Designing a Drilling Rig for the Society of Petroleum Engineers'

International University Competition

International Drillbotics Competition 2020-2021

Group B Design Report

By UVU Drillbotics:

Devon Allen, Matthew VanAlfen,

Yousuf Mohan, Michael Elliott, and Mike Abbott

Instructor:

Dr. Abdennour Seibi - *Mechanical Engineering Program*

Utah Valley University (UVU)

Table of Contents

Introduction 4

Objective 4

Safety 5

Risk Categories (identifying and categorizing risks) 7

Human 7

Chemical 8

Mechanical 8

Electrical 8

Actions, Precautions, and Measures Taken 9

Human 9

Mechanical 10

Electrical 11

Chemical: 11

Additional Administrative Policies 12

Design Considerations and Engineering Specifications 13

Rig 19

Rig Design 19

Vertical Motion 20

Drilling Fluid 21

Fluid Collection Unit 22

Pump Selection 22

WOB Sensor 23

ROP Sensor 24

Well Deviation 25

Bit Rotation 25

Alternative Bit Rotation 25

Findings and Lessons Learned 25

Major Findings 25

Learned lessons: 26

Finite Element Analysis 27

Modal Analysis and its Results 27

Harmonic Analysis and its Results 28
System Algorithm 30
Control Scheme 32
Data Collection 32
Control System 35
Cost Analysis 36
References 38
Appendix A: Student Biographies 39
Appendix B: Summary of Calculations 41
Appendix C: FEA figures 42

Introduction

The Drilling Industry has been an essential practice for over 150 years. The field and its operations have become more sophisticated and specialized. Although the field advanced so much over the years, it still lacks innovation in the automation of its drilling operations. The objective for automation of the drilling operation is to minimize injuries and human losses meanwhile maximizing accuracy while drilling wells quickly and maintaining good cost efficiency. Therefore, in keeping with SPE Drillbotics' competition purpose, the UVU team writes this proposal seeking to add to the research into automated drilling being done by many drilling companies. An automated drilling rig would reduce human error, minimize safety hazards/accidents, and increase drilling efficiency.

This proposal outlines the design procedure and the steps adopted by our team towards building an automated drilling rig with minimum costs.

Objective

The objective of this project is to design and construct a small-scale automated drilling system equipped with a proper control system, to drill a directional well, fast, safe, and cost effective. The control system must incorporate downhole and surface sensors and use the data from these sensors to control the operating parameters of the drilling rig. Since directional drilling is a critical part of this project, selection and placement of the sensors need to be studied thoroughly. As part of Group B's competition requirements, "the wellbore must be

started vertically and kicked off below a specified depth to hit multiple directional targets (at varying X/Y coordinates and vertical depths).” -DSATS

Safety

Maintaining the safety of team members, machine operators, and any participants or onlookers is of the utmost importance for our team. It played a constant role in our design considerations and planning of various components of the project. Operating the drilling rig safely is in the best interest of the Drillbotics team, the university, SPE organizers and judges of the Drillbotics competition, and of the general public.

In order to better ensure safety, two main methodologies were employed. The first one is to approach possible safety hazards on a case by case basis (Figure 1). The second is to categorize and determine a clear set of standards that delineate hazards by a risk type. OSHA guidelines [1] are the basis upon which efforts to mitigate risk can have a more concrete foundation backed by reliable information, which is widely accepted by the drilling industry. In addition, the team adopted certain safety and risk management expectations for the project, which can be found in the Hazard Prevention and Control section of the OSHA guidelines for Safety and Health [1].

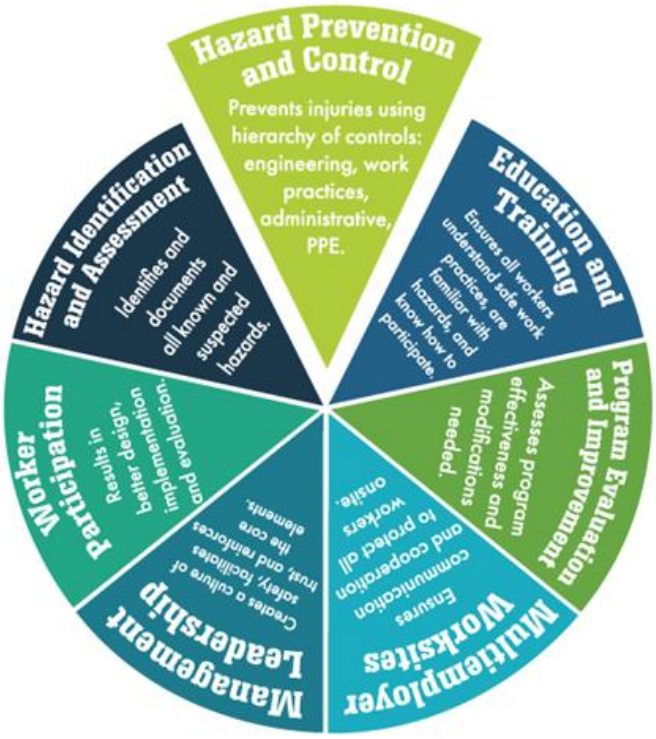

Figure 1: OSHA Core Elements of Safety & Health Recommended Practices (Hazards Focus).

Regarding risk management, our approach is to identify and divide the various risks into four different categories: human, chemical, mechanical, and electrical. The key elements of the project's safety are categorized into three different divisions: ensuring safety of individuals, of operating circumstances, and of equipment. In addition, actions were taken to effectively carry out safety precautions and ensure participants are properly trained. These actions were determined on a case-by-case basis to avoid the most common causes of injuries as shown in Figure 2 and were demarcated under isolation/removal (from design), protocol, and replacements.

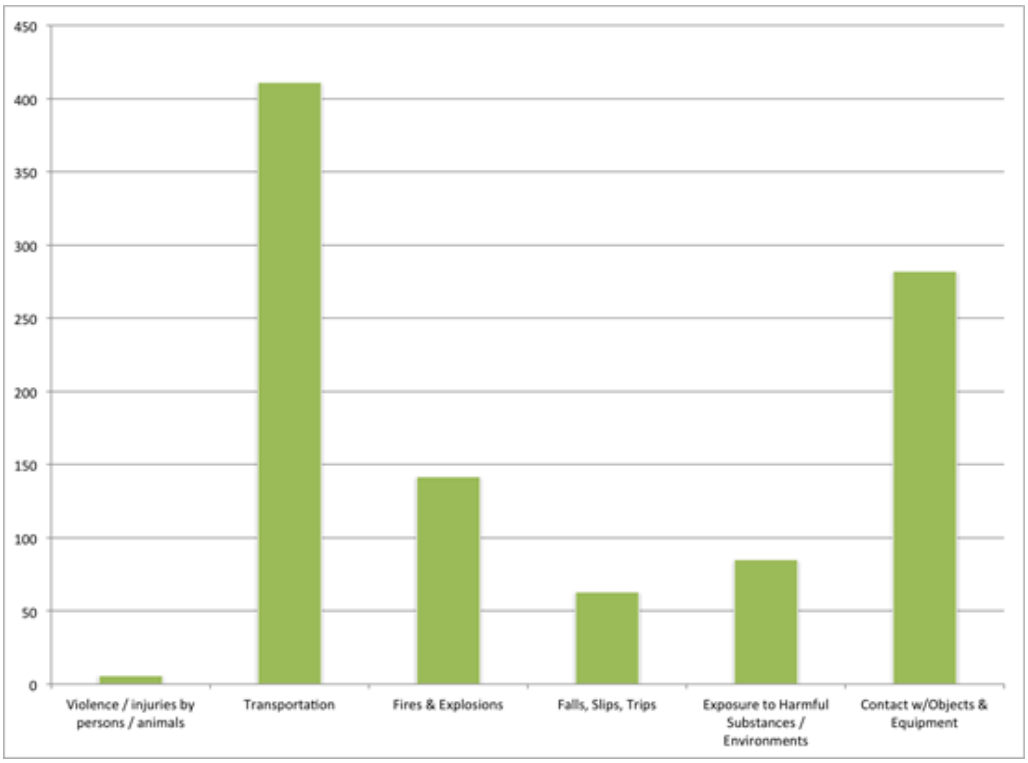

Figure 2: Aggregated chart from OSHA, Reasons for O&G Fatalities 2003-2012.

Risk Categories (identifying and categorizing risks)

Human

Human risks are those defined as any hazards caused by human error to either themselves or to their surroundings. Some common examples are input error, lack of situational awareness by either operator or observer, carelessness by personnel or a public member, and insufficient training. It is of great importance that these factors are addressed to prevent possible hazards that can pose a danger or harm to others.

Chemical

Chemical risks regard any hazards from dangerous substances used in the design, construction, or operation of the project that may harm operators and other personnel. Examples may include construction and cleaning chemicals or welding fumes. In addition, any fluids involved in the maintenance and operation of machineries.

Mechanical

Mechanical risks describe a variety of hazards surrounding machines: moving parts, tools, machine operation, etc. The most prominent risks are burns for welding, cuts from machined metal or tool bits, and pinching during operation and construction of the rig. These mechanical risks can cause severe harm, therefore most of the design considerations were made with allaying these risks in mind.

Electrical

Electrical risks describe hazards that involve electric failure and electrocution. This includes tripping on wires, contact with electronics as well as hazards from installation of the aforementioned, and their usage.

Actions, Precautions, and Measures Taken

The team has taken the following steps in regard to the pre-established risk categories. The steps include policy setting, removal, training, and substitution in response to any potential hazard.

Human

Apply all proper labels to mechanical and electrical components used in the design that are handled by anyone during operation or in the process of repair.
Procedures involving the use of the drilling rig and the event of any accident are to be determined and reviewed by the team before any testing or use of the mechanism may begin.
Any operator is to be properly trained in handling the drilling rig before use and additionally to be educated in procedures involving accident mitigation.
All personnel involved in the project or any spectator are to be outfitted with proper PPE (personal protective equipment).
All wires or loose components are to be as well organized as possible. This is to reduce the risk of tripping or colliding.

Mechanical

Control system failsafe to detect if catastrophic physical damage has occurred to the mechanism for immediate shut down of physical systems. This will include use of sensors to detect failures such as buckling or torsional shear of the drilling rod. Sensors monitoring time under excess fatigue at points under significant stress will also be installed. The control system is to immediately shut off the rig if it detects prolonged periods of high stress.
In addition to the built-in actions made by the control system, an immediate shut off switch is to be installed should any personnel or operator deem continued operation of the rig to be a risk.
The drilling mechanism has been designed to allow for easier positioning and access of the work material. An opening to one side of the drilling rig has been intentionally designed without any obstacles such as any frame material in the way. This will reduce the risk of harm when handling and moving the work material into place.

Electrical

Procedure involving checking if electrical systems are properly connected before operation and properly disconnected after operation will be taught to all team members and followed. This is to make sure that there are no faulty electrical connections.
Sensors will be put in place to detect overheating or electrical failure of any of the motors or pumps. This includes the use of temperature sensors and the control system monitoring for any drastic drop or rise in electrical consumption.

Chemical:

Members, personnel involved in the construction process are to use proper protective equipment such as safety glasses and heavy duty gloves when using any chemical.
The selection of any chemical used for coating or cleaning is being made with the consideration of adverse health effects. Any fluid or gas that causes harm under prolonged contact will be substituted for a less harmful substance if possible.

Additional Administrative Policies

There are also some risk mitigating decisions made in administrative policy to further reduce any risks that are not covered by the four categories above.

Extensive (Risks):

Due to the coronavirus pandemic, all team members are required to wear masks to team meetings. Operation of the physical rig should be handled by the minimum amount of personnel needed at any time. Social distancing is to be practiced throughout.

Design Considerations and Engineering Specifications

The drilling rig must be designed and constructed to perform safe autonomous drilling, vertical initiation, then kick off the wellbore below a given depth to hit multiple directional targets of varying (X, Y) coordinates.

Other considerations include a safety shield, downhole sensor implementation and integration into the rig's control system, surface sensor implementation and integration into the rig's control system, data feedback on different components of the rig, current industry practices, speed of drilling, accuracy of drilling, response time, competition PDC micro-bit [52] implementation, grid power limitations, continuous data feedback, and cost limitations.

Some design constraints include rig size must be within 88" by 36" to fit through doors, electric power must not exceed 25 HP, and measurements of various drilling parameters must be continuously collected by the sensors.

Engineering specifications (Table 1) regarding the various components of the build were all determined from the Drillbotics competition guidelines. These guidelines described the size of the frame, the shaft, and any data that the sensors must collect and use as feedback in the drilling rigs control system.

Table 1: engineering specifications for rig components.

Component/Item	Specification
Rig	Width under 36” and height under 80” (derived from IBC building code on door dimensions)
Drill Bit	Width cannot exceed 1.5” and Length must not exceed 2.0” if students are designing their own. PDC micro-bit of 1.5” (38.1 mm) in diameter and 2.0” in total length if using the competition’s Low axial aggressiveness and high side aggressiveness
Shaft	Round aluminum tube 3/8” inner diameter by 36” length and 0.049” wall or equivalent
Sensors	Must collect the following data: Weight on Bit (WOB) Azimuth (directional path) Inclination (from vertical axis) Depth (from drilling sample surface)

In order to transform the design considerations into engineering specifications, it was important to recognize what parts of the whole design were most important. In the history of the Drillbotics' competition, the most common failures have happened at the top of the drill pipe where it connects to either a motor, the fluid system, or both.

This failure can result due to poor control of the system, or through experiencing a "stuck pipe" where the bit stops rotating and transfers the full torque of the drilling motor into the drill pipe. Stuck pipe failure is most caused by insufficient hole cleaning, meaning the drilling fluid does not have enough energy in it to pull the cuttings all the way out of the hole. To prevent total rig failure, the rig must operate well within the failure modes of the drill pipe and ensure proper hole cleaning.

The required drill pipe dimensions are as follows: The drill pipe must not exceed 3 feet in length and the inner diameter of the pipe must not exceed 0.375" with a wall thickness no greater than 0.049" resulting in a maximum outer diameter of 0.473".

The hole cleaning capability of a rig is classically determined through its annular velocity (Figure 9). There are different recommendations for annulus velocity that have their basis in the angle of the hole (reference). Completely vertical holes only require annular velocities around 100 ft/min, while holes with a deviation from vertical require a higher annular velocity. The UVU rig will require an annular velocity of 150 ft/min or greater to ensure proper hole cleaning.

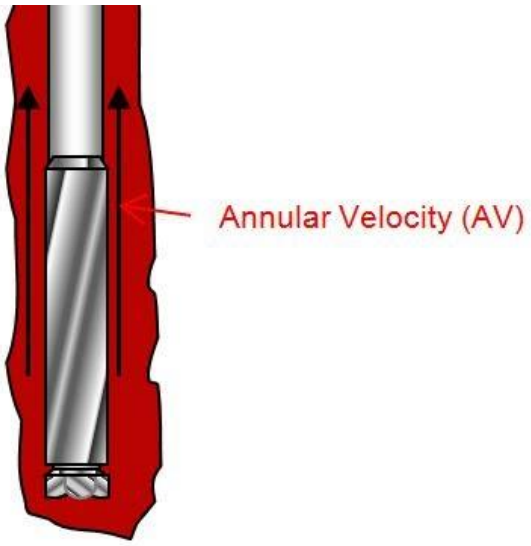

Figure 9: diagram of a drill showing annular velocity [3].

Using these parameters, we calculated the critical buckling load, the maximum allowable torque on the drill pipe, the required flow rate of the fluid system, and the losses the fluid incurs throughout its path.

Buckling Limit using Euler's Equation [6]:

$$P_{cr} = \frac{\pi^2 EI}{KL^2}$$

Pcr: Critical Buckling Load

E: Modulus of elasticity of the steel drill pipe

I: Area moment of inertia

L: Length of the column

K: Column effective length factor (by assuming its fixed at one end and free at the other)

A factor of safety of 2 was chosen for the critical load and one of 2.5 for the torque.

Torque using general torsion equation [6]:

$$T = \frac{J * \tau_{max}}{r}$$

T: Torque

J: Polar moment of inertia

max: Shear stress

r: radius of the shaft

Lateral force equation [6]:

$$F = \frac{3\delta_{max} * EI}{L^3}$$

F: Lateral Force

δ_{max}: Maximum Deflection

E: Modulus of elasticity of the steel

I: Moment of Inertia

L: Length of the shaft

Volumetric flow rate equation [3]:

$$Q=A_{annulus}v_{annular}$$

Q: Volumetric flow rate

A: Area of annulus

v: Velocity of fluid within the annulus

Head loss equation [3]:

$$h_{loss} = \left[f\frac{L}{D} + K\right] * \frac{v^2}{2g} + \Delta z$$

h_{loss}: Head loss

f: Friction Factor

L: Length of pipe/hose in feet

D: Diameter of the pipe/hose in feet

K: Minor loss factor

v: Fluid velocity

g: Gravity

Δz: Difference in height using pump outlet as datum

Through the calculations, the operating head of 15GPM was used in pump selection to ensure that even if the head suddenly jumped from around 20ft to 50ft, our pumps would continue delivering more than sufficient flow to ensure proper hole cleaning. Head loss through the bit are minor losses with behavior similar to a slightly expanding nozzle and will be determined precisely through experimentation in Phase 2 of the competition.

Rig

Rig Design

The team has designed a rig (Figure 3) with a frame to be constructed out of steel. Custom fluid and sensor connections will be machined from Aluminum. A filtering system will be used to help limit water consumption and eliminate the need to constantly mix drilling fluid.

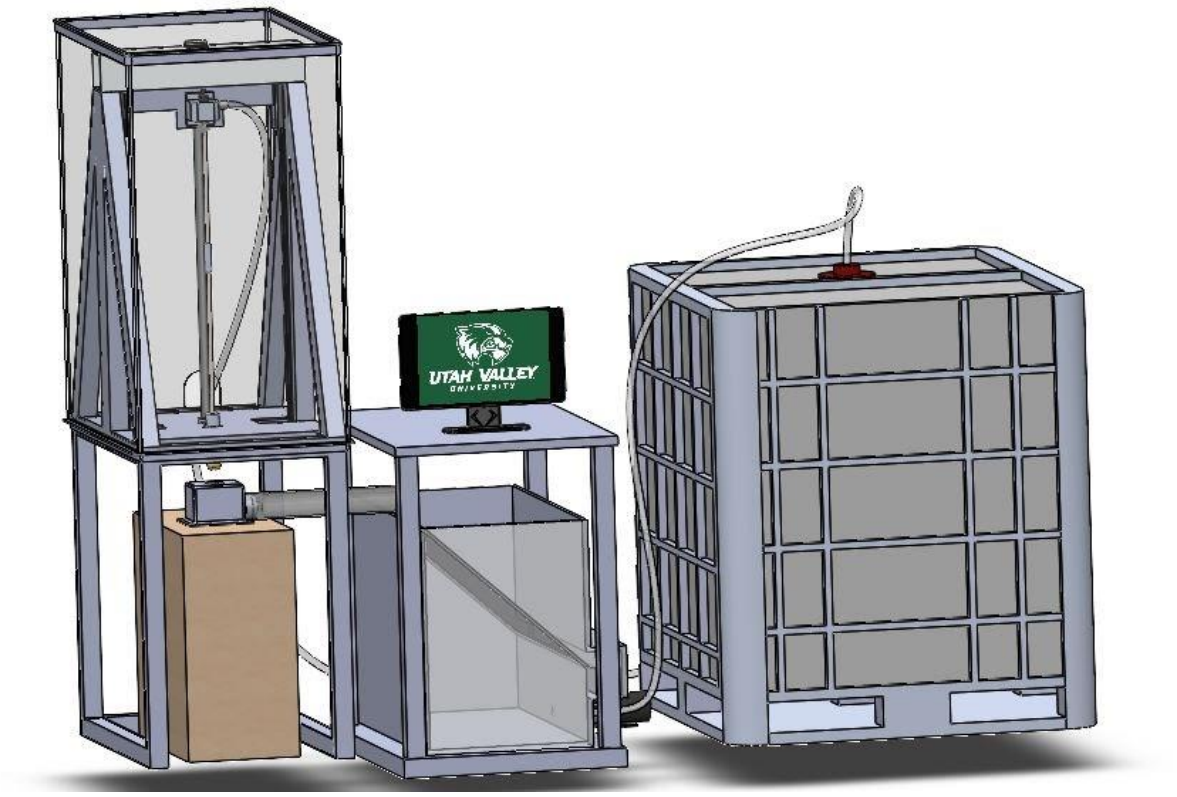

Figure 3: complete rig design.

Vertical Motion

The motion of our rig is controlled by a stepper motor and ball screw attached at the top of the frame as shown in Figure 4**.** The plate equipped with a laser for measuring the total depth will slide up and down on two linear rails on either side of the derrick. We chose this setup to control vertical motion because it can be used to accurately increase and decrease WOB as needed for the system to operate efficiently. The ball screw and rails provide constant, rigid, and direct contact for mechanical surfaces throughout all vertical motions.

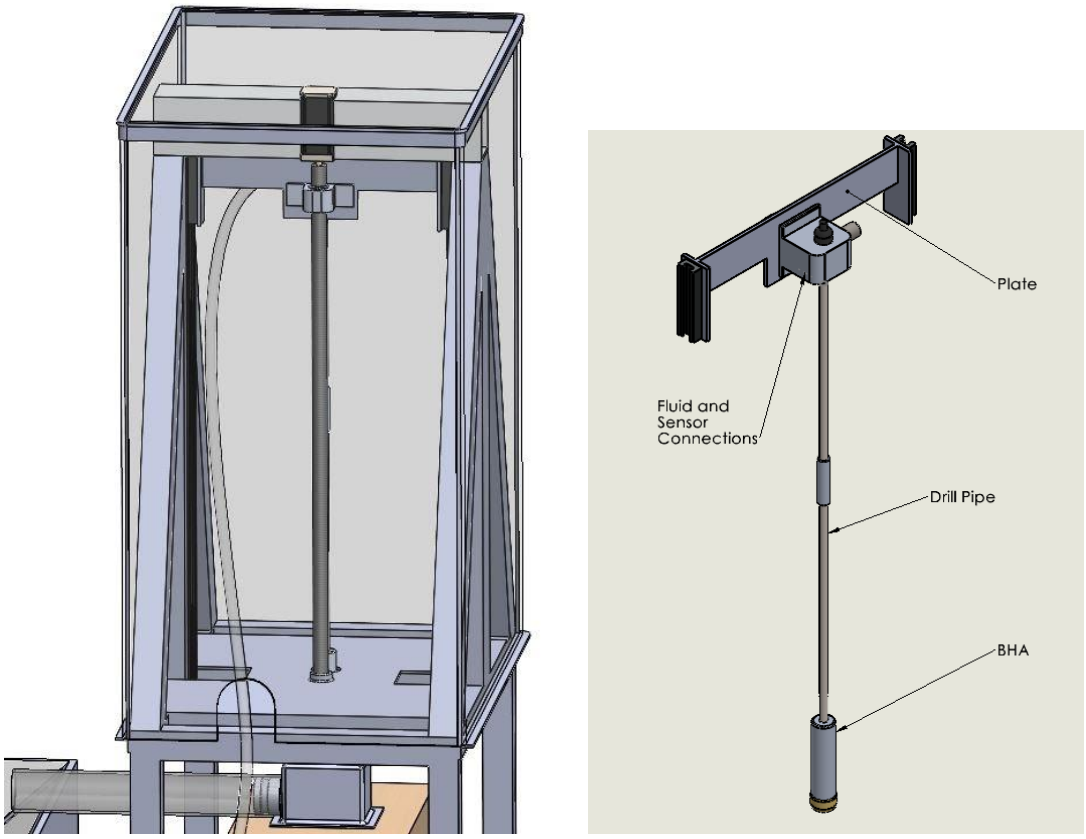

Figure 4: View from the back of the drilling rig showing the vertical driving mechanism.(LEFT) Annotated vertical moving assembly (RIGHT).

Drilling Fluid

The team selected slick water as a drilling fluid. This was chosen due to its behavior as a friction-reducing fluid and because a higher HSP will not be required for this application.

Fluid Collection Unit

A well cap will be used to contain the fluid coming out of the annulus and redirect it to a filtering tank. The cuttings will be flushed down and off the filter screen into a separate containment as shown in Figure 5. The filtered fluid will be pumped out of the filtering tank into a holding tank to be fed into the drill pipe thus allowing for a semi-contained fluid system that would be more suited for operation in remote areas with little water available.

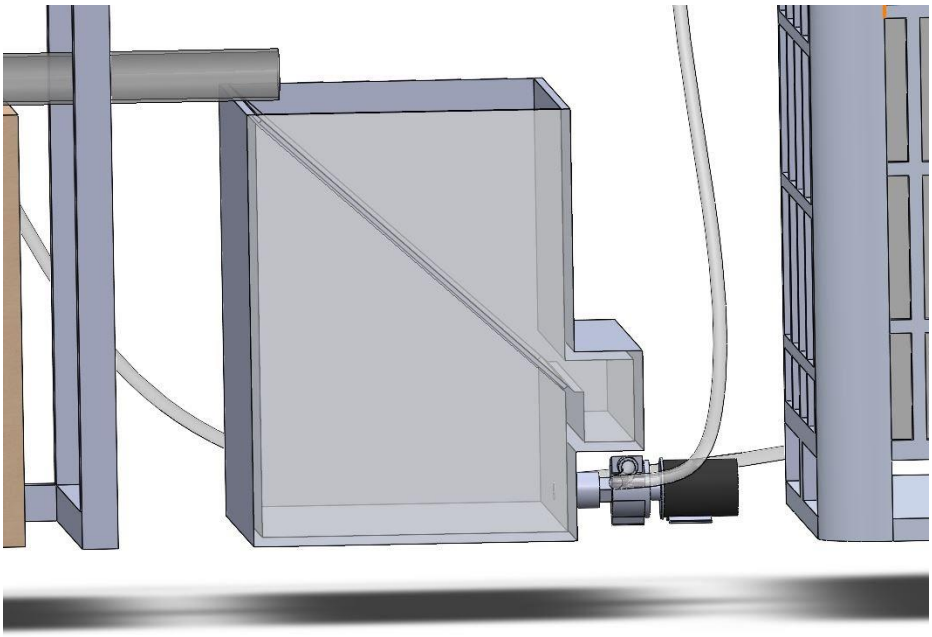

Figure 5: Side-view of the filtering tank and pump.

Pump Selection

The fluid system will be driven by one pump while another provides auxiliary functions. Both pumps (Figure 6) are Identical to maintain similar fluid fittings throughout the fluid track. Fluid calculations were completed based on an Annular

Velocity of 150 ft/min. After calculating the head losses throughout the system with Bernoulli's equation (reference) a pump was selected that allows for an annular velocity above 150 ft/min for operating head up to 55 ft or 23 psi.

Figure 6: Selected centrifugal pump

WOB Sensor

A load cell will be placed at the on the back of the fluid couple at the top of the drill pipe. There will be minimal interference in the readings at this location. Any bending that may occur will be accounted for in the sensor readings in the control system.

Figure 7: Omega S-beam Load Cell.

ROP Sensor

The laser sensor will be attached to the traveling plate measuring the distance from the top of the drill string to the top of the rock sample. Its intended application is to measure distances between 0.025 meters and 1.5 meters. This will give an accurate measurement of the depth of our well.

Figure 8: OGD580 Photoelectric distance sensor

Well Deviation

A whipstock will be used to deviate the well-bore after a certain vertical depth is reached. The drilling will be stopped, and the drill string will be raised. The safety cage will be opened and the whipstock will be inserted manually into the hole.

Bit Rotation

The UVU team will use a downhole motor to rotate the drill bit through the entire process. This was chosen to help mitigate failure of the drill pipe after the well is deviated by the whipstock. The motor will be held in place by a sheath that allows fluid coming from the pump to flow around the motor and into the bit. Power for this motor will be provided by a cable passed through the drill pipe.

Alternative Bit Rotation

If the downhole motor does not achieve an acceptable ROP, a cable running through the drill pipe will be used to turn the bit.

Findings and Lessons Learned

Major Findings

After doing extensive research on drilling rigs (offshore, and onshore) [5] the team concluded that a lot of work goes into every small detail of a functional rig. There are many, many, calculations, CAD modeling, FEA, testing, and iterations. Drilling rigs need to overcome and diminish all component failures to be operational. Otherwise, the rig loses fluid, money, injures people, and damages the environment.

The team used wrong equations to calculate parameters needed to identify and overcome bending failure. Initially, we had a lateral force of 690.88 lbf acting on the drill string, causing it to permanently deform, leading to cascading failure. After performing finite element analyses and reviewing calculations, the team realized their mistakes and reworked calculations.

Also, the team made several mistakes conducting a FEA on the drill string. A confusion between what a modal analysis vs what a harmonic analysis was glaring; no one knew what a modal analysis is used for and how it is applied. The modal analysis only needed boundary conditions, while the harmonic analysis needed both, the boundary conditions, and the loads acting on the string.

Learned lessons:

We learned how important drilling is [5] and how much work is put into a rig for it to operate safely and efficiently. Benchmark operations of a rig were reviewed and acknowledged by all team members. Due to performing several, and we mean, several, CADs and FEAs, a better understanding of each program's capabilities was established.

Finite Element Analysis

Two modeling analyses were performed; a Modal Analysis to determine the frequencies at which the drill string could buckle (resonance) and a Harmonic Analysis to study the response of the drill string's structure to the modal frequencies. The second experiment will help us determine which type/size collar to use based on the magnitude of the deformation at the resonance frequencies.

Modal Analysis and its Results

Measurements, material properties, and boundary conditions were set prior to the model. Using ANSYS, we modeled the drill string as a cylindrical beam with 18 meshed elements (for more accurate results) and fixed it at one end (Figure 10)

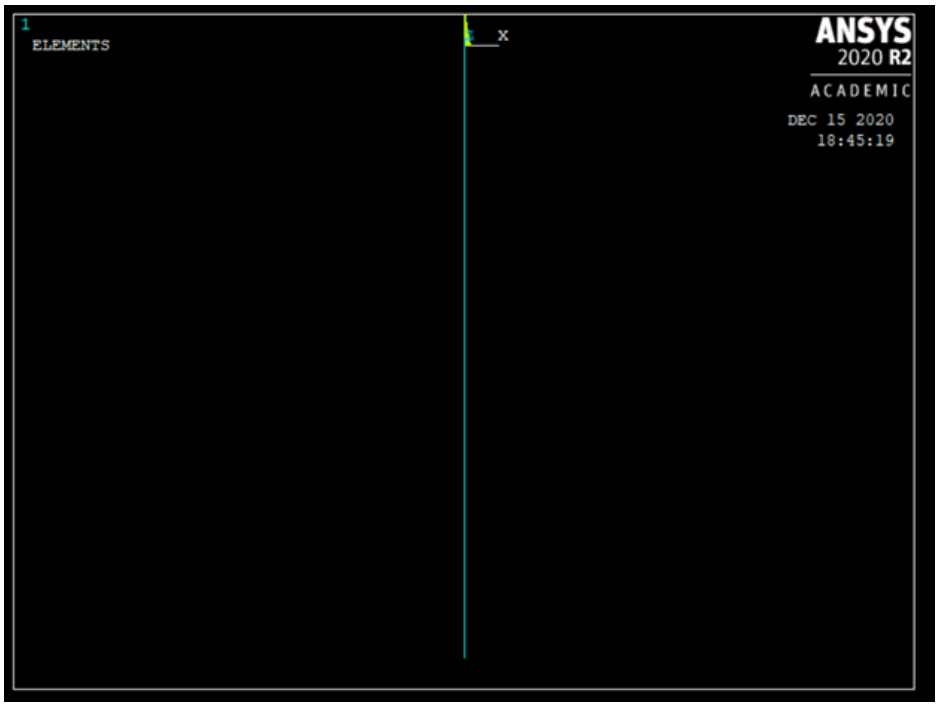

Figure 10: plot showing the drill string with boundary conditions, ready for a modal analysis.

A modal analysis with 5 modes of extraction (ANSYS uses the default method of Reduction to extract) was conducted between the 0- 1500 rpm or 0-25 Hz operating range of the drill bit (Appendix C).

****** INDEX OF DATA SETS ON RESULTS FILE ******

SET	TIME/FREQ	LOAD STEP	SUBSTEP	CUMULATIVE
1	0.68732	1	1	1
2	0.68732	1	2	2
3	4.3271	1	3	3
4	4.3271	1	4	4
5	12.236	1	5	5

Figure 11: Results table showing the four modes of the drill pipe.

The experiment showed which frequencies cause resonance; 0.69, 4.32, and 12.24 Hz. These frequencies will be used in the second experiment to identify which of the three to focus on and diminish.

Harmonic Analysis and its Results

like the Modal Experiment, measurements and material properties were identified/calculated prior to the model; However, the forces/moments in the x and y axes were applied on the drill string. The team performed two harmonic analyses at two different locations on the drill string: one at the bottom hole (Figure 12), and the other at the middle of the drill string (Figure 13).

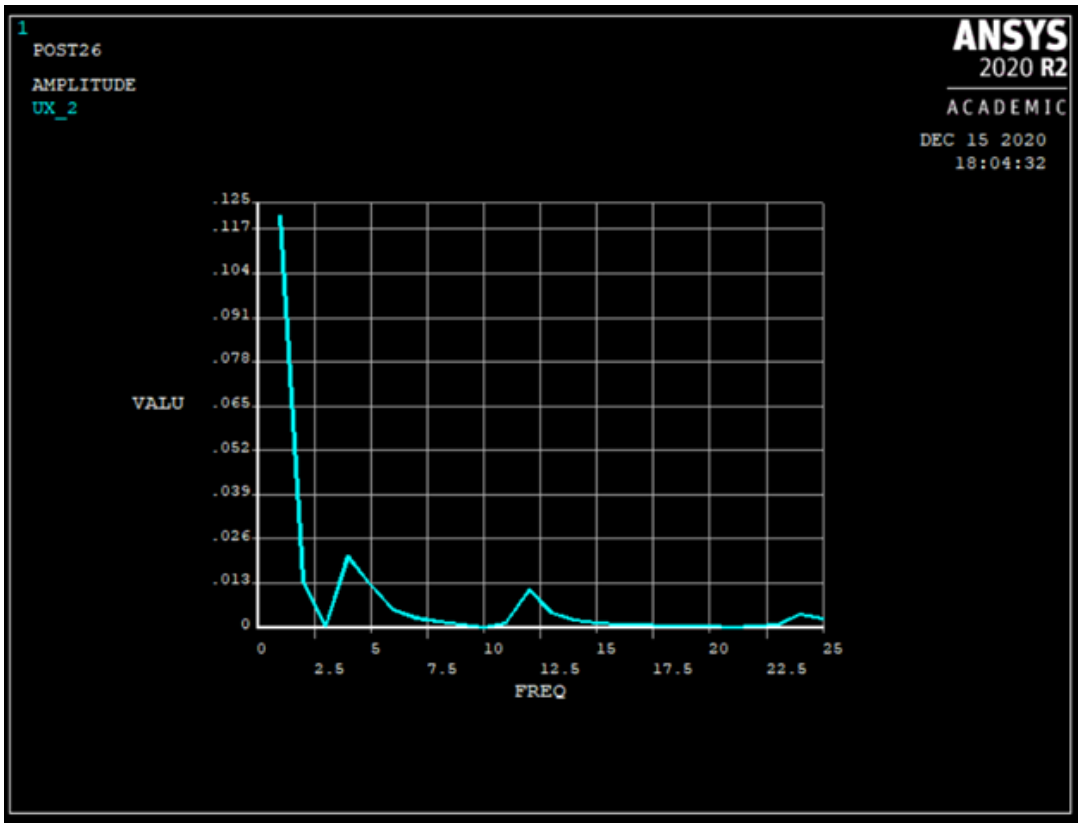

Figure 12: plot of the drill string's X-deformation values vs. frequency with all forces/moments at the bottom hole.

The deformation at the bottom hole has a max value of about 0.21 in, as can be seen in the figure above. This displacement will be constrained by the well hole, so no work needs to be done about it. Also, all the other spikes in amplitude are very small (in the 100^{th} of an inch), so they will not be addressed.

The displacement at the middle of the drill string has a max value of $4.5*10^{-2}$ in; this is again, in the 100^{th} of an inch, and therefore will not be addressed. Before correcting our calculations and remodeling our FEA, the team considered placing a

stabilizing collar to diminish what was a major case of bending. That idea was thrown away because as can be seen in the figure above, there is no need to address anything.

Appendix C has the rest of the FEA models.

System Algorithm

The drill GUI is shown in Figure 14. It is a GUI system developed for the specific purpose of making a grid of dashboard elements based on pygame, so it is easy to extend and change. The purpose of the software is to create a real time monitoring for a complex system with occasional or alternative (non-GUI based) user interaction. The Limiting factor for this is the grid rendering system implemented on the Dashboard software. For the purpose of creating and representing an entire drilling assembly with “moving” parts and gauges.

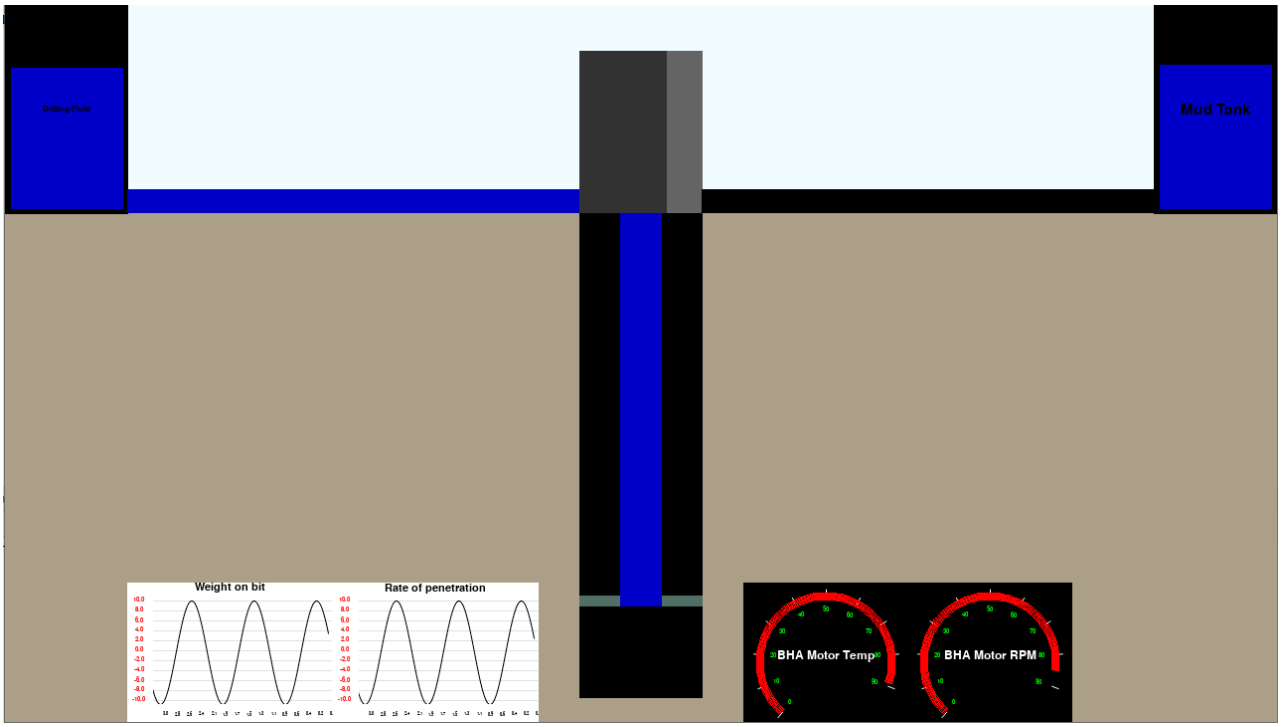

Figure 14: Diagram of the GUI showing WOB, ROP, RPM, BHA Temp, and real-time fluid flow.

The drill is made up of boxes that have sub parts to make them look like they are changing or moving. This is used to represent the drilling fluid flowing through the pipes of the system as well as the tanks. The drill motor and bit will be represented by a changing sprite (2D picture with animated frames). One challenge that remains is the curve of the drill channel. It cannot be represented by square boxes and the pygame arcs are bad at best but nearly unusable when their surface area gets larger. Gauges to show the drill status are layered on top of the simple status animation to show the current readouts in real-time and more intuitively as the gauges are physically close to where their reading is taking place. This GUI is a unique and useful part of our drilling system. Many teams rely on 3rd party software for much of their rig and do not have application specific integrations like our software development team at UVU can provide.

Control Scheme

Data Collection

Data collection is going to be handled as a tiered pass back process. The bottom hole assembly BHA will contain several sensors, controllers and an ESP32 (or similar) microcontroller. This BHA assembly will have functionality to collect information from all the sensors and aggregate it into a message group to send to the top assembly. The top assembly will have an ESP32 microcontroller and more sensors and controllers for controlling the above ground parts of the rig.

The communication between these two microcontrollers will happen with a low frequency wireless link that will go through several meters of rock without a problem. Hardware limit requirements and other software safeguards that pose an immediate problem will be handled by the microcontroller they are connected to. This will reduce the latency of the response time to near zero. Even in the event of total communication loss between platform and the BHA each component will be assured to not work outside its operational parameters.

Each link will pass up its information to the next link. BHA microcontroller to Platform microcontroller to GUI and high-level management software on a PC. All information flows from the bottom to the top in this manner. The control scheme on the other hand works in the opposite direction. The commands will be passed down from the PC to the Platform microcontroller to the BHA microcontroller. The platform

microcontroller can introduce new commands down to the BHA and will pop off it's own commands and prevent unnecessary data from being passed down to the BHA.

This process will be easy to understand and manage because it minimizes unnecessary information from being passed around. It also creates a clear command and control structure that prevents sloppy error prone code from being written later when there is far more control software. Combined this system will prevent damage to the system or operators while all hardware restrictions and responded to near instantly and operational information and commands have a definite route and structure.

The control system will be structured around minimizing the MSE [1], thus increasing the overall efficiency of the drilling action. Through the MSE we will be able to see what factors are limiting the ROP based on what is happening to the WOB and RPM. Our equation will also include the energy required to bend the drill pipe through sensor data from the bit-sub.

$$MSE = \frac{WOB}{A} + \frac{2\pi * RPM * T}{ROP * A} + \frac{EI}{\rho^2 \varphi A}$$

MSE: Mechanical specific energy

WOB: Weight on bit (measured by sensors)

A: Surface area of bit

RPM: Rotations per minute

ROP: Rate of penetration (measured by sensors)

T: Torque

E: Young's modulus of elasticity for steel

I: Moment of Inertia

ρ: Maximum displacement

φ: Maximum deformation slope

Control System

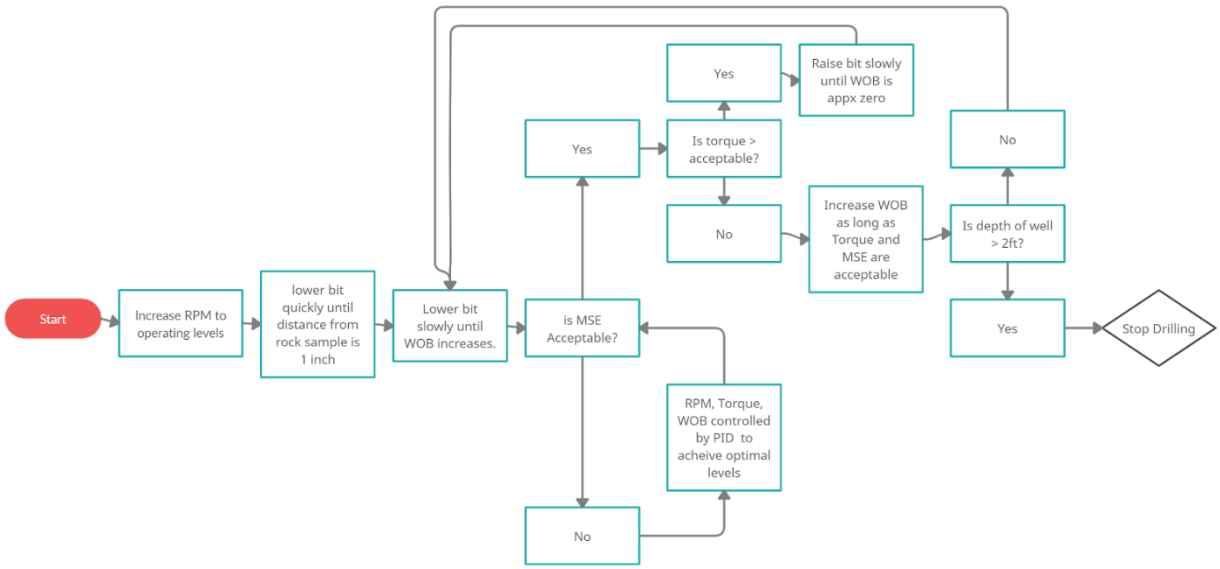

Figure 15: Block Diagram of the control system architecture.

We will be implementing a closed-loop system using sensor values and a PID controller to perform the drilling process. The main parameters to focus on are azimuth and inclination. Changes using system parameters (WOB and ROP control the direction of the drill bit) will be made to correct these parameters while drilling. More testing will allow for accurate calibrations, therefore better control of drilling.

As stated in the safety section, codes will be implemented to account for drilling problems. For example, when the code recognizes a high value for torque, it will stop rotating the bit. Changes will be made, and the drilling process will be restarted. Again, more testing will be done to optimize this process. All of this will be done in Phase 2 because that is the building phase and testing is possible; data from testing will provide

optimization values for the drilling system as a whole to be faster, more accurate, and safer.

Cost Analysis

Utah Valley University is entering the Drillbotics competition for its first time. The team is designing and constructing the rig from scratch because of this. This could lead to major changes being made in the build phase of the competition as the team discovers challenges during construction and testing of the control system. Any additional costs incurred to overcome those challenges will be added to the total cost of the rig and be reflected in Table 2.

Table 2: Total cost in US Dollars of parts if sent to competition, also includes Chargeable Weight.

PART	**PRICE (US Dollars)**
Ball Screw	99
Ball Screw Support Bearings	425
Linear Rails	120
Frame	695.08
Pressure Sensor	130.5
Flow Meter	274
Stepper Motor	40
Pump	860
Fluid Tank	170
Strain Gage	486.72
Load Cell	208
Torque Meter	150
ROP Sensor Laser	203
RPM Sensor	70
Accelerometer	7.12
Temp Probe	9.99
Control system Hardware	381.42
Total	**4329.83 US Dollars**
Chargeable Weight	**1224.51 lbs**

References

[1] Chen, Xuyue, et al. “Drilling Performance Optimization Based on Mechanical Specific Energy Technologies.” *Drilling*, 31 Oct. 2018, www.intechopen.com/books/drilling/drilling-performance-optimization-based-on-mechanical-specific-energy-technologies, 10.5772/intechopen.75827. Accessed 31 Oct. 2020.

[2] Drillingformulas.com. 2020. [online] Available at: http://www.drillingformulas.com/annular-velocity-calculation/

[3] Gerhart, Philip M. *Fundamentals of Fluid Mechanics Munson*. Hoboken, Nj, Wiley, 2016.

[4] Hughes, Baker. “PDC Micro-Bit for the 2020 SPE Drillbotics Competition.” *Drillbotics.com*,” 2020, drillbotics.com/wp-content/uploads/simple-file-list/Guidelines/Guidelines-2021/2021-

[5] Mitchell, John, and Drilbert Engineering. *Perforando Sin Problemas*. Woodlands, Tx, Drilbert Engineering, 2011.

[6] Norton, Robert L. *Machine Design: An Integrated Approach*. Boston, Prentice Hall, 2014.

Appendix A: Student Biographies

Devon Allen - Hard Team Lead

Degree: Bachelor of Science in Mechanical Engineering. Expected to graduate in May 2021.

Main area of contribution: 3-D Modeling, Fluid System, Control System

Michael Elliott - Soft Team Lead

Degrees: Robotics A.A.S. Spring 2017. Computer Science B.S. ETC Spring 2021.

Main Area of Contribution: Main graphical user interface developer.

Yousuf Mohan

Degree: Bachelor of Science in Mechanical Engineering. Expected to graduate in May 2021.

Main Area of Contribution: finite element analyses, design considerations, and control system design.

Matthew VanAlfen

Degree: Bachelor of Science in Mechanical Engineering. Expected to graduate in May 2021.

Main Area of Contribution: 3-D Modeling of Rig and sourcing materials.

Daniel Arias

Degree: Bachelor of Science in Mechanical Engineering. Expected to graduate in May 2021.

Main Area of Contribution: Safety Considerations.

Mike Abbott

Degree: Computer Science and Computer Engineering ETC. Expected to graduate in May 2022.

Main Area of Contribution: Control System Firmware and Electrical Design.

Appendix B: Summary of Calculations

Calculation	Formula	Reference	Result
Torque	$T = \frac{J\tau max}{r}$	[6]	65.52 lb-in
Buckling Limit	$Pcr = \frac{\pi 2EI}{(KL)2}$	[6]	316.36 lbf
Shear Force	$F = \frac{3\delta_{max}EI}{L^3} =$	[6]	0.429 lbf
Volumetric Flow Rate	$Q = A_{annulus} v_{annular}$	[3]	15 GPM
Head Loss	$h_{loss} = \left[f\frac{L}{D} + K\right]\frac{v2}{2g} + \Delta z$	[3]	14.5697 ft
Mechanical Specific Energy	$MSE = \frac{WOB}{A} + \frac{2\pi \cdot RPM \cdot T}{ROP \cdot A} + \frac{EI}{\rho^2 \varphi A}$	[1]	Depends on sensor readings for WOB and ROP.

Appendix C: FEA figures

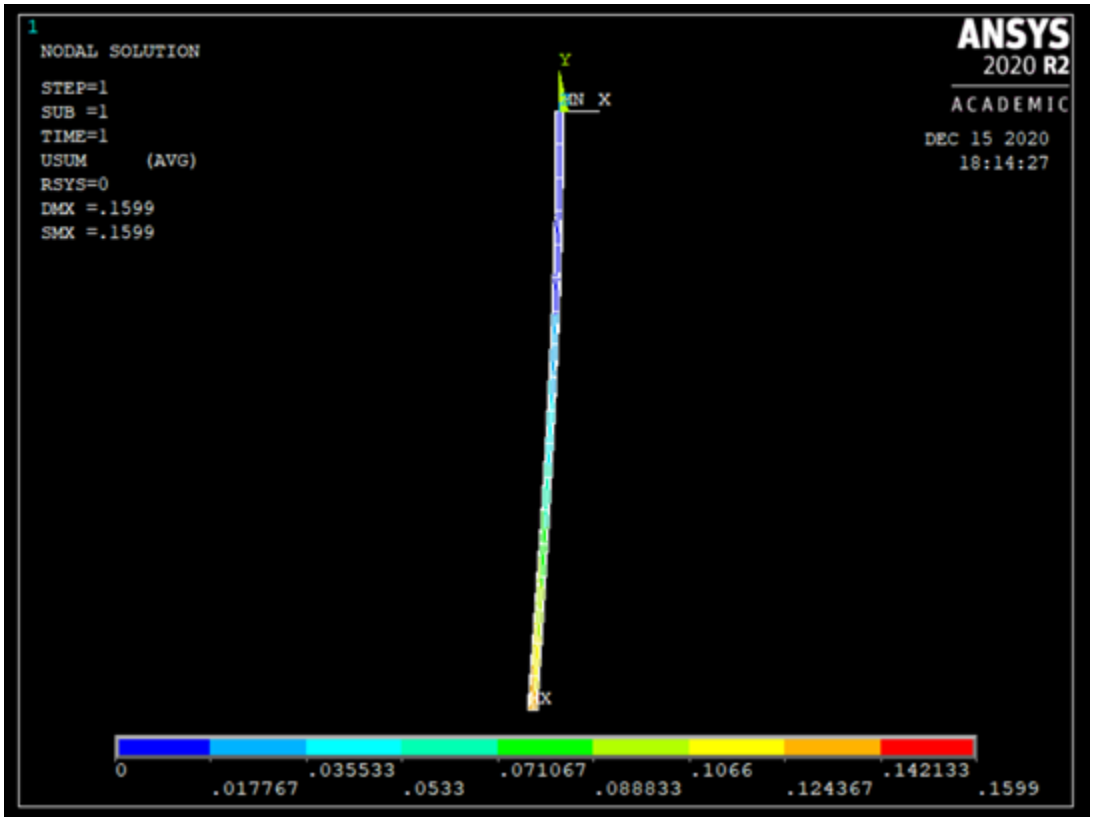

Figure showing the nodal-contour plot for the drill string.

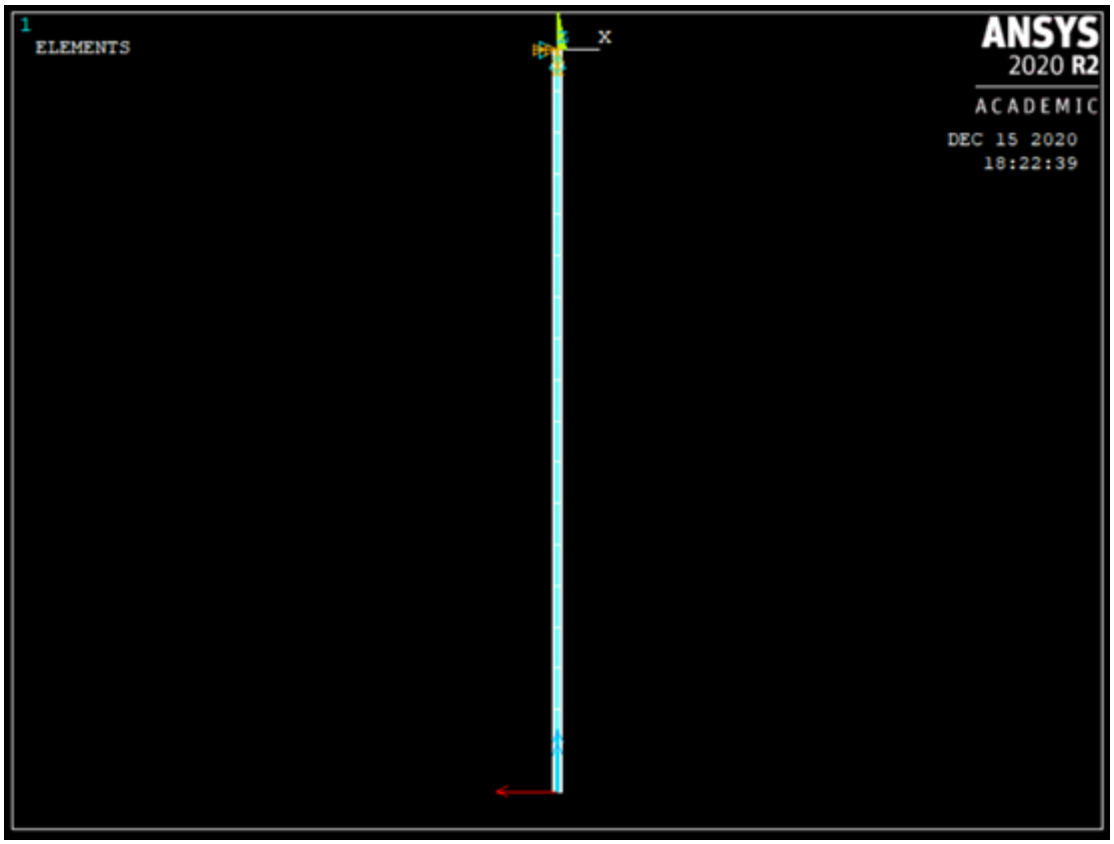

Figure showing the drill string with boundary conditions and loads applied at the bottom hole.

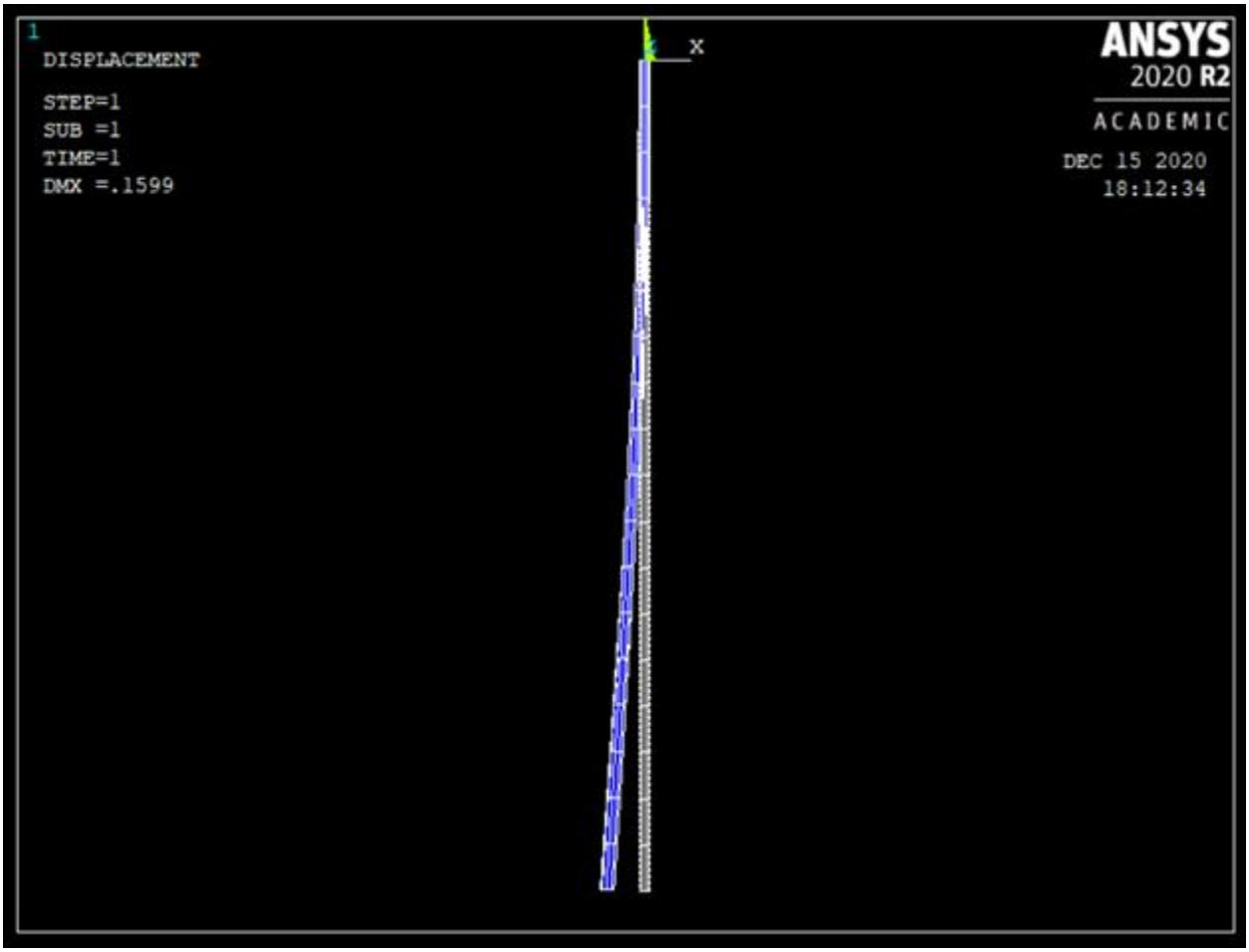

Figure showing the deformation of the drill string due to loads at the bottom hole.

Figure showing the drill string's reaction to a 12.23 Hz excitation (Modal).

Figure showing the drill string's reaction to a 4.33 Hz excitation (Modal).

Figure showing the drill string's reaction to a 0.69 Hz excitation (Modal).

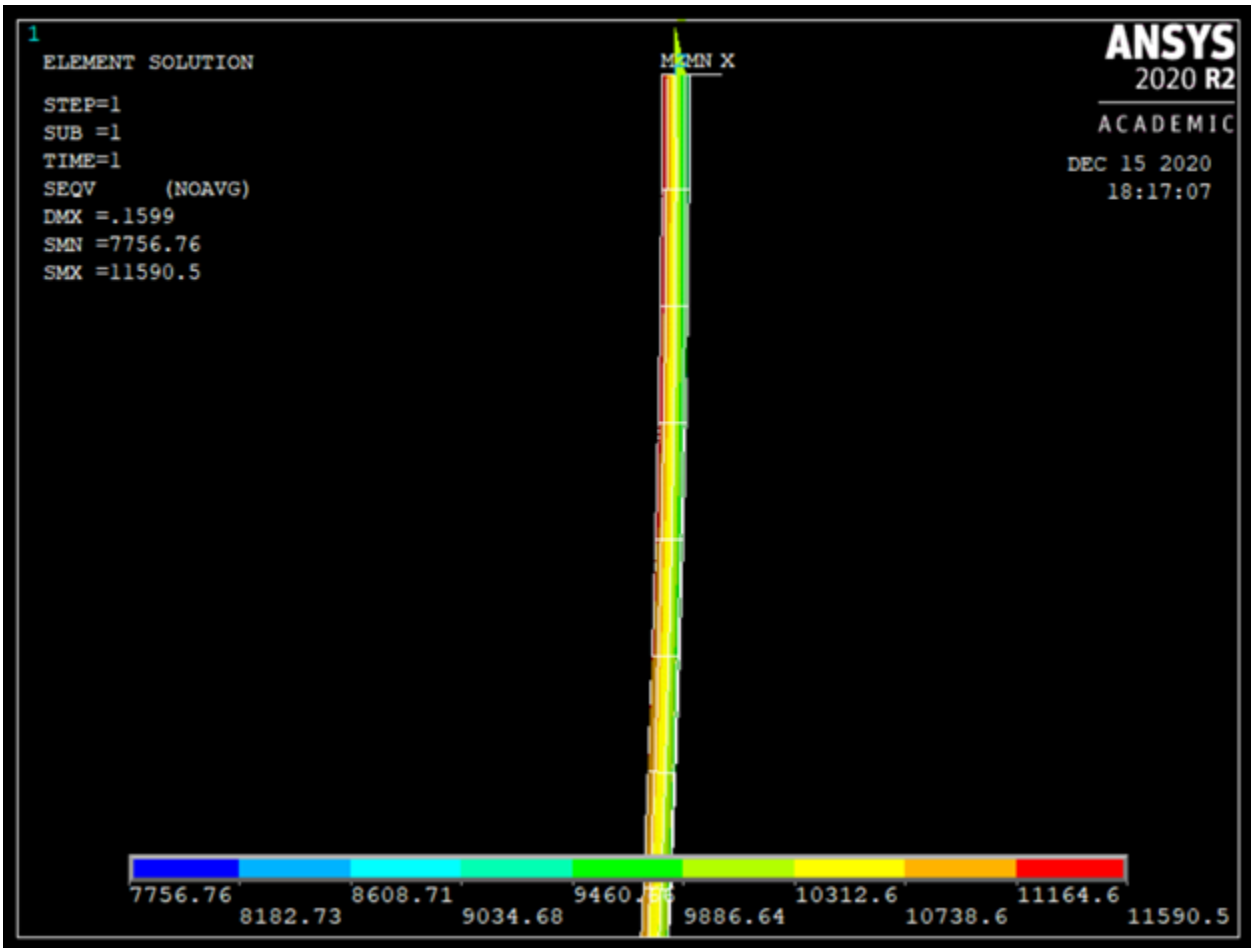

Figure showing the von mises stress on the drill string (it is zoomed in because the DMX is 0.1599 and the drill string is 36 in long, therefore it would be difficult to see the max stress values (red) when zoomed out).