Abstract

The Drilling Systems Automation Technical Section (DSATS) is a group of SPE volunteers from many nations, connected by their belief that drilling automation will have a long-term, positive influence on the drilling industry. DSATS implemented a student competition to encourage new entrants into the drilling industry who might consider creating and using automation tools and techniques in future drilling programs. The competition brings a hands on approach to the complex, multifaceted problem of drilling systems, expanding the breadth of knowledge and creative thought processes of the individuals who participate. This project challenges students who plan to become petroleum engineers and other students in related disciplines who may not currently think of the upstream drilling industry as a career opportunity. The competition requires university teams to design and build laboratory-scale drilling rigs to automatically drill through a sample of material unknown to the students. This paper presents the winning students’ summary of the rig design, construction and operation of their test results and how it relates to their new understanding of the drilling process.

In the fall of 2014, student teams from different petroleum engineering schools designed a rig that can drill through a concrete block filled with unknown formations while dealing with a drill bit and drillpipe chosen to ensure some common drilling dysfunctions. Based on the rig design, finalists from four universities were selected to move to the second phase of the competition (i.e. construction and testing phase). In the early-spring of 2015, the teams built their rigs. In May and June, they demonstrated the performance of their rig design and control algorithms by drilling the samples while witnessed by DSATS members. The winning team received a travel grant to attend the ATCE to present this paper that addresses:

- Drilling limitations and critical parameters
- Construction issues and initial operations that required a re-design
- Final design criteria, constraints, tradeoffs
- How key decisions were determined
- Summary of recorded data and key events
- Drilling parameters and how they impacted the test
We believe this to be the first competition of this kind that requires multi-disciplinary teams to work jointly within a university setting, which prepares them for the integrated team approach currently in use throughout our industry. Their designs are practical, but are not limited by the historical features that are commonly included in today’s commercial rig designs.

**Introduction and Overview**

DSATS established a sub-committee under charter from the technical section to develop and publish guidelines for a competition that would be challenging and inspiring and would hopefully encourage the adoption of automation tools and techniques in future drilling programs. The requirement for multi-disciplinary student teams teaches communication skills necessary to fully evaluate the nature of trade-offs needed to design and build a system to implement automated drilling. Sub-committee members designed the bit (Fig. 1), composite-rock block (Fig. 2), and drillstring (Fig. 3) for the final test so that the drilling would not be a trivial problem. In fact, no team was completely successful in drilling a composite-rock block of sandstone and marble using the bit and drillpipe provided by DSATS. However, the hands-on experience with the machinery, the sensors, data handling, and control requirements taught the students about more practical issues than was available in most university courses.

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**Figure 1—Drillbit**

**Figure 2—Composite-rock block**
A 1.125 inch (28.58 mm) microbit was provided by a major service company. The bit had two 0.529 inch (13.44 mm) PDC cutters with a 20 degree back rake. The two nozzles were each 0.093 inch (2.35 mm) diameter. This design provides students with a stability challenge at higher rotary speeds.

The composite-rock block was “manufactured” by another service company to be as homogenous as possible so no student team was disadvantaged with a different formation. A layer of granite was sandwiched between two samples of sandstone with unconfined compressive strength (UCS) ranging from 2 to 5 ksi; however, variability of only 10% between the samples.

If the drillstring was sufficiently stiff and resistant to buckling, there would be little challenge for developing a drilling system that encountered similar control problems to today’s conventional drilling. To make this more interesting, aluminum tubing was chosen that would be unstable and prone to buckling. The tubing chosen was round aluminum, 3/8 inch (9.53 mm) diameter x 36 inches (914 mm) long with a wall thickness of only 0.016 inch (0.41 mm). The thin wall tube could not be threaded, and tool joints were manufactured to tolerances closer than those of off-the-shelf plumbing hardware (fittings). This made the rotating dynamics of the drillstring as equal as possible for all teams.

Four university teams advanced to the second phase. They built their rigs and underwent a test conducted at each university, witnessed by DSATS sub-committee members. The winning team was selected by the committee using a scoring system that weighted certain criteria including safety, mobility, design considerations, functionality and performance. The control system and drilling algorithms were significant factors. Drilling performance metrics included ROP and wellbore quality. Data handling and visualization was also considered. Although some of these metrics could be measured directly or indirectly, the scorers had to include intangible criteria such as how well the students seemed to grasp the issues surrounding drilling automation.

In addition to the previously mentioned competition guidelines, DSATS provided several drilling limitations for the competition, including:

- The drilling machine must accurately and continuously monitor and control the Weight-on-Bit (WOB) which was limited to a maximum allowable value of 50 lbf.
- Teams were permitted to add sensors to the drillstring, but were not allowed to instrument the rock sample.
- Once drilling commences, the drilling machine must operate autonomously. Remote operation or any sort of intervention was not allowed, unless instructed by the DSATS sub-committee members.

Furthermore, the drilling machine total power consumption was limited to 2.5 HP while the rig maximum allowable expenditure was constrained to US $15,000 or its equivalent. Spending over $15,000 would result in elimination from the competition while spending over $10,000 would result in a penalty.
Drilling Limitations and Critical Parameters

The first task was to evaluate the drilling parameters and the limitations imposed by the DSATS supplied equipment to define a safe operating envelope.

Development of Theoretical Operating Envelope

As per the DSATS guidelines, a very weak drillstring was chosen to ensure drilling dysfunctions. Understanding the drillstring and bit mechanics is critical to mitigate such dysfunctions and ensure smooth operation with high rate of penetration (ROP). An important phenomenon in this regard is stick-slip, which is a severe torsional drillstring oscillation. These vibrations were found to be very secondary because the drillstring would fail in buckling or shear at the joints before any effective stick-slip could actually take place.

The drillstring specifications were received during the construction phase and theoretical analysis was carried out to determine the maximum load carrying capacity of the drillstring. Assuming both pipe ends were pinned, the thin-walled aluminum pipe had a buckling load limit of 99.4 lbf according to Euler buckling theory:

\[
F_b = \frac{\pi^2 E I}{(KL)^2} = \frac{\pi^2 993100 \cdot 0.000291}{(1 \cdot 17)^2} = 99.4 \text{ lbf}
\]

Assuming maximum shear stress of 30,000 psi, the torsional stress limit of the drill pipe as computed from Eq. (2) is 64 in-lbf.

\[
T_{\max} = \frac{\pi}{16} \sigma_{\max} \frac{OD^4 - ID^4}{OD} = \frac{\pi}{16} (30,000) \frac{0.375^4 - 0.354^4}{0.375} = 64 \text{ in \cdot lbf}
\]

Using the Barlow equation (Eq. 3), the pipe burst pressure of 2276 psi is predicted.

\[
P_b = \frac{2 \gamma_E \sigma_{\max}}{OD \cdot S_f} = \frac{2 \cdot 40000 \cdot 0.016}{0.0375 \cdot 1.5} = 2276 \text{ psi}
\]

These individual limiting parameters provided us with a better understanding and defined a safe operating envelope, which is crucial in designing and operating the rig. The limiting parameters are implemented in programming of the rig to monitor and control critical drilling parameters, specifically torque, WOB, and rotational speed. These three drilling parameters are very significant in optimizing the drilling process.

Mechanical Specific Energy

The instantaneous mechanical specific energy (MSE) is a helpful parameter in understanding and controlling the drilling system. According to Teale (1964), MSE is the ratio of total work done (the sum of thrust and rotary work per minute) per unit volume of rock excavated. A simplified form of this equation is expressed as:

\[
MSE = \frac{W_{OB}}{A_h} + \frac{2 \pi \cdot RPM \cdot T}{A_h \cdot ROP}
\]

Increasing ROP, minimizes MSE and maximizes bit performance, which makes it a crucial parameter to monitor while drilling.

Construction Challenges and Solutions

Design and Construction Challenges

Unpredicted challenges normally arise when a project is taken from the design phase to the construction phase. Several challenges were encountered during the development of the automatic drilling machine. Here are some of these construction issues along with the corrective measures taken to mitigate them:

Maintaining smooth and stable traveling-block movement  One major challenge was the railing system for the traveling block to move smoothly and accurately within the derrick. The derrick was built...
using a Unistrut metal framing system which was selected to serve as guiding rails for smooth wheels attached to the traveling block. Even though the Unistrut system was nearly frictionless, it was found to be too loose and unstable (due to lateral vibration) for the selected wheels. As a replacement, the team designed and built a Linear Bearing Railing (LBR) system in-house. Two ball bearing housings were machined from aluminum (Grade 6061) bars and bolted to the traveling block. The required linear bearings and aluminum shafts were purchased to fit the design and provide a very smooth and stable traveling-block movement.

**Changes in the drillstring design during the competition** Another significant challenge arose from changes in the drillstring design during the competition. Because the original drillstring design was stiffer and thicker, the rig was initially designed with a hydraulic top-drive in order to provide sufficient torque and therefore enhance the drilling process. However, when drillstring design was changed, the team immediately switched into a low-speed high-torque electric gearmotor. The size of the gearmotor was significantly larger than the hydraulic motor, so the derrick and traveling block had to be re-designed to accommodate the motor. In addition, due to the change in drillpipe diameter, a pump had to be incorporated to overcome the hydraulic resistance (pressure losses) of the drillstring. Additionally, an off-the-shelf swivel with low-pressure rating (90 psi) had to be replaced by a custom-made high-pressure (300 psi) swivel, which was too expensive to buy in the market. This led us to design and build a swivel in-house instead.

**Construction cost limitation** The cost limitation was also another challenge which forced the team to build many parts in-house, such as the rig substructure, derrick, travelling block, railing system, and swivel. As a result, in addition to designing and operating the rig, the students did the entire labor job, including cutting, grinding, welding, wiring, and soldering. The total rig cost was approximately 9,950 USD. Around 62% was spent on the control and measurement system, 11% on the structure and 27% on the hoisting, rotary and circulation systems.

**Safety Considerations**
Safety was one of the most critical considerations in the development of the design. As a result, a number of unsafe working conditions were identified during the design and construction phases and properly mitigated to avoid injuries. The following are some of the actions taken to improve safety of the rig operation:

- Electro-Pneumatic (EP) converters were used to control the pneumatic hoisting system, providing slow release of air from the cylinder which would prevent sudden drops of travelling block in case of emergency, such as power outage.
- Rubber bushings were mounted on the derrick bottom for safe and soft landing of the travelling block in case of mechanical failure.
- A fully transparent acrylic cover was installed to protect cards and other electronic components from unexpected water leaks.
- A fully transparent acrylic guard was installed around the water pump coupling to prevent entanglement and injury to the rig operators.
- Flexible plastic conduit was utilized to cover wires and therefore prevent mechanical damage during block movement.
- A number of computer codes (soft buttons) were implemented in the data acquisition program to safely move the travelling block up and down and fully stop all components in case of emergency.
- Variable speed drives (VDFs) were placed away from the derrick to avoid water splash.
As-built Rig Design

The rig structure (Fig. 4) consists of five major parts: i) Rig Substructure; ii) Hoisting System; iii) Rig Mast and Travelling Block; iv) Rotary System; v) Circulation System; vi) Instrumentation, Measurement and Control System.

Rig Substructure

The rig substructure was designed to be built in-house using 1½” square-iron tubing with overall dimensions of 84” x 27” x 36”. To allow rig mobility, five commercial grade caster wheels are included, each with load capacity of 1000 lbs. A 47” x 27” shelf made of ¼” thick iron sheet was included to offer extra space for rig parts. This left the rig with a space of 37” x 27” x 36” to accommodate the rock sample. This substructure was designed to pass through doors, so the rig could be used for future educational purposes. In-house built structures have been found to be significantly cheaper than readymade structures in the market. Moreover, the former has provided flexibility in the selection of dimensions, load ratings, and design styles.
**Hoisting System**
During the design phase, different hoisting systems were considered including: block and tackle, electro-mechanical, hydraulic, hydraulic-pneumatic hybrid, and pneumatic systems. Upon the evaluation of the systems for this particular application, it was decided that the conventional drawworks-type system would not be suitable due to the lack of rigidity and the difficulty in precise control of WOB and dampening drillstring vibration. The lead screw (power screw) of the electro-mechanical system would incur frictional losses and require a braking system while the electro-mechanical system would be relatively costly. The hydraulic system was not chosen due to safety concerns when dealing with high-pressure hydraulic lines along with the slow response to changing drilling environments. Considering effectiveness, ease of operation, and cost, the hybrid and hoisting systems was found to be the most suitable. The latter was selected because it was easier to implement and less costly. A double-acting 2-inch bore pneumatic cylinder with pressure capacity of 250 psi and stroke length of 3 ft was purchased and installed to operate with two EP converters, which precisely controlled the pneumatic pressure acting on both sides of the cylinder.

**Rig Mast and Travelling Block**
A compact rig mast (dimension 12” x 13” x 70”) was designed to be built with Unistrut frames as it enabled easier connections and mounting of equipment, such as the pneumatic cylinder, EP converters, and displacement sensor. The mast was mounted on the substructure using Unistrut connectors (two L-shaped and two hinge connectors), so that the rig could recline to a total height of 6 ft during transportation. The travelling block was designed to fit into the mast structure. The block is made of angle iron with dimensions of 8” x 8” x 27”. It was designed to accommodate space for the swivel, gearmotor, thrust bearing, load cell, and crossovers. The block was designed to travel up to a full cylinder stroke of 32”. It moved smoothly using two 1-inch thick polished aluminum shafts each equipped with a linear bearing system.

**Rotary System**
The drillstring could be rotated using either top-drive system or rotary table drive. The use of a rotary table drive required a kelly which would exceed the DSATS height requirement of the rig, so it was eliminated. Two options were considered for the top-drive: hydraulic and electric motors. Hydraulic systems are more complex and expensive. They also provide very high torques, which is detrimental to the drillstring. In addition, motor power decreases with temperature due to reduction in fluid viscosity. Electric motors are more environmentally friendly as they rely only on electricity. Simple design of the electric top-drive system makes it very efficient as electrical energy is directly transformed into rotational kinetic energy. Most electric top-drives have an average efficiency of 85% to 90%. The electric top-drive option was found to be superior. Hence, a ½-HP gearmotor with full load torque capacity of 105 in-lbs and maximum rotational speed of 276 rpm was used as the top-drive rotary system. A 1-HP variable frequency drive (VFD) with analog input capability was used to accurately control the motor speed.

**Circulation System**
Though the DSATS guidelines do not require a circulation system, this system was incorporated to circulate the cuttings, cool the bit, and reduce the buckling tendency of the drillstring. Assuming surface and borehole circulation conditions, a tap water circulation rate of 6 gpm yields cuttings transport ratio of 85%, cuttings transport velocity of 0.331 ft/s, and total pressure loss of 162 psi. The pressure loss is mainly due to the very narrow microbit nozzles which alone causes 135 psi pressure loss. To circulate the water at this flow rate, a 1.3-HP roller pump with flow capacity of 5.6 gpm at 200 psi discharge pressure was installed. The pump was driven by an electric motor, which was connected to a 1.5-HP VFD for control of the flow rate. A swivel was made in-house using brass housing, a punctured steel pipe, bearings, and seals. Due to fluid circulation, hydraulic pressure and jet-impact forces develop at the bit. During the
test, the flow rate and stand pipe pressures were 4 gpm and 80 psi, respectively. Based on these inputs, the jet-impact force at the nozzles was calculated as:

\[
F_j = 0.01823 \times C_d \times q \times \sqrt{\rho_w \Delta P_b} = 0.01823(0.95)(4) \times \sqrt{(8.33)(80)} = 1.9 \text{ lbf}
\]  

(5)

Similarly, the hydraulic pressure force was estimated as:

\[
F_{hyd} = A_{act} \times \Delta P_b = \frac{\pi}{4}(0.343^2 - 2 \times 0.093^2) \times 80 = 6.3 \text{ lbf}
\]  

(6)

where \(A_{act}\) is active area on which the hydraulic pressure force acts. It is the bottom inner area of the bit minus the areas of the nozzles. These two forces affect the effective compression load acting on the drillstring. The pressure force reduces the load while the jet-impact force tends to increase it. Therefore, the circulation of the fluid reduced the compression load by 4.8 lbf, which is approximately 16% of the WOB used for drilling the rock.

**Measurement, Control, and Instrumentation System**

The rig design incorporated PC-based control systems as they are flexible, inexpensive, easy to program, and capable of managing the generated data. Furthermore, they are not tied to the hardware platform, support multiple programming languages, and provide fast communication between the control programs and rig equipment. The control program interacts with the sensors and devices using analog and digital inputs/outputs features of USB based Omega data acquisition module and Phidget bridge card.

The VBA programming language was preferred to write the autonomous drilling operation code. Meanwhile, Excel was preferred for displaying and recording of different operating parameters, including WOB, ROP, depth, torque, standpipe pressure, mud flow rate, and MSE. In order to establish an effective, autonomous drilling process, various drilling parameters must be simultaneously measured and controlled. Figure 5 shows a process and instrumentation diagram (P & ID) highlighting the major rig sensors and parts. The rig was built and completed as per this design. The diagram presents important sensors, data acquisition cards and control devices used for operating the rig in automatic mode.

**Data Acquisition Module** A USB based data acquisition module was used to collect data and control the process and equipment. This 1 MHz, 16 bit module has 16 single ended analog input channels, four analog output channels and 24 digital I/O channels.
**Load Cell**  The tension/compression load cell (Fig. 6) was used to provide an indirect measurement of WOB. This cell has a load capacity of 100 lbf. It was mounted between the hoisting cylinder and the travelling block.

![Figure 6—Load cell](image)

**Tachometer**  The rotational speed directly affects ROP and drillstring vibrations, which makes it a very critical parameter to ensure a safe and optimum drilling process. An optical RPM sensor (Fig 7) was mounted at the travelling block to measure the rotational speed of the crossover sub, which connects the swivel to the drill pipe.

![Figure 7—Optical tachometer](image)

**Displacement Sensor**  Measuring the drilled depth is essential for monitoring ROP. An optical laser displacement sensor was selected. This sensor has a operating range of 100 mm to 1000 mm with an accuracy of 0.5 mm for our application. It was installed on top of the rig derrick (Fig. 8) to monitor the position of the travelling block and therefore the drilled depth.
Strain Gauges, Interface Board, and Slip-Ring  Several strain gauges are installed on the crossover to measure the weight and torque acting on the bit. A full-bridge steel strain gauge was installed to measure the torque. The strain gauges were covered with epoxy to avoid contact with water. A 4-input interface board was connected to the strain gauges to measure the output. The slip ring (contact ring) maintained connectivity between the interface board and the computer while the crossover was in rotation.

Current sensors  A clamp-type current meter was used to measure the power consumed by the electric motor. The power measurement along with RPM reading and motor efficiency was used to estimate the torque generated at the motor shaft.

Pressure Transducers  As discussed in the design section, a high pressure pump was incorporated to circulate the cuttings, cool the bit, stabilize the vibrating thin-walled drillstring, and reduce buckling tendencies. A 250-psi, 0.5% pressure transducer was installed on the water line to measure the standpipe pressure. Moreover, two 100-psi pressure transducers were installed on the air-line to measure the pressures in the upper and lower chambers of the pneumatic cylinder.

Electro-pneumatic converters  Two EP converters were used to control air pressure in the top and bottom chambers of the pneumatic cylinder. These EP converters are capable of controlling pressure between 3 and 100 psig. They were installed on top of the derrick, adjacent to the cylinder.

Flow Meter  A digital flow meter was installed downstream of the water pump (Fig. 9) to measure flow rates and therefore monitor the cutting transport ratio and annular fluid velocity. This meter can measure flow rates ranging from 1 to 15 gpm, which was suitable for our application.
Testing and Optimization Procedure

Determination of Actual Operating-Envelope
Experiments were carried out on different rock samples with in-house made drill bits (Figs 10 and 11) to analyze the reaction of the drillstring to various operating conditions. The drill pipe was found to fail due to different reasons, mainly buckling, twisting, and shearing at the joints. These conditions are directly related to two basic drilling parameters: WOB and rotational speed. Once the actual competition bit was received, an operating envelope (Fig. 12) was developed by running drilling experiments on sandstone rock with different combinations of WOB and RPM. The red line (Fig. 13) represents the envelope after theoretically accounting for pressure and jet-impact forces which resulted from fluid circulation. The first operating point was successfully chosen to be in the operating-envelope to optimize the drilling process. However, after the rotational speed was increased to the second point, the operating conditions came too close to the failure zone causing joint breakage. This is an actual operating envelope, which was developed by performing ten rig experiments (data points shown in Fig. 12). For each test run, the rig was programmed to operate at a constant rotational speed and slowly increase the WOB until the drillstring fails. Then, the failure point was recorded. At high rotational speeds, the drill pipe failed while running in the air (i.e. before teaching the rock) due to bending resulting from drillstring imbalance caused by very high drillbit weight compared to the bending stiffness of the drillpipe. Hence, before each run, a ¼-inch deep shallow hole was drilled first with 55 rpm and then RPM was increased to the desired value for that specific test run. This shallow hole eliminated excessive wobbling and bending encountered at high rotational speeds.

Figure 10—In-house bit using a solid steel bar and hardened steel inserts

Figure 11—Modified concrete bit with two nozzles
The y-intercept of Fig. 12 represents an experimental drill pipe buckling limit of 98 lbf, which is approximately the same as theoretically predicted limit (99 lbf). This plot also shows a relatively narrow safe zone at higher rotational speeds due to the significant vibration and wobbling due to heavy bit and collar weight compared to the very light and flexible drill pipe. The tests were needed to optimize the drilling operation.

**Drilling Control Algorithm**

Rotational speed and WOB were the two main parameters utilized to control the drilling operation. These two drilling parameters directly affect torque, which makes them critical in preventing the drillstring from going beyond its torsional limits. The algorithm basically aims to optimize the operation by maximizing ROP while maintaining the weak drillstring intact. A proportional-integral-derivative (PID) control loop was first suggested to control WOB where a WOB set point was introduced while maintaining the pipe below its buckling and torsional limits. Though this algorithm showed convergences towards the WOB set point, it was accompanied with considerable oscillation due to time lag and undesirable excess gain in one or more of the three controlling terms: P, I, and D. Instead, a more stable only P algorithm (Fig. 14) was introduced to control WOB while maintaining rotational speed, and WOB below the set limits, using the operating envelope. The set point for WOB varies according to computer code.
Rig Test Results and Key Events

Operating Challenges
A couple of days prior to the rig competition day, the swivel showed unexpected leaks. The leaks disturbed the operation of the strain gauges. Hence, the gauges were disabled in order to avoid a short circuit. Instead, indirect measurements of WOB were obtained through the load cell which had an error of \( \pm 2 \text{ lbs} \) due to friction at the linear bearings.

Another challenge was the high wobbling tendencies of the drillstring at higher RPM due to heavy bit and collar weights compared to the very light and flimsy drill pipe. Such wobbling is very detrimental as it results in irregular and rugose holes with diameters larger than desired. To counter this problem, the rig was programmed to start the drilling process at low rotational speed and WOB to prevent excessive wobbling and bit walking. Once the hole was initiated, the rotational speed was increased as per the rig program. The provided PDC bit has two cutters with uneven height which caused walking tendencies especially when initiating the hole, and along with the previously discussed wobbling effect, it was very challenging to control the drill pipe and prevent bending and twisting. To reduce the bit walking effect, a wooden guide shoe was installed on the bottom of the casing as shown in Fig. 15. This effectively guided the bit and helped mitigate bit walking and wobbling at the start of drilling a hole. After drilling a shallow depth (about \( 1/4" \)), bit walking and wobbling effect becomes negligible.
Rig Performance Demonstration Test Results and Analysis

On the competition day, water and air sources were first turned on and electric cables were extended to provide electricity. Based on previous experiments and analysis of the drillstring failure conditions, torque, WOB set point, and rotational speeds were limited but not restricted to 65 in-lbf, 30 lbf, and 138 rpm, respectively. The rig start button was clicked and the rig started the drilling process. The rig autonomously started the pump, top-drive, and pneumatic cylinder which started lowering the traveling block slowly and yielded a smooth bit landing. Bit walking and wobbling were mitigated at this point through the use of the wooden bit guide. Once the bit touched the rock, the rig started optimizing the rotational speed and WOB. The rig maximized the WOB and rotational speed since the torque limit was not reached. Figure 13 shows the operating condition (Operating Point 1) with respect to the drillstring operating envelope. The maximum operating conditions were set slightly below the failure line to provide an operating margin for unpredicted encounters while drilling. The top 12” sandstone layer was drilled in about 70 minutes with an average ROP of 0.86 ft/hr.

Once the bit reached the granite layer, there was no increase in depth (Fig. 16a). The depth measurement shows a drilled depth of approximately 12 inches. The ROP sharply decreased to a mean value of zero at about the 70th minute (Fig. 16b). Granite is one of the hardest rocks and drilling it with such relatively small WOB using a PDC bit is quite difficult and time consuming. As indicated by motor current measurements, torque slightly increased. However, the new torque value was still below the drillstring torsional limit, so the rig maintained the same WOB and rotational speed. The rig continued drilling but only drilled 1/8” of the granite layer after about 80 minutes since it first reached the granite layer. The team was then asked to think of a real-life solution and change drilling parameter limits if needed. Since no other drilling bit was provided, the team decided to increase the rotational speed. The WOB limit was temporarily decreased to 20 lbf (Fig. 16c) while the rotational speed set point was increased to 193 rpm. After the new rotational speed set point was reached, the WOB limit was brought back to 30 lbs. The rig was given a few minutes for each step in order to optimize the new limits without reaching the set torque limit. After the rig brought the WOB back to 30 lbs, the rig was still at about the same depth without significant progress. Upon pulling out the drillstring, the pipe was found sheared from the bottom end due to the screw in the connection. Different test parameters were recorded and some were displayed.
After drilling, wear on the bit body was only visible on ¾ of the circumference (Fig. 17). This one-sided wear can be attributed to forward bit whirl. The whirling is due to lateral and/or other types (torsional and axial) of vibrations in the drillstring assembly. This vibration is also enhanced by the weight imbalance between the bit and drillstring which causes centrifugal wobbling of drillstring. Whirl could have caused irregular lateral and/or torsional forces at the bit/drill pipe connection which enhanced the shearing effect. Since the bit and collar size are very similar, the collar/hole contact area is relatively large, so only the small collar area could escape the wear due to the forward whirl. Figure 18 shows that the sheared end of the drill pipe, which had significant ruggedness even after running inside the joint after being sheared which indicates that the joint failure occurred only a few minutes before the rig operation was stopped; otherwise, it would have been flatter and smoother.

Figure 16—Rig operating parameters during the demonstration test: a) Bit depth; b) ROP; and c) WOB

Figure 17—One-sided wear on the bit body due to forward whirl

Figure 18—Sheared, rugged drillstring after drilling test
Lesson Learned, Conclusions and Recommendations

Lesson Learned
All the participating students were seeking a petroleum engineering degree, but had different engineering backgrounds. The following are the student key learnings:

- Safety is highly important. The appropriate personal protective equipment (PPE) are vital while working in a workshop.
- The use of engineering skills to design and construct a drilling machine under real-life constraints.
- In-house fabrication skills such as cutting, grinding, boring, welding, machining, wiring, soldering, etc.
- Appreciation of the importance of the balance between design, construction quality and financial limitations.
- Teamwork and communication is critical to enhance productivity and efficiency.

Conclusions

After testing the performance of the automatic rig, measured test parameters were analyzed, drillbit and drillpipe were recovered and carefully examined, and quality of the wellbore was evaluated. Based on this information, the following conclusions can be made:

- Bit guiding is an effective technique to reduce bit walking which is a common tendency for PDC bits.
- Pressurizing the drill pipe helps reduce buckling tendencies allowing greater WOB, along with improved cutting transport ratio and jetting effect.
- PDC bits are not efficient in drilling very hard igneous rocks such as granite
- The pipe failed gradually from the shearing action of the screw inside the connection after the RPM was increased.
- The joint failure occurred only a few minutes before the operation was stopped; otherwise, it would have been flatter and smoother.
- The one-sided wear of the bit collar indicates a forward bit whirl during the drilling process

Recommendations

- A threaded pipe connection could be used for the drill pipe. The screw type pin connection in the current design shears the aluminum drillpipe at a significantly lower stress concentration than the torsional strength of the pipe.
- Use other types of bits instead of a PDC bit to penetrate the granite layer.
- Build in-house only if the part or system is too expensive or hard to acquire within a reasonable time frame. Otherwise, purchase off-the-shelf items if they are affordable.
- The U-cup seals in the swivel could be upgraded to a better quality to stop leakage. Moreover, it is important to note that rotating the swivel without fluid circulation (i.e. dry run) significantly shortens the life of the seals.
- Calibration of the sensors and pressure control in the air cylinder for smooth landing could be improved with more time and experiments.
- Strain gauges are affected by the electromagnetic waves coming from the VFD’s. A Faraday cage is necessary to isolate the VFD from the strain sensors.

DSATS Overall Results and Improvements

With respect to all of the university teams, the students did an excellent job building a scaled-down rig. All of the key drilling machines were replicated: top drive, drawworks and mud pump. All of the machines
performed as expected. The automated control systems ran in a hands-free mode during the tests. A very few times, the committee allowed the students to adjust set points, returning to automated drilling using the new values. Most of the teams started out with PID control loops that were too slow for proper control, moving to faster networks with less than one second response. In general, the complexity of the control algorithms was oversimplified resulting in an auto-driller that worked in a homogenous formation, but had difficulty when encountering a harder interval. Most teams controlled on only one parameter, although one monitored two, and due to the perceived interdependence, they only controlled on one. All of the teams gained a new appreciation for sensors, data quality and data handling.

The thin-walled drillpipe, run in compression led to severe vibrations resulting in fatigue failures. This typically occurred within the recess of the brass tool-joints. Without an accurate torque measurement, it was difficult to detect because the tube was still constrained by the tool-joint. Because DSATS worried about the tool-joint twisting off of the tube, a screw (Fig. 19) was used to prevent any turning, and this stress riser (i.e. stress concentration) led to the failure shown in Fig. 18.

![Drillstring tool-joint design](image)

Figure 19—Drillstring tool-joint design

For next year’s competition, the main adjustment will be the rock. The layers will be thinner and will not be co-planar. The transitions will not be visible from the exterior. There will be minor adjustments to the pipe connections and perhaps the tube. The same bits will be used, but the students can add limited weight to the BHA. Downhole sensors are encouraged. The challenge is to drill a vertical well as safely and quickly as possible using hands-free automation techniques.

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**Nomenclature**

- $A_{act}$ = Active area for hydraulic pressure force, in²
- $C_d$ = Discharge Coefficient
- $d_b$ = Bit diameter, in
- $E$ = Modulus of elasticity, psi
- $F_{b,J}$ = Maximum buckling force, lbf
- $F_{hyd}$ = Jet-impact force, lbf
- $F_{hyd}$ = Hydraulic pressure force, psi
- $I$ = Area moment of inertia of the pipe, in^4
- $ID$ = Inner diameter of pipe, in
- $K$ = Column effective length factor
- $MSE$ = Mechanical specific energy, psi
- $OD$ = Outer diameter of pipe, in
- $P_b$ = Working burst pressure of the pipe, psi
- $q$ = Flow rate, gpm
- $ROP$ = Rate of penetration, in/min
- $RPM$ = Rotational speed, rpm
- $S_f$ = Safety factor
- $t$ = Pipe thickness, in
- $T$ = Bit torque, in-lbs
- $T_{max}$ = Maximum torque of pipe, in-lbs
- $WOB$ = Weight on bit, lbf
- $Y_p$ = Minimum yield strength of the pipe, psi
- $\sigma_{mas}$ = Maximum shear stress of pipe, psi
- $\Delta P_b$ = Pressure loss across bit, psi

**References**

