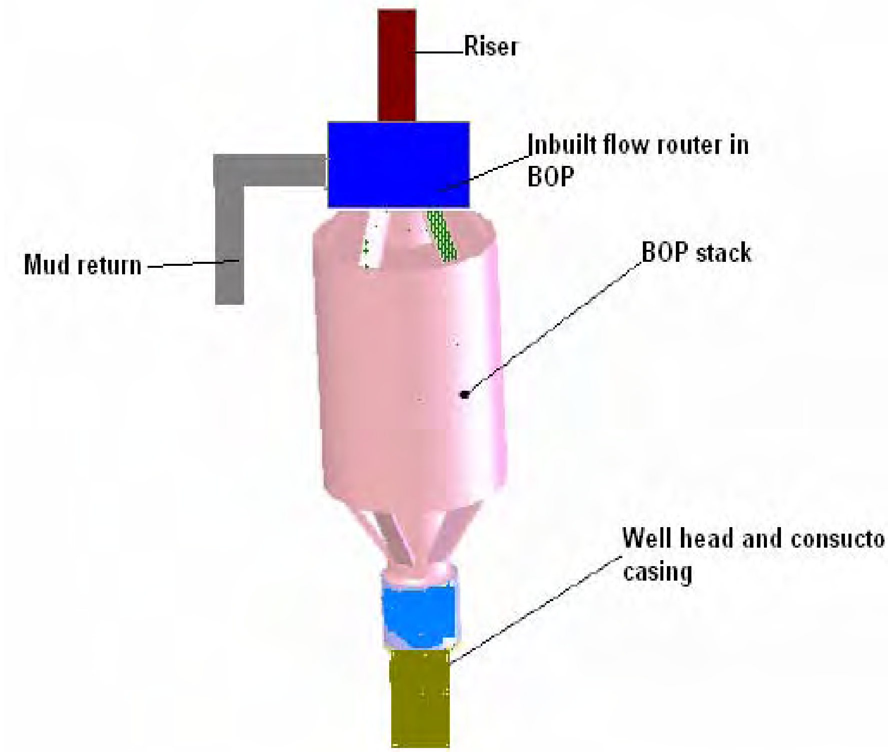


Figure K. Modified BOP design with outlet for mud pump

In the third concept of modified BOP design with outlet for mud pump, we propose to modify BOP stack to route mud from top hole and provide outlet for mud return. The mud will be supplied to mud pump through a composite hose. This may not be a good option as we need to modify BOP which is part supplied by a vendor and changes are to be made in the original design for prototype testing. As the number of seals would be less in this case, it would be good in sealing characteristics. However, in this case, there would be a sudden reduction in the cross section which can cause severe stress in the connecting hose. This may result in fatigue failure which is the same as in the case of the second concept.

Table II. Concept-1 Evaluation Matrix

Weight (%)	***Criteria***	***Existing Subsea rotating device with composite hoses***	***Proposed flow diverter design***	***Modified BOP design with outlet for mud pump***
20	Sealing capability (for mud and sea water)	**Datum**	S	+
20	Durability/Reliability		S	S
20	Maintenance ease		S	-
10	Strength		S	-
10	Cost		+	-
20	Stresses in the components		-	-
	+ Percentage		10	20
	- Percentage		20	60
	Total	0	-10	-40
	Rank	1	2	3

Concept Analysis 2:- Seals

Sealing plays the significant role of curbing the amount of leakage in drilling operations. Though seals with leak proof capabilities are available, they are expensive and complex. Hence, the solution to this lies in keeping the leakage within limits. To determine the amount of leakage that can be allowed, we need to determine the power loss due to the leakage of drilling mud. It is calculated as follows:-

Fluid Power = Flow rate * Pressure head

If we consider the loss factor to be 'α' then, Power loss is given by

α * Fluid Power = α * Q* Pressure head, where Q = flow rate

i.e. α * Fluid Power = $Q_{leakage}$ * Pressure Head

Therefore, given a flow rate and by assuming a loss factor, we can easily determine the amount of leakage that can be allowed.

If we assume a loss factor (α) of 1% and flow rate Q = 900 gpm, then,

$Q_{leakage} = \alpha * Q$ = 9gpm.

Therefore the allowable leakage is 9 gpm.

Three different concepts for sealing are evaluated:–

- Pipe threads
- Ring seals
- Gaskets.

Pipe threads provide assembling capabilities in addition to sealing capabilities. The seal capability is achieved by providing interference between the external and the internal threads. This concept has been used for drilling operations before. Hence, we assume this to be the datum.

O ring seal is a loop of elastomer with a round cross-section that is designed to be seated in a groove and compressed during assembly between the two mating parts, thus creating a seal at the interface. The major disadvantage of using an O ring seal is that it is not reliable at low temperatures that occur at the bottom of the sea. In addition to this, it takes time to assemble the mating parts using O ring seals.

Gaskets are a mechanical seal used to fill the space between two objects while under compression. This requires that they be made from compressible materials. Their major drawbacks when considering this particular scenario are assembling speed and reliability.

However, at the designing stage, we are not compromising on the aspect of quality of sealants. The functional requirement of the sealant is not to ‘minimize’ leakage, but to ‘eliminate’ it. Hence, the primary focus is on coming up with leak-proof sealants. Taper pipe threads satisfy our requirement.

Table III. Concept-2 Evaluation Matrix

Weight (%)	***Criteria***	***Pipe Threads***	***O ring seals***	***Gaskets***
20	Cost	**Datum**	S	S
30	Assembling speed		-	-
20	Reliability		-	-
15	Prone to human error		-	-
15	Suitable Geometry		S	-
	+ Percentage		0	0
	- Percentage		65	80
	S Percentage		35	20
	Total	0	-65	-80
	Rank	1	2	3

Concept Analysis 3:- Mud/ Sea- Water Riser Pipes

The types of pipes for return mud supply line assume importance depending upon the depth of water and the operational conditions. Three different concepts are developed for the design of riser pipe.

The first one is the most commonly used Segmented Pipe with mechanical connectors.

The other conceptual design is a Continuous Pipe which can be towed and installed. This helps in quick assembly, but is limited by the flexibility requirements and water depth.

The third design is fitted with strakes to reduce the vortex induced vibrations.

The pipe types are evaluated based on assembly speed, cost, flexibility, ease of handling, strength and fatigue issues. The evaluation below indicates that the Segmented Pipe is the better design. To provide an unobstructed flow path through the riser, it is proposed to use a constant diameter pipe for the mud return riser. This will result in constant cross section across complete length of the pipe. Further, the pipes would be easy to assemble. This leads to lower pressure drop, hence, an unobstructed flow path.

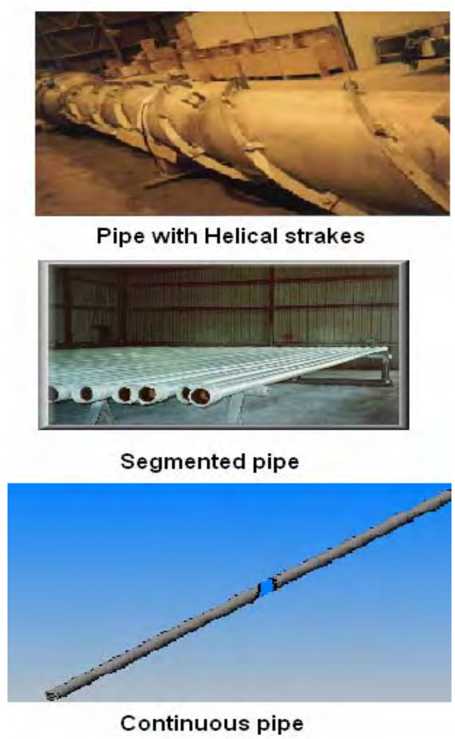


Figure L. Mud/ Sea-water riser pipes
Source: THDG Virtual Riser System, Study material provided by MMS

Riser Pipe Concept Analysis

Riser pipe is an integral part of the riser system. It satisfies three central functional requirements:-

Firstly, it provides a means for maintenance of a pressure differential between the surface and the sub sea pump by minimizing the flow restrictions and leaks.

Secondly, it adds structural stability to the riser system.

Thirdly, it provides a means for running equipment safely to the sea floor.

Order of magnitude calculations for designing Riser Pipes

Below is the design criteria specified for design of this riser system. The optimum riser diameter values are obtained and these dictate the surface power requirements given the operational flow rate of mud and water in the system.

- Mud flow Rate : 1000 gpm
- Mud Density : 10 to 20 lb/gal
- Initial Design should be capable of drilling up to around 12,000ft.

A flow analysis if performed determines the optimum riser diameter. Using this, pressure losses due to viscous effects in each riser pipe can be calculated. Assuming the surface pump is running at maximum flow rate, the viscous drag effects on each pipe can be found. The friction factor is calculated using the following equations:-

- $\mathbf{Re = (\rho\ \mathit{VL}) / \mu,}$
- $\mathbf{V=Q/((\Pi/4)*d^2)}$
- $\mathbf{f = 0.0791 / Re^{0.25}}$

From the calculated flow velocity ‘V’ and the properties of sea mud and water, we can calculate the respective Reynolds number and plot it as a function of pipe diameter.

- $\mathbf{\Delta P= f *L/d * (V^2/(2*g))}$

Thus, for a certain value of the inner diameter of the pipe, the total pressure loss for the 12000 ft long pipe can be calculated for the mud return line. This can then be plotted as a function of inner diameter of pipe.

5-10 in. diameter pipe is suitable for mud-riser pipe taking the pressure drop and the laminar flow into consideration. Riser size would be selected from available standard sizes.

External and internal loads on riser pipes

Three external forces act on the riser pipes. Effect of gravity is neglected.

1. The first force is a **tension force** applied at the end from the tensioners. It is expected to be around **3000000 N**.
2. The second is a cross current **drag force** with a value of (developed from guide funnel bracket section) which could be of the order of 1**000 N.**
3. The third applied load is an internal load. The **pressure force** from hydrostatics is around **30000000 N.** This is calculated from pump design which causes hoop's stress.

In the analysis of risers, we need to check whether the selected riser is able to withstand the above mentioned three loads.

Maximum stresses

Stress due to the Drag force

Stress= $\frac{1}{2} * \boldsymbol{\rho * C_d * D * (V(y))^2}$

where,	C_d	Drag coefficient
	$V(y)$	varies along the height of riser
	D	Outer diameter

Hoop's Stress

The Hoop's stress can be calculated from the internal pressure of 7800 psi, pipe diameter, thickness and the external pressure which is a result of the drag force. Hoop's Stress is also a function of the riser height.

Stresses in the top and bottom interfaces

Stress at top

1) Due to mud- riser pipe weight
2) Mud weight

Buoyancy will reduce the load due to riser weight at top interface.

Stress at bottom

1) Due to mud- riser pipe weight.
2) Due to Mud weight.
3) Due to hydrostatic pressure of mud.
4) In addition to the above, shear stresses develop at the bottom end due to bending moment. However, the shear stresses would not be significantly high since a flexible joint is proposed to be used instead of the fixed one.

Table IV. Concept-3 Evaluation Matrix

Weight (%)	***Criteria***	***Segmented***	***Segmented Stakes***	***Continuous***
15	Assembly ease	**Datum**	S	+
20	cost		-	+
10	Flexibility		S	-
10	Ease of Handling		-	S
35	Tensile/shear strength		S	-
10	Fatigue/endurance strength		+	-
	+ Percentage		10	35
	- Percentage		30	55
	Total	0	-20	-20
	Rank	1	2	2

Concept Analysis 4 (Power supply to drive the mud pump)

There are different ways of providing power to drive the mud pump. The pump can either be run by electric power source such as an electric motor or a hydraulic fluid can be pumped from the surface to drive the mud pump.

The various factors that need to be considered in determining the power supply to drive the pump are installation cost, efficiency of the power source and the power loss.

In the case of an electric power source, the cost of installation is substantially high. Electric motors are installed at the sea level to run the sub-sea mud pump and the electrical cables that are used to power these motors extend by thousands of feet. The cost of these cables can be a hindering factor. However, the electric power source makes up for this disadvantage in the efficiency and the power loss factors.

In the case of hydraulic power supply, a pump on the surface of the ocean pumps sea water down through a pipe to drive the mud pump. This causes the pump to have lesser efficiency and the power loss is also higher when compared to the electric power source.

One may consider the use of a pneumatic power source where a compressor is used to drive the sub-sea mud pump but such a system has lesser efficiency than hydraulic and electric power sources.

Table V. Concept-4 Evaluation Matrix

Weight (%)	***Criteria***	***Hydraulic Power Source***	***Electric power source***	***Pneumatic Power Source***
40	Installation Cost	**Datum**	-	+
30	Efficiency		+	-
30	Power loss		+	-
	+ Percentage		60	40
	- Percentage		40	60
	S Percentage		0	0
	Total	0	20	-20
	Rank	2	1	3

Concept Analysis 5 (Selection of subsea mud pump)

One of the central areas to be considered is that of the selection of the subsea mud pump. The selection of the pump is dependent on factors like horsepower rating, efficiency, ability to handle high viscosity fluids, variable flow rate ability, reliability and the capability to handle abrasive substances.

The power requirement of the pump is given as follows.

Power input = Fluid power / overall efficiency of the pump

Fluid Power= Pressure * Capacity (flow rate)

From the design criteria,
- Drilling mud density ρ = 15 ppg
- Drilling mud flow rate Q = 1000 gpm

From calculations, pressure head to be developed by the pump is around 1180m.
Maximum Pressure (P) = ρ*H*0.052 = 3020 psi

Fluid Power = P*Q = 1750 HP approximately

We have chosen an electric motor to drive the pump. In order to calculate overall efficiency, we need to assume certain efficiency for the mud lift pump and also the electric motor which drives it.

η mud-lift pump = 85% η electric motor = 85%

Overall efficiency= η mud-lift pump * η electric motor = 0.7225%

Once the fluid power and overall efficiency is calculated, we can now calculate the power requirement of the pump.

Power input = Fluid power / overall efficiency of the pump = 2500 HP

Let us consider a three phase electrical power supply with a 5500 V voltage.

Current = Power input / (Voltage* sqrt (phase)) = 200 Amperes approx.

Three different sub-sea mud pump concepts are evaluated:–

- Centrifugal pump
- Diaphragm pump
- Progressive Cavity pump

A comparative study of each of the pumps mentioned above based on various factors reveal that diaphragm pump should be preferred since it has good horsepower rating and efficiency, has the ability to handle abrasive solids and high viscosity fluids (drilling mud). It also provides a variable flow rate in a capacity range and is very reliable.

To achieve an obstructed flow path through the mud surface pump, the flow rate has to be maintained at a value 10-20% higher than the desired flow rate of the system.

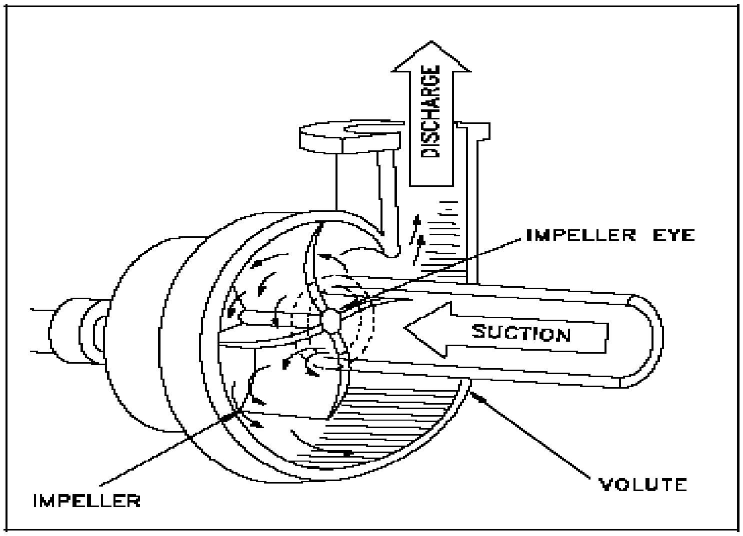


Figure M. Centrifugal Pump

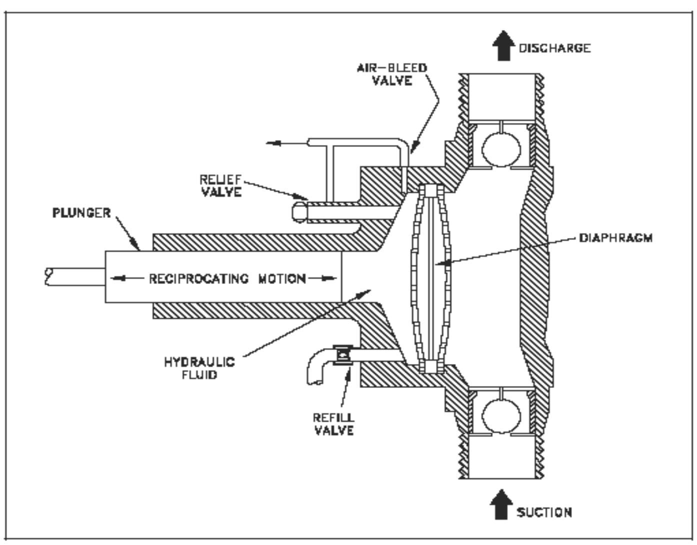


Figure N. Diaphragm Pump

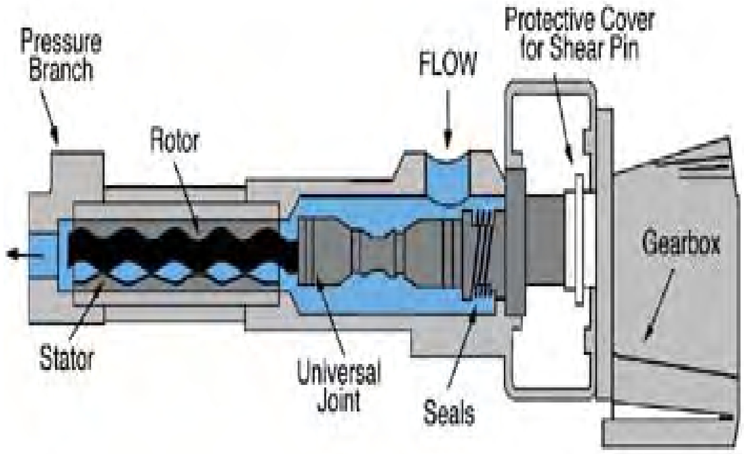


Figure O. Progressive Cavity Pump

<u>Table VI. Concept-5 Evaluation Matrix</u>

Weight (%)	***Criteria***	***Diaphragm Pump***	***Centrifugal Pump***	***Progressive cavity pump***
20	Horsepower Rating		-	S
15	Mechanical Efficiency (Considering fluids of high viscosity)		-	S
10	Ability to handle fluids of high viscosity		-	S
10	Variability of flow rate within a range		-	S
15	Reliability	**Datum**	-	S
10	Ability to handle abrasive substances(solids)		-	-
10	Dynamic sealing requirement		-	-
	+ Percentage		0	0
	- Percentage		100	20
	Total	0	-100	-20
	Rank	1	3	2

Concept Analysis 6 (Methods to prevent gumbo formation)

Gumbo, also known as hydrated sticky clay, can cause serious operational problems while drilling shale sections. This typically occurs while drilling younger shale sections that are common in certain offshore areas. The hydrated clay can cause bit balling, bottom hole assembly balling, mud rings, hole pack off and plugged flow lines. Therefore, it is important to prevent the formation of gumbo in drilling.

We analyze three different ways to prevent the formation of gumbo:–

- Using additives in the drilling mud
- Increasing flow rate
- Using electro-osmosis

Additives can be added to the drilling mud so as to provide the desirable characteristics to the mud to enable gumbo prevention. Such additives are usually either oil-based or water-based emulsions. Also, certain polymers and solutions containing potassium ions can be used. These additives provide additional advantages like reducing corrosion of drill bits, flow lines; efficient removal of cuttings and also act as a coolant for the drill bit. However, they are not environment friendly.

Gumbo prevention can also be achieved by increased flow rates of the drilling mud. However, unlike the one discussed before, this method addresses only the issue of gumbo prevention and doesn't offer any additional advantages. In addition, it also causes increased loss of circulation.

Electro-osmosis can also be used for gumbo prevention. In this method, the drill bit forms a cathode when drilling in shales and the water moves from the anode (surrounding shale) to the cathode thus preventing formation of gumbo. This method also doesn't provide any additional advantages. Also, it is a relatively new technology and is still being tested.

Table VII. Concept-6 Evaluation Matrix

Weight (%)	***Criteria***	***Additives***	***Increasing flow rate***	***Electro-osmosis***
30	Loss of circulation	Datum	-	S
20	Environmental Impact		+	+
30	Additional advantages (inhibit corrosion, removal of drill solids, cooling)		-	-
20	Cost		+	-
	+ Percentage		40	20
	- Percentage		60	50
	S Percentage		0	30
	Total		-20	-30
	Rank	1	2	3

Recommendation

The following concepts are enlisted considering a combination of various approaches from Concept-1 to Concept-6. In total, four concepts have been short-listed after appropriate combination of various approaches considered in the concept analysis.

Table VIII. Short-listed approaches

Concepts	**C-1**	Existing Subsea rotating device with composite hoses	*Pipe Threads*	Segmented	Electric power source	Diaphragm Pump	Additives
	C-2	Proposed flow diverter design	*Pipe Threads*	Segmented	Electric power source	Progressive cavity pump	Additives
	C-3	Existing Subsea rotating device with composite hoses	*Pipe Threads*	Segmented	Hydraulic Power source	Diaphragm Pump	Additives
	C-4	Proposed flow diverter design	*Pipe Threads*	Segmented	Hydraulic Power source	Diaphragm Pump	Additives

Table IX. Concept Evaluation Matrix of short-listed approaches

Parameters, weightage / Concepts	C-1	C-2	C-3	C-4
Durability (10%)	S	-	**Datum**	S
Ease of manufacturing (10%)	S	S		S
Ability to do the required function (20%)	+	+		S
Effectiveness/ Efficiency (10%)	S	S		S
Cost (10%)	-	-		-
Operational ease (10%)	S	-		S
Ease of maintenance (10%)	S	S		S
Safety/sturdiness of design (20%)	S	S		S
+ Percentage	**20**	**20**	**-**	**0**
- Percentage	**10**	**30**	**-**	**10**
Total	**10**	**-10**	**-**	**-10**
Rank	**1**	**3**	**2**	**3**

The suggested concept design recommends use of existing sub-sea rotating device with composite device, threaded pipe seals, *s*egmented type pipes for mud and sea water risers, electric power source to drive mud pump, diaphragm pump and the use of additives to prevent gumbo formation. This conceptual design will help maintain required pressure differential between the mud and sea water and also provide unobstructed mud return path.

Implementation of the Concept selected during the Conceptual Design Stage

The next stage of the design process is to embody the selected concept. Short-listing of the concept to be implemented needs to be followed up with innovative design, detailed analysis and performance optimization of each of the modules of the selected concept.

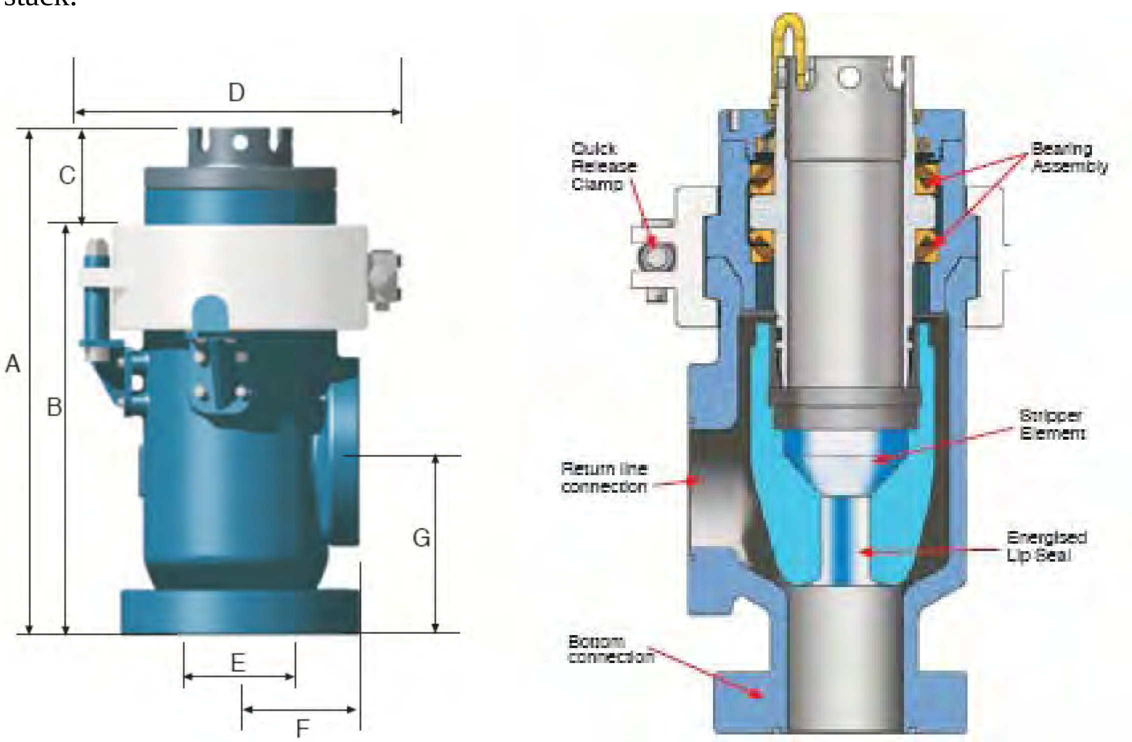
It has been identified that the following three salient features of the selected concept need extensive research and analysis:-

1. Diaphragm Pump to pump the mud up the mud-return line
2. Electric Power Source to drive the diaphragm pump
3. Segmented Riser Pipe for the mud-return line

Bottom Interfacing is another area which has to receive major attention purely because of its significance and its implications on the performance of the system. At the conceptual design stage, it was proposed to utilize a vetco flex joint for the bottom interface.

Sub-Sea Rotating Device

A variety of rotating diverters are available in the market depending upon the varying operating principles, applications, specifications and ratings. The critical components such as packing elements, bearings and hydraulic system have proven expensive. This has expanded drilling programmes without any serious failures and reliability has been proven. In a deepwater application, the development of rotating diverters is done for sub-sea installation on top of the BOP stack.



Inlet Flange	A	B	C	D	E	F	G	Outlet Flange
7 1/16" 5000#	40,5" 111,7cm	33" 84cm	12" 30cm	26" 66cm	7" 17.78cm	10 " 26,7cm	15 " 39,6cm	7 1/16" 3000#
9" 2/3000#	43" 109cm	32" 81cm	12" 30cm	26" 66cm	9" 22.9cm	10 " 26.7cm	15" 39cm	7 1/16" 3000#
11"RF 5000#	43,5" 114,3cm	34" 86,4cm	12" 30cm	26" 66cm	11" 27,9cm	10 " 26,7cm	16 " 42,4cm	9" 3000#
13 5/8" 5000#	45" 114,3cm	34" 86,4cm	12" 30cm	26" 66cm	11" 27,9cm	10 " 26,7cm	16 " 42,4cm	11" 3000#

Figure P. Sub-sea rotating device

Selected Size

Rotating diverter with 13-5/8" inlet flange has been selected for our task.

Bottom Interface

Flex Joint

Flex joints are flexible couplings used to couple the drilling riser to the BOP Stack. These are designed as a direct replacement for a standard ball joint. The fundamental constituent of the FlexJoint® is the laminated flex element. The flex element is a molded elastomeric bearing consisting of a series of spherical shaped metal reinforcements laminated between and encased by a proprietary elastomeric material. A typical non-bellows FlexJoint will include the following basic components:

Figure Q. Flex Joint

Flex Joints limit the bending stress in mooring tubes by accommodating all combinations of angular, tension and radial forces. Optional inflatable seals can be provided at the tether upper end to permit additional buoyancy inside the column. Oil States also supplies production riser flex joints that allow the riser to flex in any direction and yet maintain a seal under high internal operating pressures and high tension forces. Combining these flex joints with elastomeric tensioners provides a maintenance-free production riser system, eliminating all active air and hydraulic requirements.

OSI also designs workover and completion riser flex joints to accommodate angular motions due to platform offsets, as well as motions from thermal contraction and expansion. OSI's flex joints can withstand multimillion pound forces with large deflections and high internal pressures due to the joint's elastomeric seal. This seal consists of alternate, spherically-shaped layers of metal and elastomer, integrally molded into a single, inseparable assembly. Metal layers control stresses of each elastomer layer as well as provide axial stiffness. Despite this high stiffness, the elastomer retains an inherent softness under shearing forces. Angular movement is accomplished by pure shear through all of the elastomer laminates.

When these factors are properly considered, the flex joint can be designed with highly predictable and controllable operating characteristics. The result is a coupling that transmits very low bending stress to the connecting members - even under severe operating conditions. Oil States designs each flex joint to specific application requirements and specifications. Materials used in the flex joints consist of high grade steels and various nitrile elastomers that offer high resistance to oil well fluids. These elastomers also exhibit extremely long life under the conditions encountered during drilling and production operations.

Selection of Flex Joint

AVAILABLE SIZES FOR FLEX JOINTS					
FlexJoint ® Size (in)	Parameters				
	Nominal Riser O.D. (in.)	Axial Tension Rating (kips)	Angular Rotation (deg)	Design Pressure (psi)	Test Pressure (psi)
6	6	309	±14	5000	7500
8	8	90	±15	2220	3330
10	10	239 - 825	±14 - ±20	2350 - 5000	3525 - 6250
12	12	280 - 300	±14 - ±15	1800 - 2220	2700 - 3330
14	14	242 - 375	±15	2160 - 2200	3240 - 3300
16	16	500	±15	2400	3553
18	18	500 - 1014	±12 - ±14	2220 - 2500	3330 - 3750
20	20	740	±17	3250	4875


Subsea FlexJoint

Selected Flex Joint

Size (in)	Parameters				
	Nominal Riser O.D. (in.)	Axial Tension Rating (kips)	Angular Rotation (deg)	Design Pressure (psi)	Test Pressure (psi)
20	20	740	±17	3250	4875

Cable mounting for 2.684 umbilical cord

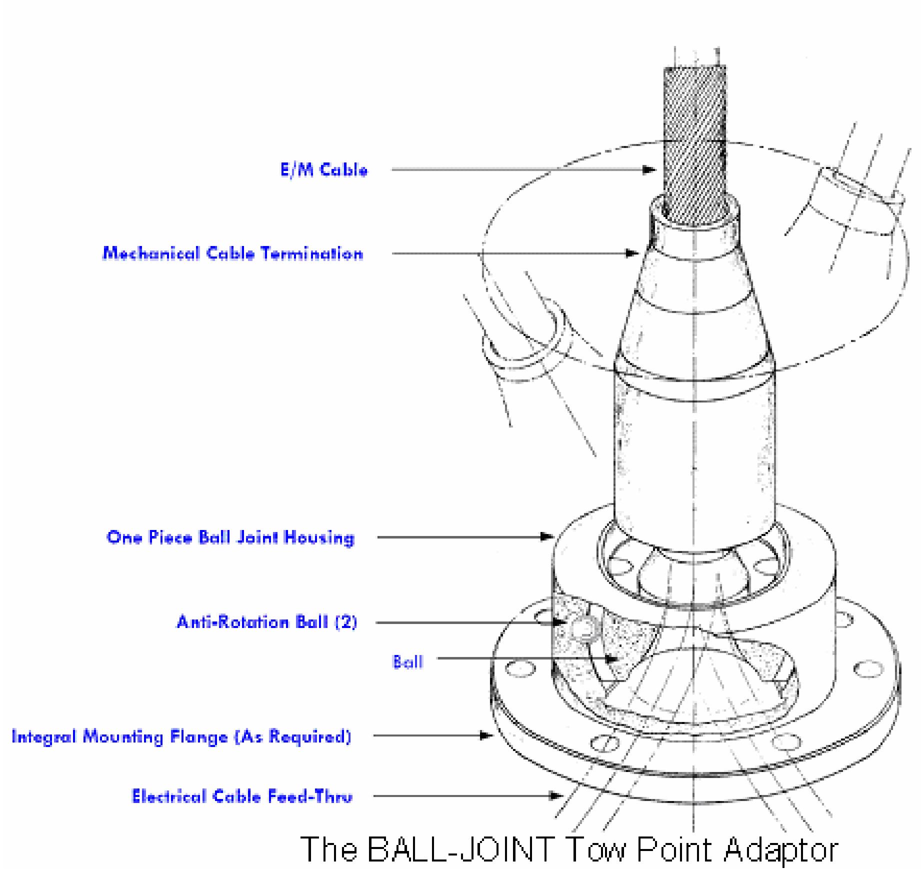


Figure R. Ball Joint Tow Adaptor

The ball joint shown above provides articulation at cable termination. This is a unique design developed by PMI industries. By reducing or eliminating bending at the cable attachment point, the BALL JOINT Tow Point Adaptor extends the working life of cable system and cuts the expense of repair and downtime. The unique patented design of the BALL JOINT Tow Point Adaptor uses stationary anti-rotation balls encased between housing and an articulating ball member. Easy assembly consists of inserting the articulating ball member through an access opening in the housing and capturing the anti-rotation balls. After assembly, the ball is restricted from rotation relative to the housing, but will articulate conically up to 30 degrees off axis. It is fabricated of corrosion resistant metals such as Nitronic® 50, INCONEL® 625, Aluminum nickel bronze, Titanium and 316 Stainless steel for compatibility with cable system and mission. BALL JOINT Tow Point Adaptors are custom engineered in sizes, materials, and degrees of articulation to meet system requirements. The BALL JOINT Tow Point Adaptor is one of many PMI products for controlling stress in underwater cable systems designed to help deal with the challenges of the ocean environment.

Bottom Interface Flange and Tapered Stress Joint

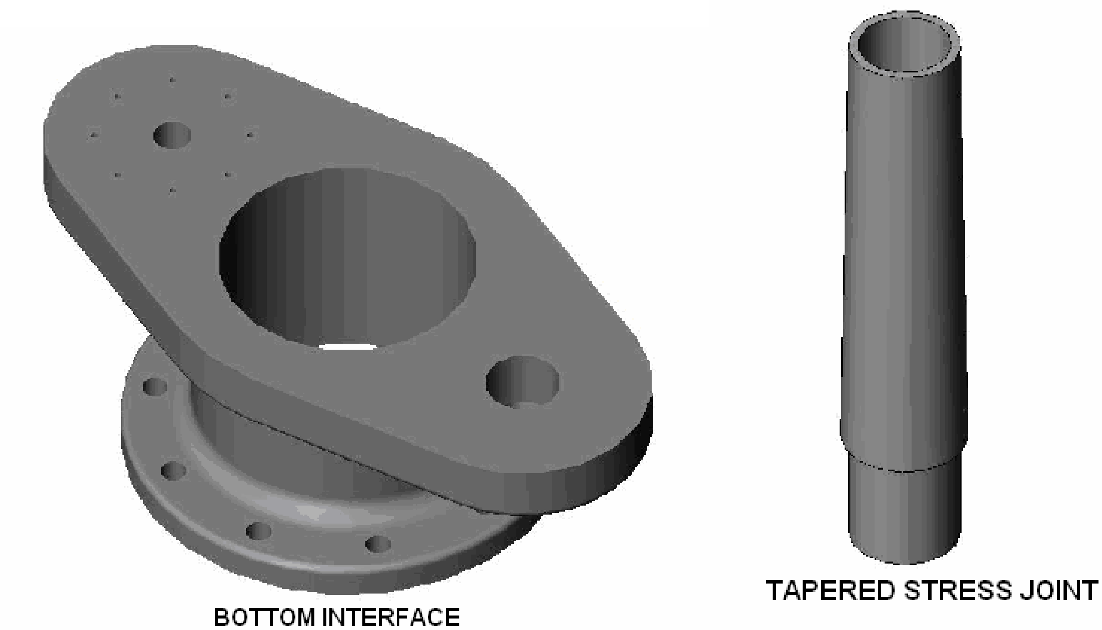


Figure S. Bottom Interface Flange and Tapered Stress Joint

The figure on the left shows the bottom interface which connects riser and cable to the flex-joint. The figure on the right is a tapered stress joint which provides certain extent of flexibility and works under the high pressure conditions. It is also easy to process and assemble.

Bottom interface analysis

Referring to the earlier report on THDG Virtual Riser System, the weight of BOP is around 240,000 lbs. The pump package together with BOP and accessories has an apparent weight of 191,500 lbs. In short, the total tension load on the bottom interface without considering buoyancy effect is 191,500 lbs. This tension load is divided equally between the cable and the mud riser. A load of 95,750 lbs is transferred to mud riser through threaded joints. A hollow cylinder is constructed to simulate the threaded connection between the mud-riser and the flange of bottom interface. Thickness of the representative cylinder is the difference between the nominal and the minor diameter of the thread and the outer diameter of the tapered stress joint. The tension load is transferred to the cable equally through 8 bolts. Eight bolts can be simulated as cylinders of equivalent diameters. A distributed tension load of 11,967 lbs is applied to each of them. The bending moment is accounted for by the flex joint installed below the bottom interface. In addition to this, the cable encounters less bending moment due to the ball joint provided at the end of the cable.

Results of the analysis

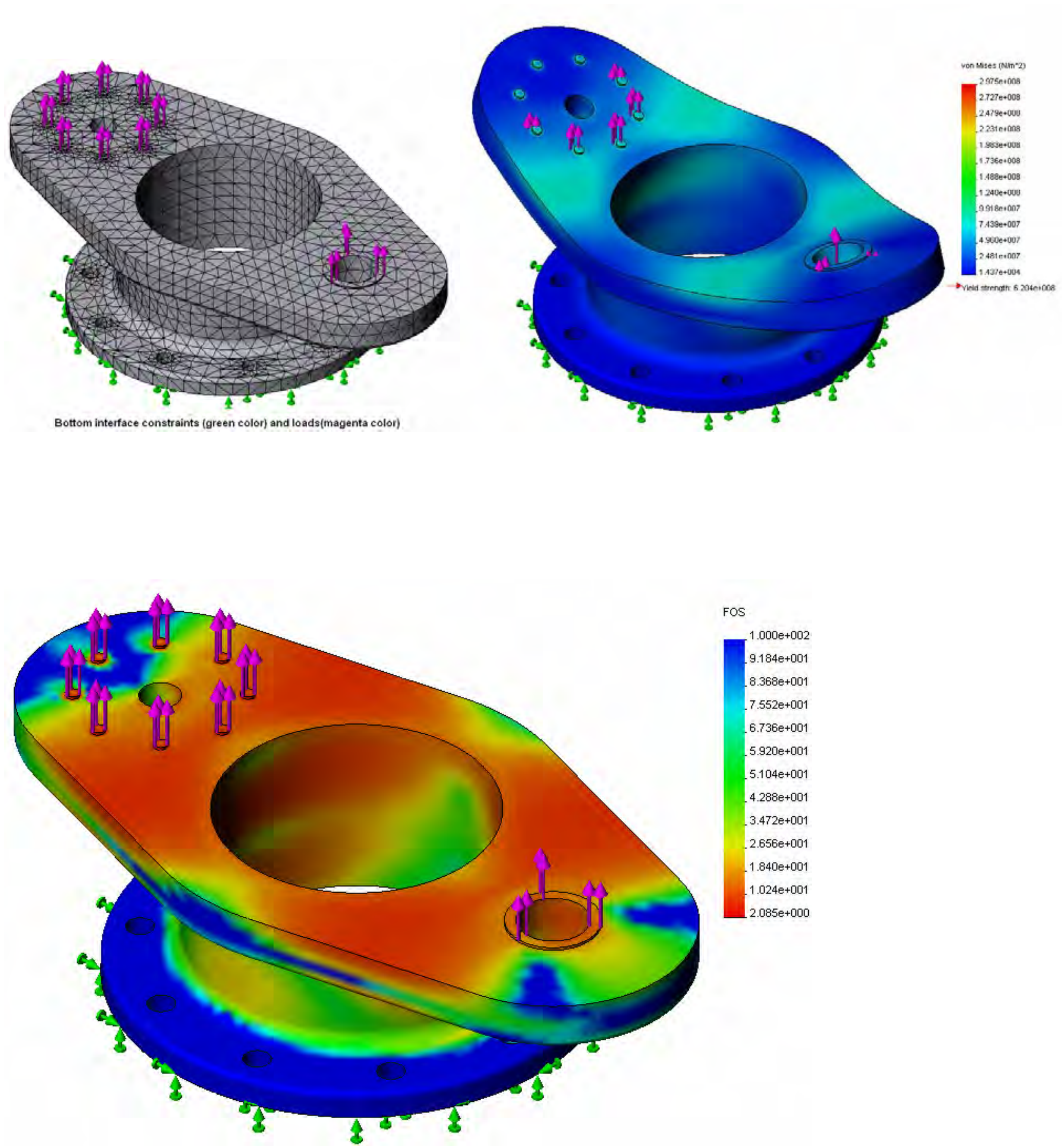


Figure T. Analysis of bottom interface

Modeling was done using Solid Works and static analysis was run using Cosmos Works.

- Yield strength for alloy steel = 6.204 X 10^8 N/m^2
- Maximum Von Mises stress = 2.975 X 10^8 N/ m^2 < Yield Strength
- Minimum factor of safety = 2.1

Guide Funnel

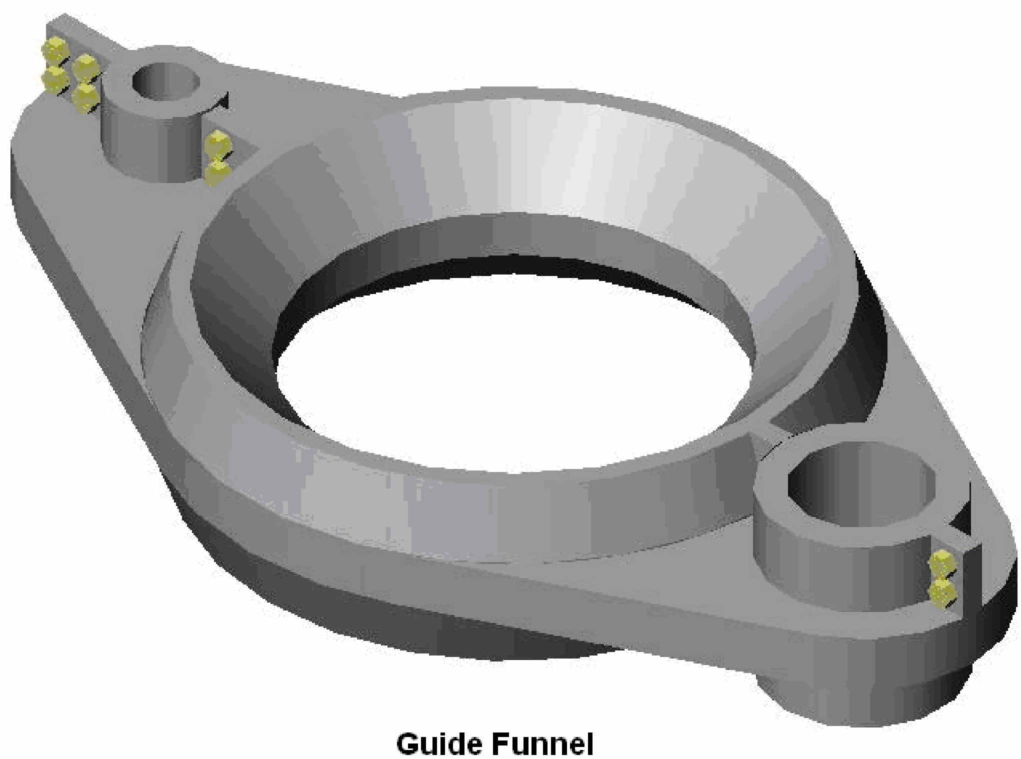


Figure U. Guide Funnel

The guide funnel bracket is used to provide a clear path to run the drill string from the floating drill rig to the sub-sea pump / BOP package. It also acts as structural support to the riser pipes. The guide funnel supports the mud riser pipe and electric cable at various points along the length of riser. This increases the stiffness of the mud riser and cable system. Further, it transfers the load exerted by the tension cable on to the mud riser.

The center distance between the guide funnel and the cable mounting is 19” which is the same as the distance between the mud riser hole and the guide funnel center. The centre hole of the guide funnel has a diameter of 18.75” which is required for clearing the drill bit and drill string. It is split into half and is connected by means of fasteners. The material used for the manufacture of guide funnel is Al Alloy 6061.

BOP

Annular blowout preventer is a large valve used to control wellbore fluids. In this type of valve, the sealing element resembles a large rubber doughnut that is mechanically squeezed inward to seal on either pipe (drill collars, drill pipe, casing, or tubing) or the open hole. The ability to seal on a variety of pipe sizes is one major advantage of the annular blowout preventer over ram-type blowout preventers. Most blowout preventer (BOP) stacks contain at least one annular BOP at the top of the BOP stack, and one or more ram-type preventers below. While not considered as reliable in sealing over the open hole as around tubulars, the elastomeric sealing doughnut is required by API specifications to seal adequately over the open hole as part of its certification process.

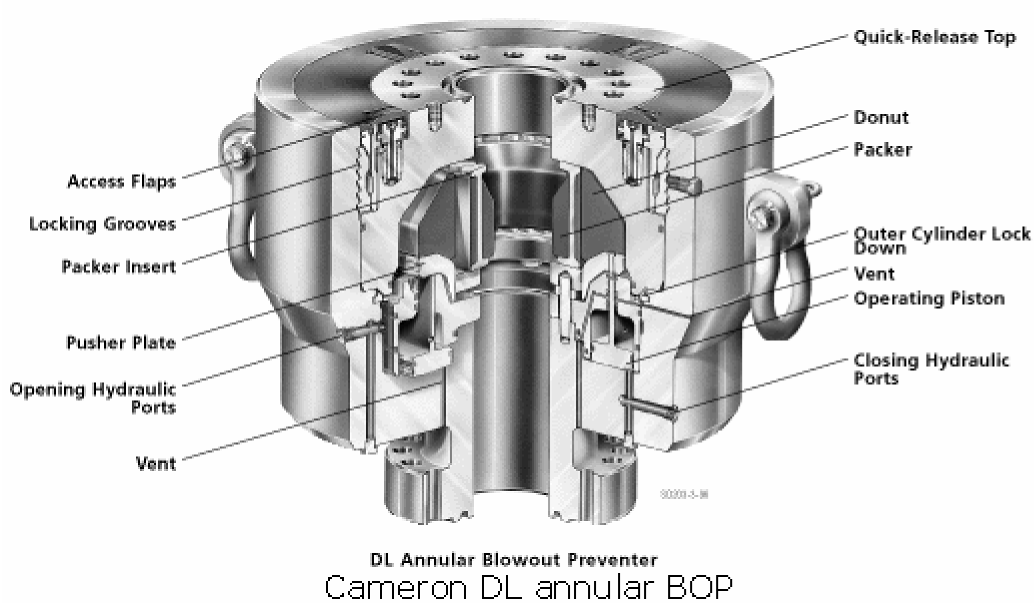


Figure V. Cameron DL Annular BOP

The above figure shows an example of Cameron DL annular BOP. In the unique design of the Cameron DL annular BOP, closing pressure forces the operating piston and pusher plate upward to displace the solid elastomer donut and forces the packer to close inward. As the packer closes, steel reinforcing inserts rotate inward to form a continuous support ring of steel at the top and bottom of the packer. The inserts remain in contact with each other whether the packer is open, closed on pipe or closed on open hole. The Cameron DL BOP is shorter in height than comparable annular preventers. A quick-release top with a one-piece split lock ring permits quick packer change-out with no loose parts involved. The design also provides visual indication of whether the top is locked or unlocked. The DL BOP is designed to simplify field maintenance.

Components subject to wear are field-replaceable and the entire operating system may be removed in the field for immediate change-out without removing the BOP from the stack. Twin seals separated by a vented chamber positively isolate the BOP operating system from well bore pressure. High strength polymer bearing rings prevent metal-to-metal contact and reduce wear between all moving parts of the operating systems. The Cameron DL BOP is available in sizes from 7-1/16" to 21-1/4" and in working pressures from 2000 to 20,000 psi.

Following table shows BOP specifications for Canam services Inc.

ANNULAR AND RAM BOP SPECIFICATIONS												
VERTICAL BORE		WORKING PRESSURE		TESTING PRESSURE		MAX. RAM SIZE		MAX. OPERATION PRESSURE		BOP TYPE OPTIONS	SERVICES OPTIONS	OPERATION OPTIONS
IN	MM	BAR	PSI	BAR	PSI	IN	MM	BAR	PSI			
7 1/16	180	210	3,000	420	6,000	5 1/2	139.70	140	2,000			
7 1/16	180	350	5,000	700	10,000	5 1/2	139.70	140	2,000			
7 1/16	180	700	10,000	1,050	15,000	5 1/2	139.70	140	2,000			
7 1/16	180	1,050	15,000	1,575	22,500	5 1/2	139.70	210	3,000			
9	230	210	3,000	420	6,000	7	177.80	140	2,000			
9	230	350	5,000	700	10,000	7	177.80	140	2,000			
9	230	700	10,000	1,050	15,000	7	177.80	140	2,000			
9	230	1,050	15,000	1,575	22,500	7	177.80	210	3,000			
11	280	210	3,000	420	6,000	8 5/8	219.08	140	2,000	ANNULAR OR DOUBLE OR SINGLE	H2S OR STANDARD	HYDRAULIC OR MANUAL
11	280	350	5,000	700	10,000	8 5/8	219.08	140	2,000			
11	280	700	10,000	1,050	15,000	8 5/8	219.08	140	2,000			
13 5/8	346	210	3,000	420	6,000	10 3/4	273.05	140	2,000			
13 5/8	346	350	5,000	700	10,000	10 3/4	273.05	140	2,000			
13 5/8	346	700	10,000	1,050	15,000	10 3/4	273.05	140	2,000			
16 3/4	425	140	2,000	210	3,000			140	2,000			
16 3/4	425	210	3,000	315	4,500			140	2,000			
16 3/4	425	350	5,000	700	10,000			140	2,000			
21 1/4	540	210	3,000	315	4,500	16	406.40	140	2,000			

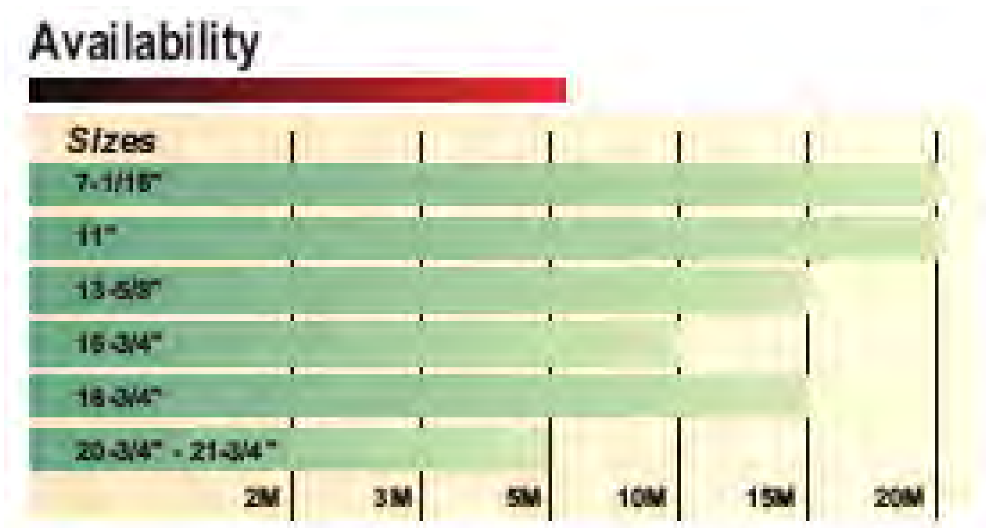
CANAM SERVICES INC BOP SPECIFICATIONS

<u>Selected size</u>

A 13 5/8" (346.1 mm) ANNULAR BOP for 10000 psi working pressure is selected. A drill string of 5.5" is considered.

Wellhead

VG-loc is a connector used with exploration systems designed for fast, reliable makeup for diverter systems and casing heads onto plain end pipe without welding or extensive preparation. The connector stabs over a field-cut casing stub and locks and seals to the stub utilizing a slip assembly actuated by set screws which drive and hold the slips against the pipe.



Features

- Fast reliable makeup without welding or extensive preparation
- Easily installed, requires no special installation tools
- Slips mechanically set; easily removed from casing stub
- Reduces drilling costs

Sealants

The sealants perform the fundamental function of preventing leakage. The joints are a critical consideration in the design of the drilling system. Leaks are likely to occur if the joints aren't leak-proof, which would result in loss of pressure differential. Also, the pipes could separate, causing damage to the equipment on the seafloor.

There are several methods of joining individual pieces of the riser pipe together. One of the standard concepts is a tapered threaded connection. There is a male type connection at one end and a female connection at the other end on each pipe. Pipes are joined together male to female. To ensure no leakage and a secure connection, a certain torque is applied to each joint when it is assembled. An advantage of this design is that it is a standard connection; hence, boat crews are familiar with the assembly procedure. This also means that assembly time will be almost the same when compared to other alternatives. The drawback of this design is that any exposed thread would be subject to wear and could then cause failure. The threads would have to be designed to prevent leakage and withstand the applied stress as well. In addition to this, the potential for cross-threading is always present.

The salient features of the pipe threads used are:-

- Ensure a good seal when screwing together pipes and fittings
- Provide an interface between the internal and external threads
- Usually made of PTFE, the most famous brand of which is Teflon
- Form a leak-proof seal and 'lubricate' the joint

Advantages

- Easier to tighten, assemble and disassemble
- Reduce / Eliminate Thread Galling. [Thread galling occurs when threads weld themselves together. This is more common with pipes and fasteners made from alloys that protect themselves from corrosion by developing their own oxide surface film, like aluminum and stainless steel.]

Pipe thread sizes are described much as bolt sizes are, although the shapes are different. For example, "½–14 NPT" identifies a pipe thread with a nominal outside diameter of ½ inch and 14 threads to the inch, made according to the NPT standard. If "LH" is added, the pipe has a left hand thread. In the United States, the pipe thread standards are:

Table X: Standard Pipe Threads

NPT	American Standard Pipe Taper Thread
NPSC	American Standard Straight Coupling Pipe Thread
NPTR	American Standard Taper Railing Pipe Thread
NPSM	American Standard Straight Mechanical Pipe Thread
NPSL	American Standard Straight Locknut Pipe Thread

The word "taper" in several of these names points to the big difference between many pipe threads and those on bolts and screws. Many pipe threads must make not only a mechanical joint but also a leak-proof one. To accomplish this, the threads become shallower the farther they are from the end of the pipe or fitting. The bottoms of the threads aren't on a cylinder, but a cone; they taper. The taper is $^{1}\!/_{16}$ inch in an inch, which is the same as ¾ inch in a foot. The figure below shows the actual profile of the taper or the thread profile.

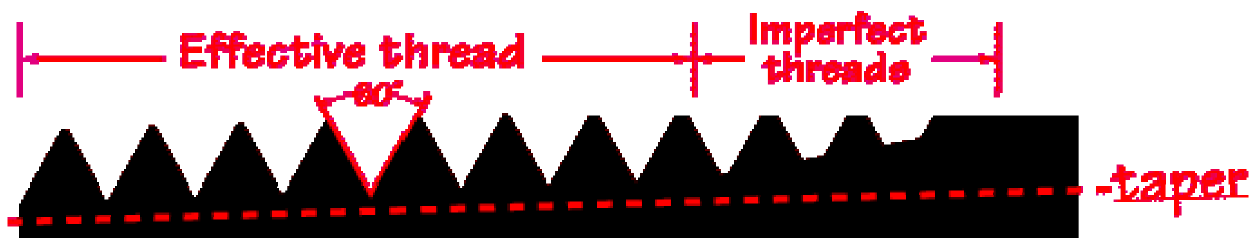


Figure W. Profile of taper thread pipe

As a result of the taper, a pipe can only screw into a fitting a certain distance before it jams, unlike threading a nut on a bolt. The standard specifies this distance, the effective thread. It also specifies another distance, the engagement, the distance the pipe can be screwed in by hand, without much effort. For workers, instead of these distances, it is more convenient to know how many turns to make by hand and how many with a wrench. Some of the recommended sealants for use with a broad range of liquids, gases, refrigerants are V-2 PTFE, TF-25, TFW PTFE*, TF-15 PTFE Thick or Thin, Petro-tape PTFE*, Black Graphite Temp-Tite, PFPE Grease etc. Another major sealant is the Vibra Seal® Pre-applied Thread Seal.

Vibra Seal® Pre-applied Thread Seal

Vibra Seal® Pre-applied Thread Sealant is a tough, non-hardening sealant engineered to be pre-applied to parts. Vibra-Seal is designed to provide an instant seal on tapered pipe threads against most fluids, fuels and lubricants but can also be used on straight threads. Vibra-Seal performs to the demanding requirements of the automotive, truck, drilling and agricultural equipment manufacturers. It provides lubricity superior to Teflon® — at a lower cost. It is available in white or burnt orange colors, Vibra-Seal coatings are highly filled water based liquids that are non-toxic and non-sagging. When dried, they become a resilient, tight clinging and non-curing sealant. Vibra-Seal coated parts also resist loosening because of the prevailing torque created by the coating.

Specifications

Resin Coating	Acrylic
Colors	White or Burnt Orange
On-Part Life	4 Years, Minimum
Toxicity	None
Torque	Tension

The tension in the fastener can be reasonably controlled by controlling the torque. For any given fastener the torque tension relationship can be stated as follows:

$$\mathbf{T = KDF}$$

where

- T = Torque, lb.-in. (N•m)
- D = Nominal bolt diameter, in. (m)
- F = Tension or clamping force, lbs. (N)
- K is a universal constant for all sizes which can be established empirically.

Significant applications of the Vibra-Seal® Pre-applied Thread Sealant

- Pipe Fittings of all Kinds
- Rear Axle Filler Plugs
- Brake Fittings
- Bearing Adjuster Nuts
- Compressor Pipe Plugs
- Overhead Fire Sprinklers
- Shower Heads
- Pressure Gauges/Sensors
- Cable Connectors
- Adjustment Screws
- Door Closure Hardware
- Screws for Plastic Assembly

K Values for Vibra-Seal® Sealants*

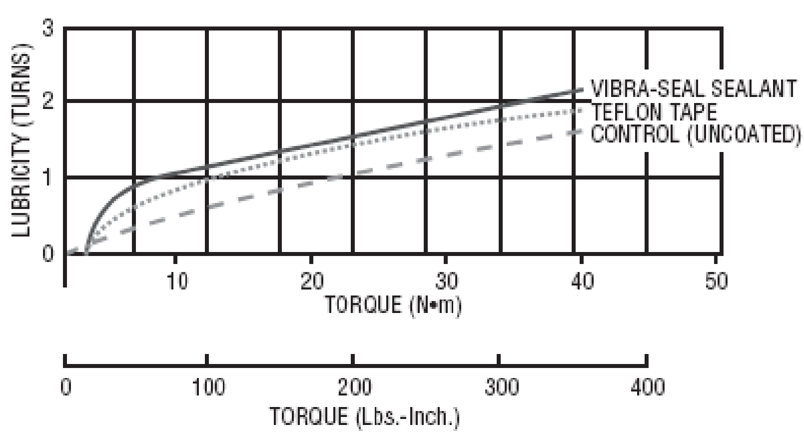
	K Value
Dry Zinc Phosphate	0.13
Zinc Phosphate/Oil	0.11
Vibra-Seal on dry Zinc Phosphate	0.11
Vibra-Seal on Zinc Phosphate/Oil	0.09

Pressure Resistance

Pipe Size	Burst Rating	Test Pressure	Test Results (Test Fluid –10 wt. Motor Oil)
1/2" NPT	10,400 psi (72 MPa)	10,000 psi (69 MPa)	Test discontinued with no sign of leakage
2" NPT	5,200 psi (36 MPa)	4,000 psi (28 MPa)	Test discontinued with no sign of leakage
3" NPT	5,000 psi (35 MPa)	3,000 psi (21 MPa)	Test discontinued with no sign of leakage

Lubricity

NPT joint assembly is made quicker and easier because of the lubricating ingredients in Vibra-Seal products which resist thread galling. Line-up adjustments can be made several hours after assembly without loss of sealing quality. Joints can be easily disassembled with regular tools even after years of service.



Reusability

Vibra-Seal products have exhibited the ability to be reused five times on 1/2" NPT sittings which are torqued up snugly. After five uses, these fittings still maintain 300 psi (2.0 MPa) hydraulic pressure without recoating.

Breakloose and Prevailing Torque Characteristics

Typical Strength Values @ Room Temperature Test Specimen	Seating Torque	Breakloose Torque	Prevailing Torque – 180°
Control (No Coating)	360 lb-ins (40.7 N•m)	243 lb-ins (27.5 N•m)	0 lb-ins (0 N•m)
Vibra-Seal Products Coating	360 lb-ins (40.7 N•m)	175 lb-ins (19.8 N•m)	21 lb-ins (2.4 N•m)

Segmented Riser Pipe

Riser selection and design is integral to all aspects of the mud recirculation system. The choice of the riser determines the fulfillment of the functional requirements of the system. The riser pipe provides a means for maintaining a pressure differential between the sea-water and mud-water. This is accomplished by minimizing the flow restrictions and leaks. Further, it adds structural stability to the riser system and provides a means for running equipment safely to the sea-floor.

The crucial consideration in the riser selection and design is the internal diameter of the riser pipe. This parameter is governed by the mud flow rate requirements and the pump power limitations. The obtained riser diameter dictates the surface power requirements given the operational flow rate of mud in the system. The following design criteria were specified for this design:

Mud Flow Rate	1000	gpm
Mud Density	15	lb/gal
Drilling Height	12000	ft
Dynamic Viscosity	34	centipoise

For facilitation of our calculations, the design criteria were converted into SI units.

Mud Flow Rate	0.0630902	m^3/s
Mud Density	1797.396405	kg/m^3
Drilling Height	3657.607315	m
Dynamic Viscosity	0.034	$N\text{-}s/m^2$

The various parameters analyzed in the determination of the optimum inner diameter are:-

1. Velocity
2. Reynolds Number
3. Friction Factor of the riser pipe
4. Pressure Loss in the pipe as a result of the friction

Pressure loss in the riser pipes occurs primarily due to viscous drag and mud lift pressure. A flow analysis performed to calculate the pressure losses due to viscous effects in each riser pipe aids in the determination of the optimum riser diameter.

The following are the calculations performed to obtain the optimum riser diameter. The expression for the pressure loss in the riser pipes is

$$\Delta p = f \frac{l}{d_i} \frac{V^2}{2g}$$

$$f = \frac{0.0791}{\mathrm{Re}^{0.25}}$$

$$\mathrm{Re} = \frac{\rho V d_i}{\mu}$$

$$V = \frac{Q}{\frac{\pi}{4} d_i^{\,2}}$$

where

Re	=	Reynolds Number
F	=	Moody Friction factor
Q	=	Pipe Flow Rate [m3/s]
d_i	=	Pipe Inner diameter [m]
μ	=	Dynamic Viscosity of fluid [m2/s]
l	=	Riser Depth

The Moody friction factor is determined from the Moody chart. The Reynolds number is calculated from the fluid density, velocity, and dynamic viscosity μ, and the pipe diameter.

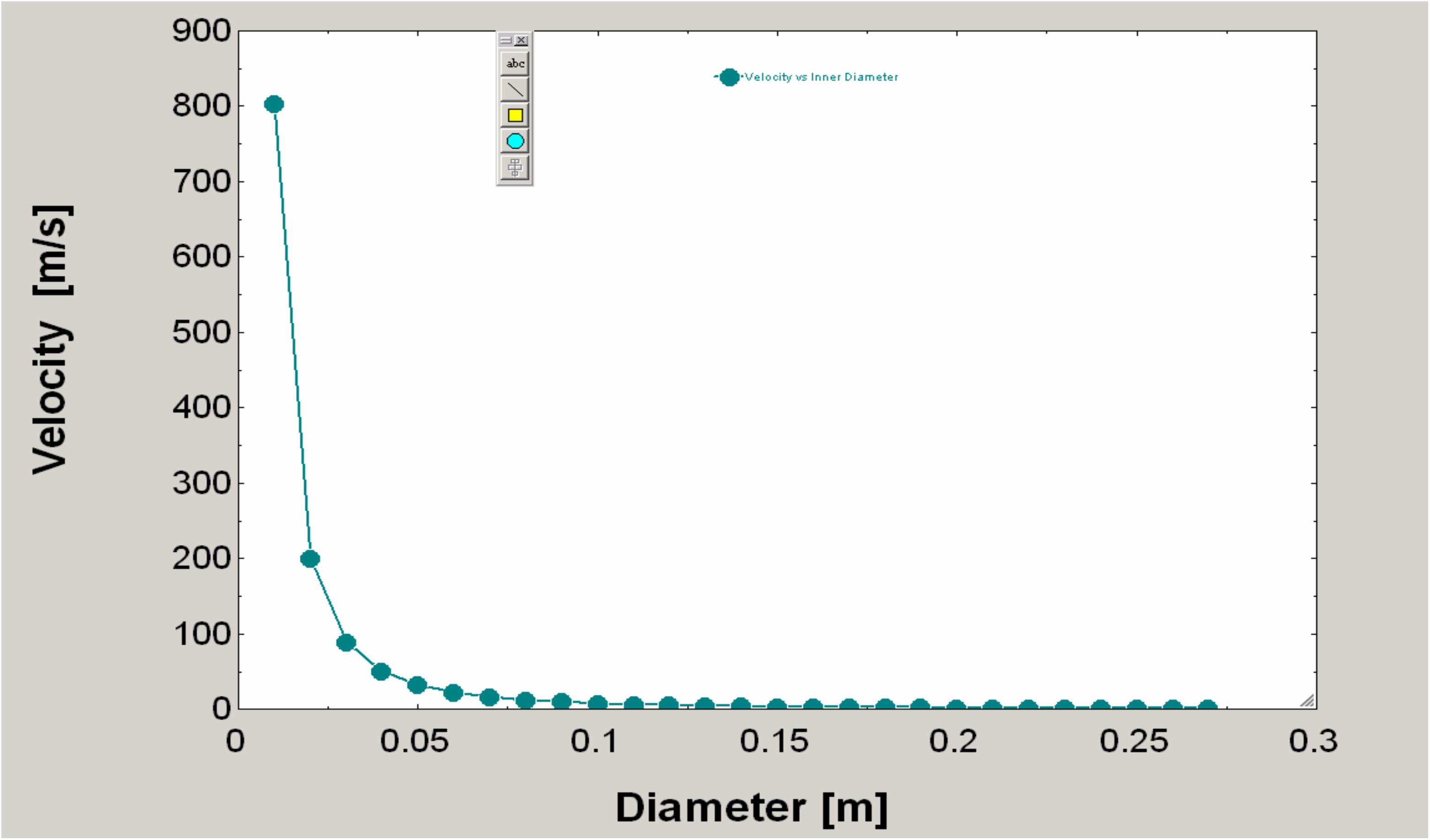
A FORTRAN code is developed to determine the values of mud velocity, Reynolds Number, Friction factor and the associated pressure loss for a range of values of the inner diameter of the riser pipe. The FORTRAN code is included in the appendix and the results from the analysis are presented here in tabulated form. From the results, the most suitable value of the inner diameter has been selected from the available standard sizes of riser pipes.

Tabulations and Plots obtained from the FORTRAN code

Velocity vs Inner Diameter

Diameter (m)	Velocity (m/s)
0.01	803.2890
0.02	200.8223
0.03	89.2543
0.04	50.2056
0.05	32.1316
0.06	22.3136
0.07	16.3937
0.08	12.5514
0.09	9.9171
0.10	8.0329
0.11	6.6388
0.12	5.5784
0.13	4.7532
0.14	4.0984
0.15	3.5702
0.16	3.1378
0.17	2.7795
0.18	2.4793
0.19	2.2252
0.20	2.0082
0.21	1.8215
0.22	1.6597
0.23	1.5185
0.24	1.3946
0.25	1.2853
0.26	1.1883
0.27	1.1019

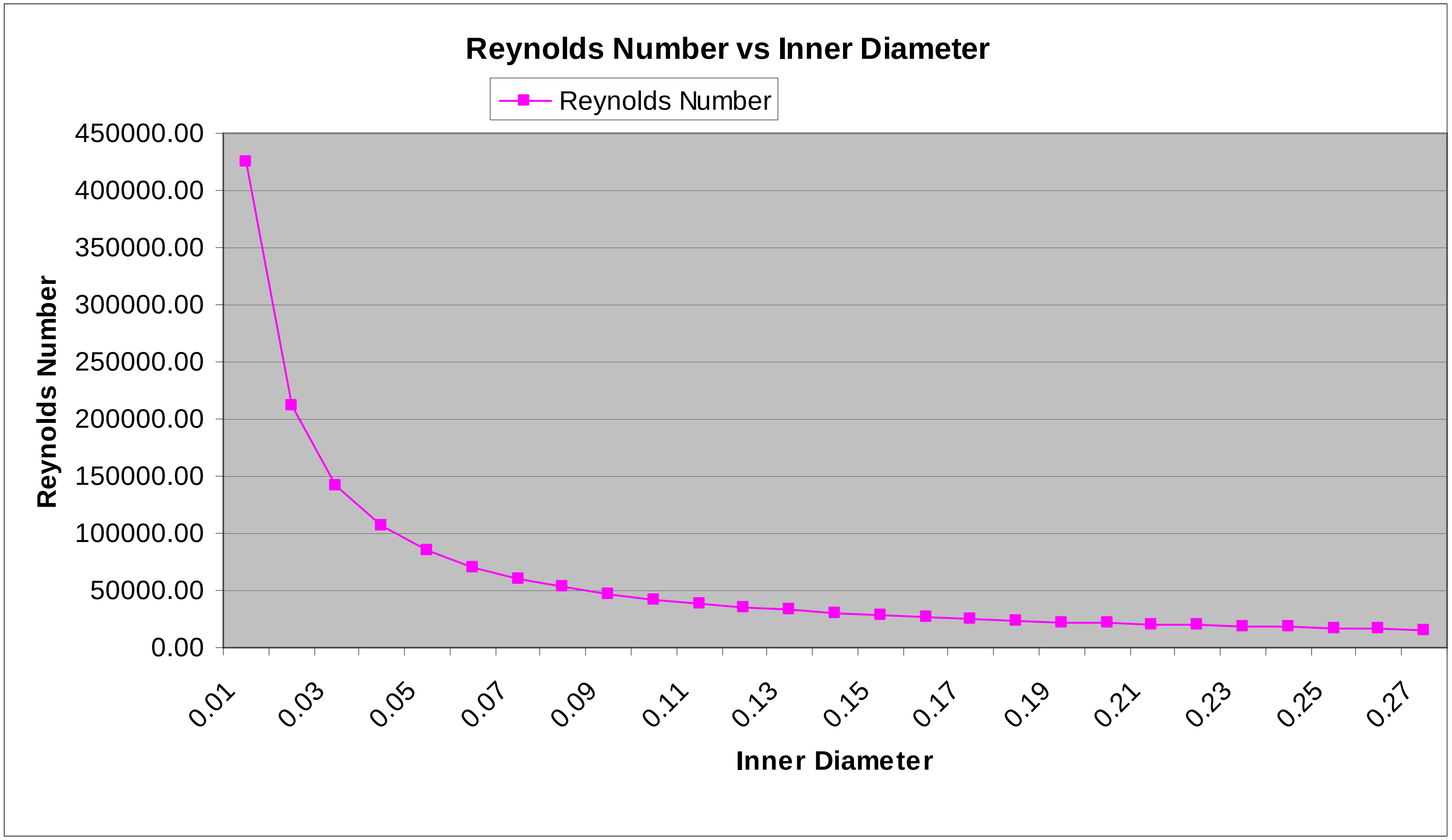
Plot showing the variation of Velocity with inner diameter of the pipe



Reynolds Number vs Inner Diameter

Diameter(m)	Reynolds Number
0.01	424655.5179
0.02	212327.7590
0.03	141551.8393
0.04	106163.8795
0.05	84931.1036
0.06	70775.9197
0.07	60665.0740
0.08	53081.9397
0.09	47183.9464
0.10	42465.5518
0.11	38605.0471
0.12	35387.9598
0.13	32665.8091
0.14	30332.5370
0.15	28310.3679
0.16	26540.9699
0.17	24979.7363
0.18	23591.9732
0.19	22350.2904
0.20	21232.7759
0.21	20221.6913
0.22	19302.5235
0.23	18463.2834
0.24	17693.9799
0.25	16986.2207
0.26	16332.9045
0.27	15727.9821

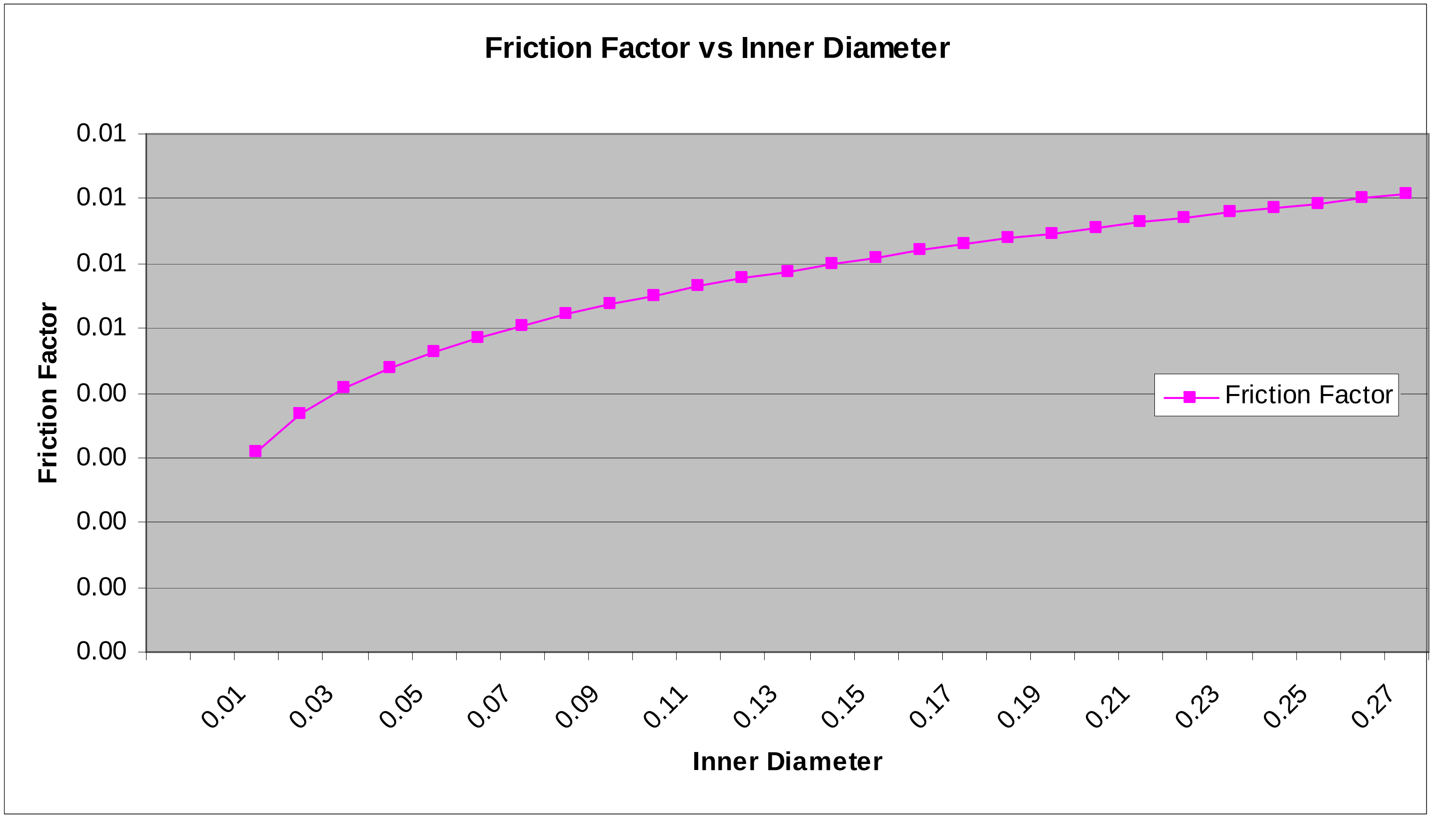
Plot showing the variation of Reynolds Number with inner diameter of the pipe



Friction Factor vs Inner Diameter

Diameter(m)	Friction Factor
0.01	0.0031
0.02	0.0037
0.03	0.0041
0.04	0.0044
0.05	0.0046
0.06	0.0048
0.07	0.0050
0.08	0.0052
0.09	0.0054
0.10	0.0055
0.11	0.0056
0.12	0.0058
0.13	0.0059
0.14	0.0060
0.15	0.0061
0.16	0.0062
0.17	0.0063
0.18	0.0064
0.19	0.0065
0.20	0.0066
0.21	0.0066
0.22	0.0067
0.23	0.0068
0.24	0.0069
0.25	0.0069
0.26	0.0070
0.27	0.0071

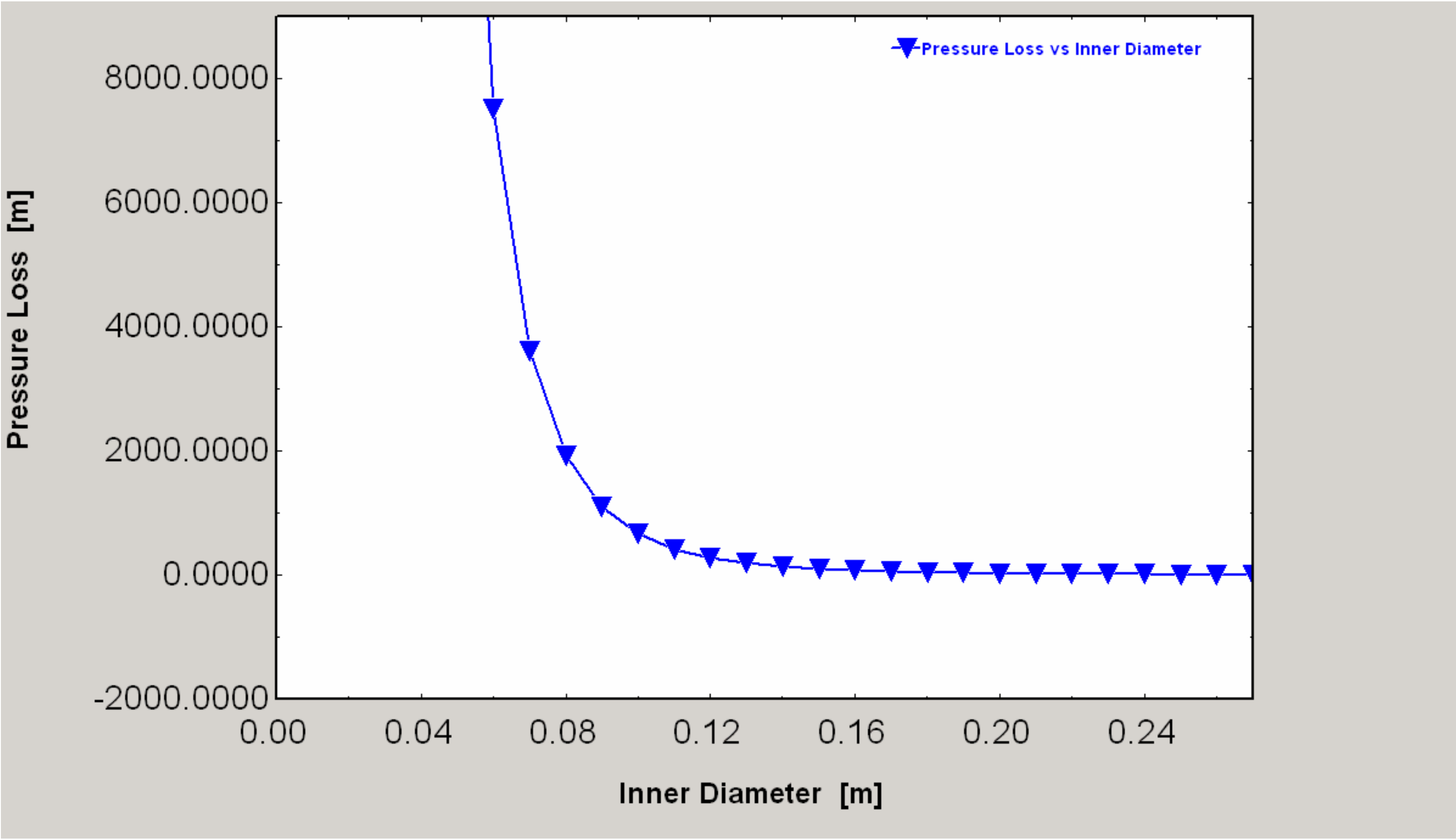
Plot showing the variation of Friction Factor with inner diameter of the pipe



Pressure Loss vs Inner Diameter

Diameter(m)	Power Loss/ Head Loss(m)
0.01	37274257.8038
0.02	1385212.8933
0.03	201875.2348
0.04	51478.2821
0.05	17836.1651
0.06	7502.2333
0.07	3607.3918
0.08	1913.0731
0.09	1093.3447
0.10	662.8405
0.11	421.4963
0.12	278.8034
0.13	190.6242
0.14	134.0605
0.15	96.5996
0.16	71.0950
0.17	53.3061
0.18	40.6317
0.19	31.4289
0.20	24.6330
0.21	19.5374
0.22	15.6639
0.23	12.6824
0.24	10.3611
0.25	8.5348
0.26	7.0841
0.27	5.9215

Plot showing the variation of Pressure Loss with inner diameter of the pipe



From the plot for pressure loss as a function of inner diameter of the riser pipe, it is evident that higher the inner diameter, lower will be the pressure loss. However, owing to some design constraints on the inner diameter of the riser pipe, a fine balance needs to be attained between the pressure loss consideration and the inner diameter consideration. From the tabulated results, it can be seen that the decrease in pressure loss is not significant in spite of increase of inner diameter in the range 0.12m to 0.20m and beyond. Hence, adopting a conservative design approach, we assume a riser pipe of inner diameter 0.14m which is about 5.5". Now, we need to compare this with the available standard sizes of riser pipes. The tabular column below shows the available riser pipe sizes.

Available Drill Pipe Sizes

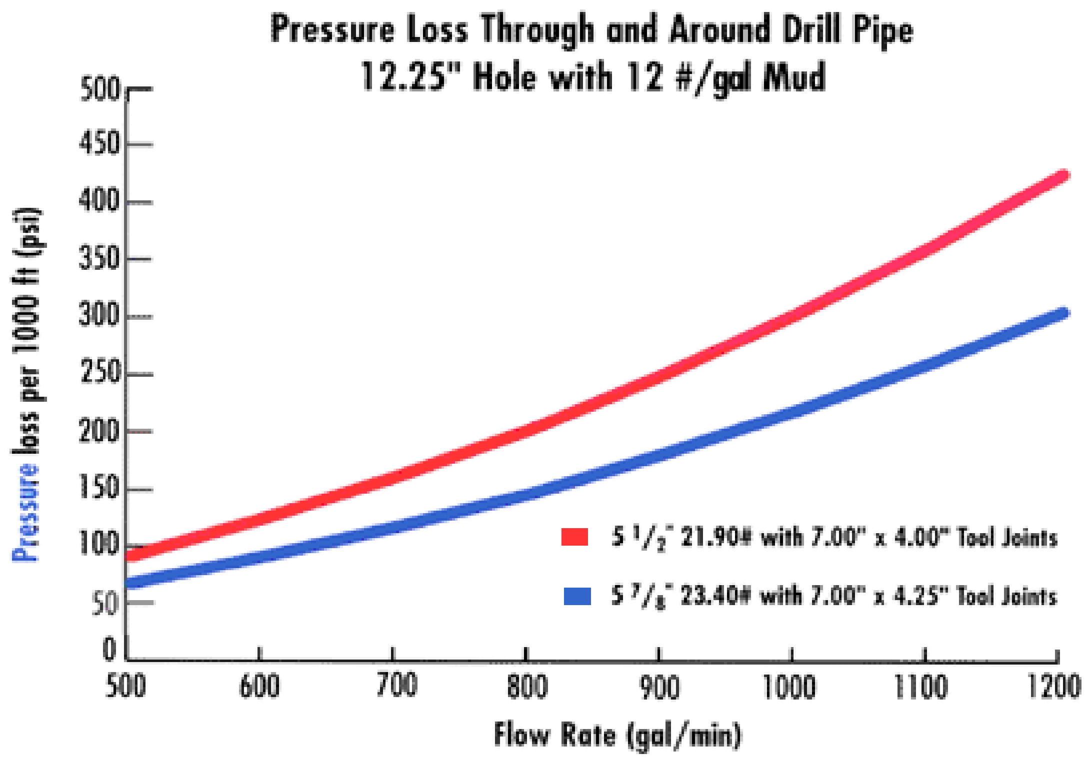
Label	Pipe OD [in]	Pipe Wall Size [#]	Adjusted Weight [lb/ft]	Pump Pressure [psi]
A	5	19.50#	22.37 (R3)	6300
B	5	25.60#	27.50 (R3)	7900
C	5 1/2	21.90#	23.77 (R3)	4500
D	5 1/2	24.70#	26.56 (R3)	4800
E	5 7/8	23.40#	24.98 (R3)	3800
F	6 5/8	25.20#	29.36 (R2)	2900

Options A and B have large pressure requirements. Options A and C have smaller than average yield margins. Options D offers a large yield margin but at the cost of weight and pressure loss. Option F has the minimum pressure requirement but has a substantial increase in weight and outer diameter. The remaining option E offers reasonable yield margin, a low pressure requirement, and is light weight.

The optimum value of the inner diameter is 0.14m which is equivalent to 5.5in. Hence, from the standard tables, the riser pipe which matches our requirement is the one with outer diameter 5 7/8 in. The corresponding inner diameter for this pipe is 5.153". Further, option E offers the following other features. It has been exclusively developed for extended reach drilling (ERD) and ultra deep wells. 5 7/8" OD drill pipe is optimized for hydraulic performance, high strength and ease of handling. It represents a logical intermediate drill pipe size between standard 5 1/2" and 6 5/8" drill pipe. It uses Grant Prideco eXtreme Torque (XT) tool joint technology. It is available in all standard API material grades and Grant Prideco proprietary grades including XD-105 and extreme V-150.

Tool Joint Torsional Strength – 94,300 ft-lbs
Tool Joint Working Torque – 56,600 ft-lbs

<u>Plot depicting a comparative pressure loss between the 5.5” and the selected pipe</u>



<u>Operational Advantages of 5 7/8" XR™ Drill Pipe</u>

<u>Hydraulic Performance</u>

5 7/8" drill pipe provides enhanced hydraulic performance compared to 5 1/2” drill pipe for ERD and ultra-deep well applications.

<u>Streamline Configuration</u>

5 7/8" drill pipe utilizes a 7” OD XT Tool joint allowing it to be used to drill inside 9 5/8” casing and 8 1/2” open-hole sections. Overshot fishing capability in an 8 1/2” hole is maintained.

<u>Logistics</u>

It eliminates the need for 6 5/8” drill pipe. 6 5/8” drill pipe is difficult to handle and can sacrifice rig space and setback capacity because it cannot be used to drill 8 1/2” hole sections.

Rig Modifications

5 7/8" drill pipe minimizes rig modifications compared to 6 5/8" drill pipe.

Final Selection of Riser Pipe

Grant Prideco 5 7/8" 23.40# (0.361"wall) S-135 Alloy Steel

Riser Pipe - Stress Analysis

Riser stress analysis is central to optimum riser design. In the stress analysis of the riser, the riser is assumed to be equivalent to a cantilever beam with the top end fixed and the bottom end subjected to a resultant load. Therefore, we model the riser pipe as per the beam bending equation. The governing equation for beam bending is as given below:-

$$\frac{\partial^2}{\partial z^2}(EI\frac{\partial^2 y}{\partial z^2}) - \frac{\partial}{\partial z}(T\frac{\partial y}{\partial z}) = F$$

where,

E	=	Young's modulus of the material
I	=	Inertia of the riser
T	=	Top tension
Y	=	Lateral static displacement
Z	=	Depth below sea-level
F	=	Lateral loads induced by the current

In addition to the loads on the riser pipe on account of top tension and ocean currents, the riser pipe experiences a load due to the resultant hydrostatic pressure of sea-water and drilling mud. Hence, the following loads acting on the riser pipe have been considered for the stress analysis:-

1. Top Tension
2. Force due to ocean currents
3. Hydrostatic Pressure on the wall of the riser pipe

The three loads are calculated separately followed by a stress analysis of the riser pipe using Solid Works and Cosmos Works. The analysis yields the Von Mises stress which is then compared to the maximum allowable stress in the riser pipe. By this exercise, the suitability of the riser pipe for the task at hand is determined.

Top tension

It is important to have an accurate evaluation of riser top tension since it has a significant effect on the design of the riser system. The top tension is calculated by using the following expression:-

$$T_{top} = W_{riser} + W_{mud} + W_{bottom} + W_{guide} - W_{buoyancy}$$

SI units have been used for the calculations.

Weight of the riser

$$\begin{aligned} W_{riser} &= \text{Weight of the riser} \\ &= \text{Weight of the riser pipe per unit length} \times g \times \text{Total depth} \\ &= 34.8097 \times g \times \text{Total depth} \end{aligned}$$

Weight of the mud

$$\begin{aligned} W_{mud} &= \text{Weight of mud} \\ &= \rho_m \times \frac{\pi}{4} \times d_i^2 \times \text{Total Depth} \times g \\ &= 23.85655 \times \text{Total Depth} \times g \end{aligned}$$

where,

- ρ_m = Density of drilling mud = 1797.396 kg/m^3
- d_i = Inner Diameter of the riser pipe = 0.13 m

Weight of the guide

W_{guide} = Weight of the guide assembly

- Spacing of the guide = 12 m
- Weight of each guide = 27.2155 kg
- Weight of guide per unit length = 2.2679 kg/m

$$\text{Weight of guide} = \text{Weight of the guide per unit length} \times g \times \text{Total depth}$$
$$= 2.2679 \times g \times \text{Total depth}$$

Weight of the BOP +Su-sea Pump Package

W_{bottom} = Apparent Wt of BOP + Apparent Wt of sub-sea pump package

$$= \frac{383000}{2}$$
$$= 191500 \text{ lbs.}$$
$$= 86862.938 \text{kg}$$

Weight equivalent of the buoyancy force

$W_{buoyancy}$ = Weight equivalent of the buoyancy force

$$= \frac{\pi}{4}(d_o^2 - d_i^2) \times \text{Total Depth} \times \rho_w$$

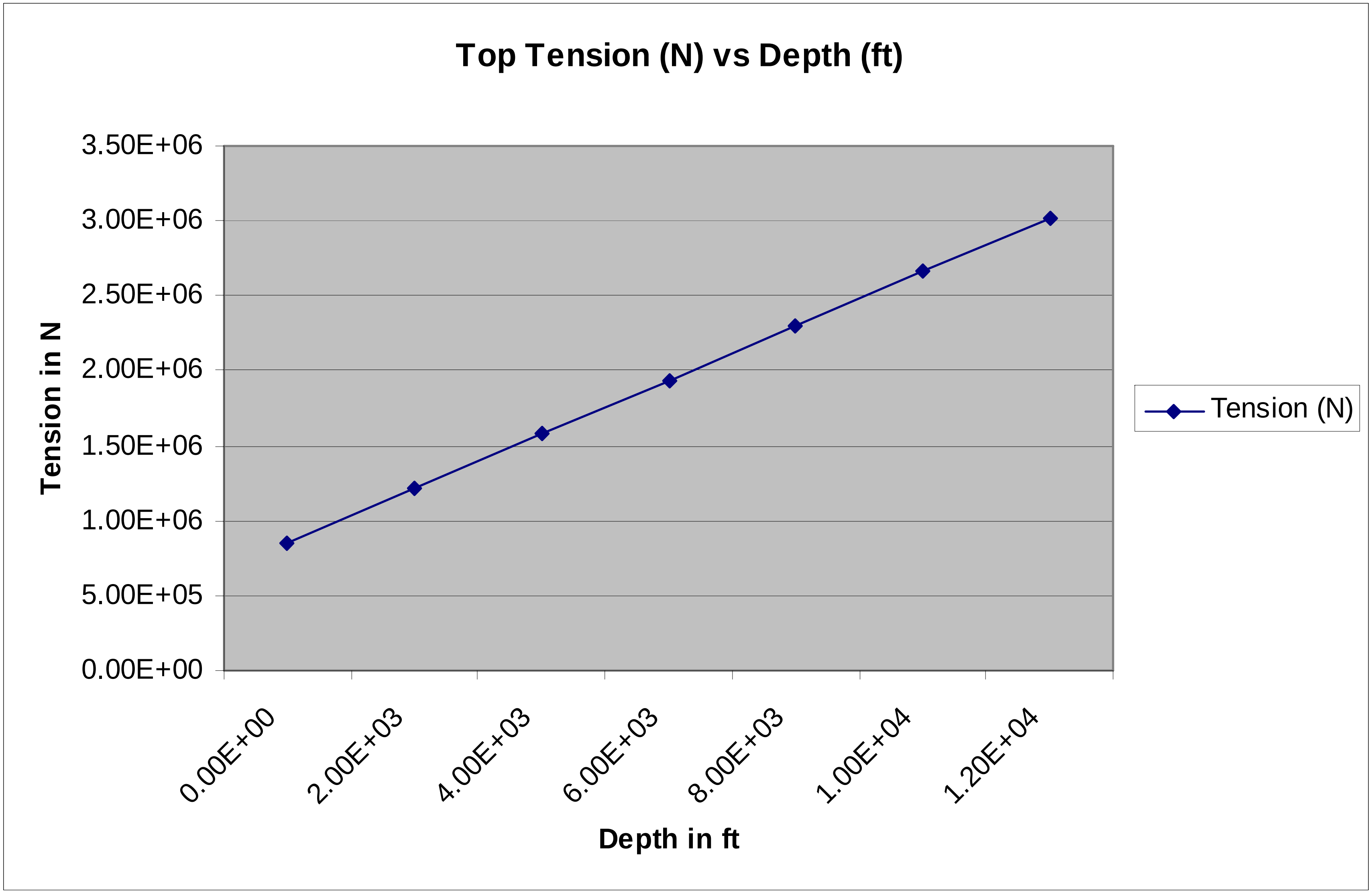
where,

- ρ_w = Density of sea-water = 1000 kg/m^3
- d_o = Outer diameter of the riser pipe = 0.14 m

A FORTRAN code was developed to calculate the top tension as a function of varying total depth. The tabulation and plot of the variation is shown below. The FORTRAN code is given in the appendix.

Tabulated Values

Depth(ft)	**Tension (N)**
0.00E+00	8.52E+05
2.00E+03	1.21E+06
4.00E+03	1.58E+06
6.00E+03	1.94E+06
8.00E+03	2.30E+06
1.00E+04	2.66E+06
1.20E+04	3.02E+06


Top Tension (N) vs Depth (ft)
Tension in N
3.50E+06
3.00E+06
2.50E+06
2.00E+06
1.50E+06
1.00E+06
5.00E+05
0.00E+00
0.00E+00
2.00E+03
4.00E+03
6.00E+03
8.00E+03
1.00E+04
1.20E+04
Depth in ft
Tension (N)

Forces due to ocean currents

The load on the riser due to sea-water currents is calculated using Morison's Equation based on relative fluid flow assumptions. The body is considered to be sufficiently slender not to disturb the incoming flow.

The drag force is proportional to the square of the current velocity and the hydrodynamic load is directly proportional to the drag coefficient (*Cd*). The choice of the drag coefficient depends on the flow regime (Reynolds number and Keulegan and Carpenter number).

$$F_d = \frac{1}{2} \times d_\varepsilon \times \rho_w \times C_d \times \| \Delta V \| \Delta V$$

d_ε	= Outer diameter of the riser	=	0.14 m
ρ_w	= Density of the water	=	1000 kg/m3
C_d	= Normal Drag co-efficient	=	2
ΔV	= Normal Fluid Velocity (or) Current Velocity	=	5 knots (assumed)

F_d = 926.2697 N

Hydrostatic Pressure on the walls of the riser pipe

The walls experience two kinds of hydrostatic pressure:-

1. On the outer wall due to sea-water
2. On the inner wall due to mud enclosed by the pipe

Resultant Hydrostatic Pressure = Mud Hydrostatic Pressure
– Sea Water Hydrostatic Pressure

At 12000 ft, **Resultant hydrostatic pressure = 28611410N/m2**

This resultant pressure acts radially outward on the inner wall of the riser pipe.

For deep water risers with high top tensions, a static analysis is found to be sufficient to assess whether the riser stresses are within the allowable range.

Static Analysis

Modeling using Solid Works
Analysis using Cosmos Works

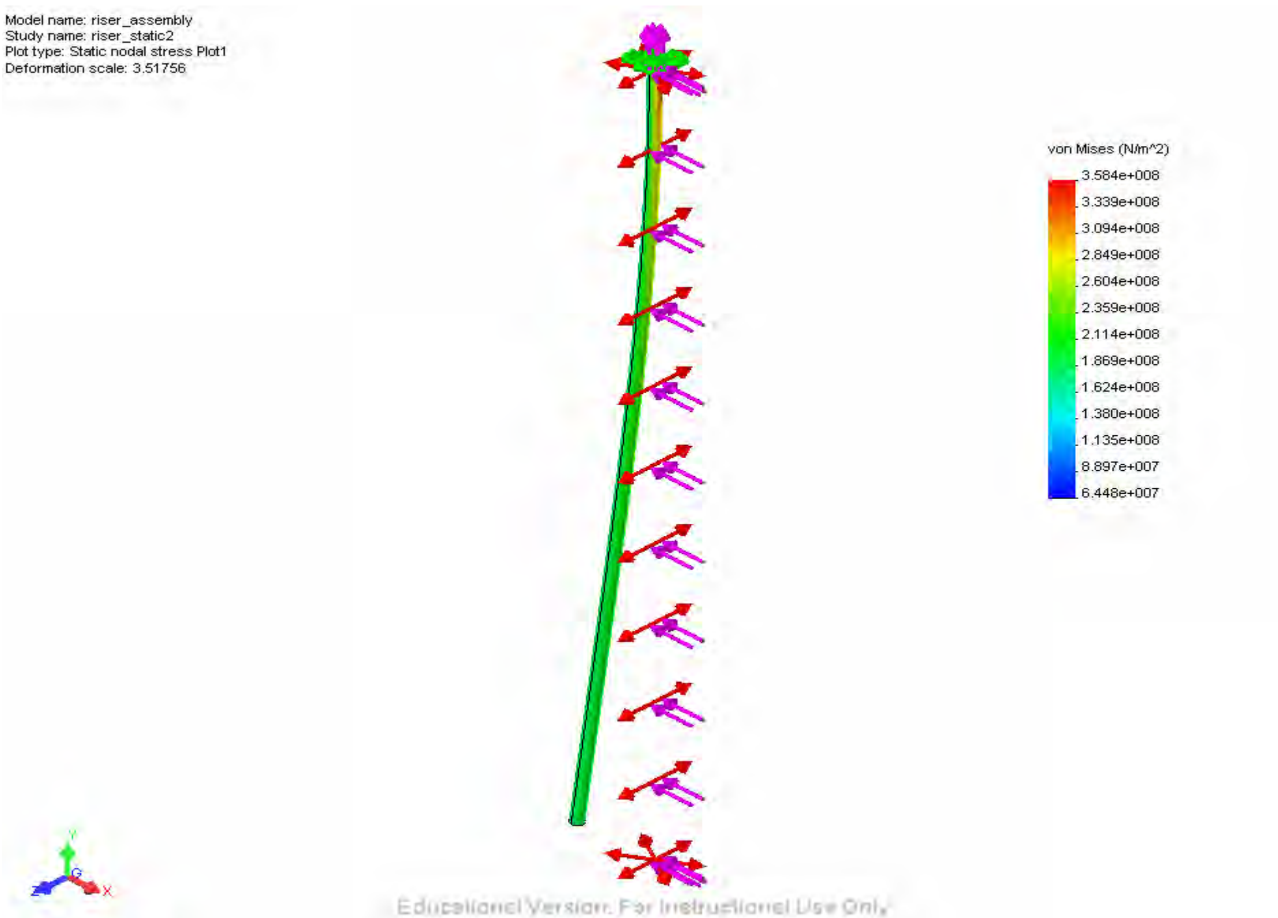


Figure X. Riser Stress Analysis

Interpretation of values obtained from the analysis

The analysis yields a maximum Von Mises stress of 3.584 e+008 N/m^2

According to the API 16Q standard,
Allowable stress for Method B (for deep water drilling) = 0.67 X σ_y

Yield Strength of Alloy Steel σ_y = 6.2042 e+008 N/m^2

Allowable Stress for the riser pipe = 0.67 X 6.2042 e+008 N/m^2
= 4.1568 e+008 N/m2

Hence, Maximum Von Mises Stress < Maximum Allowable Stress

Conclusion

The riser pipe design is validated.

Diaphragm Pump

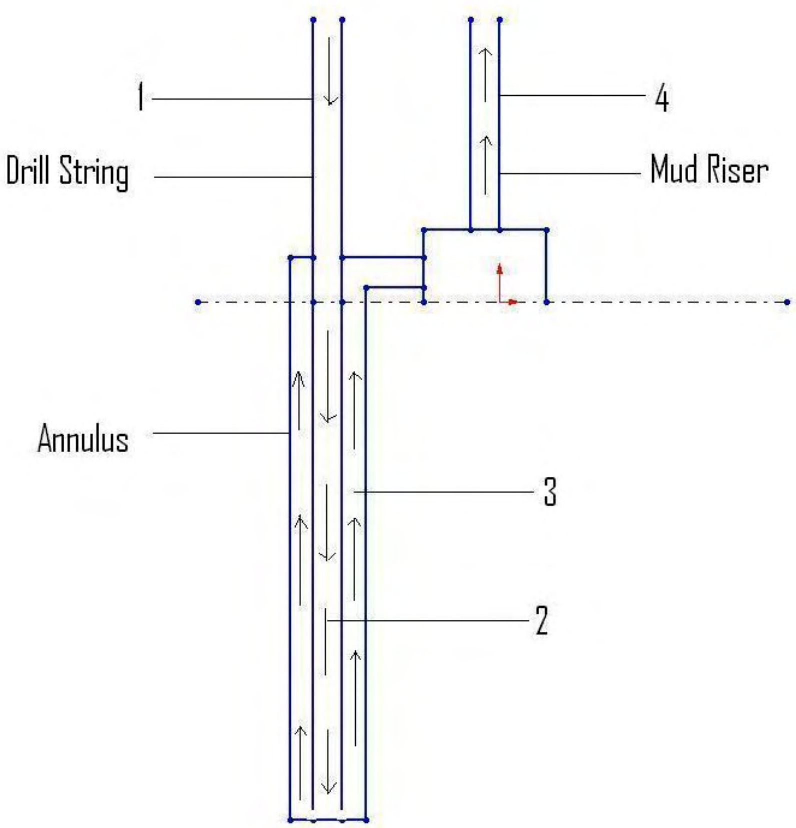


Figure Y. Line Diagram of Diaphragm Pump

The figure above is a schematic representation of the flow path of the drilling mud through the entire system. The mud is fed through the drill string into the well bore where it mixes with the drill cuttings and rises up through the annulus into the suction of the pump. Following this, the pump provides the required head for the drilling mud to reach the surface. Therefore, based on the flow path, four sections have been delineated in the system.

1) Head in the drill string above the well bore
2) Head in the drill string below the well bore
3) Head in the annulus
4) Head in the mud riser

Pump power calculation *(FORTRAN code attached in appendix)*

1) Head in the drill string above the well bore

Drill string inner diameter = 5.5in = 0.1397 m
Drill string inner diameter d_i = 4.5in = 0.1143 m

- Flow_rate = 1000 GPM = 0.0630902 cu. m/sec
- Drill_string_area = Π X d_i^2 / 4
- Velocity = Flow_rate / Drill_string_area = 6.1488 m/s
- Depth = 12000ft = 1797.396 m
- Dynamic viscosity = 0.034 N-s / m^2

Reynolds number

Re = Mud_density*velocity*depth / Dynamic_viscosity = 37153.8185

For turbulent flow, *Friction factor*

$f = 0.0791/(Re)^{0.25} = 0.0057$

Head loss due to friction h_f = f*depth*velocity^2/2*g*d_i = 351.4848 m

TH1 = depth - h_f = 3306.34 m

2) Head in the drill string below the well bore

Drill string inner diameter = 5.5in = 0.1397 m
Drill string inner diameter d_i = 4.5in = 0.1143 m

- Flow_rate = 1000 GPM = 0.0630902 cubic metre/sec
- Drill_string_area = pi* d_i^2/4
- Velocity = Flow_rate / Drill_string_area = 6.1488 m/s
- Depth = 22000ft = 6705.6 m
- Dynamic viscosity = 0.034 N-s / m^2

Reynolds number

Re = Mud_density X Velocity X Depth / Dynamic_viscosity = 37153.8185

For turbulent flow, *Friction factor*

f = 0.0791/ $(Re)^{0.25}$ = 0.0057

Head loss due to friction h_f = f X depth X velocity^2 / 2 *g*d_i = 644.3888 m

TH2 = depth - h_f = 6061.62 m

3) Head in the annulus

- Diameter of annulus = 20 in = 0.508 m
- Effective diameter = 4*annulus_area/annulus_perimeter = 0.6223 m
- Velocity = Flow_rate / annulus_eff_area = 0.2074 m/s
- Depth = 22000ft = 6705.6 m
- Dynamic viscosity = 0.034 N-s / m^2

Reynolds number

Re = Mud_density X Velocity X Depth / Dynamic_viscosity = 6822.9691

For turbulent flow, *Friction factor*

f = 0.0791 / $(Re)^{0.25}$ = 0.0087

Head loss due to friction,
h_f = f*depth*velocity^2/2*g*Effective_diameter = 0.2055 m

TH3 = depth + h_f = 6075.81 m

4) Head in the mud riser

Riser inner diameter d_i = 5.153in = 0.13 m

- Flow_rate = 1000 GPM = 0.0630902 cubic metre/sec
- Riser_area = pi* d_i^2/4
- Velocity = Flow_rate / Drill_string_area = 4.7534 m/s
- Depth = 12000ft = 1797.396 m
- Dynamic viscosity = 0.034 N-s / m^2

Reynolds number

Re = Mud_density X Velocity X Depth / Dynamic_viscosity = 32667.712

For turbulent flow, *Friction factor*

$f = 0.0791/(Re)^{0.25} = 0.0058$

Head loss due to friction h_f = f*depth*velocity^2/2*g*d_i = 187.927 m

TH4 = depth + h_f = 3842.15 m

Pump differential head = TH4+TH3-(TH1+TH2) = 1179.99 m

Assuming a pump efficiency of 0.85, **Pump BHP = 2069.89 HP**

The primary functional requirements of the pump were:-

1. Continuous Flow
2. Variable Flow rate

Based on the above pump power requirement and the other functional considerations, the following pump was found to be the ideal for the purpose.

- Crankshaft Driven Double Diaphragm Pump

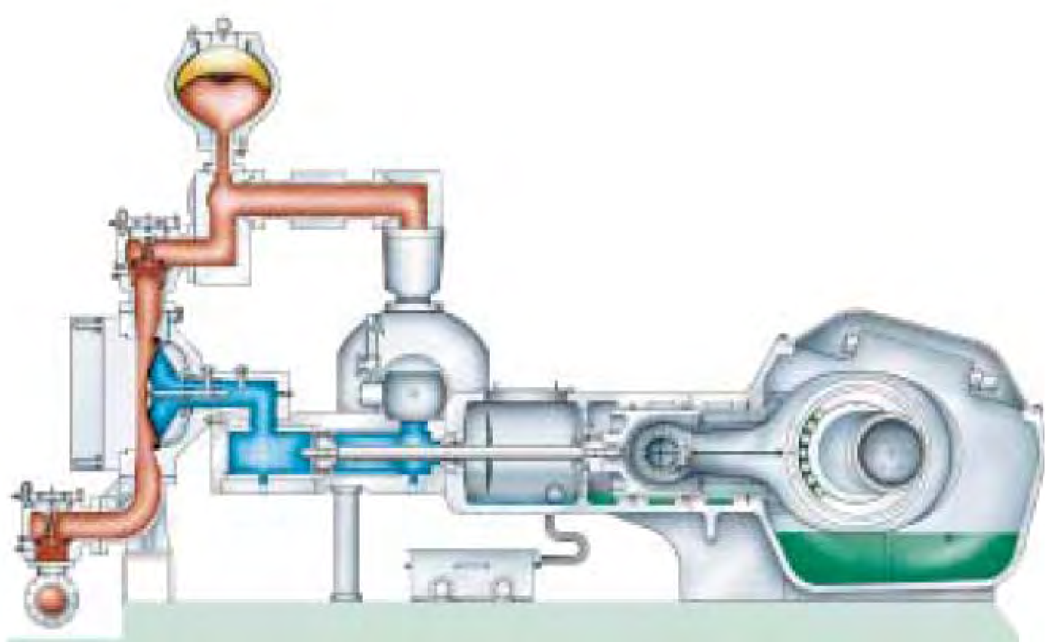


Figure Z. Crankshaft Driven Double Diaphragm Pump

Specifications of the Pump

- Pressure = 3017.67 psi
- Flow rate = 1000 gpm
- BHP = 2069.89 HP

The function of variable flow rate was addressed by using variable frequency drives with electric motors.

Pumps with the required specifications and characteristics were found to be available with GEHO. One of the GEHO pump models is shown below.

Figure A1. GEHO Pump

Electric Motor

Electric Motor performs the major function of driving the diaphragm pump and ensuring that the diaphragm pump is able to provide variable flow rates.
The speed of the electric motor determines the speed of the diaphragm pump which in turn translates into the flow rate of the drilling mud.

Assume a motor efficiency of 0.85,

Power input = Power output / Motor efficiency
= Pump BHP / Motor efficiency
= 2435.19 HP

For a three phase power supply,

Power input = Voltage*Current*sqrt(3)

Assuming a voltage of 5500 volts, the current can be evaluated as 190 amperes.

Based on the requirements, squirrel-cage electric motors with variable frequency (speed) drives have been found to be suitable.

Electric Cables

Electric cables are required to transmit power from the generators on the drill rig to the electric motor on the sea-floor. Since the drilling is being undertaken at significant depths, the length of the electric cables will be of the order of several thousand feet. Therefore, in addition to their self-load bearing capacity, the cables should be able to withstand harsh environmental conditions at such depths. Further, since the magnitude of current in the cables is high, the cables should be able to adequately dissipate the heat generated internally.

Based on the requirements, the following cables are specified.

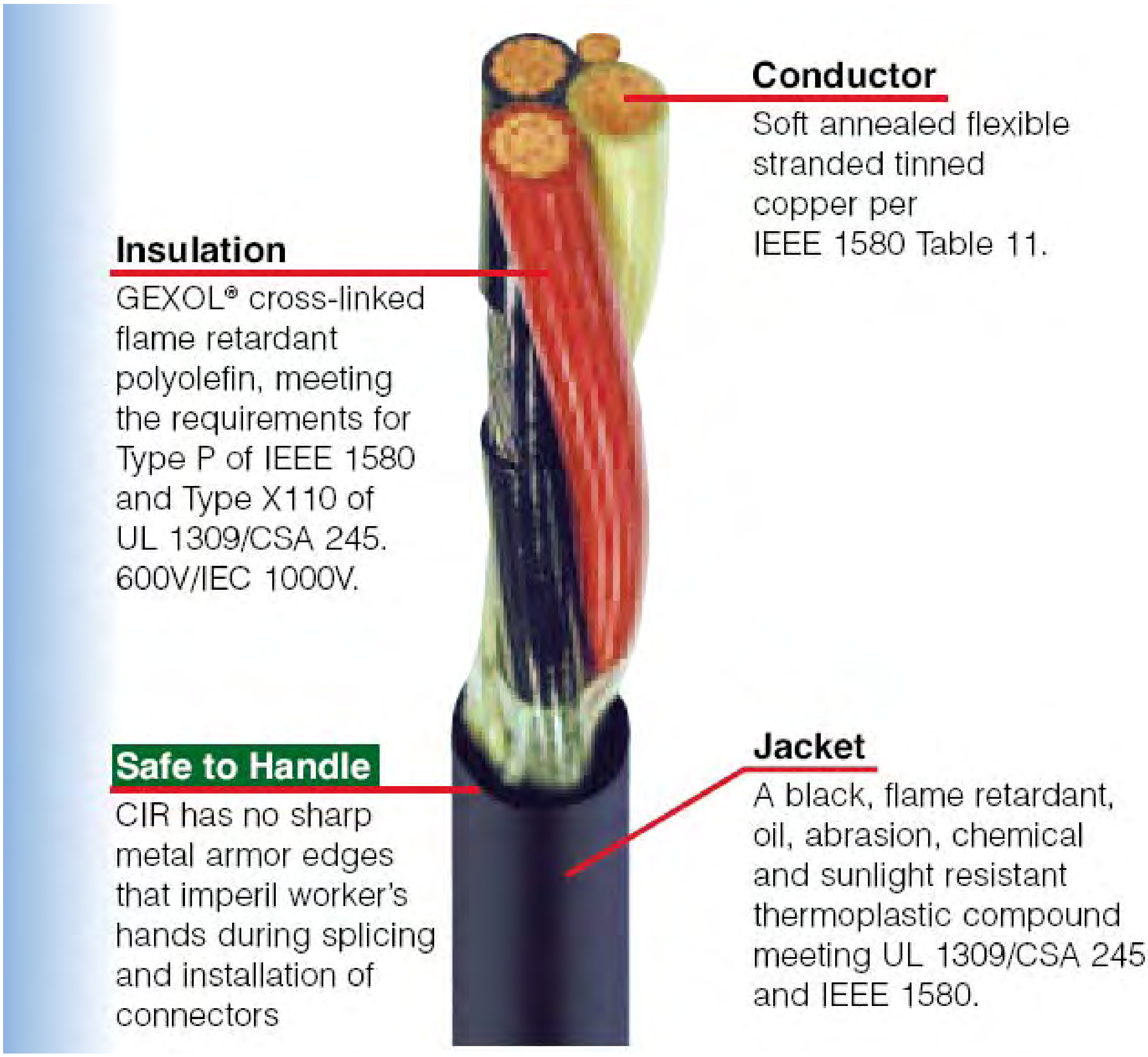


Figure B1. Electric Cable

CIR™ Power Cable

Conductor Size AWG/ kcmil	Conductor Size mm2	Number of Conductors	Grounding Conductor AWG/kcmil	Part No. 37-102	Nominal Diameter (inches)	Weight (lbs/1000 ft.)	90°C NEC Ampacity	75°C NEC Ampacity	DC Resistance at 25°C Ampacity	AC Resistance at 90°C, 60Hz (ohms/1000 ft.)	Inductive Reactance (ohms/1000 ft.)	Voltage Drop (Volts/Amp/ 1000 ft.)
14	2.1	3	3 #18	-508CIRG	0.487	161	15	15	2.91	3.64	0.04	5.069
14	2.1	4	3 #18	-509CIRG	0.523	187	15	15	2.91	3.64	0.04	5.072
12	3.3	3	3 #16	-516CIRG	0.537	210	20	20	1.83	2.28	0.03	3.195
12	3.3	4	3 #16	-517CIRG	0.578	246	20	20	1.83	2.28	0.04	3.198
10	5.2	3	3 #14	-308CIRG	0.580	277	30	30	1.15	1.44	0.03	2.028
10	5.2	4	3 #14	-408CIRG	0.685	367	30	28	1.15	1.44	0.03	2.031
8	7.6	3	10	-309CIRG	0.760	431	55	50	0.708	0.885	0.034	1.261
8	7.6	4	10	-409CIRG	0.821	513	44	40	0.708	0.885	0.037	1.263
6	12.5	3	8	-310CIRG	0.844	585	75	65	0.445	0.556	0.032	0.803
6	12.5	4	8	-410CIRG	0.915	705	60	52	0.445	0.556	0.035	0.806
4	21	3	6	-312CIRG	0.944	774	95	85	0.300	0.376	0.029	0.550
4	21	4	6	-412CIRG	1.036	956	76	68	0.300	0.376	0.032	0.553
2	34	3	6	-314CIRG	1.094	1105	130	115	0.184	0.230	0.028	0.347
2	34	4	6	-414CIRG	1.203	1381	104	92	0.184	0.230	0.030	0.350
1/0	54	3	6	-316CIRG	1.331	1669	170	150	0.117	0.147	0.028	0.232
1/0	54	4	6	-416CIRG	1.468	2107	136	120	0.117	0.147	0.030	0.235
2/0	70	3	4	-317CIRG	1.450	2062	195	175	0.0929	0.1174	0.0270	0.190
2/0	70	4	4	-417CIRG	1.602	2585	156	140	0.0929	0.1174	0.0296	0.193
4/0	109	3	4	-319CIRG	1.769	3151	260	230	0.0585	0.0753	0.0261	0.131
4/0	109	4	4	-419CIRG	1.953	3972	208	184	0.0585	0.0753	0.0287	0.134
262	132	3	3	-320CIRG	1.965	3904	297	262	0.0483	0.0628	0.0262	0.114
262	132	4	3	-420CIRG	2.188	4935	238	210	0.0483	0.0628	0.0289	0.117
373	189	3	3	-322CIRG	2.272	5246	364	322	0.0336	0.0445	0.0255	0.088
373	189	4	3	-422CIRG	2.517	6639	291	258	0.0336	0.0445	0.0282	0.091
535	273	3	2	-324CIRG	2.684	7444	446	394	0.0235	0.0326	0.0256	0.072
535	273	4	2	-424CIRG	3.039	9629	357	315	0.0235	0.0326	0.0282	0.075
777	394	3	1	-327CIRG	3.128	10619	546	483	0.0162	0.0247	0.0256	0.061
777	394	4	1	-427CIRG	3.506	13805	437	386	0.0162	0.0247	0.0282	0.063

Ampacities are based on Table 310-16 of the National Electrical Code (NEC) for conductors rate 90°C, in a multi-conductor cable, at an ambient temperature of 30°C. The 75°C column is provided for additional information. The ampacities shown apply to open runs of cable, installation in any approved raceway. Derating for more than three current carrying conductors within the cable is in accordance with NEC Table 310.15 (B) (2) (a). The ampacities shown also apply to cables installed in cable tray in accordance with NEC Section 392.11.

Based on the tabular column, the following cable was chosen.

Specifications

Nominal Diameter = 2.684”
Weight = 7.444 lb/ft
Ampacity at 75deg C = 394 amperes
Ampacity is defined as the maximum current capacity of the cable.

Current required by the motor = 190 amperes
Ampacity of the cable specified = 394 amperes

Therefore, the specified cable will serve the purpose.

Features

- Passes the same stringent crush and impact testing required by UL 2225 for Type MC-HL
- Gas & vapor tight – impervious to water and air Smaller bend radius (up to 40% smaller) than Type MC
- Reduced tray fill (up to 35% less) compared to Type MC
- Considerably more flexible than Type MC
- Reduced installation time and cost compared to Type MC
- Glands for this product cost up to 50% LESS than those for Type MC

Additives

Additives are added to the drilling mud so as to provide the desirable characteristics to the mud to enable gumbo prevention. Such additives are usually either oil-based or water-based emulsions. Also, certain polymers and solutions containing potassium ions can be used. These additives provide additional advantages like reducing corrosion of drill bits, flow lines; efficient removal of cuttings and also act as a coolant for the drill bit. However, they are not environment friendly.

Water-based Drilling Fluid

Upon its introduction in the Gulf of Mexico, a uniquely engineered water-base drilling fluid system that employs a triple inhibition approach to shale and wellbore stabilization has been shown to deliver drilling performance approximating that of its invert emulsion counterpart. The newly developed fluid system has been employed in wells in both deepwater and on the shelf where it exhibited excellent shale inhibition and waterbase stability, low toxicity and very flexible and easy-to-maintain formulations. In each well, the fluid demonstrated consistently impressive performance with good cuttings integrity and very minimal accretion while drilling through highly reactive shales. The new system essentially eliminated the typical problems associated with the conventional water-base drilling fluids used previously, such as screen blinding caused by unsheared polymer, rapid polymer depletion, high dilution rates and moderate inhibition. Further, there were clear indications that the system approaches the drilling performance and the user-friendliness of a synthetic or oil-base drilling fluid. The results of all these field trials confirmed initial observations that the fluid was easily mixed both at the mixing plant and at the rigsite. In addition, the system has exhibited minimal gumbo handling problems at the surface, with shale cuttings exhibiting good integrity and well encapsulated. Furthermore, the Cation Exchange Capacity (CEC), which is a measure of the reactivity of the clays being drilled, was consistently low (less than 10 lb/bbl) while drilling reactive shales. There were no indications of downhole bit balling, nor has there been any appreciable accretion noted on the bit and the bottom-hole assembly after trips.

Invert emulsion drilling fluids, whether oil or synthetic-base, have long been the systems of choice for technically demanding applications, particularly when targeted formations contain highly reactive shales. The superior inhibitive characteristics of invert emulsion fluids in tandem with their high rates of penetration, good lubricity and reduced risk of stuck pipe make these systems ideal for applications requiring high levels of fluid performance. When compared to water-base drilling fluids, these systems provide improved wellbore stability, a high degree of contamination tolerance, low coefficient of friction, a thin, lubricated filter cake, low dilution rates and a high degree of re-usability. Yet, the wholesale use of oilbase drilling fluids is under pressure, primarily because of tightening environmental regulations governing the disposal of oil contaminated drill cuttings. Furthermore, synthetic and oil-base drilling fluids are inherently more expensive than water-base systems.

Photos of bits after full-scale accretion and ROP test results. The new high performance water-base drilling fluid left the cutters clean while the PHPA water-base mud resulted in balled cutter.

Figure C1. Photos of bits

Cuttings from the highly reactive gumbo section in the Gulf of Mexico drilled with the new water-base system.

Figure D1. Drill Cuttings from the Gulf of Mexico

Field Results

To date, the system has been used in both deepwater and shelf wells in the Gulf of Mexico. In each, the performance of the system validated the excellent results obtained in laboratory testing. Most of the sections drilled thus far have been shallow, where the rate of penetration is usually controlled to ensure proper hole cleaning and to avoid any borehole stability problems. Nevertheless, drilling performance comparison was possible using data from the same or adjacent blocks, which showed the ROP of the new system being very similar to a synthetic-base system used earlier, and 60- 70% higher than the conventional water-base drilling fluid used previously in the targeted blocks. The fluid maintenance was easier than even the most inhibitive water-based muds, and consisted mainly of pre-mix additions to maintain the volume and minimum LGS and MBT. The fluid inhibitive character determined low dilution rates, averaging between 2 and 4 bbl premix/1 bbl cuttings drilled.

Oil-based drilling Fluid

Set-Phalt, an excellent oil-based fluid additive, seals permeable sand formations, stabilizes shale and dramatically reduces differential pipe sticking.

Additive Benefits

Differential pipe sticking is caused by poor particle size distribution and Set-Phalt is an asphalt blend that has been perfected to provide the ideal particle size distribution to prevent this malady. The asphaltic sized particle blend combination approach allows Set-Phalt to outperform ordinary Gilsonite and sodium/potassium asphalt sulfonates for sealing, torque and drag reduction and differential pipe sticking prevention at a lower cost. Set-Phalt can be used in sodium systems and potassium systems at the operator’s preference.

Where previous wells have experienced hole problems, the addition of Set-Phalt appears to prevent formation instability, prevent pipe sticking and reduce torque and drag. In some cases, Set-Phalt is being added right out of surface, and it can be shown that money is being saved because of better formation stability. Set-Phalt is compatible with all water based drilling fluid systems, and in fluids where oil has been added there does not appear to be any oil wetting of solids, nor flotation of asphalt on the surface. In permeability plugging tests and field trials, Set-Phalt, with a seepage loss control agent more adequately sealed depleted sand zones than other products including those with higher costs. The ideal use level requirement for this product is 4 to 6 pounds per barrel. With this amount of product in the system, HT/HP fluid loss control is much easier to control. In every case the requirement for resin HT/HP agents has been reduced, and in many cases they have been eliminated altogether. This product is rated one of the very best shale control additives in the market currently. Set-Phalt is manufactured as a sodium salt with NaOH for cost reduction. It can easily be modified to a potassium salt at the well site by adding KOH through the chemical barrel while adding Set-Phalt through the hopper. The ratio would be one sack of KOH for every 10 sacks of Set-Phalt. Reduce one-half sack of caustic soda for every sack of KOH added during daily treatments.

Very little change in Viscosity or electrical stability occurs up to 10 pounds per barrel. For quantities added above 6 pounds per barrel a small amount of wetter or secondary emulsifier retains the ES. A dramatic drop in HT/HP filtrate happens though. Set-Phalt cut it in half from 14 to 7 in a lab prepared synthetic oil mud.

Set-Phalt can be added to diesel oil or synthetic. Its particle distribution will help seal sands along with reducing the high temp. In a test with a leading asphalt sulfonate, Set-Phalt maintained the viscosity of the base fluid. But, the competitor dropped the yield point to one-half the mud weight. The gel strengths dropped to zero and there was severe barite settlement. With Set-Phalt, the ES remains the same at 6 pounds per barrel and only dropped from 662 to 554, without additions of wetter for the extra solids at 10 pounds per barrel. The asphalt sulfonate dropped the ES to 375…almost twice the amount of the original reading.

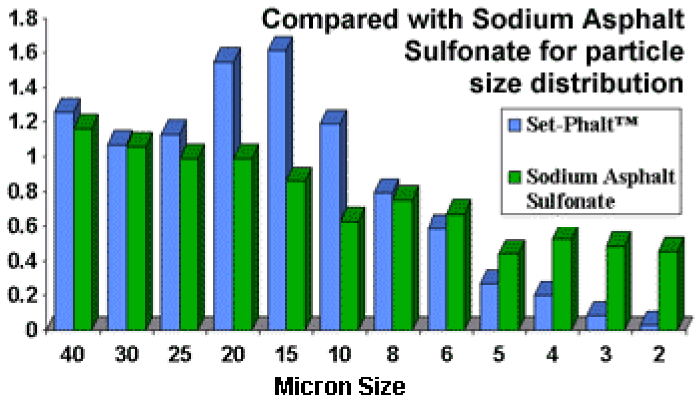
Based upon years of research on shale stability, it is apparent there does not exist a single product that represents a magic elixir for shale stability. Sale instability is caused by mechanical means, which is primarily fluid hydraulics in nature. For chemical inhibition, the secret is to prevent shock base exchange to the clay particle. Un-reactive shale formations do not require additives for inhibition because they are inert. Reactive shale formations, such as gumbo shale, are composed of calcium clay. Reactive shale formations will not swell, slough or disperse into the active mud system as long as they remain calcium charged clays. If they are base exchanged to sodium, which is easily accomplished by using a sodium system, then they will yield in a manner to even close the flow line and all the asphalt in the world, regardless of how processed will not prevent this.

If the only property desired is water solubility then sulfonated asphalt is a clear winner, although it does not appear to be as soluble as reported. However, it is not water solubility that is important, but rather it is the inhibitive nature of the filtrate. Therefore, using the filtrate from each sample, a wedge of gumbo shale obtained from the stabilizer of an off shore well in a known gumbo shale area was added. The sulfonated asphalt sample swelled, cracked and lost its original shape in 15 minutes. The Set-Phalt sample had some softening and mudding up of the filtrate, but the shale sample retained its original shape after several hours. For this test, Set-Phalt is a clear winner and it can be stated that water solubility is not a factor for promoting shale stability.

Most gumbo shale formation occurs in the upper hole. Several field tests were conducted where the spud mud was intentionally composed of gel, lime and occasionally some PHPA. Caustic soda was intentionally left out. The gumbo was drilled with no clogging and no problems. When caustic soda was added the gumbo yielded.

When drilling in the current environment, it appears that depleted sand sections cause more trouble than swelling shale. In this regard, neither Set-Phalt nor any other asphalt product will seal depleted sand by itself. The requirement includes an additional sealing agent. In combination with another LCM like Seta-Seal Fine or Plus, Set-Phalt appears to have equal sealing performance to the most expensive asphalt product available and appears to be less dispersive.

- In every single test conducted with Set-Phalt, it has always been placed in the top 10% for performance and usually number one.
- When cost is considered, no other product of this type competes.
- In permeability plugging tests and field trials, Set-Phalt with a seepage loss control agent more adequately sealed depleted sand zones and differential sticking has rarely occurred when used in this manner.



Testing Results

Set-Phalt has been used in numerous particle size distribution, rheology, and permeability plugging ability tests. The compiled graphs show its performance.

TYPICAL PROPERTIES

Appearance	Dark Brown Powder
Bulk Density	40 lbs/cu. ft.
Moisture Content	10% ± 1%
pH, 10% Solution	N/A
Ignition Point	>260ß C.
Solubility	Water Dispersible
Rec. use level	4 - 6 ppb

Summary

To summarize, by refining the need analysis, conceptually sound and feasible solutions to the problem of design of mud recirculation system have been developed by assessing the possible and previously encountered problems in the current prototype THDG system. The need to maintain pressure gradients and the efficient working of mud recirculation system providing unobstructed path for mud return have been addressed.

At the Conceptual Design stage, six concepts were developed and by a combination of various approaches, four final concepts were evaluated. A comparative study of these four concepts enabled the identification of the most practically feasible of the lot. This concept was then picked for implementation. Extensive research and analysis of each feature of the selected concept followed, the documentation of which has been provided in the form of this final project report.

The following features have been decided upon:-

1. Existing sub-sea Rotating Device
2. Vibra-seal Pre-Applied Thread Seal
3. Segmented Riser Pipes
4. Crankshaft Driven Double Diaphragm Pump
5. Squirrel Cage Electric Motor with variable frequency drive
6. Water-based Drilling Fluid / Set-Phalt

Acknowledgement

The team would like to thank Minerals Management Service for bestowing us with the opportunity to work on this prestigious project.

Further, we would like to thank Dr. Steve Suh for the opportunity and the support in our endeavor, and most importantly, for channelising our work.

During the course of this entire exercise, we were fortunate to be constantly guided by Mr. Charles Peterman and Dr. Jerome Schubert. They were instrumental in resolving our doubts and providing invaluable feedback in connection with our work. We would like to thank them for sharing their experience and sparing time in spite of their busy schedules.

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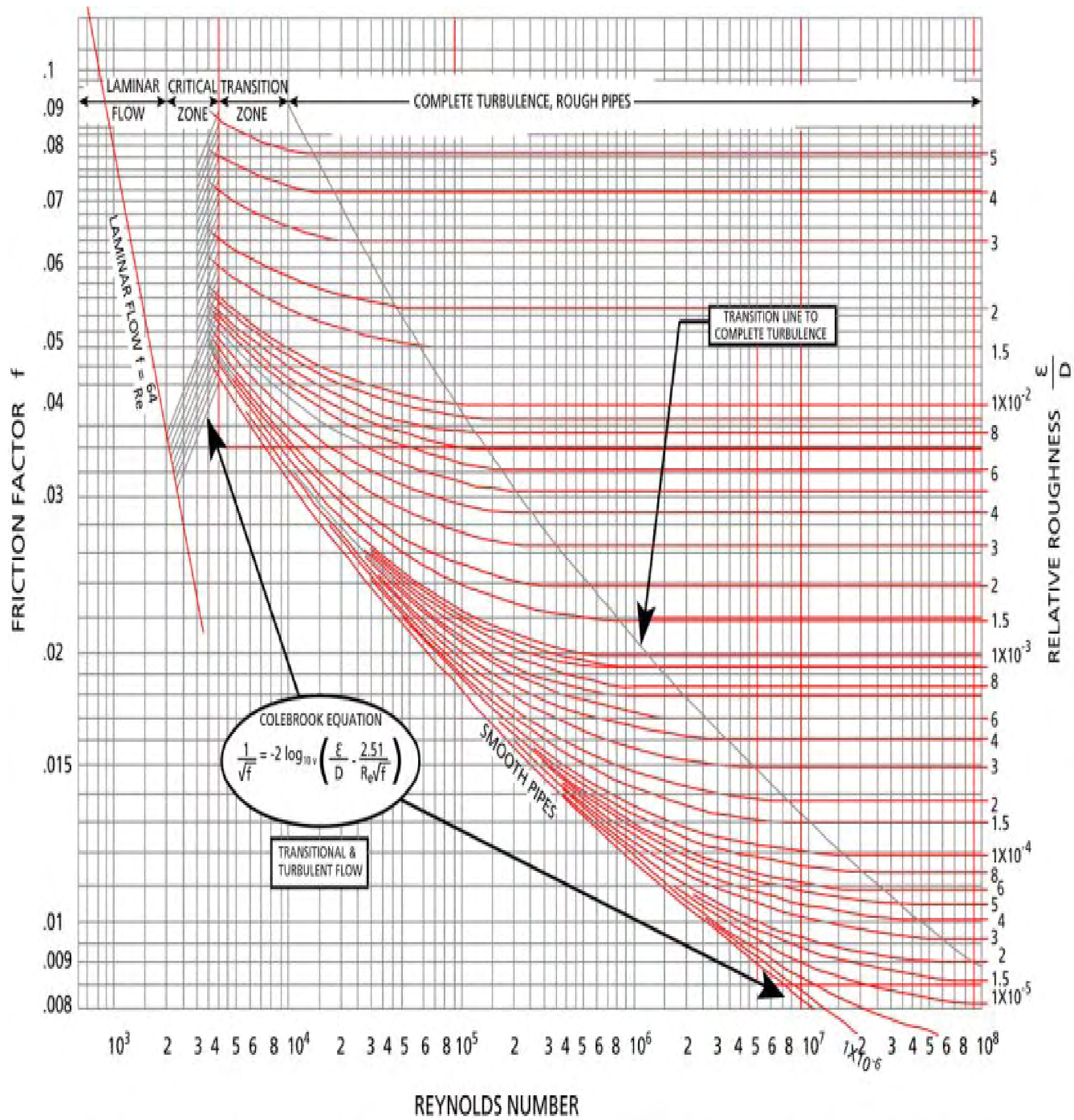
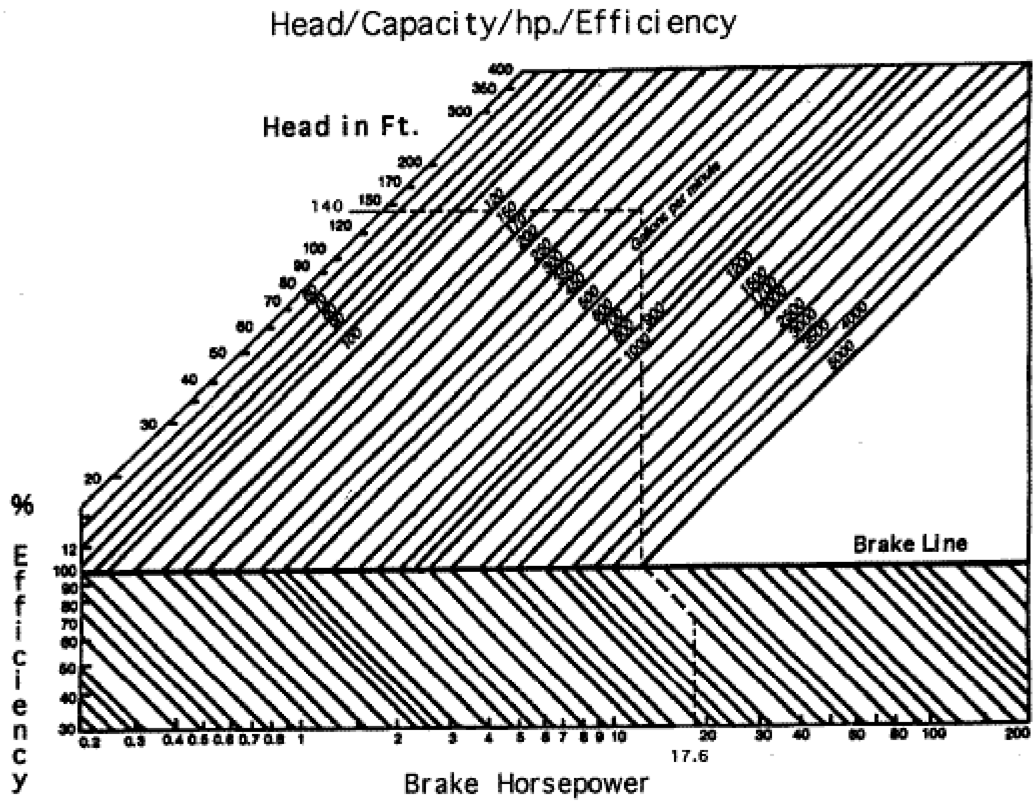
Diagrams and Graphs



Moody's chart



The relationship between head capacity, horsepower and efficiency

<u>Basic equations used in pipe flow calculations</u>

$$\text{Horsepower out} = \frac{\text{Head(feet)} \times \text{Capacity(gpm.)} \times 8.33\text{(lbs./gallon)} \times \text{specific gravity}}{33{,}000 \text{ foot pounds/minute}}$$

$$\text{TDH} = \frac{\text{Efficiency} \times \text{HP} \times 3960}{\text{GPM}}$$

Some of the other equations which went into the calculations were Continuity Equation and Bernoulli’s Equation.

Appendix

Program-1

Riser inner diameter analysis

```
c     The following program is used to optimize the riser pipe inner
c     diameter. The various parameter evaluated in the program are
c     Reynolds number, Velocity of drilling mud, Friction factor,
c     Head loss/power loss due to friction in the riser pipe
c
c---------------------------------*-------------------------------
c
c     Definition of Variables
c
c     rho= mud density = 15 pounds per gallon = 1797.396405 kg/cubic
      metre
c     ppg_to_si = conversion factor from ppg to kg/cubic meter =
      119.826427
c     flow_rate = 1000 gallons per minute
c     gpm_to_si = conversion factor from gpm to cubic meter/sec =
      0.003785
c     area = cross sectional area of the riser pipe (sq metre)
c     velocity = flow_rate/Area (metre/sec)
c     dyn_vis = dynamic viscosity = 34 centipoise = 0.034 N-s/sq. metre
c     cp_to_si = Conversion factor from centipoise to N-s/sq. metre =
      0.001
c     rey_no = reynolds_number
c     fric_fac = friction factor
c     pow_lo = power loss due to friction
c     length = length of the riser pipe = 12000 ft = 3657.607315 m
c     g = acceleration due to gravity = 9.81 sq. metre/sec
c
c-----------------------------------*------------------------------
c
c     Program
c
      implicit none
      real rho, velocity, diameter, dyn_vis, rey_no
      real fric_fac,pow_lo,length,g
      real flow_rate,area,pi
      real gpm_to_si,ppg_to_si,cp_to_si
      open (30, FILE='reynolds.xls')
      write(30,*) 'Diameter',' ','Velocity',' ','Reynolds Number'
     + ,' ','Friction Factor',' ','Power Loss'
```

```
      gpm_to_si = 0.003785
      flow_rate = 1000*gpm_to_si/60
      pi = 3.1415
      ppg_to_si = 119.826427
      rho = 15*ppg_to_si
      length = 3657.607315
      cp_to_si = 0.001
      dyn_vis = 34*cp_to_si
      g = 9.81
      do diameter = 0.01,0.27,0.01
        area = pi*(diameter**2)/4.0
        velocity = flow_rate/area
        rey_no = rho*velocity*diameter/dyn_vis
        fric_fac = 0.0791/(rey_no**0.25)
        pow_lo = fric_fac*length*(velocity**2)/(2*diameter*g)
 40     format(E13.5,'   ',E13.5,'          ',E13.5,'          ',E13.5,'          ',E13.5)
            write(30,40) diameter, velocity,rey_no,fric_fac,pow_lo
      end do
      stop
      end
```

Program-2

Top tension analysis

```
c    The following program is used to calculate and plot the variation
c    top tension with respect to depth. Top tension is a function of
c    riser weight, mud weight, cable weight, guide weight, weight
c    of the bottom package(BOP + subsea pump package) and buoyancy
c    force
c
c----------------*-------------------
c    definition of variables
c
c    riser_unit_wt_lbs = riser weight in lbs per foot = 23.40 lbs/ft
c    riser_unit_wt = riser weight in kg per metre
c    riser_wt = riser weight as a function of depth
c    rho_mud_fps = mud density in ppg = 15
c    rho_mud = mud density in kg per cubic metre
c    ppg_to_si = conversion factor from ppg to si = 119.826427
c    in_to_si = conversion factor from in to si = 0.0254
c    riser_id_fps = riser inner diameter in inches = 5.153
c    riser_id = riser inner diameter in metres
c    lbs_to_si = conversion factor from lbs to si = 0.453592
c    ft_to_si = conversion factor from ft to si = 0.3048
c    riser_i_area = riser inner crossectional area
c    mud_wt = weight of mud as a function of depth
c    depth_ft = depth in feet
c    depth = depth in metres
c    guide_unit_weight_fps = weight of a single guide in lbs=60
c    guide_spacing = spacing between two guides in metres = 12
c    guide_unit_weight = weight of a single guide in kgs
c    guide_weight_length=weight of guide per unit length
c    guide_weight = weight of the guide as a function of depth
c    cable_wt_fps = weight of cable in lbs per ft = 7.444
c    cable_unit_wt = weight of cable per unit length
c    cable_wt = weight of cable as a function of depth
c    wt_bop_sbp_fps=weight of BOP + subsea pump in lbs = 383000
c    wt_bop_sbp=weight of BOP + subsea pump
c    wt_bottom=apparent weight of bottom package
c    rho_water = density of water in kg per cubic metre = 1000
c    riser_od_fps = riser outer diameter in inches = 5.875
c    riser_od = riser outer diameter in metres
c    riser_o_area= riser outer area
c    cable_dia_fps=cable diameter in inches= 2.684
```

```
c     cable_dia=cable diameter in metres

c     cable_area=crosssectional area of the cable
c     byncy_wt = apparent weight of the bouyancy force
c     g = acceleration due to gravity = 9.81 sq. metre/sec
c
c     ***************************************
c                            Program
c     ***************************************
c
      implicit none
      real riser_unit_wt_fps,riser_unit_wt,riser_wt,riser_id_fps
      real rho_mud_fps,rho_mud,riser_id,riser_i_area
      real mud_wt,guide_spacing,guide_unit_weight_fps
      real guide_unit_weight,guide_weight,guide_weight_length
      real lbs_to_si,ft_to_si,ppg_to_si,in_to_si
      real cable_wt_fps,cable_unit_wt,cable_wt
      real wt_bop_sbp_fps,wt_bop_sbp,wt_bottom,byncy_wt
      real g,depth_ft,depth,pi,rho_water,riser_od_fps,riser_o_area
      real cable_dia_fps,cable_dia,cable_area,riser_od,tension_top
      open (30, FILE='tension.xls')
c           write(30,*) 'Depth(m)','          ','Depth(ft)','    ','Riser Wt(N)'
c     + ,'','Mud Wt(N)','','Guide Wt(N)','          ',
c     + 'Cable Wt(N)','  ','By Wt(N)','   ','T (N)'
            write(30,*) 'Depth(m)','          ','Depth(ft)','    ','Riser Wt(N)'
     + ,'  ','Mud Wt(N)','','Guide Wt(N)','          ',
     + 'Byncy Wt(N)','   ','Tension (N)'
      pi=3.1415
      g = 9.81
      riser_unit_wt_fps = 23.40
      lbs_to_si=0.453592
      ft_to_si=0.3048
      rho_mud_fps = 15
      ppg_to_si = 119.826427
      rho_mud = rho_mud_fps*ppg_to_si
      riser_id_fps = 5.153
      in_to_si = 0.0254
      guide_spacing = 12
      riser_id = riser_id_fps*in_to_si
      riser_i_area=pi*(riser_id**2)/4
      riser_unit_wt = riser_unit_wt_fps*lbs_to_si/ft_to_si
      guide_unit_weight_fps = 60
      guide_spacing = 12
      guide_unit_weight = guide_unit_weight_fps*lbs_to_si
      guide_weight_length=guide_unit_weight/guide_spacing
      cable_wt_fps = 7.444
      cable_unit_wt = cable_wt_fps*lbs_to_si/ft_to_si
      wt_bop_sbp_fps=383000
```

```
    wt_bop_sbp=wt_bop_sbp_fps*lbs_to_si
    wt_bottom=wt_bop_sbp*g/2
     rho_water = 1000
      riser_od_fps = 5.875
      riser_od = riser_od_fps*in_to_si
      riser_o_area=pi*(riser_od**2)/4
      cable_dia_fps=2.684
      cable_dia=cable_dia_fps*in_to_si
      cable_area=pi*(cable_dia**2)/4
      do depth_ft = 0,12000,2000
        depth = depth_ft*0.3048
        riser_wt = riser_unit_wt*depth*g
        mud_wt=rho_mud*riser_i_area*depth*g
        guide_weight = guide_weight_length*depth*g
        cable_wt = cable_unit_wt*depth*g
        byncy_wt=((riser_o_area-riser_i_area)+cable_area)*
     +   depth*rho_water
c                       tension_top=riser_wt+mud_wt+guide_weight+cable_wt
c               tension_top=tension_top+wt_bottom-byncy_wt
c 40     format(E13.5,' ',E13.5,'           ',E13.5,'           ',E13.5,'           ',E13.5
c      + ,'',E13.5,'           ',E13.5,'           ',E13.5)
c                       write(30,40) depth,depth_ft, riser_wt,mud_wt,guide_weight,
c      +   cable_wt,byncy_wt,tension_top
                        tension_top=riser_wt+mud_wt+guide_weight
              tension_top=tension_top+wt_bottom-byncy_wt
 40     format(E13.5,'   ',E13.5,'           ',E13.5,'           ',E13.5,'           ',E13.5
     + ,'  ',E13.5,'           ',E13.5)
                        write(30,40) depth,depth_ft, riser_wt,mud_wt,guide_weight,
     +    byncy_wt,tension_top
      end do
 50   format(A,'           ',E13.5)
      write(30,50) 'Apparent Weight of BOP + Subsea pump Package(N)',
     + wt_bottom
      stop
      end
```

Program-3

Pump Power Analysis

```
c
c     The following program is used to determine the pump power.
c     The flow path for the mud is divided into four sections
c     1) Flow down the drill pipe upto the sea flow
c     2) Flow down the drill pipe to the bottom of the well
c     3) Flow up the annulus to the wellbore
c     4) Flow up the mud riser pipe
c
c-----------------*--------------------
c     definition of variables
c
c     rho_mud = mud density
c     rho_mud_fps=mud density in pounds per gallons = 15
c     ppg_to_si = conversion factor from ppg to kg/cubic meter = 119.826427
c     flow_rate_fps = mud flow rate in gallons per minute = 1000
c     gpm_to_si = conversion factor from gpm to cubic meter/sec = 0.003785
c     drill area = cross sectional area of the drill string (sq metre)
c     drill_mud_vel = flow_rate/Area (metre/sec)
c     dyn_vis_fps = dynamic viscosity in centipoise= 34 centipoise
c     dyn_vis = dynamic viscosity
c     cp_to_si = conversion factor from centipoise to N-s/sq. metre = 0.001
c     in_to_si= conversion factro from inch to metre=0.0254
c     ft_to_si= conversion factro from feet to metre=0.3048
c     rey_no_drill = reynolds_number of flow in drill string
c     drill_fric_fac = friction factor in drill string
c     drill_id_fps = drill string inner diameter in inches = 4.5
c     drill_id = drill string inner diameter in metres
c     drill_ht_fps = height of drill pipe considered in feet = 12000 ft
c     drill_head_loss = head loss due to friction in drill string above well bore
c     drill_heads = head in drill string above well bore
c     drill_wb_ht_fps = height of drill pipe considered in well bore in feet = 22000
c     drill_wb_ht = height of drill pipe considered in well bore in metres
c     drill_wb_head_loss = head loss due to friction in drill string in well bore
c     drill_wb_head = head in the drill string in the well bore
c     casing_dia_fps = diameter of casing in inches = 20
c     casing_dia = diameter of casing in metres
c     effective_area = area of the annulus
c     effective_perimeter= perimeter of the annulus
c     effective_dia=effective diameter of the annulus
c     annulus_area=area of the annulus
c     annulus_mud_vel = velocity of drilling mud in the annulus
```

```
c     rey_no_annulus=reynold number of mud flow in annulus
c     annulus_fric_frac = friction factor in annulus
c     annulus_head_loss=head loss due to friction in annulus
c     annulus_head = head in the annulus
c     riser_dia_fps = riser internal diameter in inches = 5.153
c     riser_dia = riser internal diameter in metres
c     riser_area = crosssectional area of the riser
c     riser_mud_vel = mud velocity in the riser
c     rey_no_riser = reynolds number of mud flow in riser
c     riser_fric_fac = friction factor of mud flow in riser
c     riser_head_loss = head loss due to friction in riser
c     riser_head = head in riser
c     pump_head = head requirement of the pump in metres
c     pump_hyd_power = hydraulic horse power requirement of the pump
c     pump_power = brake horse power requirement of the pump
c     pump_eff = efficiency of pump
c     g = acceleration due to gravity = 9.81 sq. metre/sec
c
c     Program
c
      implicit none
      real rho_mud, drill_id, dyn_vis,rey_no_drill,drill_ht
      real drill_fric_frac, drill_ht_fps,drill_mud_vel
      real gpm_to_si,ppg_to_si,cp_to_si,in_to_si,g,pi,ft_to_si
      real flow_rate_fps,dyn_vis_fps,drill_area,flow_rate
      real drill_id_fps,drill_head_loss,drill_head,rho_mud_fps
      real drill_wb_ht_fps,drill_wb_ht,drill_wb_head_loss
      real drill_wb_head,casing_dia_fps,casing_dia,effective_area
      real effective_perimeter,effective_dia,annulus_area
      real annulus_mud_vel,rey_no_annulus,annulus_fric_frac
      real annulus_head,annulus_head_loss,riser_dia_fps
      real riser_dia,riser_area,riser_mud_vel,rey_no_riser
      real riser_fric_fac,riser_head_loss,riser_head
      real pump_head,pump_hyd_power,pump_eff,pump_bhp
      gpm_to_si = 0.003785
      flow_rate_fps = 1000
      flow_rate = flow_rate_fps*gpm_to_si/60
      pi = 3.1415
      ppg_to_si = 119.826427
      in_to_si = 0.0254
      cp_to_si = 0.001
      ft_to_si = 0.3048
      drill_ht_fps = 12000
      drill_ht = drill_ht_fps*ft_to_si
      rho_mud_fps = 15
      rho_mud = rho_mud_fps*ppg_to_si
      dyn_vis_fps=34
```

```
dyn_vis = dyn_vis_fps*cp_to_si
g = 9.81
drill_id_fps = 4.5
drill_id = drill_id_fps*in_to_si
drill_area=pi*(drill_id**2)/4
drill_mud_vel = flow_rate/drill_area
rey_no_drill = rho_mud*drill_mud_vel*drill_id/dyn_vis
drill_fric_frac = 0.0791/(rey_no_drill**0.25)
drill_head_loss = drill_fric_frac*drill_ht*(drill_mud_vel**2)
drill_head_loss = drill_head_loss/(2*drill_id*g)
drill_head = drill_ht-drill_head_loss

drill_wb_ht_fps = 22000
drill_wb_ht = drill_wb_ht_fps*ft_to_si
drill_wb_head_loss=drill_fric_frac*drill_wb_ht*(drill_mud_vel**2)
drill_wb_head_loss = drill_wb_head_loss/(2*drill_id*g)
drill_wb_head = drill_wb_ht-drill_wb_head_loss

casing_dia_fps = 20
casing_dia = casing_dia_fps*in_to_si
effective_area = pi*((casing_dia**2)-(drill_id**2))/4
effective_perimeter=pi*(casing_dia-drill_id)
effective_dia=casing_dia+drill_id
annulus_area=pi*(effective_dia**2)/4
annulus_mud_vel = flow_rate/annulus_area
rey_no_annulus=rho_mud*annulus_mud_vel*effective_dia/dyn_vis
annulus_fric_frac = 0.0791/(rey_no_annulus**0.25)
annulus_head_loss=annulus_fric_frac*drill_wb_ht
annulus_head_loss = annulus_head_loss*(annulus_mud_vel**2)
annulus_head_loss = annulus_head_loss/(2*effective_dia*g)
annulus_head = drill_wb_ht+annulus_head_loss

riser_dia_fps = 5.153
riser_dia = riser_dia_fps*in_to_si
riser_area = pi*(riser_dia**2)/4
riser_mud_vel = flow_rate/riser_area
rey_no_riser = rho_mud*riser_mud_vel*riser_dia/dyn_vis
riser_fric_fac=0.0791/(rey_no_riser**0.25)
riser_head_loss=riser_fric_fac*drill_ht
riser_head_loss = riser_head_loss*(riser_mud_vel**2)
riser_head_loss = riser_head_loss/(2*riser_dia*g)
riser_head = drill_ht+riser_head_loss

pump_head = riser_head+annulus_head-drill_wb_head-drill_head
pump_hyd_power = rho_mud*g*pump_head*flow_rate/746
pump_eff = 0.85
pump_bhp=pump_hyd_power/pump_eff
```

```
print *,'TH1',drill_head,' metres'
print *,'TH2',drill_wb_head, ' metres'
print *,'TH3',annulus_head, ' metres'
print *,'TH4',riser_head, ' metres'
print *,'Pump Head',pump_head,' metres'
print *,'Pump BHP',pump_bhp

stop
end
```

Appendix D

Embodiment Design Report: Top Hole Dual Gradient Drilling (December 2005)

Chris Dharmawijatno, Mahesh Sonawane, and Chris Krueger, Department of Mechanical Engineering, Texas A&M University

Embodiment Design Report:
Top Hole Dual Gradient Drilling

Prepared For

Mineral Management Services

Presented to:
Mineral Management Services
Dr. Steve Suh, PhD

Prepared by:

Chris Dharmawijatno
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Departments of Mechanical Engineering

MEEN 632 – Fall 2005 – Section 600

December 9, 2005

Embodiment Design Report

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Introduction

Dual Gradient drilling began with Shell Oil company's Marine Technology Group in the 1960's with their "3000 ft. Feasibility Study", where the beginnings of some of this technology were first conceptualized. In 1996, Conoco, Hydril, and 23 other companies conducted a "Riserless Drilling Feasibility Study", followed by the 1997 "Gas Lift Feasibility Report" conducted by Petrobras and LSU.

Currently, several projects are underway that in some way relate to Dual Gradient technology. One such project is Deep Vision, which is a collaborative effort amongst Baker-Hughes, BP, Chevron, and Transocean. This project utilizes a sub-sea centrifugal pump to circulate the mud through a mud-return line back to the drilling platform, which is then pumped back down the hole to circulate drilling products. Another project utilizes a sub sea pump to pump the mud back up the riser.

Mineral Management Services (MMS) would like to explore other methods of Dual Gradient technology, specifically a method or design which would implement Top Hole Dual Gradient technology, in which a dual pressure gradient would be employed when drilling the first two intervals of petroleum well. It is hoped that such a system will make sub-sea drilling operations more efficient, less costly, and faster.

Team MC^2 hopes that the proposals and designs presented herein address the need presented by the project sponsor, as described and understood by us in the following need analysis. Having identified the exact need, conceptual designs were developed, whereupon one was down-selected to refine and develop into an embodiment design. The final embodiment design presented in this report represents a semester's worth of design and effort by this team, and it is hoped that this design will effectively communicate the potential and feasibility of Top Hole Dual Gradient drilling technology.

Need Statement

Upon initially reviewing the problem and accompanying material, the team began to immerse themselves in the knowledge of deep-sea petroleum drilling to better understand the situation in which the problem was presented. After gaining a deeper understanding of the material, the team was able to apply that knowledge to the need presented, and the following need statement was developed:

"There is a need for a deep-sea drilling package that utilizes Top Hole Dual Gradient Technology to safely drill petroleum wellbores at a depth to exceed current capacity using an optimal amount of materials."

Another need statement developed by another team member covered other principles not covered by the above need statement.

"There is a need to design a system of device enabling the use of Top Hole Dual Gradient Technology, providing mud return, and enabling the ease of integration with the existing drilling rig equipment."

It was felt that both need statements covered points that should be included in a final need statement, which led the team to simply combine the two need statements. This yielded the teams final need statement.

"There is a need for a drilling mud recirculation system enabling the use of Dual Gradient Technology to the Top Hole of well bores to improve drilling efficiency to the maximum depth using an optimal amount of material and cost, and is easily integrated with the existing drilling package."

Function Structure

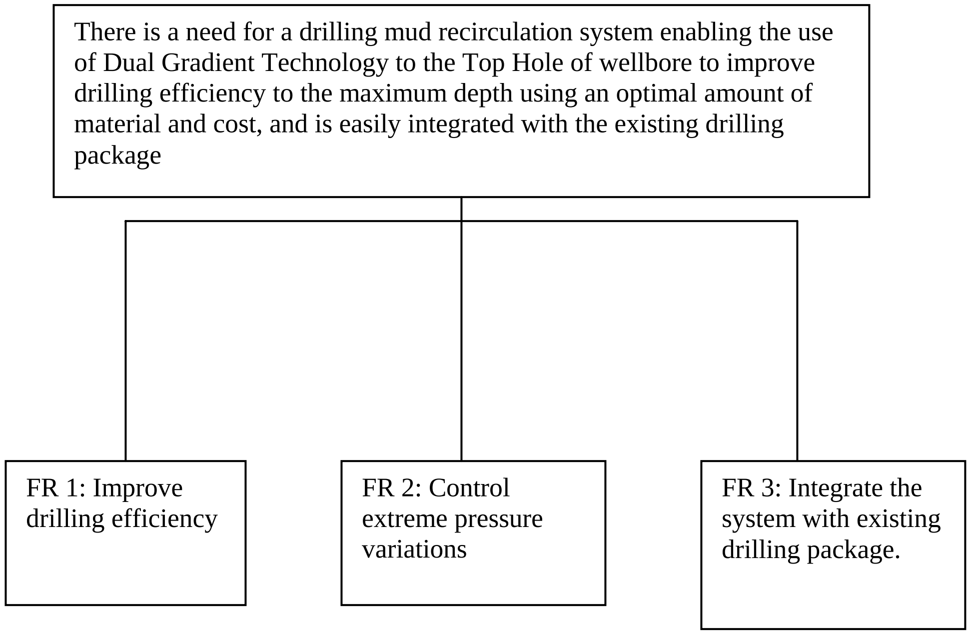


Figure 1. Primary Function Structure

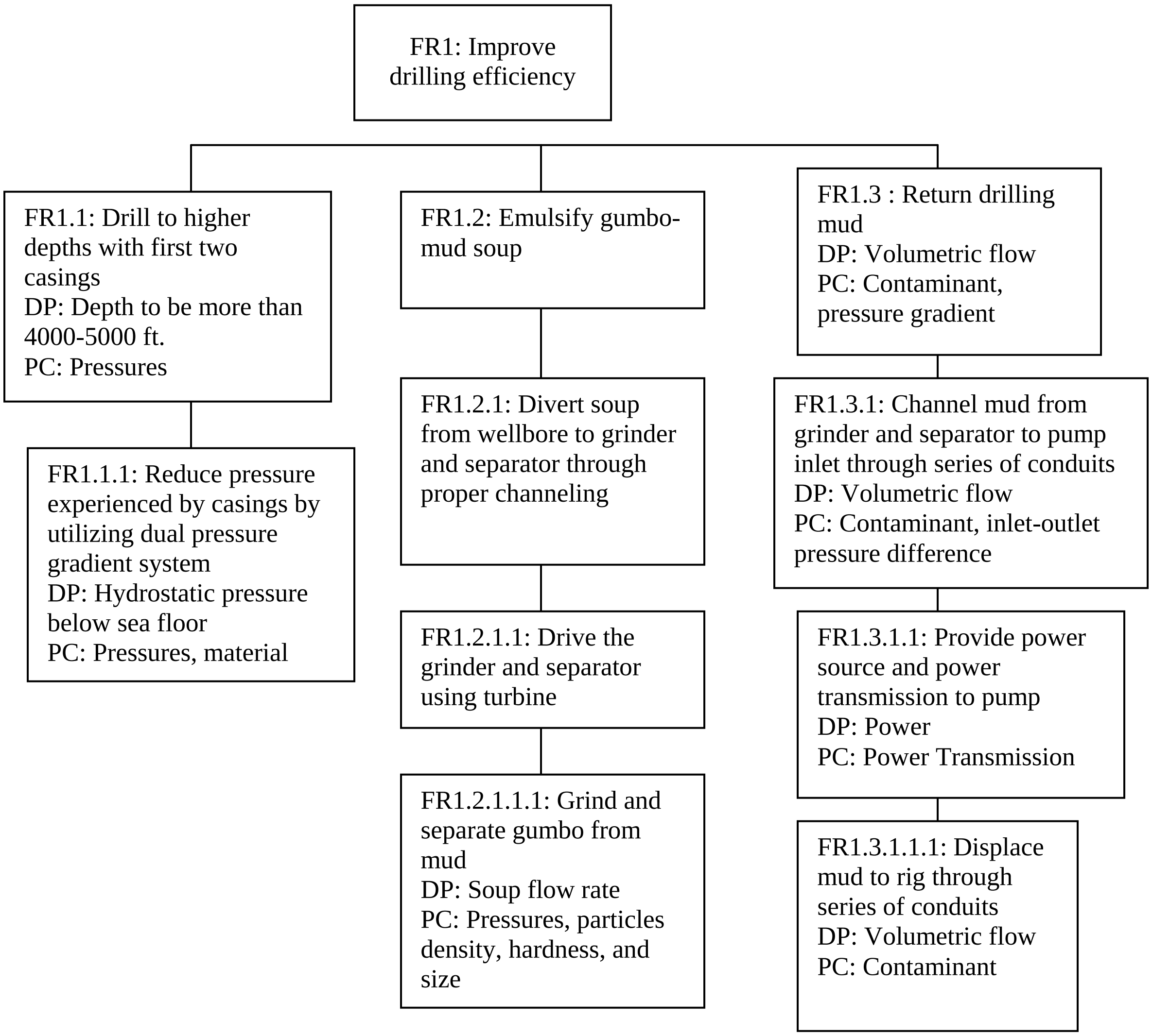


Figure 2. Function Structure: Section 1.0

FR: Functional Requirement – Describes What Needs to Be Done
DP: Design Parameter – Measurable Quantity
PC: Primary Constraint – Number Defining Limits

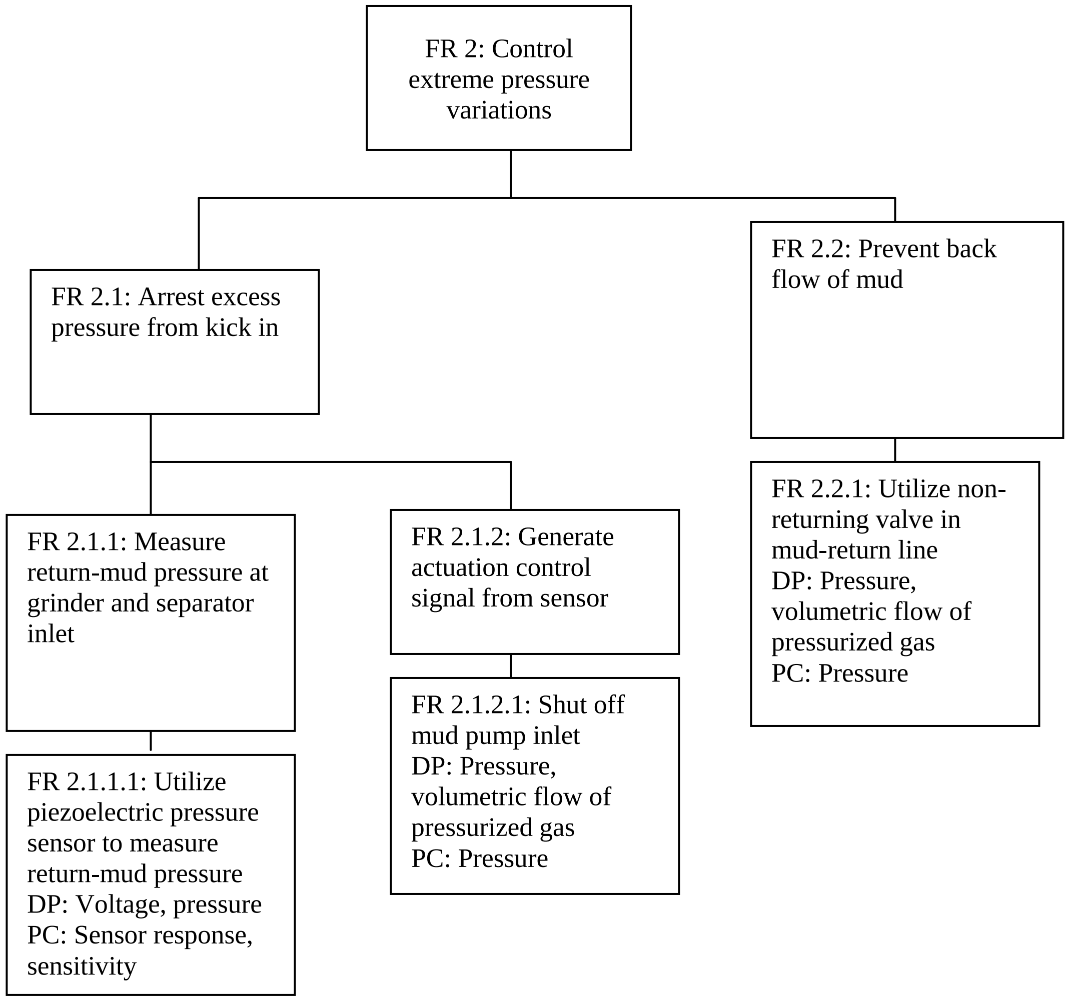


Figure 3. Function Structure: Section 2.0

FR: Functional Requirement – Describes What Needs to Be Done
DP: Design Parameter – Measurable Quantity
PC: Primary Constraint – Number Defining Limits

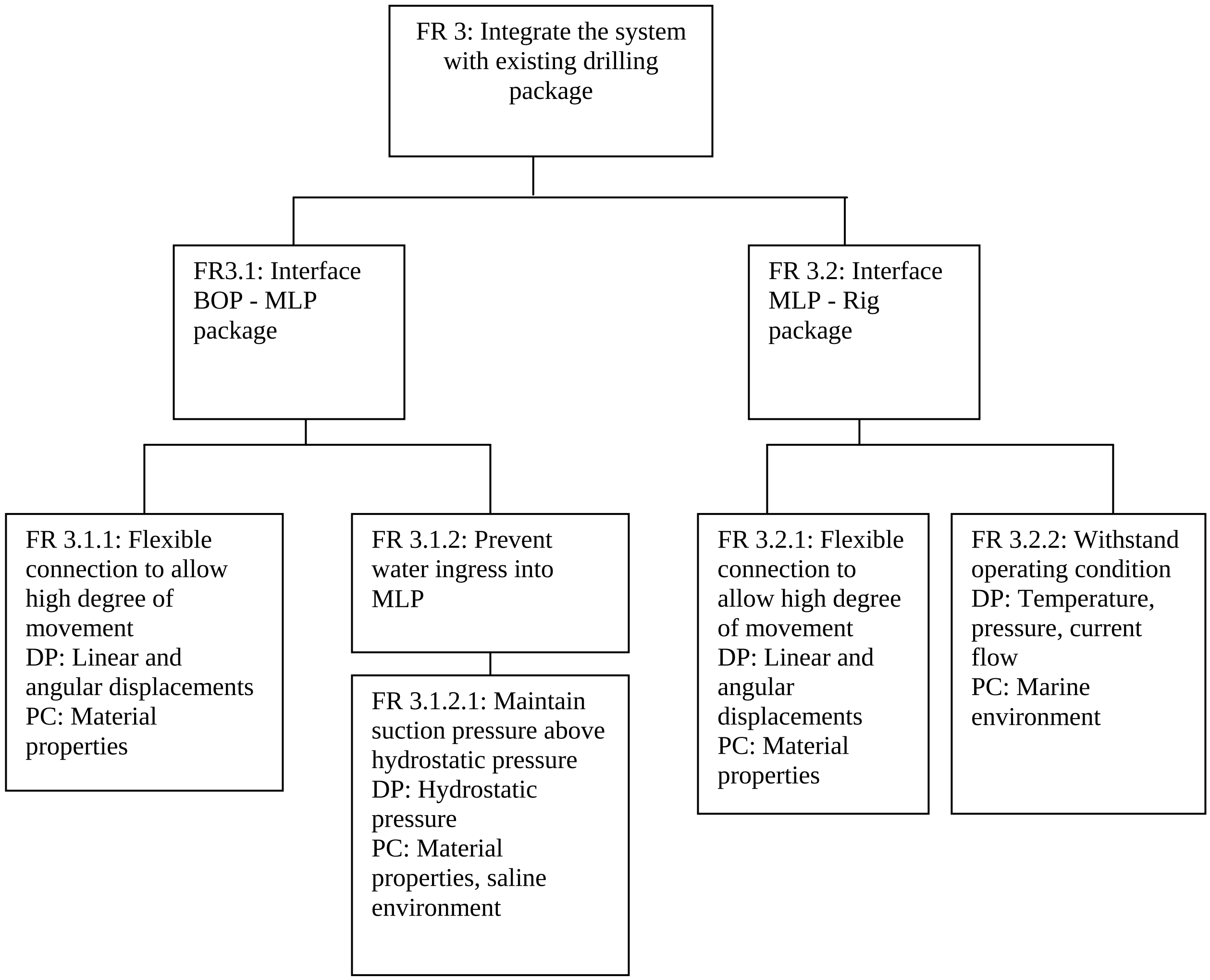


Figure 4. Function Structure: Section 3.0

FR: Functional Requirement – Describes What Needs to Be Done
DP: Design Parameter – Measurable Quantity
PC: Primary Constraint – Number Defining Limits

Concept 1: Hydraulically driven Impeller Pump

The first conceptual design is based on the usage of hydraulically-driven impeller pumps. Figure 8 shows how the fluids move inside basic impeller pump. This pump may be the most versatile pump available. For example, the total head can be increased by linking more than one impeller blade together. The impeller's blade is available from 1 inch to 10 inches or more. This pump is chosen due to the fact that it performs well to move impure liquids that may contain abrasive or aggressive slurry solutions with particles of various sizes. In addition, it is available in many different ranges of specifications thus; a complete redesign work may not be necessary, they operate with uniform flow and relatively quiet, and have a low initial cost.

Aside from the benefits offer by the impeller pumps, some of the drawbacks are their operation depends on the back pressure, they are sensitive to air in the flow. These two disadvantages may introduce large inaccuracy in flow rate calculations. In addition to these disadvantages, they have a low limit to the viscosity of the fluid,

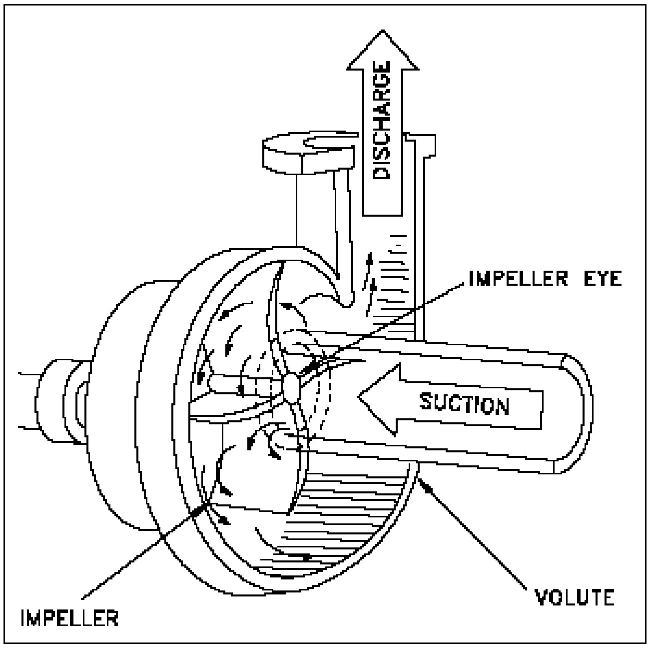


Figure 5: Basic Impeller Pump

In our system, the pump will be placed inside a casing to prevent it from being exposed to the sea water and its environment conditions. In turn, the casing will need to be able to handle the hydrostatic pressure and exposure to sea water and other operating condition that can leads to corrosion. Figure 9 shows the system configuration.

The power source of this system will be provided by a hydraulic system. A water pump placed on the rig will be used to pump sea water to nozzle shaped discharge. This high velocity water will be directed down to a turbine located on the mud line though a series of pipes. The turbine will then be used to drive the impeller pump's shaft, as well as the grinder and separator.

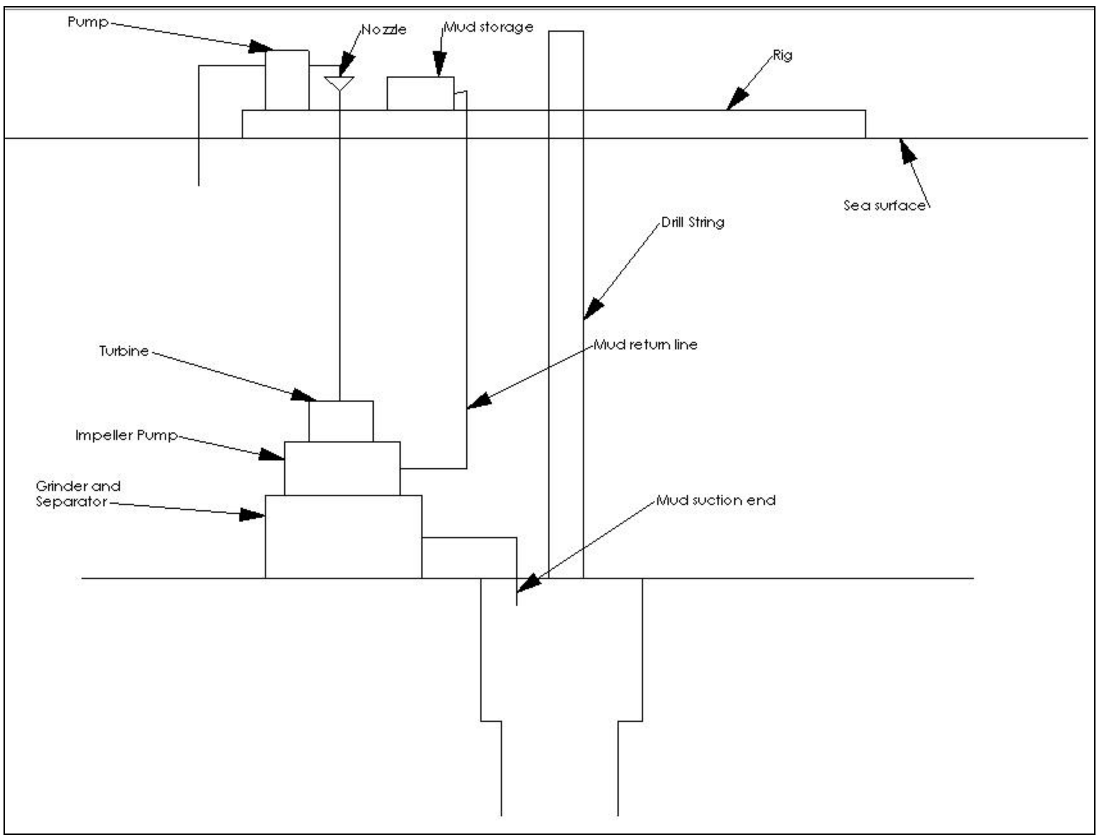


Figure 6: System Description of Hydraulic Impeller Concept

Concept 2: Mechanically Powered Double-Acting Force Pump

The route of the mud follows the general system overview, through the BOP and the MC2 device, and through the grinder and separator. Finally, the mud is sent to the pump, which is a double-acting force pump. On the down stroke, mud is sucked into the cylinder through the top left valve, and pumped out of the cylinder through the bottom right valve. On the up stroke, mud is sucked in through the bottom left valve, and pumped out of the cylinder through the top right valve. The resulting pressure closes the valves in which it is undesired that there by any mass flow. This system results in a continuous mass flow through the system on both the up and down stroke of the pump piston.

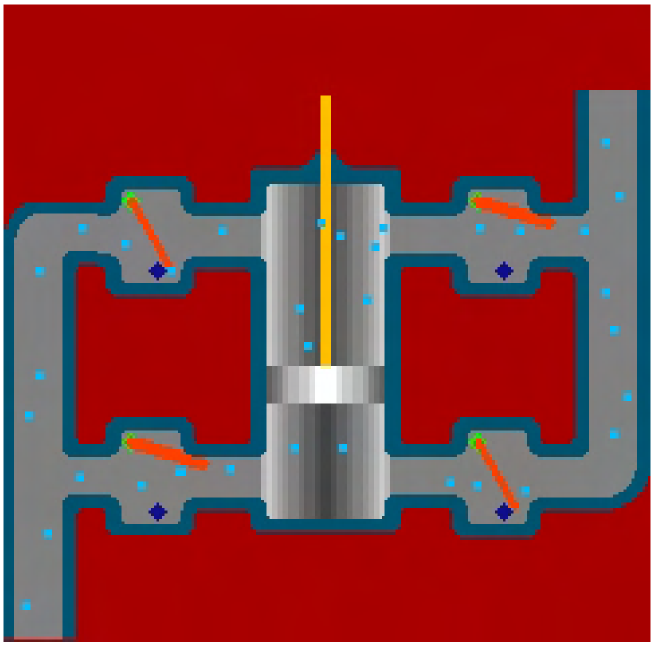


Figure 7: Double Acting Force Pump

The method of powering these devices is from a mechanical chain (see figure 11) coupled to a series of gears with gear ratios that will provide the appropriate amount of power to each system, including the grinder(s), the separator, and the double action force pump. This mechanical chain will be connected to a large ring gear surrounding the drill string. As the drill string is rotating, the gear will rotate and provide power to the pump and other systems, thus circulating and processing the mud. This will be most efficient, utilizing the power of the drill string, and since mud will only be produced when the drill string is drilling, there is no need for the pump and related systems to require power when the drill string is not operational. To address the problem of an ever-deepening drill string, the ring gear will be mounted on top of the BOP in its own casing, with roller bearings to allow it to rotate. The drill string pipe will be altered to have grooves down each pipe at every 90 degrees, and these grooves will transmit torque from the drill string to the ring gear. The grooves will be allowed to slide through the ring gear by roller bearings mounted near each groove slot. All moving parts and machinery will be encased to prevent foreign objects from tampering with the system.

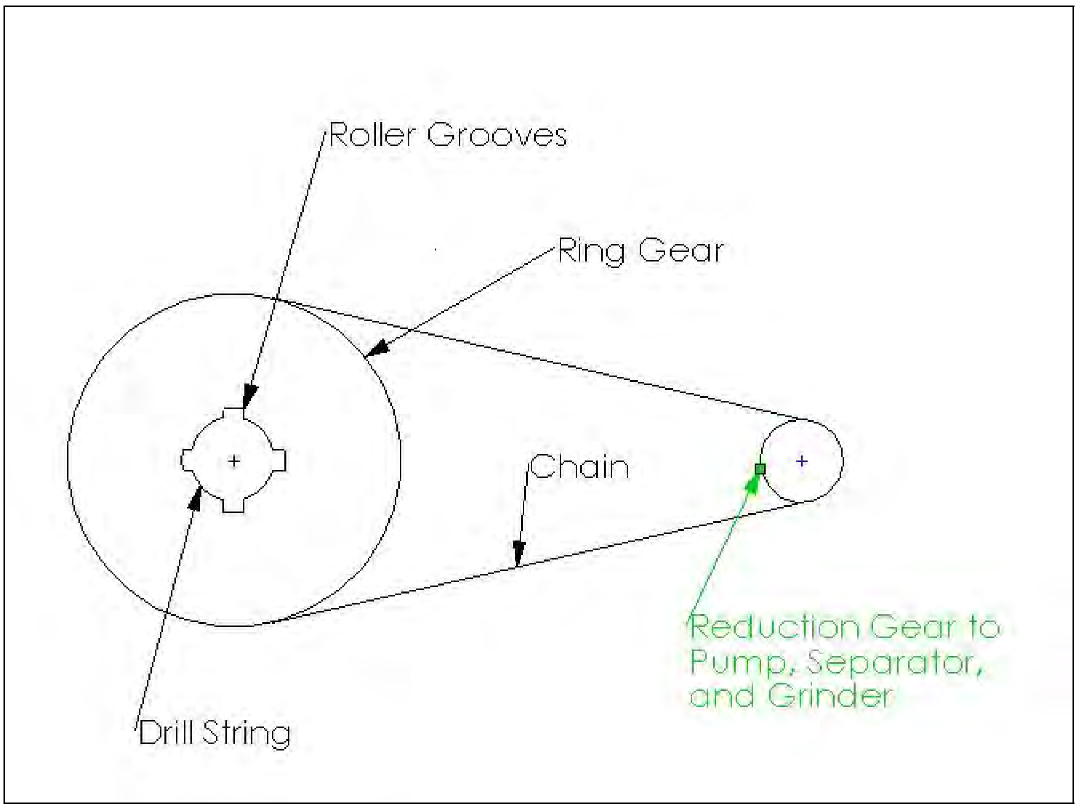


Figure 8: Mechanically Driven Chain Configuration

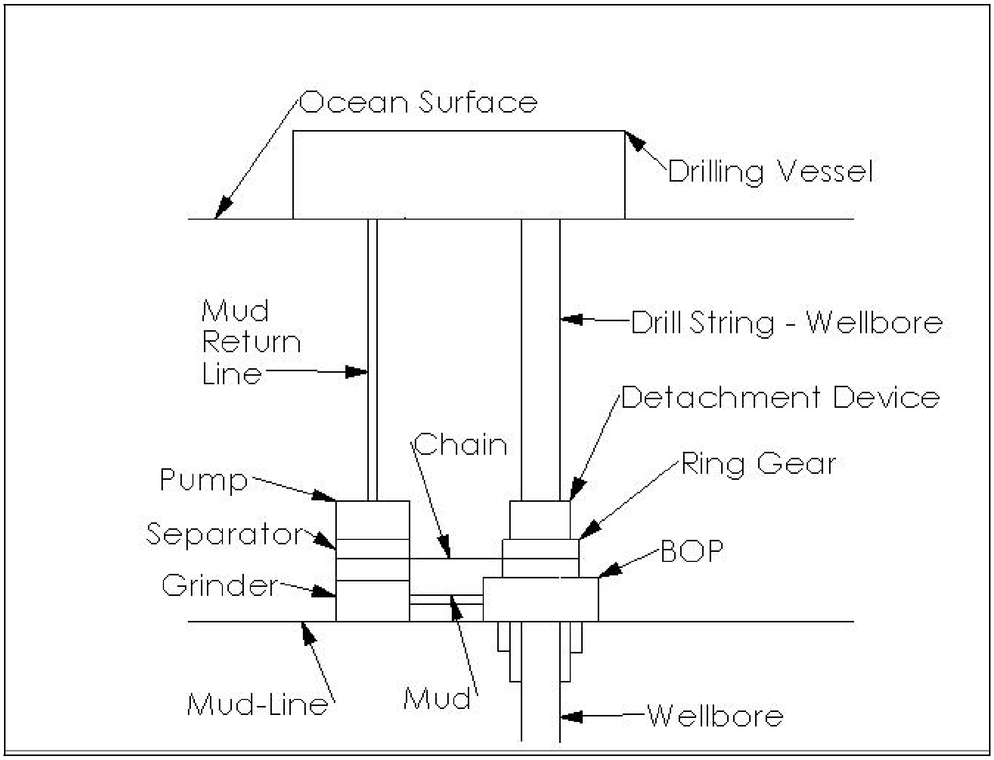


Figure 9: Mechanically Driven System Description

Concept 3: Electromagnetically driven Diaphragm Pump

The third concept envisaged by MC^2 is the use of an "Electromagnetically driven Diaphragm pump" to re-circulate the drilling mud from the mud line back to the floating platform. The concept proposes to exploit the enormous potential and versatility of the Diaphragm pump in handling drilling mud.

Overview of the Diaphragm pump and its Potential:

Diaphragm pumps are common industrial pumps that use positive displacement to move liquids. Diaphragm pumps use a diaphragm that moves back and forth to transport liquids from one place to another. It incorporates a sealed diaphragm with the material to be pumped on one side and air on the other. The diaphragm is moved back and forth, increasing and decreasing the volume of the pumping chamber and moving the material to be pumped. Check valves prevent the pumped material from returning into the pumping chamber. Pistons are either coupled to the diaphragm, or used to force hydraulic oil to drive the diaphragm. Diaphragms can be fabricated from a variety of materials such as ethylene propylene (EPDM), poly-tetra-fluoro-ethylene (PTFE), plastic, rubber, and elastomers to resist a variety of operating conditions like extreme temperatures, chemicals, sunlight, weathering, and ozone. Housing materials include aluminum, brass or bronze, cast iron, plastic and stainless steel. Rugged diaphragm pump housings can withstand high temperatures and may be exposed to various grades of water, oils, and other solvents.

Diaphragm pumps are used in a variety of industries and applications. Some devices are used in aerospace or defense, agriculture or horticulture, automotive, brewery or distillery, construction, cryogenic, dairy, or flood control applications. Other diaphragm pumps are used in food service, food processing, HVAC, machine tool, maritime, mining, and municipal applications. Diaphragm pumps for oil and gas production include special petrochemical and hydrocarbon devices that can transport large quantities of crude oil, gasoline, kerosene, diesel oil, lubricating oil, paraffin wax, asphalt, chemical raw material, and petroleum solvents.

Some of the critical advantages presented by the Diaphragm pump which are essential in the Sub-sea mud pumping operation are as follows:

- *Diaphragm pumps are highly reliable because they do not include internal parts that rub against each other. In fact, prolonged diaphragm life may be possible if the diaphragm pump is run dry to prime.*
- *Diaphragm pumps can handle a range of media that includes abrasive materials, acids, chemicals, concrete or grout, coolants, combustible or corrosive materials, effluents, ground water, and gasoline or diesel fuel Power sources include AC voltage, DC voltage, pneumatic or hydraulic systems, natural gas, gasoline, steam, water, or solar power.*
- *Metering diaphragm pumps can deliver an even, smooth flow of air, gas or a liquid at a predetermined or programmable rate.*

System description:

The system utilizes a Diaphragm pump to pump drilling Mud from the mud line to the floating platform. The MC2 device is coupled onto the BOP in order to channel the incoming mud towards the diaphragm pump. Mud Inlet Pressure sensors and Mud Inlet Mass flow rate sensors are located in the conduit from MC2 to the pump to sense the pressure and flow rate of the mud. This will provide a means of detecting a kick-in if and when there is a sudden pressure increase. The Mud enters the diaphragm pump through the inlet valve during the suction stroke of the pump. The mud is pressurized by the pump and discharged into the mud return pipe for recirculation. A pump chamber pressure sensor is located on the pump wall to protect the pump from damage due to excessive pressure. The sensor can generate signals to actuate a relief valve to release any abnormal pressure build up and protect the pump.

The piston reciprocates in a smooth bearing block which serves as a guide for the piston motion. The pump is powered by an electromagnetic force. An AC/DC supply located on the floating platform transmits electric current to an electromagnet situated at the mud line. The current is transmitted down an electric cable that is located within the cable housing already provided by the rest of the THDG project. This electromagnetic force is used to reciprocate the piston of the diaphragm pump. The piston stroke is controlled by an Electronic control module which receives signals from various sensors, such as pressure sensors, flow sensors, piston position sensors, etc., and generates an appropriate actuation signal.

System components

1	Riser	6	Electromagnetic drive	11	Mud inlet pressure, volumetric/mass flow rate sensor
2	MC2	7	Pump chamber pressure sensor and relief valve	12	Shaft guide bearing block
3	BOP	8	Outlet valve assembly	13	AC/DC power source
4	Inlet valve assembly	9	Mud return pipe	14	Electronic control module
5	Diaphragm pum[	10	Floating platform		

Table 1: Diaphragm Pump System Components

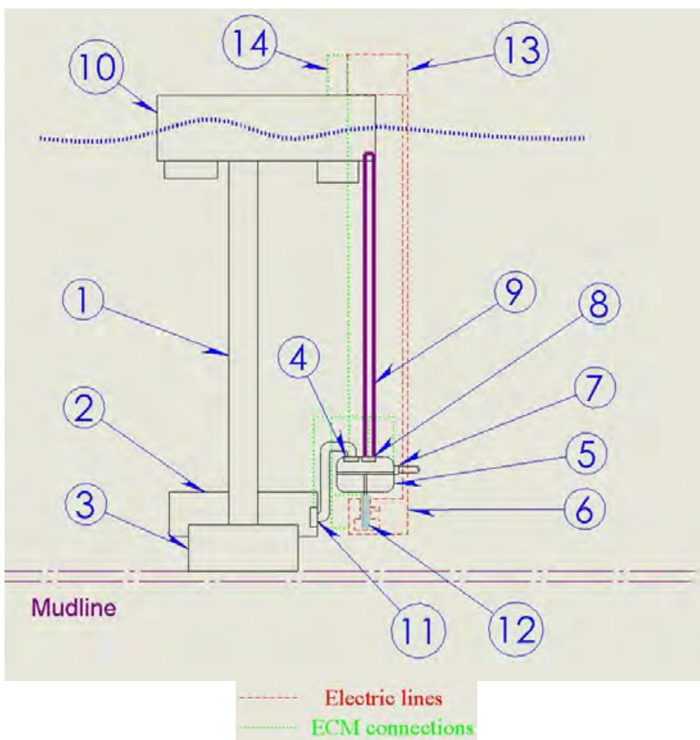


Figure 10: Electromagnetic System Description

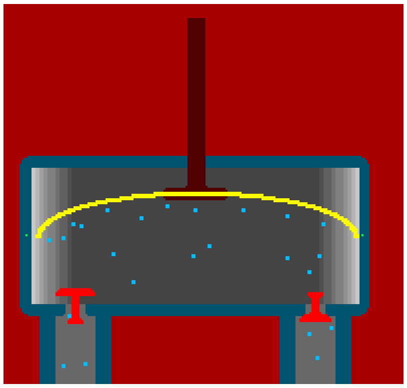


Figure 11: Diaphragm Pump

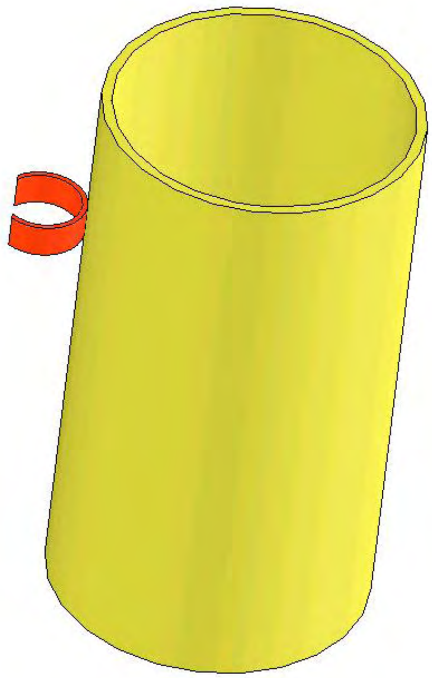


Figure 12: Power Cable Clamp on Mud Return Pipe

Recommendation

The down-selection method used was that of a quantitative weighted-average analysis. A set of criteria was developed describing aspects of the need that each concept had to address. Each criteria was given a certain weight percentage based upon how important that criterion was in relation to the rest of the criteria. The total weights of the criteria added up to 100%. For each criterion, each concept was assigned a certain number of points based on how well that concept met that criterion, relative to the other concepts. The total number of points assigned to all concepts for each criterion equaled 100. Each assigned point value was multiplied by the criteria weight to obtain the weighted points assigned. Then, all weighted points for each concept for every criteria were added together to obtain a total score for each concept, which rated its performance and the ability to meet the need relative to the other concepts. The total scores of all 3 concepts added up to 100. Finally, each of these scores for each individual on the team was averaged with the other individuals from the team, and the final score was assigned to the concepts, from which the highest scored, was chosen by the down selection process as the down-selected concept. This was the hydraulically driven impeller pump system. Though it was similar to the mechanically driven system in most respects, it was determined that it would prove more reliable in practice, and was scored accordingly, as well as other differences.

The team then deliberated on an objective and subjective basis about the concept recommended by the process, and decided that since each concept's score averaged out relatively close to the other concepts, each concept is worthy of merit. While the final design will most likely resemble the hydraulically driven impeller pump concept, it is also likely that the final design will include facets of the other two concepts.

Criteria	Cost	Safety	Integration with current system	Reliability	Simplicity of Design	Efficiency	Innovative	Maintains Appropriate Pressure	Scores
Weighted Value	0.05	0.1	0.1	0.2	0.1	0.2	0.05	0.2	1
Assigned Electromagnetic Diaphragm Pump	15	30	35	40	15	35	30	35	235
Weighted Electromagnetic Diaphragm Pump	0.75	3	3.5	8	1.5	7	1.5	7	32.25
Assigned Hydraulically Driven Impeller Pump	50	40	35	35	45	30	35	30	300
Weighted Hydraulically Driven Impeller Pump	2.5	4	3.5	7	4.5	6	1.75	6	35.25
Assigned Mechanically Driven Double Acting Force Pump	35	30	30	25	40	35	35	35	265
Weighted Mechanically Driven Double Acting Force Pump	1.75	3	3	5	4	7	1.75	7	32.5
Assigned Total	100	100	100	100	100	100	100	100	
Weighted Total	5	10	10	20	10	20	5	20	

Table 2: Individual Scoring Method for Concept Analysis

	Chris D	Mahesh	Chris K	Average
Electromagnetic Diaphragm Pump	32.25	35.5	30	32.58333
Hydraulically Driven Impeller Pump	35.25	37.75	34	35.66667
Mechanically Driven Double Acting Force Pump	32.5	26.75	36	31.75

Table 3: Team Scoring Average

Post-Recommendation Summary and Final Design Selection

Having down-selected to the hydraulically driven impeller pump, it was the wish of Team MC2 to design the embodiment design using a hydraulically driven impeller pump that derived its power from rotation of the drill string using the power configuration of concept 1. Unfortunately, it was found under the following stress analysis that the drill string would be unable to withstand the torque required to provide the power to the pump and to drill through the sea floor. It may be possible in the future to add gear reductions and other ways to minimize the torque around the drill string, but given requirements on Team MC2, it was decided it was more feasible to utilize a different concept to power the impeller pump.

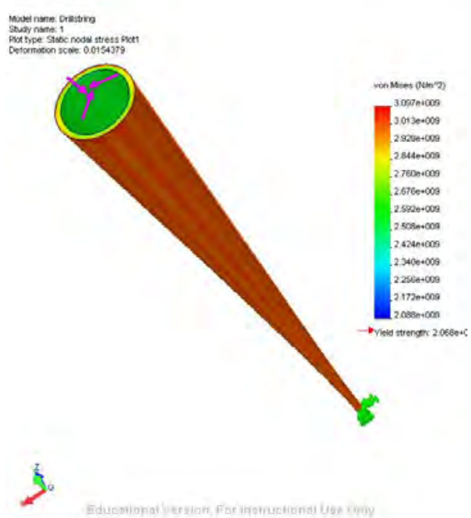


Figure 13: Stress Analysis

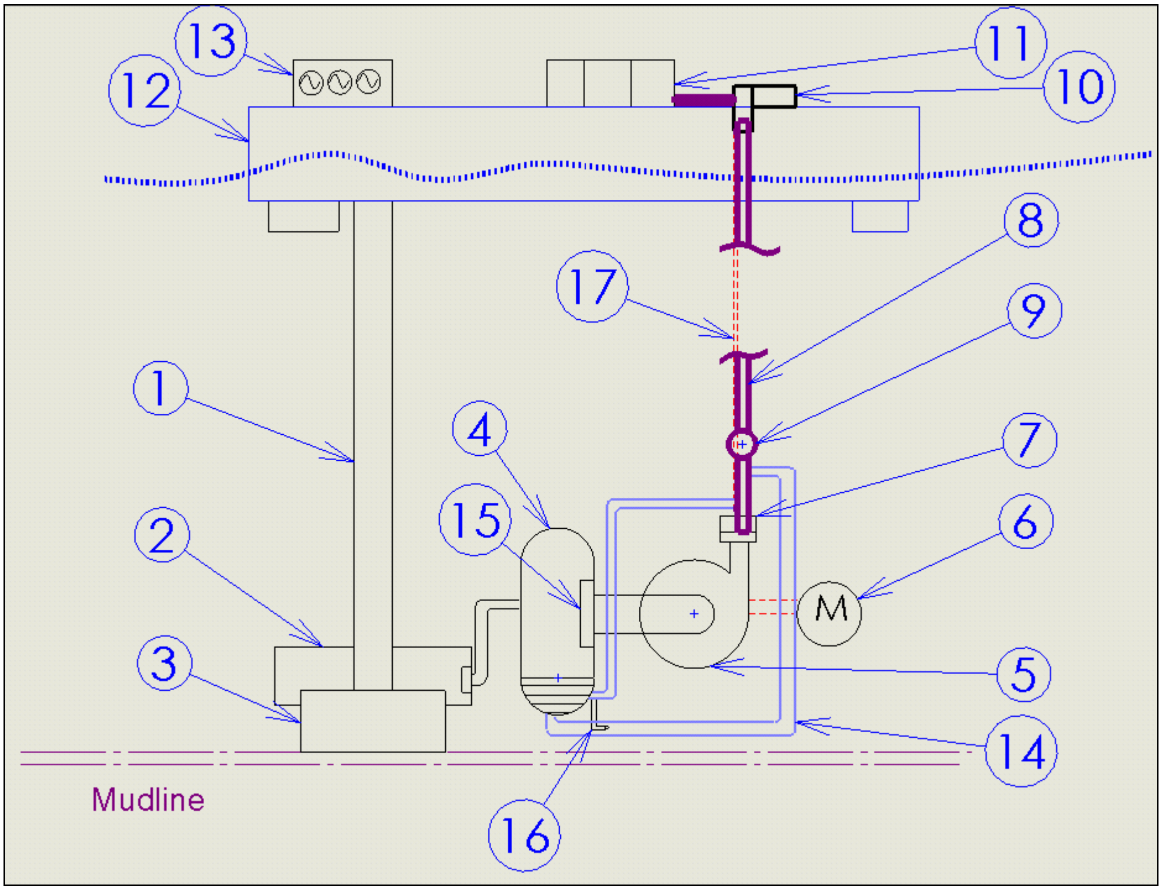
Additionally, the desire to use hydraulics to transmit power from a turbine on the drilling platform to a second turbine on the sea floor, utilizing sea water as a pressurized working fluid to transmit power, was found infeasible as it would require an enormous turbine, and that the pipe required to transmit the kind of flowrate of water required to drive the pump with the necessary power would be as large or larger than the riser, negating the positive effects of designing without the riser.

Given these considerations, it was determined that the best method of powering the pump in our design was to use an electrically powered system by running power cables to the bottom of the ocean. The following design is a culmination of this approach and the recommendation given in the conceptual design report.

Overall System Description

The overall system is presented below. The **drilling platform (12)** is located on the surface of the water. From this, the **drill string (1)** extends down through the ocean down to 12,000 feet in depth to the sea floor and drills the well. A **blow-out-preventer (BOP) (3)** is located at the top of the well bore and controls pressure fluctuations inside the well bore during drilling. The drill string is fed through the **BOP (3)**. As the **drill string (1)** drills, mud, a lubricating fluid including water, earth, and chemical additives and emulsions is circulated through the drill string to lubricate the drill bit and wash away cuttings and drilled earth. The mud is then circulated to the top of the **BOP (3)**, where currently the mud is dumped on the sea floor.

This is where Team MC2's design enters. The purpose of our design is to pump the mud back to the **drilling platform (12)** and continually recycle it through the drilling process. Our design begins with the **rotary diverter (2)** which channels the mud from the **BOP (3)**. Mud is then fed into the **separator tank (4)** where sediment accumulates. The **strainer (15)** controls entry of particulate matter and rejects particles that might harm the **pump (5)** or cause an undesired pressure drop. There is a **sediment by-pass line (14)** that controls pressure before and after the **pump (5)**. A **nozzle (16)** acts as a water jet pump that aids in the feedback system meant to control particulate matter entering the **pump (5)**. The mud then proceeds from the **strainer (15)** into the **impeller pump (5)**. This mud is then pumped up through the **mud return line (8)** up to the **drilling platform (12)**. Once arrived, the mud will be channeled through the **shale shaker/coolant/separator chamber (11)** to remove any other debris and to treat the mud, and the mud is then recycled back through the system to be pumped down the **drill string (1)**. The **mud return line (8)** has several **ball-joints (9)** and 2 adapters in between the joint that allow the line to flex with the ocean over the 2 mile distance. The **mud return line (8)** will be fed down to the bottom of the ocean using the **pipe arrestor (10)**. The **pump (5)** will be powered by an **electric motor (6)** located at the ocean floor, and will be powered by a **generator (13)** located on the **drilling platform (12)**. Power will be transmitted by **cables (17)** running from the **generator (13)**, coupled to the **mud return line (8)** down to the **motor (6)**.



1: Drill String
2: Rotary Diverter
3: BOP
4: Separator tank
15: Strainer
5: Impeller pump
6: Motor
7: Back Pressure regulator
8: Mud return line
9: First Ball joint at 40m height
10: Pipe Arrestor
11: Shale shaker / Coolant / Separator
12: Drilling platform
13: Generator
14: Sediment By-pass line
16: Nozzle
17: Conduit of Electric wires supported with clamps

Figure 14: Overall System Description

With this proposed configuration, the drilling mud is effectively circulated throughout the entire drilling system, guaranteeing an economical way to prevent the costly waste of dumping the drilling mud and its additives on the sea floor, and the environmental problem that creates. The detailed descriptions of each component can be found in the following section.

Detailed Design Analysis

Mud Return Line Pipe

The size of mud return pipe proposed in our design is 4.276 in ID pipe made of S-140 Steel. This material is more brittle than any typical drill pipe but stronger with high tensile strength of 140,000 psi.

Pipe density 0.308 lb/in^3

Drill Pipe Tube OD [in.]	Drill Pipe Tube ID [in.]	Nominal Weight Tube [lb/ft]	Adjusted Overall Joint Weight[lb/ft]	API Steel Grade	100% Tensile Strength	Ultimate Tensile Strenght
5	4.276	19.5	22.1	S-140	738,443	140,000

Table 4: Drill String Properties

Figure 15: Drill String Pipe Section

The mud return line will be subject to interior and exterior hydrostatic pressure. The exterior hydrostatic pressure will be due to the seawater, and at 12,000 feet can approach 37 MPa (5,350 psi), while the interior hydrostatic pressure is due to the mud, and that pressure can approach 43 MPa (6,228 psi) at 12,000 feet. This results in a resultant hoop stress of 36 MPa (5,343) forcing the pipe radially outward. Fortunately, the design check gave the drill string pipe section a factor of safety of 2.3 under those conditions.

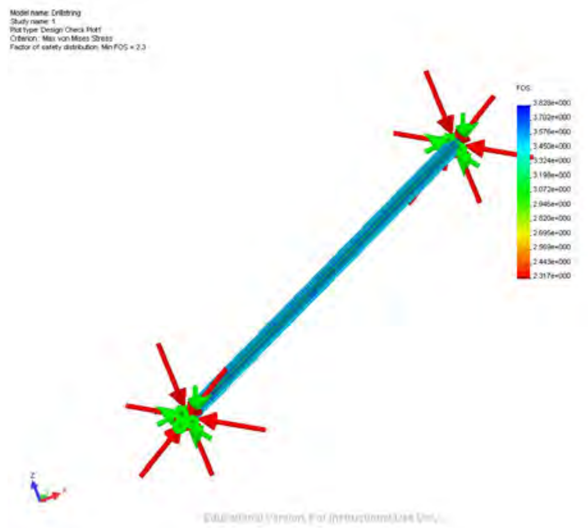


Figure 16: Drill String Design Check

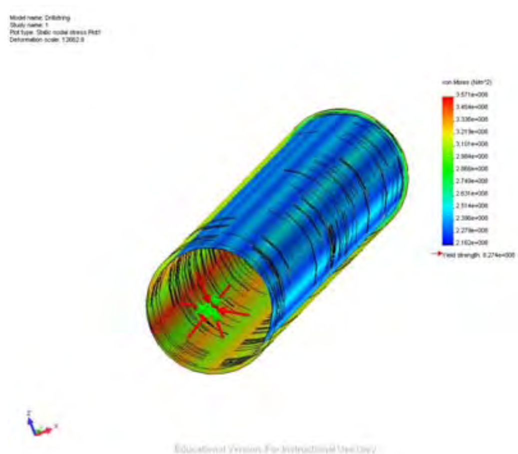


Figure 17: Stress Analysis of Drill String

The pipe for the mud return line used in the design is made of a series of 31.6 foot long pipe sections with 4.276in. ID pipes. This will require approximately 380 pipe sections to reach 12,000 feet. It is threaded on both ends so that pipe sections can be screwed in together. The pipe will be set using a pipe arrestor, as shown below, which is already in use to lower the drill string.

Figure 18: Pipe Arrestor

This pipe is the exact same pipe being used for the drill string. It was selected because it is commercially available in mass quantities and can withstand the loads in question adequately. In fact, most drilling vessels as a matter of procedure carry 1 or 2 extra lengths of drill string on board anyway during drilling operations, so it naturally makes sense to take advantage of this extra pipe and use it for the mud return line.

Ball-Socket Joint and Adapter

In order to compensate for movement of the pipe due to underwater sea current and the movement of the ship, the mud return line is needed to be connected by a special joint. This joint should provide flexibility to the Mud Return Line by providing a large degree of movement.

The type of joint chosen to address this need is the Flex-Lok Boltless Ball joint. The pipe joint is manufactured with variety of sizes, strength, and type of coating by American Ductile Iron Pipe. The coating used to protect the joint from corrosion is epoxy primer. These data along with other technical data are provided in their web site. See Reference for company web site.

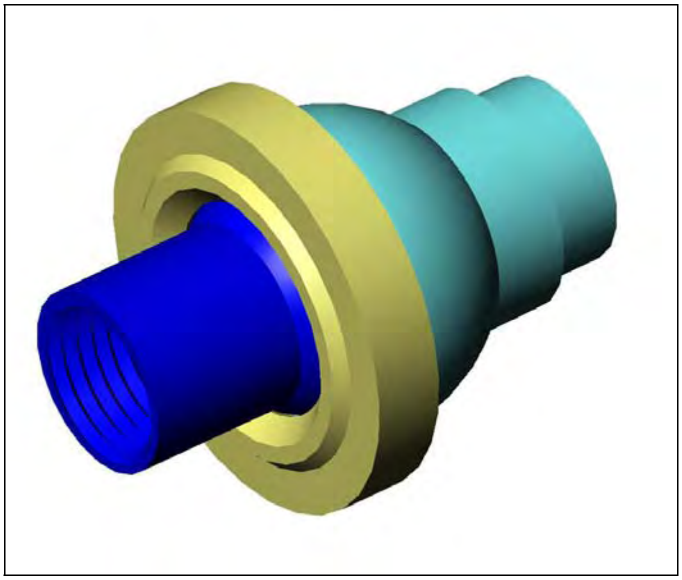


Figure 19: Ball & Socket Joint

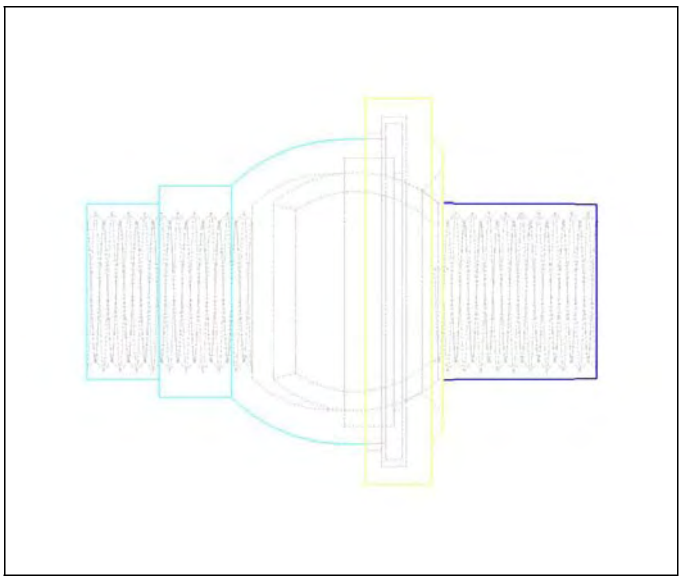


Figure 20: Ball & Socket Joint, Hidden Lines

The selection of the size of the joint is done by considering the worst joint location on the mud return line assembly, which is located at the very first connection approximately at the depth of 1000 feet below sea surface. At this location, the ball and socket joint will be exposed to a pull down weight of 117 tons (234,000 lb) due to the total weight of the mud return line minus the effect of buoyancy. In addition, the joint will also be exposed to a hydrostatic pressure of approximately 445.89 psi.

With these facts considered, the size of the joint chosen for the mud return line is 24 in. ball and socket joint which, according to the catalog, has a maximum safe end pull of 130 tons (260,000 lb). Each joint also allows a maximum cone of freedom of 15 degrees.

In order to realize a connection between the mud return pipe and the 24 in. ball and socket joint, an adapter needs to be utilized. The design and material selection of the adapter is done by considering the conditions at the worst joint location in the mud return line assembly. With the requirements for the adaptor's performance made to be the same as for the pipe joint, the material chosen is steel alloy. In addition, the adapter will also provide thread sizes that are made according to the mud return pipe and the ball and socket joint threads sizes.

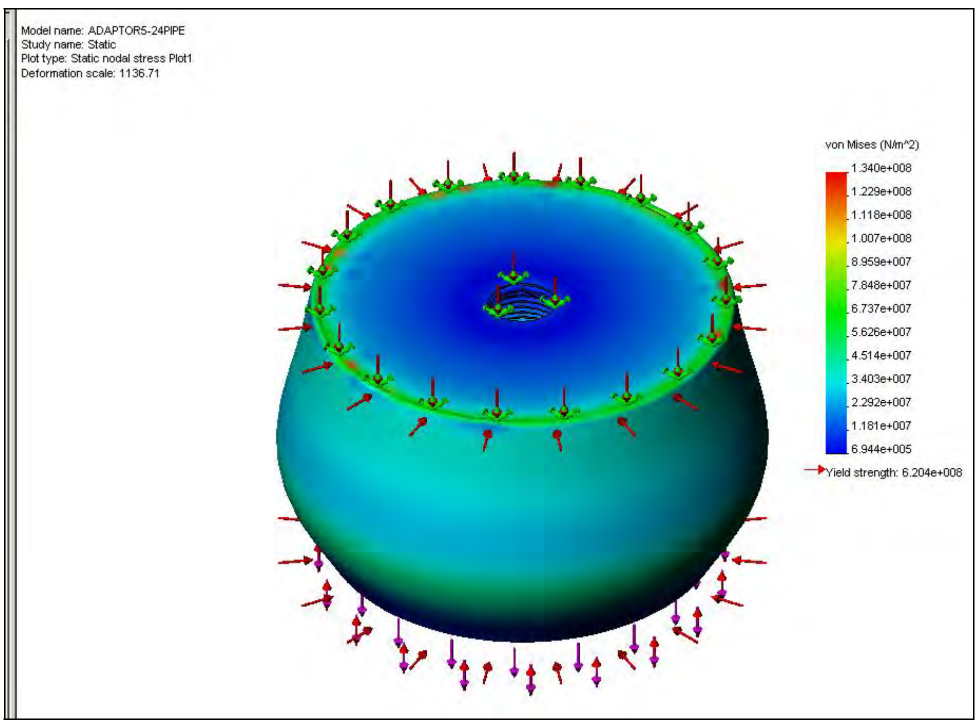


Figure 21: Stress Analysis

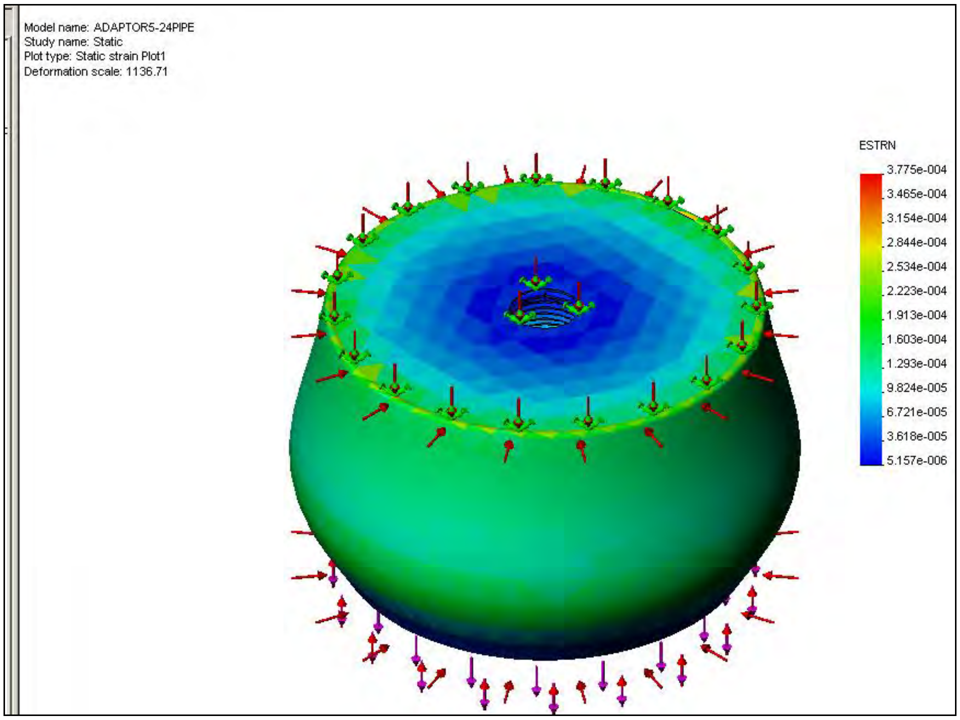


Figure 22: Strain Analysis

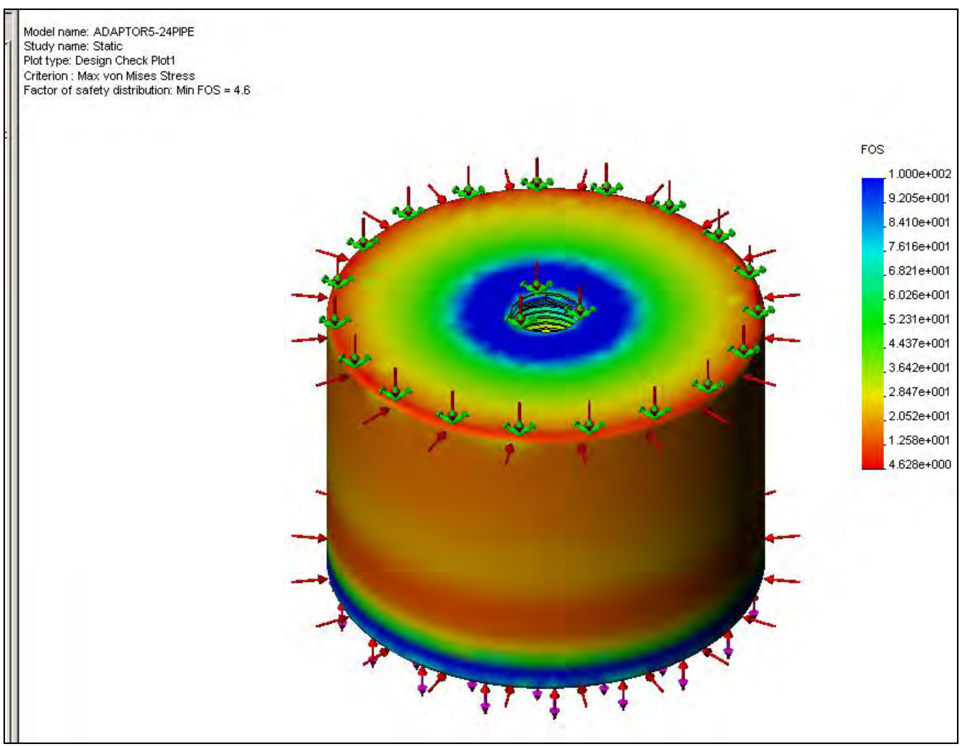


Figure 23: Design Check

Problem of pumping slurries:

A slurry is any solids suspended in liquid that cannot be dissolved by controlling the temperature and/ or pressure. The solids may or may not be abrasive. It does no good to try to identify the number of solids or their size because no one knows how these numbers relate to slurry related seal problems. Whenever we deal with slurries there are several problems we must consider:

- The slurry can clog the flexing parts of a mechanical seal causing the lapped faces to open as a result of both shaft and seal movement.
- If the slurry is abrasive it can wear the rotating components. This can be a serious problem with thin plate metal bellows seals.
- The pump rotating assembly will go out of balance as the slurry wears the impeller and other rotating components. This will cause excessive moving of the seal components.
- The pump will lose its efficiency as critical tolerances wear rapidly. This can cause vibration and internal recirculation problems. The wear will also cause the need for frequent impeller adjustments that will cause problems with mechanical seals

Proper control of slurry is important for the functioning of the impeller pump.

Water Jet pump Effect:

A Jet Pump is a type of impeller-diffuser pump that is used to draw water from wells into residences. It can be used for both shallow (25 feet or less) and deep wells (up to about 200 feet.)

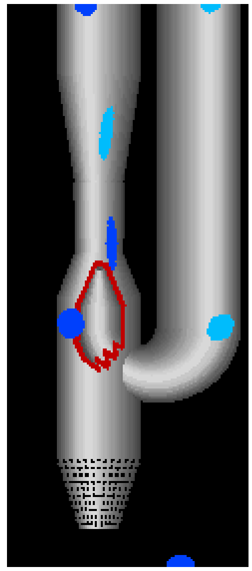


Figure 24: Water Jet Pump Effect

Shown in the figure above is the underwater part of a deep well jet pump. Above the surface is a standard impeller-diffuser type pump. The output of the diffuser is split, and half to three-fourths of the water is sent back down the well through the Pressure Pipe.

At the end of the pressure pipe the water is accelerated through a cone-shaped nozzle at the end of the pressure pipe, shown here within a red cutaway section. Then the water goes through a Venturi in the Suction Pipe.

The venturi has two parts: the Venturi Throat, which is the pinched section of the suction tube; and above that is the venturi itself which is the part where the tube widens and connects to the suction pipe. The venturi first speeds up the water, causing a pressure drop which sucks in more water through the intake.

The Impeller bypass system:

As discussed above the slurry can be detrimental to the functioning of the impeller pump. Even though minute particle can be handled by the pump it is important to prevent the big particle from entering the pump domain. The figure here shows the impeller bypass system. The system consists of a tank of 2000 gallons volume. The drilling mud entering the tank is made to pass through a strainer on its way to the impeller pump. This will lead to separation of the contaminants which will tend to settle at the bottom of the tank. An outlet pipe is routed from the bottom of the tank to the mud return line. This line will serve as a bypass line for the contaminants. These contaminants are then pumped because of the "Jet Pump Effect" caused by the high pressure water flowing through a nozzle located in the bypass line. This high pressure water is obtained from the outlet of the pump.

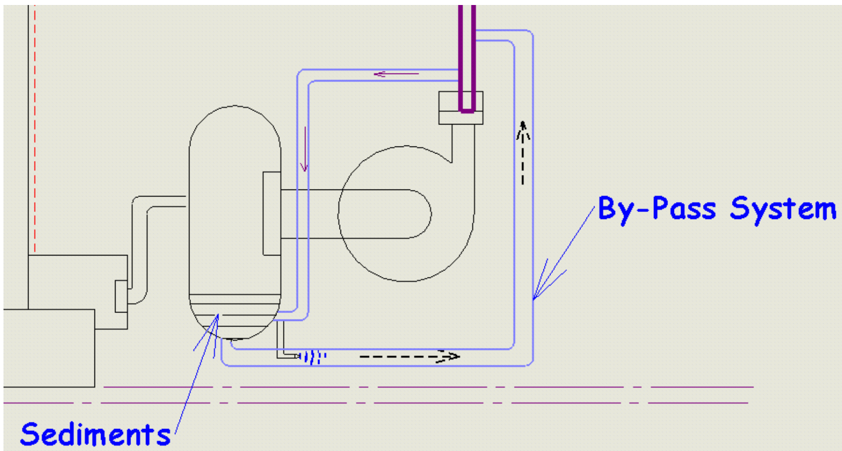


Figure 25: Impeller By-Pass System

Components:

- Storage tank : 2000 gallons
- Strainer: Dish Type
- Outlet conduit to the Pump
- Bypass pipe
- 4" Nozzle Assembly
- High pressure pipe line.

Problem of Airlock

Any significant amount of air entering the impeller pump can cause problems in the working of the impeller pump. Formation of air pockets will hamper the pressure generation in the pump. With the air pocket; the rotating pump impeller cannot develop enough constant hydraulic pressure to force the air all the way through the system. Hence it is important to monitor the pump outlet pressure continuously and maintain a back pressure on the outlet. The figures below show the pump functioning in normal mode.

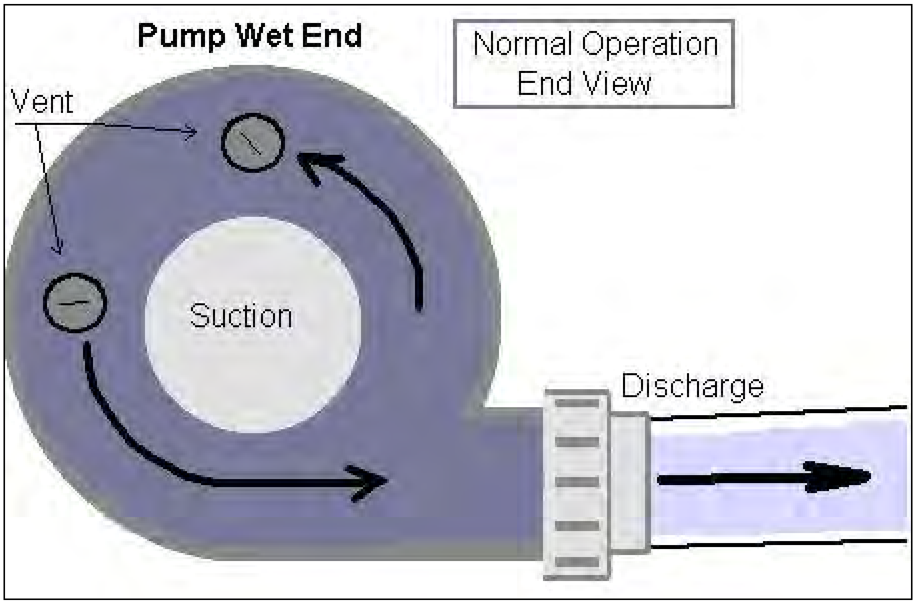


Figure 26: Normal Operation

The figures below show the pump operating with air lock.

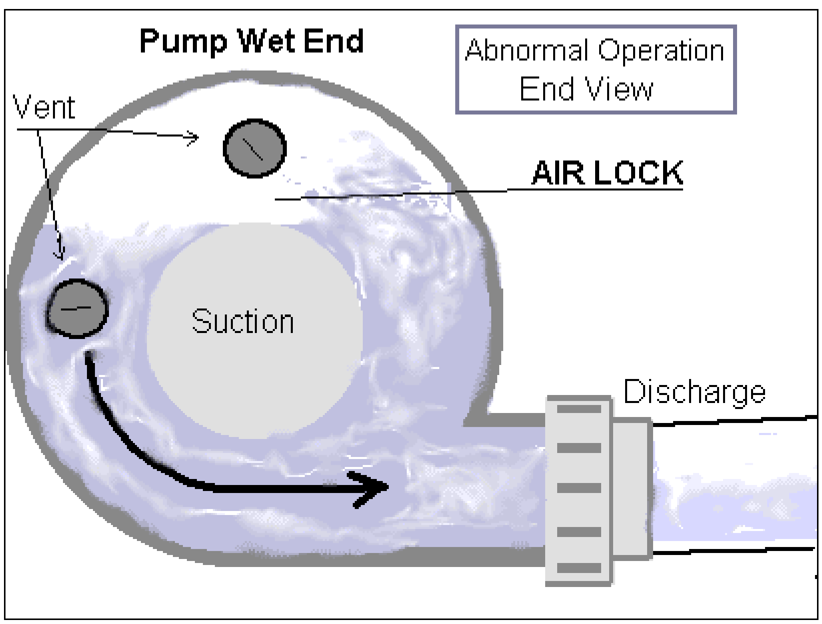


Figure 27: Abnormal Operation

Back Pressure Regulator

The back pressure regulator is a normally closed valve installed at the END of a piping system to provide an obstruction to flow and thereby regulate upstream (back) pressure. The backpressure regulator is called upon to provide pressure in order to draw fluid off the system.

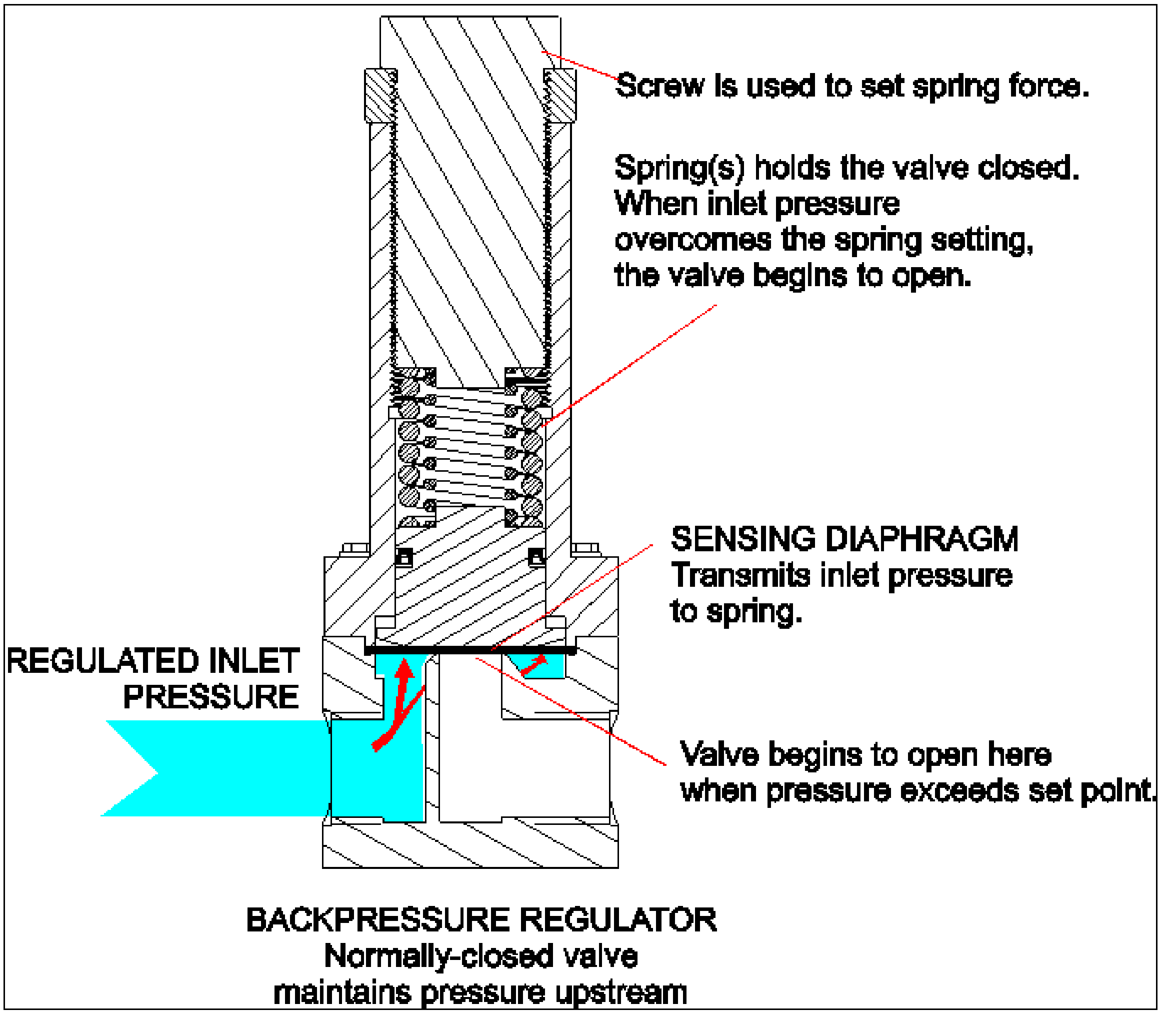


Figure 28: Back Pressure Regulator

Impeller Pump

Model: DMX API 610 (BB3), Between Bearing, Axially Split, Multistage Pump

Manufacturer: Flowserve Corporation

The pump basically is a multistage impeller pump. It consists of a series of impellers mounted on a single shaft. The shaft is supported on numerous bearings in the pump casing. Two stages are connected through volute passages. The volute serves to convert the velocity head into pressure head to minimize losses. Each impeller pressurizes the incoming fluid to a stipulated pressure and discharges in to the next impeller. In this way the pressure of the fluid id gradually increased as it flows through the pump.

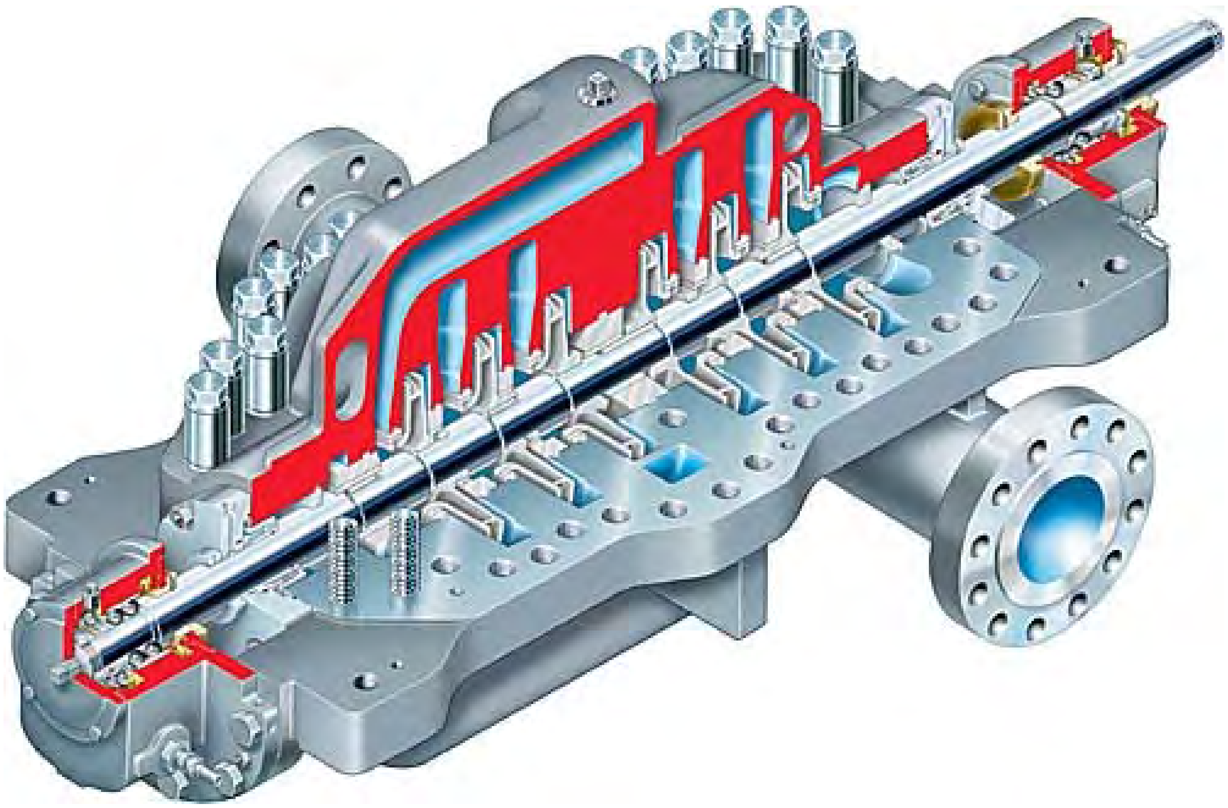


Figure 29: Multi-Stage Impeller Pump

Design Features and Options Available:

- **Pump Design** incorporates double volute hydraulic passages for radial thrust balance and opposed impeller mounting for axial thrust balance.
- **Seal Chambers to API 682** dimensional criteria allow for installation of cartridge design single, dual unpressurized and dual pressurized mechanical seals to meet safety and environmental requirements.
- **Shaft Options** include double extension for connection to auxiliary pumps or hydraulic turbines, and special shaft end machining for hydraulic fitted couplings.
- **Baseplates Designs and Pump Packages** engineered to contract requirements.
- **Dynamic Balancing and TIR Verifications** on assembled rotors assure optimum mechanical performance throughout the operating range.

Features:

- Choice of bearings
- Ball radial and thrust
- Sleeve radial and ball thrust
- Sleeve radial and tilting pad thrust
- Tilting pad radial and tilting pad thrust
- Choice of materials
- Carbon steel
- 12% chrome
- Austenitic and duplex stainless steels
- Monel
- Operating parameters
- Flow rate: Upto 13000 gpm
- Head: 7000 ft
- Specific Gravities: Down to 0.35
- Speeds to 8000 rpm
- Pressures to 275 bar (4000 psi)
- Temperatures to 200°C (400°F)

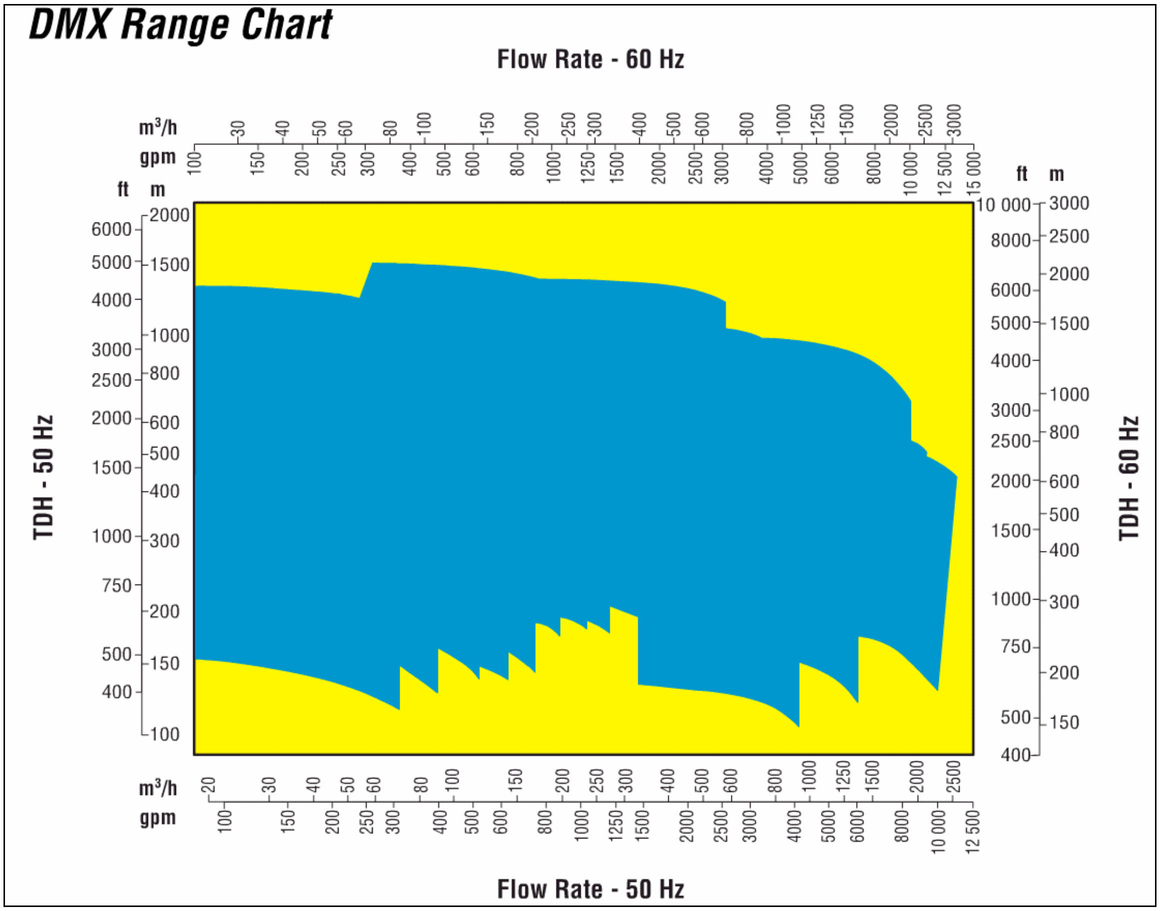


Figure 30: Pump Characteristic Diagram

AC Generator Type AMG 0900

The pump selected requires approximately 5.03 MW or 6,737 hp in order to displace the mud with the desire flow rate to the floating rig. To address this need, AC Generator capable of producing at least the same amount of power required is a must. The AC generator chosen is AMG 0900 manufactured by ABB. This generator is capable of producing up to 10 MW. The generator is built to specifications and in constructed under license by Alstom. Our design would require a 60 kV supply at 60 Hz. This yields a current of 100 Amps and a power output of 6 MW, with a factor of safety computed. The water cooled synchronous generator, which conforms to IEC and NEMA standards, is designed using ABB's patented Powerformer technology, in which they have specially designed the stator using a groundbreaking cable winding concept. This generates extremely high voltages, in fact, it is known as a VHV (Very High Voltage) generator. These high voltages allow for the generator to produce electricity at a high enough voltage so that a transformer is not required. The high voltages and low currents involved insure that minimal losses can be expected along the 2 mile distribution line from the drilling platform to the motor on the sea floor. In addition, this generator is environment friendly and capable to withstand a corrosion environment. Please refer to Appendix E for product catalog.

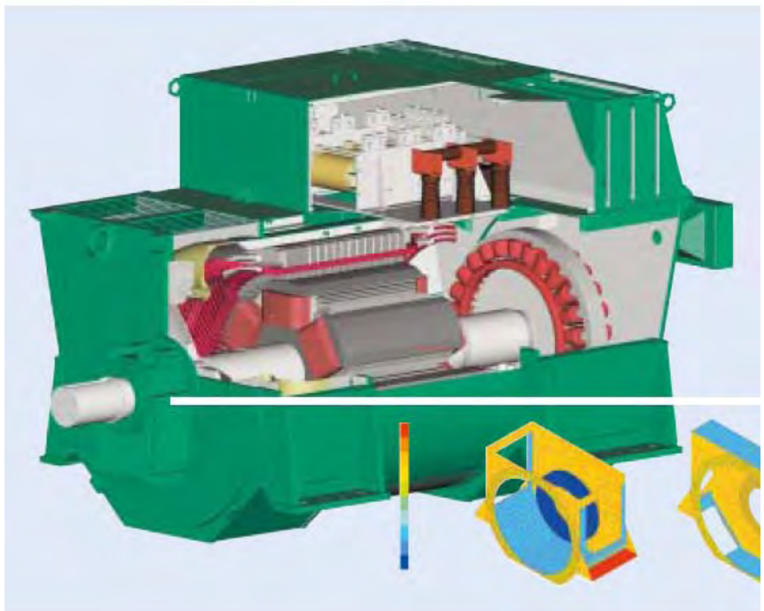


Figure 31: AMG 900 Computer Model

Figure 32: AMG 900 as built

Power Transmission Cables

Type: Superconducting (HTS) power cable

A High Temperature Superconducting (HTS) power cable is a wire-based device that carries large amounts of electrical current. There are two types of HTS cables: Warm Dielectric cable and Cryogenic Di-electric cable.

The power transmission will be done through Cryogenic Di-electric Superconducting (HTS) power cable, because of its extremely high efficiency and ability to caryy higher currents.

Cryogenic Dielectric Cable

The cryogenic dielectric is a coaxial configuration comprising an HTS conductor cooled by liquid nitrogen flowing through a flexible hollow core and an HTS return conductor, cooled by circulating liquid nitrogen. This represents an enhancement to the warm dielectric design, providing even greater ampacity, further reducing losses and entirely eliminating the need for dielectric fluids.

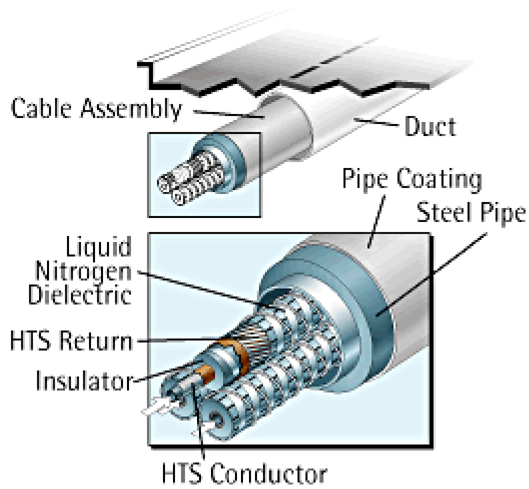


Figure 33: Construction of a cryogenic dielectric HTS cable

Advantages & Features:

- Enables three to five times more power transmission in the same space as that of conventional cables.
- Significantly lower impedence than conventional cables
- Reliable and secure because they can be designed to be smart and controllable
- Lower environmental impact because they eliminate oil and coolant used in some conventional cables.

<u>Electric Motor</u>

Type: Very High Voltage (VHV) AC Synchronous motor.

Manufacturer: ABB Inc.

The motor intended to be used is the Very High Voltage (VHV) AC Synchronous motor from ABB to drive the Hydraulic pump. ABB Inc. has introduced a novel "very high voltage" (VHV) ac synchronous motor product able to operate with inputs in the 20-70 kV range. VHV "Motorformer," an ABB-trademarked name, combines motor and transformer functions, eliminating the need for an intermediate transformer. The design applies to 4- and 6-pole machines. When not speed regulated, the four-pole motor has synchronous speed of 1,500/1,800 rpm at 50/60 Hz operation.

Motorformer's design is based on conventional synchronous motor technology, including many proven parts, such as an identical salient-pole rotor and conventional bearings. However, the main differentiator is the stator, in which the designed stator windings and stator core slotsare incorporated. Motorformer's cables are cylindrically shaped, which produces a homogenous electrical field strength, and makes it possible to increase voltage levels compared to the conventional rectangular-shaped windings. The cylindrical cable incorporates a solid dielectric layer of cross-linked polyethylene (XLPE) insulation, but uses no metallic shielding.

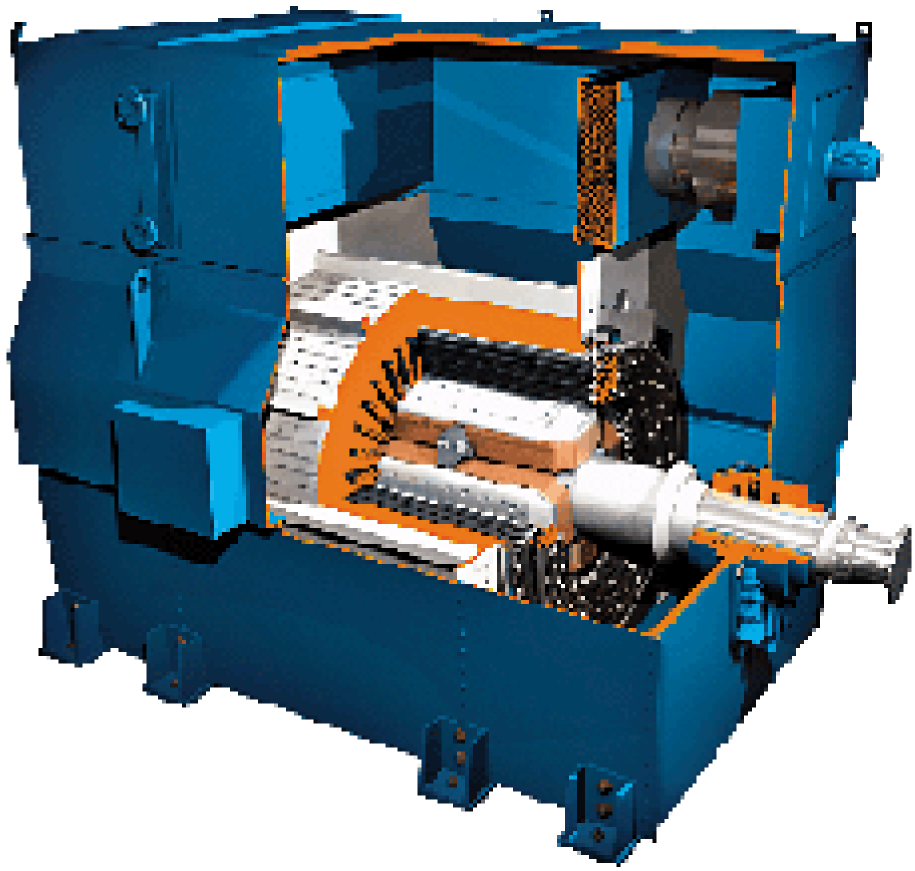


Figure 34: Electric Motor

Specifications:

- Output power: 5.5 MW at 50 Hz
- Voltages: 20 to 70 kV
- Frequency: 50, 60 Hz or VSD
- Protection: IP54, IP55, IP56
- Cooling: Water cooled
- Standards: IEC, NEMA

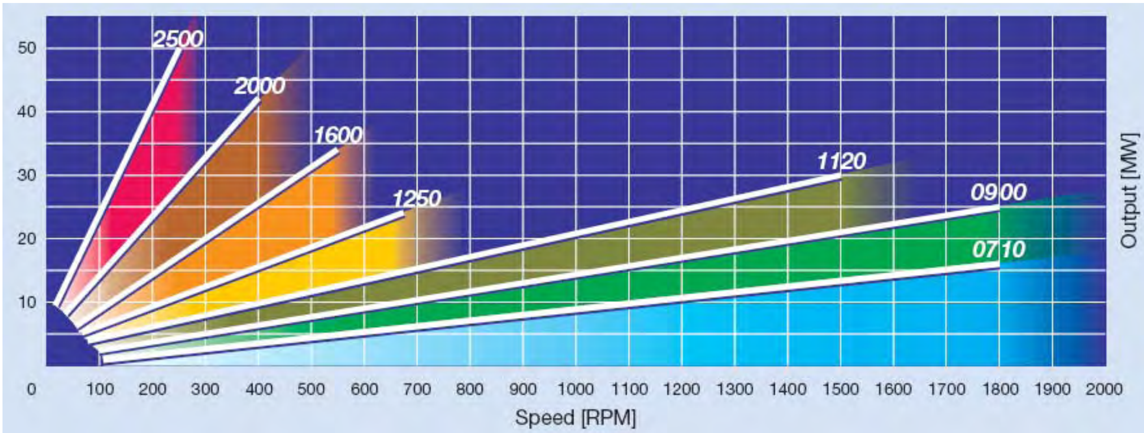
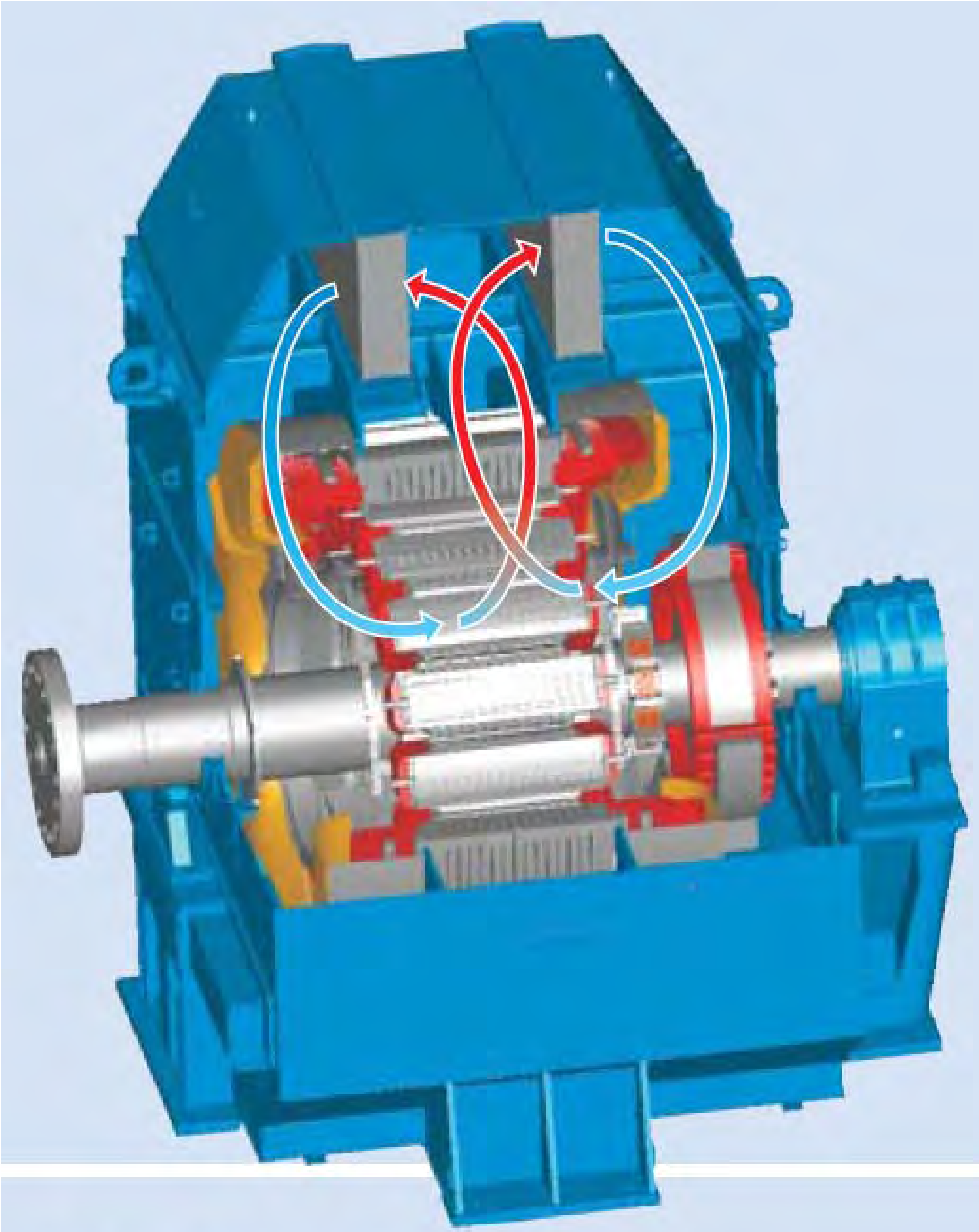


Figure 35: Motor Characteristics

Motor Cooling:

The motor provided by ABB comes equipped with its own cooling system. The cooling system chosen is the Air to water cooling system which is most suitable for this application.

The cooling air circulates in a closed circuit through the active parts of the motor and then through an air-to-water heat exchanger. This configuration passes hardly any heat to the surrounding environment, and represents an ideal solution for situations where closed circuit cooling is required due to installation outdoors, installation in a hazardous area, or whenever the quality of the surrounding air is not otherwise suitable for direct cooling. It is also ideal for installations in machine rooms with limited ventilation, such as on board ships or in pumping stations which are fully enclosed.



A totally enclosed motor (IP54) using an
air-to-water heat exchanger (IC8A1W7)

Figure 36: Air to Water Heat Exchanger

Transmission shaft

This transmission shaft is being used for power transmission from the motor to the pump.

Specifications:

- Diameter = 160 mm
- Length = 750 mm

Calculations:

Design as per ASME code:

- Permissible shear stress: - Least of: $0.3S_{yt}$ & $0.18S_{ut}$
- Since the load is intermittent and sudden starting and stopping may take place, We select
- Combined Shock and fatigue factor for bending: Kb = 2
- Combined Shock and fatigue factor for Torsion: Kt = 1.5

Permissible shear stress

$$\tau_d = 0.3S_{yt} = 0.3x220 = 66N/mm^2$$
$$or$$
$$\tau_d = 0.18S_{ut} = 0.3x399 = 72N/mm^2$$

We select the smaller τ_d that is 66N/mm^2.

$$Torque, M^t = 37377x10^3 Nmm$$
$$d^3 = \frac{16x\sqrt{(k_b M_b)^2 + (k_t M_t)^2}}{\pi\tau_d}$$
$$d^3 = \frac{16x\sqrt{(0)^2 + (1.5x34377000)^2}}{\pi x66}$$
$$d = 158.5 = 160mm$$

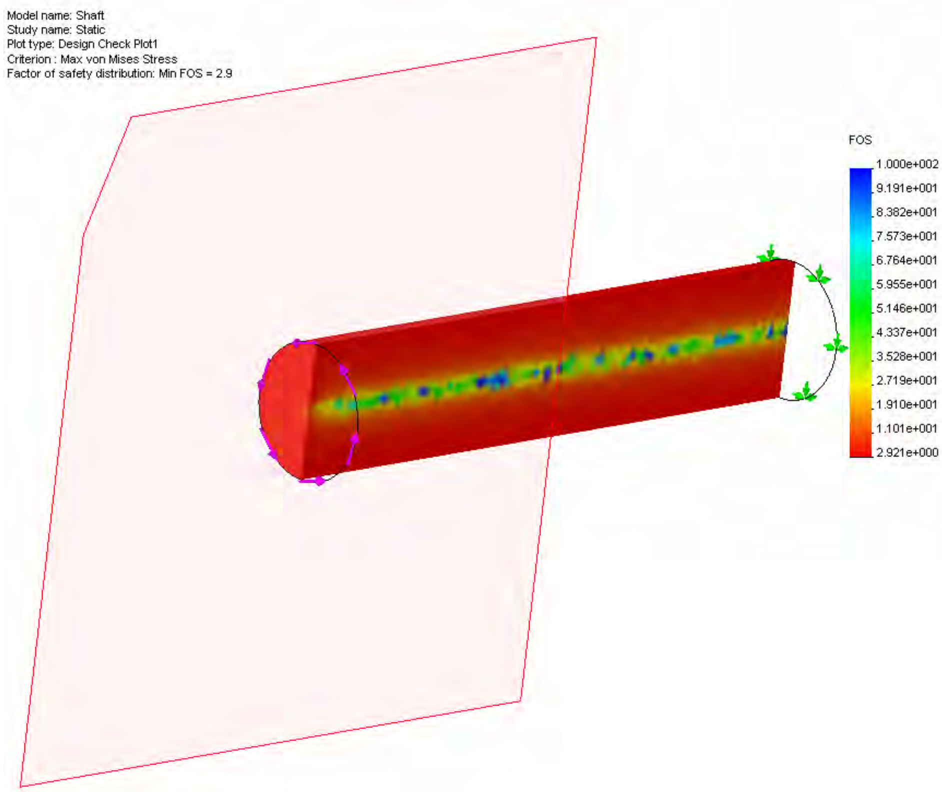


Figure 37: Stress Analysis

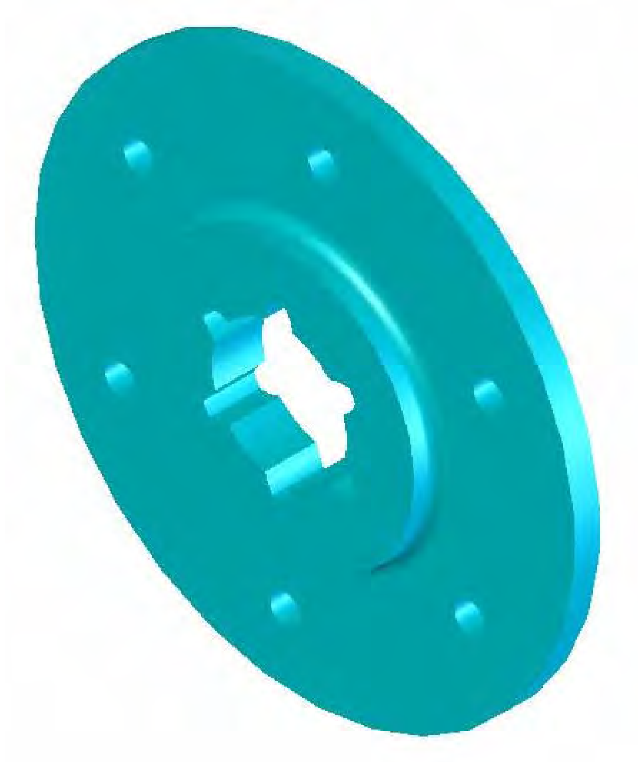


Figure 38: Coupling Flange

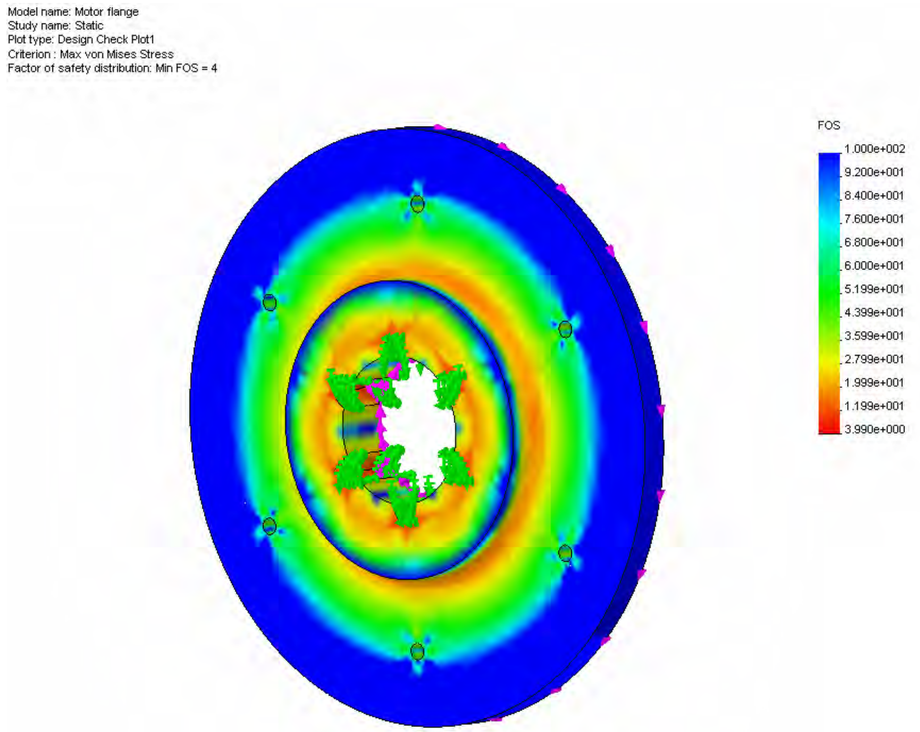


Figure 39: Coupling Flange Stress Analysis

Flange mount:

The pipe will be supported at the bottom on the casing for the motor and pump. The flange shown below will be threaded on to the lowermost pipe of the mud return line. It has got mounting holes on which the male end of the Quick connect coupling can be bolted.

Specifications:

- Material: Cast Alloy Steel
- 5” Inner diameter with internal threads
- 8 holes along 10” Pitch circle diameter

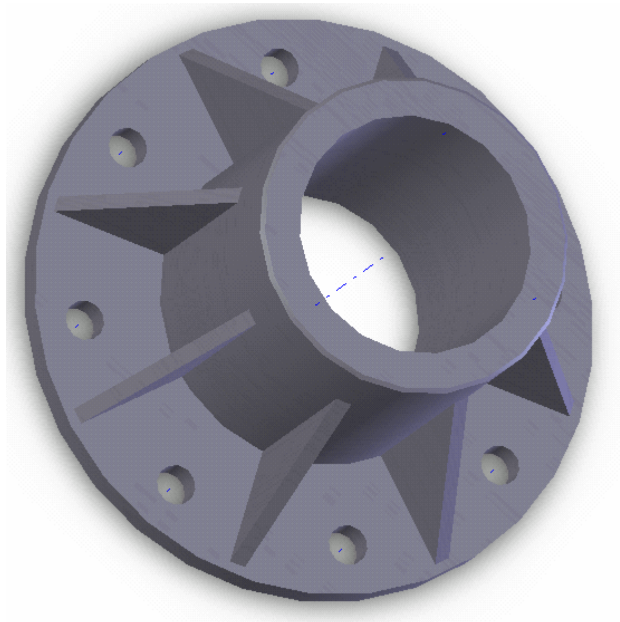


Figure 40: Flange Mount

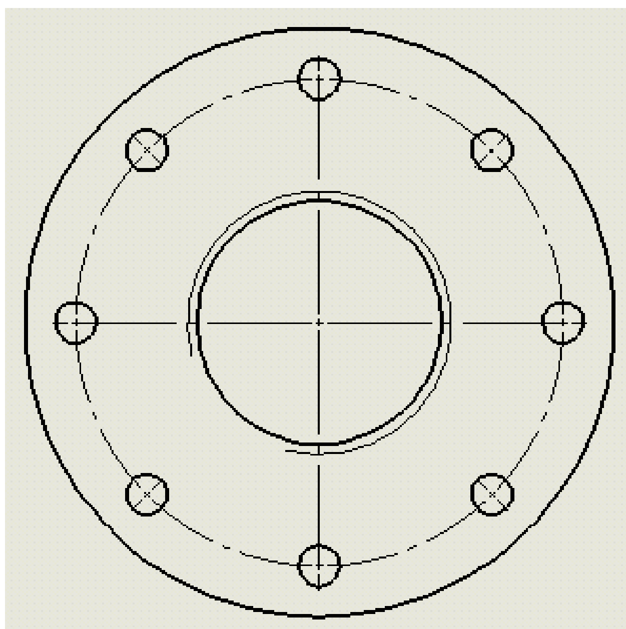


Figure 41: Flange Mount Drawing

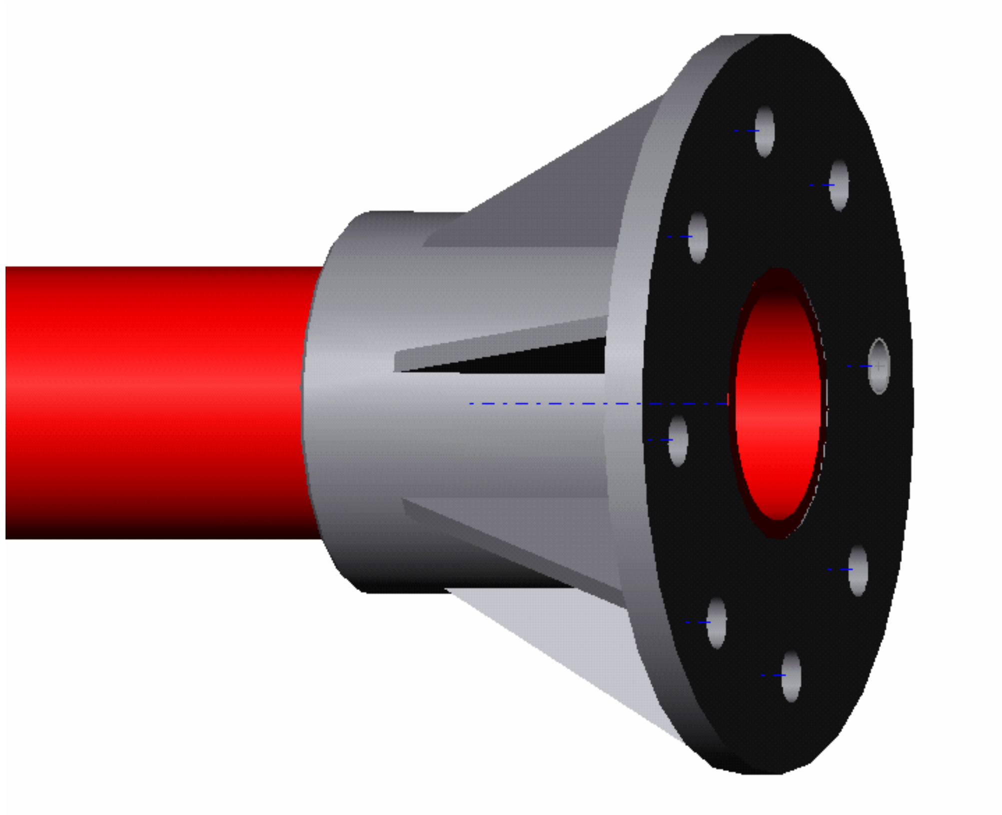


Figure 41: End Pipe with Flange Mount

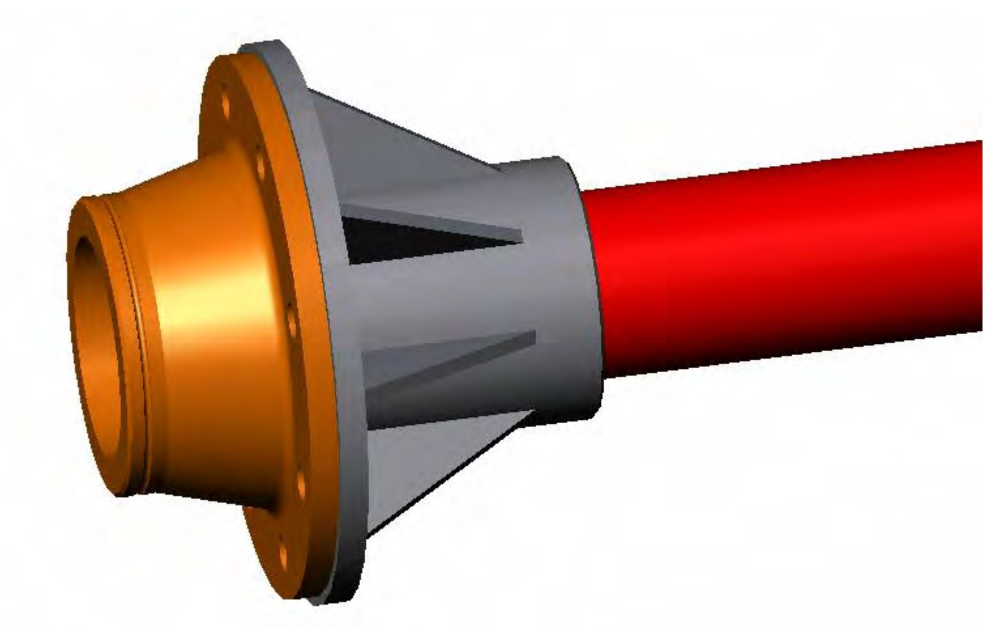


Figure 42: End Pipe Assembly with Quick Connect Coupling

Quick connect coupling:

Quick connect couplings suitable for sub-sea operations are available readily from Walther Prezision. Sub sea control system couplings are designed and manufactured to meet the rigorous demands of the offshore industry, supplying both mono and multi coupling systems for platform and underwater use.

Use of a Quick connect coupling to connect the Mudline will ensure fast, safe connection and separation of control system lines on topside and subsea structures.

Use of Quick connect coupling will offer following Design features:

- Clean-break during connection and separation
- Nominal bore sizes ranging from 2mm - 200mm
- High pressure models up to 12,500psi
- Robust materials including stainless steel, Monel, Super Duplex, Hastelloy,
- Highly reliable seal configurations using NBR, HNBR, FPM, FFKM and PEEK
- Cam action or pull-in action locking design features on multi-coupling systems
- A range of special features including non-interchangeability and pressured line connect-ability

Images below show the method of connection of the Quick connect coupling by a diver.

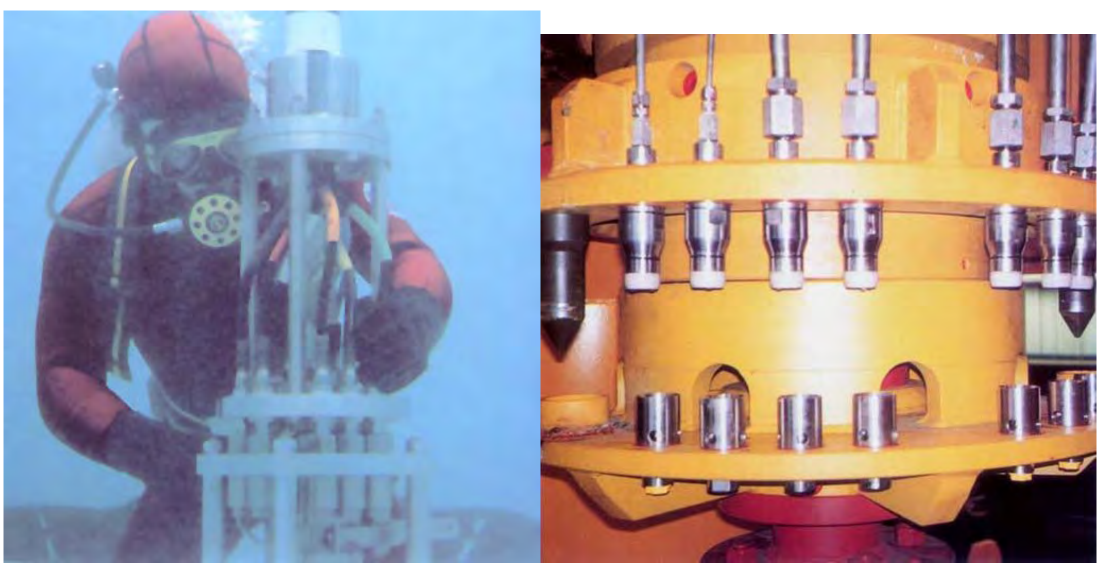


Figure 43: Quick Connect Coupling

Dish Type Strainer:

This strainer is located in the Storage tank at the outlet to the Impeller pump.

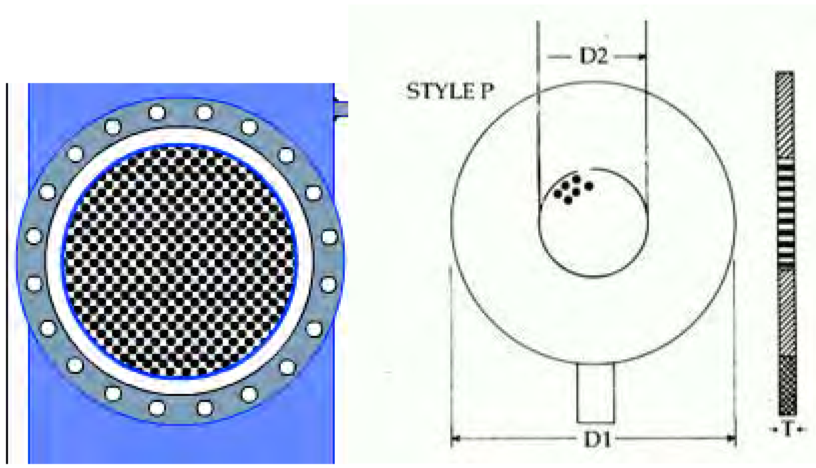


Figure 44: Strainer

5" Pipe size Strainer to be used:

Specifications:

- D1 = 11"
- D2 = 5"
- T = 11 – GA

Applications: Oil / Fuel / Chemicals

Casing (Capsule)

As mentioned before, the main component of the pump system, the pump and the motor, needs to be place on the sea bed. This is key in order to avoid cavitations on the pump system should the pump be placed on the floating rig. Thus, a body such as a casing is essential in order to protect both the pump and the motor used from high hydrostatic pressure and other factors that can affect the life of the devices just mentioned. The casing is intentionally designed in a form of capsule to minimize the amount of material needed. See figure 45. In addition, a structure in which the casing will be mounted should also be used in order to ensure the stationary of the casing. The idea of what the structure might look like can be seen in figure 46.

Due to high hydrostatic pressure and other extreme factors on the sea bed, S-140 Steel which has a very high tensile strength is chosen for the casing material. The inner diameter and the length of the casing are determined by the space needed to contain both the pump and the motor with necessary clearances. The height of the highest component, the motor, is approximated to be 12 ft. The length of the pump and motor aligned is approximated to be 24 ft. With these information known, the ID, total length, and thickness needed for the casing are approximated to be 20 ft, 51.4 ft, and 0.78 ft respectively. Refer to Calculation section.

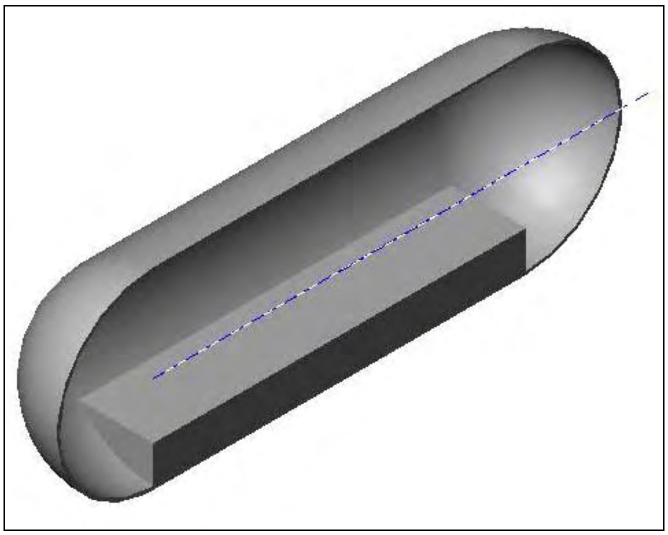


Figure 45: Section View of Casing

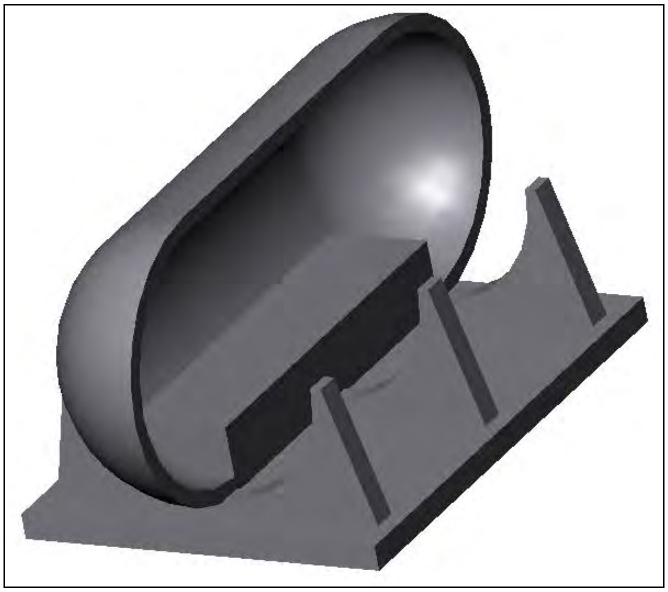


Figure 46: Capsule Stand with Section View of Casing

Aside from providing protection, the casing should allow a connection between the pump on both the suction and discharge sides to connect to the mud line assembly outside of the casing. This function is provided by a flange mount intended for the quick connect coupling. Refer to Flange Mount and Quick Connect section. In addition, the casing should also allow for an inlet and outlet to allow sea water to flow through the heat exchanger for cooling of the electric motor.

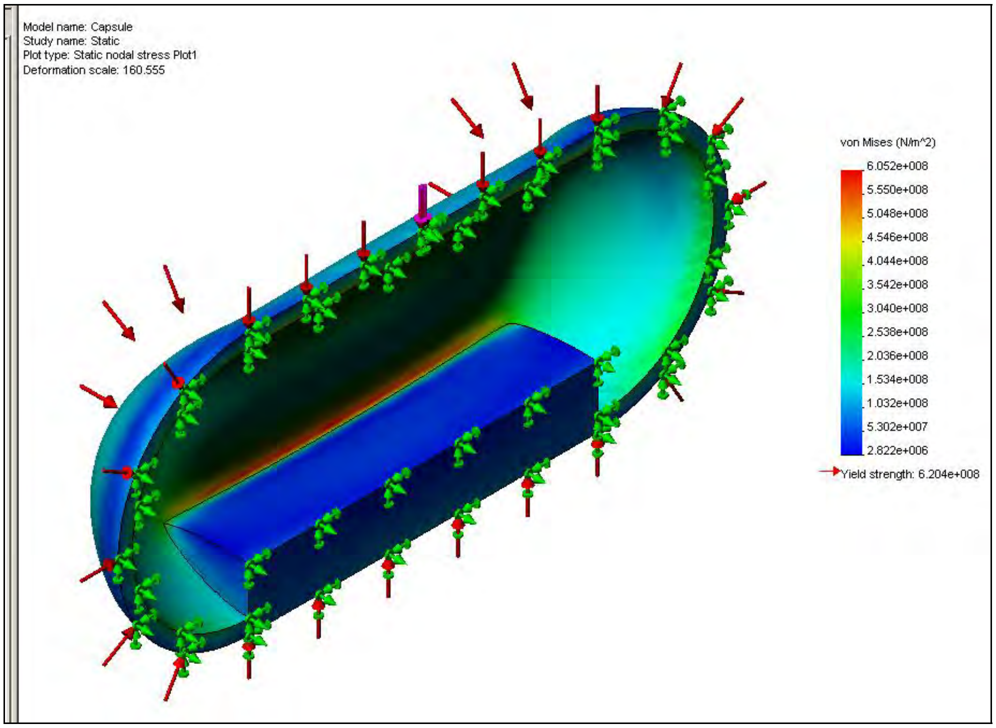


Figure 47: Casing Stress Analysis

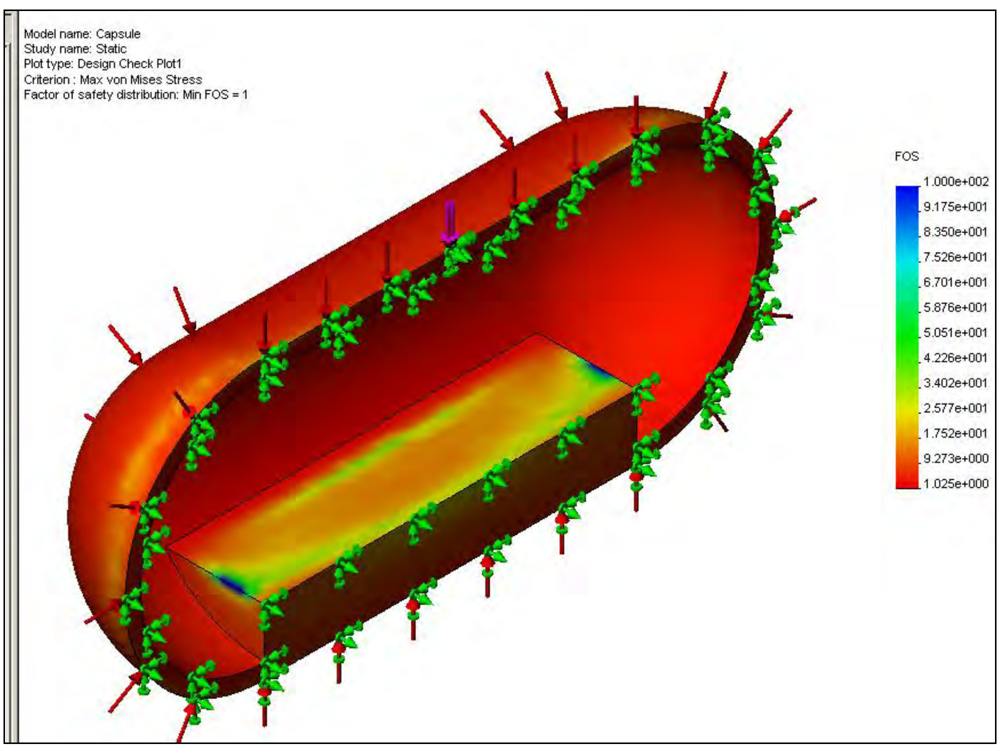


Figure 47: Casing Stress Design Check

Results and Calculations

The flow, pump head, and pump power calculations are made by considering the facts below. Where facts are given in set of range, the value that could result in worst scenario is chosen.

General information:

The flow rate of mud pumped to the surface should be equal to the flow rate of mud pumped into the well bore.

- This flow rate 'Q'is in the range of 1,200 to 1,500 GPM (4,260-5,775 in^3/s),
- Mud density $'\rho_m' = 10\,ppg\,(0.04329 lb/in^3)$,
- Dynamic mud viscosity $'\mu_m' = 10\,ccp$,
- Kinematic mud viscosity $'\nu_m' = 8.34 cst$
- Specific gravity of mud 'SG_m'= 1.199
- Specific gravity of salt water 'SG_{sw}'= 1.03,
- Saline (salt water) density $'\rho_{sw}' = 0.037\,lb/in^3$,

Due to the fact that the mud is pressurized into the well bore, the mud at the wellbore level will have an excess pressure of $10{,}000 \pm 30\%$ psi.

Drill Mud Pipe:

- S-140 Steel with tensile strength of 140,000psi is used,
- Total vertical length of pipe is 12,030 ft: 12,000 ft on discharge line and 30 ft on suction line,
- Except for the length, pipe size used on the discharge and the suction line is 4.276 in. ID, 0.362 in. thick, and 30 feet long each,
- Pipe density 0.308 lb/in3,
- Approximate roughness "ε"of pipe inner surface is 0.00015 ft

Material	S-140 Steel

e(roughness) [ft]	Q [GPM]	Q[in^3/sec]	g[ft/s^2]	Ldischarge[ft]	Lsuction[ft]	Mud density[ppg]	Mud density[l	Dynamic Mud viscosity [ccp]	Kinematic Mud viscosity	SG Mud	SG Saline	Saline density[lb
1.50E-04	1500	5775	32.2	12000	30	10	0.04329	10	8.34	1.19904	1.03	0.036972

Table 5: General Facts

Flow Calculation

The flow calculation begins from flow type determination. The type of the flow is determined by calculating the Reynolds number and is considered to be laminar if Reynolds number is less than 2,000 and turbulent if otherwise. The equation below is used in Reynolds number calculation.

$$\mathrm{Re} = 7745.8 \times \frac{V\,[ft/s] \times D_i[in]}{\upsilon_m[cst]}$$

$$\begin{aligned}&where:\\&V = velocity\ of\ mud\\&\upsilon_m = viscosity\ of\ mud\end{aligned}$$

The velocity of the fluid flowing in the conduit can be determined by using the equations below

$$\mathrm{V[ft/s]} = \frac{0.4085 \times \mathrm{Q[gpm]}}{\mathrm{D_i}^2[\mathrm{in}^2]}$$

or

$$\mathrm{V[m/s]} = \frac{21.22 \times \mathrm{Q[L/min]}}{\mathrm{D_i}^2[\mathrm{m}^2]}$$

Due to the fact that both side of the pipes (suction and discharge) have the same cross-section area, the velocity and the R_e of the mud inside these pipes is calculated to be 33.5 ft/s and 113,090 respectively. Based on the R_e flow along the pipe is determined to be turbulent.

1 Suction side
2 Discharge side

ID suction [in]	ID discharge [in]	Thickness1 [in]	Thickness2 [in]	Area1 [in^2]	Area2 [in^2]	e/D1	e/D2	Velocity1[ft/s]	Velocity2[ft/s]	Re1	Re2	f (coefficient of	
												f1	f2
4.276	4.276	0.362	0.362	5.2746	5.2745958	4.21E-04	4.21E-04	33.51258487	33.51258487	133090	133090	0.0193441	0.0193441

Table 6: Flow Calculations

Total Head and Power Calculation

The total head consists of static head, head pipe friction loss, and head fitting friction loss. There are two different terms used for total head; they are total head available ‘H_a’ and total head required ‘H_r’. As the name implied, H_a is the total absolute pressure in feet or meter accounting any losses due to frictions. H_r on the other hand is the required absolute pressure in feet or meter needed to overcome any losses due to frictions. Mathematically, these two total heads are presented below.

$$H_a = H_P + H_{av} - H_{FP} - H_{FF}$$
$$H_r = H_P + H_{FP} + H_{FF} - H_{av}$$

Where:

$\mathrm{H_{av}}$ = Total head already available in wellbore (13,485.78ft)

$\mathrm{H_p}$ = Static Head (vertical length of pipe = 12,030 ft)

$\mathrm{H_{FP}}$ = Head Pipe Friction Loss

$\mathrm{H_{FF}}$ = Head Fitting Friction Loss

The Darcy-Weisback equation below is used to calculate the head loss due to pipe friction.

$$H_{FP}[ft] = 12 \times f \times \frac{L[ft] \times (V[ft/s])^2}{Di[in] \times 2g[ft/s^2]}$$

f = friction factor

g = earth gravitation = 32.17 ft/s^2

L = lenght of pipe

V = velocity of discharged fluid

D_i = inside diameter of pipe

The friction factor is a function of the Reynolds number and the relative roughness '$\frac{\varepsilon}{D_i}$'. There are two ways of determining the friction factor 'f': using the equations provided below or by using the Moody diagram provided in the APPENDIX.

Depending on the type of the flow, the friction factor can be calculated by:

$$f = \frac{64}{\mathrm{R_e}}, \text{for laminar flow}$$

or

$$f = \frac{0.25}{(\log_{10}(\frac{\varepsilon}{3.7D_i} + \frac{5.74}{\mathrm{R_e}^{0.9}}))^2}, \text{ for turbulent flow}$$

Due to same cross section size of the pipe used on both suction and discharge sides the friction factor is calculated to be 0.0193.

The H_{fp} calculated for both the suction and discharge sides are 28.401 ft and 11,360.64 ft respectively.

The head loss due to pipe fitting is calculated by using the equation below

$$\mathrm{H_{ff}} = \frac{\mathrm{K} \times \mathrm{v}^2[\mathrm{ft/s}]^2}{(2 \times \mathrm{g}[\mathrm{ft/s}^2])}$$

while

K is a factor based on the type of fitting

As a rule of thumb, in a situation where the K value is not available, H_{ff} can conservatively be calculated as 30% of the total H_{fp} (from both suction and discharge sides). Thus, the H_{ff} calculated is 3,416.71 ft.

With all of the heads determined, Ha and Hr are calculated to be 10,710.02 ft and 13,349.97 ft respectively.

To calculate the pumping power needed to displace the mud from the well bore to the sea surface, the equation below is used.

$$Power[hp] = \frac{Q[gpm]H_r[ft]SG}{3960\eta}$$

where:

η is the assumed pump efficiency (80%)

With all variables determined, the power required is calculated to be 6,737.02 hp or 5.03 MW.

Pav[psi]	30% Deviation	Pa [psi]	Hav[ft]	Efficiency[%]
10000	0.3	7000	13485.78	0.9

ID [in]	Friction Head Loss				Total Head		BHP[HP]	BHP(KW)	BHP(MW)
	Hfpsuction[ft]	Hfpdischarge[ft]	Hff(30%)[ft]	Hp[ft]	Ha[ft]	Hr[ft]			
4.276	28.40159496	11360.63798	3416.711874	12030	10710.029	13349.97145	6737.0202	5025.8171	5.0258171

Table 7: Power Result

Stress Calculation

Pipe

The performance of the pipe is evaluated from its ability to withstand the maximum operating condition. The evaluation is done by comparing its tensile strength with the maximum stress (hoop stress in this case) experienced by the pipe. The hoop stress is calculated using the equation below.

$$\sigma_{hoop} = \frac{\Pr}{t}$$

$$\sigma_{axial} = \frac{\sigma_{hoop}}{2}$$

$$P = \rho g h$$

$$where:$$

$$\text{P = Pressure}$$

$$r = \text{Radius or width}$$

$$t = \text{Thickness}$$

There are two conditions in which the hoop stress is calculated: normal operation and clog condition. In normal operation there is a free flow of mud inside the pipe, thus mud column pressure is assumed to be zero. The only pressure experienced by the pipe is due to the hydrostatic pressure of 5,323.968 psi.

The clog condition is a situation where hydrostatic pressure is disregarded and the mud return line is clogged at the end of the discharge line. This assumption causes the pipe to experience a full mud column pressure of 6,228.78 psi.

The result of the calculation is presented in the table below.

Pressure	4.276 in. ID	4.5 in. ID
Hydro Pressure	5323.968	5323.968
Full Mud Pressure	6228.7832	6228.7832
Pressure difference	904.81521	904.81521

Table 8: Pressure Result

Pipe ID	Hoop Stress[psi	
4.276	31443.767	Normal operation
	36787.675	When mud return line is blocked

Table 9: Hoop Stress Result

The results show that the stress experienced by the pipe even at the worst operating condition is still below the tensile strength of the pipe which is 140,000 psi.

Impeller Bypass System:

Pressure requirement to move particles of shale:
Data:

- Density of Shale: 2675 kg/mm3
- Max Shale block size = 5”x5”x5”

Calc:
Weight of block = Density x Volume = 5.47 kg
Considering that the pressure is acting on the minimum surface area of the block,
Pressure required = (5.47*9.81+µ x 5.47*9.81) / (min surface area)
= (5.47*9.81+0.2 x 5.47*9.81) / (0.127^2)
= 4000 N/m2
Considering a factor of safety 2
Pressure = 4000x2 = 8000 N/ m2
Bernoulli’s equation

$$p_1 + \frac{\rho V_1^2}{2} + \rho g h_1 = p_2 + \frac{\rho V_2^2}{2} + \rho g h_2$$

h1=h2
p1-p2 = 8000 N/m2
V1=10m/s

$$p_1 - p_2 = \frac{\rho (V_2^2 - V_1^2)}{2}$$

$$\Rightarrow V_2 = 82.32 m/s$$

$$Q = \pi d_1^{\ 2} x V_1 = \pi d_2^{\ 2} x V_2$$

$$\frac{d_1}{d_2} = \sqrt{\frac{V_2^{\ 2}}{V^2_{\ 1}}}$$

$$\frac{d_1}{d_2} = 2.86$$

Flex-Lok Boltless Ball Joint and Adapter Calculation

As mentioned earlier, the size and design determination for the joint and adapter are done by considering the maximum condition they could be exposed to. The location in which this maximum operation condition can be seen is at the first joint location, 1,000 feet below sea water. At this depth, the ball joint and the adapter are exposed to the total weight of the pipe, which is 234,000 lb or 117 tons. In addition to the weight, these two components are also being exposed to a hydrostatic pressure of 445.89 psi and a mud column pressure of 6,228.78 psi.

$$Vol = \pi \frac{(D_o^{\ 2} - D_i^{\ 2})}{4} L$$

$$m = Vol(\rho_p - \rho_{sw})$$

$$W = m \frac{g}{Gc}$$

The result of the calculations are presented below

Density of pipe[lb/in^3]	0.308238214
Density of sea[lb/ft^3]	0.03699093
Effective Density[lb/in^3]	0.271247284

Table 10: Density

	Volume[in^3]	Weight[lb]	Weight[tons]
Mud	2073061.317	89742.82441	44.8714122
Pipe	759541.8003	234000	117
Total	2832603.117		

Table 11: Weight

Based on the requirements just mentioned, the 24 in. Flex-Lok Ball Joint with maximum safe pull of 130 tons is chosen.

An FE analysis on simplified adapter model is performed and provided on the Appendix D. The results show that the will not fail under these extreme conditions.

Casing (Capsule)

As mentioned before, the inner diameter and the length of the casing are determined by the space needed to contain both the pump and the motor with necessary clearances. The height of the highest component, the motor, is approximated to be 12 ft. The length of the pump and motor aligned is approximated to be 24 ft. With these information known, the ID and total length needed for the casing are approximated to be 20 ft and 51.4 ft respectively. This equation provided below is used for evaluating the stress of a shell.

$$\sigma = \frac{PR_1^{\,2}\left(1 + \frac{R_2^2}{R_1^2}\right)}{R_2^2 - R_1^2}$$

$$R_2 = -\frac{\sqrt{(P^2 - \sigma^2)}R_1}{P - \sigma}$$

where

σ = Tensile strength (140,000 psi)

P = Hydrostatic pressure (5,350.65psi)

R_1 = Inside radius (20 ft)

R_2 = Outside radius

Solving for R2, the thickness needed in order to avoid any failure due to high hydrostatic pressure at 12,000 ft below sea surface is equated to be 0.7 in.

Bending Loads on the Lower Section of Pipe:

Permanent ocean currents due to differential heating and cooling and indirect wind effects were considered for calculating the bending load on the bottom section of the pipe supported from the ocean floor. The current velocities average 50 cm/s. However in extreme cases in certain parts of the world velocities in the range of 250 cm/s have been measured.

Mass flow rate of water across the surface area of the tube = Area x Velocity.

$$Force = m'(u_2 - u_1) = \rho q(u_2 - u_1)$$

We then convert this force acting on the entire length to a UDL , w (N/mm)
Let L be the length of pipe supported from the bottom, and consider any section at a distance z from the bottom

$$M_b = \frac{1}{2}w(L-z)^2$$
$$\sigma_{zz} = M_t y / I$$
$$y = wL^4 / 8EI$$

Data:

L = length of pipe

Do = Outer diameter of pipe

Di = Inner diameter of pipe

m'= mass flow rate

Trial 1: The concept was to support 1000 feet length of the pipe from the bottom. The calculations for the stress and deflection show that the due to very high slenderness ratio the pipe will undergo excessive deflection. Hence a very small length of the pipe can be actually supported from the base.

	ft	m	
L	**1000.00**	304.80	
Do(in)	6.00	0.15	m
Di(in)	4.25	0.11	m
m(.)		11612.88	kg/s
force		850.54	
UDL		0.0028	Kg/mm
E		200000.00	N/mm2
I		19816142.29	
Deflection		**7451965.41**	mm
Stress		**4889.74**	N/mm2

Table 12: Bending Stress & Deflection Calculation

It was decided to limit the deflection to 20 mm.

	ft	m	
L	**40.00**	12.19	
Do(in)	6.00	0.15	m
Di(in)	4.25	0.11	m
m(.)		464.52	kg/s
force		34.02	
UDL		0.0028	Kg/mm
E		200000.00	N/mm2
I		19816142.29	
Deflection		**19.08**	mm
Stress		**7.82**	N/mm2

Table 13: Bending Stress & Deflection Calculation

Thus 40 feet pipe can be supported from the bottom. This is the location where the first ball joint can be located.

Summary

Team MC2 has devoted a lot of time and energy over the course of the past semester trying to complete this project to the requested specifications and the highest standards of professional engineering. Initially the goal was to accurately and comprehensively describe the need of the design using need analysis methodology. After addressing the need based on customer requirements, Team MC2 began concept development and created 3 original concepts. Upon using a quantitative down-selection procedure to determine the concept which most effectively met the need, the hydraulically driven impeller pump concept was selected and presented to the project sponsor.

Unfortunately, some of the ideas which led that concept to down-selection were proven infeasible upon further analysis, and a different concept was developed. The final concept was that of an electrically powered multi-stage impeller pump. This configuration efficiently delivers power to a powerful pump that is capable of providing sufficient total head in order to pump all mud from the sea floor to the drilling platform, a truly daunting task at over 2 miles below the surface of the ocean. This concept was developed and presented to the project sponsor, and

Appendix A: Glossary

The following terms are taken from the need statement, and required further definition to more clearly express the need.

Deep-Sea **–** This design will have to function in a marine environment with high pressure, low temperature, sub-sea currents, ecological considerations, differing water compositions, and must be mindful of local geology and geography.

Drilling Package **–** This is the system used to drill the hole through the ocean floor, including the extra equipment needed or to be discarded to perform the need, such as a power source, risers, valves, pumps, and/or new redesign of current equipment, such as the BOP, etc.

Top Hole Dual Gradient (THDG) Technology – Dual Gradient drilling technology involves drilling with a mud hydrostatic pressure gradient below the mud line, with a seawater hydrostatic pressure gradient in the riser above the mud line. Currently, Dual Gradient drilling technology is not able to be used in drilling operations for the first two layers of casing, including the structural and conductor casing strings. If a system or design can be developed for Top Hole Dual Gradient drilling, or using Dual Gradient technology in drilling the first two casing strings, then drilling operations could be performed more efficiently.

Petroleum Well bores **–** A sub-surface drilled hole concentrically encased in a series of fabricated casings and filled cement that is subject to extreme pressures, temperatures, and corrosive environments, for the extraction of petroleum.

Optimal Amount of Materials **–** Currently, in order to drill deeper holes, larger rigs and equipment are needed to overcome the huge stresses and pressures involved. If THDG is employed, some of the equipment may be able to be designed at a smaller scale, thus saving money and material, and increasing the operable range of drilling operations.

Integration **–** It is reasonable to conclude that any THDG system will be best implemented if it can be easily integrated to the fullest extent possible with existing drilling packages and equipment.

Appendix B: References

Mr. Charles Peterman and Dr. Jerome Schubert

Mineral Management Services

These two men were responsible for bringing the problem to MEEN 632, and were instrumental in answering many of our questions concerning petroleum drilling operations. Their presentations contained primarily all of the information used to develop this report.

Dr. Steve Suh

Dr. Suh is the instructor for MEEN 632, and his instruction, class notes and material were used in developing a report format and generating an appropriate need analysis of the problem.

Miss Brandee Eileef

Miss Eileef is a graduate student in the Department of Petroleum Engineering, and was a great asset for information about petroleum drilling operations.

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John Tuzson, Centrifugal Pump Design, Wiley Inter-Science.

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Appendix C: Detailed Calculations

Flow Equations

$$\mathrm{Re} = 7745.8 \times \frac{V\,[ft/s] \times D_i[in]}{\upsilon_m[cst]}$$

$$\begin{aligned}
&where: \\
&V = velocity\ of\ mud \\
&\upsilon_m = viscosity\ of\ mud
\end{aligned}$$

$$\mathrm{V[ft/s]} = \frac{0.4085 \times \mathrm{Q[gpm]}}{\mathrm{D_i}^2[\mathrm{in}^2]}$$

or

$$\mathrm{V[m/s]} = \frac{21.22 \times \mathrm{Q[L/min]}}{\mathrm{D_i}^2[\mathrm{m}^2]}$$

$$f = \frac{64}{\mathrm{R_e}}, \text{for laminar flow}$$

or

$$f = \frac{0.25}{(\log_{10}(\frac{\varepsilon}{3.7D_i} + \frac{5.74}{\mathrm{R_e}^{0.9}}))^2}, \text{ for turbulent flow}$$

Head – Power Equations

$$H_a = H_P + H_{av} - H_{FP} - H_{FF}$$

$$H_r = H_P + H_{FP} + H_{FF} - H_{av}$$

Where:

$\mathrm{H_{av}}$ = Total head already available in wellbore (13,485.78ft)

$\mathrm{H_p}$ = Static Head (vertical length of pipe = 12,030 ft)

$\mathrm{H_{FP}}$ = Head Pipe Friction Loss

$\mathrm{H_{FF}}$ = Head Fitting Friction Loss

$$H_{FP}[ft] = 12 \times f \times \frac{L[ft] \times (V[ft/s])^2}{Di[in] \times 2g[ft/s^2]}$$

f = *friction factor*

g = *earth gravitation* = 32.17 ft/s^2

L = *lenght of pipe*

V = *velocity of discharged fluid*

D_i = *inside diameter of pipe*

$$H_{ff} = \frac{K \times v^2[ft/s]^2}{(2 \times g[ft/s^2])}$$

while

K is a factor based on the type of fitting

$$Power[hp] = \frac{Q[gpm]H_r[ft]SG}{3960\eta}$$

where:

η is the assumed pump efficiency (80%)

Stress Equations

$$\sigma_{hoop} = \frac{\mathrm{Pr}}{t}$$

$$\sigma_{axial} = \frac{\sigma_{hoop}}{2}$$

$$P = \rho g h$$

where:

P = Pressure

r = Radius or width

t = Thickness

$$\sigma = \frac{PR_1^2\left(1 + \frac{R_2^2}{R_1^2}\right)}{R_2^2 - R_1^2}$$

$$R_2 = -\frac{\sqrt{(P^2 - \sigma^2)}R_1}{P - \sigma}$$

where

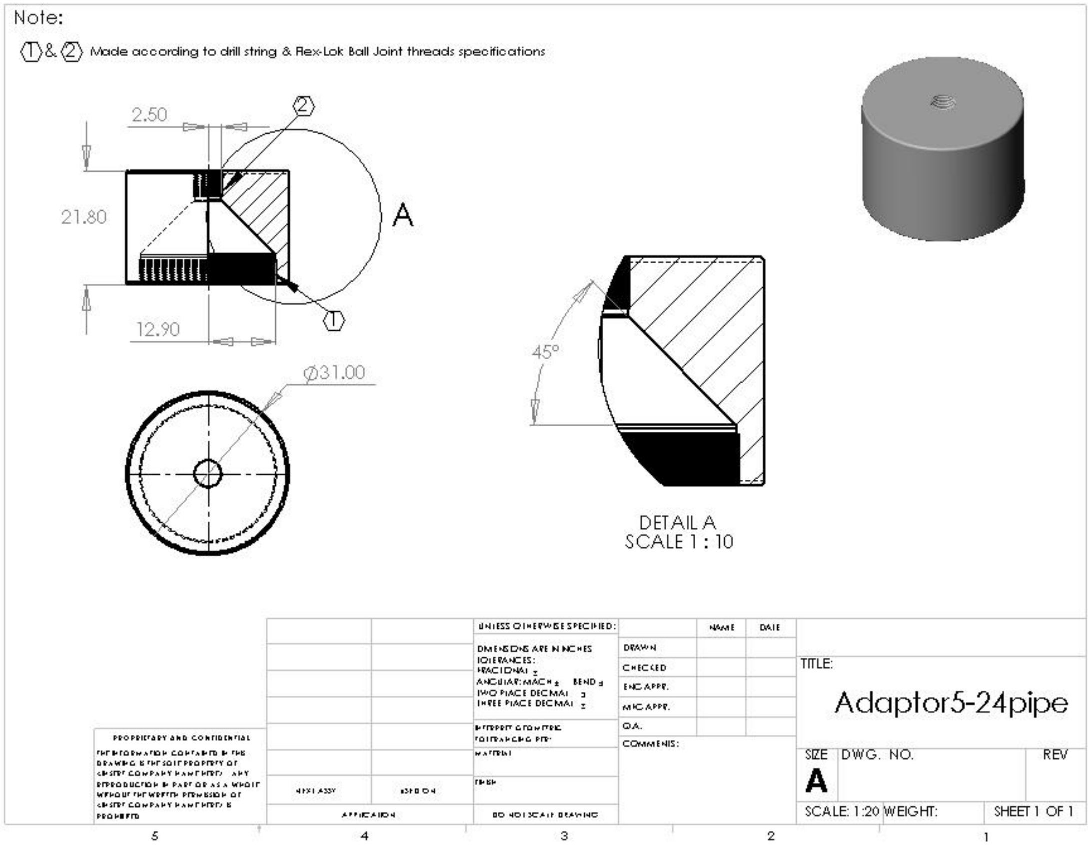
σ = Tensile strength (140,000 psi)

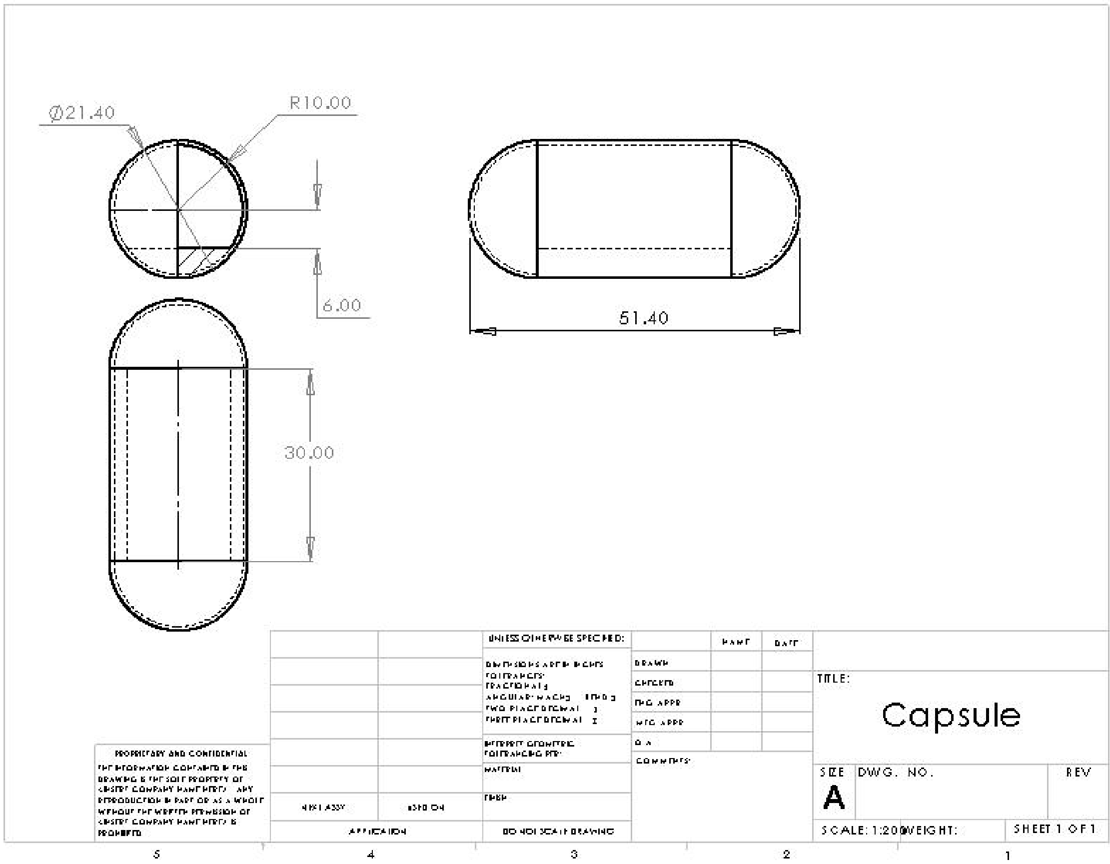
P = Hydrostatic pressure (5,350.65psi)

R_1 = Inside radius (20 ft)

R_2 = Outside radius

Appendix D: Drawings





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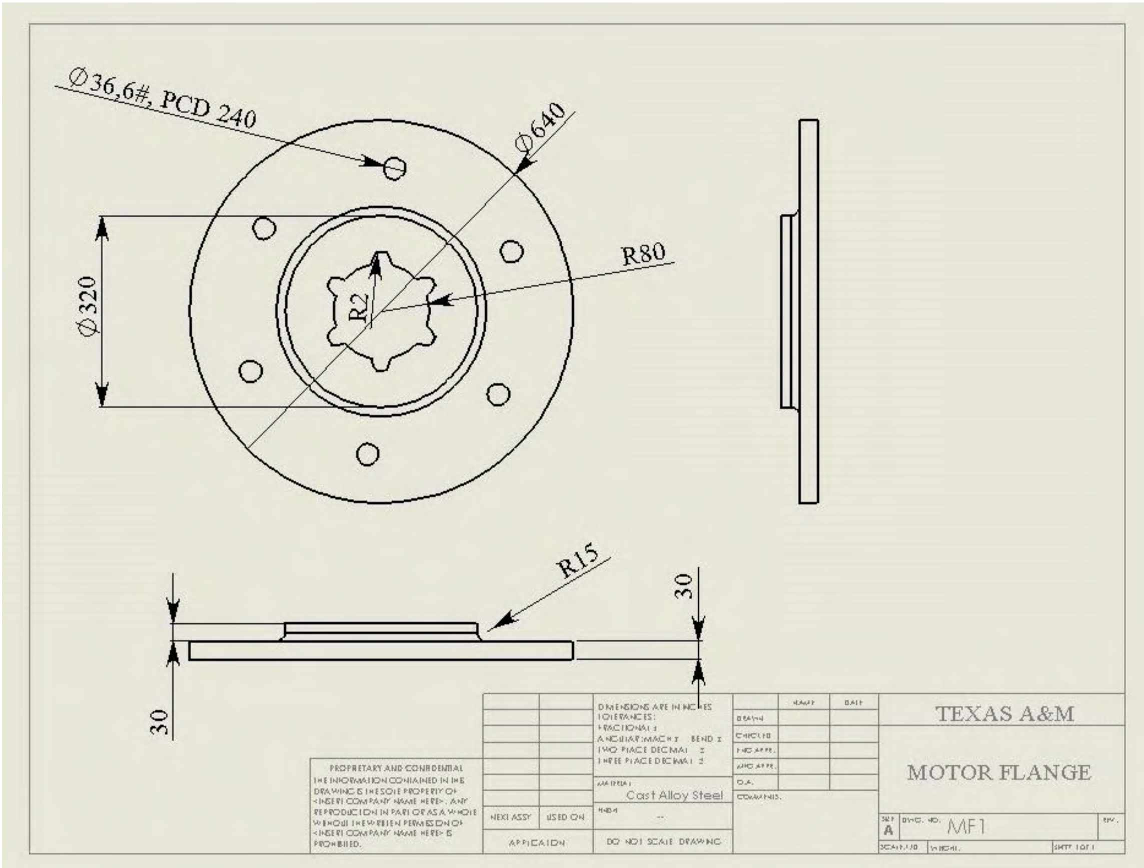
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Appendix E

Top Hole Dual Gradient System: Submersible Mud Removal Unit, Embodiment Design Report (2005) John Guinn, Gerald Thomas, and Lauren Wiseman, Department of Mechanical Engineering, Texas A&M University

Top Hole Dual Gradient System: Submersible Mud Removal Unit

Embodiment Design Report

Prepared for:

MMS

Presented to:
Dr. Charles Peterman
Dr. Jerome Schubert
Dr. Steve Suh

Prepared by:
Texas A&M University
Department of Mechanical Engineering

John Guinn
Gerald Thomas
Lauren Wiseman

MEEN 632 - Fall 2005

Embodiment Design Report

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Introduction

The purpose of this project is to design a dual gradient drilling system consisting of a direct path from the wellbore, through which mud will be extracted. This mud will then be transferred to the drilling station where it will be stored. The sponsors are interested in this concept for its benefits on the top hole portion, which is before the 20in diameter surface pipe is set. The design will allow conductor and surface pipe to be set deeper than is allowed in more conventional designs. Also, the intermediate casing can be set deeper, creates a safer environment for the conductor and surface pipe to be laid. This design will allow older, smaller drilling stations to drill in deeper water.

The key challenges of this project will be to align the major components of the design with the major constraints that are presented by drilling in ultra-deepwater environments. The functions stated in our function structure will be another guideline to follow by recognizing the design parameters and constraints placed upon it.

The following sections cover the conceptual design process for this top hole dual gradient design. This process begins with the evolution of the need statement and need analysis, proceeds into development of alternative concepts, and finishes with an evaluation of the concepts so that the best concept is chosen for further development during the preliminary design phase.

Need Statement

The evolution of the need statement began by first trying to recognize the primary functions and the primary constraints. Each team member's ideas and wording were incorporated into the first need statement as follows:

> "Design a dual gradient drilling system consisting of an isolated path on the top portion of the hole that will provide means to separate mud from the drill pipe and circulate that mud to and from the drilling vessel, place casing string deeper into the wellbore, maintain operability in extreme environmental conditions, and interface with existing drilling and wellhead equipment."

After further analysis of this preliminary need statement, it was decided that this statement was too lengthy and did not capture the most important function and constraint of the design's need. Finally, the primary function was determined to be that the design must be a dual gradient system, implemented on the top hole portion. Also, the need to transfer mud between the seafloor and drilling vessel is prominent. Further, the primary constraint is the requirement to interface with common drilling equipment that is currently in use.

Therefore, the final need statement was decided as follows:

> **"Design a top hole dual gradient system that transfers mud from the sea floor to drilling vessel and interfaces with existing drilling subsystems."**

Function Structure

From the need statement, it is determined that there are three top level functions for this design: provide a top hole dual gradient system, provide means to transfer the mud, and provide means to interface with subsystems.

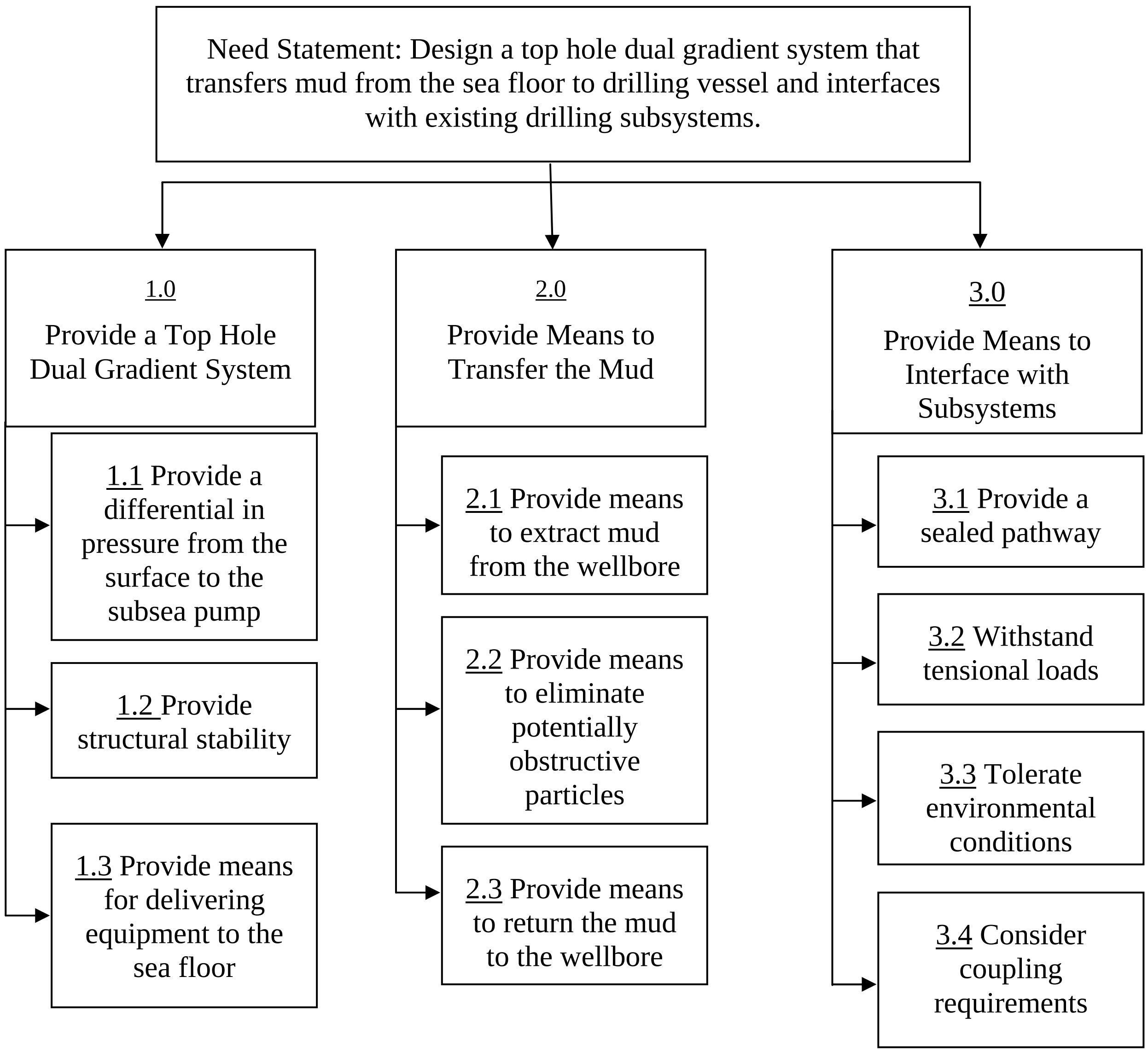

Figure 1. Primary Function Structure

1.0

Provide a Top Hole Dual Gradient System

1.1

FR: Provide a differential in pressure from the surface to the subsea pump
DP: Handle kick, mud return, minimize flow restriction and leakage
PC: Fluid flow rate (gps)

1.2

FR: Provide structural stability
DP: Withstand ocean current, temperature, extreme pressure, weight
PC: depth=10K-12K ft, temp=33°F, pressure=6000 psi, material selection

1.3

FR: Provide means for delivering equipment to the sea floor
DP: Support total weight of all equipment components
PC: Weight

Figure 2. Function Structure: Section 1.0

2.0

Provide Means to Transfer the Mud

2.1

FR: Provide means to extract mud from the wellbore
DP: Subsea and surface pumps, mud flow rate
PC: 8.4-12.5 ppg mud return

2.2

FR: Provide means to eliminate potentially obstructive particles
DP: Pipe diameter, mud weight
PC: 3-9 in. diameter

2.3

FR: Provide means to return the mud to the wellbore
DP: Subsea and surface pumps, mud flow rate
PC: 8.4-12.5 ppg mud return

Figure 3. Function Structure: Section 2.0

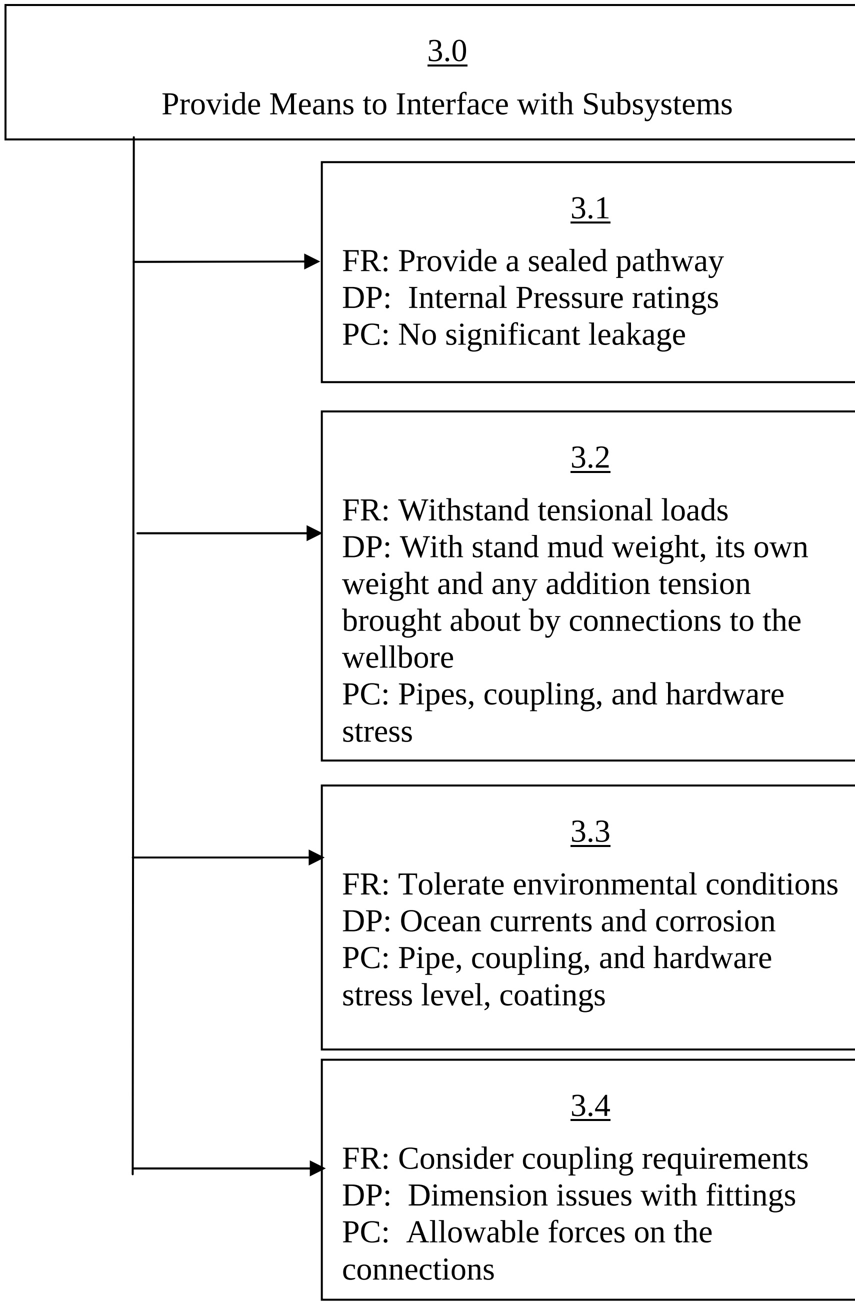

Figure 4. Function Structure: Section 3.0

Design Specifications

The table below summarizes the design requirements for this project.

Table 1. Design Requirements

Function	Design Parameter	Primary Constraint	Equation	Source
1.1	Handle kick, mud return, minimize flow restriction and leakage	Fluid flow rate (gps)	$\frac{dm}{dt}$	
1.2	Withstand ocean current, temperature, extreme pressure, weight	depth=10K-12K ft, temp=33°F, pressure=6000 psi, material selection		Design Proposal Presentation
1.3	Support total weight of all equipment components	Weight	$\sum m_1 + ... + m_n$	.
2.1	Subsea and surface pumps, mud flow rate	8.4-12.5 ppg mud return		Gupta, et. al.
2.2	Pipe diameter, mud weight	3-9 in. diameter		Design Proposal Presentation
2.3	Subsea and surface pumps, mud flow rate		$dP = P_2 - P_1$, $\frac{dm}{dt}$	
3.1	Internal Pressure ratings	No significant leakage		Design Proposal Presentation
3.2	With stand mud weight, its own weight and any addition tension brought about by connections to the wellbore	Pipes, coupling, and hardware stress	$\sum F_1 + ... + F_n$	Design Proposal Presentation
3.3	Ocean currents and corrosion	Pipe, coupling, and hardware stress level, coatings	Gerstner wave eq.	Design Proposal Presentation
3.4	Dimension issues with fittings	Allowable forces on the connections		

Overall System Description

The goal of this design is to create a dual gradient system for the top hole portion of the overall drilling system. The overall advantage of using a dual gradient system is that the casing string can be placed deeper into the wellbore, which allows fewer casings to be used, which results in deeper drilling and wellbores of larger diameters. Using the figure below, notice how subsea mudlift drilling (SMD) utilizes the mud hydrostatic pressure to take advantage of the narrow margin between pore pressure and fracture pressure.

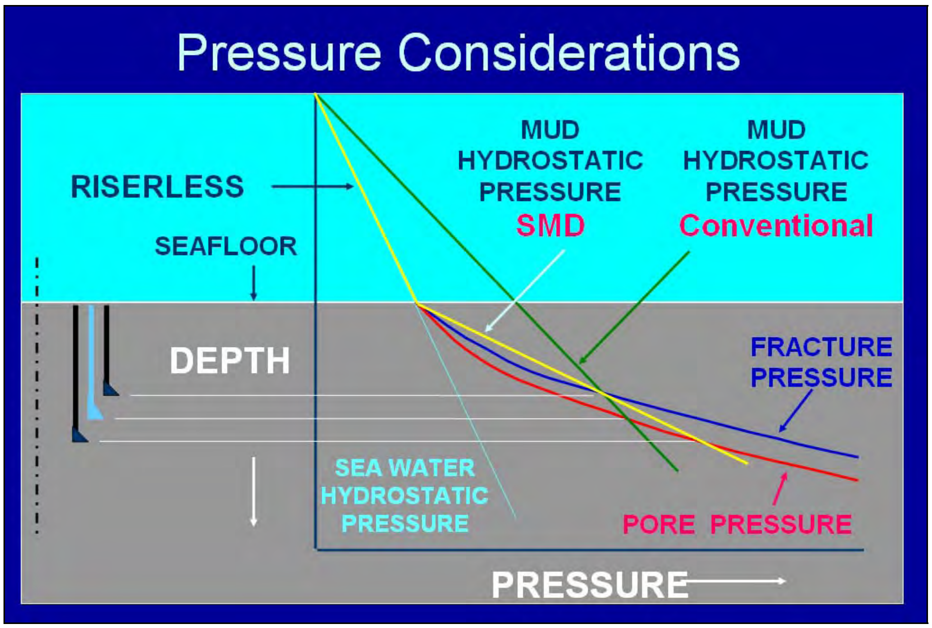

Figure 1. Dual Gradient Advantages with respect to Pressure Considerations

Notice that this figure shows casing depths on the left. As shown by the corresponding horizontal lines, the conventional system (green) would need two casing strings to reach a depth that is much less than the depth achieved by using two casing strings on the SMD system (yellow).

Specifically, this design calls for the ability to pump heavy mud from the seafloor to the drilling vessel. Further, the design must allow for a tubing system in which the mud will be transported. Recognizing the importance of these design considerations, the design team has chosen to focus on three areas for detailed design analysis: pump design, tubing design, interface design, and overall system configuration. Discussion of these detailed design areas follows in the next four subsections.

Detailed Design Analysis 1: Pump Design

Multi-phase pumping is the leading pumping technology in the offshore drilling industry; however, there is much debate over which type of multi-phase pump is best suited for the needs and environment found in deepwater drilling. The conceptual design process considered three popular pump designs: progressive cavity, helico-axial, and twin-screw pumps. Evaluation and down-selection of these pump designs concluded that the progressive cavity pump design was the best option for this system, mainly due to its ability to pump highly viscous mud at a cheaper cost of installation and maintainability than that of the helico-axial and twin-screw pump designs.

The purpose of the subsequent detailed design phase was to determine the volumetric flow rate of the mud and the power requirements for the pumps. As shown in Appendix D, the calculations began by using the linear momentum equation to find the difference between the velocity of the mud leaving the pump at the seafloor and the velocity of the mud exiting the tube at the drilling station. These calculations assumed incompressible flow. Next, the graph below was created to determine the diameter of the pipe for which the head loss would be constant.

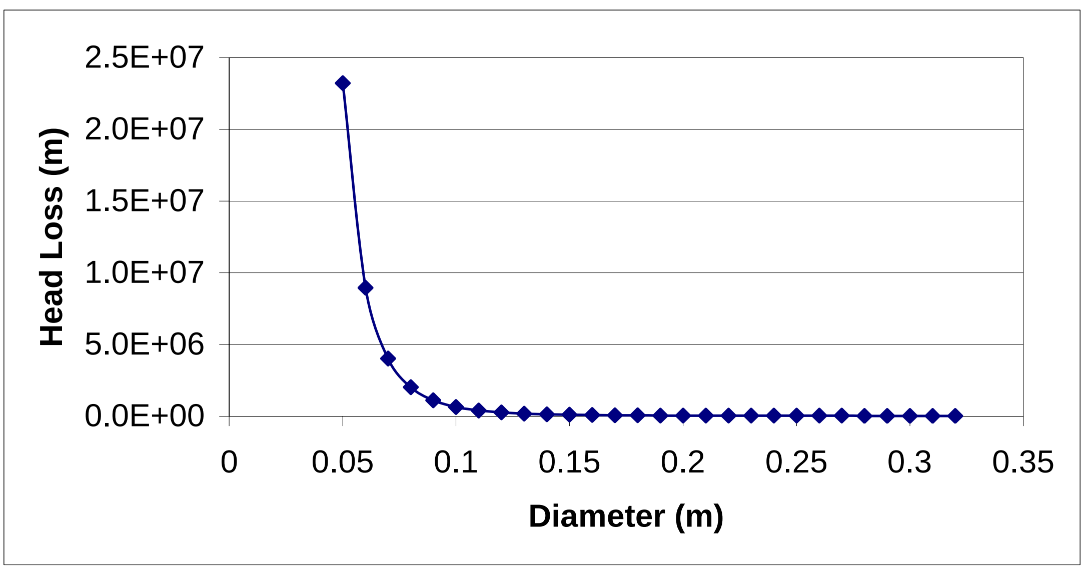

Figure 2. Pump Head Loss versus Pipe Diameter

The graph above converges when the diameter of the pipe is approximately 0.1m. A 30% deviation is assumed, which results in a chosen pipe diameter of 0.08m (approximately 3in).

Next, the diameter is held at a constant 0.08m, while the volumetric flowrate is varied. The graphs below plot hydraulic power (Hp) versus volumetric flowrate (Q), and head loss versus volumetric flowrate, respectively.

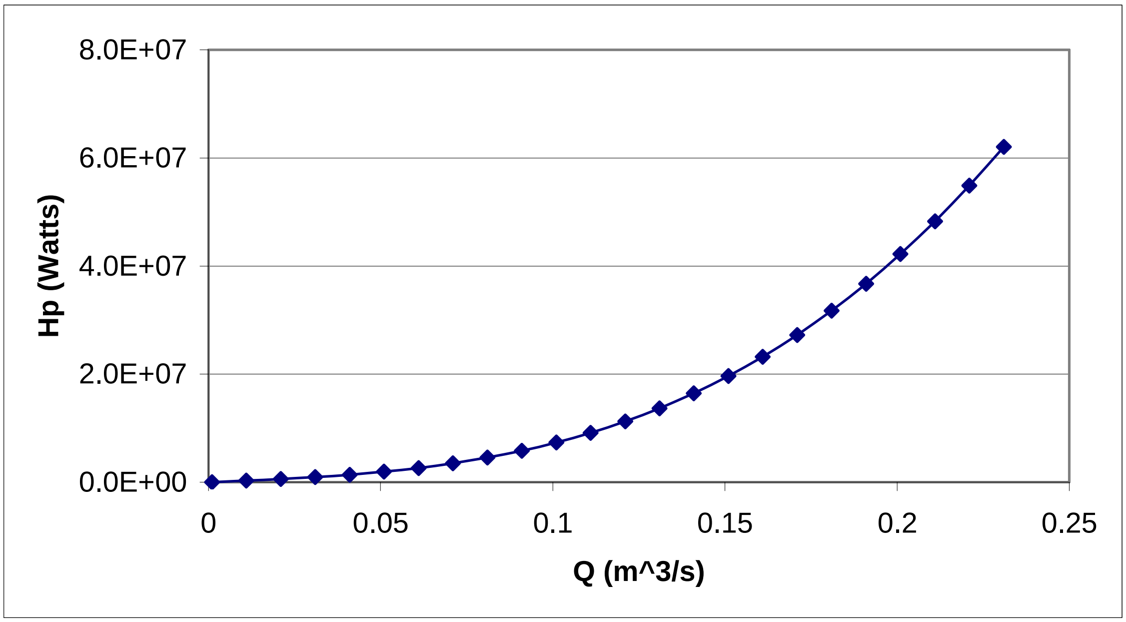

Figure 3. Hydraulic Power versus Volumetric Flowrate

This graph converges at a volumetric flowrate of approximately 0.05m^3/s, which correlates to a hydraulic power of approximately 1.9MW.

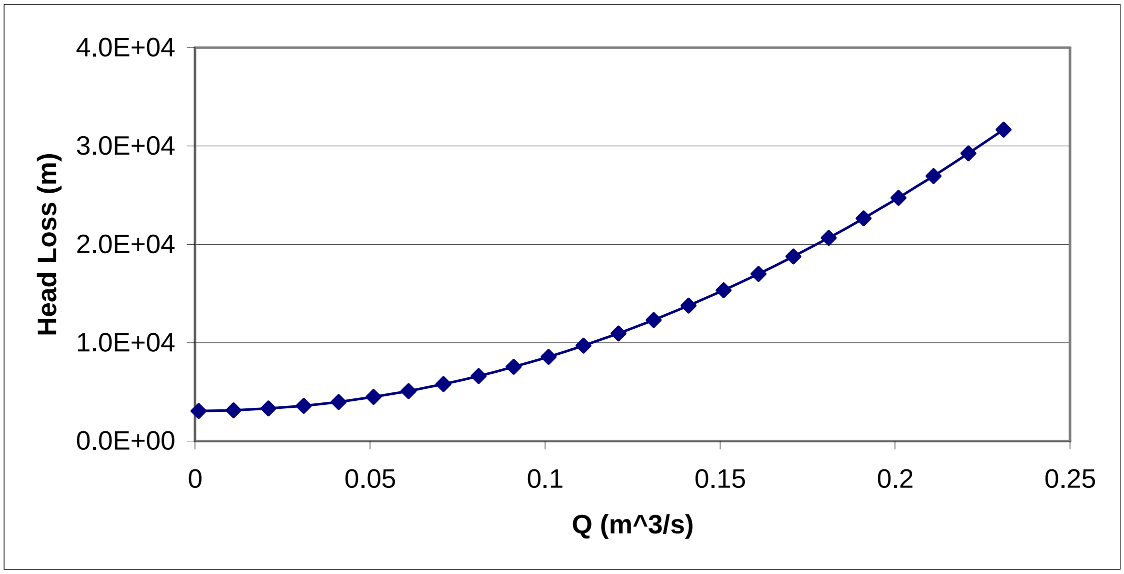

Figure 4. Head Loss versus Volumetric Flowrate

This graph also converges at a volumetric flowrate of approximately 0.05m^3/s, which correlates to a head loss of 4.5x10^3m.

In summary, it was determined that the pipe diameter should be approximately 0.08m, volumetric flowrate of the mud is 0.05m^3/s, hydraulic power is 1.9MW, and head loss is 4.5x10^3m.

The next step is to select an actual pump model. Reexamination of the progressive cavity design finds that there are no existing pump manufacturers that produce a big enough progressive cavity pump to handle these power values. Therefore, an alternate pump design was chosen: the Well Stimulation pump by Gardner Denver, shown in the figure below.

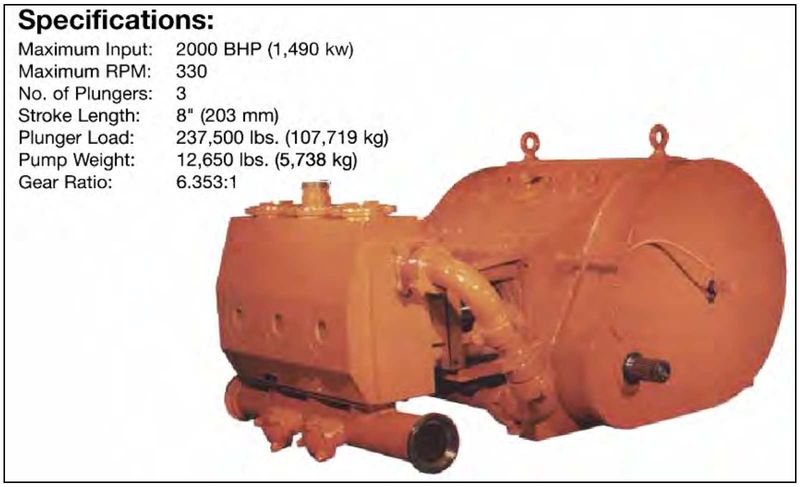

Figure 5. Gardner Denver HD 2000 CWS Well Stimulation Pump

This pump design is manufactured at specifications as high as 2,000HP (1.5MW). Thus, the THDG system would require the use of two (2) Well Stimulation pumps. (www.gardnerdenver.com).

Detailed Design Analysis 2: Tubing Design

The design specifications for the mud return lines between the pumps and the drilling vessel call for tubing that is flexible, reliable, and meets all load and pressure constraints. This type of tubing must withstand ocean currents, motion from the drilling vessel, and be able to be easily maintained over long periods of time. With respect to ocean currents, the tubing will sway in all directions, causing stress at the joints where potential separation could accrue. This potential problem can be overcome if a flexible long section of tubing is used for the initial stretch between the drilling vessel and the mud pumps.

Second, the tubing must be fed down and connected to the mud pumps, so that the system can be used for lifting the mud to the drilling vessel. This process could become long and problematic if reliable and easy-to-assemble tubing were not implemented. As a result, the design requires a vast amount of tubing in order to reach the location of the mud pump and wellbore. With this in mind, the load and pressure requirements to bring the mud back to the surface become a major issue for the long stretch of pipe.

These design constraints were crucial in determining the three possible candidates for the long stretch of tubing needed: coiled tubing, segmented pump hose, and telescope tubing. As discussed in the Conceptual Design Report, coiled tubing was chosen as the best design option, based primarily on its ease of installation, flexibility, and load carrying capability. This design requires a tubing of 3in diameter, though coiled tubing can be manufactured and purchased in a wide range of diameter sizes.

The purpose of this detailed design phase was to find the maximum allowable deflection of the tubing (2 miles long) due to movement of the drilling vessel. As shown in Appendix D, the maximum deflection of the tube is found to occur where the tubing and the connection interface. It is assumed that the moment of inertia occurs along the length of the pipe. When designing to a safety factor of 2, it is found that the shear force on the pipe (v) is $8x10^5$N. Also, the horizontal deflection of the beam is calculated as approximately $3x10^5$m; thus, the drilling vessel can move horizontally from the neutral position (exactly vertically above pump at seafloor) by almost 100,000ft (19 miles).

Detailed Design Analysis 3: Interface Design

The next phase of detailed design analysis focused on developing a connection design for the interface at which the tubing and pump meet at the seafloor, and where the tubing and drilling vessel meet.

To eliminate any problems that may occur due to twisting of the tube, the design team sought to use a connection that would somehow rotate simultaneously. Fortunately, we discovered that such a design is already in production by Emco Wheaton, as shown in the figure below.

Figure 6. Emco Wheaton D2000 World Series Swivel Joint (www.arm-tex.com)

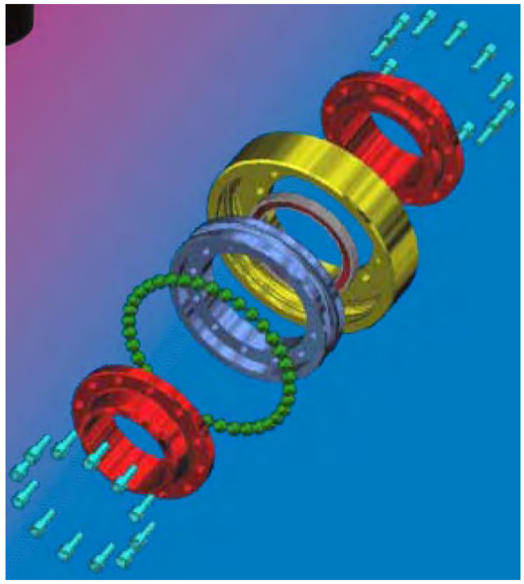

Figure 7. Emco Wheaton D2000 World Series Swivel Joint (Exploded View)

As shown in the figures above, this swivel joint design rotates on internal bearings so that the effects of twisting are not felt by the mud return lines. The design requires that two swivel joints be used: one swivel joint at the subsea connection between pumps and tubing, and one swivel joint at the sea level connection between tubing and drilling vessel.

Detailed Design Analysis 4: Overall System Configuration

This design calls for a dual gradient mud lift system to remove mud and debris from the wellbore during oil drilling. The mud and debris should be pumped from the wellbore up to the drilling vessel at sea level. Given constraints to the process are water depth (which causes cold temperatures), high pressures, and very strong water currents. Therefore, the design should be sturdy, yet agile.

With these crucial parameters in mind, the preliminary concepts were presented in the Conceptual Design Report: the Dual Pressure Model, the Sidesloper Model with Hybrid Umbilical, and the Hybrid Riser Model. Evaluation and down-selection of the three design concepts concluded that the Hybrid Riser Model was the best configuration for the needs of this design, due mainly to its ability to interface with current drilling equipment and its ease of installation and maintainability. During the detailed design phase, this system was renamed the Submersible Mud Removal Unit (SMRU).

The detailed design analysis of the overall system configuration seeks to completely develop the design and its many components. It is understood that the design should include the following: pump(s) to remove mud and debris, piping to carry the material, system controls, nozzle(s) to extract at the wellbore, connectors, and fittings.

To assist in the detailed design effort, Modern Design Thinking is needed. Modern Design Thinking is a step by step advancement from qualitative to quantitative data [Pahl, 1996]. Clarifying the task or objective of the design is necessary; in this case, clarifying the rating process for the pre-existing design, and the requirements of the mud removal unit as stipulated by concerns. Next, the mud removal unit design is broken down to establish function structures, to detail the use of each component and their purpose for the design. These steps better describe Group Technology, a systematic categorization of the mud removal unit's properties to better visualize the necessary steps toward evaluation of its design parameters to conduct value analysis.

The SMRU is to be comprised mostly of stainless steel to fight corrosion from excessive saltwater exposure. The bolts are to be A304, Medium Carbon Steel Grade 8, with zinc coating, which mate well with the stainless steel components and have a corrosion protective coat. The gaskets, which are used on the adapters, are to be made of Pure Copper. Pure copper gaskets are ductile for good part mating and air tightness and are very corrosion retardant. This unit is designed for easy installation and removal of parts, and maintenance.

The unit houses pumps and transforms the multiple pump assembly into a single connection. Using the pictorial below, from left to right, front to back respectively, the pumps are stored and transformed in the rear of the unit and converted towards the front to the single connection that is attached to the tubing.

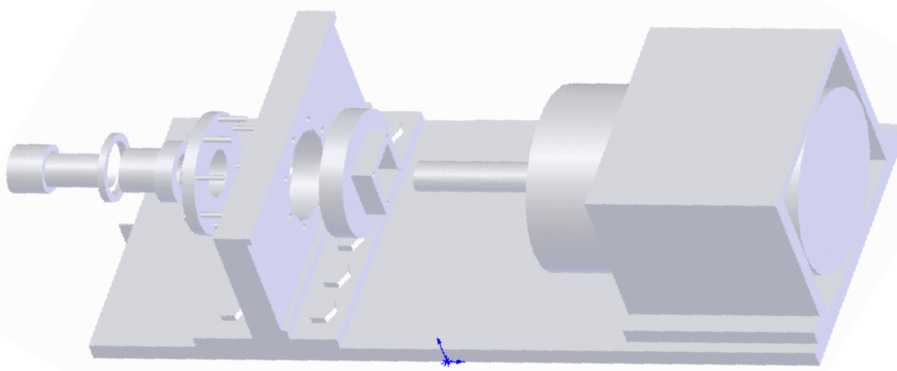

Figure 8. Submersible Mud Removal Unit

Initially with the Hybrid Riser Model, the pumps were to be run in series and stand alone, with separate pipes down to the wellbore using a pipe in pipe bundle system, but this design was clumsy and a more direct approach was taken. For this unit, the pumps are run in parallel and one tube is used at the wellbore.

As earlier stated the Submersible Mud Removal Unit is easy to install. The figure below depicts the unit with unattached adapters, without tubing and with the pumps intact in the rear of the unit.

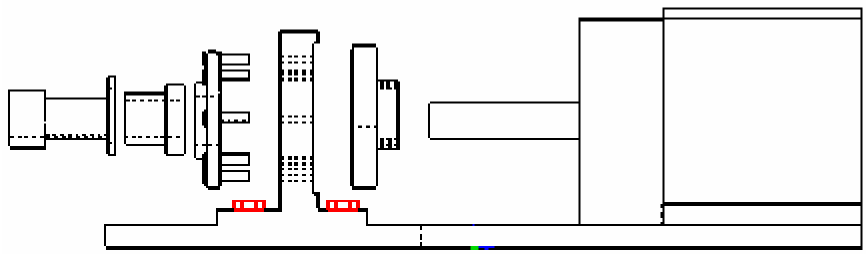

Figure 9. SMRU Exploded Side View

Each component mates together through the housing (between the red bolts above) to form an airtight, watertight seal. Below is step by step schematic of how the parts are assembled.

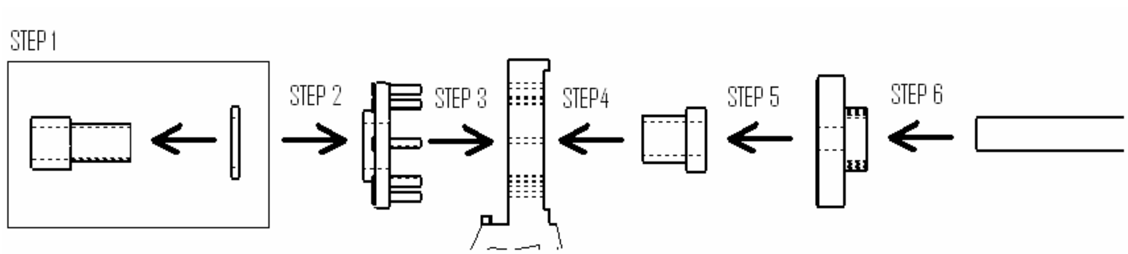

Figure 10. SMRU Assembly Steps

In STEP 1, the tube to the submersible adapter is ringed with the copper gasket, with epoxy. For STEP 2, adapter with gasket are fitted into the tube wellbore flange and STEP 3, the mated parts are bolted into the submersible mount. STEP 4, the pump to mount adapter is threaded through the mount from behind and in STEP 5 pump to mount flange is tightened on with the front bolts. In STEP 6, the pump to mount tube is attached. STEP 7 entails connecting the tube to the submersible adapter. The tube is to sleeve over the adapter as presented below.

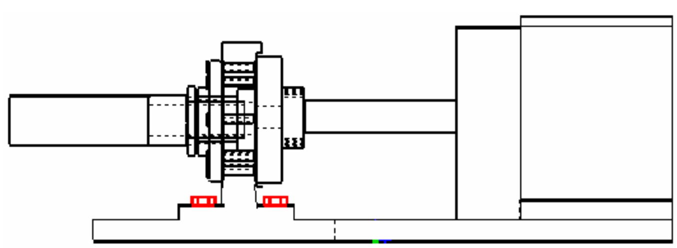

Figure 11. SMRU Tube-Adapter Assembly

STEP 8 requires that the tube be clamped to the Submersible adapter to form an airtight, watertight seal. The figure below presents a one-sided pipe clamp. A two-sided pipe clamp is required for assembly in this step and is presented later.

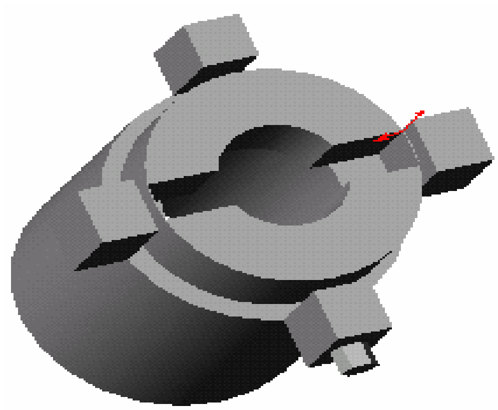

Figure 12. Pipe Clamp

The pipe clamps serve as adapter to tube clamps or adapter to adapter clamps, dependent upon which works best in-service. The clamps are to be comprised mostly of Medium Carbon Steel, Grade 8, with zinc coating like the bolts. From the picture above, the tube or adapters are fitted through the clamp and bolted together using the bolt on the clamp. As the bolt is tightened on the clamp, the diameter reduces around the mating parts until they are fastened efficiently. This material selection is sturdy and the zinc coating will ensure the parts resistance to corrosion. As the materials are between, the Submersible, the bolts, and the clamps, it will be less susceptible to contact surface corrosion. The clamp requirement is as follows:

- 1 single sided Clamp for Wellbore Nozzle to Tube Adapter
- 2 double sided Clamps for:
  1) Tube Adapter to Tubing
  2) Tube to Submersible Adapter

The number of clamps needed could change as the Submersible setup is augmented in-service. The final set-up presents the clamps intact on the unit.

STEP 9 requires that the Tube Adapter and Wellbore Nozzle be assembled and attached to the tubing. The figure below presents these two parts respectively.

Figure 13. Tube Adapter (Left) and Wellbore Nozzle (Right)

Both parts are comprised of Medium Carbon Steel, Grade 8, with outer zinc coating to fight corrosion and an inner stainless finish for tribological concerns. It is assumed that an inner stainless finish will allow the mud to smoothly move through to the tube. The 2 piece set up was selected so that nozzles can be easily replaced with. Using the adapter is to account for varying tube diameters. The Wellbore Nozzle fits into the Tube Adapter, with a waterproof silicone epoxy, using an O-ring is optional. It is questionable whether a nozzle is useful for the mud extraction; this would require testing. Therefore, using the nozzle is optional.

In STEP 10 the Wellbore Nozzle and Tube Adapter are clamped together using epoxy, and in STEP 11 they are clamped to the tube. The tube sleeves over the tube adapter. The assembly steps for STEP 9 through 11 are shown in the figures below.

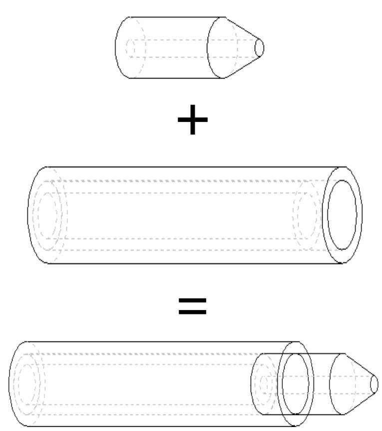

Figure 14. STEP 9—Wellbore Nozzle and Tube Adapter Assembly

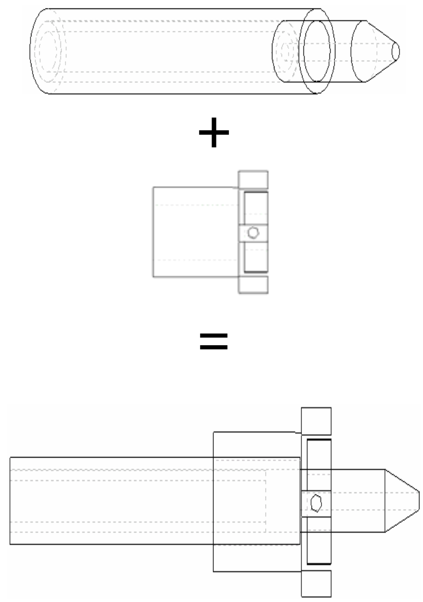

Figure 15. STEP 10—Wellbore Nozzle/Tube Adapter and Pipe Clamp Assembly

In STEP 11, the clamped Wellbore Nozzle and Tube Adapter assembly are clamped to the tube. The tube sleeves over the tube adapter and clamped with a Double Sided Pipe Clamp. The red section in the figure below is symbolic of the tubing.

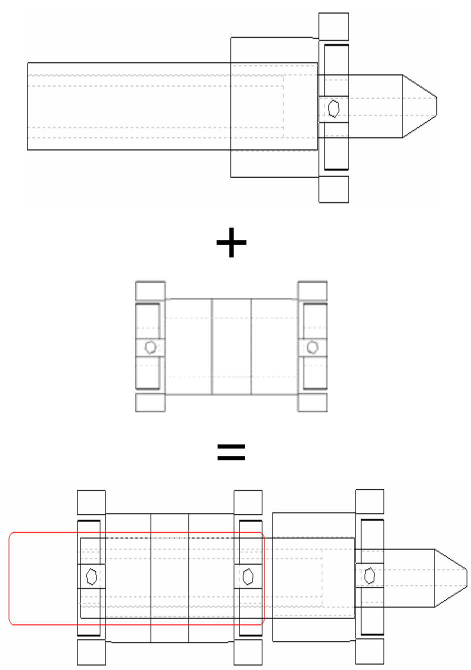

Figure 16. STEP 11—Wellbore Nozzle/Tube Adapter and Tube Assembly

At this point the unit is almost ready to be put in-service mode. The fully intact Submersible Mud Removal Unit is shown in the picture below. The Wellbore Nozzle is lowered via the Seafloor to Wellbore Tube Spool down to an acceptable height above the drill. The mud is removed by the pumps through the nozzle through the tube, through the pumps and up the return line to the vessel. This simply explains the functionality of the unit. The components addressed previously can be seen in the pictorial below (with the exception of parts that are discussed later).

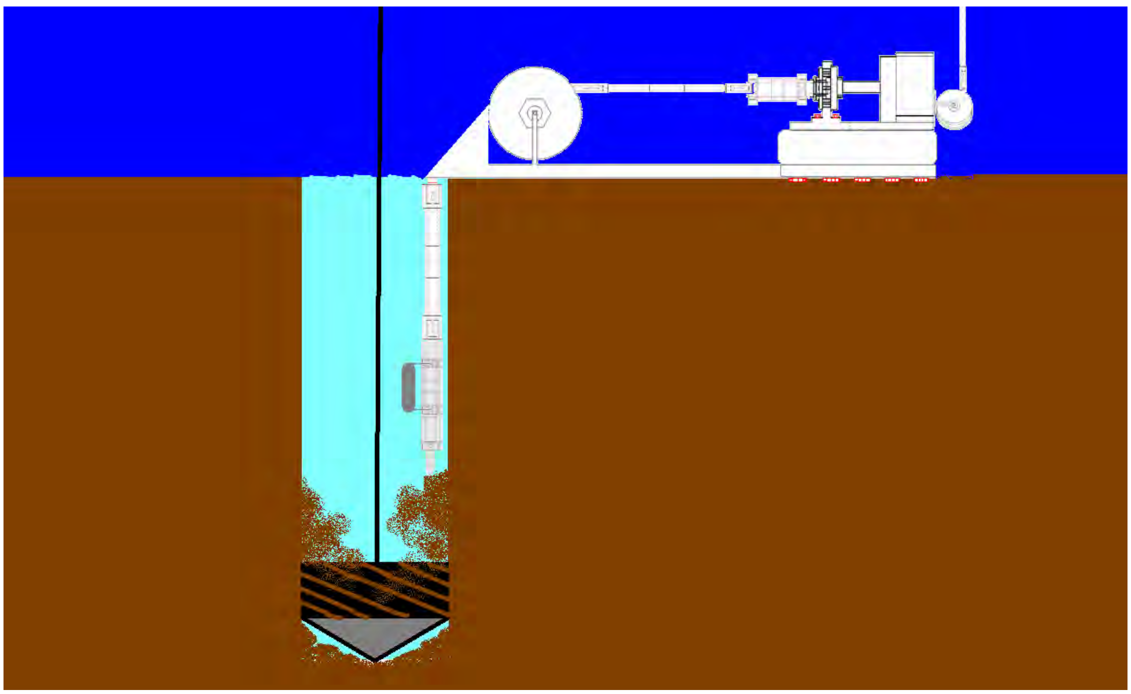

Figure 17. Full Assembly of SMRU with Drill Bit Interface

Also in need of some explanation is the Seafloor to Wellbore Tube Spool, shown below.

Figure 18. Seafloor to Wellbore Tube Spool

This component is submerged along with the SMRU. It is to be attached as shown above. Orientation of the attachment is dependent upon the sea floor terrain, and preference. The main chassis is to be made also of Medium Carbon Steel, Grade 8 with zinc coating. This spool contains the seafloor tubing and supplies it into the wellbore. It has been recommended, that as augmentation to the design, the nozzle be held in position at the top of hole, presented in the pictorial above, right at the seafloor to extract mud as it is expelled from the drill.

The second component in need of official mention is the Seafloor to Platform Tube Spool also composed of Medium Carbon Steel Grade 8 with zinc coating. This spool contains the tubing for mud return to the vessel and can be attached either to the SMRU or to the drilling vessel at sea level.

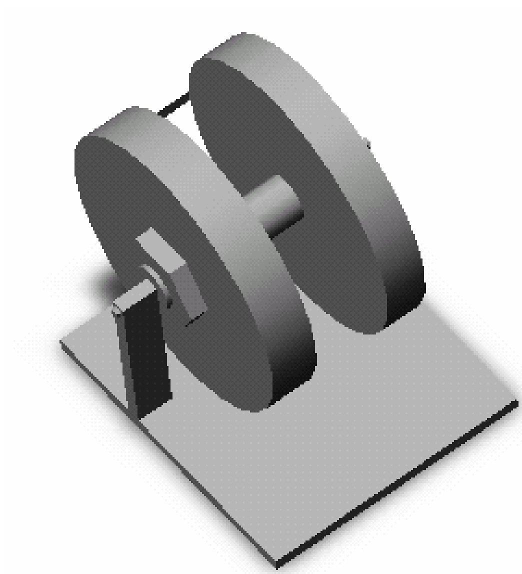

Figure 19. Seafloor to Platform Tube Spool

The third component in need of official mention is the Countersink (shown below), also composed of Medium Carbon Steel Grade 8 with zinc coating. This component holds the tube and nozzle in position above the drilling surface and acts as a stabilizer against drilling vibrations and currents.

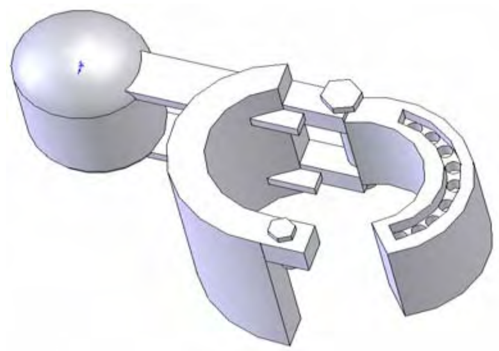

Figure 20. Countersink

This device clamps around the tubing neatly and the bolt is fastened in the proper position. If multiple countersinks are needed, they will simply clamp where need be, along the tubing, to weight it down.

For exactness, extra views of the SMRU are presented in the Appendix.

Summary

In closing, we have presented the Submersible Mud Removal Unit as an effective Top Hole Dual Gradient System. We recommend that further research be conducted to determine if this system can be applied in other deepwater drilling procedures.

Finally, we would like to thank our sponsors for giving us the opportunity to participate in this design project and for allowing us to use the unparalleled resource of their many years of experience.

APPENDICES

Appendix A: List of Abbreviations

THDG: Top Hole Dual Gradient

SMD: Subsea Mudlift Drilling

PC: Progressive Cavity

HRM: Hybrid Riser Model

Appendix C: References

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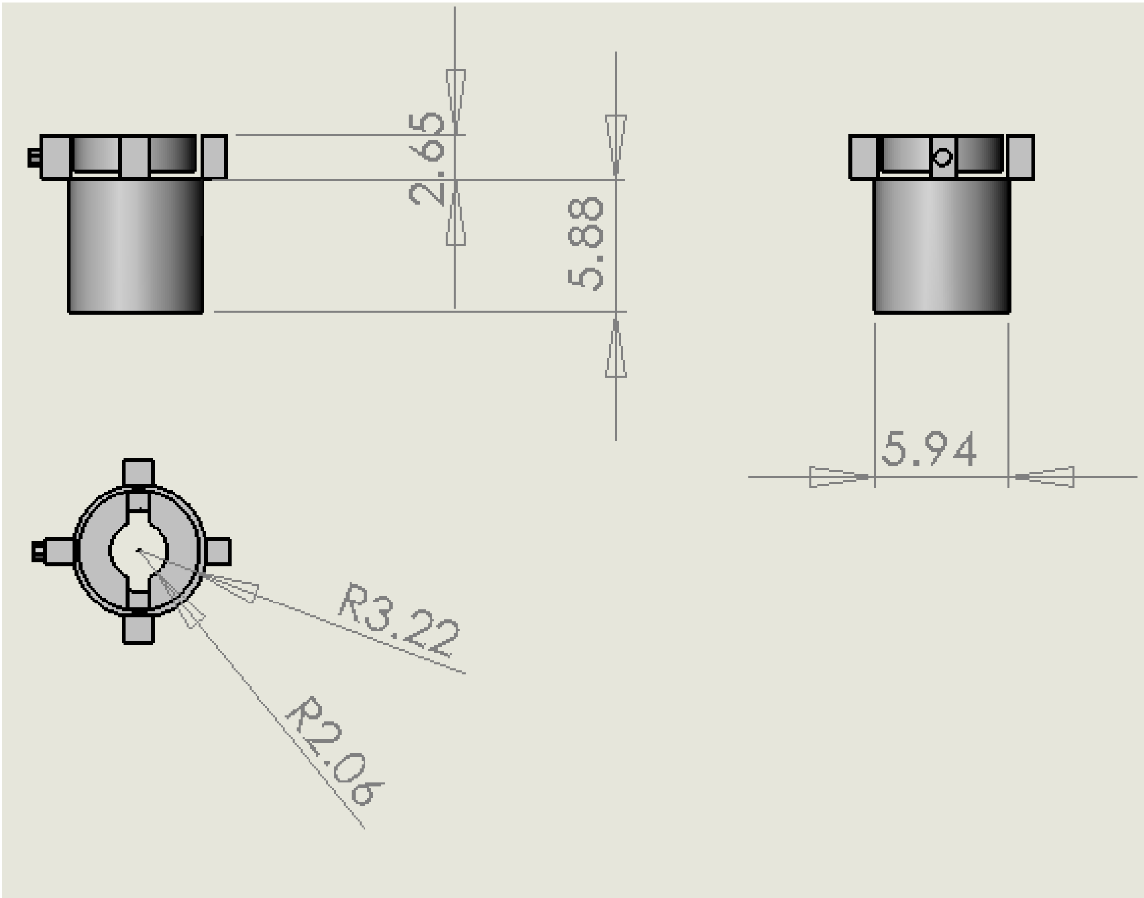
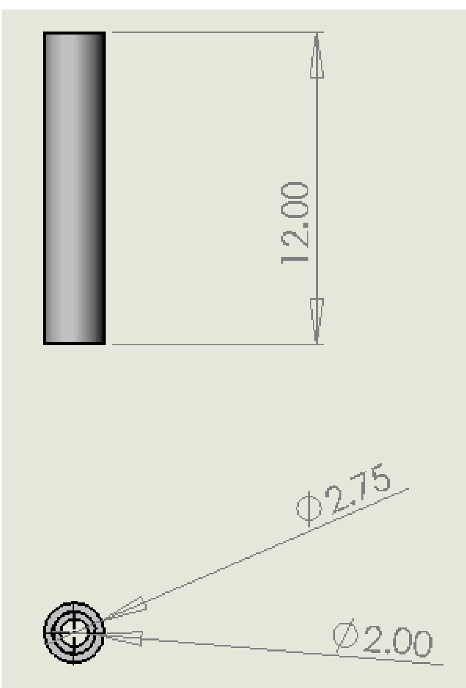
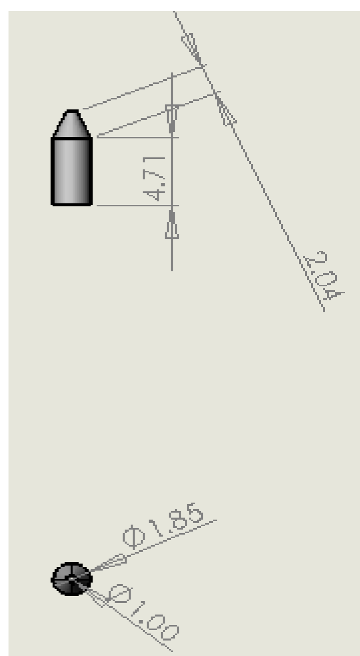
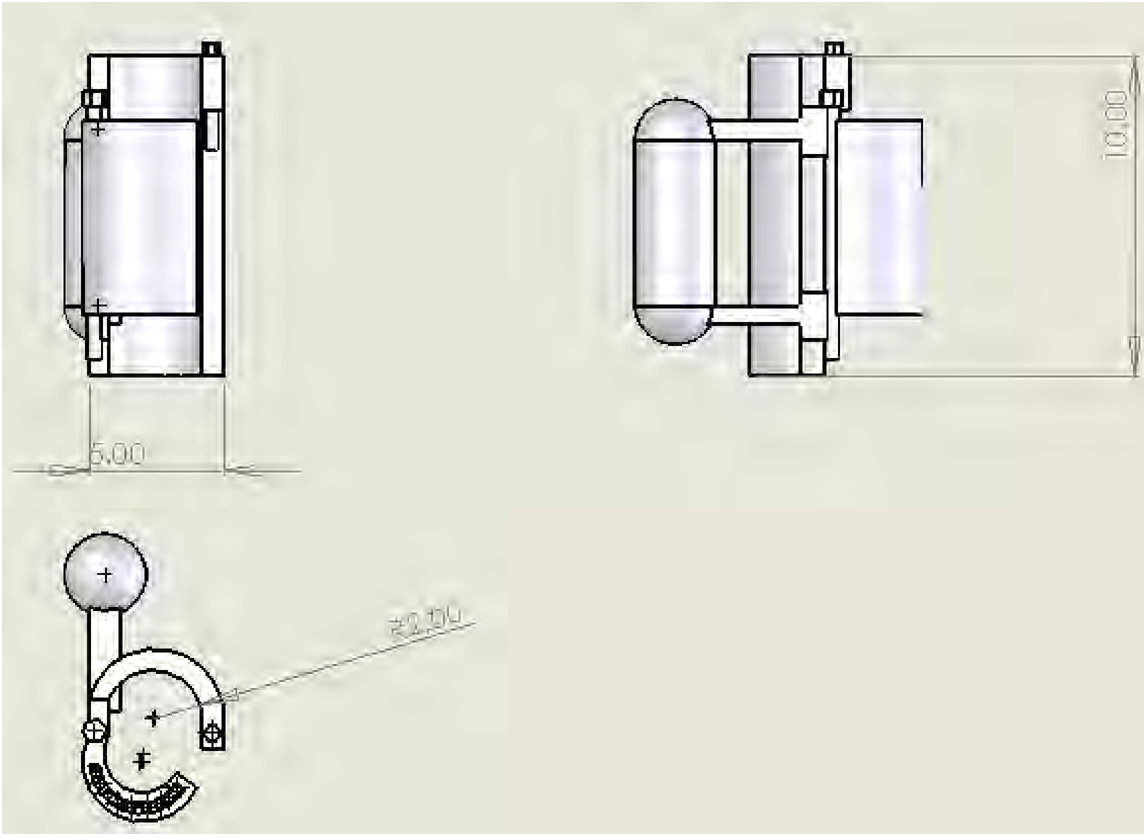
Appendix D: Detailed Calculations

Appendix E: Drawings





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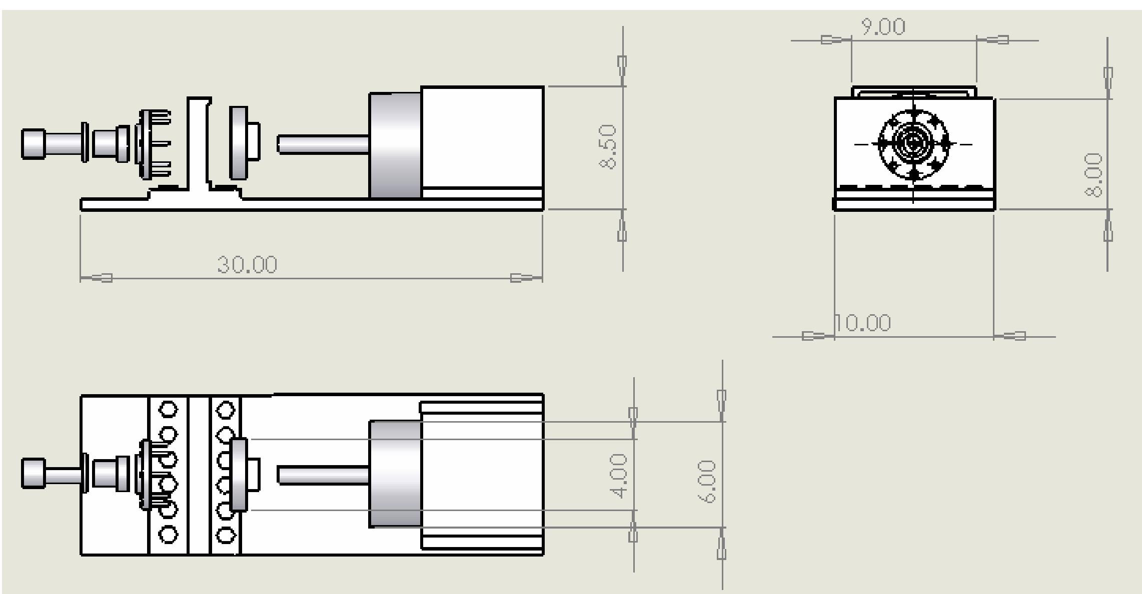
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