Acoustic telemetry, with multiple nodes in drillstring, used to achieve distributed MWD

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UNATTENDED ACOUSTIC telemetry in real-time drilling environments can now include multiple nodes in the drillstring. We utilize a primary tool near the drill bit that transmits telemetry and sensor/directional information with one or more acoustic transponding devices at other sites along the drillstring, these incorporating both the primary signal and additional information from their own local sensors.

At present, our commercial equipment has successfully deployed a primary and one MWD node, data being sent along 3,000 m of drill pipe at 20 baud. Further trials will achieve greater depths with extra nodes and will use data rates of greater than 40 baud.

INTRODUCTION

The first successful theoretical explanation of how to propagate acoustic energy suitable for telemetry purposes in a real-time drilling environment was accomplished at Sandia National Labs, New Mexico under the leadership of Dr. D. Drumheller in the 1980s and 90s. The concepts were taken to a feasibility stage, and a basic prototype was built and tested downhole. This involved external contracting resources and paved the way for practical field-proven devices and the commercialization of products by XACT Downhole Telemetry in Canada.

A typical drill pipe comprises a pin and box tool joint separated by a thinner section of pipe, usually 31 ft long (Range II pipe). Many such drill pipes make up the majority of the drillstring. If a signal is applied to one end of the string and a detector is used to determine what comes out of the other end, one sees a passband structure as shown in Figure 1.

This happens because of the repetitive nature of the drill pipes comprising the drillstring. At each joint/pipe junction, the signal is partially reflected and partially transmitted, rapidly leading to a very complicated set of interfering waves. Some wave frequencies are able to propagate along the string, and some are blocked. The predicted string response as shown has been verified by operation.

There are a number of passbands available for use. We have chosen the third – 560-705 Hz. The passband is suitable for use by longitudinal waves, so we generate these by energizing a stack of piezoelectric discs at a frequency of about 640 Hz. The stack elastically stretches a short section of our acoustic sub (albeit by only about 8 microns), producing about 25 watts of power into wave energy that propagates both up and down the sub.

Our present design contains the stack at the pin end; next is the power driver section, followed by electronics and sensors; at the box end are the rechargeable lithium-ion batteries.

The sub is an annular device built in two sizes – 121-mm (4.75-in.) OD and 165-mm (6.5-in.) OD, each approximately 9.1 m (18-ft 10-in.) long. All components are contained between mandrel (44 mm - 1.75-in. ID and 63.5 mm - 2.5-in. ID) and cover, leaving a clear bore, thereby minimizing pressure loss.

Because the stack emits waves both up and down the drillstring, there is the potential for reflections from the BHA destructively interfering with the up wave. This issue is turned to our benefit by attaching a specifically coupled set of pipes called an isolator (patented) below the sub that reflects all down waves into up waves that have a phase relationship that not only aids the original up wave but doubles its amplitude.

Unfortunately, due to recuts of drill pipe, the passbands available to us are arbitrarily modified by the number and extent of the recuts. Thus, we are not able to place the wave energy in the “sweet spot” at the computed center of the passband. Frequency notches and other distortions may cause energy loss.
I N N O V A T I N G  W H I L E  D R I L L I N G

at generally unknown frequencies, forcing us to spread our acoustic energy over significant sections of the band. We generate a 40Hz sweep of frequencies (called a “chirp”) that typically runs from 620-660Hz. The chirp lasts for somewhat less than 1/20 second, thereby defining our normal 20 baud data rate.

The individual waves that make up the chirp travel as a group, the group velocity being typically 3,900 m/sec in steel drill pipe. The group suffers attenuation and distortion as it passes along the pipe, much as an ocean wave does on a windy day. Nevertheless, a sensitive detector attached to the rig’s surface pipe (kelly, etc) detects this energy amongst the noise created by rig surface gear.

Figures 4 and 5 indicate how dispersion and other effects distort a chirp, and how the rig noise dominates the received signal, necessitating the use of sophisticated analog and digital filtering schemes.

Because the receiver is attached to a rotating traveling pipe, the detection system (electronic acoustic receiver/EAR) needs to be self-contained, comprising an accelerometer and filter, signal processor, two-way RF equipment and a battery. This is compartmentalized in linked boxes, the EAR as a whole being firmly attached as high as possible on the kelly or top drive saver sub where it transmits acoustic data and receives control signals from our main decoder and display unit (DDU), typically situated in the doghouse.

The chirps are displayed as a series of packets, each one usually containing 30 to 50 bits of information (lower screen). The decoded data is formatted to present a typical driller’s display.

RELATIVE CAPABILITY

Acoustic telemetry is just beginning to compete in a market dominated by mud pulse and electromagnetic telemetry techniques. Each has its own niche, as indicted in Table 1.

DEPTH

Depth in acoustic telemetry is primarily determined by the length of pipe in the hole, i.e., measured depth (MD), not true vertical depth (TVD). The maximum depth that can be achieved using a single acoustic tool depends on how much signal is lost as the chirps travel up the drillstring and the amount of in-band noise at the rig.

The basic attenuation factor is the inherent loss in the drillstring itself, but this value can be increased by variations in contact between the drillstring and the wall of the well. As a result, the signal loss in a slanted or horizontal well is higher than the loss in a vertical well.

Another factor that increases loss within a slanted well is the effect of the build-up

Figure 4: Launching a chirp packet.
of cuttings within the well, which also increases wall contact with the drill-string, leading to a further increase in attenuation.

The maximum depth available from a primary tool can be extended by placing additional acoustic nodes in the drillstring. In addition to taking measurements of the local pressure, each of these nodes can act as a repeater by receiving, decoding and re-transmitting the signal from the tool or node below.

The spacing between nodes can be greater than the distance from a single tool to the surface as the local area around the node is quieter than the surface rig noise.

The current maximum depths achieved during field trials of the tool have been 1,250 m for the 121-mm tool, greater than 2,000 m for the 165-mm tool, and greater than 3,000 m for the 165-mm tool with one additional acoustic node.

Figure 7 shows how the signal from the acoustic primary tool diminishes with depth. Adding a repeater boosts the signal, thereby extending the range to an estimated 4,000 m (single node). Field trials so far have allowed operations to 3,086 m MD; however, 3,500 m was projected for that well based on the actual signal-to-noise experienced.

While there is no fundamental reason why acoustic telemetry “reach” cannot be increased indefinitely with the use of repeaters, our tools are presently limited by hydrostatic pressure (15,000 psi) and temperature (125°C). This suggests that extended-reach drilling (ERD) would be a particularly suitable application.

**ERD**

ERD wells are typically of medium TVD, which means they are not HPHT environments. From a telemetry standpoint,
the reach of the well is the important factor, with wells up to 15 km in length now being planned. With distributed sensor nodes placed at intervals along the well, an acoustic telemetry system can provide signal amplification and telemetry of key sensor data over the entire length of the well. No reduction in data rate is required, as with mud pulse systems, although delays are introduced at each node due to the time required to decode and rebroadcast the data.

**DISTRIBUTED SENSOR NODES**

Telemetry nodes may be installed anywhere in the drillstring as appropriate. Typically, these nodes are selected based on a need to make measurements and provide signal amplification. Data from nodes located below any given node are combined with measurement data from that node, then re-broadcast up hole, where it is combined with data from the next node, and so on, until it is received at surface.

**MPD**

Another application of a distributed node telemetry system includes the necessarily high sample rate and telemetry of distributed pressure data for managed pressure drilling (MPD). Key to this application is the ability to switch from low-speed to high-speed pressure data. This is achieved by down-linking to each node in order to request pressure data at a rate the surface system requires in order to maintain a desired and safe surface annular pressure. High-quality ECD data is critical for the control of annular pressure using MPD techniques. The quality of this data is determined by the accuracy, location and update rate for these pressure measurements, with acoustic telemetry providing this information at approximately 10 times the speed of current methods, thereby allowing finer pressure control.

For instance, shallow gas kick issues can benefit from this improved capability.

**FIELD TRIALS, COMMERCIALIZATION**

Field trials of the acoustic telemetry distributed node system began in 2008. Initial field trials have been concerned with confirming the repeater mode of the system by automatically receiving, decoding and re-broadcasting to surface from a second node located at various distances from the primary MWD tool. To date, repeater spacings of 500 m to 2,000 m have been used in well depths from 2,000 m to 3,086 m. The maximum depth of a single node system has yet to be quantified, and tests are continuing.

Commercial application of a distributed nodes system is not expected until 2010. Extensive testing will continue in 2009 with multiple nodes as more tools are manufactured. Up to three nodes are planned to be tested in horizontal wells. Distributed node sensors currently...
include annular pressure, bore pressure and temperature. Future sensor additions will include torque, tension/compression, fluid density and shock/vibration. Advanced acoustic signal processing is also possible at each node and has promising applications in the area of real-time hole cleaning and stuck pipe prediction products.

Furthermore, the ability to transmit data while tripping is of great benefit in preventing stuck pipe in ERD operations.

**FUTURE DEVELOPMENTS**

Acoustic telemetry, and the distributed measurements offered by the use of this technology platform, can have a significant impact on the successful drilling of ERD wells due to the following issues:

- **Data rate** – Conventional MWD systems are depth-limited and/or data rates must be significantly reduced as the depth increases. Acoustic repeater nodes can be installed whenever needed to extend the transmission range without experiencing a loss in baud rate. Latency delays are introduced at each node, but the total delay experienced at surface is a minor inconvenience as compared with not getting any data at all without having to go with an expensive wired system. Latency issues associated with steering can be overcome by using two-way acoustic telemetry to provide depth information to a rotary steerable system, thus allowing automatic control of well trajectory.

- **Distributed sensors** – Multiple distributed sensor nodes located over the entire length of the well would greatly improve the determination of ECD, torque, drag, hole cleaning and temperature at specific locations in the well instead of at the usual single point at the maximum depth of the well.

- **Torque and drag monitoring** – ERD wells are often limited by wellbore tortuosity effects that lead to high torque and drag and corresponding open-hole friction factors. The greatest benefit to downhole weight-on-bit and torque data provided by an acoustic telemetry system is that these data are available real-time while tripping when it is the most valuable for ERD operations. This assumes the use of a top-drive system (common on all ERD wells) so that there is a connection between the drillstring and the acoustic receiver located on the top drive saver sub.

- **Pressure system optimization** – ERD wells are often limited by the standpipe limitations of the drilling rig. Engineers must reduce pressure losses associated with the high-pressure (internal) and low-pressure (external) sides of the circulating system. In addition to common practices of selecting drillstring components with dimensions conducive to lowering pressure losses, maximizing bit nozzle size, adjusting mud weight and mud rheology, the acoustic telemetry system provides a full through-bore design further reducing BHA and drillstring pressure losses while offering the added benefits of high-speed telemetry and distributed pressure measurements. Furthermore, surge and swab ECD effects can now be observed simultaneously at multiple locations in the well.

- **Hole cleaning and stuck pipe prevention** – Real-time acoustic hole cleaning and pipe sticking interpretations, generated at each distributed node in
the well, add significant benefits to the operation.

- Shock monitoring – Real-time, high-speed distributed shock measurements provide a much better understanding of potentially harmful drillstring vibrations. Since hole cleaning in ERD wells is accomplished by high-speed drillstring rotation typically at 100-200 rpm, the potential for destructive drillstring oscillations is more common. Having distributed shock measurements at various locations in the well provides useful information for managing drill string failures.

**SUMMARY**

Among the major benefits of an acoustic MWD telemetry tool are:

- Downhole communication requires only drill pipe to the surface.
- The system is independent of drilling fluid and formation properties.
- The tools are full bore.
- No moving parts.
- High-speed data link (20 baud is standard, 40 baud in 2010).
- Unattended operation (no field technicians required on site).
- Power provided by rechargeable batteries.
- Extended range using telemetry repeaters.
- Distributed sensor node capability.

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