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Design, Data Analysis, and Field Testing of Next Generation In-Bit Sensor Incorporating Weight and Torque on Bit Measurements

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Abstract

In-bit sensing is a growing field in the drilling industry wherein sensors are mounted at the drill bit itself and record various readings that are used to determine drilling efficiency, and identify drilling dysfunctions. Increasingly they are also used to determine valuable information about the well and geology for optimized completion and field design. Many of these sensors record RPM and acceleration, but weight on bit (WOB) and torque on bit (TOB) have been what is most desired by many drilling engineers.

In-bit sensors with WOB and TOB capability have been available for many years, but the prior generations of sensors experienced issues primarily with operational feasibility. Many of these sensors required extensive calibration of the sensor as installed in each bit, a lengthy process that did not meet the needs of a fast-paced operation. These sensors also had high signal to noise ratios that made it difficult to decouple WOB/TOB from downhole effects. In-bit data is primarily analyzed in the context of a comparison of surface data, and the high noise in prior sensors made it difficult, in many cases, to obtain a high confidence understanding of downhole effects.

A new generation of WOB/TOB sensor has been developed that incorporates the lessons learned from previous generations. The primary areas of improvement were in the WOB/TOB sensor itself, the mounting to the bit, and the operational model that enables rapid installation and deployment of this sensor module on bits while also producing clear and actionable data.

This paper will present the design and development of the sensor module itself, with an emphasis on the WOB/TOB sensor and overall reliability and operational feasibility. The paper will additionally present that program and process by which in-bit accelerations, RPM, WOB/TOB, and surface data are fused and presented to users in a clear and concise manner to quickly understand the downhole picture. Finally, this paper will present how the hardware and data analysis portions of this product has successfully been utilized to generate actionable and insightful drilling reports for wells drilled as part of an extensive field-testing campaign of this product.

Introduction to In-Bit Sensors

Several technologies have enabled the miniaturization and ruggedization of sensor packages that fit and survive on a drill bit. Micro-electromechanical system (MEMS) sensors utilize micro-fabrication technology from the semi-conductor industry to machine moving and sensing structures combined with electronic systems directly into silicon wafers. This technology first became commercially available in the 1990s and has since spread into almost every consumer and industrial application; every cell phone and every car has numerous MEMS sensors in it. Memory technology has also greatly improved over the last 20 years, the density of memory has increased over 100 times in the last 20 years.

In-bit sensing products have been available since the early 2000s (Pastusek, et al, 2007). These sensors are battery-powered, memory devices that are installed prior to the drilling run and removed and downloaded after. They automatically detect conditions from drilling and start recording upon seeing those parameters. The sensors are designed to be autonomous and to have no effect on drilling parameters or rig-site procedures. After the run, the sensor module is removed, and the data is downloaded.

Early generations of in-bit sensors had only accelerometers. These recorded accelerations and calculated revolutions per minute (RPM). The memory limitations of that era did not allow the sensors to record continuously. Rather the electronics would gather some number of samples and create statistical data over that period. For example, they would provide minimum, maximum, and average every minute.

Current sensors typically utilize multiple accelerometers, a gyro, and a temperature sensor. The use of multiple accelerometers allows a decoupling of torsional and translational accelerations as well as RPM calculation. The gyro sensor directly measures RPM. Temperature sensors are useful for understanding downhole conditions.

Drill bit stability maps, drilling parameters, and most of the decisions about drilling, however, are based on weight, torque, and RPM. Vibration and RPM data are useful for identifying areas where dysfunction and drilling inefficiency occur, but without Weight on Bit (WOB) and Torque on Bit (TOB) it is difficult to understand the root cause of the dysfunction and what corrective actions can be taken.

Accelerometers, gyros, and temperature sensors are easy to incorporate into a bit design. They are attached to a circuit board and are fundamentally "along for the ride". WOB and TOB (WT) sensors require a mechanical coupling of the sensor to the bit, and electronic coupling of the sensor to the circuit board, and a comprehensive understanding of the bit design to translate sensor readings into WT information. Many dynamics-only sensors are, in effect, encapsulated modules. This design is a viable choice, but it is not compatible with a WT sensor.

Design for Operational Suitability and Survivability

Drill bits experience extreme conditions as operators constantly push operating parameters to accomplish speed and efficiency while drilling. With the increasing aggressiveness to achieve challenging targets and decrease non-productive time (NPT), drilling conditions are continuously reaching new thresholds. While no individual drilling environment is identical, the in-bit sensing module was designed to be singular with no dependency on application or drill bit size. The intention was a product that allows for one design across a variety of conditions. In its compact, integrated design, the module is non-invasive to the design of the bottom hole assembly (BHA), adding no additional length above the drill bit or sacrifice to the material strength of the drill bit body. The interchangeable nature of the design allows for use across a range of diameter sizes from slim hole 5.0" to larger 18.5" in both steel and matrix drill bits. Fig. 1 below shows the module installed into an 8.5" 4-1/2 API connection drill bit.

Figure 1—In-bit sensing device (silver) installed into drill bit.

Drilling environments vary by region with specific industry standards and practices, well conditions, and performance metrics. In North America land operations, a fast-operating tempo is common as operators are expecting insights from the previous well to be incorporated as quickly as possible. In other cases, such as offshore and international operations, usage of in-bit sensors is planned long in advance prior to the start of a drilling campaign. To cover the range of the nature of requests, the module was designed for ease of installation and removal and to not require calibration dependent on the tool it is installed into.

Service of the module is conducted along with normal production or repair cycles of the drill bit. With a self-contained and self-activated design, there is no need for additional hands or time on-site to configure prior to running. The module is installed at the bit manufacturing or repair facility. When installed the module is in a standby mode. Given the dynamic nature of drilling operations and logistical issues with some locations, it is difficult to predict how much time the bit must be in standby before a run. To account for this, the electronics, battery, and firmware of the module integrate in a manner that allows up to 200 hours run time once data acquisition begins.

The module retention system and parts were designed to perform across varying downhole conditions, drilling parameters, and drill bit vibrations. The module must be held rigidly in place to avoid introducing noise from movement of the module inside the cavity of the drill bit to the collected drilling dynamics data. The retention of the module must also consider the need to fulfill rapid requests from customers to outfit a drill bit with the service or remove the module for a quick turnaround in data analysis.

Designed with the intention to be compatible in a variety of applications, the housing of the module is rated to 15k psi (Fig. 2). It protects the electronics and battery packages from well conditions. The housing securely holds the module with upwards of 1000 pounds of force to eliminate the input of unwanted noise into the system. The frame contains alignment features to ensure consistent accurate orientation of the sensors with the drill bit axes during data collection.

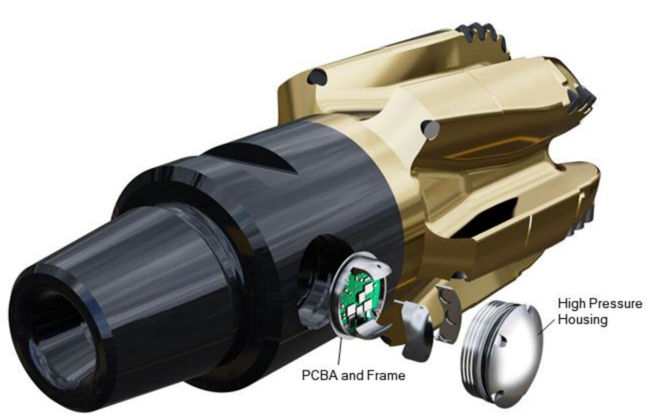

Figure 2—Exploded view of in-bit sensing device installed into drill bit.

Sensor Design Considerations

Strain Gauge Basics

The most common way across all industries to measure mechanical loads such as pressure, force, and torque is to use strain gauges. Strain gauges are electronic components whose resistance changes as a function of how much they are stretched or compressed. These gauges are mounted to an object and as the object flexes under load, the gauge flexes with it. The typical circuit for a strain gauge is illustrated in Fig. 3.

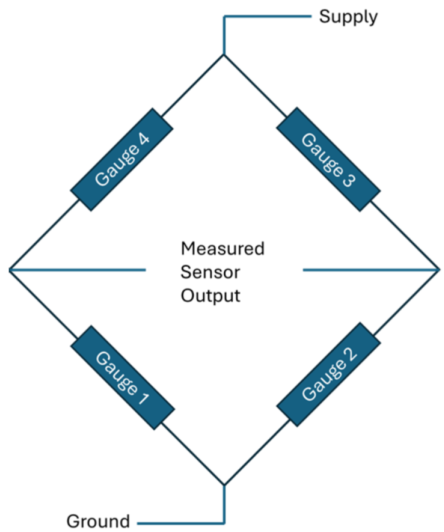

Figure 3—Generic schematic of a Wheatstone Bridge sensor circuit.

This circuit is commonly called a Wheatstone bridge. It has 2 nodes that are the supply and ground. The other 2 nodes are the sense nodes. The voltage across these nodes is the sensor output. When all four gauges are perfectly balanced (all four gauges having identical resistance) the measured output should be zero. If 2 and 3 are held constant, as the resistance of 1 increases relative to 4, due to the voltage divider effect, the bridge will become unbalanced, and the measured output will shift away from zero. If, additionally, 3 is increased relative to 2, the imbalance becomes greater.

The output of the sensor is proportional to resistance of the individual gauge. Each individual gauge changes resistance as a function of the strain that is applied to it. The strain that is applied to the gauge is a function of its placement in the system and the loads applied.

The basic Wheatstone bridge design was used for a sensor to measure Weight on Bit (WOB) and Torque on Bit (TOB). However, in the application of a drill bit, there are several unique challenges and considerations. Some of these are operational in nature, but there are several technical challenges as well. These are discussed below.

Bit Design

The generic bit will have a bit crown that is the cutting structure and cutters. This crown is attached to a shank that has the pin up connection. The area between the cutting structure and make up face of the pin thread is commonly called the shank.

A WT sensor needs to attach to the bit in such a way that the gauges detect the strain on the bit that results from the application of WOB and TOB. The pin thread is not suitable location. Load is transferred into the bit from the thread and the make up face; capturing the full load on the bit requires the sensor to be below the make up face. Additionally, the highest stress on the bit occurs on the pin thread around the threads closest to the make up face. Removing material from this section of the bit to install sensors can substantially weaken the bit and create fatigue problems.

Putting the sensors into the cutting structure is also not desirable. Particularly with directional applications, the point load on each cutter varies as the bit rotates. The sensor needs to be sufficiently far from the cutting structure to measure WOB and TOB, as opposed to instantaneous loads on one blade, for example.

Therefore, the best place to put the strain sensor is in the shank of the bit. All WOB and all TOB goes through the shank, regardless of which blade might be cutting at any given instant. The shank is a heavy cross section part, which enables material to be removed from it without reducing the bit's robustness and ability to withstand fatigue loading.

Signal Strength

However, the shank's robustness presents a challenge for accurately measuring weight and torque. The strength of metals is typically specified as the stress that results from 0.2% strain applied to them. For shanks with 4-1/2 API connections, the axial load to induce that stress is over 2,000,000 lbs. Actual drilling WOB for this size connection is on the order of 50,000 lbs. The strain on a shank while drilling is roughly 2% of what it is capable of withstanding. Strain gauges themselves have a maximum strain they are capable of withstanding before damage occurs, in many cases about 0.1% strain. In this context, a strain gauge mounted to just the bit would see perhaps 5% of its measurement range.

The strain sensor outputs a voltage that needs to be measured and recorded. This requires electronics to sample and record that voltage. Drill bits create very intense vibration and are subject to very large temperature changes while drilling. Vibration and temperature introduce noise into electronic measurements. A conventional strain sensor mounted to a drill bit will output a signal in the micro to nano volt range given typical drilling loads. Voltages of this low level are difficult to measure given that the measurement electronics are exposed to the drilling environment. Therefore, the sensor was designed in such a way that signal strength is magnified into the 10s of millivolt range, where electronic noise becomes negligible vs signal strength.

Signal Crosstalk

Weight and torque exist concurrently but the object of a WT sensor is to measure each independently. Without careful design, sensor cross talk will result. This would appear as WOB changing with TOB, or vice versa. While methods exist for canceling out cross talk, they require input from testing and analysis. They can be applied in a laboratory or research context, but they are not practical for a "drop in" sensor package that is compatible with the fast paced and dynamic nature of the oilfield. Therefore, the sensor was designed to minimize cross talk to negligible levels given the application.

For testing, characterization, and quality control a standardized test fixture was developed that allows the loading of a sensor module to deflections that occur in actual bits. This test fixture is used to ensure sensors conform to specifications and to characterize individual variation permissible by manufacturing tolerances. In Fig. 4, the output from one such test is seen. WOB load is applied and relieved in steps by a precision mechanical testing machine. The blue trace is the output of the WOB sensor. The orange trace is the output of the TOB sensor. The change in the TOB sensor is the crosstalk. The output of this chart is the relative voltage output from each sensor. The cross talk is on the order of 1%, i.e. the TOB signal changes about 1% for applied WOB. Testing has validated the design intent that WOB has similar crosstalk to TOB.

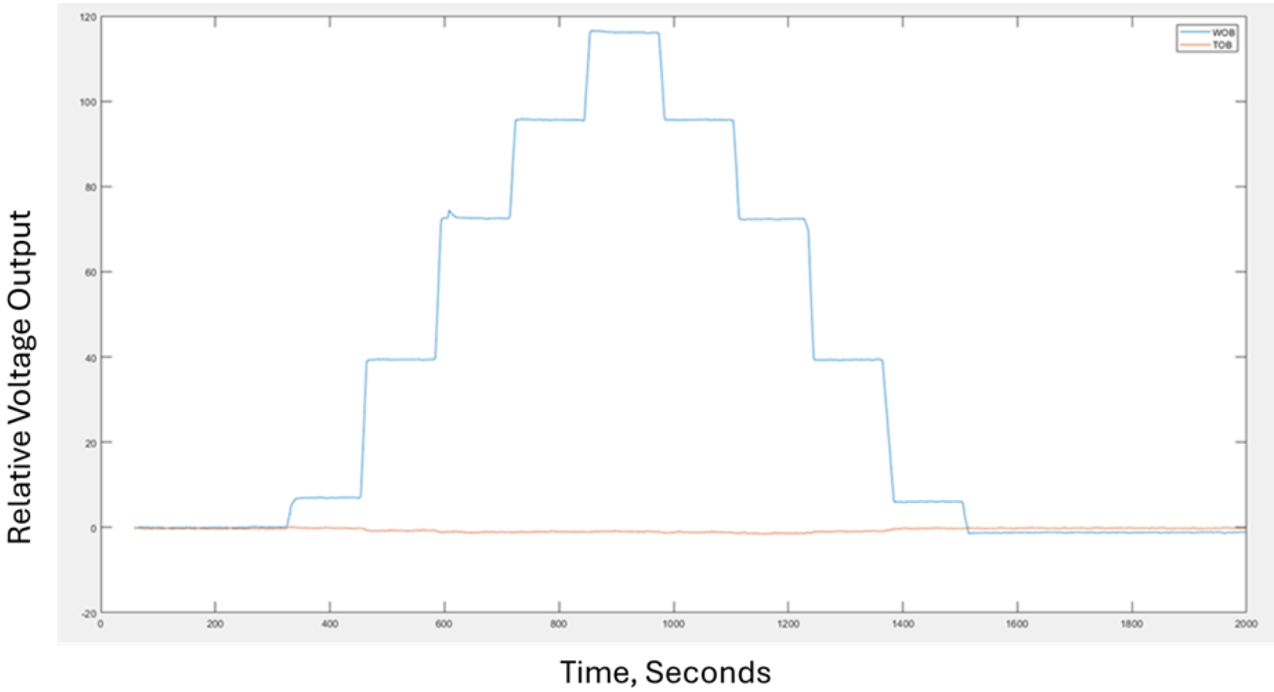

Figure 4—Lab data showing minimal cross talk between WOB and TOB sensors.

In most applications of these sensors, the error introduced by this crosstalk is negligible. The data are usually evaluated in the context of surface-indicated WOB. In some scenarios, it has been seen that the actual weight on bit is as low as 1/5th the surface-indicated weight on bit. In the context of tens of thousands of pounds, errors of perhaps 500 pounds are largely negligible. Nonethless, there are applications where the higher precision is needed, and implementation of crosstalk correction is being considered.

Sensor Design

Drilling Loads on a Bit

Without getting into elastic mechanics, the basic understanding needed to understand how the sensor works is to understand that the bit deforms under load and how it will deform for torque and axial loads. The shank can be thought of as a cylinder with a circular side pocket for the sensor to mount. As the bit is subjected to axial load, the shank will become shorter, and the diameter will increase. Torsional load is harder to visualize, but it will become longer on one axis that is 45° to the cylinder axis and become shorter on a different axis that is perpendicular to the first one.

Fig. 5 shows an exaggerated representation of how the shank will deflect under WOB and TOB. The circular feature will deform into an ellipse. These deformations on an actual bit are on the order of ten-thousandths of an inch, far below what is perceptible by sight, but they do occur.

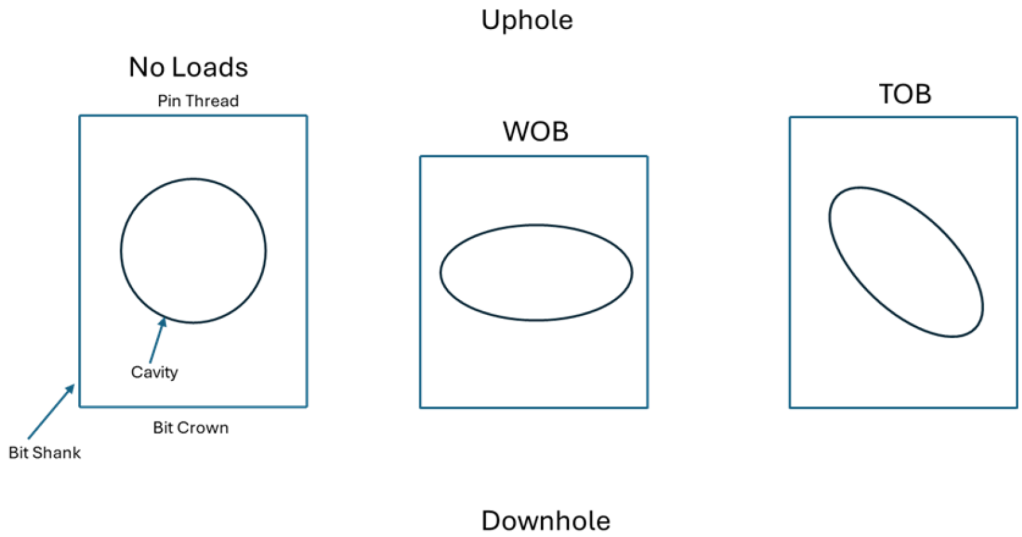

Figure 5—Illustration showing exaggerated deflections that occur to a circular cavity on the side of a bit shank in response to WOB and TOB

Fig. 6 shows the WT sensor mounted inside a bit shank. The sensor is a star shaped frame. It is clamped to the bit at 8 locations with about 200 lbs of clamping force at each location. The strain sensors are mounted on the inside of the octagonal ring in the center of the star. There is one strain gauge at each of the flat internal faces. As the shank bends, whatever displacement occurs at those 8 points is transferred through to the star and it will deflect accordingly. As 2 sets of opposing arms contract or expand, the stiffness of the arm is considerably greater than the stiffness of the inner circle. In this way, the strain effect from the bigger diameter of the cavity is concentrated into the considerably smaller diameter of the star circle. This serves to generate a mechanical load amplification that is unaffected by temperature or electronic noise. The arms are aligned with the bit so that 4 arms are orientated at the principal axes for weight. This alignment also aligns them with the null point for torque. Likewise, 4 arms are aligned with the principal axes for torque, which is the null point for WOB. This creates strong signal response and effectively eliminates cross talk from the sensor output.

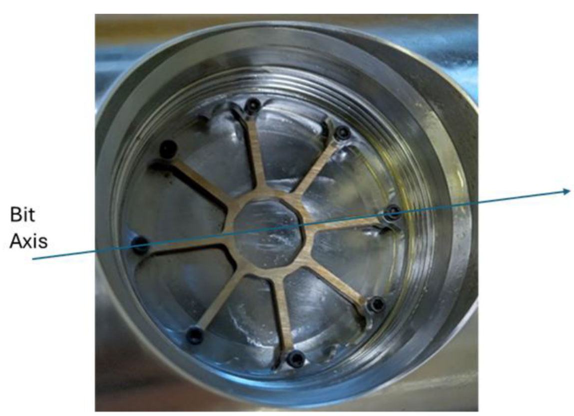

Figure 6—Sensor frame installed to a bit shank inside the sensor cavity.

Signal Processing

The output of the sensor is 2 channels of voltages from the WOB and TOB circuit. Converting this from volts to WOB and TOB requires a transfer function that accounts for the bit geometry, colloquially called the "gain factor".

A typical bit construction is a 2-piece bit, which will have a bit shank that is threaded and welded to a bit crown, which is often tungsten carbide matrix material. Shanks are standardized by thread connection type. For example, a bit with an NC40 connection shank will always have the same shank geometry regardless of the crown. Another typical construction is a one-piece steel body bit, where the shank and crown are integral and machined from one steel forging. These bits have considerably variable geometry. The object of this sensor development was to offer operational capability on 2-piece bits with 3-1/2 through 7-5/8 API REG connections, as well as NC35 and NC40. Additionally, a capability for one-piece bits was desired.

Each connection size for a 2-piece bit and each one-piece bit requires a gain factor to convert sensor readings into WOB/TOB. This gain factor is a function of initial manufacturing tolerances and strongly a function of temperature. With in-bit sensing, the window of operating temperatures is about 350°F wide. Temperature effects over such a large window can be pronounced.

Drill bit operations are fast paced, occasionally requiring sensors to be loaded and on location within hours. Given batch and factory drilling practices, the sensor data is needed as soon as possible. With many downhole WT tools, there is an extensive pre-run calibration and time-consuming post-run data processing. This is not practical in this application. A system was developed where the response of each bit and each sensor is known. This allows the sensors to be a "drop in" installation into any bit, allowing for immediate dispatch to location and data to be available within hours of download.

Downhole Effects

Fundamentally, a WT sensor is a sensor that measures strain on the bit. The Weight sensor is aligned to measure axial strain, and the Torque sensor is aligned to measure torsional strain. While drilling, there are numerous effects that induce these strains, but are not caused by applied WOB or TOB. The most prevalent of these issues are bending and downhole make up.

Bending

Modern drilling uses either adjustable kick-off (AKO) or rotary steerable systems (RSS) to steer the bit. Particularly on an AKO, the bits always experience sideloading. As shown below in Fig. 7, a bit that is subject to just WOB, without bending, will experience a uniform compressive strain across the cross section. WOB is compressive strain. A bit with bending, however, will experience a strain gradient. One side of the bit stretches which is tensile strain. The other side compresses and experiences compressive strain. When the bit experiences both WOB and TOB, the strains superimpose.

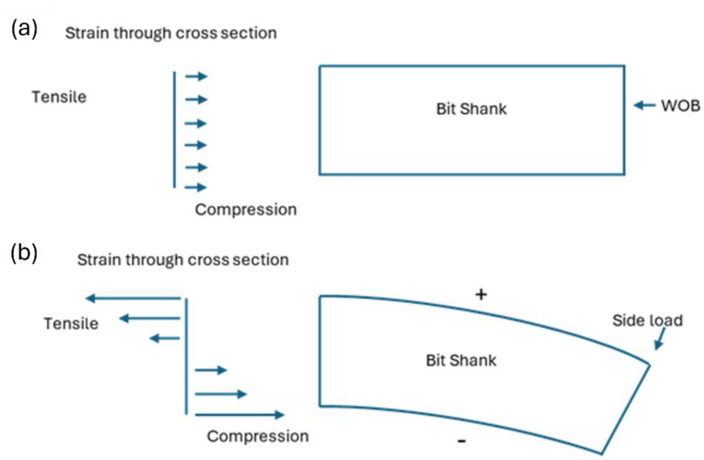

Figure 7—Illustration demonstration cross-section strain distribution through a shank subjected to side loading. (a) Bit subject to only WOB. (b) Bit subject to bending.

Typically, the sideload direction will be orientated and held constant relative to the Earth, but the bit spins. The sensor must be mounted at some position between the center water way and the outside of the shank. As the bit spins, the sensor will experience cyclical loading between tension and compression due to bending. Fig. 8 shows a plot of the WOB (1000s lbs) and the bit RPM. The time shown is about 4.5 seconds of data. In the RPM data, RPM can be seen to drop from 250 to 150 RPM and back to 250 RPM. This is likely the effect of the mud-pulse telemetry system's pulser being open, closing, and opening again. The WOB chart before the pulse has a cyclical signal with a frequency that corresponds to 240 RPM, which is the RPM reported by the gyro sensor. When the pulser closes, the frequency becomes less, due to the reduced RPM, before resuming the higher earlier frequency.

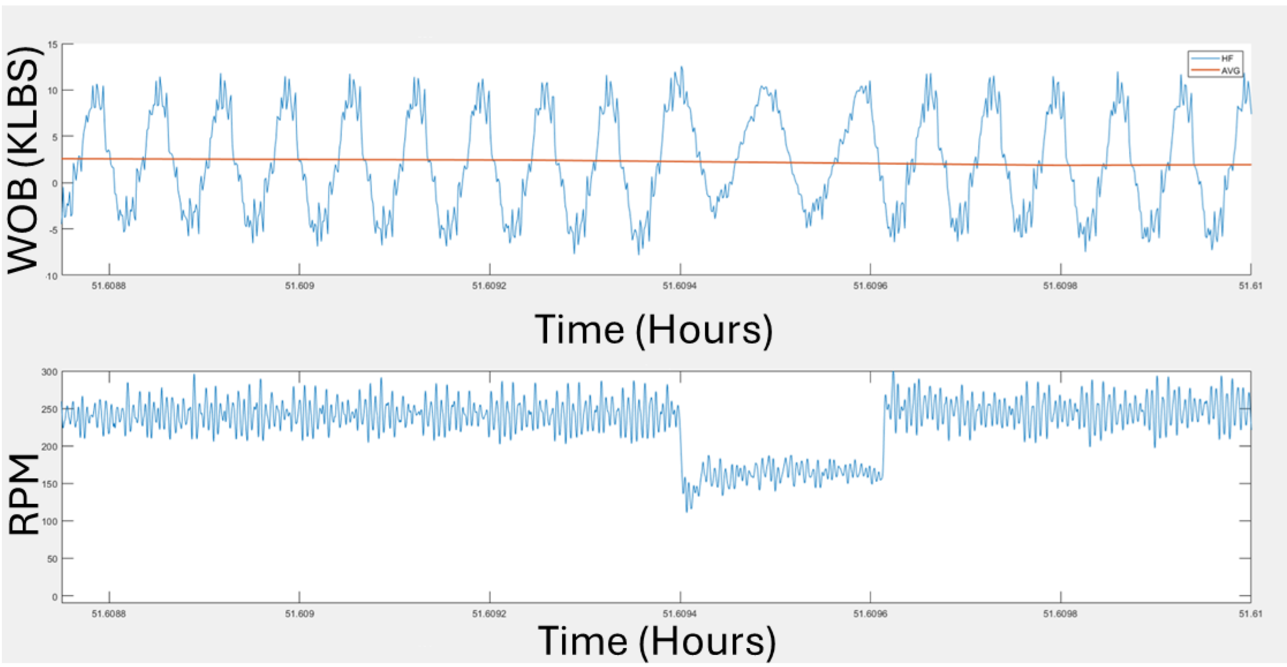

Figure 8—WOB and Gyro data from field data. The cyclical component of WOB is due to bit bending. It can be seen that when gyro RPM drops, the frequency of the WOB variation drops correspondingly.

This variation in WOB is due to bending. The High frequency (HF) data show the WOB fluctuating between −5 and +10 thousand pounds. However, the 1 second average is showing about 2500 lbs. The offset from zero of this cyclical signal is the actual WOB, the periodic component is due to bending of the bit as it rotates. One way to remove the cyclical influence and see WOB is to take an average of the high frequency (HF) signal. As can be seen in the plot, the average WOB is about 2500 lbs in this scenario.

The frequency of the WOB variation will correspond to bit rotation. In general, it will be the RPM of the bit, though in the case of whirl, it may become different. However, it is always a function of the RPM. The amplitude of this signal corresponds to the magnitude of the sideload, however. The amplitude tends to track with WOB as well, usually maintaining a relatively constant ratio. Typically, what has been seen is the that bending amplitude tends to be +/− 2.5X of the applied WOB.

If detailed information about the bit design and construction is available, it is possible to convert this amplitude into bending moment and sideloads. This information can be used to verify directional performance downhole and optimize bit design for improved directional control.

Additionally, it can be used to better understand actual loading of bits in service. The vibration, fatigue, and temperature environment of a bit with a modern BHA are typically impossible to reproduce in a laboratory environment. Real world conditions are far more aggressive than conditions that can be created in drilling labs. Rotating-bending fatigue and other forms of metal fatigue are an extremely common issue with all drilling equipment. As an example, drilling at 240 RPM for 120 hours, which is not an atypical situation, will result in nearly 2 million load cycles on one job. Many bits are repaired and reused. The data from these sensors allows far more accurate understanding of the loading the bits experience and, from that, enable data-driven considerations of fatigue life, bit design, and operating parameters.

Make Up Torque and Downhole Make Up

On the typical pin up bit, when the bit is torqued up, the make up face (MUF), the shoulder for the tool joint, is in compression. The pin thread is in tension to counter-act this compression. The nature of threads is that the application of torque results in axial load that remains after torque is relieved. After the bit is made up, the closed loop loading remains between the MUF and pin thread. This results in a strain field that is compression at the MUF, tensile at the pin thread relief. This strain field propagates from these features. As shown in Fig 9, the intensity of the field is higher closer to the MUF and dissipates with distance from those features.

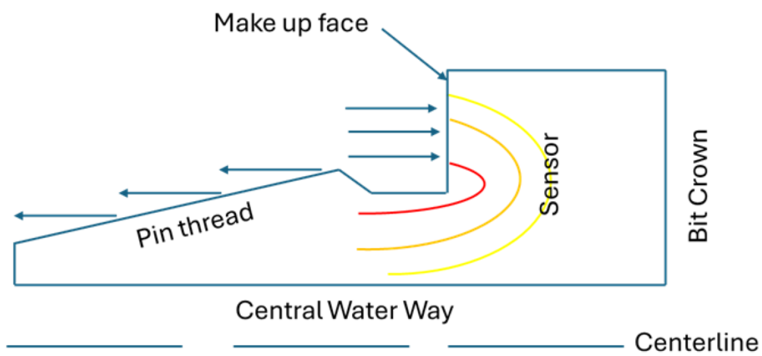

Figure 9—Illustration showing strain distribution and intensity on a bit pin when made up.

There is a desire to keep bits as short as possible for improved directional performance. This dictates that the strain sensor must be placed in the strain field. In many applications, even 1" of extra length is problematic, and to make the bit long enough to allow the sensor to be placed outside of the strain field, several times that would have to be added to the bit length; this is not a practical solution.

When the sensors are placed in this strain field, they will detect the strain that results from the make up torque. Ideal practice is to make up the bit on the surface to a torque that is higher than what will be seen downhole. In most cases, depending on shank size, the placement of the sensor places it in a location where it experiences tensile stress due to make up. As a result, when the bit is made up, a negative shift in the WOB output is recorded. The shift due to torque is recorded and this shift can be used to measure the actual make up torque of the bit. Make up torque is sometimes poorly controlled, and field issues have occurred due to incorrect make up torque.

Ideally, the make up torque on the rig is within recommended values and is not exceeded by torque experienced while drilling. Downhole make up refers to bits making up to higher torque downhole. This results in increased tensile load at the sensor and an immediate downward shift in the sensor WOB output because of this effect. The processing software compensates for this.

Downhole make up, however, is a highly undesirable, albeit common, phenomenon. It results in several deleterious effects on the bit. Firstly, it can gall the thread and make up face, leading to difficulty with break out and higher repair costs/ damaged beyond repair (DBR) costs. In more serious situations, it can lead to the box thread belling out, reduction of thread engagement, and eventual fatigue cracking and parting of the bit downhole. Field experience has shown that down hole make up is rare on RSS BHAs. It has only been observed during periods of continuous severe stick slip. On AKO BHA's however, it is quite common, typically occurring mostly during the first 30 hours of drilling. It has occurred during motor-stall events but also is seen during aggressive drilling. It is theorized that the bits catch on the rock and the momentum of the string over torques the bit. This is corroborated by experience with standard, non-sensor bits, where damage caused by downhole make up is far more common on bits used on AKO BHA than RSS.

In real life data, downhole make up can be seen in sudden shifts in WOB concurrent with TOB spikes. The accelerometers and gyro also usually show an adverse dynamic situation when these events occur. When these events occur, they are noted. Downhole make up, particularly caused by a dysfunction, such as stick slip, is a notable issue that can have adverse drilling and operational consequences. Determining and mitigating the conditions that cause them is considered one of purposes of the data. The downhole make up also changes the baseline strain field in the bit. The processing corrects for these effects to ensure continuity of accurate data.

Automated Data Processing

Once a run has been completed and the sensor removed from the bit, the sensor is connected to a computer interface and the data is downloaded to a cloud infrastructure. The data on the module's memory is encoded in a highly efficient binary format. The data is uploaded to an enterprise grade cloud database and computing system. Once the binary data is there, it is automatically unpacked to a machine and human readable format. This cloud-based system creates a unique identifier for each run, stores the data, and makes it available to end users.

The sensors operate and record at high frequency, some up to 2000 Hz. The sensor output frequencies are configured to maximize the value of the data for the application. Over the typical 100+ hour duration a drilling run this can result in over 1.6 billion data points in a single data set. This volume of data is tedious to process manually, therefore automatic tools have been developed to assist end user in run-data analysis. Once the data is on the cloud, it is enriched with statistical and signal processing algorithms, such as the Fast Fourier Transform (FFT). This enrichment is able to detect and quantify various drilling relevant measurements, such as lateral/torsion/axial vibration, presence, and characteristics of high-frequency torsional oscillations (HFTO), detection of stick slip, and others.

The end users of sensor data are typically not at the rig site or repair facility where bits are downloaded. One of the experiences with prior generations of in-bit sensors was that the end user required physical access to the sensor and performed local processing of data. This was technically possible, but not operationally practical. Any process that requires non-standard or unusual movement or servicing of bits results in delays and inefficiencies. The cloud-based model allows the sensor bits to operate within the same inventory and operational cycles as standard bits. The service technicians are able to remove the module and download the data which then is automatically processed on the cloud, and the end-user of the data is able to access it without physical access to the bit or sensor. This system creates a quick, efficient, and scalable system for collecting, processing, and distributing the data within the context of the operational environment typical for drill bit operations. It is important to highlight that surface data from the client is processed locally on the user's machine. This approach ensures that surface data is only merged with MultiSense data on the local system, respecting the client's preference and rights regarding data sharing, storage, and confidentiality.

The analysis of downhole data is often performed by comparing what happened at the bit to what the surface data indicated. Most rigs have automatic data collection that outputs 1 Hz or 1/10 Hz data from many of the rig's parameters, such as hook load, WOB, rotary RPM, and pump rate. Many analysts prefer to look at sensor data in the context of what actions were taken on the rig and what effect they created downhole. To facilitate this analysis, the automatic processing software allows the end-user to upload data from additional sources such as the rig data and/or MWD data. The software will automatically time-match these multiple data sources so that users can quickly and easily see the data both in time-based and depth-based format.

One of the challenges of surface data is that the formatting of each data file varies from the next. The header names, the order of columns, or the units used can be different depending on system used, regional preferences, and user settings. Surface data can also contain data for just the bit run of interest or data from all or some of the bit runs on a particular well. Given a surface data set, it can be a tedious exercise to manually map headers, identify the time zones, and identify the sections of the given data that are relevant to the current analysis.

The first step of the surface-data merge workflow is to import the surface data into the Minerva application for a specific run. The Minerva will read in the file and map data headers based on a best guess. As shown in Fig. 10 the user will be presented with a header aliasing table to verify that the software picked the headers correctly and that the units in the data are appropriately selected.

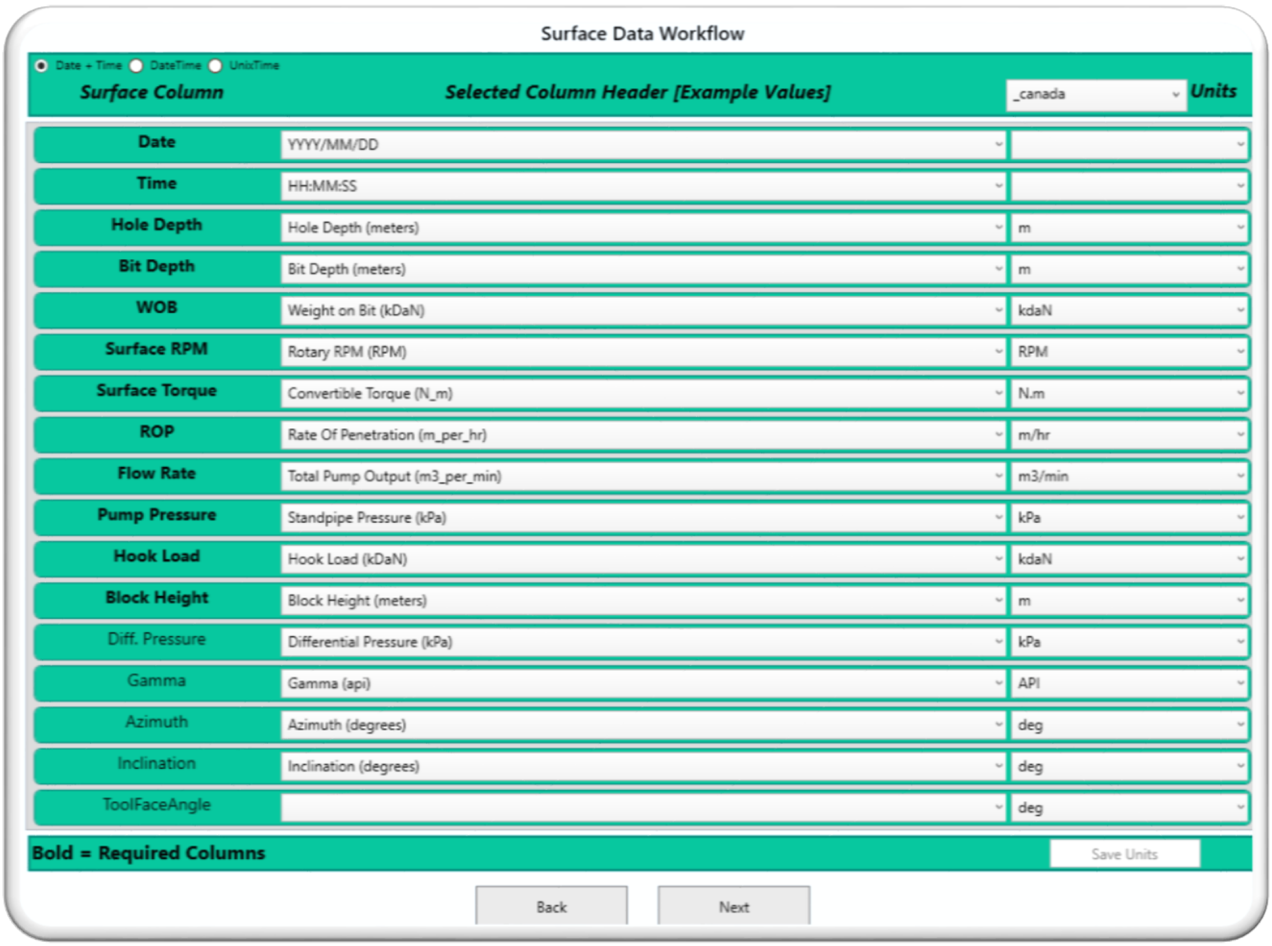

Figure 10—Column Aliasing Tab.

The next step of the surface data workflow is to identify the run of interest. The automatic software will process the surface data and identify the drilling runs present in the data. As shown in Fig. 11 the software has identified six drilling runs for a given data set. The user will select the run of interest to compare to sensor data.

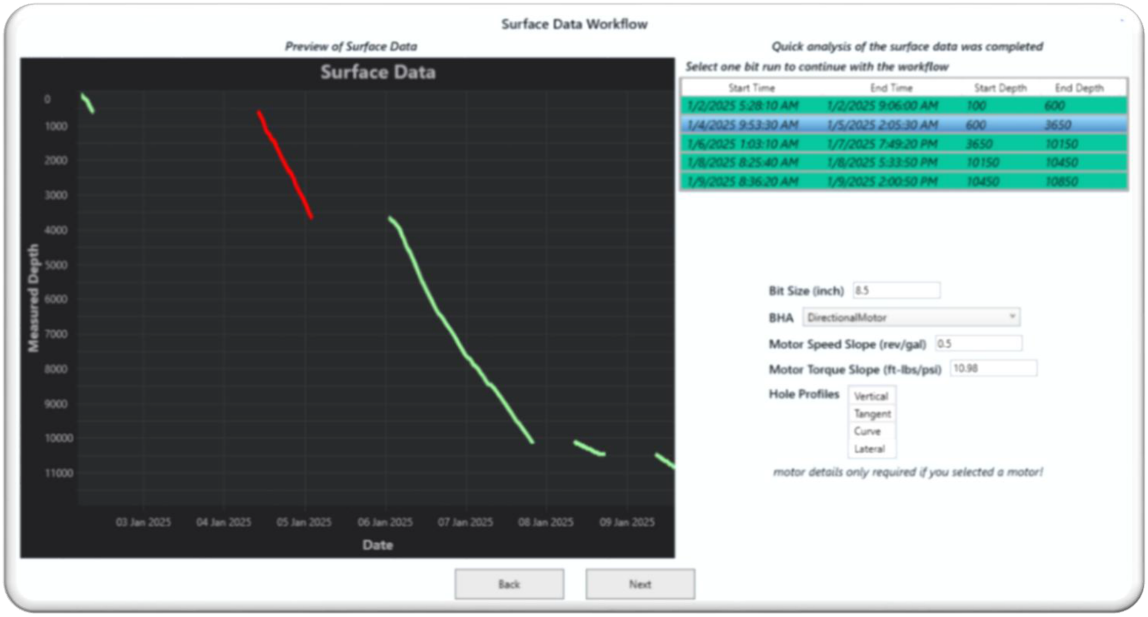

Figure 11—Surface data workflow tab – identifying the runs in surface data.

Once the surface data is ready, the automatic processing software will time match the sensor data to the surface data (see Fig. 12) considering the surface data as reference time. Downhole sensors have clocks that record and keep track of time. However, these clocks are subject to time drift. Sensors can sit for many months before a run, allowing for some drift. Additionally, once drilling starts, the sensors are subjected to temperatures as high as 340°F. Electronic clocks that can operate at such a temperature have lower accuracy than, for example, a wristwatch. Time variation of several minutes over the course of a typical 120-hour drilling operation can occur. This time drift is a function of temperature, which varies considerably during a drilling run.

Figure 12—Time shift algorithm matching the surface RPM with downhole RPM.

Once the surface and sensor data has been aligned, the data is processed through an algorithm library. The algorithm library is a collaboration with end users, engineers, researchers where they can contribute algorithms that provide event identification. The output of each algorithm is a series of events. Some events may identify operational practices; for example, the slide identification will scan the data and determine when slides are taking place, it will create statistical data over the slide, if tool face data is available, it will provide net tool face direction, standard deviation, and a slide efficiency metric. This data can be used in evaluating slide performance and drill bit steerability. The use of in-bit sensor data is highly application specific. Some users are interested in HFTO, others are interested in motor RPM, for example. The investment in infrastructure allows a platform where a menu of application specific processing algorithms can be hosted and continuously improved and expanded, further increasing the value of the downhole data.

Event Log Algorithm Library

Analyzing 120+ hours of drilling data is a tedious manual exercise. The objective of the event log algorithm library (see Fig. 13) is to create an event detection log that automatically tells end users where events of interest occurred and allows them to focus on those regions. Currently there are five main surface algorithms that are used to detect events in the surface data. These are tagging on bottom, picking off bottom, connection identification, slide detection, and stand analysis.

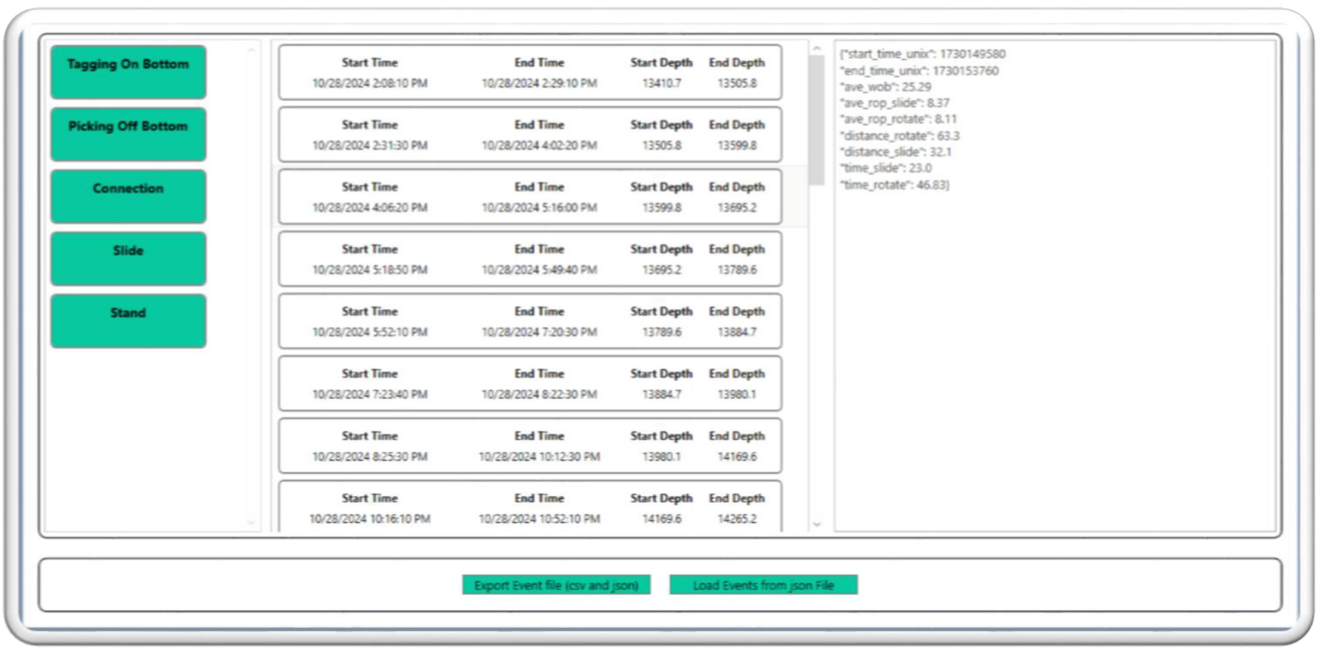

Figure 13—Event log visualizer.

The tagging on bottom algorithm detects and marks bottom-drilling events by analyzing surface log data for transitions between off-bottom and on-bottom states. It ensures each event meets the required time thresholds and updates the logs with corresponding event details.

The picking off bottom algorithm identifies picking off bottom events by detecting transitions from on bottom to off bottom states, ensuring time thresholds are met, and tagging logs accordingly. The connection identification algorithm detects and tags connection events by analyzing non-drilling periods in surface logs, validating patterns like changes in block height, hook load, and RPM against tunable thresholds, and ensuring connections are sustained for a minimum duration. The slide identification algorithm distinguishes between sliding and rotating operations by analyzing rotary RPM levels, torque, and tool face angles, using statistical methods to classify continuous RPM levels and calculate metrics like slide efficiency, net direction, and standard deviation, returning identified slides as detailed drilling events. The end product is a tabular listing of events by type, with statistics for each event.

In addition to event identification, the automatic processing software creates an easy output that can be simply consumed by business intelligence tools, providing users with the flexibility to analyze and create custom charts as needed. Below is an example of a Power BI instance developed for visualization (Fig. 14). Users can view a summary of vibration run metrics, including vibration levels, HFTO, whirl, time-based accelerations, flags, depth-based accelerations, and flags. Additionally, the template offers an HFTO summary, vibration trends, and stability maps for detailed analysis. The template includes both time-based and depth-based visualizations.

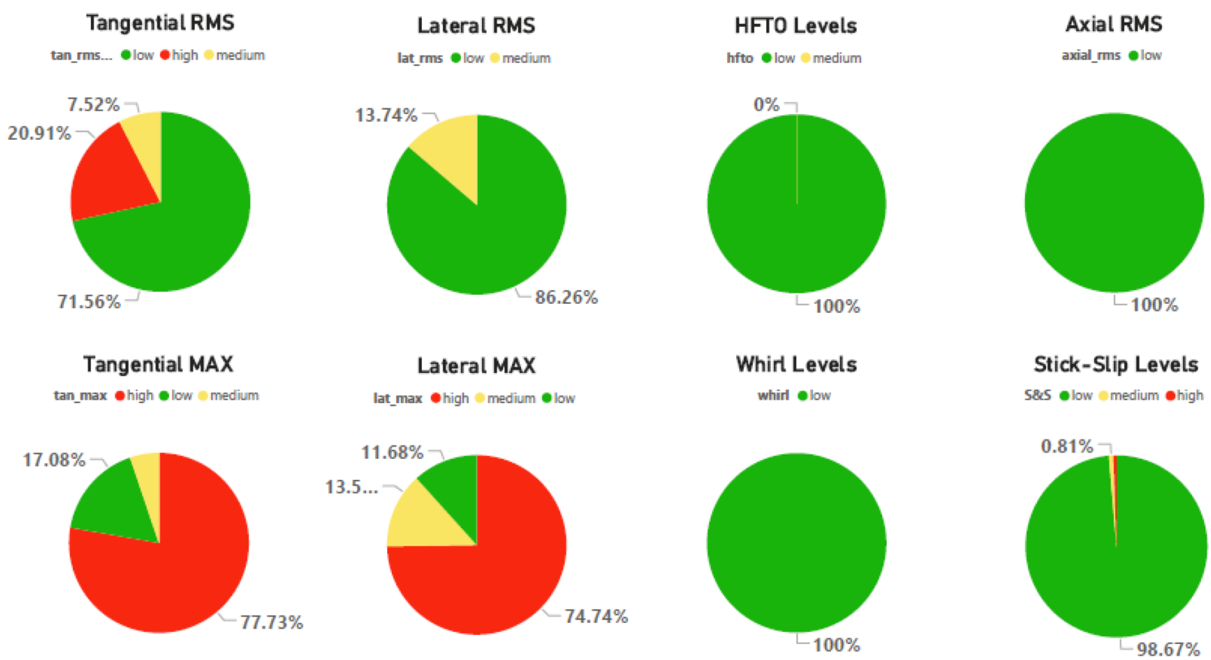

Figure 14—Summary of vibrations of a specific run provided by visualization template.

Weight and Torque Processing

Weight and Torque sensors are fundamentally sensors that measure strain on the bit. WOB and TOB create strain, as do multiple downhole effects such as make up torque, pressure, and temperature. The sensors are positioned in locations specifically chosen to avoid the influence of membrane pressure effects, thereby minimizing their sensitivity to pressure variations. Any residual pressure impact that may arise is effectively eliminated through a taring process performed at each connection. Even in vertical arrangements, the anticipated pressure increases over a single stand are negligible, and repeated taring at each stand further neutralizes any cumulative pressure effects. Similar to any weight scale that needs to be tared, the WT sensors need to be tared to account for varying downhole conditions. As an example, rig make up torque induces a considerable shift in the no-load baseline value. If the bit experiences downhole make up, this can further shift the baseline. This effect needs to be accounted for, as does temperature.

Taring is performed at each connection. The preferred way to do this is in context with surface data to ensure that the bits are truly off bottom and in a free state. Manually taring is difficult and tedious as there can be over one hundred connections for a given run. The automatic data processing platform has been leveraged to automate the taring process and turns a manual process that could take days into an automated process that is performed in seconds.

Auto-taring essentially looks at conditions that exists within the surface and sensor data that would result in no applied weight on bit or torque generated by the bit. These "zero" conditions mapped to the sensor readings, give a baseline to measure against while drilling and allows for the calculation of actual weight on bit and torque produced.

Additionally, the sensor response is temperature dependent. This dependency is known, and the automatic data processor additionally compensates for temperature effects on sensor readings. In many cases, this temperature change is quite minor. The temperature variation over connection and stand, in most cases, is negligible. However, in some cases, particularly towards the end of laterals, as the bit dulls and the mud is hotter by the time it reaches the bit, temperature variations of 50°F between connection and drilling have been seen.

Weight and Torque data has been incorporated into the automatic data processing so that in-bit WOB and TOB can be viewed in context to surface data as well as in comparison to in-bit vibration and RPM data. Fig. 15 shows one such example of in-bit data compared to surface data. The sensor fusion allowed by visualizing and processing data from multiple sources allows a more complete picture of bit performance. As an example, HFTO is often excited by specific combinations of RPM and WOB. The transition into and out of HFTO has been observed in real-world drilling operations as a response to these in-bit parameters. Further work of this analysis will allow improved understanding of bit response, not in lab, but under actual conditions.

Figure 15—Side-by-side comparison of surface and downhole data.

Examples of Field Data

One of the challenges of in-bit sensor development is that surface testing of sensors cannot duplicate downhole conditions. For smooth drilling, accelerations that are +/- 15G are common. Once dysfunctions occur, these can easily reach to 40G and higher. In one case, sustained vibration peaking around 300G has occurred. Duplicating this level of vibration on surface testing is difficult. The intensity is towards the upper limit or exceeding of what can be created in a test lab. Additionally, the vibration of drilling is often broad-band noise, rather than a discrete frequency. Noisy vibration at these levels, particularly for something the size and weight of a drill bit is not something that can be created in a lab. Bits experience high pressure and high temperature and do so for 100 hours or more per run. These conditions cannot be created in any lab. As part of the development of this technology, it was decided to perform a field-testing program to quickly identify and correct any issues prior to commercial release of this technology.

The field-testing campaign was performed in the North America land market. This market allows for fast dispatch, fast return, and allowed an extensive run count to be accumulated in a short time. Successful runs have been performed in the US Permian, US South Texas, US Northeast, US Rockies, and Alberta, Canada regions. Experience has shown that each region has operator specific practices and dysfunctions that present various challenges. South Texas, for example, has generally smooth drilling, but very high temperatures. Permian and Canada tend to prefer AKO BHA with aggressive drilling practices, leading to intense vibratory dysfunctions. Northeast prefers RSS BHAs, which create very smooth drilling, but are prone to HFTO.

Given the complex well trajectories typical today, the first and largest question for many operators is how much weight being applied from surface is translating and making it to the bit. Weight transfer is affected by torque and drag which must be estimated using modeling which involves BHA's and well profiles. Drilling fluid properties, even the procedures of taring done by the driller all can have an effect of weight on bit transfer. These are just a few of variables that can affect how much weight and energy are being used to drill. Drilling engineers look to effective weight transfer evidenced by differential pressure on the motor, mechanical specific energy (MSE) and rate of penetration (ROP). These all give indications but are not direct measurements of actual weight on the bit (WOB). The following are two examples from field trials that are exhibiting different weight at the bit then what is being applied at surface.

In Fig. 16 above, the surface WOB is held stable at surface. The differential pressure reflects this with no large spikes and consistent pressure. The ROP however is varying throughout these stands. However, when the data from the WT sensor is analyzed, the times with reduced ROP correspond to times of low WOB, resulting in invisible lost time and lower rates of penetration.

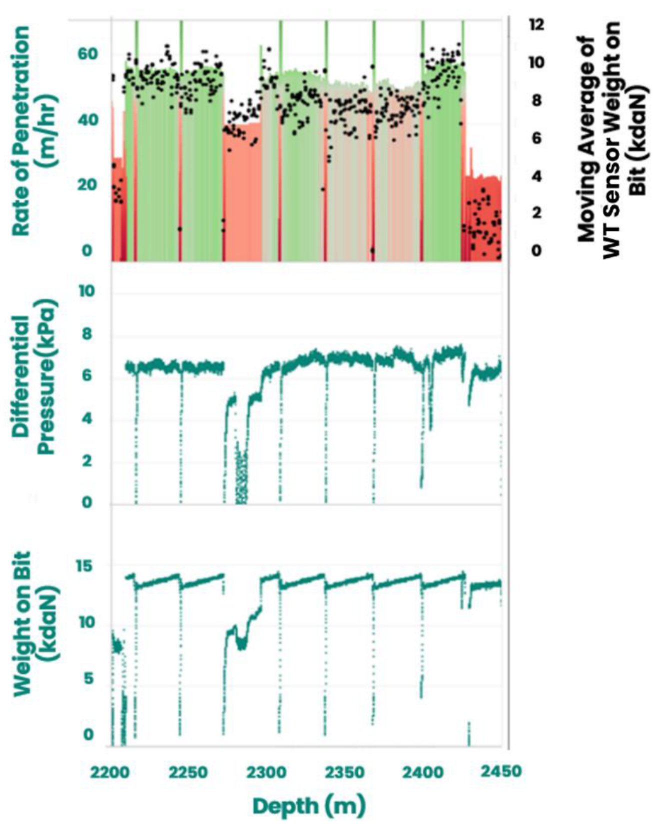

Figure 16—Surface vs Downhole WOB

Lithology changes can have a large effect on bit performance. It can also lead to borehole quality that transfers into weight transfer issues for the BHA. Fig. 17 below shows a formation change denoted by the dashed line. Following this there is a clear declining trend of WOB not being able to reach the bit causing lower ROP even though the surface WOB has remained consistent.

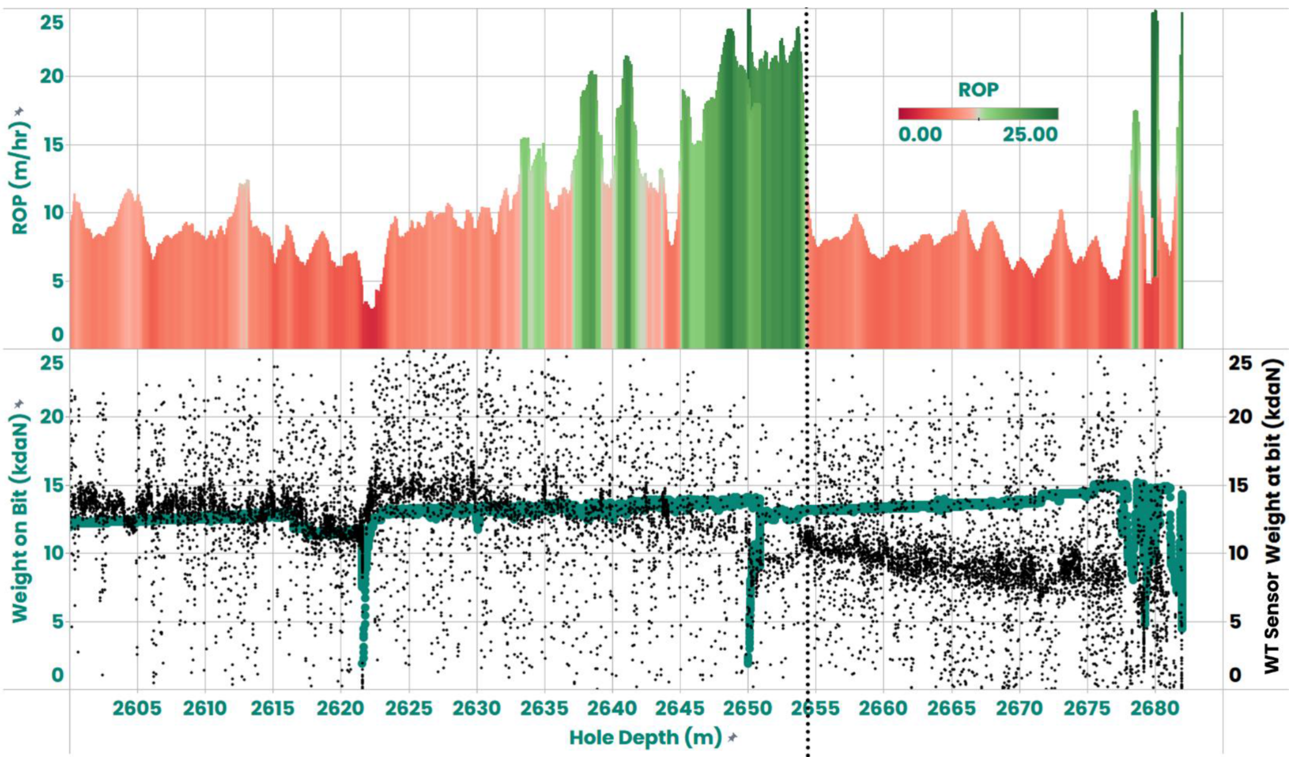

Figure 17—Formation change effecting WOB transfer.

Improved understanding of energy being applied at the bit will lead to better drilling performance. The ability to collect in-bit data allows a data driven correlation of surface data and identification of downhole tool issues. This reduces the unknowns and allows for data-optimized surface parameters.

Having an accurate way to know how much weight is being used while drilling is important for other aspects in optimization, besides the rate of penetration. Applying too much weight at the bit can result in premature damage to the cutting structure of a drill bit, in this case most often leading to a core out. It can also lead to motor stalls and an increase in drilling dysfunctions. When too little weight is applied, lateral vibrations can lead to damage, again in the cutting structure or tools. The weight being applied while drilling is one of the most important parameters used to influence drilling dysfunctions and prevent damage to downhole tools. An operator's ability to understand the energy, making it to the drill bit and fully understanding bottom hole dynamics leads to an increase in drilling efficiency.

Conclusion

This paper has presented an outline of the design and development of an in-bit sensor capable of measuring weight on bit and torque on bit, in addition to vibration, RPM, and temperature. The sensor package was designed not as a technology demonstrator, but as a full-fledged product that slots into existing drill bit operations. The mechanical design and packaging were designed with the robustness for the aggressive environment at the end of the string. It was also designed to be serviceable by standard facilities, without requiring extensively trained technicians or complicated electrical laboratories. It is a drop-in, self-contained unit that can easily be put on standard production drill bits following standard production practices.

A digital infrastructure has also been created and extended to offer automatic and quick data processing, including merging with surface data. This enables rapid data delivery to the end user and powerful data fusion visualization tools to quickly grasp the full downhole picture.

A successful field-testing campaign has been performed to validate the sensor package in real conditions and data from these test runs has already started to show that the in-bit situation can experience considerable variance from the picture created by surface data alone.

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