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Topic

**Application of Modified Integral Resonant
Control for suppressing stick–slip oscillations in
drill-strings.**

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Abstract

This thesis addresses the issue of unwanted downhole vibrations that hinder the efficiency of drilling operations, increasing costs and associated risks. The focus is on the "stick-slip" vibrations phenomenon, one of the significant challenges in deep drilling operations. Simulation results demonstrated that applying an MIRC controller can effectively reduce these vibrations and improve the stability of drilling operations. The simulation model illustrates how this controller can be integrated with the drilling system to achieve quick and precise responses to changes in torque, enhancing drilling efficiency and reducing bit wear and equipment failure.

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Introduction

1. Background of the study

Drilling is a process used to extract oil and natural gas or to explore natural resources under the surface of the earth. The process includes using special equipment to drill a well in the ground with the aim of reaching layers containing oil or gas. The process of drilling deep wells faces challenges such as unwanted vibrations resulted from interactions between the drill string and rock formation. These vibrations can be categorized into three main classes : axial, torsional, and lateral vibrations. A stick-slip event is a severe form of torsional vibration, where the drill bit experiences intermittent rotation. This occurs when the bit becomes temporarily stuck due to friction between the bit and the rock formation. Once the accumulated torque exceeds the static friction, the bit suddenly slips and rotates rapidly.

The stick slip event can accelerate wear and failure of the drill bit, reduce the drilling speed , increased risk of surface equipment failure, and increase the drilling operation costs. Thus, it is very important to detect and mitigate stick-slip issues by observing and analyzing drilling data. Anomalous changes in torque readings can be indicative of stick-slip issues, where torque may increase or decrease unexpectedly.

2. Literature Review

Many researchers have presented control strategies to address the stick-slip phenomenon. For instance, J. D. Jansen et al. (2010) proposed the use of active damping control systems to mitigate torsional vibrations in drilling systems . Abdelbaset Laib and his colleagues (2016) focused on fuzzy PID controllers to manage the nonlinearities and uncertainties inherent in drilling operations . Eva M. Navarro-López and James D.J. MacLean (2009) explored linear state feedback control for stabilizing the drill string dynamics . B. Besselink et al. (2013) discussed integrated resonance control systems designed to counteract the natural frequencies that exacerbate stick-slip vibrations .PID controllers play a crucial role in these control strategies. The proportional (P) term adjusts the input torque proportionally to the current error, providing an immediate response to deviations between the desired and actual torque, thus helping to reduce stick-slip vibrations. The integral (I) term addresses persistent errors that may accumulate during prolonged stick-slip conditions by integrating the error over time. The derivative (D) term

anticipates future errors by considering the rate of change of the error, assisting in damping rapid changes in torque, preventing overshooting and oscillations. Together, these components work synergistically to generate a corrective control signal (output signal) that adjusts the control variable (such as torque in the case of drill bit control) to accurately and quickly steer the system toward the desired value .

3. Motivation and Contribution (Thesis objectives)

In this thesis, we discussed the application of MIRC controller to regulate the input torque during drilling operations in order to continuously minimize the difference between the top and bottom velocities and thus mitigating the stick slip event.

Chapter I. Theoretical background: Drilling process and Equipment

1. Introduction

Drilling is a process whereby a hole is bored using a drill bit to create a well for oil and natural gas production. There are various kinds of oil wells with different functions:

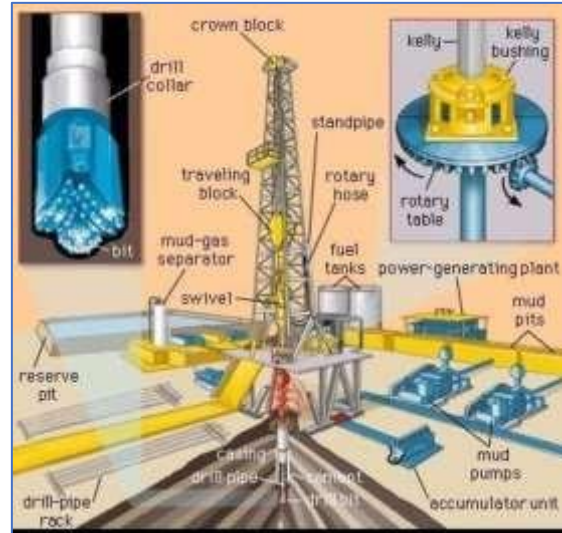
- Exploration wells (or wildcat wells) are drilled for exploration purposes in new areas. The location of the exploration well is determined by geologists.
- Appraisal wells are those drilled to assess the characteristics of a proven petroleum reserve such as flow rate.
- Development or production wells are drilled for the production of oil or gas in fields of proven economic and recoverable oil or gas
- Relief wells are drilled to stop the flow from a reservoir when a production well has experienced a blowout.
- An injection well is drilled to enable petroleum engineers to inject steam, carbon dioxide and other substances into an oil producing unit so as to maintain reservoir pressure or to lower the viscosity of the oil, allowing it to flow into a nearby well.

The process of drilling an oil and natural gas production well involves several important steps:

- Boring – a drill bit and pipe are used to create a hole vertically into the ground. Sometimes, drilling operations cannot be completed directly above an oil or gas reservoir, for example, when reserves are situated under residential areas. Fortunately, a process called directional drilling can be done to bore a well at an angle. This process is done by boring a vertical well and then angling it towards the reservoir.
- Circulation – drilling mud is circulated into the hole and back to the surface for various functions including the removal of rock cuttings from the hole and the maintenance of working temperatures and pressures.
- Casing – once the hole is at the desired depth, the well requires a cement casing to prevent collapse.

Figure 1. Drilling rig system

- Completion – after a well has been cased, it needs to be readied for production. Small holes of the casing which passed through the production zone, to provide a path for the oil or gas to flow.
- Production – this is the phase of the well's life where it actually produces oil and/or gas.
- Abandonment – when a well has reached the end of its useful life (this is usually determined by economics), it is plugged and abandoned to protect the surrounding environment.



2. Drilling Rig Systems

The rig is basically comprised of a derrick, the drawworks with its drilling line, crown block and traveling block, and a drilling fluid circulation system including the standpipe, rotary hose, drilling fluid pits and pumps. These components work together to accomplish the three main functions of all rotary rigs:

- Hoisting System
- Circulating System
- Rotating System

2. 1. The Hoisting System

The derrick supports the hook and elevators by means of the traveling block, drilling line, crown block and draw works. The draw works is powered by prime movers - two, three or even four engines.

2. 1. 1. Derrick

The derrick is a metallic structure which has four supporting legs resting on a square base. It is erected on a substructure which supports the rig floor and the rotary table and provides work space on the rig floor.

The derrick and its substructure support the weight of the drillstem at all times. The drillstem is suspended by the traveling block and drilling line, the entire load rests on the derrick. Whenever it is suspended from the crown block or resting in the rotary table. The height of the derrick does not affect its load-capacity, but it can limit the length of drill pipe sections that can be pulled out of the hole for many reasons (ex: changing drill bit). This is because the crown block must be sufficiently elevated above the rig floor

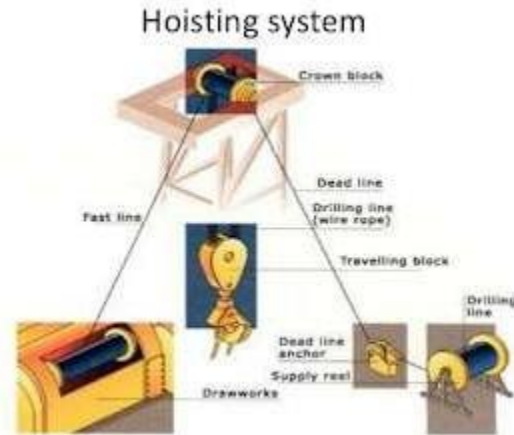


Figure 2. derrick

2. 1. 2. Traveling Block, Crown Block, Drill Line and Hook

The traveling block, crown block and drilling line are used to connect the derrick with the drill string to be lowered into or pulled out of the hole. During drilling operations, this drill string usually composed of the drill pipe, heavy weight drill pipe, drilling jar, drill collars and drill bit. The drilling line passes from the drawworks to the top of the derrick. From there, it is sheaved between the crown block and traveling block to give an eight, ten or twelve-line suspension. It is then clamped to the rig floor by the deadline anchor. The drilling line wears evenly as it is used; it has to be Cutoff time to time. The cutoff procedures are related to ton-miles of service. The ton-mile unit is calculated as the drill line moves a one-ton load a distance of one mile, and then the line receives one ton-mile of usage.

2.1. 3. The Drawworks

The main purpose of the drawworks is to lift the drillstring out of and to lower it back into the borehole. The drilling line is reeled on a drum in the drawworks. When engaged, the drum turns and either reel-in the drill line to raise the traveling block, or reel-out the drill line to lower it.



Figure 3. Travelling Block,crown block,drill line and hook

The drawworks is characterized by the brake system, which enables the driller to easily control a load of thousands of pounds of drillpipe or casing. There are at least two brake systems. One brake is a mechanical friction device and can bring the load to a complete stop.



Figure 4. Drawwork

The other brake is hydraulic or electric; it can control the speed of the descent of a loaded traveling block, but is not capable of bringing it to a complete stop. It is used to reduce the wear on the primary friction system.

An integral part of the drawworks is the transmission system. This gives the driller a wide choice of speeds for hoisting the drillstring. The drawworks also has a drive sprocket that drives the rotary table by means of a heavy-duty chain. In some cases, however, the rotary table is driven by an independent engine or electric motor.

Another feature of the drawworks is the two catheads. The make-up cathead, on the driller's side, is used to spin up and tighten the drillpipe joints. The other, located opposite the driller's position on the drawworks is the breakout cathead. It is used to loosen the drillpipe when the drillpipe is pulled out of hole.

2. 2. Circulating system

During drilling operations, In order to circulate the drilling fluids, the circulating system, mud pumps and prime movers are used. The drilling fluids are circulated from the mud tanks, through the drillstring, down to the bit and up to the surface through annulus. The cuttings are displaced from the bottom, up to the surface and separated from the drilling fluids using the shale shakers and mud cleaner. The recovered cuttings can be used by geologists to identify which formation is being drilled.



Figure 5. MUD PUMPS

2. 2. 1. Mud pumps

The mud pump is the heart of the circulating system. In drilling rig, usually there are two mud pumps. They are used to circulate the drilling fluid from the mud pits, through the

drillstring, down to the bit and return up to the surface through the annulus. There are two types of mud pumps: duplex and triplex.

The duplex pumps are double reciprocating acting. They have two cylinders, each cylinder is filled on one side of the piston with the drilling fluid, whereas in the other side the drilling fluid is being discharged. In duplex pump, the discharged volume of the drilling fluid is twice the volume of piston.

The triplex pumps are single acting pumps. They have three cylinders and the drilling fluid is filled in one side of the piston. The triplex pumps system is connected to centrifugal pumps to charge the suction parts with the drilling fluid.

The power generated by the triplex can be relatively higher than duplex because it operates at higher speed.

The mud pumps are connected to stand pipe with high pressure piping. The stand pipe is clamped to the derrick, and anchors one end of the rotary hose and keeps it clear of the rig floor during operations. The other end of the hose is connected to the swivel.

2. 2. 2. Mud Pits

The mud pits are a series of large interconnected steel tanks fitted with agitators to keep solids in suspension. There are some pits are used for circulation and others are used for mixing and storing drilling mud. Fresh water and base oil which are used for making drilling fluids are pumped from storage tanks.

2. 2. 3. Shale Shakers

Once the drilling fluid has completed one cycle from the mud pits and coming back to surface passing through the drill string, down to drill bit and up to the surface, it will contain solids, some gas if the drilling is performed through reservoir and other contaminants. These non-drilling fluids product or contaminants must be removed in order to keep the required properties needed to drill safely.

The drilling fluid passes over a series of vibrating screens of different mesh sizes. Tanks can also allow residues settling before the mud passed to the mud pits. Fine solids are removed by other components such as mud cleaner or centrifuges.

2. 3. Rotating system



Figure6 SHALE SHAKER

Rigs can be equipped with Kelly system of top-drive system. Both systems are used to rotate the drill string and the drill bit.

2. 3. 1. Kelly system

The Kelly is nearly 40 feet long, hexagonal or square on the outside and hollow inside to allow

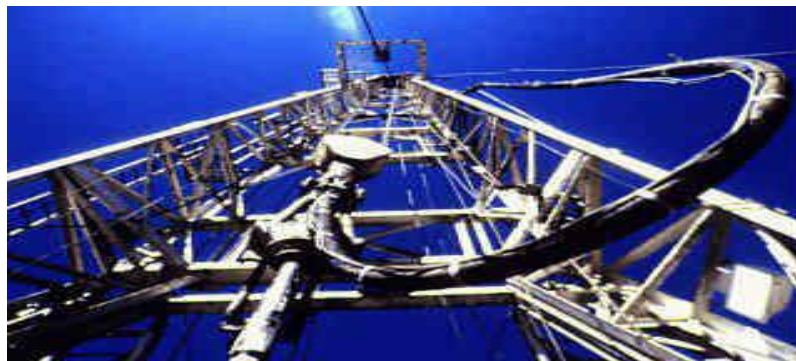


Figure7 KELLY SYSTEM

the passage for the drilling fluids. The

Kelly engages in the Kelly bushing, which allow the Kelly to move freely up and down even when rotating the Kelly by the rotary table. The Kelly cock valve is a safety

valve which can be closed to prevent back pressure to damage surface equipment like the swivel and the rotary hose.

The hook is attached with the swivel which does not rotate but supports the Kelly. The drilling fluids are pumped into the drill string through the gooseneck connection above the swivel via the rotary hose.

The rotary motion is transmitted from the rotary table to the Kelly bushing by the master bushing. The Kelly bushing engages into the master bushing using four pins which enter in four openings. Rollers within the Kelly bushing permit the Kelly to move upwards and downward.

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¹ <https://www.drillingcourse.com/2015/12/drilling-rig-systems.html>

2. 3. 2. Top drive system

It is called top drive system because the rotating motion is accomplished by a drive motor attached to the travelling block above all the drill string. An electric motor is used to generate the rotary torque which is applied to the drill string.

The main advantage of the top drive system is that connections have to be screwed or unscrewed every 30m (90 ft), because drilling can be performed by stands rather than single joint of drill pipe. The swivel and handling equipment are an integral piece of equipment in the top drive which can make the circulation and back reaming while pulling the pipe an easy task. These advantages serve to reduce drilling time which is the most important factor in drilling programming and operations.



Figure 8 TOP DRIVE

The Kelly and the Kelly bushing are not required while using the top drive system.

2. 4. BOP System

The BOP is an important piece of equipment in the rig. It is used as second barrier against any loss of pressure control. It is fitted with:

- Annular preventer
- Rams
- Choke line
- Kill line
- Annular preventer

This part of BOP seals and closes the well by a circular piece of rubber. It can close on any pipe and casing sizes, and it closes the open hole.



Figure 9 BOP

2. 4. 1. Rams

It is consisted of two rams which can move to each other. They are activated hydraulically. Pipe ram can close on drill pipe because they have semicircular openings which allow them to seal the area around the drill pipe. Blind rams are used to close the well when pipes are not in the hole, if the blind is closed on drill pipe, this will not stop the seepage of formation fluids, because they have flat edges. Shear rams are used as last solution in well control. They can cut the pipe and close the well.

2. 4. 2. Choke line

This line allows the circulation of the influx to choke manifold. It has two main valves: hydraulic and manual. The manual valve is used as safety valve in case of hydraulic valve failing.

2. 4. 3. Kill line

This line is used to inject heavy mud while well killing process. It has two valves: hydraulic and manual valves. It is fitted also with check valve or non return valve to avoid the back circulation of kill mud or formation fluids.

3. Drilling Bits

The drill bit is an important component in the drill string. The bit drills the rock in many mechanisms. The drilling bit is selected according to the formation to be drilled. The bit performance is related to several operating parameters like: weight on bit, revolution per minute, mud properties and hydraulic efficiency. When the bit is pulled out of the hole, the level of damage on the bit must be carefully recorded. The system followed to evaluate the bit is called the IADC dull grading system which is designed to facilitate the damage grading. An accurate grading can contribute effectively in bit selection in future operations. There are two main types of drilling bits: Roller cone bits, fixed cutter bit.



Figure 9 DRILLING BITS

4. The Drilling Process

We have discussed the components of the drilling rig, now let's discuss the drilling process itself. An oil or gas well is drilled in a very ordered sequence. The steps in this sequence are almost universally applied to the drilling of all wells.

- **Plan the Well:** exploration well prospects are generated by exploration geologists; while development wells locations and objectives are generated by development geologists. Once the surface locations and well objectives are known, the geologists work with the drilling engineers to develop the detail drilling proposals. In addition, all permits (environmental, safety, regulatory, etc.) are acquired during the final stages of the planning process when a solid well proposal is developed.
- **Perform Shallow Gas Survey:** To ensure there are no shallow gas hazards which may result in a kick or blow out, a shallow gas survey is performed to identify the locations and depths of any potential shallow gas hazards. Preliminary surface locations and well trajectories may be altered from the original well proposal to avoid these shallow gas hazards.
- **Prepare the Wellsite:** The site preparation involves building clearing land for use by the rig, building access roads to the well site or well pad, construct infrastructure for water, water disposal, and electricity, dig and line all mud pits to prevent ground water or water table contamination, dig reserve pits for cutting storage (for eventual disposal), and drill the holes which will eventually become the rat hole and the mousehole. The site preparation may involve multiple contractors and companies to perform all of the required work
- **Set the Conductor Casing:** Prior to the arrival of the drilling rig, an Auger Unit (in hard rock regions) will drill a large diameter hole capable of accommodating 18 in to 36 in, conductor casing. In soft rock regions or at offshore locations, a diesel hammer may be used to hammer the conductor casing into place. The conductor casing may go to depths of 40 to 300 ft depending on the location. The conductor casing is typically set through the top soil and loose rocks to the bed rock. The objective of the conductor casing is to isolate the wellbore from the top soil to ensure that loose debris does not enter the well during early drilling operations, The conductor casing is then cemented into place.

- **Move-In and Rig Up (MIRU):** Once the wellsite is prepared and the conductor casing is in-place, the rig is brought on location. Most land rigs, particularly those in North America, are transported on multiple trucks. Once on the well site or well pad, the rigging-up process begins. Rigging up the well consists of taking the rig modules from the trucks and assembling the rig. Included in the rigging up process is setting-up all of the rig systems and testing these systems. Transporting and assembling the rig may take 50-75 workers (two crews), 35 – 40 vehicles, and take up to four days. If a multi-well pad is used, once the rig is rigged-up for the first well, then the rig can simply be skidded over to the next location without having to dig-down.
- **Spud the Well:** After the rig has been inspected and all of the systems tested the well can be Spudded, Spudding a Well refers to starting the rotary drilling operations for that well.
- **Drill Down to the Surface Casing Depth:** The first section of the well to be drilled is the section that goes down to the pre-determined surface casing depth (Casing Point). Obviously, for this section of the wellbore, the drill bit diameter must be smaller than the ID (inner diameter) of the conductor casing. In this shallow section of the wellbore, fresh water aquifers (both for personal and municipal use) exist.
- **Run and Cement the Surface Casing:** Once the surface casing point is reached, the surface casing is run into the wellbore and cemented into place.
- **Pulling Out of Hole (POOH):** Tripping out of the hole with the drill pipe to remove it from the wellbore during cementing operations.
- **Continue this Process to Drill to the Next Casing Point:** This drilling process is continued to the next pre-determined casing point. The selection of these intermediate-string casing points is beyond the scope of the class, but the criteria are based on the mud weight, the Fracture Pressure of the formations to be drilled (the pressure that causes the formation to fracture), the locations of any Lost Circulation Zones, and the locations of any High Pressure Zones.
- **Continue this Process to Drill to each Casing Point:** This process is repeated for each of the planned casing points. Obviously, as successive casing strings are run and cemented into place, smaller diameter tools and drill bits must be used for continued drilling operations. The two most important drilling parameters within the Driller's control to

maximize the Rate of Penetration (ROP) of the drill bit are the weight-on-bit and the rotational speed of the rotary system in Revolutions per Minute (RPM)

- Continue this Process to Drill to Total Depth (TD): Once the final intermediate casing string is run and cemented, the drilling process is continued until the well reaches the TD (Total Depth) of the well.
- Log the Well with Open-Hole Logs: At this point, the sand face is exposed to the well and Open-Hole Logging Tools can be run in the well. Open-hole logs are used to measure certain properties of the subsurface formation that are of interest to the geologists and engineers working on the well and the reservoir.
- Run and Cement the Production Casing String or Liner: If a production casing string or production liner is to be used in the completion, then they are run and cemented at this time.
- Complete the Well: Install the well completion as: tubing, gravel packs, packers, sliding sleeves, stimulation, acidize the well, hydraulically fracture the well, artificial lift.

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² <https://www.drillingcourse.com/2015/12/drilling-rig-systems.html>

Chapter II. Modeling Dynamic Drill-String Behavior during Stick-Slip Vibrations

1. Phenomenon of Stick-Slip Vibrations

Drilling oil wells frequently involves stick-slip vibrations, which are typically considered to be self-induced. These vibrations can produce large cyclic stresses, potentially causing fatigue issues. Furthermore, the rapid bit speed during the slip phase may trigger additional vibrations in the bottom hole assembly (BHA), which are generally not expected. During the stick-slip process, the BHA intermittently comes to a complete halt. Torque accumulates on the bit and is eventually released, causing it to rotate. The bit may remain stationary for a period when it becomes stuck in the formation, and then it is set into motion once the stored energy in the drill string surpasses the threshold needed to break free. Consequently, the bit's rotation alternates between being faster and slower than the rotary table, with both rotational speed and torque on the bit potentially exceeding the values observed at the surface.

2. Torsional Drill-string Model

The model that describes the torsional vibrations of the drill string is formulated by considering the drill string as a torsional pendulum. This pendulum is driven by an electric motor at the top and influenced by the bit-rock interaction at the bottom, represented by a nonlinear friction model. The drill string is composed of a series of drill pipes, which are connected together to create a long pipe, and the bottom hole assembly (BHA), which includes drill collars, stabilizers, a heavyweight drill pipe, and the bit. To maintain the drill pipes in tension, the section of the BHA above the bit is more rigid compared to the drill pipes. As the drilling operation progresses, the drill pipes lengthen, while the BHA's length remains unchanged. This configuration allows for separate analysis of the dynamics of the drill pipes and the BHA. The following assumptions are made:

- 1) **Vertical and Straight Alignment:** The model assumes that both the borehole and the drill string are perfectly vertical and straight, without any deviation.
- 2) **Stable Bit Positioning:** It is assumed that the bit is well-stabilized, preventing any lateral (side-to-side) movement during operation.
- 3) **Simplified Drilling Mud Dynamics:** For all simulation scenarios, the effect of the drilling mud is represented by a uniform viscous damping along the entire length of the drill string.

- 4) **Consistent Drive Torque:** The applied drive torque from the top is considered to be constant and positive throughout the drilling process.

$$\left. \begin{aligned} J_d \ddot{\theta}_d - c_d(\dot{\theta}_m - \dot{\theta}_d) - k_d(\theta_m - \theta_d) + c_b(\dot{\theta}_d - \dot{\theta}_b) + k_b(\theta_d - \theta_b) &= 0 \\ J_b \ddot{\theta}_b - c_b(\dot{\theta}_d - \dot{\theta}_b) - k_b(\theta_d - \theta_b) &= -T_b \end{aligned} \right\}$$

where T_b is a nonlinear function representing torque-on-bit.

3. Nonlinear Bit–Rock Interaction

Friction forces and the torque reaction at the bit are key factors in the generation of stick-slip torsional vibrations. The nonlinear reactive torque at the bit, denoted as T_b , is primarily driven by the friction occurring during the rock cutting process and the damping effects of the drilling mud. This torque can be expressed as:

$$T_b(\omega_b) = c_{b1} \cdot \omega_b + T_{fb}(\omega_b)$$

where, c_{b1} approximates the influence of the drilling fluid on the bit behavior and T_b is the nonlinear friction torque due to bit rock interaction while undergoing stick-slip. As friction torque on bit is directly proportional to the friction coefficient, weight on bit and the bit diameter, it can be written as :

$$T_{fb} = \mu_b(\omega_b) \cdot D_b \cdot W$$

where μ_b is the bit speed dependent bit friction coefficient, D_b is the diameter of the bit and W is the weight on the bit.

The friction factor significantly influences the rotational dynamics of the drill string within the wellbore. Given that the friction coefficient of the bit varies with its rotational speed, both static and dynamic friction are present. These types of friction result in discontinuous differential equations, making the stick-slip phenomenon difficult to model accurately. To address this, the Karnopp friction model can be used to describe the friction coefficient's dependency on angular velocity. This model effectively handles the challenges of detecting zero velocity and avoids the need for switching between different state equations for slipping and sticking conditions. The Karnopp model establishes a threshold velocity interval dv . If the bit's angular speed falls below this threshold dv , the model assumes the bit's velocity to be zero. The Karnopp friction model, which incorporates both static and dynamic friction coefficients, is expressed as follows::

$$\mu_b = \begin{cases} \mu_{cb} \text{sgn}(\omega_b) & \text{if } |\omega_b| \geq dv(\text{ slip }) \\ \mu_b(\omega_b) & \text{if } |\omega_b| < dv, |\mu_b| \leq \mu_{sb}(\text{ stick }) \\ \mu_{sb} \cdot \text{sgn}(\mu_b) & \text{if } |\omega_b| < dv, |\mu_b| > \mu_{sb}(\text{ situation at the transition}) \end{cases}$$

In the context of the Karnopp friction model, the first line of the equation applies when the bit is in the sliding or slip phase, indicated by $\omega_b > 0$. During this phase, the cutting element has just fractured the rock and is now sliding over the bottom of the newly formed crater. The second line pertains to the stick phase, where the bit's cutters reach the shoulder of the cut depth and momentarily stick, causing a buildup of torque at the cutter elements. The third line describes the breakaway moment, when sufficient torque has accumulated to overcome the static friction and enable the bit to cut through the rock, thereby initiating a new cycle.

In the model: μ_b represents the static dry friction coefficient. μ_c denotes the Coulomb friction coefficient. For the bit to begin moving, the reactive torque at the bit, T_b , influenced by the friction coefficient μ_b , must exceed the static friction coefficient μ_{sb} . This overcoming of static friction initiates the bit's motion, transitioning it from a static to a dynamic state.

The sgn function is defined as :

$$\text{sgn}(\cdot) = \begin{cases} 1, & \alpha > 0 \\ 0, & \alpha = 0 \\ -1, & \alpha < 0 \end{cases}$$

As the bit's rotary speed increases, the reactive torque tends to decrease. This behavior indicates that the dry friction coefficient diminishes as the bit's rotational speed rises. To account for this dynamic relationship, the Karnopp friction model with a decaying exponential friction coefficient is utilized. This model effectively captures the reduction in frictional torque as the bit speeds up. The Karnopp friction torque model can be summarized as follows:

$$\mu_b = \begin{cases} \min[|\mu_b|, \mu_{sb}] \text{sgn}(\omega_b) & \text{if } |\omega_b| < dv \\ \mu_b(\omega_b) \cdot \text{sgn}(\omega_b) & \text{if } |\omega_b| \geq dv \end{cases}$$

$$\text{Therefore; } \mu_b = \mu_{cb}(\omega_b) + (\mu_{sb} - \mu_{cb}) \cdot e^{-\lambda|\omega_b|}$$

Where $\lambda = 0.9$ is the decaying factor. Thus, the exponential decaying behavior of T_{fb} can be written as :

The weight on bit (W), is considered to be oscillating harmonically to its surface set value, W_o .

The expression for WOB can be written as below :

$$W = W_o + k_f \cdot x_o(1 - \sin 2\pi ft)$$

The term $k_f \cdot x_o(1 - \sin 2\pi ft)$ represents the amplitude variations of the weight on bit (WOB). This value is influenced by the type of drill bit in use. Here, x_o is the depth of cut achieved in one revolution of the bit. The frequency f is related to the depth of cut x_o and the rate of penetration. For the simulations, the parameters are defined as follows: the baseline WOB, W_o is 30 kN, the stiffness coefficient k_f is 23,000 kN/m, and the frequency f is 0.005 Hz. Given these definitions, the non-reactive torque on the bit, T_b , can be described as a combination of the influences of the viscous drilling fluid and the nonlinear frictional forces during the interaction between the rock and the bit. This relationship can be expressed through the following equation:

$$T_b(\omega_b) = c_{b1} \cdot \omega_b + [\mu_{cb}(\omega_b) + (\mu_{sb} - \mu_{cb}) \cdot e^{-\lambda|\omega_b|}] \cdot D_b \cdot [W_o + k_f \cdot x_o(1 - \sin 2\pi ft)]$$

Chapter III. PID Controllers: Theory and Implementation

1. PID definition

A proportional-integral-derivative controller (PID controller) is a control loop feedback mechanism (controller) widely used in industrial control systems. A PID controller calculates an error value as the difference between a measured process variable and a desired setpoint. The controller attempts to minimize the error by adjusting the process through use of a manipulated variable

2. PID Controller Theory

The PID control scheme is named after its three correcting terms, whose sum constitutes the manipulated variable (MV). The proportional, integral, and derivative terms are summed to calculate the output of the PID controller. Defining $u(t)$ as the controller output, Controller manufacturers arrange the Proportional, Integral and Derivative modes into three different controller algorithms or controller structures. These are called Interactive, Noninteractive, and Parallel algorithms. Some controller manufacturers allow you to choose between different controller algorithms as a configuration option in the controller software. The PID Algorithms are:

- **Interactive Algorithm**

$$u(t) = K_c [e(t) + 1/T_i \int_0^t e(\tau) d\tau + T_d \frac{d}{dt} e(t)]$$

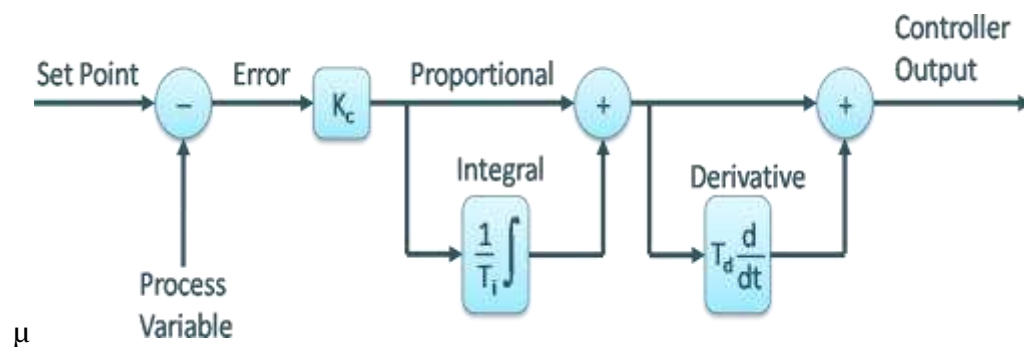


Figure 1. Interactive Algorithm

- **NonInteractive Algorithm**

$$u(t) = K_c [e(t) + 1/T_i \int_0^t e(\tau) d\tau + T_d \frac{d}{dt} e(t)]$$

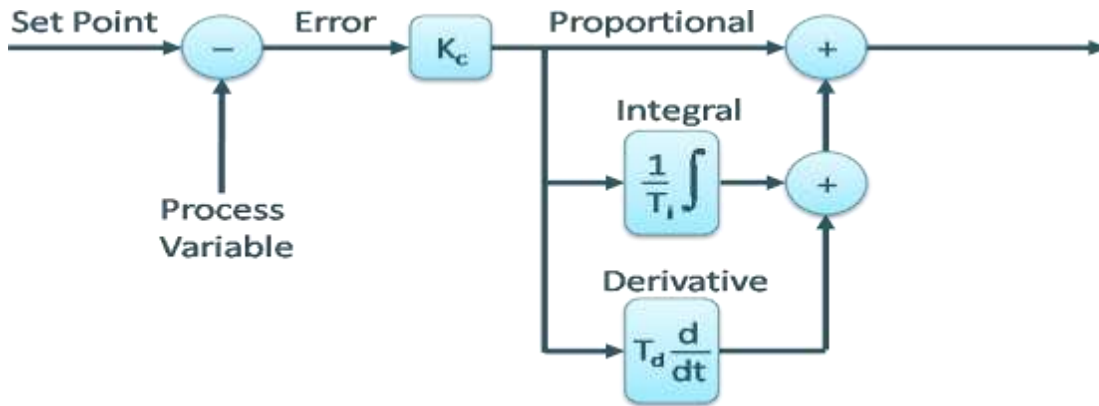


Figure 2. NonInteractive Algorithm

- **Parallel Algorithm**

$$u(t) = Kp e(t) + Ki \int_0^t e(\tau) d\tau + Kd \frac{d}{dt} e(t)$$

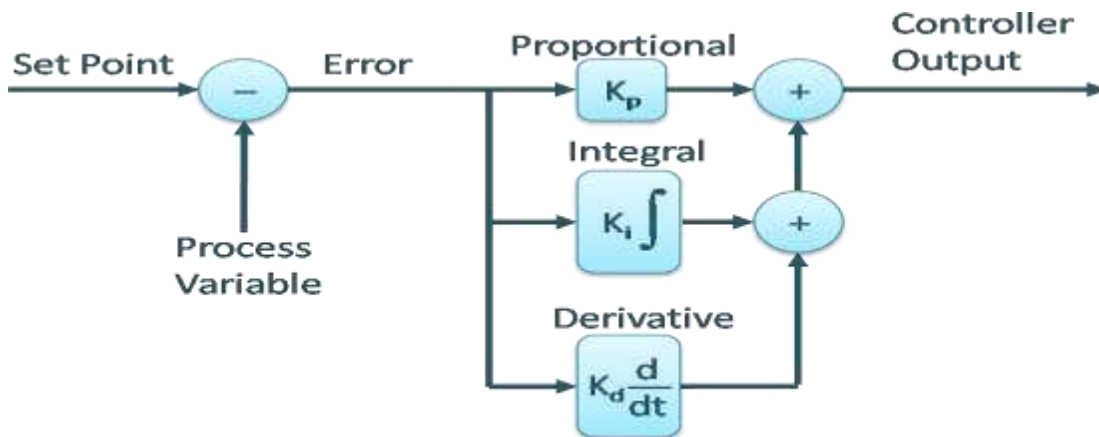


Figure 3. Parallel Algorithm

Where $Kp = Kc$: *Propotional Gain* $Ki = Kc Ti$: *Integral Gain* $Kd = KcTd$:*Derivative Gain*

$$e(t) = r(t) - y(t)$$

2.1. Proportional Term

The proportional term produces an output value that is proportional to the current error value. The proportional response can be adjusted by multiplying the error by a constant Kp , called the proportional gain constant. The proportional term is given by:

$$Pout = Kpe(t)$$

A high proportional gain results in a large change in the output for a given change in the error. If the proportional gain is too high, the system can become unstable. In contrast, a small gain results in a small output response to a large input error, and a less responsive or less sensitive controller. If the proportional gain is too low, the control action may be too small when responding to system disturbances. Tuning theory and industrial practice indicate that the proportional term should contribute the bulk of the output change.

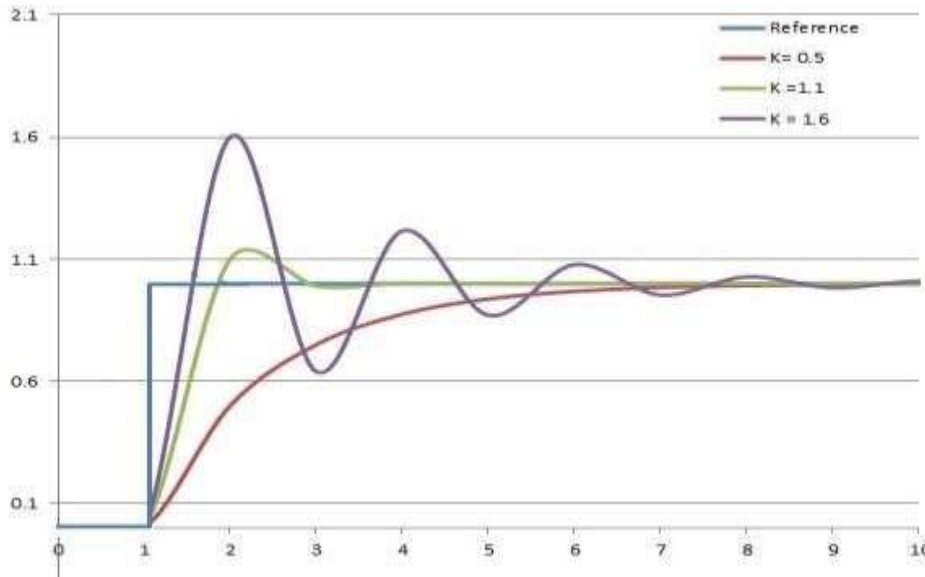


Figure 4. The effect of add K_p (K_i , and K_d) held constant

2.2 Integral Term :

The contribution from the integral term is proportional to both the magnitude of the error and the duration of the error. The integral in a PID controller is the sum of the instantaneous error over time and gives the accumulated offset that should have been corrected previously. The accumulated error is then multiplied by the integral gain K_i and added to the controller output.

$$IOut = K_i \int e(\tau) d\tau \text{ } t \text{ } 0$$

The integral term accelerates the movement of the process towards set-point and eliminates the residual steady-state error that occurs with a pure proportional controller. However, since the integral term responds to accumulated errors from the past, it can cause the present value to overshoot the set-point value.

2.3 Derivative Term

The derivative of the process error is calculated by determining the slope of the error over time and multiplying this rate of change by the derivative gain K_d . The magnitude of the contribution of the derivative term to the overall control action is termed the derivative gain, K_d . The derivative term is given by

$$D_{out} = K_d \frac{d}{dt} e(t)$$

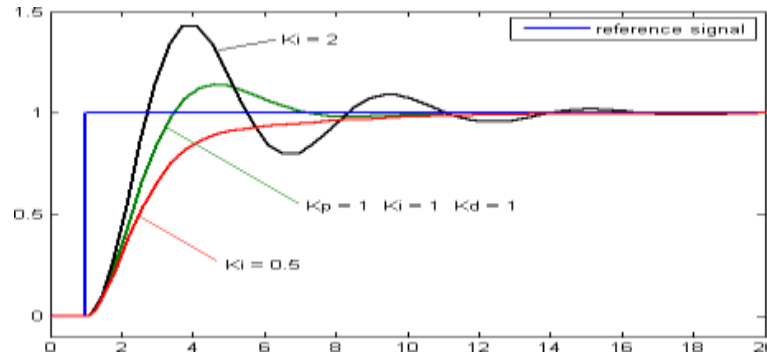


Figure 5. The effect of add K_i (K_p , and K_d) held constant

Derivative action predicts system behavior and thus improves settling time and stability of the system. An ideal derivative is not causal, so that implementations of PID controllers include an additional low pass filtering for the derivative term, to limit the high frequency gain and noise. Derivative action is seldom used in practice though - by one estimate in only 20% of deployed controllers- because of its variable impact on system stability in real-world applications.

3. PID Controller implementation

3.1. Digital Implementation of PID:

Two approaches for implementing control systems using digital technology.

- Based on software which implies a memory-processor interaction. Ex: PLCs, microcontrollers, microprocessors, DSPs, and general purpose computers are tools for software implementation.
- Based on Hardware. Ex: Digital Logic & MSI Components, ASIC & FPGA

3.2. FPGA Implementation of PID

This is a conventional approach that uses of multipliers and adders, requires large area on chip consumes more power. The advantage of this approach can be summarized as follow :

- They ensure ease of design.
- Lower development costs.
- More product revenue, and the opportunity to speed products to market.
- Real time processing Capability.
- They are superior to software-based controllers

3.2. PID Implementation Using DA Algorithm

The simplest form of the PIDcontrol algorithm is given by

$$u(t) = K_p e + K_i \int(0-t) e(t)dt + K_o \dot{e} + \text{offset}$$

Chapter IV. Application of MIRC controller for stick-slip mitigation

1. MIRC controller

The Modified Integral Resonant Control scheme was introduced by [1] to mitigate the unwanted oscillations that lead to the stick slip event. This controller scheme was added to the drill-string model described in the previous chapter. This was done by introducing a controller state Ψ in the equations of dynamic drill-string behavior then generating an extra state differential equation. Consequently, the new scheme modified system dynamics work by adding the control input of MIRC to the original top-torque input u , while additionally adding an extra state equation to the overall system dynamics. The new equations can be described by [2]:

$$\begin{aligned} J_t \dot{\phi}_t + (c_s + c_r) \phi_t + k_s \phi_t - c_s \phi_b - k_s \phi_b &= u + \eta \psi, \\ J_b \dot{\phi}_b + c_s \phi_b + k_s \phi_b - c_s \phi_t - k_s \phi_t &= -T_b, \\ \dot{\psi} + \eta \kappa \psi + \lambda [\phi_b - \phi_t] &= 0. \end{aligned}$$

The above mentioned equation can be combined and written in a matrix system as follow :

$$\dot{X} = \begin{bmatrix} (c_s + c_r)/J_t & -k_s/J_t & c_s/J_t & \eta/J_t \\ 1 & 0 & -1 & 0 \\ c_s/J_b & k_s/J_b & -c_s/J_b & 0 \\ \lambda & 0 & -\lambda & -\eta \end{bmatrix} X + \frac{u}{J_t} \begin{bmatrix} 1 \\ 0 \\ 0 \\ 0 \end{bmatrix} - \frac{T}{J_b} \begin{bmatrix} 0 \\ 0 \\ 1 \\ 0 \end{bmatrix}$$

By incorporating the scheme in question, there exists a new state which will possess its own behaviour when the system reaches a new equilibrium in addition to the previously derived equilibria

Fig. 11 illustrates the control block diagram for the MIRC vibrations damping system. The diagram arranges the mathematical equations of the closed-loop state-space into interconnected blocks for running simulation. The controller receives two inputs from the drillstring model: top velocity and bottom velocity. The initial block computes the velocity difference and scales it with the Output Feedback Gain, determining the portion of the velocity difference that forms the control input. This configuration visually represents the interactions within the MIRC control system, highlighting its function and impact on drill-string dynamics during drilling.

The velocity difference is then processed through Integrator Gain and Feedthrough Gain block to produce the control input ηx_4 . This input is summed to the surface-torque to stabilize the system. The combined signal, which includes both the control input and top-torque, is fed

into the drill-string model, establishing a closed-loop system. This process continuously adjusts the control input based on the velocity difference, reducing stick-slip oscillations and achieving stable drilling conditions.

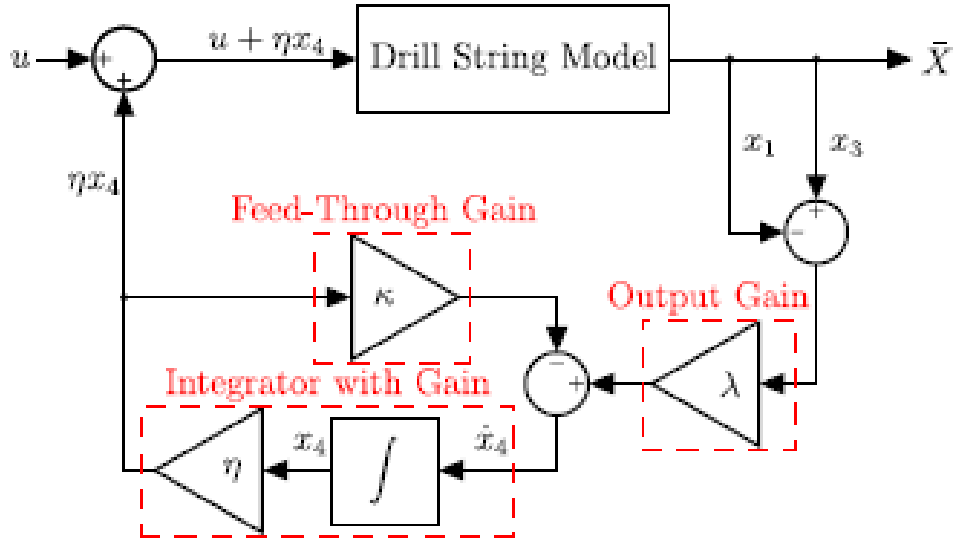


Figure 11. Control block diagram for the MIRC vibrations damping system

2. Simulation run

In the current section, we investigate the capacity of the MIRC in suppressing the stick slip oscillations through simulation run. Firstly, the system were run without the MIRC controller, then it was activated at $t=10$ s. The figure (number) shows the results of the application of MIRC for mitigating stick slip vibrations.

As depicted in this figure, it can be seen that between $t=0$ and 10 s, the unwanted vibrations take place, in which the bottom velocity differ to the top velocity. This is the sever form of torsional vibration which is the stick slip. However once we activated the MIRC controller at $t=10$ s, it was successfully employed and eliminate the stick slip event. This simulation run indicates the robustness of the MIRC controller in mitigating unwanted torsional vibration within short time.

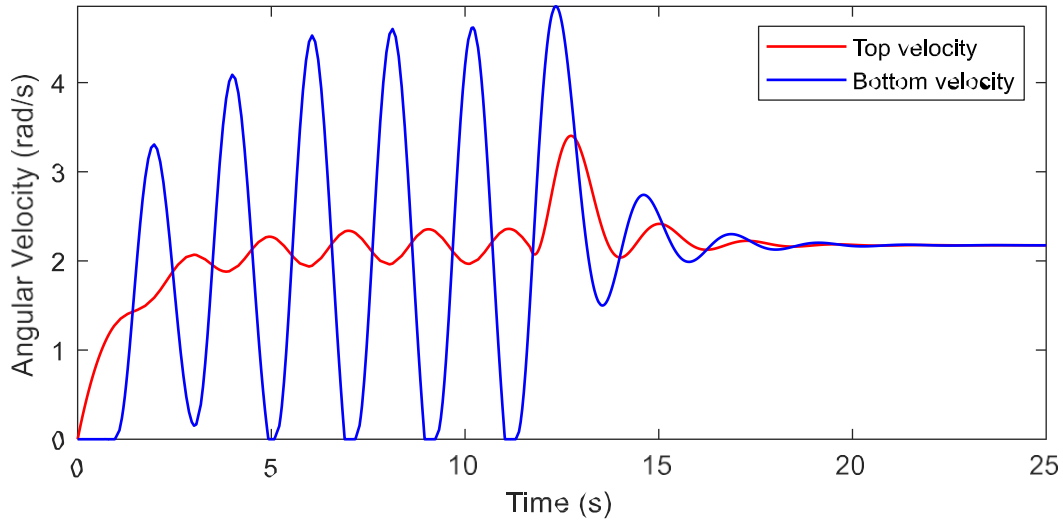


Figure 12. Results of the application of MIRC for mitigating stick slip vibrations

3. Investigation of MIRC performance across varies system parameters

In order to understand how variations in torsional stiffness (K), damping coefficient (c), top torque (T), and Weight on Bit (WOB) influence the performance of MIRC, we analyze the Vibration Reduction Factor (VRF) across different parameter settings. VRF is used as a measure of the effectiveness of MIRC in mitigating stick-slip oscillations. Higher VRF values (close to 100) indicate successful mitigation, while lower VRF values (close to 0) indicate that the MIRC struggles to suppress oscillations. Table 1 presents a sample of the obtained VRF values while varying the system parameters.

Figure 12 depicts two 3D plots representing the MIRC performance for $K=1$ and $K=10$. Data points with blue indicates high VRF values (close to 100), showing successful oscillation mitigation, while red indicates low VRF values (close to 0), showing poor oscillation control. Intermediate colors provide a gradient representing varying degrees of effectiveness. Observations from this plot reveal that VRF varies significantly with changes in T , WOB , and c . Higher torques generally result in higher VRF , indicating better performance, while lower WOB values tend to show better performance with higher VRF .

For $K=1$, the impact of top torque (T) shows that higher torque values (e.g., 40 and 50) generally lead to better performance, with VRF approaching or reaching 100. Lower torque values, however, show more variability and often lower VRF , indicating less effective control. The impact of WOB reveals that lower WOB values (1000 and 2000) show higher VRF ,

indicating better performance, whereas higher WOB values (3000, 4000, 5000) often result in lower VRF, particularly at lower damping coefficients. This suggests that the system struggles more with higher WOB. The impact of the damping coefficient (c) shows that higher damping coefficients (0.1) result in higher VRF values across various torque and WOB settings, indicating more effective control. Conversely, lower damping coefficients (0.01 and 0.001) show reduced performance, especially at high WOB values.

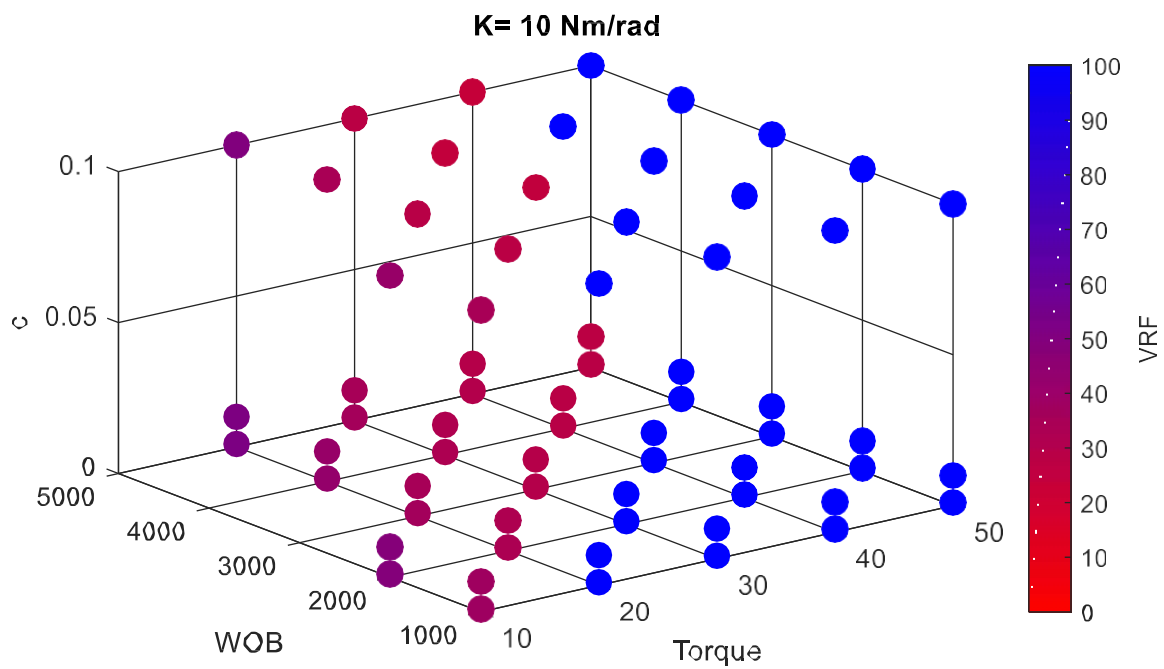
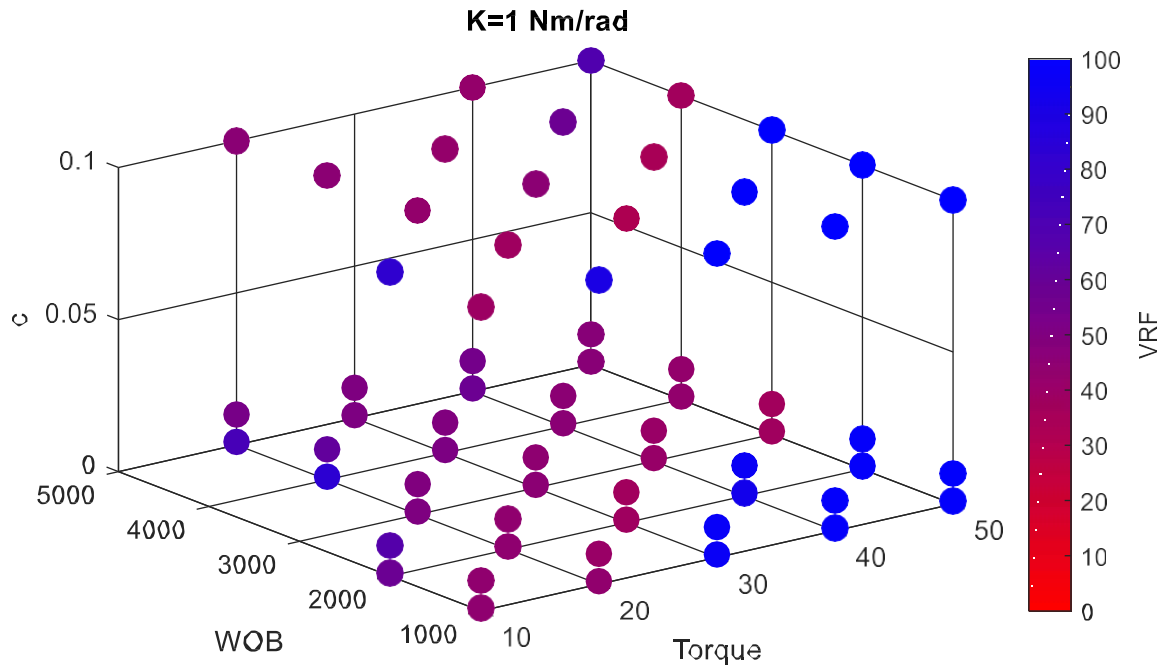
T (N m)	C (Nm/rad)	WOB (N)	K (Nm/rad)	VRF (%)
10	0.1	1000	10	34.0014
20	0.01	2000	10	31.45093
50	0.01	4000	10	99.95544
30	0.001	2000	10	99.77517
50	0.001	3000	10	99.97068
30	0.001	5000	10	35.43849
10	0.1	1000	1	38.9628
50	0.1	3000	1	99.42024
50	0.1	5000	1	68.63867
50	0.01	4000	1	41.94426
40	0.001	1000	1	98.39962
20	0.001	4000	1	82.26955
20	0.001	5000	1	71.77281

Table 1. VRF

For $K=10$, the performance remains consistently high across a broader range of torque values, indicating robust performance even at lower torque levels. The system maintains high VRF even at higher WOB values compared to $K=1$, showing less sensitivity to changes in WOB. Additionally, higher damping coefficients continue to show high VRF, and even with lower damping coefficients, the system performs well, maintaining higher VRF compared to $K=1$.

Key observations indicate that higher torsional stiffness ($K=10$) significantly improves the MIRC's effectiveness in controlling stick-slip oscillations across diverse system parameters. Higher damping coefficients (0.1) are generally favorable for better control, and optimal performance is observed at higher torques and lower WOB values. The MIRC demonstrates more stability and effectiveness with higher torsional stiffness and damping coefficients, suggesting these should be optimized in practical applications. By understanding these relationships, operators can adjust parameters such as damping coefficient, torque, and WOB to

optimize the performance of MIRC in mitigating stick-slip oscillations, leading to more efficient and stable drilling operations.



Conclusion

Using the MIRC controller successfully reduces unwanted stick-slip vibrations in drilling operations. Analysis of system parameters shows that increasing torsional stiffness and damping coefficient can improve the controller's performance. These findings suggest that by optimizing parameters such as damping coefficient, torque, and Weight on Bit (WOB), the MIRC controller's effectiveness in reducing stick-slip vibrations and enhancing drilling operations can be improved.

General conclusion

In conclusion, this memorandum addresses the issue of random drilling vibrations that hinder the efficiency of drilling operations, increase costs, and pose accompanying risks. The focus has been on the phenomenon of "stick-slip vibrations" as one of the major challenges facing deep drilling operations. Through research, various strategies and proposed controls to tackle this phenomenon have been reviewed. Special emphasis has been placed on utilizing the MIRC controller to adjust torque during drilling operations aimed at reducing differences between peak and bottom speeds, thereby minimizing "stick-slip" vibrations.

Simulation results demonstrate that the application of the MIRC controller can effectively reduce these vibrations and improve the stability of drilling operations. The simulation model illustrates how this controller can be integrated with the drilling system to achieve a rapid and precise response to changes in torque, thereby enhancing the efficiency of drilling operations and minimizing wear and damage to drilling equipment.

From these results, we recommend the continued development and enhancement of MIRC controller applications in the drilling field, along with further research to assess their impact under real-world field conditions. Additionally, we suggest intensifying training and qualification programs for drilling engineers on the use and application of these modern technologies to ensure maximum benefit.

In conclusion, we hope that this thesis contributes to the enrichment of knowledge and stimulates further research and development in the field of improving drilling operations and reducing the associated costs and risks.

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