AUTOMATIC CONTROL AND OPTIMIZATION OF DRILLING OPERATIONS

A Thesis

by

NARENDRA VISHNUMOLAKALA

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

MASTER OF SCIENCE

Chair of Committee,	Eduardo Gildin
Co-Chair of Committee,	Samuel F. Noynaert
Committee Members,	Shankar P. Bhattacharyya
Head of Department,	A. Daniel Hill

December 2015

Major Subject: Petroleum Engineering

ABSTRACT

Drilling automation initially gained acceptance in the Oil & Gas industry as a solution to increase rigsite safety. While safety-related drilling automation has been implemented, many companies are beginning to recognize that drilling automation offers possibilities of performance enhancement also. Decision making in manual oil field operations is dependent on how quickly the driller can recognize the problem, how knowledgeable the driller is regarding the problem and how quickly he/ she can find a solution for the problem. There is also a distinct lag in interpreting data and then taking corrective action. Such inefficiences are eliminated by adopting automated systems in place of human labor. In this work, the current state of automation in drilling engineering field was studied and barriers to automation were identified.

Mathematical models developed for automated drilling operations are to be simulated before testing them on a physical system. For this purpose, a simulation environment or a Drilling Simulator has been developed in LabVIEW. Automatic Managed Pressure Drilling using Constant Bottom-Hole Pressure technique was modeled using a PID controller and simulated on the Drilling Simulator. The simulator is open to design modifications. A model rig with fully automatic capabilities has been designed and constructed with design limitations on drilling parameters. To improve the performance, an optimization algorithm is proposed which makes use of Mechanical Specific Energy to maximize Rate of Penetration. The Drilling Simulator and the model rig can be used in conjunction to experiment with different models and control methodologies.

DEDICATION

Since I was born, I have been continuously receiving support, motivation and inspiration from several people around the globe, which led me to live this international masters experience. I'm really thankful to all of them. This thesis is specially dedicated to:

- My parents and my sister, for their unconditional love and support, as well as for encouraging me to do my best;
- My advisor, Dr. Gildin and officemates, for the insightful and collaborative work environment, and friendship;
- My roommates (Yatindra, Varun and Sai Krishna), for their continuous support and motivation and for being part of my family in the USA;

ACKNOWLEDGEMENTS

I gratefully acknowledge the guidance and suggestions of Dr. Eduardo Gildin, who was always very helpful, inspiring and considerate since the beginning of my journey at Texas A&M University. I am greatly indebted to him and without him this thesis might not have been written.

I also want to extend special thanks to the following individuals: Dr. Sam Noynaert, my co-advisor who was extremely helpful and supportive throughout the project, Dr. Shankar Bhattacharyya for teaching me control theory, Dr. Heitor Lima for providing me with Teaching Assistantship and supporting me financially, Prof. Fred Dupriest for being available to share his knowledge on Drilling, my project teammates especially Jung Yong Kim, for constant and unaccountable assistance. I also want to thank SPE DSATS and Mr. Fred Florence (NOV) for funding part of my research. Last but certainly not the least, I would like to thank Texas A&M University for providing good infrastructure, resources and an excellent learning environment.

NOMENCLATURE

P	Pressure
T	Time
V	Voltage
I	Current
RPM	Rotations Per Minute
BHP	Bottom-Hole Pressure
BHA	Bottom-Hole Assembly
ROP	Rate Of Penetration
MSE	Mechanical Specific Energy
WOB	Weight-On-Bit
MPD	Managed Pressure Drilling
LOA	Level Of Automation
PID	Proportional Integral Derivative
MPC	Model Predictive Control
VI	Virtual Instrument
DAQ	Data Aquistion
CBHP	Constant Bottom-Hole Pressure
ECD	Equivalent Circulating Density
AFP	Annular Friction Pressure
SPE	Society of Petroleum Engineers

TABLE OF CONTENTS

Page

LIST OF FIGURES

LIST OF TABLES

1. INTRODUCTION

1.1 Significance Of The Study

Automation in Oil & Gas industry, especially in drilling operations, although at a relatively slow pace, is becoming a reality. Technology is enabling the companies to drill challenging and unconventional wells which were previously assumed to be undrillable. The industry is slowly adapting automated drilling systems as a powerful means to increase productivity, quality and most importanly personnel safety. There is no technical reason that could not be overcome that prevents the drilling industry from attaining higher levels of drilling systems automation. However because of the highly segmented nature of the drilling industry involving operators, service companies, contractors etc., the "business pull" is unorganized. With industry collaboration and development of standards, it is likely to open space for the automation field.

There are also several driving forces for rig automation. One of the key drivers is safety. The Macondo tragedy has forced the companies to be better equipped with technologies to handle safety related issues. In an automated oilfield, there are fewer people present on the rig carrying out hands-on work. Most of the manual operations are mechanized and control operations are carried out through computer. Therefore automated systems achieve better safety by moving people away from the rig site. In addition, overall plant safety system can be improved with advanced alarm and warning systems. Sensors incorporated downhole as well as in the surface equipment assist in identifying abnormal situations faster and accurate. And improved telemetry lets the rig personnel to be informed about the situations without delay. Further immediate corrective actions can be taken to tackle the situation.

Another driving factor for automation is performance. Oil & Gas industry is such an industry where periodic downturn cycles are common. To cut down production costs, there is a need to look for optimized ways to carry out operations. Increasing Rate of Penetration (ROP), reducing non-productive time (NPT) and eliminating invisible lost time (ILT) are some of the ways to improve efficiency and overall drilling performance. There is a possibility of repeatability error, lag in decision making process or errors due to fatigue or stress by relying on human labour for all the operations. Using automated systems instead helps in reducing such errors in the system.

In short, there is an urgent need to adapt automated systems in drilling operations to improve both safety and performance. Apart from these two major drivers for automation in Oil & Gas, there are several other factors like increased well complexity, access to limited expert resources, knowledge transfer as a result of the exodus of skilled employees, data overload, environmental concerns to name a few. Although automating drilling rig is the main agenda of this study, it should be kept in mind that automation especially in an industry like Oil & Gas involves a blend of human and computer control that delivers an economically viable, safe, fit-for-purpose borehole with a design that keeps the driller and engineers in the loop, aware of the situation at all times.

1.2 Purpose Of The Study

This study is designed to address the two points mentioned in the previous section - improving safety and performance in drilling by use of automated systems. Research on drilling automation has recently begun not only at the industry level but in academia. This study serves as a starting point for research on the topic. The current state of drilling automation in the industry was briefly studied and certain barriers hindering it were identified. A simulation environment has been developed to serve as a framework for future drilling automation projects on which mathematical models can be simulated and advanced control system architectures can be tested. A completely autonomous (in terms of operation) miniature drilling rig has been designed and constructed to test the simulated models. Several experiments and tests were conducted both on the simulator and the test rig.

1.3 Research Summary

The project examines the state-of-the-art in drilling automation and develop mathematical models for Managed Pressure Drilling and Rate Of Penetration (ROP) optimization techniques. The state-of-the-art includes both petroleum applications as well as other industries. Areas such as aerospace, manufacturing and defense research are far more advanced in automation technology applications and hold many valuable insights on how to develop and apply automation. Mathematical models exist for almost all aspects of the drilling processes. Adapting these models to the automation and control of the drilling process requires research into which models will couple with the control system and create a robust system. Many of the models were developed prior to the recent developments in data gathering and sensor technology. With this recent flood in available data streams comes new possibilities for measurement and thus modeling of the drilling process.

Mathematical models for automated drilling processes have been developed and tested on a simulation environment. In this work, LabVIEW has been used to develop a simulation environment for experimental purposes. Automated models developed for various stages of the drilling process and the models were simulated and tested on this LabVIEW simulator. The system parameters or control algorithms can be modified and changes in performance of the system were studied. The simulation environment can be used for the processes to be simulated and tested in a safe, no-cost environment before implementation in real-world systems. Managed pressure drilling (MPD) process using Constant Bottom-hole pressure (BHP) technique was modeled using a Proportional Integral Derivative (PID) controller in this work and simulated on the drilling simulator.

The simulator was then interfaced to an actual system. A completely autonomous miniature drilling rig was designed and constructed in laboratory and carried out experiments along with the software incorporated in the simulator. The drilling rig has state-of-the-art sensor systems, control system and data acquisition hardware. An algorithm was developed to optimize ROP using Mechanical Specific Energy (MSE) by mitigating dysfunctions and the whole architecture was tested and studied on the model rig.

1.4 Assumptions

There are few limitations in this study and some assumptions have been made in developing the models and designs. The data used in simulations is fabricated data. Field data is not available for comparison. It is assumed that data from downhole is communicated in real-time (using wired-pipe telemetry) whereas actual data rates in field are lesser. Conclusions have been made based on results of testing on miniature model rig by scaling to a larger project. An algorithm has been developed for optimization of ROP based on the concept of MSE derived using an empirical relation.

1.5 Scope Of The Research

The Drilling Simulator developed in LabVIEW is a basic simulation environment which is open to modifications. The simulator can be easily programmed to incorporate models developed for drilling processes. MPD process has been modeled and simulated on the simulator in this current study. The MPD process was designed using a technique called Constant Bottom-Hole Pressure technique. The models can be tested using other techniques and then performance analysis can be done to evaluate better techniques. A PID controller has been used in this model to control the bottom hole pressure. Models can be developed and simulated using other controllers like Model Predictive Control (MPC) and L1 adaptive control to compare benefits or shortcomings of each model.

The model rig constructed for the project performs vertical drilling operations automatically. Directional control can be implemented by modifying the design of the rig. Also, Bottom-Hole Assembly (BHA) could be designed with downhole sensors. Tests were conducted using an ROP optimization algorithm. The performance of the algorithm can be evaluated by comparing the test results with field data. In the absence of field data, tests shall be carried out on the rig by operating the rig manually and without the optimization control program and can be compared with the automatic test results. Several tests were conducted using drill pipes on various rock types. The test results can be taken and used for developing vibrational models using system identification.

1.6 Organization Of The Report

This chapter presented significance of the problem and purpose of the study. Also discussed were some of the major assumptions in this study and finally scope of the research. The rest of the report is organized as follows: Chapter two presents a comprehensive review of literature focussing on the current state and initiatives in the field of drilling automation. Chapter three is intended to provide a background in LabVIEW programming which is required to develop the Drilling Simulator. Chapter four starts with explaining MPD process and techniques, then showing mathematical modeling of the process. The chapter is concluded by discussing control methodology in brief, the need for a simulation environment and showing few simulations results. Chapter five discusses rig design and construction. Chapter six is focussed on ROP optimization algorithm using MSE. Drilling results of a test case are also shown towards the end of the chapter. The report is finished by summarizing the report with few concluding remarks and also suggesting future recommendations for the work in Chapter seven.

2. LITERATURE REVIEW

Put simply, automation is the replacement of human labor by machines. Automation is a technique that makes a system to operate automatically assisting in the human decision-making process. Since the Industrial Revolution, there have been innumerable technological advances used to help humans work more efficiently. From the simple use of pulley systems to highly sophisticated Human-Robot Interactions (HRI), many industries have been quick to adopt these advancements, while some have progressed at a slower pace. Two examples that stand out are the aviation and automotive industries. A detailed comparison drawing parallels between the industries is presented in the paper by Thorogood et al. [1] Both have achieved high levels of automation in their processes, so why not in the case of oil and gas drilling? Perhaps it‘s all the years where drilling was considered an art based on experience rather than science, effectively creating a lag in the adaptation of automation. Just recently, though, the industry has seen rapid changes in terms of drilling automation where completely automated drilling systems are becoming a reality. The evolution of automation in drilling is discussed more in the paper by Eustes [2].

2.1 Why Automation?

The main objective for any driller is to simultaneously drill fast and drill safe, ensuring quick and accurate execution. Typically, drilling faster means less time spent drilling, which in turn works to reduce costs. At the same time, though, people are a company's most valuable asset and keeping their well being intact is of the utmost importance. These objectives can be achieved and maximized with the introduction of automated drilling rigs. This is indeed the main objective of any drilling automation process: increase safety by ensuring that well dynamics does not exceed the ones specified by its natural behavior.

With respect to efficiency, there are many drawbacks in the manual drilling process, mostly because of the constraints on human labor. Most drilling rigs are located in harsh environments, which produce considerable amount of stress on the people working there. The combined effect of an employee‘s workload, stress and fatigue affects performance, creating a greater chance for human error. In an automated system, those same limitations are essentially eliminated and drastically reduce the occurrence of such errors. When it comes down to it, an automated system is faster, more reliable, and more consistent compared to human operations none of which compare to its positive impact on human safety. Potential for human error and advantages using automation are discussed in detail in the paper by Iversen [3].

Safety is the most important aspect of drilling automation. Automating a drilling rig means performing the drilling activities with the help of automated control systems rather than human labor. This results in a reduction of the number of people on the rig floor, away from the process area. Drilling as a whole is a very complex process with several key sub-activities such as the rotary, pipe racking, pumping, cementing, casing, and directional drilling systems to name a few. These systems contain several parameters for the driller and his crew to monitor and control. An automated system can ultimately provide better control over these parameters. This is even more evident in emergency scenarios due to the system's ability to immediately recognize abnormalities. To this end, simulation environments that can handle these challenges are of great value in training personnel in this new paradigm of drilling automation. It also serve as a test bench for rigorously validating physical drilling models and in testing new forms of advanced control systems applied to several drilling processes.

Figure 2.1: Blowout at BP's Macondo prospect (Source: www.telegraph.co.uk)

2.2 Current State Of Affairs

Automation in the drilling industry is less advanced compared to other industries as discussed in this paper by Thorogood et al. [4] Failure to adopt new technology in any industry can occur for a variety of reasons. The oil and gas industry and the drilling sector in particular, has always been slow to take up new technologies due to economics, safety concerns and the drilling environment. The operator service company dynamic requires the push for innovation come from the customer. Most operators do not ask for automation and thus are not willing to pay for it. In addition, a mistrust of automation exists, especially of automation of downhole pressure control. This mistrust is based on the inaccurate assumption that a human can better process the data and make better decisions. Another reason for this slow adoption can be attributed to the fact that drilling activity takes place in extreme working conditions, above ground in unhospitable areas and downhole with high temperature, high pressure (HTHP) formations. Finding control equipment and sensors to handle this environment is difficult. It is also important to note that the drilling process is not standard for all wells as each well profile is unique in its own way. Therefore, the modeling of this process cannot be definite, but, instead has to be adaptive. All of these contributing factors make automation in drilling a difficult task. However, with each technological advancement, these limitations are being overcome. It is also no surprise that the recent boom in unconventional reservoirs is adding more motivation for transitioning into automation.

To quantify the amount of automation present in the system, a ten-level taxonomy LOA (Levels Of Automation) as defined in the paper by Endsley and Kaber [5] is used. It is described as the amount of interaction between human and computer in the system. These 1-10 levels of automation are shown in the Table 2.1. H stand for Human involvement and C stands for Computer interaction.

Table 2.1: LOA, adapted from Endsley and Kaber (1999)

Level of Automation	**Monitor**	**Generate**	**Select**	**Implement**
1. Manual Control	H	H	H	H
2. Action Support	H/C	H	H	H/C
3. Batch Processing	H/C	H	H	C
4. Shared Control	H/C	H/C	H	H/C
5. Decision Support	H/C	H/C	H	C
6. Blended Decision Making	H/C	H/C	H/C	C
7. Rigid System	H/C	C	H	C
8. Automated Decision Making	H/C	H/C	C	C
9. Supervisory Control	H/C	C	C	C
10. Full Automation	C	C	C	C

Thorogood et al. (2010) explains the LOA taxonomy as applicable to the drilling activities and classifies them into some key categories. The following is the list of all levels of automation indicating the role of computer (or in general, a control system) in carrying out a drilling operation.

1. Offers no assistance: driller must take all decision and action.
2. Offers a complete set of decision/action alternatives.
3. Offers a set of alternative and narrows the selection down.
4. Suggests a single course of action.
5. Selects and executes that suggestion if the driller approves.

6. Allows the drill a restricted time to veto before automatic execution.

7. Executes automatically, then necessarily informs the driller.

8. Executes automatically and informs the driller only if asked.

9. Executives automatically and informs the driller only if it, the computer, decides to.

10. Decides everything and actions autonomously, ignoring the driller

As per Macpherson et. al. (2013) [4], the current drilling-system is at LOA 2 with only human/computer monitoring for many operations. The technical challenge is moving this existing Level 2 system to a higher level to realize gains in productivity, efficiency, and safety. On this 10-level scale, current machinery like top drives, rotaries fall into Category 1 (or on Level 1) whereas down-hole technology for some operations is at LOA 8 or 9. This unfilled gap between LOA 2 and LOA 9 can be seen as technology opportunity. At the same time, automation should be used where it can perform better than humans or where the task is so repetitive that human performance would fall because of various reasons. When automation is used for envelope protection to reduce or eliminate human error, it must be prudently and should allow for manual override to deal with the unforeseen. Therefore developing systems with LOA 9 or 10 is also not recommended, in particular for industries like drilling. In this project, we designed and constructed an automated miniature drilling rig which is at LOA 7-8. Details about the rig construction and automation are presented in later sections.

2.3 Barriers

Unlike the automotive or aviation industries, one of the biggest things holding industry back is the lack of a common communication protocol or standards pertaining to drilling automation. This is primarily due to the highly segmented nature of the drilling industry where we must deal with multiple service companies, rig contractors, equipment manufacturers, etc. With increased well complexity, the data handling between all systems has become more difficult, and is a major problem within the various dissimilar systems.

The Society of Petroleum Engineers (SPE) and the International Association of Drilling Contractors (IADC) are working towards bringing automation in drilling to market in the near future. SPE has a specific technical section aimed at these advancements - termed the SPE DSATS (Drilling Systems Automation Technical Section). One of the group's focuses is on standardizing communication protocol for the industry. The two current standards being considered are namely WITSML and OPC UA. IADC has also put together a committee working on comprehensive automation of the drilling process alongside the integration of surface and down-hole systems.

Apart from the digital infrastructure, availability of proper instrumentation devices has also hindered progress. Special sensors are required in drilling process because 1) sensors are required to provide real-time data, and 2) many measurements are made in sub-surface environments. The paper by Cayeux et al. (2014) [7] discusses more on the necessity of sensors for drilling automation.

3. DESIGN OF DRILLING SIMULATOR

A Drilling Simulator has been designed and developed using National Instrumenets software LabVIEW. In this chapter, a brief tutorial on LabVIEW is provided first and then, programming architecture is discussed which is useful for developing the simulator. Towards the end, sensors and data acquisition hardware are discussed.

3.1 Introduction To LabVIEW

3.1.1 What Is LabVIEW?

LabVIEW (**Lab**oratory **V**irtual **I**nstrument **E**ngineering **W**orkbench) is a graphical programming environment you can use to quickly and efficiently create applications with professional user interfaces as well as to develop sophisticated measurement, test, and control system applications. LabVIEW offers integration with thousands of hardware devices and provides built-in libraries for advanced analysis and data visualization.

As its name suggests, LabVIEW provides an environment in which engineers can design their own laboratory instruments quickly and easily. Because LabVIEW programs imitate the appearance and operation of physical instruments, such as oscilloscopes and multimeters, LabVIEW programs are called virtual instruments or, more commonly, VIs and are developed in a graphical programming language known as G. G-code differs from standard sequential text-based computer code in that it relies on graphical symbols to describe procedures for the computer. In fact, the G-code of a given VI looks like a block diagram; inputs and outputs are transferred from block to block by wires that are color-coded by their data type. Each specific block represents a particular operation. LabVIEW's simple interface and easy-to-learn programming language make it a perfect choice for developing control applications (Bishop 2007). Data acquisition (DAQ) is handled easily with predefined block functions. Signals read from DAQ components are manipulated with standard block functions and the results of the program can be easily sent to an output board, which in turn sends signals to the plant.

3.1.2 Why LabVIEW?

Interactive GUI - A simple, user-friendly interface (called 'Front panel') with graphics can be developed on this platform such that even non-technical people (Rig men in our case) can operate the program. Even the programming is intuitive with drag and drop graphical icons instead of writing several lines of text.

Hardware integration - Data acquisition tools that can acquire data from almost any type of device are available. With the help of these tools, it is possible to use the same simulated program developed for mathematical automated models for real-world implementation on field as well just by replacing few blocks in the program. This deployability feature in LabVIEW i.e. the deployment of Virtual Instrument (VI) directly into the field allowing HIL/SIL applications is one of the main advantages of building simulator in LabVIEW.

Advanced Control - There are several in-built functions (such as PID Autotuning, MPC controller among others) in the software, Control Design and Simulation toolkit in particular which is of high relevance to the drilling automation applications. Any control algorithm from basic PID to non-linear control can be used directly in the program. There are provisions to execute multiple parallel loops also at high speeds on FPGAs and real-time processors.

Multithreading - LabVIEW enables your code to have automatic parallelism. In other languages if you want to run code in parallel, you have to manage multiple threads manually. The LabVIEW environment, with the compiler and execution system working together, automatically runs code in parallel whenever possible. Also, Event-driven programming features extend the LabVIEW dataflow environment to allow the user's direct interaction with the program without the need for polling.

3.2 Programming

A tutorial on LabVIEW graphical programming is provided in the book by Bishop [8]. Some of the basic concepts required to start with LabVIEW programming are discussed in this chapter.

3.2.1 Program Structure

A LabVIEW program (VI) has three components - Front panel, Block diagram and Connector pane. The front panel as shown in Fig. 3.1 is the user interface of the VI. It acts like the face of an instrument.

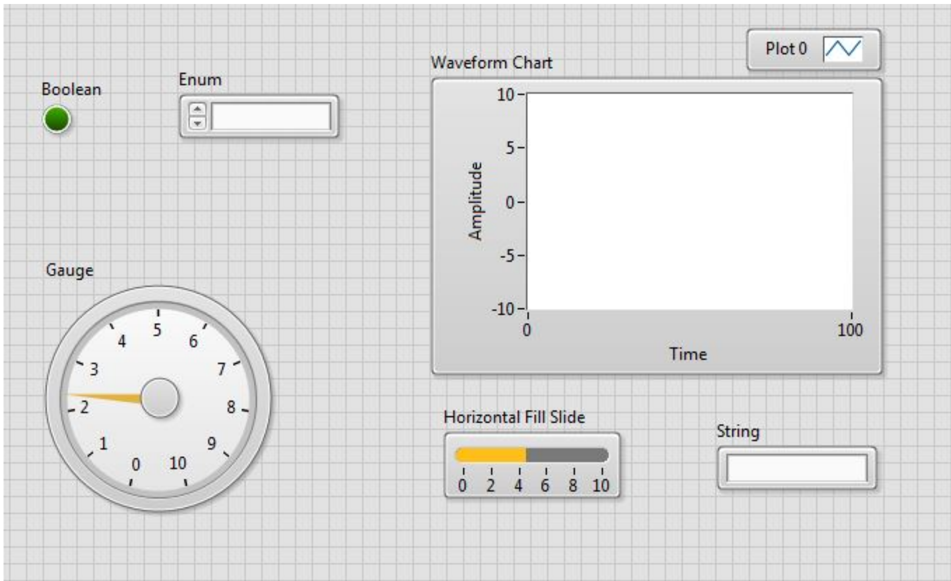

Figure 3.1: LabVIEW Front Panel

The Block Diagram as shown in Fig. 3.2 runs in the background, which is where the actual programming (using G-code) is done.

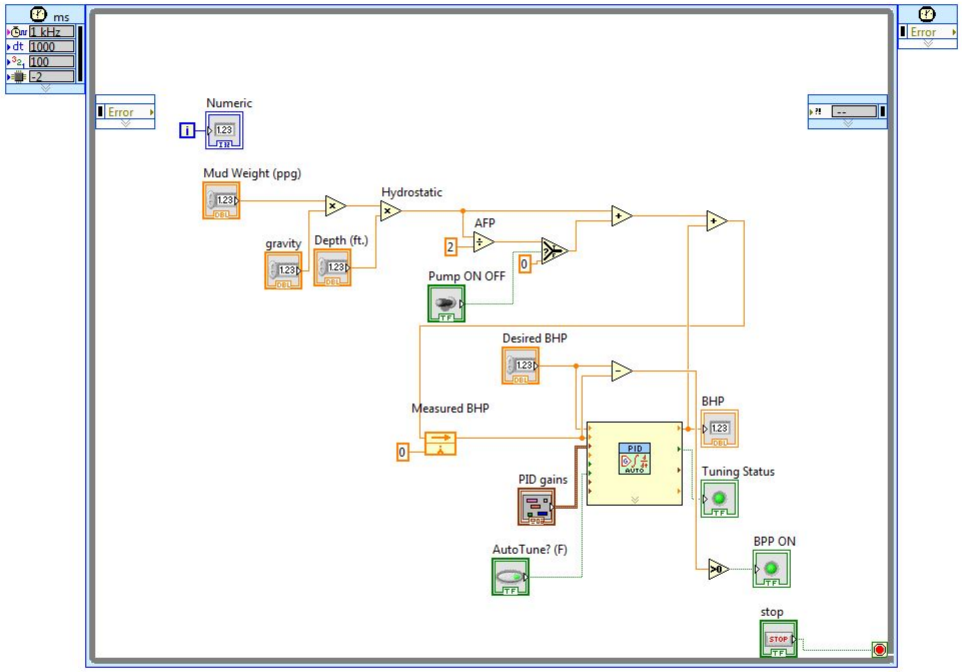

Figure 3.2: LabVIEW Block Diagram

The Icon and Connector pane allows you to use and view a VI in another VI. A VI within another VI is called a subVI. A subVI corresponds to a subroutine in text-based programming languages.

3.2.2 Programming Tools

Front panel is created using Controls and Indicators available on the Controls Palette. Controls and indicators are the interactive input and output terminals of the VI, respectively. Controls are knobs, pushbuttons, dials, and other input devices. Indicators are graphs, LEDs, and other displays. Controls simulate instrument input devices and supply data to the block diagram of the VI. Indicators simulate instrument output devices and display data the block diagram acquires or generates.

After you build the front panel, you add code using graphical representations of functions available on the Functions Palette to control the front panel objects. The block diagram contains this graphical source code. Front panel objects appear as terminals on the block diagram. Additionally, the block diagram contains functions and structures from built-in LabVIEW VI libraries. Wires connect each of the nodes on the block diagram, including control and indicator terminals, functions, and structures. The function and control pallettes are shown in Fig. 3.3.

In addition, there is a Tools Palette to create, modify and debug VIs. Debugging can be done using toolbar options like Execution Highlighting, Single-Stepping, Probing, creating breakpoints etc.

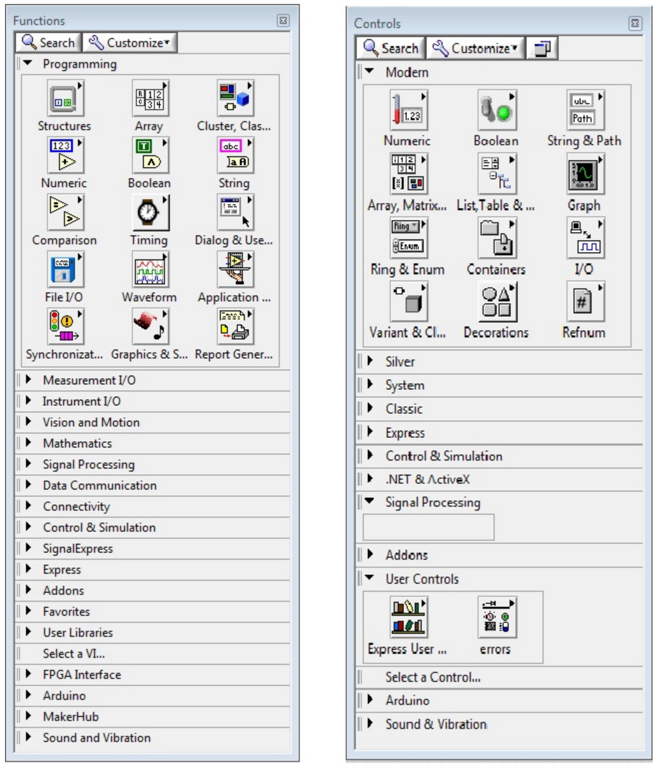

Figure 3.3: Functions palette (on the left) & controls Palette (on the right)

3.2.3 Programming Techniques

In this section, a few special programming schemes and design patters which help greatly in building an effective program are explained. Some of these are used in developing the Drilling Simulator.

3.2.3.1 Event Driven Programming

This is an asynchronous way of communicating between user interface or external I/O and the block diagram. Event-driven programming is a method of programming where the program waits on an event to occur before executing one or more functions. User interface events include mouse clicks, key presses, and so on. External

I/O events include hardware timers or triggers that signal when data acquisition completes or when an error condition occurs. Events allow you to execute a specific event-handling case each time a user performs a specific action. By using events to respond to specific user actions, you eliminate the need to poll the front panel to determine which actions the user performed. A sample program using Events is provided in Fig. 3.4.

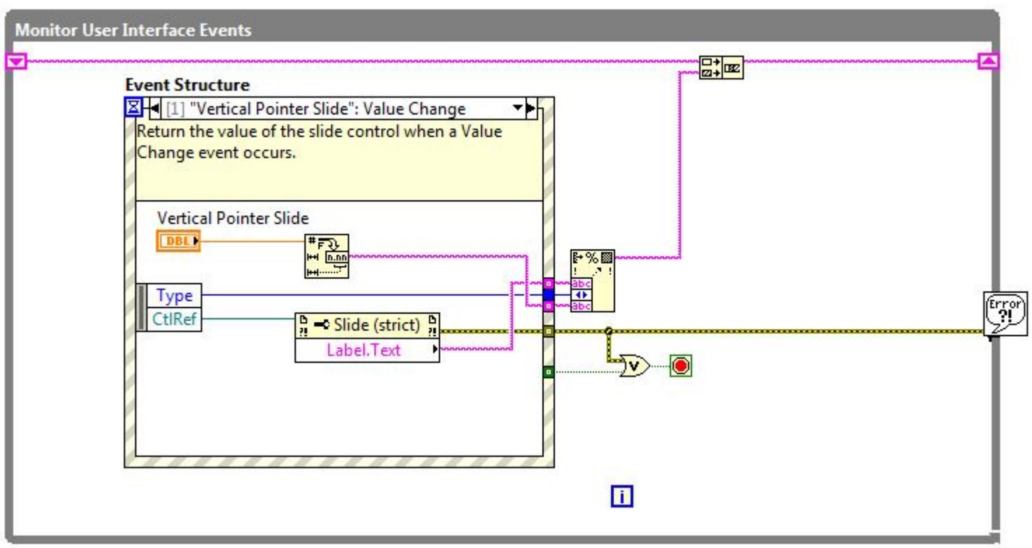

Figure 3.4: Example of program using events

3.2.3.2 Multiple-Loop Design Patterns

Master/Slave design and Producer/Consumer design are two common multiple design patterns that allow data sharing among multiple loops running at different rates. The parallel loops in the producer/consumer design pattern are separated into two categories those that produce data and those that consume the data produced.

Data queues communicate data among the loops. The data queues also buffer data among the producer and consumer loops. This design pattern allows the consumer loop to process the data at its own pace, while the producer loop continues to queue additional data. A sample program using Events is shown in Fig. 3.5.

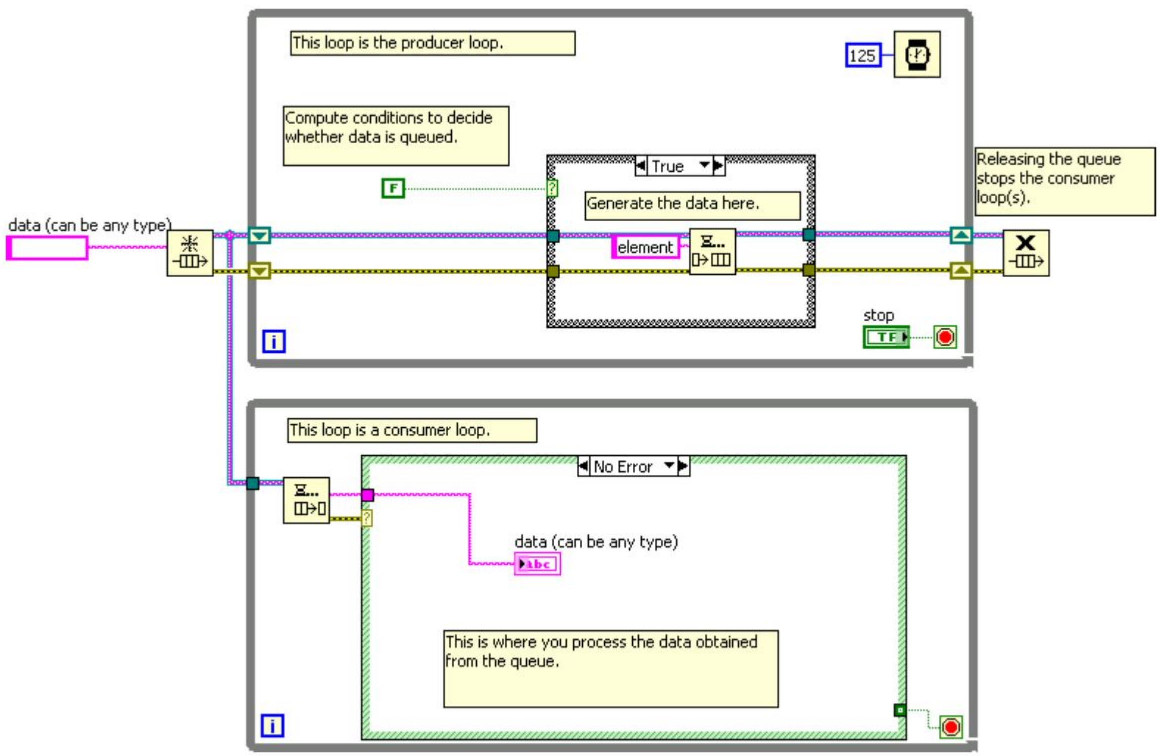

Figure 3.5: Producer/Consumer design pattern

3.3 Data Acquisition

Apart from data flow graphical programming, another powerful aspect of LabVIEW is the ability to create Data Acquisition (DAQ) applications. The purpose of data acquisition is to measure an electrical or physical phenomenon such as voltage, current, temperature, pressure, or sound. PC-based data acquisition uses a combination of modular hardware, application software, and a computer to take measurements. While each data acquisition system is defined by its application requirements, every system basically involves gathering signals from measurement sources and digitizing the signals for storage, analysis, and presentation on a PC. A basic structure of DAQ system is shown in Fig. 3.6.

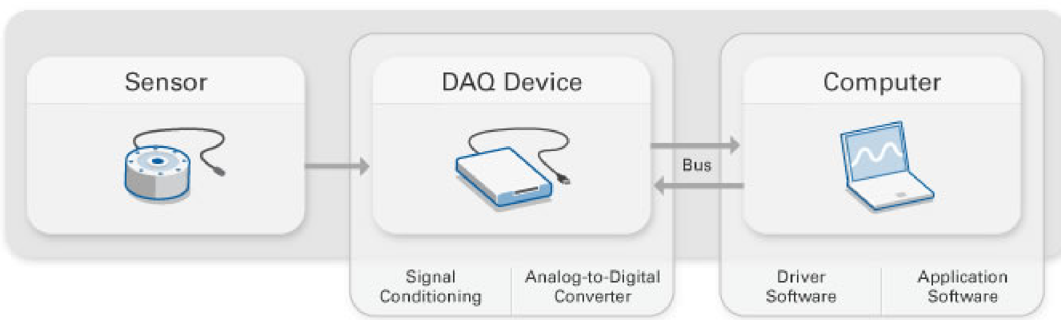

Figure 3.6: A simple DAQ system (Source: www.ni.com)

3.3.1 Sensors

The measurement of a physical phenomenon, such as the temperature of a room, the intensity of a light source, or the force applied to an object, begins with a sensor. A sensor, also called a transducer, converts a physical phenomenon into a measurable electrical signal. Depending on the type of sensor, its electrical output can be a voltage, current, resistance, or another electrical attribute that varies over time. Some of the most common phenomenon and the sensors or transducers used to measure the phenomenon are shown in Table 3.1 (Source: www.ni.com). Some sensors may require additional components and circuitry to properly produce a signal that can accurately and safely be read by a DAQ device.

Table 3.1: Phenomenon and the transducers to measure

Sensor	**Phenomenon**
RTD, Thermocouple	Temperature
Photo Sensor	Light
Microphone	Sound
Strain gauge, Piezoelectric transducer	Force and Pressure
LVDT, Potentiometer	Position and Displacement
Accelerometer	Acceleration
pH electrode	pH

DAQ hardware acts as the interface between a computer and signals from the outside world. It primarily functions as a device that digitizes incoming analog signals so that a computer can interpret them. The three key components of a DAQ device used for measuring a signal are the signal conditioning circuitry, analog-to-digital converter (ADC), and computer bus.

3.3.1.1 Signal Conditioning

Signals from sensors or the outside world can be noisy or too dangerous to measure directly. Signal conditioning circuitry manipulates a signal into a form that is suitable for input into an ADC. This circuitry can include amplification, attenuation, filtering, and isolation.

3.3.1.2 Analog-to-Digital Converter (ADC)

Analog signals from sensors must be converted into digital before they are manipulated by digital equipment such as a computer. An ADC is a chip that provides a digital representation of an analog signal at an instant in time. In practice, analog signals continuously vary over time and an ADC takes periodic samples of the signal at a predefined rate. These samples are transferred to a computer over a computer bus where the original signal is reconstructed from the samples in software.

3.3.1.3 Computer Bus

DAQ devices connect to a computer through a slot or port. The computer bus serves as the communication interface between the DAQ device and computer for passing instructions and measured data. DAQ devices are offered on the most common computer buses including USB, PCI, PCI Express, Ethernet and WiFi. A computer with programmable software controls the operation of the DAQ device and is used for processing, visualizing, and storing measurement data. A Driver Software provides the ability to interact with a DAQ device and an Application Software facilitates the interaction between the computer and the user for acquiring, analyzing and presenting measurement data.

3.3.2 DAQ Hardware

Data acquisition hardware acts as the interface between the computer and the outside world. It primarily functions as a device that digitizes incoming analog signals so that the computer can interpret them.

National Instruments offers several hardware platforms for data acquisition. The most readily available platform is the desktop computer. NI provides PCI DAQ boards that plug into any desktop computer. In addition, NI makes DAQ modules for PXI/CompactPCI, a more rugged modular computer platform specifically for measurement and automation applications. For distributed measurements, the NI Compact FieldPoint platform delivers modular I/O, embedded operation, and Ethernet communication. For portable or handheld measurements, National Instruments DAQ devices for USB and PCMCIA work with laptops or Windows Mobile PDAs. In addition, National Instruments has launched DAQ devices for PCI Express, the next-generation PC I/O bus, and for PXI Express, the high-performance PXI bus. (Source: www.ni.com)

3.3.3 Choosing DAQ Hardware

There are several parameters to consider before evaluating a Data Acquisition system or before choosing DAQ hardware for your measurement system. Some of the important aspects are discussed here in brief.

3.3.3.1 Type of Signal

DAQ device functions are broadly categorized into the following types

- Analog Input/Output
- Digital Input/Output
- Counter/ Timer

There are devices that are dedicated to just one of the functions listed above, as well as multi-function devices with a fixed number of channels for a single function, including analog inputs, analog outputs, digital inputs/outputs, or counters.

3.3.3.2 Sampling Rate

One of the most important specifications of a DAQ device is the sampling rate, which is the speed at which the DAQ device's ADC takes samples of a signal. Typical sampling rates are either hardware- or software-timed and are up to rates of 2 MS/s. The sampling rate for your application depends on the maximum frequency component of the signal that you are trying to measure or generate.

3.3.3.3 Resolution

The smallest detectable change in the signal determines the resolution that is required of your DAQ device. Resolution refers to the number of binary levels an ADC can use to represent a signal.

With the information provided in this chapter, it is possible to design or modify the Drilling Simulator built in LabVIEW and also to choose suitable hardware such as sensors, actuators and data acquisition systems to interface with the simulator.

4. MANAGED PRESSURE DRILLING AND MODELING

4.1 Managed Pressure Drilling

Managed Pressure Drilling (MPD) is a technique used in the Oil & Gas industry to drill wells with narrow pressure profiles. Although there is not a formal definition, MPD is defined by a subcommittee of the International Association of Drilling Contractors (IADC) 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. The intention of MPD is to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process.“

MPD is a general description of techniques used for well-bore pressure management. The purpose or advantages of MPD are multi-fold. MPD includes methods to improve performance by reducing non productive time (NPT) and thereby reducing costs, to improve safety in operations by limiting well kicks, lost circulation among various problems. Some of the important applications of MPD are listed below.

- Limiting total number of casing points
- Limiting NPT
- Avoiding or Limiting well kicks and lost circulation
- Increasing Rate of Penetration
- Reducing Equivalent Circulating Density

MPD is an adaptive process in that it proposes that the drilling plan is not only changeable but will change as the conditions in the well bore change. There are several techniques to implement MPD. Some of the basic techniques are:

- Constant bottom-hole pressure (CBHP) is the term generally used to describe actions taken to correct or reduce the effect of circulating friction loss or equivalent circulating density (ECD) in an effort to stay within the limits imposed by the pore pressure and fracture pressure.

- Pressurized mud-cap drilling (PMCD) refers to drilling without returns to the surface and with a full annular fluid column maintained above a formation that is taking injected fluid and drilled cuttings. The annular fluid column requires an impressed and observable surface pressure to balance the down-hole pressure. It is a technique to safely drill with total lost returns.

- Dual gradient (DG) is the general term for a number of different approaches to control the up-hole annular pressure by managing ECD in deep-water marine drilling.

The MPD process is particularly useful in drilling unconventional resources where the pore pressure and fracture pressure gradient window is narrow. Any significant variation, typically loss of annular friction pressure caused due to mud pump shut-down, in pressure causes the bottom-hole pressure (BHP) to go out of the pressure gradient window (or drilling window) resulting in situations like kick, lost circulation or other phenomena. It is not practically possible to balance the pressure variations with hydrostatic (mud) head. The paper by Gabaldon et al. [9] discusses more on how MPD enhances well control.

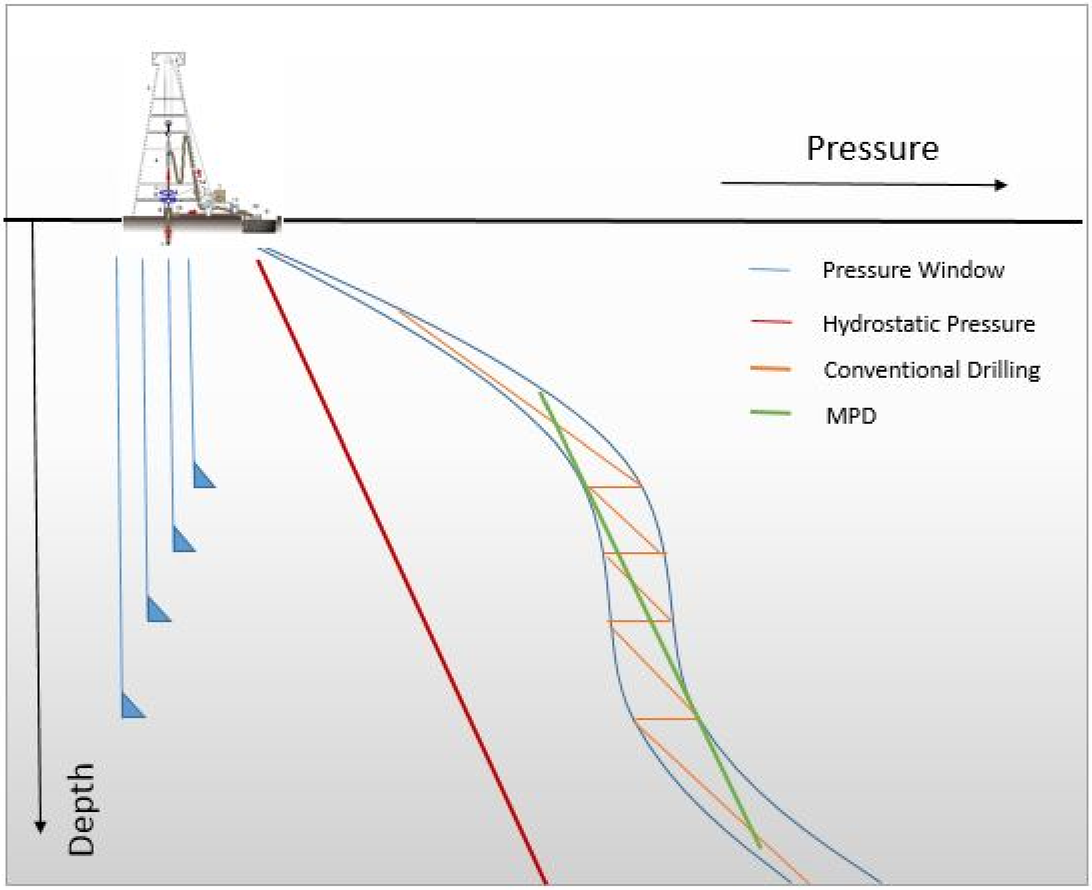

Figure 4.1: MPD using CBHP technique

Nygaard et al. (2008) [10] explains the techniques and advantages of MPD process in detail. Of the many different technologies and processes required to drill a well, none is more central to a successful drilling operation than those that control Bottom-Hole Pressure (BHP). We have used this constant BHP technique of MPD in our model. It is a process whereby the annular pressure is held constant within a pressure window at a specific depth. The pressure margin has an upper boundary limit defined by Fracture pressureand a lower boundary limit defined by Pore Pressure. Fig. 4.1 shows a comparison in BHP control between conventional drilling (BHP is shown in orange) and MPD (BHP is shown in green). The curved blue lines indicate the pressure window bounded by pore pressure on the left and fracture pressure on the right. Pore Pressure is the pressure of the fluid inside pore spaces. Fracture pressure is the pressure a formation can withstand before it fails or splits. Both pore pressure and fracture pressure are predicted or estimated using models or correlations developed by Eaton in his paper [11].

BHP Dynamic is the Bottom Hole Pressure when the mud is circulating in the well-bore or in other words, when the mud pump is ON. It is also referred to as the Equivalent Circulating Density (ECD) or Equivalent Mud Weight (EMW). BHP is governed by a fundamental pressure equation (in an open circulation system).

Unlike an open circulation system, in which the drilling fluid flows out of the well under atmospheric pressure, a closed circulation system seals off the wellhead and applies surface back pressure to the fluid in the annulus by restricting its flow through a choke manifold. The system is shown in the figure below.

In the closed circulation system, the fundamental equation is:

$$BHP = Hyd + AFP + BPP, \tag{4.1}$$

and when the rig pumps are OFF, there will not be any friction pressure (AFP = 0). But the term BPP (pressure from back pressure pump) is always present to compensate for any pressure losses during connections etc. In this way, the BHP can always be maintained constant. All MPD systems that provide constant BHP rely on a rotating control device (RCD) as the primary pressure seal. The annulus back pressure is managed using a choke manifold connected to the RCD. The CBHP process is modeled and the choke control is automated in this project. Fig. 4.2 shows

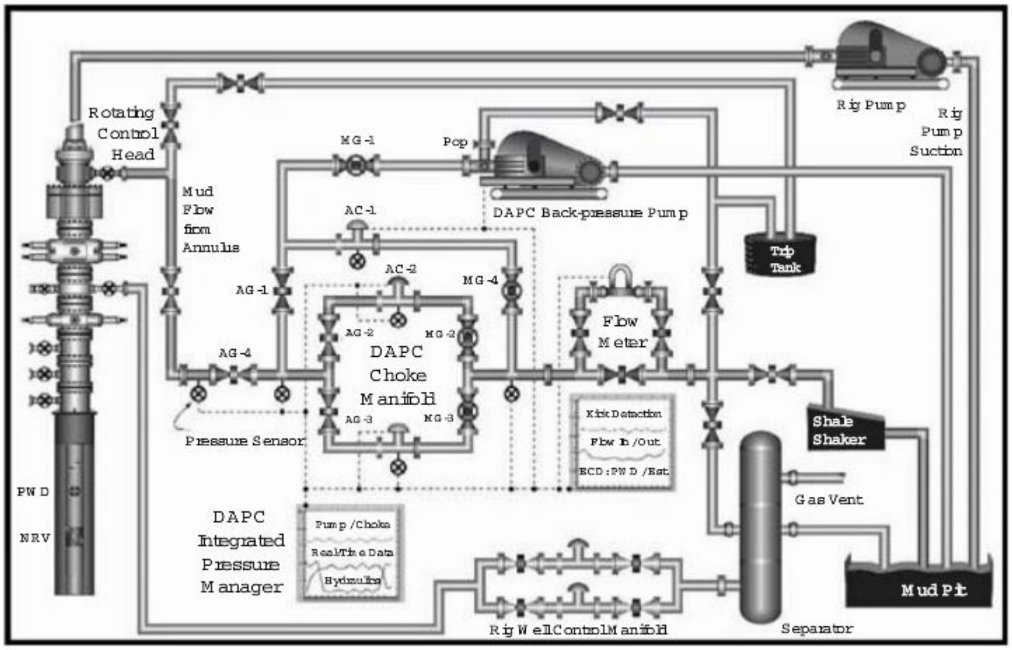

Figure 4.2: Closed circulation system (adapted from *Managed Pressure Drilling* by Bill Rehm et al.)

a schematic of the closed circulation system.

4.2 Mathematical Modeling

In theory, the ability to control a well is based on the geometric relationship between the BHA and the well-bore. Although the underlying calculations can be complex mathematically (Bourgoyne et al. 1986; Sawaryn and Thorogood 2005; Sawaryn and Tulceanu 2007; Sawaryn and Tulceanu 2009), the wellpath is actually quite predictable in a controlled environment. The MPD process is a closed loop mechanism as opposed to the open loop system in conventional drilling processes. A back pressure coupled with a choke manifold is used to compensate for the pressure variations in the wellbore. A simple math- ematical model is developed for the setup using mass balance in the annulus (Godhavn 2010).

To this end we write:

$$\frac{d(\rho V)}{dt} = \rho Q_{in} + \rho Q_{bp} - \rho Q_{out} \tag{4.2}$$

where Q_{in} indicates mud pump flow rate in to the drill pipe ; Q_{out} is mud flow rate out of the annulus ; Q_{bp} is flow rate due to the additional back pressure pump; ρ is mud density; V is annular volume

Assuming that changes in annular volume are negligible and the difference in density values along the borehole length are insignificant, we can derive the relation for the rate of change of density as:

$$\frac{d\rho}{dt} = \frac{\rho(Q_{in} + Q_{bp} - Q_{out})}{V} \tag{4.3}$$

By introducing compressibility factor, the density rate changes can be expressed in terms of pressure rate changes as follows:

$$\beta = \frac{1}{\rho}\frac{\partial P}{\partial \rho} \Rightarrow \frac{d\rho}{dt} = \beta\rho\frac{dP}{dt} \tag{4.4}$$

$$\frac{dP}{dt} = \frac{Q_{in} + Q_{bp} + Q_{out}}{\beta V} \tag{4.5}$$

The system can be modeled as a closed-loop system by compensating for the pressure losses with a back pressure pump through a choke manifold. The flow rate out of the choke and pressure are related with choke characteristics. The choke opening (position), z is the control variable of the system.

$$Q_{out} = C_v(z)\sqrt{\frac{P}{\rho}} \tag{4.6}$$

4.3 Control Design

Based on the model developed in the previous section, a controller is designed for the process to automatically control the MPD process. In this work, MPD process using Constant Bottom-Hole Pressure (CBHP) technique is used in modeling and simulations. There are several control methodologies available to implement pressure control mechanism in MPD.

- Reactive MPD: The drilling operation is performed in conventional way but add some level of MPD system exists on top to handle any surprises during drilling. This is the most common MPD strategy used in the industry. One application of such system is having a surface back pressure pump to adjust Equivalent Mud Weight (EMW) and enhance well control.
- Proactive MPD: The drilling program including drilling fluids and casing program is designed from the start with the goal of using all the advantages of MPD. This method offers more benefits than the reactive method.

In this work, we use the reactive MPD control methodology to control bottom-hole pressure. First we explore different control theories that can be implemented for this system. Then we design control system for the plant model developed in the previos section.

4.3.1 Proportional-Integral-Derivative (PID) Controller

Despite many advancements in control theory, PID controllers are the most used controllers in the industry. In practice PI controllers are more common because the derivative action is sensitive to measurement noise. The reasons for the wide spread use is because of its low complexity, low maintenance requirements and well established tuning methods. The basic idea of PID is a simple feedback mechanism comparing the system output with set points and minimize the error using three control parameters. The structure of PID control is shown in Fig. 4.3. The main idea of the three terms in PID controller are discussed below.

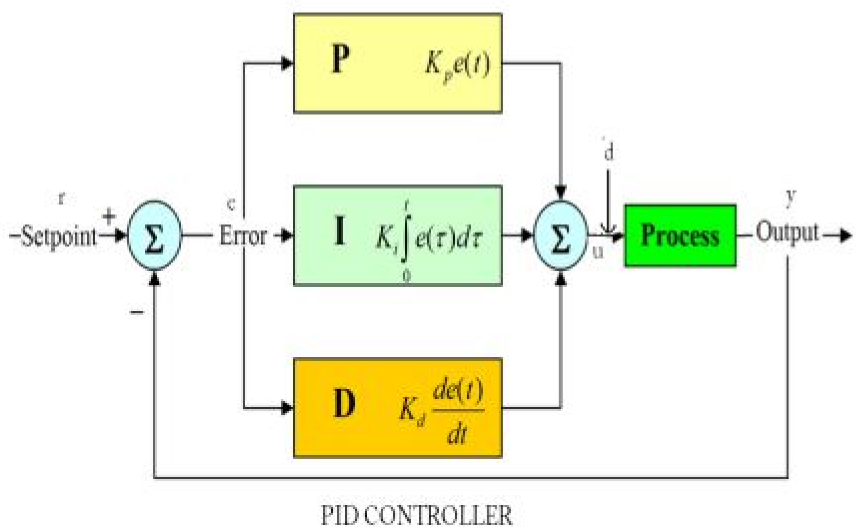

Figure 4.3: PID control system structure (Source: www.codeproject.com)

- P element: proportional to the error at the instant - reaction to the "current error" letting the control effect take place as fast as possible and drive the error to the direction of minimization. Changing this term will affect the steady state error and the dynamic performance.

- I element: proportional to the integral of the error up to the instant, which can be interpreted as the accumulation of the past error. This term minimizes the steady state error and accelerates the movement of the process reaching the reference value. Change this term will affect the steady state error and system stability.

- D element: proportional to the derivative of the error at the instant, which can be interpreted as the prediction of the future error. This term improves the system stability and the speed of dynamic reaction.

Tuning of PID parameters can be done intuitively by adjusting the parameters. A summary of the effect of parameters on the plant response is shown in Table 4.1 to assist in tuning process. A more conventional procedure called Zeigler-Nicholas (ZN) method is also available for tuning PID parameters.

Table 4.1: PID tuning criteria

Parameter Increase	**Rise time**	**Overshoot**	**Settling time**	**SS Error**
Kp	Decreases	Increases	Small Change	Decreases
Ki	Decreases	Increases	Increases	Decreases
Kd	Small Change	Decreases	Decreases	Small Change

4.3.2 Model Predictive Controller (MPC)

In this method, the plant model is first used to predict future responses (trajectory over a period of time) based on the future inputs and initial values. The control inputs and future errors between predicted and reference trajectories are sent in to an optimizer function to minize the errors. A basic structure of the MPC scheme is shown below.

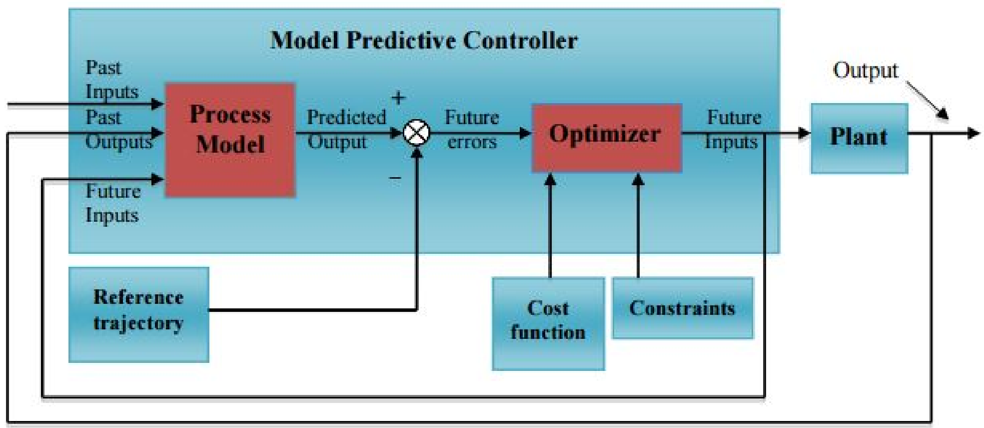

Figure 4.4: MPC control system structure

Overall performance of MPC is better than PID. Because the MPC system predicts the state of the plant in operation, it has better control during dynamic changes, whereas the PID controller needs to be retuned online whenever the plant dynamics change.

4.3.3 Other Advanced Controllers

There are other controller options to implement MPD like Model Reference Adaptive Control (MRAC). As the name suggests, a reference model is chosen to generate a desired trajectory and tracking error is computed. This mechanism uses two feedback loops whose parameters are changed based on the tracking error. More information on the controller and its implementation to MPD can be found in the thesis work of Pedersen [12].

Another latest controller being developed for MPD is L1 adaptive control. It is a modification of MRAC in that it incorporates a low-pass filter in the feedback loop. Implementation of L1 adaptive control to MPD was not studied and out of scope of this work. Information on the control scheme can be found in the paper by Cao [13].

Each type of controller has its own advantages and limitations. For the purpose of simulation in this work, PID controller has been used owing to its low complexity and readily available tuning methods. The simulations are carried out in a software 'LabVIEW'. The simulator has an auto tuning feature that calculates the PID gains for the plant model. The design of Simulator is explained in detail in my paper [14] presented at the International Federation of Automatic Control.

4.3.4 Control System

A PID controller (control variable z) has been used in this model to control the choke pressure and track the set bottom-hole pressures (reference variable).

$$z = Ke + \frac{K}{T_i}\int e.dt + KT_d\frac{de}{dt} \tag{4.7}$$

The non-linearities in the system can be compensated by linearizing the model using nominal values (denoted by '0') and with careful tuning of the PID controller, it can be represented as a first order system.

$$P_0 = \rho_0 \left(\frac{Q_{out0}}{C_v(z_0)} \right)^2 \tag{4.8}$$

$$\Delta P = \frac{a\Delta z + c\Delta q}{1 + T_p s} \tag{4.9}$$

$$a = \frac{\partial P}{\partial z}|_0; c = \frac{\partial P}{\partial Q_{out}}|_0; T_p = \frac{-1}{\frac{\partial \dot{P}}{\partial P}}|_0$$

The values of the unknowns can be found from field data. The work by Godhavn (2010) [15] has detailed description of the model. This control system for automatic MPD was successfully implemented at the Kvitebjorn field in the North Sea.

To provide real-time measurements of bottom-hole pressure for the feedback system in the simulation, the BHP is calculated as a sum of all the annular pressures including hydrostatic pressure (due to mud column), annular friction pressure losses (due to circulation), surge, swab pressures as well as any surface pressures. API Power Law model has been used to model the friction pressure losses. [1]

$$BHP = Hyd + AFP + BPP$$

$$AFP = \Delta P_{DP} + \Delta P_{DC} + \Delta P_{Nozzle}$$

[1] Other pressure losses are neglected.

$$+\Delta P_{DC-Ann} + \Delta P_{DP-Ann}$$

$$+\Delta P_{surge} + \Delta P_{swab}$$

where *BHP* is Bottom-Hole Pressure; *Hyd* is Hydrostatic pressure due to mud column; *BPP* is Pressure due to back pressure pump; *AFP* is Annular Friction Pressure losses which results from friction in drill pipe (DP), drill collars (DC), Annulus (Ann) and Nozzles, because of drilling fluid circulation.

4.4 Drilling Simulator

A Drilling Simulator has been designed in LabVIEW to serve as a basic simulation environment for testing and implementing control algorithms for drillign automation. The performance of the model and the designed control system can be studied from the simulation results. A PID controller is designed and simulated for MPD operations in the drilling simulator. Other control methodologies like MPC (Breyholtz, Nygaard, Nikolaou, 2011) can also be modeled and implemented in the simulator. The model is a simplistic one with several limitations. The model is based on the assumption that bottom-hole pressure reading is available in real-time. For simulation purposes, we assume an ideal model such that the bottom-hole pressure reading is available in real-time. This imposes some limitations that can be easily fixed in real scenarios. The structure of the simulator is described below.

4.4.1 Front Panel

This is the face of the (virtual) instrument. The front panel of the drilling simulator is a user-friendly GUI that depicts the control room at the drilling rig site. The user has the option to select the type of formation to be drilled. The user has to input various drilling parameters being used in the drilling operation such as drill pipe dimensions, drill collar dimensions and bit nozzle sizes (these are used to calculate annular friction pressure losses). In addition, the user has to input control parameters viz. plant model variables calculated based on the field data. Once all the inputs are given as shown in Fig. 4.5, the simulation can be started. The drilling operation can be started by lowering the pipe either by increasing depth manually, using a slider or by using a joystick to control the movement of drill pipe. As the simulation is running, the user has control over parameters like mud pump operation - ON/OFF, mud flow rate and mud weight that causes variations in the BHP. There are display options for pressure gauges, choke position monitor, BHP variation chart window and any other information needed by the operator. There are also options for manual control of equipment that are automated in the simulator viz. choke opening or set point of BHP. (The simulator runs by default in automatic mode).

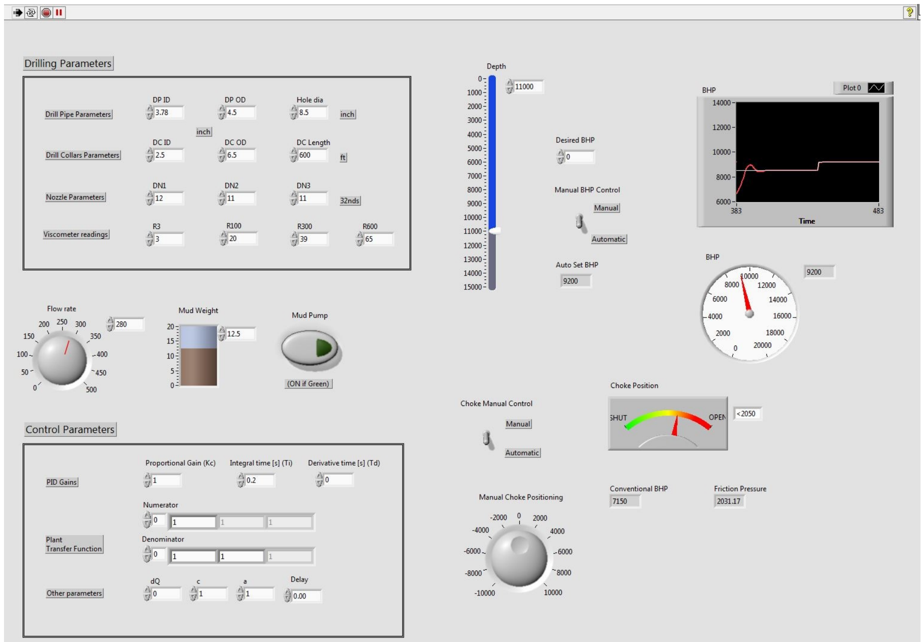

Figure 4.5: Front panel of the simulator

4.4.2 Block Diagram

This part of the simulator runs in the background, which is where the actual programming is done. LabVIEW has an exclusive toolkit for design of control systems called "Control Design & Simulation" Tookit. The drilling simulator was developed using many of the built-in functions of the toolkit. The main part of the program is built inside the Simulation loop function. Some important functions used are PID Controller, PID Autotuning, Construct Transfer Function, Simulation Timing and Feedback node among others as shown in Fig. 4.6. These functions were used in the program to track reference bottom-hole pressures at various depths. These reference points are set using a lookup table function. Data acquisition functions are used to read values from joystick. Graphics functions like 3-D picture control were used to display 3-D animations of the formation and drill pipe as the process of drilling in the formation was carried out.

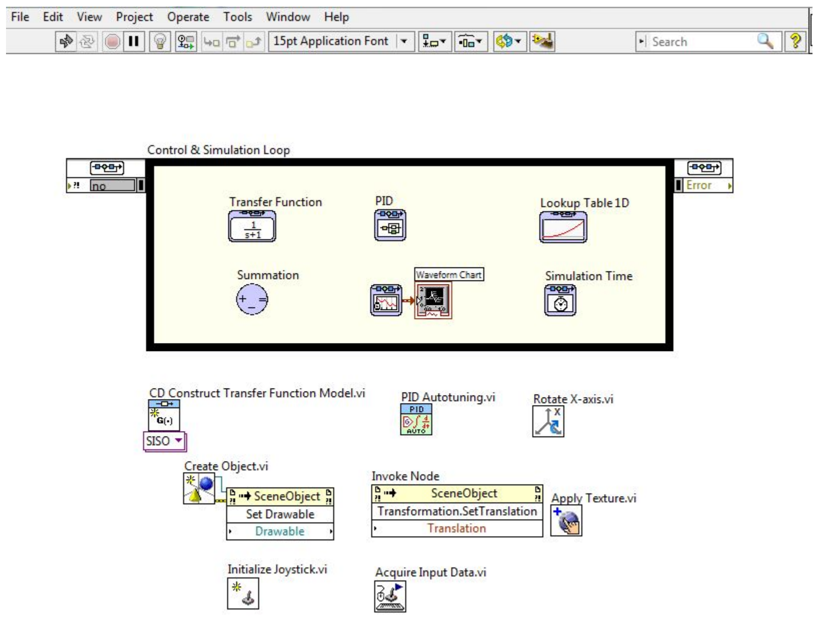

Figure 4.6: Functional blocks of block diagram

4.4.3 Highlights

Remote Control - The drilling simulator can be accessed by other users from any other location over internet. LabVIEW has different tools to accomplish this. In realworld application, the drilling program can be hosted by a driller at the drill rig site and the program can be shared with other users (can be supervisor at office, contractors and others). The users have the provision to monitor the drilling activity as well as control the drilling operations from their locations through a web browser. We have used a simple web publishing tool in LabVIEW to share the drilling simulator with other users. This application is useful in situations where frequent access to the rig site is not possible.

3-D Graphics - The drilling activity can be seen as a 3-D animation (with 360 degree camera control) on front panel in real-time as the simulation is running. The movement of the drill-pipe (including rotation) and the formation being drilled are shown in the animation. Other equipment like mud pump, back pressure pump, choke manifold can be included in the animation further.

Manual Override - It is important to have manual override controls for all the operations that are automated. This is to have a better control in case unpredictable incidents occur. In the drilling simulator, there are manual controls for choke operation and setting bottom-hole pressure.

Realistic simulation - To provide a feel of the real-world drilling operation, control of the movement of drill pipe (up and down the borehole) is done using a joystick (Windows Xbox 360 controller in this case). The joystick is treated as an input device and data is acquired in to the program. Other parameters that can be controlled using the joystick are mud pump ON/OFF operation, manual over-ride toggle switches etc. as shown in Fig. 4.7. A vibration feedback can also be included in the program to indicate when the drill pipe is on-bottom for example.

Figure 4.7: Drilling Simulator operated using joystick

4.4.4 Experiment Results

The Drilling Simulator developed in LabVIEW was tested on synthetic field data. Plant parameters are chosen arbirtarily. There is provision to manually adjust PID gains. However, a LabVIEW built-in function 'PID Auto-tuning' can be incorporated instead. With this setup, the simulation is run over a depth of 0 - 14,000 ft. Several test cases as mentioned below are applied to test proper functioning of automatic MPD operation in the simulator.

The objective of the control system is to track the set pressure values such that bottom-hole pressure is maintained constant in any case. As shown in Fig. 5, the required BHP represented by white line is efficiently tracked (red line represents measured BHP) by the controller. At around 525 seconds (not real time) mud pump is switched OFF which led to a drop in BHP as there is no annular friction pressure now. It can be seen from the figure that the required BHP is achieved, after transients at around 550 seconds. The set-point tracking can also be seen when the reference BHP value is increased at 375 seconds.

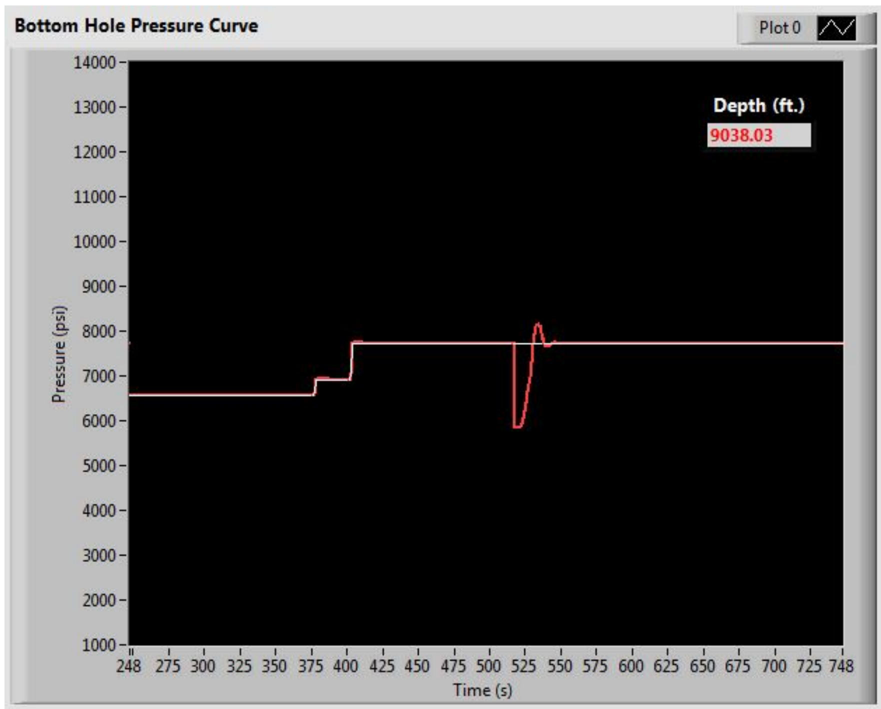

Figure 4.8: Set-point tracking of BHP

The well profile is not described exclusively here because the example is very general and the simulator allows the user to change the well model seamlessly to explore any other formulations. The novelty here is that the simulator can be used as a platform for implementing any kind of control technique.

5. DESIGN AND CONSTRUCTION OF AUTOMATED MODEL DRILLING RIG

A completely autonomous miniature drilling rig is designed and constructed with objectives of improved performance and better safety system. The Drilling Simulator is interfaced to the physical rig and then mathematical models and control systems developed for drilling operations are tested on the rig.

The rig is constructed subject to a few design constraints and simulated operational dysfunctions. The constraints include 1) Maximum Weight-on-Bit (50 lbf) that can be applied 2) Total amount of power available for the entire system (2.5 hp). The automated drilling rig can be tested to drill approximately 2-ft x 2-ft x 2-ft concrete block with various strata. Operational dysfunctions like vibrations encountered down-hole are simulated by using an extremely thin drill pipe of 0.016" wall to drill the well. A model of the rig developed in Solidworks can be seen in Fig. 5.1. The real rig which was built and used in this research is shown in Fig. 5.2.

By optimizing the drilling efficiency in this controlled environment, we believe that what we learn in this research could possibly be applicable in the real drilling operation. The goal is to enable the drilling process to be more productive by managing various risks while keeping a safe operational practice in place. The focus of the project is on maximizing Rate of Penetration (ROP) thereby optimizing performance. The concept of Mechanical Specific Energy (MSE) is used to develop a control algorithm for designing automatic control systems. The types of dysfunctions encountered down-hole are discussed in detail in the following sections. Each dysfunction can be corrected with a particular response specific to the dysfunction. The corrective actions are also discussed. The control algorithm is developed in LabVIEW incorporating these dysfunctions and corresponding corrective actions.

This chapter is organized as follows. We start by discussing Rig construction supported by engineering drawings followed by sensor design and Instrumentation. The actual test results are shown and discussed in a separate chapter. Design and Construction of the rig is divided into three segments - Mechanical system, Electrical System and Instrumentation. Each of the segments is explained in detail in this section. A 3D model of the drilling rig mechanical structure developed in SolidWorks is shown below.

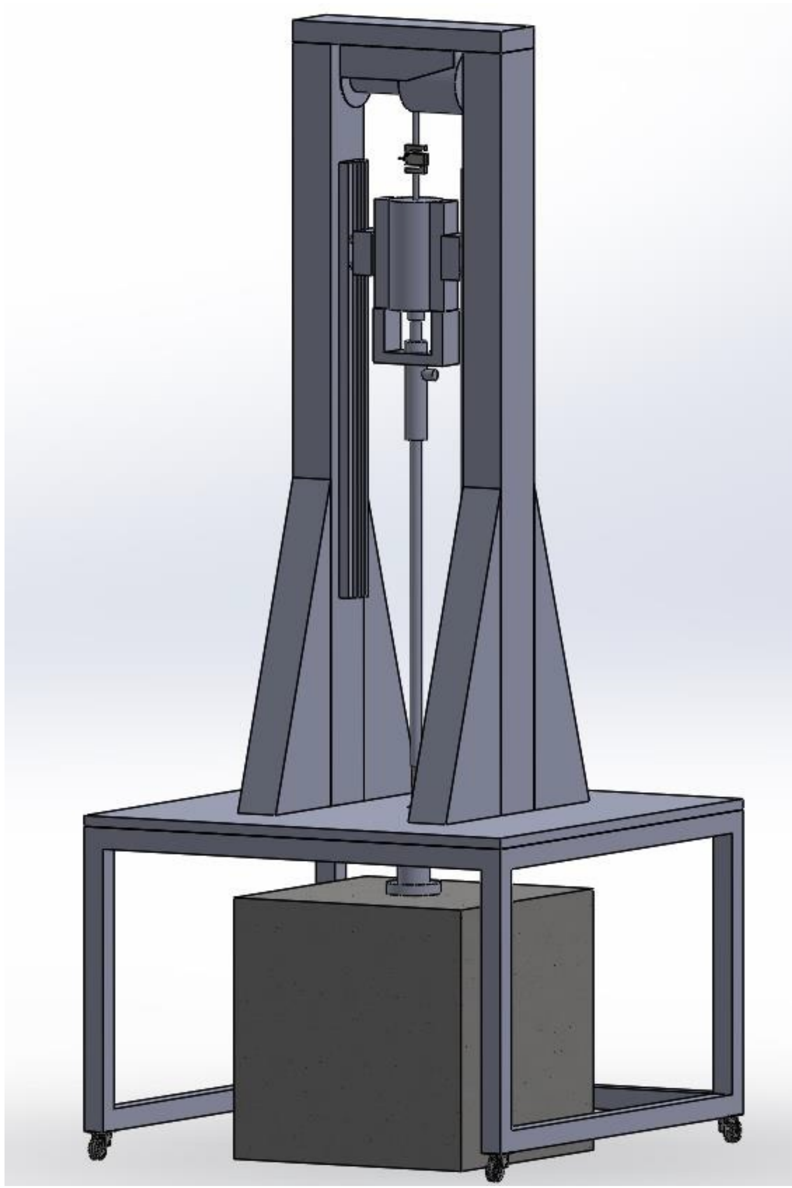

Figure 5.1: SolidWorks model of rig structure (not to scale)

Figure 5.2: Miniature autonomous model drilling rig

5.1 Mechanical System

Selection of drilling rig depends mainly on the drilling environment, power required, economic, and mobility (Bourgoyne et al. 1986). The intended model rig for this project has to drill through approximately 2-ft x 2-ft x 2-ft concrete block with maximum WOB of 50-lbs and with rig mobility in consideration. Conventional rotary drilling technique has been used as opposed to percussion drilling as it provides better control minimizing dysfunctions. Although Kelly bushing system would provide extra stabilization for the drill string, top drive mechanism has been used for our system as the WOB can be controlled more accurately and precisely this way. A bell nipple has been used on the rig floor to compensate for the stabilization. The important subsystems of the rig are discussed below.

5.1.1 Hoisting System

The hoisting system serves many functions in the drilling operation. It includes derrick, drawworks, Top drive and drilling line. The main function is to raise and lower the drill strings to make connections and various trips. Steel support pipes and I-beam mounted on the rig floor serve as the derrick. Top drive runs along guide rails on the derrick which acts as elevator system. The guide rails are also equipped with a braking system to hold the top drive when it is not in use. WOB is supplied by weight of top drive unit. Weight blocks can be placed on the motor if additional weight is required.

5.1.2 Mobilization

Mobility of rig is important, this includes moving the rig to the drill site, rig up, rig down, and changing necessary mechanical parts with ease in an economical manner. Especially in some regions, mobility of the rig is critical as many wells are drilled in the same field in very short period of time. The drilling rig for this project was fabricated with a portable land drilling rig, i.e. flex rig, as a model. The rig floor is supported by four height adjustable steel pipes with casters. The rig also has detachable derrick which improves mobility.

5.1.3 Circulation System

An effective drilling fluid circulation system is needed for well stability, to remove rock cuttings, lubricate and cool the drill bit. The system includes mud pumps, various mud-mixing equipment, mud pits, shale shakers, etc. In our model, a closed loop circulation system using a small water pump and filter has been used. A swivel is placed between top drive and drill pipe to pump drilling fluid down-hole without leak. Blow-Out-Preventer (BOP) stack was not used in the rig system. A bell nipple (with rubber gasket on the bottom, a flange welded on top and a flow outline) was used to allow sufficient transportation of cuttings through the annular space.

5.2 Electrical System

There is a limitation on the maximum power that can be drawn from the grid which is 2.5 HP. It should be able to power the top drive motor, water pump, draw works motor and data acquisition systems simultaneously.

5.2.1 Top Drive

Top drive system is a crucial component of the rig. The top drive motor provides drill string rotation to carry out drilling operation. This motor is hinged to the carriage, placed on the guide rail and it moves down with the drill pipe when drilling. A power rating of 2 HP was chosen to leave enough margin for the water pump and draw works motor to work. DC machines have a good advantage over AC machines when the application requires wide speed and load variation. A Brushless DC (BLDC) motor along with the speed encoder and variable voltage and variable frequency source would be ideal for this application, however a brushed motor is also a viable option.

5.2.2 Draw Works Motor

This motor (gear motor) is used to maintain the desired WOB the bit and for pulling out the top drive after drilling. The motor typically runs at very low rpm and requires a gear system to maintain proper speed control. This machine is placed on the rig platform and is hinged to the top drive motor through a pulley system.

5.2.3 Water Pump

Water pump has been used for circulation in to drill pipe and out of annulus cleaning rock cuttings and also cooling down the bit. The swivel and bell nipple system ensures that drilling mud is circulated in the system without any leakage and maintaining sufficient pressure.

5.3 Instrumentation

A control system model was designed to optimize performance. To implement the control system in actual application, data has to be transferred from plant to control system and vice-versa. Measurements made at plant using sensors are given as input to the control system that is in computer. Outputs based on the control algorithm are given to the plant using actuators. An interface is required for communication and data transmission between the plant (hardware) and control system (software). These three topics - Sensors, Actuators and Data Acquisition are addressed in this section.

5.3.1 Sensors

There are some key parameters to be measured in real-time to ensure proper functioning of the optimization program. The parameters and corresponding sensors to measure the parameters are discussed below.

5.3.1.1 Weight-On-Bit (WOB)

This is an indirect measurement. WOB was calculated by having a hanging S-beam load cell ahown in Fig. 5.3 measure tension in the drill line of hoisting system and relate it to the weight applied on the bit. A double pulley system was used to hoist top drive. Corresponding tension to weight conversions are done in the program.

Sensor Type: S-beam load cell

Name of the Sensor used: FUTEK Make, Model: LSB300, Item: FSH00962

Specification: 200 lb Tension & Compression Load cell

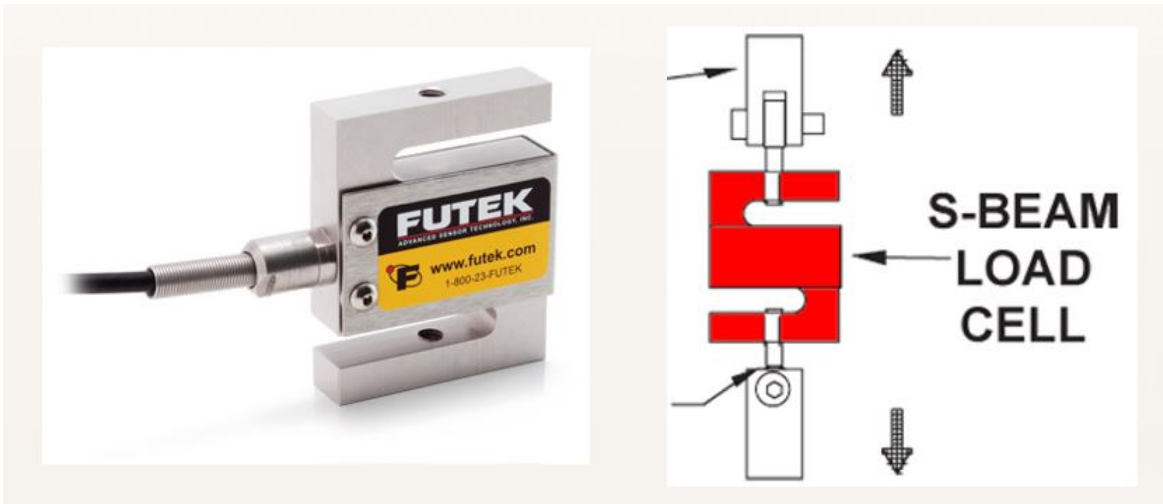

Figure 5.3: S-beam load cell to measure WOB (Source: www.futek.com)

5.3.1.2 Rotational Speed (RPM)

We have built an optical tachometer as shown in Fig. 5.4, using infrared (IR) sensing technology to measure rotational speed of the top drive motor.

Sensor Type: Reflective Optical IR Sensor

Name of the Sensor used: TCRT5000L TCRT5000

Specification: Transistor Output Infrared 950mm 5V 3A

Figure 5.4: Optical tachometer to measure RPM

5.3.1.3 Torque

Torque is measured indirectly using Power equation, P = V*i = T*w. The Variable Frequency Drive (VFD) gives voltage output and by measuring the current drawn by it, torque can be calculated. Power losses in gearbox and couplings are assumed negligible. Proper calibration ensures accurate measurements.

Sensor Type: Current measuring Sensor (See Fig. 5.5)

Name of the Sensor used: Current Sensor Module; Model : ACS712

Specification: 66 to 185 mV/A output sensitivity

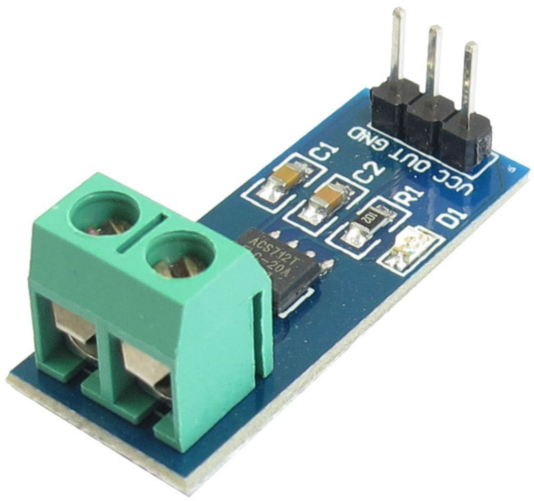

Figure 5.5: Current sensor to calculate torque

5.3.1.4 Rate Of Penetration (ROP)

ROP is calculated by measuring the total vertical depth (TVD) drilled and dividing the value by the total time taken to drill the depth. TVD is measured using a optical laser sensor shown in Fig. 5.6 mounted on top of the rig.

Sensor Type: Distance measuring Laser Sensor

Name of the Sensor used: Wenglor make; Model : OPT2011

Specification: DC 50- 3050mm RNG 4-20mA OR 0-10VDC; 1 mm accuracy

Figure 5.6: Laser sensor to calculate ROP (Source: www.automationdirect.com)

5.3.1.5 Vibration

Vibrations in the drill pipe are the performance limiters of ROP and hence a key parameter in the optimization algorithm. A triaxial accelerometer was used to measure vibrations in X, Y, Z directions. Measuring vibrations in three directions helps in identifying the type of dysfunction occuring down-hole.

Sensor Type: Triaxial MEMS accelerometer

Name of the Sensor used: GY 521 MPU6050 (See Fig. 5.7)

Specification: +/- 8g range

Figure 5.7: Accelerometer chip to calculate vibrations

5.3.1.6 Temperature

Temperature measurements are made on the equipment such as top drive, draw-works motor, hardware interfaces and others to ensure that the equipment are not overloaded. High temperature indicates overload and alarms/ warnings are generated based on the algorithm. A simple RTD is sufficient for our system.

5.3.2 Actuators

5.3.2.1 RPM Control

One of the outputs of the control system is motor speed or RPM. Based on the control algorithm, a value of RPM is generated in real-time and the drill pipe is required to operate at the set RPM. A Variable Frequency Drive (VFD) shown in Fig. 5.8 solves this purpose. We have selected Omega DC series motor which can receive analog inputs for our operation.

5.3.2.2 WOB Control

The second parameter of the control algorithm is weight-on-bit. It can be controlled by sending analog voltage signals to the draw-works motor. A simple PID loop ensures that the WOB is brought to the reference set-point.

Figure 5.8: DC drives to control motors (Source:www.omega.com)

5.3.3 Data Acquisition

The next important part of the control system is the Data Acquisition hardware. DAQ devices as shown in Fig. 5.9 serve as an interface between hardware that is sensors and actuators and software that is LabVIEW run on a PC.

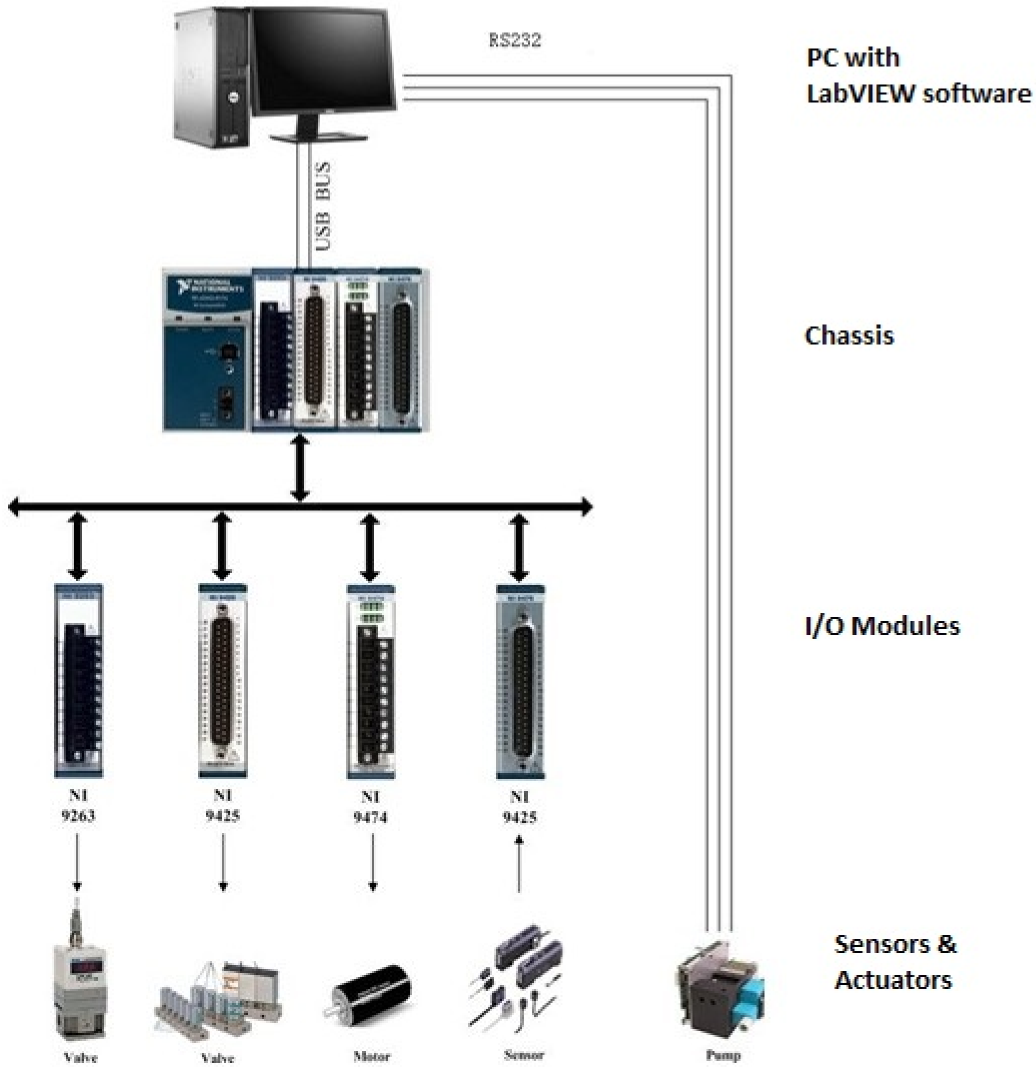

Figure 5.9: Data acquisition components (Source:www.ni.com)

A compactDAQ system was developed for this project. A complete CompactDAQ system requires both a chassis and NI C Series modules. The sensor or signal is conditioned and digitized within the module, and the chassis controls the timing and data throughput for the whole system. The system timing controller is located in the CompactDAQ chassis, which enables the synchronization of all modules installed in a single chassis.

We have used NI cDAQ-9174 shown in Fig. 5.10 as the chassis for this application. The cDAQ-9174 is a 4-slot CompactDAQ USB chassis designed for small, portable, mixed-measurement test systems. It can be combined with up to four NI C Series I/O modules for a custom analog input, analog output, digital I/O, and counter/timer measurement system.

Figure 5.10: National Instruments CompactDAQ 9174 chassis (Source: www.ni.com)

We have used three modules with the chassis for I/O purpose viz. NI 9219, NI 9263, NI 9205, NI 9401.

The NI 9219 shown in Fig. 5.11, is a 4-channel universal C Series module designed to measure several signals from sensors such as strain gauges, resistance temperature detectors (RTDs), thermocouples, load cells, and other powered sensors. The channels are individually selectable, so you can perform a different measurement type on each of the four channels. We used NI 9219 to acquire signals from S-beam load cell, temperature, voltage and current values. The National Instruments 9205 is a C Series module, for use with NI CompactDAQ and CompactRIO chassis.

The NI 9205 features 32 single-ended or 16 differential analog inputs, 16-bit resolution, and a maximum sampling rate of 250 kS/s. Each channel has programmable input ranges up to 10 V. We used NI 9205 to acquire data from tri-axial accelerometer.

The NI 9401 is an 8-channel, 100 ns bidirectional digital input module for any NI CompactDAQ or CompactRIO chassis. You can configure the direction of the digital lines on the NI 9401 for input or output by nibble (4 bits). Thus, you can program the NI 9401 for three configurations: eight digital inputs, eight digital outputs, or four digital inputs and four digital outputs. NI 9401 was used to acquire data from IR sensor to measure pulses.

The NI 9263 shown in Fig. 5.12, is a 4-channel, 100 kS/s simultaneously updating analog output module for any NI CompactDAQ or CompactRIO chassis. It also features 30 V overvoltage protection, short-circuit protection, low crosstalk, fast slew rate, high relative accuracy, and NIST-traceable calibration. The NI 9263 module includes a channel-to-earth ground double isolation barrier for safety and noise immunity. This module was used to control DC drives, for manual override of potentiometers, to operate Emergency Shutdown Control (ESD) etc.

Figure 5.11: NI Universal analog input module (Source: www.ni.com)

Figure 5.12: NI analog output module (Source: www.ni.com)

6. OPTIMIZATION OF ROP USING MSE

6.1 Dysfunctions

Drilling Automation is the ‘control‘ of drilling processes by computer instead of humans. Therefore designing control system for the processes is key in automation. For automatic control of the rig, several control systems have been designed in this application. The most important one is the control system for ROP optimization.

Rate of Penetration (ROP) depends on several factors such as Weight on Bit (WOB) which creates rock indentation higher WOB implies deeper indentation, Motor rotations per minute (RPM) which creates cutting length on the rock higher RPM implies more sliding distance, bit aggressiveness and rock strength among other non-linear effects. For a given bit type and a given formation, ROP can be optimized using WOB and RPM. The dependency of ROP on drilling parameters is shown in Fig 6.1.

The algorithm is developed based on the concept of Mechanical Specific Energy (MSE). The Mechanical Specific Energy (MSE) concept has been widely used to quantify the efficiency of the energy used to remove the volume of rocks in drilling operation. This concept was first suggested in 1965 by Teale [16] in The Concept of Specific Energy in Rock Drilling. However, it did not get much attention as it should in the academic research until ExxonMobil implemented MSE surveillance throughout the company worldwide in the early 2000. Since then, there has been several laboratory scale drilling experiments and industry application based on the MSE concept, and many successful cases has been reported. The concept of MSE

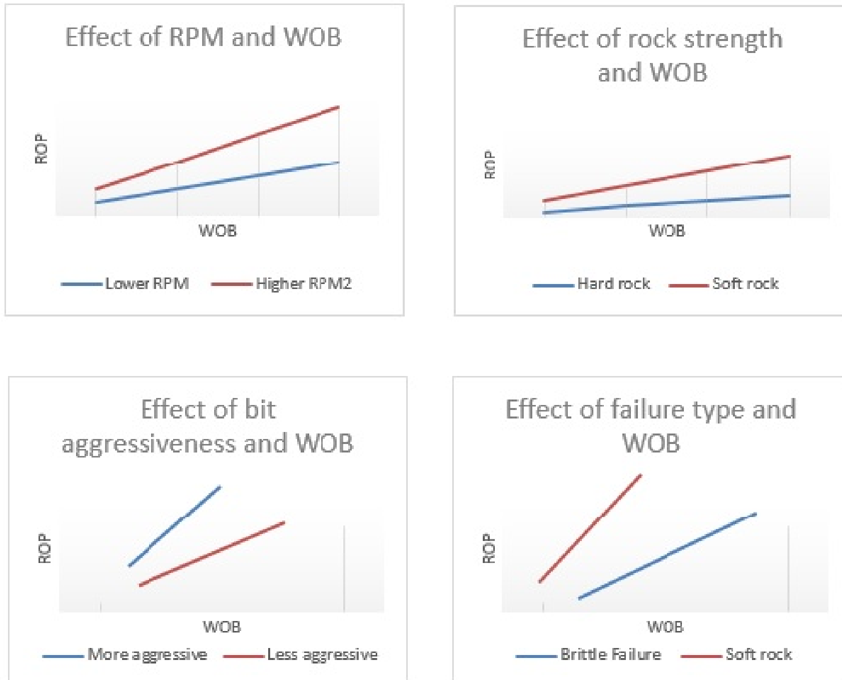

Figure 6.1: Dependency of ROP on various parameters

has been used in the work by Noynaert as shown in his paper [17]. MSE can be mathematically expressed with total energy input and total rock volume removed as shown in Eq. 6.1.

$$MSE = \frac{TotalEnergyInput}{TotalRockVolumeRemoved} \tag{6.1}$$

According to Teale, there is a distinctive correlation between the MSE and the strength of the rock. Not only that there is a positive correlation, but the MSE should equal to the rock strength if the drilling system is hundred percent efficient in just cutting the rock volume. Expanding the above equation, the MSE equation becomes

$$MSE = \frac{(EnergyInputfromVertical) + EnergyInputfromRotation}{RockVolumeRemoved} \quad (6.2)$$

Eq. 6.2 can be expanded with WOB, RPM, Torque, ROP, and bit-diameter as shown below,

$$MSE = \frac{(4 \times WOB)}{BitDia^2 \times \pi} + \frac{(480 \times Torque \times RPM}{BitDia^2 \times ROP} \quad (6.3)$$

Where:

MSE = Mechanical Specific Energy, psi.

WOB = Weight-On-Bit, lbs.

Bit Dia = Bit Diameter, inches.

Torque = Torque from rotation, ft-lbs.

RPM = Rotation per Minute

ROP = Rate of Penetration, ft/hr

The importance of the MSE concept does not only lay in its physical meaning but the application of the surveillance program to optimize rock cutting efficiency. Simply put, ROP can be optimized by minimizing the MSE, which can be accomplished by varying the drilling parameters in real time through the surveillance program or having a modification to the existing engineering design to remove limiting factors prohibiting lower MSE realization.

The control algorithm is based on the above formula. Using the parameters WOB & RPM, the system is designed to minimize MSE and thus improve ROP. The parameters are adjusted as long as the MSE value decreases or remains constant. The rate of penetration (ROP) should increase proportionately to increase in WOB and RPM. If the increase is not proportionate, it is an indication that bit is performing inefficiently and that a dysfunction is present in the system.

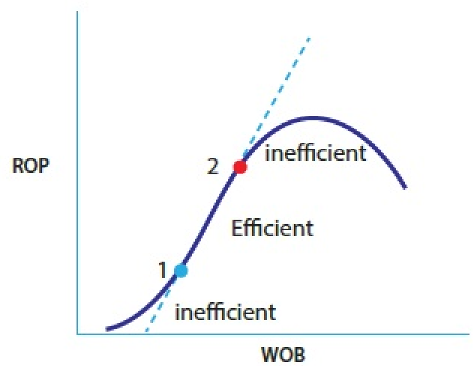

Figure 6.2: The bit is considered performing efficiently if ROP increase is proportionate to WOB

Beyond Point 2 (called founders point) in Fig. 6.2, the bit is considered performing inefficiently. In our application, we have the control algorithm, based on the surveillance program, to automatically change variables to minimize the MSE in real time by eliminating possible dysfunctions. There are several types of dysfunctions that can occur down-hole, to the drill-string or to the drill-bit namely

1. Bit balling
2. Bottom-hole balling
3. Interfacial severity

4. Whirl (Lateral Vibrations)
5. Stick-slip (Torsional Vibrations)
6. Axial Vibrations

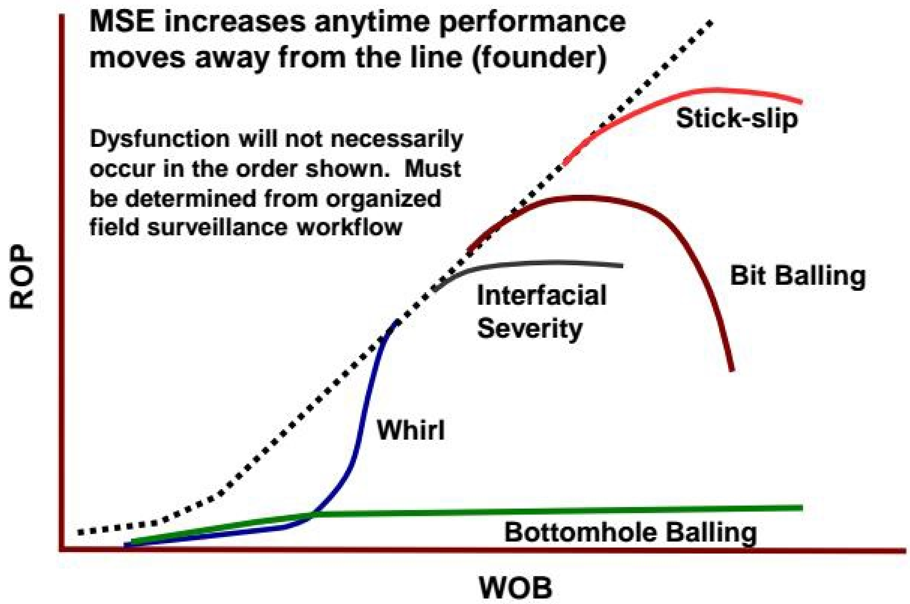

Figure 6.3: The most common dysfunctions encountered and the response of ROP to drilling parameters like WOB is shown here.

The type of dysfunction can be diagnosed using MSE as shown in Fig. 6.3 and corrective action corresponding to the dysfunction can be taken to optimize performance. Each of the dysfunctions is briefly explained below. For the miniature drilling system we are designing, some of the dysfunctions may not be significant and can be ignored in the control algorithm at this point of time. The applicability of the dysfunction to our current application is also described below.

6.1.1 *Bit Balling*

It is the accumulation of material on the face of the cutting structure that interferes with Depth Of Cut (DOC) when weight is applied. The material carries a portion of the WOB so that the load on the cutter tips is reduce so DOC is reduced. As material is compacted it builds compressive strength and is able to carry some of the bit load, which reduced DOC. Balling then occurs in degrees and effects ROP in degrees. MSE tells us the severity of the effect on DOC, torque and ROP. It should be noted that Balling is not simply material stuck to the bit. It must be material on the cutter itself that is strong enough to interfere with depth of cut.

Response: Increase pump (flow) rate to use all horsepower. Reduce WOB to below founders point to reduce DOC and cut a thinner ribbon to mitigate balling. This results in loss of ROP which can be compensated by increasing RPM.

Applicability: Balling is common and is observed under high hydrostatic heads. Given the size of rock sample (2 ft. TVD) and BHA (1.125 inch dia PDC drill bit), the chances of bit balling are less and is ignored in the performance optimization algorithm. Even if there was a situation of bit balling, since the maximum WOB is just 50 lbs which is assumed to be under founder, the weight on bit is not reduced and RPM is increased.

6.1.2 *Bottom-hole Balling*

This usually occurs when the hydrostatic head is very high and in deep impermeable rock (shale). Bottom-hole balling is observed when the rock cuttings accumulate and form a layer at the bottom. BHB results in a very high MSE value and ROP becomes unresponsive to WOB.

Response: Since ROP is unresponsive to WOB, all that can be done is to maximize hydraulics (Increase flow rate) and increase motor RPM.

Applicability: It is almost impossible to have bottom-hole balling in our application because the hydrostatic head cannot be large for a 2 ft. deep hole. Also, it is more common with insert bits.

6.1.3 Interfacial Severity

When a hard material is encountered in the formation, bit force is concentrated on the bit cutter in contact with the hard material causing bit damage. In uniform rock, the load per area on the cutter face equals the rock compressive strength. But if a formation includes very high strength material, high point loading occurs at the contact points with the cutter.

Response: Reduce WOB to limit bit damage. Operate at moderate RPM values.

Applicability: Interfacial severity failure is not common. When it is encountered it is usually only for short intervals in an entire well (unless you are drilling horizontally in the zone). Also, usually only in wells with general rock strengths above 10-20 ksi. Therefore this situation is ignored in our optimization algorithm for the 2 ft. rock sample drilling operation. Though there were layers of hard formation, it is optimum to drill off the layer at the existing operating parameters as the layer would not be more than few inches. But one corrective action that is included in the algorithm is to reduce RPM to prevent bit damage.

6.1.4 Whirl

When the bit is rotated using the drill string, any imbalance tends to cause the BHA to flex and develop a sine wave resulting in lateral vibrations. The wave may rotate with the string in a jump rope action, or it may oscillate across the hole. This lateral movement of the string off center is referred to as whirl.

Response: The magnitude of the wave has to be reduced on order to mitigate lateral vibrations and improve ROP, bit life and borehole quality. Primary response to whirl is to increase WOB to increase the DOC to suppress the bit tilt due to the sine wave. RPM must be changed to ensure that the whirl is not resonating.

Applicability: Whirl can occur when there is imbalance in BHA (worse at resonant RPM). Mitigating this dysfunction is important in our application because the clearance is small (drill pipe is 1 inch dia and drill bit is 1.125 inch dia) and small lateral vibrations can affect borehole quality badly. But the drill pipe provided is very stiff (1 inch Outer Diameter and 7/16 inch Inner Diameter) which makes it difficult for whirl to propagate. The algorithm is designed in such a way that when whirl is encountered, WOB is increased to its maximum design limit and ROP is increased slowly as long as MSE is not increasing.

6.1.5 Stick-slip

The torque due to motor rotating the drill pipe generates bit torque and drag causing the drill string to twist and turn. Stickslip is a resonant-period torsional oscillation in the drill string. While the RPM at the surface is constant, the bit is speeding up and slowing down as the string winds and unwinds. If the amplitude is small, this is called an oscillation. If the swing in speed is so great the bit comes to a full stop during the backward motion, it is call full stickslip.

Response: The shape of the torque curve at the surface will be symmetric if we are experiencing only oscillations. It will be non-symmetric if the bit is fully stopping for any period of time. Increasing WOB causes an increase in bit torque which drives higher torque oscillations. Effect on MSE is usually subtle up to the point that the accelerations cause full stickslip. RPM is increased to keep ROP high.

Applicability: This type of dysfunction usually is dominant when the drill string is long. The chances are high when a small diameter drill pipe is used. But the small diameter is not a problem in our case because of large stiffness (high wall thickness). Real-time data is obtained and plotted to identify asymmetric curve which is an indication of Stick-slip. WOB is reduced and RPM is increased as corrective action.

It is important to know the type of dysfunction occurring down-hole to take a necessary corresponding corrective action to improve performance. MSE surveillance is an efficient method for determining drilling performance. As discussed in previous section, MSE quantifies the work or energy being used per volume of rock drilled. Therefore, whenever an increase in MSE is observed, it means that more energy is required to drill the same volume of rock and this implies that the bit is not perfectly efficient. A dysfunction has occurred and by knowing the type of dysfunction, a corrective action corresponding to the dysfunction (as explained in this section for each type of dysfunction) can be taken that makes the MSE go down. The below table summarizes the dysfunction type and corrective actions needed to be taken on WOB and RPM. A more general description of diagnosis and driller's response for dysfunctions is provided in Table 6.1.

Table 6.1: Summary of driller's response for dysfunctions and applicability

Dysfunction	**Concern?**	**WOB**	**RPM**
Whirl	Yes	Increase	Decrease
Stick-Slip	Yes	Decrease	Increase
Bit Balling	No	Decrease	Increase
Bottom-hole Balling	No	-	Increase
Interfacial Severity	May be	Decrease	-

6.2 Optimization Scheme & Algorithm

MSE surveillance provides an objective assessment of efficiency of the system. Regardless of the cause of the dysfunction, the manner in which the driller uses the MSE to maximize real-time performance is the same. To achieve a better performance, the driller must conduct step changes by varying one parameter at a time. Here, the drilling parameters WOB & RPM are changed and performance is monitored. The paper [18] by Dupriest explains in detail about optimizing ROP using MSE. A step-by-step version of the implemented algorithm is given next.

Dysfunction	Whirl	Stick Slip	Bit Balling	Bottom-hole Balling	Interfacial Severity
Reason	Caused due to imbalance in BHA	Caused due to high bit torque	Accumulation of cuttings on bit cutters	Cuttings form a filter cake like layer at the bottom	Hard material embedded in softer material
Diagnosis	Lateral Vibrations Worse as RPM is increased	Torsional Vibrations Periodic torque oscillations	Common in sand/ shales ROP decreases with increase in WOB	ROP unresponsive to WOB or RPM	MSE increases Axial shocks High torque readings
Response	Increase WOB, Reduce RPM	Reduce WOB, Increase RPM	Reduce WOB, Increase GPM (and RPM)	Increase GPM	Increase WOB (but not until damage)

Figure 6.4: Dysfunctions - diagnosis & response

1. If the MSE declines, the dysfunction is getting better and the performance is improving. Continue with more of the same change (for eg., increasing WOB).

2. If the MSE increases, the dysfunction is becoming worse and performance is declining. Change the parameter in the other direction (now, reducing WOB).

3. If the MSE stays the same, performance is on the straight line portion of the drill off curve in Figure 1.9. Continue with more of the same change (increasing WOB).

This concept of MSE was used in developing a control algorithm to optimize ROP. The flow chart shown in Fig. 6.5 is the basis for the algorithm. It shows the action to be taken to improve performance and achieve higher ROP while drilling operation is continuously being executed. As described in previous section, the dominant type of dysfunction is Whirl for which the corrective action is to increase WOB and RPM. Bit balling and bottom-hole balling are assumed to be absent. Torsional vibrations (Stick-slip) is identified by plotting data points and observing asymmetric curve.

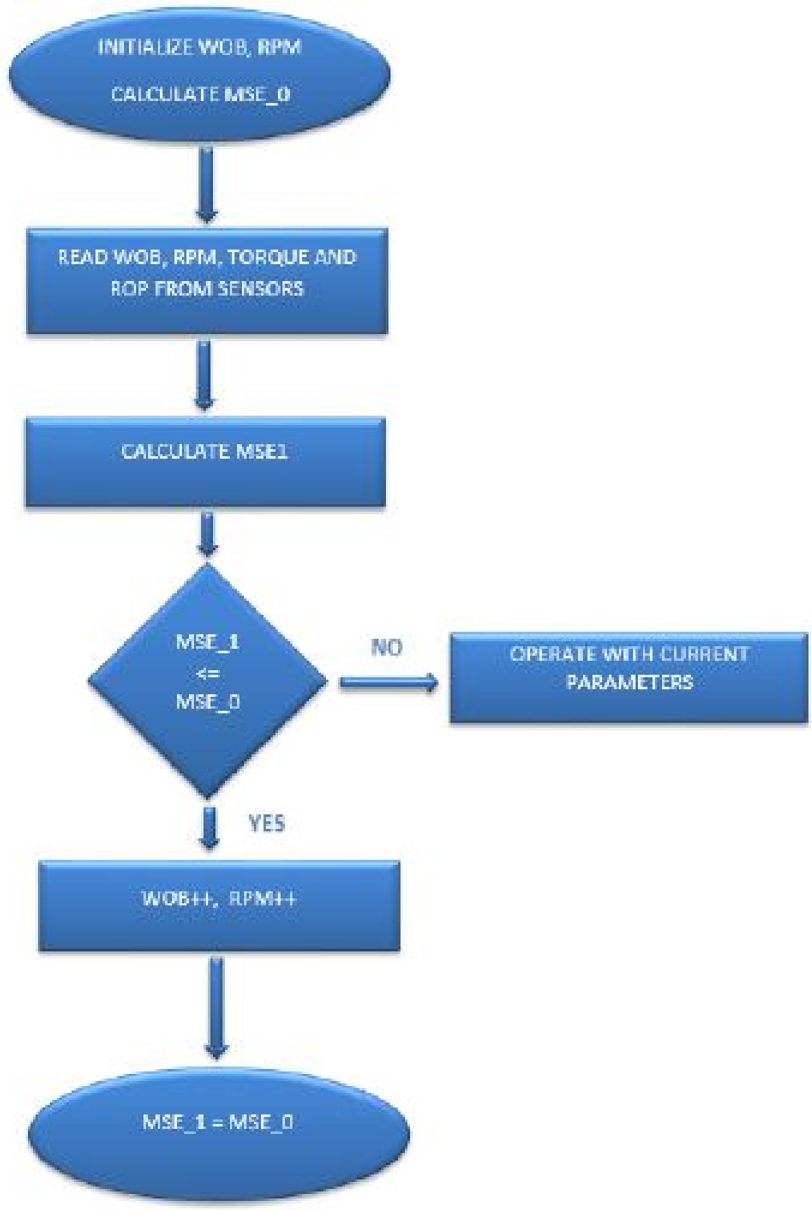

Figure 6.5: Control algorithm for optimizing ROP using MSE

6.3 Results

A test case was designed to test for automation and performance optimization capabilities of the model rig. The test case was chosen such that real-world abnormalities or dysfunctions are simulated in this scenario. A Sandstone formation of 2 ft. x 2 ft. x 2 ft. block as shown in Fig. 6.6 was chosen as the rock sample to be drilled. A very hard material, granite was interlaced in the relatively soft sandstone formation. This is to introduce interfacial severity dysfunction during operation. The formation layers are not perfectly intact leaving gaps imitating fractures.

Figure 6.6: Rock sample for the test case

An extremely thin drill pipe (wall thickness = 0.016 inch) of 3 ft. length was chosen to drill the formation. Fig. 6.7 shows the relative size of the drill pipe.

This 'weak' drill pipe was selected to simulate all types of dysfunctions pertaining to vibrations namely whirl, stick-slip, axial vibrations and even buckling. How the system handles dysfunctions and drills through hard formation is the challenge. Baker Hughes provided a 1.125 inch dia PDC micro-bit with brazed cutters and two nozzles each of 2.35 mm diameter. Brass tool joints were used for connections. The drill bit picture is shown in Fig. 6.8.

Figure 6.7: Drill pipe used to drill the formation

Figure 6.8: Drill bit used to drill the formation

Although not shown here, the complete assembly involved other equipment, namely, a 100 GPH capacity water pump for circulation to clean out rock cuttings and to cool the bit; aswivel connecting mud pump and drill pipe, a bell nipple ensuring no leakages and a centralizer to align the pipe. There were also certain design limitations imposed on the system - Drawworks motor is limited to put a maximum total weight of 50 lbf on the bit and the total power of all subsystems combined should be less than 2.5 HP.

With these specifications, the test was conducted. Below is the sequence of operations that are carried out while drilling a formation using the model rig.

1. Mount the rig on rock sample, connect the drill bit and Click Run on the program

2. Draw works runs at maximum speed until Tag Bottom

3. Top Drive, Circulation, Draw works run simultaneously
4. Drilling is started with preset safe values for WOB, RPM
5. WOB & RPM are updated during the operation real-time
6. Data from all sensors is logged and backed-up real-time
7. Drilling activity is completed on reaching TVD
8. Emergency Shut Down (ESD) option (both in software & push button) is available in case of an accident/ uncommon situation

6.3.1 Test Performance

The test was conducted with this rig setup for the above mentioned test case. Since the extremely thin drill pipe brings in excessive vibrations, the rig was operated much lower than the rated capacity. WOB was limited to 35 lbf and total power consumed by the system during operation was not more than 1 horsepower. The limitations were lowered to avoid breakage of drill pipe. The challenging part of the test was to drill the hard formation which is granite. The objective was to observe the response of algorithm to dysfunctions like vibrations and interfacial severity.

The test was started with an initial set of values for WOB and RPM. The initial values in this case were 15 lbf and 200 rpm. Once the drilling had started, WOB and RPM were increased gradually since the initial phase involves drilling of softer formation. The drilling continued seamlessly with low vibrations that were taken care by the algorithm. As the bit approached the hard formation of granite, vibrations increased excessively. This is a case of interfacial severity dysfunction. The algorithm responded by decreasing WOB which is the corrective action for this type of dysfunction. To compensate for loss in ROP, RPM value was increased. Data from all the sensors was continuously logged through out the operation. Here, two such logs are shown. One is accelerometer's x-axis log shown in Fig. 6.9. As can be seen in the figure, vibrations during drilling of softer formation were low and a transition in range of values can be seen when the bit encountered hard granite formation. In response to the high vibrations and also to high MSE, RPM values as can be seen in the logs shown in Fig. 6.10, were increased after transition in to hard formation.

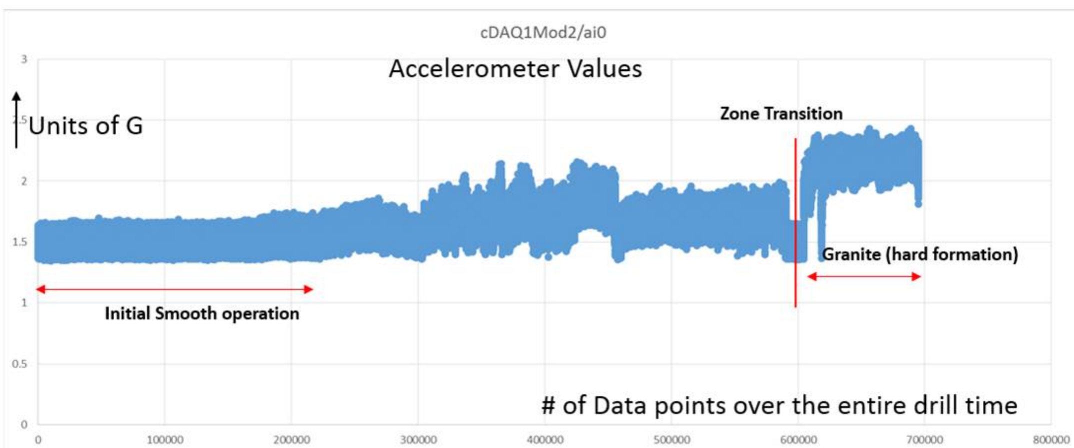

Figure 6.9: Logged data from accelerometer sensor

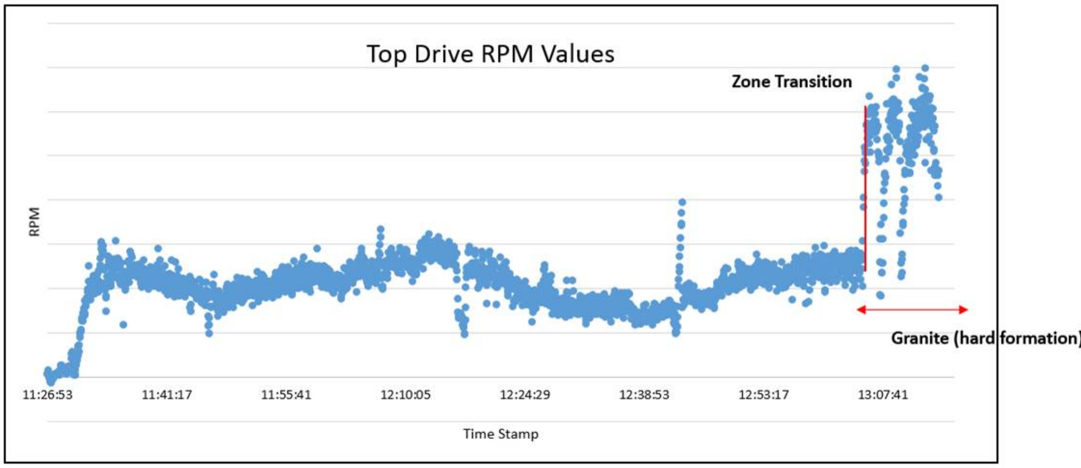

Figure 6.10: Logged data from optical tachometer sensor showing RPM variation

The rig could successfully tackle the dysfunction and was able to drill through granite for about one inch, after which the drill pipe broke. A failure analysis conducted on the broken drill pipe revealed that the pipe broke because of excessive torsional vibrations and also the pipe was subjected to several mechanical fatigue at the joint which is where the tear occured as shown in Fig. 6.11. The test was ended by operating Emergency Shut Down button on the panel to turn off all the rig equipment. Wellbore quality was then checked using a caliper. The drilled wellbore was perfectly straight and very smooth as can be seen in Fig. 6.12.

Figure 6.11: Drill pipe broken at the joint while drilling granite formation

Summary Of Test Results:

- Average ROP 1.3 ft./hr
- Total Drill Time: 80 mins
- Maximum WOB used: 35 lbf
- Maximum RPM: 600

- Wellbore quality: very smooth, straight hole

Figure 6.12: Wellbore after drilling

7. CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE WORK

In this chapter, we conclude the findings of the thesis and make recommendations for future research on this topic.

7.1 Concluding Remarks

- Automation as the most game-changing opportunity in drilling now, is improving performance, safety and economics. The industry has slowly transitioned from manual to automated operations for surface systems but the downhole system is still emerging. Despite several barriers, drilling automation field has seen lot of advancements in the recent past.

- A three-phase process - 'Design, Simulate & Test' can be adopted to carry out any drilling automation research project. This framework was used in this work and all the three phases were covered.

- The easy oil is slowly diminishing and the well profiles are getting more and more complex. Using the traditional and conventional methods to carry out drilling operations is not feasible on such wells. Several unconventional drilling techniques have been proposed for the tighter wells. One such technique is Managed Pressure Drilling (MPD). MPD process using Constant Bottom-Hole Pressure (CBHP) is a common technique employed to drill tight wells avoiding situations like kick and lost circulation among many other issues.

- Controlling choke manifold manually to maintain bottom-hole pressure using back pressure pump system in the MPD process has several shortcomings. A simple controller like PID ensures automatic control of BHP. Simulations run on fabricated data were shown using the automatic choke control.

- A Drilling Simulator has been developed to serve as a simulation environment to carry out simulations for the developed mathematical models. The simulator mimics control room of the driller on field providing an user interface to control field equipment and monitor drilling activity real-time.

- The mathematical models after validating with simulations have to be tested on a physical system like a model rig to ensure performance and safety. For this purpose, a miniature autonomous model rig has been designed and constructed with modern sensors, actuators and data acquisition systems.

- Rate of Penetration (ROP) during drilling although is directly proportional to parameters like Weight-on-Bit and rotation speed in theory, doesn't show the behavior in reality owing to several dysfunctions encountered down-hole. Identifying and mitigating the dysfunctions during drilling is the key to achieve better ROP and hence better performance. Mechanical Specific Energy (MSE) relates the drilling parameters to performance with an empirical relation. Algorithms are developed to minimize MSE and thereby optimize ROP.

- An autonomous model rig has been designed and constructed to carry out drilling activities on various rock samples using different optimization schemes. Improvements in performance and overall plant safety can be achieved using automated systems for drilling operations.

7.2 Scope Of Work

7.2.1 Simulations On The Drilling Simulator

The Drilling Simulator serves as a framework to experiment with mathematical models and control systems. In this work, a model was developed for Managed Pressure Drilling process using Constant Bottom-Hole Pressure technique and a control system was designed for the model using a PID controller. The control system was then incorporated in the simulator to simulate the automatic MPD process. The same simulation framework can be used to test the model with other controllers like Model Predictive Controller (MPC), Model Reference Adaptive Controller (MRAC) or modern controllers like L1 adaptive controller. The PID system needs to be replaced with the new controller and the same simulation setup can be used to carry out simulated MPD operations. In addition to trying out different controllers, models can be developed using other MPD techniques like Dual-gradient drilling. By carrying out simulations of various systems, a performance analysis can be made comparing different controllers highlighting benefits and shortcomings of each controller. We can also evaluate feasibility and applicability of each controller and each MPD technique and determine the most economical way to carry out the MPD process.

7.2.2 Improving Automation Capabilities Of The Model Rig

Although the constructed model drilling rig is completely autonomous, there are few limitations on the system like absence of Bottom-Hole Assembly (BHA), inability to handle directional drilling etc. With some design changes, these limitations can be overcome. Beacuse of absence of field data, comparison could not be done between existing system and the proposed automated system. There is no quantitative measure of improvement in performance by using automation in our operations. One alternative is to carry out the drilling operation on the same test case but without the autodriller. Then a comparison can be made between manual and automated operations and quantitative results can be shown. Also, we need to capitalize on the advantages of using LabVIEW for automation and control. One idea is to exploit the remote control feature in LabVIEW. The Drilling Simulator interfaced to the model rig can be hosted on a website and it can be left open to industry. Interested drilling companies can be given access to the program and they can incorporate their optimization algorithms or schemes and carry out testing on our model rig remotely.

7.2.3 Optimizing Performance Through Automation

One of the two main objectives of Automation, as discussed through out the report, is to improve performance (the other being improving safety). To improve performance, it is proposed that Rate of Penetration is to be increased by mitigating dysfunctions encountered downhole. In this work, a very general scheme has been used to mitigate the dysfunctions. The concept of Mechanical Specific Energy (MSE) has been used to determine if the bit is performing efficiently or if it is being affected by dysfunctions. A better approach is to first identify the type of dysfunction occuring down-hole and then take corresponding corrective action to mitigate the dysfunction. A detailed study on dysfunctions helps the user to determine the causes of a dysfunction, it's diagnosis and finally the driller's response to the dysfunction. The most common dysfunction type is vibrations. Modeling the vibrations is still an issue in the industry. Our model rig can be used as a test bench to carry out experiments with different drilling mechanisms and by observing input patterns and responses, probably a system identification would yield, if not the perfect model, a close approximation of vibration model.

BIBLIOGRAPHY

[1] Thorogood, J., Aldred, W. D., Florence, F., & Iversen, F. (2010, December 1). Drilling Automation: Technologies, Terminology, and Parallels With Other Industries. Society of Petroleum Engineers. doi:10.2118/119884-PA

[2] Eustes, A. W. (2007, January 1). The Evolution of Automation in Drilling. Society of Petroleum Engineers. doi:10.2118/111125-MS

[3] Iversen, F., Gressgrd, L. J., Thorogood, J., Balov, M. K., & Hepso, V. (2013, March 1). Drilling Automation: Potential for Human Error. Society of Petroleum Engineers. doi:10.2118/151474-PA

[4] Macpherson, J. D., de Wardt, J. P., Florence, F., Chapman, C. D., Zamora, M., Laing, M. L., & Iversen, F. P. (2013, September 30). Drilling Systems Automation: Current State, Initiatives and Potential Impact. Society of Petroleum Engineers. doi:10.2118/166263-MS

[5] David B. Kaber & Mica R. Endsley (1999). The effects of level of automation and adaptive automation on human performance, situation awareness and workload in a dynamic control task. Theoretical Issues in Ergonomics Science ISSN 1463922X. doi:10.1080/1463922021000054335

[6] De Wardt, J. P., Macpherson, J. D., Zamora, M., Dow, B., Hbaieb, S., Macmillan, R. A., Anderson, M. W. (2015, March 17). Drilling Systems Automation Roadmap - The Means to Accelerate Adoption. Society of Petroleum Engineers. doi:10.2118/173010-MS

[7] Cayeux, E., Daireaux, B., Dvergsnes, E. W., & Florence, F. (2014, June 1). Toward Drilling Automation: On the Necessity of Using Sensors That Relate to

Physical Models. Society of Petroleum Engineers. doi:10.2118/163440-PA

[8] Robert H. Bishop LabVIEW 8 2007. Pearson Prentice Hall, NJ.

[9] Gabaldon, O., Culen, M., Bacon, W., & Brand, P. (2014, May 5). Enhancing Well Control Through Managed Pressure Drilling. Offshore Technology Conference. doi:10.4043/25256-MS

[10] Breyholtz, O., Nygaard, G. H., Siahaan, H., & Nikolaou, M. (2010, January 1). Managed Pressure Drilling: A multi-level control approach. Society of Petroleum Engineers. doi:10.2118/128151-MS

[11] Eaton, B. A. (1975, January 1). The Equation for Geopressure Prediction from Well Logs. Society of Petroleum Engineers. doi:10.2118/5544-MS

[12] Pedersen, T. (2008), Experimental Evaluation of Model-Reference Adaptive Control for Managed Pressure Drilling. Masters Project, NTNU.

[13] Cao, C. & Hovakimyan, N. (2006a), Design and Analysis of a Novel L1 Adaptive Controller, Part I: Control Signal and Asymptotic Stability, in 'Proceedings of the 2006 American Control Conference.

[14] Vishnumolakala, N., Gildin, E. & Noynaert, S. F., (2015, May). A Simulation Environment for Automatic Managed Pressure Drilling, International Federation of Automatic Control

[15] Godhavn, J.-M. (2009), Control Requirements for High-End Automatic MPD Operations, in SPE/IADC Drilling Conference and Exhibition.

[16] Teale, R., 1965, The Concept of Specific Energy in Rock Drilling, Int. J. Rock Mech. Min. Sci., 2, pp. 5773.

[17] Noynaert, S. F., & Gildin, E. (2014, October 27). Going Beyond the Tally Book: A Novel Method for Analysis, Prediction and Control of Directionally Drilled

Wellbores using Mechanical Specific Energy. Society of Petroleum Engineers. doi:10.2118/170979-MS

[18] F.E. Dupriest, SPE, ExxonMobil, and J.W. Witt, SPE, and S.M. Remmert, SPE, RasGas Co. Ltd., (November 2005). Maximizing ROP With Real-Time Analysis of Digital Data and MSE. International Petroleum Technology Conference - IPTC 10607.

[19] Dupriest, F. and Keoderizt, W. " Maximizing Drill Rates with Real-Time Surveillance of Mechanical Specific Energy", SPE paper No.92194 presented at annual Drilling Conference, Amsterdam, Netherlands, 23-25 February, 2005

[20] Pessier, R.C. and Fear, M.J., "Quantifying Common Drilling Problems with Mechanical Specific Energy and Bit-Specific Coefficient of Sliding Friction", IADC/SPE paper No.24584 presented at 67th Annual Conference and Exhibition Washington D.C., 4-7 October, 1992

[21] A. Ersoy (2003). Automatic drilling control based on minimum drilling specific energy using PDC and WC bits. Institute of Materials, Minerals and Mining in association with AusIMM.

[22] Todd Robert Hamrick (2011). Optimization of Operating Parameters for Minimum Mechanical Specific Energy in Drilling. Dissertation submitted to the College of Engineering and Mineral Resources at West Virginia University.

[23] Miguel Armenta (2008). Identifying Inefficient Drilling Conditions Using Drilling-Specific Energy. Society of Petroleum Engineers - SPE 116667.

[24] Kaasa, G.-O. (2007), A Simple Dynamic Model of Drilling for Control., Technical report, Hydro Oil and Energy, Porsgrunn Research Centre.