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Forfatter: Tor Helge Haara Tjemsland (signatur forfatter)
Fagansvarlig: Olav Gerhard Nygaard Veileder: Olav Gerhard Nygaard	
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1 Summary

This paper will present an overview of the applications of the measurements performed by the Measurement-While-Drilling and Logging-While-Drilling tools. An evaluation of the available telemetry techniques used to transfer the measured data from the downhole tools to surface are performed, with special emphasis on Mud-Pulse Telemetry (MPT) and Wired-Pipe Telemetry (WPT). MPT is by far the method most commonly used on the Norwegian Continental Shelf. WPT is a new technology that allows a vast amount of data to be transferred, which could create new features for the MWD/LWD service, and improve on others. The paper give an overview of the current procedures applied during downhole communication with MPT, and explore the changes that could be introduced by utilizing WPT. It is shown that WPT would allow several new applications of the downhole measurements, without the same problems transferring data as MPT. WPT do not have the same proven record of high reliability as MPT. Hence, MPT is probably going to remain the preferred telemetry method in the future.

The paper explores the possibility to integrate the downhole measurements into a drilling control system. It gives an example from Managed Pressure Drilling where this already has been successfully utilized, and explore different other scenarios where an integration is possible. To fully be able to exploit the downhole data, the amount of data received would need to be high. If utilized in an automation system, the driller would need to fully understand how the system works, and be given the means to override the automation system if necessary.

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2 Introduction

MWD telemetry is required to link downhole and surface MWD components in real-time. The system to support it is quite complex, with both downhole and surface components that operate together. MWD telemetry is the process of transmitting information between downhole MWD tools in the BHA to retrieval at surface. Uplinking is the process of transmitting information from downhole to surface, and downlinking is the process of transmitting information and commands from surface to downhole. Connectivity between downhole and surface is described as half-duplex; we can transmit information in both directions, but not simultaneously. [1]

In 1964, a mud valve was suggested to transmit data up the mud-column, and in the 1970`s transmission of data from tools contained within the bottom hole assembly (BHA) to surface was achieved. [2] This system, called mud-pulse telemetry (MPT), utilized pressure pulses created in the downhole tools for the transmission. Through the continuous column the drilling fluid, the pressure pulses were detected on surface using a pressure transducer. This system was commercially introduced by Teleco Oilfield Services Incorporated (now a part of Baker Hughes) in 1978. It revolutionized the directional drilling industry by providing the directional driller with real-time information for determination of the wellbore`s geometric position and steering system performance.

Companies soon recognized the value of mud-pulse telemetry and developed formation evaluation devices within the BHA. Transmission of this data to surface in real-time allowed the wells trajectory to be referenced to geological features. Initially, natural gamma-ray and basic resistivity devices were introduced and this soon expanded to an increasing range of sophisticated devices.

As the number of measuring devices in the BHA increases, so does the need for an increase in data transmission from downhole to surface. To utilize the value of these measurements, MPT technology continuously improves, and other telemetry technologies are developed. MPT is still the most common, and compared to the alternative technologies, the MPT systems are characterized by a proven record of high reliability in a wide range of operating environments.

Wired-pipe telemetry is a newly developed telemetry method which, compared to MPT, ensures a vast amount of data is being received from the downhole components. The technology could create new features for the MWD/LWD service, and improve on others.

Several oil service companies provide their own versions of the different MWD/LWD measurement tools and the system used to transfer data to surface. The principle is the same in-between the companies and this paper will therefore concentrate on the system utilized by Baker Hughes. Historically, Baker Hughes has been one of the leading companies in the evolution of downhole communication. Not only were they the first to commercially deliver Mud-Pulse Telemetry, they were also the first company that developed the equipment which made it possible to connect their downhole measuring tools to a networked wired-pipe system. The wired-pipe system described in this paper is provided by NOV.

The drilling process still heavily depends on pure manual control. In principle, there is little difference from the way the drilling process is controlled today and 50 years ago. [3]The process is

mainly controlled using surface data consisting of often limited number of parameters, some of which are quite crude measurements derived from secondary data sources. Typically data consists of surface WOB, pump flow rate and standpipe pressure, string rotation and surface torque. As the development of automation systems are increasing, there could be a possibility of integrating downhole measurements from the MWD/LWD tools into a Drilling Control System. The technology has already been deployed, using downhole pressure measurements to help adjusting the annular pressure in an MPD process.

3 Downhole Tool Applications

Many fields currently being drilled by the petroleum industry require the use of high angle, extended reach wells to access remote hydrocarbon deposits. [4] Pre-drilled geomechanical modeling efforts are routinely undertaken in fields where significant wellbore instabilities are known to exist. However, it is not always possible to construct a robust pre-drill model due to a variety of reasons (e.g., insufficient useful data). This combined with the fact that significant geological uncertainties may still exist, could limit the effectiveness of pre-drill geomechanical models when applied to a current drilling campaign.

LWD borehole images provide critical useful information in terms of borehole quality and position within the reservoir. When used in real time, these images can help with making decisions on drilling hazard migration and well placement during drilling. Recent advances in telemetry rates show that higher resolution image quality, approaching or equaling that of memory data is now available real-time. This technology has enabled the visualization of geomechanical features at sufficient resolution to be useful for real-time decision-making applications.

3.1 Directional Drilling

Directional drilling is the intentional deviation of a wellbore from the path it would normally take. [5, 6] It is the ability to plan and drill a wellbore along a predetermined trajectory to hit a sub-surface target or targets. The target may be geometric or may be adjusted real-time based on information learned about the formation while drilling. This is accomplished through the use of whip stocks, bottomhole assembly (BHA) configurations, instruments to measure the path of the wellbore in three-dimensional space, data links to communicate measurements taken downhole to the surface, mud motors and special BHA components and drill bits, including rotary steerable systems (RSS), and drill bits. The directional driller also exploits drilling parameters such as weight on bit and rotary speed to deflect the bit away from the axis of the existing wellbore.

The advantages of directional drilling are that it allows access to reservoirs that cannot be reached with a vertical well from above. Production and ultimate recovery is increased with a horizontal well that exposes more of the reservoir. There is also a reduced cost and HSE impact by having the possibility to drill multiple wells from one surface location. On an offshore location, like on the Norwegian Continental Shelf, the ability to drill from the same surface location is a major advantage.

3.1.1 Requirements for directional drilling

In both directional and vertical wells, the position of the well must be known with reasonable accuracy to ensure the correct wellbore path and to know its position in the event a relief well must be drilled. It is also critical in terms of a safety and economic value with regards to collision avoidance with existing and planned wells. Thus, it is required to take surveys is every so often. The diagnostic data from the downhole components, such as the steering parameters programmed in the tool, is useful to be able to troubleshoot and prevent failures of the directional tools. The possibility to run

more advanced tools, which measure the downhole drilling parameters, is a service highly appreciated by the directional driller to get a real-time picture of the drilling progress.

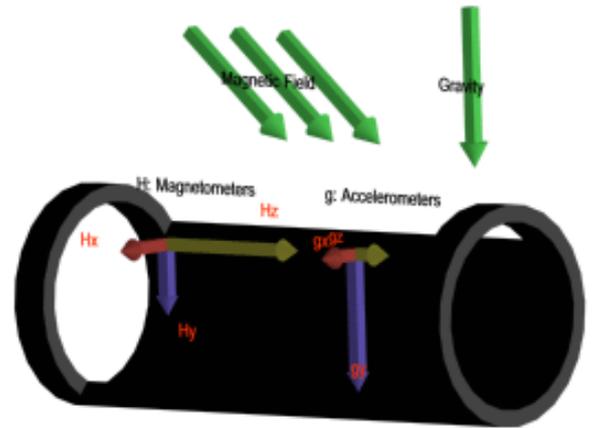
3.1.1.1 Survey

A survey is a complete measurement of the inclination and azimuth of a location in a well, typically the total depth at the time of the measurement. [5] The measurements themselves include inclination from vertical and the azimuth (or compass heading) of the wellbore if the direction of the path is critical. These measurements are made at discrete points in the well, and the approximate path of the wellbore computed from the discrete points. Measurement devices range from simple pendulum-like devices to complex electronic accelerometers and gyroscopes used more often as MWD becomes more popular.

Wellbore positioning is normally determined real-time by acquisition of data from the accelerometer and magnetometer sensors contained within the MWD system. The magnetometer can however not be used to close to the casing, since the magnetic properties of the steel will corrupt the measurement. The magnetometers are very sensitive to interference, and the components in the BHA closest to the measuring device have to be made of non-magnetic material. Even increased activity at the sun will in some cases affect the directional measurements, and can lead to deviation. [7] The earth's magnetic field will be disturbed if the intensity of particles from the sun which hits the earth is powerful enough when the direction of the Interplanetary Magnetic Field (the sun's magnetic field) is opposite of the Earth's. The effect is most often seen on it strongest during night time and is commonly referred to as a geomagnetic storm. Dependent on location and wellpath design, the criticality of such disturbances have to be considered in each case.

3.1.1.2 Real-Time measurements

During drilling, continuous real-time measurements are received to better control the wellpath. If using a mud motor, which have a bend in the string close to the bit, information of the direction the bit is pointing is necessary. Steering the well with a mud motor, the string is kept stationary, and pumping mud through the string through the motor makes the bit rotate. The direction of the bend is measured against a known reference point on a MWD tool, and is transferred to surface as either magnetic or high-side-toolface. High-side-toolface (HSTF) explains the direction of the bend looking down the well along the drillstring. If you are drilling a 90° horizontal well, a 0° toolface would mean that the bend is pointing straight up. 0° will when using HSTF always be the point in a given cross-section of the well that is closest to the surface. Due to this, the HSTF would be of no use when drilling a vertical well. Therefore, while kicking off from a vertical well, magnetic toolface (MTF) is transferred from the tool. MTF gives the compass heading of the bend, and is used

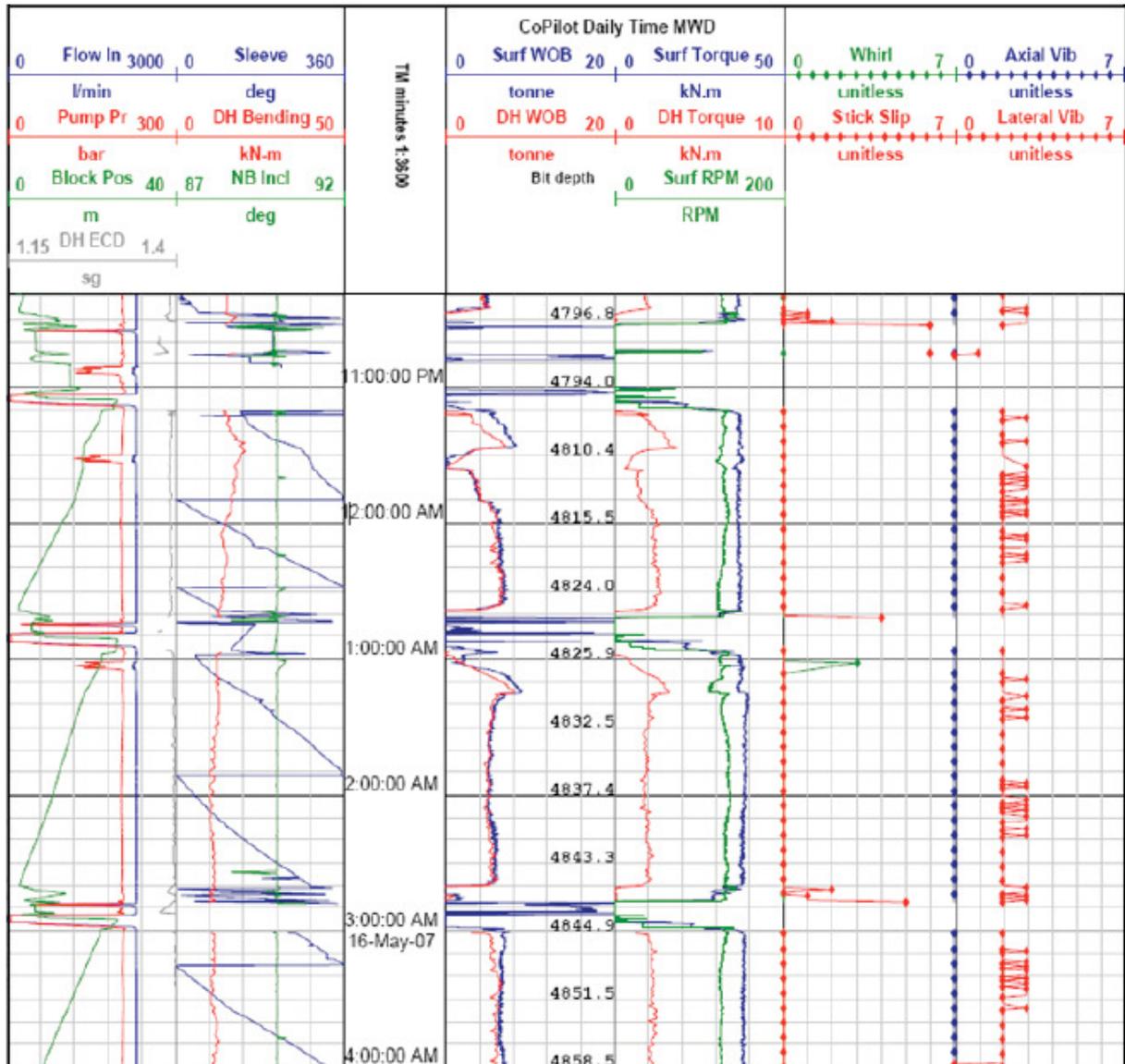


Baker Hughes et al. 2012

Figure 1: Sensor position in the directional measurement tool. The forces from the magnetic field are measured by the magnetometer. Gravity is measured by the accelerometer.

by the directional driller until the inclination of the well is large enough for HSTF to be reasonable to use.

Parameters such as the near bit inclination and rotating azimuth provide a real-time data of the direction of the well. Also parameters explaining the status of the different components in the steering unit are sent to surface to give an indication of the performance and status of the directional tool.



Klotz et al. 2008

Figure 2: These time-based tracks show real-time drilling dynamics data in combination with surface drilling parameters. By plotting downhole data vs. surface data, it can be seen clearly how drilling parameters applied at surface influence the downhole BHA.

Service companies can provide a service used for real-time drilling optimization where the forces acting on the BHA are measured. Monitoring these values, transmitted as vibration and stick-slip, give a picture of the downhole environment, and can be used to improve the drilling progress and protect the downhole equipment. For example, Baker Hughes CoPilot service utilizes an advanced downhole acquisition and processing sub that is incorporated into the BHA. This downhole sub simultaneously samples 14 sensors such as:

- strain gauges (to measure downhole weight on bit, torque, bending moment and detect whirl and bit bounce)
- accelerometers (to measure accelerations in 4 directions: axial, lateral-x, and lateral-y, and tangential)
- magnetometer (to measure downhole rotational speed and detect whirl)
- annular and bore pressure
- Temperature (internal and external).

This raw data is processed downhole (scaled, temperature and pressure compensated), then written to the tools memory and made available for transmission to surface, where it is interpreted and used to optimize the drilling process.

Downhole drilling dynamics subs have been used for several years as a part of the common BHA for drilling. The internal sampling rates of these tools are in the 100Hz range. However, only a minor fraction of the data is transmitted to surface in real-time.

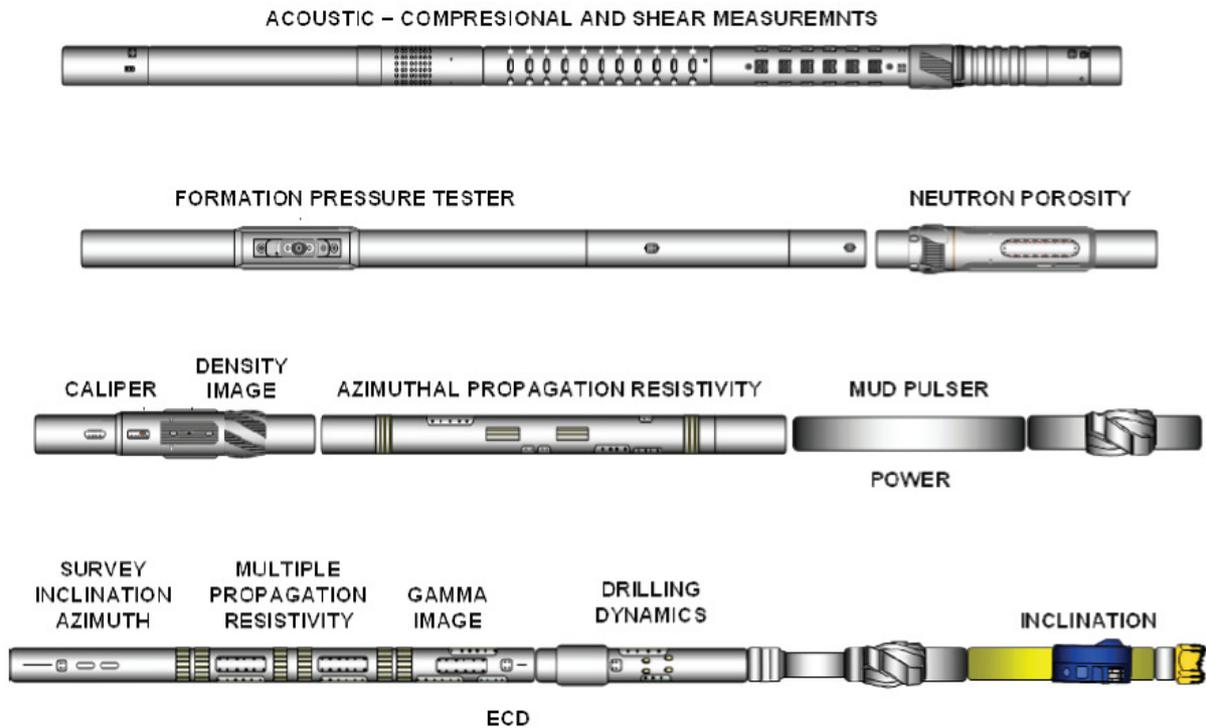
3.1.1.3 Downhole commands

While steering the well using RSS, it is necessary to have the possibility to make adjustments to the steering parameters programmed into the tool. Depending on the system used, these commands could be a force or direction needed to steer the well path along the planned trajectory, a desired target inclination or to enable/disable the steering unit itself.

3.2 The MWD/LWD service

Measurement-While-Drilling (MWD) is the evaluation of physical properties, usually including pressure, temperature and wellbore trajectory in three-dimensional space, while extending a wellbore. [5] The measurements are made downhole, stored in solid-state memory for some time and later transmitted to the surface. Most MWD tools have the ability to store the measurements for later retrieval when the tool is tripped out of the hole, to provide higher resolution logs than it is possible with the relatively low bandwidth mud-pulse data transmission system.

Logging-While-Drilling (LWD) is the measurement of geologic formation properties while using tools incorporated into the drilling assembly. [6] A variety of services are available to evaluate the zones being drilled through. Most importantly, LWD seeks to define reservoirs'; porosity, permeability, pressure, producibility, hydrocarbon content and/or boundaries. It enables valuable, real-time decisions on wellbore placement, determination of fluid properties before alteration by drilling fluid invasion. It also assures log data acquisition in applications unsuitable for wireline.



Klotz et al. 2008

Figure 3: Example of an advanced MWD/LWD toolstring.

3.2.1 Bi-Directional Communication

There is a variety of different MWD/LWD tools measuring the physical properties downhole and the geological formation properties of the drilled formation. The different service companies have their own tools to perform these measurements, and send the information to surface.

Depending on the service, there could also be necessary to send commands and requests to the MWD/LWD tools. This is known as a downlink. Adjustments to the data output and performance of the tools can be changed from surface, often depending on the requirements from the client.

3.2.1.1 Formation pressure and fluid sampling tools

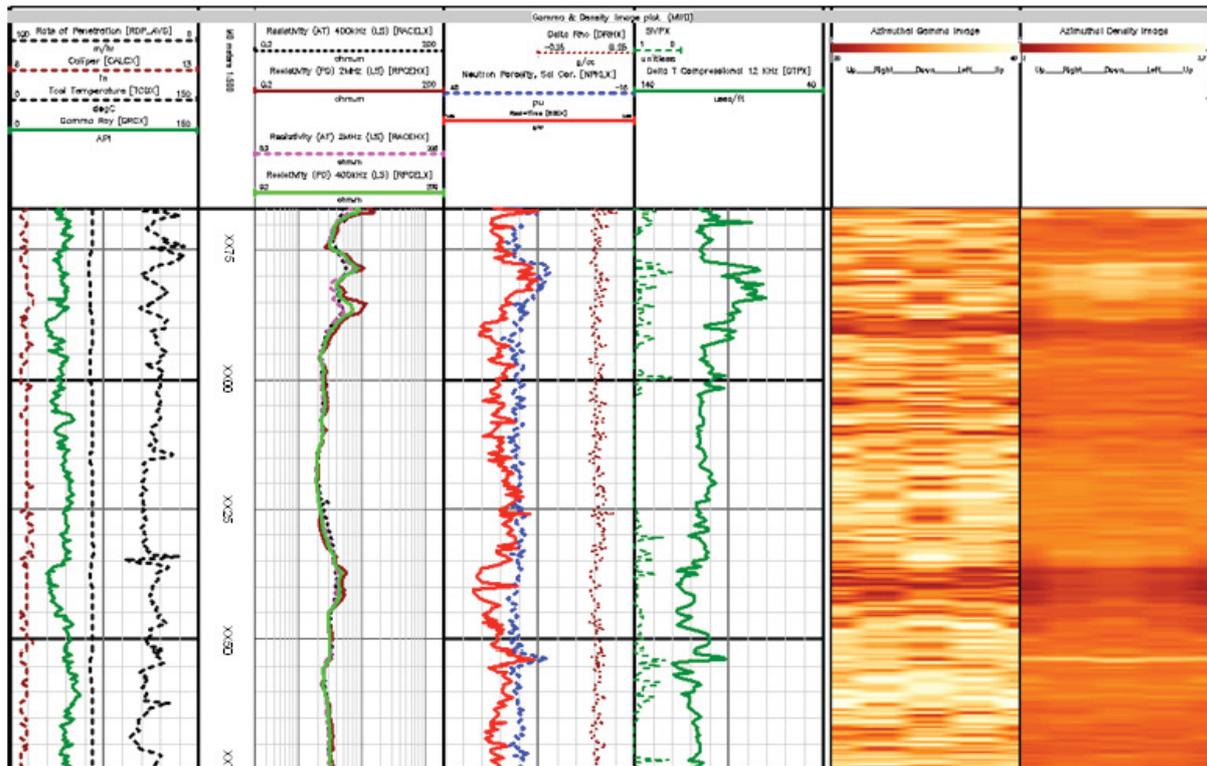
Service companies provide tools that give the downhole formation pressure and mobility while drilling. [8] The newest generation of tools, also provides an opportunity to take samples of the formation fluid. This is a service that previous only was provided by wireline. The values of the pressure measurements can be seen in a variety of areas at the well site, such as reservoir characterization, drilling efficiency, wellbore integrity and safety.

3.2.2 Power requirements

Acquisition of measurements is a challenging task for MWD/LWD service providers since downhole power is required. This is solved by installing a downhole turbine into the BHA, which converts kinetic energy of the mud flow in the string into electrical energy. The turbine sub provided by Baker Hughes, is called BCPM (Bi-Directional Communication and Power Module). [9] This provides 33 VDC and has a 300 Watt power output capability. Different configurations of the turbine determine which flow range that is required to create power.

The requirement for power depends on the number of tools in the BHA. The need for power could sometimes exceed the output of the power module. This could be resolved using a battery sub installed in the BHA. [10] Also there will be no generation of power when the flow is off, or below the start-up threshold to the power module. Tools could have batteries integrated in them, to perform the measurements when the power-module does not generate power.

There will also be a maximum flow threshold, which determines the maximum flow that can be pumped through the power-module. Exceeding this is not desirable, as it could damage the downhole turbine.



Klotz et al. 2008

Figure 4: Screen capture of a typical visualization of real-time formation evaluation data presented during drilling. The data is sent using MPT, drilling with an average ROP of 30 m/hr. The log shows from left to right: Track 1: Rate of Penetration (ROP) 0-100 m/hr; Caliper Log (inches); Tool Temperature (°C); Gamma Ray in API units. Track 2 is the depth scale in meters. Track 3 is the resistivity with 4 resistivity curves transmitted in real-time with different depth of detection. Track 4 is the porosity track with Density in g/cc, Neutron Porosity in porosity units and delta rho as the quality parameter in g/cc. Track 5 is the acoustic information with real-time compressional measurements and the semblance for quality control. Track 6 is the Gamma Image and Track 7 is the Density Image. Both the images are used for real-time dip interpretation for true dip which in turn together with the other information is used in the real-time wellbore placement operation.

4 Current Procedures Applied During Downhole Communication

The vast majority of the wells being drilled on the Norwegian Continental Shelf are conventional wells where the communications with the downhole tools are conducted with mud-pulse telemetry. The following explanation of the existing procedures will therefore be under the assumption that it is a conventional drilled well, where mud-pulse telemetry is used. A thorough explanation of the MPT system follows in a later subchapter.

4.1 Normal operation – drilling/circulating

Prior to tripping in hole with the BHA, the MWD/LWD tools are being tested and programmed on surface. The tools are then being programmed to send up the different data required by the client. These requirements could be different from client to client, well to well, which sections being drilled etc. A resemblance would be that the data required are larger the closer to the reservoir the well gets. Hence, to be able to get good resolution data, the desired data-rate (the “speed” the data is being transmitted with) from the client will also increase as the well gets deeper.

Drilling in the reservoir, especially when geosteering the well using the LWD logs, the data resolution of the logs is important. However, getting the directional and vibration data for the Directional Driller as well as the measurements of the physical properties in the wellbore will of course be of equal importance. There are, in other word, a vast amount of data required to be able to drill the well the best way. The limitations may therefore be the data-rate that the mud-pulser managed to send the data to surface with. If that is the case, the solution would be limitations to the rate of penetration (ROP), to increase the amount of data received from downhole per drilled meter. Hence, more rig time could be spent drilling/logging than possible necessary. This would however only increase the data density of the data that is dependent on the position in the well, such as the LWD measurements of the formation. Time related data, such as pressure and strain, will be sent up and stored with the same data density regardless of the ROP.

4.1.1 Nuclear sources

Some of the LWD tools have to use a nuclear source installed in them prior to running in hole. These tools, which measure neutron porosity and gamma density, are very important while geosteering the well, and are usually run in the sections close to the reservoir. To be able to use nuclear sources for logging proposes, there is a lot of regulations that needs to be followed. Continues measurements of the radiation are performed, to ensure that it is always known where the source is. The MWD/LWD tools do not perform any of these measurements itself, but a LWD tool that is working, continuously transmits reasonable data, is a good indication that the source is installed in the tool. A stand-alone radiation detector is mounted on the flow-out line from the well, and it will trigger an alarm in the MWD/LWD operators monitoring system if radiation is detected. When the alarm is triggered, the operator has to notify the driller, who stops circulation. A manual reading is then performed at the shakers to confirm the radiation measurements. If an incident like

this should occur, the goal would be to prevent as much radiation contamination of the rig as possible.

4.2 Survey

During the drilling of a bore hole, one regularly measures the inclination, azimuth and measured depth of the trajectory at a point near the drill bit. Such a measurement is required by the Norwegian Petroleum Directorate (Ptil):

“During drilling operations the Licensee is required to know the well’s position at all times. Measurements which determine inclination and azimuth shall be taken at intervals not exceeding 100 m, and they shall be commenced after the surface casing has been set, or at the depth that the Norwegian Petroleum Directorate deems necessary”. [11]

These are minimum requirements, and when drilling deviational wells, more frequent measurements may be taken to permit a more accurate determination of the wellbore trajectory. The directional driller decides if a survey station can be skipped or not.

It is usual to perform a directional survey after each drilled stand. To get a good measurement, the torque has to be worked out of the drill string, and the string has to be kept stationary. The MWD tool is programmed to make a measurement if the tool is powered up without rotation. Hence, the flow through the tool has to be reduced to the amount where the tool shuts off. When the flow then is brought back up, the tool makes the necessary measurements and sends them to surface. The time to take each survey will depend on the startup time of the mud-pulser in the tool, and the data-rate used to transmit the measurements. When the data is received, and rotation of the string commences, the MWD changes its data transfer to continue transmitting the measurements from the MWD/LWD tools.

When the stand is drilled down, a connection is performed where a new stand is added to the drillstring. During this process, there is no flow through the drillstring. For this reason, the survey process is usually performed prior to commence drilling on the new stand. This way, the survey is performed while establishing circulation again after the connection, which saves rig time.

This practice could vary dependent on the procedure on rig, and sometimes also be change depending on the condition of the well. After every drilled stand the driller makes measurements of the weight it requires to move the drillstring up and down in the well. Comparing these to the last performed measurements and simulated values, give an indication whether or not the hole is in good condition. Over-pull, when the up weight is larger than expected, could indicate poor hole-cleaning or tight hole. In those cases it is not desired to stay stationary longer than necessary, especially not on the top of a stand. If the drill string then gets stuck, it leaves little room for the driller to move the pipe. Even though it will be more time consuming, surveys are in those cases usually performed prior to picking up a new stand and performing a connection.

At surface, the survey is then verified prior to re-commencement of drilling operations. Most drilling programs call for a survey to be recorded each drilled stand. Errors associated with survey data has been modeled, allowing the uncertainty associated with the selected survey program to be defined with a certain statistical probability. In cases where it is important to reduce the positional

uncertainty, more advanced surveying methods are employed. These include use of multiple sensors within the BHA and/or use of more frequent survey data sets. It is not accounted for gross error in the model; hence a quality control of survey data should be considered critical in all cases.

4.3 Downlink

During downlinks, adjustments to the flow in or RPM have to be performed for the downhole tool to recognize the action it is required to do. During the time a downlink takes, data transfer from downhole stops. The newest generation's mud-pulsers are able to recognize the downlink and continue transmitting data; however they still stop sending data at the end of the downlink to give a confirmation that it was successful. This will of course affect the real-time logs, and continue drilling while sending downlinks, could lead to poorer data resolution on the logs. To assure sufficient data density, the procedure could therefore be a limitation on the ROP while sending these downlinks. In some instances, it could also be required to stop drilling until the downlink has finished. The time needed from the data transfer stops to the confirmation that the bottomhole tool understood the downlink command is received, will vary, but can in some cases take several minutes. When geosteering the well, adjustments to the wellpath will be decided from the real-time analysis of the downhole LWD data. The consequence of this could be that it would be necessary to send a large amount of downlinks during the drilling to adjust the parameters in the steering unit. Since it is important with a good resolution LWD log during geosteering, it is usual to stop drilling while downlinking the required drilling parameters. Hence, during this phase of the drilling, quite a lot of time could be spent off-bottom downlinking.

Baker Hughes has developed a system to send downlinks without adjusting the pump output or the string RPM. A module is connected on rig floor which diverts between 10-20% of the flow being pumped down the string. This gives the same effect as adjusting the pump output, but is remote controlled from by the MWD operator on the rig. Even though this affects the inflow in the well, this is not a part of the rigs drilling equipment. Hence, approval from the driller needs to be given prior to operating the downlink controller, as it affects the flow into the well and the stand pipe pressure.

4.4 Optimizing drilling parameters

With moderate data transmitting levels of LWD service using conventional MPT, it is typical to transmit these data sets to surface every 45 to 60 seconds. These update rates are sufficient to quantifiably enhance performance, but provide an incomplete snapshot view of downhole drilling dynamics, especially when drilling with high ROP or when presented with telemetry decoding difficulties.

Stick-slip is a torsional vibration mode which can result in very high angular accelerations and peak values in rotary speed (including backwards rotation) at the BHA. These accelerations and peak rotary speeds can damage the drill bit and BHA components resulting in premature failure. Stick-slip also negatively impacts drilling performance by providing a less effective cutting action of the drill bit to the formation. The most harmful vibrations can critically damage the BHA in a matter of a few minutes (e.g. back whirl events). Hence, there can be insufficient time to react and prevent a failure resulting from the damaged caused. The true severity and character of the dynamic event might not

become evident before from post well analysis is done of memory data. When the highest LWD service levels are used it is sometimes even necessary to restrict or stop transmission to surface of some dynamics sensor data to maximize bandwidth available for real-time formation evaluation data transmission.

While milling casing, there could be a problem with pack-off events close to the bit. In these cases, a CoPilot could be run to try to spot these events early. Also close monitoring of other downhole parameters such as WOB and torque would be helpful to see that the surface force is transmitted down to the bit, and that the BHA does not get hang-up in something above it. When monitoring the bore- and annular pressure, changes in the measurements could indicate pack-off. In these events an early warning is important, since the pressure buildup starts slowly, but increases almost exponentially as it gets time to develop. This would eventually be seen clearly from the surface parameters, such as the stand pipe pressure. Hence, this is a service where the amounts of updates from the downhole parameters are important.

4.5 Reservoir navigation

Reservoir navigation can be described as pro-active geosteering using LWD measurements to update geological models in real-time, and thereby refining the wellpath to stay in a defined formation target. [2] The more complete the LWD measurement set is in real-time, the better the chance for an accurate model update. A complete LWD data set for reservoir navigation could include multiple propagation resistivity measurements, deep reading resistivity images, nuclear porosity measurements and images, and gamma-ray measurements and images.

Reservoir navigation applications can also call for measurements that can help determine optimal production zones and update reservoir model parameters in real-time. For instance, data from a formation pressure test can be used to calculate pressure gradients and even determine reservoir fluid mobility using a complete pressure transient analysis.

The interactive real-time usage of formation evaluation information while drilling long horizontal wells has a direct influence on the productivity of the well. [12] Depending on the reservoir geometry, depositional environment and post deposition tectonic movement, long horizontals are likely to pass through several reservoir zones and often faulting. This consequence of this could be that the reservoir being penetrated has large variations in quality. Faults are often of sub seismic magnitude and can lead to an increased uncertainty in the interpretation. In faulted reservoirs high LWD data density is often necessary to be able to ensure interpreting of images for geological and structural evaluation with high confidence. This is particularly important in marginal fields and if high precision steering is required to maintain the optimal well trajectory.

4.6 Formation pressure point and fluid sampling

LWD pressure testing tools can be used to make accurate formation pressure measurements to adjust drilling fluid properties in real-time for avoiding kicks or fluid loss. [2] When a formation pressure test is performed, the drill string has to be stationary and all torque worked out. [13] After downlinking a command to the LWD tool to start a test, the tool deploys a test pad which seals to the

formation at the desired test depth, and the pressure test commence. During the test, the drillpipe must be kept stationary. In the instance of a fluid sample being collected, the test itself may take several hours. During the fluid sampling, continuous information is received regarding the performance of the tool. However, during formation pressure testing, which also is the start sequence of a fluid is sampling, no information is sent to surface prior to the test ending. Hence, there is not possible to see if it is a good test before it is completed. LWD pressure tests are performed “blindly”, with pre-programmed test parameters. The result of the test is transmitted to surface for analysis, which even with data compression techniques can require a significant amount of time. If the test parameters were not optimal, the test can be performed again with optimal parameters by downlinking to the tool and reprogramming it. This is of course at the cost of additional operation delays.

Prior to an operation where it is known that the string is going to be kept stationary for a while, it is usually included into the drilling program to perform a sticky test. Even though there is continuous circulation during the pressure test to keep the tools powered up, there is still a risk of getting the drillstring differentially stuck. Hence, the time the drillstring is stationary should be kept to a minimum.

4.7 Tripping operations and flow-off events

As mentioned earlier, it is not possible to communicate with the tool without having sufficient circulation through the power-module. If a battery package is installed, the pressure data during the tripping and flow-off events will be stored in the memory, but not be accessible on surface until the memory from the tool is downloaded.

It would however be possible to get the maximum and minimum pressures from the period without sufficient flow. These data would be sent up together with the survey data, and to retrieve them the ordinary survey procedure has to be followed. The minimum pressure reading would, if there is no flow, be the pressure of the above mud column, i.e. the hydrostatic pressure. Maximum recorded pressure is used when performing LOT/FIT test. The reading from the downhole sensor will then show the maximum pressure recorded downhole during the test, and is most often used to confirm the surface data from the test.

4.8 Well control operations

Well control operations are the emergency procedures followed when formation fluids begin to flow uncontrolled into the well, commonly known as a kick. The two widely accepted methods adopted by the drilling industry are known as the “Drillers Method” or the “Wait and Weight” method. In both methods it is necessary to maintain the bottomhole pressure continuously above formation pore pressure to prevent further influx of formation fluid. It is normally considered ideal that the bottomhole pressure is maintained just slightly above formation pressure to prevent fracturing other stratum and creating the conditions for an underground blowout.

Most kill operations are conducted at flow-rates below which the MWD tools are able to transmit mud-pulses; hence the downhole pressure gauges mounted in the BHA cannot be used. Due

to a battery package in MWD tool, the tool will perform pressure measurements during the kill operations, but only the max and min pressure will be sent to surface when the tool starts pulsing again.

4.9 Lost circulation event

Conventional MPT pulsars are vulnerable to blockage when Lost Circulation Material (LCM) is pumped. This can cause loss of transmission or, in the very worst case, complete blockage of the drill string preventing further drilling fluid circulation. This can be highly inconvenient as it normally requires a trip out of hole to replace the blocked MPT system. In a situation where LCM is being circulated this can also be hazardous as a well control incident is either potentially imminent or occurring.

4.10 Verification of MWD/LWD tool and shallow hole testing

It is common practice to shallow test the BHA when running in hole as a final check of functionality before reaching bottom. Decoding MPT signals during a shallow test can be difficult as the mud is cold and un-sheared. This can cause uncertainty in the shallow hole test if full decode is not achieved. Additionally, with a Rotary Steering System (RSS) in hole, it could also be required to check that the downlink communication functions correctly.

The BHA's usually have a float sub installed in them, which only allows flow down the string. Hence, when tripping in hole, the string will not contain mud. Due to the buoyancy, the common procedure is to fill the string and break circulation every 1000 meters. It is during one these events the shallow test is performed. Preferably it is performed as early in the tripping process as possible. If the MWD string does not respond as expected, a trip out of hole is required to change MWD components. However, a verification of the complete MWD string is always done in the derrick prior to running in hole. The majority of times, faults with the MWD tools are discovered then. Hence, some oil companies do not want to spend rig time on performing a shallow-hole test. The cumulative time spent on the tests would exceed the time it takes to do a complete trip out of hole in those rare events of a faulty MWD string.

Prior to start drilling in a well where the mud has been stationary for a while, it is usual to choose a slow data-rate. As circulation of the mud commences, the mud parameters will change, for instance induced by the temperature changes. When proper downhole communication is established, it could be required to downlink to a faster data-rate.

Pulling out of hole, the same verification of the MWD string is done in the derrick, as when tripping in. Most importantly this is to verify the resistivity readings when the tool is hanging in air. Laying them in a steel basket, would make it impossible to compare the post- and pre-run verifications. While connected to verify the tool, it is usual to download the memory data from them as well, to quickly be able to provide the customer with the complete formation evaluation memory logs.

4.11 Trouble shooting

In case of a failure on the tools, a diagnostic downlink could be sent, which request a set of parameters from the tools with information not given during normal operation. This could for instance include current and voltage output/input to the different components. Receiving this information and comparing it to the known reference values, could be helpful in the troubleshooting process, and might helping preventing a costly trip out of hole.

Prior to tripping out of hole, the wellbore must be circulated clean from the generated cuttings. Depending on the length of the well, it could take some hours before the state of the well is satisfactory. The troubleshooting will take place during this time, as well as the decision if to continue drilling without the faulty part. A part of the troubleshooting would be to lower the flow below the power-up threshold of the tool for different periods of time. It has been experienced that the faulty part could start functioning again if the toolstring has been without power for some time.

4.12 Data processing and distribution

When the measured downhole drilling parameters and formation evaluation data are received at surface, it gets processed and stored in a database which is periodically replicated from the wellsite to a secure data center. [10] It is also sent from the MWD/LWD service company's surface software system to the client's computer system via WITSML.

The WITSML software format a data stream through a firewall and into the client's IT environment for applications by the operator in proprietary or third party software's. The received and processed data can then be displayed instantly on the rig, in field headquarters, and in off-site collaboration centers.

5 Telemetry Techniques

In telemetry systems, a telemetry channel carries information. There are several telemetry channels that can carry a signal, and these can be grouped into two classes; those that require no change to the drillstring, and those that require either a modification to the drillstring or a radical change in drilling practices. We can further classify the transmission methods based on how far they can transmit information, and their channel capacity. The channel capacity is usually expressed in bits per second. When classifying in this manner, it will range from conventional methods which use existing channels and which are limited in capacity, to those that are unconventional and use additional channels, but which can handle a greater flow of information.

From a technical standpoint, the ideal MWD telemetry system is one that has a great reach and high potential data rate.

Examples of transmission methods that transmit information in the telemetry channels include mud pulse telemetry, which use the fluid filled bore of the drillstring; stress-wave telemetry, which transmits acoustic signals within the wall of the drillstring; electromagnetic telemetry, which transmits a signal through the formation; wired-pipe telemetry, which employs wired joints of oilfield tubular. The methods mainly used in commercial drilling operations are Mud-Pulse Telemetry and Electro-Magnetic Telemetry. Both of these are relatively low data-rate systems, but the first offers a great reach in mud-filled boreholes, while the second, has a niche marked in air and under-balanced drilling applications.

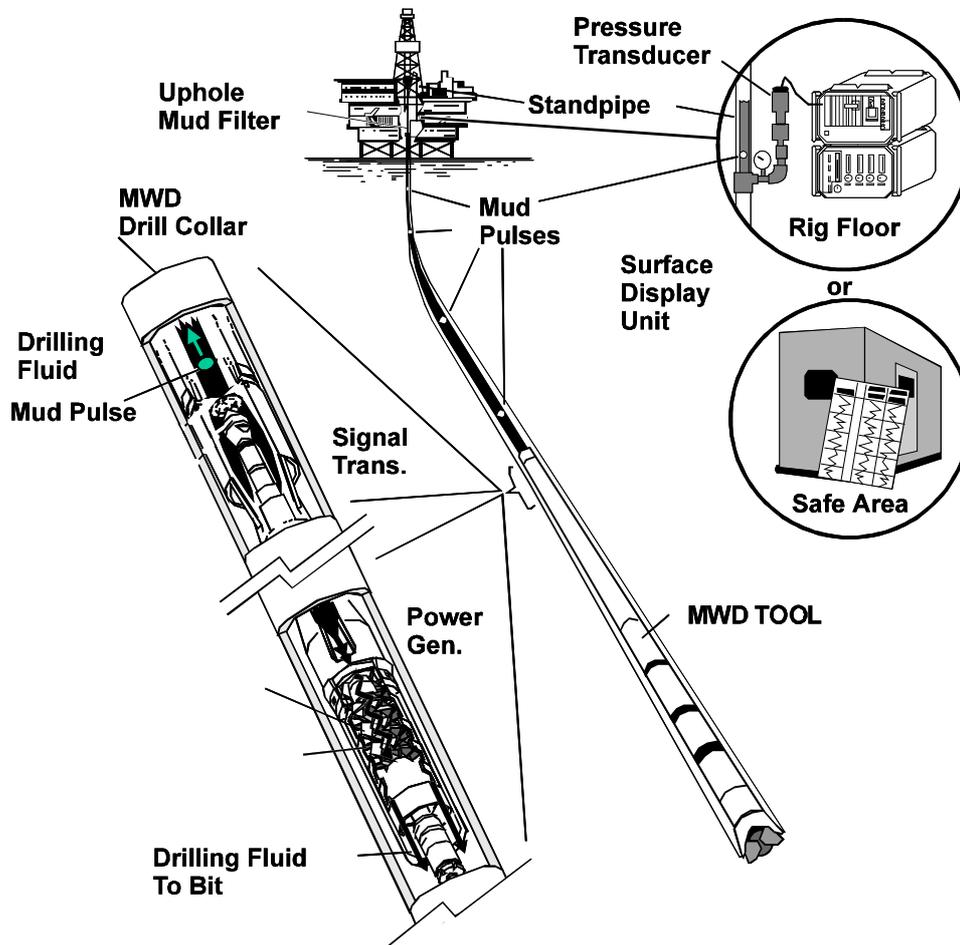
On the Norwegian continental shelf, Mud-Pulse Telemetry is the main telemetry used; hence the following text gives a thorough explanation of the theory and equipment used for this. Wired-pipe is the telemetry technique that gives by far the biggest information stream from the downhole tools to surface. Due to the extreme data transfer from the wired-pipe technology compared to the other available telemetry methods, it is possible that the wired-pipe technology will be more common, and maybe the preferred telemetry method in the future. Hence, there is also a review of the wired-pipe technology. There is also a brief description of the type of transmitters used by other methods than mud-pulse and wired-pipe telemetry.

5.1 Mud-Pulse Telemetry

In any telemetry system, there is a transmitter and a receiver. In MPT telemetry, the transmitter and receiver technologies are often different if information is being uplinked or downlinked. In up-linking, the transmitter is an MWD tool in the BHA which can generate pressure fluctuations in the mud stream. This tool is commonly referred to as the mud-pulser, or more simply the pulser. The surface receiver system consists of sensors that measure the pressure fluctuations, and signal processing modules that interpret these measurements. The interpretation of the signal is known as decoding.

Downlinking is achieved by either periodically varying the flow-rate of the mud in the system, or by periodically varying the rotation-rate of the drillstring according to a timed sequence. Downhole in the MWD system, a sensor and electronics respond to either the flow or pressure

changes due to the fluctuating flow-rate to detect the downlink signal. The one provided by Baker Hughes is integrated in the BCPM, which recognize the downlinks by monitoring the turbine RPM of the power-module. [9] When varying the rotation, a downhole sensor, such as a magnetometer, is used to detect the downlink.



Baker Hughes et al. 2006

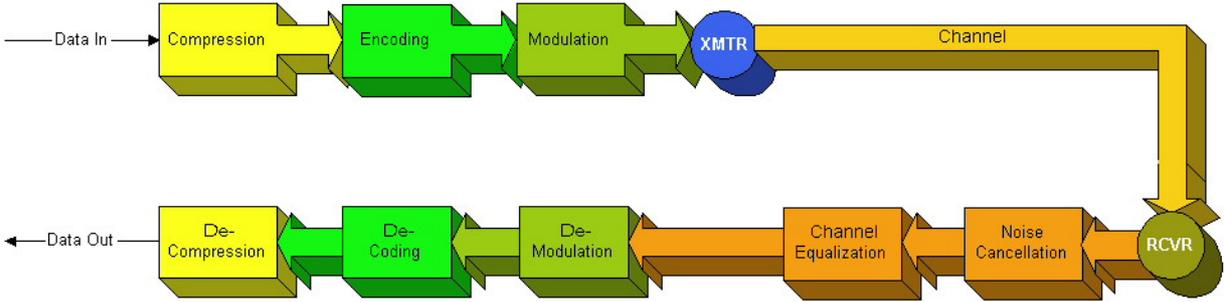
Figure 5: MWD tool communication to surface. The Pulsar is equivalent to the transmitter, the channel is the mud filled drillpipe and the receiver is the transducer mounted in the standpipe at surface.

5.1.1 Surface Systems and Sensors

The downhole transmitter is only one part of the MWD telemetry system. The other elements are the transmission channel, surface receiver, and additional surface and downhole processing layers. The surface and downhole components of the system are designed to provide a reliable system delivering the highest possible bit rate.

The surface system is basically the inverse of the downhole system, with a few extra tasks added to compensate the measured signal for distortion during transmission. In the downhole system the data is compressed and then formatted for transmission. It is then encoded and next modulated depending on the pulser type. This is the final waveform delivered to the transmitter;

with some synchronization overhead added at this point. The signal travels through the mud-column, where it is attenuated and distorted with various noise components, and is detected by the surface receiver system. The detection is measured by sensors whose number and complexity depends on the difficulty of transmission and the downhole tool being used. These signals are then treated to remove the noise components and distortion, and the downhole transmission process reversed; the data are demodulated, and then synchronized and decoded; bit errors are detected and if possible, corrected; words are then parsed and decompressed, and delivered to their final destination, a database, where they are grabbed by other routines for permanent storage or transient calculations.



Baker Hughes et al. 2006

Figure 6: Block diagram of the MWD telemetry system, showing matching downhole and surface components.

As the design of the mud-pulsar is unique for each individual MWD service company, so too is the design of the MWD surface system. What differentiates MWD companies is not just how fast the pulsar can be made to activate and how the data is transmitted, but the efficiency with which the data is extracted from the measured signal on surface. Decoding efficiency is a critical component affecting the performance of the MWD telemetry service.

The surface system consists of a sensor set, components for conditioning and digitizing the signals measured from the sensor, and a digital signal processing unit for processing these measurements.

5.1.1.1 Sensors

The primary sensor for measuring mud pressure pulses is the pressure transducer, which is typically mounted in the standpipe. There are three types of pressure transducers used: static, dynamic and differential. Static transducers measure from 0 psi to a defined maximum. Standard ratings are 5, 10 or 15 kpsi full scale.

The dynamic pressure transducer responds only to dynamic components in the signal within a specified measurement bandwidth, and so it can be used to detect the signal. Because the sensor has only to measure over a dynamic range in amplitude, rather than the complete static range, it is possible to increase the sensitivity and digital resolution of the sensor. The dynamic sensor

development has a high dynamic range of about 1000 psi, which yields a 5, 10 or 15 times increase in digital resolution compared to the static sensors.

Flow meters have also been used in the standpipe to measure MWD telemetry, as have annular pressure sensors. In a Venturi flow meter, flow passes through a constriction. Due to higher flow velocity, there is a pressure drop which is measured using a differential pressure transducer. As the flow velocity changes, so does the pressure drop.

Data enters the MWD surface system from many sources, not just from the pressure transducers. For example, sensors may also be hooked up to measure Rotation-Per-Minute (RPM), hookload, block height and surface torque. To further facilitate decoding, pump stroke counters and a second pressure transducer may also be connected to the system.

5.1.1.2 Surface Systems

The pressure transducers are connected to a MWD surface system, where analog signal is conditioned and digitized. The signal from the pulser is eventually extracted and decoded, and the MWD data is stored and displayed. The complexity of the MWD surface system is dependent on the MWD/LWD service being run, and decoding challenges increase with increasing data-rate and depth.

From a MWD view point, the major difference between older generations of surface systems and more recent ones is the ability of the newer systems to recover a very small signal from the pulser that is buried in background pressure noise. In systems with only one pressure transducer, or a single flow sensor, decoding is limited to simple filtering to reduce noise. With the addition of pump stroke counters, the ability to compensate for pressure signals generated by the mud pumps is possible, and one of the major sources of pressure noise can be eliminated.

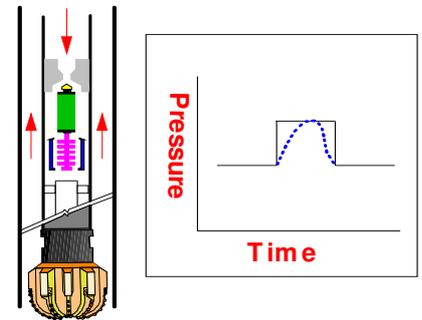
The development of sophisticated real-time Digital Signal Processing (DSP) routines combined with high resolution analog to digital converters and a fast processing system makes it possible to deliver reliable MWD mud-pulse telemetry at high data-rates at deep depths. This surface platform provides not only noise cancellation, but also advanced digital signal processing to characterize the telemetry channel and to remove telemetry channel distortion, referred to as channel equalization.

5.1.2 Signal transmitted

MWD service companies employ their own commercial mud-pulsers to transmit the data from downhole to surface. There are several different types of pulsers in use and we can classify them based on the type of signal they can generate; discrete pulses or continuous-wave signals. Discrete pulses can be either negative or positive, leading to the two classes of pulsers that can generate only discrete pulses: the negative and positive pulsers. Rotary valve pulsers can generate continuous-wave signals, and the shear-valve pulser is capable of generating both discrete and continuous-wave signal. All mud-pulsers operate independent from the surface; there is no direct electrical or mechanical connection from the downhole tools to surface.

5.1.2.1 Positive Pulse

Pulsers that create “positive pulses” contain a mechanism that partially restricts the flow of drilling fluid inside the drill pipe. This restriction results in an increase in hydraulic pressure. Pulses transmitted in the mud inside the drill pipe propagate at the speed of sound in mud (between 900 to 1 450 m/s) to the surface, where they are sensed by a pressure transducer, measured and processed. Several of the pulser design creates positive pulses, where the most common of which is the Poppet Valve design. There exist two types of this pulser; one uses the pressure of the mud to assist opening the valve, in other words a “hydraulically assisted” valve. These cost-efficient pulsers are capable of data rates up to 12 bits per second. The second type is fully isolated from the drilling fluid and consequently requires more power to open the valve. The advantage with the second type is that it is not prone to plugging by solids or LCM in the drilling mud, which makes this type of design highly reliable. However, since higher data-rates require more power, the telemetry rates may not be as fast as 12 bps with this second type. Depending on the design of the pulser, either type may be retrievable.

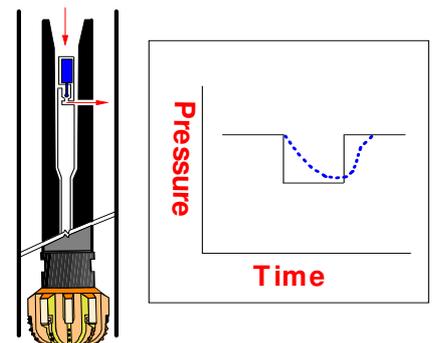


Baker Hughes et al. 2006

Figure 7: Positive pulse – Pressure restriction inside the drillpipe, momentarily increase the pressure measured at the standpipe on the rig floor.

5.1.2.2 Negative Pulse

The “negative pulse” pulser incorporates a means, usually a rotating valve, to vent some of the drilling fluid to the annulus. This results in a momentary pressure drop as seen at the standpipe on the rig floor. This type of pulser is not hydraulically assisted, as it is not operating in direct opposition to the flow of mud. Further, this pulser does not require the same amount of power as a fully enclosed “positive pulse” pulser, which makes it power efficient and capable of higher data-rates. The shearing action of the valve makes it less susceptible to plugging by solids in the LCM pill.

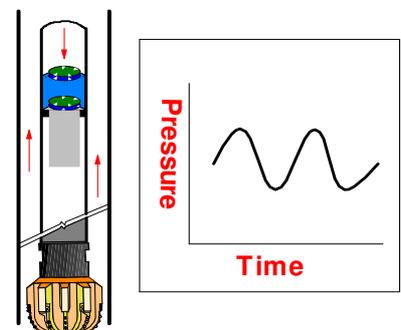


Baker Hughes et al. 2006

Figure 8: Negative Pulse – Pressure restriction inside the drillpipe, momentarily decreases the pressure measured at the standpipe on the rig floor

5.1.2.3 Rotary and Shear

The pulsers described above are only capable of generating a train of discrete pulses, either negative or positive. Pulsers of the rotary or shear valve design can generate continuous wave signals at a given frequency, and the information is encoded either in the frequency of the signal, or its relative phase. These types of pulsers consist of two slotted disks, placed one above the other perpendicular to the mudflow. One of the disks is stationary, while the other is free to rotate. The speed of the rotor controls the frequency of the continuous pressure wave generated in the mud. If the rotor oscillates so that the aperture of the two disks is controlled, then the valve is termed a shear valve. Generally, rotary valves can generate



Baker Hughes et al. 2006

Figure 9: Rotary and shear valves. Pressure restriction inside the drill pipe created by a rotor within the pulser.

only continuous-wave signals, while shear valves are very versatile and can generate both discrete and continuous wave signals.

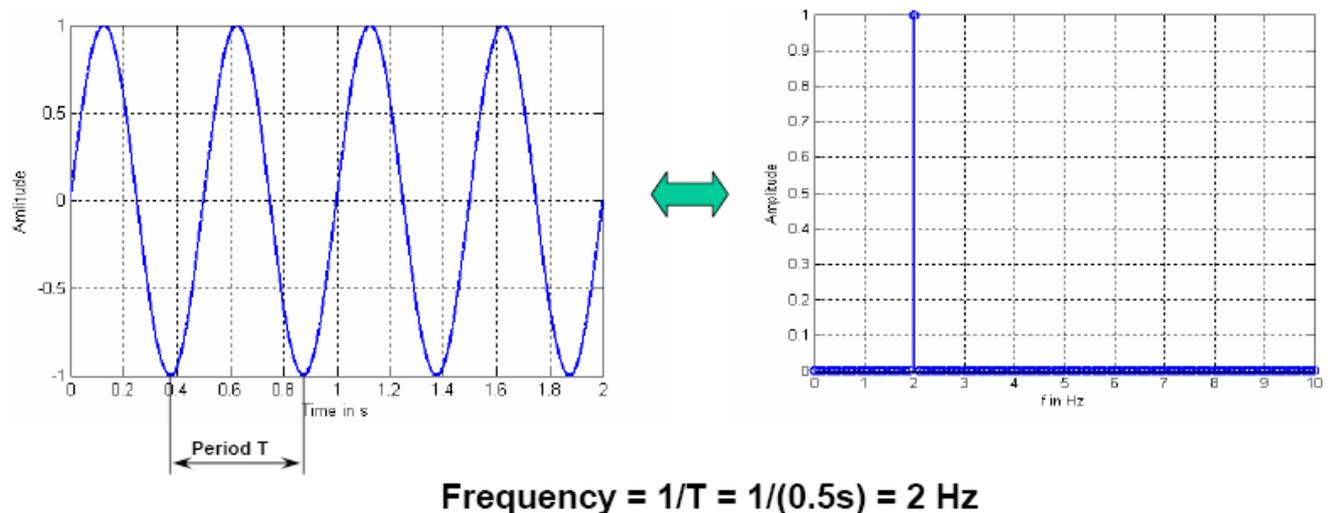
5.1.3 Signal Property Description

Mud-pulse telemetry is a complex process involving encoding the data from the MWD tools, transmitting the encoded signal to surface, and decoding the data from the received signal. During transmission from downhole to surface, the encoded signal is distorted and noise is added. Much of the surface processing involves removing the noise and correcting for distortion so that the encoded data can easily be decoded.

5.1.3.1 Signal theory related to MPT

Properties used to describe a sinusoidal waveform are its amplitude, frequency and phase. Amplitude is the measurement from some base value, usually zero, but it might be referred to peak-to-peak amplitude in which case the amplitude is measured from the minimum to the maximum of the waveform. In measuring MPT pulse amplitudes, the peak-to-peak value is always used.

Frequency is simply the number of cycles of the sinusoidal waveform that occur per unit time, and is measured in Hertz (Hz), which is the number of cycles per second. Phase is the relative offset in sinusoidal waveforms measured in fractions of a cycle of the waveform; for example, if two sinusoids are a 180 degrees out-of-phase, then they are shifted $\frac{1}{2}$ -cycle with respect to each other, so that one is inverted with respect to the other.

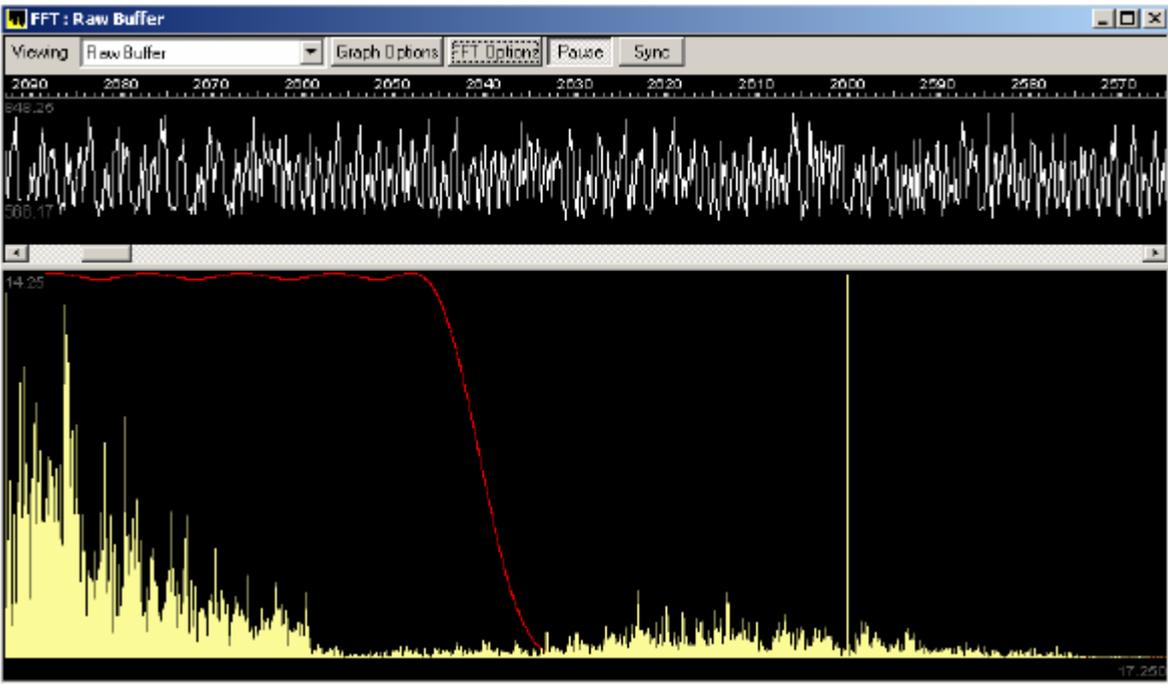


Baker Hughes et al. 2006

Figure 10: The FFT algorithm is used to switch between the time-domain and frequency domain representation of a signal. The time data is directly related to frequency data and knowing either one completely describes the signal.

A MPT signal can be represented in either the frequency domain or the time domain. In a relationship established by Fourier, it was proved that any signal can be uniquely expressed as the sum of sine waves of different frequencies and amplitudes. This concept means that no matter how random, any signal can be created by adding specific sinusoidal signals together and conversely, that the same signal can be broken down and represented as the sum of its sinusoidal parts. This allows us to take a signal, like the standpipe pressure signal, and break it down by frequency into its individual components for analysis.

This means that any waveform generated by a pulser can be approximated as the sum of a set of sinusoids that have specific frequencies, amplitudes and phases. The mapping between the pulser waveform (in the time domain) and its component sinusoids (in the frequency-domain) is called the Fourier Transform. Efficient algorithms used to calculate the Fourier Transform of a signal are called Fast Fourier Transform (FFT) algorithms.



Baker Hughes et al. 2008

Figure 11: A screen capture of the incoming raw signal in the top track and the corresponding frequency distribution in the lower track. A FFT algorithm is used to calculate the frequencies from the raw signal.

5.1.3.2 Groups of signals

There are two groups of signals that are used in the transmission of information: baseband and passband signals. The transmission of information in a sequence of discrete pressure pulses is known as baseband signaling. If the pulses are further modulated by a carrier signal, which shifts the transmission bandwidth higher in frequency, then this is known as passband signaling.

Most commercially available mud-pulsers use baseband signaling. In some instances, rotary or shear valve pulsers can use passband signaling in addition to baseband signaling. This capability is important as it provides the opportunity to shift the transmission into frequency bandwidths that are less affected by drilling noise, resulting in more reliable telemetry.

As an example, baseband signaling is affected by torque noise and the stick-slip behavior of the drillstring. By using passband signaling we can move the signal clear of this noise source.

5.1.3.2.1 Baseband Transmission

There are basically two ways encoding the information sent by the downhole pulser. Either by encoding the information directly so the presence and absence of pulses are signaling elements, or by encoding the information in the position of the pulses. The first of these is referred to as Pulse Code Modulation, and the second as Pulse Position Modulation.

5.1.3.2.1.1 Pulse Code Modulation (PCM)

In this method of encoding the information, the time-line is divided into intervals of equal time, each of which is a bit-period. We directly translate the binary signal that is to be transmitted, represented by a stream of 1's and 0's, into one of two states. For example, a binary one may be encoded as the presence of a pulse within a bit-period and a binary zero as the absence of a pulse within this period.

In this type of encoding, each bit-period contains a signaling element (a symbol) and the transmission rate of these symbols is expressed in baud ("symbols per second"). The symbol rate represents the transmission rate of symbols over the transmission channel.

The bit rate, in bits per second, is another measure of information transfer, and is the number of binary digits (1's and 0's) delivered to the transmitter, and received at the receiver, per second. In some systems, the bit rate is given by the inverse of the bit-period (T) times the number of bits per symbol (b).

$$bps = \frac{b}{T} \quad (1)$$

MWD companies use a variety of coding schemes according to their individual requirements. Example of PCM schemes are the SplitPhase and Miller codes.

In SplitPhase codes, a logical '1' is represented by increase in signal level at the mid-point of a bit period, while a logical '0' is represented by a decrease in signal level. Obviously this pattern can quite easily be represented by pressure pulses, and it is robust encoding type in high noise environments (such as torsional stick-slip noise).

In Miller codes, a logical '1' is represented by a change in signal level at the mid-point of a bit-period. If a logical '0' is preceded by a logical '1' then there is no change in signal level at the bit-period boundary; but if two logical zeros occur in sequence, then there is a change in signal level at the bit-period boundary. Again, pulses can quite easily represent this pattern.

The frequency bandwidth of each PCM code is of interest since it indicates how hard an MWD pulser must be driven to obtain a given bit rate. However, valve wear should be balanced

against decoding rehabilitee. That is, although the codes with more valve transition per unit time result in greater valve wear, they have more clocking information and the surface system is better able to maintain synchronization with the downhole system.

5.1.3.2.2 Pulse Position Modulation (PPM)

In Pulse Position Modulation, the information is encoded in the position of a number of pulses within a specified time interval. Just as in the PCM techniques, the time-line is divided into intervals of equal time, but here they are termed slots rather than bit-periods. However, unlike the PCM techniques which are bit-based, this type of scheme is a word-based transmission system; a word of K-bits is encoded M-pulse, which can occur in N-slots.

The rules for creating the pulse pattern to represent a word are relatively straight-forward; a pulse is 1 ½ slots wide; pulses always start on a slot boundary; data pulses must be separated by at least 1 ½ slots; and the last two slots of a word must be empty. For example a 7-bit word is represented by 3 pulses in 17 slots, and an 8 bit word by 3 pulses in 19-slot.

While the calculation of the bit rate of a PCM code is straight forward, it is more difficult to calculate the bit rate of a PPM code. We can, however, calculate it by assuming a word length of 16-bits, which is represented by 6 pulses in 34 slots. As mentioned previously, each pulse is 1 ½ slots wide: so the 16-bit word is transmitted in 2/3*34 pulse widths. The relationship between bit rate and pulse width is:

$$bps = \frac{3 \cdot 16}{2 \cdot 34} \cdot \frac{1}{pw} = \frac{0.706}{pw} \approx \frac{5}{7pw} \quad (2)$$

Pulse Position Modulation is very efficient in terms of pulses per bit, it requires only 6-pulses to transmit 16 bits. Comparisons with the PCM schemes, SplitPhase require an average of 21 pulses to transmit 16 bits, while Miller requires an average of 11.

One additional advantage using PPM codes is that they come with built-in error detection. The pulse pattern rules limit the possible location of valid pulses, and can be used to discriminate between valid pulses and those created by noise source.

5.1.3.2.3 Passband Transmission

If the baseband signal described in the previous section is modulated with a signal which has a constant carrier frequency, then the resultant signaling is termed passband. Any baseband signaling can be made into a passband signal by modulating it with a carrier signal.

There are three subset of passband signaling that are of interest: frequency modulation, phase modulation and amplitude modulation. The last of these is a hybrid between passband and baseband, but it is included in this section because it involves a carrier signal.

5.1.3.2.3.1 Amplitude Modulation

Amplitude-Shift-Keying (ASK) is the use of an amplitude modulated waveform to carry digital information. A baseband signal may be thought of as a sequence of alternating pulses and gaps. In ASK, a waveform of a single frequency is used to represent a pulse and no signal is sent for a gap (the transform may be inverted so that a gap is represented with a waveform of known signal, a pulse with no signal). Any of the baseband signals (Pulser Code or Pulse Position Modulations) can be represented by ASK. While in theory any frequency can be used for the waveform, one of the

restrictions is that the waveform demonstrates the property of continuous phase. This property results in lower energy requirements by the pulser, and lower energy losses while transmitting the waveform through the drilling fluid. Continuous phase means that the phase of the signal changes smoothly at the boundary of a pulse. For many mud-pulsers, valid ASK frequencies are given by the inverse of the pulse width times an integer.

5.1.3.2.3.2 Frequency Modulation

Frequency-Shift-Key (FSK) is the use of a frequency modulated waveform to carry digital information. If the pulse train is thought of as a sequence of pulses and gaps, then a first frequency represents a pulse, and a second frequency represents a gap. The order of the frequencies is not important, so long as it is known at both the transmitter and receiver. As with ASK, the phase should change continuously at pulse boundaries where two different frequencies meet. This type of FSK is termed continuous-phase FSK, or CPFSK for short. Another restriction imposed with mud-pulse telemetry is that transition between signals takes place at either the maximum or minimum amplitude, to conserve energy in the generation of the signal. This restriction also ensures that the two frequencies are orthogonal. They do not disturb each other during transmission and are easily distinguished at the detector on surface. This is an extremely valuable property for the transmission.

5.1.3.2.3.3 Phase Modulation

Phase-Shift-Key (PSK) is the use of a phase modulated waveform to carry digital information. In PSK transmission the frequency is kept constant, and the phase of the signal is changed at signal boundaries. With binary PSK (only two states to be represented, 0 or 1), the phase difference is 180-deg. As with ASK and FSK transmission, the phase of the signal is continuous at symbol boundaries.

The carrier frequency is the frequency used in generating the PSK waveform. The signal is concentrated in a bandwidth about the carrier, and the extent of the bandwidth depends on the bit-rate and the baseband code being modulated.

5.1.3.2.4 Comparison of Modulation Methods

The chosen modulation mode will depend on the drilling environment. FSK can operate in poorer reception conditions, and can handle about a 30% lower signal-to-noise ratio at the receiver than either PSK or ASK. FSK has also the ability to switch to ASK demodulation at the receiver, without changing from FSK transmission. Should one frequency become corrupted by drilling noise; then FSK has the ability to cancel amplitude modulation noise, which makes it relatively robust. A disadvantage with FSK is that the bandwidth is relatively high compared to PSK. So if the telemetry bandwidth is reduced due to noise and problems transmitting the signal through the mud, then PSK is a better option.

5.1.4 Signal Attenuation

One of the challenges that successful MPT decoding has to overcome is the attenuation of the signal with depth. Increasing depth has a significant influence on the amplitude of the signal measured to surface. [1] This is also influenced by the mud properties. Due to its compressional properties, oil based mud would give back a smaller signal compared to water based mud. Delivering adequate signal strength at the tool, so that it can be detected at surface, is an important property of the mud-pulser. Successful decoding at extended depths becomes a significant challenge, and in

order to maintain an acceptable signal-to-noise ratio, MWD service companies may reduce data rate to maintain decoding performance. The ability to downlink to the MWD tool provides an ability to improve signal decoding by changing data-rates without tripping. A reduced data-rate results in longer or wider pulses, which improve the probability of pulse detection. With the latest generation of mud-pulser there is a possibility to send a downlink to change the size of the pressure pulses it generates.

Mud-pulse decoding is dependent on a large range of interrelated variables, each of which adds to the decoding challenge and each of which can vary in importance with the configuration of the rig and borehole. Some of the variables are mud type and properties, drillstring hydraulics, surface equipment, pumping type and condition, rig surface hydraulic configuration, pulse amplitude and shape, measured and true vertical depth, wellbore profile, drilling dynamics and so on. The drilling environment is dynamic and unique, and a challenge to achieving high data-rate mud-pulse telemetry.

5.1.4.1 Flow Rate

Increasing flow rate to overcome signal attenuation is one option to increase the pulse height, and therefore increase the probability of pulse detection. The pulse height at the transmitter depends primarily on the change in pressure drop when the pulser is activated. The pressure drop will vary inversely with the diameter of the restriction (a larger restrictor will result in a lower pressure drop) and directly with the square of the fluid velocity.

Increasing the mud flow rate, which increases the fluid velocity through the pulser, will significantly increase the pulse height generated by the pulser. While it is not normally possible to change the restriction in MWD tools without pulling out of hole, it may be possible to change flow-rates. However, increasing the flow-rate will increase noise in the mud channel as well as increasing the wear on downhole components.

5.1.4.2 Mud properties

As mentioned previously, drilling fluid properties have a significant effect on pulse attenuation. Pulse height attenuation can be described by Lamb's equation;

$$\frac{p_x}{p_0} = e^{-\frac{x}{L}} \quad (3)$$

That is, the ratio of the pulse height, p_x , at depth X , to the pulse height of the transmitter, p_0 , is given by the term on the right hand side of the equation. The variable L is given by:

$$L = \frac{D}{2} c \sqrt{\frac{2}{v2\pi f}} \quad (4)$$

Where D is the inside diameter of the pipe, c is the wave speed in mud, v is the kinematic viscosity (the ratio of fluid dynamic viscosity and density), and f is the frequency of the signal.

Changing the mud viscosity can have a significant effect, more so that changing the mud density. Doubling the viscosity in a water base system can reduce the percentage of the pulse amplitude detected at surface from 25% to 14% of the original pulse height at 1700m, a 43% change. This change is more dramatic at 10 000 m, where doubling the viscosity causes nearly a 70% reduction in pulse height detection at surface, making it difficult to decode the signals.

While this equation is a model and only represents part of the overall dynamic environment, it does show that the mud properties and the distance between the downhole transmitter and receiver on the surface can pose a significant challenge to decoding.

5.1.5 Noise Sources

In MWD telemetry we use a very broad definition of noise. Noise is anything other than the MWD telemetry signal in the measurements. [1] Since the amplitude of the noise is often larger than the amplitude of the signal, we use several techniques to remove noise and enhance the signal.

The ratio of signal power to noise power in the measurements is termed the Signal-to-Noise Ratio (SNR), and is usually represented in decibels (dB). A value of 0 means that the signal and noise have the same power, while positive values means that there is more signal power than noise power. Hence, a negative value means that there is more noise power than signal power. The objective of much of the noise cancellation is to increase the SNR in the measurements.

Noise is generally considered to be additive; a waveform is generated at the pulser and as it travels up to the measurement location, several other signal components are added. The noise cancellation task is ideally to remove all of the added noise components in the measured signal. This is done with a collection of techniques, from simple “canned” filtering where the operator can choose from a set of filters, through matched filtering where the received symbol is correlated with a desired symbol shape, to active filtering where independent measurements of the noise are made and removed from the measurements. The frequency range for baseband mud-pulse telemetry is from zero to about 5 Hz, and for passband telemetry is from about 2 to 40 Hz.

For simplicity in the sources are grouped into pump sources, drilling excitation sources, and drilling dynamics sources.

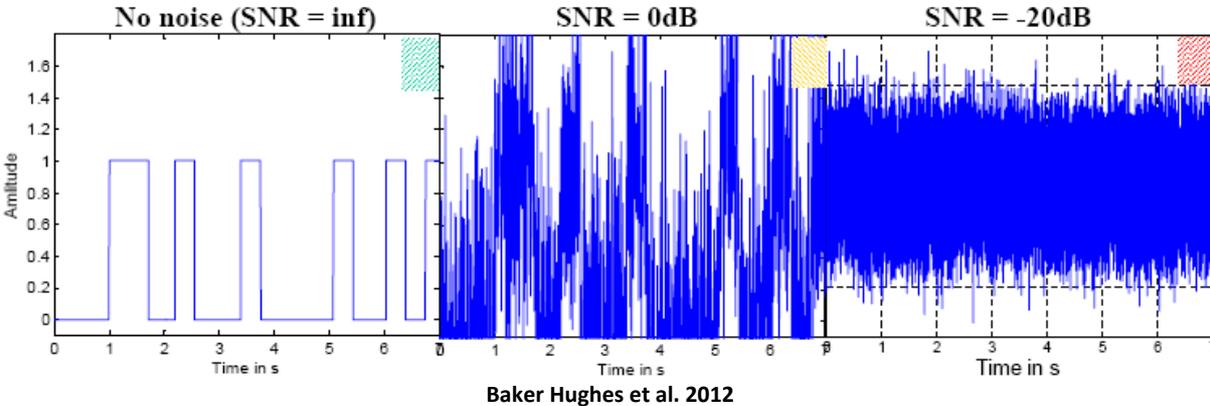


Figure 12: An illustration of how noise would affect the signal. As the Signal-to-Noise ratio decreases, the signals amplitude gets more and more camouflaged by the measured noise.

5.1.5.1 Pumps

Signals generated by the pumps are a major source of noise in the pressure measurements. With a triplex pump pumping at 90 strokes per minute (SPM), a large signature is generated at three times this frequency, or:

$$\text{Triplex pump frequency} = \frac{3 \cdot \text{SPM}}{60 \text{ sec}} = 4.5 \text{ Hz} \quad (5)$$

This signal is not sinusoidal and several harmonics may be present at 6, 9, 12 and so on, times the stroke rate. If the pump is not in good condition, a significant fundamental signal may also be present. In this example, this would be at 1.5 Hz.

Frequencies generated by the pumps appear at the top half of the baseband frequency range, and within the passband frequency range. In deep wells the telemetry signal may be quite small in amplitude and impossible to visually recognize in the raw measured data since the pump noise is high in amplitude. The pump noise may be ten-times or greater in amplitude than the downhole pressure pulses.

Aside from frequency interference from individual pumps, two or more pumps being run simultaneously can add noise due to amplitude modulation of the signals from the individual pumps. This amplitude modulation results in a signal at the “beat frequency” which is the difference between the individual pump rates. For example, if two triplex pumps are operating at 60 SPM and 50 SPM respectively, a low frequency beat signal might be observed in the standpipe at 0.167 Hz (60-50)/60, or three times this, 0.5 Hz. This signal will fall well within the mud-pulse baseband signal bandwidth.

5.1.5.2 Drilling Excitation

Drilling excitations can be regarded as sources of noise for mud-pulse telemetry, but are usually of lesser importance than the mud pumps. These could include excitations caused by drillstring rotation and mud motors. When the string is rotated it will move laterally, and a periodic excitation with the same frequency as the drillstring rotation may be coupled into mud. This may result in some distortion of the MWD signal.

The rotor in the mud motor will generate an excitation at a frequency given by the number of lobes on the rotor times the motor-speed. This excitation couples into the mud, and has been measured downhole. It can, therefore, add noise and distortion to the MWD signal.

5.1.5.3 Drilling Dynamics

Torsional oscillation of the drillstring is a principal source of noise. This is a periodic motion of the drillstring in torsion, and is due to the fact that the large mass of the BHA is on the end of a slender length drillpipe. If there is an increase in friction at the bit, or in the BHA, then the drillstring may start to oscillate at its first natural torsional frequency. This is a common mode of behavior for any drillstring, and is referred to as “torsional oscillation” of the drillstring. Its periodicity is generally longer than about 2 seconds; in other words, it has a frequency of less than 0.5Hz.

If the oscillations become severe, and the drillstring comes to a complete stop, then the phenomenon is referred to as stick-slip. The periodicity of the stick slip behavior will be longer than that of the torsional oscillation, with cycles longer than 5 seconds (0.2 Hz) being common. The longer the drillstring and the more severe the stick-slip behavior, the longer the stick-slip cycle becomes. In extreme cases, the bit and drillstring may rotate backwards and damage the bit.

Stick-slip and torsional oscillation noise fall within the frequency bandwidth used by baseband signaling, and can be extremely disruptive to baseband telemetry. There are several ways to minimize the impact that this noise has on telemetry. If vibration stick-slip is detected, this should be reacted to by either raising the RPM or lowering the Weight-On-Bit (WOB), or both, in an attempt to reduce the severity of the torsional motion. This is mainly to protect the BHA, and there are some cases, such as dropping angle, where the severity of the stick-slip behavior cannot be reduced. Then a high-pass filter could be applied to remove the frequencies where the noise appears.

High-pass filtering attempts to remove the interfering stick-slip signal from the measured pressure signal, and can be successful when the interference is very sinusoidal (as in pure torsional oscillations) and is at a very long frequency (as for long drillstrings). When the frequency of the torsional oscillation is high, the high-pass filter will remove too much of the baseband signal power, and there will not be sufficient signal remaining for reception. In this case, increasing the bit rate in combination with high-pass filtering may result in continued MWD transmission, since majority of the power in the MWD bandwidth may be moved above the cut-off frequency of the high-pass filter.

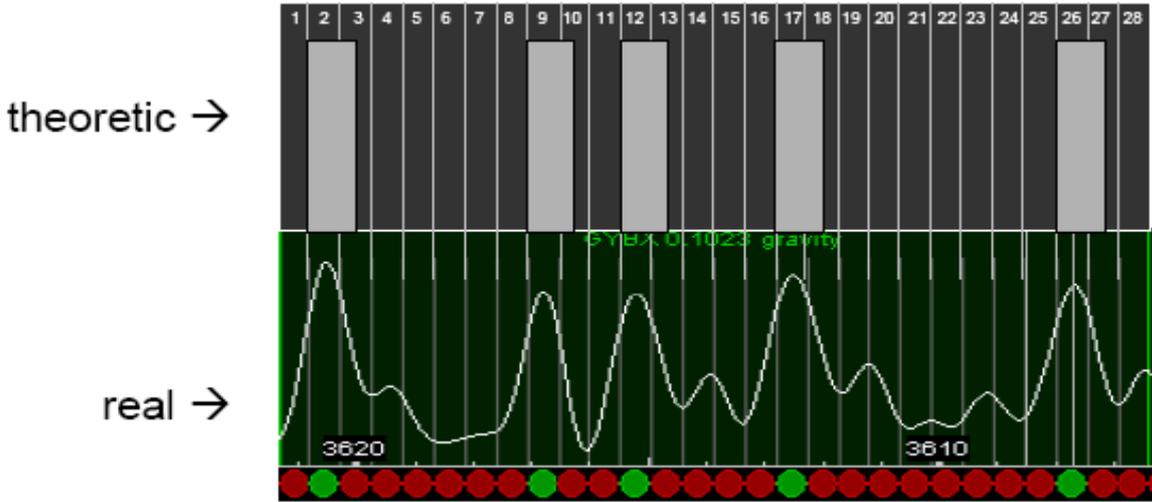
There is one instance when this strategy will not work, and that is when fully developed stick-slip is present. This motion is non-sinusoidal and contains many harmonic frequencies. It is doubtful if increasing the data-rate will move the MWD transmission bandwidth clear of these interfering frequencies. With baseband transmission, all that will work in these circumstances is to detect stick-slip motion and if possible change the drilling parameters to remove it.

Another phenomenon that may include drilling noise in the mud stream and interfere with the mud-pulse transmission, is operating at the natural frequency of the drillstring. This is termed the critical speed of the drillstring, and can cause resonant behavior of the drillstring. Prediction of the critical rotation speeds of drillstrings are best done using critical speed modeling software if available. These will predict the drillstring rotations to avoid. Critical speeds can also be avoided by real-time monitoring using vibration stick-slip or advanced drilling dynamics services, like Baker Hughes CoPilot. The drilling dynamic service also includes the ability to detect drillstring whirl, which is off-center rotation of the BHA, and can generate interference at frequencies 2 to 4 times greater than the drillstring rotation rate. These frequencies will interfere with passband signaling.

5.1.5.4 Other sources of noise

Reflections within the transmission system can be quite destructive. Reflections are created at each ID change that the up-traveling MPT waveform encounters, resulting not only in a loss of signal power, but also in interference with succeeding symbols. It can be quite severe if the change in ID is abrupt, which often occurs at a change in pipe sections. The best way to combat drillstring reflections is through drillstring design practices. This can be modeled to help predict the impact and recommended potential alternatives.

One other potential source of reflections is at the pumps in the upper end of the hydraulic system. A pulsation damper is used to limit the amplitude of the pump stroke pressure pulses, like a hydraulic shock absorber, which also has the effect of modifying the top end of the transmission system. The pressure in the pulsation dampener can either be increased or decreased within the operating range of the device to change top boundary condition from a soft system (high pre-charge) to a stiff system (low pre-charge). In a soft system the reflected pulse is inverted; in a stiff system the reflected pulse is not inverted. If the system is too soft, the down-traveling (reflected) pulses can potentially cancel out the up-traveling pulses at the sensor. Conversely, if the system is too stiff, the down-traveling mud pulses add in amplitude to the up-traveling pulses, thereby making the easier to detect. However, the amplitude of the pump stroke signal is also increased. The solution is to maximize the signal-to-noise ratio (SNR) at the measurement location; it is probably better with wide pulse widths in a stiffer system is since the increase in pulse height is larger than the increase in pressure amplitude of the pump stroke pulses.



Baker Hughes et al. 2008

Figure 13: An example of how the signals pressure pules might appear after the surface software system has removed noise from the signal. The upper track show the theoretical pressure pulses, while the lower track show the processed pressure data. In this example, it can be seen clearly where the signal amplitudes are located, hence a valid downhole measurement can be decoded.

5.1.6 Noise cancellation

As described previously, torque noise due to torsional oscillations can be cancelled by a combination of methods, but the most direct method is high-pass filtering. A variety of high-pass filters exist for this purpose. Additional low-pass or band-pass filters may be deployed to isolate the signal bandwidth from noise sources. This has the effect of increasing the SNR at the input to the demodulators or pulse detectors.

5.1.6.1 Pump Noise Cancellation (PNC)

Pump noise cancellation algorithms require pump strobe signals from each active pump. The signature for each pump is assembled by marking the time at which successive pump strobos occur, and stacking the pressure records between the strobos. This results in random noise being cancelled out, and the pump signature emerges.

This pump signature is subtracted from the raw pressure data; the result is the measured pressure signal with the signal from the pump cancelled out. In the ideal case this resultant signal contains only the signal from the MWD pulser. Pump noise cancellation algorithms are needed for any high bit-rate baseband signaling, severe decoding issues and for any passband signaling.

Depending on the water depth and length of the riser, a pump might be used as a booster, to improve the hole-cleaning in the bigger ID riser. The rig pump used for this is not connected through the standpipe, and will not add any noise to the signal. It is therefore important not to add this as a part of the PNC calculation, since removing the theoretical calculated noise from this pump, could cancel out some of the transmitted downhole signal.

5.1.6.2 Down-Traveling Noise Cancellation

Down-traveling signals that can originate from the surface equipment interfere with the up traveling mud-pulses and can cause significant distortion. These signals may originate from reflections of the original mud-pulses caused by the mud pumps, pulsation dampers, pipe diameter changes, trapped air or gas in surface lines, and so on. Echoes of the original pulse have the effect of attenuating and distorting upcoming signals. When the measured signal strength is below 0.5 bars, this can have a very negative effect on the ability to successfully decode the data. The algorithm to cancel these down-traveling signals requires the input from two pressure transducers spaced some distance apart in the surface lines. The pressure transducers must preferably be of the same type and the same make.

In the algorithm, the measurement at the upstream transducer is delayed by a time increment, and then subtracted from the downstream transducer. This has the effect of cancelling all down-traveling waveforms which take the time increment to travel between the two transducers, and the remaining signal is the time delayed difference of the up traveling waveforms. When the remaining signal is high-passed and integrated, the up traveling waveforms are recovered. The time delay between the upstream and downstream transducers is determined by cross-correlating measurements from the two transducers.

Since the pump signals are known to be traveling down the drillstring, this algorithm is quite good at removing them. It also removes all other down-traveling signals, such as those due to reflections, and can result in considerable clean-up of the surface measurement. This application is not only required to deliver high speed telemetry, but is generally very useful in problematic decoding environments where noise is significant.

5.1.6.3 Channel Equalization

One surface processing task is to remove any distortion of the waveforms that may have occurred during their transit through the telemetry channel. A number of different techniques are used for this. One of these is called matching filtering, and is described below to give an example of how they could work.

5.1.6.3.1 Matched filtering

Assuming that a rectangular shaped pulse with very abrupt edges is generated by the pulser downhole. As it is transmitted through the mud channel it gets banged around, loses some of its original crispness, and gets spread out. By the time it reaches the surface and gets detected by the surface sensors it has the shape of a shark fin.

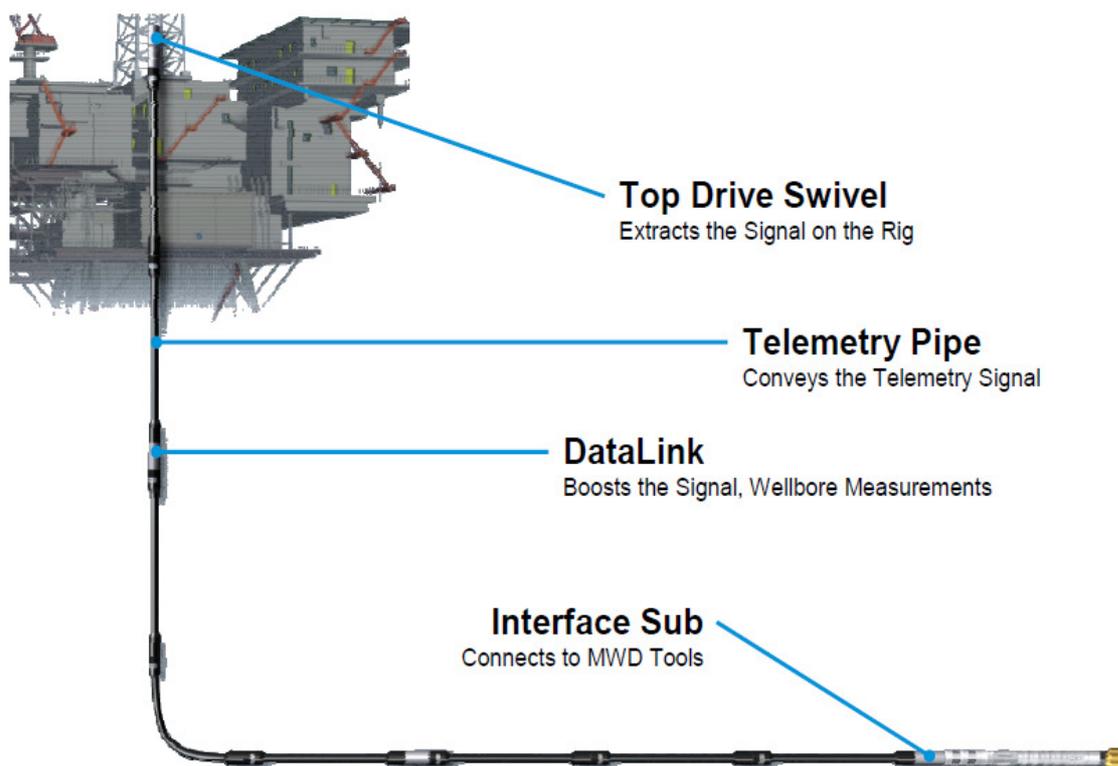
In order to detect the pulse in an optimal fashion, a matched filter is correlated with the arriving pulse-train; the best matched filter is one that looks exactly like the arriving pulse. The implications of this is that no matter what distortion is added in the mud channel; if a representative pulse can be isolated at the receiver, then it can be used to detect succeeding pulses.

5.2 Wired-Pipe

A wired-pipe telemetry system use electrical wires built into every component of the drillstring to carry an electrical signal directly to surface. There are several oilfield service companies currently developing wired drillpipe systems. [14] The current marked leader is NOV IntelliServ, which also was the first to provide drillstring telemetry commercial. Their wired-pipe technology has been utilized in over 50 wells, and has successfully demonstrated data transmission rates of 2 megabits per second in testing facilities, and 57 000 bits per seconds in several field tests. [15, 16]

The following is mainly a review of NOV IntelliServ system, but should provide a representative picture of the wired-pipe telemetry.

The IntelliServ network offers an ultra-high-speed alternative to current mud-pulse and electromagnetic telemetry methods. The network utilizes individually modified drilling tubulars to provide bi-directional, real-time, drillstring telemetry. [2] This greatly enhanced band-width in comparison to existing technology makes it possible to obtain large volumes of data from downhole tools and other measurement nodes along the drillstring instantaneously, greatly expanding the quantity and quality of information available while drilling. The broadband network maintains this vast data volume independent of depth and distance. An important benefit when drilling deep wells in deep water or extended-reach laterals.



Allan et al. 2009

Figure 14: Wired-pipe telemetry schematic

Within the BHA, a short sub contains a communications interface between the MWD and IntelliServ data protocols; it is at this point that the communications protocol of the service company is “repackaged” to allow transmission on the IntelliServ network wire to surface. The reserve occurs on surface via another device, which allows the MWD service company to retrieve its downhole data.

In order to use wired-pipe telemetry, changes have to be made to the drilling equipment and MWD/LWD transmission. All of the components above the interface sub needs to be wired and the Top-Drive System modified. Also the configuring of MWD/LWD Transmission Lists will be changed, due to the increased data steam.

5.2.1 Wired pipe transmission line.

In general, The IntelliServ Network system transmission line is composed of four main components. [15]

5.2.1.1 Interface sub

The Interface sub connects to the MWD/LWD and RSS tools to allow bi-directional communication of logs and commands. Each service company manufactures an interface sub jointly with IntelliServ. The interface sub is owned by the service company, and is currently provided either by Baker Hughes, Schlumberger D&M, Sperry Drilling Services or Weatherford. Although slight variations exist between the vendors, interface subs are generally consistent across the industry.

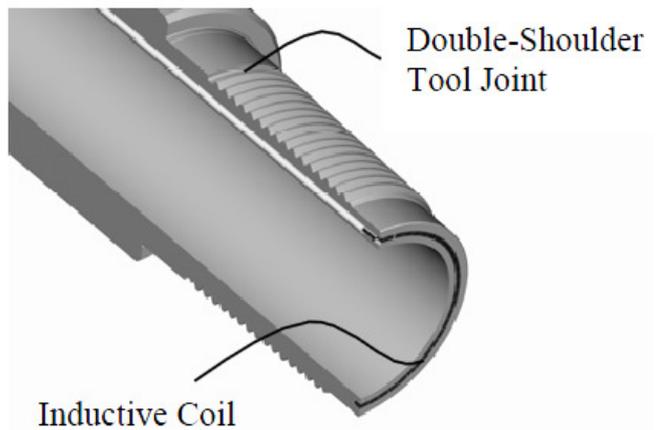
Baker Hughes INTEQ developed the industry’s first interface sub, linking the tools in the INTEQ BHA to the IntelliServ Network in 2003. [17] The primary objectives was to take full advantage of the drillstring telemetry network’s high-speed capabilities, but also to minimize the impact on existing MWD tool architecture and operation. This resulted in a decision to keep the current MWD data bus as a communication backbone for all components connected below the telemetry network. Hence, no modifications are necessary to interface existing MWD tools to the network, allowing fully functional MPT tools to be deployed parallel with the drillstring network. To ensure the drillstring telemetry remained transparent from MWD perspective, simple protocol converters where established at the downhole tool and surface computers interface.

An interface sub provides a physical and electrical crossover between the MWD/LWD tool string and the telemetry network. The interface sub contains both a MWD micro-controller board and a telemetry network repeater board with a sheared battery power source. The box end contains a telemetry network inductive coupler and the pin end contains a MWD tool coupler.

At surface, data from the downhole tools is delivered to the service company via the IntelliServer. The tool data is simply encapsulated within the network package at the interface sub, transmitted to surface and then unwrapped for delivery to the MWD acquisition computer system by the network surface server.

5.2.1.2 The wired-pipe

The drillstring telemetry network comprises conventional drilling tubular modified to incorporate a high speed, low loss data cable running through the length of each joint. [18] The cable terminates at unique, inductive coils that are installed in the pin and corresponding box shoulder of every connection and transmit data across each tool joint interface. The double-shoulder connection configurations, used in the second-generation IntelliPipe, provide an ideal location for coil placement, with each coil installed in a protective groove in the secondary torque shoulder. When two connections are threaded together, the pin end coil in one joint is brought in close proximity with the box end of another. The coils are circular in design and require no special orientation of the tool joints at make-up. The coils are circular in design and require no special orientation of the tool joints at make-up.

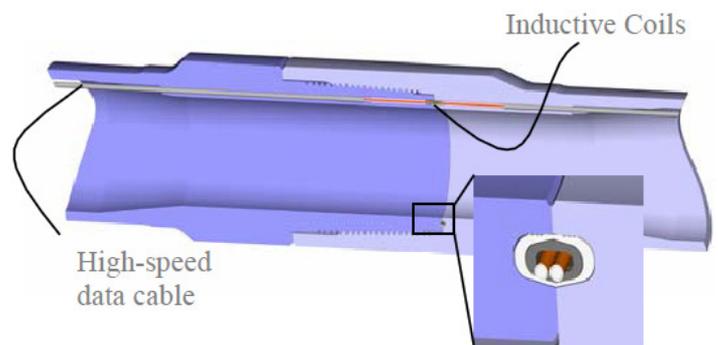


Reeves et al. 2006

Figure 15: Cutaway of Double-Shouldered Pin Tool Joint Showing Location of Inductive Coil

In addition to drillpipe, the simplicity of design allows conversion of other common drilling tubular in various sizes to support data transmission. Heavy weight drillpipe, drill collars, drilling jars, string stabilizers, roller reamers and accessories machined with double shouldered connections have all been modified to support the network. [2]

The signal conductor may be in form of an armored high strength, stainless steel, coaxial data cable stretched on the inside of the pipe wall, or it could be a data-cable embedded in the drill pipe wall. The first solution enables easy access to the data cable for maintenance or replacement. [3] The solution with a data cable imbedded in the pipe body is advantageous with regards to cable wear and interference with objects traveling on the inside of the drillpipe such as wiper darts or wireline equipment. In a drillpipe configuration, the conduit passes through the body of the tool joint and then enters into the internal diameter of the drillpipe at the internal upset. The conduit is held under tension in the drillpipe tube, maintaining its position against the tube wall under most conditions and minimizing interference with mudflow or deployment of tools through the center of the assembly. The cable runs through the pipe without affecting drillpipe properties. However, a stabbing guide is required, but depending on the training of the rig-crew, there should be no additional tripping time. The overall drillpipe and tool joint design achieves the goal of being transparent to normal rig operating procedures. Double-shouldered connections do require a higher make-up torque than standard API connections, but with this exception, intelligent



Reeves et al. 2006

Figure 16: Cutaway of Made-Up Drill Pipe Tool Joint Connection Showing Location of Inductive Coils and Data Conduit

tubular are identical in mechanical and hydraulic performance to non-wired double-shouldered drilling tubular. In contrast to the connections in the MWD tool string, any thread compound chemistry can be used.

Once made up, the coils come near each other and induce the signal down the pipe without direct contact. An electromagnetic field associated with the alternating current signal transmitted through the cable is responsible for transmitting data. As the alternating electromagnetic field from one coil induces an alternating current in the nearby coil, data is transmitted from one tubular to the next.

5.2.1.3 Signal repeaters

As there is some signal loss over the wire, battery powered signal repeaters are added periodically to increase the signal. Commonly, these electronic elements are known as booster assemblies, and are provided by NOV under the name IntelliLink. Their function is to boost the signal and ensure a proper signal-to-noise ratio and avoid data loss. The separation between the repeaters controls the maximum bit rate, and is integrated in the drillstring with spacing typically between 400-500 meters.

Booster joints consists of a 1.2 meter long sub containing a lithium battery powered electronics package threaded on a specially manufactured drillpipe joint, such that the full booster assembly measures the same total length as a standard drillpipe joint with an extended length lower tool joint. The lithium batteries will add some limitations to the IntelliServ Broadband Network, with a lifetime typically around 90 days, and a temperature limitation of a 150°C.

These repeaters also serve as individually addressable nodes within the telemetry network. Sensors are located at each signal repeater and provide a standalone measurement at its location. In the IntelliLink the commercially available sensors measure the absolute value of temperature and pressure. However, other measurements are on the roadmap to be developed, such as vibration, strain and caliper.

5.2.1.4 Top drive swivel

A key component of The IntelliServ Network is the Top Drive Interface Swivel which provides the interface between rotating and stationary environments. It is installed at the lower end of the top drive assembly, often replacing an existing saver sub. It consists of a telemetry-enabled sub inductively coupled to a non-rotating member. Network traffic moves through the sub and into the swivel, which in turn is connected to IntelliServ's data acquisition system via surface cabling.

5.2.2 Advantages of a wired-pipe Network

The main advantage of a wired-pipe network is the greatly enhanced band-width in comparison to existing technology; which makes it possible to obtain large volumes of data from downhole tools and other measurement nodes along the drillstring instantaneously. This will greatly

expand the quantity and quality of information available while drilling, and save expensive rig-time for the customer.

The wired-pipe drillstring works independently of the medium present, and can transmit data regardless of fluid environment - hydrocarbon, water, air or foam – or even while suffering total losses. There is no loss of signal strength along the drillstring, and no interference from acoustic noise or the operation of other equipment such as mud pumps.

The large volumes of data could change the application of the MWD/LWD measurements in several ways. While some of the new application areas already have been utilized commercially, there are several other application areas that could be exploited and improved with this technology.

5.2.2.1 Wellbore positioning

The use of wired-pipe potentially allows both the efficiency and quality of the survey process to be improved. Data can be transmitted to full sensor accuracy in real-time for near-instantaneous verification. This will save time and allow immediate identification of poor quality data such as that resulting from drillstring movement during survey the acquisition. It will also allow multiple directional sensors placed within the MWD system to be used continuously in real-time while drilling ahead. With the development of suitable algorithms, this will allow fewer conventional survey stations to be required without deteriorating uncertainty, or allow an improvement in wellbore positioning uncertainty without the requirement for increased conventional surveying operations.

The near instantaneous communication with the downhole system also allows downlinks to be performed without interrupting the drilling process. Hence, there is no need to take any consideration to limit the downlinks while steering the well.

5.2.2.2 Flow-off data

With battery powered MWD tools in the BHA, it is also possible to obtain the measurements from the tripping as well. Monitoring the annular pressure would improve the control of swab and surge during tripping, and could be used to optimize the tripping speed.

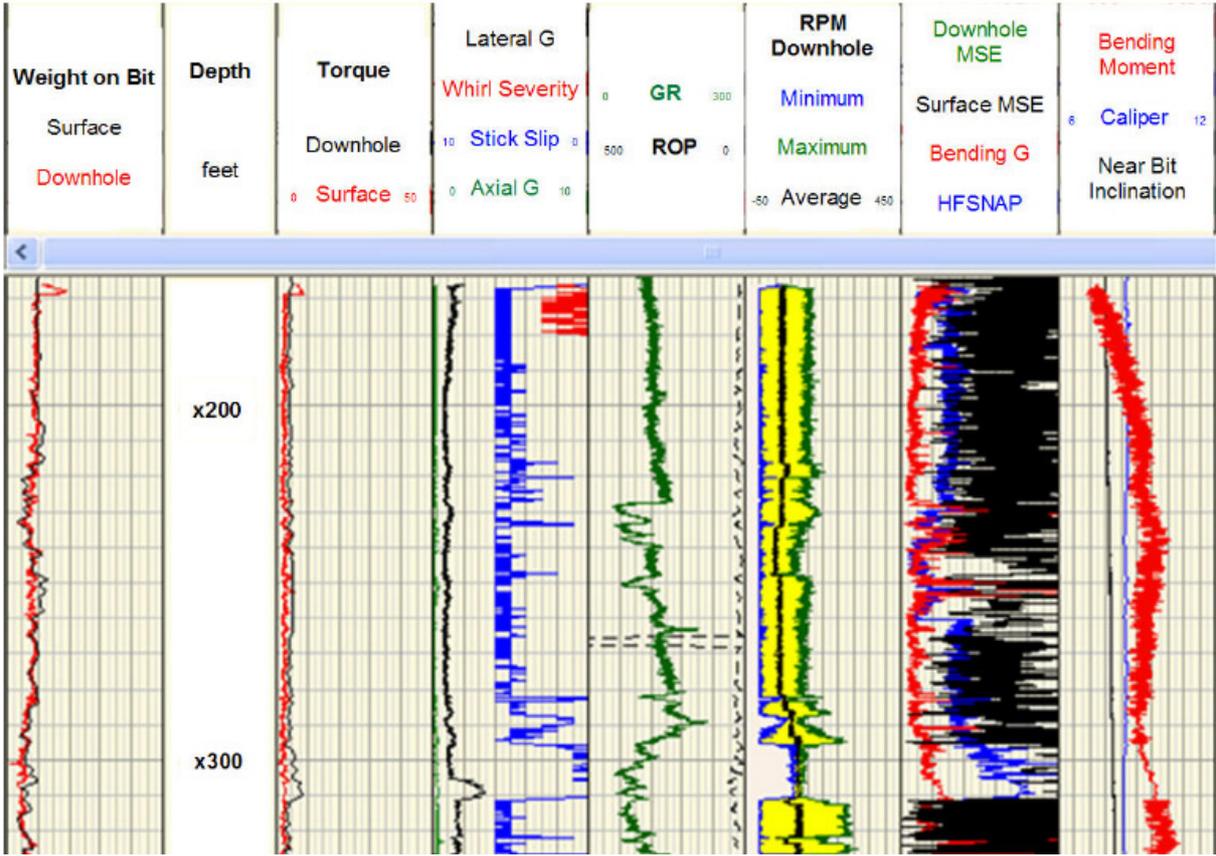
During LOT/FIT tests a complete pressure profile of the well could be provided. Especially during Leak-off-tests (LOT), this could be useful in verifying the Leak-off pressure for the formation. The formation usually starts to leak-off at a pressure lower than the maximum pressure seen in the test. With MPT it is only possible to get the maximum measurement during the flow-off events.

There will be no communication to the downhole tools during the actual connection of a new drillpipe. When picking up a new stand, the top drive swivel is not connected to the wired-pipe network before the new stand is added to the drillstring.

5.2.2.3 Optimizing Drilling Parameters for Efficient Drilling

A wired-pipe delivers a more complete visualization of the downhole dynamic environment in real-time, allowing monitoring of a far wider range of drilling dynamic variables. This provides the

opportunity to identify and diagnose damaging vibration events more quickly with higher accuracy for immediate and correct parameter adjustment to avoid damage to the downhole toolstring or borehole. The effect of any parameter adjustment can then be seen more clearly and immediately as opposed to tracking trends in vibration levels which can take 10 minutes or more to become apparent with conventional mud-pulsed updates.



Manning et al. 2008

Figure 17: Screen capture of surface and downhole drilling dynamics data through an interval of very difficult reading. The real-time data displayed above was updated every 10 seconds using wired-pipe telemetry.

5.2.2.3.1 Improved ROP

An improved visualization includes the opportunity to continuously monitor parameters, which have an immediate effect on instantaneous and gross ROP, such as downhole WOB. With continuously transmitted downhole WOB information, any tendency for the drillstring to hang up can be immediately identified and corrected with minimal impact upon drilling performance. Coupled with continuous downhole torque measurements, this can be used to determine the dull condition of the bit and removes some uncertainty as to when it is time to trip to change the drill bit.

5.2.2.3.2 Vibration Management

With wired-pipe a more complete view of stick-slip, axial and torsional vibration is available. It can be used real-time to more rapidly identify and more accurately migrate the undesired vibration

levels for increased drilling performance. This will for instance give better drill bit cutting action, and lower risk of equipment and formation damage.

5.2.2.3.3 Improved Hole Quality

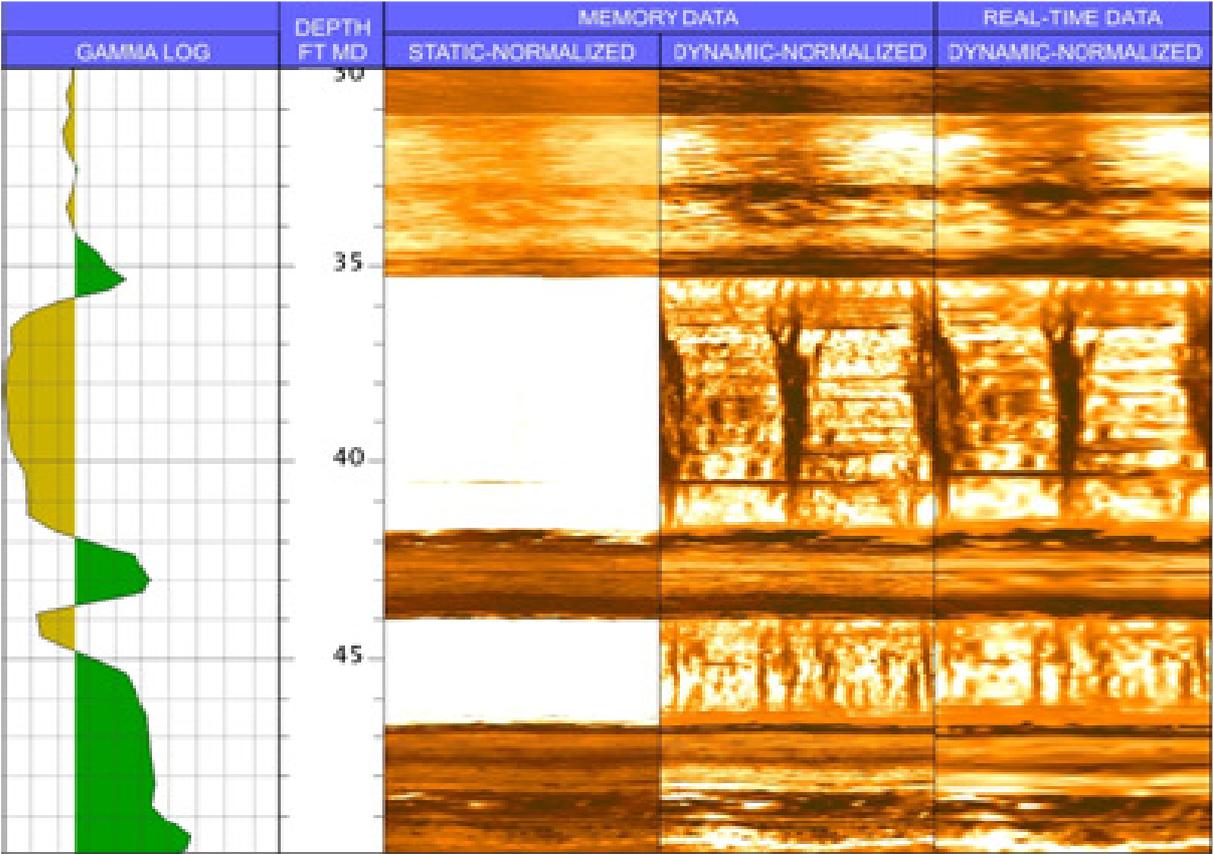
A unique capability of Baker Hughes' CoPilot advanced drilling optimization service is the measurement of BHA bending moment which is a measure of the side force acting on the BHA. This measurement can be used to accurately estimate borehole curvature and has also proven to be valuable when drilling through highly interbedded formation sequences where formation strength varies greatly across interfaces. Under these conditions, the drill bit can take the path of least resistance while drilling ahead and form a high local dogleg in the hole. Left unattended, this can cause damage to the drillstring components, as well as risk damage to completion strings when run through it. In areas where this drilling environment exists, field specific drilling procedures are employed which use the BHA bending moment measurement to identify generation of dogleg, measure its magnitude and, if necessary, reduce it – monitoring the effectiveness of the operation in real-time. It can take significant time to reduce the severity of a "typical" high local dogleg by reaming and sometimes be difficult to reduce it to a safe level to allow drilling to continue. This is dependent upon the size of the dogleg which builds up in the hole. A high local dogleg will be a function of both the severity of the initial deflection and how quickly the generation of the dogleg is identified. Using wired-pipe will enable rapid identification of a dogleg being formed in hole, allowing for appropriate corrective actions, e.g. drilling parameter adjustment, to be implemented. Hence, the severity of the high local dogleg is reduced, which eliminate the need for further remedial action or at least saves time and enhancing the effectiveness of the remedial action.

When short gauge drill bits with active cutting structures are used, there is a risk that a "cyclic" hole is drilled. [2] This is commonly termed "hole-spiraling" and is a natural phenomenon in boring process. The effects of hole-spiraling can; deteriorate the quality of the LWD data (especially shallow reading borehole images), increase friction in the borehole, required increased reaming on BHA trips or cause problems running subsequent BHA's of different geometry and casing strings. By increasing the friction in the borehole, hole-spiraling can negatively effect on-bottom drilling efficiency and increase time required to trip out of hole. Hole-spiraling cannot normally be confidently identified in real-time due to insufficient real-time data density, especially when drilling at a high ROP. It is normally only identified from processed memory data such as borehole images, where regular diagonal stripes can be seen across the log with mask features which would otherwise be clearly seen. Borehole spiraling can also be identified from sinusoidal oscillations of BHA bending moment or continuous inclination data from memory. With wired-pipe, the onset of hole-spiraling could be immediately identified in real-time from any one of a number of sensors including continuous inclination, borehole images or BHA bending moment data. Variation in drilling parameters can then be made to eliminate the cyclic effect and, if not effective, assist in the decision to POOH to change to a different drill bit or continue drilling ahead, monitoring the effect in real-time.

5.2.2.3.4 Borehole Stability Prediction and Monitoring

LWD acoustic measurements, particularly the formation shear velocity, can also be used to compute rock strengths for wellbore geomechanics applications. [2] The rock strengths can be used for determining fracture gradients, as well as identifying potential borehole breakout zones which could lead to stuck-pipe incidents. However, full acoustic waveforms are required at the surface for

accurate shear velocity analysis, hence, conventional mud-pulse telemetry systems are limited in what they can deliver for these applications. But in addition to acoustic measurements, high-resolution borehole images have real-time applications for identifying and characterizing borehole breakout and drilling induced features. LWD images transmitted to surface with conventional mud-pulse telemetry using data compression techniques are limited in their resolution due to either the narrative resolution of the LWD sensor (e.g. density and gamma-ray images), or data loss from the compression techniques. Getting sent a higher data volume, opens up the possibility to see well resolved drilling induced fractures, as well as natural fractures which have been opened up from the drilling process.



Wolfe et al. 2009

Figure 18: Geometrical and structural features logged with high-resolution electrical imager. A comparison of the dynamic-normalized memory data in the 4th track with the real-time dynamic –normalized wired-pipe telemetry data in the 5th track, show that the data is almost similar.

5.2.2.4 Minimizing “Hidden” Non-Productive-Time (NPT)

There are operations during the drilling process which are time consuming, while not directly contributing to the overall progress of the well construction. These are not typically classified as NPT as provision is normally made for them preparing the drilling program and budget. However, the cumulative time associated with each of these operations, can be significant over a complete well. Operators try to save rig time where it is possible, and always search for procedures and solutions to

achieve this. Several of the operations performed today using conventional MPT can be either improved upon or eliminated when utilizing wired-pipe.

5.2.2.4.1 Survey

Using wired-pipe technology, field test show that the actual time saving per orientation survey could exceed three minutes per successful survey. [10] In the instances where pipe movement or magnetically interference would corrupt the survey measurement, this would be recognized immediately. The process of taking a new survey could therefore start instantly. This would in all instances reduce the overall time spent on the operation, and the time the drillstring is stationary is kept to a minimum.

5.2.2.4.2 Verification and shallow hole testing

Using wired-pipe, the MPT functionality can be checked by simply observing pulses without the need to decode, while full system functionality is attained in parallel via the data cable through the wired-pipe. The downlinking functionality can also be checked instantly. Time spent would therefore be reduced to the time it takes to establish sufficient circulation and power up the MWD toolstring.

The need for downloading LWD data at surface would not be immediate if all deliverables are presented via wired-pipe and fully quality checked (QC) before the tool returns to surface. The time saved on this would depend on the toolstring. It would still be necessary to connect to the tools to verify the state of the sensors, especially the resistivity reading, since it cannot be properly verified on deck. But for the other tools with stand-alone memory (i.e. CoPilot and the Formation Pressure Tester), it would not be urgent to download the memory.

5.2.2.4.3 Downlink

Sending a downlink would as mention be instantly, there would in no cases be necessary to neither reduce ROP nor pull off bottom. In most instances, this could also be performed while drilling using MPT. The real advantage with regards to saving rig-time would be when there is a need for high data resolution. Then the MPT downlink needs to be sent with reduced ROP or even off-bottom.

5.2.2.4.4 Controlling ROP

There will be no need for drilling with controlled ROP due to poor data density from the LWD measurements. The limitation of the ROP would therefore only be due to drilling performance or hole-cleaning issues.

5.2.2.4.5 Formation pressure testing and fluid sampling

Wired-pipe allows continuous communication with the downhole tools during the process of a pressure test. A real-time analysis of the full pressure profiles would allow optimal parameter adjustment in real-time, to help assure the best pressure data possible is collected. The data density acquired from the pressure test would also be similar to memory data quality, and more suitable for updating pore pressure models, and adjusting the drilling fluid parameters. [2]

During field tests, a reported time saving of seven minutes per formation test was enabled by the wired-pipe LWD system. [10] It would also open for the possibility to abort a test, if the data indicates that the tool does not perform as required, e.g. it does not seal against the formation.

5.2.2.4.6 Trouble shooting

In the instance where it would be necessary to trouble shoot the downhole tools, the process of circulating the hole clean and preparing to pull out of hole (POOH) would commence. The advantage of a wired-pipe system would be the access to more data at a faster rate. The improved two-way communication allows performing a comprehensive set of tool diagnostics that is only available when downloading the memory on surface when using MPT.

If managing to determine where the fault lies, a time consuming trip could be avoided. As an example, the resistivity sensor could stop sending reasonable data. Usually drilling forward without this sensor would not be permitted, due to the importance of the formations resistivity properties. The resistivity measurements sent to surface is calculated from four different resistivity receivers internally in the resistivity tool. If one of these fails, the calculated values sent to surface would be of no use. It is however possible to calculate the resistivity using only three of the receivers. Direct communication to the resistivity sub, would clarify instantly if this would be possible.

5.2.2.4.7 Confirmation of network functionality

However, using wired-pipe would in a couple of instances create some extra “hidded” NPT. During tripping in hole, confirmation of network functionality needs to be tested with a go/no-go fixture. The frequency of testing would depend on the rig-crews familiarity with the wired-pipe system.

The connection procedures itself would also be not be as efficient as when using ordinary drillpipe. A stabbing guide would be required to protect the inductive coils embedded within the connections in each stand. Training of the rig-crew would be necessary, so the operation would most likely get more efficient as the get familiarized with the new equipment.

5.2.2.5 Well control operations

With battery powered LWD tools in the BHA, it is also possible to obtain the pressure measurements during a low-flow killing operation of the well. It would also supply with the different pressure readings along the string from the signal repeaters, to give a clear view of the well's pressure profile.

5.2.2.6 Lost circulation event

With use of LCM, wired-pipe could provide an immediate advantage since it is has no narrowing of the fluid path and is therefore insensitive to LCM. However, in most cases, the mud-pulser would be run as part of the BHA as a contingency for lost communication or failure through the wired-pipe. A trip could therefore still be required if the pulser sub gets blocked. Baker Hughes mud-pulser is also the power module for the downhole tools. Removing the pulser from the MWD string, would require another turbine sub to provide the power to the toolstring.

5.2.2.7 Pore Pressure Prediction

In order to avoid well control operations from kicks or lost circulation, pore pressure models can be updated from LWD pressure, acoustic and seismic measurements and used to predict pressure ahead of the bit for refining drilling parameters before a problem occurs.

Relatively low-bandwidth LWD resistivity measurements have been used with pore pressure models to predict pore pressure changes with some success. However, it is well known that acoustic measurements (compressional and shear wave velocities of the formation) are more sensitive to, and correlate better with formation pressure changes. These measurements require detailed acoustic waveform analysis to select the right arrival time from different acoustic modes. For conventional mud-pulse telemetry applications, the bandwidth is too low to send the full waveforms to the surface for processing and interpretation. Therefore the processing is done automatically in the LWD tools downhole. However, the processing is quite often subject to picking the wrong arrival times, thus calculating the wrong formation velocities, without the guidance of an interpreter. This frequently leads to quite erroneous pore pressure predictions. If the entire set of acoustic waveform data was streamed to surface, real-time interpretation and QC would be possible. Then the acoustic processing and resulting pore pressure predictions would be as accurate as possible.

The LWD acoustic measurements are limited in their ability to predict pressure changes ahead of the bit since they are only capable of measuring changes in the vicinity of the drilling assembly. Their lower frequency LWD seismic counterparts have the potential to detect pressure changes ahead of the bit. Although measurement quality, or fidelity, in the drilling environment is still an issue for these measurements, the potential exists for using them to identify pressure changes hundreds of meters ahead of the bit. In order to do this though, full waveforms from VSP (Vertical Seismic Profile) data will be required for analysis at surface. Not only is this measurement useful for detecting pressure changes, but it will give better prediction of the formation tops, well before they are reached in the drilling process. However, seismic data-set densities are notoriously large and would require wired-pipe transmission rates at a minimum to be useful in real-time.

5.2.3 Sensors in the signal repeaters

The network nodes in the signal repeaters offer the unique opportunity to make additional pressure measurements distributed along the entire length of the drillstring. [19] The systems additional dynamic insight helps to manage a constant bottomhole pressure as well as drilling at or under balance. Having the pressure measurement from several places along the string makes it possible to calculate the rate it changes with and establishing pressure gradients along the wellbore. The continuous pressure readings distributed at different locations along the drillstring and the calculated gradients, gives valuable information that can guide decision making in several applications, such as kick, losses and differential sticking.

To regain well control during a kick, wellsite personnel must circulate out the wellbore influx and replace the fluid column with denser mud. During this process, constant bottomhole pressure must be maintained to prevent additional wellbore influx. Constant bottomhole pressure is achieved by closely operating the choke to keep adequate back pressure and is historically achieved based on surface measurements. However, with the wired-pipe drillstring, wellsite personnel are offered high-resolution downhole and annular pressure readings along the string. This additional data is available

regardless of flow, providing hydrostatic pressure even at typical kill rates of 10-20 strokes per minute.

The measurements now commercially available from the signal repeaters are the already mentioned pressure and temperature readings. There are other measurements on the roadmap to be developed, such as vibration, strain and caliper. If a strain sensor gets commercially available, this would measure the tension and compression at its location. This could then be used to accurately identify sections in the wellbore where the drillstring experience increasing friction or sticking. The accurate tracking of the reduced tension gradients measured by the drill string will allow to accurately pin-point the location. [20]

If a large increase of different sensors for use during the drilling operations starts to be commercially available, it would introduces a challenge for selecting the optimal sensor layout. The different sensor measurement can be transferred to a variety of useful information during the drilling process. The sensors could be sensitive to various scenarios, such as kicks and circulations losses. Most likely there will be limitations to the amount of sensors that will be available to install in the signal repeaters and a risk analysis of the more likely scenario during drilling operation should be performed prior to selecting the sensor layout.

5.2.4 Limitations of wired pipe technology

As mentioned earlier, the signal repeaters are the main component to ensure a proper signal to noise ratio and avoid data loss, and the distance between them would decide the limitation of the maximum bit rat.

The mechanical properties of the pipe remain unchanged, and the maximum dogleg severity recommendation for the IntelliServ pipe is the same as to its un-wired counterpart. The wiring do not affect the tensile strength of the pipe itself, and the armored coax cable is designed to fail at approximately the strain at which the pipe yields. Depending on the grade of the pipe, this failure strain may be somewhat after the yield strain of the pipe. However, prior to tensile failure of the coax cable, some permanent plastic deformation may be sustained by the cable. Wired-pipe has been deployed in drilling environment with extremely harsh vibrational conditions, included air hammer drilling and multiple jarring events. It has also been used in drilling operations where it has been exposed to acid, cement and through-string wireline logging. [15, 18]

The wired-pipe should therefore not be of lower quality then an ordinary drillpipe. The only new downhole components which then differs from a conventional setup is the interface sub and signal repeaters. The interface sub is provided by the same service company that provides the MWD/LWD tools and would therefore be an integrated part of their tools with more or less the same ratings. For instance, the Baker Hughes Intelli Interface Sub is rated to 150°C and 1725 Bar.

This is the same rating as for the IntelliLinks signal repeaters, and should be sufficient in most cases. However, an issue to considered is when drilling in HPHT wells. If the downhole environment is getting close to the maximum rating of 150°C, the locations of the signal repeaters in the drillstring could become an issue. During drilling, mud circulation is important to avoid over-heating of the downhole components. Mud pumped down the string would be colder than the downhole

environment, and therefore help to lower the temperature and cool the downhole components. The mud travels quickly down the drillstring, and exits at the bit. It would have a cooling effect from inside of the string, but as it exits through the bit and gets past the larger outside diameter pipe which are in the BHA, its traveling speed slows down. A typical BHA configuration could be up to 200 meters if an advanced MWD/LWD service is being run. The cooling effect from the drilling fluid should still be sufficient to control the temperature of the electronics in the MWD/LWD tools under normal circulation circumstances. However, if drilling a long horizontal well, the formation temperature would not change throughout the horizontal section. This means that the signal repeaters added to the drillstring roughly every 500 meters behind the bit would get poorer and poorer cooling effect from the mud traveling up through the annulus. Even if sensors closer to the surface would get a better cooling effect from the mud traveling inside the pipe, they get quite a lot poorer cooling from the slow traveling mud in the annulus. Hence, the overall cooling effect would be a less on a signal repeater far away from the bit in a horizontal section.

However, since the signal repeaters have standalone nodes measuring the temperatures continuously, it would be possible to monitor when the temperature is getting close to the maximum rating. Monitoring would also be possible during an event where the circulation is below the startup rate of the MWD power module. During these low flow circulation events, the friction between the BHA and the wellbore is increased, which consequently generates an additional temperature increase in the downhole tools. Obviously if the flow rate is low due to a well incident, such as a kill operation or some sort of lost circulation event, the concern for the health and state of the tools is not a priority. But there could be several other reasons why the operator wants to continue rotating without sufficient flow through the tool. An example could be if some of the rig equipment fails and needs to be changed. Changing a failed component in the pathway of the drilling mud between the mud pit and the drillstring would not possible with high flow. The operator might still be interested in rotating the pipe anyway, since keeping the drillstring stationary for too long in the well is not desirable. If this is done for an extended period of time, the friction heat could then provide enough heat to damage the electronics inside the tools. The MWD/LWD tools should therefore be programmed to send up continuous heat measurements as well as the pressure measurements when the flow is below the start-up threshold for the MWD power module. There are special procedures that needs to be followed when the temperature of the downhole components gets close to the maximum rating of 150°C. Circulation has to be staged up slowly to reduce the temperature, without powering up the MWD/LWD toolstring. The possibility to continuously monitor the downhole tool temperature would improve this procedure; it would be no doubt about when the temperature reaches a safe level and the drilling operations could continue.

5.2.5 Reliability

Introducing additional components to a drilling system raises questions about the impact of the additional complexity on whole system reliability. [2] Since the wired channel operates independently of the conventional MPT channel, it provides additional telemetry redundancy. The ability to efficiently switch between the two telemetry methods has been proven on several commercial jobs, as it has the ability to simultaneously transmit from both channels. Additional reliability gains are achieved by the ability to troubleshoot any problems within the BHA more effectively. By having complete access in real-time to the MWD/LWD measuring nodes, you gain the

possibility to more systematically troubleshoot and correct problems before or without tripping out of hole. It also makes it possible to reprogram the MWD/LWD firmware when in hole.

The wired-pipe technology does not have the same proven record of high reliability as MPT. Continuous improvement is needed to improve reliability, and reduce network downtime. During field trials, network downtime has been caused by several different reasons, and different approaches were used to improve the service; [18]

- The network electronics board in the interface sub temporarily ceased to function when exposed to significant voltage fluctuations from the downhole turbine power source. This was resolved via firmware programming modifications.
- Movement of the top drive support struts served a data cable carrying the network signal from the top drive to the logging cabin. Measures were conducted to securing the data cable better to prevent cable damage. In the future, this connection is planned to be wireless, which of course would remove the issue with cable damage.
- Regular mis-stabbing of the top drive into new stands caused mechanical damage to secondary pin shoulder, and inductive coils, at the lower end of the top drive assembly. A data swivel top drive was used in place of a saver sub and was identified as having a high potential for being damaged if the driller did not have adequate control over stabbing when making up pipe. [16] The alignment of the top drive was identified as critical to prevent damage to the data swivel. An increase in the sensitivity of the driller's joystick and familiarize the rig-crew better with handling procedures reduced the possibility for mis-stabbing.
- Intermittent short circuits were seen in the wired components, coming from failure in the production process.

Network interruptions like this prevent any significant data transmission from the amplification joints. As contingency, the networked MWD tools can be programmed to identify any interruption to the wired-pipe network, and automatically enable the mud-pulser at such times.

One of the major challenges for wired-pipe telemetry applications will be the real-time processing and display of massive amounts of data in order to allow us to make effective decisions. That is, the downhole transmission rates will not be the limitation, but our human limitations in being able to visualize and make decisions on these massive amounts of data.

5.3 Additional MWD Transmitters

Below is a short introduction of the type of transmitters used by methods other than mud-pulse telemetry and wired-pipe. These sections are not exhaustive, and are included for reference only.

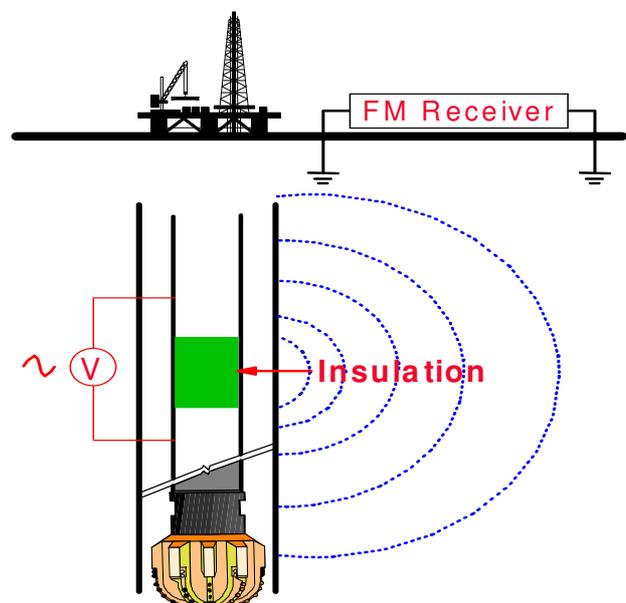
5.3.1 Electromagnetic

Electromagnetic telemetry (EMT) system uses the drillstring as a dipole electrode, superimposing data words on a low frequency (2-20Hz) source. [1] The receiver antenna typically consists of two electrodes buried in the ground close to the wellhead, although arrays that are more complex are possible. Offshore, the situation is more difficult since the receiver array needs to be placed on the seafloor to detect the signal. Hence, the EM telemetry systems are largely relegated to the low data-rate, shallow depth, onshore market. [21] EM signals suffer higher attenuation than mud-pulse signals, and certain types of formations may effectively block transmission. However, other than a hardwire link to surface, EMT is the most commonly used commercial MWD data transmission in the compressible fluid environments common in underbalanced drilling applications. While the EM transmitter has no moving parts, this advantage is somewhat balanced by the high vibrations generally encountered in underbalanced drilling applications. Communication and transmission with EMT system can be bi-directional (both uplinking and downlinking are possible).

EM signal amplitude generally attenuates exponentially against depth, although this is highly dependent on mud and formation resistivity. Modeling will provide information about the expected signal tendencies, for example the effect of casing on signal amplitudes. The EM transmission is heavily influenced by many factors, among them the presence of extremely resistive thin beds in the formation and the distribution of surface resistivity. These factors are hard to include in the simulations.

EM Telemetry involves transmitting through the formation adjacent to the wellbore, and formation, mud and surface properties greatly influence the attenuation of the signal. EM telemetry is a reliable means of transmission in areas in which formation and mud properties cooperate. Even in those areas, it is generally only reliable to depths shallower than 3000 meters. As with all generalities, there are exceptions, and EM Telemetry has been achieved to depths greater than 5000 meters with repeater-less systems.

Decreasing the frequency of the EM signal results in an increase in signal strength, but it also decreases the bandwidth of the telemetry system. Therefore, achievable telemetry bandwidth, the data-rate, must be balanced against the reach (maximum achievable depth of the well). Since the conductivity of the formation depends on drilling



Baker Hughes et al. 2006

Figure 19: Electromagnetic Telemetry – Alternating current emitted by the MWD tool is detected at surface by two or more receivers

location, only the electrical properties of mud can be changed in order to influence the electromagnetic transmission.

5.3.2 Acoustic Transmission

Acoustic telemetry (Stress-wave Telemetry) uses a downhole sonic telemetry signal that propagates up the drillstring. [1] Though data-rates are generally relatively high, significant attenuation of the acoustic signal occurs at drillpipe connections and at any point where the pipe contacts the borehole wall. Thus, signal repeaters (acoustic amplifiers) are often required in the drillstring as well depth increases.

The operating frequency band of acoustic telemetry is much higher and broader than for Mud-Pulse Telemetry and Electromagnetic Telemetry, ranging from 400 Hz to 2 KHz. [22] This range of frequencies enables acoustic telemetry to operate at significantly higher telemetry rates, even when employing simple telemetry algorithms.

The successful development of a commercial LWD acoustic telemetry system (LAT) required resolving two critical hurdles, dynamic attenuation and non-stationary noise. Dynamic variations in the attenuation occur due to various phenomena associated with drilling processes. Borehole conditions affect acoustic wave attenuation in a drillpipe. These conditions include characteristics of the borehole and casing, the deviation of the borehole, physical properties of the drilling mud, and the extent of contact between pipe and the borehole wall. In addition, attenuation depends on the characteristics of the drillstring including its mechanical properties, construction, and the type of mechanical connections between pipes. Any instantaneous variation in one or more of the properties changes the attenuation.

Non-Stationary noise typically results from a combination of processes occurring downhole including types of drill bits disintegrating the formation, weight on bit, type of formation, the RPM of the drillstring, contact between tubing and formation and casing, and type of mud motor used. In addition, surface equipment like mud pumps, rotary tables, or top drives generate significant noise. Normal rig operations and environment-related noise add to the overall noise.

The very basic telemetry system would comprise of a downhole transmitter to package and transmit data and a surface receiver to receive and decode the data. Any downhole transmitter could be damaged by shocks generated during the drilling process. However, an easy method of migrating drilling shock related damage is to position the transmitter as far away from the drill bit as possible. The preferred position for most other LWD sensors and tools is as close to the bit as possible in the BHA. Therefore, the downhole transmitter can be designed to be above all LWD tools. This concept results in a couple of advantages for the system. The noise generated at the bit would be attenuated and distorted by the LWD tools before it reached the transmitter. The transmitter would also be located at the top of the BHA and would therefore be connected directly to the drill collars, which are extremely good conveyers of acoustic signals.

Additional acoustic isolation from the drilling noise is obtained by positioning an acoustic attenuator between the drill bit and the transmitter. The attenuator is designed specifically to attenuate in-band noise in the acoustic telemetry frequency band of operation. This device

attenuates noise as it enters the communication channel. It also helps attenuate signals generated by the transmitter itself before they reflect from the drill bit and reenter the channel where they can cause inter-symbol interference. The transmitter interfaces with the MWD/LWD data bus to access tool information.

An optional repeater could be positioned between the downhole transmitter and the surface receiver. It would act as a signal booster to increase the depth of operation and the rate at which data would be transmitted. The repeater has similar design specifications to the downhole transmitter and functions similarly.

The drillstring could travel as much as 30-40 meters in one stand run. This variation could be completely avoided by fixing the receiver below the top drive or above the Kelly and below the swivel. This positioning of the transceiver enables the transceiver to move with the drillstring and lead to minimal interference with rig operations. The transceivers transfers, via a wireless link, digitized acoustic signals to a data processing and storage computer located in a safe area. The processing computer is used as a platform to interface with all components of the LAT system, to decode the acquired acoustic signals, and display, evaluate, and store this material as needed.

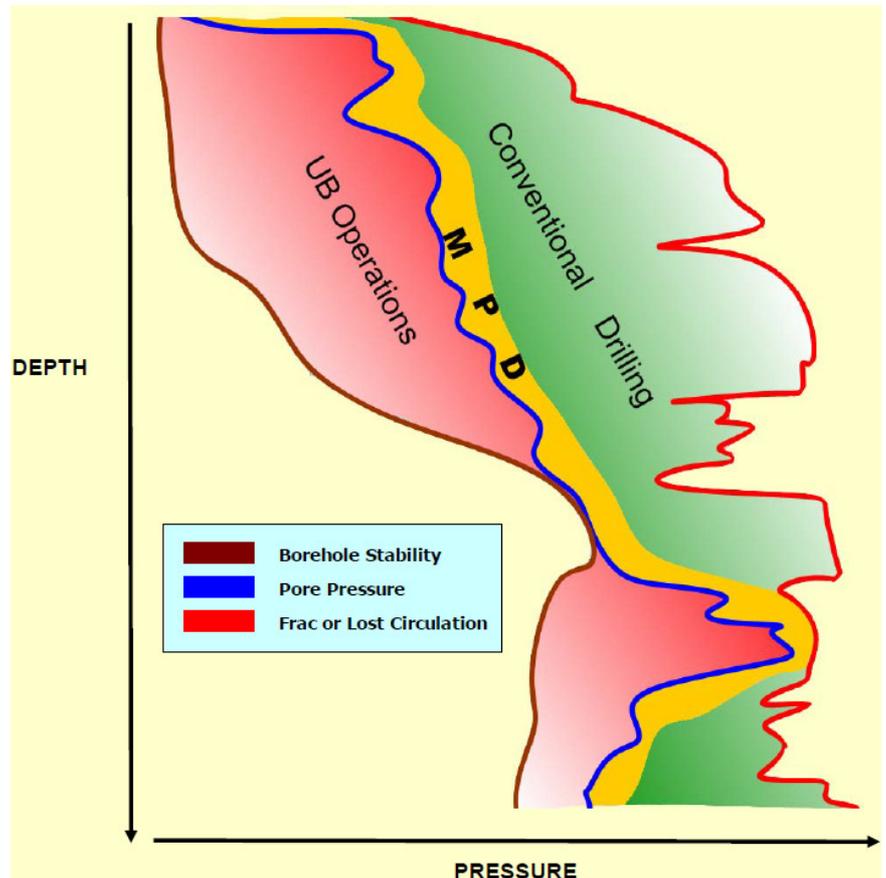
6 Drilling Processes and Automation

The pressure in the wellbore, the annular pressure, is a combination of the hydrostatic pressure of the fluid and cuttings in the well, as well as applied pressure from circulation or at surface.

Formations being drilled through contain fluid, such as water, oil or gas, which is being held within pores of the formation. The pressure the formation fluid is held within the pores is referred to as pore pressure. Fracture pressure is the pressure required to fracture the formation.

During drilling it is usually desirable to keep the annular pressure above the pore pressure and below the fracture pressure. As the drilling process gets more complicated, for instance in depleted reservoirs or deepwater wells, the margins between pore- and fracture pressure becomes smaller. Controlling the pressure profile, or the annular pressure, of the well, is therefore of great importance.

Automation is the introduction of control systems and information technology to reduce the physical and/or mental workload of human operators in charge of a running process. [23] It is a step beyond mechanization, which assists operators by replacing human power by mechanical. In the drilling industry, automation has been relatively low, but automation of various aspects of the drilling process such as ensuring mud properties, pipe handling, precise borehole pressure control (used for instance in Managed-Pressure-Drilling), and automation of the different drilling operations, such as tripping, directional drilling and pump start up, are now either commercially available or on the verge of becoming available.



Malloy et al. 2009

Figure 20: Drilling Windows for Conventional Drilling Operations, Managed Pressure Drilling Operations and Underbalanced Drilling Operations

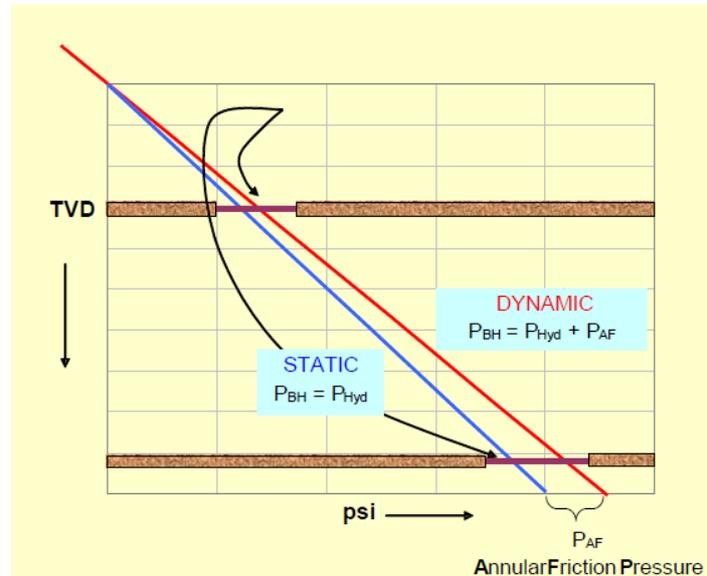
6.1 Drilling processes

There exist several different processes to drill a well, where management of the annular pressure profile mainly is the difference. A short introduction to the most common is presented in the following subchapters for reference.

6.1.1 Conventional Drilling

The conventional drilling circulation flow path begins in the mud pit, from where the drilling fluid is pumped down hole through the drillstring, through the drill bit and up the annulus. It exits the top of the wellbore which is open to the atmosphere and through a flowline to mud-gas separation and solids control equipment. When the gas and cuttings is removed, it is diverted back to the mud pit. [24] All this is done in an open vessel (wellbore and mud pit) that is open to the atmosphere. Drilling in an open vessel presents a number of difficulties.

Conventional wells are most often drilled overbalanced. Overbalance can be defined as the condition where the pressure exerted in the wellbore is greater than the pore pressure in any part of the exposed formations. Annular pressure management is primarily controlled by mud density and mud pump rates. In the static condition, bottomhole pressure (P_{BH}) is a function of the hydrostatic column's pressure (P_{Hyd}), where:



Malloy et al. 2009

Figure 21: Ideally, Static and Dynamic Pressure Are Within Formation Pressure and Fracture Pressure Window

In the dynamic condition, when the mud pumps are circulating the hole, P_{BH} is a function of P_{Hyd} and annular friction pressure (P_{AF}), where:

$$P_{Hyd} \geq P_{BH} \quad (6)$$

In the dynamic condition, when the mud pumps are circulating the hole, P_{BH} is a function of P_{Hyd} and annular friction pressure (P_{AF}), where:

$$P_{BH} = P_{Hyd} + P_{AF} \quad (7)$$

Because the vessel is open, increased flow-out, not pressure, from the wellbore is often an indicator of an imminent well control incident. If there is a suspicion that there are an influx of formation fluid into the well, circulation is stopped, and the flow out of the well is monitored. In that short span of time, a tiny influx has the potential to grow into a large volume kick. Pressures cannot be adequately monitored until the well is shut-in and becomes a closed vessel.

6.1.2 Underbalanced Drilling

In general terms, underbalanced drilling operations and techniques are primarily utilized to enhance reservoir productivity. [24] Underbalanced Drilling (UBD) is a drilling activity employing appropriate equipment and controls where the pressure exerted by the fluid in the wellbore is intentionally less than the pore pressure in any part of the exposed formations. The intent is to bring formation fluids to surface, where P_{Hyd} is less than P_{BH} .

In addition to improved rate of penetration, the chief objectives of underbalanced drilling are to protect, characterize, and preserve the reservoir while drilling so that well potential is not compromised. To accomplish this objective, influxes are encouraged. The influxes are allowed to traverse up the hole and are suitably controlled by surface containment devices.

With the capability to deploy a complete MWD/LWD toolstring into underbalanced drilling environments while maintaining full data transmission via wired-pipe telemetry, the application of UBD techniques to complex directional/horizontal wells can be expanded dramatically.

6.1.3 Managed Pressure Drilling

Managed Pressure Drilling (MPD) is an application driven technology designed to migrate drilling hazards such as lost circulation, stuck pipe, wellbore instability and well control incidents. To drill these problem wells, various techniques can be employed to manage the annular hydraulic pressure profile of the exposed wellbore. Proactive control of the equivalent mud weight within the drilling window tends to allow the option to set casing seats at depths greater than can be achieved conventionally through overbalanced drilling and reduces non-productive time.

MPD utilizes technology to drill with a planned and pre-described pressure profile using techniques and equipment beyond those available conventionally, while UBD is simply drilling below pore pressure intentionally. Where UBD typically seek formation influx into the well bore, MPD makes every attempt to avoid influx. Any flow incidental to MPD operations is to be contained using an appropriate process, in similar fashion to conventional drilling. Compared to conventional drilling practices, containment of influxes is generally better controlled with MPD due to advances in techniques associated with the equipment employed.

The vast majority of MPD is practiced while drilling in a closed vessel utilizing a Rotating Control Device with at least one drillstring Non-Return Valve, and a Drilling Choke Manifold. Manual controlled and microprocessor controlled chokes are available depending on the application. Presuming that the wellbore is capable of pressure containment by sealing the wellbore, pressure throughout the wellbore can be better monitored at the surface on real-time basis. In a closed system, changes in pressure are seen immediately. By more precisely controlling the annular wellbore profiles, detection of influxes and losses are virtually instantaneous. The safety of rig personnel and equipment during everyday drilling operations is enhanced.

In some challenging drilling environments wellbore stability pressures and pore pressure may be in very close proximity to one another. In some wells the lines will cross, where the pore pressure will be less than the well bore stability pressure. Under those conditions, precise control of the

annular pressure profile is critical to simultaneous well control and wellbore stability. In this application, UBD is not the application of choice because of overriding well stability concerns.

6.1.3.1 Reactive MPD

There are two basic approaches to utilizing MPD – Reactive and Proactive. Reactive MPD uses Managed Pressure Drilling methods and/or equipment as a contingency to mitigate drilling problems after they arise. The well is typically planned with conventional drilling methods and MPD equipment and procedures are activated only after unplanned event occur. This method is often described by the Health, Safety and Environmental (HSE) variation. Depending on the equipment, the operation becomes more and more proactive where control is more precise.

6.1.3.2 Proactive MPD

Proactive MPD uses Managed Pressure Drilling methods and/or equipment to actively and precisely control the annular pressure profile throughout the exposed wellbore. This approach utilizes the wide range of tools and techniques available to better control placement of casing seats, utilizing fewer casing strings, providing better control of mud density requirements and mud costs, and employ finer pressure control to provide more advanced warning of potential well control incidents. All of which lead to more time tending to drilling operations and less time spent in non-productive activities.

Many drilling problems can be directly attributed to poor hydraulic control; hence, manipulation of the wellbore pressure profile can diminish or eliminate chronic drilling problems. Virtually every variation of MPD involves manipulation and management of the entire pressure profile, particularly in the exposed wellbore. Listed below are many of the factors that affect downhole hydraulics. Used singularly or in combination they can be manipulated, managed, employed, and exploited to accomplish the objectives of managed pressure drilling to decrease non-productive time along with the hazards and the expenses that typically accompany that non-productive time.

- Wellbore Geometry
- Drilling Fluid Density
- Drilling Fluid Rheology
- Annular Backpressure
- Wellbore Strengthening
- Annular Friction Pressure

6.2 Automation

In general, process automation is motivated by a desire to increase economical and/or operational performance while making a process as safe as possible. [23] To realize the benefits with automation, the system must be carefully designed in order to ensure that the overall operation and economic issues are addressed. Rather than completely replacing humans, automation systems improve performance during normal operations, while allowing the operator to intervene to varying

decreases in case of abnormal events. An obvious requirement of automation is to ensure that it does not result in critical situations, detected or undetected, becoming worse than without the automatic system in place.

Attempting to directly automate every single aspect of a relatively complex process, such as drilling, is highly challenging, if at all possible.

Automation is a general term referring to a variety of automation strategies with different modes of human-machine interaction. In general the role of both the human operator and the automation system will be affected by the chosen mode of automation. The term “modes of automation” refers to different degrees of automation, which is a deciding factor in the work role of both the driller and the automation system. Today’s mode of automation in the drilling industry is low, but increasing. Higher modes of automation are likely to be developed as long as the development is motivated by the desire to improve both the efficiency and safety of the drilling operations.

6.2.1 Modes of automation

The role of both the driller and the automation system will be dependent on the chosen automation strategy. The level of automation can be divided into different modes. The mode does not need to be a permanently chosen mode; the driller should be able to move between different modes of automation during a single drilling operation. Even though a high mode of automation is used, the driller is still the absolute authority of the operation. This means that the driller must be given the means to override the automation system if necessary.

In the modes of automation concept the major change to the driller’s working environment happens when the automation level increases to “management by consent”. The driller will be supported by the automation system up to that level of automation, but from mode 4 and upwards the driller will be supporting the automation system. This is a major change, and the result will be that the driller is no longer directly operating the equipment at all. In general there are two categories of tasks left for an operator in an automated system. The driller may be expected to monitor that the automation systems performs and behaves as expected, and if not the drillers should manually take-over the system, or call for expert personnel to assist. In general it is impossible for the designer of the automation system to foresee all possibilities in a complex environment, and if the system fails, the driller must have the authority to manually take over the operation.

6.2.1.1 Mode 0:

“Direct manual control” mode. In this mode the driller will receive no support at all from the automation system; hence, it is the lowest degree of automation. The driller is presented with raw signal, and simple alarms associated with topside hardware.

6.2.1.2 *Mode 1:*

“Assisted manual control” mode. The significant contribution of the automation system in this mode is the introduction of software which analyzes the current situation of the well, and presents the information to the driller. This will improve the quality of the decision-making of the driller.

6.2.1.3 *Mode 2:*

“Shared control” mode. This is the first mode at which the automation system will start to directly interfere with the operation of the equipment. The main feature of this mode will be envelope protection. The philosophy of envelope protection systems are to not interfere as long as the conditions of the well are within a predefined range of acceptable values. If the system detects that the driller will violate these constraints, the system will limit the driller’s actions.

6.2.1.4 *Mode 3:*

“Management by delegation” mode. In this mode some of the drilling crew’s tasks are delegated to the automation system. This means that some of the tasks are fully automated by a closed-loop controller. Examples of automated modules are automatic pressure control in MPD operation using topside choke, fully automated tripping module, and pump start-up module. The main reason for introducing closed-loop control is to improve the overall performance of the automation system.

6.2.1.5 *Mode 4:*

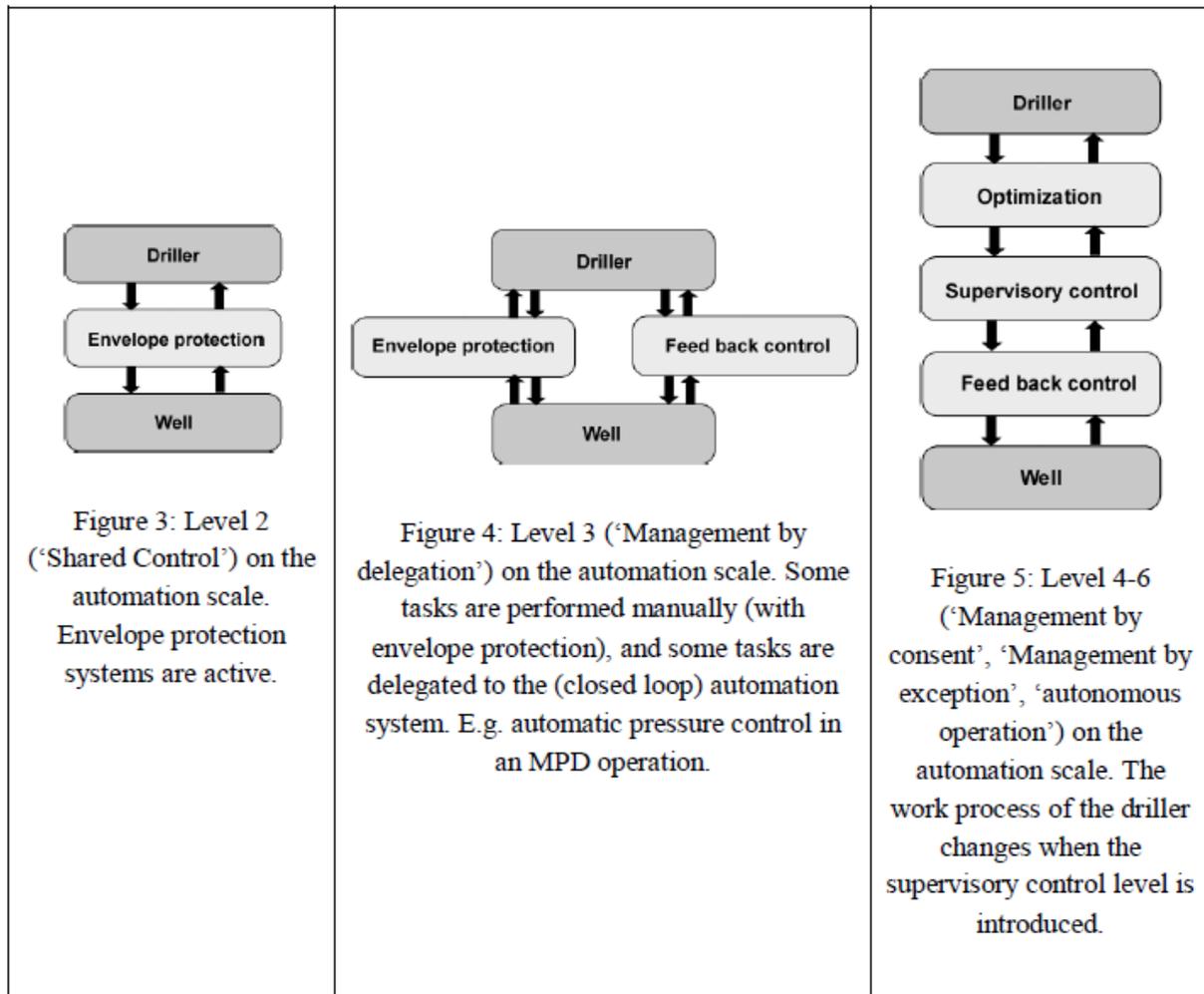
“Management by content” mode. This mode of automation introduces supervisory control, which is a technique of efficiently co-ordinate several closed-loop controllers. To achieve such a mode of control, models describing the well and how the closed-loop controllers behave and interact are needed. Introduction of supervisory control will be by nature result in auto-driller functionality. The driller will be operating the system by choosing operational modes (drill one stand, trip out on stand, make a connection, start circulating), and defining key variables as well.

6.2.1.6 *Mode 5:*

“Management by exception” mode. This mode of automation is separated from the previous by additional logic which determines the next operational mode. This mode should be considered to be an autonomous mode where the driller has the authority to interfere if the system does not behave as expected.

6.2.1.7 *Mode 6:*

“Autonomous operation” mode. In a fully autonomous system the human does not play a significant role, and the only remaining task is to monitor, or if it is necessary to reduce the chosen mode of automation in order to regain control of the system in abnormal situations.



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Figure 22: An illustration of the levels between the driller and the well/topside equipment when using automation level 2 through 6

6.2.2 Envelope protection

The basic idea of envelope protection system is to prevent the driller from damaging either the topside equipment or the well. An envelope protection system is a system which does not interfere as long as the driller does not try to exceed the boundaries of the envelope. The challenge associated with development of such a system is the continuous calculation of the boundaries of the envelope. These boundaries should be dynamically calculated based on the current state of the well, and known topside machine limitations (which are static boundaries).

An envelope protection system which takes the well conditions into consideration when calculating the boundaries has been successfully implemented. Limitations on pump acceleration, and pipe movement are calculated by analyzing the conditions of the well. One of the challenges associated with development of envelope protection is the requirement of a detailed model to estimate the current conditions of the well, and to predict the outcome of the driller's actions (new circulation rate, tripping velocity etc.).

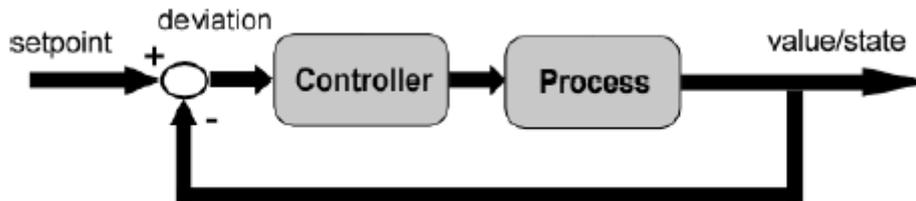
6.2.3 Sequential procedure

A sequential procedure is a preprogrammed sequence, and as an example it might be a calculated (non-optimal) velocity slope for tripping out a stand. [23] Such an approach could be considered too be open-loop. This implies that the response from the well when applying the sequence is ignored. As a result of not considering the well response in the logic, the safety margin for such approaches needs to be significant to ensure that the sequence does not in any way damage the well.

6.2.4 Closed-loop

Sequential approaches are implemented on rigs today. The assumption is that the closed-loop behavior approach is superior, but there is a lack of continuous high quality downhole data. Wired-pipe has been introduced as a solution to dramatically increase the rate, quality and amount of downhole data becoming available topside in real-time. If such a technology is not used, the downhole conditions needs to be calculated.

When moving up the automation ladder, closed-loop becomes essential. Closed-loop control is a well-known concept from control engineering, where the operator sets a desired value (set-point) on a state of the process. The closed-loop algorithm compares the measurement with the desired value, and uses the available input to compensate for the deviation. Hence, the full potential of closed-loop control will become apparent when continuous, high quality downhole measurements become available topside.



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Figure 23: Illustration of the closed loop control concept. The driller feeds the automation system with a set-point, and the closed loop algorithm compensates for the deviations from this set-point.

A feedback control system (closed-loop) will at all times try to compensate for undesired situations. [23] The operator will not necessarily detect such a situation. Therefore the automation system should always include additional logic to detect if the feedback system has started compensating for an undesired state in the well. For instance, if there is a sudden influx in the well during an MPD operation, the pressure in the well will during an initial phase increase until there is equilibrium between the pressure in the reservoir and the well. The response of a low-level automation will be to detect this as a deviation from the given set point and the measured value of this state. By nature the closed-loop algorithm will try to reduce the pressure in the well to compensate for this deviation by slightly opening the topside choke opening to reduce the pressure. If the driller is not observant and relies on the automation system it may take several minutes until the condition of the well is detected, and the control system will by probably by then have made the situation worse.

To fully utilize the higher levels of automation to improve the performance of the overall drilling operations, high quality reliable downhole data will be the key to allow the drilling operation to operate closer to the boundaries of the operation while taking safety issues into consideration. It is likely that if high quality downhole data through wired-pipe (or competitive technology) becomes available at a large number of wells/operations, the demand for closed-loop control will grow rapidly.

6.2.5 Challenges with automation

Monitoring of drilling operations is a task where a human may not excel routinely for long periods of time, unless non-optimal, abnormal or unwanted situations are indicated by an alarm system. [23] Diagnostic and warning systems (expert systems) have been proposed as an appropriate strategy to increase the performance of human operators who have a monitoring role. Expert systems are often designed to give the operator a warning/alarm when the system fails, but for some critical situations this may be too late. An efficient strategy should be to analyze the current situations and try to predict if a failure is likely to occur in the immediate future. The higher the level of automation is, the more crucial the communication about the automation systems mode and intentions become.

Unfortunately it is only after the automation system has misbehaved that the driller can detect its misbehavior. Since a manual take-over of the drilling process is likely to be motivated by an abnormal situation, and it requires both skill and experience to recognize both the reason for the abnormal situation and the correct counter-action to bring the well/system back to normal operational conditions. The time available to do both tasks are most likely limited. Detection systems and decision support systems may be of assistance, but in general the behavior of the driller will be based on experience. Drillers with experience from manual operations would most likely have a more intuitive understanding of when a manual take-over is needed. If a highly automated environment becomes the norm, then the manual skills of the drillers will most likely decline, and that may reduce the probability of the driller safely handling a manual take-over.

There are possible issues related to trust when discussing expert systems.[23] In general such systems have prevented several possible dangerous situations, but if these systems are extremely reliable, there is a possibility that the drilling crew will rely on them at all times, and when a rare failure occurs, the drilling crew may not detect the failure due to overreliance on the automation system. An opposite problem is expert systems which produce false alarms at a high frequency. In such case, the drilling crew is likely to mistrust the alarms, and in extreme cases ignore or even switch of the alarms completely. Sensor failures and sensors drifting may result in expert systems raising false alarms regarding downhole conditions.

6.2.6 Control algorithms and models

There are algorithms developed which represent a possibility to coordinate RPM, hook position, and circulation rate such that the WOB can be controlled, and an optimal ROP is achieved. WOB poses significant control challenges, but if it is controlled it can be kept closer to an optimum, and an optimal ROP can be obtained. [23]

6.2.6.1 Supervisory control

The main task of a supervisory control level is to coordinate all the low-level feedback controllers and calculate their set-points. [23] There are different control strategies for this level, one of them being known as Model Predictive Control (MPC). MPC is the only advanced control technique that has a significant and widespread impact on industrial processes control; hence the possibility should be there to introduce it in the drilling process as well. The main reason for its success are its ability to handle multivariable control problems naturally, take account of actuator limitations, and allow the process to operate closer to its constraints. MPC is a form of control in which the current control action is obtained by solving, at each sampling instant, a finite-horizon open-loop optimal control problem, using the current state of the plant as the initial state. The either linear or nonlinear models used in the MPC algorithm can be obtained through various methods, such as experimental step response models or mathematical models.

The MPC algorithm represents a possibility to coordinate the surface parameters to achieve an optimal ROP. If sufficient reliable downhole data are available, there is also a possibility to include these in the process.

The necessary inputs to the supervisory control level are constraints due to operational bounds and machine limitations. The machine limitations are most likely constant during the whole operation, but the constraints related to downhole conditions should be updated if new information becomes available. In addition to constraints, the set-points for the crucial variables have to be provided, such that the output variables, e.g. pressure, hook position, RPM, is brought to their desired values.

Information about the downhole conditions would be available even with slow sampled downhole data. Hence, the possibility would be there to update the MPC algorithm with this information. Including the limitations of the downhole toolstring as a part of the algorithm would be an efficient measure to avoid downhole tool failures. A more accurate visualization of the downhole parameters would be provided by a wired-pipe telemetry system, which again would result in a more accurate process control system. This would especially be a major advantage to try to avoid operating the downhole tools outside their limitations.

6.2.6.2 Hydraulic models

With the introduction of wired-pipe telemetry, more information from downhole to surface would be available. However, this does not replace the need for hydraulics models. [25] On the contrary, more measurements from the process will increase the range of applications for hydraulic models. There is a large potential of applying models for forward predictions related to e.g. well control, MPD and extended reach drilling. Also, models are needed to provide information on variables that are not being measured directly. Models may also replace sensors that drift or fall out and in general improve the methodologies of filtering measured data.

7 Integrating the MWD/LWD Service Into the Drilling Control System

During normal drilling practice and with the systems that are in place now, the MWD systems are not integrated into the drilling control system. The data from the MWD/LWD tools is received in the service companies' surface software system, and distributed from this to the monitoring computers rig site and onshore. The data then has to be processed and interpreted by the dedicated persons watching them, and real-time decisions have to be made from this.

The data format is raw data and it requires manual interpretation and action in order to use the data in controlling the drilling process. [3] Since the data is not fed into any drilling process control system, it is a manual, open-loop control. Using conventional mud-pulse telemetry, the time from when the actual downhole measurements were taken until the process parameters can be adjusted may be several minutes at best. Due to this, the use of drilling data in the time window where they have its highest value potential is limited.

7.1 Directional Drilling

Trying to fully automate such a complex process as directional drilling would be a hard task to overcome. Several uncertainties exist prior to drilling the well, and changes to the planned well trajectory could be necessary during the drilling process. Especially in the lower sections of the well, and when geosteering, the well path could be dependent on formation tops and reservoir properties. Also it would be impossible to predict the performance of the steering unit itself, and several adjustments to its steering parameters would be required as drilling commences.

Some advanced steering unit has the possibility to adjust some of the parameters internally. When drilling in tangent sections, the desired inclination could be programmed into the tool, and it would use an integrated inclination sensor to maintain this inclination. This function could also be used when building or dropping the angle of the well. The desired inclination is programmed into the tool, together with the force the tool should use to reach it. When it target inclination is reached, the tool is set-up to maintain this until told otherwise. However, this is just possible with the inclination, and the azimuthal direction of the well needs to be monitored and adjusted manually.

This feature of the steering unit controls the direction of the well in the same way as a control system would. Hence, it would serve no purpose to integrate this function into the drilling control system.

All the other parameters in the steering unit are changed by decisions from the directional driller. There should be no reason that an introduction of wired-pipe, which results in more downhole data and instantaneously communication with the downhole tool, would change that. Monitoring the wellpath and performance of the steering unit is done by highly trained directional drillers, which in turn advises the driller if any adjustments have to be done to the surface parameters. Introduction of any high mode of automation with respect to directional drilling therefore seems very unlikely.

7.1.1 LWD tools used for reservoir navigation

As mentioned will the formation properties measurements from the LWD logs determine if any change to the planned well trajectory are necessary, or at least confirm the formation prognosis. It could be thought that these measurements could be exploited more efficiently, and maybe integrated in some sort of drilling automation system.

However, due to the complexity of the LWD measurements and the nature of the measurement, data processing and control is needed on surface prior to using the data. [3] For instance, there is also an interpretation aspect to a resistivity image that still requires human interaction. Increasing the data density with the use of wired-pipe telemetry will not change the need for interpretation. The resistivity image data or other LWD data is therefore not feasible for direct input into drilling process control software.

In exploration wells there would not be much information available about the formations along the wellpath. Models generated by interpretation of seismic data could be the only information available of the properties and structure of the different formations. Hence, little is known about the formation and what to expect from the LWD measurements. This is not the case in highly explored fields, where several wells are drilled already. The response from the LWD tools would, in most instances, indicate the familiar formation boundaries and could even explain the location in a given formation. When this is the case, it could be possible to integrate the LWD measurements into a low mode of automation. For instance if the plan is to drill the well only into the top of the reservoir formation, the drilling control system could be programmed to stop drilling when the measurements indicates that the reservoir has been reached.

The usefulness of such a function integrated into the drilling control system would be limited. Drilling a well the conventional way, the geologist would, in cooperation with the MWD/LWD engineer, keep a close eye on these measurements throughout the drilling, notifying the driller to stop drilling when the target depth is reached. As already mentioned, a computer based system would not be able to interpret these data properly anyway.

7.2 Optimizing drilling parameters

Better utilization of the measured downhole drilling parameters would be possible if the amount of collected data increased, for instance by the use of wired-pipe. Deviations would be detected as early as possible, and measures taken to correct them. These measures could be integrated into a Drilling Control System.

It would probably also be possible to do this using slow sampled data from MPT or similar, but events like vibrations could have major impacts on the decoding performance. This could in some instances result in few, or none updates of the downhole parameters, and the efficiency of the measures will not be monitored. Nor would the automation system receive any new data for its calculations.

7.2.1 Vibrations

When severe levels of vibrations are measured, a reduction of these would be necessary. Flowcharts are developed with the actions to take in these instances. [26] These explain the different changes to the surface parameters that could be required depending on the type of vibrations experienced. Hence, the process of reduction or elimination of the vibrations could be automated by the drilling control system. Having continuous downhole updates would also ensure that the results of the changes is seen quickly, or if further measures need to be taken. Under some circumstances the vibrations caused by the drilling operations would have to be ignored, for instance due to high angle of the well or trying to break through rough formations. Even though a high mode of automation would be possible in most cases, the driller would require the option to change to a lower mode during these phases of the drilling operation.

7.2.2 Drilling performance

Integrating the downhole measurements into the drilling control system as an addition to the surface parameters would improve on the efficiency of the drilling performance. With the downhole WOB and torque values available, more information would be available about the forces at the bit. The impact of altering the surface parameters would become evident, and the correct measures could be taken to improve the drilling performance.

Measuring the bend of the string could also be an early indication on the development of high local doglegs. Depending on the drilling operation, it could be necessary to react on a sudden change in the bending moment as fast as possible. Algorithms could be developed to automatically detect and warn rig-site personnel when such an event is taking place.

7.3 Monitoring annular pressure

The Equivalent Circulation Density (ECD) is the gradient value calculated from the downhole pressure measurement and reflects the effective density exerted by a circulating fluid against the formation. [5] This value is monitored closely, and any significant change to its trend is reacted upon. It is expected that the ECD trend is increasing as the wellbore gets deeper, i.e. pressure increases, due to higher friction loss and more cuttings accumulate in the annulus. If the ECD value gets close to the calculated fracture gradient, measures will be implemented. This could be reduction of the flow-rate or hold back on the ROP to reduce the amount of generated cuttings. The deviations from the established trends usually takes place over a period of time, and the decision to which measure to make is often stated in the pre-well drilling program.

Any change that affects the drilling progress is not desirable and especially reduction of ROP has to be approved by the client. The approach could therefore be different from client to client, or even depending on their representative on the rig. For instance, if the ECD value is higher than desired due to accumulated cuttings, a reduction of ROP would be a possibility. Another approach would be to drill down the stand as fast as possible, and instead spend time circulating the hole clean in-between connections.

To improve the drilling progress, and reducing the time spent, integrating the MWD pressure measurements directly into a drilling control system could be a solution. If it is predetermined which approach to take if such an instance develop, suitable algorithms could be developed and coded into the automation software to adjust the drilling parameters as required. This feature would be possible in the highest modes of automation. It would most likely also be possible with slow sampled downhole data, since there is no need for continuous measurements, only a well-developed trend.

7.3.1 Well control

As mentioned earlier, most kill operations are conducted at flow rates below which the MWD tools are able to transmit mud-pulses. Hence, the use of downhole pressure gauges mounted in the BHA cannot be used. Having available continuous downhole pressure measurements, irrespective of the flow condition, via wired-pipe will enable checking validity of calculations, monitoring execution of the well control operation and ultimately reduce the uncertainty for safer, more precise and effective outcome.

However, any variation to established procedures must be carefully considered. Rig site personnel seldom have to perform kill operations, and an influx to the well will create a stressful situation among those involved. Hence, whichever well control method is adopted, it is important that documented procedures are fully understood and followed by the rig personnel to avoid gross errors. But the opportunity to enhance current practice using wired-pipe throughout the kill operation does exist.

7.4 MWD measurements integrated into a MPD control system

Managed-Pressure-Drilling with automatic control of the back-pressure choke was the first application where real-time downhole drilling data was used for direct closed-loop control of the downhole drilling process. [3] The emergence of this technology is likely due to the possibility to obtain real-time data of the downhole pressure by means of a hydraulic model calibrated against slow-sampled downhole data.

In an automated MPD system, the automation of the choke manifold is performed by a control system consisting of two main parts; a hydraulic model that predicts the downhole pressure in real-time, and a feedback control algorithm which automates the choke manifold to maintain the desired downhole pressure.

Thus, it would be possible to integrate the MWD measurements transmitted through Mud-Pulse Telemetry in an automated MPD process. If utilizing a wired-pipe telemetry system which would give frequent updates of the downhole parameters, integration of the real-time into a model could also be used to control the back-pressure in the MPD operation. To obtain a robust solution with the respect to possible failures in the drillstring telemetry, a real-time hydraulic model could estimate the downhole pressure every second for feedback to the surface back-pressure control system. Due to the higher data sampling due to the wired-pipe, the model could be calibrated against the downhole measurements every 2 seconds. This would ensure extremely high accuracy in the downhole pressure estimate at all times during normal drilling. However, if a kick is detected, the

control system should switch to using the high-speed telemetry pressures directly. The hydraulic model would have significantly reduced accuracy in case of high compressibility (two-phase) flow.

7.4.1 Optimizing the annular pressure

The combination of continuous annular pressure readings integrated in an automated MPD process could improve the well control in the entire drilling operation. As mentioned, it has already been successfully implemented in the drilling process.

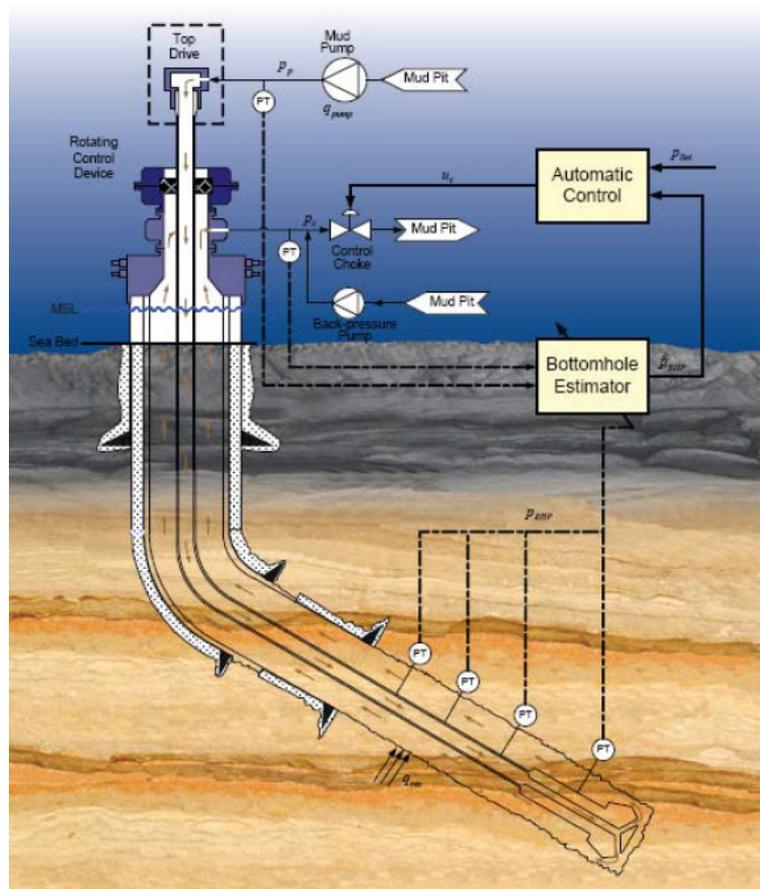
Another example of this application could be a tripping operation. During tripping, the pressure in the well will be affected by the movement of the pipe, and pressure fluctuations are induced. [23] The main primary goal of a tripping operation is to keep the annular pressure within its boundaries, while the second one would be to complete the tripping operation as fast as possible.

If a self-optimizing approach is used, the optimization level will calculate a constant semi-optimal set-point, and rely on the lower level feedback controllers to maintain the pressure at this level. A low-level feedback controllers will likely not prevent the annular pressure deviating from the set-point to some degree, a safety-margin is needed to prevent the pressure from exceeding the drilling window.

An optimized tripping operation could be achieved by the following example;

If a true optimal set-point is continuously calculated, an optimal pressure set-point curve could be calculated, which will allow the pressure set-point to be slightly increased while tripping out, and oppositely reduced while tripping in. Calculating these curves would allow for faster tripping without violating the pressure boundaries.

Optimizing the tripping operation in a conventional drilling process would also be possible using wired-pipe. The effect on the drilling control system would not be as complicated as for MPD, since it would only be the tripping speed of the surface operations that would affect the annular pressure, no back pressure would be applied at surface.



Hovda et al. 2008

Figure 24: Schematic diagram of an Automated MPD system utilizing distributed downhole sensors for real-time model calibration.

7.5 Surface sensors

The MWD service could consist in a variety of surface sensors to be able to detect and extract the signal from the downhole tools. These sensors are connected directly to the MWD software, and only used to ensure proper data retrieval. The rig provides its own measurements of the same surface parameters, with a secondary measurement performed by the mud-logging service company.

The set-up of surface sensors will depend on the telemetry method used. If wired-pipe telemetry is used, without running MPT as a contingency, the pressure sensors to detect the mud-pulses as well as the sensors used for noise cancelation would be redundant. In such an instance, only the radiation monitoring would be required at surface.

7.5.1 Radiation detector

The radiation monitoring is the only surface measurement that is only performed by the MWD engineer, and the action taken will depend on his reaction. The fact that this is a surface measurement increases the importance of a quick response. In a drilling situation, there are usually people in the logging unit at all times, which should react if the radiation alarm is triggered. But in a very unfortunate situation, this might not be the case. However, if something happens with the radioactive source installed in the LWD sub, the measurements would give no reasonable values. The time from when this happens until the contamination reaches surface, would be a while, of course dependent on the flow-rate and annular volume. It is very likely that someone recognizes the bad LWD measurements, since these data is being monitored by several people, both offshore and onshore. Hence, troubleshooting of the LWD toolstring would in the vast majority of cases already have commenced, and the engineer would be in the logging unit to react on the triggered alarm.

However, this is a measurement that it should be easy to connect to a drilling control system. The required response would be to shut off the pumps to further investigate the cause of the alarm. In the majority of operations, the main concern would be to limit the radiation contamination of the mud-system and the rig. Hence, the measurement could be integrating into the highest mode of automation.

8 Discussion & Conclusion

The discussion of the different aspects and features of the different technologies are done more thoroughly in its associated subchapters.

8.1 Telemetry methods

As mentioned several times, the vast majority of wells are drilled using mud-pulse telemetry. This technology has a proven record of its performance, and the indications are that this is going to be the preferred technology also in the future, both for Conventional and Managed Pressure Drilling processes. However, MPT would not be the preferred option in an Underbalanced Drilling Process, and techniques such as Electromagnetic Telemetry is used. The focus in this paper has been on mainly on MPT and Wired-pipe.

8.1.1 Mud-pulse telemetry vs. Wired-pipe telemetry

The wired-pipe telemetry performance is, in theory, without any doubt a better technique with regards to downhole communication. Hence, a question arises of why this technology is not being utilized more often.

8.1.1.1 Data-rates and noise interference

Using MPT, the raw data-rate (the symbol rate in the telemetry channel) and the effective data-rate (the raw data rate adjusted for data compression and transmission overhead), can be quite different. A comparison of data rates between MWD service companies will therefore be quite difficult due to the variations in between them. For instance, one company's 12 bit word transmitted at 12 bits per second may give the same data density on surface as another company's 6 bit word transmitted at 6 bit per second. Nor does a comparison of data-rate give any indication if competitor companies will have the same performance in decoding that data-rate. The ability to decode the data at surface will be of equal or higher importance. Data rates typically achieved with mud-pulse telemetry systems range from 3 to 40 bits per second. [1, 27]

In addition, the performance of MPT are affected by noise introduction by mud pumps, signal loss due to depth, fluid properties, and/or fluid flow rate since flow is required for transmission. Both signal noise and attenuation could cause decoding errors, which results in missing or misinterpreted measurements. The wired-pipe is not affected by any of these factors, and the data-rate is only determined by the spacing of the signal repeaters.

With wired-pipe the bottleneck in data acquisition would be in the surface processing equipment, or internally in the LWD tools. In MPT it would be the transmission rate or the data recovery. The internal sampling rate in LWD sensors could sometimes limit the data delivery rate, and in other instances the measurement principle is the limiting factor. [3] Some downhole measurements are based on a certain number of readings to get a statistical base to compute a value that in turn is transmitted to surface. Other downhole sensors are designed to only take readings often enough to transmit up values every 30 to 60 seconds. With wired-pipe, sensor redesign,

internal communication upgrades and software upgrades are required to remove many of these limitations and enable use of a larger part of the available bandwidth.

8.1.1.2 Monitoring annular pressure

Using wired-pipe to continuously measure the annular pressure would without any doubt increase the possibility of better real-time monitoring and well control, especially during flow-off events such as connections. However, during a connection procedure, the driller's attention would mainly be on adding the new stand of drillpipe to the string. Even more so using wired-pipe, due to the slightly more advanced connection procedures. Hence, to fully be able to benefit from these measurements, an automation system that would not require the driller's attention would have to be installed. This could then be updated with the real-time measurements, in contrary to using the single post-connection value provided with the survey using MPT.

It could also be worth mentioning that a good flow-off measurement would require static flow conditions in the well. In instances where the procedure is to perform the survey prior to connection, for instance due to poor hole condition, these measurements could be of no value. The usual procedure is to reduce the flow to a rate where the power module stops generating power, and increase it back up again to the required flow rate. Hence, some frictional pressure would be included to the annular pressure, which would give a higher measurement than the actual hydrostatic pressure in the well during the connections. Using these data to calculate the back-pressure during a MPD system would therefore also be wrong. The theoretical calculated back-pressure would be too little, which in the worst case could lead to a fluid influx into the well. It would therefore not be possible to include flow-off pressure from MPT into an automated MPD process in such instances. Using wired-pipe telemetry with continuous pressure monitoring would of course resolve that.

8.1.1.3 Well control

As mentioned several times, data transmission for telemetry systems such as MPT is only possible during fluid flow, meaning that the status of the downhole environment is unknown while pumps are off, or at reduced flow such as during a well kill operation. [19] The procedures to handle such well incident are developed to meet those conditions. Even though better monitoring of the annular pressures would be available with wired-pipe, a great amount of care should be taken changing the pattern of behavior. This are well established procedures, and even if the rig-crew have regular drills on how to perform them, they rarely, if ever, have executed the procedure in a real event. Recover the well barriers should in all instances be the main goal in the event of a well control operation; other concerns for the well should come in second line. More accessible downhole data could equally well increase the likelihood of making the operation more confusing or complicated, as to be an advantage for the driller.

8.1.1.4 Cost and reliability

To run a reliable wired-pipe service, some modifications have to be performed on the drilling equipment on the rig, and the rig-crew must get sufficient training handling the new equipment.

Hence, there is a cost related to changing technology. Also, while running the wired-pipe technology, the MPT system serves as a backup if the wired-pipe system malfunctions or fails. This redundancy ensures minimum data requirements are continually met and avoids NPT for equipment troubleshooting or repair. [27] Since the pulser can be an integrated part of the sub that generates power (e.g. Baker Hughes' BCPM) to the toolstring, the MPT system will be an integrated part of the MWD/LWD string.

Until wired-pipe can show to the same proven record of high reliability as MPT in a wide range of operating environments, it is very likely that the MWD/LWD toolstring will remain unchanged. However, if the wired-pipe is found to be reliable, future MWD/LWD tools could have very little embedded electronics. Commands and control could instead take place from surface computers via the network. This fundamental architecture change would enable significant reduction in tool cost and complexity, which would improve toolstring reliability and reducing the non-productive time associated with tool failures.

Running wired-pipe will also require a minimum of two dedicated field specialists on the rig. [15] On offshore rigs, especially on the smaller sub-submersibles and jack-up rigs, lack of bed space is a usual problem. Therefore, the trend is to try to remote control more of the drilling process from onshore control centers, to reduce the amount of people on the rig. This will however not be an important issue if the deployment of wired-pipe is proved to give a great advantage drilling new wells. However, until the technology gets a foothold, this concern will not speak to its advantage.

8.1.1.5 Cooperation between different service companies

The wired-pipe delivered by NOV is an open architecture which allows any MWD/LWD service company that manufactures an interface sub to connect to the networked drillpipe. The MWD/LWD toolstring is still provided by the same service company as before, functioning the same way. Hence, no combination of different MWD/LWD tools from different providers would be possible in the wired-pipe set-up either.

In some rare instances, different service companies have their tools in the same BHA. This could be done to compare the measurements provided by the two different MWD/LWD companies. When this is done using MPT, one of the service companies have to run their tool in silent mode, i.e. measuring the data and saving them to the memory, not transmitting data to surface. It would not be possible to use two mud-pulsers in the same mud channel, since they would just disturb each other's signal.

This option is not possible with wired-pipe. The tool run in silent mode would have to be placed outside the other service company's toolstring, i.e. above the interface sub. As mentioned earlier, all the components above the interface sub must be wired, something an MWD/LWD tool is not. An alternation to allow this could be possible, but not very likely.

8.2 Integration into a Drilling Control System

The problem with integration the MWD/LWD measurements into a drilling control system would be that the likelihood of retrieving bad values due to poor decoding is too large. Poorly

decoded measurements would give false measurements, which would trigger false alarms from the control system. If then a true alarm is raised, the probability of the drilling crew trusting the alarm system decreases with the number of false alarms they have experienced. If the amount of reliable downhole data was increased, for instance by wired-pipe telemetry, the integration process would be simpler.

Another important issue in monitoring is the communication between the automation system and the driller. It is important that the state of the automation system is communicated to the driller. The driller needs to be informed about the systems intentions in order to understand its behavior. In order to further improve the quality of the automation system its behavior should be predictable. If both the mode/state of the system and its future actions (prediction) are communicated to the driller it will prevent the driller from misunderstanding whether a critical situation has been detected, and if it is being handled or not. To ensure that the quality of the expert system is high, the driller needs to monitor the data which are sent to the system. As the level of automation increases, there is a risk that the automation process could cause a degradation of the rig-crews experience with the drilling process.

The involvement of several different companies, with different technologies, is necessary to integrate the downhole measurements into drilling control system. The drilling control system would in most instances be the responsibility of the drilling contractor, while the downhole measurements would be provided from the MWD service company. If wired-pipe telemetry is used, this would also involve another company to provide the wired-pipe components and surface system. Hence, there would be a lot of different software's and systems that have to interact. The input of data to the control system could be through WITSML or rig-specific data communication software. This will by all means not be impossible, but will complicate the drilling process. Clear guidelines must be in place for this to operate in a safe manner.

However, the advantages would be major if integration was achieved. Algorithms which for instance automatically detect when a kick, loss, pack off or differential sticking event take place could be developed. If a proper process control system is developed, for instance using a MPC controller, better control of the drilling process would be achieved. It would give the possibility adjust the surface parameters and verify that it has the desired effect on the downhole drilling parameters. This way the drilling process would be optimized and damage on surface equipment and downhole tools would be avoided.

A further exploitation of automation during a MPD processes, for better control of the annular pressure, would be a large improvement to the safety of the drilling operations and probably lead to a reduction of time and cost induced by drilling a well.

8.3 Relations to health, safety and environment

Safety is always the primary goal of any drilling operation and this will always remain the case. The high-speed wired-pipe provides the opportunity to enhance the safety of operations from a number of perspectives. The significance of this will increase as drilling activity progresses into ever more challenging environments.

8.3.1 Downhole Annular and Formation Pressure Monitoring

One of the primary benefits with wired-pipe is the opportunity to increase the safety of drilling operations. The ability to continuously transmit data at high-speed (interrupted only while making drillstring connections), completely independent of drilling fluid properties and circulation rate, allows monitoring of a wide array of well status information.

The most immediate safety benefit is via monitoring of downhole annular pressure from sensors already available within most MWD systems. Earlier kick detection and more precisely controlled bleed-off procedures will deliver a higher degree of certainty in preventing escalation of well control incidents as well as improving drilling efficiencies. Similarly, the ability to monitor downhole swab and surge pressure while tripping will simultaneously optimize tripping speed for enhanced safety and efficiency.

8.3.2 Reducing manual handling

Over the years the amount of manual handling on rigfloor has been severely reduced. This has been a major enhancement to the safety. However, building the MWD/LWD toolstring still require quite a lot of manual handling due to the complexity of the connections. Any automation of this operation is not very likely. The MWD engineer must still verify that all the connections are made-up properly, and that there is no contamination on the internal communication line used by the tools.

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